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CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS

Part I

The impact of distributed generation On Equipment rated above 1 kV

**Working Group
A3.13**

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WG A3.13

Changing Network Conditions and System Requirements

Part I

The impact of distributed generation on Equipment rated above 1 kV

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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 market, further utilisation of transmission corridors, multi-directional power-flows in distribution networks, increased capacity needs, increased efficiency requirements, etc., compounded by the request to improve or at least not to erode the quality of supply. 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 and control 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 issues, etc.

CIGRE 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-equipment¹. 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, of increased complexity, of more intelligence incorporation 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 I, is on the impact of power plants in distribution networks on the specifications for HV-equipment. In the other Technical Brochure, Part II, the impact of long distance transmission will be treated.

Other developments have been indicated in a SC A3 internal working document [1], 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 circuit-breakers (NSDD: non-sustained disruptive discharges, dealt with by IEC SC 17A) and GIS-disconnectors (in relation to transformers, dealt with by CIGRE JWG A2/A3/B3.21 and IEEE PC57.142 working groups [2])
- Very steep RRRV (rate of rise of recovery voltage) phenomena, such as for medium voltage: transformer fed faults, reactor limited faults and short-line faults (presently

¹ HV-equipment is equipment with a rated voltage above 1 kV

covered by amendment 2 to IEC 62271-100, June 2006, [30]); and for high voltage: 3-phase short line faults and long line faults (to be studied by WG A3.19)

- 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 under severe conditions of clearing inrush currents (are regarded as so unique that for the moment no further investigations by CIGRE are required).

A summary of the findings, recommendations and conclusions of CIGRE WG A3.13's studies is given in Appendix A, i.e. a Report presented at the SC A3 Colloquium 2007 in Rio de Janeiro [54]. Other publications of WG A3.13 are presented in the Appendices B, C and D, where specific items for distributed generation, general items and items related with out-of-phase and synchronizing are treated, respectively.

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- A. *Changing Network Conditions and System requirements
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- B. *Changing Network Conditions and System Requirements
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CIGRE SC A3&B3 Joint Colloquium 2005, Tokyo, Report 103 [22]

- C.** *Changing Network Conditions and System Requirements* [3]
IEEE/CIGRE Int. Conf. on Future Power Systems 2005, Amsterdam
- D.** *Dielectric, Switching and System Requirements under Out-of-Phase Conditions, during Synchronisation and under Comparable Stresses* [35]
CIGRE SC C4/A1/A2/A3/C1 Symposium 2007, Zagreb, Report 0701

ACRONYMS AND ABBREVIATIONS

AG	asynchronous generator
AVR	automatic voltage regulator
AWAE	American Wind Energy Association
BESS	battery energy storage system
BFW	boiler feed water
CCPP	combined cycle power plants (steam and gas turbine)
CCT	critical clearing time
CT	current transformer
DFIG	double fed induction generator
DG	dispersed generation or distributed generation
DSO	distribution system operator
EHV	extra high voltage
FERC	Federal Energy Regulatory Commission
FPCF	first-pole-to-clear factor
GT	gas turbine
HRSG	heat recovery steam generator
HV	high voltage (to IEC definitions > 1kV, but also used as MV)
MV	medium voltage (not an IEC term, but used for systems > 1 kV and < 52 kV)
NERC	North American Electric Reliability Council
OHL	overhead-line (OH-line)
PV	photovoltaic generator
SCADA	supervisory control and data acquisition (system)
SG	synchronous generator
SMES	super-conducting magnetic energy storage
ST	steam turbine
STIG	steam injected gas turbine
SVC	static var compensator
RRRV	rate of rise of recovery voltage or steepness of TRV
RV	recovery voltage (power frequency)
T30	test duty 30 of IEC 62271-100
TRV	transient recovery voltage
TSO	transmission system operator
VT	voltage transformer
WEC	wind energy converter (windmill)
WECC	Western Electricity Coordinating Council

1. INTRODUCTION

In recent years, in a number of countries, distributed generation has evolved to a substantial or significant part of the overall electric power generation capacity, especially by wind energy converters and co-generation plants. And, the prospect is a further huge increase, both absolutely and relatively. In Europe, for instance, the installed capacity of wind energy converters increased from 2.5 GW installed capacity in 1995 to 34 GW in 2004 [4]. The increasing costs of energy and the societal emphasis on environmental issues have also stimulated the growth of small combined heat and power generation for residential, commercial and industrial applications as well as for greenhouses, where the concept of total energy installations (including a further optimization of co-generation through the exploitation of CO₂ from the exhaust-gasses, the trading of electricity and the storage of heat) took off. Furthermore, the European Community has put forward targets by 2010 for the share of renewable energy sources and co-generation in the electric power generation. This will lead to an increase of the share of renewable energy from 14% to 22%, including hydro power, and of the share of co-generation energy from 9% to 18%. As the output of renewable sources and combined heat and power plants is very dependent on the weather conditions and heating demand, at full load the contribution from dispersed energy sources to the peak power balance in the year 2010 would consequently be 60% [5][6][7]. In Quebec (Canada), nearly 4000 MW of wind energy are expected to be developed in the next decade. This capacity accounts for nearly 10% of the annual peak load and 30% of the annual light load. Similar policies to stimulate a more sustainable power supply have been implemented in other parts of the world, thus emphasizing that distributed generation will definitely play an important role. At the CIGRE SC C1 Session 2006, the Special Reporter formulated this development as being on the threshold of a new revolution in the large scale electric infrastructures, comparable with the revolution caused by the regional and international interconnections, halfway into the last century [8]. A further penetration of dispersed generation into distribution-grids as well as into (sub)transmission-grids, is therefore a reality.

In the past, until today, it was preferred that during each disturbance in the network, the distributed generators were immediately switched from the grid, to keep the operational condition of the network simple and clear, safe and suitable for auto-reclosing. The risk that small generators would feed the fault arc was eliminated and the fault location procedure remained straight forward.

However, the onset of dispersed and renewable energy sources are forcing system operators to re-consider the contribution of the distributed power plants to system services as voltage control, reactive power support, fault-ride-through capacity, post-fault network restoration, black-start facilities, frequency support, frequency control, etc. [47]. Depending on the applied technology of the generator and the driving energy converter, the different types of DGs can facilitate these services to a certain degree. At this moment, the most important requirements are related to the fault-ride-through characteristics, as short-circuits in the transmission systems otherwise will lead to the loss of a substantial part of the power generating capacity. The adverse contribution of DG without an adequate fault-ride-through capacity to system unbalance, and even the occurrence of large black-outs, has been pointed out in [9] (D.A. Baeza); see figure 1.



Figure 1.- Wind production during short-circuits

Another important feature is the under-frequency tripping of DGs, where usually the protection level settings are unnecessarily high (for instance 49.5 to 49.7 Hz in a 50 Hz system), thus adversely influencing power deficit situations and eventually black-outs.

For example, from a technical point of view, modern design of windmills offer the possibility to employ their inertial energy, freewheeling independent from the power frequency, to overcome to a large extent the difficulties during voltage and frequency dips. Also many co-generation plants are capable of contributing to the overall system performance for a longer period of time rather than to adhere to the old policy of immediate tripping.

When DGs contribute to these and other ancillary services, clearly large advantages for the power system are offered, but the networks and their equipment are not naturally equipped for such a behaviour, at least not in distribution-networks [49]. More precisely, the distribution grids were originally not designed to accommodate power plants at all (opposite to transmission and some industrial grids). These new 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. The impact of these developments on the network conditions and requirements to the equipment are the topic of this Technical Brochure.

2. TECHNOLOGY OF DISTRIBUTED GENERATORS

2.1 Windmills

According to CIGRE Technical Brochure 185 [10] wind energy conversion systems can be distinguished by 8 different types of WEC, four of which are with an AG (asynchronous generator) and the others with a SG (synchronous generator).

1. An AG, squirrel-cage rotor type, directly connected to the grid (usually through a step-up transformer), with a fixed speed of the wind turbine and a reactive power consumption dependent on the rotor slip. Reactive power compensation by means of a capacitor-bank may be added, but with a decrease of the network voltage the reactive power supply from the capacitor-bank decreases quadratic, while, due to a larger slip, the AG requires even more reactive power. The AG contributes to the short-circuit current, but with a relatively fast decay (short-circuit current disappears within 5 to 7 cycles).
2. A SG, directly connected to the grid (possibly through a step-up transformer), with a fixed speed of the wind turbine. Needs to be synchronised. Supports the voltage by a controllable reactive power output. Contributes substantially to the short-circuit current.
3. An AG, squirrel-cage rotor type, connected to the grid by means of a full converter, with a variable speed of the wind turbine. Supports the voltage by a controllable reactive power output up to the capacity of the converter. Does not contribute to the short-circuit current, as the converter limits the current to typically 1.1 pu.
4. A SG, connected to the grid by means of a full converter; see 3.
5. An AG with almost fixed speed of wind turbine and a dynamic control of the slip (thyristor controlled additional resistance to the rotor). Small possibilities to control the slip (i.e. speed) and therefore the consumption of reactive power. Further see 1.
6. A SG, mechanically direct driven by the rotor of the wind mill (without any gearing) and connected to the grid through a full converter. See 3.
7. A double fed induction generator (DFIG) with a wound rotor and a converter that supplies a variable frequency current to the rotor, thus controlling the rotor speed to an optimum, that depends on the wind speed. The partial converter (supplying the rotor only) is less expensive than a full converter, but still offers to a large extent the facilities of a variable speed drive. Under steady state conditions the machine is behaving like a SG, albeit with different values for the characteristic parameters. Does contribute moderately to the short-circuit currents.
8. A SG, mechanically direct driven by the rotor of the windmill, with permanent magnets in the rotor circuit and a full converter as interface with the network; further see 6.

The generators with a full converter (3, 4, 6 and 8) will behave more or less identical, from the point of view of the network. Differences are coming from the dimensions of, mainly, the converter and from the characteristics of the controllers (for speed/power, for voltage/reactive power, for protection purposes, for start/stop operations, for mastering and communication). The rotors are freewheeling and their inertial energy can be employed during system disturbances. Several possibilities of voltage and/or reactive power control are normally available. The largest advantage is an optimal conversion from wind energy to electric energy is achieved. This is a large advantage over the less expensive fixed frequency windmills (1, 2, 5), which nowadays are to be considered as obsolete, especially above 750 kW. One popular

WEC is the double fed induction generator (DFIG), being an attractive compromise between the cheaper technologies without frequency-control and the most expensive technologies with an utmost control range. The technology originates from controlled drive systems, where the design is popular as well. WECs up to 5 MW are available, and the developments are still going strong. The other technology employed is the gearless SG with a full converter (6 and 8).

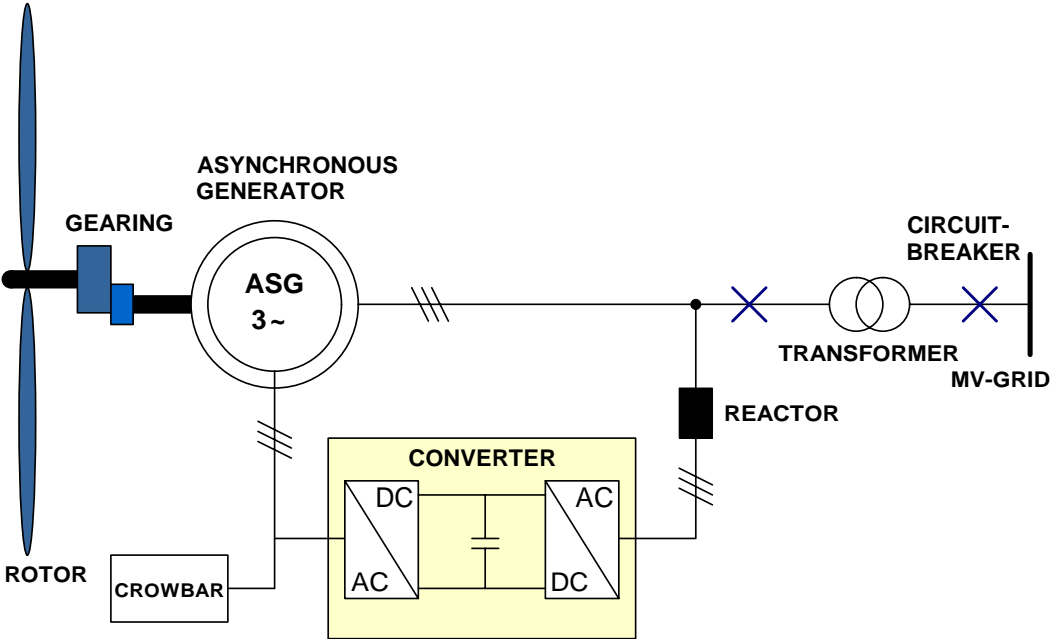


Fig. 2 DFIG

Full converters are also applied in small power plants such as micro-turbines, fuel-cells, photo-voltaic systems, energy storage systems as SMES (super-conducting magnetic energy storage), BESS (battery energy storage system) and flywheels. Due to the application of a converter, these small power plants are able to limit their contribution to fault currents, to support reactive power balance and voltage control, to restore systems after disturbances, to 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 in the network. Besides the added costs, one main disadvantage is the generation of harmonics, although nowadays converter technologies and mitigation techniques show substantial improvements. The topic of power-electronics will be discussed in chapter 6.

DFIG

In the double fed induction generator (DFIG) the 3-phase power frequency connection to the stator windings is electrically separated from the 3-phase variable frequency connection to the rotor windings. The control of the AC/DC and DC/AC converters has been designed and set in such a way that the frequency of the rotor supply is equal to the power frequency minus the frequency that corresponds to the mechanical speed of the rotor (or through the gearing to the mechanical speed of the rotor of the windmill). In other words: the magnetic field rotating along the periphery of the rotor has a rotational velocity that consists of the speed of the magnetic field with respect to the rotor (and forced by the variable frequency supply of the converters) plus the mechanical rotational speed of the rotor itself; the total velocity of the rotor magnetic field corresponds to the rotational velocity of the stator magnetic field and the phase shift or angle between these two magnetic fields determines the torque of the generator. From the perspective of the magnetic fields, the induction generator is acting as a synchronous machine.

The construction of the rotor windings, the excitation, the magnetic circuit and the magnetic materials, the stray fluxes are very different and hence the machine characteristics are different: reactances and time constants (much lower than the time constants of synchronous machines [11]). The behaviour of the DFIG under transient conditions therefore differs considerably from that of a synchronous and even an asynchronous generator. Its behaviour is to a large extent depending on the setting of the many control mechanisms as shown in figure 3. Apart from the complicated actions undertaken by the converters and their controls, the power electronics is protected by a crowbar that may bypass the rotor-side converter, thus forcing the generator to an induction generator mode of operation. However, the crowbar will not short-circuit the rotor windings, but add an extra resistance, up to 20 times the rotor winding resistance [12], which is already relatively high for wound windings. And the crowbar will not act immediately, but depending on the circumstances and setting sometimes after several power frequency cycles. Moreover, it can be de-activated again and even very fast after activating. Besides, the rotational speed of the induction generator can be far from the speed belonging to the power frequency, so that all these factors lead to the conclusion that the machine will not act as a normal asynchronous generator either.

Another speciality of DFIG (and synchronous generators with a full converter) during transients is that the rotor of the windmill may freewheel with respect to the system frequency, thus serving as a freely controllable source of inertial energy.

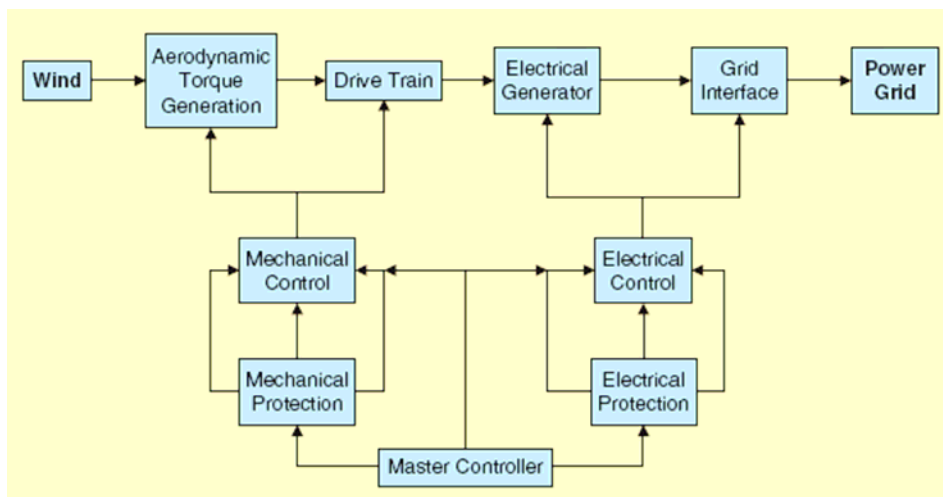


Fig. 3 General scheme of WEC-controls, incl. DFIG [13]

2.2 Co-generation

On the other hand there are numerous power plants with conventional lay-outs and various generators driven by: reciprocating machines (gas-motors, diesel-engines), gas turbines (single shaft GTs derived from heavy duty types or multi-shaft GTs derived from the aircraft, i.e. aero-derivatives), steam turbines (incineration of refuse, of biomass, of bio-gas, and solar thermal/geo-thermal installations), small hydro plants (including pump storage), or air-pressure turbines (compressed air storage installations). Furthermore, combined cycle power plants (CCPP) can have a GT, ST and generator on one shaft or GT and ST on separate shafts with each its own generator. As most of these technologies are used for co-generation purposes, practically all are more or less regarded as contributing to environmental sustainability. The generators can be synchronous or asynchronous machines, and depending on the size directly connected to the distribution-grid or through a step-up transformer. These power plants and the DFIG windmills will have the most impact on the (distribution) networks. The studies of WG A3.13 are therefore focused on such technologies.

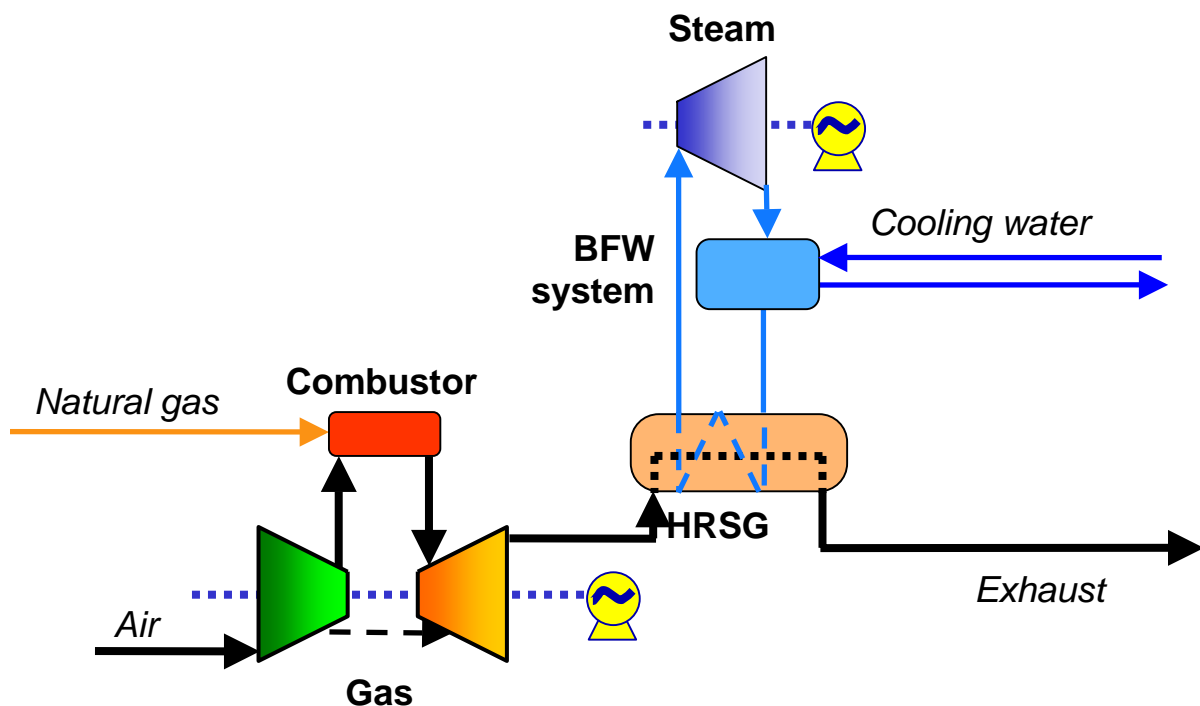


Fig. 4 Combined Cycle Power Plant (CCPP)

The exhaust gases flow through Heat Recovery Steam Generators (HRSG), that contain components as the economiser, the evaporator, a superheater and a drum in the natural flow HRSG. The HRSG may be without or with supplementary firing (un-fired or fired HRSG) or even a fully fired conventional boiler can be used instead. Most HRSGs are of the once-through boiler type (i.e. without drum) [14]. Such alternatives are of course optimized for the processes where the heat or steam is employed. With supplementary firing more operational flexibility is possible, while additional cooling or a by-pass to the boiler gives more flexibility for the generation of electricity. These features are relevant when ancillary services like fault-ride-through capability, power frequency support and black-start capacity are required.

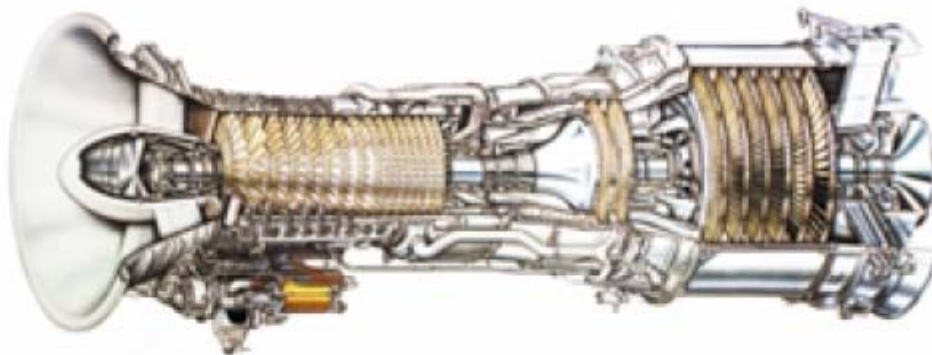
GT and CCPP

Cogeneration plants are relatively simple for the lower power range (some MW up to roughly 10 MW), but more complicated for units of several tens of MW or even hundreds of MW. The last category are either fuel fired boilers delivering steam to steam turbines and exhaust heat or steam for industrial processes or combined cycle power plants (CCPP) with one or more gas turbines, the exhaust gases of which are used to generate steam for a steam turbine and exhaust heat or steam for industrial processes or district heating. All rotating equipment of a combined cycle plant may be installed on one axis (air compressor, gas turbine, steam turbine and generator) or on separate axis with separate generators. When assembled to one axis, the steam turbine often can be decoupled by a special clutch, in order to facilitate starting up procedures and independent operation of the gas turbine. Not only the control is depending on the number of axis applied in the CCPP, but also the dynamic behaviour of the plant, as the gas turbine/generator sets will react different from the steam turbine/generator sets or the sets with only one axis.

Heavy duty gas turbines consist of a single axis with a large compressor, combustors and a gas turbine, that delivers mechanical energy to the compressor as well as to the load (i.e. the generator). The inertia is determined by compressor, gas turbine and generator. The operational speed is relatively low for a gas turbine, as the generator runs 3000/3600 rpm or even 1500/1800 rpm. Below roughly 40% of the rated speed, the gas turbine is not capable to deliver enough torque for the compressor and therefore normally the generator is used as motor to bring the set up to speed.

Aero-derivatives are gas turbines based on the technology used for air craft gas turbines. Where in aircrafts the power of the gas turbine is used to drive the air prop, aero-derivatives use the supplementary energy to drive a generator. The size is up to several tens of MW and they normally use two axis, one to drive the compressor and the other to drive the generator. The compressor and its part of the gas turbine can run at an optimal speed, independent from the power frequency. The generator with its part of the gas turbine (called the power wheel) run at 3000/3600 rpm, but with a very low inertia.

The exhaust gases of the gas turbines are used for a steam generator in order to improve the overall efficiency, that can go up to almost 60% to generate electricity (Brayton cycle plus Rankin cycle) and to far higher percentages of the energy efficiency, when the remaining exhaust heat can be exploited usefully. To reduce the NO_x-emission a small amount of water (steam) is injected in the combustor chambers, among other measures. A special design of rather small gas turbines is the STIG (steam injected gas turbine), where the steam turbine is replaced by the injection of relative large quantities of steam directly into the gas turbine (that acts as a combined gas and steam turbine). This combined function of the gas turbine is known as the Cheng-cycle.



LM2500 Gas Turbine

Fig. 5 Double axis, aero-derivative gas turbine, also available as STIG

For instance, in order to contribute to frequency control GTs should be either operated with some margin from the rated capacity (say at 95% - 97% of its rated power) or be operated with temporary over-firing by accepting, as consequence, that residual life is consumed at a higher rate due to the high temperatures at the first row of turbine blades.

The setting of the droop of the primary power-frequency control is another problem with GTs, as the power output of a GT is proportional to the rotational speed (i.e. power frequency), but also the pressure build-up of the compressor, thus giving a reduction of the electric power output proportional to the square of the actual system frequency ($P \sim \text{freq}^2$), right at the moment that more power is required. GTs therefore have to be temporarily overfired or operated with adequately widened power regulation range to effectively contribute to primary power-frequency control in particular in isolated systems subject to large frequency decays. In some power plants the control of emissions and the control of the gas temperatures prohibit overfiring.

Most of STs of CCPP are operated in the sliding pressure mode (inlet valves fully open), thus not contributing to the primary frequency control because they react to frequency deviations with some minutes delay. On the other hand, if the ST is operated with inlet valve pressure control, it can partly compensate for the inherent deficit in power when the frequency drops, so that the power plant will contribute to the required primary power control.

Of course the percentage of GTs in the whole installed power generation capacity of the system is an important parameter. In fact there is a clear trend to a higher share. In [14] figures varying from 25% up to 50% as a percentage of the national installed capacity have been given for CCPP and simple GT driven plants i.e. percentages that force GTs to substantially contribute to the droop control. For instance in the power system of Turkey, in 2006 one third of the 40,000 MW installed capacity is contributed by gas fired CCPPs.

Black-start conditions put forward special measures to bring the GT generator set up to self-supporting speed, as well as special precautions for the HRSG. Once-through boilers, if applied, face problems when loaded under, say, 30%, thus making them less suitable for the initial phase of system restoration. In this respect it should also be stated that DGs of the size of several tens of MW should be able to withstand low frequency operation, down to 47.5 Hz continuously and down to 46.5 Hz or 47 Hz for a few seconds in a 50 Hz network.

The inertia of commercial GTs can be learned from table 4.3 of CIGRE Technical Brochure 238 [14]. For a size of hundreds of MW, heavy duty GT generators have an inertia constant: $H = 7$ to 8 s. Smaller units show smaller inertia constants: $H = 5$ to 7 s. Small units (less than 15 MW): $H = 2$ to 4 s. Aero-derivative GTs: $H = 1.3$ to 2.2 s. In this respect a first rough indication of the critical clearing time can be derived from [15]: $CCT = \sqrt{(H/50)}$ s (i.e. infinite power at busbar).

Just for reference purposes: modern windmills (DFIGs) of several MW have typically an inertia constant of 2.5 to 3.5 s.

Table I: Rough indication of Critical Clearing Times

Technology	H (s)	$\sqrt{(H/50)}$ (ms)
Large GT	7 – 8	400
Medium size GT	5 - 7	350
Small size GT	2 – 4	250
Aero-derivative GT	1.3 – 2.2	180
Windmills	2.5 – 3.5	250

2.3 Other small power generation technologies

It has to be remembered that unbalances in electric power can only be survived by the availability of enough inertial energy! In that respect, some words may be spent to small plants. The inertial energy of windmills is only profitable, when they remain connected to the disturbed grid.

Small hydro-plants use either conventional SG, mostly with very simple or even without speed regulators and a simple AVR, or induction machines (no speed control, no AVR, no synchronisation device) with or without shunt capacitors to supply the reactive power. Like with the large hydro power plants, from these generating sets the inertial energy can be employed for system stability.

High speed micro-turbines need a power-electronic interface to be connected to the LV-grid and therefore behave as a converter. The same applies to fuel cells, but opposite to micro-turbines, by a lack of inertia, fuel cells cannot adapt very fast the power output. Also PV-systems are connected to the grid through converters and like fuel cells they cannot react fast to power demands, even worse as they are dependant on the intensity of sunshine. SMES, BESS (battery energy storage system) and flywheels all are connected through converters and are able to react fast to the active and reactive power demands for a limited amount of time. Like the micro-turbines they offer some inertial energy for system stability.

Another development could be the large scale implementation of rather simple co-generation machines for house-hold applications, replacing the conventional gas fired heat supply (high efficiency boiler). For instance, by applying a Stirling motor that drives a simple single phase induction generator. Studies and experiments are going on to see the technical, economical and societal impact of the application of tens of thousands of such sets. One of the phenomena that may have an impact on LV-grids (< 1 kV) and, possibly, on distribution-grids above 1 kV as well, is the facility and/or circumstances that all these single phase induction generators will start at the same moment, thus requiring too much reactive power, leading to voltage instability.

3. REGULATIONS AND POLICY WITH RESPECT TO DISTRIBUTED GENERATION

In their rules and requirements Regulators have to take into consideration both the reliability of the power systems and the support of sustainable energy sources. Easy access for massive installation of wind-mills and of certain types of co-generation plants to the network may hamper the prevailing security and safety levels of the public electric power supply systems. With an increase of sustainable power generation as indicated in chapter 1, it is clear that requirements have to be put forward with respect to power control, power support, voltage control, reactive power support, voltage and frequency deviations, fault-ride-through, frequency control, black-start capacity, and other ancillary services.



Fig. 6 Wind farm in the North Sea

So far, the requirements are restricted to medium size power plants and above (larger than 10 MW or some tens of MW) and even then only a few of the ancillary services are addressed by some TSOs. Where in the past most attention has been given to the grid connection requirements for medium size co-generation plants, nowadays the major debate is on the requirements for wind-farms. Nevertheless, from the system point of view, the individual small power plants may be equally important for the local network stability. Requirements to prevent a sudden large loss of power generation in the MV-networks should be established as well (see also chapter 4).

At the CIGRE Sessions 2006 a good overview of the present requirements and developments in some national gridcodes has been given [16][17][18]. The requirements for wind-farms were discussed with respect to power control, performance in relation to frequency variation range, reactive power supply and fault-ride-through. Some countries put forward requirements for wind-farms above a certain size (for instance 30 MW), others in case the wind-farms are directly connected to transmission grids (UK) or sub-transmission and transmission grids (Germany).

3.1 Fault-ride-through requirements

Most gridcodes nowadays put forward requirements with respect to fault-ride through capacity, but they are still struggling with the precise descriptions of the requirements. However, there is worldwide a trend to define the voltage drop at the high-voltage side of the transformer, that connects the wind-farm to the (sub)transmission grid. Just as an indication, three examples of the fault-ride through requirements are shown in figure 7. Mostly the wind-farm has to ride through a voltage dip down to 15% of the rated voltage (Spain and Brazil: 20%), but in England and Wales (indicated as UK in the figure below) the code requires ride through down to 0% of the rated voltage. The duration of the dip is 140 ms in UK, up to 625 ms in Germany (500 ms in Spain and Brazil). Hydro Québec requires an initial ride through at 0% of the voltage up to 150 ms.

After clearing the fault in the (sub)transmission grid, it generally takes some time before the voltage is recovered to its original value. The wind-farm has to sustain this post fault period as well. Moreover, it has to contribute to the recovery of the voltage. In [13], the developments and debates in the USA, at the end of 2005, are given. In the meantime the FERC (Federal Energy Regulatory Commission), after hearing the arguments of stakeholders like the AWEA (American Wind Energy Association), the WECC (Western Electricity Coordinating Council) and the NERC (North American Electric Reliability Council), decided not to follow requirements as strict as put forward for instance in Germany, but to require only a fault-ride-through capability of wind-farms for ≤ 150 ms and for a residual voltage $> 15\%$ at the connection point.

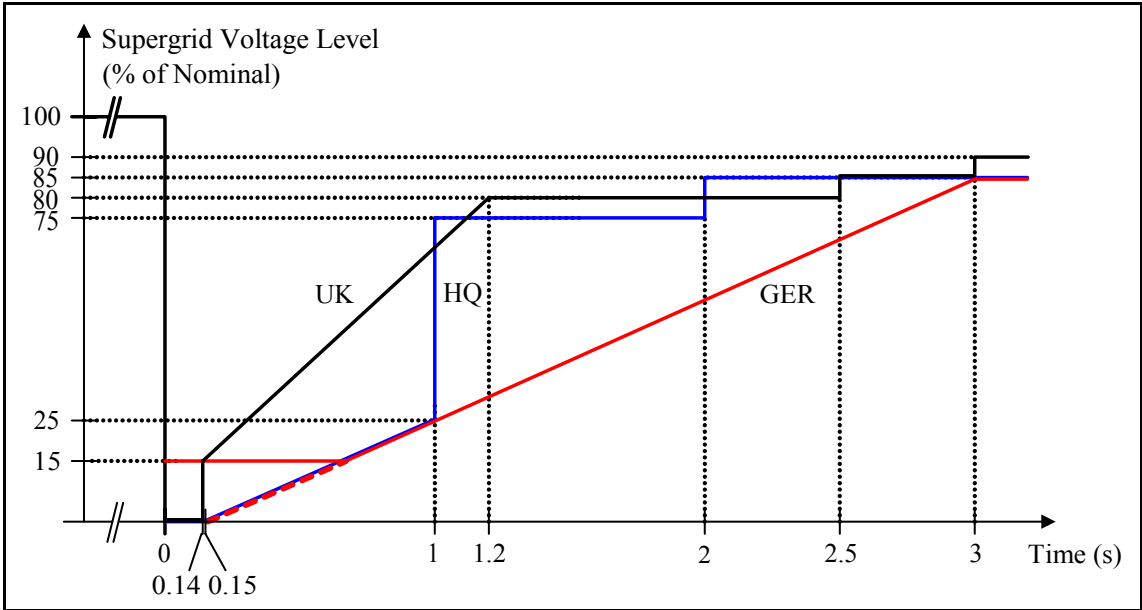


Fig. 7 Examples of Fault-Ride Through requirements

There is still world-wide a lot of debate, but, at the same time there are also efforts to harmonise the requirements. Important to note is the clear trend to require that during voltage dips wind-mill farms have to stay connected to the network.

These requirements are more or less in line with requirements put forward for conventional power plants of the same size and/or grid connection (subtransmission or transmission). For individual wind-mills and smaller power plants no general trend can be seen and utilities still accept or even apply the old policy of tripping the power plants as soon as a disturbance occurs. This policy is related to safety issues, which of course is of great concern as well for the gridcodes.

3.2 Other requirements

Apart from fault ride through requirements for voltage dips, there are also requirements for fault ride through during temporary overvoltages, asymmetrical faults and frequency variations. As an example Hydro-Quebec's requirements regarding fault ride through capability of wind plants connected to its transmission network, as described in [20], and presented below:

- The wind plants must be designed, built, operated and protected so as to remain in service without tripping any wind plant equipment during the voltage and frequency variations shown in Table II, Fig. 7 and Table IV as well as during various fault conditions summarized in Table III. These voltage and frequency variations can occur simultaneously and could be reached when the system experiences extreme contingencies.

Table II: Minimum time periods during which wind plant must remain in service without any tripping during voltage variations

Voltage (pu) ^{note 1}	Minimum time
$V < 1,0$	see Fig. 7
$1,0 \leq V \leq 1,10$	Long period ^{note 2}
$1,10 < V \leq 1,15$	300 seconds
$1,15 < V \leq 1,20$	30 seconds
$1,20 < V \leq 1,25$	2 seconds
$1,25 < V \leq 1,40$ ^{note 3}	0,10 second
$V > 1,40$ pu ^{note 3}	0,033 second

Note 1: Positive sequence voltage on the high-voltage side of the switchyard

Note 2: According to the time needed to bring back the network to a normal state, within the allowed steady state voltage range (up to a few hours)

Note 3: Temporary blocking is allowed for facilities using power electronics when the voltage exceeds 1,25 pu Normal operation must however resume immediately once the voltage drops below 1,25 pu

Table III: Faults for which wind plants must remain in service

Fault	Number of cycles	Voltage	Comments
Three-phase	9		normally cleared fault
	45	0,25 pu ⁽¹⁾	remote fault
Double phase-to-ground	9		normally cleared fault
	45	0,5 pu ⁽¹⁾	remote fault
Phase-to-phase	9		normally cleared fault
	45	0,6 pu ⁽¹⁾	remote fault
Single-phase to ground	15		delayed cleared fault

⁽¹⁾ Positive sequence voltage at high-voltage side of switchyard during a remote fault

Table IV: Minimum period of time during which wind plant must remain in service without any tripping during frequency variations

Under Frequency (Hz)	Over Frequency (Hz)	Minimum time
$59,4 \leq F \leq 60,0$	$60,0 \leq F \leq 60,6$	Unlimited
$58,5 \leq F < 59,4$	$60,6 < F \leq 61,5$	11 minutes
$57,5 \leq F < 58,5$	$61,5 < F < 61,7$	1,5 minutes
$57,0 \leq F < 57,5$		10 seconds
$56,5 \leq F < 57,0$		2 seconds
$55,5 \leq F < 56,5$		0,35 second
$F < 55,5$	$F \geq 61,7$	Instantaneous

- The requirement regarding the ability to withstand the frequency variations listed in Table IV is also applicable to any wind plant connected to Hydro-Quebec transmission system through the distribution system.

In the USA the technical requirements for the interconnection of individual DG are given in IEEE Standard 1547, a series of standards that is under development. At the moment two parts have been approved and published [55][56]. In case of system disturbances, the main standard IEEE Std 1547 emphasizes the fast disconnection of DG rather than putting forward fault ride-through requirements. For instance: a disconnecting time < 160 ms for a voltage at the point of common coupling less than 50% or higher than 120% is required or for a frequency smaller than 57 Hz (59.3 Hz for DG < 30 kW) or higher than 60.5 Hz. Larger clearing times are allowed for smaller voltage and frequency deviations.

Other requirements are related to voltage and reactive power control, online information sharing with the TSO or DSO and active power control by the TSO. Especially in Spain REE is applying a control center to dispatch the power from windfarms larger than 10 MW. Further requirements are put forward to prevent islanding, for synchronisation, for safety (disconnectors, earthing, blocking), but these requirements are specially for individual DGs [57].

There is, certainly in Europe [58], a tendency to harmonise and standardize the requirements for small power plants, windmill farms and individual wind mills. Standardisation is also in the interest of manufacturers and operators of small generators.

4. NETWORK TOPOLOGIES RELATED TO DISTRIBUTED GENERATION

As illustrated in figure 8, DG 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 power flow patterns. Short-circuit currents will show directions and amplitudes that are dependent on the operational mode of the DGs. 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.

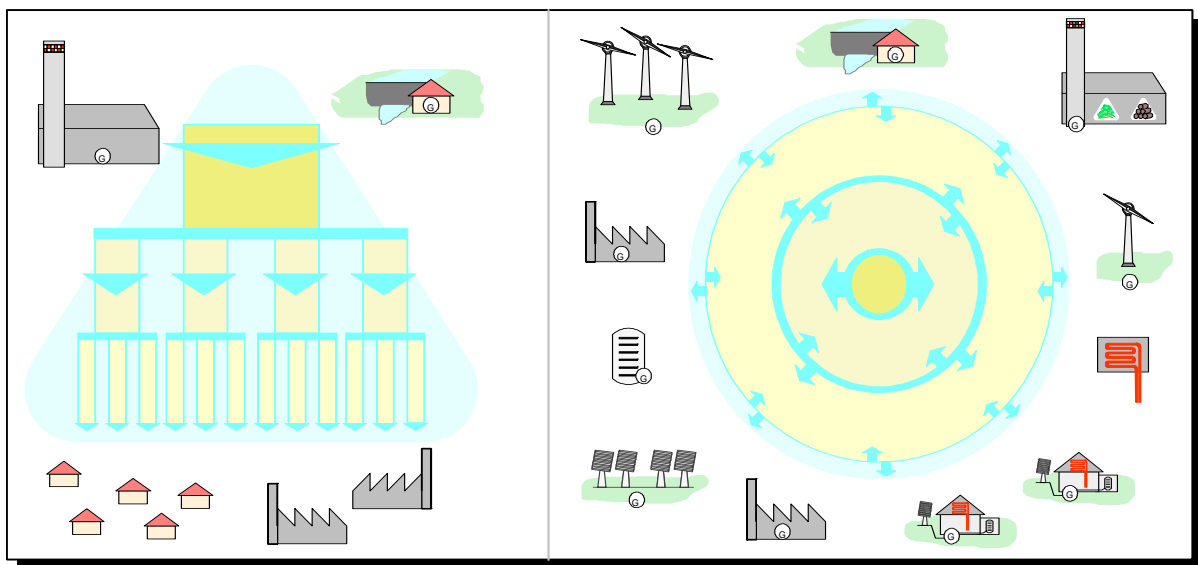


Fig. 8 Structural change of power flows in distribution grid

For example, in a MV distribution-network without DG, the fault current is determined by the impedance of the power-transformer plus the impedance of the distribution-feeder up to the fault location. The ratio between these two impedances is such that the peak value of the short circuit current is already reduced considerably at a distance of, say, 1 km from the substation. At a distance of several km also the AC-value of the short-circuit current is reduced considerably. But, in the case of small size DG, the impedance of the generator plus step-up transformer is much larger than the impedance of the HV/MV power-transformer supplying the MV network: up to some orders of magnitude for each generator. This means that the impedance of the distribution-feeders is of far less influence, even when a number of small generators are connected to the same feeder. The impact of the DG on the amplitude of the short-circuit current may be of importance or not, depending on the electrical distances from the grid source, on the rated power and the technology and number of DG and the several impedances.

In industrial plants with self-generation often the power plant is directly connected to the main MV busbar or even through a separate transformer (i.e. step-up transformer) to the transmission network. Similar scenarios can be found in large power plants with auxiliary generators (for instance: a pre-inserted GT, a GT driving the feed water pump, a GT for the

auxiliary electric plant, a black-start unit). In distribution grids there are many instances where separate OH lines/cables connect the DG directly to the main busbar in the substation. In transmission or sub-transmission grids, the DG are connected by separate transformers. For wind mills one can also find dedicated distribution networks, separate from the distribution network to supply the load (in some regions of the Netherlands typically new, non-redundant, 20 kV public networks are used to connect wind mills while old, redundant, 10 kV grids are used to supply power to loads[21], see figure 21). In addition wind farms, which are power plants consisting of many wind mills, are usually directly connected through step-up transformers to the transmission network.

At transmission levels less problems are expected with such power plants, as transmission grids are used to connect large generators. Moreover short-circuit powers are normally far larger than those of the power plants, and short-circuit currents are cleared much faster than many of the short circuits in distribution networks. Multi-directional power flows and complicated short-circuit current patterns are not an issue at the transmission level. Out-of-phase conditions in case of DG are not so different from out-of-phase conditions of other plants and can therefore be treated equally (specified duties for switchgear, special protection and control equipment, synchro-check and synchronising equipment, interlocking, 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 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 [48]. 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 (see chapter 3).

In order to profit from DG and to minimize its drawbacks for the network have led to an innovative optimization of protection settings and control circuits. In this respect, reference is made to [45] where the following recommendations are outlined:

DG connected to faulty MV or LV distribution-feeders

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

DG connected to healthy MV or LV (radial) distribution-feeders in case of short circuits in an other MV or LV feeder supplied by the same substation

- SGs and AGs should be kept in service if short circuit is cleared in the standard low time (say, within 200 ms for multi-phase faults)
- Protect SGs against loss of synchronism
- Protect AGs against sustained overspeed and overcurrent

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

- SGs and AGs should be kept in service in case of multi phase faults in the HV network cleared in short time (≤ 200 ms) and in case of 1-phase-to-ground faults in HV network even if of long duration (say, 0.5 – 1.0 s)
- Protect SGs against loss of synchronism
- Protect AGs against sustained overspeed and overcurrent

Islanding

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

However these measures are only feasible when short protection clearing and auto-reclosing times (100 ms to 200 ms) can be reached, which may not be the case in distribution-networks [22]. But, as stated before, DFIG 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 disappearance.

Already today, upgrading the protection and voltage control systems and setting-up new operation and maintenance rules in distribution-grids with a large amount of power generation is an issue. As local DG increases, the networks will need to be updated in distribution capacity or heavily utilized up to their limits, depending on the type of dispatch-ability of DG, on configuration of the network and on size, number and location of DG. Information on the operational mode of small power plants is normally not well known by the utility, so it is very difficult to estimate the load profile. This leads to the situation, where the redundancy in the power supply system is not fully known. The redundancy is partly covered (to an unknown extent) by the DGs, which leads to the inherent requirement that not all power generators should be tripped at the same moment. At the distribution-level, the uncertainties on power flows and the anticipated short-circuit current flows are a problem, together with the huge increase in installed capacity in some networks, as indicated also in [23]. Use can be made of the dynamic loading capabilities of the cables, OH-lines and transformers involved, but the overloading capacity of switchgear is still an area for research (CIGRE SC B3) and Standardization.

The need to improve or at least maintain power quality as the complexity of distribution networks increases, must also be considered. Unpredictable power flows and differentiated reliability claims may lead to a requirement for sophisticated control and protection in addition to “new” switching duties. Network components may need to fulfill new duties such as controlled switching, very short fault clearing times, dynamic loading capabilities (utilization of cycling loading capabilities), intelligent switching, advanced communication, voltage regulation and power flow control. New developments in power electronic technologies such as active filters, SVC’s and flexible series compensation may also influence basic system parameters such as (short-circuit) current profiles, voltage profiles, TRVs, overvoltages, harmonics and voltage asymmetry. They may also result in the development of “unusual” network topologies compared to historical practice.

As stated previously, operating in an island mode is rather exceptional as it is very difficult to achieve the proper tuning between DG power and load at the moment of islanding and an acceptable frequency regulation capacity for a public network. Normally the large interconnected transmission network serves as an enormous reservoir to deal with power

unbalances and the claim is correct that without this large interconnected facility the huge penetration of DG, and especially of wind mills, would be impossible. The multiple power transfers between regions and countries (see figure 9), which may be contributed by the electricity production patterns from DG, is the subject of the CIGRE WG A3.13 Technical Brochure, Part II.

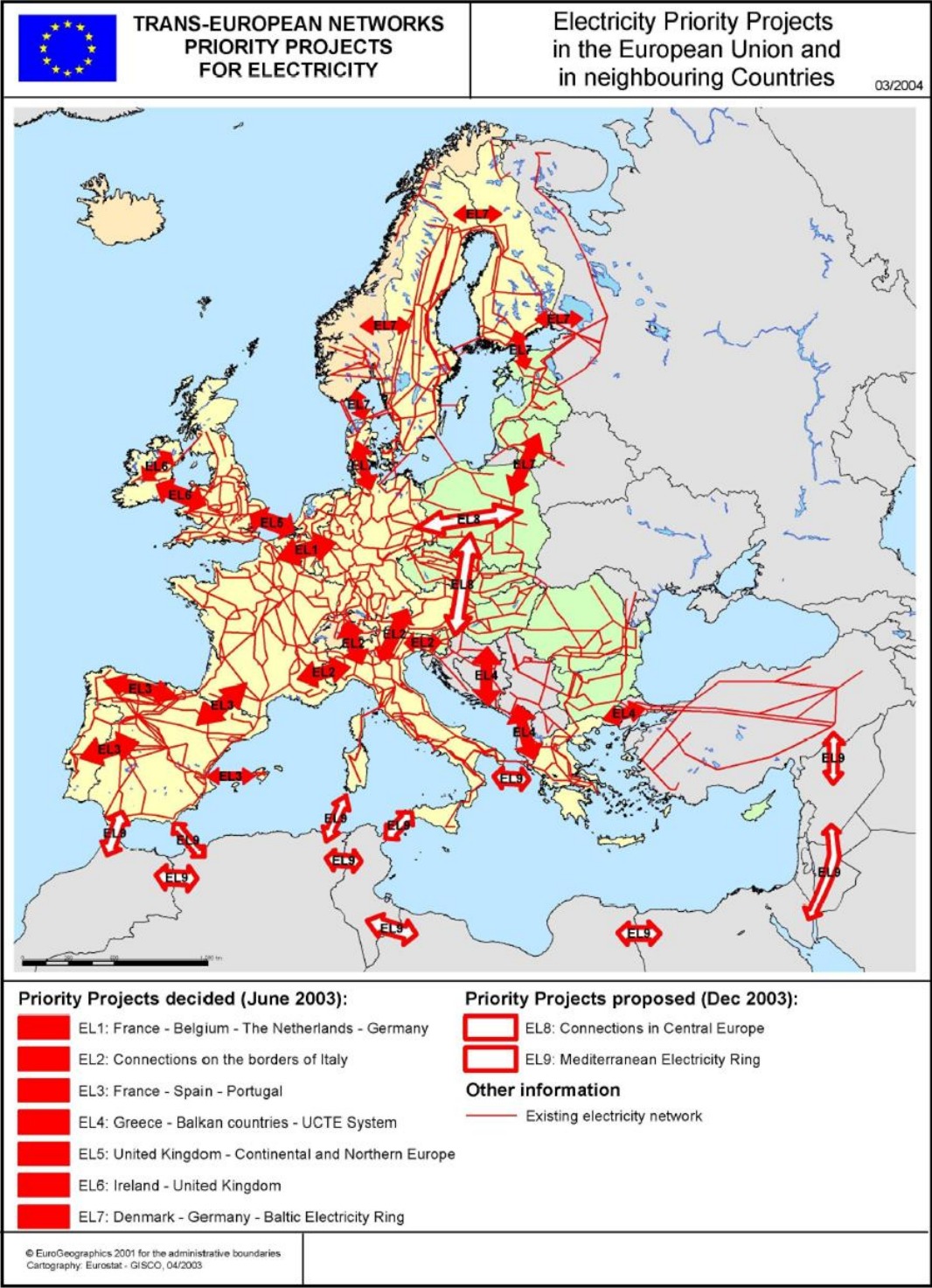


Fig. 9 European Energy and Network Policy - Priority Interconnection Plan

Island operation

To date there are very few examples of public distribution networks that can be operated part-time decoupled in an island mode [57]. On the other hand the tendency towards achieving islanding capability using distributed generation is noticeable in the distribution networks, as already applied in industrial plants with auto-production. This development is also driven by the new regulations of a liberalized power market. Another trend that can be seen is the use of isolated networks supplied by distributed generators like windmills or solar power modules combined with generators powered by biomass energy or gas turbines or reciprocating motors thereby balancing the energy demand.

A radial network with an uni-directional power flow (passive network) can be protected by relatively simple protection principles, such as unidirectional overcurrent/time relays. Radial and meshed networks with a bi-directional power flow need more complicated protection systems and even new protection designs to prevent the selectivity of the protection being impaired. Additionally, protection and circuit-breakers have to be designed for short clearing times to prevent stability problems. Communication between protection systems and between control systems (reverse interlocking, blocking, trip signal transfer etc.) are needed to ensure selectivity and to minimize fault durations.

Such systems are equally required to facilitate network decoupling and islanding. An example of a three-stage decoupling strategy can be given. It is based on the direction of the reactive power flow and the magnitude and duration of the voltage drop during the fault. For a reasonable islanding only faults taking place outside of the network which is foreseen to be islanded will be considered. A directional reactive power measurement can exactly discriminate between internal and external fault. This ensures that decoupling is initiated only in case of an external fault.

Taking into account the ability to achieve a stable recovery of the distributed generators, the amount of voltage drop and its duration is decisive. This is why a three-level voltage criterion is introduced. The greater the voltage drop, the faster the decoupling process will be done. To find out applicable voltage and time delay thresholds dynamic simulations are necessary. This avoids unnecessary decoupling and islanding.

As traditionally passive distribution networks become active, an issue of importance is safety; for instance: 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 signals, voltage check (auto-reclosing) and frequency check (islanding) have to be built in at the location of the HV switchgear. These measures are more or less comparable with those for large power plants connected to transmission networks and serve to a large extent as protection of the power plants. Together with the requirements for more advanced and faster protection systems, this means that more intelligence and communication has to be incorporated in the HV-devices [24][25][26][27]. The IEC standard 61850 will support this new requirements of communication in stations.

In the case where islanding of a distribution network or a part of the network is foreseen, functions are needed such as frequency control, voltage control, adaptive protection, system restoration, facilities for synchronisation and synchro-check. A few examples are listed:

frequency control

- an autonomous frequency control
- with settings different from the control during interconnected operation
- load shedding facilities
- generation dispatching facilities
- spinning reserve
- facilities to adapt easily the generators' output (for instance: by-pass of boiler, over-firing GTs)

voltage control

- advanced voltage control (droop control)
- reactive power sources
- facilities to prevent voltage instability

adaptive protection

- different settings due to different power and short-circuit power flows

system restoration

- black-start facilities
- facilities to tune the active load to the restoration of generation
- facilities to tune the reactive load to the restoration of generation

synchronisation

- enough facilities for synchronisation within the distribution grid
- facilities to re-connect with the surrounding networks
- enough possibilities for synchro-check.

Switchgear and other equipment have to be able to support these functions and to fulfil the related duties [24]. Moreover, the grid, the HV-equipment and the secondary equipment have to handle system conditions with a deviating power frequency and/or voltage deviations (amplitude, harmonics, negative sequence and zero sequence voltages). Especially the combination of transient phenomena under deviating system conditions have to be considered carefully, when islanding is applied.

5 TRANSIENT PHENOMENA

When considering network stability, control/protection systems and power quality, a high short-circuit power is normally recommended. The consequence however will be the occurrence of high short-circuit currents. Network equipment is designed to cater for the prospective short-circuit conditions, however particular aspects, such as high DC-components and/or out-of-phase performance, need special consideration when network topologies change and generators are added. Increasing quantities of distributed generation increase the likelihood of out-of-phase conditions in transmission, sub-transmission, distribution and industrial grids. A possible consequence of lightweight turbine-generator-sets employed is that conditions such as full phase opposition and even pole slipping might occur. Under these circumstances the out-of-phase current is defined primarily by the out-of-phase angle and the network impedance. With large out-of-phase angles, the out-of-phase current is probably larger than the contribution of the generator to a busbar short-circuit current. In addition, the TRV conditions related to full phase opposition can be more severe than those experienced when interrupting “simple” short-circuit currents [28].

5.1 Out-of-phase conditions

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 aero-derivative GTs, 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 SG, 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; see figure 19. This applies also to AG and even to DFIG [29]. Users are warned that loss of life and serious damage to shafts, gears, bearings, (gas/steam/wind)turbine blades, etc. can occur [36]. The stresses have to be withstood by the HV-equipment as well, but the generator’s short-circuit or out-of-phase currents are smaller than the system fed short-circuit currents. Breaking the out-of-phase current is an optional duty for HV circuit-breakers[30][31][32][33] and its specification probably has to be re-considered [22][35].

In figure 10 the transient behaviour of a SG, as simulated with NETOMAC®, is shown with t_f representing the 3-phase fault duration and t_{oop} the out-of-phase condition. Immediately after a fault clearing time of 233 ms, the out-of-phase angle is 90° , but it is still increasing up to about 150° , 150 ms later. A larger fault clearing time will lead to an out-of-phase angle of 180° , but the impact of 150° is only a few percent lower than the impact of an angle of 180° [35]; see also figure 18.

For the simulation of the TRV, when clearing the out-of-phase current, it is assumed that the out-of-phase angle will reach 180° , but such an assumption is quite normal as utilities tend to specify their generator circuit breakers for full phase opposition [19].

A simplified single line diagram of the network simulated is given in figure 11. In the next figures details of the TRV due to clearing the phase opposition current I_{oop} are elaborated for

several network and service conditions: (i) for the load of the 20 kV network various values have been chosen, (ii) the short circuit power of the 110 kV-network has been chosen to be low or high and (iii) a capacitor to reduce the RRRV (rate of rise of recovery voltage) can be connected to the transformer side of the generator circuit-breaker or not.

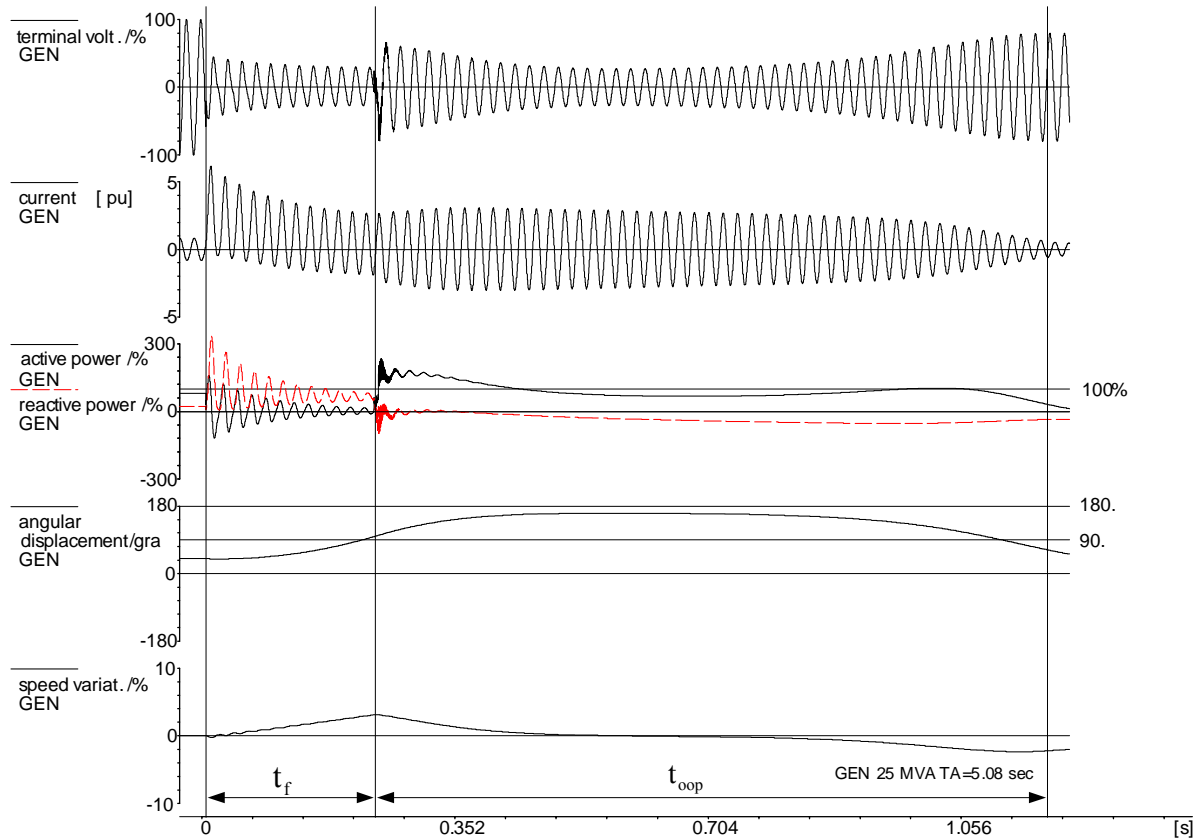


Fig. 10 Simulation of 25 MVA synchronous generator (CHP) dynamic behaviour during/after 233 ms short-circuit in distribution-network

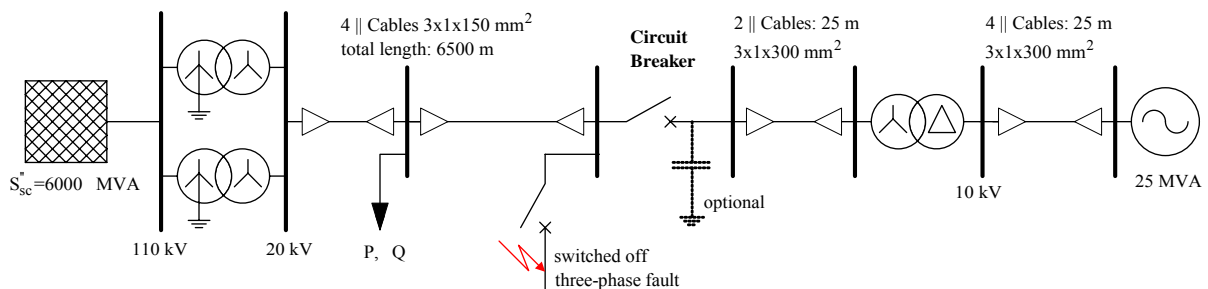


Fig. 11 Single line diagram of simulated MV-network

In figure 12 the results of the simulation for the case of a high short-circuit power at the 110 kV-side (6000 MVA), no load (i.e. no damping) of the MV network (0% load) without the application of the optional capacitor can be seen. A high frequency component caused by the step-up transformer and cables at one side of the generator circuit-breaker and a low frequency component caused by the 110/20 kV transformers and the cables at the other side of the circuit-breaker are visible. As a comparison, figure 13 shows the same case but with a

rather low short-circuit power at the 110 kV-side (400 MVA). The higher frequency seems not to be changed, but the lower frequency is about 50% decreased. The amplitude of the high-frequency component is somewhat lower, whilst that of the low-frequency component has increased. Despite some difference in the waveshape, the peak-values of both TRVs are almost identical, but: note the boosting effect of the low frequency component in figure 13.

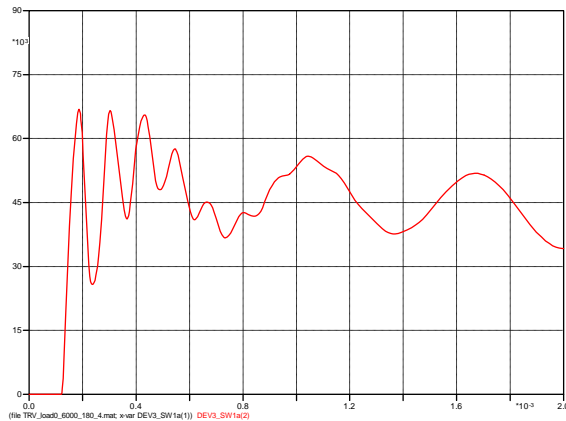


Fig. 12 Simulated TRV for 6000 MVA, 0% load, without capacitor

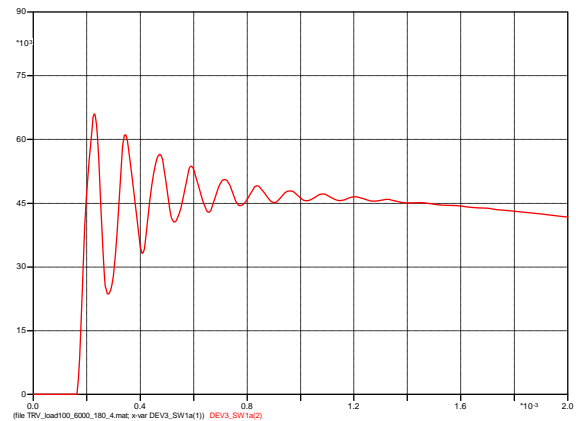


Fig. 14 Simulated TRV for 6000 MVA, 100% load, without capacitor

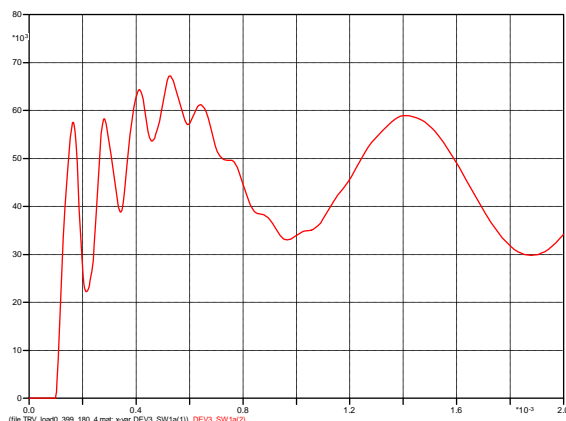


Fig. 13 Simulated TRV for 400 MVA, 0% load, without capacitor

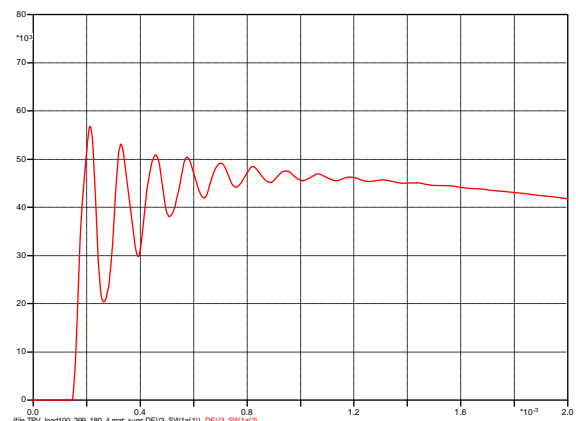


Fig. 15 Simulated TRV for 400 MVA, 100% load, without capacitor

The effect of the load on the damping of the TRV is visible in the figures 14 and 15 for a short-circuit power at the 110 kV-side of 6000 and 400 MVA respectively. The 100% load has hardly any effect on the high-frequency component but gives overcritical damping to the low frequency oscillations. For the 400 MVA-case, the boosting effect of the low-frequency component in the TRV disappears, so that the peak value of the TRV decreases.

In comparison with the requirements in the Standards the steepness of the TRV (RRRV) is rather high, as will be discussed in a further section. A possibility to reduce the RRRV is to add a capacitor at one or both terminals of the circuit-breaker. For the 6000 MVA-case, the impact of a capacitor of 100 nF at the side of the step-up transformer can be seen in the figures 16 (0% load) and 17 (100% load). The higher frequency is indeed reduced and so is the RRRV, but the overshoot of the TRV reaches up to a far higher peak value, hence stressing the circuit-breaker during the dielectric phase of the TRV (in comparison to the high RRRV-stresses during the thermal phase of the TRV).

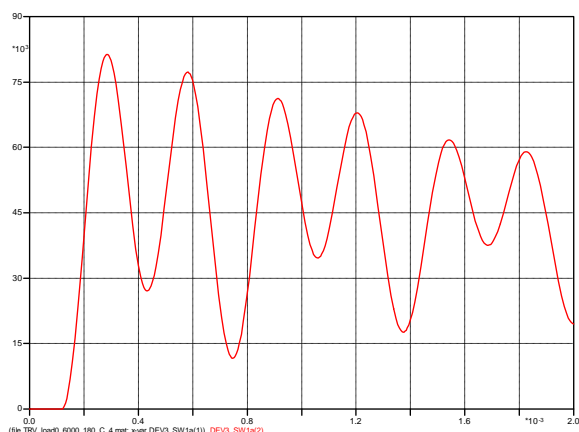


Fig. 16 Simulated TRV for 6000 MVA, 0% load, with capacitor

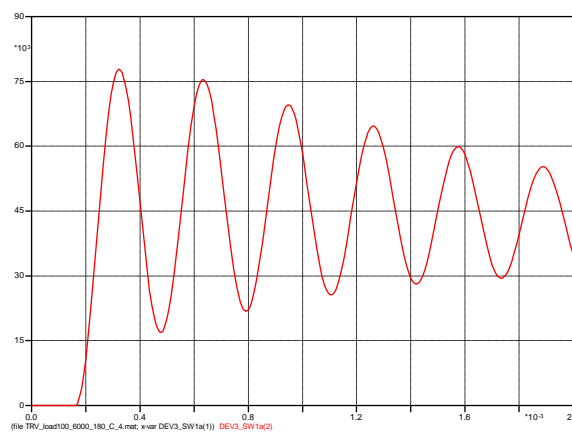


Fig. 17 Simulated TRV for 6000 MVA, 100% load, with capacitor

The simulations are based on a system voltage in the MV-network of 20 kV instead of 24 kV, i.e. the rated voltage given in the IEC-Standards. In order to compare the results of the simulations with values given in the Standards, the peak values of the TRV will further also be expressed in pu.

In the next tables a number of typical characteristics of the simulated TRVs are elaborated to be compared with the specified values in the Standards.

Table V

	Angle=180°				
	Ssc_net=6000MVA				
	Load 0%	Load 25%	Load 50%	Load 75%	Load100%
TRV	2 Parameter	2 Parameter	2 Parameter	2 Parameter	2 Parameter
U1(kV)					
t1(μs)					
U1/t1(kV/μs)					
Uc (kV)	66.84	66.6	66.27	66.16	65.97
Uc (pu)	4.1	4.1	4.1	4.1	4.0
t2(μs)					
t3 (μs)	50.8	50.7	50.6	50.5	50.5
Uc/t3 (kV/μs)	1.32	1.31	1.31	1.31	1.31
td (μs)	4.08	4.11	4.06	4.04	4.04

As was already clear from the figures, the influence of the load on the first part of the TRV is nil, but from table V it can be learned that the peak value is rather high: 4.1 pu in comparison to 3.13 pu as specified in the Standards. Also the RRRV (U_c/t_3) is much higher than 0.35 kV/μs given in the Standards. In fact the value for the RRRV shown in table V has even to be raised by 17% in order to be comparable with a value based on 24 kV. On the other hand, as stated in IEC 62271-100, test duty T30 is considered to cover the higher RRRV-stress that occurs under out-of-phase conditions¹. The RRRV for T30 (i.e. a short-circuit test at 30% of the rated short-circuit current, close to 25% being the rated value for out-of-phase duties) is 2.47 kV/μs at 24 kV (class S1), much higher than the values occurring in the simulated cases

with a cable network. (For a 24 kV-network with OH-lines, class S2, RRRV is specifies as 0.71 kV/ μ s and 3.01 kV/ μ s for out-of-phase and T30 respectively.)

¹ Note that the peak value of the TRV of T30 is only 2.61 pu, compared to for instance 3.13 pu for out-of-phase in the Standards, so that the complete rise of the out-of-phase TRV is not covered.

Table VI

		Angle=180°				
		Ssc_net=400MVA				
		Load 0%	Load 25%	Load 50%	Load 75%	Load100%
TRV	4	Parameter 4	Parameter 2	Parameter 2	Parameter 2	Parameter 2
U1(kV)		57.54	57.33			
t1(μ s)		50.71	50.61			
U1/t1(kV/ μ s)		1.13	1.13			
Uc (kV)		67.19	59.69	57.08	56.95	56.78
Uc (pu)		4.1	3.7	3.5	3.5	3.5
t2(μ s)		426	429			
t3 (μ s)				50.6	50.6	50.5
Uc/t3 (kV/ μ s)				1.13	1.12	1.13
td (μ s)		4.07	4.06	4.04	4.1	4.03

At a lower short-circuit power in the 110 kV grid, both peak values and RRRVs decrease to a certain extent (except of no load), but not below the specified values in the Standards; see table VI.

The effect of a capacitor of 100 nF is given in table VII, where RRRV is less than half the values shown in table I, but the peak values are far larger.

Table VII

		Angle=180°				
		Ssc_net=6000MVA/with Capacitance 100 nF				
		Load 0%	Load 25%	Load 50%	Load 75%	Load100%
TRV	2	Parameter 2	Parameter 2	Parameter 2	Parameter 2	Parameter 2
U1(kV)						
t1(μ s)						
U1/t1(kV/ μ s)						
Uc (kV)		81.32	80.11	79.04	78.4	77.77
Uc (pu)		5.0	4.9	4.8	4.8	4.8
t2(μ s)						
t3 (μ s)		142	141	141	140	140
Uc/t3 (kV/ μ s)		0.571	0.566	0.561	0.558	0.555
td (μ s)		18.4	18.3	18.3	18.2	18.2

Another important parameter is the out-of-phase angle, as can be seen in the next two tables; table VIII for the case of 6000 MVA and table IX for the case of 400 MVA. The tables show that the Standards cover, under the circumstances that have been simulated, an out-of-phase angle up to 99°, apart from the RRRV that is considered to be covered by T30 (two-part test). Peak value and RRRV are proportional to $\sin(\frac{1}{2}\psi)$ with ψ as the out-of-phase angle [35].

Table VIII

	Load 0%			
	Ssc_net=6000MVA			
	Angle=90°	Angle=120°	Angle=150°	Angle=180°
	TRV	2 Parameter	2 Parameter	2 Parameter
U1(kV)				
t1(μs)				
U1/t1(kV/μs)				
Uc (kV)	47.26	57.88	64.56	66.84
Uc (pu)	2.9	3.5	4.0	4.1
t2(μs)				
t3 (μs)	50.7	50.8	50.7	50.8
Uc/t3 (kV/μs)	0.932	1.14	1.27	1.32
td (μs)	4.07	4.11	4.07	4.08

Table IX

	Load 0%			
	Ssc_net=400MVA			
	Angle=90°	Angle=120°	Angle=150°	Angle=180°
	TRV	4 Parameter	4 Parameter	4 Parameter
U1(kV)	40.68	49.83	55.58	57.54
t1(μs)	50.77	50.75	50.7	50.71
U1/t1(kV/μs)	0.801	0.982	1.1	1.13
Uc (kV)	47.51	58.19	64.9	67.19
Uc (pu)	2.9	3.6	4.0	4.1
t2(μs)	426	426	426	426
t3 (μs)				
Uc/t3 (kV/μs)				
td (μs)	4.09	4.09	4.07	4.07

Figures 18 and 19 show that both the RV and the out-of-phase current above 120°, do not differ much from those belonging to an out-of-phase angle of 180° (less than 15%). An angle of 90° gives stresses that are 30% lower than those belonging to 180°. In figure 18 the RV as a product of the FPCF and the voltage factor is presented; FPCF is usually 1.5 for distribution grids and the voltage factor is $2 \cdot \sin(\frac{1}{2}\psi)$, so the RV is $3 \cdot \sin(\frac{1}{2}\psi)$. In figure 19 the current ratio I_{oop}/I_{sc} is plotted versus the ratio of reactances X_1 and X_2 , for various out-of-phase angles. X_1 can be regarded as the reactance of the generator and X_2 as the reactance at the other side of the circuit-breaker, i.e. the reactance of the network. I_{oop} is the out-of-phase current, that depends on the out-of-phase angle and both reactances, and I_{sc} is the short-circuit current supplied by the generator in case of a busbar fault and thus depending on X_1 .

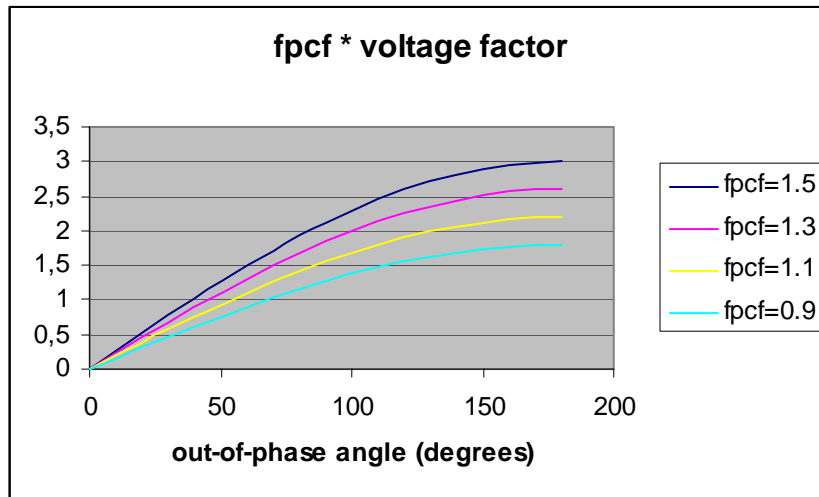


Fig.18 Recovery voltage RV as product of FPCF and voltage factor

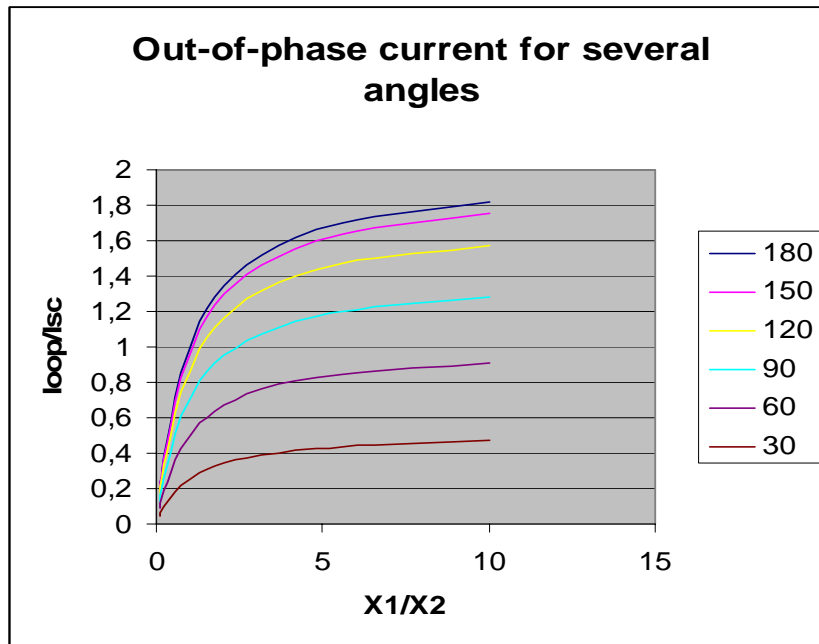


Fig.19 I_{oop}/I_{sc} as a function of X_1/X_2 and out-of-phase angle

As references for the simulations [37][38] are mentioned and the authors of [38] assisted CIGRE WG A3.13 by preparing the simulations with the results shown above.

Further details on out-of-phase conditions are available in the Technical Brochure, Part II, chapter 6.

5.2 Longitudinal dielectric withstand capability of switching equipment

Distribution circuit breakers have to perform new duties, such as system separation (out-of-phase switching), synchronisation of generators and/or systems, synchro-check before closing, etc. Such requirements are not so clear from the Standards, where for instance the specification for a dielectric type test across open contacts is between 3.2 and 4.0 pu (power frequency/1 min.), while a repetition in service is performed at lower stresses (e.g. 70% i.e. 2.2 to 2.8 pu).

According to IEEE Std. C37.013 [34] higher test voltages have to be applied (table 5 of Std.): 50 kV for rated voltages of 15.8 kV and below (i.e. 5.47 pu @ 15.8 kV), 60 kV for rated voltages up to 27.5 kV (i.e. 3.78 pu @ 27.5 kV) and 80 kV for rated voltages up to 38 kV (i.e. 3.65 p.u @ 38 kV). The same test voltages are applied for general purpose circuit-breakers with a rated voltage of 15.8, 27.5 and 38 kV resp. [31][32][33]: i.e. the 1 minute test voltage across open contacts and to ground under dry conditions.

According to IEC 60694, table 1a, from a rated voltage of 12 kV up to 52 kV the 1 minute power frequency test across open contacts of circuit-breakers (column (2)) varies from 4.0 to 3.2 pu respectively. Across open contacts of disconnectors (column (3)) it varies from 4.6 to 3.7 pu respectively. Therefore, in clause 4.2 of IEC 62271-100 [30] it is recommended to require for circuit-breakers applied under conditions of system separation and synchronisation the longitudinal withstand stresses of column (3).

With the recommendation, as stated in IEC 62271-100 and reduction for tests in service to 70%, the values given remain above 2.5 pu, being the longitudinal stress under conditions of separated systems with an earth fault at one side. Special attention, however, should be given to outdoor applications, where the same stresses have to be withstood under rain, and at least 2 pu should be withstood under polluted conditions.

5.3 Short-circuit currents

The impact of the increased number of generators tied to the distribution networks on the short-circuit currents may include:

- high values of dc component resulting from the high rate of decrease of the ac component in SG
- high initial peak value of the short-circuit current,
- high peak value of the last current loop before interruption
- long arcing time of the circuit-breaker for the major extended loop or very long arcing time in the case of delayed current zeros.

These conditions have to be related to the short-circuit current supplied through the HV/MV power transformer. The high X/R ratios of modern, low-loss power transformers also lead to large DC components. Moreover, these power transformers still form the largest supplier of the short-circuit current and the contribution of individual small generators can be neglected in comparison to the contribution from the power transformers. The sum of the contributions of a large number of small generators, however, may not be neglected. But, to the opinion of WG A3.13, the increase of the overall DC-time constant is unlikely to exceed values specified in the Standards [30].

For current transformer the situation may be different, as the transient DC-component of short-circuit currents is considerably influencing the non-linear saturation effect of current transformers. For pure current measuring purpose this effect is desirable to protect the high sensitive measuring equipment. For protection purpose saturation is one of the most adverse phenomena which may lead to malfunction of protection relays.

Figure 20 shows the magnetic flux of an iron core current transformer during a short-circuit current with a transient DC-component. It can be seen that the magnetic flux reached by the steady-state component is considerably lower than that of the transient component. If the magnetic flux is exceeding the saturation flux of the iron core, the current transformer is going to be saturated and the current transmission behaviour is strongly distorted. That is why practically the transient component is only responsible for saturation effects.

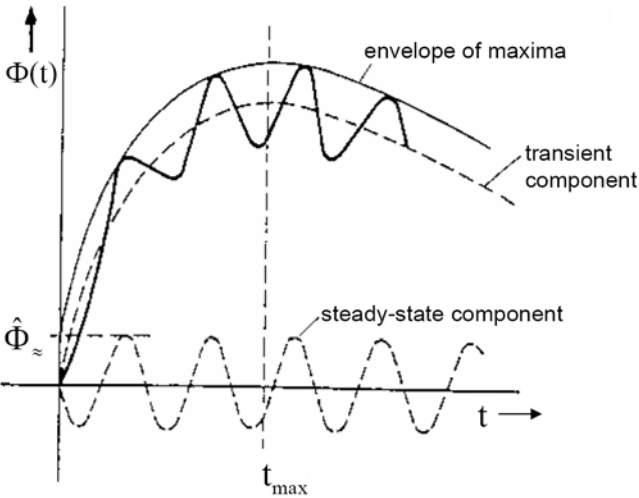


Fig. 20 Saturation effect of current transformers due to the DC-component

Thus the current transformer dimensioning must be based on the DC-components which are expected in the network. Up to now in distribution networks a network time τ_N constant of around 50 ms could be assumed. In DG networks this figure can be expected much higher.

$$\frac{\Phi(t)}{\hat{\Phi}_{\approx}} = K_{tf} = \frac{\omega \tau_N \tau_S}{\tau_N - \tau_S} \left(e^{-\frac{t}{\tau_N}} - e^{-\frac{t}{\tau_S}} \right) - \sin \omega t$$

The above equation gives an analytical basis for determining the over-dimensioning factor K_{tf} considering DC components according to IEC 60044. τ_S refers to the secondary time constant of a current transformer which lies in the range of 1 to 5 seconds in case of iron core current transformers. K_{tf} gives the factor of overdimensioning above the pure steady-state current transformer design. This could lead to a current transformer which is several ten times bigger than the steady-state design.

To keep the current transformer dimensioning within tolerable price and space limits, modern relay technology requires only dedicated saturation free transmission time periods from the beginning instant of the short-circuit. This strategy ensures a proper protection function, but allows saturation in principle.

A different situation exists in case of a larger generator or set of generators that is directly connected to the transmission network through a step-up transformer. In that case the contribution of the single generator will be considerable and the phenomena listed above have to be taken into account. This applies not only to the generator circuit-breakers, but to all circuit-breakers in the direct vicinity of these generators. Here the application of the Standard for generator circuit-breakers has to be considered [34]. An amendment to this Standard is in the final stage of approval and will cover also cases with generators from 10 to 100 MVA. It also considers generator circuit-breakers connected by means of shielded cables.

AG deliver a fast decreasing short-circuit current, that disappears within roughly 100 ms. After clearing the fault, the recovery currents absorbed by AG (and motors) will be severe, comparable with their contribution to the short-circuit currents. These recovery currents have a strong influence on the recovery of the voltage and may even lead to voltage instability. The recovery currents may last quite long, thus stressing the thermal capacity of the generators and HV-equipment[39]. Another, even more stressful, condition is the sudden open-terminal with reconnection, where currents larger than the short-circuit current will appear [39].



Fig. 21 Windmills in the Netherlands connected to a separate 20 kV-network

The short-circuit contribution of double-fed induction generators (DFIG) is very special, as it is influenced by many parameters, such as the operational mode of the generator, the control and protection setting of the crowbar, the control settings of the rotor-side converter and of the stator-side converter, the settings of the protection, the pitch control of the vanes, the

control of the hydraulic brake, etc. In a number of papers [40][41][42][46] examples have been given of short-circuit currents as calculated by means of simulations, sometimes compared with test results [43][44]. The general trend is that the short-circuit currents are much lower than when supplied by conventional AG or SG. Further the waveshape of the currents varies very widely and is difficult to understand intuitively. For example, the second peak can be higher than the first current peak [40] and the DC component can show a pattern quite different from what will be expected from conventional machines [40][43][44]. This is caused by the AC-component of the rotor current, whereas the AC-component of the (stator) short-circuit current is related to the rotor DC-current.

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 [28]. Also power system instabilities (angular, voltage, or frequency instability) could lead to severe transient phenomena and consequential events. In this respect it should not be overlooked that, due to the trend to work plant harder, it is expected that systems, including distribution-networks with DG, are operated closer to the stability limits.

6 POWER ELECTRONIC EQUIPMENT

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 electronics 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 normally will 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 overcurrents and short-circuit currents, power electronics are also vulnerable to over-voltages and transients in the system.

6.1 Harmonics

Distortion of voltages and currents in power systems is caused by power electronic equipment, by non-linear load (as arc furnaces, fluorescent and ballast lamps, etc.) and other non-linear phenomena like inrush-currents, over-excitation 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 (for instance low voltage applications), 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.

A feature of DG, certainly those of a conventional technology, is the ability to absorb harmonics. Usually this can be regarded as an advantage, unless the machines get thermally overloaded. A problem faced by utilities that apply ripple control is that the ripple signal will be absorbed as well by the numerous generators.

6.2 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 [50] or a low pass filter [51]. 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 currents 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.

Filter-banks and filter-bank switching are not covered by the Standards, as the circumstances for their application vary too widely 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.

All equipment within a filter-bank are subjected to a high content of harmonic currents, especially since filter-banks are intended to absorb the 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 (2005), cl.4.7.1, it is recommended that circuit-breakers 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.

6.3 Filter bank switching

Equipment used to switch the filter-bank currents are circuit-breakers, load-interrupters and sometimes disconnectors. Circuit-breakers are able to make and break all currents up to their rated short-circuit current, while switches 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 and are only rated to withstand the short-circuit current. However, 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, but 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-bank switching will show super-harmonic voltages on the normal TRV resulting in a higher peak value of the TRV.

Another phenomenon to be considered is that at switching off of 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.

To verify the breaking capacity of a circuit-breaker, 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. It

is expected that the initial part of the TRV at filter-bank switching is not critical for vacuum technology circuit-breakers, as applied in distribution networks.

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 circuit-breaker, the circuit-breaker can be tested for the higher peak-value or a circuit-breaker with a higher rated voltage can be chosen.

To summarise; filter-banks have to be switched by switchgear with a very low probability of re-strike. Modern circuit-breakers 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 circuit-breakers able to withstand the peak-value of the TRV, which is higher than the RV for capacitor-banks. Furthermore circuit-breakers 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.

6.4 Other aspects

All equipment involved has to withstand the thermal, dielectric and mechanical effects of the distorted currents and related TOV's, especially the capacitor banks and reactors. In dealing with the harmonic stresses for current transformers (CT) and voltage transformers (VT), the application for measuring and protection purposes must be separately considered. The design of CTs and VTs for protection purposes is not affected by harmonics, but the accuracy is. An overloading of capacitive VTs with harmonics is possible in principle, but not realistic because their fields of application are HV and EHV transmission networks where a large harmonic content is not observed.

For measuring purposes, in connection with the control system of thyristor-controlled devices, the accuracy and the frequency response has to be mentioned. In practice the frequency response of conventional CTs and VTs is quite poor (figure 22 for inductive type CTs and VTs) and special attention must be paid to their accuracy in respect of the absolute value and phase shift [52].

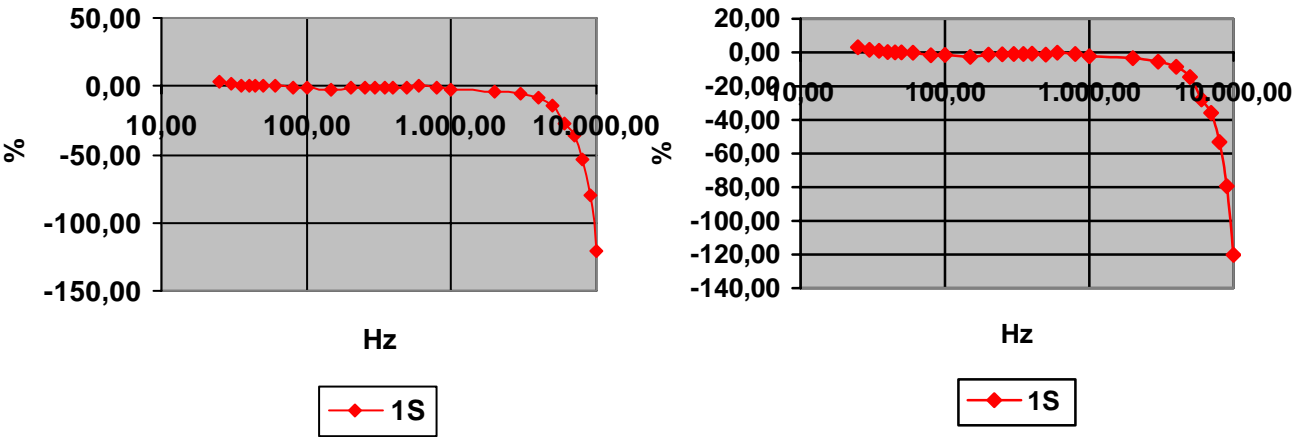


Figure 22: Sample frequency responses of VT (left graph) and CT (right graph)

7 POSSIBLE IMPACT ON THE STANDARDS

- Distribution circuit breakers have to perform new duties, such as system separation (out-of-phase switching), synchronisation of generators and/or systems, synchro-check before closing, etc. Taking into consideration the recommendation given in clause 4.2 of IEC 62271-100 [30], the longitudinal stresses in service are generally covered for the condition with separated systems on both sides of the circuit-breaker. Special attention however should be given to outdoor applications, where the same stresses have to be withstood under wet, polluted and aged conditions.
- Increase of power carrying capacity by taking advantage of dynamic (cycling) loading has an increasing trend to be used for cables, OH-lines and transformers. The switchgear, connected to these components, that has inherently a shorter thermal time constant, should not limit the capacity of the whole branch in the distribution network. Switchgear therefore has to be up-rated or a dynamic loading capacity has to be defined. The topic of dynamic loading is addressed with CIGRE SC B3 and must be considered in the Standards, either by overloading capacities or by certain recommendations. Note that the present revision of IEC 60694 is taking dynamic loading into account (subclause 8.2 of future IEC 62271-1).
- Frequency and voltage deviations larger than what is covered by the Standards are possible in case of islanding operation, putting the discussion whether type test results for 50 Hz can be applied in a 60 Hz network and visa versa in another light. Note that present Standards require T100 and T60 to be performed with both frequencies.
- Out-of-phase switching is addressed in the Standards, but while the specified recovery voltage covers an out-of-phase angle of 115°, the TRV peak value seems to cover an angle up to about 99°. 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 forcing specifications to cover a wider range of out-of-phase angles. In case of restrikes and failing circuit-breakers, the damage to equipment, especially power generating plants, can be enormous. Control of separation instant in order to avoid out-of-phase interruption with too large angles, as may be performed in the HV-EHV transmission grids by out-of-step tripping relays, is not easily applicable in the distribution networks [59].
- RRRV as specified for the out-of-phase TRV is not steep enough, but IEC 62271-100 [30] mentions that this is covered by the RRRV of T30. This, however, is true up to an out-of-phase angle of roughly 99°, as for larger angles the first line of T30's TRV-envelope has to reach higher.

8 CONCLUSIONS AND RECOMMENDATIONS

- Distribution networks are changing rapidly, both in a technical sense and in an organisational setting, because of developments with large implementation of dispersed generation, more strict requirements for power quality and liberalisation (the unbundling of transmission and distribution functions, the unbundling of production and network functions, the unbundling of commercial activities and monopolistic activities, the bundling of infrastructures for different commodities).
- 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.
- The consequences of these developments for primary plant include: more redundancy (even meshed systems), more surge arresters at vital points, some single phase systems become three-phase, instrument transformers and protection become three-phase systems, more advanced 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.
- Higher short-circuit currents, higher load currents, more complicated network topologies lead to distribution grids that show a large similarity with transmission grids. An adequate specification of the equipment involved is required. However, the wider application of more advanced, upgraded and/or complicated equipment does not mean intrinsically that the Standards for this equipment have to be adapted.
- Conventional generators contribute to the short-circuit currents and power quality in a well-known way. Care should be taken of the fact that DGs are small and dispersed, meaning that the feeder itself will give less damping to the AC- and DC-components in comparison to the experience with short-circuit currents supplied from the main busbar (transformers).
- Modern generators, equipped with full converters or DFIG (as applied in modern windmills) 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. But, special attention should be given to current transformers, as in some cases the DC-time constant may be larger than specified.
- Nowadays, in case of system disturbances, small generators are, to a large extent, forced to separate from the distribution network, whilst medium size and large size generators and windmill-parks, connected to the (sub)transmission grids are generally required to ride-through faults and to contribute to system stability and system restoration. Due to the massive increase in dispersed generation, there is a trend to require small generators connected to distribution networks for fault-ride-through capability as well as system support. Modern technologies are very suited to deliver some of these ancillary functions, when properly specified [53].
- The examples of the regulations as given in chapter 3, in combination with the possibilities of modern technologies, justify the conclusions that international harmonisation of the requirements of ancillary services for the today's popular dispersed generators is possible. This harmonisation is also good for other involved stakeholders such as operators and manufactures of windmills.

- An innovative optimization for fault-ride-through rules, especially for conventional dispersed generators is given in chapter 4 and presented as follows:
 1. DG connected to faulty MV or LV distribution-feeders:
 - Disconnect SGs immediately after fault clearing (before the auto-reclosing instant)
 - Disconnect AGs, if the short-circuit clearing time and dead time before reclosure of the MV-line are too long and inertia of generators is low
 - Disconnect all DGs in case of permanent faults
 2. DG connected to healthy MV or LV (radial) distribution-feeders in case of short circuits in an other MV or LV feeder supplied by the same substation:
 - SGs and AGs should be kept in service if short circuit is cleared in the standard low time (say, within 200 ms for multi-phase faults)
 - Protect SGs against loss of synchronism
 - Protect AGs against sustained overspeed and overcurrent
 3. DG connected to healthy MV or LV (radial) lines in case of faults in the supply HV network:
 - SGs and AGs should be kept in service in case of multi phase faults in the HV network cleared in short time (≤ 200 ms) and in case of 1-phase-to-ground faults in HV network even if of long duration (say, 0.5 – 1.0 s)
 - Protect SGs against loss of synchronism
 - Protect AGs against sustained overspeed and overcurrent
 4. Islanding:
 - Disconnect automatically SGs under islanding conditions, unless the network, protection and control is specifically designed for stable supply of an island from DG
 - Disconnect AG generators under self-excitation conditions.
- 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 reclosing, etc.
- These system conditions lead to requirements, especially for switchgear, that are related with smart network operation: advanced circuit-breakers provided with control circuits, 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, etc.
- Special requirements that may have an impact on the Standards have been addressed in the former chapter, and are, for the moment, restricted to dynamic loading of switchgear and out-of-phase switching by circuit-breakers.
- The problems related to an increased content of harmonics was discussed in chapter 6, where generally speaking the quality of electronic power converters reduces the impact of individual apparatus, but this effect is compensated by the increase of the application of power electronics. So far, no need for special requirements for the conventional equipment is foreseen. When filter-banks are applied, its components of course require special considerations as well as the switchgear that has to switch on and off the filter-banks (see chapter 6).

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Appendix A

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
Report PS2-01**

CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS

Studies performed by CIGRE WG A3.13

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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]

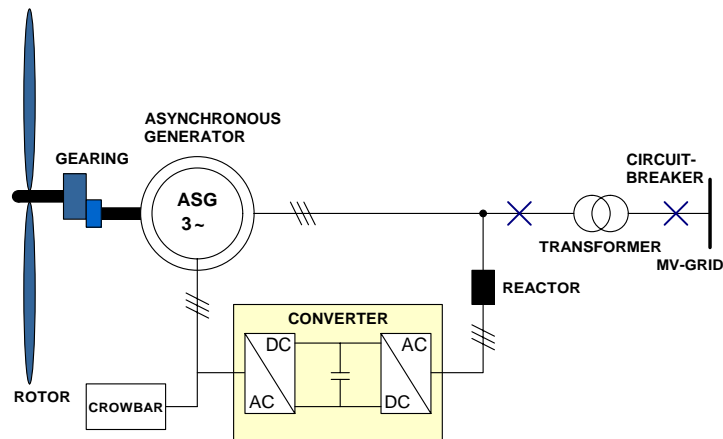


Fig. 1 DFIG: double fed induction generator with variable speed

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 (≤ 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.

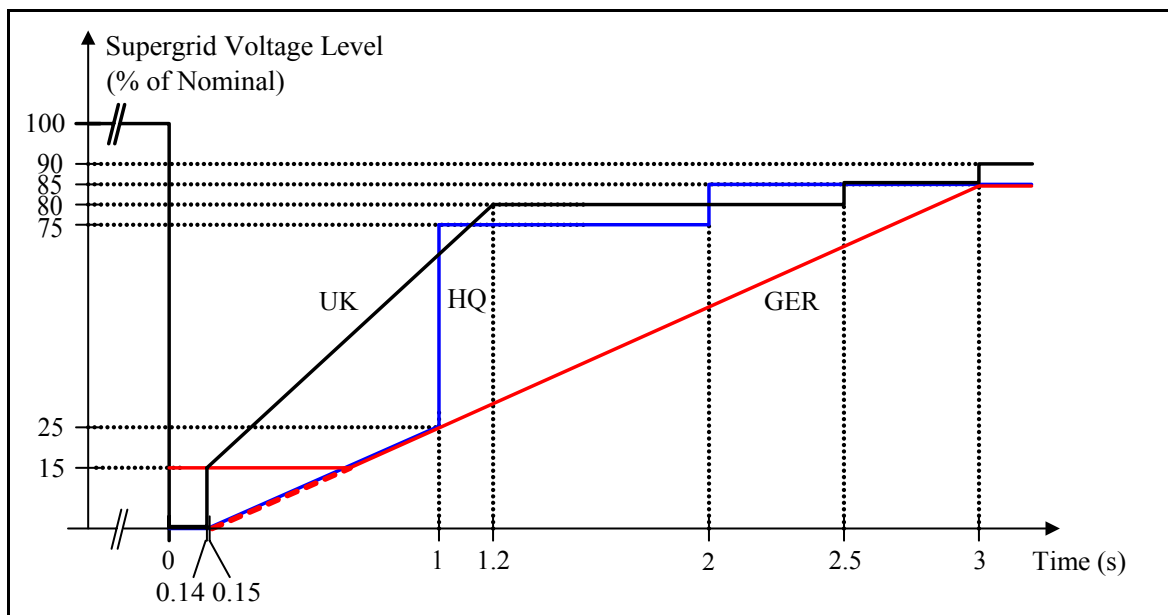


Fig. 2 Examples of fault-ride through requirements

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 an 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 bypassing 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 a 735 kV Series 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° [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 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

TOV				
Section	phenomenon	pu	measure	remark
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
SFO				
Section	phenomenon	pu	measure	remark
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 B

CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS PART I: DISTRIBUTED GENERATION

**Report presented at the CIGRÉ SC A3&B3 Joint Colloquium 2005, Tokyo
Report 103**

CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS PART I: DISTRIBUTED GENERATION

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Keywords

Distributed generation, DFIG, out-of-step, generator circuit-breakers, out-of-phase TRV

Abstract

Attention is given to the impact of increased distributed generation on system requirements as put forward to HV-equipment: bi-directional power flows, unusual patterns of short-circuit currents, probability of out-of-step conditions, consequences of out-of-phase (especially TRV's), false synchronisation, islanding, requirements for synchronisation, harmonics. The way of connection and the behaviour of distributed generation plants is divided in several categories, like with or without converters, synchronous, induction or doubly fed induction generators (DFIG). A comparison is made with DG connected to transmission grids.

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, 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.

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), of reduction of size and complexity, of the incorporation of more

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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. [1]

As most utilities face the increase of distributed generation, WG A3.13 has chosen to devote this paper to the impact of power plants in distribution networks on the specifications for HV-equipment. In future publications the impact of long distance transmission and other developments will be treated.

2. Description of power plants connected to distribution networks

In line with the scope of CIGRE SC A3 “High-Voltage Equipment”, WG A3.13 is giving special attention to 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.

To the last group (b) belong power plants such as micro-turbines, fuel-cells, photo-voltaic systems, energy storage systems as SMES (super-conducting magnetic energy storage), BESS (battery energy storage system) and flywheels, certain types of windmills. Due to the application of a converter, these small power plants are able to limit their contribution to fault currents, to support reactive power balance and voltage control, to restore systems after disturbances, to 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. One main disadvantage is the generation of harmonics, although nowadays converter technologies and mitigation technologies show substantial improvements [2]. Nevertheless one has to be aware of the possibility of harmonic resonance problems and that low and high voltage equipment may have to be specified for the higher content of harmonics in applied voltages and/or currents. Also the protection systems have to work more and more on frequency discriminating basis. But, it seems, to the opinion of CIGRE WG A3.13, not to be necessary to investigate such technologies more in detail due to their softening impact on transients in the system.

The studies of WG A3.13 are therefore focused on (a): power plants with a conventional lay-out and flexible generators driven by reciprocating machines (gas-motors, diesel-engines), by gas turbines (single shaft gas turbines derived from heavy duty types or multi-shaft gas turbines derived from the aircraft, i.e. aero-derivatives), by steam turbines (incineration of refuse, of biomass, of bio-gas, and solar thermal/geo-thermal installations), by small hydro plants (including pump storage), by air-pressure turbines (compressed air storage installations) and by windmills. Furthermore, combined cycle plants with gas turbine, steam turbine and generator on one shaft or gas turbine and steam turbine on separate shafts with each its own generator. As most of these technologies are used for co-generation purposes, practically all are more or less regarded as contributing to environmental sustainability. The generators can be synchronous or asynchronous machines, sometimes equipped with power electronic devices (the so-called double-fed generators) to control the rotor current (voltage control, slip, frequency for variable speed, reactive power output).

For the transient phenomena in networks (occurrence of a short-circuit, clearing of a short-circuit, mis-synchronisation, system separation, islanding) the fuel control systems of the conventional plants are so slow that they can be regarded as fixed. The dynamics of the prime mover are relevant during the first second for the very fast control systems and during the first minutes for the slower systems (for instance: simple hydro plants, simple steam turbines, steam turbines in combined cycle plants). [3][4]

The inertia of small machines used in those systems can vary and the rotor speed can change relatively fast (within a few hundreds of ms) to reach out-of-phase conditions in case of short circuits. A rough indication of the critical clearing time is $\sqrt{H/50}$ s (derived from [5]). Some examples of inertia constants H of gas-turbine driven power plants are: 7 to 9 s for heavy duty gas-turbines (hundreds of MW), 5 to 7 s for smaller units, down to 2 to 4 s for small units (tens of MW), and 1.3 to 2.2 s for aero-derivative gas-turbines [4]. Windmills with induction generators give an H of 2.5 [6] to 3.5s [7].

From the excitation point of view (magnetic fields of the machines and the magnetic field control) there are a few time windows of interest. In the very short time frame (within the first half cycle) no effect of the excitation is noted. In the second time frame (from half cycle to few hundreds of ms) the dynamics of the excitation systems have to be considered for modern generators as used in DG. In many instances the excitation systems can be set to behave completely differently thus providing high degree of behavioural variability. In the third (long) time frame of more than a few hundreds of ms other parts of the DG controls play a role. [7][8][9][10]

3. Power flow and short-circuit currents

Distributed generation in distribution, sub-transmission, and industrial networks leads to a structural change of the power flows, as the generated energy is normally independent from the local energy demand. The unidirectional, mainly radial, power flow from the transmission grid through the distribution network to the load will change to a bi-directional, mainly meshed, complicated power exchange system (see Fig. 1).

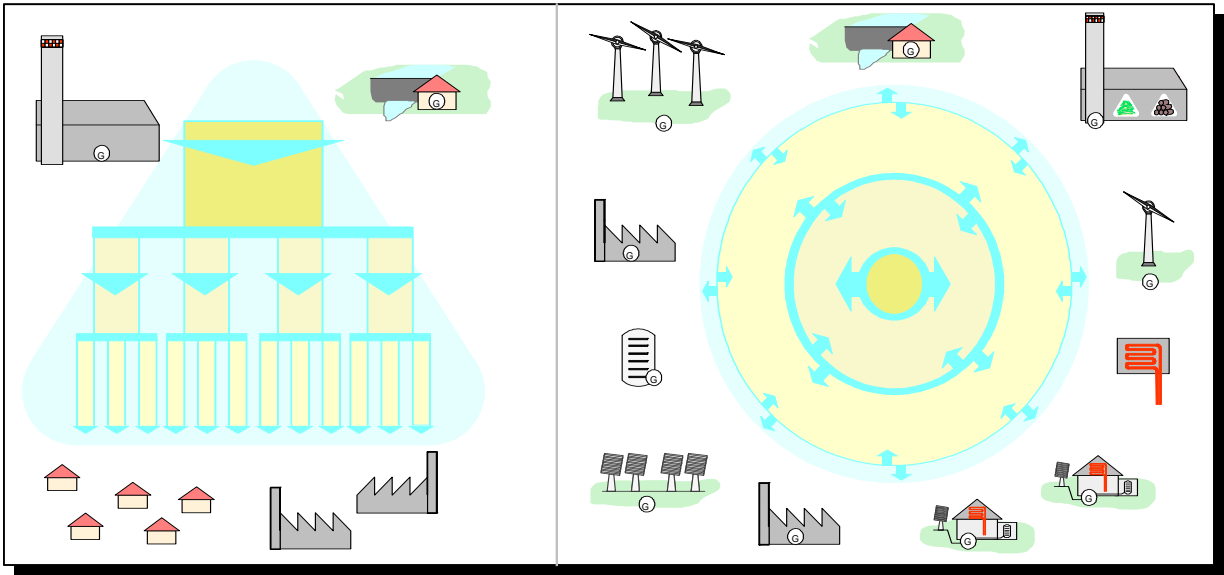


Fig. 1: From an unidirectional power flow to a bi-directional power flow distribution system

Such developments may trigger problems such as overloading of components and connections, voltage profile, voltage control and voltage instability. Moreover, short circuit currents will flow in a different pattern, non-selective tripping may occur, transient phenomena behave in a different way.

Depending on the operational mode of the generators power flows vary widely. Under certain circumstances the power flow may change quite suddenly, for instance due to wind shifts or due to tripping of distributed generators during system disturbances. It is a task of the system planner to foresee such changes in power flow patterns and to put forward loading requirements for the components involved. Equipment overload capabilities may be required. Changing power flows are of importance also for protection experts, as protection systems have to cope with the related currents and 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 then in the conventional systems with single source feeding. These different profiles could be difficult to understand intuitively and can impact the protection coordination.

4. Transient effects of a short-circuit current

Short-circuit currents cause mechanical and thermal stresses on equipment. Protection systems are designed to be fast enough to prevent any thermal overstressing of the plant or network. The problem of the dynamic forces due to the crest value of the short-circuit current is normally not covered by

protection systems (with the exception of current limiting fuses). In distribution networks the full asymmetrical short-circuit peak current (i.e. with a complete DC-offset) is up to 2.5/2.6 times the rms value for 50/60 Hz, respectively. However, in systems with a share of (a)synchronous machines like DG contribution the SC peak current ratio can deviate as shown in the figure 2.

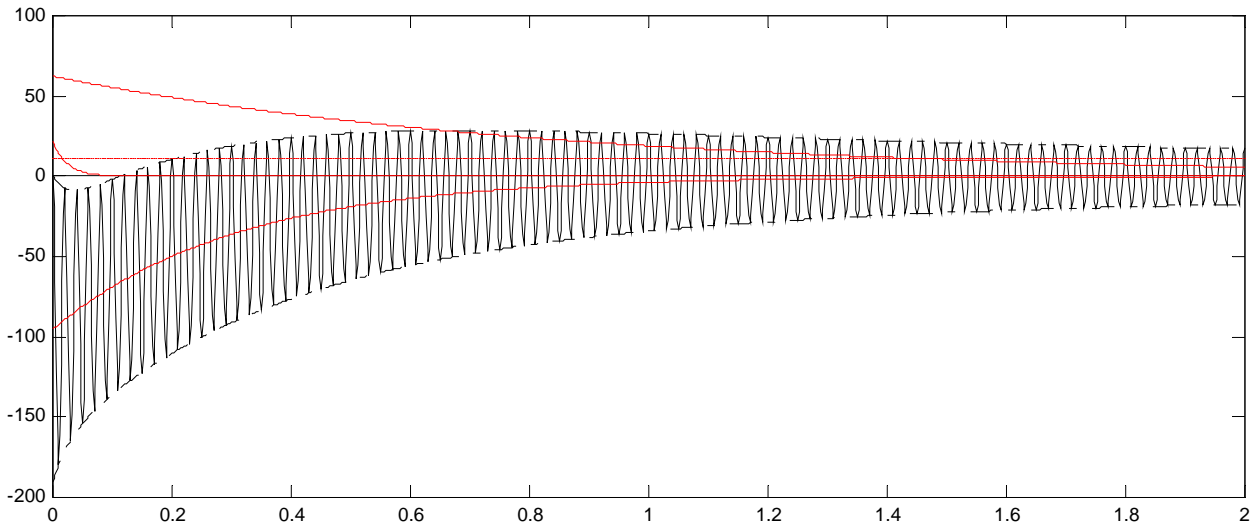


Fig. 2: Short-circuit current in the vicinity of a generator with varying AC- and DC-component (X-axis: time t in s; Y-axis: currents as percentage, 100% = AC-component at $t=0$)

Since the DGs are located in distribution systems they will increase the DC component in their vicinity. However, to the opinion of WG A3.13, this increase of overall DC-time constant is unlikely to exceed values specified in the Standards [11] apart from the breakers connecting the generators to the network where the generator circuit breaker standard has to be considered [12]. On the other hand in DG networks DC-components have to be considered more in detail for transient current transformer dimensioning, despite the fact that the DC-time constants are still be expected to be lower than in transmission networks.

If a DG system is located in the vicinity of an existing installation where the equipment is already close to its SC limits, it might be necessary to utilize means of current limiting like Is-limiters, CLIPS and other current limiting technologies. Conventional fuses could not be used to trip DG because they would not be fast enough (for ratios of SC current to continuous current typical to the DG systems) to act within the first half-cycle where the limiting is needed.

A closer look into modern (> 750 kW) windmills reveals that their behaviour during short-circuits is much more complicated. As reported in [6][13] directly coupled synchronous generators are nowadays less popular and the manufacturers' trend is towards doubly fed induction generators. The reason for the popularity of these variable speed DFIG is that the rated power of the expensive converter is about one third of the rated power of a full converter, with rather comparable control possibilities. 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 across the rotor-side converter [7][9][14]. As the settings are normally tuned for an optimal conversion of wind energy [15], realistic settings of DFIG controls should be considered.

Power plants are designed to cope with three-phase terminal short-circuits, but are generally not tested for the full short-circuit current. To our knowledge manufacturers of generators and manufacturers of generating sets (windmills, co-generators, gas-turbine packages) are not fond of such experiments despite the fact that short-circuits in MV-networks are very realistic and that the damping by the

network itself is very limited. Much effort, however, is given to establish simulation tools, that are verified by small scale tests [14].

5. Transient phenomena at clearing the short-circuit

Many small power units are operated in such a way that for any disturbance in the network, they are immediately switched off by a circuit-breaker (so, after roughly 50 to 100 ms). The protection of the small units (less than a few MW up to 10 MW) is conventional: instantaneous overcurrent, time overcurrent, instantaneous undervoltage, stator/rotor earth fault detection, time under/overvoltage, time under/overfrequency, unbalance, high temperature, differential, under/over excitation, reverse power, rotor overload. For generators connected to the MV-network without a step-up transformer, the connecting circuit-breaker should be specified as a generator circuit-breaker to IEEE [12]. For generators connected through a step-up transformer, the circuit-breaker at the MV-side may be specified to IEC [11], but it is recommended to consider a design tested for test duty T30S (circuit-breakers directly connected to transformers) [16].

For large power plants, and in many cases also for medium size power plants, utilities put forward requirements that generating plants contribute to the stability of the network and remain connected for a certain period of time. Especially after the disturbance these power units are needed to restore the active and reactive power balance. The required “ride through time” varies from several hundreds of ms for smaller or special units up to more than 1 s for large conventional power units.

Due to the enormous increase in distributed generation in recent years, utilities tend to put forward similar requirements for the small power generating units. In a number of countries “ride through”-requirements have been imposed on windmill-farms, groups of small power plants that together form an equivalent of a medium size or even a large size power plant. Apart from the behaviour during system disturbances, requirements are put forward with respect to voltage control and even for

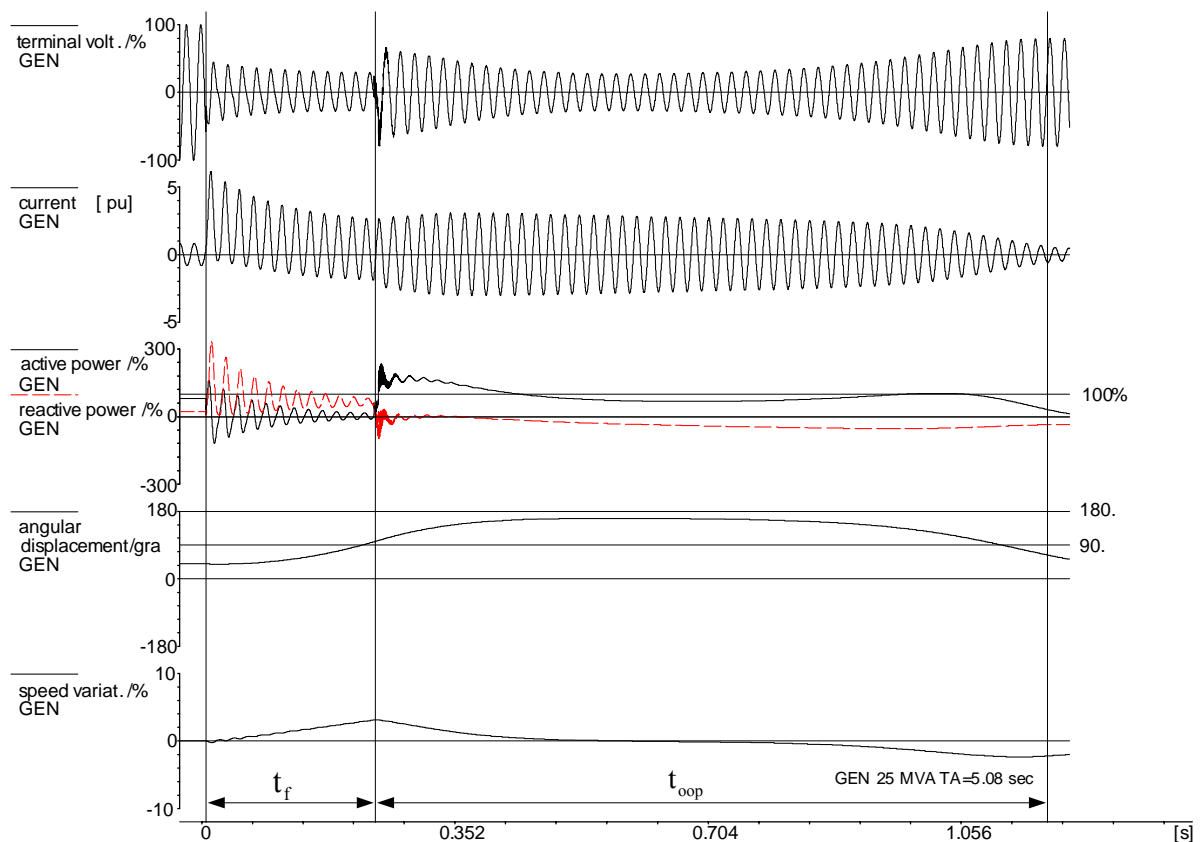
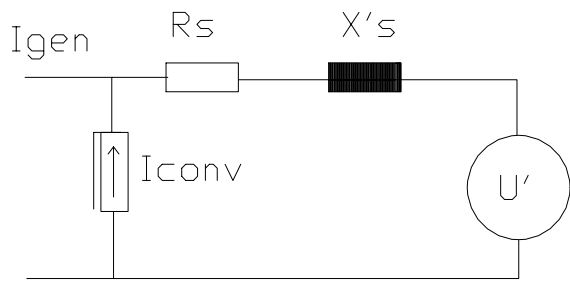


Fig 3: Simulation of 25 MVA synchronous generator (CHP) dynamic behaviour during/after 233 ms short-circuit in MV-network

frequency droop control. However, there is still a large dispute between those responsible for the networks and those responsible for the small power generating units, with the main question of who is to be blamed for the disturbances and who has to pay for the countermeasures necessary to warrant system stability (see [17][18] and the related discussions).

As discussed in the former chapter, smaller units are stressed at the moment of the short-circuit occurrence. Furthermore, these units are stressed a few cycles later when they are switched off and the brake jammed on. 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 generating technologies, like for example aero-derivative gas turbines [8] or modern windmills [6] 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. Figure 3 shows corresponding behaviour of a synchronous generator simulated with NETOMAC[®] with t_f representing the 3-phase fault duration and t_{oop} the out-of-phase condition. 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 [8], even with DFIG [9]. Users are warned that loss of life and serious damage to shafts, gears, bearings, (gas/steam/wind) turbine-blades, etc. can occur [19].

Asynchronous machines are known to show a fast decreasing contribution to the short-circuit current and after, say, 100 ms no back-emf will be experienced. At the disappearance of the short-circuit, however, the large amount of reactive power required by the asynchronous generator will lead to a sustained voltage dip and long start-up currents, but in amplitude lower than the short-circuit current [20]. A more stressful condition is the short open-terminal situation where, at reconnection, currents larger than the short-circuit current will appear [20].



U' controlled by rotor,
e.g. torque setting

Fig.4: Equivalent circuit of DFIG

In comparison with the above mentioned DGs, the behaviour of the Double Fed Induction Generators (DFIGs) is complicated. It is difficult to draw general conclusions on the impact of these units on the network conditions. For instance, DFIGs use crowbars across the rotor circuits disconnecting the converter from the rotor winding. After the crowbar operates the DFIG becomes a conventional induction machine, while before, it operates more or less as a synchronous machine, as can be learned from the equivalent circuits shown in [15]; see fig.4. Therefore the total DFIG behaviour will also depend on how fast and how long the crowbar will operate (sometimes only a few cycles, or even less [14])[21]. On the other hand, due to its ability to control in a

fast way the rotor torque and because of rotor speed decoupling, the dynamic behaviour of DFIG shows to be generally more stable than that of synchronous generators [13].

6. Transient phenomena at clearing out-of-phase

It is clear that out-of-phase conditions under “ride through”-requirements are very realistic. Depending on the ratio between the system short-circuit power and the generator short-circuit power, out-of-phase currents may become more severe than short-circuit currents. Small synchronous units have to be designed for out-of-phase conditions, otherwise the “ride through”-requirement will lead to considerable damage.

Interrupting out-of-phase current may cause problems as well. Breaking the out-of-phase current is a duty of the generator circuit-breaker; i.e. the circuit-breaker that connects the generator to the distribution or industrial grid. This circuit-breaker may be specified according to IEEE [12] or it may

be a regular breaker specified to IEC [11]. Where in [12] an optional out-of-phase duty is required in a straight forward approach, to [11] out-of-phase is more treated as a multi-part test: the initial part of the TRV is covered by short-circuit tests and the crest of the TRV by a non-mandatory phase-opposition test.

The wave-shape of the TRV under out-of-phase conditions can be split into several time domain parts. The power frequency recovery voltage part will depend on the phase angle between generator and system, and on the difference in frequency. This will lead to the recovery voltage factor (theoretically up to 3.0 for the first clearing pole). The natural frequencies and damping of the generator-system at one hand and the network at the other hand will determine the TRV in the ms range. Together or separate they determine the amplitude factor and, in combination with the recovery voltage factor, the crest value of the TRV. The initial part of the TRV (i.e. the first hundreds of μ s) forms the steep rise of the TRV (RRRV) which is determined by the local capacitances and surge impedances at both sides of the circuit-breaker. In combination with dI/dt , the sum of equivalent surge impedances and capacitances gives the RRRV and the t_d (time delay). See figure 5.

IEC [11] gives a recovery voltage factor of 2.5 and an amplitude factor of 1.25 for rated voltages below 100 kV. The crest value of the TRV under out-of-phase is therefore 3.13 pu, where in IEEE [12] 3.18 pu is specified. For smaller power units IEEE requires a RRRV of 3.3 kV/ μ s; IEC requires approximately ten times lower RRRV, but the amendment 2 of [11] requires that circuit-breakers directly connected to transformers have to fulfil a RRRV larger than 3.3 kV/ μ s, at least for test duty T30S [16].

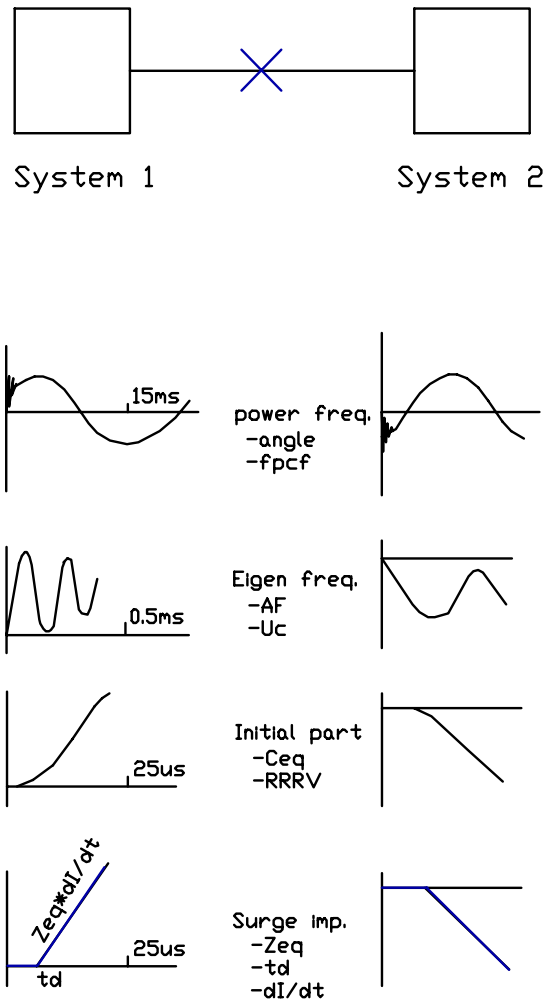


Fig 5: Components of out-of-phase-TRV

CIGRE WG A3.13 has also conducted some system studies to simulate the phenomena described. To that purpose a distribution network, typical for German cities, has been modelled, representing a 20 kV cable grid with municipal load and industrial load, including a co-generation plant of 25 MVA, fed by two 110/20 kV transformers. A 3-phase short-circuit occurs somewhere in the 20 kV-network, not far from the main substation, thus reducing the voltage from 20 kV to almost nihil. The generator will accelerate up to full phase-opposition, when the short-circuit current is tripped and the generator, at the 20 kV-side of its step-up transformer, is disconnected from the grid. The TRV across this last circuit-breaker's first clearing pole has been simulated by EMTP, under the assumption of a pre-fault voltage of 20 kV. The results are shown in figure 6. The simulated generator is a synchronous machine and its excitation is assumed not to deviate too much from normal, due to the relatively low short-circuit and out-of-phase currents (see also fig. 3).

Several cases have been studied, varying the load of the network (0, 10, 20 MW) leading to different TRV-peak values (5.1 pu, 4.4 pu, 4.1 pu resp.), equivalent to amplitude factors as high as 1.7, 1.5, 1.4 resp. Also the connection between circuit-breaker and step-up transformer has been varied, leading to an initial RRRV of 2.6 kV/ μ s and a t_d of 0.3 μ s for a bare connection resp. a RRRV of 1.6 kV/ μ s and a t_d of 1.1 μ s for a cable connection.

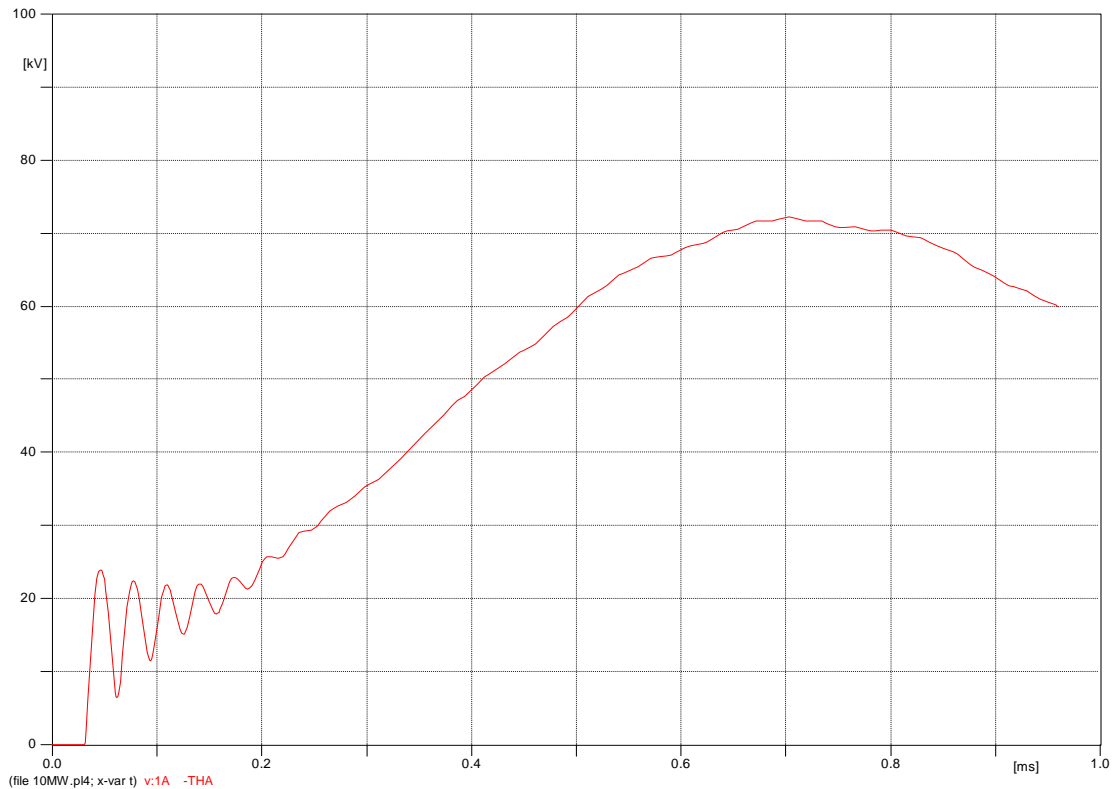


Fig.6: TRV simulated for out-of-phase clearing, 20 kV, 10 MW load, cable-connection

In figure 6 can be recognised a high-frequency part generated by the step-up transformer (with the generator and the cable connection to the circuit-breaker) and a low-frequency part at the other side of the circuit-breaker, generated by the cable network. As in this case the short-circuit power of the network is very low (the network impedance is relatively high), a very large part of the recovery voltage (totally: 3 pu due to out-of-phase) is experienced at the network side of the circuit-breaker and the low damping of the cable network is dominant (a high amplitude factor). Opposite, the steep initial part is completely dominated by the high eigen-frequency of mainly transformer and its connection to the circuit-breaker. To amendment 2 of IEC 62271-100 [11] in such cases the circuit-breaker has to be specified as class CSS (intended to be used in cable systems and in small capacitance connections to transformers). For test duty T30S a RRRV of $4.95 \text{ kV}/\mu\text{s}$ (@ 24 kV) is required, double the RRRV for normal capacitance connections, class CS [16].

But where the RRRV is covered by IEC, the peak-value of the out-of-phase TRV is only 61 kV, 3.1 pu (@ 24 kV). The discrepancy between 3.1 pu and the simulated crest values is caused by the fact that within IEC reduction factors have been introduced to take into consideration the low probability of full phase opposition, and the low probability that the eigen-frequencies at both sides of the circuit-breaker will match in such a way that both amplitudes may be added (i.e. a common high amplitude factor). The examples given, however, show that full phase opposition is far from academic for DG, certainly in case of ride-through requirements, and that high overall amplitude factors can be reached. In addition it can be stated that, despite the fact that the out-of-phase RV will show a beat-pattern (fig. 3), an out-of-phase angle above 90° gives already considerable TRV-peak values [8]. Furthermore, cases, where the short-circuit power from the network are much higher than in the example of fig.5, will show a proportionally larger amplitude for the high-frequency part and a much lower amplitude for the network part.

It should be mentioned that the use of MV surge arresters and surge capacitances could in certain cases reduce the magnitude as well as the steep rise of TRV.

7. Mis-operation and out-of-phase synchronisation

Other transient phenomena that have to be mentioned are false switching operations in the vicinity of dispersed generation. In chapter 5, above fig. 4, an example of a short duration open terminal has been given, leading to stressful currents at reconnection of asynchronous or synchronous generators [8][20]. Similar conditions will appear when in the vicinity of small generators a large power unit is connected to the network without adequate synchronizing (mistake in operation, defect synchronisation check, defect synchronizing equipment, pre-strike or re-strike in generator circuit-breaker, flash-over across open poles of breaker or disconnecter, etc.); but also somewhere in the network with re-closing or automatic system restoration. Under such conditions the distributed generators will be disconnected from the grid and switching duties comparable with those in the former chapter will be required.

Although it is outside the scope of this WG, it is recommended that the DG units utilizing synchronous machines or equivalent machines be specified to withstand full terminal short circuit, out of phase synchronising, loss of synchronism in the power network, and out-of-phase synchronising of neighbouring units. It may be desirable that full terminal short circuit and out of phase synchronising be verified with type testing.

8. System separation and islanding

With the growing use of the DG in distribution networks these DG systems should preferably support the same requirements as large power units, i.e. ride-through most of power system disturbances without being disconnected from the network. At the same time, since traditionally passive distribution networks become active, distribution circuit breakers may have to perform new duties, such as system separation, out-of-phase switching (chapter 6), synchronisation of generators and/or systems, etc. Such requirements are not so clear from the Standards, where for instance the specification for a dielectric type test across open contacts is roughly 2.9 pu/1 min., while a repetition of a type test in service is performed at even lower stresses (e.g. 70% i.e. 2.0 pu).

Another issue of importance is safety: clearance, earthing, status-information, SCADA, interlocking... meaning that in the HV-devices more intelligence and communication has to be incorporated.

9. Transmission- and Subtransmission-connected DG

In some countries distributed generation is connected to a (sub)transmission grid in stead of a distribution or industrial network. Such connections are for instance windfarms (in stead of singular windmills), larger power plants, locations without distribution networks or too weak distribution networks, power plants far from load centres and industrial plants with generating facilities directly connected through separate transformers.

At transmission levels less problems are expected with such power plants, as transmission grids are used to connect large generators. Moreover short-circuit powers are normally far larger than those of the power plants, and short-circuit currents are cleared much faster than in distribution networks. Multi-directional power flows and complicated short-circuit current patterns are not an issue at the transmission level. Out-of-phase conditions in case of DG are not so different from out-of-phase conditions of other plants and can therefore be treated equally (specified duties for switchgear, special protection and control equipment, synchro-check and synchronising equipment, interlocking, etc.).

To put it the other way around: the problems described in former chapters show that distribution networks are changing to more complicated grids, comparable with transmission networks. Therefore deeper technical analyses, more comparable with the approach of transmission experts, are required.

10. Conclusions

- DG, connected to the distribution grid through full converters are expected not to trigger any special requirements for HV-components, apart from, infrequently, special requirements due to harmonic resonance or to avoid harmonic resonance.
- DG, based on rotating generators directly connected to a distribution or industrial network (maybe through a step-up transformer) should be treated carefully with respect to its contribution to short-

circuit currents (complicated patterns), the appearance of out-of-step conditions (certainly when “ride through” is required), reconnection and re-closing and more severe TRV-requirements.

- Out-of-phase becomes more probable due to the low inertia constants and cannot longer be ignored. The necessity for synchronising and islanding put forwards extra requirements for primary and secondary equipments. Safety aspects will add additional requirements.
- DFIG shows a complicated transient and dynamic behaviour, but will generally lead to softer transients and a better dynamic performance (short-circuit currents, ride through stability, out-of-step). Its behaviour is strongly influenced by the settings of the converter and crowbar controls.
- There is a need to carefully specify and test both HV-equipment and power plant equipment for short-circuit, out-of-phase conditions, overloading capabilities and system separation.

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Appendix C

CHANGING NETWORK CONDITIONS AND SYSTEM REQUIREMENTS

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

Changing Network Conditions and System Requirements

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CIGRE WG A3.13

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.

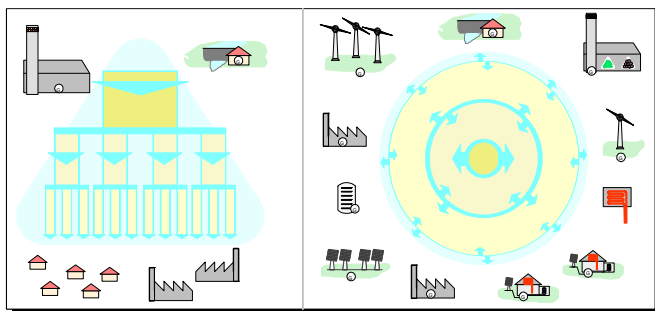


Fig. 1: Structural change of power flows in distribution grid

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].

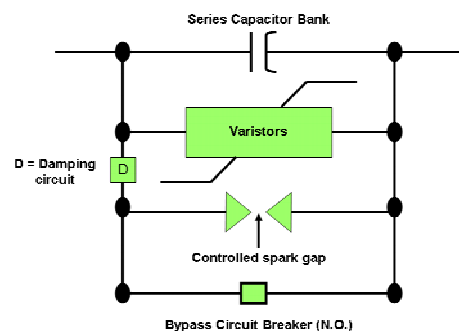


Fig. 2: basic components of a series capacitor bank

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 TRVpeak. 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 D

**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 on
Transient Phenomena in Large Electric Power Systems
in Zagreb, April 2007-03-18
Report 0701**

Dielectric, Switching and System Requirements under Out-of-Phase Conditions, during Synchronisation and under Comparable Stresses.

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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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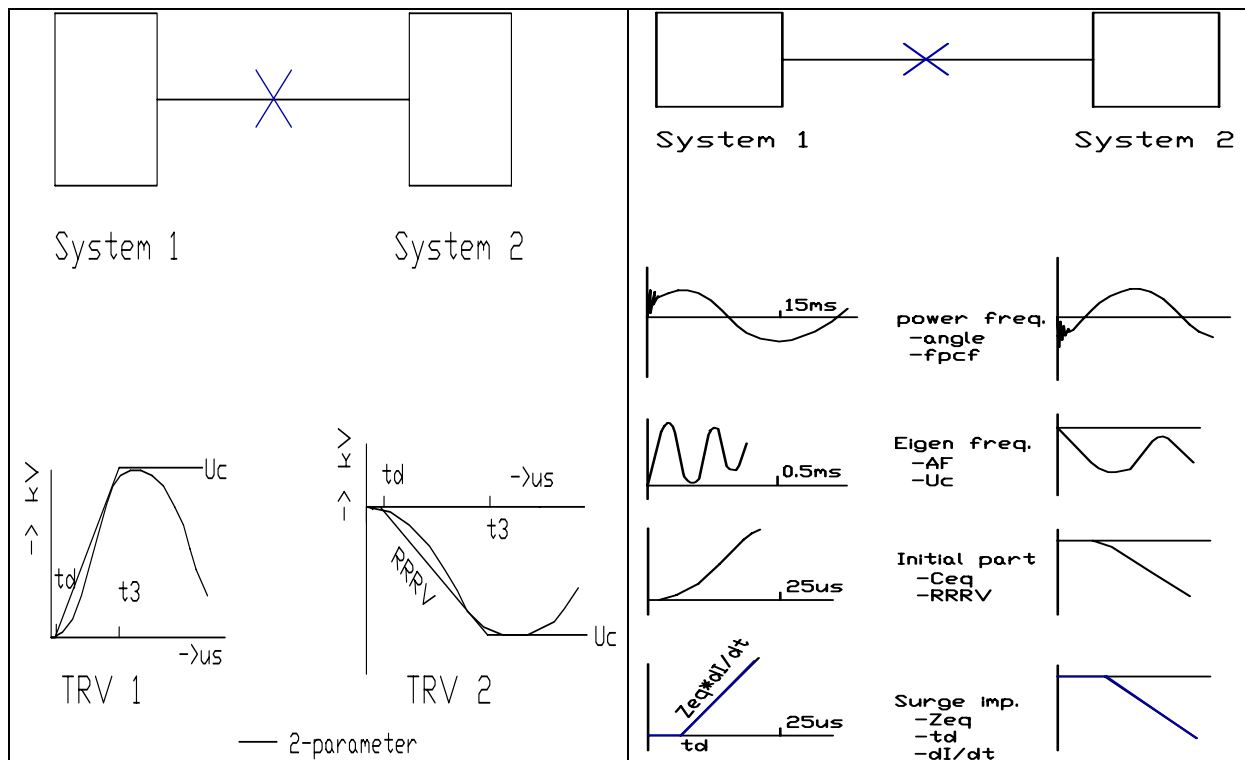


Fig. 1 Longitudinal stresses across the first-pole to clear out-of-phase

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 (ψ), 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

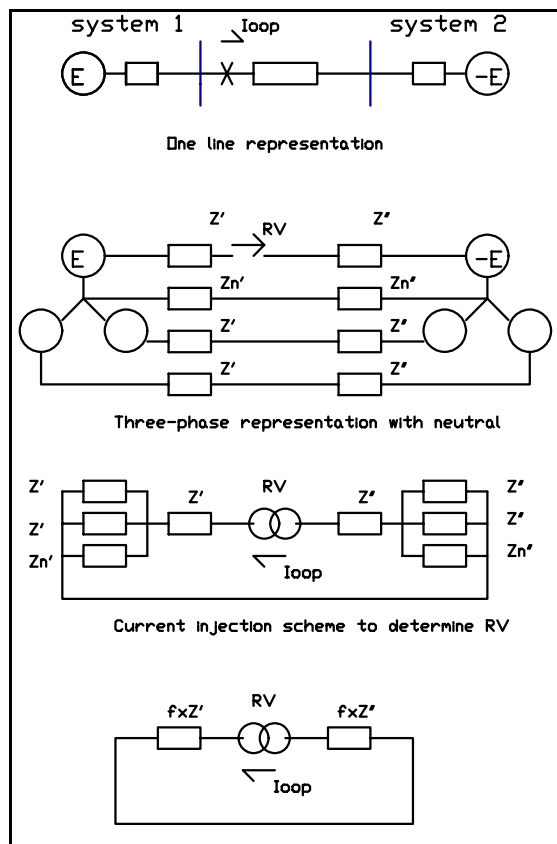


Fig. 3 Out-of-phase RV with $f = \text{total } fpcf$

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:

$RV = I_{oop} * fpcf * (Xd'' + Xtr + Xs)$. 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 μ 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).

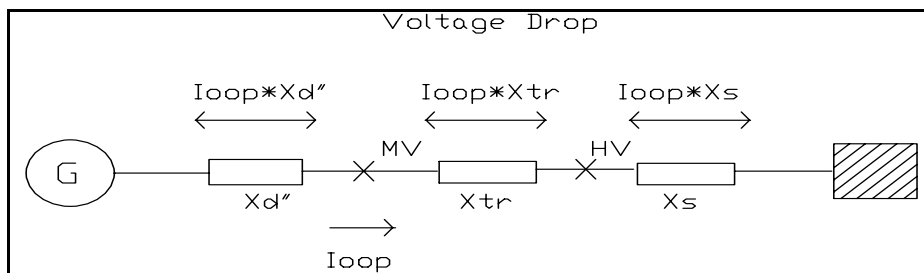


Fig. 4 Generator circuit-breaker RV

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 ψ , 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 μ 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.

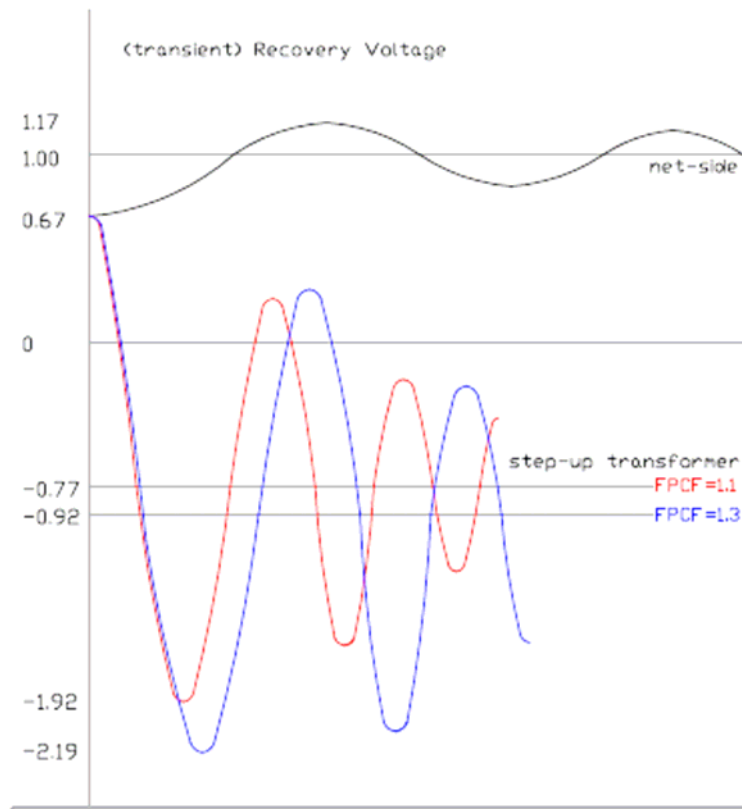


Fig. 5 Out-of-phase Recovery Voltage. Case (i)

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,

1. 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)
2. 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.

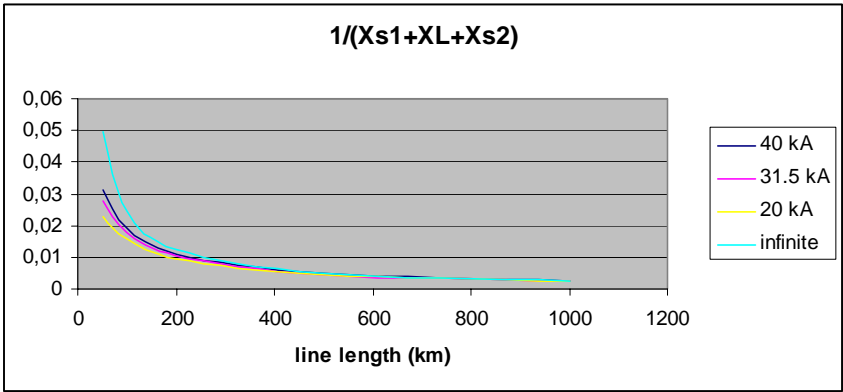


Fig. 6 Total admittance as function of line length

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 μ 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 $\sin(\frac{1}{2}\psi)$.

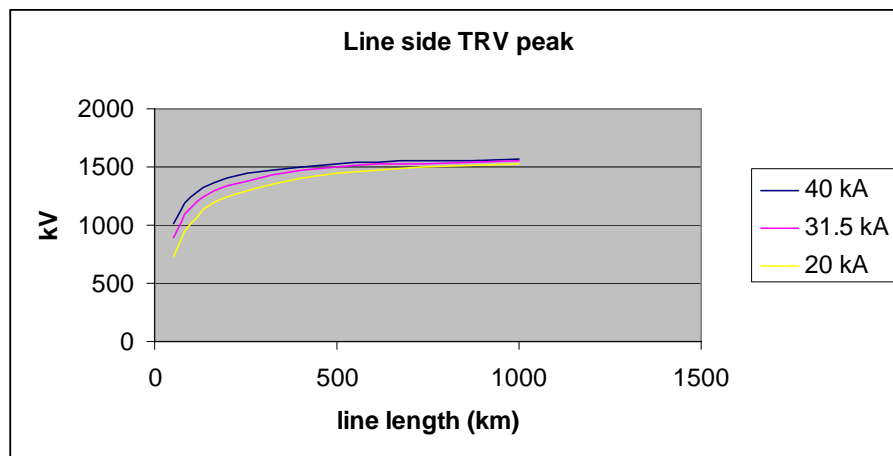


Fig. 7 Line side TRV peak value as function of length in a 420 kV-network

It can be concluded that the TRV peak values can be considerably higher than specified in the Standards (857 kV @ 1335 μ 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 ≤ 245 kV. The values given in column (2) of the tables 1a and 1b [11], applicable for rated voltages ≤ 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 ≥ 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 ≤ 245 kV, the highest class of insulation has been taken from table 1a, and for ≥ 300 kV the values given in table 2a:

Rated voltage (kV)	(2) 1min withstand (kV) ⁺⁾	(2) 1min withstand (pu) ⁺⁾	(3) 1min withstand (kV) ^{Δ)}	(3) 1min withstand (pu) ^{Δ)}
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: additional rated insulation levels in North America.

⁺⁾ Specified for longitudinal insulation of circuit breakers with rated voltage ≤ 245 kV

^{Δ)} Specified for longitudinal insulation of disconnectors (all rated voltages) and of circuit breakers with rated voltage ≥ 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.

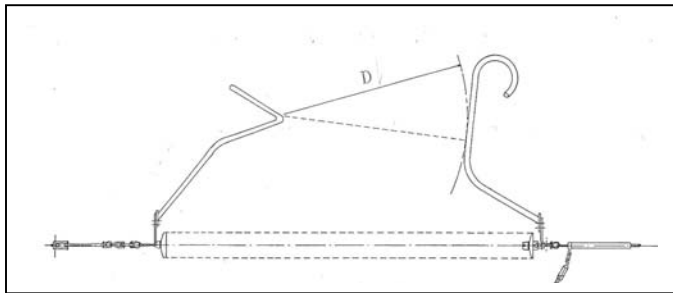


Fig.8 Special protective spark gap fitted in the line anchor insulator strings to substation gantry; $D = 1700 \text{ mm}^\circ$ for 380 kV lines; $D = 800 \text{ mm}$ for 150 kV lines.

$^\circ SI 50\% \text{ flashover voltage} = 1040 \text{ kV}(3 \text{ pu})$

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]

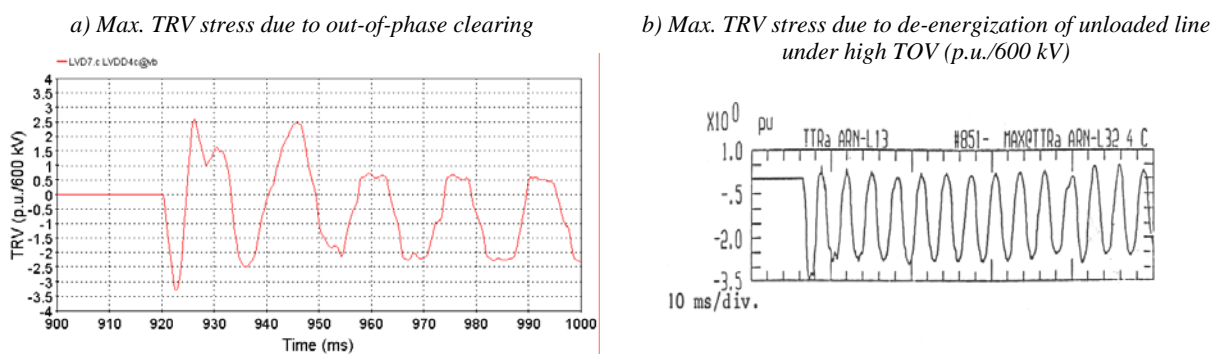


Fig. 9: Maximum TRV stresses due to out-of-phase clearing and de-energization of unloaded line under high TOV

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 un-earthed 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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