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TECHNICAL REPORT

**Dynamic characteristics of inverter-based resources in bulk power systems –
Part 4: Behaviour of inverter-based resources in response to bulk grid faults**

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INTERNATIONAL
ELECTROTECHNICAL
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INTERNATIONAL ELECTROTECHNICAL COMMISSION

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DYNAMIC CHARACTERISTICS OF INVERTER-BASED RESOURCES IN BULK POWER SYSTEMS –

Part 4: Behaviour of inverter-based resources in response to bulk grid faults

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IEC TR 63401-4 has been prepared by subcommittee SC 8A: Grid Integration of renewable energy generation, of IEC technical committee TC 8: Systems aspects of electrical energy supply. It is a Technical Report.

The text of this Technical Report is based on the following documents:

Draft TR	Report on voting
8A/100/DTR	8A/104/RVDTR

Full information on the voting for its approval can be found in the report on voting indicated in the above table.

The language used for the development of this Technical Report is English.

This document was drafted in accordance with ISO/IEC Directives, Part 2, and developed in accordance with ISO/IEC Directives, Part 1 and ISO/IEC Directives, IEC Supplement, available at www.iec.ch/members_experts/refdocs. The main document types developed by IEC are described in greater detail at www.iec.ch/standardsdev/publications.

A list of all parts in the IEC 63401 series, published under the general title *Dynamic characteristics of inverter-based resources in bulk power systems*, can be found on the IEC website.

The committee has decided that the contents of this document will remain unchanged until the stability date indicated on the IEC website under webstore.iec.ch in the data related to the specific document. At this date, the document will be

- reconfirmed,
- withdrawn,
- replaced by a revised edition, or
- amended.

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INTRODUCTION

Wind turbines and photovoltaic based power sources employ power electronic converters. Their controllable characteristics significantly change the behaviour of the power system to bulk grid faults, which brings new challenges to the reliability and safety of the modern power systems. Relay protection plays a key role in safe and stable operation of power systems for identifying and isolating faults quickly and reliably.

Relay protection operates on electrical characteristics when a fault occurs. Legacy protection principles are generally based on the fault characteristics of the synchronous machine. With the large-scale integration of these inverter-based resources (IBRs) into power systems, the diversity in IBR topologies and control strategies makes the fault behaviour turn to complex, and the electrical characteristics in the faulted power systems are significantly changed from the traditional. Legacy relay protections could be negatively affected.

Considering these challenges, this technical report aims at presenting the fault behaviour of IBRs in different topologies and control strategies, and then evaluating the adaptability of existing relay protection principles in IBR scenarios. In this report, IBRs are generally classified as full-scale converter based IBR (including Type-IV wind turbine and PV inverter) and Type-III wind turbine (also referred to as doubly-fed induction generator based wind turbine).

DYNAMIC CHARACTERISTICS OF INVERTER-BASED RESOURCES IN BULK POWER SYSTEMS –

Part 4: Behaviour of inverter-based resources in response to bulk grid faults

1 Scope

This part of IEC 63401, which is a technical report, mainly focuses on the fault behaviour of IBRs and performances of the existing relay protection in grids with large-scale integration of IBRs.

This document mainly includes:

- The IBR fault current requirements in present grid codes, including the requirements of active and reactive currents in positive- and negative-sequence systems during symmetrical and unsymmetrical faults.
- Fault current behaviour of IBRs, including the current components in transient and fundamental frequency in different IBR topology and control schemes.

Adaptability of existing relay protection with the large-scale integration of IBRs, including the performances of distance protection, phase selector, directional relay and over-current protection.

2 Normative references

There are no normative references in this document.

3 Terms, definitions and abbreviated terms

3.1 Terms and definitions

No terms and definitions are listed in this document.

ISO and IEC maintain terminological databases for use in standardization at the following addresses:

- IEC Electropedia: available at http://www.electropedia.org/
- ISO Online browsing platform: available at http://www.iso.org/obp

3.2   Abbreviated terms

Abbreviated term	Description
DER	Distributed Energy Resource(s)
DFIG	Doubly Fed Induction Generator
EMF	Electromotive Force
ENSI	Equivalent Negative-Sequence Impedance
EPS	Electrical Power System
EPSI	Equivalent Positive-Sequence Impedance
ESE	Energy Storage Element
EZSI	Equivalent Zero Sequence Impedance
FRT	Fault Ride Through
FSC	Full-Scale Converter
GSC	Grid-Side Converter
IBR	Inverter-Based Resource
I1A	Positive-Sequence Active Current
I1R	Positive-Sequence Reactive Current
I2A	Negative-Sequence Active Current
I2R	Negative -Sequence Reactive Current
MSC	Machine-Side Converter
PMSG	Permanent Magnet Synchronous Generator
PCC	Point of Common Coupling
RCI	Reactive Current Injection
RSC	Rotor Side Converter
SG	Synchronous Generator
WT	Wind Turbine

4   Existing requirements for fault current behaviour of IBRs

4.1   Review of the present requirements

Considering the influence of IBRs during the fault, the technical requirements for connecting IBRs to power system have been established in many countries around the world. Taking the network code on requirements for grid connection of generators in EU as an example, the power-generating modules must be capable of remaining connected to the network and continuing to operate stably when a symmetrical voltage drop occurs at the point of common coupling (PCC), unless the protection scheme for internal electrical faults requires the disconnection of the power-generating modules from the network. The fault-ride-through capabilities in case of asymmetrical faults must be specified [1][1].

Table 1 shows the parameters for Figure 1 for fault-ride-through capability of power-generating modules and the detailed parameters in some countries are given in Table 2.

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[1]   Numbers in square brackets refer to the bibliography.
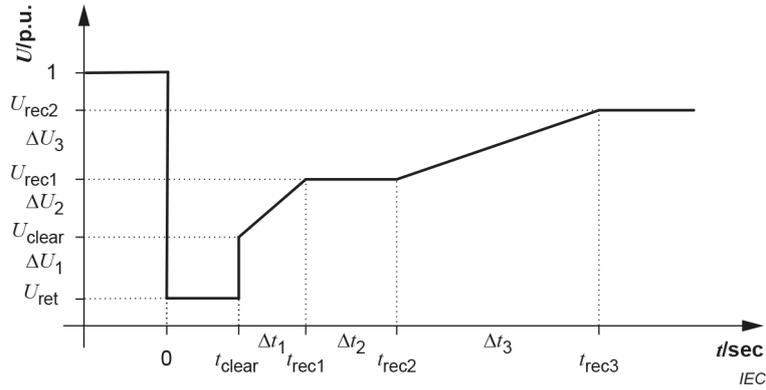
Figure 1 – Fault-ride-through profile of power-generating modules

The diagram represents the lower limit of a voltage-against-time profile of the voltage at the PCC, expressed as the ratio of its actual value to its reference 1 p.u. value before, during and after the fault, U_{ret} is the retained voltage at the PCC during the fault, t_{clear} is the instant after the fault is cleared, U_{clear} is the instantaneous voltage after the fault is cleared, U_{rec1}, U_{rec2}, t_{rec1}, t_{rec2} and t_{rec3} specify certain points of the lower limit of voltage recovery after the fault is cleared.

Table 1 – Parameters for Figure 1 for fault-ride-through capability of power-generating modules

Voltage parameters (p.u.)		Time parameters (seconds)	
U_{ret}	0-0.2	t_{clear}	0,15-0,625
U_{clear}	$U_{ret} + \Delta U_1$	t_{rec1}	$t_{clear} + \Delta t_1$
U_{rec1}	$U_{clear} + \Delta U_2$	t_{rec2}	$t_{rec1} + \Delta t_2$
U_{rec2}	$U_{rec1} + \Delta U_3$	t_{rec3}	$t_{rec2} + \Delta t_3$

**Table 2 – Detailed parameters for Figure 1 for fault-ride-through capability
of power-generating modules in different countries**

Requirements for different countries	Requirements for wind power in China	Requirements for PV power in China	Requirements for wind power and PV power in Germany	Requirements for wind power in Denmark	Requirements for wind power in USA
Duration of under voltage ride-through	U_{ret} = 0,2pu t_{clear} = 625 ms	U_{ret} = 0 t_{clear} = 150 ms	Symmetrical fault, U_{ret} = 0 t_{clear} = 150 ms Asymmetrical fault, U_{ret} = 0 t_{clear} = 220 ms	Symmetrical fault, U_{ret} = 0 t_{clear} = 250 ms	U_{ret} = 0,15pu t_{clear} = 625 ms
Duration of over voltage ride-through	None	U_{pcc} = 1,30pu t_{uni} = 500 ms U_{pcc} = 1,20pu t_{uni} = 10s	U_{pcc} = 1,30pu t_{uni} = 100 ms U_{pcc} = 1,24pu t_{uni} = 60s	None	None
Fault voltage recovery time	U_{rec2} = 0,9pu t_{rec3} = 2s	U_{rec2} = 0,9pu t_{rec3} = 2s	Symmetrical fault, U_{rec2} = 0,85pu t_{rec3} = 3s two-phase short-circuit fault U_{rec2} = 0,85pu t_{rec3} = 5s	Symmetrical fault, U_{rec2} = 0,9pu t_{rec3} = 10s	U_{rec2} = 0,9pu t_{rec3} = 3s
Active power recovery Rate	At least 10 % P_n/s	At least 30 % P_n/s	At least 20 % P_n/s	At least 10 % P_n/s	At least 10 % P_n/s
Dynamic reactive power capability	t_{res}≤ 75ms, t_{dur}≥550 ms I_T≥1,5 × $(0,9-U_{pcc})I_n$ $(0,2≤U_{pcc}≤0,9)$	t_{res}≤ 60ms t_{adj}≤ 150ms $η<20 %$ $I_T≥K_1 × (0,9-U_{pcc})I_n$ $(U_{pcc}<0,9, 1,5≤K_1≤2,5)$ $I_T≥K_2 × (1,1-U_{pcc})I_N$ $(U_{pcc}>1,1, 0≤K_2≤1,5)$	t_{res}≤30ms t_{ste}≤60ms	$I_T≥I_n$	None
Requirements for positive-sequence and negative-sequence reactive current	None	None	$\Delta u_1 = \dfrac{\lvert U_1 \rvert - U_{1min}}{U_n}$ $\Delta u_2 = \dfrac{U_2}{U_n}$ $\Delta i_1 = k \cdot \Delta u_1$ $\Delta i_2 = k \cdot \Delta u_2$	None	None

where U_{pcc} is the voltage at the PCC in p.u., P_n is the rated active power output of power-generating modules, I_n is the rated current of power-generating modules, I_T is the reactive output current of power-generating modules, t_{uni} is the uninterrupted operation time of power-generating modules, t_{res} is the response time of dynamic reactive current, t_{adj} is the adjustment time of dynamic reactive current, η is the maximum overshoot of dynamic reactive current, t_{dur} is the duration time of dynamic reactive current, t_{ste} is the steady time of dynamic reactive current, U_n is the rated line voltage at the PCC, U_{1min} is the average line voltage at the PCC within one minute, U_1 is the positive-sequence voltage during the short-circuit fault, U_2 is the negative-sequence voltage during the short-circuit fault, Δu_1 is the ratio of the difference positive-sequence voltage between average line voltage to rated line voltage during the short-circuit fault, Δu_2 is the ratio of negative-sequence voltage to rated line voltage during the short-circuit fault, Δi_1 is the positive-sequence reactive current during the short-circuit fault and Δi_2 is the negative-sequence reactive current during the short-circuit fault, and k is the scale factor.

Taking the technical requirements for connecting IBRs to power system in USA, China and Germany as an example, as shown in 4.2, 4.3 and 4.4.

4.2 Requirements for wind power stations and PV stations by NERC

According to IEEE 1547-2018 and its amendment published in 2020 [2], there are 3 different voltage ride-through capability abnormal performance categories shown as follows,
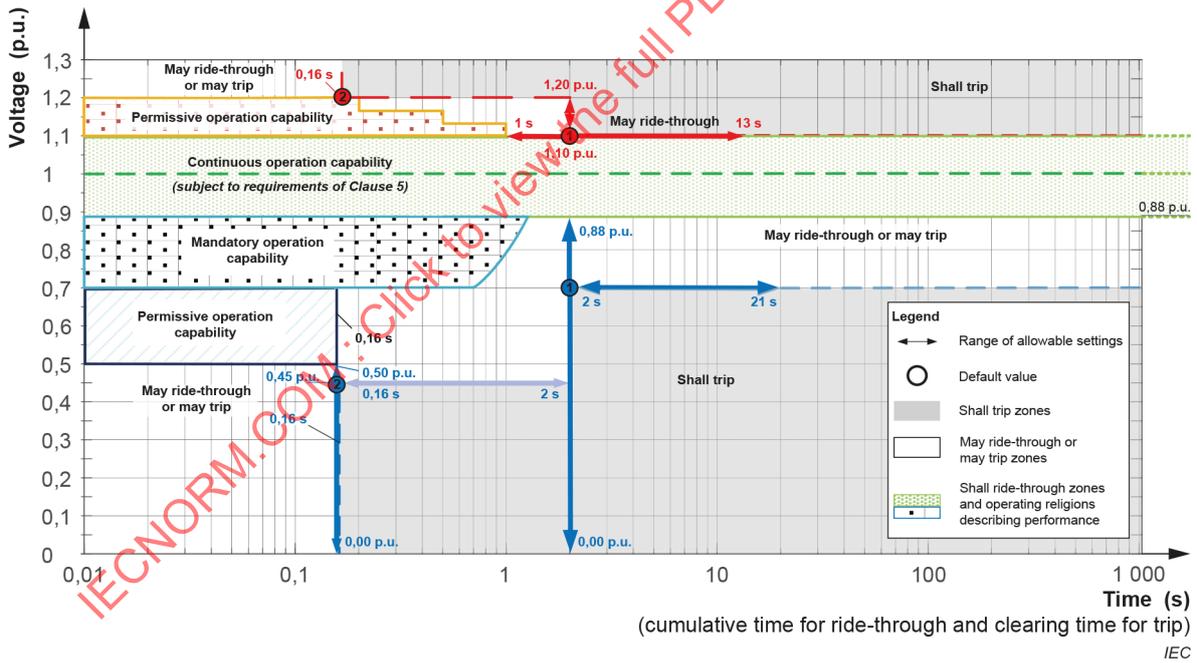
Figure 2 – Category Ⅰ Abnormal voltage ride-through requirement [2]
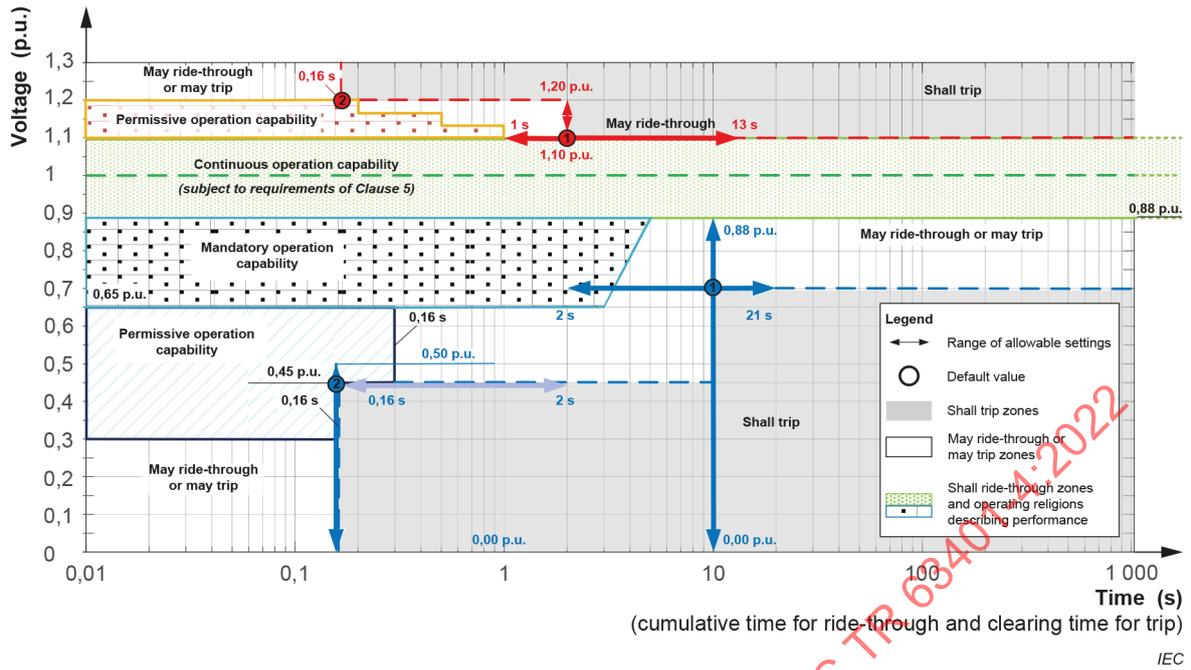
Figure 3 – Category II Abnormal voltage ride-through requirement [2]
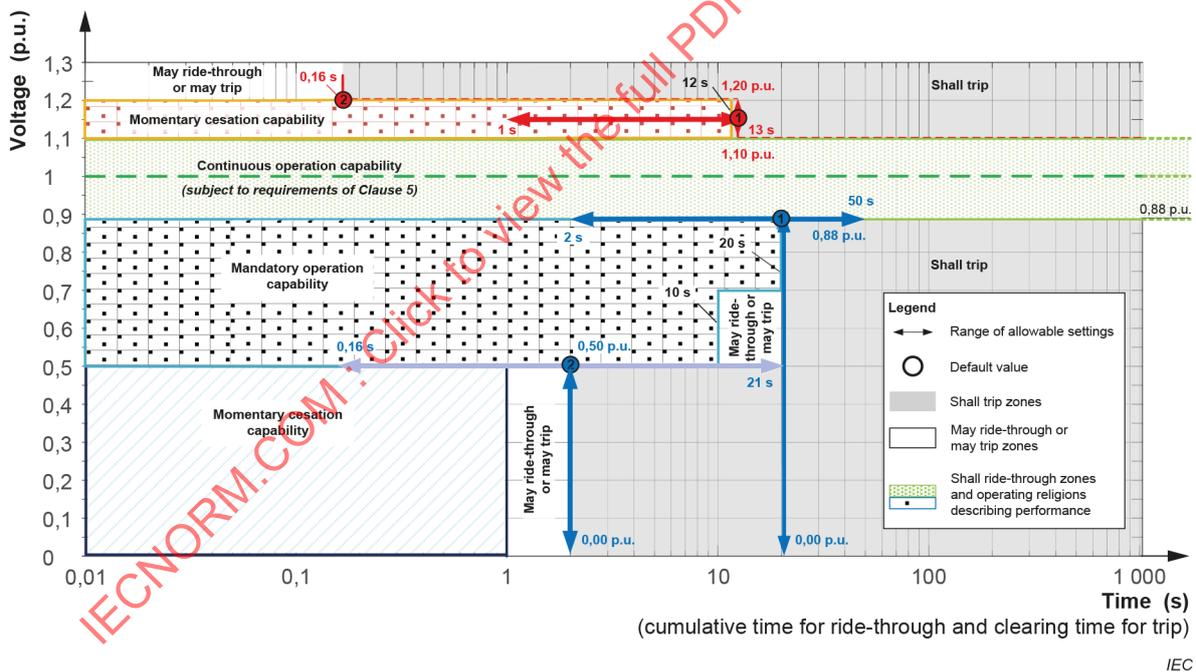
Figure 4 – Category III Abnormal voltage ride-through requirement as amended in [2]

In Figure 2, Figure 3 and Figure 4, depending on the magnitude of voltage and disturbance duration time, different operation regions are presented. The differences among three performance categories also lie in the disturbance duration time and range of magnitude of voltage. The low-voltage ride-through performances in different operation regions for all three performance categories are as follows:

1) within the mandatory operation region, the distributed energy resources (DER) must operate synchronously with the Area electrical power system (EPS) and continue to exchange current with the Area EPS without stopping power supply and tripping-off.

2) within the permissive operation region, the DER must operate synchronously with the Area EPS or must not trip and may continue to exchange current with the Area EPS or may stop power supply.

3) within the continuous operation regions, the DER must operate synchronously with the Area EPS and continue to transmit active power at least the same level of magnitude as the active power before disturbance.

4) within the permissive operation region, the DER must operate synchronously with the Area EPS or shall not trip and may continue to exchange current with the Area EPS or may stop power supply.

5) within the momentary cessation operation region, when the DER is connected to the Area EPS, it shall temporarily stop power supply. When the applicable voltage returns, the DER must immediately restore output of operation.

4.3 Requirements for wind power stations and PV power stations in China

According to the technical requirements for connecting wind farms to power system [3], the active power recovery speed and dynamic reactive power support capacity are set during the under voltage ride through process. The under voltage ride through requirements for wind farms in China are shown in Figure 5.
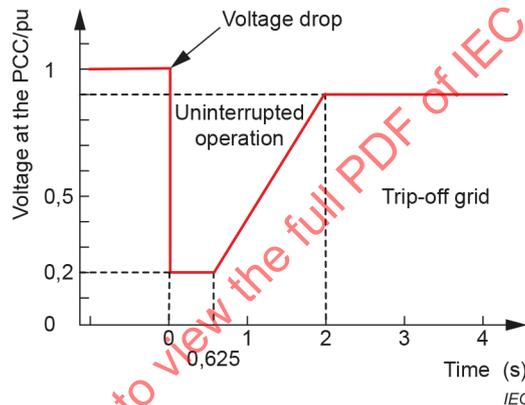
Figure 5 – Under voltage ride through requirements for wind farms in China

When the voltage at the PCC of wind farms drops to 20 % of nominal voltage, the wind turbines in the wind farms should ensure uninterrupted operation for 625 ms without trip-off grid. Besides, the wind turbines should also ensure uninterrupted operation when the voltage at the PCC of wind farms recovers to 90 % of nominal voltage within 2 seconds.

(1) Active power recovery

For wind turbines that are not trip-off grid during the fault, the active power should be recovered with the rate of at least 10 % P_n per second from the time point of voltage recovery.

(2) Dynamic reactive power support capability

When a symmetrical fault occurs at the PCC of wind farms, it should respond quickly from the moment of voltage drop. And reactive current should be provided by wind turbines for voltage support. Detailed requirements are as follows.

From the moment of voltage drop, the response time of the dynamic reactive current should not be more than 75 ms, and the duration time of the dynamic reactive current is not less than 550 ms.

The dynamic reactive current provided by wind turbines should meet the following requirements:

$$I_\mathrm{T} \geq 1{,}5 \times (0{,}9 - U_\mathrm{pcc})I_\mathrm{n} \quad 0{,}2 \leq U_\mathrm{pcc} \leq 0{,}9 \tag{1}$$

where I_T is the reactive output current, U_pcc is the voltage at the PCC of wind farms in p.u. and I_n is rated current of wind turbines.

However, for two-phase short-circuit fault and single-phase-to-ground short-circuit fault, there are no detailed requirements for the dynamic reactive current capability of wind turbines.

In summary, wind turbines should have the capability of under voltage ride through during the symmetrical fault. The dynamic reactive current capability, response speed and duration time of wind turbines are required definitely according to the China criteria. However, the dynamic reactive current capability of wind turbines during the asymmetric fault is not required.

According to technical requirements for connecting photovoltaic power stations to power system, the active power recovery speed and dynamic reactive power support capacity are set during under and over voltage ride through process. The under voltage ride through requirements for photovoltaic power stations in China are shown in Figure 6.
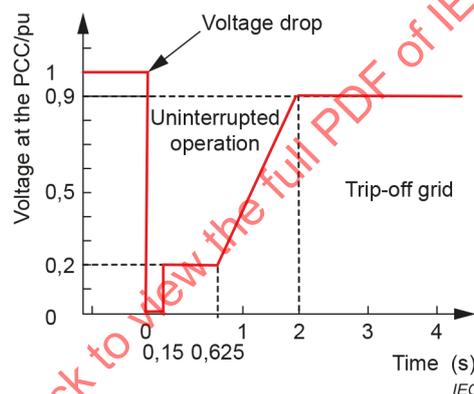
Figure 6 – Under voltage ride through requirements for photovoltaic power stations in China

When the voltage at the PCC of photovoltaic power stations drops to zero, the photovoltaic (PV) power units should ensure uninterrupted operation for 150 ms without trip-off grid. In addition, PV power units should be operated uninterrupted for 625 ms when the voltage at the PCC drops to 20 % of nominal voltage. And the PV power units should also ensure uninterrupted operation when the voltage recovers to 90 % of nominal voltage within 2 seconds.

The operation requirement and dynamic reactive power support capacity for PV power units are also set during over voltage ride through process. The over voltage ride through requirements for photovoltaic power stations in China are shown in Figure 7.
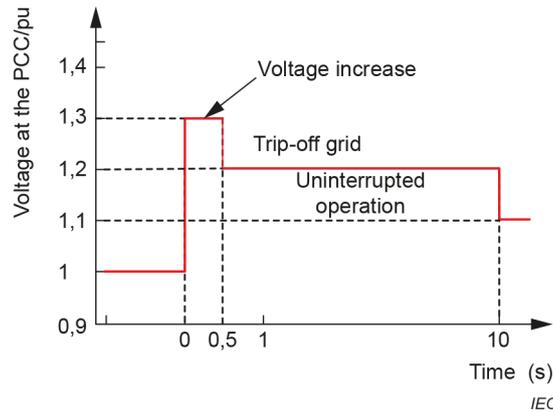
**Figure 7 – Over voltage ride through requirements
for photovoltaic power stations in China**

When the voltage at the PCC of photovoltaic power stations increases to 130 % of nominal voltage, the PV power units should ensure uninterrupted operation for 500 ms without trip-off grid. Besides, PV power units should be operated uninterrupted for 10s when the voltage at the PCC increases to 120 % of nominal voltage. And the PV power units should also ensure uninterrupted operation when the voltage at the PCC increases to 110 % of nominal voltage.

(1) Active power recovery

For PV power units that are not trip-off grid during the fault, the active power should be recovered with the rate of at least 30 % P_n per second from the time point of voltage recovery.

(2) Dynamic reactive power support capability

When a short-circuit fault occurs at the PCC of photovoltaic power stations, it should respond quickly from the moment of voltage drop or voltage increase. And reactive current should be provided by PV power units for voltage support. Detailed requirements are as follows.

From the moment of voltage drop or voltage increase, the response time of dynamic reactive current should be no more than 60 ms and the adjustment time of dynamic reactive current should be no more than 150 ms, the maximum overshoot of dynamic reactive current should also be no more than 20 %.

The dynamic reactive current provided by PV power units during low and over voltage ride though should meet the following requirements:

$$
\begin{cases}
I_T \geq K_1 \times (0,9 - U_{pcc})I_n & U_{pcc} < 0,9 \\
I_T \geq K_2 \times (1,1 - U_{pcc})I_n & U_{pcc} > 1,1 \\
1,5 \leq K_1 \leq 2,5 \quad 0 \leq K_2 \leq 1,5 &
\end{cases}
\tag{2}
$$

where I_T is the reactive output current, a positive value represents inductive reactive current, and a negative value represents capacitive reactive current. I_n is the rated current of PV power unit.

The maximum effective value of dynamic reactive current should not exceed $1,05I_n$ in case of the symmetrical fault, and the maximum effective value of dynamic reactive current should not exceed $0,4I_n$ in case of the asymmetrical fault. Besides, the control error of dynamic reactive current should not be more than 5 %I_n.

In summary, PV power units should have the capability of under and over voltage ride through during the short-circuit fault. The dynamic reactive current capability, response speed and duration time of PV power units are definitely required according to the China criteria. However, the guideline does not have requirements for negative-sequence reactive current capability under short-circuit fault.

4.4   Requirements for wind power stations and PV power stations in Germany

The basic requirements for wind power stations and PV power stations in Germany are as follows [4], according to VDE-AR-N 4120.
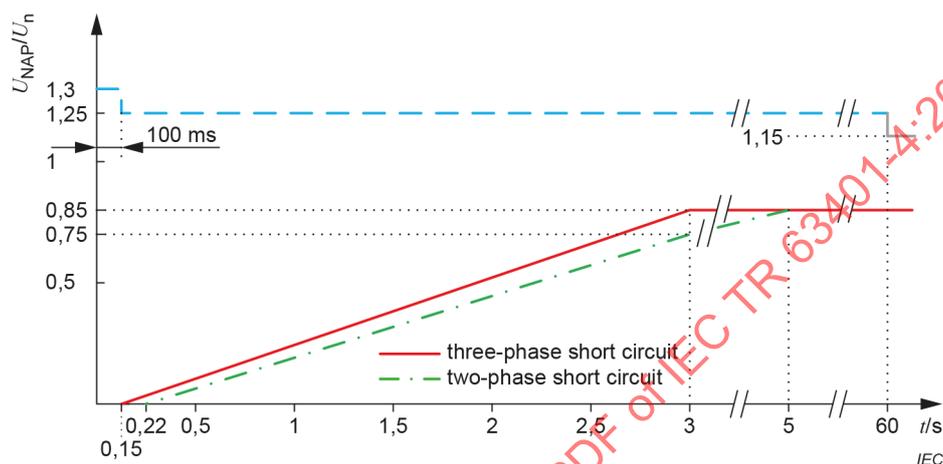
**Figure 8 – Voltage ride through requirements for type II
power stations according to VDE-AR-N-4120**

In Figure 8, blue line is the over voltage ride through curve for type II power stations(include wind power stations and PV power stations). Red line and green line are under voltage ride through curves for type II power units under three-phase short-circuit fault and two-phase short circuit fault respectively.

According to the criteria, when the voltage at the PCC of type II power stations increase to 130 % of nominal voltage, type II power units should ensure uninterrupted operation for 100 ms. When the voltage at the PCC of type II power stations increase to 124 % of nominal voltage, type II power units should ensure uninterrupted operation for 60 s.

Under three-phase short-circuit fault, when the voltage at the PCC of type II power stations drops the zero, type II power units should remain uninterrupted operation for 150 ms. Type II power units should also ensure uninterrupted operation when the voltage at the PCC recovers to 85 % of nominal voltage within 3 s.

Under two-phase short-circuit fault, when the voltage at the PCC of type II power stations drops the zero, type II power units should remain uninterrupted operation for 220 ms. Type II power units should also ensure uninterrupted operation when the voltage recovers to 85 % of nominal voltage within 5 s.

(1)   Active power recovery

For type II power units that are not trip-off grid during the circuit, the active power should recover at the rate of at least 20 % P_n per second from the moment of voltage recovery.

(2)   Dynamic reactive power capability

Type II power units should contribute positive-sequence and negative-sequence reactive current to the grid for supporting the voltage recovery and depressing three-phase unbalance degree. Reactive current priority is higher than active current. The response time of the reactive

current should be less than 30 ms and the stabilization time of the reactive current is less than 60 ms.

(3) Requirements for positive-sequence and negative-sequence reactive current

According to VDE-AR-N 4120, during the short-circuit fault, the extra positive-sequence and negative-sequence reactive current should be provided by type II power units to support the voltage recovery. The requirements of the dynamic reactive current is shown in Figure 9.
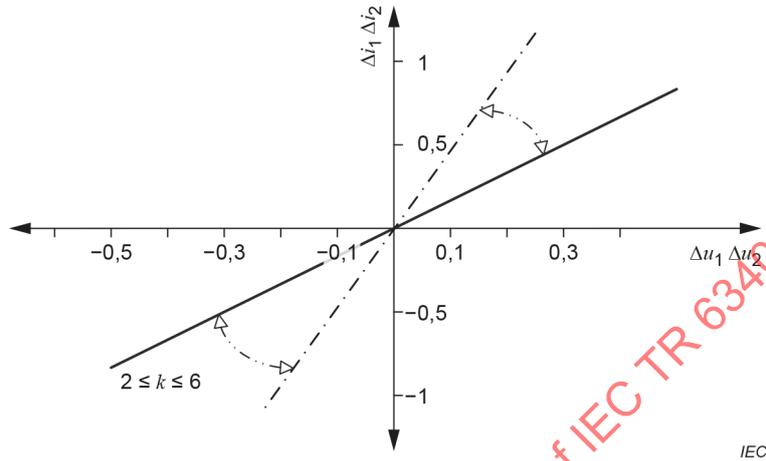
Figure 9 – Requirements of the reactive current according to VDE-AR-N 4120

$$\begin{cases} \Delta u_1 = \dfrac{\left|U_1\right| - U_{1min}}{U_n} \\[2mm] \Delta u_2 = \dfrac{U_2}{U_n} \\[2mm] \Delta i_1 = k \times \Delta u_1 \\[2mm] \Delta i_2 = k \times \Delta u_2 \end{cases} \tag{3}$$

U_n is the rated line voltage at the PCC, U_{1min} is the average line voltage at the PCC within one minute, U_1 is the positive-sequence voltage during the short-circuit fault, U_2 is the negative-sequence voltage during the short-circuit fault, Δu_1 is the ratio of the difference positive-sequence voltage between average line voltage to rated line voltage during the short-circuit fault, Δu_2 is the ratio of negative-sequence voltage to rated line voltage during the short-circuit fault, Δi_1 is the positive-sequence reactive current during the short-circuit fault and Δi_2 is the negative-sequence reactive current during the short-circuit fault, and k is the scale factor.

According to the Germany criteria, during the short-circuit fault, positive-sequence and negative-sequence reactive current should be provided. The value of positive-sequence and negative-sequence reactive current is proportional to Δu_1 and Δu_2, respectively.

In summary, according to VDE-AR-N 4120, type II power units should have the capability of high and under voltage ride through under symmetrical or asymmetrical short-circuit fault and the dynamic reactive current capability, response speed and duration time are required definitely. Besides, type II power units can also provide negative-sequence reactive current during the asymmetric short-circuit fault.

4.5 Clause summary

According to the analysis above, the following conclusions can be drawn.

1) Present grid codes and guidelines contain the requirements for reactive current under both symmetrical and unsymmetrical faults. The UVRT curve only shows the relationship of steady state of fault and time.

2) Present grid codes and guidelines contain the requirements for reactive components and negative-sequence components when an asymmetrical fault occurs.

3) It is necessary to require the transient behaviour of inverter based resources.

5 Analysis on the behaviour of fault current

5.1 Fault current needs

From the perspective of power system, the needs of fault current can be catalogued into transient and steady-state aspects. Following fault inception, power sources are required to provide appropriate fault currents helping the correct functioning of protection elements and circuit breakers in isolating short circuit. Furthermore, during the unsymmetrical faults, power sources are favourable to provide reactive currents in both positive- and negative-sequence networks. The required positive-sequence reactive current boosts the residual positive-sequence voltage and thus help the transient stability of the system. The required negative-sequence reactive current decreases the negative-sequence voltage in the grid and thus suppress the overvoltage on the healthy phases [5], [6].

In the traditional power system, the fault current of synchronous generator had been well studied in analytical and experimental methods. The fault current consists of fundamental frequency component and other transient components including DC and double grid frequency components. The momentary current can easily reach 10 times of the pre-fault value. On one side, the sudden increase of the current can be easily detected by protection elements in achieving excellent sensitivity and selectivity. On the other hand, the momentary current is been calculated to rate the circuit breakers. In sequence domain, synchronous generator can be represented with a voltage behind reactance in the positive-sequence network and a pure reactance in the negative-sequence. Thus, the positive-sequence current naturally boosts the positive-sequence voltage and supresses the negative-sequence voltage and therefore the voltage of the healthy phases.

Unlike synchronous generator, wind turbines and photovoltaic based power sources contribute fault current that controlled by its converters. The following clauses details the fault current characteristics of their fault current in terms of two different topologies, namely full-scale-converter based wind turbine / inverter and DFIG-based wind turbine.

5.2 Fault current characteristics of full-scale-converter based IBRs

5.2.1 General

FSC-based WT and PV inverter are two typical IBRs for the renewable power generation. Their topologies are shown in Figure 10 and Figure 11. The FSC-based IBRs connect with power grid through grid-side converter (GSC). As a result, although the prime energy is different, the fault currents contributed by PMSG-based WTs and PV inverters are fully governed by GSC and have many similar characteristics that can be categorized by the GSC control schemes in different grid code requirements [7], [8].
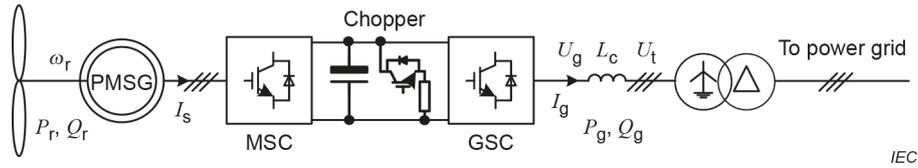
Figure 10 – Typical topology of a Type-IV WT
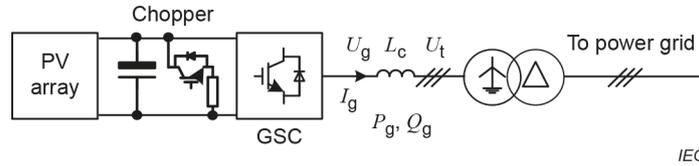
Figure 11 – Typical topology of a VSC-based PV inverter

5.2.2 Typical control schemes of FSC-based IBRs

5.2.2.1 General

After a fault occurs, the grid voltage and the active power rapidly drop. Due to the response of the inner-loop control, the voltage generated by the GSC cannot instantly track the terminal voltage thus results in overcurrent to the GSC. Moreover, if the MSC or PV array do not decrease the active power, the DC bus would suffer the overvoltage risks and even trip from grid. Furthermore, if an unsymmetrical fault occurs, negative-sequence component of grid voltage poses oscillations in active power (mechanical torque), reactive power, DC voltage and output current. To ride through the faults, FSC-based IBRs employ special control and protection schemes to suppress the overstress and follow the current injection requirements.

5.2.2.2 Chopper scheme

The chopper circuit is designed to consume the overvoltage of the DC bus with the resistance. It is normally controlled with a hysteresis logic. With this hardware, the DC voltage will be ruled within the safe range. Since the line-to-line voltage at the IBR terminals typically drop from the pre-fault value, the GSC would have enough control ability to generate voltage that follows the grid voltage and keep the fault current within the GSC current capacity. Since the chopper circuit is installed at the DC bus, the impact of chopper on fault current is insignificant.

5.2.2.3 AC current control schemes

The AC current control scheme is designed to make the current follow the reference quickly to independently adjust the active and reactive power of the GSC. Thus, the dynamics of the AC current control scheme can be evaluated with the reference tracking and disturbance rejecting performances. During voltage dip, the basic GSC AC current control scheme is based on proportional-integral (PI) controllers and positive-sequence grid voltage orientation with PLL as shown in Figure 12.
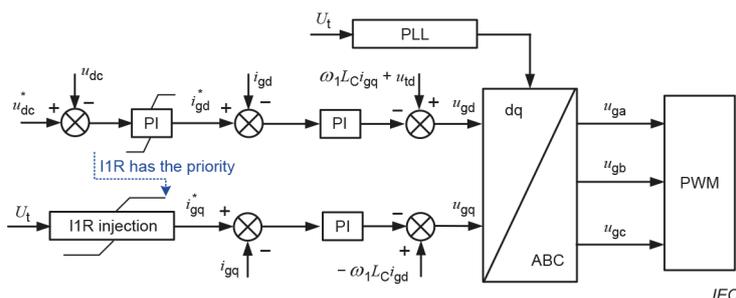
Figure 12 – Diagram of basic AC current control strategy of GSC during fault

For the symmetrical fault scenario, the reference of the AC current control scheme is decided by the positive-sequence reactive current (I1R) injection requirements of grid codes where reactive current is prioritized and proportional to the voltage deviation as discussed in Clause 4.

For the unsymmetrical fault scenario, the above AC current control would generate negative-sequence voltage to resist the negative-sequence current. In this scenario, FSC-based IBRs does not contribute to negative-sequence current and can be regarded as open circuit (or high impedance) in the negative-sequence network.

In addition to the basic AC current control shown in Figure 12, GSC may employ additional negative-sequence control to eliminate the oscillations in DC voltage or active power caused by voltage unbalance as shown in Figure 13 [9]. In this scenario, these special control schemes introduce negative-sequence current and determine the angle difference between negative-sequence voltage and current.
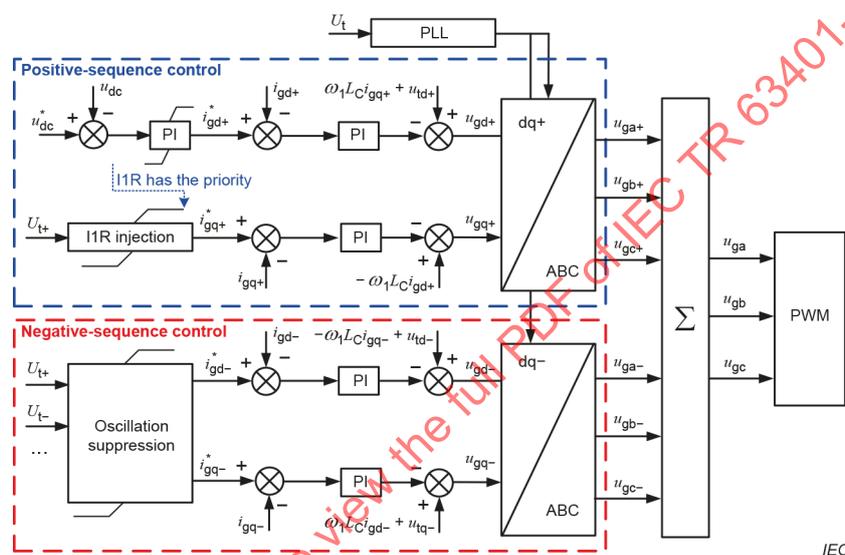
Figure 13 – Diagram of positive- and negative-sequence AC current control strategy of GSC for eliminating oscillations during voltage unbalance

Furthermore, in order to inject the required positive- and negative-sequence reactive currents (I1R and I2R) to comply with new grid codes [4], negative-sequence AC current control schemes and current limiting schemes are introduced to provide negative-sequence reactive current that decreases the negative-sequence voltage level. From the perspective of negative-sequence network, FSC-based IBR can be treated as a given impedance when the positive- and negative-sequence current references do not reach the current limitation, however, once the current references reach the limitation, the FSC-based IBR cannot be treated as a constant impedance because the nonlinearity introduced by the current limiting schemes.
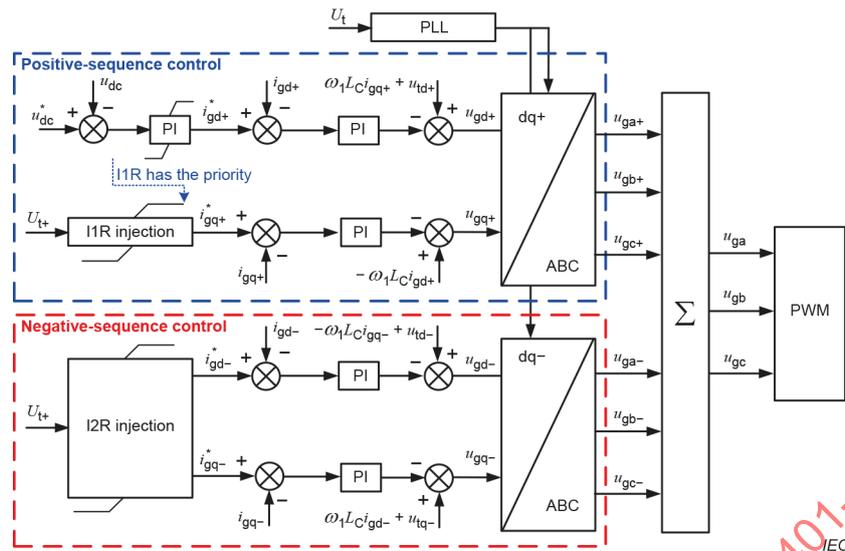
Figure 14 – Diagram of positive- and negative-sequence AC current control strategy of GSC for complying I1R and I2R injection requirements

5.2.3 Fault current characteristics of FSC-based IBR during symmetrical fault

Following the fault inception, the fault current of FSC-based IBR will quickly track the current references within the first few cycles. The fault current of FSC-based IBR mainly consists of two components, namely a DC transient component and a fundamental-frequency component. The DC transient current component is a result of constant-linkage theorem of inductors including choke filter. And the phase angle and magnitude of the fundamental-frequency current component are modulated by the responses of PLL and outer-loop control (including DC voltage control and current injection blocks). Since the control schemes, parameters and configuration are various in different manufacturers and types, it is difficult to depict the characteristics of transient current of FSC-based IBRs with some generic expressions.

During a slight symmetrical voltage dip, the required I1R does not occupy all of the current capacity of GSC. Thus the active current reference is not a constant but controlled by the outer-loop control (DC voltage control) trying to balance the DC voltage by increasing the output active current. Since the response of the inner current loop of the control strategy is much faster than that of outer-loop control, FSC-based IBR can be treated as a current source controlled with these outer-loop control in the positive-sequence network [10], [11].

For a severer symmetrical voltage dip, the required I1R may occupy most of the current capacity of GSC. Thus the active current reference is limited and the DC chopper circuit would be enabled to keep the DC voltage within the same range. In this way, the positive-sequence active and reactive currents are dominated by the I1R injection block and current limitation scheme. In this way, the FSC-based IBR can be also treated as a controlled current source that specifies by I1R injection requirements in grid code and the current saturation schemes designed by manufactures.

5.2.4 Fault current characteristics of FSC-based IBR under unsymmetrical fault

Ruled by the similar I1R injection requirements in the existing grid codes, FSC-based IBRs contribute similar positive-sequence currents in symmetrical fault scenarios. FSC-based IBRs would contribute different fault currents in different negative-sequence control configurations.

When FSC-based IBRs employ the basic AC current control in Figure 12 in unsymmetrical fault scenarios, the current references only consists of positive-sequence components. Thus, the negative-sequence fault current component will be greatly suppressed by the inner-loop controller. Under this type of control, FSC-based IBRs can be treated as open-circuit or as a high- impedance branch in the negative-sequence network.

When FSC-based IBRs employ the special AC current control in Figure 13 to eliminate the oscillations caused by the voltage unbalance, negative-sequence current will be provided. However, it is complicated to tell the active and reactive components (or the phase angle) of the negative-sequence fault current with respect to the negative-sequence voltage. On one side, the negative-sequence current various in different control targets [12]. The angle difference between negative-sequence current and voltage could be as large as 150 degrees. On other side, the negative-sequence currents would further change the positive-sequence current through the current limitation schemes. As a result, the FSC-based IBRs can be treated as a controlled current source with strong nonlinearity under this types of control.

When FSC-based IBRs employ the decoupled AC current control in Figure 14 to comply with the I1R and I2R injection requirements in the new grid codes, FSC-based IBRs are expected to mimic a pure reactance in the negative-sequence network where the negative-sequence current lags the negative-sequence voltage by degrees. However, the positive- and negative-sequence current limitation schemes would also introduce nonlinearity into the fault current analysis.

5.3 Fault current behaviour of doubly fed induction generator (DFIG) based wind turbine (WT)

5.3.1 General

Apart from the FSC-based IBR, DFIG-based WT is another typical IBR that has been widely used as one of the leading technologies for wind power generation, for its advantage in cost, efficiency and reliability [13]. The topology of a typical DFIG-based WT is shown in Figure 15. As it shows, two AC/DC converters are installed between the rotor winding and the terminal bus so that the converters are designed to deal with only a small part (typically 30 %) of the rated power of the WT. As a result of the non-full size converters, after a grid fault occurs, DFIG-based WT has to employ additional control schemes and electric circuits as the fault ride through (FRT) solutions to protect the converter from overvoltage and overcurrent as well as to inject the required reactive current in complying the modern grid codes. The non-full size converters and the special FRT solutions are two underlying reasons why DFIG-based WT has different fault current behaviour from that of FSC-based IBRs.
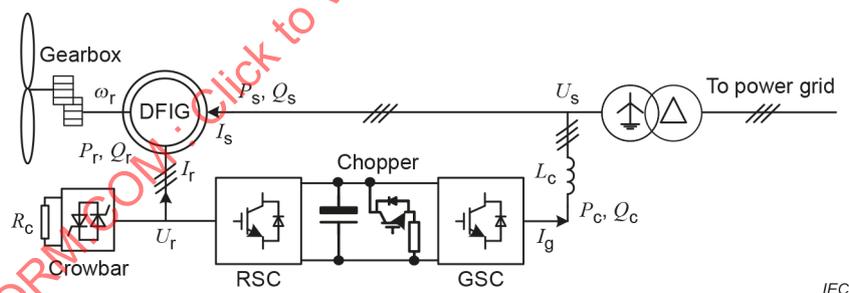
Figure 15 – Typical topology of a DFIG-based WT

5.3.2 FRT solutions of DFIG-based WT

The energy conversion in a DFIG-based WT relies on the mechanical and electromagnetic energy storage elements (ESEs), namely the spinning rotor, DC capacitor and AC inductors, as shown in Figure 16. The essential states of these ESEs, namely rotor speed, DC voltage and AC current, are controlled by the corresponding controllers in normal operation mode, respectively, as shown in Figure 17. Thus, from the perspective of energy flow, control schemes are designed in each corresponding time scale of ESE to convert the wind energy into power grid eventually.
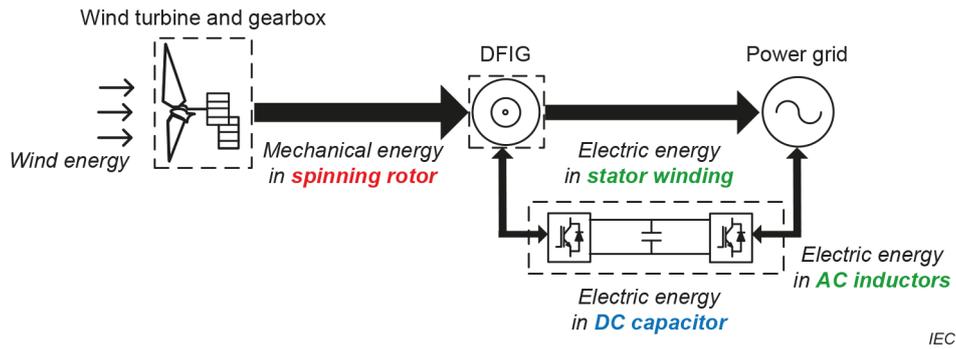
Figure 16 – Energy flow and ESEs of a DFIG-based WT in normal operation
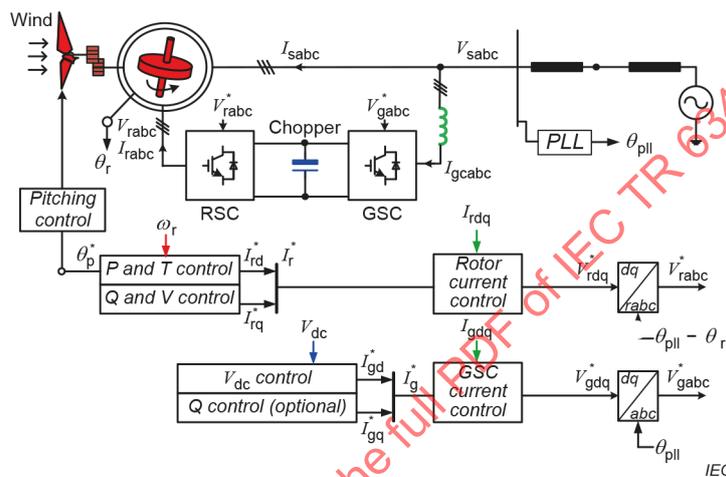
Figure 17 – ESEs and vector control scheme of a DFIG-based WT in normal operation

Once a short-circuit fault occurs in power grid, synthetically affected by voltage dip and regulation of corresponding control, ESEs start to charge or accelerate sequentially, viz., charging first appears in the current of the AC inductor then in the voltage of the DC capacitor, finally acceleration appears in the rotor speed of the spinning rotor. Owing to those unbalanced power, if DFIG-based WT still employs the control schemes designed under normal grid conditions when it suffers from grid faults, ESEs and other vulnerable components may be overloaded and destroyed under the transient processes, such as mechanical breakage of shaft, overvoltage of DC capacitor and overcurrent of converters.

Although the detailed configuration and setting are different in DFIG-based WTs according to different manufactures, from the perspective energy flow, the existing FRT solutions can be generally summarized and categorized in Figure 18. Since those FRT solutions are designed for some certain targets, it should be noted that a successful ride through relies on the sequential switching of those control and protection schemes [14].
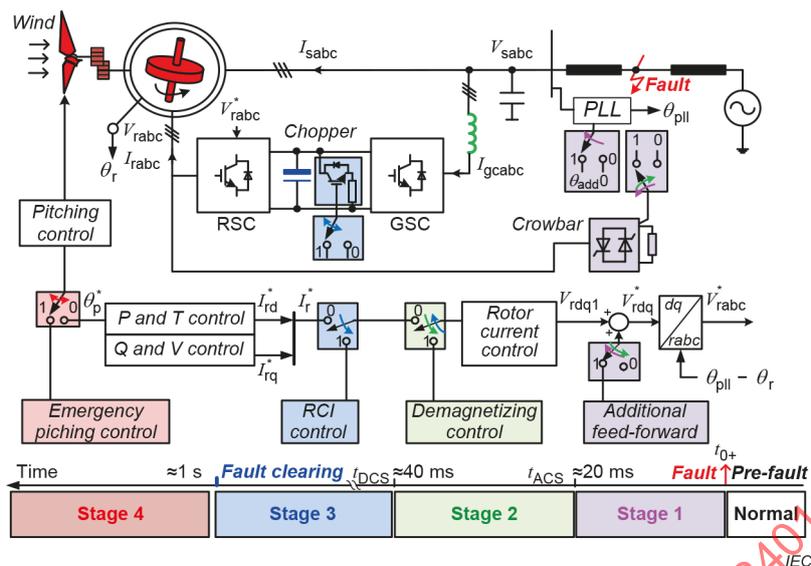
Figure 18 – FRT solutions of a DFIG-based WT during grid fault

FRT Stage 1: Control strategies coping with rotor transient electromotive force (EMF)

After a grid fault occurs, dynamic compensations are switched on and added to the output of regular controllers to restrain the gradient of states with enhanced dynamic controllability. As shown in Figure 18, additional compensations are instantly switched on and added to the decoupling term of rotor current control and phase-angle of the phase-locked loop (PLL), respectively. However, under the severe fault conditions, the magnitude of transient electromotive force (EMF) can be 3 to 5 times higher than the normal value. As a result of limited output voltage of the rotor side converter (RSC), rotor current will still be rapidly accumulated to a dangerous range. Therefore, as a classical FRT solution, the crowbar circuit may switched on to bypass the transient unbalanced power and protect the RSC, as shown in Figure 18.

FRT Stage 2: Control strategies coping with control capability recovery

When the magnitude of rotor transient EMF falls to the certain threshold, as shown in Figure 18, the stage 1 ends and the control strategies of the second stage are enabled. During the FRT stage 2, RSC are unblocked and the demagnetizing control are switched on to govern the rotor current reference. This strategy is designed to shorten the recovery time from voltage dip to reactive current injection (RCI).

FRT Stage 3: Control strategies coping with DC voltage and reactive current injection

Once the control capacity of RSC recovers, demagnetizing control is switched off and RCI control is switched on to govern the rotor current reference until fault clearing, as shown in Figure 18. Meanwhile, the DC chopper may be employed mainly in this stage to keep the DC capacitor safe.

FRT Stage 4: Control strategies coping with rotor over speed

During Stage 3, reactive current, rather than active current, is prioritized in most of grid codes. As a result, driven by the sudden diminution of active power and electromagnetic torque, spinning rotor accelerates gradually. In order to protect WT from over speed, emergency pitching control will be switched on to decrease the mechanical torque by rapidly increasing the pitch angle of rotor blades.

Coordination of FRT solutions in different grid faults

As mentioned above, those FRT are specially designed for different targets, and a DFIG-based WT can successfully ride through the grid fault only if all those targets are achieved orderly and properly. Hence, typically, according to the fault severities and the sequence of ESEs charging/acceleration, those FRT solutions should be sequentially switched as shown in Figure 18 and Figure 19 [14].
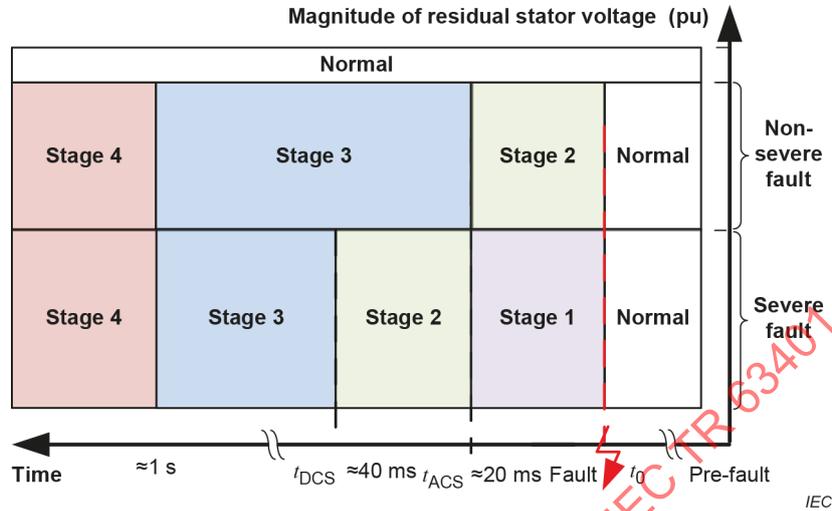
Figure 19 – FRT solutions of a DFIG-based WT during grid fault

5.3.3 Fault current behaviour of DFIG-based WT during symmetrical faults

In recent research, analytical expressions of DFIG-based WT' fault current under symmetrical voltage dip is proposed by so-called operational inductance as shown in Table A.1 in Annex A [14]. It can be a useful tool to present the behaviour of the fault current components

1) The fault current of DFIG-based WT, during symmetrical faults, is mainly composed of three components in different frequency, as shown in Table A.1 and Figure 20. The steady-state component is a fundamental-frequency component whose magnitude is constant during the fault. The quasi-DC component is a transient component whose frequency is close (but not strictly equal) to zero. The quasi-fundamental component is another transient component whose frequency is grid frequency when the crowbar is disconnected or is the frequency corresponding to rotor speed when the crowbar is connected.
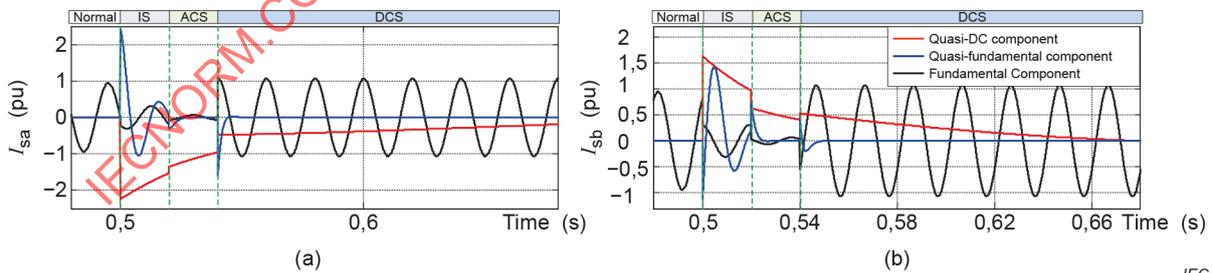
Figure 20 – The identified components of fault currents by the analytical expression

2) The transient components of DFIG-based WT's fault current, namely the quasi-DC component and the quasi-fundamental component, will decay with the certain time constants. Moreover, the quasi-fundamental component decays much faster than the quasi-DC component.

3) The magnitude, frequency and time constants of those fault current components are different in stages in terms of FRT solutions.

With this understanding, the differences between fault currents of DFIG-based WT and the SG can be summarized to help understand as follows:

1) The frequency of current components is different. The fault current of the SG typically composes of the fundamental, the DC and the second harmonic components. However, the fault current of the DFIG-based WT, on one side, does not have second harmonic component, on the other side, has the quasi-fundamental component.

2) The magnitude of the symmetrical current is different. As shown in the text books, the magnitude of the SG's symmetrical current is decided by the sub-transient inductance which is much smaller than the steady-state inductance. As a result, the symmetrical current over 5 to 10 time than the normal value. However, the magnitude of the DFIG-based WT's symmetrical current is decided by the transient operational inductance of the DFIG-based WT which is much greater than the sub-transient inductance of the SG. As a result, the maximum value of the DFIG-based WT's fault current is much smaller than that of the SG.

5.3.4 Fault current behaviour of DFIG-based WT during unsymmetrical faults

Since the zero-sequence voltage and zero are blocked by transformers. the focus of the fault current analysis of the DFIG-based WT during unsymmetrical faults is the negative-sequence current and its phasor relationship between the negative-sequence voltage, especially when consider the control and protection solutions on the rotor side converter. During unsymmetrical faults, an additional EMF, corresponding to the negative-sequence stator voltage, will be inducted in the rotor winding. Since its magnitude is proportional to 2-slip, it is much greater than the EMF during normal operation (proportional to slip), more importantly, it does not decay. As a result, the crowbar is more likely to be activated for a longer time even until the fault is cleared [15], [16].

Under crowbar protection, the fault current is composed of a positive-sequence current component, a negative-sequence current component and still the transient components of quasi-DC and quasi-fundamental frequency mentioned in 5.3.3. It further shows that, when crowbar is activated, the negative-sequence current lags the negative-sequence voltage by an angle around 75 degrees. Thus, the DFIG can be represented with a fixed inductive reactance in series with a resistance (RL) in the negative-sequence network. It will naturally decrease the negative-sequence voltage but absorb active power from the power grid. However, the DFIG absorbs positive-sequence reactive power from power grid and decreases the positive-sequence voltage level when crowbar circuit is operated. It violates the I1R injection requirement in the grid code.

Further research shows that, when the voltage unbalance is mild and the DFIG-based WT uses positive- and negative-sequence control scheme to eliminate the double grid frequency oscillations in electromagnetic torque, the negative-sequence current would lead the negative-sequence voltage by 90 degrees, thus the DFIG provides negative-sequence reactive current like a capacitor. It increases the negative-sequence voltage in the network and against the new grid code requirement in negative-sequence current injection,

To make the DFIG-based WT inject the required reactive currents in both positive- and negative-sequence networks, a new decoupled control scheme is proposed in [17] to coordinate the positive- and negative-sequence, active and reactive current references of both the RSC and GSC. Under this kind of control scheme, the DFIG-based WT can comply with the negative-sequence current injection in the new grid code within its current limit.

5.4 Behaviour of large-scale wind farm when outgoing line faults

In this case, behaviour of large-scale wind farm are the composition of all wind turbines. It is hard to obtain the fault current expressions of wind farm. However, we can still summarize some characteristics of wind farm according to the simulation and fault field recording data. Next, fault characteristics of wind farm including DFIG/PMSG-based WTs when symmetric and asymmetric fault occurs at outgoing line are overviewed according to the fault field recording data from Shanxi Province power grid of China.

The topology of wind farm integrated to power grid is shown in Figure 21. Two groups of fault field recording data are collected. One is a BG fault at point F1, the other is an ABCG fault at point F2. The three-phase voltage and current of the right side of the 220 kV outgoing line and DFIG based wind farm are recorded. Here, the three-phase voltage and current of the right side of the 220 kV outgoing line are expressed as u_{OL} and i_{OL}, respectively. The three-phase voltage and current of the DFIG based wind farm are expressed as u_D and i_D, respectively.
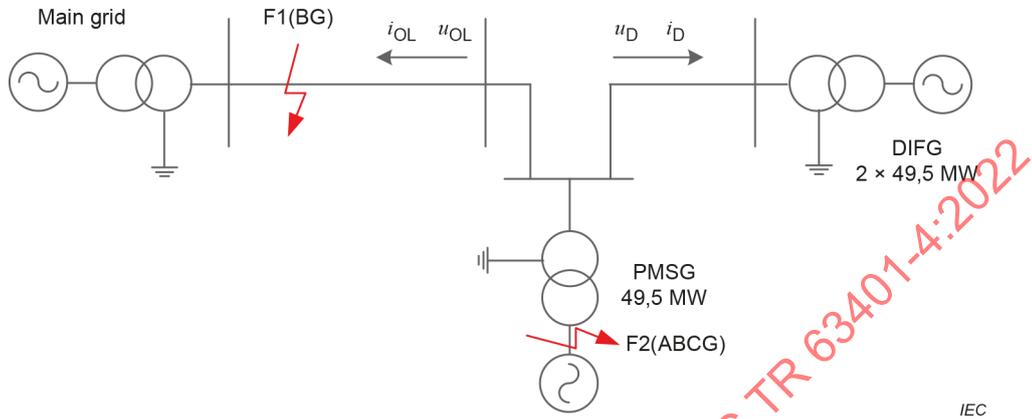
Figure 21 – The topology of wind farm integrated to power grid in Shanxi Province

The u_{OL}, i_{OL}, u_D, i_D recorded when a BG fault occurs at point F1 are shown in Figure 22 and Figure 23.
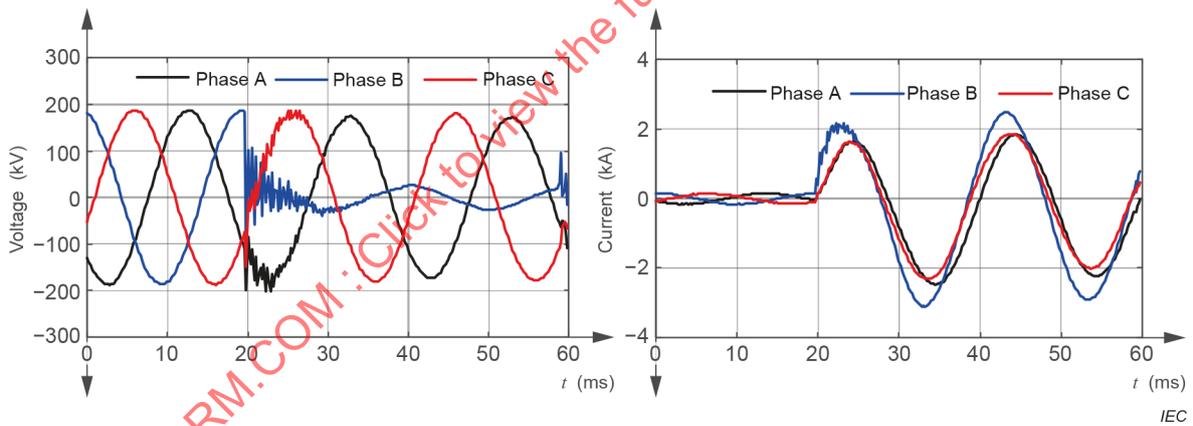
Figure 22 – The u_{OL} and i_{OL} recorded when BG fault occurs at point F1
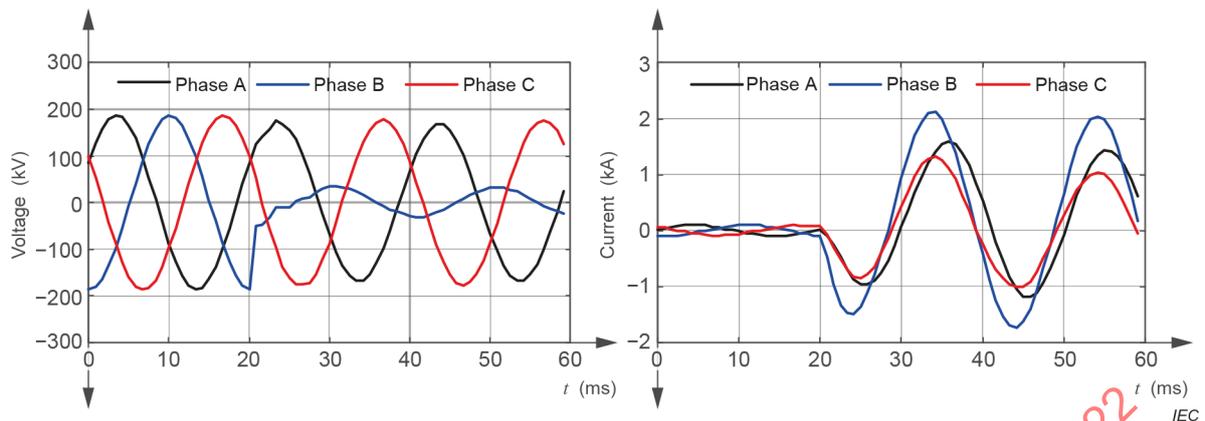
Figure 23 – The u_D and i_D recorded when BG fault occurs at point F1

When a fault occurs at point F1, the three-phase current i_{OL} is supplied by a wind farm including both DFIG and PMSG based WTs and i_D is supplied by only a DFIG WT based wind farm. It can be seen from Figure 22 and Figure 23 that the three-phase current amplitudes and phases supplied by the wind farm are approximately the same, namely that the three-phase current mainly is zero sequence component. The reason for this phenomenon is that the equivalent positive and negative sequence impedance (EPSI and ENSI) of the wind farm is far bigger than the equivalent zero sequence impedance (EZSI). To further explain this, the EPSI, ENSI, EZSI of the wind farm are calculated based on the recorded data and shown in Figure 24 and Figure 25. It can be seen from Figure 24 and Figure 25 that EPSI is biggest, ENSI is in the middle and EZSI is far smaller than EPSI and ENSI.
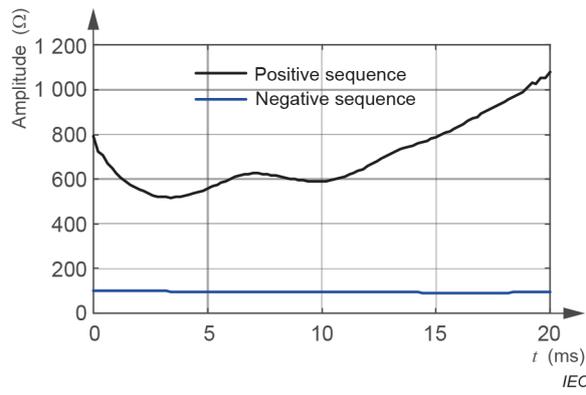
(a) **Amplitudes of EPSI and ENSI**
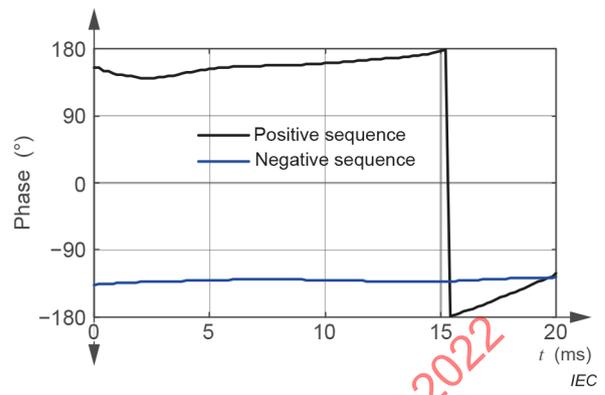
(b) **Phases of EPSI and ENSI**
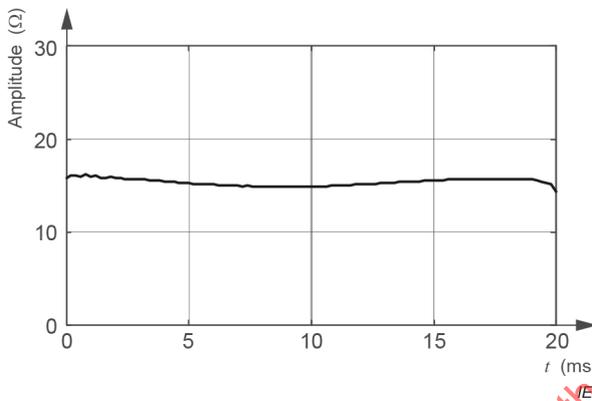
(c) **Amplitudes of EZSI**
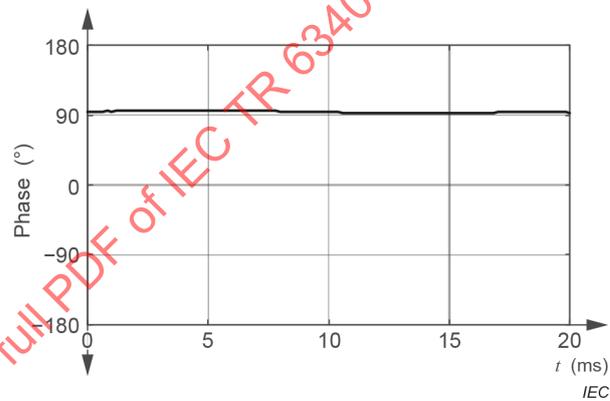
(d) **Phases of EZSI**

Figure 24 – The EPSI, ENSI, EZSI of wind farm including both DFIG and PMSG based WTs

(a) **Amplitudes of EPSI and ENSI**

(b) **Phases of EPSI and ENSI**

(c) **Amplitudes of EZSI**

(d) **Phases of EZSI**
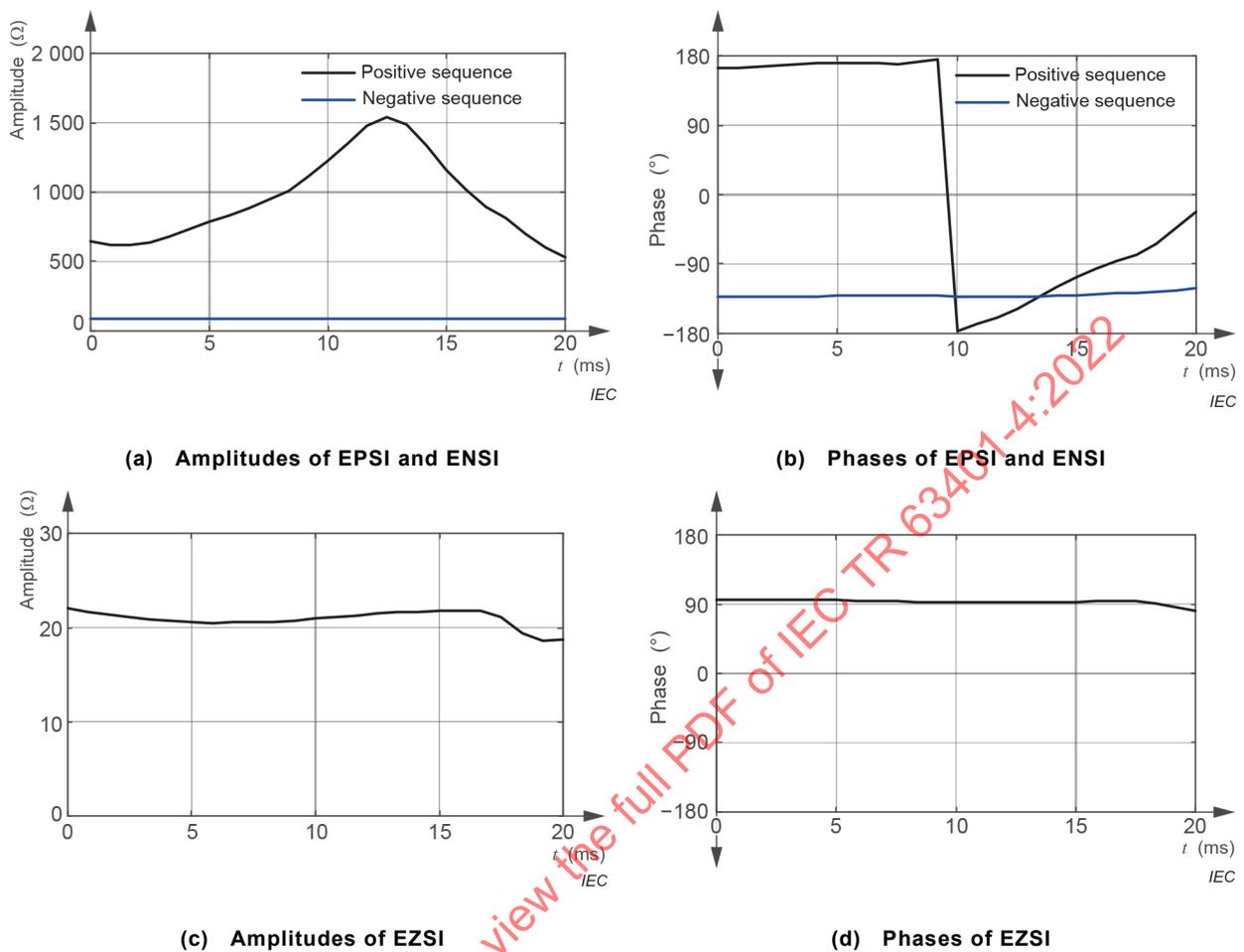
Figure 25 – The EPSI, ENSI, EZSI of wind farm including only DFIG based WTs

The u_{OL}, i_{OL}, i_D recorded when ABCG fault occurs at point F2 are shown in Figure 26. When a fault occurs at point F2, the three-phase current i_{OL} is from the main grid and i_D is supplied by only the DFIG WT based wind farm. It can be seen from Figure 26 that the fault is a high impedance fault and the three-phase voltage after the fault is relatively high. However, the three-phase current i_{OL} supplied by the main grid is very big, compared to the three-phase current i_D, which is supplied by only the DFIG WT based wind farm, namely that the wind farm is a weak-infeed system. That is when the fault occurs, the short-circuit current supplied by wind farm is small, which is caused by the vulnerability of power electronic converters.
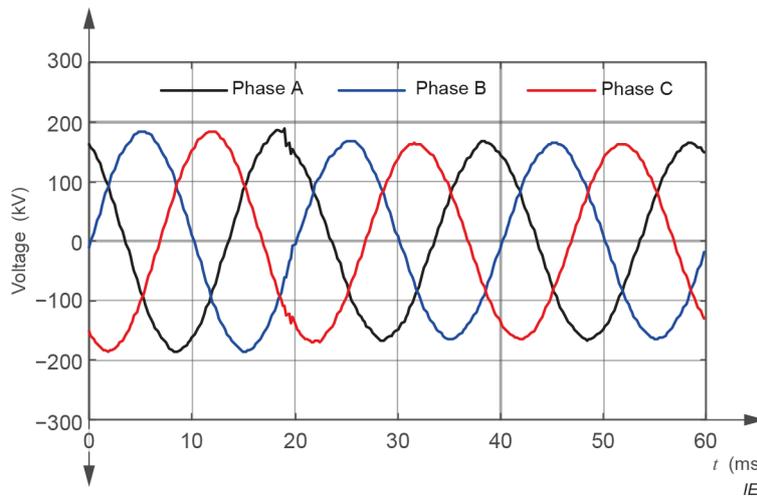
(a) three-phase voltage
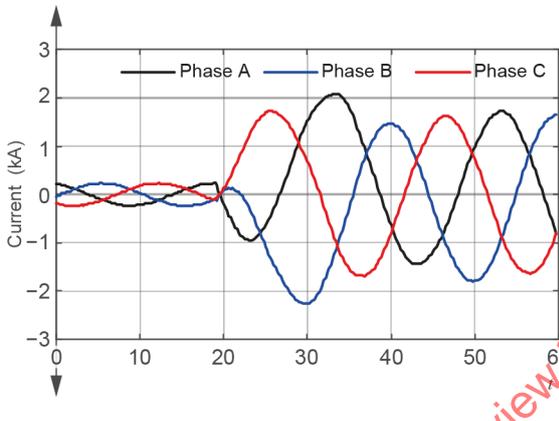
(b) three-phase current from main grid
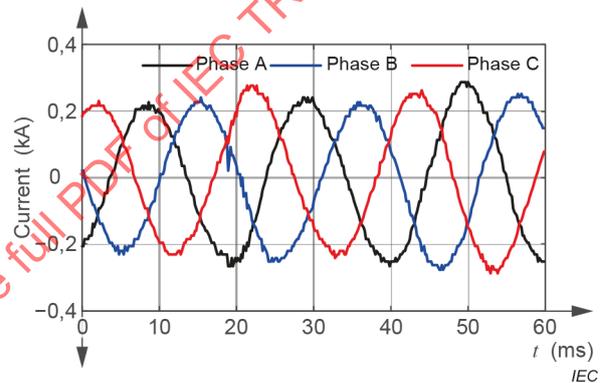
(c) three-phase current from wind farm

Figure 26 – The u_{OL}, i_{OL} and i_D recorded when ABCG fault occurs at point F2

5.5   Clause summary

According to this clause, the following conclusions can be drawn.

1) Following fault inception, power sources need to provide appropriate fault currents in support of fault isolation and power system stability. The transient components of the fault current need to be evaluated in rating circuit breakers and protection design. Moreover, power sources are favourable to provide positive-sequence reactive currents in boosting positive-sequence voltage in support of transient stability. During unsymmetrical faults, power sources are favourable to provide negative-sequence reactive currents in suppressing negative-sequence voltage as well as the overvoltage in the health phase(s).

2) Fault current characteristics of IBRs are quite different from those of conventional power sources (SGs). In terms of fault behaviour, IBRs can be generally classified into FSC-based IBR and DFIG-based IBR. Moreover, the fault current characteristics are different in various control schemes and protection circuits.

3) FSC-based IBR contributes insufficient transient current and quickly tracks the current references. However, since the current capacity of GSC is limited and the active and reactive current references are respectively regulated by I1R injection and outer-loop control, FSC-based IBR can be treated as a nonlinear controlled current source under symmetrical faults. During unsymmetrical faults, FSC-based IBR would contribute similar positive-sequence reactive current to fulfil the I1R injection requirement. Moreover, the negative-sequence fault current of FSC-based IBR is different from control configurations. When the basic AC current control is used only for regulating positive-sequence current, FSC-based IBR does not contribute negative-sequence current and can be treated as open-circuit. When the negative-sequence AC current control is used to eliminate the oscillations caused by the voltage unbalance, negative-sequence current will be provided but its phase angle is variable in different targets. When the decoupled AC current control is used to comply with the I2R injection requirements, FSC-based IBR mimics a pure reactance in the negative-sequence network when I2R does not reach its limitation.

4) DFIG-based IBR contributes two significant transient current components whose frequency is close to DC and grid frequency. During symmetrical faults, these transient current components are complicated because DFIG-based IBR may trigger various FRT control schemes and hardware circuits in certain sequence. The steady-state current components of DFIG-based IBR in a positive-sequence system are quite like that of FSC-based IBR since they follow the same I1R injection requirement. During severe unsymmetrical faults, a crowbar circuit would be easily triggered and both considerable active and reactive currents are injected into the negative-sequence system. During mild unsymmetrical faults, considerable negative-sequence fault current would be provided by the DFIG-based IBR even when using the rotor current control only for positive sequence. When negative-sequence AC current control is used to eliminate the oscillations of electromagnetic torque, the negative-sequence reactive current provided by the DFIG-based IBR would increase the negative-sequence voltage. When using the decoupled control scheme, the DFIG-based IBR can comply with both I1R and I2R injection requirements.

6 Impact of IBRs on relay protection

6.1 Influence factors of IBRs on relay protection

Fault characteristics are the basis of protection research. The wind power system has significantly different fault characteristics from the regular power grid due to its special structure and control strategy [18].

Wind power is a controlled system, thus the fault performance depends on its control objective and strategy. The wind power system should follow the demand of under voltage ride-through (UVRT) when a fault occurs, which decides its control objective. Although there are different types of wind turbines and various control strategies, the control objectives differ little. Thus the general fault characteristics are similar. Either DFIG or PMSG, to protect the safety of converters during a fault, has limited ability to provide short-circuit current, thus performs a weak-infeed feature shown in Figure 27(a). The high-frequency switch operations of converters in wind turbine generators introduce high harmonic shown in Figure 27(b). The equivalent sequence impedances of the wind power system vary from the control process of wind turbine during a fault shown in Figure 27(c). In addition, the short-circuit current of DFIG with crowbar protection activated may perform frequency deviation shown in Figure 27(d).

(a) **Weak infeed**

(b) **High harmonics**

(c) **Unsteady sequence impedances**

(d) **Frequency deviation**
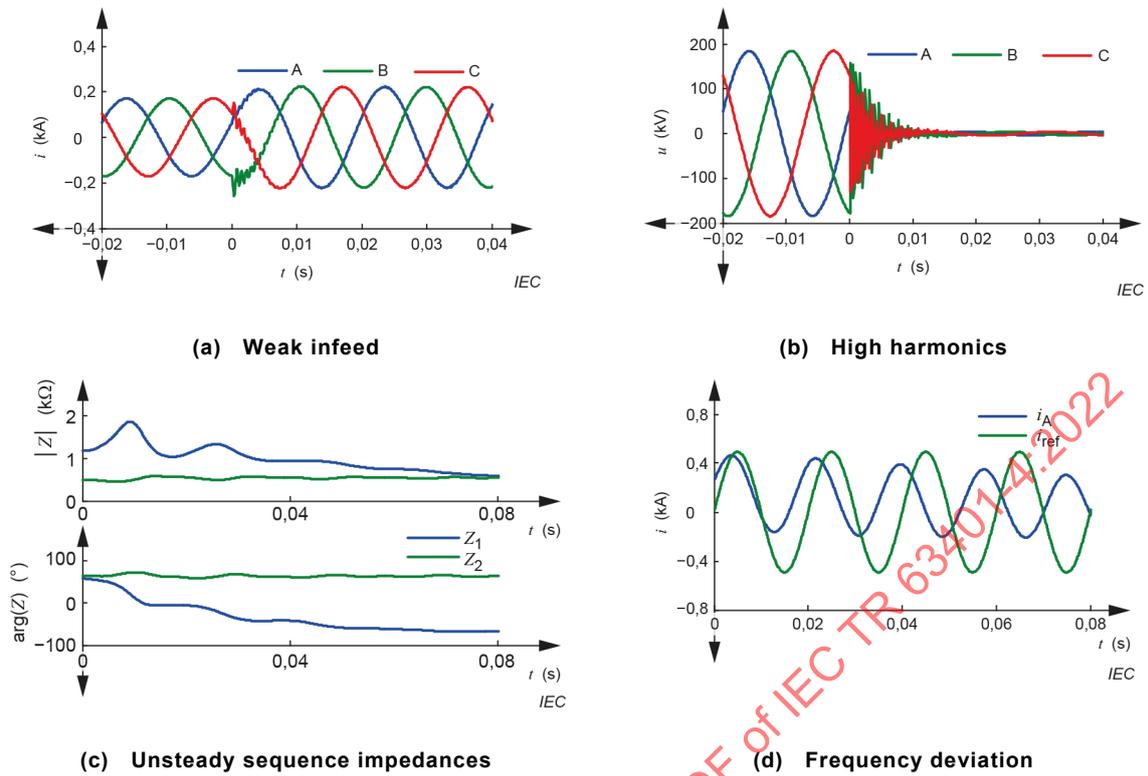
Figure 27 – General fault characteristics of wind power system

6.2   Impact on distance protection

6.2.1   Basic principle of distance protection

Currently, distance protection can mainly be divided into measuring distance protection and compensating distance protection. Measuring distance protection relays which can distinguish the internal and external fault by measuring the distance from fault point to the relay include power frequency component distance relay and time-domain distance relay [18]. Compensating distance protection relays construct protection criteria by comparing the amplitude and phase angle of electrical quantities, including power frequency variation component distance relay and phase-comparison distance relay. The diagrams of wind power integration system for distance protection are shown in Figure 28. Power frequency component distance relay, time-domain distance relay and phase-comparison distance relay depend on the full fault network in Figure 28(a), and power frequency variation component distance relay is based on the additional fault network in Figure 28(b).
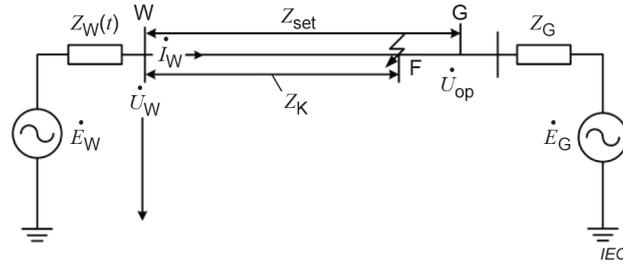
(a) Full fault network
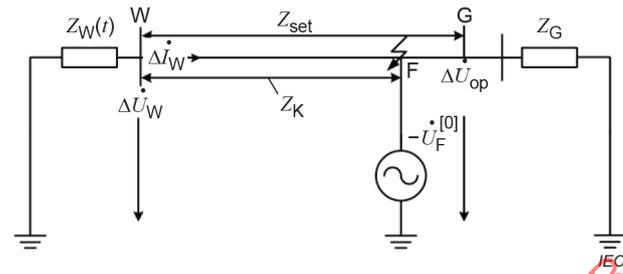
(b) Fault component network

Figure 28 – Diagrams of wind power integration system for distance protection

In Figure 28, Z_K is the line impedance from the relay equipment to the fault point; Z_{set} is the setting impedance; Z_W and Z_G are the system impedances of the two terminals; U_W and I_W are the measured voltage and current at terminal W, and they can be expressed as the following two forms according to whether the fault is grounding or not.

For grounding fault:

$$\begin{cases} \dot{U}_W = \dot{U}_\phi \\ \dot{I}_W = \dot{I}_\phi + K \times 3\dot{i}_0 \end{cases}, \phi = \text{a,b,c} \tag{4}$$

where K is the compensation coefficient of zero sequence current: $K = \dfrac{(z_0 - z_1)}{3z_1}$.

For non-grounding fault:

$$\begin{cases} \dot{U}_W = \dot{U}_{\phi\phi} \\ \dot{I}_W = \dot{I}_{\phi\phi} \end{cases}, \phi\phi = \text{ab,bc,ca} \tag{5}$$

where $\dot{U}_W$ and $\dot{i}_W$ are the voltage and current at terminal w, which can also be expressed as the above two forms according to whether the fault is grounding or not, the only difference is substituting the full component into the fault component. The adaptability of each distance relay to the wind power integration system is analysed based on the above two fault networks.

6.2.2 Power frequency component distance relay

The basic principle of power frequency component distance relay is to calculate the fault distance by solving the impedance between the fault point and the relay equipment. Its basic measurement distance equation is:

$$Z_K = \frac{\dot{U}_W}{\dot{I}_W}$$

(6)

The internal and external fault can be judged by the location of Z_K in the protection zone formed by Z_{set}. The principle of power frequency component distance relay is unrelated to the fault characteristics of the backside system. Thus the power frequency component distance relay is not influenced by the integrated wind power in theory. However, considering the high harmonic injection and frequency deviation of fault current during a fault occurs in wind power integration system, the phasor extraction by Fourier algorithm in the present power frequency component distance relay has a large deviation due to the limit of Fourier algorithm. The power frequency component distance relay is influenced accordingly.

6.2.3 Time-domain distance relay

The measuring distance equation is:

$$u_W = i_W R_K + L_K \frac{di_W}{dt}$$

(7)

According to equation (7), the protection principle of time-domain is also unrelated to the fault characteristics of the backside system. Thus it is not influenced by the integrated wind power system in theory. Meanwhile, because the time domain algorithm is adopted in time-domain distance relay, it is not influenced by the high harmonic injection and frequency deviation of fault current. Above all, time-domain distance relay has good performance in wind power integration system. It should be noticed that the phase selection result is impacted in presence of Inverter-based generators. However time-domain distance relay always calculates three phase to ground impedances and three phase to phase impedances. If one of six impedances is smaller than the threshold, it will trip. Thus, time domain distance relay is not impacted for it is based on the line model [18], [19].

6.2.4 Power frequency variation component distance relay

For power frequency variation component distance relay, the compensation voltage of fault component at the setting point can be calculated by equation [20].

$$\Delta \dot{U}_{op} = \Delta \dot{U}_W - \Delta \dot{I}_W Z_{set}$$

(8)

The internal and external fault can be judged by the amplitude relationship of the compensation voltage $\Delta \dot{U}_{op}$ and the pre-fault voltage $\dot{U}_F^{[0]}$ at the fault point. Since the pre-fault voltage at the fault point differs little from the nominal voltage U_N of the line.

$$\left| \Delta \dot{U}_{op} \right| > k_{rel} U_N$$

(9)

where k_{rel} is the reliable coefficient, and usually set as 1,1 to 1,2. The operating criterion can be expressed as the impedance form:

$$\left| Z_W + Z'_{set} \right| \geq \left| Z_W + Z_K \right| \tag{10}$$

where $Z_W = \dfrac{kZ_{W1} + Z_{W2}}{1 + k}$, $k = \Delta I_1 / \Delta I_2$, $Z'_{set} = \dfrac{1}{p} Z_{set} + (\dfrac{1}{p} - 1)Z_W$, $p = k_{rel} U_N / U_F^{[0]}$.

It can be seen from the basic equation of power frequency variation component distance relay that, since $1/p < 1$, $Z'_{set} < Z_{set}$, meaning power frequency variation component distance relay will not mal-operate. However, its protection range varies with Z_m. In addition, because the system impedance of wind power is far larger than the one of regular power, the real protection range is very narrow, and the fault component distance relay at wind power side may refuse operation.

6.2.5   Phase-comparison distance relay

For phase-comparison distance relay, the internal and external fault can be judged by the phase relation between $\dot{U}_{op}$ and $\dot{U}_W$. Its protection criterion is expressed as

$$90° \leq \arg \frac{\dot{U}_{op}}{\dot{U}_W} \leq 270° \tag{11}$$

where $\dot{U}_{op} = \dot{U}_W - \dot{I}_W Z_{set}$. It can be transformed into the form of impedance as

$$90° \leq \arg \frac{Z_K - Z_{set}}{Z_K} \leq 270° \tag{12}$$

As with the power frequency component distance relay, phase-comparison distance relay is not influenced by the backside system, namely it is not influenced by the integrated wind power system. However, the high harmonic and frequency deviation of fault current of wind power system will influence the phasor calculation of the voltages. Thus the operation performance of phase-comparison distance relay is impacted in wind power integration system.

Next the simulations are carried out to validate the correction of analysis above. A simulation model is shown in Figure 29.
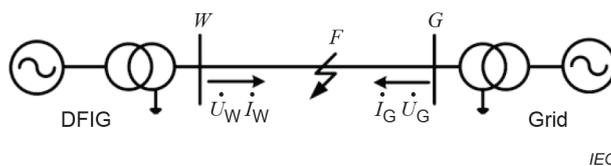
Figure 29 – Wind power integration system

The DFIGs in Figure 29 are assumed to be in rated operation state, namely they are operated in super-synchronous speed. The operation results of the above four distance relays are simulated based on the wind power integration model when different types of fault occur at

different locations of the outgoing line. The distance relays are set as 80 % of the total line length. 20ms sliding window is adopted to obtain fault data, and faults occur at 0s.

Figure 30 demonstrates the performance of the above four distance relays when a BC fault occurs at the midpoint of the *WG* line in Figure 30. For power frequency component distance relay (relay 1) and time-domain distance relay (relay 2), the relationship between measured impedance and protection zone is illustrated. For power frequency fault component distance relay (relay 3), the relationship between the compensation voltage of fault component and the setting voltage is presented. And for phase- comparison distance relay (relay 4), the phase relationship between the compensation voltage and the voltage at the relay equipment is given.

(a) **Relay 1**

(b) **Relay 2**

(c) **Relay 3**

(d) **Relay 4**
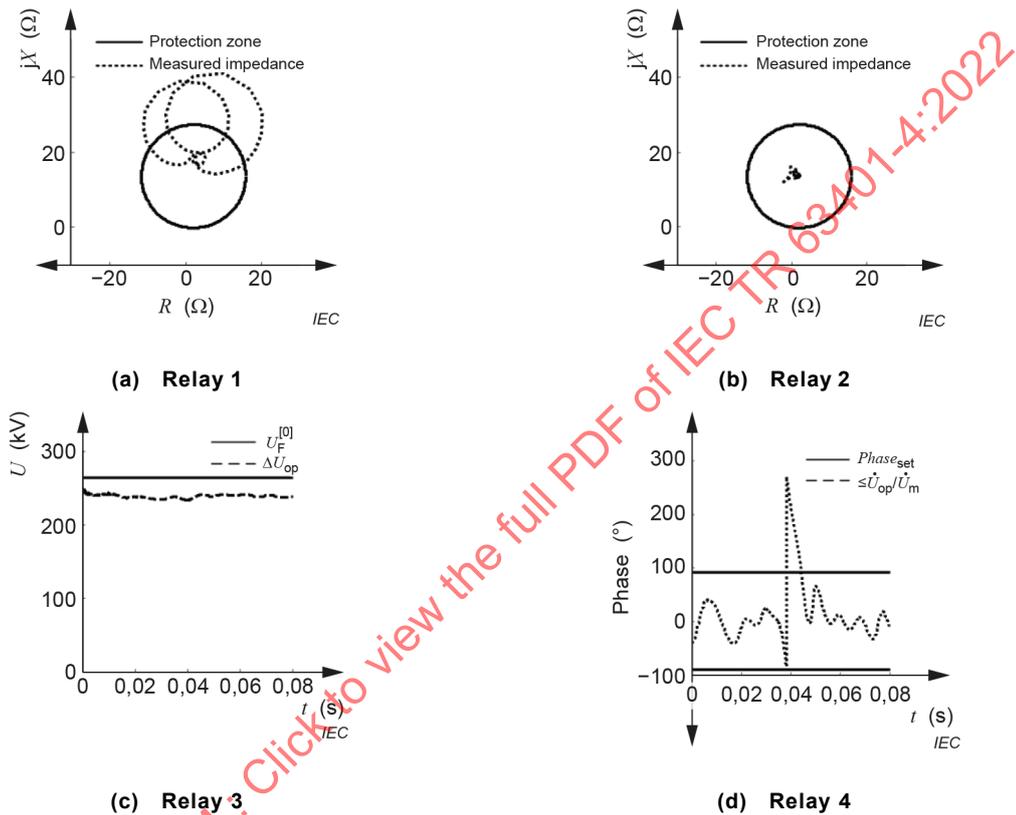
Figure 30 – Operation performance of distance relays when the BC fault occurs at the midpoint of DFIG wind power outgoing line

It can be seen from Figure 30 that when the BC fault occurs at the midpoint of DFIG wind power outgoing line, the crowbar protection operates, which will make the frequency of the electrical signal at the wind power side deviate. Thus, the judgment results of power frequency component distance relay and phase-comparison distance relay are unstable which will make them refuse to operate. Time-domain distance relay only relates to the feature of the line. Thus its measuring result is steady and the relay can operate correctly. The weak-infeed of the wind power system causes the large system impedance, which will narrow the protection range of power frequency variation component distance relay badly. Thus it refuses to operate even when the fault is at the midpoint of the line.

For further verification, the operation results of the above four distance relays when BC faults occur at different locations of the DFIG wind power outgoing line are given in Table 3. All the results are obtained by judging the data during 0,04s after fault occurs. In Table 3, "1" means internal fault, "0"means external fault, and ""\" means the judgement results are unstable.

**Table 3 – Simulation results of distance relays when BC faults occur
at different locations of the DFIG wind power outgoing line**

Fault distance	Relay 1	Relay 2	Relay 3	Relay 4
20 km	\	1	1	\
40 km	\	1	0	\
60 km	\	1	0	\
80 km	\	0	0	\

It can be seen from the results in Table 3 that when BC faults occur in the outgoing line, the judgement results of power frequency component distance relay and phase-comparison distance relay are unstable because of the phasor measurement errors caused by the frequency deviation feature of DFIG wind power system; the judgement results of time domain distance relay are stable and correct; while power frequency variation component distance relay will refuse to operate even when the fault distance is 40 km. The simulation results verify the adaptability analysis of distance relays to wind power integration system.

6.2.6   Conclusion

The basic principles of power frequency component distance relay and phase-comparison distance relay depend on the fault characteristics of line, meaning they are unrelated to the fault characteristics of backside system theoretically. However, the frequency deviation feature of the DFIG wind power system will lead to phasor extraction errors in the two distance relays, which makes judgement results of the two distance relays unstable.

The basic principle of time-domain distance relay is also unrelated to the fault characteristics of backside system. It is also not influenced by the frequency deviation feature of DFIG wind power system since the time-domain algorithm is adopted. Thus time-domain distance relay remains good performance in wind power integration system.

The operation performance of power frequency variation component distance relay is determined by the impedance characteristics of backside system. And since the system impedance of wind power is far larger than the one of regular power, the real protection range is very narrow, and the fault component distance relay at wind power side may refuse to operate.

6.3   Impact on phase selector

6.3.1   Fault component of phase current difference based phase selector

According to the superposition theorem, the fault network includes two parts, one is the normal network and the other is the additional fault network. The additional fault network is shown in Figure 31 [20].
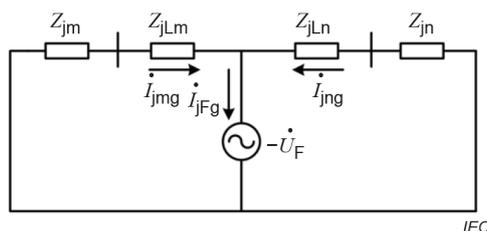
Figure 31 – Fault component network

According to Figure 31, it can be obtained that

$$\begin{cases} \dot{I}_{1mg} = C_1 \dot{I}_{1Fg} \\ \dot{I}_{2m} = C_2 \dot{I}_{2F} \\ \dot{I}_{0m} = C_0 \dot{I}_{0F} \end{cases} \tag{13}$$

Where distribution coefficients $C_1 = \dfrac{Z_{1Ln} + Z_{1n}}{Z_{1m} + Z_{1Lm} + Z_{1n} + Z_{1Ln}}$, $C_2 = \dfrac{Z_{2Ln} + Z_{2n}}{Z_{2m} + Z_{2Lm} + Z_{2n} + Z_{2Ln}}$,

$C_0 = \dfrac{Z_{0Ln} + Z_{0n}}{Z_{0m} + Z_{0Lm} + Z_{0n} + Z_{0Ln}}$.

In the regular system positive and negative sequence impendence are the same and they are far smaller than those of a wind farm. Therefore, the ratio of negative and positive distribution coefficients for a wind farm satisfies

$$k_{C21} = \frac{C_{W2}}{C_{W1}} = \frac{Z_{W1} + Z_{L1} + Z_{G1}}{Z_{W2} + Z_{L2} + Z_{G2}} \approx \frac{Z_{W1}}{Z_{W2}} \tag{14}$$

Because the positive and negative sequence impedance of wind farm fluctuates, according to Figure 27, the performance of the phase selector will be impacted in the power system with a wind farm.

Namely the fault components of phase current difference $\Delta\dot{I}_{AB}$, $\Delta\dot{I}_{BC}$, $\Delta\dot{I}_{CA}$, they are calculated as follows.

$$\begin{cases} \Delta\dot{I}_{AB} = \Delta\dot{I}_A - \Delta\dot{I}_B = (1-a^2)C_{m1}\Delta\dot{I}_{F1} + (1-a)C_{m2}\dot{I}_{F2} \\ \Delta\dot{I}_{BC} = \Delta\dot{I}_B - \Delta\dot{I}_C = (a^2-a)C_{m1}\Delta\dot{I}_{F1} + (a-a^2)C_{m2}\dot{I}_{F2} \\ \Delta\dot{I}_{CA} = \Delta\dot{I}_C - \Delta\dot{I}_A = (a-1)C_{m1}\Delta\dot{I}_{F1} + (a^2-1)C_{m2}\dot{I}_{F2} \end{cases} \tag{15}$$

Take AG fault as an example to analyse the performance of the fault component of phase current difference based phase selector. If an AG fault occurs, $\Delta\dot{I}_{F1} = \dot{I}_{F2} = \dot{I}_{F0}$. Besides, under the premise of $C_{m1} = C_{m2}$, the absolute values of $\Delta\dot{I}_{AB}$, $\Delta\dot{I}_{BC}$, $\Delta\dot{I}_{CA}$ satisfy

$$\begin{cases} |\Delta\dot{I}_{AB}| = 3|C_{m1}||\Delta\dot{I}_{F1}| \\ |\Delta\dot{I}_{BC}| = 0 \\ |\Delta\dot{I}_{CA}| = 3|C_{m1}||\Delta\dot{I}_{F1}| \end{cases} \tag{16}$$

When $C_{m1} \neq C_{m2}$, it has to meet equation (17) to identify the fault types at least.

$$\begin{cases} \left| \Delta \dot{i}_{BC} \right| < \left| \Delta \dot{i}_{CA} \right| \\ \left| \Delta \dot{i}_{BC} \right| < \left| \Delta \dot{i}_{AB} \right| \end{cases} \tag{17}$$

Thus, the phase of k_{C21} has to satisfy

$$-\frac{\pi}{3} < \arg(\frac{C_{m2}}{C_{m1}}) < \frac{\pi}{3} \tag{18}$$

However, since the positive and negative sequence impedance of wind farm are unstable, it may not satisfy equation (18). Thus, the fault component of phase current difference based phase selector allows for the possibility of wrong phase selection results.

6.3.2   Fault component of sequence current based phase selector

Sequence component phase selector is based on the amplitude and phase features of the fault component of positive, negative and zero sequence current.

When an AG fault occurs, $\alpha = \arg(\Delta \dot{I}_1 / \dot{I}_2) = 0°$, $\alpha = \arg(\dot{I}_0 / \dot{I}_2) = 0°$. When BC fault occurs, $\beta = 180°$. When BCG fault occurs, $\alpha = 0°$, $\beta = 180°$.

According to the principle above, the premise of correct fault selection results is based on the constant amplitude and phase relationships between the positive, negative and zero sequence current. Thus, it can be concluded that the fault component of sequence current based phase selector also allows for the possibility of wrong phase selection results.

The behaviour of traditional phase selectors under different kinds of faults is illustrated in Table 4. In Table 4, CG/CAG presents the phase selection result which sometimes is CG, sometimes is CAG. "–" presents that no result is output by phase selector.

Table 4 – Behaviour of traditional phase selectors under different kinds of faults

Fault type	Phase selector 1		Phase selector 2	
	DFIG farm	PMSG farm	DFIG farm	PMSG farm
AG	CG/CAG	AG/ABG	AG/BCG	BCG
BG	AG/ABG	BG/BCG	BG/CAG	CAG
CG	BG/BCG	CG/CAG	CG/ABG	ABG
ABC	ABC	ABC	ABC	ABC
BC	-	BC/ABC	CA/ CAG	BC/BCG
CA	-	CA/ABC	CA/ABG	CA/ABG
AB	-	AB/ABC	AB/BCG	AB/BCG
BCG	-	BCG/ABC	BCG/AG	BCG/ABG
CAG	-	CAG/ABC	CAG/BG	CAG/BCG
ABG	-	ABG/ABC	ABG/CG	ABG/CAG