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Potential Issues and Mitigation to RoCoF with High Penetration of IBRs

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INTRODUCTION

The adoption of renewable sources of energy represents an inevitable path in the transition to a low carbon future being mandated in many jurisdictions across the globe. Some jurisdictions have implemented very aggressive renewable portfolio standards that create an imminently challenging scenario requiring a creative technical framework. One such example is the case of Puerto Rico, an islanded electric grid with peak load of about 2.5 GW and with a goal of achieving 100% renewable energy production by 2050, and with an astounding intermediate milestone of 40% renewable energy production by 2025. The existing landscape of renewable generation implies they are exclusively inverter-based resources, or IBRs, which have profound differences in characteristics and behaviour from conventional synchronous energy sources. These IBRs are interfaced with the grid through voltage source converters and their behaviour is entirely dependent on their controls, rather than on physical parameters. For this reason, they also have limitations. For example, IBRs have limited short-circuit current injection capability because this current is limited by the inverter rating rather than a magnetic discharge, greatly impacting the effectiveness of conventional overcurrent and distance protection relays. IBR response to disturbance is also not governed by physical inertial parameters such as the case of synchronous machines.

Technology also impacts their response. IBRs can operate in two different modes, the first one being grid following, where the IBR synchronizes with the grid through a phase-locked loop (PLL) and regulates its output to maximize positive-sequence current output, and the second one being grid forming, where the IBR regulates frequency and output voltage and outputs imbalanced current in a similar fashion than what synchronous generators do, but with limitations. Grid forming operation allows IBR to regulate their response times and contribute to system inertia, although it can do little to provide short-circuit currents.

This paper analyses transitional states to high IBR penetration. It provides an energy balance analysis of replacing conventional sources of generation with renewable sources, including the challenging aspect of low capacity factor and required utility-scale battery energy storage systems (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, but also the required nameplate installed of solar and wind sources. All energy storage connected in the past were not required to have grid-forming capabilities, but the T&D

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operator in the island started demanding grid-forming capability for all new utility-scale energy storage. For the purposes of the studies in this paper, grid-forming capabilities are assumed not to be implemented. Rather, to allow protection system dependability and security, the paper analyses the impact of short-circuit sources, i.e., synchronous condensers, required to maintain system security during fault and N-1 contingency analysis. The impact of these synchronous condensers on system inertia and frequency nadir are also quantified through simulation studies, conducted using PSSE simulation environment.

The Puerto Rico island grid is used as a case study. The authors conduct an extensive contingency study with dynamic simulations and analyse the impact of synchronous condensers on system inertia.

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

As of the time of writing this manuscript, the generation mix in the island consists of about 450 MW installed nameplate IBR, of a total of about 3.8 GW. The capacity factor of these IBR results in 3.7% of total energy, the majority of which being PV generation. Table 1 summarizes the generation mix, which includes conventional synchronous generating plants (heavy oil, diesel and natural gas powered), as well as the existing solar, wind and BESS resources. The existing BESS, amounting 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 amounts to about 2.5 GW.

For the purposes of the tests conducted in this paper, the specific generation units used in the trip contingency scenarios are not revealed for confidentiality purposes, 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

	Synchronous Generators	PV-Wind	BESS	Total
MVA Rating	3,311	456.54	40	3,807
***H* (MVA-s)**	11,807	0	0	11,807
$R = \Delta f(pu)/\Delta P(pu)$	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 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, respectively, which represent tripping of different conventional generation units that currently exist in the system. While the system would be stable for the first three events, the UFLS scheme would activate 283 MW load-shedding in the fourth contingency scenario. As the amount of generation loss increases, the frequency nadir reaches lower values and the absolute value of RoCoF increases. In this paper, RoCoF is measured between the first and second cycles.

Fig. 1 shows the results for contingency scenario 3. 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

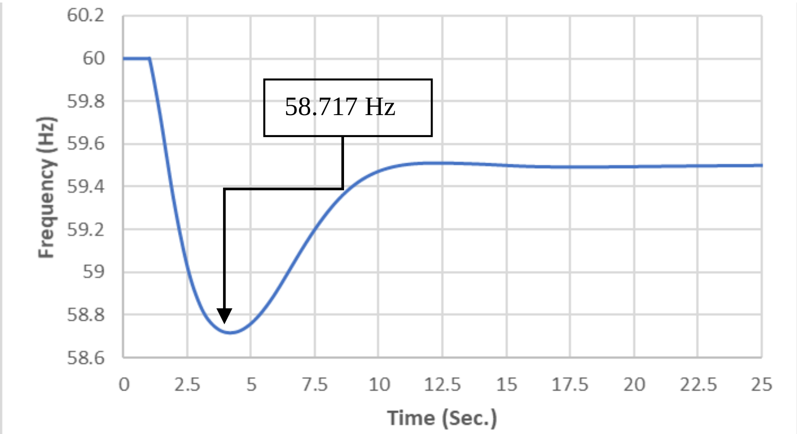

Fig. 1. Monitored frequency for contingency scenario 3 with the existing generation mix.

2. FUTURE GENERATION SCENARIOS

Future scenarios based on the interconnection queue and energy regulator's laws 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 Tranche 1 and 6 (cumulatively), which are described in sections 3 and 4, respectively. The scenario presented in section 5 is a variation of 4 and assumes the installation of 1.5 GVAR of synchronous condensers and equivalent retirement of conventional generation plants.

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

3. The Power System after the First Interconnection Tranche

The first interconnection tranche will comprise of 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). This is illustrated in

Table 4. 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 MTRs [8], all 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 BESS. 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 and other generators with the similar MW were selected to participate in the contingency analysis, as shown in Table 5. As it can be observed, the absolute value of RoCoF increases and the frequency nadir and settling frequency values are not significantly different. 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 frequency simulation results for Scenario 3. Like in the previous case, the frequency settles below 60 Hz because the AGC was not modelled.

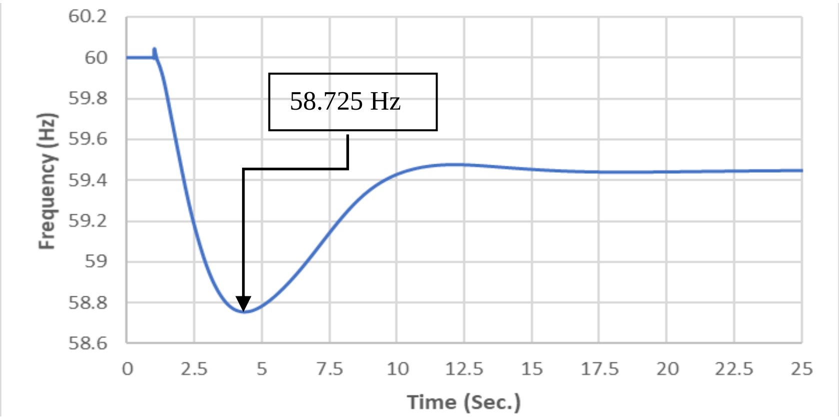

Fig. 2. Monitored frequency for contingency scenario 3 after the first interconnection tranche.

4. The Power System after the Renewable Procurement Plan is executed

Under this scenario, the total installed nameplate capacity of renewable IBRs is expected to exceed 70% while the energy production from renewable sources reaches 40%. 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. 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. Fig. 3 shows the obtained simulation results for frequency for contingency scenario 3. The authors analyse the contribution of synchronous condensers to this loss of inertia in the next section.

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

	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

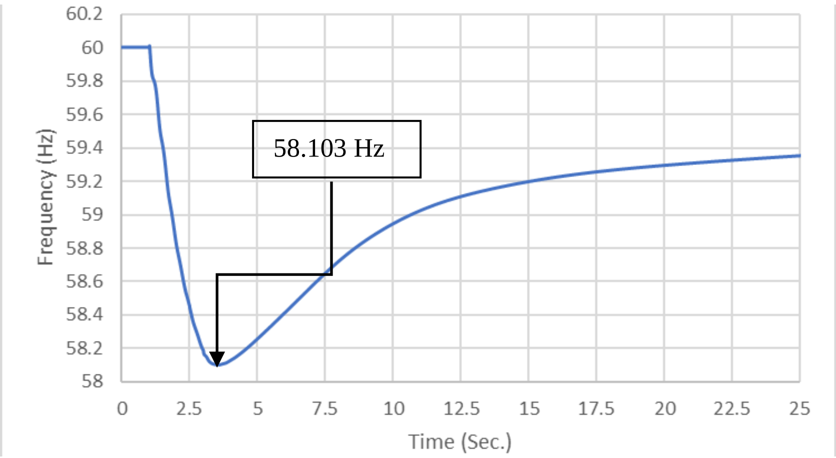

Fig. 3. Monitored frequency for contingency scenario 3 after interconnection tranche 6.

5. The System after the Renewable Procurement Plan is executed (40% Renewable Energy) and Installing 1.5 GVAR of Synchronous Condensers

The previous simulation case has demonstrated the system becomes less stable as more IBRs are integrated. The authors now analyse a scenario that assumes synchronous condensers will be deployed. While it is possible to convert existing conventional generation plants, the authors speculate most of condensers will need to be new installations due to difficulties and cost of retrofitting old plants.

While representing synchronous condensers in PSSE v35, it is assumed the inertia of synchronous condensers is similar to those of conventional plants being retired. The frequency response results in the RoCoF as captured in Table 9 (compare with Table 7). Also, the frequency nadir improves, as illustrated in Fig. 4, reflecting the system behaviour under contingency scenario 3. However, the results of the third contingency still results in load shedding. Finally, the settling frequency value has not been changed significantly before and after adding synchronous condensers which is expected.

Table 8: Generation mix and parameters after Tranche 6 and 1.5GVAR of synchronous condensers.

	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)**	13,988	0	0	13,988
***R* = Δf(pu)/ΔP(pu)**	5.83%		5.0%	

Table 9: Simulation results of generation loss tests after Tranche 6 and 1.5GVAR of synchronous condensers.

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	59.604	59.244 @ 5.383 sec	-0.442
Contingency 2	221	3.477 & 3.267	Stable	59.517	59.024 @ 6.175 sec	-0.515
Contingency 3	358	3.400	**Unstable**	59.333	58.191 @ 4.321 sec	-0.895
Contingency 4	507	3.400 & 3.477	**Unstable**	59.007	57.845 @ 3.987 sec	-1.334

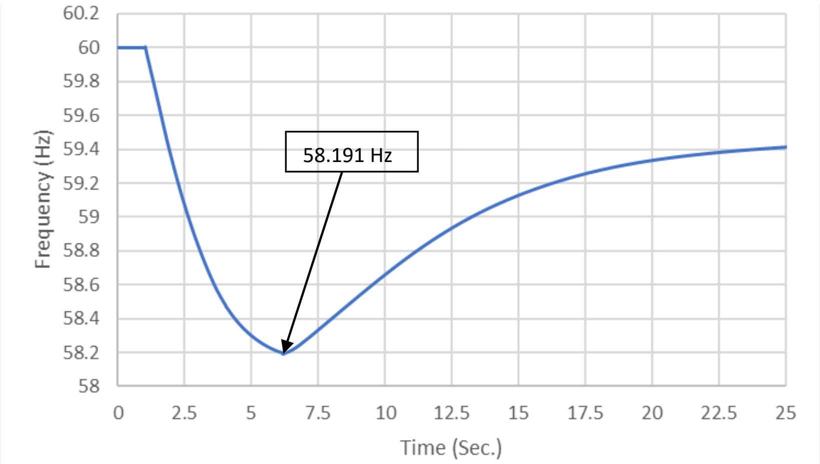

Fig. 4. Monitored frequency for contingency scenario 3 after interconnection tranche 6 and 1.5GVAR of Synchronous Condensers.

6. 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. At the same time, the studies encompass the retirement of all coal generation by 2028. Tranches 1 and 6, cumulatively, are studied in two different scenarios. A third study scenario was introduced as incorporation of 1.5GVAR synchronous condensers on top of tranche 6. The studies covered various contingencies that are representative sudden loss of generation (trip) to asset on system stability.

The studies allowed the T&D operator to conclude the following:

1. The system performance will significantly deteriorate after tranche 1, although the renewable generation offset provides additional headroom for synchronous generators.

2. After tranche 6, 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 adding 1.5GVAR synchronous condensers across the island. This results in a visible performance improvement.

The results in the paper highlight the importance of improving frequency response support, which can be achieved through adding synchronous condensers. 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 the need to install synchronous condensers to improve system stability. An investigation of achieving a similar objective by using grid forming inverters is underway under a separate effort.

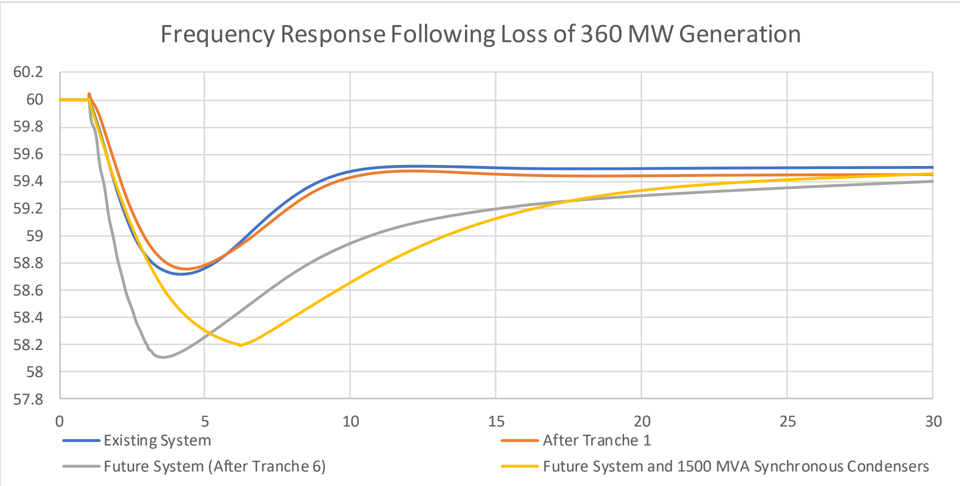

Fig. 5. Comparison of the frequency response for sudden loss of 360 MW of conventional generation for the four scenarios considered in this paper.

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