European Network of
Transmission System Operators
for Electricity

Determining generator fault clearing time for the synchronous zone of Continental Europe

- Version 1.0 -

RG-CE System Protection & Dynamics Sub Group

3 February 2017

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1. Introduction

The Critical Fault Clearing Time (CFCT) is the most common criteria for evaluation of transient angle stability. The CFCT is the maximum time during which a disturbance can be applied without the system losing its stability. Calculation of CFCT is widely performed in almost every time horizon starting from real-time or close to real-time up to planning studies several years ahead.

The System Operation GL [1] states in Article 38.2

"*All TSOs of each synchronous area shall coordinate the dynamic stability assessments, which shall cover all or parts of the synchronous area.*"

…and further in Article 39.2

"*Each TSO shall ensure that the fault clearing times for faults that may lead to wide area state transmission system instability are shorter than the critical fault clearing time calculated by the TSO in its dynamic stability assessment carried out in accordance with Article 38.*"

Moreover, Network Code on Requirements for Grid Connection of Generators (NC RfG) [2] Article 19.3 requires for synchronous generators of type D that...

"The relevant TSO and the power-generating facility owner shall enter into an agreement regarding technical capabilities of the power-generating module to aid angular stability under fault conditions."

Despite the fact that the phenomenon is well described in literature the approach for calculating fault clearing time is not coordinated and sufficiently specified in the European network codes and operational guidelines.

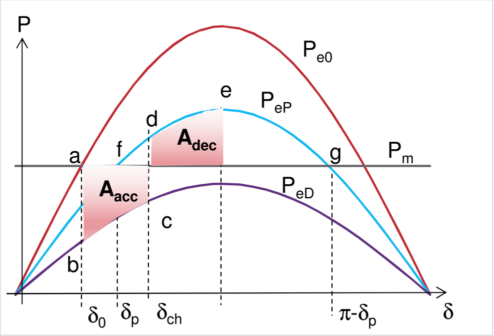
This report is intended to provide a better understanding of the impacting factors related to the calculation of CFCT. Based on a questionnaire circulated between the members of SG SPD the different approaches related to determination of CFCT are analysed. The report may serve as input towards a more harmonised approach among the European TSOs.

The report focuses on synchronous generation and does not address issue related to asynchronous generators or generators with a converter-based interface.

2. Description of phenomena

The equal area criterion is a graphical–analytical method for fast assessment of the first-swing transient stability. The power–angle transient characteristics corresponding to the three stages of the disturbance (prefault, during fault conditions and postfault) are illustrated in the next figure. The following text is based on [3].

The point a, situated at the intersection of the $P_{e0}(\delta)$ curve with the mechanical power line $P_m = ct.$, to which the δ_0 angle corresponds, defines the initial state of the system. At the instant of the fault occurrence, the operating point suddenly moves in the point b, on $P_{eD}(\delta)$ curve. Because $P_m > P_{eD}$, the generator rotor accelerates and the angle δ increases up to δ_{ch} (point c on the P_{eD} characteristic), when the fault is cleared. After the fault is cleared the operating point suddenly jumps from c to d and continues to move on the P_{eP} curve with negative acceleration since $P_m < P_{eP}$, until the deceleration area A_{dec} becomes equal to the acceleration area A_{acc} (point e), indicating that the transient stability condition is satisfied. In the absence of damping, the rotor will continue to swing around δ_P (point f is the new post fault steady state point). If the two areas do not become equal up to point g the acceleration becomes again positive and the synchronism is lost.



3. Fault cases

CFCT calculations are relevant for nodes which are critical for maintaining synchronism of the interconnected system. The method is also applied to any connection study of a new generating unit. To generate a more comprehensive overview of the system stability CFCT may also be done on a contingency list.

Due to different practices, tools and sensitivity for stability of responsibility area TSOs are using different methods to calculate the CFCT. Other driving factor is significant improvement in computing power, development of software which allows more detailed analysis than provided by the classical approach.

In order to operate the system closer to the limits it is less acceptable to constrain the output of a particular generator by evaluating the CFCT against a normative clearing time, e.g. 150 ms. The operational range can be determined based on the specific protection scheme plus a margin instead.

A contingency list may consist of a number of nodes which are close to power plants and nodes connecting tie lines. The faults are then applied in the line, for intact grid, and for a number of critical n-1 states, close to HV power station bus-bars. The cases for the n-1 states were chosen in cooperation with TSOs. Clearing the fault is done by disconnecting the faulted line.

According to the available reference the following two types of approaches are considered:

1. Calculated CFCT is crosschecked directly against the effective clearing time (which includes breaker opening time, tele-protection time). Moreover, based on such results, protection settings can be modified (in accessible range).
2. Calculated CFCT is referred to the requirement of normative CFCT for a type of fault (e.g. 150 ms coming from Grid Code). The underlying assumption is that this threshold is above the clearing time required from protection equipment plus a margin to consider the effective response time.

The TSO replies to the questionnaire suggest an accuracy of the calculation method between 5-10 ms, which should be considered in the security margin.

3phase, 2phase, 1phase with/without reclosing

3phase fault is foreseen as a fundamental disturbance in CFCT analysis. Generally, asymmetrical faults are treated as less severe and they are checked only in specific situations.

For new equipment / new installation, 1phase fault with/without auto reclosing is also very often examined.

An empirical study showed that the CFCT of a single-phase fault is about two times the CFCT of the equivalent three-phase fault without reclosing.

Breaker failure/backup protection clearing times?

There is no common practice related to this issue. In case of breaker failure, the backup protection scheme is analysed for some TSOs. Breaker failure is usually analysed when designing protection schemes near power plants, but not all TSOs consider it as a contingency case . In particular, such an analysis might be needed for extra-large units (app. 1 GW rated power) for which typical breaker failure backup protection scheme could be insufficient in relation to results of calculated CFCT.

Fault location (Point of connection or generator terminal)

According to the answers received from the TSOs, there is a general rule that the fault location is on the HV level. The range of locations (sending / receiving end, distance from the bus-bar) varies depending on the particular situation.

Security margin

There are different solutions to deal with security margin:

– No extra margin.

- No specific security. If the CFCT is close to the normative fault clearing time it is verified that the specific protection devices ensure a sufficient margin.
- Considering the margin created by a worst case initial condition
- Determined a percentage depending on the network state (N versus N-1)
- A fixed delay of 50 ms is added to the FCT.
- In order not to hazard the auxiliary supply because of the voltage recovery after a fault, the security margin is considered as follows: $t_{critical} - t_{150ms} > approx. 30\ ms$.
- Or evaluating the voltage recovery at t_{150ms} and verifying that the following condition $U_{Generator} \leq 85\ \%$ does not last longer than 500 ms)
- Sufficient distance and coordination with backup protection.
- In other cases, the calculation methodology involves gradual reductions of the time during which the fault is applied, i.e. in predefined steps (Δt) until reaching the admissible time (T). When this T is found, there is an uncertainty in the safety margin equal to the last fault time-down step (Δt) that has been applied. Therefore, an additional simulation with a fault time equal to T plus half time step shall be performed (T+Δt/2). If the result is admissible, the critical time will be T, otherwise it will be T minus half time step (T-Δt/2). This way, an objective safety margin is applied depending on the size of the time step between simulations.

This CFCT is used in order to analyse the needs of the equipment levels of the protection system, for example to determine the line protection scheme (2SP/2C, 2SP/1C or 1SP/1C[1]) which will be set according to the critical times. The fault has to be cleared before this critical time has been reached, and that even in N-1 conditions. [4]

At least resolution of computation algorithm should be considered. Also some inaccuracy of the model should be considered in the margin unless the analyses are typically performed in the off-line mode, and the results should be applied in situations in which all specified preconditions are satisfied.

4. Initial operating point

To determine the critical fault clearing time (CFCT) of synchronous machines a proper initial operating point is essential. The following parameters have an influence on the distance to the instability point of the generator. By increasing the active power of the generator the rotor angle is increasing and the generator gets closer to the instability point. When operating a generator in an under-excited mode with a constant active power output the rotor angle is greater than in an over-excited operating point. Therefore, an under-excited operating point is more critical concerning the transient stability of the generator. If the generator voltage is decreasing at constant active power, the generator current has to rise. This leads to a higher voltage drop over the generator's impedance and consequently to a larger rotor angle. Therefore, a lower generator voltage is more critical than a higher voltage relating to transient stability of a synchronous generator.

If the auxiliary supply is not modelled in detail, i.e. if it is modelled as a simple P-Q-load, a security margin can be necessary when determining the critical fault clearing time. A three-phase short circuit near to the generator leads to a voltage drop also in the auxiliary supply. Assuming a long fault clearing time, the voltage drop can be deep and the voltage recovery time can be long. It is important to avoid an under voltage protection trip of the auxiliary supply.

The methodology of the different TSOs to determine the critical fault clearing time is analysed by using the survey information. Nine TSOs have filled in the survey. The evaluation of the survey concerning the initial operating point of the synchronous generator and the auxiliary supply is shown below.

Following parameters concerning the initial operating point were addressed in the survey:

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[1] Redundancy level. For instance 2SP/2C is double **S**ystem **P**rotection with double **C**ommunications channels.

1. Active power
2. Reactive power
3. Generator voltage
4. Auxiliary supply

1. Active power	Number of replies
Adjustment of the initial operating point of the generators only near to the fault	7
Use rated power as initial operating point	7
Complete capability curve considered	2
Depending on individual Scenario	1
2. Reactive power	
CFCT at maximum under-excited mode (Q_{min})	3
CFCT at Q_{min} and Q_{max}	2
Complete capability curve considered	1
Determine Q_{crit} and limit Q in operation	1
Depending on individual Scenario	2
3. Generator voltage	
0.95 pu – 1.0 pu	3
Lowest acceptable and rated voltage	3
Typical operation point	1
Rated voltage only	2
4. Auxiliary supply	
Static load model	4
Both static and dynamic (induction machines) model depending on the scope of the study	4

The most common approach is to adjust the operating point only of generators near to the fault. Then, the TSO majority calculates the critical fault clearing time at the rated active power, the maximum under-excited operating point (Q_{min}) and at the lowest acceptable and rated voltage of the generator.

The connection point of the auxiliary supply is at the generator point or at the HV side over a separate transformer. The voltage recovery time for the auxiliary supply is amongst others depending on the connection point of the auxiliary supply. Therefore, the connection point of the auxiliary supply has to be considered.

Auxiliary supply is generally modelled by simple loads, and sometimes by asynchronous motors (Amprion and CEPS).

5. Modelling

The following section gives examples on which details are included in different TSO models. Some simulation tools have dedicated features to support the calculation. Some examples are presented.

For all considered TSOs the observed area is fully modelled. In particular, generators are individually modelled using detailed models of excitation systems and governors. For the neighboring countries equivalent models are used.

RTE maintains a database of approx. 450 generator models. These models consist of alternator/turbine models, AVRs with PSS and limiter loops, and governors. This database is constantly updated especially when new power plants are connected to RTE grid.

Transelectrica uses the same modelling for the different dynamic analysis. The dynamic database of Romania consists of 120 generators models for hydro, combined cycle, thermal and nuclear power plants, 60 models for wind power plants, and 15 models for PV power plants. Static model for all loads. Wind and PV power plants are modelled in a dynamic database.

REE is using the IEEE IZ load model for PSS/E (constant current for P and constant impedance for Q). For active power load frequency dependency is also considered. The different types of technology for wind and PV power plants are modelled in a dynamic database and also depending on the network codes (concerning behaviour during voltage dips) are being complied with and without fault ride through capability.

For studies Amprion are using the Continental European model. The 380 kV and 220 kV grids of Amprion are fully modelled. For the 110 kV network a reduced model is used. The reduction level of the 110 kV network depends on the influence from the 110 kV network on the dynamic behaviour. Wind generation is aggregated at the 110 kV level with dynamic models. In the context of transient stability and CFCT determination, the model contains step-up-transformers, synchronous generators, converter models, AVR, PSS and GOV. Under and over-excitation limiters are not always represented. Loads are modelled as static. PV-infeed is modeled as a constant P and Q. For studying the start-up of power plants more detailed AVR, PSS and GOV models are used.

Energinet.dk uses the same dynamic model for transient and voltage stability studies. The model used to represent the Western part of Denmark comprises 70 detailed models of synchronous machines and around 100 generic models. Type 1 wind farms are modelled by 60 asynchronous generators and the remaining wind and solar infeed by around 200 converter models. No special load model is used for transient studies.

Generally, generator protections are not taken into account, except by Terna where they can be activated. At REE nuclear power plants and large thermal generators are typically modelled with real protection settings. When specific protections of generators are not modelled, loss of synchronism, frequency and min/max voltage generic relays are considered, and also over-speed for some type of wind farms.

In case of nuclear power plants or large thermal generators it is common to include specific protections with real settings. For the remaining units, generator protections are generally not taken into account, except by Terna where they can be activated. When specific protections of generators are not modelled, loss of synchronism, frequency and min/max voltage generic relays are considered, and also over-speed for some type of wind farms. The latter is the case in the REE database.

Example of built-in features of simulation tools

The following section gives a few examples of built-in features in the different simulation tools used by some European TSOs, which can be used to support the calculation of CFCT.

At RTE, there is an integrated CFCT calculation function in the Eurostag software. Loss of synchronism of generators is detected by a specific automaton with an angular or speed criteria for a given event, and the CFCT is calculated using the dichotomy (bisection) or incremental method. Other external scripts can provide active or reactive limits of generators. The French defence plan DRS (see chapter 8) is also modelled using a specific automatic built-in feature.

In PowerFactory, CFCT calculations are typically done by TSO-specific scripts. In order to speed up the simulation, a built-in feature can be used to interrupt the time domain simulation as soon as a pole slip of a synchronous generator is detected.

In PSLF, the CFCT module is also a user written (non-standard) extension. The implementation at PSE allows specifying several locations of the fault for one scenario (different topology, initial conditions) and running a simulation by checking the angle increment criteria. The CFCT output report presents the results for each fault with the indication of the most critical unit or group of units affected by a particular fault. Boundary conditions and thresholds can be specified to optimize the calculation time and to avoid calculating the CFCT if it gets much longer than the clearing time of the backup protection.

Like most other tools, PSS/E does not have a built-in function to calculate CFCT either. MAVIR uses a user-written script to perform such calculations. The program simulates a fault at a specified bus, trips the specified branches connected to the bus one by one when clearing the fault, and obtains the CFCT values for each branch. Loss of synchronism is detected when during the simulation (10 seconds by default) the rotor angle of any generator in the specified subsystem reaches a certain value (180 degrees by default) relative to the initial value before the fault. The program can be configured to calculate numerous cases during one run. The results are stored in an external database, including the CFCT, the case definition and the generators that first lose synchronism, as well as their maximum rotor angle values.

6. Operational and planning studies

As in the general case, 3 phase fault is the fundamental disturbance simulated for operational and planning studies. Some TSOs also perform single phase fault studies, with and without reclosing in N and N-1 conditions.

Depending on the circumstances, seasonal or special cases considering changes in topology and generation can be used as well.

The time horizon varies greatly and depends on the objective of the study:

- connection studies
- on demand: ad-hoc studies requested due to operational security reasons
- month-ahead studies, to take into account planned and unplanned outages (lines, bus-bars or protection equipment) that can reduce the stability margins,
- seasonal studies, based on seasonal exchange and forecast data, changes in generation, in N topology and N-k topologies;
- one year studies (for example to evaluate the best period for planned bus-bar protection maintenance)
- long term planning studies performed for a 2 to 5 year time horizon, with the possibility to extend the analysis to 10 years.

In general, no such method is applied and used in the control room, especially not dynamic simulations. Stability studies are usually performed by a department outside the control room. These studies can include an unplanned outage of an HV (lines, bus-bar, …) or LV (bus-bar protection, …) device or particular weather conditions (wind, snow, storm, fire,…) or double circuit faults.

Static calculations are more usual in control rooms. The aim of these simulations is to calculate short circuit currents, overloads, over-voltages or under-voltages before the dispatcher undertake appropriate actions.

Only Terna performs N-k static and dynamic simulations in the control room.

At RTE, dispatchers at the national control centre have a 24/7 access to a database of dynamic studies and to calculated gradients giving the effect of an increase of active power on reactive limits (for example, if a power plant produces 100 MW more than its power output used in the study, it can absorb 100 Mvar less). These dynamic studies are performed by a dedicated team working during office hours.

There are only few examples of commanding generators to limit their operating range (market interaction).

In the case of RTE, for stability reasons, many generators, mostly nuclear power plants, are operated with a limited range of reactive power. In some extreme cases, for stability purposes, they have to limit their active power output too. It happens mostly when a double circuit faults are considered due to storms. For this type of event, the active power of a nuclear power unit can be lowered in the range of 100 to 400 MW during several hours.

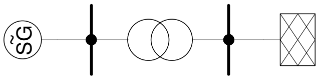
Terna takes into account generator limitations due to operational constraints or market conditions, and REE can limit the generation in case N-1 conditions are not fulfilled in a specific area.

7. NC RfG compliance testing and impacting factors

In relation to the current report, Article 14.3 of the Network Code on Requirements for Grid Connection of Generators (NC RfG) [2] gives some general guidance as to how CFCT shall be calculated in order to demonstrate that a generator comply with the NC. This Article is relevant for type B, C and D of synchronous as well as non-synchronous generation (article 18-19, 21-22).

When the conditions for the compliance testing are defined the following issues shall be considered

- Fault cases
    - Condition 18 in the preamble of the RfG specifies that "the most common fault clearing time in Europe is currently 150 milliseconds".
        - This means that breaker failure/backup protection shall not be considered for compliance testing
        - Using 150 ms as the normative rule the TSO shall ensure sufficient security margin against activation time and model inaccuracies
    - Since the RfG specifies a minimum residual voltage of 0.05-0.30 pu at Point of Common Coupling for type (B) and C[2] a certain minimum fault impedance is required.
        - The R/X ratio of the fault impedance needs to be determined
    - Article 14.3b allows defining requirements for asymmetrical faults. This may in particular be relevant for non-synchronous generation
    - Repetitive faults are not mentioned but, especially in relation to non-synchronous generation, this may be relevant [5]
- Test model configuration
    - The test is to be applied at the connection point i.e. where the generator is connected to the transmission system
    - A typical test configuration will be set up by a generator, a step-up transformer and a transmission bus with a specified short circuit power



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        - If the transmission system is modelled by a Thévenin equivalent (voltage source behind impedance) the frequency will be constant. This may lead to a too optimistic fault recovery.
        - If the transmission system is modelled by a single rotating machine behind impedance, this allows for modelling inertia. In this case, an excitation system model may be required.
        - The R/X ratio of the short circuit impedance will affect the results…
        - The most accurate representation will be to use the full system model. Usually, the TSO is unable to share this model, which means that the asset owner will not be able to validate the results.
    - Dynamic models of generator and generator controls are required.
    - Auxiliary supply shall be considered
- Initial operating point
    - The operating point shall be determined considering that the CFCT is worsened by
        - high active power
        - low reactive power (absorbing)
        - lower generator voltage
    - Auxiliary supply at the generator terminal will offset the generator, which may further lower the CFCT

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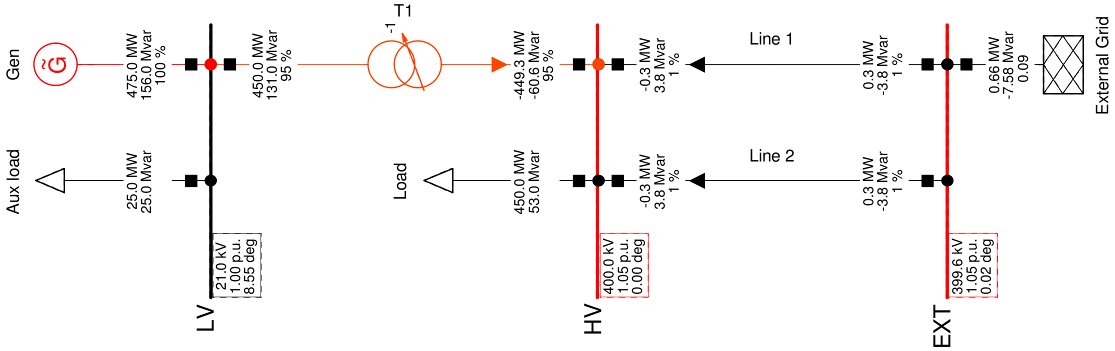
[2] 0.05-0.03 pu for synchronous generation and 0.05-0.15 for non-synchronous generation of type B and C. Article 16 table 7.1 specifies 0 pu for type D.

Example of impacting factors

In order to illustrate how different parameters may affect the CFCT results, a small test network is constructed based on the "Controller test report" developed by SG SPD [6]. The model is slightly extended by adding two lines to define the short circuit power at the HV bus.

Unless specifically stated the HV and LV voltages are maintained at 1.0 pu by the external grid and an ideal transformer tap-changer, respectively. All other generator, transformer and controller parameters are set according to the original report.



Generator 500 MVA, 21 kV, TGOV1, SEXS, PSS2A	Transformer 500 MVA, 419/21 kV, ideal tap changer controlling LV bus	Ssc=8000 MVA@bus HV Zline1=Zline2 = Zsc*2 = 380kV^2/8000MVA*2 = 36.1 Ω, R/X=0.1 Rline1+jXline1 = 3.59+j35.92 Ω	External Grid Ideal voltage source.
Auxiliary load Constant impedance	Main load Constant impedance		

The short-circuit is applied to Line 2 near bus HV and then tripped. For the reference case shown above the CFCT is 203 ms. The following table shows the CFCT after varying a single parameter.

	Alternative a	Alternative b	Alternative c
Initial operating point	475+j156 Mvar **203 ms** (ref.)	500+j156Mvar **193 ms**	475-j50 Mvar **177 ms**
Fault impedance	5+j0 ohm (0.3pu voltage) **338 ms**	0+j5 ohm (0.24pu voltage) **263 ms**	3.54+j3.54 ohm (0.26pu voltage) **316 ms**
Short circuit ratio (line impedance)	R/X =0.0 (0.00+j36.10 Ω) **200 ms**	R/X =0.25 (8.76+j35.02Ω) **207 ms**	R/X =0.5 (16.14+j32.29 Ω) **216 ms**
Short circuit power from external grid at HV bus	1000 MVA **127 ms**	2000 MVA **156 ms**	Infinite **226 ms**
Terminal voltage	0.90 pu **176 ms**	0.95 pu **191 ms**	1.05 pu **214 ms**
Auxiliary load	Constant I **204 ms**	Constant P **205 ms**	
Controller	No GOV **199 ms**	NO AVR **194 ms**	No Gov+AVR **190 ms**

The example illustrates the impact of varying some of the relevant factors to consider when determining the fault scenario. The factors may have a different impact in other examples. Therefore, no general conclusion can be drawn from the above example.

8. Other issues

System Protection Scheme (SPS)[3] – Generator tripping

Reducing the active power of the generator by tripping is a very effective and relative simple method exercised by a simultaneous rapid change of the torque balance on the generator rotors (this action directly reduces the acceleration area (A_{acc}) shown on the figure in chapter 2). This solution is widely used in order to maintain stability of group of units or to prevent system instability after severe disturbances.

As a consequence of generator tripping by opening the generator circuit breakers the unit may transfer to house load operation (for the resynchronisation process the SPS scheme shall consider generating units of high priority with the ability to enter into house load operation).

Usually, generator tripping is foreseen as a preventive measure, where losing of the unit initiated by the protection system allows maintaining the synchronism of the remaining generators in the vicinity (connected to the same bus-bar or the same substation) and prevents the disturbance propagating to other group of generators.

In case when many units are affected by severe fault, the number of generators programmed to trip should be determined by an off-line stability analysis. This analysis should consider a variety of pre-fault conditions such as: location of the fault, network topology, set-point of the unit, effective clearing time, and primary and backup protection. As a result of the analysis, a look-up table of the pre-programmed cases and an execution order can be set up as a basis for the SPS logic.

It has, however, to be mentioned that there are some disadvantages of generator tripping:

- due to predetermined conditions and limited possibility of real-time changes in the SPS logic, the range of activation could be overestimated; however, lower accuracy of such a solution should be treated as an inherent feature,
- generator tripping has in general a negative influence on shaft fatigue and its life span expectation; so, using this solution should only be considered when the probability of activation is relatively low. Therefore, generator tripping is rather applicable as an additional protection system or a temporary measure for a weak network with a high concentration of generator units.

In case when a better performance is necessary, there are the following alternatives:

- restitution trip, where a group of units working in parallel would lose synchronism after a severe disturbance and, therefore, tripping one of them beforehand is an effective remedy for avoiding the risk to trip and resynchronise all units.
- real-time dynamic assessment involving curative action – this solution relies on a real-time measurement and a direct communication with protection systems equipped with fault recognition and powerful computer systems capable of performing a dynamic analysis in close to real-time conditions, which deliver an accurate number of units to trip or the volume of power to reduce (the latter, only if fast-valving is available).

Improved protection functions

Regardless of the mentioned proposition to improve the performance of this kind of special protection scheme, an action to prevent generator tripping should be undertaken in the first place. There is a need to provide that kind of requirements for the short circuit protection scheme, which ensure fast and selective elimination of faults. At present, increased attention is paid to the problem of ensuring a backup of the basic

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[3] As defined in SPD report on Special Protection Schemes [11]

protection functions (distance and differential) and to tele protections. Where a short circuit on a bus-bar in substations near to a power plant may cause a risk for the stability of generators, some TSOs consider using duplicated bus-bar protection (to cover the case of maintenance or failure).

Another aspect that could improve the conditions of stability is fast clearing of short circuits by considering breaker failure protections (BFP). If a breaker failure occurs, the generators may be exposed to a short-circuit even longer than 200 ms. A novel approach, not yet widely used, is a special solution of BFP, in cooperation with other protections, for the purpose of recognising the type and place of a short circuit. This allows a significant reduction of the physical fault clearing time in comparison to typical scheme of BFP.

Generation connected at distribution level

Generally, a generator connected to a distribution system will see higher network impedance compared to the same generator connected at the transmission level. Therefore, this generator is better able to keep up the terminal voltage during a fault in the transmission system. On the other hand, improper island detection schemes and insufficient implementation of grid code requirements may cause the generator to disconnect during a simple fault on the transmission system. Seen from the transmission system, the calculation of CFCT for generators embedded in the distribution system is difficult due to the interaction with the load, other generating units and unknown network data.

Specific examples

- Fast valving (criteria, applications)
  - At RTE, fast-valving controls are always modelled in the governor models of generators if they exist. The activation is triggered by acceleration and speed criteria (the latter only for nuclear power plants). They increase the CFCT for generator-near faults significantly by rapidly decreasing the mechanical power of the generator. Nevertheless, power plants have no obligation to implement these controls.
- Teletripping schemes (SPS) (Terna, RTE, REE)
  - In France, there is a zone that could lose synchronism in case of a particular N-2 line forced outage when this zone is exporting power above a certain threshold. Instead of preventively lowering the production, an automaton (special protection scheme) detects the N-2 tripping and sends a generator tripping order (for one or two generators). The distance between the automaton that detects the N-2 situation and the automaton that trips the generators is about 100 km. The delay between the detection and the tripping is less than 200 ms. In order to limit the risk of unnecessary tripping of generators, the automaton is switched on only when the exported power of the zone is above a threshold that is calculated every week.
  - In Italy, a specific area risks losing synchronism during N-k events when certain transit conditions are fulfilled (value and direction of active power). To protect against this risk, an SPS has been installed that automatically performs a trip (with a total delay of about 200 ms) of production groups after specific contingencies. Such actions help mitigating the risk of loss of synchronism between electrical areas.
- Protection settings (during maintenance re-tuning of parallel or adjacent protection takes place at RTE and REE)
  - When the bus-bar differential protection is out of service the second zone distance protection clearing times of the connected substations are generally reduced.
- Defence systems (SPS) (Terna), DRS (RTE)
  - A defence plan called DRS (Détection de Rupture du Synchronisme) against loss of synchronism is modelled in Eurostag. 19 zones with coherent dynamic behaviour have been defined and out-of-step relays implemented on the border lines. They open the lines in order to isolate the out-of-synchronism zone after detection of voltage swings.
  - In some areas of Italy the distance protections trigger an out of step functionality which distinguishes “simple” electromechanical oscillations (in this case the protection does not trip)

from cases of real loss of synchronism (in the latter cases the protection trips and opens the tie line).

9. Advanced techniques for monitoring

This chapter gives examples of advanced monitoring techniques related to CFCT both from the point of view of the existing applications and ongoing research.

The importance to investigate these approaches is due to the fact that the Continental European (CE) system may frequently be exposed to the risk of being operated near its stability limits. In order to have a comprehensive understanding of power system security margins, it is necessary to identify the operating conditions (represented by operating points) that could result in a potential loss of control.

In accomplishing this task, Dynamic Security Assessment (DSA) represents an advanced technique for monitoring widely adopted by TSOs in CE. The aim of DSA is mainly at defining a set of limit points beyond which the standard security criteria are violated, by using a simulation tool for the solution of a differential algebraic equation (DAE) system determining the power system behaviour in different, in advance defined contingency cases. Actually, DSA furnishes important information to system operators such as the transient security of a specific operating condition under various contingencies.

CFCT, is one of the main items of DSA and it is traditionally estimated according to the classical approaches described in the previous chapters (i.e. with the well-known equal area criterion). However, due to the associated high computing time, this approach does not seem fully appropriate in a real time application.

The advent of synchrophasor technology [7] offers new opportunities for DSA and hence for CFCT determination as its basic item. In a future perspective, significant benefits are expected in terms of computational burden reduction compared to traditional time-domain simulation programs of large scale power system [8].

In particular, synchrophasor data today available in TSO environment could allow the application of more straightforward approaches that, acting directly based on real-time measurements, are able to extract the information on the dynamic system security such as CFCT without explicit solution of a set of high order differential equations. These category of approaches is called *direct methods* and can be found in [9] [10].

Despite the potential benefits no operational implementation is available yet. This is due to the complexity of the tools and in particular due to their incapacity to provide easily usable information for the operator (i.e. which actions to consider when a problem is identified).

10. Conclusion and recommendations

The implementation of the GL System Operation and NC RfG requires a more harmonised approach related to the calculation of the Critical Fault Clearing Time.

This report is intended to provide better understanding of the impacting factors related to the calculation of CFCT. Based on a questionnaire circulated between the members of SG SPD the different approaches related to determination of CFCT have been analysed. There are many similarities in the way the CFCT are calculated by the TSOs. However, due to different challenges, tools and experiences, each TSO uses a different approach.

The differences relate to time horizon, fault definition, operating point and modelling.

In order to operate the system closer to the limits, it is less acceptable to constrain the output of a particular generator by evaluating the CFCT against a normative clearing time, e.g. 150 ms. The operational range can be determined based on the specific protection scheme plus a margin instead.

Another approach is to set the requirements for CFCT depending on the network state. For instance, 150 ms could be applied for a local “N” state and 120 ms for an “N-1” situation. The criteria may also consider the probability of occurrence of contingency (e.g. high or low risk of circuit breaker failure).

It is recommended that each TSO considers the following issues:

- At least every five years calculates the CFCT of each synchronous generator connected to the transmission grid at a voltage level above 200kV if relevant structural system changes have taken place
- This calculation shall be based on a full system model also used for other types of stability studies
- It is necessary to ensure that the maximum protection activation time is lower than the CFCT (also considering generator protection)
- If necessary, the active or reactive power limits of a generator shall be restricted in order to guarantee proper fault clearing

As a follow-up of this report could focus on how temporary and permanent technical limits due to issues with CFCT are specified and communicated by the different TSOs to the generator operators

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