

Use of Performance Indices for Contingency Screening for Rapid Assessment of Dynamic Security Region

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Abstract: This paper proposes a method for screening of contingencies in order to reduce the computational burden of constructing dynamic security regions. The method exploits the results of time-domain simulation to calculate performance indices (PI) for different operating points. The contingencies with less relevant PIs are eliminated as they are encountered in the course of the simulation without changing the boundaries of the security region. The proposed method is tested on a modified New England system and on a Brazilian Power System network, with its actual security regions. The results show that the method is accurate and provides a significant time reduction, making it feasible for real-time operation use.

1. Introduction

The growth of electric power systems and the increase in their complexity has been accompanied by increasing challenges in its operation. This rise in complexity also increases difficulty in the approach of the “security versus cost” dilemma. In real-time operation, a way to approach this dilemma is by using online security assessment tools, which reduce the complexity of the security analysis and allow proper operation without unnecessary increase in costs. The Brazilian ISO, named *Operador Nacional do Sistema Elétrico* (ONS), employs this approach both in the static and dynamic security assessment (DSA) and uses the program known by the commercial name of *Organon* [1]. In the Brazilian case, the dynamic security assessment is done through time-domain simulation (TDS), which is very time-consuming. Thus, efforts have been made to reduce the computation time to a manageable level, such as through contingency screening [2].

Among the several approaches adopted for screening, there are the direct methods whose objective is to classify a dynamic contingency as stable or unstable, such as the one described in [3]. A common problem with this approach lies in the calculation of the critical energy, which may lead to undetermined classification or in the conservativeness of the results. A series of techniques were developed by [3]-[6] to minimize these problems. Another characteristic of the direct methods is that it is not easy to correlate the results and the power system’s condition after the outage.

Another common approach for screening is based on the evaluation of the system behaviour after the contingency with respect to the system operation criteria. This evaluation can be performed by computing one or more performance indices, which are a relative measure of the contingency’s severity to the system [1], [7]. Various indices were studied in the literature, such as the ones related with transient stability [7]-[11], the ones related with frequency behaviour [12]-[15], and the ones related with voltage [16]. Some other works use different strategies involving fuzzy logic [17], risk quantification [18] and regression models [19]. These approaches, while not allowing a direct evaluation of the system’s stability without full TDS, provide good

information about the system’s condition with respect of the operation criteria. Performance index-based approaches have also been used for voltage stability monitoring [20], [21].

The contingency screening as presented in the literature is usually applied for the security analysis of a single or a few operating points (OP), and few works have explored its application to various possible OPs at the neighbourhood of the original OP. In fact, experience with DSA shows that the relevance of a contingency is very sensible to the system’s condition.

This paper aims at combining the contingency screening with the process of evaluating the neighbourhood of a given OP when constructing the Dynamic Security Region (DSR). In other words, instead of repeatedly evaluating the same contingencies throughout the entire process, contingency screening is applied considering the progression of the performance indices (PI) in order to discard the contingencies that will not affect the boundaries of the DSR, and therefore, reduce the computational burden. This paper focuses on angle and frequency stability, specifically the transient stability, with a study period window up to 20 seconds. However, the approach can be expanded to include any condition dependent PI to assess other stability phenomena, such as angular oscillatory stability or voltage stability.

Results are presented for several scenarios of a modified New England network and some actual scenarios of the complete Brazilian Power System Network model, showing that the method allows the reduction in the total time needed to compute the Security Region (SR) while keeping the accuracy of the results.

2. Security Region Assessment

The main objective of security region assessment in power system operation is the maximization of the system security while minimizing the operation cost. The security requirements of the system are normally dealt with as constraints that can be seen as boundaries of the possible OP of the power system [22]. A SR can have two or more dimensions. Each axis of a SR is, usually, a grouping of variables associated with the operation, for example, the total generation of certain power plants. Fig. 1 illustrates a SR

where each axis represents the power dispatch of a generation group in MW. All possible safe OPs lie within the hatched area and the insecure ones lie outside.

The distance between an OP and the security boundary is associated with the system's level of security in the OP. Thus, if the axes of the SR represent the total generation of a group of power plants, then the system operator can redispatch them to increase security.

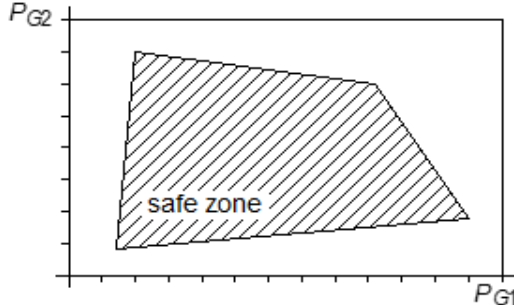


Fig. 1 – Example of a SR.

The necessary steps to obtain the SR so that it can be computed online are discussed in [1] and, briefly, are:

1. Identify the areas to be monitored based on the dispatcher's experience and operating orders from operational planning studies.
2. Identify the contingency list, which can be done by considering every N-1 contingency in the monitored area and other N-k common contingencies.
3. Identify the power plants that should be grouped in Generation Groups, usually done by a sensitivity analysis tool and considering the branches of the contingency list. Power plants with opposite sensitivity are grouped in two different generation groups and a third generation group, composed of the power plants with low influence on these branches, is used to compensate the redispatch of the first two groups.

The ONS employs the software *Organon* in its control rooms and the integration between *Organon* and the ONS' Energy Management System (EMS) allows online dynamic security assessment of the OP and its neighbourhood, which is done as described below:

1. The EMS' state estimator generates a power flow base case, which represents the actual OP, based on the system's real time measurements and modelling.
2. *Organon* reads the base case and runs a time-domain simulation for each contingency in the contingency list to assess the system's security for each of these disturbances.
3. A Continuation Power Flow method is employed by *Organon* to generate a new OP in the neighbourhood of the starting OP. This new OP has different generation dispatch among three generation groups, which can be controlled by the system operator, whereas the system's load remains the same [1], [2].
4. This new OP is evaluated as described in step 2.
5. Steps 3 and 4 are repeated until a contingency is encountered that causes instability. In that case, a binary search is done to find a secure OP at the SR's limit (SRL).

6. Steps 3-5 are repeated for a number of different radial directions from the original OP, selected by the user.

Fig. 2 shows the concept of the process described in steps 1-5, i.e., evaluation in a single direction, and Fig. 3 illustrates a security region in which 4 directions were analysed.

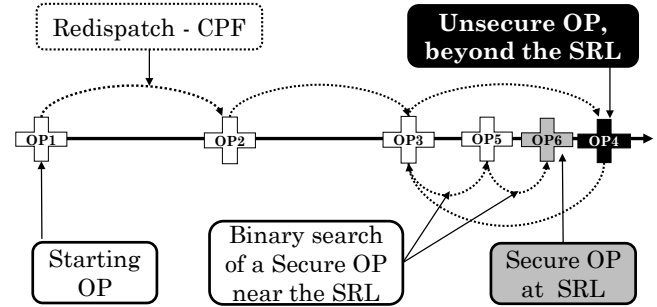


Fig. 2 – Concept of the assessment in a single direction.

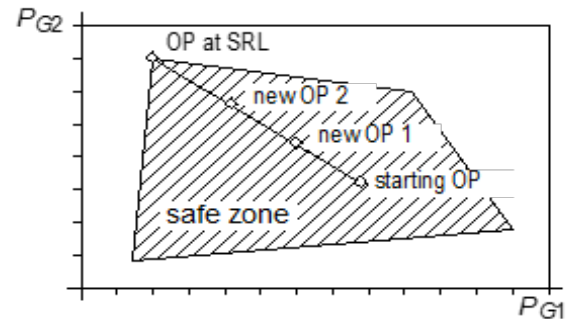


Fig. 3 – Example of a direction in a SR.

An SR thus constructed affords the system operator a visual indication of the system's security and allows redispatch of the power plants of each generation group to move the actual OP to a safer region. It is necessary, then, to maintain the required response for the SR computation within an acceptable time window, otherwise the decision-making process may consider an expired corrective action.

The performance of the SR generation is affected by several factors, such as, the size of the network model and the number of contingencies to be simulated. The network model is always represented in as much detail as possible to guarantee observability. Also, as the transmission grid increases, so does the network model and the number of equipment that should be considered while building the contingency list. It is important then, to reduce the number of simulated contingencies while keeping the ones that are more severe to the system in a given scenario, which can be achieved by a screening process.

3. Performance Indices

The goal of a system Performance Index (PI) is to measure the impact of a disturbance or contingency on a power system and is often calculated after the detailed time-domain simulation of the disturbance. A higher index indicates a more relevant contingency. The contingencies, then, are ranked by their severity and can also be classified as stable or unstable based on the system response [23]. Various indices for DSA were proposed and analysed by [7], [10], [11]

and [24] and some of those will be detailed in the next sections.

3.1. Index Based on Transient Energy Conversion

This index is based on the concept of energy conversion between kinetic and potential of the system. The kinetic energy can be defined as the energy stored in the form of spinning movement of the rotors, while the potential energy of a system can be divided into three: the position of the rotors related to the system's Center of Inertia (COI), the reserved magnetic energy in the system and the transmission loss.

During a fault, kinetic energy is added to the system due to the speed increase in the rotors. If the system has enough margin to absorb the additional kinetic energy in the form of potential energy, it will keep the synchronism and may achieve a new stable operating point. If the system has no such capability, it may lose synchronism and reach the point of instability. This transient energy exchange is referred to as transient energy function, described mathematically as the difference between kinetic and potential energy [25].

The larger the difference between kinetic and potential energy during the disturbance, the closer to instability the system is. This concept leads to an index described as the maximum difference between transient potential energy and kinetic energy:

$$PI_{EN} = \max(|V_{KE}(t) - V_{PE}(t)|) \quad (1)$$

where:

V_{KE} : kinetic energy;

V_{PE} : potential energy.

3.2. Index Based on Dot Product

Dot products are used in detecting Exit Point in the Transient Energy Method. A Dot Product defined in [7] associates the total accelerating power vector with the rotor angle vector of the machines in the system:

$$A_{ACC} = \sum_{i=1}^{Ng} (f_i \cdot \delta_i) \quad (2)$$

$$f_i = P_{mi} - P_{ei} - \frac{M_i}{M_t} P_{COI} \quad (3)$$

$$P_{COI} = \sum_{i=1}^{Ng} (P_{mi} - P_{ei}) \quad (4)$$

$i = 1, 2, \dots, Ng$

where:

M_i : inertia constant of each generator;

M_t : inertia constant of all generators;

P_{mi} : mechanical power input of each generator;

P_{ei} : electrical power output of each generator;

δ_i : rotor angle with respect to COI;

Ng : number of generators in the system.

The dot product shows bigger oscillations when the system is closer to instability, thus the difference between maximum and minimum values will be higher in those cases. The index derived is:

$$PI_{ACC} = \max(A_{ACC}(t)) - \min(A_{ACC}(t)) \quad (5)$$

3.3. Index Based on Frequency Deviation

The frequency deviation is also an indicator of the evolution of the system's dynamic after a contingency, especially during a significant imbalance between load and generation. Contingencies that result in system islanding are examples of disturbances that cause large frequency excursion in a power system.

Indices based on frequency deviation are described in [17] and a simpler version of the one based on the maximum frequency deviation is defined as:

$$PI_{FREQ} = \max_{i=1 \dots Ng} \frac{\Delta f r_i}{f r_{NOM}} \quad (6)$$

$$\Delta f r_i = |f r_i(t) - f r_{NOM}| \quad (7)$$

$$i = 1, 2, \dots, Ng$$

where:

$f r_i$: frequency of each generator;

$f r_{NOM}$: nominal frequency of the power system;

Ng : number of generators in the system.

3.4. Composite Index

As proposed by [7], two or more indices can be combined to form a composite index, which is a numerical combination of individual indices. In this case, each individual index has a weight whose value may depend on the power system's characteristics [10]. The idea behind this concept is that each index covers one of the system dynamic variations and, thus, a composite index could reduce ranking errors. Although a higher number of indices in a composite index is desirable from the accuracy point of view, it could increase the computation burden [24]. Reference [24] suggests up to three individual indices when combining indices.

4. Contingency Screening of the Proposed Method

It was observed from extensive experience with simulation that some of the contingencies in the contingency list are harmless for a given system's scenario, while being of utmost importance in other cases. Fig. 4 shows an example of a system where the relevance of every branch depends on the dispatch of the generation groups.

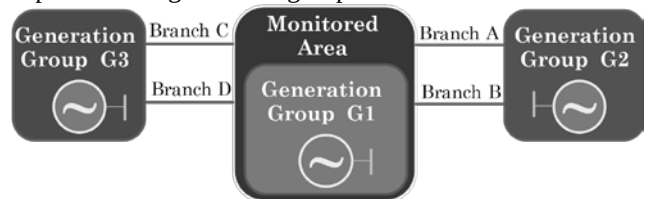


Fig. 4 –Example System with its monitored area and generation groups.

If dispatch in G1 is relatively small when compared to the load in the monitored area, i.e., the load is being supplied by G2 and G3, the outage of each of the 4 branches interconnecting the monitored area with G2 and G3 will be of great importance and, thus, complete time-domain simulation should be always done.

On the other hand, the smaller the generation of G2 the less relevant will be the branches A and B and the bigger the impact of contingency in branches C and D. The opposite will be true when the generation of G3 is reduced while

generation of G2 is increased. In this case, the contingencies in A and B will be relevant but C and D will not.

This work extends the general approach of the contingency screening by considering that the contingency list relevance is not necessarily the same for all directions in SRA and that, in the end, only the contingency that limits the direction is relevant. The proposed method exploits the time-domain simulation results during the DSA to calculate the PI of the contingency at every OP. The contingencies are ranked according to its PI and the one which is always ranked higher is more likely to be the one that will first cause system's instability. If a contingency is repeatedly ranked low for every PI calculated, then it will be excluded from the list after some repetition in the lower rank. This approach will lead to fewer contingencies being simulated as the DSA gets closer to the limit of stability and therefore reducing the time needed to compute the SR.

The following steps constitute the process executed for a direction:

1. Starting from the original OP, calculate the selected PI for each contingency with time-domain simulation results. Rank the contingencies and select the last ones as candidates to be excluded from the list.
2. For a new OP, calculate the PI, rank the contingencies and select the last ones as candidates for exclusion.
3. Exclude from the contingency list the ones that were selected as candidates consecutively for a defined number of OP.
4. Steps 2 and 3 are repeated with the remaining contingencies on the list until the SRL is reached or the remaining contingencies fall below a threshold number.

The flowchart of the described method is shown in Fig. 5, where four parameters should be defined by the user:

1. The minimum size of the contingency list allowed.
2. The PIs to be calculated.
3. The maximum percentage of contingencies that can be exclude at each evaluated OP.
4. The number of consecutive selections of a contingency before its exclusion from the list.

A representation of the processes with the contingency list reduction is shown in Fig. 6.

It is important to choose the PI according to the system operation criteria. As will be show in the discussion section, one PI may capture a problem missed by others. In this work, the indices were selected to allow the evaluation of the transient stability, PI_{ACC} and PI_{EN} , and the system performance after islanding, PI_{FREQ} .

Other indices should be considered when evaluating different operation criteria, such as maximum angular displacement or the duration of a voltage sag or when assessing other stability phenomena, such as voltage stability or oscillatory stability. The principal requirement is that the PI should be sensitive to the criterion of interest and reflect it consistently. For instance, [21] uses PMU measurements to track the Thevenin equivalent voltage and reactance of the system as seen from pre-specified load buses, and monitors voltage stability from PIs based on: 1) ratio of Thevenin equivalent reactance to load impedance, as an indicator of proximity to the tip of the nose curve; 2) rate of change of the Thevenin equivalent reactance; and 3) rate of change of the

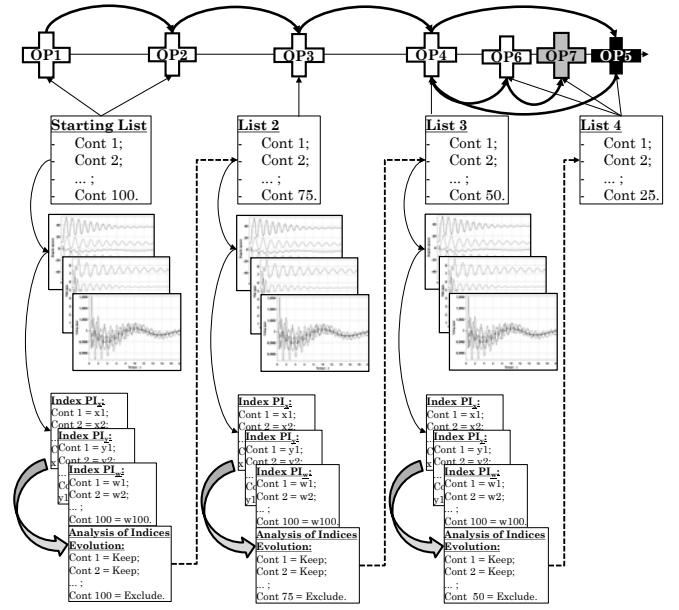


Fig. 5 – Central Grid monitored area.

Thevenin equivalent voltage. Settings of overexcitation limiters, on-load tap changers, etc. are adjusted accordingly.

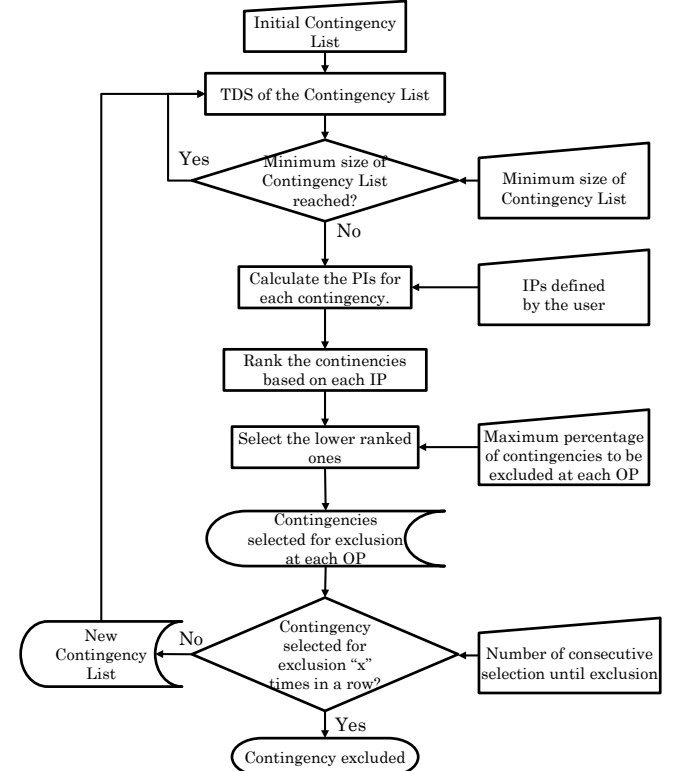


Fig 6 – Flowchart of the proposed method.

At this time, the Brazilian ISO (ONS) is primarily interested in angle and frequency stability, and therefore this work developed only the pertinent PIs. Other criteria will be considered later, when deemed necessary.

5. Study System

A case study is conducted in a modified New England network, where the original generators were replaced by the complete model of the actual generators of the Brazilian power system. Reference [25] details the characteristics of this network, the monitored areas, the generation groups and the contingency list. Fig. 7 shows the network with the central

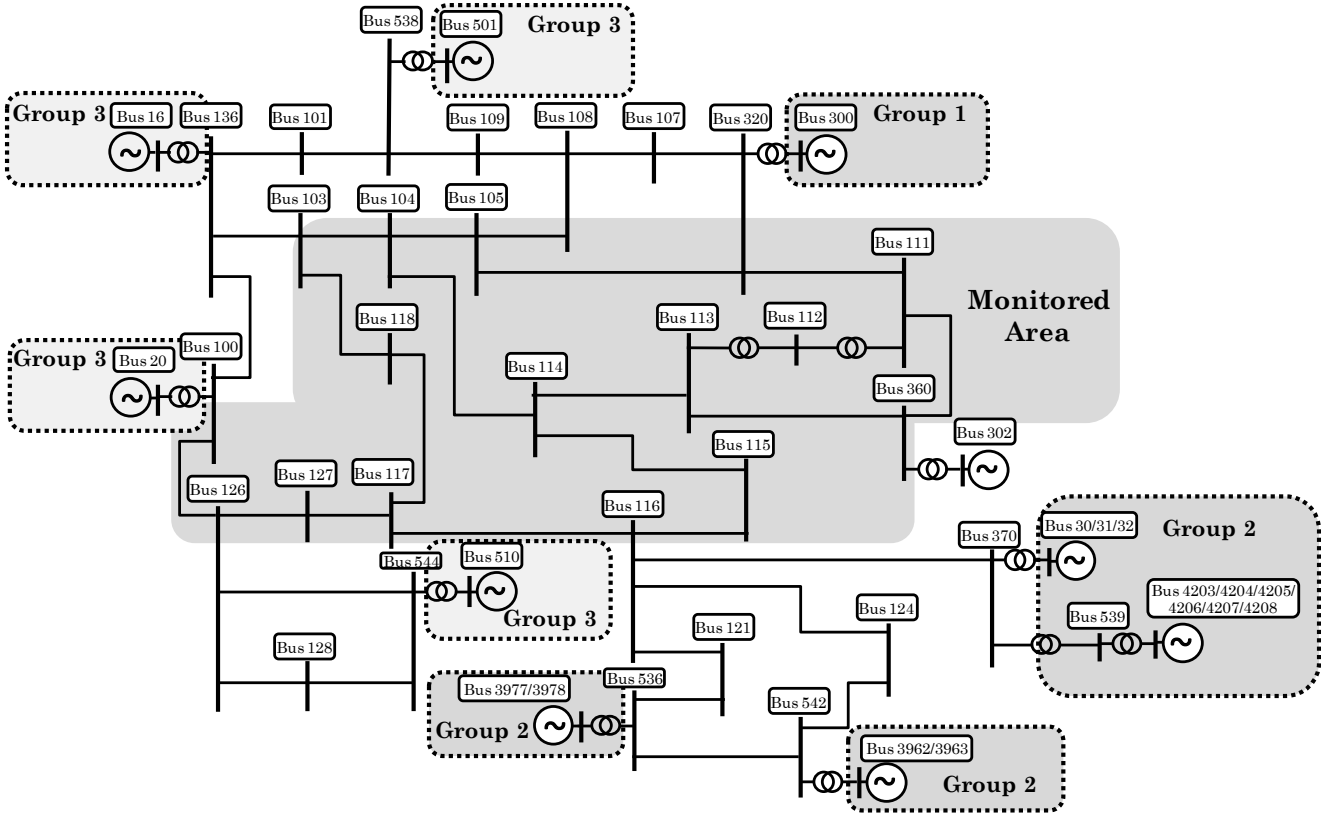


Fig. 7 – Central Grid monitored area.

monitored area, here named Central Grid, and the selected generation groups.

The contingency list contains seventeen N-1 and nine N-2 contingencies. All time-domain simulations consist of a 100 ms single-phase fault in one of the branches' busbars followed by the switching off of the faulted branches. The total time-domain simulation is of 20 sec.

A second monitored area for the same network, here called South Grid, is illustrated in Fig. 8. The contingency list contains nine N-1 contingencies with the same time-domain simulation parameters as used in Central Grid.

A total of 30 DSR were evaluated for each monitored area. In order to verify the influence of the system's parameters on the proposed method, variations were applied in the load ZIP model, in the load level and in the generator's models, which could be a mix of Hydro and Thermal models or Thermal only. Results will be presented for the limiting ZIP model (100% of each type).

A second batch of cases using the complete Brazilian Power System network model were performed. Due to the size of this model, which has over 6700 buses and 9700 branches, the DSR is performed for smaller monitored areas. In this work, 3 areas were used to evaluate the proposed method. For the first monitored area, called North of MG, a contingency list composed by twelve N-1 and eight N-2. For the second monitored area, East of MG, the contingency lists consist of twenty-one N-1 and three N-2. The third monitored area, called 440/230 kV of SP, has a contingency list with seven N-1 and fourteen N-2 contingencies.

All simulations were done using *Organon*, which adopts a parallel processing approach in a master/slave

configuration, and a computer with an Intel Core i7-3537U 2.0 GHz processor and 8GB of RAM.

6. Simulation Results

6.1. New England Network Model

For the New England network model, the following criteria were used:

- The indices used were the ones described in section 3.
- The selection of contingency candidates for exclusion considered the ones below the second quartile, i.e., last 50% contingencies in the ranking.
- The contingencies were excluded if selected three times consecutively by all indices.
- The minimum number of contingencies in the list was set at 20% of the original total.

The maximum distance between two OPs was set at 200 MW to assess the accuracy of the method in cases where the behaviour of the indices was not monotonic.

6.1.1 Time Reduction: Table 1 shows the time reduction using the proposed method for the Central Grid with only thermal generators. The total time needed to compute the SR, with screening process included, was considerably reduced when compared with the original complete case, with the time reduction between 5% and 30%.

Table 2 shows the time reduction for the Central Grid with a mix of hydro and thermal generators, with the time reduction between 14.5% and 31%.

The results for the South Grid are given in Table 3 and Table 4.

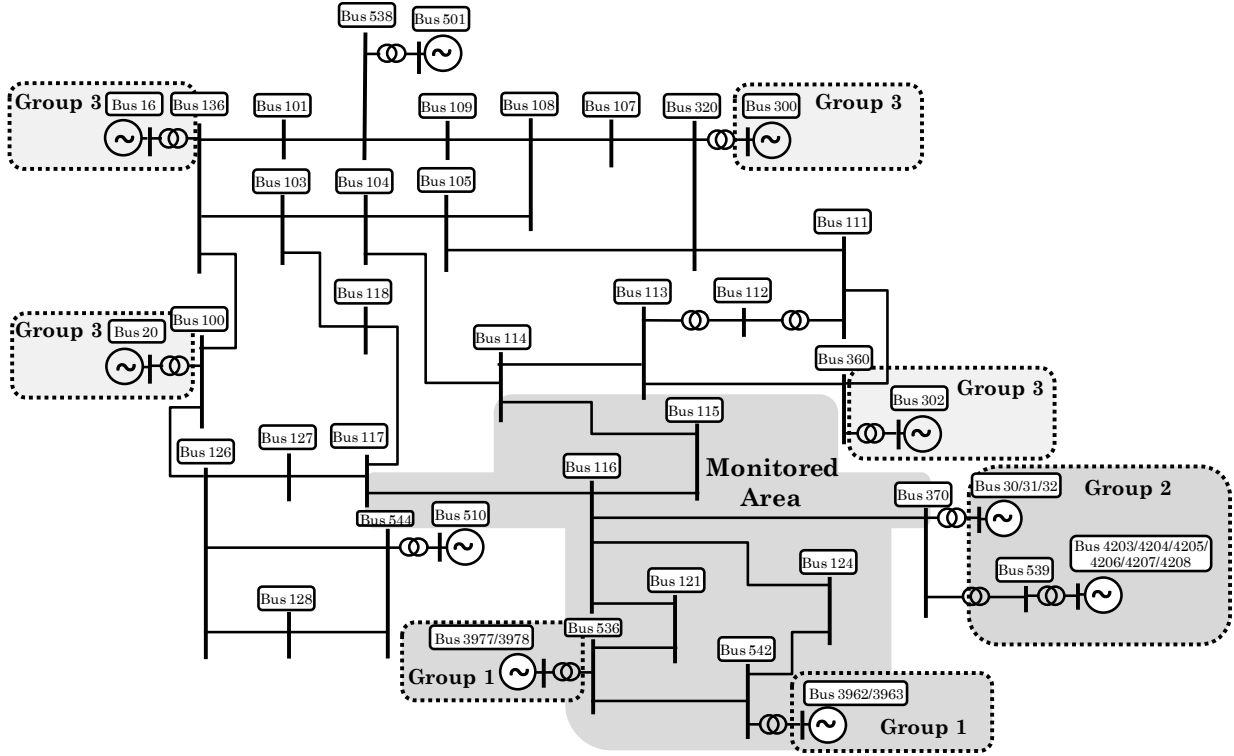


Fig. 8 – South Grid monitored area.

Table 1 Time reduction in DSR for Central Grid, Thermal Generators Model.

Central Grid - Thermal Power Plant Model				
Load Model		100% Z_{cte}	100% I_{cte}	100% P_{cte}
Load Level	Minimum	7.8%	7.6%	5.1%
	Light	20.1%	18.1%	17.9%
	Medium	30.6%	23.1%	18.9%
	Nominal	26.5%	21.3%	21.1%
	Heavy	24.9%	21.4%	18.3%

Table 2 Time reduction in DSR for Central Grid, Mixed Generators Model.

Central Grid - Hydro + Thermal Power Plant Model				
Load Model		100% Z_{cte}	100% I_{cte}	100% P_{cte}
Load Level	Minimum	14.8%	15.3%	14.6%
	Light	27.9%	25.9%	22.7%
	Medium	30.9%	30.4%	25.1%
	Nominal	31.0%	25.9%	20.5%
	Heavy	31.2%	19.4%	22.2%

It is observed in these cases that the higher the load, the better the performance of the method. This happens because it is easier to identify the worst contingency when the system is more stressed as the PI evolves out faster. Since the method aims at identifying the contingency which is more restrictive for a given direction, it performs better for the higher load.

The difference in time reduction of the cases can be attributed to two main factors. The first is the size of the contingency list, which contribute to a bigger number of contingencies being excluded from the list in the Central Grid DSR assessment. The second is the distance between the starting OP and the SL, which allows the calculation of more indices and, thus, the exclusion of more contingencies.

Table 3 Time reduction in DSR for South Grid, Mixed Generators Model.

South Grid - Hydro + Thermal Power Plant Model				
Load Model		100% Z_{cte}	100% I_{cte}	100% P_{cte}
Load Level	Minimum	0.3%	0.2%	0.8%
	Light	2.6%	2.4%	3.1%
	Medium	3.8%	3.7%	3.2%
	Nominal	7.3%	5.8%	5.9%
	Heavy	11.2%	9.5%	8.5%

Table 4 Time reduction in DSR for South Grid, Thermal Generators Model.

South Grid - Thermal Power Plant Model				
Load Model		100% Z_{cte}	100% I_{cte}	100% P_{cte}
Load Level	Minimum	1.6%	1.5%	1.0%
	Light	4.3%	4.6%	4.9%
	Medium	5.5%	5.2%	4.9%
	Nominal	9.7%	8.0%	6.9%
	Heavy	14.1%	12.2%	10.3%

6.1.2 Accuracy: In all simulated cases, the contingency that limited the direction remained in the contingency list until the SL was reached, thus satisfying the accuracy requirement.

An example of a particular case is the assessment of the DSR for the Central Grid where 20 directions were analysed. As illustrated in Fig. 9, the boundaries of the SR where limited by:

- Contingency no. 20 in 10 directions (1, 2, 6, 8, 9, 10, 15, 16, 18 and 19).
- Contingency no. 25 in 4 directions (7, 11, 17 and 20).
- Contingency no. 24 in 1 direction (14).

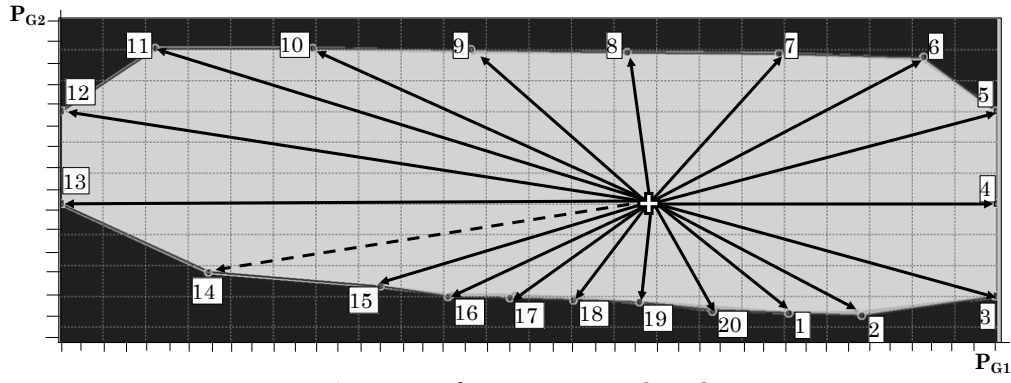


Fig. 9 – SR of a case in Central Grid.

- Maximum generation in 5 directions (3, 4, 5, 12 and 13).

Direction number 14, represented by the dashed line, was the only one limited by contingency no. 24 and this contingency remained in the contingency list through the entire process, as can be seen in Table 5.

Table 5 Contingencies list of Direction 14 of a case in Central Grid Area.

Contingency no.	Starting OP	OP 2	OP 3	OP 4	OP 5	OP 6
n1	Keep	Keep	Keep	Keep	Keep	Keep
n2	Keep	Keep	Keep	Keep	Keep	Keep
n3	Keep	Keep	Keep	Keep	Keep	Keep
n4	Keep	Keep	Keep	Keep	X	X
n5	Keep	Keep	Keep	Keep	X	X
n6	Keep	Keep	Keep	X	X	X
n7	Keep	Keep	Keep	X	X	X
n8	Keep	Keep	Keep	X	X	X
n9	Keep	Keep	Keep	X	X	X
n10	Keep	Keep	Keep	Keep	X	X
n11	Keep	Keep	Keep	Keep	Keep	X
n12	Keep	Keep	Keep	Keep	X	X
n13	Keep	Keep	Keep	Keep	Keep	Keep
n14	Keep	Keep	Keep	Keep	Keep	X
n15	Keep	Keep	Keep	Keep	Keep	Keep
n16	Keep	Keep	Keep	Keep	Keep	Keep
n17	Keep	Keep	Keep	Keep	Keep	X
n18	Keep	Keep	Keep	Keep	Keep	X
n19	Keep	Keep	Keep	X	X	X
n20	Keep	Keep	Keep	Keep	Keep	Keep
n21	Keep	Keep	Keep	Keep	Keep	X
n22	Keep	Keep	Keep	Keep	Keep	X
n23	Keep	Keep	Keep	Keep	X	X
n24	Keep	Keep	Keep	Keep	Keep	Keep
n25	Keep	Keep	Keep	Keep	Keep	Keep
n26	Keep	Keep	Keep	X	X	X

The analysis of the South Grid shows that one contingency causes system islanding, which is contingency no. 6. This contingency is responsible for most of the limitations in the South Grid DSR and, thus, its impact on the system need to be captured by one of the indices.

Fig. 10, 11 and 12 illustrates the evolution of the PI_{ACC} , PI_{EN} and PI_{FREQ} , respectively, for a direction limited by contingency no. 6. Each line is a contingency and the bold dashed line is the contingency no. 6. The values in the horizontal axis are the distance in MW between the starting OP and a new OP.

It can be seen that only PI_{FREQ} was able to capture the relevance of contingency no. 6, thus keeping it in the contingency list. It shows the importance of employing

different indices in order to avoid the exclusion of a relevant contingency.

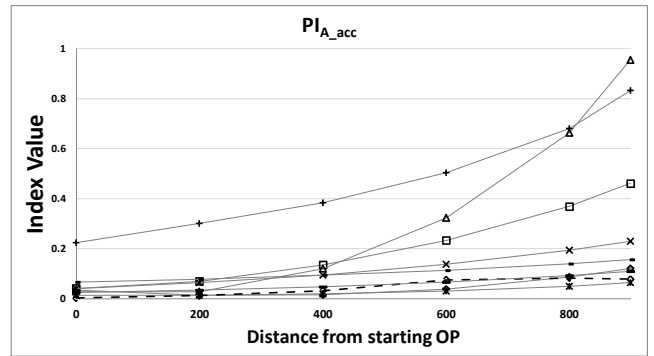


Fig. 10 – Evolution of PI_{ACC} for a given case.

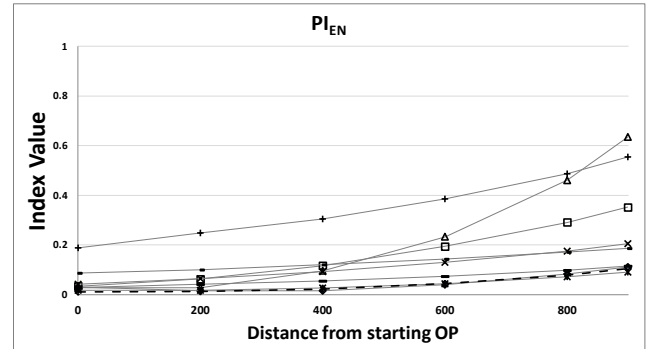


Fig. 11 – Evolution of PI_{EN} for a given case.

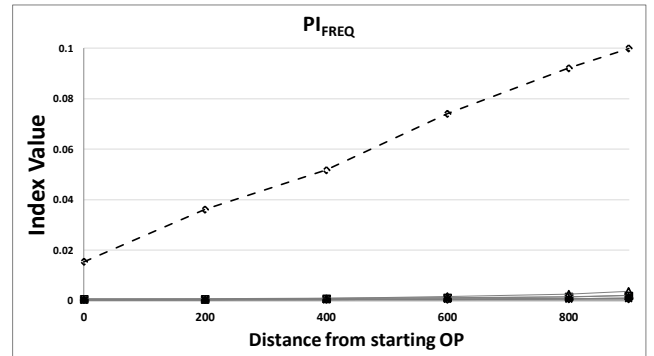


Fig. 12 – Evolution of PI_{FREQ} for a given case.

It is important to mention that the time-domain simulation processing time was of 20s to allow the classification of the system behaviour as stable or unstable. It was observed during the tests that using only the first 0.5s

after fault clearing causes no significant variation in indices calculation when compared with indices calculation using the entire observation period. This was mentioned in [7], [10] and [17] and could be used for further development.

6.2. Brazilian Network Model

The Complete Brazilian Network Model was used to generate some of the SR employed in ONS' control rooms. The following criteria were used in the Brazilian Network cases:

- The indices used were the ones described in section 3.
- The selection of contingency candidates for exclusion considered the ones below the first quartile, i.e., last 25% contingencies in the ranking.
- The contingencies were excluded if selected two times consecutively by all indices.
- The minimum number of contingencies in the list was set at 30% of the original total.

The maximum distance between two OPs was set at 200 MW.

6.2.1 Time Reduction: Table 6 shows the computation time in seconds for TDS, in the DSR process and the total time due to the use of the proposed method. The range of values is similar to the one obtained in the New England network, and the differences between the cases in both network model follow the same reasons.

Table 6 Time Reduction in DSR for the Brazilian Network

	440/230 kV of SP 21 Contingencies	440/230 kV of SP 30 Contingencies
Without proposed method	10981 s	16195 s
With proposed method	7669 s	11091 s
Time reduction	30.2%	31.5%

A way to utilize the spared time due to the use of the proposed method is to increase the contingency list, thus ensuring a more proper evaluation of the power system's security. To assess the impact of the increase of the contingency list on the proposed method, an additional case where evaluated for the 440/230 kV of SP monitored area with thirty contingencies was analysed. The required computation times, in seconds, are shown in Table 7.

Table 7 Time Reduction in DSR for the Brazilian Network

	East of MG	North of MG	440/230 kV of SP
Without proposed method	3556 s	8669 s	10981 s
With proposed method	3209 s	6889 s	7669 s
Time reduction	9.8%	20.5%	30.2%

The percentage reduction shown a little improvement, because the contingencies added to the list were not responsible for the limitation of any direction in the DSR. Even so, the absolute time reduction shows an advantage of the method employment.

6.2.2 Accuracy: In all simulated cases, the contingency that limited the direction remained in the contingency list until the SL was reached, thus satisfying the accuracy requirement.

6.2.3 Sensitivity of the User Defined Parameters:

The user defined parameters have direct impact on the methods performance, using overly restrict parameters may lead to exclusion of the most relevant contingency and, on the other hand, parameters overmuch flexible will not provide good time reduction. Thus, a sensitivity analysis was carried in order to obtain a range of recommended initial values when analysing a new network model or monitored area, which are shown in Table 8.

Table 8 Recommended Starting Values of User Defined Parameters.

Minimum Size of Contingencies List.	Percentage of Contingencies to be Excluded at each OP	Consecutive Selection Before Exclusion
30%	50%	3

The proposed initial values provided satisfactory results in all evaluated cases and can be used in any given power system. Further adjustments should be done to optimize the time reduction without compromise the accuracy.

7. Conclusions

Online DSA is a very important application that helps improving the reliability of a power system. The increase in the complexity of power systems increases the computational burden in DSA, where the number of contingencies being simulated is one of the factors responsible for the increase in computation time.

This paper proposed a method that exploits the fact that TDS simulation is already done in SR assessment. The results of the TDS are used to calculate PI that are used to rank and exclude contingencies based on the evolution of its impact on the system in a given direction. Results shows that the method has satisfactory accuracy and allows the reduction in the total time needed to compute the SR. Also, it was observed that the same SR used by the Brazilian ISO can be obtained with less computational burden.

The proper selection of the PI is important to comply with the system operation criteria adopted by the system operator. With reliable and fast contingency screening, a larger contingency list can be used in the beginning and the method will naturally exclude the ones not significant to that particular OP. Also, with faster DSA, it may be possible to perform future scenario DSR assessment based on load forecast and network maintenance schedule.

The TDS time used for all cases was of 20s to allow the classification of the system behaviour as stable or unstable. It was observed during the tests that using only the first 0.5s after fault clearing causes no significant variation in indices calculation when compared with indices calculation using the entire observation period. This was mentioned in [7], [10] and [17] and could be used for further development.

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