Fault current contribution from state of the art DG's and its limitation

Anton Janssen°, Maarten van Riet, Jan Bozelie, Justin Au-yeung

***Abstract*—The paper describes the policy and considerations of a Dutch utility with respect to the assessment of the fault current contribution of DG's, especially for DFIGs.**

Simulations and measurements confirm the validity of a simplified approach of the behaviour of DFIGs and full converter generators under fault current conditions.

A new fault current limiter (FCL) for single phase fault currents is described shortly. It is compared with conventional neutral treatment methods and can be applied for special cases. In addition, measurements of fault current limiting through full converters are shown.

***Keywords*: MV fault currents, zero sequence component, DG, DFIG, full converter, FCL.**

I. INTRODUCTION

Liberalization transformed the world of electric power supply from vertical organized utilities, controlling the generation, transmission and distribution in a certain region, to horizontal organized utilities, facilitating access to transmission and distribution networks for all kind of electric power providers and consumers. Rationales behind the policy to overthrow the old structure were (1) efficiency improvement through free market mechanisms, (2) stimulation of alternative power generation technologies through independency between generation and network operation and (3) cost reduction for the monopolistic networks through a stringent regulatory regime. Free access to the networks has been achieved, albeit at the cost of loss of centralized control over power generation facilities. Network operators are no longer involved in the choice for location, extension or reduction of power generation sites, in the technology applied at such sites and in the operation of the plants. Nowadays they have to adapt their networks adequately to the erratic movements of the market. The adaptability applies with respect to the large power plants as well as to distributed generation (DG).

DSOs (Distribution System Operators) face a lack of technical information about the technology and operation of the dispersed generators in their grids. The situation is comparable with the knowhow about loads, but the difference arises from the impact of production on the network, being generally larger. Moreover, the large number of connected loads enables statistical approach, which utilities have already gathered experience over decades. However the number of dispersed generators is usually limited compared to the number of loads. Besides many types of dispersed generation show the same operational behavior, due to common drivers such as wind speed, heat requirements and spot market prices. These rather unpredictable drivers hamper the utilities in their planning capabilities.

Nowadays most utilities cannot apply their old methods for load forecasting in their networks, as the share of power generation is hidden. The lack of information about the operational mode of dispersed power generators explains why stability issues and transient phenomena, cannot be answered straight forward. Utilities have to develop simplified rules to deal with fore-mentioned uncertainties, which must not result in over-specifying the networks. The authors will highlight certain rules and considerations, which are applied by their utility for making short-circuit calculations in MV networks.

II. SHORT-CIRCUIT CURRENTS

Typical examples of distribution networks in the Netherlands are underground 10 or 20 kV cable-networks connected to 150 kV (sub)transmission levels. Because of the transformers' ratio (15 or 7.5), the 150 kV network reactance is hardly noticed at MV-level, and can be neglected (typically 0.02 Ω, varying between 0.01 and 0.03 Ω, @ 10 kV). Besides, a tap-changer is controlling the MV busbar voltage U_B, including dead-band, hysteresis and compound compensation. All transformers are YΔ-configuration, leaving the neutral treatment at the MV-side independent from that at 150 kV-side.

The power transformers mostly are either 66 MVA or 44 MVA with a nominal voltage of 11 kV at the secondary side and short-circuit voltages of 20% or 18% respectively, leading to transformer reactances of 0.37 Ω or 0.50 Ω. A typical transformer for the 20 kV-grids is 100 MVA, nominal voltage 21 kV, 16% uk, giving a reactance of 0.70 Ω. Normally each transformer is supplying its own MV-network and is not operated in parallel with another transformer. The MV main switchboard (31.5 kA) is able to deal with the fault current from a single transformer (about 18 kA[1]). The X/R ratio of such transformers is 40 to 60 ms or more [2], so that the peak value of a fault current right behind the transformer may reach 2.76*18 = 50 kÂ.

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[1] The fault current depends on cos(φ), load current and voltage (see fig. 1, 2), opposite to short-circuit withstand capability tests for transformers, where tap position and nominal tap voltage are predominant parameters [1].

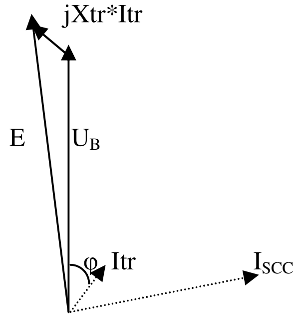

Fig. 1. Vector diagram to calculate the short-circuit current at the MV-side of a transformer with tap-changer that controls U_B; superposition method [3]

Modern MV cables (single phase XLPE, 240/630 mm^2 Al) show a reactance of 0.04 or 0.05 Ω/km and a resistance of 0.125 or 0.05 Ω/km respectively [2][4]. Roughly speaking the resistance of 1 km cable equals that of the power trans-former and its impact on the peak factor(-15%) is as high as the increase of the short-circuit impedance (+15%). The fault current at 1 km distance from the substation reaches a peak value of 37 kÂ in case of a 630 mm^2 Al and 31 kÂ, in case of a 240 mm^2 Al (see fig. 4A). Other types of cable (3-phase paper insulated) show less inductance, more resistance per km.

III. IMPACT OF DISTRIBUTED GENERATORS

In addition to the fault current flowing through the power transformer, dispersed generators in the MV-grid will contribute to the total short-circuit current. Though, opposite to the situation with the power transformer, the influence of the cable is negligible, as can be seen from the example of a single generator/step-up transformer unit of 3 MVA, connected to a 10 kV-grid (nominal voltage: 10.5 kV). A short-circuit impedance of 16% gives a combined reactance of 6 Ω; and a X/R ratio of 14 gives a resistance of 0.43 Ω. A distance to the fault location of 1 km will add 0.04 Ω to the reactance and 0.125 Ω to the resistance (XLPE cable, 240 mm^2 Al). Both reactance and X/R ratio change hardly between 0 to 1 km, and the fault current stays ~1 kArms. A distance of 10 km reduces the peak current to 75%: 1.9 kÂ.

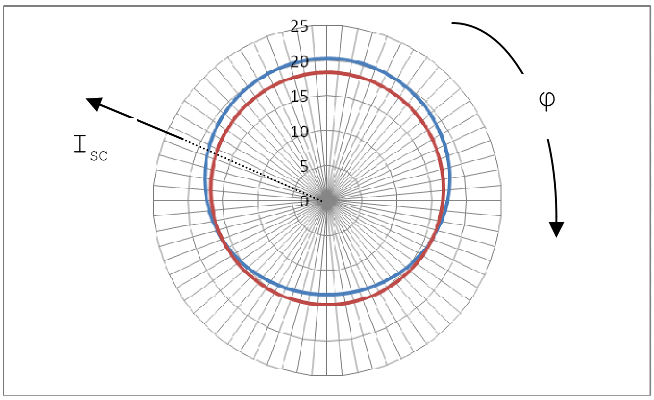

Fig. 2. Fault current (kArms) supplied by a 66 MVA, 150/11 kV transformer (20%), kArms as function of power factor angle (top: 0°, cos(φ)=1): blue for U_B=10.7 kV, Itr=3470 A; red for U_B=10.5 kV, Itr=1730 A.

So, by a single generator of such a size the MV network will not be dramatically overstressed. However, tens of generators will result in another picture. Say 10 generators, say each at a distance of 2 km from the main switchboard and assume a fault at the main switchboard (e.g. fig. 4C). They add 10 kArms and 25 kÂ to the 50 kÂ coming from the power transformer; a sum close to the limits of the main switchboard (80 kÂ). Other ways to connect the generators (all generators connected to one or two cables) will interfere with the capacity of the cables (240 mm^2 Al: 1 to 2 generators; 630 mm^2 Al: 3 generators) and is not an option; fig. 4B.

MV switchgear further away in the feeders, as it usually has been specified for 12.5 kA (31.5 kÂ) can hardly deal with the fault current coming from the power transformer. This becomes overstressed by the additional fault currents from a number of generators.

Quite often DG will appear in clusters as the location of the grid is convenient for (*a*) windmills or for (*b*) co-generation plants (total energy installations, fig. 3). Other producers will either be (*c*) singular (e.g. waste incineration plants, district heating, industrial co-generation plants) or form (*d*) clusters connected to LV networks (biogas incineration, fuel cells, PV). The (*e*) larger production facilities (several tens of MW) are normally connected to a HV network through a separate step-up transformer. Also (*f*) conglomerates as windmill parks or green house parks (up to hundreds of MW) are connected to a HV network [5]. So, the examples (*a*)(*b*)(*c*) are typical for generators connected to MV grids: up to ten pieces with a size around one to a few MW each.

Total energy installations and other co-generation plants mostly are equipped with rather conventional synchronous or asynchronous generators, frequently connected to the MV grid through step-up transformers. The short-circuit reactance of the step-up transformer is typically 6% and the (sub)transient reactances of the (a)synchronous generators are typically 15% to 20%. Care has to be taken for the fact that the reactances are related to the MVA rating of the generators (and not the MW-rating) and that the MVA-rating of the transformers is larger than that of the generator. With cos(φ) = 0.9 and a transformer rating of 125%, the overall reactance becomes 18% to 22%, related to the MW rating of the generators.

Nowadays small synchronous generators insulated for 10 kV are available, that are connected without step-up transformer to 10 kV networks. The subtransient reactances are about 17%, giving 15%, when based on the MW-rating and a cos(φ) = 0.9.

Windmills are equipped with constant speed generators or variable speed drives. Most constant speed designs offer two operating modes with each a different constant speed, but essentially they use conventional synchronous or asynchronous generators with a step-up transformer. Variable speed drives are available with a limited range of speed variation (the so-called DFIG: double fed induction generator) or with a wide range of speed variation (synchronous generators with a full converter). Variable speed drives offer the possibility to adapt the rotational speed of the windrotor blades to optimal operation conditions; extracting maximum power from the wind. Especially at higher ratings of the wind energy converter the variable speed design, although more expensive, pays off.

Fig. 3. Greenhouse area with total energy installations, supplying CO_2, heat and electricity

IV. VARIABLE SPEED GENERATORS

A. Generators with full converters

Seen from the MV network, generators equipped with a full converter behave as power electronic equipment with a large inertial energy. Whatever technology is applied for the generator itself (synchronous or asynchronous machine, the number of pole pairs, permanent magnet excitation, gear box or direct coupling with wind rotor), the design of the converter determines the transient response to fault conditions in the network. As the cost of a converter is proportional to the voltage and current rating, manufacturers design converters with a marginal capacity for over-currents. Meaning that the thermal short-circuit contribution is limited to for instance 120% of the rated current. This means also that the short-circuit current contribution of such a design is independent from the distance to the fault. For fault current calculations and software applications one has to treat these generators as current sources[2].

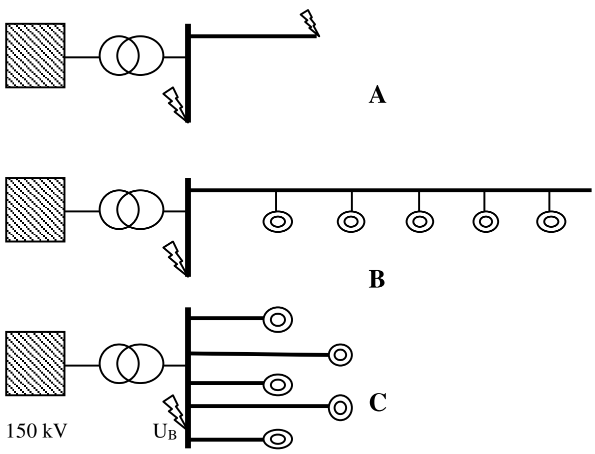

Fig. 4. Different network topologies, without and with DG

To be precise, the short-circuit current is not limited by the construction of the converter, but by the intervention of the controller, that will control the converter in a way to avoid the current to reach overstressing values [6]. The behavior depends especially on the setting of this controller and may vary from case to case. In general the controller will act very fast and even limit the peak current. The peak current is far smaller than values from conventional generators.

Generators with full converters are connected to the MV grid through step-up transformers, as shown in fig. 5. The next paragraphs deal with the DFIG technology, pictured in fig. 6.

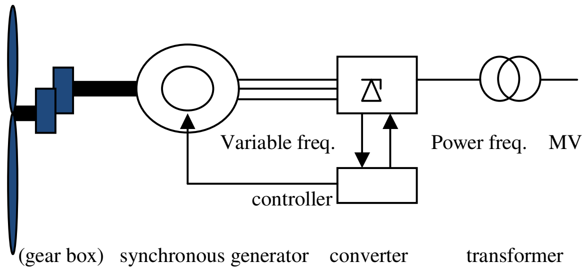

Fig. 5. Synchronous generator with full converter, with or without gear box

[2] As the influence of MV cables is neglectable, conventional models will do.

B. DFIG - General

The operational behavior of a DFIG under fault conditions is rather complicated [7]:

1. the wound rotor induction machine with slip rings is different from a squirrel cage machine
2. the influence of the converter forcing a current through the rotor introduces similarities to a synchronous generator
3. the controller of the converter and the controller of the crowbar have a large influence on the transient behaviour, but its setting is usually unknown to owners and network operators.

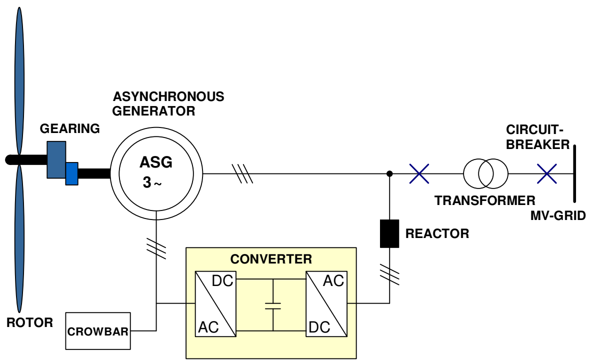

Fig. 6. Double Fed Induction Generator (DFIG)

Like with synchronous generators and squirrel cage induction machines, the stator windings of a DFIG generate a magnetic field that rotates with a speed equal to the power frequency $\boldsymbol{\omega}$ (divided by the number of pole pairs). In order to transfer electro-magnetic power from stator to rotor or reverse, the rotor magnetic field has to rotate at the same speed as the stator field. Amplitude and phase angle between stator and rotor magnetic fields determine the amount of power transferred and the direction of the power flow (i.e. from the leading to the lagging field). In synchronous machines the rotor winding and therefore the magnetic field is rotating at the same speed **ω** (synchronously). The rotor speed of asynchronous machines deviates by a certain slip **s**. A voltage with low frequency (**s*ω**) is induced in the rotor conductors, so that the rotational speed of the rotor magnetic field is the sum of the mechanical speed **(1-s)*ω** and **s*ω**. The slip **s** is a function of the torque, and usually only a few %.

The DFIG shows a rotor speed that varies, but the converter takes care for adaptation of the rotor current frequency in such a way that the rotor magnetic field is running synchronous with the stator magnetic field. Due to the slip a voltage with a frequency **s*ω** will be induced in the rotor windings, but the controller of the rotor-side converter will compensate for that and will dominate the flux pattern, at least under steady state conditions.

C. Generator terminal fault

At the moment of an instant short circuit at the stator terminals of any machine, the voltage disappears and the magnetic flux previously generated by the three-phase supply will stop rotating (in fact starts rotating slowly) and will decay with a certain time constant [6][8]. In the rotor bars a voltage will be induced with a frequency equal to the mechanical speed of the rotor, but in opposite direction, meaning that the induced rotor flux stops rotating as well. Two magnetic fields are now superimposed: the DC stator field that induces an AC voltage in the rotor windings, and the originally synchronous running rotor field (maybe decaying). The rotor flux induces an AC voltage in the stator windings. The induced voltages, however, are large due to the higher speed difference between suddenly fixed stator flux and the spinning rotor. Consequently rotor current and rotor flux will increase fast to compensate for the induced field. The additional rotor flux forces AC and DC components of the stator currents to counteract by increasing accordingly, leading to a further increase of the induced voltages and so on. Ultimately, rotor and stator currents are limited by the stray inductance between rotor and stator windings.

With a synchronous generator, initially the damping windings play a large role, with similar characteristics as the bars of a squirrel cage rotor. The rotor field winding will continue to induce a synchronous magnetic field, depending on the power of the exciter and the setting of its controller. In an induction generator, it is the stray inductance that determines the stator short-circuit current. The decay of the current is determined by the time constants of the stator windings (DC-component) and rotor bars (AC component) and is relatively short (1 to 2 cycles of power frequency).

An induction machine with a wound winding rotor is behaving in a similar way, but will show a higher stray inductance and a shorter time constant depending on the external resistance connected to the slip rings. The amplitude and the damping of the rotor currents are influenced by the external resistance. The peak value of the short circuit current will therefore be less than that of a squirrel cage induction machine. This may also be the case with DFIGs, as the induced voltage from the suddenly still standing stator flux could force the crowbar to by-pass the converter and insert an additional resistor. The resistor is in the order of 10 to 20 times higher than the resistance of the rotor windings.

D. DFIG – Short-circuit current

To learn how fast the crowbar will be triggered a three-phase fault in the MV-network will be assumed. As discussed above, the impedance of the MV cables can be neglected with respect to the short-circuit impedance of a DG. Let the stray inductance of the DFIG be 20% and that of the step-up transformer 6%, then the fault will lead to a voltage dip of 77% at the terminals of the DFIG. Note, that a voltage dip of ς % (less than 100%) leads to a part of the stator flux that stops rotating (ς %) and a part that continues rotating (100 - ς %). Superposition of the phenomena described and the stationary conditions is applicable.

So, the induced rotor voltage from the still standing stator flux will be about 77% of that at a 100% terminal fault. It is proportional to the stator flux and to the rotor speed, as the stator flux is standing still. Initially, the stator flux may be corresponding to maximum operating conditions: maximum torque, maximum speed, maximum slip (i.e. absolute value, as the rotor speed is over-synchronous and slip negative). Under these conditions the converter voltage will be maximal as well, counteracting the induced rotor voltage. This is proportional to the synchronous rotating stator flux and proportional to the slip of about 30%. At the moment of the fault, the induced rotor voltage is coming from the same stator flux, standing still, and the rotor speed ("slip" of 130%), more than 4 times higher than under the maximum operating conditions. A flux of 77% still gives a 3 times higher voltage than under maximum operating conditions. Therefore, the thyristors of the crowbar will be fired and the crowbar (external resistance) will be connected to the rotor windings.

At firing the crowbar, the initial conditions of fluxes and currents are completely different from those when a squirrel cage induction machine would be short-circuited. Exact values for the comparison of fault currents depend on the DFIG

Fig. 7. A cluster of windmills

characteristics and operational conditions. General trends are that wound winding rotors show a higher leakage inductance, so that the relative short-circuit inductance of the DFIG compared to that of a squirrel cage generator increases from, say, 15% to, say, 18%. The crowbar is rather large, 10 to 20 times larger than the rotor resistance **Rr** and approaches the short-circuit reactance **ω*Ls**, as seen from the stator. This leads to a short-circuit impedance of the DFIG of, typically, 23%. The stator current AC component damps out with the rotor time constant **Tr = Lr/(20*Rr)**, less than half a cycle. The DC component damps out slowly with the stator time constant. After half a cycle the peak factor of the fault current will be 1.3*√2 or less, in comparison to 1.7*√2 or more for squirrel cage machines. When including a step-up transformer with a leakage impedance of 6%/1.25, the peak value of the DFIG short-circuit current becomes 4.6 p.u. compared to 9 p.u. for a conventional asynchronous generator (without step-up transformer: 12 p.u.). In the further text 1 p.u. is based on the MVA rating and nominal current of the generator.

E. Resumption of the grid voltage

During the fault the rotor will accelerate and by clearing the short-circuit current the stator voltage will resume and the stator flux starts to rotate again. With an induction machine, this requires a large amount of reactive power, that hampers the voltage to reach its nominal value within a short time. Usually, before resumption, the stator current has disappeared completely and the transient currents at resumption are comparable with the fault currents.

Modern windmills in the MW-range and equipped with DFIG will show some special features with respect to (i) fault-ride through, (ii) fast resumption of power supply, (iii) control of heavy transient and dynamic phenomena [9][10]. This means the converter is dimensioned in such a way that during transients it is able to control to a large extent the rotor voltage. For example the occurrence and clearing of faults, staying synchronized to the power grid for immediate support with active and reactive power. The energy for that purpose is extracted from the magnetic energy in the DFIG, that otherwise would be destroyed in the fault current, and from the voltage across the crowbar.

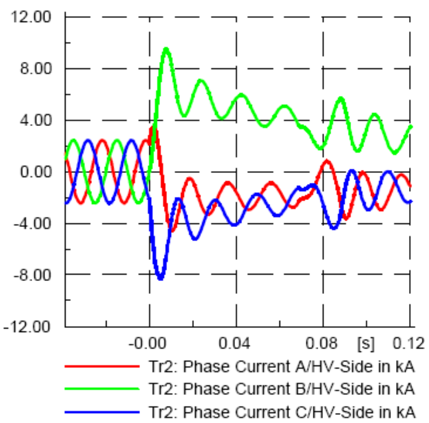

Fig. 8 Simulation of DFIG-park, 60 MW, 80% voltage dip at HV-side, currents at MV-side, with crowbar from 5-70 ms

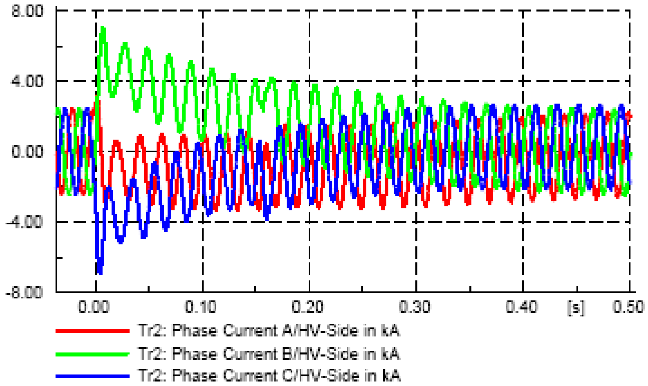

Fig. 9 Simulation of DFIG-park, 60 MW, 80% voltage dip at HV-side (150 ms), currents at MV-side, without crowbar

Even at maximum power output, when voltage margins of the converter are minimal, enough capacity in the converter has to be available to fulfill the manufacturer's targets. At other operational conditions, the converter will show inherently more margin and can more easily control the transients.

F. Considerations

Modern crowbars are only triggered for a few cycles to protect the converter hardware and the converter controller will further limit the transients [11]-[14]; as depicted in fig. 8. Without intervention of the crowbar lower peak values might be expected [15], as the controller will force the rotor currents to their original values (AC-part in fig.9). An erroneous setting of the parameters of the converter controller may exacerbate the wave shape and peak factor of the stator currents [16], but this is regarded as exceptional and negligible within a network with several DFIGs. Further, one has to be careful when extrapolating academic models to service conditions, as the models are used to study some particular effects of designs, controllers or controller settings, without considering operational techno-economical features of real machines (for instance when sizing the converters and the DC-link). Figure 10 to 12 show results from real measurements of a DFIG to a network fault, confirming the above considerations.

The figures for the contribution of DFIGs, as stated at the end of D, are rather conservative, but not extreme. It has to be emphasized that for utilities' short-circuit calculations in distribution networks, precise models of each DG are not necessary or even not available in a planning stage.

Based on the fore-mentioned chapters and simplifications for practical use, the following guidelines for short-circuit current calculations have been implemented:

- default short-circuit impedance value for synchronous generators plus step-up: 20%, based on MVA-rating of generator; peak factor: 1.9*√2
- default short-circuit impedance value for asynchronous generators plus step-up: 20%, based on MVA-rating of generator; peak factor: 1.8*√2
- default short-circuit impedance value for (a)synchronous generators with full converter plus step-up: 67%, based on MVA-rating of generator (150% overloading capability of

converter for 0.2 s); peak factor: 2*√2 (as a converter overload capability of 300% is assumed for half a cycle [17])

- default short-circuit impedance value for DFIG plus step-up: 28%, based on MVA-rating of generator; peak factor: 1.3*√2
- default short-circuit current from HV/MV transformer, without DG, based on voltage E of fig. 1
- default short-circuit current from HV/MV transformer, in case of DG, based on 110% of nominal system voltage; equivalent source method [3].

Some examples of fault current measurements at the MV-side, on DFIGs inclusive crowbars; voltage dip in MV-grid.

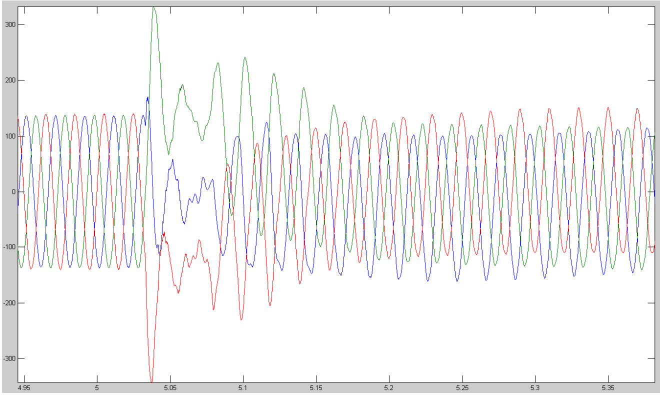

Fig. 10 Fault current measurement at MV-side of 3 MW DFIG, 70% dip (residual voltage 30%), longer than 350 ms, peak: 2.4 p.u.

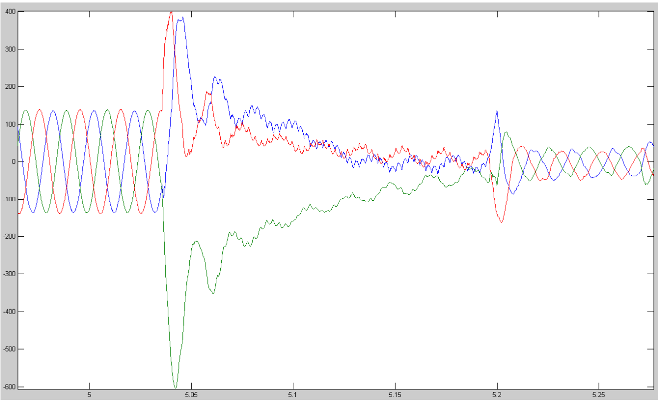

Fig. 11 Fault current measurement at MV-side of 3 MW DFIG, 100% dip 160 ms, 3 MW set point, peak: 4.47 p.u.

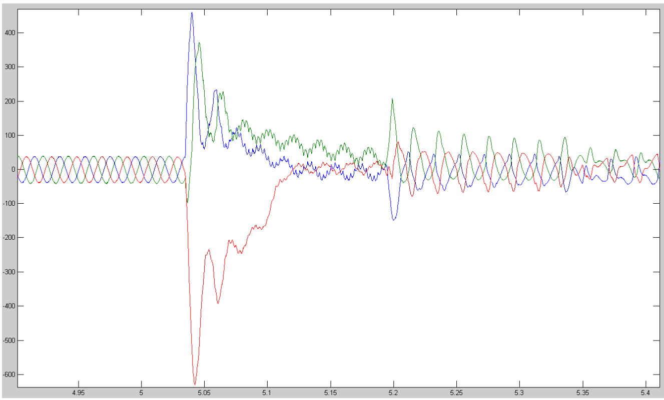

Fig. 12 Fault current measurement at MV-side of 3 MW DFIG, 100% dip 160 ms, 1 MW set-point, peak: 4.64 p.u.

V. ASYMMETRIC FAULTS

Asymmetric faults should not be mixed up with asymmetrical currents. Asymmetrical currents are presented in fig. 13, where the DC-components can be seen and the peak value in phase A. This is a 3-phase fault current without zero sequence component, as discussed so far. In case of a single or double phase fault, the fault is called asymmetrical, leading to negative sequence and/or zero sequence components in the phase current(s).

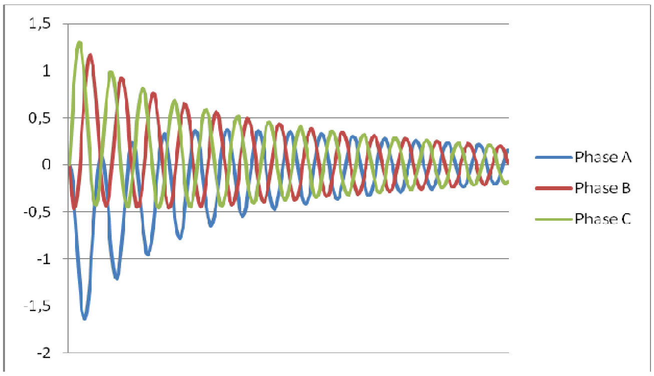

Fig. 13 Asymmetrical fault currents, peak in bottom phase (phase A)

In service many faults start as a single phase to earth failure and evolve to a double phase to earth and/or a three-phase to earth fault. The fault current will contain zero sequence and DC-components. When the fault evolves in such a way that each phase is involved around voltage minimum, a higher peak value may be reached than shown before, but it is rather unlikely that dielectric breakdowns occur in such a pattern [2].

Apart from the peak value of the short-circuit current, for thermal reasons, its 1 or 3 s value is of importance. However, conventional DG generators will trip at such durations of the fault, while DFIGs and generators with full converters will either trip or reduce the short-circuit current to very low values. A third important value of the short-circuit current is the DC-component at the moment of fault clearing [2]. Nowadays the IEC Standard for circuit-breakers [18] and the IEEE Standard for generator circuit-breakers [19] take into consideration fault clearing duties with high DC time constants (120 ms up to 52 kV (IEC) and 131 ms (IEEE), peak value 2.7 * RMS-value).

In service most faults are of an evolving nature, including faults currents that involve a zero sequence component. The value of the zero sequence component is determined by the neutral treatment of the MV grid. In case of generators directly connected to the MV network it may be preferred to reduce the zero sequence impedance of the network in order to limit transient and temporary overvoltages (for instance due to self extinguishing faults [4]) and to be able to detect stator-to-earth faults in the generators easily and reliably. For low neutral impedance MV networks, a three-phase inductive fault current limiter (FCL) has been developed that reduces the fault peak current by inserting a rather large zero sequence impedance in series with the equipment to be protected.

VI. FCL BY ZERO SEQUENCE IMPEDANCE

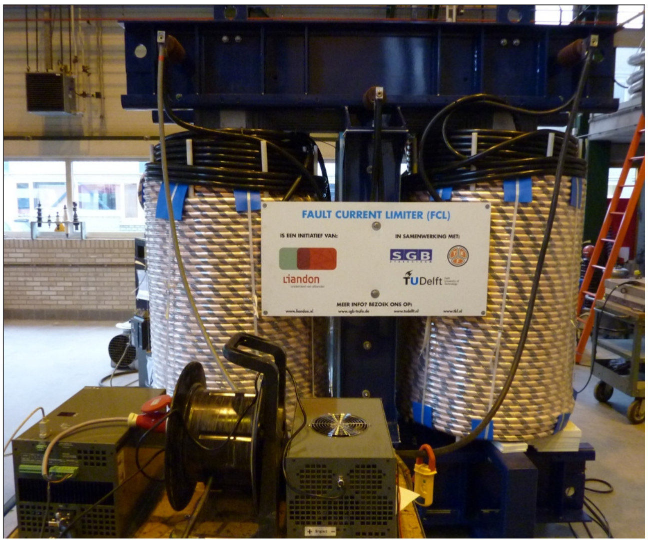

Fig. 14 Three-phase inductive FCL with common core and trifilar windings

A new three-phase inductive FCL has been developed [20] to reduce the current contribution from single phase faults [4]. It consists of a 3-leg core with 3-phase trifilar windings around the outer legs, the flux returns through the inner leg. DC-windings around each of the outer legs bring these into saturation, thus limiting strongly the AC-flux (and reduce the AC reactance) for normal operation. Each half cycle, a zero-sequence fault current will de-saturate one of the outer legs, so that a considerable AC-flux will flow through this outer leg and the middle leg (increasing the AC reactance); see figure 14 and 15.

By simulations, small scale tests and prototype tests the fault current capability of the design has been proven. At KEMA High-Power Laboratory a 10 kV/10 kA 3-phase power source has been short-circuited by the FCL and proved to be able to reduce the single phase fault from 25 kApeak to 4.7 kApeak, while multi-phase fault currents have been reduced to 22 kApeak only.

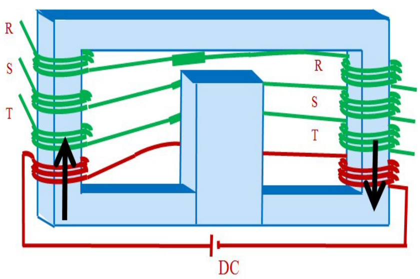

Fig. 15 Diagram of 3-phase FCL magnetic circuit

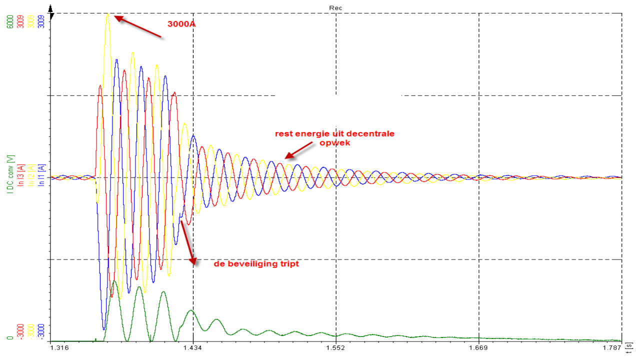

Fig. 16. Small scale laboratory 3-phase fault test
Peak value (yellow) 3000 A; green is current though DC-windings

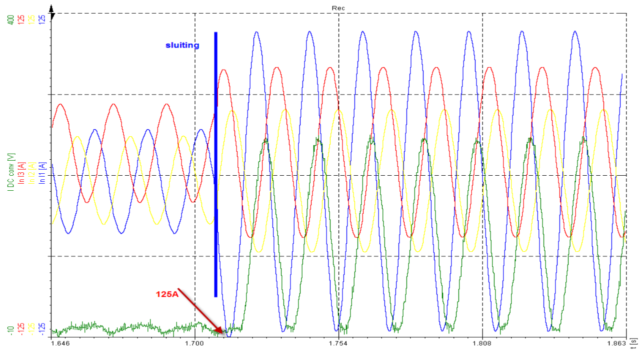

Fig. 17. S protection boratory 1-phase fault test
Peak value (blue) 125 A; green is current through DC-windings

Due to the limited amount of material, the device is rather inexpensive compared with other FCL technologies. But, as impedance grounding of neutrals is far less expensive, the FCL is to be applied in special cases only. For instance in networks where a fixed neutral is required, but some feeders have to be protected for large single phase short-circuit currents (i.e. large single phase loads, railways, arc furnaces, grids dedicated for 20/10 kV DG, for instance with auto-transformers as step-up, etc.).

VII. FCL BY FULL CONVERTER GENERATORS

Another way to limit short-circuit current is using the converters of equipments such as full converters connected with (a)synchronous generators The converters of multi-MW machines show to have a relatively large thermal margin. Some examples of fault current measurements on full converter with synchronous generators are illustrated in figure 18 and 19. These full converters are able to withstand short-circuit currents of about 1.4 p.u., for 200 ms, and a first peak that is considerably larger, up to more than 3 p.u. Within 200 ms they limit the fault current also to these values, which are much smaller than those of regular synchronous generators. The continuous short-circuit current will be less, e.g. 120%.

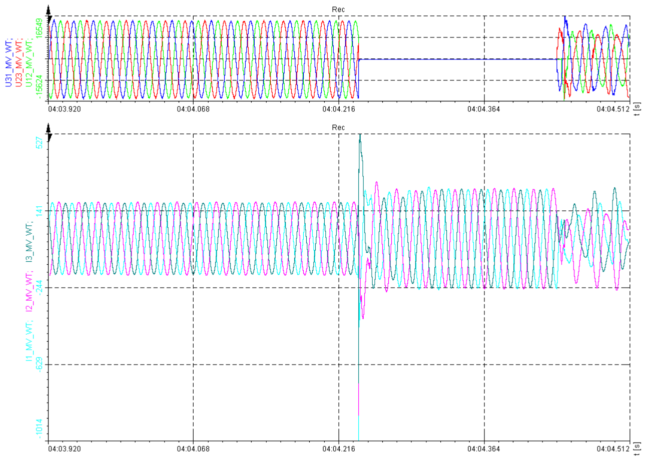

Fig. 18 Fault current measurements at MV-side of 2 MW full converter at full load, 100% dip, Isc = 1.39 p.u., peak: 2.93 p.u. (the tripe spike at 04:04.240 seems to be a flaw in the measurements)

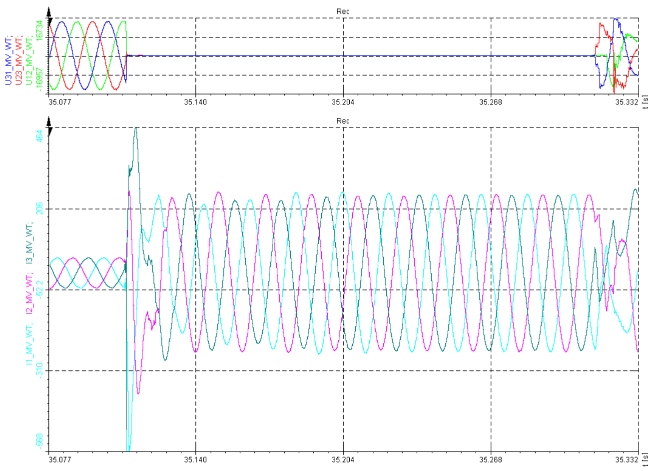

Fig. 19 Fault current measurements at MV-side of 2 MW full converter at 30% load, 100% dip, Isc = 1.36 p.u., peak: 3.16 p.u.

VIII. CONCLUSIONS

The following conclusions can be drawn:

- A fault current in a MV network depends strongly on the HV/MV transformer characteristics and the way it is operated (transformers in parallel, tap position, tap control, load current, power factor).
- In addition, the length and type of MV cable(s) between transformer and fault location (between main busbar and fault) reduces considerable the RMS (15%/km) and peak factor (15%/km) of the fault current.
- Length of cable between DG and fault location can be neglected, for 10 kV as well as for 20 kV. Generally, as a simplification of the network, for fault current calculations the configuration in figure 4C can be applied.
- The overall short-circuit impedance of a (a) synchronous generator (seen from the MV network) without step-up transformer is comparable with that of a DG with step-up transformer.
- The fault current contribution of a DG with a full converter is limited, up to 1.5 p.u. (200 ms) with a peak value of 3.0 p.u., in stead of about 5 p.u.. with a peak of 10 p.u.. Longer duration: 1.2 p.u.
- The fault contribution of DFIG is moderate, resulting in a peak value less than half of that of a squirrel cage induction generator of equal size; e.g. maximum 4.6 p.u. compared to 9 p.u.; this reduction is caused by either the crowbar or the rotor side converter (or both).
- Zero-sequence components of fault currents and single phase fault currents are usually reduced by an impedance in the neutral of power transformers, resulting in higher transient and temporary voltages. For special cases with a low neutral impedance to reduce overvoltages and neutral shift, an FCL inserting a large zero-sequence reactance has been presented.
- DG with full converters form an FCL by themselves, meaning that they limit the fault current more or less independent from distance to the fault and operational conditions.

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