Final Report and Model for Marshalls Energy Company (Majuro, Republic of Marshall Islands)

Assessment of Variable Renewable Energy (VRE) Grid Integration, and Evaluation of SCADA and EMS system design in the Pacific Island Counties

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Report for the Pacific Power Association and the World Bank
Selection # 1238727

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1 Introduction

The Pacific Power Association, in consultation with The World Bank, has identified the need for VRE integration assessment and SCADA-EMS system design to support the development of the nascent renewable energy sector in the region. This report has been developed as a part of the "Assessment of Variable Renewable Energy (VRE) Grid Integration and Evaluation of SCADA and EMS system design in the Pacific Island Countries" project.

The assignment consists of four interrelated tasks and each section of this report corresponds to a specific task. The first section is on the grid integration and planning studies and in this task, the consultants used the available power system data, validated the dynamic characteristics of the existing generators, and collaborated with utilities to build and populate several models for specific islands. In this task, the consultants identified the grid stability and reliability issues for different VRE penetration levels and different demand scenarios.

The second section is on the assessment of energy storage applications in power utilities. The main objective of this task was to assess the interest and cost-effectiveness of the energy storage systems, and the role that it can perform as grid support including identification and probable solutions to implementation challenges that may arise.

Based on best practices adopted in other countries, a grid code has been developed for Majuro and this is available in Appendix 1 of this report. The grid code was written after assessing the requirements relating to voltages and frequency range of the island, understanding different options to integrate Renewable Energy sources into the system and how Renewable Energy generators could respond to grid disturbances. In the grid code, special emphasis was given to state the grid support capabilities that are expected from Renewable Energy generators.

The fourth section presents the results of the assessment of the needs for Supervisory control and data acquisition (SCADA) and Energy Management System (EMS).

2 Task 1: Grid Integration and Planning Studies

Grid integration and planning studies have been conducted as part of this project to assess the effect of different penetrations of variable renewable energy (VRE) generation on the operation and stability of specific networks within a number of the Pacific Island countries.

The Pacific Island country (PIC) networks each have underlying grid stability issues, caused primarily because these are small island networks with very little inertia and support to maintain system stability and frequency. The generation that is connected to these networks often does not have the appropriate control systems in place to manage behaviour during disturbances; and this also impacts the overall stability of these grids.

The move towards a more sustainable and reliable power sector will result in more renewable generation technologies connecting to these networks. It is the purpose of these studies in Task 1 to:

- Assess the operational and stability characteristics of the existing networks;
- Assess and understand the capability of each of the studied networks to accommodate renewable, intermittent generation;
- Identify operational limitations and optimal range of power generation mix between existing and new generation to prevent adverse impacts; and
- Provide recommendations on strategic reinforcements and other methods of increasing VRE penetration.

The networks studied in Task 1 are:

Pacific Island Country	Network under Study
Samoa	Upolu
Federated States of Micronesia	Chuuk
Federated States of Micronesia	Kosrae
Tonga	Tongatapu
Federated States of Micronesia	Pohnpei
Marshall Islands	Majuro
Tuvalu	Funafuti

2.1 Power system study methodology

The following steps have been taken to assess each of the networks under study:

1) Development and finalisation of base case network models using existing Digsilent network model files where available, or developing Digsilent models from data collected from utilities.

2) Perform load flow studies to assess the steady state performance of the power system. The following assessments have been made:
   - The loading conditions of network components in the system (measured as a percentage of rating) with the given demand level. Network components with loading conditions above 90% of the specified rating are reported.
   - The voltage profile across the network (measured in per unit) with the given demand level. Nodes with a recorded voltage magnitude above 1.10pu and below 0.90pu have been reported.
   - Network capability to meet a scaled load demand (depending on size of network) of existing load demand level. Any overloads and voltage violations have been reported.

3) Perform contingency and switching operation studies to assess the steady state performance in each power system under credible outage or switching operation conditions. The contingency studies are performed on mesh networks, while the switching operation studies are applied to the radial network with switch devices on or between feeders. The following assessments have been made:
   - The loading conditions of network components in the system (measured as a percentage of rating) under the credible outage or switching operation conditions. Network components with loading conditions above 90% of the specified rating have been reported.
   - The voltage profile across the network (measured in per unit) with the given demand level under the credible outage or switching operation conditions. Nodes with a recorded voltage magnitude above 1.10pu and below 0.90pu have been reported.
   - Network capability to meet a scaled load demand of 105% and 110% of existing load demand level under credible outage or switching operation conditions. Any overloads and voltage violations have been reported.

4) Perform fault studies to assess fault levels at power plant busbars and those nodes with switches in each power system. The following assessments have been made:
   - Three phase fault levels;
   - Single phase to ground fault level;
   - Make fault current at 10 ms and Break fault current at 50 ms for a 50 Hz system; and
   - Make fault current at 12 ms and Break fault current at 60 ms for a 60 Hz system.

5) Perform stability studies to determine stability performance in each power system for credible dynamic events and contingencies. The studies are carried out based on the given load demand level in the system. The following assessments have been made:
   - Frequency and voltage response of the system subsequent to the loss of the largest generating unit in the system.
   - Frequency and voltage response of the system subsequent to the loss of the feeder with the largest MW load demand.
   - Rotor angle and voltage stability of the system subsequent to a three phase fault applied on feeders followed by tripping of the feeder with 150 ms delay. A fault is applied respectively on the feeders with the smallest and the largest MW load demand.
   - Frequency and voltage response of the system subsequent to the MW output change from the PV sites. The MW output of all PV sites in the system will is assumed to drop from maximum MW output level down to 0 MW output level within 10 seconds. After 20 seconds delay the MW output of all PV sites in the system are assumed to rise from 0 MW output level to the maximum MW output level within 10 seconds.

Steps 1 – 5 as listed above have formed the basis of the study of each network to understand its operational characteristics and any limitations. Following this, the penetration of renewable generation connected to the network is increased in suitable increments (depending on the size of the network) and the following steps are performed to assess the network capability to accommodate these renewables.

To assess and identify maximum renewable generation capacity that can be integrated into the utility power grid, the power system model is set up as follows:

- Existing network topology.
- The assumed maximum load demand level, which could be 3% ~ 5% higher than the existing maximum load demand level if the system has adequate network capacity.
- Renewable generation capacity (PV generation) considered to be at 5%, 10%, 15%, and 20% of total installed generation capacity in the system. New renewable generation sites could be distributed across the system.
- Renewable generation is fully dispatched in the considered operational scenarios. The conventional generators, however, is dispatched based on merit order to balance the rest

of power mismatch in the system. The calculated spinning reserve capacity shall be more than 10% of the demand level.

The following studies are performed:

6) Stability simulations to assess system frequency response for the two events:
   - The sudden loss of the largest generating units on line
   - The drop of MW output from all PV site with 10 seconds
     - If the minimum frequency deviation of the system for any event is within 2% of nominal frequency, it indicates that the system has the capability to integrate the amount of assumed renewable generation capacity.
     - If the minimum frequency deviation of the system for any event is greater than 2% of nominal frequency, then the following steps should be taken:
   - Switch on one of the conventional generators connected to the system and assume that it is operated at its minimum MW output. To balance the power mismatch in the system, the MW output of other conventional generators is adjusted accordingly.
   - Perform stability simulations again for the same event(s) to determine if the system frequency is within 2% of nominal frequency.
     - If the frequency is now within the 2% threshold, this indicates that the system has the capability to integrate the amount of assumed renewable generation capacity with the support of more spinning reserve from conventional generators.
     - If the frequency remains above the 2% threshold, this indicates that the system cannot suitably integrate the amount of the assumed renewable generation capacity. Battery storage is a potential solution (and this is studied in more detail in Task 2).

2.2 Majuro Network, Marshall Islands

The Marshall Islands is a small country in the North Pacific region, made up of over 1,000 islands and atolls. Majuro is an atoll upon which is the largest city of the Marshall Islands with a population of over 20,000 people. The power system on Majuro is operated by the Marshalls Energy Company (MEC). Majuro is a 60 Hz system and has a backbone network of 13.8 kV whereby there are two adjacent power stations on the island which output at 13.8 kV, and three feeders distribute power from here around the island. The voltage then steps down to 4.16 kV for the last mile of each of the three feeders.

The network single line diagram (SLD) is provided in Figure 2-1 and shows the power station feeding the various loads on the island and the feeder configuration is shown in Figure 2-2.

Figure 2-1: Single line diagram for the Majuro power system

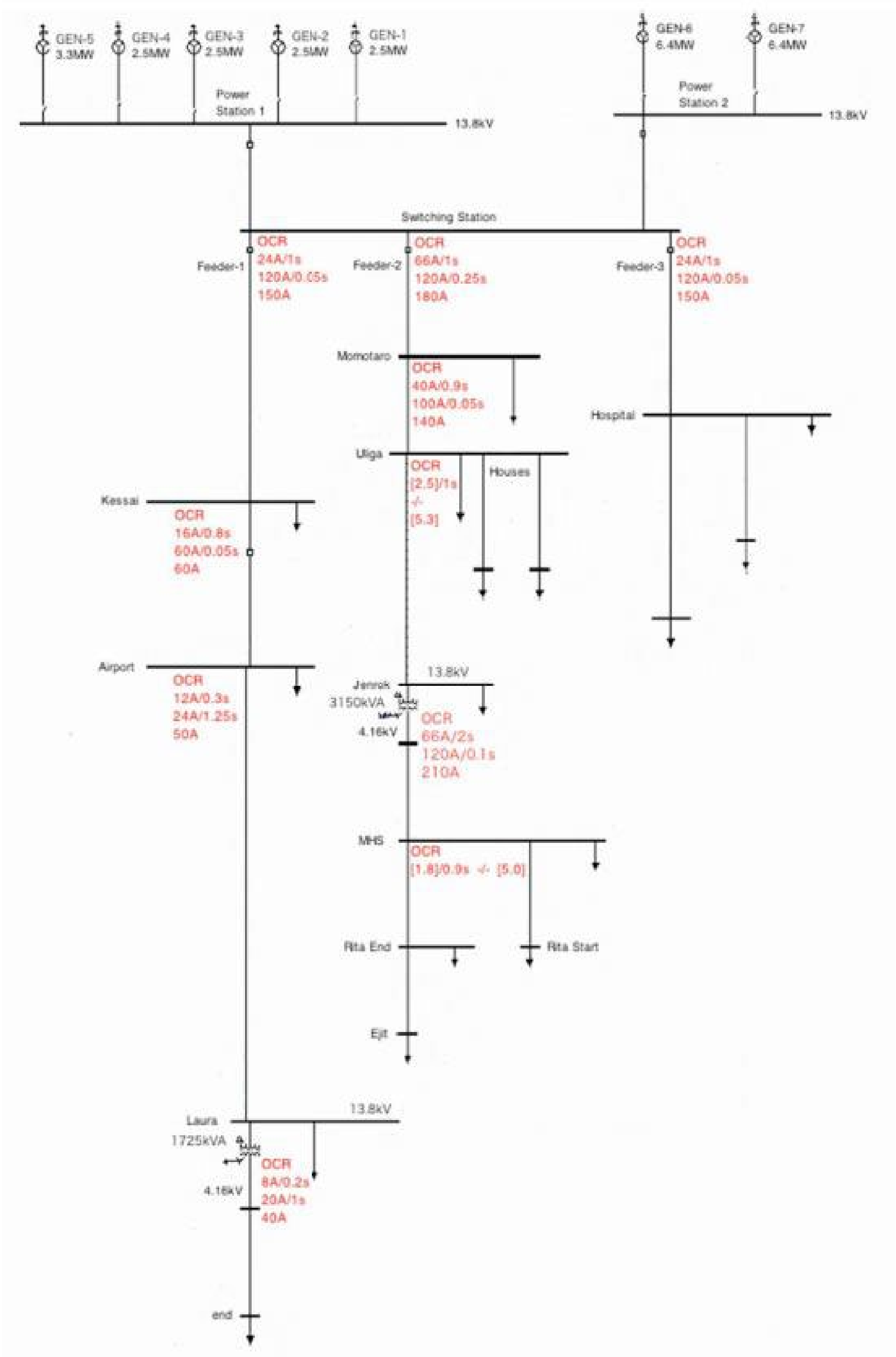
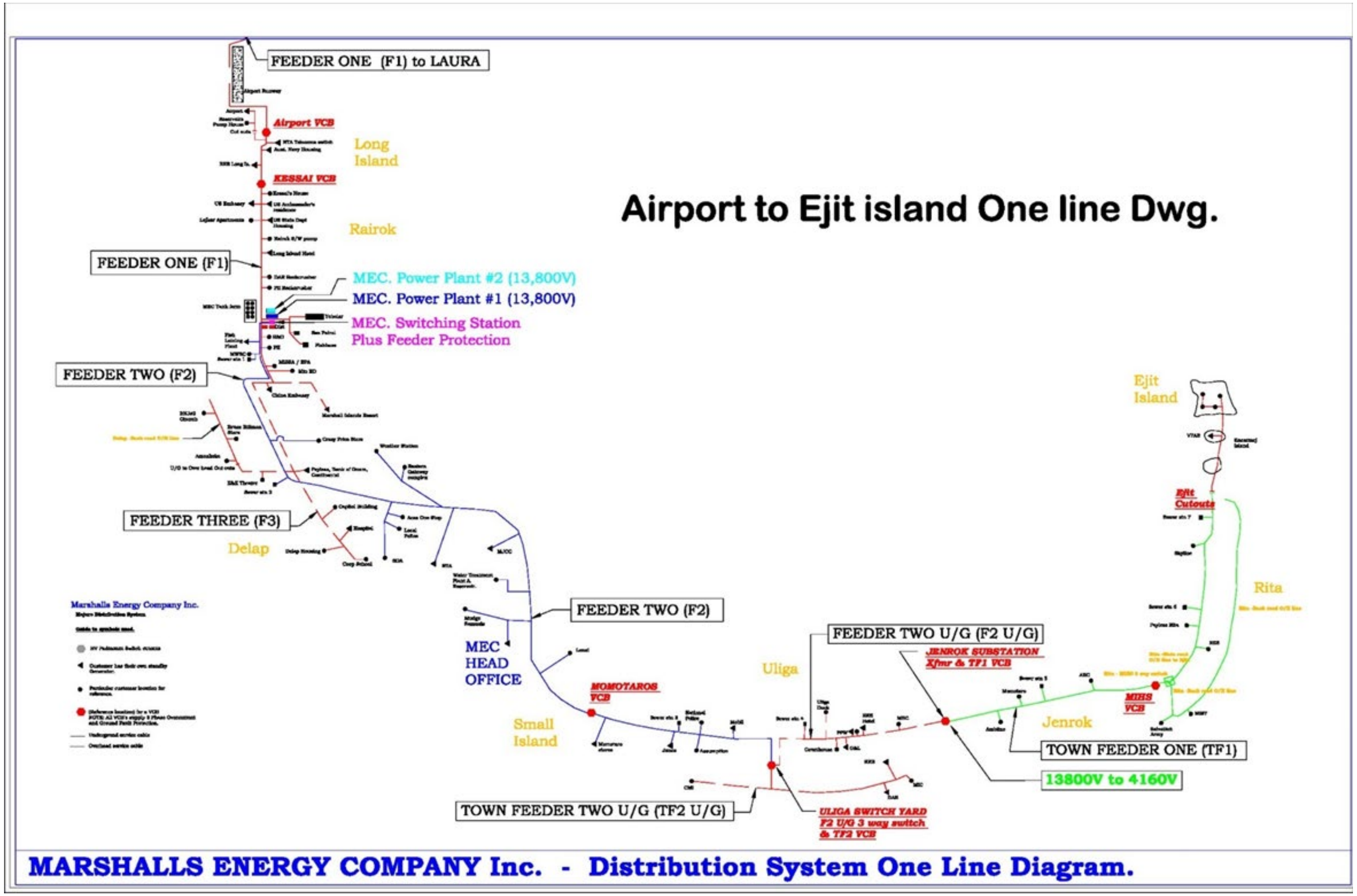


Figure 2-2: Feeder configuration of the Majuro power system



The MEC power stations comprise seven diesel generators. Power Station 1 houses five generators rated at 3.125 kVA and 4.125 kVA while Power Station 2 hosts the remaining two generators. Some of the generators have operational constraints (due to age, wear and tear, etc.) and so their maximum output is limited. The installed generation capacity of the Majuro network is provided in Table 2-1 below. There are also two PV generation sites also connected to the system.

Table 2-1: Majuro power station generating units

Unit Name	Type	Rated Capacity (kVA)	Available Capacity (kW)
DG1	Diesel	3,300	1,500
DG2	Diesel	3,300	2,000
DG3	Diesel	3,300	0
DG4	Diesel	3,300	0
DG5	Diesel	3,300	2,500
DG6	Diesel	6,400	6,000
DG7	Diesel	6,400	5,000
PV1	PV	228[1]	205
PV2	PV	667	600

In addition to the two PV sites listed in the table above, there are plans to connect more solar PV generation to the island, as it is understood to be the most abundant and cost-effective renewable generation source for the Marshall Islands area.

The maximum demand of the network is around 8,900 kW, and the minimum demand is around 3,000 kW. The demand levels were derived from 2016 demand data collected during the Inception Mission. It is now known that the demand levels have increased to 9,300 kW in 2018.

2.2.1 Power system data and assumptions

The data made available for the power system studies of the Marshall Islands utility network on Majuro is described in detail in the Data Collection Report (D3 – Data Collection Report, April 2018).

2.2.2 Summary of Power System Studies and Scenarios

The following table provides a summary of the power system studies performed on the Majuro network, and the different network conditions/scenarios considered.

Study	Scenarios
Load Flow	Maximum Demand 10% Load scaling, 20% Load scaling
Load Flow	Minimum Demand
Fault Level	Maximum Fault Level Conditions
Stability Study – Existing System	Loss of second largest generator, Loss of second largest feeder,

[1] The kVA value was derived based on 0.90 power factor

Study	Scenarios
	3ph fault and feeder trip, Increase/decrease of PV generation
Stability Study – 20% Renewable Generation Penetration	Loss of second largest generator, loss of second largest feeder, 3ph fault and feeder trip, Increase/decrease of PV generation
Stability Study – 20% Renewable Generation Penetration	Loss of second largest generator, Loss of second largest feeder, 3ph fault and feeder trip, Increase/decrease of PV generation

2.2.3 Power system study results

The following subsections provide the results of the power system studies performed on the Majuro network.

2.2.3.1 Load flow studies

Load flow studies were performed on the Majuro network model. The studies encompassed maximum and minimum demand scenarios, and demand scaling of the maximum demand scenario to understand the implications of load growth.

The scenarios can be summarised as follows:

Maximum demand scenario

The table below presents the results of the maximum demand load flow studies for base case (current demand level) and then two stages of load scaling.

Table 2-2: Maximum demand scenario load flow results

Demand Level	Maximum thermal loading (%)	Maximum Voltage (pu)	Minimum Voltage (pu)
Base Case	52%	1.02	0.89
10% Load Scaling	58%	1.02	0.86
20% Load Scaling	64%	1.02	0.83

It can be seen from the results that under normal operating conditions, the existing network on Majuro has no thermal loading issues. The maximum loading on the existing network is 52% and so there is significant capacity for future load growth on the network. There are some low voltage issues on the network with one 4.16 kV busbar recording a low voltage of 0.89 pu which is outside the ±10% limits. The low voltage is at the end of Feeder 1 due to long length of the circuit and unavailability of voltage regulation facilities at the Laura 4.16 kV terminal. The voltage profile at Rita 4.16 kV is around 0.92 pu under the maximum loading conditions, which may also need to be addressed. In addition, some other low voltages are experienced on the 13.8 kV network but these are above 0.9 pu threshold.

Minimum demand scenario

The table below presents the results of the minimum demand load flow studies for the current minimum demand level.

Table 2-3: Minimum demand scenario load flow results

Demand Level	Maximum thermal loading (%)	Maximum Voltage (pu)	Minimum Voltage (pu)
Base Case	14%	1.04	0.99

The maximum loading on the network is recorded as 14% under minimum demand conditions. The maximum voltage on the network is 1.04 pu, while the minimum voltage is recorded as 0.99 pu suggesting there are no issues.

2.2.3.2 Fault level studies

The fault level studies were carried out assuming all generation connected to the system is switched on, thus providing conditions for maximum fault level. A three-phase fault study was conducted to determine the maximum fault currents on the Majuro network. Table 2-4 shows the maximum 3 phase fault currents at the main power station 13.8 kV busbar.

Table 2-4: Maximum fault level results

Fault Level	kA	Busbar	Voltage Level
Three Phase ip	14.774	1000 PS-BUS	13.8
Three Phase Ib	3.795	1000 PS-BUS	13.8

The main power station has the highest fault level, which is to be expected. There were no switchgear or circuit breaker ratings provided for the network and so a clear determination of the fault levels being within acceptable limits cannot be made at this stage. Based on standard switchgear ratings for these voltage levels, it is not expected that the system fault levels are in excess of any rated equipment. However, it is recommended that the fault level results presented in the table above are compared against the switchgear and circuit breaker ratings to ensure if the network is operating within the safe limits of its protection system.

Figure 2-3: Typical Switchgear Ratings from 4 – 38 kV (Source: Siemens USA)

ANSI C37.06-1987 (and 1964 and 1979) Circuit Breaker Ratings ("Constant MVA" Rating Basis)

Historic "MVA Class"	Max kV	Rated kA	Max kA	Range Factor	Continuous Current	Dielectric (kV)		Close & Latch (kA)	
						60Hz	BIL	rms (1.6KI)	Peak (2.7KI)
250	4.76	29	36	1.24	1200 2000	19	60	58	97
350	4.76	41	49	1.19	1200 2000 3000	19	60	78	133
500	8.25	33	41	1.25	1200 2000 3000	36	95	66	111
500	15	18	23	1.30	1200 2000	36	95	37	62
750	15	28	36	1.30	1200 2000 3000	36	95	58	97
1000	15	37	48	1.30	1200 2000 3000	36	95	77	130
1500	38	21	35	1.65	1200 2000 3000	80	150	56	95

2.2.3.3 Stability studies

The voltage and frequency response of the system (maximum demand scenario) were assessed for three distinct events:

1) Loss of the largest generator on the system;
2) Loss of the largest feeder (largest MW loading) on the system; and
3) Reduction in PV output from the specified MW to 0 MW within 10 s then increase back up to the specified output from 0 MW after 20 s.

The voltage and rotor angle stability were assessed in the event of:

4) A three phase fault on the largest demand conductor followed by the tripping of the feeder after 150 ms.

An initial set of studies was carried out on the existing Majuro network to understand the behaviour of the system under these conditions. The generation mix for these studies is as shown in Table 2-5 with 2724 kW of spinning reserve available.

Table 2-5: Generation mix on Majuro with 8% renewable generation contribution

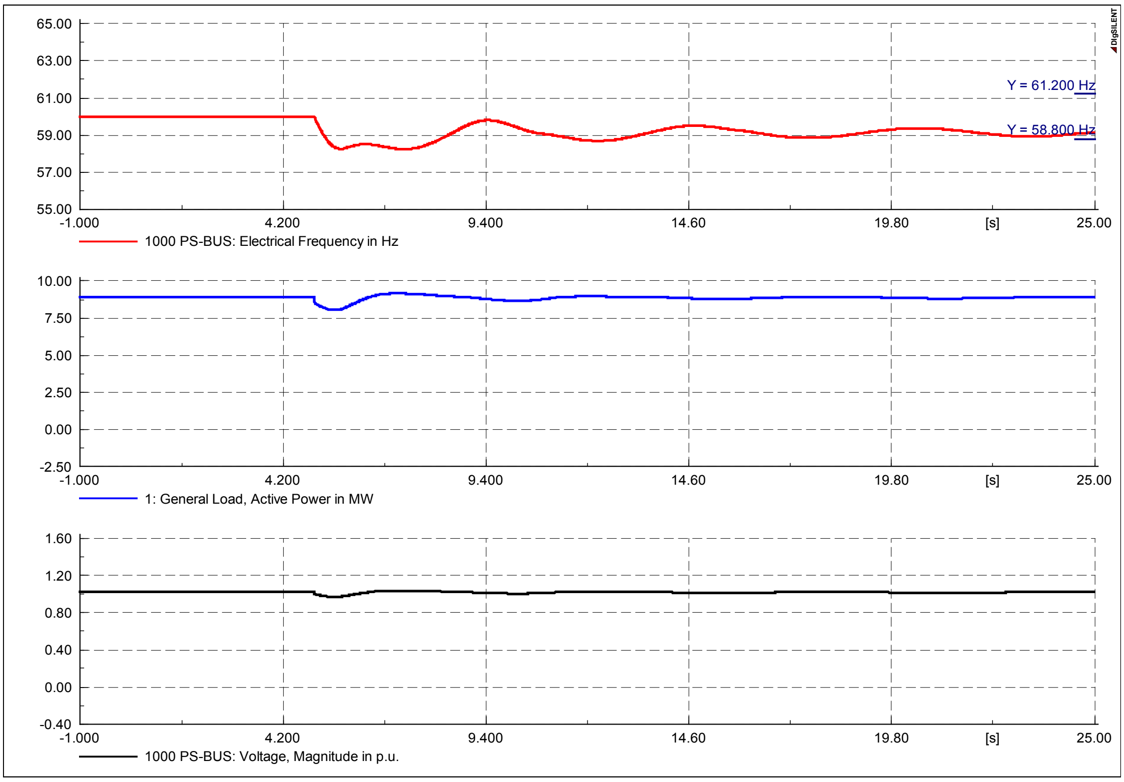
Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	DG6	2	1	5400.0	600.0	20.8%
	DG7	2	0	0.0	0.0	0.0%
	DG1	3	0	0.0	0.0	0.0%
	DG2	3	1	2000.0	400.0	13.9%

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
	DG3	3	0	0.0	0.0	0.0%
	DG4	3	0	0.0	0.0	0.0%
	DG5	3	1	615.5	1884.5	65.3%
	Sub-total			**8015.5**	**2884.5**	
	PV 1	1	1	184.5	0.0	0.0%
Renewable	PV 2	1	1	540.0	0.0	0.0%
	Sub-total			**724.5**	**0.0**	
				8740.00	**2884.50**	**32.4%**

Loss of second largest generator

There are three diesel generators operating in the generation dispatch scenario detailed in Table 2-5. The loss of the largest generator, DG6, will result in system frequency collapse since the spinning reserve available on the system is approximately half that of the MW output of the largest generator and the amount of spinning reserve is insufficient to make up the loss of the largest generator. As such, the second largest generator, DG2, was tripped to assess the capability of the network to withstand this credible contingency. The voltage and frequency responses of the system to this event are shown in Figure 2-4.

Figure 2-4: Voltage & frequency response to loss of second largest generator

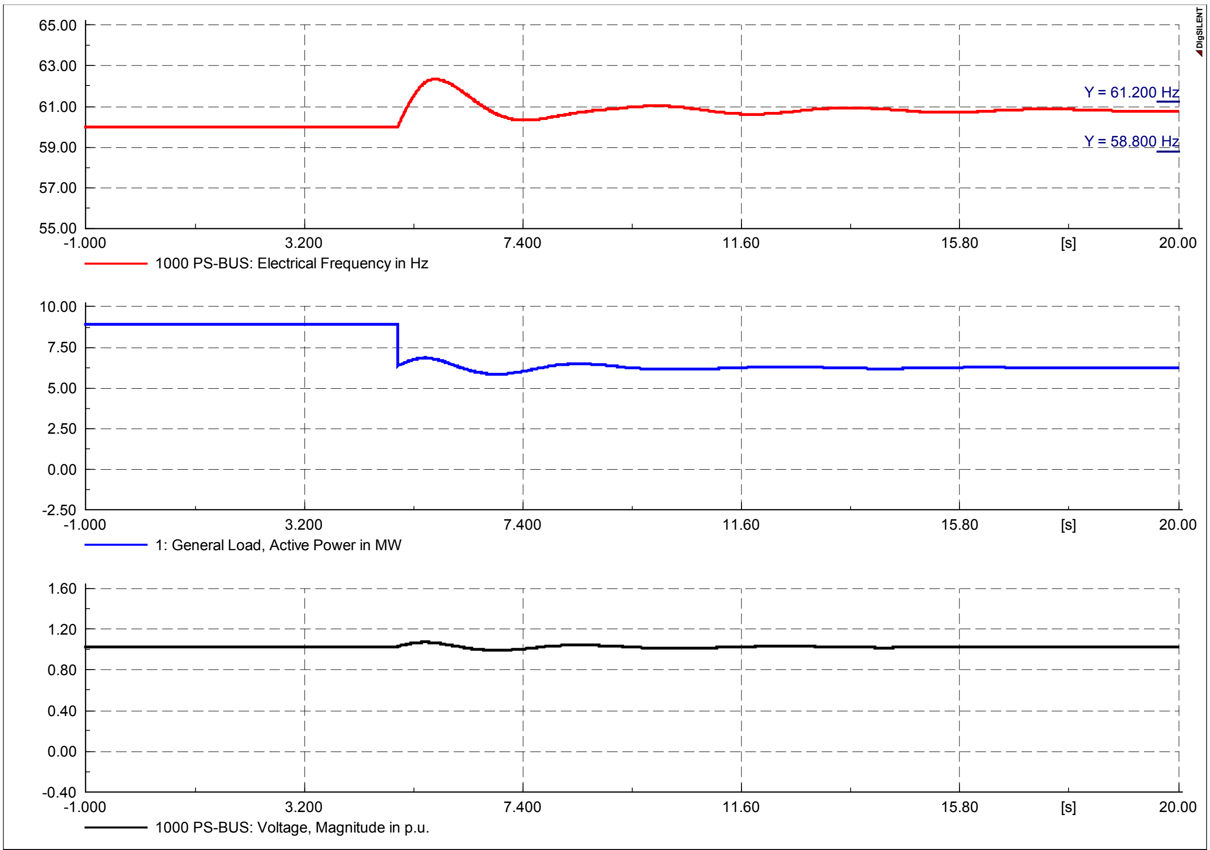


Upon the loss of the second largest generator, the system frequency falls to around 58.5 Hz which is below the allowable frequency deviation limit of 2%. The frequency recovers within a few seconds, remaining stable and within the bandwidth for the remainder of the study. The voltage dips slightly when the generator is lost but recovers to nominal within 2 s.

Loss of second largest feeder

The largest loaded feeder (feeder with the largest load demand) in the system is Feeder 2. The system could not cope with the loss of this much load rejection (i.e. 52.7% of supply from the power station) and so the loss of the second largest feeder, Feeder 1 (circuit “1000_1010_1A”) was studied. The feeder, accounting for 30.3% of supply from the power station, was tripped and the voltage and frequency responses are shown in Figure 2-6. The generation mix assumed in this case is the portfolio as presented in Table 2-5.

Figure 2-5: Voltage & frequency response to loss of second largest feeder



The feeder is tripped at 5 s and the frequency increases from 60 Hz to 62 Hz initially, which is in excess of the 2% allowable frequency deviation limit. The frequency then settles around 61 Hz after approx. 5 s. Prolonged operation at this frequency may potentially activate over-frequency mitigation measures, such as generator over-frequency protection. The voltage remains within the acceptable ±10% limits throughout the event.

Three phase fault & subsequent tripping of demand feeder

As before, simulating a fault followed by a trip on the largest demand feeder was not feasible for this network and so the second largest feeder is studied here. A three-phase fault was applied on the second largest feeder and cleared within 150 ms at which point the circuit was tripped off. The voltage and rotor angle responses of the connected generators to these events are shown in Figure 2-6 and Figure 2-7 respectively.

Figure 2-6: Voltage and frequency response to fault and subsequent feeder trip

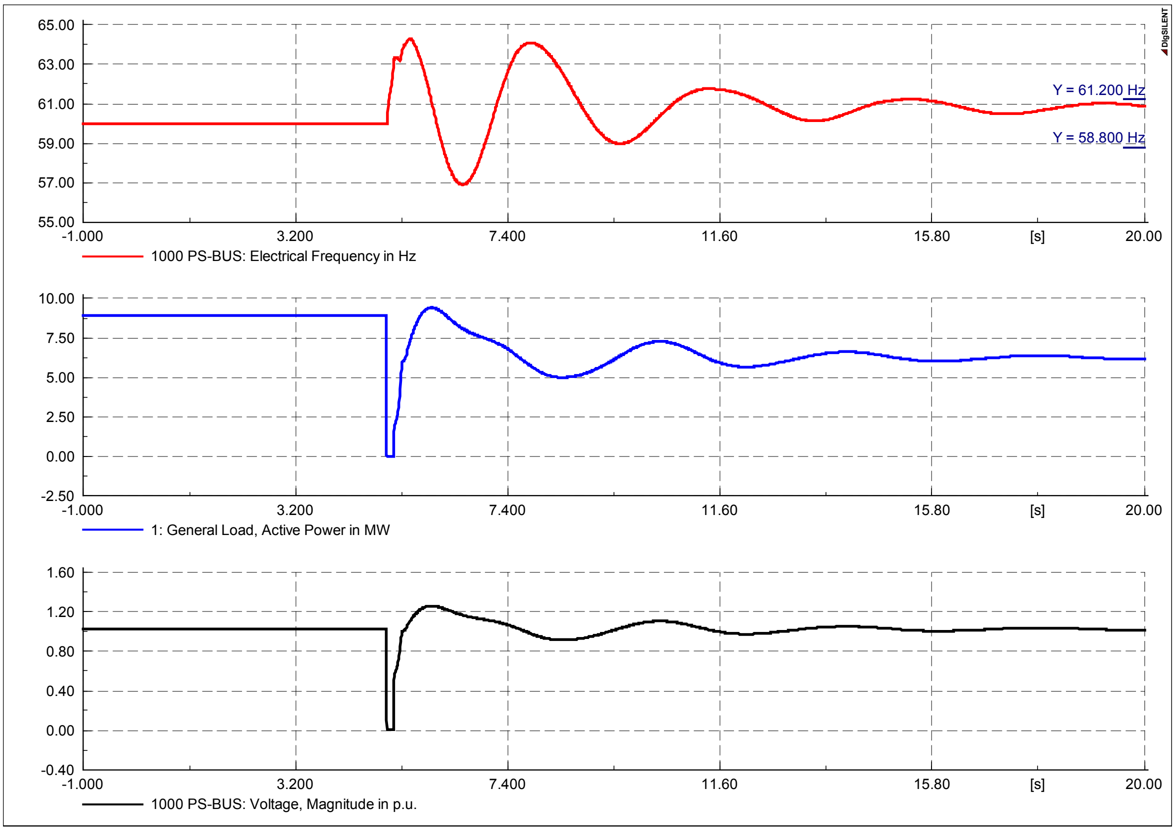
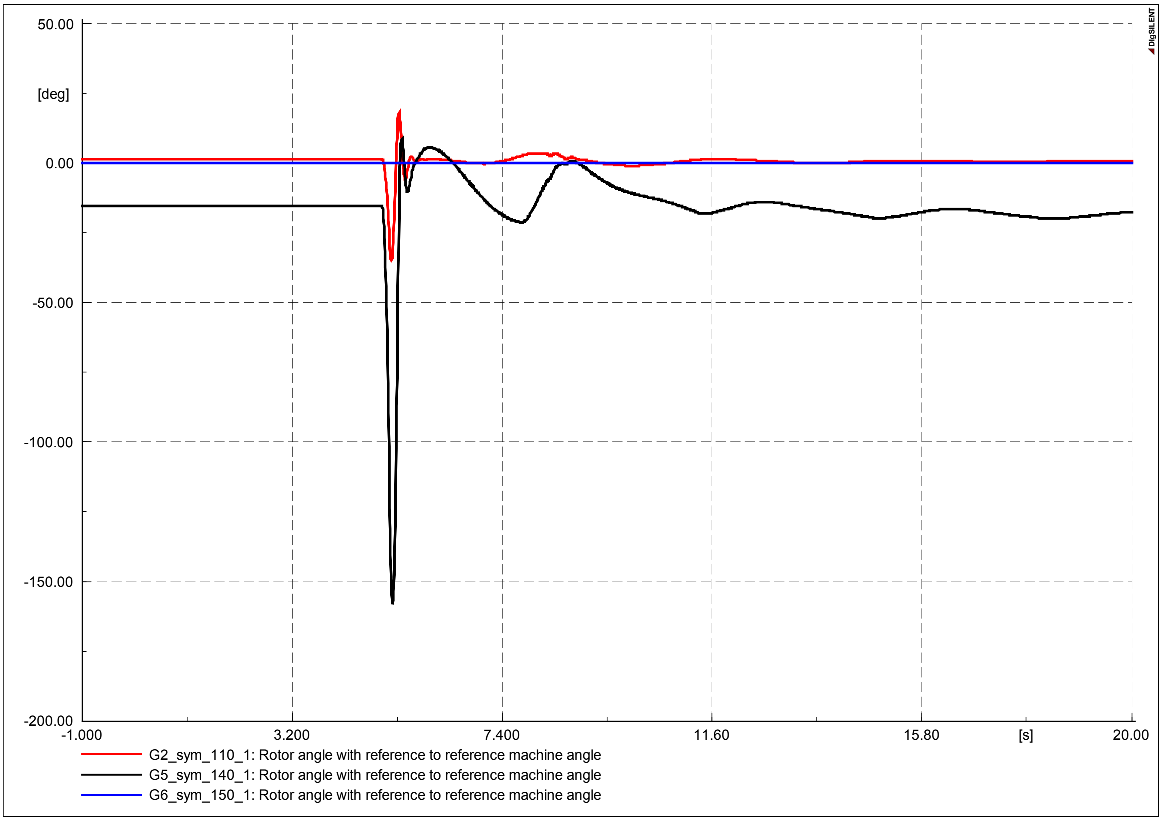


Figure 2-7: Rotor angle response to fault and subsequent feeder trip

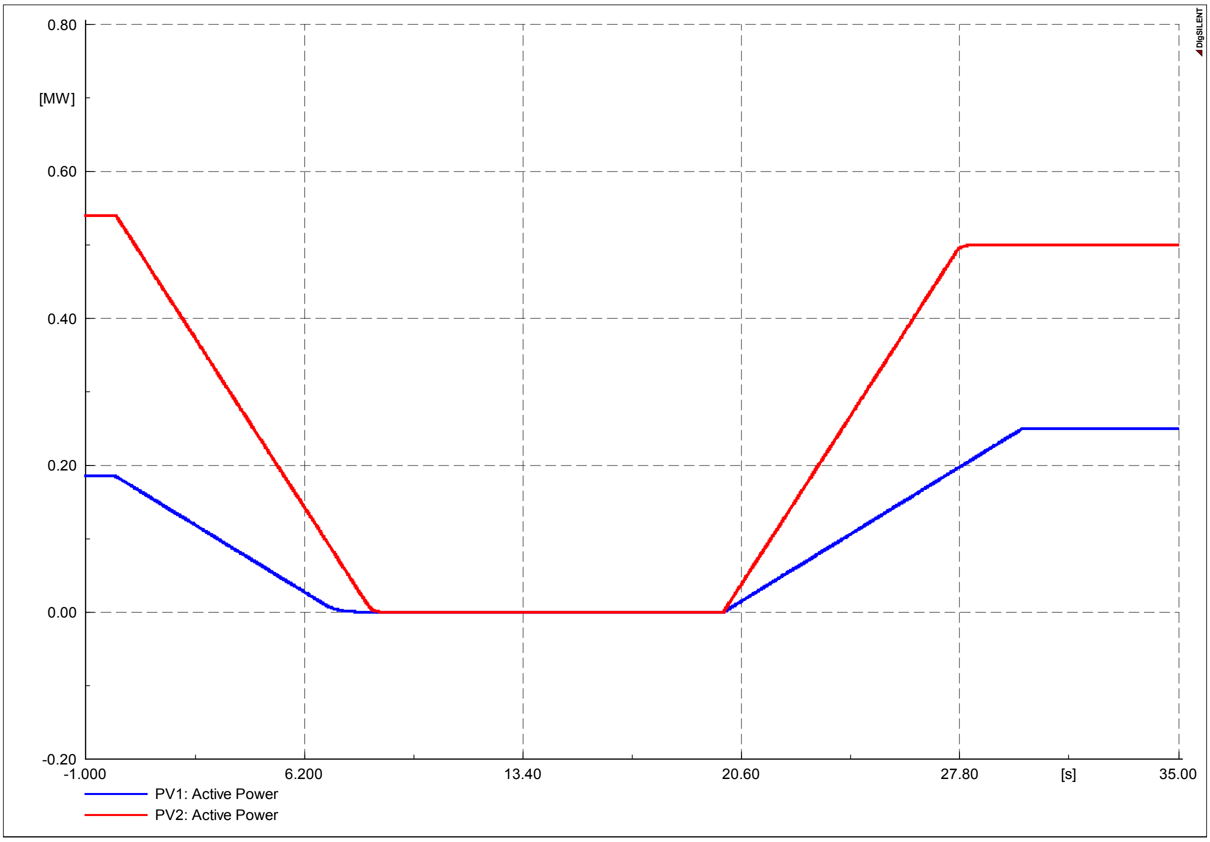


Immediately after the fault, the voltage at the monitored bus (power station busbar) drops to 0 pu. Upon the tripping of the circuit, the voltage recovers very quickly (within a few milliseconds), however it peaks above 1.2 pu before oscillating slightly and returning to nominal value after 10 s. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event. System frequency peaks above the 2% allowable limit at 64 Hz at the time of the fault/feeder trip and then drops to 57 Hz before swinging to 63.5 Hz then oscillating within the ±2% bandwidth, damping out towards the end of the study period. Overall stability is maintained on the system.

Reduction/increase of PV output to/from maximum/0MW

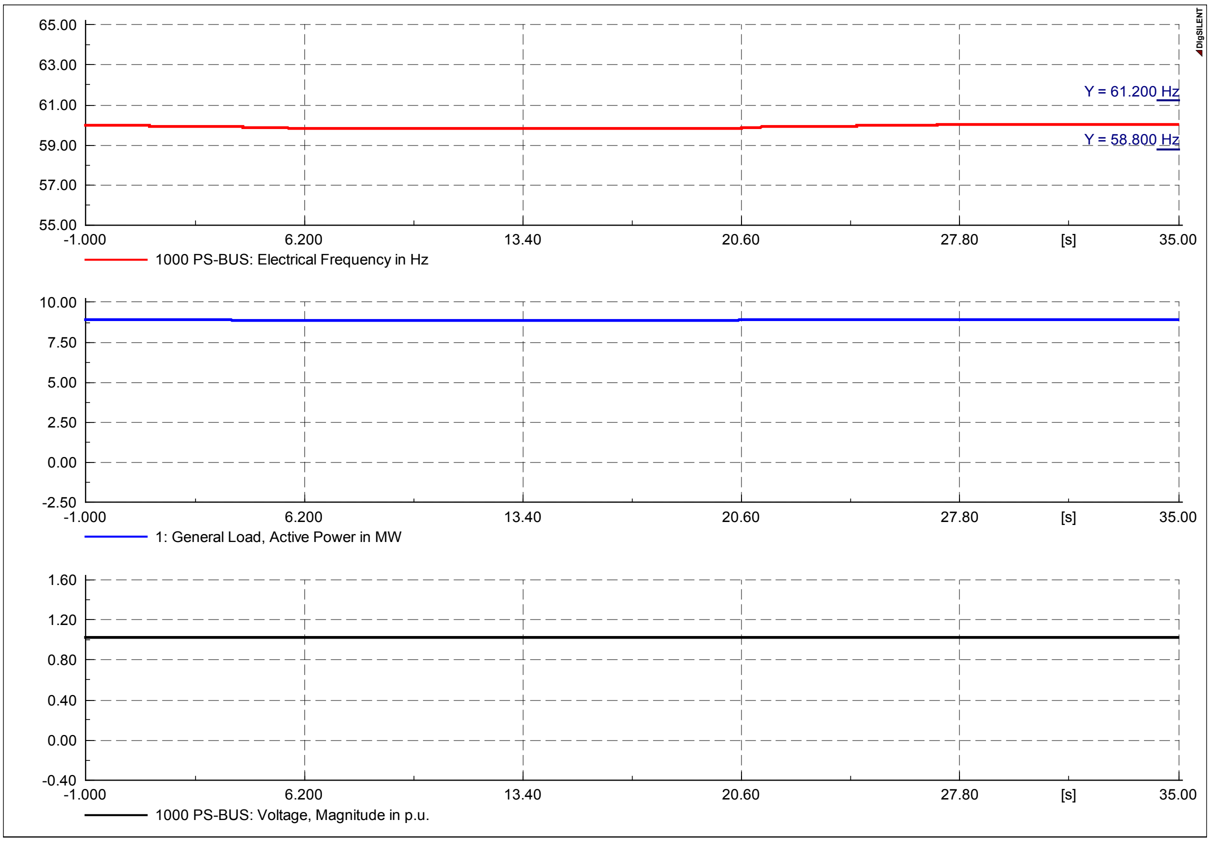
The voltage and frequency response to changing solar PV output on the connected generation on the Majuro network is presented below. The two PV sites were assumed to be operating at 90% of the rated capacity before being simultaneously reduced to 0 MW, and then returning to the initial MW output level after 20 s. The PV output is shown in Figure 2-8.

Figure 2-8: PV MW output of all sites on Majuro



The voltage and frequency responses are shown in Figure 2-9.

Figure 2-9: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases accordingly and then increases when the generators ramp up again to maximum output. The frequency remains within the 2% limit throughout the duration of the study. The voltage fluctuates in line with the changes in active power and frequency but stays around nominal.

The impact of the changing PV output is minimal as the contribution of PV generation is only 8% of the total generation output. This indicates that the system is capable of withstanding the ramping down and ramping up of 725 kW PV generation in this scenario. Sufficient spinning reserve capacity in this scenario plays an important role to maintain system frequency within the 2% limit.

2.2.4 Increasing penetration of VRE

There are plans to increase the penetration of solar PV on the Majuro network over the next few years to achieve 100% electrification of urban and rural areas. A number of studies have been performed to assess the capability of the network to accommodate different levels of renewable generation, whereby the stability and response of the system are tested for the sudden increase and decrease of MW output, such as that experienced from cloud cover. The voltage, frequency and rotor angle responses are also tested (studies in Section 2.2.2.3 are repeated) for each of the penetrations of VRE to understand the impact on the stability of the system for other credible events as the percentage of VRE on the system increases against the level of conventional generation. Two levels of renewable generation have been studied and the results are provided below.

2.2.4.1 20% renewable generation contribution

The following sections present the results which highlight the ability of the Majuro network to operate with 20% of its generation output being provided by VRE, in this case solely from PV generation. The total generation mix assumed for this and subsequent studies is listed in Table 2-6 where the operational conventional generation is assumed to be operating at a reduced output to allow for the provision of spinning reserve and the maximum demand has been scaled up accordingly.

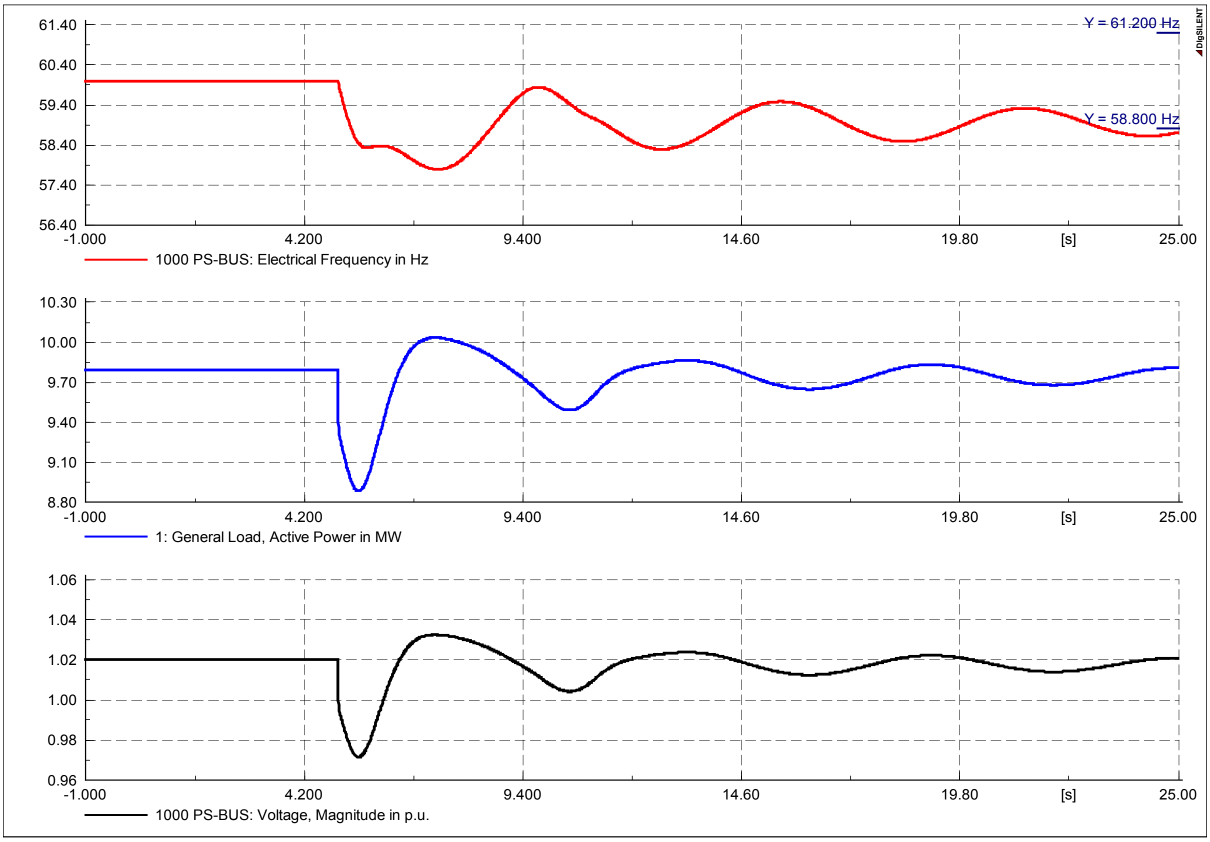
Table 2-6: Generation mix on Majuro with 20% renewable generation contribution

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	DG6	2	1	5400.0	600.0	20.0%
	DG7	2	0	0.0	0.0	0.0%
	DG1	3	0	0.0	0.0	0.0%
	DG2	3	1	2000.0	400.0	13.3%
	DG3	3	0	0.0	0.0	0.0%
	DG4	3	0	0.0	0.0	0.0%
	DG5	3	1	500.0	2000.0	66.7%
	Sub-total			**7900.0**	**3000.0**	
Renewable	PV 1	1	1	184.5	0.0	0.0%
	PV 2	1	1	540.0	0.0	0.0%
	New PV	1	1	1170.0	0.0	0.0%
	Sub-total			**1894.5**	**0.0**	
				9794.50	**3000.00**	**30.9%**

Loss of second largest generator

There are three diesel generators operating in the generation dispatch scenario detailed in Table 2-6. The loss of the largest generator, DG6, will still result in system frequency collapse. As such, the second largest generator was tripped to assess the capability of the network to withstand this credible contingency. The voltage and frequency responses of the system to this event are shown in Figure 2-10.

Figure 2-10: Voltage & frequency response to loss of second largest generator

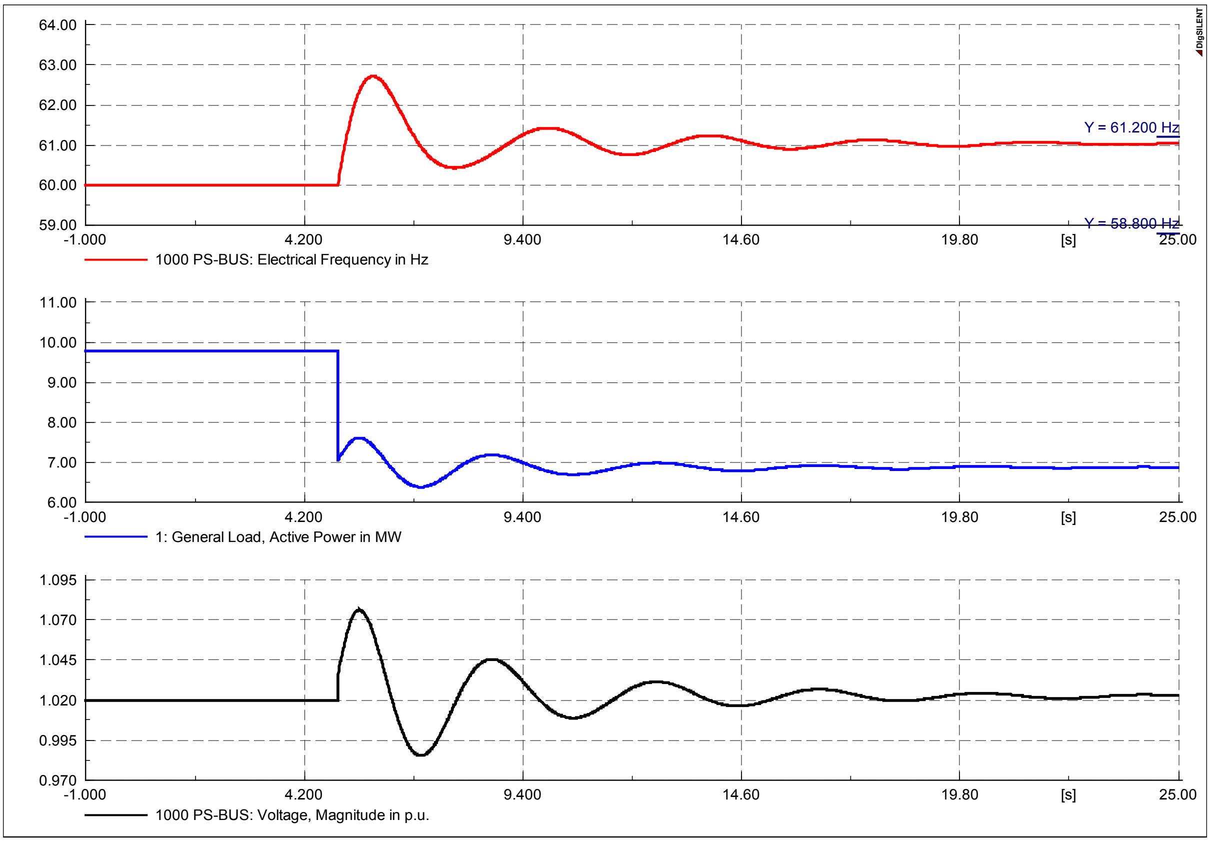


Upon the loss of the second largest generator, the system frequency falls to around 58 Hz which is below the allowable frequency deviation limit of 2%. The frequency oscillates across lower limit of 58.8 Hz several times within the duration of the study however the system remains stable. The voltage dips to 0.97 pu when the generator is lost but recovers and begins oscillating around nominal within 2 s.

Loss of second largest feeder

The largest loaded feeder (feeder with the largest load demand) in the system is Feeder 2. The system could not cope with the loss of this much load rejection and so the loss of the second largest feeder, Feeder 1 (circuit “1000_1010_1A”) was still studied. The feeder was tripped and the voltage and frequency responses are shown in Figure 2-11. The generation mix assumed in this case is the portfolio as presented in Table 2-6.

Figure 2-11: Voltage & frequency response to loss of second largest feeder



The feeder is tripped at 5 s and the frequency increases from 60 Hz to reach 62.6 Hz initially, which is in excess of the 2% allowable frequency deviation limit. The frequency then settles around 61 Hz after approx. 10 s. Prolonged operation at this frequency may activate over-frequency mitigation measures, such as generator over-frequency protection. The voltage remains within the acceptable ±10% limits throughout the event, peaking at 1.07 pu.

Three phase fault & subsequent tripping of demand feeder

As before, simulating a fault followed by a trip on the largest demand feeder was not feasible for this network and so the second largest feeder is studied here. A three-phase fault was applied on the feeder and cleared within 150 ms at which point the circuit was tripped off. The voltage and rotor angle responses of the connected generators to these events are shown in Figure 2-12 and Figure 2-13 respectively.

Figure 2-12: Voltage and frequency response to fault and subsequent feeder trip

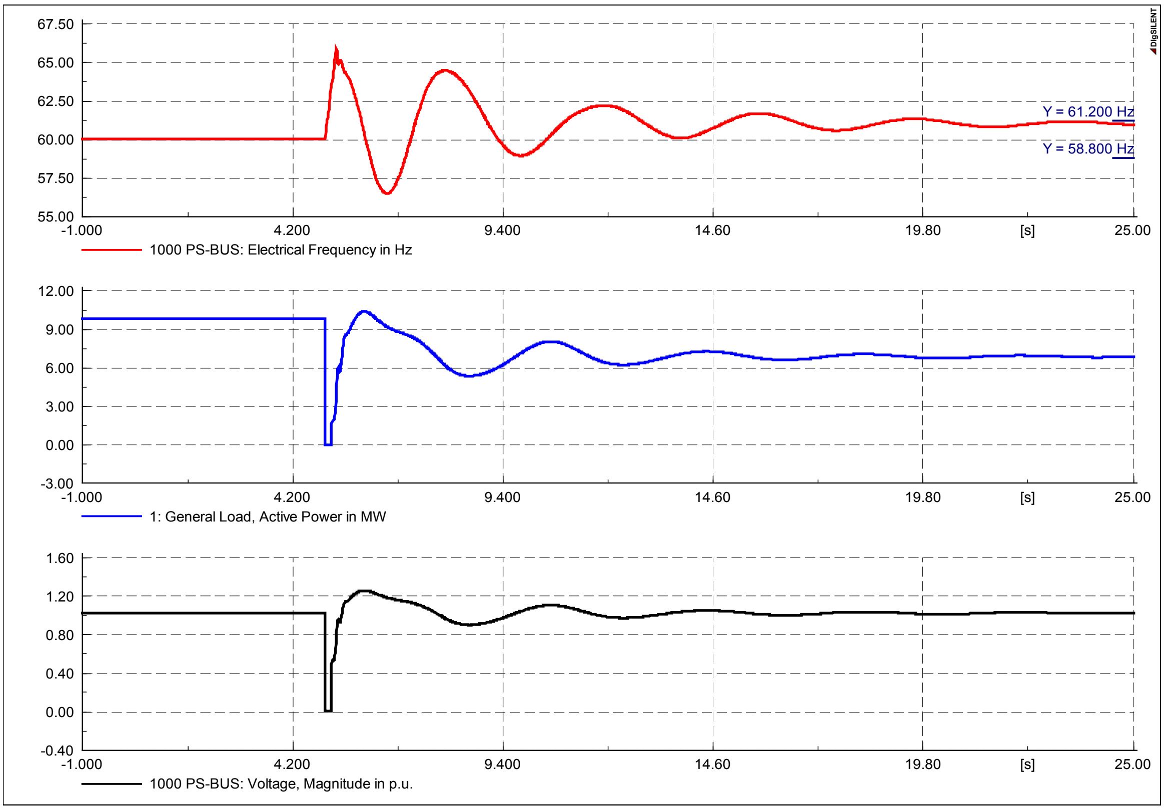
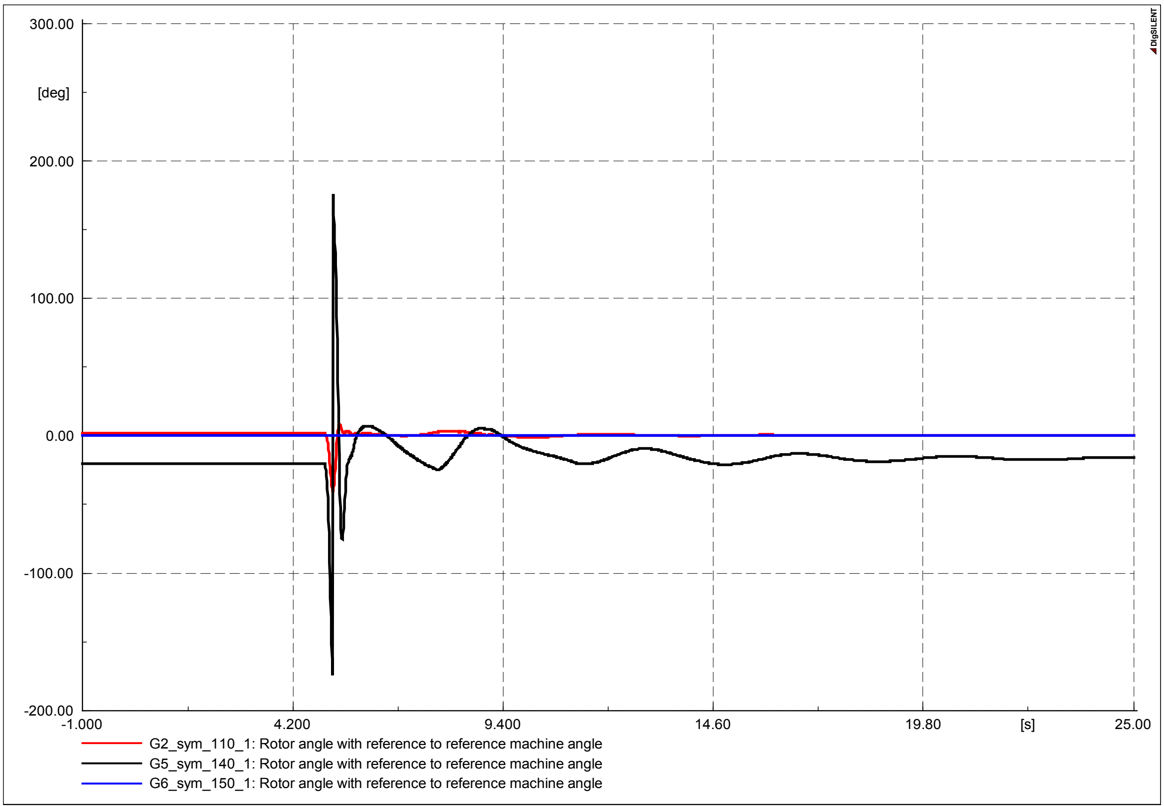


Figure 2-13: Rotor angle response to fault and subsequent feeder trip

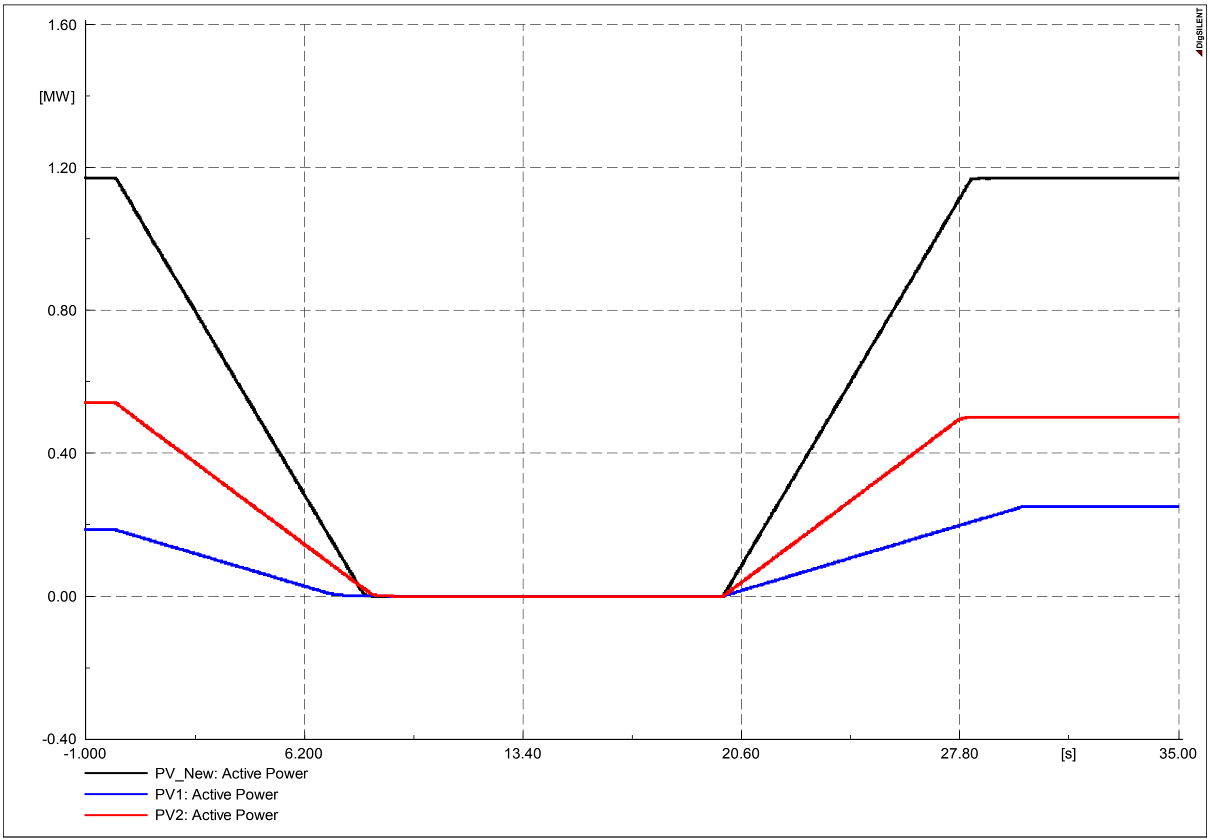


Immediately after the fault, the voltage at the monitored bus (power station busbar) drops to 0 pu. Upon the tripping of the circuit, the voltage recovers very quickly (within a few milliseconds), however it peaks above 1.2 pu before oscillating slightly and returning to nominal value after 10 s. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event. System frequency, however, peaks above the 2% allowable limit at over 65 Hz at the time of the fault/feeder trip and then drops to 57 Hz before swinging to 64.8 Hz. The frequency continues to oscillate and exceeds the higher limit of 61.2 Hz, damping out towards the end of the study period. Overall stability is maintained on the system.

Reduction/increase of PV output to/from maximum/0MW

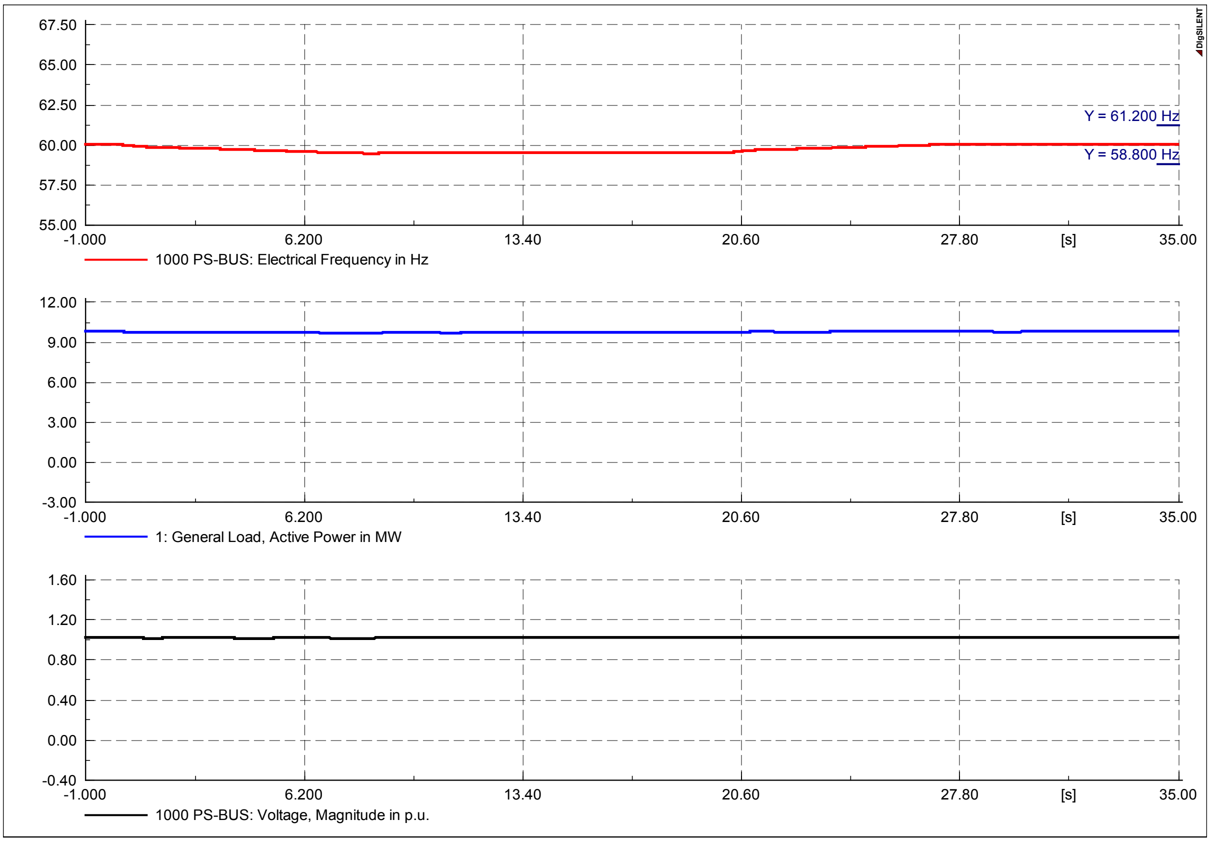
The voltage and frequency response to changing solar PV output on the connected generation on the Majuro network is presented below. The PV sites were assumed to be operating at the specified output before being simultaneously reduced to 0 MW, and then returning to the initial MW output after 20 s. The PV output is shown in Figure 2-14.

Figure 2-14: PV MW output of all sites on Majuro



The voltage and frequency responses are shown in Figure 2-15.

Figure 2-15: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases accordingly and then increases when the generators ramp up again to maximum output. The frequency remains within the 2% limit throughout the duration of the study. The voltage fluctuates in line with the changes in active power and frequency but stays around nominal.

The impact of the changing PV output does not have a significant impact on the overall operation or stability of the system. This indicates that the system is capable of withstanding the ramping down and ramping up of 1,894 kW PV generation in this scenario. Sufficient spinning reserve capacity in this scenario plays an important role to maintain system frequency within the 2% limit.

2.2.4.2 40% renewable generation contribution

The following sections present the results which highlight the ability of the Majuro network to operate with 40% of its generation contribution being provided by VRE, in this case solely from PV generation. The total generation mix assumed for this and subsequent studies is listed in Table 2-7 where the operational conventional generation is assumed to be operating at a reduced output to allow for the provision of spinning reserve and the maximum demand has been scaled up accordingly.

Table 2-7: Generation mix on Majuro with 40% renewable generation contribution

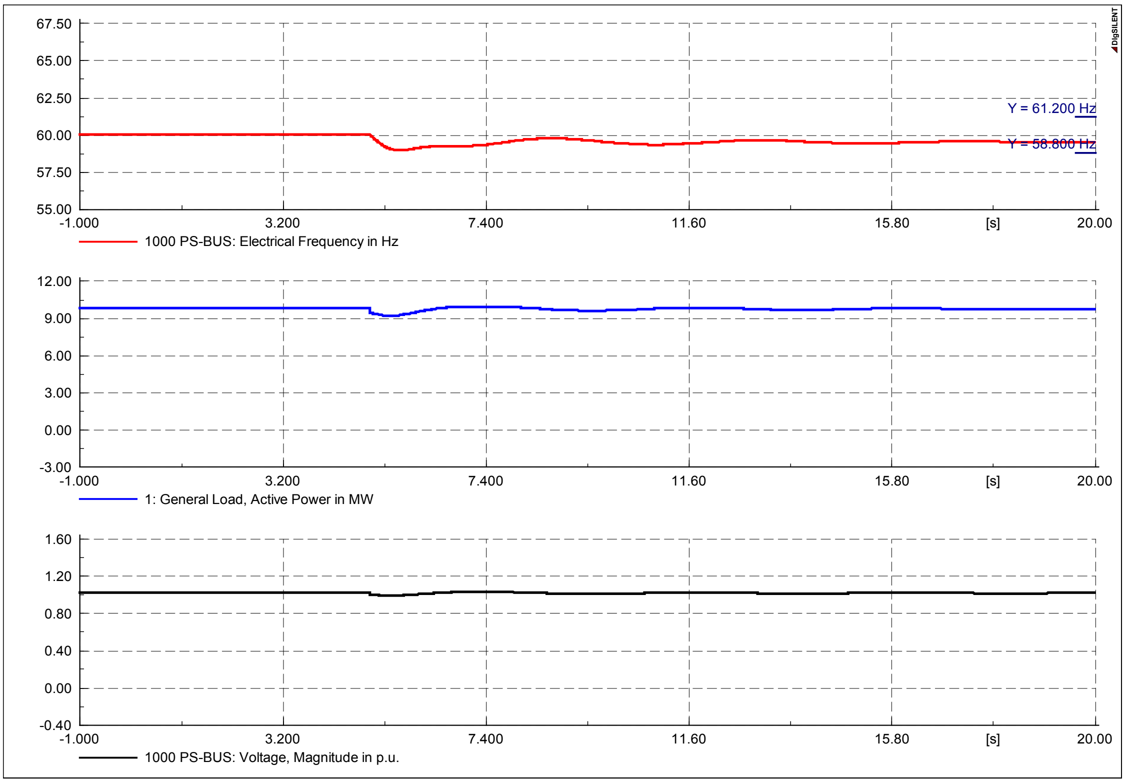
Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel	DG6	2	1	4800.0	1200.0	46.6%
	DG7	2	0	0.0	0.0	0.0%
	DG1	3	0	0.0	0.0	0.0%
	DG2	3	1	1025.5	1374.5	53.4%

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
	DG3	3	0	0.0	0.0	0.0%
	DG4	3	0	0.0	0.0	0.0%
	DG5	3	1	0.0	0.0	0.0%
	Sub-total			**5825.5**	**2574.5**	
	PV 1	1	1	184.5	0.0	0.0%
Renewable	PV 2	1	1	540.0	0.0	0.0%
	New PV	1	1	3150.0	0.0	0.0%
	Sub-total			**3874.5**	**0.0**	
				9700.00	**2574.50**	**26.5%**

Loss of second largest generator

There are three diesel generators operating in the generation dispatch scenario detailed in Table 2-5. The loss of the largest generator, DG6, will result in system frequency collapse. As such, the second largest generator was tripped to assess the capability of the network to withstand this credible contingency. The voltage and frequency responses of the system to this event are shown in Figure 2-16.

Figure 2-16: Voltage & frequency response to loss of second largest generator

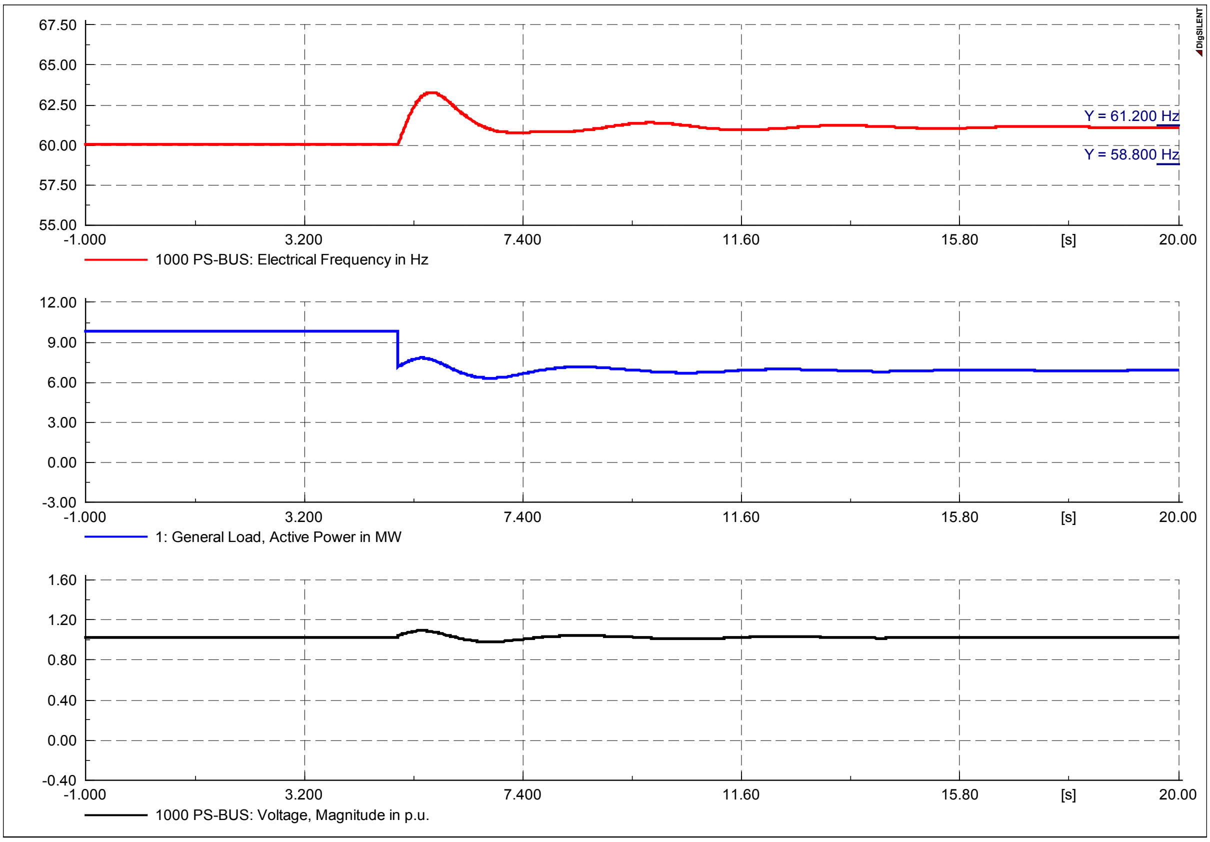


Upon the loss of the largest generator, the system frequency falls to around 58.8 Hz, remaining just within the allowable frequency bandwidth for operation in contingency situations. The frequency increases up to closer to 60 Hz and the system remains stable for the remainder of the study. The voltage dips slightly when the generator is lost but recovers to nominal within 2 s.

Loss of second largest feeder

The largest loaded feeder (feeder with the largest load demand) in the system is Feeder 2. The system could not cope with the loss of this much load rejection and so the loss of the second largest feeder, Feeder 1 (circuit “1000_1010_1A”) was studied. The feeder was tripped and the voltage and frequency responses are shown in Figure 2-17. The generation mix assumed in this case is the portfolio as presented in Table 2-7.

Figure 2-17: Voltage & frequency response to loss of second largest feeder



The feeder is tripped at 5 s and the frequency increases from 60 Hz to reach 63 Hz initially, which is in excess of the 2% allowable frequency deviation limit. The frequency then settles around 61.2 Hz after approx. 5 s. Prolonged operation at this frequency may activate over-frequency mitigation measures, such as generator over-frequency protection. The voltage remains within the acceptable ±10% limits throughout the event.

Three phase fault & subsequent tripping of demand feeder

As before, simulating a fault followed by a trip on the largest demand feeder was not feasible for this network and so the second largest feeder is studied here. A three-phase fault was applied on the feeder and cleared within 150 ms at which point the circuit was tripped off. The voltage and rotor angle responses of the connected generators to these events are shown in Figure 2-18 and Figure 2-19 respectively.

Figure 2-18: Voltage and frequency response to fault and subsequent feeder trip

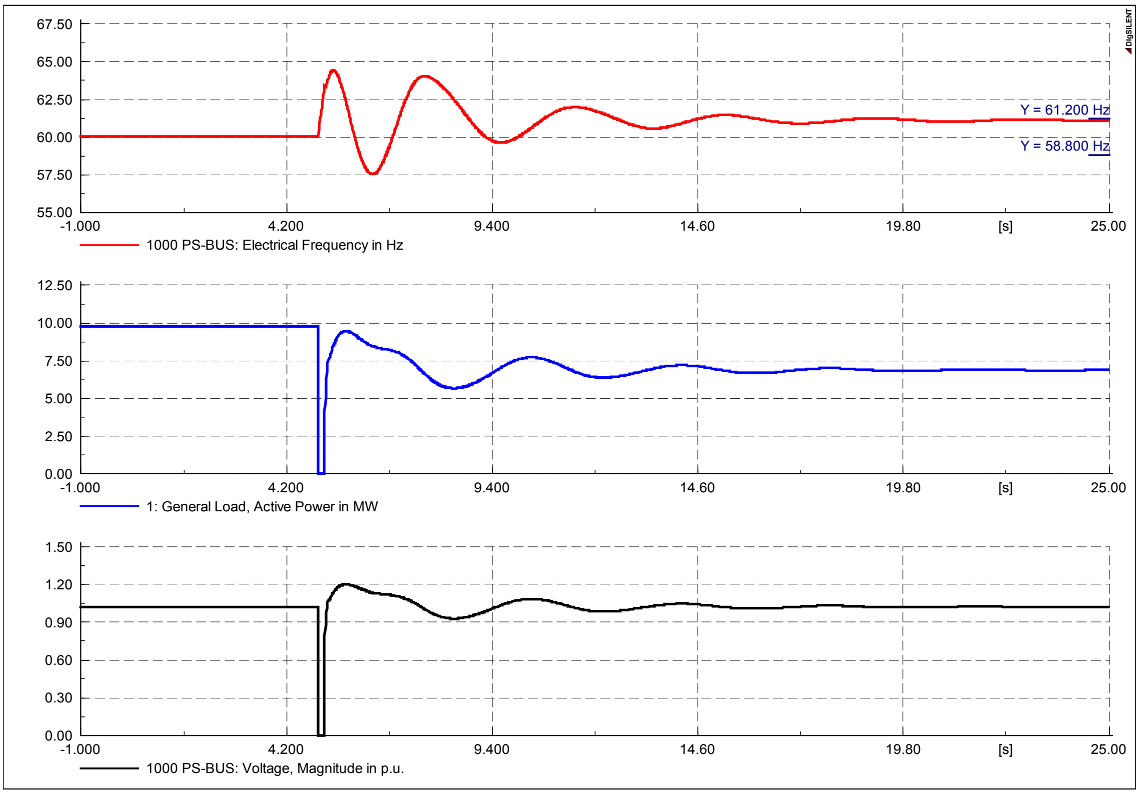
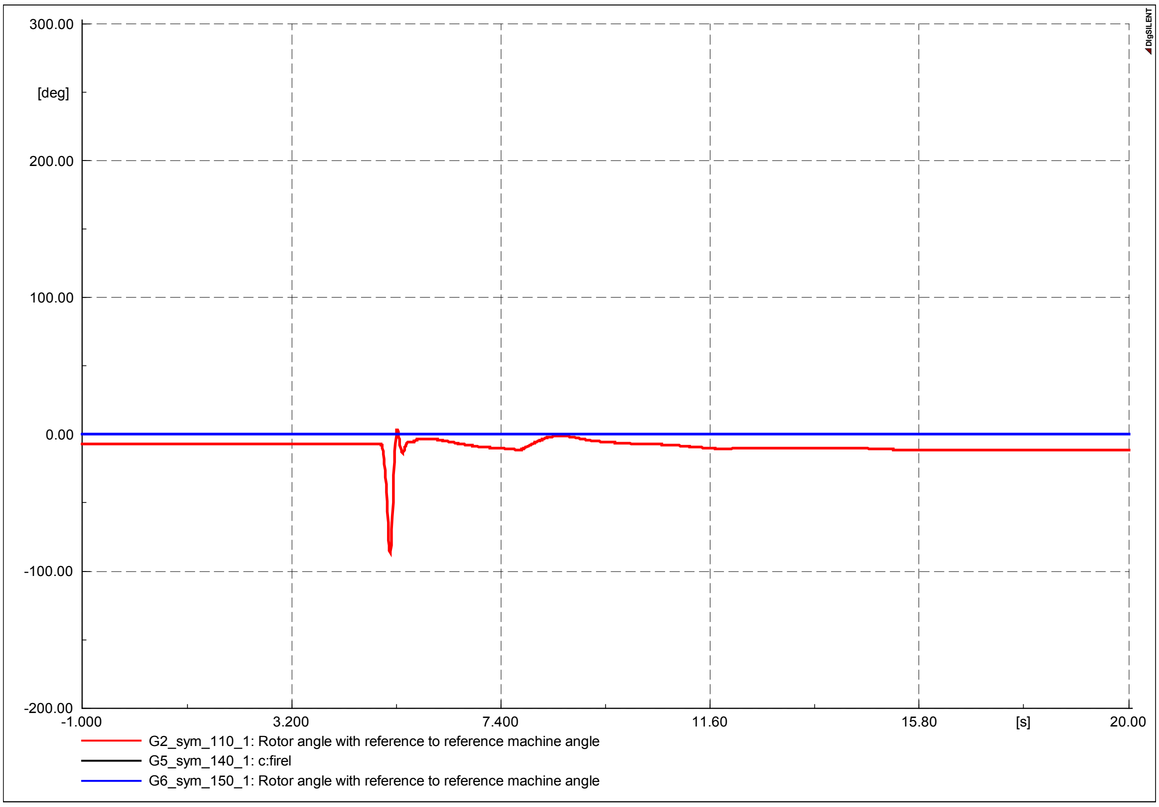


Figure 2-19: Rotor angle response to fault and subsequent feeder trip

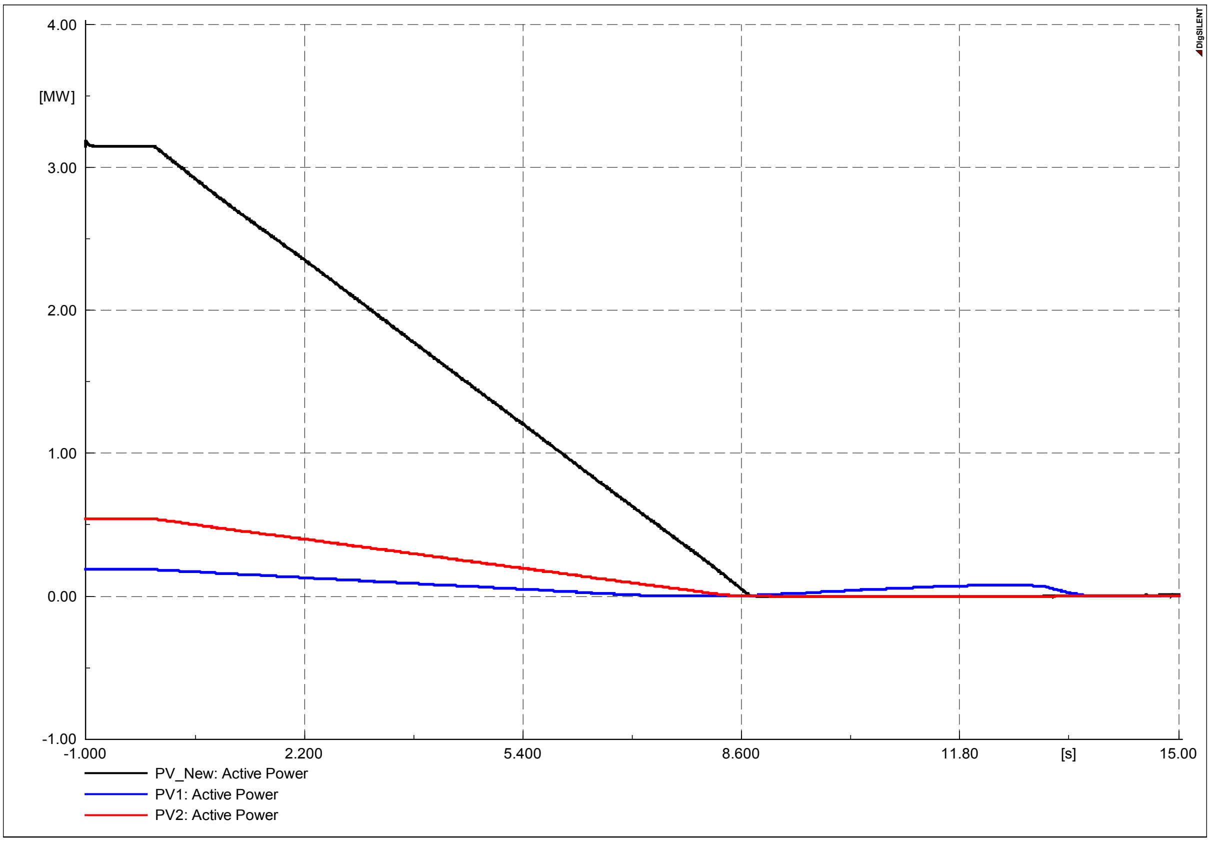


Immediately after the fault, the voltage at the monitored bus (power station busbar) drops to 0 pu. Upon the tripping of the circuit, the voltage recovers very quickly (within a few milliseconds), however it peaks above 1.2 pu before oscillating slightly and returning to nominal value after 10 s. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event. System frequency, however, peaks above the 2% allowable limit at 64 Hz at the time of the fault/feeder trip and then drops to 57.5 Hz before swinging to 63.5 Hz then oscillating within the ±2% bandwidth, damping out towards the end of the study period. Overall stability is maintained on the system.

Reduction/increase of PV output to/from maximum/0MW

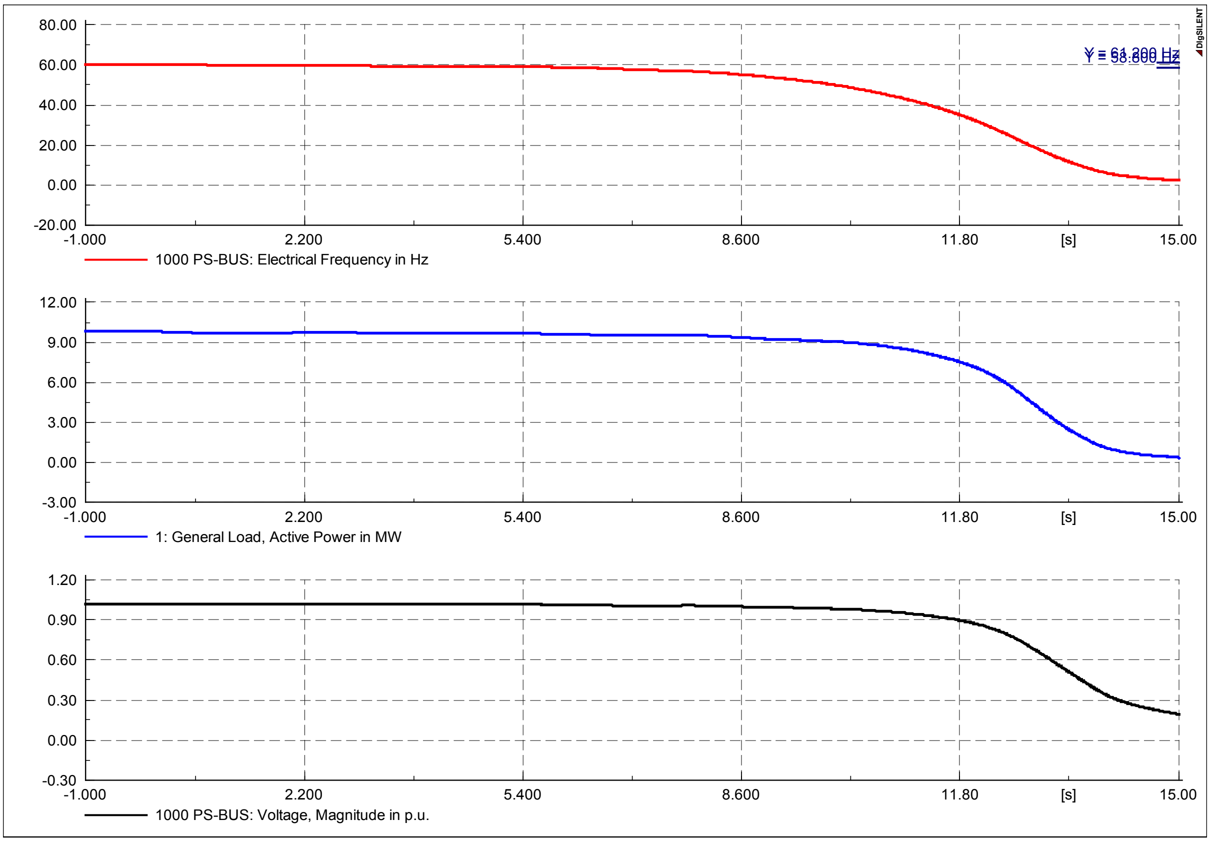
The voltage and frequency response to changing solar PV output on the connected generation on the Majuro network is presented below. The PV sites were assumed to be operating at the specified output before being simultaneously reduced to 0 MW, and then returning to the initial output after 20 s. The PV output is shown in Figure 2-20.

Figure 2-20: PV MW output of all sites on Majuro



The voltage and frequency responses are shown in Figure 2-21.

Figure 2-21: Voltage and frequency response to changing PV MW output



As seen from Figure 2-20 and Figure 2-21, the system is unable to maintain stability when such a large proportion (40%) of the generation mix is lost simultaneously. The system frequency collapses as the MW output of the PV generators decreases and it cannot recover.

2.2.5 Summary of power system study results

The results presented in the previous sections show that under normal operating conditions i.e. maximum and minimum demand, the network has no thermal issues with capacity to accommodate load growth. There are some low voltage issues on the 4.16 kV network in the maximum demand case that need be addressed to improve network performance and reduce losses.

The fault level studies show that the maximum expected fault levels on this network are reasonable for the individual voltage levels however it is recommended that these are checked against the installed switchgear ratings to ensure safe operation.

The stability studies performed as part of this study highlighted some operational constraints of the existing system, as well as when penetrations of VRE are increased. The existing system remains stable, however the voltage and frequency do exceed acceptable limits in most cases. The generation mix is compromised as several of the diesel generators are out of service and the remainder must supply the load and provide spinning reserve. It is this which compromises the ability of the system to remain stable following a significant event.

Two levels of increased solar PV penetration have been studied and their stability and responses are summarised in Table 2-8.

Table 2-8: Summary of Stability Studies with increasing penetrations of VRE

Study	Existing System	20% PV contribution	40% PV contribution
Loss of second largest generator	Out of limits (f)	Out of limits (f)	On limit
Loss of second largest demand feeder	Out of limits (f)	Out of limits (f)	Out of limits (f)
Fault at power station & subsequent loss of feeder	Out of limits (f), (v)	Out of limits (f), (v)	Out of limits (f), (v)
Increase/Decrease PV response	OK	OK	System Collapse

The system is not able to maintain stability following the loss of the largest generator nor of the largest feeder. As such the studies were carried out for the second largest generator and second largest demand feeder. The frequency of the system exceeds the limits in most cases studied for the loss of the second generator, although overall stability is maintained.

The system is able to maintain stable subsequent to the loss of the second largest demand feeder in all cases, however, the frequency deviation exceeds the 2% limits. In all scenarios, including the existing network, the system frequency is exceeded immediately following a fault on the largest demand feeder, and there are some oscillations outside the limits following the tripping of the feeder. Though these excursions do not impact the overall stability of the system, mitigation should be provided to minimise this. It is recommended that the system be made more robust in order to cope with this credible contingency event.

The system response to the ramping down/ramping up of the connected solar PV generation shows that the system is capable of managing the temporary loss of all PV output presently and with 20% of the generation being provided by renewables. Increasing this to 40% compromises the ability of the system to remain stable and the amount of spinning reserve is insufficient to manage the substantial loss in PV generation.

2.2.6 Recommendations for the present and future scenarios

The Majuro network has a small penetration of renewable generation, 805 kW, currently connected to the system which makes up about 2.5% of the installed capacity (but 4.5% of available capacity). There are plans to connect more solar PV to the network in the coming years and two scenarios have been studied here to understand the ability of the network to accommodate increasing penetrations.

Increasing levels of VRE penetration have been studied to understand how the network will withstand the changing generation mix. Overall, the system is not significantly impacted by increasing the contribution from solar PV generation to 20% of the total generation dispatch, however increasing this to 40% greatly alters the systems capability to recover from the loss of PV. The issues with the existing system are exacerbated by the inability of several of the diesel generators to operate.

It is recommended to improve the existing system robustness such that it responds more stably to the credible contingencies studied here, both now and in future as VRE connection increases. Various methods of improving system resiliency are available e.g. changing the generation dispatch (improving or replacing existing generators) to maximise spinning reserve, connecting battery storage, etc.

3 Task 2: Assessment of energy storage applications in power utilities

3.1 System studies on energy storage for frequency support

The prime objective of this task is to identify, assess and benchmark suitable storage solutions for frequency support, which would facilitate the deployment of variable renewable energy sources reviewed in task 1. The assessment and the benchmarking activity considers technical as well as economic and financial aspects of proposed solutions and configurations.

The analysis of storage requirements directly feeds from the dynamic modelling in Task 1 plus additional information required to determine the times of under / oversupply and uncertainty in forecasting renewable resources in real time to balance the power system.

The costs of wind and solar generation have decreased dramatically over the last decade, and the performance in terms of efficiency and reliability has steadily improved, making these viable sources of electricity, especially for grids that have in the past relied solely on diesel generators. If these renewable technologies could be integrated into an existing grid, consumers would generally experience an immediate benefit through a reduction in the amount of diesel consumed. However, the power produced by VRE is intermittent because the energy in the wind and solar radiation varies depending on the weather conditions. The operating frequency of electricity networks is a function of the balance of supply and demand, so grids must be able to control the frequency with varying supply from VRE.

The balancing of supply and demand has become one of the critical limiting factors in the increase of wind and solar generators for grids. Dynamic stability aspects of the network, such as voltage and frequency control, require fast response from generators, storage facilities and/or demand-response to match changes in demand. High-speed diesel engines can have the capability to respond to such changes within seconds. The Pacific Islands already show evidence that the fast response of high-speed diesel engines allows for very high instantaneous penetrations of renewable power in networks.

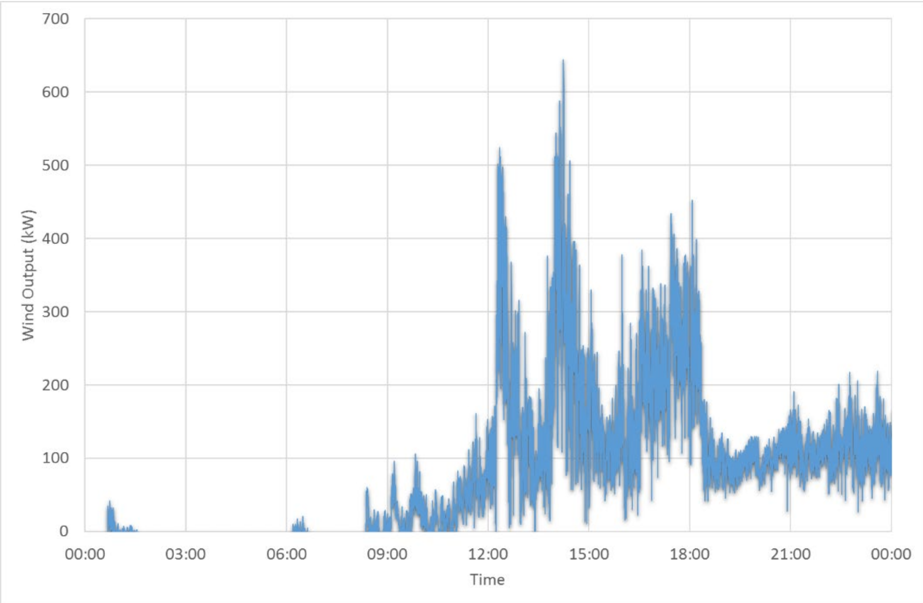
Fast frequency response within seconds or even fractions of a second can also be obtained from non-traditional sources including lithium-ion batteries, flywheels, and demand-response with thermal storage. Each of these sources can react to restore the balance of power but each has its limitations. Batteries respond very quickly but the relationship between the “number of cycles” and “depth of discharge” needs to be managed to optimise the useful life. Flywheels can respond very quickly but cannot sustain their response. Similarly, demand-response with thermal storage can be fast, but in a small grid is normally only available for short periods at a time. Owing to reductions in capital costs in recent years, lithium-ion batteries are becoming the most popular solution for small grids, but they need to be carefully selected, adequately sized and correctly installed.

The studies done here are to examine the current performance of the diesel generators and batteries in Majuro and the technical limit with the economic impact for increasing solar power.

3.1.1 Wind and Solar intermittency

Continuous fluctuations in supply from VRE is normally termed “intermittency”. Wind variations are mainly due to fluctuations in the wind speed and direction, while solar PV mainly varies due to shadowing from clouds and changes in daylight hours through the course of the year. Figure 3-1 shows the intermittent output from a wind turbine measured every second over the course of a day at Aleipata, Samoa, as an example.

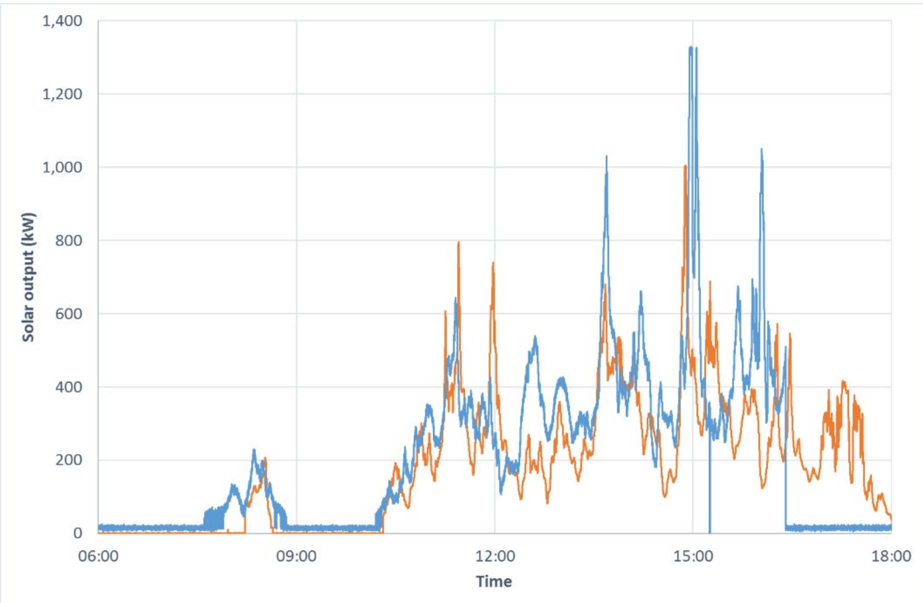
Figure 3-1. Wind power for recorded on 10 December 2016 at Aleipata



In a large grid with significant installed generation capacity, the grid-connected VRE plants can be located far away from each other to mitigate the effects of the variability of wind and solar irradiance, but for small grids, this is often not possible due to the small area that they serve. In addition, small grids may only have one wind turbine, so short-term variations in wind conditions have a more severe effect on the grid than in a grid where multiple turbines that are geographically spread.

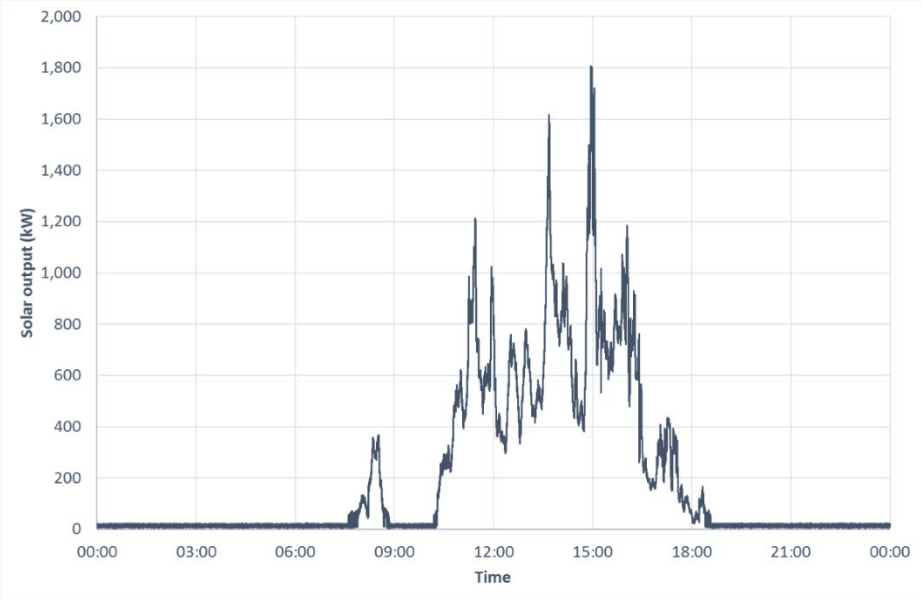
Figure 3-2 shows the individual outputs (measured at one second intervals) from two solar PV plants that are approximately 1 km apart.

Figure 3-2. Individual outputs from 2 Solar PV plants located 1 km apart



It seems that the two plants are exposed to the same cloud cover at the same time, but the combined output (Figure 3-3) shows there is not an exact correlation between the outputs of the two solar plants and the overall output is smoother than what would be obtained by doubling the output of the one farm.

Figure 3-3. Combined output of two solar plants 1 km apart (Source: Project confidential).



For fast frequency control, however, the plants do show a difference in response which reduces the overall ramp rate required to balance the system.

The models developed in Task 1 are used to determine the impact of disturbances (e.g. loss of a generation unit, distribution line) on frequency and voltage control. Task 1 identifies the maximum penetration of variable renewable resources for a selection of energy mix scenarios.

The studies conducted in Task 2 determine suitable solutions for short-term dynamic stability. In particular, the analysis determines the most suitable solution meeting minimum system stability requirements, while minimising system operating costs (e.g. storing long-term energy for later in the day/night).

A wide range of technologies has been considered including the use of batteries for frequency support and use of AGC (Automatic Generation Control). AGC provides techno-economic control where frequency control is not only based on the security of supply but also based on economic criteria.

These options have been modelled in the GDAT model and the results have been stated in the sections below.

This section focuses on the technologies for frequency support. Diesel generators have the capability to ramp up quickly and this could be in seconds or minutes depending on the nominal speed of the unit. The high-speed diesel units have the capability to ramp faster than the slow speed units.

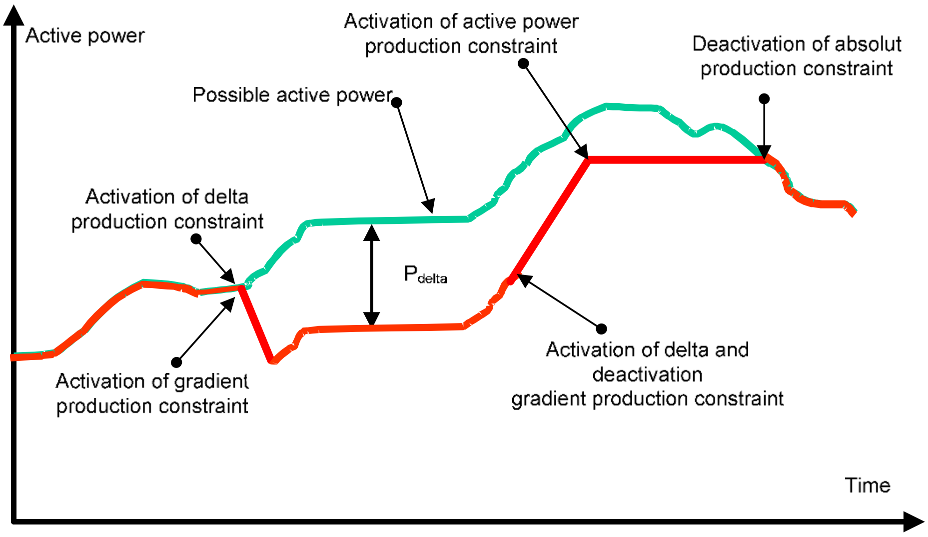
At present, a number of non-traditional sources are commercially available for frequency control/support and these sources include the use of Variable Renewable Energy (VRE) Sources, Fly-wheels, Synchronous Condensers and Batteries. More details of each of these resources and associated costs are as provided in the next sections.

3.1.2 VRE enhanced frequency control provision and calculation of costs

Enhanced frequency control provision can be provided by wind and solar farms in 3 ways.

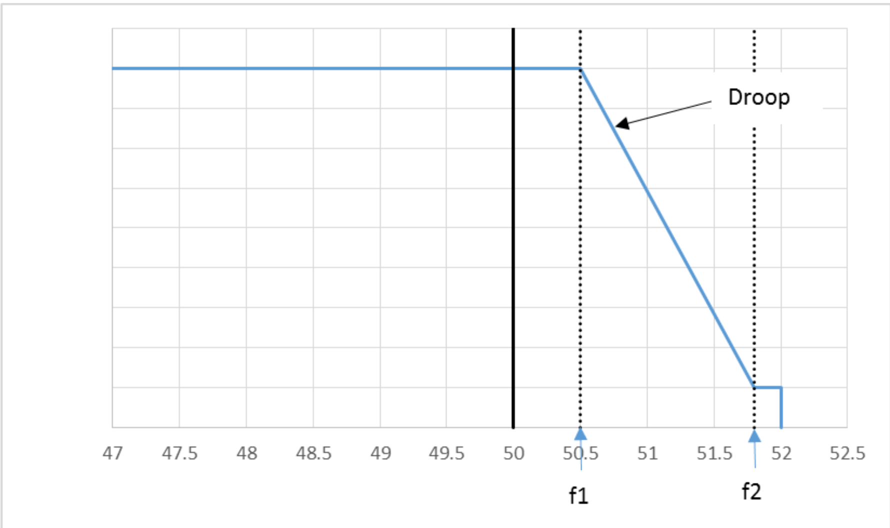
Option 1: The VRE plants are backed off from their full instantaneous maximum capacity, i.e. their outputs are limited. This is technically possible if the VRE plant control system can accept a set point from a central control system or a control philosophy is adopted in which the inverter is kept at an actual production, which is 5 - 10 percent below the maximum production (Figure 3-4) for primary frequency control purposes (Pdelta). The reduction in production of VRE plant will have to be replaced by diesel generation and so there would be a short run cost impact which would be in form of additional fuel costs. The average annual fixed costs (per kWh) for the VRE plant also increase as the generation is curtailed but there is no reduction in capital cost. Thus, if before implementing the scheme, the plant was generating at an average cost of $0.10 / kWh, after introduction of the scheme, the plant's average cost are increased to $0.11 / kWh as the scheme reduces the generator output by 10%.

Figure 3-4 Reducing wind and solar power plant to be able to provide frequency control



Option 2: VRE provides high-frequency response only – The VRE plant will only respond by decreasing instantaneous power when the frequency is high. Figure 3-5 shows the typical response required in grid codes and programmed into most small VRE inverters. This response is designed for security only and so that the VRE will start reducing their output if the frequency is above 0.5 Hz the nominal value. The reduction is linear to frequency change and a full response is required when frequency is 1.5 Hz above the nominal value.

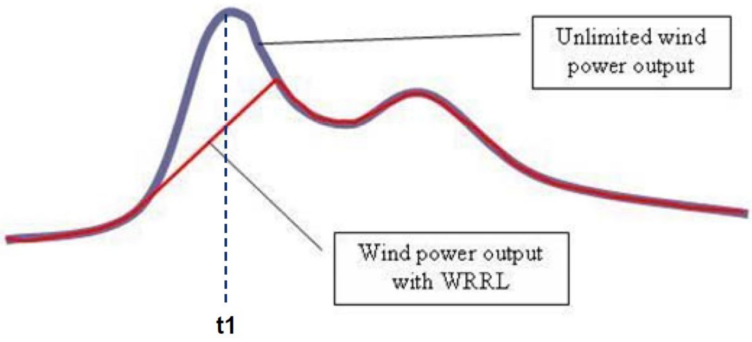
Figure 3-5 Typical VRE high frequency response only



Option 3: VRE ramp rate is limited – The VRE ramp rate is reduced to prevent frequency excursions. The up ramp on wind and solar can be easily limited in the inverter control logic. The ramp rate limitation is used worldwide to ensure wind and solar power plants do not ramp up too quickly. Ramp rates are generally not applied to domestic solar PV systems. This limitation prevents the wind / solar farm from producing full output and the amount of unused energy can be predicted. This essentially free energy that was lost and the cost can be calculated using the same method used Option 1 above. A down rate limiter can be provided to solar power plants using camera's to predict when clouds will cover the panels. The output is then reduced in a slower controlled ramp before the clouds actually cover the panels. This logic has not yet been applied to wind farms as it is difficult to predict future wind gusts

and lulls. Batteries can be used to control the VRE power plant ramp rate. The battery discharges power to soothe the down ramp and then charges to reduce the up ramp. This logic is applied to PV panels in Tonga. The use of batteries to control ramp rate on each power plant is suboptimal to using a central battery to controlling all the variation in all PV plants, simply based on the fact that all PV plants will not reduce at the same time and there is a netting effect.

Figure 3-6 Wind power output with wind ramp rate limit (WRRL)2



3.1.3 Fly Wheel and calculation of costs

The Flywheel principle is based on kinetic energy. The rotation speed contributes to Flywheels can spin within a range of 8,000 to 60,000 revolutions a minute. High-speed Flywheels are relatively small and possess a large energy capacity storage and because of the power electronics used the speed of the flywheel does not affect the electric frequency output of the installation. This result, in addition to the high energy capacity, also in a larger bandwidth the installation can deliver its energy.

Although at the moment there are many developments, the general specifications regarding 0.1 to 20 MW flywheels with a charge/ discharge time from 15 min to 1 hour.

Beacon Power has a demonstration plant in Hazle, PA, USA which consists of 200 flywheels each with a max power rating of 100 kW, 25 KWh, as shown in Figure 3-7, charge and discharge under commercial operation from July 2014[3]. Lifetime output of 100 kW flywheel is estimated to be 4.375 MWh. Beacon flywheel is estimated to be capable of 100,000 to 175,000 cycles (20 times that of batteries). The cost of installation was US$ 52.415M or US$ 2,600 / kW installed.

Various islands off the coast of Australia have installed flywheels as a form of energy storage to complement wind and solar PV systems. For example, the Flinders Island Hybrid Energy Hub features a single 900 kW wind turbine and 200 kW solar array. The storage systems include a 750 kW/300 kWh battery and an 850 kVA flywheel[4].

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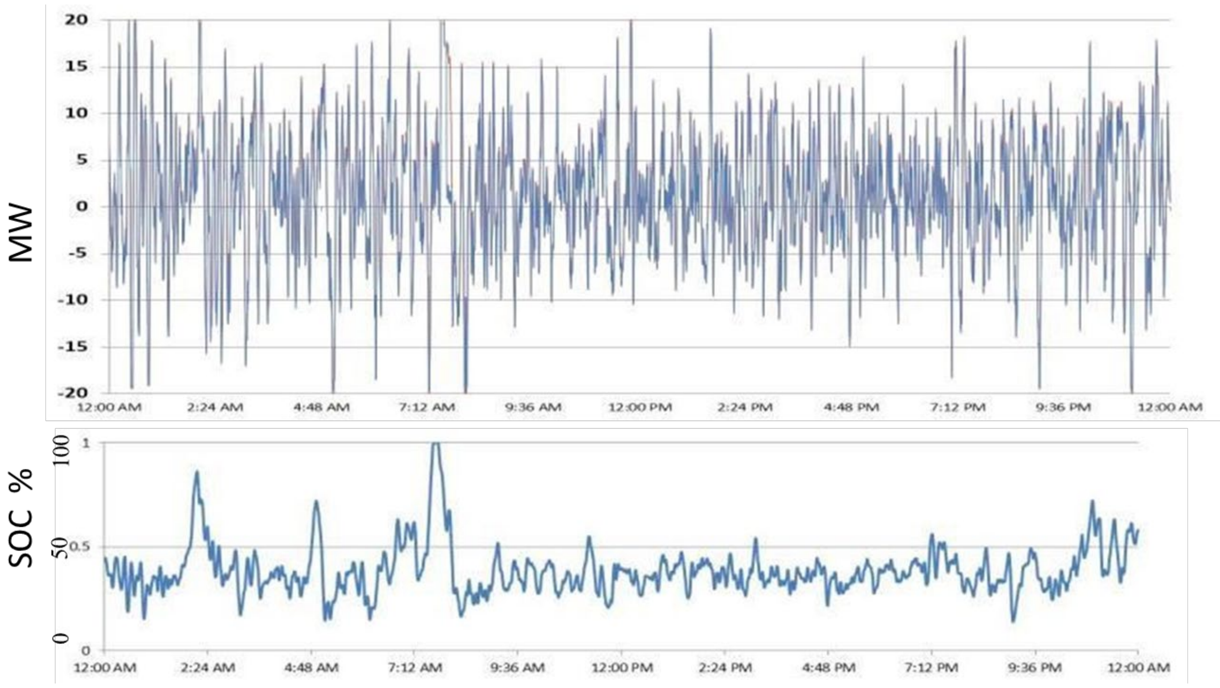
[2] AESO System Impact Studies, Phase 2 Assessing the impacts of increased wind power on AIES operations and mitigating measures, July 2006

[3] http://www.sandia.gov/ess/docs/pr_conferences/2014/Thursday/Session7/02_Areseneaux_Jim_20MW_Flywheel_Energy_Storage_Plant_140918.pdf

[4] Flicking the switch: (Hybrid) energy comes to Flinders Island. https://arena.gov.au/blog/flinders-island

Figure 3-7 Beacon Power installation in Hazle, PA, USA flywheel performance and state of charge (SOC)



3.1.4 Synchronous Condensers and calculation of costs

Synchronous condensers are synchronous electrical machines attached to the electricity grid that can provide inertia to the grid. Hydro and pumped storage units have compressors to empty the water from the water turbines. Hydro units have relative low speed with many poles to give the nominal frequency and the only friction is turbine blades running against air. The changing from Synchronous Condenser Operation (SCO) to generation on hydro units requires the air to be removed and input gates opened. This changeover is less than 2 minutes depending on the unit design. Gas turbines have clutches installed which disconnect the generator from the turbine. The clutch does require regular maintenance.

For Ireland, DNV KEMA notes that the conversion of non-profitable or deactivated power station is currently seen as the most cost-effective option for applying synchronous condensers[5]. Making an accurate cost calculation in general is not possible however, because depending on the existing installation the project will differ from unit to unit. Investments are relatively low when most of the existing infrastructure can be utilised (e.g. Step-up transformer, network infrastructures, buildings, auxiliary equipment and machinery, substations, etc.). In addition, the excitation and control and excitation itself may be changed, depending on the specific machine. The costs shown are therefore only a very rough indication.

General specifications:

- Energy consumption: 1 % – 4 % of the nominal power rating
- Inertia: approximately 1 sec.
- Response time: immediate
- Start-up time (if switched off): < 15 min.

The cost for converting the gas turbine to provide SCO operation is estimated to be US$100 / kW.

[5] System Service Provision - An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services, DNV KEMA Energy & Sustainability

3.1.5 Batteries and calculation of costs

The most feasible current battery technologies are Sodium Sulphur (NaS) and Lithium-ion (Li-ion) [6]. The latter has a far smaller power to energy ratio and therefore can be used for frequency response. Li-ion is thus a cheaper alternative as opposed to NaS regarding frequency response services. For peak shaving, however, and ultimately energy storage, NaS batteries are considered to be the better technology at the moment, having a power to energy ratio of approximately 1:8.

The proposed batteries have the following general characteristics:

- Energy efficiency: 95 % (Li-ion); 90 % (NaS)
- Ramp-up time: < 1 electrical frequency cycle period
- Load time: 2 min – 3 hours (Li-ion); 1 hour – 8 hours (NaS)
- Life cycle: > 4,500 load cycles

The capital costs for Li-ion batteries is US$750 / kWh[7] and for NaS US$2,200 /kWh[8]. The cost of inverter is estimated to be US$1,000 / kW[9].

Bloomberg estimates Li Ion batteries to be under US$ 200 / kWh[10] and a recent report from USTDA has batteries at US$375 / kWh and inverters at US$300 / kWh [11]

The capital cost for Samoa's current batteries of 8 MW and 13.6 MWh is $ 8.8 m for inverters and batteries. The estimated cost break down is $375 /kWh for batteries and US$ 500 / kW for inverters.

The estimated capital cost for batteries for Majuro of 2 MW with 2 MWh is $ 1.0 m for inverters and $0.75 m for batteries a total of $1,750,000. For a ten year life time of batteries and inverter, with a 2% interest on debt and fixed O&M of US$7.5 / kW[12], the annualised cost is $209,821 as shown by annuity calculator below:

Annuity Payout Calculator

Installed Capacity	2000	kW
	2	MW
Capital Expenditure	$ 1,750,000	USD
	1.75	m USD
Fixed Opex	$ 15,000	USD/year
Variable Opex	$ -	USD/hour
Energy Availability	99%	%
	-	USD/year
Life of the Plant	10	Years
Interest on Debt	2%	%
Interest on Equity	0%	%
Debt to Equity Ratio	1	%
WACC	2.00%	

Annual Payments		
Capital Payment	$ 194,821	USD
Fixed Opex	$ 15,000	USD
Variable Opex	$ -	USD
Total	$ 209,821	USD

Inputs in yellow

[6] System Service Provision - An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services, DNV KEMA Energy & Sustainability
[7] Energy Master Plans for the Federated States of Micronesia, Castalia, 2018
[8] System Service Provision - An independent view on the likely costs incurred by potential System Service Providers in delivering additional and enhanced System Services, DNV KEMA Energy & Sustainability
[9] Energy Master Plans for the Federated States of Micronesia, Castalia, 2018
[10] https://www.bloomberg.com/news/articles/2018-03-08/the-battery-will-kill-fossil-fuels-it-s-only-a-matter-of-time
[11] US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017
[12] US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017

The estimated capital cost for batteries for Majuro of 16 MW inverter and with 32 MWh of batteries is $20m with an annualised cost is $2,234,031 as shown by annuity payment calculator below:

Annuity Payout Calculator

Installed Capacity	1000	kW
	1	MW
Capital Expenditure	$ 20,000,000	USD
	20	m USD
Fixed Opex	$ 7,500	USD/year
Variable Opex	$ -	USD/hour
Energy Availability	99%	%
	-	USD/year
Life of the Plant	10	Years
Interest on Debt	2%	%
Interest on Equity	0%	%
Debt to Equity Ratio	1	%
WACC	2.00%	

Annual Payments		
Capital Payment	$2,226,531	USD
Fixed Opex	$ 7,500	USD
Variable Opex	$ -	USD
Total	$2,234,031	USD

Inputs in yellow

3.2 Generation Dispatch Analysis Tool (GDAT)

3.2.1 Introduction to GDAT

The Generation Dispatch Analysis Tool (GDAT) is a product in MATLAB© & Simulink©.

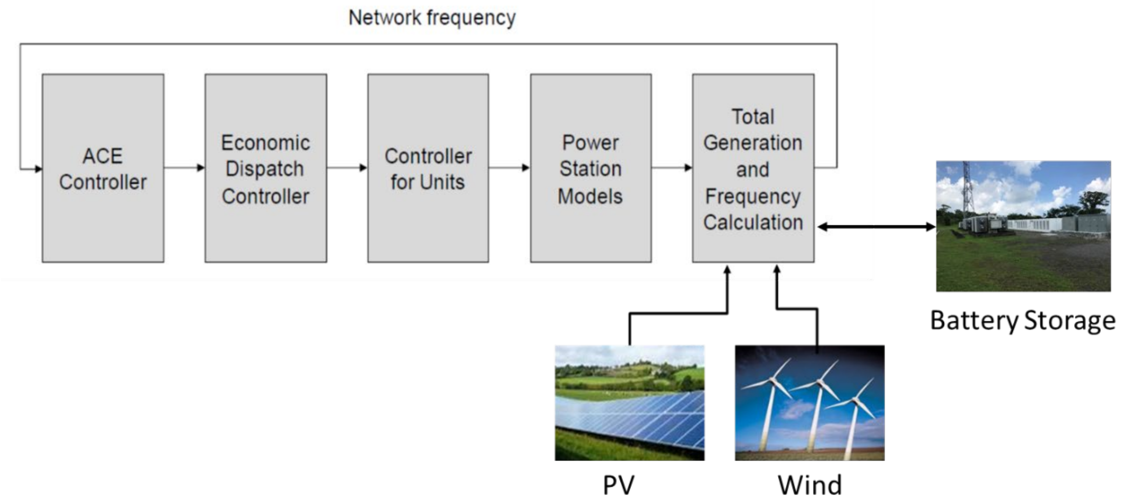
The Generation Dispatch Analysis Tool is used for four main purposes

1. Determining the benefits for controlling network frequency using primary (governor) and secondary (AGC) control options;
2. Analyse impact of non dispatchable renewable energy on frequency control;
3. Analyse the benefits of storage on frequency control;
4. Tuning Automatic Generation Controller;
5. System Operator controller dispatch performance analysis; and
6. System Operator dispatch audit.

The Generation Dispatch Analysis Tool was developed in 1998 for the optimisation of Automatic Generation Control settings for improved secondary frequency reserve, economic dispatch and interchange power control. From 2007 the tool has been refined for intermittent resources management and used for minute to minute wind farm integration studies in Mauritius and small island systems. The Generation Dispatch Analysis Tool has also been used for system operation studies and system operator audits in South Africa, Tanzania, Thailand and Abu Dhabi. Each of these systems are also analysing the impact of future renewable energy plants on minute to minute dispatch, as shown in Figure 3-8. South Africa has increased the wind and solar renewable penetration to nearly 10% of peak demand and South Africa for example is using the tool to analyse the impact of solar and wind projects on secondary frequency reserve. South Africa extensively uses pump storage for energy storage and the running of these power plants is required for secondary control when there is significant wind and solar power plants online. The power plants are required for energy storage but are more important for system security during the day to cope with rapid ramping required during the shoulder periods when solar is dropping off and demand is increasing.

The GDAT model for Majuro also includes battery storage systems for system security studies and for energy storage analysis.

Figure 3-8 Generation Dispatch Analysis Tool with wind and solar inputs added



The studies under taken in GDAT use original recorded generation, demand and frequency data from SCADA. The technical parameters for power plants such as ramp rates, network dynamics and frequency control capability are modelled. Additional constraints including spinning reserve, storage capability are also included. For Majuro, the studies are to determine the appropriate level of automatic control to ensure frequency control with increasing VRE with and without using batteries for frequency control and storage.

The user can select the options for the study, including which units to use for frequency control, controller settings, reserve levels, demand and power plant technical parameters.

GDAT calculates the resultant frequency with the various configurations of controller settings and also calculates the cost of dispatch from the cost curves entered into the model. The model is designed to commits and de-commits diesel units to ensure sufficient spinning reserve level without committing too many units.

The results from the studies therefore analyse the techno-economic benefits of the options selected to study. The technical limits for various control strategies and levels of VRE can be determined as well as the economic impact of each option studied.

3.2.2 Input data to GDAT for Majuro studies

The models developed for Majuro are based on hourly data records received for the period ending 31 January 2018. The real time PV data was obtained from recorded 2 second data from the reservoir where we have records for the 0.6 MW PV plant. For the Solar PV that is installed in town we have taken the PV records from reservoir for another ‘similar’ day and scaled this to 0.4 MW to account for hospital PV and other sites.

The weekend demand profile is taken from data provided by Majuro as recorded on Saturdays the 11 March 2017, shown in Figure 3-9, and 7 October 2017. The Saturday has a lower midday profile than the Sunday and hence is a worse case than the Sunday profile. The weekday demand profile is taken from data provided by Majuro as recorded on Thursdays 16 March 2017, as shown in Figure 3-10, and 5 October 2017:

Figure 3-9 Majuro demand profile for weekend recorded on 11 March 2017

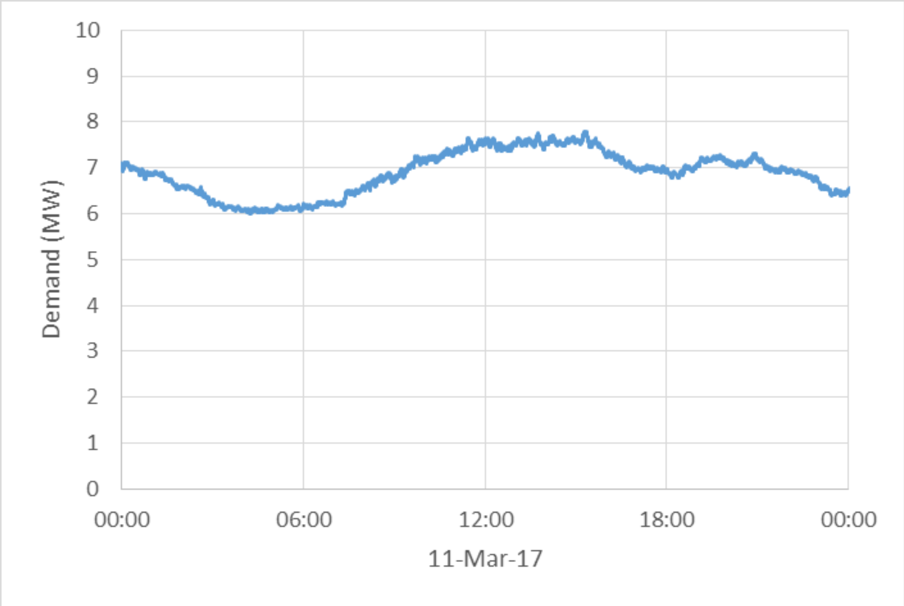
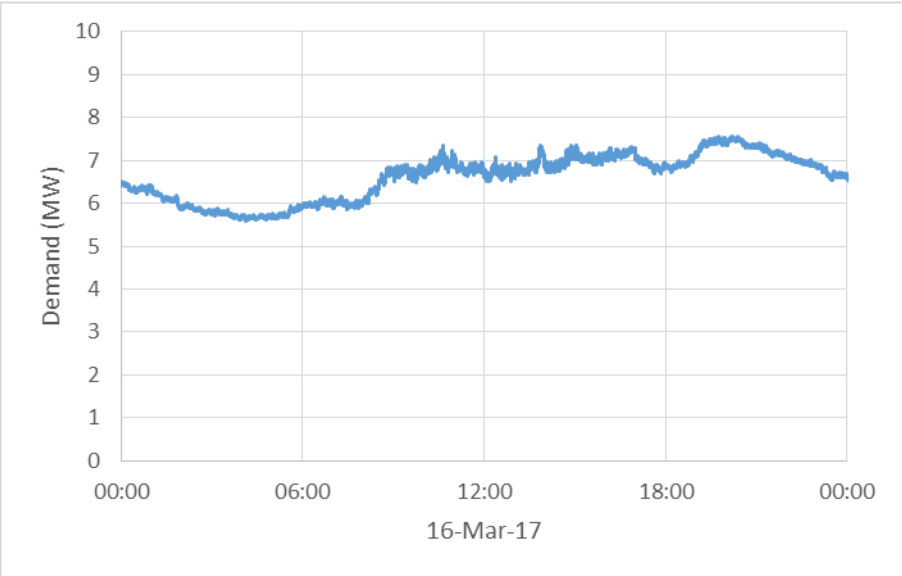


Figure 3-10 Majuro demand profile for weekday recorded on 16 March 2017



The names in the model are made generic to reflect that this is not the actual output of any specific unit as it are seen that the wind and solar outputs can be scaled to reflect an increase/decrease in wind or solar capacity.

Table 3-1: Generation and GDAT name for Generation Plants

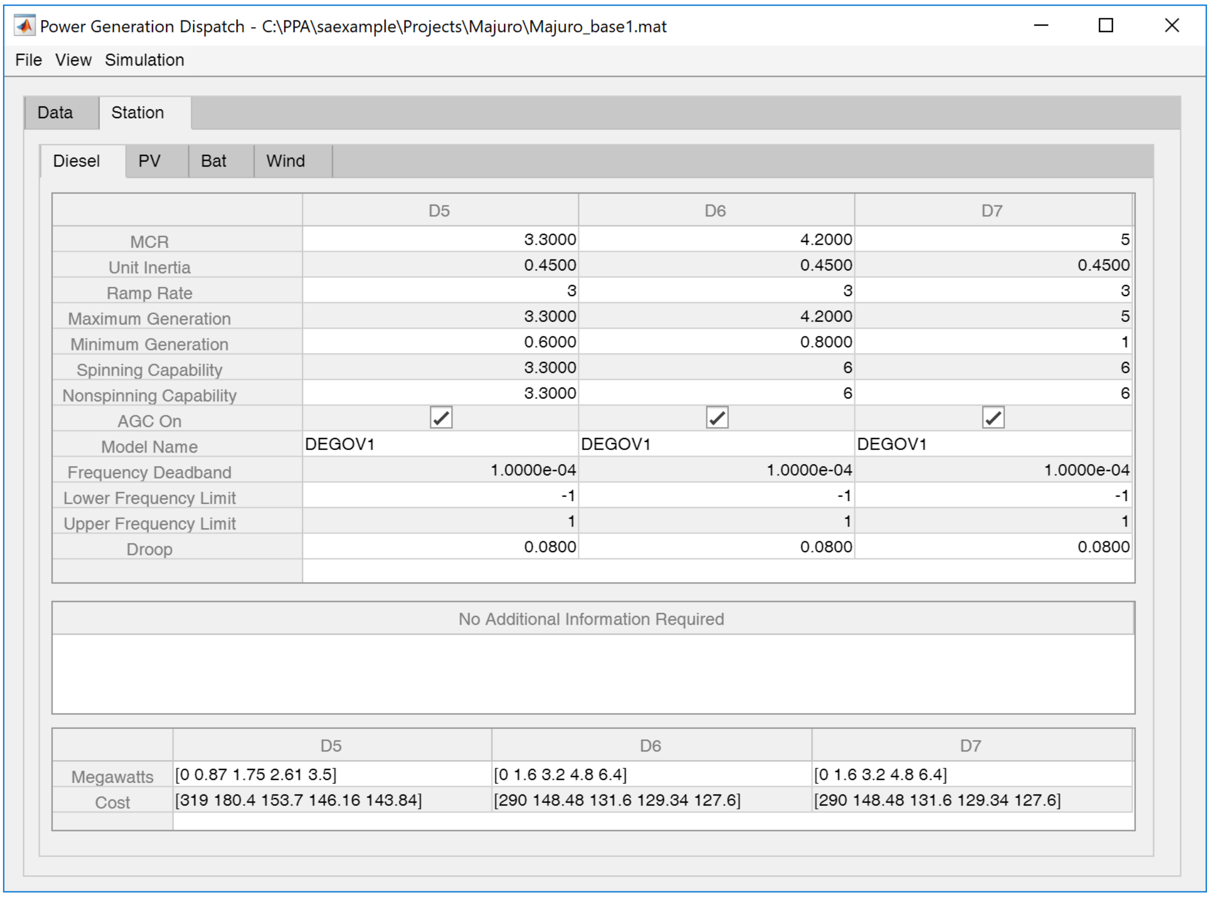
Name	Capacity (kW)	Type	GDAT name
D5	3300	Cat Diesel	D5
D6	4200	Duetz Diesel	D6
D7	5000	Duetz Diesel	D7
Reservoir	600	PV	PV1

Hospital	400	PV	PV2

A Wind Power Plant is added to the model "W1" but not utilised for these studies as it is understood there is no immediate plan for a wind farm.

Generation parameters used for inputs into the model for Diesel and PV power plants are shown in Table 3-2 and Table 3-3.

Table 3-2: Majuro diesel generation parameters

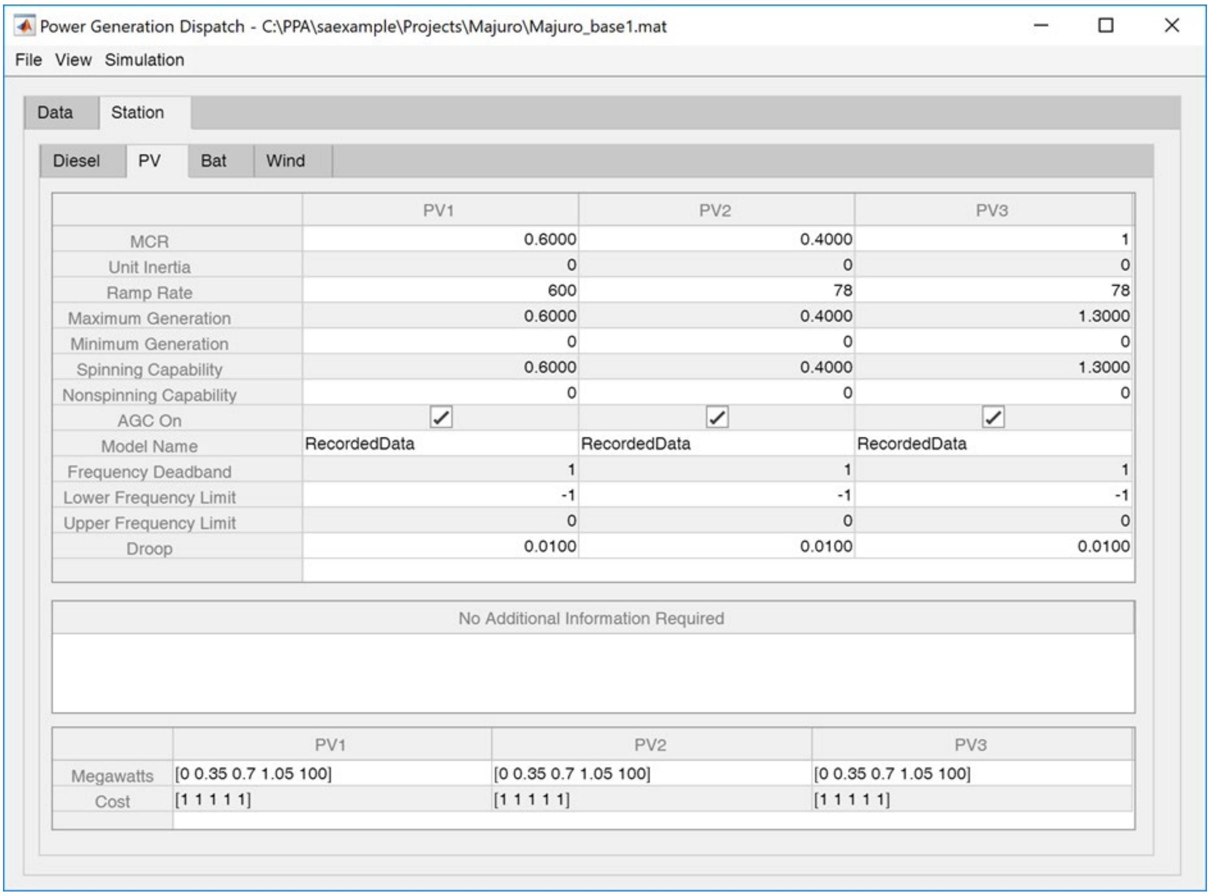


	D5	D6	D7
MCR	3.3000	4.2000	5
Unit Inertia	0.4500	0.4500	0.4500
Ramp Rate	3	3	3
Maximum Generation	3.3000	4.2000	5
Minimum Generation	0.6000	0.8000	1
Spinning Capability	3.3000	6	6
Nonspinning Capability	3.3000	6	6
AGC On	✓	✓	✓
Model Name	DEGOV1	DEGOV1	DEGOV1
Frequency Deadband	1.0000e-04	1.0000e-04	1.0000e-04
Lower Frequency Limit	-1	-1	-1
Upper Frequency Limit	1	1	1
Droop	0.0800	0.0800	0.0800

No Additional Information Required

	D5	D6	D7
Megawatts	[0 0.87 1.75 2.61 3.5]	[0 1.6 3.2 4.8 6.4]	[0 1.6 3.2 4.8 6.4]
Cost	[319 180.4 153.7 146.16 143.84]	[290 148.48 131.6 129.34 127.6]	[290 148.48 131.6 129.34 127.6]

Table 3-3: Majuro PV parameters



Power Generation Dispatch - C:\PPA\saexample\Projects\Majuro\Majuro_base1.mat

File View Simulation

Data | Station

Diesel | PV | Bat | Wind

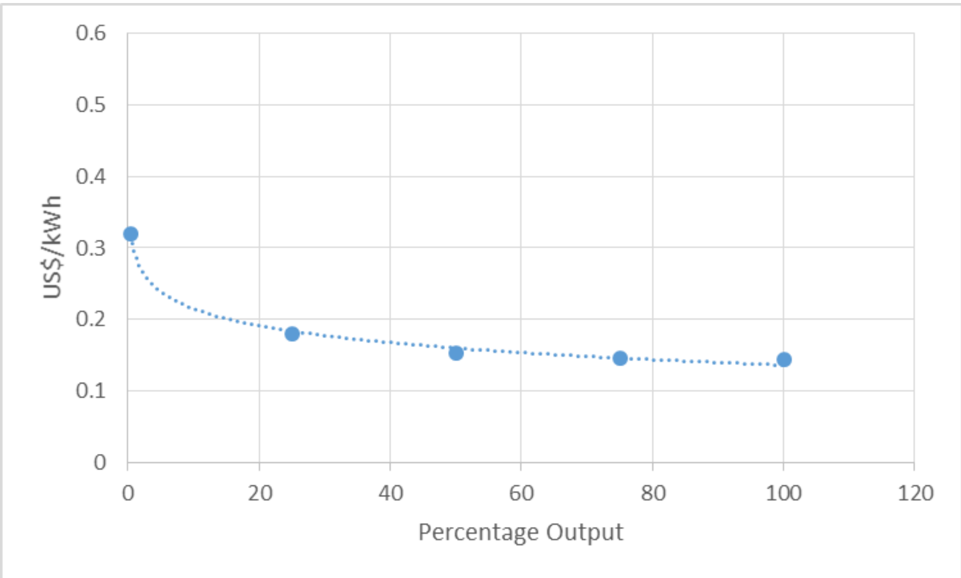
	PV1	PV2	PV3
MCR	0.6000	0.4000	1
Unit Inertia	0	0	0
Ramp Rate	600	78	78
Maximum Generation	0.6000	0.4000	1.3000
Minimum Generation	0	0	0
Spinning Capability	0.6000	0.4000	1.3000
Nonspinning Capability	0	0	0
AGC On	✓	✓	✓
Model Name	RecordedData	RecordedData	RecordedData
Frequency Deadband	1	1	1
Lower Frequency Limit	-1	-1	-1
Upper Frequency Limit	0	0	0
Droop	0.0100	0.0100	0.0100

No Additional Information Required

	PV1	PV2	PV3
Megawatts	[0 0.35 0.7 1.05 100]	[0 0.35 0.7 1.05 100]	[0 0.35 0.7 1.05 100]
Cost	[1 1 1 1 1]	[1 1 1 1 1]	[1 1 1 1 1]

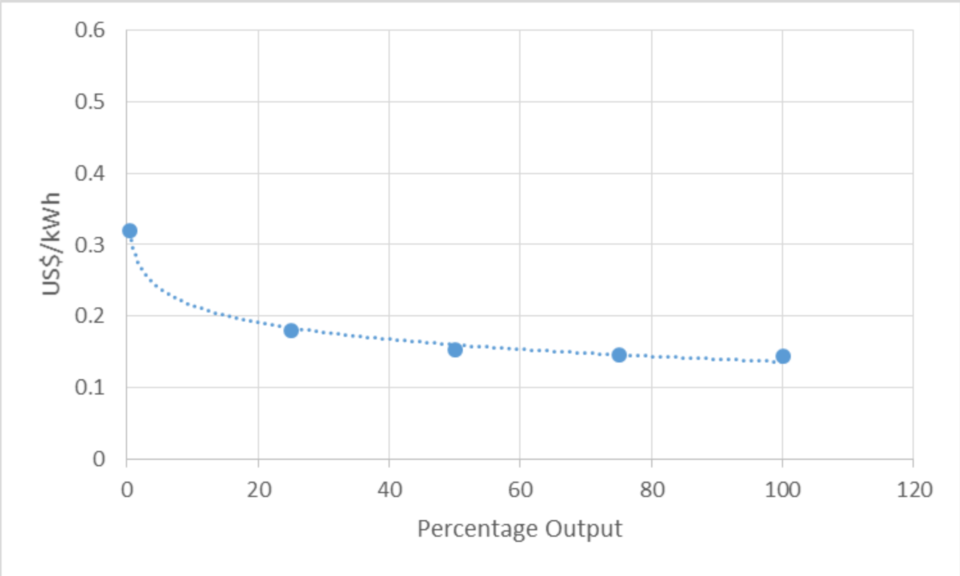
The fuel cost curve that plots power against US$/kWh for CAT units, as shown in Figure 3-11 below, is based on CAT manufacturer's diesel generator's performance[13]. The cost curve was drawn for a fuel cost of US$ 0.58 per litre[14]. The minimum generation is set to be at 20% of the rated capacity as a typical minimum value. Similar calculations were performed for Deutz units, as shown in Figure 3-12.

Figure 3-11 CAT diesel units cost curve



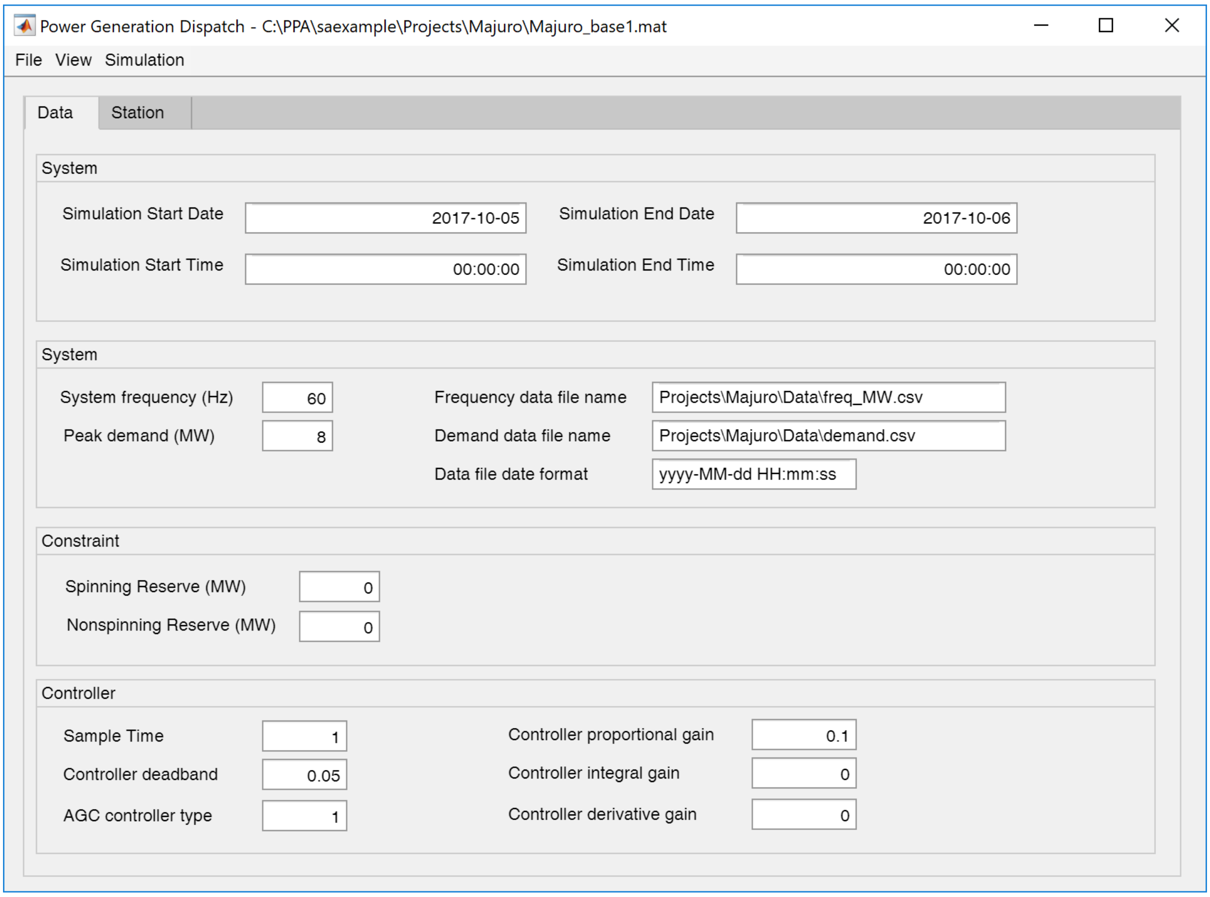
[13] Marshalls Energy Company Generator Efficiency Study, QH10548RP0001, Jacobs, June 2014
[14] Email correspondence with MEC, July 2018

Figure 3-12 Duetz diesel units cost curve



The key parameters for the AGC controller are shown in Figure 3-13 below, for the purpose of the analysis, the demand is assumed to be the same as generation. The demand was calculated by summing the generation. The other parameters selected are described in the appendix. For Majuro the simulation is run every second for a day.

Figure 3-13 GDAT controller parameters



The solar PV power output dates chosen were the week of 11 March as provided by MEC which recorded the 1 second output at the reservoir PV plant. Base case 1 and base case 3 PV1 data is from 11 March 2017 and PV2 data from 16 March 2017 as shown in Figure 3-14, which was a typical partially cloudy days in the pacific islands with constant drops in PV power. Base 2 and 4 is PV data from 14 and 15 March 2017, as shown in Figure 3-15, which was a relatively sunny days with significant periods of low PV output followed full output from the PV plants

Figure 3-14 Recorded 'normalised' one second PV output Base Case 1 and 3

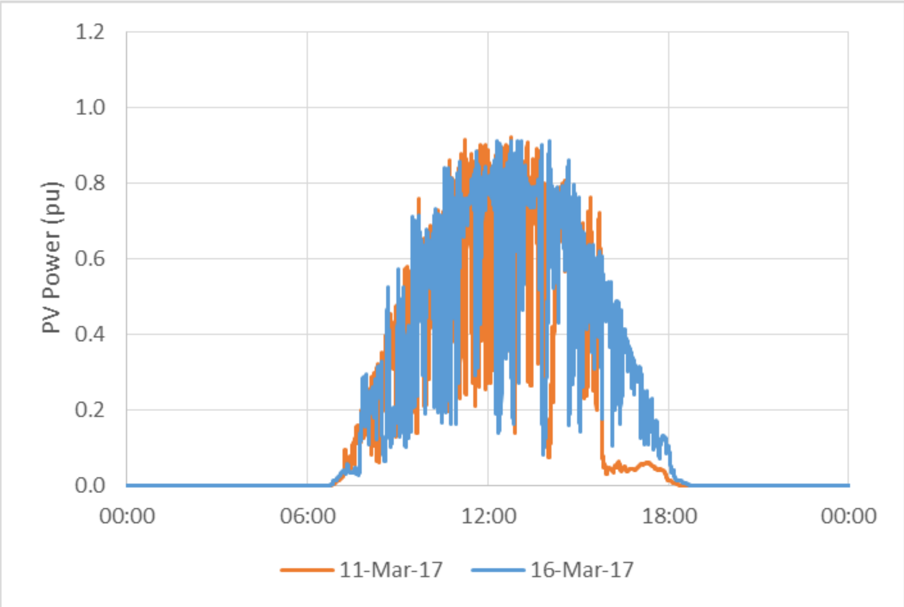
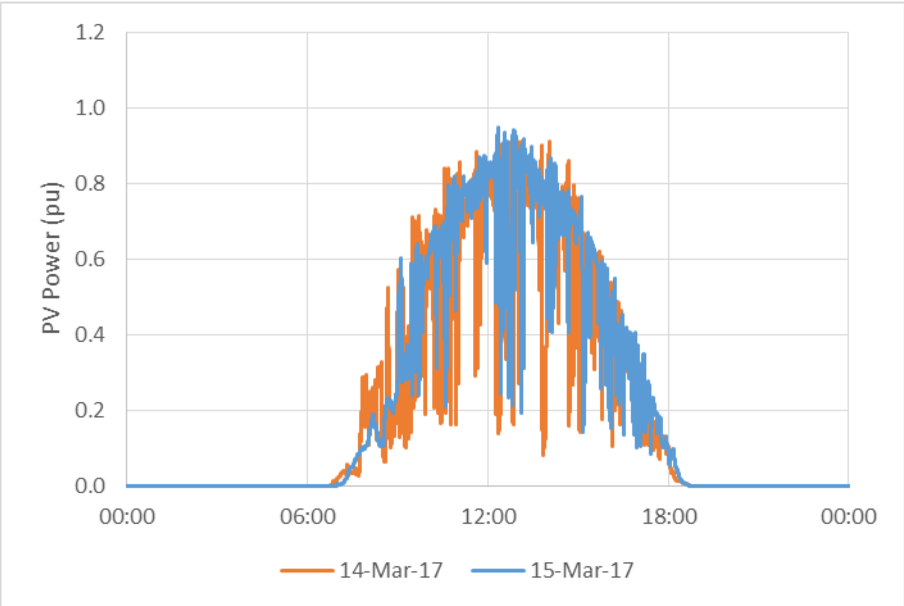


Figure 3-15 Recorded 'normalised' one second PV output Base case 2 and 4



3.3 Results of Generation Dispatch Analysis Tool (GDAT)

The following analysis was carried out on the GDAT tool:

1. The simulations performed: Base case – re-run/simulated the day in question with the same conditions to ensure accuracy of the model developed.
2. Increased spinning reserve to understand the techno economic impacts of increasing spinning reserve
3. Add batteries on primary frequency control only and then on AGC
4. Increased PV to reduce diesel to minimum during the day and maximise usage of batteries on primary control and then on AGC control

The summary of the simulations with various changes to input parameters is shown in Table 3-4.

Table 3-4 Simulations performed

					Controller status	
Case Number	**Simulation date**	VRE Installed (MW)	% peak	**PV data date**	**Solar PV**	**Battery**
Base 1	11 Mar 2017	1	13%	11&16/03/17	AGC	off
1	11 Mar 2017	4	50%	11&16/03/17	AGC	off
2	11 Mar 2017	4	50%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
3	11 Mar 2017	8	100%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
4	11 Mar 2017	12	150%	11&16/03/17	AGC	2 MW / 2 MWh on Gov & AGC
5	11 Mar 2017	16	200%	11&16/03/17	AGC	16 MW / 32 MWh on Gov & AGC
6	11 Mar 2017	16	200%	11&16/03/17	AGC	16 MW / 32 MWh on Gov & AGC – diesel off
Base 2	7 Oct 2017	1	13%	14&15/03/17	AGC	off
7	7 Oct 2017	4	50%	14&15/03/17	AGC	off
8	7 Oct 2017	4	50%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
9	7 Oct 2017	8	100%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
10	7 Oct 2017	12	150%	14&15/03/17	AGC	2 MW / 2 MWh on Gov & AGC
11	7 Oct 2017	16	200%	14&15/03/17	AGC	16 MW / 32 MWh on Gov & AGC
12	7 Oct 2017	16	200%	14&15/03/17	AGC	16 MW / 32 MWh on Gov & AGC – diesel off
Base 3	16 Mar 2017	1	13%	11&16/03/17	AGC	off
13	16 Mar 2017	4	50%	11&16/03/17	AGC	off
14	16 Mar 2017	4	50%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
15	16 Mar 2017	8	100%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
16	16 Mar 2017	12	150%	11&16/03/17	AGC	2 MW / 2 MWh on Gov & AGC
17	16 Mar 2017	16	200%	11&16/03/17	AGC	16 MW / 32 MWh on Gov & AGC
18	16 Mar 2017	16	200%	11&16/03/17	AGC	16 MW / 32 MWh on Gov & AGC – diesel off
Base 4	5 Oct 2017	1	13%	14&15/03/17	AGC	off
19	5 Oct 2017	4	50%	14&15/03/17	AGC	off
20	5 Oct 2017	4	50%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
21	5 Oct 2017	8	100%	14&15/03/17	AGC	2 MW / 2 MWh on Gov

22	5 Oct 2017	12	150%	14&15/03/17	AGC	2 MW / 2 MWh on Gov & AGC
23	5 Oct 2017	16	200%	14&15/03/17	AGC	16 MW / 32 MWh on Gov & AGC
24	5 Oct 2017	16	200%	14&15/03/17	AGC	16 MW / 32 MWh on Gov & AGC – diesel off

3.3.1 Base Case 1 & Simulation cases 1 – 6 Weekend (11 Mar 2017) with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

Base Case 1: Weekend (11 March 2017) - Simulation of original PV with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017.

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-16 shows the simulation of generation unit outputs for Saturday 11 March 2017, with PV1 set at 0.6 MW & PV 2 set at 0.4 MW. This is the base case for these simulations where we can compare techno-economic impact of cases 1 to 6. The simulated frequency, as shown in Figure 3-17, shows the expected frequency variations are improved compared to the actual recorded frequency variations. The improvement is which is due to fact that the simulation has the diesel units on AGC whilst in reality the diesel power station is controlling the frequency manually.

Figure 3-16 Simulated generation on 11 March 2017 with current installed PV

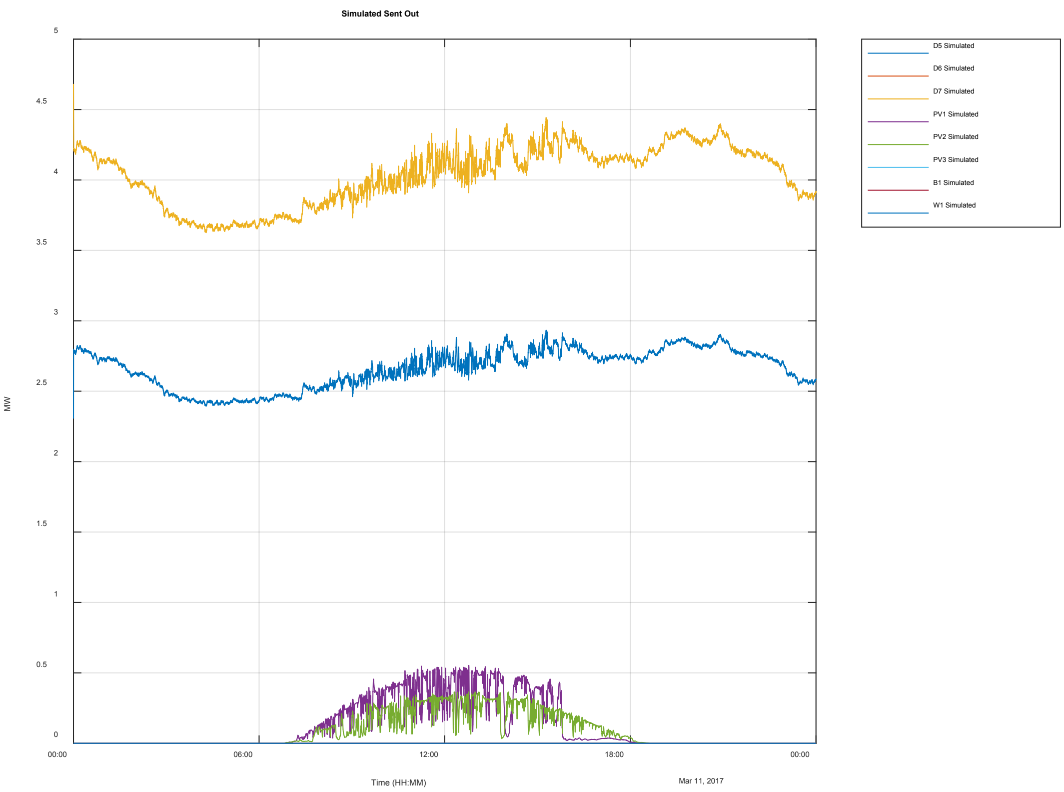
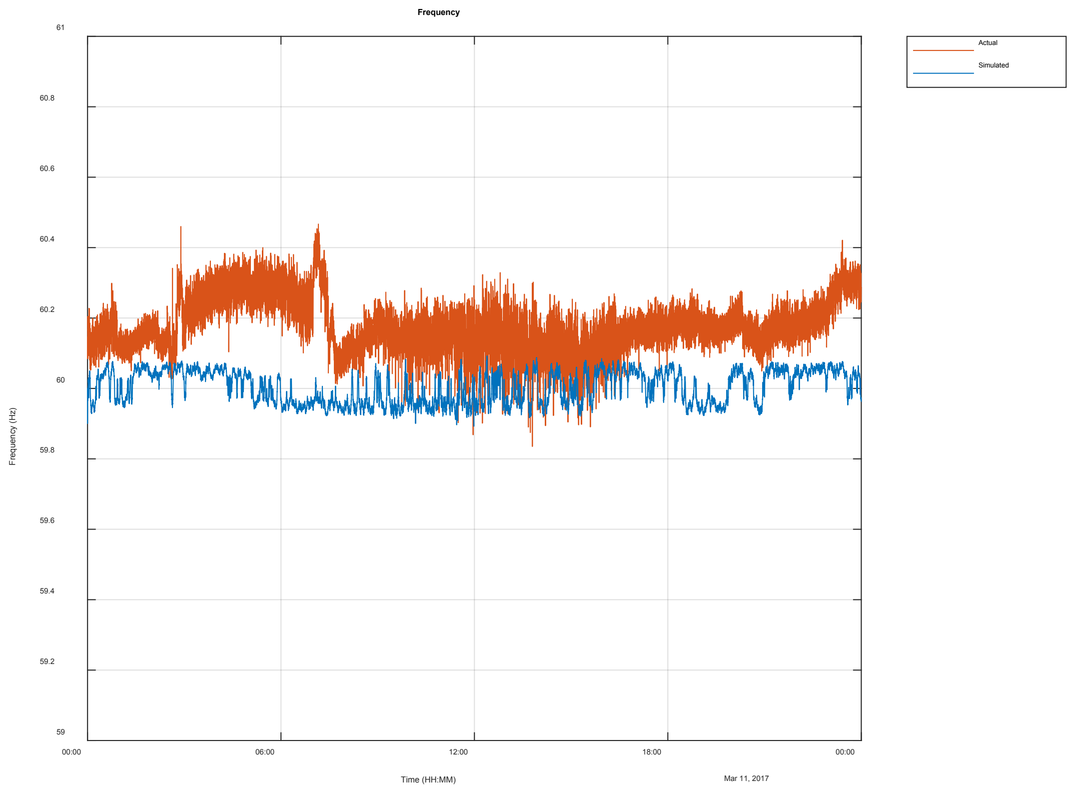


Figure 3-17 Simulated frequency on weekend with current installed PV



<u>Case 1: Weekend (11 March 2017) - 4 MW of PV</u>

For Case 1 the PV power plants are set to 2 MW each giving a total PV of 4 MW, Diesel units D5 and D7 units perform the frequency control, as shown in Figure 3-18. The frequency is acceptable but there are frequency excursions where the Diesel Power plant is starting to struggle to control the frequency with high PV penetration and variation, as shown in Figure 3-19. When diesel unit is at minimum generation the PV is backed off to control frequency which does not happen in this case.

Figure 3-18 Simulated generation on weekend with 4 MW PV

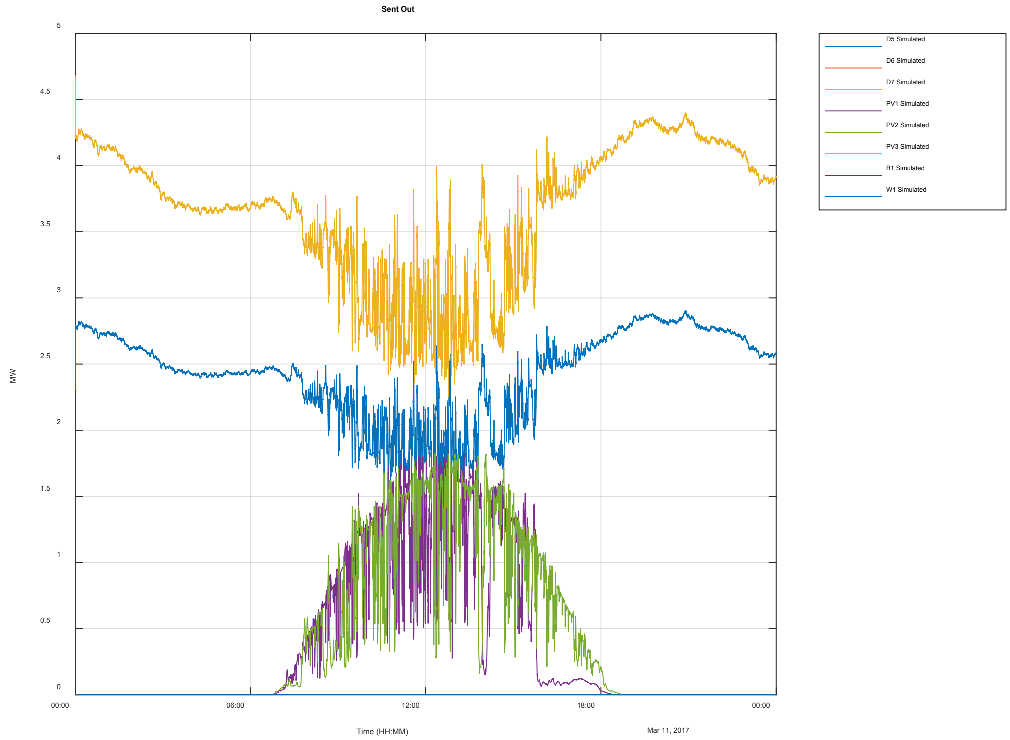
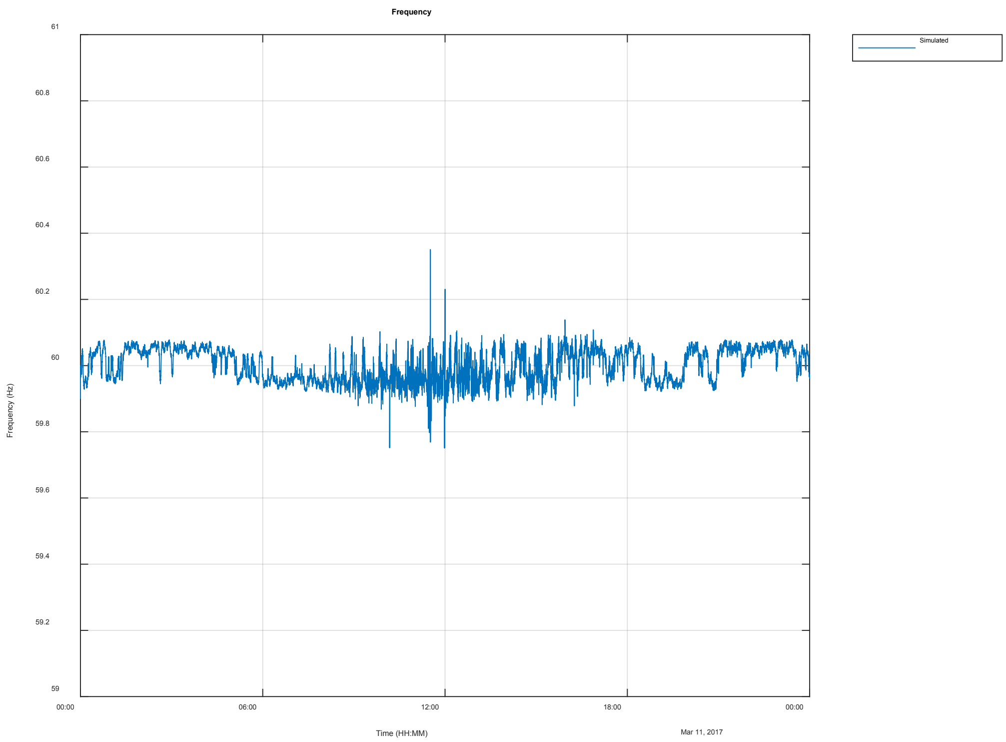


Figure 3-19 Simulated frequency on weekend with 4 MW PV

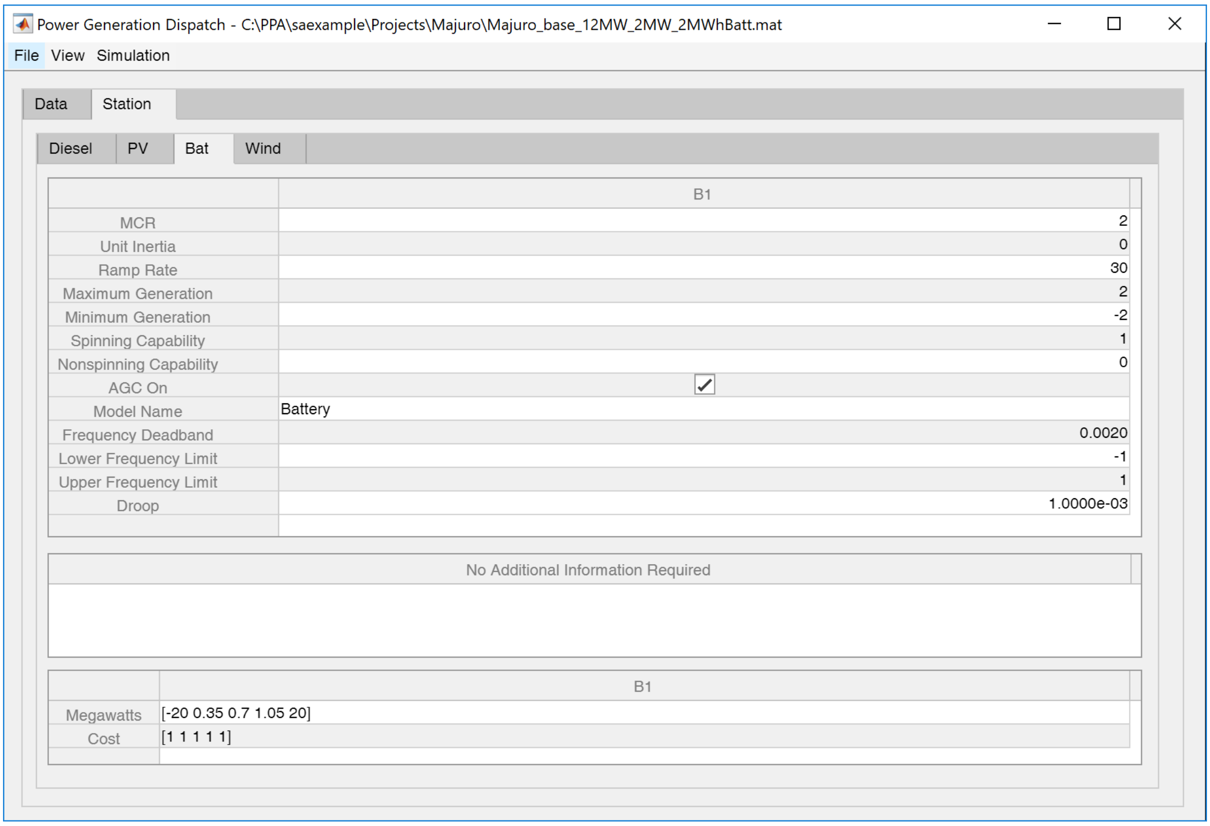


Case 2: Weekend (11 March 2017) - 4 MW of PV and 2 MW / 2 MWh battery on primary frequency control

Batteries can be used for primary frequency control only and thus only respond to frequency variations. For these simulations, the battery control parameters are in Figure 3-20. The deadband is set to 0.1 Hz and thus the battery will respond to frequency variations outside of this range and droop is set to 0.1 %, thus a 0.1% change in frequency will result in 100% change in power. Thus the battery will go from zero output to full output if the frequency drops from 59.9 to 59.85 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.1 to 60.15 Hz.

A 2 MW / 2 MWh battery costs US$ $209,821 per annum or US$ 575 per day.

Figure 3-20 Battery parameters when on primary frequency control only



The simulated frequency improves when 2 MW battery is on primary frequency control only, as shown in Figure 3-21. There are a few occasions during the period when the battery is utilised and the response is enough to prevent frequency excursion, as shown in Figure 3-22. The diesel fuel costs remain the same at $1,817 as for case 1 showing the battery is just performing primary frequency control and the battery on discharges a few percent. The net loss of US$ 185 is calculated for the simulation day including the battery costs.

Figure 3-21 Simulated frequency for weekend with 4 MW of PV and 2 MW / 2 MWh battery on primary frequency control

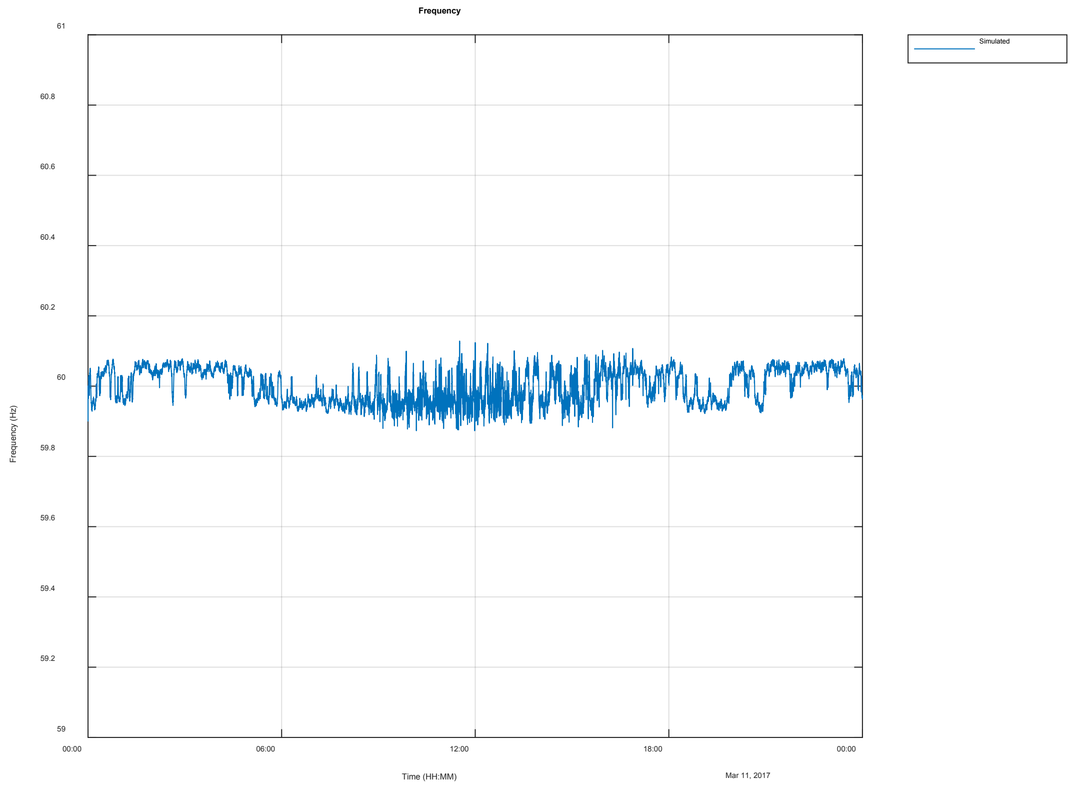
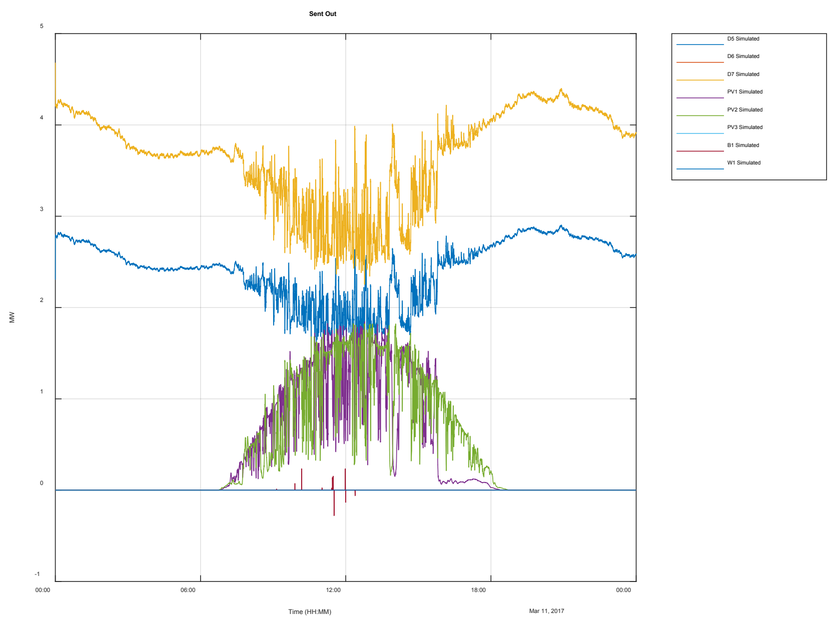


Figure 3-22 Simulated generation power for weekend with 4 MW of PV and 2 MW / 2 MWh battery on primary frequency control



Case 3: Weekend (11 March 2017) - 8 MW of PV and 2 MW / 2 MWh battery on primary frequency control

For Case 3 the PV power plants are set to 4 MW each giving a total PV of 8 MW, Diesel units D5 and D7 provides the secondary control under AGC to perform the control assisted by a 2 MW battery on primary frequency control, as shown in Figure 3-23. The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in Figure 3-24. The battery full range is not fully utilised to control the frequency and so battery size is fine for frequency control for this simulation case, as shown in Figure 3-25.

All of the available energy from the 8 MW of PV is used resulting which results in a fuel saving of US$4,156 and a net saving of US$ 609 for the simulation day.

Figure 3-23 Simulated generation for weekend with 8 MW of PV and 2 MW / 2 MWh battery on primary frequency control

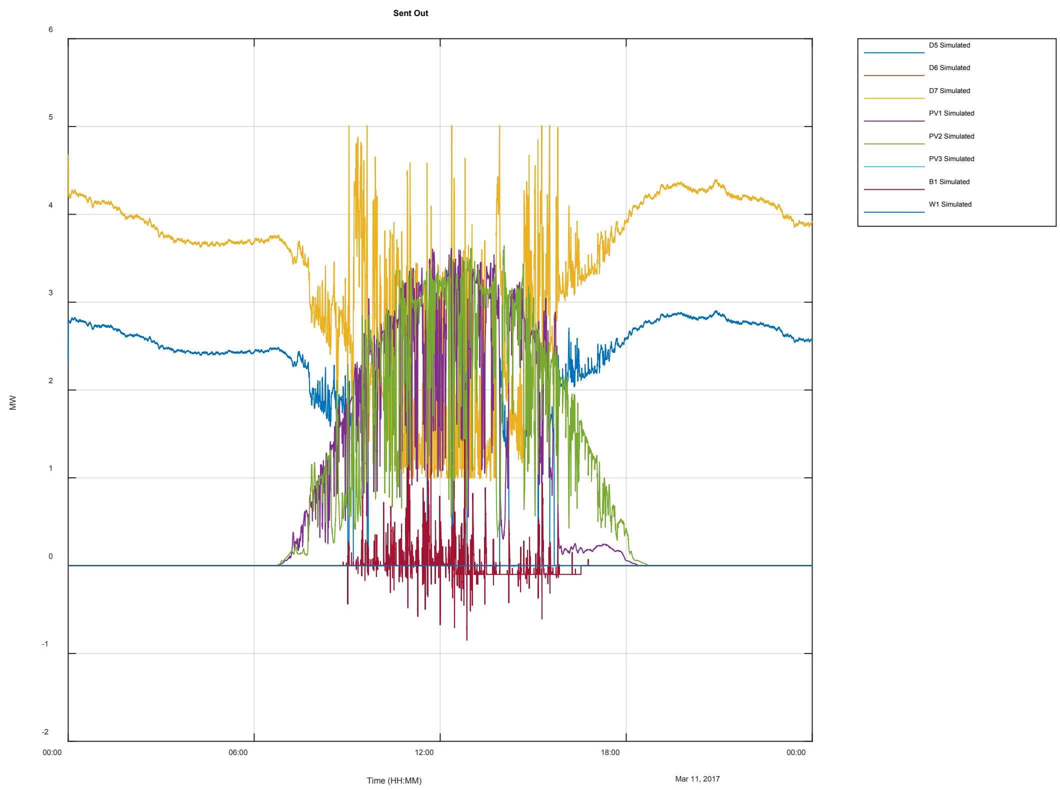


Figure 3-24 Simulated frequency for weekend with 8 MW of PV and 2 MW / 2 MWh battery on primary frequency control

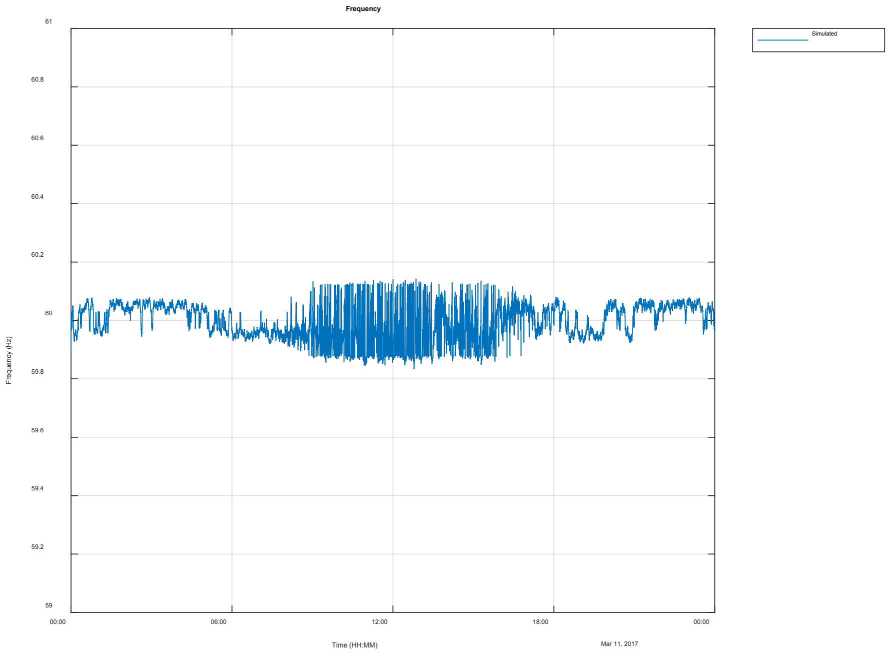
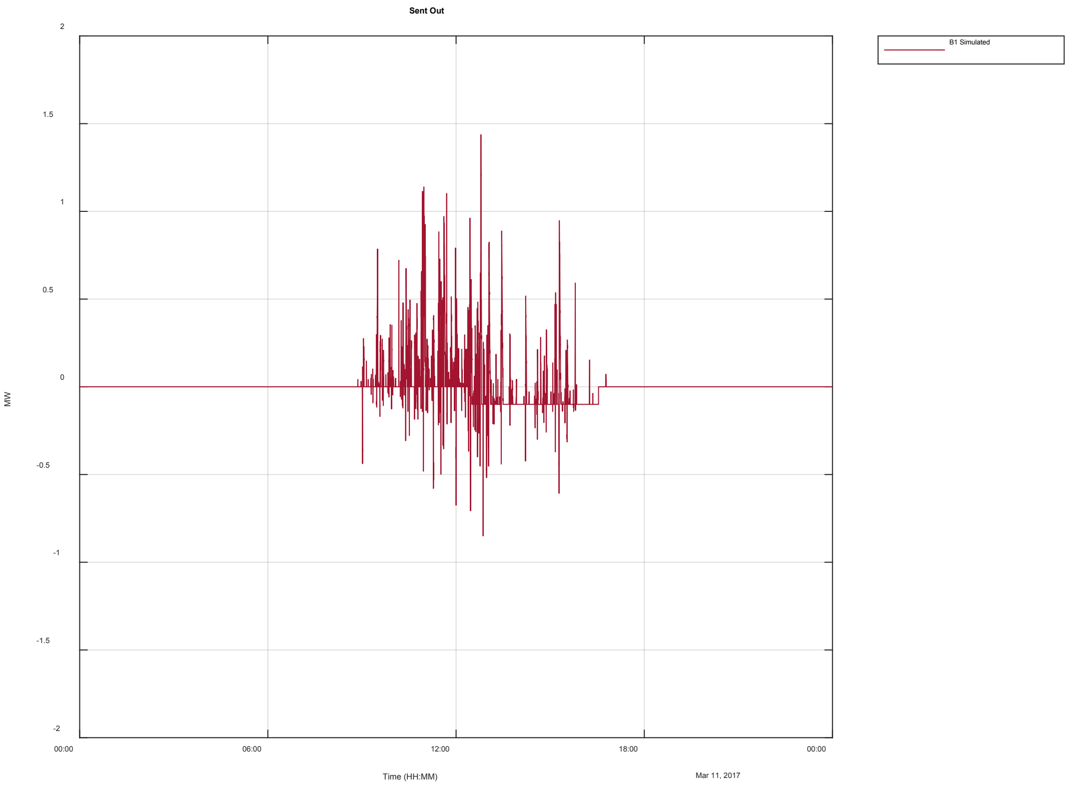


Figure 3-25 Simulated battery output for weekend with 8 MW of PV and 2 MW / 2 MWh battery on primary frequency control



Case 4: Weekend (11 March 2017) - 12 MW of PV and 2 MW / 2 MWh battery on AGC

Case 4 is simulating the same as Case 3 increasing the PV to 12 MW and on AGC. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

1. Starting batteries with a charge of 20% - assuming batteries have been utilised the previous evening – update to actual midnight value to give a typical continuous day's profile (need to run simulation twice)
2. Battery is discharged whenever possible to displace diesel. Batteries provide power at half their potential – keeping the remaining half available for primary frequency control
3. Battery is charged using any excess PV available – when PV exceeds demand minus diesel generation minimum demand. Battery is charged to 95% keeping some capacity for primary frequency control high frequency response after charging.
4. The discharge level is limited by the AGC controller to 50% of the battery size to ensure frequency is controlled at the same time as optimising the energy available – essentially system security before economics

Figure 3-26 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost full charge level, as shown in Figure 3-27, by 11:30. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 17:30. The simulated diesel generator 1 output is at minimum generation for most of the period from 10:00 Hrs to 16:30 Hrs, as shown in Figure 3-28.

The fuel savings for Case 4 is $ 6,734 compared to $ 4,516 for Case 3. This increase is due to an increase PV output of 12.8 MWh and this case has a net savings of $ 563 for the simulation day.

Figure 3-26 Simulated battery output for weekend when 2 MW / 2 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

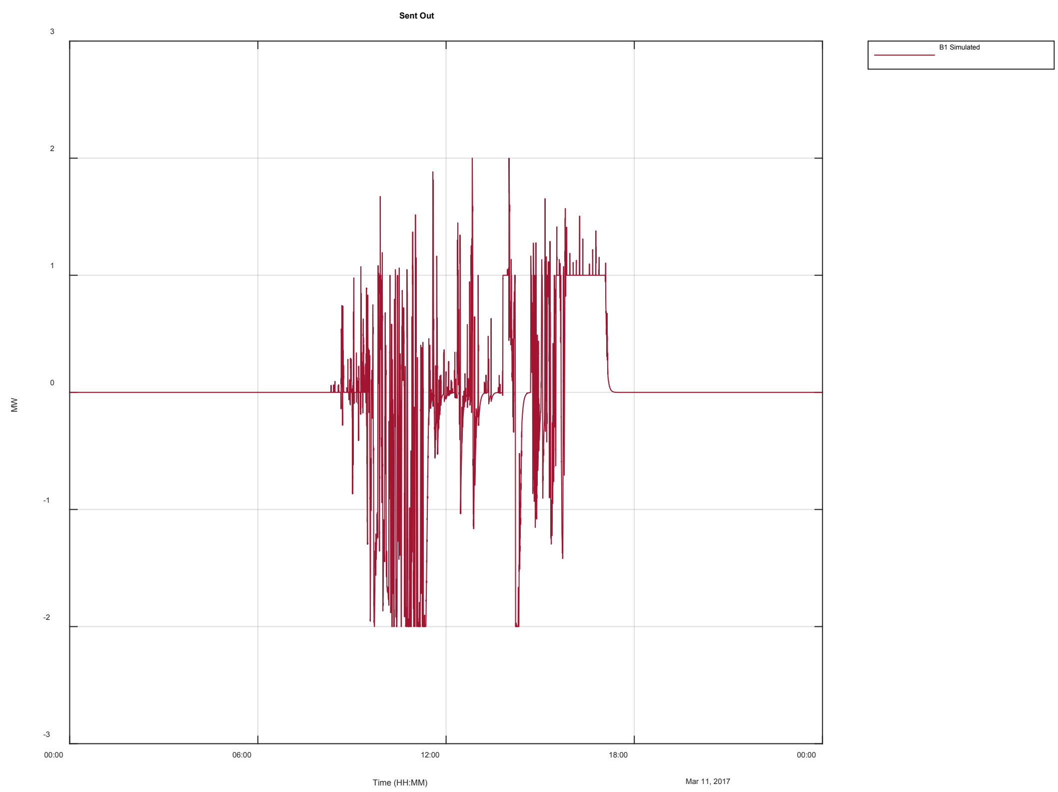


Figure 3-27 Simulated battery charge level for weekend when 2 MW / 2 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

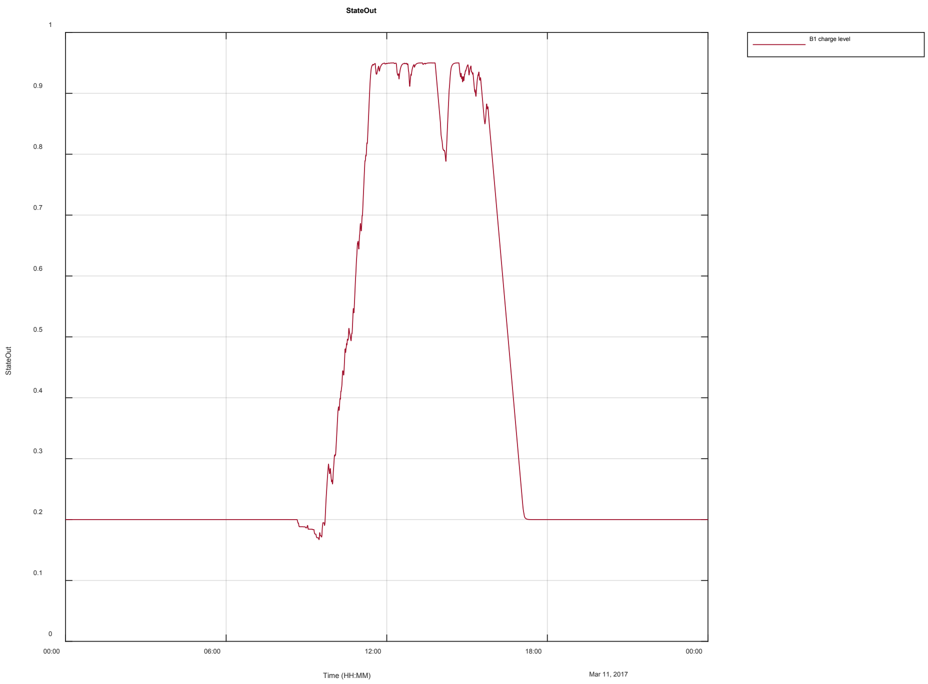
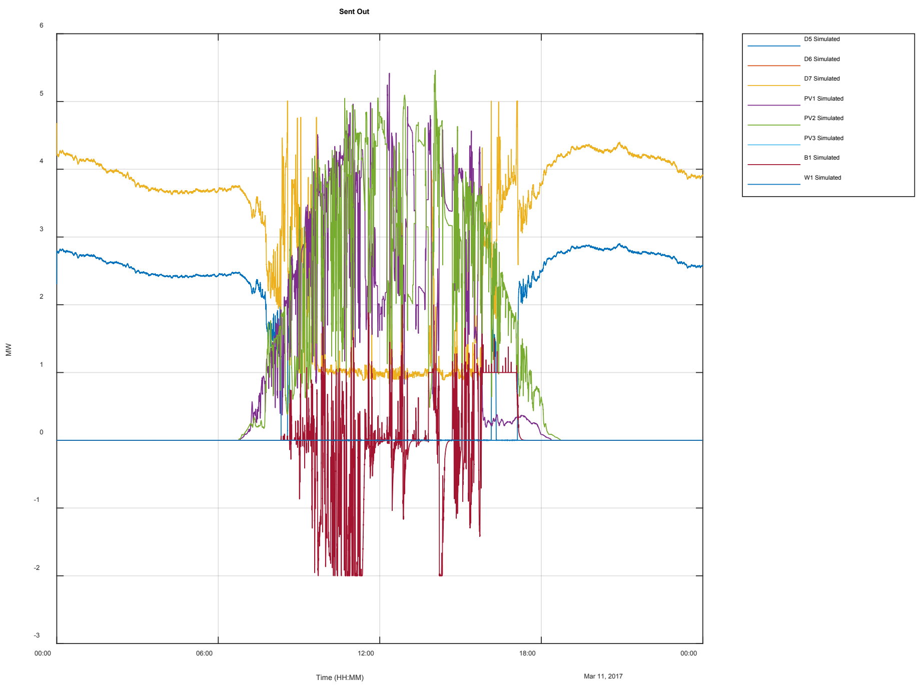


Figure 3-28 Simulated generator outputs for weekend when 2 MW / 2 MWh battery provides both primary frequency control and AGC with 12 MW of PV.



Case 5: Weekend (11 March 2017) - 16 MW of PV and 16 MW / 32 MWh battery on AGC

This case is where the PV is increased to 16 MW and a 16 MW / 32 MWh battery is on AGC and primary frequency control. The simulated generation, as shown in Figure 3-29 shows that the inverter size required is around 8 MW.

The simulated frequency is within acceptable limits, as shown in Figure 3-30. There are a no frequency excursions which means the inverter size is adequate. The battery charges to 90% by 16:00 and fully discharges by 20:00, as shown in Figure 3-31.

The energy not utilised is 0.8 MWh or 1.1% of energy lost and thus the battery is adequately sized for this simulation day. This case has a net loss of $ 4,361 for the simulation day. This loss could be reduced by $1,220 per day if inverters were only 8 MW in size.

Figure 3-29 Simulated generator output for weekend when 16 MW/ 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.

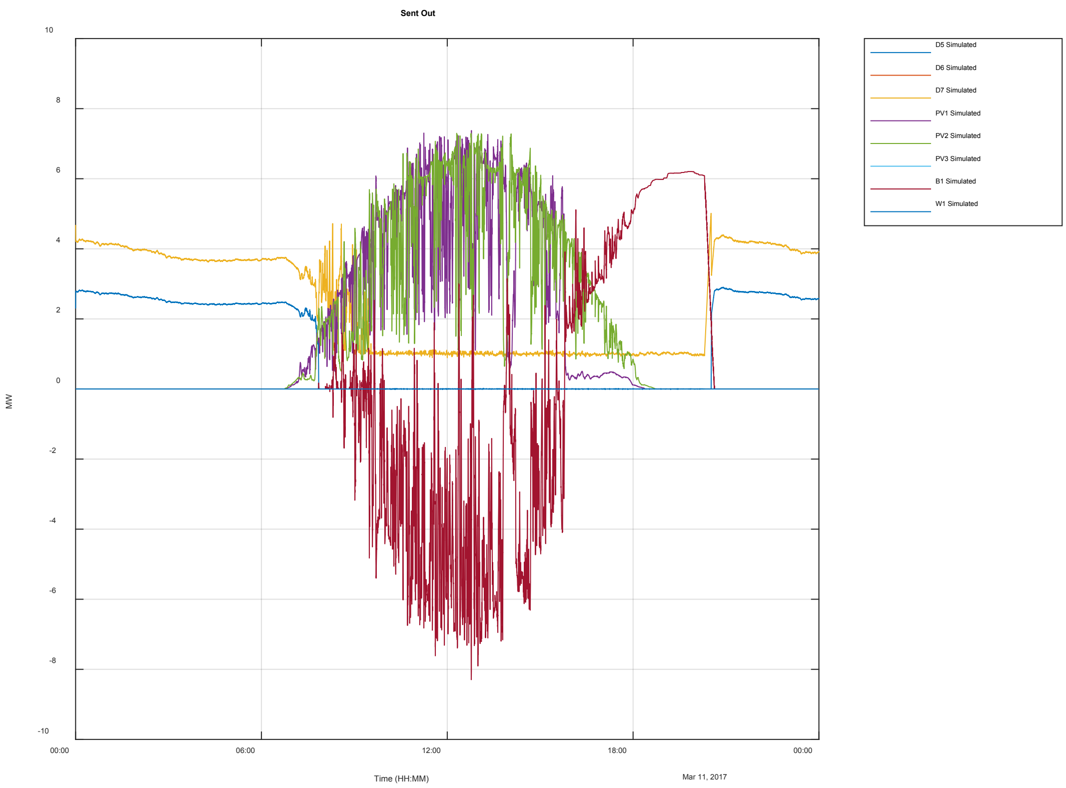


Figure 3-30 Simulated frequency for weekend when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV.

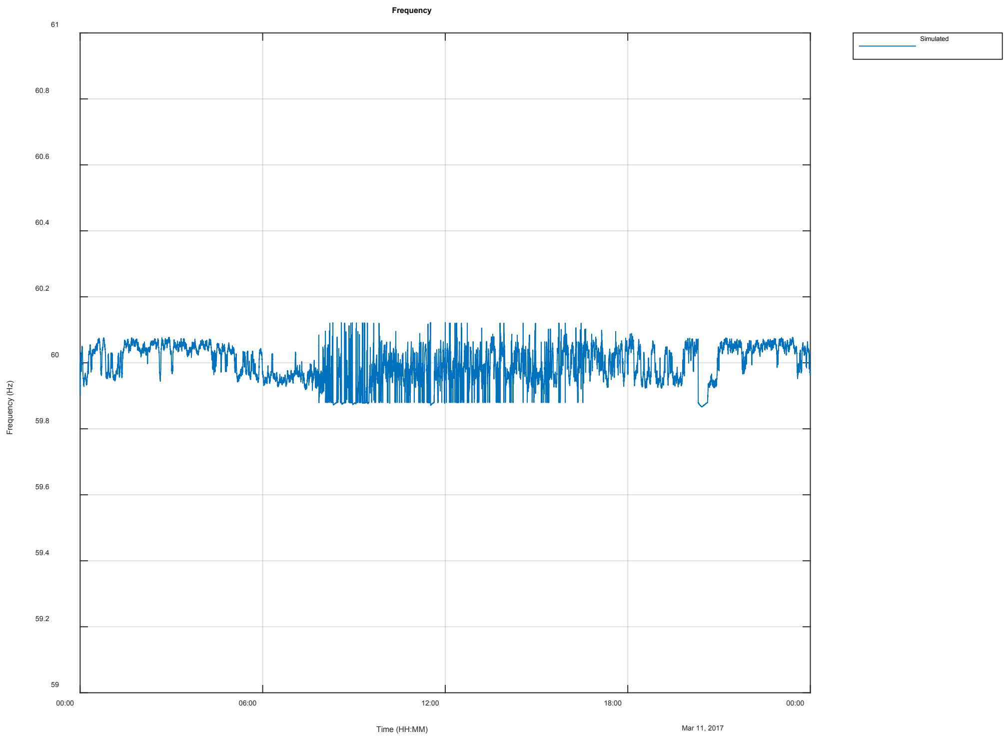
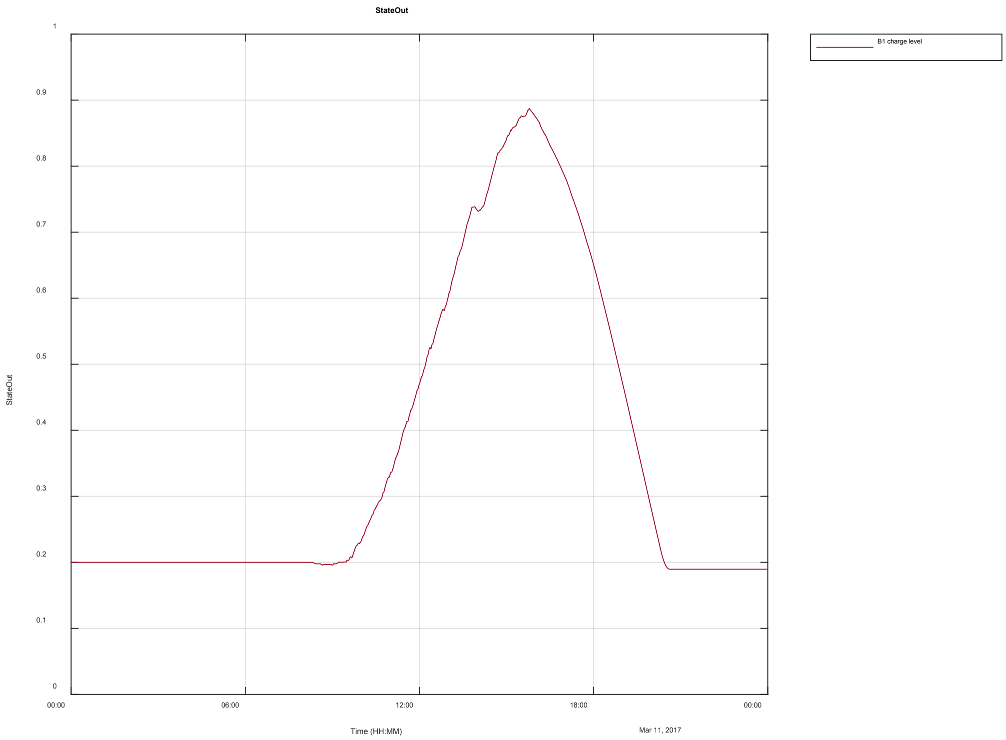


Figure 3-31 Simulated battery charge for weekend when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV.



Case 6: Weekend (11 March 2017) - 16 MW of PV and 16 MW / 32 MWh battery on AGC and all diesel off

This case is a repeat of Case 5 but now the last diesel unit is allowed to go off line. In case 5 the 0.8 MWh of PV power is spilt which equates to 1.1 % of energy lost. Figure 3-32 shows that all diesel generators are off from 10:00 to 18:30.

Figure 3-33 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery to 70% of full charge, as shown in Figure 3-34, by 12:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until 18:30. No diesel is required for the simulation day. Figure 3-35 shows the simulated frequency which shows there is sufficient control range to control the frequency.

The fuel costs for Case 6 is $193 lower than case 5 which is not much of a fuel saving when generator is switched off. A higher level of PV would be required to fully utilise batteries.

Figure 3-32 Simulated generator output for weekend when 16 MW/ 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.

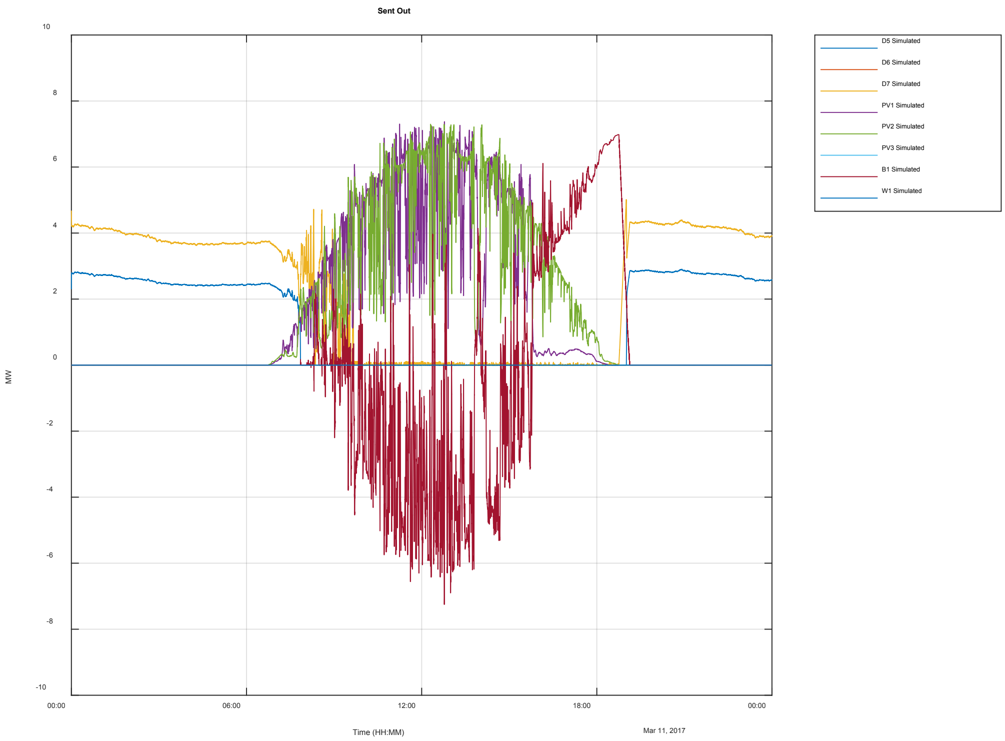


Figure 3-33 Simulated battery output for weekend when 16 MW/ 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.

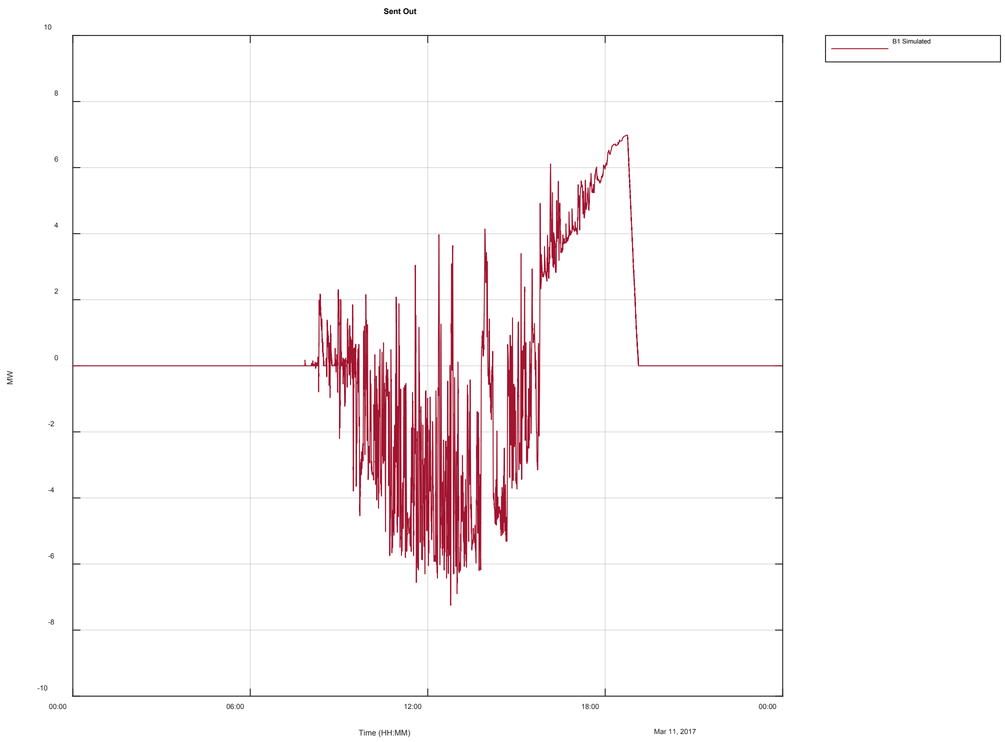


Figure 3-34 Simulated battery charge level for weekend when 16 MW/ 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.

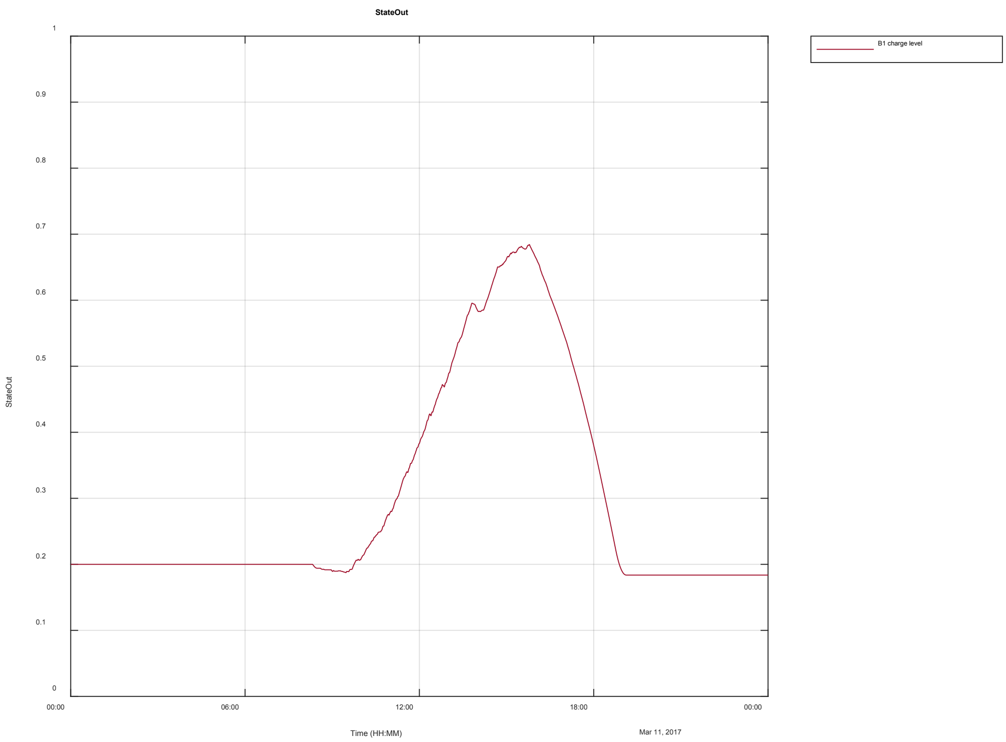
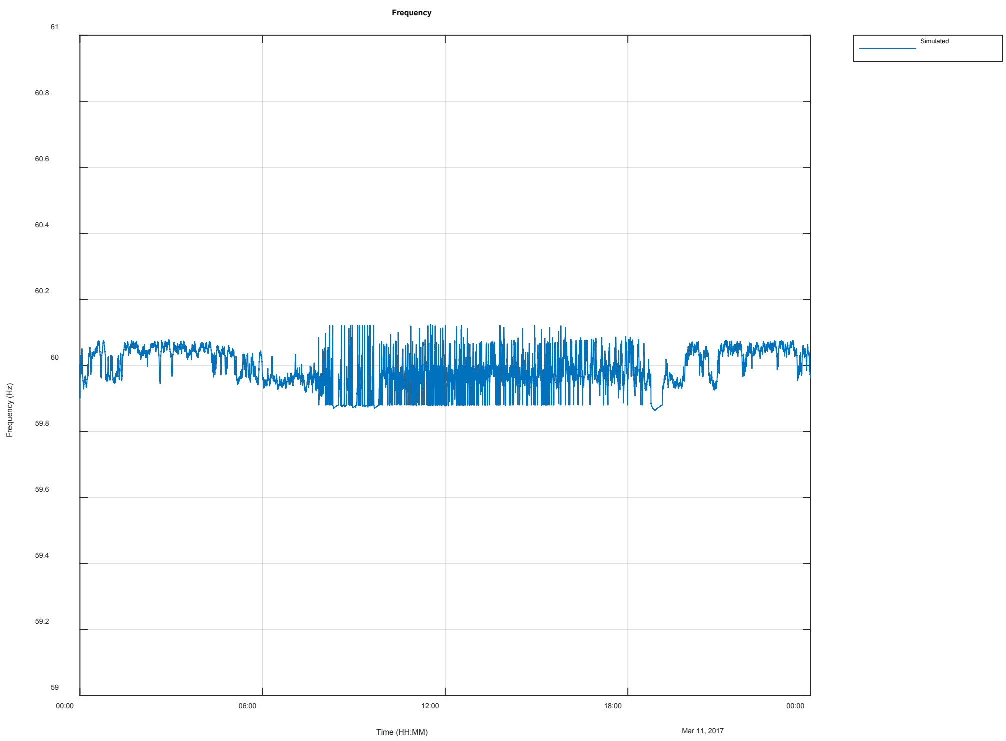


Figure 3-35 Simulated frequency for weekend when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.



3.3.2 Base Case 2 & Simulation cases 7 – 12 (7 Oct 2017) with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017

<u>Base Case 2: Weekend (7 Oct 2017) - Simulation of original day with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017.</u>

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-37 shows the simulation of generation unit outputs for Saturday 7 October 2017, with PV1 of 0.6 MW from 14 March 17 and PV2 of 0.4 MW from 15 March 2017. This is the base case for these simulations where we can compare techno-economic impact of cases 7 to 12. The simulated frequency, as shown in Figure 3-38, shows a slight improvement in frequency compared to the recorded frequency as the simulated frequency is with AGC and the recorded frequency is without AGC.

Figure 3-37 Simulated generation on weekend (7 October) with current installed PV

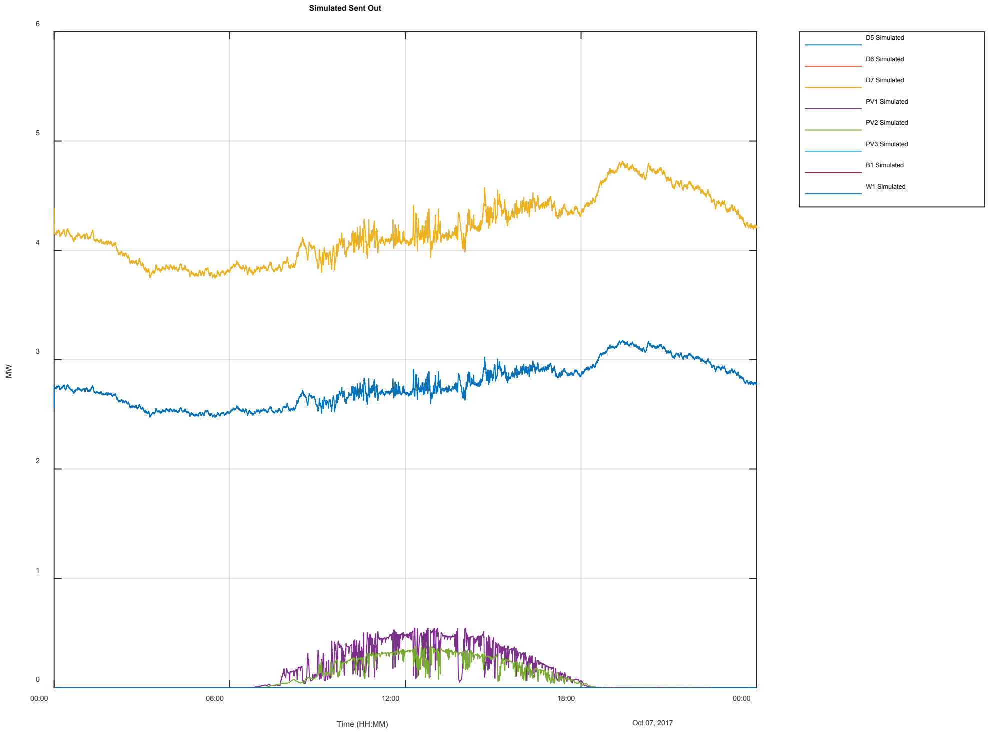
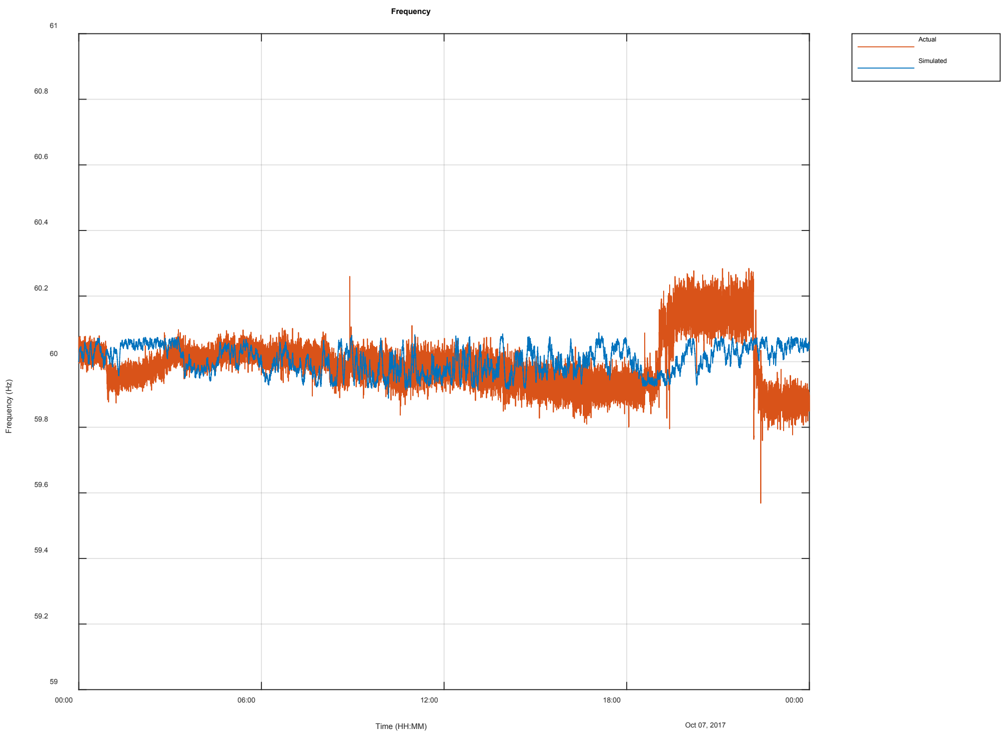


Figure 3-38 Simulated frequency on weekend (7 October) with current installed PV



Case 7 - 12: Weekend (7 October 2017) – Repeat of cases 1-6 with demand from 7 October and PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017.

Cases 7 – 12 is the repeat of the simulations for a typical weekend but with demand from 7 October and PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017. The simulated frequency is within an acceptable range for case 7 with 4 MW total PV simulated, as shown in Figure 3-, but the simulated frequency control is worse with the more volatile PV variations. Case 9 with 8 MW of simulated PV with a 2 MW / 2 MWh battery on primary frequency control results in an acceptable frequency control, as shown in Figure 3-. Case 10 with 12 MW of simulated PV with a 2 MW / 2 MWh battery on AGC also results in an acceptable frequency control, as shown in Figure 3-. Case 12 with the 16 MW of PV and 16 MW / 32 MWh battery on AGC has a very similar same result as for case 6 except battery is charge slightly more, as shown in Figure 3-36.

The fuel savings for the same scenario for the weekend cases are very similar except the PV production for the cases 7 -12 was slightly more than for cases 1-6 so daily fuel and net savings are higher. As only an 8 MW inverter is required this has been factored into the calculations below.

Table 3-5 Comparison of daily fuel saving and net savings for a weekday with different PV input data

Simulation description	Case 1 - 6 daily diesel fuel savings	Case 7 - 12 daily diesel fuel savings	Case 1 - 6 daily net savings	Case 7 - 12 daily net savings
4 MW PV and no battery	1,818	1,986	390	427
4 MW PV and 2 MW / 2 MWh battery on gov	1,817	1,985	-185	-149
8 MW PV and 2 MW / 2 MWh battery on gov	4,516	4,913	609	699
12 MW PV and 2 MW / 2 MWh battery on AGC	6,374	6,731	563	439
16 MW PV and 8 MW / 32 MWh battery on AGC	9,781	10,409	-2,260	-2,289
16 MW PV and 8 MW / 32 MWh battery on AGC and all diesel allowed to go off	9,974	10,818	-2,067	-1,880

Figure 3-39 Case 7 - Simulated frequency on weekend with 4 MW PV

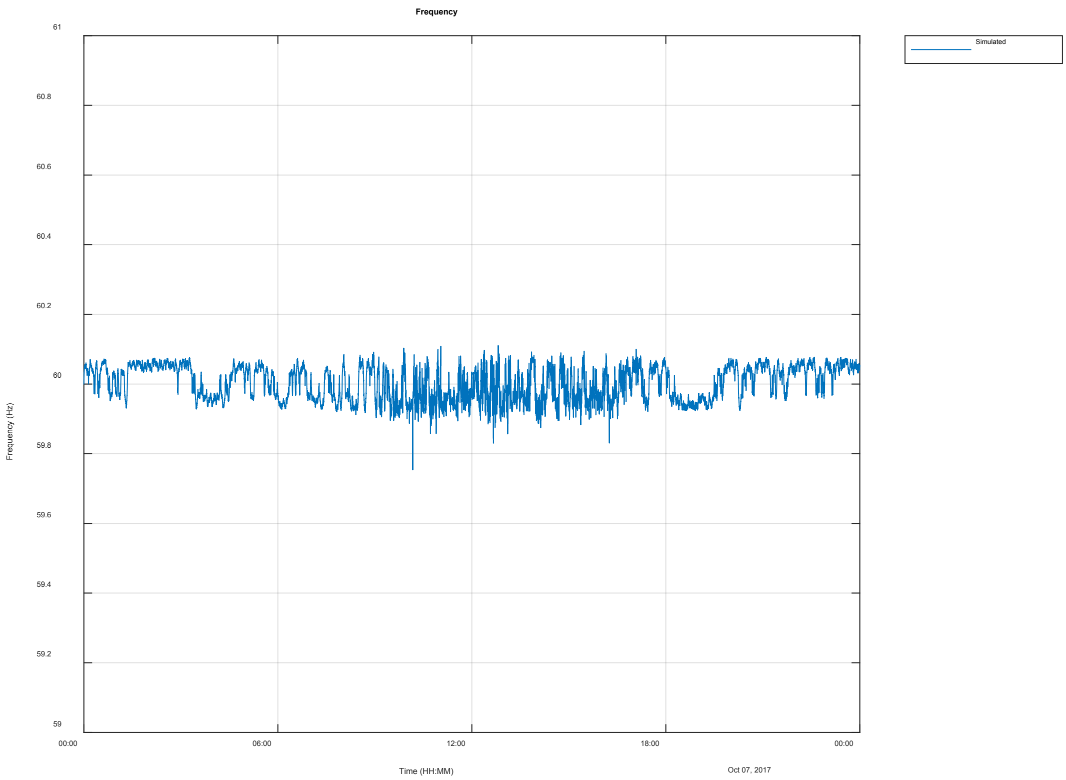


Figure 3-40 Case 9 - Simulated frequency on weekend with 8 MW PV and 2 MW / 2 MWh battery on primary frequency control

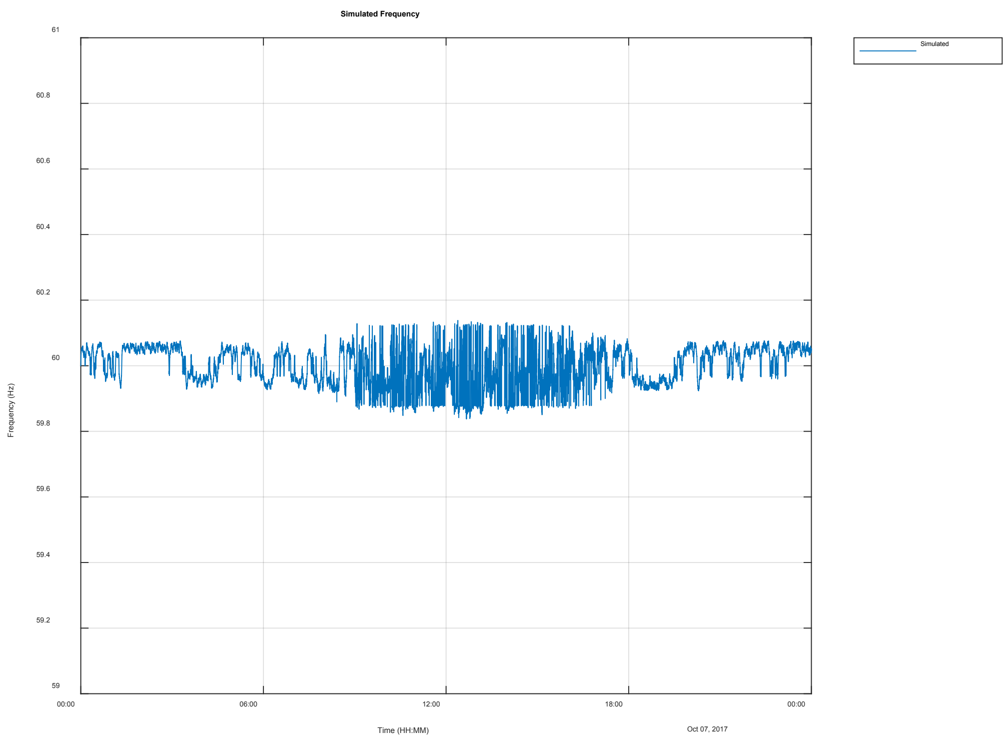


Figure 3-41 Case 10 - Simulated frequency on weekday with 12 MW PV and 2 MW / 2 MWh battery on AGC.

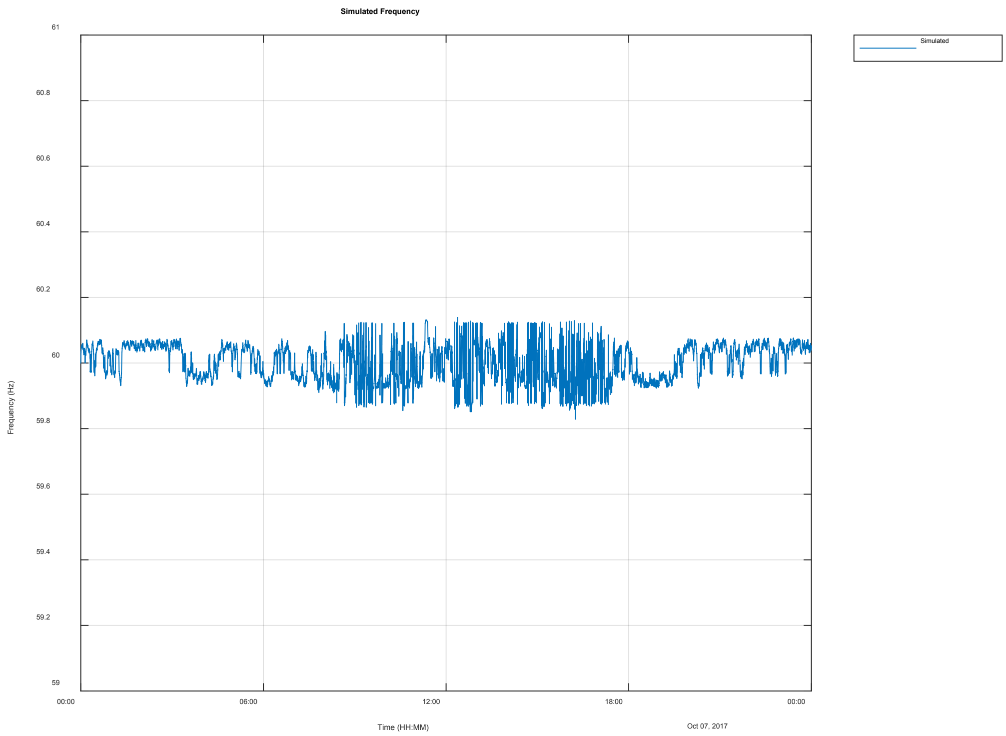
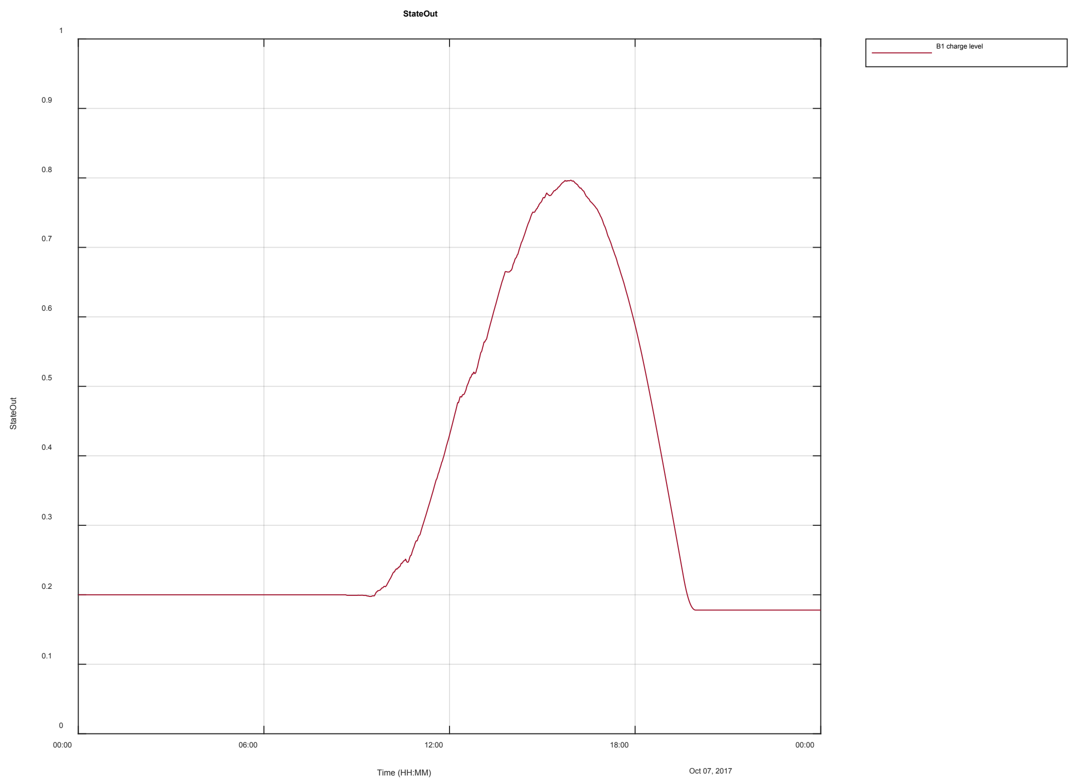


Figure 3-36 Case 12 - Simulated charge level on weekend with 16 MW PV and 16 MW / 32 MWh battery on AGC and all diesel units off.



3.3.3 Base Case 3 & Simulation cases 13 – 18 Weekday (16 Mar 2017) with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

Base Case 3: Weekday (16 Mar 2017) - Simulation of original with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-37 shows the simulation of generation unit outputs for Thursday 16 March 2017, with 0.6 MW from PV1 from 11 Mar 2017 (representing the reservoir plant) and 0.4 MW from PV 2 (representing the Hospital and in town plants) from 16 Mar 2017. This is the base case for these simulations where we can compare techno-economic impact of cases 13 to 18. The simulated frequency, as shown in Figure 3-38, shows the expected shows the expected frequency variations are improved compared to the actual recorded frequency variations. The improvement is which is due to fact that the simulation has the diesel units on AGC whilst in reality the diesel power station is controlling the frequency manually.

Figure 3-37 Simulated generation on weekday with current installed PV

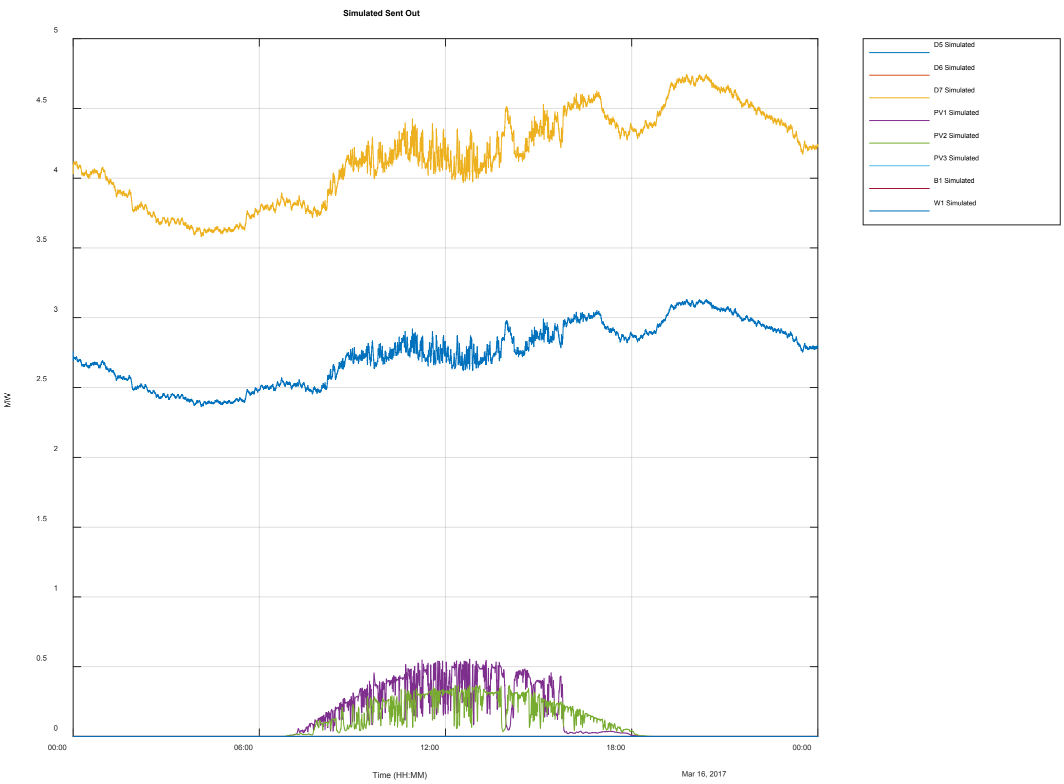
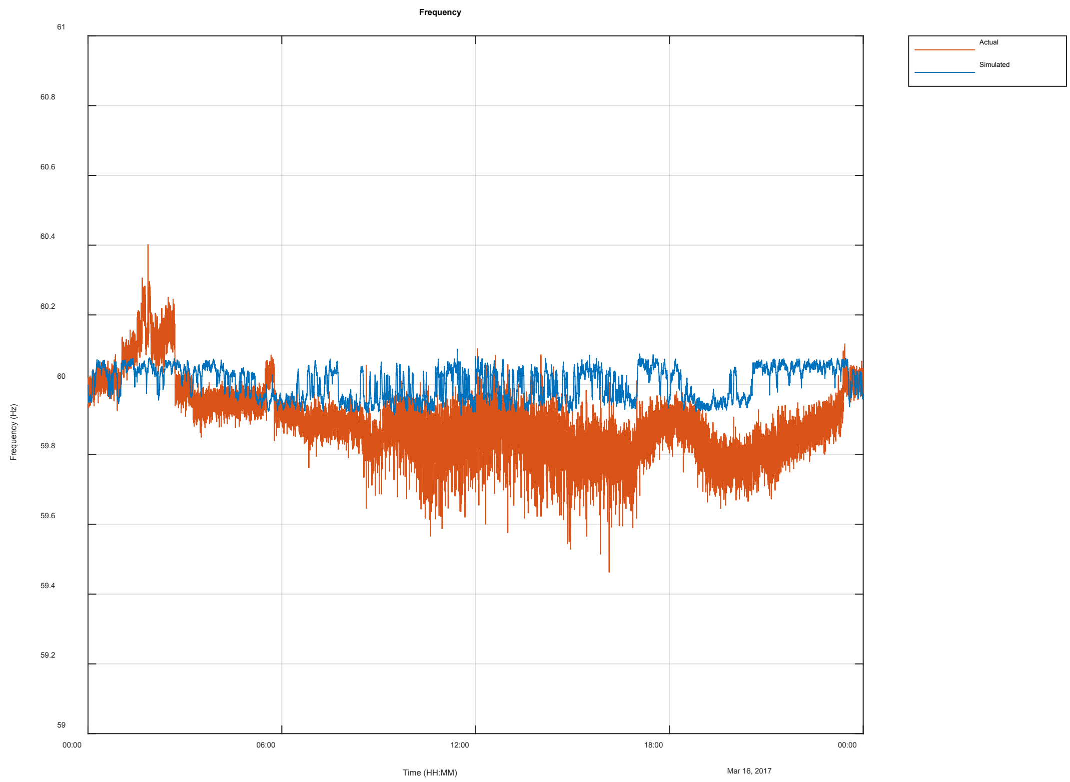


Figure 3-38 Simulated frequency on weekday with current installed PV



Case 13: Weekday (16 March 2017) - 4 MW of PV

For Case 13 the PV power plants are set to 2 MW each giving a total PV of 4 MW, Diesel units D5 and D7 are the units on to perform the control, as shown in Figure 3-39. The frequency is acceptable but there are frequency excursions where the Diesel Power plant is battling to control the frequency.

Figure 3-39 Simulated generation on weekday with 4 MW PV

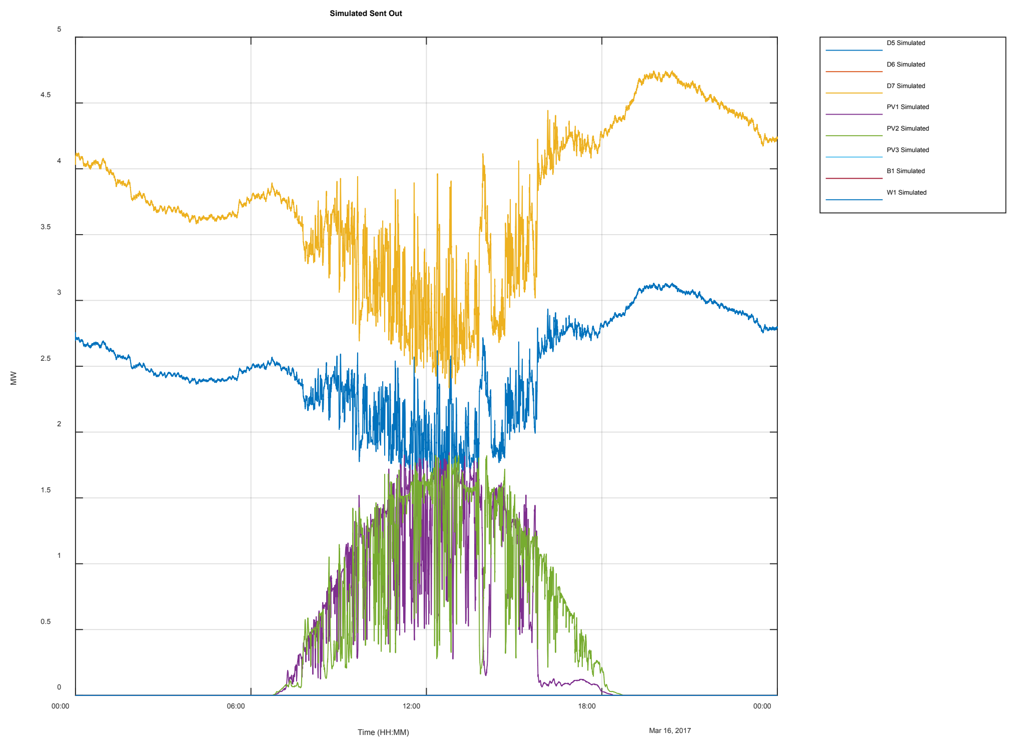
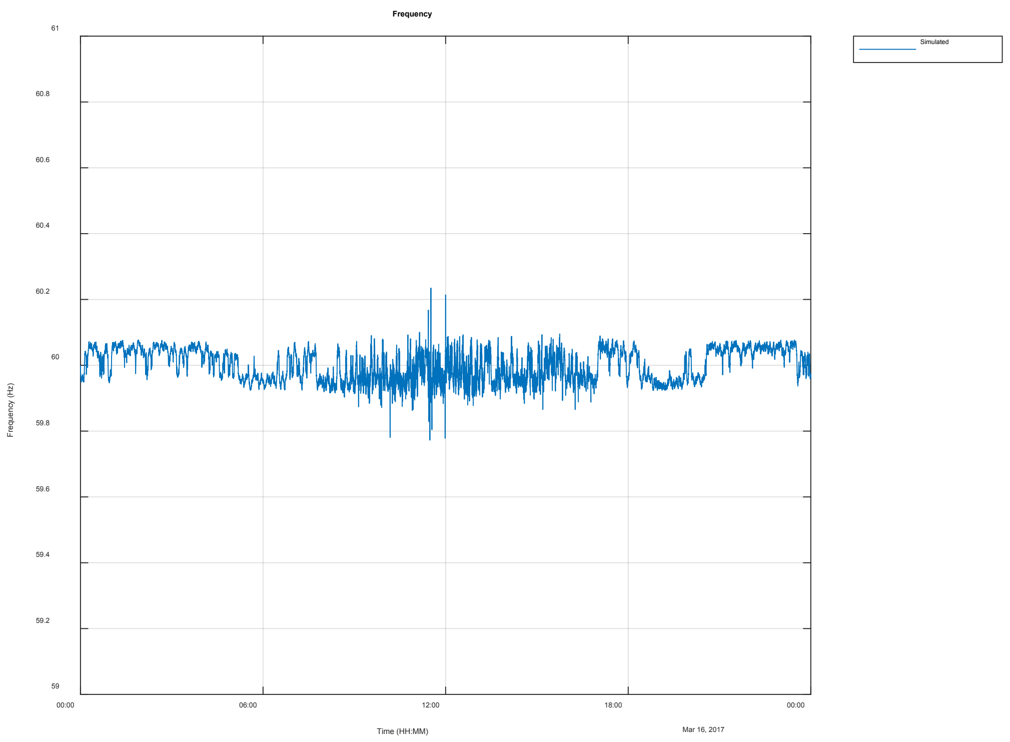


Figure 3-40 Simulated frequency on weekday with 4 MW PV



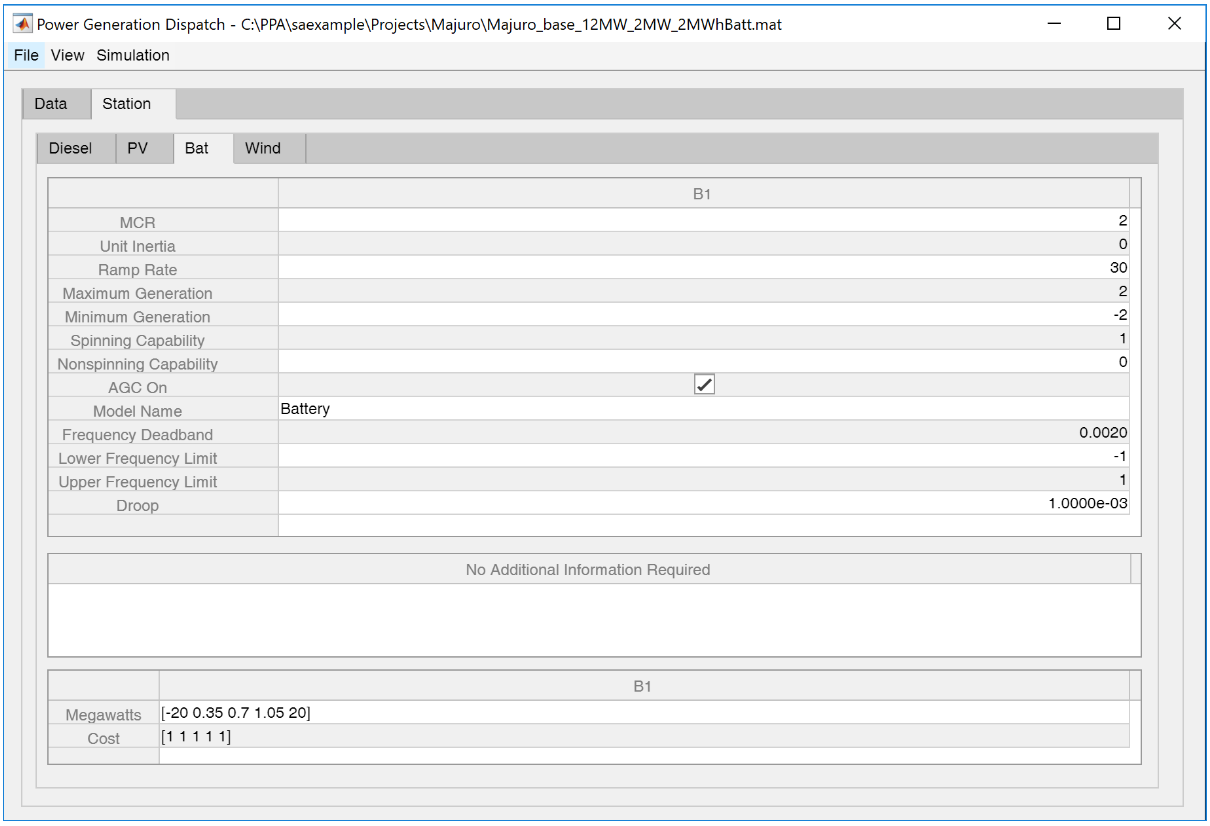
Case 14: Weekday (16 March 2017) - 4 MW of PV and 2 MW / 2 MWh battery on primary frequency control

Batteries can be used for primary frequency control only and thus only respond to frequency variations. For these simulations, the battery control parameters are shown in A 2 MW / 2 MWh battery costs US$ $209,821 per annum or US$ 575 per day.

Figure 3-41. The deadband is set to 0.1 Hz and thus the battery will respond to frequency variations outside of this range and droop is set to 0.1 %, thus a 0.1% change in frequency will result in 100% change in power. Thus, the battery will go from zero output to full output if the frequency drops from 59.9 to 59.85 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.1 to 60.15 Hz.

A 2 MW / 2 MWh battery costs US$ $209,821 per annum or US$ 575 per day.

Figure 3-41 Battery parameters when on primary frequency control only



The simulated frequency improves when a 2 MW battery is on primary frequency control only, as shown in Figure 3-42. The battery is sufficient to prevent the few frequency excursion, as shown in Figure 3-43. The diesel fuel costs remain almost the same at $20.747 as for case 13 showing the battery is just performing primary frequency control and the battery on discharges a few percent. The net cost of US$ 168 is calculated for the simulation day including the battery costs.

Figure 3-42 Simulated frequency for weekday with 4 MW of PV and 2 MW / 2 MWh battery on primary frequency control

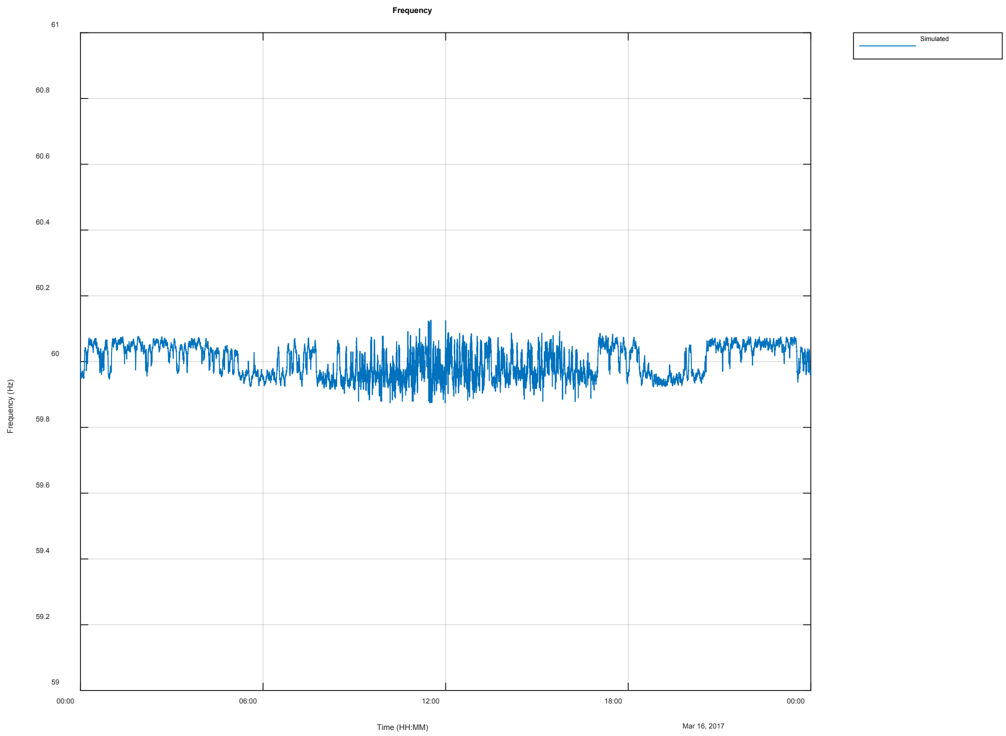
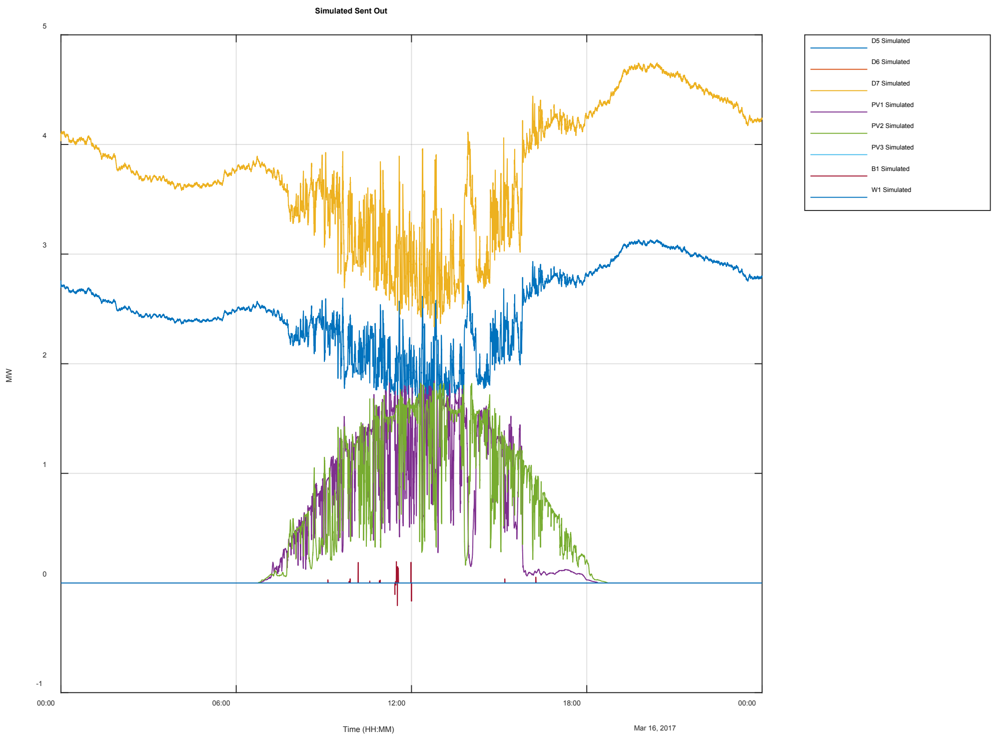


Figure 3-43 Simulated generation for weekday with 4 MW of PV and 2 MW / 2 MWh battery on primary frequency control



Case 15: Weekday (16 March 2017) - 8 MW of PV and 2 MW / 2 MWh battery on primary frequency control

For Case 15 the PV power plants are set to 4 MW each giving a total PV of 8 MW, Diesel units D5 and D7 provides the secondary control under AGC to perform the control assisted by a 2 MW / 2 MWh battery on primary frequency control, as shown in Figure **3-44** . The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in Figure **3-45**. The battery full range is not fully utilised to control the frequency and so battery size is adequate for frequency control for this simulation case.

All of the available energy from the 8 MW of PV is used resulting in a fuel saving of US$4,509 and a net saving of US$ 602 for the simulation day.

Figure 3-44 Simulated generation for weekday with 8 MW of PV and 2 MW / 2 MW battery on primary frequency control

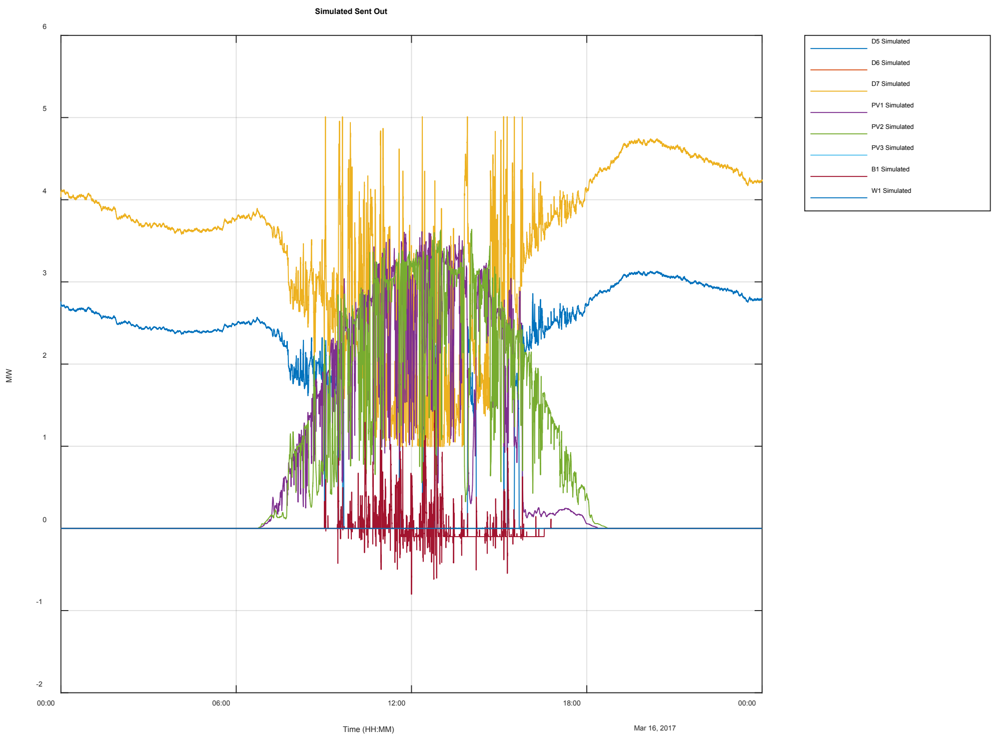
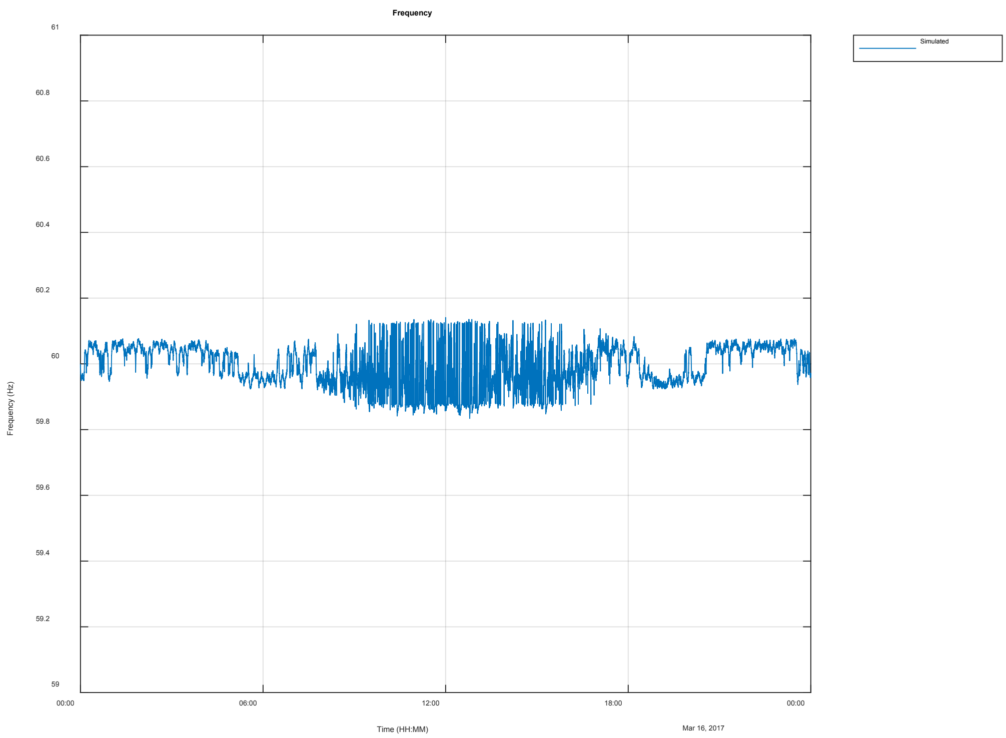


Figure 3-45 Simulated frequency for weekday with 8 MW of PV and 2 MW / 2 MWh battery on primary frequency control



<u>Case 16: Weekday (16 March 2017) – 12 MW of PV and 2 MW / 2 MWh battery on AGC</u>

Case 16 is simulating the same as Case increasing the PV to 12 MW and on AGC. The batteries also provide primary frequency control as for the simulations above. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

1. Starting batteries with a charge of 20% - assuming batteries have been utilised the previous evening – update to actual midnight value to give a typical continuous day's profile (need to run simulation twice)
2. Battery is discharged whenever possible to displace diesel. Battery provide power at half their potential – keeping the remaining half available for primary frequency control
3. Battery is charged using any excess PV available – when PV exceeds demand minus diesel generation minimum demand. Battery is charge to 95% keeping some capacity for primary frequency control high frequency response after charging.
4. The discharge level is limited by the AGC controller to 50% of the battery size to ensure frequency is controlled at the same time as optimising the energy available – essentially system security before economics

Figure 3-46 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost full charge level, as shown in Figure 3-47, by 12:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 17:30. The simulated diesel generator 1 output is at minimum generation for most of the period from 10:00 Hrs to 16:30 Hrs, as shown in Figure 3-48.

The fuel savings for Case 16 is $ 6,433 compared to $ 4,509 for Case 15. This reduction is due to an increase PV output of 14.5 MWh and this case has a net saving of $ 622.

Figure 3-46 Simulated battery output for weekday when 2 MW / 2 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

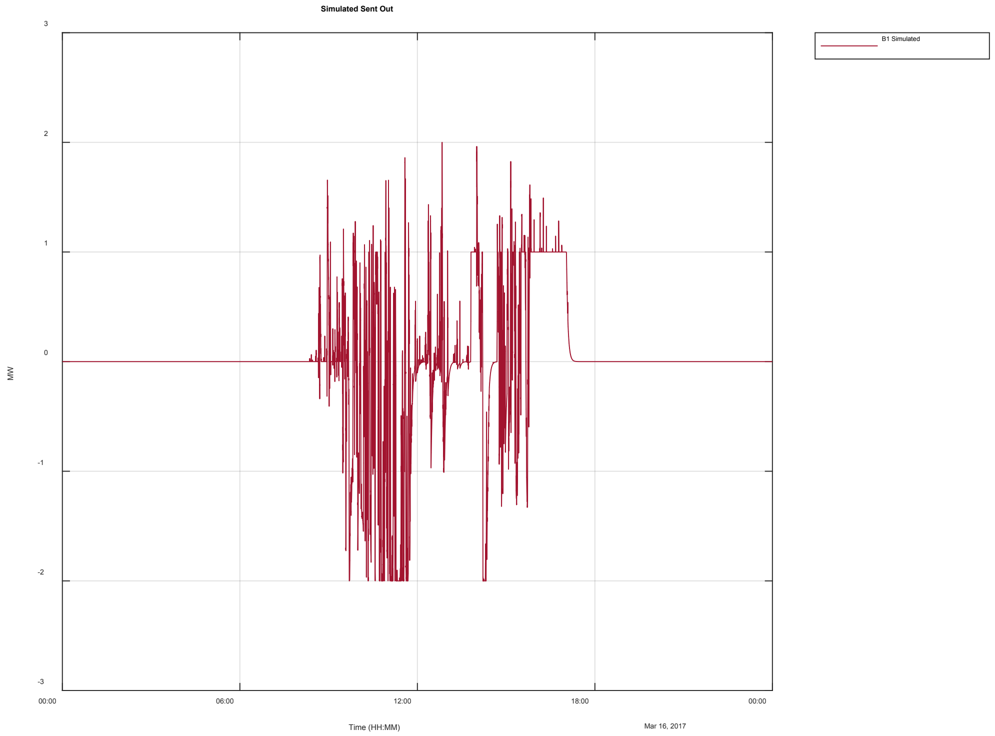


Figure 3-47 Simulated battery charge level for weekday when 2 MW / 2 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

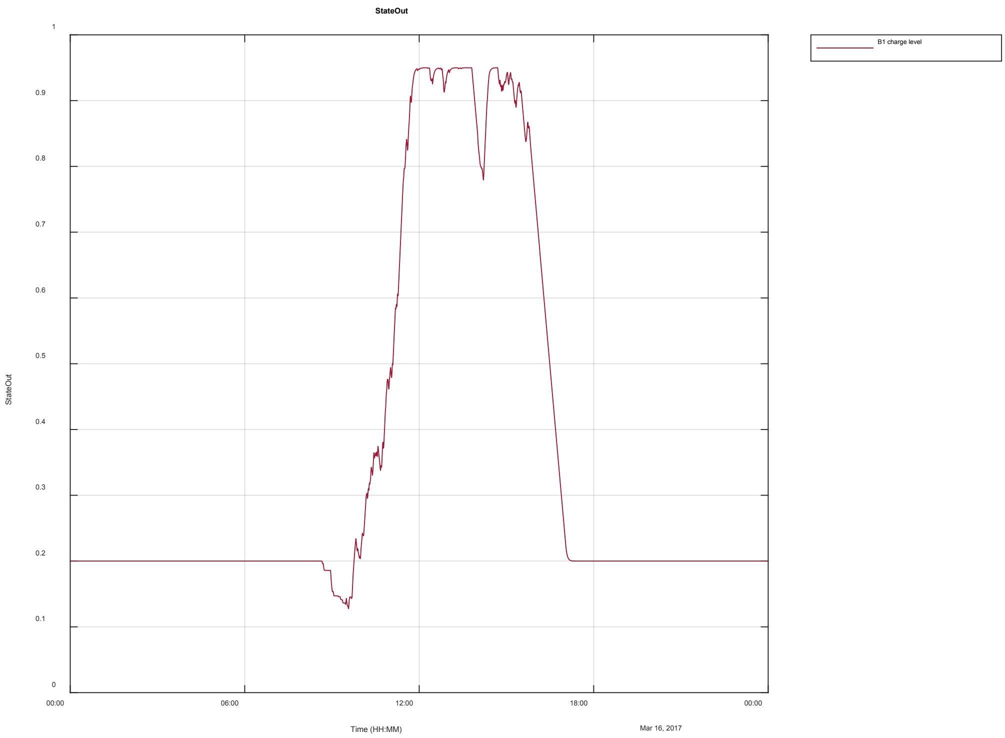
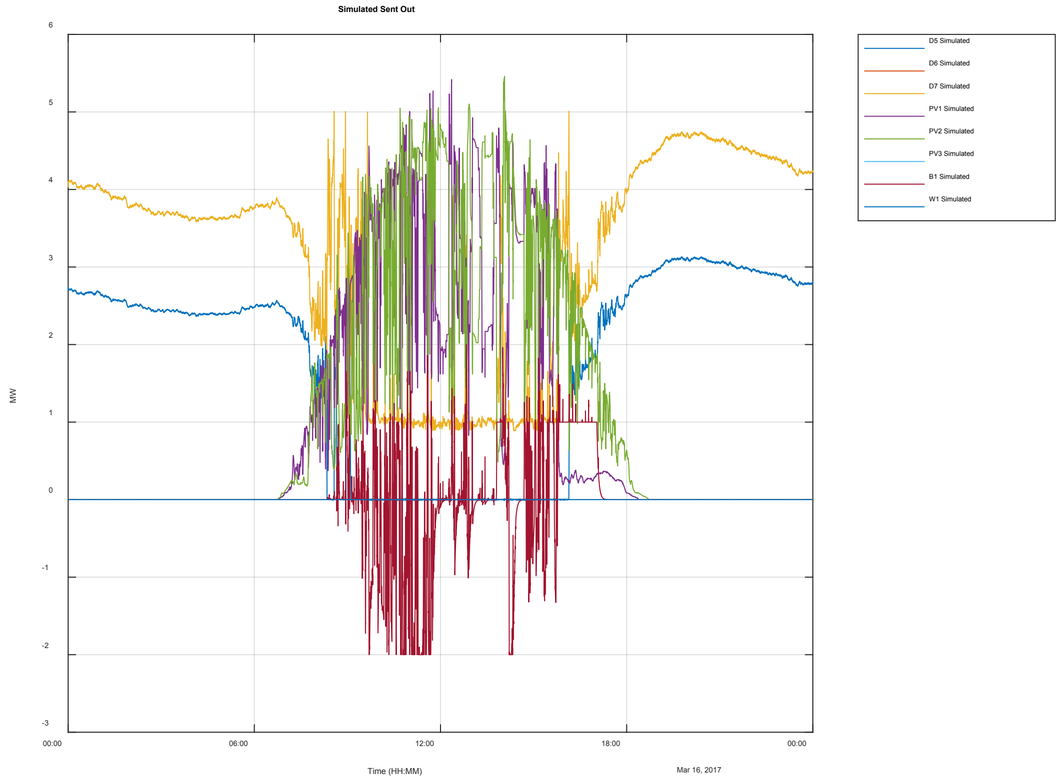


Figure 3-48 Simulated generator outputs for weekday when 2 MW / 2 MWh battery provides both primary frequency control and AGC with 12 MW of PV.



<u>Case 17: Weekday (16 March 2017) – 16 MW of PV and 16 MW / 32 MWh battery on AGC</u>

This case is where the PV is increased to 16 MW and a 16 MW / 32 MWh battery is on AGC and primary frequency control. The simulated generation, as shown in Figure 3-49, shows that the inverter size required is around 8 MW.

The simulated frequency is within acceptable limits, as shown in Figure 3-50. There are a no frequency excursions which means the inverter size is adequate. The battery charges to 85% by 16:30 and fully discharges by 20:00, as shown in Figure 3-51.

The energy is fully utilised and thus the battery is adequately sized for this simulation day. This case has a net loss of $ 3,475 for the simulation day. This loss could be reduced by $1,220 per day if inverters were only 8 MW in size.

Figure 3-49 Simulated generation output for weekday when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV.

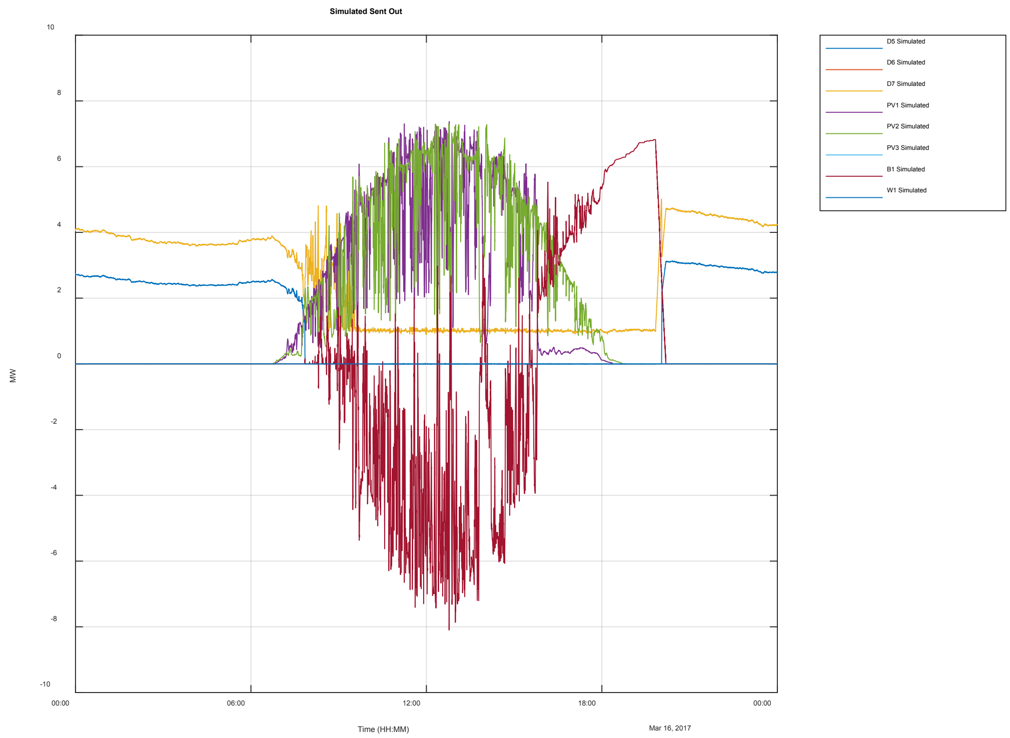


Figure 3-50 Simulated frequency for weekend when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV.

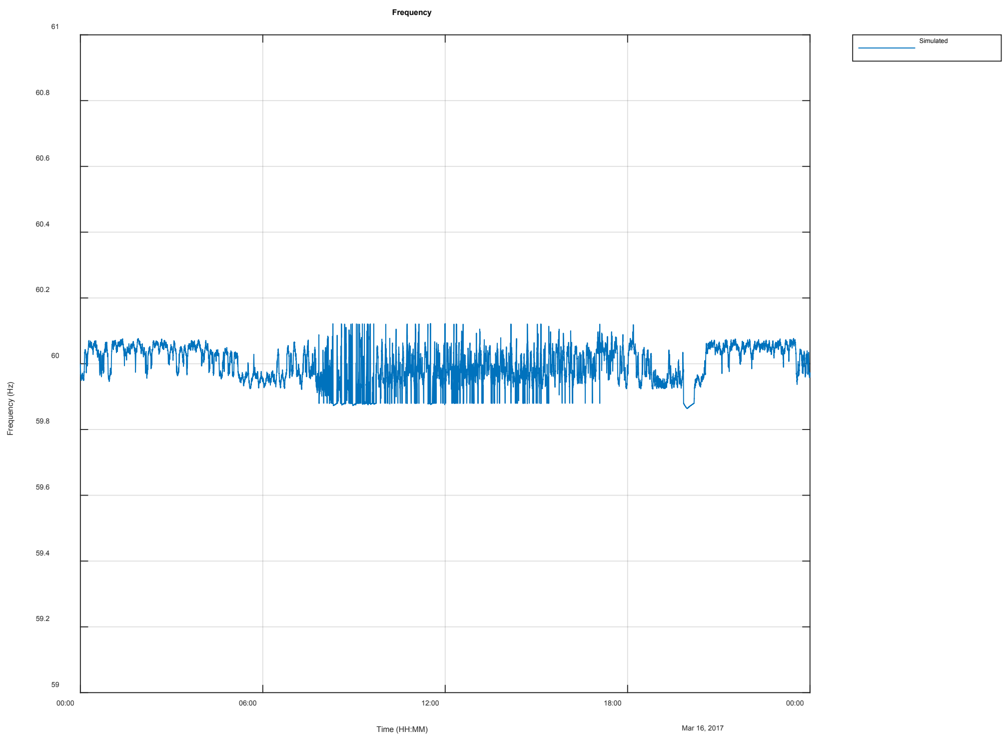
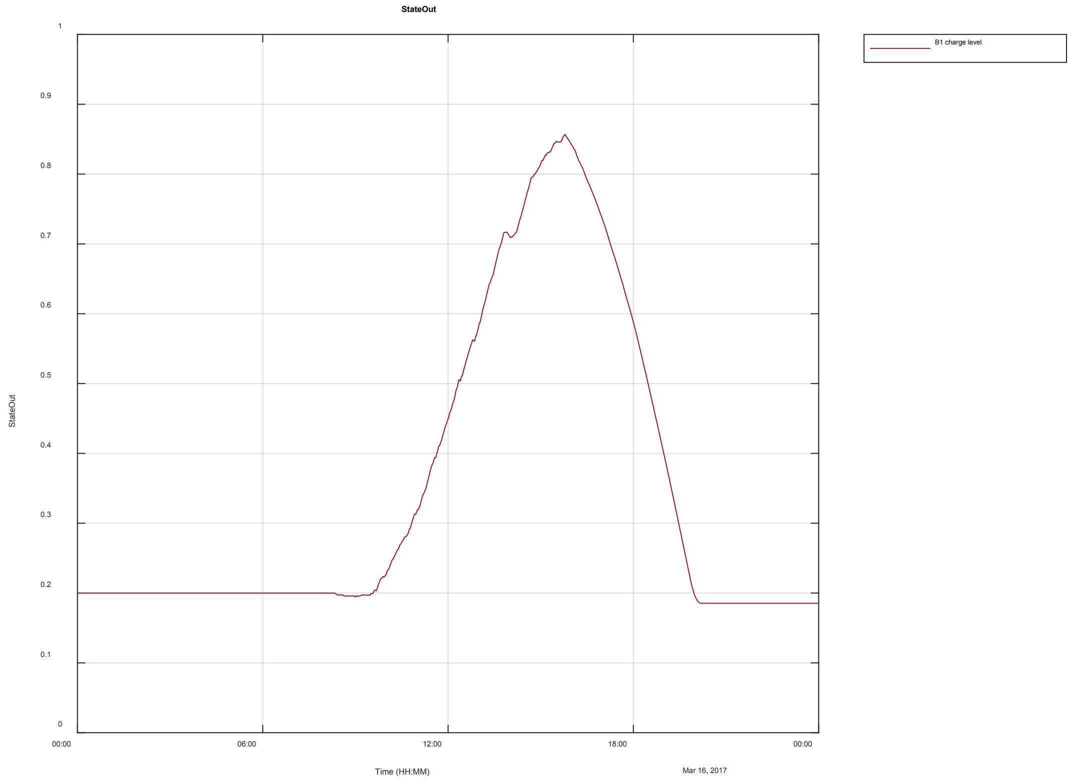


Figure 3-51 Simulated battery charge level for weekday 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV.



<u>Case 18: Weekday (16 March 2017) – 16 MW of PV and 16 MW / 32 MWh battery on AGC and all diesel off</u>

This case is a repeat of Case 17 but now the last diesel unit is allowed to go off line. The simulated frequency is within acceptable limits even when the last unit is off, as shown in Figure 3-52. There are a few frequency excursions which means the inverter size is adequate could be bigger as it is often at full charge MW output level, as shown in Figure 3-53. The battery only charges to 65% and all diesel units are off until 19:00.

The nett loss with all units off is slightly reduced to $ 3,290 compared to case 17 of $3,836. As for Case 6 an inverter size of 8 MW is sufficient to control frequency which could reduce daily costs by $ 1,220.

Figure 3-52 Simulated frequency for weekday when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.

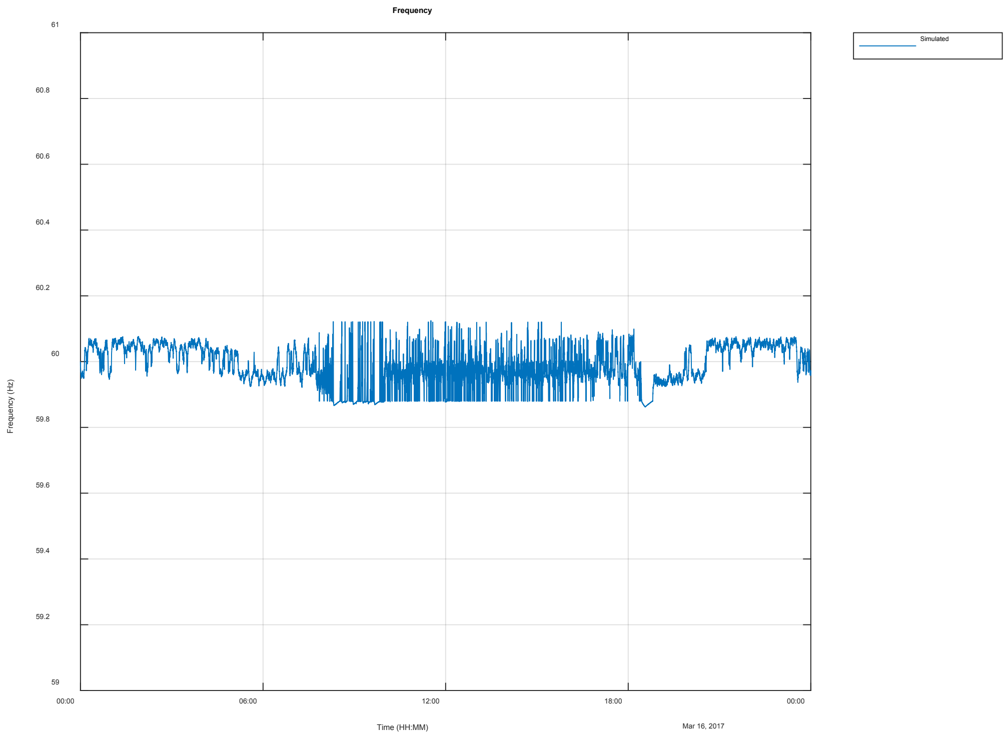
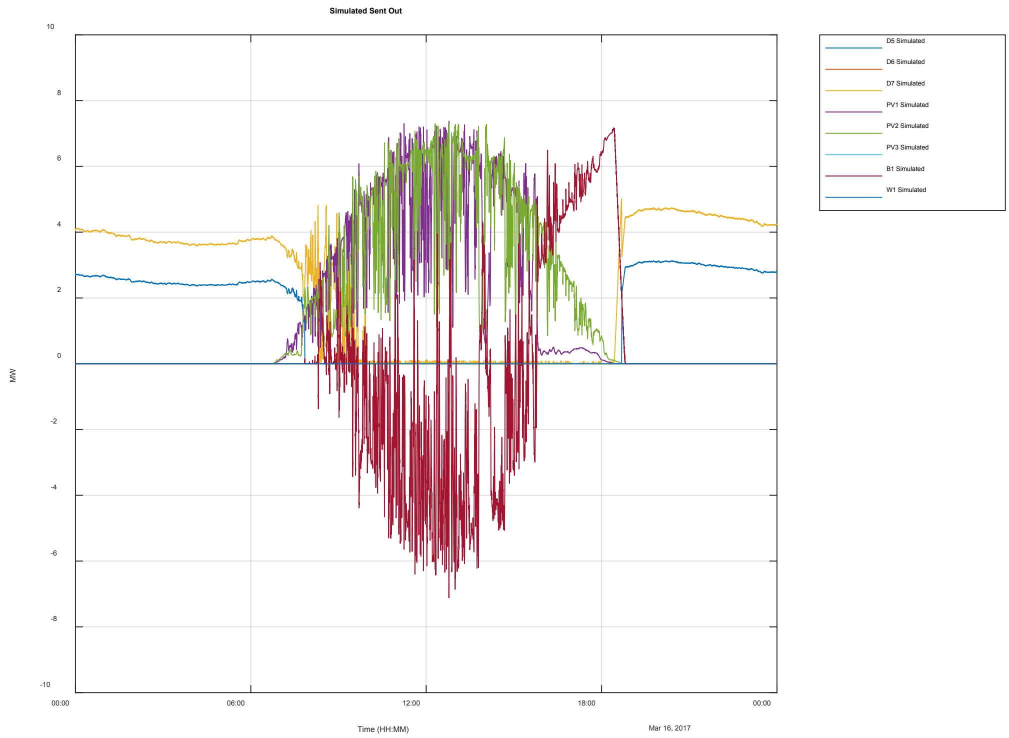


Figure 3-53 Simulated generation output for weekday when 16 MW / 32 MWh battery provides both primary frequency control and AGC with 16 MW of PV. All diesel units allowed to go off.



3.3.4 Base Case 4 & Simulation cases 19 – 24 (5 Oct 2017) with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017

<u>Base Case 2: Weekday (5 Oct 2017) - Simulation of original day with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017.</u>

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-54 shows the simulation of generation unit outputs for Thursday 5 October, with PV1 of 0.6 MW from 14 March 17 and PV2 of 0.4 MW from 15 March 2017. This is the base case for these simulations where we can compare techno-economic impact of cases 7 to 12. The simulated frequency, as shown in Figure 3-55, shows an improvement in frequency compared to the recorded frequency as the simulated frequency is with AGC and the recorded frequency is without AGC.

Figure 3-54 Simulated generation on weekday with current installed PV

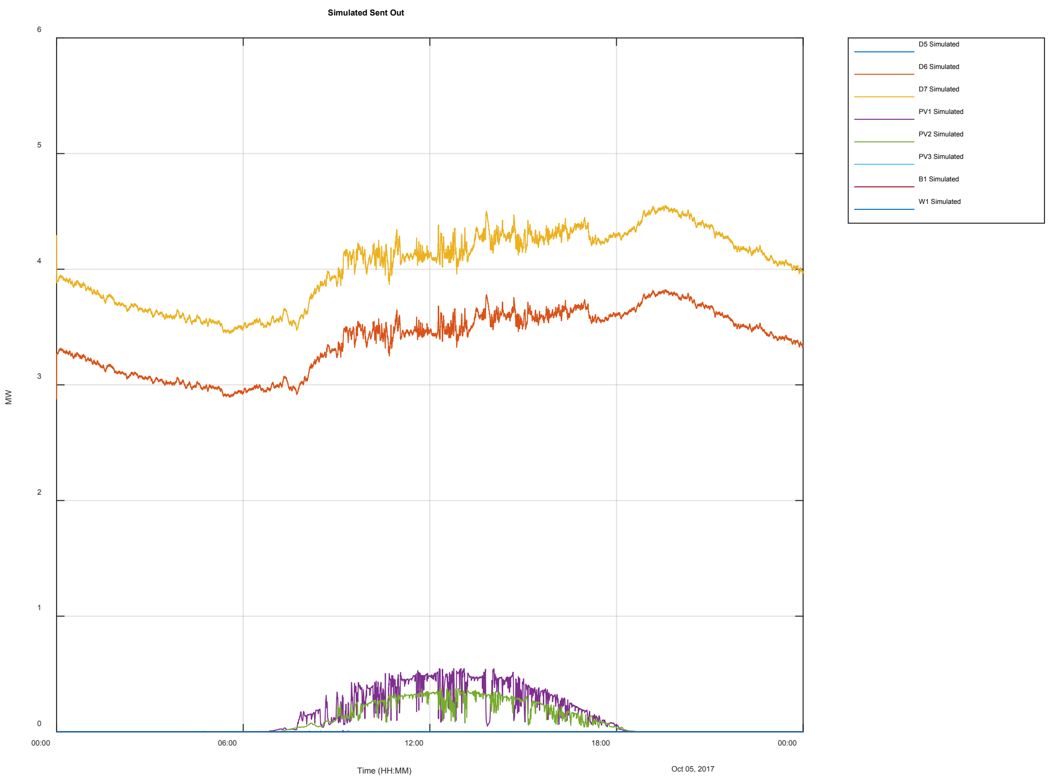
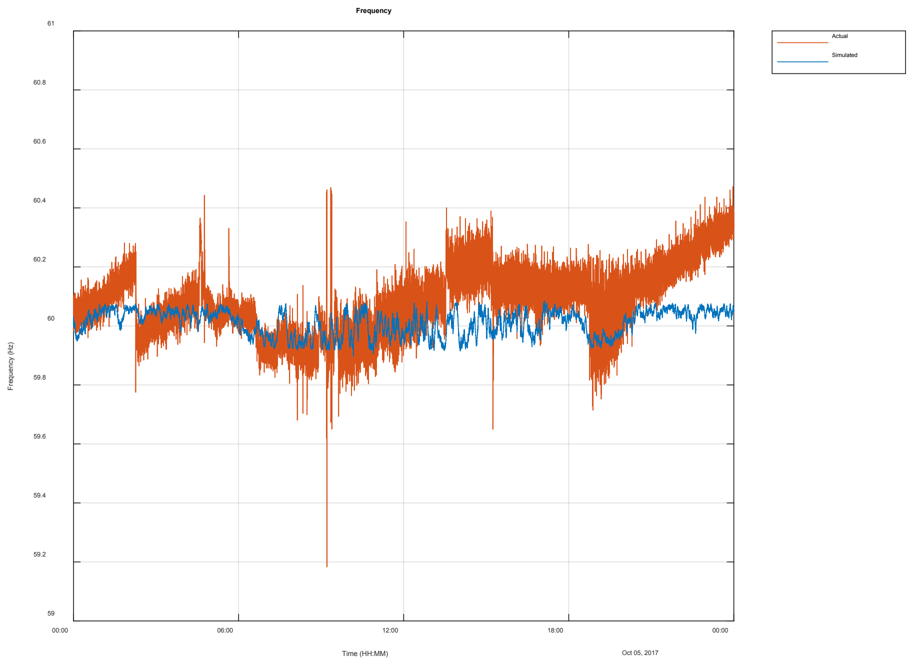


Figure 3-55 Simulated frequency on weekday with current installed PV



<u>Cases 19- 24: Weekday – Repeat of cases 13-18 with demand from 5 October and PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017.</u>

Cases 19 - 24 is the repeat of the simulations for a typical weekday but with a demand from 5 October and PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017. The simulated frequency is within an acceptable range for case 19 with 4 MW total PV simulated and no batteries, as shown in Figure 3-56 but the simulated frequency control is worse with the more volatile PV variations. Case 21 with 8 MW of simulated PV with a 2 MW / 2 MWh battery on primary frequency control results in an acceptable frequency control within acceptable limits of 59.5 to 60.5 Hz, as shown in Figure 3-57. Case 22 with 12 MW of simulated PV with a 2 MW / 2 MWh battery on AGC also results in an acceptable frequency control but with a few excursions which suggest a larger inverter is required, as shown in Figure 3-58. Case 24 with the16 MW of PV and 16 MW / 32 MWh battery on AGC has a very similar same results as for case 16.

The fuel savings for the same scenario for the weekend cases are very similar except the PV production for the cases 13 -18 was slightly less than for cases 19 - 24 so daily fuel and net savings are lower.

The simulations also show that for cases 23 and 24 an 8 MW inverter is sufficient which reduces the daily costs by $ 1,220 as was the situation for last two cases for each simulation day. As only an 8 MW inverter is required this has been factored into the calculations below.

Table 3-6 Comparison of daily fuel saving and net savings for a weekday with different PV input data

Simulation description	Case 13 - 18 daily diesel fuel savings	Case 19 - 24 daily diesel fuel savings	Case 13 - 18 daily net savings	Case 19 - 24 daily net savings
4 MW PV and no battery	1,836	1,901	408	342
4 MW PV and 2 MW / 2 MWh battery on gov	1,835	1,902	-168	-276
8 MW PV and 2 MW / 2 MWh battery on gov	4,509	4,598	602	341
12 MW PV and 2 MW / 2 MWh battery on AGC	6,433	6,827	622	490
16 MW PV and 8 MW / 32 MWh battery on AGC	9,785	10,125	-2,255	-2,616
16 MW PV and 8 MW / 32 MWh battery on AGC and all diesel allowed to go off	9,970	10,365	-2,070	-2,377

Figure 3-56 Case 19 - Simulated frequency on weekday with 4 MW PV

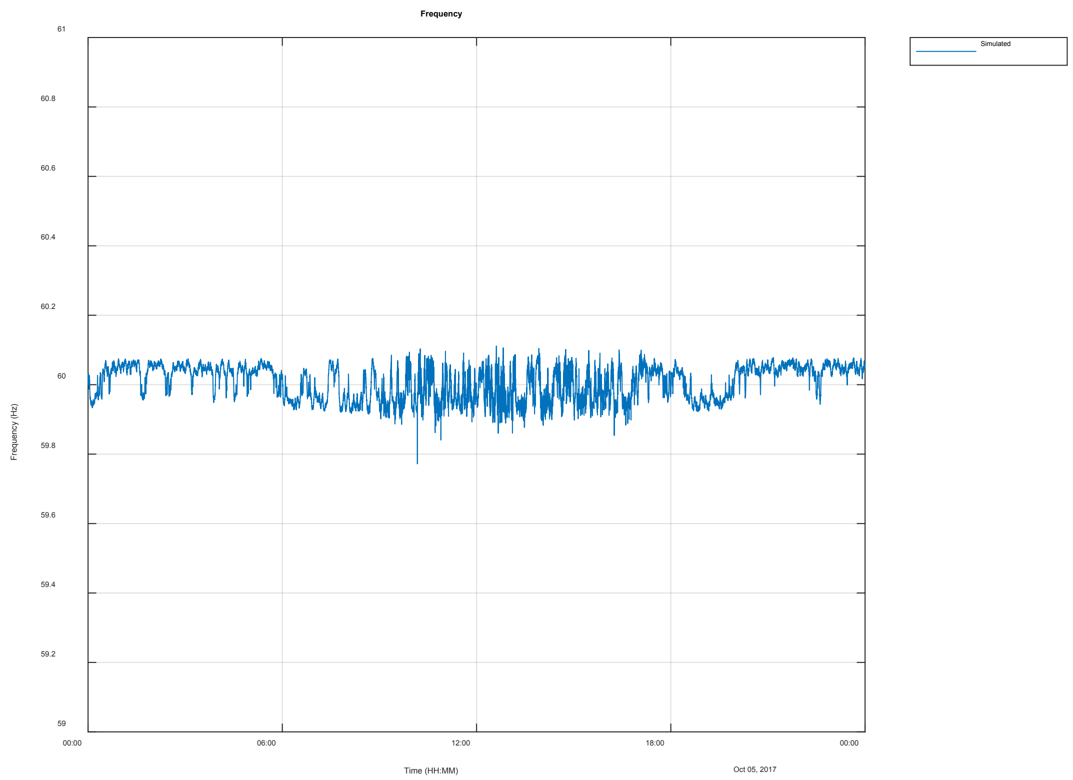


Figure 3-57 Case 21 - Simulated frequency on weekday with 8 MW PV and 2 MW / 2 MWh battery on primary frequency control

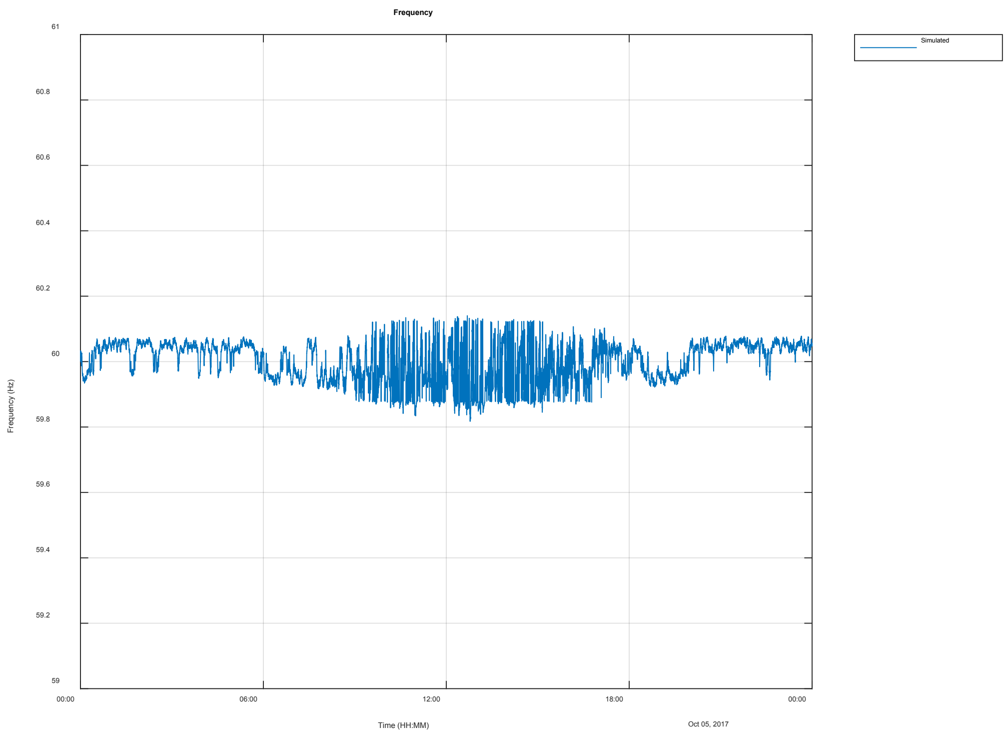


Figure 3-58 Case 22 - Simulated frequency on weekday with 12 MW PV and 2 MW/ 2 MWh battery on AGC and primary frequency control.

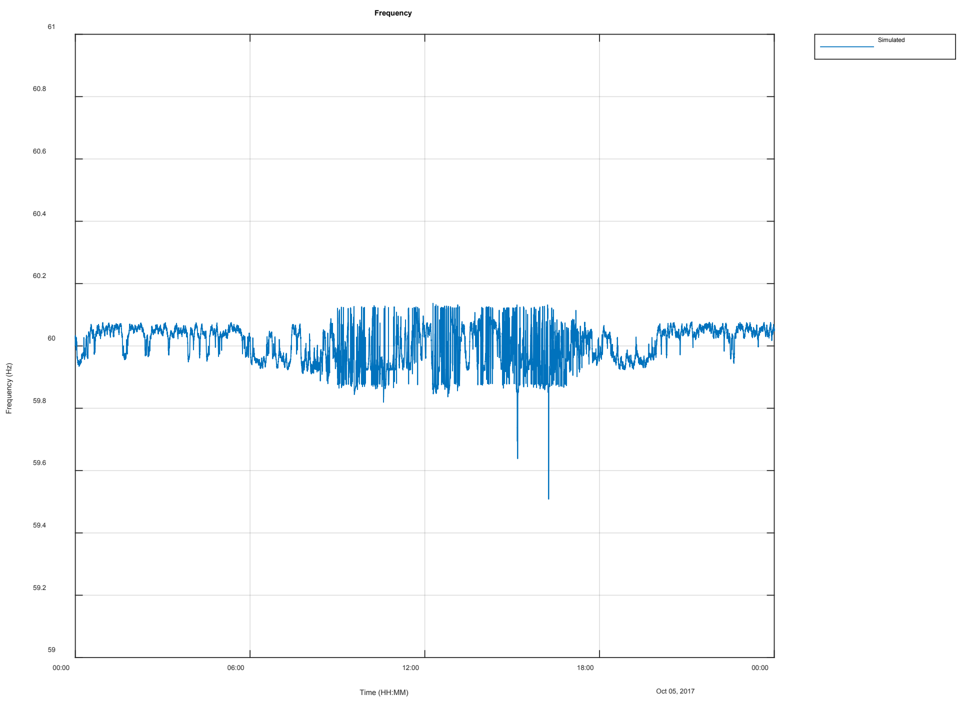
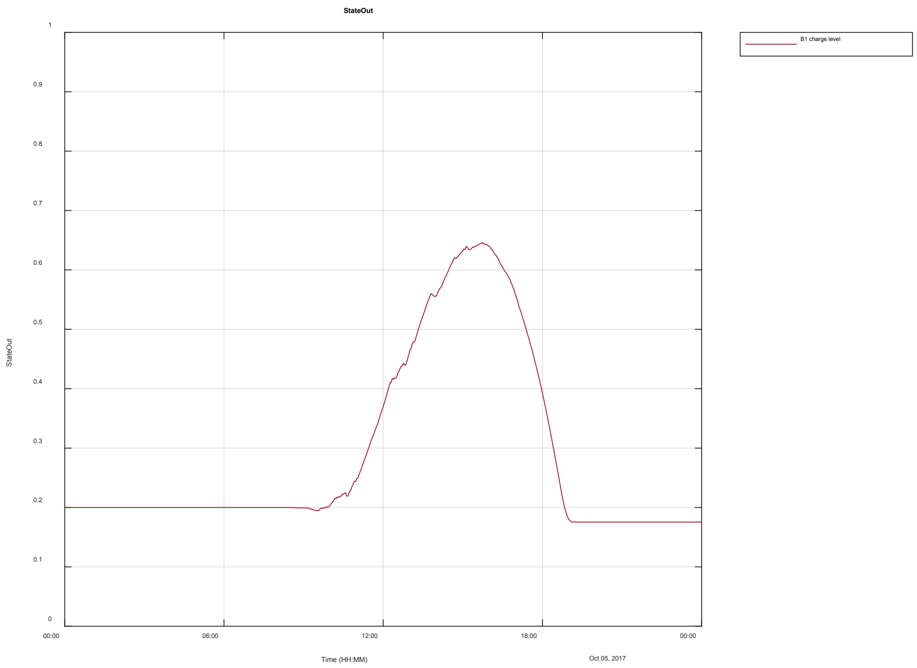


Figure 3-59 Case 24 - Simulated charge level on weekday with 16 MW of PV and 16 MW / 32 MWh battery on AGC and all diesel units off.



3.4 Financial Assessment of incorporating Storage

The simulations economic results are shown in Table **3-7**. The results are the calculated daily fuel consumed for the simulation case which is based on the fuel cost curve, as shown in Figure 3-11 and calculated every second. This is to obtain a reasonably accurate fuel calculation which depends directly on the instantaneous power the unit is producing.

The fuel percentage is the comparison of the base case for each day, which sets the benchmark for further studies.

The diesel power produced is to determine the average price per MWh. The PV power produced and the maximum that could have been produced shows if it was required to reduce the PV power output for frequency control. This is done as a last resort when the diesel or batteries cannot control frequency, the percentage reduction is an indication of the increased costs for the energy produced by the PV plants. Thus, if the PV is reduced by 10% then the average price for PV is increased by the same percentage.

Table 3-7 Summary of economic results of simulations

No	Sim demand date	PV Installed (MW)	Diesel fuel costs	% fuel to sim base	Diesel MWh	PV MWh	PV max (MWh)	PV MWh reduced	% reduction	Comments
Base 1	11 Mar 17	1	21,967	100%	154.1	4.8	4.8	0.0	0.0%	off
1	11 Mar 2017	4	20,149	92%	139.6	19.2	19.04	-0.2	-1.1%	off
2	11 Mar 2017	4	20,149	92%	139.6	19.2	19.04	-0.2	-1.1%	2 MW / 2 MWh on Gov
3	11 Mar 2017	8	17,451	79%	120.5	38.2	38.08	-0.2	-0.4%	2 MW / 2 MWh on Gov
4	11 Mar 2017	12	15,592	71%	106.8	52.0	57.12	5.1	8.9%	2 MW / 2 MWh on Gov & AGC
5	11 Mar 2017	16	12,186	55%	81.5	77.0	76.16	-0.8	-1.1%	8 MW / 32 MWh on Gov & AGC
6	11 Mar 2017	16	11,993	55%	81.3	77.0	76.16	-0.8	-1.1%	8 MW / 32 MWh on Gov & AGC – diesel off
Base 2	7 Oct 2017	1	22,775	100%	159.7	5.2	5.2	0.0	0.0%	off
7	7 Oct 2017	4	20,789	91%	143.9	20.9	20.79	-0.1	-0.6%	off
8	7 Oct 2017	4	20,790	91%	143.9	20.9	20.79	-0.1	-0.6%	2 MW / 2 MWh on Gov
9	7 Oct 2017	8	17,862	78%	123.1	41.7	41.58	-0.1	-0.2%	2 MW / 2 MWh on Gov
10	7 Oct 2017	12	16,043	70%	109.6	55.2	62.38	7.2	11.5%	2 MW / 2 MWh on Gov & AGC
11	7 Oct 2017	16	12,366	54%	82.2	82.2	83.17	0.9	1.1%	8 MW / 32 MWh on Gov & AGC
12	7 Oct 2017	16	11,957	53%	80.4	83.7	83.17	-0.5	-0.6%	8 MW / 32 MWh on Gov & AGC – diesel off
Base 3	16 Mar 2017	1	22,582	100%	158.3	4.8	4.76	0.0	0.0%	off
13	16 Mar 2017	4	20,746	92%	143.8	19.2	19.04	-0.2	-1.1%	off
14	16 Mar 2017	4	20,747	92%	143.8	19.2	19.04	-0.2	-1.1%	2 MW / 2 MWh on Gov
15	16 Mar 2017	8	18,073	80%	124.7	38.2	38.08	-0.1	-0.4%	2 MW / 2 MWh on Gov
16	16 Mar 2017	12	16,150	72%	110.3	52.7	57.12	4.4	7.7%	2 MW / 2 MWh on Gov & AGC
17	16 Mar 2017	16	12,797	57%	85.6	77.0	76.16	-0.8	-1.1%	8 MW / 32 MWh on Gov & AGC
18	16 Mar 2017	16	12,612	56%	85.4	77.0	76.16	-0.8	-1.1%	8 MW / 32 MWh on Gov & AGC – diesel off
Base 4	5 Oct 2017	1	23,314	100%	170.1	5.2	5.2	0.0	0.0%	off
19	5 Oct 2017	4	21,413	92%	154.4	20.9	20.79	-0.1	-0.6%	off

20	5 Oct 2017	4	21,412	92%	154.4	20.9	20.79	-0.1	-0.6%	2 MW / 2 MWh on Gov
21	5 Oct 2017	8	18,716	80%	133.4	41.8	41.58	-0.2	-0.5%	2 MW / 2 MWh on Gov
22	5 Oct 2017	12	16,487	71%	116.5	58.8	62.38	3.6	5.8%	2 MW / 2 MWh on Gov & AGC
23	5 Oct 2017	16	13,189	57%	91.0	83.7	83.17	-0.5	-0.6%	8 MW / 32 MWh on Gov & AGC
24	5 Oct 2017	16	12,950	56%	90.7	83.7	83.17	-0.5	-0.6%	8 MW / 32 MWh on Gov & AGC – diesel off

The simulations show that it is possible to increase the renewable energy penetration up to 4 MW with no battery support, but diesel units must be on AGC. A 2 MW / 2 MWh battery can sustain 8 – 12 MW of PV without a negative impact on frequency control. An 8 MW / 32 MWH battery size is required for a PV of 16 MW to utilise the excess energy from the PV and maintain adequate frequency control and the financials below are based on a 8 MW /32 MWh battery for the last two simulations in each base case.

Table 3-8 shows a summary of the simulation cases in order to get an idea of how much saving is possible for including the annualised costs of PV and Battery. This is the summary is an average of the two PV simulation data sets used for cases.

The PV costs is estimated to be US$0.10 /kWh and the PV energy costs is calculated by the energy that could have been produced multiplied energy cost. Inverter costs are estimated at US$ 500 per kW and battery at US$ 375 / kWh installed

The technical ability to take off all diesel units needs further analysis but saves more than US$ 200 per day.

Table 3-8 Summary of a key cases and estimated costs and overall savings per day

No	PV MW	Diesel fuel costs	fuel savings	$/kwh	% fuel to base	Diesel MWh	PV MWh	PV max MWh	PV reduced	% reduction	Add. PV energy costs	Add. Battery cost	net saving
1 & 7	4	20,469	1,498	0.144	92%	141.8	20.1	19.9	-0.2	-0.8%	1,494		408
2 & 8	4	20,470	1,497	0.144	92%	141.7	20.1	19.9	-0.2	-0.8%	1,494		-167
3 & 9	8	17,657	4,310	0.145	79%	121.8	40.0	39.8	-0.1	-0.3%	3,485	575	654
4 & 10	12	15,818	6,149	0.146	71%	108.2	53.6	59.7	6.1	10.2%	5,477	575	501
5 & 11	16	12,276	9,691	0.150	55%	81.8	79.6	79.7	0.1	0.0%	7,469	4,901	-2,274
6 & 12	16	11,975	9,992	0.148	54%	80.8	80.3	79.7	-0.7	-0.8%	7,469	4,901	-1,973
13 & 19	4	21,079	1,869	0.142	92%	149.1	20.1	19.9	-0.2	-0.8%	1,494		375
14 & 20	4	21,080	1,869	0.141	92%	149.1	20.1	19.9	-0.2	-0.8%	1,516		-222
15 & 21	8	18,395	4,554	0.143	80%	129.1	40.0	39.8	-0.2	-0.4%	3,507	575	472
16 & 22	12	16,318	6,630	0.144	71%	113.4	55.8	59.7	4.0	6.7%	5,499	575	556
17 & 23	16	12,993	9,955	0.147	57%	88.3	80.3	79.7	-0.7	-0.8%	7,490	4,901	-2,436
18 & 24	16	12,781	10,167	0.145	56%	88.1	80.3	79.7	-0.7	-0.8%	7,490	4,901	-2,224

The simulations show that with 4 MW of PV power plants and no batteries will save US$ 408 for a weekend day and a simulated saving of US$375 for the week day. 12 MW of PV power plants and keeping 2 MW / 2 MWh battery on primary frequency control and AGC gives an additional cost of US$ 501 for a weekend day and US$556 for the week day. 16 MW of PV power plants and keeping 8 MW / 32 MWh battery on primary frequency control and AGC gives an additional cost of US$ 2,274 for a weekend day and US$2,436 for the week day

Switching the last unit off during the day saving on fuel running last unit at minimum generation will realise more savings US$ 200 a day but the practicality needs to be checked.

Annualising the savings from these simulations gives a rough estimate of the value of batteries from a security perspective alone and then from a 'less' secure perspective where the energy stored is utilised between 20 and 95% of battery capacity.

Annualising the solar costs, battery costs and fuel savings by simply taking the weekend results multiplied by 2 days and 52 weeks and the week day results multiplied by 5 days and 52 weeks gives a very rough estimate of the potential annual savings shown in Table 3-9.

The case of 4 MW of PV and no battery has an estimated saving of US$ 140,000 per annum. The 8 and 12 MW cases with 2 MW / 2 MWh battery has an annual estimated saving of US$ 190,000. The case where 16 MW of PV is installed with 8 MW / 32 MWh battery the annual estimated costs increase around US$ 800,000 per annum.

Table 3-9 Estimated annualised solar and battery costs and fuel savings

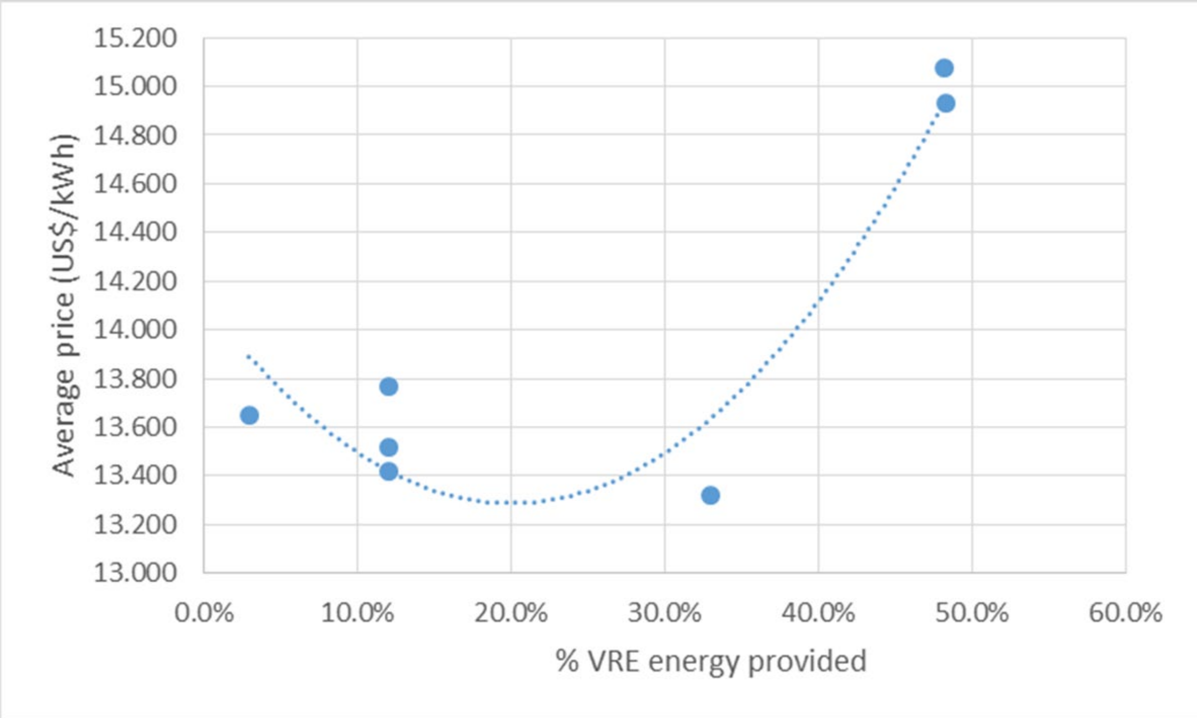
Description	PV Installed (MW)	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated additional battery costs (pa)	Estimated nett saving (pa)
4 MW PV and no battery	4	13%	683,701	543,707	0	139,995
4 MW PV and 2 MW / 2 MWh battery on gov	4	50%	683,565	549,401	209,247	-75,083
8 MW PV and 2 MW / 2 MWh battery on gov	8	50%	1,674,214	1,274,343	209,247	190,624
12 MW PV and 2 MW / 2 MWh battery on AGC	12	100%	2,405,237	1,999,286	209,247	196,705
16 MW PV and 8 MW / 32 MWh battery on AGC	16	150%	3,638,267	2,724,228	1,783,824	-869,785
16 MW PV and 8 MW / 32 MWh battery on AGC and all diesel allowed to go off	16	200%	3,724,678	2,724,228	1,783,824	-783,374

The 'variable' costs for a system is typically just the diesel cost divided by the energy produced by all power plants, which for the base case is estimated to be US$ 8,293,080 at an average 13.8 USc/ kWh. The total variable costs (including additional VRE and battery costs) decrease by 2 % when there is 8 - 12 MW of PV, and 2 MW / 2 MWh battery. The average 'variable' tariff drops to 13.3 USc/ kWh in these cases. For the 16 MW of PV and a 8 / 32 MWh battery the tariff increases 10% to 15 USc/kWh.

Table 3-10 Estimated annualised solar and battery costs and fuel savings

Description	PV Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total 'variable' costs from base cases
4 MW PV and no battery	4	50%	8,153,085	13.416	2%
4 MW PV and 2 MW / 2 MWh battery on gov	4	50%	8,368,163	13.770	-1%
8 MW PV and 2 MW / 2 MWh battery on gov	8	100%	8,102,456	13.330	2%
12 MW PV and 2 MW / 2 MWh battery on AGC	12	150%	8,096,375	13.322	2%
16 MW PV and 8 MW / 32 MWh battery on AGC	16	200%	9,162,865	15.076	-10%
16 MW PV and 8 MW / 32 MWh battery on AGC and all diesel allowed to go off	16	200%	9,076,454	14.934	-9%

Figure 3-60 Average variable tariff as VRE energy is added



3.5 Tariff Impact Assessment

This section is examining the impact that the introduction or substitution of VRE has on current tariffs. The Pacific Power Association (PPA) published every year the Benchmarking Report which shows the Average Supply Costs for all member islands and the published tariff in the year. The following Table 3-11 gives a good indication of what the average supply costs (US Cents/kWh) were over the past years and the year on year fluctuations mainly due to fuel cost changes.

Table 3-11: Average Supply Costs (US Cents/kWh)[15]

		2012	2013	2014	2015	2016	2017	average
Tuvalu	TEC	96.60	85.66	n/a	91.91	67.22	48.61	**78.00**
Kosrae	KUA	50.40	54.42	61.54	50.67	44.94	48.85	**51.80**
Yap	YSPSC	56.20	56.91	57.79	46.48	n/a	53.08	**54.09**
Chuuk	CPUC	56.60	61.26	55.13	42.71	38.27	35.21	**48.20**
Pohnpei	PUC	50.80	48.13	n/a	35.32	n/a	28.75	**40.75**
Majuro	MEC	44.30	45.60	46.51	38.94	29.62	34.86	**39.97**
Tonga	TPL	40.30	38.91	44.00	99.28	84.47	64.70	**61.94**
Samoa	EPC	42.00	44.36	43.76	45.12	n/a	28.22	**40.69**

In many cases the average annual tariff is not covering these costs as is shown in the below table that compares the average supply costs versus tariff.

15 Reference: PPA Benchmarking Report Fiscal year 2017 (published September 2018)

Table 3-12: Average Supply costs versus Tariffs for 2017 in US c/kwh[16]

		Average Supply Cost	Tariff
		2017	2017
Tuvalu	TEC	48.61	56.00
Kosrae	KUA	48.85	42.80
Yap	YSPSC	53.08	45.07
Chuuk	CPUC	35.21	47.13
Pohnpei	PUC	28.75	49.05
Majuro	MEC	34.86	34.60
Tonga	TPL	64.70	44.35
Samoa	EPC	28.22	42.15

Since the major cost component of the conventional power unit produced is that of fuel, the volatility in diesel prices has a major high-risk effect on the tariff. The tariff or levelized cost of electricity of solar PV and/or battery storage (in any combination) will reduce that risk drastically as the major cost is the capital cost which can be depreciated over time in a constant controllable manner. Further the studies and scenarios in the previous chapters have shown the optimal solution for each island and hence the impact assessment is looking at those and calculating the net effect on the tariff (2017) for all scenarios.

In the case of Majuro, several options of combining Solar PV with Battery storage have an impact on variable costs. The total decrease in total variable costs from the base case scenario would be 2%. Variable costs meaning fuel costs plus annualised costs of PV and battery. This is used to estimate the incremental system cost in each case.

Table 3-13: Majuro - Estimated annual total variable costs and percentage savings

Description	PV Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total 'variable' costs from base cases
4 MW PV and no battery	4	50%	8,153,085	13.416	2%
4 MW PV and 2 MW / 2 MWh battery on gov	4	50%	8,368,163	13.77	-1%
8 MW PV and 2 MW / 2 MWh battery on gov	8	100%	8,102,456	13.33	2%
12 MW PV and 2 MW / 2 MWh battery on AGC	12	150%	8,096,375	13.322	2%
16 MW PV and 8 MW / 32 MWh battery on AGC	16	200%	9,162,865	15.076	-10%
16 MW PV and 8 MW / 32 MWh battery on AGC and all diesel allowed to go off	16	200%	9,076,454	14.934	-9%

The impact of the changes in variable costs for each scenario and the overall impact on a tariff (in options have this percentage in 2017 terms) are illustrated below.

16 Reference: PPA Benchmarking Report Fiscal year 2017 (published September 2018)

Table 3-14: Estimated Impact on Supply Costs and Tariff (in 2017 annualised figures)

Description	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total 'variable' costs from base cases	2017 Supply Cost USc/kWh	Impact on Supply Cost	2017 Tariff Usc/kwh	Impact on Tariff
4 MW PV and no battery	8,153,085	13.416	2%	34.86	34.59	34.60	34.33
4 MW PV and 2 MW / 2 MWh battery on gov	8,368,163	13.77	-1%	34.86	35.00	34.60	34.74
8 MW PV and 2 MW / 2 MWh battery on gov	8,102,456	13.33	2%	34.86	34.59	34.60	34.33
12 MW PV and 2 MW / 2 MWh battery on AGC	8,096,375	13.322	2%	34.86	34.59	34.60	34.33
16 MW PV and 8 MW / 32 MWh battery on AGC	9,162,865	15.076	-10%	34.86	36.37	34.60	36.11
16 MW PV and 8 MW / 32 MWh battery on AGC and all diesel allowed to go off	9,076,454	14.934	-9%	34.86	36.20	34.60	35.94

The best-case scenarios as described above would have no significant impact on the tariff as the savings in variable costs are not significant and generally tariffs reflecting supply costs already. The average supply costs of around US cents 40 /kwh for the years 2012-2017 have been relatively steady compared to other islands.

3.6 Recommendations for application of storage

The studies show that 4 MW of PV can be installed without the need for batteries primary frequency control support. More than 4 MW of installed PV will require batteries for frequency control.

The secure strategy would be to install 2 MW of battery for primary frequency control once installed PV is more than 4 MW. The simulations show that the 2 MW / 2 MWh battery is probably sufficient for 12 MW of installed PV but this strategy requires that all major PV plants can reduce their output from a centralised control system (AGC).

The most optimal economic solution of the simulations performed is 2 MW / 2 MWh battery with 8 - 12 MW of installed PV giving an estimated annual savings of US$ 190,000.

The simulations show that installing 16 MW of PV with 8 MW / 32 MWh of battery with the current demand will increase the variable component of the tariff by 10% from 13.3 to 15 USc / kWh. This is not a major increase on the overall tariff. These studies would need to be repeated on the new demand, PV costs and battery costs in a few years' time to determine the next optimal step.

4 Task 3: Supporting the Development or Revision of Grid Codes

Please refer to Appendix 1

5 Task 4: Assessment of the needs for Supervisory control and data acquisition (SCADA) and Energy Management System (EMS)

5.1 Background: SCADA Systems

Supervisory Control and Data Acquisition (SCADA) is an Information Technology System which the main task is to communicate with remote elements, obtain information from them and import to a central control system with capacity to store, validate and monitor the values imported.

Main functions of the SCADA are:

1. Data Acquisition
2. Communications Management
3. Information Validation and conversion to engineering units
4. Alarm subsystem
5. Monitoring and trending
6. Supervisory Control

The values stored are used also by applications oriented to different aspects of the System.

In SCADA Systems used in electricity systems, complementary functions can be incorporated:

1. Generation Control Functions
2. Network Control
3. Quality assurance
4. System Economic Optimization
5. System Planning

Those aspects are developed in the following points in the context of island distribution systems with conventional diesel generators, and Renewable Energy installations, including roof top installations.

5.2 SCADA Systems Basic activity

As indicated into the acronym of SCADA, **S**ystem **C**ontrol **a**nd **D**ata **A**cquisition, is the basic package which collects information from remote sources of information and validates it, monitors alarm violations, performs control actions, Communications Management and System Monitoring. In addition, it can have the capability to execute orders transmitted by the system, to the field.

5.2.1 Data Acquisition

Collect information from the field which could be of different types:

a. Analogue values like Voltage, Current or Power (active or reactive). Those values captured from the field in analogue ways are converted into digital in counts values (±0 – 2000), transmitted in digital format and, at reception are transformed to engineering values (Volts, Amperes…). Also, could be included in this type the number of a tap or the actual value of a meter.

b. Position or digital values like open/close, active/non-active… collected and send to the Control Centre as 0 or 1. Represents either the status of a breaker or an isolator or an alarm activated or not.

c. Values of meters or similar, presented in a higher precision than a normal Analogue value.

That information, collected in the field, uses a Remote Terminal Unit (RTU) which concentrates the information, prepare it to communicate and transfer it to the control center when requested to do it.

This communication is requested by the Control Center, normally on timely basis (scan). In case of alarms, the RTU may initiate the communication with the Control Center, requesting to stablish a communication and to be interrogated.

Size and capacity of RTU's can be adjusted to the needs, from a simple RTU to collect one value to RTU's to collect and operate a big substation, using in each case the appropriate technology. Even the Programmable Logic Controller (PLC[17]) has been used in small systems.

5.2.2 Communications

The Communications between the Control Centre and the RTU's can be supported by any available WAN technologies (Wide Area Communication) and several applications protocols.

Communications technologies used for transmission of big amount of information in wide area can be based on wired or wireless solutions. The wired solution vary from Fiber-Optic and xDSL communication , to simple PLC (Power Line Carrier). The wireless technologies can be based on Cellular data communication technologies (2G: GSM, GPRS / 3G:UMTS, HSPA / 4G:LTE) or other Radio solutions such as WiMAX or Coupling.

Depending on the size of information and the frequency required to transmit it, and considering the acceptable delay, the best option could be one or the other.

The operation of the SCADA system is dependent on reliable communication from each station to the central control station. International best practice recommends that Power Utilities establish their own communication network and not be dependent on public Telecommunication operators. A Telco's objective is different to earn revenue from selling bandwidth, whereas a Power Utility has to ensure the reliability of the power network. We therefore recommend that a utility owned Telecommunication network be established to provide the communications required for the Control system.

The protocols used can be divided in four main groups:

a. For many years the SCADA suppliers have imposed proprietary protocols, used exclusively in their own installations. This situation creates a dependency between the supplier of the RTU's that should be the same (or compatible) with the SCADA system if you want to avoid that an RTU supplier shall emulate the SCADA protocol with the information provided by the supplier. This situation is changing but some of those protocols are still in service due to extended usable life of RTU's.

b. Some general-purpose protocols like Modbus or DNP (Distributed Network Protocol) are quite efficient for use in the Electricity Networks control, at different levels. Despite the age of these protocols, they are still in use (Modbus was created at the end of 70's), with good results.

c. Special protocols are designed by international standardization bodies such as IEC (International Electrotechnical Commission), specifically for Electricity Systems applications such as the IEC 60870 series of standards. The IEC 60870-5-101 and 104 protocols provide serial and IP connectivity, respectively, between the IEDs and RTUs in the substations or generation plants with the control center. The IEC 60870-6, also known as TASE protocol, provide communication between the control centers. The advantage of these application protocols is interoperability, that allows multi-vendor option for systems and elements.

d. The Internet Protocol (IP) is the principal communications protocol used in the Internet, using source and destination addresses. Its routing function enables internetworking and is useful for connection between RTU's in the Field and with the Control Centre

[17] PLC acronym is used also as Power Line Carrier, a communication technology that uses the electric wires as communications carrier.

All those protocols could be used, but some precautions need to be taken, especially in communications security.

The selection of the protocol will depend on the communication technology that is decided upon, and can be finalised during project implementation.

5.2.3 Information validation

The analogue information (± 0 – 1 mA as example) is converted and sent to the control centre in counts ± 0 – 2000 (for example, 0 ma = 0 counts and 1 mA 1.900 counts). The first activity in the Control Centre is convert the counts into engineering units, computing the parameters of the conversions. Normally a part of the available area/capacity is dedicated to overflow detection.

When the information arrives to the Control Centre, the first activity is to validate the value received. To determine if the value received is correct, it must be inside the expected limits and the variation between two or three consecutive values must be coherent with the potential variation of the element measured. Those checks are done to all values received and alarmed. Any measure can have various sets of limits, but usually two are used: Pre-alarm and alarm.

Those alarms are registered and presented to the operator.

5.2.4 Alarms subsystem

The alarms become one simplified way to alert operators to some irregularities in the system. This helps to the operator to concentrate in those messages.

The problem arises when the number of simultaneous alarms becomes too high. A low voltage generalized situation, will generate an alarm for each voltage measured point and each time that goes in or out of any limit.

Some systems use Alarms Intelligent Processors (AIP) or Intelligent Observation Systems (IOS) that study, concentrate and summarise as much as possible the alarms to be presented to the operator. This recent functionality is still in its infancy and will require some more development, but even under those circumstances still a useful tool.

Alarm messages are time stamped, in some systems with the time of arrival to the Control Centre, without precision, in others time is stamped by the RTU, with a precision of few milliseconds. This last functionality is known as “Sequence of Events” because it allows to establish in the control centre the real sequence of events that took place in the system, allowing better compression of the incident and the capability to take more adequate decisions.

Alarms are stored in a file ordered by time, for later study.

Operators are requested to recognize an alarm when they see it (to cancel audible alarms and stop blinking screens or indicators) and delete them from the active alarms list when solved.

The historical of alarms cannot be deleted.

5.2.5 Monitoring and trending

The SCADA stores the values in its data bases in two different ways:

a. Contains the last values received from the field. Could be considered an image of the network in a certain time and under known conditions. This image of the system can be saved, manually or automatically for subsequent studies, of this situation or as representative of some similar network conditions in the future.

b. Selected values could be individually monitored, so in a particular Data Base each selected value received from this source or calculated with digital and/or received values, is saved on a dedicated Data Base and presented as a tabular or as a graphic trend.

Data Bases can be presented to the operator in form of tabular or full graphic. Tabular presentation presents more precise individual values while graphical information provides a better global view of the current system conditions. Both are alternative ways to present the same information.

Ref: REE (www.ree.es)

5.2.6 Supervisory Control

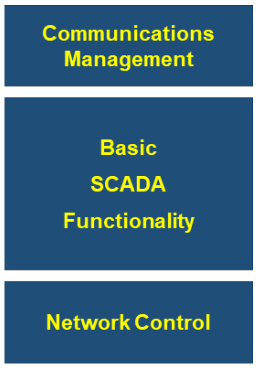
SCADA not only allows collection of a range of information and make it available in the Control Centre, but also allows transmission of instructions to the RTU that are precisely executed on the field.

Those orders are typically:

- Open/Close isolators and breakers
- Connect/disconnect elements such as shunt devices or batteries
- Raise/Lower the tap changers in transformers when permission is received
- Establish and modify setting points in Reactive power generation or transformers voltage control
- Establish or modify generation set points
- Voltage control, by modifying the reactive power generation set point.

All those potential actions will allow and efficient control of the network conditions.

5.2.7 Resume of Basic Functionality



The functions described in the points above constitute the SCADA – Basic Functionality. All SCADA Systems shall be capable to perform those activities that can be found to control large and small generating units from the Control Room.

Differences between large and small systems are in the system size, number of points controlled, the capacity of the IT System, number of RTU's, or the functionality of the specific applications.

5.3 Added applications

The contribution of the SCADA to control electricity systems, starting with transmission systems, started being commercially available and in the late 60's and early 70's, for the electricity system control becoming very soon in the most efficient control tool to improve system information and control and, at the same time, reduce operative costs.

For that reason and around the SCADA a big set of applications has been developed being today the foundation of an efficient and safe control system.

Some of the top functionalities are listed below, grouped considering their main objectives, that will facilitate, not only the understanding of their use but also in order to show possible options.

5.4 EMS versus DMS

There are two main suites of external applications that group the main functionalities design, according to different objectives of the network to be controlled like generators control, transmission systems or distribution systems:

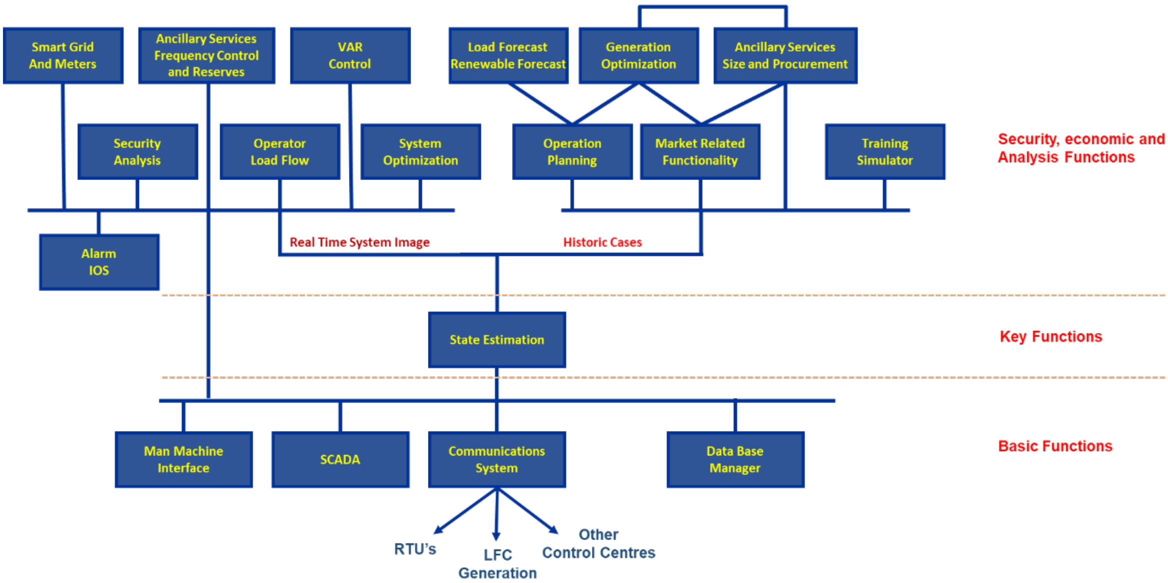
a. **Energy Management System (EMS)** oriented to generation and transmission systems. The main characteristics of those systems are those that are the relatively big size in generation and load, small or medium number of substations and extra high number of controlled elements, with the system fully meshed, operated with almost all breakers closed.

b. **Distribution Management Systems (DMS)** oriented to distribution systems operated radially, without forming loops in the system, with a high number of stations controlling a small number of elements on each station. Operation must be done by opening and closing elements of the network, in most cases passing thorough zero voltage.

The MEC power network consisting of 13.8kV, 4.16kV and LV networks resembles more a Distribution network than a Transmission network. The deployment of the Control System therefore requires consideration of DMS rather than EMS functions.

5.4.1 EMS System

The added EMS functionalities are supported by the SCADA System and the information obtained from the field. The following picture represents the different functions normally presented in schematic way, an EMS System functionality.



Briefly, the following applications are oriented to:

5.4.1.1 State Estimation

Normally values are measured with a certain level of error introduced by measurement or when transformed from analogue to digital format. It is acceptable that, in the best of cases, the error are around 1%. This means than any value in the system, as example a Voltage at 220 kV, the value sent to Control Centre is 220 kV, but the real value could be any value between 198 and 222 kV. The same errors or higher are expected with flows and current readings.

This situation is unavoidable and means that the image of the system will have some distortion in the values received, while, at the same time, some other values may be lost or not available.

If under these conditions, the operator tries to perform any study (load flow or contingency analysis) the results, if any solution is reached, may include some deviations that make the values with a low accuracy and even useless.

State Estimator tries to solve those incoherencies and obtain the best possible image with the values received and the multiples redundancies available in the system. This will generate an equation system with more equations than variables, solved normally by Newton – Raphson iterative process, to find a set of values, using a minimum quadratic deviation, coherent among them.

The result is the most probable coherent set of values.

The system takes care to weigh automatically the values regarding the proximity between the received and calculated values.

This is calculated over the electric model of the network, formed not only by all generators and loads in the system, but also with a mathematical representation of the network, which may introduce errors in the calculated values of impedance or resistance of any equipment in the network, including lines, transformers, shunt devices or loads, active and reactive. Any mistake in those values will automatically reduce the results accuracy or prevent to the application to reach a solution.

This function is very complex to fine tuning and in to many cases the results does not reach a minimum required accuracy.

5.4.1.2 Load Flow

Once the State estimator is well tuned and available, then using its solution as input, it is possible to run the Load Flow, which taking as input the network model and the generation and load in each node, calculates the in real voltages and flows on each node or network element at real time or in study mode. In top of this, and using the solution as a Base Case, the Load Flow will simulate any new situation (modify generation or load profiles or the network topology, presenting as input, the modified loads, generations and topology, the Load Flow will present as output the system conditions after the simulation (Voltages and Flows).

5.4.1.3 Optimal Load Flow.

In this case, the inputs are the same but, in addition the results will show the optimal values for some control elements values like reactive generation, shunt devices or tap changes, that can be proposed to change, after evaluation with a cost for any control change, that simulates the priority. System losses will have also a cost. The control function to be minimized will display the cost optimal set of values of control elements: maximum losses reduction with a minimum cost. The use of different costs for each action, will reflect the system control priorities.

5.4.1.4 Ancillary Services requirements

Two of the most important aspects for system security: Different Types of Reserves for Frequency Control and capacity to Voltage Control are the main ones:

a. The **Load Frequency Control (LFC)**, is the application in the system that controls directly the governors of the dedicated generating units and in an automated close loop, increases or reduces the actual generation to maintain the frequency stability. The final action of the LFC, send the raise/lower or fix a set point, is also known as Automated Generation Control (AGC)

b. **Voltage control**, especially with the appearance of Renewable Generation parks, and its limited participation in the voltage control, compared with the conventional units (combined cycle gas units as example), has become one of the major quality issues problems. The intensive use of all tools available today like shunt devices, VAR systems or even SVC and STATCOM units are frequently found for voltage control

5.4.1.5 Security Analysis

It is the suite of applications oriented to verify that the Security Criteria are fulfilled any time, during operation planning or in Real Time. Perhaps the most known application is the Contingency Analysis

(CA), where all the conditions included in the security criteria are tested during operation planning and in Real Time.

This suite of functions are basic to determine the capability of the system to survive to any contingency included in the Security Criteria stablished in the Grid Codes or in the Regulation laws.

5.4.1.6 Forecast Applications

Load demand forecast and Renewable Generation forecasts applications, normally at park level, for wind and solar generation.

Forecast is done at long term level for planning considerations and at next year level to guarantee the availability of resources, at infrastructure level.

At medium term or few months to plan maintenance of generation units and network elements or verify the availability of generation to supply the energy that are demanded by all clients.

At day ahead, to operation planning including security constrains and in Real Time for security analysis at few minutes to few hours in advance.

5.4.1.7 Generation schedule

Taking the load and RE forecasts as inputs, the generation schedule is now possible, where the generation needs are anticipated for the day ahead or in Real Time for the near future.

In addition to verify the needs of generation also controls the availability on the system of the different types of reserves, according with the security constrains.

5.4.1.8 Generation Control

It is a highly complex activity and requires specific tools. Most of the information is collected by SCADA Systems (one or more) and addressed to a Control Room, where the different parts of the power plant/unit are monitored or controlled by operators. Some actions launched are executed in automated mode.

This control philosophy is extended to most large power plants from Nuclear Plants to Coal, Gas or hydro units. It is not a simple application. To control a unit or a power plant requires a group of applications that in a coordinated mode facilitate to operators the plant control, from the high voltage park to any kind of fuel supply.

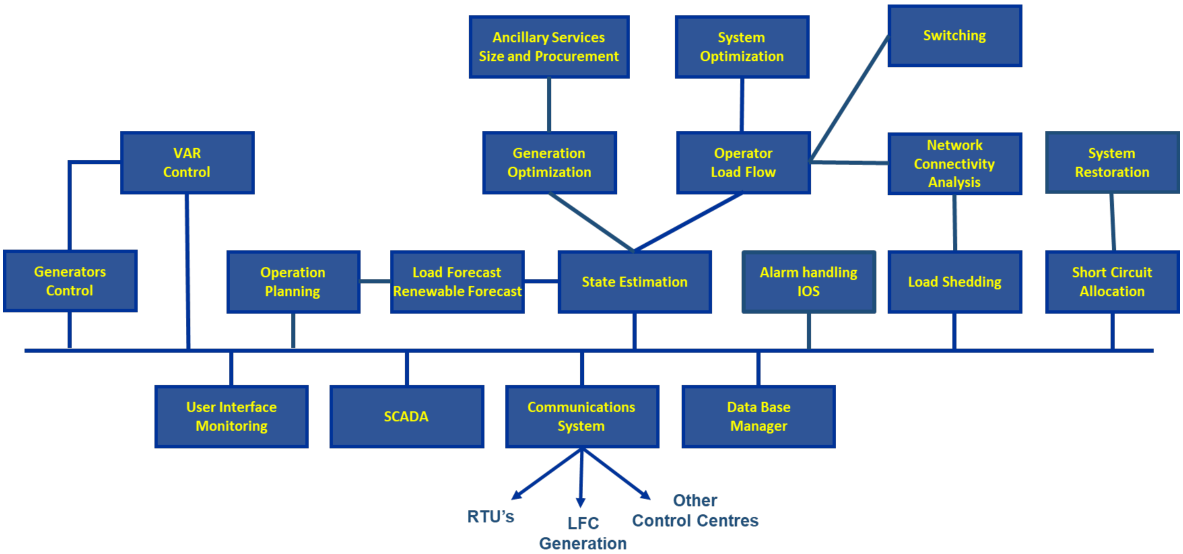
Ref: https://www.winsted.com/resources/case-studies/university-virginia/

Those applications facilitate that today many generating units are controlled from a centre located outside of the plant itself, reducing considerably the operation costs.

5.4.2 DMS System

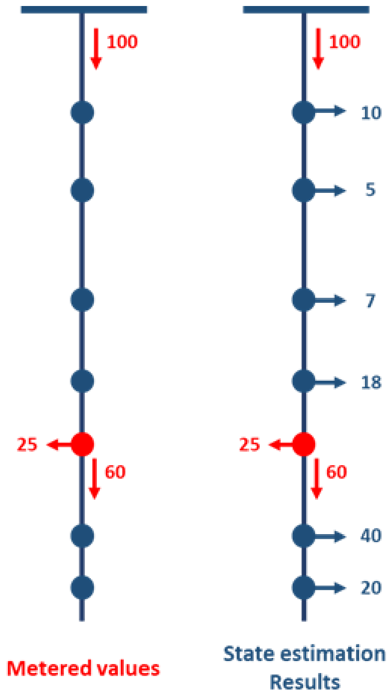
The Distribution Management System is more oriented to distribution networks management. For networks operated as radial, the applications are completely different to the case of meshed networks.

Functionality of applications are similar than in case of EMS but the methodology and mathematical approach are quite different.



The main applications are:

5.4.2.1 State Estimation (SE).



The state estimator is an integral part of the overall monitoring and control systems for transmission networks. It is mainly aimed at providing a reliable estimate of the system values. State estimators allow the calculation of these variables of interest with high confidence despite the facts that the measurements may be corrupted by noise or could be missing or inaccurate.

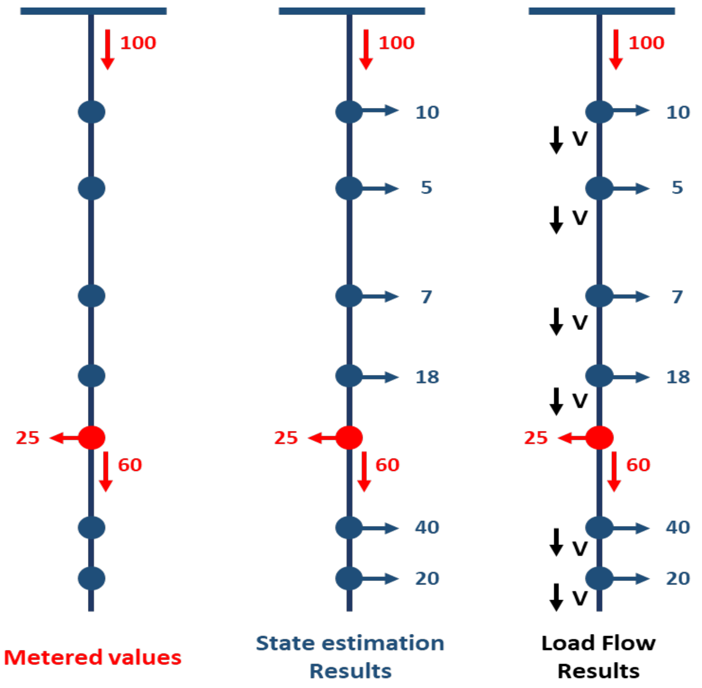
Even though we may not be able to directly observe the state, it can be inferred from a scan of measurements which are assumed to be synchronized. The system appears to be progressing through a sequence of static states that are driven by various parameters like changes in load profile. The outputs of the state estimator can be given to various applications like Load Flow Analysis, Contingency Analysis, and other applications.

5.4.2.2 Load Flow Applications (LFA).

The Load Flow study is an important tool involving numerical analysis applied to a power system. The load flow study usually uses simplified notations like a single-line diagram and focuses on various forms of AC power rather than voltage and current. It analyses the power systems in normal steady-state operation. The goal of a power flow study is to obtain complete voltage angle and magnitude information for each bus in a power system for specified load and generator real power and voltage conditions. Once this information is known, active and reactive power flow on each branch as well as generator reactive power output are analytically determined.

Due to the nonlinear nature of this problem, numerical methods are employed to obtain a solution that is within an acceptable tolerance. The load model needs to automatically calculate loads to match telemetered or forecasted feeder currents. It utilises customer type, load profiles and other information to properly distribute the load to each individual distribution transformer. Load-flow or Power flow studies are important for planning future expansion of power systems as well as in determining the best operation of existing

For a better understanding of the combined use of those two application the following schemes represent a feeder with only the metered information, the second one after the State Estimation, (that used load profiles, number of clients…) which estimates the load in the transformer stations without this information and the third after running and Load Flow, which calculate all flows and voltages. The estimated values will probably to some extent modified by the load flow due the results of losses calculation in each feeder section. The accuracy of the results are a function of the accuracy of the State Estimator.



5.4.2.3 Generation Control.

A generator embedded in the Distribution networks is normally of power capacity compatible with the feeder where it is allocated. This makes that groups are significantly smaller than units connected into the transmission grid. Groups are easy to operate and at the same time supporting network security and the frequency and voltage maintenance. Big control panels filled with push buttons and analogic measures in the past, have been substituted by digital systems that provide in a screen much better capacity to operate the generator and monitor its values.

This application is normally developed by each supplier for their own supplied generators. This control application always runs in top of a SCADA System and the generation control is limited in most cases to the generator from the same supplier. For that reason, in some cases we found two SCADA systems dedicated to control generators from different suppliers.

As reviewed within EMS functionalities earlier, the Load Frequency Control (LFC) and Automated Generation Control (AGC) are part of the EMS system. Normal operation for an electricity system is that frequency is controlled in high voltage systems using SCADA + LFC/AGC modules, and in that case, there is no need to maintain the frequency in the distribution side.

In the isolated systems, normally there is only one system controlled from a single Control Centre. In that case, all functionality shall be included in the Control Centre and under the SCADA System.

In general, there are two common ways to control frequency:

- ✓ Manually: The Control Centre or the Generation Operator controls the frequency by transferring instructions directly to generators or to operators to manually increase or reduce generation. This control system gives a pour quality on frequency control. This methodology is used in some isolated systems (such as UK, India…).

- ✓ Automated: The Computer controls the deviation of the frequency, generating the raise / lower signals to the generators control elements to maintain the frequency precisely to set point. Even some dispatches take the responsibility to control the hour deviation and set the frequency monthly to correct the “electric hour” (Laufenburg). This control method produces a very precise frequency control but is much more expensive to implement. This is the common control methodology used across Europe and USA… Its main advantage is to allow fair interchanges.

It is also true that the basic capacity of any SCADA to collect information and presented to the operator facilitates the monitoring and control of some additional points (breakers, transformers…).

5.4.2.4 Network Connectivity Analysis (NCA)

By analysing the network information obtained thorough the SCADA System, NCA considers the position of all switching elements and assists to the operator to know operating state of the distribution network indicating radial mode, loops and parallels in the network.

5.4.2.5 Switching Schedule & Safety Management.

Control engineers prepare switching schedules to isolate and make safe a section of network before work is carried out, and the DMS validates these schedules using its network model. When the required section has been made safe, the DMS allows a Permit To Work (PTW) document to be issued. After its cancellation when the work has been finished, the switching schedule then facilitates restoration of the normal running arrangements.

5.4.2.6 Voltage Control

Is responsible for the control of voltage in the system, using:

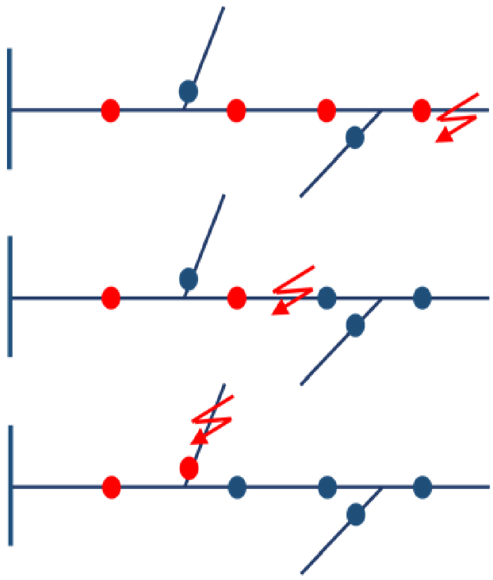
- ✓ Reactive power generation or absorption in generators (VAR control)
- ✓ Modifying the transformer’s ratio, changing in cold or in hot. In this last case, also known as Load Tap Changing, where the transformer is in service, the number of changes per day is normally limited.
- ✓ There are also autotransformers that has a ratio very close to 1.0 which means that the voltage variation is small and are used only for voltage control in the same voltage level.
- ✓ Use of external control elements like shunt devices (batteries or reactors) or advanced voltage controllers like SVC’s or STATCOM’s

Most of those elements can be used in automated way, controlling the voltage in the connection point. In some cases, the objective voltage is a function of the nominal voltage and current load.

5.4.2.7 Short Circuit Allocation.

Unexpected and undesired short circuits in the network are a reality that cannot be avoided but could be reduced with good maintenance that will improve the system reliability. The impact of a short circuit and its impact into the Quality of Service can be limited by detecting the portion of the network where the short circuit took place, so restoration can start faster.

Short circuit allocation is based in the use of short circuit current elements in the network that simply detects its pass and communicate the detection to the Control Centre. The following graphic shows its application to determine the short circuit allocation.



The blue dots represent the locations with a short circuit pass detector and the red the ones that elements that detected the pass of the current.

For each location of the short circuit in the network (feeder) there is a different configuration of elements which detected the pass of the short circuit current and in consequence the short circuit location itself which will allow to the operator to start actions to restore the system immediately.

The detectors shall be capable to communicate with the centre by themselves (using a PLC or GRPS communication, as example) or incorporating the signal into an RTU that collects other types of information.

5.4.2.8 Load Shedding Application (LSA)

One of the key aspects in an electric system control is maintain the equilibrium between Load and Generation. Operation Planning (day ahead) or real time adjustments are meant to control the generation to supply the demand.

But in cases of extraordinary demand or generation trip, this balance is lost. The system reacts modifying the system frequency that must be corrected increasing (or reducing) the generation in other units. The problem becomes more critical when the generation margins have been exhausted. In this case, the only solution is to reduce the load, known as load shedding.

This reduction or Load Shedding can be done manually or automated using a Load Shedding Application (LSA).

The most common method is to reject some load when the frequency reaches some values, with the double objective to protect the generators and to stabilize the network, which makes the restoration easy and faster.

Normally the “trigger” is a protection that reads the frequency or the frequency drop speed, anticipating the frequency lower values and reacts tripping some feeders to achieve the load reduction. In a system normally there are few levels of frequency to reduce the load (between 3 and 5) and at each frequency level a certain amount of load is rejected (from 15% to 25%).

5.4.2.9 Fault Management & System Restoration (FMSR).

Incidents in the network are, by its own nature, impossible to avoid or reduce. Number of landed thunderbolts or number of storms in a year, are impossible to reduce but, the quality of service are improved if the extension is reduced and the restoration is faster.

Those applications tend to reduce the restoration time by automating part of the restoration process. This functionality requires an excellent electric model and intensive information compilation. Is especially useful for those utilities that have by law, for safety purposes, limited the time to test lines or cables (some countries have this limitation in 1 minute) and, after this elapsed time, to test a cable requires the presence of operators on location, to verify there is no danger for the public during the test.

The FMSR is also useful for big distribution networks with a large number of potential restoration paths.

5.4.2.10 Distribution Load Forecasting (DLF)

As said above, one of the main aspects to consider is the balance between generation and load. System load includes the client’s consumption and the system technical and nontechnical losses. This is an information which is not known on operation planning or even in the immediate future on Real Time. Also, the Non-dispatchable generation (in general renewable or auto-generation) is not known in advance.

The main objective is to schedule the conventional dispatchable generation, in advance, which will allow to apply generation optimization processes and program maintenance preventive and corrective works.

The traditional energy balance equation is:

$$CG + RE + IB = LO + SL$$

Where: CG is the Conventional Dispatchable Generation

LO is the total Load (Estimated)

IBs are the interchanges balance (operation decision). Not applicable in isolated systems.

SL are the System Losses (Technical + Non-Technical)

RE is the Renewable Generation (Forecasted with error)

ERE is the Embedded Renewable Generation (Estimated)

The same balance equation could be written as:

$$\mathbf{DG = \underbrace{(LO + SL)}_{\text{Estimated together}} - \underset{\text{Estimated Individually}}{RE}}$$

So to consider the schedule of conventional dispatchable generation, there is a need to perform two separated operations:

- ✓ Load + Losses forecast, this will require a cleaned historic load data base.
- ✓ Renewable or non-dispatchable generation, which could be estimated global in the island or park by park, independently if it is solar or wind parks.

Those forecasts shall be calculated for at least two different time horizons:

- ✓ Day (or week ahead) for operation planning.
- ✓ Minutes or hours ahead for real time security analysis performance calculation.

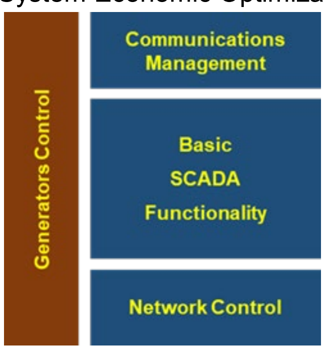
5.4.2.11 Load Balancing via Feeder Reconfiguration (LBFR)

Consist on automate the decision process to decide the network configuration from the network topology, deciding the status of all embedded isolators or breakers (open or close) which for big systems may represent thousands of different configurations. The application will consider which one is the optimal one.

5.4.3 Requirements of the Distribution Systems

In the Distribution Systems like the one in Marshall Energy Company or as seen in the other islands, 3 requirements are identified:

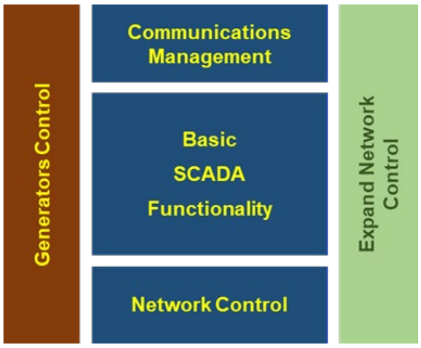
- Network Control and Monitoring
- Quality assurance
- System Economic Optimization



5.4.3.1 Network Control and Monitoring

- SCADA Systems normally provide enough capacity for system monitoring and control.
- User interface should be simple and capable to show the network at different details level depending on the real-time requirements.
- Zoom, Panning and Clustering shall be available in the system.
- The capacity to supervisory control shall be protected in a two steps operation (i.e. selection and execution)

Capacity to control a wall system are appreciated



5.4.3.2 Quality Assurance

Quality of service is essential for any distribution system. This could be considered under two aspects, with the same level of rank.

1. Service Continuity: Consisting in the maintenance of the service under different situations and circumstances.

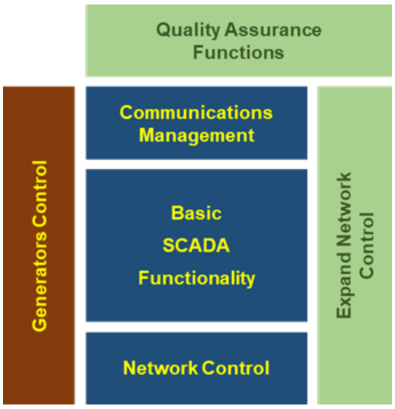
   The main problem to face for continuity of service is the external incidents into the network, such as; lightning, storms, high speed winds, car accidents, vegetation… There are only limited ways to avoid the existence of those incidents, but they can be mitigated using more secure network elements.

   If the incident cannot be avoided, then, to improve the quality and reduce the time with blackout, the efforts shall be put to reduce the restoration time and the extension of the blackout.

2. Quality of the supply: considering as the main parameters the frequency, voltage, harmonics…

There are not external factors that impact into those quality aspects. Operation planning, normally for the day ahead, is the operation time where those aspects shall be considered and the resources existing made available for operation

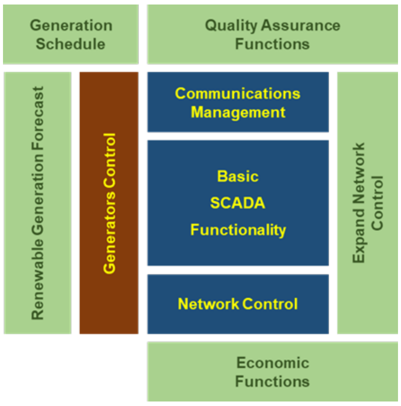
Some applications to control those aspects, together with the Reserves size and allocation, which do not directly impact into quality, but in case of other incidents, will help to limit the extent and magnitude of the incident and eventually reduce the restoration time.



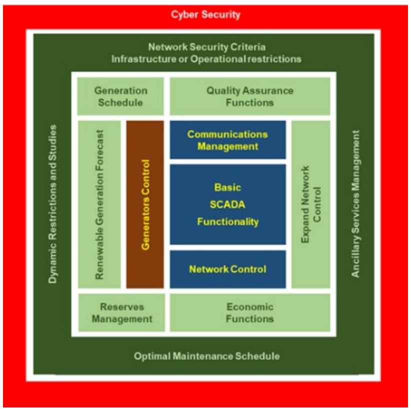
5.4.3.3 System Economic Optimization

Economy is one of the aspects that comes immediately after the quality and service assurance.

When talking about economy in the network operation and considering that generation scheduling is already optimized, the main aspect is loss reduction. The SCADA application should provide the tools to control the network losses: Optimal switching in the network and feeder loss reduction.



Once this status are fulfilled, after later considerations and integrations, the system can reach a final status. Some of those functionalities could be anticipated.



5.4.4 Recommendation between EMS and DMS

Both are highly powerful tools, but considering:

- The operation of the systems are radial and not meshed
- The size and low complexity of the networks
- The requirements and constrains of the Distribution Systems
- The priorities expressed by the Distribution Utilities

Our recommendation is look for a tailored Distribution Management System (DMS) instead of adapting an EMS to Island systems.

In our opinion and understanding, there are too many functionalities and operation changes to be introduced at the same time, so we propose to divide the functions in coherent groups and introduce them into ordinary operation in two or three steps.

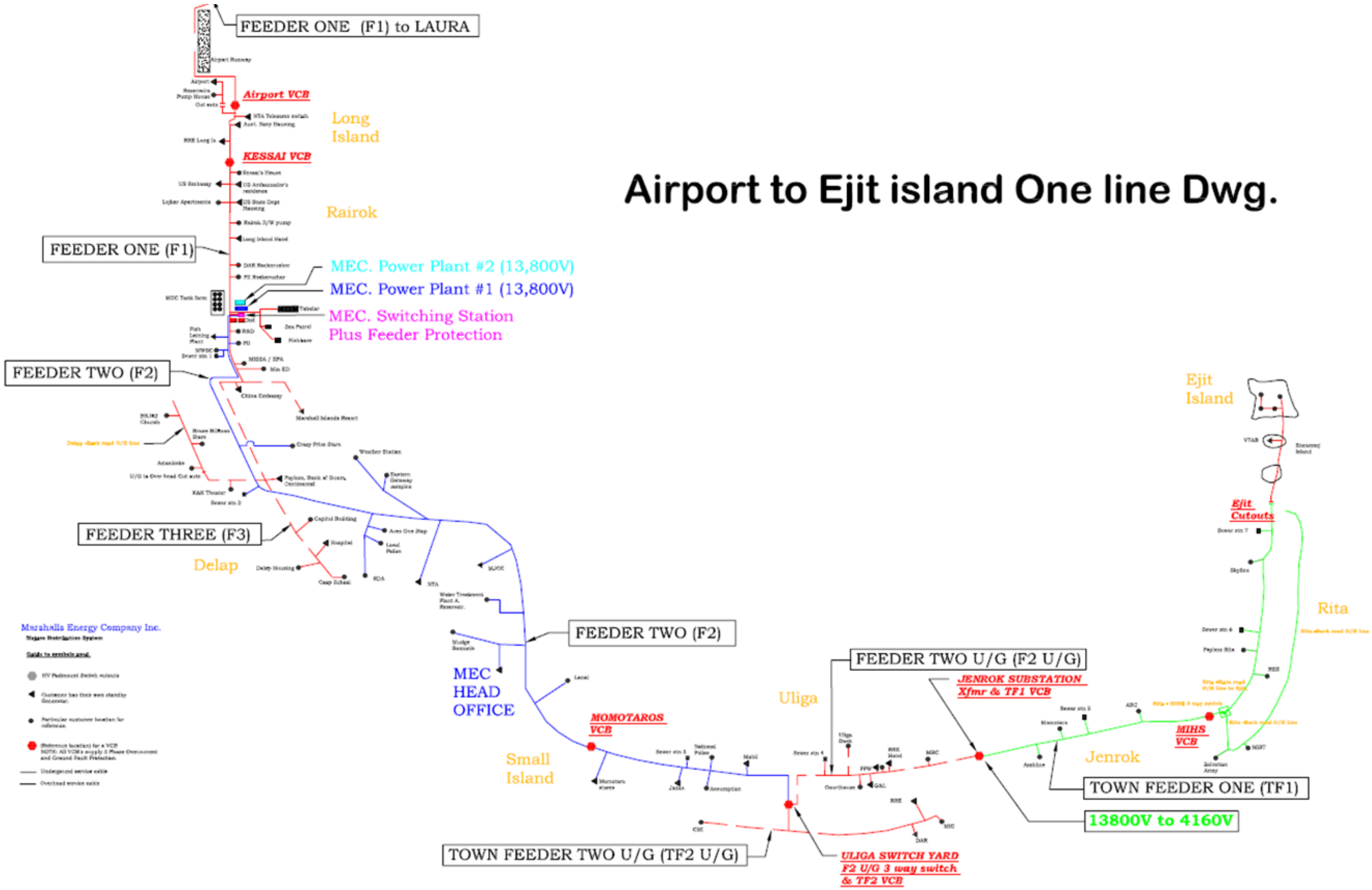
5.5 MARSHALL ISLANDS ENERGY COMPANY

5.5.1 Network and available Operation Systems

The salient points of the electricity system in Marshall Energy Company can be summarised in the following data:

Concept	Value	Unit
Peak Load	8,2	Mw
Energy generated per year	53.713	Mwh
Generators Conventional	7	
Generators Renewable	3	
Conventional Installed power	32,0	Mw
Renewable Installed power	0.8	Mw
Available SCADA for Generation Control	Yes	
Controls some breakers	Yes	
Operated Radial	Yes	
Number of feeders	3	

Marshall Energy Company single line diagram




Airport to Laura Village One line Dwg.
FEEDER ONE (F1) to LAURA
FEEDER ONE (F1) to LAURA
FEEDER ONE (F1) to LAURA
Laura

An existing SCADA System controls the frequency and co-ordinates Units in Diesel groups.

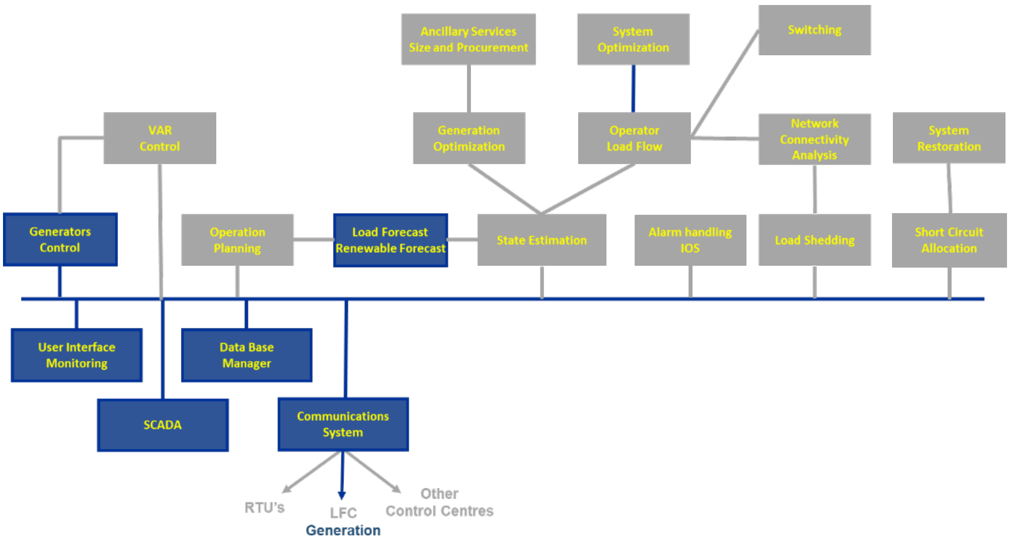
Functionality is limited to:

a. Full control of the generation units, including some optimization of the generation assigned to each unit.

b. Basic control (switching) of some feeder heads. Plan to expand it to some other substations

c. No additional functionalities available in top of the SCADA

The figure shows the actual SCADA configuration:



Battery and VRE control systems that have SCADA functionality also have the same capability to perform basic control functionality (such as open and close breakers), monitor system status (breaker positions, power flows, voltages and currents), alarms, Generation Control, a User interface to display diagrams and trends, and record data. There is the potential for Diesel, Battery or VRE control systems to provide some or all of the functionality described below but this has to be investigated on a case by case basis.

5.5.2 Applications Proposal

There are plans to expand the functionality of the SCADA to improve the network system operation.

Any expansion can be organized in different ways, one is doing it in a single step the other one is perform the expansions in two or three steps.

The first option has the advantage that all functionality are available as soon as possible, the second one delays the full functionality but allows a more consolidated knowledge step by step.

Training is an important aspect and the second alternative will allow to consolidate one knowledge and functionality before starting with the second set of functions.

In the following points the possible expansions and the recommended one are developed.

5.5.3 Priorities

Recommended priority for improvements:

1. Improve quality of Service
2. Economic Optimization (Reduce Technical losses)
3. Detect non-technical losses

5.5.4 Functionality proposal

Two steps are considered, the first one oriented to quality of service and the second oriented to economic optimizations in network operation or loss reduction.

5.5.4.1 Quality improvement

In the first step, the functionality propose id to include all applications related with the quality control and improvement.

Specifically:

1. **Short circuit allocation**. Once installed in the network, some detectors of short circuit current (as an example, an overcurrent relay or a specific detector) and their detection sent to the centre.

   If in this location there is an RTU, it can be used to include this signal, as any other in the RTU communications. As an alternative, for those measurement points, where no RTU is installed, communications could be based on Power Line Carrier (PLC), fibre optic links or GPRS sim cards.

2. **Load Shedding**. Load shedding is the capability to disconnect from the network some selected loads, when some specific system conditions are reached:

   a. When the frequency reaches a certain value, the load are automatically disconnected. The total amount of load could be a percentage of the actual load (50%) in 3 to 5 steps of frequency and load. The objective is to stop the drop of frequency before reaches the value where the units are disconnected for security reasons. If this point is reached, shedding will produce a general blackout of connected loads.

   b. Manually from the control centre. When some specific situation can take place that does not fulfil the security criteria and could lead to a general blackout that can be avoided by disconnecting a certain level of load. This load can be disconnected from the control centre.

3. **State Estimation**. Contrary to the EMS, where state estimation calculates the Voltage and Flows and corrects missing or erroneous loads and generation, the DMS calculates the load values in intermediate not measured points.

4. **Operator Load Flow**. Calculates intermediate voltage and flows between the different not measured lines or cables. It is obvious than in distribution is not practical to install an information point at each transformation to low voltage, to measure all loads in the system, but for forecasting, flow control (considering the different cables/lines capacity), operation planning and voltage control, it is valuable information.

5. **Voltage and VAR control.** Voltage is one of the main indicators of the quality of the system. The main tools to control the voltage in the network are, ordered by priority:

   a. VAR control by generating units, including Diesel units and, if possible, wind and solar generation.

   b. Transformer taps, which can be changed in hot.

   c. Batteries, SVC's or STATCOM, to control voltage in different network points.

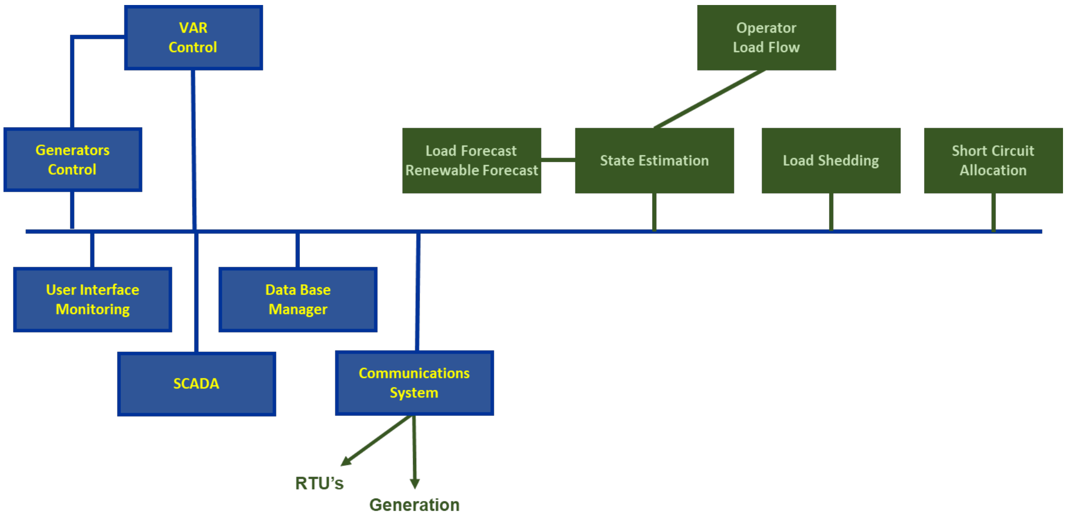
   d. Shunt devices (reactance's)

   e. Transformer taps, which cannot be changed in hot.

A weight methodology will determine the optimal solution.

6. **Load and Renewable forecast.** Forecast is a technology to preview some values using not only the historical cleaned data base, but also the variable parameters: Temperature, sun insolation, clouds, rain… These values are needed for generation optimization.

The functionality, after this phase shall be:



5.5.4.2 Economic Optimization and technical loss reduction

1. **System Optimization.** The technical losses are a function of the resistance and the quadratic of the current circulated between two points. Resistance is a value that depends on the infrastructure and characteristics of the lines or cables. But the Current depends on the network topology. A Minimum could be reached by modifying the network topology, moving loads from one feeder to another or making some loads in parallel, without closing loops.

   This function together with other possibilities (voltage management…) will determine the topology with minimum losses.

   At the beginning, the capability to apply this functionality (topology modification) could be not high enough but following applications can be used also to select the optimal planning options, which will habilitate the use of this function for planning and present conditions.

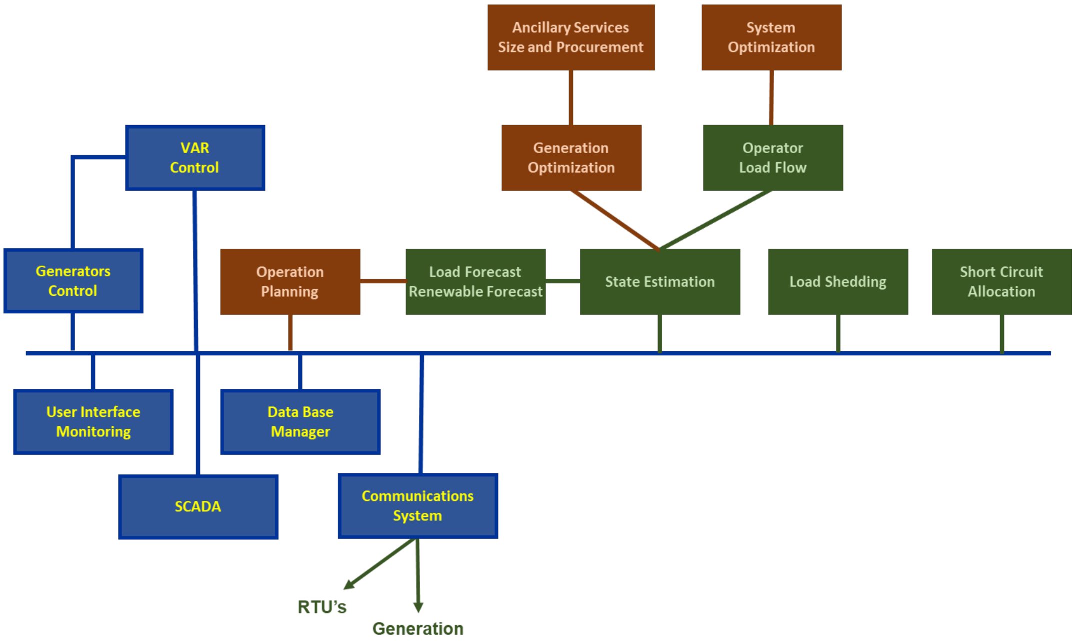
2. **Generation optimization**. After the load and Renewable forecast, we have the amount of energy to be produced by the conventional generation. The split of this generation among the different groups or energy sources will define the optimal generation profile, considering the energy costs, including hydro generation, the system losses and ancillary services requirements like Reserves or Voltage Control.

3. **Ancillary Services** are defined by FERC as "those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system." Certainly, the Marshall Energy Company system is not inside the definition of "transmission interconnected systems" but is also true that to operate a system like Marshall Energy Company requires consideration of the need for Ancillary Services

   The evaluation of the needs of ancillary services includes reserves of different types or the Voltage Control requirements. The evaluation of Ancillary Services must be allocated and monitored in real Time.

4. **Operation Planning**. Most of the functionalities described above are potentially used for operation planning, evaluating the different alternatives presented.

   The functionality after this second phase are (in brown tones is the second phase):



5.5.4.3 Functionality not recommended

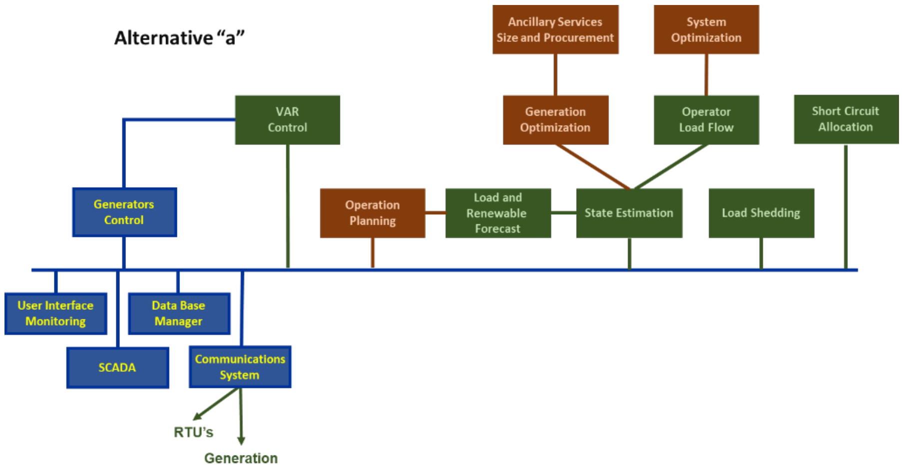
Some functionality is more oriented to much larger systems, where an operator cannot have a detailed knowledge of the full grid. This is not the case observed in the Marshall Energy Company electricity system. These functions are not recommended.

1. **Switching**, proposes a sequence of network operations to restore the system, after an incident, or to prepare the isolation of a network section for maintenance purposes.
2. **Network connectivity.** Analyses the system topology watching for loops or parallel sections, which may produce a loss on protections selectivity.
3. **System restoration,** after an incident, these applications calculates the sequence of operations for optimal restoration of areas in blackout.
4. **Intelligent Alarm Operation.** Alarms are generated in the RTU's or at the control centre if some of the values received exceeds the established limits. In case of an extra high number of alarms and messages some intelligent selection or grouping of them is required to avoid submitting to the operator an excessive number of alarms. This functionality is useful in case of hundreds of alarms, but of little value for small systems with few alarms.

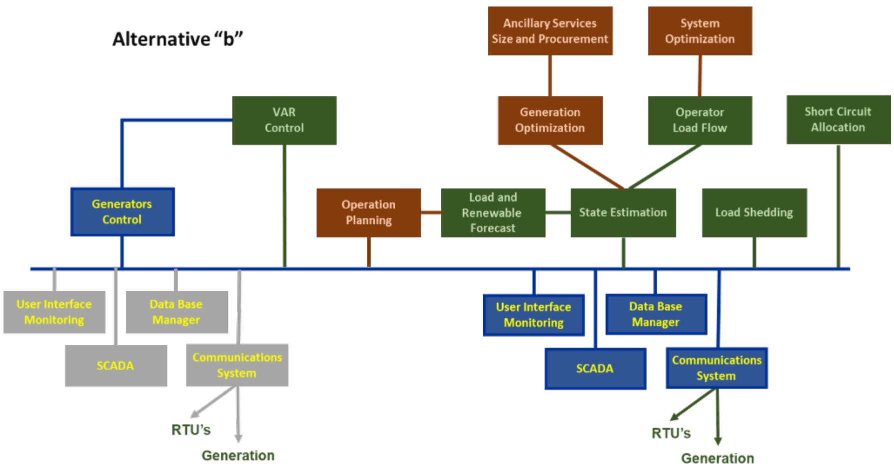
5.6 Architecture Potential alternatives

Assuming that the system functionality is the one selected, there are few potential architectures of the system with their own pros and cons. The following alternatives apply:

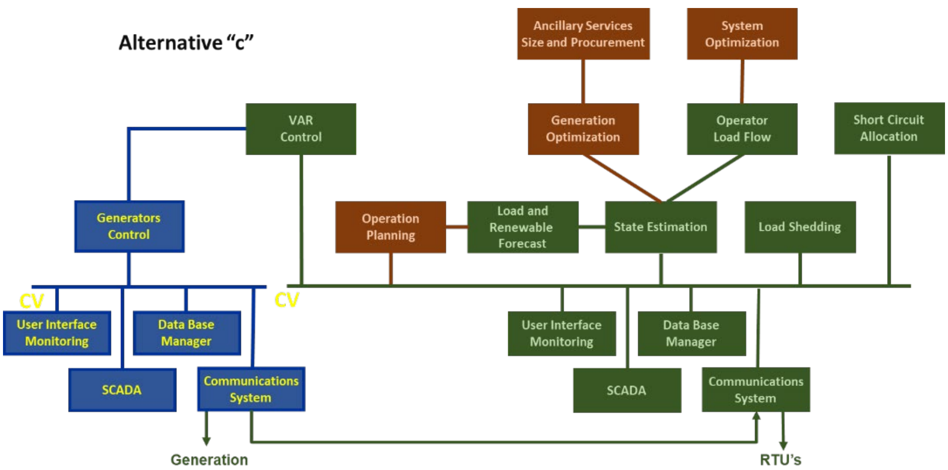
a. Use the actual SCADA system that is available in the Marshall Energy Company system for diesel generation control (blue blocks in the following figures) and expand its functionality with the one required for distribution network control (green blocks at first step, and brown in second).



b. Use a new and more powerful SCADA System, with the new grid and generation applications and transfer the generation operation to the new SCADA.



c. Add a new SCADA for network application and maintain the old one for conventional operation.



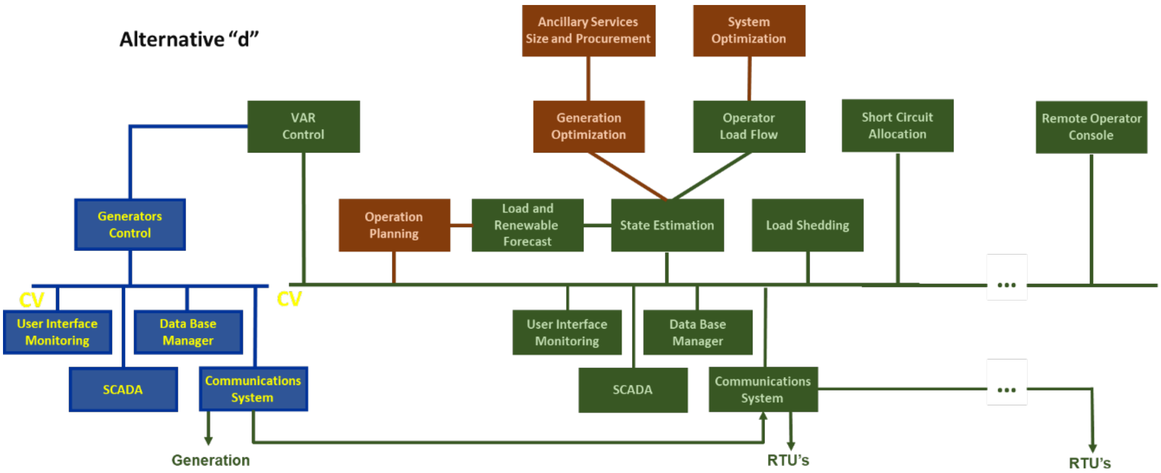
Marshall Islands electric system is difficult to manage from a single control Centre. It will require information from all islands to monitor and perform supervisory control actions. Another architecture could be organized in this case, considering a single system or splitting the system in two controls centres: installing the control centres in Majuro and Ebeye.

Depending on the quality of the communications, systems could be interconnected becoming one backup of the other.

Another alternative is install a single system in Majuro and a satellite system in Ebeye.

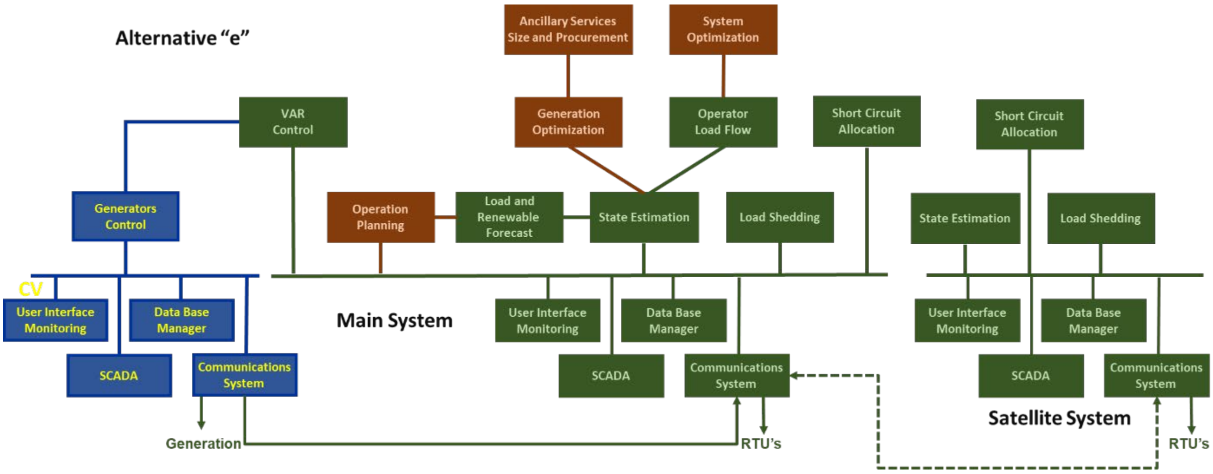
These technically possible approach made possible two additional alternatives:

d. Place one full system in Majuro and a satellite system in Ebeye. This alternative requires a good communication between both centres and each one will have full functionality. There are no backup centres, so, if it fails both centres will lose the functionality.



e. Place one full system in Majuro and a second system in Ebeye.

f. The secondary system will have only the activities to be performed in Real Time and interchange the information with the main centre to exchange off line results. If good communication between both centres is available, then some cooperation and interchange of results could be done: one could be backup of the other.



All alternatives are potentially acceptable, but some aspects shall be take into consideration, before taking a decision:

- The alternative "a" will require to increase the functionality of the actual generators control system. It's not clear that this functionality already exists and been tested and in service in other installations.
- Alternative "a" will require to modify the existing control of generators, especially if the software versions of network applications (operating system, data base…) are not compatible with the existing, installed some time ago.
- Alternative "b" will require a new version of generators control functions, if available, in the network applications provider, for the installed generators. It is a risky situation to programme a functionality to control generation, while now is working at satisfaction.
- Alternative "c" requires new hardware and arecome a separate system. Maintains the generators control as it is.
- Alternative "d" requires good and fast communications between both centres.
- Alternative "e" will require more hardware and SCADA licenses do, in general aremore expensive.

Considering those aspects and because:

- It is mandatory to maintain the generators control provided by the generators supplier, that works satisfactorily, and we do not want to compromise this activity and take extra risks.
- The cost to program and adapt new functions and introduce them in a working system, has always a certain level of risk
- Due to the actual cost of hardware has been reduced for a same power and capacity
- Due to the capacity to cooperate between the different utilities in the region, as are explained below

Considering those reasons, we recommend the alternative "d" as starting point, to be followed by an expansion to alternative "e" when needed.

5.7 Additional elements to install in the network

To make the functionality proposed develop its full capability, some additional elements shall be installed in the network:

- Remote Terminal Units
- Capacity to modify the system topology
- Communications and protocols

- Cyber Security

5.7.1 Remote Terminal Units (RTU's)

RTU's are the terminals that give to the SCADA the information needed monitor the network, introduce topology changes and execute the applications.

An RTU can have the capability to read and transmit or execute:

- Analogue values as voltage and flows
- Digital values as breakers or isolators position, relays activity as protections or short circuit current detection
- Execute orders as open or close, up and down (transformer taps)

The optimal location of the RTUs is based on the load type, load capacity, level of voltage reductions and failure rate.

Other criteria are the communications capability and the availability to have energy supply facilities.

There are some algorithms that help to optimize the RTU location.

Considering the topology of the network in Marshall Energy Company, to start with, the number of RTU's shall be between 6 and 10.

5.7.2 Capacity to modify the system topology

One of the advantages of the SCADA is to intervene and modify some of the main parameters of the network, like the topology.

Open and closing some of the isolators or breakers the flow direction of the energy will change as the feeder's configuration changes.

Depending on the characteristics of the element to be operated, with or without flow as example, will provide more flexibility to intervene in the topology.

The best use is in case of an area in blackout, the topology changes may reduce the area isolated.

5.7.3 Communications and protocols

All communications technologies are available to be used from PLC to Optical Fibre going thorough radio or GPRS sim cards.

The set of standard protocols are used for this communication, most of the systems can offer more than one. Standard protocols have the advantage that RTUs from different vendors can be mixed in the network, which helps to reduce the RTU prices by introducing competitive pricing.

The communications should be protected to avoid intrusions, improving the cyber security.

5.7.4 Cyber Security

As in any other control centre the cyber security is a must in order to protect the information and the access.

Some security standards developed by FERC or ISO, among others are helpful to maintain under control the system operative

5.8 Procurement, Training and Commitment

The activity of procurement will consist of:

- design of the system including the functionality,
- preparation of technical specifications

- preparation of a call (tender) for offers and to accept bids from different potential providers (open to any potential participant or a short list of suppliers), including all the terms and conditions
- Evaluate bids and decide the winning offer and contract negotiation and signature

Once the supplier has been accepted and before the commitment, the training process shall start where the personnel are trained in the administration and maintenance of the system and to its use by the network operators.

The commitment shall include the installation in the final location and all tests before final acceptance.

5.8.1 Procurement

The main activity for procurement is, based in a previous design, prepare the technical specifications and contractual conditions to ask for offers to some potential suppliers.

Once the process to receive the bids is done, the decision mechanism, included in the offer conditions, are applied to determine the winner bid.

The following step are the contract negotiation, based on the contractual conditions included in the offers request.

The activity of procurement is highly time consuming and in consequence has a high cost associated.

In the case of utilities working together for procurement purposes, this activity will need to be repeated for each utility that wishes to establish a network control as designed above.

For the procurement between all or some of the utilities, common specifications and similar systems can be procured for each utility, with adjustments for the hardware requirements for each one.

For the utilities grouping in this process, should be able to report certain time and cost advantages:

- ✓ One core technical specification should be valid for the all systems. This will reduce the number of specifications and contractual conditions to be prepared.
- ✓ The individual price obtained for group of systems are lower than independent individual negotiations for each one.
- ✓ During the negotiation for a group of systems some other advantages, besides the price, could be achieved.
- ✓ It are possible to share some spare parts, that will also reduce the global cost

For all those reasons we recommend preparing common specifications and request offers for a group of systems to be developed together and with the same basic functionality.

Some location specific aspects can be included, as options.

5.8.2 Training

As part of the contract, the two training activities should be developed: training of administrators and users.

- ✓ Training for administrators is specially oriented to maintenance of system hardware and software, particularly the application of new versions, and the ordinary system maintenance, population and expansion of Data Bases, RTU's, communications… Resolution of any kind of problems, with the objective to maintain the system operation.
- ✓ Users training is to prepare the potential operators to perform and execute all applications of the system, included supervisory control or prepare reports, as examples.

This is knowledge that should be acquired in the utility and must retained by it.

But there are additional aspects that shall be considered:

- ✓ The minimum number of people assigned to SCADA in each utility. As administrators, should ideally be between 2 and 3, due the fact that there are unavoidable vacation or illness periods and the risk that one may decides to try other working options. However, in the Pacific Islands, staff resources are usually limited, so other options are:

- ✓ Sharing the trained resources among the different utilities, considering the capacity to be connected from distance, with secured communications, will reduce the number of formed administrators to 1 or 2 per utility.
- ✓ On the other hand, organize training courses for 2 or 3 people many times, in different locations, is an expensive scenario, compared with a single session for 10 to 16 administrators in the same location. Similarly valid for users training

Because of this, joint training and agreements for support among them will reduce the training and operational costs for each utility.

In consequence of those aspects, we recommend a joint training and an agreement between all utilities for a common support.

5.8.3 Commissioning

Includes all tests for acceptance and the installation on site.

Tests are commonly divided in two:

- Factory Acceptance Test (FAT) where the supplier executes the tests and is witnessed by the client. All functionality is tested. No real data are available, but the data could be simulated and loaded to the system from another computer that simulated the field. Until the results of FAT are not satisfactory, con not start the SAT.
- Site Acceptance Tests (SAT) where the system is tested by the client in their own facilities, with real data, and must be witnessed by the supplier. With the acceptance of SAT, the system is accepted, and the guarantee period starts.

As mentioned before, if there is an agreement between a number of utilities, the supplier can run a single FAT process, which is an expensive activity, instead of an independent FAT for each individual system. This way, the coordination of utilities will reduce the testing costs, without reducing its effectiveness, which will reduce the global costs for the supplier and in consequence for the utilities.

SAT must be carried on each system independently, but after initial problems detection and solving normally the remaining ones will go much faster, with the same acceptable results.

Those conditions lead us to suggest again an agreement between all utilities to make a joint test of the systems.

All aspects commented in the previous points regarding the development of a consortium, are aimed at:

- ✓ Simplifying all activities related with the commitment of a new system
- ✓ Reducing the final price of each system
- ✓ Establishing a cooperative framework to maintain updated and solve potential problems in the day by day operation.
- ✓ Maintaining the utility financial independency and its juridical personality.

With all those reasons we suggest reaching an agreement for Procurement, including spare parts, training, test, commitment and operation of the Network SCADA Systems.

5.9 Cost Benefit Analysis (CBA)

The Cost Benefit Analysis must include the following aspects:

1. Procurement and Installation financial cost
2. Operational costs
3. Evaluation of benefits obtained

The useful life time for the system, for reasons of CBA calculation is set at 10 years.

The results of these analysis shall report if the operation is economically sustainable or is a cost centre for the utility.

5.9.1 Installation financial cost

Corresponds to the cost of the procurement, test, training and commitment of the SCADA System, including potential financial costs.

Those costs shall include:

- ✓ The SCADA hardware and software
- ✓ Commitment of the system, including training and test. Exclude decoration of the Control Centre.
- ✓ For the study a total of 5 RTU's shall be considered, including needed network elements and the RTU itself.
- ✓ Communications required at RTU's and in the Centre.

Considering the potential cost reduction for agreements between electric utilities.

The useful life-time of the system can be set to 10 years.

5.9.2 Operational costs

The operational cost can be considered in 1 or 2 additional people during the useful life of the system. This assumes that the administrators of the actual system for generation control will take part also in the Network SCADA system, as administrator.

1 additional full-time personnel is needed in the case of a cooperative environment, and 2 additional personnel in an isolated scenario.

The reason for those values is the need to guarantee that knowledge remains in the company and, on top of this, the expert must be available in presence or in call for 7x 24 hours. With one expert, this is not guaranteed due to working calendar availability (vacations or illness).

So, in this case, a minimum of 2 operational experts are required at all the time, however more is recommended. But in case of a consortium (coordination between the utilities) , this third person, could be a reserve for substitution in other utilities, when needed for a limited time..

This is way in case of NO consortium, the need to contract people are the 3 needed minus 1, the actual expert, which make 2 new employees.

In case of consortium, the need to contract people are the 3 needed minus 1, the actual expert and minus 1 evaluated as the assistance between partners in the consortium, which make 1 new employee.

No termination costs need to be considered. As per experience, once the useful life is over either for size of the system or obsolescence of some equipment, the system are substituted by another one and the expertise acquired by the administrators are very valuable for a new system.

5.9.3 Benefits

The benefit that incorporates all improvements in network control are in the reduction of the number of partial or total blackouts and the reduction of the extent and duration of those blackouts.

The difficulty are to evaluate the reduction in blackouts and evaluate the benefit of this reduction.

The benefits are tangible in those aspects related with a non-supplied energy and immaterial for the image of the utility in any scenario, owned by some public administration or a private ownership.

First one can be quantitatively approached while the second only accept qualitative considerations.

This is a very complex issue. Two alternatives have been considered in the time, both equally valid, but with very different results:

5.9.3.1 From the utility perspective.

It is obvious that the utility suffers in its image from blackouts. But no monetary costs shall be considered besides there is an easily quantification for image recovery (discounts to clients, sometimes as per law, advertising in TV or similar…).

Considering the direct cost of the blackout there are two components:

- There is energy not supplied, but at the same time is not produced, so does not consume extra fuel. It is an almost even balance.
- There was a benefit expected for the sale of the unsupplied energy that now is not obtained.

Damage in the network shall be covered by an insurance policy either with insurance outsourcing or by auto insurance.

Those costs were approached by a named “cost of unsupplied energy”, which is evaluated in as many ways as utilities. Perhaps the average is considering 10 times of the clients cost or the most popular tariff.

5.9.3.2 From the society perspective.

It is true that the cost impact of a blackout to the civil society is also higher: loss of production in some factories, commercial activity stopped for a certain time. Damage of some goods at each home, due the loss of refrigeration, loss of capacity to recover electronic communication means (TV, Laptops, smart phones…), Hotels reputation in front of their clients may cause economic losses, and in top of them the loss of personal or home security aspects due the darkness or the unavailability of alarm systems.

All those aspects are not included in the cost of a blackout but their impact into the country economy is much higher than the impact on the utility economy.

For this reason, a second methodology has been developed lately considering the economic impact that a blackout of variable duration may produce.

Public companies shall consider, at least partially, this social cost.

It is clear that for the CBA are much easier to evaluate costs than profit, but simple analysis must show clear benefits.

5.10 SCADA Conclusions and Recommendations

Considering the aspects expressed above, we recommend:

- ✓ Establish one topology based on the maintenance of the existing SCADA to control the conventional generation.
- ✓ Implement a new SCADA system for network control
- ✓ Functionality regarding the Quality of Service are in the first phase. When this phase are consolidated, then a second phase with the Economic Optimisation and Losses Reduction are implemented.
- ✓ Together with the first phase, the commitment and test of 4 to 6 RTU’s, considering both systems
- ✓ For `procurement, training, commitment, test and commercial operation we recommend achieving an agreement with other utilities in order to reduce the investment and operational costs.
- ✓ To calculate the Cost Benefit Analysis, we recommend considering the investment and financial costs for an expected life of 10 years, the operative costs for the same period and the social benefits attached to the reduction of blackouts in extension and duration.

5.10.1 Recommendation for staged SCADA implementation and roadmap: Majuro

We recommend the following staged implementation roadmap with the scope and objective of each stage as indicated:

	Stage 1: Deploy basic SCADA	Stage 2: Extend and deploy level 1 DMS functions	Future: Deploy level 2 DMS functions and other technologies
Capabilities	Establish basic SCADA capabilities with visibility of the main 13.8kV stations, generation and PV plants with the ability to perform remote switching of the network	Extend the SCADA to include additional stations (4.16kV network) and additional signals Implement level 1 DMS functions (as listed below) to optimise the operation of the power network	Implement additional DMS functions (as listed below) Extend the SCADA visibility to the LV network using SMART meter technology
Objectives (benefits)	Monitor the status of the power network and the status of generation from a central control station and improve detection of outages, alarms and voltage violations Operate the power network (i.e. perform switching) from a central control station to improve restoration and safety	Improve the scope of visibility Improve plant overload detection and protection co-ordination with load flow and short circuit calculation capabilities Improve scheduling of generation with better load forecasting and by considering the available renewable capacity Improve grid security with emergency / block load shed capability	Support the implementation of virtual power plants to improve balancing of supply and demand Improve the control of the microgrid by supporting energy storage capabilities Reduce distribution system losses through volt/var optimisation Reduce demand and energy consumption through conservation voltage regulation

The scope of each stage proposed is detailed here below.

Stage 1: Basic SCADA

During this stage we recommend SCADA visibility be established from the central control station for the main 13.8kV MV stations including MEC Power stations and PV plants with the following capabilities:

- Monitoring of the following:
    - Switch positions (status of breakers and isolators)
    - Basic power flow measurands (e.g. amps, MW, MVAR and voltages) at key network positions
    - Transformer tap positions
    - Alarm signals limited to common / grouped alarms (Alarms are expanded in stage 2)
- Provide remote control capability of:
    - Open / close of switches (breakers and isolators)
    - Set generator setpoints and limits
    - Raise / lower transformer tap positions
- Visualise the status of the power network including topology processing to indicate the energized / de-energized / earthed parts of the network.
- Integrate with the existing SCADA and Generation Control system deployed at the Power station. Retain the existing frequency control mechanism.
- Record the load profile and generation data for future load forecasting.

The main dependencies during this stage are:

- Communication

  The operation of the SCADA system is dependent on reliable communication from each station to the central control station. International best practice recommends that Power Utilities establish their own communication network and not be dependent on public Telecommunication operators (A Telco's objective is different to earn revenue from selling bandwidth, whereas a Power Utility has to ensure the reliability of the power network).

- Plant capabilities

  The implementation of SCADA is subject to the capability of the installed plant, especially to accept remote control signals. The plant information available to us at this stage is limited and this needs to be confirmed in the next project phase.
- Topology model

  The topology processing (to identify energized/de-energized state of the network) will require the connectivity of the plant to be modelled. This requires accurate network data to be available which is typically captured in a GIS based system or in network schematic diagrams. The availability of such data needs to be confirmed in the next project phase.

Stage 2: Extend SCADA and deploy level 1 DMS functions

During this stage we recommend the extension of the SCADA visibility to include additional stations (4.16kV network), extend the signals that are monitored and deploy some DMS functions listed below:

- Extend the signals monitored in the following areas:
  - Include additional stations (4.16kV network)
  - Include additional power flow measurands at more network points
  - Include additional alarm signals to monitor individual alarms (subject to availability of alarm signals)
- Load flow study module:
  This will enable load flow studies to be done via the SCADA system considering the actual network condition or simulated network conditions. Network overload and voltage violations can be studied for different operation conditions and by simulating different network topologies (e.g. tripping of generators / transformers with or without PV plant being available).
- Short circuit calculation
  This module is an extension of the load flow study module to determine the minimum and maximum fault levels at different network positions and operating conditions. This information is important to validate the ratings of equipment and for protection co-ordination studies.
- Distribution load forecasting
  With this module the historical load profile and generation output data is used in combining with the weather forecast for short term load forecasting. The forecast of the available renewable capacity is considered to improve the scheduling and most economic dispatch of generation.
- Emergency / block load shed application:
  In the situation where insufficient generation capacity is available to meet the demand, the emergency / block load shed application will provide the ability to block load shed on a rotational basis to avoid inadvertent tripping of generators on overload. This improves the network security.

The implementation of these DMS functions are dependent on the following:

- Network model

  The DMS functions requires an accurate network model to be available. This includes both the connectivity model (as required for the topology processing in stage 1) and the electrical parameters of the plant. This requires accurate network data to be available which is typically captured in a GIS based system. The availability of such data needs to be confirmed in the next project phase.

Future Stage: Deploy level 2 DMS functions supporting other technologies

In future, the following DMS modules can be considered as the grid evolves:

- Virtual power plants module

A virtual power plant/pool (VPP) is a collection of power generation sources (e.g. rooftop solar, wind), energy storage devices and demand-response participants located in a distributed energy system. Incorporating these VPPs will become increasingly important in future for utilities and aggregation of these VPPs needs to be considered in the SCADA / DMS to balance generation with the demand. The grid code policy and infeed tariffs will have an impact on the penetration of VPPs.

- Microgrid Energy Storage module

  The network is essentially a microgrid. The introduction of energy storage capabilities will improve the control of the microgrid and the use of renewable technologies. Any meaningful energy storage capacity introduced in the grid must be considered in the optimal dispatch of generation. The implementation of this module will depend on future storage facilities added in the network.

- Volt/var optimization module

  At present we expect the equipment available to regulate voltage is limited to the generator var control setpoints and the transformer tap positions. The ability to reduce distribution system losses with volt/var optimisation through the network is thus limited. This optimization can be considered in future when additional var control mechanism becomes available in the network.

- Conservation voltage reduction

  Similar to the volt/var optimization, the ability to regulate the voltage at the customer to reduce demand and energy consumption (mainly by resistive loads) can be considered in future when additional var control mechanisms becomes available.

- LV visibility

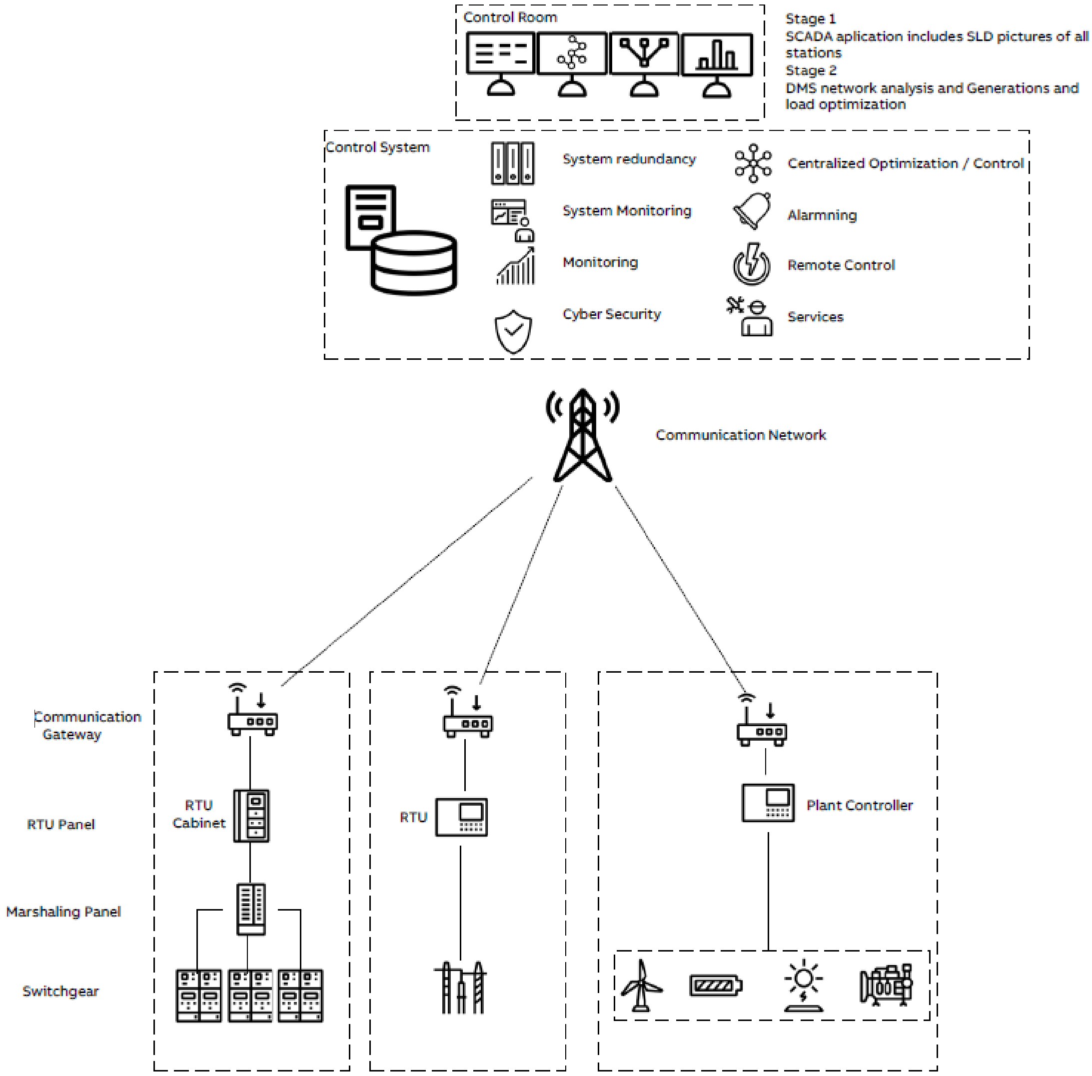
  Extending the LV visibility up to the customer can be achieved with the deployment of SMART meters with bi-directional communication. This can automate outage notification, identify voltage violations and support future volt/var optimization and conservation voltage reduction. This implementation will depend on MEC's SMART meter strategy, and integration with the SCADA central control should be considered in future when deployed.

- State Estimator

  The state estimator is beneficial to provide estimated data for intermediate network points where analog measurements are not available. It may also be required if other optimization applications require a state estimator (which may be the case depending on the SCADA technology of the supplier). The State Estimator module is dependent on a network model like the Power Flow module.

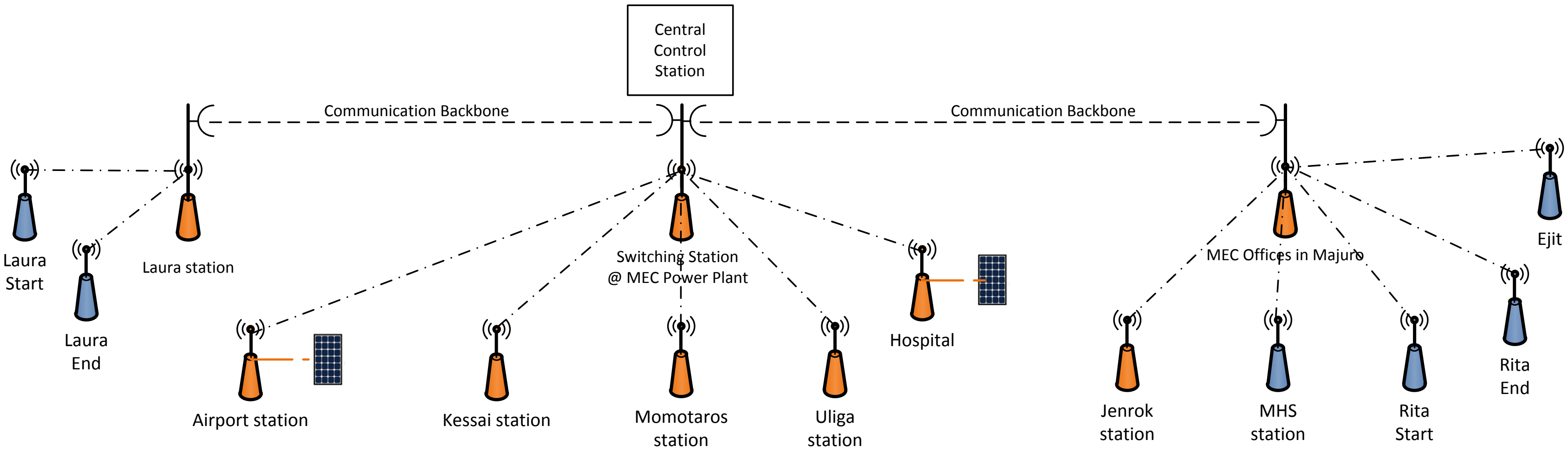
The conceptual design of the SCADA Control System is described in Figure 5-1.

Figure 5-1: Conceptual design of the SCADA Control System



The conceptual design solution of the communication network is described in **Figure 5-2**.

Figure 5-2: Concept communication network diagram for Majuro network



Notes:
1) It is assumed that limited Utility owned fibre optic cables exists, hence a radio based network is proposed for economic reasons and ease of deployment.
2) Each station links to the nearest high-site connected to the communication backbone. The number and location of the high-sites and stations are provisional estimates and based on the limited information available and needs to be confirmed in the next project stage.
3) Line-of-sight paths and signal propagation budget calculations need to be confirmed in the next project stage.
4) The Central Control Station can be located anywhere on the communication backbone. It is assumed best located near the main power plant but could be located at the MEC offices also.

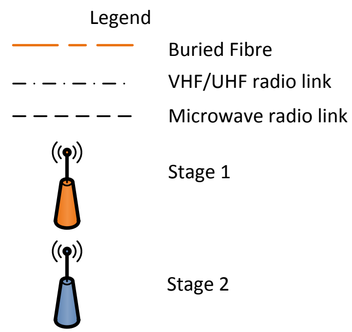


Figure 2: Concept communication network diagram for Majuro network

5.10.2 SCADA Cost Estimate

The estimated cost to implement stage 1 and 2, based on the scope as described above and the conceptual design solution.

Table 5-1: Estimated cost for stage 1 and 2

	Stage 1				Stage 2				
	Qty	Unit	Unit cost	Total cost	Qty	Unit	Unit cost	Total cost	Notes
Central Control Station									
Infrastructure works (building)									Excluded (scope unknown)
Hardware									
- Cabinet and network equipment	1	lot	$ 15,000	$ 15,000					
- Servers	2	each	$ 10,000	$ 20,000				$ -	
- Workstations	2	each	$ 3,500	$ 7,000				$ -	
- UPS	1	each	$ 5,000	$ 5,000				$ -	Limited capacity assuming standby generator
- Communication (link to backbone)	1	lot	$ 5,000	$ 5,000				$ -	Short buried fibre link
- Weather station	1	lot	$ 5,000	$ 5,000					To improve future load forecasting
Software licences	1	lot	$ 20,000	$ 20,000	1	lot	$ 40,000	$ 40,000	
Design and engineering	1	lot	$ 40,000	$ 40,000	1	lot	$ 60,000	$ 60,000	
Installation and commissioning	1	lot	$ 20,000	$ 20,000	1	lot	$ 40,000	$ 40,000	
				$ -				$ -	
Substations				$ -				$ -	
Hardware				$ -				$ -	
- RTUs	9	each	$ 20,000	$ 180,000	6	each	$ 20,000	$ 120,000	
- Transducers	25	each	$ 2,000	$ 50,000	25	each	$ 2,000	$ 50,000	Provisional estimate subject to site audit
- Communication equipment: Backbone	3	each	$ 25,000	$ 75,000				$ -	
- Communication equipment: Stations	9	each	$ 5,000	$ 45,000	6	each	$ 5,000	$ 30,000	
- Auxiliary DC system	9	each	$ 10,000	$ 90,000	6	each	$ 10,000	$ 60,000	Provisional estimate subject to site audit
Design and Engineering	1	lot	$ 40,000	$ 40,000	1	lot	$ 30,000	$ 30,000	
Installation, adaptation and commissioning	9	each	$ 15,000	$ 135,000	6	each	$ 15,000	$ 90,000	Provisional estimate subject to site audit
				$ -				$ -	
Travel and accommodation	1	lot	5.0%	$ 37,600	1	lot	5.0%	$ 26,000	
Project overheads	1	lot	5.0%	$ 37,600	1	lot	5.0%	$ 26,000	
Contingency	1	lot	15.0%	$ 112,800	1	lot	15.0%	$ 78,000	
								$ -	
				$ 940,000				$ 650,000	

The cost for the future stage is subject to the scope of implementation of the additional DMS modules and implementation of other technologies (i.e. energy storage facilities, var control technologies, SMART meters etc.) and therefore cannot be estimated at this stage

Appendix 1

Grid Code for Majuro. Please refer to the attached draft code.

Marshalls Energy Company

Grid Connection Code for Renewable Power Plants and Battery Storage Plants

Version 0.2

April 2019

Enquiries: The secretariat
Telephone:
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Version control

Marshalls Energy Company		
Document #	Title: **Grid Connection Code for Renewable Power Plants including Battery Storage Plants**	Print Date: **[Date]**
Revision # **0.2 Draft**	Prepared By: **Dr Graeme Chown and Rahul Desai – Ricardo Energy & Environment**	Date Prepared: **April 2019**
Effective Date: **[Date]**	Reviewed By: **Trevor Fry – Ricardo Energy & Environment**	Date Reviewed: **April 2019**
Standard: **Code**	Approved By: **[Approver's Name]**	Date Approved: **[Date]**

1 Objectives

(1) The primary objective of this grid connection code is to specify minimum technical and design grid connection requirements for *Renewable Power Plants* connected to or seeking connection to the Marshalls Energy Company's network.

(2) This document shall be used together with other applicable requirements for connecting to the network.

(3) This code was based on EU Commission Regulation 2016/1388, Kingdom of Swaziland Grid Code for Renewable Power Plants Connected to the Electricity Transmission System or the Distribution System and IEEE 1547, and adapted for the Majuro network

2 Scope

(1) The grid connection requirements in this code shall apply to all *Renewable Power Plants,* which shall for this code include *Battery Storage Plants,* connected or seeking connection to the Marshalls Energy Company's network.

(2) This grid connection code shall, at the minimum, apply to the following technologies:

(a) *Photovoltaic*

(b) *Wind*

(c) *Battery Storage*

(3) Unless otherwise stated, the requirements in this grid connection code shall apply equally to all *Renewable Power Plants*, *Storage Plants* and Types.

(4) The *Renewable Power Plant* shall, for the duration of its generation licence issued by an appropriate authority (MEC to advise who this is), comply with the provisions of this grid connection code and all other applicable codes, rules and regulations.

(5) Where there has been a replacement of or a major modification to an existing *plant*, the *plant owners/operators* shall be required to demonstrate compliance with these requirements before being allowed to operate commercially.

(6) Compliance with this grid connection code shall be applicable to the *Renewable Power Plants* depending on their rated power and, where indicated, the nominal voltage at the *point of connection to the grid*. Accordingly, *Renewable Power Plants* are grouped into the following three Types:

(a) Type A: 0 *MVA* – less than 0.2 *MVA* connected 400 V network

(b) Type B: 0.2 *MVA* – less than 1 *MVA* connected to the 11 kV network or 400 V network

(c) Type C: *1 MVA* or higher and any plants connected to 22 kV network or higher

(7) The requirements of this grid connection code are organized according to above-defined Types.

(8) The *Marshalls Energy Company* shall supply the *Renewable Power Plants* owner with detail of their Network that is sufficient to allow an accurate analysis of the interaction between the plant and the Marshalls Energy Company's network, including information about other generation facilities.

3 Definitions and Abbreviations

Active Power Curtailment Set-point

The limit set by the *Marshalls Energy Company* for the amount of active power that the *Renewable Power Plant* is permitted to generate. This instruction may be issued manually or automatically via a communication facility. The manner of applying the limitation shall be agreed between the parties.

Available Active Power

The amount of active power (MW), measured at the *point of connection to the grid,* that the *Renewable Power Plant* could produce based on plant availability as well as current renewable primary energy conditions (e.g. wind speed, solar radiation or charge available).

Curtailed Active Power

The amount of Active Power that the *Renewable Power Plant* is permitted to generate by the *Marshalls Energy Company* subject to network or system constraints.

Marshalls Energy Company

Means the Marshalls Energy Company established under the Marshalls Islands Act of 1996.

Rated power

The highest active power measured at the *point of connection,* which the *Renewable Power Plant* is designed to continuously supply.

Rated wind speed

The average wind speed at which a *Wind Power Plant* achieves its *rated power*. The average wind speed is calculated as the average value of wind speeds measured at hub height over a period of 10 minutes.

Renewable Power Plant

One or more *unit(s)* and associated equipment, with a stated *rated power,* which has been connected to the same *point of connection* and operating as a single power plant.

It is, therefore, the entire *Renewable Power Plant* that shall be designed to achieve requirements of this code at the *point of connection*. A *Renewable Power Plant* has only one *point of connection*.

In this *code*, the term *Renewable Power Plant* is used as the umbrella term for *a unit* or a system of generating *units* producing electricity based on a primary renewable energy source (e.g. wind, sun, water etc.) and *Battery Storage Plant*. A *Renewable Power Plant* can use different kinds of primary energy source. If a *Renewable Power Plant* consists of a homogeneous type of generating *units* it can be named as follows:

PV Power Plant (*PVPP*)

Single *Photovoltaic* panel or a group of several *Photovoltaic* panels with associated equipment operating as a power plant.

Wind Power Plant (*WPP*)

Single turbine or a group of several turbines driven by wind as fuel with associated equipment operating as a power plant. This is also referred to as a wind energy facility (WEF)

Battery Storage Power Plant (*BSPP*)

Single battery or a group of several batteries installed for system security through provision of frequency and voltage control services and or used for storage of electrical energy.

Renewable Power Plant (*RPP*) Controller

A set of control functions that make it possible to control the *Renewable Power Plant* at the *point of connection to the grid*. The set of control functions shall form a part of the *Renewable Power Plant.*

***RPP* Generator**

Means a legal entity that is licensed to develop and operate a *Renewable Power Plant*.

Voltage Ride Through (*VRT*) Capability

The capability of the *Renewable Power Plant* to stay connected to the network and keep operating following voltage dips or surges caused by short-circuits or disturbances on any or all phases in the *Network*.

4 Tolerance of Frequency and Voltage Deviations

(1) The *Renewable Power Plant* shall be able to withstand frequency and voltage deviations at the point of connection to the grid under normal and abnormal operating conditions described in this grid connection code while reducing the active power as little as possible.

(2) The *Renewable Power Plant* shall be able to support network frequency and voltage stability in line with the requirements of this grid connection code.

(3) Normal operating conditions and abnormal operating conditions are described in section 4.1 and section 4.2, respectively.

4.1 *Normal Operating Conditions*

(1) Unless otherwise stated, requirements in this section shall apply to all Types of *Renewable Power Plants*.

(2) All *Renewable Power Plants* shall be designed to be capable of operating within the voltage range of ±10% around the nominal voltage at the point of connection to the grid. The actual operating voltage differs from location to location, and this shall be decided by the *Marshalls Energy Company* in consultation with the affected customers (including the *Renewable Power Plant*), and implemented by the *Renewable Power Plant owner or operator*.

(3) The nominal frequency of the *Marshalls Energy Company*'s network is 60 Hz and is normally controlled within the limits of 59.5 to 60.5 Hz.

(4) All *Renewable Power Plants* facilities shall be capable of remaining connected to the network and operate within the frequency range of 57.0 to 62.0 Hz.

(5) *Marshalls Energy Company* and the power-generating facility owner may agree on wider frequency ranges, longer minimum times for operation or specific requirements for combined frequency and voltage deviations to ensure the best use of the technical capabilities of a power-generating facility, if it is required to preserve or to restore system security.

(6) Tripping times for when frequency goes outside of the normal operating range of 59.0 to 61.0 Hz shall be agreed with *Marshalls Energy Company*. *Marshalls Energy Company* shall co-ordinate such settings to minimise the risk of cascade tripping and network collapse.

(7) All *Renewable Power Plants* shall be capable of continuous operation, at up to 100% active power output, within a frequency range of 59.0 to 61.0 Hz and voltage range of 10% either side of nominal voltage.

(8) The active power output from all Type B and C *Renewable Power Plants* shall not decrease by more than a proportionate decrease when the frequency varies within the range of 57.0 to 59.0 Hz.

(9) When the frequency on the *Marshalls Energy Company*'s network is higher than 62.0 Hz for longer than 4 seconds, the *Renewable Power Plant* may be disconnected from the grid.

(10) When the frequency on the *Marshalls Energy Company*'s network is less than 57.0 Hz for longer than 200ms, the *Renewable Power Plant* may be disconnected.

(11) The *Renewable Power Plant* shall remain connected to the *Marshalls Energy Company*'s network for a rate of change of frequency of up to and including 1.0 Hz per second measured over a rolling window of 500 ms, provided that the network frequency remains within the range of 57.0 to 59.0 Hz.

4.1.1 Synchronising to the *Marshalls Energy Company's* network

(1) *Renewable Power Plants* of Type B and C shall only be allowed to connect to the *Marshalls Energy Company*'s network, at the earliest, 3 seconds after:

(a) for Type B, the voltage at the *point of connection to the grid* is within ±10% around the nominal voltage,

(b) for Type C, the voltage at the *point of connection to the grid* is within ±5% around the nominal voltage,

(c) frequency in the *Marshalls Energy Company*'s network is within the range of 59.0 Hz and 60.2 Hz.

(d) removal of the synchronisation block signal received from the *Marshalls Energy Company's SCADA* system

4.2 ***Abnormal Operating Conditions***

4.2.1 Tolerance to sudden voltage drops and peaks

(1) *Renewable Power Plants* of Types B and C shall be designed to withstand and fulfil, at the *point of connection to the grid*, voltage conditions described in this section and illustrated in Figure 1 below.

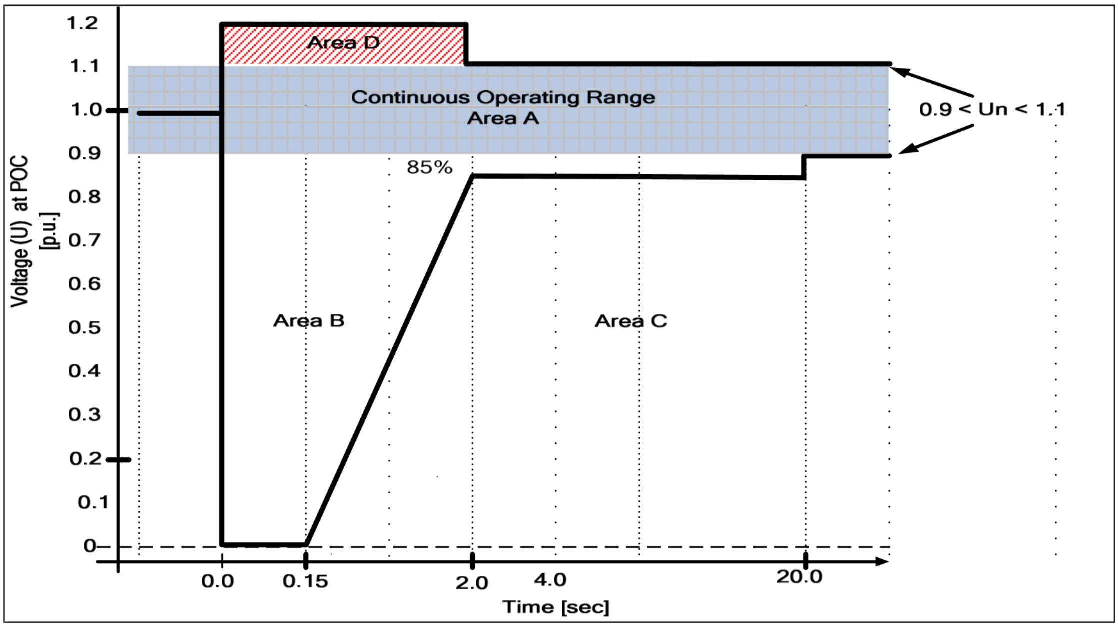
(2) The *Renewable Power Plant* shall be designed to withstand voltage drops and peaks, as illustrated in Figure 1 and supply or absorb reactive current within the transient design ratings of the plant.

(3) The *Renewable Power Plant* shall be able to withstand voltage drops to zero, measured at the *point of connection to the grid*, for a minimum period of 0.150 seconds without disconnecting, as shown in Figure 1.

(4) The *Renewable Power Plant* shall be able to withstand voltage peaks up to 120% of the nominal voltage, measured at the *point of connection to the grid*, for a minimum period of 2 seconds without disconnecting, as shown in Figure 1.

(5) Figure 1 shall apply to all types of faults (symmetrical and asymmetrical i.e. one-, two- or three-phase faults) and the bold line shall represent the minimum voltage of all the phases.

Figure 1: Voltage Ride Through Capability for the Renewable Power Plant of Type B and C



If the voltage (U) reverts to area A during a fault sequence, subsequent voltage drops shall be regarded as a new fault condition. If several successive fault sequences occur within area B and evolve into area C, disconnection is allowed, see Figure 1.

(6) In connection with symmetrical fault sequences in areas B and D of Figure 1, the *Renewable Power Plant* shall have the capability of controlling the reactive power. The following requirements shall be complied with:

(a) **Area A:** The *Renewable Power Plant* shall stay connected to the network and maintain normal production.

(b) **Area B:** The *Renewable Power Plant* shall stay connected to the network. In addition, the *Renewable Power Plant* shall provide maximum voltage support by supplying a controlled amount of reactive current so as to ensure that the *Renewable Power Plant* helps to stabilise the voltage.

(c) **Area C (Figure 1):** Disconnecting the *Renewable Power Plant* is allowed.

(d) **Area D:** The *Renewable Power Plant* shall stay connected to the network and provide maximum voltage support by absorbing a controlled amount of reactive current so as to ensure that the *Renewable Power Plant* helps to stabilise the voltage within the design capability offered by the *Renewable Power Plant*.

(7) The supply of reactive power has first priority in area B, while the supply of active power has second priority. If possible, active power shall be maintained during voltage drops, but a reduction in active power within the *Renewable Power Plant's* design specifications is acceptable.

5 Frequency Response

(1) In case of frequency deviations in the *Marshalls Energy Company*'s network, the *Renewable Power Plants* shall be designed to be capable to provide power-frequency response in order to stabilise the grid *frequency*. The metering accuracy for the grid frequency shall be at least ±10mHz.

5.1 Power-frequency response curve for *Renewable Power Plants*

(1) This subsection applies to all *Renewable Power Plants.*

(2) *Renewable Power Plants* shall be designed to be capable to provide power-frequency response as illustrated in Figure 2.

(3) The default settings for f_{min}, f_{max}, f_1 to f_5 shall be as shown in Table 1 for *Renewable Power Plants* unless otherwise agreed with *Marshalls Energy Company*.

(4) It shall be possible to set the frequency response control function for all frequency points shown in Figure 2. It shall be possible to set the frequencies f_{min}, f_{max}, as well as f_1 to f_5 to any value in the range of 57 - 62 Hz with a minimum accuracy of 10 mHz.

(5) The *Renewable Power Plants* shall be equipped with the frequency control *droop* settings as illustrated in Figure 2. Each *droop* setting shall be adjustable between 0% and 10%. The actual *droop* setting shall be as agreed with the *Marshalls Energy Company*.

(6) The *Marshalls Energy Company* shall decide and advise the *Renewable Power Plants* on the *droop* settings required to perform the control between the various frequency points.

(7) If the active power from the *Renewable Power Plants* is regulated downward below the unit's design limit P_{min}, shutting-down of individual *Renewable Power Plant units* is allowed.

(8) It shall be possible to activate and deactivate the frequency response control function in the interval from f_{min} to f_{max}.

(9) If the frequency control setpoint (P_{Delta}) is to be changed, such change shall be commenced and be completed no later than 1 second after receipt of an order to change the setpoint.

(10) The accuracy of the control performed (i.e. change in active power output) and of the setpoint shall not deviate by more than ±2% of the setpoint value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

Figure 2: Frequency response requirement for *Renewable Power Plants*

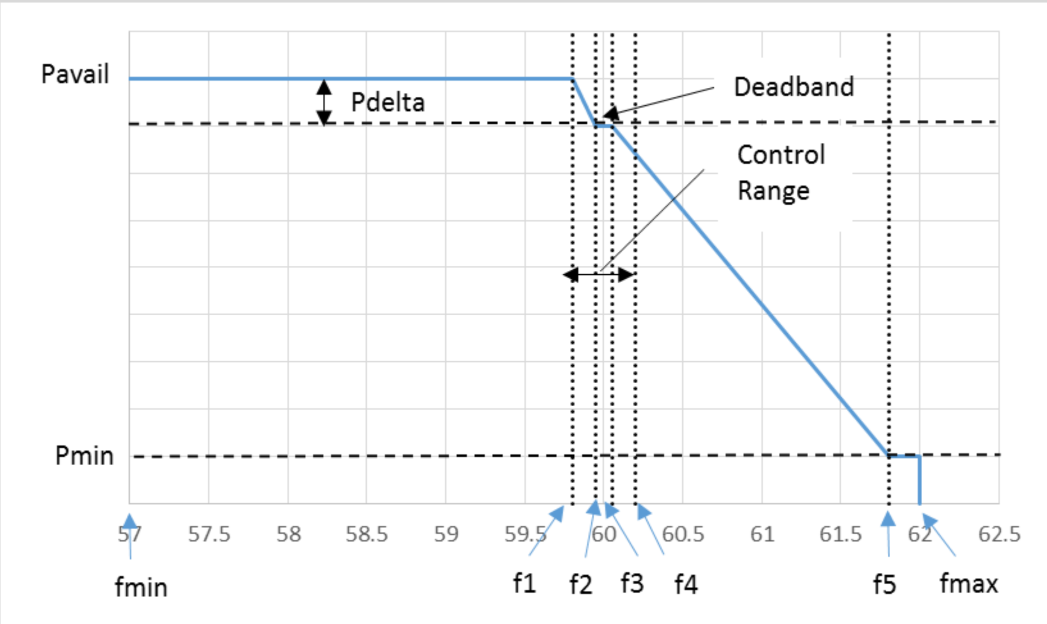


Table 1: Frequency Default Settings

Type	Type A PVPP & WPP	Type B & C PVPP & WPP	Type A, B & C BSPP	Unit
f_{min}	57.0	57.0	57.0	Hz
f_{max}	62.0	62.0	62.0	Hz
f_1	57.0	59.0	59.8	Hz
f_2	57.0	59.5	59.9	Hz
f_3	60.5	60.5	60.1	Hz
f_4	61.0	61.0	60.2	Hz
f_5	62.0	62.0	62.0	Hz
P_{Delta}	0	As agreed with *CPUC*	100	%

5.2 Procedure for setting and changing the power-frequency response curves for Renewable Power Plants

(1) The *Marshalls Energy Company* shall give the Renewable Power Plants owner/operator a minimum of 2 weeks if changes to any of the frequency response parameters (i.e. f_1 to f_5) are required. The *Renewable Power Plant* owner/operator shall confirm with the *Marshalls Energy Company* that requested changes have been implemented within two weeks of receiving the *Marshalls Energy Company's* request.

5.3 Synthetic Inertia

(1) Type B & C asynchronous *Renewable Power Plants* shall be capable of providing synthetic inertia in response to frequency changes, activated in low and/or high frequency conditions by rapidly adjusting the active power injected to or withdrawn from the AC network in order to limit the rate of change of frequency. The requirement shall at least take account of the results of the studies undertaken by *MEC* to identify if there is a need to set out minimum inertia.

(2) The principle of the control system to provide Synthetic Inertia and the associated performance parameters shall be agreed between *MEC* and the *Renewable Power Plant* owner.

6 <u>Reactive Power Capabilities</u>

6.1 Type A *Renewable Power Plants*

(1) Type A *Renewable Power Plants* shall not actively regulate the voltage at the *point of connection*. Type A *Renewable Power Plants* shall not cause the network voltage the *point of connection* to exceed the normal operating voltage limits specified in Paragraph 4.1.

6.2 Type B & C *Renewable Power Plants*

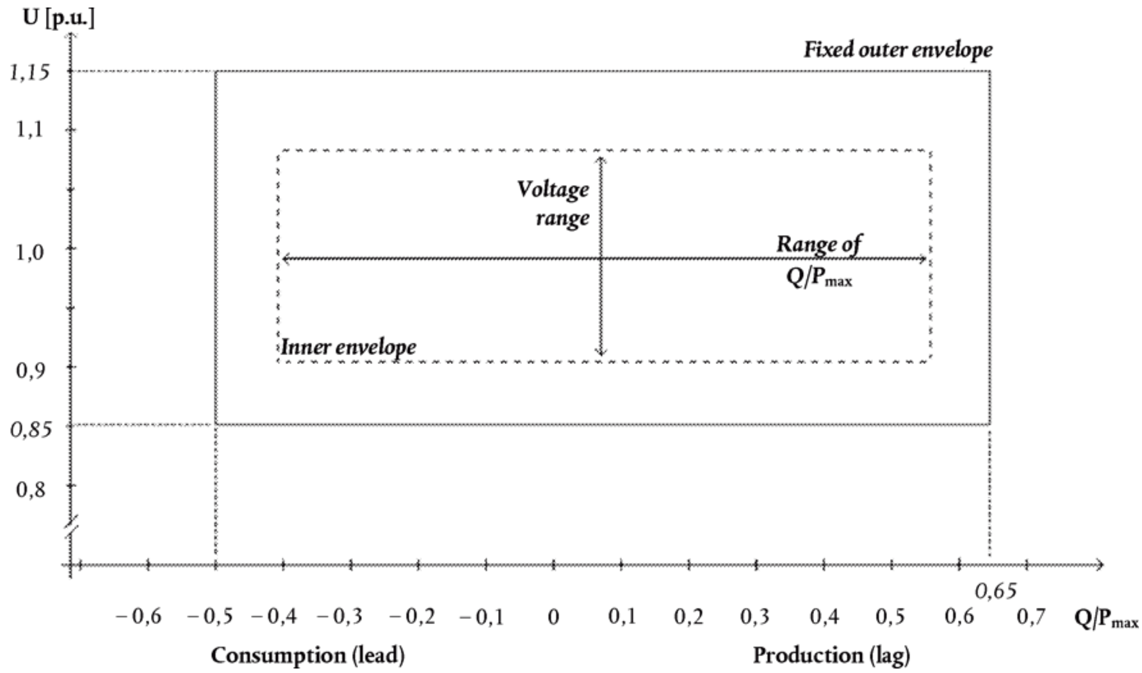
(1) *Type B* & C *Renewable Power Plants* shall be designed with the capability to operate in a voltage (V), power factor or reactive power (Q or *MVA*r) control modes as described in section 7 below. The actual operating mode (V, power factor or Q control) as well as the operating point shall be agreed with the *Marshalls Energy Company*.

(2) The reactive power capabilities of *Type B* & C *Renewable Power Plants* at maximum active power transmission capacity shall be capable of providing reactive power at its maximum active power transmission capacity and at every possible operating point below maximum active power transmission capacity. For *Type B* & C *BSPP* the minimum power shall be the full import capability of the *BSPP* when charging.

(3) *Renewable Power Plants* shall be designed to supply rated power (MW) for power factors as specified in Table 2 below.

(4) In addition the *Renewable Power Plants* shall be designed in such a way that the operating point can lie anywhere within the inner envelope in Figure 3.

Figure 3 U-Q/P_{max}-profile of *Renewable Power Plants*



The diagram represents the boundaries of the U-Q/P_{max}-profile with the voltage at the connection point, expressed in pu, against the ratio of the reactive power (Q) to the maximum capacity (P_{max}). The position, size and shape of the inner envelope are indicative.

Table 2 Parameters for the inner envelope for Type B & C

Type	Maximum range of Q/P_{max}	Maximum range of steady- state voltage level in PU
Type B	0.975	0.225
Type C	0.95	0.225

7 Reactive Power and Voltage Control Functions

(1) The following requirements shall apply to *Type B & C Renewable Power Plants*.

(2) The Renewable Power Plants shall be equipped with reactive power control functions capable of controlling the reactive power supplied by the Renewable Power Plants at the point of connection to the grid as well as a voltage control function capable of controlling the voltage at the point of connection to the grid via orders using setpoints and gradients.

(3) Synchronous Renewable Power Plants shall be equipped with a permanent automatic excitation control system that can provide constant alternator terminal voltage at a selectable setpoint without instability over the entire operating range of

the synchronous Renewable Power Plants. The specifications and performance of the excitation control system shall include:

(a) bandwidth limitation of the output signal to ensure that the highest frequency of response cannot excite torsional oscillations on other *Power Plant*s connected to the network;

(b) an underexcitation limiter to prevent the AVR from reducing the alternator excitation to a level which would endanger synchronous stability;

(c) an overexcitation limiter to ensure that the alternator excitation is limited to less than the maximum value that can be achieved whilst ensuring that the synchronous *Renewable Power Plant* is operating within its design limits;

(d) a stator current limiter;

(4) The reactive power and voltage control functions are mutually exclusive, which means that only one of the three functions mentioned below can be activated at a time.

(a) Voltage control

(b) Power Factor control

(c) Q control

(5) The control function and applied parameter settings for reactive power and voltage control functions shall be determined by the *Marshalls Energy Company* and implemented by the *Renewable Power Plant*s. The agreed control functions shall be documented in the *operating agreement*.

7.1 Reactive power (Q) Control

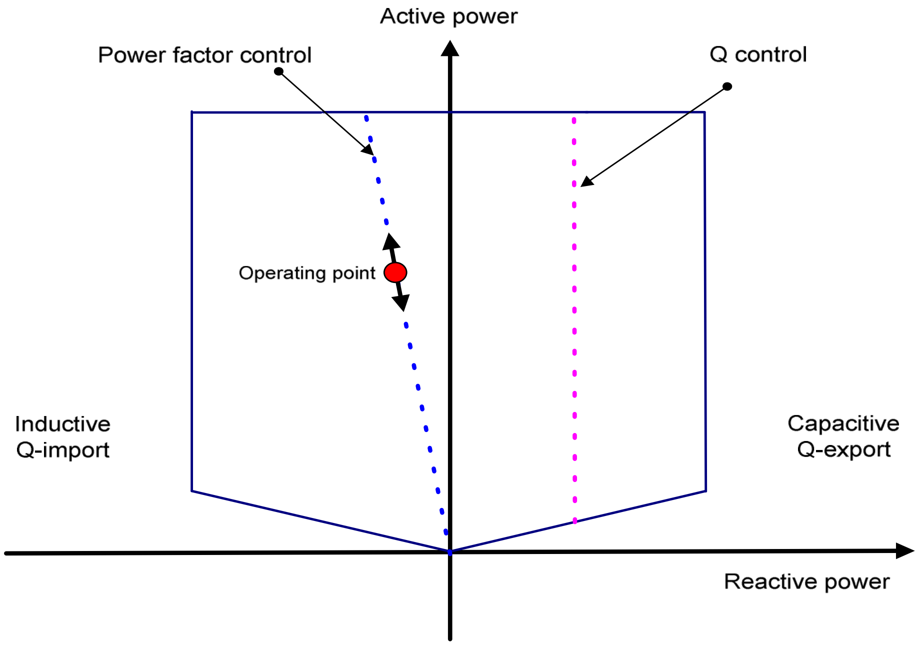
(1) Q control is a control function controlling the reactive power supply and absorption at the point of connection to the grid independently of the active power and the voltage. This control function is illustrated in Figure 4 as a vertical line.

(2) If the Q control setpoint is to be changed by the *Marshalls Energy Company*, the *Renewable Power Plant* shall update its echo analogue setpoint value in response to the new value within 1 second. The *Renewable Power Plant*s shall respond to the new set point within 30 seconds after receipt of an order to change the setpoint.

(3) The accuracy of the control performed and of the setpoint shall not deviate by more than ±2% of the setpoint value or by ±0.5% of maximum reactive power, depending on which yields the highest tolerance.

(4) The *Renewable Power Plant*s shall be able to receive a Q setpoint with an accuracy of at least ±0.5% of maximum reactive power.

Figure 4: Reactive power control functions for the *Renewable Power Plant*s



7.2 Power Factor Control

(1) Power Factor Control is a control function controlling the reactive power proportionally to the active power at the point of connection to the grid. This is illustrated in Figure 4 by a line with a constant gradient.

(2) If the power factor setpoint is to be changed by the *Marshalls Energy Company*, the *Renewable Power Plant* shall update its echo analogue setpoint value to in response to the new value within 1 second. The *Renewable Power Plant* shall respond to the new set point within 30 seconds after receipt of an order to change the setpoint.

(3) The accuracy of the control performed and of the setpoint shall not deviate by more than ±0.02.

7.3 Voltage Control

(1) Voltage control is a control function controlling the voltage at the point of connection to the grid.

(2) If the voltage setpoint is to be changed, such change shall be commenced within 1 second and completed no later than 30 seconds after receipt of an order to change the setpoint.

(3) The accuracy of the voltage setpoint shall be within ±0.5% of nominal voltage, and the accuracy of the control performed shall not deviate by more than ±2% of the required injection or absorption of reactive power according to *droop* characteristics as defined in Figure 5.

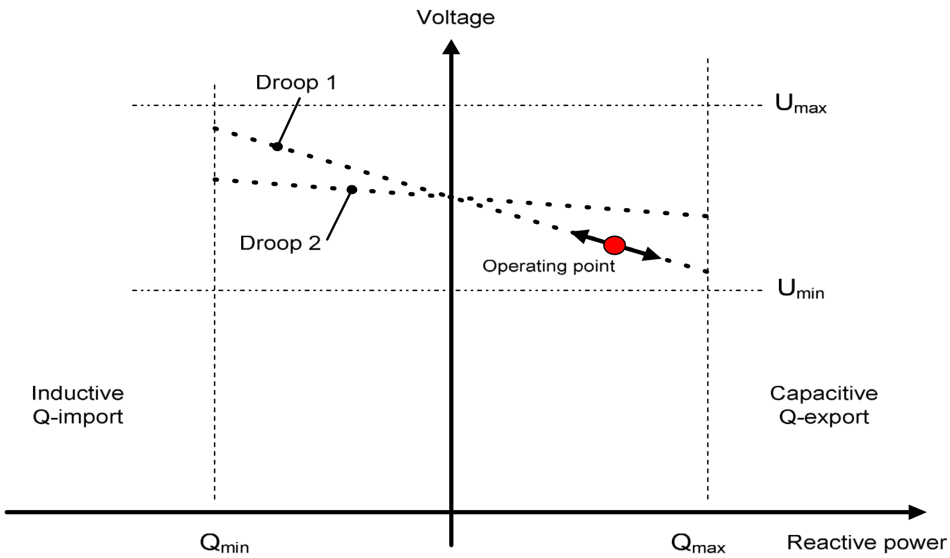
(4) The individual *Renewable Power Plant* shall be able to perform the control within its dynamic range and voltage limit with the *droop* configured as shown in Figure 5. In

this context, *droop* is the voltage change (p.u.) caused by a change in reactive power (p.u.).

(5) When the voltage control has reached the *Renewable Power Plant's* dynamic design limits, the control function shall await possible overall control from the tap changer or other voltage control functions.

(6) Overall voltage coordination shall be handled by the *Marshalls Energy Company*.

Figure 5: Voltage control for the *Renewable Power Plant*



8 <u>Power Quality</u>

(1) The following requirements shall apply to all *Renewable Power Plants*.

(2) *Power quality* and voltage regulation impact shall be monitored at the point of connection to the grid and shall include an assessment of the impact on *power quality* from the *Renewable Power Plant* concerning the following disturbances at the point of connection to the grid*:*

(a) voltage fluctuations:

(i) rapid voltage changes

(ii) flicker

(b) high-frequency currents and voltages:

(i) harmonics

(ii) inter-harmonics

(iii) disturbances greater than 2 kHz.

(c) unbalanced currents and voltages:

(i) deviation in magnitude between three phases

(ii) deviation in angle separation from 120° between three phases.

(3) The *Renewable Power Plant* and its interconnection system shall not inject dc current greater than 0.5% of the full rated output current at the point of connection.

(4) When the *Renewable Power Plant* is serving balanced linear loads, harmonic current injection into the network at the point of connection shall not exceed the limits stated below in Table 3. The harmonic current injections shall be exclusive of any harmonic currents due to harmonic voltage distortion present in the network without the *Renewable Power Plant* connected.

Table 3—Maximum harmonic current distortion in percent of current (I)[a]

Individual harmonic order h (odd harmonics)[b]	$h < 11$	$11 \leq h < 17$	$17 \leq h < 23$	$23 \leq h < 35$	$35 \leq h$	Total demand distortion (TDD)
Percent (%)	4.0	2.0	1.5	0.6	0.3	5.0

[a] I = the greater of the local network maximum load current integrated demand (15 or 30 minutes) without the RPP unit, or the RPP unit rated current capacity (transformed to the point of connection when a transformer exists between the RPP unit and the point of connection).

[b]Even harmonics are limited to 25% of the odd harmonic limits above.

(5) *Power quality* and voltage regulation impact shall be monitored at the point of connection to the grid.

(6) Voltage and current quality distortion levels emitted by the *Renewable Power Plant* at the point of connection to the grid shall not exceed the apportioned limits as determined by the *Marshalls Energy Company*.

(7) The *Renewable Power Plant* shall ensure that the *plant* is designed, configured and implemented in such a way that the specified emission limit values are not exceeded.

(8) The maximum allowable voltage change at the *Renewable Power Plant* after a switching operation by the *plant* (e.g. of a compensation devices) shall not be greater than 2%.

9 Islanding

(1) For an unintentional island in which the *Renewable Power Plant* energizes a portion of the network through the *point of connection*, the *Renewable Power Plant* interconnection system shall detect the island and cease to energize the network within two seconds of the formation of an island.

(2) *Renewable Power Plant* can be requested to intentionally island under certain conditions. The *Renewable Power Plant* requested to intentionally island shall have the facilities to detect an island condition, and have the capability to actively control frequency and / or voltage. *Marshalls Energy Company* shall provide the conditions and requirements from the for *Renewable Power Plant* intentional islanding.

10 Protection and Fault levels

(1) Unless otherwise stated, requirements in this section apply to all *Types* of *Renewable Power Plants*.

(2) Protection functions shall be available to protect the *Renewable Power Plant* and to ensure a stable network.

(3) The *Renewable Power Plants* shall ensure that the plant is dimensioned and equipped with the necessary protection functions such that the *plant* is protected against damage due to faults and incidents in the network.

(4) Protection schemes may cover the following aspects:

- external and internal short circuit,
- asymmetric load (negative phase sequence),
- stator and rotor overload,
- over-/underexcitation,
- over-/undervoltage at the connection point,
- over-/undervoltage at the alternator terminals,
- inrush current,
- asynchronous operation (pole slip),
- protection against inadmissible shaft torsions (for example, subsynchronous resonance),
- *power-generating module* line protection,
- unit transformer protection,
- back-up against protection and switchgear malfunction,
- overfluxing (U/f),
- inverse power,
- rate of change of frequency, and
- neutral voltage displacement.

(5) The *Marshalls Energy Company* may request that the set values for protection functions be changed following commissioning if it is deemed to be of importance to the operation of the network. However, such change shall not result in the *Renewable Power Plants* being exposed to negative impacts from the network lying outside of the design requirements.

(6) The *Marshalls Energy Company* shall inform the *Renewable Power Plants* owners/operators of the highest and lowest short-circuit current that can be expected at the point of connection to the grid as well as any other information about the network as may be necessary to define the *Renewable Power Plant's* protection functions.

11 Active Power Constraint Functions

(1) This section shall apply to Types B and C *Renewable Power Plants.*

(2) For system security reasons it may be necessary for the *Marshalls Energy Company* to curtail the *Renewable Power Plant's* active power output.

(3) The *Renewable Power Plants* shall be capable of:

(a) operating the plant at a reduced level if active power has been curtailed by the *Marshalls Energy Company* for system security reasons and for frequency control.

(b) receiving a telemetered MW Curtailment set-point sent from the *Marshalls Energy Company.*

(4) The *Renewable Power Plants* shall be equipped with constraint functions, i.e. supplementary active power control functions. The constraint functions are used to avoid imbalances in the *Marshalls Energy Company's* network or overloading of the network in connection with the reconfiguration of the network in critical or unstable situations or the like, as illustrated in Figure 6.

(5) Activation of the active power constraint functions shall be agreed with the *Marshalls Energy Company*.

The required constraint functions are as follows:

(a) Absolute production constraint

(b) Delta production constraint

(c) Power gradient constraint

(6) The required constraint functions are described in the following sections.

11.1 Absolute Production Constraint

(1) An Absolute Production Constraint is used to constrain the output active power from the *Renewable Power Plants* to a predefined power MW limit at the point of connection to the grid. This is typically used to protect the network against overloading and for frequency control.

(2) If the setpoint for the Absolute Production Constraint is to be changed, such change shall be commenced within 1 second and completed not later than 2 seconds after receipt of an order to change the setpoint.

(3) The accuracy of the control performed and of the setpoint shall not deviate by more than ±2% of the setpoint value or by ±0.5% of the *rated power,* depending on which yields the highest tolerance.

11.2 Delta Production Constraint

(1) A Delta Production Constraint is used to constrain the active power from the *Renewable Power Plants* to a required constant value in proportion to the possible active power.

(2) A Delta Production Constraint is typically used to establish a control reserve for control purposes in connection with primary frequency control.

(3) If the setpoint for the Delta Production Constraint is to be changed, such change shall be commenced within 1 second and completed no later than 2 seconds after receipt of an order to change the setpoint.

(4) The accuracy of the control performed and of the setpoint shall not deviate by more than ±2% of the setpoint value or by ±0.5% of the rated power, depending on which yields the highest tolerance.

11.3 Power Gradient Constraint

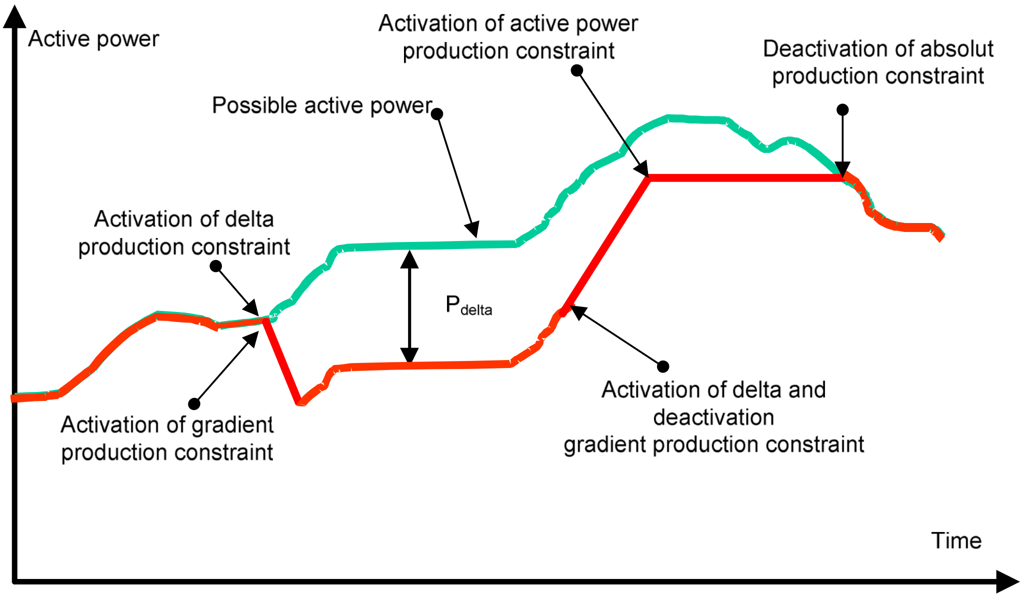
(1) A Power Gradient Constraint is used to limit the maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the setpoints for the *Renewable Power Plant.* A Power Gradient Constraint is typically used for reasons of system operation to prevent changes in active power from impacting the stability *of the* network.

(2) If the setpoint for the Power Gradient Constraint is to be changed, such change shall be commenced within 1 second and completed no later than 2 seconds after receipt of an order to change the setpoint.

(3) The accuracy of the control performed and of the setpoint shall not deviate by more than ±2% of the setpoint value or by ±0.5% of the *rated power,* depending on which yields the highest tolerance.

(4) The active power constraint functions are illustrated in **Figure 6**.

Figure 6: Active power control functions for a Renewable Power Plant



12 Control Function Requirements

(1) *Renewable Power Plants* shall be equipped with the control functions specified in Table 4. The purpose of the various control functions is to ensure overall control and monitoring of the *Renewable Power Plant's* generation.

(2) The *Renewable Power Plants* control system shall be capable of controlling the ramp rate of its active power output with a maximum MW per minute ramp rate set by the *Marshalls Energy Company*.

(3) These ramp rate settings shall be applicable for all ranges of operation including positive ramp rate during start up, positive ramp rate only during normal operation and negative ramp rate during controlled shut down. They shall not apply to frequency regulation.

(4) The *Renewable Power Plants* shall not perform any frequency response or voltage control functions without having entered into a specific agreement to this effect with the *Marshalls Energy Company*.

(5) The specifications and regulation functions specified shall comply with the international standard IEC 61400-25-2.

Table 4: Control functions required for *Renewable Power Plants*

Control function	**Type A**	**Type B**	**Type C**
Frequency control	X	X	X
Absolute production constraint	-	X	X

Control function	Type A	Type B	Type C
Delta production constraint	-	X	X
Power gradient constraint	-	X	X
Q control	-	X	X
Power factor control	-	X	X
Voltage control	-	X	X

13 Signals, Communications & Control

(1) All signals shall be made available at the *point of connection to the grid* by the *Renewable Power Plants*.

13.1 Signals from the *Renewable Power Plants* available at the point of connection to the grid

(1) This section shall apply to *Renewable Power Plants* of *Type B and C*.

(2) Signals from the *Renewable Power Plants* to the *Marshalls Energy Company* shall be broken up into a number of logical groups depending on functionality.

(3) The following signal list groups shall apply:

(a) ***Signals List #1*** – *General*

In addition, *Renewable Power Plants* shall be required to provide certain signals from Signals Lists 2, 3, 4 and 5. These lists relate to:

(b) ***Signals List #2*** – *Renewable Power Plant Availability Estimate;*

(c) ***Signals List #3*** – *Renewable Power Plant MW Curtailment data;*

(d) ***Signals List #4*** – *Renewable Power Plant frequency response settings*

(e) ***Signals List #5*** – *Renewable Power Plant meteorological data.*

13.1.1 Signals List #1 – General

(1) The *Renewable Power Plants* shall make the following signals available at the *Marshalls Energy Company* designated *communication gateway equipment* located at the *plant's* site:

(a) Actual sent-out (MW) at the point of connection to the grid

(b) Active Power Ramp rate of the entire *Renewable Power Plant*

(c) Reactive Power Import/Export (+/-*MVAr*) at the point of connection to the grid

(d) Reactive power range upper and lower limits

(e) *Power Factor*

(f) *Voltage output*

(g) *Echo MW set point*

(h) *Echo MVAr set point*

(i) *Echo Voltage set point*

13.1.2 Signals List #2 – *Renewable Power Plants* Current Availability Estimates

(1) The *Renewable Power Plants* shall make available the following signals at the *Marshalls Energy Company* designated *communication gateway equipment* located at the *plant* site:

(a) Current available maximum MW updated every second.

(b) Current available *MVA*r updated every second.

13.1.3 Signals List #3 – *RPP* MW Curtailment Data

(1) The *Renewable Power Plants* shall make the following signals available at a designated *communication gateway equipment* located at the *plant's* site:

(a) *Plant* MW Curtailment facility status indication (ON/OFF) as a double bit point. This is a controllable point which is set on or off by the *Marshalls Energy Company*. When set "On" the *plant* shall then clarify and initiate the curtailment based on the curtailment setpoint value below.

(b) Curtailment in progress digital feedback. This single bit point will be set high by the *plant* while the facility is in the process of curtailing its output.

(c) *Plant's* MW Curtailment Set-point value (MW- feedback).

(2) In the event of a curtailment, the Marshalls Energy Company will pulse the curtailment setpoint value down. The *plant's* response to the changed curtailment value will be echoed by changing the corresponding echo MW value. This will provide feedback that the *plant* is responding to the curtailment request.

13.1.4 Signals List #4 – Frequency Response System Settings

(1) The *Renewable Power Plants* shall make the following signals available at a designated communication gateway equipment located at the *plant's* site:

(a) *Frequency Response System* mode status indication (ON/OFF) as a double bit point

13.1.5 Signals List #5 – Renewable Power Plants Meteorological Data.

(1) *Renewable Power Plants* shall make the following signals available at the *Marshalls Energy Company's* designated communication gateway equipment located at the *plant* site:

(a) Wind speed (within 75% of the hub height) – measured signal in meters/second (for *WPP only*)

(b) Wind direction within 75% of the hub height) – measured signal in degrees from true north(0-359) (for *WPP only*)

(c) Air temperature- measured signal in degrees centigrade (-20 to 50)

(d) Air pressure- measured signal in millibar (800 to 1400).

(e) Air density (for *WPP only*)

(f) Solar radiation (for *PVPP only*)

(2) The meteorological data signals shall be provided by a dedicated Meteorological Mast located at the *plant's* site or, where possible and preferable to do *so*, data from a means of the same or better accuracy.

(3) Energy resource conversion data for the facility (e.g. MW/ wind speed) for the various resource inputs to enable the *Marshalls Energy Company* to derive a graph of the full range of the facilities output capabilities. An update will be sent to the *Marshalls Energy Company* following any changes in the output capability of the facility.

13.2 Update Rates

(1) Signals shall be updated at the following rates:

(a) Analog Signals at a rate of 1 second

(b) Digital Signals at the rate of 1 second.

(c) Meteorological data once a minute

13.3 Control Signals Sent from *Marshalls Energy Company* to the *Renewable Power Plants*

The control signals described below shall be sent from *Marshalls Energy Company* to the *Type B and C Renewable Power Plants*. The *plants* shall be capable of receiving these signals and acting accordingly.

13.3.1 Active-Power Control

(1) An *Active-Power Control* setpoint signal shall be sent by *Marshalls Energy Company* to the *Renewable Power Plant's* control system.

(2) This setpoint shall define the maximum Active Power output permitted from the *plant*. The *plant's* control system shall be capable of receiving this signal and acting accordingly to achieve the desired change in Active Power output.

(3) The *Renewable Power Plants* shall make it possible for the *Marshalls Energy Company* to remotely enable/disable the Active-Power control function in the plant's control system.

13.3.2 Connection Point CB Trip facility

(1) A facility shall be provided by the *Marshalls Energy Company* to facilitate the disconnection of the *plant*. It shall be possible for Marshalls Energy Company to send a trip signal to the circuit breaker at the *HV* side of *the point of connection to the grid.*

13.3.3 Synchronisation block signal

(1) A Synchronisation block signal shall be sent by *Marshalls Energy Company* to the *Renewable Power Plant's* control system to prevent the *Renewable Power Plant* from synchronising when system conditions dictate this.

13.4 *Renewable Power Plants* MW availability declaration

(1) The *Renewable Power Plant* shall submit *plant's* MW availability declarations whenever changes in MW availability occur or are predicted to occur. These declarations shall be submitted by means of an electronic interface in accordance with the requirements of *Marshalls Energy Company's* data system.

13.5 Data Communications Specifications

(1) The *Renewable Power Plant* shall have external communication gateway equipment that can communicate with a minimum of two simultaneous SCADA Masters, independently from what is done inside the *plant*.

(2) The location of the communication gateway equipment shall be agreed between affected participants in the connection agreement.

(3) The necessary communications links, communications protocol and the requirement for analogue or digital signals shall be specified by the *Marshalls Energy Company* as appropriate before a connection agreement is signed between the *plant* and the *Marshalls Energy Company*.

(4) *Active Power Curtailment* or *Voltage Regulation* facilities at the *plant* shall be tested once a quarter. It is essential that facilities exist to allow the testing of the functionality without tripping the actual equipment.

(5) Where signals or indications required to be provided by the *plant* become unavailable or do not comply with applicable standards due to failure of the *plant* equipment or any other reason under the control of the *plant owner/operator*, the *plant owner/operator* shall restore or correct the signals and/or indications within 24 hours.

14 Testing and Compliance Monitoring

(1) All *Renewable Power Plants* shall demonstrate compliance to all applicable requirements specified in this grid connection code and any other applicable code or standard, before being allowed to connect to the network.

(2) The *plant* shall review, and confirm to the *Marshalls Energy Company*, compliance by the *plant* with every requirements of this code.

(3) The *Renewable Power Plant* shall conduct tests or studies to demonstrate that the *plant* complies with each of the requirements of this code.

(4) The *Renewable Power Plant* shall continuously monitor its compliance in all material respects with all the connection conditions of this code.

(5) Each *Renewable Power Plant* shall submit to the *Marshalls Energy Company* a detailed test procedure, emphasising system impact, for each relevant part of this code prior to every test.

(6) If *Renewable Power Plant* determines, from tests or otherwise, that the *plant* is not complying with one or more sections of this code, then the *plant owner/operator* shall (within 1 hour of being aware):

(a) notify the *Marshalls Energy Company* of that fact,

(b) advise the *Marshalls Energy Company* of the remedial steps it proposes to take to ensure that the relevant *plant* can comply with this code and the proposed timetable for implementing those steps,

(c) diligently take such remedial action to ensure that the relevant *plant* can comply with this code; the *plant owner/operator* shall regularly report in writing to the Marshalls Energy Company on its progress in implementing the remedial action, and

(d) after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *Marshalls Energy Company* that the relevant *plant* is then complying with this code.

(7) The *Marshalls Energy Company* may issue an instruction requiring the *plant* to carry out a test to demonstrate that the relevant *plant* with the code requirements. A *plant* may not refuse such an instruction, provided it is issued timeously and there are reasonable grounds for suspecting non-compliance.

(8) The *plant* owner/operator shall keep records relating to the compliance of the *plant* with each section of this grid connection code, or any other code applicable to that *plant*, setting out such information that the *Marshalls Energy Company* reasonably requires for assessing power system performance, including actual *plant* performance during abnormal conditions. Records shall be kept for a minimum of 5 years (unless otherwise specified in the code) commencing from the date the information was created.

15 Reporting to Marshalls Energy Company

(1) The *Renewable Power Plant* shall design the system and maintain records *such* that the following information can be provided to the *Marshalls Energy Company* on a monthly basis in an electronic spread sheet format:

(a) Non-renewable/supplementary fuel used by the power plant.

(b) Actual hourly availability and output energy to the grid that occurred and the average primary resource for that hour.

(c) Actual hourly electricity imports from all sources as applicable.

(d) Any curtailed energy during the month.

(2) These reports are to be submitted before the 15th of the following month to *Marshalls Energy Company* via an email.

(3) These reports should also include details of incidents relating any unavailability of the network which prevented the *plant* from generating.

(4) The *Marshalls Energy Company* requires suitable and accurate dynamic models, in the template specified by the requesting party applying for a connection to the *network*, in order to assess reliably the impact of the *plant* proposed installation on the dynamic performance and security and stability of the power system.

(5) The required dynamic models must operate under RMS simulation to replicate the performance of the *plant* or individual units for analysis of the following network aspects:

(a) *Plant's* impact on network voltage stability

(b) *Plant's* impact on Quality of Supply at *point of connection*

(c) *Plant's* impact on network protection co-ordination

(d) *Plant's FRT* (Fault Ride Through) capability for different types of faults and positions (h) *plant's* response to various system phenomena such as:

(i) switching on the network

(ii) power swings

(iii) small signal instabilities

(6) *Plant's* data exchange shall be a time-based process.

(a) **First stage** (during the application for connection)

(i) The following information shall be submitted by the *plant owner/operator* to the *Marshalls Energy Company*, as applicable:

- Physical location (including the GPS coordinates)

- Site Plan
- Number of wind turbines or *units* to be connected
- MW output per turbine or *unit*
- Initial phase MW value
- Final phase MW value and timelines
- Any other information that the service provider may reasonably require

(ii) For the detailed *plant* design, the *Marshalls Energy Company* shall make available to the *plant owner/operator* at least the following information:

- *Point of connection* to the grid including the nominal voltages,
- Expected fault levels,
- The network service provider's connection between the Point of connection to the grid and the *plant*,
- The busbar layout of the point of connection to the grid and *point of connection* substations,
- The portion of the network service provider's grid that will allow accurate and sufficient studies to design the *plant* to meet the Grid Code. This information shall include:
    - Positive and zero sequence parameters of the relevant network service provider's transmission and distribution, transformers, reactors, capacitors and other relevant equipment
    - The connection of the various lines transformers, reactors and capacitors etc.

(b) **Second stage** (after detailed *plant* designs have been completed but before commissioning the *plant*)

(i) During this stage, the *plant* shall provide information on:

- Selected *plant* technology data.
- Fault ride through capability and harmonic studies test report
- Generic test model and dynamic modelling data per wind turbine or *unit* as from the type approval and tests result

(c) **Third stage** (after commissioning and optimisation of the *plant*)

(i) During this stage, the *plant* is compelled to provide information on:

- A validated *plant's* electrical dynamic simulation model using commissioning test data and measurements

- Test measurement data in the format agreed between the *plant* and the Marshalls Energy Company, as applicable.

(7) The dynamic modelling data shall be provided in a format as may be agreed between the *plant owner/operator* and the Marshalls Energy Company, as applicable.

(8) In addition, the *Renewable Power Plant* Generator shall provide the Marshalls Energy Company with operational data as prescribed in **Appendix 4**.

16 Appendix 1 - *Wind Power Plants*

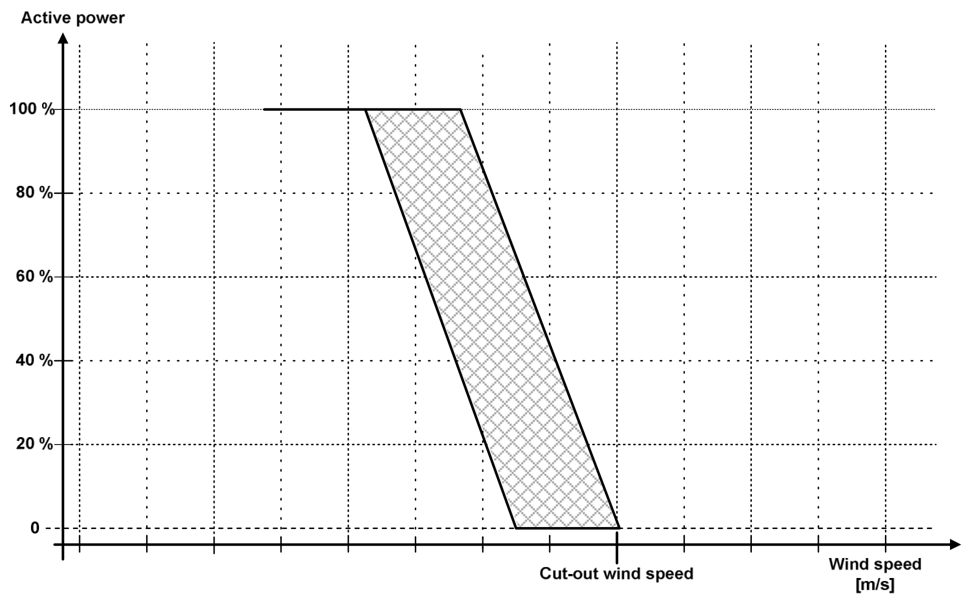
16.1 High Wind Curtailment

(1) It shall be possible to continuously downward regulate the active power supplied by the *plant* to an arbitrary value in the interval from 100% to at least 40% of the rated power. When downward regulation is performed, the shutting-down of individual wind turbine *generator* systems is allowed *so* that the load characteristic is followed as well as possible.

(2) The *Wind Power Plant* shall stay connected to the *network* at average wind speeds below a predefined cut-out wind speed. The cut-out wind speed shall as a minimum be 25 m/s, based on the wind speed measured as an average value over a 10-minute period. To prevent instability in the *network*, the *Wind Power Plant* shall be equipped with an automatic downward regulation function making it possible to avoid a temporary interruption of the active power production at wind speeds close to the cut-out wind speed.

(3) Downward regulation shall be performed as continuous or discrete regulation. Discrete regulation shall have a step size of maximum 25% of the rated power within the hatched area shown in Figure 7. When downward regulation is being performed, the shutting down of individual wind turbine *generator* systems is allowed. The downward regulation band shall be agreed with the *Marshalls Energy Company* upon commissioning of the wind power plant.

Figure 7: Downward regulation of active power at high renewable speeds



17 <u>Appendix 2 - *Photovoltaic Power Plants*</u>

No special requirements for solar PV except the general requirement specified in this code.

Appendix 3 - *Battery Power Plants*

No special requirements for *Battery Power Plants* except the general requirement specified in this code.

18 Appendix 4 - Documentation

18.1 Master Data

Description	**Text**
Identification:	
Name of *electricity supply undertaking*	
Plant name	
ID number	
Planned commissioning	
Technical data:	
Manufacturer	
Type designation (model)	
Type approval	
Approval authority	
Installed kW (*rated power*)	
Cos φ (*rated power*)	
Cos φ (20% *rated power*)	
Cos φ (no load)	
3-phase short-circuit current immediately in front of the *power plant* (RMS)	
Point of connection	
Voltage level	

Description	**Text**
Plant address:	
Contact person (technical)	
Address1	
House number	
Letter	
Postal code	
BBR municipality	
X/Y coordinates	
Title number	
Owners' association on titled land	
Owner:	
C ID number	
Company name	
Contact person (administrative)	
Address1	
House number	
Letter	
Floor	
To the right/left	
Postal code	
Email address	

18.2 Technical Documentation

18.2.1 Step-Up Transformer

Description	**Value**
Make	
Type	
Comments	

Description	**Symbol**	**Unit**	**Value**
Nominal apparent power (1 p.u.)	S_n	*MVA*	
Nominal primary voltage (1 p.u.)	U_p	kV	
Nominal secondary voltage	U_s	kV	
Coupling designation, eg Dyn11	-	-	
Step switch location	-	-	Primary side ☐ Secondary side ☐
Step switch, additional voltage per step	du_{tp}	%/trin	
Step switch, phase angle of additional voltage per step:	phi_{tp}	degree/step	
Step switch, lowest position	n_{tpmin}	-	
Step switch, highest position	n_{tpmax}	-	
Step switch, neutral position	n_{tp0}	-	
Short-circuit voltage, synchronous	u_k	%	
Copper loss	P_{cu}	kW	
Short-circuit voltage, zero system	u_{k0}	%	
Resistive short-circuit voltage, zerosequence system	u_{kr0}	%	
No-load current	I_0	%	
No-load loss	P_0	%	

18.2.2 Single Line Diagram Representation

(1) This applies to all *Renewable Power Plants* of Type B and C.

(2) A single-line diagram representation of the plant shall be created, with indication of *point of connection to the grid,* metering points, including settlement metering, limits of ownership and operational supervisor limits/limits of liability. In addition, the type designation for the switchgear used shall be stated *so* as to make it possible to identify the correct connection terminals.

(3) In instances when a single-line diagram representation is included in the grid use agreement between the *Renewable Power Plant* and Marshalls Energy Company, the grid *connection agreement* can be enclosed as documentation.

18.2.3 PQ Diagram

(1) This applies to all *Renewable Power Plants* of Type B and C.

19 Appendix 5 – Compliance test specifications

19.1 Introduction

This section specifies the procedures to be followed in carrying out testing to verify compliance with this *Code.*

19.2 Test procedures

19.3 *Renewable Power Plants* protection function verification

Parameter	Reference	Description
Protection function and settings	Section 9	**APPLICABILITY AND FREQUENCY** All new *Renewable Power Plants* coming on line or at which major refurbishment or upgrades of protection systems have taken place. **Routine review:** All *plants* to confirm compliance every six years. **PURPOSE** To ensure that the relevant protection functions in the *Renewable Power Plants* are coordinated and aligned with the system requirements. **PROCEDURE** *1.* Establish the system protection function and associated trip level requirements from the *Marshalls Energy Company*. *2.* Derive protection functions and settings that match the *Renewable Power Plant* and system requirements. *3.* Confirm the stability of each protection function for all relevant system conditions. *4.* Document the details of the trip levels and stability calculations for each protection function. *5.* Convert protection tripping levels for each protection function into a per *unit* base. *6.* Consolidate all settings in a per *unit* base for all protection functions in one document. *7.* Derive actual relay dial setting details and document the relay setting sheet for all protection functions. *8.* Document the position of each protection function on one single line diagram of the generating *unit* and associated connections. *9.* Document the tripping functions for each tripping function on one tripping logic diagram. *10.* Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant

		protection relay manufacturers’ information into one document. 11. Submit to the *Marshalls Energy Company* for its acceptance and update.
Protection function and settings (cont.)	Section 9 (cont.)	**Review:** 1. Review Items 1 to 10 above. Submit to the *Marshalls Energy Company* for its acceptance and update. Provide the *Marshalls Energy Company* with one original master copy and one working copy. **ACCEPTANCE CRITERIA** All protection functions are set to meet the necessary protection requirements of the *plant* with a minimal margin, optimal fault clearing times and maximum plant availability. Submit a report to the *Marshalls Energy Company* one month after commissioning and six-yearly for routine tests.

19.3.1 *Renewable Power Plants* protection integrity verification

Parameter	Reference	Description
Protection integrity	Section 9	**APPLICABILITY AND FREQUENCY** All new *Renewable Power Plants* coming on line and all other *power stations* after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified. **Routine review:** All *plants* on: item 1 below: Review and confirm every 6 years Item 2, and 3 below: at least every 12 years. **PURPOSE** To confirm that the protection has been wired and functions according to the specifications. **PROCEDURE** 1. Apply final settings as per agreed documentation to all protection functions. 2. With the *unit* off load and de-energized, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations. 3. Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV breaker). Document all trip test responses. 4. Apply short-circuits at all relevant protection zones and with *generator* at nominal speed excite *generator* slowly, record currents at all relevant protection functions and confirm correct operation of all relevant protection functions. Document all readings and responses. Remove all short-circuits. 5. With the *Renewable Power Plants* at nominal production. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses.

		Review: Submit to the *Marshalls Energy Company* for its acceptance and update. **ACCEPTANCE CRITERIA** All protection functions are fully operational and operate to required levels within the relay *OEM* allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard. Submit a report to the *Marshalls Energy Company* one month after test.

19.3.2 - *Renewable Power Plants* active power control capability verification

<table>
<tr><th>Parameter</th><th>Reference</th><th>Description</th></tr>
<tr><td>Active power control function and operational range</td><td>Section 10 depending on Type</td><td>APPLICABILITY
All new Renewable Power Plants coming on line and after major modifications or refurbishment of related plant components or functionality.
Routine test/reviews: Confirm compliance every 6 years.

PURPOSE
To confirm that the active power control capability specified is met.

PROCEDURE
The following tests shall be performed within an active power level range of at least 0.2p.u.or higher
1. The plant will be required to regulate the active power to a set of specific setpoints within the design margins.
2. The plant will be required to obtain a set of active power setpoints within the design margins with minimum two different gradients for ramping up and two different gradients for ramping down.
3. The plant will be required to maintain as a minimum two different set levels of spinning reserve within the design margins.
4. The plant will be required to operate as a minimum to limit active power output according to two different absolute power constraint set levels within the design margins.
5. The plant will be required to verify operation according to as a minimum two different parameter sets for a frequency response curve within the design margins.

ACCEPTANCE CRITERIA</td></tr>
</table>

		1. The *plant* shall maintain the set output level within ±2% of the capability registered with the *Marshalls Energy Company* for at least one hour. 2. The *plant* shall demonstrate ramp rates with precision within ±2% of the capability registered with the *Marshalls Energy Company* for ramp up and down. 3. The *plant* shall maintain a spinning reserve set level within ±2% of the capability registered with the *Marshalls Energy Company* for at least one hour. 4. The *plant* shall maintain an absolute power constraint set level within ±2% of the capability registered with the *Marshalls Energy Company* for at least one hour. 5. The *plant* shall demonstrate that the requested frequency response curves can be obtained. Submit a report to the *Marshalls Energy Company* one month after the test.

19.3.3 *Renewable Power Plants* reactive power control capability verification

Parameter	Reference	Description
Reactive power control function and operational range	Sections 6 and 7 depending on Type	**APPLICABILITY** All new *Renewable Power Plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the reactive power control capability specified is met. **PROCEDURE** The following tests shall be performed within a minimum active power level range of at least 0.2 p.u. or higher 1. The *plant* will be required to regulate the voltage at the point of connection to the grid to a set level within the design margins. 2. The *plant* will be required to provide a fixed Q to a set level within the design margins. 3. The *plant* will be required to obtain a fixed PF within the design margins. **ACCEPTANCE CRITERIA** 1. The *plant* shall maintain the set voltage within ±5% of the capability registered with the *Marshalls Energy Company* for at least one hour. 2. The *plant* shall maintain the set Q within ±2% of the capability registered with the *Marshalls Energy Company* for at least one hour. 3. The *plant* shall maintain the set PF within ±2% of the capability registered with the *Marshalls Energy Company* for at least one hour.

		Submit a report to the *Marshalls Energy Company* one month after the test.

19.3.4 *Renewable Power Plants* power quality calculations

Parameter	**Reference**	**Description**
Power quality calculations for: 1. Rapid voltage changes 2. Flicker 3. Harmonics 4. Inter-harmonics	Section 8 depending on Type	**APPLICABILITY** All new *plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the limits for all power quality parameters specified is met. **PROCEDURE** The following tests shall be calculated within a minimum active power level range from 0.2p.u. to 1.0p.u. 1. Calculate the levels for rapid voltage changes are within the limits specified over the full operational range. 2. Calculate the flicker levels are within the limits specified over the full operational range. 3. Calculate the harmonics are within the limits specified over the full operational range. 4. Calculate the interharmonics are within the limits specified over the full operational range.

5. High frequency disturbances		5. Calculate the disturbances higher than 2 Hz are within the limits specified over the full operational range. **ACCEPTANCE CRITERIA** 1. The calculations shall demonstrate that the levels for rapid voltage changes are within the limits specified over the full operational range. 2. The calculations shall demonstrate that the flicker levels are within the limits specified over the full operational range. 3. The calculations shall demonstrate that the harmonics are within the limits specified over the full operational range. 4. The calculations shall demonstrate that the interharmonics are within the limits specified over the full operational range. 5. The calculations shall demonstrate that the disturbances higher than 2 Hz are within the limits specified over the full operational range Submit a report to the *Marshalls Energy Company* one month after the test.

19.3.5 *Renewable Power Plants* fault ride through simulations

Parameter	Reference	Description
Simulations of fault ride though voltage droops and peaks.	Section 4	**APPLICABILITY** All new *plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: None. **PURPOSE** To confirm that the limits for all power quality parameters specified is met. **PROCEDURE** By applying the electrical simulation model for the entire *plant* it shall be demonstrated that the *plant* performs to the specifications. 1. Area A - the *plant* shall stay connected to the network and uphold normal production. 2. Area B - the *plant* shall stay connected to the network. The *plant* shall provide maximum voltage support by supplying a controlled amount of reactive power within the design framework offered by the technology, see Figure 1. 3. Area C - the *plant* is allowed to disconnect. 4. Area D - the *plant* shall stay connected. The *plant* shall provide maximum voltage support by absorbing a controlled amount of reactive power within the design framework offered by the technology, see Figure 1. **ACCEPTANCE CRITERIA** 1. The dynamic simulations shall demonstrate that the *plants* fulfils the requirements specified. Submit a report to the *Marshalls Energy Company* three month after the commission.

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