21, rue d'Artois, F-75008 PARIS
http : //www.cigre.org

CIGRE US National Committee
2022 Grid of the Future Symposium

Improvement of Frequency Nadir and RoCoF in Puerto Rico under High IBR Scenarios by using Grid-Forming Capabilities

A. NASSIF, M. RAHMATIAN, H. OTHMAN, A. PAASO
LUMA Energy
USA

MOTIVATION

Renewable energy resources have been instrumental in the path to a low carbon future. In the United States, many jurisdictions have implemented aggressive renewable portfolio standards (oftentimes termed RPS) dictating end states as well as intermediate milestones to achieve high levels of penetration. Well known examples are those in Los Angeles and Puerto Rico, where the Department of Energy funded transitional pathways to 100% renewable energy in their LA100 and PR100 studies.

The case of Puerto Rico is a challenging one, as the island is not interconnected to the main continental US electric grid. It serves a peak load of over 2.5 GW and most large generation plants, predominantly heavy oil and coal, are located in the south of the island, whereas the majority of the load consumption is in the north. The Electric Bureau passed a law in 2019 that renewable energy production must reach the following goals: 40% by 2025; decommission of coal by 2028; 60% by 2040; 100% by 2050 [1]. These goals indicate the generation mix will see large leaps in inverter-based resource (IBR) adoption very abruptly in various locations of the island, and the system must be prepared to accommodate these interconnections without degradation in stability, security, and reliability.

Problems associated with large IBR adoption are not new and have been reported extensively [2]-[4]. IBRs are interfaced through transistor-based voltage source converter bridges and their behaviour is entirely dependent on their gating control schemes, rather than on physical construction and associated parameters, as it is the case with conventional rotating generation. The main limitations of IBRs are their inherent small short-circuit currents (as the inverters are inherently designed to cope with current loading through their transistors instead of a magnetic discharge, which directly impact how protective relays operate) and their response to disturbances (as inertial response is not governed by physics such as in the case of rotating machinery, but rather on electrical time constants).

Advances have been made in IBR control methods to allow more flexibility and mitigate these problems. Grid-forming capabilities enable operation that no longer relies on a phase-

alex.nassif@lumapr.com

locked loop to synchronize with the grid, as in the case of grid-following inverters, and rather have a fixed voltage and frequency setpoint [5]. These advances also allow the IBR to control response times and contribute to system inertia, although not to short-circuit capability [6]. This feature is a valuable addition to systems with high IBR adoption although it has not yet reached full commercial adoption in solar and wind IBRs, as it has matured mostly in battery energy storage systems (BESS) [7]. This paper analyses transitional states to high IBR penetration in an island power system. It provides an energy balance analysis of replacing conventional sources of generation with IBRs, including the challenging aspect of low capacity factor and the requirement for utility-scale BESS to allow a gradual transition from conventional rotating generators to solar or wind IBRs. This not only provides the energy resulting in this renewable portfolio standard [1], but also the required nameplate installed of solar and wind sources. To allow protection system dependability and security, the paper illustrates how the adoption of grid-forming BESS can contribute necessary amounts of inertia to maintain system security during fault and N-1 contingency analysis and how the conversion of retired coal plants is imperative to allow continuance of dependable protection operation. The impact of these BESS on system frequency nadir is quantified through power system dynamic simulations. The studies contained in this paper are conducted using PSSE v35 simulations and addresses potential IBR inertial contributions when operating both as grid following and grid forming resources. Although the grid forming capability of IBRs are not entirely implemented in PSSE v35, all its grid-firming capabilities (virtual inertia, frequency and voltage regulation, etc.) are present and are sufficiently represented to support the conclusions presented in this paper. Hence, while the authors use the term “grid forming” to describe the impact of the grid-forming IBRs, a more technically correct term would be “grid firming”. For simplicity, the authors chose to utilize the term “grid forming” as this is what is required in the recently amended Minimum Technical Requirements (MTR) [8].

KEYWORDS

Frequency Nadir, Inverter-Based Resources, Low Inertia Systems, Power System Stability

1. THE EXISTING GENERATION MIX (3.7% RENEWABLE PENETRATION)

As of the time of writing this manuscript, the generation mix comprises about 450 MW of installed nameplate IBR, or around 11% of all installed MW capacity of about 3.8 GW. The operation of these resources results in about 3.7% of total energy provided by IBRs, the majority of which being PV generation. Table 1 summarizes the generation mix real and apparent power, which includes conventional synchronous generating plants fuelled by heavy oil, diesel and natural gas, as well as the existing amount of IBR-based PV generation, wind generation and energy storage. The existing battery energy storage systems, amounting in aggregation to about 40 MW, were installed for the purposes of enabling the PV and wind renewable generation plants to meet the older version of the Minimum Technical Requirements (MTR) [8], in particular the ramp rate requirement. Table 1 also shows the calculated total generation inertia constant *H* as well as the calculated total governor droop speed control constant *R*. The same summary reveals the peak load, combining all instantaneous forms of generation, amount to about 2.5 GW, over 90% of which supplied by the conventional heavy oil, diesel and gas generation plants.

Most of the generation is located in the south of the island, whereas most of the load is in the north. For the purposes of the tests conducted in this paper, the specific generation units that were used in the trip contingency scenarios are not revealed for confidentiality, but the total amount of generation loss is reflected in the results table. The Pmin of synchronous generators reflect minimum power purchase agreement contractual obligations and operational constraints.

Table 1: The existing system with 11% of nameplate renewable generation

Existing Generation Mix				
	Synchronous Generators	**PV-Wind**	**BESS**	**Total**
MVA Rating	3,311	456.54	40	3,807
***H* (MVA-s)**	11,807	0	0	11,807
***R* = Δf(pu)/ΔP(pu)**	7.3%		5.0%	
Pmax (MW)	2,531	400	40	2,971
Pmin (MW)	998	1	-40	960

To study the response of the current system to sudden loss of generation, four tests (contingency scenarios) have been designed to simulate different amounts of generation loss. Table 2 shows the simulation results for loss of 180 MW, 230 MW, 363 MW and 568 MW generation, respectively, which represent tripping of different conventional generation units that currently exist in the system. The simulation results show that the system would be stable for the first three generation loss events, while the simulations suggest the protection system would need to activate 283 MW load-shedding for the test in the fourth contingency scenario. As the amount of generation loss increases, the frequency nadir reaches to lower values and the absolute value of RoCoF increases. In this paper, RoCoF is always measured between the first and second cycles.

Fig. 1 shows the obtained simulation results for frequency at one of the most important substations (a major substation located near the north of the island). The system frequency stabilizes and settles, but it does not return to 60 Hz because in this work the authors did not model the automatic generation control (AGC). To note, not modelling the AGC does not affect the conclusions drawn from these studies.

Table 2: Simulation results of generation loss tests in the existing system

Contingency Scenario	Total Gen Loss (MW)	H (sec)	Result	Frequency at 20 sec	Frequency Nadir (Hz)	RoCoF
Contingency 1	180	2 x 2.267	Stable	59.749	59.421 @ 3.654 sec	-0.311
Contingency 2	230	2 x 2.267 + 3.3	Stable	59.690	59.260 @ 3.575 sec	-0.390
Contingency 3	363	3.4	Stable	59.494	58.717 @ 4.146 sec	-0.574
Contingency 4	568	3.477 + 3.4	**Unstable**	59.529	57.969 @ 3.300 sec	-0.978

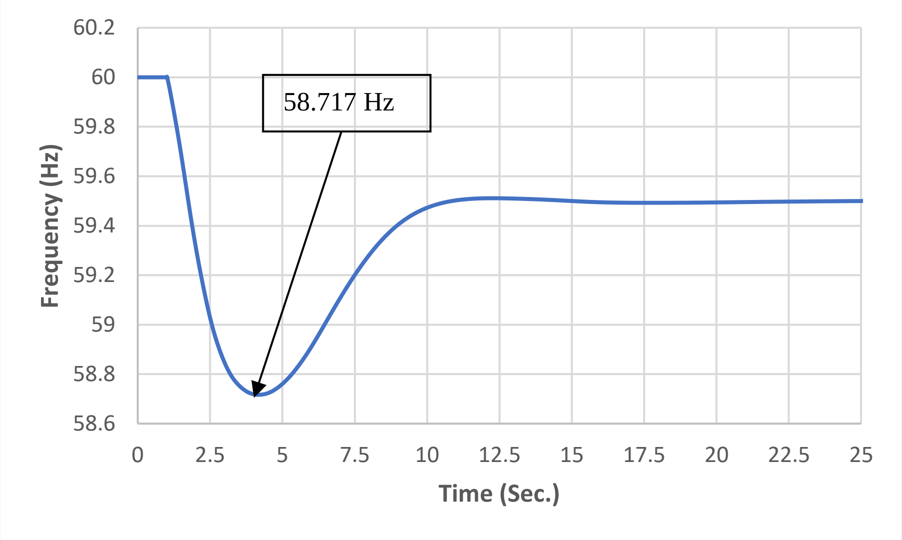

Fig. 1. Monitored frequency for contingency scenario 3 with the existing generation mix.

2. FUTURE GENERATION SCENARIOS AND GRID-FORMING CAPABILITIES

Future scenarios that are foreseen based on the interconnection queue and energy regulator's laws are present in this section. These scenarios are presented in Table 3, which describes the future scenarios mandated by the Electricity Bureau as a Resolution and Order [9].

To capture critical stages of this transition, the studies in this paper address procurement tranches 1 and 6 (cumulatively), which are described in sections 2.1 and 2.2, respectively. The scenario presented in section 2.3 is a variation of 2.2 and assumes future inertial response capabilities of solar and wind IBR inverters that are currently not commercially available but are studied to illustrate how they can enhance system stability.

Table 3: Future procurement tranches to reach an RPS of 40%

	Solar PV or equivalent other energy, MW		4-hr. Battery Storage equivalent, MW	
Procurement Tranche	Minimum	Cumulative	Minimum	Cumulative
1	1000	1000	500	500
2	500	1500	250	750
3	500	2000	250	1000
4	500	2500	250	1250
5	500	3000	125	1375
6	750	3750	125	1500

2.1 The Power System after the First Interconnection Tranche

The first interconnection tranche comprises IBRs connected in many locations of the transmission network. This essentially represents a leap from about 11% to 40% IBR apparent power nameplate capacity, and it is estimated that the renewable energy production would rise by about 10% (due to the estimated capacity factors of wind and solar). While this is just the first step towards the 100% renewable energy goal, it is representative of the major upcoming efforts towards the ultimate vision for the island.

According to the recently revised MTRs [8], all new utility-scale renewable plants are required to provide frequency regulation and ramp rate control. As a result, one of the ways developers have found to meet these requirements is to install energy storage to provide these services. All energy storage connected in the past were not required to have grid-forming capabilities, but the T&D operator in the island started demanding grid-forming capability for all new utility-scale energy storage. As a result, while tranche 1 comprises the installation of 500 MW energy storage as represented in Table 4, these were not required to have grid-forming capabilities.

To accommodate all the renewable energy being integrated after tranche 1, the operations team determined the dispatch order in the AGC needs to be modified. Since the dispatch of the case has been changed, the exact same tests for the existing system cannot be repeated. Therefore, other generators with the same amount of MW were selected to represent their trip tests and the simulation results are listed in Table 5. For the purposes of this paper, these contingency scenarios are roughly equivalent to those presented in the previous section. As it can be observed, the absolute value of RoCoF increases as compared to the existing case and so does the inertia MVA-s. On the other hand, the frequency nadir and settling frequency values are not significantly different for the first three stable events. The reason is likely to be the response of the conventional machines' governors, which can impact the results a few seconds after the event.

Table 4: Generation mix and parameters after the first tranche of renewable generation

	Synchronous Generators	**PV-Wind**	**BESS**	**Total**
MVA Rating	3,311	1,692	446	5,448
Pmax (MW)	2,531	1,549	407	4,487
Pmin (MW)	998	1	-407	593
***H* (MVA-s)**	11,807	0	0	11,807
***R* = Δf(pu)/ΔP(pu)**	7.3%		5.0%	

Table 5: Simulation results of generation loss tests after Tranche 1.

Contingency Scenario	**Total Gen Loss (MW)**	**H (sec)**	**Result**	**Frequency at 20 sec**	**Frequency Nadir (Hz)**	**RoCoF**
Contingency 1	180	2.42	Stable	59.728	59.408 @ 3.371 sec	-0.408
Contingency 2	221	3.4	Stable	59.670	59.289 @ 3.821 sec	-0.516
Contingency 3	360	2 x 2.42	Stable	59.440	58.725 @ 4.321 sec	-0.859
Contingency 4	581	2 x 2.42 + 3.4	**Unstable**	59.029	57.349 @ 3.987 sec	-1.664

Fig. 2 shows the obtained simulation results for frequency at the same substation monitored during the first test for Scenario 3. Like in the previous case, the frequency settles below 60 Hz because the AGC was not modelled.

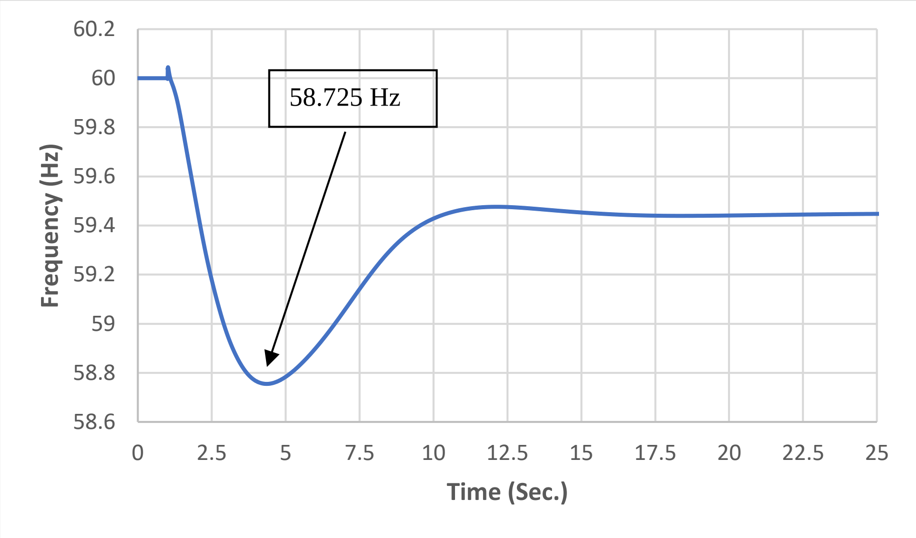

Fig. 2. Monitored frequency for contingency scenario 3 after the first interconnection tranche.

2.2 The Power System after the Renewable Procurement Plan is executed (40% Renewable Energy)

As mentioned earlier, the renewable procurement plan will be executed in 6 tranches and is intended to reach 40% renewable energy penetration [9]. The total installed nameplate capacity of renewable IBRs is expected to exceed 70%. At the end of this plan, all coal generation plants will be retired, and it is speculated they may be converted to synchronous condensers (this retirement is scheduled to 2028). This is the scenario assumed by the authors and studied in this subsection. Table 6 shows the system information for this scenario. This will result in decrease of system inertia from 11,807 MVA-s to 6,966 MVA-s. The equivalent governor droop speed control constant of the conventional machines is estimated to reduce from 7.3% to 5.83%, indicating less reliance on the conventional machines for frequency support.

As explained previously, the T&D operator has required the MTR to be modified for tranches 2-6 to require all new energy storage to be connected using grid-forming inverters. This means the 1 GW of energy storage will have grid forming capabilities and can provide synthetic inertia and frequency regulation. While a small amount compared to the total renewable nameplate to be added, the capability does provide significant improvements in performance.

Table 6 presents the configuration under this scenario and Table 7 presents the simulation results for 4 scenarios similar to those present in the previous sections. To note, the system is visibly more sensitive to disturbances because the system inertia has reduced. This illustrates the importance of augmenting system frequency regulation as more renewable generation is integrated. Fig. 3 shows the obtained simulation results for frequency for contingency scenario 3.

Table 6: Generation mix and parameters after Tranche 6 of the Renewable Procurement Plan

Generation mix after Tranche 6					
	Synchronous Generators	**PV-Wind**	**BESS**	**Total**
MVA Rating	3,246	4,966	1,329	9,541
Pmax (MW)	1,276	4,339	1,142	6,757
Pmin (MW)	460	1	-1,142	-645
***H* (MVA-s)**	6966	0	0	6966
***R* = Δf(pu)/ΔP(pu)**	5.83%		5.0%	

Table 7: Simulation results of generation loss tests after tranche 6.

Contingency Scenario	**Total Gen Loss (MW)**	**H (sec)**	**Result**	**Frequency at 20 sec**	**Frequency Nadir (Hz)**	**RoCoF**
Contingency 1	188	3.477 + 3.3	Stable	59.596	59.141 @ 3.604 sec	-1.243
Contingency 2	221	3.477 + 3.267	Stable	59.503	58.903 @ 3.383 sec	-1.435
Contingency 3	358	3.4	**Unstable**	59.295	58.103 @ 3.521 sec	-2.717
Contingency 4	507	3.4 + 3.477	**Unstable**	59.102	57.668 @ 2.567 sec	-4.061

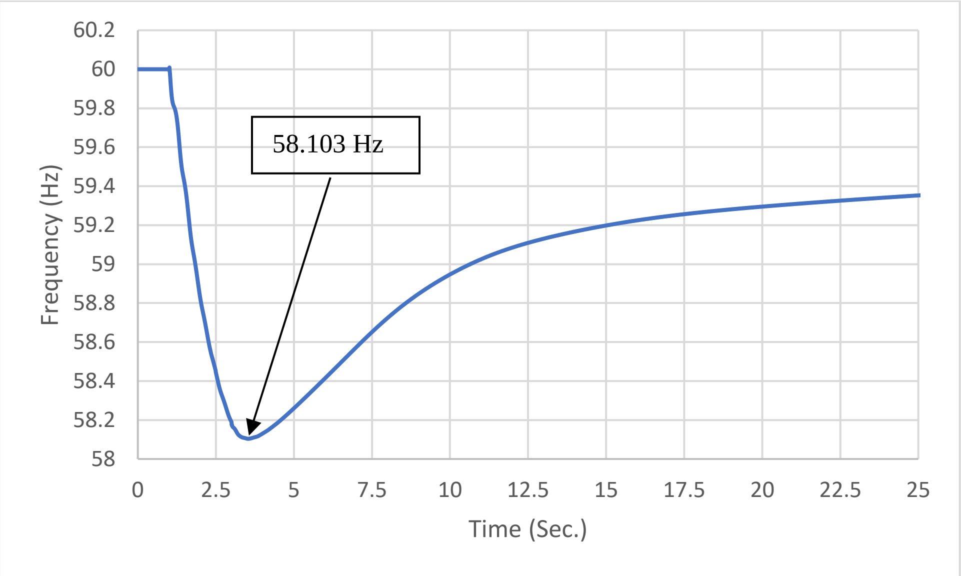

Fig. 3. Monitored frequency for contingency scenario 3 after interconnection tranche 6.

2.3 The Power System after the Renewable Procurement Plan is executed (40% Renewable Energy) assuming 800MW of Renewable Generation has Grid-Forming Capability

The previous simulation case has demonstrated the electrical system becomes less stable as more IBRs are integrated. The authors analyse a scenario that assumes grid-forming capabilities will gradually become more prevalent in renewable generation plants. In fact, this capability has already been conceptualized for wind turbines and solar inverters. While the technology has not achieved commercial maturity, it appears as it is imminent, as per many advances recently published and documented in a 2020 roadmap for renewable generation grid forming inverters [10]. To represent this potential integration in the future, the authors have assumed 800 MW of the IBRs will have this capability, which is approximately the size of tranche 6, for the purposes of the studies contained in this paper.

Representing grid forming generation in PSSE v35 was not a simple task, as it required a very substantial amount of manual tuning of their PID controllers. As this tuning allowed achieving fast frequency response, the authors then tried to mimic synthetic inertia in the frequency response of the renewable generation and energy storage units. The fast frequency response, which is similar to the inertial response of conventional units, has helped reduce the RoCoF, as captured in Table 9 (as compared to Table 7). Also, the frequency nadir has also shown improvement, as illustrated in Fig. 4, a figure that captures the system behaviour under contingency scenario 3. Furthermore, the system does not show any underfrequency load shedding for the third contingency scenario as the frequency does not dip below 59 Hz. All the impacts can be considered as one of the characteristics of the grid forming characteristics of the inverters. These studies illustrate the importance and impact of adopting this capability.

Table 8: Generation mix and parameters after Tranche 6 and 800 MW of grid-forming IBR generation.

	Synchronous Generators	PV-Wind	BESS	Total
MVA Rating	3,246	3,456	2,279	8,981
Pmax (MW)	1,276	3,532	1,942	6,750
Pmin (MW)	460	1	-1,942	-1,481
***H* (MVA-s)**	6966	0	0	6966
***R* = Δf(pu)/ΔP(pu)**	5.83%		5.0%	

Table 9: Simulation results of generation loss tests after Tranche 6 and 800 MW of grid-forming IBR generation.

Contingency Scenario	Total Gen Loss (MW)	H (sec)	Result	Frequency at 20 sec	Frequency Nadir (Hz)	RoCoF
Contingency 1	188	3.477 + 3.3	Stable	59.785	59.395 @ 2.850 sec	-1.192
Contingency 2	221	3.477 + 3.267	Stable	59.743	59.262 @ 2.892 sec	-1.374
Contingency 3	358	3.4	Stable	59.686	59.112 @ 2.950 sec	-1.567
Contingency 4	507	3.4 +3.477	**Unstable**	----	----	-2.635

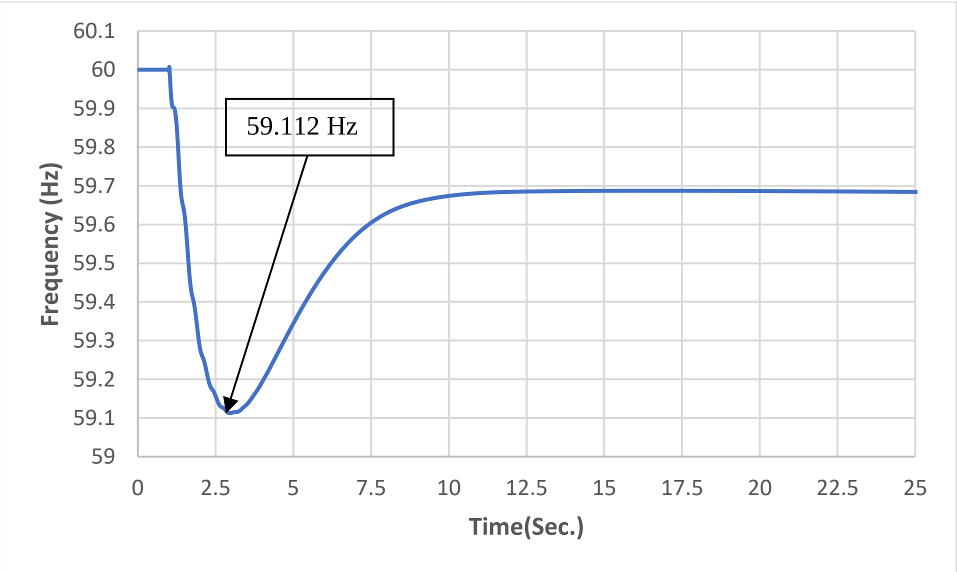

Fig. 4. Monitored frequency for contingency scenario 3 after interconnection tranche 6 and 800 MW of IBR generation with grid-forming capabilities.

3. CONCLUSIONS

This paper presented power system dynamic simulations of the transmission electricity grid of Puerto Rico under various renewable energy adoption scenarios that represent the initial steps to its pathways to 100% renewable energy state. These initial steps are in the form of six utility scale renewable interconnection tranches that are to be procured prior to 2025 and intended to be constructed prior to 2028. At the same time, the studies encompass the existing mandate to retire all coal generation by 2028, although these conventional generation plants are studied as if they can be converted to synchronous condensers to help support system stability after the reduction in rotating machinery. The two future scenarios are those of first and sixth tranches cumulatively, respectively. For tranches 2-6, all utility scale energy storage will have grid forming capability. A third study scenario was introduced as a sensitivity on the incorporation of grid forming capabilities of renewable IBRs for tranche 6. The studies covered various contingencies that are representative sudden loss of generation (trip) to asset on system stability.

The studies allowed deriving the following conclusions:

1. Without system improvements, the system performance will significantly deteriorate after tranche 1, which does not require grid-forming inverters. For sudden loss of 10% of total generation, or about 20% of the spinning reserve, the system will become unstable.
2. After tranche 6, cumulatively representing an addition of 4.25 GW of grid-following renewable IBRs and 1 GW of grid forming IBRs, the sudden loss of only 5% of total generation, or 7% of the spinning reserve, drives the system unstable. This is also a result of the retirement of about 60 MW of synchronous generation and their conversion to synchronous condensers.
3. A sensitivity study was done in assuming all the generation under tranche 6 (about 800 MW) has grid forming capabilities. This results in a visible performance improvement, where instability is lost after a sudden loss of about 6% total generation or 8% spinning reserve.

The results in the paper highlight the importance of grid forming inverters in the system stability. In fact, a comparative performance analysis is shown in Fig. 5, which shows the dynamic response of the four scenarios presented in this paper under sudden loss of 360 MW of conventional generation. This figure shows the deterioration of frequency nadir and RoCoF as more grid following IBRs are added to the system, and how grid forming capabilities can add tremendous value in improving system stability.

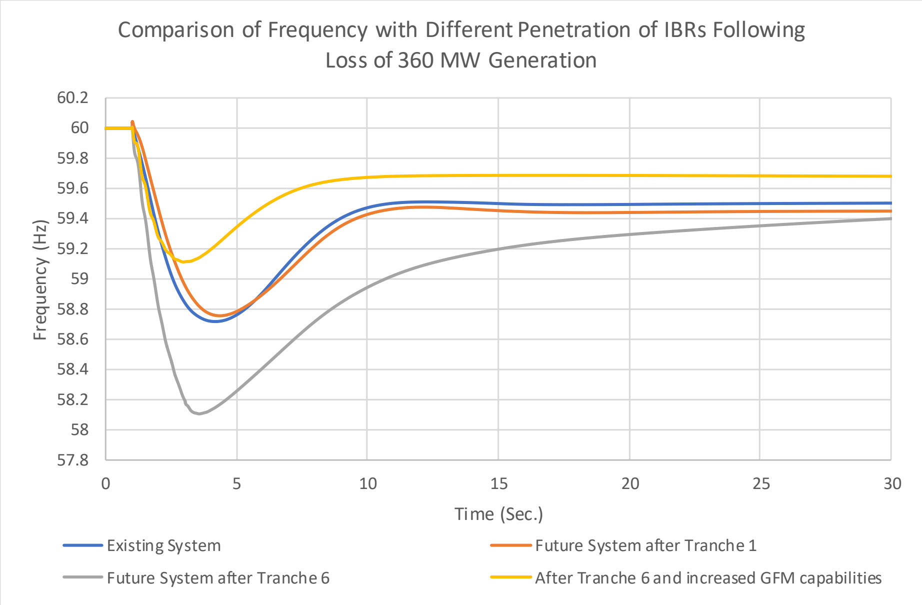

Fig. 5. Comparison of the frequency response for sudden loss of 360 MW of conventional generation for the four scenarios considered in this paper.

BIBLIOGRAPHY

[1] Puerto Rico Act 17-2019 Politica Publica Energetica, available at https://aeepr.com/es-pr/QuienesSomos/Ley17/A-17-2019%20PS%201121%20Politica%20Publica%20Energetica.pdf

[2] T. Ackermann, T. Prevost, V. Vittal, A. J. Roscoe, J. Matevosyan and N. Miller, "Paving the Way: A Future Without Inertia Is Closer Than You Think," in IEEE Power and Energy Magazine, vol. 15, no. 6, pp. 61-69, Nov.-Dec. 2017, doi: 10.1109/MPE.2017.2729138.

[3] Denholm, Paul, Trieu Mai, Rick Wallace Kenyon, Ben Kroposki, and Mark O'Malley. 2020. Inertia and the Power Grid: A Guide Without the Spin. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6120-73856. https://www.nrel.gov/docs/fy20osti/73856.pdf.

[4] Denholm, Paul and Ben Kroposki. 2022. Understanding Power Systems Protection in the Clean Energy Future. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-82269. https://www.nrel.gov/docs/fy22osti/82269.pdf

[5] Gevorgian, Vahan, Jun Hao, Rui Yang, Yingchen Zhang, and Ella Zhou. 2021. Clean Grid Vision: A U.S. Perspective – Chapter 3. Transmission Grid-Supporting Technologies. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5C00-78644. https://www.nrel.gov/docs/fy21osti/78644.pdf

[6] W. Du et al., "Modeling of Grid-Forming and Grid-Following Inverters for Dynamic Simulation of Large-Scale Distribution Systems," in IEEE Transactions on Power Delivery, vol. 36, no. 4, pp. 2035-2045, Aug. 2021, doi: 10.1109/TPWRD.2020.3018647.

[7] Li, Y, Yuan, X, Li, J, Xiao, H, Xu, Z, Du, Z. Novel Grid-forming control of permanent magnet synchronous generator-based wind turbine for integrating weak AC grid without sacrificing maximum power point tracking. IET Gener Transm Distrib. 2021; 15: 1613– 1625. https://doi.org/10.1049/gtd2.12121

[8] Puerto Rico Electric Power Authority, Minimum Technical Requirements (2022 version).

[9] Goverment of Puerto Rico Public Service Regulatory Board (Puerto Rico Energy Bureau), Final Resolution and Order on the Puerto Rico Electric Power Authority's Integrated Resource Plan, available at https://energia.pr.gov/wp-content/uploads/sites/7/2020/08/AP20180001-IRP-Final-Resolution-and-Order.pdf

[10] Lin, Yashen, Joseph H. Eto, Brian B. Johnson, Jack D. Flicker, Robert H. Lasseter, Hugo N. Villegas Pico, Gab-Su Seo, Brian J. Pierre, and Abraham Ellis. 2020. Research Roadmap on Grid-Forming Inverters. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5D00-73476. https://www.nrel.gov/docs/fy21osti/73476.pdf.