

**336**

**CHANGING NETWORK CONDITIONS  
AND  
SYSTEM REQUIREMENTS**

Part II

The impact of long distance transmission on HV equipment

**Working Group  
A3.13**

**December 2007**



# **WG A3.13**

## **Changing Network Conditions and System Requirements**

### **Part II**

## **The impact of long distance transmission on HV equipment**

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## PREAMBLE

Networks are changing due to business drivers such as environmental concerns (including reduced dependence on fossil energy sources), competitive power markets, further utilisation of transmission corridors, multi-directional power-flows in distribution networks, increased capacity needs, consumers' demands for higher power quality, increased efficiency requirements, etc. These developments have led to technology changes (e.g. distributed generation, wind-farms, compensated lines, phase shifters, filter-banks, non-linear loads, HVDC, FACTS, advanced protection, control and automation systems) and consequentially to special requirements for HV equipment, for instance with respect to harmonics, temporary overvoltages (TOV), transient recovery voltages (TRV), out-of-phase conditions, power quality, etc.

CIGRÉ WG A3.13 “Changing Network Conditions and System Requirements” has given special attention to the consequences of the growth in distributed generation (co-generation plants as well as sustainable power generation) and to the consequences of long distance transmission (from remote generating stations to load areas and multiple power transfers between regions and nations), leading to angular and voltage stability problems and the need for reactive power compensation. In both cases the interaction between protection and control systems on one hand and the network dynamics on the other hand will play a dominant role in the severity and probability of the phenomena that have to be withstood by the applied HV-equipment. These phenomena have to be considered against a background of increased utilisation of equipment (in terms of age, loading and voltage stresses), of reduction of size and increase of complexity, of the incorporation of more intelligence and the application of more over-voltage protection and smart devices. Methods of condition and utilisation assessment of power system components with regard to asset management become progressively applicable.

As the two main topics – the impact of distributed generation & the impact of long distance transmission – address different expertise in the power industry, WG A3.13 has chosen to issue two Technical Brochures. This Technical Brochure, Part II, is on the impact of long distance transmission on the specifications for HV-equipment. In the other Technical Brochure, Part I, the impact of distributed generation is dealt with.

Other developments have been mentioned in a SC A3 internal working document [40], but the investigations on the impact of these developments on the specifications of HV equipment are either treated by other working groups or seen as covered in another way. These developments are:

- The generation of harmonics due to the wide introduction of power electronics and the design of filter banks, including switching of filter banks (will be addressed in both WG A3.13 Technical Brochures)
- Very high frequency phenomena, related to vacuum CBs (NSDD: non- sustained disruptive discharges, dealt with by IEC SC 17A) and GIS-disconnectors (in relation to transformers, dealt with by CIGRÉ JWG A2/A3/B3.21 and IEEE PC57.142 working groups [41])
- Very steep RRRV (rate of rise of recovery voltage) phenomena, for medium voltage: transformer fed faults, reactor limited faults and short-line faults (presently covered by amendment 2 to IEC 62271-100, June 2006); and for high voltage: 3-phase short line faults and long line faults (studied by WG A3.19) [85]
- Special conditions of high frequencies and/or saturation in relation to the behaviour of instrument transformers (to be investigated by WG A3.15)

- Very special phenomena, like the TRV (transient recovery voltage) under severe conditions of clearing inrush currents (are regarded as so unique that for the moment no further investigations by CIGRÉ are required).

A summary of the findings, recommendations and conclusions of CIGRÉ WG A3.13's studies is given in Appendix C, i.e. a Report presented at the SC A3 Colloquium 2007 in Rio de Janeiro. Other publications of WG A3.13 are presented in the Appendices D, E and F, where general items, specific items for long distance transmission and items related with out-of-phase and synchronizing are treated, respectively.

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#### **C. *Changing Network Conditions and System requirements Studies performed by CIGRÉ WG A3.13***

CIGRÉ SC A3 Colloquium 2007, Rio de Janeiro, Report PS2-01 [89]

#### **D. *Changing Network Conditions and System Requirements***

IEEE/CIGRÉ Int. Conf. on Future Power Systems 2005, Amsterdam [2]

#### **E. *Long Distance AC Power Transmission and Shunt/Series Compensation Overview and Experiences***

CIGRÉ SC A3 Session 2006, Report A3-206 [33]

- F.** *Dielectric, Switching and System Requirements under Out-of-Phase Conditions, during Synchronisation and under Comparable Stresses* [68]  
CIGRÉ SC C4/A1/A2/A3/C1 Symposium, Zagreb, 2007  
Transient Phenomena in Large Electric Power Systems, Report 0701

## ACRONYMS AND ABBREVIATIONS

ACSR	aluminium conductor steel re-inforced
ATP-EMTP	Alternative Transient Program - Electro-Magnetic Transients Program
ATR	auto-transformer
CB	circuit-breaker
CT	current transformer
DG	dispersed generation or distributed generation
EHV	extra high voltage
EXB	expanded bundle (conductors)
FACTS	flexible AC transmission system
FFO	fast front overvoltage
FPCF	first-pole-to-clear factor
FSC	fixed series capacitor
GIS	gas insulated station
HSGS	high-speed grounding switch
HSIL	high surge impedance loading (line)
HPP	hydro electric power plant
HSR	high speed auto-reclosing
HV	high voltage
HWLL	half-wave length line
IPP	independent power producer
LIPL	lightning impulse protection level
LIWV	lightning impulse withstand voltage
LLF	long line fault
MCOV	maximum continuous operating voltage
MOSA	metal-oxide surge arrester
MOV	metal-oxide varistor
OHL	overhead-line (OH-line)
OLTC	on-load tap-changer
OPGW	optical ground wire
PIR	pre-insertion resistor (closing resistor)
PLC	power line carrier
PST	phase shifting transformer
PT	potential transformer
ROW	right-of-way
RRRV	rate of rise of transient recovery voltage (TRV) or steepness of TRV
RV	power frequency component of recovery voltage
SA	surge arrester
SC	series capacitor
SCADA	supervisory control and data acquisition (system)
SFO	slow front overvoltage
SIL	surge impedance loading
SIPL	switching impulse protection level
SIWV	switching impulse withstand voltage
SLF	short line fault
SPAR	single phase auto-reclosing
SPS	special protection system
SR	shunt reactor
SSR	sub-synchronous resonance

SVC	static var compensator
TCSC	thyristor controlled series capacitor
TCR	thyristor controlled reactor
TNA	transient network analyser
TOV	temporary overvoltage
TPHSR	three-pole high speed auto-reclosing
TPP	thermoelectric power plant
TRV	transient recovery voltage
TSC	thyristor switched capacitor
TSO	transmission system operator
TWVO-SR	tapped winding variable Mvar output shunt reactor
UHV	ultra-high voltage
VT	voltage transformer
WAMS	wide area monitoring system
XLPE	cross-linked polyethylene

## 1. INTRODUCTION

The privatisation and liberalization of the electric energy sector has considerably increased interregional and international energy transactions and created a greater need for large power transfers over long distances. In the meshed EHV grids, in particular in Europe and North America, long distance power wheeling takes place with a technique referred to as “multiple power transfers”. It is in some cases used up to its capability limits and relies upon the synchronous generators of the power plants in operation along the transmission route to maintain angular and voltage stability. Multiple power transfers may take place across various countries/regions on distances spanning up to 2000km from the power export areas to the remote importing areas.

Unbundling and liberalization of the electric energy industry has also caused a more intensive use of some of the point-to-point long EHVAC and EHVDC transmission systems, raising power transfers to the upper limit of transmission capabilities, in some cases to the detriment of transmission reliability (violation of the (N-1) or (N-2) security requirement). The use of line/systems up to, and sometimes above their secure transmission capacity, has been the root cause of some recent major blackouts in industrialized countries.

More use and reliance on transmission has been caused by the liberalization of power generation and by the growing environmental restrictions for the construction of new power plants. In several cases the independent power producers (IPPs) have located their new thermoelectric power plants, which are fired with imported fossil fuels (gas, coal, fuel oil), in places remote from the loads to be served, or far from optimal transmission locations. In a few countries, the construction of large wind farms has also required transmission over relatively long distances and the need to provide new transmission and generation reserve capacities in order to deal with the volatile generation patterns inherent with the operation of large wind farms.

The higher power transfers have increased the stresses on transmission components, which in critical regions are required to continuously operate at the maximum permitted voltages and/or currents, and sometimes above these limits. This may cause, in particular, stresses on EHV circuit breakers (CBs) which exceed the values stipulated by the IEC Standards for overvoltages, arcing conditions and TRVs.

In spite of the installation of phase shifting transformers and/or series capacitor banks for controlling the power flow in critical transmission lines, many interconnection lines are loaded very close to their thermal limits for normal operation and overloaded in emergency conditions. In order to utilize the temporary overloading capacity of transmission line conductors (allowed in many cases for 15 to 60 minutes before reaching a limiting temperature) overload protection based on the monitoring of conductor temperature is recommended, to replace the standard overload protection by distance and overcurrent relays, which trip too fast (0.5 s to some s).

On the other hand, the increase of power transfers over long distances on existing transmission lines cannot be accompanied by the erosion of transmission reliability which might result. In fact, the increased automation of industry and higher continuity of supply required by the tertiary sector, by electric driven transports and by the domestic and commercial sectors, demand an improvement of power quality, i.e. limitation of number and duration of supply interruptions, reduction of number of voltage dips, improved voltage regulation, limitation of harmonic distortion and of voltage asymmetry in 3-phase supplies. Upper limits to these quality indexes have been stipulated by the Regulators in various countries, including also penalties to be paid to the customers in case of violation.

To address the changing transmission network conditions, multiple actions are required, including technological improvement and reduction of failure rates of high voltage equipment, use of new components (FACTS), improvement of monitoring, automatic control and protection systems, use of Wide Area Monitoring Systems (WAMS) and of Special Protection Systems (SPSs), efficient maintenance, etc.

The economically exploitable hydroelectric resources and lignite fields have been fully utilized in many countries with electric power transmission over distances up to 1000km and, in some cases, with EHVAC series-shunt compensated lines and EHVDC transmission lines spanning distances up to about 1500km and 1800km, respectively. The ever increasing cost of economically transportable fossil fuels (gas, oil, high quality coal) and the restrictions on use of nuclear power will in future make the bulk electricity transmission over longer distances from large economical hydroelectric and lignite resources more attractive. Pre-feasibility studies of some very long distance (up to 3200km) transmission projects have been performed in the last decade. Some typical examples that can be mentioned are:

- (i) From Inga Falls (Republic of Congo) to South Africa (~ 3000km).
- (ii) From Inga Falls to Nigeria (1550km) extended with multiple transfers to Western Africa (up to 2500km).
- (iii) From the Amazon River Basin to South-Eastern Brazil (~ 2500km).
- (iv) From Central Siberia to Russia (~ 3000km; 4 independent projects on different routes)
- (v) From Western Siberia to Central Europe (~ 3200km); from Central Siberia to China (~ 2700km).
- (vi) From Eastern Siberia to South Korea (~ 2500km).

The technologies considered for these prospective projects are the following:

- EHV–UHV Half Wave Length AC transmission (naturally tuned on distance of 3000km at 50Hz and of 2500km at 60Hz): projects (iv) at 50Hz; AC transmission alternatives for projects (i) and (v) at 50Hz and for projects (iii) and (vi) at 60Hz.
- EHV-UHV DC transmission, a technology that has no specific distance limits. DC transmission alternatives for projects (i), (iii) and (vi).
- EHVAC transmission lines compensated with series capacitors (SCs) and shunt reactors (SRs). Project (ii) at 50Hz.

The technically acceptable upper limit of compensation with SCs is considered to be 75% for lines transmitting power from remote hydroelectric power plants. Assuming these lines are loaded at their surge impedance loading (SIL), the upper limit of point-to-point transmission distance with series-shunt compensated lines is 1800 to 2000km at 50Hz.

In many developed countries utilities not only face problems finding routes for new OH-lines but in maintaining existing rights-of-way. The extension and uprating of the transmission capacity is therefore very difficult and utilities are forced to look at ways of operating their plants harder.

Congestion of infrastructures and strong demand for environmental conservation may justify the use of long stretches of EHVAC cross-linked polyethylene (XLPE) insulated underground cables, which require a large shunt compensation. These cable stretches may be solidly connected to overhead lines, to form mixed cable-overhead lines, whose design and operation have special technical features.

## 2. CONTINUOUS OPERATION AT VOLTAGES EXCEEDING STANDARD RECOMMENDED VALUES

### 2.1 Introduction

It has been recently reported [23] that in Japan 600 km long-500kV transmission lines carrying power from a remote generating station to load centers, are planned to be operated at 600kV at the sending end, i.e. about 10% above the maximum continuous operation voltage of 550 stipulated by the IEC Standard 60038.

Present transmission constraints might lead other utilities to consider this way of boosting line power carrying capacity. It is therefore worthwhile to review the beneficial and negative effects of operating at voltages higher than specified in the IEC Standards.

### 2.2 Beneficial effects

- For an assigned power to be transmitted, the increase of operation voltage allows a corresponding decrease of current. Power transmissible at the thermal limit of line conductors increases in proportion to voltage.
- Surge impedance loading of transmission lines,  $V^2/Z_0$  ( $Z_0$  = surge impedance), increases proportionally to square of operation voltage.
- In long distance transmission, where the controlling phenomenon is angular stability, the increase of voltage raises the limit transmissible power proportionally to the square of operation voltage.
- For an assigned transmitted power, Joule losses are reduced, not less than proportionally to  $(V_N/V_{s,M})^2$ , where  $V_N$  and  $V_{s,M}$  are the rated voltage and the higher sending end proposed operating voltage, exceeding the maximum value recommended by the Standards, respectively.
- Voltage drops in the lines and transformers, expressed in pu, are also reduced, generally more than proportionally to  $(V_N/V_{s,M})^2$  for an assigned transmitted power. Reduction of voltage drop markedly depends on line loading and power factor at receiving end: a voltage increase at sending end of 10% may result in a voltage drop reduction by 50%.
- The charging power generated by line and cable capacitances increases proportionally to square of voltage; the reactive power consumed in the series reactances of lines and transformers decreases proportionally to square of current i.e. about proportionally to  $(V_N/V_{s,M})^2$ . Mvar balance of network is significantly improved during operation at high load demand of the system.
- The magnetic field under the lines, is somewhat reduced, proportionally to current i.e. proportionally to  $V_N/V_{s,M}$  for an assigned transmitted power.

## 2.3 Negative effects

- Power transformers and generators, if not specified for operation at the desired higher voltage, are overfluxed, resulting in large increase of magnetizing current, of iron loss, of sound noise. If flux density in transformers cores exceeds about 1.95 Tesla, saturation occurs and these effects become unacceptable.
- In transmission lines with conductors designed at the upper limit of corona (say. with an average electric field on conductor surfaces of 16-17kVrms/cm at maximum operation voltage allowed by the IEC Standards), corona losses, RI and audible noise will increase and may create problems. Calculations and checks are therefore necessary for each specific line design.
- SRs are generally designed for continuous operation at the maximum voltage specified by the IEC Standards (f.i.  $V_M = 420\text{kV}$  for  $V_N = 380\text{kV}$ ;  $V_M = 525\text{kV}$  or  $550\text{kV}$  for  $V_N = 500\text{kV}$ ). The fact that loading of SRs depends on operation voltage should not be overlooked. If voltage exceeds  $V_M$ , the current increases in proportion to voltage, causing a Joule loss increase more than proportional to the square of voltage increase (due to winding temperature increase). The iron losses in magnetic core also increase due to flux density increase. Unless SRs are specified for operation at the higher desired voltage, overheating may become unacceptable. Absorbed Mvars by SRs increase with the square of voltage. SRs are subject to mechanical vibrations, which of course increase with the operation voltage and increase the life expenditure. In conclusion, SRs must be specified, designed and factory tested for the highest planned continuous operation voltage.
- Metal oxide varistor surge arresters (MOSAs) must be operated at a voltage not exceeding their maximum continuous operation voltage (MCOV), preferably with some margin, to avoid an excessive leakage current flow and risk of thermal run away (instability) and destruction. MOSAs should therefore be replaced or up-rated if the MCOV is exceeded. Impact of the increased rated voltage of MOSA's on the insulation co-ordination is reviewed in the next paragraph.
- An increase of operation voltage causes in general an increase of the temporary overvoltages and of transient (switching) overvoltages. This increase is proportional to the operation voltage increase if phenomena are controlled by linear components. Of course the operation voltage increase not accompanied by an increase of insulation or reduction of pu overvoltages, causes an erosion of the insulation margins and an increase of the risk of flashover. Effects of continuous increase of operation voltage should be dealt with separately for HV equipment protected or non protected by MOSAs, as follows:
  - i) Equipment protected with a determinist approach by MOSAs, in particular the electrical machines of substations and generating stations: the operation voltage increase may require a proportional increase of MCOV and of rated voltage of MOSAs, which brings along the proportional increase of the switching impulse protection level (SIPL) and lightning impulse protection level (LIPL).

If the margins between the switching impulse withstand voltage (SIWV) and lightning impulse withstand voltage (LIWV) of equipment and the SIPL and LIPL of MOSAs, respectively, do not remain adequate, the risk of equipment failure is increased.

The IEC Standards 60694 – “Common specifications for High-Voltage switchgear and controlgear” [35], and IEC Standard 60076-3 “Power Transformers – Part 3-Insulation

levels, dielectric tests and external clearances in air” [42], generally recommend two (IEC 60694) or even three (IEC 60076-3) sets of insulation levels (i.e. of 60” power frequency, SIWV and LIWV) for each rated voltage  $\geq 100\text{kV}$ . The higher recommended insulation levels allow for raising the operation voltage somewhat above the maximum recommended IEC values without any important increase of failure rates. Of course the higher IEC specified withstand voltages provide the highest margin of safety.

- ii) Insulation systems not protected by MOSAs, as are usually the self-restoring insulations of OH transmission lines: the specified short time power frequency withstand voltage and 50% SIWV have margins above the expected temporary overvoltages and switching overvoltages, determined such as to render very low the risk of flashovers in operation. Usually the insulation coordination of the self-restoring insulations of EHV lines is based on a probabilistic approach. This shows that an increase of the switching overvoltages amplitude by 10% as may be caused by a 10% increase of operation voltage, causes the increase of risk of flashovers of equipment not protected by MOSAs by an order of magnitude (for instance, from  $10^{-4}$  to  $10^{-3}$ ).
- If external insulation is exposed to pollution, it is necessary to check that the increase of operation voltage does not cause a higher risk of flashover and, where necessary, apply corrective measures.
- With regards to CBs, disconnecting switches, instrument transformers, support insulators, etc., the increase of operation voltage can affect in varying degrees the insulation performance. In particular, as discussed in a previous paragraph, the risk of flashover may increase if relatively low equipment insulation levels have been specified for the rated voltage of interest. Similar considerations apply for the TRVs on CBs, because the increase of operation voltage causes in general an increase of the TRVs.
- It should be kept in mind that the performance guarantee of equipment specified and tested according to the IEC Standards is only warranted if the equipment operation voltage does not exceed the maximum values stipulated by the Standards for each rated voltage.
- The electric field under the lines increases proportionally to operation voltage. However, nowadays environmental restrictions in the permits for a right-of-way are stricter for the magnetic field strength, that is reduced proportional to the current, than to the electric field strength.

In summary, the WG is of the opinion that the continuous operation voltage should remain within the maximum values stipulated by the IEC Standards. In case these values are exceeded in order to utilize the benefits reviewed in section 2.2, and the transmission system is to be newly built, precautions should be adopted in the specification of equipment in order to avoid the above mentioned inconveniences. If the system is in existence, some equipment may have to be replaced/up-rated or an increase of risk of failure may have to be accepted.

## 2.4 Operating practices

Distinction has to be made between the un-intended, short-term operation above the maximum operating voltage for equipment and the intentional increase in operating voltage to maximise system utilization. The un-intended, short-term, operation forces system operators to quickly

take actions to reduce the voltage to values within the rated bandwidth (i.e. below the maximum operating voltage for equipment). IEC specifies the maximum operating voltage for equipment equal to the rated operating voltage. North-American practice however, requires equipment to be able to be operated 10% above the rated voltage (IEEE/ANSI).

Utilities that uprate the operating voltage, will increase the voltage especially during periods of high load, thereby resulting in too high operating voltages during periods of low load. Nowadays many utilities have no control anymore of the reactive power output and voltage regulation of the large generators. Furthermore the systems have become very complicated, especially at low load when a system with many cable lines is behaving capacitive, and the overall voltage profile is difficult to keep under control if switchable or variable SRs are not available.

Most of the utilities are not too concerned about the switchgear, although high operating voltages lead to consequences with respect to TRVs and transient overvoltages, which are proportional to the operating voltage. More attention is paid to risk of saturation of transformer and generator magnetic cores, electrical clearances, safety issues, audible noise, excitation losses in transformers, increased magnetizing currents, reduced loading capability in terms of current for transformers, reduced margin to the MCOV of MOSA, etc.

Many countries in Europe will not intentionally operate their EHV networks above IEC rated voltage, although there is a clear trend to raise the average target voltage. For instance, the 380 kV UCTE grids are generally operated at about 400 kV. In the past a margin of 10% was available before reaching 420 kV, whilst nowadays the margin has decreased to 5%, which under certain circumstances may be too small. In North-America, some utilities will keep the operating voltage under, for instance, 550 kV with an average target of 500 kV and 10% margin. But at lower voltage levels, more utilities will apply operating voltages up to 110% of the rated voltage, even when these voltages are higher than the IEC rated voltage. In some utilities the operating voltage in parts of the 500 kV-network exceed 550 kV for more than 10% of the time, while parts of their 230 kV-network exceed 245 kV more than three-quarter of the time. In Japan one utility has planned operating parts of the 550 kV-network up to 600 kV by carefully exploring the margins they still have in parameters like the FPCF, ratio  $C_0/C_1$ , etc. [23].

In conclusion it can be stated that utilities all over the world are looking for means to utilize their networks further. Increasing the operating voltage is one of the possibilities employed at the cost of smaller margins to the rated or maximum operating voltage. The risk of exceeding the maximum operating voltage for equipment has increased, but so far utilities exceed the maximum rated voltage by exception (emergency situations). Only a few utilities intentionally operate parts of their systems above the equipment's maximum operating voltage for substantial periods of the time.

### 3. TEMPORARY OVERVOLTAGES (TOV)

In general, TOV in an AC power transmission system can originate from earth faults, switching operation such as load rejection, no-load operation of long lines, overspeed of generators, resonance, ferroresonance conditions or a combination of these.

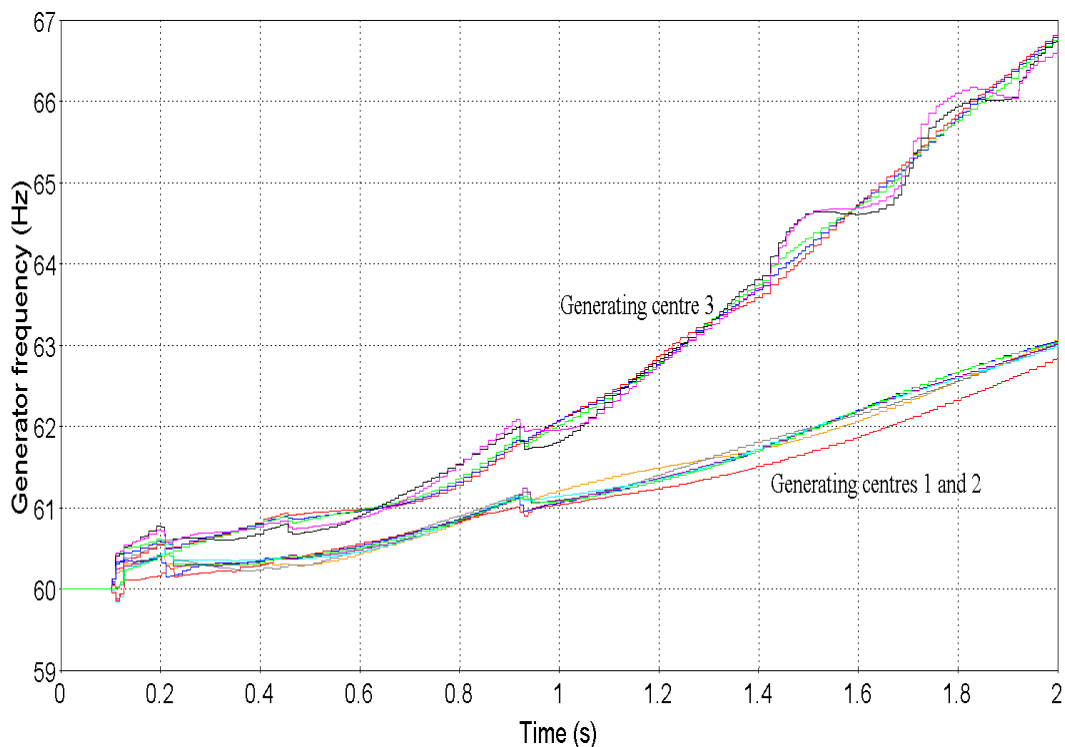
#### 3.1 TOV following load rejection

Large TOV due to the combination of: earth faults, Ferranti and transformer saturation effects as well as generator overspeeds following a full load rejection, can occur on long distance AC power transmission systems. These TOV are particularly severe for equipment in long distance radial systems.

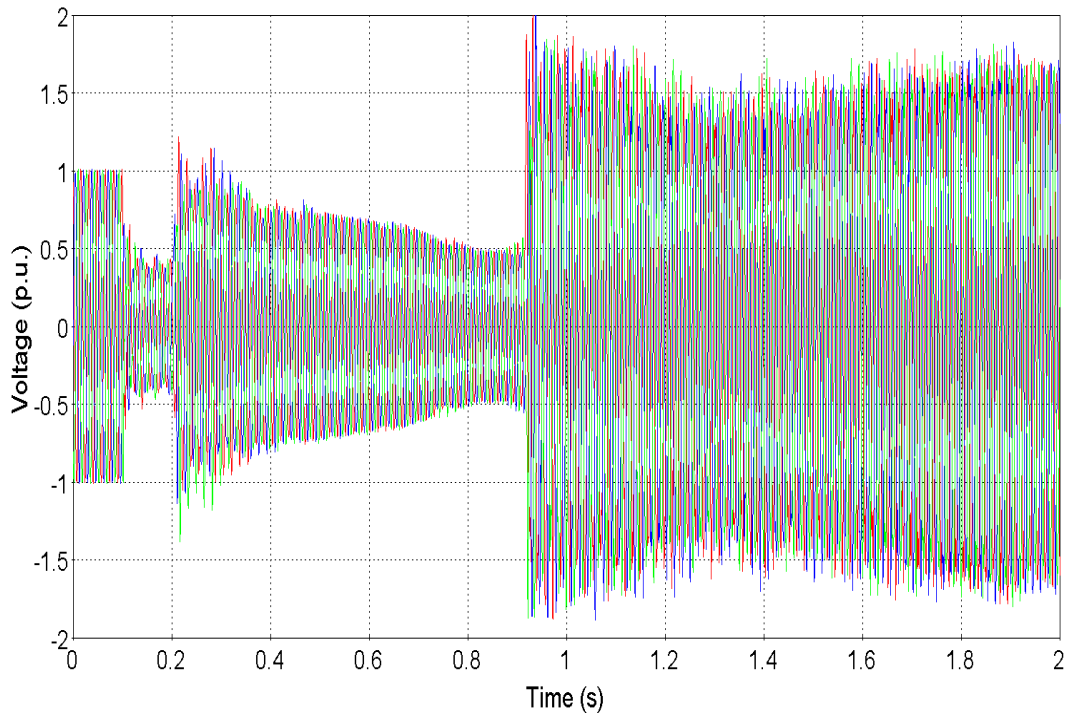
*First example: Quebec (Canada)*

Figure 3.1-1a shows an extreme disturbance in the 735-kV series-compensated system of Quebec, Canada (see Appendix A.1, figure A1-1), which includes several transmission corridors of 1000-km length. It can cause a loss of synchronism with distant generating stations, leading to a full load rejection due to the simultaneous opening of several line circuit breakers under out-of-phase conditions [3].

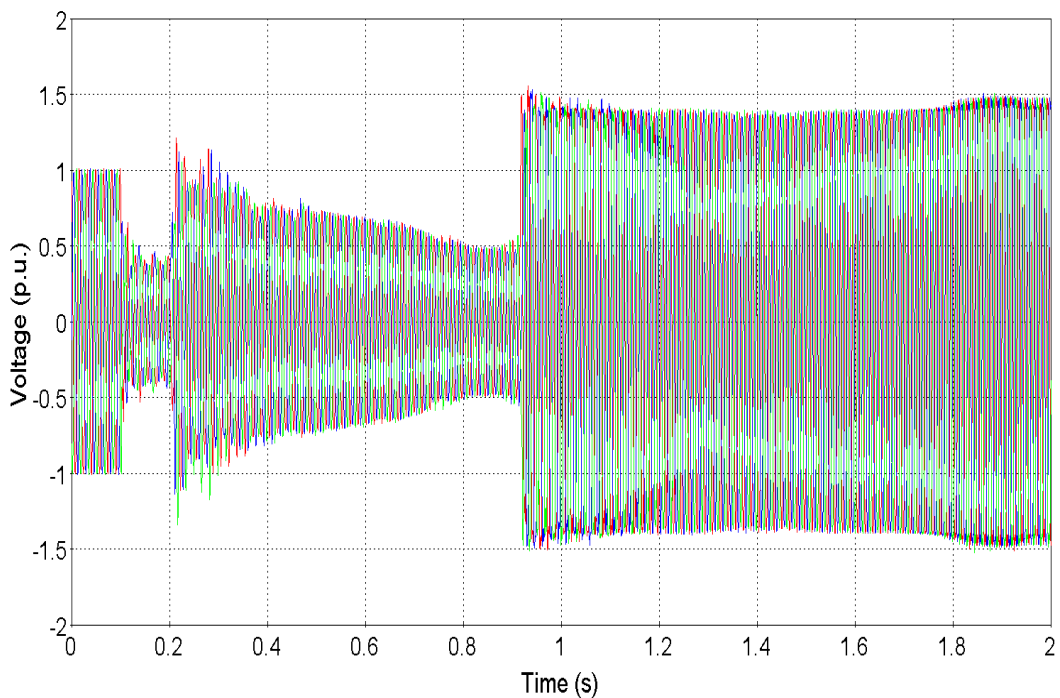
Following a system separation, large TOV appear on long unloaded lines that are still connected to generators. These TOV could reach the protective levels of permanently connected 588-kV and 612-kV rated surge arresters, typically 1.9 pu to 2.0 pu, and be maintained on system equipment as long as the unloaded line are still fed by generators (figure 3.1-1b). Although these events are infrequent and beyond the normal design criteria regarding the system transient stability, strategic equipment should be protected against excessive and prolonged TOV in order to prevent damage and to ensure a rapid system restoration following a major disturbance.



a) Loss of synchronism with distant generating centres



*b) TOV following a system separation with 588-kV and 612-kV rated permanently connected surge arresters*



*c) TOV following a system separation with switchable 484-kV rated surge arresters*

*Fig. 3.1-1: TOV following a full load rejection in the 735-kV series compensated system of Quebec, Canada – 1 pu = 600 kV-peak phase-to-ground*

The use of switchable 484-kV rated surge arresters having 1.6-pu residual voltage at a 1000  $\mu\text{s}$ , 5 kA discharge current (not defined by surge arrester standard in general), in combination with the fast removals of unloaded lines from generators by overvoltage protection, would

allow a reduction of the magnitude as well as the duration of TOV (figure 3.1-1c). As a consequence, line circuit breakers in this system should have adequate TRV withstand capabilities for line opening under out-of-phase conditions and for unloaded line switching under high TOV.

*Second example: Turkey*

The Turkish 420kV – 50Hz grid (see single-line diagram in Appendix A3 – Fig. A3-1) is reported. This grid spans a distance of over 1,500km from the East to the West of the country and is also significant regarding TOVs. In the peak hours, when all the hydroelectric power plants (HPPs) of Euphrates River basin are operated close to full output, a large power transfer is performed to the load areas of North-Western and South-Western Turkey, over a distance of about 1000km via seven single-circuit series compensated lines. The problem of TOVs caused by load rejection at the receiving end, had to be considered, when the first two 420kV lines were commissioned in the early 1970s from the Keban 1350MW HPP to Ankara and Istanbul (see Appendix A3, figure A3-1). At present, the grid is meshed, installed generation capacity is 40,000 MW, with load areas and generating stations along the East to West 420kV trunk line system. Although the probability of full load rejection and associated TOVs has become negligible, important TOVs can occur when the long 420kV lines are heavily loaded and suddenly become lightly loaded due to a large loss of generation in the Eastern region or due to a large loss of load in the Western regions.

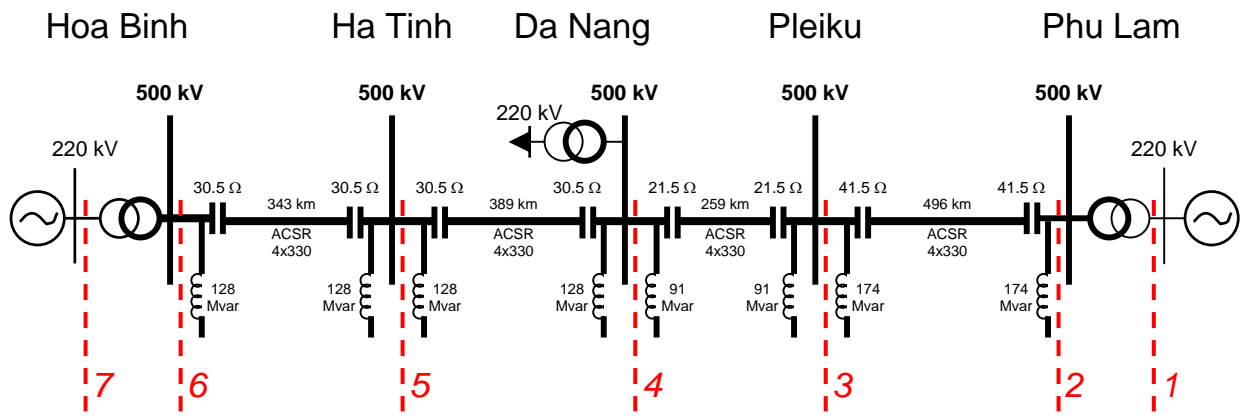
Since the early days of operation, TOVs have been limited in Turkey in all instances using the following countermeasures:

- (i) Automatic switching-on of 420kV SRs at the intermediate substations along the transmission route, initiated by local overvoltage relays, generally set at 427kV with time delay of 1.5s. When the lines are heavily loaded, most of the SRs are disconnected by opening their dedicated CB and keeping the disconnecting switch close, thus enabling the automatic fast reinsertion of SRs at any moment. SF6 CBs can be left open and energized on one side, without problems.
- (ii) Fast automatic disconnection at the sending end of the long 420kV lines which happen to become open-ended due to intervention of protection relays, via transfer tripping from the open end. Transfer tripping is performed via power line carrier channels utilized also for the directional comparison tele-protection of the lines.

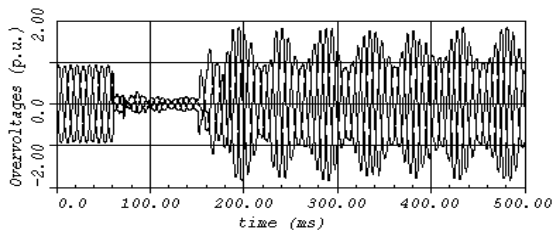
The above two countermeasures and the conventional protection of the generating units, have prevented equipment damage in all the system disturbances recorded since commissioning of the 420kV lines in the early 1970s. TOVs are limited to less than 1.4 pu. In the Turkish 420kV grid, conventional surge arresters with rated voltage of 360kV, are used for protection of transformers and SRs against the switching and lightning overvoltages (no provision is made for limiting TOVs by SAs).

*Third example: Vietnam*

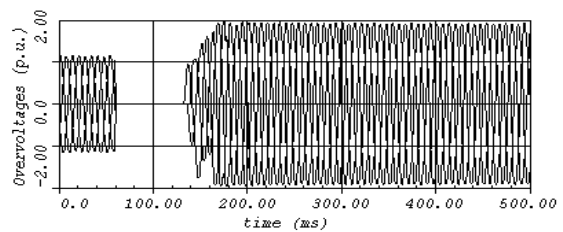
As a third example, the long radial 500-kV, 50 Hz series-compensated system in Vietnam, as described in [4], is particularly affected by TOV following a full load rejection (or network separation). The particular configuration of this system, which features a radial single-circuit line of 1500-km length, is subjected to network separation by tripping a single line circuit breaker. Figures 3.1-2a, 3.1-2b and 3.1-2c illustrate the possible locations of grid separations



a) Locations of network separation

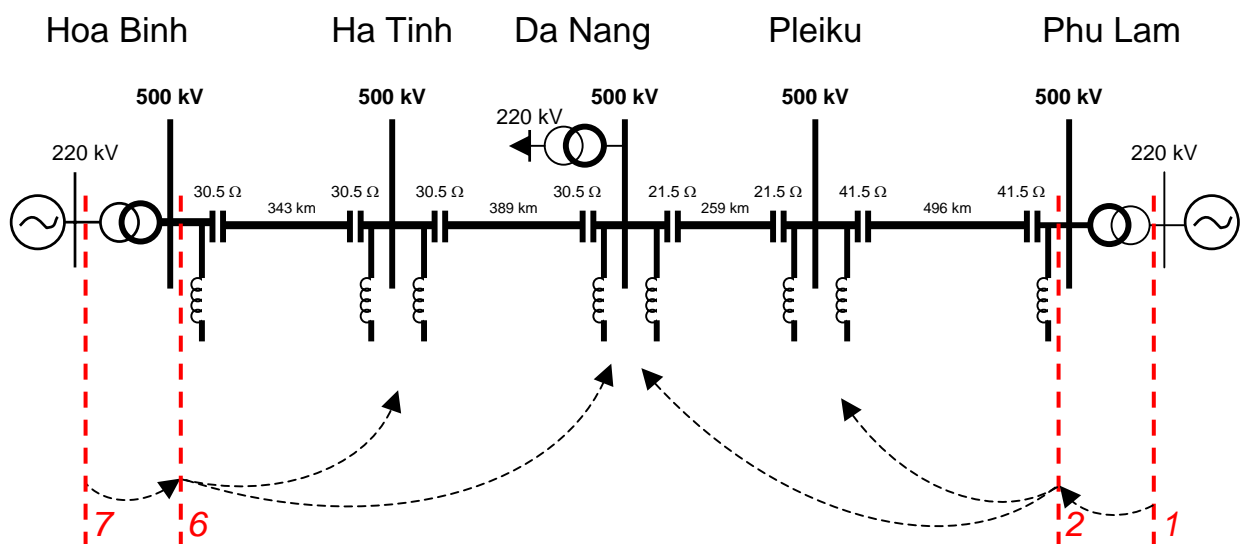


b) TOV at Phu Lam 500 kV busbar following a network separation at location 1

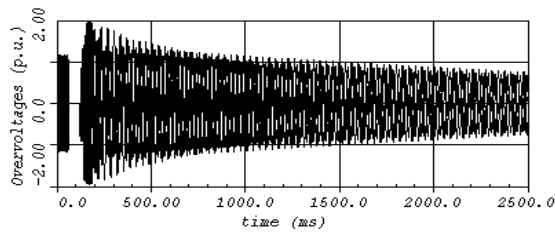


c) TOV at Phu Lam 500 kV line end following a network separation at location 2

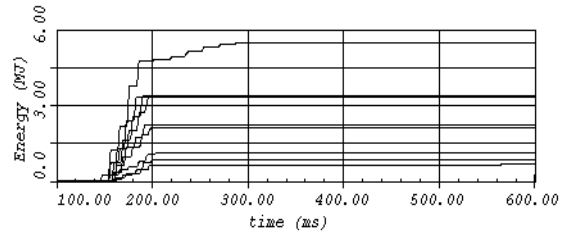
Fig. 3.1-2: Locations of network separation and associated TOV on the long radial series compensated system in Vietnam; 1 pu = 449 kV-peak phase-to-ground



a) Fast transfer tripping scheme implemented in the 500-kV series-compensated system in Vietnam



b) TOV at Phu Lam end of 500 kV line – Effect of fast transfer tripping



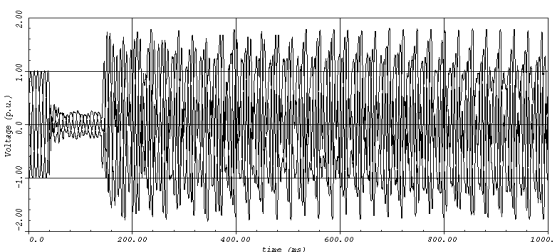
c) Energy stresses in 468-kV rated surge arresters at Phu Lam 500 kV line end, at Pleiku and Da Nang busbars

Fig. 3.1-3: Effect of fast transfer tripping on TOV and energy stresses following a network separation at location 2;  $1 \text{ pu} = 449 \text{ kV-peak phase-to-ground}$

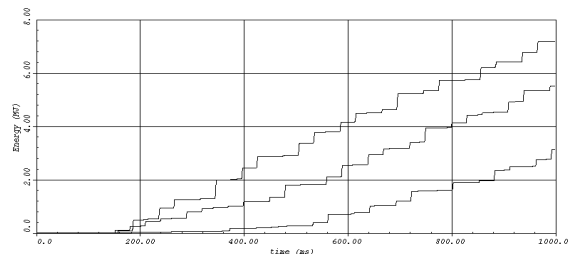
and the associated TOV conditions. Fast transfer trips and overvoltage protections have been implemented in this system to limit TOV duration as well as energy stresses in 468-kV rated surge arresters (figures 3.1-3a, 3.1-3b and 3.1-3c). Furthermore, line circuit breakers with adequate TRV withstand capabilities have been implemented in this system for line opening under out-of-phase conditions and for unloaded line switching under high TOV.

#### Fourth example: Chili

The series-compensated transmission system in Chile consists of two parallel 500-kV single-circuit lines running more than 400 km [5]. As illustrated in figure 3.1-4, TOV and energy stresses in 420-kV rated surge arresters are particularly severe following a full load rejection in this system. The implementation of fast transfer trips from 230-kV to 525-kV side for all the 525-230-66 kV and 525-230 kV power transformers together with the addition of overvoltage protections including remote transfer trip features for all the 500-kV line terminals allow to efficiently control the TOV duration in the 500-kV system as well as the energy stresses in 420-kV rated surge arresters. Again, line circuit breakers with adequate TRV withstand capabilities have been applied in this system for line opening under out-of-phase conditions and for unloaded line switching under high TOV.



a) TOV following a full load rejection



b) Maximum energy stresses in 420-kV rated surge arresters

Fig. 3.1-4: TOV and energy stresses in 420-kV rated surge arresters following a full load rejection –  $1 \text{ pu} = 408.2 \text{ kV-peak phase-to-ground}$

### 3.2 Ferroresonance

The following ferroresonance phenomena are on record from ATP-EMTP analysis and from operation experience of HV-EHV transmission systems operated with a solidly grounded neutral:

- (i) One open phase during the dead time for single phase auto-reclosing (SPAR) in lines with neutral grounded SRs connected to the terminals. One or two line open phase(s) may also occur due to stuck CB poles or faulty operation of the control circuits. When applying SPAR, following self-extinction of the secondary arc current, ferroresonance may occur between the coupling capacitances of the open phase with the energized phases and the saturable inductance of SR(s). The temporary overvoltages may be considerably limited by the corona phenomenon and depend on the following parameters: degree of line shunt compensation; saturation level and V-I characteristic of SR(s); onset voltage of visible corona on line conductors; presence of parallel circuits on same right of way or tower. Overvoltages in the range of 1.4 to 3.5 pu phase-to-ground and in range of 2.4 to 3.5 pu across open contacts of line CBs have been calculated for the 420kV grid of Turkey [6][16]. The build-up time of the open-phase(s) overvoltages is 40 to 60ms. In section 3.6 open phase occurrence is further elaborated.
- (ii) Series compensated line terminated in an autotransformer or SR. This rare ferroresonance phenomenon was reported to be initiated by a short circuit or line energization.
- (iii) Opening of one phase in a transformer feeder, i.e. an HV line connected to an un-loaded or lightly loaded step-down transformer. The ferroresonant circuit is formed by the coupling capacitances with the energized phases and the magnetizing inductance of transformer.
- (iv) Opening of one circuit of a double-circuit HV transformer feeder. The open circuit becomes energized via the mutual capacitances with the other circuit. Ferroresonance may occur if transformer is un-loaded or lightly loaded
- (v) A case of parallel ferroresonance on even harmonics ( $2^{\text{nd}}$ ,  $4^{\text{th}}$ ) was reported when a 500kV line was energized from a busbar supplying an un-loaded autotransformer.
- (vi) In a solidly grounded neutral network, if a line terminated in a delta connected un-loaded or lightly loaded transformer undergoes an open phase at the sending end, ferroresonance may build up between the zero-sequence capacitances of the open phase and the magnetizing inductance of the transformer.

Overvoltages (i) might damage surge arresters (SAs), shunt reactors (SRs) and circuit-breakers (CBs); the secondary arc re-ignition may render unsuccessful the line SPAR. Countermeasures are the following: (a) accept the risk in specific cases after analysis of the overvoltages with ATP-EMTP; (b) apply SRs provided with neutral reactor; (c) trip the CB pole of SR phase connected to faulty line phase in same instant as faulty phase is tripped; reconnect automatically the SR phase 2-3s after the successful SPAR of the line (it is assumed that SR has equal zero-sequence and positive-sequence reactance).

The ferroresonance phenomena (iii), (iv) and (vi) can be eliminated by providing the transformer with a CB and protection circuits disconnecting it instantaneously when an open phase or open circuit on the transformer feeder is detected. Modern series capacitor (SC) banks are provided with relays which detect the harmonics caused by a ferroresonance phenomenon as (ii) and by-pass the capacitors.

### 3.3 Resonance due to inrush/magnetizing currents

The harmonic components of the inrush currents of transformers and SRs can produce temporary overvoltages, when their frequency corresponds to resonance frequencies in the

network. Normally the lower harmonics are involved - up to the fifth harmonic – resulting in low frequency, low damping (typically parallel) resonance in the presence of filter banks, shunt capacitor banks or even cable systems. This situation may, for instance, be present at HVDC converter stations with filter banks. Unlike short transient excitations (load changes, blocking of converters, occurrence or clearing of faults), that generate overvoltages of typically 1.7 pu for only a few cycles at most, inrush currents may last much longer (tens of seconds) and occur frequently.

The slow decay of the inrush current peak causes a slow shift in the harmonic content creating a possibility for build-up of resonances in the system. Furthermore, the very slow shift in harmonic currents allows TOV to be “built up” in an optimal way. TOV’s up to 2 pu and even more have been reported (2.4 pu [43]), but large amplitudes only occur when perfect resonance is present with low natural damping (high quality factor) [44][45]. Low damping may occur at UHV system voltages [78].

Following a full load rejection (e.g. complete blocking of HVDC converters), when the substation voltage may become 1.2 to 1.3 pu, the inrush currents are more severe and the harmonic overvoltages can reach values beyond 2.5 pu. However, it is unlikely that transformers will be energised immediately after load rejection. On the other hand, due to the high voltage caused by load rejection, the steady state transformer magnetising current may show more pronounced peak values (like inrush currents). This is particularly the case if the system voltage was already high before load rejection.

### **3.4 Resonance in mixed cable-OH-lines**

Long EHV shunt compensated insulated cable lines, and mixed lines consisting of long cable sections in series with overhead line (OHL) sections, may undergo large energization TOVs due to resonance at low-order harmonics. Resonance natural frequencies in transmission networks composed of OHLs are in general quite high. The equivalent impedance is inductive and of increasing value for frequencies usually up to at least 300-400Hz. The behaviour is substantially different in presence of long cables, whose large capacitance causes low resonance frequencies of the network, in some cases in proximity of the third harmonic [7]. Cable shunt compensation by SRs has small influence on the resonance frequency.

Analysis has shown that the no-load energization can initiate TOVs causing saturation of SRs and generation of DC components and large harmonics, superimposed on the fundamental. High harmonic distortion and overvoltages then build-up if the network is resonant at such harmonic excitation. Details on the phenomenon are provided in reference [7].

ATP-EMTP analyses have been performed for the 400kV, 66km long, 50Hz, 2500 mm<sup>2</sup> Cu, XLPE insulated cable line considered for installation in a crossborder tunnel of the Alpes. The cables are assumed to be about 100% shunt compensated with SRs, about 50% connected at each terminal. The open ended cable line with the associated SRs has an equivalent reactance virtually infinite at 50Hz, as seen from one terminal with the other terminal open-ended. At 150Hz, it becomes -j64 Ω and it is in resonance with the equivalent reactance of the network if the energizing 400kV busbar has a short circuit power of 7500 MVA. Figure 3.4-1 shows, in this condition, the maximum no-load energization overvoltage calculated in a statistic study (1000 energizations). The overvoltage is of long duration (as long as the inrush currents). These TOVs may stress protective equipment; energy dissipated in SAs may exceed their capacity. Fast Fourier transform analysis shows that the phase-to-ground overvoltages are due mainly to the 3<sup>rd</sup> harmonic components, as a result of the resonance.

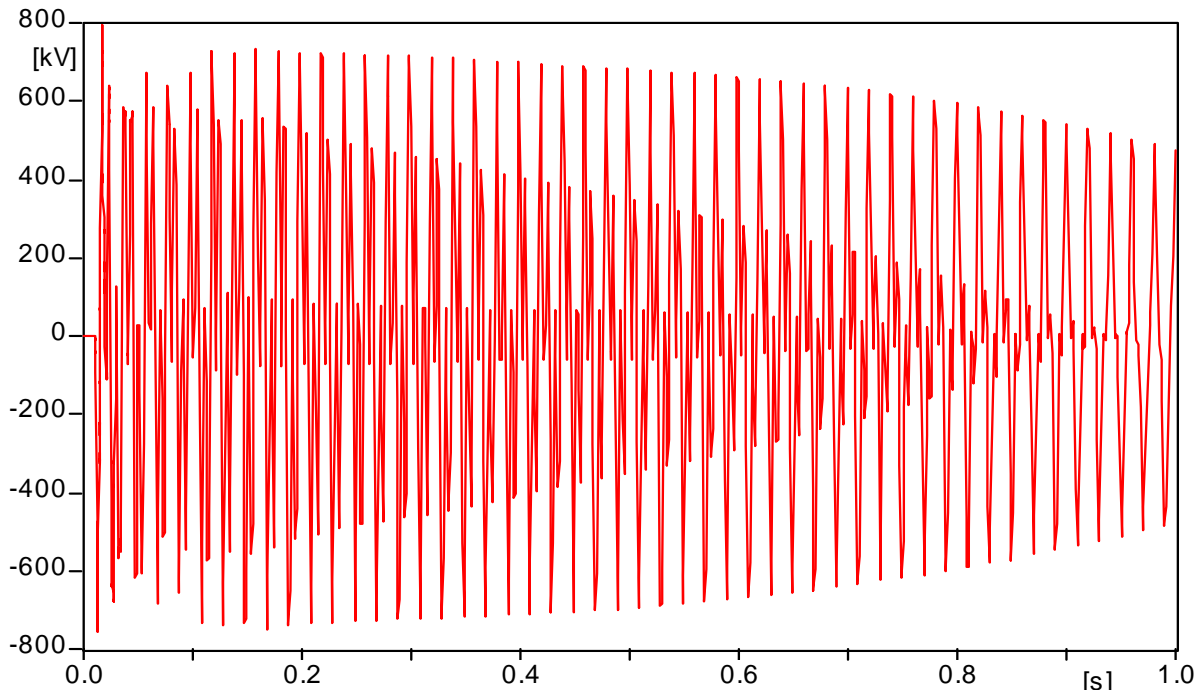


Fig. 3.4-1 Phase-to-ground no-load energization over-voltage of a 400kV -50 Hz - 66km cable line in T phase at energizing bus. SAs connected at cable terminals are simulated

### 3.5 TOVs due to faults in Half Wave Length Lines (HWLLs)

The main features of HWLLs are recalled here for convenience of readers not familiar with this subject. A lossless HWLL (3000km at 50Hz; 2500km at 60Hz) has the following transmission coefficients:

$$\mathbf{A}=\mathbf{D}=1; \mathbf{B}=\mathbf{C}=0 \quad (3.5-1)$$

Let  $\mathbf{V}_s$ ,  $\mathbf{V}_r$ ,  $\mathbf{V}_{mp}$  and  $\mathbf{I}_s$ ,  $\mathbf{I}_r$ ,  $\mathbf{I}_{mp}$  be the sending end, receiving end and mid point voltage and current phasors of the HWLL, respectively; let  $\mathbf{Z}_0 = \sqrt{l/c}$  be the line surge impedance; let  $I_n$  be the current at the line ends in operation at surge impedance loading (SIL)  $P_o = 3\mathbf{V}_r^2/\mathbf{Z}_0$ .

The equivalent circuit of the lossless HWLL ( $\lambda/2$ ) is formed (figure 3.5.1) by two cascade connected T equivalent circuits of a quarter wave length lossless line ( $\lambda/4$ ). The following simple steady-state operation equations are arrived at [8]:

$$\mathbf{V}_r = -\mathbf{V}_s; \quad \mathbf{I}_r = -\mathbf{I}_s; \quad \mathbf{I}_{mp} = \mathbf{V}_r/\mathbf{Z}_0; \quad \mathbf{V}_{mp} = \mathbf{Z}_0\mathbf{I}_r. \quad (3.5-2)$$

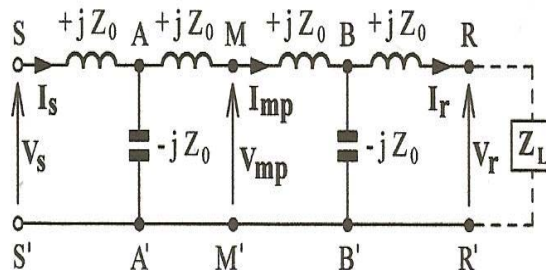


Fig. 3.5-1 Equivalent circuit of a lossless HWLL

The equations (3.5-1), (3.5-2) and figure 3.5-1 prompt the following main operating features of the lossless HWLLs:

- HWLL transfer impedance and shunt admittance are nil ( $\mathbf{B}=\mathbf{C}=0$ ). Voltage and current at sending and receiving end have the same rms values and are in phase opposition.
- Voltage in the central part of HWLLs is subject to large variation, in proportion to receiving end current, i.e. to line load for assigned voltages at line ends:  
 $V_{mp} = 0$  at no load;  
 $V_{mp} = V_s = V_r$  at SIL;  
 $V_{mp} = 2V_s = 2V_r$  at 2xSIL.  
 $V_{mp} =$  virtually infinite with the receiving end short circuited ( $V_r = 0$ )
- The mid point current  $I_{mp} = V_r/Z_0 = I_n$  is constant irrespective of line loading if  $V_r = V_s$  are constant (say, rated voltage). This feature causes a drastic drop in transmission efficiency when load is less than 0.5 SIL.
- The HWLL does not produce or absorb reactive power, regardless of line load. This feature of the conventional lines operated at SIL occurs for any loading in the HWLLs because voltage in the central part of the line is self-adjusted to line load: at no-load ( $V_{mp} = 0$ ;  $I_{mp} = I_n$ ) the Mvars generated by the line capacitances near the ends are consumed in the series inductances of the central part; at high loading (say, 2xSIL) the central part of the line ( $V_{mp} = 2V_s = 2V_r$ ;  $I_{mp} = I_n$ ) generates extra capacitive Mvars that are consumed by the line inductances near the line ends where current is high ( $I_r = I_s = 2 I_n$ ). There is no Ferranti effect and no risk of self-excitation of synchronous generators as long as frequency is regulated at rated value. A lossless HWLL is equivalent in principle to a short line from the transmission stability point of view ( $\mathbf{B} = 0$ ;  $\delta = 180^\circ$ ).
- Frequency variations cause the HWLL to depart from the  $\lambda/2$  length and adversely affect the good characteristics referred to above. Attention must therefore be given to the disturbances that may cause large frequency changes, such as load rejection or loss of generation. Load rejection, if accompanied by frequency increase, makes the line un-tuned and causes the generation of capacitive Mvars by the line and build-up of overvoltages due to Ferranti effect.
- It is difficult to supply loads at intermediate points of an HWLL because of voltage variation depending on line load and also owing to transmission instability risk if such loads are large.

Equations (3.5-2) and also the equivalent circuit of figure 3.5-1 show that large power frequency overvoltages build-up in the central part of the lossless HWLL during line short circuit located at, or close to, the line ends ( $V_{mp} = Z_0 I_r$  is proportional to the receiving end short circuit current). If  $V_r = 0$  (3- $\phi$  short circuit), the circuit at the right of B-B' in figure 3.5.1 is in parallel resonance and has infinite impedance. Then  $I_{mp} = 0$  (equivalent to open circuit in M-M') and the circuit seen from S-S' becomes series resonant. Consequently the voltage  $V_{mp}$  is infinite if  $V_s$  is not nil, as confirmed by the last one of equations (3.5-2)

If the HWLL is analysed by simulating the ohmic resistance of conductors and neglecting the corona losses, the calculated temporary overvoltage at mid point caused by a 3- $\phi$  short circuit at one line end exceeds 10 pu. On the other hand it has been demonstrated [8] [9] that in reality the corona losses heavily load the central part of the line when the onset visible corona voltage is exceeded. This phenomenon and, to a much less extent, the consequential variation of conductor line-to-ground capacitance, cause a drastic reduction of the temporary overvoltages and also set-up a limit to the transmissible power as regards transient stability.

However temporary overvoltages are still high during faults in a real lossy HWLL and in the sending and receiving end systems, if faults occur in locations not far from either end of the HWLL. The higher the visible corona onset voltage, the higher are the overvoltages. The EMTP simulation with a corona model based on published measurements on large conductors with gradients up to 60kVrms/cm, has provided the following maximum TOVs for an 800kV-50Hz-3200km long HWLL with visible corona onset voltage of 1.30 pu (1 pu =  $800\sqrt{2}/\sqrt{3}$ kV) (conductor capacitance variation due to corona is not considered):

- (i) 3-phase short circuit at 2600km from sending end of HWLL: 2.93 pu; 3-phase short circuit in the 400kV receiving systems connected to the HWLL via 800/400kV autotransformers: up to 2 pu.
- (ii) 1-phase-to-ground short circuit at 2200km from sending end: 1.95 pu.
- (iii) phase-to-phase and phase-to-phase-to-ground short circuits: intermediate values between cases (i) and (ii).

Maximum temporary overvoltages of 2.7 pu and 2.2 pu have been calculated for 800kV and 1050kV, 60Hz, 2500-2700km long HWLLs, for the most unfavourable locations of 3-phase and 1-phase-to-ground short circuits in the HWLL, respectively.

These TOVs may control the design of HWLL insulation.

It has been shown [9] that the single-phase high-speed reclosure (HSR) is not practically feasible in HWLLs because it is not possible to perform the extinction of the large secondary arc current with simple, reliable and cost effective means. On the other hand, it has also been shown that the 3-phase HSR (TPHSR) is feasible with use of conventional, reliable apparatuses for discharging the HWLL during the dead time before reclosure, in particular by installing, phase-to-earth, at each line end, either inductive type transformers rated at some MVA per phase, or a high-speed grounding switch (HSGS).

Insulation design of HWLLs should comply with the following requirements:

*i) Case of a single-circuit HWLL*

Insulation should withstand the TOVs caused by faults located anywhere in the receiving and sending end networks of the HWLL, which in Case Studies have been calculated to reach 2-2.05 pu. In case of critically located multi-phase faults internal to the HWLL, an additional line insulation flashover in the central part of the HWLL caused by TOVs (up to 2.7 – 3 pu) can be tolerated, because this will be a rare event and will not exclude the feasibility of the TPHSR

*ii) Case of two parallel operated single-circuit HWLLs*

In addition to the requirement of item i) above, the insulation should be designed to withstand the TOVs caused by any type of short circuit in one of the parallel lines, to preserve operation of at least the other HWLL. In Case Studies, these TOVs have been calculated to reach 2.2 pu.

Subject to validation of the corona loss model available in the literature for very high electric field gradients, the above TOVs caused by the short circuits can be withstood by the prospective HWLLs designed to carry SIL, with a modest oversizing of insulation in

comparison with the conventional lines of the same rated voltage, without need of TOVs limitation by MOSAs connected to the central part of the line. MOSAs, if applied, should possess an exceedingly large energy absorption capacity.

### **3.6 Open phase occurrence in shunt compensated lines. Single-pole auto-reclosing**

SRs connected to line ends may largely magnify the recovery voltage in 1 or 2 open-phase occurrences of EHV lines, in particular during dead time before SPAR of transmission lines after the secondary arc extinction, because of unequal compensation of the positive and zero-sequence line capacitances. As SRs are in parallel with conductor capacitance to ground, the equivalent phase-to-ground reactance at power frequency is inductive and very high when the shunt compensation is large (above about 65%). In open-phase conditions, therefore, a series resonance may occur with the coupling capacitances of the energized phases, and large TOVs may stress the open-phase and associated equipments, in particular SRs, CBs and surge arresters.

One or two open-phase(s) condition may occur also in case of stuck CB pole(s) in the opening and closing operation.

EMTP analyses have shown that the losses due to corona phenomenon and saturation of SR cores may drastically limit the open-phase(s) to ground TOVs, in particular when circuit conditions are close to resonance. On the other hand, SR saturation may also cause ferroresonance and large TOVs in a wide range of shunt compensation conditions [6].

Figure 13 from reference [6] (second next page) shows the computed peak values of TOVs, open phase(s)-to-ground and across the open contact(s) of the line energizing CB, for two 380kV-50Hz lines of the Turkish grid (figure 10 from [6], figure A3-1). One line is 466km long, has triplet bundle ACSR Cardinal conductors and visible corona onset voltage of 1.75 pu (on 380kV basis) and is series-shunt compensated. The other line is 271km long, has twin bundle ACSR Cardinal conductors and visible corona onset voltage of 1.35 pu, and is shunt compensated at one end. Core saturation of SRs was taken to start at 1.25 pu or, alternatively, at 1.5 pu (on 380kV basis). Shunt compensation was varied from 15% to 100%. Overvoltages were calculated with and without simulation of corona, to show the influence of corona losses. Surge arresters were not simulated.

Figure 5 from [6] (second next page) shows, for comparison with figure 13 from [6], the peak value of TOVs as a function of the degree of line shunt compensation, for a fully linear 380kV system (corona losses and saturation of SRs not simulated).

Figure 13 from [6] (next page) shows that:

- in the lines with low visible corona onset voltage (say, 1.30 – 1.35 pu) the peak value of open phases(s) TOVs does not exceed 1.6 pu to-ground and does not exceed 2.6pu across open contacts of the line CB;
- in the lines with high visible corona onset voltage (say, 1.75 pu) the open phase(s) TOVs can reach 2.2 pu to ground and 3.0 pu across the open contacts of CB.

The open-phase TOVs may cause reignition of the secondary arc current after extinction, making the SPAR unsuccessful. Unless the open-phase(s) condition and TOVs duration is

short, damages could occur in SRs due to overheating and high vibrations and in surge arresters. A flashover across the open contacts of CB at one of line ends, if prolonged, could cause the explosions of the interrupting chambers. Countermeasures may include the following:

- Use phase discrepancy relays limiting the duration of 1 or 2 open-phase operation: if SPAR is applied, setting may be 1-2 sec longer than the dead time.
- Compute the overvoltages for specific projects. Identify the degree of shunt compensation and characteristics of SRs which mitigate the phenomenon. Compute the energy dissipation in MOSAs and limit time to avert risk MOSAs' failure.
- If analyses are addressed to investigate feasibility of SPAR, study the onset possibility of ferroresonance between partially saturated SR(s) and line capacitances, liable to widen the range of shunt compensation degree causing large open-phase TOVs after the secondary arc extinction.
- If it is found that the single open-phase TOVs can cause an unsuccessful SPAR and/or introduce risk to damage equipment during SPAR, a logic circuit can be implemented for the temporary single-phase disconnection of SR(s) from the faulty line phase during the dead time. This operation would be initiated by line protection relays simultaneous with tripping of the faulty line phase. The switched-off phase of SR(s) should be automatically reinserted shortly after the successful SPAR.

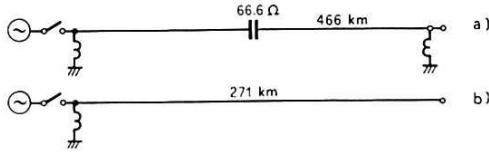


Fig. 10 — 380 kV — 50 Hz lines studied.

- a) Line with triple bundle ACSR cables  
 conductor diameter  $\phi = 30.42$  mm; bundle spacing  $\Delta = 45.7$  cm;  
 phase-to-phase distance  $D = 7.5$  m (flat configuration)  
 $r_1 = 0.0209 \Omega/\text{km}$ ;  $x_1 = 0.266 \Omega/\text{km}$ ;  $c_1 = 13.8 \text{ m}\mu\text{F}/\text{km}$ ;  
 $r_0 = 0.303 \Omega/\text{km}$ ;  $x_0 = 0.991 \Omega/\text{km}$ ;  $c_0 = 8.42 \text{ m}\mu\text{F}/\text{km}$
- b) Line with twin bundle ACSR cables  
 conductor diameter  $\phi = 29.6$  mm; bundle spacing  $\Delta = 45.7$  cm;  
 phase-to-phase distance  $D = 8.9$  m (flat configuration)  
 $r_1 = 0.0319 \Omega/\text{km}$ ;  $x_1 = 0.315 \Omega/\text{km}$ ;  $c_1 = 11.6 \text{ m}\mu\text{F}/\text{km}$ ;  
 $r_0 = 0.315 \Omega/\text{km}$ ;  $x_0 = 0.980 \Omega/\text{km}$ ;  $c_0 = 7.73 \text{ m}\mu\text{F}/\text{km}$

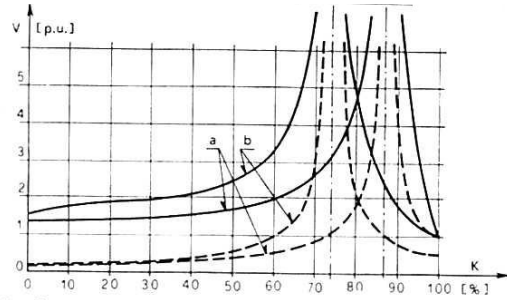


Fig. 5 — Peak value of open-phase overvoltages and power frequency components for the case of linear system and corona losses not simulated: a) single-phase opening; b) two-phase opening.  
 — phase to ground peak voltage;  
 - - - power frequency component.

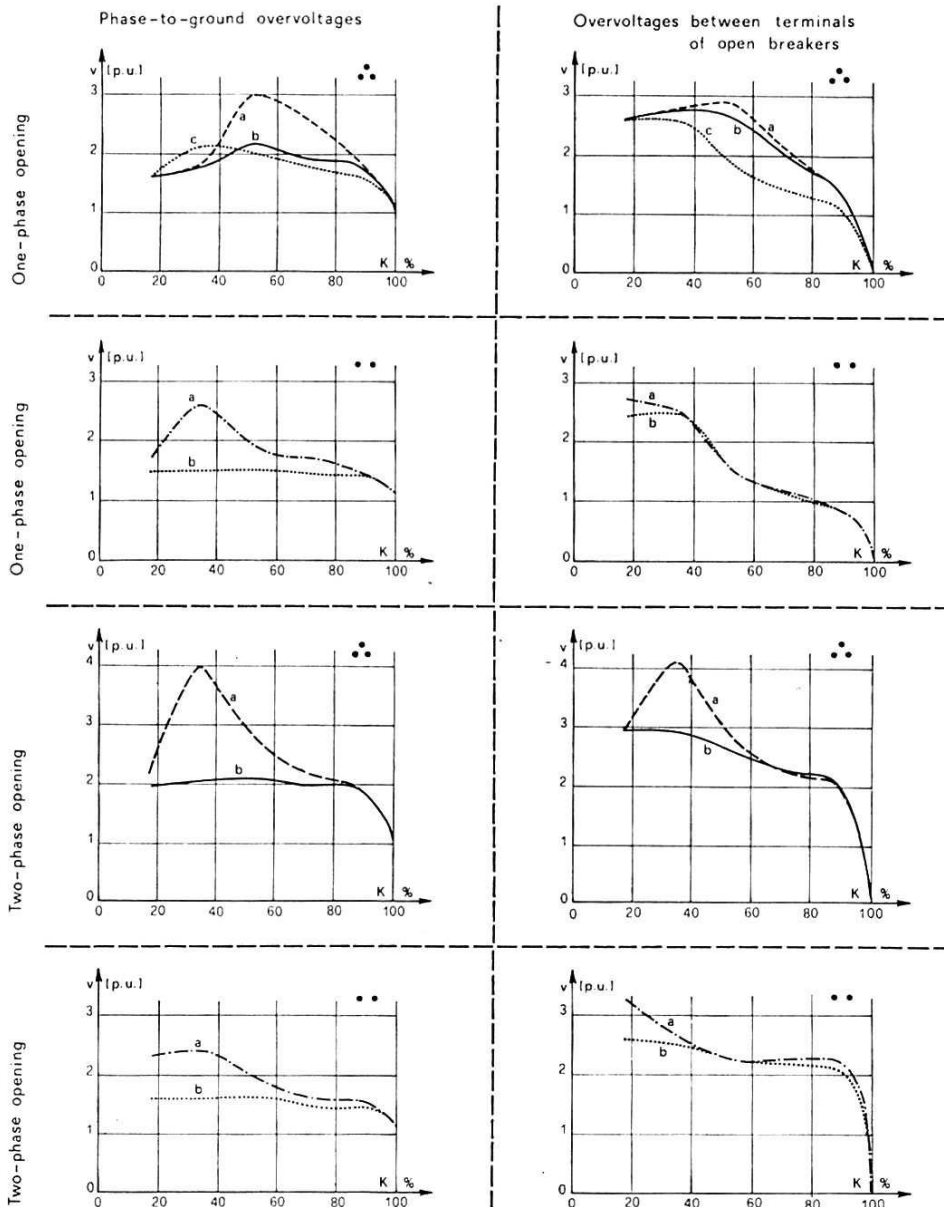


Fig. 13 — Overvoltage amplitude versus compensation degree for the two lines of Fig. 10 (\*\* stands for twin bundle conductors; . stands for triplet bundle), and for 1 and 2 open phase conditions. Shunt reactors saturation is simulated in all cases above threshold  $v_s$  indicated below  
 - - - corona neglected;  $V_s = 1.5$  p.u.; - - - corona simulated;  $V_s = 1.25$  p.u.  
 — corona simulated;  $V_s = 1.5$  p.u.; ..... corona simulated,  $V_s = 1.25$  p.u.

Line source voltage taken as 380 kV and 420 kV, for the triplet and twin bundle conductor lines, respectively. All overvoltages are expressed in p.u. of  $380 \cdot \sqrt{2/3} = 310.27$  kV

## 4. TRANSIENT OVERVOLTAGES

IEC 60071[21] divides transient overvoltages into (1) slow-front overvoltages (SFO) due to normal switching operations such as line energization and re-energization, switching inductive and capacitive currents, fault occurrence and fault clearing; (2) fast-front overvoltages (FFO) due to lightning, flash-overs, re-ignitions and restrikes at a short distance; and (3) very-fast-front overvoltages (disconnecter operations and fault occurrence within GIS). The time to the peak of the overvoltage is 20 to 5000 $\mu$ s, 0.1 to 20  $\mu$ s and less than 0.1  $\mu$ s, respectively.

### 4.1 Transmission line energization and automatic high-speed reclosure

There is vast literature and field experience on switching overvoltages of OH transmission lines (OHL) and on most of the applicable means for mitigation. The no-load energization of OHLs causes overvoltages  $\leq 3$  pu. Many utilities design OHLs of rated voltages up to 420kV with a 3 pu high probability ( $V_{50\%} + 3\sigma$ , or 99.86% in Gaussian approximation) switching impulse withstand voltage (SIWL). With this approach, the only applied overvoltage mitigation measure is specification of the pole-discrepancy for closing of CBs to be less than 5 ms.

OHLs of rated voltage of 500kV and above are usually designed with lower pu SIWL and require means for limitation of the energization overvoltages. The following means have been applied (pu overvoltage limitation is given in bracket):

- Closing resistors ( $\leq 2.0 - 2.2$  pu with 1 resistor step;  $\leq 1.5 - 1.6$  pu with 2 resistor steps);
- Synchronizing of pole closures at busbar voltage zero ( $\leq 2.0$  pu);
- Surge arresters (SAs) with adequate energy absorption capacity ( $\leq 1.7 - 2.2$  pu according to SIPL of SAs);
- Staggering the closure of line CB poles ( $\leq 2.4$  pu).

SRs, if available, are usually preconnected to the line (preferably, at receiving end) before energization and limit both the temporary and transient energization and re-energization overvoltages.

The overvoltages caused by the single-pole automatic reclosure (SPAR) are usually  $\leq 2.4$  pu (up to 2.7 – 3.0 pu with very unusual line and grid configurations). In any case they do not exceed the no-load energization over-voltages if the above listed limitation means are applied. The line three-pole high-speed reclosure (TPHSR) may cause overvoltages up to 3.8 – 4 pu, if no mitigation measures are applied. The following limiting means can be used:

- Inductive type potential transformers (PTs) connected at the line terminals: these PTs discharge the line in the dead time (usually 0.5s), if no SR is connected to the line. The TPHSR overvoltage is practically reduced to the case of no-load energization;
- SAs connected at line terminals, which limit overvoltages within about the SIPL of SAs;
- Synchronizing of pole closure: if made when voltage across contacts of each pole is close to zero, overvoltage is  $\leq 2$  pu. When this solution is applied, measurement of trapped charge (DC) voltage requires special apparatuses, usually not available in substations. Practical solutions are the following:
  - if the line has SR(s), close each pole when the oscillatory discharge voltage beat on line side of relevant phase is minimal [16];

- if SR(s) and/or inductive type PTs are not available, synchronize the pole reclosure of the non faulty phases at the peak (or 50% peak) of the busbar voltage with the same polarity as the trapped charge; polarity is determined to be the same as the phase voltage at instant of current interruption; faulty phase(s) can be reclosed when the busbar voltage is nil. By assuming a scattering of CB pole closing of  $\pm 1.5$ ms, TPHSR overvoltages are  $\leq 3$  pu.
- Use of closing resistors: with 1 step resistors, overvoltage is  $\leq 2.5$  pu.

#### 4.2 Switching of shunt capacitor banks, transformers and shunt reactors

Switching on of shunt capacitor-banks gives a severe voltage dip, followed by a voltage overswing at the resulting natural frequency of the network with capacitance (typically 300 to 900 Hz). Switching overvoltages are up to 1.6 pu, but voltage magnification elsewhere may cause much higher overvoltages (for instance at remote capacitor-banks, at open ended lines, at radially fed transformers, by capacitive coupling between transformer windings) [11]. Under such circumstances uncontrolled energization of capacitor banks presents an unacceptable risk of system flashover so that measures as pre-insertion resistors, series reactors or controlled switching are necessary. The topic of overvoltage protection by means of surge arresters is a complex one, considered in detail in [12].

CBs are specially designed to interrupt capacitive currents with a minimum probability of restrikes. In case of a restrike the shunt capacitor bank is energized again while it is still charged with an opposite voltage. The FFO may show amplitudes twice as large as the SFO described above; and even more in case of multiple restrikes. It is therefore strongly recommended to apply only CBs with a very low restrike probability, notwithstanding the fact that manufacturers of EHV CBs have difficulties proving this performance. In any case controlled switching is recommended [13].

The energization inrush current of transformers and SRs is usually expressed in pu as follows: inrush current peak/peak value of rated current. The energization of large power transformers leads to high inrush currents (up to typically 4 pu to 4.5 pu for energization from outer winding) that are rich in harmonic content, and lead to temporary rather than transient overvoltages, with transient peaks up to 2.0 – 2.5 pu. The interruption of transformer magnetizing current is normally not a problem.

SRs can be designed such that the inrush current does not exceed 2.8 – 3.0 pu. When switching off SRs, current chopping will occur. High SFO may be produced depending on the amplitude of the inductive current at the moment of chopping and high FFO in case of restrike.

Switching-off of SRs may be quite frequent (daily) in operation and therefore deserves due attention because restrikes are dangerous for CBs and SRs. Chamber explosions, causing serious damage to close-by equipment, have occasionally occurred on CBs not tested or not protected or controlled for the specific duty.

The IEC Standard 62271-110 [76] recommends test methods for CBs used for switching-off SRs; however it advises that laboratory tests using an actual SR will not necessarily be valid for other installation cases. On the other hand, it is not easy or practical to perform field tests for specific SR applications. Thus other countermeasures are advisable.

The phenomena to be considered when switching-off SRs are the following:

- Current chopping caused by negatively damped (i.e. amplified) current oscillations due to arc instability because of the small rated inductive current typical of SRs;
- Possible re-strike due to insufficient build-up of dielectric strength across contact gaps;
- Interruption capability of high-frequency currents after re-strike, with possible multiple re-strikes and voltage escalation.

Limitation methods of the longitudinal overvoltages to acceptable values for CBs, that are used to switch-off SRs, are the following:

*i) Use of metal oxide surge arresters (MOSAs)*

If the current chopping overvoltage causes the operation of MOSAs, the phase-to-ground overvoltage is limited on SR side within the MOSA SIPL; however the risk of re-strike is somewhat reduced but not eliminated. MOSAs are in any case applied to limit - generally with a margin of not less than 25% - the switching and lightning overvoltages which can stress SRs.

*ii) Use of linear opening resistors in series with auxiliary switches, connected across the main contacts of CB*

Resistors with ohmic rating of same order of SR surge impedance (say. 4000  $\Omega$ ) limit the overvoltages due to current chopping and the probability and severity of re-strike. Switchable opening resistors have been applied with air blast CBs. Use of opening resistors has been discontinued in modern installations supplied with SF6 CBs, to avoid the added complexity and increased risk of failure that is brought with them.

*iii) Use of metal oxide varistors (MOVs) connected across the contacts of CB*

These MOVs limit the TRVs across CB as well as the re-strike overvoltages, thus reducing also the stresses on SRs. Some more details on use of MOVs across the contacts of CB, are provided in section 5.2 dealing with line CBs clearing of short circuit currents flowing through SC banks.

Use of MOVs across the contacts of CBs is particularly effective for limiting the overvoltages in the cases of un-earthed SRs or of SRs earthed via a neutral reactor.

*iv) Use of synchronizing relays for controlled opening of CB poles.*

Controlled opening eliminates the risk of re-strikes because it permits contact separation in each pole at a point on the current wave that ensures a sufficiently long arcing time, i.e. an adequate separation of contacts for successful interruption at the first current zero. The synchronizing device uses as source voltage the secondary winding of the inductive or capacitive type PTs supplied by the busbar or line terminal to which the SR is connected.

In summary, the controlled pole opening of CBs used for switching-off SRs is the most effective means for eliminating the risk of CB damage. Combined with the use of MOSAs connected close to SRs' terminals for protection against the switching and lightning overvoltages, it ensures trouble-free switching of SRs. However, keeping in mind that the synchronizing device (a digital controller) might occasionally malfunction or be out of service, it is advisable also to specify CBs that have been laboratory type tested to switch-off SRs, in accordance with IEC 62271-110. See also CIGRÉ Technical Brochure 305 [38].

Controlled pole opening of CBs (item *iv*) is applied with good results in the Turkish transmission grid (see Appendix A3, figure A3-1) for switching-off thirty-five 420kV SRs. MOSAs with rated voltage of 360kV are connected to the SRs terminals. In addition, CBs are

specified to have passed a representative laboratory type test as per IEC 61233 (i.e. predecessor of IEC 62271-110). Most of the 420kV SRs in Turkey have the neutral solidly grounded. A few are grounded via a neutral reactor.

**4.3 Transient overvoltages due to fault clearing in EHV-lines**

Line/substation fault clearing can also produce high SFO in series compensated lines. In general, the magnitudes of these transient overvoltages vary depending on: line length, rated characteristics of series-capacitor banks, fault types, fault locations as well as the location(s) of series-capacitor bank(s) along the line. Records of annual fault occurrence on the 735-kV series-compensated system in Canada show that 90.2% of faults are 1-phase-to-ground and 9.8% are 2-phase/3-phase faults [14]. The EHV system of Hydro Quebec is shown in Appendix A1, figure A1-1.

Concerning the clearing of 1-phase-to-ground faults, for the case of a 230-km line with series compensation at one line end, a maximum 1.80-pu SFO was observed while a maximum 2.07 pu was recorded on a 379-km line with series compensation at the middle [17]. These overvoltages due to 1-phase-to-ground fault clearing are withstood by the insulation of the 735-kV lines in Canada.

Although the annual occurrence of 2-phase and 3-phase faults is low, much more severe SFO were observed when clearing these types of faults. For the case of a 230-km line with series compensation at one line end, a maximum of 3.25-pu SFO was observed when clearing 2-phase ungrounded line faults. For the case of the 379-km line with series compensation at the middle, a maximum of 3.12-pu SFO was recorded when clearing 3- $\Phi$ -to-ground substation faults [17]. The overvoltages due to 2-phase/3-phase fault clearing are much higher than the switching impulse withstand voltage of 735-kV line insulation. The applied mitigation measure is the use of permanently connected SAs at both line ends and also of SAs at one terminal of SCs located at the line midpoint.

The installation of permanently connected SAs at both line ends has also allowed limiting the maximum SFO in the Chilean 500-kV series-compensated system to 2.09 pu [5].

Table 4.3-I: Fault occurrence on 735-kV transmission lines of Quebec, Canada with total length of 11280 km

Type of fault	Annual occurrence
1-phase-to-ground	38.3 (90.2%)
2-phase-to-ground and 2-phase ungrounded	3.64 (8.6%)
3-phase-to-ground and 3-phase ungrounded	0.48 (1.2%)

The very low failure rate (0.38 faults/100km-year, as shown in Table 4.3-I) recorded for the 735-kV transmission lines of Quebec is due, on one hand to the high rated voltage and associated high insulation level and, on the other hand, to the very low keraunic level of the region, to the absence of pollution and of human activities contributing to line failures.

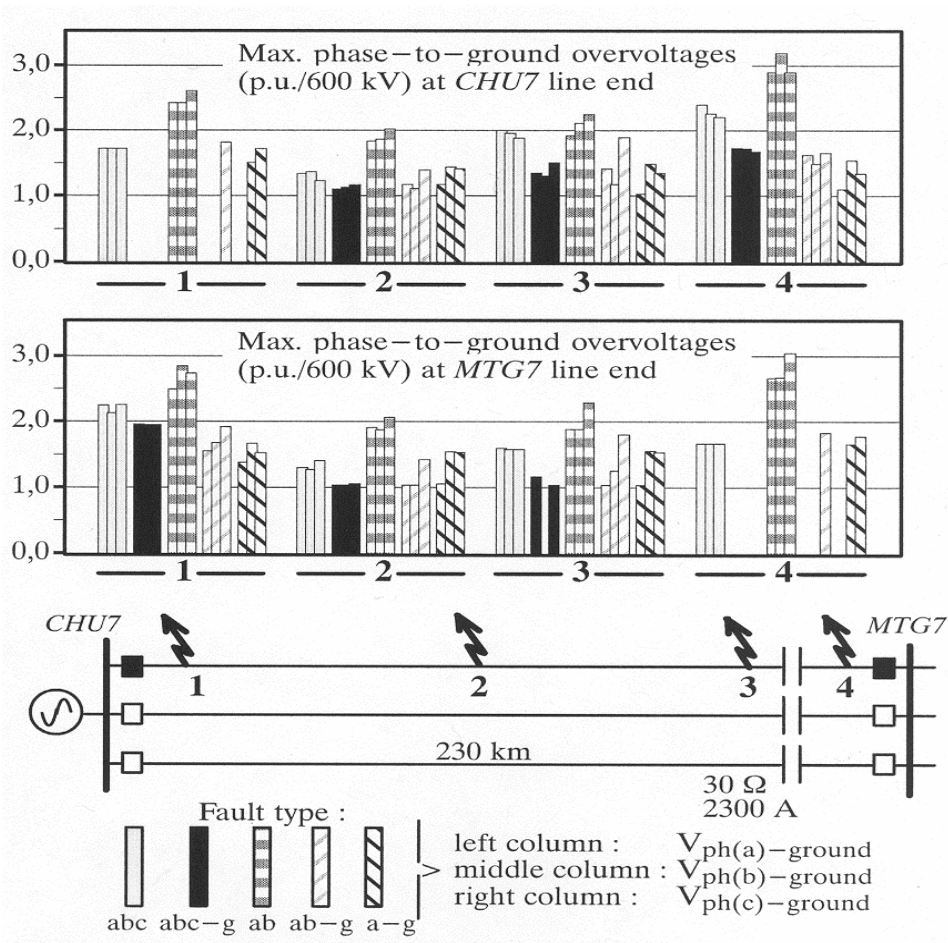


Fig. 4.3-1 Maximum phase-to-ground SFO at both line ends due to fault clearing in a 735- kV series compensated line of Canada [3] – SC located at one line end

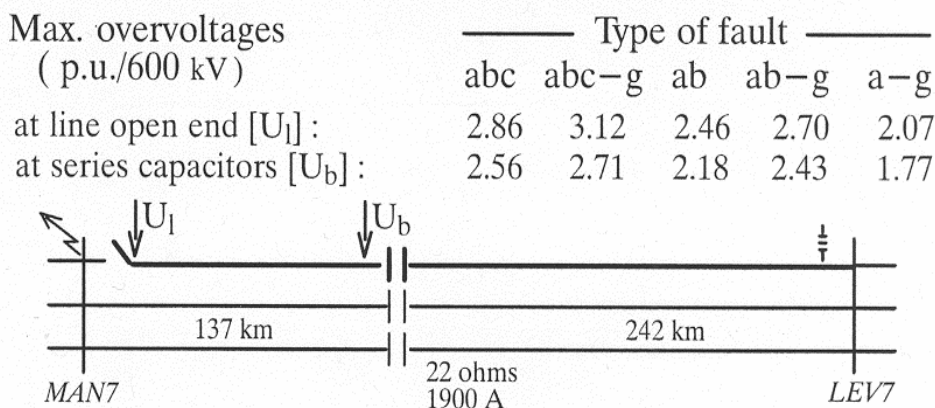
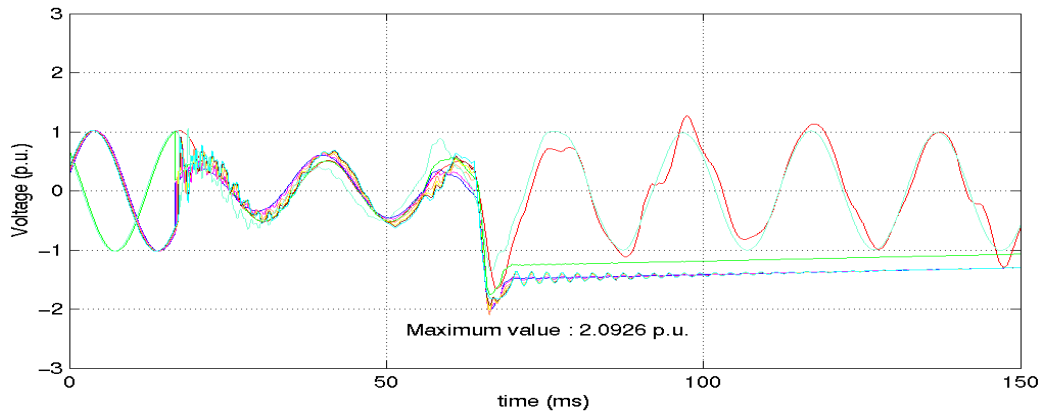


Fig. 4.3-2 Maximum phase-to-ground SFO at  $U_1$  and  $U_b$  due to a busbar fault clearing in the 735- kV series compensated system of Canada [3] – SC located out along the line



*Fig. 4.3-3 Maximum phase-to-ground SFO (pu/408.2 kV) due to clearing a 2-phase ungrounded fault on a 500 kV series compensated line of Chile [4] equipped with surge arresters at both line ends*

#### 4.4 Requirements for permanently connected SAs and switchable MOSAs

The selection of the ratings for permanently connected MOSAs is generally performed in accordance with the IEC standards 60099-4 [87] and 60099-5 [88]. For example in the Hydro-Quebec 735-kV series-compensated system the following MOSAs characteristics have been selected: maximum continuous operating voltage (MCOV)  $\geq 1.05 U_m$ , where  $U_m$  is system maximum operating voltage:  $MCOV \geq 1.05 \cdot 765 \text{ kV} / \sqrt{3} = 463.8 \text{ kV rms}$ . The selected MCOV for MOSAs is 470 kV rms resulting with the selected manufacturer in a rated voltage of 588 kV rms.

In order to obtain sufficient insulation safety margins, these MOSAs are installed close to equipment with non self-restoring insulation such as power transformers, SRs. They are also located at 735-kV series-compensated line ends for limiting the magnitudes of SFO along the line as well as TRV stresses on line CB during line fault clearing.

In the 735-kV grid of Quebec special switchable and potentially sacrificial MOSAs with lower rated voltage have also been applied to limit the load rejection TOVs (a function normally not provided by standard MOSAs). As discussed in section 3.1, following a full load rejection (or a system separation), large TOVs appear on long unloaded lines that are still connected to generators. These TOVs could reach the protective levels of the standard 588 kV MOSAs and impose excessive energy stresses on these MOSAs. In order to better limit the TOVs magnitude and duration as well as prevent damage to system strategic equipment (i.e. circuit breakers, power transformers, SRs, permanently connected MOSAs, etc.), a special protection system consisting of switchable MOSAs compounded by an overvoltage protection has been implemented. Fig. 4.4-1 illustrates the design principle of this special protection system. The selected switchable, potentially sacrificially special MOSAs have the following characteristics:

Rated voltage	484 kV rms
Maximum continuous operating voltage (MCOV)	387 kV rms
TOV withstand capability	530 kV rms for 30 s
Maximum insertion time	15 s

In case of detection of local power swing and/or, system over-frequency and/or of loss of transmission corridor, the maximum residual voltage with current wave of 5 kA, with 1000  $\mu\text{s}$  wave front is 1.6 pu ( $1 \text{ pu} = 735 \text{ kV} \sqrt{2} / \sqrt{3}$ ). In case of energy absorption exceeding their capability, these special MOSAs are

foreseen to fail in a safe failure mode, i.e. resulting in a short circuit without explosion of the porcelain housing.

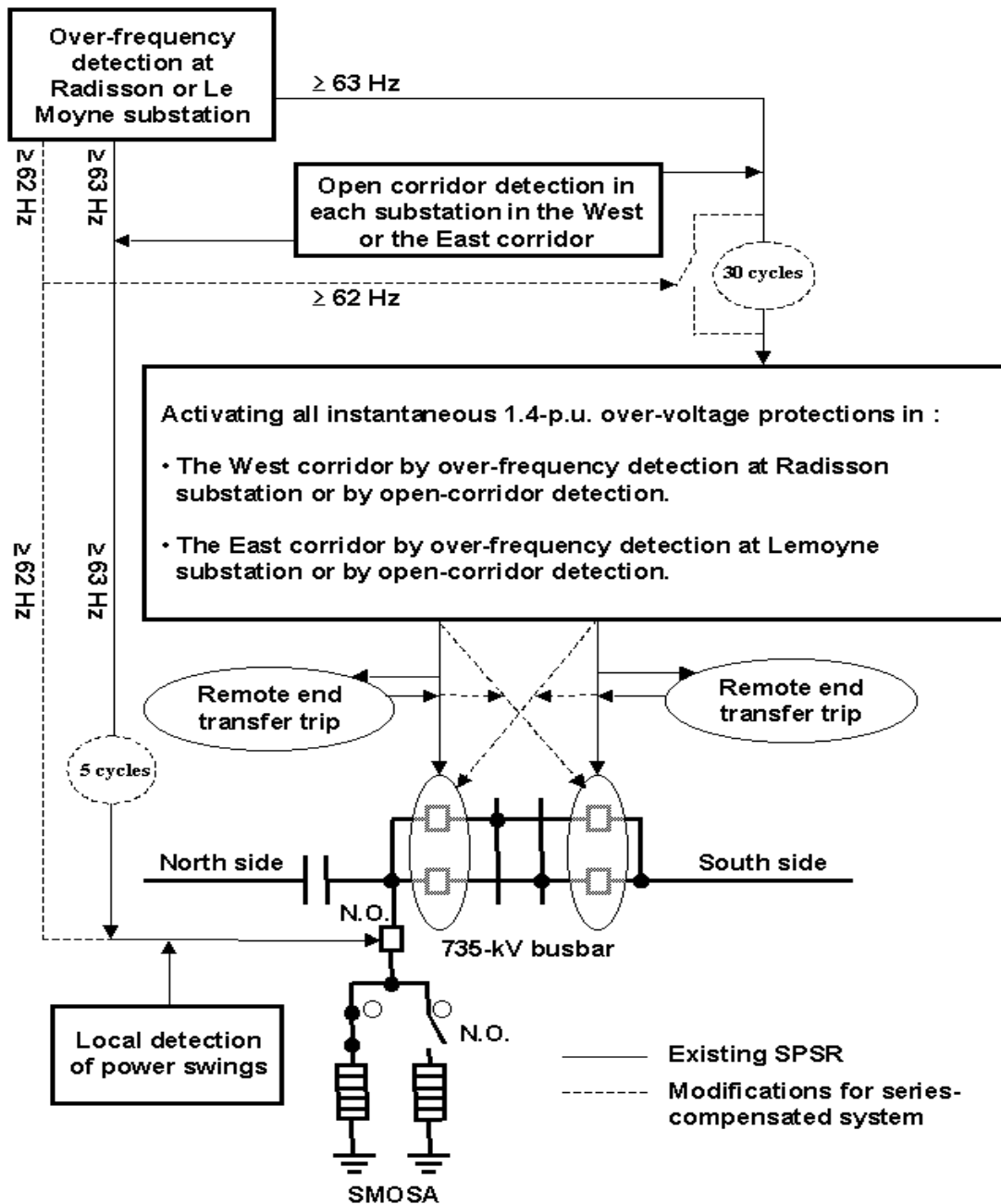


Fig. 4.4-1: Special protection system using switchable, potentially sacrificial MOSAs and overvoltage protection for limiting TOV magnitude and duration.

## 5. TRANSIENT RECOVERY VOLTAGES

### 5.1 Clearing of OH-line faults

In the International Standards [22] clearing of faults from OH-lines is specified with TRV's when breaking 100%, 60%, 30% and 10% rated short-circuit current. The TRV-waveshapes have either 4-parameter envelopes, based on over-damped responses from the system plus reflected waves from the shortest lines, or 2-parameter envelopes, based on under-damped single frequency response typically for transformer secondary faults. The TRV-peak values vary from 1.82 to 2.0 pu (systems with neutral solidly grounded). Three-phase to ground faults are covered by IEC, but IEC also notes that the probability of multi-phase ungrounded faults is so low that it can be neglected (see note below).

For EHV and UHV transmission systems 3-phase faults are generally less than 3% of all faults and about one quarter are three-phase faults without contact to ground. These ungrounded faults are to a large extent caused by bush fires or other fires under the OH-line. Ungrounded 3-phase faults lead to a FPCF of 1.5. As the discussion on the FPCF are mainly related to T100, the next considerations have to be taken into account:

- the probability that the maximum short-circuit current is close to T100 is low
- the maximum short-circuit current level will be related to a fault in or close to the substation
- the probability of a multi-phase fault is low
- the probability of a bush-fire close to a substation is low.

The combination of all these low probabilities leads to the conclusion that 3-phase faults close to a substation with maximum short-circuit power can be neglected, so that clearing grounded 3-phase fault currents are within IEC the basis for rating (for systems with an effectively grounded neutral).

Apart from these test duties, that are derived from old TNA-studies for meshed transmission networks [79], special test duties have been introduced for single phase fault current switching, for out-of-phase switching and for short-line fault (SLF) clearing. SLF deals with a single phase fault at a distance of a few km or less from the substation, where especially the very steep RRRV due to the travelling waves, is crucial for the CB performance.

Under discussion within CIGRÉ WG A3.19 is the necessity to test for 3-phase short-line faults and to test for faults at a longer distance (roughly 100 km), where in both cases the travelling waves could perhaps lead to higher TRV peak values than in the single phase case. The studies of WG A3.19 on single phase and multi-phase LLF consider whether these applications are covered by the TRV for Out-of-Phase, provided that the shortest time to peak as given in the IEC-Standards is prescribed.

### 5.2 Clearing of series-compensated line faults

The increase of TRVs across line CBs when clearing fault currents flowing through series capacitors (SCs), has been known for many years [24]. This phenomenon is caused by the trapped charge that can remain on SCs at the moment of line current interruption. The associated voltage adds to the TRVs that occur without SCs.

It has been demonstrated [25] that modern SCs protected by MOVs cause higher and more frequent TRVs on line CBs than SCs of old technology protected by self-triggered spark gaps. The largest TRVs occur in the presence of maximum trapped charge on SCs located on both the line and bus side of a CB. Referring to figure 5.2-1, which shows four of the series

compensated lines of the Turkish 420kV grid, this phenomenon occurs in the CBs of the intermediate Yesilhisar substation when clearing faults located at point 10 or point 3.

TRVs up to 4.78 pu [25] (see table 5.2-I) or up to 4.8 pu [17] can occur if no measures are applied for limitation. RRRV usually does not exceed 1.3kV/ $\mu$ s. For EHV CBs the IEC Standard [22] stipulates a TRV of 2.5 pu for the out-of-phase breaking current type test, with RRRV of 1.54 kV/ $\mu$ s. This is the highest required TRV by the Standards and should be referred to when checking the CB capacity here dealt with.

There are two applicable approaches for solving the problem: specify CBs with increased TRV capability or apply measures for TRV limitation. If applied to 420 kV and 550 kV CBs, the first solution generally requires use of an increased number of chambers in series per pole (say, 3 instead of 2). Along with this solution, there is a higher cost and higher installation space requirement, and reduction of mechanical security because of increased number of operating mechanisms and complexity.

The following measures have been applied for limiting the TRVs here dealt with:

- (i) Use of CBs with linear opening resistors rated at 400 to 600  $\Omega$ , switched by auxiliary contacts of the CB.
- (ii) Use of surge arresters (SAs) connected phase-to-ground on the series compensated lines.
- (iii) Use of MOVs connected in parallel with the main contacts of CBs.
- (iv) Fast by-passing of SCs of the faulty line by forced triggering of the protection spark gap, or by closing the by-pass CB.

Switched linear resistors have been used in the 1960s – 1970s (in North America, Turkey, etc.), in particular with air blast CBs, a technology which permitted the application of both the closing and opening resistors. Modern SF6 puffer type CBs can be fitted with closing resistors, but are generally not designed to be fitted with switched opening resistors or with closing and opening resistors. On the other hand, cases of mechanical failure (explosions of resistors due to stuck closed auxiliary contacts of CBs and prolonged current flow on resistors) have occurred. Use of solution (i) has therefore been discontinued.

EMTP studies performed for the 500kV transmission system of British Columbia (Canada) [17] have shown that a TRV reduction to within 3.2 pu when clearing short circuit currents flowing through SCs is feasible when using SAs at both line ends and at the line midpoint. Special design SAs having a switching impulse protection level (SIPL) of 1.57 pu, a rated voltage of 372kV and MCOV of 318kV [17] have been applied in this system.

In many EHV grids, in particular in most of the 420kV grids of Europe, standard commercial SAs with SIPL of about 2 pu are applied with rated voltage of 360kV, the MCOV of which has some margin above the maximum operation voltage. ATP-EMTP studies have shown that the SAs cannot adequately limit the TRVs [25].

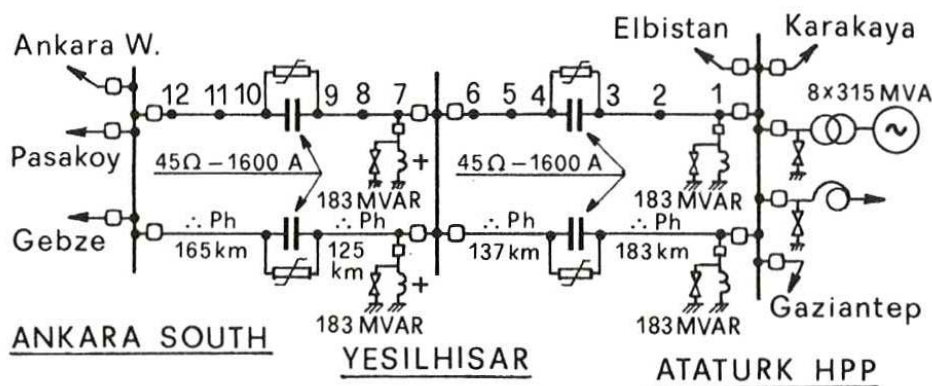
Solution (iii) uses MOVs connected in parallel with the interrupting chambers of CBs [25] [16]. These MOVs are standard MOSAs in porcelain or polymer housing, which can be fitted in the space allocated on CBs for the closing resistors, in parallel with the grading capacitors. Checks made by three leading manufacturers of live-tank CBs have shown that the mechanical design made for supporting the closing resistors is adequate for supporting MOVs instead. If no use is made of closing resistors, the MOVs can thus be applied without further design modification of the CBs.

ATP-EMTP studies for a 420kV grid have shown that MOVs with a 1kA SIPL of 2.5 pu connected across a line CB can limit the TRV to within 2.5 pu, provided there is no network re-synchronizing requirement with the involved CB. On the other hand, if the MOVs connected in

parallel with contacts of CB are required to withstand with good margin the voltage beats during re-synchronizing of separated systems, they must have a higher rated voltage (i.e. higher temporary overvoltage withstand capacity and higher SIPL) and consequently TRVs are limited to within 3 pu. The latter solution has been applied with commercial 420kV CBs possessing a TRV withstand capacity of 3 pu. Actually, for the sake of standardization of the interrupting chambers of 420kV and 550kV CBs, most manufacturers supply 420kV CBs with 2 chambers per pole designed for 550kV, providing a TRV capacity of 2.5 pu at 550kV and 3 pu at 420kV.

Solution (iv), i.e. fast by-passing of SCs, is feasible if SCs are provided with forced triggered protective spark gaps. It requires a high reliable triggering signal transmission to SC, if the SC is located out along the line, far from the protection relays detecting the line fault. Keeping in mind that a transfer signal failure or spark gap forced triggering mis-operation might have disastrous consequences (possible explosion of interrupting chambers of CB), a signal receipt confirmation of by-passed SC bank is advisable before tripping the line CB. The consequential delay in the line fault clearing should be acceptable. In some systems SCs of lines adjacent to a faulty line contribute to TRV magnification [25]. The ensuing need of also having to by-pass SCs external to the faulty line may erode or jeopardize system stability.

If by-passing of SC is performed by closing the by-pass CB with a transfer signal, the total time delay is increased by the closing time of the by-pass CB (this depends on type of operating mechanism), to which the time of auxiliary relay and the discharge time of capacitors through the damping reactor must be added.



+ assumed out of service

Fig. 5.2-1 - Single-line diagram of the 420 kV lines Ataturk HPP- Yesilhisar- Ankara South, Turkey

The results of an ATP-EMTP analysis performed for the 420 kV series-shunt compensated lines shown in figure 5.2-1 are reported next. These lines are part of the 420 kV national grid of Turkey shown in Appendix A3, figure A3-1 and connect the Ataturk 2400 MW hydroelectric power plant to Ankara and Istanbul metropolitan areas over a distance of 940 km [25]. The transmission section shown in figure 5.2-1 consists of two single-circuit 420 kV lines equipped with triplet bundle 3x726 sqmm ACSR conductors, in service since 1995, each including two SCs banks rated at 45 Ω - 1600 A and protected by MOVs with a protection level at 10 kA of 2.2 pu ( $1 \text{ pu} = \sqrt{2} \cdot 45 \Omega \cdot 1600 \text{ A} = 101.8 \text{ kV}$ ).

EMTP simulations were first performed with the two lines in service prior to a fault, without any means for limiting TRVs. Results are summarized in Table 5.2-I, cases A.I to A.IV. The highest TRV of 3.99 pu occurs when clearing the highest short circuit current, i.e. for faults

close to SCs terminals (point 10 in figure 5.2-1). This TRV and the bus and line side components are plotted versus time in figure 5.2-2a. The highest component occurs at the bus side.

Table 5.2-I TRVs on CBs of Ataturk HPP-Yesilhisar-Ankara South series compensated lines.  
All lines in service prior to fault, unless otherwise indicated. (1 pu=420√2/√3=342.9kV)

Case	3-φ - to-Gr Fault at	Max. TRV across CB			TRV compon. [p.u/p.u]		RRRV [kV/μs]	Energy Dissip. [MJ]	CB at	Means for TRV reduct.
		[kV]	[p.u.]	Ph.	Bus Side	Line Side				
A. I	10	1367	3.99	T	2.47/1.51	0.52	-	YESIL.	NONE	
A. II	9	1154	3.37	S	1.16/2.21	1.03	-	ANKARA.		
A. III	4	1159	3.38	S	1.00/2.38	0.95	-	ATATURK		
A. IV	3	1356	3.95	T	2.28/1.67	0.48	-	YESIL.		
A. V <sup>''</sup>	10	1639	4.78	T	3.57/1.21	0.64	-	YESIL.		
B. I	10	1224	3.57	T	2.01/1.56	0.47	0.70	YESIL.	+) SAs	
B. II	9	1065	3.11	S	1.16/1.94	0.95	0.00	ANKARA		
B. III	4	1023	2.98	S	1.04/1.94	0.93	0.10	ATATURK		
B. IV	3	1264	3.69	T	1.98/1.71	0.44	1.30	YESIL.		
B. V <sup>''</sup>	10	1155	3.37	T	1.03/1.34	0.44	.70	YESIL.		
C. I	10	1017	2.97	T	2.22/0.75	0.39	1.10	YESIL.	++) MOVs across CBs	
C. II	9	960	2.80	S	1.05/1.75	0.85	0.17	ANKARA		
C. III	4	973	2.84	S	0.92/1.92	0.78	0.24	ATATURK		
C. IV	3	1001	2.92	T	2.08/0.84	0.37	0.80	YESIL.		
C. V <sup>''</sup>	10	1036	3.02	T	2.40/0.62	0.38	2.10	YESIL.		

+) MOSAs with SIPL of 2.04 pu are simulated at the terminals of each line, phase-to-ground

++) V-I curve of simulated MOVs is provided in Par. 3.4 of ref. [25]

") Only one line in service from Ataturk HPP to Ankara South

A magnification of the TRVs occurs if one of the parallel lines of figure 5.2-I is out of service: case A.V in table 5.2-I shows a TRV increase from 3.99 to 4.78 pu. On the other hand, a magnification of the TRVs by as much as 20% occurs if a 3-phase short circuit insulated from ground is simulated instead of the cases of 3-phase-to-Gr short circuits reported in table 5.2-I.

Cases B.I to B.V of table 5.2-I summarize the results obtained by repeating the same 3-phase-to-ground fault cases with simulation of MOSAs on the bus side and line side of CBs, of the standard type in use in Turkey with rated voltage of 360 kV rms and SIPL of 700 kV (2.04 pu). As shown in table 5.2-I, these MOSAs do not limit the TRVs within the maximum withstand capacity (3 pu) of the available 2-chamber per pole commercial 420 kV CBs.

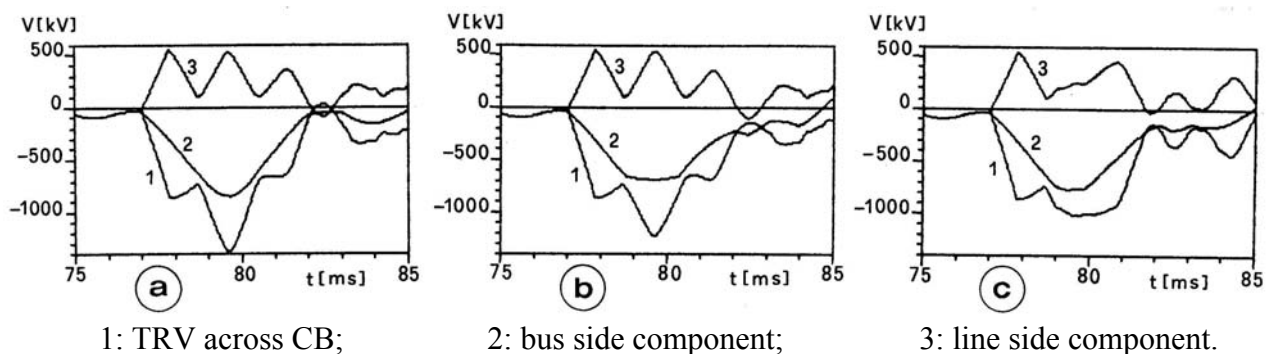


Fig. 5.2-2 – TRVs versus time across an Yesilhisar CB of one Yesilhisar –Ankara S. line.

a: no TRV limiting means (case A.I, table 5.2-I)

b: TRV limited by MOSAs (case B.I., table 5.2-I)

c: TRVs limited by MOVs across CBs (case C.I, table 5.2-I)

Cases C.I to C.IV of table 5.2-I summarize the results obtained by simulating MOVs connected across the contacts of CBs, with a 1 kA SIPL of 3 pu. TRVs for the Yesilhisar CBs are reduced from 3.99 pu to 2.97 pu. Figure 5.2-2c is a plot of this TRV. The energy dissipated in MOVs during fault clearing is 1.1 MJ, i.e. 20% of MOVs energy capability. Case C.V of table 5.2-I shows that the same MOVs provide a drastic limitation of the TRVs if one of the two lines of figure 5.2-1 is out of service, from 4.78 pu to 3.02 pu, still with a limited energy dissipation (40% of MOVs energy capability).

MOVs limiting the TRVs are by-passed in normal operation by the closed contacts of CBs and therefore are not subject to losses. On the other hand, during re-synchronizing of two separated sub-systems via a CB, these MOVs are subject to a voltage beat, with voltage variable from about zero to 2 times the phase-to-ground operation voltage. This requirement controls the choice of the V-I curve of the applicable MOVs.

In the Turkish 420 kV grid, the MOVs here dealt with are specified to withstand without damage  $2 \times 420 / \sqrt{3} = 485$  kVrms for 5 minutes, following the energy dissipation of  $2 \times 2.8 = 5.6$  MJ, which can be caused by 3 of the most adverse TRVs in close succession prior to re-synchronization. The MOVs fitted on the two-chamber per pole 420 kV CBs are similar to Class 4 MOSAs with rated voltage of  $2 \times 270$  kV = 540 kV (MCOV = 430 kV).

Figure 5.2-3 shows the power and energy dissipated during one beat, equivalent in average to 2.6 kJ per second. The MOVs can therefore withstand re-synchronizing beats lasting 16.5 minutes. As a safety measure, it is foreseen that a timer, initiated by opening for whatever reason of a CB equipped with MOVs, after 15 minutes will block closing of CB and open the disconnecting switches on the two sides of CB, to prevent overheating of MOVs in case of delayed re-synchronizing or permanent opening of the line.

Analysis has shown that, in the case where there are no requirements of system re-synchronizing with the CBs of interest, MOVs rated  $2 \times 225$  kV = 450 kV could be used, limiting the TRVs within 2.5 pu.

The good operation experience of 12 years (396 CB pole-years) in the Turkish 420 kV transmission grid has confirmed the viability of the TRVs limitation by MOVs connected in parallel with the contacts of CBs.

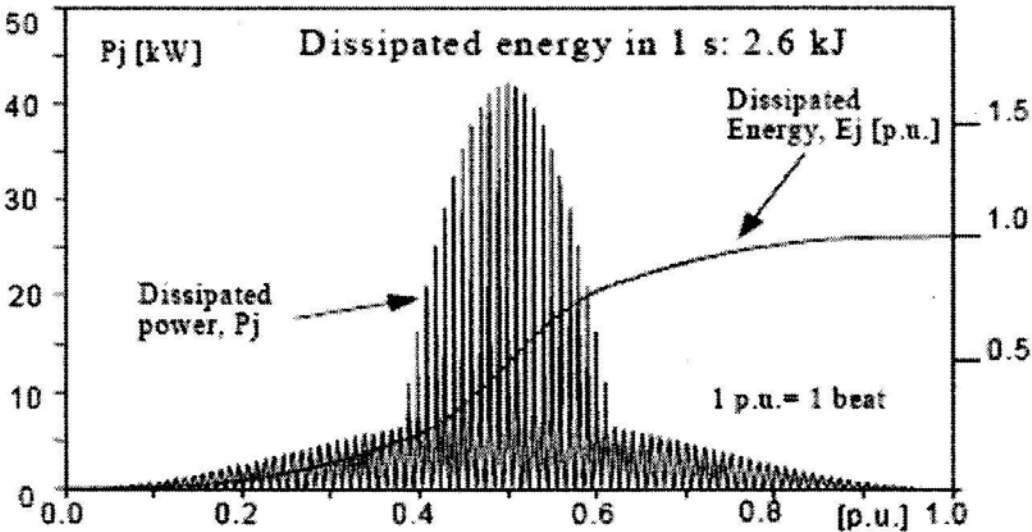


Fig. 5.2-3 – Power and energy dissipated in MOVs connected across a CB, versus time, during one beat when synchronizing two 420 kV networks

### 5.3 Interruption of capacitive currents

Former studies of CIGRÉ SC 13, WG 13.04, give detailed information about the phenomena related to the interruption of capacitive currents associated with shunt capacitor-banks, filter banks, unloaded lines and unloaded cables [54][55][56][57]. Also in a recently published CIGRÉ Technical Brochure, 305 “Guide for the Application of IEC 62271-100 and IEC 62271-1”, part 2, background information on capacitive current switching tests has been given [38]. Based on the information given in Technical Brochure 305, some aspects relevant for long lines will be elaborated in the next paragraphs.

After the initial voltage jumps, the recovery voltage contains power frequency components, some of which are only applicable to OH-lines. The initial phenomena and the power frequency phenomena are summarized below.

The initial voltage jumps, immediately after the interruption of the capacitive current, are caused by:

- at the source side of the CB a sudden reduction of the source side voltage due to the disappearance of the negative voltage drop across the source side impedance
- if load is a shunt capacitor, a sudden increase of the load side voltage due to the disappearance of the negative voltage drop across a (possible) load side reactor
- if load is an un-loaded (open ended) line, a sudden increase of the line side voltage due to travelling waves that equalize the voltage increase across the line as caused by the Ferranti-effect.

The initial voltage jumps may cause re-ignitions at very short arcing times, thus leading to longer arcing times, that will give a higher probability of restrike-free interruptions.

The power frequency recovery voltage is dependent on the neutral treatment at the source side, on the neutral treatment at the load side, on the probability of switching during an earth fault and on the time interval until the next clearing pole (pole non-simultaneity, which according to the standard [30] should not exceed 1/6 cycle). Under the condition of no earth fault and no neutral shift at the source side, the source side voltage will be around 1 pu. Distinction can be made between the following recovery voltage components at the load side of the CB's first clearing pole:

- the DC-voltage at the load side capacitance (1 pu) with a correction for the Ferranti-effect (i.e. 1% for a 200 km long line at 50 Hz and 4% for a 500 km long line) and the load side voltage jump across a series reactor in front of a shunt-capacitor bank (up to 10%) [58]
- the AC-neutral shift of the shunt capacitor-bank (in case of a non-earthed neutral: 0.5 pu after the quarter cycle of power frequency that it lasts until the next poles clear, or 1.0 pu in case of a large non-simultaneity)
- the AC-interphase coupling in an OH-line (or the virtual neutral shift of the line: 0.2 pu after a quarter cycle)
- the AC-inter-circuit coupling in an OH-line (up to 0.2 pu has been reported) [58][38].

As explained in [38] and shown there in figure 29, the effect of the neutral shift at the load side has been translated into a voltage factor that should be applied for single phase type tests. In the Standards, the 0.5 pu shift of the neutral of a shunt-capacitor bank gives a power frequency recovery voltage that reasonably can be approached by a single phase test with a voltage factor of 1.4, thus a recovery voltage of 2.8 pu.

In a similar way, for unloaded OH-lines, the neutral shift of 0.2 pu at the line-side gives a voltage factor of 1.1 when simulated by single phase tests. In addition an induced voltage from another circuit on the same towers may appear, giving an inter-circuit coupling of 0.2 pu (for moderate line lengths). The induced voltage at the load side results in an increase of the voltage factor to 1.2, in order to simulate adequately the inter-circuit coupling. For long lines the inter-circuit coupling may be larger; moreover, the Ferranti-effect cannot be neglected, as shown in figure 5.3-1, where the switching simulation results of unloaded 550 kV-lines of Furnas, Brazil, are plotted; see also [77]. The longer the line, the larger the voltage jump. The Ferranti-effect at the line-side and/or temporary overvoltages at the moment of switching off the OH-line, may cause recovery voltages that are higher than twice the voltage factor multiplied by the rated voltage of the CB. How to cover such situations is addressed in the following paragraphs.

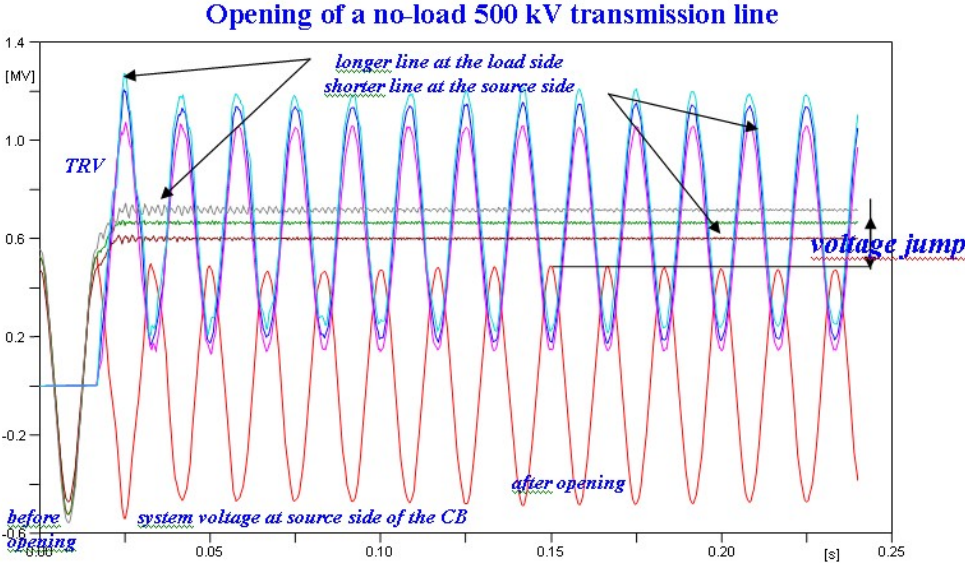


Fig. 5.3-1 No-load switching of 550 kV-lines with different lengths

Single phase testing for clearing unloaded OH-lines requires a voltage factor of 1.2, as prescribed in the Standards [22][28]. The test is performed at the rated voltage of the CB, and it has been assumed that the rated voltage includes the system voltage plus the initial voltage jump. For systems with a non-effectively earthed neutral, the Standards prescribe a voltage factor of 1.4 (single phase test), meaning that CBs designed and tested for this voltage factor will show a positive margin, when applied in systems with an effectively earthed neutral: +17%.

An identical situation occurs when switching off shunt capacitor-banks. The Standards require a voltage factor of 1.0 for systems and capacitor banks with earthed neutrals and a voltage factor of 1.4 if one neutral is or both neutrals are non-earthed. When properly tested for a non-earthed neutral and applied for an earthed neutral, a positive margin of about 40% is possible, depending on the neutral shift in the system at the location of the bank. By such a margin, when properly applied, certain temporary overvoltage conditions are covered [23]. But, in case of clearing under earth fault conditions, the margins quickly disappear, as the voltage factors prescribed then are 1.4 for systems and capacitors with both earthed neutrals, and 1.7 otherwise.

So, careful consideration is necessary when use is made of the different voltage factors offered in the Standards to cover extended networks. [38] mentions another approach, that may be

useful for cases that occur infrequently. Reference is made to out-of-phase switching tests, where high peak values of the TRV have to be covered at currents relatively small in comparison to short-circuit currents, but larger than capacitive currents. In the next section capacitive current switching under TOV-conditions, as well as out-of-phase switching will be addressed.

Another characteristic of long lines is the level of the line-charging currents which may be higher for extra long lines than the preferred values given in the Standards: 125 A at 245 kV, 400 A at 420 kV, 500 A at 550 kV and 900 A at 800 kV [38]. This is certainly the case for healthy phase switching under phase-to-earth faults and the case of simultaneous switching of multiple series connected lines, which may occur in the early stages of system development, but also in the circumstances of system disturbances.

Careful examination is recommended of the probability of simultaneous occurrence of circumstances that lead to TOVs [36]. Some examples are:

- a phase-to-earth fault on a long OH-line with consequential line tripping, first the load side
- load rejection, leading to high over-voltages that cause a phase-to-earth fault and consequential line tripping
- a phase-to-earth fault on a long OH-line with a failure of the CB to trip and consequential multiple line switching
- load rejection of a heavily loaded long line and consequential line tripping without shunt compensation.

Shunt compensated lines do not show a DC-recovery voltage at the load side, but a voltage oscillation with a frequency lower than the power frequency (power frequency\* $\sqrt{(K/100)}$  with K being the compensation percentage) [59], making the recovery voltage stress less severe than with uncompensated lines. The difference between switching off an unloaded line without shunt-compensation and with shunt compensation can be seen in figures 5.3-2 and 5.3-3, respectively. The simulations have been performed by Furnas, Brazil, for their 550 kV lines [77].

Series compensated lines show the same behaviour as uncompensated lines, but the Ferranti-effect will be less. Besides, series compensated lines may also be shunt compensated, showing the oscillatory recovery voltage at the line-side.

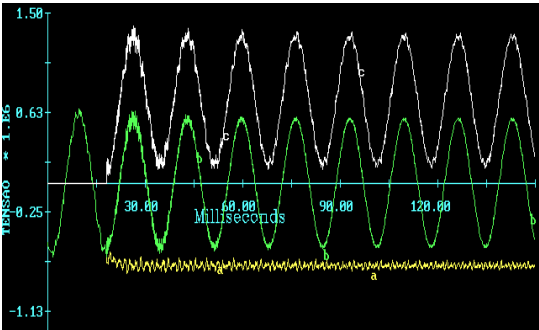


Fig. 5.3-2 Switching off a 550 kV line without shunt-compensation: green: busbar-side; yellow: line-side; white: TRV

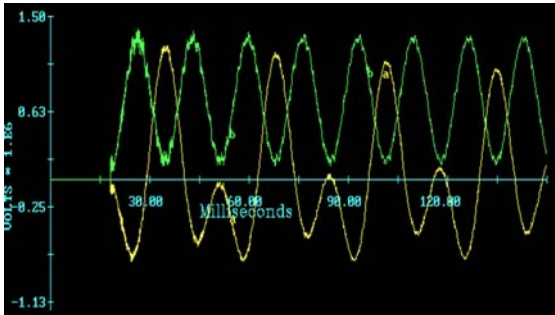


Fig. 5.3-3 Switching off a 550 kV line with / without shunt compensation: yellow: TRV with compensation; green: TRV no compensation (green as white of fig. 5.3-2)

Summarizing, capacitive switching of unloaded long lines differs from clearing the capacitive currents on small or medium length lines, as the capacitive currents will be higher<sup>1</sup> (frequently under circumstances of disturbances), the induced voltages will be higher, the Ferranti effect more dominant and switching under high TOV-conditions more probable. On the other hand, usually shunt compensation will be applied and possibly also series compensation, both leading to less severe recovery stresses when switching off the long OH-line.

<sup>1</sup> Higher capacitive currents do not mean that switching is more difficult for CBs.

### 5.4 Out-of-phase interruption and de-energization of unloaded lines under high TOV

It has been mentioned in section 3.1 that line circuit breakers in long distance radial shunt/series-compensated systems are subjected to TRV stresses due to out-of-phase clearing and de-energization of unloaded line under high TOV. As illustrated in figure 5.4-1a and 5.4-1b, in the 735-kV series-compensated system in Canada [3] [15], maximum TRV stresses due to out-of-phase clearing and unloaded line interruption under high TOV are of 3.3 pu and 3.5 pu respectively. These TRV stresses are beyond the IEC requirements for 800-kV class circuit breakers [22]. As a consequence, special EHV circuit breakers with appropriate TRV withstand have been implemented in this system.

Severe TRV stresses due to out-of-phase clearing and unloaded line interruption under high TOV have also been observed in the 500-kV series-compensated systems in Vietnam and in Chile [4] [5]. 550-kV line circuit breakers with adequate TRV withstand capabilities have also been applied in these systems. The figures given are also representative for other 500 kV grids.

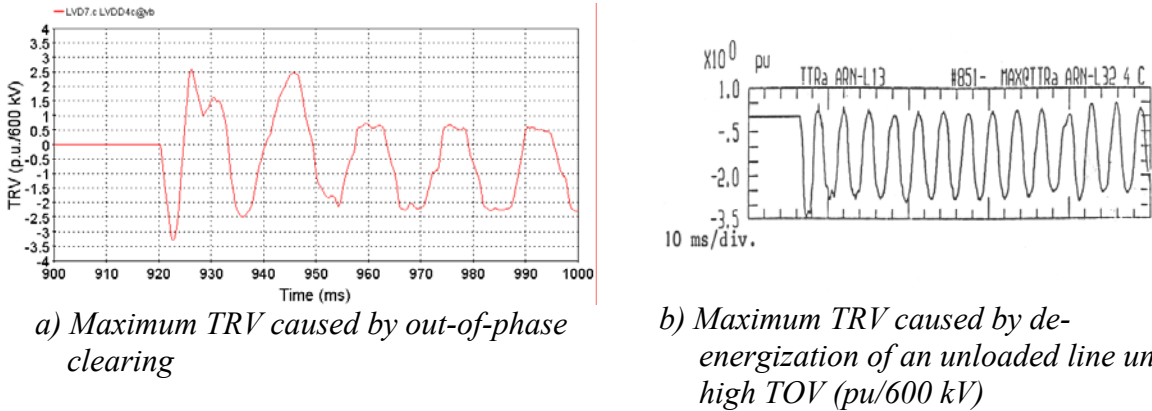


Fig. 5.4-1 Maximum TRVs caused by out-of-phase clearing and de-energization of a 735 kV unloaded line in Canada under high TOV

For the 400 kV – 50 Hz long lines in Turkey (Appendix A3, figure A3-1), CBs have been specified, since the early 1970s, on the basis of system transient analysis, with more severe unloaded line breaking capacity than IEC requirements. Prototype testing to break capacitive currents of at least 650 Arms with a pre-switching phase-to-phase voltage of 500 kVrms and an after breaking source side phase-to-phase voltage of 400 kV, with and without ground faults in one or two phases (earth fault factor 1.26) was performed. Over 30 years of operation experience has confirmed the adequacy of these requirements, which were first applied for minimum oil and air blast CBs, and then for SF6 CBs.

## 5.5 Clearing faults in Half Wave Length Lines

The CBs at the ends of naturally tuned HWLLs have to withstand the highest TRVs when clearing faults located close to the end of the HWLL. The ATP – EMTP analyses performed for 800kV and 1050kV, 60Hz, 2500km long HWLLs [8] [9], have shown that the CB at the sending end is subject to TRVs of 3.2 pu, however with a modest RRRV ( $0.25 \text{ kV}/\mu\text{s}$ ), when clearing a 3- $\phi$  short circuit located at the receiving end. Similar TRVs have been calculated for 800kV, 50Hz, 3000-3200km long HWLLs.

EHV CBs are required by IEC Standards [22] to withstand TRVs of 2.5 pu when interrupting in out-of-phase conditions. It is therefore necessary to use CBs with up-rated TRV capacity or to apply TRVs limiting measures, such as MOVs connected in parallel with the contacts of CBs.

## 6. OUT-OF-PHASE SWITCHING

### 6.1 Out-of-phase phenomena

When a CB interrupts a current, between two systems, the systems will pass into new steady-state operation conditions. The transition from the pre-switching voltages (equal for both terminals of the CB) to the new power frequency voltages after clearing will follow a transient pattern, typically with an over-swing and dominated by the natural frequencies of the systems on each side of the CB. The power frequency voltage across the CB is called the recovery voltage (RV), whereas its transient part is called the transient recovery voltage (TRV). Under phase-opposition (an out-of-phase angle of  $180^\circ$ ), the (transient) voltages on each side will have an opposite sign and can be regarded as parts of the total (transient) recovery voltage; see figure 6.1-1 for these parts of the TRV. Note that the amplitudes of TRV1 and TRV2 may differ considerably, depending on the difference between pre-switching and after clearing voltages at each side of the CB.

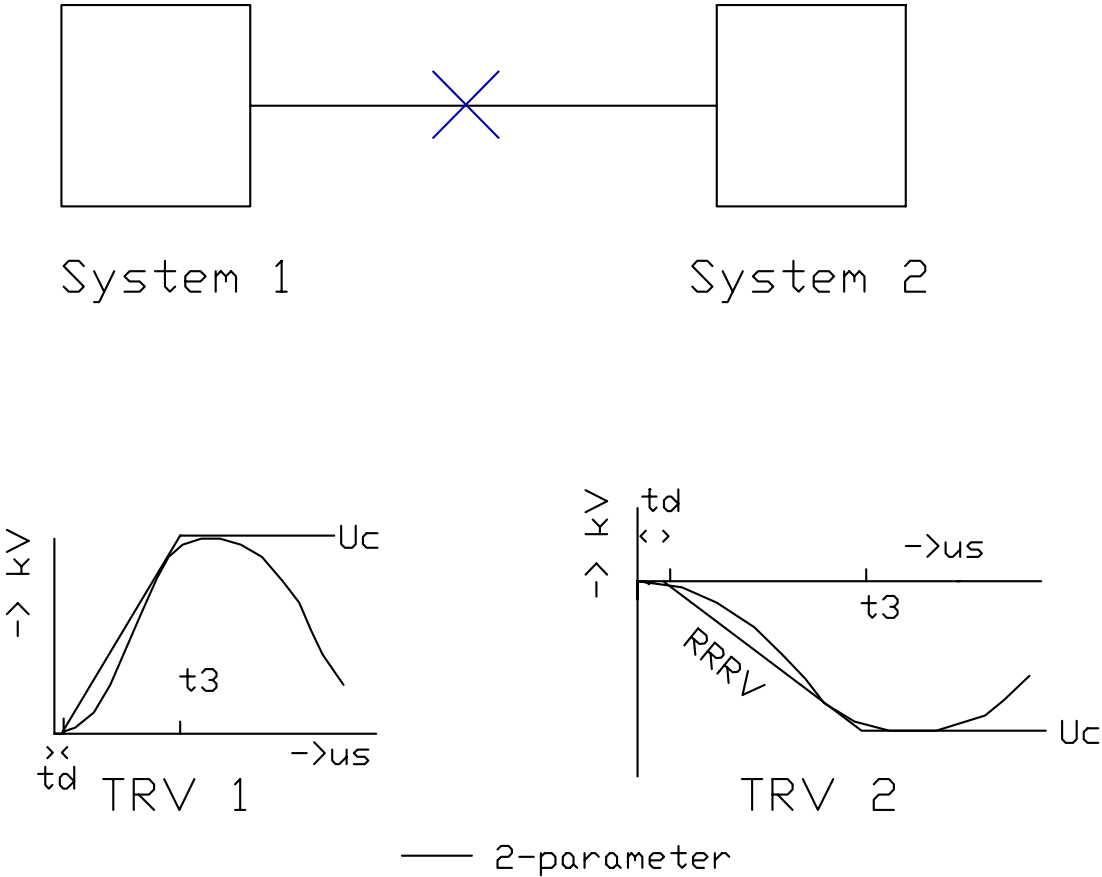


Fig. 6.1-1 Longitudinal stresses across the first-pole to clear out-of-phase

In the Standards TRV waveshapes are defined by an envelope consisting of two or more lines. The relevant parameters for out-of-phase are shown in figure 6.1-1: the steep line defined by a time delay ( $t_d$ ) and the rate-of-rise of the RV (RRRV), and the horizontal line by the time it starts ( $t_3$ ) and the peak value of the (partial) TRV ( $U_c$ ). As the last two are the main

characteristics, the two-line type of envelope is called a two-parameter waveshape, whereas a three-line type is referred to as a four-parameter waveshape (not shown in the figure).

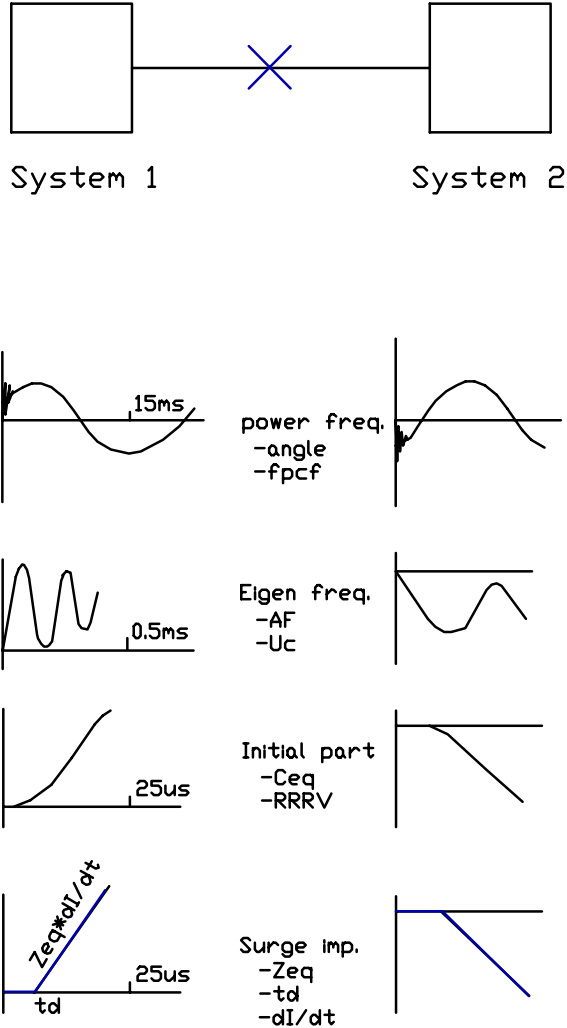


Fig. 6.1-2 Characteristics of the TRV

6.1.1 Power frequency Recovery Voltage (RV)

In figure 6.1-2, this is further illustrated and the variables that influence the characteristics are given. With reference to the first line, the total power frequency RV will be determined by the out-of-phase angle and the first-pole-to-clear factor (FPCF), that plays an important role in 3-phase systems and is normally determined by the earthing factor of the system(s) at the location of the CB [29]. A distinction has to be made between multi-phase faults with and without connection to earth. For three-phase ungrounded faults, independent from the earthing factor the FPCF will always be 1.5. But, in the IEC Standard the three-phase ungrounded fault is regarded as very exceptional and is therefore disregarded. According to the Standard, clearing a three-phase grounded fault leads to a FPCF of 1.3 for effectively earthed systems and a FPCF of 1.5 for other systems. Out-of-phase conditions lead to voltage swings with a low frequency beat pattern and somewhere in the middle between the two system sources there exists an equilibrium where the voltage is zero. This equilibrium can be seen as a virtual three-phase short-circuit without connection to earth. But, opposite to clearing real three-phase faults, the FPCF is not determined by the earthing condition of the virtual fault, as illustrated in figure

6.1-3. The earthing conditions of both systems may allow a zero-sequence current to flow and therefore the FPCF for out-of-phase clearing is determined by the neutral status of both systems.

In figure 6.1-3 both systems are represented by equivalent networks to Thevenin's rule. The RV can be calculated by the principle of superposition, here illustrated by the so-called current injection method, where in addition to the situation before interruption a current is injected across the open contacts. The current is equal in amplitude to the interrupted current, but with an opposite direction. The voltage across the current source is equal to the RV.

The Neptune scheme of  $Z_1$  and  $Z_n$  ( $Z_1+Z_1//Z_1//Z_n$ ) can be replaced by a single impedance, with  $Z_n = \alpha Z_1$  and the zero sequence impedance  $Z_0 = k Z_1 = Z_1 + 3Z_n$ , resulting in  $k = 1+3\alpha$  and  $\alpha = (k-1)/3$ . The Neptune scheme shows to be replaceable by  $Z_1(3k/(1+2k))$ . This exercise can be undertaken at both sides of the first clearing pole. When the k-factor is equal for system I and system II,  $RV = 2E(3k/(1+2k))$ , as  $I_{oop}$  times the sum of  $Z_1$  at both sides is equal to  $2E$  (at full phase opposition). Meaning that  $FPCF = 3k/(1+2k)$ , similar to FPCF of clearing grounded three phase faults. (The factor "f" in figure 6.1-3 is equal to the FPCF.)

A situation with a different k-factor at each side of the CB will be shown in case (i) of the next section. As an example  $k=0.8$  (FPCF=0.92) at the side of the step-up transformer and  $k=3.25$  at the system-side (FPCF=1.3). By means of k,  $Z_n$  can be calculated:  $\alpha=-0.067$  for  $k=0.8$  and  $\alpha=0.75$  for  $k=3.25$ . Through the interconnected Neptune schemes at both sides, the overall  $\alpha$ -factor and k-factor can be deduced. In this case it is assumed that  $X_s = 6(X_d'' + X_{tr})$  and, so,  $\alpha=0.42$  and  $k=2.25$ , leading to an overall FPCF=1.23. Fig. 6.1-6/6.1-7.

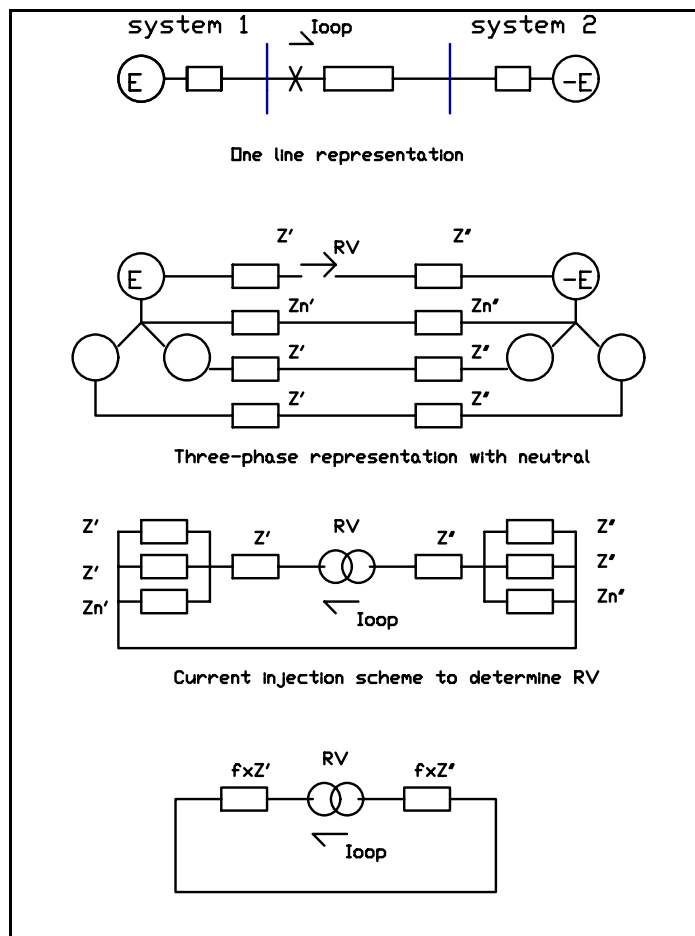


Fig. 6.1-3 Out-phase RV

The RV is determined by two factors: the FPCF and a voltage factor that depends on the out-of-phase angle; i.e.  $2 * \sin(\frac{1}{2}\psi)$ , normally taken as 2 for  $\psi = 180^\circ$ . In reality, the out-of-phase angle can be smaller than  $180^\circ$ , the source voltages can be smaller or larger than 1 pu and the system's earthing factors may differ. With respect to the FPCF it can be stated that according to the Standards only in case of an effective neutral grounding in both systems (at the moment of the out-of-phase clearing) FPCF will be 1.3, otherwise FPCF has to be taken as 1.5. But EHV systems show also very low earthing factors that lead to single phase to earth short-circuit currents larger than the three-phase short-circuit current and FPCF as low as 1.1 or even less than 1.0 [30]. Another case with a very low earthing factor is that of a step-up transformer with a generator connected, as will be discussed in the next section.

In figure 6.1-4, the effect of both factors is given. It can be seen that, in the case where FPCF is 1.3 rather than 1.5, there will be a reduction of the RV and peak-value of the TRV of 13% only. It can also be seen that full phase opposition with a non-effective earthed system leads to a total RV of  $2 * FPCF = 3.0$ . Smaller angles will lead to less severe RVs, but note that for angles as low as  $120^\circ$  the reduction is less than 15%, for angles of  $90^\circ$  the reduction is only 30% and half as severe RV-values are reached at  $60^\circ$ .

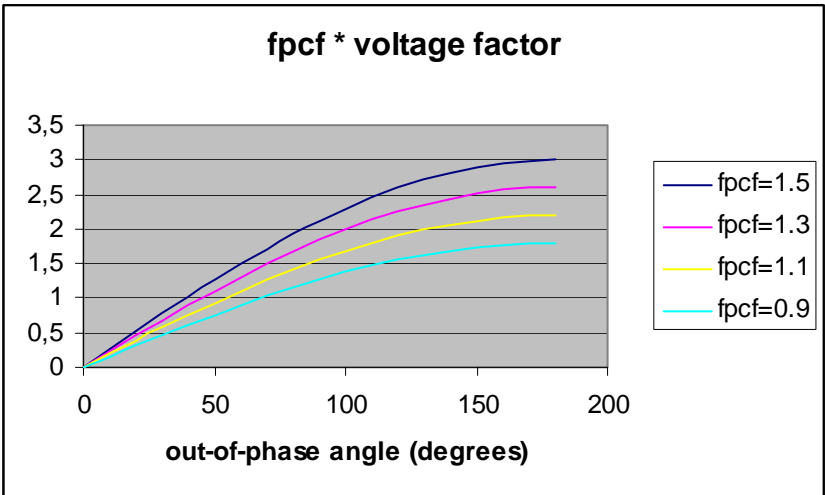


Fig.6.1-4 RV as product of FPCF and voltage factor

6.1.2 Transient Recovery Voltage

Back to figure 6.1-2, second line: the transient voltage responses at each side of the CB to the interruption of the current give over-swings, which are independent from each other. The peak value of the total TRV depends on the damping of the over-swings of the transient voltage responses (described by the amplitude factors,  $k_f$ ) and on the natural frequencies of both systems. When the natural frequencies do not coincide, the peak values at each side will not appear at the same moment and should therefore not be added up to describe the total TRV-peak. Mostly the natural frequencies will differ so much that the peak at one side only has to be considered, together with the RV at the other side (i.e. without overswing).

The initial part of the partial TRVs can be regarded as an S-shape that rises fast (third line of figure 6.1-2). The beginning of the initial part is especially important for HV CBs. This part is described by a ramp-function, the RRRV, and a delay before it rises. The phenomena under discussion are very fast and the systems are best simulated by travelling waves and (equivalent)

surge-impedances.  $RRRV = Z_{eq} * dI/dt$  (at the moment of interruption; i.e. at current zero). The local (stray) capacitances, close to the CB, in parallel to  $Z_{eq}$  causes the S-shape of the ramp-function, or in a simplified representation: the time delay, as shown in the last line of figure 6.1-2.

For out-of-phase conditions, the very initial part of the TRV can thus be approached by the time delay at both sides and by the surge impedances at both sides. The total TRV is approached by the shortest time delay followed by the ramp function of the related RRRV, and, at the longest time delay, of the sum of both RRRVs (see figure 6.1-5 for the initial part of the TRV).

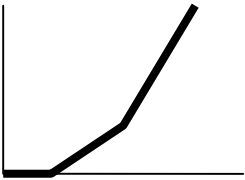


Fig.6.1-5

The parts of the RV at each side of the CB have to be known as each part may show a different transient behaviour. In case k (i.e. FPCF) is different at both sides of the CB, the overall k-factor has to be calculated as explained above, but to estimate the parts of the RV at each side of the CB the following approach can be followed.

Through the neutral impedances  $Z_n$  in the Neptune schemes at each side, the equivalent networks are connected to earth. Because  $\alpha$  is much smaller than 1.0, the branch with  $Z_n$  is more or less short-circuiting the two branches with the second and third phase of the Neptune scheme, so that in a first approach these parallel branches can be omitted. In a second approach  $Z_n$  can be disregarded with respect to  $Z_1$  of the first clearing phase, as shown in the figure 6.1-8, thus leading to the simple estimation of the proportions of the parts of the RV as depending on  $Z_1$  at each side. The largest part is at the side with the highest  $Z_1$ , while the FPCF corresponds to the overall k-factor. This approach is applied in the next section (6.2). From each part of the RV and the systems characteristics the TRV at each side of the CB can be calculated.

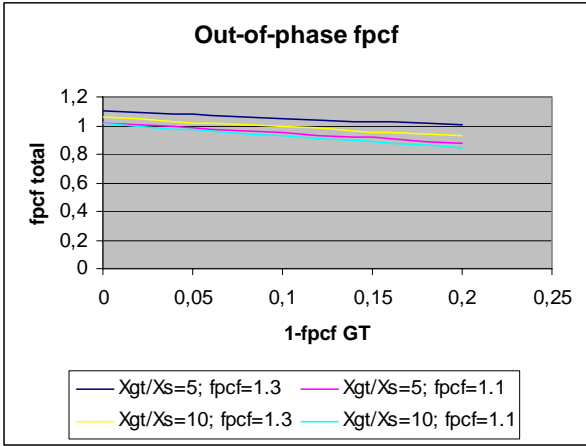


Fig. 6.1-6 Overall FPCF as a function of generator/transformer FPCF (note: 1-FPCF)

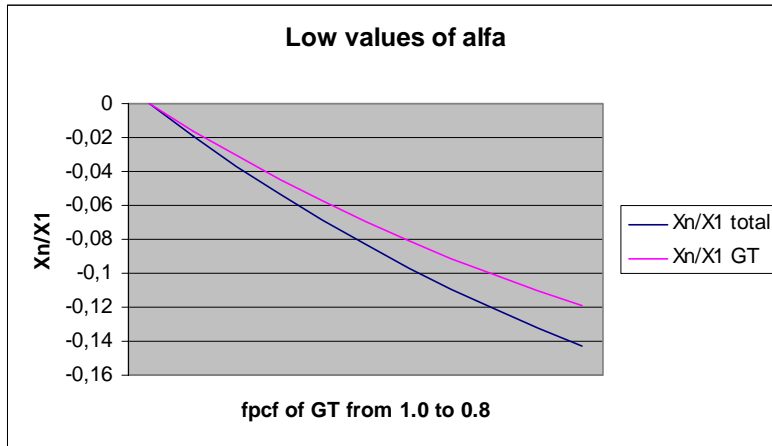


Fig. 6.1-7 Example of low values of overall  $\alpha = X_n/X_1$

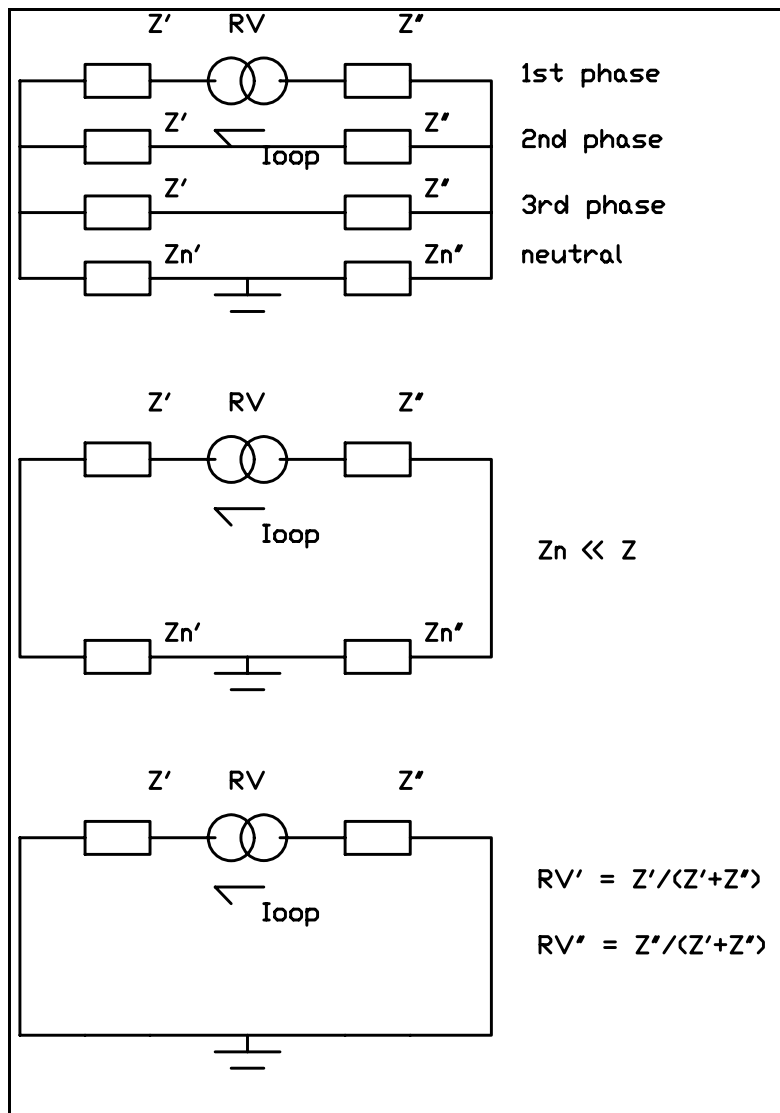


Fig. 6.1-8 Approximate calculation of RV components

### 6.1.3 Out-of-phase current

The out-of-phase current itself is dependent on the out-of-phase angle in a similar way as the RV:  $I_{oop} = 2 * E * \sin(\frac{1}{2}\psi) / \Sigma(\text{reactances})$ . Above  $90^\circ$ ,  $I_{oop}$  is approaching the maximum value under full phase opposition:  $2E / \Sigma(\text{reactances})$ . It also depends on the reactances as shown in figure 6.1-9, where  $I_{oop}$  between system 1 (with source reactance  $X_1$ ) and system 2 (with source reactance  $X_2$ ) is compared with the short circuit-current  $I_{sc}$  delivered by system 1 ( $I_{sc} = E/X_1$ ) [31].

Note that for angles exceeding, say,  $75^\circ$  the out-of-phase current may become larger than the short-circuit current contribution from a source with a larger reactance than that of the other system, as is normally the case with generating plants. Thus generators and step-up transformers are more stressed by  $I_{oop}$  than by  $I_{sc}$ .

Note also that the rotor excitation shortly before and during short-circuit or out-of-phase conditions is complicated, leading normally to high (subtransient) source voltages and consequently high currents. Generators are not tested for such short-circuit currents or even nominal short-circuit currents.

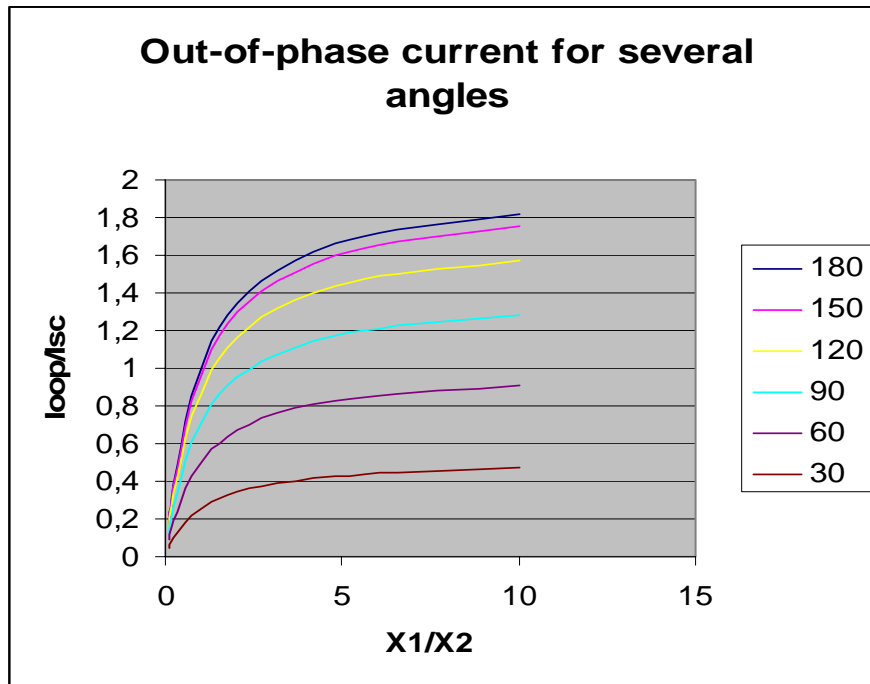


Fig.6.1-9  $I_{oop}/I_{sc}$  as a function of  $X_1/X_2$  and out-of-phase angle

### 6.2 System considerations

The circumstances that may lead to system separation are:

- transient instability (slow fault clearing, false synchronisation of large network elements or large power plants)
- voltage instability (inadequate reactive power and/or voltage regulation, poor or adverse tapchanger control)
- small signal instability (amplification of power swings due to negative damping)
- frequency instability (system inability to react to sudden load/generation unbalances)
- cascade trippings (multiple lightning faults, weather conditions, overloading, vegetation growth, temporary overvoltages)

- protection mal-operation
- false synchronisation of a single generator
- a combination of these phenomena.

Large increases in distributed generation, including many windmills and windmill parks, and the multiple power transfers across longer distances, increase the probability of occurrence of many of these events as detailed in the following examples:

- medium voltage networks typically have fault clearing times which exceed the maximum clearing time for continued stability of small generating plants equipped with synchronous generators
- the optimal control of reactive power supply and voltage regulation by small generators has not been established yet
- windmills are very sensitive for wind variations, especially under high wind conditions, which may result in co-incident tripping of many units
- small cogeneration plants (e.g. for greenhouses) are operated in large groups without consideration of wider network requirements
- systems are more commonly operated up to, or even beyond, their loading capabilities
- (small) generators are tripped and synchronised more regularly than ever before
- certain DG power generation technologies cannot provide inertial energy required for the immediate dynamic response to sudden load/generation unbalances. This reduces the average inertia constant of the whole system and hence reduces the margin to the dynamic stability
- it is important that DG remain connected to the network during voltage and/or frequency deviations caused by faults and other disturbances as specified for the large conventional generators, thus contributing to ride through system disturbances with their active and reactive outputs and their inertia
- on the other hand, the growing use of dispersed generation increases the probability of out-of-phase conditions.

All these trends lead to the conclusion that out-of-phase conditions have to be studied more carefully than in the past. A better understanding of the effects and consequences of out-of-phase conditions and of the present and future probabilities of occurrence is considered to be necessary.

In common with the recently published Guide for Application of IEC 62271-100 and IEC 62271-1<sup>1</sup> [37][38], two out-of-phase cases are considered here:

- (i) generating units that separate from the system
- (ii) major systems that separate.

Whilst the focus of the above mentioned Guide is to explain the TRV-values given in the Standards, a more fundamental approach is taken here with emphasis on the behaviour of system topologies not directly considered in the Standards.

<sup>1</sup> Note that IEC Standard 62271-1 will be the number of the next edition of IEC 60694.

### 6.2.1 Case (i)

Out-of-phase switching may be applicable to a generator CB at the MV-terminals of a generator, as specified in IEEE Standard C37.013 (1997) [34], or to a generator CB at the HV side of the step-up transformer, normally specified as a general purpose CB to IEC 62271-100 or ANSI/IEEE C37.04/06/09. In both situations, as shown in figure 6.2-1, the total RV is caused by the disappearance of the voltage drop across the reactances of the generator, the step-

up transformer and the system:  $RV = I_{oop} * FPCF * (X_{d''} + X_{tr} + X_s)$ , taking into consideration the overall FPCF as described in subsection 6.1.1.

The largest voltage drop will generally be across the generator sub-transient reactance. The transformer reactance is in the range from 0.1 to 0.15 pu, whilst modern generators have a sub-transient reactance in the range 0.18 – 0.27 pu; lower values (0.12 – 0.15 pu) were typical in old 2-pole turbine generators. The system reactance is typically five (or more) times smaller than sub-transient generator plus transformer reactance. Further the natural frequency of the generator windings is 2 to 3 times lower than the natural frequency of the transformer windings. System frequencies usually have the lowest values, defined primarily by the travelling waves of the shortest OH-lines. In terms of surge impedances and local capacitances, the generator will offer the lowest surge impedance (in the range of several tens to less than 100 Ohms) with the highest capacitance (typically 0.1  $\mu$ F) and the transformer the highest surge impedance (thousands of Ohm) with the smaller local capacitances. The system's surge impedance does not exceed 300 - 400 Ohm with local capacitances comparable with the capacitance of a transformer (thousands of pF).

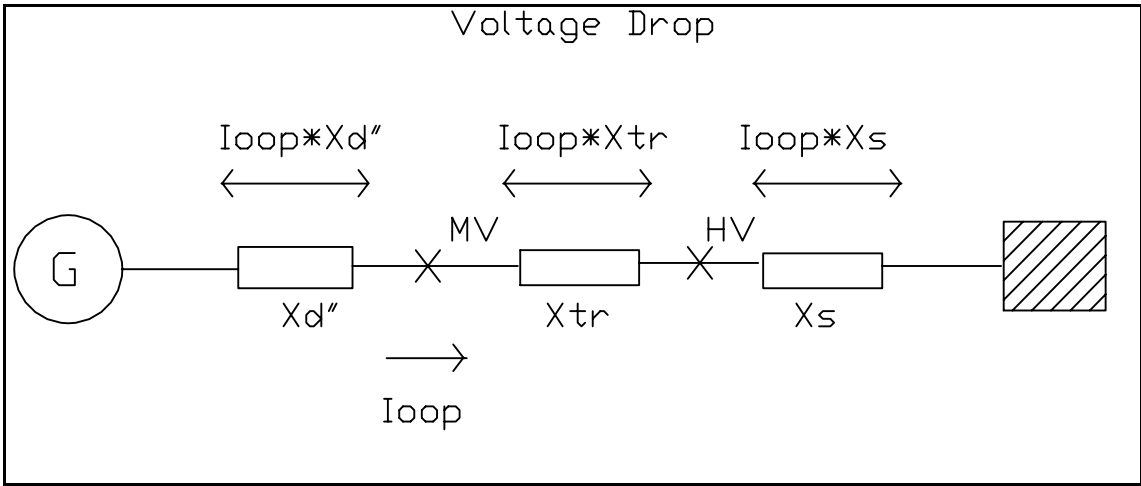


Fig. 6.2-1 Generator CB RV

Seen from the HV-side of a step-up transformer (winding configuration: YN-D), it is assumed that the earth fault factor and therefore the first-pole-to clear factor (FPCF) are very low:  $k=Z_0/Z_1$  is 0.7 to 0.9. With  $k$  being about 0.8 the FPCF becomes 0.92, and the second and last pole clearing factors are larger than the FPCF [29]. On the other hand, as shown in subsection 6.1.1, the total FPCF is to be considered and not the individual FPCF at each side of the CB. Depending on the FPCF at the other side of the CB (net-side), the total FPCF can vary as indicated in figure 6.1-6. For  $k=0.8$  at the generator-transformer side and a FPCF of 1.1 at the net-side, the total FPCF will become 0.94 to 0.96, depending on the ratio of the normal sequence reactance at the generator/transformer side versus the normal sequence reactance at the network side. See figures 6.1-6 and 6.1-7.

And with a FPCF = 1.3 at the net-side, the total FPCF becomes 1.06 for a ratio of the subtransient generator/transformer reactance which is five times the reactance at the net side. To derive the total RV, this total FPCF has to be multiplied with the out-of-phase voltage, which depends on the out-of-phase angle. In this example, the total RV for full phase opposition will reach a value of 2.12 pu with 5/6 of the voltage appearing at the step-up transformer side of the CB and the remaining 1/6 appearing at the network side, in addition to

the pre-clearing voltage of 4/6 pu. So, at the step-up transformer side the terminal voltage of the first clearing pole jumps from 0.67 pu to - 1.10 pu ( $\Delta = 1.77$  pu) and at the other terminal from 0.67 pu to 1.02 pu ( $\Delta = 0.35$  pu).

For a FPCF = 1.1 at the net-side,  $k=0.80$  at the transformer side and a ratio of reactances of 5 (thus a total FPCF of 0.96), and full phase opposition, the terminal voltages jump from 0.67 pu to - 0.93 pu ( $\Delta = 1.60$  pu) resp. to 0.99 pu ( $\Delta = 0.32$  pu). With smaller out-of-phase angles  $\psi$ , the total RV, the two parts of the RV and the voltage jumps are smaller in proportion to  $\sin(\psi)$ .

At the generator-transformer side the amplitude factor (over-swing) will be quite large (for instance 80%: amplitude factor 1.8), as the losses will be relatively low (X/R ratio of 50 or more) and the generator side capacitance large. But a significant depression of the voltage at the generator terminals and therefore of the RV at the HV-side of the transformer can be expected [39], figure F.1 of [22]. This phenomenon leads to a considerable reduction of the voltage at this side of the HV CB, typically resulting in a residual voltage of 80% to 90%; i.e. a sub-sub-transient source voltage of 0.8 to 0.9 pu, in the first few hundreds  $\mu$ s after clearing the out-of-phase current. The effect is larger at larger currents but is not observed for generators with fully laminated poles and a damper winding [39]. Let us assume that the resulting generator/transformer-side RV is reduced by 10%.

Apart from the depression, other phenomena have to be taken into account as well: change of rotor speed, the transient/subtransient/sub-subtransient source voltages that will be considerably higher than 1 pu, the behaviour of the automatic voltage regulation AVR, the time delays in the excitation of the rotor, etc. All these phenomena can be simulated by advanced EMTP-software, but are less suited for general studies and beyond the scope of WG A3.13. The tendency, though, is to increase the source voltage at the generator side.

The amplitude factor of the RV is determined by the natural frequencies of each side of the CB and normally the natural frequencies differ substantially, such that the components of the TRV at both sides of the CB swing independently and their crests do not coincide.

Shortly before clearing the voltage at both terminals of the CB pole is defined by:  $V_{cb} = E_s + (E_g - E_s) \cdot X_s / (X_d'' + X_t + X_s)$ , where  $V_{cb}$  is the CB terminal voltage,  $E_g$  is the source voltage at the generator side and,  $E_s$  the source voltage at the net-side. If  $E_g = -1.0$  pu,  $E_s = +1.0$  pu (at full phase opposition) and  $X_d'' + X_t = 5 \cdot X_s$  then  $V_{cb} = 0.67$  pu. The net-side RV will swing from 0.67 pu to about 1.0 pu (see former pages). With an over-swing of the voltage jump corresponding to an amplitude factor of 1.5, a peak value 1.17 pu is reached.

The transformer side will swing from 0.67 pu to - 0.92 pu (assuming net-side FPCF 1.3 and 10% depression) with an amplitude factor of 1.8, thus giving a peak value of - 2.19 pu. For a net-side FPCF of 1.1 (and 10% depression), the voltage will jump at the transformer side from 0.67 pu to - 0.77 pu; with an amplitude factor of 1.8, a peak value of -1.92 pu is reached.

In order to estimate the crest value of the total TRV, the assumption is made that the peak at one side coincides with the power frequency RV at the other side (similar to the dielectric bias lightning impulse test where at one side the lightning impulse is applied whilst at the other terminal  $0.7 \cdot \sqrt{2/3} U_r$  is applied). In this case, with  $0.7 \cdot \text{amplitude factor} \cdot RV \approx RV$ ,

1. The peak at the net-side (1.17 pu) coincides then with - 0.92 (resp. - 0.77 pu) at the step-up transformer side, summing up to a TRV peak value of 2.1 (resp. 1.9 pu).
2. The peak at the step-up transformer's side -2.19 (resp. -1.92 pu) coincides with 1.0 pu at the net-side, summing up to 3.2 (resp. 2.9 pu).

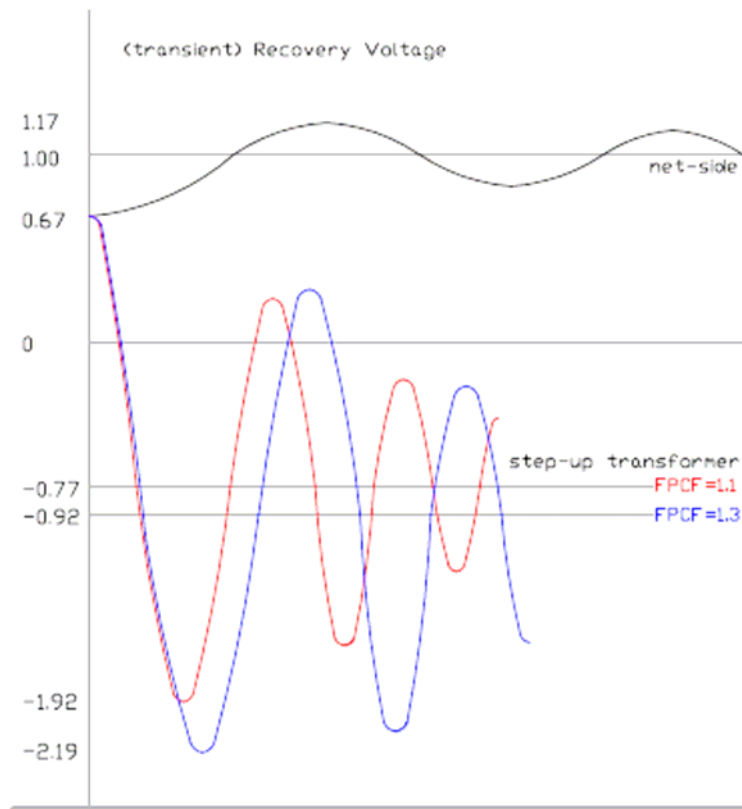


Fig. 6.2-2 Out-of-phase RV. Case i.

These peak values are higher than 2.5 pu, as specified in IEC 62271-100 for systems with  $FPCF = 1.3$ . In figure 6.2-2, the waveshapes on both sides of the first clearing pole are schematically given assuming full phase opposition. Reducing the out-of-phase angle will shift  $V_{cb}$  from 0.67 pu towards 1.0 pu, thus decreasing the over-swing at the net-side but increasing the over-swing at the step-up transformer side. Moreover, due to the lower out-of-phase current the generator will show less depression and this leads to a higher residual voltage.

At an out-of-phase angle of  $90^\circ$  the out-of-phase voltage is 1.41 pu. Assuming no depression, a reactance ratio of 5,  $k = 0.80$  at the step-up transformer side and  $FPCF = 1.3$  at the network side, it can be calculated that the total RV = 1.49 pu, of which 1.24 pu at the step-up transformer side. The peak-value of the TRV is thus  $0.25 + 1.8 \cdot 1.24 = 2.5$  pu: a value which is recognised in the Standards. In other words, for these specific assumptions, the Standards do not address out-of-phase angles in excess of  $90^\circ$ .

In case of a system with a floating neutral, or equipped with Peterson-coils, the  $FPCF = 1.5$ . The RV will be 3.0 pu and in the example given 2.5 pu will be at the step-up transformer side and 0.5 pu at the net-side. The voltage at the net-side terminal will jump from 0.67 pu to 1.17 pu. At the other terminal the depression of the generator gives a reduction factor 0.9, thus leading to a voltage jump from 0.67 pu to -1.58 pu. With an amplitude factor of 1.8, the TRV at this side will reach up to -3.38 pu and the total TRV up to 4.55 pu at full phase opposition. Assuming no depression and an out-of-phase angle of  $75^\circ$  the RV becomes 1.83 pu, 0.30 pu at the net-side and 1.53 at the step-up transformer side; resulting in a peak value of the TRV of  $1.8 \cdot 1.53 + 0.30$  pu = 3.1 pu, close to 3.13 as given in the Standards.

For a CB at the MV-side of the step-up transformer, the IEEE/ANSI Standard C37.013 is applicable. In this Standard an out-of-phase angle of  $90^\circ$  has been taken as the basic

assumption to specify the TRV requirements. It has to be mentioned however that frequently (up to tens of percent of the users) utilities specify an angle of 180°; see for instance [32].

The explanation above is based on large power generation plants, but a similar approach can be used for smaller power plants connected through a MV/LV step-up transformer to a distribution grid. Normal switching operations will be performed at the LV-side, but the MV CB will be required to clear short-circuit currents and out-of-phase currents. In fact similar to the statement in IEEE/ANSI C37.013, where it presumed that usually the CB at the HV-side of the step-up transformer will clear out-of-phase currents (see section 6.3). For MV-CBs, the specified peak value of the TRV is 3.13 pu (IEC 62271-100), but the out-of-phase assignment and the related test duty are non-mandatory.

For distributed power plants with a MV-generator connected to the MV-distribution grid without a step-up transformer, IEEE/ANSI Standard C37.013 is applicable.

### 6.2.2 Case (ii)

When during out-of-phase conditions the equilibrium point (virtual short-circuit point) is somewhere on the OH-line that connects the two systems going out of synchronism, protection systems will trip the CB. Whilst it is possible to install advanced and complicated out-of-phase blocking systems to delay the tripping command until the beating out-of-phase angle is small, this is uncommon and switching can normally occur over a wide range of out-of-phase angles. The TRV across the first clearing pole is determined by the system parameters on the busbar side of the CB and by the line parameters at the line side. As the largest impedance will be on the line side, the largest voltage excursion will also appear at the line side.

The out-of-phase current is, to a large extent, dependent on the out-of-phase angle and the length of the OH-line. Due to the traveling wave effects, the TRV at the line side will exhibit a triangular shape and its peak value can be calculated as twice the wave traveling time along the OH-line multiplied by the RRRV. The traveling time is proportional to the line length, but the RRRV shows a decreasing trend with increasing line length due to the decrease in out-of-phase current ( $I_{oop}$ ). Specifically  $RRRV = Z_{eq} * dI_{oop}/dt$  where  $Z_{eq}$  is the equivalent surge impedance for the first pole clearing the 3-phase out-of-phase current. Based on the studies of WG A3.19 and the literature [91]  $Z_{eq}$  is about 300  $\Omega$ , when the fact is taken into account that the bundle-conductors will only contract at currents much larger than out-of-phase currents. At a power frequency of 50 Hz, this leads to  $RRRV = 0.14 * I_{oop}$  kV/ $\mu$ s with  $I_{oop}$  in kArms, and at 60 Hz to  $RRRV = 0.17 * I_{oop}$  kV/ $\mu$ s.

Due to the influence of the source impedances of both systems, the amplitude of  $I_{oop}$  is not inversely proportional to the line length. Therefore, the peak value of the line side TRV will still increase with an increasing line length. This effect, however, becomes smaller for OH-lines with longer lengths.

Figure 6.2-3 shows the total admittance of both systems and the interconnecting line as a function of the line length, for different (but arbitrarily chosen to be equal at both sides) source impedances of the systems; i.e. for 420 kV systems with a short-circuit power equivalent to short-circuits of 40 kA, 31.5 kA and 20 kA in comparison to infinite short-circuit powers.  $X_L$  is based on an inductance of 1mH per km.

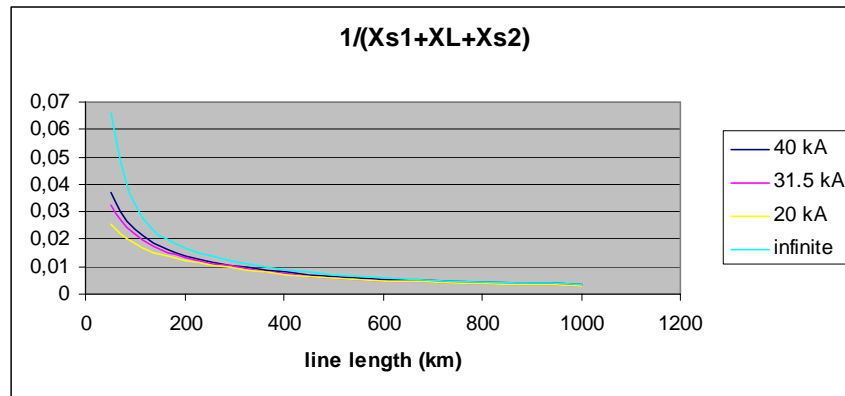


Fig. 6.2-3 Total admittance as function of line length, 420 kV, 50 Hz

In addition to the line side TRV, the system side TRV should be added, similar as with SLF-cases (short-line fault). As  $I_{oop}$  is defined to be 25% of rating in the Standards and is often less than this in reality (15%), the system side TRV can be estimated to be 25% (15%) of the TRV associated with, for instance, T100. The peak value at the system side is then less than 0.37 pu (0.22 pu). For an OH-line with a length of 100 km, the return traveling time will be roughly 650  $\mu$ s, close to  $t_2$ , as defined for T100. For a 420 kV/40 kA CB, the TRV-peak at the line side is then  $650 \cdot 0.14 \cdot 10 = 910$  kV i.e. 2.7 pu. In this example, the peak value of the total TRV will be close to 3.1 pu for  $I_{oop} = 25\%$ , 50 Hz.

Smaller out-of-phase angles lead to smaller out-of-phase currents and smaller RRRVs, but given a certain out-of-phase current, the TRV characteristics are more or less independent from the out-of-phase angle, but determined by the line length, the equivalent surge impedance and the equivalent system side parameters. In figure 6.2-4, the TRV peak values (line side) as a function of line length are shown for the example above (figure 6.2.3). The out-of-phase currents are based on full phase opposition. As the TRV peak value at the line side is proportional to  $I_{oop}$ , it is also proportional to  $\sin(\frac{1}{2}\psi)$ , as discussed in the former subsection.

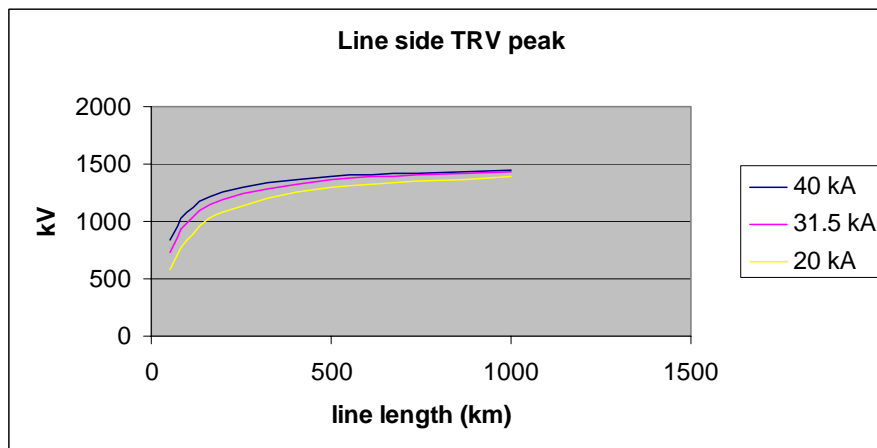


Fig. 6.2-4 Line side TRV peak value as function of length (420 kV, 50Hz)  
 Note that 40, 31.5 and 20 kA (legend) are not the out-of-phase currents,  
 but the short-circuit currents at the busbars at both OH-line ends.

It can be concluded that the TRV peak values are considerably higher than specified in the Standards (857 kV @ 1335  $\mu$ s for a rated voltage of 420 kV), even when taking into account smaller out-of-phase angles. For instance with a line length of 200 km and source impedances

corresponding to a short-circuit current of 20 kA, an out-of-phase angle of 120° will still give a line side peak value of 931 kV. Combined with a system side RV of roughly 75 kV this results in a total TRV peak of 1006 kV (50 Hz). A line length of 100 km between substations with source impedances corresponding to 40 kA and an out-of-phase angle of 120° will also give 931 kV at the line side and 1006 kV in total. For 60 Hz, the out-of-phase current will be lower due to the 20% higher line reactance, but this effect is compensated by higher RRRV per kA, so that the TRV peak values are more or less comparable with 50 Hz. The IEC peak value of 857 kV is reached at out-of-phase angles as small as 80° and 96° for 200 km and 100 km lines respectively (40 kA sources); 85° and 108° respectively (31.5 kA sources); 93° and 140° respectively (20 kA sources). See also the figures 6.2-6 and 6.2-7 [69].

The time to peak is shorter than specified in the Standards, as illustrated in figure 6.2-5. The requirements and conditions as given in the Standards will be discussed in the next section.

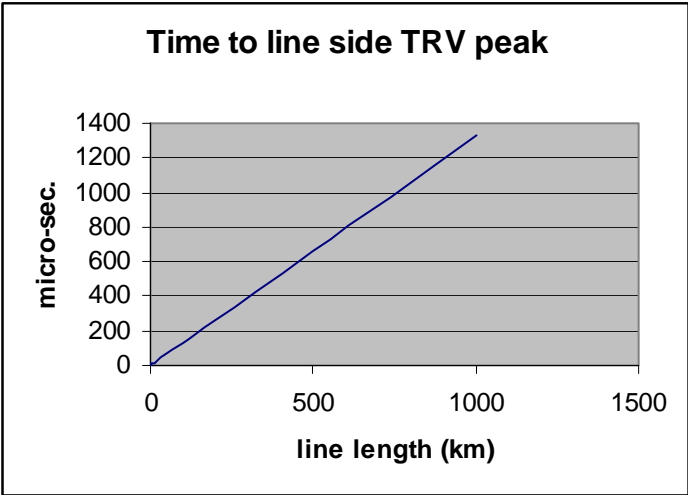


Fig. 6.2-5 Time to peak of TRV

Calculations and simulations for real networks show out-of-phase TRV peak values as high as 3.3 to 3.5 pu [33] for very extended networks (hundreds of km, low currents) and 3.0 to 3.5 pu for meshed networks (hundred or less km, relatively high currents).

Out-of-phase switching on series compensated OH-lines has not been addressed yet, but it is evident that the electrical charge on the SCs will add to the peak value of the TRV. Unfortunately, right at the moment of current clearing the voltage across the SCs is at maximum value, unless the capacitors have been by-passed by the self-triggered or forced triggered spark gaps. The situation is similar to clearing short-circuit currents. In modern SCs metal-oxide varistors are installed in parallel to the capacitor bank. Such varistors limit the voltage across the capacitor banks. Moreover special surge arresters connected phase-to-ground or varistors across the arcing chambers of the CBs are applied, thus limiting the total TRV peak value at clearing short-circuit currents and out-of-phase currents as well. The countermeasures for limiting the peak value of the TRV at clearing short-circuit currents are also effective at clearing out-of-phase currents. See also the sections 5.2 and 5.3.

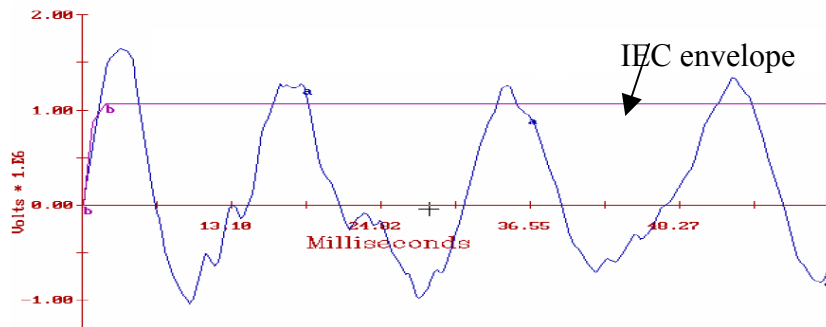
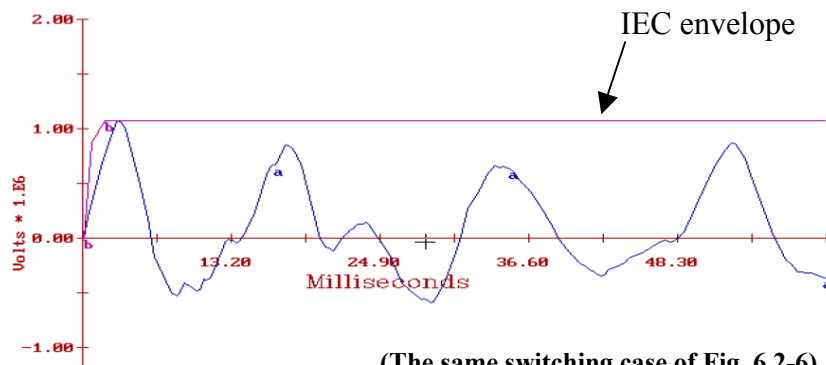


Fig. 6.2-6 TRV caused by switching under 180° out-of-phase (example from simulations performed for Furnas, Brazil, 550 kV-network)



(The same switching case of Fig. 6.2-6)

Fig. 6.2-7 TRV caused by switching under 65° out-of-phase condition (example from simulations performed for Furnas, Brazil, 550 kV-network)

### 6.3 Requirements in the present Standards

#### 6.3.1 Requirements in the IEC-Standards

According to IEC 62271-100 CBs have to be capable to interrupt out-of-phase currents up to 25% of the rated short-circuit current. The type test for out-of-phase conditions consists of two test duties: one at 25% of the rated short-circuit current and one at 5% of the rated short-circuit current. The TRV-requirements are similar for both test duties and can be described as follows.

For rated voltages up to 100 kV, a 2-parameter TRV is required (Amendment 2 to IEC 62271-100, July 2006): first pole-to-clear factor is 2.5, the amplitude factor is 1.25 and the RRRV can be calculated from  $U_c = 2.5 \cdot 1.25 \text{ pu}$  and  $t_3 = 2 \cdot t_3$  for T100, thus lower than RRRV for T100<sup>1</sup>. Total peak value: 3.13 pu.

For rated voltages from 100 kV up to 245 kV in systems with not-effectively earthed neutrals, a 4-parameter TRV has been defined: first pole-to-clear-factor is 2.5, the amplitude factor is 1.25 and the RRRV is 1.67 kV/μs, also lower than RRRV for T100 (2.0 kV/ μs). Total peak value 3.13 pu.

For rated voltages of 100 kV and above in systems with effectively earthed neutrals, a 4-parameter TRV has been defined: first pole-to-clear-factor is 2.0, the amplitude factor is 1.25 and the RRRV is 1.54 kV/μs, also lower than RRRV for T100. Total peak value 2.5 pu.

The power frequency recovery voltages RV, given in the Standard, are thus 2.5 pu for systems with not-effectively earthed neutrals (i.e. FPCF = 1.5) and 2.0 pu for systems with an effectively earthed neutral (i.e. FPCF = 1.3). The related out-of-phase angles can be calculated by  $2 \cdot \arcsin\{\frac{1}{2}(2.5/1.5)\} = 115^\circ$  and  $2 \cdot \arcsin\{\frac{1}{2}(2.0/1.3)\} = 101^\circ$ , respectively.

<sup>1</sup> T100, T60, T30 and T10 are the test duties to proof the CBs capability to make and break short-circuit currents with an amplitude equal to 100%, 60%, 30% and 10% respectively of the rated short-circuit current assigned to the CB: IEC Standard 62271-100.

### 6.3.2 Requirements in the ANSI/IEEE Standards

Reference is made to IEEE Standard C37.04 [26], ANSI Standard C37.06 [27], ANSI Standard C37.06.1 (1997) and IEEE Standard C37.09 [28]. The requirements for the type test are identical to the IEC Standard: the out-of-phase current is limited to 25% of the rated short-circuit current, the RV is 2.0 pu for systems with an earthed neutral and 2.5 pu for systems with a non-earthed neutral, the amplitude factor to determine the peak value of the TRV is 1.25.

### 6.3.3 Requirements in the IEEE Standard C37.013

For generator CBs, applied between generator and step-up transformer, IEC refers to ANSI/IEEE Standard C37.013[34]. As in the IEC Standard, the out-of-phase switching performance is an optional requirement. The test duty is based on an out-of-phase current equal to 50% of the rated short-circuit current and an out-of-phase angle of  $90^\circ$ . The RV is therefore 2.1 pu and with an amplitude factor of 1.5 the peak value of the TRV is 3.18 pu, about the same as IEC. The RRRV, however, is much steeper and depends on the size of the power generating unit: 3.3 to 5.2 kV/ $\mu$ s for power generating units from below 100 MW to more than 1000 MW respectively. This RRRV is roughly equal to the RRRV required for the short-circuit tests, which vary from 3.0 to 6.0 kV/ $\mu$ s. The RRRV values for out-of-phase tests are much higher than those required by IEC and can be deduced directly from the values for short-circuit tests and the out-of-phase angles given.

It should be noted that in this Standard the rated short-circuit current is defined as the maximum short-circuit current supplied through the step-up transformer (so with the short-circuit at the generator side of the generator CB). The requirements for clearing the system fed fault give a TRV peak value of 2.25 pu and the RRRV is much steeper than the RRRV's required in the IEC Standard for short-circuit test on general purpose CBs.

### 6.3.4 Scope of IEC 62271-100

Apart from the TRV requirements as mentioned above, it is relevant to know the scope of the Standards in order to understand the range of applications. In general in IEC Standard 62271-100 three-phase CBs are dealt with, under the exclusion of generator CBs, by-pass breakers for SC-banks and CBs applied at higher operating voltages than the rated voltage, as may occur at sudden load rejection.

In addition, with respect to the TRV-requirements, the following situations have been excluded: CBs adjacent to generator circuits, CBs with series reactors, CBs applied for series compensated lines, and CBs in the vicinity of shunt-capacitor banks.

Furthermore, clearing of three-phase faults without connection to earth is not covered and for short-line fault clearing performance type tests simulating a single phase fault are regarded to cover all types of short-line faults. Out-of-phase switching requirements have been specified for conditions without a fault at either side of the CB.

In chapter 8, Guide to the selection of CBs for service, additional information about out-of-phase characteristics has been given. The text is almost identical to the text in the Application Guide ANSI/IEEE C37.010, clause 4.15, note (2):

*The requirements of this standard cover the great majority of applications of circuit breakers intended for switching out-of-phase conditions. Several circumstances would have to be combined to produce a severity in excess of those covered by the tests of this standard and, as switching during out-of-phase conditions is rare, it would be uneconomic to design circuit breakers for the most extreme conditions. Where frequent out-of-phase switching operations are anticipated, or where for other reasons out-of-phase switching is a matter of importance, the user should consider actual system RVs. A special circuit breaker, or one rated at a higher voltage, may sometimes be required. As an alternative solution, the severity of out-of-phase switching duty is reduced in several systems by using relays with coordinated impedance-sensitive elements to control the tripping instant, so that interruption will occur before the instant the phase angle is 180°.*

Moreover, in IEC 62271-100 it is explicitly stated that higher RRRV values than required for the out-of-phase test duties may occur, but are considered to be covered by the high RRRV requirements for T30. However, the TRV co-ordinates  $U_1$  and  $t_1$  for T30 reach not as far as necessary for the out-of-phase TRV.

#### 6.3.5 Scope of ANSI C37.013

As stated in a former section, the standard out-of-phase current switching duty for generator CBs is restricted to an out-of-phase angle of 90°. The text of clause 5.2.10.1:

*The majority of generator circuit breakers are expected to close but not to interrupt under full phase opposition conditions because the latter task could be solved more conveniently by the circuit breaker on the high-voltage side of the transformer. Only generator circuit breakers having full interrupting capability (to clear short-circuit currents on either side of the circuit breaker) could have an assigned out-of-phase switching rating. The rating is limited as outlined in table 13 (90 degrees). Note – when out-of-phase current switching is of special importance and the user specifies the generator circuit breaker for full-phase opposition capability, a special circuit breaker will be required with an interrupting rating (in MVA) often exceeding rated short-circuit current interrupting capability, especially with the following: a) RV of  $1.73 * V (= 3 pu)$ , b) current between trafo-fed and geno-fed.*

Guidance for application is further given in the clauses 6.3.8 and 6.3.10 and in Appendix A5 of C37.013.

## 6.4 Probability of out-of-phase conditions

In the discussions about the specifications for out-of-phase current switching and the dielectric withstand strength during synchronisation, the system conditions leading to out-of-phase situations and the probability of out-of-phase conditions are combined (see also CIGRÉ Technical Brochure 305 [38]). In the view of WG A3.13, the decision to consider out-of-phase conditions or to disregard these conditions is up to the users, and utilities may apply risk management techniques to support their choice. Indeed the probability of the occurrence of an out-of-phase condition in meshed networks is, apart from generator plants, rather low in comparison to extended networks with a radial structure to power plants at a long distance.

Possibly the probability of occurrence of out-of-phase conditions will increase due to the increased implementation of distributed power plants and the growing trend of multiple power transfers between different regions in the world.

But, given a decision of a utility to specify their system and its components for out-of-phase conditions, the Standards should offer an adequate set of specifications that offer the users confidence that the equipment can be applied in most situations (typically 90% of the cases). Therefore, it seems to be less appropriate to specify reduced requirements, as the probability of occurrence of an out-of-phase condition is regarded as negligible. In any case, when applicable, users are recommended to verify the actual stresses under out-of-phase conditions with the specifications given in the Standards.

A number of cases are known of problems during out-of-phase conditions and/or synchronization, especially with large phase angles between the systems involved. Many years ago, a 120° out-of-phase synchronisation of a 383 MVA steam turbine-generator on the EHV side of the step-up transformer had been reported due to an erroneous connection in the secondary circuits. The generator withstood the electro-dynamic forces due to the large out-of-phase current, but the transformer was heavily damaged, possibly due to the addition of the axial forces coming from the inrush currents to the radial forces caused by the out-of-phase currents. Other cases have been reported from USA, Germany (a 3-phase auto-reclosure incident), Belgium, and others. Cases have been reported where 3-phase faults occurred and consequentially large out-of-phase angles (up to 180°). Equipment under severe stresses is not limited to switchgear, but involves expensive transformers and generators as well. In [31] the damage to a number of windmills has been reported, due to the false synchronisation of sub-systems and co-generation plants.

Out-of-phase switching on series compensated OH-lines has not been addressed yet, but it is quite evident that the electrical residual charge on the SCs will add to the peak value of the TRV. The countermeasures for limiting the peak value of the TRV at clearing short-circuit currents (see sections 5.2 and 5.3) are also effective at clearing out-of-phase currents.

Commercial out-of-phase tripping relays (as for instance could be applied for interconnection lines) generally have the capacity to issue the tripping order in case of loss of synchronism at a suitable instant, such as the out-of-phase angle at the opening moment falls within the capacity of a CB, i.e. 90°. But, the application of out-of-step and power swing relays is limited due its difficult setting, that requires extended transient system studies [92][93][94].

## **6.5 Conclusions and recommendations**

### *6.5.1 Conclusions*

- The Standards for general purpose CBs do not cover generator CBs or CBs applied adjacent to generators and do not cover CBs applied in series compensated OH-lines.
- The Standards disregard situations with increased operating voltages due to load rejection and out-of-phase conditions with a fault in one of the systems. However, for CBs applied under situations with frequent out-of-phase conditions and/or important consequences the user is recommended to consider actual system RVs.
- The RV, as specified in the Standards for out-of-phase conditions, is 2.0 and 2.5 pu, respectively for systems with an effectively earthed neutral and not-effectively earthed neutral. The peak value of the TRV is 2.5 and 3.13 pu, respectively.

- The RVs in the Standards are based on an out-of-phase angle of 101° and 115° for systems with an effectively earthed/non-effectively earthed neutral, respectively. But based on the peak-value of the TRV the out-of-phase angle in the Standards is limited to about 90°, despite the fact that in many cases the angle will be random. For generator CBs and special applications users frequently (up to tens of percent of the cases) ask for out-of-phase angles of 180°.
- Out-of-phase switching of generators at the MV-side can be regarded as covered by IEEE/ANSI C37.013 for angles < 90°.
- Out-of-phase angles larger than roughly 75° may lead to out-of-phase currents larger than the short-circuit contribution of the generator (under nominal conditions) and may damage the generator. The out-of-phase currents, however, are smaller than the rated short-circuit current of the circuit-breaker (or maximum short-circuit current at the busbar).
- According to both IEEE and IEC, the specified RRRV of the TRV is lower than the RRRV specified for T100, whereas higher values occur in the systems, but the RRRV for out-of-phase switching is considered to be covered by T30 (multipart testing).
- The TRVs are based on system conditions without an earth fault. For situations with frequent out-of-phase switching and frequent synchronisation, the Standards recommend to specify actual TRVs in the system (taking into account blocking relays for large out-of-phase angles when applied) and to adapt the requirements for the longitudinal dielectric strength accordingly.
- Under normal system conditions (no earth fault, no temporary overvoltages), full phase-opposition switching of a generating plant at the HV-side leads to TRV peak values of 2.9 to 3.2 pu; and higher values for systems with un-earthed neutral.
- The peak values of the TRV as specified in the Standards cover out-of-phase angles up to 90° or, in case of systems with un-earthed neutral, even less (75°).
- For out-of-phase switching of OH-lines, calculations show peak values of the TRV of, for instance, 3.5 pu (200 km length,  $I_{oop} = 15\%$  of 40 kA) or 3.1 pu (100 km length,  $I_{oop} = 25\%$  of 40 kA) and even beyond for longer line lengths, under full phase opposition. Clearing an out-of-phase current on a 100 or 200 km OH-line between 420 kV substations (each with a short-circuit current of 40 kA) requires out-of-phase angles less than 96° and 80°, respectively, to achieve TRV peak values of 2.5 pu, as specified in the Standards.
- During synchronisation, a longitudinal power frequency withstand voltage larger than 2.0 pu, preferably 2.5 pu or even 3.0 pu, seems to be a reasonable requirement for CBs used for that purpose. The related auxiliary components, such as grading capacitors, MOVs, insulating materials, should be equally specified and tested (see chapter 7 and [95]).
- Under out-of-phase switching conditions the first-pole-to-clear factor is determined by the neutral status of the systems at both sides of the CB, as shown by the double Neptune-scheme. Depression of the generator subtransient source voltage has to be taken into account, unless the rotor is equipped with fully laminated poles and a damper winding.

### 6.5.2 Recommendations

- False synchronisation, mis-operation of protection equipment and faulty switching operations by operators [7], can lead to considerable damage. Re-strikes at clearing out-of-phase currents with considerable out-of-phase angles will also lead to comparable consequences. In the opinion of WG A3.13, the following developments in modern networks will lead to a higher probability of these phenomena: increased transmission

distances, distributed generation leading to large power transfers, system separation on overloaded OH-lines, large power swings due to tripped generation, etc. Utilities have to look carefully for such situations and, when applicable, specify the appropriate requirements for the protection equipment and switchgear involved.

- In the opinion of WG A3.13, the present Standards do not give users adequate guidance for specifying TRV-values for out-of-phase conditions and dielectric withstand requirements under synchronisation conditions. Either the specifications should be revised or more guidance should be included in the main text.
- As the high TRV-requirements may lead to increased costs of the CBs, the appropriate application of out-of-phase specifications, only where necessary, is recommended. It is therefore necessary to distinguish several situations:
  - situations where out-of-phase conditions can be neglected: no requirements for CBs
  - situations where out-of-phase may occur with small out-of-phase angles only:  
standard requirements for CBs
  - situations where out-of-phase may occur with random out-of-phase angles: special requirements for CBs ( $I_{oop}$ ,  $TRV_{peak}$ , RRRV).

## 7. BEHAVIOUR OF CBS DURING SYNCHRONIZING AND RECLOSURE

External and internal flashovers across the open contacts of EHV CBs have occurred in operation during synchronizing or during the dead time before the automatic reclosure of CBs. These events generally cause a busbar fault, and also explosions of CB poles if flashovers occur internally in the interrupting chambers. It is therefore obviously necessary to specify the CBs to withstand with a reasonable margin the overvoltages liable to occur during these manoeuvres and to preserve this capacity in operation.

As discussed in section 5.2, prior to synchronizing the CB is subject to a voltage beat with periodical voltage variation from zero to 2 times the phase-to-ground maximum operation voltage, for instance  $2 \times 420 / \sqrt{3} = 485$  kVrms or  $2 \times 550 / \sqrt{3} = 635$  kVrms in 420 kV and 550 kV grids, respectively.

The vast majority of the synchronizing manoeuvres are performed for connection of generating units to the grid. As the involved CBs are generally not directly connected to an OH-line, the exposure to large lightning and switching overvoltages during the short synchronizing time is negligible. On the other hand, prior to reclosure of a line CB during re-synchronizing of separated sub-systems, lightning overvoltage waves could stress the open CB on line side. In case of frequent synchronizing, clause 2.3.2.4 of IEC 60071, Part 2 [36] conservatively recommends consideration of the occurrence of an earth fault during synchronisation (at one side), thus leading to higher longitudinal voltages: up to 2.5 pu for a short time.

With regard to the dielectric requirements under synchronizing operations simultaneously with a substantial transient or temporary overvoltage, clause 4.2 of IEC 62271-100 [22] indicates that the standard requirements may be insufficient and the application of the requirements as specified for disconnectors across open contacts is recommended.

Some reported cases of CB failures during synchronizing of generating units have been caused by flashovers on contaminated and wet external insulation of the interrupting chambers of live tank CBs, or by failure of the grading capacitor in parallel with one of the contacts, or by a too low specified value of the power-frequency withstand voltage across open CB contacts eroded by aging or by other reasons. Rare flashovers across the open contacts of CBs during the dead time before the automatic reclosure as caused by lightning have been reported in absence of surge arresters or of special protective air gaps at the open line terminal [60].

In clause 4.2 of IEC 60694 [35] different requirements for the longitudinal withstand voltage across open contacts for the safety function (eg. disconnectors) and for the operation function (eg. CBs) are specified for rated voltages  $\leq 245$  kV. The values given in column (2) of tables 1a and 1b [35], applicable for rated voltages  $\leq 245$  kV, are used for the specification of the longitudinal requirements of CBs, while the values given in column (3) of the same tables are used for the longitudinal requirements for disconnectors. For rated voltages  $\geq 300$  kV, the values of column (3) of the tables 2a and 2b are specified for the 1min power frequency type test across open contacts of both CBs and disconnectors, however the values of column (2) are accepted for routine tests. In the next table 7-I the power frequency short-duration withstand voltages are reported for some rated voltages for comparison, including the withstand voltages in pu. For rated voltages  $\leq 245$  kV, the highest class of insulation has been taken from table 1a of [35], and for rated voltages  $\geq 300$  kV the values given in table 2a of [35] have been taken.

*Table 7-I Insulation requirements for CBs and disconnectors as per IEC 60694 [35]*

Rated voltage (kV)	(2) 1minute withstand (kV) <sup>+) </sup>	(2) 1minute withstand (pu) <sup>+) </sup>	(3) 1minute withstand (kV) <sup>Δ) </sup>	(3) 1minute withstand (pu) <sup>Δ) </sup>
24	50	3.61	60	4.33
72,5	140	3.34	160	3.82
145	275	3.28	315	3.76
245	460	3.25	530	3.75
420	520	2.14	610	2.52
550	620	1.95	800	2.52
550 °	710	2.24	890	2.80
800	830	1.80	1150	2.49

° from table 2b of [35]: additional rated insulation levels in North America.

<sup>+)</sup>  Specified in tables 1a and 2a of [35] for: (i) phase-to-earth, phase-to-phase and for longitudinal insulation of circuit breakers with rated voltage  $\leq 245\text{kV}$ ; (ii) for phase-to-earth and phase-to-phase insulation of CBs with rated voltage  $\geq 300\text{kV}$

<sup>Δ)</sup>  Specified for longitudinal insulation of disconnectors (all rated voltages) and of circuit breakers with rated voltage  $\geq 300\text{kV}$

It is noted that the alternative power frequency and lightning impulse insulation levels according to the North American practice (Table 2b of [35]) are higher than the international values (Table 2a of [35]). In particular the short duration power-frequency withstand voltages across open contacts of CBs  $\geq 300\text{ kV}$  of Table 2a (international standard) are about 25% higher than the maximum beat voltage during synchronizing; this margin is 40-45% with reference to Table 2b (North American alternative practice).

The short duration power-frequency withstand voltages across open contacts have been specified in IEC 60694 [35] by considering a 3 sec-1.5 pu overvoltage due to load rejection on generators side and the nominal voltage (1 pu) in phase opposition on network side.

The IEC-Standard 62271-203 “Gas-insulated metal-enclosed switchgear for rated voltages above 52 kV” [62] (the previous Standard 60517), makes reference to these tables in IEC 60694, but for the highest rated voltages different short-duration power frequency withstand voltages are specified as follows:

*Table 7-II*

Rated voltage (kV)	(2) 1min withstand (kV)	(2) 1min withstand (pu)	(3) 1min withstand (kV)	(3) 1min withstand (pu)
420	650	2.68	815	3.36
550	710	2.24	925	2.91
800	960	2.08	1270	2.75

These statements and specifications in the Standards indicate that with respect to out-of-phase conditions and synchronisation, a longitudinal power frequency dielectric withstand strength to column (3) rather than column (2) should be required explicitly for CBs, also for rated voltages  $\leq 245\text{ kV}$ .

In the ANSI/IEEE Std. C37.013 [34] a particular requirement is for the dielectric withstand strength after clearing, when, especially for generator CBs, out-of-phase voltages across the CB chambers will occur. The external dielectric withstand strength has to be at least 5.5 pu/1 min. for rated voltages  $\leq 15.8\text{ kV}$  and 3.8 pu/1 min. for rated voltages  $> 15.8\text{ kV}$ . The internal dielectric strength under loss of the pressure of the insulating medium has to be more than 1.5 \*

2.0 = 3.0 pu for longitudinal stresses, and 1.73 pu and 1.0 pu respectively for phase-to-phase and phase-to-earth stresses.

According to clause 2.3.2.2 of IEC Standard 60071, part 2, “Insulation coordination. Application guide” [36] full load rejection will lead to temporary overvoltages, which are normally less than 1.2 pu for moderately extended systems, but could reach values up to 1.5 pu for large extended networks, and even more in case of (ferro)resonance. (Ferro)resonance, however, should be avoided and mitigation measures are suggested (cl. 2.3.2.3 and 2.3.2.6). The longitudinal overvoltages across the CB open terminals are equal to the temporary overvoltages when the rejected load was of a static nature. But, in case of motors and especially generators the longitudinal overvoltage can reach values up to 2.5 pu and in very extended systems even more. A power frequency longitudinal overvoltage as high as 2.5 pu is also given in clause D.1.3.2. of IEC 60694.

With regards to the HV-EHV CBs of generating units, the open contact withstand voltages specified by IEC Standard 60694 [35] are sufficient for synchronizing, provided CBs are maintained to the IEC power-frequency withstand voltages while in operation.

A comparison of the external insulation across the open contacts, of dead tank and live tank CBs should be based on two different concepts.

In the dead tank design the external phase-to-ground insulation (the bushings) also provides the insulation between open contacts during synchronizing. Bushings are required to withstand the continuous operation voltage even in the presence of pollution. External insulation of dead tank CBs that is trouble free in normal operation with the CB closed, is also adequate during synchronizing with CB open.

In live tank CBs, the external insulation between terminals is not energized when CB is closed. A deficiency in the external insulation, caused by pollution and humidity or icing, may show up during synchronizing when the voltage beat stresses insulation.

According to the IEC Standards 60694 (art.6.2.7.1) and 62271-100 (art.6.2), the 1 minute power frequency voltage type test across open contacts of CBs with rated voltage > 245kV, is to be performed in dry conditions only. For instance, CBs with rated voltage of 420kV are to be type tested in dry conditions as follows: (i) phase-to-earth and between phases at 520kV; (ii) across open contacts at 610kV (reduced at 520kV in routine test). There is no evidence that this test warrants the withstand at 485kV out-of-phase during synchronizing under rain, in particular if the rain at ANSI Standards (more severe than at the IEC Standards) is specified, or if an even moderate insulator pollution is foreseen.

Concerning pollution, articles 6.2.8 and 5.14 of the IEC Standards 60694 specify that the artificial pollution tests are not necessary when the creepage length,  $I_t$ , of longitudinal insulation of CBs that are exposed to out-of-phase conditions, is not less than calculated with the formula:

$$I_t = 1.15 \cdot I_f \cdot U_r \cdot k_D \text{ (mm)}, \quad (7-1)$$

where:  $I_f$  is the minimum nominal specific creepage distance (mm/kVrms) according to Table 11 of IEC 815;  $U_r$  is the rated voltage of CB (kVrms) and  $k_D$  is the correction factor due to insulator diameter as per art.5.3 of IEC 815.

The WG A3.13, while recognizing the possible difficulties encountered when testing EHV CBs between open contacts at power frequency under rain and with artificial pollution, keeping in mind the failures which have occurred in operation during synchronizing with very severe consequences (generally busbar faults), recommends the following requirements for the longitudinal power frequency dielectric tests of EHV live tank CBs used for frequent synchronization of generators:

- Perform a 1 minute wet type test with out-of-phase applied voltage, at two times the maximum phase-to-earth system operating voltage. See also [95].  
If this wet test is not feasible, the dry type power frequency voltage test across open contacts should be performed with a voltage higher than specified in Table 2a of the IEC Standards 60694, such as to cover, according to test laboratories experience, the withstand reduction occurring under rain in out-of-phase conditions.  
In any case, the power frequency test voltage across open contacts of CBs shall be not less than specified for disconnectors in the IEC Standards 60694 [35].
- If pollution is foreseen at site of installation, and creepage distance of CB external longitudinal insulation is less than the length calculated with formula (7-1), perform an artificial pollution type test as required in art. 6.2.8 of IEC 60694, at the voltage  $1.15U_r$  (i.e. at  $1.15 \cdot \sqrt{3} = 2$  times the phase-to earth rated voltage; see also [95]) as recommended in art. 5.14 of IEC Standard 60694 (for switching devices exposed to out-of-phase conditions). The test is to be performed with the foreseen pollution level, by applying one of the test methods recommended by the IEC Standards 60507.  
If none of these pollution withstand requirements is complied with, the substation operator should adopt provisions for maintaining clean the insulators of live tank CBs used for frequent synchronizing. However, a case has been recently reported of a thermoelectric power plant close to the ocean shore in Western Africa, where flashovers have occurred 4 times across live-tank CBs during generator synchronizing at the HV side, in spite that live substation washing is performed with de-mineralized water at 15 days intervals. The longitudinal insulation of the CBs is reported to have a creepage length of 25 mm/kV of rated grid voltage.

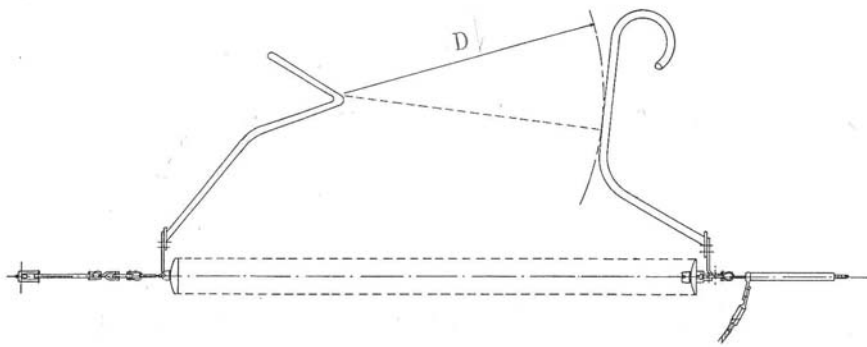
Synchronizing of sub-systems is generally much less frequent than synchronizing of generating units. The probability of a large reduction of power-frequency withstand voltage due to pollution and humidity/icing at the moment of synchronizing is thus lower for line CBs. On the other hand, the line CBs in open position are exposed to lightning and switching overvoltages. In particular, multiple lightning strokes may cause travelling waves to almost double in amplitude on the line side of an open CB during the dead time before reclosure. As the resulting overvoltages may exceed the lightning impulse withstand capacity of CB across open contacts, some form of protection should be applied. Protection can be performed with MOSAs or with air spark gaps.

MOSAs, if installed at line ends for limiting switching and lightning overvoltages phase-to-ground, also provide protection for an open CB.

Transmission system operators which do not apply MOSAs at line ends, usually apply a protection with air spark gaps. To ensure the protection is adequate for line CBs in the open position and does not cause un-necessary flashovers in normal operation with the CB closed, the special air gap protection should comply with the following requirements:

- i) The 50% flashover voltage of gap should be about the same with positive and negative switching impulses as well as lightning impulses. The ratio of 50% flashover voltages between lightning and switching impulses should be as low as possible, i.e. close to unity.
- ii) The gap should withstand with very high probability the switching overvoltages caused by line energization and by the high-speed re-energization.
- iii) With the line CB in closed position the gap should withstand with very high probability lightning overvoltages that have been drastically reduced by reflection at busbars where other lines terminate and/or by the surge arresters protecting transformers. This allows the use of gaps with a 50% lightning impulse withstand voltage considerably lower than the spark gaps protecting the line insulator strings.
- iv) In the presence of large fast front incoming lightning overvoltages with line circuit breaker in open position, the time to flashover must be shorter in the gap than in the protected CB.

Fig. 7.1 shows a specially shaped protective air gap complying with the above requirements, that has been applied in Italy for many years with good operation results. The gaps are fitted in the line anchor insulator strings to substation gantry. Typical gap distances are provided in the figure caption for 380kV and 150kV line applications. The switching impulse 50% flashover voltage with distance of 1700mm is 1040kV ( $3.36\text{pu on } (380/\sqrt{3}) \cdot \sqrt{2}\text{kV basis}$ ).



*Fig.7-1 Special protective spark gap fitted in the line anchor insulator strings to substation gantry;  $D = 1700\text{ mm}$  for 380 kV lines;  $D = 800\text{ mm}$  for 150 kV lines.*

### **Summary of recommendations**

- The power frequency withstand voltage across open contacts (under rain in type test) of CBs used for synchronizing should have the values specified in the Standard for the disconnectors
- In case of CBs used for frequent synchronizing, the occurrence of an earth fault may have to be considered during synchronizing.
- The external insulation across open contacts of live tank CBs used for frequent synchronizing (generator CBs) should, in addition, be specified to withstand in phase opposition 2 times the maximum phase-to-earth power-frequency operation voltage in a type test under rain and with pollution representative of the expected local environmental conditions.
- Line CBs used for synchronizing of separated sub-systems, or used for the automatic line reclosure, are exposed in open position to lightning overvoltages which may exceed their withstand capacity. Protection is ensured by MOSAs connected phase-to-earth at the line end, or by specially shaped air spark-gaps with spacing considerably lower than applied in the horn gaps protecting the standard insulator strings of the lines.

## 8. TRANSIENT CURRENTS

### 8.1 Inrush currents

The consequences of inrush currents on transformers, SRs, shunt capacitor banks, back-to-back banks and restrikes when switching off shunt capacitor-banks have been extensively reported in the literature.

Under certain conditions, and particularly in very weak systems (as may exist with long transmission lines), energizing transformers or SRs can lead to severe voltage dips, to disturbances in protection and/or telecommunication systems and to false operation of protection relays of parallel connected transformers due to “sympathetic” inrush. Apart from countermeasures that can be taken within the protection, secondary and tele-communication systems, the voltage drops due to large inrush currents are reduced if the short circuit power at the energizing busbar is relatively high. On the other hand, the higher short circuit power, the higher is the inrush current. In special cases the inrush currents can be reduced by applying controlled switching [43]; in the past pre-insertion resistors were also occasionally applied. Advanced controlled switching offers the possibility of avoiding very high inrush currents due to residual flux with opposite polarity to the applied voltage.

Energizing of shunt capacitor banks produces inrush currents whose amplitude and frequency depends on the nominal reactive power of the bank and the substation short circuit power:  $I_{\text{inrush}}/I_{\text{nom}}=f_{\text{inrush}}/f_{\text{nom}}=\sqrt{(P_{\text{sc}}/Q_{\text{c}})}$ ; see annex H of [22]. When switching on back-to-back banks the small reactance between the back-to-back banks causes a much higher amplitude and frequency of the inrush current. In both the IEC and the ANSI Standards for CBs, inrush currents for back-to-back banks are specified with maximum 20 kA<sub>peak</sub> and maximum 20 kHz.

Energization of high voltage shunt capacitor banks with grounded neutral may cause large inrush current flow through the grounding system and induction in secondary circuits. Adequate grounding systems and electromagnetic compatibility (EMC) measures are necessary to prevent unacceptable problems.

Extra high inrush currents can be produced when energizing charged capacitor banks, for instance during restrikes at switching off the capacitor bank, especially in connection to long lines and high TOVs (see section 5.3).

The amplitude of inrush currents when energizing transformer and SRs are shortly dealt with in section 4.2.

### 8.2 Secondary arc current during single-phase auto-reclosing (SPAR)

Secondary arc current during SPAR is mainly a problem of arc extinction on the line, and not a problem for the line CBs involved. It is assumed that in EHV (345-765kV) OH-lines an arc current not exceeding 40 A will generally self-extinguish within one second. It has been reported [84] that in UHV (1000-1200kV) OH-lines the self-extinction of secondary arc occurs with high probability for somewhat higher currents (say, up to 75A), due to the longer length of gap across which the arc is ignited. Arcs with a current exceeding 120 A are supposed not to

self-extinguish, whereas arc currents between 40 A and 120 A may lead to self-extinction in EHV lines, but after substantially longer arcing times than 1 second. Stability limits for the auto-reclosing time during a SPAR-cycle depend on transmission grid configuration and may be less than 1 second in long single-circuit radial lines with loading of the order of SIL. It should however be noted that in meshed grids, without risk of angular instability, the SPAR limit time might be much longer and is controlled by the flow of negative and zero-sequence currents in the system instead of by angular stability. Usually a SPAR time of 1 to 2.5 seconds is applied. To be at the safe side, EHV system design is based on arc currents below 40 A.

During the auto-reclosing time, a voltage is induced by capacitive coupling from the healthy phases to the disconnected, floating conductor. In long OH-lines, it is this electrostatic induced voltage that maintains the arc between the disconnected conductor and earth. The induced voltage is quite large, as it depends on the ratio between the capacitances of (1) the energized phase conductors to the floating phase conductor and of (2) the floating phase to earth.

The currents flowing in the energized phases electromagnetically induce a voltage in the disconnected phase which adds to the electrostatically induced voltage and somewhat contribute to the secondary arc current flow, by an amount depending on fault location.

By the secondary arc resistance (100 to 1000  $\Omega$  [70]) the induced voltage is reduced to the arc voltage (several kV to few tens of kV). As soon as the arc self-extinguishes, the former arc channel has to withstand the electrostatic induced RV. The leakage current is rather low (tens to hundred of A), but the RV shows an overswing with a 1-COS shape, thus reaching about 1 pu.

SRs, when applied, may much increase the electrostatic induced voltage (see section 3.6), but SRs can only effectively reduce the arc current to a value below 40 A, if a properly tuned neutral reactor is added between the neutral of the SRs and earth [74][75][81][82]. But, and certainly at the highest operating voltages, it may be difficult to find a value for the neutral reactor, suitable for all prevailing situations, thereby making it not always possible to limit the arc current to acceptably low values. On the other hand, SRs may have to be out of service when the lines are heavily loaded, i.e. when the SPAR is more useful. The auto-reclosing time may also be critical and therefore an alternative solution to limit the arcing current is the use of HSGS (High Speed Grounding Switches).

In order to reduce the time for secondary arc extinguishing, so that the SPAR time can be limited to, for instance, 1 s, single pole operated HSGS can be used. This switchgear is applied at each line end and at each phase. After interruption of the single phase-to-earth fault current on the line (by the CBs at both line ends), the HSGS are closed for a fraction of a second, enough to reduce the induced voltage to some kV so that the secondary arc disappears. After the single pole opening of the HSGS, the line-breakers will close again and the single-phase auto-reclosing will be successful if the fault is of a transient type. The CO-operation cycle of a HSGS lasts for some hundreds of ms.

As soon as one or two HSGS are closed, the voltage on the faulty phase conductor is no longer an electrostatic induced voltage. In fact the electromagnetic induced voltage plays an important role, because a conductive loop is formed that picks up the magnetic field from the healthy phases. The conductive loop consists of

- one HSGS, the phase conductor, the secondary arc and the ground return path or
- one HSGS, the phase conductor, the other HSGS and the ground return path.

The electromagnetic induced currents may be of a magnitude up to 6 to 8 kA [71][72] and depend on line configuration, line length and line loading. In [71] a trend is shown that longer lines show a smaller induced current.

The interruption of the electromagnetic induced current by the first HSGS that opens, gives a TRV, the RRRV of which is determined by the surge impedance of the phase conductor multiplied with  $dI/dt$  of the electromagnetic induced current. The peak value of the TRV is determined by the induced voltage along the line ( $M \cdot dI/dt$  of the load currents of the healthy phases) multiplied with the amplitude factor of the TRV-overswing.

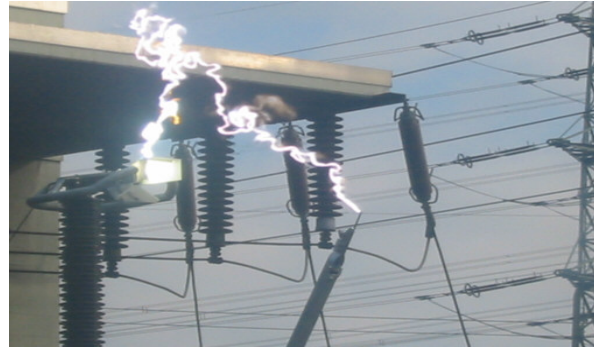
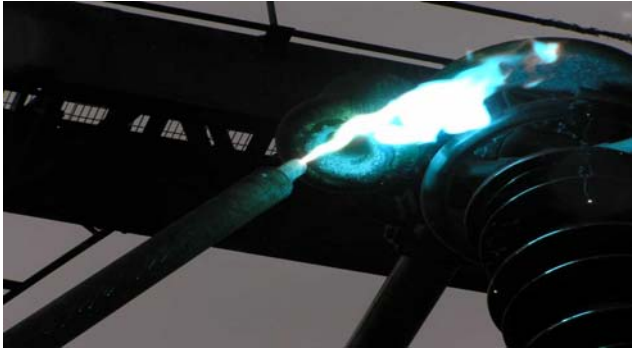
The second HSGS breaks in fact a electrostatic induced current of low amplitude, but the TRV will follow a 1-COS waveshape, giving a peak value of about double the capacitive induced voltage. TRV peak values of about, or even above, 1 pu have been reported [72][73].

HSGS are very special switching devices, with particular test duties, that not yet have been standardized. Their design is based on the design of CB interrupters. Apart from the special electrostatic and electromagnetic current interruption duties, another test duty mentioned in the literature has to do with long arcing times. Such long arcing times may occur when at the moment of clearing by the HSGS, a phase-to-earth fault appears in a healthy phase (for instance due to lightning). Then suddenly the induced currents will become larger and show an induced superimposed DC-component that prohibits a current zero crossing until the fault current at the other phase is cleared. Although for the HSGS the TRV peak value is lower, the extended arcing time poses a special requirement to the interrupter and operating mechanism of the HSGS. Arc extension up to 80 ms has been reported.

Utilities that apply HSGS to extinguish the secondary arc claim that in this way they can apply SPAR to long, heavy loaded lines, especially in UHV-networks.

### **8.3 Current switching by earth switches**

Many OH-line networks incorporate double circuit towers or parallel circuits and it is not uncommon for one circuit to be earthed at both ends for maintenance whilst the other remains in service. Under these circumstances magnetic coupling can induce significant currents in the loop formed by the conductors and earth. This situation can present an onerous duty for earth switches at the line ends which are required to make, break and carry the induced current. The exact conditions to which the earth switches are exposed depends on the specific line geometries and operating conditions (parallel line load current); however typical National Grid (U.K.) line constructions at 400 kV result in induced currents of approximately 10% of the load current in the parallel circuit (i.e. up to about 400 A). This value is significantly in excess of values presently found in IEC standards. Network experience with older earth switch designs is that making and carrying this current is not problematic, however breaking operations result in significant arcing. The following photo (figure 8.3-1) shows the arc drawn by switching approximately 120-130 A in the National Grid network. The second photograph (figure 8.3-2) shows the arc drawn during a 400 A breaking test of a conventional earth switch design.



*Fig.8.3-1 Earth switch breaking of a 120-130 A Fig.8.3-2 Earth switch breaking of a 400 A*

In the case of multiple EHV circuits, in particular double-circuit OH-lines, current may circulate in the de-energized and earthed circuit also due to electrostatic coupling with adjacent energized circuits. Earthing switches in these conditions must possess current making, carrying and breaking capacity for earthing and un-earthing at one terminal: (i) with the other terminal open (capacitive current); (ii) with the other terminal closed (inductive current). The induced current specified in the IEC Standard 62271-102 (2001) [61] for Class B EHV earthing switches is 160A, but this value will be exceeded by the application of longer OH-lines as well as by the higher loading of the OH-lines. Whilst there is no evidence, as already noted, that this will pose a safety risk or that the equipment will be significantly damaged, future Standards should better reflect the new conditions.

#### **8.4 Compact, HSIL- and EXB-lines**

High surge impedance loading lines (HSIL) were first proposed in the 1980s [46][47][48][49][50][51]. Good experience has been reported from Brazil with expanded bundle conductors, that give less reduction of the surge impedance than with HSIL, but still a 20% to 30% increase of the SIL but having the advantage of easier implementation [52][53]. In Appendix B, the concept of HSIL and EXB has been further elaborated. See also the studies of CIGRÉ WG B2.06, mainly based on the experience in Brazil [83].

No detrimental behavior of the power system has been attributed to the use of properly-designed lines of the types discussed in the Appendix B. It should be said, however, that due to the increased inter-phase coupling that characterizes compact and HSIL lines, the extinction of secondary arcs in a faulted phase within the dead-time period usually considered for SPAR becomes more difficult – or even quite improbable if extra-long HSIL-lines are considered – [53]. This difficulty can make the implementation of SPAR unattainable in certain cases. There may also be a limitation on the span-length, as the Standards prescribe minimum phase-to-phase distances as a function of the span-length, or vice versa maximum span-lengths as a function of the phase-to-phase distance.

#### **8.5 Fault currents with delayed current-zero crossings**

Studies conducted on the Hydro-Quebec 735-kV series-compensated system (Appendix A, figure A1-1) revealed the existence of unusual delayed current-zero crossing phenomenon, which may occur for some series-compensated line circuit breakers. The main factors

contributing to delayed current-zero are the presence of one or more parallel series-compensated lines, the location of series capacitor banks on line terminals and the presence of metal-oxide varistors (MOV) protecting series-capacitor banks. The severity of the phenomenon is related to a combination of operational and topological factors. If the breaker located near the series capacitor bank opens last, then the breaker located further away from the fault (a 2-phase ungrounded, 2-phase-to-ground or 3-phase-to-ground line fault near the capacitor bank) is predisposed to delayed current-zero. The network upstream from the circuit breaker must be inductive, as are the cases for the breakers at the CHURCHILL end of the CHURCHILL – MONTAGNAIS corridor and for the breakers at the LEMOYNE end of the LEMOYNE – ALBANEL corridor. However, an inductive path can also appear for the MONTAGNAIS – ARNAUD corridor if one or more capacitor banks in the CHURCHILL – MONTAGNAIS corridor are by-passed. EMTF simulation results have shown that one of the most severe cases appears on the breakers at LEMOYNE end of the LEMOYNE – ALBANEL corridor during a 3-phase-to-ground or a 2-phase ungrounded line fault near the series-capacitor banks at ALBANEL. In this case, the time delay for the first zero crossing of the prospective fault current could reach 113 ms as shown in figure 8.5-1 [18].

Test results show that air-blast CBs can interrupt such asymmetric short-circuit currents thanks to high arc voltages developed during current breaking process whereas modern single-pressure SF<sub>6</sub> CBs may have problems to interrupt fault current after such large arcing times. Two special SF<sub>6</sub> CB designs were developed and tested for this application in the Hydro Québec system. As illustrated in figure 8.5-2, SF<sub>6</sub> CB type A, which is capable of developing high arc voltages during the current breaking process, has to interrupt fault currents after a maximum arcing time of 28 ms whereas SF<sub>6</sub> CB type B, which develops low arc voltages during current breaking process, has to interrupt fault currents after a maximum arcing time of 60 ms, as shown in figure 8.5-3 [18]. Three-phase cases are more complicated, but the first clearing pole will help the other poles, as has been shown in chapter 10 of [37].

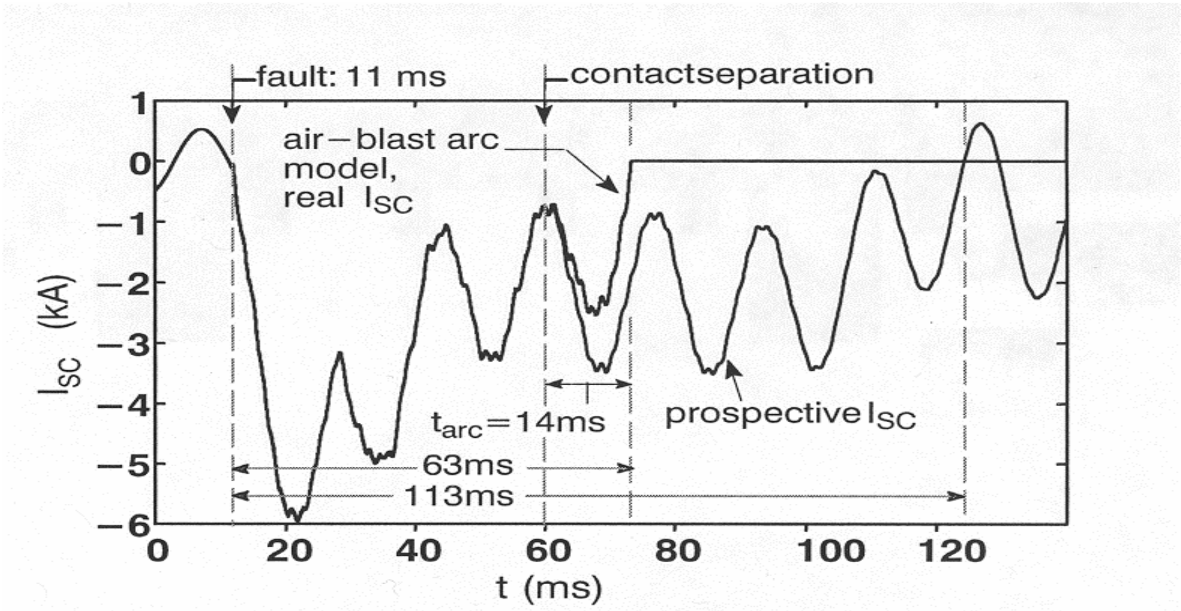


Fig. 8.5-1 Fault current seen by series-compensated line CB with unusually delayed current-zero crossing

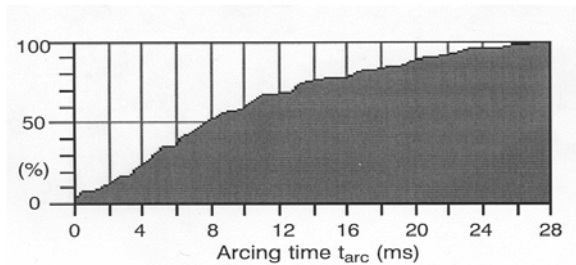


Fig. 8.5-2 Cumulative frequency of arcing times, SF<sub>6</sub> CB type A

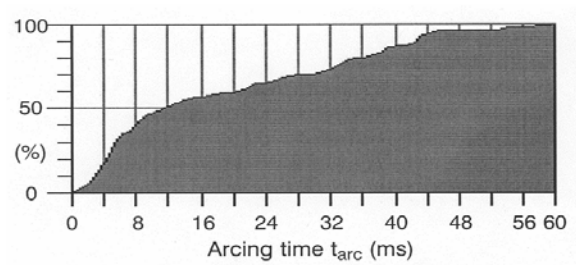


Fig. 8.5-3 Cumulative frequency of arcing times, SF<sub>6</sub> CB type B

It should be mentioned that the time delay for the first zero crossing of the prospective fault current is strongly dependent on the fault locations, the type of fault (i.e. 1-phase-to-ground, 2-phase-to-ground, 2-phase ungrounded, 3-phase-to-ground or 3-phase ungrounded fault) as well as the total series resistance of the circuit. Therefore, it is necessary to include, when analyzing this phenomenon, the effects of current interruption without delay with natural zero crossing in one or two phases as well as the total arc fault resistance. Furthermore, the occurrence probability of this phenomenon according to the locations of circuit breakers should be evaluated in order to optimize their performance requirements.

The problem of delayed short circuit current zero crossing has been analysed for the series compensated 420kV lines of the Turkish system, initially with the TNA and subsequently with the EMTP program. Fig.8.5-4 shows one of the worst cases: a 1-phase-to-ground short circuit current in the Elbistan A-Ankara West 468km-420kV line (see Appendix A, figure A3-1), located at Avanos close to the SCs terminal on the Ankara West side. Simulations have been performed by assuming a nil fault resistance and CB arc resistance, with fault occurrence at time  $t_0 = 10\text{ms}$ .

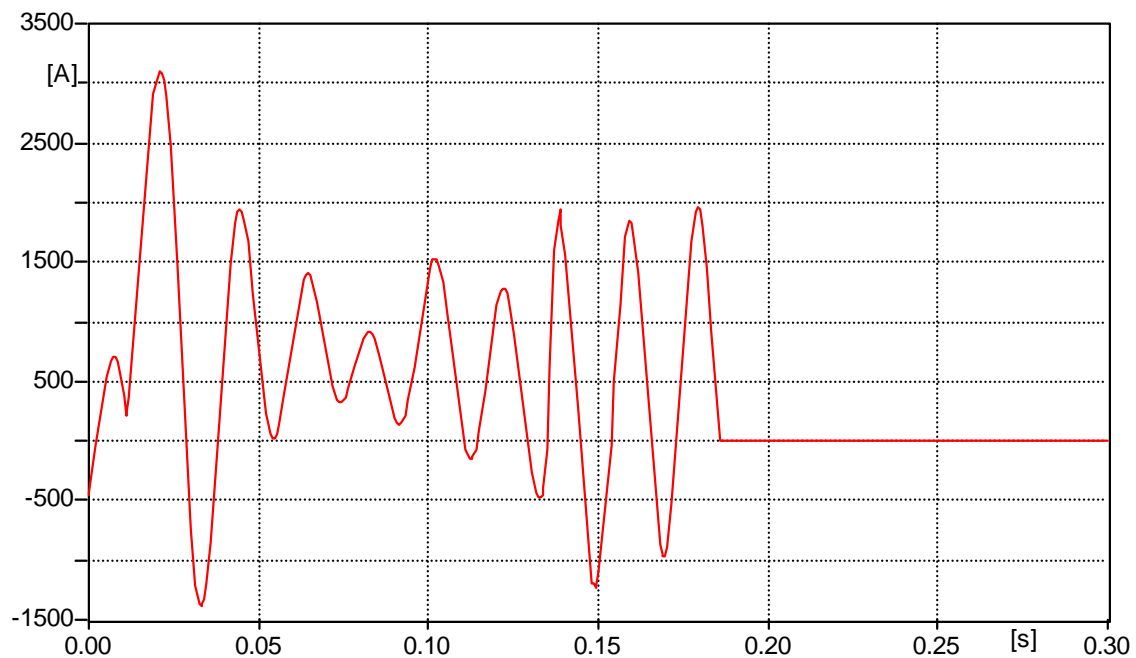
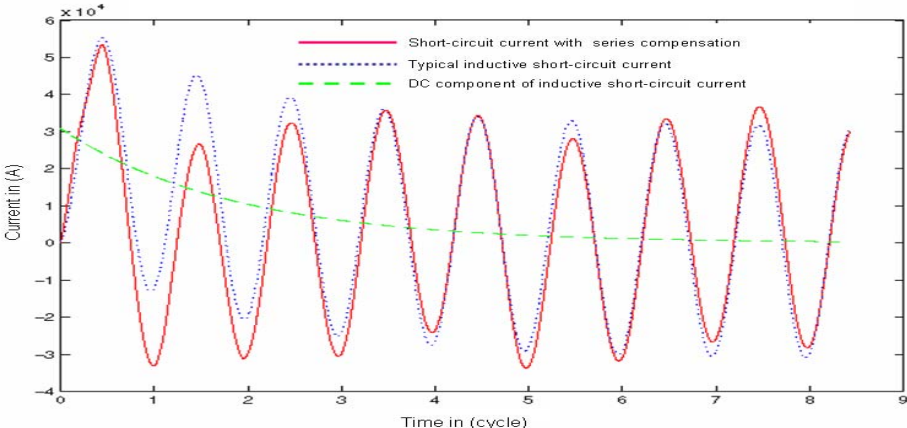


Fig. 8.5-4 1-phase-to-ground short circuit current in the Elbistan A-Ankara West shunt-series compensated line of Turkey (see Fig. A.3-1), for fault located at Avanos on the Ankara side terminal of SCs.

Figure 8.5-4 shows no current zero crossing in the time interval between 28ms and 100ms after fault inception, due to the DC offset combined with a beat between the power frequency forced current and the natural oscillation of the shunt-series compensated line at a frequency close to power frequency. However, the case illustrated by figure 8.5-4 is not dangerous for the line CB, for the following reasons: the physical separation of the contacts does not occur before 60ms after fault inception (relay time plus mechanical operation time of CB); the short circuit current is small and the relevant arc resistances in the chambers of CB (2 or 3 per pole in SF6 420kV CBs; 4 per pole in 420kV minimum oil old CBs) and the fault resistance, generally present in 1-phase-to-ground faults, damp the DC component and generally force current to zero, with earlier interruption; on the other hand, oscillating currents with average value of only several hundreds amperes in the period of absence of zero crossings (see figure 8.5-4) are interrupted by SF6 CBs even if arc duration exceeds the values encountered in the conventional prototype short circuit tests. More than 30 years of operation experience has confirmed that the phenomenon of delayed current-zero crossing in series compensated lines is not a problem for CBs in Turkey.

**8.6 Low frequency oscillations superimposed on power frequency fault currents**

In a series-compensated transmission system, the transient response contains a sub-synchronous component inherent to the R-L-C series circuit leading to low frequency oscillations being superimposed onto the power frequency fault currents, as illustrated in figure 8.6-1 [19]. This phenomenon, which might be originated from the sub-synchronous resonance phenomenon mentioned in section 9.3, has been observed on the main series-compensated transmission system as well as on the secondary sub-transmission system (LV side of transformers connected to the main transmission system) albeit with a lesser intensity. The X/R ratios which are used in international standards to characterise the asymmetrical components of inductive short-circuit currents are not valid to describe the low frequency oscillations superimposed on power frequency fault currents. To evaluate the circuit breaker interrupting capability in presence of this phenomenon, a new method based on proportional quantities to arc energy has been proposed in [19].



*Fig. 8.6-1 Short-circuit current in series-compensated system vs. typical inductive short-circuit current*

## 8.7 DC offset currents when energizing long EHV cable-OH-line sections

In [63] the ATP-EMTP analyses of switching overvoltages and of the single-phase high-speed reclosure have been reported only for case studies of mixed cable-OH lines, for which the phenomenon of long duration DC offset current has not been observed. The authors however observed that long duration DC offset energizing currents may occur when switching-on a long highly shunt compensated cable line (not including OH-line sections), and some alternative countermeasures were proposed for this phenomenon.

Figure 8.7-1 is the single-line diagram of the mixed 400 kV – 50 Hz line analysed in par. IV of [63], consisting of 60 km of cable line in a tunnel, solidly connected at one end to a 200 km long 400 kV OH-line. The cables are highly shunt compensated, to allow the no-load energization of the mixed line from a busbar where the short circuit power is relatively low, without incurring unacceptably large TOVs.

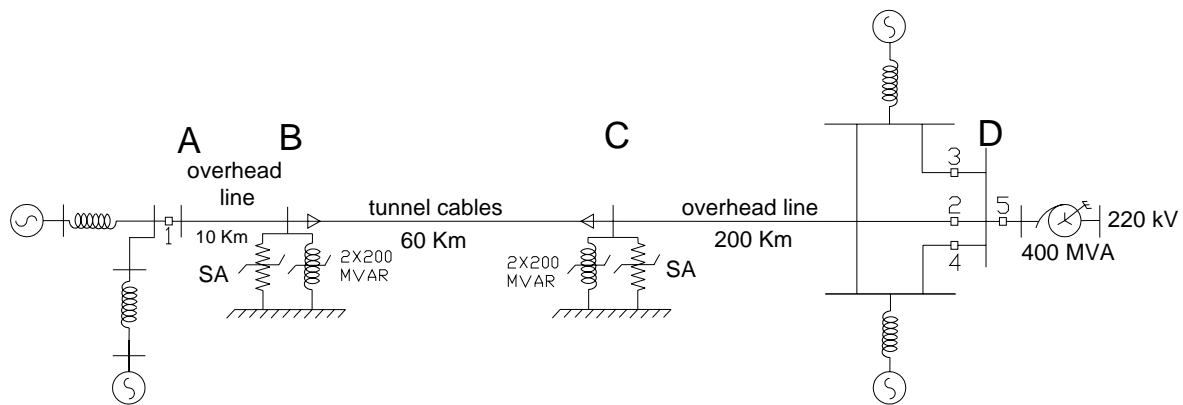


Fig.8.7-1 Single-line diagram of a mixed cable-overhead 400 kV – 50 Hz line

Analysis was first performed for the no-load energization currents of the mixed cable-OH-line (figure 8.7-1), switched as one block from terminal A or D, in the most unfavourable conditions as regards the possibility of build-up of DC current offset, i.e. the cables are 100% shunt compensated and energization from busbar D occurs at the instant of voltage nil in one phase. Results show a very fast decay of the DC offset current due to the presence of the OH-line section, without adverse effects on the line CB which for various reasons (fault occurrence, mis-operation of protection relays, etc.) might disconnect the mixed cable-OH-line shortly after energization. A similar result is obtained if the mixed line energization is performed from busbar A.

Below some results are reported<sup>\*)</sup> for the case of switching individually the cable line section shunt compensated at about 100%, from busbars B or C (figure 8.7-1), assuming that CBs are installed at each cable terminal. Figure 8.7-2 shows large DC offset currents, which decay to about zero only 4 s after the cables energization, as shown in the bottom-right diagram.

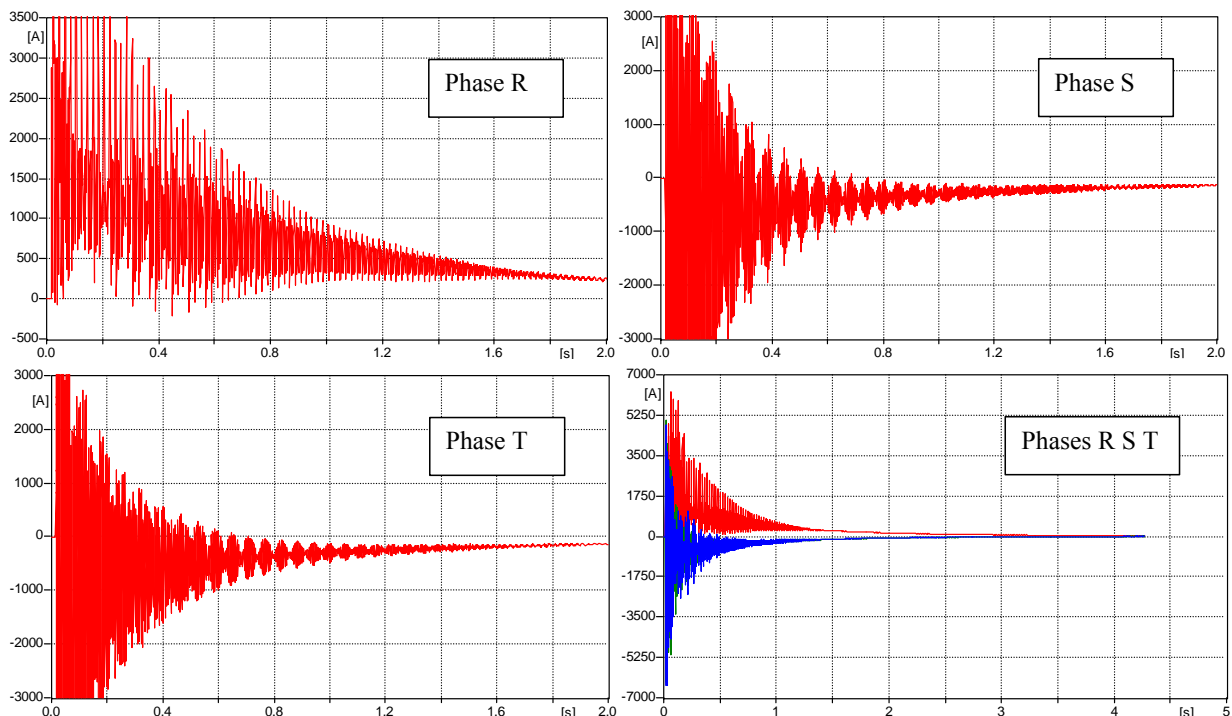
<sup>\*)</sup> Analyses performed by L. Colla and F. Illiceto at Rome University “La Sapienza”, not yet published at time of writing.

The following alternative countermeasures are proposed for the case of very long highly shunt compensated EHV cable lines, not including solidly connected long OH-line sections:

**Solution A.** Use synchronizing relays in the cable line CBs, in order to separately close each phase when the relevant voltage is at the maximum. Figure 8.7-3 shows that, with this provision, no DC offset currents occur.

Analyses have also shown that the shunt compensation of the 60km long-400kV-50Hz cable line section of Fig. 8.7-1 should not exceed 90%, in order to leave a small AC no-load cable residual charging current and thus ensure current zero occurrence without delay in the presence of small DC offset currents. The latter may be caused by the unavoidable small departure of the contact closing instant of CB from the precise instant of maximum voltage.

**Solution B.** If the cable line is to be tripped out automatically after the energization from one terminal due to a fault, the faulty phase(s) – that are not affected by the long duration DC offset – is (are) opened without any intentional delay by the line protection relays. The healthy phase(s) is (are) open with a delay of some seconds, to ensure the damping of the DC offset current(s). This delay should not disturb operation of the network energizing the cables, because in the healthy phases of the cables, assuming a shunt compensation close to 100%, the AC symmetrical component of the currents remains very small after disconnection of the faulty phase(s). This stems from the fact that the EHV 3-single core cables have a zero-sequence capacitance equal to the positive-sequence capacitance, and the same is true for the SRs (star connected with solidly earthed neutral; 5 legged core or shell core type if three-phase units are used).



*Fig.8.7-2 No-load energization currents of the 60 km-400 kV cable line of Fig. 8.7-1, 100 % shunt compensated, from busbar C, when voltage is nil in phase R. The bottom-right diagram shows the same currents computed up to 5 sec.*

Figure 8.7-4 shows the currents at the energizing busbars of the cables, in presence of a 1-phase-to-ground short circuit cleared in 100ms by the single-phase opening of the faulty phase. If the cable line protection relays cannot be used to perform the function of delayed opening of the healthy phase(s), this function can be performed by the phase discrepancy relays with appropriate time setting.

Solution C. To rely entirely on the synchronizing relays (Solution A.) or line protection relays (Solution B.) may involve some risk in case of a relay malfunction. The combination of (A.) and (B.), both low cost countermeasures, can be applied, to ensure that CB opening in presence of large DC offset currents will not occur. It is also recommended to perform the switching-on analysis of specific cable projects (as regards length, rated voltage and frequency), in particular for computing the departure from 100% shunt compensation required for successful application of Solution A.

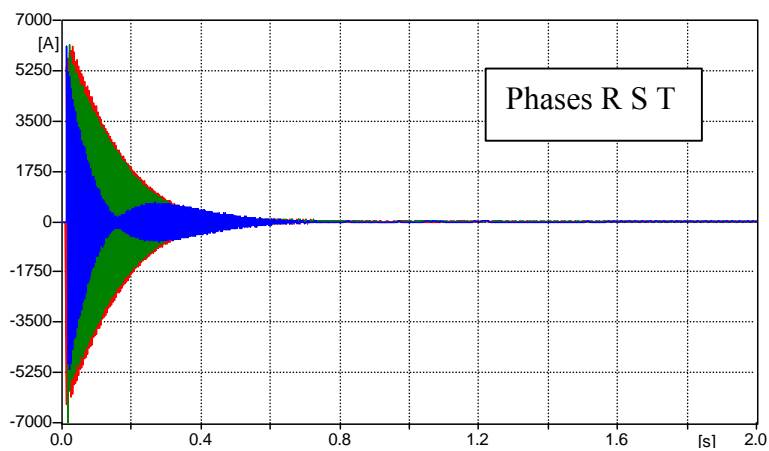


Fig. 8.7-3 No-load energization currents of the 60 km-400 kV cable line of Fig. 8.7-1, 100 % shunt compensated, from terminal C, at the instants of maximum voltage in each phase, with use of CB with synchronizing relay

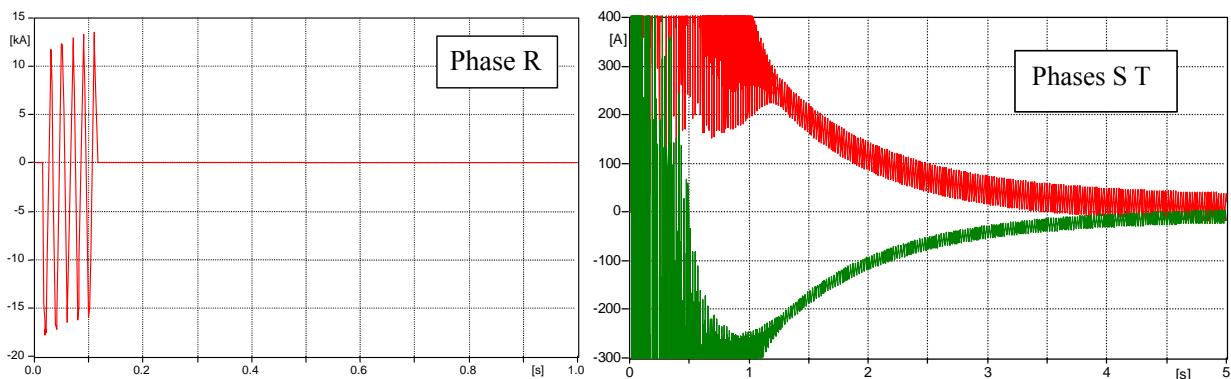


Fig. 8.7-4 Energization of the 60 km-400 kV cable line 100 % shunt compensated of Fig. 8.7-1, in presence of a 1-phase-to-ground short circuit in phase R

It is also recommended to perform the switching-on analysis of specific cable projects (as regards length, rated voltage and frequency), in particular for computing the departure from 100% shunt compensation required for successful application of solution A.

## 9. SERIES CAPACITOR BANK TECHNOLOGIES AND OPERATING EXPERIENCE

### 9.1 Technologies

Series compensation involves the use of capacitance in series on a transmission line to compensate for the inductive reactance. It is used to improve power system transient stability, improve voltage regulation on long transmission lines and increase power transfer capability of the line. Series Capacitors (SCs) reduce voltage drop due to inductive Mvar flow and also reduce Ferranti effect overvoltages. SCs are also used to control power sharing among parallel lines in proportion to cross-section (conductivity) of phase conductors. This form of compensation first became popular in the 1950's and today there are over 500 installations worldwide (see Appendix A for some examples).



*Fig 9.1-1 Example of a 735 kV SC Bank*

The basic components of a SC bank are:

- Main support insulators
- Platform
- Disconnect switches
- Capacitors
- By-pass circuit breaker
- Overvoltage protection, and
- Protection and control system

The capacitors are installed on platforms which are insulated from ground. Each phase has a separate platform and the phases are connected to the high-voltage thru disconnects. A by-pass disconnect is open when the capacitor bank is in service. The SC bank is removed from and placed into service by the respective closing and opening of the by-pass circuit breaker

Faults on a transmission system electrically not far from SCs may cause the capacitors to be stressed by intolerable overvoltages. Spark gaps and/or MOVs are therefore used to protect the capacitors.

In general, SC banks use four types of schemes:

- i. *Slow-reinsertion type*: the bank is protected by a self-triggered gap and a by-pass circuit breaker only.
- ii. *Instantaneous reinsertion type*: the bank is protected by MOVs, forced triggered spark gaps in most cases and by-pass CB; see Figure 9.1-2.
- iii. *Fast reinsertion type*: the bank is protected by two self-triggered gaps, a low setting gap with a circuit breaker in series and a high setting gap with a by-pass circuit breaker in parallel.
- iv. *Thyristor controlled SC*: thyristors are used to bypass or insert modules of capacitance and inductance, rapidly modulating the line reactance; this scheme offers faster bank restoration into service due to the shorter cool-down time of the thyristor valves compared with the cool-down time of MOVs; see Figure 9.1-3.

In today's designs the by-pass CB and control/protection systems are located at ground level; all-film insulated capacitors, more reliable spring operated CBs, laser powered signal transmission and digital protection/control systems are used. These changes have significantly reduced downtime and resulted in high bank reliability and availability.

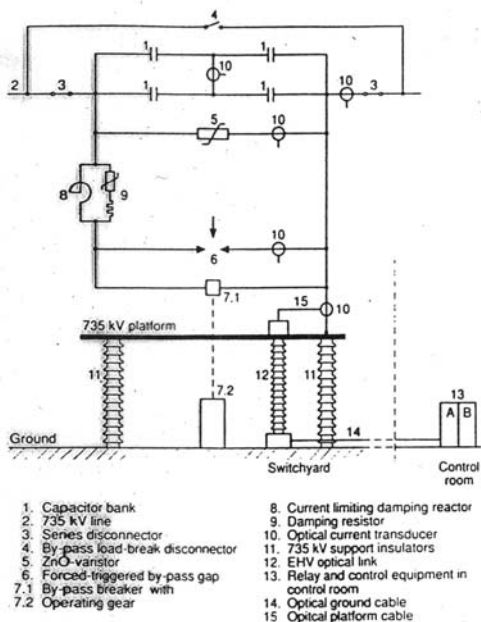


Fig.9.1-2 SC Bank protected by MOVs

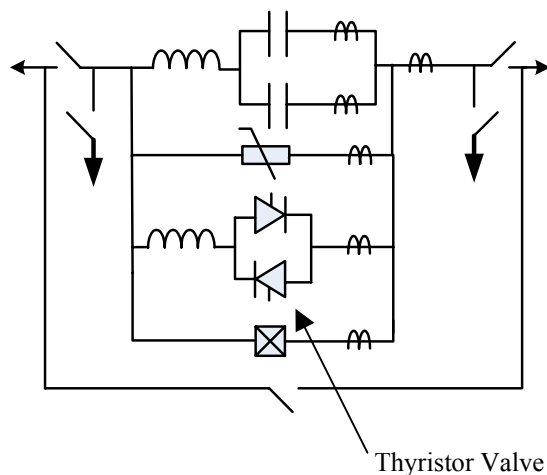


Fig.9.1-3 Thyristor Controlled SC Bank

## 9.2 Overvoltage Protection

Because the capacitors are placed in series with the line, a fault on the transmission system can cause the capacitors to see overvoltage conditions. Spark gaps and/or metal oxide varistors are used to protect the capacitors. Capacitor overvoltage protection can be provided by an MOV only scheme, an MOV with forced triggered bypass gap scheme or a thyristor bypass scheme. The forced triggered bypass gap is included with the MOV protection when the power system fault conditions result in too high duty on the MOV. The gap is triggered during more severe faults (generally, faults internal to series compensated lines) thereby limiting the duty on the MOVs. Gapless (MOVs only) designs are accepted by some utilities for mid-line applications.

The MOV sizing must account for the time to bypass and the expected duty cycle of the SC bank, which depend on utility practice. Typical duty cycles are given in Appendix A.

IEEE Std. 824-1994 provides general guidelines for the protection of SC banks [90].

## 9.3 Subsynchronous Resonance (SSR)

A concern associated with the use of SCs is SSR. This phenomenon, which does not occur with hydropower plants, could affect thermal power plants with long shaft turbine-generators (steam turbine-generators, gas turbine generators, combined cycle gas/steam turbine-generators, nuclear turbine-generators, etc.) connected to load centers through series compensated lines. SC on a transmission line can cause the electric network's natural frequency to be subsynchronous and to coincide with the complement to system frequency of one of the torsional natural vibration frequencies of the turbine-generator rotor shaft string, leading to damaging torsional oscillating torques in the turbine-generators [86].

In general, for the integration of series compensation to an existing network, a screening process based on system frequency responses has to be analyzed to establish potential risks of sub-synchronous torsional interactions with the existing thermal generating plants. In case of potential problems, there are protection schemes that can be used to detect the onset of SSR: torsional relays that continuously monitor the turbine-generator's shaft for torsional oscillations and relays to detect sub-synchronous current to trip generators or by-pass the SCs whenever a certain time-SSR current amplitude-criterion is exceeded. Other more costly countermeasures to SSRs (special filters, etc.) are described in the literature. Limitation of the degree of series compensation of lines terminating at steam or gas turbine generating stations and/or network topology operation restrictions, or fast automatic by-passing of SCs, have also been applied as countermeasures to SSR.

## 9.4 Protection Requirements

The addition of SCs in transmission lines can have a substantial effect on the protection of the compensated line as well as on adjacent transmission lines. Transmission lines are inductive in nature. The addition of series capacitance reduces the inductive impedance of the network, which influences protection relay measurements and may cause protection to fail to operate or to operate incorrectly. Some of the problems that can be introduced by the addition of SCs are: voltage and current reversal; gap flashing transients; and low frequency transients. Protection systems need to be designed to cater to these problems.

Erroneous operation of older technology electromechanical distance relays, if used in directional comparison protection schemes, was possible in series compensated and adjacent lines (in particular with SCs located at line end) due to the voltage reversal phenomenon and incorrect measurement of distance to the fault. Electronic analogue and digital relays, provided with voltage memory, have overcome the problem of voltage reversal and operate correctly in the directional comparison teleprotection schemes including SC banks installed at the line ends, i.e. in switching-transformer stations.

Modern line differential protections using optical fibre telecommunication channels are a good scheme for the protection of series compensated lines, because they are not affected by the voltage and current reversal phenomena. In the past, segregated phase comparison teleprotection schemes using microwave telecommunication channels have also been used.

### **9.5 TRV on CB Line Fault Clearing**

Trapped charge on the SC can increase the TRV across circuit breakers, and the levels can be higher than those specified in industry standards. This topic is covered in section 5.2.

### **9.6 Operating Experiences with SC**

See Appendix A.

## 10. FLEXIBLE AC TRANSMISSION SYSTEMS (FACTS)

Three different kinds of equipment to control power flows are distinguished by WG A3.13:

- power-electronic devices (SVC, StatCom, TCSC)
- phase shifting transformers
- variable Mvar output SRs (with on-load tap-changers).

For HV-equipment no adverse effects of the application of such devices has been reported, apart from overvoltages due to single pole clearing of phase-to-ground faults behind phase shifting transformers.

FACTS is an acronym standing for Flexible AC Transmission Systems, which encompasses a large number of different systems, developed under the initiative of the EPRI. Many of these systems have been widely installed, some of them are still under an experimental mode. The purpose of the FACTS is to enhance the control of the Power Flows and to increase the Power Transmission Capability of existing infrastructures, by making use of power electronics components and devices capable to perform functions of conversion or commutation, for power ranging from some tens to some hundreds of MVA.

The power electronic systems are characterized by their inherent capability to have a response almost instantaneous to a change of operating conditions, as compared to more classical systems of control, like on-load tap-changers of power-transformers, phase-shifting transformers, mechanically switched shunt compensation, control of active/reactive power of generators or change of topology of the power system.

The impact of power electronics, phase-shifting transformers and variable Mvar output SRs on conventional high-voltage equipment will be treated in the next sections.

### 10.1 Power electronics equipment, harmonics and filter banks

Power electronics normally offer a lot of flexibility, controllability and a smoothing effect in terms of (over)currents and (over)voltages to the network. Power electronic devices for instance can limit short-circuit currents and can supply or consume reactive power quite easily, even under idle (unloaded) operation. Such properties lead to advantages for voltage control and system restoration, but lead also to new requirements on the system protection and advanced protection schemes.

The most notable negative impact is the generation of harmonics, but power electronics are not the only source of harmonics. Harmonics have a negative effect on power quality. Conversely, a low power quality has a negative effect on the operation and control of power electronics, that may lead to separation from the network. Depending on the power source or load behind the power electronics, after such a disturbance a fast restoration is also possible. Apart from over-currents and short-circuit currents, power electronics are also vulnerable to over-voltages and transients in the system.

#### *Harmonics*

Distortion of voltages and currents in power systems is caused by power electronic equipment, by nonlinear load (as arc furnaces, fluorescent and ballast lamps, etc.) and other non-linear phenomena like inrush-currents, overexcitation of transformers, corona of transmission lines in

bad weather conditions. Power electronic equipment is used at all voltage levels and even when the harmonic generation of the individual equipment is low, their large numbers in combination with a certain level of resonance in the power system may lead to a high level of voltage distortion. This equipment mainly consists of rectifiers and converters, which, at the distribution level, are found mostly in industrial plants and public transportation systems. At transmission levels the converters are predominantly applied in HVDC and SVC installations.

Inrush currents can equally be found at each voltage level, but unlike harmonics generated by the continuous switching process of power electronics, transformer energization is a relatively rare switching event. However, during such an energization action, high overvoltages due to resonance with filter-banks may occur [44][45].

Overexcitation of transformers leads to an odd harmonic content, mostly of the current. This can lead to overheating of the transformer and false operations of transformer differential protection. The odd harmonics must be detected and the differential protection blocked temporarily. The overheating can be avoided by the application of dedicated overflux protection functions.

Transient overexcitation can result in ferroresonance. The resonance circuit is built up by the non-linear transformer reactance and a capacitance which can be realized by different surrounding equipment like cables, capacitor banks, capacitive voltage transformers or grading capacitors on CBs. The resonance voltages and currents contain subharmonic and overharmonic components and contain the third harmonic because this resonance mainly occurs in the zero sequence networks. Dedicated damping measures are necessary because ferroresonance conditions can lead to destruction of equipment.

#### *Filter banks*

An inductance in series with a capacitor bank can be tuned for a certain harmonic frequency, thus forming a low impedance path (short-circuit) for the harmonic currents of that frequency. More advanced combinations of reactors, capacitors and resistors can be tuned to form a filter with a certain bandwidth for more harmonic frequencies or a low pass filter. It is necessary to study the harmonic impedance of the network involved under a variety of system conditions in order to optimise the filter characteristics and the influence of shunt capacitor banks in general.

The effect of connecting a filter-bank to a substation is that the harmonic distortion in the voltage will to a large extent disappear, but at the same time, the filter-bank will force harmonic current to flow towards and through the filter-bank. Conversely, switching off means that the distortion in the currents will be reduced but that the voltages will be disturbed again.

At HVDC installations temporary over-voltages (TOV) have to be considered. Filter bank switching during the presence of TOV's, especially with re-striking, may give very high over-voltages and attention has to be given to adequate switching equipment [64].

It is noticeable that in some cases filter banks in HVDC applications will be installed between the converter and the transformer i.e. not on the HV-side of the transmission network. Since the harmonics do not pass through the converter transformer it is dimensioned only on the basis of the fundamental frequency component. Also, the HV-CBs are exposed to almost no harmonics caused by the HVDC converters.

Filter-banks and filter-bank switching are not covered by the Standards, as the circumstances for their application are too varied for harmonisation. Phenomena like filtering characteristics, load currents, transient over-voltages, TRV's, etc. seem to be too varied for effective standardization. Normally, dedicated system studies are performed to define the system and component stresses under normal and abnormal conditions. Depending on the system configuration and the values of the involved components, voltage resonance is possible, especially through the combination of converters, saturated transformers and filters. In this respect it should be mentioned that the neutrals of filter-banks are normally earthed.

All equipment within a filter-bank is subjected to a high content of harmonic currents, especially since filter-banks are intended to absorb the harmonics. Since filter-banks at power frequency behave like capacitor banks, they are also used to supply reactive power and are rated accordingly, e.g. a double-tuned 100 Mvar filter-bank for 12/24 harmonics. All equipment has to be designed for the thermal, electrical and dynamic stresses caused by the additional harmonic currents. For instance, in ANSI C37.012 (1979), cl.4.7.1, it is recommended that CBs be rated for a single or back-to-back capacitor-bank switching current that is 1.25 to 1.35 times the nominal capacitor-bank current. Also, for capacitor-banks it is recommended to choose a nominal voltage that is greater than the operating voltage: for normal shunt capacitor-banks (not filter-bank capacitors) a nominal voltage that is roughly 10% higher than the operating voltage is recommended to cover the extra dielectric stresses due to harmonics.

#### *Filter bank switching*

Equipment used to switch the filter-bank currents are CBs, switches and sometimes disconnectors. CBs are able to make and break all currents up to their rated short-circuit current, while load interrupters are designed to break load and capacitive currents only, whilst having full fault making capability. Disconnectors have no specific rating for switching load or capacitive currents, apart from bus-transfer currents, and are only rated to withstand the passage of short-circuit current. Since the Standards for switching equipment do not cover filter banks, the phenomena related to switching filter-banks will be compared with those related to switching capacitor-banks.

With a high percentage of harmonic distortion, especially at the lower harmonics, the currents may show more than two current zeros per power frequency cycle. In this way the breaking of the current might take place earlier than at the regular power frequency current zero. Since a filter-bank behaves mainly as a capacitor-bank, current interruption at an instant not corresponding exactly to voltage maximum will lead to lower trapped charges (DC-voltages) on the filter-bank (capacitor-bank), thus reducing the dielectric stresses at current interruption.

As stated before, energised filter-banks give distorted currents with almost sinusoidal voltages, while disconnected filter-banks give low harmonic currents but distorted voltages. Compared with switching off a capacitor-bank, the TRV for filter-banks will show super-harmonic voltages on the normal TRV resulting in a higher peak value of the TRV. In addition it is also possible that voltage resonance occurs at the busbar, controlled by the filter-bank to be switched or not.

Another phenomenon to be considered is that at switching off a capacitor bank, the short-circuit impedance causes a negative voltage jump (lower RV), but switching off a reactor in series with the capacitor-bank (as in a filter-bank) causes a positive voltage jump and thus a higher peak value of the RV [65].

A third issue to be considered is that, especially with HVDC applications, load shedding or blocking of the converter may occur. Through the Ferranti effect TOVs might occur lasting up to 1s, depending on the automatic voltage regulation (AVR) of nearby generators, or up to tens or hundreds of seconds, depending on transformer tap-changer actions. Exactly at the moment of a TOV the reactive power compensation, including the filter-banks, must be switched off, again leading to a higher than normal TRV.

To verify the breaking capacity of a CB, the following statements can be accepted. The harmonic content of the filter-bank current is not relevant for the breaking performance, especially not for modern technologies, due to the short physical time constants in the arc. The same phenomenon allows for the current injection testing method as applied at synthetic tests. However, the superimposed harmonic components in the RV are relevant during the first milliseconds after interruption (first HF-cycles). Nevertheless, as CBs are designed to withstand the RRRV of short-line fault tests, it is expected that the initial part of the TRV at filter-bank switching is not critical (at least at somewhat longer arcing times).

With respect to the peak-value of the TRV, the harmonic component in the RV, plus the other phenomena (positive voltage jump, TOV, possible resonance) can be ascertained after proper system studies and the applicable TRV envelope can be defined. The calculated peak value can then be compared with the performance of the proposed CB; or the CB can be tested for the higher peak-value; or a CB with a higher rated voltage can be chosen; or special measures can be taken e.g. MOV in parallel with the arcing chambers [66]. Test circuits are available to verify CB performance under filter-bank switching conditions [65] and the phenomena described are most pronounced in the first clearing pole [64].

To summarise; filter-banks have to be switched by switchgear with a very low probability of re-strike. Modern CBs with a very low probability of re-strike should face no problems with the slightly higher RRRV for filter-banks in comparison to capacitor banks, while the distortion of the current will be no problem at all. It is important to carefully select CBs able to withstand the peak-value of the TRV, which is higher than the RV for capacitor-banks. Furthermore CBs with a high level of mechanical endurance are necessary. It is also recommended to apply controlled switching in order to limit inrush transients from the filter-banks as much as possible. Controlled switching can also be used to further reduce the probability of re-strikes at switching off.

## **10.2 Phase-shifting transformers and autotransformers with phase-shifting capability**

### *Phase-shifting transformers*

A quadrature booster is a specific type of phase shifting transformer (PST) which, when connected in series with a transmission line, directly modulates the real power transfer. Two types of PSTs are used: the two core design for the large rated power and high voltages (EHV grids); the one core design for medium and small power and not too high voltage grids (< 245 kV).

Two-core PSTs (quadrature boosters) are composed of a shunt unit (star/star) connected to a series unit (delta/series (star)). The winding arrangement between the shunt and series units is such that a voltage with a  $90^{\circ}$  phase shift is applied to the line voltage. Functionally the PST, takes the voltage between two phases and injects it into the third phase. This is performed on

all three phases, varying the phase angle between the  $V_{in}$  and  $V_{out}$  of the PST, and therefore the phase difference between the two ends of the circuit into which it is connected. This allows the PST to operate in two modes: Boost (advance) leading to increased power flows and Buck (retard) leading to reduced power flows.

The single-core PSTs are provided with two windings: the excitation winding supplied by the line voltages and the tapped regulation winding connected in series with the line. Two schemes are in use: the “T-extended delta” and the “delta-hexagonal”.

From the perspective of this Technical Brochure a main reported phenomenon of note is the behaviour of PSTs under unbalanced fault conditions. In either ‘buck’ or ‘boost’ mode the PST relies on a balanced three-phase system to function properly since the method of operation utilises two phases to energise the third phase. Consequently, for a single-phase fault at the terminals, very large voltages can appear on un-faulted phases of the PST. These appear transiently during the CB trip sequence on the PST circuit as it interrupts the currents in each of the PST phases.

During three phase interruption of a single-phase fault to earth on the series terminals of the PST, and depending on the characteristics of the CB, it is probable that the faulted phase will be the last to clear. This imposes a voltage of 1pu across the series winding, causing the voltage on the two un-faulted phases to rise (approx. 2.5pu), as a result of the coupling between the series and shunt transformer. The remaining energised phase of the shunt unit can further contribute to the total voltage seen on the un-faulted terminals, resulting in a transient over-voltage of up to 4 or 5 pu.

The effect is non-linear, meaning that even tap positions adjacent to the centre tap can contribute to very large voltages on the PST during single phase to earth faults. Unless the PST is at centre tap the voltage applied at the PST terminals is excessive and beyond the insulation level and can only be controlled by the use of surge arresters. When the duty is severe, high-energy surge arresters must be fitted, in any case at both sides of the PST. Further it is strongly recommended to install a CB or full bay between PST and OH-line in order to prevent typical line phenomena to influence the PST (single phase faults, SPAR).

The on-load tap-changers (OLTCs) to be used in PSTs must comply with technical requirements which differ, and may be much more severe than the ones of OLTCs used in power transformers. High recovery voltages may build-up across the contacts of the change-over selector. In the single-core design, where the regulation takes place at the line end, very high recovery voltages occur.

The OLTC of PSTs may be crossed by very high short circuit current, because the series impedance of PSTs is generally small and thus does not limit the short circuit current as it does in power transformers. In particular, in PSTs with single-core design, when the OLTC in the position for  $0^\circ$  regulation, the series winding is off-circuit and the OLTC must withstand the full short circuit current of the network.

When operating the PSTs in parallel, high circulating currents between the OLTCs can occur in certain OLTC positions, owing to the low series impedances compounded by the high step voltage.

The technical specification of PSTs should consider the above mentioned phenomena, to allow manufacturers of PSTs to make an optimal technical-economical design.

Beyond the scope of this Technical Brochure are other problems more related to the transformer itself (for instance fluxing, over-excitation, re-energization by auto-reclosing the line).

#### *Auto-transformers with phase-shifting capability*

When an EHV (say, 330kV to 500kV) overhead line (grid) is built for overlaying and up-rating the transmission capacity of an existing HV (say, 132kV to 220kV) line (grid), it may occur that generation and loads are in existence and connected to the HV grid. The overlaying EHV line is connected via step-up autotransformers (ATRs) at the sending end and step-down ATRs at the receiving end. The addition of twice the impedance of the ATRs to the impedance of the EHV line limits its power flow, thus not allowing an adequate reduction of power flow in the underlying lower voltage line(s), which is (are) required to be operated in parallel for security of transmission.

In some recent applications, the problem has been solved by using ATRs which, in addition to the conventional in phase voltage regulation, have an in-quadrature voltage regulation. This is realized by inserting, preferably in the grounded neutral side of the common winding of the ATR, a regulation winding wound in the core column of another phase, i.e. by adding or deducting a voltage out-of-phase by  $120^\circ$  or  $60^\circ$ , leading or lagging. The in-quadrature (largest) components of these injected voltages realize the desired phase-shift, which may be in steps, however with a total amplitude not exceeding  $\pm 10^\circ$ .

An even larger phase-shift can be obtained by adding in the winding of each phase, two regulation windings: one  $120^\circ$  out-of-phase wound in the 2<sup>nd</sup> core column and one  $60^\circ$  out-of-phase wound in the 3<sup>rd</sup> column, such as their vectorial sum is precisely in-quadrature, and the in-phase voltage regulation associated with the addition of only one  $120^\circ$  or  $60^\circ$  voltage vector is avoided.

Owing to the impedance of the ATR and to the application of the in-quadrature regulation in the neutral grounded side, the constraints on OLCTs for the PSTs, as mentioned on the former page, do not occur in the ATRs with built in phase shifting capability. Initial cost and losses are much lower than with application of a separate PST in series with the ATRs.

### **10.3 Variable Mvar output shunt reactors (with on-load tapchangers)**

There are some transmission networks that have the following reactive power control requirements:

- Absorption of the charging power of transmission overhead and/or cable lines is needed;
- Mvar absorption must be adjustable continuously or in small steps according to system load and generation dispatching;
- A relatively slow speed regulation of Mvar absorption is acceptable (say, total Mvar variation range in 2-3'), because there are no rapidly variable loads (as arc furnaces, steel mills, electric drives for transports, etc.)
- There is no need for many years to install power factor correction shunt capacitors in the HV-EHV busbars of interest.

In these cases use can be made of tapped winding variable Mvar output shunt reactors (TWVO-SRs) with on-load tap-changer (OLTC) [67].

The Mvar output of a SR with gapped core is inversely proportional to the square of number of turns of the windings. Turn number variation is achieved in TWVO-SRs in the same way applied for voltage regulation in power transformers, i.e. by switching in or out the turns of a tapped winding by means of the OLTC. HV and EHV SRs have star connected windings with graded insulation. Use can thus be made of a 3-pole star point located OLTC.

By using commercial OLTCs, the feasible Mvar regulation range of HV TWVO-SRs is from 40%-45% to 100% of rated power for SRs with BIL of 650kV-950kV; it is from 50%-60% to 100% for EHV TWVO-SRs with BIL of 1300-1550kV. Number of taps of OLTC varies from  $\pm 8$  to a maximum of  $\pm 17$ .

The use of TWVO-SRs with OLTC has many advantages, particularly in the public networks of developing countries: they have costs and power losses some times lower than SVCs and STATCOMS, they do not generate harmonics, availability for service is higher and maintenance is simple (similar as for power transformers with OLTC). Average losses, and overtemperatures of copper and oil, are lower in operation with variable Mvar output in comparison with conventional fixed output SRs, that are continuously operated at full load. This has a positive impact on insulation ageing.

The need of switching on and off TWVO-SRs is infrequent, because most of the Mvar regulation is done with the OLTC. Switching on is done with the SR preset for minimum Mvar output (maximum number of turns) resulting in very low flux density in core, and thus negligible inrush current and limited voltage jump in comparison with a fixed Mvar output SR of same rated power. Applications have been made in networks from 110kV to 400kV, reportedly with very good operation experience.

## 11. POSSIBLE IMPACT ON THE STANDARDS

1. Capacitive switching of unloaded long lines differs from clearing the capacitive currents on small or medium length lines, as the capacitive currents will be higher (certainly during disturbances), the induced voltages will be higher, the Ferranti effect more dominant and switching under high TOV-conditions more probable. The values, specified for power frequency voltage, recovery voltage, transient recovery voltage and switched currents, may exceed those given in the Standards. When shunt compensation and/or series compensation is applied less severe stresses may be expected.
2. The Standards are based on an out-of-phase switching angle that is limited to about 90°, despite the fact that in many cases the angle will be random. It is strongly recommended this limitation to be clarified in the Standards to give users clearer guidance, as users who specify the non-mandatory test duty for out-of-phase conditions are expected to have good reasons to do so. These users expect the type test to be adequate for most network conditions. An approach could be to distinguish different situations:
  - situations where out-of-phase conditions can be neglected: no requirements for CBs
  - situations where out-of-phase may occur with small out-of-phase angles only: standard requirements for CBs
  - situations where out-of-phase may occur with random out-of-phase angles: special requirements for CBs ( $I_{oop}$ ,  $TRV_{peak}$ , RRRV).
3. Electrostatic and electromagnetic induced currents are larger for long EHV OH-lines than for medium or small lengths. For long lines they are larger than specified in the Standards.
4. The recently published Standard IEC 62271-109 on by-pass switches for series capacitor banks [80] shows that series compensation is no longer treated as an exotic means to control voltages and to up-rate power transmission capacity. By regarding the components of a series capacitor bank as equipment that has to be standardized, series compensation has become a standardized solution. Therefore the effects of series compensation on other equipment, such as the OH-line CBs, should be considered as well in the Standards.
5. It is common practice today to refer to the out-of-phase switching test duty for high peak values of (transient) recovery voltages, which appear when switching under TOV, switching long unloaded lines, clearing faults on series compensated lines, clearing LLF. An approach of specifying special requirements for large out-of-phase angles might offer a possibility for further standardization for situations, where out-of-phase is used as a reference.
6. Despite the fact that extensive ATP/EMTP studies will still be needed, the consensus of the utilities that contributed to WG A3.13 studies shows an interest for future standardization of CB applications for high TOVs, out-of-phase conditions and series compensation.
7. The application of the special HV equipment referred to in this Technical Brochure (HSGS, switchable MOSA, special purpose MOV) is not yet regarded as wide enough to be standardized, but deserve the attention of users and manufacturers from the point of view of adequate testing, for instance for mechanical vibrations.

## 12. CONCLUSIONS AND RECOMMENDATIONS

1. A number of societal developments are being seen, such as liberalisation (IPPs that locate their power plants remote from load centers and disregard optimal solutions with respect to transmission grids), environmental responsibility (large windmill farms that require system support from relatively long distances), congestion of infrastructures (large difficulties to find new routes for OH-lines or even maintaining existing routes) and societal pressure (power quality).
2. These developments have led to long distance power transmission from remote sources, multiple power transfers, regionally and internationally over long distances, and to a further utilization of transmission corridors. This leads to an increase of the application of long shunt and series compensated OH-lines and long compensated cable sections. Other technologies are UHV-transmission, HVDC-connections and, possibly, HWLL.
3. With long distance transmission becoming more prevalent, more severe TOVs, transient over-voltages and TRVs will be produced. Effective and cost-efficient measures to limit these overvoltages and adequate specifications for the involved HV equipment are needed.
4. Studies show that the proper application of shunt/series compensation and eventually also HWLL offers large advantages for the above described developments.
5. A few examples were given of continuous system operation at voltages exceeding standard recommended values. The continuous operation voltage should remain within the maximum values stipulated by the IEC Standards. In the case of a newly built transmission system where these values are to be exceeded in order to utilize the benefits of higher operating voltages, precautions should be adopted in the specification of equipment to avoid certain inconveniences. If the system is in existence, some equipment may have to be replaced/up-rated or an increased risk of failure may have to be accepted.
6. Load rejection leads to high TOVs that are controlled by teletripping of long un-loaded lines, automatic connection of SRs, CBs specified for the occurring unloaded line switching and out-of-phase switching. Some utilities apply also MOSAs, in a few cases switch-able and sacrificial, to control TOVs under severe circumstances.
7. Ferroresonance may lead to severe TOVs, but known precautions can be applied to avert risk of occurrence. This applies also for resonance due to inrush or magnetizing currents. Note that for the highest system voltages the natural damping is relatively low. Special attention must be paid to ferroresonance phenomena when applying SPAR in shunt compensated lines.
8. In the near future more and more long EHV cable circuits will be installed. Long cable sections, especially in combination with OH-line sections, may require attention for avoiding large TOVs due to low-order harmonic resonance in the system.
9. HWLL shows to be, technically and economically, a promising technology alternative to HVDC for very long distance (2500-3000km) transmission. Large TOVs build-up are expected in HWLLs, which can be controlled by advanced engineering.
10. Transmission line no-load energization leads to transient overvoltages generally smaller than 3.0 pu and causes no problems for OH-lines designed with a 3.0 pu high probability ( $V_{50\%} + 3\sigma$ ) SIWL (European practice). However OH-lines with a SIWL of 2.5 pu require overvoltage limitation measures (PIR, controlled switching, MOSA, staggered poles, pre-connected shunt-reactors). Transient overvoltages due to SPAR can be controlled in the same way. TPHSR requires further measures.
11. For the application of shunt capacitor-banks and shunt reactors, CBs have to comply with the respective specifications in the Standards (very low probability for restrikes, class C2, and extended mechanical endurance, class M2). Furthermore, controlled switching is

recommended for shunt capacitors or required for shunt reactors. The latter should be protected with MOSAs.

12. Clearing of fault currents flowing through series capacitor banks results in high TRVs. TRV peak values can be limited by switched opening resistors, fast by-passing of the capacitor bank, MOSAs connected phase-to-earth or MOV in parallel with the arcing chambers of the CBs. The first two solutions bring additional problems - reliability, retardation, selectivity - discouraging application in modern transmission systems. Use of special MOSAs with very low SIPL can limit TRV-peak value to within 3.2 pu, whereas MOVs in parallel with arcing chambers of CBs can limit TRV-peak value within 3 pu or 2.5 pu, depending on whether or not there is the requirement for system synchronization with the involved CBs.
13. Capacitive switching of unloaded long lines differs from clearing the capacitive currents on small or medium length lines, as the capacitive currents will be higher (certainly during disturbances), the induced voltages will be higher, the Ferranti effect more dominant and switching under high TOV-conditions more probable. On the other hand, usually shunt compensation may be applied and possibly also series compensation, both leading to less severe recovery stresses when switching off the long OH-line.
14. Under out-of-phase switching conditions the first-pole-to-clear factor is determined by the neutral status of the systems at both sides of the CB, as shown by the double Neptune-scheme. Depression of the generator subtransient source voltage has to be taken into account, unless the rotor is equipped with fully laminated poles and a damper winding.
15. Under normal system conditions (no earth fault, no temporary overvoltages), full phase-opposition switching of a generating plant at the HV-side leads to TRV peak values of 2.9 to 3.2 pu; and higher values for systems with un-earthed neutral. The Standards are based on an out-of-phase angle that is limited to about 90°, despite the fact that in many cases the angle will be random. Out-of-phase switching at the MV-side can be regarded as covered by IEEE/ANSI Standards C37.013 for angles < 90°; larger angles (180°) are frequently (some tens of percent of the cases) specified by users and manufacturers are willing to design, test and supply adequate generator CBs.
16. For out-of-phase switching of OH-lines, calculations show peak values of the TRV of, for instance, 3.5 pu (200 km length,  $I_{oop} = 15\%$  of 40 kA) or 3.1 pu (100 km length,  $I_{oop} = 25\%$  of 40 kA) and even beyond for longer line lengths, under full phase opposition. Clearing an out-of-phase current on a 100 or 200 km OH-line between 420 kV substations (each with a short-circuit current of 40 kA) requires out-of-phase angles less than 96° and 80°, respectively, to achieve TRV peak values of 2.5 pu, as specified in the Standards.
17. According to both IEEE and IEC, the specified RRRV for out-of-phase switching is lower than the RRRV specified for test duty T100. Although higher values occur in the systems, the RRRV for out-of-phase switching is considered to be covered by test duty T30 (multipart testing).
18. The power frequency withstand voltage across open contacts of CBs used for synchronizing should have the values specified in the Standards for the disconnectors. The external insulation across open contacts of live tank CBs used for frequent synchronizing (generator CBs) should, in addition, be specified to withstand under out-of-phase conditions 2 times the maximum phase-to-earth power-frequency operation voltage with pollution representative of the expected local environmental conditions during synchronizing.
19. Line CBs used for synchronizing of separated sub-systems, or used for the automatic line reclosure, are exposed in the open position to lightning overvoltages which may exceed their withstand capacity. Protection can be warranted by MOSAs connected phase-to-earth at the line end, or by specially shaped air spark-gaps with spacing considerably lower than applied in the horn gaps protecting the standard insulator strings of the lines.

20. Electrostatic and electromagnetic induced currents are larger for long OH-lines than for medium or small lengths. This affects the specification of earthing switches in particular with multiple-circuit lines, and the secondary arc phenomena. Measures to reduce the secondary arc current to values that force self-extinction within the SPAR dead time are the application of a neutral reactor at shunt reactors or HSGSs, but for some long compact lines even these countermeasures cannot prevent the necessity to resort to TPHSR.
21. Special transient current conditions, like delayed current zero's or low frequency oscillation at fault clearing on series compensated lines have been addressed, as well as the DC-offset current when energizing long highly shunt compensated EHV cables. The phenomena and measures to be taken are described.

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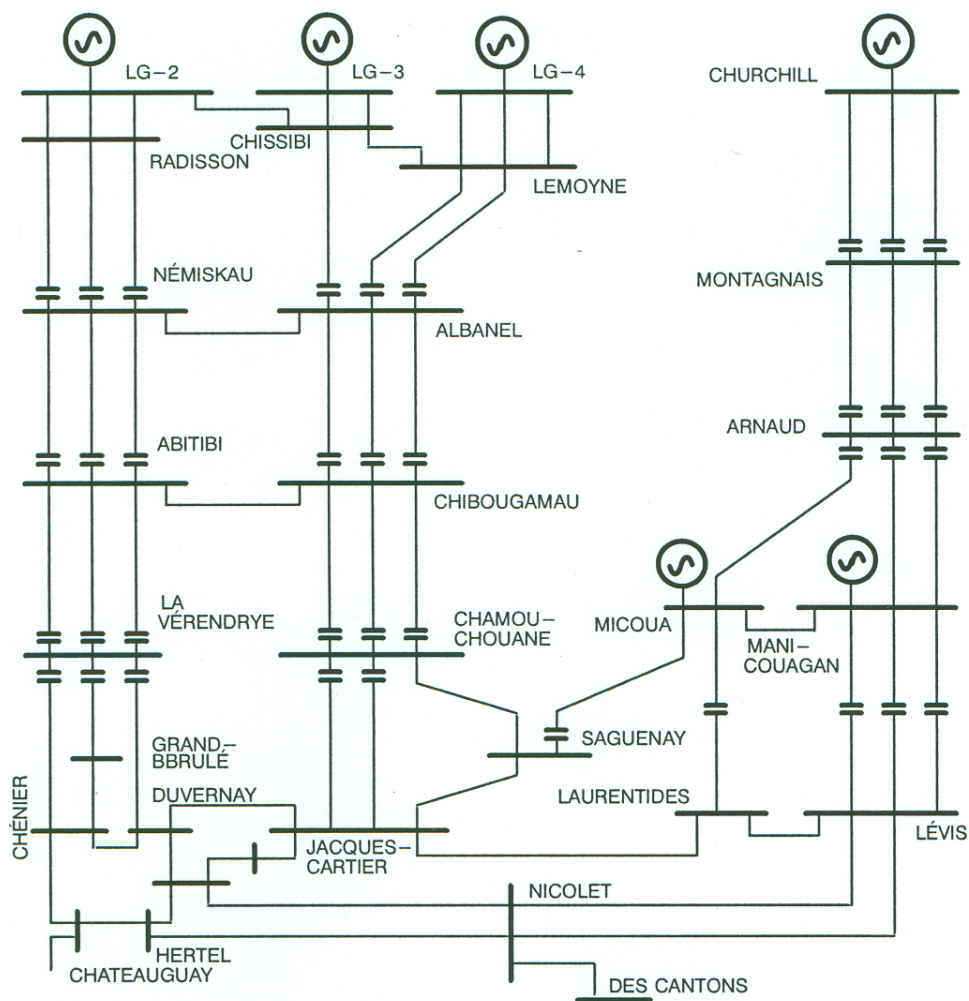
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**APPENDIX A  
OPERATING EXPERIENCES WITH SERIES CAPACITORS**

Series compensation is a well established technology with about 150,000 Mvar series capacity installed worldwide and an increasing rate of 3500 Mvar/year. In the next sections the experience with SC banks of several utilities in the world is collected and presented: Hydro-Québec (Canada), BC-Hydro (Canada), TEIAS (Turkey), Chile, Mali/Senegal, Brazil, BPA (USA) and Sweden.

**A.1 Series Compensation in Hydro-Quebec 735 kV transmission system (Canada)**

Hydro-Quebec's 735 kV transmission system is a long, radial network with its main generating centers located approximately 1000 km north of the two main load centers, Montreal and Quebec City. A schematic of the Hydro-Quebec 735 kV series compensated system is shown below (figure A1-1). The Hydro-Quebec series compensation system consists of 32 SC banks at 11 different substations. The series compensation of individual lines varies between 17% and 44%. These banks are protected by MOVs, for instantaneous reinsertion after fault clearing, in parallel with a controlled spark gap and by-pass circuit breaker. Hydro-Quebec reports that the banks have performed very satisfactorily over the 15 years they have been in-service.



*Fig. A1-1 Hydro-Québec 735 kV series compensated system*

Table A1-I summarizes rated characteristics of SC banks on Hydro-Québec 735-kV transmission system.

Table A1-I: Rated characteristics of SC banks on Hydro-Québec 735 kV transmission system.

Locations	Rated characteristics of SC banks		Rated characteristics of MOVs protecting SC banks	
	Zc (Ω)/(%)	Ic (Arms)	60-Hz voltage protective level (pu*)	Energy capacity (MJ)
Montagnais	30/34	2300	2.6	21
Arnaud (North)	25/34	2200	2.5	26
Arnaud (South)	25/44	2200	2.5	60
Bergeronnes	22/17	1900	2.5	10
Périgny	22/17	1900	2.5	10
Saguenay (North)	22/26	1900	2.5	18
Némiscau	16/20	2200	2.5	15
Albanel (to Lemoyne)	16/20	2600	2.5	10
Albanel (to Chissibi)	16/20	2200	2.5	10
Abitibi	25/34	2300	2.5	10
Chibougamau	25/32	1900	2.5	12
La Vérendrye	34/40	2600	2.5	17
Chamouchouane	25/40	1800	2.5	40

(\*) 1 pu =  $Z_c \times I_c \times \sqrt{2}$  peak voltage

## A.2 Series Compensation in BC-Hydro 500 kV transmission system (Canada)

BC Hydro's 500 kV transmission system has 11 SC banks for a total of 6590 Mvar at 6 different substations. The series compensation is installed at the midpoints of the lines. The first SC banks were installed in the early 1970's and used spark gap protection and PCB/paper capacitors. These early banks had many equipment and control problems and parts of the protection and circuit breaker hydraulic systems had to be redesigned by the supplier. Over the years these banks have been refurbished with non-PCB capacitors, new protection and control schemes and MOV protection. The refurbishment program has significantly reduced the banks annual maintenance downtime from an initial 2-month outage requirement to the current 2-day requirement.

The MOV sizing is designed to account for the time to bypass and the expected duty cycle of the SC bank. Typical duty cycles considered are:

- i. A worst case 3-phase internal fault (i.e. a fault internal to the line containing the SC bank) followed by bank re-insertion followed by a second worst case fault followed by a sustained bypass for MOV cooling.
- ii. Three worst case 3-phase external faults (i.e. a fault external to the line containing the SC) and bank remaining in-service followed by a worst case internal fault followed by a sustained bypass for MOV cooling.

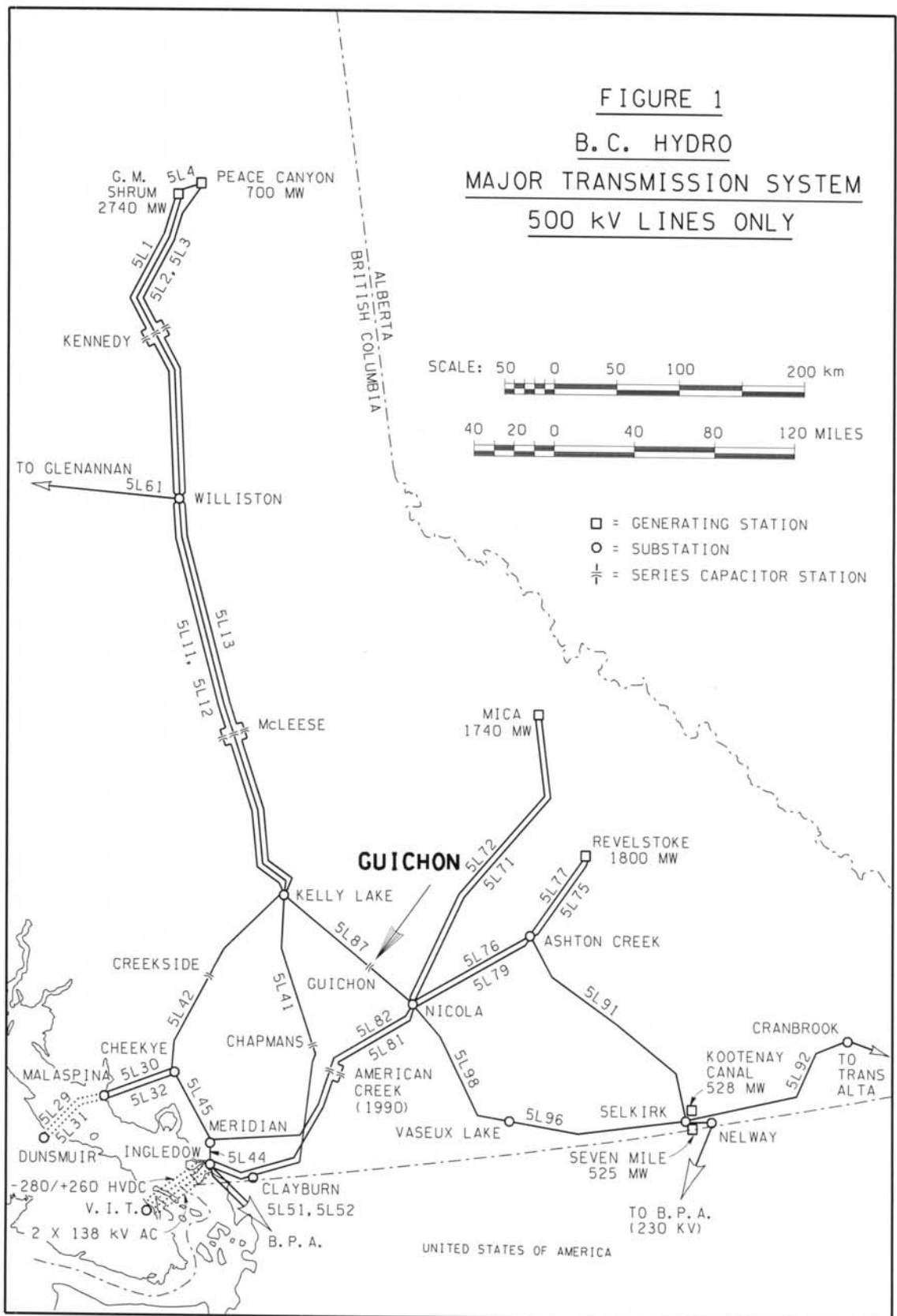


Fig. A2-1 BC Hydro 500 kV System

Table A2-I: Rated characteristics of SC banks on BC Hydro 500 kV transmission system

Locations	Rated Characteristics of SC		Rated Characteristics of MOV Protecting SC		Length of Lines (kM)
	Z <sub>c</sub> (Ω)/ % Compensation	I <sub>c</sub> (A)	60 Hz Voltage Protective Level (pu*)	Energy Capacity (MJ)	
Kennedy 1 & 2	45.4/50	2310	2.6	Gap Only	278
Kennedy 3	45.5/100	2300	2.92	Gap Only	139
McLeese 1 & 2	54/50	1950	2.2	41.2	330
McLeese 3	53.0/approx 50	1950	2.2	95.1	330
American Creek (1 & 2)	40.0/approx 50	2120	2.63	Gap + 20 Mjoule	264/248
Chapmans	51.2/58	1900	2.2	98	272
Creekside	36.8/55	2180	2.4	97.9	197
Guichon	24.3/approx 50	2400	2.42	Gap + 59.5 Mjoule	146

\* 1 pu = Z<sub>c</sub> x I<sub>c</sub> x √2 peak voltage

### A.3 Series Compensation in the 420 kV transmission system of Turkey

SCs have been installed since the early 1970's in the long distance East-to-West 420 kV transmission system of Turkey. As of 2006 there are in operation 17 SC banks with a total rated power of 3950 Mvar. Installation of 4 additional SC banks is planned in the North-Eastern region with a total rated power of 780 Mvar. The location and reactance of the SCs banks are shown in figure A3-1. The average series compensation on a transmission distance of 950km is about 47%. Individual lines have a compensation not exceeding 58%.

All the SC banks of Turkey have a scheme suitable for fast reinsertion: 6 old banks are protected by the dual-gap dual-breaker scheme (reinsertion occurs in about 80ms after fault clearing); 11 banks are protected by metal oxide varistors (MOVs) for instantaneous reinsertion after fault clearing, supplemented by a forced triggered gap and a by-pass CB. The same scheme will be applied for the 4 new banks planned for installation. System studies did not show justification for use of thyristor controlled SCs.

Each phase of a SC bank is provided with a platform mounted discharge impedance (a special full iron core reactor or a no-load distribution transformer) connected in parallel with the SC, which ensures the discharge of the bank in less than 0.5 s after the de-energization of each phase of the line, i.e. before the single-pole high-speed reclosure. This circuit avoids the amplification of the line re-energization overvoltages by the SCs.

In the SCs banks protected by MOVs, the spark gap and by-pass CB have the following functions: to instantaneously by-pass the MOVs in the rare events when thermal capacity of MOVs is exceeded (severe short circuits internal to a series compensated line or repeated severe short circuits external to the series compensated line) or when energy dissipation rate of rise in MOVs is exceedingly high; to by-pass the SC bank in case of failure of MOVs; to provide a back-up for operation with the low-speed ( $\sim 0.5$  s) reinsertion scheme in case of unavailability of the MOVs or of the associated electronic protective control devices.

SCs have been located in substations as far as possible electrically distant from the large power plants, in order to limit the short circuit current flow through the protective MOVs, thus limiting the required energy absorption capacity of MOVs of the various banks in the range from 20 to 40 MJ per phase. MOVs are designed to carry without being by-passed 2 of the most severe 3-phase short circuits or 4 1-phase-to-ground short circuits, all external to the series compensated line and occurring in close succession.

The protection level of MOVs is 2.2 pu at 10 kArms ( $1 \text{ pu} = \sqrt{2} X_c I_n$ , where  $X_c$  is SC reactance and  $I_n$  is rated current).

The spark gaps are triggered by a numerical relay, if temperature of MOVs or energy rate of rise reaches the allowed set limits. The spark gaps also possess a conventional voltage self-triggering capacity, set at 2.5 pu and used in the back-up slow-speed emergency reinsertion mode.

Each by-pass CB has three single-pole operating mechanisms at ground potential, independent for each phase. It is a CB with special requirements with regards to: the making current; the capacity to carry the discharge oscillatory currents superimposed on short circuit current, and to withstand with adequate margin an overvoltage equal to the maximum setting of the protective gaps. Requirements for by-pass CBs are specified in IEC Standard 62271-109 [80].

All the SC banks are provided with a damping circuit to limit the discharge current intensity and dampen oscillations, to within values which cannot damage capacitor units, fuses, connections, spark gaps and by-pass switches. Peak discharge current is to be limited to within 50 times the rms value of rated current of SC bank and the making current capability of the by-pass CB.

The problem of TRVs on CBs in series compensated lines is dealt with in section 5.2.

In Turkey several SC banks are installed at line ends, in switching - transformer stations, thus avoiding the extra construction and operation costs due to creation of dedicated stations out along the lines.

The series compensated lines are protected with two directional comparison protection schemes: a permissive overreaching transfer tripping protection scheme and a blocking scheme, generally using power line carrier telecommunications. These schemes have been used since the late 1970s, at first with analogue electronic relays and subsequently with numerical relays, and all provided with a voltage memory thus enabling fast selective operation in presence of the voltage reversal phenomenon. The current reversal phenomenon cannot occur in the Turkish series compensated lines, owing to location of SC banks which are not close to large power plants.

Phase comparison and travelling wave relays have never been applied in Turkey. However, the new series compensated lines will take advantage of the differential protection applicable with fiber optic telecommunication channels.

Some of the series compensated lines originate from steam thermoelectric power plants (see figure A3-1). The sub-synchronous resonance phenomenon (SSR) therefore had to be carefully investigated. The applied countermeasures are the following:

- Meshed configuration of the 420 kV grid, avoiding as far as possible emergency operation of a series compensated line radially connected to steam or gas turbine generators (this may occur only on contingencies of 3<sup>rd</sup> order or higher).
- Limitation of the percentage series compensation in critical lines originating from the thermoelectric power plants.
- Installation of sub-synchronous oscillation relays and torsional monitor equipment, which in very rare events could initiate the tripping of 1 or 2 steam turbine generators or, in one line only, could initiate the fast by-passing of a SC bank via transfer tripping.

TEIAS, the Transmission System Operator of Turkey, reports that the above measures have allowed their SCs to operate without major troubles for over 30 years.

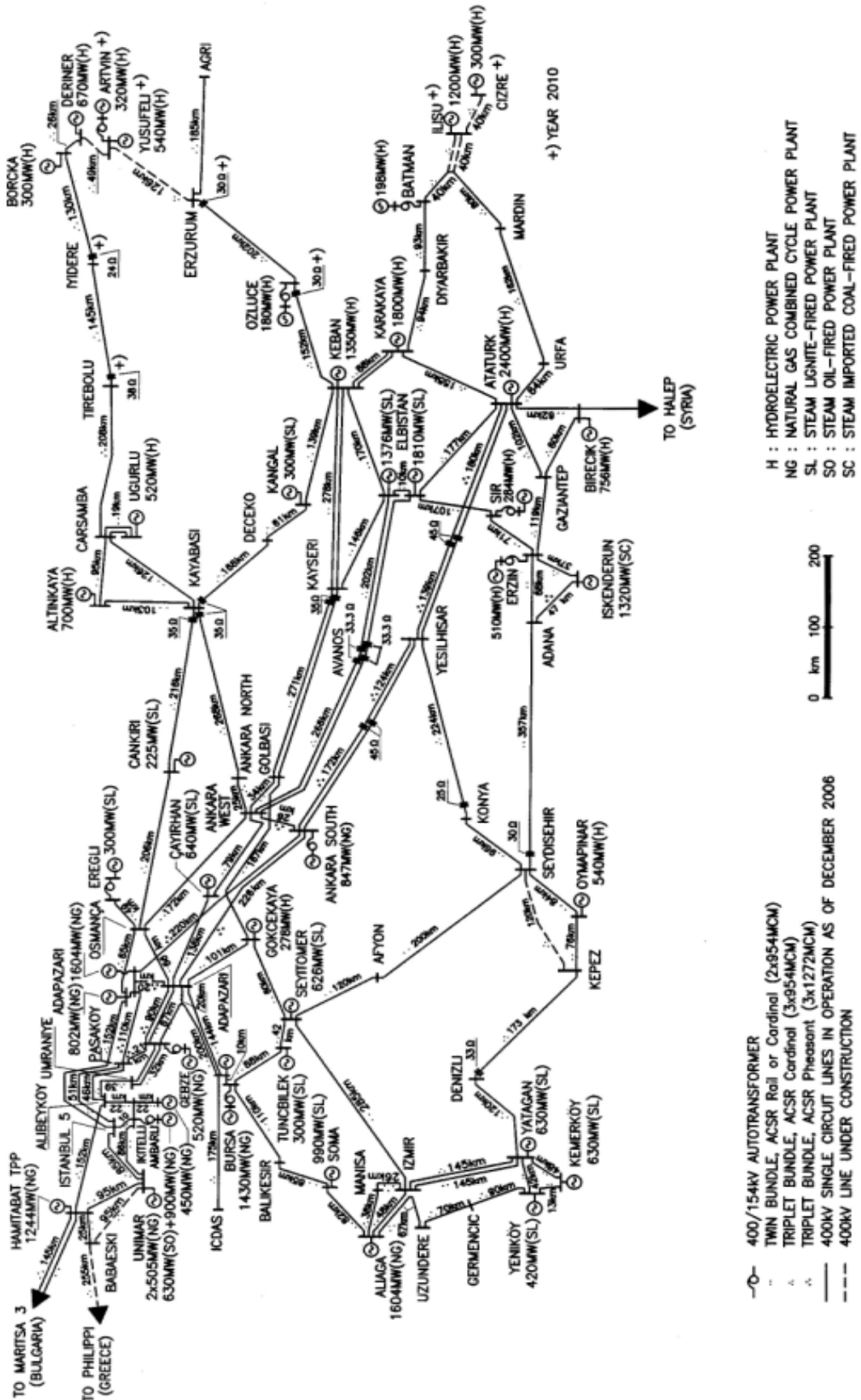


Fig. A3-1 The Turkish 420 kV grid in the year 2006

## A.4 Series Compensation in Chile

The Chilean 500 kV transmission system uses series compensation on two North to South lines. Four SC banks are installed at the Ancoa 500 kV substation for a line series compensation close to 50%.

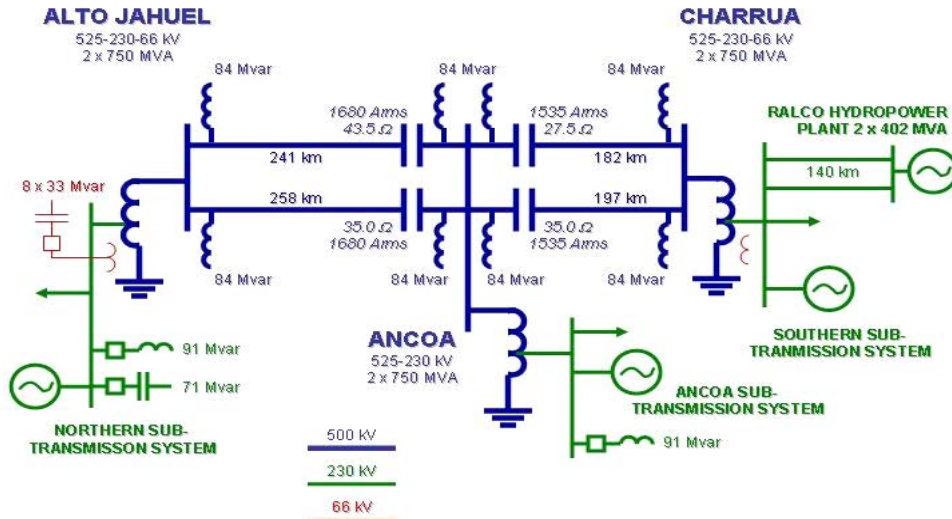


Fig. A4-1 The Chilean 500 kV-50 Hz Series Compensated Transmission System

## A.5 Series Compensation in Mali and Senegal

An application of a 50 % series compensation has been made in a 940 km - 225 kV single circuit line, transmitting power from the Manantali (Mali) hydroelectric power plant to Dakar (Senegal) with a 200 km spur additional line to Nouakchott (Mauritania), as shown in figure A5-1. SC banks are protected by MOVs ensuring instantaneous reinsertion at line fault clearing, triggered spark gaps and by-pass CBs. The line has been in operation since 2001.

No failures or problems have occurred in the SC banks. However, interruptions of service of some SC banks have been caused by the centralized protection scheme using a server operated with a “Windows Imbedded” system. The inconvenience was reportedly caused by dust deposition in the main card of server, and has been easily eliminated.

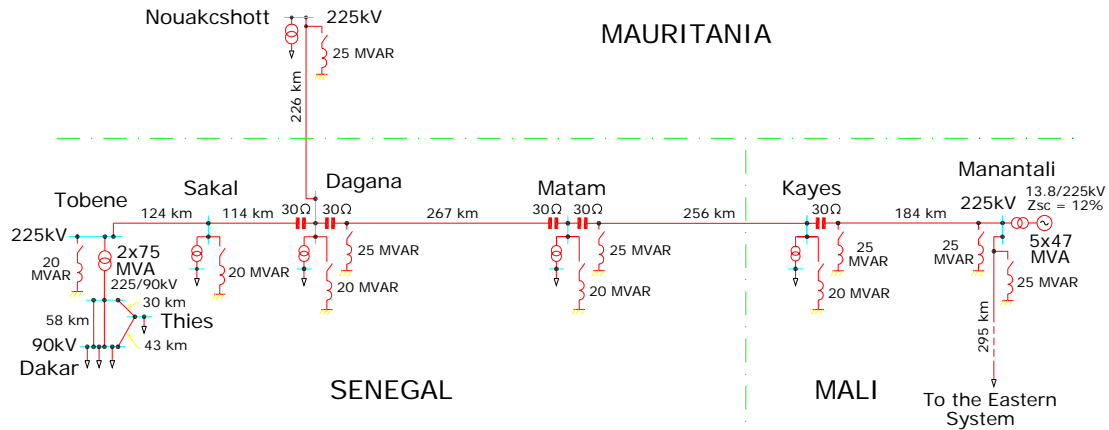


Fig. A5-1 Single-line diagram of the 225kV-50Hz series-shunt compensated Manantali (Mali), Dakar (Senegal), Nouakchott ((Mauritania) transmission system.

## A.6 Series Compensation in Brazil

The Brazilian electric-power system is predominantly supplied by hydropower stations generally built in areas remote from the main load centers, which are mostly concentrated in the southeast and southern regions of the country.

From an electrical point of view, the existing Brazilian network is composed of four main subsystems: south, southeast, northeast and north. Besides these four subsystems, one has to mention the important Itaipu transmission system which ranges between the Itaipu power plant located in the southern region and the load centers fed by its power, in the State of Sao Paulo and other areas of the southeast region, thousands of kilometers away.

These subsystems are located far away from each other, in geographical areas that have distinct hydrological characteristics. To optimize the use of the water available and to provide an efficient supply for electric loads all over the country, energy exchanges between these areas became indispensable and long transmission corridors and interconnection trunks had to be built.

The economical feasibility of long-distance electric-power transmission projects in Brazil depends largely on the use of extra-high voltage levels and of SC banks, which have the effect of bringing about a reduction of the electrical distances and, as a consequence, an increase of the transmission capacity of the lines and of system stability. In the Brazilian grid most of the SCs have been installed on the subsystem-interconnection trunks or on their receptor systems.

SC banks started to be used in Brazil in 1989 on the Itaipu 765 kV AC transmission lines, which operate today with nine fixed capacitor banks (FSCs) and 9,945 Mvar of reactive power. At present there are 47 SC banks in operation in the country: four TCSCs (thyristor-controlled series compensators) and 43 FSCs. Most of them (33) operate at the 500 kV level. There are nine 765 kV banks and five 230 kV banks. The total reactive power of the installed banks amounts to 21,773 Mvar.

The major concentration of these banks occurs on the North-South 500 kV Interconnection (with two circuits in operation today) and its receptor southeast subsystem. The third circuit of this interconnection trunk – which will use eight additional SC banks – is already being built. In addition, bids for several other transmission lines planned with SC banks were received in Brazil.

Up to the start of operation of the 2<sup>nd</sup> circuit of the North-South Interconnection, by the end of 2003, SC banks and their MOVs had to be dimensioned to withstand the stresses imposed by two consecutive external single-phase short circuits (as a consequence, for instance, of a non-successful auto-reclosing). The fault clearing time to be considered in this case depends of the voltage level of the equipment to which the bank is connected; for example, 100 ms at the 500 kV level.

Since then, the design criteria for external faults have been changed to allow the capacitor-bank's by-pass after the detection of a non-successful auto-reclosing. The by-pass lasts until the fault is cleared, at which point the capacitor bank is reinserted within no more than 300ms. This option was only considered after dynamic studies demonstrated no risks for system transient operation under such conditions. The goal was to reduce the overall cost of the MOV and consequently of the SC bank without additional operational risks.

For all internal faults the capacitor-bank's by-pass is allowed.

In a series bank, in the same way that the MOVs protect the capacitors, the gaps act to protect the MOVs from absorbing energy beyond their capability. But this protection must not interfere with the primary directives concerning the equipment's performance in case of external faults.

The varistor duties associated with external faults provide the basis for the current threshold of the protective system, that include components such as the protective gap for normally-cleared single-phase and three-phase faults. Both thresholds (energy and current) are set with a level of security above the decisive external fault.

With the increasing number of SC banks in operation in Brazil, one of the concerns of the designers of future applications has to be the adjustment of all the current and energy threshold settings to ensure their coordinated operation, without putting the equipment at risk. This topic will receive careful attention during the execution of the basic project analysis of the third circuit of the North-South Interconnection. A special difficulty for the implementation of such coordination is the fact that most of the transmission systems (as well as the equipment comprised therein) don't evolve exactly as planned.

Table A6-2 presents, in the second and third columns, approximate values of some series-capacitor dimensioning quantities for (respectively) the first and second circuits of the North-South Interconnection (shown in figure A6-1). The first column shows the names of the substations at which the SCs were installed and the types of compensators installed at each site (FSCs or TCSCs).

The SC of the North-South Lines have the following characteristics: MOV protected with slow speed self-triggered by-pass gaps and by-pass CB. FSC installed in 2003, 1500 A, 23.08  $\Omega$ , 35.7 kV. TCSC installed in 2004, 1500 A, 13.27 (variable to 15.92)  $\Omega$ , 23.88 kV. No high-speed reclosure is applied to the series compensated lines.

The line lengths are:

Imperatriz – Colinas	344 km
Colinas – Miracema	174 km
Miracema – Gurupi	255 km
Gurupi – Serra da Mesa	257 km

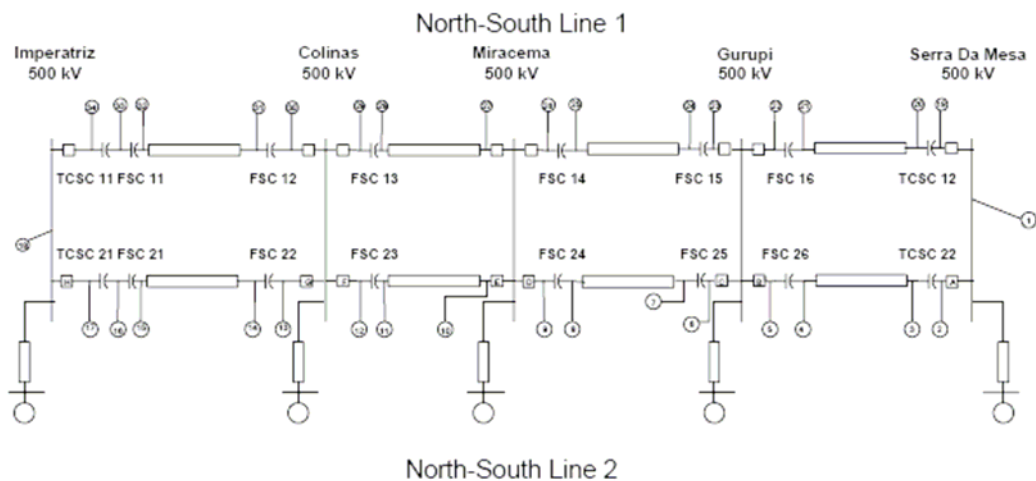


Fig. A6-1 Single-line diagram of the 500kV series compensated North-South transmission system showing names of the substations at which SCs are installed and types of compensators

Table A6-2 - Comparison with N/S I - Installed MJ

Series Capacitors	MOV N/S I (MJ/phase)	MOV N/S II (MJ/phase)
TCSC - S. Mesa	23.04	20.2
FSC - Gurupi	36.75	41.4
FSC - Gurupi	48.76	38.6
FSC - Miracema	30.2	41.4
FSC - Colinas	42.9	55.2
FSC - Colinas	32.8	41.4
FSC - Imperatriz	29.7	36.5
TCSC-Imperatriz	25.5	20.2

Fig. A6-2 Table showing a comparison of MOVs installed MJ

In figure A6-1 the small circles indicate the points at which short-circuits were simulated during the studies performed by the supplier of the SCs installed on the second circuit of the North-South Interconnection. The following Table contains information on design parameters of the eight SCs included in this order.

	TC21	FC21	FC22	FC23	FC24	FC25	FC26	TC22
	Imperatriz	Imperatriz	Colinas	Colinas	Miracema	Gurupi	Gurupi	S. Mesa
E <sub>ext</sub> : Worst Case External Fault Duty Where Bypass Is Not Allowed (MJ)	9.8	20.8	21.5	32.4	23.5	23.9	21.5	11.4
MOV Study Defining Case for E <sub>ext</sub>	G12, G12A	G12A	G12A	G8	B6, B12	B8A	B4, B10	B2
High Energy Threshold Margin Factor	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
E <sub>set</sub> : High MOV Energy Bypass Threshold (MJ)	10.3	21.8	22.6	34.0	24.7	25.1	22.6	12.0
I <sub>ext</sub> : Worst Case Peak MOV Current During External Fault (kAp)	10.1	13.6	15.2	16.8	12.8	13.5	14.6	10.1
MOV Study Defining Case for I <sub>ext</sub>	G12A	G12-1	G12A	G8	B6A, B8, B12A	B8A	B4	B4A
High Current Threshold Margin Factor	1.10	1.10	1.10	1.10	1.10	1.10	1.10	1.10
I <sub>set</sub> : High MOV Current Bypass Threshold (kAp)	11.1	15.0	16.7	18.5	14.1	14.9	16.1	11.1
E <sub>int1</sub> : Worst Case Close-in Internal Fault Duty (MJ)	10.3	21.8	22.6	34.0	24.7	24.6	22.6	12.0
MOV Study Defining Case for E <sub>int1</sub>	K12, K16	K10, K14	K8, K16	K2, K4-1	E4, E10	E12, E14	E8, E16	E2, E6
MOV Protective Level Voltage (PLV, kVp)	81.6	131.3	131.3	131.3	131.3	131.3	131.3	81.6
Energy Overshoot for Remote Internal Fault (0.3ms x I <sub>set</sub> x PLV, MJ)	0.3	0.6	0.7	0.7	0.6	0.6	0.6	0.3
E <sub>int2</sub> : Worst Case Remote Internal Fault Duty, Theoretical (E <sub>set</sub> + Overshoot, MJ)	10.6	22.4	23.2	34.7	25.2	25.7	23.2	12.2
MOV Minimum Energy Rating, Not Including 15% Energy Margin (Maximum of E <sub>ext</sub> , E <sub>int1</sub> , and E <sub>int2</sub> , MJ)	10.6	22.4	23.2	34.7	25.2	25.7	23.2	12.2
MOV Minimum Energy Rating, Including 15% Energy Margin (MJ)	12.1	25.8	26.7	40.0	29.0	29.5	26.7	14.1
Multipher to Account for Unequal Current Sharing Between Columns	1.1084*	1.1084*	1.1084*	1.1084*	1.1084*	1.1084*	1.1084*	1.1084*
MOV Minimum Installed Energy Rating, With Current-Sharing Considerations (MJ)	13.5	28.6	29.6	44.3	32.2	32.7	29.6	15.6
Number of Blocks of MOV per Column	11	17	18	18	18	18	18	11
Number of Columns of MOV per Phase	48	56	60	80	60	56	60	48
MJ Capacity per MOV Block	0.0383	0.0383	0.0383	0.0383	0.0383	0.0383	0.0383	0.0383

Fig. A6-3 Table showing design information for the 8 new SCs

TERNA, the operator on BOT scheme of the Imperatriz-Serra Da Mesa 500kV-60Hz-1030km long series compensated lines (Fig. A6-1) has informed the following operational performance of the SC banks since commissioning:

i) Average yearly availability for service

Year	2005	2006
TCSCs	94,68%	99,78%
FSCs	96,95%	99,98%

ii) Failures have occurred in the thyristor control modulus, in the MOVs and in the cooling system

iii) The statistical records of performance of protection relays of series compensated and adjacent lines has been as follows:

Year 2004: 93.8% correct performance

Year 2005: 98.2% correct performance

## A.7 Series Compensation in BPA 500 kV transmission system (USA)

Bonneville Power Administration's 500 kV transmission system has 17 conventional SC banks ranging in size from 192 to 912 Mvar and one 202 Mvar TCSC currently in service. The degree of compensation ranges from 35% to 70%. A combination of gapped/MOV and gapless MOV/Breaker protective schemes are used.

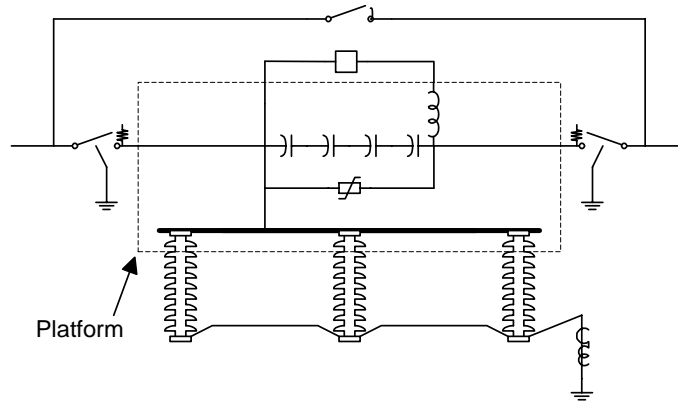


Fig. A7-1 Typical scheme of BPA SC bank with MOV and by-pass CB

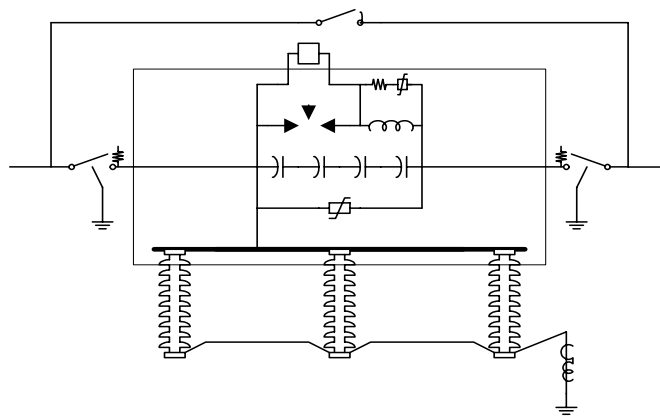


Fig. A7-2 Typical scheme of BPA SC bank with MOV and by-pass gap

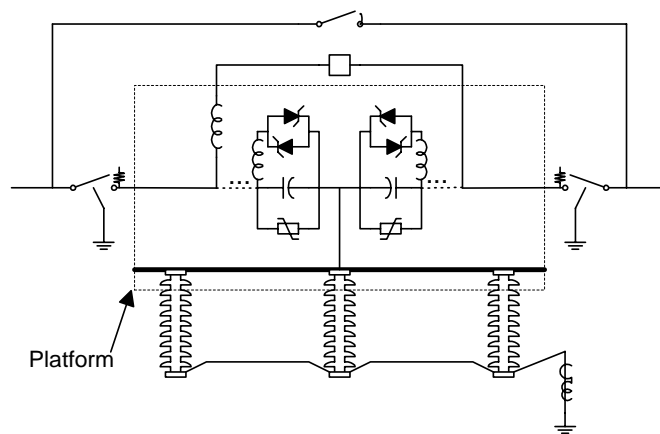


Fig. A7-3 Scheme of BPA Thyristor controlled SC bank with MOV and by-pass CB

BPA reports excellent reliability, also during system transients, and a very low outage rate with their SC banks. The only real problems have been a few inadvertent gap operations, which BPA reports are not significant operationally as they close the bypass breaker on every gap operation and open the breaker approximately 1 second later to re-insert the bank. However protection and control systems have been built redundantly, thus preventing forced outages due

to failures in the secondary equipment. SSR could occur at one location under low line load conditions and can be avoided by by-passing the SC.

#### **A.8 Series Compensation in Sweden**

Series compensation has been in service in Sweden since the 1950s. SC banks are installed on eight 400 kV transmission lines connecting the north of Sweden with central Sweden and on a 400 kV line connecting Sweden and Finland. These banks range in size from 155 Mvar to 600 Mvar. The protection scheme used on the banks is MOV including the older banks (1950 and 1960 vintage) which were modernized and upgraded in the 1990s.

Apart from a few problems with the MOVs, the operational service experience has been very good.

## Appendix B

### COMPACT, HSIL- AND EXB- LINES

#### 1. Background, Design Concepts and Experience in Brazil

The need to transmit ever-increasing amounts of electric power has to be met, in practically every country, through the use of more and more restricted transmission-line corridors, due either to environmentalist pressures or to economical constraints determined by the cost of land. To sort this dilemma out, power utilities are under constant pressure to design transmission lines of greater transmission capacities. Due to this concern much attention is being given since the 1970s to tower designs of the compact type [46][47]. The compaction technique involves the handling of the top tower geometry in order to place the phases as close as possible. Therefore the geometry of conventional and compact towers differ basically in the phase-to-phase insulation distances which, depending on the insulation-coordination criteria, could be about 50% shorter in designs of the compact type. The immediate consequence of this is a reduction of the tower's geometric-mean diameter (GMD) and an associated decrease of the line surge impedance, leading to an increase of its surge-impedance loading (SIL) or "natural power", which is the maximum amount of power that can flow through a long transmission line with low voltage drop. The transmission of power amounts above the SIL causes the line to consume reactive power and voltage drops to occur. These effects frequently determine the need to implement countermeasures such as the use of shunt and/or series compensation. The increase of the SIL associated with the compact design warrants, on its turn, a considerable increase of the line's transmission capacity and, in some contexts, a reduction of series compensation and of the voltage-supporting requirements.

The SIL is calculated by the following formula:

$$SIL = V^2/Z_1$$

where:  $V$  = System Voltage (phase to phase)

$Z_1$  = Positive-sequence surge impedance of the line

Compaction increases the coupling between phases and consequently the positive-sequence surge impedance ( $Z_1$ ) which, on its own, determines an increase in the line SIL. Of course there are always limiting factors that determine the maximum possible compaction for lines and towers of a given design. These limits are determined mainly by the maximum risk of inter-phase insulation failure admitted in the previously-established insulation-coordination criteria and by the need to avoid excessively high electric-field gradients at the surfaces of sub-conductors, which could increase the corona level to objectionable levels.

Compaction can provide increases in the line SIL of up to 20% or 30%, as exemplified in table B-1 with data from a Brazilian planning study [48] involving alternative designs for a 250 km, 525 kV transmission line envisaged in 1995 as part of the expansion of the transmission system that supplies electric power to the Brazilian Centre and South regions. This increase of the "natural" power-transmission capacity can not only determine a reduction of the number of lines necessary to transmit a given amount of electrical power but also a decrease of the right-of-way width of the line(s) corridor. Besides the economical advantages, such possibilities would certainly contribute to limit complaints of the public living in the corridor's neighborhood and of environmentalists.

Table B-I Electrical parameters of three alternative designs of a 525-kV transmission line of Brazil

Parameters	Conventional	Compact	HSIL
$R_0$ (Ohms/km)	0.1979	0.3838	0.3869
$X_0$ (Ohms / km)	1.5372	1.4867	1.4027
$\omega C_0$ (mhos / km)	3.14E-06	2.92E-06	3.39E-06
$R_1$ (Ohms / km)	0.0218	0.0173	0.0139
$X_1$ (Ohms / km)	0.3520	0.2656	0.1850
$\omega C_1$ (mhos / km)	4.72E-06	6.17E-06	8.85E-06
$Z_1$ (Ohms)	273	208	145
SIL (MW)	1009	1327	1904

The data in the fourth column of the above table were obtained for the alternative of a High Surge-Impedance-Loading Line (HSIL), a design concept proposed in the 1980s [49] while the first compact lines were being designed, built and commissioned in several countries. Paper [49] was soon followed by others [50][51].

The HSIL lines are conceived as *taylor-made* system components that can be designed as required by the specific characteristics of the new proposed transmission system, having also the advantages pointed out for compacted lines. The basic design principle of a HSIL associates the increase of the number of sub-conductors in a bundle and the decrease of the phase-to-phase insulation distances with the equalization of the superficial electrical field of each sub-conductor. As an outcome of this overall optimization process, the bundle configuration determines a non-symmetrical disposition of the sub-conductors with different radii near the tower and in the midspan. Depending on the number of sub-conductors, the surge-impedance loading could reach a level twice as high as the typical value provided by conventional line designs. An improvement of the line performance in what concerns the environment-disturbing phenomena of corona, audible noise and radio interference is also afforded by the HSIL design conception. Of course this possibility provides a new flexibility to the task of planning a transmission system.

During a program to test and implement the HSIL technology in Brazil, the attention of Brazilian researchers was driven to the possibility of developing an intermediate concept, the expanded bundle (EXB) technique, which allows the increase of TL's SIL by means of a repositioning of the line conductors, as proposed in [49], but without reducing the phase-to-phase distances of the towers. This technique makes it possible to upgrade the power-transmission capacity of existing transmission lines by changing their hardware fittings (suspension and spacers) in order to modify the bundle geometry while the same towers are kept [52]. Although the increase of the line SIL is less pronounced in this case than that warranted by the HSIL technique in its original concept, the EXB design is easier to study, test and implement. In areas of moderate right-of-way costs the cost/benefit ratio of this solution may be attractive for new transmission lines as well as for existing ones requiring upgrading. Accordingly, from 1994 onwards the EXB concept has been widely used in Brazil, specially in the North and Northeast regions, for new 230 kV and 500 kV transmission lines and for existing lines requiring upgrading. In 2005 CIGRÉ WG B2.06 presented in *Électra* the results of its studies on HSIL-lines, mainly based on the experience in Brazil [83].

Figure B.1 shows alternative tower designs considered during the planning of the second 500 kV circuit interconnecting the Brazilian North and Northeast regions. The first circuit used V-guyed towers and four 954 MCM ACSR cables per phase in a conventional bundle disposition, as shown on the left of the figure. This arrangement resulted in a line SIL of 1000 MW. As for the second circuit a SIL of 1200 MW was required, the alternative of a compact line using self-supported towers and four 954 MCM ACSR cables (shown on the centre of figure B.1) was considered, since this project was well known and already operating in the utility's (Eletronorte) system. However, the utility (CHESF) finally decided to use the same V-guyed tower design of the first circuit, with a special bundle arrangement optimized to provide the approximate equalization of the electrical field on the conductors' surface. The optimization procedure led to two asymmetrical bundles: a rectangular shape for the center phase and a trapezoidal shape for the outer phases (right of figure B.1). Varying the dimensions of these arrangements the SIL would range from 1100 MW to 1400 MW. The final design resulted in a 1200 MW SIL, as shown in table B-II.

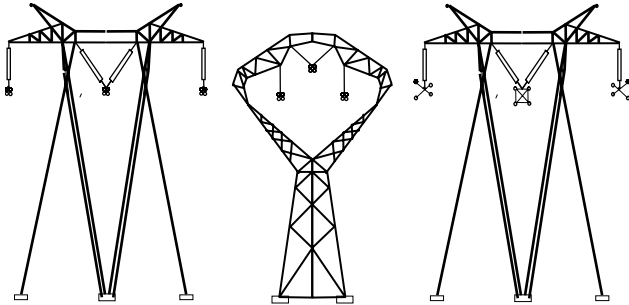


Fig. B.1 Conventional, compact and EXB tower designs considered in CHESF's study.

Table B-II Electrical parameters provided by the alternatives considered in CHESF's study.

Parameters	Regular guyed tower	Self supported tower-compact	EXB Guyed tower
R1( $\Omega$ /km)	0,017	0,018	0,017
X1( $\Omega$ /km)	0,32	0,27	0,27
B1 ( $\mu$ S/km)	5,19	6,13	6,19
SIL ( MW)	1000	1200	1200

**2. Other Technical Aspects**

The decision to use any of the line-design concepts mentioned in the previous section is normally determined in Brazil by economical and environmental reasons. Normally the choice of one of these concepts does not determine, by itself, levels of electrical stresses that switchgear, transformers and other substation equipment specified in accordance with the current IEC criteria can not withstand. It is assumed that a utility's decision to implement any line design (not only the ones discussed in this text) will always be taken on the basis of previously-performed proper studies that can show, for example, that the risk of insulation failure is not higher than the maximum level admitted in the company's insulation-coordination criteria, that lightning and switching surges can be adequately

limited by surge arresters at the line ends or at midspan without exceeding their energy-absorption capacity etc. as exemplified in [48].

On the basis of the Brazilian experience, no particularly-inconvenient behaviour of the power system can normally be attributed to the use of properly-designed lines of any of the types discussed in this text. It should be said, however, that due to the increased inter-phase coupling that characterize compact and HSIL lines the extinction of secondary arcs in a faulted phase within the dead-time period usually considered for single-pole auto-reclosing becomes more difficult – or even quite improbable if extra-long HSIL are considered –, as shown in [53]. This difficulty can make the implementation of single-pole auto-reclosing unattainable in certain cases.

## **Appendix C**

### **CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS STUDIES PERFORMED BY CIGRÉ WG A3.13**

**Report presented at the CIGRÉ SC A3 Colloquium 2007, Rio de Janeiro, September 2007  
Report PS2-01**

# CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS

## Studies performed by CIGRE WG A3.13

A.L.J. Janssen °    F. Iliceto    Q. Bui-Van    S. Morais    B. Middleton    J. Jäger

### SUMMARY

This report is a summary of the two CIGRE Technical Brochures that, on behalf of CIGRE SC A3, will be published in 2007 on Changing Network Conditions and System Requirements, with a focus on the consequences for HV AC Equipment.

### KEYWORDS

Distributed generators, shunt/series compensated lines, out-of-phase switching, synchronizing, TOV, TRV, Ferranti-effect, transient overvoltages, SPAR, TPHSR, HWLL, MOSA, MOV, SMOSA

### 1. INTRODUCTION

As society has developed, the role of utilities has changed in response to commercial, regulatory and environmental pressures. Many utilities with responsibilities for transmission and distribution networks now have limited influence on the planning and operation of large power plants, which, historically, were an integral part of network operation and, particularly, of voltage control. Large generators are typically sited on the basis of primary energy source availability (fuel, hydro capability, etc), or of environmental restrictions, and are consequently often far removed from load centers. The transmission of large quantities of energy over long distances poses certain problems of its own and creates a need for the greater use of “local” reactive power generation to control the network voltage profile.

It is also clear that, over time, installed capacity of distributed generation increase. Despite its “local” nature it might also contribute to the difficulty of managing the networks. Shunt capacitor banks, Static Voltage Regulators (SVRs) and FACTS are now being widely installed to supply reactive power for voltage control in place of more conventional means (large generators, rotating compensators). Many of these new devices generate harmonics and create the possibility of harmonic resonance due to capacitor banks, of distorted voltages/currents from power electronics and other non-linear phenomena (magnetizing currents), which must all be controlled. Often this leads to a need for additional harmonic filtering.

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Interconnections between major networks are becoming increasingly important but also more difficult to achieve due to the difficulties associated with obtaining new rights-of-way for the erection of overhead lines. Consequently, existing overhead lines have to be up-rated in loading capacity whilst more shunt or series compensated lines, and even shunt-compensated cables or HVDC connections, are applied.

Future power systems can be characterized by a mixture of distributed generation connected at medium voltage and low voltage, and long distance transmission from remote large-scale power plants. Problems such as reactive power control (shunt capacitor banks, shunt reactors, FACTS), long overhead lines (compensation requirements), large short-circuit currents (high dc time constant, delayed current zeros, fault current limiting) and severe TRV's (generator circuit-breakers, transformer fed faults, faults behind reactors, out-of-phase switching) can all be foreseen and are considered in this document.

In addition to changes in the high voltage nature of networks, more advanced protection schemes, intelligent interlocking and tele-tripping, controlled switching and the collection & exchange of information are all influencing network development.

In summary, network conditions are changing due to the introduction of new components, new designs, new applications and new ways of operation. The introduction of modern surge arresters and varistors, non-conventional applications of switchgear, series and shunt capacitor banks, filter-banks, FACTS, phase-shifters, advanced protection and control, windmill-farms, converter connected power plants are creating more complicated transmission and distribution networks. These changes bring with them changing stresses such as transient and temporary overvoltages, high harmonic levels, asymmetrical voltages, and changes in the nature of short-circuit currents.

In order to structure these versatile changes, the main directions of the changes have to be found, taking into consideration the possible impact on the specifications for HV equipment. From the point of view of CIGRE SC A3 "High Voltage Equipment", the most relevant network changes are on one side more complex grids due to distributed generation and the introduction of advanced protection and control systems, and on the other side the greater utilization of long distance interconnections with its reactive power and voltage control. These are considered against a background of increased utilization of equipment in terms of age, loading & voltage stresses, complexity and reduction in equipment size, incorporation of more intelligence and the application of more overvoltage protection and smart devices.

In 2002 CIGRE SC A3 has established a new WG A3.13 "Changing Network Conditions and System Requirements" to investigate these developments and its consequences for HV equipment. In 2003 WG A3.13 started its studies and delivered in 2004 to SC A3 an internal working document, called the Scoping Document [1]. In the same year it has been proposed and accepted by SC A3 to split the work into two WGs and WG A3.19 has been established to study the effects of three-phase SLF and LLF on the TRV requirements. (LLF is a line fault at a long distance thus introducing high TRV peak values at the line side [6]). In 2007 WG A3.13 has finalized its studies and two CIGRE Technical Brochures will be published; one on the impact of distributed generation and one on the impact of long distance transmission.

A summary of the findings and conclusions of WG A3.13's studies will be presented here. [2][3][4][5]

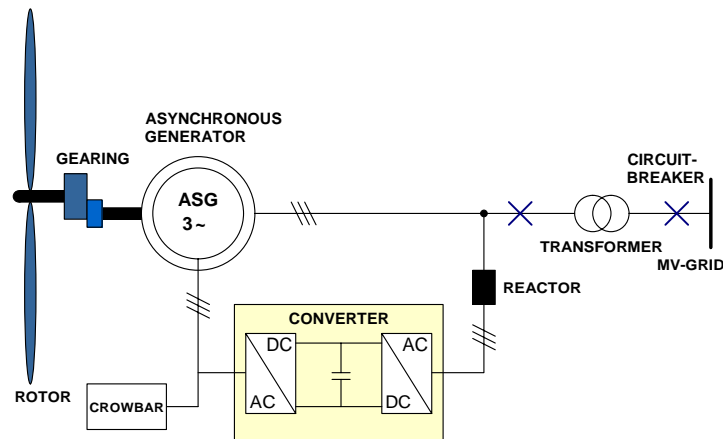


Fig. 1 DFIG: double fed induction generator with variable speed

## 2. DISTRIBUTED GENERATION

The large increase in dispersed generation and the trend to an even further growth give enough evidence that the effects and impact of distributed generators on the system's behavior cannot longer be neglected. The developments lead to special requirements and special phenomena such as higher short-circuit power requirements, higher short-circuit currents, other patterns of power flows and short-circuit power flows, different voltage profiles and voltage variations, fast and advanced protection, complicated controls, situations of potential islanding, synchronisation, out-of-step switching, phase opposition currents, harmonics, safety issues, fault location, black-start conditions, system restoration, etc.

Many small power units are protected in such a way that for any disturbance in the network, they are immediately switched off by a circuit-breaker at the low voltage side or at the high voltage side of the step-up transformer (after roughly 50 to 100 ms), thus reinstating the passive feature of the distribution network. In this way they enable the conventional selective protection, auto-reclosing and fault location in the distribution grids and prevent out-of-phase conditions, unintended island operation, safety problems and severe damage to the power plants. However, when distributed generation has expanded to a significant share, requirements have to be put forward that these generating plants contribute to the stability of the network and remain connected for at least a certain period of time so that voltage sags can be limited in amplitude and duration, overloads are reduced and regional power deficits are avoided [7]. The "ride through time" is specified as several hundreds of ms for smaller or special units up to more than 1 s for large conventional power units.

Measures to profit from DG and to minimize its drawbacks for the network are with a clever optimization of protection settings. In this respect, reference is made to [8] where the following recommendations are given:

### DG connected to faulty MV or LV distribution-feeders

- Disconnect synchronous generators immediately after fault clearing (before the auto-reclosing instant)
- Disconnect asynchronous generators, if the short-circuit clearing time and dead time before reclosure of the MV-line are too long and the inertia of the generators is low
- Disconnect DG in case of permanent faults

### DG connected to healthy MV or LV (radial) distribution-feeders in case of short-circuit in another MV or LV feeder supplied by the same substation

- Synchronous and asynchronous generators should be kept in service if short-circuit is cleared in the standard low time (say, within 200 ms for multiphase faults)
- Protect synchronous generators against loss of synchronism
- Protect asynchronous generators against sustained overspeed and overcurrent

DG connected to healthy MV or LV (radial) lines in case of faults in supply HV network

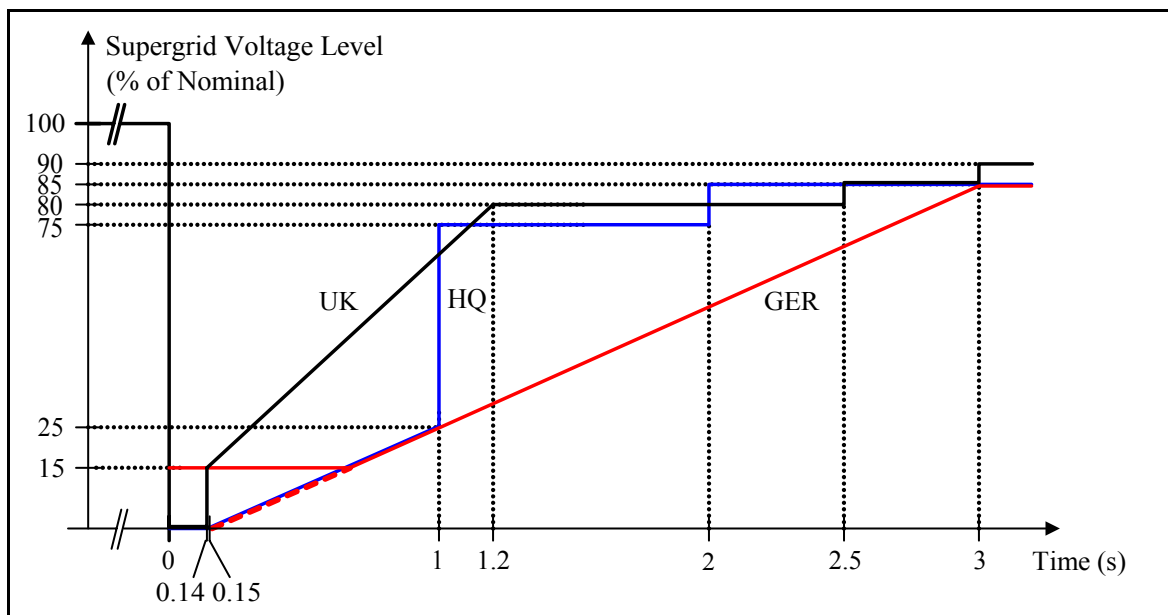
- Synchronous and asynchronous generators should be kept in service in case of multiphase faults in the HV network cleared in short time ( $\leq 200$  ms) and in case of single phase to ground faults in HV network even when of long duration (say, 0.5 – 1.0 s)
- Protection synchronous generators against loss of synchronism
- Protection asynchronous generators against sustained overspeed and overcurrent

Islanding

- Disconnect automatically synchronous generators under islanding conditions, unless the network, protection and control is specifically designed for stable supply of an island from DG
- Disconnect asynchronous generators under self-excitation conditions.

However these measures are only feasible when short protection clearing (100 ms to 200 ms) and auto-reclosing times can be reached, which may not be the case in distribution-networks [2]. But, modern technology wind mills, as DFIGs and generators connected through full converters, should inherently be able to fully ride through fault conditions, even for longer clearing times, and resume power supply within a few cycles after fault clearing. From a technical point of view, modern design of windmills offer the possibility to employ their inertial energy, freewheeling independent from the power frequency (figure 1), to over-come to a large extent the difficulties during voltage and frequency dips. But also many co-generation plants are capable to contribute to the overall system performance for a longer period of time than corresponding to the old policy of immediate tripping.

Some examples of fault ride through requirements as a function of duration of the voltage dip and the residual voltage are given in figure 2: England and Wales (UK), Hydro Québec (Canada) and Germany.



*Fig. 2 Examples of fault-ride through requirements*

The examples of the regulations, in combination with the possibilities of modern technologies, justify the conclusion that international harmonisation of the requirements of ancillary services for most of the nowadays popular dispersed generators is possible, but will also be a good development for involved stakeholders.

Because of developments as the large penetration of dispersed generation, more strict requirements for power quality and liberalisation, distribution networks are changing rapidly, both in a technical sense as in a organisational setting. The consequences of these developments are quite clear in the secondary equipment: more metering, tele-metering, more signalling, tele-control, fast and advanced protection, extended telecommunication, advanced information available on-line to system operators and off-line to asset managers, data mining techniques, data sharing techniques, automatic system restoration functions.

Looking at the primary plant, more redundancy is applied, even meshed distribution systems, more surge arresters at vital points, some single phase systems become three-phase, some instrument transformers and protection become three-phase systems, more advanced network neutral treatment, switchgear and fuses become upgraded to circuit-breakers, booster-transformers and other voltage control equipment are applied, smart operating voltages are introduced, together with higher loading capabilities and higher short-circuit powers.

Modern generators, equipped with full converters or DFIG, show a limited contribution to the short-circuit current in comparison to the conventional generators. It is not expected that the behaviour of the DC-components of the short-circuit current will lead to DC-time constants larger than those stated in the Standards [10][11][12][13].

System conditions, like fault-ride-through, system restoration and/or islanding require primary and secondary equipment to be able to cope with phenomena like detection of system separation, frequency control, spinning reserve, voltage control, load rejection, out-of-phase condition, synchronisation, synchro-check, longitudinal dielectric stresses, but also safety issues like disconnected parts, earthed parts, automatic re-closing, blocking, etc. These system conditions lead to requirements, especially for switchgear, that are related with smart network operation: advanced circuit-breakers, able to communicate on-line, to perform diagnostics, to take decisions, to perform functions as auto-restoration and synchronisation, to act within the advanced protection systems of the distribution grids, to perform controlled switching, to assist fault location, etc.

Special requirements that may have an impact on the Standards are, for the moment, restricted to dynamic (cyclic) loading of switchgear and out-of-phase switching by circuit-breakers. Out-of-phase switching is addressed in the Standards, but is covering an out-of-phase angle up to about 90°. Light drives for conventional generators and/or a lack of inertial energy in separated systems may cause out-of-phase angles to reach higher values than 90° in short times, thus enforcing specifications to cover a wider range of out-of-phase angles. In case of re-strikes and failing circuit-breakers, the damage to equipment, especially power generating plants, can be enormous. RRRV as specified for the out-of-phase TRV is by far not steep enough, but IEC 62271-100 [10] mentions that this is covered by the RRRV of T30. This, however, is true up to an out-of-phase angle of roughly 90°, as for larger angles the first line of T30's TRV-envelope is not long enough. Larger out-of-phase angles (180°) are specified by many users and manufacturers are willing to design, test and supply adequate generator circuit-breakers.

Recent development in the Standards show more attention to steep and high TRVs for MV-networks (amendment 2 to IEC 62271-100) and to generator circuit-breakers for small power plants, 10 to 100 MW (IEEE C37.013 [14]). Users should be aware of these improvements, taking in mind the aforementioned short-comings.

### **3. LONG DISTANCE TRANSMISSION**

The privatisation and liberalization of the electric energy sector has considerably increased interregional and international energy transactions and created a greater need for large power transfers over long distances. More use and reliance on transmission has also been caused by the growing environmental

restrictions for the construction of new power plants and transmission lines. In several cases the independent power producers (IPPs) have located their new thermoelectric power plants, to be fired with imported fossil fuels (gas, coal, fuel oil), in places remote from the loads to be served, or far from optimal locations as regards transmission. In a few countries, the construction of large windmill farms has also required transmission along relatively long distance and the need to provide new transmission and generation reserve capacities in order to face the volatile patterns of generation inherent to operation of large windmill farms. Congestion of infrastructures and strong demand of environment conservation may justify the use of long stretches of EHVAC cross-linked polyethylene insulated underground cables, even in non-urban areas, requiring a large shunt compensation. These cable stretches may be solidly connected to overhead lines, to form mixed cable-overhead lines, whose design and operation have special technical features.

Several methods to increase the transmission capacity are used: utilize OH-lines, cables and transformers up to their dynamic (cyclic) loading capacity, increase the operating voltage, apply shunt and/or series compensation, apply phase shifting transformers, apply FACTS devices and HVDC systems, apply HSIL-lines (high surge impedance loading lines) and EXB-lines (expanded bundle lines). Not yet applied, but an economically promising technology is very long distance transmission by HWLL (half wave length lines).

The continuous operation voltage should remain within the maximum values stipulated by the IEC Standards, but in case these values are exceeded in order to utilize the benefits of higher operating voltages [9], precautions should be adopted in the specification of equipment and, in existing systems, some equipment may have to be replaced/up-rated in order to avoid certain inconveniences or an increase of risk of failure has to be accepted.

Temporary overvoltages (TOVs) in large transmission systems are mainly caused by the Ferranti-effect (load rejection), ferro-resonance (single pole auto-reclosure in shunt compensated lines), low-order harmonic resonance (long EHV cable length in combination with OH-lines). Countermeasures are: tele-tripping, automatic connection of shunt reactors, the application of (switch-able) surge arresters and circuit-breakers specified to handle the long unloaded line switching and out-of-phase switching conditions.

The transient overvoltages specific for large transmission systems are the slow front transient overvoltages (switching overvoltages), occurring at energizing OH-line and single pole (SPAR) or three-pole re-closure (TPHSR) of OH-lines. Depending on the switching impulse withstand level (SIWL) of the OH-lines (typically 3.0 pu in Europe with withstand probability of 99.86% ( $V_{50\%} - 3\sigma$ ) and 2.5 pu in North-America) countermeasures (closing resistors, controlled switching, surge arresters, staggered poles, pre-connected shunt reactors) may be necessary to withstand the switching surges, generally smaller than 3.0 pu. But TPHSR requires special attention, as the switching surges may be larger, dependent on the system lay-out.

Secondary arc current during SPAR is mainly a problem of arc extinction on the line, and not a problem for the line circuit-breakers involved. Shunt reactors can only effectively reduce the arc current to a value below 40 A, if a properly tuned neutral reactor is added between the neutral of the shunt reactors and earth. But as, certainly at the highest operating voltages, it may be difficult to find a value for the neutral reactor, suitable for all prevailing situations, it is not always possible to limit the arc current to acceptably low values. On the other hand, shunt reactors and associated neutral reactors may have to be out of service when the lines are heavily loaded, i.e. when the SPAR is more useful. The re-closing time may also be critical and therefore an alternative solution to limit the arcing current is the use of High Speed Grounding Switches (HSGSs).

Electrostatic and electromagnetic induced currents are larger for long OH-lines than for medium or small lengths. This affects the specification of earthing switches in particular of multiple-circuit lines, as well as secondary arc phenomena. Measures to reduce the secondary arc current to values that force self-

extinction are mentioned in the former paragraph, but for some long compact lines even these countermeasures cannot prevent the necessity to resort to TPHSR.

Switching off of unloaded long lines differs from clearing the capacitive currents on small or medium length lines, as the capacitive currents will be higher (certainly under circumstances of disturbances), the induced voltages will be higher, the Ferranti effect more dominant and switching under high TOV-conditions more probable. On the other hand, usually shunt compensation may be applied and possibly also series compensation, both leading to less severe recovery stresses when switching off the long OH-line. Nevertheless utilities with long OH-lines specify voltage factors higher than those given in the IEC-Standards for capacitive current switching.

Clearing of fault currents flowing through series capacitor banks result in high TRVs, due to the electric charge on the series capacitors. TRV peak values can be limited by switched opening resistors, by fast by-passing the capacitor bank, by MOSAs connected phase-to-earth or MOV in parallel to the arcing chambers of the CBs. The first two solutions bring along problems (reliability, retardation, selectivity) discouraging application in modern transmission systems. Use of special MOSAs with very low SIPL can limit TRV-peak value within 3.2pu, whereas MOVs in parallel with arcing chambers of CBs can limit TRV-peak value within 3pu or 2.5pu, depending on whether there is or not the requirement of system synchronization with the involved CBs. [15][16]



*Fig 3: example of 735 kV capacitor bank*

Full phase-opposition switching of a generating plant at the HV-side leads to TRV peak values of 2.9 to 3.2 pu; and higher values for systems where an earth fault occurs or a temporary overvoltage. For full phase opposition switching of OH-lines, calculations show peak values of the TRV from 2.7 pu (420 kV/63 kA, 100 km length,  $I_{loop} = 15\%$ ) to 3.1 pu (420 kV/40 kA, 100 km length,  $I_{loop} = 25\%$ ) and even beyond for longer line lengths). Opposite to the reality in the systems, the RRRV specified in the Standards for out-of-phase switching is lower than the RRRV specified for test duty T100. But, to the Standards, the RRRV for out-of-phase switching is considered to be covered by test duty T30 (multipart testing), what is not completely true for large out-of-phase angles. Despite the fact that in many cases the out-of-phase angle will be random, the Standards are based on an angle that is limited to about  $90^\circ$  [17]. Special attention is asked for synchronizing, where the power frequency withstand voltage across open contacts (under rain in type test) of circuit-breakers should have the values specified in the Standards for

Special attention is asked for synchronizing, where the power frequency withstand voltage across open contacts (under rain in type test) of circuit-breakers should have the values specified in the Standards for the disconnectors. In that case, the external insulation across open contacts of live tank circuit-breakers should be specified to withstand two times the phase-to-earth maximum power-frequency operation voltage with pollution representative of the expected local environmental conditions. Line circuit-breakers used for synchronizing of separated sub-systems (or used for the automatic line re-closure) are exposed in open position to lightning overvoltages which may exceed their withstand capacity. Protection can be warranted by MOSAs connected phase-to-earth at the line end, or by specially shaped air spark-gaps.

In an appendix of the Technical Brochure on Long Distance Transmission the service experience of utilities from several parts of the world with respect to series compensation is given.

#### 4. CONCLUSION

The work of WG A3.13 has revealed several system changes due to new technical, economical and political circumstances influencing the power systems. New amount of stresses and requirements on the power system devices have been found consequently. This phenomena are widely know and not new by themselves, but up to now only treated as theoretical, because the network conditions which lead to such extreme were not realistic. Now these effects can not be neglected anymore because these are more and more becoming common in future power systems.

The content of both Technical Brochures is given in Annex A. Annex B shows an overview of the temporary and slow front overvoltages (TOVs and SFOs) as discussed in Technical Brochure on Long Distance Transmission.

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#### **ANNEX A: content of the Technical Brochures on Changing Network Conditions and System Requirements**

Apart from general chapters (Membership, Acknowledgement, Preamble, Content, Acronyms and Abbreviations, Introduction, Conclusions and recommendations, References, Appendices) the two Technical Brochures contain the following chapters:

##### **Technical Brochure Part I on the impact of distributed generation on equipment rated above 1 kV**

- Technology of distributed generators  
(windmills, co-generation)
- Regulations and policy with respect to distributed generation
- Network topologies related to distributed generation
- Transient phenomena  
(out-of-phase conditions, longitudinal dielectric withstand capability)
- Power electronic equipment  
(harmonics, filter-banks)
- Possible impact on the Standards

##### **Technical Brochure Part II on the impact of long distance transmission on HV equipment**

- Continuous operation at voltages exceeding standard recommended values
- Temporary overvoltages (TOV)  
(load rejection, resonance, ferroresonance, HWLL)
- Transient overvoltages  
(OH-line energization, reclosure, fault clearing, MOSA)
- Transient recovery voltages  
(clearing faults on series compensated OH-lines, capacitive currents, under high TOV)
- Out-of-phase switching
- Behaviour of CBs during synchronisation and reclosure
- Transient currents  
(induced currents, secondary arc currents, DC offset currents)
- Series capacitor bank technologies and operating experiences
- Flexible AC Transmission Systems (FACTS)  
(power electronic equipment, harmonics, filter banks, phase-shifting transformers, variable shunt reactors)
- Possible impact on the Standards

As appendices the papers presented by CIGRÉ WG A3.13 are attached to the Technical Brochures.

**Annex B: overview of temporary and slow front overvoltages (TOVs and SFOs) as discussed in the Technical Brochure Part II on Long Distance Transmission**

<b>TOV</b>				
<b>Section</b>	<b>phenomenon</b>	<b>pu</b>	<b>measure</b>	<b>remark</b>
3.1	Load rejection + TOV	1.9-2.0	MOSA	Hydro Quebec
		1.6	SMOSA	Hydro Quebec
		2.0	MOSA	Vietnam
		1.7	MOSA	Chili
		1.4	Unloaded lines tele-tripping, automatic insertion of shunt reactor	Turkey
3.2	Ferroresonance	1.4-3.5		mitigation possible
3.3	Inrush/magnetizing current	2.0		Build-up resonance
		2.5		+ TOV
3.4	Cable/OH-line	2.0		resonance
3.5	HWLL	2.7-3.0		3 ph. short-circuit at close to line ends
		2.0-2.2		1 ph. short-circuit at close to line ends
3.6	SPAR + ferroresonance	1.6		Low onset corona voltage
		2.2		High onset corona voltage
<b>SFO</b>				
<b>Section</b>	<b>phenomenon</b>	<b>pu</b>	<b>measure</b>	<b>remark</b>
4.1	Line energization	< 3.0		
		2.0-2.2	PIR	
		1.5-1.6	Two-step PIR	
		< 2.0	Controlled sw.	
		1.7-2.2	MOSAs with low SIPL	
		< 2.4	Staggered poles	
	Re-closing	< 2.4	SPAR	
		2.7-3.0	SPAR	Unusual configurations
		3.8-4.0	TPHSR	
		< 3.0	TPHSR + SR or inductive PTs	
		1.7-2.2	TPHSR + MOSAs	
		< 2.0	TPHSR + controlled sw.	Without trapped charge on line
		< 3.0	TPHSR + controlled sw.	With trapped charge on line
		< 2.5	TPHSR + PIR	
4.2	Shunt cap.bank closing	1.6		
	Transformer closing	2.0-2.5		
4.3	Fault clearing	1.8-2.1		1 ph. fault
		3.1-3.3		2/3 ph. fault

## **Appendix D**

### **CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS**

**Report presented at the IEEE/CIGRÉ International Conference on Future Power Systems 2005, Amsterdam, November 2005**  
**Report O 06-09**

# Changing Network Conditions and System Requirements

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## Abstract

*CIGRE WG A3.13 is studying the impact of changing network conditions and system requirements on the specification of conventional HV equipment within the scope of SC A3. They see three main developments leading to future networks: the strong increase in distributed generation, the increase in the transmission of bulk power over long distance and the increase in the application of power electronics. The impact of each development is described, conclusions are given or studies going on are highlighted.*

## Keywords

*high voltage equipment, distributed generation, long distance transmission, reactive power compensation, transients, TOV, TRV, out-of-phase, filter banks*

## 1. Introduction

Networks are changing due to business drivers such as environmental concerns (including concerns as running out of fossil energy sources), competitive power market, further utilisation of transmission corridors, multi-directional power-flows in distribution networks, increased capacity, increased efficiency, etc. These developments lead to technology changes (e.g. distributed generation, wind-farms, shunt compensation, shunt/series-compensated lines, phase shifters, filter-banks, non-linear loads, HVDC, FACTS, advanced protection and control systems) and consequentially to special requirements, for instance with respect to harmonics, temporary overvoltages (TOV), transient recovery voltages (TRV), out-of-phase conditions, power quality, etc.

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CIGRE WG A3.13 “Changing Network Conditions and System Requirements” is giving special attention to the consequences of the growth in distributed generation (co-generation plants as well as sustainable power generation) and to the consequences of long distance transmission (a larger distance between power generation and power distribution, leading to voltage problems and the need for reactive power compensation). In both cases the interaction between protection and control systems on one hand and the network dynamics on the other hand will play a dominant role in the severity and probability of the phenomena that have to be withstood by the applied HV-equipment. These phenomena have to be considered against a background of increased utilisation of equipment (in terms of age, loading and voltage stresses), reduction of size and complexity, incorporation of more intelligence and the application of more over-voltage protection and smart devices. [1]

## 2. Distributed Generation

In line with the scope of CIGRE SC A3 “High-Voltage Equipment”, WG A3.13 is studying the consequences of distributed generators on the equipment in the networks. With that in mind the distributed generators can be divided into two groups: (a) generators directly coupled to the grid, possibly through a step-up transformer, and (b) generators that are coupled by means of a full converter, probably through a step-up transformer. The directly coupled generators (a) can be synchronous or asynchronous machines, sometimes equipped with power electronic devices (the so-called double-fed induction generators DFIG) to control the rotor current (voltage control, slip, frequency for variable speed, reactive power output).

Due to the application of full converters, the latter group (b) is able to limit its contribution to fault currents, to support reactive power balance and voltage control, to better restore systems after disturbances, to better adapt to frequency variations, phase angle variations and voltage variations. Thus converters have an advantageous influence on the system behaviour and therefore on the requirements for other components. Besides the added costs, one main disadvantage is the generation of harmonics, although nowadays converter technologies and mitigation technologies show substantial improvements. The topic of power electronics will be dealt with later on.

As illustrated in Fig. 1, distributed generation in distribution, sub-transmission, and industrial networks leads to a structural change of the power flows, as the generated energy is mostly independent from the local energy demand. Changing power flows are of importance also for protection experts, as protection systems have to cope with the related currents and flow patterns. Short-circuit currents will show directions and amplitudes that are dependent on the operational mode of the distributed generators. In addition, in the DG systems (especially distributed windmills) the short circuit profiles along distribution feeders are different from those prevailing in the conventional systems with single source feeding. These different profiles could be difficult to understand intuitively and can impact the protection coordination and the short-circuit current withstand and interruption requirements for the related switchgear.

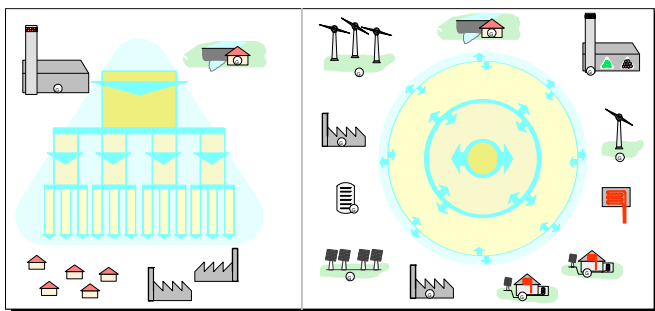


Fig. 1: Structural change of power flows in distribution grid

Many small power units use to operate in such a way that for any disturbance in the network, they are immediately switched off by a LV or MV circuit-breaker (after roughly 50 to 100 ms), thus enabling selective protection, auto-reclosing and fault location in the distribution grids and preventing out-of-phase conditions, unintended island operation, safety problems and severe damage to the power plants. However, more and more utilities put forward requirements that generating plants contribute to the stability of the network and remain connected for a certain period of time so that voltage sags can be limited in amplitude and duration, overloads are reduced and regional power deficits are avoided. The “ride through time” is specified as several hundreds of ms for smaller or special units up to more than 1 s for large conventional power units.

Power generating units are stressed at the moment of the short-circuit occurrence. Furthermore, these units are stressed again a few cycles later when they are switched off and the brake is applied (especially windmills). The generators which remain connected to the grid will accelerate due to the lack of load. Both frequency and phase angle will start to deviate from that of the main grid and some low inertia power generators, like for example aero-derivative gas turbines or modern windmills, will accelerate quite fast. Anyway, at the moment that the short-circuit is cleared by the relevant circuit-breakers, the small generators suddenly have to face the system frequency and system phase angle again. For synchronous machines, a relatively large out-of-phase current will flow between generator and the system,

leading again to high dynamic stresses, maybe even larger than the stresses due to short-circuit currents. This applies also to asynchronous generators and even to DFIG. The stresses have to be withstood by the HV-equipment as well, but the generator’s short-circuit or out-of-phase currents are normally smaller than system fed short-circuit currents. But, breaking the out-of-phase current is an optional duty for MV circuit-breakers[13][14] and its specification has probably to be re-considered [2].

A closer look into modern, larger (> 750 kW) windmills with doubly fed induction generators (DFIG) reveals that their behaviour during short-circuits is much more complicated. Their transient behaviour during and immediately after short circuits can vary considerably depending on the setting of the converter controls, including the setting of protection systems such as the crowbar switch across the rotor-side converter. On the other hand they show inherently a much better stability performance and fault ride through capability. The developments in these modern drive technologies is still rapid and general conclusions cannot yet be drawn although there is an inkling that their contribution to transient currents and voltages may in fact be favourable in comparison to that of conventional generators (less severe, but detectable, so that protection systems can still be selective). The main drive for these characteristics is the fact that the WEC (wind energy converter) itself will suffer less from system transients and can continue its operation.

Other transient phenomena related to DG are false switching operations in the vicinity of dispersed generation; such as accidental system separation or generator disconnection, false synchronisation of separate systems or generators (plus consequential tripping), network restoration and auto-reclosing under adverse conditions. Also power system instabilities (angular, voltage, or frequency instability) could lead to severe transient phenomena and consequential events. In this respect it should be stated that, due to the trend to work plant harder, it is expected that systems, including MV-networks with DG, are operated closer to the stability limits.

Measures to gain the profits from DG and to minimize its drawbacks for the network are with a clever optimization of protection settings, i.e.: no disconnection within the first protection zone in transmission networks (for instance: 200 ms), disconnect synchronous generators from faulty MV-lines before the auto-reclosing time, disconnect asynchronous generators with too low inertia constants from faulty MV-lines within auto-reclosing time, disconnect synchronous generators automatically under islanding conditions, disconnect asynchronous generators under self excitation conditions, etc [3]. However these measures are only feasible when short protection clearing and auto-reclosing times (100 ms to 200 ms) can be reached, which is normally not the case in MV-networks [2]. As stated before DFIG and generators connected through full converters should inherently be able to fully ride through fault conditions and supply power within a few cycles after fault disappearance.

Another issue of importance is safety concerns, such as: clearly de-energized and/or earthed parts of the network, reliable status-information on the generators through SCADA-systems, and interlocking functions where necessary. Furthermore functions as synchro-check, synchronisation, voltage check (auto-reclosing) and frequency check (islanding) have to be built in at the location of the HV/MV switchgear. These measures are more or less comparable with those for large power plants connected to transmission networks and serve to a large extent to protect the power plants. Together with the mitigation measures mentioned in the former paragraph and the requirements for more advanced and faster protection systems, this means that more intelligence and communication has to be incorporated in the HV-devices

Since traditionally passive (no power source) distribution networks become active, distribution circuit breakers may have to perform new duties, such as system separation, out-of-phase switching, synchronisation of generators and/or systems, etc. Such requirements are not so clear in the existing Standards for general purpose circuit-breakers, but in paragraph 4.2 of IEC 62271-100 an insulation level has been suggested for specific circuit-breakers with occasionally separate systems at both terminals [13]. Also out-of-phase switching is an optional duty in IEC 62271-100, seldom applied, but in the near future a larger number of MV-circuit-breakers might be subjected to this duty (depending on fault ride through requirements and the implementation of mitigation measures). Out-of-phase angles above 90° lead already to considerable peak values of the TRV[4]. Moreover the related RRRV (Rate of Rise of Recovery Voltage), as specified in the IEC-Standard, has to be taken from test duty T30S [19], meaning that a class S circuit-breaker (directly connected to a step-up transformer) has to be specified [2]. IEC TC 17A/C has accepted the IEEE Standard on generator circuit-breakers C37.13 [16], where for special applications the above requirements are covered. In both the Standards and the Application Guides users have to be attended at the above requirements for HV switchgear that may face out-of-phase and system separation events. Furthermore utilities are looking for guidance to support them in specifying appropriate short-circuit current withstand and clearing requirements [5][6], more comparable to those of industrial and off-shore plants.

### 3. Long Distance Transmission

When active power is transmitted over very long distances, reactive power compensation is required in order to keep voltage profiles along transmission lines within acceptable operating voltage range for various load-flow conditions. The following equipment can generate or absorb reactive power: shunt-capacitor banks, shunt-reactor banks, generators in leading/lagging modes, synchronous condensers, series-capacitor banks, series reactors, transformers, cables, lightly/heavily loaded lines, Static VAR Compensators (SVC), HVDC converters, FACTS, and variable Mvar reactors [7].

Shunt compensation is applied in meshed networks as well as in long radial transmission systems. Due to the unbundling between power generation and power transmission, the power plant locations are in many cases not optimal from the transmission network point of view. Consequentially a structural mismatch of reactive power and need for reactive power control becomes evident in almost all HV-grids. With the increased application of other reactive power compensation equipment, there is a demand for highly reliable circuit-breakers to switch shunt capacitor banks or shunt reactors on a daily basis or even more frequently. The test procedures prescribed in the IEC 62271-100 for capacitive current switching and in the IEC 62271-110 for small inductive current switching [21] should be rigorously applied to reflect the most frequent operational duties. Additionally there will be a significant increase in the application of controlled switching devices (point-on-wave) in order to avoid high switching overvoltages or inrush transients during shunt-reactor or shunt-capacitor switching. In recent years CIGRE WG A3.07 recommended special test requirements for circuit-breakers with point-of-wave controllers [20].

The reactive power compensation in series compensated systems is created by series-capacitor banks that are located along transmission lines, preferably in the substations at the end of long line sections. In most applications fast re-insertion of SCs is required for the effective up-rating of transmission angular stability. Instantaneous re-insertion is achieved by protecting SCs against transient overvoltages by means of adequately rated metal-oxide varistors (MOV), supplemented by a forced triggered spark-gap and a by-pass circuit-breaker; Fig. 2. Adverse effects of series compensation can be mentioned: special requirements for line protection relays, sub-synchronous resonances (SSR), the increase of switching overvoltages (SOV) along transmission lines and the increase of transient recovery voltages (TRV) imposed on the line circuit-breakers. Special requirements, beyond the Standards, are put forward to cover the stresses anticipated in series compensated systems. The requirements are specific per application of series compensation and within CIGRE WG A3.13 experts try to compile an overview of the international practices, in order to look for possibilities for harmonisation and the exchange of experience [18].

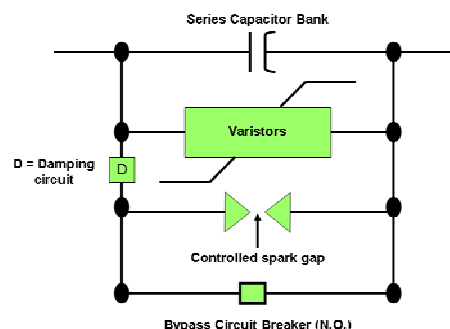


Fig. 2: basic components of a series capacitor bank

In the case of long distance transmission, extreme disturbances can cause a loss of synchronism with distant generating centres, leading to system separation and to full load rejection by simultaneous opening of several line circuit-breakers under loss-of-synchronism or out-of-phase conditions. Following full load rejection, TOV due to the Ferranti effect appear on long unloaded lines that are still connected to generators. Special TOV protection schemes consist of the fast removal, after full load rejection, of unloaded lines from generators. Therefore, line circuit-breakers should have adequate TRV withstand capability for switching unloaded lines under high TOV conditions. Again utility experts come with specific requirements for their HV equipment (circuit-breakers, arresters, special switching equipment, switchable MOA [10], controlled switching, protection and interlocking systems [17], instrument transformers, OH-line insulation, etc.).

Additional topics such as higher than rated operating voltages, transient overvoltages, out-of-phase conditions, switching duties on long lines and mitigation measures are under study within CIGRE WG A3.13 and results will be released at the CIGRE SC A3 Session 2006. Within the scope of another CIGRE WG A3.19 is the specification of the TRV caused by faults on long lines, where triangular wave shapes similar to those of the short line fault (SLF) are generated, but with a much higher peak value and lower frequency [12]. Conclusions and recommendations for both single phase and three-phase faults are in preparation.

Another special topic to be addressed under long distance transmission is that of long compensated AC-cables. EHV/UHV cables with a length of several tens of km will normally need shunt reactors, preferably with variable Mvar absorption capacity, to compensate the reactive power generated by the cables. Several articles have been published on the interaction of compensated EHV-cables with the series connected OH-lines and/or the surrounding network. Phenomena like harmonic resonance and sustained secondary arcs have been reported. Third harmonic resonance for example could build up due to the strong reduction of the system's Eigen frequency, as caused by the large capacitive cables. Saturation effects of transformers or shunt reactors can lead to severe temporary overvoltages (TOV), for instance when energizing an unloaded mixed EHV-line [8]. Harmonic overvoltages, large secondary arc currents and ground return currents with or without countermeasures put forward requirements for additional and/or special HV-equipment (for instance: heavy duty arresters, high-speed grounding switches, additional circuit-breakers, neutral reactors, etc.).

A component also related to long distance transmission is a phase shifter or quadrature booster (QB). The main reported transient phenomenon is the behaviour of QB's under unbalanced fault conditions. In either 'buck' or 'boost' mode the QB relies on a balanced three-phase system to function properly since the method of operation utilises two phases to energise the third phase. Consequently, for a single-phase fault at the terminals, very large voltages can appear on un-faulted phases of the QB. These appear transiently during the

circuit-breaker trip sequence on the QB circuit as the currents in each of the QB phases are interrupted.

During three phase interruption of a single-phase fault to earth on the series terminals of the QB, and depending on the characteristics of the circuit-breaker, it is probable that the faulted phase will be the last to clear. This imposes a voltage of 1pu across the QB series winding, causing the voltage on the two un-faulted phases to rise (approx. 2.5pu), as a result of the coupling between the series and shunt transformer. The remaining energised phase of the shunt unit can further contribute to the total voltage seen on the un-faulted terminals, resulting in a transient over-voltage of up to 4 or 5 pu [1].

The effect is non-linear, meaning that even tap positions adjacent to the centre tap can contribute to very large voltages on the QB during single phase to earth faults. Unless the QB is at centre tap the voltage applied at the QB terminals is excessive (beyond the insulation level) and can only be controlled by the use of surge arresters. Because the duty is severe, high-energy surge arresters must be fitted to both sides of the QB. Another solution may be found in special protection schemes with single pole tripping.

QBs have special requirements as regards dielectric tests and withstand capacity to the short circuit electro-dynamic stresses, which make their design complicated [22].

#### 4. Power Electronics

Power electronics normally offer a lot of flexibility, controllability and a smoothing effect in terms of overcurrents and overvoltages in the network. Unless pulse width modulation (PWM) or an equivalent technology is applied, a negative impact is the distortion of voltages and currents due to the generation of harmonics, giving an adverse effect on power quality. Power electronic devices themselves are also vulnerable to power quality, over-currents, over-voltages, short-circuit currents and transients.

The level of distortion in the system voltages can be reduced by the application of harmonic filters. However, filter banks and filter-bank switching are not covered by the Standards [13][14]. All equipment within a filter-bank is subjected to a high content of harmonic currents and is to be specified accordingly.

With a high percentage of harmonic distortion, especially at the lower harmonics, the currents may show more than two current zeros per power frequency cycle. In this way the breaking of the current might take place earlier than at the regular power frequency current zero but as a filter-bank behaves mainly as a capacitor-bank, current interruption at an instant not corresponding exactly to voltage maximum will lead to lower trapped charges (DC-voltages) on the filter-bank (capacitor-bank), thus reducing the dielectric stresses at current interruption. On the other hand, compared with switching off a regular capacitor-bank, for filter-banks the circuit-breaker TRV will show harmonic voltages superimposed on the normal TRV resulting in a higher

overall TRV<sub>peak</sub>. In addition it is also possible that voltage resonance occurs at the busbar, controlled by the filter-bank to be switched. Another phenomenon to be considered is that of switching off of a reactor in series with the capacitor-bank (as in a filter-bank) causing a positive voltage jump and thus a higher peak value of the recovery voltage. A third issue to be considered is that, especially with HVDC applications, load shedding or blocking of the converter may occur. Through the Ferranti effect TOVs might occur lasting up to 1s, depending on the automatic voltage regulation (AVR) of nearby generators, or up to tens or hundreds of seconds, depending on transformer tap-changer actions [9]. During TOV condition the reactive power compensation, including the filter-banks, should be switched off, again leading to a higher than normal TRV.

To verify the breaking capacity of a circuit-breaker, the following statements can be accepted. The harmonic content of the filter-bank current does not impact the breaking performance of a circuit-breaker, especially of modern technology, due to the short physical time constants of the arc (the same phenomenon allows for the current injection as applied at synthetic tests in power labs). However, the superimposed harmonic components in the recovery voltage might be relevant during the first milliseconds after interruption. Nevertheless, as many circuit-breakers are designed to withstand the RRRV of short-line fault tests, it is expected that the initial part of the TRV at filter-bank switching is not critical (at least at somewhat longer arcing times).

With respect to the peak-value of the TRV, the harmonic component in the recovery voltage, plus the other phenomena (positive voltage jump, TOV, possible resonance) can be ascertained after proper system studies and the applicable TRV envelope can be defined. Then, (a) the calculated peak value can be compared with the performance of the circuit-breaker under purchase or (b) the circuit-breaker can be tested for the higher peak-value or (c) a circuit-breaker with a higher rated voltage can be chosen or (d) special measures can be taken e.g. MOV parallel to the arcing chambers. Test circuits are available to verify circuit-breaker performance under filter-bank switching conditions and the phenomena described are most pronounced in the first pole to clear [11].

Filter-banks should be switched by switchgear with a very low probability of re-strike. The distortion of the filter-bank current will not be a problem, but the recovery voltage will be (slightly) higher than that at switching regular shunt capacitor banks, as specified in the IEC Standard [13]. Furthermore, circuit-breakers with a high class of mechanical endurance (M2) are necessary and it is recommended to apply controlled switching, if available [1].

Note that power electronic converters are expensive so that they are not oversized and their ability to withstand conditions beyond their rating is very limited. Moreover, an important reason for a converter to limit its short-circuit current contribution is to protect itself. Moderate

overcurrents and overvoltages exceeding the design capabilities will quickly destroy the power electronics. Although for the primary equipment the limitation of fault currents can be regarded as an advantage, for system protection it normally is a disadvantage. To that effect, CIGRE WG A3.16 (Fault Current Limiters) is studying the interaction between protection systems and current limiting devices.

Another remark to be made is that the transient behaviour of converters is to a certain extent also determined by the process behind the converter, certainly when active power is involved. Sometimes the electric power generation technology behind the converter reacts far slower than the reaction time of the power electronic devices, thus limiting the inherent good performance of the converters. Fuel cells, for instance, are reported to give the effect of very slow responses to transients in the network, thus eliminating certain advantages of the converters. This however, is more a problem for system studies than for the interaction between systems and HV-equipment.

The increased injection of harmonics from LV-grids into MV and HV-networks is a problem of power quality and is more related to the vulnerability of the same sort of LV-equipment as the equipment that generates harmonics. For the HV-equipment in the distribution and transmission networks it is not (yet) regarded to form a problem, apart from the equipment used in filter banks and for filter bank switching as described before.

## 5. Conclusions

Networks are going to be operated at their limits with regard to loading, means of operation, geographical extensions and stability criteria. The physical effects as e.g. dynamic behaviour of generators and TRV due to long line switching, are well-known for a long time, but the consequences are now becoming realistic because of the increased DG as well as long distance transmission projects. Measures to mitigate or reduce these effects and adaptation of the Standards and Application Guides will be necessary. Utilities are looking for guidance and harmonisation of their specific requirements.

Specific topics mentioned are:

- Load current and short-circuit current profiles in networks with DG change with respect to flow, amplitude and variation. Consequences for involved HV-equipment are evident.
- In case of transients, immediate disconnecting of DG will limit the special requirements for HV-equipment only to the withstand capability of short-circuit peak values.
- Fault ride-through requirements will have an impact on the specifications of circuit-breakers, that have to be able to withstand and switch under out-of-phase conditions, synchronisation, and islanding. IEEE C37.13 or IEC 62271-100, class S, are **recommended** for such

applications; the dielectric withstand capability should be **adapted** and **more guidance** to users is needed.

- The impact of transients is, relatively speaking, larger on dispersed power generating units than on the network and its HV-components. **Countermeasures** such as a clever application of advanced protection schemes, as illustrated, are therefore preferred.
- It is expected that new technologies like DFIG will relax the phenomena described.
- Filterbanks require **specific requirements** for the peak value of the TRV. Controlled switching is recommended for frequent switching duties of filter- and shunt compensation banks and **adequate test specifications** are needed.
- Series compensation, loss-of-synchronism, switching under TOV or high operating voltage conditions, long compensated EHV-cables still require **special attention** for each individual case. Attempts are made to come to an overview of practices and to some **harmonisation** of solutions and specifications for HV-equipment.

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## **Appendix E**

### **LONG DISTANCE AC POWER TRANSMISSION AND SHUNT/SERIES COMPENSATION OVERVIEW AND EXPERIENCES**

**Report presented at the CIGRÉ SC A3 Session 2006  
Report A3-206**

**LONG-DISTANCE AC POWER TRANSMISSION AND SHUNT/SERIES COMPENSATION  
OVERVIEW AND EXPERIENCES**

**Q. Bui-Van F. Gallon F. Iliceto A.L.J. Janssen<sup>o</sup> B. Middleton M. Waldron  
CIGRE WG A3.13**

***SUMMARY***

Within SC A3 “High-voltage Equipment”, the scope of CIGRE WG A3-13 “Changing Network Conditions and System Requirements” is to investigate the impact upon substation equipment of recent network developments. Such developments include dispersed generation, long distance transmission of power, reactive power compensation/voltage control, power quality issues, power electronics and the study has to cover both their degree of expected penetration and the severity of their influence. From the point of view of HV-equipment the necessity for future adaptations of the standards will be considered.

WG A3.13 has presented its view with respect to the development and impact of dispersed generation, power quality and power electronics on conventional HV equipment in two articles [1][2]. This report presents the equivalent views of the WG regarding developments in long and very long distance transmission and the associated impact upon HV AC equipment.

After introducing the developments such as multiple power transfers across countries and across borders, unbundling and liberalization, long distance and very long distance power transfers, further utilization of power transmission corridors and utilization of overloading capacity, technologies as mixed insulated cable/OH-line sections (shunt-compensated cables), series compensated OH-lines and half-wave length lines (HWLL) are considered.

In the report the temporary overvoltages, which are more prevalent with long transmission lines (load rejection, system separation, ferroresonance, resonance and HWLL), transient overvoltages (energization of OH-lines/shunt capacitor banks/transformers/reactors, re-strikes, re-energization and fault clearing), transient recovery voltages (fault clearing, series compensated lines, de-energization of un-loaded lines, out-of-phase switching, HWLL) and transient currents are addressed. There is also a brief summary of the technology of, and service experience with series capacitor banks. To FACTS, including phase shifting transformers and variable shunt reactors, will be referred shortly.

In a CIGRE Technical Brochure, to be issued in 2006/2007, the topics mentioned in this and former publications will be dealt with in a more extensive way.

**KEYWORDS**

Long distance transmission, shunt compensated OH-lines, series compensated OH-lines, half-wave length lines, shunt compensated cables, TOV, transient overvoltages, TRV

**ACRONYMS:** *see Appendix*

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## 1. CHANGE OF NETWORK CONDITIONS

The privatisation and liberalization of the electric energy sector has considerably increased interregional and international energy transactions and created a greater need for large power transfers over long distances. In the meshed EHV grids, in particular in Europe and North America, long distance power wheeling takes place. This technique, referred to as “multiple transfers”, is in some cases used up to its capability limits and relies upon the synchronous generators of the power plants in operation along the transmission route to maintain angular and voltage stability. Multiple transfers may take place across various countries/regions on distances spanning up to 2000km from the power export areas to the remote importing areas.

Unbundling and liberalization of the electric energy industry has also caused a more intensive use of some of the point-to-point long EHVAC and EHVDC transmission systems, raising power transfers to the upper limit of transmission capabilities, in some cases with detriment of transmission reliability (violation of the (N-1) or (N-2) security requirement). The use of line/systems up to, and sometimes above their secure transmission capacity, has been the root cause of some recent major blackouts in industrialized countries.

More use and reliance on transmission has been caused by the liberalization of power generation and by the growing environmental restrictions for the construction of new power plants and new transmission lines. In several cases the independent power producers have located their new thermoelectric power plants, to be fired with imported fossil fuels (gas, coal, fuel oil), in places remote from the loads to be served, or far from optimal locations as regards transmission. In a few countries, the construction of large wind farms has also required transmission along relatively long distance and the need to provide new transmission and generation reserve capacities in order to face the volatile patterns of generation inherent to operation of large wind farms.

The higher power transfers have increased the stresses on transmission components, which in critical regions are required to continuously operate at the maximum permitted voltages and/or currents, and sometimes above these limits. This may cause, in particular, stresses on EHV CBs exceeding the values stipulated by the IEC Standards as regards overvoltages, arcing conditions and TRVs.

In spite of the installation of many phase shifting transformers and/or of some SCs for directing properly the power flow in critical transmission lines, several interconnection lines are loaded not far from their thermal limit in normal operation and happen to be overloaded in emergency conditions. In order to utilize the temporary overloading capacity of transmission line conductors (often for 15 to 60 minutes before reaching the limit temperature) an overload protection based on monitoring of conductor temperature becomes recommendable, to replace the current overload protections by distance and overcurrent relays (tripping too fast, generally in less than 3 seconds).

On the other hand, the increase of power transfers over long distances on existing transmission lines does not allow for erosion of transmission reliability which might result. In fact, the increased automation of industry and higher continuity of supply required by the tertiary sector, by electric driven transports and by the domestic and commercial sectors, demand an improvement of power quality, i.e. limitation of number and duration of supply interruptions, reduction of number of voltage dips, improved voltage regulation, limitation of harmonic distortion and of voltage asymmetry in 3-phase supplies. Upper limits to these quality indexes have been stipulated by the Regulators in various countries, including also penalties to be paid to the customers in case of violation.

To face the changing transmission network conditions, multiple actions are required, including technological improvement and reduction of failure rates of high voltage equipment, use of new components (FACTS), improvement of monitoring, automatic control and protection systems, use of Special Protection Systems, efficient maintenance, etc.

The economically exploitable hydroelectric resources and lignite fields have been fully utilized in many countries with electric power transmission over distances up to 1000km and, in some cases, with EHVAC series-shunt compensated lines and EHVDC transmission lines spanning on distances up to about 1500km and 1800km, respectively. The ever increasing cost of economically transportable fossil fuels (gas, oil, high quality coal) and the restrictions on use of nuclear power will in future make attractive the bulk electricity transmission on longer distances from large economic hydroelectric and lignite resources. Pre-feasibility studies of some very long distance (up to 3200km) transmission projects have been performed in the last decade. Some typical examples can be mentioned:

- (vii) From Inga Falls (Republic of Congo) to South Africa (~ 3000km).
- (viii) From Inga Falls to Nigeria (1550km) extended with multiple transfers to Western Africa (up to 2500km).
- (ix) From the Amazon River Basin to South-Eastern Brazil (~ 2500km).
- (x) From Central Siberia to European Russia (~ 3000km; 4 independent projects on different routes)
- (xi) From Western Siberia to Eastern-Central Europe (~ 3200km); from Central Siberia to China (~ 2700km).
- (xii) From Eastern Siberia to South Korea (~ 2500km).

The technologies considered for these prospective projects are the following:

- EHV–UHV HWLL AC transmission (naturally tuned on distance of 3000km at 50Hz and of 2500km at 60Hz): projects (iv) at 50Hz; AC alternatives for projects (i) and (v) at 50Hz and for projects (iii) and (vi) at 60Hz.
- EHV-UHV DC transmission, a technology that has no specific distance limits. DC alternatives for projects (i), (iii) and (vi).
- EHVAC transmission lines compensated with SCs and SRs. Project (ii) at 50Hz.

The technically acceptable upper limit of compensation with SCs is considered to be 75% for lines transmitting power from remote hydroelectric power plants. By considering these lines loaded at SIL, the upper limit of point-to-point transmission distance with series-shunt compensated lines is about 2000km at 50Hz.

Congestion of infrastructures, for instance in Europe and Japan and strong demand of environment conservation may justify the use of long stretches of EHVAC XLPE insulated underground cables, in some cases in non-urban areas, in particular on the new planned crossborder motorway or railway tunnels (about) 65 km long between Austria and Italy, requiring a large shunt compensation. These cable stretches may be solidly connected to overhead lines, to form mixed cable-overhead lines, whose design and operation have special technical features.

## 2. TEMPORARY OVERVOLTAGES (TOVs)

In general, TOVs in an AC power transmission system can originate from faults, switching operation such as load rejection, resonance, ferroresonance conditions or a combination of these.

### 2.1 TOV following a full load rejection

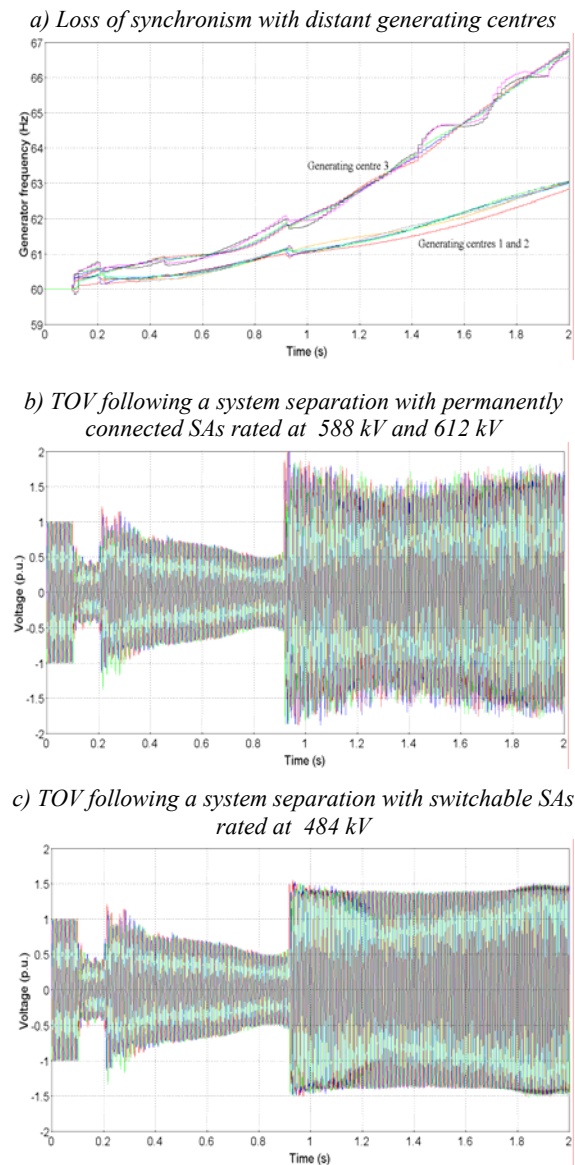
Large TOVs due to the combination of: earth faults, Ferranti and transformer saturation effects as well as generator overspeed following a full load rejection, can occur on long distance AC power transmission systems. These TOV are particularly severe for equipment in long distance radial systems. As illustrated in Fig. 1a, an extreme disturbance in the 735kV series-compensated system in Canada, which includes several transmission corridors of 1000 km length, can cause a loss of synchronism with distant generating centers, leading to a full load rejection by the simultaneous opening of several line circuit breakers under out-of-phase conditions [3].

Following a system separation, large TOV appear on long unloaded lines that are still connected to generators. These TOV could reach protective levels, typically 1.9 p.u. to 2.0 p.u., of permanently connected SAs rated at 588 kV and 612 kV and be maintained on system equipment as long as the unloaded line are still fed by generators (Fig. 1b). Although these events are infrequent and beyond the normal design criteria regarding the system transient stability, equipment should be protected against excessive and prolonged TOV in order to prevent damage to strategic equipment and to ensure a rapid system restoration following a major disturbance.

The use of switchable 484 kV rated SAs (having a residual voltage of 1.6 p.u. at a 1000  $\mu$ s discharge current) in combination with the fast removals of unloaded lines from generators by overvoltage protections would allow a reduction of the magnitude as well as the duration of TOVs (Fig. 1c). As a consequence, line CBs in this system should

Fig. 1: TOV following a full load rejection in the 735-kV series compensated system in Canada

$$1 \text{ p.u.} = 735 \sqrt{3}/\sqrt{2} = 600 \text{ kV-peak } \Phi\text{-to-Gr}$$



have adequate TRV withstand capabilities for line opening under out-of-phase conditions and for unloaded line switching under high TOV.

Similar examples can be given for long distance radial series-compensated transmission like for instance the 500-kV systems in Vietnam [4], Chile [5] and BC-Hydro. In the Turkish 420 kV long distance transmission system the following countermeasures to load rejection at receiving end have proved to be efficacious in all events since the early 1970's: (1) automatic switching-on of 420 kV SRs initiated by local overvoltage relays (generally set at 440 kV with time delay of 2s); (2) fast disconnection at sending end of unloaded lines by transfer tripping.

## 2.2 Ferroresonance

The following ferroresonance phenomena are on record from ATP-EMTP analysis and from operation experience of HV-EHV transmission systems operated with solidly grounded neutral:

- (vii) One open phase during the dead time for SPAR in lines with neutral grounded SR connected to the terminals. One or two line open phase(s) may occur due to stuck CB poles or irregular operation of the control circuits. Following selfextinction of the secondary arc current, ferroresonance may occur between the coupling capacitances of open phase with the energized phases and the saturable inductance of SR(s). The TOVs may be considerably limited by the corona phenomenon and depend on the following parameters: lines shunt compensation degree; saturation level and V-I characteristic of SR(s); onset voltage of visible corona on line conductors; presence of parallel circuits on same right of way or tower. Overvoltages in the range of 1.4 to 2.5 p.u. phase-to-Gnd and in range of 2.4 to 3.5 p.u. across open contacts of line CBs have been calculated for the 420kV grid of Turkey [6]. The build-up time of the open-phase(s) overvoltages is 40 to 60ms.
- (viii) Series compensated line terminated in an autotransformer or SR. The rare ferroresonance phenomenon was ignited by a short circuit or by line energization.
- (ix) Opening of one phase in a transformer feeder, i.e. an HV line connected to an un-loaded or lightly loaded step-down transformer. The ferroresonant circuit is formed by the coupling capacitances with the energized phases and the magnetizing inductance of transformer.
- (x) Opening of one circuit of a double-circuit HV transformer feeder. The open circuit becomes energized via the mutual capacitances with the other circuit. Ferroresonance may occur if transformer is un-loaded or lightly loaded
- (xi) A case of parallel ferroresonance on even harmonics (2<sup>nd</sup>, 4<sup>th</sup>) was reported when a 500kV line was energized from a busbar supplying an un-loaded autotransformer.
- (xii) In a solidly grounded neutral network, if a line terminated in a delta connected un-loaded or lightly loaded transformer undergoes an open phase at sending end, ferroresonance may build up between the zero-sequence capacitances of the open phase and the magnetizing inductance of transformer.

Overvoltages (i) might damage SAs, SRs and CBs; the secondary arc re-ignition may render unsuccessful the line SPAR. Countermeasures are the following: (a) consider the risk as negligible if so addressed by analysis of the overvoltages with ATP-EMTP; (b) apply SRs provided with neutral reactor; (c) trip the CB pole of SR phase connected to the faulty phase of the line at the same instant as the faulty phase is tripped by the OHL CB; reconnect automatically the SR phase 2-3s after the successful SPAR of the line (it is assumed that SR has equal zero-sequence and positive-sequence reactance).

The ferroresonance phenomena (iii), (iv) and (vi) can be eliminated by providing the transformer with a CB and protection circuits disconnecting it instantaneously when an open phase or open circuit on transformer feeder is detected. Modern SCs are provided with relays which detect the harmonics caused by a ferroresonance phenomenon as (ii) and by-pass the capacitors.

## 2.3 Resonance due to mixed cable-OH-lines

Long EHV shunt compensated insulated cable lines, and mixed lines consisting of long cable sections in series with OHL sections, may undergo large long duration no-load energization overvoltages due to resonance at low-order harmonics. Resonance natural frequencies in transmission networks composed of OHLs are in general quite high. The equivalent impedance is inductive, of increasing value, for frequencies usually up to at least 300-400Hz. The behaviour is substantially different in presence of long cables, whose large capacitance causes low resonance frequencies of the network, in some cases in proximity of the third harmonic [7].

Analysis has shown that the cable no-load energization can initiate TOVs causing saturation of SRs and generation of large harmonics, superimposed on the fundamental and Dc components. High harmonic distortion and overvoltages then build-up if the network is resonant at such harmonic excitation.

ATP-EMTP analyses have been performed for the 400kV, 66km long, 50Hz XLPE insulated cable line considered for installation in a crossborder tunnel of the Alps. The cables are assumed to be 100% shunt compensated with

SRs, half connected at each terminal. The open ended cable line with the associated SRs has an equivalent reactance virtually infinite at 50Hz. At 150Hz, it becomes  $-j64 \Omega$  and it is in resonance with the equivalent reactance of the network if the energizing 400kV busbar has a short circuit power of 7500 MVA. Fig.2 shows, in this condition, the max. no-load energization overvoltage calculated in a statistic study (1000 energizations). This overvoltage is of long duration (as long as the inrush currents). These TOVs stress SAs and protective equipment; energy dissipation in SAs may exceed their capacity. Fast Fourier transform analysis shows that the phase-to-Gr overvoltages are due mainly to the 3<sup>rd</sup> harmonic components, as a result of the resonance.

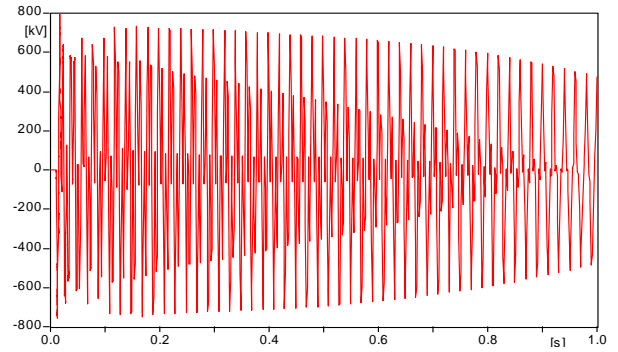


Fig.2: Phase-to-Gr no-load energization over-voltage of a 400kV - 66km cable line in T phase at energizing bus. SAs connected at cable terminals are simulated.

#### 2.4 TOV due to faults in HWLLs

The main features of HWLLs are recalled here for convenience of readers not familiar with this subject. A lossless HWLL (3000km at 50Hz; 2500km at 60Hz) has the following transmission coefficients:  $\mathbf{A}=\mathbf{D}=1$ ;  $\mathbf{B}=\mathbf{C}=0$ .

Let  $V_s$ ,  $V_r$ ,  $V_{mp}$  and  $I_s$ ,  $I_r$ ,  $I_{mp}$  be the sending end, receiving end and mid point voltage and current phasors of the HWLL, respectively; let  $Z_0 = \sqrt{l/c}$  be the line surge impedance. The following simple steady-state operation equations are arrived at [8]:

$$V_r = -V_s; I_r = -I_s; I_{mp} = V_r/Z_0; V_{mp} = Z_0 I_r.$$

The equivalent circuit of the lossless HWLL ( $\lambda/2$ ) is formed (fig.3) by two cascade connected T equivalent circuits of a quarter wave length lossless line ( $\lambda/4$ ).

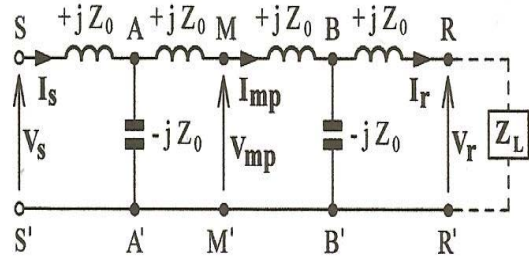


Fig. 3: Equivalent circuit of a lossless HWLL

The equations and figure prompt the following main operating features of the lossless HWLLs:

- HWLL transfer impedance and shunt admittance are nil ( $B=C=0$ ). Voltage and current at sending and receiving end have the same rms values and are in phase opposition.
- Voltage in the central part of HWLLs varies in proportion to receiving end current, i.e. to load for assigned voltages at line ends:  $V_{mp} = 0$  at no load;  $V_{mp} = V_s = V_r$  at SIL;  $V_{mp} = 2V_s = 2V_r$  at  $2xSIL$ ;  $V_{mp} = \text{infinite}$  with the receiving end short circuited ( $V_r = 0$ )
- The mid point current  $I_{mp} = V_r/Z_0$  is constant irrespective of line loading if  $V_r = V_s$  are constant (say, rated voltage).
- The HWLL does not produce or absorb reactive power, regardless of line load; there is no Ferranti effect and no risk of self-excitation of synchronous generators as long as frequency is regulated at rated value. A lossless HWLL is equivalent in principle to a short line from the transmission stability point of view ( $B = 0$ ;  $\delta = 180^\circ$ ).

If the HWLL is analysed by simulating the ohmic resistance of conductors and neglecting the corona losses, the calculated temporary overvoltage at mid point caused by a 3- $\phi$  short circuit at one line end exceeds 10 p.u. In reality it has been demonstrated [8] [9] that the corona losses heavily load the central part of the line when the onset visible corona voltage is exceeded. This phenomenon and, to a much less extent, the consequential variation of conductor line-to-Gr capacitance, causes a drastic reduction of the TOVs and also sets-up a limit to the transmissible power as regards transient stability.

However TOVs are still high during faults in the HWLL and in the sending and receiving end systems, if faults occur in locations not far from either end of the HWLL. The higher the visible corona onset voltage, the higher are the overvoltages. The EMTP simulation with a corona model based on published measurements on large conductors with gradients up to 60kVrms/cm, has provided the following TOVs for an 800kV-50Hz-3200km long HWLL with visible corona onset voltage of 1.30p.u. (1p.u. =  $800\sqrt{2}/\sqrt{3}$ kV) (conductor capacitance variation due to corona is not considered):

- (iv) 3- $\phi$  short circuit at 2600km from sending end: 2.93p.u.; 3- $\phi$  short circuit in the 400kV receiving systems: 2p.u
- (v) 1- $\phi$ -to-Gr short circuit at 2200km from sending end: 1.95 p.u.
- (vi)  $\phi$ -to- $\phi$  and  $\phi$ -to- $\phi$ -to-Gr short circuits: intermediate values between cases (i) and (ii).

Maximum TOVs of 2.7p.u. and 2.2p.u. have been calculated for 800kV – 1050kV, 60Hz, 2500-2700km long HWLLs, for the most unfavourable 3- $\phi$  and 1- $\phi$ -to Gr short circuits, respectively. These TOVs may control the design of HWLL insulation.

### 3. TRANSIENT OVERVOLTAGES

IEC 60071[21] divides transient overvoltages into (1) SFO due to normal switching operations such as line energization and re-energization, switching inductive and capacitive currents, faults and fault clearing; (2) FFO due to lightning, flash-overs, re-ignitions and restrikes at a short distance; (3) very-fast-front overvoltages (disconnecter operations and faults within GIS). The time to overvoltage peak are respectively 20 to 5000 $\mu$ s; 0,1 to 20  $\mu$ s and less than 0,1  $\mu$ s.

#### 3.1 Transmission line energization and automatic high-speed reclosure

There is a vast literature and field experience on switching overvoltages of OHLs and on most of the applicable means for mitigation. The no-load energization of OHLs causes overvoltages  $\leq 3$  p.u.. Many utilities design the OHLs of rated voltage up to 420kV with a 3 p.u. high probability ( $V_{50\%} + 3\sigma$ , or 99.86% in Gaussian approximation) SIWL. With this approach, the only applied overvoltage mitigation measure is specification of the pole-discrepancy for closing of CBs to be less than 5 ms.

OHLs of rated voltage of 500kV and above are usually designed with lower p.u. SIWL and require means for limitation of the energization overvoltages. The following means have been applied (p.u. overvoltage limitation is given in bracket):

- Closing resistors ( $\leq 2.0 - 2.2$  p.u. with 1 resistor step;  $\leq 1.5 - 1.6$  p.u. with two steps);
- Synchronizing of pole closures at busbar voltage zero ( $\leq 2.0$  p.u.);
- (SAs with adequate energy absorption capacity ( $\leq 1.7 \div 2.2$  p.u. according to SSPL of SAs);
- Staggering of poles closure of line CB ( $\leq 2.4$  p.u.).

SRs, if available, are usually preconnected to the line (preferably, at receiving end) before energization and limit both the temporary and transient energization and re-energization overvoltages.

The overvoltages caused by the SPAR are usually  $\leq 2.4$  p.u. (up to 2.7 – 3.0 p.u with very unusual line and grid configurations). In any case they do not exceed the no-load energization over-voltages if the above listed limitation means are applied. The line TPHSR may cause overvoltages up to 3.8 – 4 p.u., if no mitigation measures are applied. The following limiting means can be used:

- Inductive type PTs connected at the line terminals: these PTs discharge the line in the dead time (usually 0.5s), if no SR is connected to the line. The TPHSR overvoltage is practically reduced to the case of no-load energization;
- SAs connected at line terminals, which limit overvoltages within about the SSPL of SAs;
- Synchronizing of pole closure: if made when voltage across contacts of each pole of the CB is close to zero, overvoltage is  $\leq 2$  p.u..

Measurement of trapped charge (DC) voltage requires special apparatuses, usually not available in substations. Practical solutions are the following:

- if the line has SRs, close each pole when the oscillatory discharge voltage beat on line side of the relevant phase is minimal [17];
- if SR(s) and/or inductive type PTs are not available, synchronize the poles reclosure of non faulty phases at peak (or 50% peak) of busbar voltage with same polarity as trapped charge; polarity is determined to be the same as phase voltage at instant of current interruption; faulty phase(s) can be reclosed when busbar voltage(s) is (are) nil. By assuming a scattering of CB pole closing of  $\pm 1.5$ ms, TPHSR overvoltages are  $\leq 3$  p.u..
- Use of closing resistors: with 1 step resistors, overvoltage is  $\leq 2.5$  p.u.

#### 3.2 Switching of shunt capacitor banks, transformers and shunt reactors

Switching on of shunt capacitor-banks gives a severe voltage dip, followed by a voltage overswing with the natural frequency of network and capacitor (typically 300 to 900 Hz). Switching overvoltages are up to 1.6 p.u., but power frequency voltage magnification may give much higher overvoltages (for instance at remote capacitor-banks, at open ended lines, at radial fed transformers, by capacitive coupling between transformer windings) [11]. Under such circumstances uncontrolled energization presents an unacceptable risk of system flashover so that measures as pre-insertion resistors, series reactors or controlled switching are necessary. The topic of overvoltage protection by means of SAs is a complex one, considered in detail in [12].

CBs are specially designed to interrupt capacitive currents at a minimum probability of restrikes. In case of a restrike the shunt capacitor bank is energized again while it is still charged with an opposite voltage. The FFO may show amplitudes twice as large as the SFO described above; and even more in case of multiple restrikes. It is therefore strongly recommended to apply only CBs with a very low probability for restrikes, notwithstanding the fact that manufacturers of EHV and UHV CBs have difficulties to proof this performance. Besides – and not as a substitute – controlled switching is recommended [13].

The energization of large power transformers from outer winding leads to high inrush currents (up to typically 4 p.u. maximum) that are rich in harmonic content, and lead to temporary rather than transient overvoltages, with transient peaks up to 2.0 – 2.5 p.u.. SRs can be designed such that the inrush current does not exceed 2.8 – 3.0 p.u.. The interruption of transformer magnetizing current is normally not a problem, but at switching off shunt reactors current chopping will occur. High SFO may be produced depending on the amplitude of the inductive current at the moment of chopping. The SFO and the FFO in case of restrike are dangerous for CBs and SRs. Mitigation measures such as MOSAs and controlled switching are necessary.

### 3.3 Transient overvoltages due to fault clearing

Line/substation fault clearing could also produce high SFO along series compensated lines. In general, the magnitudes of these transient overvoltages vary depending on: line lengths, rated characteristics of SC, fault types, fault locations as well as the location(s) of SC along the line. Records of annual fault occurrence in the 735 kV series-compensated system in Canada show that 90.2% of faults are 1- $\Phi$ -to-ground and totally 9.8% are 2- $\Phi$ /3- $\Phi$  faults [14].

Concerning the clearing of 1- $\Phi$ -to-ground faults, for the case of a 735 kV/230 km line with series compensation at one line end, a maximum 1.80 p.u. SFO was observed whereas the maximum 2.07 p.u. was recorded on a 735kV/379 km line with series compensation at the middle [15]. These overvoltages due to 1- $\Phi$ -to-ground fault clearing are withstood by the insulation of 735 kV lines in Canada.

Although the annual occurrence of 2- $\Phi$  and 3- $\Phi$  faults is low, much more severe SFO were observed when clearing these types of faults. For the case of a 230 km line with series compensation at one line end, the maximum of 3.25 p.u. SFO was observed when clearing 2- $\Phi$  ungrounded line faults. For the case of the 379 km line with series compensation at the middle, the maximum of 3.12-p.u. SFO was recorded when clearing 3- $\Phi$ -to-ground substation faults [15]. These overvoltages due to 2- $\Phi$ /3- $\Phi$  fault clearing are much higher than the SWIL of 735 kV line insulation. The applied mitigation measure is the use of permanently connected SAs at both line ends and also of SAs at one terminal of SCs located at the line midpoint.

The installation of permanently connected SAs at both line ends has also allowed limiting the maximum SFO in the Chilean 500 kV series-compensated system to 2.09 p.u. [5].

## **4. TRANSIENT RECOVERY VOLTAGES (TRVs)**

### 4.1 Clearing of OHL faults

In the IEC Standard [22] clearing of faults in OHLs has been specified with TRV's for breaking the 100%, 60%, 30% and 10% rated short-circuit current of the CB. The TRV-waveshapes have either 4-parameter envelopes, based on over-damped responses from the system plus reflected waves from the shortest lines, or 2-parameter envelopes, based on under-damped single frequency responses typically for transformer secondary faults. 3- $\phi$ -to-ground faults are covered by IEC Standards, but note that multi-phase faults without ground are regarded as too peculiar. The TRV-peak values vary from 1.82 to 2.0 p.u. (system neutral solidly grounded).

Apart from these test duties, that are derived from old TNA-studies for meshed transmission networks, special test duties have been introduced for single phase fault current switching, for out-of-phase switching and for short-line fault (SLF) clearing. SLF deals with a single phase at a distance of a few km or less from the substation, where especially the very steep RRRV (rate of rise of recovery voltage) due to the travelling waves, is crucial for the CB performance. Under discussion is the necessity to test for 3- $\phi$  short-line faults and to test for faults at a long distance (roughly 100 km), where in both cases the travelling waves could perhaps lead to higher TRV peak values than in the single phase case.

### 4.2 Clearing of series-compensated line faults

The increase of TRVs across line CBs when clearing fault currents flowing through SCs, has been known for many years. This phenomenon is caused by the trapped charge that can remain on SCs at the moment of line current interruption. The associated voltage adds to the TRVs that occur without SCs.

It has been demonstrated [16] that modern SCs protected by MOVs cause higher and more frequent TRVs on line CBs than SCs of old technology protected by self-triggered spark gaps. The largest TRVs occur in the presence of max.trapped charge on SCs located on both the line and bus side of a CB. RRRV usually does not exceed 1kV/ $\mu$ s. TRVs up to 4.6 p.u. [16] or up to 4.8 p.u. [17] can occur if no means are applied for limitation. IEC Standards [22]

stipulate for the EHV CBs a TRV of 2.5 p.u. for the type test of out-of-phase breaking current, with RRRV of 1.54 kV/ $\mu$ s. This is the highest required TRV and should be referred to for checking the CB capacity here dealt with.

There are two applicable approaches for solving the problem: specify CBs with adequately increased TRV capability; apply means for TRVs limitation. The former solution generally requires use of EHV CBs with an increased number of chambers in series per pole (say, 3 instead of 2 in 420kV CBs; 4 instead of 2 in 550kV CBs), i.e. with considerably higher cost and installation space requirement, and reduction of mechanical security because of increased number of operating mechanisms and complexity.

The following means have been applied for limiting the TRVs here dealt with:

- (v) Use of CBs with linear opening resistors rated at 400+600 $\Omega$ , switched by auxiliary contacts of CB.
- (vi) Use of SAs connected phase-to-Gr to the series compensated lines.
- (vii) Use of MOVs branched in parallel with the main contacts of CBs.
- (viii) Fast by-passing of SCs.

Switched linear resistors have been used in the 1960s – 1970s, in particular in air blast CBs, a technology which permitted the application of both the closing and opening resistors. Modern SF6 puffer type CBs can be fitted with closing resistors, but are generally not designed to be fitted with switched opening resistors or with closing and opening resistors. On the other hand, cases of mechanical failure (explosions of resistors due to stuck closed auxiliary contacts) have occurred. Solution (i) has therefore been dropped.

EMTP studies performed for a 500kV transmission system [17] have shown that TRVs' reduction within 3.2 p.u. when clearing short circuit currents flowing through SCs is feasible with use of SAs at both line ends and at line midpoint, having a SSPL of 1.57 p.u., a rated voltage of 372kV and MCOV of 318kV [17]. SAs of special design have been applied in this project.

In many EHV grids, in particular in most of the 420kV grids of Europe, standard commercial SAs with SSPL of about 2 p.u. are applied with rated voltage of 360kV, the MCOV of which has some margin above the max. operation voltage. ATP-EMTP studies have shown that SAs cannot adequately limit the TRVs [16].

Solution (iii) consists on use of MOVs branched in parallel with the interrupting chambers of CBs [16]. These MOVs are standard SAs which can be fitted in the space allocated on CBs for the closing resistors, in parallel with the grading capacitors, without design modification. ATP-EMTP studies for a 400kV grid have shown that MOVs with 1kA SSPL of 2.5 p.u. branched across CBs limit the TRVs within 2.5 p.u., if there is no requirement of network resynchronizing with the involved CB. If MOVs are required to withstand with good margin the voltage beats during resynchronizing of separated systems, they must have an higher rated voltage (higher temporary overvoltage withstand capacity) and consequently TRVs are limited within 3 p.u.. The latter solution has been applied with commercial 420kV CBs possessing a TRV withstand capacity of 3 p.u.. Actually, for the sake of standardization, most manufacturers supply 420kV CBs with 2 chambers per pole designed for 550kV, providing a TRV capacity of 2.5 p.u. at 550kV and 3p.u. at 420kV. The good operation experience of 10 years (330 CB pole-years) in the Turkish 420 kV grid has confirmed the viability of this solution [16].

Solution (iv), i.e. fast by-passing of SCs, is feasible if SCs are provided with forced triggered protective spark gaps. It requires a triggering signal transmission of high reliability to SC, if the latter is located far from the protection relays detecting the line fault. Keeping in mind that a transfer signal failure might have disastrous consequences, signal receipt confirmation is advisable before tripping the line CB; the consequential delay in line fault clearing should be acceptable. In some systems [16] SCs of lines adjacent to a faulty line contribute to TRVs magnification. The ensuing need of by-passing also SCs external to faulty line may jeopardize system stability.

#### 4.3 Out-of-phase clearing and de-energization of unloaded lines under high TOV

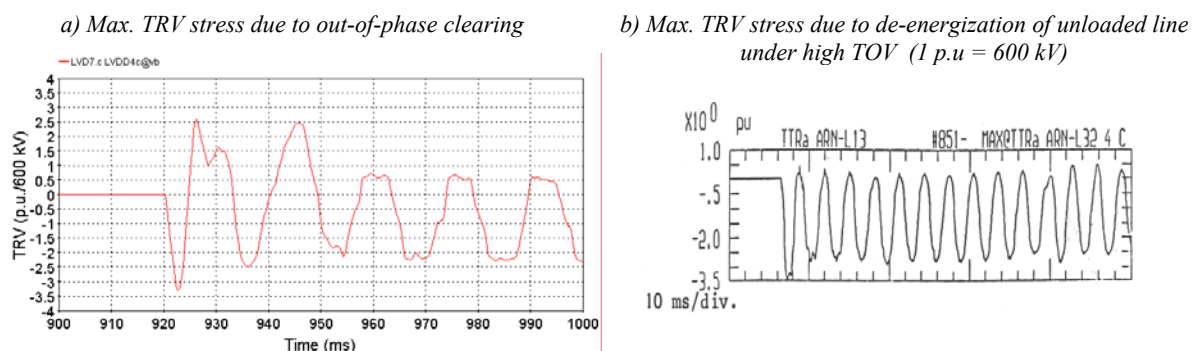


Fig. 4: Maximum TRV stresses due to out-of-phase clearing and de-energization of unloaded 735 kV line under high TOV

It has been mentioned in section 2.1 that line circuit breakers in long distance radial shunt/series-compensated systems are subjected to TRV stresses due to out-of-phase clearing and unloaded line de-energization under high TOV. As illustrated in Fig. 4a and 4b, in the 735 kV series-compensated system in Canada [3] [15], maximum TRV stresses due to out-of-phase clearing and unloaded line de-energization under high TOV are of 3.3 p.u. and 3.5 p.u., respectively. These TRV stresses are beyond the IEC requirements for 800kV class CBs [22]. As a consequence, special EHV CBs with appropriate TRV withstand have been implemented in this system.

Severe TRV stresses due to out-of-phase clearing and unloaded line de-energization under high TOV have also been observed in the 500 kV series-compensated systems in Vietnam and in Chile [4] [5]. 550 kV line CBs with adequate TRV withstand capabilities have also been applied in these systems. The figures given are also representative for other 500 kV grids.

#### 4.4 Clearing faults in HWLLs

The CBs at the ends of naturally tuned HWLLs have to withstand the highest TRVs when clearing faults located close to the end of the HWLL. The ATP – EMTP analyses performed for 800kV and 1050kV, 50Hz, 2500km long HWLLs [8] [9], have shown that the CB at the sending end is subject to TRVs of 3.2p.u., however with a modest RRRV (0.25 kV/μs), when clearing a 3-φ short circuit located at the receiving end. Similar TRVs have been calculated for 800kV, 50Hz, 3000-3200km long HWLLs. It is therefore necessary to use CBs with adequate TRV capacity or to apply TRVs limiting measures, as MOVs branched in parallel with the contacts of CBs.

### **5. TRANSIENT CURRENTS**

- The consequences of inrush currents of transformers, SRs, shunt capacitor banks, back-to-back banks and restrikes at switching off shunt capacitor banks are well-known in the literature.
- Induced current switching with earthing switches:  
In the case of multiple EHV circuits, in particular double-circuit OHLs, current may circulate in the de-energized and earthed circuit due to electrostatic and electromagnetic coupling with adjacent energized circuits. Earthing switches in these conditions must possess current making and breaking capacity for earthing and un-earthing at one terminal: (i) with the other terminal open (capacitive current); (ii) with the other terminal close (inductive current). Earthing switches must also possess a continuous current carrying capacity. In some situations (long heavily loaded double-circuit EHV lines) the induced current foreseen in the IEC Standard 62271-102/2001 for Class B EHV earthing switches (160Arms) may be exceeded. In the 400kV National Grid of the U.K. a current rating of ~ 10% of load current of parallel circuit is specified (i.e. up to ~ 400A). However there is no evidence of safety risk from network experience with old earthing switches not specified for this current rating.
- Secondary arc current during SPAR is mainly a problem of arc extinguishing on the line, but not for the switchgear involved.
- Fault currents in series compensated lines with delayed current zero's need special attention when specifying the involved CBs [18].
- The same applies for fault currents with superimposed sub-harmonic currents [19].

### **6. SERIES CAPACITOR BANK TECHNOLOGIES AND OPERATING EXPERIENCES**

Series compensation involves the use of capacitance in series on a transmission line to compensate for the inductive reactance. SCs are used to improve power system transient stability, improve voltage regulation on long transmission lines, reduce voltage drop due to inductive Mvar flow and reduce Ferranti effect overvoltages. SCs increase power transfer capability of the line and are used to control power sharing among parallel circuits in proportion to cross-section (conductivity) of phase conductors. This form of compensation first became popular in the 1950's and today there are over 500 installations worldwide.

Because the SCs are placed in series with the line, a fault on the transmission system can cause the capacitors to see overvoltage conditions. Spark gaps and/or MOVs are used to protect the capacitors.

In general, series capacitor banks use four types of protective schemes:

- v. *Slow-reinsertion type*: the bank is protected by a triggered gap and a by-pass CB only.
- vi. *Instantaneous reinsertion type*: using MOVs and, in most cases, forced triggered spark gaps; see figure 5.
- vii. *Fast reinsertion type*: two self-triggered gaps, a low setting gap with a CB in series and a high setting gap with a by-pass CB in parallel.
- viii. *Thyristor controlled series capacitor*: thyristors are used to bypass or insert modules of capacitance and inductance, rapidly modulating the line reactance; see figure 6.

In today's designs by-pass CB and control/protection systems are located at ground level, all-film capacitors are used, more reliable spring operated CBs, laser powered signal transmission and digital protection/control systems. These changes have significantly reduced downtime and resulted in high bank reliability and availability.

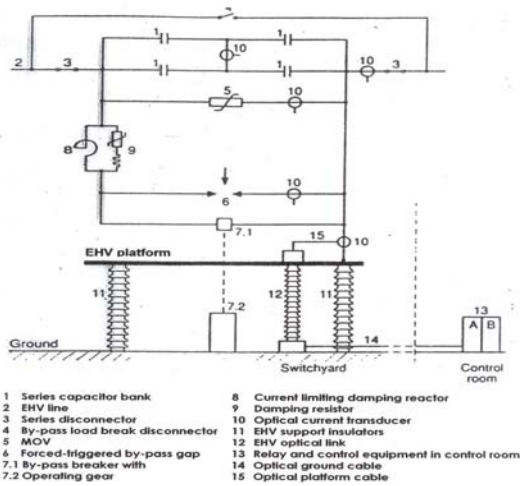


Fig.5: Series Capacitor Bank as per scheme ii

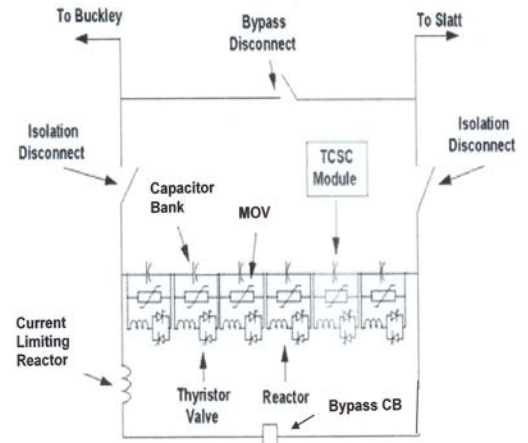


Fig.6: Thyristor controlled Series Capacitor Bank as per scheme iv

The energy dissipation capacity of MOVs protecting SCs markedly affects costs. Usually it is expressed in terms of number, intensity and duration of line short circuits that the MOVs are required to ride through without damage.

A problem associated with use of SCs maybe subsynchronous resonance (SSR), due to the interaction with turbine-generators. This phenomenon only occurs in the case of steam turbine-generators connected to load centers through series compensated lines. SCs on a transmission line can change the electric network's natural frequency to coincide with the mechanical system's natural frequency, leading to damaging torsional oscillating torques in the turbine-generator shafts. However, protection schemes that detect subsynchronous current can be used to trip generators or by-pass the SCs whenever a certain time-SSR current amplitude criterion is exceeded.

Defective operation of old electromechanical distance relays or associated directional comparison protection schemes could occur in series compensated lines, in particular with SCs located at line ends, due to the voltage reversal phenomenon. Electronic and digital relays, provided with voltage memory, have eliminated this problem.

## 7. FLEXIBLE AC TRANSMISSION SYSTEMS (FACTS)

Three different kinds of equipment to control voltage and power flows are distinguished by WG A3.13: power-electronic devices (SVC, StatCom, etc.)

- phase shifting transformers
- variable Mvar output shunt reactors (with on-load tap-changers [20]).

For HV-equipment no adverse effects of the application of such devices has been reported, apart, maybe, from overvoltages due to single pole clearing of phase-to-ground faults behind phase shifting transformers (to be prevented by three-phase clearing). For further information reference is made to the future Technical Brochure.

## 8. CONCLUSIONS

8. A number of societal developments lead to multiple power transfers, regionally and internationally, along long and very long distances, and to a further utilization of transmission corridors. This leads to an increase of the application of long shunt and series compensated OHLs and long compensated cable sections. Other technologies are HVDC-connections and, possibly, HWLL.
9. With long distance transmission more prevalent and more severe TOVs, transient over-voltages and TRVs will be produced. On one hand effective and cost-effective measures to limit these overvoltages are necessary and on the other hand an adequate specification of the involved HV equipment.
10. Measures mentioned are the application of (high performance) MOSA, switched SAs, tele-tripping, controlled switching, advanced protection systems, SRs with neutral reactor where applicable, MOV across CB units, specification of very low probability of restrike CBs, (closing/opening resistors), by-passing SCs.
11. Adequate specification of HV equipment in substations mainly addresses shunt/series compensation means, SAs and CBs.
12. CB specifications are mainly to be adapted for capacitive current switching under TOV conditions and the phase opposition test duty, covering also a number of fault clearing TRV-conditions.
13. Despite the fact that for each case extensive ATP/EMTP studies will be needed, the experience of the utilities that contributed to WG A3.13 studies shows comparable TOVs and TRVs. Maybe this offers some possibilities for the standardization of CB applications for high TOVs, out-of-phase conditions and series compensation.

14. Studies show that the proper application of shunt/series compensation and HWLL offers large advantages under the developments described above.

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### APPENDIX

ATP	Alternative Transient Program	SA	Surge arrester
EMTP	Electromagnetic Transient Program	SC	Series capacitor bank
CB	Circuit-breaker	SFO	Slow front overvoltage
FACTS	Flexible AC transmission system	SIL	Surge impedance loading
FFO	Fast front overvoltage	SIWL	Surge impulse withstand level
HWLL	Half-wave length transmission line	SPAR	Single phase automatic reclosure
MCOV	Max. continuous operation voltage	SR	Shunt reactor
MOSA	Metal oxide surge arrester	SSPL	Switching surge protection level of SA
MOV	Metal oxide varistor	SVC	Static var compensator
OHL	Overhead transmission line	TOV	Temporary overvoltage
PT	Potential transformer	TPHSR	3-phase (3- $\phi$ ) high speed reclosure
RRRV	Rate of rise of recovery voltage	TRV	Transient recovery voltage

**Appendix F**

**DIELECTRIC, SWITCHING AND SYSTEM REQUIREMENTS UNDER OUT-OF-PHASE CONDITIONS, DURING SYNCHRONISATION AND UNDER COMPARABLE STRESSES**

**Report presented at the CIGRÉ SC C4/A1/A2/A3/C1 Symposium 2007, Zagreb, April 2007  
Report 0701**

## **Dielectric, Switching and System Requirements under Out-of-Phase Conditions, during Synchronisation and under Comparable Stresses.**

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The Netherlands    Italy    Canada    Brazil    U.K.    Canada

On behalf of CIGRE WG A3.13

### **SUMMARY**

Recent developments in electrical networks can increase the probability of out-of-phase switching and dielectric stresses being applied to open circuit-breakers, due to asynchronous systems at both sides. This report presents a systematic study of TRV-stresses associated with generator separation and system separation. TRV peak values are higher than required in the Standards, even for relatively small out-of-phase angles (75° to 90°), and the dielectric stresses are high with respect to the short-duration power frequency withstand voltages across a circuit-breaker open contacts, especially taking into consideration the external insulation under pollution and ageing processes. To the opinion of the authors, the Standards should be revised to give users clear and adequate guidance on the assessment and specification of TRV-values and dielectric withstand requirements under out-of-phase conditions.

### **KEYWORDS**

Out-of-phase, synchronisation, TRV, RRRV, First-Pole-to-Clear Factor (fpcf), longitudinal dielectric stress

### **1. INTRODUCTION**

Within CIGRE SC A3 “High-voltage Equipment”, WG A3.13 “Changing Network Conditions and System Requirements” has investigated the impact of developments in electrical networks upon conventional high voltage apparatus. The major relevant trends identified are:

- 1) increasing implementation of distributed generation
- 2) increasing distances of bulk power transmission
- 3) increasing application of power electronics (generation, transmission, distribution and load).

One of the phenomena studied is the increased probability of out-of-phase conditions. Operating of systems closer to their limits may lead to steady-state, transient and dynamic stability problems and the problems are exacerbated by the increasing complexity of the power systems: large distances between load and power generation centres, regional concentrations of wind farms and associated power transmission and reserve problems, the changed nature of distribution grids and a trend to consider island operation of parts of the (distribution) system.

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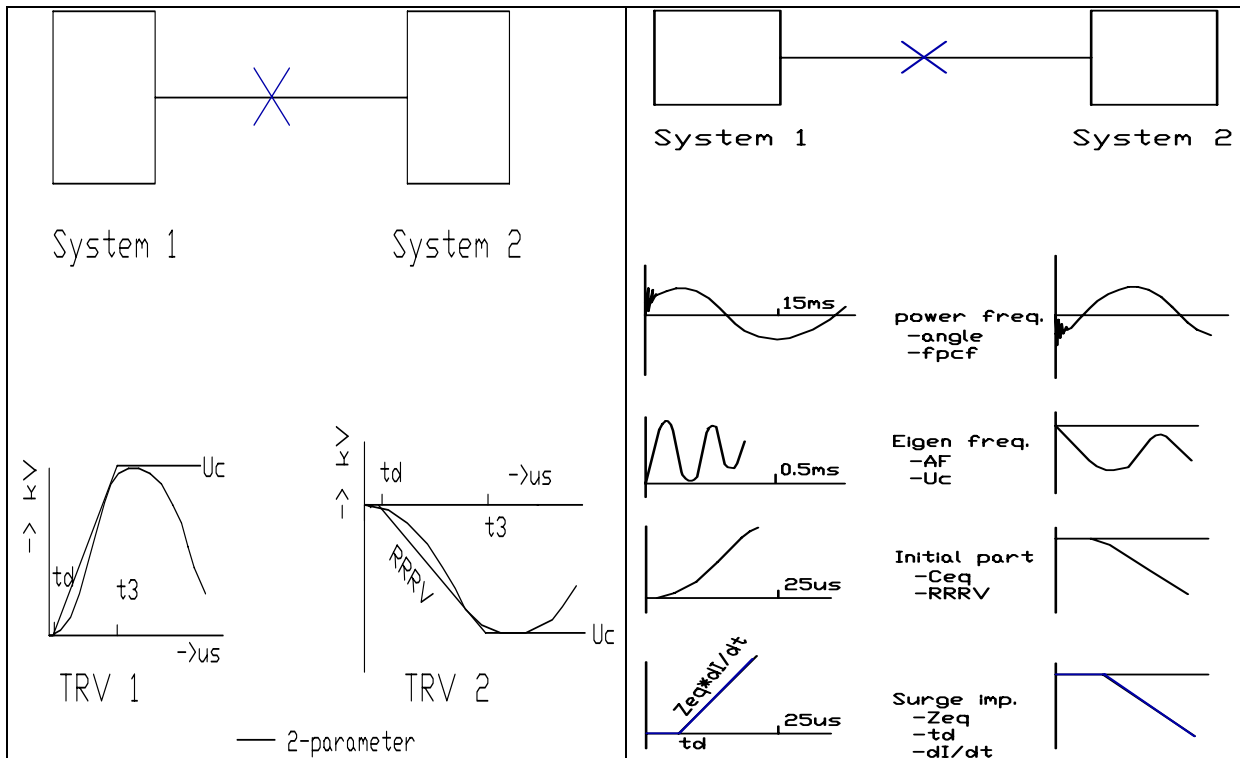


Fig. 1 Longitudinal stresses across the first-pole to clear out-of-phase

Fig. 2 Characteristics of the RV and TRV

The stresses on HV equipment, especially circuit-breakers (figure 1), under out-of-phase conditions and during synchronisation of generators and networks have been investigated and are presented in the following sections. Present Standards [1][2][3][4] define out-of-phase TRV (transient recovery voltage) and RRRV (rate of rise of recovery voltage) conditions on the basis of parameters including out-of-phase angle ( $\psi$ ), out-of-phase current ( $I_{op}$ ), recovery voltage (RV), natural frequency, damping and amplitude factors (AF) and travelling wave behaviour. Figure 2 shows schematically the different time domains which are relevant for the TRV-studies and reference [5] presents the relation between the different parameters in 3-phase systems. The out-of-phase test duty leads to the highest TRV-peak requirements for circuit-breakers.

WG A3.13 will publish more detailed information in two CIGRE Technical Brochures during 2007.

## 2. SYSTEM CONSIDERATIONS

The circumstances that may lead to system separation, either singly or in combination, include:

- transient instability (slow fault clearing, false synchronisation of large network elements or large power plants)
- voltage instability (inadequate reactive power and/or voltage regulation, poor or adverse tapchanger control)
- small signal instability (amplification of power swings due to negative damping)
- frequency instability (system inability to react to sudden load/generation unbalances)
- cascade trippings (multiple lightning, weather conditions, overloading, vegetation growth, temporary overvoltages)
- protection mal-operation
- false synchronisation of a single generator.

Large increases in distributed generation, including many windmills and windmill parks, and multiple power transfers across longer distances, increase the probability of occurrence of many of these events as detailed in the following examples:

- medium voltage networks typically have fault clearing times which exceed the maximum clearing time for continued stability of small generating plants equipped with synchronous generators
- the optimal control of reactive power supply and voltage regulation by small generators has not been established yet
- windmills are very sensitive for wind variations, especially under high wind conditions, which may result in co-incident tripping of many units
- small cogeneration plants (e.g. for greenhouses) are operated in large groups without consideration of wider network requirements
- systems are more commonly operated up to, or even beyond, their loading capabilities
- (small) generators are tripped and synchronised more regularly than ever before
- certain distributed power generation technologies cannot provide inertial energy required for the immediate dynamic response to sudden load/generation unbalances. This reduces the average inertia constant of the whole system and hence reduces the margin to the dynamic stability
- it is important that dispersed generators remain connected to the network during voltage and/or frequency deviations caused by faults and other disturbances as specified for the large conventional synchronous generators, thus contributing to ride through system disturbances with their active and reactive outputs and their inertia
- on the other hand, the growing use of dispersed generation increases the probability of out-of-phase conditions.

All these trends lead to the conclusion that out-of-phase conditions have to be studied more carefully than in the past. A better understanding of the effects and consequences of out-of-phase conditions and of the present and future probabilities of occurrence is necessary.

### 3. OUT-OF-PHASE PHENOMENA

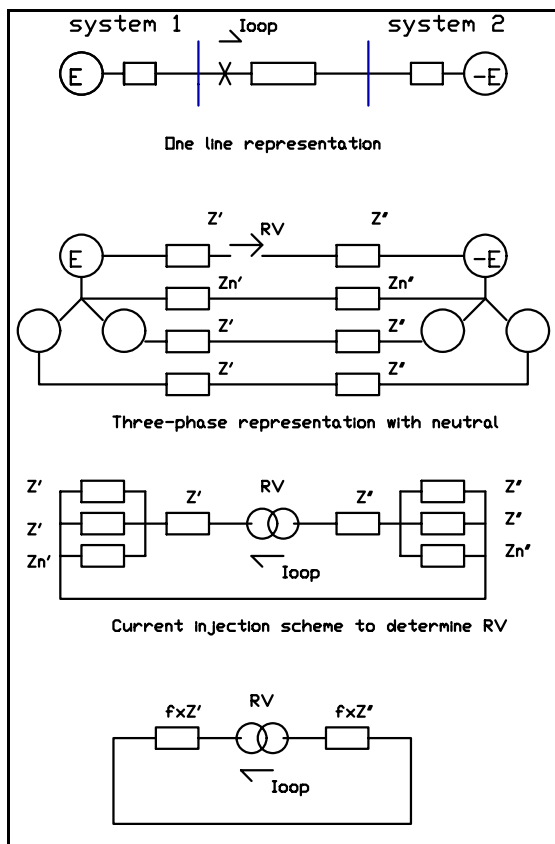


Fig. 3 Out-of-phase RV with  $f = \text{total fpcf}$

In common with the recently published Guide for Application of IEC 62271-100 and IEC 62271-1 [15], two out-of-phase cases are considered here:

- generating units that separate from the network
- major systems that separate.

Whilst the focus of the above mentioned Guide is to explain the values given in the Standards, a more fundamental approach is taken here with emphasis on the behaviour of system topologies not directly considered in the Standard.

#### 3.1 Case (i)

Out-of-phase switching may be applicable to a generator circuit-breaker at the MV-terminals of a generator, as specified in IEEE Standard C37.013 (1997) [10], or to a generator circuit-breaker at the HV side of the step-up transformer, normally specified as a general purpose circuit-breaker to IEC 62271-100 or ANSI/IEEE C37.04/06/09. In both situations, as shown in figure 4, the total RV is caused by the disappearance of the voltage drop across the reactances of the generator, the step-up transformer and the system and the overall fpcf:

$RV = I_{\text{oop}} * \text{fpcf} * (X_{d''} + X_{tr} + X_s)$ . The overall fpcf is a combination of the fpcf (depending on the neutral treatment  $Z_n$ ) of the systems at both sides of the circuit-breaker and can be deduced from the double Neptune-scheme as shown in figure 3.

The largest voltage drop will generally be across the generator sub-transient reactance. The transformer reactance is in the range from 0.1 to 0.15 pu whilst many modern generators have a sub-transient reactance in the range 0.18 – 0.27 pu; lower values (0.12 – 0.15 pu) were typical in old 2-pole turbine generators. The system reactance is typically five (or more) times smaller than sub-transient generator plus transformer reactance. Further, the natural frequency of the generator windings is 2 to 3 times lower than the natural frequency of the transformer windings. System frequencies usually have the lowest values defined primarily by the travelling waves of the shortest OH-lines. In terms of surge impedances and local capacitances, the generator will offer the lowest surge impedance (in the range of several tens to less than 100 Ohms) with the highest capacitance (typically 0.1  $\mu$ F) and the transformer the highest surge impedance (thousands of Ohm) with the smaller local capacitances. The system's surge impedance does not exceed 300 - 400 Ohm with local capacitances comparable with the capacitance of a transformer (thousands of pF).

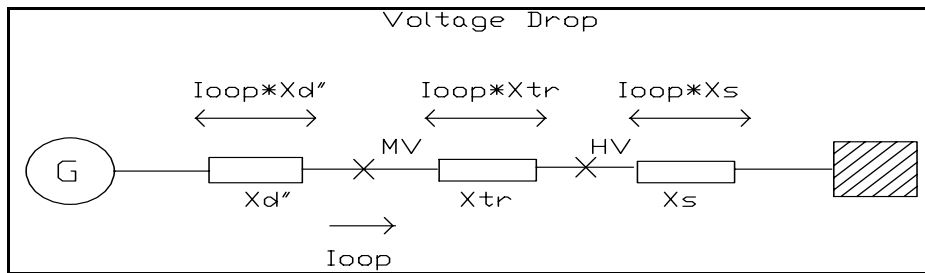


Fig. 4 Generator circuit-breaker RV

Seen from the HV-side of a step-up transformer (winding configuration: YN-D), it is assumed that the earth fault factor and therefore the first-pole-to clear factor (fpcf) are very low:  $k=Z_0/Z_1$  is 0.7 to 0.9. With  $k$  being about 0.8 the fpcf becomes 0.92, and the second and last pole clearing factors are larger than the fpcf [5]. On the other hand, as shown in figure 3, the total fpcf is to be considered and not the individual fpcf at each side of the circuit-breaker. For  $k=0.8$  at the generator-transformer side and a fpcf of 1.1 at the net-side, the total fpcf is 0.94 to 0.96, depending on the ratio of normal sequence reactance at the generator/transformer side versus the normal sequence reactance at the network side.

With a fpcf of 1.3 at the net-side, the total fpcf becomes 1.06 for a sub-transient generator/transformer reactance which is five times the reactance at the net side. To derive the total RV, this total fpcf has to be multiplied with the out-of-phase voltage which depends on the out-of-phase angle. In this example, the total RV for full phase opposition will reach a value of 2.12 pu, with 5/6 of the voltage appearing at the step-up transformer side of the circuit-breaker and the remaining 1/6 appearing at the network side, in addition to the pre-clearing voltage of 4/6 pu. So, at the step-up transformer side the terminal voltage of the first clearing pole jumps from 0.67 pu to - 1.10 pu ( $\Delta = 1.77$  pu) and at the other terminal from 0.67 pu to 1.02 pu ( $\Delta = 0.35$  pu). For smaller out-of-phase angles  $\psi$ , the total RV, the two parts of the RV and the voltage jumps are smaller in proportion to  $\sin(\frac{1}{2}\psi)$ .

At the generator-transformer side the amplitude factor (over-swing) will be quite large (for instance 80%: amplitude factor 1.8), as the losses will be relatively low (X/R ratio of 50 or more) and the generator side capacitance large. A significant depression of the voltage at the generator terminals and therefore of the recovery voltage at the HV-side of the transformer can be expected [16], figure F.1 of [1]. This phenomenon leads to a considerable reduction of the voltage at the HV circuit-breaker, typically resulting in a residual voltage of 80% to 90%; i.e. a sub-subtransient source voltage of 0.8 to 0.9 pu, in the first few hundred  $\mu$ s after clearing the out-of-phase current. The effect is larger at larger currents but is not observed for generators with fully laminated poles and a damper winding [16].

The amplitude factor of the RV is determined by the natural frequencies of each side of the circuit-breaker and normally the natural frequencies differ substantially such that the components of the transient recovery voltage at both sides of the circuit-breaker swing independently and their crests do not coincide.

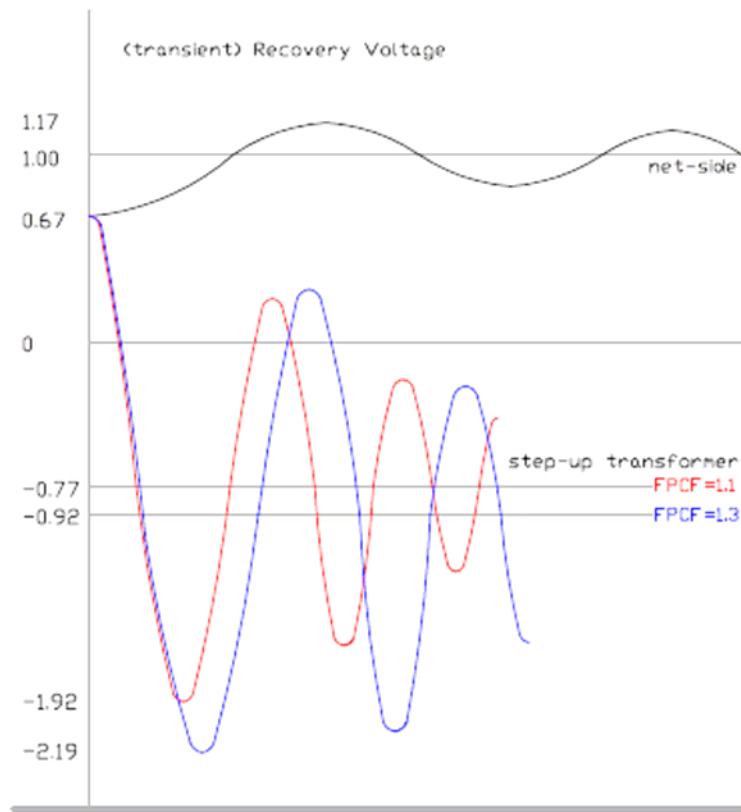


Fig. 5 Out-of-phase Recovery Voltage. Case (i)

Shortly before clearing the voltage at both terminals of the circuit-breaker pole is defined by:  $V_{cb} = E_s + (E_g - E_s) * X_s / (X_d'' + X_t + X_s)$ , where  $V_{cb}$  is the circuit-breaker terminal voltage,  $E_g$  is the source voltage at the generator side and,  $E_s$  is the source voltage at the net side. If  $E_g = -1.0$  pu,  $E_s = +1.0$  pu (full phase opposition) and  $X_d'' + X_t = 5 * X_s$  then  $V_{cb} = 0.67$  pu. The net side RV will swing from 0.67 pu to about 1.0 pu (see former page and figure 5). With an over-swing of the voltage jump corresponding to an amplitude factor of 1.5, a peak value of 1.17 pu is reached.

The transformer side will swing from 0.67 pu to -0.92 pu (assuming net side fpcf of 1.3 and 10% depression) with an amplitude factor of 1.8, thus giving a peak value of -2.19 pu. For a net-side fpcf of 1.1 (and 10% depression), the voltage will jump at the transformer side from 0.67 pu to -0.77 pu; with an amplitude factor of 1.8, a peak value of -1.92 pu is reached.

In order to estimate the crest value of the total TRV, the assumption is made that the peak at one side coincides with the power frequency recovery voltage at the other side. In this case,

3. the peak at the net side 1.17 pu coincides with -0.92 pu (resp. -0.77 pu) at the step-up transformer side, summing up to a TRV peak value of 2.1 (resp. 1.9 pu)
4. the peak at the step-up transformer's side -2.19 pu (resp. -1.92 pu) coincides with 1.0 pu at the net side, summing up to 3.2 pu (resp. 2.9 pu).

These peak values are higher than 2.5 pu, as specified in IEC 62271-100 for systems with fpcf = 1.3.

In figure 5, the wave-shapes on both sides of the first clearing pole are schematically given assuming full phase opposition. Reducing the out-of-phase angle will shift  $V_{cb}$  from 0.67 pu towards 1.0 pu, thus decreasing the over-swing at the net side but increasing the over-swing at the step-up transformer side. Moreover, due to the lower out-of-phase current the generator will show less depression and this leads to a higher residual voltage.

At an out-of-phase angle of 90° the out-of-phase voltage is 1.41 pu. Assuming no depression, a reactance ratio of 5,  $k = 0.80$  at the step-up transformer-side and  $fpcf = 1.3$  at the net side, it can be calculated that the peak-value of the TRV is 2.5 pu: a value which is recognised in the Standards. In other words, for these specific assumptions, the Standards do not address out-of-phase angles in excess of 90°.

In a system with a floating neutral, or equipped with Peterson coils, the  $fpcf = 1.5$  and the maximum RV will be 3.0 pu. The total TRV for the same example case can reach 4.55 pu at full phase opposition. Without depression, an out-of-phase angle of 75° gives a RV of 1.83 pu and a peak value of the TRV of 3.1 pu which is close to 3.13 pu as given in the Standards (for systems with  $fpcf$  of 1.5).

For a circuit-breaker at the MV-side of the step-up transformer, the IEEE/ANSI Standard C37.013 [10] is applicable. In this Standard an out-of-phase angle of 90° has been taken as the basic assumption to specify the TRV requirements. It has to be mentioned however that many utilities specify an angle of 180°; see for instance [8].

### 3.2 Case (ii)

When, during out-of-phase conditions, the equilibrium point (virtual short-circuit point) is somewhere on the OH-line that connects the two systems going out of synchronism, protection systems will trip the circuit-breaker. Whilst it is possible to install advanced and complicated out-of-phase blocking systems to delay the tripping command until the beating out-of-phase angle is small, this is uncommon and switching can normally occur over a wide range of out-of-phase angles. The TRV across the first clearing pole is determined by the system parameters on the busbar side of the circuit-breaker and by the line parameters at the line side. As the largest impedance will be on the line side, the largest voltage excursion will also appear at the line side.

The out-of-phase current is, to a large extent, dependent on the out-of-phase angle and the length of the OH-line. Due to the traveling wave effects, the TRV at the line side will exhibit a triangular shape and its peak value can be calculated as twice the wave traveling time along the OH-line multiplied by the RRRV (rate of rise of the recovery voltage). The traveling time is proportional to the line length, but the RRRV shows a decreasing trend with increasing line length due to the decrease in out-of-phase current ( $I_{oop}$ ). Specifically  $RRRV = fpcf * Z_{eq} * dI_{oop}/dt$  where  $Z_{eq}$  is the equivalent surge impedance. Due to the influence of the source impedances of both systems, the amplitude of  $I_{oop}$  is not inversely proportional to the line length. Therefore, the peak value of the line side TRV will still increase with an increasing line length. This effect, however, becomes smaller for OH-lines with longer lengths.

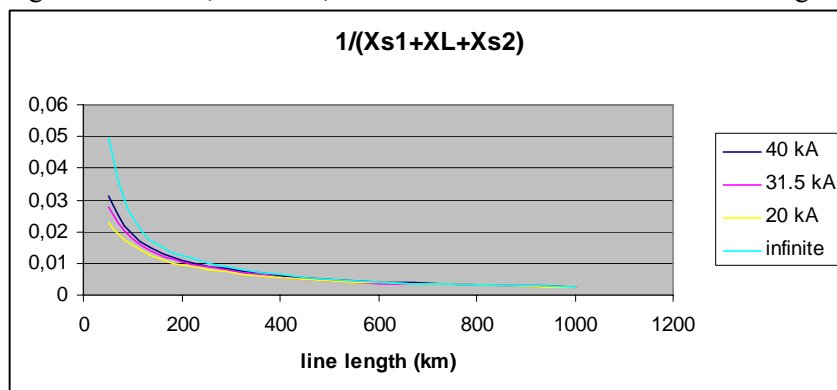


Fig. 6 Total admittance as function of line length

Figure 6 shows the total admittance of both systems and the interconnecting line as a function of the line length, for different (but arbitrarily chosen to be equal at both sides) source impedances of the systems; i.e. for 420 kV systems with a short-circuit power equivalent to short-circuit currents of 40 kA, 31.5 kA and 20 kA in comparison to infinite short-circuit powers.

In addition to the line side TRV, the busbar side TRV should be added. As  $I_{oop}$  is defined to be 25% of rating in the Standards and is often less than this in reality (15%), the system side TRV can be estimated to be 25% (15%) of the TRV associated with, for instance, T100. The peak value is then less than 0.37 pu (0.22 pu). For an OH-line with a length of 100 km, the return traveling time will be roughly 650  $\mu$ s, close to T2, as defined for T100. For a 420 kV/40 kA circuit-breaker, the peak value of the total TRV will be close to 4.1 pu for  $I_{oop} = 25\%$  and 2.5 pu for  $I_{oop} = 15\%$  of the rated short-circuit current.

In figure 7, the TRV peak values (line side) as a function of line length are shown for the example above (figure 6). The out-of-phase currents are based on full phase opposition. As the TRV peak value at the line side is proportional to  $I_{oop}$ , it is also proportional to  $\sin(\frac{1}{2}\psi)$ .

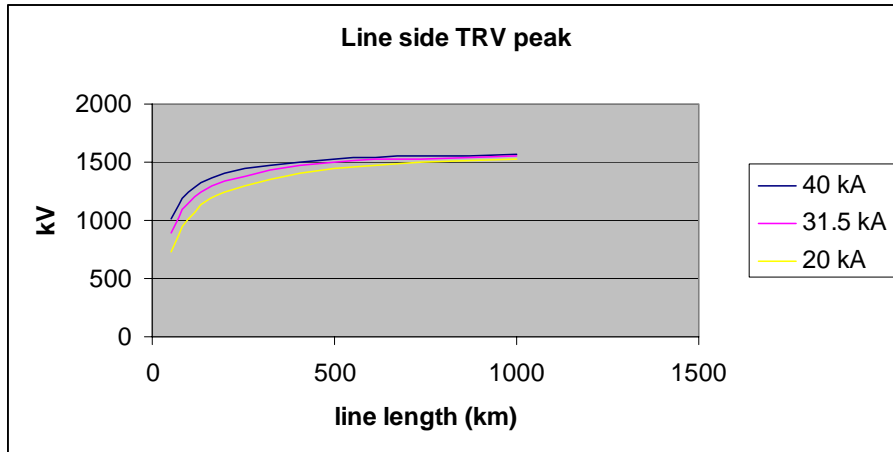


Fig. 7 Line side TRV peak value as function of length in a 420 kV-network

It can be concluded that the TRV peak values can be considerably higher than specified in the Standards (857 kV @ 1335  $\mu$ s for a rated voltage of 420 kV), even when taking into account smaller out-of-phase angles. For instance with a line length of 200 km and source impedances corresponding to a short-circuit current of 20 kA, an out-of-phase angle of 120° will still give a line side peak value of 1075 kV. Combined with a system side RV of roughly 100 kV this results in a total TRV peak of 1175 kV. A line length of 100 km under the same conditions will give 875 kV at the line side and 975 kV in total. The IEC peak value of 857 kV is reached at out-of-phase angles as small as 75° and 90° for 200 km and 100 km lines respectively.

Calculations and simulations for real networks show out-of-phase TRV peak values as high as 3.3 to 3.5 pu [9] or even 3.9 pu [19] for very extended networks (hundreds of km, low currents) and 3.0 to 3.5 pu for meshed networks (hundred or less km, relatively high currents).

#### 4. DIELECTRIC STRESSES ACROSS OPEN CONTACTS

During synchronization the longitudinal voltages applied to open contacts vary from zero to 2 pu in a periodic, beating pattern for periods of seconds or minutes. In case of frequent synchronisation, clause 2.3.2.4 of IEC 60071, part2 [13] recommends consideration of the occurrence of an earth fault during synchronisation (at one side!), thus leading to higher longitudinal voltages: up to 2.5 pu for a short time.

Clause 2.3.2.5 of [13] recommends careful examination of the probability of simultaneous occurrence of circumstances that lead to temporary overvoltages. Examples include an earth fault with consequential line tripping firstly at load side, load rejection with high overvoltage causing an earth fault, load disconnection under heavy pollution conditions, or a failure of a circuit-breaker to trip a line fault with a generator still feeding the earth fault. In such cases a careful system study is required.

Clause 2.3.2.2 of [13] indicates that full load rejection will lead to temporary overvoltages, which are normally less than 1.2 pu for moderately extended systems but which could reach values up to 1.5 pu for large extended networks and even more in case of (ferro)resonance. (Ferro)resonance, however, should be avoided and mitigation measures are suggested (cl. 2.3.2.3 and 2.3.2.6). The longitudinal overvoltages across the circuit-breaker open terminals are equal to the temporary overvoltages when the rejected load was of a static nature. But, in case of generators the longitudinal overvoltage can reach values up to 2.5 pu and in very extended systems even more. A power frequency longitudinal overvoltage as high as 2.5 pu is also given in clause D.1.3.2. of IEC 60694 [11].

With regard to the dielectric requirements under synchronising operations simultaneously with a substantial transient or temporary overvoltage, clause 4.2 of IEC 62271-100 [1] indicates that the standard requirements may be insufficient and the application of the requirements as specified for disconnectors across open contacts is recommended. In clause 4.2 of IEC 60694 [11] different requirements for the longitudinal withstand voltage across open contacts for the safety function (eg. disconnectors) and for the working function (eg. circuit-breakers) are specified for rated voltages  $\leq 245$  kV. The values given in column (2) of the tables 1a and 1b [11], applicable for rated voltages  $\leq 245$  kV, are used for the specification of the longitudinal requirements of circuit-breakers, while the values given in column (3) are used for the longitudinal requirements for disconnectors. For rated voltages  $\geq 300$  kV, the values of column (3) of the tables 2a and 2b are specified for the 1min power frequency type test across open contacts of both circuit-breakers and disconnectors, however the values of column (2) are accepted for routine tests. In the following table the power frequency short-duration withstand voltages are reported for some rated voltages for comparison, including the withstand voltages in pu. For rated voltages  $\leq 245$  kV, the highest class of insulation has been taken from table 1a, and for  $\geq 300$  kV the values given in table 2a:

Rated voltage (kV)	(2) 1min withstand (kV) <sup>+) </sup>	(2) 1min withstand (pu) <sup>+) </sup>	(3) 1min withstand (kV) <sup>Δ) </sup>	(3) 1min withstand (pu) <sup>Δ) </sup>
24	50	3.61	60	4.33
72,5	140	3.34	160	3.82
145	275	3.28	315	3.76
245	460	3.25	530	3.75
420	520	2.14	610	2.52
550	620	1.95	800	2.52
550 <sup>°</sup>	710	2.24	890	2.80
800	830	1.80	1150	2.49

<sup>°</sup> from table 2b: additional rated insulation levels in North America.

<sup>+)</sup> Specified for longitudinal insulation of circuit breakers with rated voltage  $\leq 245$ kV

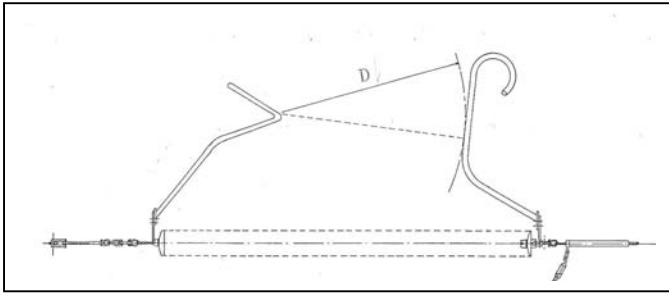
<sup>Δ)</sup> Specified for longitudinal insulation of disconnectors (all rated voltages) and of circuit breakers with rated voltage  $\geq 300$ kV

IEC-Standard 62271-203 “Gas-insulated metal-enclosed switchgear for rated voltages above 52 kV” [17] (the previous Standard 60517), makes reference to these tables in IEC 60694 but for the highest rated voltages different short-duration power frequency withstand voltages are specified:

Rated voltage (kV)	(2) 1min withstand (kV)	(2) 1min withstand (pu)	(3) 1min withstand (kV)	(3) 1min withstand (pu)
420	650	2.68	815	3.36
550	710	2.24	925	2.91
800	960	2.08	1270	2.75

External and internal flashovers across the open contacts of EHV circuit-breakers have occurred in operation during synchronizing of generating units (due to contaminated wet insulators in live tank circuit-breakers, due to failure of grading capacitor in dead tank breakers, etc.) or during the dead time before line automatic re-closure. These events generally cause a busbar fault, and also explosions of circuit-breaker poles. It is therefore necessary to specify the circuit-breakers to withstand with a reasonable margin the over-voltages liable to occur during these manoeuvres and to preserve this capacity in operation.

Some reported cases of circuit-breaker failures during synchronizing of generating units have been caused by flashovers on contaminated and wet external insulation of the interrupting chambers of live tank circuit-breakers, by failure of the grading capacitor in parallel with one of the contacts, or by inadequately specified power-frequency withstand voltage of circuit-breakers across open contacts eroded by aging or by other reasons. Rare flashovers across the open contacts of line circuit-breakers during the dead time before the automatic re-closure have been reported to be caused by multiple lightning strokes in absence of surge arresters or of special protective air gaps at the open line terminal [18]. Figure 8 shows a special protective gap shaped such as to minimize the influence of polarity and wave shape of LIs and SIs on flashover voltage and to provide a time to flashover shorter in the gap than in the protected open circuit-breaker. For decades, in Italy, there is very good service experience with the application of these special protective gaps.



*Fig.8 Special protective spark gap fitted in the line anchor insulator strings to substation gantry;  $D = 1700 \text{ mm}^\circ$  for 380 kV lines;  $D = 800 \text{ mm}$  for 150 kV lines.*

*$^\circ \text{SI } 50\% \text{ flashover voltage} = 1040 \text{ kV} (3 \text{ pu})$*

In live tank circuit-breakers the external insulation between terminals is not energized when the circuit-breaker is closed. It is recommended that for the external insulation across open contacts of live tank circuit-breakers used for synchronizing, the withstand voltages as specified to column (3) of the tables 1a, 1b, 2a and 2b of IEC 60694 [11], should be withstood in a type test under wet test conditions and also under representative artificial pollution conditions.

All the dispersed statements in the Standards support the view point that with respect to out-of-phase conditions and synchronisation, circuit-breakers longitudinal dielectric withstand should be specified to column (3) rather than column (2) for all rated voltages.

## **5. OTHER CONDITIONS LEADING TO HIGH TRV PEAK VALUES**

When clearing single or multi-phase faults distant from the substation on an OH-line (instead of at a short distance, as with short-line faults), the well-known triangular wave-shape of the TRV at the line side will rise to high values, depending on the wave travelling time from the circuit-breaker terminal up to the location of the fault and back. This phenomenon is known as long line fault (LLF) and has been discussed in [14]. As the time to the peak value of the TRV is rather long, it is comparable with the TRV for out-of-phase switching. Peak values of 2.4 pu have been reported [14] and LLF is a subject of study for CIGRE WG A3.19.

Clearing faults in series compensated OH-lines leads to TRV values in excess of the values specified in the Standards, due to the charging voltage on the series capacitor banks. Peak values of the TRV as high as 4.6 pu (420 kV-system in Turkey) and 4.8 pu (800 kV system in Canada) could be expected without certain countermeasures. By means of special MOSA with a low SSPL (switching surge protective level) of 1.57 pu, Hydro Québec manages to reduce the TRV peak value to 3.2 pu. In Turkey, MOV parallel to the arcing chambers of circuit-breakers have been applied successfully. Depending on the requirement of re-synchronisation by the circuit-breaker, the TRV peak can be reduced to 2.5 pu or 3.0 pu. These solutions lead nevertheless to TRV peak values comparable with or beyond those given before for out-of-phase conditions.

Although there is no real application of half-wave length lines (HWLL, 3000 km at 50 Hz; 2500 km at 60 Hz), a number of studies on over-voltages and TRVs have been performed for this interesting technology for long distance bulk power transmission. Simulations show that clearing faults in HWLL will lead to TRV peak values as high as 3.2 pu, again comparable with the TRV peak values mentioned before for out-of-phase clearing [9].

Another switching phenomenon giving high TRV values is the de-energization of unloaded OH-lines under high TOV (temporary overvoltages) conditions [15]. For the 800 kV system of Hydro Québec TRV peak values of 3.3 pu to 3.5 pu have been reported under such conditions; see figure 9b. [9]

Out-of-phase switching on series compensated OH-lines has not been addressed yet, but it is evident that the electrical charge on the series capacitors will add to the peak value of the TRV. Unfortunately, right at the moment of current clearing the voltage across the series capacitors is at maximum value, unless the capacitors have been by-passed by the self-triggered or forced triggered spark gaps. The situation is similar to clearing short-circuit currents. In modern series capacitors metal-oxide varistors are installed in parallel to the capacitor bank. Such varistors limit the voltage across the capacitor banks. Moreover special surge arresters connected phase-to-ground or varistors across the arcing chambers of the circuit-breakers are applied, thus limiting the total TRV peak value at clearing short-circuit currents and out-of-phase currents as well. The countermeasures for limiting the peak value of the TRV at clearing short-circuit currents are also effective at clearing out-of-phase currents; see figure 9a. [9]

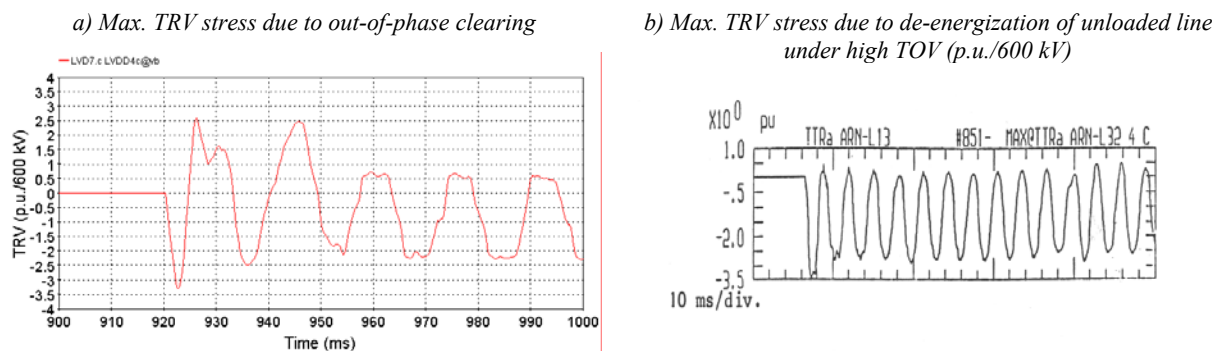


Fig. 9: Maximum TRV stresses due to out-of-phase clearing and de-energization of unloaded line under high TOV

## 6. CONCLUSIONS

- The Standards showed to be based on an out-of-phase angle substantially less than 180°, despite the fact that in many cases the angle will be random, ranging up to 180°. For generator circuit-breakers and special applications users already ask for out-of-phase angles of 180°.
- The RV in the Standards [1][4] is 2.0 or 2.5 pu respectively for systems with an effectively earthed neutral or a non-effectively earthed neutral with a TRV of 2.5 and 3.13 pu respectively.
- Both IEEE and IEC specify the RRRV of the TRV for out-of-phase switching to be lower than the RRRV specified for T100, whereas higher values occur in the systems. The RRRV for out-of-phase switching is considered to be covered by T30 (multi-part testing).
- Standardised TRV is based on system conditions in the absence of an earth fault. For situations with frequent out-of-phase switching and synchronisation, the Standards recommend to specify actual TRVs in the system (taking into account tripping and blocking relays for out-of-phase conditions when applied) and to adapt the requirements for the longitudinal dielectric strength accordingly.
- Under rather normal system conditions (no earth fault, no temporary overvoltages), full phase-opposition switching of a generating plant at the HV-side leads to TRV peak values in the range of 2.9 to 3.2 pu in systems with effectively earthed neutral and higher values for systems with un-earthed neutral. The peak values of the TRV as specified in the Standards, cover out-of-phase angles up to 90° or, in case of systems with unearthed neutral, even less (75°).
- For out-of-phase switching of OH-lines, calculations show peak values of the TRV from 2.5 pu (100 km length,  $I_{oop} = 15\%$ ) to 4.1 pu (100 km length,  $I_{oop} = 25\%$ ) and even beyond for longer line lengths, under full phase opposition. The Standards cover out-of-phase angles up to 90° (line length < 100 km) or up to 75° (line length < 200 km).
- During synchronisation, a longitudinal power frequency withstand test voltage larger than 2.0 pu, preferably 2.5 pu or even 3.0 pu, is a reasonable requirement for circuit-breakers used for that purpose. The related auxiliary components, such as grading capacitors, MOVs, insulating materials, external insulation, should be equally specified and tested.

- Under out-of-phase switching conditions the first-pole-to-clear factor is determined by the neutral status of the systems at both sides of the circuit-breaker, as shown by the double Neptune-scheme. Depression of the generator source voltage has to be taken into account, unless the rotor is equipped with fully laminated poles and a damper winding.
- False synchronisation, mal-operation of protection equipment and erroneous switching operations by operators [7], may lead to considerable damage. Re-strikes at clearing out-of-phase currents with large out-of-phase angles will also lead to comparable consequences. Developments in modern networks lead to a higher probability of the phenomena described: distributed generation leading to large power transfers, systems separation on overloaded OH-lines, large power swings due to tripped generation, etc.

## 7. RECOMMENDATIONS

- Utilities have to look carefully for such situations and, when applicable, put forward the appropriate requirements to the protection of involved equipment and switchgear.
- The present Standards do not give users clear and adequate support in specifying TRV-values for out-of-phase conditions, for clearing of fault currents flowing through series capacitors and for dielectric withstand requirements under synchronisation conditions. The requirements should be revised or more guidance should be incorporated to improve understanding.
- Since increased TRV requirements may lead to increased costs of circuit-breakers, enhanced out-of-phase requirements should be limited in their application or countermeasures to limit TRV should be used [9].

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