Siemens PTI Report Number: R054-15

Integrated Resource Plan Volume II: Transmission Analysis

Draft for the Review of the Puerto Rico Energy Commission.

Prepared for

Puerto Rico Electric Power Authority

Submitted by:
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August 17, 2015

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Revision History

Date	Rev.	Description
July 7 2015		Draft for the review of the Puerto Rico Energy Commission.
August 17, 2015		Second draft for the review of the Puerto Rico Energy Commission

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Section

1

Introduction

The objective of this Volume II of the IRP study is to present the analysis conducted and the transmission system reinforcements necessary to allow the integration of the various generation portfolios assessed (the Portfolios) for the modernization of PREPA's fleet and achieve MATS compliance under the different futures that could materialize in Puerto Rico (the Futures). Both the Futures and Portfolios have different performance with respect to the transmission system and this is described below.

1.1 The Futures

As, was observed in Volume I, there are four different futures under evaluation and these are presented below, highlighting their relevance for transmission assessment. The Futures are fully described in section 5 of Volume I.

1.1.1 Future 1 – Aguirre offshore gas port (AOGP)

This future is designed to represent the most likely set of assumptions of PREPA's future. Under this Future the AOGP is built and there is gas availability at Aguirre which the associated conversion of the Aguirre Steam Units 1 & 2 to burn natural gas and the repowering of the Aguirre Combined Cycle. This results in efficient and relatively cheap generation in the South.

Future 1 assumes on the other hand that no gas will be available in the North of the island which means that the generation in the North is limited to burn Light Fuel Oil (LFO) and which will make it relatively expensive. Future 1 requires extensive use of transmission system to maximize the use of the generation in the South and minimize the operating costs.

Future 1, as all futures below assumes that for MATS compliance the steam units at San Juan and Palo Seco need to be retired or relegated to limited use, hence new generation is to be installed, regardless of the investments on the transmission system. As shown in this report some of this generation is necessary to be located in the North of the island due to PREPA's reliability issues.

1.1.2 Future 2 – No Aguirre offshore gas port

The main component of this Future is that the AOGP is not build and hence the new Aguirre steam units need to be retired for MATS compliance and the new generation at Aguirre will also burn LFO. In this case there is no reason to install all the new generation at this site and some of them are installed at San Juan instead, burning LFO. This future makes reduced use of the transmission system as there is limited cost differential between the North and the South and in consequence and some investments required under Future 1 can be postponed.

1.1.3 Future 3 – Gas in the North

This future assumes that there will be gas in the North after July 2022 (FY 2023) and in this case, as was the case for Future 2, the new generation being installed in the North includes units built to replace Aguirre 1&2. Also in this case there is no significant differential cost between the generation in the North and the South. The congestion in transmission system is negligible.

The facts above results in a reduced use of the transmission system, however in this case, this reduction will only happen after the LNG terminals in the North are built or a gas pipeline is in place. This is highly unlikely to happen until several years after the San Juan Steam Plants (SJSP) and the Palo Seco Steam Plants (PSSP) have to be retired or relegated to limited use (currently assumed by December 31, 2020 when the last of the new Palo Seco units in the North is online) for MATS compliance. Therefore, there will be several years with a situation which is identical to Future 1 and requiring significant use of the transmission system. This future does not result in a reduction of the transmission investments.

1.1.4 Future 4 – Reduced Demand Increased DG

This future is very similar to Future 1 with the difference that it considers greater levels of distributed generation, mostly photovoltaic projects, which would only be present during the daylight hours and it results in similar use of transmission as Future 1 during the critical night hours.

1.2 The Portfolios

The Supply Portfolios have been designed from a point of view of minimizing capital investments, maximizing fuel efficiency, or introducing more system flexibility, as described below. From a transmission point of view the impact of the different portfolios is most apparent in the long term as the existing fleet is replaced by the new more efficient and flexible fleet.

- ***Supply Portfolio 1*** focuses on minimizing investments by pursuing repowering initiatives and utilizing existing equipment to the extent possible. This Portfolio differs the least from the current generation and also its long term performance is expected to differ the least from the current system, in particular during night conditions when the impact of renewable is insignificant.
- ***Supply Portfolio 2*** builds smaller new units in the form of 1x1 combined cycles with the goal of designing a flexible generation system that can better follow the net load[1] profile. The location of the generation is a function of the Futures above depending on the availability of gas.
- ***Supply Portfolio 3*** focuses on large combined cycle builds. This Supply Portfolio is potentially the most efficient but may not be as flexible as Supply Portfolio 2. From a transmission point of view it is similar to Portfolio 2 as while the units are larger there are fewer units in the system. One key difference is Future 2 and 3 under which this Portfolio maximizes the generation in the North.

1.3 Conditions to be analyzed

Table 1-1 below shows a balance of the generation both in the north and the south of the system for the various combinations of Portfolios and Futures for the short term and long term. The short term represents the conditions at the retirement of SJSP and PSSP

[1] Net Load = Gross Load – Renewable Generation

(expected by December 2020). The long term represents the conditions in 2035 and values marked in red in Table 1-1 include the supplemental duct firing to provide flexible capacity.

For the short term we observe that the most critical condition occurs under Futures 1, 3 and 4 where there is gas in the South but not in the North initially, and there is limited generation in the North. Portfolio 1&2 have the minimum amount of generation in the North (610 MW) while Portfolio 3 consider the installation of an F-Class machine at Palo Seco and has increased capacity (359 MW versus 210 MW).

Therefore the short term conditions (2020) will be evaluated for Portfolio 2 (1 is the same) and Future 1 (3 and 4 are the same short term).

Table 1-1; Overview of Scenarios and Portfolios from a generation location point of veiw

	Year	Short Term (2020)				Long Term (2035)						
	Portfolio	1&2	3	2	3	1	2	2	2	3	3	3
	Futures	1,3&4	1,3&4	2	2	1,3&4	1&4	3	2	1&4	3	2
North	Palo Seco SCC-800 (Duct Fired)	210		210		210	210	216	210			
North	Palo Seco 1x1 F-class		359		359					359	369	359
North	S J Repowering	400	400	400	400	400	400	400	400	400	400	400
North	San Juan 1x1 F-class or H Class			359	359			369	359		393	359
South	Aguirre 1&2	900	900	900	900	1085						
South	Costa Sur 5&6	820	820	820	820	1005						
South	Aguirre 1&2 CC Unit Gas Repower	263	263	255	263	263	263	263	255	263	263	255
South	Aguirre 1x 1x1 F-class or H Class						369				393	359
South	Aguirre 2x 1x1 F-class or H Class						738	738	717	787		
South	Costa Sur 2x 1x1 F-class or H Class						738	738	738	787	787	787
South	AES & EcoElectrica	961	961	961	961	961	961	961	961	961	961	961
	Total North	610	759	969	1117	610	610	985	969	759	1162	1117
	Total South	2944	2944	2936	2944	3315	3070	2701	2672	2798	2404	2361
	Grand Total	3555	3703	3905	4061	3926	3681	3686	3640	3556	3567	3478

For Future 2 we observe that under Portfolios 2 and 3 there is increased generation in the North and the possibility of delaying transmission system investments needs to be studied. Noting that under Portfolio 2 the amount of generation in the North is slightly less than in Portfolio 3, we selected this case to be the studied and its findings would also be applicable to Portfolio 3.

Finally initially we consider carrying out the study under the 2020 peak load conditions, but based on the results of the PROMOD runs, the heavier transfers on the transmission system occurs later in time by the moment the Aguirre Combined Cycle units are repowered; July 2022 (FY 2023), thus this year was selected for the study.

In summary the short term analysis will be conducted for the following scenarios:

- **Case 1-A Short Term Heavy Transmission Use:** Portfolio 2 Generation, Future 1, Peak Load for FY 2023 (occurring in August 2022).

- **Case 1-B Short Term Moderate Transmission Use:** Portfolio 2 Generation, Future 2, Peak Load for FY 2023 (occurring in August 2022).

With respect of the long term (2035), we observe in the table above that Portfolio 1 under Future 1, 3 & 4 and Portfolio 2 under Futures 1&4 have a similar generation location in the North. These cases have minimal generation in the North and will be assessed considering Portfolio 2.

Other combinations of Portfolios and Futures have a more balanced distribution of the generation and are expected to be significantly less problematic from a transmission point of view. To demonstrate this we considered selecting Portfolio 2 under Future 2 or Portfolio 3 under Future 3. As this last case has slightly more generation in the North, Portfolio 2 was selected and the benefits would only be somewhat better on Future 3. Based on this the following cases were selected for the study.

- **Case 2-A Long Term Heavy Transmission Use:** Portfolio 2 Generation, Future 1, Peak Load for FY 2036 (occurring in August 2035). This case will be tested using the reinforced system identified during the study of Case 1-A

- **Case 2-B Long Term Moderate Transmission Use:** Portfolio 2 Generation, Future 2, Peak Load for FY 2036 (occurring in August 2035). This case will be tested using the reinforced system identified during the study of Case 1-B.

The short term cases above were evaluated using the guidelines from below:

- Contingency analysis (ACCC) – for determining the critical contingencies.

- Reactive requirements (QV) – for determining a rough value of the required reactive power MVArs.

- Optimal power flow analysis (OPF) – for determining the optimal placement of the reactive power compensation.

- Load flow analysis – for testing the proposed solution.
- Voltage stability analysis (PV) – for determining the reactive power margins with the proposed solution.
- Dynamic simulations for evaluating the short and long term dynamics.

The table below provides a summary of the load flows selected for analysis:

Table 1. PSS®E loadflow case identification.

Scenario	PSS®E Load flow Case	Date	Futures	Portfolio	Total gen. [MW]
1-A	A-2022-night_peak.sav	Aug 11 21 hrs 2022	1, 3 & 4	1 & 2	2883
	E-2022-day_peak.sav	Aug 10 12 hrs 2022	1, 3 & 4	1 & 2	2789
2-A	C-2035-night_peak.sav	Aug 9 21 hrs 2035	1 & 4	2	2853
	G-2035-day_peak.sav	Aug 8 12 hrs 2035	1 & 4	2	2666
1-B	B-2022-night_peak.sav	Aug 11 21 hrs 2022	2	2	2883
	F-2022-day_peak.sav	Aug 10 12 hrs 2022	2	2	2789
2-B	D-2035-night_peak.sav	Aug 9 21 hrs 2035	2	3	2853
	H-2035-day-peak.sav	Aug 8 12 hrs 2035	2	3	2666

For the long term cases, the reinforced system was tested to demonstrate its viability as indicated above.

Section

2

Steady state modeling

We present below the main assumptions made in the modeling of all cases under evaluation.

2.1 Generation assumptions

All cases are studied under the following assumptions with respect of generation:

- Palo Seco Steam Plant (PSSP) Units 3 & 4 and the San Juan Steam Plant units 9 & 10 will be retired or relegated to limited use by December of the 2020. With this all steam units at these plants will be out of service. The in-service generation in North must be enough to comply PREPA's reliability issues.

- The San Juan Repowering (San Juan units 5 & 6) are considered available, however due to its relatively low availability the effect of one unit failing while the other is in maintenance is considered in the study.

- New and Flexible generation at Palo Seco Plant will be available by the time that SJSP and PSSP units are suspended. Although the size of this units have already been defined in the selection of the Portfolios to 210 MW (3x70 MW), under our analysis we considered the minimum number of units that needs to be online for various operating conditions.

- Renewable Projects expected to be online for the different times of analysis and modeled levels of penetration. These projects must comply with the PREPA's Minimum Technical Requirements.

- Distributed generation (DGs) installed and projections included.

- For the long term the generation was considered as defined in the Portfolios discussed above.

The base case for representing the PREPA's grid with all of the upgrades at the transmission system by the 2022 was submitted by PREPA the 17th of April 2015. We describe below the main reinforcements in the case.

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2.1.1.1 [redacted]

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2.1.1.2 [redacted]

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Section

3

Short Term Steady State Assessment Case 1-A

As indicated before Case 1-A corresponds to Generation Portfolio 2, Future 1 and the peak load of FY 2023 (occurring in August 2022), is expected to make heavy use of transmission and hence is assessed first.

3.1 Dispatch Conditions

The analysis was conducted for the nigh peak as this is the time the heaviest use of transmission occurs.

The base dispatch conditions were obtained from the PROMOD runs at 21 hrs August 11 of 2022 and are detailed in Table 3-1 below.

We observe in Table 3-1 that one train of the combined cycle from San Juan 5 repowering (200 MW) is online at its maximum output as well as two of the three new 70 MW combined cycle trains considered at Palo Seco and dispatched close to its minimum.

Note that while we are considering the Palo Seco generation as defined in the Portfolio 2 (3x 70 MW SCC800), in this study we confirm that this is the right size and fewer units would put the system at risk.

Finally we observe that the total generation at the 2022 night peak case was of 2,884 MW, with a total spinning reserve of 535 MW (18.5%). The available spinning reserve is also shown at Table 3-1.

Table 3-1. FY2022 – Night peak case (1-A).

Unit	Dispatch [MW]	Reserve [MW]
806 C.S.6 23.000	369.4	40.6
809 AG.1 24.000	378.7	71.3
810 AG.2 23.000	297.0	153.0
811 SJREPST1 13.800	44.7	12.7
836 AERO MAY #1 13.800	25.0	25.0
838 AERO MAY #3 13.800	25.0	35.5
839 AERO MAY #4 13.800	25.0	35.5
856 SJREPG1 13.800	110.3	32.0
858 ECOGT1 17.100	162.7	0.0
859 ECOGT2 17.100	162.7	0.0
860 ECOSTEAM 17.100	181.5	0.0
871 AES 1 21.000	227.0	0.0
872 AES 2 21.000	227.0	0.0

Unit	Dispatch [MW]	Reserve [MW]
6302 PSCC-2 15.000	22.9	47.1
6303 PSCC-3 15.000	22.9	47.1
10601 AG_REPCC-1 15.000	263.5	0.0
10602 AG_REPCC-2 15.000	263.5	0.0
TOTAL	**2884**	**535**
Total thermal	**2809**	
Total hydro	**59**	
Total renewable	**16**	

3.2 Contingency Selection and Planning Criteria

The purpose of the contingency analysis is to determine possible conditions that may put at risk the operation of PREPA's power system due to severe branch overloads or in the extreme voltage collapse; given the limited generation in the North.

3.2.1 [redacted]

[redacted]

3.2.2 Planning Criteria

All facilities under normal or contingency conditions must be below their normal rating (Rate A – current expressed as MVA). If the loading results greater than 85%, it will be reported, as some of current PREPA' transmission lines are limited to this power transfer level.

Bus voltages under normal and contingency conditions should be within the 0.95 to 1.05 pu range. We note however that if under certain contingency conditions the voltage is under 0.95 pu but over 0.90 pu, then this is reported but not considered a major violation of the case.

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Section

4

Reactive Power Compensation Selection for Case 1-A

The purpose of this section is to identify the reactive power requirements at North to provide voltage support for the critical contingencies with the proposed generation in the North.

The starting case considers the critical but possible situation that no generation is online at San Juan, and due that, it has reduced and inoperable voltages at North. With this, is desired to investigate the reactive power requirements to achieve normal voltages at both pre and post-contingency. Also the analysis was conducted with only two of the three units at PSCC in service.

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4.2.1 Methodology

PREPA provided a list of possible places to install the reactive power compensators in case that this study concludes about a requirement at the San Juan metropolitan area. The available PREPA's stations that were considered are:

- San Juan Plant
- Monacillo TC
- Bayamón TC
- Aguas Buenas GIS
- Sabana Llana TC

By solving a traditional power flow, a significant amount of time is often spent trying to achieve a good solution. Multiple iterations are required, results are analyzed and new estimates of the control values are determined for use in the next solution. Much time may be spent trying to parametrically determine what values of the controls will provide a feasible solution.

The PSS®E OPF (Optimal Power Flow) application complements the main PSS®E power flow program providing an analytic model to determine the best set of decision (e.g. size and location of reactive power compensation) with respect to a stated quantitative performance measure (i.e. objective function). It efficiently achieves this result by formulating and solving an optimization problem, defining the goal as a combination of objective functions and a set of variable constraints to satisfy.

Power system performance quality requires satisfying both the global objective and the constraints. By adjusting control variables, the solution process determines conditions that simultaneously satisfy the constraint equations and minimize the objective function. A complete optimal power flow problem statement thus requires specification of the objective function, the controls, and the constraints.

The adopted criterion was to require that dependent variables, such as a bus voltages magnitudes and branch flows especially in the North area, must be within maximum and minimum limits for the desired solution.

Objective functions are expressions of cost in terms of the power system variables.

When selecting as the objective function minimizing the shunt reactive compensation, the OPF solution determines the minimal amount of reactive support that needs to be placed at candidate buses.

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Section
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Steady State Analysis of Case 1-B

This section presents the contingency analysis of the Case 1-B at FY2023, which represents a moderate use of the transmission system and considers that as there is no gas available in both North and at Aguirre, the part of the new generation is installed in the North. In this case a Class-F combined cycle is placed at San Juan. The objective is to verify if the levels of dynamic reactive power compensation are still required, as was the case the high use of the transmission, as well as the additional transmission reinforcements identified.

5.1 Dispatch Conditions.

Originally, none of the new investments identified in this study were considered (see Section 4.4) to determine if they would still be required.

The base dispatch conditions for the FY2023 night peak case were obtained from the PROMOD runs at 21 hrs August 11 of 2022, and at 12 August for the day peak.

The total generation at the 2022 night peak case was of 2884 MW, with a total spinning reserve of 846 MW (29.4%). Note that the three units from PSCC are online and the new class-F combined cycle San Juan (with a maximum capacity of 359 MW) was at minimum dispatch (111.6 MW). The San Juan Repowering was off line. See table below.

For the day peak, the total generation was 2789 MW, with a total spinning reserve of 855 MW (42.9%). Note that there is only one unit at PSCC online and this was the only thermal generation on the North, because 482 MW of renewable were also dispatched at the north. The total dispatch of renewable generation was 798 MW including distributed generation.

Table 5-1. FY2023 – Night peak and day peak cases (1-B).

Unit	Night peak Dispatch [MW]	Day peak Dispatch [MW]
805 C.S.5 23.000	**350.00**	**366.25**
806 C.S.6 23.000	**366.38**	**409.59**
809 AG.1 24.000	**382.00**	**230.00**
810 AG.2 23.000	**331.80**	**230.00**
858 ECOGT1 17.100	**162.73**	**88.27**
859 ECOGT2 17.100	**162.73**	**88.27**
860 ECOSTEAM 17.100	**181.54**	**98.47**
871 AES 1 21.000	**227.00**	**227.00**
872 AES 2 21.000	**227.00**	**227.00**
6301 PSCC-1 15.000	**57.16**	**22.86**
6302 PSCC-2 15.000	**70.11**	**0**
6303 PSCC-3 15.000	**66.06**	**0**
8801 SJCC-1 15.000	**111.58**	**0**
10604 AG_CC-2 15.000	**111.58**	**0**
TOTAL	**2884**	**2789**
Total thermal	**2808**	**1988**
Total hydro	**59**	**3**

Unit	Night peak Dispatch [MW]	Day peak Dispatch [MW]
Total renewable	17	798[2]

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[2] 95 MW are DG.

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Section

6

Steady State Analysis of Case 2-A

This section presents the contingency analysis of the Case 2-A corresponding to heavy transmission use for FY2036. It considers that all of the reinforcements that were found necessary under the analysis of the 2022 conditions.

6.1 Dispatch Conditions

The analysis was conducted for the night peak as this is the time when the heaviest use of transmission occurs. Also we verified it for the day peak where all the renewable are available.

The base dispatch conditions were obtained from the PROMOD runs at 21 hrs August 9 of 2035 for the night peak and at the 12 hrs August 8 for the day peak.

The total generation at the 2035 night peak case was of 2839 MW, with a total spinning reserve of 820 MW (28.9%). Note that both trains of the combined cycle San Juan Repowering are offline and three 70 MW combined cycle trains from Palo Seco considered online at minimum capacity.

The total generation for the day peak case was 2664 MW, with a total spinning reserve of 988 MW (34.8%). Note that there is no thermal generation online at north due to the high renewable penetration (785 MW located at North). The total dispatch of renewable generation was 1316 MW. In both cases, the two STATCOM were producing reactive power close to its midpoint output.

The day peak case has a dispatch of 1345 MW of thermal generation and 1316 MW in renewable, which 785 MW are located at North and 400 MW are from DGs.

The table below shows dispatches at both cases.

Table 6-1. FY2035 – Night peak and day peak cases (2-A).

Unit	Night peak Dispatch [MW]	Day peak Dispatch [MW]
858 ECOGT1 17.100	162.73	88.26
859 ECOGT2 17.100	162.73	88.26
860 ECOSTEAM 17.100	181.53	98.46
871 AES 1 21.000	227.00	227.00
872 AES 2 21.000	227.00	227.00
6301 PSCC-1 15.000	22.80	0
6302 PSCC-2 15.000	22.80	0
6303 PSCC-3 15.000	22.80	0
9601 CSUR_CC-1 15.000	326.17	122.76
9602 CSUR_CC-2 15.000	330.00	114.92
10601 AG_REPCC-1 15.000	263.45	263.45
10602 AG_REPCC-2 15.000	263.45	0.00

Unit	Night peak Dispatch [MW]	Day peak Dispatch [MW]
10603 AG_CC-1 15.000	114.92	0.00
10604 AG_CC-2 15.000	315.48	0.00
10605 AG_CC-3 15.000	114.92	114.92
TOTAL	**2839**	**2664**
Total thermal	**2758**	**1345**
Total hydro	**59**	**3**
Total renewable	**22**	**1316**[3]

All of the investments at the transmission system that were considered from the study of case 1-A (Section 4.3), were considered also available.

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[3] 400 MW are DG.

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Section

7

Steady State Analysis of Case 2-B

This section presents the contingency analysis of the Case 2-B for the, which represents a moderate use of the transmission system and considers that all of the reinforcements that were found at the case 1-B are available.

7.1 Dispatch Conditions

The base dispatch conditions were obtained from the PROMOD runs at 21 hrs August 9 of 2035 for the night peak. Note that both trains of the combined cycle San Juan Repowering are offline, the three 70 MW combined cycle trains from Palo Seco considered online and the class-F combined cycle at San Juan also online.

The day peak was at the 12 hrs August 8 of 2035; due to the high renewable penetration (785 MW located at North), no thermal generation was considered online at North. The total dispatch of renewable generation was 1316 MW, of which 400 MW are distributed generation dispersed in the island.

All transmission investments recommended in the study were considered in service, with the exception of the STATCOMs. Although the STATCOMs are recommended to be installed even under Future 2, given the uncertainty with respect of the actual demand reduction, here we wish to confirm that with the expected 2035 conditions the STATCOMs are still not necessary.

Table 7-1. FY2035 – Night peak and day peak cases (2-B).

Unit	Night peak Dispatch [MW]	Day peak Dispatch [MW]
858 ECOGT1 17.100	**162.73**	**88.27**
859 ECOGT2 17.100	**162.73**	**88.27**
860 ECOSTEAM 17.100	**181.54**	**98.47**
871 AES 1 21.000	**227.00**	**227**
872 AES 2 21.000	**227.00**	**227**
6301 PSCC-1 15.000	**57.16**	**0**
6302 PSCC-2 15.000	**22.86**	**0**
6303 PSCC-3 15.000	**57.16**	**0**
8801 SJCC-1 15.000	**251.06**	**0**
9601 CSUR_CC-1 15.000	**367.65**	**286.50**
9602 CSUR_CC-2 15.000	**369.17**	**218.75**
10601 AG_REPCC-1 15.000	**102.09**	**0**
10602 AG_REPCC-2 15.000	**102.09**	**0**
10604 AG_CC-2 15.000	**228.74**	**0**
10605 AG_CC-3 15.000	**251.06**	**111.58**
TOTAL	**2851**	**2665**
Total thermal	**2770**	**1346**

Unit	Night peak Dispatch [MW]	Day peak Dispatch [MW]
Total hydro	**59**	**3**
Total renewable	**22**	**1316**[4]

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[4] 400 MW are DG.

7.3 Conclusions of the steady state analysis for Case 2-B

It was verified that with the expected load conditions for 2035 the STATCOMs could be further postponed. The system with the other short term transmission reinforcements proposed operates within the planning criteria.

It's important to note that during the day peak, thermal generation is limited by a high penetration of renewable (1346 MW thermal vs. 1316 MW renewable), which represents nearly 50% of the dispatched generation, from where 785 MW are generated at the North.

Again it must be stressed here that the STATCOMs will be necessary if the load is above 3,000 MW as was shown earlier and PREPA should proceed with their acquisition even under Future 2 that has increased generation in the North.

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Section

8

Short-term Dynamic Analysis

This section presents the results of the analysis conducted to evaluate the system behavior from the point of view of angular stability and frequency excursions. With this type of simulations it is possible to verify that for the critical faults analyzed, the generators are able to recover a stable operating point.

This study complements the evaluation carried out in the previous sections that lead to the selection of the investments at the transmission system, as required for adequate performance under normal and contingency (single, double and single + generation) conditions.

The night peak cases characterized by a concentration of thermal generation in the South, present the risk of larger angles and during a disturbance these angles could reached or exceeds its maximum stable (recovery) values, and thus resulting in the generator losing the synchronism.

On the other hand the cases with large amounts of renewable generation represent a condition where the risk of losing the stability is due to the reduction in rotating inertia that implies a high renewable penetration. These cases may present large frequency excursions if the renewable generation does not contribute to the stabilization of the frequency. However this is not expected in this case as PREPA's Minimum Technical Requirements (MTRs) mandate the incorporation of storage that ensures fast response to frequency decline from the renewable generation.

The focus of this study was the dynamic analysis for both regimes of generation.

8.1 Dynamic models

The following dynamic models, as used in previous studies, were added to represent the dynamics of existing and future equipment:

- Underfrequency relay models (UFLT).
- Energy STORAGE models (STORAGE1) to provide contingency reserve in the order of 10% of the total renewable project.
- Generic PV model for the future identified PV projects with its associated STORAGE model.
- Generic PV model for the future Generic PV projects with its associated STORAGE model.
- Generic PV model for the future generic DG projects without STORAGE mode.
- GNET equivalent for small hydro units.

Furthermore, the incorporation of new dynamic models was necessary:

- UST8H used for modeling Siemens Gas Turbines in single shaft combined cycle with a steam turbine. For the governor response against frequency events it was supposed a margin of 20%. Note that the frequency response of this model is achieved only by considering the contribution of the gas turbine.

  This model was used at:

  - SCC-800 units Palo Seco plant
  - Class-H units at Aguirre
  - Class-H units at Costa Sur
  - Class F units at San Juan

- SVSM03U1 for modeling the STATCOMs of Monacillo and San Juan, with its standard protections and considering a transient overload of rated current of 125% during 2 seconds.
- The python script SETGOV.py was used for setting the limits of the speed governors in order to have a contingency reserve greater than 5%.

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Section
9

Considerations for extreme events

9.1 Introduction

The formulation of the IRP plan is focused on the system's operation under normal and contingency conditions. These conditions occur in the normal course of business and PREPA is expected to supply its entire load with very limited to no interruptions.

However, in power systems "Major Events" can occur that exceed the design capability of the system and it is not expected that the entire load will be supplied. Hurricanes are this type of events, which can cause load shed, sometimes significant, for relatively long duration of time, e.g. in the multiple weeks timeframe.

Due to its geographical location surrounded by the Atlantic Ocean and Caribbean Sea and by its condition of tropical island, Puerto Rico annually experiences a great activity of hurricanes and tropical storms between the months of June and November, the Hurricane Season. These atmospheric systems affect the transmission and subtransmission lines and distribution feeders causing the interruption of electric service to most of the island and, depending on the magnitude, can affect the whole island. Multiple important transmission lines run South-North through the mountains in the center of the island; after storms or hurricanes, these places are inaccessible causing delays in the restoration of the electric system. With a disrupted South-North transmission system, the generating units at North play a crucial role in supplying the local load as the system is recovered and the power flows south to north are reestablished. It is important to note that the renewable projects do not have a role in the electric system restoration, mainly because their variability would difficult this restoration.

In this section of the report we discuss the potential impact of these types of Major Events on the proposed future configuration of PREPA's power system with emphasis on the conditions that may prevail after the installation of the new combined cycle at Palo Seco for the critical Future 1 and 4, that minimizes the generation in the North due to the availability of gas only in the South of the island and do not consider a new combine cycle plant in San Juan. The analysis is performed for the recommended Portfolio 3 that has an F-Class combined cycle in Palo Seco (359 MW), but the case the 3 SCC800 are used (3x70MW) is also discussed (Portfolio 1 or 2).

As will be observed, as a result of this analysis, it is recommended that stand-by generation be available at Palo Seco or San Juan, beyond what is already considered in the IRP. An assessment shall be performed to determine which standby generation alternatives results feasible and more economical for PREPA's operations, especially if the transmission system is reconstructed by the investments explained in this volume in addition to the ones carried out by PREPA in the recent years. . Among others, the assessment must consider the environmental permitting process to allow for such addition of generating capacity to the one resulted from the IRP study, along with the costs associated to the implementation of the corresponding projects. The assessment also known as a System Restoration Study or Blackstart should consider the number of alternative transmission paths that would allow PREPA's operation to reconnect generation to the north and/or transfer load to the south, thus minimizing the reliance on generation located in the north.

Finally, it should be stressed that a System Restoration Study is well beyond the scope of the IRP work and the intention here is to provide indication on the level of load – generation balance that PREPA could have after a Major Event. Hence, it was assumed, only for determining this balance, that PREPA could maintain Palo Seco 3 & 4 as limited use for being used as standby generation. Thus, the results of this analysis shall not be understood as a recommendation for maintaining Palo Seco as limited use after the implementation of the IRP generation and transmission projects, but just an assessment of what would be the effect of adding these levels of generation.

9.2 Starting System Conditions

The starting system conditions correspond to those in the night peak of 2022 that has a peak load of 2,809 MW (2,885 MW generation). Table 9-1 below shows the initial load considered by area.

Table 9-1: Initial Load

Area	Initial Load MW
S.JUAN	509.1
BAYAMÓN	562
CAROLINA	280.7
CAGUAS	472.3
ARECIBO	288.9
PONCE ES	111.7
PONCE OE	195.1
MAYAGÜEZ	290.2
AEE AUX GENS	99.8
Total Load	**2809.8**

As presented earlier for 2022 the recommended Portfolio 3 considers an F Class Combine Cycle (359 MW) at Palo Seco and this will be the basis for the analysis. Portfolios 1 & 2 consider three new combined cycle units (210 MW), instead but there are cost disadvantages of this solution and it is just commented as per what it's impact would be.

The San Juan Repowering (400 MW), three Cambalache units (3x83 MW) and the 21 MW GT's at Palo Seco and Vega Baja complement the base generation considered in the North of the island and that could be committed to confront a Major Event.

The table below shows this generation as well as the additional generation options to be considered; hypothetically maintaining the Palo Seco 3 & 4 available with limited use.

In the table we identify two supply levels depending on what is available in the North. Supply 1 (1175 MW) considers the base units considered in the IRP with environmental (MATS) compliance. Supply 2 (1,607 MW) considers that in addition to this generation the Palo Seco 3 & 4 are maintained with limited use. Note that this additional generation is provided as an example of the effect of having stand by generation and a System Restoration Study may result in an alternative solution.

Table 9-2 Generation Supply

	Generation Availability in the North			
			Operating Range	
Bus	Name	Type	Min MW	Max MW
811	SJ Rep Steam 1	CCP	56.0	57.7
812	SJ Rep Steam 1	CCP	56.0	57.7
856	SJ Rep Gas 1	CCP	99.0	142.3
857	SJ Rep Gas 2	CCP	99.0	142.3
6304	PSCC F-Class	CCP	112.0	359.0
880	Cambalache1	GT	50.0	82.66
881	Cambalache2	GT	50.0	82.66
882	Cambalache3	GT	48.0	82.66
829-1	PaloSecoGT11	GT	21	21
829-2	PaloSecoGT12	GT	21	21
830-1	PaloSecoGT21	GT	21	21
830-2	PaloSecoGT22	GT	21	21
831-1	PaloSecoGT31	GT	21	21
831-2	PaloSecoGT32	GT	21	21
828-1	VegaBajaGT11	GT	21	21
828-2	VegaBajaGT12	GT	21	21
Total Supply 1			**738.0**	**1175.0**
819	Palo Seco 3 *	Steam	130	216
820	Palo Seco 4 *	Steam	130	216
Total Supply 2			**998.0**	**1607.0**

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9.5 Recommendations

Based on the above it is recommended that stand-by generation be installed at Palo Seco or San Juan to minimize the load shedding during Major Events. An assessment shall be performed to determine which standby generation alternatives results feasible and more economical for PREPA's operations, considering, among others, the transmission system reconstruction by the investments explained in this volume, the environmental permitting process to allow for such addition of generating capacity, and the costs associated to the implementation of the corresponding projects. A System Restoration Study would address these considerations.

9.6 Additional Considerations

The presentation above just provides an overview of the generation availability to supply the load and it did not enter in the actual procedures to recover the system.

It is important that PREPA updates it Black Start Plans, in the context of a System Restoration Study, to ensure that the generating units considered can be brought online; i.e. cranking paths are identified to bring black start power to those units that do not have black start capability, and paths for the generation to be re-directed to priority loads (e.g. the Cambalache units to supply the metropolitan area). Also emergency preparedness procedures should be in place so that the generating units are verified and their availability confirmed before the start of the hurricane season and as hurricanes are identified that could hit the island, procedures to start the units are put in place.

Additionally PREPA should consider storing modular towers that could help expedite the system restoration of the transmission system using temporary structures[5]. These structures would expedite the re-establishing of key links North South, which will be a crucial component of the reliability of PREPA's system.

Finally it must be stressed that the renewable generation should not be considered as a means to supply the load following a major event; or used with great care given its variability and the weakened condition under which both the generation and the transmission systems will be after this type of events.

In other words, during these extreme conditions, renewable generation cannot be dispatched given a weakened condition of the power system, which will result in additional cost to PREPA given current contractual provisions with the PPOAs.

[5] See for example IEEE Standard 1070-1995, "IEEE Guide for the Design and Testing of Transmission Modular Restoration Structure Components" and Transmission Emergency Restoration Systems For Public Power (http://www.lindsey-usa.com/catalogs/ERS/nwppapaper020328.pdf)

Section
10

Long-term Dynamic Analysis

The aim of this section is to verify the frequency stability on the long term. For this, representative ramping events at the solar irradiation were studied using measurements and parameters from the first study of renewable integration.

In order to simulate the control mechanisms of the restoration of the frequency of PREPA's power system, it was necessary to add a simulation model representing the dynamics of Automatic Generation Control (AGC).

The following generators were considered participating in secondary frequency control:

Table 10-1. Available generating units considered on the AGC logic

BUS	NAME	Case 1-A day peak		Case 1-B day peak		Case 2-A day peak		Pmax
		PGEN	Reserve	PGEN	Reserve	PGEN	Reserve	
805	C.S.5	250	130	366	14	0	0	380
806	C.S.6	250	130	410	0	0	0	380
809	AG.1	230	200	230	200	0	0	430
810	AG.2	0	0	230	200	0	0	430
858	ECOGT1	88	74	88	74	88	74	162
859	ECOGT2	88	74	88	74	88	74	162
9601	CSUR_CC-2	0	0	0	0	125	244	369
9602	CSUR_CC-1	0	0	0	0	115	254	369
10605	AG_CC-3	0	0	0	0	115	254	369
			608 **22%**		**562** **20%**		**900** **32%**	

Note that for 2035, it was considered that both units of the combined cycle at Costa Sur (CSUR_CC 1&2) and at least one unit of the Aguirre combined cycle (AG_CC -3) will participate in the AGC.

Only day peaks were considered as the objective is to evaluate the impact of renewable generation.

10.1 Ramp events

During the analysis, the following ramps that simulate the loss of the solar irradiance have been studied:

1) Ramp1- Long duration power ramp: ramp rate of -2%/minute during 30 minutes affecting all PV's in the island.
2) Ramp2 - Longest duration power ramp in a cluster, ramp rate of -3%/minute during 30 minutes affecting all PV´s in the North Cluster.
3) Ramp3 - Steep power ramp: ramp rate of -3%/minute during 15 minutes affecting all PV's in the island.

The ramping event 1 implies a reduction of the solar irradiance at all the island with a rate of -2%/min during 30 minutes, which is equivalent to say that the photovoltaic generation in the entire island is reduced in 60% after 30 minutes. For example, for the case A at day peak, after 30 minutes the PV generation in the entire island is reduced from 692 MW to 276 MW.

The ramping event 2 implies a reduction of the solar irradiance at the North of the island with a rate of -3%/min during 30 minutes, which is equivalent to say that the photovoltaic generation at the North of the island is reduced in 90% after 30 minutes. For example, for the case A at day peak, after 30 minutes the PV generation in the entire island is reduced from 424 MW to 269 MW.

The ramping event 3 implies a reduction of the solar irradiance at all the island with a rate of -3%/min during 15 minutes, which is equivalent to say that the photovoltaic generation in the entire island is reduced in 45% after 15 minutes. For example, for the case A at day peak, after 15 minutes the PV generation in the entire island is reduced from 692 MW to 381 MW.

The Table 10-2 describes the amount of PV generation that is reduced at the different ramps and the total PV generation at the end of the simulation for 2022 and 2035 cases. Also the column "PV gen" describes the dispatch of the PV generation at the beginning of the simulation for each of the clusters (North and South).

Table 10-2. PV generation and ramping events

Cluster	2022				2035			
	PV gen	Ramp 1	Ramp 2	Ramp 3	PV gen	Ramp 1	Ramp 2	Ramp 3
North	470.87	-282.5	-423.8	-211.9	755.8	-453.5	-680.2	-340.1
South	221.92	-133.1	0	-99.9	436.9	-262.1	0	-196.6
Total	**692.79**	**-**	-	-	**1193**	**-**	**-**	**-**
Reduction at PV	**-**	-415.6	-423.8		-	-715.6	-680.2	-536.7
Total PV at the end of the ramp	**-**	**276**	**269**	**381**	-	**477**	**512.8**	**656**

10.2 Simulation results

During a severe event like a fast negative ramping at a renewable resource, the available units that participate in the frequency control increase their output following the AGC load set point.

If the ramp at which the overall PV generation is reduced is not very fast, the units commanded by the AGC with a high ramping rate can keep the frequency deviation imperceptible. An example of this can be observed at Figure 10-3, where the frequency droop is negligible. Now, if some units commanded by the AGC reach its maximum power output before the renewable generation ramp has finished, it can occur that the available units that still have reserve do not have sufficient ramp rate to maintain the frequency and low values may be reached. An example of this can be observed at Figure 10-16 where frequency reached a minimum of 59.93 Hz because Aguirre #1 was the only with available reserve at 1400 seconds.

In the present study two important aspects are verified:

1. That reserve margins of secondary frequency regulation are sufficient.

2. That the units involved in the frequency regulation can avoid frequency drops due to long deep ramps at the renewable generation that might activate load shedding protections.

The results of the long-term analysis are summarized at the next table. If the frequency deviation is lower than 0.1% it is considered negligible.

Case	Ramp 1	Results – max. freq, dev.	Ramp 2	Results – max. freq, dev.	Ramp 3	Results – max. freq, dev.
1-A 2022 day peak	Figure 10-1	Negligible; reserve ok.	Figure 10-5	Negligible; reserve ok.	Figure 10-9	Negligible; reserve ok.
1-B 2022 day peak	Figure 10-13	59.93 Hz; reserve ok.	Figure 10-17	59.92 Hz; reserve ok.	Figure 10-21	Negligible; reserve ok.
2-A 2035 day peak	Figure 10-25	Negligible; reserve ok.	Figure 10-29	Negligible; reserve ok.	Figure 10-33	Negligible; reserve ok.

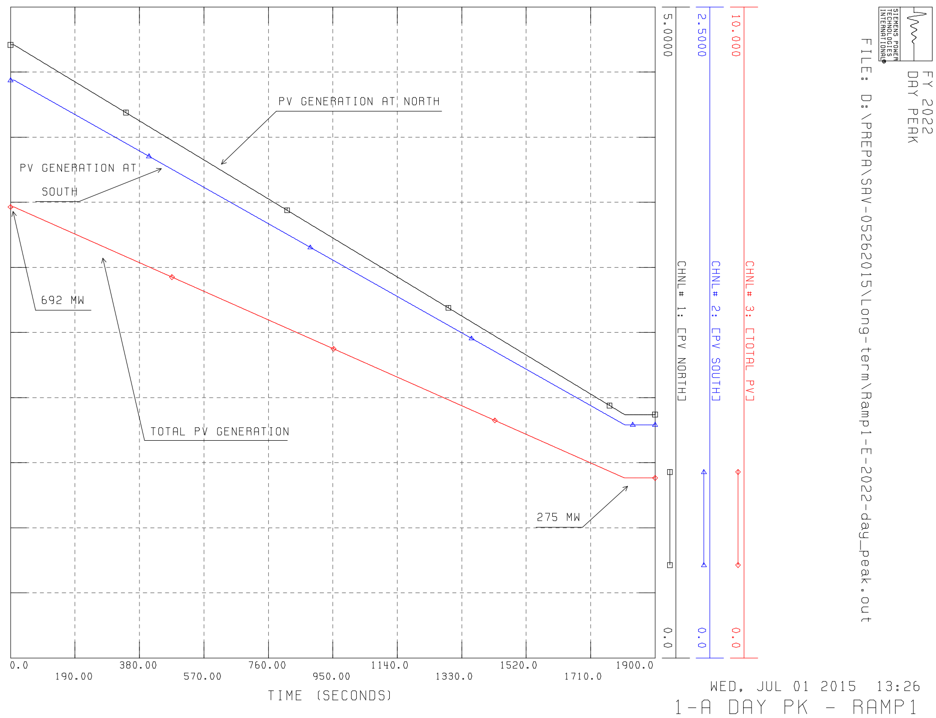


Figure 10-1. 1-A 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – PV generation.

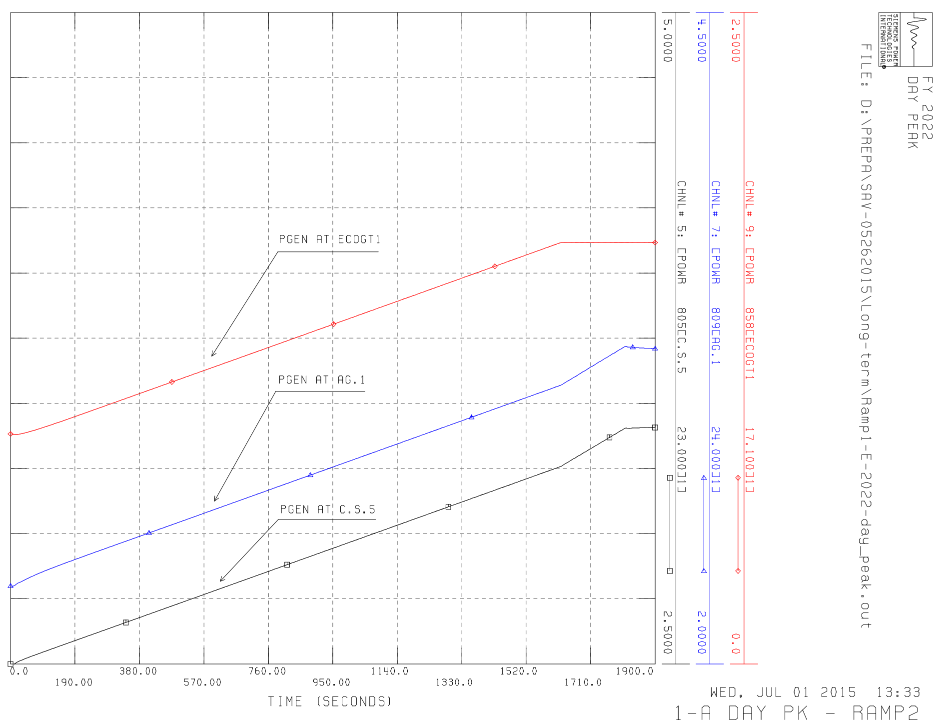


Figure 10-2. 1-A 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – Units that participate in the AGC.

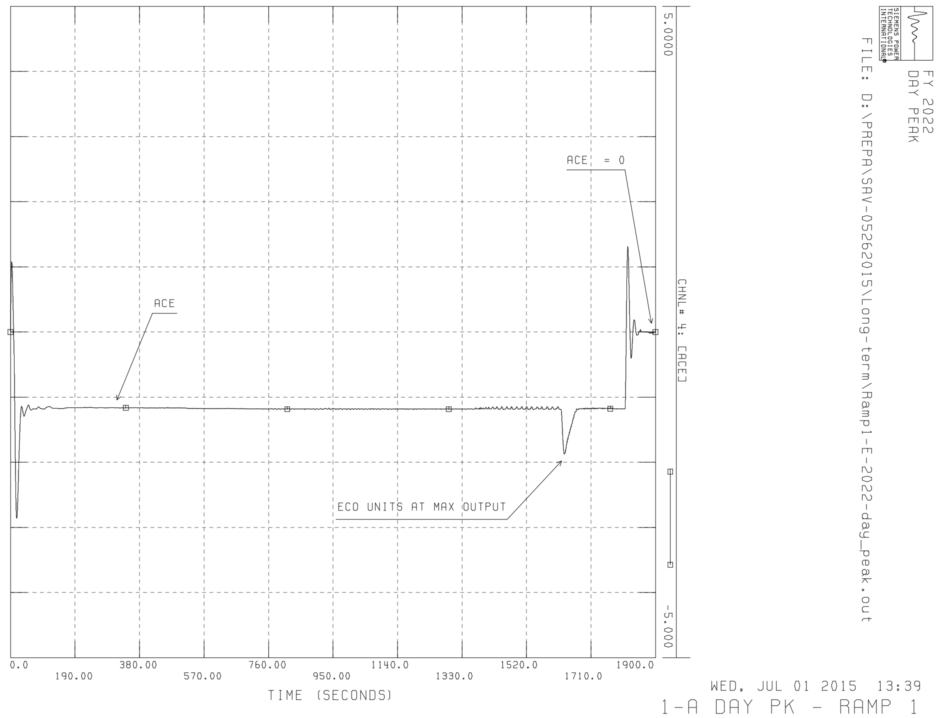


Figure 10-3. 1-A 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – AREA CONTROL ERROR (ACE).

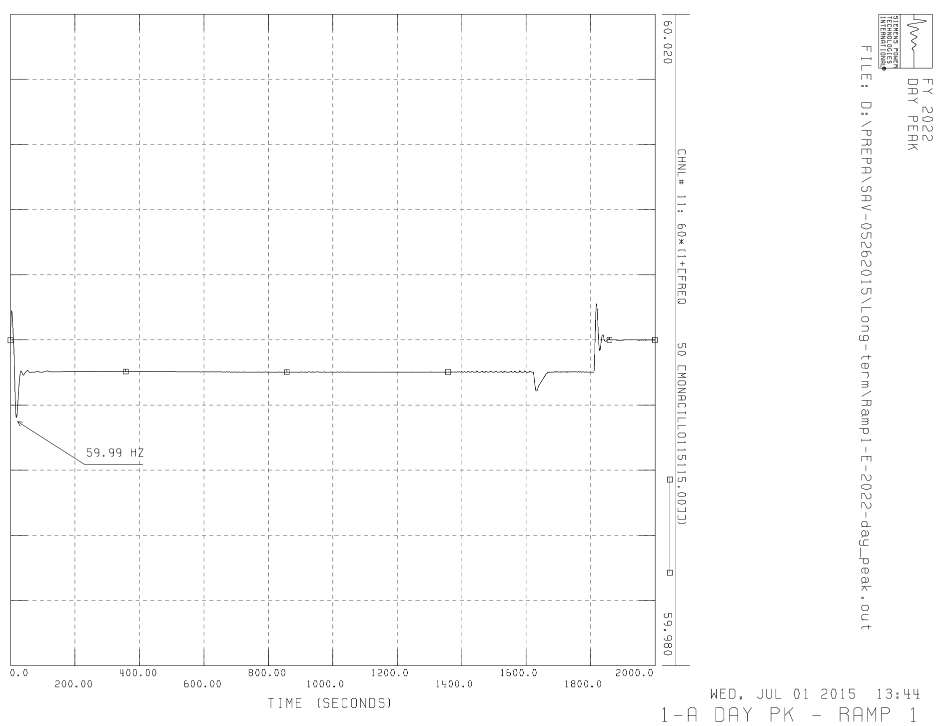


Figure 10-4. 1-A 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – frequency [Hz] at Monacillo.

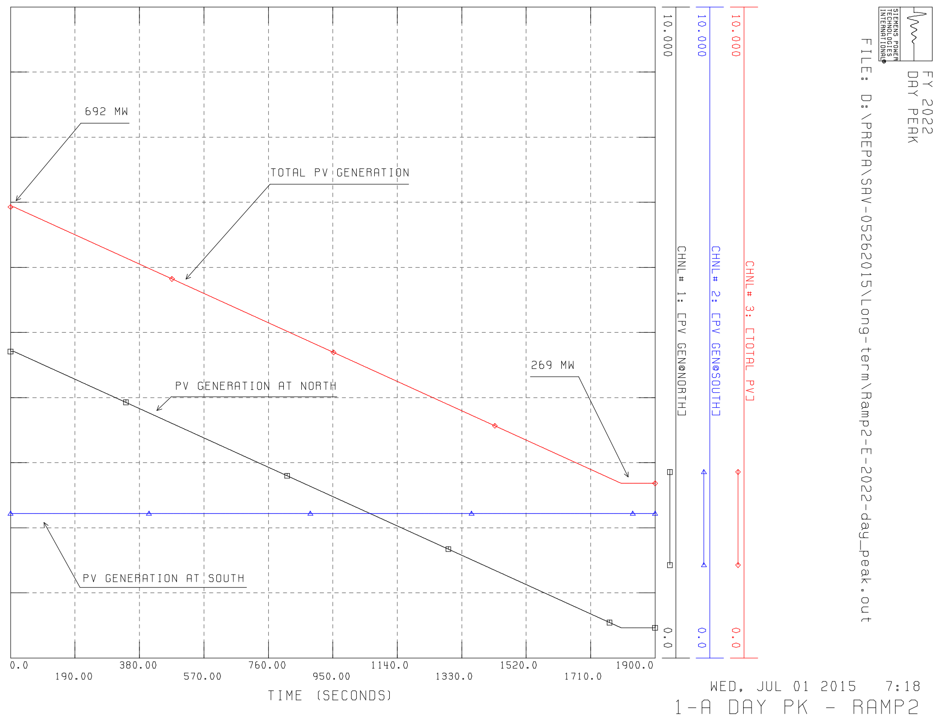


Figure 10-5. 1-A 2022 day peak – ramp 2: loss of 90% of PV generation at the North – PV generation.

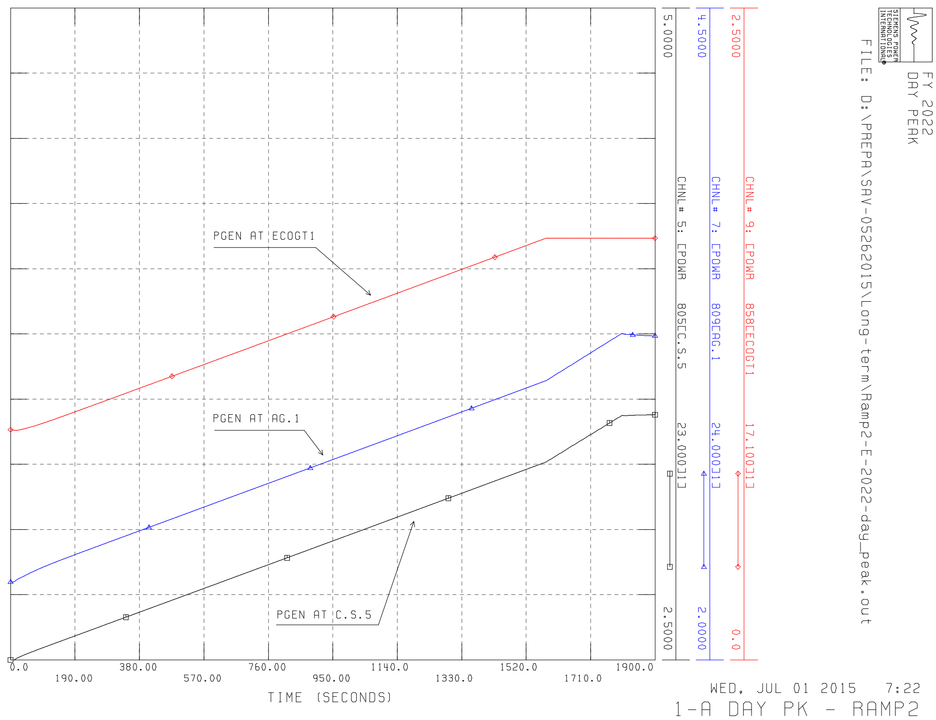


Figure 10-6. 1-A 2022 day peak – ramp 2: loss of 90% of PV generation at the North – Units that participate in the AGC.

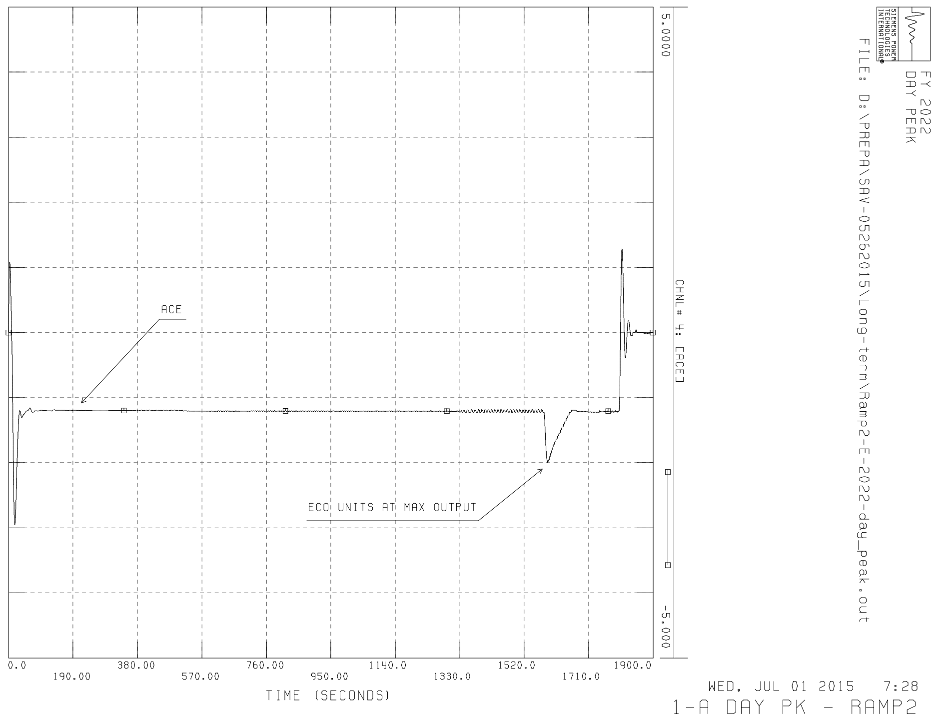


Figure 10-7. 1-A 2022 day peak – ramp 2: loss of 90% of PV generation at the North – AREA CONTROL ERROR (ACE).

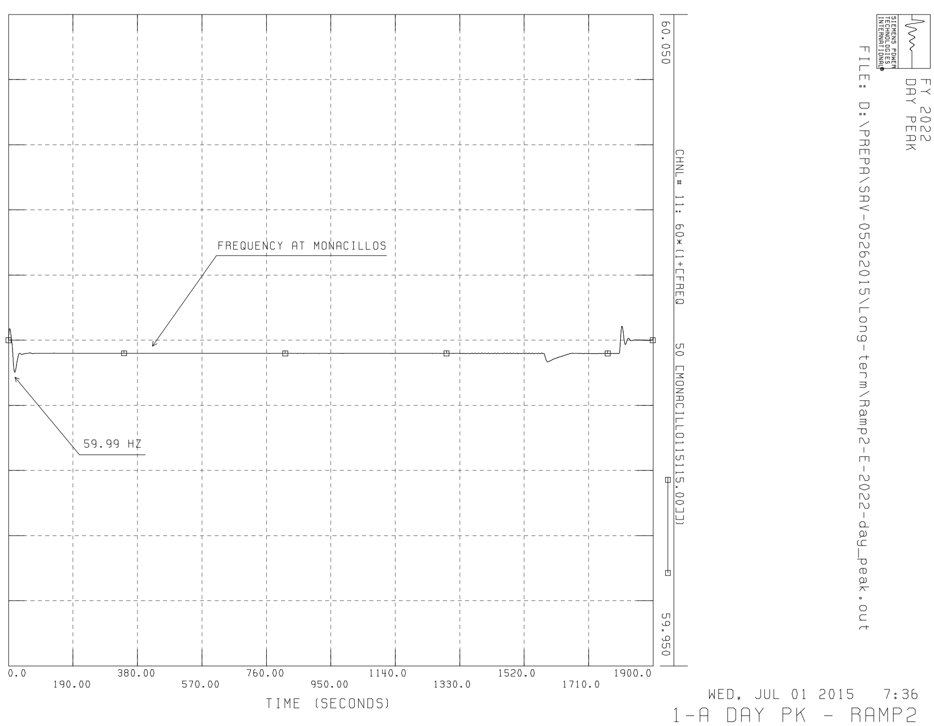


Figure 10-8. 1-A 2022 day peak – ramp 2: loss of 90% of PV generation at the North – frequency [Hz] at Monacillo.

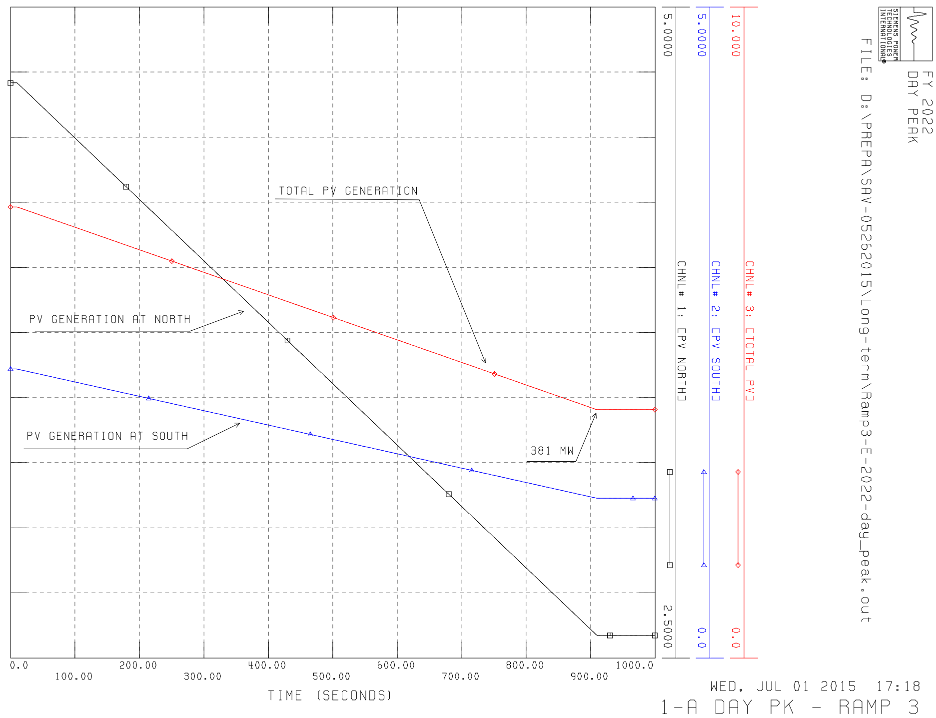


Figure 10-9. 1-A 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – PV generation.

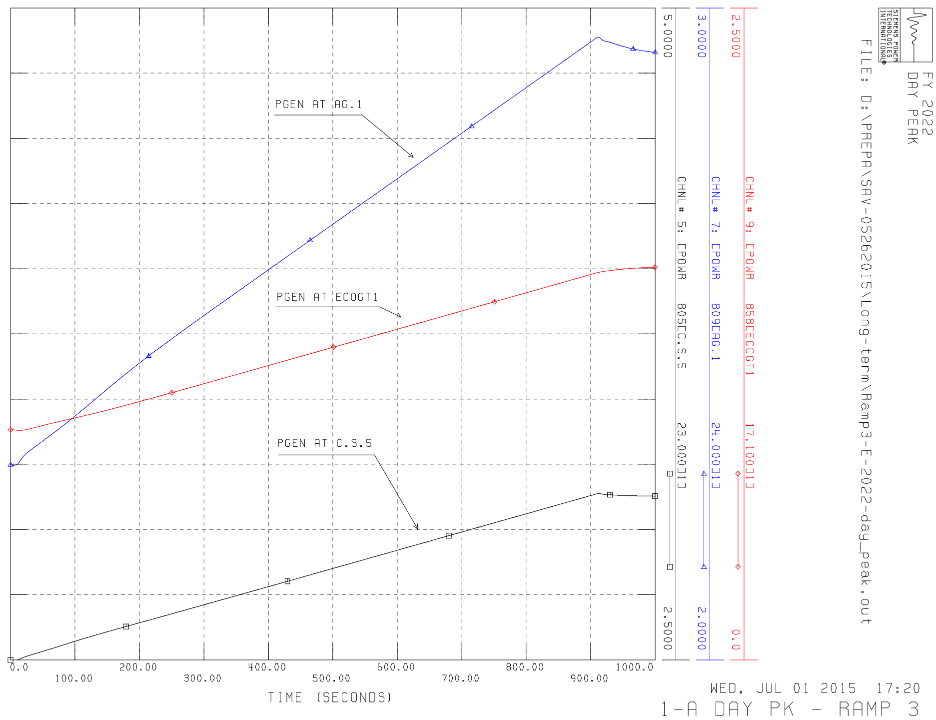


Figure 10-10. 1-A 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – Units that participate in the AGC.

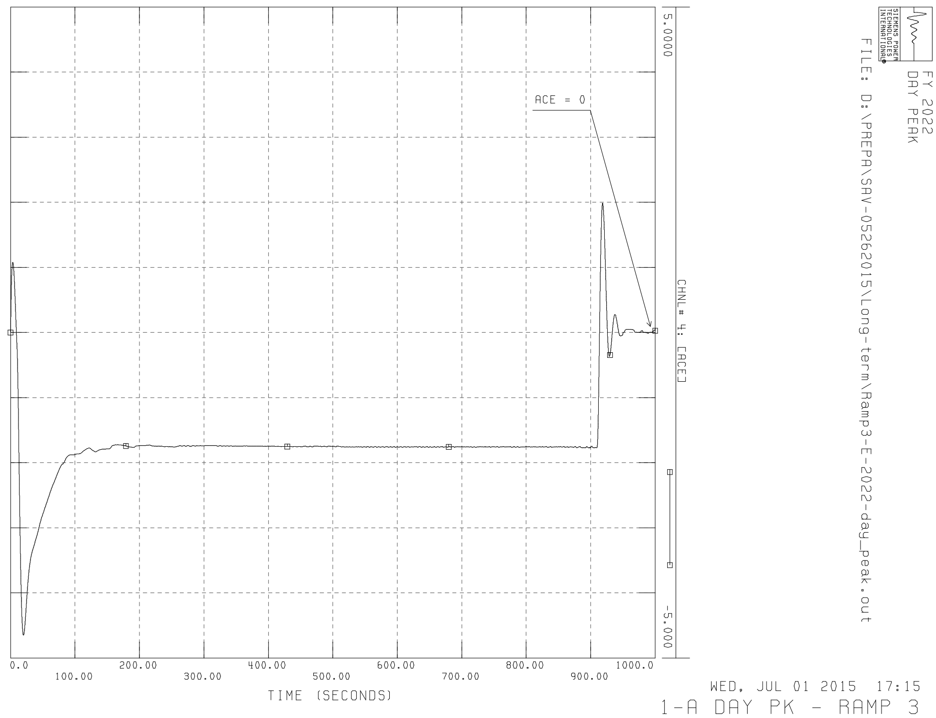


Figure 10-11. 1-A 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – AREA CONTROL ERROR (ACE).

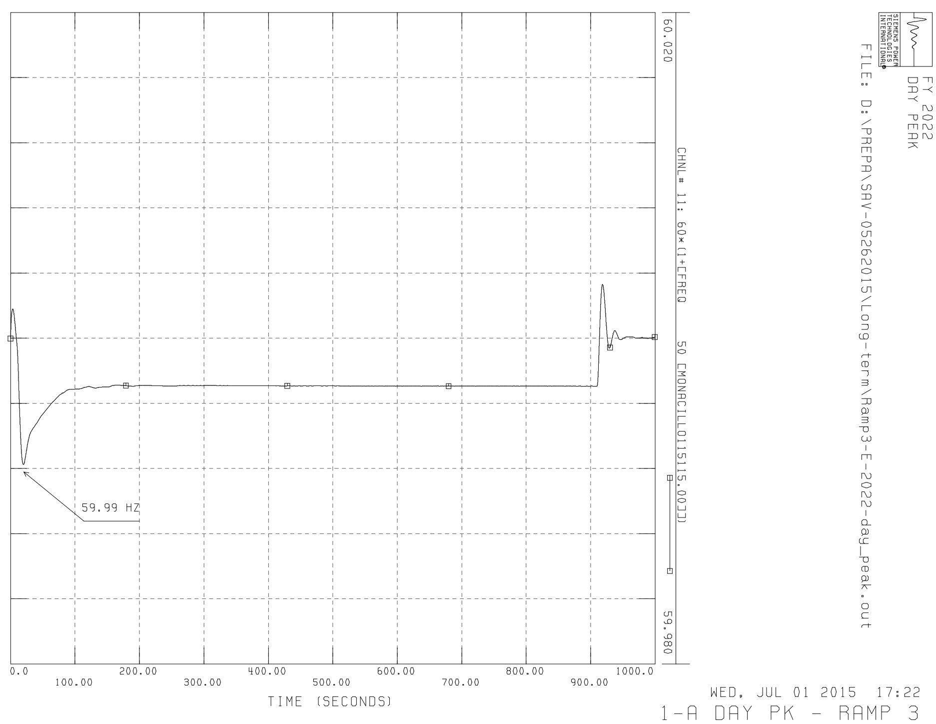


Figure 10-12. 1-A 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – frequency [Hz] at Monacillo.

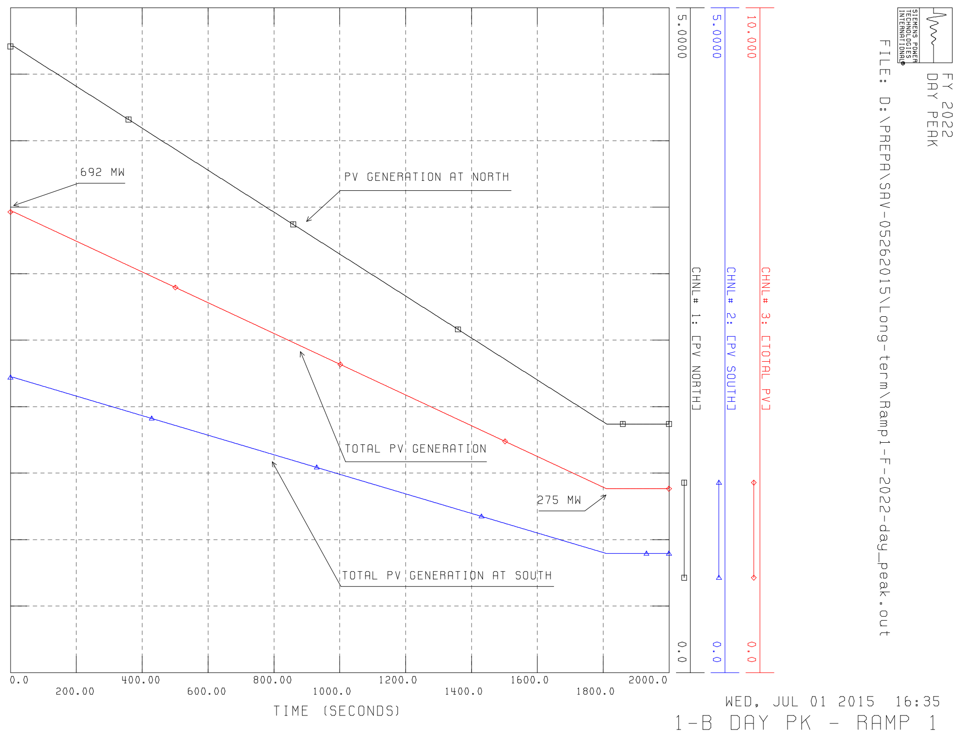


Figure 10-13. 1-B 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – PV generation.

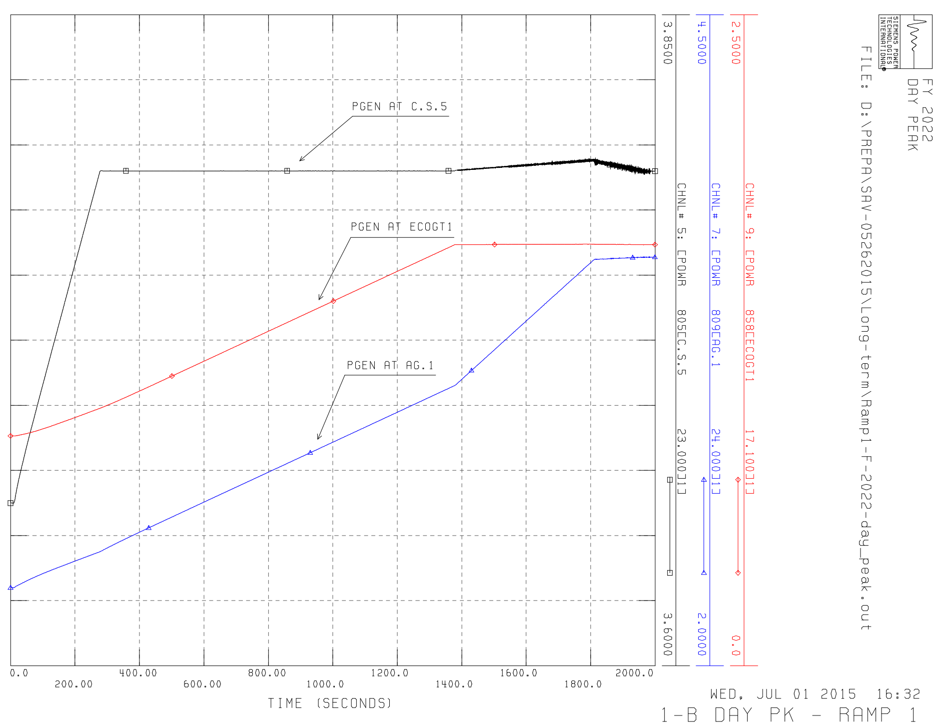


Figure 10-14. 1-B 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – Units that participate in the AGC.

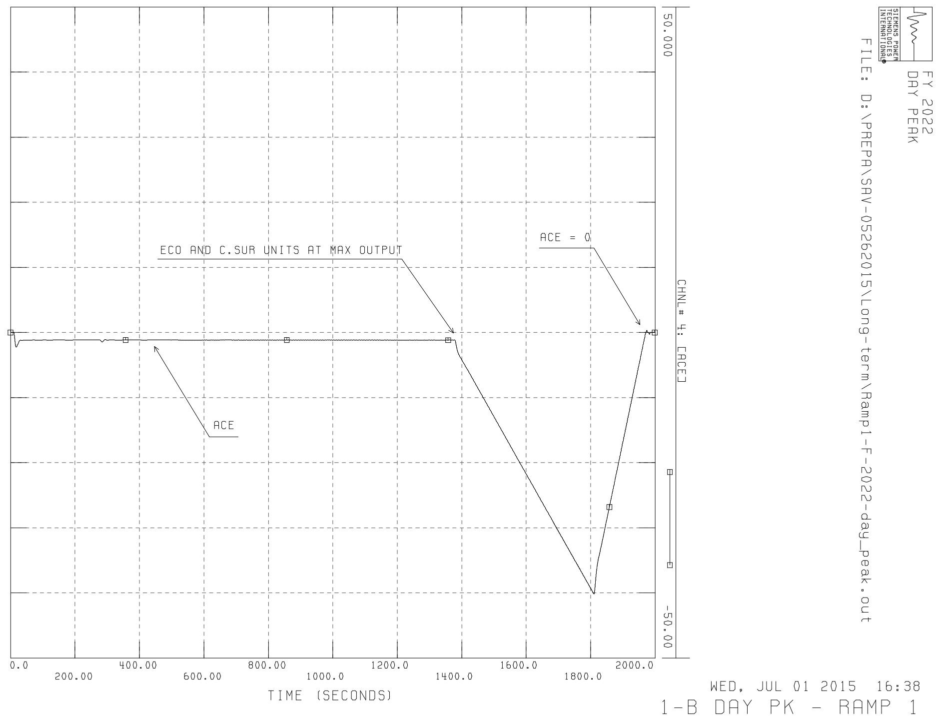


Figure 10-15. 1-B 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – AREA CONTROL ERROR (ACE).

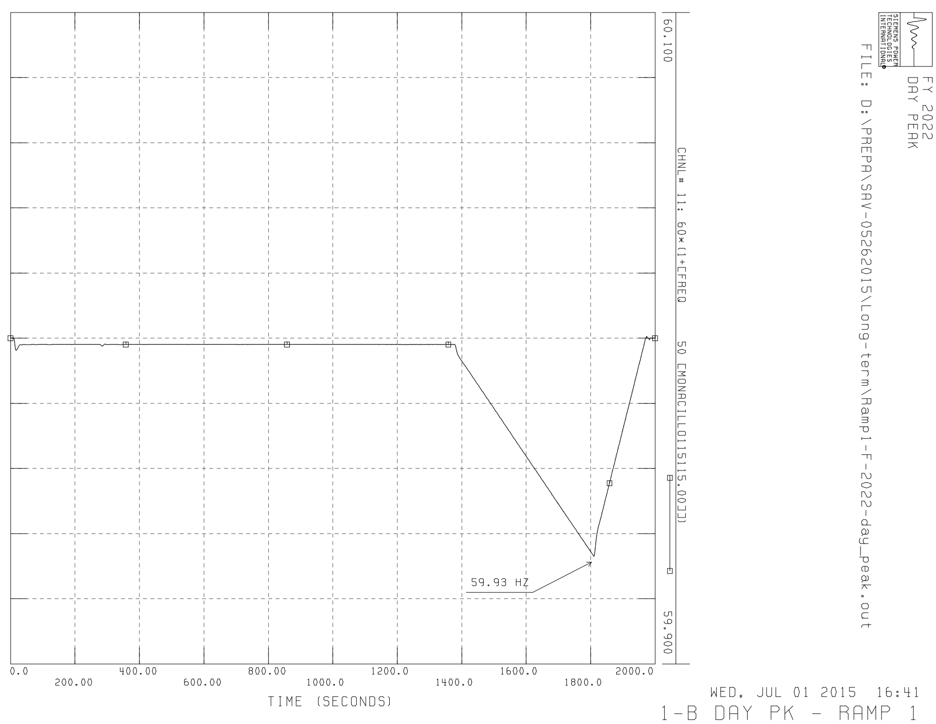


Figure 10-16. 1-B 2022 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – frequency [Hz] at Monacillo.

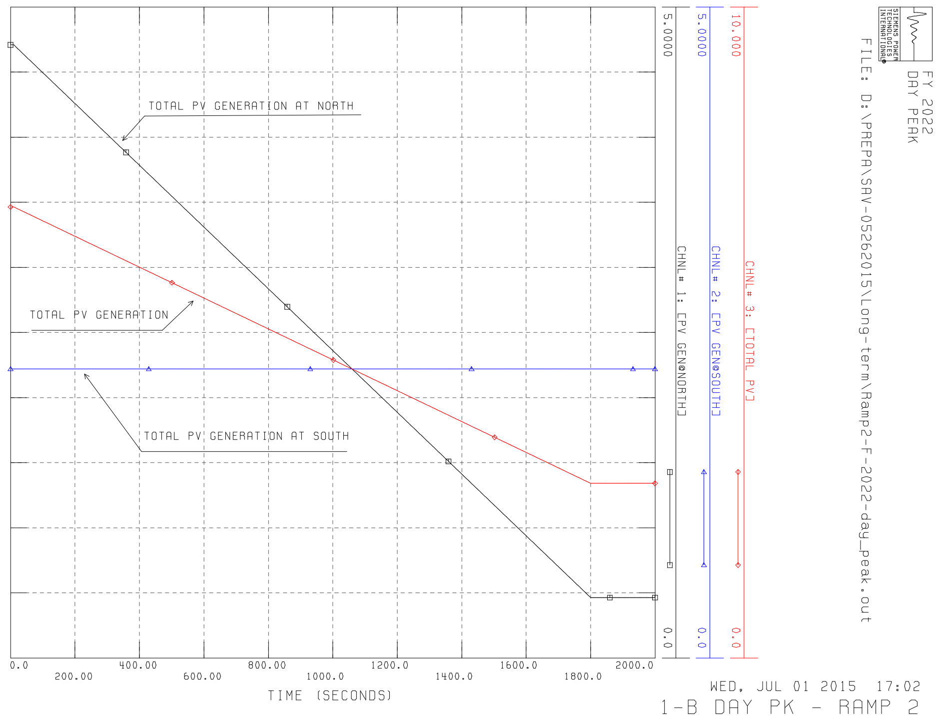


Figure 10-17. 1-B 2022 day peak – ramp 2: loss of 90% of PV generation at the North – PV generation.

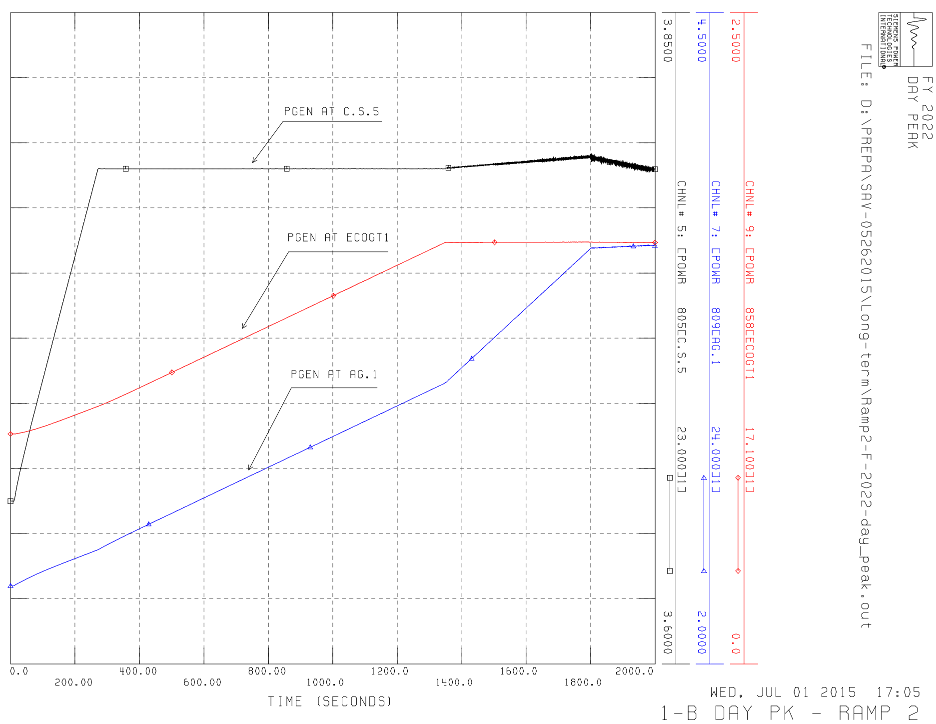


Figure 10-18. 1-B 2022 day peak – ramp 2: loss of 90% of PV generation at the North – Units that participate in the AGC.

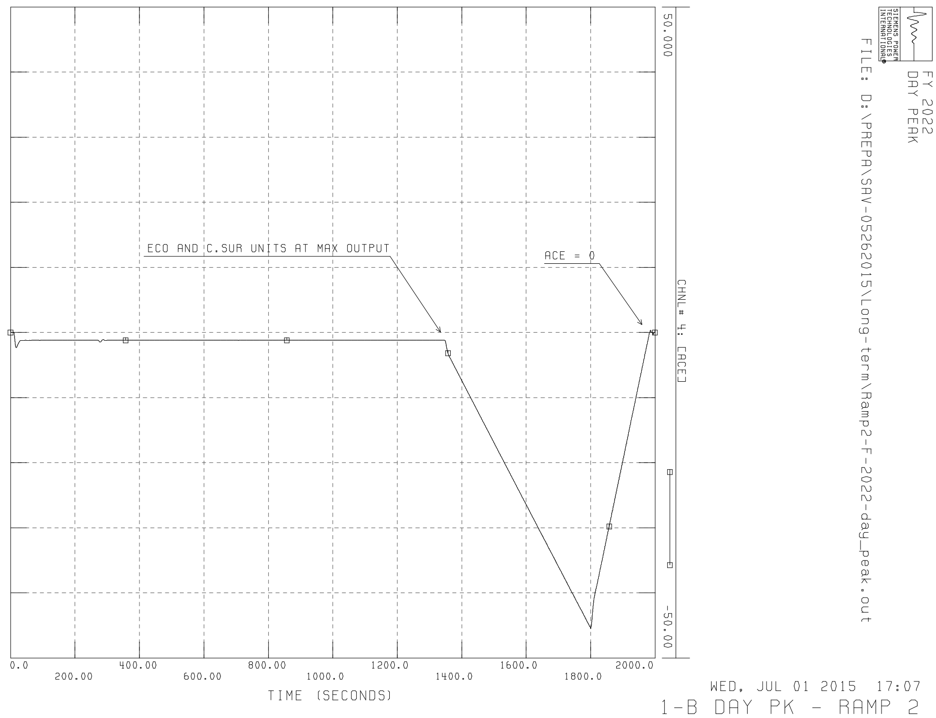


Figure 10-19. 1-B 2022 day peak – ramp 2: loss of 90% of PV generation at the North – AREA CONTROL ERROR (ACE).

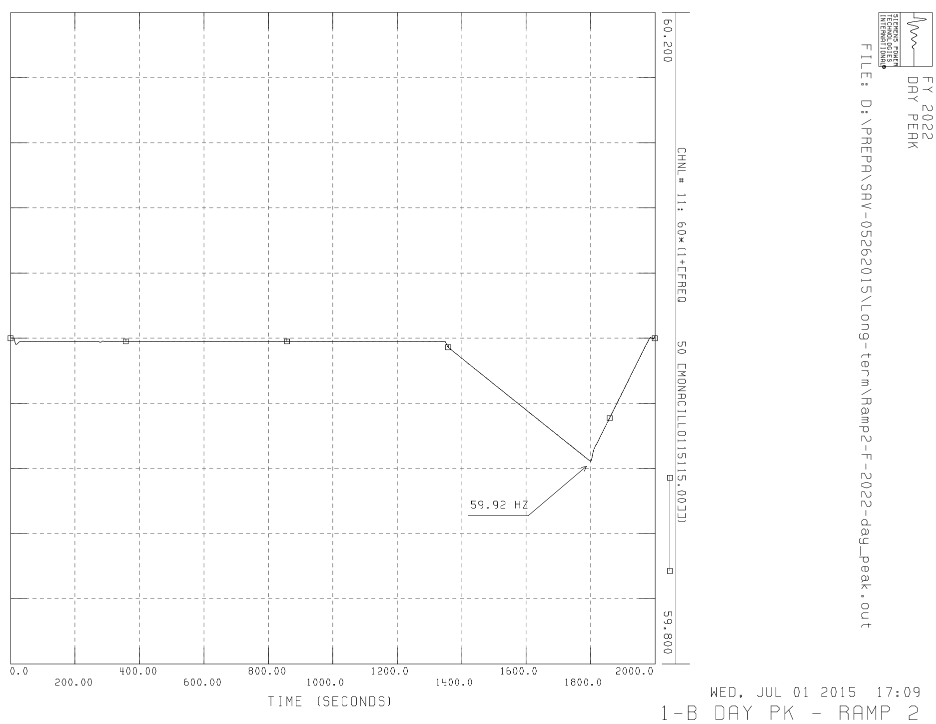


Figure 10-20. 1-B 2022 day peak – ramp 2: loss of 90% of PV generation at the North – frequency [Hz] at Monacillo.

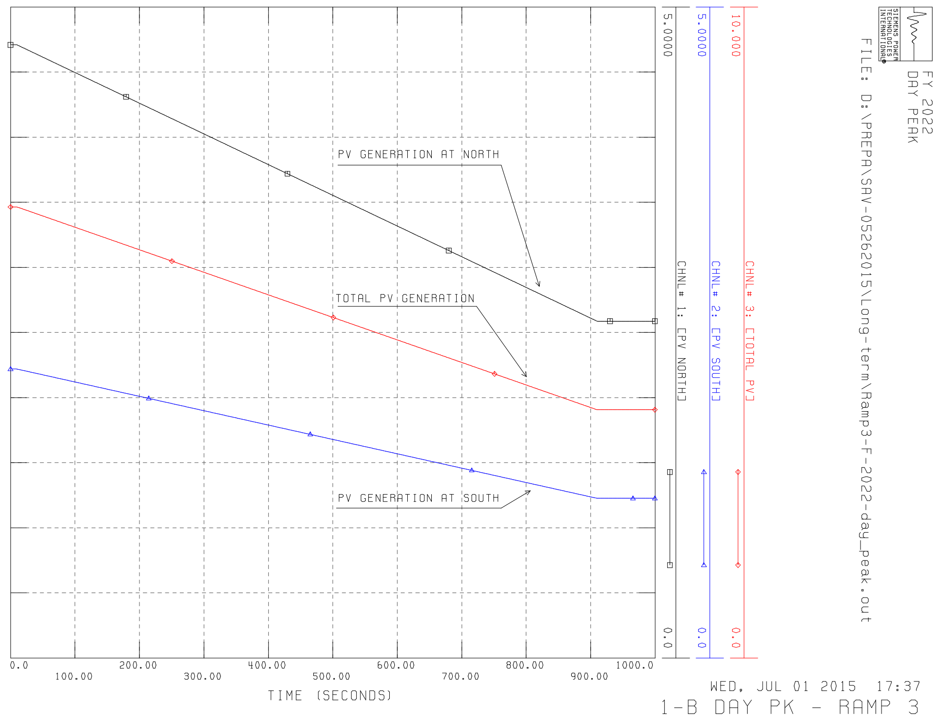


Figure 10-21. 1-B 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – PV generation.

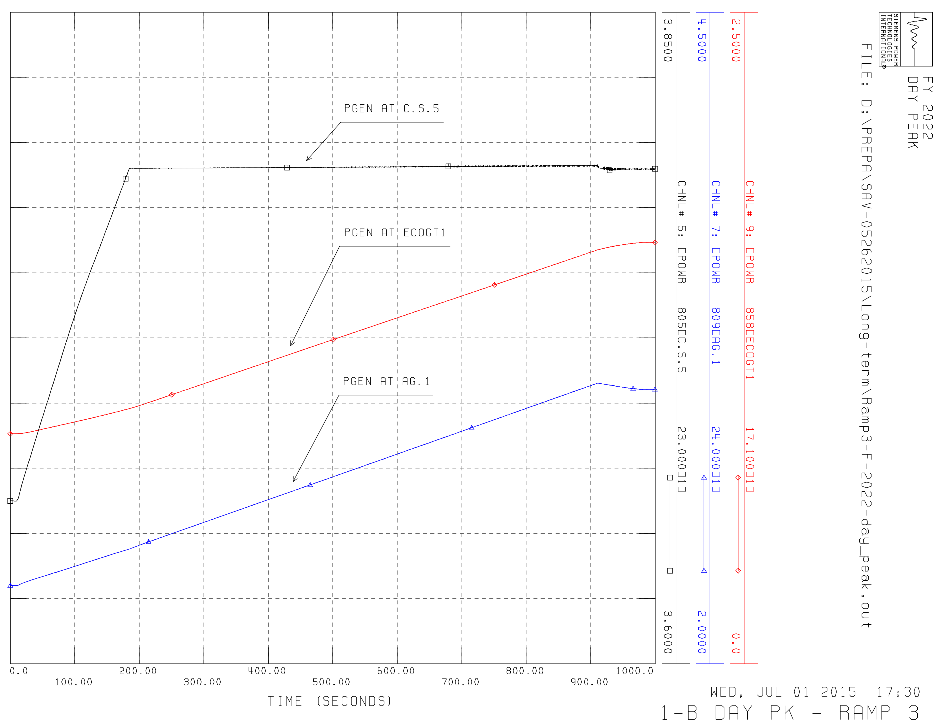


Figure 10-22. 1-B 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – Units that participate in the AGC.

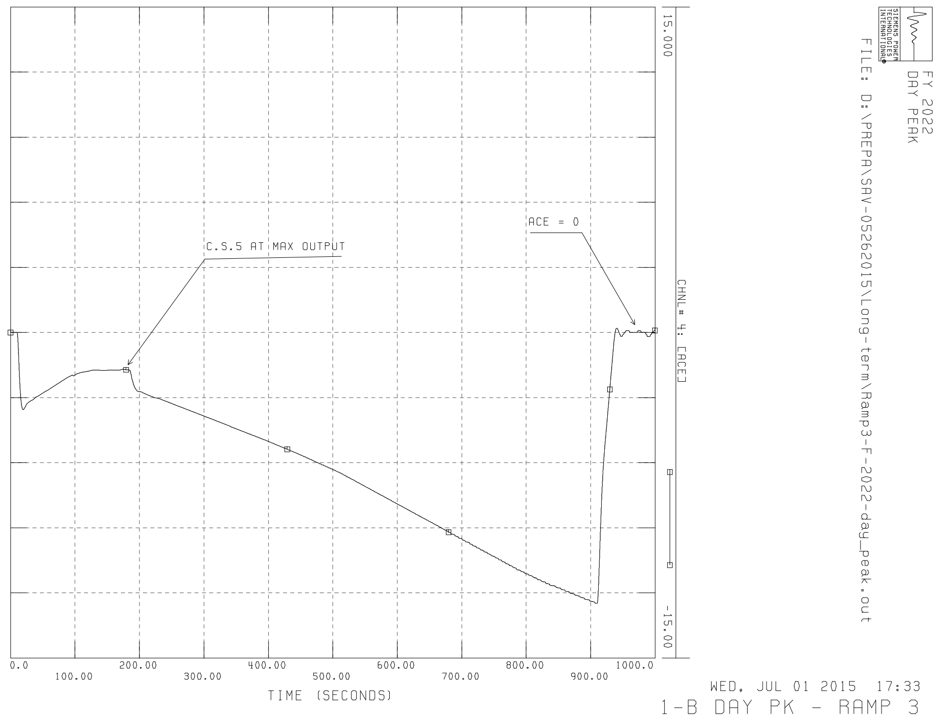


Figure 10-23. 1-B 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – AREA CONTROL ERROR (ACE).

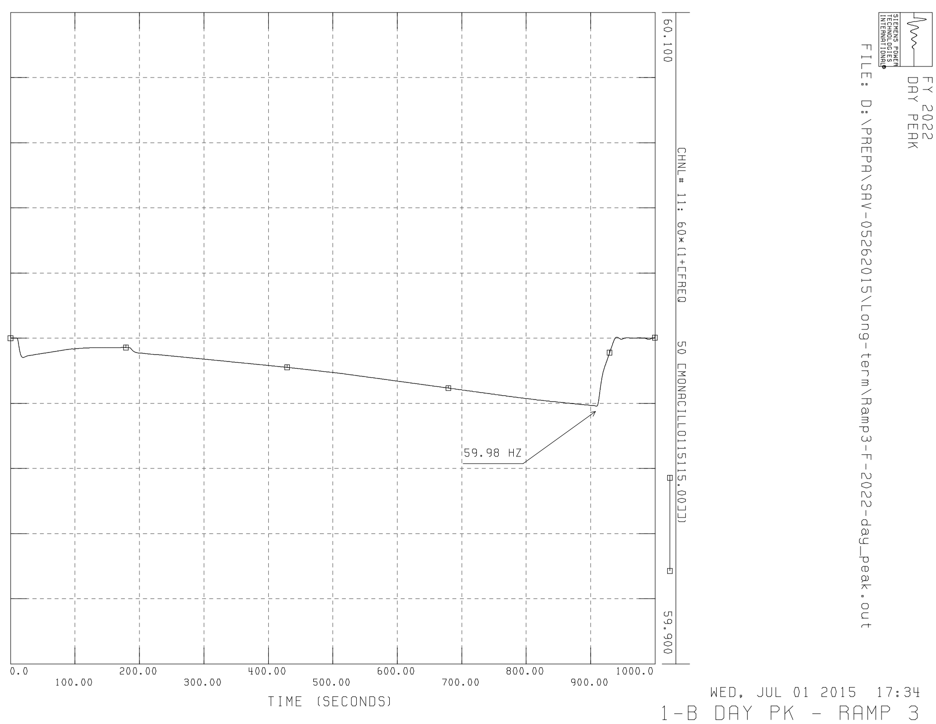


Figure 10-24. 1-B 2022 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – frequency [Hz] at Monacillo.

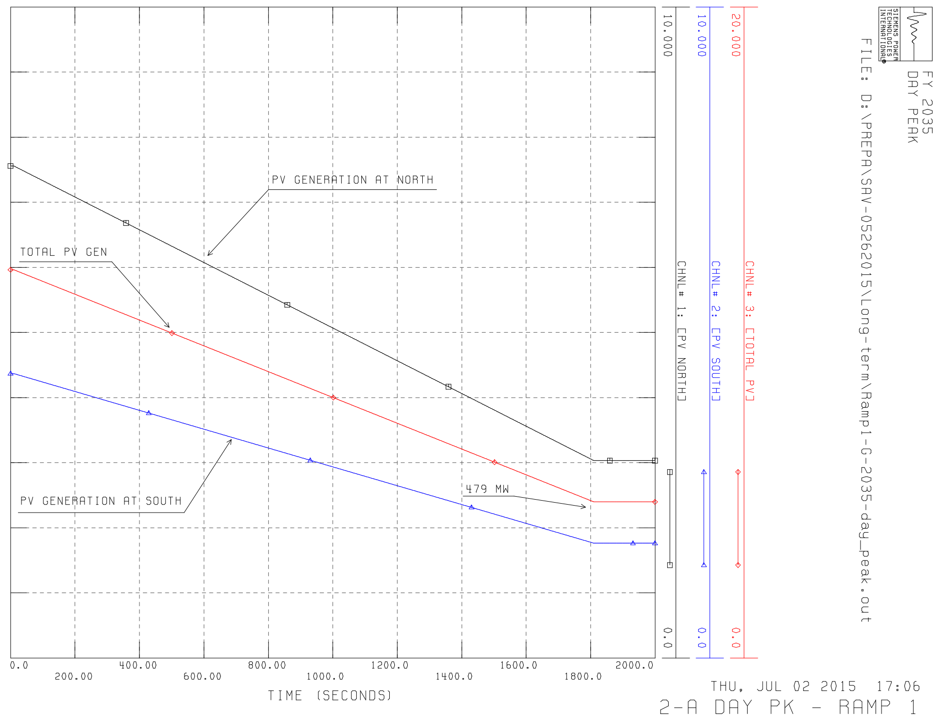


Figure 10-25. 2-A 2035 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – PV generation.

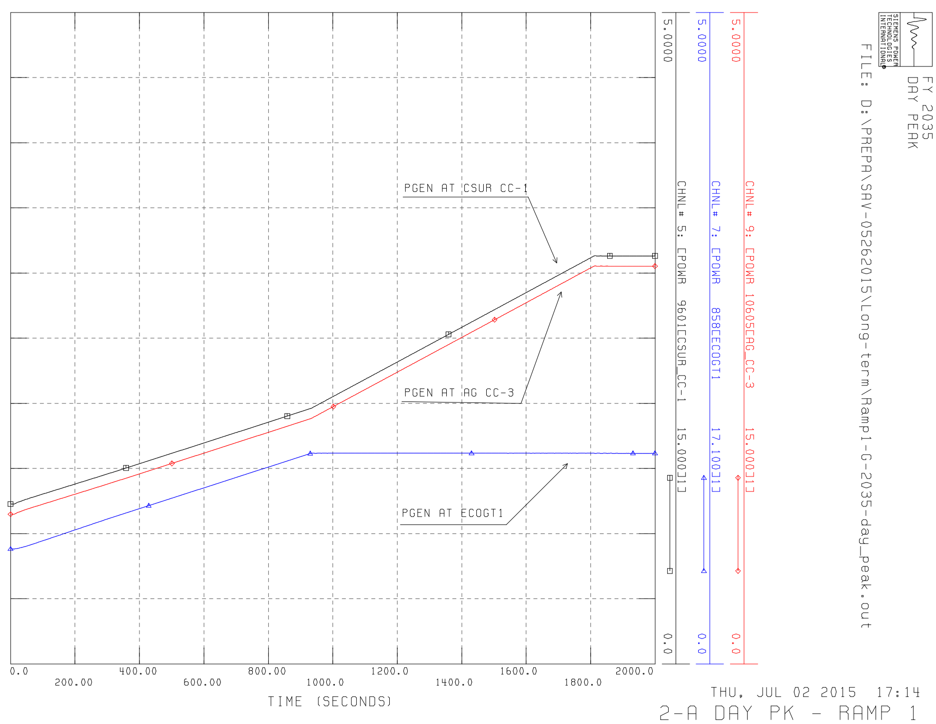


Figure 10-26. 2-A 2035 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – Units that participate in the AGC.

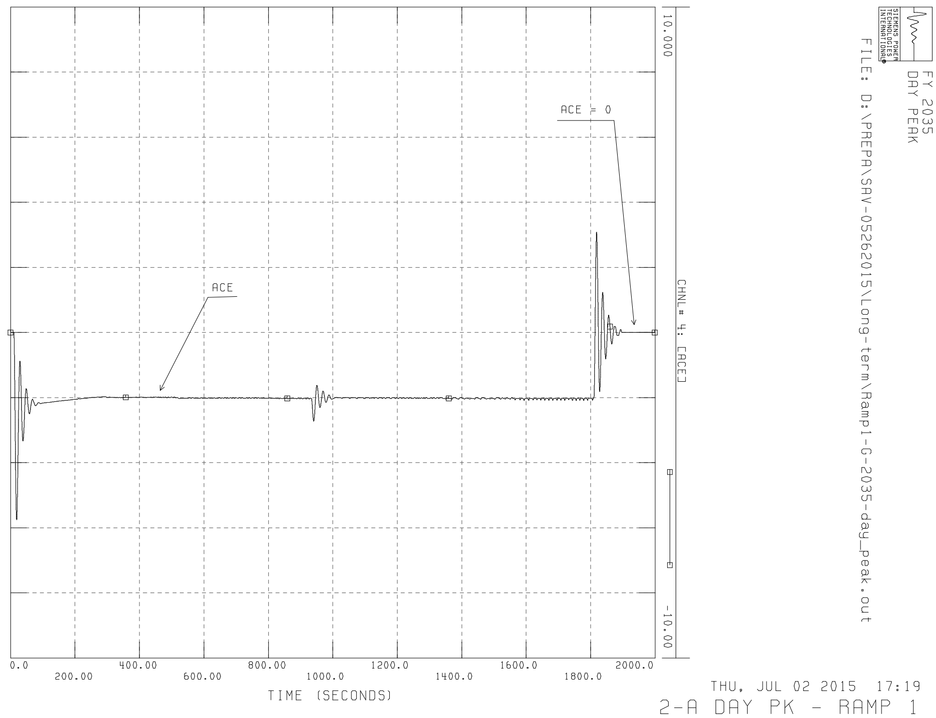


Figure 10-27. 2-A 2035 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – AREA CONTROL ERROR (ACE).

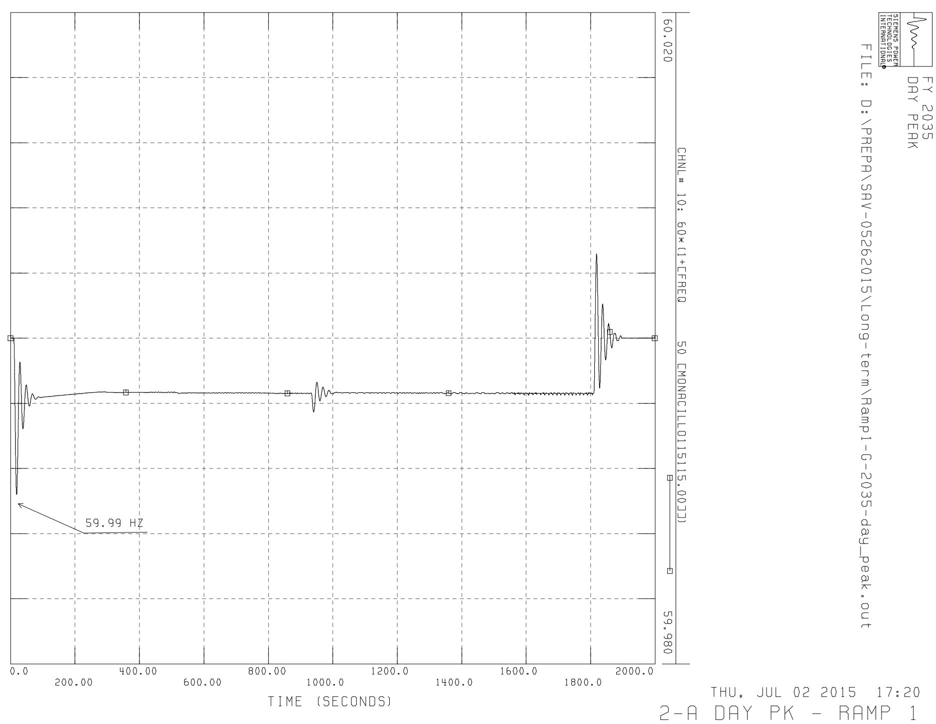


Figure 10-28. 2-A 2035 day peak – ramp 1: loss of 60% in 30 min of the PV generation of the island – frequency [Hz] at Monacillo.

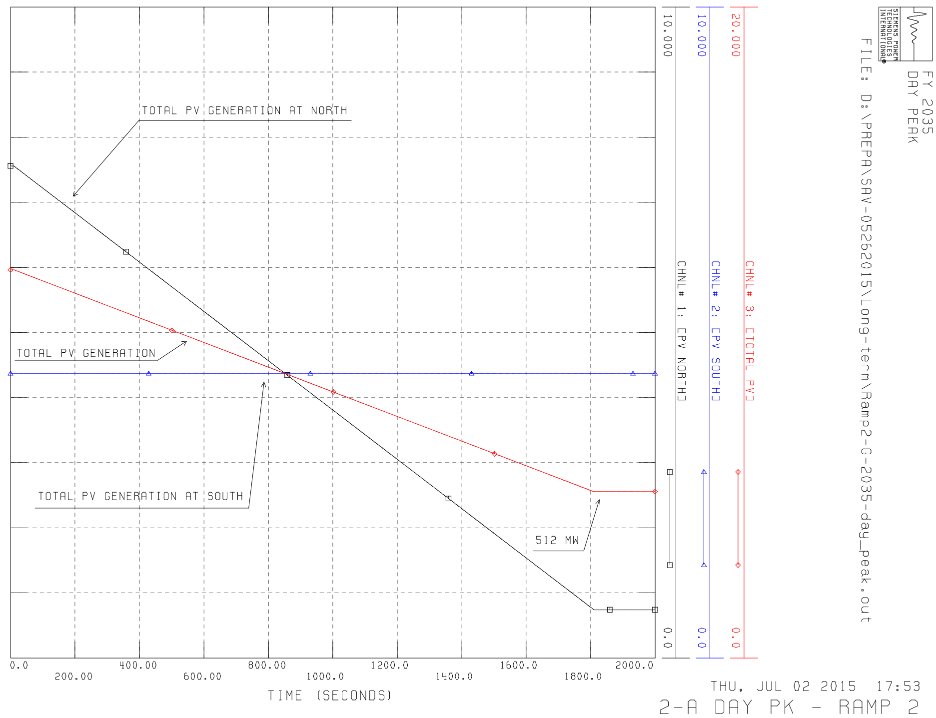


Figure 10-29. 2-A 2035 day peak – ramp 2: loss of 90% of PV generation at the North – PV generation.

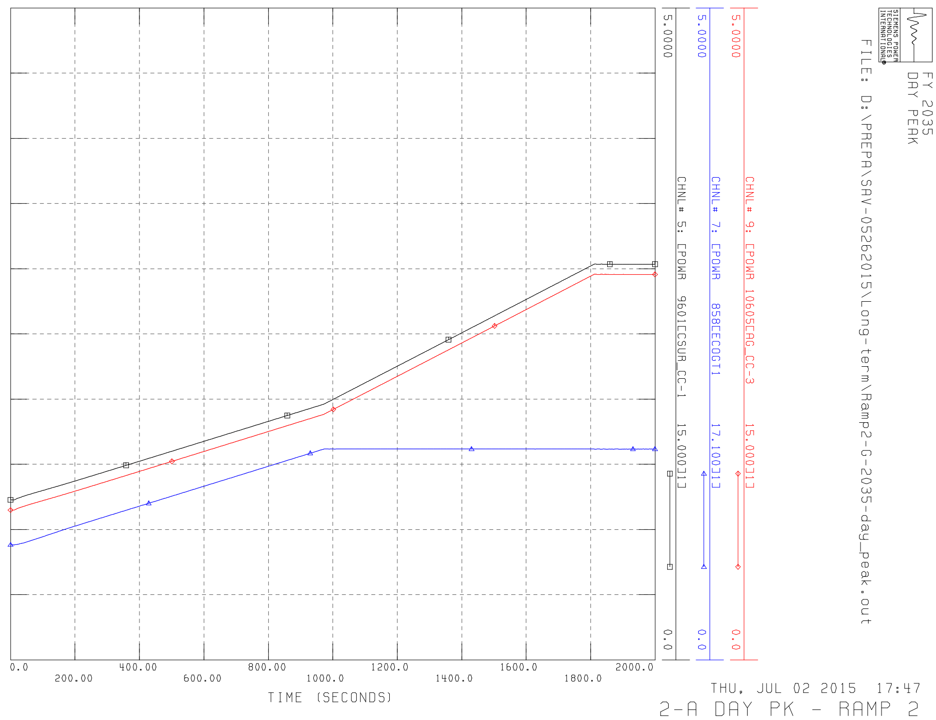


Figure 10-30. 2-A 2035 day peak – ramp 2**: loss of 90% of PV generation at the North – Units that participate in the AGC.**

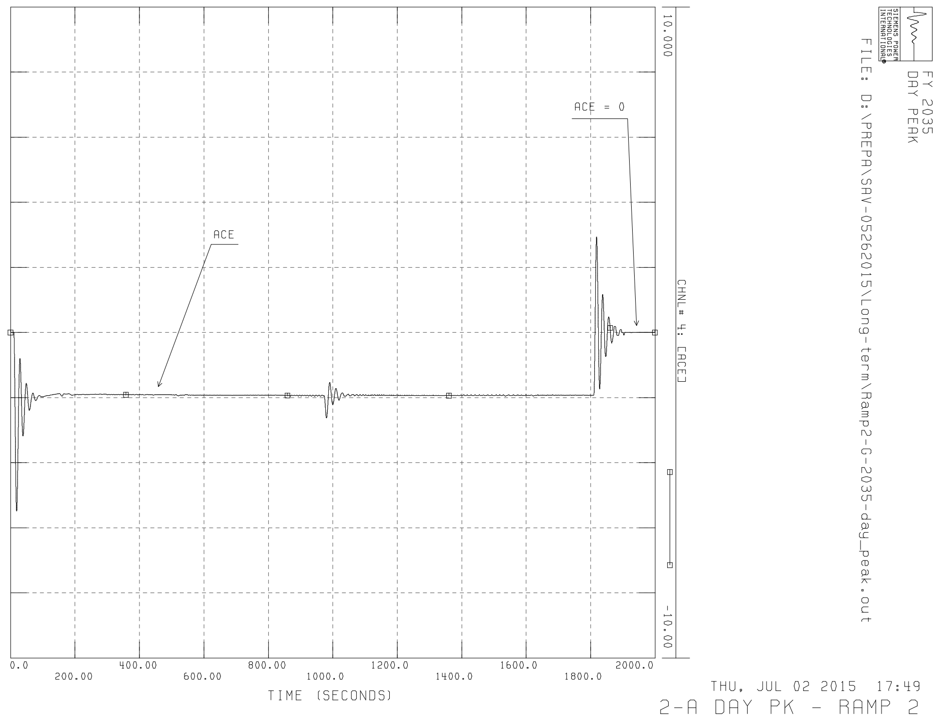


Figure 10-31. 2-A 2035 day peak – ramp 2: loss of 90% of PV generation at the North – AREA CONTROL ERROR (ACE).

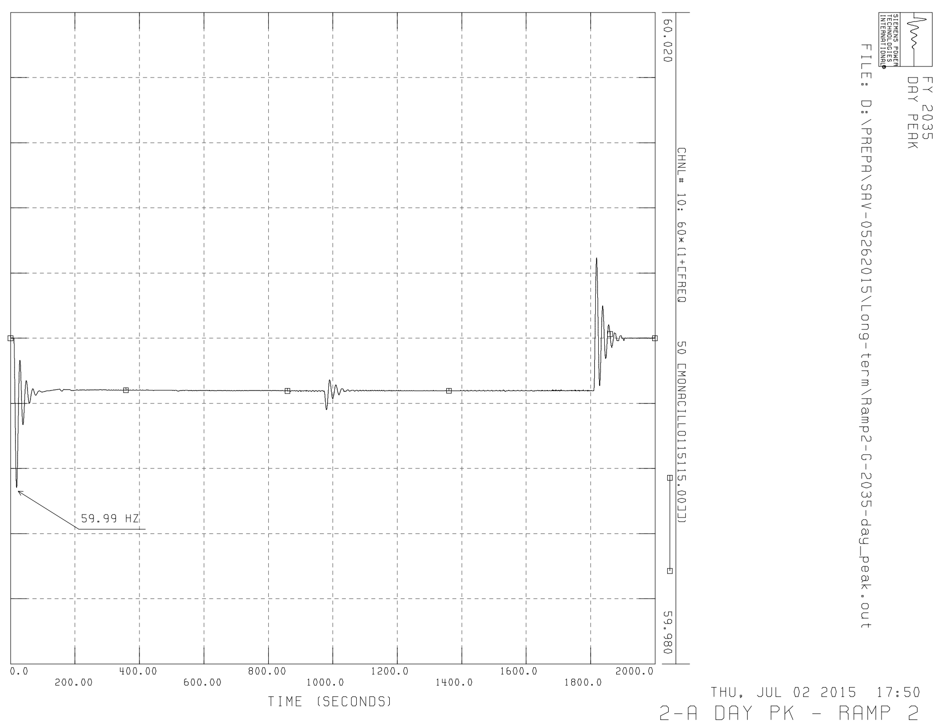


Figure 10-32. 2-A 2035 day peak – ramp 2: loss of 90% of PV generation at the North – frequency [Hz] at Monacillo.

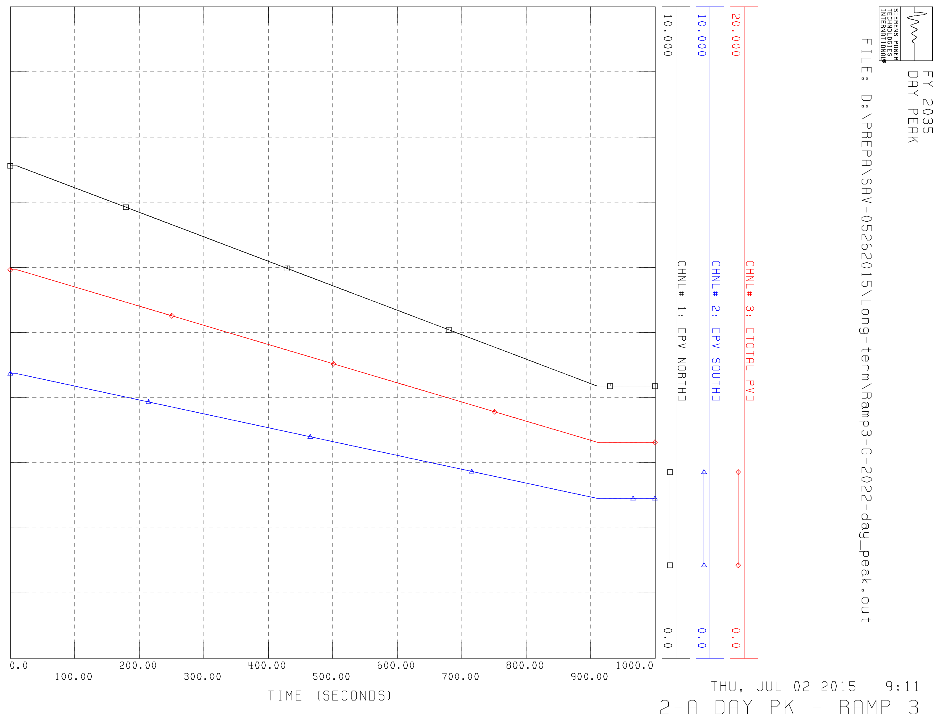


Figure 10-33. 2-A 2035 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – PV generation.

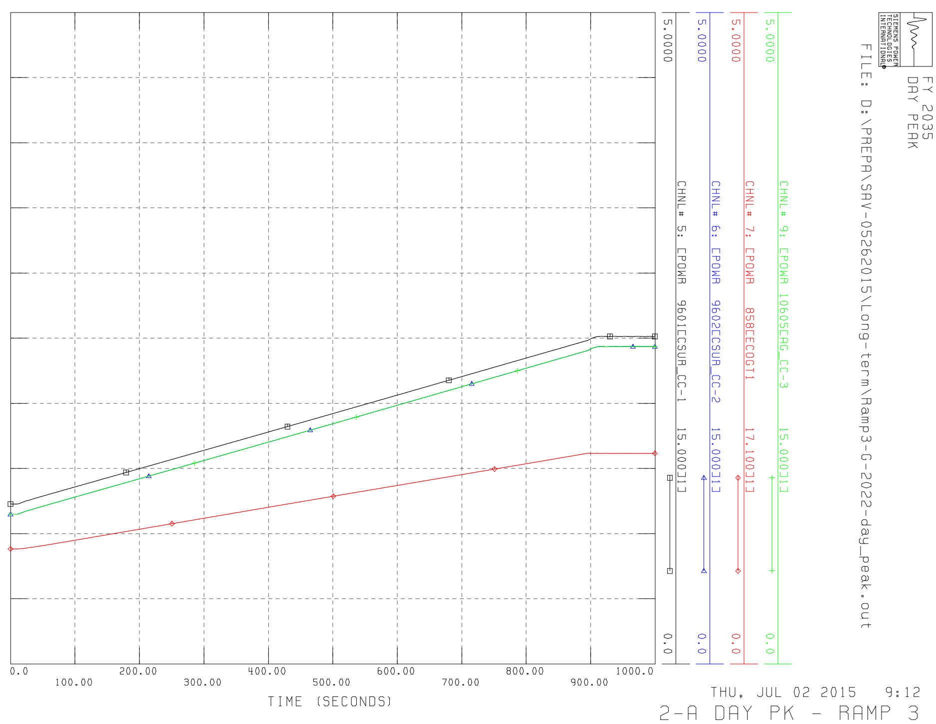


Figure 10-34. 2-A 2035 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – Units that participate in the AGC.

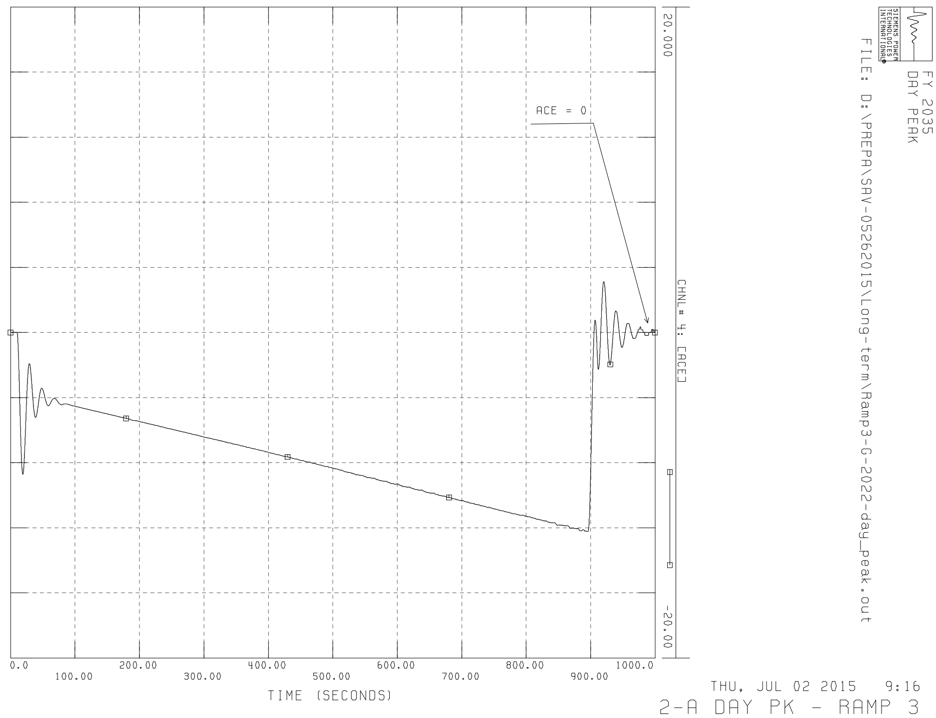


Figure 10-35. 2-A 2035 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – AREA CONTROL ERROR (ACE).

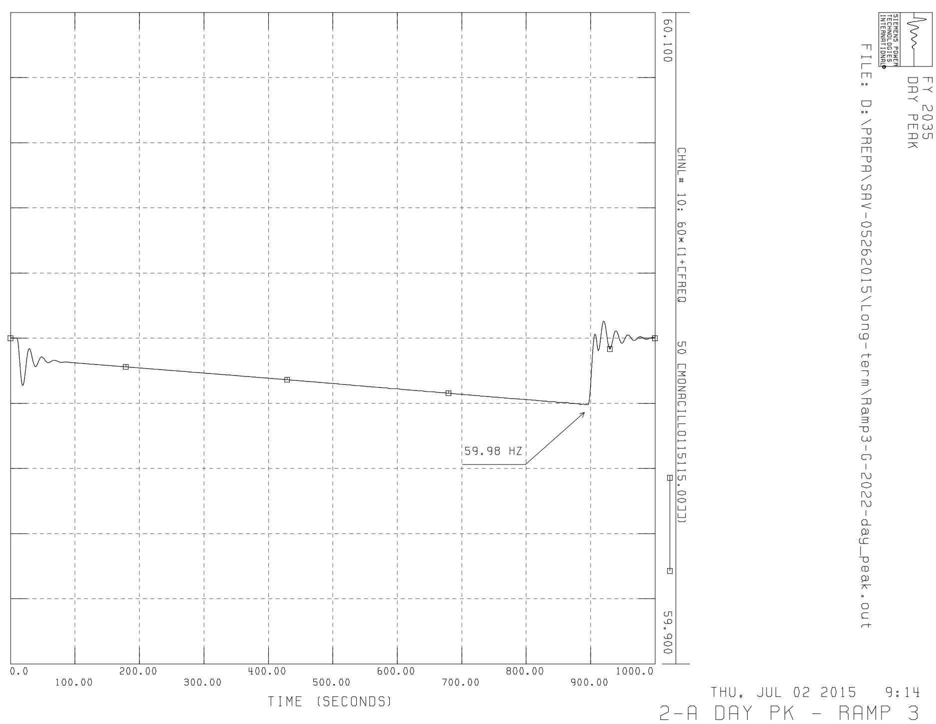


Figure 10-36. 2-A 2035 day peak – ramp 3: loss of 45% in 15 min of the PV generation of the island – frequency [Hz] at Monacillo.

Section
11

Summary of Capital Expenditures

11.1 Introduction

In the previous sections of this report we presented a number of transmission investments that are fundamental for the secure operation of the PREPA system once the units at Palo Seco Steam Plant and San Juan Steam Plant are suspended or relegated to limited use.

In this section of the report we provide further details on the location of these investments, the level of expenditures and the timeline. Also we present additional investments that are also crucial for the reliability of the system.

The investments are separated in 3 groups:

- **Main Transmission Projects:** This includes the investments necessary to integrate the new generation and to ensure that the transfer of power from the South to the North can be done in a secure manner, as it now will rely more heavily on transmission with reduced sources in the North. They include the investments identified in this study as well as reconstruction (i.e. performance of critical repairs) on transmission lines and switchyards that are an integral part of the system.

- **Other T&D Reliability Projects:** These include projects at the transmission, subtransmission and distribution level required to repair and reinforce the system as well as its ongoing repair and expansion to attend existing and new customers.

- **Support Projects:** These include warehouses, tools and equipment, land acquisitions, communications and other investments required to support the transmission function.

The center of this section will be the Main Transmission Projects, but we will provide information on the expected level of investments on the Reliability Projects and Support Projects as well.

11.2 Main Transmission Projects

11.2.1 Project overview and timeline

Table 11-1 presents a summary of the main transmission projects and their latest construction start and expected commissioning date. Figure 11-1 presents the associated time line highlighting the different components of the project (Engineering and Procurement and Construction).

It can be observed in the table and figures below that these projects are subdivided in 230 KV line reconstructions, 115 kV line reconstruction, dynamic reactive compensation (the STATCOMs), new 115 kV transmission lines, and the new Bayamón 230/115 kV transformer. Figure 11-2 shows the corresponding timeline by category.

Figure 11-3 to Figure 11-5 show the geographical location of these investments on PREPA's transmission system and in them it can be noted their criticality in ensuring realizable transmission of power from the South to the North of Puerto Rico and as it now will rely more heavily on transmission injections points (from Bayamón and Sabana Llana 230 kV) with reduced sources in the North. In particular it is important to observe that as noted in Table 11-1 the line reconstructions are critical to avoid repeated and extended outages of these lines that compromise the reliability of the system as another facility may fail during its outage creating and N-2 condition on otherwise unrelated facilities that should not fail at the same time.

11.2.2 Considerations on the timelines

PREPA engineering was a critical contributor to the timeline presented in this report and in their expert opinion with construction in Puerto Rico they consider it a very aggressive one and its successful realization depends closely on various precedent conditions, which are detailed below:

- Availability of the necessary funds for these projects.
- Full availability of the necessary technical and engineering human resources for completing these projects. This is critical mainly because there is a large amount of experienced technical personnel which is expected to be retired before January 2016.
- No limitation to hire human resources and technical and engineering services as required for the projects.
- PREPA's helicopters are fully available for the transmission lines works.
- Timely award of construction permits by the Office of Permits Management (OGPe).
- The Environmental Quality Board (EQB) does not require an environmental impact assessment.
- Timely completion of the easements and right of ways acquisitions for the new transmission lines, including all land surveying studies and legal processes.
- The purchase of equipment and services is done on time and without delays caused by bid protests or other complaints, e.g. union employees' demands.
- The contract for the purchase upon request of control and protection relays is approved.
- The projects construction schedule is not delayed by third parties complaints or law suits against PREPA regarding the construction works.
- The projects sites are free from archaeological findings, contamination or similar conditions, which could require remedies or mitigation actions.

- There is no additional legislation or amendments to existing legislation increasing the limitations to PREPA's operations and structure.

- There are no force majeure events such as storms and hurricanes affecting the project construction.

- The coordination of programmed outages is done in a timely manner, without risking the reliability and security of the power system for which is considered a minimum of contingencies on the generation and transmission systems. This coordination can be fully achieved only if there are no additional contingencies to those already planned for. The coordination of programmed outages is particularly critical for the reconstruction of the transmission lines, some of which share the same easement.

If any of these conditions is not fulfilled, the projects work schedule will be delayed and as a consequence the ability of the system to operate reliably with reduced generation in the North of the island.

Table 11-1 Main Transmission Projects

Main Transmission Projects Facility	Voltage	Project Scope	Benefit	New Rating MVA (if Applicable)	Latest Construction Start	Latest In service Date
Dynamic Reactive Compensation STATCOM 100 MVAR Monacillo	115 KV	STATCOM at 100 MVAR	Capacity	100	1/2/2017	1/2/2019
		Monacillo TC Bus Extension			1/2/2017	1/2/2019
Dynamic Reactive Compensation STATCOM 100 MVAR at SJSP	115 KV	STATCOM at 100 MVAR	Capacity	100	1/2/2019	1/2/2021
		San Juan or Bayamón TC Bus Extension			1/2/2019	1/2/2021
New 230/115 kV Transformer Bayamón	230/115 kV	Second Transformer and major expansion of 230 and 115 kV yard Bayamón TC for its incorporation.	Capacity	350	1/2/2017	1/2/2019
Mayagüez TC Capacitor Bank	115 KV	Switchable capacitor bank at Mayagüez TC	Capacity	50	7/1/2017	1/1/2019
San Juan GIS 38 kV & 115 kV Bus	115 KV	Expand San Juan Substation 115 kV	Reliability		7/4/2015	1/4/2019
Control and Protection Metropolitan Area TC	115 KV	Improve the protection coordination and control in Monacillo TC and Viaducto TC	Reliability		7/4/2015	1/4/2017
Bus Reconstruction	115 KV	Normalize TC Monacillo and Viaducto 38 kV Buses	Reliability		7/4/2015	1/4/2017
Venezuela Transmission Center	115 kV	Transmission Center to provide backup to Monacillo TC, includes 150 MVA transformer	Reliability	150	1/2/2018	1/2/2021
Yabucoa - Humacao Corridor(41000 &36300) Reinforcement and Relocation	115 kV	New underground cable 115 kV Yabucoa TC – Humacao TC include new terminals at Yabucoa TC and Humacao TC + Series Reactors	Capacity	231	1/2/2018	1/2/2021
Line 50900 Aguirre - Aguas Buenas	230 kV	Change of insulation and hardware	Reliability - Reduce likelihood of N-1-1	924	7/1/2015	7/1/2018
Line 51000 Aguirre - Aguas Buenas	230 kV	Change of insulation and hardware	Reliability - Reduce likelihood of N-1-1	924	7/1/2015	7/1/2018
Line 50900 Aguas Buenas - Bayamón TC	230 kV	Change of insulation and hardware	Reliability - No extended outages	924	5/1/2020	11/1/2020

Main Transmission Projects Facility	Voltage	Project Scope	Benefit	New Rating MVA (if Applicable)	Latest Construction Start	Latest In service Date
Line 51000 Aguas Buenas - Sabana Llana TC	230 kV	Change of insulation and hardware	Reliability - No extended outages	924	10/1/2018	4/1/2019
Line 50200 Costa Sur - Manatí TC	230 kV	Change of insulation and hardware	Reliability - No extended outages	462	9/1/2017	9/1/2018
Line 50200 Manatí TC - Bayamón TC	230 kV	Change of insulation and hardware	Reliability - No extended outages	462	8/2/2016	8/2/2017
Line 50100 Cambalache TC - Manatí TC	230 kV	Change of insulation and hardware	Reliability - No extended outages	462	1/1/2016	7/1/2016
Line 36100 Bayamón TC – Ciales	115 kV	Bario Piña - Bayamón: Change of insulation, hardware and 1192.5 kcmil ACSR conductor	Reliability / Capacity	231	6/1/2016	12/1/2017
Line 37800 Cayey - Caguas & Caguas TC - Monacillo TC	115 kV	Reconstruction and change 1192.5 kcmil ACSR conductor Cayey - Caguas	Capacity	231	12/2/2015	6/2/2017
Line 37400 Cambalache TC - Barceloneta TC	115 kV	Reconstruction	Reliability	231	6/1/2016	12/1/2017
Line 38900 Hato Rey TC – Martin Peña GIS	115 kV	Change of insulation, hardware and 50% structures	Reliability	240	12/1/2016	12/1/2017
Line 36200 Monacillo TC- Quebrada Negrito	115 kV	Reconstruction and change of conductor 556.5 kcmil SSAC or 1192.5 kcmil ACSR	Reliability		7/1/2016	7/1/2018
Line 41400 Humacao TC-Juncos TC	115 kV	Reconstruction and change of conductor 1192.5 kcmil ACSR	Reliability		7/1/2016	1/1/2020
New 115 kV Underground Cable Sabana Llana TC – Berwind TC	115 kV	New 115 kV cable (2750 kcmil Cu) parallel to existing aerial line 38900.	Reliability		7/1/2016	7/1/2019

Main Transmission Projects Facility	Voltage
San Juan GIS 38 kV & 115 kV Bus	115 KV
Control and Protection Metropolitan Area TC	115 KV
Bus Reconstruction	115 KV
Line 37800 Cayey - Caguas & Caguas TC - Monacillo TC	115 KV
Line 50100 Cambalache TC - Manati TC	230 kV
Line 36100 Bayamón TC – Ciales	115 kV
Line 37400 Cambalache TC - Barceloneta TC	115 kV
Line 36200 Monacillo TC- Quebrada Negrito	115 kV
Line 41400 Humacao TC-Juncos TC	115 kV
New 115 kV Underground Cable Sabana Llana TC – Berwind TC	115 kV
Line 50200 Manati TC - Bayamon TC	230 kV
Line 38900 Hato Rey TC – Martin Peña GIS	115 kV
Dynamic Reactive Compensation STATCOM 100 MVAR Monacillo	115 KV
New 230/115 kV Transformer Bayamon	230/115
Mora Capacitor Bank	115 KV
Line 50200 Costa Sur - Manati TC	230 kV
Venezuela Transmission Center	115 kV
Yabucoa - Humacao Corridor(41000 &36300) Reinforcement and Relocation	115 kV
Line 51000 Aguas Buenas - Sabana Llana TC	230 kV
Dynamic Reactive Compensation STATCOM 100 MVAR at SJSP	115 KV
Line 50900 Aguas Buenas - Bayamón TC	230 kV
Line 50900 Aguirre - Aguas Buenas	230 kV
Line 51000 Aguirre - Aguas Buenas	230 kV

Figure 11-1: Detailed Time Line By Project

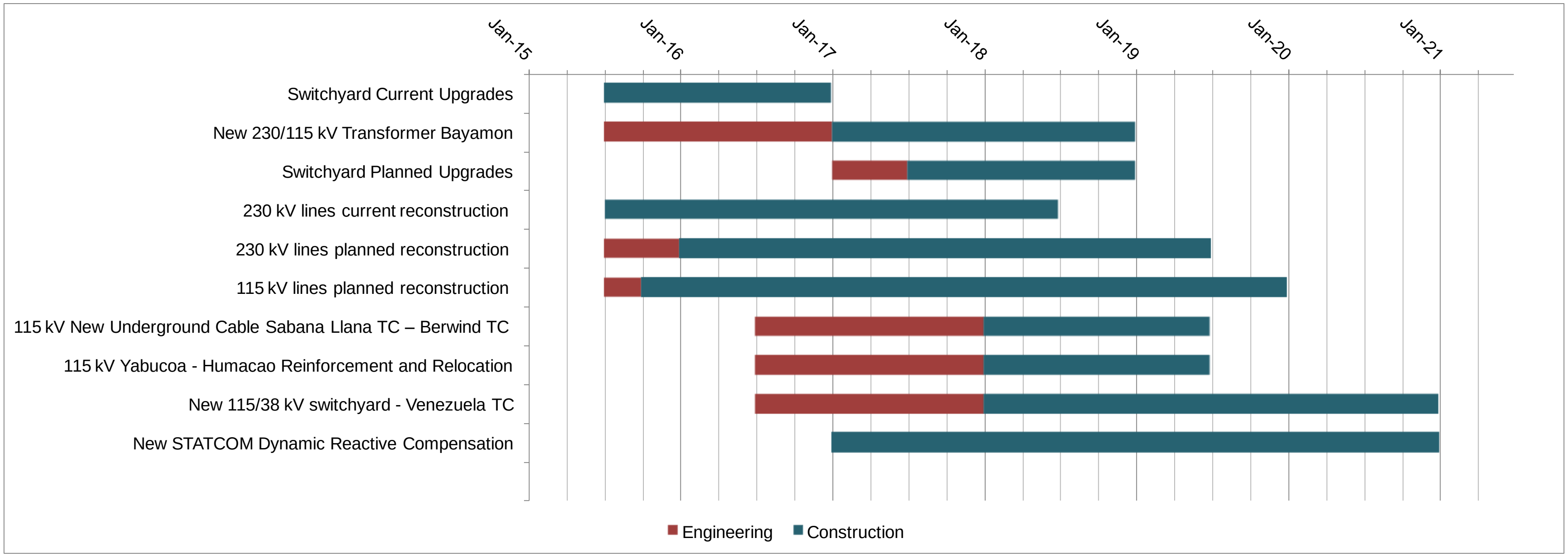


Figure 11-2 Summarized Timeline by Project Category

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

11.3 Other T&D Reliability Projects:

As indicated above, these projects consist of investments at the transmission, subtransmission and distribution level required to repair and reinforce the system to ensure system reliability and continuity of service to PREPA's customers. Also projects that include investments to attend new customers, general expenditures in system repair, including pole replacement and new distribution feeders, etc.

11.4 Support Projects:

These projects include Improvement to Lands and Buildings, Office Modules for Technical Offices, Equipment Computer Systems, Communications Equipment - Customer Service, General Tools and Equipment, New Facilities Construction, Warehouses improvement, Equipment for Construction, and Tools and Equipment for Distribution System.

These projects complement the Transmission and Distribution function and are typical of well functioning utilities.

11.5 Capital Expenditures

As shown in Table 11-2 below the level of expenditure expected for the projects above is $ 1,981 million of which $ 274 are associated with the main transmission projects and the balance are the other T&D projects and support projects. These costs are in constant (real) 2015 $ and include financing expenses and in particular Interest during construction. Table 11-3 provides further detail on the investments by main transmission project.

Table 11-2 Capital Expenditures by Project Type

Capital Costs	Unit	Total
Main Transmission Projects	$ million	274
Other T&D Reliability Projects	$ million	1,662
Support Projects	$ million	45
Total	**$ million**	**1,981**

Table 11-3

Main Transmission Projects Capital Costs Summary	Commercial on line date	All-in Capital Costs ($2015 thousands)
Dynamic Reactive Compensation STATCOM 100 MVAR Monacillo	1/2/2019	17,307
Dynamic Reactive Compensation STATCOM 100 MVAR at SJSP	1/2/2021	18,904
New 230/115 kV Transformer Bayamón	1/2/2019	24,176
Mora Capacitor Bank	1/1/2019	526
San Juan GIS 115 kV Bus	1/4/2017	9,554
Control and Protection Metropolitan Area TC	1/4/2017	8,928
Bus Reconstruction	1/4/2017	2,527
Venezuela Transmission Center	1/2/2021	10,351
Yabucoa - Humacao Corridor(41000 &36300) Reinforcement and Relocation (New 115 kV underground cable)	1/2/2021	13,619
Line 50900 Aguirre - Aguas Buenas	7/1/2018	15,453
Line 51000 Aguirre - Aguas Buenas	7/1/2018	15,453
Line 50900 Aguas Buenas - Bayamón TC	11/1/2020	7,646
Line 51000 Aguas Buenas - Sabana Llana TC	4/1/2019	10,343
Line 50200 Costa Sur - Manatí TC	9/1/2018	22,308
Line 50200 Manatí TC - Bayamón TC	8/2/2017	18,759
Line 50100 Cambalache TC - Manatí TC	7/1/2016	10,140
Line 36100 Bayamón TC – Ciales	12/1/2017	2,028
Line 37800 Cayey - Caguas & Caguas TC - Monacillo TC	6/2/2017	12,168
Line 37400 Cambalache TC - Barceloneta TC	12/1/2017	10,444
Line 38900 Hato Rey TC – Martin Peña GIS	12/1/2017	2,028
Line 36200 Monacillo TC- Quebrada Negrito	7/1/2018	11,715
Line 41400 Humacao TC-Juncos TC	1/1/2020	16,832
New 115 kV Underground Cable Sabana Llana TC – Berwind TC	7/1/2019	12,574
Total Main Transmission Projects		273,784

Appendix

A

Reactive Power Compensation Devices

In this section it's given a quick glance at the typical compensation devices used as countermeasures for voltages issues.

Several reactive compensation devices are available in nowadays, but a special care must be taken when choosing the technology, as each device is designed to maximize its performance for a particular application.

Some of the important are:

- **Mechanical switched devices (MSD**) are appropriate for solving voltage control issues, by using capacitors/reactors to provide the additional MVARs. They have a delay time due to the breaker switching time, typically in the order of 80-100 ms, and they cannot provide a fine voltage control. If daily switching is expected, the lifecycle will be considerably reduced.

- **The static VAr compensator (SVC)** presents different configurations depending of the final use. Essentially they require a capacitor/reactor banks to perform the voltage control. The most typical configuration is the FC-TCR SVC, where a capacitor bank is permanently connected and the current through the reactor bank is controlled by thyristors. They require larger space than the MSD devices.

- **The static compensator (STATCOM)** uses a voltage source converter for providing the required MVARs, consequently the required space is considerably reduced. They are fast acting and are able to go to the full output in half cycle.

A.1 Mechanical switched capacitors (MSC)

Mechanically switched devices are the most economical reactive power compensation devices. They are a simple and low-cost, but low-speed solution for voltage control and network stabilization under heavy load conditions. Their utilization has almost no effect on the short-circuit power but it supports the voltage at the point of connection.

The MSC incorporates only passive components such as capacitors and reactors and can be connected directly to the high voltage busbar system or via a coupling transformer.

However, the effectiveness of voltage stabilization depends on the distance from the fault location. The MSC does not create any harmonics, but may interact with system harmonics.

The control system realizes, among other features, the following main control:

- automatic switching of the capacitor banks according to the need of the network system.
- sufficient hysteresis is built into the control to avoid repetitive switching ("hunting").
- each capacitor bank can also be manually switched ON and OFF.
- remote (Dispatch Center) and local (Substation) mode of operation.

A.2 The Fixed Capacitor + Thyristor-Controlled Reactor Static VAr Compensator (FC-TCR SVC)

The FC-TCR SVC is a VAr generator arrangement that uses a permanently connected capacitor with a thyristor-controlled reactor.

The current in the reactor can be controlled from maximum (thyristor valve closed) to zero (thyristor valve open) by controlling the delay angle (α) of the thyristor valve.

At the maximum capacitive VAr output, the thyristor-controlled reactor is off ($\alpha = 90°$). To decrease the capacitive output, the current in the reactor is increased by decreasing α.

At zero VAr output, the capacitive and inductive currents are equal and thus the capacitive and inductive VArs are canceled.

If the rating of the reactor is greater than the capacitor, with a further decrease of α the inductive current becomes larger than the capacitive current, resulting in a net inductive output.

The operation of the TCR results in a non-sinusoidal current waveform in the reactor, in other words, the thyristor-controlled reactor in addition to the fundamental current it also generates harmonics.

For achieving a medium size compensator a larger reactor is required, so that important harmonic currents are expected.

They also requires of a special-tuned harmonic filters and a special design power transformer.

The losses-Q characteristic of the FC-TCR type SVC is constituted by:

- The capacitor losses which are relatively small but constant.
- The reactor losses which increase with the square of the current.
- The thyristor losses which increase almost linearly with the current.

Thus, the total losses decrease while increasing the capacitive VAr output. At zero output of the SVC, the current in the capacitor is circulated through the reactor via the thyristor valve, resulting in important standby losses.

This type of SVC is disadvantageous when the average VAr output is low, as for example in case of reactive requirements of dynamic compensation of power systems.

A.3 The Thyristor-switched capacitor + Thyristor-Controlled Reactor Static VAr Compensator (TSC-TCR SVC)

They consist of n-capacitor banks which are individually switched by a thyristor valve (TSC) and a thyristor controlled reactor (TCR).

This type of SVCs are capable of switching the capacitor banks in and out within one cycle of the applied AC voltage, so that the TCR has to be somewhat larger in practice than one of the TSCs in order to provide enough overlap (hysteresis) between the "switching in" and "switching out" VAr levels.

Depending on the number of TSC branches used, the response of the TSC-TCR type SVC may be somewhat slower than its FC-TCR SVC counterpart. Note that the maximum delay of switching in a single TSC with a charged capacitor is one full cycle, while the maximum delay of a TCR is only half of a cycle.

At zero output of the SVC all of the capacitor banks are switched-out and the TCR current is negligibly small, and consequently the losses are almost zero.

As the capacitive output is increased, the TSC banks are switched-in with the TCR absorbing the surplus capacitive VArs. Thus, with each switched-in of the TSC bank, the losses are increased by a fixed amount. Also the losses of the TCR, which vary from maximum to zero due to the successive switching of the TSC banks, needs to be added.

It can be say that on average the losses of the TSC-TCR SVC type vary proportionately with the reactive power output.

This type of loss characteristic is clearly advantageous in those applications where the SVC is used for dynamic compensation and does not required in average a high reactive power output under the normal operation of the power system.

A.4 The Static Compensator (STATCOM)

The STATCOM are based on voltage sources to produce reactive power without reactive energy storage components (capacitor/reactor banks) by circulating alternating current among the phases of the AC system. The operation is similar to an ideal synchronous machine whose reactive power output is varied by the excitation system, that's why they are termed analogously to the rotating synchronous compensator, the Static Synchronous Compensator or STATCOM.

The voltage source converter (VSC) produces a set of controllable three-phase output voltages with the frequency of the AC power system. Each of the output voltages are in phase and coupled to the AC system by a relatively small tie reactance.

When varying the amplitude of the output voltages, the reactive power exchange between the STATCOM and the AC system is controlled similarly to a rotating synchronous machine.

They present a mirror-type VAr characteristic, i.e: a 100 MVA STATCOM is able to provide full 100MVAr capacitive or either 100 MVAr inductive.

The main difference between the different STATCOM manufacturers is the technology used on the voltage converter.

On the other hand, older designs which use three-level converters leads to step-shape currents and so to an important flow of harmonic currents.

The multi-level VSC technology produces sinusoidal shape currents with very low harmonic components. With this, no special transformer design or low order harmonic filters are required.

A.5 SVC and STATCOM features comparison

An important aspect of both compensation devices is the amount of reactive power that they can supply. The reactive power output in an SVC, as they use capacitor banks, depends on the square of the voltage, while in a STATCOM it depends linearly with the voltage. So, an SVC rated at 100 MVAr is able to supply only 81 MVAr when the voltage is depressed at 90%, while a STATCOM with same size is able to supply 90 MVAr. In other words, if 81 MVAr of reactive power compensation are required, it will be needed a 100 MVAr SVC, while with a 90 MVAr STATCOM will be enough.

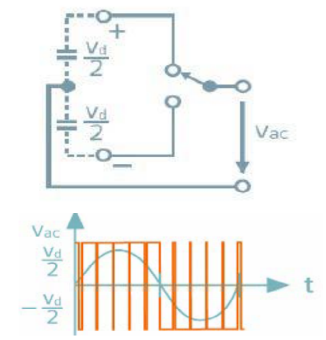
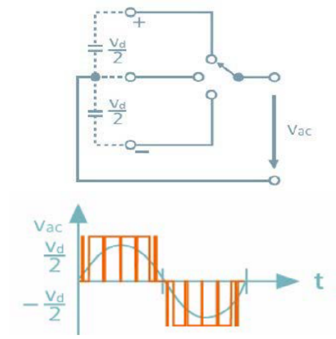
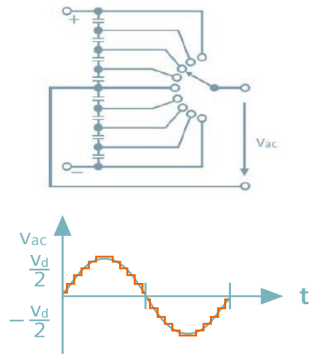
Having exposed the general aspects of each type of technologies, a summary of the relevant aspects of the different compensation devices are shown at below.

Table 11-1. Pros and cons of the SVC and STATCOM.

	TCR-FC	TCR-TSC	STATCOM
V-Q characteristics	Max. capacitive VAr output decreases with the square of voltage decrease.	Max. capacitive VAr output decreases with the square of voltage decrease.	Max. capacitive VAr output decreases linearly with voltage decrease.
Loss vs. output	High losses at zero output. Losses decrease smoothly with cap. output & increase with inductive output.	Low losses at zero output. Losses increase step-like with cap. output & smoothly with ind. output.	Low losses at zero output. Losses increase smoothly with both cap. and inductive output.
Harmonic generation	High (large TCR). Requires siginificant filtering	Low (small TCR)	Very low if multi-pulse converter is used.
Max. theoretical delay	Half cycle (real ~2 cycles)	One cycle (real ~3 cycles)	Negligible (real ~1 cycle)
Transient behavior	Poor (the FC causes transient over-voltages in response to step disturbances)	Can be neutral (Capacitors can be switched out to minimize transient over-voltages	Can be used for damping transient using a P.O.D.[6] signal.

[6] P.O.D. stands for Power Oscillation Damping

Table 11-2. Different type of VSC technology

Two level converter	Three level converter	Multilevel converter
		

SVC PLUS is an advanced STATCOM with Modular Multilevel Converter (MMC) technology developed by Siemens.

The MMC provides a nearly ideal sinusoidal-shaped waveform on the AC side. Therefore, there is only little – if any – need for high-frequency filtering and no need for low order harmonic filtering.

SVC PLUS uses robust, proven standard components, such as typical AC power transformers, reactors, capacitors, and industrial class IGBTs (Insulated Gate Bipolar Transistors) that are widely used and proven technology for traction and industrial drives.

The design of SVC PLUS is fully flexible. Both containerized and open rack solutions are available.

Containerized solution is ideal when space is limited and costly, but the size is limited to a maximum of +/-50 MVAr. Three standardized pre-engineered configurations covering +/-25, +/-35, or +/-50 MVAr are available as containerized solutions, and up to four of these units can be configured as a system operating in a fully parallel manner.

The open rack solution is available in blocks of ± 25, ± 35, ± 50, ± 75, and +/-100 MVAr, and can be grouped in parallel for achieving a maximum size of +/-400 MVAr.

The relevant aspects of a containerized STATCOM (SVC plus) and an SVC (SVC classic) manufactured by Siemens, both of ± 50 MVAr capacity are shown below:

- Lower space requirements - Figure A-1 and Figure A-2
- Lower Harmonic generation (Multilevel technology) - Figure A-3
- Lower Losses (lower switching frequency) - Figure A-4

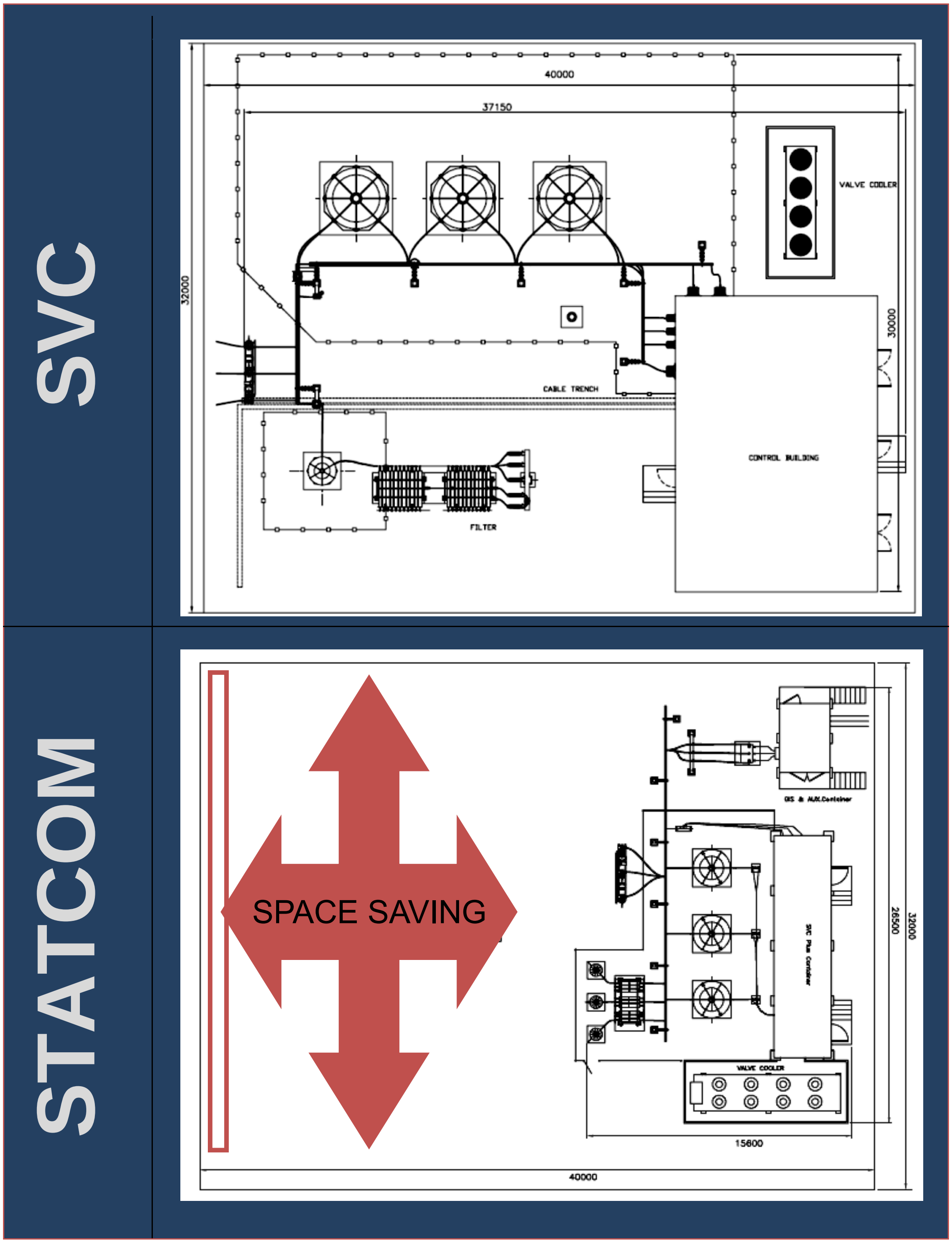


Figure A-1. Size comparison between the SVC and a containerized STATCOM.

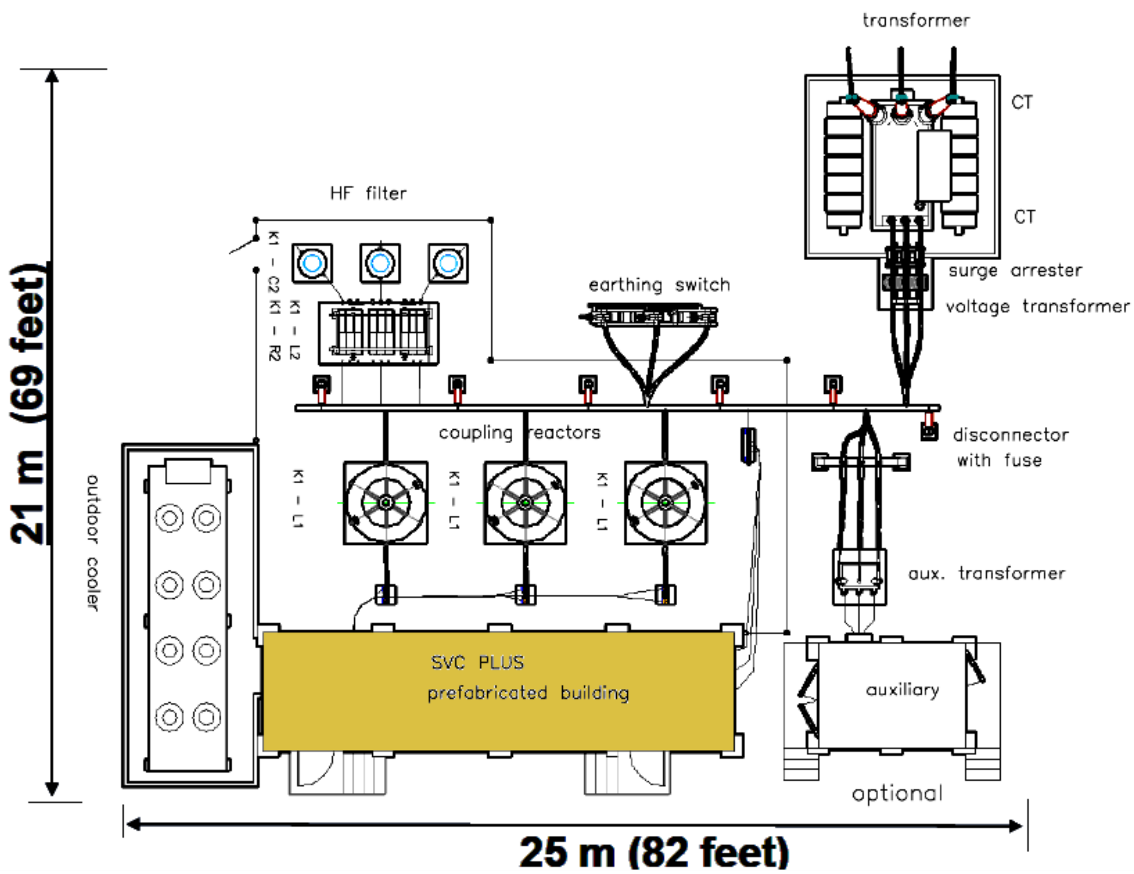


Figure A-2. Layout and space requirements for a containerized STATCOM of 50 MVA.

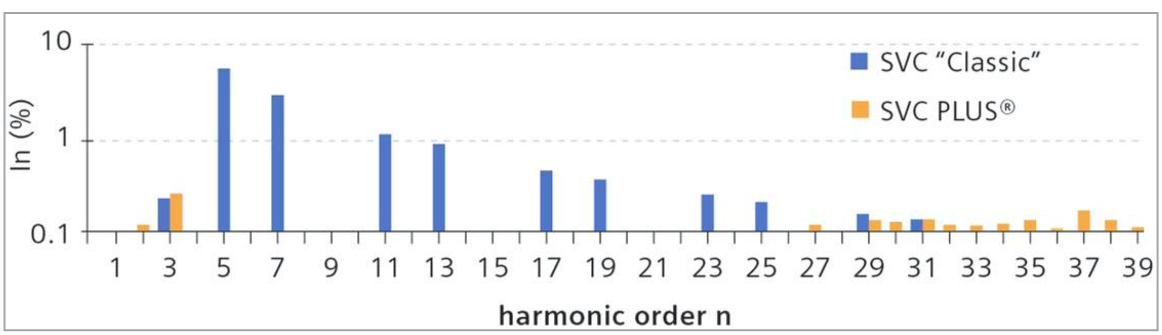


Figure A-3. Harmonic currents for the SVC and STATCOM.

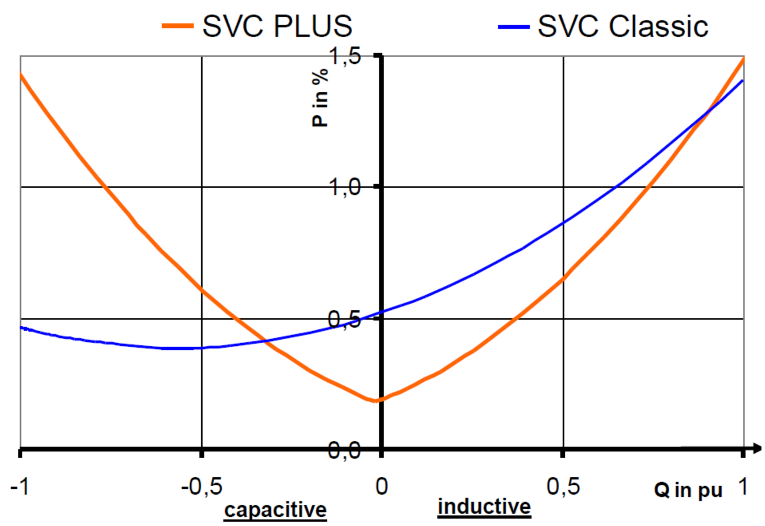


Figure A-4. Losses comparison for the SVC and STATCOM.

The space requirement for a conventional SVC of 50 MVA is in the order of 40 x 32 meters, while a similar rated STATCOM is reduced to 25 x 21 meters.

Figure A-5 shows a typical lay-out of an open rack STATCOM device which consists of two parallel modules of ± 100 MVAr capacity. As can be seen, the space requirement is of 50 x 30 meters, which is in the order of the requirement of a 50 MVA SVC.

If due to reliability purpose is desired to split among two different locations the reactive compensators, the lay-out and space requirements for a 100 MVA open-rack STATCOM.

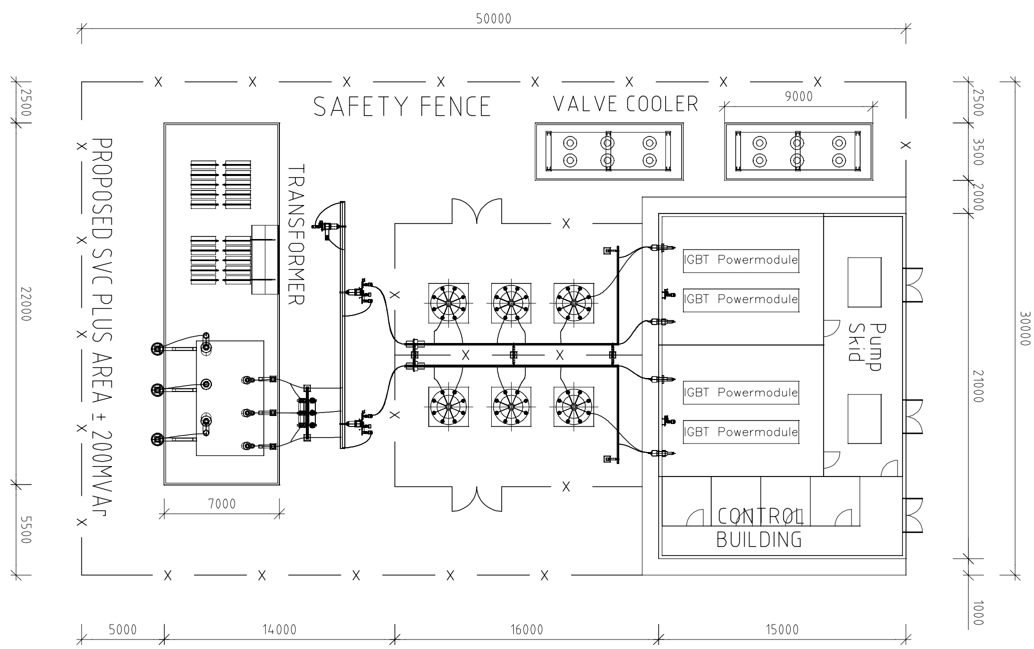


Figure A-5. Layout and space requirements for an open-rack STATCOM of 200 MVA.

A.6 Conclusions of the reactive power compensation devices section

Considering PREPA's requirements, Siemens PTI leans its opinion to support the use of STATCOM devices.

Aspects such as low space requirements are of a high relevance, as the new compensation devices will be installed in existing power stations.

The reactive power output should be in average zero, due that they will be expected to supply reactive power only under contingency situations.

Finally, as few generation is expected in the North of the island, low short-circuit levels are expected, and the use of capacitor banks will require of specially-designed harmonic filters, while when using a STATCOM this problems will be negligible.

By installing the reactive compensators at two locations the reliability will be substantially increased.

Appendix

B

Short-term dynamic simulations (*Confidential*)

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