CIGRE-502 **2022 CIGRE Canada Conference & Expo**
Calgary, Alberta, Oct.31 – Nov. 3, 2022

Power System Reliability Assessment Considering the Automatic Definition of Topological Corrective Actions

Fernando De Marco*
DIgSILENT GmbH
Germany

Arne Ellerbrock
DIgSILENT GmbH
Germany

SUMMARY

This paper presents a novel method for the power system reliability assessment considering the automatic definition of topological corrective actions (TCAs). The method comprises the TCA optimization followed by a probabilistic reliability assessment (PRA).

The automatic definition of TCAs comprises two nested inner and outer loops that minimize the additional operating expenses (OPEX) following contingencies that produce unacceptable network conditions. The TCAs encompass the disconnection of single branches, switching on and off predefined sets of circuit breakers and changing the tap position of phase shifter transformers. Sensitivity factors are used to define the elements in which a TCA could be potentially applied and anticipate the changes in the power flows produced in other elements due to their maneuver. Unit commitment calculations are used to optimize the additional OPEX associated to the redispatch of conventional generation, curtailment of variable renewable energy generation and load shedding, whenever allowed.

The PRA is run to quantify the reliability of particular contingencies and scenarios by means of contingency reliability cost (CRC) and scenario reliability cost (SRC) indexes. These indexes associate probabilities to system impacts, these latter being quantified by the additional OPEX required to eliminate the network constraints in the post-contingency scenario.

The methodology was automated in DIgSILENT PowerFactory 2022 software using built-in contingency and sensitivity analyses and unit commitment calculation functions. The case study presents results of the application of the proposed methodology to the IEEE RTS-96 benchmark model. Results show that the proposed methodology allows to identify the most critical contingencies for a given scenario in terms of the highest CRC, and the most critical scenario in terms of the highest SRC. It is verified that the effective TCAs allow to reduce the CRC of all contingencies and the SRC of all scenarios compared to the cases without TCAs.

KEYWORDS

Contingency analysis, operation planning, reliability, topological corrective actions, unit commitment.

*f.demarco@digsilent.de

1 INTRODUCTION

Power system operators are required to provide continuous supply of electric power while maintaining strict operating and reliability standards in the most economically efficient possible manner. Reliability of a power system refers to the probability of its satisfactory operation over the long run. It denotes the ability to supply adequate electric service on a nearly continuous basis, with few interruptions over an extended time period. Reliability is the overall objective in power system design and operation. To be reliable, the power system must be secure most of the time [1]. The power system behavior is stochastic in nature, and its assessment should therefore be based on probabilistic techniques that capture this behavior [2].

Topological actions (TAs), including transmission line, shunt element and busbar switching, as well as transformer tap changing are effective measures to address unacceptable post-contingency conditions at no additional cost since they only involve operational actions and have minimal effects on generation and load demands [3]. However, under stressed system conditions, TAs may not successfully relieve all overloads and voltage violations for some severe contingencies [4].

In traditional contingency analysis (CA) loading and voltage violations are not directly linked to consequences for grid users and the costs to mitigate them. Also, unit commitment (UC) and optimal power flow calculations tend to over-estimate such costs because they do not consider cascading effects and the capability of operators to reconfigure the grid through switching actions.

This paper presents an efficient approach for the automatic definition of topological corrective actions (TCA) to minimize the additional operating expenses (OPEX) following contingencies in the network. We assume that the initial operating point of the system has already been optimized and the goal is to find the set of actions that allows to minimize the MW change and associated costs. The MW change can be associated to the redispatch of conventional generation, curtailment of variable renewable energy (VRE) generation and load shedding, whenever allowed. Possible TCAs comprise the connection and/or disconnection of single branches, pre-defined switching actions on one or more circuit breakers, and changing the tap position of phase-shifter transformers (PSTs). Sensitivity factors are used to define the elements in which a TCA could potentially be applied and anticipate the changes in the power flows produced in other elements due to their maneuver.

This paper proposes to run a probabilistic reliability assessment (PRA) after the TCA optimization algorithm to quantify the system reliability by associating probabilities to system impacts. The PRA recognizes that some situations are more likely to be encountered than others. The probability of the situation is therefore used in the PRA process to weight the contingency impact [5]. The impact of a contingency is typically quantified in terms of the deviations of the critical physical variables with respect to the allowed values [5], [6]. In contrast, we propose to measure the impact by the additional OPEX required to eliminate the network constraints in the post-contingency scenario.

The contingency reliability cost (CRC) and the scenario reliability cost (SRC) indexes are defined to quantify the reliability of particular contingencies and scenarios. This assessment provides valuable information for the optimization of the pre-fault scenario and also for planning the network reinforcements.

The methodology was automated in DIgSILENT PowerFactory 2022 software using built-in functions. The case study presents results of the application of the proposed methodology to the IEEE Reliability Test System 96 (RTS-96) [7]. It is verified that the most critical contingency and scenario can be identify by means of the highest CRC and SCR indexes, respectively.

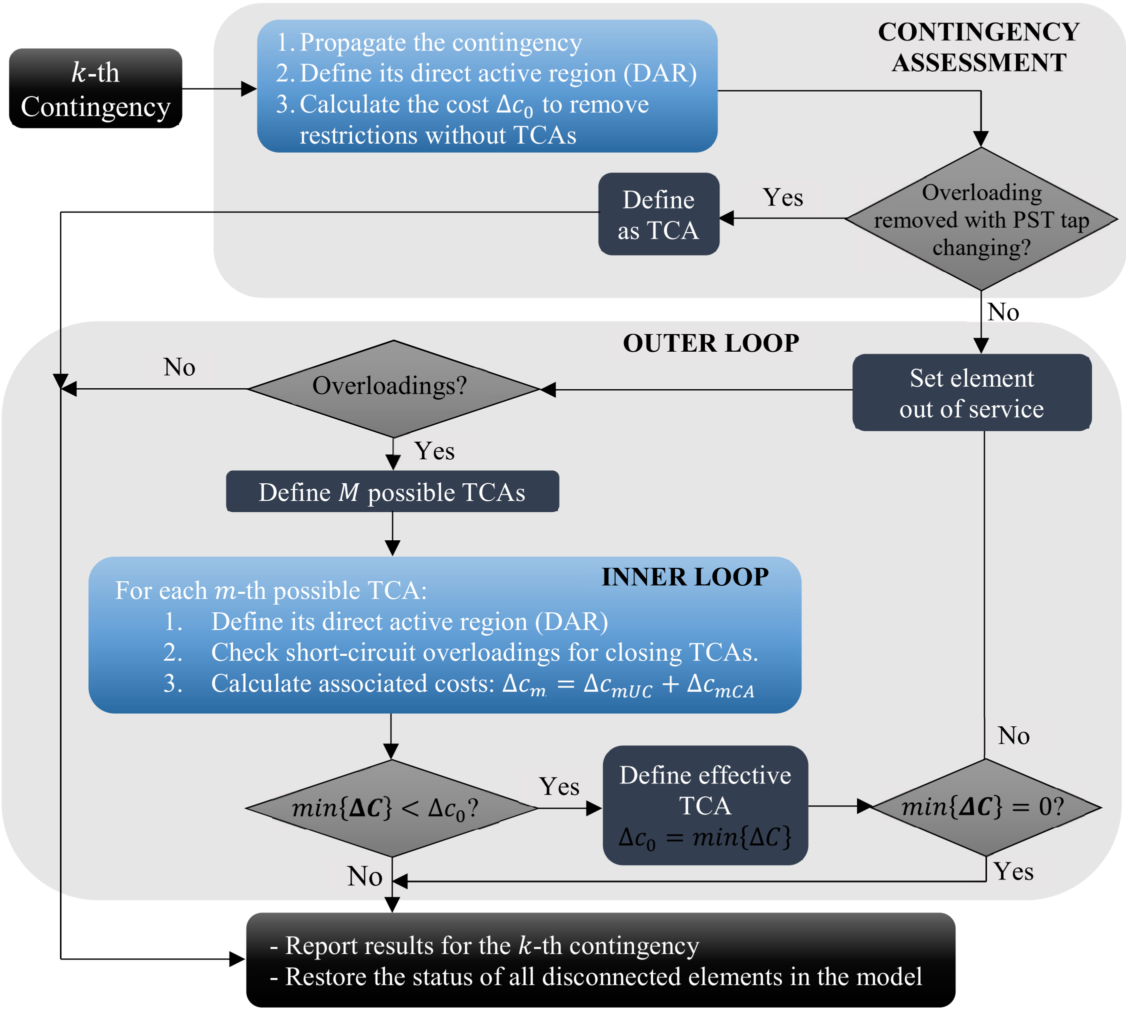
The remainder of this paper is organized as follows. Section 2 presents the proposed method for the TCA optimization and reliability assessment. Section 3 presents results for a study case, and Section 4 concludes.

2 PROPOSED METHODOLOGY

This section presents the proposed methodology comprising the TCA optimization followed by the probabilistic reliability assessment.

2.1. TCA Optimization

Following a contingency that leads to an unacceptable operating condition for a given initial system operating point, the objective of the algorithm is to find the sequence of TCAs that minimizes the total cost of the MW change required to restore the system to a new acceptable operating point in steady state. Figure 1 presents the algorithm proposed for the definition of the TCAs required to address the k-th critical contingency, which comprises an initial contingency assessment followed by two nested inner and outer loops.



TCA: topological corrective action; PST: Phase-shifter transformer

Figure 1. Flowchart for the definition of topological corrective actions (TCA) to address the k-th contingency.

It is assumed that the initial operating state of the grid in terms of topology and generation dispatch for the given load distribution has already been optimized in a separate process. Also, it is considered that the assessment of the implementation of the TCAs must be sequential to ensure that the network transitions through safe points of operation as the TCAs are applied in practice [3].

It is important that the new operating point is obtained by the least amount of control changes in the neighborhood of the overloaded element. Therefore, it becomes important to constraint the local optimization with the objective of finding close control variables that result in the smallest possible topological changes [8]. The direct active region (DAR) is therefore defined as the set of buses and branches in which the contingency has a significant impact in terms of voltages, angles, and power flow deviations with respect to base case values [9]. The branches and single-port elements (generators, loads and shunt compensators) within the DAR are identified by means of the line-outage distribution factors (LODF) and power transfer distribution factors (PTDF) [10], respectively.

2.1.1. Contingency assessment

Each critical contingency is characterized before starting the search for TCAs in the outer loop. The effects of the contingency are propagated if they lead to branches loaded above the maximum value L_{maxST} allowed for a short-term. The highly overloaded elements are sequentially disconnected so as to emulate the automatic operation of the protection relays. If the user-defined maximum number of N_p iterations is reached, an uncontrolled cascade tripping (UCT) is detected and the contingency is not further analyzed.

A UC calculation is run to obtain the additional post-contingency OPEX Δc_0 and associated MW shift ΔE_0 without considering the application of any TCA. The search for possible TCAs in the outer loop continues if there are branches loaded between 100 % and L_{maxST} in the post-contingency scenario after applying the automatic tripping actions. Branches are selected as part of the DAR if their LODFs exceed a predefined minimum threshold $LODF_{min}$ [9].

2.1.2. Outer Loop

The outer loop keeps adding TCAs as long as they allow to reduce the associated post-contingency OPEX below the value Δc_0 obtained in the previous iteration (or the initial contingency analysis). The possible TCAs comprise either the disconnection of one branch in the DAR (automatically found from the sensitivity analysis), or predefined combinations of circuit-breaker opening and closing actions. A "possible" TCA is considered an "effective" TCA if it allows to minimize the additional cost Δc_0 of the post-contingency MW change with respect to the state in which it is not applied.

2.1.3. Inner loop

The effects of the M possible TCAs within the DAR of the k-th contingency are assessed in the inner loop. A possible TCA is disregarded when it would lead to a UCT process (only one stage of protection tripping is allowed) that relies on the proper operation of the protection systems.

In the inner loop the costs of post-contingency MW shift associated to each TCA are stored in the vector $\boldsymbol{\Delta C} = [\Delta c_1, \dots, \Delta c_M]$.

The additional costs $\Delta c_m = \Delta c_{mCA} + \Delta c_{mUC}$ required to eliminate remaining overloadings after the m-th possible TCA is applied have the following two components:

- Outage impact (Δc_{mCA}): Outages are propagated by disconnecting the elements with loadings above the maximum allowed value. The MW load and generation disconnected by the TCA are then affected by fixed costs.
- Economic optimization (Δc_{mUC}): A UC redispatch calculation is run to obtain the total cost of the required MW change in terms of conventional generation redispatch, VRE generation curtailment and load shedding, if allowed. The UC also determines the required PST tap changes and is run only for TCAs that do not lead to UCT or short-circuit overloadings. If the overloadings are removed only with PST tap changing, this is defined as the only effective TCA, the outer loop is not entered and the master loop moves to the next iteration.

2.2. Probabilistic Reliability Assessment (PRA)

The PRA relies on an enumeration of contingencies and draws from their simulation a quantitative and probability-weighted evaluation of the system behavior [5]. The reliability of contingency k is measured by the contingency reliability cost (CRC) index defined as:

$$CRC_k = p_k \times \Delta c_k \times d_k, \tag{1}$$

where p_k is the probability of occurrence of the k-th contingency, Δc_k the cost of the MW shift required to eliminate the post-contingency overloadings, and d_k the contingency duration.

The reliability of scenario s is measured by the scenario reliability cost (SRC) index defined as [5]:

$$SRC_s = \sum_{k=1}^{K_s} CRC_k, \quad (2)$$

where K_s is the number of critical contingencies in the s-th scenario.

The CRC and SRC allow to rank contingencies and scenarios, respectively, and identify the most critical ones from a reliability viewpoint (i.e. the ones leading to the highest indices).

3 CASE STUDY

The methodology described in Section 2 was implemented in Python language and DIgSILENT PowerFactory v2022 software [11] was used to represent the network model and run the electrical calculations. This section presents results for a case study based on DC load flow calculations and using the Cbc solver for the UC calculations.

3.1. Test System

The methodology was applied to the IEEE RTS-96 three-areas model [7] comprising 73 buses, 120 branches and 96 generating units, with a total generating capacity of 10215 MW and a peak load of 8550 MW (base scenario or S1). Figure 2 presents the area interchange diagram of system with load flow results for the base scenario. A PST is connected in series with the line between Areas 1 and 3.

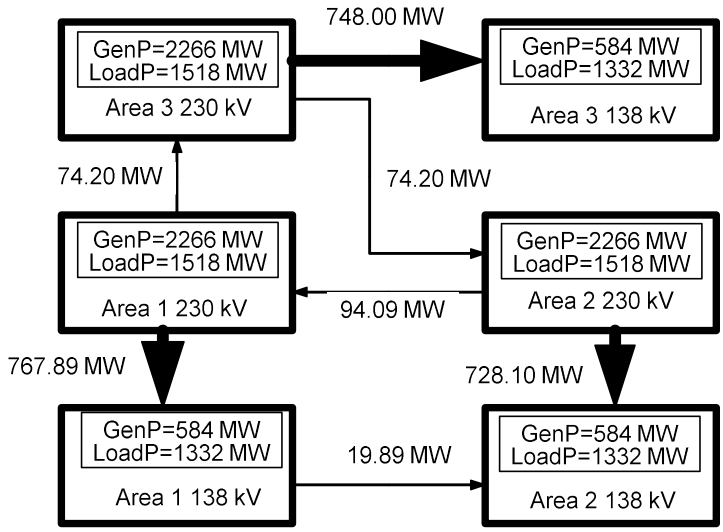


Figure 2. Area interchange diagram of the RTS-96 system with results for the base scenario S1. (GenP: active power generation; LoadP: active power consumption).

The MW shift of only hydro and gas generating units was allowed at redispatch (both upward and downward) costs of 5 \$/MWh and 15 \$/MWh, respectively. The coal-fired generating units were replaced by wind generators with curtailment costs of 15 \$/MWh, and shedding was allowed at all loads at 20 \$/MWh. The minimum active power dispatch of the synchronous generating units was set at 50% of their rated capacity.

The permanent ratings of the 138 kV and the 230 kV lines were set to 175 MVA (0.732 kA) and 350 MVA (0.878 kA), respectively. It was allowed a maximum short-term loading $L_{maxST} = 130$ %.

The permanent outage rates of transmission lines and transformers were taken from [12] and are specified in Table 1. It is assumed that the short-term operation planning comprises a day-ahead UC and the real-time generation redispatch is performed every hour of the day [13]. The permanent outage times in Table 1 are higher than the redispatch period (one hour). Therefore, it is considered that the system incurs in the post-contingency additional OPEX for a maximum of 1 hour, after which the full system can be redispatched to minimize the overall production costs, hence d_k=1 hour for all k.

Table 1. Line and transformer failure data [12].

Element	Failure rate (occurrence/year)	Outage time (hours/occurrence)
134 kV lines	1.0858/100km	6.6
230 kV lines	0.5429/100km	12.4
230/134 kV transformers	0.0121	495.0

3.2. Base Case Analysis

A total of 120 contingencies comprising the disconnection of a line or a transformer were analyzed in the base case (scenario S1). Out of these, only 29 contingencies lead to overloadings and were therefore processed by the TCA optimization algorithm. The results for the 10 contingencies leading to the highest CRC (without TCAs) are shown in Table 2 in which the CRC reduction is calculated as follows:

$$CRC\ Reduction = \frac{CRC\ with\ TCA - CRC\ without\ TCA}{CRC\ wit\quad TCA} \times 100\% \tag{3}$$

The contingency that requires the highest post-contingency MW shift and highest additional OPEX is #19 (274 MW with a cost of $3223), and there is no effective TCA identified for this contingency. However, the most critical contingency from a reliability viewpoint is #16, which has a CRC without TCAs of 0.204$/h.

Table 2. Summary of results for the ten contingencies with the highest CRC in the base scenario (S1).

Outage			Without TCA			With TCA			CRC Red. (%)	Effective TCAs
k	Element*	Prob (1/h)	ΔE (MW)	Δc ($/h)	CRC ($/h)	ΔE (MW)	Δc ($/h)	CRC ($/h)		
16	12_23_1 A3	6.683E-05	244	3053	**0.204**	105	1150	0.077	62	Open 12_13_1 A3, Open 11_9_1 A3
19	13_23_1 A3	5.984E-05	**274**	**3223**	0.193	274	3223	0.193	0.0	None
15	12_23_1 A2	6.683E-05	218	2724	0.182	0	0	0.000	100	Open 12_13_1 A2, Open 11_10_1 A2, Change PST taps
18	13_23_1 A2	5.984E-05	250	2922	0.175	190	2379	0.142	19	Change PST taps
27	15_21_1 A2	3.391E-05	214	2478	0.084	114	1227	0.042	50	Change PST taps
28	15_21_1 A3	3.391E-05	200	2299	0.078	178	2024	0.069	12	Change PST taps
32	15_24_1 A1	3.591E-05	159	1991	0.071	0	0	0.000	100	Open 11_14_1 A1, Change PST taps
33	15_24_1 A2	3.591E-05	136	1703	0.061	103	1293	0.046	24	Change PST taps
22	14_16_1 A3	2.693E-05	153	1916	0.052	147	1643	0.044	14	Open 11_13_1 A3
21	14_16_1 A2	2.693E-05	145	1807	0.049	0	0	0.000	100	Open 11_13_1 A2

(*) The name of the element is "X_Y_N Aa" where X and Y are the from and to buses, N the number of circuit and "a" the area number.

Table 3 details the problem solution for contingency #16, including the required TCAs and the required MW shift per element. The assessment of this contingency comprised 3 outer loop and 54 inner loop iterations.

The redispatch cost of a security-constrained unit commitment (i.e. ensuring that the system is N-1 compliant for all contingencies – pre-fault optimization) in this scenario is $2331, which doubles the additional post-contingency OPEX ($1150) of the most critical contingency #16. This large difference justifies the search for TCAs that allow to permanently operate the system at a lower production cost, and reduce the additional OPEX cost in case of contingencies.

Table 3. TCA optimization results for contingency #16 (outage of line 12_23_1 in area A3) in the base case (S1).

```
- Required TCAs:
  Disconnection of
    Line 12_13_1 A3
    Transformer 11_9_1 A3
 -- Change in Generation
#       Generator  MW Change (MW)    MW Change Cost ($/h)
1         01_1 A3           10.0                150.0
2         01_2 A3            3.4                 50.8
3         02_1 A3           10.0                150.0
4         02_2 A3           10.0                150.0
5         22_1 A3           -2.7                 13.5
6         22_5 A3          -50.0                250.0
   Total Generation MW change:  86.08 (+33.39/-52.69) MW at $764.31
 -- Change in Load
#         Element  MW Change (MW) MW Change Cost ($/h)
1    load 14_1 A3           19.3             386.0
 -- No transformer tap changes are required
- Overall Total MW change: 105.38 MW, $1150.35
```

3.3. Analysis of additional scenarios

Further analyses were run for the additional scenarios S2 and S3 in which the loads of the 138 kV and 230 kV networks were scaled by the factors in Table 4. The nine 197 MW units connected to bus 13 in the three areas are in charge of the MW balancing of the system (slacking) for the load flow solution.

Table 4. Load scaling factors in the operation scenarios S1 (base case), S2 and S3.

Area	Un (kV)	Load Scaling Factor (pu)			Total Load (MW)		
		S1	S2	S3	S1	S2	S3
1	138	1.0	1.0	1.1	1332	1332	1465
	230	1.0	1.0	1.1	1518	1518	1670
2	138	1.0	1.1	1.1	1332	1465	1465
	230	1.0	0.9	0.9	1518	1366	1366
3	138	1.0	0.9	1.1	1332	1199	1465
	230	1.0	1.1	1.1	1518	1670	1670
				Total	8550	8550	9101

Table 5 presents the SRC index for the three scenarios calculated with and without TCAs along with the SRC reduction, which was calculated as defined in (3) for the CRC. The most critical scenario is S2, which is the one with the highest SCR (1.836$/h) without TCAs. It is verified that the effective TCAs allow to reduce the SRC in the three scenarios, the largest reduction (57.8 %) being achieved for scenario S3.

Table 5. SRC with and without TCAs for the three scenarios.

Scenario	SRC ($/h)		SRC Reduction (%)
	Without TCA	With TCA	
S1 (base)	1.650	0.800	51.5
S2	1.836	0.841	54.2
S3	1.095	0.462	57.8

4 CONCLUSIONS

This paper proved that the search for the most effective TCAs to reduce the OPEX following contingencies in the network can be automated using built-in functions available in industrial-grade software, including sensitivity and contingency analyses and unit commitment calculations.

The proposed methodology allows to identify the most critical contingencies for a given scenario in terms of the highest CRC, and the most critical scenario in terms of the highest SRC. It is verified in the case study that the effective TCAs allow to reduce the CRC in all contingencies and the SRC in all scenarios. Also, it is shown that the most critical contingency from a reliability viewpoint (having the highest CRC) might not necessarily be the one requiring the highest MW shift to remove overloadings.

In the case study the redispatch cost from a security-constrained UC is much higher than the one calculated from a post-contingency UC considering TCAs, thus justifying the search for TCAs that allow to permanently operate the system at a lower production cost.

BIBLIOGRAPHY

[1] P. Kundur et al., "Definition and classification of power system stability IEEE/CIGRE Joint Task Force on Stability Terms and Definitions," *IEEE Trans. Power Syst.,* vol. 19, no. 3, p. 1387–1401, Aug. 2004.

[2] R.Billinton and R. N. Allan, Reliability Evaluation of Power Systems, 2nd Ed., Plenum Press, 1996.

[3] W. Shao and V. Vittal, "A new algorithm for relieving overloads and voltage violations by transmission line and bus-bar switching," Proc. IEEE PES Power Syst. Conf. and Expo., New York, Oct. 2004.

[4] W. Shao and V. Vittal, "Corrective Switching Algorithm for Relieving Overloads and Voltage Violations," IEEE Trans. on Power Syst., vol. 20, no. 4, Nov. 2005.

[5] N. Maruejouls, V. Sermanson, S. Lee and P. Zhang, "A practical probabilistic reliability assessment using contingency simulation," in *IEEE PES Power Systems Conference and Exposition*, New York, NY, USA, 2004.

[6] Z. Fang, H. Liu and J. Su, "Theory and system design of online risk assessment on urban power system," in *Int. Conf. on Sustainable Power Generation and Supply*, Nanjing, China, Apr. 2009.

[7] IEEE Reliability Test System Task Force of the Application of Probability Methods Subcommittee, "The IEEE Reliability Test System-1996," *IEEE Trans. on Power Syst.,* vol. 14, no. 3, pp. 1010-1020, 1999.

[8] D. C. Pinheiro and C. A. Castro, "Elimination of transmission system overloads through branch switching," Proc. IEEE PowerTech, Eindhoven, Jul. 2015.

[9] L. Platbrood, F. Capitanescu, C. Merckx, H. Crisciu and L. Wehenkel, "A Generic Approach for Solving Nonlinear Discrete Security Constrained Optimal Power Flow Problems in Large Scale Systems," IEEE Trans. on Power Syst., vol. 29, no. 3, pp. 1194 - 1203, May 2014.

[10] H. Ronellenfitsch, M. Timme and D. Witthaut, "A Dual Method for Computing Power Transfer Distribution Factors," *IEEE Trans. on Power Syst.,* vol. 32, no. 2, pp. 1007 - 1015, Mar. 2017.

[11] DIgSILENT GmbH, "PowerFactory 2022 User Manual," Jan. 2022.

[12] R. Billinton and L. Wenyuan, Reliability Assessment of Electric Power Systems Using Monte Carlo Methods, New York: Plenum Press, 1994.

[13] C. Rahmann, A. Heinemann and R. A. Torres, "Quantifying operating reserves with wind power: Towards probabilistic-dynamic approaches," *IET Generation, Transmission and Distribution ,* pp. 1-8, Sep. 2015.