



## PS1 – S1-01



### Protection Security Assessment Using Automated Fingerprint Analysis

Johann JAEGER<sup>1</sup>, Chris O. HEYDE<sup>2</sup>, Rainer KREBS<sup>2</sup>  
Friedrich-Alexander University Erlangen-Nuremberg<sup>1</sup>, Siemens AG<sup>2</sup>  
Germany  
[chris.heyde@siemens.com](mailto:chris.heyde@siemens.com)

#### KEYWORDS

Protection security assessment, blackout prevention, protection coordination, holistic simulation, routinely contingency check, finger print analysis.

#### ABSTRACT

Protection security assessment of power grids becomes an important task in the course of a competitive energy business and a decarbonized power generation. The analysis of past blackouts studied by the North American Electric reliability Council (NERC) shows that protection relays are involved in about 75% of all major disturbances. One reason for that is the non adequate adaption of the protection systems to the changing network conditions. In particular the relay hidden failures causes relay malfunctions and blackouts in the past.

This paper is presenting a new automated method for blackout prevention. It analyzes and assesses the security of protection systems of networks as a whole. Routinely checks of contingency sequences are carried out and reveal bottlenecks of the protection behavior itself and of the coordination of network and protection. The numerical simulation tool PSS<sup>®</sup>SINCAL is used providing the possibility of a holistic simulation of network and protection behavior on a fully automated manner. The handling of the big amount of resulting data is done by an intelligent visualization method like a “finger print” analysis.

#### 1 INTRODUCTION

The complexity of power systems is increasing worldwide because of permanent network extensions and ongoing interconnections. The introduction of a competitive energy business and a decarbonized power generation is enforcing this development. The infeeds of distributed and renewable generation is requiring an increased transmission capacity and stability requirements in power systems. An important factor for blackout prevention is a regular review of the protection tripping behavior itself and of the protection coordination concept. In the field of transmission networks, protection coordination is developing more and more towards a task of handling nationwide power systems under continuous change and with numerous protection devices preferably graded by software tools. The aim of the presented method is to provide an automated protection security assessment system. It is analyzing the protection system of a whole network and is based on the network simulation tool PSS<sup>®</sup>SINCAL [6]. The simulation of routinely sequences of fault and contingency scenarios reveal bottlenecks due to the selectivity of the protection system and can discover relay hidden failure in particular. Based on the identification of bottlenecks adapted settings can be derived improving the protection behavior under the changing network conditions. This leads to an important enhancement of the protection and network security of today's and future power grids consequently.

## 2 METHOD OF INVESTIGATION

### 2.1 SC-Fault Simulation

The principle structure of the method of investigation is shown in Fig. 1. The procedure starts with the short-circuit (SC) fault simulation. Different kind of faults and different amounts of fault impedances may be considered. With use of the automatic control of the applied simulation tool, it is possible to simulate different network and fault scenarios without making any time-consuming manual changes. In this way the tripping behavior of the protection devices in case of SC-faults is checked. The fault location is moving through the whole network in steps of e.g. 5% of the line length. The simulation tool calculates the reaction of all considered protection devices during all simulated SC-faults.

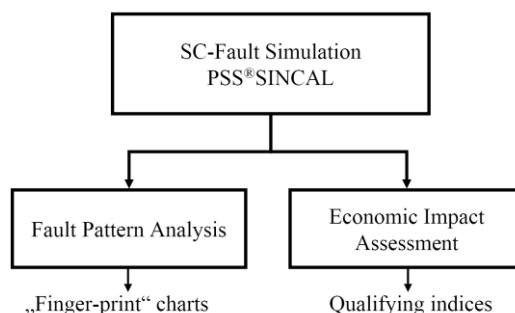


**Fig. 1:** Principle structure of method of investigation

The whole data will be recorded by a data bank system which includes the network and protection input data as well as the whole resulting data. Further on line outages, line overloading, system separations or other customized contingencies can be simulated revealing hidden failures [1,2].

### 2.2 Fault Pattern Analysis

A general evaluation method of protection system behavior is given by the terms of Fig. 2. Following definitions are stated:

- |               |                                                                                                                                                   |
|---------------|---------------------------------------------------------------------------------------------------------------------------------------------------|
| Dependability | – The probability that a protection system will trip circuit breakers when it is required.                                                        |
| Security      | – The probability that a protection system will not trip circuits breaker when it is not required to do so.                                       |
| Reliability   | – The probability a protection system will operate with the required performance. This parameter includes the aspects dependability and security. |

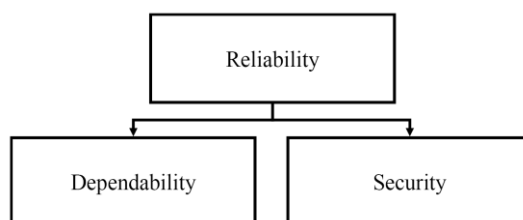


**Fig. 2:**General structure of protection behavior evaluation

The fault pattern analysis is based on this structure. The evaluation algorithms are focused to discriminate a violation of dependability and security. Dependability can also be described by the condition of “underfunction” and the security by the condition of “overfunction” of protection systems. This information will be completed by the tripping times of all SC-faults.

These informations enable a typification of fault patterns regarding their relation between relay malfunction and network configuration. For example in a analyzed network a typical network conditions as a parallel line configurations with mutual coupling producing frequently a violation of the security parameter. This would be a typical fault pattern found out. Based on that an adaption of protection settings could improve the situation.

The illustration of the fault pattern analysis is done by so called “finger-print” diagrams. Fig. 3 is shown a diagram of protection tripping times.

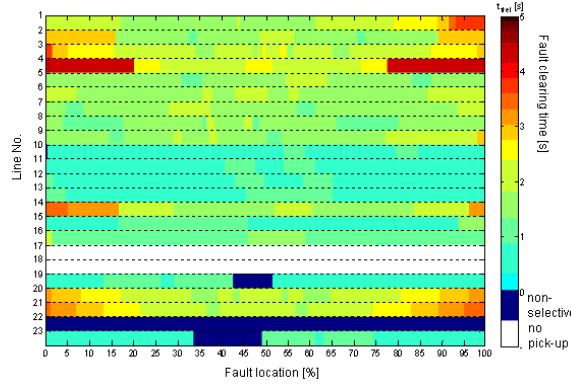


**Fig. 3:** “Finger-print” diagram of protection tripping times

On the x-axis the fault locations and on y-axis the lines are depicted. The amount of tripping time is characterized by the color which is given by the scaling on the right hand side of Fig. 3. Additionally the violation of the dependability (white color) and security (dark blue color) is given.

### 2.3 Economic Impact Assessment

The economic impact assessment is the second path of the method of investigation in Fig. 1. It should estimate the damage of equipment caused by extended fault durations and monetary losses caused by unintentional outages due to relay misoperations. The estimated costs can be used for economic assessments of necessary investments in further protection setting studies, upgraded protection equipment or maintenance schedules. The outage cost assessment methods are generally divided into three approaches, that is, macroscopic, microscopic and analytical [3]. The macroscopic approach attempts to relate the outage costs to a national level by estimating the total cost of outage over a annual period of time. It is difficult to accurately assess the value of unserved energy for every customer due to a large amount of data. Thus as a first macroscopic approach the Gross National Product (GNP) estimation is proposed. The outage costs per kWh can be calculated as follows:

$$\text{outage cost (\$/kWh)} = \frac{\text{GNP (\$)}}{\text{TotalEnergyConsumption(kWh)}} \quad (1)$$

The calculated outage cost represents the ratio of the served energy and the economic value that is derived from the served energy. Estimated values of interruption costs for individual customers are different, depending on the types of customer sector, such as residential, agricultural, industrial or commercial. Relatively, residential and agricultural sectors have lower outage costs, while industrial and commercial sectors have higher outage costs. It was reported in [4] that estimated outage costs for residential, agricultural, industrial and commercial sectors due to a temporary outage are \$4,05/kWh, \$3,53/kWh, \$6.78/kWh and \$39,69/kWh respectively. Although the macroscopic approach does not provide the exact annual outage costs, it is easier to evaluate this as using the microscopic or analytical approach which are based on a big data collection and further assumptions which includes further uncertainties.

The amount of unintentional non-served loads can be quantified as a qualifying index e.g. by the degree of selectivity. It will be calculated for each fault location as the ratio of the load which is served after the real protection trippings to the load which should be served in the case of 100% selectivity. The degree of selectivity is 1, if the fault could be cleared fully selectively. Unselective cleared faults lead to a qualifying index less than 1.

## 3 EXAMPLE CASES

### 3.1 Nationwide Transmission System

The analysis was performed on basis of a real existing 400/230-kV transmission system. It comprises an installed power of 60 GVA, 650 lines and 900 transformers. The number of distance and overcurrent protection devices refers to around 10 000. The main challenges of this study was the big

dimension of network and high number of relays of different manufacturers, mixture of short and long lines, high number of zero-sequence mutual line couplings, large coupling transformers and the significant impact of line loading on distance zone settings.

For the new lines, not yet equipped with protection relays, one set of distance and earth-fault protection was added. The characteristics of the numerical multifunction relays 7SA522 and 7SA6 (SIEMENS) were used for this purpose [5].

The study included all short-circuit protection functions which need mutual coordination. The following test sequences were run:

1. Test of distance protection stand alone
2. Test of earth fault overcurrent protection stand alone
3. Test with all protection devices (Functions 21, 21N, 50/51/67 and 50N/51N/67N)

The first two test series were performed in advance to study the protection functions independent of each other. The third test included the complete range of protection functions according to the collected data from the network.

The analysis of the simulation results according to the proposed method and a corresponding protection re-coordination in case of revealed bottlenecks has led to an improvement of the protection performance in the usual case of low resistance faults. This indicates that the distance protection, which operates in the normal fault case, is now much better coordinated with the proposed new settings. Fig. 4 shows two “finger-print” diagrams of one dedicated region of our studied network accordingly.

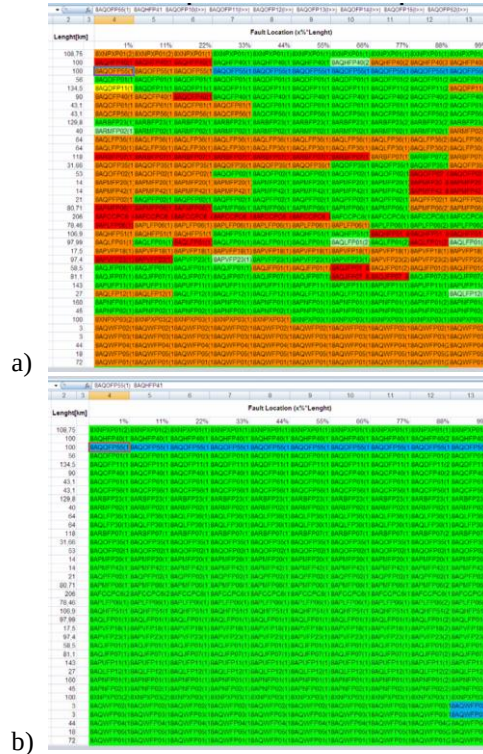


**Fig. 4:** “Fingerprint” diagram of 3-ph-faults  
a) Initial status of protection systems  
b) Exemplary protection behavior after recoordination

The violation of the protection dependability and security is illustrated by different colors. Green color means fully selective fault clearing. Fig. 4a) represents the initial status of the analysis and Fig. 4b) the status of the re-coordinated protection system. In this case a fully improvement without any bottlenecks could be achieved. In other cases of network regions only a partly improvement could be achieved which was the majority of cases.

Further results are stated as follows. It has however to be considered that the selective tripping in at least the second zone was the test criterion. The lines where zone overreach occurs are

characterized in the result sheets by corresponding marked protection false operations. These are the lines where teleprotection is an absolute precondition for selective fault clearance.

When lines are switched off or power plants are out of service, the zone reducing effect of the intermediate infeeds at substations is reduced and consequently the zone reach extended. This results in a higher probability of second zone overlapping and false tripping. This is the reason why all lines should be equipped with teleprotection to ensure 100% non-delayed fault clearance.

The check procedure followed the agreed methodology test routines were developed and used to process the high amount of data. In this way, a great number of statistical diagrams and tables were produced which allow a comprehensive overview over the installed protection systems.

Only a good quality of collected data allowed plausible results for relay schemes and their settings. The detection of non-sufficiently set protection devices was realized due to dedicated macros for plausibility checks.

The performed protection evaluation gives a good overview over the installed protection systems and their setting. From the produced statistics we can see, how many relays do not meet the performance requirements or deviate from practical setting rules. The new coordinated protection settings were automatically generated by the macros according to the defined rules. It was then possible to simulate and test the protection with the old, the new settings.

About 500.000 faults were automatically simulated with the simulation system and the reaction of the protection relays monitored and stored. Decisive improvements have been achieved in the selective clearance of faults. However, a number of faults remain where the coordination of settings alone is not sufficient but teleprotection is needed to ensure selective fault clearance. The results of the simulation indicate the physical or technical problems individually for each concerned line, so that the network operator can plan and realize suitable measures.

### 3.2 Distribution System with DG-Infeeds

The following analysis is based on an existing 20-kV-distribution network with limited earth-fault current by means of a low impedance star-point earthing ( $I_{1p} \leq 2 \text{ kA}$ ). The configuration is depicted in Fig. 5. The network operates normally in an open-ring structure equivalent to a radial configuration. The main infeed is established from the 110-kV-subtransmission voltage level. The 20-kV-distribution network consists of 14 cable feeders A to N equipped with 14 distance relays (21). The distance relays 21A and 21I are followed by the overcurrent relays 51A and 51I. The feeder lengths are between 2.1 km and 14.6 km. The impedance data refer to  $R' = 0.17..0.38 \Omega/\text{km}$  and  $X' = 0.12 \Omega/\text{km}$

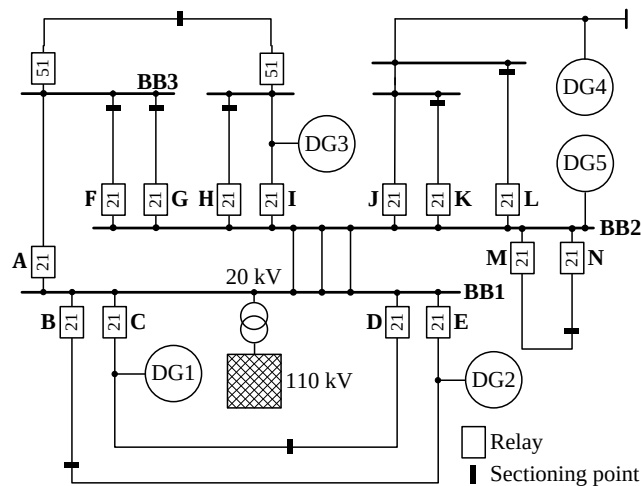


Fig. 5: 20-kV-distribution network with DG infeeds

The distance protection relays pick-up by means of the under-impedance starting facility as common in such networks. The low-set current threshold is  $I > 0.67 \cdot I_n$ . General pick-up is set above  $I >> 2.33 \cdot I_n$ . For phase-to-phase faults a voltage drop down to 70% of  $U_n$  leads to a sensitive pick-up between  $0.67 \dots 2.33 \cdot I_n$ . The undirectional pick-up delay time for tripping is 400 ms. Only the underreaching tripping zone 1 with a time delay of 50 ms is activated. It covers between 10% and

100% of the feeder length depending on the consumer stations along the feeder. The rest of the feeder is protected by the undirectional starter facility. Both overcurrent relays 51A and 51I have only activated one definite time stage as  $I > 2.33 \cdot I_n$  and  $t > 100$  ms undirectional.

Five distributed generator (DG) are infeeding. Their point of common coupling (PCC) is along the feeders DG1 to DG4 and the busbar BB2 (DG5) respectively. They comply with the distribution code of the distribution network operator (DNO). Their most important data can be seen in Table I. Unless otherwise noted they are synchronous machines.

|     | Generation unit |           | Generator transformer |           |
|-----|-----------------|-----------|-----------------------|-----------|
|     | $S_{nDG}$ [MVA] | $x''$ [%] | $S_{nT}$ [MVA]        | $u_k$ [%] |
| DG1 | 5.0             | 18.5      | 6.3                   | 7.0       |
| DG2 | 8.0             | 18.5      | 10.0                  | 7.0       |
| DG3 | 8.0             | 18.5      | 10.0                  | 10.0      |
| DG4 | 2.4             | 18.5      | 2.5                   | 6.0       |
| DG5 | 4.0             | 18.5      | 5.0                   | 7.0       |

**Table 1:** Data of the DG units: Nominal power  $S$ , sub-transient reactance  $x''$  and impedance voltage  $u_k$

The considered interconnection protection functions of the DG units are:

- Undervoltage (27) –  $U < 0.45 \cdot U_n$ ,  $t(U <) = 300$  ms  
 $U < 0.8 \cdot U_n$ ,  $t(U <) = 1.5 \dots 2.7$  s
- Frequency (81) –  $f > 51.5$  Hz,  $t(f >) = 100$  ms  
 $f < 47.5$  Hz,  $t(f <) = 100$  ms

An overcurrent protection function protects the DG system (e.g. the cable from the PCC to the generator transformer). For all DG units it is possible to discriminate faults in the distribution network from faults in the DG system by current, activating the instantaneous high-set element and the delayed low-set element ( $t(I >) = 400$  ms). Faults in the DG system are cleared instantaneous whereas for faults in the distribution network tripping is delayed.

In the followings results of the proposed method for SC-faulted network conditions are presented.

The analyses in the steady state domain are done by the simulation software PSS<sup>®</sup>SINCAL. The “Running fault method” from [7] uses automatic batch routines of the simulation software to simulate different fault scenarios, i.e. different fault locations, without making any time-consuming manual changes in the database of the simulation software. Here the behavior of the system protection is routinely tested by the variation of the fault location through the entire network, e.g. in steps of 5% of the corresponding feeder length. In this way the fault runs effectively through the whole network. The simulation software calculates the response of all protection devices for each fault location. From this amount of data two meaningful characteristics are filtered identifying the reliability of the system protection:

- The clearing time of the system protection for each fault location (protection functions of the DG units are excluded).
- The degree of selectivity for each fault location as the ratio of the load which is served after the real protection trippings to the load which should be served in the case of 100% selectivity. The degree of selectivity is 1, if the fault could be cleared fully selectively. Unselective cleared faults lead to a qualifying index less than 1.

Fig. 6a shows the results of the clearing time without any DG units connected to the network. Each row corresponds to a protection zone. The x-axis corresponds to the fault location. The clearing time (and the degree of selectivity) is color-coded. For example row 1 corresponds to the protection zone of relay 21A, i.e. feeder A from busbar BB1 to BB3. Row 2 corresponds to the protection zone of relay 51A, i.e. feeder A from busbar BB3 to the end of the feeder. Moving along the x-axis to 50% zone length one can read the clearing time via the color-bar for a 3ph-fault at the middle of the protection zone.

The end of each underreaching zone can be identified definitely as the change of the clearing time from 50 ms (dark) to 400 ms (light). In the case of DG units connected (Fig. 6b) it can be found that the first zone of relay 21I is shortened compared to the case without DG units (Fig. 6 encircled).

This is due to intermediate infeeds. An infeed between the relay and the fault location influences the measured impedance  $Z_{Rel}$  and causes a measuring error  $\Delta Z$ . The measuring error is proportional to the ratio of current of the intermediate infeed  $I_{DG}$  and the current at the relay location  $I_{Rel}$ .

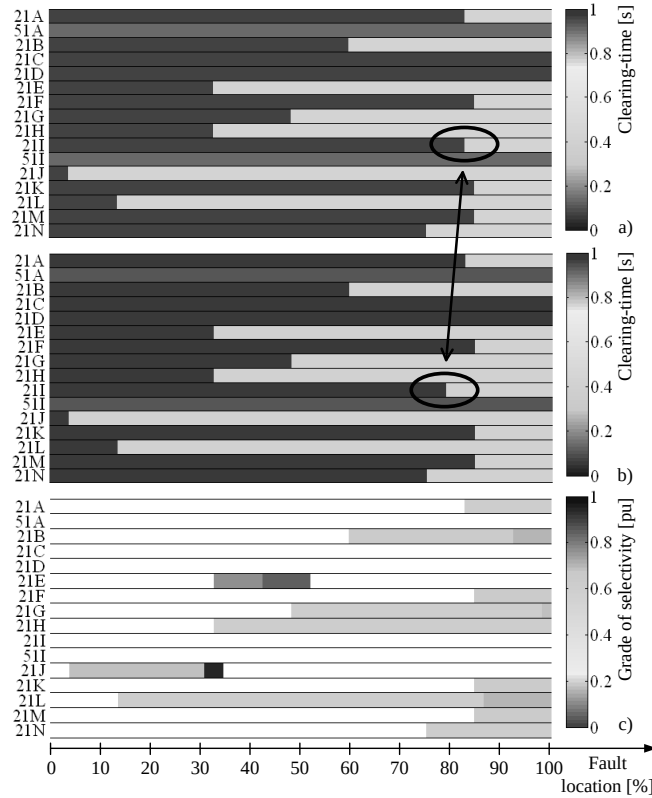


**Fig. 6:** "Finger-prints" of 3ph-faults (top-down)

- a) Clearing-time of the system protection without DG units
- b) Clearing-time with all DG units connected
- c) Degree of selectivity of the system protection with all DG units connected

Regarding the degree of selectivity followings can be stated. Without any DG units connected to the network the trippings were selective. The associated chart is not given; it would be just black colored. But it is not in the case of all DG units connected (refer to Fig. 6c). Here the degree of selectivity is down to 60% (e.g. protection zone 21H) if the fault is behind the end of the first zones where the unidirectional starter facilities trip. That is down to 60% of the load which should be served, if the fault clearing is 100% selective, cannot be served. Relays with DG units along the course of their protection zones lost security due to sympathetic tripping because the short-circuit current contribution of the DG units starts the corresponding unidirectional starter facilities. Based on that the corresponding outage costs can be calculated with an assumed outage period e.g. 1h accordingly.

#### 4 CONCLUSION

A new method of analysis and assessment of protection systems is proposed. It could be shown that the protection security can be improved by a software automated method. This can be applied to nationwide transmission systems as well as distribution systems with DG infeeds in particular. Different concepts can be checked using only one simulation setup.

The evaluation gives rather reliable results based on real network data. An appropriate visualisation method has been developed to illustrate the enormous amount of output data clearly arranged for further investigations. Based on these visualisation diagrams, practical constraints of protection coordination concepts can be easily detected and systematic solutions can be proposed. In this way a protection coordination concept can be evaluated properly and the procedure as well as the

existing constraints can be documented understandably. This is properly supporting the protection security assessment in today's and future power grids.

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