Proceedings of the 33rd European Safety and Reliability Conference (ESREL 2023)
Edited by Mário P. Brito, Terje Aven, Piero Baraldi, Marko Čepin and Enrico Zio
 Published by Research Publishing, Singapore.
doi: 10.3850/978-981-18-8071-1_P447-cd

Connection Capability of Distributed Generation Units in A Power System under Active Network Management

Juan SUN

Service de Métrologie Nucléaire, Université libre de Bruxelles, Belgium. E-mail:juan.sun@ulb.be

Pierre-Etienne LABEAU

Service de Métrologie Nucléaire, Université libre de Bruxelles, Belgium. E-mail:Pierre.Etienne.Labeau@ulb.be

In a power system featuring a large share of distributed generations (DGs), the variability of power supply results in various issues in the implementation of more DG units incorporation to the existing distribution networks, particularly, congestion risk. Active Network Management (ANM) could provide (almost) real-time control, by possibly curtailing their production in case of grid congestion so as to allow more DG units integration, while deferring costly and time-consuming network upgrades. This paper provides a methodology for the fast assessment of the connection capability of DG units to a grid in ANM scheme, based on efficient Monte Carlo sampling. Besides, resorting to correlated sampling, it is possible to simultaneously estimate the congestion risk with and without connecting a new DG unit of variable capacity. This significantly reduces the computation burden in assessing the connection capability of a grid. The effectiveness of the proposed method is demonstrated on a test power grid.

Keywords: Active Network Management, distributed generation, curtailment, efficient Monte Carlo Sampling, congestion risk, correlated sampling.

1. Introduction

Towards the road of energy transition, the amount of decentralized production connected to the Medium-Voltage (MV) power system is significantly increasing. As a consequence, when the power produced is not consumed locally, reverse power flows are injected into the High-Voltage (HV) grid. More frequent line congestions and voltage problems are likely to occur. However, the appearance of Active Network Management (ANM), emerged as (almost) real-time control of power, voltage and frequency within a network (Järventaustac et al. 2010), could provide an effective solution for operating the injection of energy produced by Distributed Generation (DG) units to the grid, by possibly curtailing their production in case of grid congestion. It will help optimize both the use of the present grid infrastructure and the number of connected DG units. These interruptible connections offered to DG customers (also known as Non-Firm Generators, NFGs), combined with a set of rules about the order they are dispatched or curtailed under an ANM scheme, would maximize the use of renewable generation, and allow connection of larger generators. The curtailment rules are actually the Principle of Access (PoA) rules, e.g. Last-In-First-Out (LIFO) and Pro-Rata schemes. The former one means that the first NFG to sign a contract in the ANM scheme is always the last one to be curtailed. It is easily implemented and does not affect existing generators, but might discourage investment in future DG development. When abide by Pro-Rata rule, the required curtailment is shared between all NFG units, proportionally to the rated capacity or actual output of the generators. It also signifies that revenue losses are shared equally.

With an ANM arrangement deploying different PoA schemes among the connected units, more DG units are likely to be incorporated into the distribution power system. The impact of an

ANM performance must be assessed in order to guarantee, for each DG unit's owner, a sufficient profitability. Due to the uncertainties associated with generation and load demand fluctuations, a probabilistic methodology should be applied to propagate the loads and generations, on the grid model, while using an Optimal Power Flow (OPF) to estimate the most economical curtailment for congestion case. The results are expressed with our proposed probabilistic Risk Indices (RI), related with power curtailment and the probability of congestion occurrence, to expose the congestion risk. Meanwhile, the Utilization Factor (UF) of each unit displays the decrease against the more classical Capacity Factor (i.e. CF) after the corresponding curtailment management.

Consider an existing power grid operated with an ANM scheme, where there are q DG units connected to n substations. Once a new DG unit incorporation, there will be q+1 DG units. As a matter of fact, a methodology was proposed (Faghihi et al. 2015) for probabilistic risk assessment of connecting a given DG unit with given capacity to the existing grid under an ANM scheme. Probability density functions (pdf's) for their respective generation as well as for the loads at the different nodes of the grid are first elicited. As a direct Monte Carlo Sampling (MCS) of these pdf's turns out to be prohibitively time-consuming, an alternative approach is used: possible congestions have to be analyzed, not on the basis of the detailed generations and loads, but on the Net Balance (NB) at each node of the grid. This net balance is the algebraic sum of all productions minus the total load in a substation. A domain of the NB space that is free from any congestion risk can be identified. In order to do so, the net balance space is discretized, and safe and unsafe cells resulting from this discretization are then obtained, by checking if an acceptable solution of the Load Flow equations exists at each corner of those cells. The optimal curtailment of DG units must on the contrary be calculated using the detailed variant of generations and loads associated with any unsafe net balance variant. This is achieved based on a targeted (systematic) importance sampling of only those detailed variants (all individual productions and loads) likely to lead to congestion, i.e. those corresponding to NBs belonging to unsafe cells. This work provides foundation for our research. Hence, risk indices can be calculated efficiently for a given situation of the grid with q connected DG units.

However, from the viewpoint of the system operators, they prefer to get a quick evaluation on how much installed capacity of this new DG unit is most suitable to a given node in their present grid, while not affect too much the economic benefit of DG unit owners. In order to estimate the evolution of the indicators (i.e. RI, UF of each unit) caused by the addition of one specific DG unit at a given node, it would be necessary to independently compute estimations of the indicators for both the situations with and without a new connection in a high accuracy, as the difference between those indicators might be small. This leads to a significant increase in computing load. But resorting to a Correlated Sampling (CS) method, a unique computation will simultaneously bring the risk estimations for these cases (q+1 and q DG units, resp.), with an acceptable accuracy. This idea can be generalized: by considering a fictitious new DG unit to be connected to a given node with a variable installed power, the connection capacity can be derived from the same type of computations in a limited amount of time.

The paper is organized as follows. Section 2 presents the assessment algorithms for the connection capability of distributed units under ANM, and lists the RI calculation for different scenarios (e.g. q or q+1 case), by mathematical theory supporting. Section 3 states the application of this methodology to a grid case. Results of test are given in Section 4. Conclusion are in Section 5.

2. Congestion Risk Estimation in Different Scenarios

2.1. *Illustration of the assessment algorithms*

For the purpose of fast selecting the most optimal capacity unit integrated into the current power system, a fictitious DG unit of a given type, to be connected to a given node, with a variable installed power should be taken into account. We could investigate the evolution of these indicators (i.e. the RI, UF of each DG unit) in presence of accepting the variable capacity, from high-capacity to low-capacity, until the limit 0 for this low-capacity. Eventually, the connection capacity can be derived from the same type of computations in a limited amount of time.

Let us denote the case with q+1 DG units as reference case (i.e. *ref* case), while the initial case (i.e. q case) will be perturbed scenario (i.e. *per* case). As for the situations of new DG unit integration with a variable installed capacity, whose value is set lower than that is in *ref* case, they are also treated as perturbation scenarios.

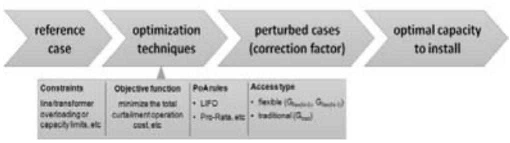

Fig. 1.Illustration of the algorithms

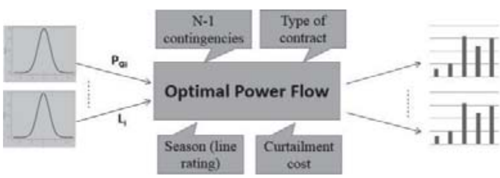

Fig. 2.Schematic diagram for curtailment estimation

The detailed illustration of the assessment algorithms for the connection capability of distributed units under ANM, is displayed in Fig.1. The evaluation program starts from reference case facing the worst congestion, when a new DG unit with definite high-capacity is incorporated at a given node. Then as shown in Fig.2, the power curtailment dispatched to each flexible DG unit in *ref* case could be obtained through optimization techniques (i.e. OPF). As a matter of fact, this performance assessment is achieved based on a targeted (systematic) importance sampling, what will be detailed explained in Section 3.2. Afterwards, with the help of correlated sampling method, introducing correction factor ("statistical weighting") in the results of the *ref* case, we could receive unbiased estimation for both *ref* and *per* scenarios (or perturbation scenarios) in one computation process. Eventually, the most optimal DG unit, installed into the current power system, will be selected from these corresponding analysis of perturbation scenarios.

So the progression of the evaluation algorithms should be provided in three steps:

- Assessing the risk indices in a given power grid;
- Assessing the impact of a possible new connection to a given node;
- Assessing the connection capacity at a node for each type of DG unit.

2.2.*Assessment of risk indices in a given grid*

We adopt the classical definition of risk as the product of the probability of occurrence of the undesired event, i.e. $P(E_i)$, and the related consequence, i.e. $f(E_i)$ (Rocchetta et al. 2015). The risk formula, listed in Eq.(1), is taken all undesired events into account. In this study, the curtailment for power overload case is used to represent the consequences. Thus, the total risk index (i.e. sum of all seasons) in one contingency can be expressed as Eq.(2).

where χ is the set of all seasons conditions (e.g. summer, inter-season, winter). C_k is the kth contingency (e.g. N/N-1 configuration). $f_l(C_k,\chi)$ is the performance function under congestion (e.g. the amount of curtailed power, evaluated by OPF, seen in Fig.2) for each generator in the conditions of the lth season. $P_l(C_k/\chi)$ is the probability of congestion occurrence in the lth season. n_s is the total number of seasonal conditions, n_c is the total number of configurations. Let p_k be the probability of configuration k. q_l is the probability of the lth season. The total risk indices due to all contingencies are then obtained as Eq.(3).

$$RI = \sum_{i} P(E_i) \times f(E_i) \tag{1}$$

$$RI(C_k/\chi) = \sum^{n_s} q_l \times P_l(C_k/\chi) \times f_l(C_k,\chi) \tag{2}$$

$$RI = \sum_{k=1}^{n_c} \sum_{l=1}^{n_s} p_k \times q_l \times P_{kl}(C_k/\chi) \times f_{kl}(C_k,\chi) \tag{3}$$

Apply the risk estimation into a given grid. If the grid comprises n substations, to which wind farms (WFs) and CHP (Combined Heat and Power) units are connected, the total load in substation i is denoted L_i. n_i is the total number of DG units connected to node i. The production of the jth DG unit connected to node i is denoted P_{ij}. Thus, under a given situation kl, φ_{kl} is the probability of congestion happening, related with the joint pdf of the DG productions and load. The risk index will be Eq.(4).

$$RI_{kl} = \iint f_{kl}(\bar{L},\bar{P})\varphi_{kl}(\bar{L},\bar{P})d\bar{L}d\bar{P} \tag{4}$$

$$NB_i = \sum_{j=1}^{n_i} P_{ij} - L_i \tag{5}$$

Where $\bar{P}$, $\bar{L}$ are the vectors of the productions of DG units and of the load. They compose the so-called variants of the problem, related to the total number of DG units and substations. The more DG units connected, the higher the dimensions of the problem to be analyzed, what will increase the computational burden. We use the concept of Net Balance, defined as the algebraic sum of all generator productions minus the total load in a substation, e.g. with Eq.(5) at node i. Identifying possible congestion situations based on the NBs will therefore dramatically decrease the dimension of the problem analysis, only related to the total number of substations. These NB variants will naturally form the NB space, where a boundary between uncongested and congested regions appear. In order to estimate this boundary, the NB space will be discretized into cells, approximating both safe (i.e. no congestion occurrence) and Unsafe Region (i.e. UR, congestion region), by load flow calculations at each corner in those cells. As a result, the UR consists of n_{cel} Unsafe Cells (UC). Afterwards, Eq.(4) can be derived as:

$$RI = \sum_{\mathrm{UC}} \int d\overline{NB} \int f(\bar{L}(\overline{NB},\bar{P}),\bar{P})\varphi(\bar{L}(\overline{NB},\bar{P}),\bar{P})d\bar{P} \tag{6}$$

In a second stage, only those detailed variants (all individual productions and loads) likely to lead to congestion will be sampled as inputs of OPF calculation, providing the total curtailment cost minimization. In fact, a targeted (systematic) importance sampling approach could be done for producing enough sampled variant. When wind generations and loads (i.e. $\bar{P}_{w,j}$, $\bar{L}_j$) are sampled from their respective joint pdf, i.e. $\varphi(\bar{P}_w)$,$\varphi(\bar{L})$, the sampling of the CHP generations (i.e.$\bar{P}_{CHP,j}$) is forced to take place from the truncated intervals inside a given UC. However, it is still likely that many samples of $\bar{P}_w$ and $\bar{L}$ will not be compatible with any output of the existing CHP productions, for specific UCs (Faghihi et al. 2015). Yet a set of CHP productions could be compatible with other UCs. In this way, each variant $\bar{P}_{w,j}$ and $\bar{L}_j$ might lead to contributions in all UCs: either the CHP variant is incompatible with the UC, or it leads to a contribution to the OPF evaluation. At last, the risk index in a given configuration will be estimated by averaging the curtailed power weighted by the probability of congestion occurrence, as:

$$\tilde{RI} = \frac{1}{N}\sum_{j=1}^{N}[\sum_{UC} f(\bar{\mathrm{P}}_{w,j},\bar{\mathrm{P}}_{CHP,j},\bar{\mathrm{L}}_j)\cdot\prod_{i=1}^{n} P_{CU,i}(P_{wi,j},L_{ij})] \tag{7}$$

Where the sampling size is N; $P_{CU,i}$ means the probability of the existing CHP production falling into a given UC at the ith substation; $\prod_{i=1}^{n} P_{CU,i}(P_{wi,j},L_{ij})$is the product of $P_{CU,i}$ at each node.

2.3. *Impact of a possible new connection to a given node*

A trend towards a growing integration of DG units will urge the operators to consider when a new DG unit is likely to be connected to a substation. Its impact will be reflected on the evolution of these indicators (i.e. RIs, UFs). With CS approach, more accurately assess the supposedly small difference in the risk indices between two situations (*ref* and *per* cases) in one single simulation.

2.3.1. *Correlated sampling approach*

In order to easily understand the reason why choose CS method, two simplified risk indices (i.e. RI_1, RI_2) are examples in the below. Where $D(RI_1\text{-}RI_2)$ is the variance of the difference.

$$RI_1 = \int f(x)\varphi_1(x)dx \tag{8}$$

$$RI_2 = \int f(x)\varphi_2(x)dx \tag{9}$$

$$D(RI_1 - RI_2) = D(RI_1) + D(RI_2) - \mathrm{cov}(RI_1, RI_2) \tag{10}$$

$$RI_1 = \int f(x)\frac{\varphi_1(x)}{\varphi_2(x)}\varphi_2(x)dx \tag{11}$$

In reality, RI_1, RI_2 are estimated with two independent batches of random variables, their covariance will be zero, i.e. $cov(RI_1, RI_2)=0$. However, if these two batches of sampled variables are correlated with each other, the covariance between RI_1 and RI_2 will be positive. Correspondingly, the variance of the difference between RI_1 and RI_2 will be decreased by using correlated random variables. Secondly, if there is just a little difference between two pdf's, it could be very easy to make the estimation of the difference quite misleading due to random noises. Through CS approach, we could use the same batch of random sampled variables to simultaneously estimate RI_1, RI_2 in one computation. The value of RI_1 could be deduced from RI_2 evaluation, written as equation Eq.(11), Where correction factor (i.e. $\frac{\varphi_1(x)}{\varphi_2(x)}$) is as compensations in the results of RI_2. Except of that, the computation time is another key issue.

2.3.2. *Assessment for per case*

According to Eq.(11), $\frac{\varphi^{per}(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)}{\varphi^{ref}(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)}$ will be as correction factor ('statistical weight') between *per* and *ref* cases. It is the ratio between the probability of the *per* case correlated sampling (of WFs, CHP production and load at each substation) falling into the *j*th sampled variant over that of *ref* case correlated sampling dropping into it. Thereby, the corrector factor should be estimated at each point of sampled variant. The risk indices in *per* situation will be expressed as:

$$\tilde{RI}^{per} = \frac{1}{N}\sum_{j=1}^{N}[\frac{\varphi^{per}(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)}{\varphi^{ref}(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)}\cdot\sum_{UC} f(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)\cdot \prod_{i=1}^{n} P_{CU,i}^{ref}(P_{wi,j},L_{ij})] \tag{12}$$

If this given connection node has WFs, CHP units and load installed, the correction factor calculation is specially defined for two scenarios:

- The CHP unit is added, the correction factor will be represented by $\frac{\varphi^{per}(\bar{P}_{CHP,j})}{\varphi^{ref}(\bar{P}_{CHP,j})}$;
- The WF is added, the joint pdf of WFs, $\varphi(\bar{P}_w)$, has been changed, the correction factor is simplified by $\frac{\varphi^{per}(\bar{P}_{w,j})}{\varphi^{ref}(\bar{P}_{w,j})}$.

Once a new CHP unit is connected to a given substation without any previous CHP generator, the corrector factor between the *per* and *ref* cases will be equal to 1. As a consequence, the risk indices for the *per* scenario, will be directly come out from *ref* case. Hence, there is no need to assess the impact of a new DG unit of a given type if no other DG unit of the same type is connected to the same node, since the results in *per* case have been listed in *ref* case.

2.3.3. *Limitation of CS approach application*

There is still some limitation of CS approach application. When calculate the situation of q DG units connection from q+1 case through CS approach, please notice the option of PoA rules. As the LIFO rule does not affect the existing installed generators, it will be convenient to deduce the situation before. By contrary, the Pro-Rata rule may increase curtailment for additional units, and we cannot predict the scenario before (i.e. q case) from q+1 case. However, with regarding to other perturbation scenarios (i.e. a new DG connection with the same type but lower capacity than that in *ref* case), there is no limitation for CS algorithm application, whether it employs LIFO, Pro-Rata rules to the whole power grid or to local substations.

2.4. *Assessment of the connection capacity at a node of a new DG unit*

Resorting to the CS algorithm, we can also estimate the evolution of these indicators (i.e. RIs, UFs) for the perturbation scenarios in presence of this new varying installed capacity, i.e. the same type but lower-capacity DG unit than that in *ref* case is incorporated into the existing power grid. Ultimately, at some point, we decide, based on the evolution of these indicators, which installed power is acceptable in the present power grid with the ANM scheme. Accordingly, the risk indices in this perturbation scenarios are only related to the type of connected DG unit. Eq.(13) is for a new WF integration while Eq.(14) is for a new CHP unit connected into node *g*.

$$\tilde{R}I^{per} = \frac{1}{N}\sum_{j=1}^{N}\left[\frac{\varphi^{per}(\bar{P}_{w,j})}{\varphi^{ref}(\bar{P}_{w,j})}\cdot\sum_{UC} f(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)\cdot\prod_{i=1}^{n} P_{CU,i}^{ref}(P_{wi,j},L_{ij})\right] \tag{13}$$

$$\tilde{R}I^{per} = \frac{1}{N}\sum_{j=1}^{N}\left[\frac{\varphi_g^{per}(\bar{P}_{CHP,gj})}{\varphi_g^{ref}(\bar{P}_{CHP,gj})}\cdot\sum_{UC} f(\bar{P}_{w,j},\bar{P}_{CHP,j},\bar{L}_j)\cdot\prod_{i=1}^{n} P_{CU,i}^{ref}(P_{wi,j},L_{ij})\right] \tag{14}$$

3. Application of the Methodology

The structure of the proposed methodology mainly consists of three parts: preprocessing, sample generation and risk estimation, as shown in Fig.3.

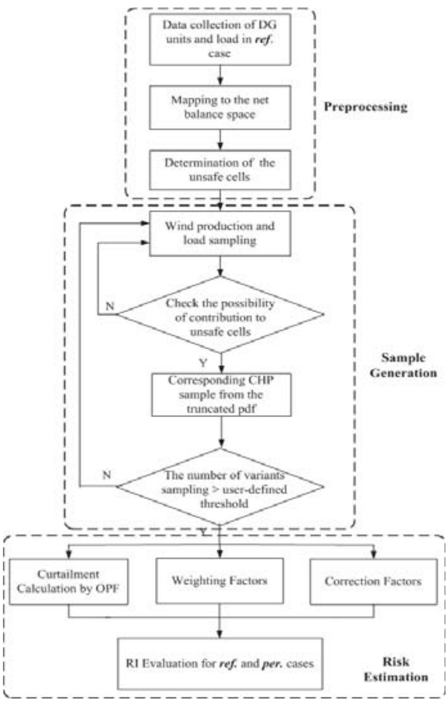

Fig. 3.Flowchart of the methodology

3.1. *Preprocessing*

As shown in Fig.3, the preprocessing stage aims to identify the UR based on the discretization of the NB space, and to partition the NB space into safe and UCs. In this way, the UR in the different configurations may be constructed through these corresponding UCs. At this stage, three steps need to be handled.

- Data collection. With the collection of the actual generations and loads, the NB domain can be determined. Fig.4 shows the NB space with 2 substations. The dots are NB variants.
- Identification of possible congestions. A mesh is defined on the NB domain, see Fig.4, and the space is then divided into a set of hyper-cubes (cells). The situations associated to the corners of the generated cells are analyzed by a load flow.
- Determination of the UCs. If all the corners of a cell are safe (i.e. if they cause no congestion on the grid), then this cell is considered as a safe cell; otherwise it is considered as a UC. The UR in the NB space consists of the corresponding UCs, as shown in Fig.5. In the meantime, we obtain the discretized approximation of the security border by checking the corners of the cells in the mesh. As shown in Fig.5, a security boundary divides the NB space into the corresponding safe and unsafe regions. Adding a DG unit capacity to node 1 corresponds to extending the NB domain, without affecting the security boundary.

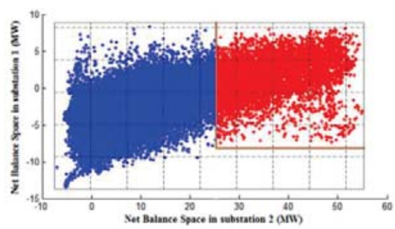

Fig. 4.Approaching the security boundaries by a mesh

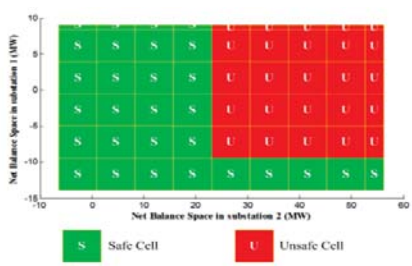

Fig. 5.Discretization of the NB space in safe and unsafe cells

3.2. *Sample generation process*

Once the congested region has been identified and discretized in the NB space, we present a validated systematic sampling scheme to make sure that enough sampled variants go into these unsafe region/cells and estimate the probabilities of violation of operating constraints due to congestions in grid elements.

From the DG production measurement data, we could find the stochastic dependence structure of wind units through correlation coefficient matrix, and model Weibull marginal distribution pdf/PDF for wind speed. Based on these marginal distributions, their joint pdf is constructed thanks to a Gaussian Copula. Since Gaussian copula is easy to implement for high-dimensional variables, it seems to be a good choice for modeling multivariate wind distributions [9]. Then, a Monte Carlo sampling approach is applied to generate a large number of correlated wind speed samples, and sampled wind speeds are converted to electric power using the power curve. With regarding to the load model, it is obtained by normalizing the historical load data of each year to the maximum consumption of the corresponding substation in that year.

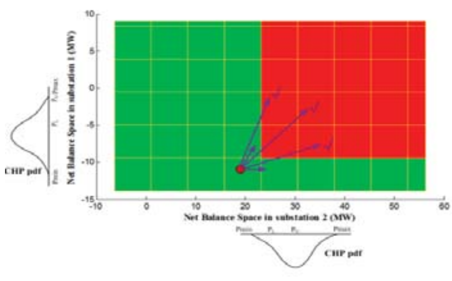

Fig. 6.CHP sample from the truncated pdf

After sampling wind and load from the corresponding joint pdf's, significant values of CHP productions correspond to values likely to make the NB fall in a UC (Faghihi et al. 2015). So we check the possibility of CHP samples that can contribute to each UC. For each UC, shown in Fig.6, a compatible value of the CHP production at each node *i* is sampled from the corresponding truncated pdf, if possible. Of course, there is still many sampling wind and load that are not compatible with any output of the existing CHP productions, for some specific UCs. At this step, all related production and consumption samples under each configuration (i.e. seasons, N/ N-1 contingencies) have been generated. In parallel, under each configuration, the weighting factor in each UC, i.e. $\prod_{i=1}^{n} P_{CU,i}$, will be computed by the product of the probability of having the CHP production at each node.

3.3. *Risk estimation*

The main objective of OPF calculation is to dispatch the curtailed power,achieving the total curtailment cost minimization, while consider seasons (for line ratings), N-0/N-1 contingencies, the curtailment cost of each specific DG type and the different PoA arrangements. In the presence of an ANM scheme, a DC-OPF is brought in to look for the optimal solution, while balance the network constraints.

As for the correction factor calculation, it is expressed in these 4 steps.

- Identify the scenarios of perturbation (perturbed pdf's): the type of the added DG unit (i.e. WF or CHP) and the type of connected substation must be specified in order to generate the correlated sample in the *per* case;
- Sample variants from the joint pdf of the reference case;
- Calculate the corresponding correction factor for each *ref* variable;
- Estimate the risk indices of the *per* case in each specific configuration.

Finally, the risk indices in the *ref* case can be estimated by averaging the corresponding curtailments weighted by weighting factor, while the correction factor as the compensation to *ref* case result, we will receive the results in different *per* scenarios. Eventually, the most optimal DG unit will be selected.

4. Results and Analysis

The current situation, without accounting for new DG unit incorporation, is defined as *Per 1.* case, where there is a total of 9 WFs, 12 CHP units and 9 other generators. Via the load flow calculation analysis in each configuration (i.e. seasons and N/N-1 configurations), the locations of active constraints in the *Per 1.* case are identified and marked in Fig.7 by ①~⑦. A new 10MW WF (i.e. WF10) added to bus 13 is as *Ref.* case. There will be a new possible congestion at place ⑧ under some specific conditions, in addition to the existing constraints at ①~⑦.

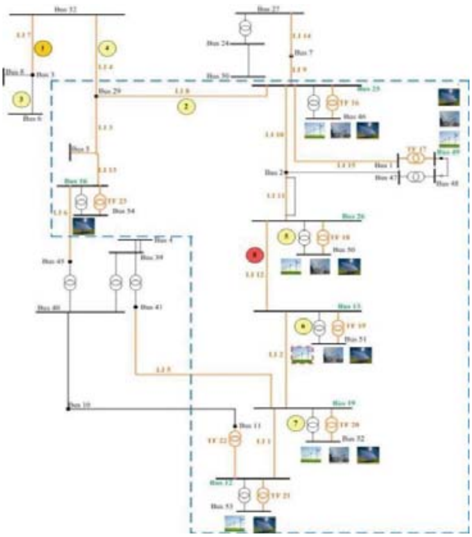

Fig. 7.East Loop simplified topology

As shown in Fig.8, in the LIFO scheme, WF10 will encounter almost 16 MWh/year energy curtailment, while all the others curtailed DG units will share a 7.5 MWh/year cut. Nevertheless, for the Pro-Rata rule, each of the WF4, WF7, WF10 and CHP16 units will undergo approximately 2 MWh/year of energy curtailed. The remaining 2 MWh /year is shared by the other units. With the help of the CS approach, we could estimate the congestion risk in *Per.1* case from that in the *Ref.* case. Fig.9 compares the expected values of the total energy curtailment in the *Ref.* and *Per 1.* cases.

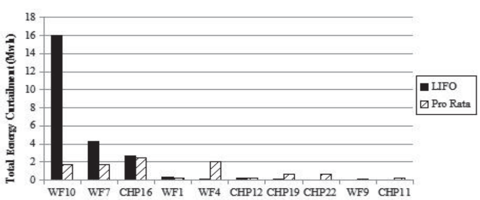

Fig. 8.Total energy curtailment under the two rules

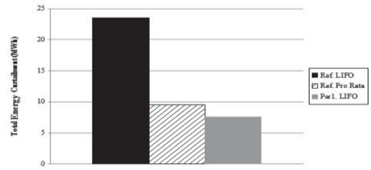

Fig. 9.Total energy curtailment in the *Ref.* and *Per 1.* cases

5. Conclusion

The key contribution of this research is to propose an efficient methodology for the connection capacity assessment of a new DG unit to an existing grid, using an ANM scheme. Furthermore, the use of correlated sampling allows significantly reducing the computation time so that one computation is able to simultaneously provide the risk estimation for both the reference case and other perturbed scenarios. For instance, if the operators needs a quick reply to a possible request of connecting a new DG unit to a given substation in the current grid, we could provide a whole feedback analysis and flexible strategy related to a possible candidate DG unit integration, including the type and capacity. Besides, the congestion level due to a new DG unit connection into the current grid is reflected by risk indices and the revenue of each generator could be reflected by its UF, which contains the economic benefits. Last but not least, if the operator needs to implement other PoA arrangements, they could easily insert additional constraints or logical commands to this general methodology.

References

Järventaustac, P., Repo, S., Rautiainen, A., and Partanen, J. 2010. Smart grid power system control in distributed generation environment. *Annal Reviews in Control*, 34: 277-286.

Faghihi, F. 2015. Probabilistic curtailment analysis for transmission grid planning using Active Network Management. Ph.D dissertation, Service de Métrologie Nucléaire, Université libre de Bruxelles, Belgium.

Rocchetta, R., Li, Y.F., and Zio, E. 2015. Risk assessment and risk-cost optimization of distributed power generation systems considering extreme weather conditions. *Reliability Engineering and System Safety*, 136: 47-61.