D4 – Final Report and Model for Pohnpei Utilities Corporation (Pohnpei)

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

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 Counties" 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 collaborate 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 Pohnpei 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	Tonga
Federated States of Micronesia	Pohnpei
Marshall Islands	Majuro
Tuvalu	Fongafale (Funafuti atoll)

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 will be 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 will be 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 will be reported.
    - Network capability to meet a scaled load demand of 105% or 110% (depending on size of network) of existing load demand level. Any overloads and voltage violations will be 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 will be performed on mesh networks, while the switching operation studies will be applied to the radial network with switch devices on or between feeders. The following assessments will be 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 will be 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 will be 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 will be 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 will be made:
   - Three phase fault levels;
   - Single phase to ground fault levels where vector group of transformers in the network is known and zero sequence current path of the network is properly represented in the model;
   - 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 will be 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 will be 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 be 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 will be assumed to rise from 0 MW output level to the maximum MW output level within 10 seconds.

Steps 1 – 5 as listed above will form the basis of the study of each network to understand their operational characteristics and any limitations. Following this, the penetration of renewable generation connected to the network will be increased in suitable increments (depending on the size of the network) and the following steps will be 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 5% ~ 10% higher than the existing maximum load demand level if the system has adequate network capacity.

- Renewable generation capacity (PV generation) considered to be at 10% to 40% of total installed generation capacity in the system. New renewable generation sites could be distributed across the system.
- Renewable generation will be fully dispatched in the considered operational scenarios. The conventional generators, however, will be 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 will then be performed:

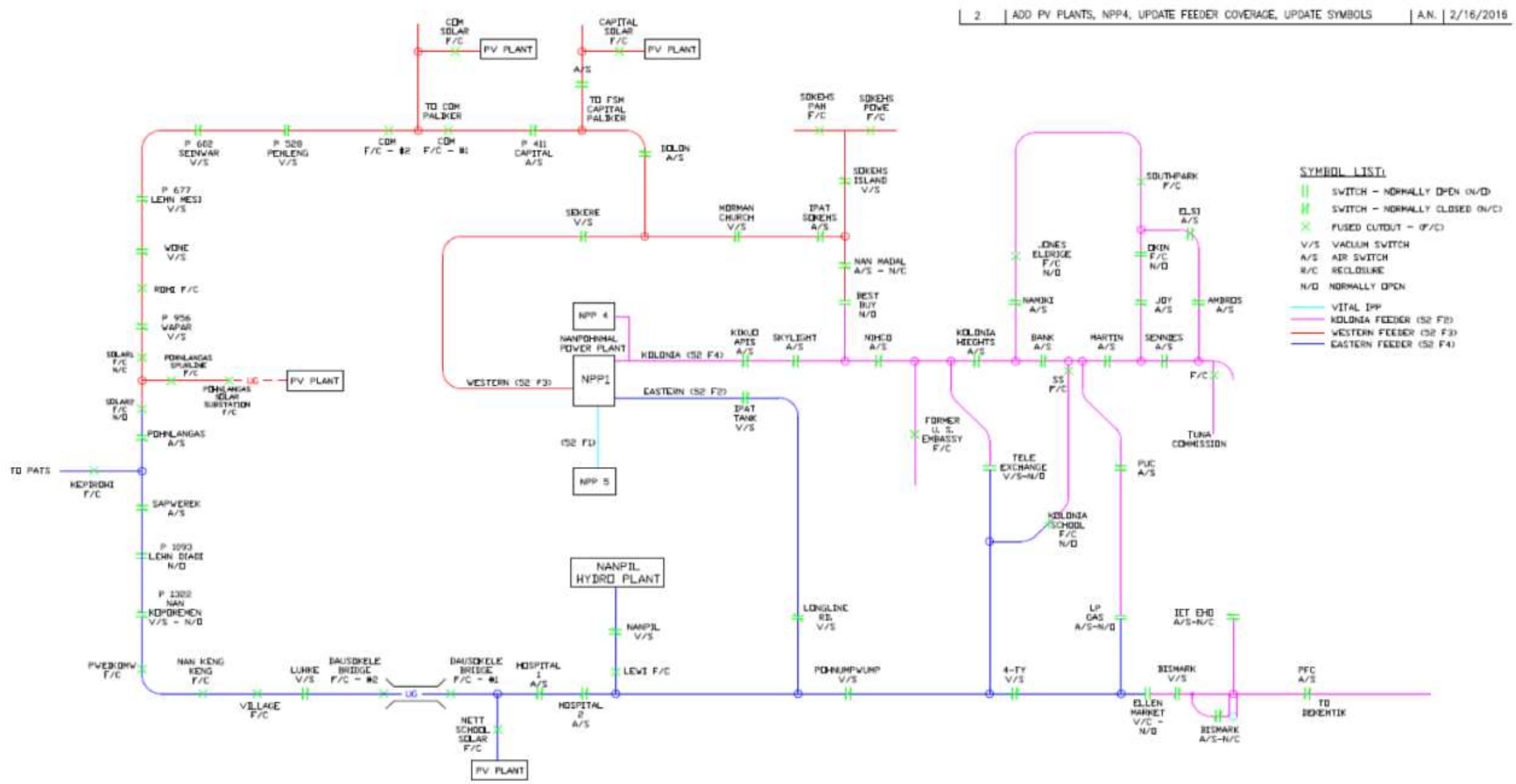
6) Stability simulations to assess system frequency response for the two events:
   - The sudden loss of the largest or the second largest generating unit on a system
   - The drop and rise of MW output from all PV site with 10 seconds
     - If the minimum frequency deviation of the system for any event 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 Pohnpei Network, Federated States of Micronesia

Pohnpei is one of the four states within the Federated States of Micronesia. The utility company in charge of operating and managing the power grid in Pohnpei is the Pohnpei Utility Corporation (PUC). The network under study for this project is the PUC power network on Pohnpei Island. The network is a 60 Hz system with a backbone network of 13.8 kV. There are three operational diesel power stations on the island, one of which has been decommissioned, a hydro power station and a solar PV plant. The power stations are interconnected and three separate 13.8 kV distribution circuit feeders carry power around the island.

The network SLD is provided in Figure 2-1 and shows the three feeders supplying the island.

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



A summary of the available generation capacity in Pohnpei is provided in Table 2-1.

Table 2-1: Pohnpei installed generation capacity

Name	Unit ID	Available Capacity (kW)	Type
Nanpohnmal (NPP1)	3516C_G1, 3516C_G2, 3516C_G4, 3516C_G5	4 x 1650kW	Diesel
Nanpohnmal (NPP4)	3512_G2	1 x 600 kW	Diesel
VITAL Power Station (NPP5)	VOLVO_G1, VOLVO_G2, VOLVO_G3, VOLVO_G4	4 x 350 kW	Diesel
Hydro Power Station	HPSG1	1 x 725 kW	Hydro
Pohnlangas PV	POHLOK	600 kW	Solar
President's Office	PALKIER (1)	20 kW	Solar
Elementary School	DAUSOKELE1	200 kW	Solar
COM-FSM	PALKIER (2)	160 kW	Solar

As can be seen from the table, the available generation capacity of the Pohnpei network in the system study is 10,305 kW, with 1,705 kW (about 16.5%) being renewable. The maximum demand of the network is around 5.1 MW, and the minimum demand is 3.7 MW. The maximum and minimum demands were measured in February 2018.

2.2.1 Power system data and assumptions

The data made available for the power system studies of the Pohnpei utility network is described in detail in the Data Collection Report (D3 – Data Collection Report, April 2018). Data that was not provided and therefore has to be assumed includes:

- Future generation plans – no future generation plans were provided for the island
- Switchgear fault ratings were not provided, only calculated fault levels at the 13.8 kV busbars
- Detailed power plant generation output was not provided – automatic voltage regulator (AVR) parameters are assumed.
- Grid code, local operational requirements – no grid code or local operational requirements provided. Primarily US industry standards are followed.

2.2.2 Summary of Power System Studies and Scenarios

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

Study	Scenarios

Load Flow	Maximum Demand 5% Load scaling, 10% Load scaling
Load Flow	Minimum Demand
Fault Level	Maximum Fault Level Conditions
Stability Study – Existing System, no PV	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip
Stability Study – Existing System, existing PV	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – Existing System, existing PV, varied diesel generation dispatch	Loss of largest generator
Stability Study – 1200kW Renewable Generation Penetration	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – 1200kW Renewable Generation Penetration, varied diesel generation dispatch	Loss of largest generator, 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – 2400kW Renewable Generation Penetration	Loss of largest generator, loss of Western feeder, loss of Eastern feeder 3ph fault and feeder trip Increase/decrease of PV generation
Stability Study – 2400kW Renewable Generation Penetration, varied diesel generation dispatch	Loss of largest generator, 3ph fault and feeder trip Increase/decrease of PV generation

2.2.3 Power system study results

The subsections to follow provide the results of the power system studies performed on the Pohnpei network.

2.2.3.1 Load flow studies

Load flow studies were performed on the Pohnpei 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	59.44	1.042	0.960
5% Load Scaling	62.79	1.043	0.957
10% Load Scaling	66.15	1.043	0.954

It can be seen from the results that there is adequate headroom for an increase in demand on the Pohnpei network when considering steady state operation, with a maximum circuit loading of 66% even with a 10% increase in demand across the island. The maximum and minimum voltages on the network range from around -4% to +4% of nominal, suggesting there are no issues but improvements in voltage profile would be beneficial and reduce losses. The voltage profile around the network does not vary considerably with the gradual increase in demand.

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	32.09	1.029	0.984

The maximum loading on the network is recorded as 32% under minimum demand conditions. The maximum and minimum voltages on the network are both within standard operational limits for distribution networks.

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. Three phase and single-phase-to-ground faults) were studied and Table 2-4 shows the results of these.

Table 2-4: Maximum fault level results for Pohnpei

Fault Level	kA	Busbar	Voltage Level
Three Phase ip	9.648	NPP1BUS1	13.8
Three Phase Ib	2.508	NPP1BUS1	13.8
Single Phase ip	12.842	NPP1BUS1	13.8

Single Phase Ib	6.292	NPP3BUS1	13.8

The fault level is highest at the power station busbars, which is to be expected. There were no switchgear or circuit breaker ratings provided for the 13.8 kV 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 will be 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 2-2: 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) was assessed for a number of events including:

1) Loss of the largest generator on the system;
2) Loss of the Eastern Feeder;
3) Loss of the Western Feeder; and
4) Reduction in PV output from maximum MW to 0 MW within 10 s then increase back up to maximum output from 0 MW after 20 s.

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

5) A three-phase fault on the Western Feeder followed by the tripping of the conductor after 150 ms.

The parameters of the AVRs have been assumed for the conventional generators operating on the Pohnpei system, and in some cases the AVRs have been switched off (in Stability study 4) to minimise interference.

Existing generation with PV switched off

An initial set of studies was carried out on the Pohnpei network with no PV generation in operation, only conventional diesel generation and the hydro plant, to understand the behaviour of the system under these conditions. The generation mix for these studies is listed in Table 2-5 with approximately 1,667 kW of spinning reserve available in this scenario.

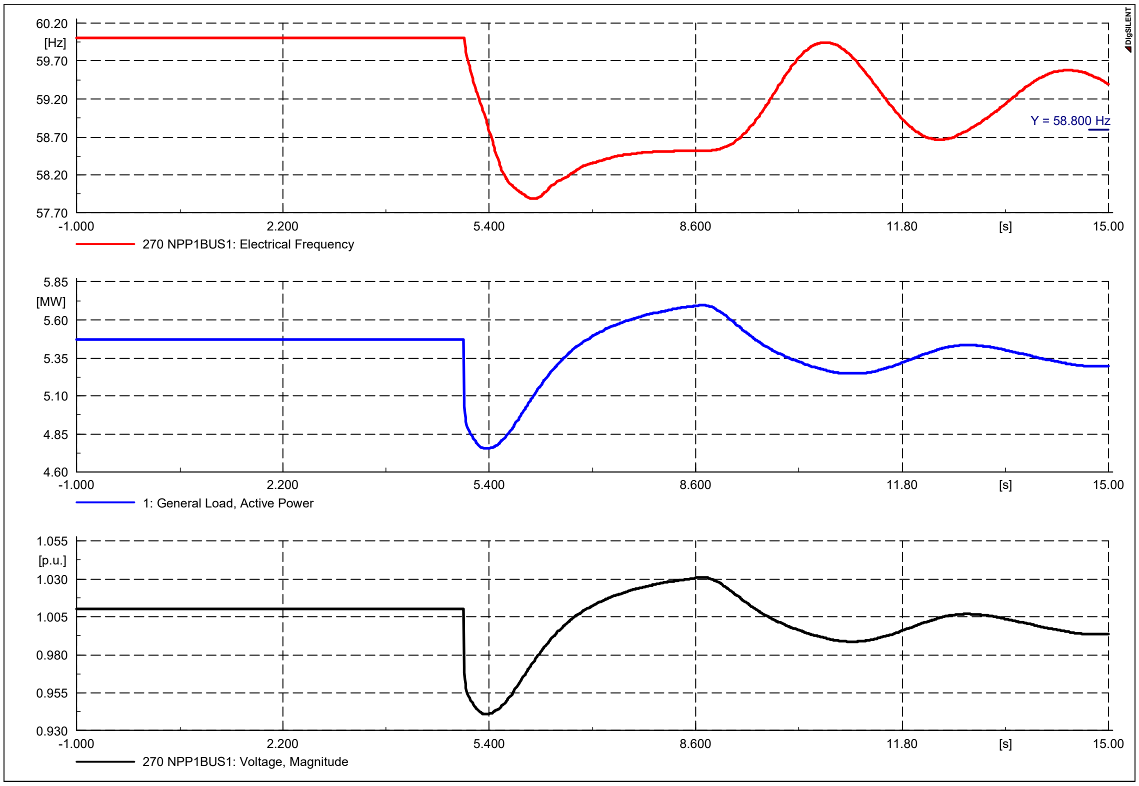
Table 2-5: Generation mix on Pohnpei with no PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	4.3%
	3516C_G1	3	1	1485	165	9.9%
	3516C_G2	3	1	1485	165	9.9%
	3516C_G4	3	1	1485	165	9.9%
	3516C_G5	3	1	550.5	1099.5	66.0%
	3512_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	Sub-total			**5658**	**1667**	
Renewable	PALIKER (1)	1	1	0.0	0.0	0.0%
	PALIKER (2)	1	1	0.0	0.0	0.0%
	DAUSOKELE1	1	1	0.0	0.0	0.0%
	POHLOK	1	1	0.0	0.0	0.0%
	Sub-total			**0.0**	**0.0**	
				5658	**1667**	**29.5%**

Loss of largest generator

Diesel generator unit 3516C_G4 is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-3.

Figure 2-3: Voltage & frequency response to loss of largest generator



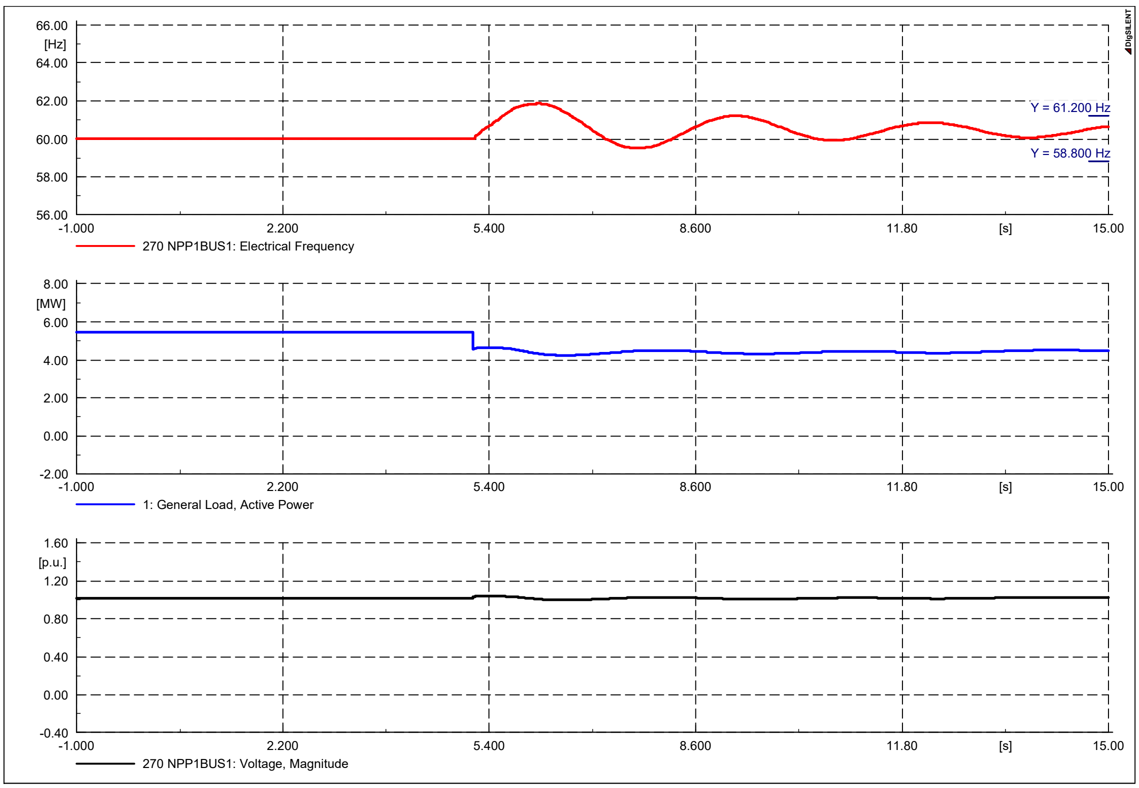
It can be seen from Figure 2-3 above that the system frequency exceeds the 2% allowable frequency deviation upon the loss of the largest generator (operated at 1,485 kW) on the system and reaches a minimum value of less than 58 Hz before slowly recovering. The voltage drops to around 0.94 pu. In order to prevent system frequency falling below 58 Hz subsequent to the loss of the largest generating unit, reducing its MW output level or increasing the number of generating units in operation may be necessary.

Western feeder trip

Tripping the Western feeder causes the frequency and voltage responses shown in

Figure 2-4. The power transfer over the western feeder from Nanpohnmal power plant before the trip is around 1,095 kW, accounting for approximately 20% of the power supply from the power plant.

Figure 2-4: Voltage & frequency response to loss of Western feeder

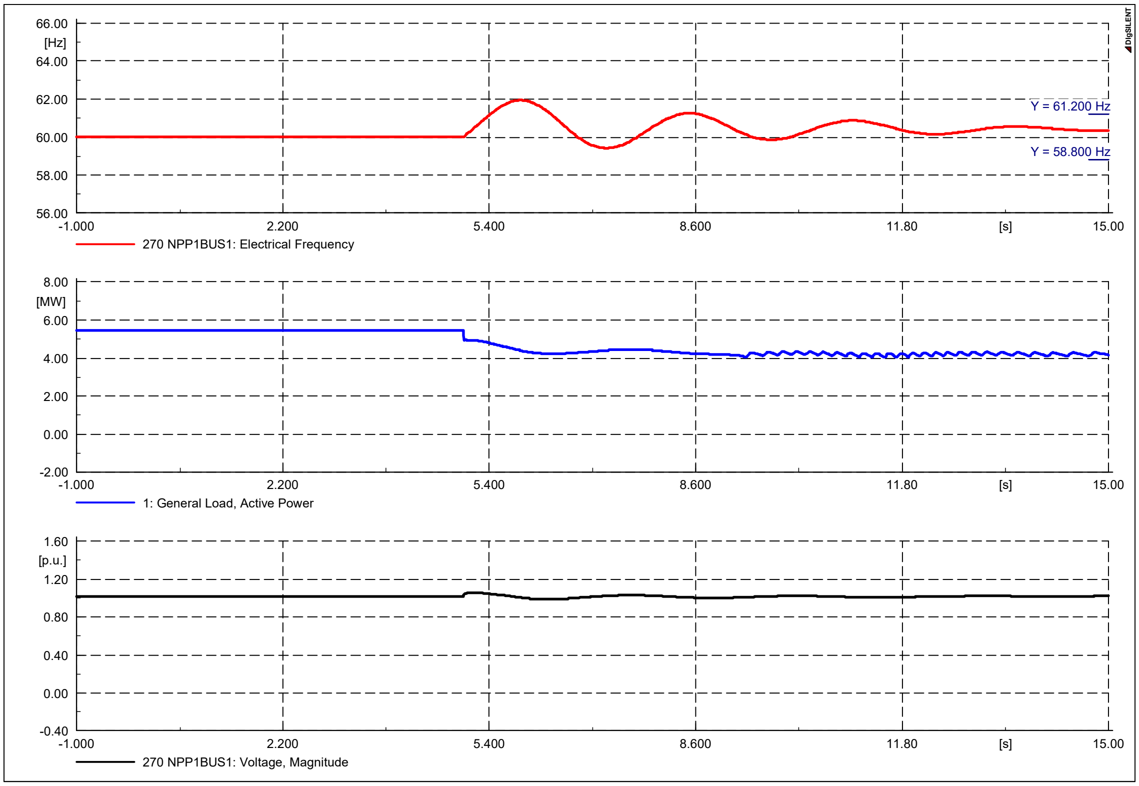


The frequency increases slightly upon the loss of the Western feeder and it exceeds the 2% deviation limit for around 1 second before returning to within the acceptable bandwidth and settling. The voltage remains within limits for the duration of the study.

Eastern feeder trip

Tripping the Eastern feeder causes the frequency and voltage responses shown in Figure 2-5. The power transfer over the Eastern feeder from Nanpohnmal power plant before the trip is around 1,640 kW, accounting for approximately 30% of the power supply from the power plant.

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



Similar to the Western feeder, the loss of the Eastern feeder causes the system frequency to exceed the 2% deviation momentarily before returning to within the allowable bandwidth and settling. The voltage remains within the limits for the duration of the study.

Three phase fault (cleared after 150ms), trip Western feeder

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses 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

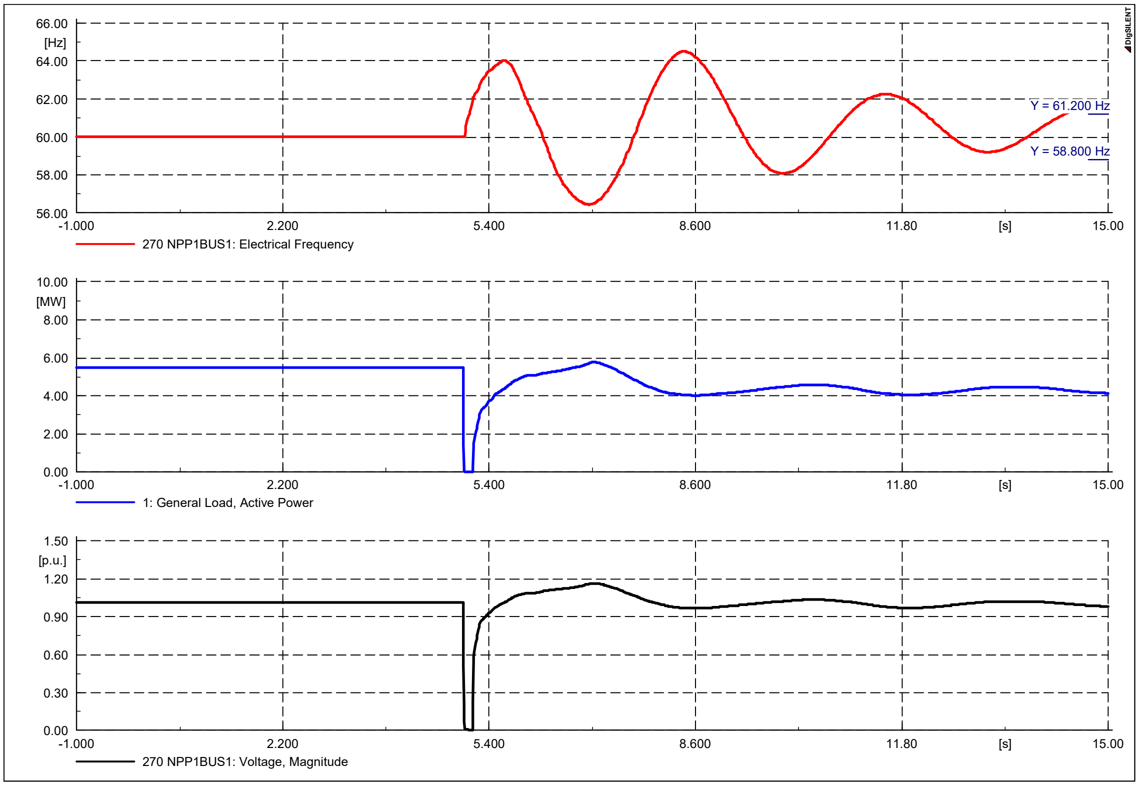
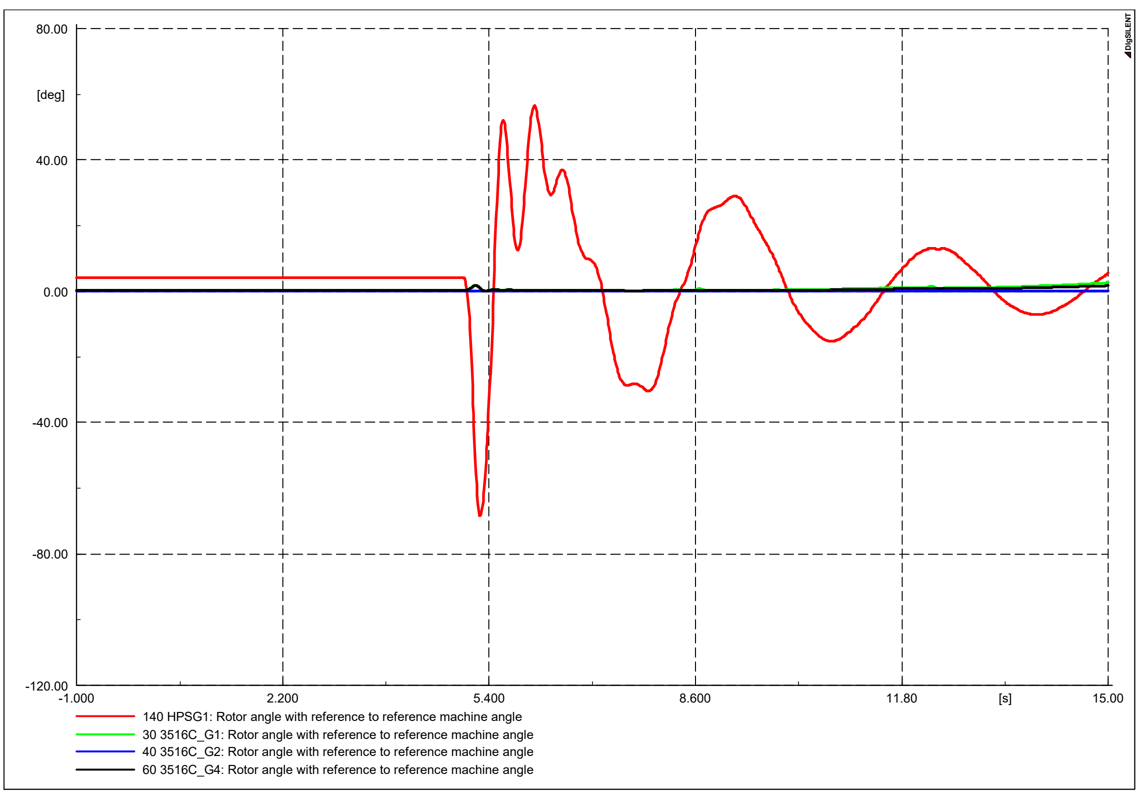


Figure 2-7: Rotor angle response to fault and subsequent feeder trip



Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds), however is rises to almost 1.2 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station. System frequency oscillates outside the ±2% bandwidth reaching 64 Hz and 56 Hz after fault inception and this does not settle to within the allowable limits within the study time period.

Existing generation with PV switched on

The studies above were repeated with the Pohnpei PV generation now connected to assess the impact of this generation on the stability of the system following a credible contingency. The generation mix for these studies is provided in Table 2-6. In this case, renewable generation output approximately accounts for 13.9% of total generation output and the available spinning reserve capacity is around 801 kW in the system.

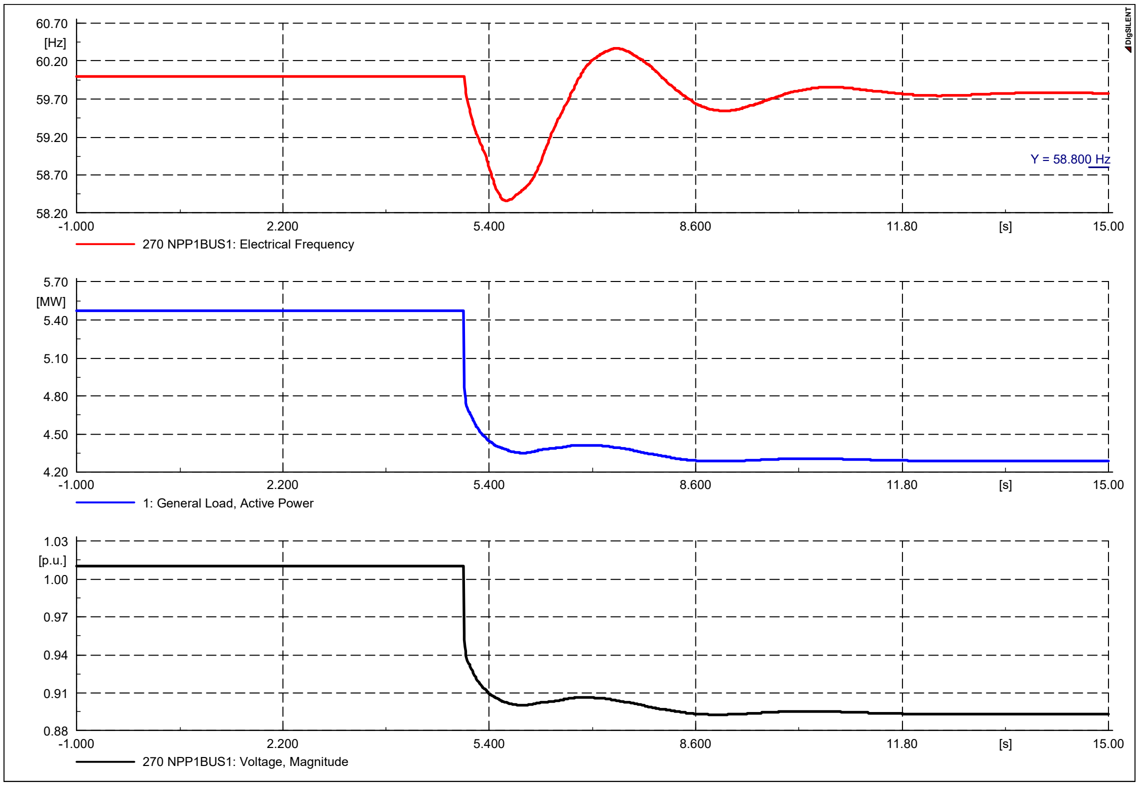
Table 2-6: Generation mix on Pohnpei with PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	9.1%
	3516C_G1	3	1	1485	165	20.6%
	3516C_G2	3	1	1485	165	20.6%
	3516C_G4	3	1	1251.5	398.5	49.8%
	3516C_G5	3	1	0	0	0.0%
	3512_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	Sub-total			**4874**	**801**	
Renewable	PALIKER (1)	1	1	16.0	0	0.0%
	PALIKER (2)	1	1	128.0	0	0.0%
	DAUSOKELE1	1	1	160.0	0	0.0%
	POHLOK	1	1	480.0	0	0.0%
	Sub-total			**784.0**	**0**	
				5658	**801**	**14.2%**

Loss of largest generator

Diesel generator unit 3516C_G1 is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-8.

Figure 2-8: Voltage & frequency response to loss of largest generator

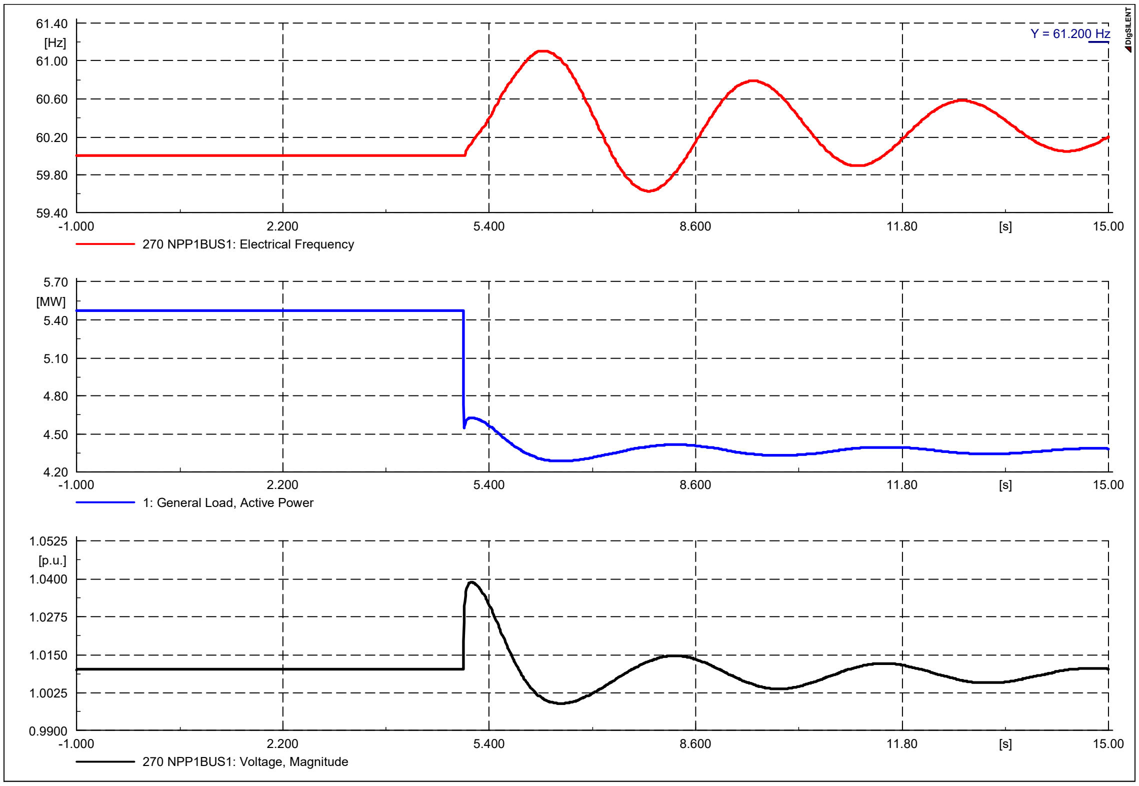


Upon the loss of the largest generator (operated at 1,485 kW), the system frequency drops to 58.3 Hz which is outside the 2% limit for frequency deviations, however this recovers quickly to around 59.75 Hz. The voltage drops to 0.89 pu and does not recover but remains steady at this value. This indicates that this generation dispatch scenario is unable to prevent system frequency and voltage drops outside their respective limits in the event where the largest generator is tripped. An additional diesel generator may need to be switched on to provide more spinning reserve and support system voltage recovery.

Western feeder trip

Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-9.

Figure 2-9: Voltage & frequency response to loss of Western feeder

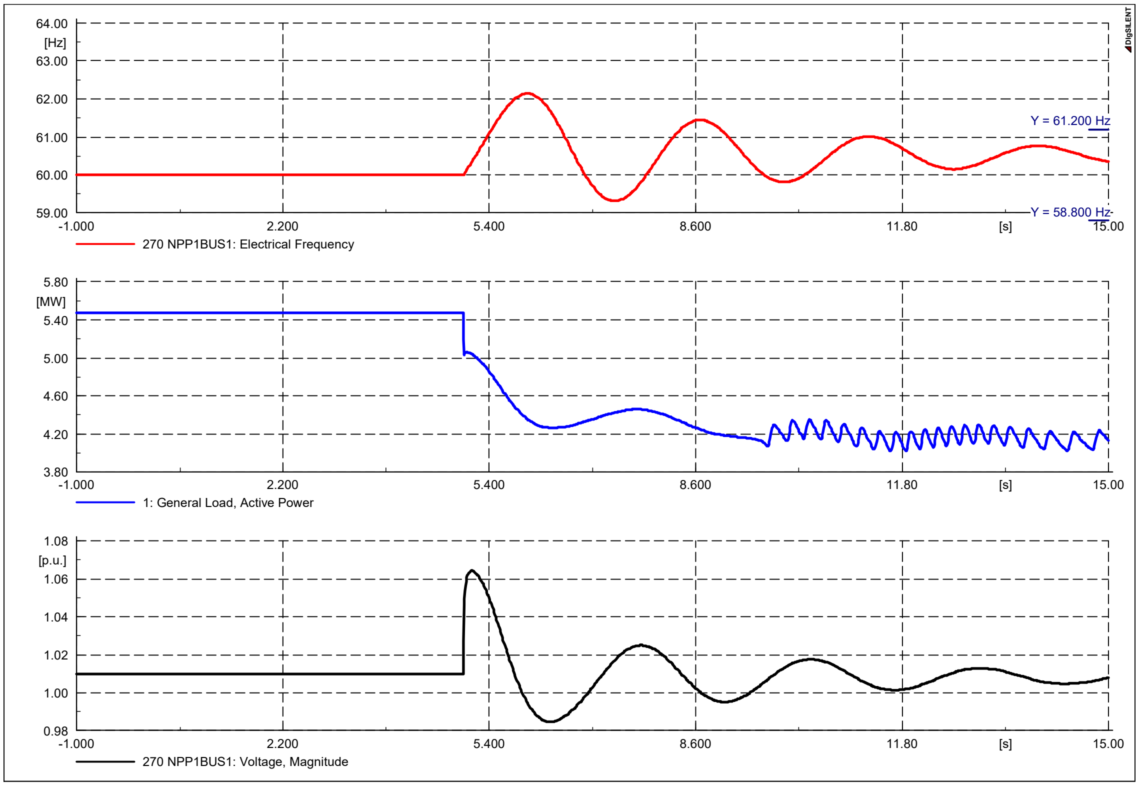


The frequency increases slightly upon the loss of the Western feeder but it remains within the acceptable bandwidth for the duration of the study. The voltage peaks at 1.04 pu but also remains within limits for the duration of the study.

Eastern feeder trip

Tripping the Eastern feeder causes the frequency and voltage responses shown in **Figure 2-10**.

Figure 2-10: Voltage & frequency response to loss of Eastern feeder



The loss of the Eastern feeder causes the system frequency to exceed the 2% deviation momentarily before returning to within the allowable bandwidth and settling. The voltage peaks at 1.06 pu but also remains within limits for the duration of the study.

Three phase fault (cleared after 150ms), trip Western feeder

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-11 and Figure 2-12 respectively.

Figure 2-11: Voltage and frequency response to fault and subsequent feeder trip

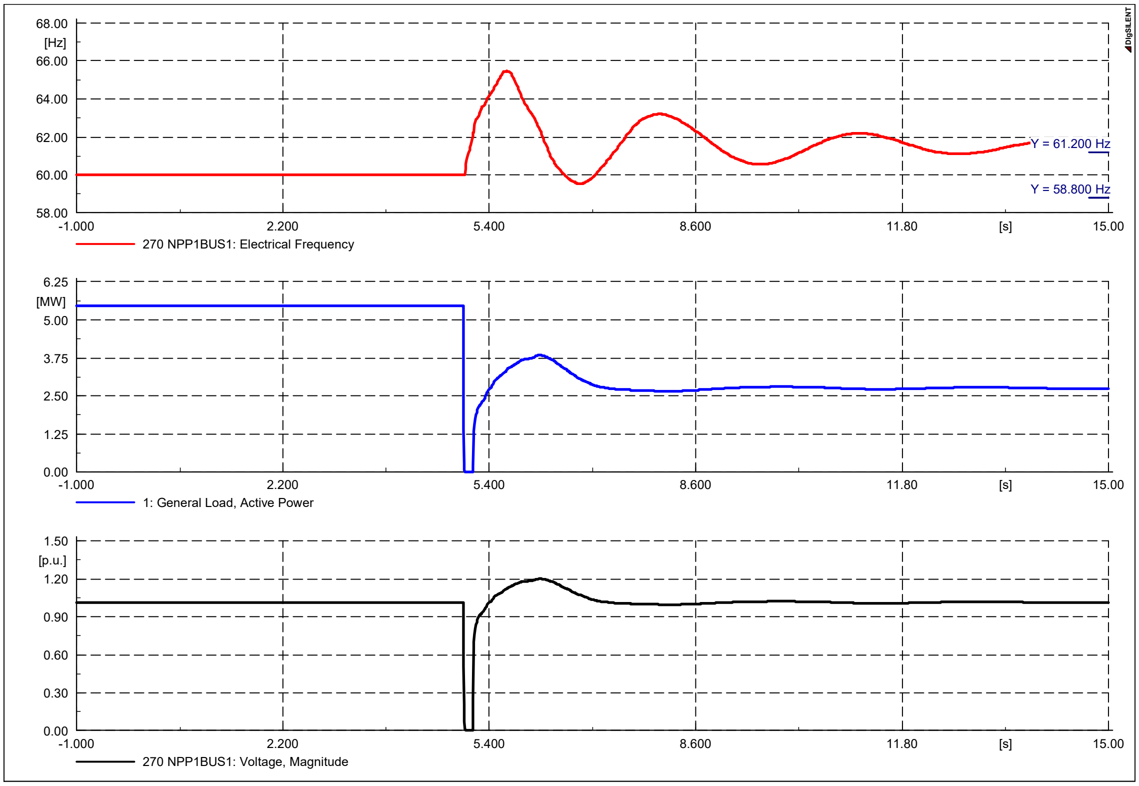
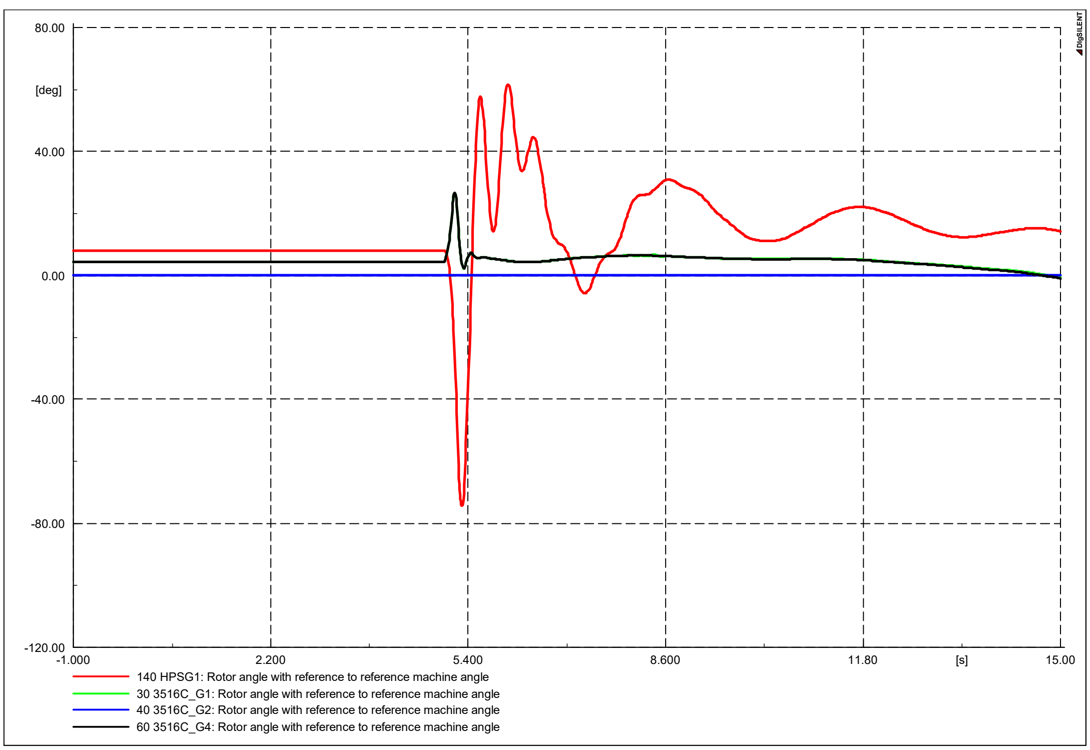


Figure 2-12: Rotor angle response to fault and subsequent feeder trip

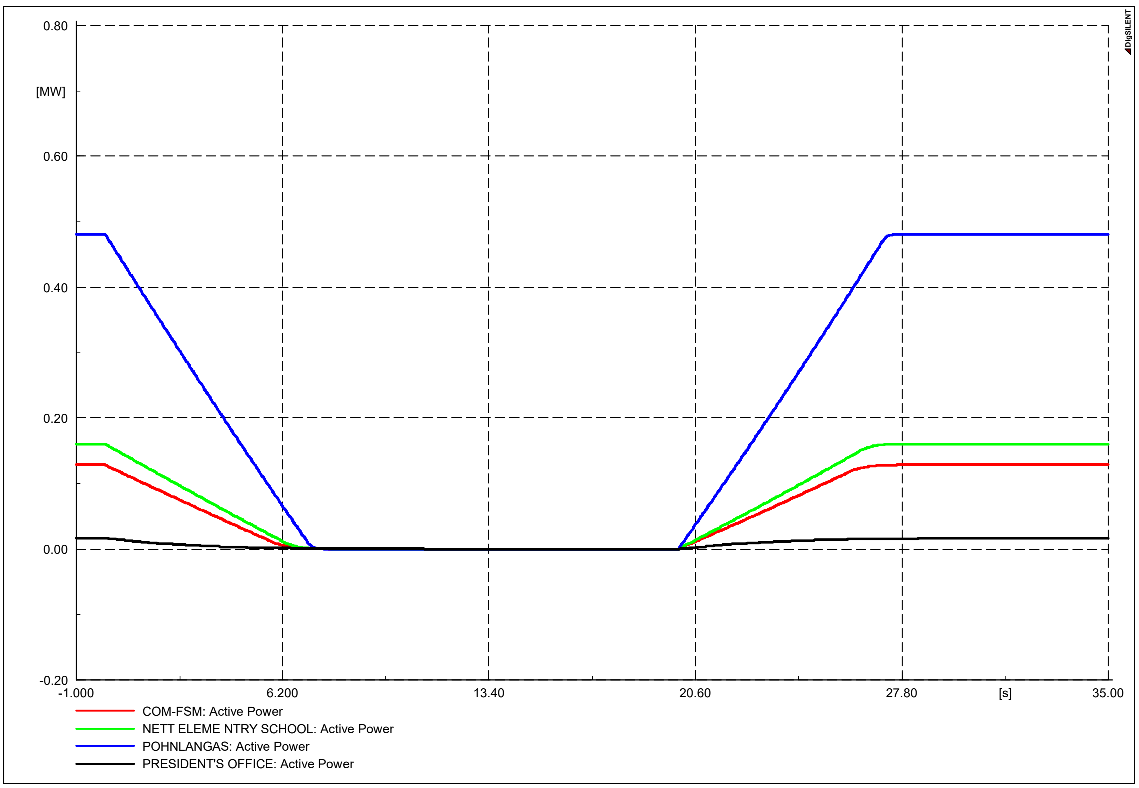


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds), however is rises to almost 1.2 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station. System frequency oscillates outside the ±2% bandwidth reaching a high of 65 Hz after fault inception and this does not settle to within the allowable limits within the study time period.

Reduction/increase of PV output to/from maximum/0MW (AVR off)

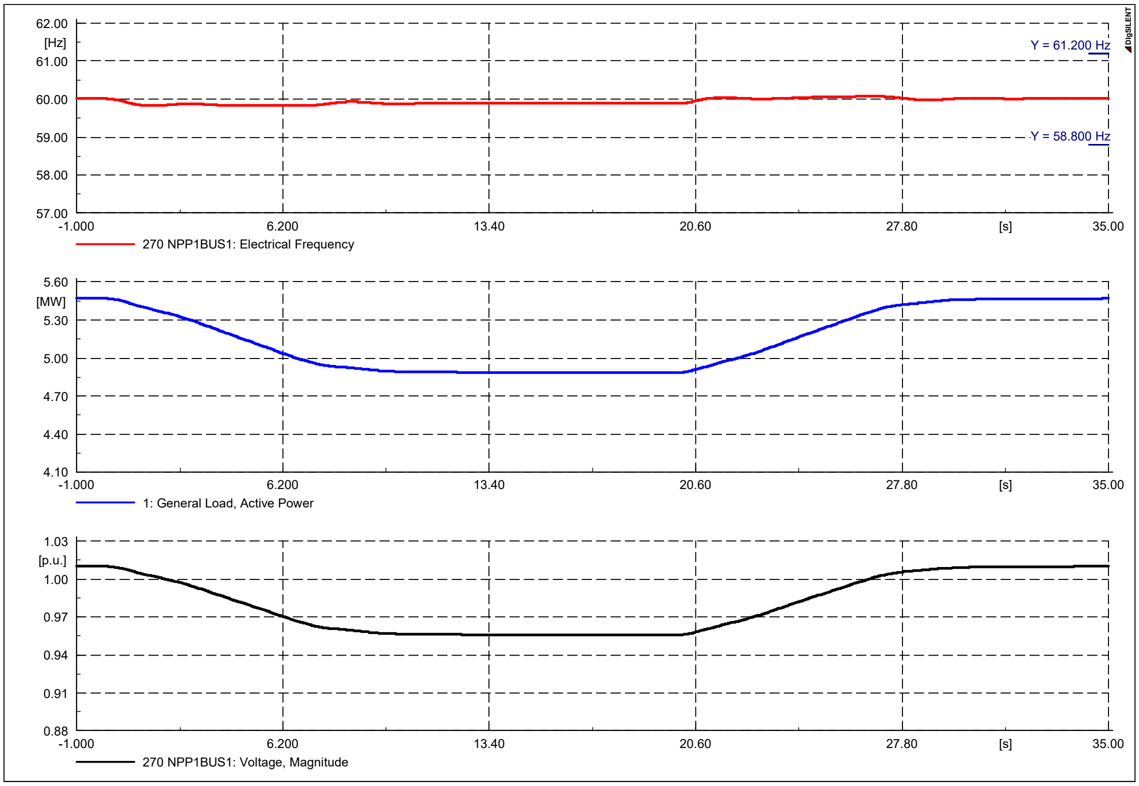
The PV sites connected to the island network were assumed to be operating at 80% output before being simultaneously reduced to 0 MW (to reflect sudden cloud coverage), and then returning to 80% output after 20 s. The PV generation is not set to maximum output because maximum demand is so low and the diesel generation is operating at minimum output; the PV generation cannot exceed 80%. The generation mix assumed in this case is that presented in Table 2-6. The PV output is shown in Figure 2-13.

Figure 2-13: PV MW output of all sites on Pohnpei



The voltage and frequency responses are shown in Figure 2-14.

Figure 2-14: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases minimally and stays around 60 Hz for the duration of the study. The voltage Reduces to 0.95 pu and ramps up again to 1.01 pu as the PV generation increases back to 80% output. The simulation results indicate that in this operational scenario, the system is capable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

Existing generation (varied dispatch) with PV generation

From the studies above with the conventional generation dispatch as described, the stability of the Pohnpei system is not guaranteed with the frequency deviating to outside the 2% limit in many cases after credible contingency events. As such, the generation dispatch has been varied to that shown in Table 2-7. This dispatch has PV generation operating at 80% and also has more diesel generation operating online at lower outputs which provides more spinning reserve. The stability studies were repeated with the updated generation dispatch to assess the impact on stability on those cases where there were issues of instability. In this case, the available spinning reserve capacity is around 3,122.5 kW in the system.

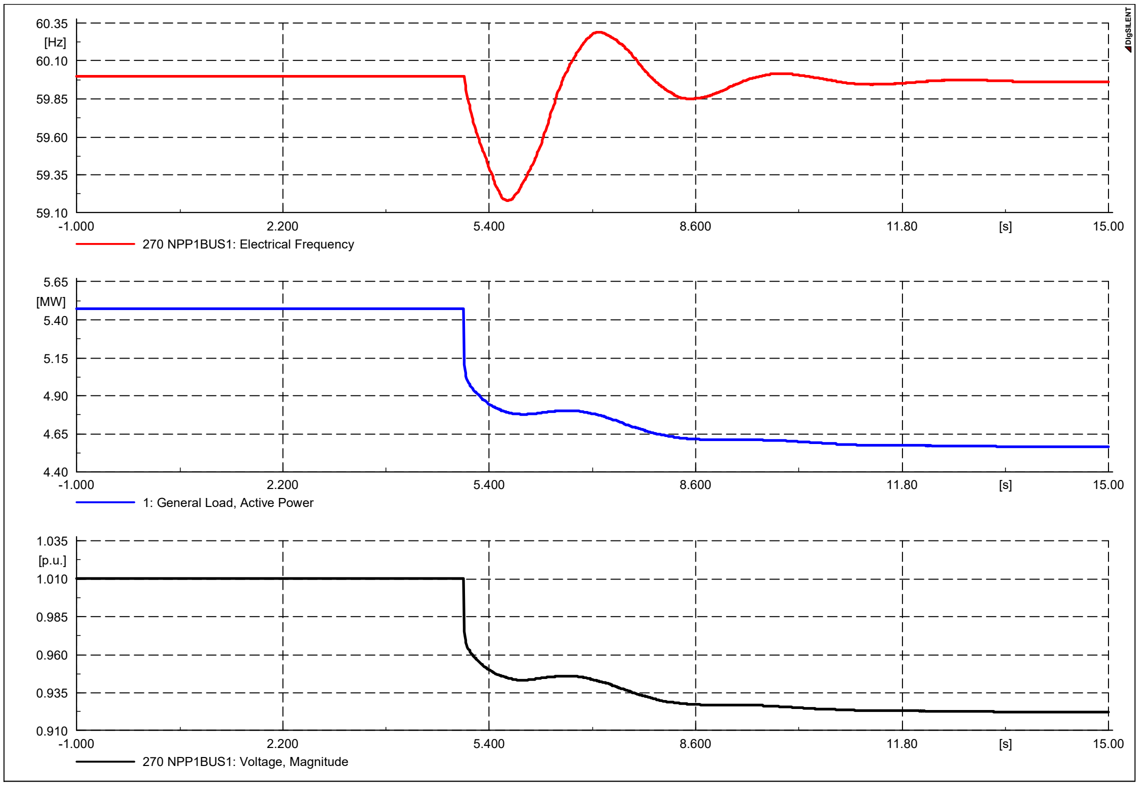
Table 2-7: Updated generation mix on Pohnpei with PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	540	185	5.9%
	3516C_G1	3	1	1000	650	20.8%
	3516C_G2	3	1	907.5	742.5	23.8%
	3516C_G4	3	1	907.5	742.5	23.8%
	3516C_G5	3	1	907.5	742.5	23.8%
	3512_G2	3	1	540	60	1.9%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	Sub-total			4802.5	3122.5	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Sub-total			784.0	0.0	
				5586.5	3122.5	55.2%

Loss of largest generator

Diesel generator unit 3516C_G1 (operated at 1,000 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-15.

Figure 2-15: Voltage & frequency response to loss of largest generator



The frequency response of the system with this generation dispatch portfolio is improved and the frequency remains within the limits for the duration of the study. The voltage reduces to 0.92 pu following the event and stabilises there. This response is improved from the previous generation dispatch in Table 2-6 and no limits are exceeded.

2.2.4 Increasing penetration of VRE

There are plans to increase the penetration of VRE on the Pohnpei network, primarily from solar PV however, detailed generation expansion planning information was not available. As such, the Pohnpei system has been tested with different levels of additional PV penetrations and a number of studies have been performed to assess the capability of the network to accommodate this higher level of renewable generation e.g. 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.

2.2.4.1 Additional 1200 kW of solar PV generation

The following sections present the results which highlight the ability of the Pohnpei network to accommodate 1,200 kW of additional PV generation. The generation mix assumed for these studies is listed in Table 2-8 where the typical conventional generation dispatch is assumed and the existing PV generation on the system operating at 80%. In this case, the load demand of the system is assumed to be 6,018 kW, 10% above the existing maximum load demand level, and renewable generation output accounts for 32% of total generation output with available spinning reserve of 1,436 kW in the system.

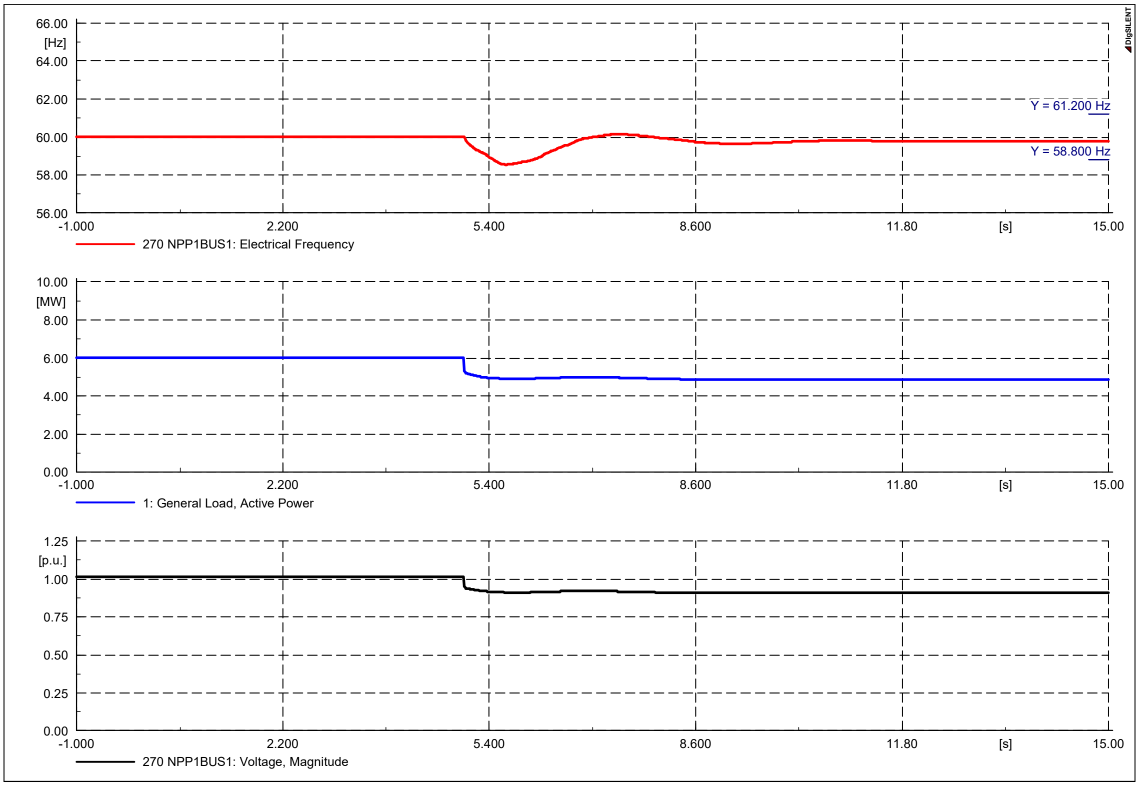
Table 2-8: Generation mix on Pohnpei with additional 1200kW PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	5.0%
	3516C_G1	3	1	1485	165	11.5%
	3516C_G2	3	1	1485	165	11.5%
	3516C_G4	3	1	616.5	1033.5	72.0%
	3516C_G5	3	1	0	0	0.0%
	3512_G2	3	1	0	0	0.0%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	Sub-total			**4239.0**	**1436.0**	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	1200.0	0.0	0.0%
	Sub-total			**1984.0**	**0.0**	
				6223	**1436**	**23.1%**

Loss of largest generator

Diesel generator unit 3516C_G1 (operated at 1,485 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-16.

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

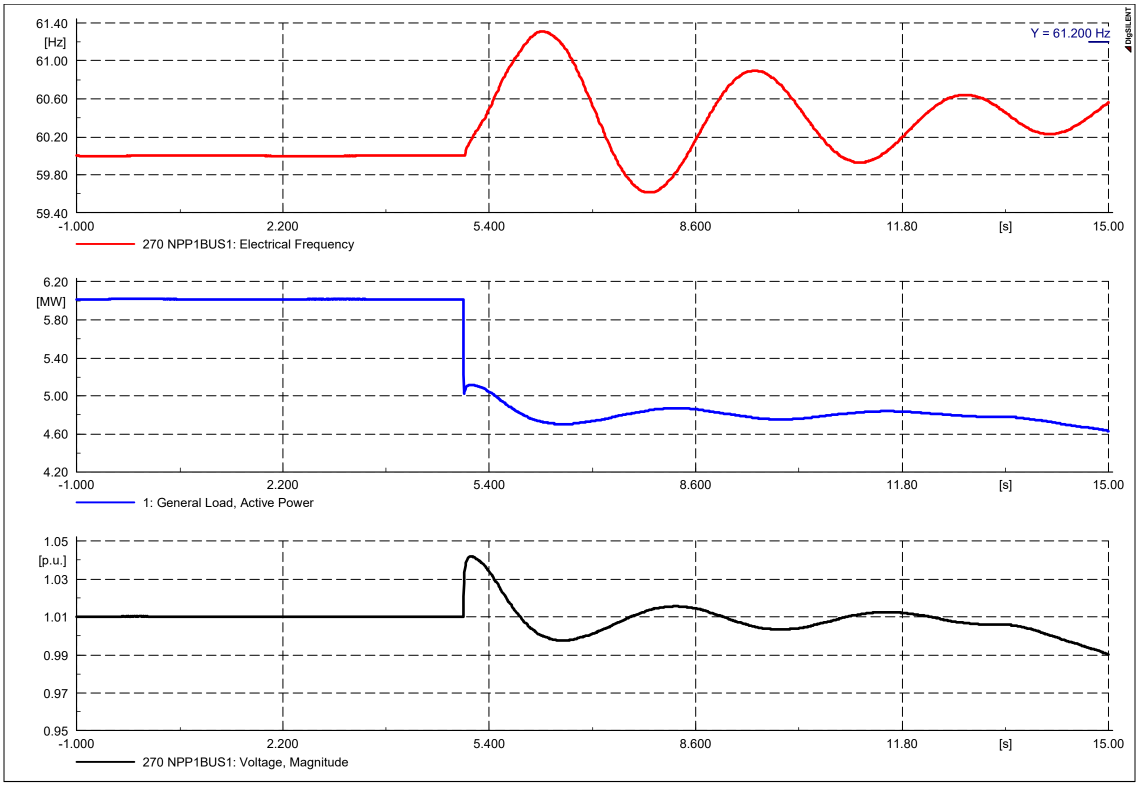


Upon the loss of the largest generator, the system frequency drops to 58.7 Hz which is marginally outside the 2% limit for frequency deviations, however this recovers quickly and there are no oscillations in the response. The voltage drops to 0.92 pu and remains steady at this value.

Western feeder trip

Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-17.

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

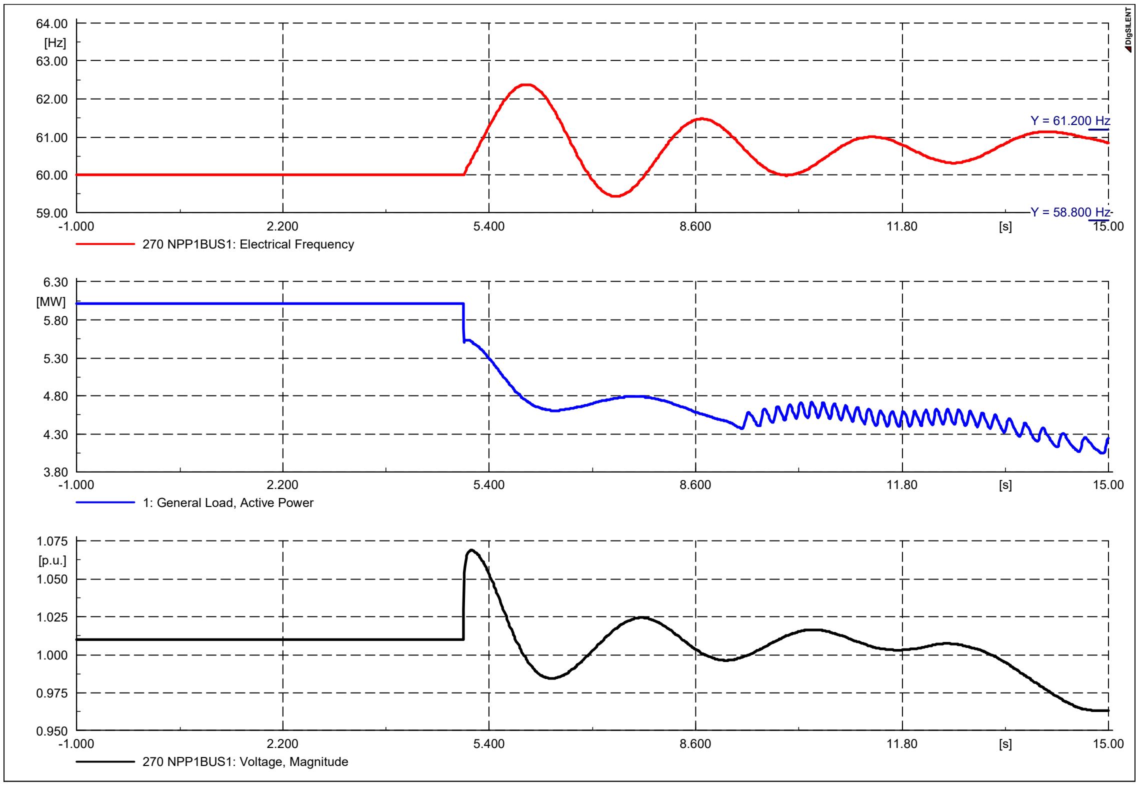


The frequency increases upon the loss of the Western feeder and marginally exceeds the limit of 61.2 Hz but it reduces quickly and remains within the acceptable bandwidth for the duration of the study. The voltage peaks at 1.04 pu but also remains within limits for the duration of the study.

Eastern feeder trip

Tripping the Eastern feeder causes the frequency and voltage responses shown in **Error! Reference source not found.**.

Figure 2-18: Voltage & frequency response to loss of Eastern feeder



The loss of the Eastern feeder causes the system frequency to exceed the 2% deviation limit before returning to within the allowable bandwidth and settling. The voltage peaks at 1.07 pu but also remains within limits for the duration of the study.

Three phase fault (cleared after 150ms), trip Western feeder

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-19 and Figure 2-20 respectively.

Figure 2-19: Voltage and frequency response to fault and subsequent feeder trip

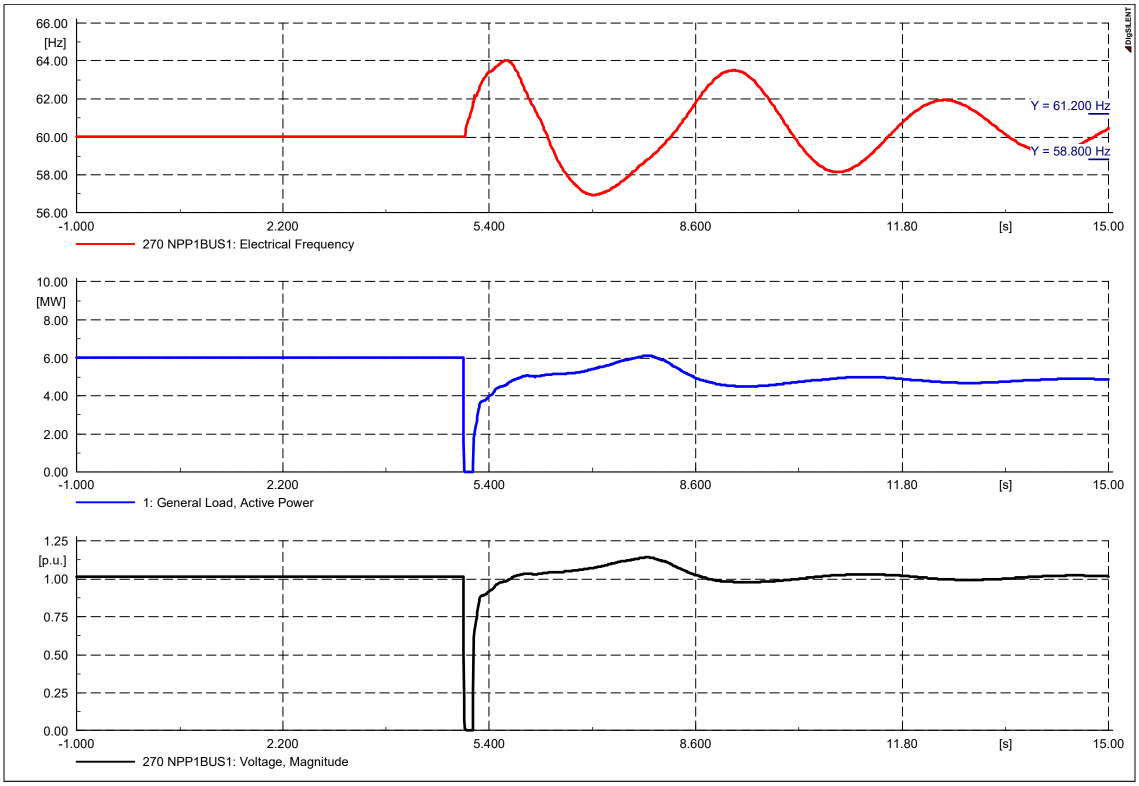
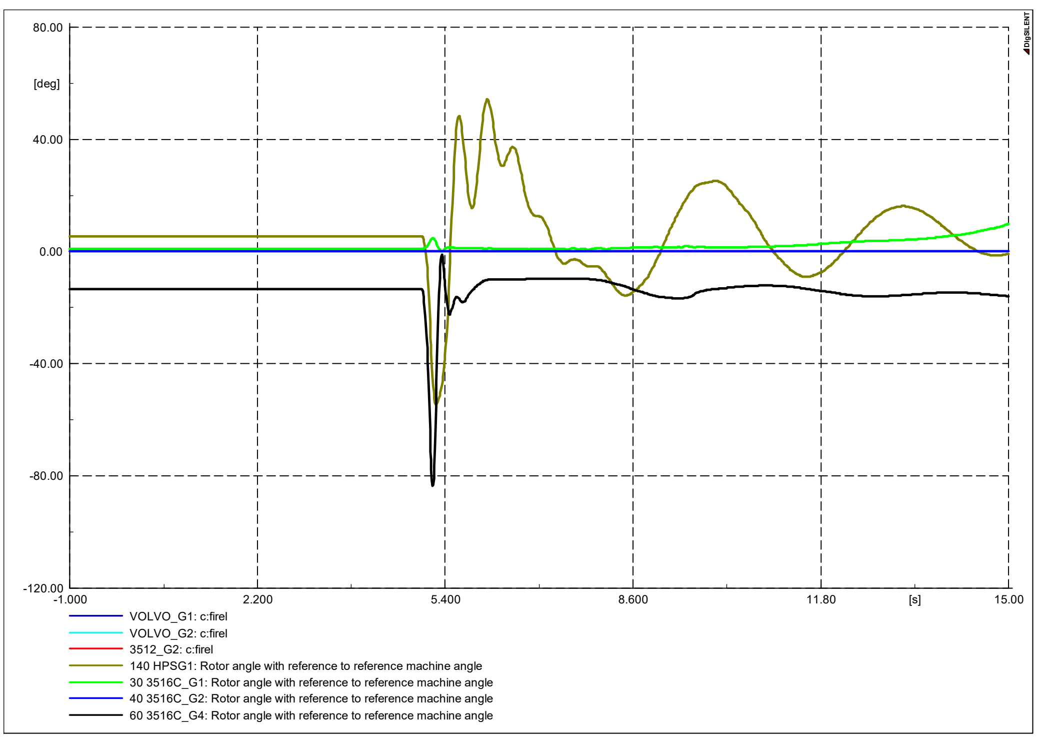


Figure 2-20: Rotor angle response to fault and subsequent feeder trip

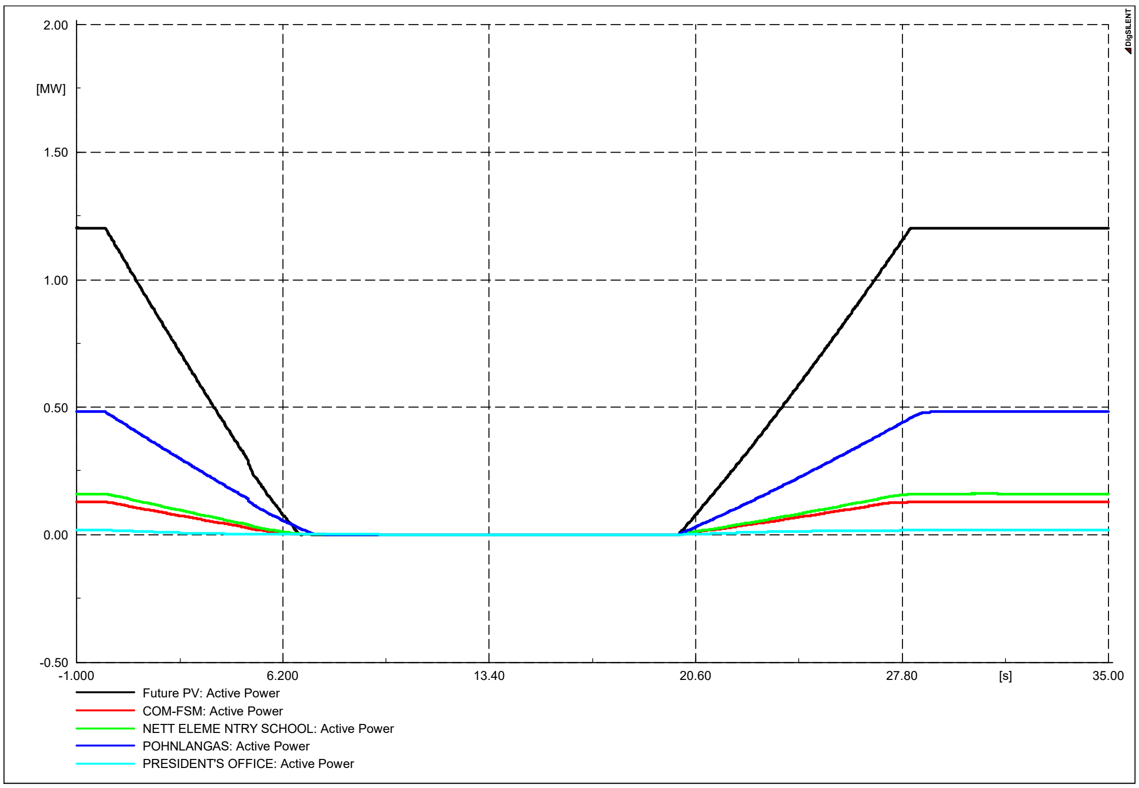


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.1 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station and at G4. System frequency oscillates quite significantly outside the ±2% bandwidth reaching a high of 64 Hz and a low of 57 Hz after fault inception.

Reduction/increase of PV output to/from maximum/0MW (AVR off)

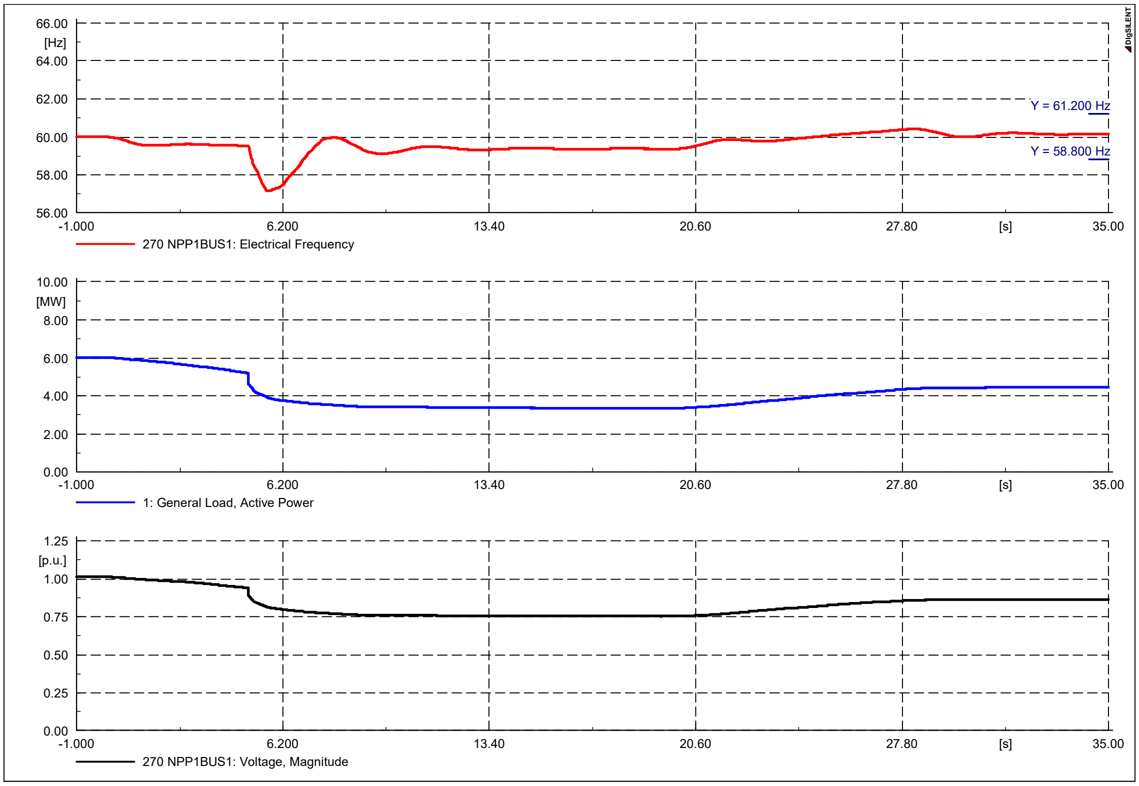
The PV sites connected to the island network were assumed to be operating at 80% output before being simultaneously reduced to 0 MW (to reflect sudden cloud coverage), and then returning to 80% output after 20 s. The new PV generation is set to maximum output of 1,200 kW. The PV output is shown in Figure 2-21.

Figure 2-21: PV MW output of all sites on Pohnpei



The voltage and frequency responses are shown in Figure 2-22.

Figure 2-22: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases sharply to approximately 57 Hz, recovers then stays around 60 Hz for the duration of the study. The voltage reduces to 0.75 pu and voltage collapse in the system could potentially be the case when the PV generators ramp down. The simulation results indicate that in this operational scenario, the system is incapable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

2.2.4.2 Additional 1200 kW of solar PV generation – Updated generation dispatch

Similar to the response of the system with the existing generation portfolio, there are large frequency deviations, and in some cases, the potential for voltage collapse when only three diesels generators and the hydro generator are online. As such, the following sections present the results of studies with 1,200kW of additional PV generation with an updated conventional generation dispatch to provide more spinning reserve and system inertia. The generation mix assumed for these studies is listed in Table 2-9.

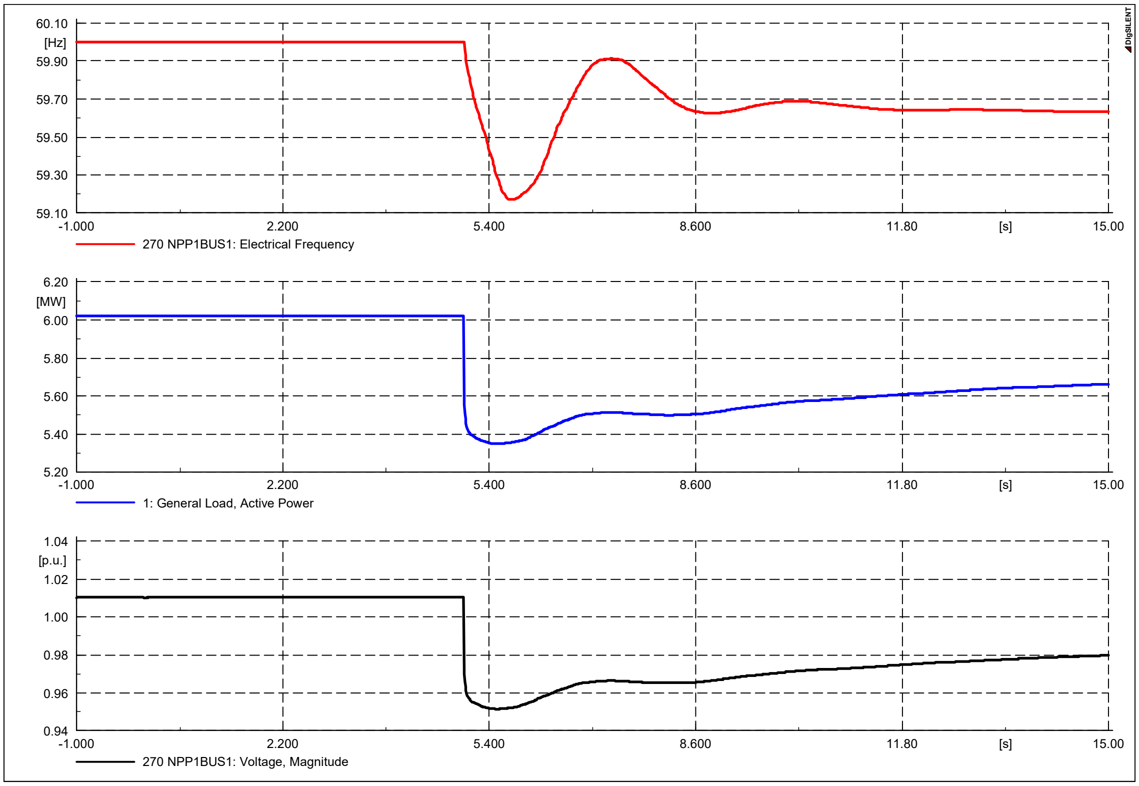
Table 2-9: Updated generation mix on Pohnpei with additional 1200kW PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	540	185	5.0%
	3516C_G1	3	1	1000	650	17.6%
	3516C_G2	3	1	825	825	22.4%
	3516C_G4	3	1	825	825	22.4%
	3516C_G5	3	1	825	825	22.4%
	3512_G2	3	1	224	376	10.2%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	0	0	0	0.0%
	Sub-total			**4239.0**	**3686.0**	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	1200.0	0.0	0.0%
	Sub-total			**1984.0**	**0.0**	
				6223	**3686**	59.2%

Loss of largest generator

Diesel generator unit 3516C_G1 (operated at 1,000 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-23.

Figure 2-23: Voltage & frequency response to loss of largest generator



Upon the loss of the largest generator, the system frequency drops to 59.2 Hz which within the operational limits. The voltage drops to 0.95 pu and increases steadily up to 0.98 pu.

Three phase fault (cleared after 150ms), trip Western feeder

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-24 and Figure 2-25 respectively.

Figure 2-24: Voltage and frequency response to fault and subsequent feeder trip

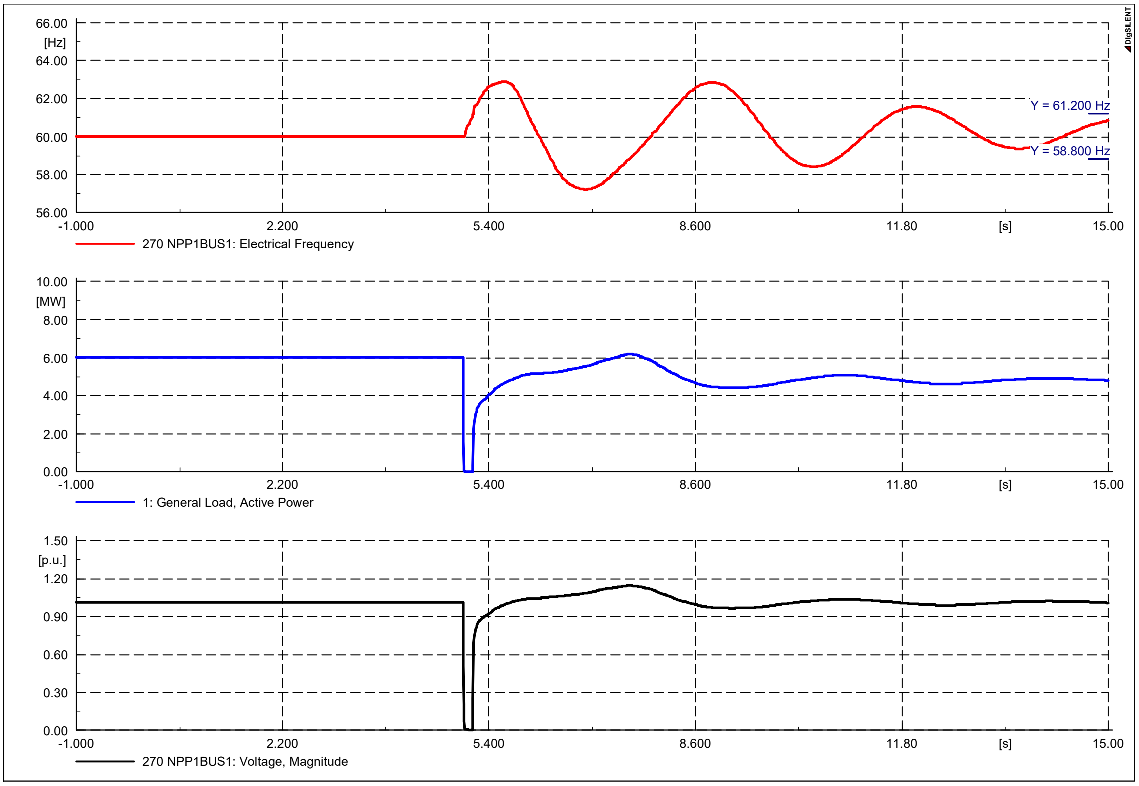
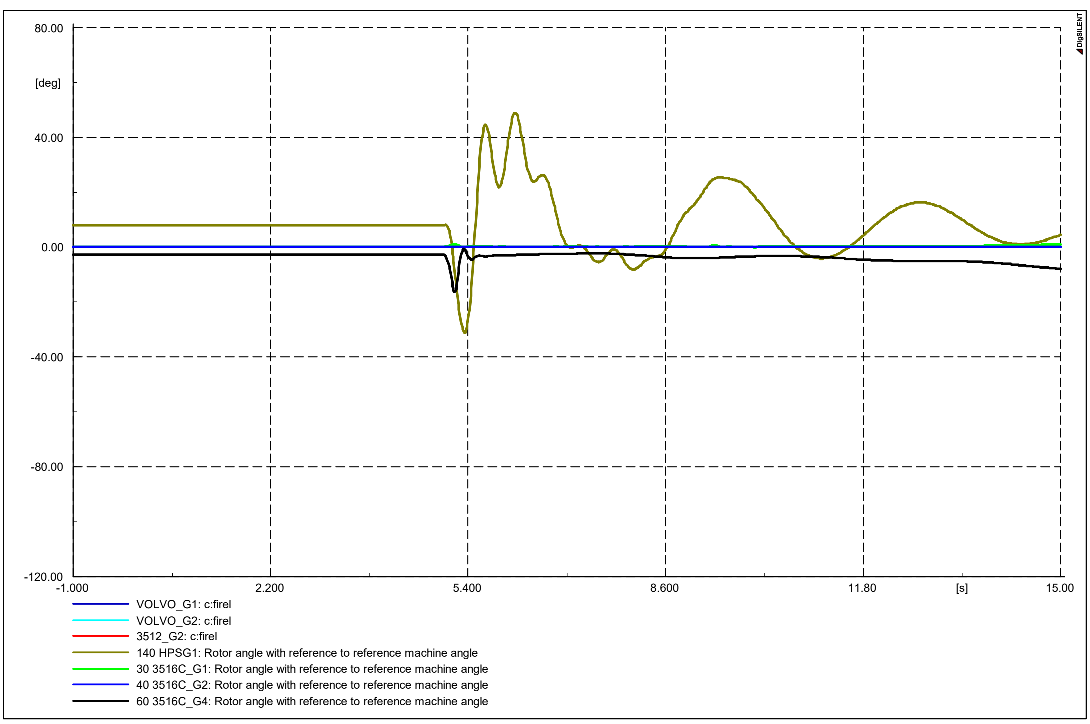


Figure 2-25: Rotor angle response to fault and subsequent feeder trip

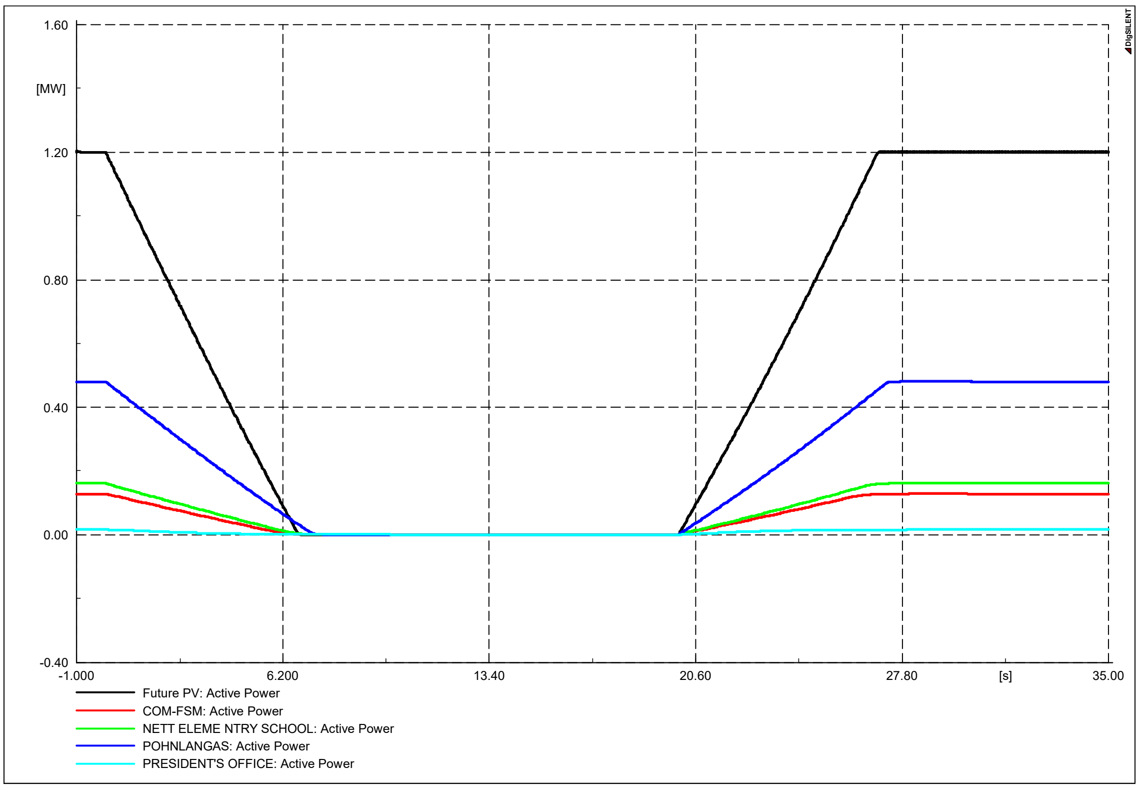


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.1 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is some rotor swing experienced at the hydro power station. System frequency oscillates quite significantly outside the ±2% bandwidth reaching a high of 63 Hz and a low of 57 Hz after fault inception.

Reduction/increase of PV output to/from maximum/0MW (AVR off)

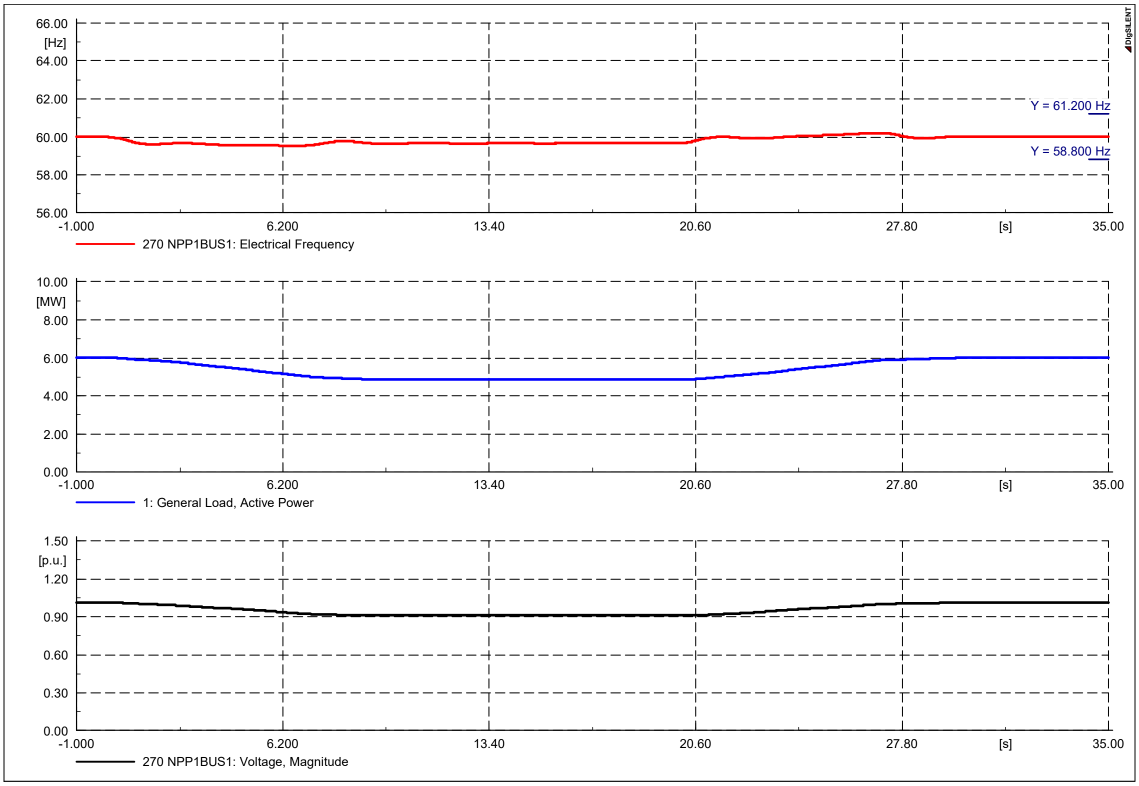
The PV sites connected to the island network were assumed to be operating at 80% output before being simultaneously reduced to 0 MW (to reflect sudden cloud coverage), and then returning to 80% output after 20 s. The new PV generation is set to maximum output of 1,200 kW. The PV output is shown in Figure 2-26.

Figure 2-26: PV MW output of all sites on Pohnpei



The voltage and frequency responses are shown in Figure 2-27.

Figure 2-27: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases marginally and then fluctuates slightly around 60 Hz for the duration of the study. The voltage reduces to 0.9 pu when the PV generators ramp down which is just within the ±10% limit for voltage. The simulation results indicate that with more conventional generators on line, the system is basically capable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

2.2.4.3 Additional 2400 kW of solar PV generation

The following sections present the results which highlight the ability of the Pohnpei network to accommodate 2,400 kW of additional PV generation. The generation mix assumed for these studies is listed in Table 2-10 where the typical conventional generation dispatch is assumed and the existing PV generation on the system operating at 80%. In this case, renewable generation output accounts for 51% of total generation output with available spinning reserve of 986 kW in the system.

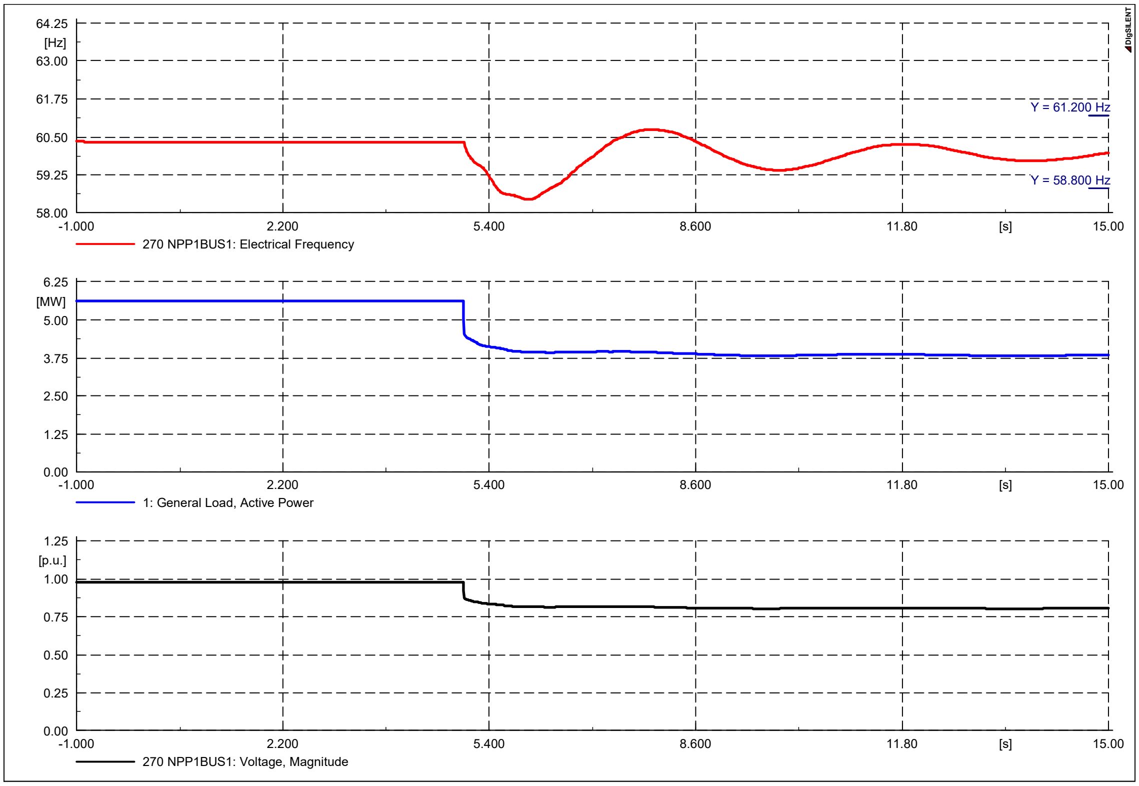
Table 2-10: Generation mix on Pohnpei with additional 2400kW PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	652.5	72.5	7.4%
	3516C_G1	3	1	1485	165	16.7%
	3516C_G2	3	1	901.5	748.5	75.9%
	3516C_G4	3	1	0	0	0.0%
	3516C_G5	3	1	0	0	0.0%
	3512_G2	3	1	0	0	0.0%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	1	0	0	0.0%
	Sub-total			**3039.0**	**986.0**	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	2400.0	0.0	0.0%
	Sub-total			**3184.0**	**0.0**	
				6223	**986**	15.8%

Loss of largest generator

Diesel generator unit 3516C_G1 (operated at 1,485 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-28.

Figure 2-28: Voltage & frequency response to loss of largest generator

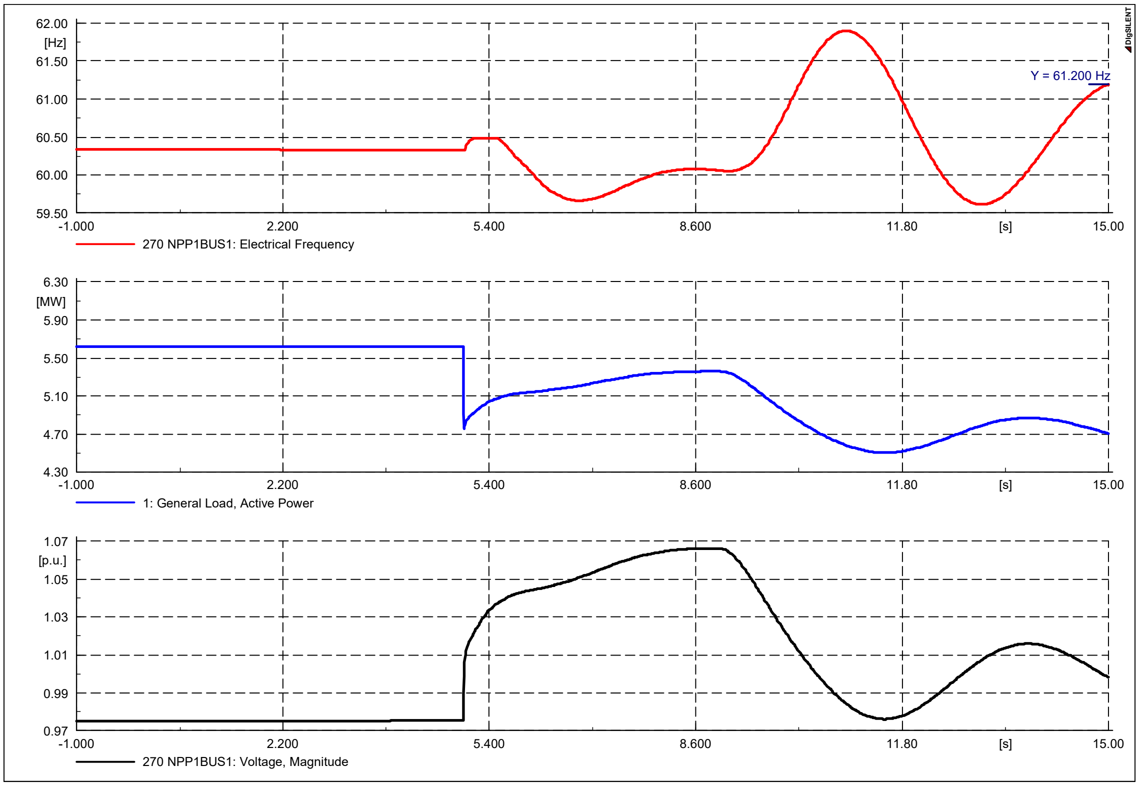


Upon the loss of the largest generator, the system frequency initially drops to 58.1 Hz which is outside the operational limits. The voltage drops to 0.8 pu which is in excess of the ±10% limit for voltage. Voltage instability could thus be expected following the loss of the largest generator.

Western feeder trip

Tripping the Western feeder causes the frequency and voltage responses shown in Figure 2-29.

Figure 2-29: Voltage & frequency response to loss of Western feeder

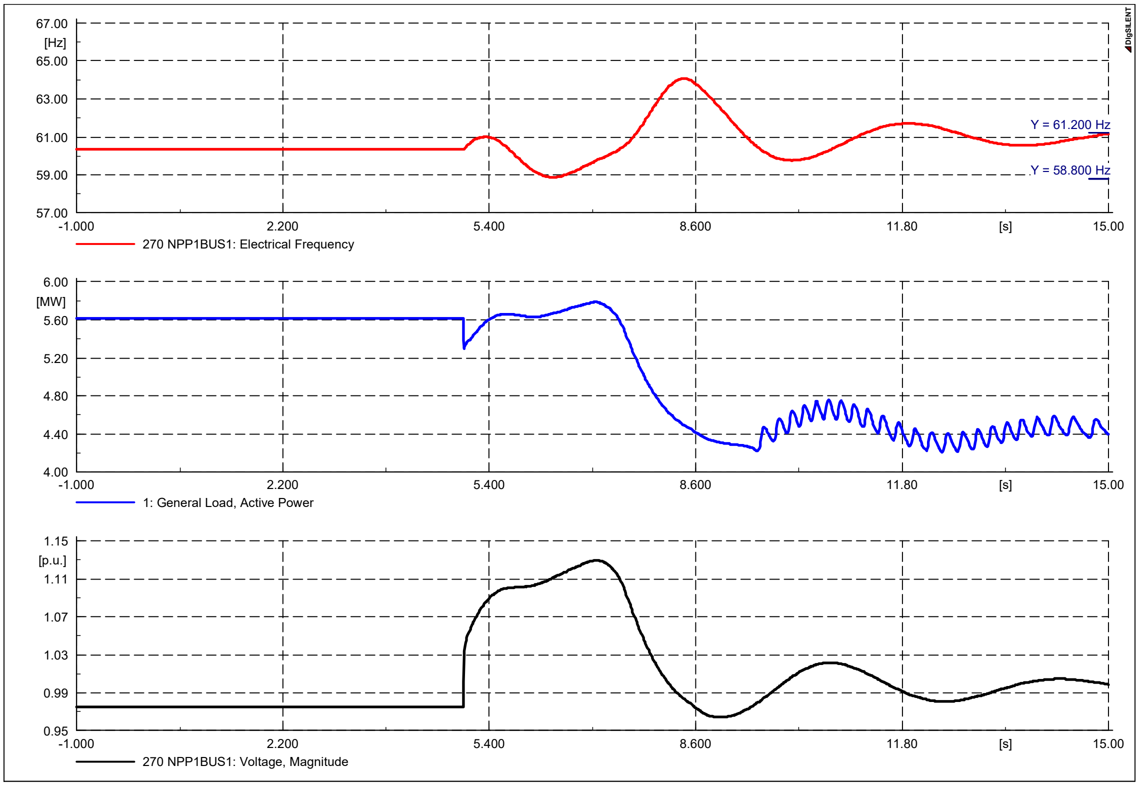


Upon the loss of the Western feeder the frequency swings upwards to almost 62 Hz and continues to oscillate for the duration of the study. The voltage peaks at 1.07 pu and has oscillations which mirror the frequency ones, however the voltage remains within limits for the duration of the study.

Eastern feeder trip

Tripping the Eastern feeder causes the frequency and voltage responses shown in Figure 2-30.

Figure 2-30: Voltage & frequency response to loss of Eastern feeder



The loss of the Eastern feeder causes the system frequency to exceed the 2% deviation limit before returning to within the allowable bandwidth and settling. The voltage peaks at 1.13 pu and then reduces to within limits for the duration of the study.

Three phase fault (cleared after 150ms), trip Western feeder

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-31 and Figure 2-32 respectively.

Figure 2-31: Voltage and frequency response to fault and subsequent feeder trip

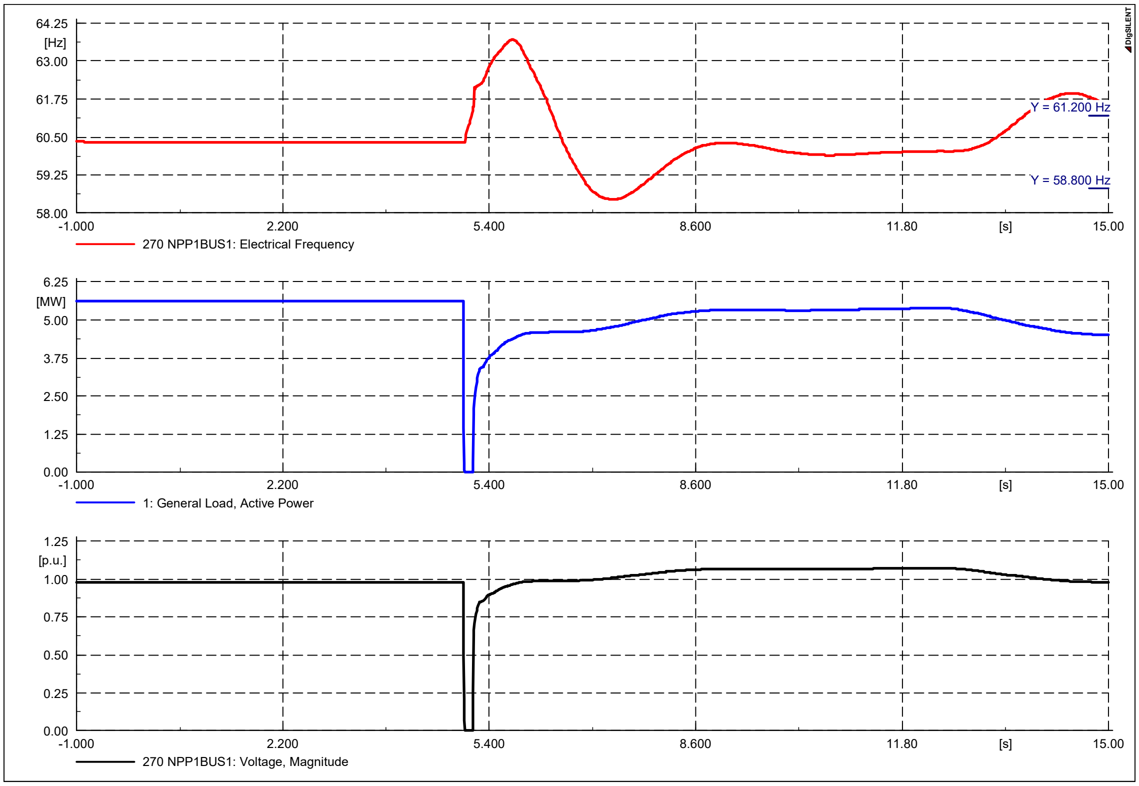
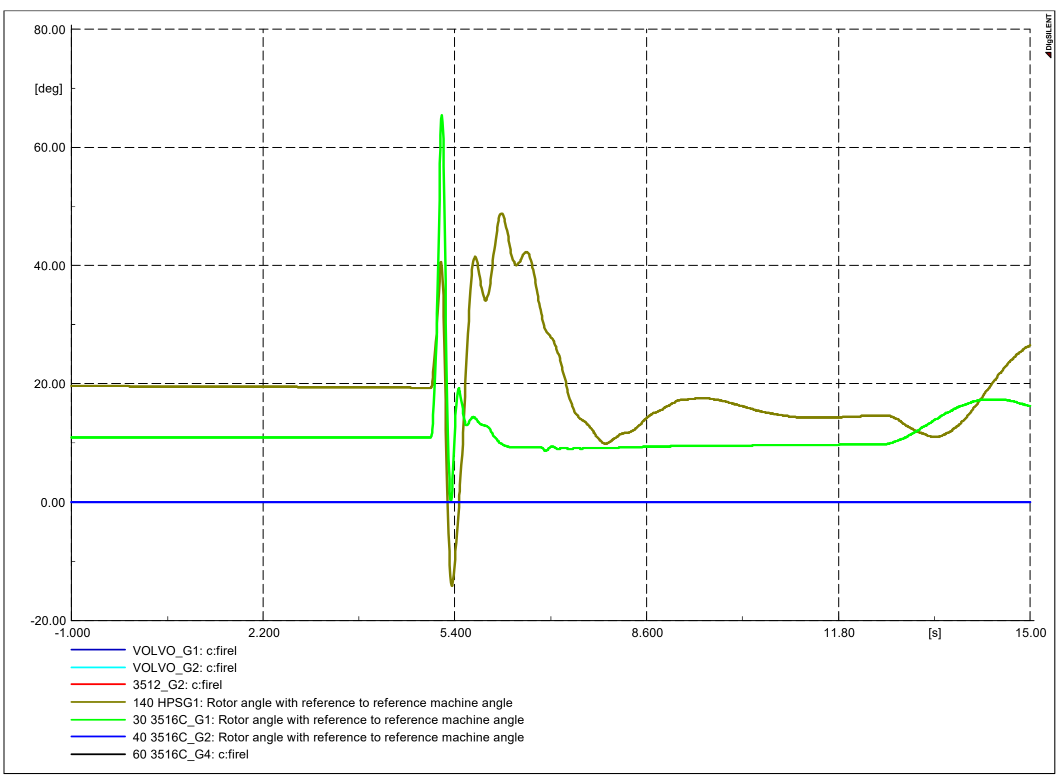


Figure 2-32: Rotor angle **response to fault and subsequent feeder trip**

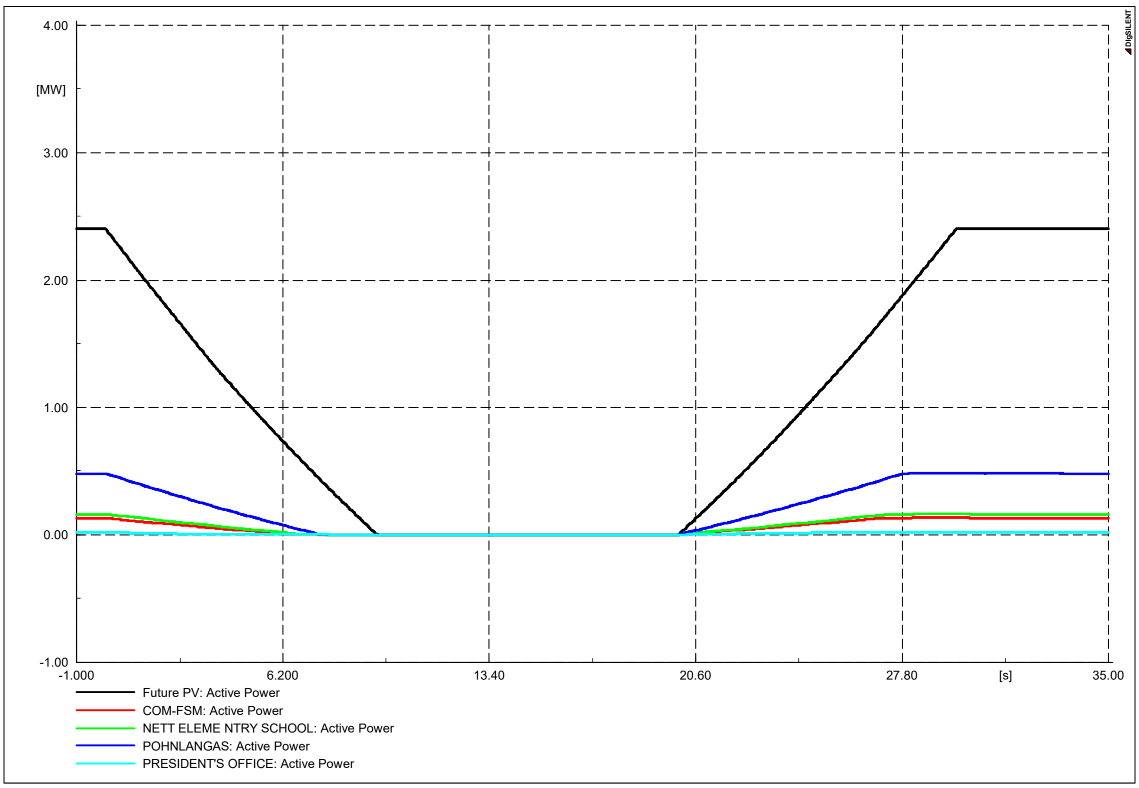


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.05 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station and at G1. System frequency oscillates quite significantly outside the ±2% bandwidth reaching a high of 64 Hz after fault inception.

Reduction/increase of PV output to/from maximum/0MW (AVR off)

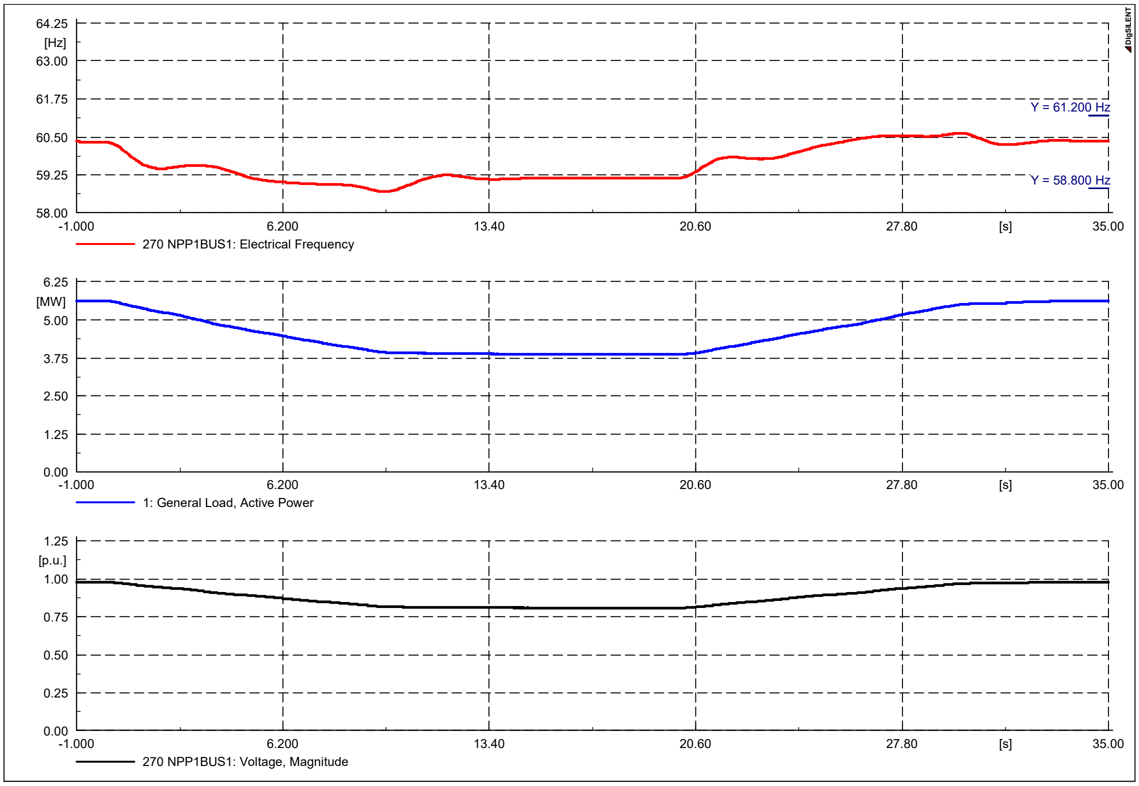
The PV sites connected to the island network were assumed to be operating at 80% output before being simultaneously reduced to 0 MW (to reflect sudden cloud coverage), and then returning to 80% output after 20 s. The new PV generation is set to maximum output of 2,400 kW. The PV output is shown in Figure 2-33.

Figure 2-33: PV MW output of all sites on Pohnpei



The voltage and frequency responses are shown in Figure 2-34.

Figure 2-34: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases accordingly to slightly below 58.8 Hz and then steadily returns to nominal. The voltage reduces to 0.8 pu and the system may potentially experience voltage collapse when the PV generators ramp down. The simulation results indicate that in this operational scenario the system is incapable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

2.2.4.4 Additional 2400 kW of solar PV generation – Updated generation dispatch

Similar to the response of the system with the existing generation portfolio and with the addition of 1,200kW new PV, there is instability when only two diesels generators and the hydro generator are online and there is a contingency situation. As such, the following sections present the results of studies with 2,400kW of additional PV generation with an updated conventional generation dispatch to provide more spinning reserve. The generation mix assumed for these studies is listed in Table 2-11.

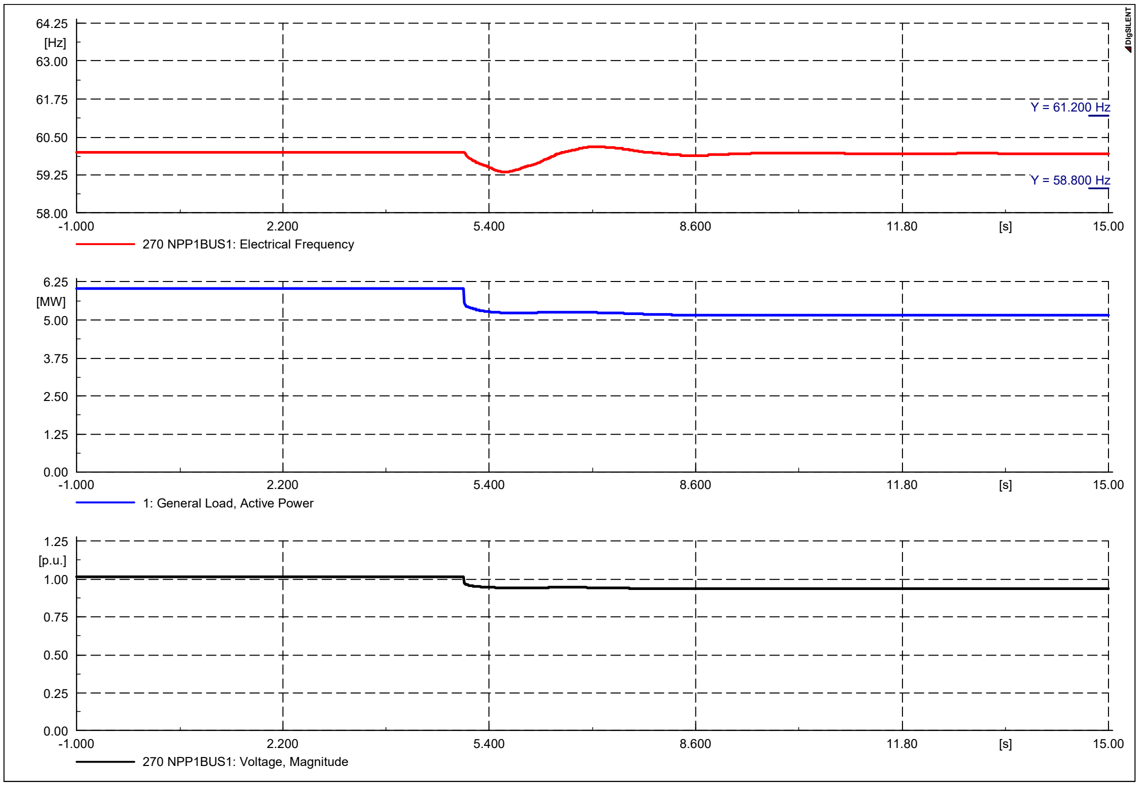
Table 2-11: Updated generation mix on Pohnpei with additional 2400kW PV generation

Generation Type	Unit ID	Merit Order	Generator Available Status	Actual Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Diesel & Hydro	HPSG1	2	1	540	185	4.3%
	3516C_G1	3	1	1000	650	15.2%
	3516C_G2	3	1	500	1150	26.8%
	3516C_G4	3	1	500	1150	26.8%
	3516C_G5	3	1	500	1150	26.8%
	3512_G2	3	1	0	0	0.0%
	Peaker_G1	3	1	0	0	0.0%
	Peaker_G2	3	1	0	0	0.0%
	VOLVO_G1	3	1	0	0	0.0%
	VOLVO_G2	3	1	0	0	0.0%
	VOLVO_G3	3	1	0	0	0.0%
	VOLVO_G4	3	1	0	0	0.0%
	Sub-total			**3040.0**	**4285.0**	
Renewable	PALIKER (1)	1	1	16.0	0.0	0.0%
	PALIKER (2)	1	1	128.0	0.0	0.0%
	DAUSOKELE1	1	1	160.0	0.0	0.0%
	POHLOK	1	1	480.0	0.0	0.0%
	Future	1	1	2400.0	0.0	0.0%
	Sub-total			**3184.0**	**0.0**	
				6224	**4285**	**68.9%**

Loss of largest generator

Diesel generator unit 3516C_G1 (operated at 1,000 kW) is tripped in these studies as the largest generator on the system. The frequency and voltage response of the system are shown in Figure 2-35.

Figure 2-35: Voltage & frequency response to loss of largest generator



Upon the loss of the largest generator, the system frequency dips slightly but remains within limits and recovers quickly to nominal. The voltage drops to around 0.95 pu which is well within the ±10% limit for voltage.

Three phase fault (cleared after 150ms), trip Western feeder

A three-phase fault was simulated at the power station busbar (NPP1BUS1). The fault was cleared within 150 ms at which point the Western feeder is tripped off. The voltage and rotor angle responses to these events are shown in Figure 2-36 and Figure 2-37 respectively.

Figure 2-36: Voltage and frequency response to fault and subsequent feeder trip

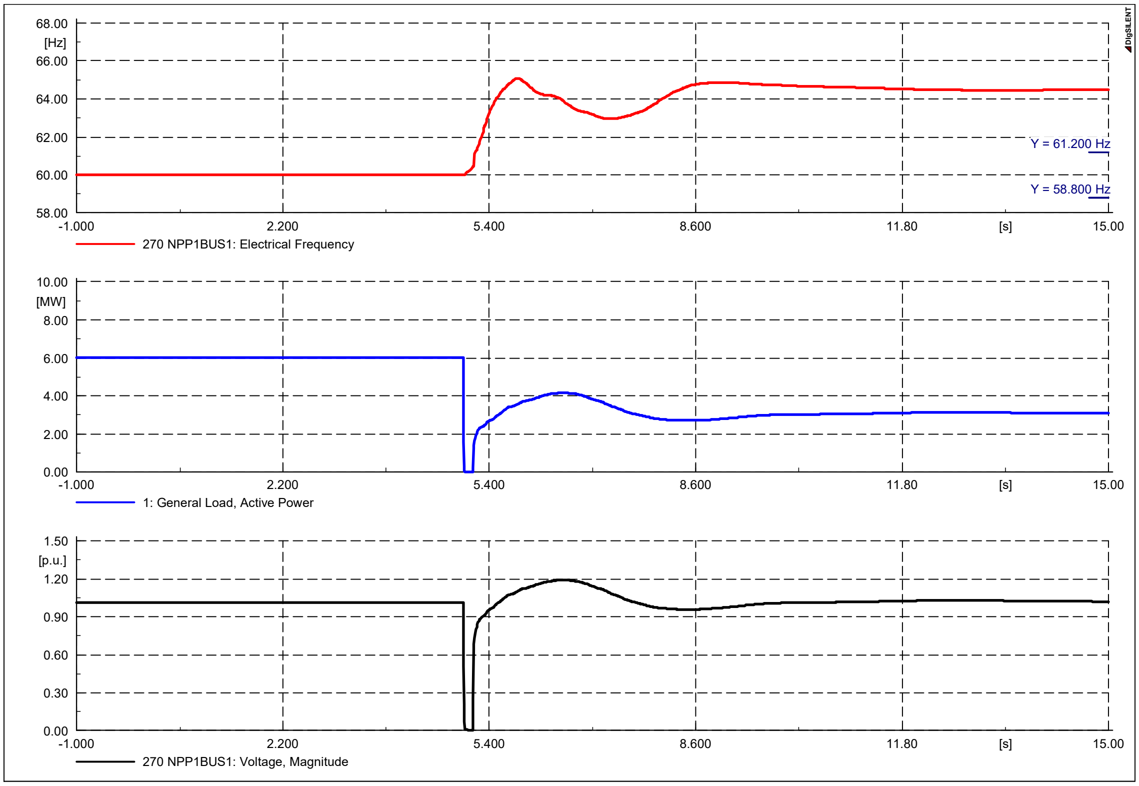
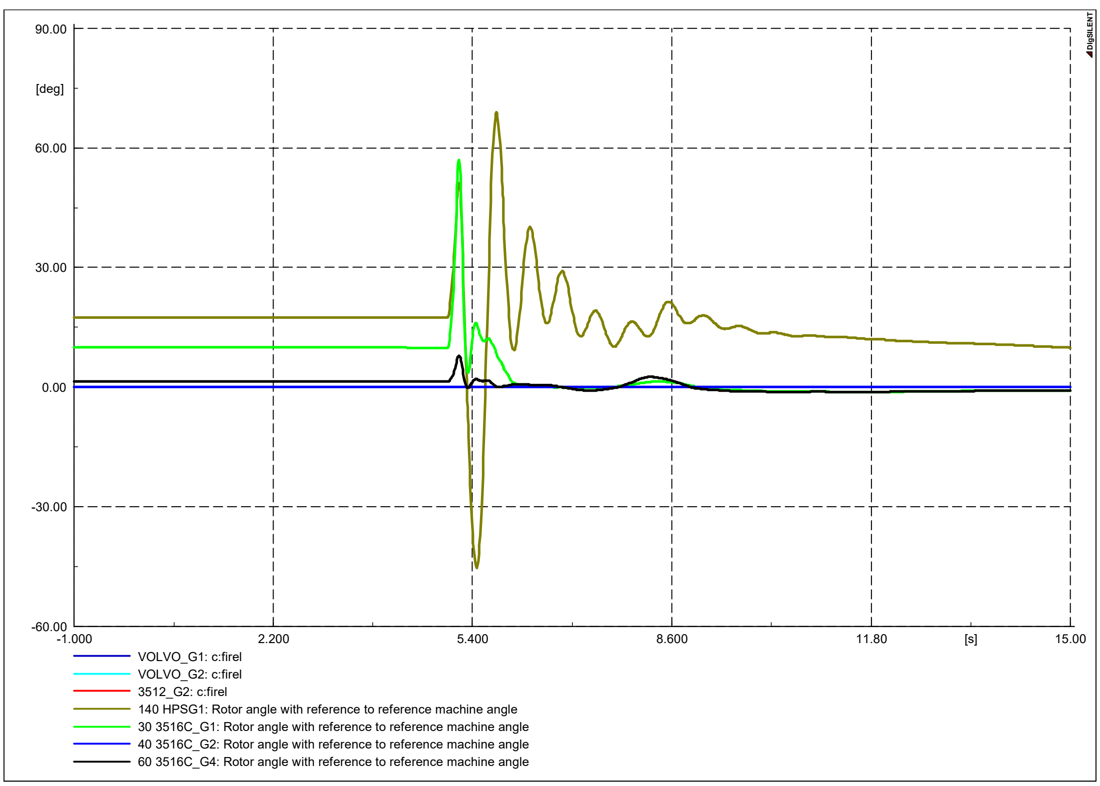


Figure 2-37: Rotor angle response to fault and subsequent feeder trip

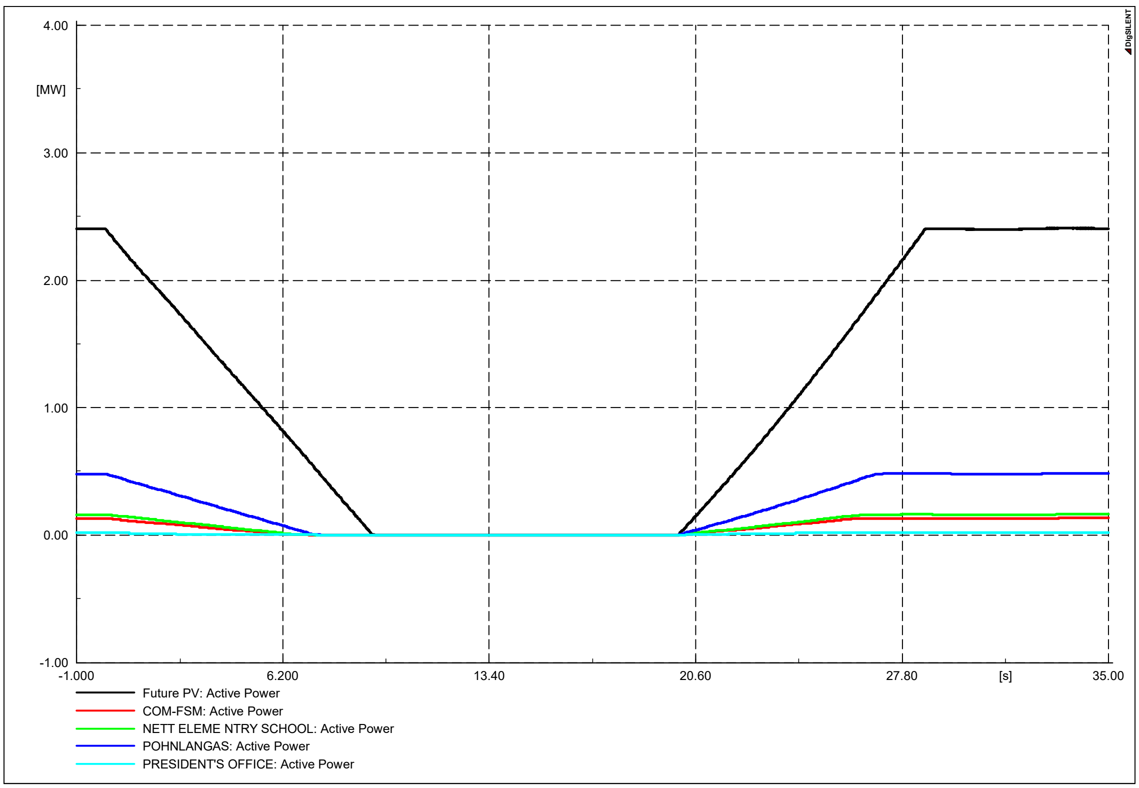


Immediately after the fault, the voltage at the monitored bus (substation busbar) drops to 0 pu. Upon the tripping of the Western feeder, the voltage recovers very quickly (within a few milliseconds) and rises to around 1.2 pu before returning to nominal value again. The operational generators in the system remain in synchronisation without pole-slip subsequent to the fault event however there is a significant rotor swing experienced at the hydro power station and at G1. System frequency rises quite significantly outside the ±2% bandwidth reaching a high of 65 Hz after fault inception and remaining at this high level for the duration of the study.

Reduction/increase of PV output to/from maximum/0MW (AVR off)

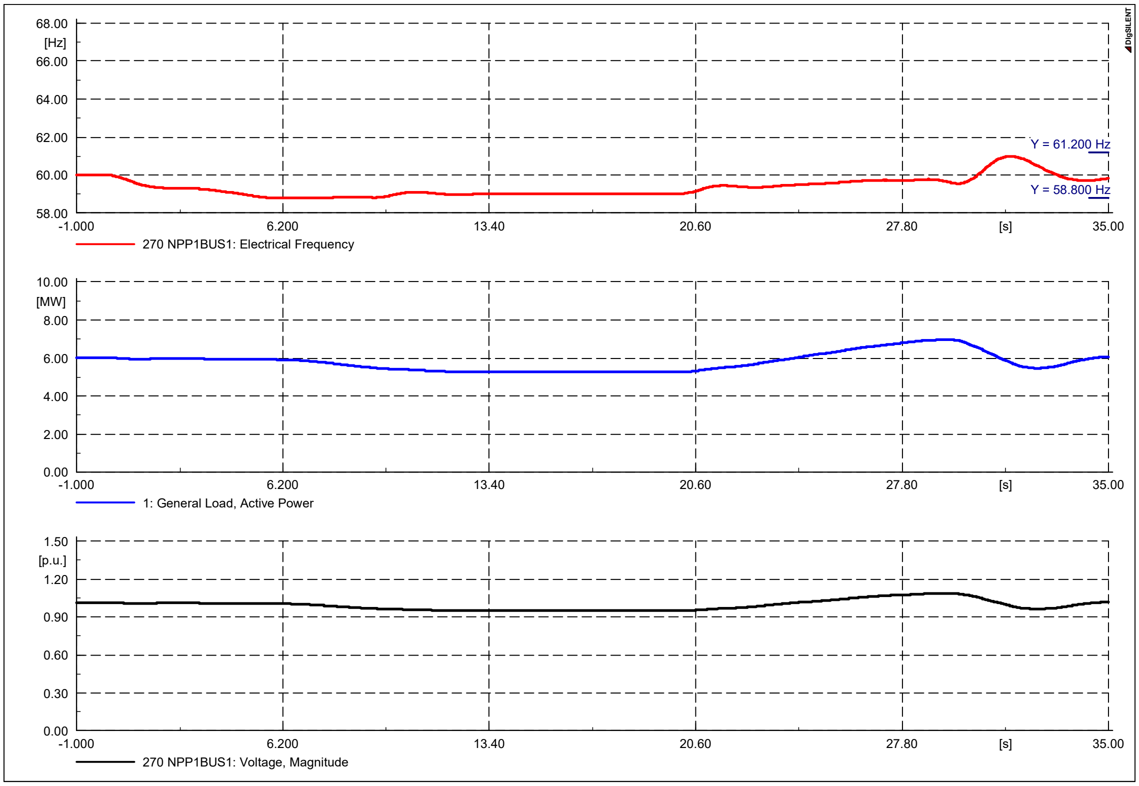
The PV sites connected to the island network were assumed to be operating at 80% output before being simultaneously reduced to 0 MW (to reflect sudden cloud coverage), and then returning to 80% output after 20 s. The new PV generation is set to maximum output of 2,400 kW. The PV output is shown in Figure 2-38.

Figure 2-38: PV MW output of all sites on Pohnpei



The voltage and frequency responses are shown in Figure 2-39.

Figure 2-39: Voltage and frequency response to changing PV MW output



As the MW output of the PV generators decreases, the frequency decreases accordingly to sit on the limit of 58.8 Hz for the duration that the PV output is reduced to 0 kW. The voltage reduces to around 0.94 pu when the PV generators ramp down and rises to 1.1 pu when they ramp up again before reducing back down to around nominal. The simulation results indicate that in this operational scenario the system is capable of withstanding the drop and rise of PV generation within the given kW capacity and kW output level.

2.2.5 Summary of power system study results

The results presented in the previous sections show that under normal steady state operating conditions i.e. maximum and minimum demand, the network has no thermal or voltage issues and it also has some headroom for future demand growth.

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. The system was assessed with and without the existing penetration of PV generation to understand if this impacts system stability. From the simulation results it is evident there is insignificant impact with PV generation added however there are still various instances where the system performance exceeds the allowable limits of frequency and voltage. Changes to the generation dispatch were also assessed to see the benefit of having more conventional generation online, and the provision of spinning reserve. The changes to the generation dispatch profile of the conventional generators improved the response of the system however, there do remain some issues. These are summarised in Table 2-12. The addition of 1,200kW and 2,400kW of PV generation to the system were also studied with different conventional generation dispatch profiles.

Table 2-12: Summary of Stability Studies with increasing penetrations of VRE

Study	Loss of largest generator	Loss of Western feeder	Loss of Eastern feeder	Fault at power station then trip of Western feeder	Increase/ decrease of PV
Existing system, no PV	Low frequency	High frequency (marginal)	High frequency (marginal) & small oscillations in P	Large frequency oscillations (high & low), high voltage (1.2pu), large rotor angle swings (70deg)	-
Existing system, with PV	Low frequency, low retained voltage	OK	High frequency (marginal) & small oscillations in P	Large frequency oscillations (high & low), high voltage (1.2pu), large rotor angle swings (75 deg)	OK
Existing system, with PV, varied dispatch	Frequency OK, 0.92pu retained voltage	-	-	-	-
1200kW additional PV	Frequency OK, 0.92pu retained voltage	Marginal deviation in frequency	High frequency & small oscillations in P	Large frequency oscillations (high & low), high voltage (1.1pu), large rotor angle swings (80 deg)	Low frequency, low retained voltage (0.75pu) (potential voltage collapse)
1200kW additional PV, varied dispatch	OK	-	-	Frequency out of limits (high & low)	Low retained voltage (0.9pu)
2400kW additional PV	Low frequency (marginal), 0.8pu retained voltage	High frequency	High frequency, high voltage 1.13pu	Frequency out of limits (high & low), large rotor angle swings (60 deg)	Marginal deviation in frequency, low retained voltage (0.8pu) (potential voltage collapse)
2400kW additional PV, varied dispatch	OK	-	-	High frequency, high voltage (1.2pu), large rotor angle swings (70 deg)	Marginal deviation in frequency

There are a variety of issues that need to be addressed to ensure the Pohnpei system can maintain stability in the event of a credible outage. The variation of the generation dispatch definitely improves the response of the system by providing more spinning reserve and fall back generation however more steps should be taken.

2.2.6 Recommendations for the present and future scenarios

The Pohnpei network has a reasonable penetration of renewable generation, 1,705 kW, currently connected to the system (about 16.5% of the available generation capacity). There are plans to connect more solar PV to the network in the coming years however it is not known exactly where and how much this will be.

The results of the stability studies indicate there must be improvements made to the network to ensure it is more robust. The voltage in many cases reaches ±20% of nominal and so increased voltage support is recommended to prevent such large fluctuations. The frequency response exceeds the 2% acceptable limit in many cases, however, in many other cases the violation is marginal and so the introduction of battery storage to the island could help to improve the frequency response and keep it within the limits.

Support at the hydro power station to maintain stability is recommended as it is particularly affected by large rotor angle swings upon the loss of the feeders since it is connected to the Eastern feeder and so is particularly impacted by this change in power system configuration.

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.

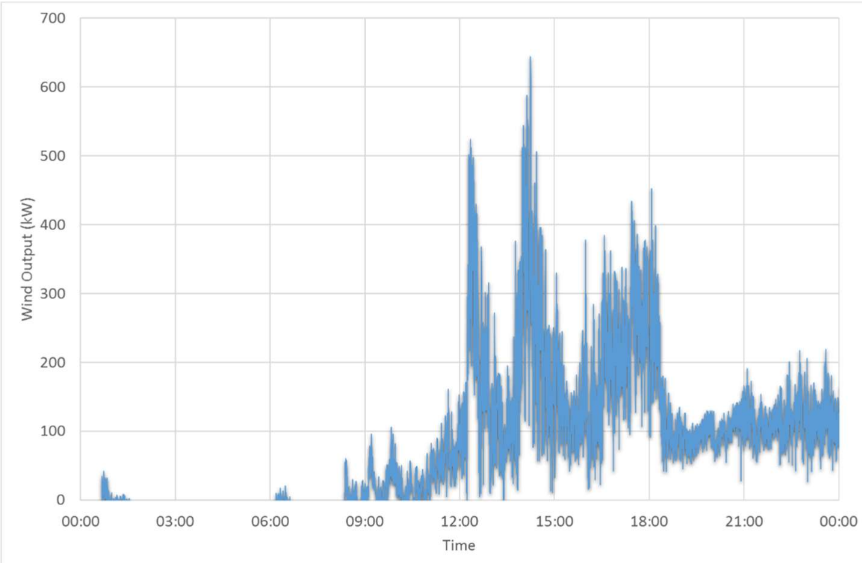
The studies done here are to examine the current performance of the diesel generators and batteries in Pohnpei and the technical limit with the economic impact for increasing solar power.

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 which, has been used as an example.

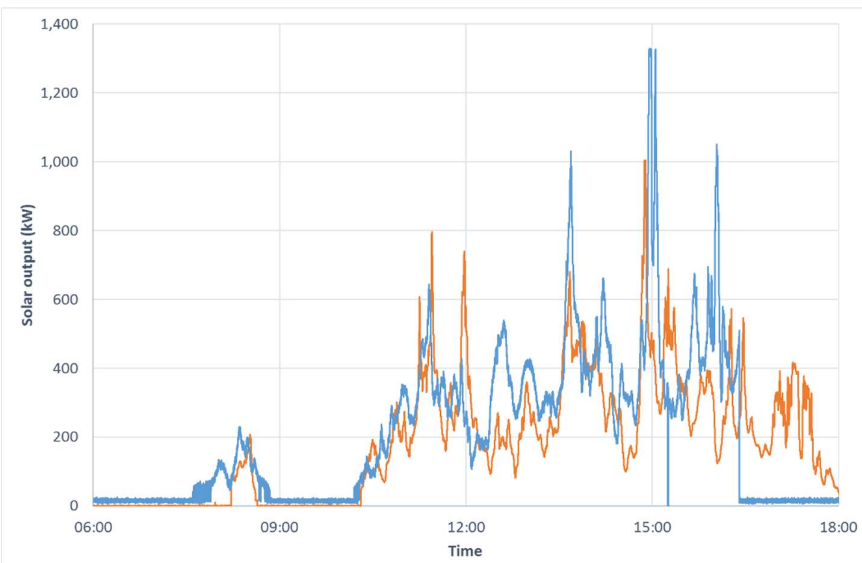
Figure 3-1. Wind power for recorded on 10 December 2016 at Aleipata



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 gird where multiple turbines that are geographically spread.

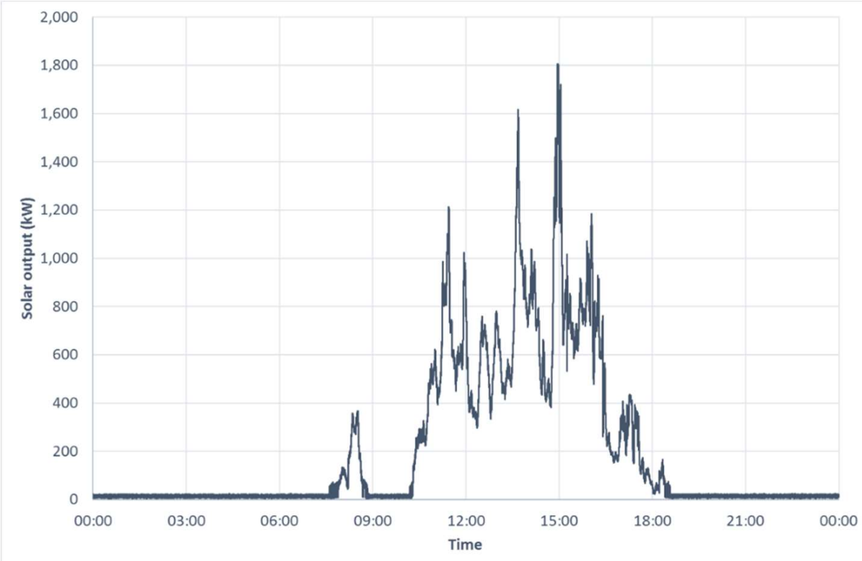
Figure 3-2 shows the individual outputs (measured at one second intervals) from two solar PV plants that are approximately 1 km apart.

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 will determine suitable solutions for short-term dynamic stability. In particular, the analysis will determine 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 on the next sections.

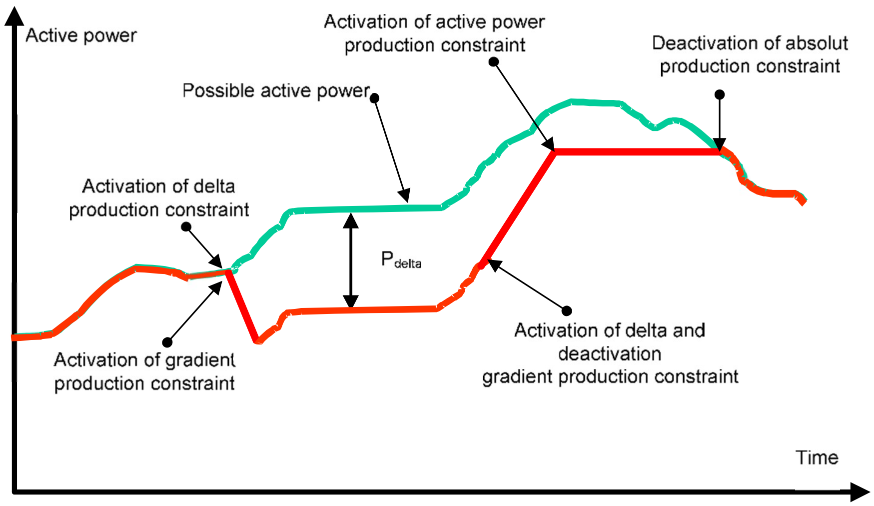
3.1.2 VRE enhanced frequency control provision and calculation of costs

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

<u>**Option 1**: The VRE plants are backed off from their full instantaneous maximum capacity, i.e. their outputs are limited</u>. 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

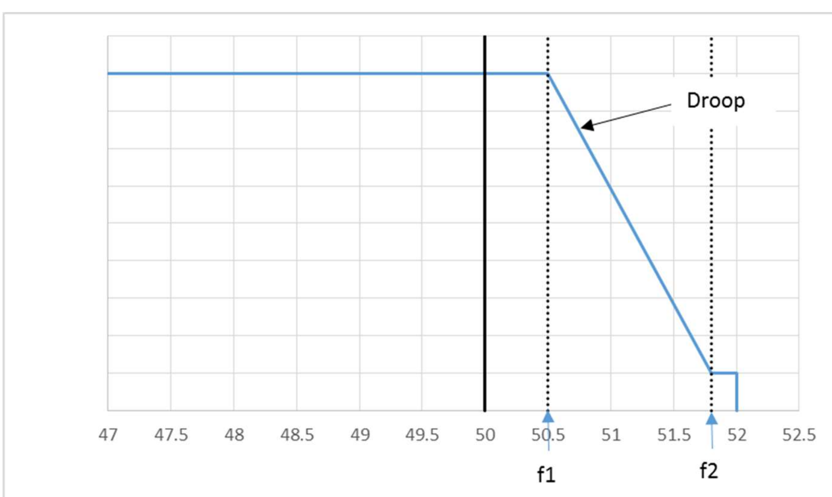
curtailed but there is no reduction in capital cost. Thus, if before implementing the scheme, the plant was generating at an average cost of $0.10 / kWh, after introduction of the scheme, the plant's average cost will be increased to $0.11 / kWh as the scheme reduces the generator output by 10%.

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.

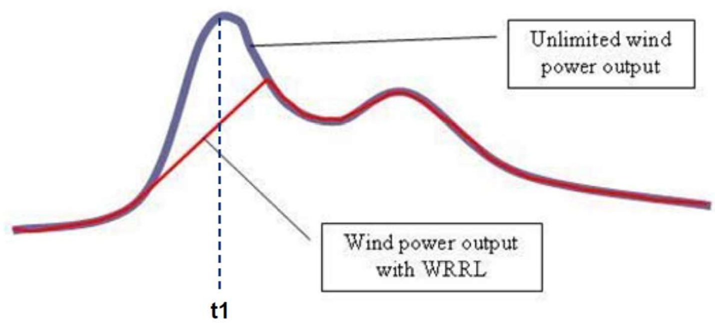
Figure 3-5 Typical VRE high frequency response only



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 sooth 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)1



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[2]. 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[3].

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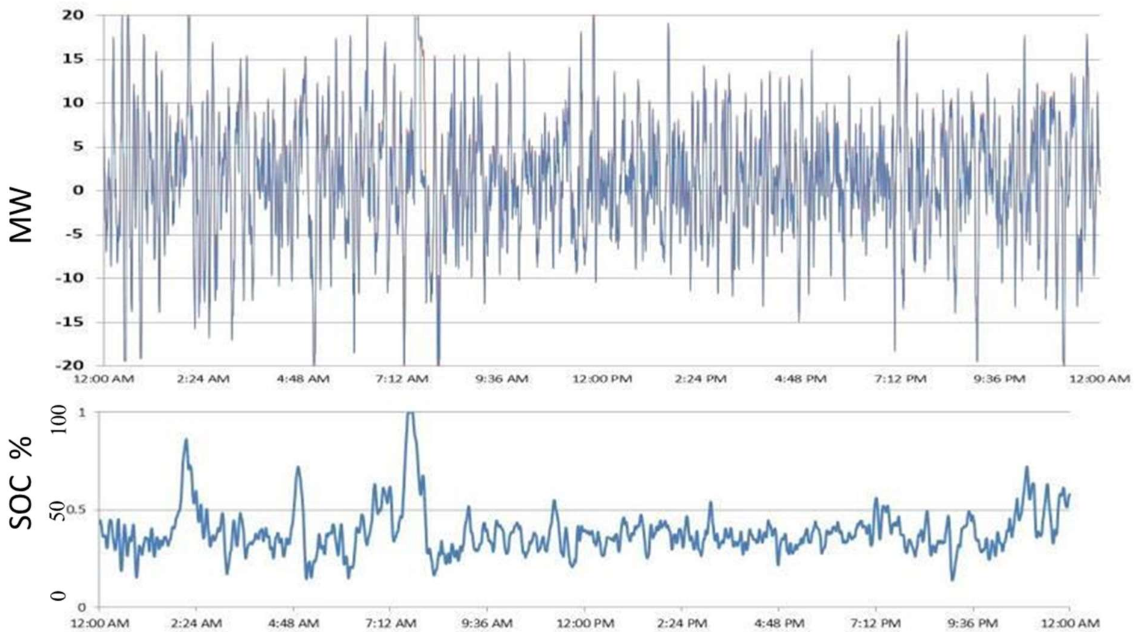
[1] AESO System Impact Studies, Phase 2 Assessing the impacts of increased wind power on AIES operations and mitigating measures, July 2006

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

[3] 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. Hydro and pump 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[4]. 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.

[4] 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) [5]. 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[6] and for NaS US$2,200 /kWh[7]. The cost of inverter is estimated to be US$1,000 / kW[8].

Bloomberg estimates Li Ion batteries to be under US$ 200 / kWh[9] and a recent report from USTDA has batteries at US$375 / kWh and inverters at US$300 / kWh [10]

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 Pohnpei 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[11], 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

[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
[6] Energy Master Plans for the Federated States of Micronesia, Castalia, 2018
[7] 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
[8] Energy Master Plans for the Federated States of Micronesia, Castalia, 2018
[9] https://www.bloomberg.com/news/articles/2018-03-08/the-battery-will-kill-fossil-fuels-it-s-only-a-matter-of-time
[10] US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017
[11] US TRADE AND DEVELOPMENT AGENCY, South Africa Energy Storage, Technology and Market Assessment, March 2017

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©.

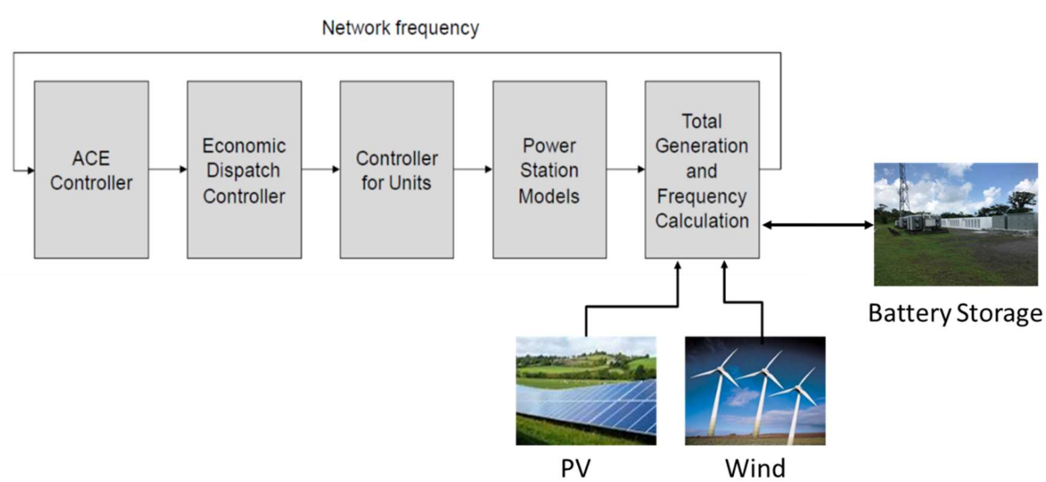
The Generation Dispatch Analysis Tool is used for four main purposes

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 Pohnpei 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 Pohnpei, 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 Pohnpei studies

The models developed for Pohnpei are based on hourly data records received for the week of 06 August 2018. The real time PV data was obtained from recorded 2 second data from the reservoir at Majuro where we have records for the 0.6 MW PV plant. This is the same plant size as for Pohnlangas PV plant. For the Solar PV that is installed in town we have taken the PV records from Majuro reservoir for another ‘similar’ day and scaled this to 0.4 MW to account for school PV and other sites.

The weekend demand profile is taken from data provided by Pohnpei as recorded on Sunday the 12 August 2018, shown in Figure 3-9.

The weekday demand profile is taken from data provided by Pohnpei as recorded on Wednesday 08 August 2018, as shown in Figure 3-10.

Figure 3-9 Pohnpei demand profile for weekend recorded on 12 August 2018

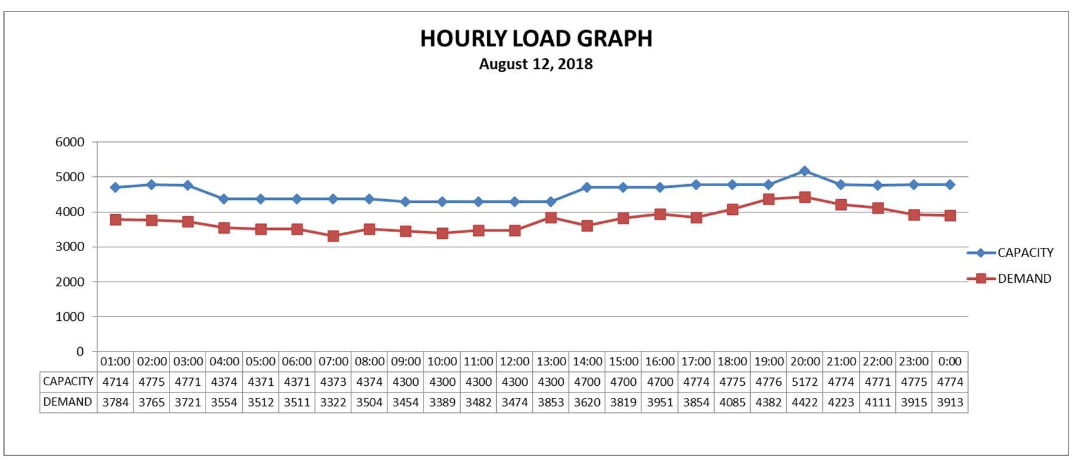
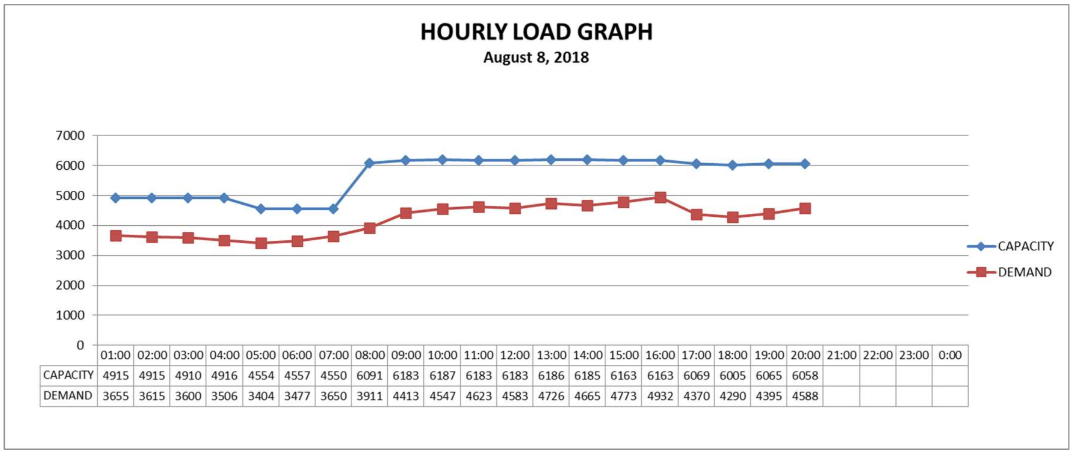


Figure 3-10 Pohnpei demand profile for weekday recorded on 08 August 2018



The names in the model are made generic to reflect that this is not the actual output of any specific unit as it will be 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
NPP1 U2	1650	Cat Diesel	D1
NPP1 U3	1650	Cat Diesel	D2
NPP1 U4	1650	Cat Diesel	D3
NPP4 U1	400	Cat Diesel	D4
NPP4 U 2	400	Cat Diesel	D5
NPP 5 U1	350	Volvo	D6
NPP 5 U2	350	Volvo	D7
NPP 5 U3	350	Volvo	D8
NPP 5 U4	350	Volvo	D9
Nanpil Hydro	500	Hydro	H1
School and COM-FSM	400	PV	PV1
Pohnlangas	600	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: Pohnpei diesel generation parameters

Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei_12MWPV_8MW_8MWh_Batt._AGC.mat

File View Simulation

Data | Station

Diesel | PV | Wind | Batt | Hydro

	D1	D2	D3	D4	D5	D6	D7	D8	D9
MCR	1.6500	1.6500	1.6500	0.4000	0.4000	0.3500	0.3500	0.3500	0.3500
Unit Inertia	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500	0.4500
Ramp Rate	1.6500	1.6500	1.6500	0.4000	0.4000	0.3500	0.3500	0.3500	0.3500
Maximum Generation	1.6500	1.6500	1.6500	0.4000	0.4000	0.3500	0.3500	0.3500	0.3500
Minimum Generation	0.1650	0.1650	0.1650	0.0800	0.0800	0.0700	0.0700	0.0700	0.0700
Spinning Capability	1.6500	1.6500	1.6500	1.6500	0.6000	0.3500	0.3500	0.3500	0.3500
Nonspinning Capability	1.6500	1.6500	1.6500	1.6500	0.6000	0.3500	0.3500	0.3500	0.3500
AGC On	✓	✓	✓	✓	✓	✓	✓	✓	✓
Model Name	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1
Frequency Deadband	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03
Lower Frequency Limit	-1	-1	-1	-1	-1	-1	-1	-1	-1
Upper Frequency Limit	1	1	1	1	1	1	1	1	1
Droop	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800	0.0800

	D1	D2	D3	D4	D5	D6	D7	D8	D9
Droop Control	0	0	0	0	0	0	0	0	0
T1	15	15	15	15	15	15	15	15	15
T2	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000	0.2000
T3	5	5	5	5	5	5	5	5	5
T4	5	5	5	5	5	5	5	5	5
T5	5	5	5	5	5	5	5	5	5
T6	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500	0.2500

	D1	D2	D3	D4	D5	D6	D7	D8	D9
Megawatts	[0 0.456 0.91...	[0 0.456 0.91...	[0 0.456 0.91...	[0 0.1 0.2 0.3 ...	[0 0.1 0.2 0.3 ...	[0 0.09 0.18 0...	[0 0.09 0.18 0...	[0 0.09 0.18 0...	[0 0.09 0.18 0...
Cost	[456 258 235 ...	[456 258 235 ...	[456 258 235 ...	[456 258 235 ...	[456 258 235 ...	[415 240 200 ...	[415 240 200 ...	[415 240 200 ...	[415 240 200 ...

Table 3-3: Pohnpei PV parameters

Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei_base_4.mat

File View Simulation

Diesel | PV | Wind | Batt | Hydro

	PV1	PV2	PV3
	0.4000	0.6000	0.0200
	0	0	0
	78	78	78
	0.4000	0.6000	0.0200
	0	0	0
	0.4000	0.6000	0.0200
	0	0	0
	✓	✓	✓
	RecordedData	RecordedData	RecordedData
	0.0400	0.0400	0.0400
	-1	-1	-1
	0	0	0
	0.0100	0.0100	0.0100

	PV1	PV2	PV3
	Projects\Pohnpei\Data\PV_1.csv	Projects\Pohnpei\Data\PV_2.csv	Projects\Pohnpei\Data\PV_3.csv
	0	0	0

	PV1	PV2	PV3
	[0 0.35 0.7 1.05 1.4]	[0 0.35 0.7 1.05 1.4]	[0 0.35 0.7 1.05 1.4]
	[1 1 1 1 1]	[1 1 1 1 1]	[1 1 1 1 1]

The fuel cost curve that plots power against US$/kWh for CAT units, as shown in Figure 3-11 below, is based on CAT manufacturers diesel generator's performance12. The cost curve was drawn for a fuel cost of US$ 0.829 per litre13. The minimum generation is set to be at 20% of the rated capacity as a typical minimum value. Similar calculations were performed for Volvo units14, as shown in Figure 3-12.

Figure 3-11 CAT diesel units cost curve

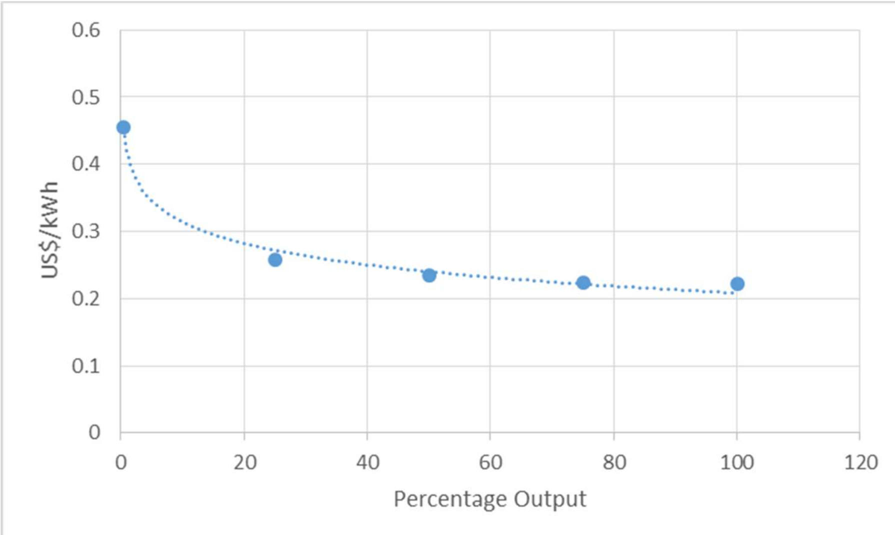
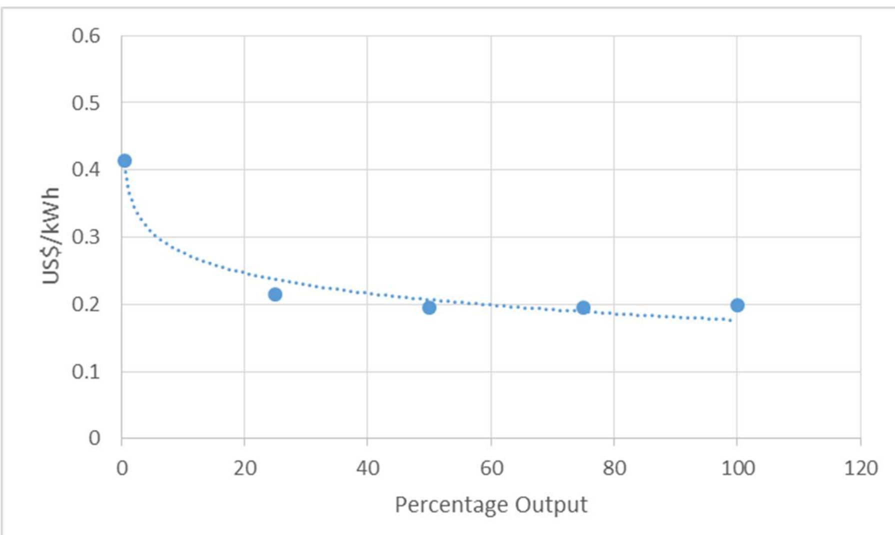


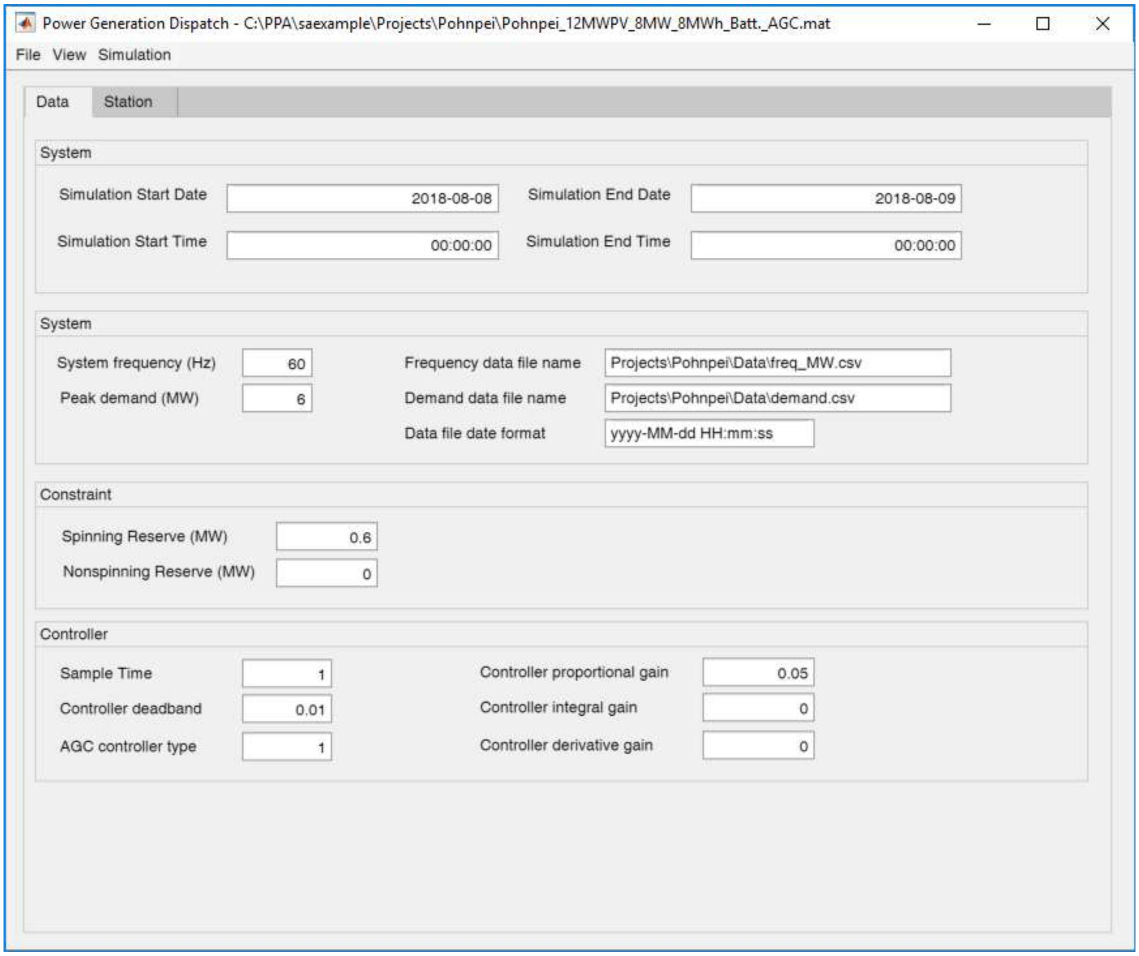
Figure 3-12 Volvo diesel units cost curve



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 Pohnpei the simulation is run every second for a day.

[12] Catepillar manual CAT XQ2000
[13] Email correspondence with Pohnpei, August 2018
[14] 3.1.1 GESAN DVS630 datasheet.pdf

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

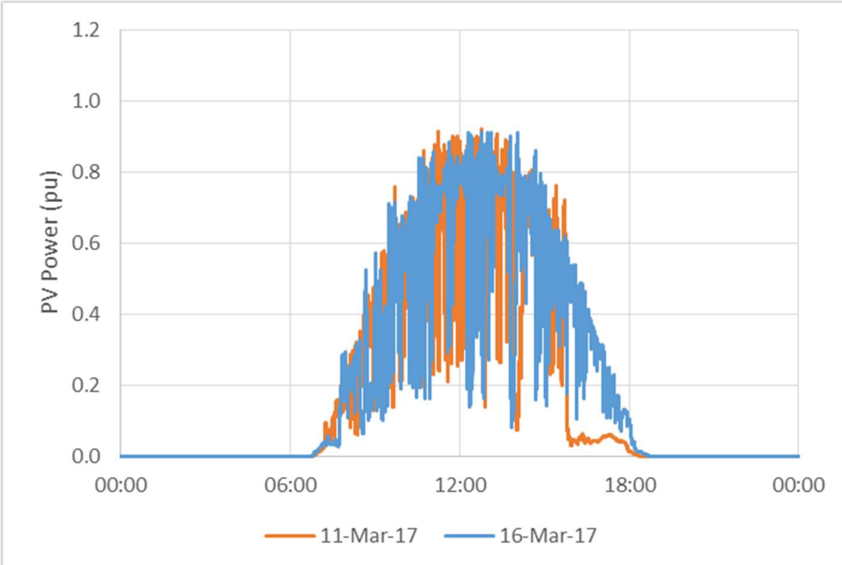
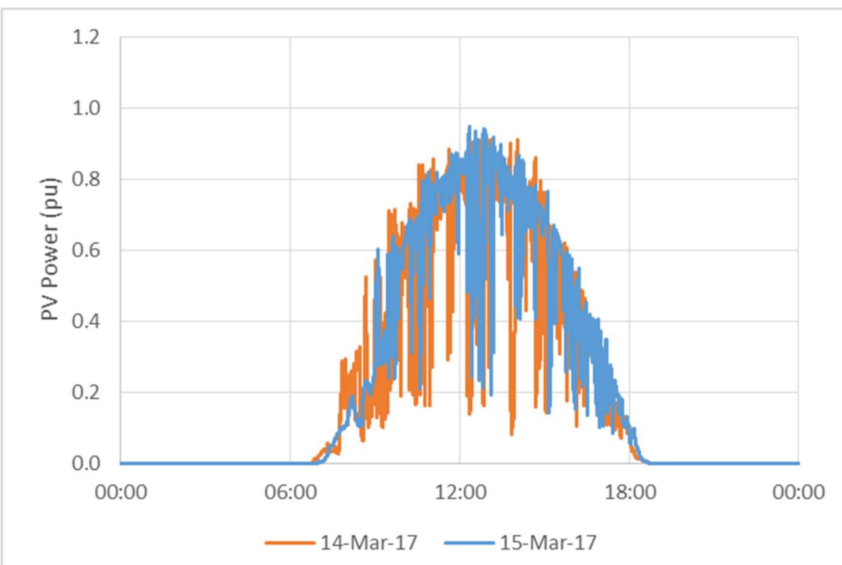


Figure 3-15 Recorded 'normalised' one second PV output Base case 2 and 4



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	12 Aug 2018	1	20%	11&16/03/17	AGC	off
1	12 Aug 2018	3	60%	11&16/03/17	AGC	off
2	12 Aug 2018	3	60%	11&16/03/17	AGC	1 MW / 1 MWh on Gov
3	12 Aug 2018	6	120%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
4	12 Aug 2018	9	180%	11&16/03/17	AGC	4 MW / 4 MWh on Gov & AGC
5	12 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC
6	12 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
Base 2	12 Aug 2018	1	20%	14&15/03/17	AGC	off
7	12 Aug 2018	3	60%	14&15/03/17	AGC	off
8	12 Aug 2018	3	60%	14&15/03/17	AGC	1 MW / 1 MWh on Gov
9	12 Aug 2018	6	120%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
10	12 Aug 2018	9	180%	14&15/03/17	AGC	4 MW / 4 MWh on Gov & AGC
11	12 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC
12	12 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
Base 3	8 Aug 2018	1	20%	11&16/03/17	AGC	off
13	8 Aug 2018	3	60%	11&16/03/17	AGC	off
14	8 Aug 2018	3	60%	11&16/03/17	AGC	1 MW / 1 MWh on Gov
15	8 Aug 2018	6	120%	11&16/03/17	AGC	2 MW / 2 MWh on Gov
16	8 Aug 2018	9	180%	11&16/03/17	AGC	4 MW / 4 MWh on Gov & AGC
17	8 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC
18	8 Aug 2018	12	240%	11&16/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off
Base 4	8 Aug 2018	1	20%	14&15/03/17	AGC	off
19	8 Aug 2018	3	60%	14&15/03/17	AGC	off
20	8 Aug 2018	3	60%	14&15/03/17	AGC	1 MW / 1 MWh on Gov
21	8 Aug 2018	6	120%	14&15/03/17	AGC	2 MW / 2 MWh on Gov
22	8 Aug 2018	9	180%	14&15/03/17	AGC	4 MW / 4 MWh on Gov & AGC
23	8 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC

24	8 Aug 2018	12	240%	14&15/03/17	AGC	8 MW / 8 MWh on Gov & AGC – diesel off

3.3.1 Base Case 1 & Simulation cases 1 – 6 Weekend (12 August 2018) 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 day. Figure 3-16 shows the simulation of generation unit outputs for Saturday 12 August 2018, with PV1 set at 0.4 MW & PV 2 set at 0.6 MW. Only the CAT units are on AGC to represent the current situation. 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 without the general noise from a varying demand. 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 12 August 2018 with current installed PV

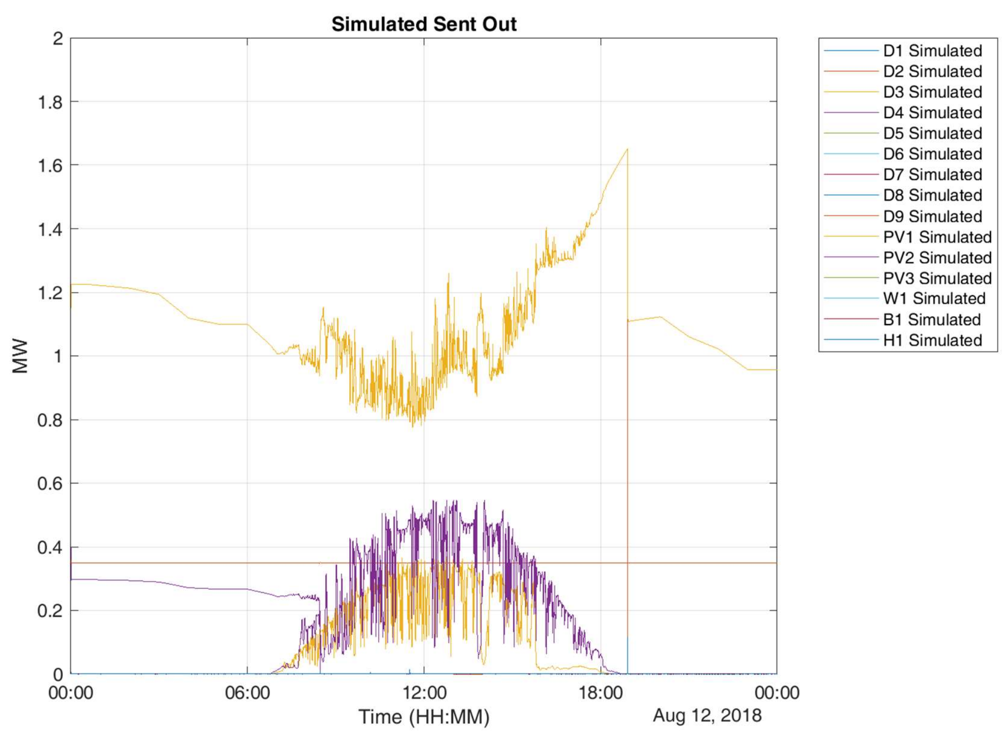
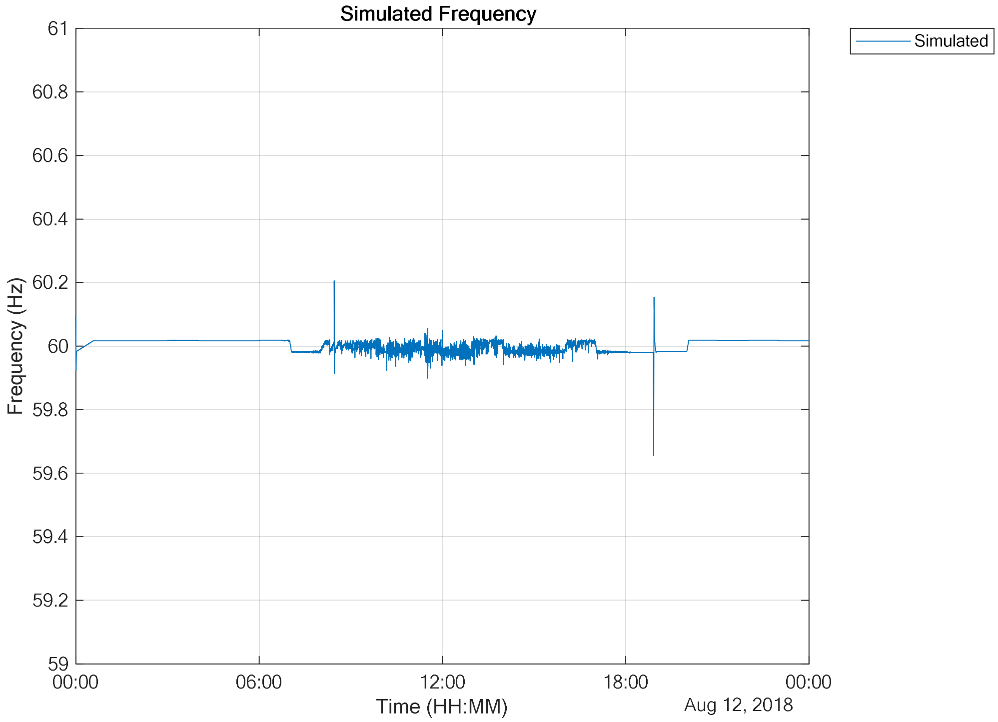


Figure 3-17 Simulated frequency on weekend with current installed PV



<u>Case 1: Weekend (12 August 2018) - 3 MW of PV</u>

For Case 1 the PV power plants are set to 1.5 MW each giving a total PV of 3 MW, CAT diesel units perform the frequency control, as shown in Figure 3-18. The frequency is acceptable but there are frequency excursions where the CAT 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 3 MW PV

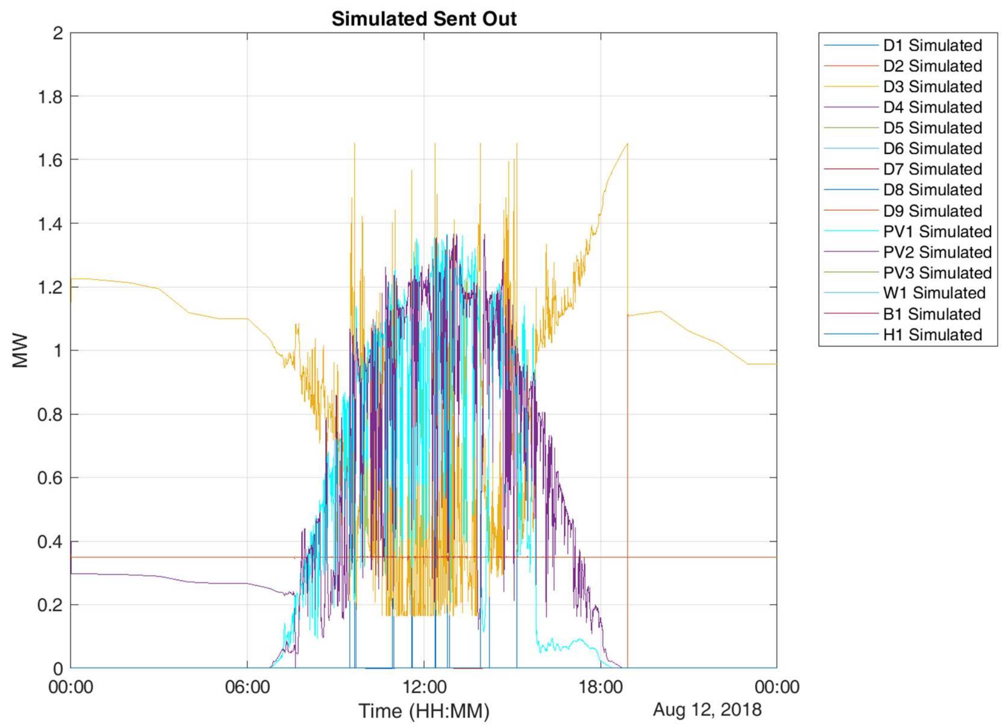
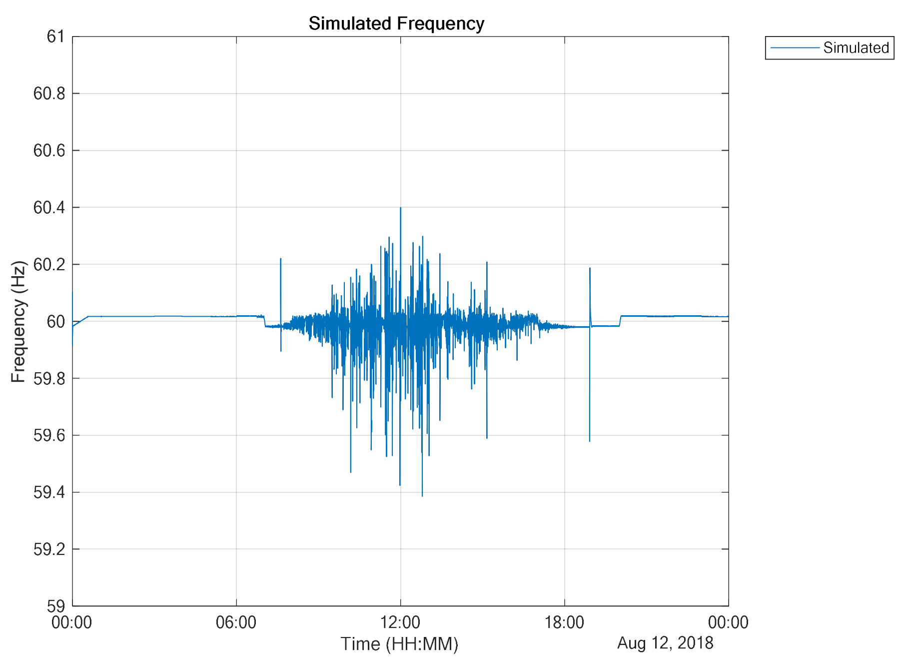


Figure 3-19 Simulated frequency on weekend with 3 MW PV

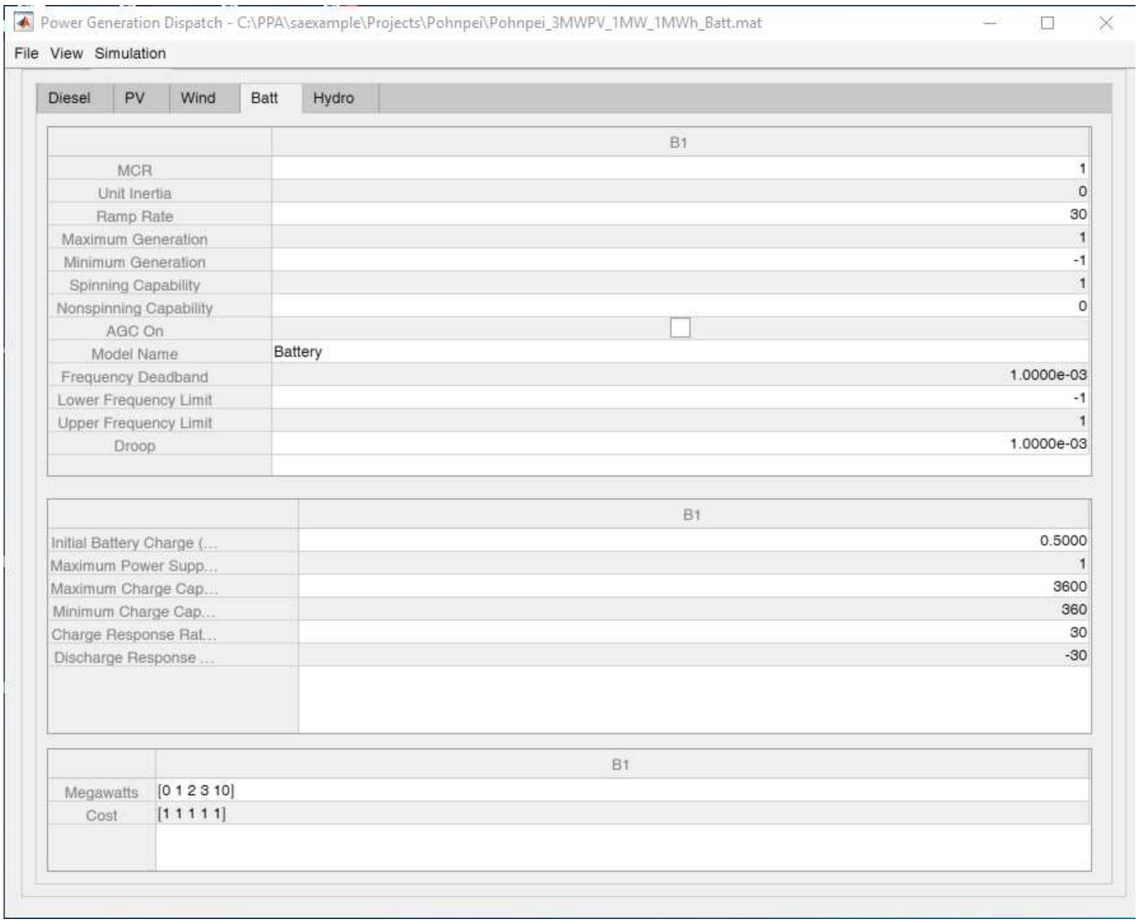


<u>Case 2: Weekend (12 August 2018) - 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control</u>

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 1 MW / 1 MWh battery costs US$ $104,910 per annum or US$ 287.43 per day.

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



The simulated frequency improves when 1 MW battery is on primary frequency control only, as shown in Figure 3-21. The battery is utilised for half its output and the response is enough to prevent frequency excursions, as shown in Figure 3-22. The diesel fuel costs remain the same at $16,805 as for case 1 showing the battery is just performing primary frequency control and the battery on discharges a few percent. The net saving of US$ 873 is calculated for the simulation day including the battery costs.

Figure 3-21 Simulated frequency for weekend with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control

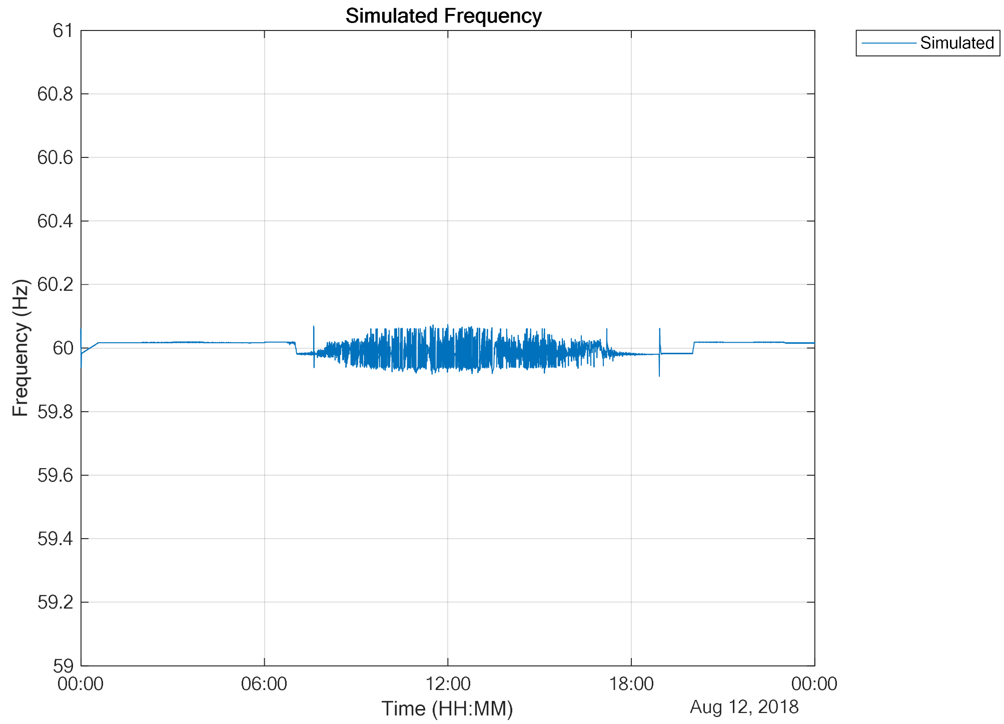
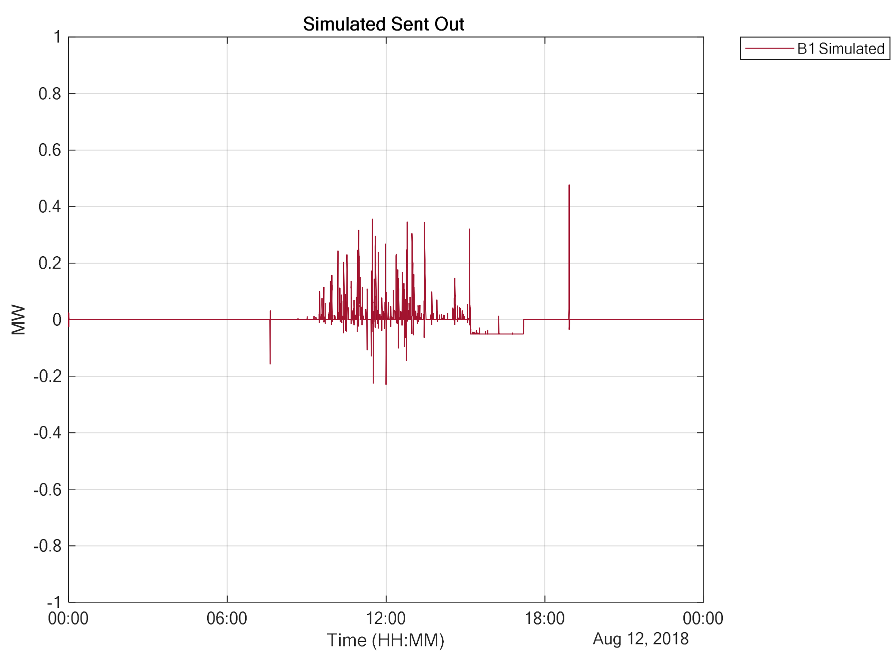


Figure 3-22 Simulated battery power for weekend with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control



Case 3: Weekend (12 August) - 6 MW of PV and 2 MW / 2 MWh battery on primary frequency control

For Case 3 the PV power plants are set to 3 MW each giving a total PV of 6 MW, all diesel units provides the secondary control under AGC to perform the control assisted by a 2 MW battery on AGC, as shown in Figure 3-23. 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

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 with the battery charging to 80%, as shown in Figure 3-25.

All of the available energy from the 6 MW of PV is used resulting which results in a fuel saving of US$5,139 and a net saving of US$ 2,133 for the simulation day.

Figure 3-23 Simulated generation for weekend with 6 MW of PV and 2 MW / 2 MWh battery on AGC and primary frequency control

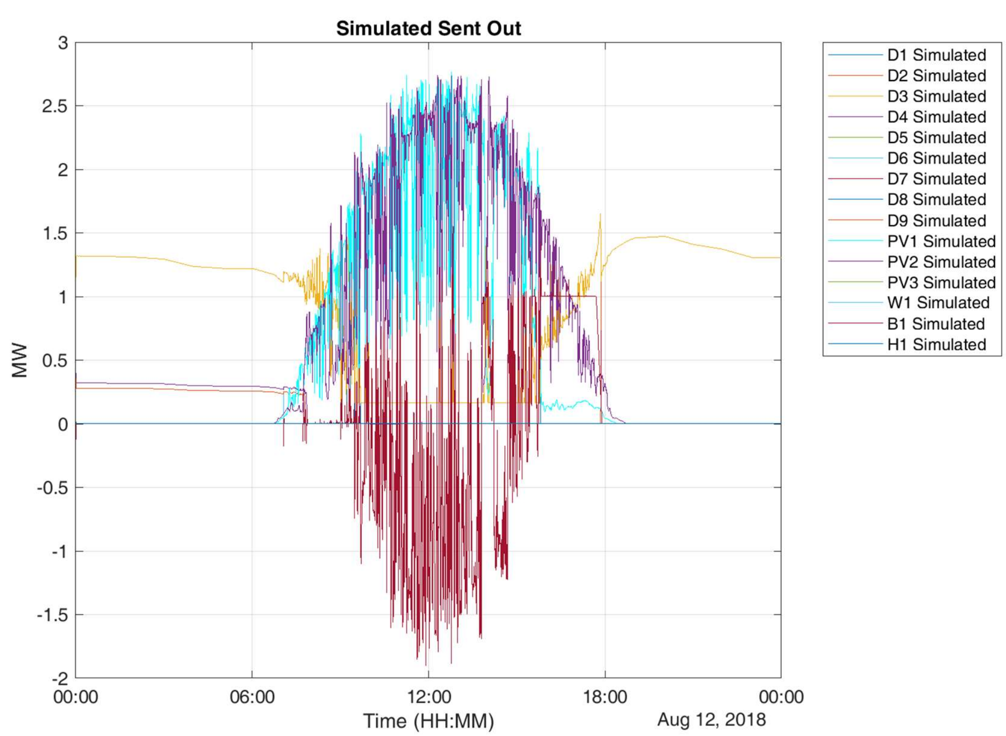


Figure 3-24 Simulated frequency for weekend with 6 MW of PV and 2 MW / 2 MWh battery on AGC and primary frequency control

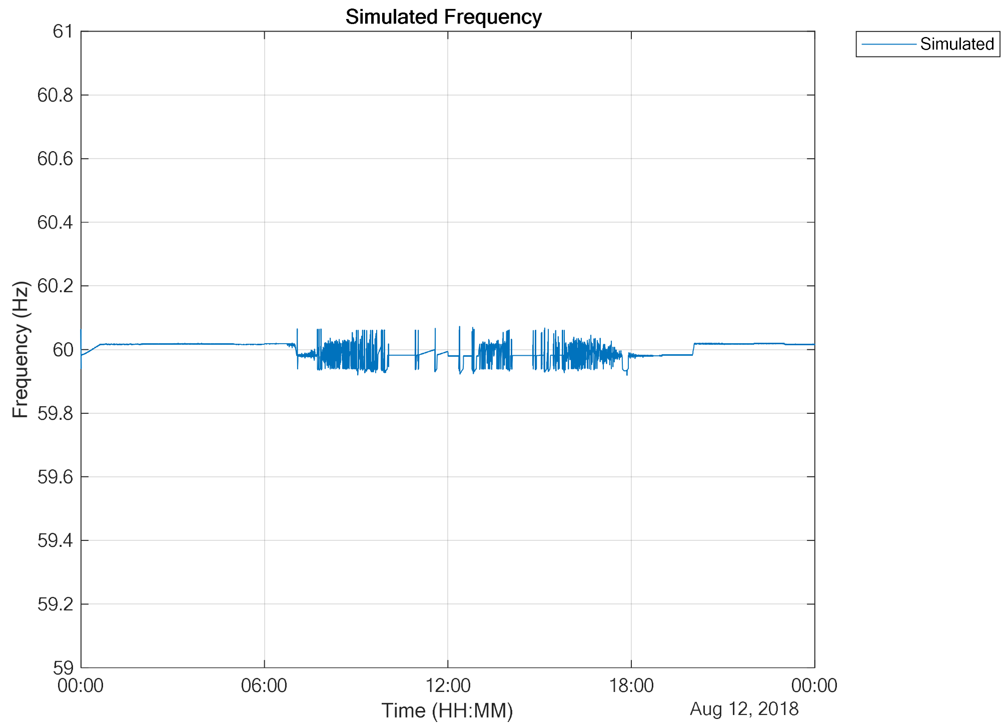
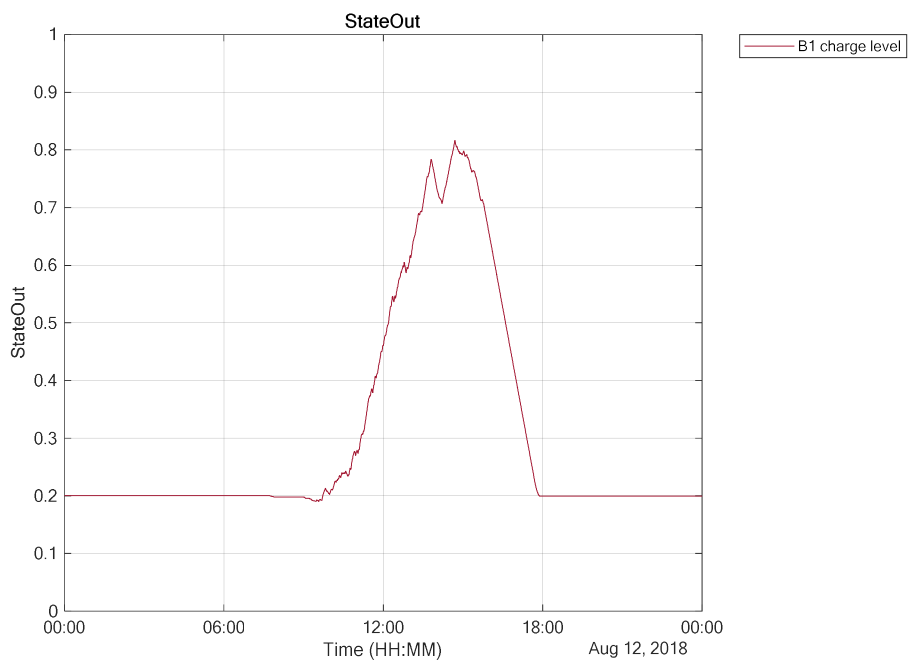


Figure 3-25 Simulated battery charge for weekend with 6 MW of PV and 2 MW / 2 MWh battery on AGC and primary frequency control



Case 4: Weekend (12 August 2018) - 9 MW of PV and 4 MW / 4 MWh battery on AGC

Case 4 is simulating an increase the PV to 9 MW and doubling the battery to 4 MW / 4 MWh on AGC.

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, by 15:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 22:00. The simulated diesel generator 1 output is at minimum generation for most of the period from 10:00 Hrs to 17:30 Hrs, as shown in Figure 3-28.

The daily fuel savings for Case 4 is $ 8,019 compared to $ 5,139 for Case 3. This increase is due to an increase PV output of 14 MWh and this case has a net savings of $ 2,980 for the simulation day.

Figure 3-26 Simulated battery output for weekend when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.

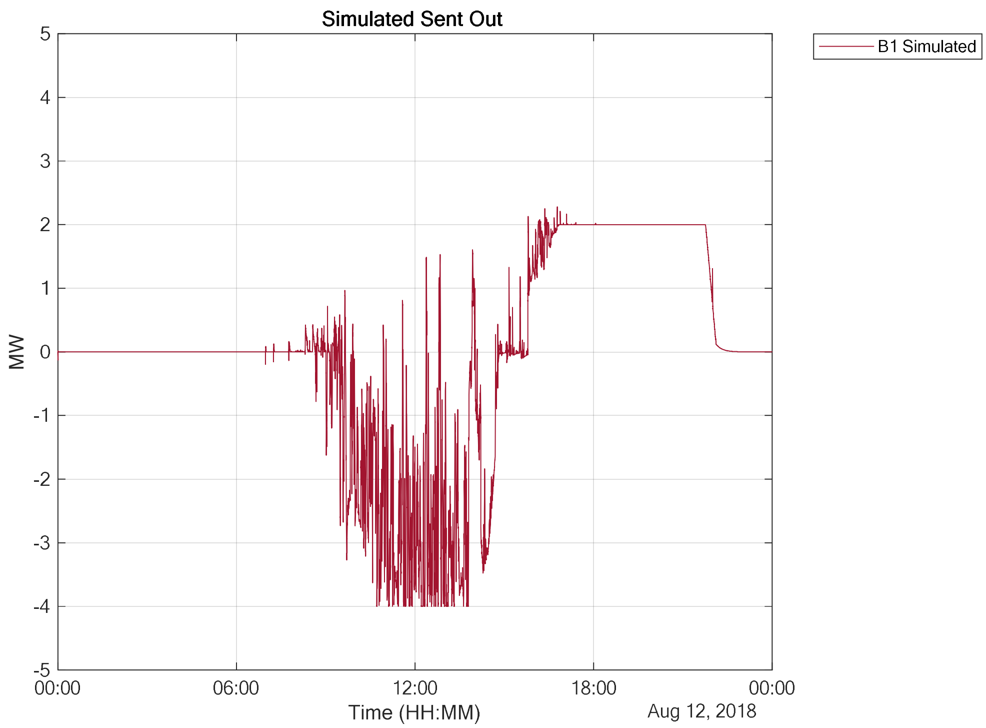


Figure 3-27 Simulated battery charge level for weekend when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.

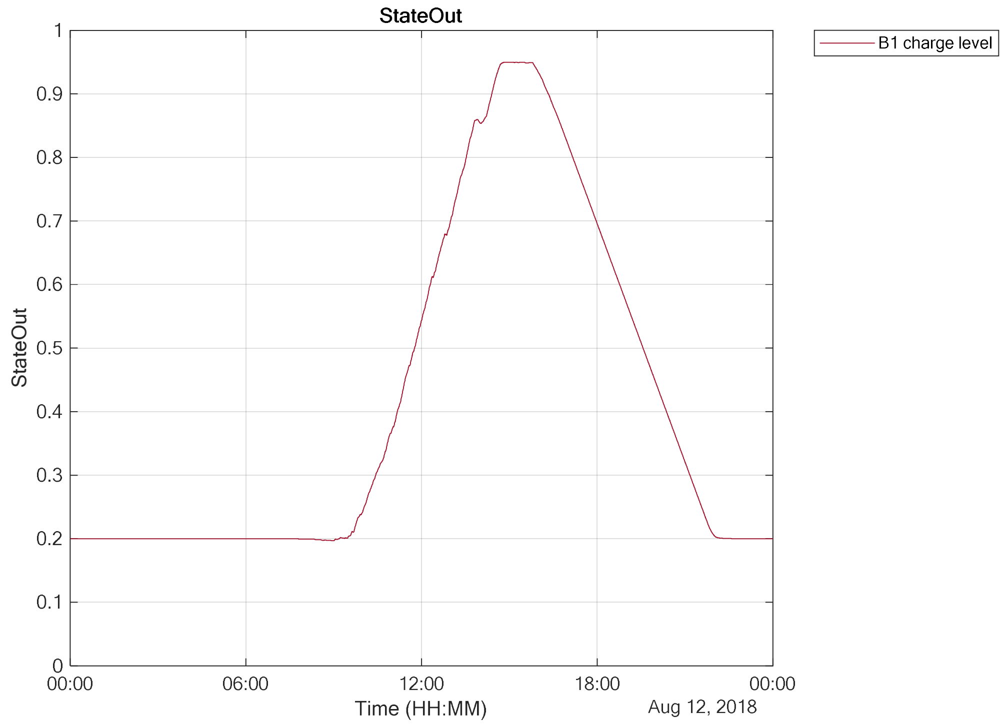
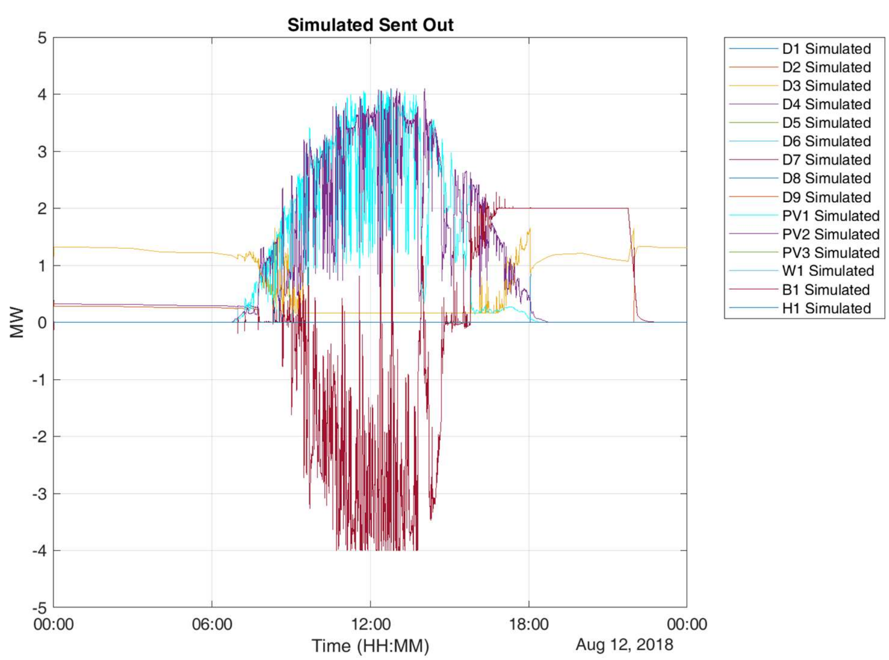


Figure 3-28 Simulated generator outputs for weekend when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.



Case 5: Weekend (12 August 2018) - 12 MW of PV and 8 MW / 8 MWh battery on AGC

This case is where the PV is increased to 12 MW and an 8 MW / 8 MWh battery is on AGC and primary frequency control. The simulated generation, as shown in Figure 3-29 that shows that the inverter size required of 8 MW is just sufficient.

The simulated frequency is within acceptable limits, as shown in Figure 3-29.. There are a no frequency excursions which means the inverter size is adequate, as shown in Figure 3-31. The battery charges to 60% by 16:00 and fully discharges by 24:00, as shown in Figure 3-31.

The energy from PV is nearly all utilised and thus the battery is adequately sized for this simulation day. This case has a net saving of $ 3,922 for the simulation day.

Figure 3-29 Simulated generator output for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.

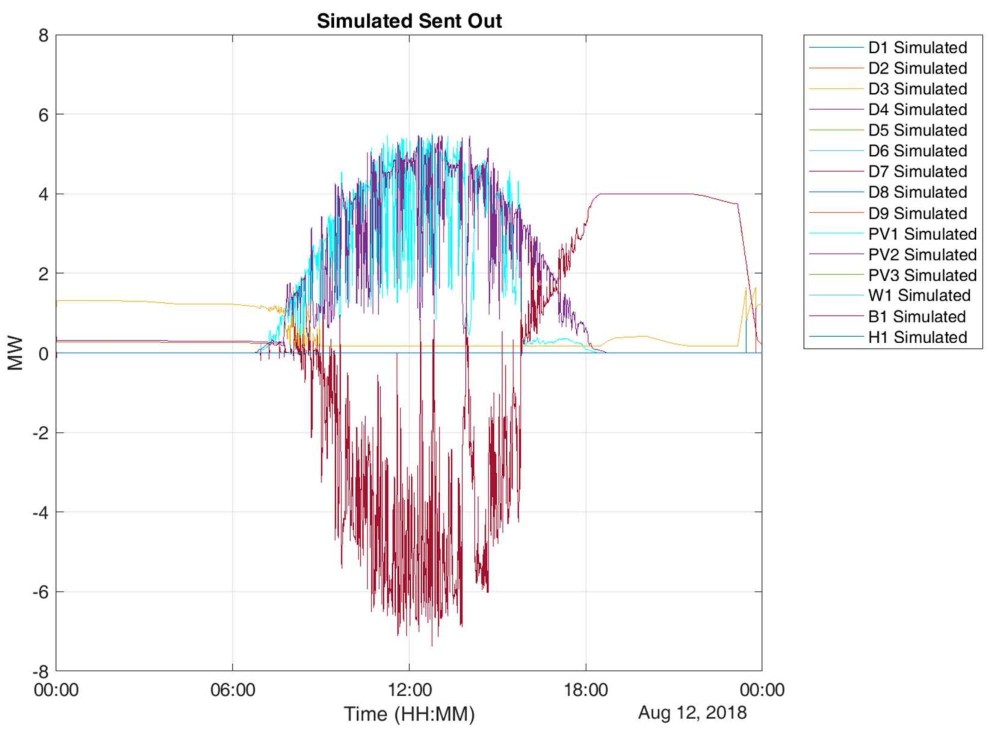


Figure 3-30 Simulated frequency for weekend when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

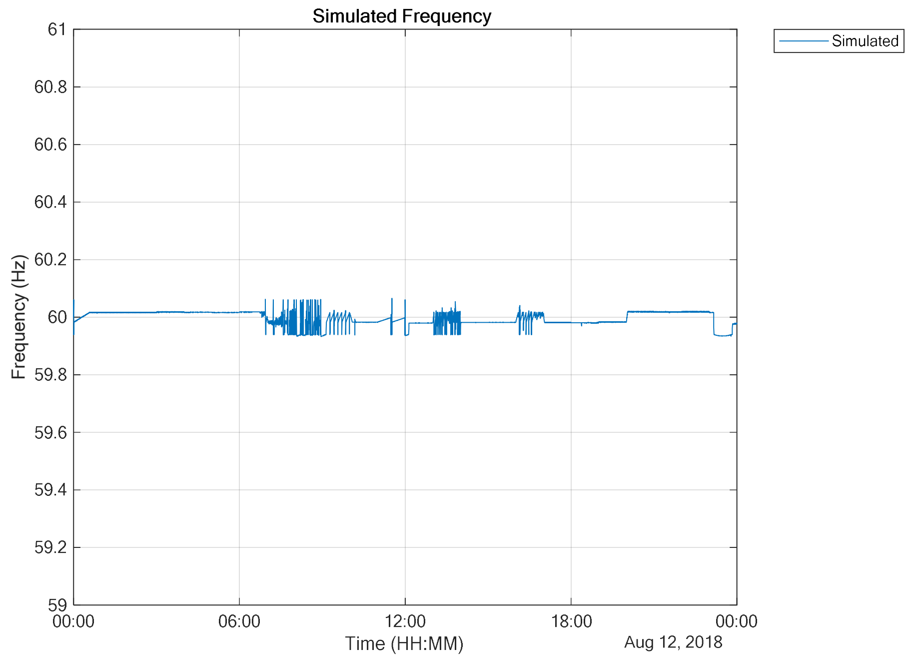
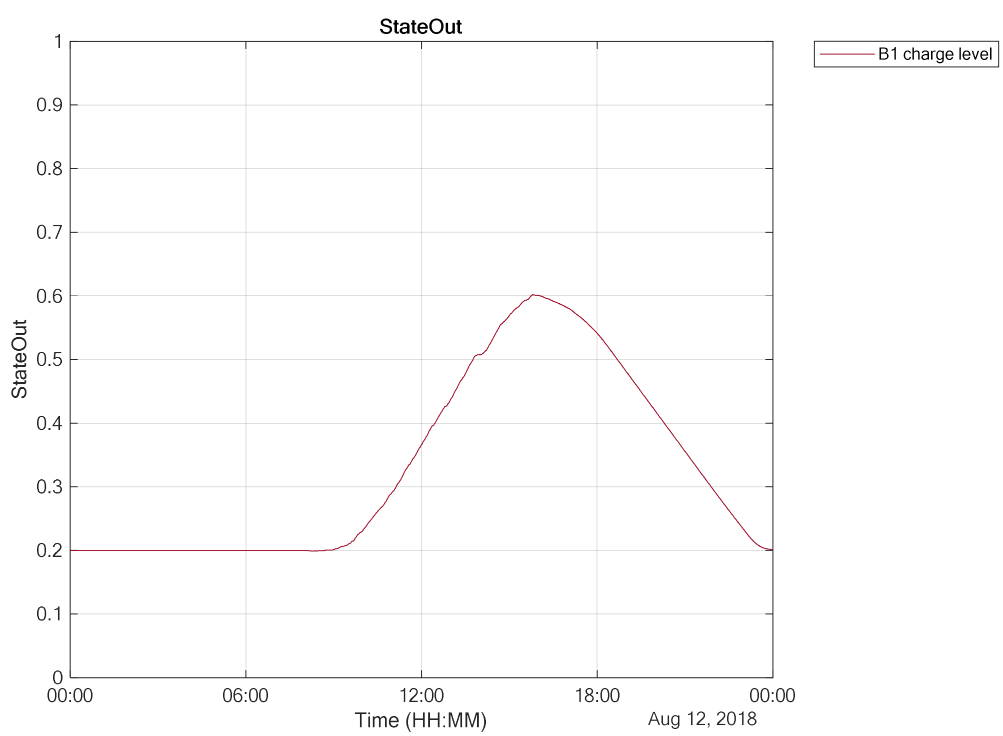


Figure 3-31 Simulated battery charge for weekend when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.



Case 6: Weekend (12 August 2018) - 12 MW of PV and 8 MW / 8 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 0.6 MWh of PV power is spilt which equates to 1.0 % of energy lost. Figure 3-32 shows that all diesel generators are off from 10:00 to 18:00.

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 60% of full charge, as shown in Figure 3-34, by 16:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until 23:30. 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 $113 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 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.

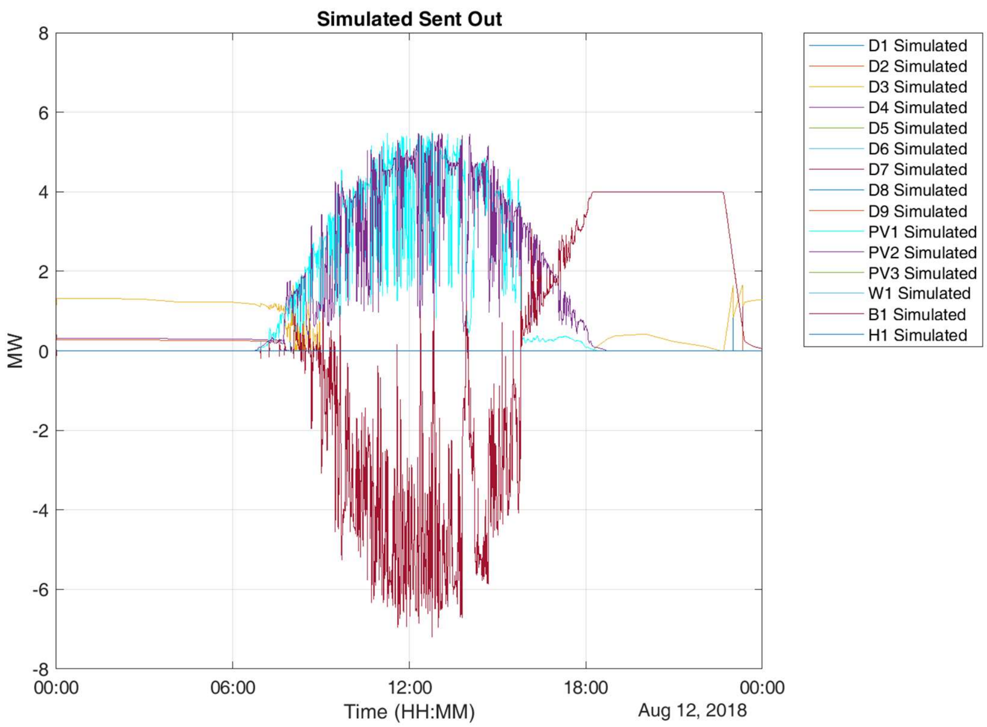


Figure 3-33 Simulated battery output for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to switch off.

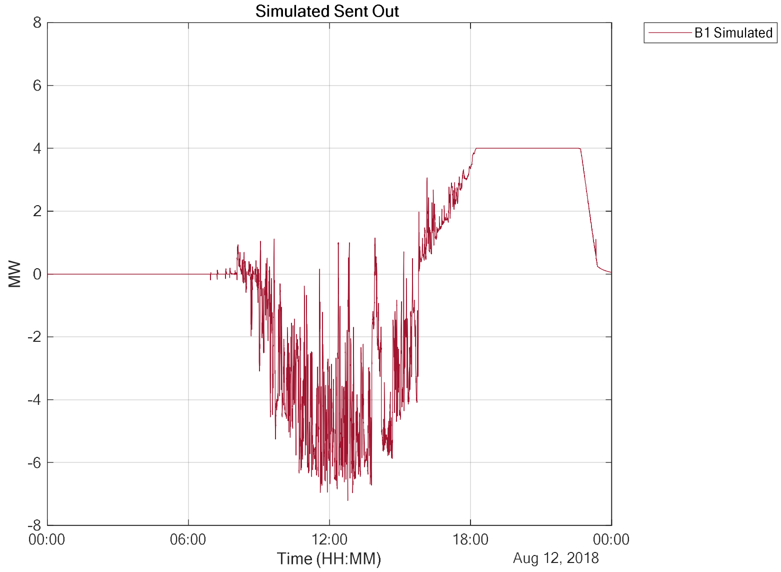


Figure 3-34 Simulated battery charge level for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.

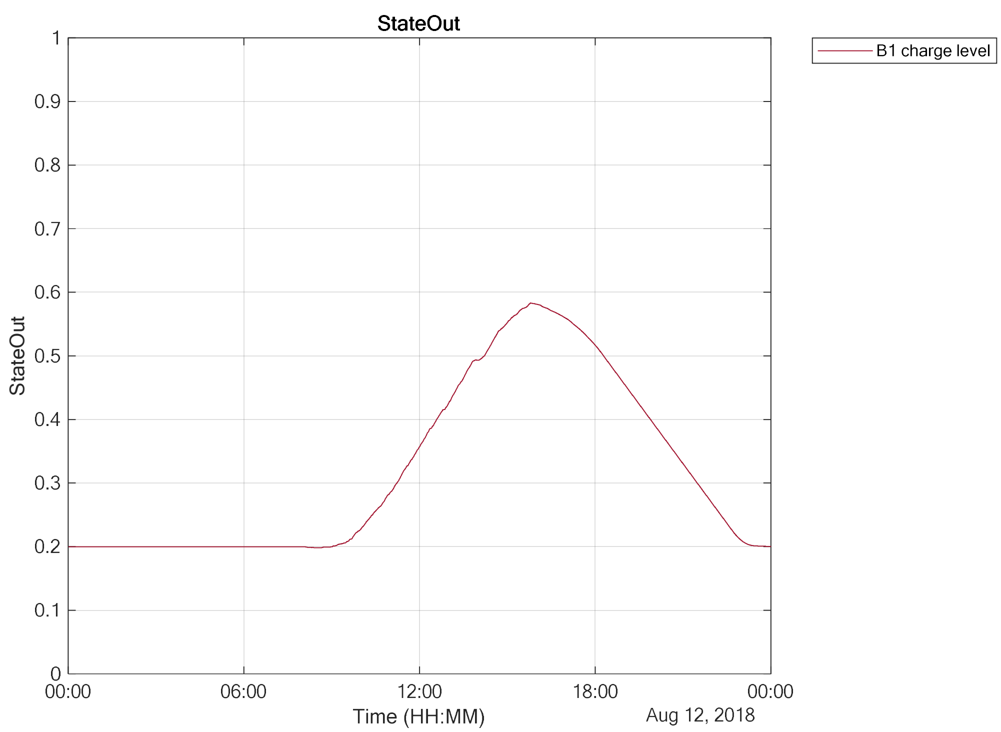
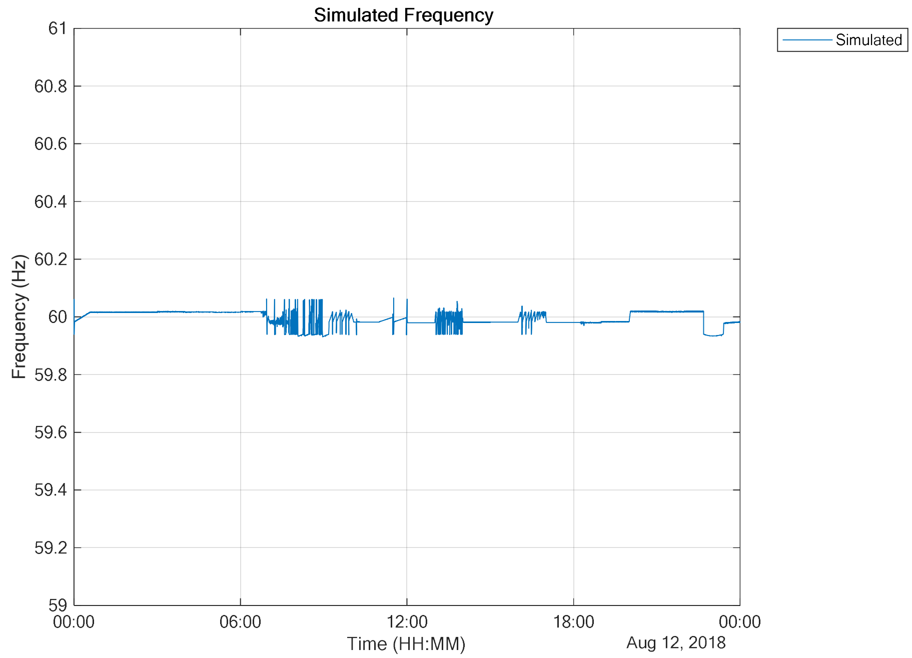


Figure 3-35 Simulated frequency for weekend when 8 MW/ 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.



3.3.2 Base Case 2 & Simulation cases 7 – 12 (12 August 2018) with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017

<u>Base Case 2: Weekend (12 August 2018) - Simulation of original day with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and with Hydro on.</u>

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data.

Figure 3-36 shows the simulation of generation unit outputs for Sunday 12 August 2018, with PV1 of 0.4 MW from 14 March 17 and PV2 of 0.6 MW from 15 March 2017. For this base case and simulations the hydro generation is online, off AGC as it is not dispatchable as a run of river and output is as recorded on 8 August 2018. The CAT generators are only units on AGC. 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 3-37, is more or less what is expected with any second by second changes from demand.

Figure 3-36 Simulated generation on weekend (12 August 2018) with current installed PV

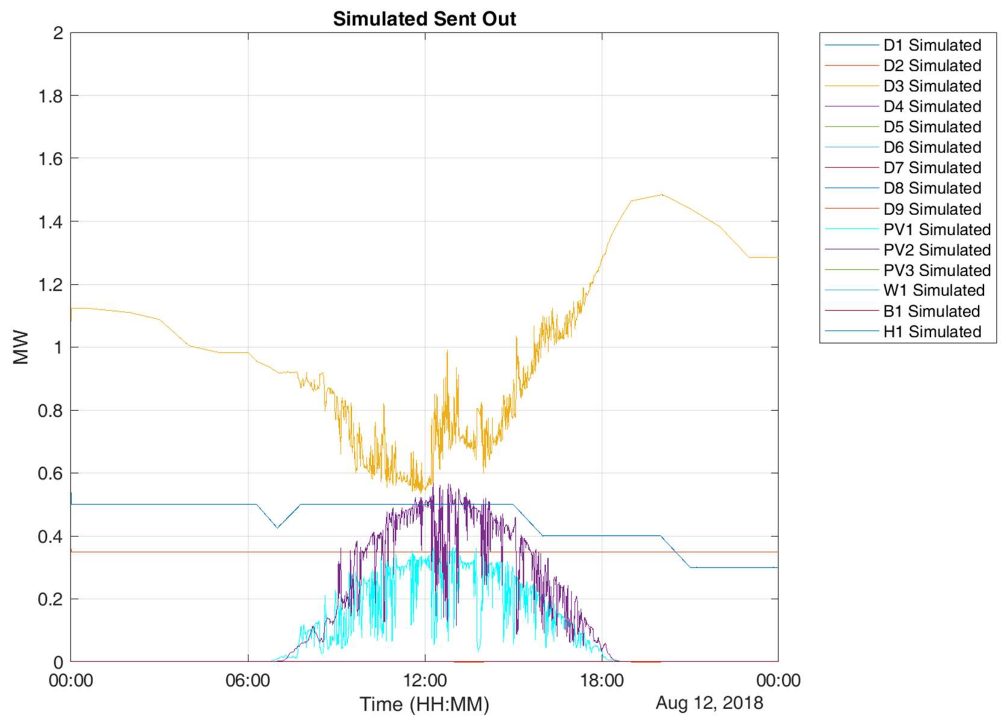
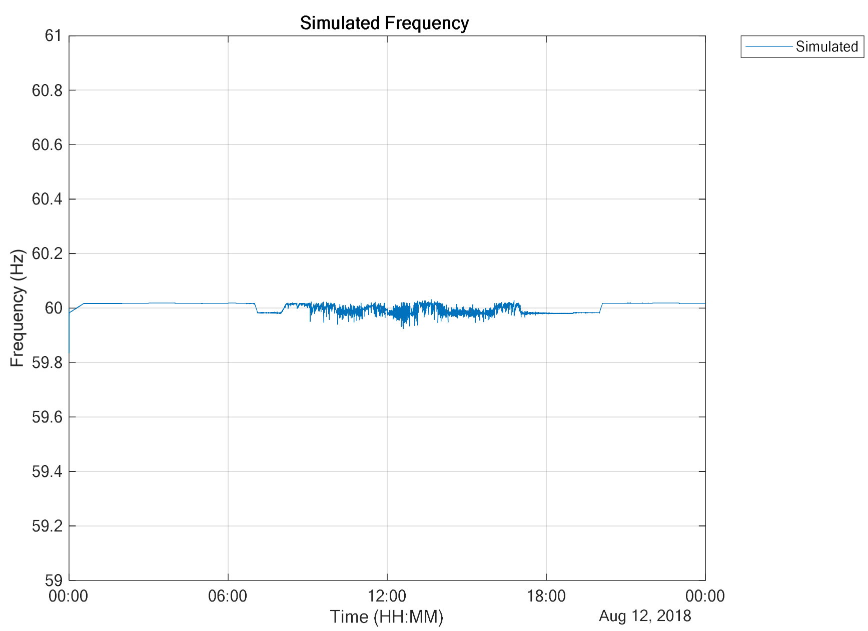


Figure 3-37 Simulated frequency on weekend (12 August 2018) with current installed PV



<u>Case 7 - 12: Weekend (12 August 2018) – Repeat of cases 1-6 PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and hydro data from 8 August 2018.</u>

Cases 7 – 12 is the repeat of the simulations for a typical weekend but with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017. The simulated frequency is within an acceptable range for case 7 with 3 MW total PV simulated, as shown in

Figure 3-38, but the simulated frequency control is worse with the more volatile PV variations. Case 9 with 6 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 3-39. Case 10 with 9 MW of simulated PV with a 4 MW / 4 MWh battery on AGC also results in an acceptable frequency control, as shown in Figure 3-40. Case 12 with the 12 MW of PV and 8 MW / 8 MWh battery on AGC has a very similar same result as for case 6 except battery is charge slightly more, as shown in Figure 3-41.

The fuel savings for the same scenario for the weekend cases is very similar except the PV production for the cases 7 -12 was slightly less than for cases 1-6 so daily fuel and net savings are lower.

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
3 MW PV and no battery	2,133	2,123	1,161	1,098
3 MW PV and 1 MW / 1 MWh battery on gov	2,133	2,127	873	815
6 MW PV and 2 MW / 2 MWh battery on gov	5,139	4,770	2,133	1,634
9 MW PV and 4 MW / 4 MWh battery on AGC	8,019	7,460	2,980	2,212
12 MW PV and 8 MW / 8 MWh battery on AGC	11,569	12,478	3,922	4,543
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	11,643	12,565	3,995	4,630

Figure 3-38 Case 7 - Simulated frequency on weekend with 3 MW PV

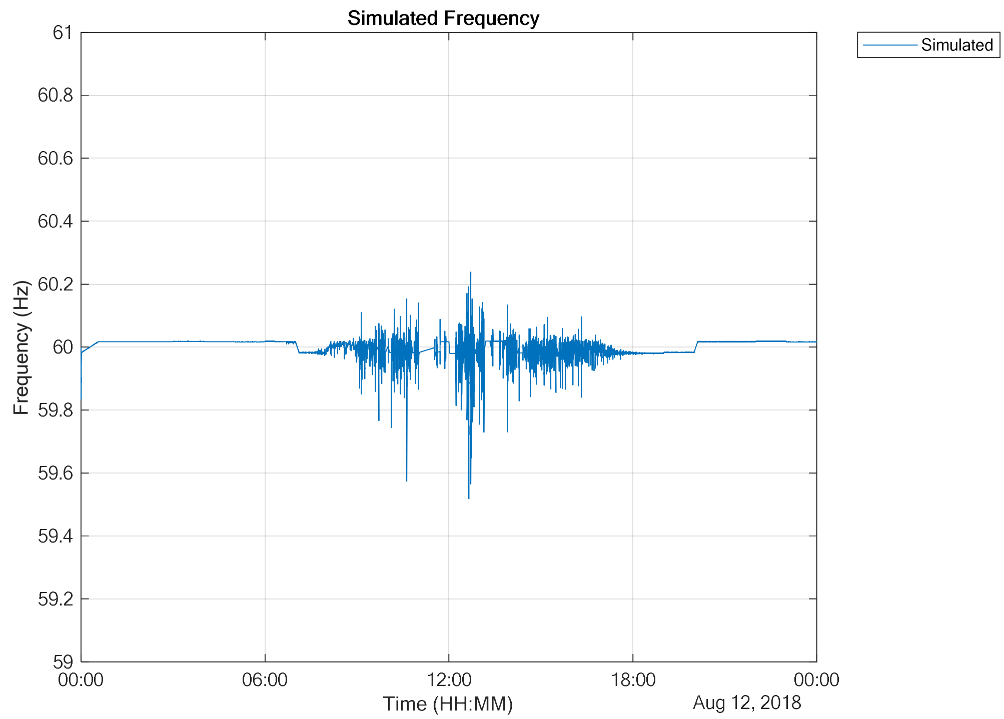


Figure 3-39 Case 9 - Simulated frequency on weekend with 6 MW PV and 2 MW / 2 MWh battery on primary frequency control

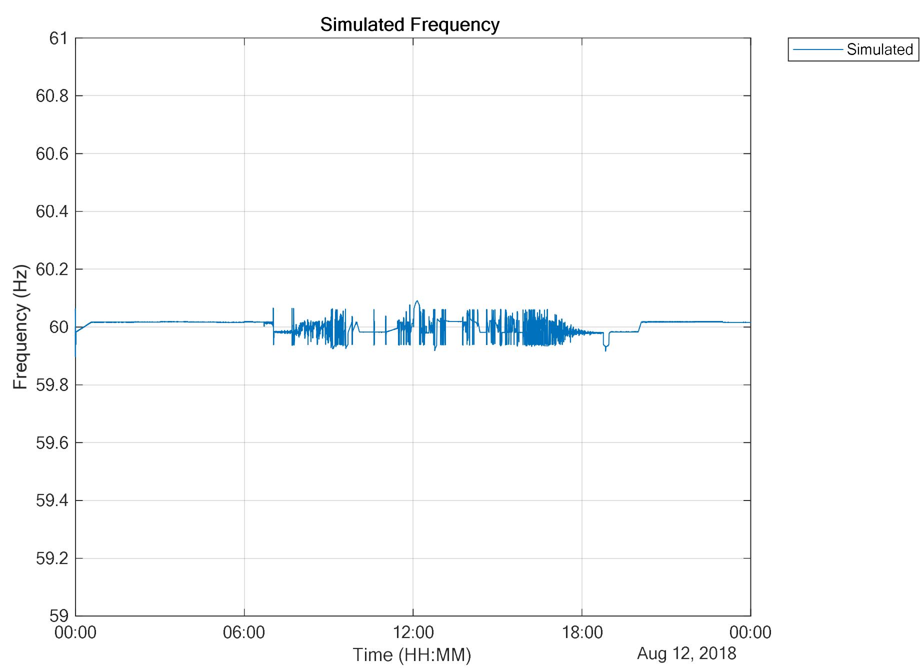


Figure 3-40 Case 10 - Simulated frequency on weekday with 9 MW PV and 4 MW / 4 MWh battery on AGC.

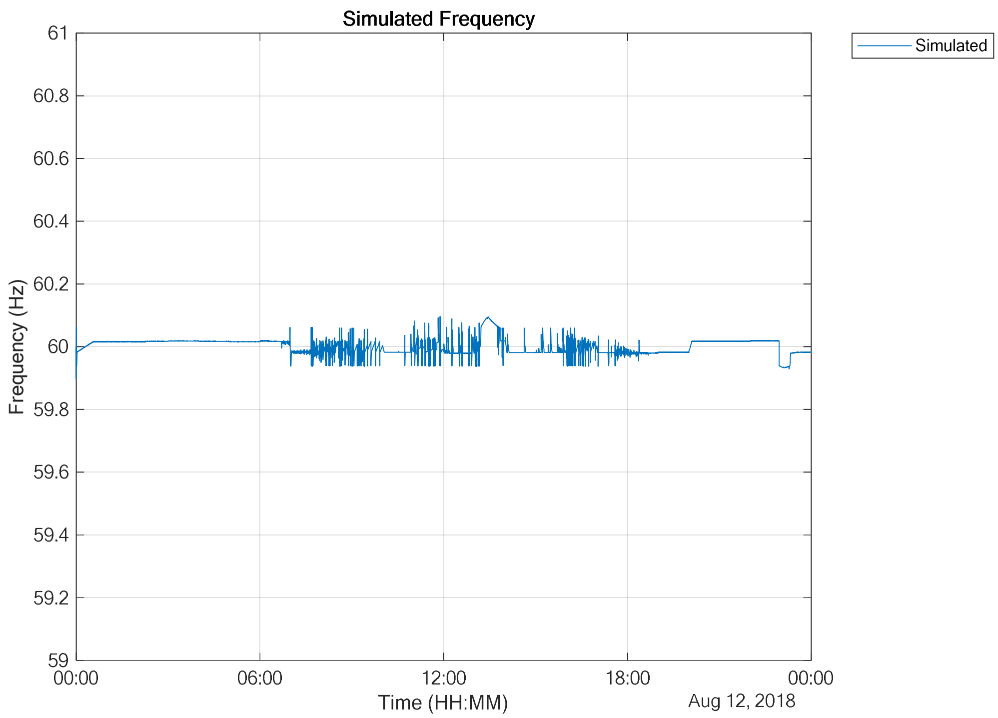
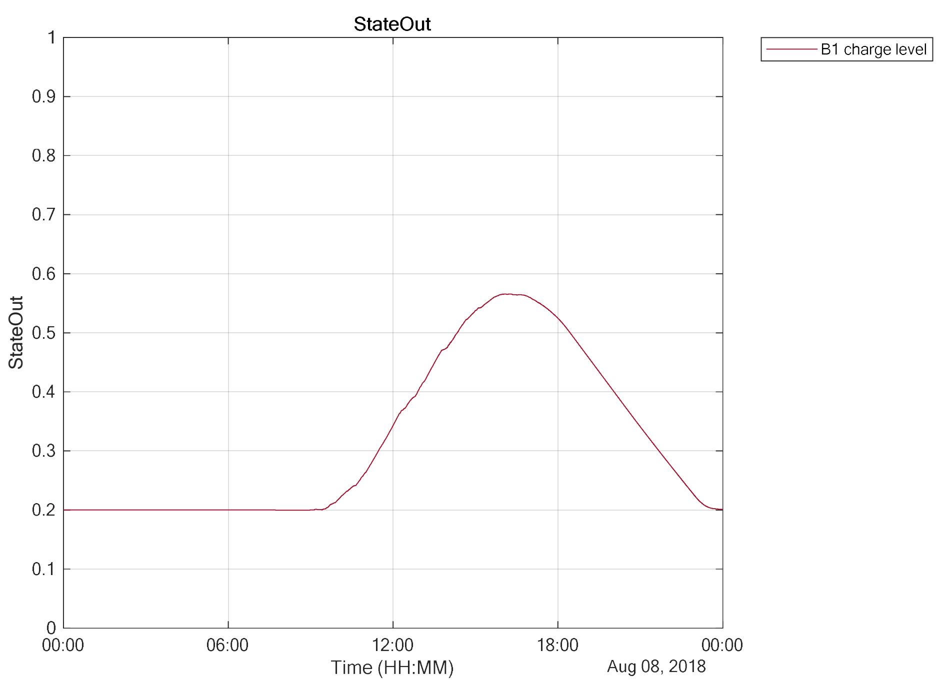


Figure 3-41 Case 12 - Simulated charge level on weekend with 12 MW PV and 8 MW /8 MWh battery on AGC and all diesel units off.



3.3.3 Base Case 3 & Simulation cases 13 – 18 Weekday (8 Aug 2018) with PV1 from 11 Mar 2017 & PV 2 from 16 Mar 2017

Base Case 3: Weekday (8 August 2018) - 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 3-42 shows the simulation of generation unit outputs for Wednesday 8 August 2017, with 0.4 MW from PV1 from 11 Mar 2017 (representing the town plants) & 0.6 MW from PV 2 (representing Pohnlanga PV) from 16 Mar 2017. Only the CAT generators are on AGC as is the current situation. 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 3-43, shows the expected shows the expected frequency variations which are typical for this amount of PV.

Figure 3-42 Simulated generation on weekday with current installed PV

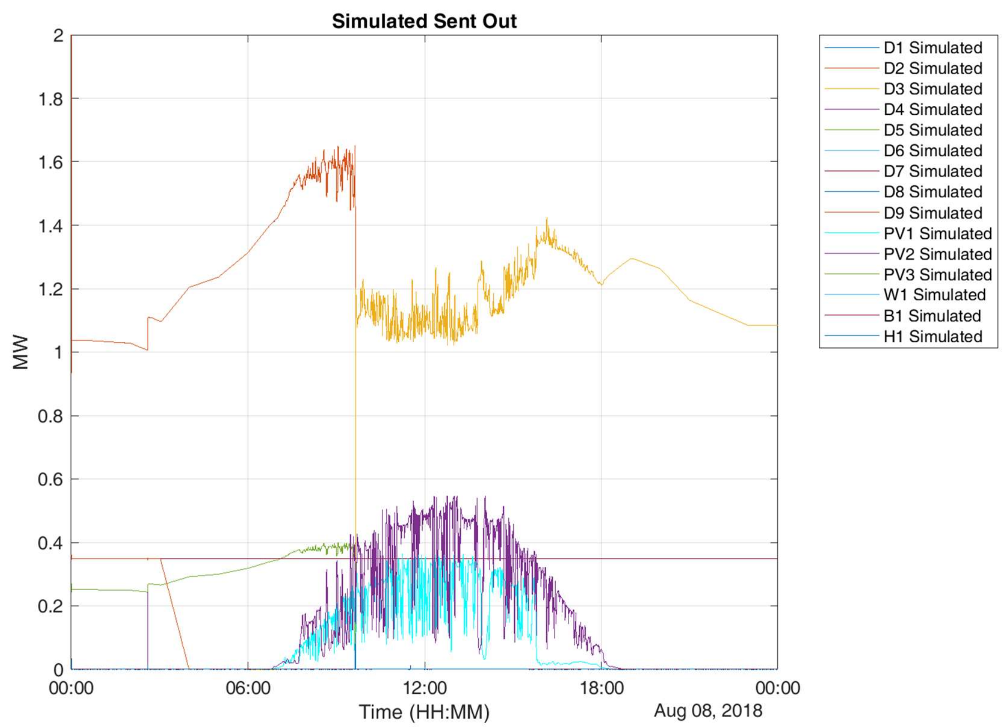
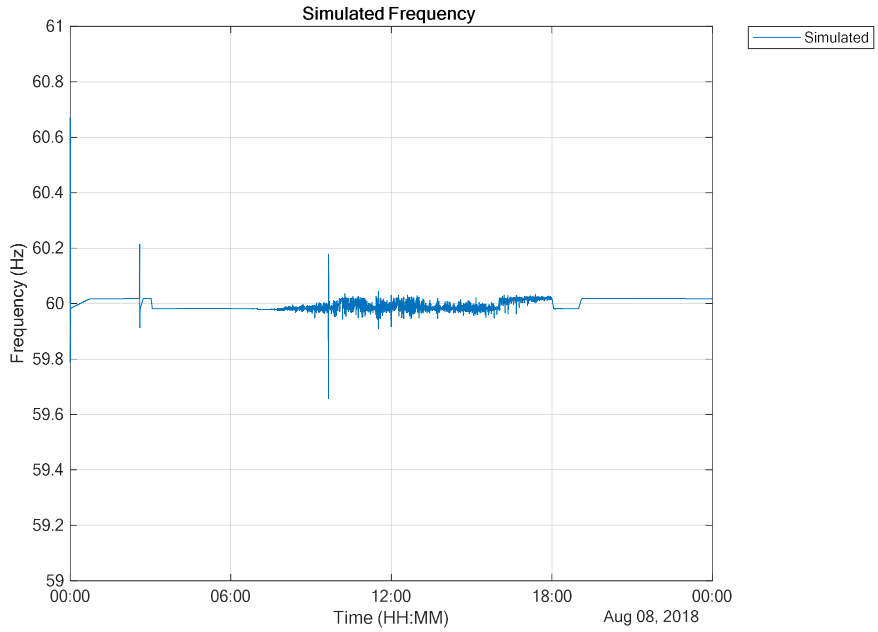


Figure 3-43 Simulated frequency on weekday with current installed PV



Case 13: Weekday (8 August 2018) - 3 MW of PV

For Case 13 the PV power plants are set to 1.5 MW each giving a total PV of 3 MW, CAT diesel units are the units on to perform frequency control, as shown in Figure 3-44. The frequency is acceptable but there are frequency excursions where the Diesel Power plant is battling to control the frequency.

Figure 3-44 Simulated generation on weekday with 3 MW PV

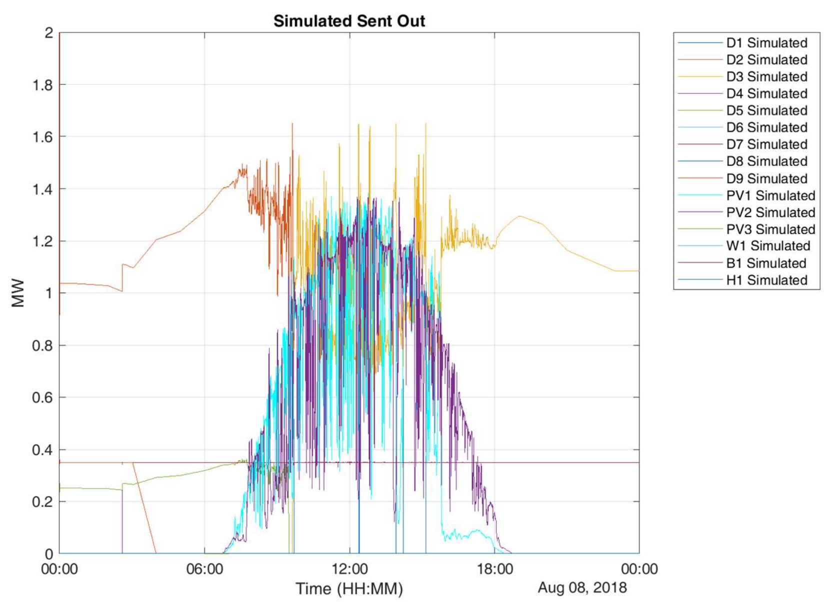
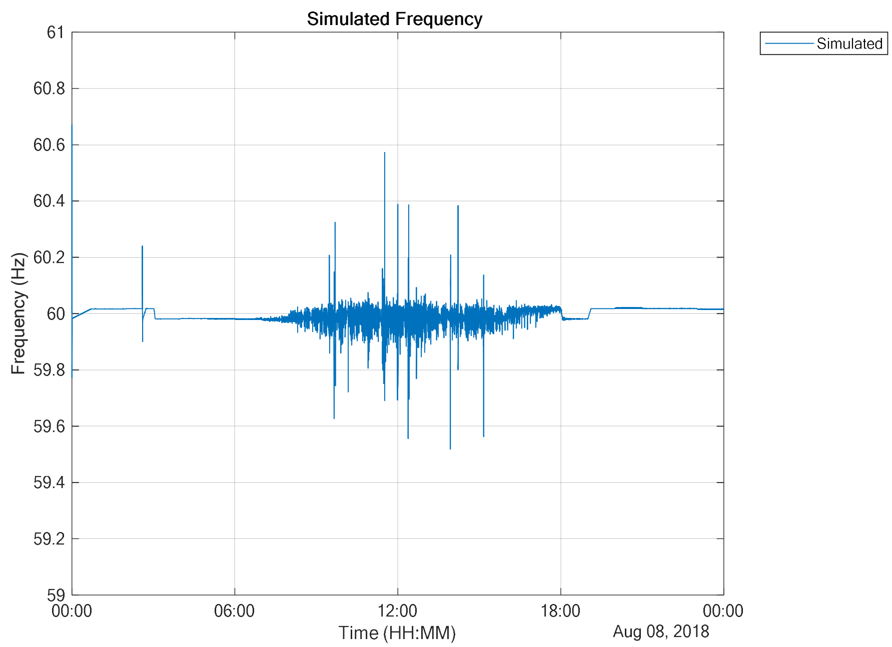


Figure 3-45 Simulated frequency on weekday with 3 MW PV

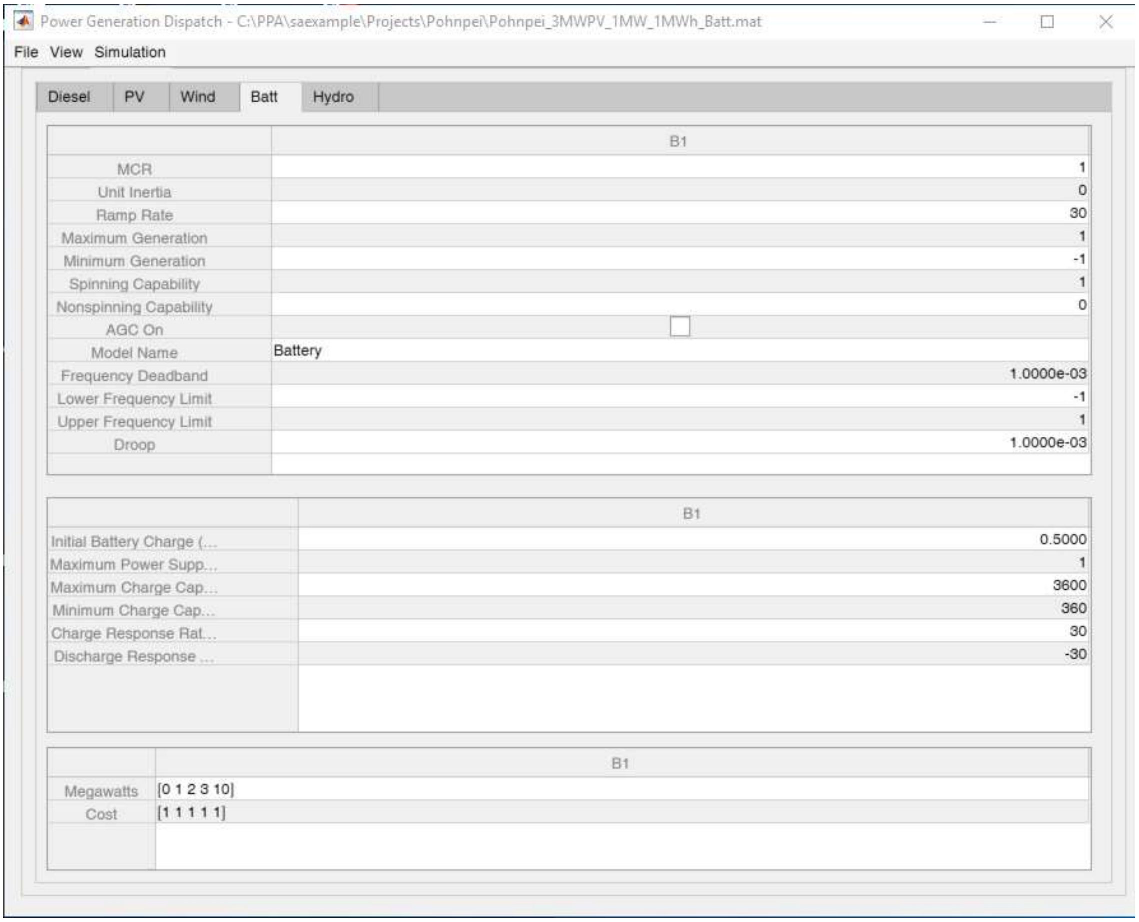


<u>Case 14: Weekday (8 August 2018) - 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control</u>

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 Figure 3-46.

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.

Figure 3-46 Battery parameters when on primary frequency control only


Power Generation Dispatch - C:\PPA\saexample\Projects\Pohnpei\Pohnpei_3MWPV_1MW_1MWh_Batt.mat

File View Simulation

Diesel | PV | Wind | Batt | Hydro

	B1
MCR	1
Unit Inertia	0
Ramp Rate	30
Maximum Generation	1
Minimum Generation	-1
Spinning Capability	1
Nonspinning Capability	0
AGC On	☐
Model Name	Battery
Frequency Deadband	1.0000e-03
Lower Frequency Limit	-1
Upper Frequency Limit	1
Droop	1.0000e-03

	B1
Initial Battery Charge (...	0.5000
Maximum Power Supp...	1
Maximum Charge Cap...	3600
Minimum Charge Cap...	360
Charge Response Rat...	30
Discharge Response ...	-30

	B1
Megawatts	[0 1 2 3 10]
Cost	[1 1 1 1 1]

The simulated frequency improves when 1 MW battery is on primary frequency control only, as shown in Figure 3-47. The battery is sufficient to prevent the few frequency excursion, as shown in Figure 3-48. The diesel fuel costs remain almost the same at $19,425 as for case 13 showing the battery is just performing primary frequency control and the battery on discharges a few percent. The net saving of US$ 875 is calculated for the simulation day including the battery costs.

Figure 3-47 Simulated frequency for weekday with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control

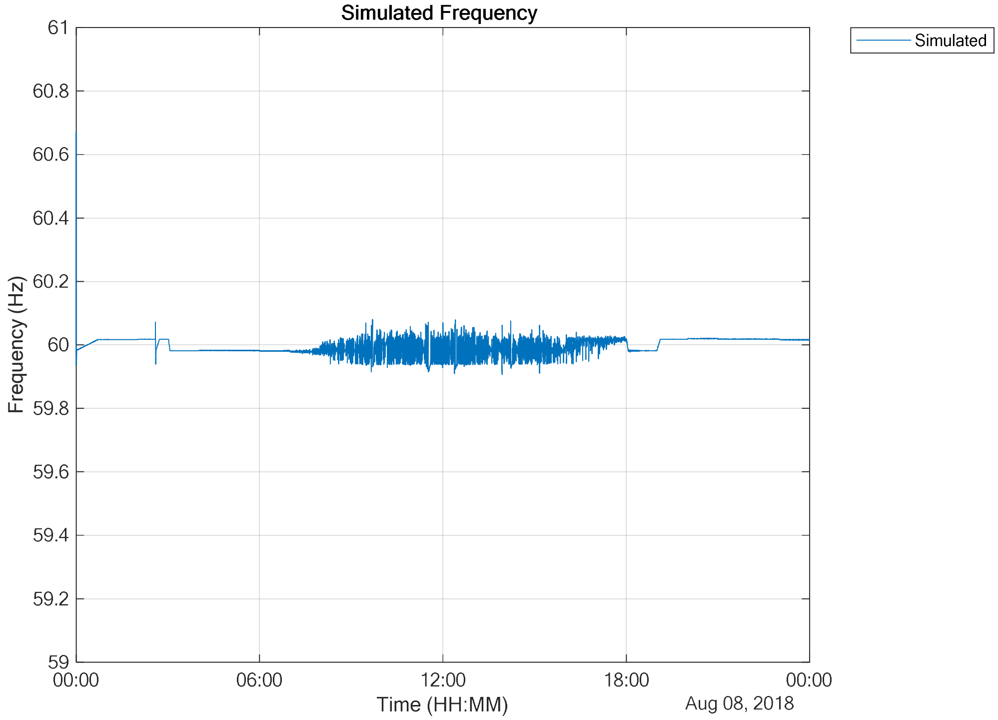
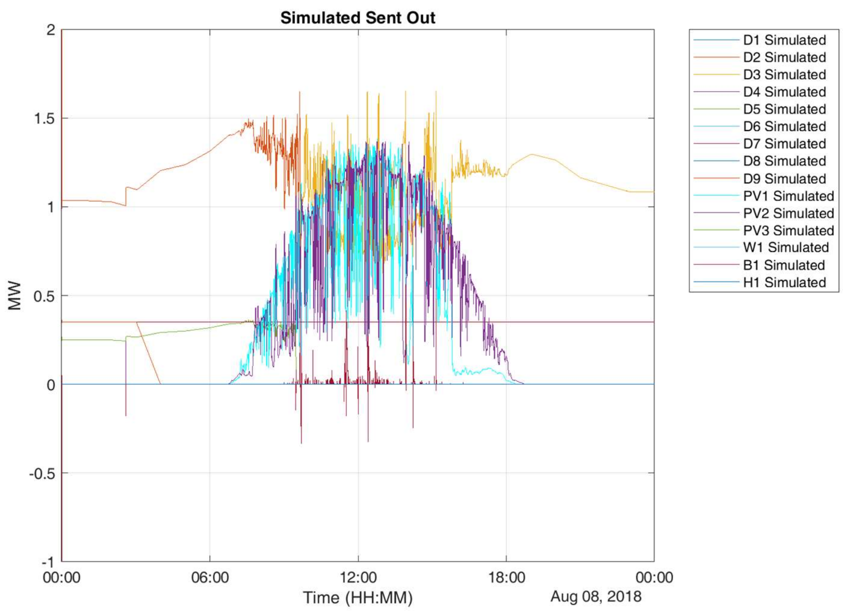


Figure 3-48 Simulated generation for weekday with 3 MW of PV and 1 MW / 1 MWh battery on primary frequency control



Case 15: Weekday (16 March 2017) - 6 MW of PV and 2 MW / 2 MWh battery on primary frequency control

For Case 15 the PV power plants are set to 3 MW each giving a total PV of 6 MW, all diesel units 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 3-49 . The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in Figure 3-50.

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.

Nearly all of the available energy from the 6 MW of PV is used resulting in a fuel saving of US$5,027 and a net saving of US$ 2,021 for the simulation day.

Figure 3-49 Simulated generation for weekday with 6 MW of PV and 2 MW / 2 MW battery on primary frequency control

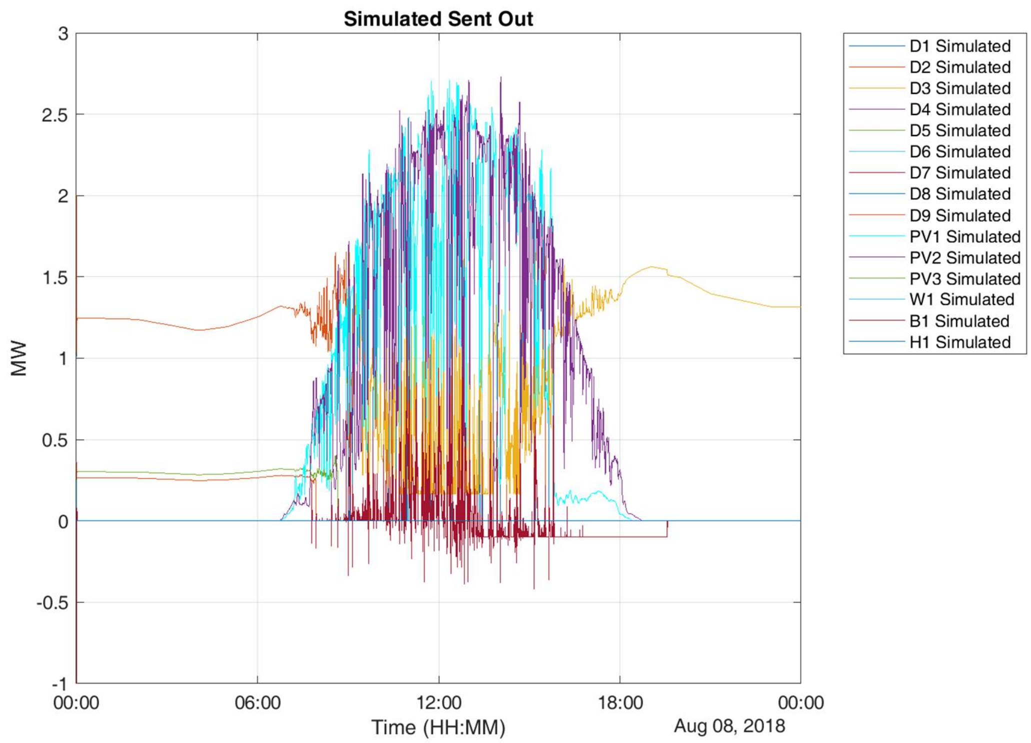
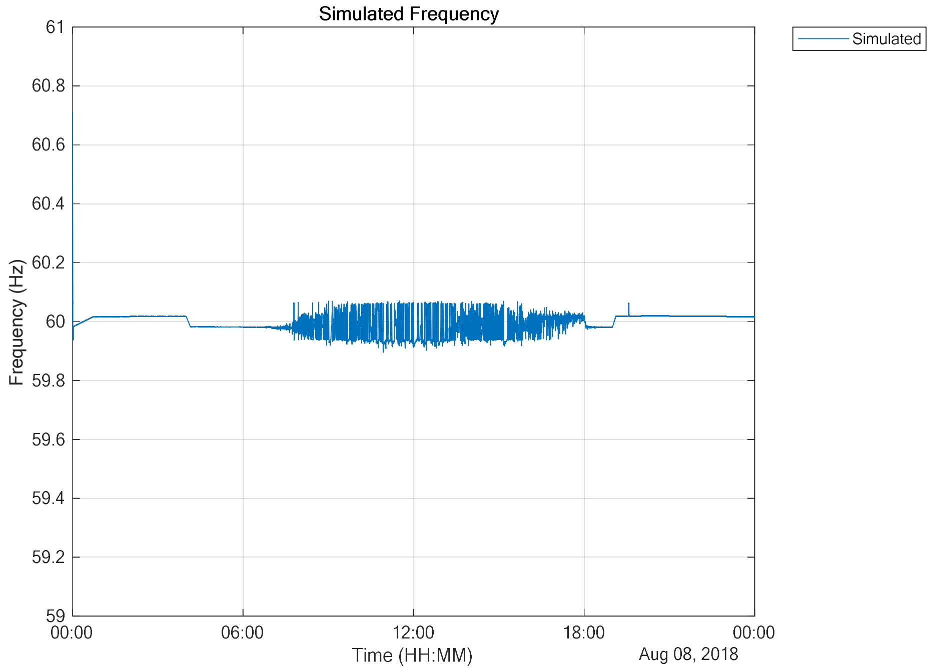


Figure 3-50 Simulated frequency for weekday with 6 MW of PV and 2 MW / 2 MWh battery on primary frequency control



Case 16: Weekday (8 August 2018) – 9 MW of PV and 2 MW / 2 MWh battery on AGC

Case 16 is simulating the same as Case increasing the PV to 9 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. 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 **3-51** shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery 60% charge level, as shown in Figure 3-52, by 15:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 18:30. 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 3-53.

The fuel savings for Case 16 is $ 8,375 compared to $ 5,027 for Case 15. This reduction is due to an increase PV output of 14.4 MWh and this case has a net saving of $ 3,386.

Figure 3-51 Simulated battery output for weekday when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.

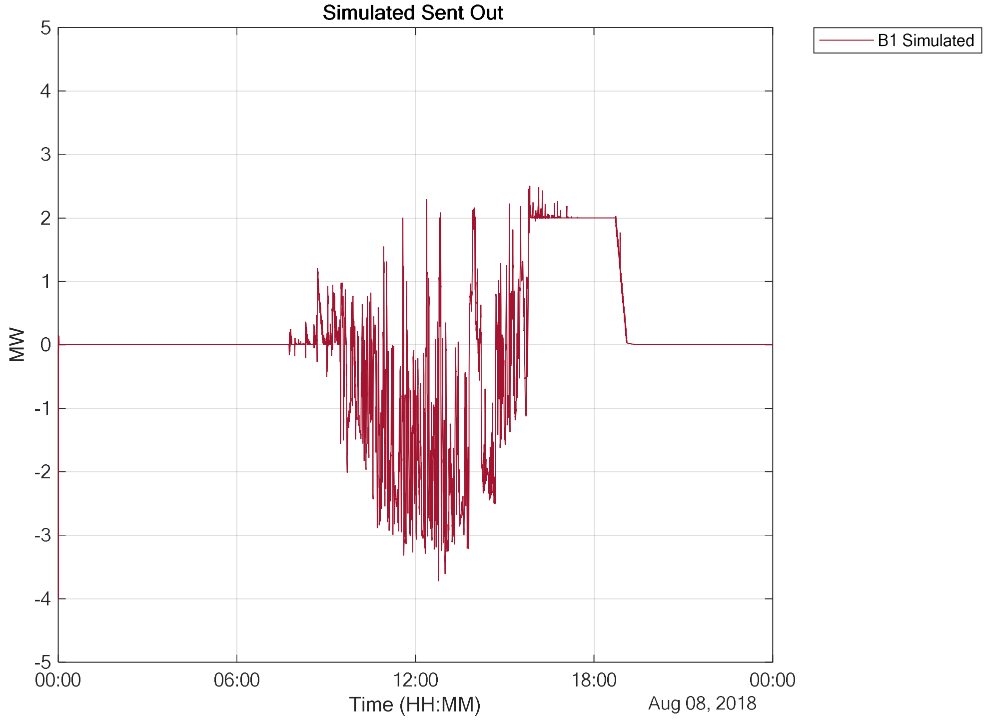


Figure 3-52 Simulated battery charge level for weekday when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.

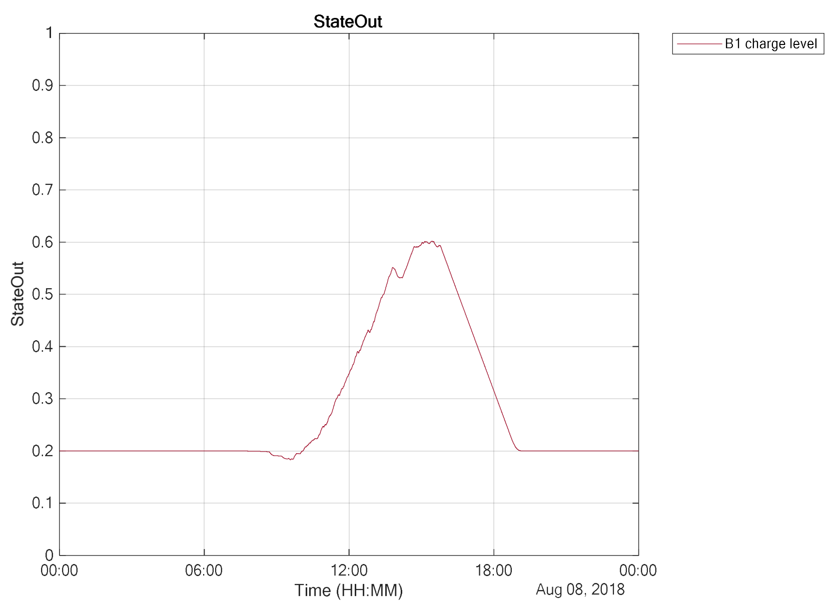
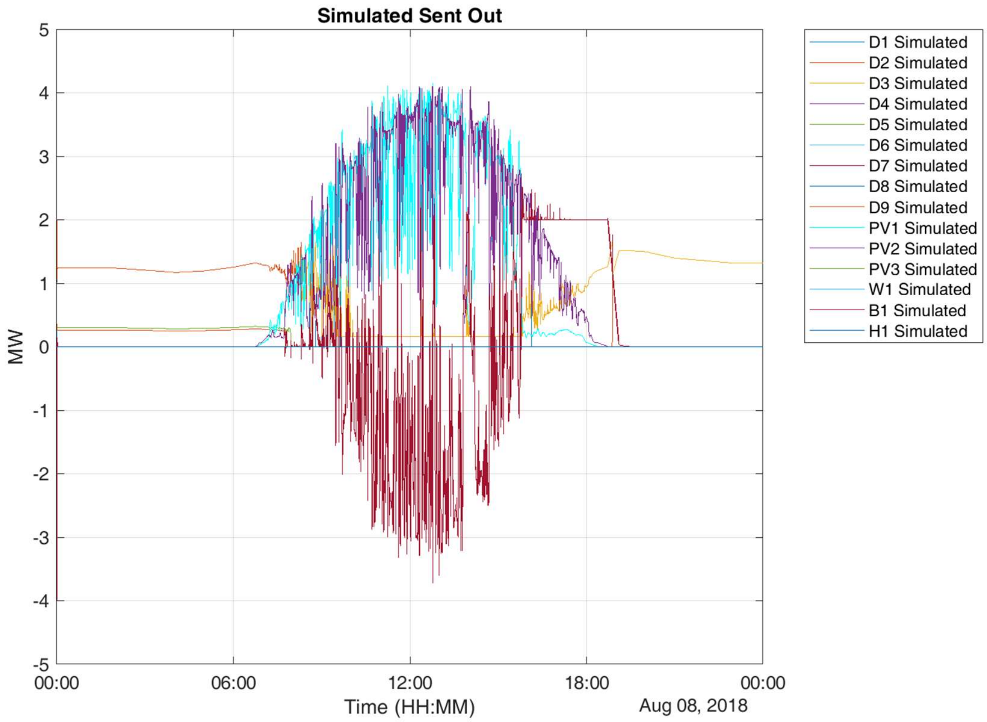


Figure 3-53 Simulated generator outputs for weekday when 4 MW / 4 MWh battery provides both primary frequency control and AGC with 9 MW of PV.



<u>Case 17: Weekday (8 August) – 12 MW of PV and 8 MW / 8 MWh battery on AGC</u>

This case is where the PV is increased to 12 MW and an 8 MW / 8 MWh battery is on AGC and primary frequency control. The simulated generation, as shown in Figure 3-54., shows that the inverter size is more than sufficient.
The simulated frequency is within acceptable limits, as shown in Figure 3-55. The battery charges to 50% by 16:30 and fully discharges by 20:00, as shown in Figure 3-56.

The energy is nearly fully utilised and thus the battery is adequately sized for this simulation day. This case has a net saving of $ 3,957 for the simulation day.

Figure 3-54 Simulated generation output for weekday when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

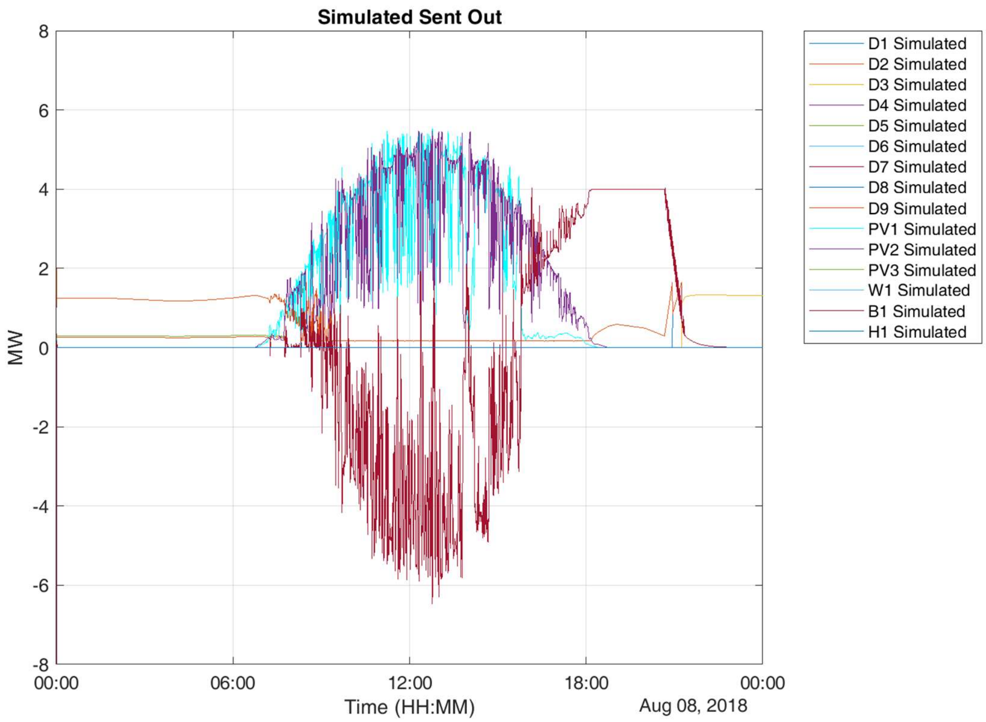


Figure 3-55 Simulated frequency for weekend when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.

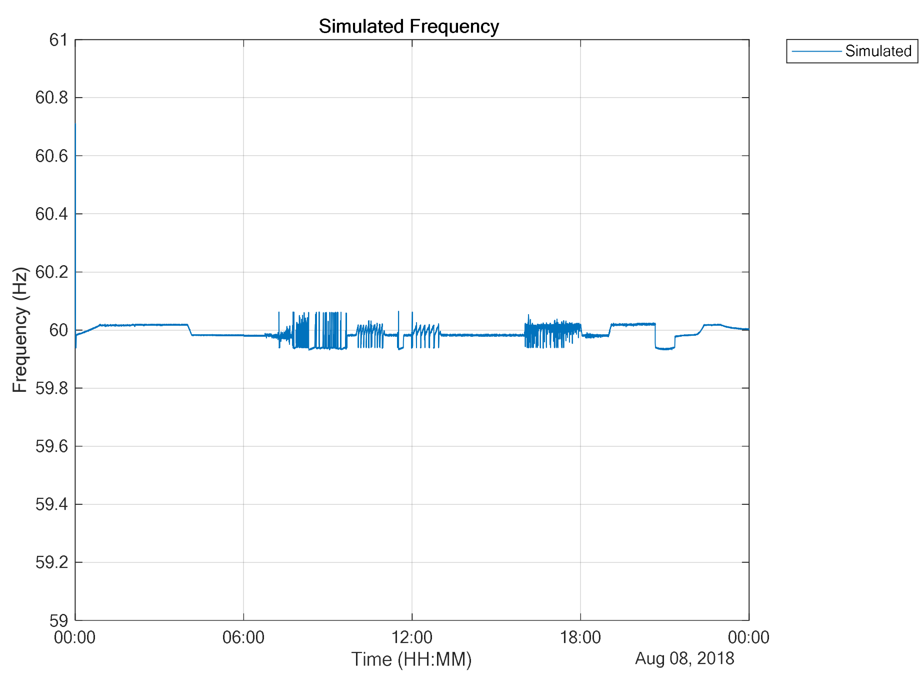
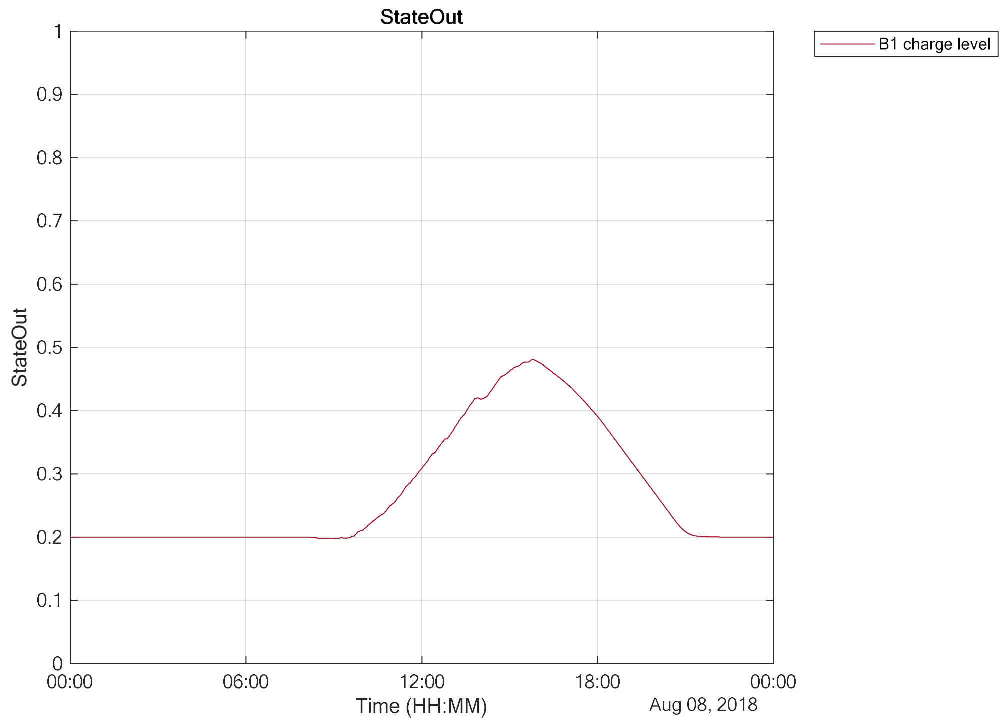


Figure 3-56 Simulated battery charge level for weekday 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV.



<u>Case 18: Weekday (8 August 2018) – 12 MW of PV and 8 MW / 8 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 3-57. The inverter size is adequate again as for previous case, as shown in Figure 3-58. The battery only charges to 45% all diesel units off until 18:00.

The nett saving with all units off is slightly increased to $ 4,012 compared to case 17 of $3,957.

Figure 3-57 Simulated frequency for weekday when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.

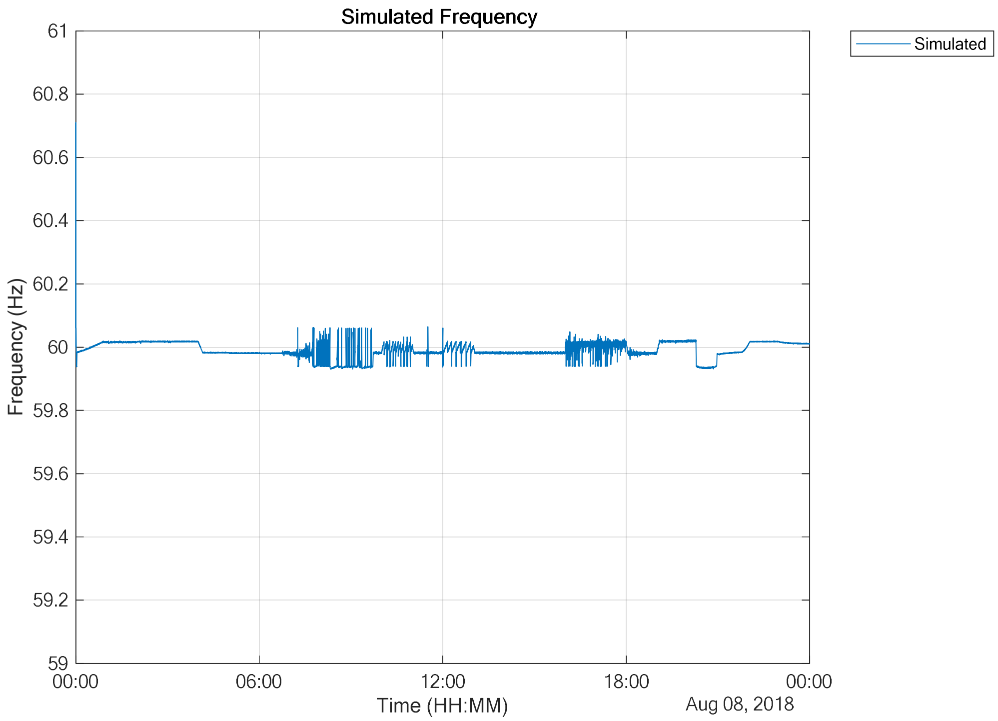
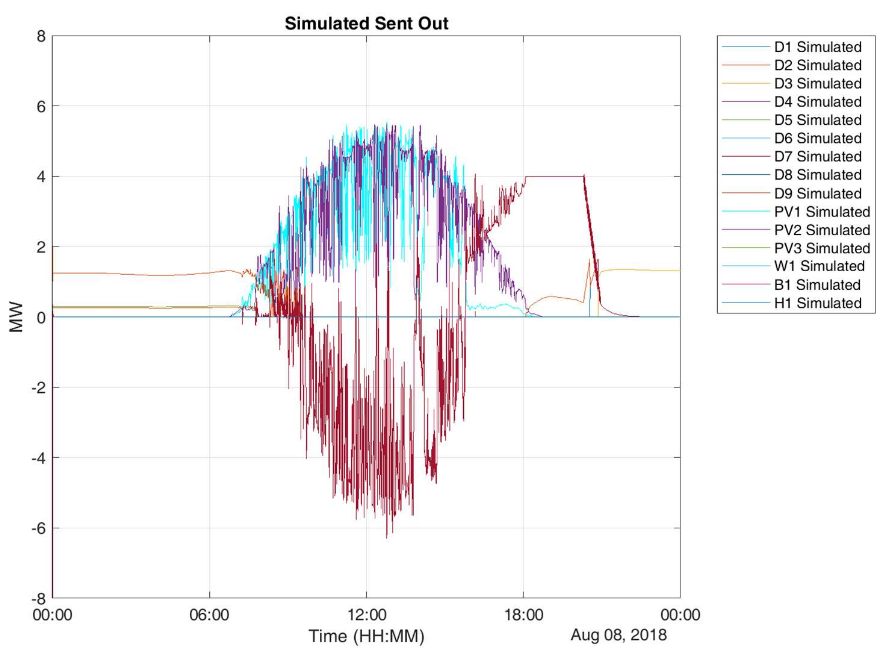


Figure 3-58 Simulated generation output for weekday when 8 MW / 8 MWh battery provides both primary frequency control and AGC with 12 MW of PV. All diesel units allowed to go off.



3.3.4 Base Case 4 & Simulation cases 19 – 24 (8 August 2018) with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and hydro units on

Base Case 2: Weekday (8 August 2018) - Simulation of original day with PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017 and with hydro data from 8 August 2018.

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-59 shows the simulation of generation unit outputs for Wednesday 8 August 2018, with PV1 of 0.4 MW from 14 March 17 and PV2 of 0.6 MW from 15 March 2017. For this base case and simulations the hydro generation is online, off AGC as it is not dispatchable as a run of river and output is as recorded on 8 August 2018. 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 3-60, is more or less what can be expected with second by second changes in demand.

Figure 3-59 Simulated generation on weekday with current installed PV

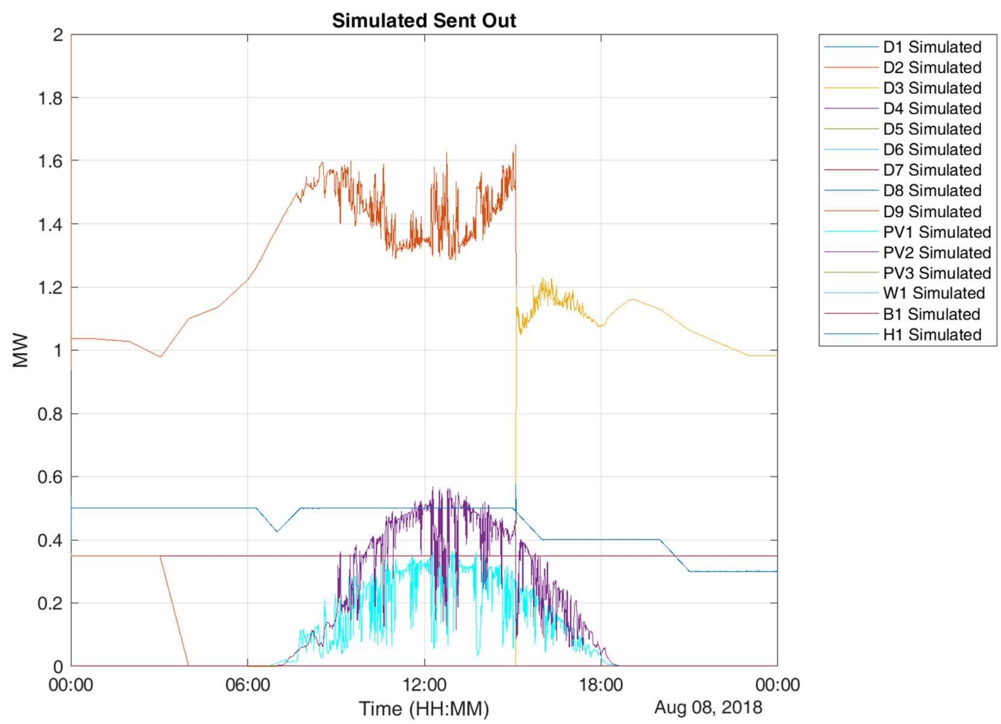
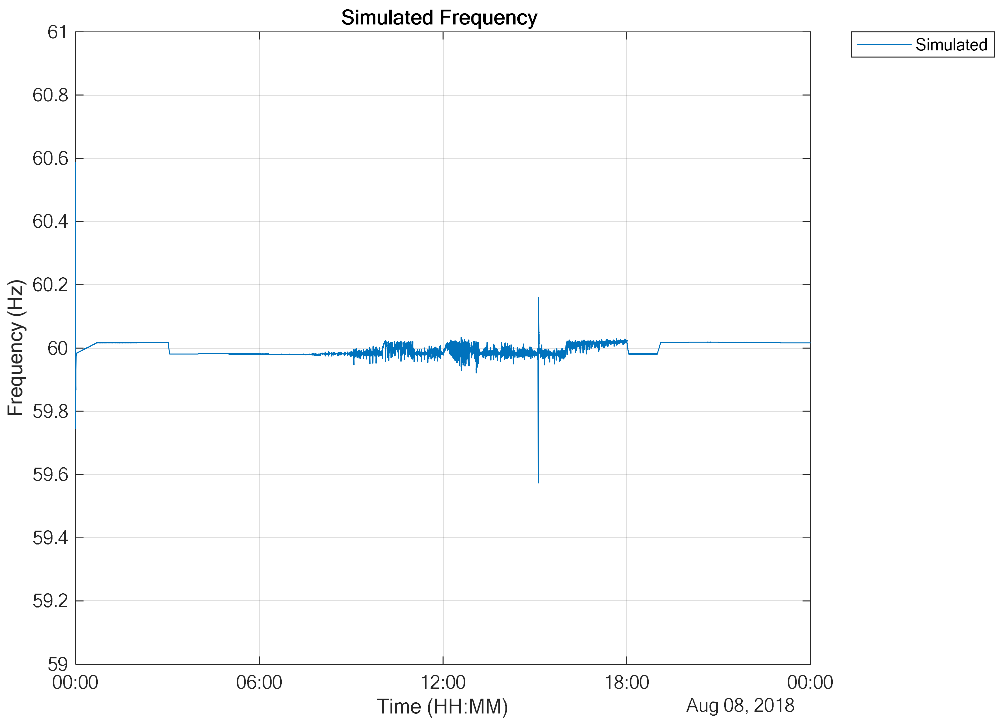


Figure 3-60 Simulated frequency on weekday with current installed PV



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

Cases 19 - 24 is the repeat of the simulations for a typical weekday but with hydro units on as recorded on 8 August 2018 and PV1 from 14 Mar 2017 & PV 2 from 15 Mar 2017. The simulated frequency is within an acceptable range for case 19 with 3 MW total PV simulated and no batteries, as shown in Figure 3-61 but the simulated frequency control is worse with the more volatile PV variations. Case 21 with 6 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 3-62. Case 22 with 9 MW of simulated PV with a 4 MW / 4 MWh battery on AGC also results in an acceptable frequency control but with no excursions which suggest a inverter size is good, as shown in Figure 3-63. Case 24 with the12 MW of PV and 8 MW / 8 MWh battery on AGC has the battery charging to full output around 18:00 and battery discharges unit 02:00 am the next day. All diesel units are off from 10:00 am to 02: m the next day.

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

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
3 MW PV and no battery	2,109	2,182	1,137	1,135
3 MW PV and 1 MW / 1 MWh battery on gov	2,117	2,183	857	811
6 MW PV and 2 MW / 2 MWh battery on gov	5,027	5,604	2,021	2,376
9 MW PV and 4 MW / 4 MWh battery on AGC	8,375	9,051	3,336	3,678
12 MW PV and 8 MW / 8 MWh battery on AGC	11,604	12,511	3,957	4,418
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	11,660	12,657	4,012	4,564

Figure 3-61 Case 19 - Simulated frequency on weekday with 3 MW PV

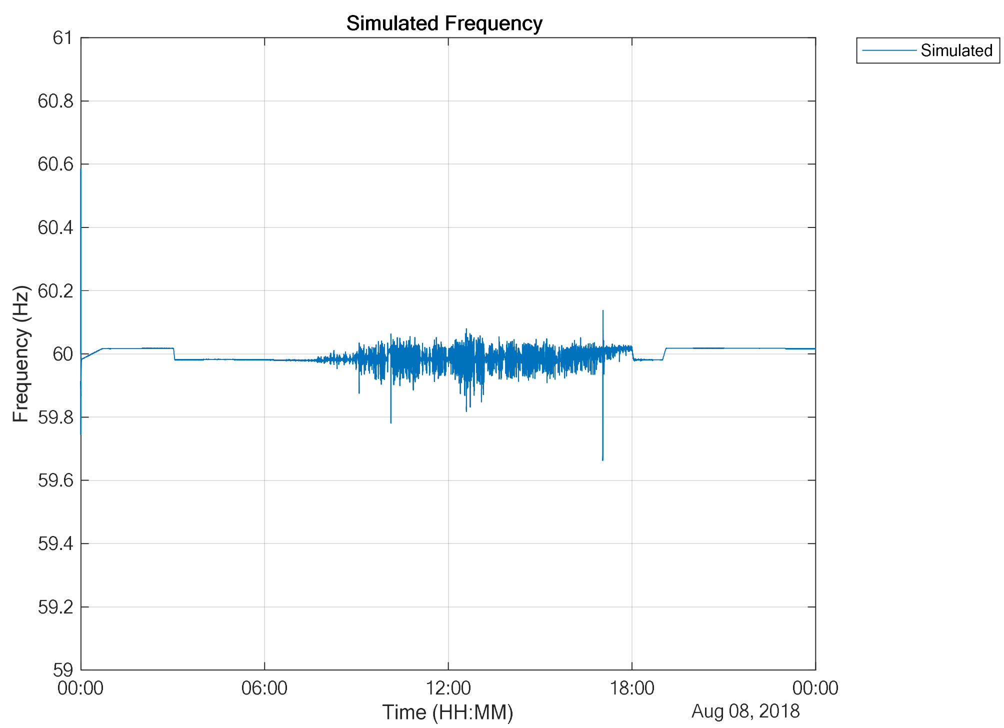


Figure 3-62 Case 21 - Simulated frequency on weekday with 6 MW PV and 2 MW / 2 MWh battery on primary frequency control

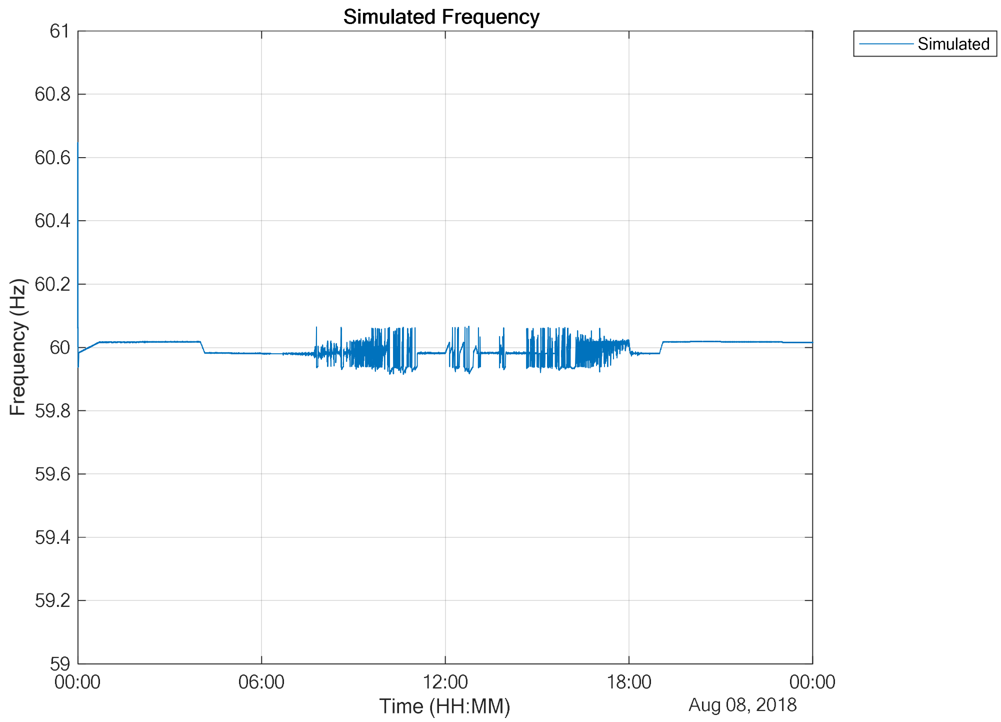


Figure 3-63 Case 22 - Simulated frequency on weekday with 9 MW PV and 4 MW/ 4 MWh battery on AGC and primary frequency control.

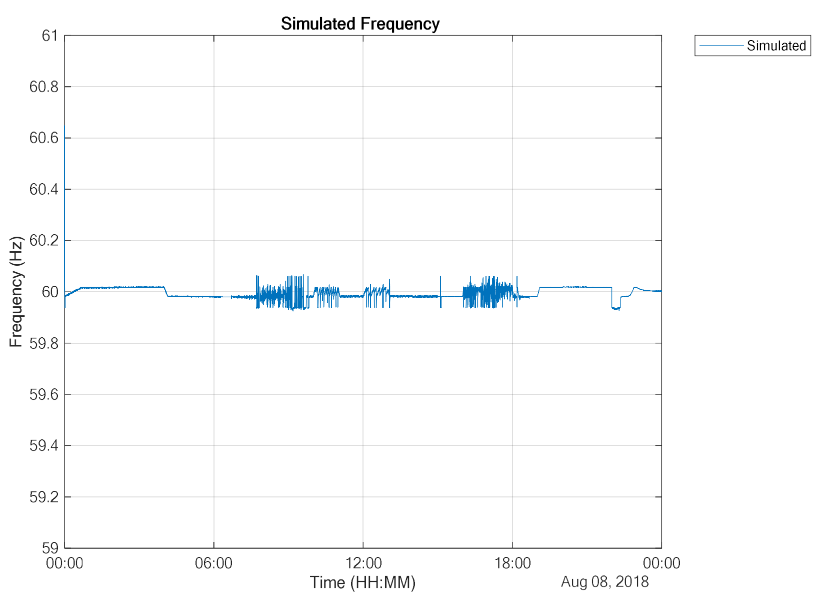
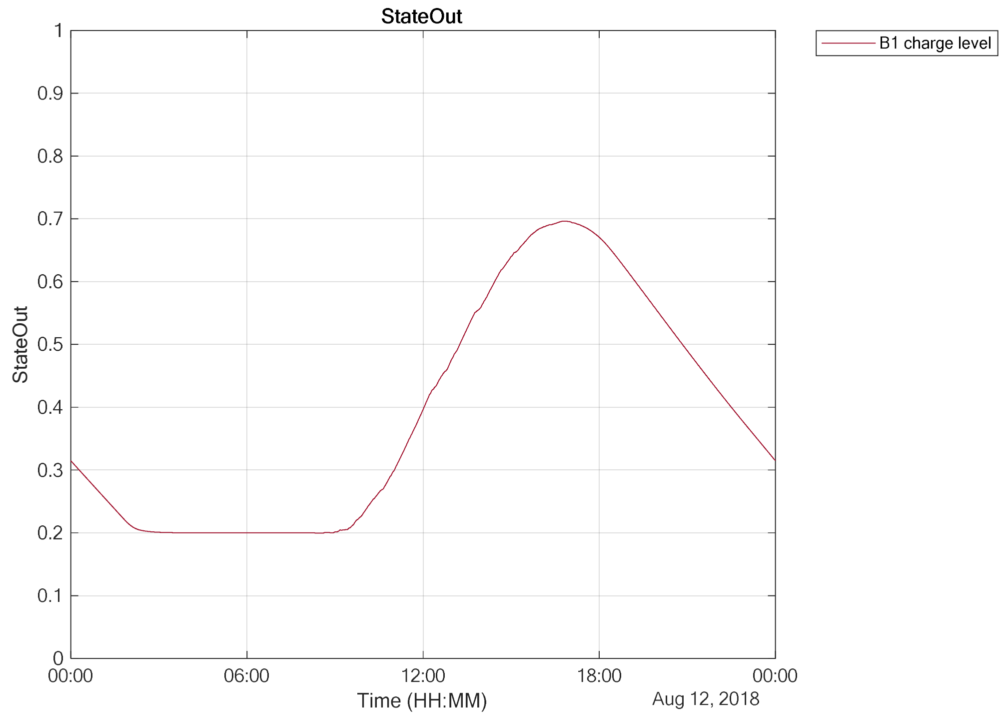


Figure 3-64 Case 24 - Simulated charge level on weekday with 12 MW of PV and 8 MW / 8 MWh battery on AGC and all diesel units off.



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	12 Aug 2018	1	18,938	100%	81.8	4.9	4.9	0.0	0.0%	off
1	12 Aug 2018	3	16,804	89%	72.3	14.4	14.59	0.2	1.6%	off
2	12 Aug 2018	3	16,805	89%	72.3	14.3	14.59	0.2	1.7%	1 MW / 1 MWh on Gov
3	12 Aug 2018	6	13,799	73%	57.7	28.9	29.17	0.3	1.1%	2 MW / 2 MWh on Gov & AGC
4	12 Aug 2018	9	10,918	58%	44.8	41.9	43.76	1.9	4.3%	4 MW / 4 MWh on Gov & AGC
5	12 Aug 2018	12	7,368	39%	31.0	57.73	58.34	0.6	1.0%	8 MW / 8 MWh on Gov & AGC
6	12 Aug 2018	12	7,295	39%	29.5	57.73	58.34	0.6	1.0%	8 MW / 8 MWh on Gov & AGC – diesel off
Base 2	12 Aug 2018	1	16,464	100%	70.8	5.1	5.1	0.0	0.0%	off
7	12 Aug 2018	3	14,341	87%	60.0	14.2	15.37	1.2	7.9%	off
8	12 Aug 2018	3	14,337	87%	62.0	14.1	15.37	1.2	8.0%	1 MW / 1 MWh on Gov
9	12 Aug 2018	6	11,694	71%	48.3	27.9	30.74	2.8	9.3%	2 MW / 2 MWh on Gov & AGC
10	12 Aug 2018	9	9,004	55%	36.4	40.1	46.11	6.0	13.0%	4 MW / 4 MWh on Gov & AGC
11	12 Aug 2018	12	3,986	24%	17.2	62.5	61.48	-1.0	-1.6%	8 MW / 8 MWh on Gov & AGC
12	12 Aug 2018	12	3,899	24%	17.3	62.5	61.48	-1.0	-1.6%	8 MW / 8 MWh on Gov & AGC – diesel off
Base 3	12 Aug 2018	1	21,542	100%	93.0	4.9	4.86	0.0	0.0%	off
13	12 Aug 2018	3	19,432	90%	83.4	14.4	14.59	0.2	1.1%	off
14	12 Aug 2018	3	19,425	90%	83.4	14.4	14.59	0.2	1.1%	1 MW / 1 MWh on Gov
15	12 Aug 2018	6	16,515	77%	69.5	28.3	29.17	0.9	2.9%	2 MW / 2 MWh on Gov
16	12 Aug 2018	9	13,166	61%	54.5	43.3	43.76	0.5	1.1%	4 MW / 4 MWh on Gov & AGC

17	12 Aug 2018	12	9,937	46%	40.1	57.7	58.34	0.6	1.1%	8 MW / 8 MWh on Gov & AGC
18	12 Aug 2018	12	9,882	46%	40.1	57.7	58.34	0.6	1.1%	8 MW / 8 MWh on Gov & AGC – diesel off
Base 4	12 Aug 2018	1	19,045	100%	82.2	5.2	5.2	0.0	0.0%	off
19	12 Aug 2018	3	16,864	89%	71.8	15.6	15.70	0.1	0.6%	off
20	12 Aug 2018	3	16,863	89%	71.8	15.6	15.70	0.1	0.6%	1 MW / 1 MWh on Gov
21	12 Aug 2018	6	13,441	71%	56.2	31.2	31.40	0.2	0.6%	2 MW / 2 MWh on Gov & AGC
22	12 Aug 2018	9	9,994	52%	40.6	46.8	47.10	0.3	0.6%	4 MW / 4 MWh on Gov & AGC
23	12 Aug 2018	12	6,535	34%	28.5	62.5	62.80	0.3	0.5%	8 MW / 8 MWh on Gov & AGC
24	12 Aug 2018	12	6,388	34%	26.4	62.5	62.80	0.3	0.5%	8 MW / 8 MWh on Gov & AGC – diesel off

The simulations show that it is possible to increase the renewable energy penetration up to 3 MW with no battery support, but diesel units must be on AGC, a 1 MW/1 MWh battery is recommended. A 2 MW / 2 MWh battery can sustain 6 MW of PV without a negative impact on frequency control and similarly for a 4 MW/ 4 MWh battery can sustain 9 MW of PV. An 8 MW / 8 MWH battery size is required for a PV of 12 MW to utilise the excess energy from the PV and maintain adequate frequency control.

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$ 100 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	3	15,573	2,128	0.236	88%	66.1	14.3	15.0	0.7	4.7%	999		1,130
2 & 8	3	15,571	2,130	0.232	88%	67.1	14.2	15.0	0.7	4.8%	999		844
3 & 9	6	12,746	4,955	0.241	72%	53.0	28.4	30.0	1.6	5.2%	2,496	575	1,883
4 & 10	9	9,961	7,740	0.246	56%	40.6	41.0	44.9	3.9	8.7%	3,994	1,150	2,596
5 & 11	12	5,677	12,024	0.235	32%	24.1	60.1	59.9	-0.2	-0.3%	5,492	2,299	4,232
6 & 12	12	5,597	12,104	0.236	31%	23.4	60.1	59.9	-0.2	-0.3%	5,492	2,299	4,313
13 & 19	3	18,148	2,145	0.234	89%	77.6	15.0	15.1	0.1	0.8%	1,010		1,136
14 & 20	3	18,144	2,150	0.234	89%	77.6	15.0	15.1	0.1	0.8%	1,028		834
15 & 21	6	14,978	5,316	0.239	74%	62.8	29.8	30.3	0.5	1.7%	2,542	575	2,198
16 & 22	9	11,580	8,713	0.244	57%	47.5	45.1	45.4	0.4	0.8%	4,057	1,150	3,507
17 & 23	12	8,236	12,057	0.239	40%	34.3	60.1	60.6	0.5	0.8%	5,571	2,299	4,187
18 & 24	12	8,135	12,158	0.244	40%	33.3	60.1	60.6	0.5	0.8%	5,571	2,299	4,288

The simulations show that with 3 MW of PV power plants and no batteries will save US$ 1,130 for a weekend day and a simulated saving of US$1,136 for the week day. 9 MW of PV power plants and keeping 4 MW / 4 MWh battery on primary frequency control and AGC gives an additional cost of US$2,596 for a weekend day and US$3,507 for the week day. 12 MW of PV power plants and keeping 8 MW / 8 MWh battery on primary frequency control and AGC gives a saving of US$ 4,232 for a weekend day and US$4,187 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$ 100 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 3 MW of PV and no battery has an estimated saving of US$ 410,000 per annum. The 6 case with 2 MW / 2 MWh battery has an annual estimated saving of US$ 760,000. The case where 16 MW of PV is installed with 8 MW / 8 MWh battery the annual estimated savings increase around US$ 1.5 million per annum.

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

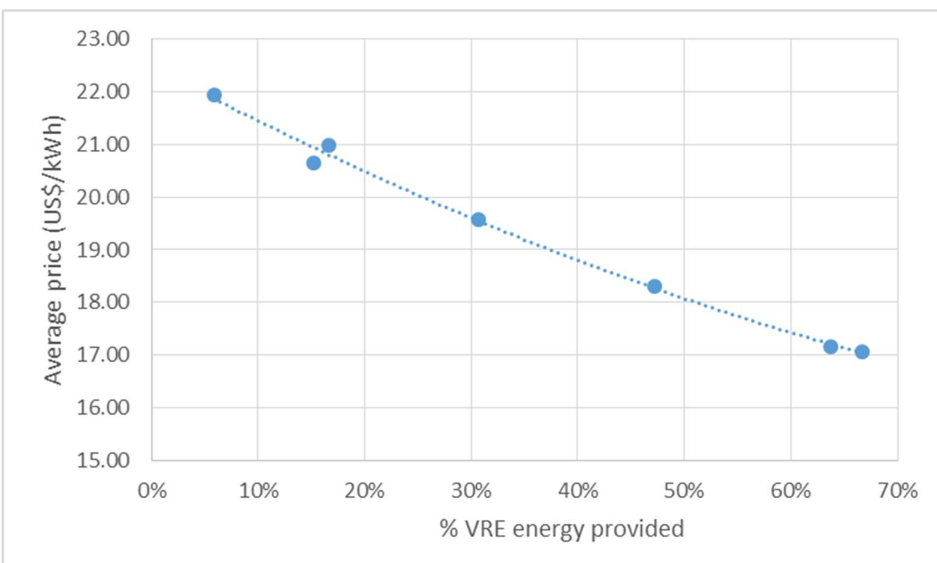
Description	PV Installed (MW)	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated additional battery costs (pa)	Estimated nett saving (pa)
3 MW PV and no battery	3	60%	779,140	366,317	0	412,823
3 MW PV and 1 MW / 1 MWh battery on gov	3	60%	780,380	371,140	104,623	304,617
6 MW PV and 2 MW / 2 MWh battery on gov	6	120%	1,897,329	920,616	209,247	767,467
9 MW PV and 4 MW / 4 MWh battery on AGC	9	180%	3,070,354	1,470,091	418,493	1,181,769
12 MW PV and 8 MW / 8 MWh battery on AGC	12	240%	4,385,365	2,019,567	836,986	1,528,812
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	12	240%	4,419,991	2,019,567	836,986	1,563,438

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$ 7,117,181 at an average 23.2 USc/ kWh. The total variable costs (including additional VRE and battery costs) decreases incrementally as more PV and suggested batteries are added, giving an estimated 11% with 6 MW of PV and 22% saving with 12 MW of PV.

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
3 MW PV and no battery	3	60%	6,704,358	20.656	6%
3 MW PV and 1 MW / 1 MWh battery on gov	3	60%	6,812,564	20.992	4%
6 MW PV and 2 MW / 2 MWh battery on gov	6	120%	6,349,714	19.563	11%
9 MW PV and 4 MW / 4 MWh battery on AGC	9	180%	5,935,411	18.300	17%
12 MW PV and 8 MW / 8 MWh battery on AGC	12	240%	5,588,369	17.167	22%
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	12	240%	5,553,743	17.058	22%

Figure 3-65 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.

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 Pohnpei option with 12MW PV combined with 8 MW/8MWH battery on AGC substituting all of the diesel generation would have the biggest impact on the variable costs. The total decrease in

[15] PPA Benchmarking Report Fiscal year 2017 (published September 2018)

[16] PPA Benchmarking Report Fiscal year 2017 (published September 2018)

total variable costs from the base case scenario would be 22%. 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: Pohnpei - 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
3 MW PV and no battery	3	60%	6,704,358	20.656	6%
3 MW PV and 1 MW / 1 MWh battery on gov	3	60%	6,812,564	20.992	4%
6 MW PV and 2 MW / 2 MWh battery on gov	6	120%	6,349,714	19.563	11%
9 MW PV and 4 MW / 4 MWh battery on AGC	9	180%	5,935,411	18.3	17%
12 MW PV and 8 MW / 8 MWh battery on AGC	12	240%	5,588,369	17.167	22%
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	12	240%	5,553,743	17.058	22%

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

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
3 MW PV and no battery	6,704,358	20.656	6%	28.75	27.51	49.05	47.81
3 MW PV and 1 MW / 1 MWh battery on gov	6,812,564	20.992	4%	28.75	27.91	49.05	48.21
6 MW PV and 2 MW / 2 MWh battery on gov	6,349,714	19.563	11%	28.75	26.60	49.05	46.90
9 MW PV and 4 MW / 4 MWh battery on AGC	5,935,411	18.3	17%	28.75	25.64	49.05	45.94
12 MW PV and 8 MW / 8 MWh battery on AGC	5,588,369	17.167	22%	28.75	24.97	49.05	45.27
12 MW PV and 8 MW / 8 MWh battery on AGC and all diesel allowed to go off	5,553,743	17.058	22%	28.75	25.00	49.05	45.30

Even though the average supply costs of US cents 40.75/kwh for the years 2012-2017 are already well below the actual tariff of US cents 49.05/kwh, the best-case scenario as described above would have a net impact on the tariff of more than US cents 4/kwh (from US cents 49.05/kwh to US cents 45.27/kwh).

3.6 Recommendations for application of storage

The studies show that 3 MW of PV can be installed without the need for batteries primary frequency control support. More than 3 MW of installed PV will require batteries for frequency control.

The secure strategy would be to install 1 MW of battery for primary frequency control once installed PV reaches 3 MW. The simulations show that the 2 MW / 2 MWh battery is probably sufficient for 6 MW of installed PV but this strategy requires that all major PV plants can reduce their output from a centralised control system (AGC).

The annual savings increase when 9 MW with a 4 MW/4 MWh battery is installed to over US$ 1 million.

The simulations show that installing 12 MW of PV with 8 MW / 8 MWh of battery with the current demand will decrease the variable component of the tariff by 22% from 23 to 17 USc / kWh. This is a major decrease on the overall tariff based on 0.82 US$ / litre (3.14 US$ per gallon). 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

Based on best practices adopted in other countries, a grid code has been developed for the Pohnpei Utilities Corporation. This code 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.

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

5.1 Introduction

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

The description of SCADA systems is provided in Appendix 3. This includes an explanation of SCADA system's basic activity, details of additional applications of SCADA, comparison of Energy Management System (EMS) and Distribution Management System (DMS).

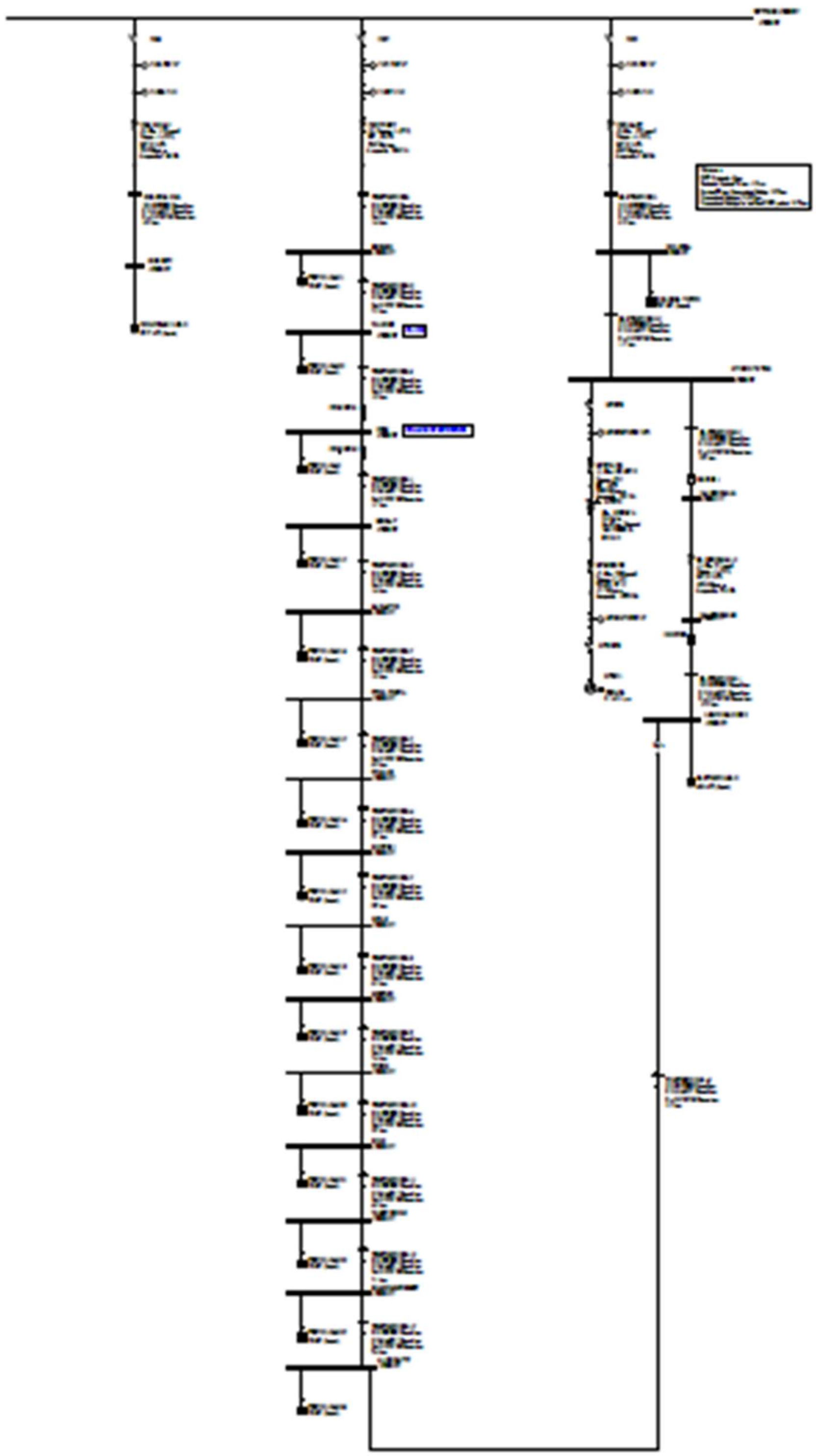
5.2 Network and available Operation Systems

The salient points of the electricity system in Pohnpei can be summarised in the following data:

Concept	**Value**	**Unit**
Peak Load	1.000	kw
Total Energy generated per year	1.535,6	Mwh
PV Energy generated per year	1.183,6	Mwh
Hydro Energy generated per year (1)	352,0	Mwh
Available Generators Conventional		
Generators Renewable		
Conventional Installed power		Mw
Renewable Installed power		Mw
Available SCADA for Generation Control		
Controls some breakers		
Operated Radial		
Number of feeders	3	

(1) Some unavailability's during the year

POHNPEI single line diagram:



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

Functionality is limited to:

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

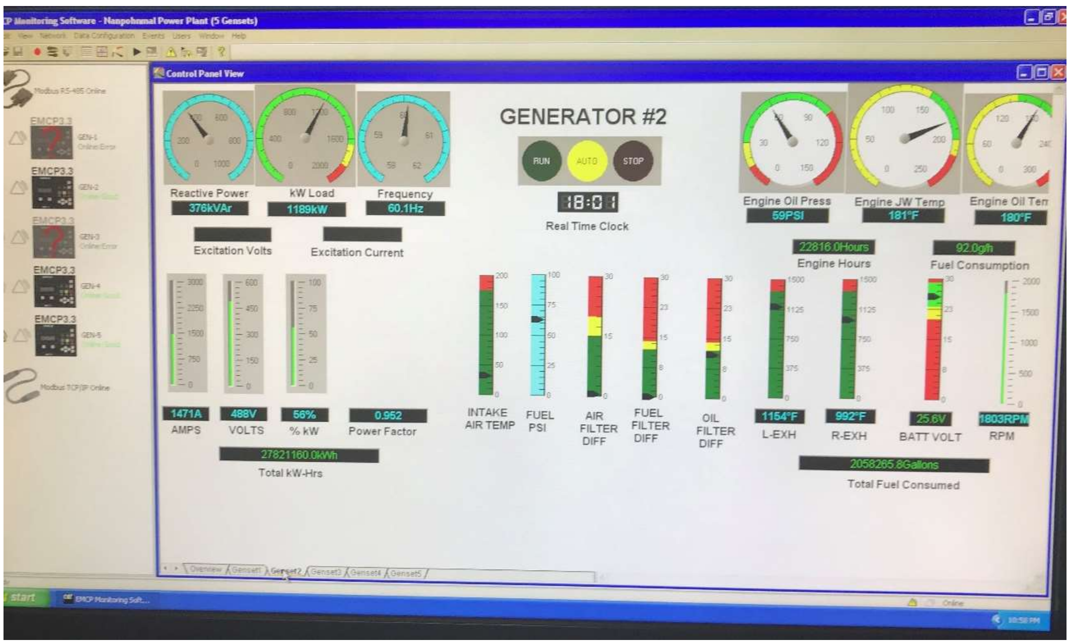
b. Control of the Vital generation units by IPP. This not linked to the control system above.

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

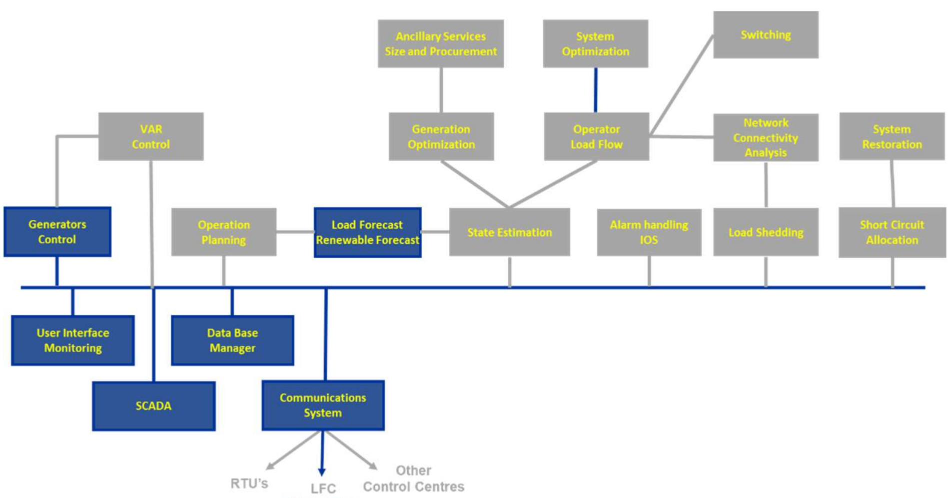
d. No additional functionalities available in top of the SCADA

In addition there is a two data recording systems one for the Caterpillar Diesel units as shown in Figure 5-1 and an information system at Pohnpei Hydro Power Station.

Figure 5-1 Caterpillar information system display



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.

5.3 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 performing the expansions in two or three steps.

The first option has the advantage that all functionality will be 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 will be developed.

5.3.1 Priorities

The priority for improvements:

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

5.3.2 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.

5.3.2.1 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:

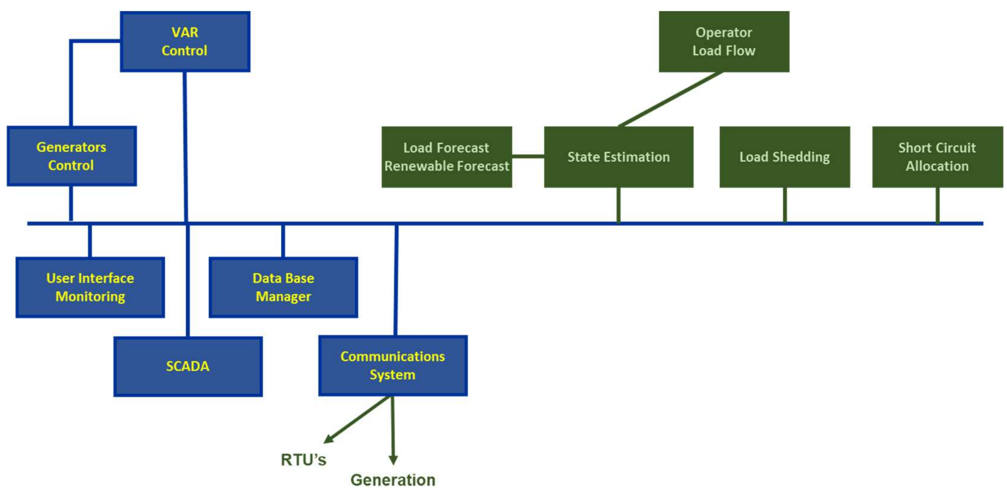
   a. When the frequency reaches a certain value, the load will be automatically disconnected. The total amount of load could be a percentage of the actual load (50%) in 3 to 5 steps of frequency and load. The objective is to stop the drop of frequency before reaches the value where the units will be disconnected 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:



5.3.2.2 Economic Optimization and technical loss reduction

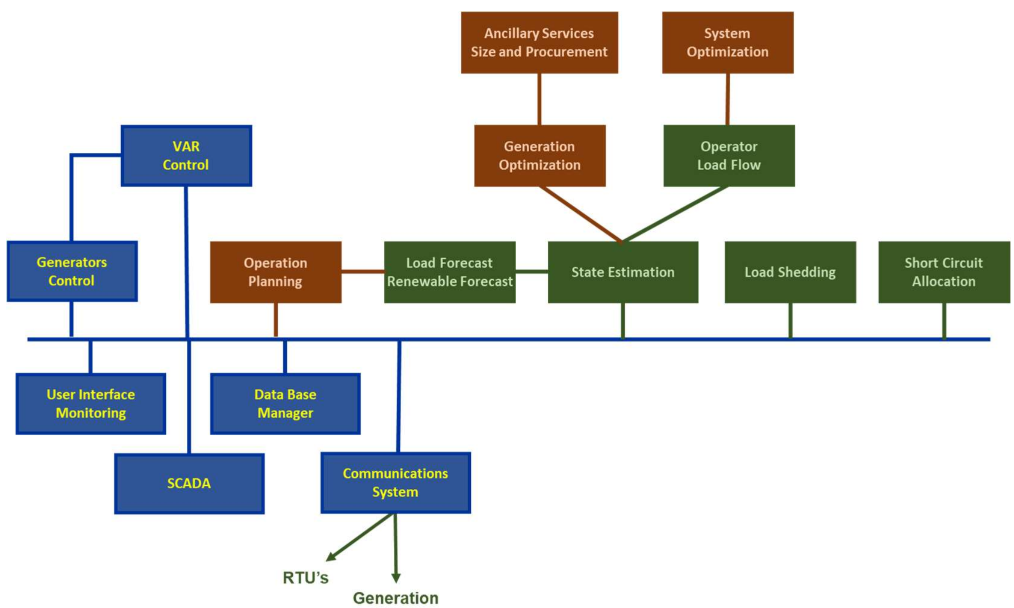
1. **System Optimization.** The technical losses are a function of the resistance and the quadratic of the current circulated between two points. Resistance is a value that depends on the infrastructure and characteristics of the lines or cables. But the Current depends on the network topology. A Minimum 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 POHNPEI system is not inside the definition of “transmission interconnected systems” but is also true that to operate a system like POHNPEI requires consideration of the need for Ancillary Services
4. 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.
5. 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 will be (in brown tones is the second phase):



5.3.2.3 Functionality not recommended

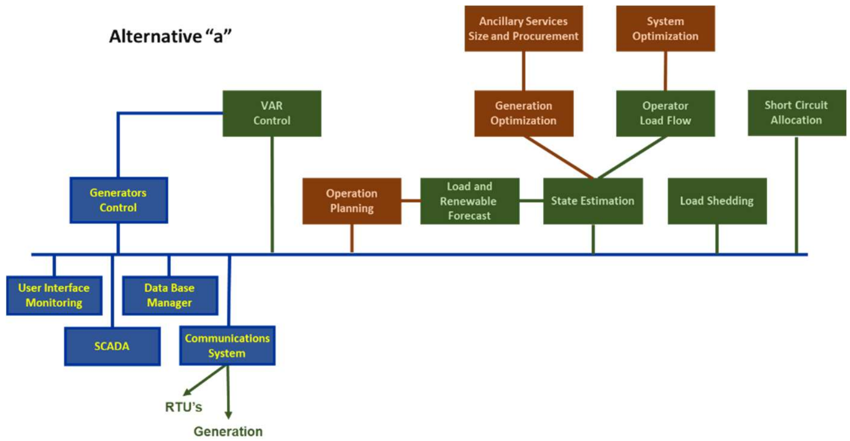
Some functionality is more oriented to much larger systems, where an operator cannot have a detailed knowledge of the full grid. This is not the case observed in the POHNPEI electricity system. These functions are not recommended.

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.

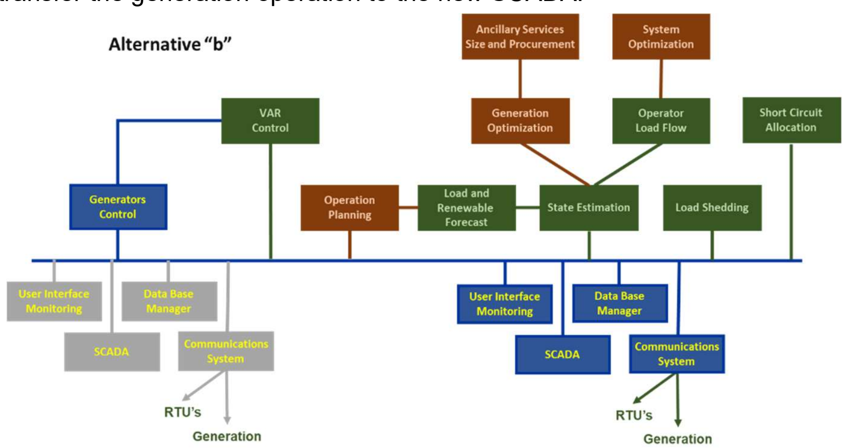
5.4 Architecture Potential alternatives

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:

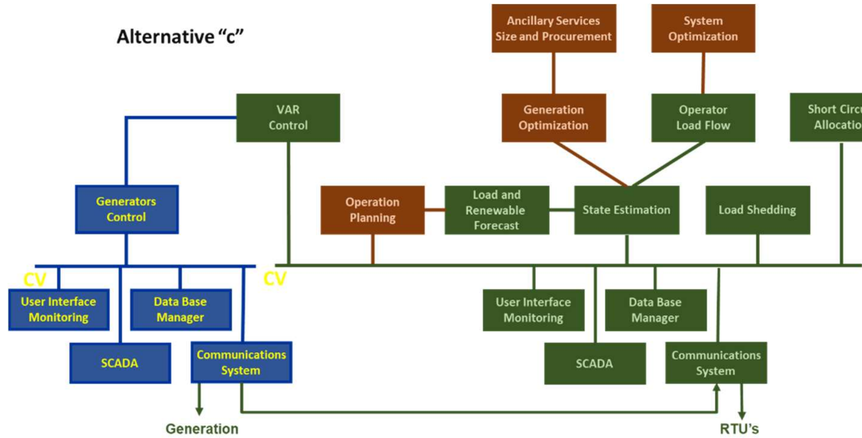
a. Use the actual SCADA system that is available in the POHNPEI system for diesel generation control (blue blocks in the following figures) and expand its functionality with the one required for distribution network control (green blocks at first step, and brown in second).



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.



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 will become a separate system. Maintains the generators control as it is.

Considering those aspects and because:

- It is mandatory to maintain the generators control provided by the generator's 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 will be explained below

Considering those reasons, and the system size, we recommend for the first phase the alternative "c" as optimal solution, complete the option "c" shall be considered in the future. Maintain the actual system conditions could be an acceptable conservative solution.

Especial economic considerations shall be considered due the economic impact of the investment and operational costs per kwh served.

5.5 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

5.5.1 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 POHNPEI, to start with, the number of RTU's shall be between 3 and 4.

5.5.2 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.

5.5.3 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.

5.5.4 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 will be helpful to maintain under control the system operative

5.6 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 will be 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.

5.6.1 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, will be applied to determine the winner bid.

The following step will be 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 will be 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 will be 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.

5.6.2 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.

5.6.3 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 will be 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 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.

5.7 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.

5.7.1 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 3 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.

5.7.2 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 on call during 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 will be the 3 needed minus 1, the actual expert, which make 2 new employees.

In case of consortium, the need to contract people will be 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 will be substituted by another one and the expertise acquired by the administrators will be very valuable for a new system.

5.7.3 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 will be 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 public 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:

5.7.3.1 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 an 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.

5.7.3.2 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 one home, due the loss of refrigeration, loss of capacity to recover electronic communication means (TV, Laptops, smart phones), Hotels may suffer economic losses and streetlighting outages can impact public safety.

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 will be much easier to evaluate costs than profit, but simple analysis must show clear benefits.

5.8 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 will be in the first phase. When this phase will be consolidated, then a second phase with the Economic Optimisation and Losses Reduction will be implemented.
- ✓ Together with the first phase, the commitment and test of at least 3 RTU’s.
- ✓ For `procurement, training, commitment, test and commercial operation we recommend achieving an agreement with other utilities 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.

5.8.1 Recommendation for staged implementation and roadmap: Pohnpei

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 of the Power station, large PV plants and some reclosers on the 13.8kV backbone with the ability to perform remote switching of the network	Extend the SCADA to include all PV plants and additional reclosers on the 13.8kV backbone 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 backbone switching nodes including the Power stations and the large PV plant 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
- 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 must 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 all PV plants and additional nodes on the 13.8kV backbone and deploy some DMS functions listed below:

- Include SCADA visibility of all PV plants.

- 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.

Note: All 13.8kV nodes may not be covered with visibility at stage 2 depending on the final budget and cost to implement telemetry for each recloser.

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

  This 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

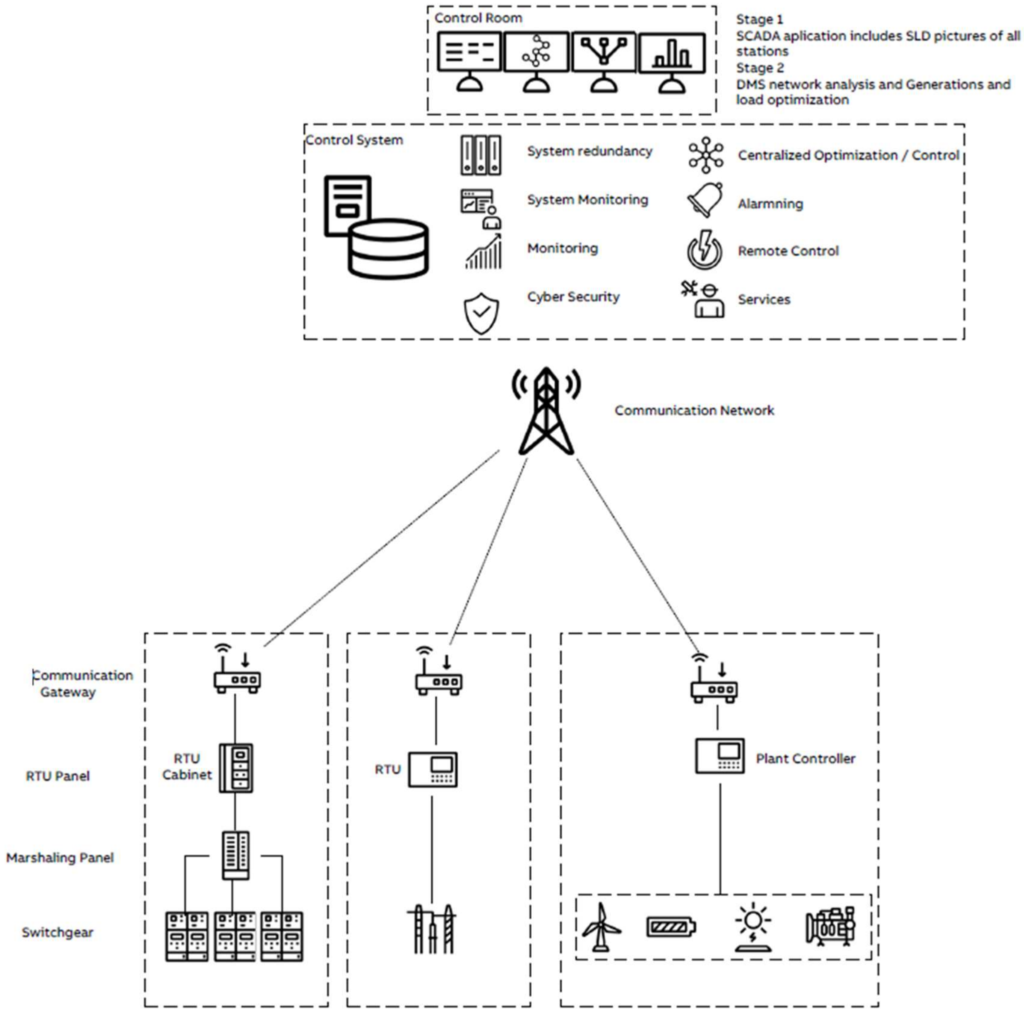
  Extending the LV visibility up to the customer can be achieved with the deployment of SMART meters with bi-directional communication. This can automate outage notification, identify voltage violations and support future volt/var optimization and conservation voltage reduction. This implementation will 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 will be 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

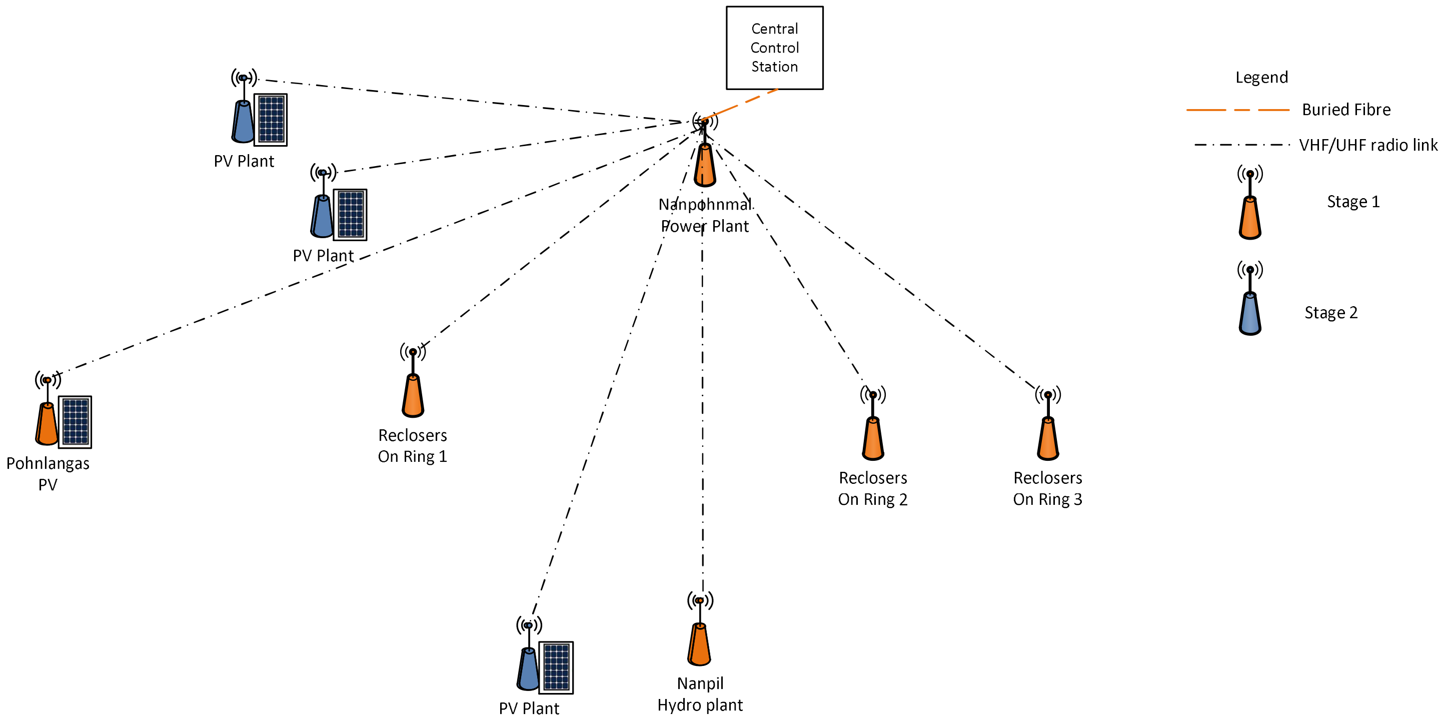
The conceptual design of the SCADA Control System is described in Figure 5-2.

Figure 5-2: Conceptual design of the SCADA Control System



The conceptual design solution of the communication network is described in Figure 5-3.

Figure 5-3: Concept communication network diagram for Pohnpei 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) Due to short distance, each station links to the high-site near the power station. Line-of-sight paths and signal propagation budget calculations need to be confirmed in the next project stage.
3) It is assumed the Central Control Station will be located at the power plant but can be located at any office in town with an additional communication link.

Figure 2: Concept communication network diagram for Pohnpei network

5.8.2 Cost Estimate

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

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

	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 Comms tower)	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	$ 30,000	$ 30,000	
Design and engineering	1	lot	$ 40,000	$ 40,000	1	lot	$ 40,000	$ 40,000	
Installation and commissioning	1	lot	$ 20,000	$ 20,000	1	lot	$ 30,000	$ 30,000	
				$ -				$ -	
Substations				$ -				$ -	
Hardware				$ -				$ -	
- RTUs: Main power plant	1	each	$ 30,000	$ 30,000					Provisional estimate subject to site audit
- RTUs (Reclosers)	20	each	$ 5,000	$ 100,000	15	each	$ 5,000	$ 75,000	Provisional qty for telemetry of switches on back
- RTUs (PV sites)	1	each	$ 5,000	$ 5,000	3	each	$ 5,000	$ 15,000	Telemetry of PV sites
- Transducers	10	each	$ 2,000	$ 20,000	10	each	$ 2,000	$ 20,000	Provisional estimate subject to site audit
- Communication equipment: Central Station	1	each	$ 20,000	$ 20,000				$ -	
- Communication equipment: Stations	21	each	$ 5,000	$ 105,000	18	each	$ 5,000	$ 90,000	
- Auxiliary DC system	21	each	$ 2,000	$ 42,000	18	each	$ 2,000	$ 36,000	Provisional estimate subject to site audit
Design and Engineering	1	lot	$ 20,000	$ 20,000	1	lot	$ 10,000	$ 10,000	
Installation, adaptation and commissioning	21	each	$ 5,000	$ 105,000	18	each	$ 5,000	$ 90,000	Provisional estimate subject to site audit
				$ -				$ -	
Travel and accommodation	1	lot	5.0%	$ 29,200	1	lot	5.0%	$ 21,800	
Project overheads	1	lot	5.0%	$ 29,200	1	lot	5.0%	$ 21,800	
Contingency	1	lot	15.0%	$ 87,600	1	lot	15.0%	$ 65,400	
								$ -	
				$ 730,000				$ 545,000	

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.

Appendices

Appendix 1: Grid Connection Code

Appendix 2: Description of GDAT model

Appendix 3: Description of SCADA and EMS

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