

# Methodologies for a dynamic probabilistic risk assessment of the fast cascade occurring in cascading failures leading to blackouts

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**Abstract:** Blackouts result from cascading failure in transmission power systems. The typical development of a cascading failure can be split in two phases. In an initial slow cascade phase, an initiating contingency triggers a thermal transient developing on characteristic times much larger than the electrical time constants. This transient increases significantly the likelihood of additional contingencies. The loss of additional elements can then trigger an electrical instability. This is the origin of a subsequent fast cascade, where a rapid succession of events can lead the system to blackout. Based on these two phases and because cascading mechanisms occurring in each phase are very different, the blackout Probabilistic Risk Assessment (PRA) can be decomposed in two levels. A methodology for the level-I (PRA of the slow cascade) was already developed. Level-II analysis is the assessment of the fast cascade. It starts when the transmission power system becomes electrically unstable and finishes when the system reaches an electrically stable state (blackout state or operational state with load shedding). The aim of this paper is to discuss possible adequate methodologies for the level-II and to apply one of them to a test system.

**Keywords:** PRA, Dynamic reliability, Blackout, Power systems.

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## 1. INTRODUCTION

A blackout is a total collapse of the electrical grid on a large area leading to a power cutoff, due to a cascading failure. The typical development of a cascading failure leading to a blackout can then be split in two phases [1,2]. Following the occurrence of an initiating event, thanks to the *N-1* security rule applied by transmission system operators, the grid stays electrically stable. A competition then starts between operator corrective actions and possible additional failures, either due to thermal effects or independent. This phase is called *slow cascade*, because it displays characteristic times between successive events ranging from minutes to hours. The occurrence of additional events during this phase can trigger an electrical instability (violation of protections set points, angular instability, etc.). Then a second phase called *fast cascade* occurs, ruled by electrical transients, displaying characteristic times between successive events ranging from milliseconds to tens of seconds. This phase is too fast to allow operators to take corrective actions and is characterized by a rapid succession of electrical events (additional failures, protection actions, etc.) whose occurrence order and timing are driven by the power system's dynamic evolution in the course of this transient. After this fast cascade, the electrical grid reaches a stable state: a possible collapse of the power system in some zones, or a major load shedding. Once a blackout or a major load shedding occurred, the recovery period can be viewed as an additional (and last) phase. According to this typical blackout development, [1] proposed a three-level blackout Probabilistic Risk Assessment (PRA) based on dynamic reliability. In particular, the level-II is the assessment of the fast cascade. It starts when the electrical dynamics of the system becomes dominant (the system can then be subject to electrical instability and the steady-state simulation does not capture anymore the grid behavior) and finishes when the system reaches an electrically stable state (blackout state or operational state with load shedding). Preliminary studies on the fast cascade can be found in [3,4]. However, these works did not study which dynamic reliability methodology should be the most convenient for the fast cascade. The aim of this paper is to discuss these different methodologies and to apply one of them to a test system.

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This paper is organized as follows. As protection systems play a crucial role in fast cascade, Section 2 introduces them. Then, Section 3 describes the fast cascade. Section 4 reviews dynamic reliability methodologies. Section 5 discusses the application of dynamic reliability methodologies to the fast cascade. Section 6 presents an application.

## 2. PROTECTION SYSTEMS

### 2.1. Introduction

Protection systems have globally two aims [5]. The first one is to disconnect the faulty circuit must be disconnected quickly in order to keep the continuity and quality of service, when a fault occurs. The second one is to disconnect elements operating in unacceptable conditions in order to protect them. These extreme working conditions can be due to specific electrical transients (independently or not of a fault occurrence). Any protection system needs three functions: the measurement of electrical variables, the detection of the fault from these measurements and the removal of faults or the disconnection of elements operating in unacceptable conditions. Thus, the major subsystems of protection systems are the transducers (i.e. current and voltage transformers), the relays to detect abnormal conditions and initiate the trips, and the circuit breakers to disconnect elements. A protection system relies also on a battery, in order to provide power during disturbances. Specific line protection systems can include communication channels to coordinate relays at line extremities.

### 2.2. Categories

Several categories of protection systems exist, according to the element to protect [5]:

- Over-current protections. An over-current relay is simply a relay that operates (instantaneously or with an intentional time delay) when the current exceeds a pre-determined value.
- Distance protections. They respond to the complex apparent impedance  $Z$  ( $Z = \bar{V}/\bar{I}$ , where  $\bar{V}$  is the element complex voltage and  $\bar{I}$  its complex current) between the relay location and the fault location. They are usually using three zones with different tripping times. The aim of zone 1 is to protect the line section instantaneously, but not to trip the protected line if a default occurs on an adjacent line. As errors in the fault location prediction could occur (e.g. measurement errors), zone 1 does not protect the entire line. The purpose of zone 2 is then to cover the area non-covered by zone 1 and it deliberately overreaches beyond the remote terminal of the transmission line. This zone 2 has an intentional time delay. It also backs up the distance relay of the neighboring line. Zone 3 is applied as a remote backup to zones 1 and 2 of an adjacent line.
- Over-excitation protections. Over-excitation, due to a combination of low frequency and high voltage, can cause thermal distress in power transformers and generators. Therefore, over-excitation protections trip generators and transformers if the ratio of the voltage to frequency exceeds a pre-determined value.
- Under-voltage and over-voltage protections. Protections for generator overvoltage have in general both an instantaneous unit and a time delay unit with an inverse time characteristic. Under-voltage can be a problem for auxiliary equipment and can then cause indirectly the trip of the generator.
- Under-frequency and over-frequency protections. The operation of generators at abnormal frequencies (either over-frequency or under-frequency) can induce mechanical resonances in the many stages of turbine blades. The abnormal frequencies protections trip the turbine, with a time delay depending on the speed deviation.
- Loss-of-field or loss-of-excitation protections. The source of excitation for a generator can be completely or partially removed and this kind of event can induce dangerous operating conditions for both the generator and the system. The detection method is based on the variation of impedance viewed from the generator terminals (through distance relays).
- Loss-of-synchronism. When a generator loses synchronism, the resulting high peak currents and off-frequency operation can cause damage to the generator. The generator thus should be tripped

without delay. The conventional relaying approach for detecting a loss-of-synchronism condition also relies on the analysis of complex apparent impedance as viewed from the generator terminals.

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In order to help to stabilize the system in particular situation, under-frequency and/or under-voltage (depending on the country) load-shedding relays are installed on the grid, as well as pump storage unit tripping relays. Defense plans give specific voltage and/or frequency steps for these relays (load percentage to shed with a time delay for each step). Only these relays are designed to protect the overall system in order to avoid reaching a feared situation. All other protection systems are designed to protect a particular component or a particular subsystem. The latter can thus have a negative effect on the overall system (e.g. power plants under-frequency protections).

### **2.3. Erroneous operations**

There are mainly two types of protection system erroneous operations: unwanted trips (i.e. a protection system trips when it should not do) and missing trips (i.e. a protection system fails to trip when it should do) [6]. Unwanted trips group spontaneous trips and unselective trips. There are mainly five causes for these erroneous operations. Two are common to unwanted and missing trips: measurements errors can occur and the actual set point of a relay can differ from its nominal value. One is specific to unselective trips: the timer ruling time delay can fail and the relay can then send an erroneous trip order to the circuit breaker. Two are specific to missing trips: due to a hardware failure, the relay can fail to send a trip order to the circuit breaker and the circuit breaker can fail to trip.

## **3. THE FAST CASCADE**

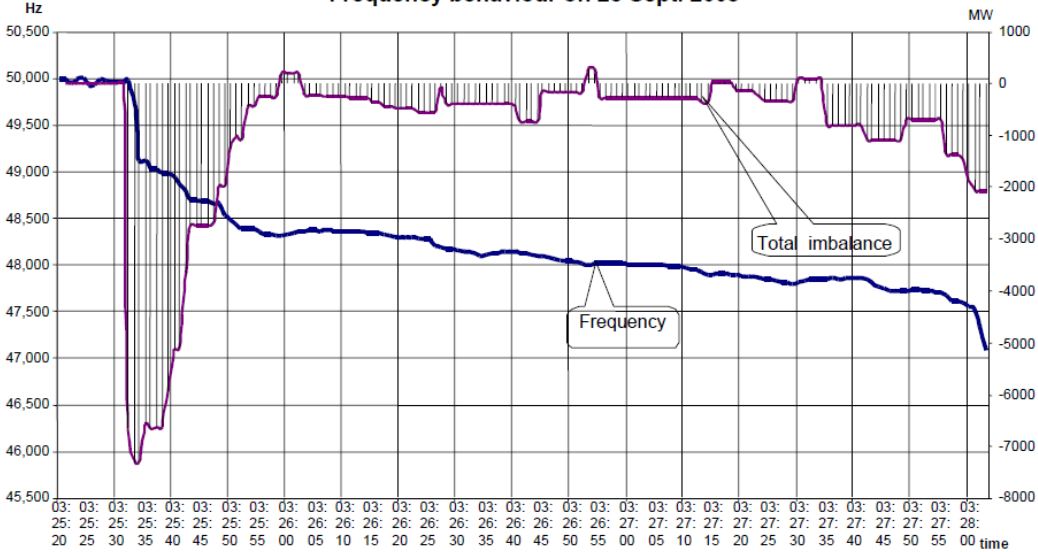
### **3.1. Analysis of past fast cascades**

On August 14, 2003, a blackout occurred in the Northeastern area of the United States and in the Southeastern area of Canada [7]. The fast cascade was triggered at 16:05:55 EDT when the Dale-West Canton 138-kV line tripped due to sag into a tree. At 16:05:57 EDT, 16:08:59 EDT and 16:09:06 EDT, three 345-kV lines tripped by zone 3 relays. There was no fault, but rather high flows above the lines emergency ratings with depressed voltages which induced the distance relays to disconnect the lines. The last trip caused a large power swing from Pennsylvania and New York through Ontario to Michigan. Between 16:09:08 and 16:10:27 EDT, multiple power plants tripped, totaling 946 MW. These trips were due to various reasons: isolation of power plants after the disconnection of lines from the low voltages, over-excitation, transformer fault... These events accelerated the spread of the cascade: between 16:10:36 and 16:13 EDT, a thousand of events occurred on the grid, driven by electric transients and automatic equipment operations. Hundreds of lines were disconnected due to over-currents and large oscillations which triggered distance relays (in zone 1), leading to the splitting of the system into multiple islands. Several islands endured extreme conditions and their power plants tripped successively due to under-voltages, over-currents, loss-of-synchronism, under-frequencies... Once an island endured under-frequency, load shedding was automatically performed due to defense plans, but it did not avoid the blackout. Indeed, the primary reason of this blackout was a voltage collapse and under-voltage load shedding was not implemented. At 16:13 EDT, much of the northeastern United States and the province of Ontario were in the dark.

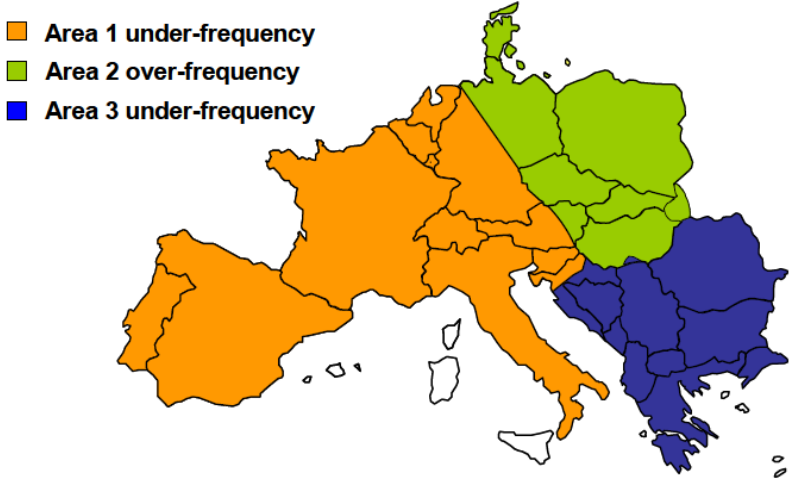
On September 28, 2003, a blackout occurred in Italy [8]. The fast cascade was triggered at 03:25:21 by the trip of a 380-kV line between Switzerland and Italy due to a flashover with a tree. At 03:25:25, 03:25:26 and 03:25:28, three 220-kV lines tripped due to high overloads (overcurrent protections). The Italian grid then lost its synchronism with the UCTE main grid which entailed the disconnection of all remaining connecting lines between Italy and UCTE by distance protections or overcurrent protections. The Italy grid became isolated. The total imbalance of this isolated area just after the separation was about 6,646 MW for a total load of about 27,220 MW. This negative imbalance between power injection to the system and system load caused an abrupt frequency drop. Figure 1

shows the frequency transient. The primary control operation of the generating units increased the generation of about 1,465 MW a few seconds after the event, but the frequency fell by 1.5 Hz in this time. All the pumping units in service were automatically disconnected between 49.720 and 48.985 Hz, shedding about 3,220 MW. Moreover, starting from 49.70 Hz, 7,710 MW of load was automatically shed during the frequency transient (about 85% of 1300 frequency relays functioned normally). But about 7,532 MW of generation were also lost during the transient for many reasons (turbine tripping, under-frequency relays, under-voltage relays ...). Therefore, frequency fell below 47.5 Hz, resulting in the tripping of the generating units that were still in operation, leading to a blackout at 03:28:05.

**Figure 1: Frequency transient leading to blackout in Italy in 2003. From [8].**  
**Frequency behaviour on 28 Sept. 2003**



**Figure 2: Schematic map of UCTE area split into three areas. From [9].**



On November 4, 2006, a major system disturbance occurred in Europe [9]. The fast cascade was triggered by the manual coupling of two busbars in the Landesbergen substation at 22:10:11. It initiated a cascade of line disconnections. In a first stage, from 22:10:13 to 22:10:27, 14 lines tripped due to their overcurrent protections. However, the busbar coupling triggered also angular oscillations which increased as lines were disconnected. Between 22:10:28 and 22:10:30, additional lines were tripped by distance protections due to these oscillations, leading to the splitting of the European power systems in three areas as shown in Figure 2 (Eastern, Western and Northeastern). The power balance in each area was then no longer ensured. These three islands evolved then independently and we will focus here on the second part of the fast cascade in the Western area. The Western area faced a lack of generation (about 8,940 MW over a generation of 182,700 MW) which induced a sharp frequency

drop to 49 Hz in 8 seconds. About 17,000 MW of loads and 1,600 MW of pump-storage units were shed due to this frequency decrease. A large amount (about 10,200) of wind and combined-heat-and-power generation tripped during this frequency transient because their under-frequency relays were set at 49.5 Hz. Except for one thermal generation unit (700 MW), no high power generation units connected to the TSO network tripped, as their under-frequency relays are set at 47.5 Hz. Both load shedding and primary frequency regulation lead to the stabilization of the frequency. The blackout was then avoided.

### 3.2. Main characteristics of a fast cascade

The analysis of previous examples, as well as fast cascades of other blackouts let us to emphasize the main characteristics of a fast cascade. The operators cannot take any corrective actions during this phase. Apart failures of protection systems, failures of grid elements (independent or due to thermal effect) can be neglected, since the mean time between failures is much larger than the fast cascade duration. The fast cascade is entirely driven by electrical transients and the action of protection systems. Once the fast cascade is triggered, the system endures extreme conditions. These conditions lead to the disconnection of transmission and generation elements by their protection systems, for various reasons. We should emphasize that the normal behavior of distance protections, whose the aim is to isolate faulty elements, can lead to the disconnection of elements without the presence of the fault of the grid. Extreme conditions lead also to automatic actions to try to stabilize the power systems, such as automatic generation control and load shedding. There is then a competition between automatic disconnection of elements which worsen the conditions and automatic corrective actions which improve them. The erroneous operations of relays can affect this competition. The fast cascade can then lead either to an operational state with load shedding, or to a blackout.

## 4. DYNAMIC RELIABILITY

### 4.1. Concepts

In “classical” reliability studies, possible scenarios as well as their frequencies are estimated independently of process variables (like temperatures, pressures, currents, voltages ...) evolution. The branches of the event trees are developed before any dynamic analysis according to the systems that should be solicited during the transient. Obviously, this approach is not relevant for the fast cascade analysis, where all the transitions are caused by the precise evolution of electric variables. The main idea of dynamic reliability is to describe the power system not only by discrete states, but also by a set of process variables (e.g. temperatures, currents, voltages). This allows considering the mutual interaction between discrete system states and continuous process variables: in each system state, process variables follow a deterministic evolution and transitions between system states depend on process variables. Dynamic reliability then allows considering dependencies between events through process variables: the trip of an element can trigger trip of another one through process variables.

### 4.2. The theory of probabilistic dynamics

The Theory of Probabilistic Dynamics (TPD) offers a framework capable of modeling the concepts of dynamic reliability [10]. Let  $\bar{x} \in \mathbb{R}^N$  be the vector of electrical variables describing the dynamic behavior of the power system. For each grid state  $i$ , the evolution of electrical variables is characterized by specific dynamic equations

$$\frac{d\bar{x}}{dt} = \bar{f}_i(\bar{x}, t), \quad (1)$$

or, in an equivalent explicit form,

$$\bar{x}(t) = \bar{g}_i(t, \bar{x}_0), \quad \bar{x}_0 = \bar{g}_i(0, \bar{x}_0). \quad (2)$$

The embranchments in a fast cascade correspond to transitions between two dynamics  $\mathbf{j}$  and  $\mathbf{i}$ , which are characterized by transition rates  $\mathbf{p}(\mathbf{j} \rightarrow \mathbf{i}|\bar{\mathbf{x}})$ , possibly dependent on the electrical variables value but explicitly independent of time in the Markovian case. If the transition from state  $\mathbf{j}$  to state  $\mathbf{i}$  is due to the action of the protection system  $\mathbf{k}$ , and if we assume that the protection system is perfectly reliable and acts instantaneously, the corresponding transition rate is given by

$$\mathbf{p}(\mathbf{j} \rightarrow \mathbf{i}|\bar{\mathbf{x}}) = \delta(x_l - s_k) \frac{dx_l}{dt}, \quad (3)$$

where  $x_l$  is the monitored electrical variable and  $s_k$  is the set point. We denote by  $\pi(\bar{\mathbf{x}}, \mathbf{i}, t)$  the probability density function to find the power system with electrical variables  $\bar{\mathbf{x}}$  in state  $\mathbf{i}$  at time  $t$ . This distribution is normalized as follows,

$$\sum_{\mathbf{i}} \int_{\mathbb{R}^N} \pi(\bar{\mathbf{x}}, \mathbf{i}, t) d\bar{\mathbf{x}} = 1. \quad (4)$$

The integral form of the Chapman-Kolmogorov equation, which gives the evolution of  $\pi(\bar{\mathbf{x}}, \mathbf{i}, t)$ , can be written in the Markovian case,

$$\begin{aligned} & \pi(\bar{\mathbf{x}}, \mathbf{i}, t) \\ &= \int_{\mathbb{R}^n} \pi(\bar{\mathbf{u}}, \mathbf{i}, 0) \delta(\bar{\mathbf{x}} - \bar{\mathbf{g}}_i(t, \bar{\mathbf{u}})) e^{-\int_0^t \lambda_i(\bar{\mathbf{g}}_i(s, \bar{\mathbf{u}})) ds} d\bar{\mathbf{u}} \\ &+ \sum_{\mathbf{j} \neq \mathbf{i}} \int_0^t \int_{\mathbb{R}^N} \mathbf{p}(\mathbf{j} \rightarrow \mathbf{i}|\bar{\mathbf{u}}) \pi(\bar{\mathbf{u}}, \mathbf{j}, t - \tau) \delta(\bar{\mathbf{x}} - \bar{\mathbf{g}}_i(\tau, \bar{\mathbf{u}})) e^{-\int_0^\tau \lambda_i(\bar{\mathbf{g}}_i(s, \bar{\mathbf{u}})) ds} d\bar{\mathbf{u}} d\tau, \end{aligned} \quad (5)$$

where

$$\lambda_j(\bar{\mathbf{x}}) = \sum_{\mathbf{i} \neq \mathbf{j}} \mathbf{p}(\mathbf{j} \rightarrow \mathbf{i}|\bar{\mathbf{x}}) \quad (6)$$

is the total transition rate out of configuration  $\mathbf{j}$ . The interpretation of equation (4) is the following: the power system is in state  $\mathbf{i}$  at time  $t$  with electrical variables  $\bar{\mathbf{x}}$  either if it has been in state  $\mathbf{i}$  from the beginning of the fast cascade with process variables  $\bar{\mathbf{u}}$ , following dynamics  $\bar{\mathbf{g}}_i(t, \bar{\mathbf{u}})$  with a survival probability given by  $\exp\left[-\int_0^t \lambda_i(\bar{\mathbf{g}}_i(s, \bar{\mathbf{u}})) ds\right]$ , or if the last transition to state  $\mathbf{i}$  took place at time  $\tau < t$  with electrical variables  $\bar{\mathbf{u}}$ , where the power system left state  $\mathbf{j}$  following dynamics  $\bar{\mathbf{g}}_i(\tau, \bar{\mathbf{u}})$  with a survival probability given by  $\exp\left[-\int_0^\tau \lambda_i(\bar{\mathbf{g}}_i(s, \bar{\mathbf{u}})) ds\right]$ .

This Markovian theory of probabilistic dynamics must be extended in order to be applicable to the fast cascade:

- The dynamic of a power system is usually described by a set of differential algebraic equations, instead of ordinary differential equations as presented in Equation (1). The set of electrical variables can therefore be split in two subsets: the differential variables  $\bar{\mathbf{x}}_d \in \mathbb{R}^n$  (dependent variables for which derivatives are present) and the algebraic variables  $\bar{\mathbf{x}}_a \in \mathbb{R}^m$  (dependent variables for which no derivatives are present). Equation (1) can then be rewritten as

$$\frac{d\bar{\mathbf{x}}_d}{dt} = \bar{\mathbf{f}}_{d,i}(\bar{\mathbf{x}}_d, \bar{\mathbf{x}}_a, t), \quad \bar{\mathbf{0}} = \bar{\mathbf{f}}_{a,i}(\bar{\mathbf{x}}_d, \bar{\mathbf{x}}_a, t) \quad (7)$$

Equation (2) remains valid. Each time an event causes a modification in the power system configuration, the theory presented above assumes that the new dynamics starts from the final situation reached in the previous configuration. It is true for the differential variables which are the same just before and just after the change. However, the algebraic variables can endure an instantaneous change which can be modeled by a shock for a transition from state  $\mathbf{j}$  to state  $\mathbf{i}$  as

$$\bar{\mathbf{x}}_a^+ = \bar{\mathbf{y}}_{ji}(\bar{\mathbf{x}}_d, \bar{\mathbf{x}}_a^-), \quad (8)$$

where  $\bar{\mathbf{x}}_a^+$  and  $\bar{\mathbf{x}}_a^-$  are the value of the algebraic variables after and before the transition, respectively. The Chapman-Kolmogorov equation can be slightly modified to consider these shocks.

- The fundamental equations of the TPD presented above consider that the transition in the power system state occurs with no delay after the crossing of a protection system set point by an electrical variable. This is not true since protection systems have delays (intentional or not) between the crossing of the set point and disconnection of the element. The most convenient way to consider these time-delays is probably the Stimulus-Driven TPD (SDTPD) [11]. A stimulus is the name

given to any situation that can initiate a transition. The stimulus  $\mathbf{G}_k$  associated to a protection system  $k$  is therefore activated as soon as its set point is crossed. As the time-delays associated with protection systems do not follow the Markovian hypothesis (i.e. they do not follow an exponential probability distribution), a semi-Markovian extension of the TPD is required. If a time-delay associated with the protection system  $k$  is intentional, the stimulus  $\mathbf{G}_k$  has to be deactivated as soon as its set point is re-crossed in the other way. In the opposite case, if the time-delay is not intentional (e.g. time-delay between the trip order sent by the relay and the actual trip by the circuit breaker), the stimulus stays activated. When a transition between two system states occurs, some inactive stimuli can be directly activated due to the shock (i.e. those involving algebraic variables) while some active stimuli can be directly deactivated (for the same reason). However, some active stimuli can stay activated and the problem then becomes non-Markovian (the residual delay must be considered).

The mathematical formulation of these extensions can be found in [11].

### 4.3. Numerical schemes

When using dynamic reliability, a classical Event Tree (ET) is modified into a Dynamic Event Tree (DET), or a Continuous Event Tree (CET), so that configuration changes triggered by the evolution of electrical variables create the possible branch points of the tree. However, contrarily to the ET, the exhaustive analysis of all sequences is impossible. Indeed, since embranchments can occur at any time on any branch, a DET contains in principle an infinity of branches. Thus, any practical numerical scheme must be based on assumptions limiting the number of branches to analyze. We can classify numerical schemes in three groups, according to the main assumption: restriction of the possible branching points in time (i.e. discretization of time), Monte Carlo (MC) simulation and combination of the both.

Discrete Dynamic Event Trees (DDET) denotes a family of similar methods providing discrete, hence finite, approximations of a DET. After the occurrence of an initiating event, electrical variables follow evolution laws associated to the resulting system configuration. The corresponding deterministic transient evolution defines a *mother branch*. Electrical variables evolution is computed by simulation. New branches are generated from this mother branch at user-specified discrete time intervals due to all possible events causing the system to branch off and according to branching rules (e.g. crossing on a demand-related hardware set point or probabilistic thresholds). New branches are generated from the secondary branches, and this branching process is carried on from each branch. The development of a scenario (or a branch) is stopped as soon as an absorbing state is reached (either a damage state or a safe situation). Several ways exist to manage the combinatorial explosion of sequences. One way is to resort to truncation criteria: the development of a branch can be stopped as soon as the probability to keep evolving along this branch goes lower than a predefined threshold, or if the scenario contains more than a predefined number of combined equipment failures. Finally, the frequency of the user-specified absorbing state can be calculated as they develop in the simulation, and related scenarios are identified.

MC simulation proposes to restrict the study of the DET to a random sample of sequences among all the possible scenarios. At the beginning of each MC run, the value of the uncertain parameters (e.g. set points of protection systems) is sampled. A possible evolution of the power system is then built, by sampling successive transitions (sampling of transition times and states) that could occur during the transient. This two-level sampling is often referred to as *double randomization*. The transitions are to be sampled along the calculation of the dynamic trajectories, as transition rates are electrical variables-dependent.

The two techniques presented above, DDETs and MC simulation have complementary advantages and drawbacks. DDETs are based on a systematic search of all possible scenarios, according to branching rules, but the combinatorial explosion of sequences is not always easy to manage. On the other hand, the finite number of MC runs cannot ensure that all types of sequences contributing significantly to the risk have been sampled. There are two ways to combine DDETs and MC simulation: skeleton-based

MC and MCDET. The skeleton-based MC computes first purely set point-based transitions DDET, assuming all transitions in operation are frozen. Based on this *skeleton*, MC simulation is used to investigate scenarios leaving the skeleton in operation. The main idea of the MCDET [13] is to split the set of “aleatory” (random) variables into two subsets: the subset of discrete variables that can be treated by the DDET analysis and the subset of all remaining variables (i.e. all the continuous and remaining discrete variables). For each MC run, the random variables of the second subset are sampled and the DDET conditioned by these sampled values is then built.

During the fast cascade, the transitions between system states are due to the protection systems. The variability of the embranchments in the corresponding DET is due to the possible erroneous operations of these protection systems. The only consideration of timer failures and circuit breaker failures leads to a DET with a finite number of branches. The challenge is then the integration of the measurements errors and differences between actual set point of a relay and its nominal value. As explained in [3], instead on using an uncertainty both on the measurement and on the set point, only an “equivalent” uncertainty can be considered on a set point. Indeed, only the difference between the set point and the measured variable is important. Obviously, this equivalent uncertainty must be such that the total amount of uncertainty remains constant. The skeleton-based MC is proposed in [3] to consider this uncertainty in the PRA. However, as electrical variables do not always obey a monotonous behavior, if a set point is crossed more than one time, the corresponding branch has to be only generated on the first passage of this value. This entails the management of taboo regions, which increases the complexity of the numerical scheme. Thus, the technique of the MCDET seems to be the most adapted to the PRA of the fast cascade. At the beginning of each MC run, set points of protection systems are sampled. The corresponding exhaustive DET can then be computed. For large power systems, a probabilistic cutoff criterion (i.e. the simulation of branches with a probability lower than a threshold is stopped) should be introduced to keep the computational effort practicable.

## 5. LEVEL-II OF CASCADING FAILURE PRA

### 5.1. Methodology

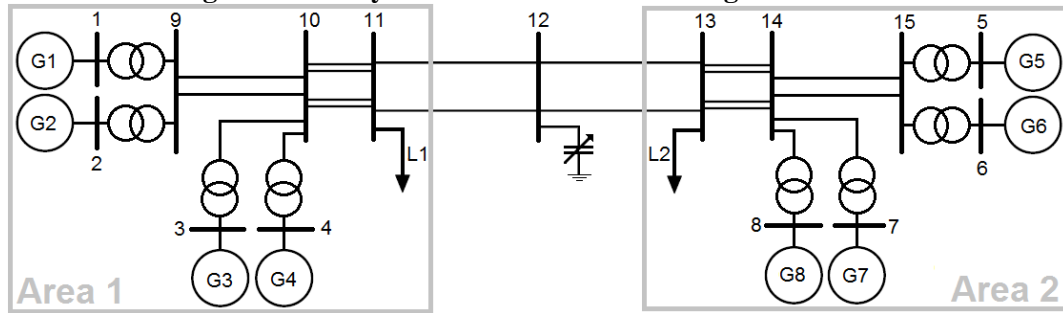
Previous Section proposes the MCDET technique for the level-II of cascading failure PRA. This technique requires however a simulator which has the ability to terminate itself just before the occurrence of a transition and can then restart with and without the transition. As professional programs are not designed for this purpose, it is not always possible to configure them for the MCDET technique. We thus propose to use a pure MC simulation as a first example of a level-II cascading failure PRA. A small modification of the traditional MC simulation can be introduced to simplify the simulation: instead of sampling possible failures of protection systems during the simulation, they can be sampled initially, before the beginning of the dynamic simulation itself. The dynamic simulator used is EUROSTAG.

### 5.2. Test system

The test system used is shown in Figure 3. It is an adaptation of the *Kundur's Two-Area System* [14]. There are 8 power plants with a maximal power of 400 MW for each of them. The load connected is 679.7 MW (and 70 MVar) into bus 11 and 1250.9 MW (and 140 MVar) into bus 13 (total active load: 1930.6 MW). The generated power is 245 MW in each power plant. Overhead lines are protected with overcurrent and distance relays. There are under-frequency and under-voltage load shedding as system protection scheme. Generators are modeled by synchronous machines equipped with IEEE-AC4A excitation systems, power system stabilizers and a gas turbine-governor system. Power plants are protected with over-excitation, under-voltage, under-frequency and over-frequency relays. The dynamic load model used is the multiplicative load model with a constant impedance instantaneous characteristic and a constant power long-term characteristic [15]. The recovery time constant is taken equal to 1 second.



**Figure 3: Test system for a level-II cascading failure PRA.**



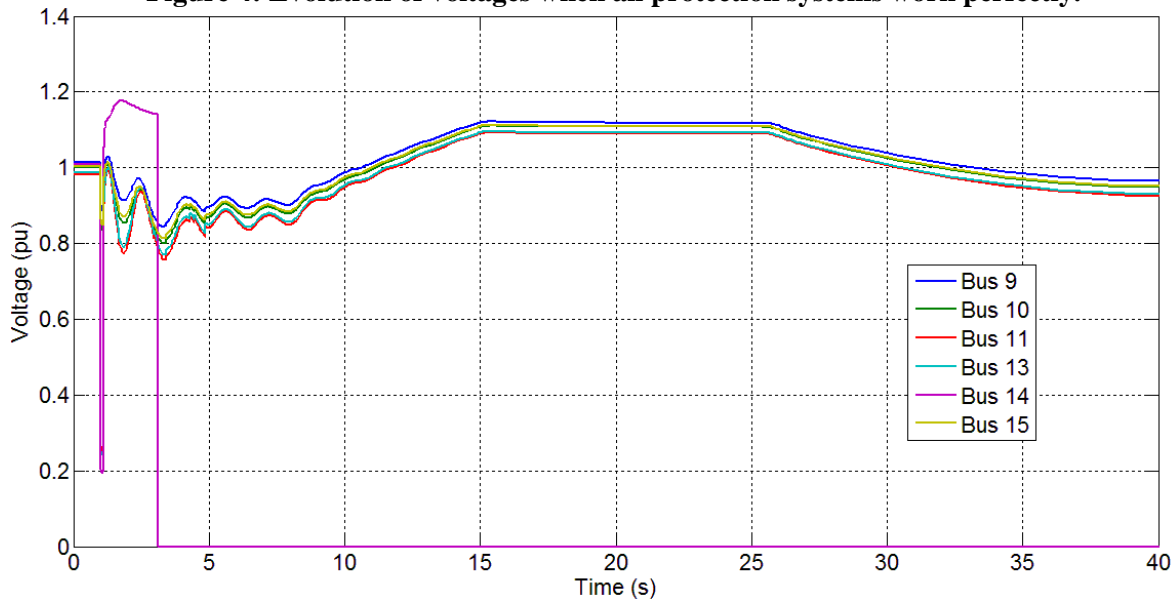
We consider that set points are distributed normally around their mean with a standard deviation equal to 1% of the mean. The probability of failure of lines circuit breakers is taken to  $10^{-3}$ . The probability of failure of load shedding circuit breakers is taken to  $10^{-2}$ . The probabilities of an unwanted immediate trip and an unwanted delayed trip due to timer failure are  $2.5 \times 10^{-3}$  for line protection systems,  $5 \times 10^{-3}$  for load shedding relays and  $5 \times 10^{-3}$  for generator protection systems. We should note that no detailed statistics exist to estimate accurately these values. We estimated the order of magnitude of these stochastic parameters on the basis of fault statistics from Fingrid, the Finnish TSO [16].

## 5.2. Results

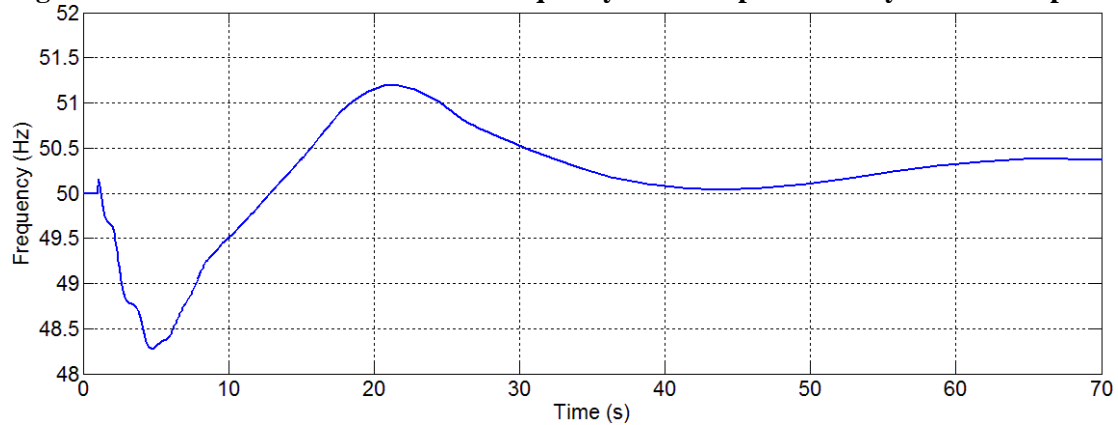
The studied scenario is the following. One of the lines between buses 14 and 15 has been previously lost (i.e. during the slow cascade). The event triggering the fast cascade is a short circuit followed by the loss of the remaining line between buses 14 and 15.

When all protection systems are considered as “perfect” (i.e. no erroneous operation), the blackout is avoided thanks to the load shedding. The total loss of supplied power is then 546.2 MW (28% of the initial load). Figure 4 shows the evolution of voltages for some buses in this case. Figure 5 shows the evolution of the frequency in the main island (buses 1-4 and 7-14). Voltages and frequency in this main island are quickly stabilized thanks to load shedding. Table 1 gives the sequence of events.

**Figure 4: Evolution of voltages when all protection systems work perfectly.**



**Figure 5: Evolution of the main island frequency when all protection systems work perfectly.**

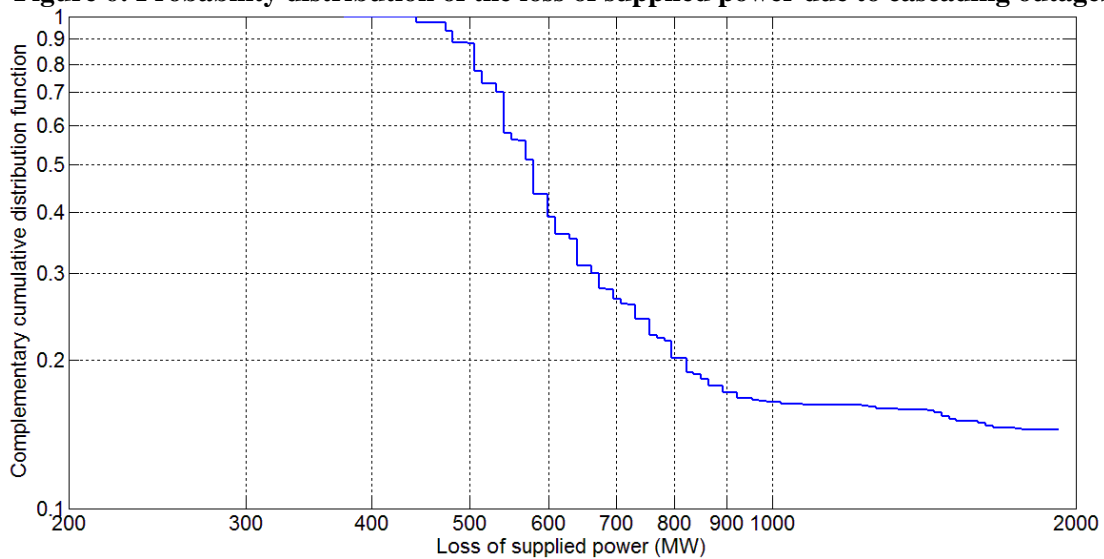


**Table 1: Sequence of events when all protection systems work perfectly.**

Time (s)	Event
1.00	Short circuit on line 14-15
1.10	Trip of the line 14-15
2.97	Under-frequency load shedding: 5% of load shed at bus 11, 5% of load shed at bus 13
3.11	Trip of the generator 5, trip of the generator 6
3.43	Under- frequency load shedding: 5% of load shed at bus 11, 5% of load shed at bus 13
4.30	Under-voltage load shedding: 5% of load shed at bus 13
4.32	Under-voltage load shedding: 5% of load shed at bus 11
4.46	Under- frequency load shedding: 5% of load shed at bus 11, 5% of load shed at bus 13
4.87	Under-voltage load shedding: 5% of load shed at bus 13
4.87	Under- frequency load shedding: 5% of load shed at bus 11, 5% of load shed at bus 13

When we include the possible erroneous operations of protection systems, the mean loss of supplied power is 798.2 MW (41% of the initial load) and the probability of blackout is 0.15. It means that erroneous operations of protection systems increase significantly the mean loss of supplied power and that a blackout can occur due to specific sets of these erroneous operations. The probability distribution of the loss of supplied power is shown in Figure 6. We should also note that the probability to have a loss of load smaller than the loss of load without erroneous operation of protection systems is 0.42. The total number of MC runs is 50,000.

**Figure 6: Probability distribution of the loss of supplied power due to cascading outages.**



To estimate the contribution to the risk of the different protection systems, we can use importance measures [17]. Because the chosen probabilities of failures are not backed up by empirical evidence, we propose to use the Birnbaum importance (also called the reliability importance) as it is independent of the current probabilities of failures. The Birnbaum importance index  $I_{B,i}$  related to the failure of component  $i$  can be defined as

$$I_{B,i} = R_i^+ - R_i^-, \quad (9)$$

where  $R_i^+$  and  $R_i^-$  are the risks when the probability of failure of component  $i$  are set to 1 and 0, respectively [17]. If the Birnbaum importance index is positive, the failure of the component increases the risk, and if the Birnbaum importance index is negative, the failure of the component decreases the risk. The measure of risk chosen for the computation of this index is the loss of supplied power. The undervoltage relays of generators 7 and 8 appear to be the most critical components: in case of failure of the timer leading to an unwanted immediate trip or an unwanted delayed trip, the Birnbaum importance indices are 932 MW and 500 MW, respectively. On the contrary, the lowest Birnbaum index is the one related to unwanted immediate load shedding of the undervoltage load shedding relay of load 13 at 0.84 pu: it is equal to -213 MW (i.e. an unwanted load shedding decreases the risk).

## 6. CONCLUSIONS

We showed in this paper that fast cascades leading to blackout or major system disturbances are entirely driven by electrical transients and the action of protection systems. The possible erroneous operations of protection systems can strongly influence the sequence of events. It is then important to consider them in any PRA of the fast cascade. We discussed the qualities and drawbacks of several numerical schemes for the application of dynamic PRA to fast cascades. We applied a pure MC simulation to a test system. This application shows that, even if a blackout is avoided when all protection systems work perfectly, a blackout can occur for specific sets of erroneous operations of protection systems. It reinforces thus the idea that the consideration of these erroneous operations is necessary. However, the pure MC simulation does not seem to be the most efficient techniques. Other techniques, such as MC-DET should be developed, applied, and compared with the pure MC simulation.

These results motivate also the need to study more in depth the possible erroneous operation modes of protection systems and the collection of statistics to estimate accurately the stochastic parameters.

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