Identification of the critical cluster of generators by during fault angle trajectory estimation for transient stability analysis

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***Abstract*—Decades ago, limitations in computing power led to the creation of fast direct stability analysis (TSA) methods. Driven by the increasing complexity of power systems and the escalation of critical scenarios, these methods are in demand once again. The identification of the critical cluster (CC) of generators is a prerequisite for direct transient stability analysis techniques, such as the extended equal area criterion. Current research in CC identification prioritizes the use of real-time data or time-domain simulations. While promising, these methodologies do not align with the minimal data requirements of direct TSA methods. This paper proposes a straightforward method to identify potentially critical generators with low data requirements. The method is based on Taylor series expansion of generator angles to identify the ones exhibiting the most significant angle deviations during sustained fault conditions. Extensive simulations on the French network strongly support the idea and confirm the improvement achieved by the proposed methodology.**

***Index Terms*—classical model, critical cluster, direct method, Taylor series, transient stability**

I. Introduction

When a multi-machine power system is subjected to a large disturbance, a Critical Cluster of generators (CC), coherent in their response to the disturbance, pushes the system towards instability. In Transient Stability Analysis (TSA), knowledge of the CC of generators is a prerequisite for a considerable number of analysis techniques, especially the direct methods, such as the transient energy function method [1] and Extended Equal Area Criterion (EEAC) [2]- [6].

Decades ago, limited computing power led to the proposal of direct methods for transient stability analysis. Today, power systems operate near their limits with growing uncertainties. This has led to a substantial increase in critical scenarios to study, calling for fast analysis methods, once again. EEAC is an example of a fast direct TSA technique that relies on the conjecture of the separation of the generators into two groups, the CC and the Non-critical Cluster (NC) of the remaining generators. Since the CC is initially unknown, for a given fault scenario, EEAC evaluates a set of Candidate CCs (CCCs). For each CCC, it forms a One-Machine Infinite Bus (OMIB) equivalent model of the power system. It then applies the equal area criterion and integrates the OMIB model equations to find a Critical Clearing Time (CCT). After evaluating all the CCCs, the true CC is finally selected as the one with the minimum CCT. When using EEAC and similar direct TSA techniques, the initial step is to estimate a set of potentially critical generators based on specific criteria, such as initial acceleration, and then combine them to form CCCs [6]. We refer to this set as the Inclusive CC (ICC) because it includes the true CC.

While direct identification of the CC is often a challenging task, there are uncomplicated methods proposed to find the ICC, to be subsequently assessed in order to identify the true CC. The simplest technique is the "acceleration criterion". It is based on the initial accelerations the generators acquire at the disturbance inception [2]. According to this criterion, generators likely to be critical are considered to be those with the largest initial accelerations. Despite promising results, challenges arose in implementing this approach [4]. Some generators not initially prioritized experienced significant rotor angle variations over time, leading to instability. This rendered the initial acceleration criterion invalid. As an alternative, the "composite criterion" was proposed, combining initial accelerations and generators' electrical distance to the fault [4]. The composite criterion outperformed the sole acceleration criterion. However, neither approach reliably identified the critical generators.

The "trajectory criterion" is a more sophisticated method based on the conjecture that the criticality level of a specific generator is directly tied to the magnitude of its rotor angle at an appropriate assessment time [5]. With an initial estimation of the CCT, the method employs the Taylor series of generator angles to estimate their angle at an appropriate instant of time after the fault. Subsequently, it identifies the generators with the highest angles as the inclusive CC. This method's reliability in practical applications is questionable because it heavily relies on two key parameters: the initial estimation of CCT and assessment time. The latter is the specific time at which an assessment or evaluation of generator angles is

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conducted to identify the critical ones.

There are more recent techniques proposed in the literature for critical cluster identification. The use of a set of generator pair-wise potential energy measures is proposed in [7], [8]. This technique requires generator buses' time-domain data provided by simulation or measurements. The method proposed in [9] presents a coupling coefficient to describe the coupling strength between all generators in the system. In order to determine the CC, the method requires pre- and post-fault system snapshots. The authors of [10] propose a technique for direct correlation of the phase angle separation of critical generator bus pairs to power transfer on major interfaces. The method proposed in [11] uses principal component analysis and K-means clustering to cluster the generators. A deep learning neural network framework is proposed in [12] to monitor transient stability in real-time and detect the set of critical generators. The growing number of complex critical power system scenarios demands efficient analytical methods. While methodologies relying on time-domain simulations or measurements are promising, they often struggle with computational speed and data requirements. In contrast, direct TSA methods offer rapid and data-efficient computations, making them better equipped to address this challenge.

This paper aims to introduce a CC identification technique that achieves two main objectives: I) The technique exclusively utilizes power system classical model data and does not require detailed time-domain simulations or measurements. II) In contrast to previous techniques that also rely solely on classic model data, the proposed technique provides a more reliable estimation of ICC. The proposed method conjectures that the critical generators can be identified among the set exhibiting the most significant angle deviations during an extended during-fault period of the system. The method relies on Taylor series to make a single estimation of generator angles at the given assessment time. This strategy liberates the approach from relying on the initial CCT estimation, while still retaining the parameter of assessment time. Due to its minimal data prerequisites, this method can be implemented without demanding detailed model or time-domain data.

After outlining the Taylor series equations in Section II, and explaining the details of the proposed method in Section III, the paper presents several simulation results for stressed fault scenarios on the French network. These results are intended to evaluate the performance of the proposed method, the validity of the conjecture made, and the presence of an optimal value for the parameter assessment time that applies to different fault scenarios.

II. Taylor series for generator angle trajectories estimation

The proposed method employs the Taylor series to provide an estimate of generator angles at a designated assessment time. In the classical model of the power system, a classical representation for synchronous generators is often considered. This representation incorporates a constant voltage behind

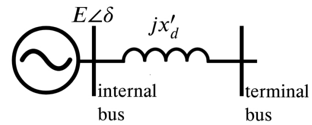

Figure 1: Classical representation of a synchronous generator by a constant voltage behind direct-axis transient reactance.

their direct-axis transient reactance x'_d, as shown in Fig.1. By dividing the network buses into n synchronous generator internal buses, and r remaining buses in this model, the bus voltages can be related to nodal current injections using the network admittance matrix $\hat{\boldsymbol{Y}}$, as follows:

$$\begin{bmatrix} \tilde{\boldsymbol{I}}_{\boldsymbol{n}} \\ \boldsymbol{0} \end{bmatrix} = \hat{\boldsymbol{Y}} \begin{bmatrix} \tilde{\boldsymbol{E}}_{\boldsymbol{n}} \\ \tilde{\boldsymbol{V}}_{\boldsymbol{r}} \end{bmatrix} \tag{1}$$

where hat and tilde denote complex and phasor values. $\tilde{\boldsymbol{E}}_{\boldsymbol{n}}$ denotes the synchronous generators' internal voltages behind their x'_d, $\tilde{\boldsymbol{I}}_{\boldsymbol{n}}$ is the generators' current, and $\tilde{\boldsymbol{V}}_{\boldsymbol{r}}$ denotes the voltages of the r remaining network buses. The network admittance matrix $\hat{\boldsymbol{Y}}$ incorporates the load impedances and generators x'_d values. This matrix can be partitioned as follows:

$$\begin{bmatrix} \hat{\boldsymbol{Y}}_{nn} & \hat{\boldsymbol{Y}}_{nr} \\ \hat{\boldsymbol{Y}}_{rn} & \hat{\boldsymbol{Y}}_{rr} \end{bmatrix} \tag{2}$$

By eliminating all the buses except the internal buses of the synchronous generators, the reduced admittance matrix can be obtained. Assuming zero injection currents for all buses except the source buses, the reduction can be achieved through matrix operations:

$$\tilde{\boldsymbol{I}}_{\boldsymbol{n}} = \hat{\boldsymbol{Y}}^{red} \tilde{\boldsymbol{E}}_{\boldsymbol{n}} \tag{3}$$

where:

$$\hat{\boldsymbol{Y}}^{red} = \hat{\boldsymbol{Y}}_{nn} - \hat{\boldsymbol{Y}}_{nr} \hat{\boldsymbol{Y}}_{rr}^{-1} \hat{\boldsymbol{Y}}_{rn}$$

In this context, for each individual generator k, ignoring the generator damping, the swing equations can be expressed as follows [13]:

$$\begin{aligned} M_k \frac{d\omega_k}{dt} &= P_{m_k} - P_{e_k} \\ \frac{d\delta_k}{dt} &= \omega_0 \omega_k \end{aligned} \tag{4}$$

where δ_k denotes the generator k angle (in electric radians) giving the position of the rotor with respect to a synchronously rotating reference, ω_k and M_k are its angular speed, and inertia coefficient, P_{m_k} and P_{e_k} denote the generator mechanical and electrical power, $\omega_0 = 2\pi f_0$, and f_0 is the system base frequency.

The electrical power output of the generator can be expressed as follows [13]:

$$\begin{aligned} P_{e_k} &= Re[\tilde{E}_k \tilde{I}_k{}^*] \\ &= Re[\tilde{E}_k \sum_{j=1}^{n} (\tilde{E}_j \hat{y_{kj}})^*] \end{aligned} \tag{5}$$

where $\tilde{E_k} = E_k \angle \delta_k$ is the voltage behind x'_d of the synchronous generator k, and $\hat{y_{kj}} = y_{kj} \angle \theta_{kj}$ is the element of row k and column j of the reduced admittance matrix.

The Taylor series is a mathematical technique used to approximate a function by representing it as an infinite sum of terms, each based on the function's derivatives, evaluated at a specific reference point. Specifically, a one-dimensional Taylor series can be employed to establish a connection between the change in the rotor angle of a generator and the time. Expanding the Taylor series about the generator k initial angle $\delta_k\Big|_{t^i}$, at time t^i, and truncating it after the t^4 term, we have:

$$\begin{aligned}\delta_k(t) = \delta_k\Big|_{t^i} + \frac{d\delta_k}{dt}\Big|_{t^i} t + \frac{1}{2}\frac{d^2\delta_k}{dt^2}\Big|_{t^i} t^2 \\ + \frac{1}{6}\frac{d^3\delta_k}{dt^3}\Big|_{t^i} t^3 + \frac{1}{24}\frac{d^4\delta_k}{dt^4}\Big|_{t^i} t^4\end{aligned} \tag{6}$$

where, considering Eqs. 4 and 5, the derivatives of δ_k at time t_i can be obtained as follows:

$$\frac{d\delta_k}{dt}\Big|_{t^i} = \omega_0 \omega_k\Big|_{t^i} \tag{7}$$

$$\frac{d^2\delta_k}{dt^2}\Big|_{t^i} = \frac{\omega_0}{M_k} P_{m_k} - \frac{\omega_0}{M_k}\sum_{j=1}^{n} A_{kj}\Big|_{t^i} \tag{8}$$

$$\frac{d^3\delta_k}{dt^3}\Big|_{t^i} = \frac{\omega_0}{M_k}\sum_{j=1}^{n}\Big[B_{kj}\Big|_{t^i}(\frac{d\delta_k}{dt}\Big|_{t^i} - \frac{d\delta_j}{dt}\Big|_{t^i})\Big] \tag{9}$$

$$\begin{aligned}\frac{d^4\delta_k}{dt^4}\Big|_{t^i} = \frac{\omega_0}{M_k}\sum_{j=1}^{n}\Big[A_{kj}\Big|_{t^i}(\frac{d\delta_k}{dt}\Big|_{t^i} - \frac{d\delta_j}{dt}\Big|_{t^i})^2 \\ + B_{kj}\Big|_{t^i}(\frac{d^2\delta_k}{dt^2}\Big|_{t^i} - \frac{d^2\delta_j}{dt^2}\Big|_{t^i})\Big]\end{aligned} \tag{10}$$

where A_{kj} and B_{kj} are defined as follows:

$$\begin{aligned}A_{kj}\Big|_{t^i} = E_k E_j y_{kj} cos(\delta_k\Big|_{t^i} - \delta_j\Big|_{t^i} - \theta_{kj}) \\ B_{kj}\Big|_{t^i} = E_k E_j y_{kj} sin(\delta_k\Big|_{t^i} - \delta_j\Big|_{t^i} - \theta_{kj})\end{aligned} \tag{11}$$

Similarly, the Taylor series expansion of generator k angular speed can be written as follows:

$$\begin{aligned}\omega_k(t) = \frac{1}{\omega_0}\Big(\frac{d\delta_k}{dt}\Big|_{t^i} + \frac{d^2\delta_k}{dt^2}\Big|_{t^i} t + \frac{1}{2}\frac{d^3\delta_k}{dt^3}\Big|_{t^i} t^2 \\ + \frac{1}{6}\frac{d^4\delta_k}{dt^4}\Big|_{t^i} t^3 + \frac{1}{24}\frac{d^5\delta_k}{dt^5}\Big|_{t^i} t^4\Big)\end{aligned} \tag{12}$$

where:

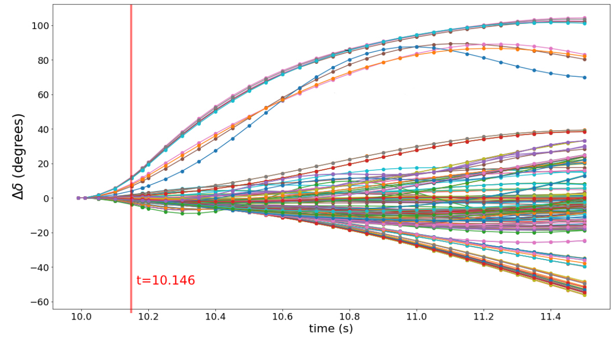

Figure 2: Generator angle deviations for a fault in the French network cleared 146 milliseconds after its inception.

$$\begin{aligned}\frac{d^5\delta_k}{dt^5}\Big|_{t^i} = \frac{\omega_0}{M_k}\sum_{j=1}^{n}\Big[3A_{kj}\Big|_{t^i}(\frac{d^2\delta_k}{dt^2}\Big|_{t^i} - \frac{d^2\delta_j}{dt^2}\Big|_{t^i}) \\ (\frac{d\delta_k}{dt}\Big|_{t^i} - \frac{d\delta_j}{dt}\Big|_{t^i}) + B_{kj}\Big|_{t^i}\Big((\frac{d^3\delta_k}{dt^3}\Big|_{t^i} - \frac{d^3\delta_j}{dt^3}\Big|_{t^i}) \\ - (\frac{d\delta_k}{dt}\Big|_{t^i} - \frac{d\delta_j}{dt}\Big|_{t^i})^3\Big)\Big]\end{aligned} \tag{13}$$

Right after the fault initiation, at $t_i = 0$, the angular speed $\omega_k = 0$ and all the odd derivatives of δ are zero.

A. During-fault trajectory criterion

Definition 1 (Critical cluster): In a multi-machine power system, the critical cluster of generators refers to a set of generators that contribute to the loss of synchronism following a significant disturbance. These generators are identified by their rising rotor angle, indicating their progression towards an out-of-step condition.

Definition 2 (Inclusive critical cluster): In a multi-machine power system, the estimated inclusive critical cluster of generators refers to a set of generators selected through specific criteria, which includes the critical cluster of generators.

Extensive transient stability studies and simulation of several fault cases revealed that ordinarily the generators that have the highest angle deviations, after some time in a sustained during-fault state, often encompass the critical cluster. As an example, in the case of a fault occurring on the French network, a dichotomic time-domain simulation is performed to find the CCT at 146 milliseconds. Illustrated in Fig. 2, for a fault cleared slightly after the critical time of 146 milliseconds, the generators with the highest post-fault angle deviations are the same as the ones with the highest angle deviations in the during-fault state.

Conjecture 1: For a given fault scenario, the set of generators displaying the highest angle deviations under a sustained fault encompasses the critical cluster. This set is denoted as the Inclusive CC.

Algorithm 1 computes the generator angle deviations at a given assessment time using the Taylor series equations applied within the during-fault state. Then, based on the above conjecture, to identify the ICC among all the generators,

Algorithm 1 Individual Taylor series to find generators' angle deviations at a given assessment time during fault state

DTC ($\boldsymbol{S}$,$\hat{\boldsymbol{Y}}^{red}$)
Input
1) $\boldsymbol{S}$: data of synchronous generators considering the classical model
 · $\boldsymbol{S}[j].M$: generator j inertia coefficient
 · $\boldsymbol{S}[j].E$: generator j internal voltage magnitude
 · $\boldsymbol{S}[j].P_m$: generator j mechanical power
 · $\boldsymbol{S}[j].\delta^i$: generator j initial internal angle
2) $\hat{\boldsymbol{Y}}^{red}$: system during-fault admittance matrix reduced to synchronous generator internal nodes

Output
 · $\boldsymbol{\Delta\delta_{t_a}}$: vector of synchronous generators angle deviations at the given assessment time t_a

Parameter
1) f_0: system base frequency
2) t_a: assessment time

s $\leftarrow$ $length(\boldsymbol{S})$: number of synchronous generators
$\omega_0 = 2\pi f_0$
for $k = 1 : s$ **do**
 for $j = 1 : s$ **do**
 $A_{kj} = \boldsymbol{S}[k].E \cdot \boldsymbol{S}[j].E \cdot |\hat{\boldsymbol{Y}}^{red}[k,j]| \cdot \cos(\boldsymbol{S}[k].\delta^i - \boldsymbol{S}[j].\delta^i - \angle\hat{\boldsymbol{Y}}^{red}[k,j])$
 $B_{kj} = \boldsymbol{S}[k].E \cdot \boldsymbol{S}[j].E \cdot |\hat{\boldsymbol{Y}}^{red}[k,j]| \cdot \sin(\boldsymbol{S}[k].\delta^i - \boldsymbol{S}[j].\delta^i - \angle\hat{\boldsymbol{Y}}^{red}[k,j])$
 end for
 $\frac{d^2\delta}{dt^2}[k] = \frac{\omega_0}{\boldsymbol{S}[k].M}\left(\boldsymbol{S}[k].P_m - \sum_{j=1}^{s} A_{kj}\right)$
end for
for $k = 1 : s$ **do**
 $\frac{d^4\delta}{dt^4}[k] = \frac{\omega_0}{\boldsymbol{S}[k].M}\sum_{j=1}^{s}\left(B_{kj}(\frac{d^2\delta}{dt^2}[k] - \frac{d^2\delta}{dt^2}[j])\right)$
 $\boldsymbol{\Delta\delta_{t_a}}[k] = \frac{1}{2}\frac{d^2\delta}{dt^2}[k]{t_a}^2 + \frac{1}{24}\frac{d^4\delta}{dt^4}[k]{t_a}^4$
end for
return $\boldsymbol{\Delta\delta_{t_a}}$

Algorithm 2 performs a sorting process using the obtained angle deviations at the given assessment time. By finding the most significant gap between the generators' angle deviations, those with higher values above the gap are chosen as the members of the ICC.

Similar to the other offline TSA techniques, the proposed method only necessitates inputs such as the forecasted load and generation values, and the system admittance matrix, to derive the terminal voltage and power of the generators via a load flow computation. These values, along with the generators' transient reactance, can then be utilized to determine the inputs needed for Algorithm 1 [6].

III. Performance measures

As previously mentioned, the aim of the proposed method is to provide a good estimation of the ICC. To measure the quality of this estimation, two indices are defined.

The first index is false negative FN, which shows the ratio of elements in the actual critical cluster set CC that are falsely identified as non-critical and are not present in the estimated inclusive critical cluster set $EICC$. The index is defined as follows:

$$FN = \frac{|CC \notin EICC|}{|CC|} \tag{14}$$

Algorithm 2 Identification of the ICC

ICC ($\boldsymbol{\Delta\delta_{t_a}}$)
Input
1) $\boldsymbol{S}$: data of synchronous generators considering the classical model
 · $\boldsymbol{S}[j].name$: generator j name
 · $\boldsymbol{\Delta\delta_{t_a}}$: vector of synchronous generators angle deviations at the given assessment time t_a

Output
 · $\boldsymbol{ICC}$: Vector of inclusive critical cluster of generators

Sort the vector $\boldsymbol{\Delta\delta_{t_a}}$ in descending order to obtain $\boldsymbol{\Delta\delta_{t_a}}^{sorted}$.

Sort $\boldsymbol{S}$ by $\boldsymbol{\Delta\delta_{t_a}}$ in descending order to obtain $\boldsymbol{S}^{sorted}$

Identify the value of i^* such that:
$i^* = \underset{i\in\{1,\ldots,s-1\}}{\text{argmax}} (\boldsymbol{\Delta\delta_{t_a}}^{sorted}[i] - \boldsymbol{\Delta\delta_{t_a}}^{sorted}[i+1])$.

$\boldsymbol{ICC} = \boldsymbol{S}_{sorted}[1 : i^*].name$

return $\boldsymbol{ICC}$

where $|CC|$ shows the cardinality of the set of actual CC, and $|CC \notin EICC|$ shows the number of elements in CC that are not present in the set of estimated inclusive critical cluster $EICC$.

A value of 1 for FN indicates that none of the elements of the CC are present in the $EICC$. In other words, all the elements of CC are falsely identified as non-critical. On the other hand, a value of the index equal to 0 indicates a perfect estimation of the CC, where $EICC$ is indeed an inclusive CC in the sense of Definition 2.

While the FN index offers valuable insights, it has a limitation: when many generators are falsely identified as critical, they will include the CC, resulting in an FN index value of zero. However, this over-inclusivity complicates the subsequent steps in direct TSA methods. To address this issue, a false positive index FP is defined as follows:

$$FP = \frac{|EICC \notin CC|}{|EICC|} \tag{15}$$

A value of the FP index equal to 0 indicates that the elements of the $EICC$ are also part of the CC. On the other hand, a value of the index close to 1 indicates that $EICC$ includes a considerable number of extra elements falsely identified as critical generators. A value equal to 1 shows that none of the elements of the CC are present in the $EICC$ and all the elements of $EICC$ are falsely identified as critical.

IV. Simulation results

This section presents the results of applying the proposed method to the French Extra-High Voltage power system, which comprises over 400 synchronous generators, 2900 transmission lines, and 8800 transformers. The network is modelled using Eurostag software, incorporating a detailed model for synchronous generators with regulators.

To evaluate the method's performance, from a comprehensive database of highly stressed fault scenarios, 100 three-phase short-circuit faults are selected. For each of these

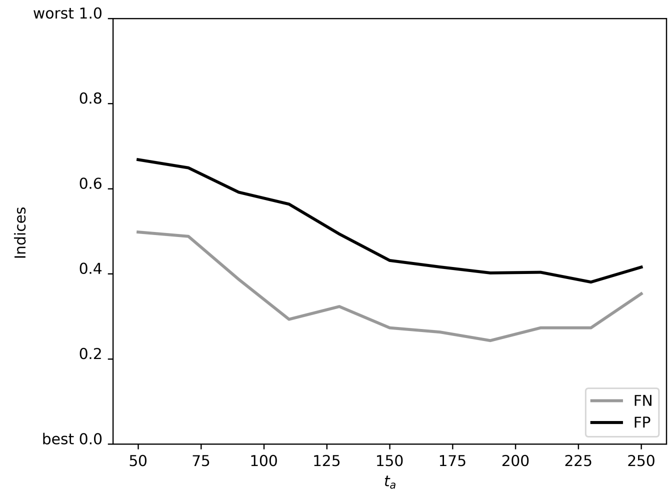

Figure 3: The average of indices for 100 case studies with different values of parameter t_a

scenarios, a dichotomic time-domain simulation is conducted to identify the CCT, and the CC while the fault is cleared at the CCT. The generators with advancing angles toward an out-of-step condition are considered as the actual CC in each scenario. Those are determined directly by Eurostag.

As can be seen in Algorithm 1, the performance of the method is tied to the parameter t_a, denoting the assessment time. t_a is the instant of time at which the generator angle deviations are estimated to identify the critical set. To investigate the impact of assessment time on the method performance, a sensitivity analysis is conducted. Fig. 3 presents the average of the indices for various t_a values ranging from 50 ms to 250 ms. The proposed method has better and almost consistent performance within the range of 150 ms to 225 ms. Lower t_a values may lack sufficient separation between generator angle deviations to effectively identify critical ones, while higher t_a values may, among others, invalidate the assumptions of the Taylor series used for estimating generator angle deviations.

To mitigate the dependence of the proposed method on the assessment time parameter, a potential solution is to employ a range of assessment times. Algorithm 1 can be executed for each time step within this range. Consequently, the resulting output would include synchronous generator angle deviations across the specified time span, rather than solely at t_a. Subsequently, the average angle deviation values over the entire time range can be computed and regarded as the generators' angle deviation. Finally, algorithm 2 can be employed to find the generators with higher values above the maximum gap between them as the members of the ICC. In this section, we have considered a time range from 150ms to 200ms, with a step size of 0.5ms.

Table I compares the average values of the indices for the proposed method against the acceleration criterion as a base technique for CCI. For the acceleration criterion, the top 10% of generators with the highest acceleration are selected as the $EICC$. The median of both indices for this criterion is more

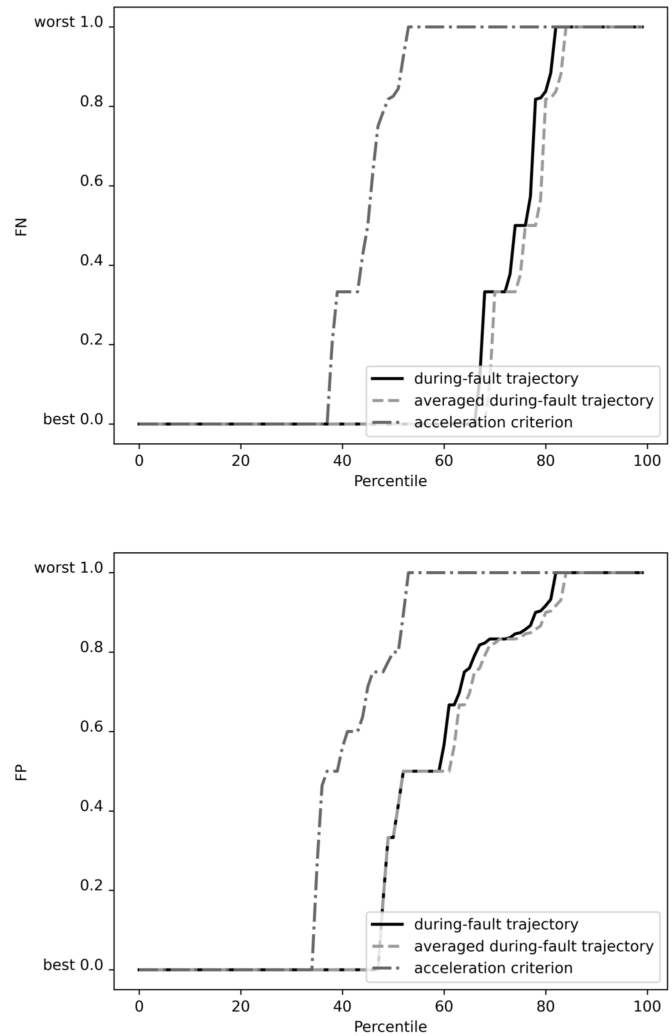

Figure 4: Percentile Distributions of indices for acceleration criterion and the proposed method.

than 0.5 indicating an unacceptable performance for most of the case studies. This poor performance can be attributed to the presence of low-inertia generation units in the French network. While these units accelerate rapidly, they are not always critical. For the proposed method, with an assessment time parameter equal to 170 ms or with averaging, both indices have comparatively lower values indicating that for the majority of the case studies, the critical generators of the $EICC$ include the elements of CC, without a considerable number of extra elements.

Despite the generally acceptable results of the method pro-

Table I: The average of indices for 100 case studies for acceleration criterion and for the proposed method

Index	FN	FP
Acceleration criterion	0.558	0.588
During-fault trajectory criterion	0.263	0.416
Averaged during-fault trajectory criterion	0.243	0.406

posed, in comparison to the time-domain simulation, it cannot handle some of the complex fault scenarios. To highlight this, Fig. 4 shows the percentile distributions of the values of the indices for all the case studies. The indices are computed using the acceleration criterion and the proposed method. It should be noted that the results presented are for some of the most stressed transient stability scenarios on the French network. As evident from the results, the proposed method demonstrates nearly equivalent index values whether using a single assessment time or employing averaging, albeit with slightly better outcomes observed with the latter. However, it's worth noting that averaging requires more computational time. In more than 60% of cases, both of the proposed approaches have an FN value of 0, demonstrating their superior performance compared to the acceleration criterion. This means that for more than 60% of the considered cases, the elements of CC are within the $EICC$. Moreover, for both approaches, for around 50% of cases the FP is equal to 0, meaning that for half of the cases, the $EICC$ is identical to the CC with no extra element.

However, in 20% of cases, both indices are equal to 1, implying that none of the elements of the CC are identified in the $EICC$. This can be attributed to several reasons. First, the proposed method relies solely on classical model data, while simulations are performed using detailed dynamic models. Secondly, not considering the post-fault state could pose challenges for some case studies, where removing the fault might change the criticality ranking of the generators. Lastly, the considered scenarios are complex and sometimes difficult to interpret even with detailed time domain simulation.

V. Conclusions and Discussions

This paper presents a simple but novel method for identifying the critical cluster of generators, an inevitable requirement for some of the direct transient stability analysis techniques. The extensive simulations conducted on the French power network demonstrated that the proposed method outperforms the traditional acceleration criterion, offering a more accurate and reliable identification of the critical generators. The proposed method can be executed either with a single assessment time or by averaging over a set of assessment times. A sensitivity analysis was conducted to find the optimal range for the assessment time parameter. Such an analysis is essential for tailoring the parameter to suit the unique requirements of any given power system. The results indicate that whether utilizing a single assessment time within the optimal range or employing averaging, the proposed method reliably estimates the inclusive critical cluster for most of the case studies. However, for about 20% of cases, none of the critical generators are identified. Considering the method's minimal data requirements and its ability to reliably estimate the inclusive critical cluster for the majority of the stressed case studies examined, it can be regarded as a promising tool for direct transient stability analysis. However, further research is necessary to advance the performance of the method. Potential enhancements may involve incorporating estimations of generators angular speeds in addition to their angles, as well as releasing the method from its simplifying assumptions.

While the proposed method shows promising results on the French network, network characteristics can vary significantly across different regions. To address this concern, we acknowledge the need for further studies at the European level to evaluate the method's generalizability and limitations. Our observations highlight that low inertia hydro plants react significantly to transient events, often resulting in sharp angle increases and their frequent inclusion within the CC. However, the paper does not address scenarios with high penetration low inertia plants, such as small hydro and renewable units. The integration of low inertia units poses new challenges, as they often have less fault-tolerance and inertia compared to traditional synchronous generators. Future research on the identification of the CC should focus more on the understanding of the transient stability dynamics with high penetration of such units. Furthermore, our observations suggest that relying solely on the during-fault state in the proposed method might lead to inefficacy in scenarios where the network undergoes islanding during the post-fault state. Further research on such scenarios can contribute to enhancing the proposed method.

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