Methodology of risk assessment and decomposition in power grid applications

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Abstract: The most common approach to risk assessment for power systems is based on the N − 1 principle. Nevertheless, the economic rationale suggests its relaxation in cases where the consequences are relatively minor and exacerbation when they are large. This study addresses this need by proposing an alternative operational risk assessment methodology that is based on both probabilities and costs of possible contingencies. The foundations are built on listing all possible contingencies that may be considered by the transmission system operator (TSO). As only a subset of these contingencies can be examined in reasonable time, the upper and lower risk boundaries are introduced to quantify the risk underestimation. The ratio of those limits is used as an accuracy indicator, which – according to the desired level – may help the TSO to identify the required number of contingencies that have to be analysed. Furthermore, several approaches to improve the reduction of the number of simulated contingencies are discussed and the results obtained basing on the dynamic IEEE39 model are presented.

1 Introduction

1.1 Background

The power grid can work within a variety of states among which some are safer than others [1, 2]. The risk assessment of a given state is usually a difficult task as both probability of the contingency and costs of its consequences are hard to quantify. As a result, the popular risk management methods are related to fulfilling of the wide-known N − 1 principle. The N − 1 principle [3, 4] states that after any contingency related to a loss of a single element: (i) the operational conditions must not lead to triggering an uncontrollable cascading outage propagation and (ii) all values of currents and voltages remain within their safety limits. Nowadays, power systems are subject to many changes which increase the number of unpredictable events. Wind and photovoltaic generation is growing rapidly, demand side response occurs, the system can shift from its normal state to an alert state [1] with the parameters within safety limits, however if it is not resistant to at least one of possible further contingencies, the N − 1 principle is violated. The TSO has a certain period of time in which remedial actions have to be taken to restore the compliance with the N − 1 principle. However, with the risk assessment based on binary measures (alike the N − 1 principle) or qualitative severity indexes, there is little or no information on the cost resulting from the consequences of considered failures and no cost-based incentives for remedial actions that have to be taken. More importantly, the safety provided by fulfilling the static N − 1 principle may often be illusory, as this approach does not take into account dynamic phenomena related to rotor angle, voltage or frequency stability. On the other hand, dynamic models of power systems allow simulating the consequences of events comprehensively, due to including the actions of the primary and secondary control, protection relays, load shedding and so on. Therefore, it seems that continuous risk measures based on time-domain simulations (TDS) should extend the binary criterion based on the static N − 1 principle.

1.2 Literature review

Within the vast variety of accessible risk estimation techniques, some are based on Monte Carlo (MC) simulations, where the set of contingencies to be analysed is not necessarily predefined. On the other hand, the analytical methods are intrinsically connected to a known closed contingencies set. Approaches based on MC were proposed by Kirschen et al. [3, 5–7] who introduced security indexes related to voltage instability, overload severity and cascading severity. For example, the MC methodology is enhanced to take into account time-dependent phenomena such as cascade tripping of elements due to overloads, malfunction of the protection system and potential power system instabilities [3]. The aspect of security of supply measured using expected energy not served (EENS) and based on static MC simulations is also presented in [8], where Jayaweera et al. suggested that the security of supply can be significantly affected by changes in weather patterns and that it should be reflected in risk derivation. Vrakopoulou et al. [9] introduced constraints (complementary to the N − 1 one) dependent on weather conditions. This MC-based group of methods is extremely time consuming as many runs of simulations are required. Hence, their applicability in short-term or real-time horizons is limited, however they may be of practical use for assessing the risk in mid- and long-term horizons, e.g. in the analysis of generation adequacy. On the contrary, the group based on analytical methodologies, due to their computational performance, is suitable for real-time as well as short-term calculations that are of our main interest. McCalley et al. [10] tackled the problem of the risk related to transient and oscillatory instabilities in the grid. Furthermore, Lebrevelec et al. [11] analysed the French network and took joint aspects of cost and security into account, whilst Wan et al. [12] paid attention to voltage security issues in risk assessment. In [13], Dissanyaka et al. calculated the critical clearing time (CCT) – the system is considered as safe if the actual fault clearing time is shorter than the CCT. Different approach was presented by Wang et al. in [14], where incorporating risk cost in the OPF objective function was considered. The risk index comprised probability and the severity factor, with the latter based on the difference between the actual and the maximal current flows over the branches. Datta and Vittal [15] introduced a risk measure similar to the one presented in this paper. They showed that introducing wind generation strengths...
the system as operating points of conventional generators are decreased. As a result, CCTs are larger and conventional generators are more robust against short circuits.

1.3 Approach

In all analytical methodologies, only a subset of contingencies is analysed. In some cases, the choice of the most relevant ones is made basing strictly on expert knowledge, while in others the contingency list includes single or double faults. However, a predefined set of contingencies, as long as it does not cover all possible fault combinations, does not constitute a complete probability space. In a strict sense, this leads to an incorrect probability measure – the resulting risk is permanently underestimated and may vary significantly if the predefined set is modified. Therefore, the aim of this paper is not only to provide another competitive methodology of risk estimation but rather to assess how significantly these indexes are underestimated and how to assess their accuracy. What is more, the proposed extension is general and applies to all indexes that could represent costs of contingencies, as far as it is possible to estimate the upper boundary of such costs.

The strength of the approach is that we do not need to know neither the list of all possible contingencies nor their costs and probabilities directly. This results from the fact that all of them, except those few that are examined in detail, can be treated as one aggregated contingency. Its probability, due to the assumption on completeness of the probability space, is intrinsically connected with the probabilities of the examined subset and hence, only the probabilities and costs for this subset have to be known exactly.

This paper is organised as follows. In Section 2, we show its theoretical foundations using the standard approach based on EENS, transformed into economical terms using the value of lost load (VoLL). Furthermore, several approaches to diminish the complexity of the calculations are discussed. The example is based on the IEEE39 power system model (Section 3), where for the sake of simplicity, the set of all contingencies was limited only to include transmission lines contingencies, namely the three-phase short circuits that are weather dependent. However, the weather is not the only factor that is reflected in probability. Finally, Section 4 summarises all the accomplishments and states the directions for further development.

2 Theoretical framework

2.1 Risk definition

Let us define a set $S^{\text{cont}}$ including all kinds of contingencies that may be experienced by the TSO – the so-called credible contingencies [16]. They can include one, two or more faults that can happen independently, which means that they are not considered as related to a cascading effect, but as resulting from external conditions as bad weather. A cascading effect is considered as a potential consequence of a contingency – an explanation with a $N-3$ contingency follows. Let us consider three independent faults that occur in various moments $t_1, t_2, t_3$ and result in two additional events in $t_4$ and $t_5$, including actions of protection relays, load shedding and so on. According to the aforementioned approach, only the latter two are the consequences of that contingency (defined by the first three) and hence, only those two may be used to calculate the cost related to that contingency.

In order to proceed further, we take the classical approach to risk management and define the risk measure $R(T)$ as an expected cost of all contingencies from $S^{\text{cont}}$ that can happen during $T$.

$$R(T) = \sum_{s \in S^{\text{cont}}} P(s)C(s),$$

(1)

where $P(s)$ is the probability that the considered contingency $s$ will occur. The cost $C(s)$ reflects all events that occurred due to the considered contingency, up to the moment $T$. The usual approach is to set $T$ long enough, to allow achieving a new steady state (even if the consequences of the contingency were not repaired).

Considering the example used at the beginning of this section – if after $t_4$ there are no more events and if the steady state is reached, the consequences may be analysed and their cost may be calculated. Depending on the system, this cost is expected to be non-zero for a subset of contingencies and, in general, may reflect the costs of lost demand, redispatch and restoration as well as the social and political costs.

In this paper, the attention is paid only to the cost expressing the lost demand. Furthermore, in order to calculate such a cost a conservative assumption is made – if the contingency consists of multiple faults, we calculate its cost basing on one simulation – with all faults taking place at the same time $t = 0$. Hence, to obtain the cost of the $N-3$ contingency from the example considered above, all the faults are treated as if they started at the beginning of a TDS, which means that $t_1 = t_2 = t_3 = 0$. This simplification was chosen for computational purposes, to limit the number of simulations in a way not to overestimate the risk. Considering the fact that the probability of that contingency covers all combinations of faults inception times $0 <= t_1, t_2, t_3 < T$, the case with simultaneous faults was chosen as a representative one, having one of the most severe consequences, especially with respect to transient rotor angle instabilities (e.g. generator trips followed by frequency sags leading to load shedding). Therefore, the cost was obtained directly for the representative case and is expected to be one of the highest when compared with the costs for other fault combinations for that contingency, and in particular much higher than the cost obtained as an average cost for all combinations. The cost calculation process is based on load shedding events collected during the TDS and described by the following expression:

$$C(s) = \text{VoLL} \cdot \int_0^T \text{LostLoad}(t) \, dt,$$

(2)

where \text{LostLoad}(t)$ expresses the load shed (e.g. by an under-frequency or under-voltage protection relay) at a given time $t$ and due to the contingency $s$. \text{VoLL}$ represents the value of lost load that is assumed to be constant for the whole considered system and hence, $C(s)$ represents the cost of unsatisfied energy.

In order to simplify the description, the time $T$ dependency will be skipped in further equations, i.e. $R \equiv R(T)$ and $S^{\text{cont}} \equiv S^{\text{cont}}(T)$ as the attention is paid only to one value of $T$, specified at the beginning of the risk assessment process.

2.2 Risk boundaries

Taking into account all $N$ network elements leads to $2^N$ possible contingencies. This number would be increased if we additionally considered various demand and generation scenarios or if segments of transmission lines were analysed separately. Analysis of such number of combinations is still infeasible due to large computational costs of TDS. Hence, in real cases a true value of $R$ remains unknown, however its upper and lower boundaries may be calculated.

The set $S^{\text{cont}}$ used in the sum in (1) can be split into two subsets $S^{\text{cont}} = S^H \cup S^L$, with $S^L$ representing cases for which TDS have been performed and exact costs have already been calculated. Estimation of risk based only on the first subset is always lower than the real risk value and hence, such estimation constitutes the lower risk boundary $R^L$.

$$R^L = \sum_{s \in S^L} P(s)C(s).$$

(3)

For the $S^H$ subset, TDS are not performed to calculate the cost exactly, e.g. due to computational expenses or time limitations, albeit an overestimated value of the cost related to contingencies in that subset may be found. Although various approaches could be used for that purpose, here a conservative one is considered. It is based on accounting all contingencies from $S^L$ as leading to the maximal value $c^B$, expressing the cost of total blackout. However, the maximal value could also reflect other factors like costs of
redispatch, restoration or social and political ones. According to a similar classification [11], the TSO is able to assign a cost lower than the cost of total blackout to the unexamined contingencies. Therefore, we consider as follows.

The iterative process of extending the set $S^L$, in order to reach the expected accuracy $a_{\text{TSO}}$ (as presented in Fig. 3), may be performed in various ways. First, the extension could be performed by adding one or several contingencies in each iteration, and secondly – the order of adding contingencies could be random, based on their probability or another classification.

The example presented below utilises groups of $N-k$ contingencies, starting with $k=1$ and increasing it in next iterations. Such approach was based on the assumption that TSOs’ experience is influenced by the $N-1$ criterion referring to transmission lines, which were considered in this risk assessment approach as well. Therefore, $S^H$ was decomposed into subsets of independent line failures which contain different contingencies, namely $N-1, N-2, N-3, \ldots, N-k$, and hence, the sum in (1) was rewritten as follows:

$$R = R^L + C^H \sum_{s \in S^H} p(s),$$

and thus the desired inequality holds: $R^L \leq R \leq R^H$.

The sum on the right-hand side of (4) is taken over all the elements in $S^H$, which may include up to $2^N$ of possible contingencies. Identifying probabilities for each of them may be found cumbersome, especially for large power systems. Therefore, specific methodology and assumptions need to be chosen by the operator basing on the available statistical models and historical data. However, the proposed method is independent of the probability values that could in general differ significantly from one contingency to another. Having the probabilities for $s \in S^L$ already estimated, the ones for all $s \in S^H$ may be calculated using (5), which establishes a fast way for implementing the $R^H$ calculations (the set of contingencies is expected to be based on TSOs expert knowledge and hence it is assumed that $P(S^L \cup S^H) \approx 1$).

$$\sum_{s \in S^H} p(s) = 1 - \sum_{s \in S^L} p(s).$$

Furthermore, as it is depicted in Fig. 1, gradual, e.g. iterative, increasing the size of $S^L$ is expected to decrease the difference between $R^L$ and $R^H$ and hence the risk uncertainty.

The ratio of lower and upper boundaries in (3) and (4) may be used to define the risk accuracy $a = R^L/R^H$. Its main properties are as follows.

i. The higher the difference between $C^H$ value and the expected value of the cost of the contingencies from $S^L$, the lower the accuracy.

ii. Increasing the number of contingencies in $S^L$ (additionally decreasing the one in $S^H$), results in an increase of the accuracy $a$.

As a consequence of the first property, the overestimation of $C^H$ should be as low as possible to achieve higher accuracies for the same set of $S^L$. On the other hand, the second property may be used in an iterative procedure of calculating the risk, which would stop after reaching the accuracy level accepted by the TSO, denoted as $a_{\text{TSO}}$. Such an iterative procedure of reaching $a_{\text{TSO}}$ is depicted in Fig. 2, whereas the scheme of the whole process including the $S^L$ subset extension is shown in Fig. 3. Once the TSOs accuracy limit $a_{\text{TSO}}$ is known, the first set of contingencies $S^L$ has to be prepared. Some of the vast number of methods of decomposing $S^H$ into $S^L$ and $S^H$ are discussed in Section 2.3. Establishing the set $S^L$ allows us to perform TDS for each of its contingencies, whereas including their probabilities, e.g. obtained with the help of an external model including weather forecast, allows us to calculate the risk $R$, its boundaries $R^L$, $R^H$ and accuracy $a$.

### 2.3 Risk decomposition

The iterative process of extending the set $S^L$ with elements from $S^H$, in order to reach the expected accuracy $a_{\text{TSO}}$ (as presented in Fig. 3), may be performed in various ways. First, the extension could be performed by adding one or several contingencies in each iteration, and secondly – the order of adding contingencies could be random, based on their probability or another classification.

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\[
R = \frac{P(s_C^1)(s_C^2) + P(s_L^1)C(s_L^2) + \ldots + P(s_L^n)C(s_L^1)}{R F_i} + \frac{P(s_L^1)C(s_L^2) + \ldots + P(s_L^n)C(s_L^1)}{R F_i} + \ldots + \frac{P(s_L^1)C(s_L^2) + \ldots + P(s_L^n)C(s_L^1)}{R F_i},
\]

(6)

The underlined components in (6) represent the contribution \( RF_i \) of the lack of contingencies \((k = 0)\) and the cases with \( N - k (k > 0) \) contingencies, to the total risk \( R \). Probabilities for each \( RF_i \) in the sum from (6) are obtained with those describing the behaviour of single lines failures, independently. For line \( L_i \), the probability of being subject to an independent fault is equal to \( P^i \), and the one of remaining in operation, equal to \( 1 - P^i \). Therefore, the probability \( P(s) \) of contingency \( s \) may be expressed as a product of probabilities for single independent lines:

- for a single \((k = 1)\) contingency

\[
P(s^1) = P^i \prod_{j \neq i} (1 - P^j),
\]

(7)

- for a \( k \) = 2 contingency

\[
P(s^2) = P^i P^j \prod_{n \neq i, j} (1 - P^n),
\]

(8)

Coming back to the scheme from Fig. 3, in order to proceed with the depicted iterative risk reduction process, all \( N - 1 \) contingencies are incorporated into the initial subset \( S^1 \). If the desired accuracy is not achieved after the first iteration, \( S^i \) is extended with \( N - 2 \) and \( N - 3 \) in next iterations and so on. However, the number of simulations required for risk assessment may quickly increase above computational capabilities. Therefore, some of the following simplifications could be introduced to speed up the calculation process.

i. Analysis of short circuits in nodes instead of branches: The TDS are usually based on contingencies related to short circuits in branches. Instead, the ones in buses could be examined first. If no cost is obtained for both buses adjacent to a line, the short circuit in that line are very likely to have no cost as well. The procedure could be as follows:

(a) Examine short circuits in all buses.
(b) Identify buses characterised by non-zero costs.
(c) Examine short circuits only in lines adjacent to identified buses.

ii. Analysis of the border positions of the branch instead of many: For the purpose of a more detailed analysis, the consequences of short circuits in various locations of a given line are analysed. In order to simplify the procedure, locations closest to the nodes (0.1 and 99.9% location) may be checked as the first. Hence, if the cost of short circuits in the borders of the branch is zero, no further simulations are necessary and the cost equal to zero may be assigned to other locations on that line as well.

iii. Obtaining an average cost for a given \( RF_i \): The estimation can be obtained by simulating only a subset of contingencies that incorporate \( N - k \) faults. The number of elements that assures an acceptable level of confidence can be identified using the statistical inference theory.

iv. Splitting a given \( RF_i \) into two parts: One part is calculated exactly, e.g. in the area where the weather is severe and another one is based on average costs.

3 Example of IEEE39 system

In this section, the methodology explained in the previous section is illustrated with an example. The selected system is the well-known standard IEEE39 case. In order to simplify the example, the risk assessment implementation has been focused only on failures of transmission lines. According to [17], short circuits in these elements are the main reason of outages in the transmission system.

3.1 Model

The IEEE39 case includes ten synchronous generators with the total generation of 6191 MW. The generator G1 which is located in node 39 represents the interconnection with a larger power system, while the rest of generators represent real units. The power demand is equal to 6150 MW, and the spinning reserve is 1791 MW. In the analysis, the Matpower IEEE39 power flow model was used.

For the purposes of our research and development of the IEEE39 dynamic model, the G1 PSLF software was used. The model includes: the sixth-order models of round-rotor machines (genrou), the excitation circuits (sexc) and the power system stabilisers (pss2a), with their parameters taken from [18].

In order to model the primary control, a prime mover models of steam turbines (ieeeg1) were introduced, with the data coming from a typical thermal generation unit in the Polish power system. Subsequently, the secondary control components, namely the agc2 and uclp2 models, were included in our IEEE39 power system. Parameters for the agc2 and uclp2 models were chosen experimentally, allowing us to ensure the appropriate quality of frequency regulation. Moreover, the following models of protection relays were introduced:

- Generator out-of-step relay model (asynchronous operation protection) – the model of impedance protection that reacts to asynchronous power swing (oopsw); a symmetrical lenticular shape (formed by two circles) was chosen for the characteristic of the out-of-step relay, allowing it to switch off a generator-transformer block after detecting asynchronous operation of the generator.
- Line short-circuit relay model – the model of distance relay with lens characteristics, with permissive overreaching transfer trip (zpott), it was assumed that the protection switches the line off 150 ms after the fault occurs in the protected zone.
- Line overload protection – the model of branch overcurrent relay with inverse time characteristic (locti); it was assumed that the protection may switch the line off after a time depending on the degree of the overload.

Finally, the dynamic IEEE39 power system model was equipped with definite time under-frequency automatic load shedding relays that disconnect the portion of bus loads when the frequency drops below the assumed threshold. The lsdt1 load shedding relay model was used, allowing the determination of three stages of load shedding in time, which were identified as events of losing load expressed in (2).

With the model prepared as described above, the TDS were performed in order to calculate the cost of each contingency, basing on the approach from Section 2. The value of lost load – VoLL = 2.66 · 10^7 USD/MWh was used in those calculations.

3.2 Dynamic versus static simulations

The general idea proposed in this paper is to extend the power systems security assessment based on static simulations with TDS based on a dynamic model of the considered power system. Such a methodology allows including a wider range of factors affecting the systems security and improves detecting situations where the \( N - k \) criterion is not met in the dynamic approach, despite the fact that it was fulfilled in the static one (based on classical power flow). This problem is illustrated in the following example of TDS for the IEEE39 model (Fig. 4), where the analysed post-contingent state was obtained by disconnecting the line connecting nodes 28 and 29 (by changing its status from 1 to 0). Afterwards, the power flow equations were solved and the static \( N - 1 \) criterion was checked – the loads of other branches in the post-contingent network were compared with those from the pre-contingent one, representing the steady, normal state of the IEEE39 system. Special
attention was paid to the 21-22 line – it was found that its load was not affected by the disconnection of the 28-29 line and remained equal to 97% of its rating in both pre- and post-contingent states. Other branches of the system were not overloaded as well, therefore basing on this static $N-1$ analysis, it was concluded that the IEEE39 test system remained in secure operation, despite disconnecting the 28-29 line.

Second, the $N-1$ state was initiated within TDS – by introducing a metallic three-phase short circuit in the half-length of the 28-29 line. Although this short circuit was cleared by the lines distance protection (zdpprt) after 150 ms, it resulted in the loss of synchronism by the generator at bus 38 and tripping it by its out-of-step protection (ooslen), resulting in a loss of 830 MW of produced power. The disturbance of power balance caused the activation of primary and secondary control, leading to an increase of generation in other generators. Afterwards, the power flow changed and the current in the observed line 21-22 exceeded the maximum permissible value (the branches 16-17, 16-19 and 19-33 were also overloaded, but in lesser extent), which resulted in switching the line 21-22 off by its overload protection (locti). This disconnection caused severe power swings that led to a total collapse of the power system. Therefore, in this case the dynamic $N-1$ state analysis was proved to be insecure, opposite to the conclusion made in the static approach.

Since emergency shutdowns of lines usually occur as a result of clearing the faults by system protections (i.e. as in the TDS described above) and not by manual openings of circuit breakers (corresponding to the prior static simulation), actual operating conditions of power systems may be modelled only within TDS. Therefore, results presented in the next section were carried out by using a dynamic model of the IEEE39 power system. It should be noted that due to the configuration of the test system, fulfilling the $N-1$ criterion for some branches is disabled by definition (e.g. line 16-19) – faults of such branches were not included in the analysis.

3.3 Probability estimation – weather influence

In the theoretical approach from Section 2.1, the concept of all possible contingencies was necessary to justify the correctness of upper risk boundary calculations. Here, for the sake of simplicity, we limited the set of all contingencies to transmission lines and assumed that these elements are exposed to only one kind of failures, specifically the three-phase short circuits. The probability of such failures is influenced by many factors, like ageing, human errors and the weather, which was assumed to be the most important one [17].

In real implementations, the weather influence could be provided by an external module that uses weather forecasts and historical data to assess the probabilities of elements faults in hourly resolution. However, for the purpose of this analysis, parameters for the exemplary system were obtained according to historical data from PSE – the Polish TSO [19].

All the aforementioned factors are reflected by those historical values, namely the mean time to repair MTTR and the average frequency of failures $f^i$. Those values are the monthly averages, as those with higher temporal resolution (e.g. daily) are unavailable – therefore $f^i$ cannot represent varying weather conditions. For the purposes of our analysis, two types of weather conditions were considered, specifically the normal and the severe ones, with the first described by $f^i$ expressed by the annual average and the latter – by the annual average increased by 50% [20], which provides an approximation of the severe weather effect, albeit it does not represent the influence of the most severe phenomena as snow, ice, hurricanes and so on. This is due to the fact that such weather conditions rarely happen in an uninterrupted way during the whole month. However, for real applications by the TSO, the daily resolution along with weather forecasts would provide better estimation of the failure rate in severe conditions.

In case of transmission lines, the frequency $f^i$ is given as an average per unit of length, hence the lengths of the lines need to be used to acquire the frequency of failure $f^i$ of a given line $L_i$.

Another way to obtain the probability of failure $P^i$ of the line $L_i$ could be based on the Markov approach [21], where the lines rate of failures $\lambda$ (failures/time) and rate of repair $\mu$ (1/time) are used. However, both approaches are connected by the formula given in the following equation:

$$P^i = \frac{\lambda}{\lambda + \mu} = \text{MTTR} \cdot f^i.$$  
\hspace{1cm} (9)

3.4 Probability and risk decomposition

In real applications, taking into account all possible contingencies is hardly possible, especially in the case of models comprising many elements. Therefore, the set of contingencies $S_{\text{cont}}$ should be limited to TSOs knowledge and reflect the credible contingencies including the most crucial elements of their power system models, e.g. buses, transmission lines, transformers or generators.

Following Section 2.3, the decomposition of $S_{\text{cont}}$ including transmission lines contingencies is made by splitting it into subsets of $N-1, N-2, \ldots, N-N$ contingencies. For the purpose of this paper, the respective probabilities for all considered contingencies were calculated for both – the normal and severe weather conditions. The cumulative values of those probabilities, specifically $P^0, P^1, P^2, P^3$ and $P^4$, are collected in Table 1.

As expected, the probability $P^0 = P(\varnothing)$ of remaining in the current system state (without contingencies) is lower, while the probabilities of contingencies with $k \geq 1$ faults are higher in the severe weather than in the normal case. It may also be seen that the $N-1$ subset constitutes an important factor in both weather scenarios. Probabilities $P^i$ in severe weather conditions are twice as large as in the normal ones and the ratio grows to 4 and 7 for $P^3$ and $P^4$, respectively. However, the contingencies with $k \geq 3$ faults seem to be of minor importance.

Table 1: Probability decomposition

| Probability          | $P^0$, % | $P^1$, % | $P^2$, % | $P^3$, % | $P^4$, % |
|----------------------|----------|----------|----------|----------|----------|
| normal weather       | 94.57    | 5.29     | 0.14     | 0.0020   | 0.00003  |
| severe weather       | 91.96    | 7.72     | 0.31     | 0.0079   | 0.00020  |

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Table 2 Normal weather – risk boundaries results

| Simulation results | $RF_{k,1}$ | $RF_{k,2}$ | $RF_{k,2}$ |
|--------------------|------------|------------|------------|
| $\hat{R}^L[10^2\text{USD}]$ | 38.52      | 16.95      | 16.60      |
| $\hat{R}^H[10^2\text{USD}]$ | 14.89      | 16.55      | 16.59      |
| $a,\%$ | 38.66      | 97.65      | 99.97      |

Table 3 Severe weather – risk boundaries results

| Simulation results | $RF_{k,1}$ | $RF_{k,2}$ | $RF_{k,2}$ |
|--------------------|------------|------------|------------|
| $\hat{R}^L[10^2\text{USD}]$ | 74.08      | 26.71      | 25.57      |
| $\hat{R}^H[10^2\text{USD}]$ | 21.75      | 25.38      | 25.54      |
| $a,\%$ | 29.36      | 95.04      | 99.89      |

4 Conclusions

This paper proposed an approach to estimate the risk index based on the probability and potential costs of contingencies. As the analysis of all possible contingencies allowing the exactness of risk estimation is computationally infeasible, the upper and lower risk boundaries were offered to provide an approximated risk value – bounded from below and above. The accuracy indicator (ranging from 0 to 100%), reflecting the ratio of the lower to the upper boundary, was introduced and included in an iterative algorithm of risk assessment.

In order to illustrate the introduced theoretical approach, the IEEE39 dynamic network was used as an example. The comparison of static and dynamic model was made to show that in the static one the cost can be considerably underestimated. Therefore, it was suggested that for the purposes of risk assessment, the dynamic model and TDS should be used whenever possible. The presented approach was based on iterating over the groups of single, double and triple transmission lines simultaneous faults (three-phase short circuits), and showing the results of the risk decomposition for those groups.

However, due to significant computational burden related to TDS, the proposed method is applicable only in off-line analyses, e.g. for the purpose of short-term planning. In order to meet the criteria of possible on-line applications, e.g. real-time operations, the proposed approach could be coupled with contingency screening methods, based on static analyses or direct (and hybrid) methods of transient stability assessment [22]. The efficiency gain of such coupling, allowing the reduction of the number of long TDS, is the topic of research carried out by the authors.

Moreover, the usage of HPC hardware is strongly recommended to increase the computational efficiency. For the purposes of this paper, one server with 128 GB of RAM and 2 Intel Xeon 2.80 GHz processors, 20 cores each (40 cores in total) was used, allowing to perform parallel TDS and achieving the average around 1.5 s for one TDS of a period of 30 min.

Finally, the impact of different weather conditions (directly affecting the probabilities of lines faults) on risk accuracy was considered. It was shown that under bad weather conditions, factors related to multiple faults are of bigger importance than under good weather conditions.

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