Dynamic Frequency Control Support by Energy Storage to Reduce the Impact of Wind and Solar Generation on Isolated Power System's Inertia

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***Abstract*—In electrical islands, frequency excursions are sizeable and automatic load shedding is often required in response to disturbances. Moreover, the displacement of conventional generation with wind and solar plants, which usually do not provide inertial response, further weakens these power systems. Fast-acting storage, by injecting power within instants after the loss of a generating unit, can back up conventional generation assets during the activation of their primary reserve. This paper relies on dynamic simulations to study the provision of such a dynamic frequency control support by energy storage systems in the French island of Guadeloupe with large shares of wind or solar generation. The results show that fast-acting storage, by acting as a synthetic inertia, can mitigate the impact of these sources on the dynamic performance of the studied island grid in the case of a major generation outage. The other concerns raised by renewables (e.g., variability, forecast accuracy, low voltage ride-through, etc.) have not been addressed within this project.**

***Index Terms*—Frequency control, isolated power systems, power system dynamic stability, power system security, solar power generation, supercapacitors, wind power generation.**

Acronyms

ALS	(Under-frequency) automatic load-shedding.
DESS	Distributed energy storage system(s).
DFCS	Dynamic frequency control support.
PV	Photovoltaic.
RES	Renewable energy sources.
ROCOF	Rate of change of frequency.

I. Introduction

EDF Island Energy Systems (EDF SEI) operates several electrical islands with peak loads in the range 115–435 MW, namely Corsica and the French overseas departments (Guadeloupe, Martinique, French Guiana, and Réunion).

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For technical reasons that will be further detailed in this paper, frequency control is challenging in such isolated power systems. Indeed, they are notably characterized by very fast changes in the rotating speed of generators after any sudden imbalance between production and demand such as the loss of a large generating unit. Conventional technologies used for power generation are not always capable of responding quickly enough to prevent unacceptably low frequency in such cases, even when the available amount of frequency control reserve exceeds the power deviation. It results in relatively frequent use of automatic load-shedding (ALS) to restore the power equilibrium and prevent frequency collapse, with subsequent consequences on the economic activity, among others.

Besides, electronically coupled sources have been growing rapidly in electricity systems over the past few years. In particular, due to attractive feed-in tariffs, the island grids operated by EDF SEI have experienced a rapid increase in wind and photovoltaic (PV) generation: dozens of MW have already been put into service and a grid connection queue around 100 MW was reported *for each system* at the end of 2010. The technical features of these renewable energy sources (RES) raise concerns, notably regarding their impact on system reliability and security. In particular, in most cases, they do not provide inertial response and, therefore, tend to alter the transient frequency response of power systems [1]–[7]. That is one of the reasons why a maximum instantaneous penetration limit of variable RES (30%) has been put in place in the French islands by the ministerial order [12].

Various solutions have been proposed to tackle the inertia issue, such as extra rotating masses added to power systems via the connection of generators dispatched in synchronous compensation mode [5]. Another option consists of making electronically coupled sources able to mimic the rotational inertia of conventional generators. The provision of this so-called "synthetic" or "virtual" inertia requires new features to be added to the power conversion system of these units. For example, variable-speed wind turbines can supply synthetic inertia thanks to a supplementary loop in their control system [4]–[11]. The required power is extracted from the rotating masses of the turbines, which makes this response close to the one of conventional plants, even if it cannot be considered as synchronous inertia *stricto sensu*. Besides, other inverter-interfaced generators that do not inherently have a source of stored energy, such as PV, can also supply synthetic inertia on condition that a sufficient energy store is included in their power conversion chain [13], [14]. However, all the options discussed in the literature have some shortcomings that require further studies—synthetic inertia by wind turbines: limited by speed and power ratings, recovery period, etc. [4], [6], [10], [11]— and, when they cannot be put in place, distributed energy storage systems (DESS) offer an interesting alternative.

Indeed, in a previous paper [15], the use of fast-acting storage to provide a prompt, short-term support to frequency control in isolated power systems is investigated. The purpose of this dynamic frequency control support (DFCS) is to take advantage of the short response time—milliseconds in some cases [16], [17]— of modern DESS to improve the dynamic performance of isolated power systems. In [15], dynamic simulations carried out on the case of the French island of Guadeloupe show that storage performing DFCS can effectively mitigate the frequency excursions caused by generation outages, thus reducing the need for load-shedding.

Following these promising results, and in view of the development of noninertia type RES in EDF SEI grids, further investigations have been carried out: this paper deals with the use of fast-acting DESS to provide dynamic frequency control support in electrical islands with high shares of renewables. This advanced service will become all the more necessary in the case of a major generation outage as the inertial response of these isolated power systems will progressively be eroded by the displacement of conventional synchronous units with wind and PV generation in the future.

As explained in [18], dynamic and power-hardware-in-the-loop simulations have been used to study the provision of DFCS by energy storage in Guadeloupe, including cost/benefit analysis and experimental test of a small-scale prototype. Ultracapacitors ([19], [20]) are well-suited to such a pulse power application and have, therefore, been included in the storage units modeled during this project. This technology has already been tested in the field: for instance, a MW-scale ultracapacitor-based DESS was built in Hawaii in 2006 to counteract the power and voltage fluctuations of a wind farm [21]. It performed as designed and provided significant stabilization to the grid, but was unfortunately destroyed by an earthquake less than a year after it was commissioned. This said, although this paper focuses on ultracapacitors, other storage technologies such as flywheels and batteries (see [17]) are capable of providing similar dynamic performance.

In Section II, this paper gives a theoretical background, defines DFCS, and explains how it can complete the existing frequency control scheme in the French islands. The layout of the DESS to provide this service and the control strategies that have been developed are then described in Section III. Finally, the last section analyses the simulations that have been conducted with wind and PV penetration levels up to 30% in Guadeloupe, an amount that should be reached soon.

II. Theoretical Background and Introduction to DFCS

A. Transient Frequency Response of Power Systems

In any power system, the active power generation must constantly match the demand. Disturbances in this balance are compensated for by the kinetic energy of the rotating generators and motors connected to the network, resulting in a variation in the system frequency f from its set-point value f_0. Under small signal conditions, the time derivative of the frequency deviation Δf can be estimated as follows [22]:

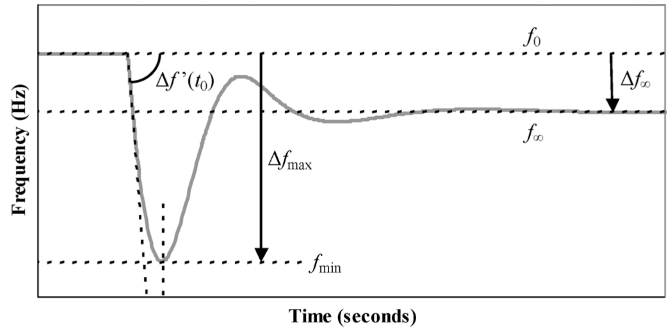

Fig. 1. Typical system frequency response to a large generation outage.

$$\frac{d(\Delta f)}{dt}(t) = f_0 \frac{P_m(t) - P_e(t)}{2E_{K\mathrm{eq}}} = f_0 \frac{\Delta P^{pu}(t)}{2H_{\mathrm{eq}}} = f_0 \frac{\Delta P^{pu}(t)}{M_{\mathrm{eq}}} \tag{1}$$

where $P_m(t)$ and $P_e(t)$ [MW] are the power generation and demand, $E_{K\mathrm{eq}}$ [MW.s] is the kinetic energy stored in the rotating masses of the synchronous area at f_0, $H_{\mathrm{eq}} = E_{K\mathrm{eq}}/VA_{\mathrm{base}}$ [MW.s/MVA, on VA_{base}] is the per unit inertia constant of the power system, and M_{eq} [s] is its mechanical starting time.

Several levels of control are performed to maintain the system frequency at its set-point f_0. Each of them has its own specifications and relies on a given amount of power reserve that is kept available to cope with power deviations [23], [24]. In particular, the restoration of the power equilibrium in the first seconds after an incident is performed by the primary frequency control. All the generating units located in a synchronous area are fitted with a speed governor to perform this task. In steady-state, the activation of their primary reserve follows a proportional speed-droop characteristic such as

$$\frac{\Delta P_i(t)}{P_{ni}} = -\frac{1}{\delta_i} \frac{\Delta f(t)}{f_0} \tag{2}$$

where $\Delta P_i(t)$ [MW] is the variation in the power output of the generator i provided that its reserve is not completely used up, P_{ni} [MW] is its rated power and δ_i [w/o dim.] is its permanent droop. On a power system scale, the contributions of the generating units combine with the self-regulating effect of load to restore the balance between generation and demand after a disturbance. Fig. 1 shows the typical aspect of the system frequency response after a sudden large loss of generation.

Early in the transient stage, some power is drawn from the rotating masses of the remaining generation, which causes the frequency to decrease. At t_0, the rate of change of frequency (ROCOF) is proportional to the magnitude of the overload on the remaining generation (e.g., a loss of power $\Delta P_0 < 0$ [MW]) and inversely proportional to the remaining kinetic energy $E'_{K\mathrm{eq}}$. It thus depends on how many and which units are running at the time of the outage. From (1), we derive

$$\Delta f'(t_0) = f_0 \frac{\Delta P_0}{2E'_{K\mathrm{eq}}} = f_0 \frac{\Delta P_0^{pu}}{M'_{\mathrm{eq}}}. \tag{3}$$

Within seconds, the primary control reserve is activated by the frequency deviation and restores the power equilibrium. The frequency drops to a nadir $f_{\min}$ that depends on many factors

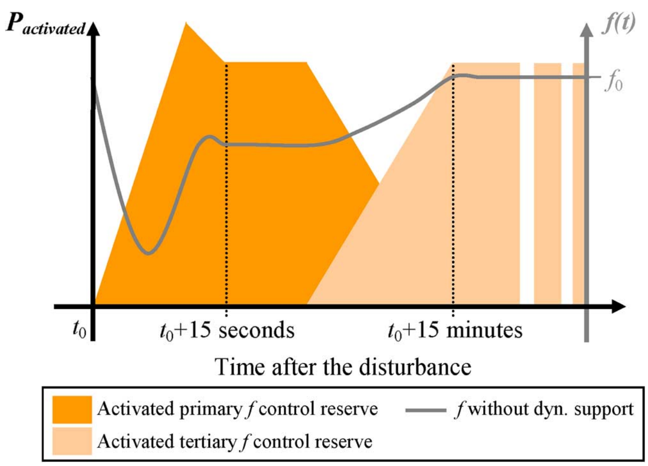

Fig. 2. Activation of reserves in French isolated grids—current practices.

(amplitude of the power imbalance, system inertia, dynamic characteristics of generators and loads, etc. [24]).

Provided that the primary reserve capacity of the remaining power plants is sufficient to cover the incident, the frequency stabilizes at a value f_∞. The quasi-steady-state deviation Δf_∞ is governed by the amplitude of the disturbance and by the network power frequency characteristic K [MW/Hz]

$$\Delta f_\infty = \frac{\Delta P_0}{K} \tag{4}$$

where K can be estimated by adding the power frequency characteristics of the generators subject to the primary frequency control ($K_i = P_{ni}/(\delta_i f_0)$ for the machine i) with the one corresponding to the self-regulating effect of loads [24].

If the primary reserve is insufficient or too slow, the only way to prevent a hazardous deep drop in f is ALS, which is performed using under-frequency relays in HV/MV substations. The system load is divided among stages that are gradually shed when the frequency reaches preset thresholds. This staggered operation allows disconnecting the appropriate amount of load for the restoration of balanced conditions.

B. Frequency Control in French Island Energy Systems

Based on the grid code [25], Fig. 2 illustrates the activation of frequency control reserves following an incident at time t_0 (e.g., loss of generation) in the systems operated by EDF SEI. Secondary control does not exist in the French islands, as often in isolated grids. Frequency regulation is thus performed through primary control (automatic) and tertiary control (manual). Generators must activate their primary control reserve within 15 s in response to disturbances. They must be able to maintain this contribution, which must comply with (2), for at least 15 min to enable other generation assets to be brought online (e.g., peaking turbines). RES such as wind and PV do not participate in frequency control at present.

Table I compares some data concerning frequency control in the former UCTE and in Guadeloupe. It emphasizes at least two typical properties of isolated power systems:

1) For technical reasons, the inertia constant of island grids is usually low, even if the commitment of combustion turbines drives it up at peak time.

TABLE I
COMPARISON OF SOME SALIENT FIGURES REGARDING FREQUENCY CONTROL

	Former UCTE [24]		**Guadeloupe**	
System load (2009)	Off-peak	Peak	Off-peak	Peak
	250 GW	400 GW	150 MW	250 MW
Reference incident [MW]	3000		Around 25	
K [MW/Hz]	15000	21000	60	100
f_∞ [Hz] using eq. (4)	49.8	49.86	49.58	49.75
M_{eq} [s]	12		7	9
$\Delta f'(t_0)$ using eq. (3)	-50 mHz/s	-30 mHz/s	-1.2 Hz/s	-0.6 Hz/s
1st stage of ALS [Hz]	49 Hz		48.5 Hz	

2) For economic reasons, generators in islands are large compared with the system load. That is why any outage results in a considerable overload of the remaining units.

In Guadeloupe, the minimum amount of primary power reserve that must be kept available (~20 MW) is set so as to maintain the risk of activating each stage of ALS under given power quality limits. In real-time, the system operator adjusts the working points of generators to allocate at least as much reserve as needed; because of 2), the actual amount of primary power reserve can be up to twice as high as required.

The combination of 1) and 2) leads to a high sensitivity of system frequency to generation outages: for instance, Table I shows that the ROCOF is over 20 times higher in Guadeloupe than in former UCTE after occurrence of a reference incident consisting in the loss of the largest infeed. Most of the generation technologies used in island grids, including Diesel engines and steam turbines, cannot respond fast enough in such cases to prevent a deep frequency drop. In spite of efforts to provide ample primary reserve, with subsequent costs, it results in the activation of the first stage(s) of ALS.

C. Additional Concerns Due to Wind and PV Generation

Besides, the isolated grids operated by EDF SEI have been experiencing a noticeable increase in wind and PV generation over the past few years, which has resulted in a need for the assessment of their impact on frequency control.

On the one hand, the inertial response of these renewable sources is either lower than that of conventional generators (case of fixed-speed wind turbines) or negligible (case of electronically coupled devices such as variable-speed wind turbines and PV) [1]–[7]. As the installed capacity of RES increases, synchronous units must be dispatched down and eventually shut down when their minimum power output is reached, which reduces the overall power system inertia. Therefore, according to (1) and (3), the displacement of conventional generation with wind and PV plants leads to higher ROCOF, i.e., further weakens the ability of isolated power systems to handle generation outages.

On the other hand, part of the generation embedded within distribution networks—among which most of the wind and PV plants— disconnect from the grid during under frequency excursions. With the exception of unwanted operation of mains decoupling relays, this is not an inherent flaw of electronically coupled resources, which are now able to comply with extended frequency ride-through requirements (e.g., 46–52 Hz in the French island grids). In fact, the distributed generators in question trip offline for two main reasons: 1) because they were put into service before such reinforced ride-through capabilities became mandatory and 2) because they are still compelled to do so by

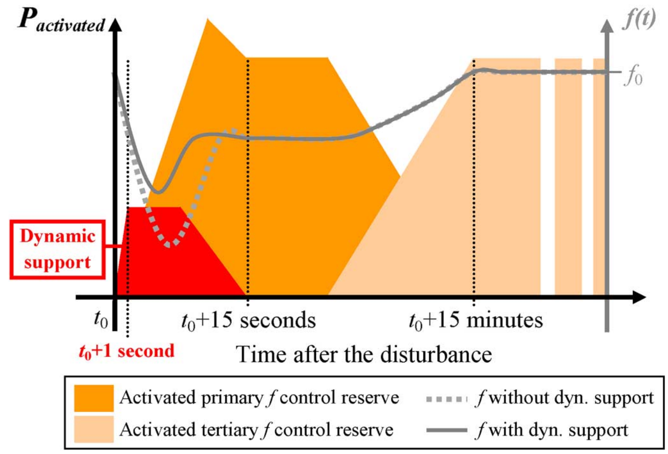

Fig. 3. Activation of reserves in French isolated grid—DFCS and its effects.

the grid code [25] in one particular case: the generation devices connected to a distribution feeder equipped with an automatic recloser on its main circuit breaker must disconnect from the grid when the frequency falls below 49.5 Hz. This requirement was originally put in place to protect distributed synchronous generators and appliances fitted with motors. On the whole, these disconnections increase the total imbalance to be handled following the loss of a major infeed, with subsequent adverse effects on the frequency response of the grid.

Furthermore, higher shares of wind and PV, which do not supply governor response, also lead in a decreased number of units involved in primary frequency control. The impact on the dynamic performance of the primary reserve is not trivial; however, all other things being equal, (4) shows that it results in increased quasi-steady state-deviations as the network power frequency characteristic K goes down when the primary reserve is allocated on fewer generators.

Due to these impacts, among other concerns such as the management of variability and forecast errors (not addressed herein), a maximum penetration limit of variable renewables is now imposed in the French islands [12]. To maintain power system security, these sources can be required to temporarily disconnect from the grid when their instantaneous penetration level reaches 30%. This value was set based notably on an international review of comparable cases, on various internal studies and on the operational experience of EDF SEI. According to the grid code [25] (REF 3), it may be revised in the future to make allowance for advances in RES integration.

D. Dynamic Support by Energy Storage Systems

DFCS is an advanced service that can be provided by modern storage systems to isolated grids. As shown in Fig. 3, it consists of injecting (or absorbing) power in the time-frame of hundreds of milliseconds up to seconds after a disturbance so as to support the other generation assets during the activation of their primary reserve. Some power is supplied by the DESS for a short period of time in lieu of being drawn from the kinetic energy of the rotating masses: during the frequency fall, the storage behaves as a "synthetic inertia." Consequently, it mitigates the ROCOF and $\Delta f_{\max}$, which make it a possible solution to the inertia concern discussed above.

By reducing the ROCOF during the activation of primary control reserve, DFCS could complete the existing frequency ancillary services in the French island grids such as Guadeloupe. Considering the characteristics of these systems, dynamic support should comply with the following requirements:

— **Deployment time**: the dynamic reserve must be activated some time before ALS starts (at 48.5 Hz in Guadeloupe). As the ROCOF can exceed 1 Hz/s in French islands, it must then be fully deployed in less than 1 s to be useful.

— **Duration of delivery**: the dynamic reserve must be supplied at least until the power deviation is completely offset by the primary control, that is to say, until the frequency nadir is reached (which takes 2 to 3 s). This duration can be extended to about 10 s so as to support the frequency recovery as well.

— **End of delivery**: the end of delivery must be progressive in order to avoid creating any sudden imbalance in a system that is already weakened. A 10-s ramp down from full power to zero has performed well in dynamic simulations.

It is worth noting that response time is the key parameter of dynamic support. Therefore, although it only requires "short-term" storage (e.g., ultracapacitors) to perform DFCS, other fast-acting technologies (e.g., batteries and flywheels) could have the same effect on the system transient frequency response. Moreover, any storage system of suitable energy capacity could provide other services in addition to dynamic support (e.g., participation in primary control). These questions fall beyond the scope of this paper but offer interesting perspectives for further technical/economic analysis.

In a previous paper [15], simulations were made to assess the amount of dynamic reserve required to keep the nadir $f_{\min}$ above the first threshold for ALS in the case of a generation outage in Guadeloupe. The case study presented below focuses on the effect of DFCS with larger shares of RES.

III. Overview of the DESS Structure and Control

A. Overview of the Considered Ultracapacitor Storage Unit

A scalable, generic model of DESS for power system analysis has been developed and validated during this research (see notably [16] and [18] for details). Fig. 4 shows the structure of the ultracapacitor-based DESS that has been designed, modeled, simulated, and then tested using real-time simulation. The ultracapacitor bank is connected to the grid through a power electronic conversion system including a PWM boost chopper and a PWM voltage source inverter.

The DESS supervision selects the appropriate operating mode and computes the active/reactive references $P_{r\_\mathrm{ref}}/Q_{r\_\mathrm{ref}}$ that are tracked by the automated control routines. A phase locked loop (PLL) is used to synchronize the DESS to the grid. The control of the inverter is carried out in the rotating $d-q$ frame. To track the active power reference P_{r_ref}, the control routines alter the storage current i_{sc} through the chopper: the resulting power flow is followed by the inverter since its direct current component i_{rd} is used to control the voltage of the dc-bus. The reactive power of the DESS is controlled through the quadrature current component i_{rq} of the inverter. This control scheme was chosen to facilitate a future upgrade of this

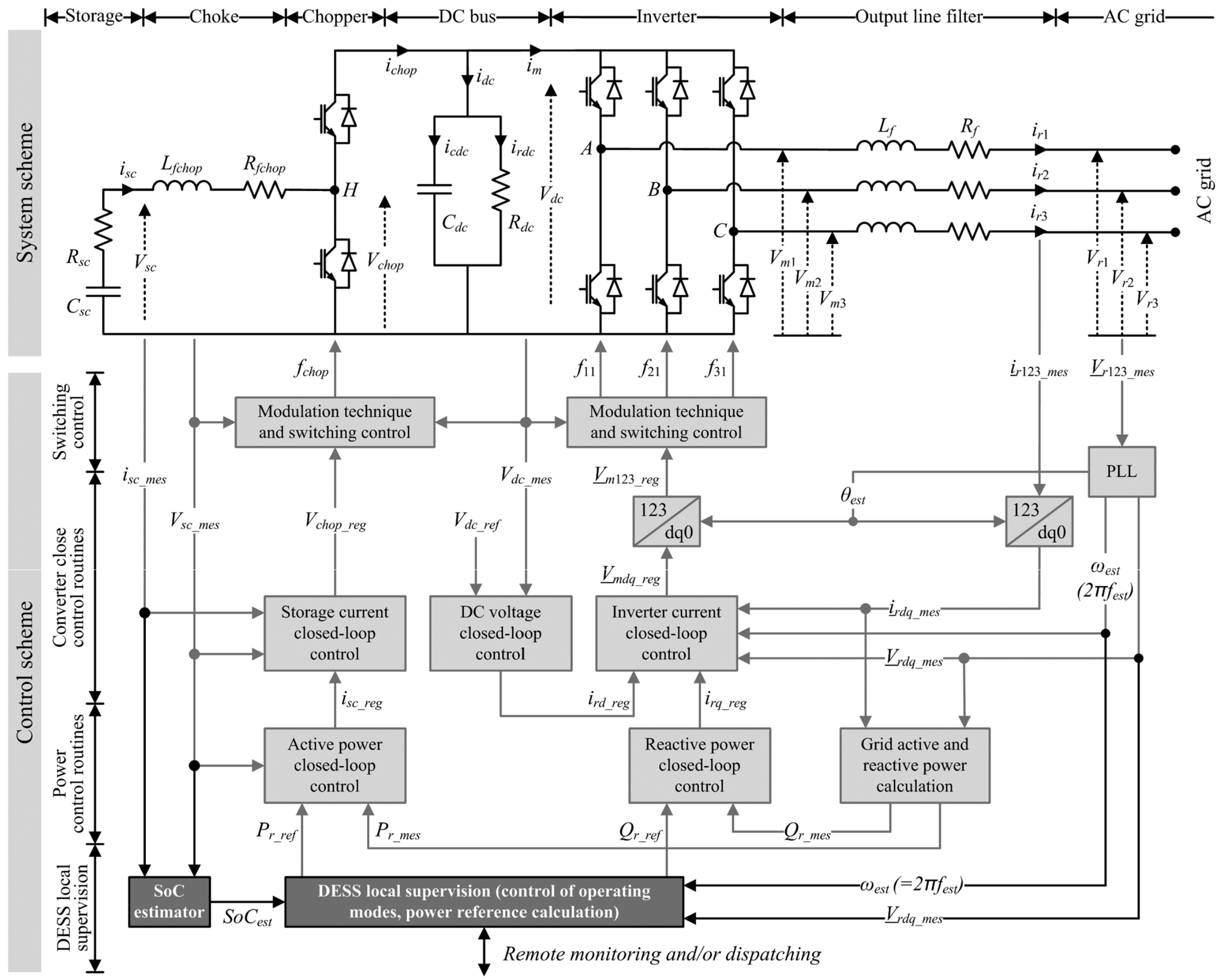

Fig. 4. Layout of the ultracapacitor DESS based on a voltage source converter to perform DFCS.

DESS model to a multisource power station (hybrid RES + storage).

B. DESS Supervision to Perform Dynamic Support

The proposed supervisory control is local and automatic so as to take full advantage of the dynamics of ultracapacitors.

Since DFCS is a matter of active power, this paper focuses on the calculation of P_{r_ref}. However, although we set $Q_{r\_\mathrm{ref}} = 0$ in the following, storage units providing both dynamic support and local voltage control at the same time have also been considered by the authors, with promising results (see [16]).

The DESS supervision was developed using an iterative process including dynamic and real-time simulations [18]: all the refinements found necessary to improve the operation of the lab prototype (filtering, delays, etc.) have then been included in the models to make them as realistic as possible. To perform DFCS, the main input to the control system is the frequency estimation f_{est} from the PLL. The following three operating modes are included in the DESS supervision herein:

1) The first one is based on two **power/frequency droops** (δ_1 and δ_2) as shown in Fig. 5. With δ_1 set at 1% or 2% (full activation of the reserve for a Δf of 0,5 and 1 Hz, respectively), this control was found to perform well during moderate transients: it provides sufficient support without inducing any unwanted disturbance on the system operation as the DESS response is proportionate to the amplitude of the event. A user-defined deadband (DB) is introduced to ensure high availability of the storage: it avoids progressive discharge due to continuous action of the DESS when the frequency is close to f_0. The main drawback of this first operating mode is its relatively long response time (P_{r_ref} "follows" the frequency excursions), which has a detrimental effect on the ability of the DESS to handle serious outages.
2) That is why the DESS supervisory control was completed by a second operating mode whose activation is controlled **based on the time derivative of *f***. Full deployment of the dynamic reserve is performed when the measured ROCOF falls below the preset threshold ξ_{boost} for at least $T_{\mathrm{on\_boost}}$ [Fig. 5 (2a)]. This "boost" control is deactivated and a progressive transition to the first operating mode is carried out as soon as the ROCOF is positive for more than $T_{\mathrm{off\_boost}}$ [Fig. 5 (2b)], indicating that the frequency recovery has started. With appropriate settings of ξ_{boost} [using (3)] and of the time delays, this function enables a selective detection of major generation outages in no more than a few 100 ms.
3) The DESS switches to **charging and standby mode** when f_{est} stays inside the deadband for at least T_{charging}. Delaying the charging by a few 10 min after an event is useful to avoid adding extra load onto the system as long as it remains possibly weakened. This feature is all the more

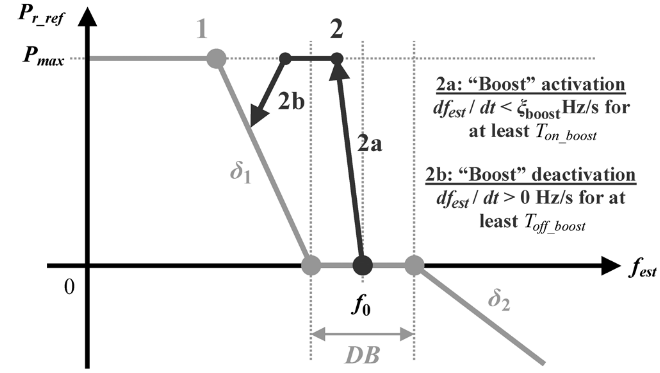

Fig. 5. Calculation of the active power references of the DESS for DFCS.

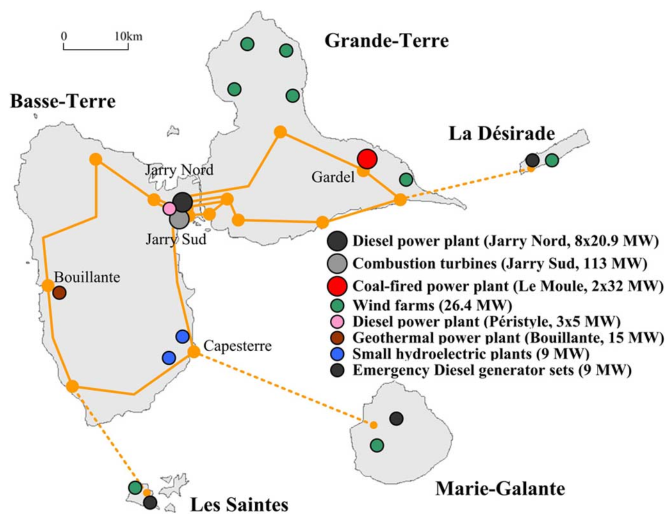

Fig. 6. HV grid and generation assets in the archipelago of Guadeloupe.

interesting as it does not have significant adverse effects on power system security: indeed, statistics over several years show that the probability of occurrence of a second event likely to require DFCS within the half hour after an outage is negligible (less than 1%). Once charged, the storage stands by: the state of charge (SoC) remains at its reference $\mathrm{SoC_{ref}}$ and a small amount of power—a few percent of the DESS rated power— is drawn from the grid to cover the idling losses.

IV. Case Study: DFCS in Guadeloupe With and Increasing Wind/PV Penetration

A. Presentation of the Guadeloupean Power System

Located in the eastern Caribbean Sea, the archipelago of Guadeloupe is an overseas department of France. It covers 1600 km^2 and its population was around 400 000 inhabitants in 2010. The peak demand on the system reached 260 MW in 2010 [26]. Fig. 6 presents the structure of the HV grid as well as the major generation centers of this isolated power system.

The transmission system is operated at 63 kV and includes 13 substations. The main existing generating sets as at the end of 2009 are presented in Table II (according to [26]).

Fig. 7 shows an example of daily generation profile in Guadeloupe. Within the current French feed-in tariffs scheme, RES have the highest priority level in the dispatch order (bottom of

TABLE II
Main Generation Assets in Guadeloupe at the End of 2009

Power station	Plant type	Number of units	Unit rated power	Total (plant) rated power
Peaking generation				
Jarry Sud	Combustion turbines	4	20-40 MW	113 MW
Conventional baseload / intermediate generation				
Jarry Nord	Diesel engines	8	20.9 MW	167.2 MW
Le Moule	Bagasse/coal boilers	2	32 MW	64 MW
Péristyle	Diesel engines	3	5 MW	15 MW
Renewable Energy Sources				
Bouillante	Geothermal	2	5-10 MW	15 MW
Embedded	Small hydroelectric	12	0.1-3.5 MW	9.6 MW
Embedded	Wind farms	12	0.5-4.4 MW	26.4 MW
Embedded	Photovoltaic plants	Many	Variable	11 MWp

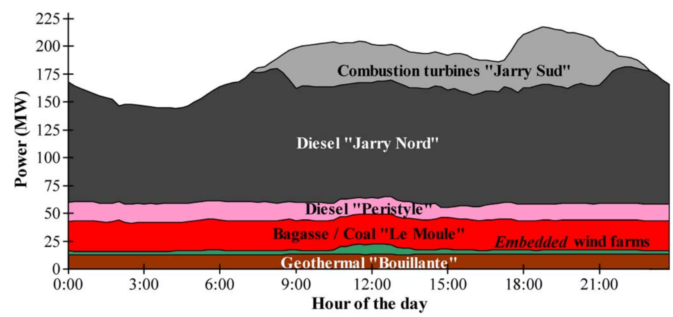

Fig. 7. Example of a daily generation profile in Guadeloupe.

the "dispatch stack") and do not participate in frequency control. The priority level of the fossil-fuel stations is set either by contractual agreements in the case of nonutility owned facilities (e.g., bagasse/coal-fired plants) or according to the economic merit order in any other case. The generating sets with the highest operating costs (peaking turbines) are at the top of the "dispatch stack:" they are committed last and for the shortest possible duration. The primary reserve is provided by Diesel engines, bagasse/coal-fired units and combustion turbines during peak demand periods.

B. Dynamic Models Used to Carry Out the Simulations

The provision of DFCS by DESS in Guadeloupe with higher shares of noninertia-type RES has been characterized using the Eurostag software package v4.4. Eurostag is a time-domain simulation program that uses phasor representation for electromechanical power system dynamic simulation (transient, mid- and long-term stability) [27].

The model of the Guadeloupean grid is based on data provided by EDF SEI (lines, transformers, etc.). The dynamic models of all fossil power plants contributing to frequency control have been developed by EDF R&D using real measurements made during power system disturbances. Synchronous-generator-based RES (i.e., geothermal and small hydro plants) are represented using standard models from the Eurostag library. The inertia constants of synchronous generating units have been computed using manufacturer information. Finally, five real generation outages have been reproduced in Eurostag in order to tune the load representation (static load model + induction motors) and validate the dynamic model of the Guadeloupean power system (see details in [16]): the simulation results have been found in good agreement with the real—measured— response of the system.

TABLE III
SOME CHARACTERISTICS OF THE MODELED ULTRACAPACITOR-BASED DESS

Power conversion system			
Rated apparent power (S_n)		600 kVA	
Rated active power (P_n)		500 kW	
Efficiency at rated power		Around 95 %	
Ultracapacitor bank			
Ultracapacitor bank arrangement		6p x 16s Maxwell BMOD0165-P048	
Total system capacitance (C_{sc})		61.9 F	
Operating voltage range		300 V (SoC_{min}) – 750 V (SoC_{max})	
DESS control and local supervision			
δ_1 / δ_2	2 % / 4 %	DB	± 100 mHz
ξ_{boost}	-0.8 Hz/s	$T_{on\ boost} / T_{off\ boost}$	100 ms / 100 ms

TABLE IV
PRESENTATION OF THE STUDIED SCENARIOS (REASONABLE WORST CASES)

	Scenario 1	Scenario 2
Demand [MW]	135.4	
Wind (and/or PV) penetration	12 %	30 %
Generation unit that trips	Le Moule bagasse/coal unit 1 (21.3 MW)	
Primary control reserve [MW]*	28.5	
M_{eq} **[s]***	6.0	5.1
Estimated K [MW/Hz]*	46	38

*Values calculated at time t_0 + *epsilon*, *i.e.* without the unit that trips off-line

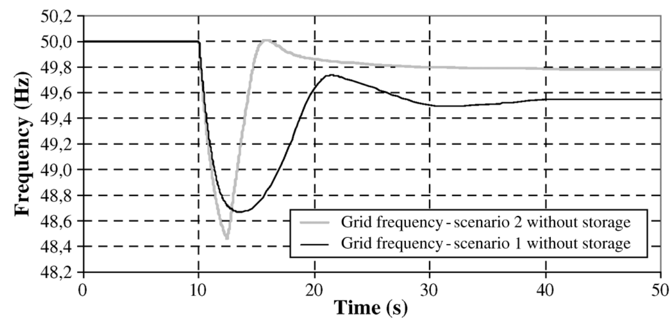

Fig. 8. Frequency response of the studied power system: scenario 1 versus scenario 2 without storage nor disconnection of RES during the transient.

Wind and PV generators are indifferently modeled as power injectors providing no inertial response. This choice, which relies on the assumption that most future variable RES will be of electronically coupled type, is rather conservative as it disregards the—relatively low— inertia of fixed-speed wind turbines already in operation in Guadeloupe (machines in the range 20–275 kW). Besides, the variability of RES is neglected over the time-frame of interest: constant power is assumed.

The DESS model described above is interfaced to the grid using the Eurostag "converter" element, which is an advanced current injector controlled in the $d-q$ frame. Table III shows some characteristics of the storage unit designed for the simulations. The ultracapacitor bank is sized so that it still can deliver its rated power for at least 15 s at the end of its service life; DFCS responses are illustrated in [15], [16], and [18].

C. Description of the Studied Scenarios

The provision of DFCS by fast-acting storage has been studied using a deterministic approach, i.e., under reasonable worst-case assumptions. Therefore, in the rest of the paper, we focus on two main scenarios with 12% and 30% of noninertia type RES in the active power generation, respectively.

Scenario 1 is based on a real operating point of the Guadeloupean power system recorded in 2009 during off-peak hours, i.e., at a time when the system inertia is close to its minimum—"critical dynamic situation." The instantaneous penetration level of wind is 12% (wind + geothermal + hydro: 20%). Primary control reserve is provided by Le Moule and Jarry Nord plants (respectively, 2 and 4 units online).

As presented in Table IV, scenario 2 derives from scenario 1, which is modified to increase the penetration of noninertia type generation up to 30% (wind + geothermal + hydro: 37%), with no change in the demand (135.4 MW), nor in the primary reserve (28.5 MW). To this end, the active power set-point of dispatchable generators must be adjusted. In accordance with the usual dispatch order used by EDF SEI (see Section IV-A), only the Jarry Nord plant is concerned in this case. Due to the technical constraints of the Diesel engines (minimum admissible power set-point), one unit must be shut down to achieve a feasible operating point: some conventional synchronous generation is actually displaced—decomitted— by wind generation. The overall rotating kinetic energy of the system is thus around 15% lower in scenario 2 than in scenario 1. The network power frequency characteristic K is also reduced, as explained in Section II-C.

The simulated disturbance is the same for the two scenarios: a coal-fired unit producing 21.3-MW trips offline at $t_0 = 10$ s.

D. Simulation Results and Discussion

1) Impact of Noninertia Type Generation: As shown in Fig. 8, the displacement of synchronous generation by noninertia type sources has noticeable consequences: the initial ROCOF decreases from -1.15 Hz/s (scenario 1) to -1.33 Hz/s (scenario 2) and the activation of the first stage of ALS (10% of the load disconnected at 48.5 Hz) is required in scenario 2 whereas scenario 1 has no impact on network users. As predicted by the literature, a higher share of electronically connected RES reduces the ability of the studied power system to respond to severe contingencies, possibility resulting in more frequent outages for customers.

2) Possible Role of DFCS Supplied by Fast-Acting Storage: The potential of the proposed dynamic support provided by DESS to tackle the inertia concern have been analyzed. To this end, ultracapacitor DESS performing DFCS have gradually been introduced within the modeled power system of Guadeloupe and series of dynamic simulations have been carried out. The results that have been obtained are presented in Table V (scenario 1) and Table VI (scenario 2). In these tables, the highest ALS stage activated during each simulation—interesting metric to contemplate the effects of both noninertia type RES and DESS in terms of quality of supply— is reported as a function of the two following variables:

- The installed storage power capacity, i.e., the total amount of dynamic reserve available to handle the generation outage.
- The proportion of noninertia type generation that trips offline when the frequency falls below 49.5 Hz (see Section II-C), thus aggravating the initial power imbalance.

For instance, the case presented in Fig. 8 corresponds to the top left hand corner of Table V ("0": no load shedding) and Table VI ("1": first stage of ALS triggered). In some cases, the second stage—10% of the load shed at 48, 2 Hz— and even the third stage—another 10% of the load disconnected at 47, 9 Hz— of ALS are required to stabilize f, out of the five that

TABLE V
SCENARIO 1—HIGHEST TRIGGERED ALS STAGE AS A FUNCTION OF THE STORAGE POWER CAPACITY AND OF THE PROPORTION OF NONINERTIA TYPE GENERATION LOST DURING THE TRANSIENT (DISCONNECTION AT 49.5 Hz)

Scenario 1		Share of wind / PV generation lost during the transient						
		0 %	10 %	20 %	30 %	40 %	50 %	60 %
Total installed storage power (performing DFCS)	0 MW	0	1	1	1	1	1	1
	0.5 MW	0	1	1	1	1	1	1
	1 MW	0	0	1	1	1	1	1
	1.5 MW	0	0	1	1	1	1	1
	2 MW	0	0	1	1	1	1	1
	2.5 MW	0	0	0	1	1	1	1
	3 MW	0	0	0	1	1	1	1
	3.5 MW	0	0	0	1	1	1	1
	4 MW	0	0	0	0	1	1	1
	4.5 MW	0	0	0	0	1	1	1
	5 MW	0	0	0	0	1	1	1
	5.5 MW	0	0	0	0	0	1	1
	6 MW	0	0	0	0	0	1	1
	6.5 MW	0	0	0	0	0	1	1
	7 MW	0	0	0	0	0	0	1
	7.5 MW	0	0	0	0	0	0	1
	8 MW	0	0	0	0	0	0	1
	8.5 MW	0	0	0	0	0	0	1
	9 MW	0	0	0	0	0	0	1
	9.5 MW	0	0	0	0	0	0	1
	10 MW	0	0	0	0	0	0	1

TABLE VI
SCENARIO 2—HIGHEST TRIGGERED ALS STAGE AS A FUNCTION OF THE STORAGE POWER CAPACITY AND OF THE PROPORTION OF NONINERTIA TYPE GENERATION LOST DURING THE TRANSIENT (DISCONNECTION at 49.5 Hz)

Scenario 2		Share of wind / PV generation lost during the transient						
		0 %	10 %	20 %	30 %	40 %	50 %	60 %
Total installed storage power (performing DFCS)	0 MW	1	1	1	2	2	2	3
	0.5 MW	1	1	1	2	2	2	3
	1 MW	0	1	1	2	2	2	3
	1.5 MW	0	1	1	2	2	2	3
	2 MW	0	1	1	2	2	2	3
	2.5 MW	0	1	1	1	2	2	3
	3 MW	0	1	1	1	2	2	3
	3.5 MW	0	1	1	1	2	2	2
	4 MW	0	1	1	1	2	2	2
	4.5 MW	0	1	1	1	2	2	2
	5 MW	0	0	1	1	2	2	2
	5.5 MW	0	0	1	1	2	2	2
	6 MW	0	0	1	1	2	2	2
	6.5 MW	0	0	1	1	1	2	2
	7 MW	0	0	1	1	1	2	2
	7.5 MW	0	0	1	1	1	2	2
	8 MW	0	0	1	1	1	2	2
	8.5 MW	0	0	0	1	1	2	2
	9 MW	0	0	0	1	1	2	2
	9.5 MW	0	0	0	1	1	2	2
	10 MW	0	0	0	1	1	1	2

compose the defense plan of the studied grid against extreme contingencies. Two main conclusions can be drawn from these simulations:

1) It is crucial to the system reliability and security that the proportion of wind and PV plants that trip offline during the frequency transient remains as low as possible. Indeed, these disconnections seriously deteriorate the dynamic behavior of the studied power system as penetration levels increase.
2) It is possible, using appropriate control strategies, to take advantage of the dynamic performance of modern DESS to mitigate, and even fully offset in some cases, the impact of electronically coupled sources on the transient performance of the studied power grid following a generation outage. The activation of one stage of ALS—i.e., 10% of the customers in the dark— can be avoided in most cases thanks to DFCS.

In the simulations above, the provision of dynamic support is contemplated in a rather centralized form: MW-scale DESS composed of parallelized 500-kW units, controlled/monitored by the system operator. However, a more distributed approach involving smaller units down to a few kW could be considered as well. In all cases, it is necessary to make sure that the DESS supplying DFCS can remain connected to the grid when they are the most needed, i.e., during severe frequency excursions. Therefore, they should not be put in place in feeders equipped with an automatic recloser on their main breaker (special setting of the DESS mains decoupling relay: 49.5 Hz) or downstream the under-frequency relays used to perform ALS.

V. CONCLUSION

Isolated grids are inherently sensitive to generation outages and are being further weakened as electronically coupled sources displace conventional synchronous generation. Based on dynamic simulations, this paper investigates the use of fast-acting storage to tackle this issue by providing DFCS, i.e., a prompt, short-term support to frequency control. An ultracapacitor DESS is studied and dedicated supervision algorithms are developed to take full advantage of its very short response time. The results show that such a fast-acting storage can help mitigate the impact of noninertia type generation such as wind and PV on the dynamic performance of island systems in the case of a major generation outage.

Although DFCS is performed using ultracapacitors herein, our conclusions remain valid with any other fast-acting storage techniques, either "standalone" or coupled with RES. Besides, any device with a sufficient energy capacity would be able to perform other services in addition to DFCS, thus capturing more value. Such an aggregation of benefits still appears as a key factor of success for DESS, as their costs remain high.

This paper focuses on a way to reduce the impact of wind and PV plants on the transient performance of power systems following a generation outage. It should be kept in mind that many other aspects regarding the integration of renewables in isolated power systems (e.g., variability, forecast accuracy, etc.) must still be investigated and, in some cases, it is not sure whether storage will be of any help (e.g., during severe voltage dips). Therefore, more R&D is needed on the mix of solutions that could be put in place to allow higher penetration levels of variable RES in islands in the future. Further work includes various technical/economic studies on these topics, as well as an evolution towards probabilistic approaches to properly quantify risk levels and draw meaningful conclusions.

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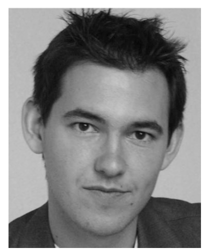

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