Proc. of the European Safety and Reliability Conference (ESREL 2026)
Edited by José C. Matos, Paulo B. Lourenço, Michael Beer, Daniel Oliveira,
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doi: 10.3850/ESREL2026061419_esrel26-p26299-cd

Towards a Tool for Assessing Frequency Stability in Islanded Distribution Grids, Based on a Newly Developed Python RMS Simulation Program Built on the PandaPower Framework

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The emergency operation of distribution networks as islanded grids - temporarily independent from the interconnected transmission system - can enhance power supply resilience. Such networks typically exhibit low inertia, making frequency stability a key concern. Until now, islanded operation has mainly been considered for system restoration under transmission system operator (TSO) responsibility, leaving distribution system operators (DSOs) with little experience in assessing frequency stability. Commercial tools are expensive and tailored to TSO needs, motivating the development of simple, cost-effective solutions for evaluating and monitoring frequency stability in potential islanding scenarios. In this work, a dynamic phasor-based simulation tool was developed to assess frequency stability. It uses the PandaPower data structure to model the network and includes essential components such as lines, buses, loads, and generators with their controllers. The tool is successfully validated against PowerFactory and applied to a real section of a distribution network in a hypothetical islanded mode, using rate of change of frequency (RoCoF) and frequency nadir as stability indicators while considering single and double contingency scenarios.

Keywords: frequency stability, rate of change of frequency, frequency nadir, online dynamic security assessment, phasor-based time domain simulation, pandapower, distribution network, island operation

1. Background and Motivation

Modern societies are highly dependent on the supply of electrical energy. The energy system, consisting of production, transmission, and distribution, is undergoing a rapid transformation toward renewable energy sources. The fluctuating availability of renewable energy, the loss of inherent inertia from conventional power plants, and the increasing complexity of the system present new challenges for grid operators. Against this backdrop, new concepts to enhance resilience are being developed. One such concept is the emergency operation of distribution networks as islanded grids, which can temporarily operate independently of the interconnected transmission system and continue to supply their customers. Both during the planning phase and in the operation of islanded grids, their stability must be assessed, with different stability phenomena being distinguishable as frequency stability, rotor angle stability, voltage stability and converter driven stability according to Al Kez et al. (2023).

The most fundamental condition for operating an electrical network is the balance between generation and consumption of active power. Imbalances in active power lead to a drop or rise in system frequency, which first mitigated by primary control and then retored to nominal frequency of 50 Hz by secondary control. How quickly and how much primary control power is required depends largely on the system's inherent inertia - the instantaneous reserve of the energy system - which in today's transmission networks is primarily provided by the rotating masses of conventional power plants.

In distribution networks, however, there are mainly small power plants with little or no inherent inertia. For emergency island operation of such distribution networks, this shifts the focus to frequency stability. This contrasts sharply with the current responsibilities of distribution system operators (DSOs), whose networks operate exclusively in interconnected mode, where frequency control is the responsibility of transmission system operators (TSOs). Until now, the existence of islanded grids has only been considered in the context of system restoration and under the responsibility of TSOs. Thus, assessing frequency stability is a task that DSOs have so far paid little or no attention to.

The assessment of frequency stability, as well as the evaluation of other stability phenomena, is currently carried out by TSOs using so-called online dynamic security assessments (online DSA). In this process, a model that dynamically represents the behavior of the network under consideration is fed with real-time measurement data from the actual grid. This means the model contains both the current state of the real system and predictive capability for the system's dynamic response to changes in boundary conditions. Based on this, a predefined list of hypothetical contingency scenarios is continuously simulated, and the occurrence of instabilities or limit violations is analyzed. Common software products include Gridscale X DSA (formerly known as Siguard DSA) by Siemens AG (2025) and DSATools by Powertech Labs Inc. (2025). These advanced and costly tools are specifically tailored to the needs of TSOs. Given that DSOs currently have no basis for requiring such tools but increasingly wish to address the topic of island operation and frequency stability, there is a growing motivation to develop simple, cost-effective tools for assessing and monitoring frequency stability in potential islanding scenarios.

Accordingly, after further motivating in detail in Section 2, the current work describes the implementation and application of a lightweight dynamic RMS simulation tool suited for integration in online DSA frameworks assessing frequency stability in emergency island operation scenarios. Thereby, Section 3 describes the mathematical formulation of the dynamic system and its solution. Section 4 addresses the specific implementation and integration with the existing open-source tool pandapower, which then is verified in Section 5, Section 6 presents a case study based on a remote section of a distribution network in South Tyrol including a frequency stability analysis. Section 7 concludes.

2. Fundamentals and State of the Art

Morison et al. (2007) details the essential components of most DSA tools. The main proceeding is:

(1) Measurement of electrical grid quantities
(2) Grid state estimation
(3) Dynamic modeling of the entire network
(4) Selection of relevant contigency scenarios
(5) Simulation of all contingency scenarios and evaluation of results against predefined criteria (e.g., stability indices, limit violations)
(6) Presentation of results, issuance of alarms

Compared to transmission systems, state estimation in distribution grids is subject to significantly higher uncertainty due to lower measurement density, reduced redundancy, and the generally lower accuracy of available measurements. This situation currently affects the reliability of the simulation results, but is expected to diminish in the near future. The network model of step 3 must be sufficiently detailed to provide reliable assessments. Either the entire interconnected network must be represented, or an appropriate modeling approach for adjacent, non-represented network sections must be found. Powertech, e.g., specifies a maximum model size of 100,000 buses and 15,000 generators. At the same time, a large number of scenarios must be calculated, especially when considering multiple contingencies. Given that all calculations are continuously repeated in cycles of about 5 to 15 minutes, computational efficiency is key.

Also for distribution networks, this remains a critical factor, as DSOs are expected to have fewer resources for parallelizing contingency simulations than TSOs. Against this backdrop, the root mean square (RMS) simulation method has proven particularly effective (Machowski et al. (2008)). It enables the representation of dynamic phenomena on a time scale ranging from several minutes down to about 100 ms, thereby covering the electromechanical behavior of typical energy systems, including their control algorithms. Faster processes, such as electromagnetic transients, are not resolved, resulting in significant computational savings. Thus, the RMS simulation method is suitable for representing classical stability phenomena such as frequency, angle, and voltage stability, whereas instabilities caused by switching operations of inverter power electronics cannot be captured. These are instead analyzed using EMT simulations, which are employed in grid integration and grid connection studies.

3. Mathematical Modelling

The modeling approach implemented in this work includes all essential components of an energy system, such as buses, lines, transformers, loads, generators, and their associated control and regulation systems. The mathematical model used to describe the time-dependent behavior of the energy system belongs to the RMS model category. All alternating quantities such as current and voltage, which can be approximately represented by harmonic oscillations at the fundamental frequency of 50 Hz with time-dependent amplitudes and phase shifts, are expressed as complex phasors.

While transients in the network and in generator stators are neglected - leading to algebraic equations - nonlinear differential equations arise for generator rotors and all controllers. The resulting system equations thus form a set of differential-algebraic equations (DAEs). To solve this DAE system, the current implementation uses the *partitioned solution* approach, where differential and algebraic equations are solved separately and alternately. Comprehensive background is given e.g. in Machowski et al. (2008) and Padiyar (2018). Currently, the differential equations are solved using a multi-step explicit method (Heun's method), and the algebraic system, which is linear, is solved using LU decomposition. To preserve the linearity of the equation system, several modeling assumptions were made for both generators and loads. The consideration of generators is restricted to non-salient-pole machines, for which identical transient reactances in the direct and quadrature axes can be assumed, which allows modeling the generator as an equivalent current source with a rotor-angle-independent and therefore time-invariant shunt admittance. Loads are likewise modeled using constant impedances, enabling them - together with the time-invariant generator admittances - to be directly integrated into the bus admittance matrix without requiring recalculation at each time step. Both the linearity of the equation system and its temporal invariance - apart from discrete events - already provide, from a purely mathematical perspective, a significant computational advantage compared to nonlinear equation systems, which would need to be solved anew at every time step in the absence of the aforementioned assumptions.

4. Implementation

The implementation presented here builds on the open-source tool pandapower (Thurner et al. (2018)), which was developed for static analysis of electrical networks. It uses pandapower's basic data structures and functionalities, such as creating, manipulating, and storing network models and performing load flow calculations. The implementation described here, inspired by MatDyn Cole and Belmans (2011), enables time-domain simulation based on pandapower's static solutions. For this purpose, static generator models from pandapower are extended with dynamic models to represent their time-dependent behavior. These include not only the generator model itself (GEN) but also all models of its control and regulation components, such as the speed governor (GOV), power system stabilizer (PSS), voltage regulator/exciter (EXC), and underexcitation limiter (UEL). These control and regulation components occupy correponding slots in each power plant model. Fig. 1 shows the model configuration used in this work with the currently implemented slots as a block diagram. Unlike pandapower's

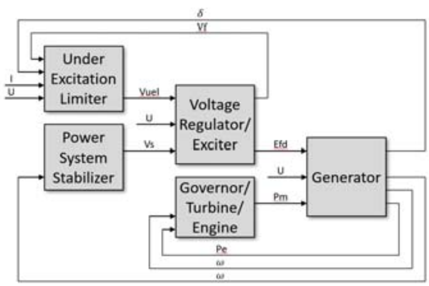

Fig. 1. Power plant controler framework.

tabular approach for specifying static models, the current implementation uses a hierarchical approach for specifying dynamic models. Based on a plant type stored in PandaPower's data tables, dynamic models and parameters are referenced hierarchically. Thereby, the plant type, which specifies an entire power plant, refers to a generator model defined as device-type and additionally to several other device-types for each device slot required to control the power plant. Device types themselves reference device models and device parameters to fully specify the dynamic behavior of the devices.

5. Verification

To assess frequency stability, an accurate prediction of the dynamic behavior of the energy system under study is essential. In this section, an error analysis is performed to evaluate the accuracy of the simulation tool implemented in this work, using the commercial software PowerFactory as a reference benchmark. Given the objective of frequency stability assessment, the focus is primarily on the time evolution of system frequency and the rotor angular velocities of individual generators. In future applications of the assessment tool, events such as generator outages, line disconnections, and large load steps will be considered. These disturbances typically result in steep gradients in the frequency trajectory, which are compensated after a few seconds by primary frequency control. Consequently, the simulations must provide reliable results within this initial post-disturbance period, and the verification presented here is restricted to this timeframe. The time required for stabilization depends on the configuration of primary control reserves, the dynamics of generating units, and the overall system inertia. According to ENTSO-E (2020), the frequency nadir in interconnected systems is typically reached within the first 10 seconds. In islanded grids, which are the focus of this work and generally exhibit low inertia, Vasconcelos et al. (2024) report a time range of approximately 1 to 2 seconds for reaching the nadir. To validate the implemented code, various network models and scenarios were analyzed. One example, based on the IEEE 9-bus system, is presented for illustration. The system, shown in Fig. 2, comprises nine buses, three loads and three generators each equipped with a transformer. All generators include voltage regulators and power system stabilizers, while generators G1 and G3 additionally include speed governors. To induce a disruption event, a transmission line (between T3 and Load B) is disconnected, causing the system to deviate from its steady state and initiating a transient response. Fig. 3 displays the simulation results of this event obtained using both the implemented software and PowerFactory. The figure shows the time profiles of rotor speeds, turbine outputs, exciter voltages, and terminal voltages of the three generators. The disturbance occurs at second 1, after which all quantities exhibit significant gradients. The focus here is not on the physical processes themselves but on the error estimation. Therefore, Table 1 summarizes the relative deviations between the results of the two simulation tools revealing a good agreement especially for the frequency focused within this work.

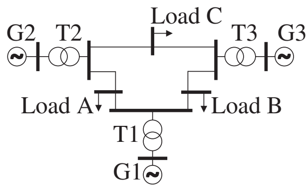

Fig. 2. IEEE 9-bus-system including three generators (G1, G2, G3), three transformers (T1, T2, T3) and three loads (A,B,C)

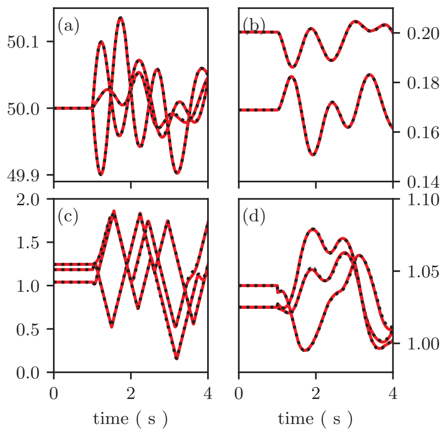

Fig. 3. Results (red) and reference results (black dotted) for (a) generator speed in Hz, (b) turbine power in p.u., (c) excitation voltage in p.u. and (d) terminal voltage in p.u. of the generators of the IEEE 9-bus-system.

Table 1. Maximum mean-normalized error within the first three seconds after the event.

	generator speed	turbine power	excitation voltage	terminal voltage
G1	3.14e-05	1.46e-03	2.26e-02	1.63e-03
G2	4.31e-05	-	3.21e-02	1.29e-03
G3	3.99e-05	1.29e-03	2.89e-02	8.74e-04

6. Application to islanded part of distribution network

The stability assessment program currently implemented does not yet include online integration of measurement data, their processing within state estimation, nor real-time model adaptation to account for switch positions and transformer tap changer settings. Consequently, the application presented in this section represents a purely offline approach applied to a representative network state of a real distribution grid segment under a hypothetical islanding scenario. The considered segment is part of the 20 kV distribution network near Sarentino and is operated by Edyna. Under normal conditions, this segment is connected to the transmission grid and supplies approximately 10,000 consumers. For most of the time - particularly during the summer months - the entire distribution network generates more electricity from renewable sources than it consumes. In preparation for a predicted transmission grid interruption, the concept foresees operating individual sections of the distribution network as islands to maintain supply for local consumers. The segment analyzed below includes two hydroelectric plants, two biomass plants, and one photovoltaic plant, as illustrated in Fig. 4 and listed in Table 2. Beside the plant type, Table 2 lists the rated power and the model type of each generator. If the generator is modelled dynamically the controlers listed in Table 3 are used, otherwise the active and reactive power is assumed to be constant. Consequently, underfrequency ride-through requirements, which obligate PV systems to remain connected down to defined frequency limits before disconnecting, are not considered in this work so far. Biomass plants equipped with internal combustion engines often exhibit faster dynamics compared to conventional hydropower plants, due to the superior controllability of the fuel source and the absence of hydraulic dead times. In modeling, these differences can primarily be accounted for through inertia constants, droop settings, and control time constants. To reduce overall complexity, this study refrains from using plant-specific models and parameters for the time being.

Table 2. Generators in the islanded part of the distribution network.

Name	Plant type	Rated Power (MVA)	Model
G1	Hydro	5.000	dynamic
G2	Biomass	0.276	dynamic
G3	Biomass	0,200	dynamic
G4	Hydro	0,720	dynamic
G5	PV	0.112	static

Fig. 4 shows the network model as a schematic single-line diagram, providing a general overview of the island grid. The detailed model used for the subsequent results, however, comprises 39 buses, 42 lines, 5 generators, and 16 loads. Thereby, the loads represent local network stations that supply various consumers at the low-voltage level, while some generators represent combined generator units.

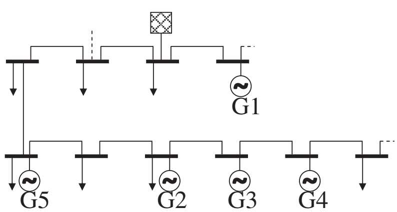

Fig. 4. Schematic island topology including generators listed in Table 2. The external grid (top) and dashed lines are disconnected for island operation.

Table 3. Controllers included in the dynamic generator models

Device-Slot	Model
Generator	Model 1.1
Governor/Turbine	IEEE G1
Exciter	EXC_DC1A
Under-Excitation-Limiter	*not used*
Power-System-Stabilizer	PSS_STAB1

Table 4 lists the contingencies considered, along with the corresponding results for the frequency stability indicators - Nadir and RoCoF. Additionally, the associated (summed) loss of active power for the generators assumed to fail is provided. As shown, the list includes all single and double failures involving Generators 2 to 4, excluding Generator 1, since its loss cannot be compensated even under static considerations.

Table 4. Contingency scenarios and frequency stability indicator results.

#	Event	Loss (MW)	Nadir (Hz)	RoCoF (Hz/s)
C1	Outage of G3	-0.12	49.90	0.17
C2	Outage of G2	-0.17	49.86	0.23
C3	Outage of G4	-0.43	49.61	0.59
C4	Outage of G3 & G2	-0.29	49.75	0.40
C5	Outage of G2 & G4	-0.60	49.45	0.76
C6	Outage of G4 & G3	-0.55	49.50	0.71

To illustrate the behavior of the generators, particularly the primary control response, Fig. 5 shows the prime mover output for each generator in per-unit (p.u.) as time series for contingency scenario C1. Starting from the steady-state condition, which persists until the outage of generator G3, the prime mover power of the failed generator drops to zero, while the primary controls of the remaining generators increase their output to compensate for the resulting power deficit. Fig. 6

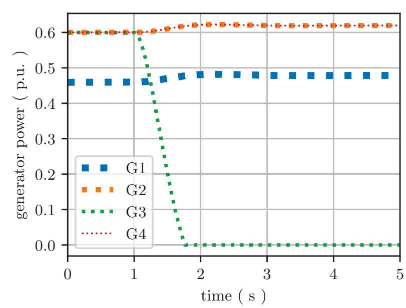

Fig. 5. Power of the prime movers of individual generators in p.u. for contingency C1.

illustrates the power delivered to the grid, shown as absolute values (in MW) and as stacked curves. Unlike the prime mover power, which is subject to inertia, the power actually injected into the grid drops instantly to zero for the failed generator as its connection is interrupted automatically as soon as failure is detected. This visualization highlights two aspects: first, how system balancing evolves over time, as shown by the top line representing the total power; and second, that this balancing is primarily achieved through the output of the largest generator, G1. However, since the primary control requires some time to increase power output, there is a temporary deficit in active power within the network, causing frequency deviations.

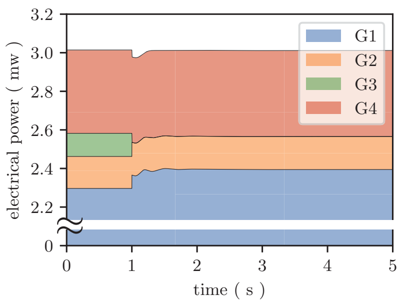

Fig. 6. Absolute generator output powers for contingency C1 as stacked curves.

Fig. 7 shows the rotor frequencies of the individual generators, as well as the average frequency of those generators that remain connected to the grid after the outage event. Due to the low line impedances between the connected generators, the internal voltage phasors are strongly coupled, so their frequencies exhibit only minor deviations.

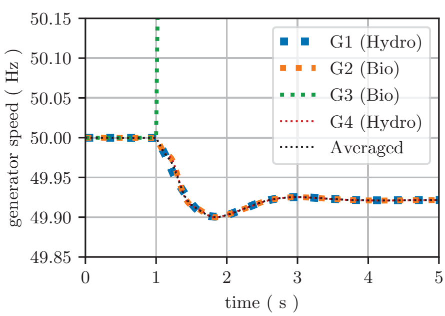

Fig. 7. Individual generator speeds and the arithmetic mean for the remaining generators during contingency C1

Therefore, the average frequency trajectory can be considered for determining the RoCoF and the nadir. Fig. 8 accordingly shows the averaged frequencies of all connected generators for each of the singe-failure (blue colors) and double-failure (red colors) contigencies, respectively. The RoCoF is defined as the time derivative of the frequency deviation immediately after the event. According to ENTSO-E (2020) it is the most important indicator of a power systems' state of health from the point of view of frequency stability. For this purpose, a discrete derivative is calculated according to

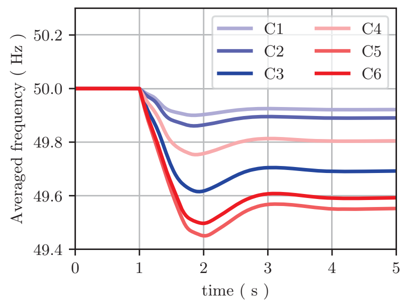

Fig. 8. Averaged frequencies for all contingencies.

$$\mathrm{RoCoF} = \left.\frac{d\Delta f}{dt}\right|_{t=0^+} \approx \frac{f_{t=0} - f_{t=\Delta t}}{\Delta t} \tag{1}$$

using a time window of $\Delta t = 500\,\mathrm{ms}$ resulting in the values given in Table 4. The nadir values correspond to the local minimum frequency immediately following the event.

Steep frequency gradients, i.e., RoCoF values of large magnitude, can cause pole slipping in conventional generators. This occurs when the prime mover forces the rotor to jump forward by one pole pair. The potential consequences include severe mechanical stress on the generator, leading to shaft damage, and extremely high currents that can cause thermal damage to the coils. Ultimately, this can result in complete destruction of the generator and massive grid instability. Therefore, power plant operators aim to disconnect their machines when RoCoF values exceed certain critical thresholds, which of course accelerates the frequency decline.

In this context, ENTSO-E (2018) proposes reference values for RoCoF protection relays intended to trip generators, aiming to harmonize national grid codes regarding generators' RoCoF withstand capability. For an averaging window of 500 ms, a RoCoF threshold of $\pm 2, \mathrm{Hz/s}$ is suggested, which is not exceeded by any of the results presented in Table 4. Furthermore, the European Commission (2017) defined binding EU-wide requirements for automatic remedial actions. The first step of this gradual scheme is triggered at 49 Hz, foreseeing a load shedding of 12.5%. This threshold is likewise not reached by any of the current results. However, it should be kept in mind that the results strongly depend on the machine and controller parameters which, in the scope of this work, were chosen based on typical values rather than exact specifications.

7. Conclusion and outlook

Within the scope of this work, a dynamic RMS-based simulation code was developed, verified, and applied to a real distribution network operating in a hypothetical island mode to assess its frequency stability. The simulation tool uses the PandaPower data structure to represent the network model and accounts for key components such as lines, buses, loads, and generators, including their controllers and auxiliary devices. It was verified using PowerFactory and is suitable for evaluating frequency stability based on the indicators RoCoF and nadir. The presented case study, assuming an islanded operation with standard parameters for all generators and controllers, showed no violations of the two most important frequency stability indicators.

A major objective is to integrate the simulation tool with a digital twin to enable real-time frequency stability assessment. Furthermore, the authors intend to extend the tool to dynamically include additional components such as inverters in combination with renewable energy sources. However, the underlying RMS-based approach imposes limitations on the lower time scales, excluding the assessment of new and significantly faster transient stability phenomena, such as inverter-driven instabilities.

Acknowledgement

This work has been funded by European Union under Grant Agreement no. 101075665 (eFORT) as well as the German Federal Ministry of Education and Research under grant No. 03SF0637 (RESIST). The content of the article reflects the views only of the authors.

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