Final Report and Model for Electric Power Corporation (Samoa)

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

WORLD BANK GROUP

ESMAP
Energy Sector Management Assistance Program

PPA
PACIFIC POWER ASSOCIATION

ED 10514 | Issue Number 3 | Date 30/05/2019
Ricardo in Confidence

Customer:

The World Bank

Customer reference:

Selection # 1238727

Confidentiality, copyright & reproduction:

The financial and technical support by the Energy Sector Management Assistance Program (ESMAP) is gratefully acknowledged. ESMAP—a global knowledge and technical assistance program administered by the World Bank—assists low- and middle-income countries to increase their know-how and institutional capacity to achieve environmentally sustainable energy solutions for poverty reduction and economic growth. ESMAP is funded by Australia, Austria, Denmark, the European Commission, Finland, France, Germany, Iceland, Italy, Japan, Lithuania, Luxemburg, the Netherlands, Norway, the Rockefeller Foundation, Sweden, Switzerland, the United Kingdom, and the World Bank Group.

Contact:

Graeme Chown
Ricardo Energy & Environment
Gemini Building, Harwell, Didcot, OX11 0QR, United Kingdom

t: +44 (0) 1483544 944
e: graeme.chown@ricardo.com

Ricardo-AEA Ltd is certificated to ISO9001 and ISO14001

Author:

Chown, Graeme, TNEI;AF-Mercados

Approved By:

Fry, Trevor

Date:

30 May 2019

Ricardo Energy & Environment reference:

Ref: ED10514- Issue Number 3

Table of contents

Appendices

1 Introduction

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

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

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

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

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

2 Task 1: Grid Integration and Planning Studies

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

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

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

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

The networks studied in Task 1 are shown in the table below:

Table 2-1: Network Studies for Pacific Island Countries

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

2.1 Power system study methodology

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

1) Development and finalisation of base case network models using existing DIgSILENT network model files where available, or developing DIgSILENT models from data collected from utilities.
2) Perform load flow studies to assess the steady state performance of the power system. The following assessments have been made:
   - The loading conditions of network components in the system (measured as a percentage of rating) with the given demand level. Network components with loading conditions above 90% of the specified rating have been reported.
   - The voltage profile across the network (measured in per unit) with the given demand level. Nodes with a recorded voltage magnitude above 1.10pu and below 0.90pu have been reported.
   - Network capability to meet a scaled load demand of 105% or 110% (depending on size of network) of existing load demand level. Any overloads and voltage violations have been reported.

3) Perform contingency and switching operation studies to assess the steady state performance in each power system under credible outage or switching operation conditions. The contingency studies will be performed on mesh networks, while the switching operation studies have been applied to the radial network with switch devices on or between feeders. The following assessments have been made:
    - The loading conditions of network components in the system (measured as a percentage of rating) under the credible outage or switching operation conditions. Network components with loading conditions above 90% of the specified rating have been reported.
    - The voltage profile across the network (measured in per unit) with the given demand level under the credible outage or switching operation conditions. Nodes with a recorded voltage magnitude above 1.10pu and below 0.90pu have been reported.
    - Network capability to meet a scaled load demand of 105% and 110% of existing load demand level under credible outage or switching operation conditions. Any overloads and voltage violations have been reported.
4) Perform fault studies to assess fault levels at power plant busbars and those nodes with switches in each power system. The following assessments have been made:
    - Three phase fault levels;
    - Single phase to ground fault level;
    - Make fault current at 10 ms and Break fault current at 50 ms for a 50 Hz system; and
    - Make fault current at 12 ms and Break fault current at 60 ms for a 60 Hz system.
5) Perform stability studies to determine stability performance in each power system for credible dynamic events and contingencies under various operational scenarios with different VRE generation contribution levels. The studies are carried out based on the given load demand level in the system. The following assessments have been made:
    - Frequency and voltage response of the system subsequent to the loss of the largest generating unit in the system.
    - Frequency and voltage response of the system subsequent to the loss of the feeder with the largest MW load demand.
    - Rotor angle and voltage stability of the system subsequent to a three phase fault applied on feeders followed by tripping of the feeder with 150 ms delay. A fault is applied respectively on the feeders with the smallest and the largest MW load demand.
    - Frequency and voltage response of the system subsequent to the MW output change from the PV sites. The MW output of all PV sites in the system is assumed to drop from specified 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 have been assumed to rise from 0 MW output level to the specified MW output level within 10 seconds.

Steps 1 – 5 as listed above have formed 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 have been increased in suitable increments (depending on the size of the network) and the following steps are performed to assess the network capability to accommodate these renewables.

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

- Existing network topology.
- The assumed maximum load demand level, which could be 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%, 20%, and 30% of total installed generation capacity in the system. New renewable generation sites could be distributed across the system.
- Renewable generation is fully dispatched in the considered operational scenarios. The conventional generators, however, are dispatched based on merit order to balance the rest of power mismatch in the system. The merit order of conventional generators is assumed based on good engineering practice if unavailable. The calculated spinning reserve capacity shall be more than 10% of the demand level.

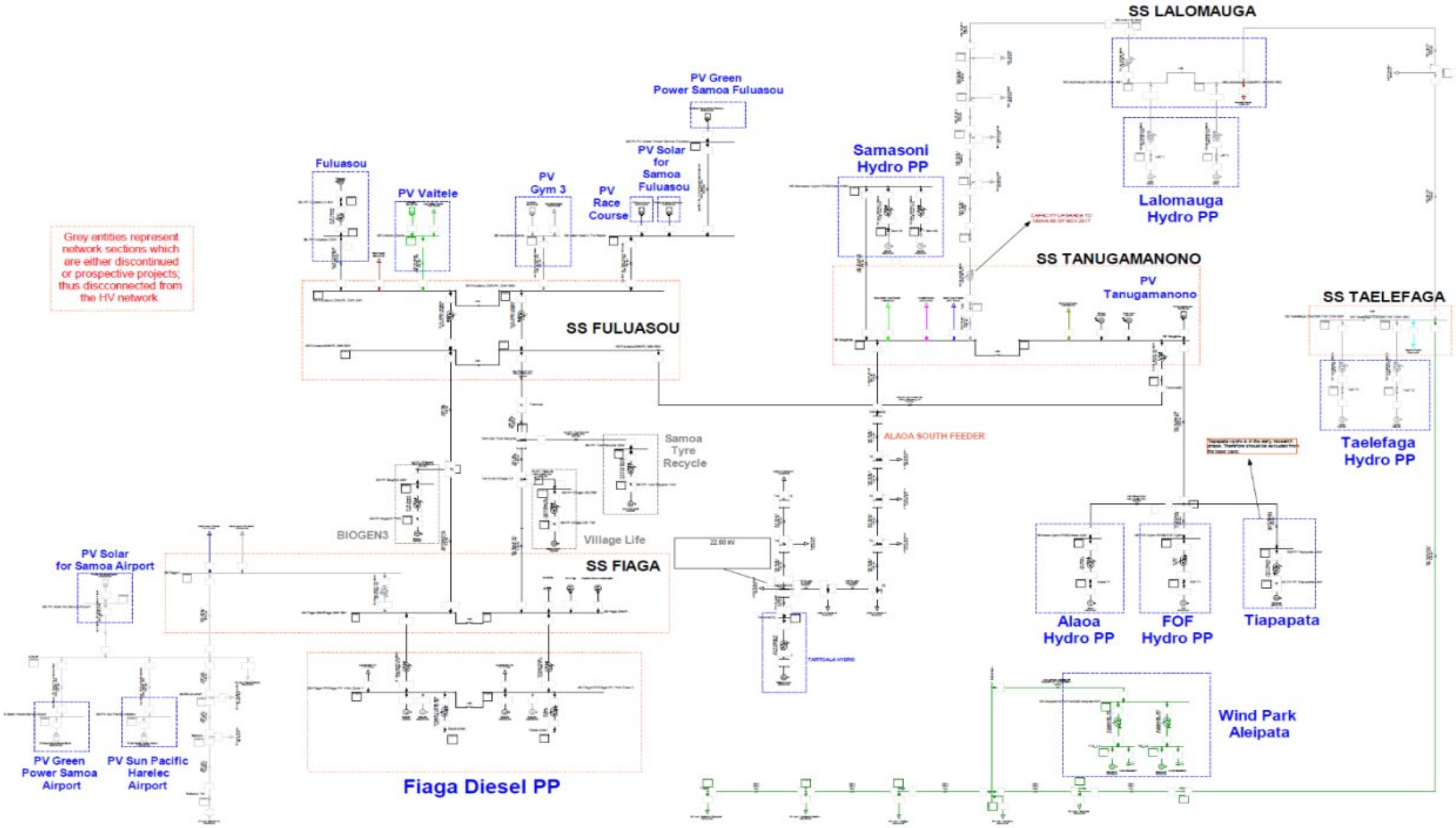
The following studies will then be performed:

6) Stability simulations to assess system frequency response for the two events:
   - The sudden loss of the largest generating units on line
   - The drop of MW output from all PV site with 10 seconds
      - If the minimum frequency deviation of the system for any event is within 2% of nominal frequency, it indicates that the system has the capability to integrate the amount of assumed renewable generation capacity.
      - If the minimum frequency deviation of the system for any event is greater than 2% of nominal frequency, it is anticipated that the following steps should be taken:
   - First step: Switch on one or more of the conventional generators connected to the system and assume that they are operated at their minimum MW output to increase the spinning reserve capacity of the system. To balance the power mismatch in the system, the MW output of other conventional generators including the largest generating unit is adjusted accordingly. Re-run the simulations to confirm 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.
   - Second Step: If the first step does not work, 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 Upolu Island Network, Samoa

The power system on Upolu Island has four voltage levels (shown in Figure 2-1 below) in operation: 33 kV, 22 kV, 11 kV and 400 V. The network single line diagram (SLD) (DIgSILENT model) shows the 33 kV and 22 kV networks’ connection configuration.

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



The generation connected to the system is a mix of conventional and renewable generation as presented in Table 2-2 below. This was extracted from the DIgSILENT model provided by the client.

Table 2-2: Generation connected to Upolu Island power system

Conventional Generation			Renewable Generation		
Power plant	Rated Capacity (kW)	Technology	Power plant	Rated Capacity (kW)	Technology
Alaoa	1000	Hydro	PV GYM 3	250	PV
FOF	1600	Hydro	PV Green Power Samoa Airport	2400	PV
Fuluasou	680	Hydro	PV Green Power Samoa Fuluasou	2400	PV
LM #1 (LALOMAUGA)	1760	Hydro	PV Race Course	2200	PV
LM #2 (LALOMAUGA)	1760	Hydro	PV Solar for Samoa Airport	2000	PV
Sam #1 (SAMASONI)	900.0	Hydro	PV Solar for Samoa Fuluasou	2000	PV
Sam #2 (SAMASONI)	900.0	Hydro	PV Sun Pacific Harelec Airport	2000	PV
TAF #1 (TAELEFAGA)	2000	Hydro	PV Tanugamanono	150	PV
TAF #2 (TAELEFAGA)	2000	Hydro	PV Vaitele	250	PV
Tafitoala Hydro	460	Hydro	Aleipata #1	275	Wind
Fiaga #1	5770	Diesel	Aleipata #2	275	Wind
Fiaga #2	5770	Diesel			
Fiaga #3	5770	Diesel			
Fiaga #4	5770	Diesel			
Sub-total (kW)	**36,140**			**14,200**	
Total (kW)	**50,340**				

As can be seen from the table, the installed generation capacity of the Upolu network is 50,340 kW with conventional generation capacity of 36,140 kW and renewable generation of 14,200 kW. The renewable generation accounts for 28.2% of the total installed generation capacity. In addition, there are two battery storage sites with 2000 kW & 3500 kWh installed at the airport, and 6000 kW and 10200 kWh installed at Fiaga.

In accordance with the network data in the DIgSILENT model, it is anticipated that other conventional generation may be connected to the Upolu network in the near future, such as the 3x4000 kW generating units proposed by TAFAIGATA IPP, and the 480kW hydro generating unit at Tiapapata. These generating units, however, will not be considered in the system studies.

The maximum demand of the network is 25,982 kW, and the minimum demand is 13,084 kW.

2.2.1 Power system data and assumptions

The data made available for the power system studies of the Samoa utility network on Upolu Island 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 and so none have been assumed in this case.
- Fault levels and switchgear ratings – no switchgear ratings have been provided and so these have been assumed as typical industry values

- Grid code, local operational requirements – no grid code or local operational requirements provided, typical industry standards

2.3 Power System Study Results

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

2.3.1 Load flow studies

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

The load flow results for above 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 2-3: Maximum demand scenario load flow results

Demand Level	Maximum thermal loading (%)	Maximum Voltage (pu)	Minimum Voltage (pu)
Base Case	67.5	1.066	0.976
10% Load Scaling	72	1.064	0.96

The highest recorded voltage on the network in the maximum demand scenario is 1.066pu at the BB Auto LM busbar on the 33 kV network. The lowest voltage on the network in this scenario was recorded as 0.976pu at the Tafitoala Hydro 22 kV busbar. All voltages on the Upolu network remain within the ±10% limits.

There are no thermal loading issues on this network in this scenario, with a maximum loading of 67.5% experienced on the 22 kV West Coast 2 Tie feeder which has the rated capacity of 10.3 MVA or 271 amps at nominal voltage of 22 kV. All 33 kV circuits are loaded less than 33% of their ratings and other 22 kV circuits are loaded less than 49% of their ratings.

The load of the maximum demand scenario was scaled to 110% and the load flow studies performed again to allow assessment of the resilience of the existing network to meet increased demand. The results highlight a maximum voltage of 1.064pu recorded at the BB Auto LM 33 kV busbar and a minimum voltage of 0.96pu at the Tafi TN-LM 22 kV busbar. The maximum thermal loading in the network is 72% along the South TN-LIN circuit. Most circuits are loaded less than 52% of their ratings.

Minimum demand scenario

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

Table 2-4: Minimum demand scenario load flow results

Demand Level	Maximum thermal loading (%)	Maximum Voltage (pu)	Minimum Voltage (pu)
Base Case	49.8	1.053	0.908

The highest voltage on the Upolu network for the minimum demand scenario was recorded as 1.053pu at the BB Auto LM busbar on the 33 kV network, while the lowest voltage was seen on the 11 kV network where the Fiaga PP busbar showed a voltage of 0.908pu. All voltages on the network remain within the limits for this scenario.

The 22 kV West Coast 2 Tie feeder was again the most heavily loaded on the network, showing a maximum loading of 49.8% under minimum demand operating conditions.

Based on loading condition over 33 kV and 22 kV networks under the scaled maximum load demand scenarios, it is anticipated that Upolu network has plenty headroom for connection of new generation and demand to the system.

2.3.2 Contingency studies

The Upolu Island network is not suitable for contingency studies to be carried out as the 33kV and 22kV networks are basically radial in configuration and the network model would not be able to operate upon the loss of certain assets.

2.3.3 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. Table 2-5 shows the results for both 3 phase and single-phase-to-ground faults; peak current (ip) and break current (Ib) are shown for each voltage level and Ib has been captured at 50ms after the fault.

Table 2-5: Maximum fault level results for Upolu Island

Fault Level	kA	Busbar	Voltage Level
Three Phase ip	8.695	Fiaga 33kV BB1/BB2	33
Three Phase Ib	2.359	Fiaga 33kV BB1/BB2	33
Single Phase ip	13.774	Fiaga 33kV BB1/BB2	33
Single Phase Ib	9.026	Fiaga 33kV BB1/BB2	33
Three Phase ip	9.406	FL 22kV BB1/BB2 (Fuluasou)	22
Three Phase Ib	2.965	FL 22kV BB1/BB2 (Fuluasou)	22
Single Phase ip	7.800	SS Tanugamanono 22kV	22
Single Phase Ib	4.544	SS Tanugamanono 22kV	22
Three Phase ip	31.549	Fiaga PP 11kV Zone 1/ Zone 2	11
Three Phase Ib	7.874	Fiaga PP 11kV Zone 1/ Zone 2	11
Single Phase ip	n/a	n/a	11
Single Phase Ib	n/a	n/a	11

There were no switchgear or circuit breaker ratings provided for the Upolu Island 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 (see Figure 2-2 below), 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

2.3.4 Stability studies

The stability of the system (maximum demand scenario) in terms of rotor angle, voltage and frequency stability was assessed for various events including:

1) Loss of the largest generator on the system;
2) A three phase fault on the largest demand conductor followed by the tripping of the conductor after 150 ms; and
3) A three phase fault on the smallest demand conductor followed by the tripping of the conductor after 150 ms.

The stability performance of the system was assessed for a number of operational scenarios taking into consideration various contribution levels of VRE generation. Based on good engineering practice, a merit order is assumed for all generating units in the system in order to meet the maximum demand needs in those operational scenarios.

There is a battery storage facility being commissioned on Samoa at the time of writing (6MW at Fiaga), with an existing 2MW battery installed already at the airport. To demonstrate the impact of these batteries on the frequency response of the system, the stability studies have been carried out both with and without the batteries connected.

2.3.4.1 Stability Study Case 1 (0% VRE Contribution)

The generation dispatch of the island's generators for this study case is shown in Table 2-6. This generation dispatch represents the system assuming no renewable generation is available e.g. at night (or with island-wide cloud cover, with no wind). In this generation dispatch scenario, the spinning reserve of the system is estimated to be 9484.5 kW, which is approximately 39% of the total generation kW output.

Table 2-6: Generation mix on Samoa for Study Case 1

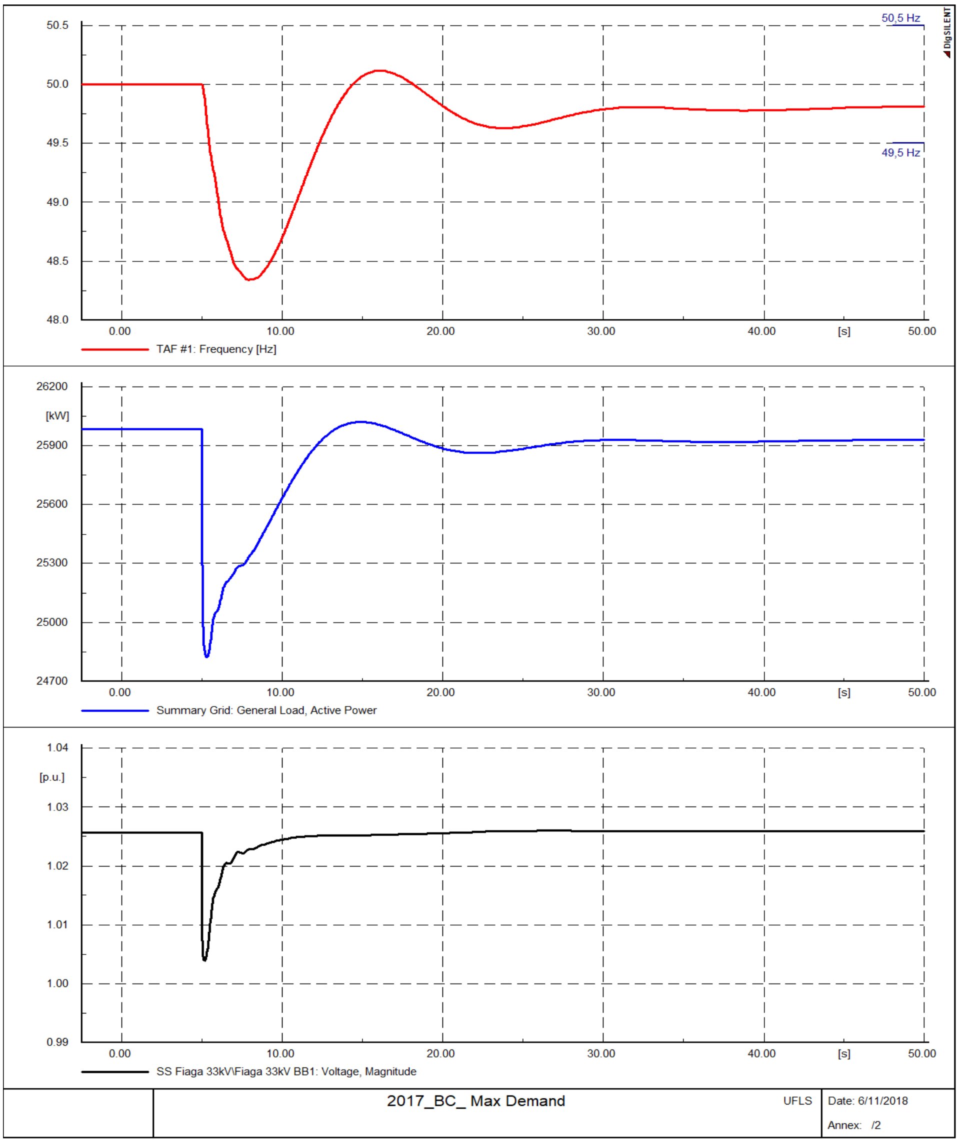
Generation Type	Unit ID	Merit Order	Operational Status	Maximum Generation Output (kW)	Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
	Alaoa	2	1	1000	850.0	150.0	1.6%

Conventional generation	FOF	2	1	1600	1360.0	240.0	2.5%
	Fuluasou	2	1	680	578.0	102.0	1.1%
	LM #1 (LALOMAUGA)	2	1	1760	1496.0	264.0	2.8%
	LM #2 (LALOMAUGA)	2	0	1760	0.0	0.0	0.0%
	Sam #1 (SAMASONI)	2	1	900.0	765.0	135.0	1.4%
	Sam #2 (SAMASONI)	2	1	900.0	765.0	135.0	1.4%
	TAF #1 (TAELEFAGA)	2	1	2000	1700.0	300.0	3.2%
	TAF #2 (TAELEFAGA)	2	1	2000	1700.0	300.0	3.2%
	Tafitoala Hydro	2	1	460	391.0	69.0	0.7%
	Fiaga #1	3	1	5770	4904.5	865.5	9.1%
	Fiaga #2	3	1	5770	3462.0	2308.0	24.3%
	Fiaga #3	3	1	5770	3462.0	2308.0	24.3%
	Fiaga #4	3	1	5770	3462.0	2308.0	24.3%
	Sub-total			**36140**	**24895.5**	**9484.5**	**100.0%**
Renewable generation	PV GYM 3	1	0	250	0.0	0.0	0.0%
	PV Green Power Samoa Airport	1	0	2400	0.0	0.0	0.0%
	PV Green Power Samoa Fuluasou	1	0	2400	0.0	0.0	0.0%
	PV Race Course	1	0	2200	0.0	0.0	0.0%
	PV Solar for Samoa Airport	1	0	2000	0.0	0.0	0.0%
	PV Solar for Samoa Fuluasou	1	0	2000	0.0	0.0	0.0%
	PV Sun Pacific Harelec Airport	1	0	2000	0.0	0.0	0.0%
	PV Tanugamanono	1	0	150	0.0	0.0	0.0%
	PV Vaitele	1	0	250	0.0	0.0	0.0%
	Aleipata #1	1	0	282.0	0.0	0.0	0.0%
	Aleipata #2	1	0	282.0	0.0	0.0	0.0%
	Sub-total			14214.0	0.0	0.0	0.0%
	Total			**25982**	**24895.5**	**9484.5**	**39.1%**

Loss of largest generator

The largest generators on the system are the Fiaga diesel generators which are all 5.778 MW in size, and in this case Fiaga #1 is operating at the highest output of 4904 kW and so it was tripped to study the impacts on the system. The voltage and frequency responses are shown in Figure 2-3. This network does not have the battery storage facilities connected.

Figure 2-3: Voltage & frequency response to loss of largest generator – without battery storage connected (Case 1)



After the loss of the largest generating unit, the available spinning reserve in the system is around 8619 kW as per in Table 1-6. The available spinning reserve is much more than the generation output of the largest generating unit and is adequate to cover the loss of the largest generating in terms of power balance of generation and demand in this case.

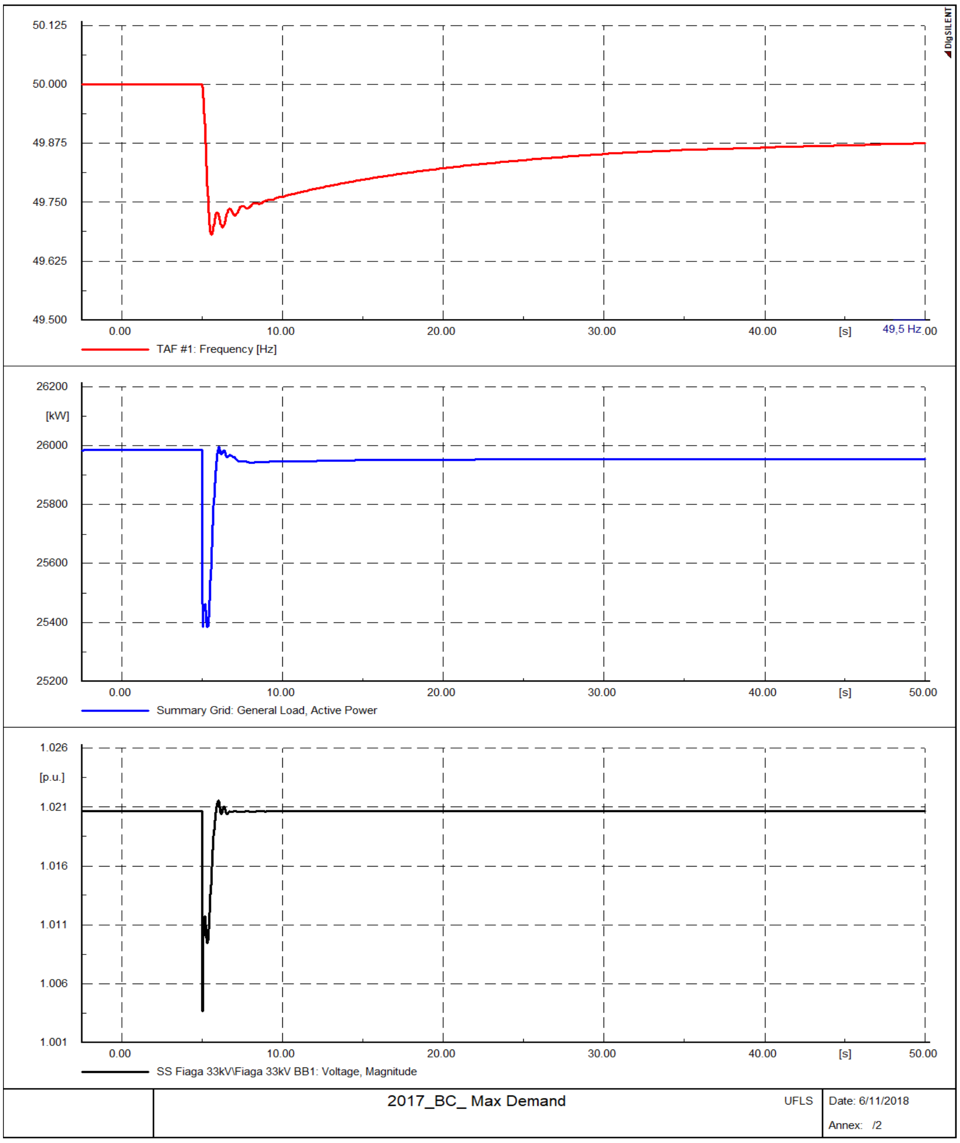
The generator is tripped at 5 s and the frequency drops from 50 Hz down to around 48.3 Hz. The frequency then takes around 25 seconds to recover and settle at around 49.8 Hz. This is a large deviation, much larger than the 2% allowable limit for frequency, since the Fiaga #1 generator represents almost 20% of the total generation operating on the system at the time.

It is expected that small inertia of the system combined with dynamic response of hydro generating units plays an import role to the large frequency deviation after the loss of the largest generating unit. In this case it is common practice to execute a scheme such as under frequency load shedding (UFLS) to return the system to nominal. As a result, the system is unable to withstand the loss of the largest generating unit operated at 4904 kW in this scenario, unless other solution is available to prevent large frequency drop.

Despite the large deviation in frequency, all other generators on the system remain connected to the system and the system is stable. The voltage at the Fiaga 33 kV busbar drops by about 0.02pu as the generator is tripped and this recovers to its original level, around 1.025pu, within 5 s.

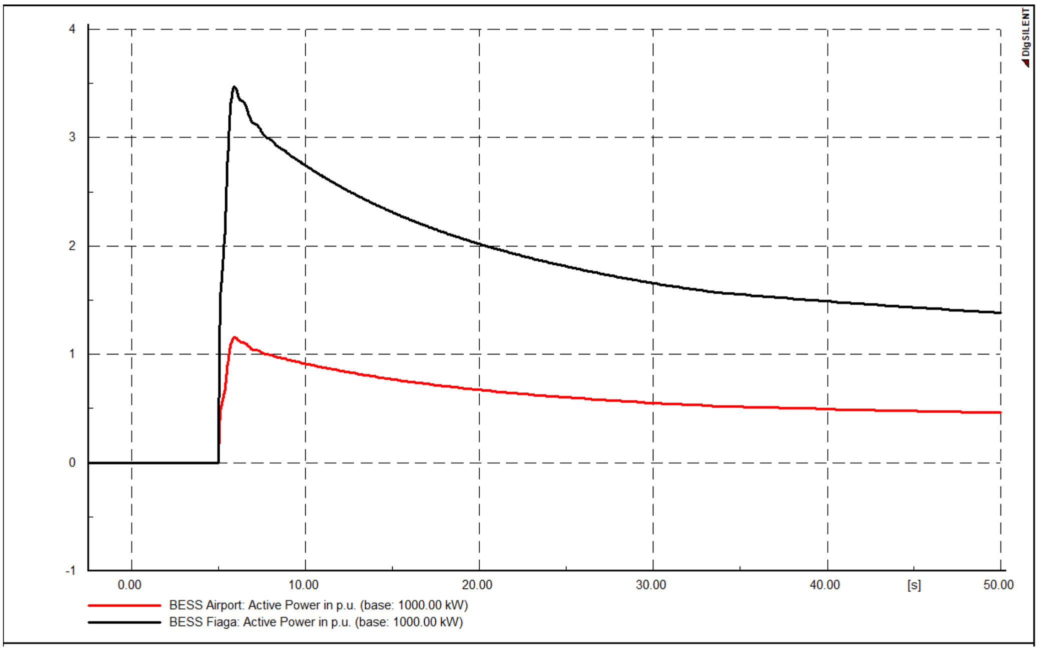
The study was repeated to include the battery storage sites on the island to assess the impact on the system's ability to withstand the loss of the largest generator. The same generation dispatch was applied and the frequency and voltage responses are shown in Figure 2-4 below.

Figure 2-4: Voltage & frequency response to loss of largest generator – with battery storage connected (Case 1)



The frequency response of the system when 8MW of battery storage is connected is noticeably improved. The frequency reduces to around 49.7 Hz and recovers to 49.875 Hz steadily. There is no longer a large deviation which would result in UFLS being executed. The responses of both battery storage facilities are shown in Figure 2-5.

Figure 2-5: Battery storage active power response to loss of largest generator (Case 1)



The batteries respond instantaneously to the event and the contribution decreases over time as the system frequency recovers.

Tripping of largest demand feeder after a fault

The largest loaded feeder under the generation dispatch profile detailed in Table 1-6 (the feeder with the largest load demand) in the system is the 33 kV TN-LM 5 which is carrying 4MW for the study conditions. A three phase fault is applied on the feeder for 150 ms and the fault is then cleared with the feeder tripped. The voltage and frequency response and rotor angles to the tripping of the largest feeder are shown in Figure 2-6 and Figure 2-7 respectively.

For this faulted trip event, the frequency of the system increases from 50 Hz up to almost 55.5 Hz which is well outside the 2% limit. The voltage at the Fiaga 33 kV busbar drops to 0.77 pu from 1.015pu during the fault and recovers to the acceptable level immediately after the fault is cleared. It is advised that the frequency rise shall be checked against the over-frequency relays of conventional generators in the system and relevant solution shall be taken to prevent cascade tripping of conventional generators due to frequency rise.

Figure 2-6: Voltage and frequency response to largest feeder trip (Case 1)

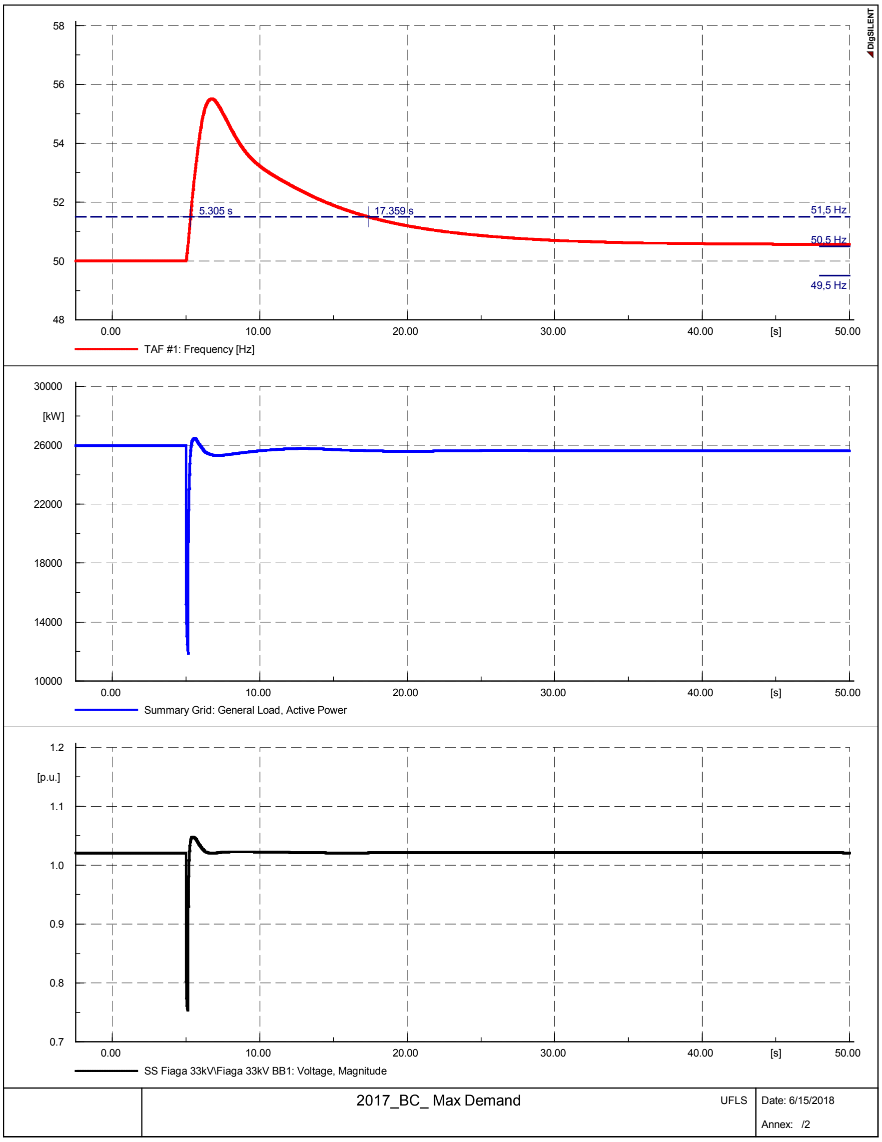
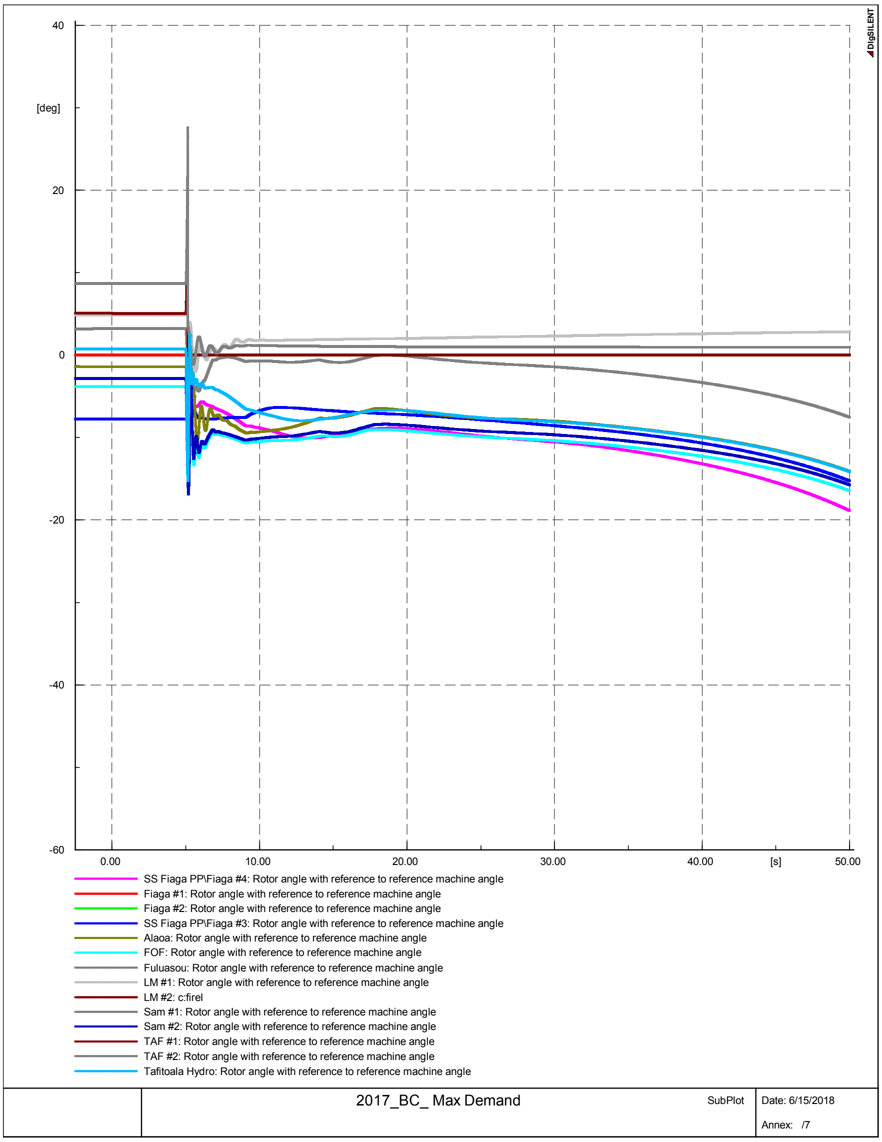


Figure 2-7: Rotor angle response to largest feeder trip (Case 1)

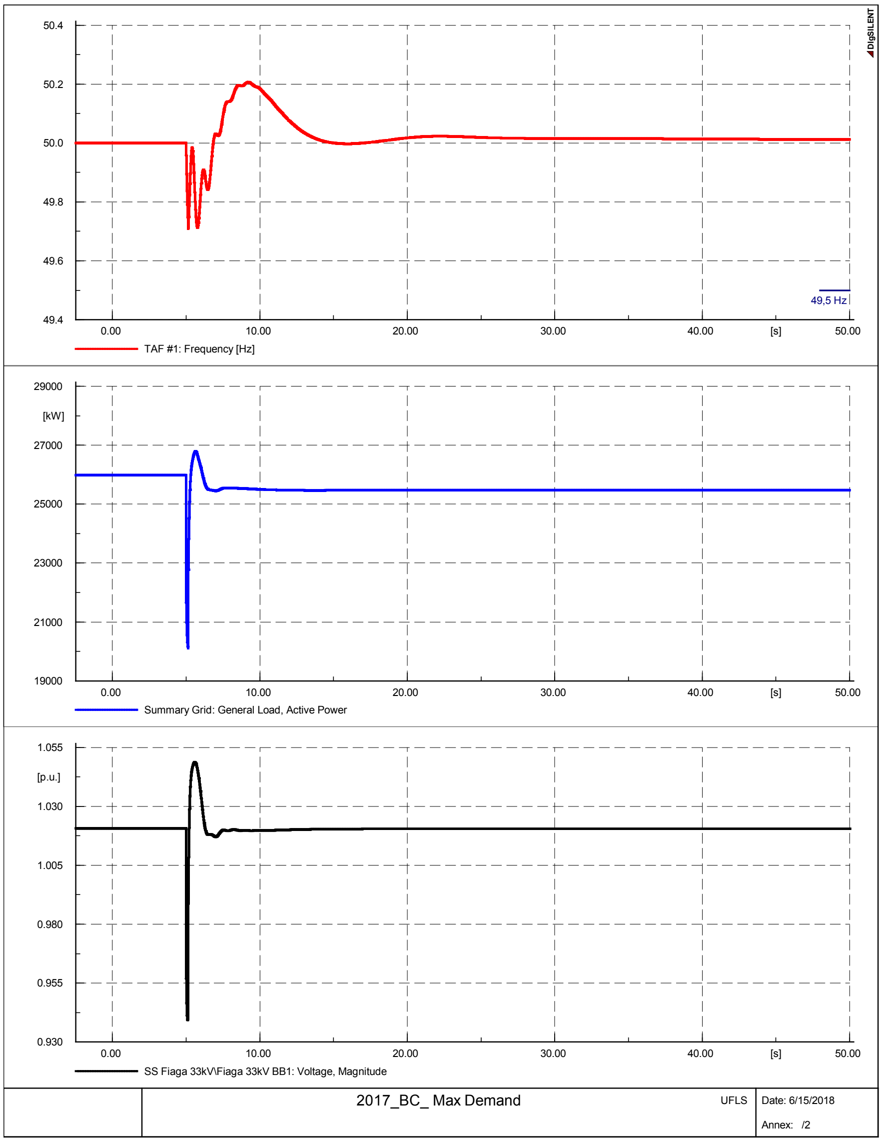


The rotor angles of the generators in the system fluctuate during and after the fault shown in Figure 1-7, however they settle within a few seconds. Despite the large frequency deviation, all of the generators on the system remain connected and the system is stable.

Tripping of smallest demand feeder with a fault

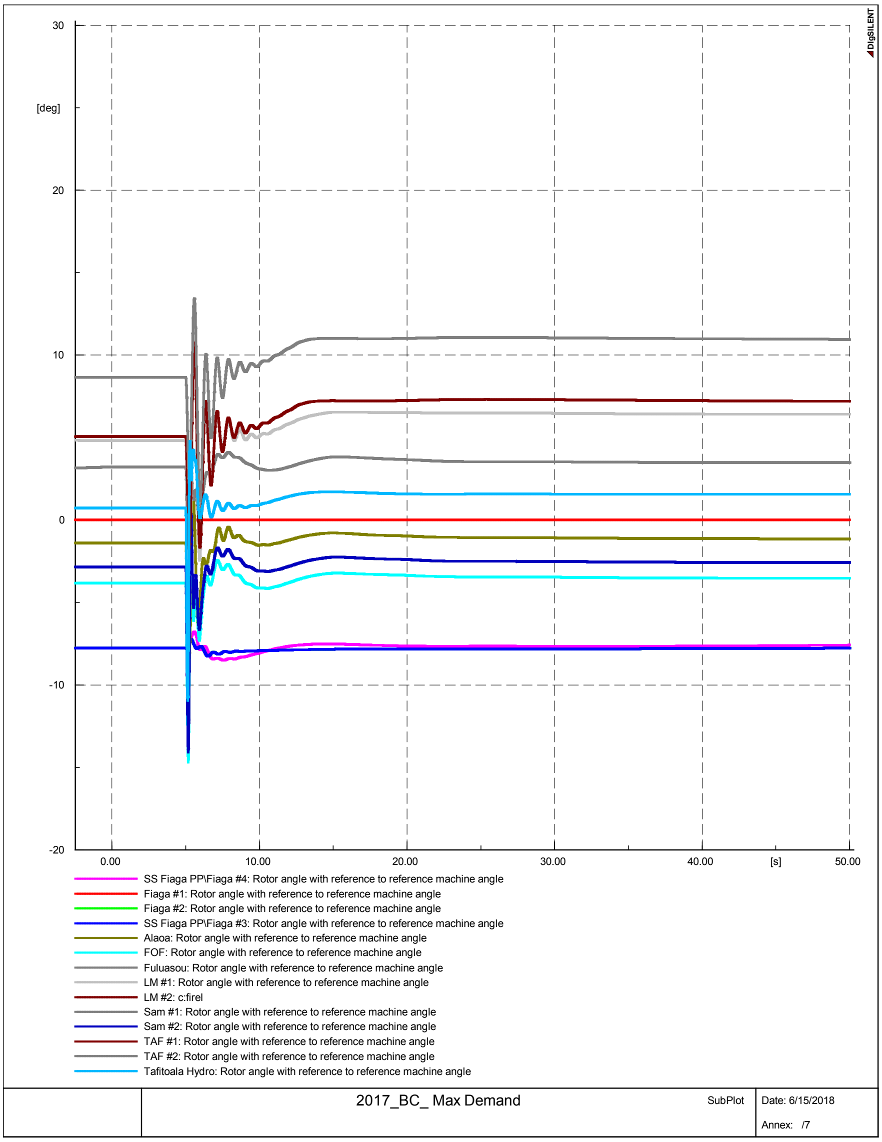
Tripping of the smallest demand feeder on the system (22kV South Coast 4 feeder on the dead-end side of the Aleipata Wind Farm) after a three phase fault applied on the feeder for 150ms results in the frequency and voltage response of the system and rotor angle responses of generators as shown in Figure 2-8 and Figure 2-9 respectively.

Figure 2-8: Voltage and frequency response to smallest feeder trip (Case 1)



Upon the tripping of the lightest loaded demand feeder after a fault, the frequency varies from 49.7 Hz up to 50.02 Hz and settles to 50.01 Hz within couple of seconds. The voltage at Fiaga 33 kV busbar drops to 0.940 pu during the fault and recovers to the acceptable level after the fault is cleared. All generators in the system remain connected and the system is stable.

Figure 2-9: Rotor angle response to smallest feeder trip (Case 1)



2.3.4.2 Stability Study Case 2 (20% VRE Contribution)

The generation dispatch of the island's generators for study case 2 is shown in Table 2-7. This generation dispatch represents the system assuming 20% of renewable generation contribution is available from all renewable generation sources. In this generation dispatch scenario, the spinning reserve of the system is estimated to be 6287.2 kW, which is approximately 24% of the total generation kW output.

Table 2-7: Generation mix on Samoa for Study Case 2

Generation Type	Unit ID	Merit Order	Operational Status	Maximum Generation Output (kW)	Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Conventional generation	Alaoa	2	1	1000	800.0	200.0	3.2%
	FOF	2	0	1600	0.0	0.0	0.0%
	Fuluasou	2	1	680	544.0	136.0	2.2%
	LM #1 (LALOMAUGA)	2	1	1760	1408.0	352.0	5.6%

	LM #2 (LALOMAUGA)	2	0	1760	0.0	0.0	0.0%
	Sam #1 (SAMASONI)	2	1	900.0	720.0	180.0	2.9%
	Sam #2 (SAMASONI)	2	1	900.0	720.0	180.0	2.9%
	TAF #1 (TAELEFAGA)	2	1	2000	1600.0	400.0	6.4%
	TAF #2 (TAELEFAGA)	2	1	2000	1600.0	400.0	6.4%
	Tafitoala Hydro	2	1	460	368.0	92.0	1.5%
	Fiaga #1	3	1	5770	4616.0	1154.0	18.4%
	Fiaga #2	3	1	5770	3750.5	2019.5	32.1%
	Fiaga #3	3	1	5770	4596.3	1173.7	18.7%
	Fiaga #4	3	0	5770	0.0	0.0	0.0%
	Sub-total			36140	20722.8	6287.2	100.0%
Renewable generation	PV GYM 3	1	1	250	92.5	0.0	0.0%
	PV Green Power Samoa Airport	1	1	2400	888.0	0.0	0.0%
	PV Green Power Samoa Fuluasou	1	1	2400	888.0	0.0	0.0%
	PV Race Course	1	1	2200	814.0	0.0	0.0%
	PV Solar for Samoa Airport	1	1	2000	740.0	0.0	0.0%
	PV Solar for Samoa Fuluasou	1	1	2000	740.0	0.0	0.0%
	PV Sun Pacific Harelec Airport	1	1	2000	740.0	0.0	0.0%
	PV Tanugamanono	1	1	150	55.5	0.0	0.0%
	PV Vaitele	1	1	250	92.5	0.0	0.0%
	Aleipata #1	1	1	282.0	104.3	0.0	0.0%
	Aleipata #2	1	1	282.0	104.3	0.0	0.0%
	Sub-total			14214.0	5259.2	0.0	0.0%
	Total			**25982**	**25982.0**	**6287.2**	**24.2%**

Loss of largest generator

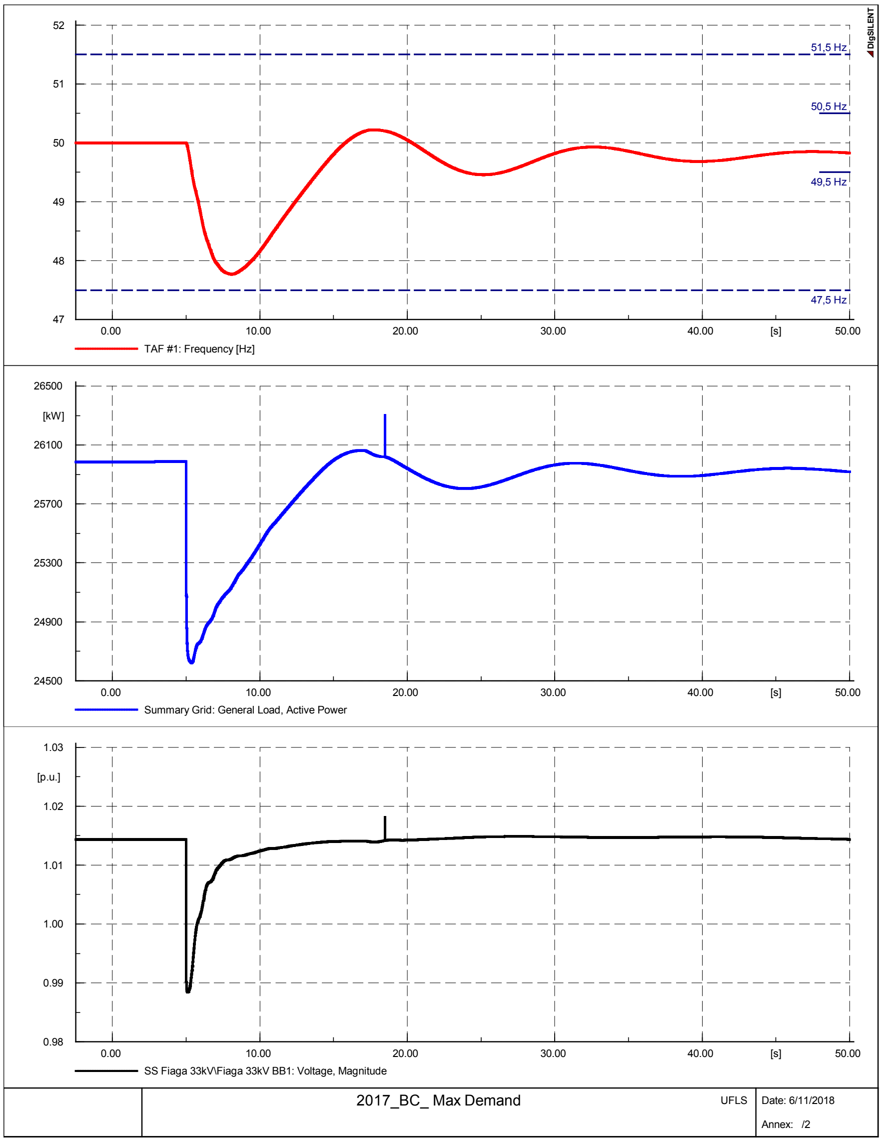
The largest generating unit, which is on-line in this operational scenario, is Fiaga #1 and is operating at the highest output of 4616 kW. The voltage and frequency responses for the loss of largest generator are shown in Figure 2-10. This network does not have the battery storage facilities connected.

After the loss of the largest generating unit, the available spinning reserve in the system is around 5133 kW as per Table 2-7. The available spinning reserve is more than the generation output of the largest generating unit and basically adequate to cover the loss of the largest generating in terms of power balance of generation and demand in this case.

The generator is tripped at 5 s and the frequency drops from 50 Hz down to around 47.8 Hz in this case. The frequency then takes around 25 seconds to recover and settle at around 49.8 Hz. This frequency deviation is much larger than the 2% allowable limit. This indicates that the system is unable to withstand the loss of the largest generating unit, unless further mitigation is available to prevent the large drop in frequency.

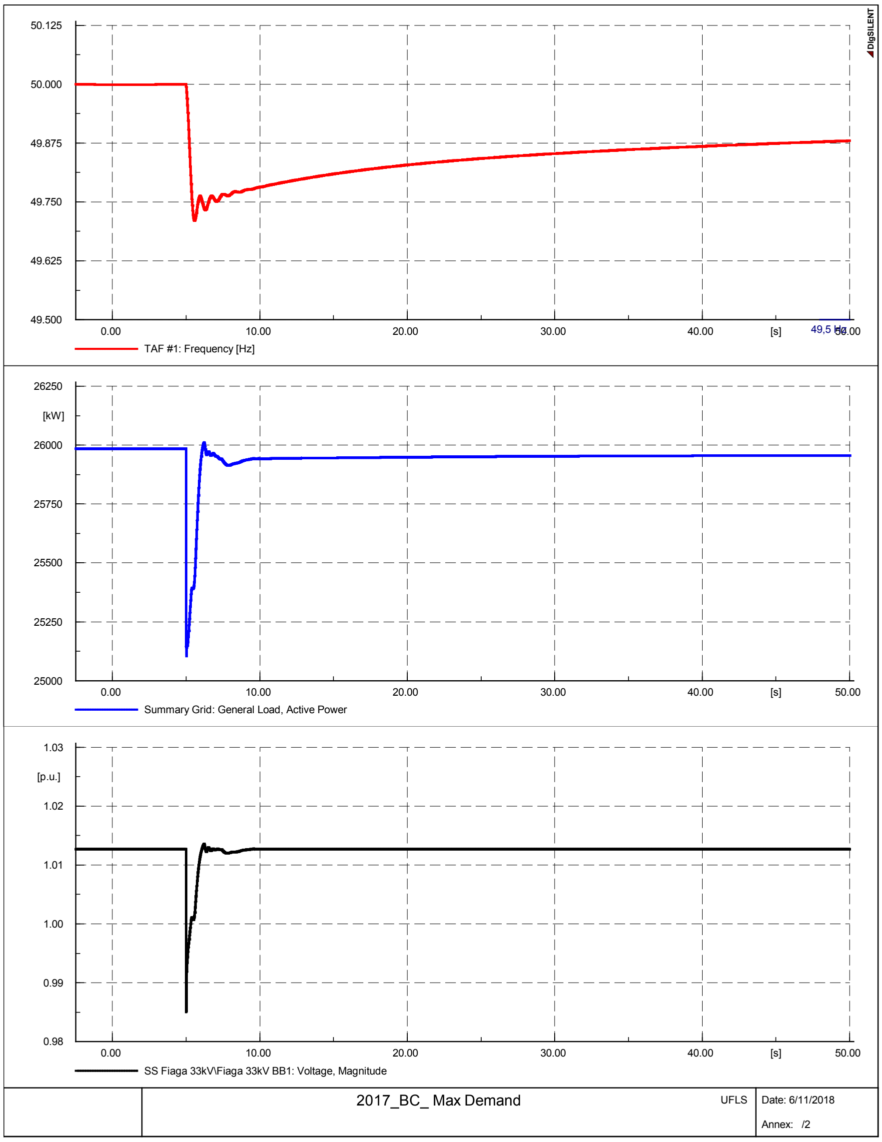
Despite the large deviation in frequency, all other generators on the system remain connected to the system and the system is stable. The voltage at the Fiaga 33 kV busbar drops by about 0.025pu as the generator is tripped and this recovers to its original level, around 1.025pu, within 10 s.

Figure 2-10: Voltage & frequency response to loss of largest generator – without battery storage connected (Case 2)



The study was repeated to include the battery storage sites on the island to assess the impact on the system's ability to withstand the loss of the largest generator. The same generation dispatch was applied and the frequency and voltage responses are shown in Figure 2-16 below.

Figure 2-11: Voltage & frequency response to loss of largest generator – with battery storage connected (Case 2)



The frequency response of the system when 8 MW of battery storage is connected is noticeably improved. The frequency reduces to around 49.7 Hz and recovers to 49.875 Hz steadily. The batteries respond instantaneously to the event and the contribution decreases over time as the system frequency recovers.

Tripping of largest demand feeder after a fault

A three phase fault is applied on the feeder of 33 kV TN-LM 5 for 150 ms and the fault is then cleared with the feeder tripped. The voltage and frequency response to the tripping of the largest feeder is shown in Figure 2-12 . The rotor angle response of generating units in the system to the tripping of the largest feeder is shown in Figure 2-13. This network does not have the battery storage facilities connected.

The feeder is tripped at 5.15 s and the frequency increases from 50 Hz up to almost 55 Hz which is well outside the 2% limit. All conventional generators in the system reduce their kW output in order to prevent frequency rise. The voltage at the Fiaga 33 kV busbar drops from 1.011pu to 0.68pu immediately after the fault and then it tries to recover to its pre-fault level. After 25 seconds, however, conventional generators in the system experience pole-slip and the system voltage collapses.

Figure 2-12: Voltage and frequency response to largest feeder trip (Case 2)

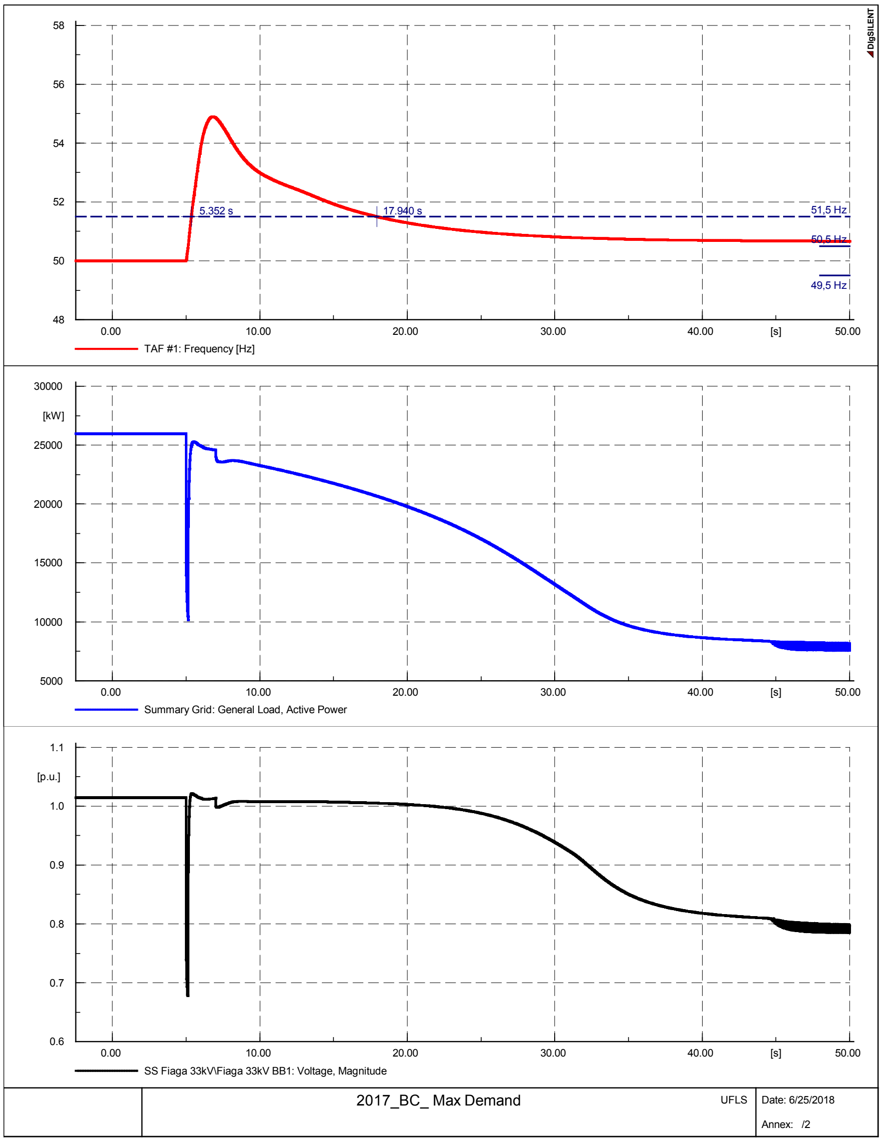
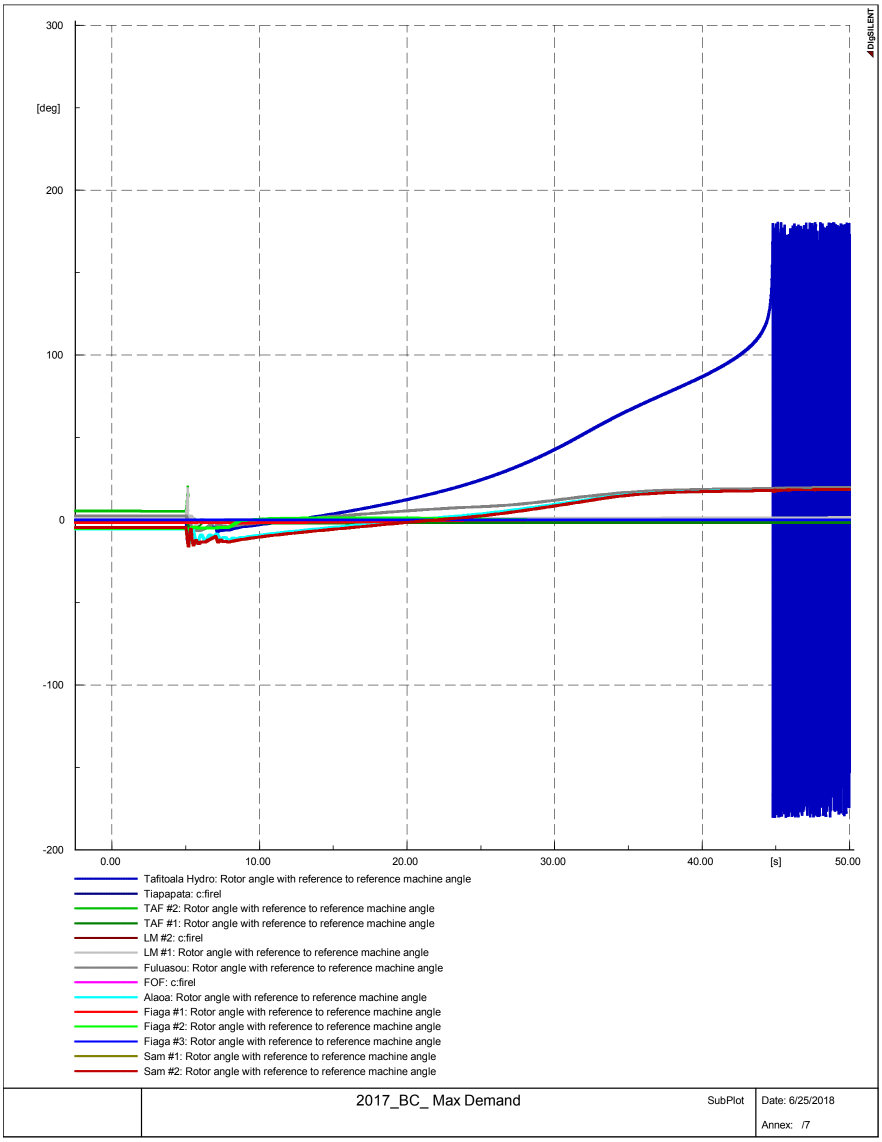


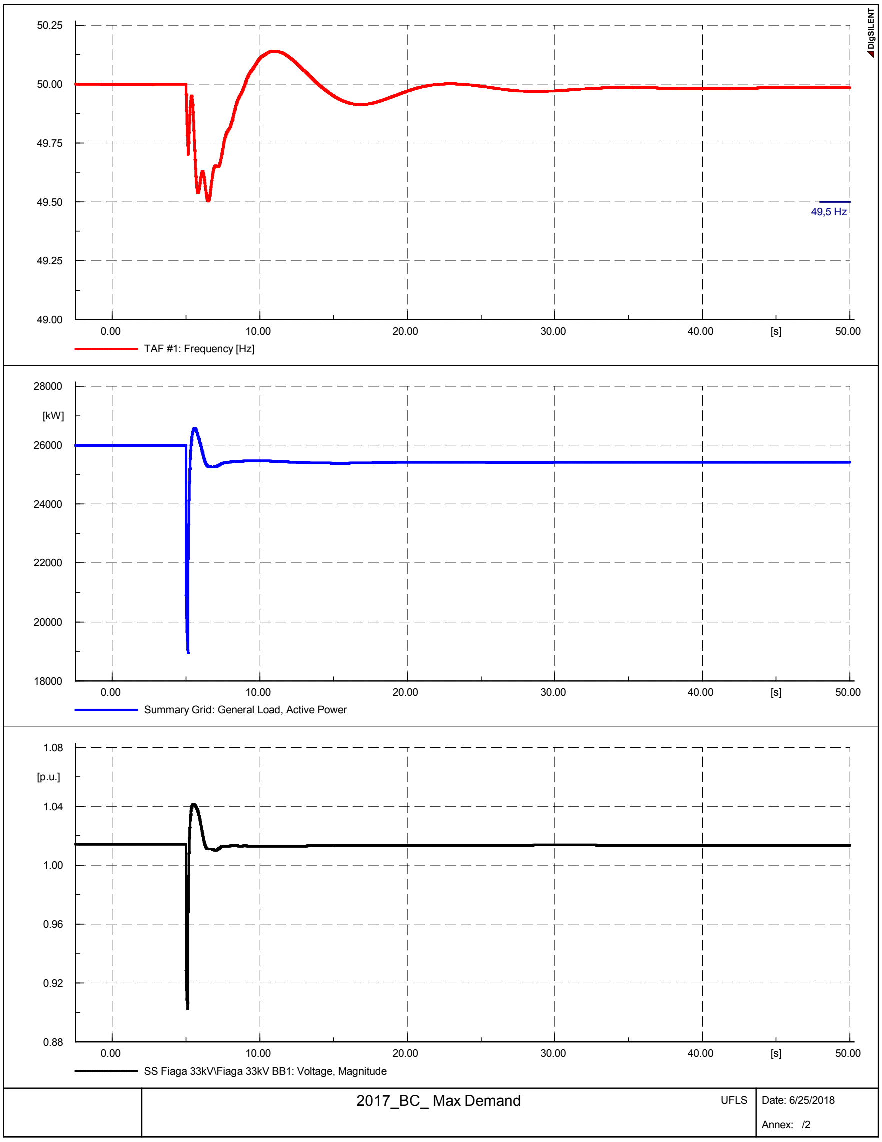
Figure 2-13: Rotor angle response to largest feeder trip (Case 2)



Tripping of smallest demand feeder with a fault

Tripping of the smallest demand feeder on the system (22kV South Coast 4 feeder on the dead-end side of the Aleipata Wind Farm) after a three phase fault applied on the feeder for 150ms results in the frequency and voltage response of the system as shown in Figure 2-14.

Figure 2-14: Voltage and frequency response to smallest feeder trip (Case 2)



For this faulted trip event, the frequency of the system is within the 2% limit. The voltage at the Fiaga 33 kV busbar drops to 0.905 pu from 1.015pu during the fault and recovers to the acceptable level immediately after the fault is cleared, and the system remains stable throughout.

2.3.4.3 Stability Study Case 3 (50% VRE Contribution)

The generation dispatch of the island's generators for Case 3 is shown in Table 2-8. This generation dispatch represents the system assuming 50% of renewable generation contribution is available from all renewable generation sources. In this generation dispatch scenario, the spinning reserve of the system is estimated to be 5297.2 kW, which is approximately 20% of the total generation kW output.

Table 2-8: Generation mix on Samoa for Study Case 3

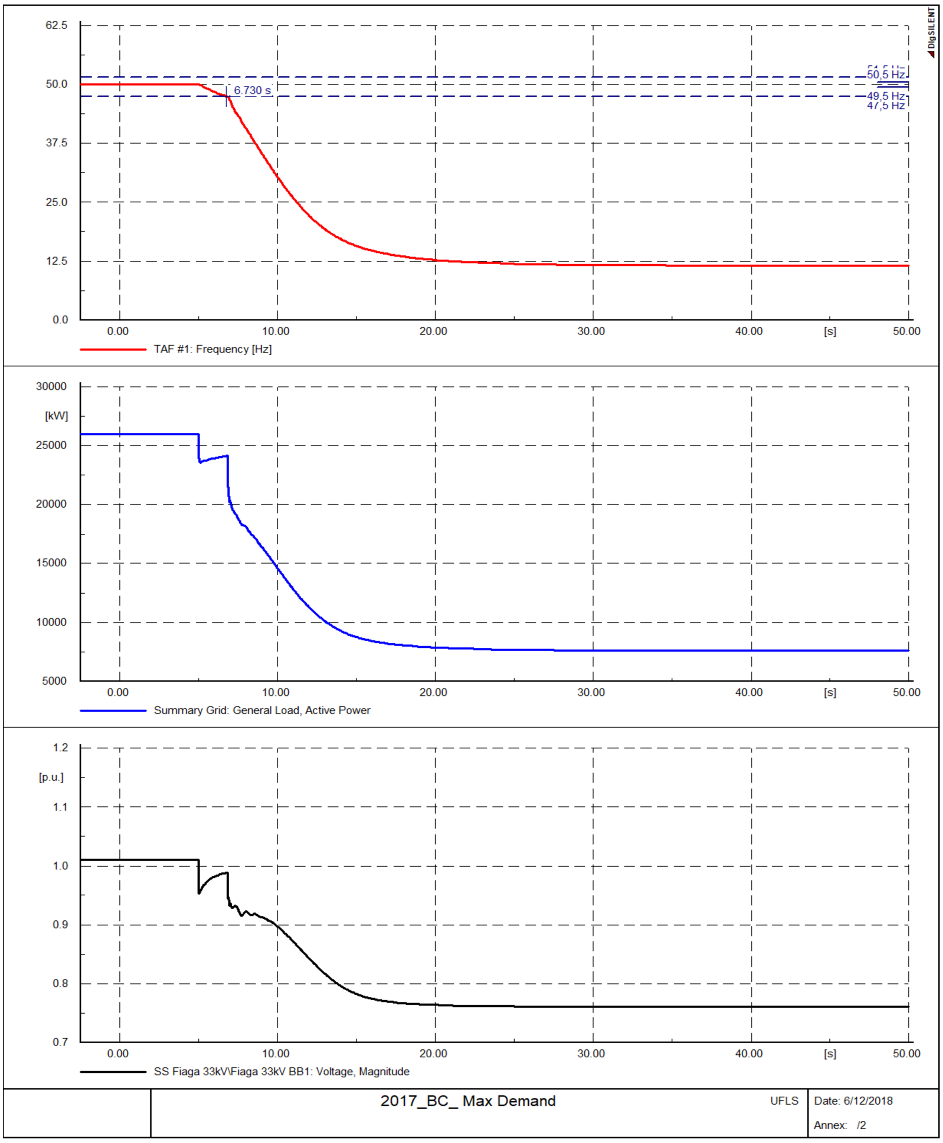
Generation Type	Unit ID	Merit Order	Operational Status	Maximum Generation Output (kW)	Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Conventional generation	Alaoa	2	1	1000	600.0	400.0	7.6%
	FOF	2	0	1600	0.0	0.0	0.0%
	Fuluasou	2	1	680	408.0	272.0	5.1%
	LM #1 (LALOMAUGA)	2	1	1760	1056.0	704.0	13.3%
	LM #2 (LALOMAUGA)	2	0	1760	0.0	0.0	0.0%
	Sam #1 (SAMASONI)	2	1	900.0	540.0	360.0	6.8%
	Sam #2 (SAMASONI)	2	0	900.0	0.0	0.0	0.0%
	TAF #1 (TAELEFAGA)	2	1	2000	1200.0	800.0	15.1%
	TAF #2 (TAELEFAGA)	2	0	2000	0.0	0.0	0.0%
	Tafitoala Hydro	2	1	460	276.0	184.0	3.5%
	Fiaga #1	3	1	5770	4616.0	1154.0	21.8%
	Fiaga #2	3	1	5770	4351.3	1418.7	26.8%
	Fiaga #3	3	0	5770	0.0	0.0	0.0%
	Fiaga #4	3	1	5770	600.0	400.0	7.6%
	Sub-total			36140	13047.3	5292.7	100.0%
Renewable generation	PV GYM 3	1	1	250	227.5	0.0	0.0%
	PV Green Power Samoa Airport	1	1	2400	2184.0	0.0	0.0%
	PV Green Power Samoa Fuluasou	1	1	2400	2184.0	0.0	0.0%
	PV Race Course	1	1	2200	2002.0	0.0	0.0%
	PV Solar for Samoa Airport	1	1	2000	1820.0	0.0	0.0%
	PV Solar for Samoa Fuluasou	1	1	2000	1820.0	0.0	0.0%
	PV Sun Pacific Harelec Airport	1	1	2000	1820.0	0.0	0.0%
	PV Tanugamanono	1	1	150	136.5	0.0	0.0%
	PV Vaitele	1	1	250	227.5	0.0	0.0%
	Aleipata #1	1	1	282.0	256.6	0.0	0.0%
	Aleipata #2	1	1	282.0	256.6	0.0	0.0%

	Sub-total			14214.0	12934.7	0.0	0.0%
	Total			**25982**	**25982.0**	**5297.2**	**20.4%**

Loss of largest generator

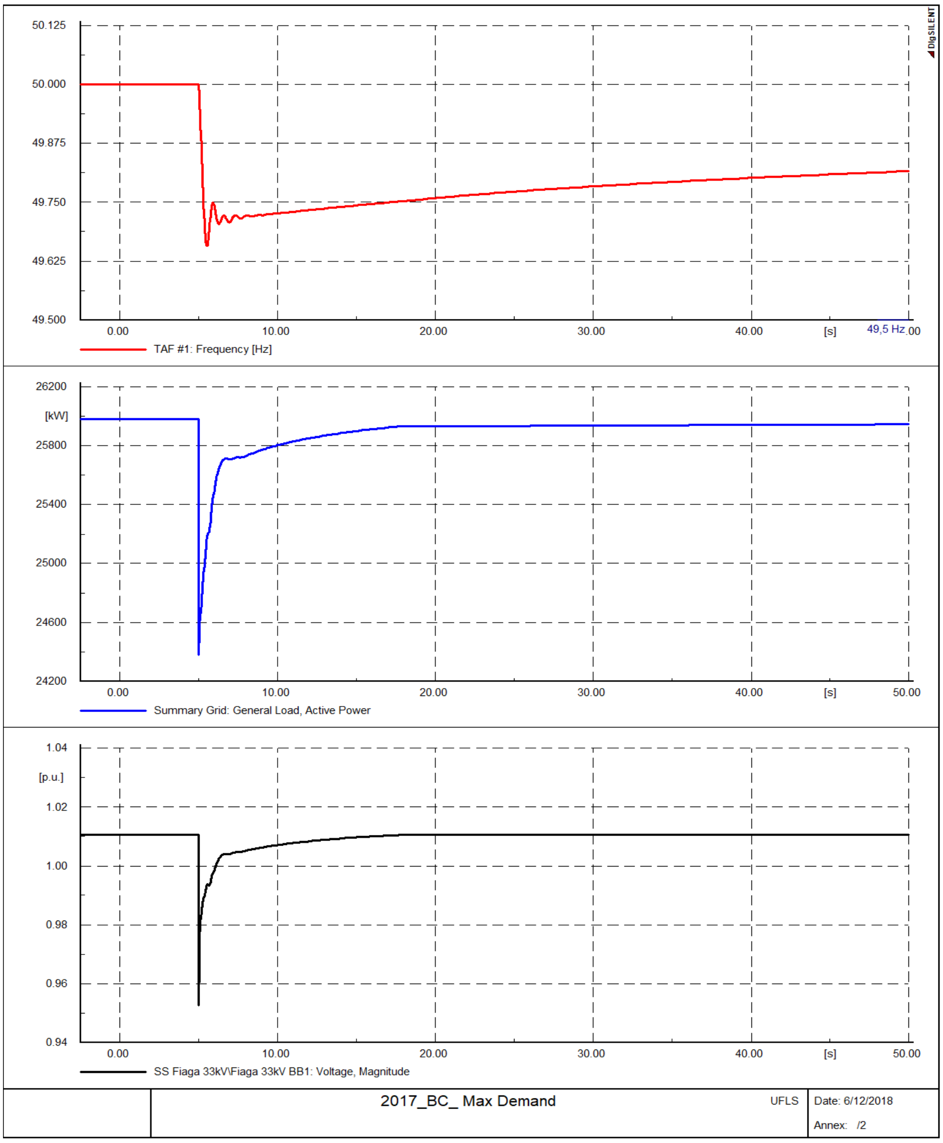
The largest generating unit, which is on-line in this operational scenario, is Fiaga #1 and is operating at the highest output of 4616 kW. The voltage and frequency responses are shown in Figure 1-15. This network does not have the battery storage facilities connected at this stage. After the loss of the largest generating unit, the available spinning reserve in the system is around 4138 kW as per Table 2-8. The available spinning reserve is less than the generation output of the largest generating unit and is inadequate to cover the loss of the largest generating in terms of power balance of generation and demand in this case. It can be seen from Figure 2-15 that the system cannot cope with the loss of the largest generator with this penetration of renewables operating on the system and the system suffers both frequency and voltage collapse. The combination of inadequate spinning reserve with small inertia of the system and slower dynamic response of hydro-generating units are the primary reasons why the frequency collapses following the loss of the largest generating unit in this case.

Figure 2-15: Voltage and frequency response to loss of largest generator – without battery storage



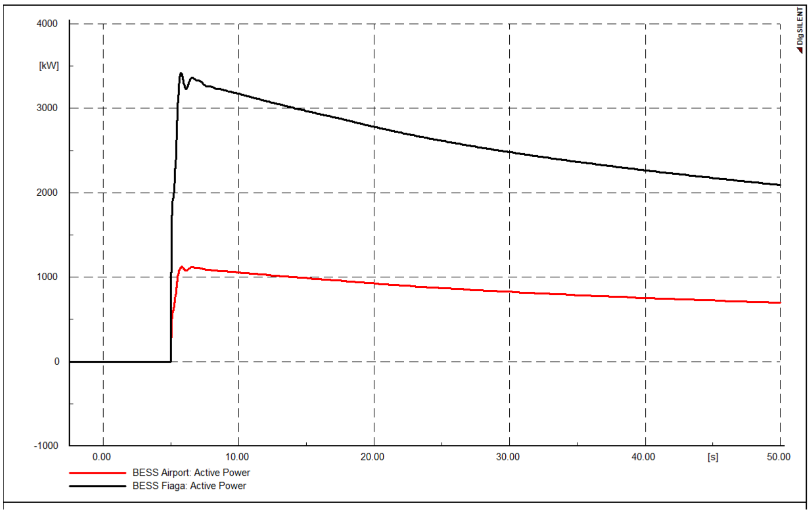
With the two batteries included on the system, the study was repeated with the same generation mix and the responses are shown in Figure 2-16.

Figure 2-16: Voltage and frequency response to loss of largest generator – with battery storage



The connection of battery storage improves the response and the stability of the system and it no longer suffers voltage and frequency collapse. The contributions of the battery storage facilities are shown in Figure 2-17.

Figure 2-17: Battery storage active power response to loss of largest generator



The batteries respond instantaneously to the event and the contribution decreases over time as the system frequency recovers.

Three phase fault & tripping of largest demand feeder

The largest loaded feeder under the generation dispatch profile detailed in Table 1-8 is the 33 kV TN-LM 5. A three-phase fault which results in the tripping of this feeder causes the voltage and rotor angle responses as shown in Figure 2-18 and Figure 2-19 respectively. The battery storage facilities are not connected in this study.

The feeder is tripped at 5.15 s and the frequency increases from 50 Hz up to almost 53 Hz which is well outside the 2% limit. The voltage at the Fiaga 33 kV busbar drops from 1.011pu to 0.625pu immediately after the fault and then it tries to recover to its pre-fault level. After a few seconds, however, the system experiences voltage collapse.

Figure 2-18: Voltage and frequency response to largest feeder trip – without battery storage (Case 3)

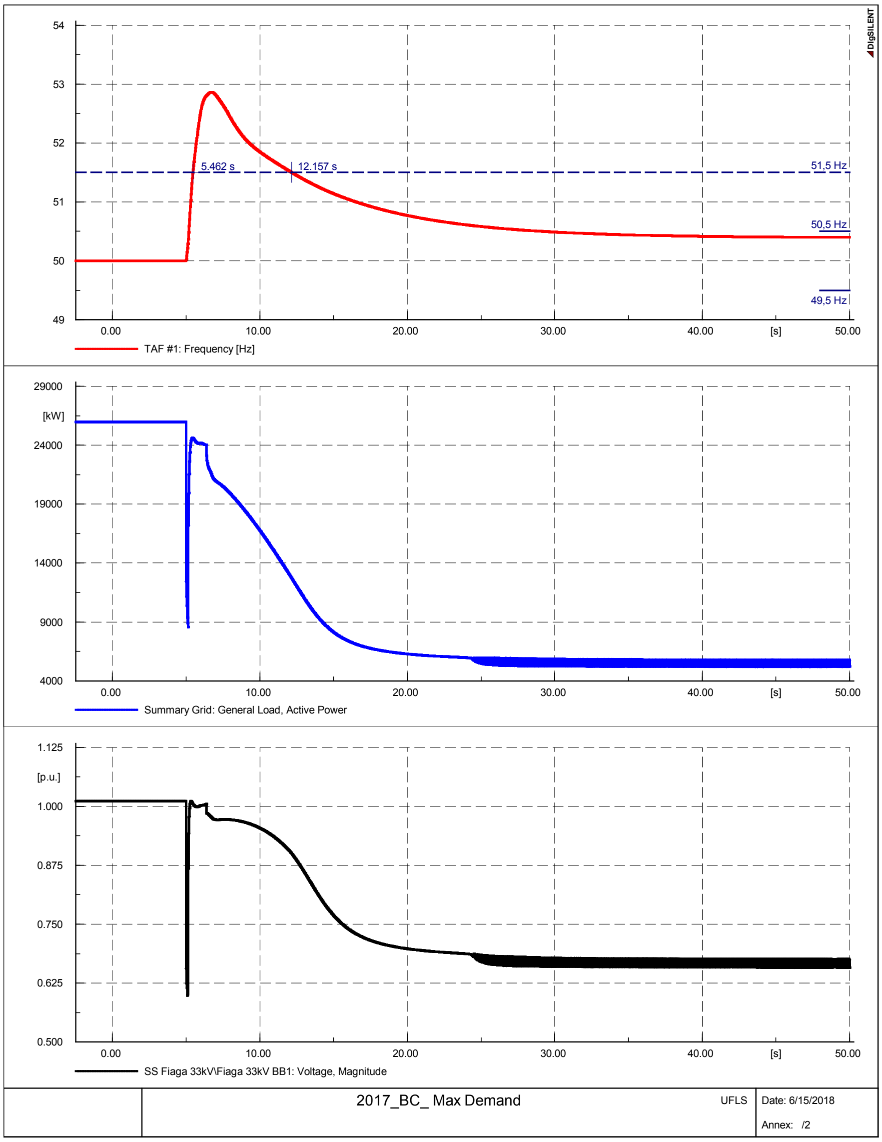
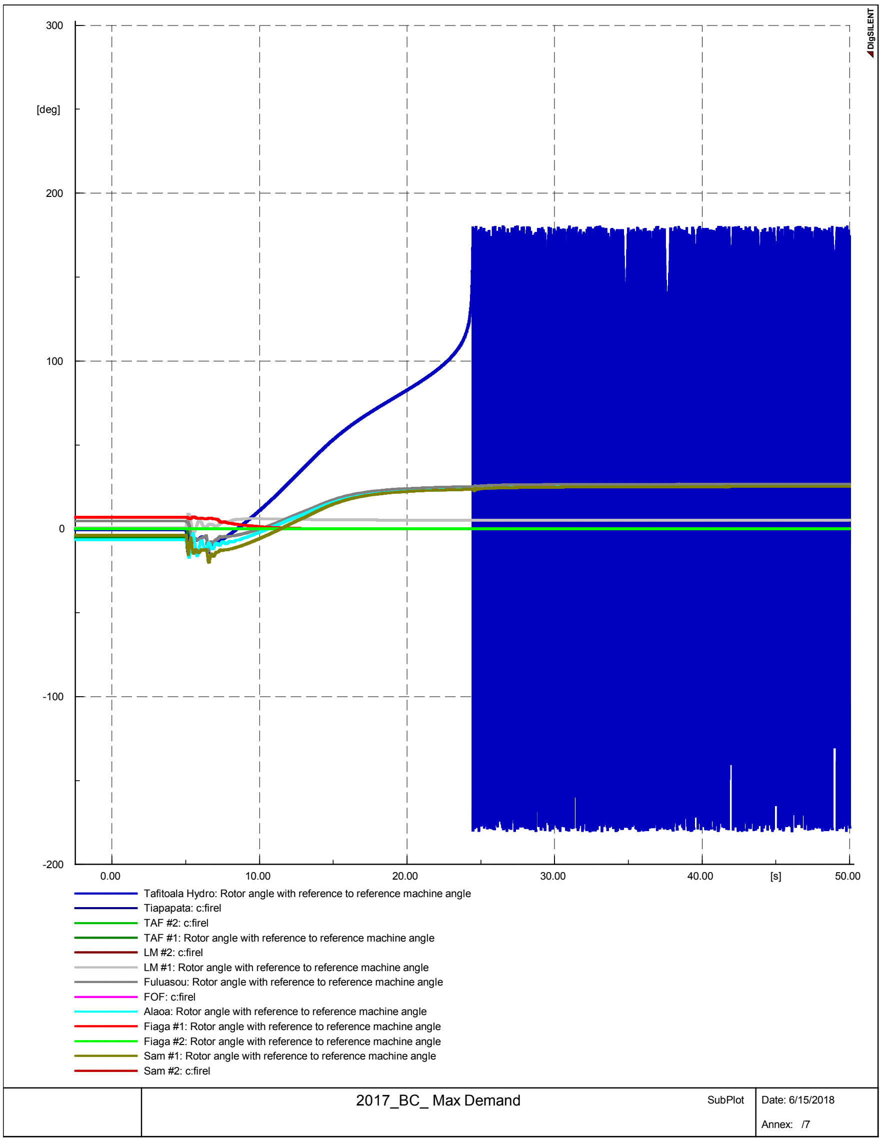


Figure 2-19 Rotor angle response to largest feeder trip (case 3)

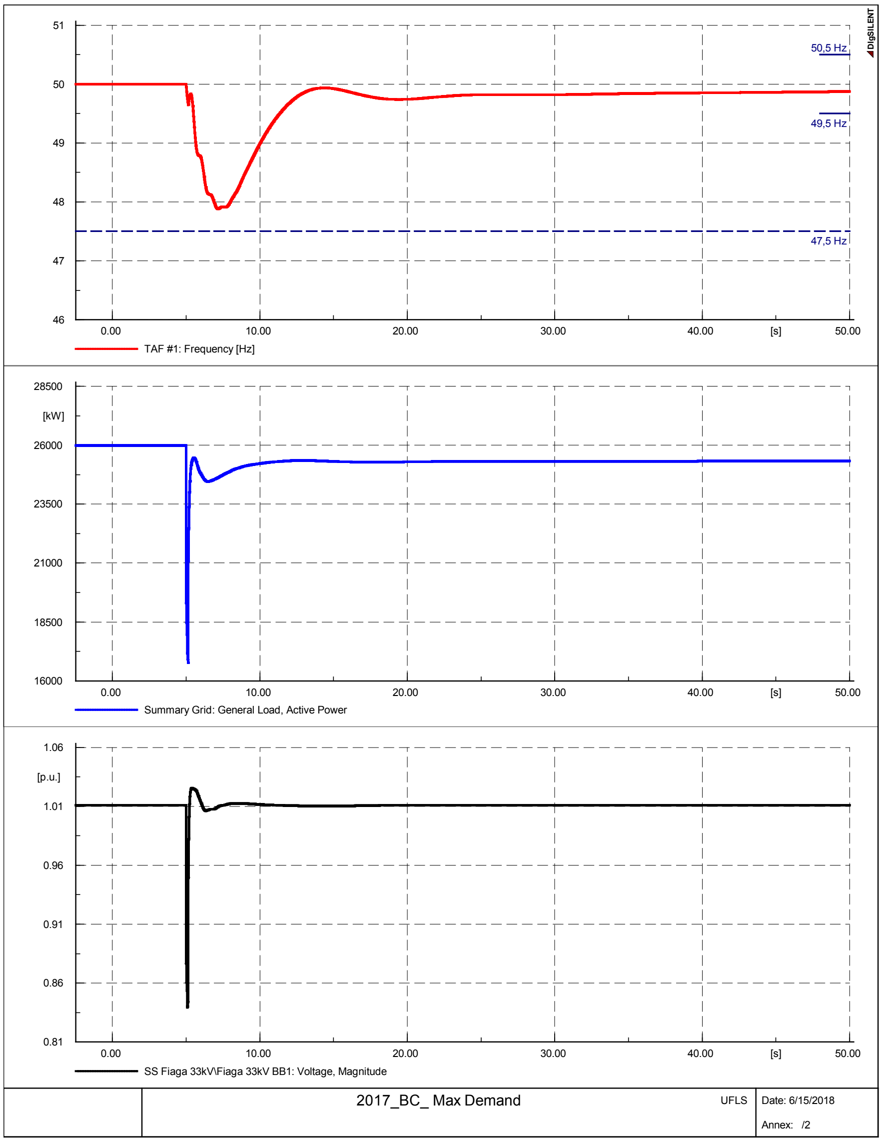


The rotor angles of the generators in the system, shown in Figure 2-19, indicate that pole-slip of generators takes place after the fault is cleared and the system goes unstable. It is advised that further mitigation should be considered to avoid pole-slip of generators and prevent system collapse after such a fault.

Tripping of smallest demand feeder with a fault

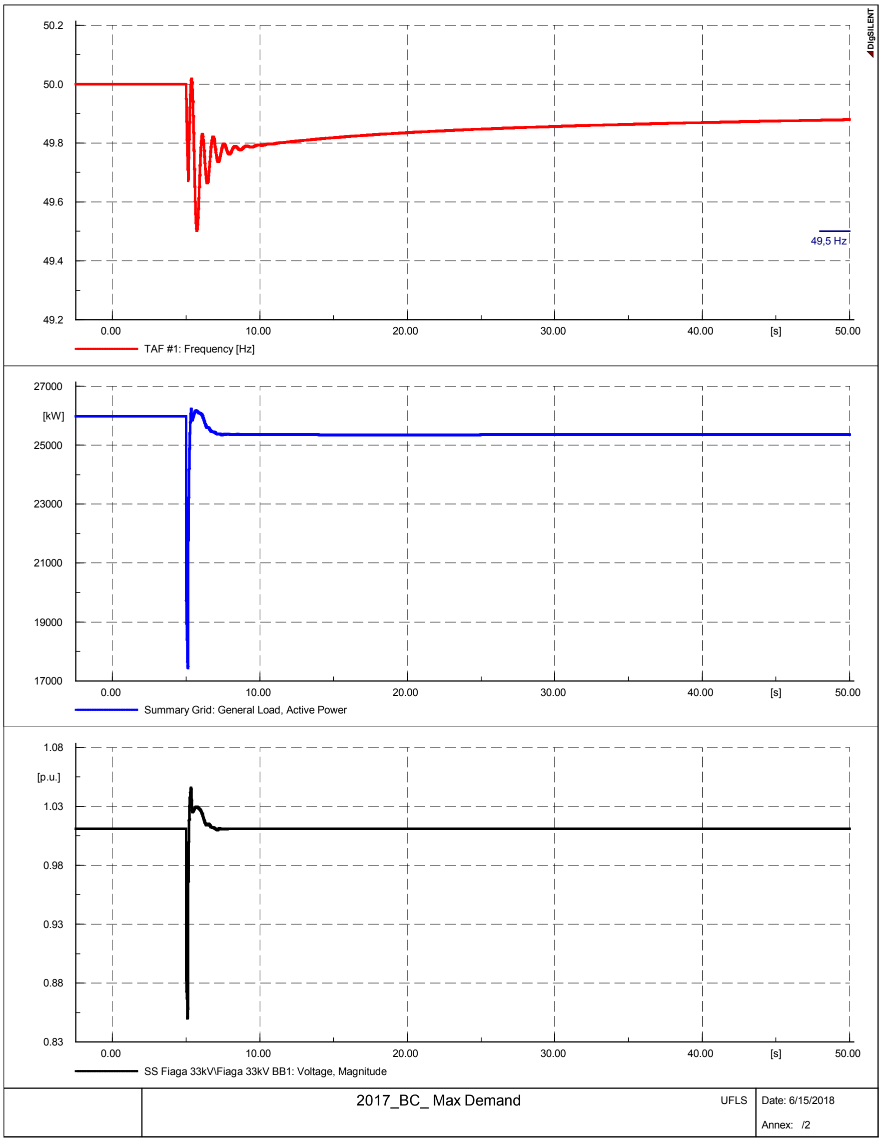
Tripping of the 22kV South Coast 4 feeder on the dead-end side of the Aleipata Wind Farm after a three phase fault applied on the feeder for 150ms results in the frequency and voltage response of the system as shown in Figure 2-20 (without battery storage support).

Figure 2-20: Voltage and frequency response to smallest feeder trip without battery storage (Case 3)



The system frequency drops from 50 Hz to 47.9 Hz after tripping the feeder. The voltage at Fiaga 33 kV busbar drops to 0.850 pu during the fault and recovers to the acceptable level after the fault is cleared. Other generators in the system remain connected and the system is stable. With the support of battery storage for the same event, the frequency and voltage response of the system is shown in Figure 2-21.

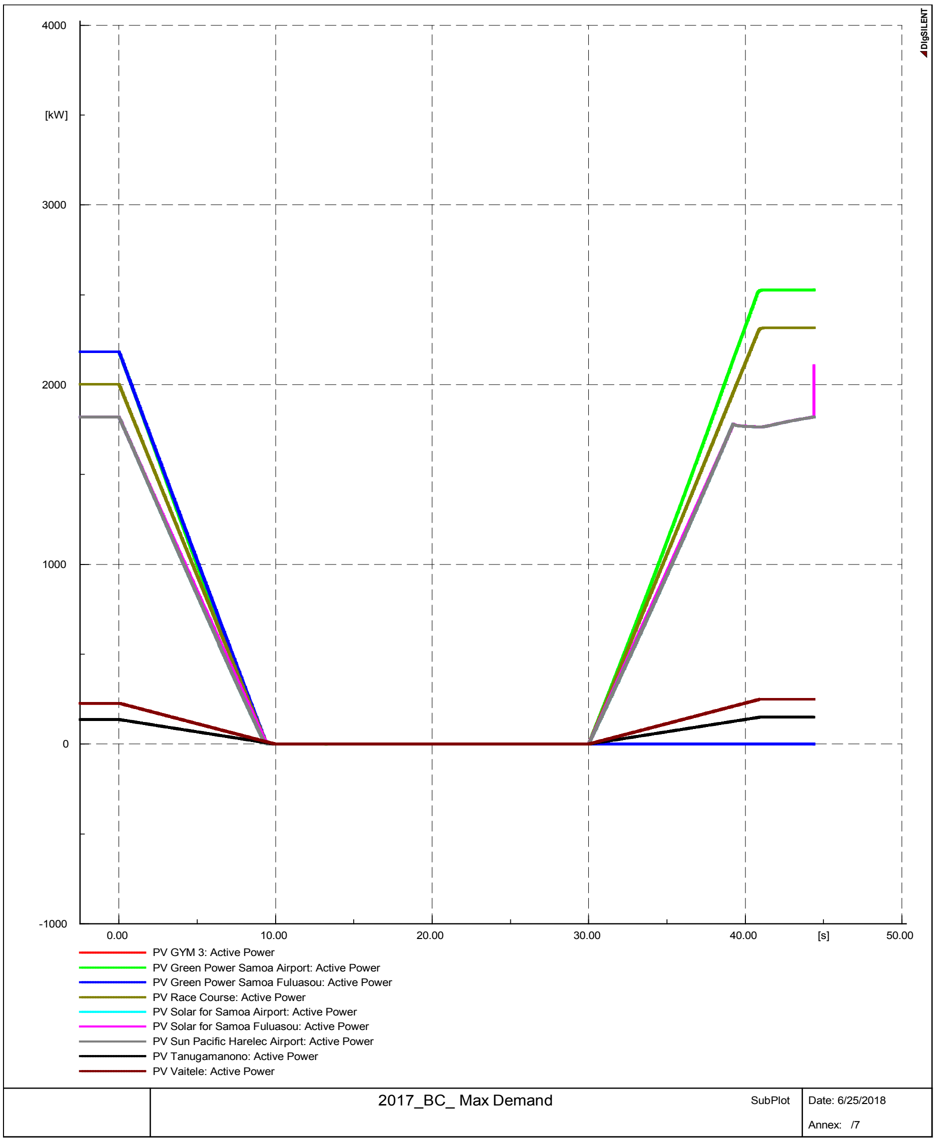
Figure 2-21: Voltage and frequency response to smallest feeder trip with battery storage (Case 3)



2.3.5 PV Generation Ramping Down and Up

The voltage and frequency response of the system (maximum demand scenario) was also assessed for PV generation ramping down and up during a short period. All of the PV sites on the island are operating at the maximum kW output. A simulation involving the simultaneous reduction to 0 MW (to reflect sudden cloud coverage) of all PV sites, and then their return to the maximum kW output after 20 s was carried out. The PV output is shown in Figure 2-22.

Figure 2-22: PV MW output of all sites on Upolu Island



A specific generation mix was prepared in Table 1-9 for such a study as application of generation mix in Table 2-8 will result in frequency collapse immediately after the PV generation ramping down to 0 kW within 10 seconds. In this specific generation mix, the total PV generation output is 12,421 kW and up to 1,1062 kW spinning reserve is available to meet the power deficit in the system.

Table 2-9: Generation mix on Samoa for PV Generation Ramping down and up Studies

Generation Type	Unit ID	Merit Order	Operational Status	Maximum Generation Output (kW)	Generation Dispatch (kW)	Spinning Reserve (kW)	Spinning Reserve (%)
Conventional generation	Alaoa	2	1	1000	500.0	500.0	4.5%
	FOF	2	0	1600	0.0	0.0	0.0%
	Fuluasou	2	1	680	340.0	340.0	3.1%
	LM #1 (LALOMAUGA)	2	1	1760	880.0	880.0	8.0%
	LM #2 (LALOMAUGA)	2	0	1760	0.0	0.0	0.0%
	Sam #1 (SAMASONI)	2	1	900.0	450.0	450.0	4.1%
	Sam #2 (SAMASONI)	2	0	900.0	0.0	0.0	0.0%
	TAF #1 (TAELEFAGA)	2	1	2000	1000.0	1000.0	9.0%
	TAF #2 (TAELEFAGA)	2	0	2000	0.0	0.0	0.0%
	Tafitoala Hydro	2	1	460	230.0	230.0	2.1%
	Fiaga #1	3	1	5770	2885.0	2885.0	26.1%
	Fiaga #2	3	1	5770	2885.0	2885.0	26.1%
	Fiaga #3	3	1	5770	3877.3	1892.7	17.1%
	Fiaga #4	3	1	5770	500.0	500.0	4.5%
	Sub-total			36140	13047.3	11062.7	100.0%
Renewable generation	PV GYM 3	1	1	250	227.5	0.0	0.0%
	PV Green Power Samoa Airport	1	1	2400	2184.0	0.0	0.0%
	PV Green Power Samoa Fuluasou	1	1	2400	2184.0	0.0	0.0%
	PV Race Course	1	1	2200	2002.0	0.0	0.0%
	PV Solar for Samoa Airport	1	1	2000	1820.0	0.0	0.0%
	PV Solar for Samoa Fuluasou	1	1	2000	1820.0	0.0	0.0%
	PV Sun Pacific Harelec Airport	1	1	2000	1820.0	0.0	0.0%
	PV Tanugamanono	1	1	150	136.5	0.0	0.0%
	PV Vaitele	1	1	250	227.5	0.0	0.0%
	Aleipata #1	1	1	282.0	256.6	0.0	0.0%
	Aleipata #2	1	1	282.0	256.6	0.0	0.0%
	Sub-total			14214.0	12934.7	0.0	0.0%

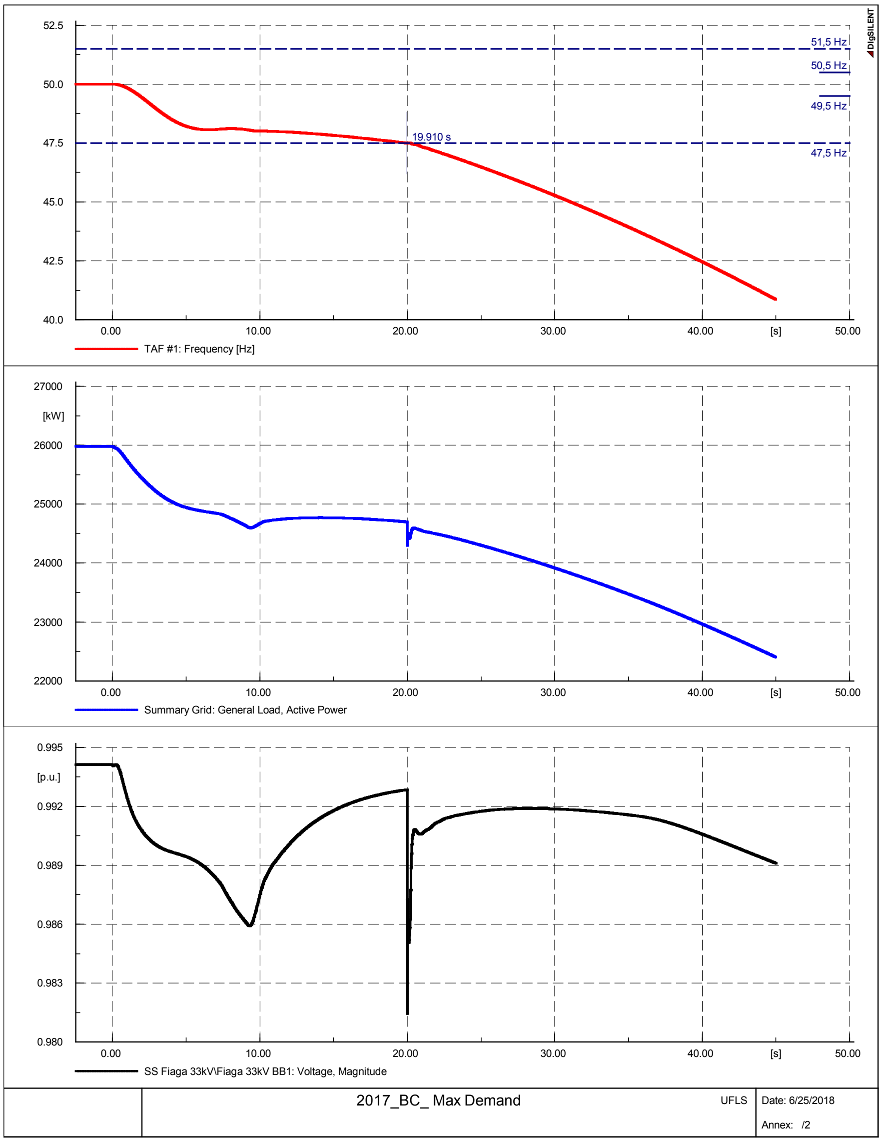
	Total			**25982**	**25982.0**	**11062.7**	**42.6%**

PV Generation Ramping Down and Up without Battery Storage

The voltage and frequency responses for PV generation ramping down and up without support from battery storage are shown in Figure 2-23.

As the kW output of the PV generators decreases, the frequency and voltage decrease accordingly. The voltage drops from 1.005pu to 0.986pu when all PV generation output goes down to 0 kW. System frequency drops from 50 Hz to 47.5 Hz at 20 seconds and collapses before the PV generation begins ramping up again. This indicates that even when the system has 11062 kW spinning reserve available, it is still incapable of preventing frequency collapse when 12,421 kW PV generation ramps down within 10 seconds.

Figure 2-23: Voltage and frequency response to changing PV MW output – without battery storage



PV Generation Ramping Down and Up with Battery Storage

The study was performed again with the connection of battery storage to assess the impact on the frequency and voltage response of the system and its ability to manage this contingency. The frequency responses of the system and kW output of battery storages are shown in Figure 1-24 and Figure 1-25 respectively.

Figure 2-24: Voltage and frequency response to changing PV MW output - with battery storage

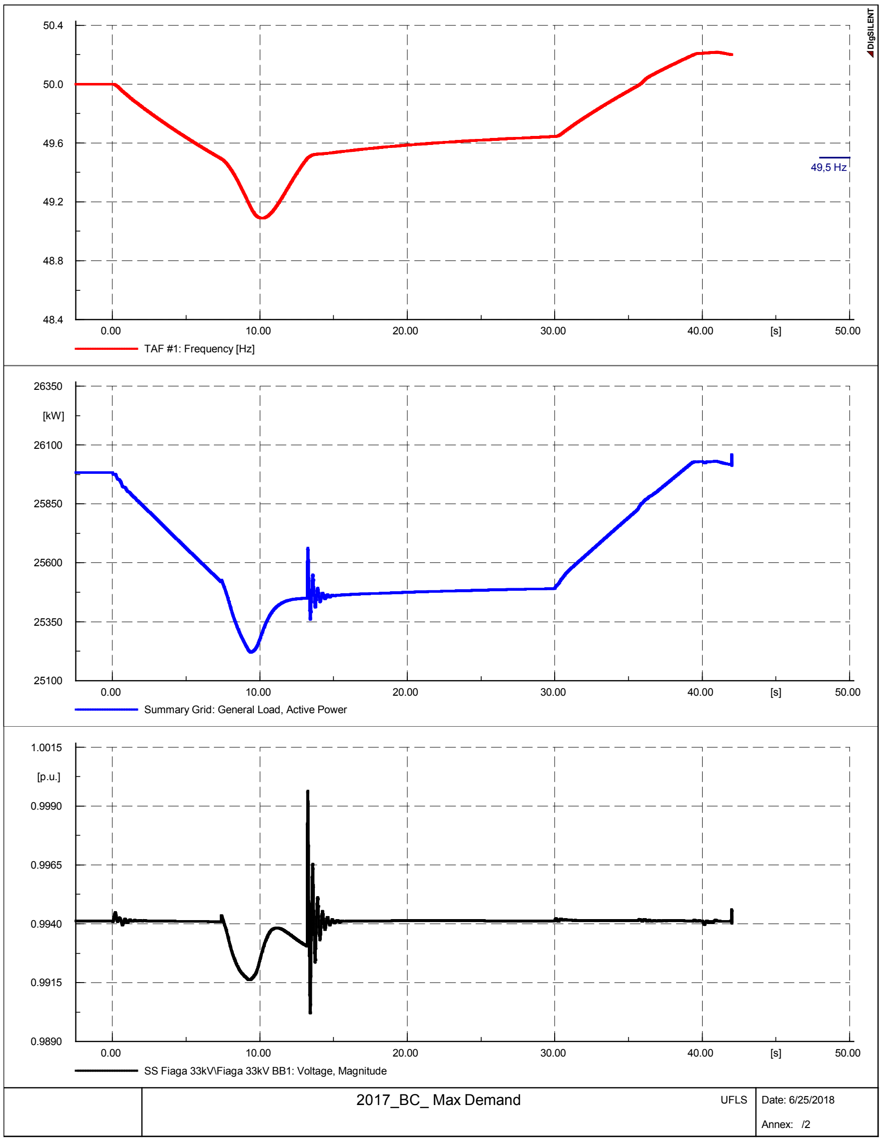
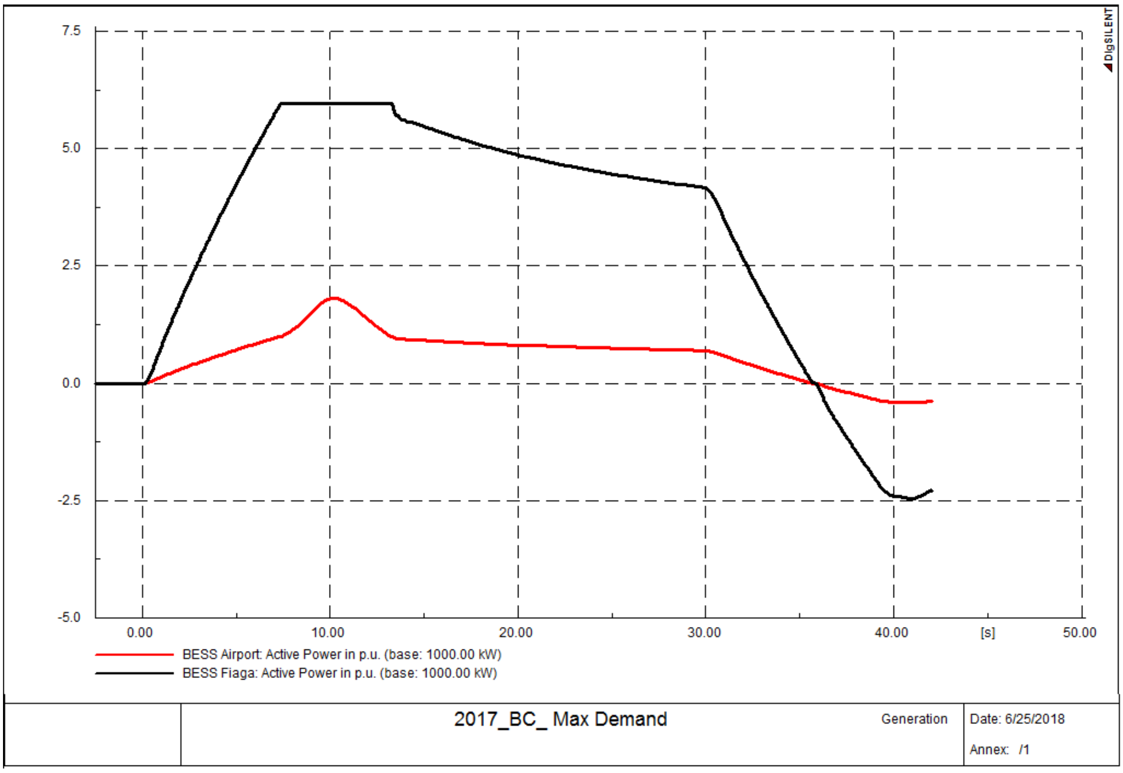


Figure 2-25: Active power response from battery storage



It can be seen that the battery storage prevents system frequency drop from being below 49 Hz and succeeds in helping the system to maintain stability. This indicates that the 8 MW battery storage installed in Samoa power system, combined with availability of adequate spinning reserve, is capable of managing the 12.4 MW PV generation quickly ramping down and up in system operation.

2.3.6 Summary of power system study results

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

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 were performed both with and without battery storage connected to the network (battery storage is presently being commissioned on the island). For the loss of the largest generator on the system, the system frequency deviates far in excess of the 2% limit (which could trigger UFLS) and the frequency even collapses in the case with more kW output from renewable generation to meet the system demands. The addition of battery storage improves the system response quite significantly for this contingency.

The tripping of the largest demand feeder after a fault results in higher frequency rise (more than 52 Hz), or even pole-slip of generators in the system. The high frequency rise should be checked against the over-frequency relays of conventional generators in order to prevent cascade tripping of those conventional generators.

The tripping of the smallest demand feeder after a fault results in changes in voltage and rotor angle, however, there are no angle stability issues in this case and all generators on the system remain connected and the system is stable. When more kW output is produced by the three PV sites connected to the feeder, tripping of the smallest demand feeder results in significant drop of system frequency. The battery storage is, however, able to prevent the frequency drop and maintain the frequency within acceptable limits.

The voltage and frequency variations in the case of total loss/gain of all PV generation in the system exceed the operational ±2% limits for a number of seconds and eventually the system collapses before the PV generation ramps up again. As before, the addition of battery storage to the network improves the frequency response and overall stability of the system to this same event but further mitigation is likely required to maintain the frequency to within acceptable limits.

2.3.7 Recommendations for the present and future scenarios

The Upolu Island network already has a large penetration of renewable generation connected to the system, nearly 30% of the total installed generation capacity. It is expected more renewable generation will be connected to the system in the future. Though the system studies show that some headroom is available in the network for future renewable generation connection, detailed system studies shall be undertaken to identify where and the amount of renewable generation is connected and what actions are taken to enable such a connection.

From Section 1.3.4 it has been shown how the connection of battery storage is able to prevent system frequency drop and maintain system frequency to within acceptable limits during contingency conditions. In case that the battery storage is not adequate to keep the frequency within the 2% deviation limit, the UFLS could be an option to manage this. It is a reasonable action to execute UFLS in cases of emergency or fault such that the frequency can recover and the system does not collapse.

Under normal operating conditions however, UFLS is not a desirable action to take. In the case where all PV generation drops to 0 MW within 10 s; this is a situation that could occur easily depending on cloud cover in the area but it would not be recommended to start shedding load as the PV generation could ramp up again just as quickly. The connection of battery storage improves the response in this case however, further mitigation is recommended to improve overall system frequency stability and response to prevent the need for UFLS under any circumstances. System studies to identify the amount of UFLS scheme and to coordinate with utilisation of the battery storage would be necessary.

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.

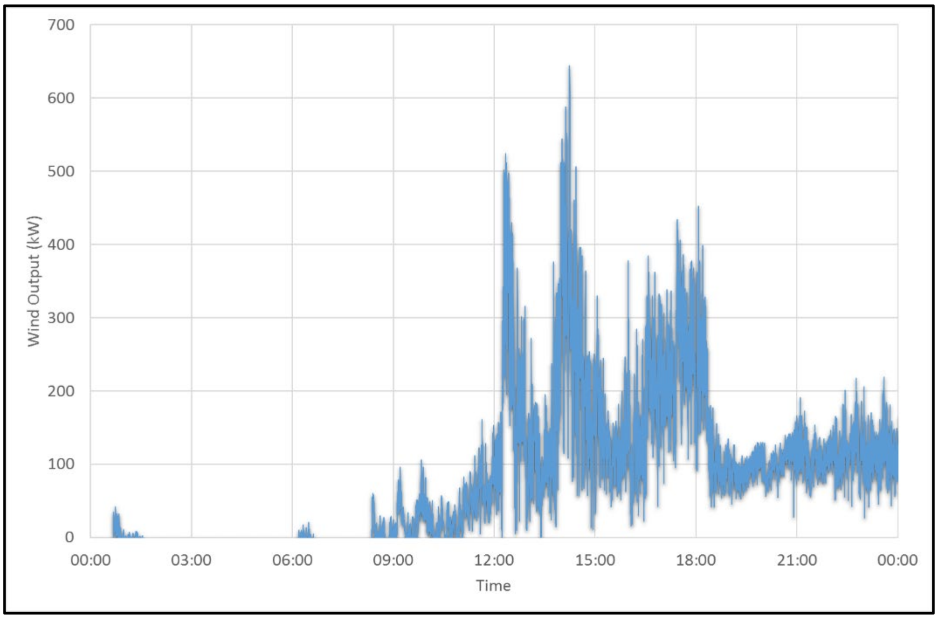
Fast frequency response within seconds or even fractions of a second can also be obtained from non-traditional sources including lithium-ion batteries, flywheels, and demand-response with thermal storage. Each of these sources can react to restore the balance of power but each has its limitations. Batteries 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 Samoa and the technical limit with the economic impact for increasing both wind and 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.

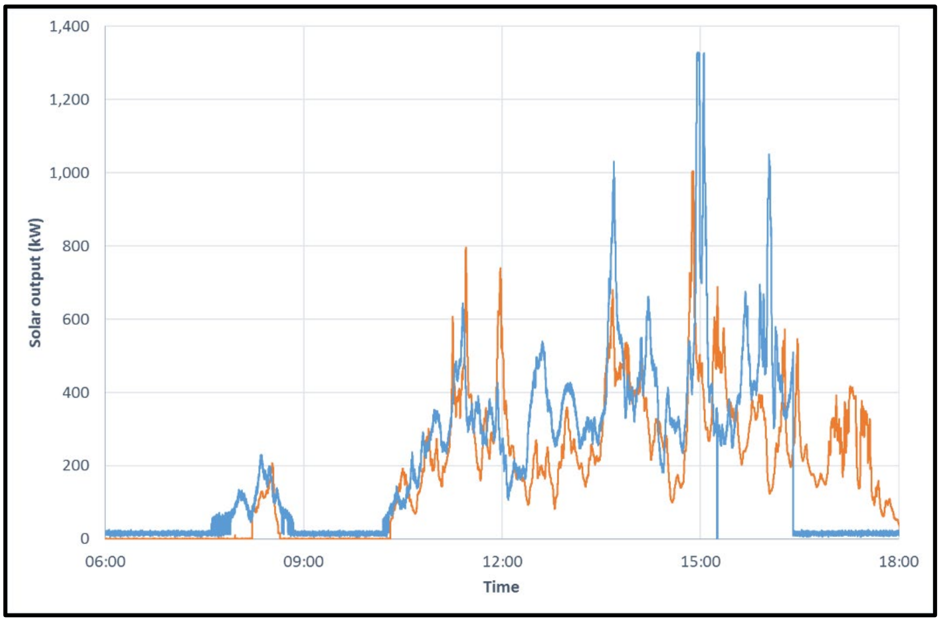
Figure 3-1. Wind power for recorded on 10 December 2016 at Aleipata



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

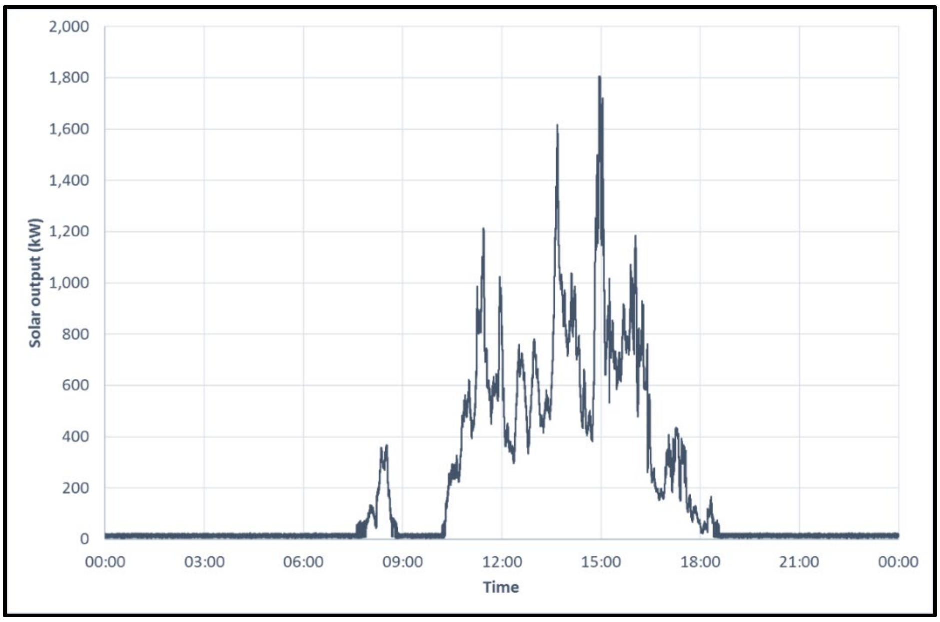
Figure 3-2 shows the individual outputs (measured at one second intervals) from two solar PV plants that are approximately 1 km apart.

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



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

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



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

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

The studies conducted in Task 2 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 focusses 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.

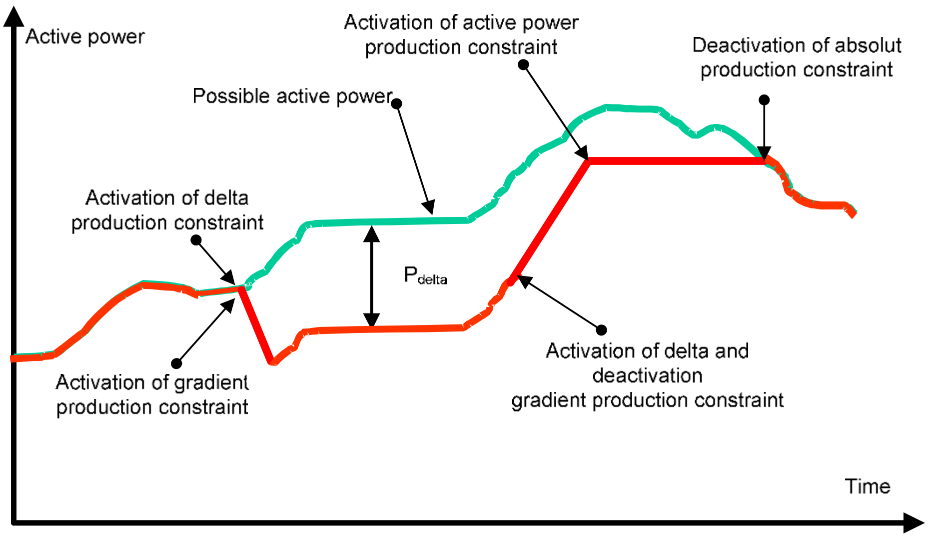
At present, a number of non-traditional sources are commercially available for frequency control/support and these sources include the use of Variable Renewable Energy (VRE) Sources, Fly-wheels, Synchronous Condensers and Batteries. More details of each of these resources and associated costs are as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

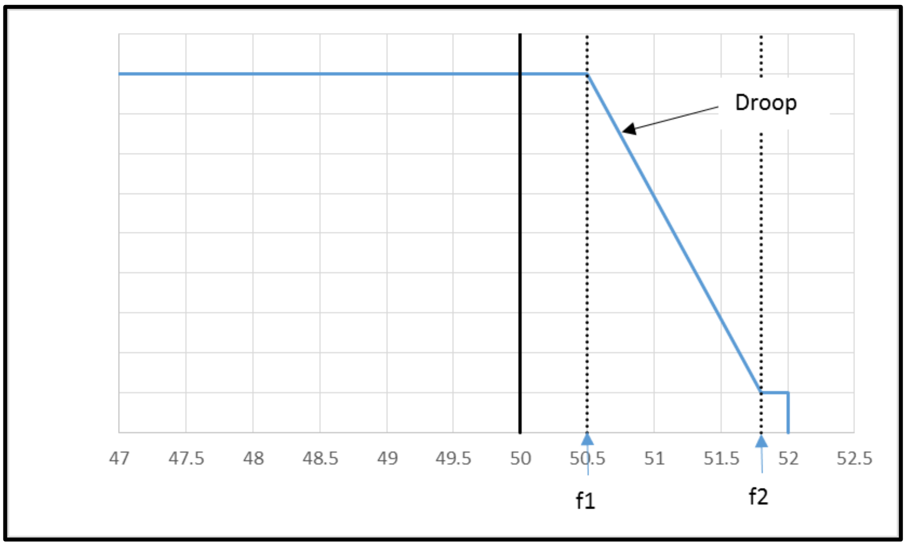
Option 1: The VRE plants are backed off from their full instantaneous maximum capacity, i.e. their outputs are limited. This is technically possible if the VRE plant control system can accept a set point from a central control system or a control philosophy is adopted in which the inverter is kept at an actual production, which is 5 - 10 percent below the maximum production (see Figure 2-4) 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



<u>**Option 2**: VRE provides high-frequency response only</u> – The VRE plant will only respond by decreasing instantaneous power when the frequency is high. Figure 2-5 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.

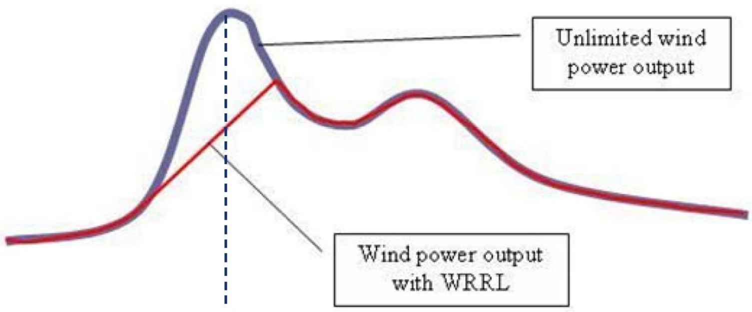
Figure 3-5 Typical VRE high frequency response only



<u>**Option 3:** VRE ramp rate is limited</u> – 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, Figure 2-6. 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 (shown in Figure 2-7) 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].

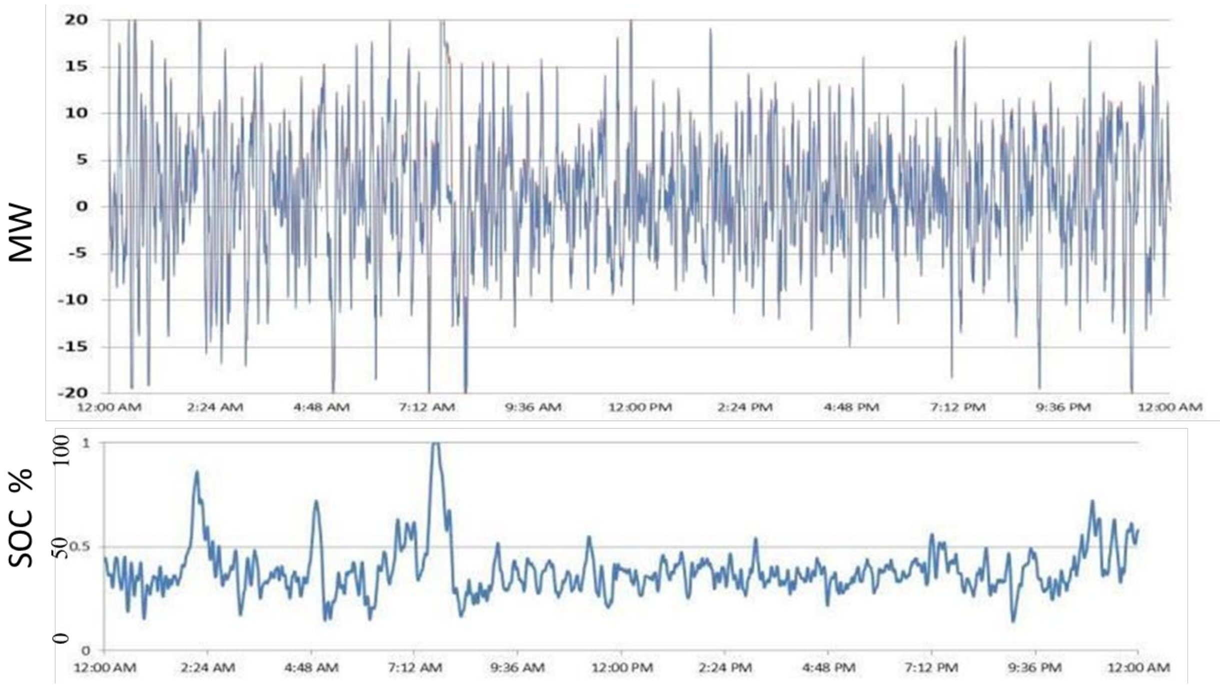
---

[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 50 Hz 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 infrastructure, 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].

The estimated capital cost for Samoa's current batteries of 8 MW and 13.6 MWh is $ 8 m for inverters and $10.3 m for batteries a total of $18.3m. For a ten year life time of batteries and inverter, excluding interest and inflation (this is assumed to be a soft loan), the annualised cost is $1.8m. If the interest rate for the loan is 5% above inflation then the annualised cost is

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

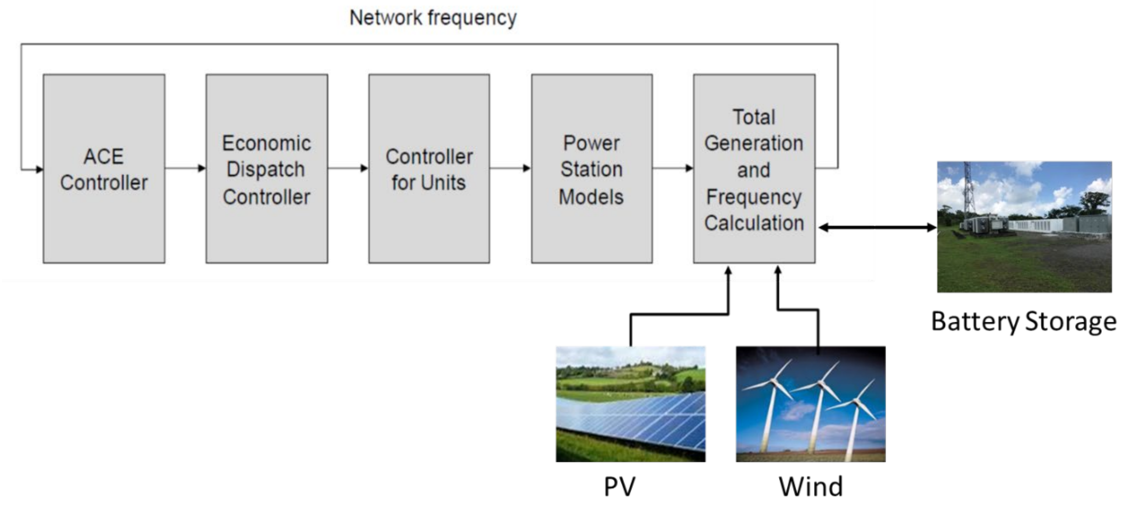
1. Determining the benefits for controlling network frequency using primary (governor) and secondary (AGC) control options
2. Analyse impact of non dispatchable renewable energy on frequency control
3. Analyse the benefits of storage on frequency control
4. Tuning Automatic Generation Controller
5. System Operator controller dispatch performance analysis
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, Figure 2-8. 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.

[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

The GDAT model for Samoa 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 Samoa, 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 Samoa studies

The models developed for Samoa are based on real-time data records received which were for the period between 13 October 2016 and 24 July 2017. Only those units for which the real-time data records were available were modelled.

For the Solar PV that are installed at the Green Power Samoa Airport, the real-time power records were only available for November 2016. So for studies beyond this point, the real-time power data that was available for Solar PV for Samoa Airport was used as this was nearest similar plant. This is a slightly worse case scenario than the original day being simulated.

The key dates used for the testing various scenarios are:

1. **06 November 2016** – a Sunday with a high level of Solar PV generation (very volatile); it has high levels of wind generation during the day and large generation from the non-dispatchable hydro units.
2. **07 December 2016** – a Thursday with a high level of Solar PV generation (very volatile); it has high levels of wind generation during the day and significant generation from non-dispatchable hydro units. The System Frequency is volatile during the day and this reflects the difficulty that the system operator would have faced in controlling the frequency in these periods with high wind and solar power.

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, data file name and GDAT name for Conventional and Renewable Generation Plants

Conventional Generation				
Power plant	Rated Capacity (kW)	Technology	File name	GDAT name
FOF	1,600	Hydro Run-of-the-River	TAELG1#	H3
Fiaga #1	5,778	Diesel	FIAGG#	D1
Fiaga #2	5,778	Diesel	FIAGG#	D2
Fiaga #3	5,778	Diesel	FIAGG#	D3
Fiaga #4	5,778	Diesel	FIAGG#	D4
Tanu	5.778	Back-up diesel	TANU	D5
LM #1	1,760	Hydro Run-of-the-River	LALO#	H1
LM #2	1,760	Hydro Run-of-the-River	LALO#	H2
Sam #1	900	Hydro Run-of-the-River		
Sam #2	900	Hydro Run-of-the-River		
TAF #2	2,000	Hydro dam	TAELG2#	H4
Total (kW)	**32,032**			

Renewable Generation				
Power plant	Rated Capacity (kW)	Technology	File Name	GDAT Name
Aleipata #1	275	Wind	WIND	W1
Aleipata #2	275	Wind	WIND	W1
PV GYM 3	250	PV		
PV Green Power Samoa Airports	2,400	PV	FALEGPS	PV1
PV Green Power Samoa Ful.	2,400	PV	RACEGPS	PV2
PV Race Course	2,200	PV	RACEEPC	PV3
PV Solar for Samoa Airport	1,400	PV	FALESFS	PV4
PV Solar for Samoa Fuluasou	2,400	PV	RACESFS	PV5
PV Sun Pacific Harelec	1,100	PV	FALESPS	PV6

Generation parameters used for inputs into the model for Diesel, Hydro, PV and Wind power plants are shown in Table 3-2, Table 3-3, Table 3-4 and Table 3-5.

Table 3-2: Samoa diesel generation parameters

Unit Name	D1	D2	D3	D4	D5
Model type	Diesel	Diesel	Diesel	Diesel	Diesel
MCR	5.7780	5.7780	5.7780	5.7780	5.7780
Unit Inertia	0.4500	0.4500	0.4500	0.4500	0.4500
Ramp Rate	6	6	6	6	6
Maximum Generation	5.7780	5.7780	5.7780	5.7780	5.7780
Minimum Generation	0.5000	0.5000	0.5000	0.5000	0.5000
Spinning Capability	5.7780	5.7780	5.7780	5.7780	5.7780
Nonspinning Capability	5.7780	5.7780	5.7780	5.7780	5.7780
AGC On	☑	☑	☑	☑	☑
Model Name	DEGOV1	DEGOV1	DEGOV1	DEGOV1	DEGOV1
Frequency deadband	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03
Lower frequency limit	-1	-1	-1	-1	-1
Upper frequency limit	1	1	1	1	1
Droop (R)	0.0400	0.0400	0.0400	0.0400	0.0400

Table 3-3: Samoa hydro generation parameters

Unit Name	H1	H2	H3	H4
Model type	Hydro	Hydro	Hydro	Hydro
MCR	1.6000	1.9000	1.9000	2.5000
Unit Inertia	4	4	4	4
Ramp Rate	1.6000	1.9000	1.9000	2.5000
Maximum Generation	1.6000	1.9000	1.9000	2.5000
Minimum Generation	0.2000	0.2000	0.2000	0.2000
Spinning Capability	1.6000	1.9000	1.9000	2.5000
Nonspinning Capability	1.6000	1.9000	1.9000	2.5000
AGC On	☐	☐	☐	☐
Model Name	TGOV1	TGOV1	TGOV1	TGOV1
Frequency deadband	1.0000e-03	1.0000e-03	1.0000e-03	1.0000e-03
Lower frequency limit	-1	-1	-1	-1
Upper frequency limit	1	1	1	1
Droop (R)	0.0400	0.0400	0.0400	0.0400

Table 3-4: Samoa PV generation parameters

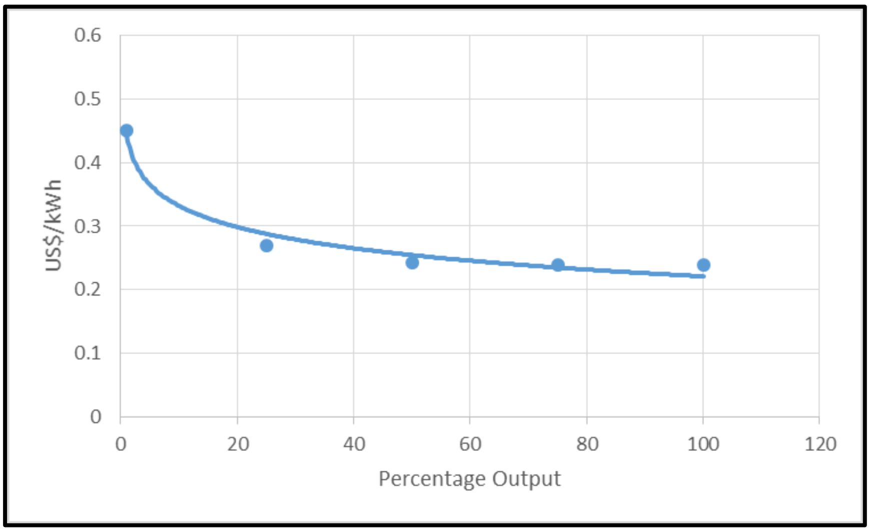
Unit Name	PV1	PV2	PV3	PV4	PV5	PV6
Model type	Solar	Solar	Solar	Solar	Solar	Solar
MCR	2.4000	2.4000	2.2000	1.4000	2.1000	1.1000
Unit Inertia	0	0	0	0	0	0
Ramp Rate	600	600	600	600	600	600
Maximum Generation	2.4000	2.4000	2.2000	1.4000	2.1000	1.1000
Minimum Generation	0	0	0	0	0	0
Spinning Capability	2.4000	2.4000	2.2000	1.4000	2.1000	1.1000
Nonspinning Capability	0	0	0	0	0	0
AGC On	☑	☑	☑	☑	☑	☑
Model Name	RecordedData	RecordedData	RecordedData	RecordedData	RecordedData	RecordedData
Frequency deadband	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100
Lower frequency limit	-1	-1	-1	-1	-1	-1
Upper frequency limit	0	0	0	0	0	0
Droop (R)	0.0100	0.0100	0.0100	0.0100	0.0100	0.0100

Table 3-5: Samoa wind generation parameters

Unit Name	W1
Model type	Wind
MCR	0.7000
Unit Inertia	0
Ramp Rate	600
Maximum Generation	0.7000
Minimum Generation	0
Spinning Capability	0.7000
Nonspinning Capability	0
AGC On	☑
Model Name	RecordedData
Frequency deadband	0.0100
Lower frequency limit	-1
Upper frequency limit	0
Droop (R)	0.0100

The fuel cost curve that plots power against US$/kWh for Fiaga diesel units, shown in Figure 3-9 below, is based on a typical similar sized CAT generator's performance. The cost curve was drawn for a fuel cost of US$ 0.9 per litre, which is in line the cost that was reported by the power station. The minimum generation is was assumed to be at 10% of the rated capacity or 0.57 MW.

Figure 3-9 Fiaga diesel units cost curve



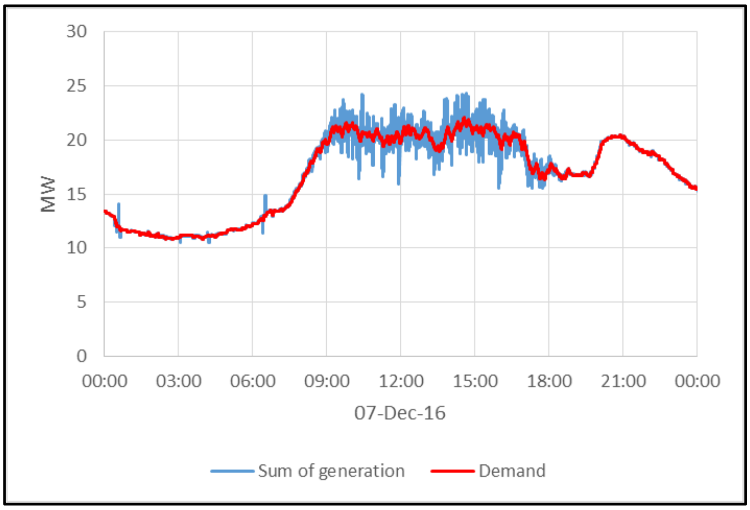
The key parameters for the AGC controller are shown in For the purpose of the analysis, the demand is assumed to be the same as generation. The demand was calculated by summing the generation Figure 2-11. The parameters selected are described in the appendix. For Samoa the simulation is run every second for a day.

Figure 3-10 GDAT controller parameters

Sample Time	1
Frequency error gain	0.2
Controller deadband	0.01
Controller proportional gain	0.1
Controller integral gain	0
Controller derivative gain	0
agcControllerType	1

For the purpose of the analysis, the demand is assumed to be the same as generation. The demand was calculated by summing the generation but this had to be smoothed as it would otherwise reflect the intermittency of renewables. Figure 3-11 shows how the demand has been smoothed by limiting the rate of change of demand every second. During the hours where there is no generation from Solar PV, the demand is the sum of the generation. The other alternative is to derive the demand from the sum of generation corrected for estimated induction motor load frequency response but in Samoa's case the frequency recorded on changes every 0.05 Hz and the data was not accurate enough for this calculation.

Figure 3-11 Example of how the demand is 'smoothed' on 07 December 2016



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. Added batteries that have already been installed in Samoa 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 3-6 .

Table 3-6 Simulations performed

				Controller status		
Case Number	Simulation date	VRE Installed (MW)	% peak	Solar PV	Wind	Battery
1	05-Nov-16	12.6	63%	AGC	AGC	off
2	05-Nov-16	12.6	63%	AGC	AGC	off
3	05-Nov-16	12.6	63%	AGC	AGC	B2 on Gov
4	05-Nov-16	12.6	63%	AGC	AGC	Gov
5	05-Nov-16	25.2	126%	AGC	AGC	Gov
6	05-Nov-16	25.2	126%	AGC	AGC	AGC
7	05-Nov-16	25.2	126%	AGC	AGC	AGC
8	05-Nov-16	37.8	189%	AGC	AGC	AGC
9	05-Nov-16	37.8	189%	AGC	AGC	AGC
10	09-Dec-16	12.6	63%	AGC	AGC	off
11	09-Dec-16	12.6	63%	AGC	AGC	B2 on Gov
12	09-Dec-16	12.6	63%	AGC	AGC	Gov

13	09-Dec-16	25.2	126%	AGC	AGC	Gov
14	09-Dec-16	37.8	189%	AGC	AGC	Gov
15	09-Dec-16	37.8	189%	AGC	AGC	AGC

Case 1: 05 November 2016 - Simulation of original case

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 3-12. The simulated data shows a reasonable correlation with the recorded data. Figure 3-14 shows the simulated frequency is similar to the recorded frequency, the frequency deviation is between 49.6 and 50.4 Hz. This confirms that the GDAT model is a good representative of the actual system. The frequency is acceptable but bordering on the outer boundary for normal frequency control of between 49.5 – 50.5 Hz. This shows the system is on its limit with the recorded penetration and current ability of the diesel units. There is only one unit running so the next scenario is to see if there is a frequency improvement with two units running.

Figure 3-12 Original recorded generation data on 05 November 2016

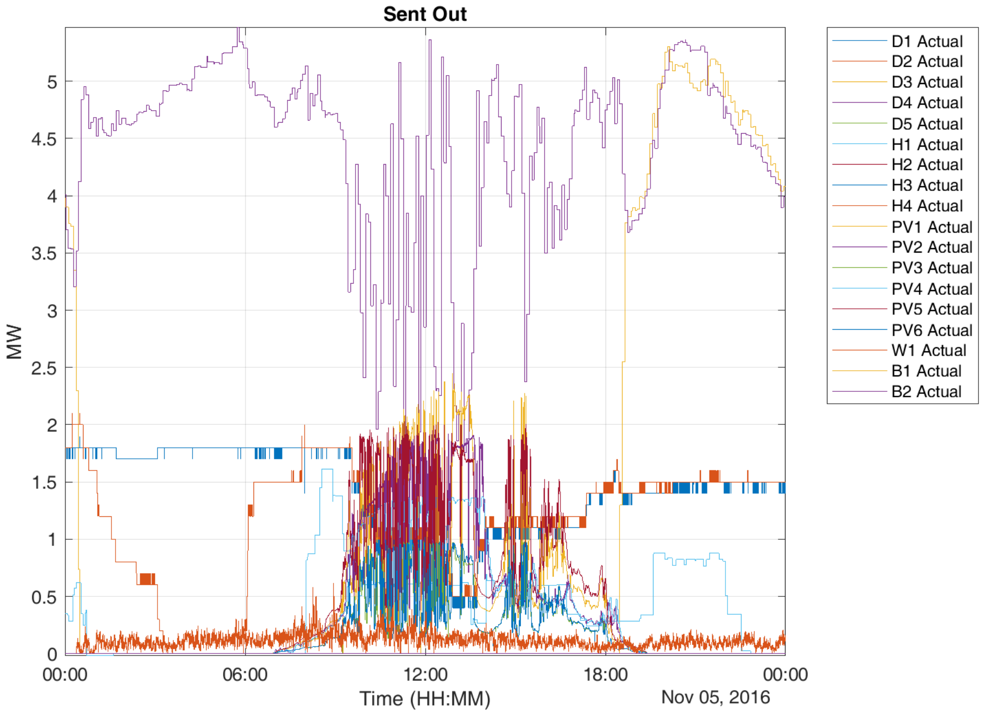


Figure 3-13 Simulated generation data on 05 November 2016

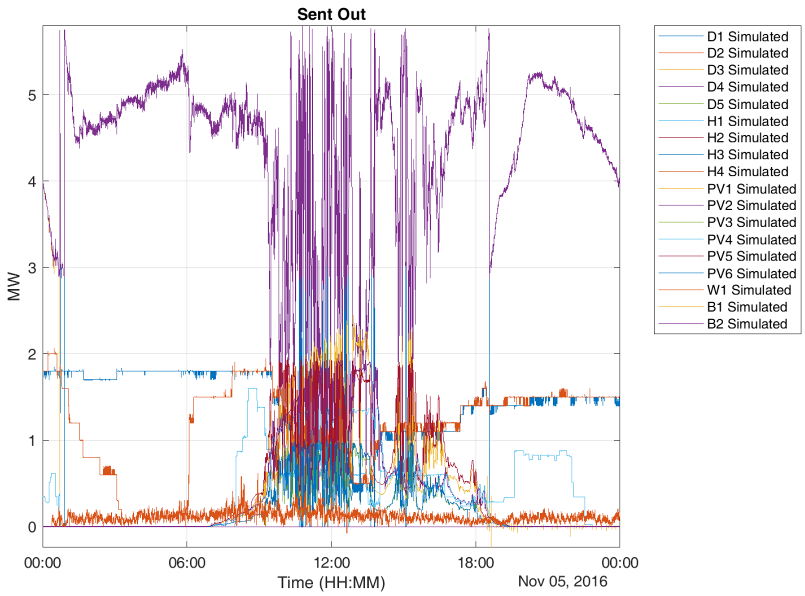
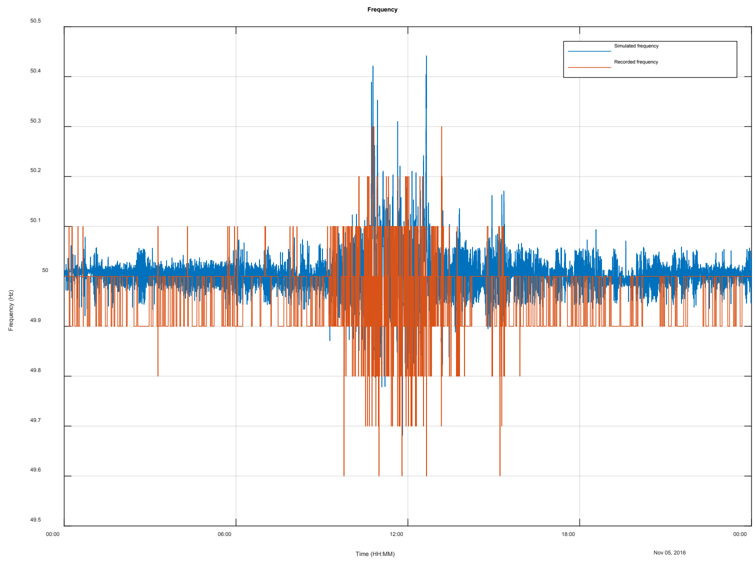


Figure 3-14 Original recorded and simulated frequency for 05 November 2016



Case 2: 5 November 2016 - Committing more diesel units to control frequency

This case is to see if there can be an improvement in frequency control if more than just the one diesel unit is running when there is high PV output. With two units running, the diesel units reach their minimum 10% output quite often, shown in Figure 3-16 This is not sustainable operation, and should there have been a greater variation then the frequency would not have been controlled by the two units as they are often at minimum output. The frequency control, Figure 3-16 with two units has improved during the periods of high PV variation. With two unit operating instead of one, the simulated daily fuel costs have increased from $32,116 to $32,984 a 3 percent increase in fuel consumption due to running both units at a lower efficiency without producing more diesel power.

Operating two units does improve spinning reserve and halves the size of the single contingency. These types of studies assist in determining the most appropriate techno-economic solution.

Figure 3-15 Simulated diesel generation output for 5 November 2016 with D3 and D4 operating under AGC

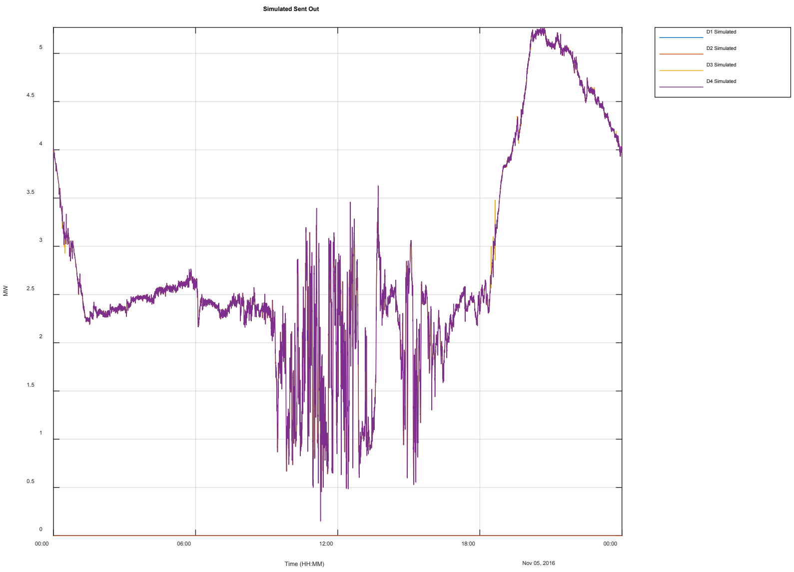
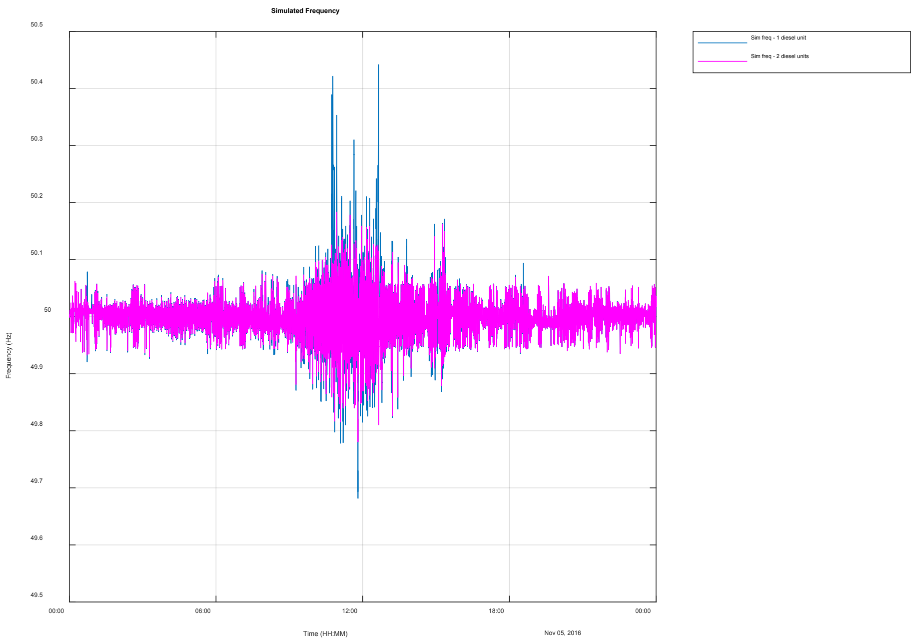


Figure 3-16 Simulated frequency for 5 November 2016 with one and two diesel units controlling frequency



<u>Case 3: 5 November 2016 - Battery B2 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 3-17. The deadband is set to 0.05 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 49.95 to 49.9 Hz and similarly will go to from 0 to full charge with a frequency variation from 50.05 to 50.1 Hz.

Figure 3-17 Battery parameters when on primary frequency control only

Unit Name	B1	B2
Model type	Battery	Battery
MCR	6	2
Unit Inertia	0	0
Ramp Rate	600	200
Maximum Generation	6	2
Minimum Generation	-6	-2
Spinning Capability	6	2
Nonspinning Capability	0	0
AGC On	☐	☐
Model Name	Battery	Battery
Frequency deadband	1.0000e-03	1.0000e-03
Lower frequency limit	-1	-1
Upper frequency limit	1	1
Droop (R)	1.0000e-03	1.0000e-03

The simulated frequency improves dramatically when battery B2 is on primary frequency control only, Figure 3-18 There are a few occasions during the period when the battery is at fully charging and the response is not enough to prevent high frequency, Figure 3-19. The diesel fuel costs of $32,180 are the more or less same as for case 1 of $32,116. The battery output moves up and down and the net effect is a charging of the battery from 50 – 63%, Figure 2-20.

Figure 3-18 Simulated frequency for 5 November 2016 with one diesel units controlling frequency with and without battery B2 on primary frequency control

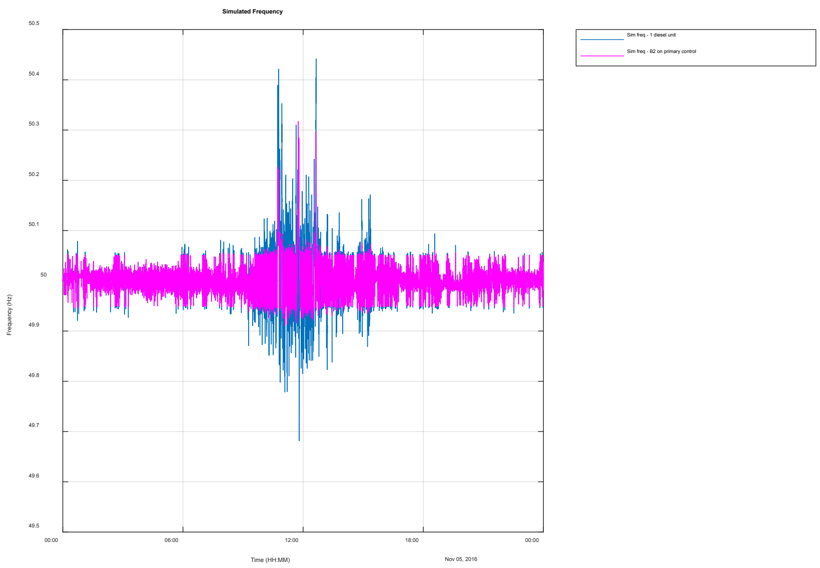


Figure 3-19 Simulated B2 battery output for 5 November 2016 when B2 is providing primary frequency control

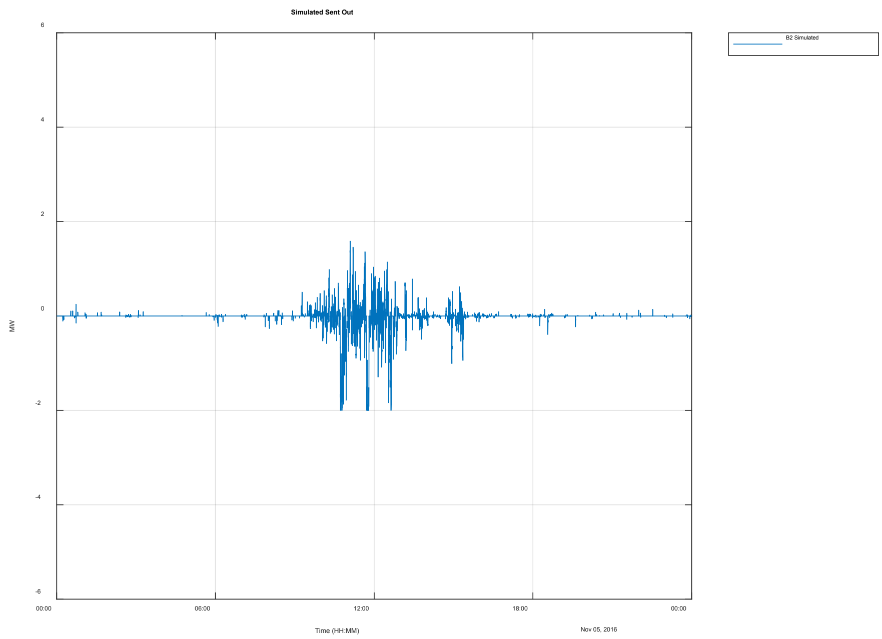
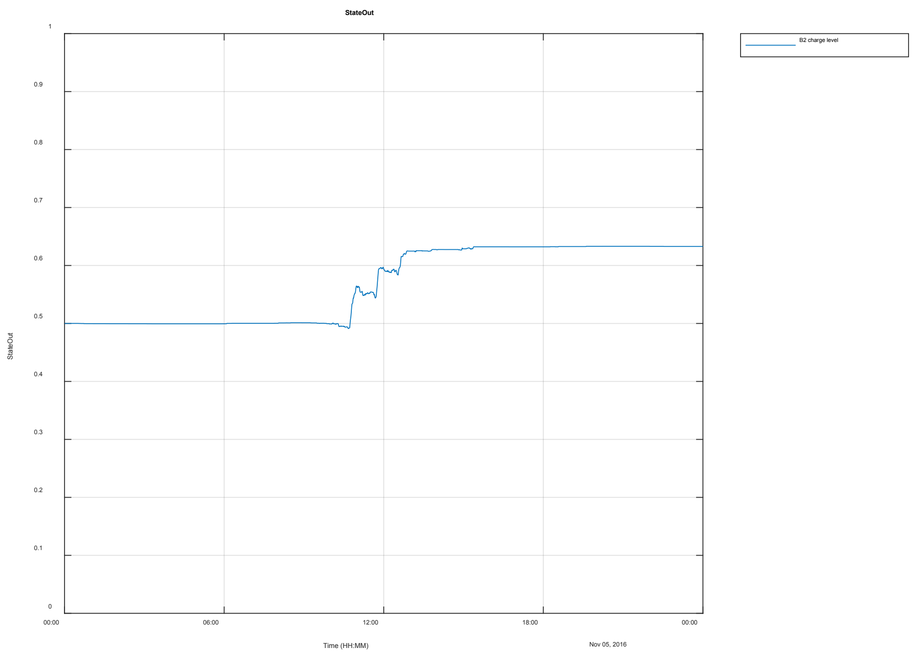


Figure 3-20Simulated B2 battery charge level for 5 November 2016 when B2 alone is providing primary frequency control



Case 4: 5 November 2016 - Batteries B1 & B2 on primary frequency control

The simulated frequency excursions when only battery B2 is on primary frequency control are removed when both batteries are on primary frequency control, Figure 3-21. The batteries output only reaches half of the ±8 MW available capacity and hence there and more VRE could be accommodated, Figure 3-22. The diesel fuel costs of $32,138 are the more or less same as for case 1 of $32,116.

The case where the batteries are on AGC and charged and discharged on a regular basis is not economically viable as there is no surplus VRE. Any charging will use more diesel power and this increases the fuel cost by 5% due to inefficient battery cycle and thus is not recommended.

Figure 3-21 Simulated frequency for 5 November 2016 with one diesel units controlling frequency with and without both batteries on primary frequency control

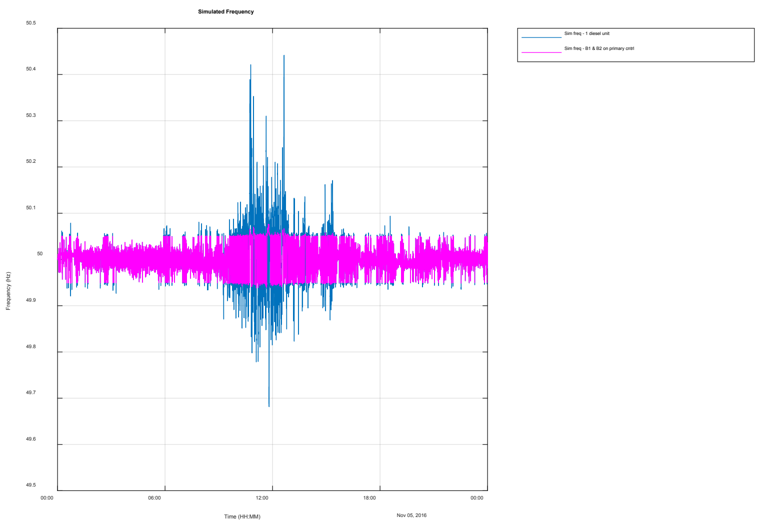
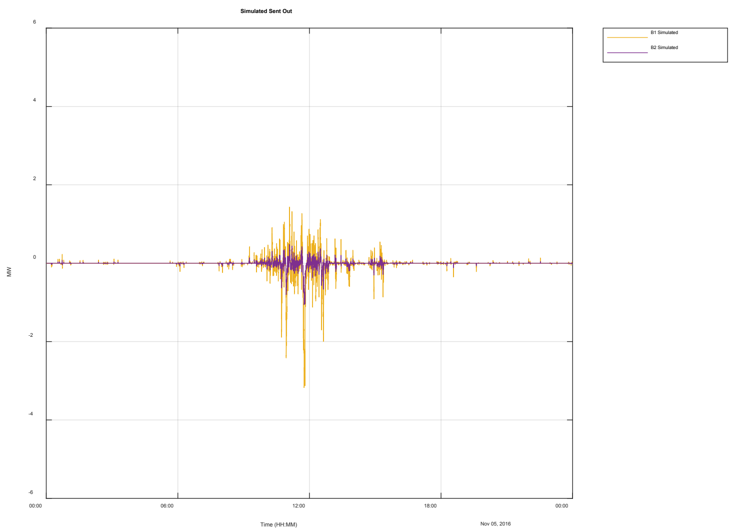


Figure 3-22 Simulated B1 & B2 battery output for 5 November 2016 when both batteries are providing primary frequency control



<u>Case 5: 5 November 2016 - Doubling the installed VRE with Batteries B1 & B2 on primary frequency control</u>

This case is to predict the possible future scenarios. The operation of the system is secured with the existing batteries and more VRE could be accommodated. This case assumes that the current recorded VRE is doubled, that is each plant is doubled in size. Whilst this may not be practical in reality, it is a worst case from a simulation of variability unless the next PV plant is greater than double the size of all the plants at the airport or Race Course (7 MW). Any increase in VRE away from these two PV sites will have overall less variability than what would be seen by increasing the capacity at the existing sites. The wind expansion is assumed to be at the same site with same size wind turbines.

The simulation reduces the VRE power plants when there is surplus power and the diesel generator is at minimum power. The VRE is reduced from 93.2 MWh to 75 MWh, an 18.2% reduction, essentially making the annualised cost from VRE 18% more expensive if the reduction was required every day.

The MW output from the batteries is not fully utilised even when the VRE is doubled, Figure 3-23, thus the simulations indicate there is room to increase VRE power even further without the requirement for more batteries on primary frequency control.

Figure 3-24 shows the diesel units output and the simulation shows quite a long period when the unit is at minimum generation. Case 7 will investigate the cost saving if the last unit is switched off, but for this, case the batteries need to take over frequency control and be on AGC.

Figure 3-23 Simulated B1 & B2 battery output for 5 November 2016 when both batteries are providing primary frequency control and VRE doubled.

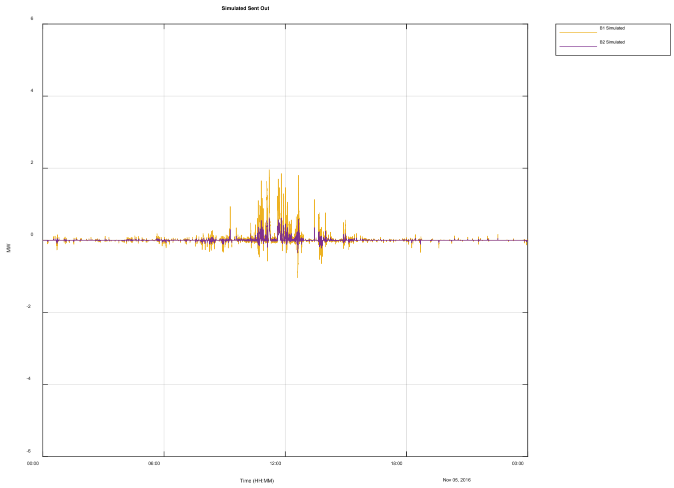
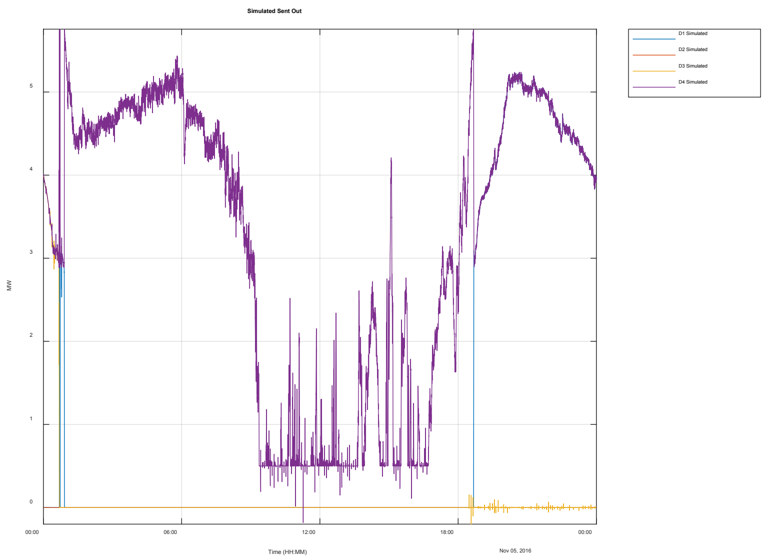


Figure 3-24 Simulated diesel units output for 5 November 2016 when both batteries are providing primary frequency control and VRE doubled.



Case 6: 5 November 2016 - Doubling the installed VRE with Batteries B1 & B2 on primary frequency control and AGC

Case 6 is simulating the same as case 5 but now with batteries on AGC. 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
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 VRE available – when VRE 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 charge discharge level is limited by the AGC controller to ensure frequency is controlled at the same time as optimising the energy available – essentially system security before economics

Figure 3-25 shows the when both battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess VRE to charge the batteries almost full charge level, Figure 3-26, by 15:00. The batteries then discharge instead of using diesel generation from 18:00 Hrs until charge level is 20%. The 2nd diesel generator start is delayed by an hour compared to case 5 whilst the batteries are discharging, Figure 3-27. The simulated diesel generator 4 output is at minimum generation for most of the period from 09:30 Hrs to 16:30 Hrs. When simulating was allowed to take all units off the simulation didn't take the last unit off as it was required for spinning reserve.

The fuel costs for case 6 is $ 22,269 compared to $ 25,142 for case 5. This reduction is due to an increase VRE output of 12.4 MWh which is used to charge the batteries and is later discharged instead of using diesel power. Using the batteries on AGC in this simulation case saves an extra $2,873 or 11% extra savings on fuel costs.

Figure 3-25 Simulated B1 & B2 battery output for 5 November 2016 when batteries providing both primary frequency control and AGC with VRE doubled.

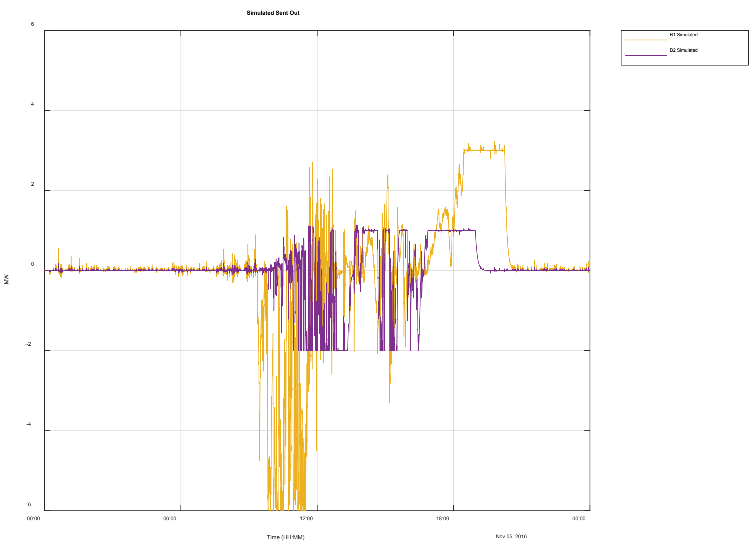


Figure 3-26 Simulated B1 & B2 battery charge level for 5 November 2016 when batteries providing both primary frequency control and AGC with VRE doubled.

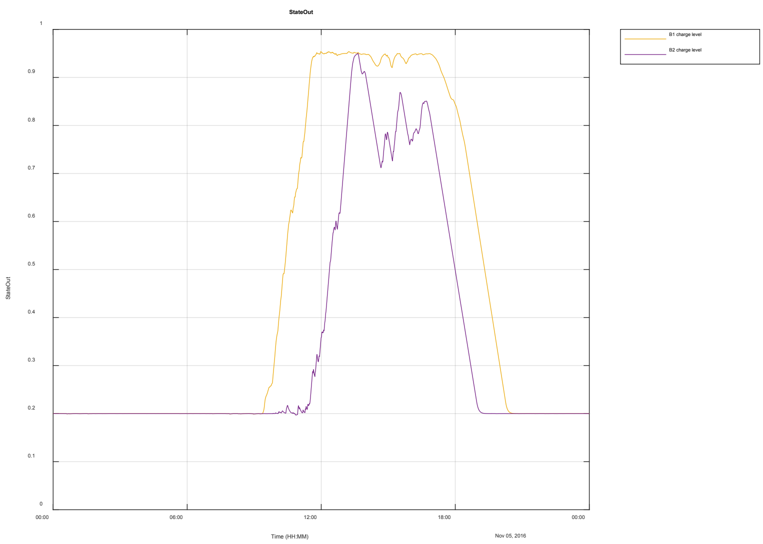
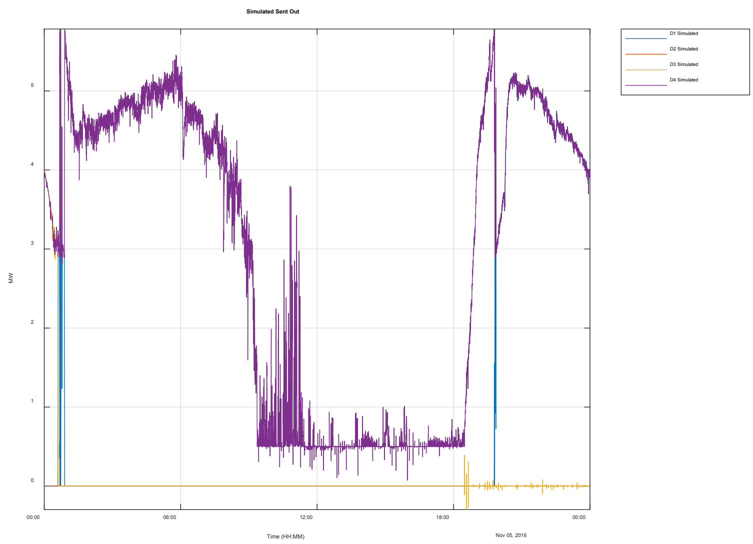


Figure 3-27 Simulated diesel units output for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE doubled.



<u>Case 7: 5 November 2016 - Tripling the installed VRE with Batteries B1 & B2 on primary frequency control</u>

This case is a repeat of Case 5 but now the VRE is tripled. The simulated frequency is within acceptable limits even when the VRE is tripled, shown in Figure 3-28.

The MW output from the batteries is half utilised when the VRE is tripled, shown in Figure 2-29, thus the simulations indicate that the maximum VRE can be increased with the current 8 MW of batteries on primary frequency control.

The VRE is reduced from 139.8 MWh to 94.3 MWh, a 32.5% reduction, essentially making the annualised cost from VRE 32.5 % more expensive if the reduction was required every day. This case requires further studying using batteries on AGC and maximising surplus energy. For case 8, the batteries are put on AGC to see what further optimisation is possible.

Figure 2-30 shows the diesel units output and the simulation shows quite a long period when a single unit is at minimum generation, so this is a potential case to see if it's possible to take all diesel units off. Case 9 will investigate this possibility further.

Figure 3-28 Simulated frequency for 5 November 2016 when both batteries providing both primary frequency control with VRE tripled.

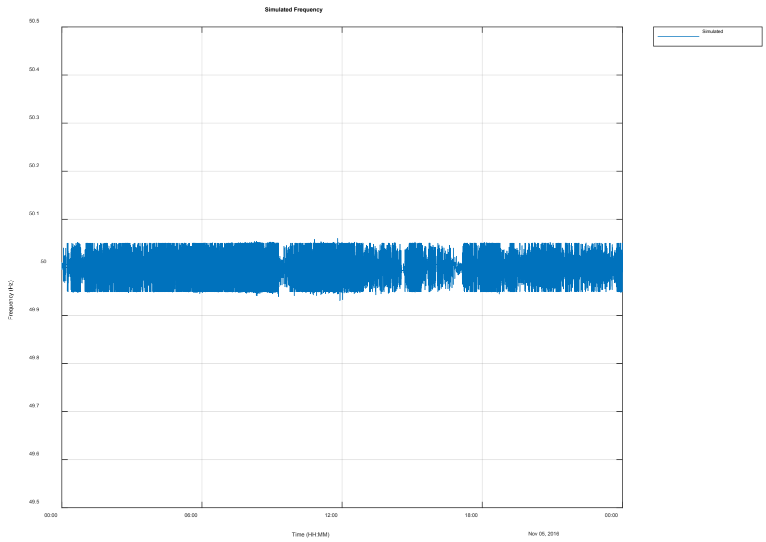


Figure 3-29Simulated B1 & B2 battery output for 5 November 2016 when both batteries are providing primary frequency control and VRE tripled.

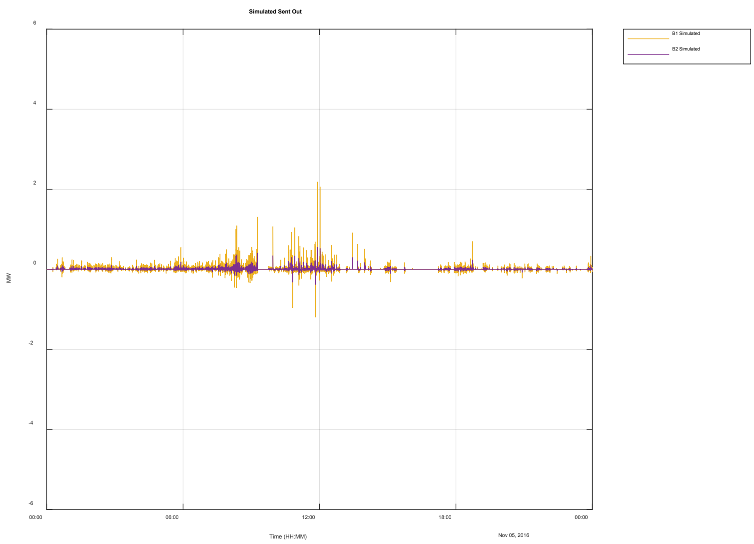
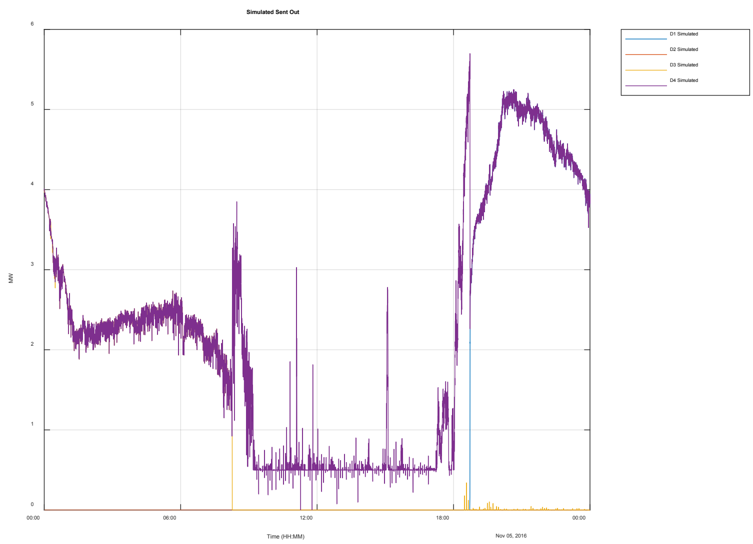


Figure 3-30 Simulated diesel units output for 5 November 2016 when both batteries are providing primary frequency control and VRE tripled.



<u>Case 8: 5 November 2016 - Tripling the installed VRE with Batteries B1 & B2 on primary frequency control and AGC.</u>

Simulating a VRE output of three times the current level means that the VRE exceeds the demand for most of the daytime when the sun is shining. The simulated frequency is within an acceptable range for most of the day, Figure 2-31, except the period when the batteries are charging. In this period there are a few high frequencies which are not significant but could be reduced if VRE ramp rate up is dynamically decreased.

The last diesel unit is at minimum output from 11:00 Hrs to 19:00 Hrs, Figure 2-32, and during this time the battery and VRE do control the frequency satisfactorily apart from the high frequencies noted above.

Figure **2-33** shows the batteries are using their full range to control the frequency and even with this the batteries are charging to full output, set as 95%, by 13::00 Hrs, Figure 2-35 Simulated VRE outputs for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled**.**

This indicates that more storage can be applied when the VRE is tripled but this is a weekend low demand period.

The VRE individual outputs are as high as current diesel generation outputs, Figure 2-35, so the single contingency size has not increased except if more than one PV plant decreases because of a single weather or network related contingency. The VRE outputs from 12:00 Hrs are limited to control the frequency once the batteries are charged, Figure 2-34. The simulation successfully controls the frequency with the batteries assisting when there is a sudden drop in VRE power output. The simulation curtails the VRE output on individual plants to a maximum of 3 MW and thus the single contingency is now less than when diesel units are operating.

The fuel costs for this case is $20,669which is only an additional 7% saving in fuel compared to the case where the VRE is doubled. For this simulation, the VRE is curtailed by 45.5 MWh or 32.5 % of its potential output.

Figure 3-31 Simulated frequency for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled.

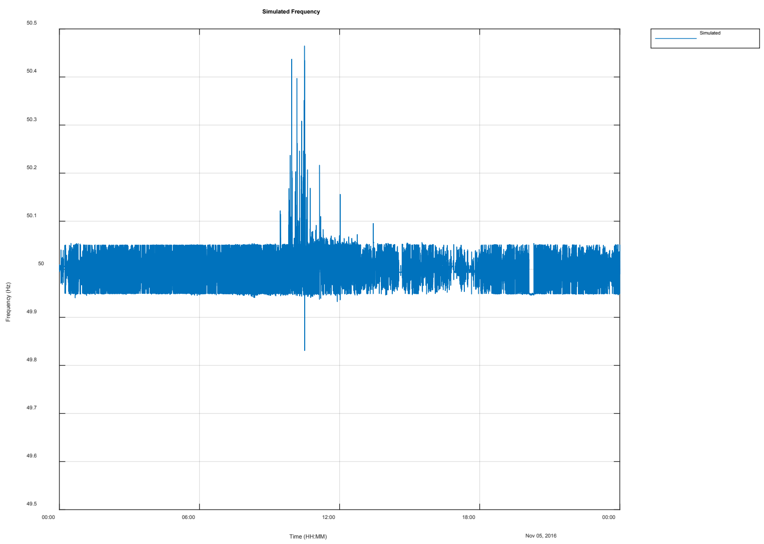


Figure 3-32 Simulated diesel units output for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled.

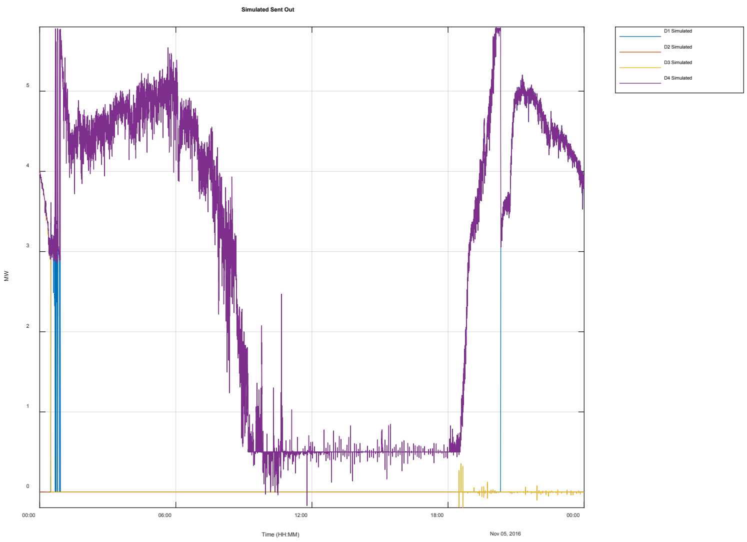


Figure 3-33 Simulated battery outputs for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled.

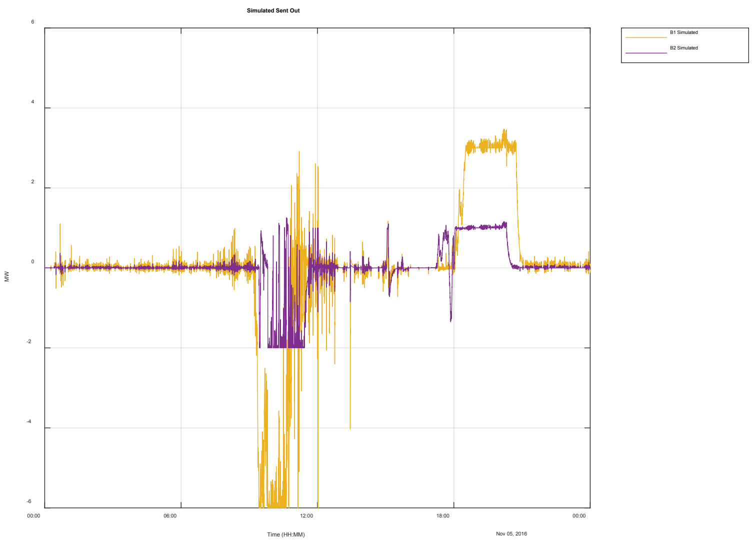


Figure 3-34 Simulated battery charge levels for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled.

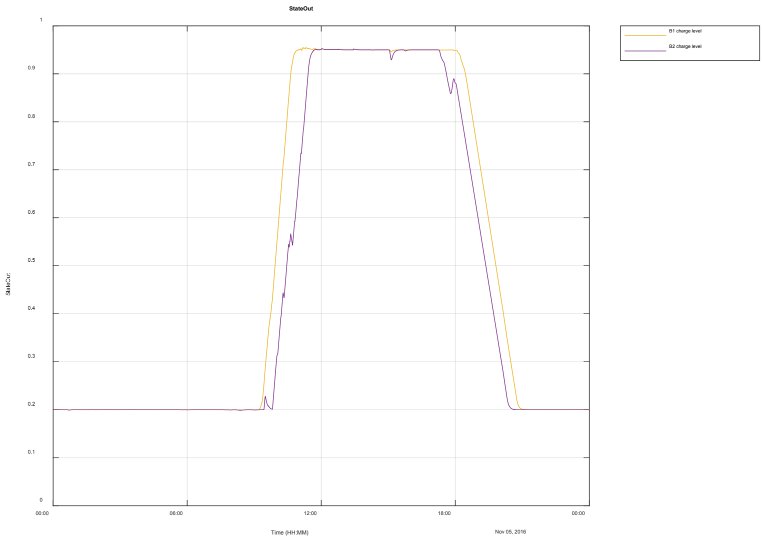
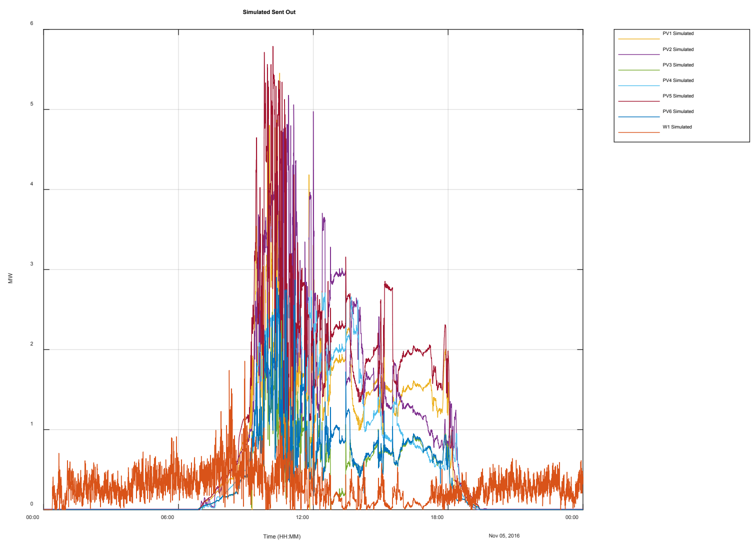


Figure 3-35 Simulated VRE outputs for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled.



Case 9: 5 November 2016 - Tripling the installed VRE with Batteries B1 & B2 on primary frequency control and AGC with all diesel units allowed to go offline.

Simulating a VRE output of three times the current level means that the VRE exceeds the demand for most of the day time when the sun is shining and also results in the last diesel unit run at minimum output of 0.5 MW. This case simulates the techno economic impact of taking the last diesel unit off.

The frequency control is the similar as when the last diesel unit was on in Case 8, Figure 2-36. All Diesel units are off from 12:00 to 19:00, Figure 2-37. The diesel production drops by 3 MWh and the VRE pick most of this up. The fuel saving is not significant at $809 per day but reducing the running hours on the unit at minimum generation by 7 hours every sunny weekend might be significant. When all the diesel units are off only the hydro units are providing any significant inertia and the battery inverters have to be capable of doing the frequency control.

Figure 3-36 Simulated frequency for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled and all diesel units allowed to go off-line.

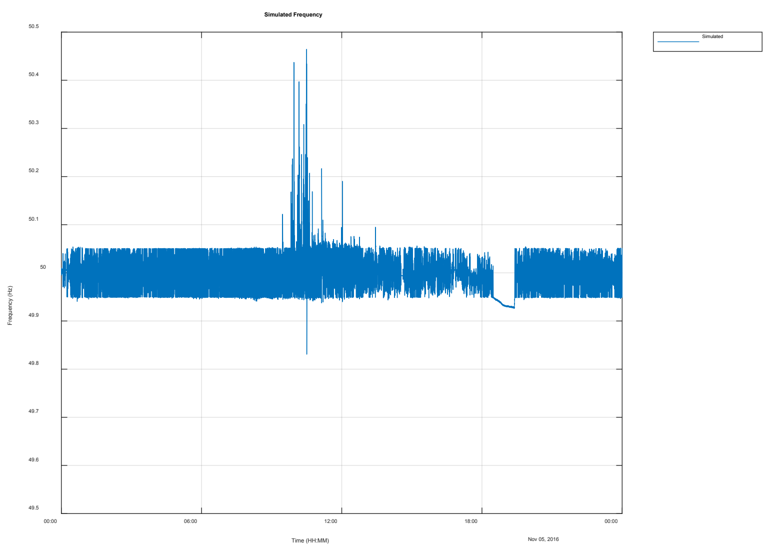
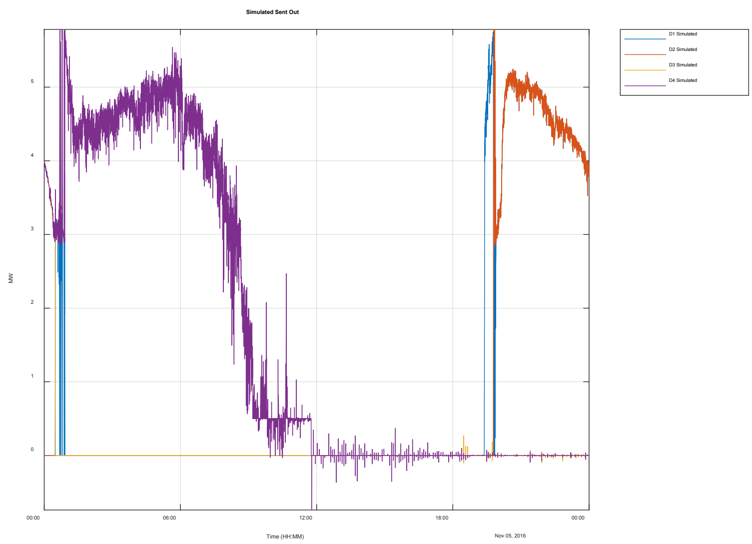


Figure 3-37 Simulated diesel units output for 5 November 2016 when both batteries providing both primary frequency control and AGC with VRE tripled and all diesel units allowed to go off-line.



Case 10: 07 December 2016 - Simulation of original case

The original case is simulated to see if the GDAT model is reasonably representative of the actual recorded data. Figure 2-38 shows the original recorded generation unit outputs for 07 December 2016. The simulated data shows a reasonable correlation with the recorded data shown in Figure 2-14 Original recorded and simulated frequency for 05 November 2016

Figure 2-40 shows the simulated frequency is similar to the recorded frequency, the frequency deviation is between 49.6 and 50.4 Hz. The frequency is acceptable but bordering on the outer boundary for normal frequency control of between 49.5 – 50.5 Hz. This shows the system is on its limit with the recorded penetration and current ability of the diesel units. The simulation keeps 3 units running between 01:00 Hrs and 06:00 Hrs to keep spinning reserve whereas on the actual day one unit is taken off. The fuel costs for the base case is $65,872 against the actual recorded case of $66,560 only a one percent difference.

Figure 3-38 Original recorded generation data on 07 December 2016

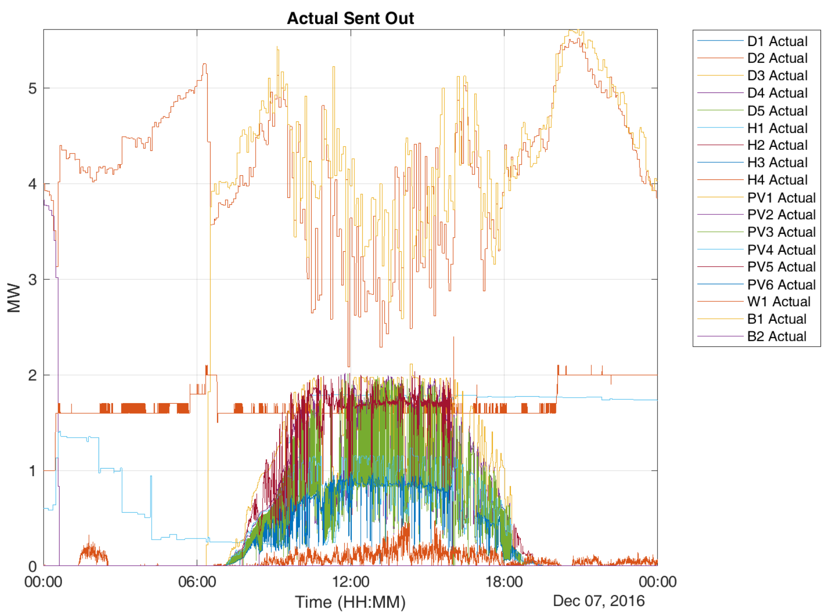


Figure 3-39 Simulated generation data for 07 December 2016

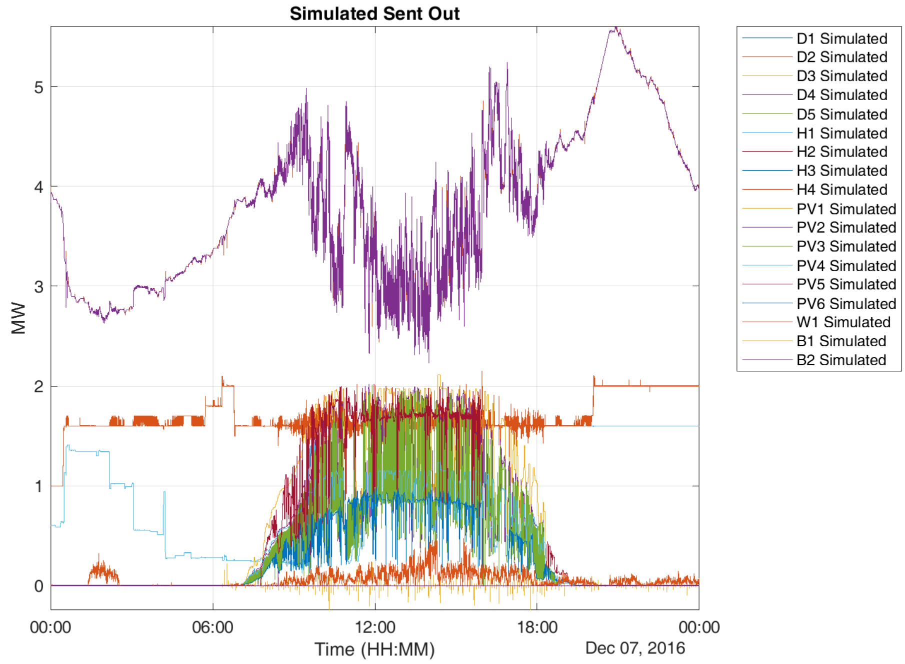
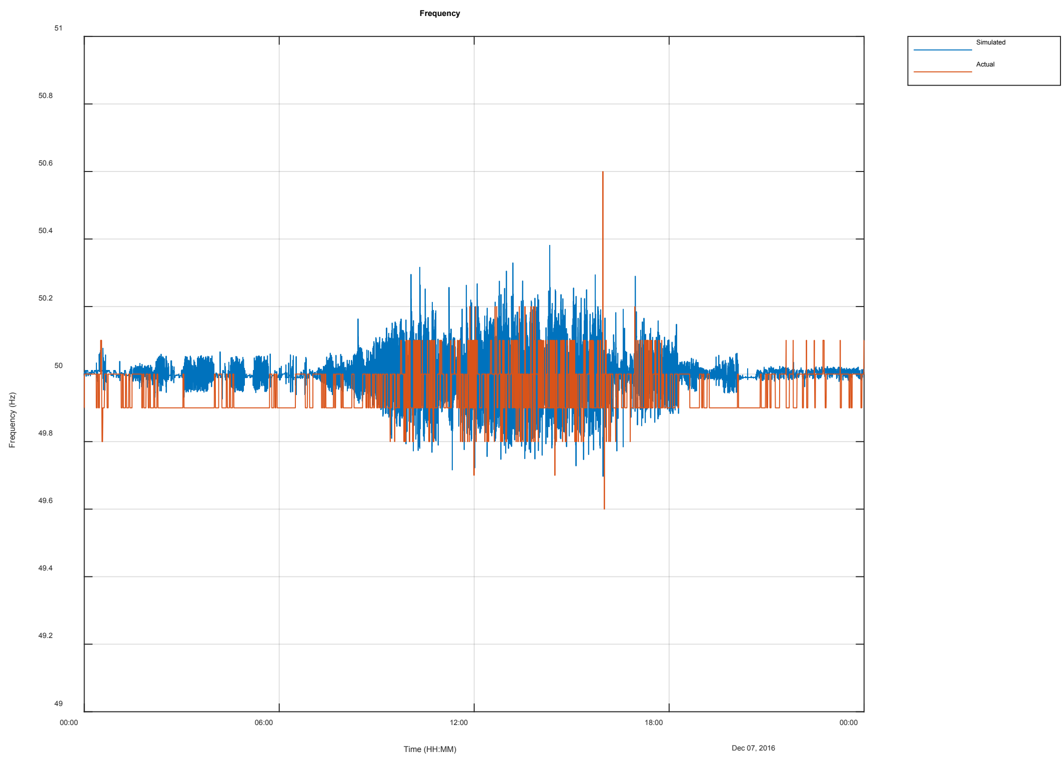


Figure 3-40 Original recorded and simulated frequency for 07 December 2016



Case 11: 07 December 2016 - Battery B2 on primary frequency control

The simulated frequency improves dramatically when battery B2 is on primary frequency control only, Figure 2-41. Unlike for the simulation on 5 November, there are a no occasions during the period when the battery is unable to control the frequency, Figure 2-42. The diesel fuel costs of $65,871 is almost the same as case 10 of $65,872 as the battery charge remains almost the same at 50%.

Figure 3-41 Simulated frequency for 7 December 2016 with one diesel unit controlling frequency with and without battery B2 on primary frequency control

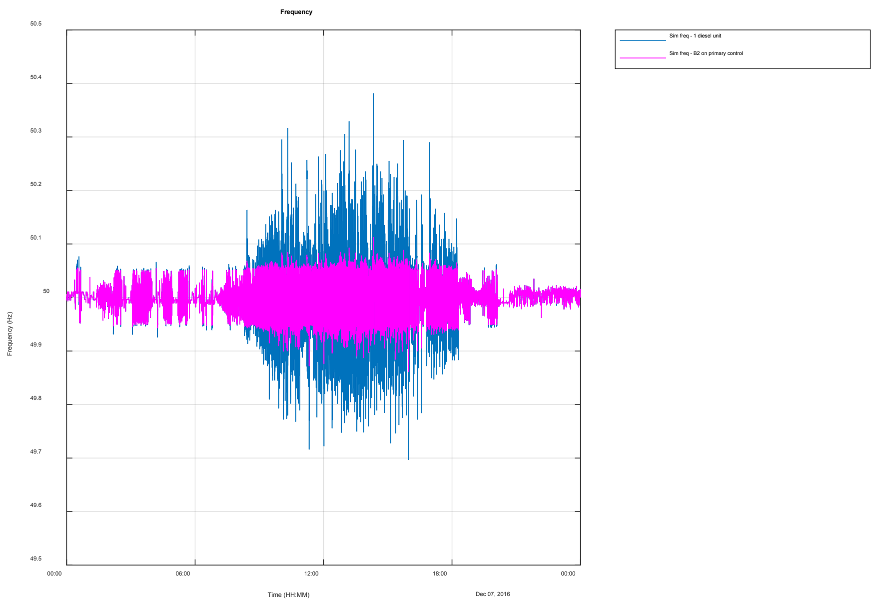
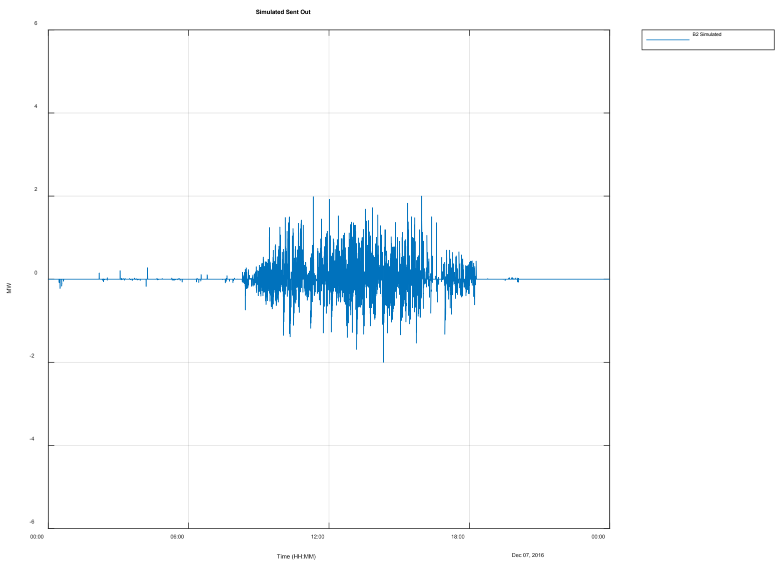


Figure 3-42 Simulated B2 battery output for 7 December 2016 when B2 is providing primary frequency control

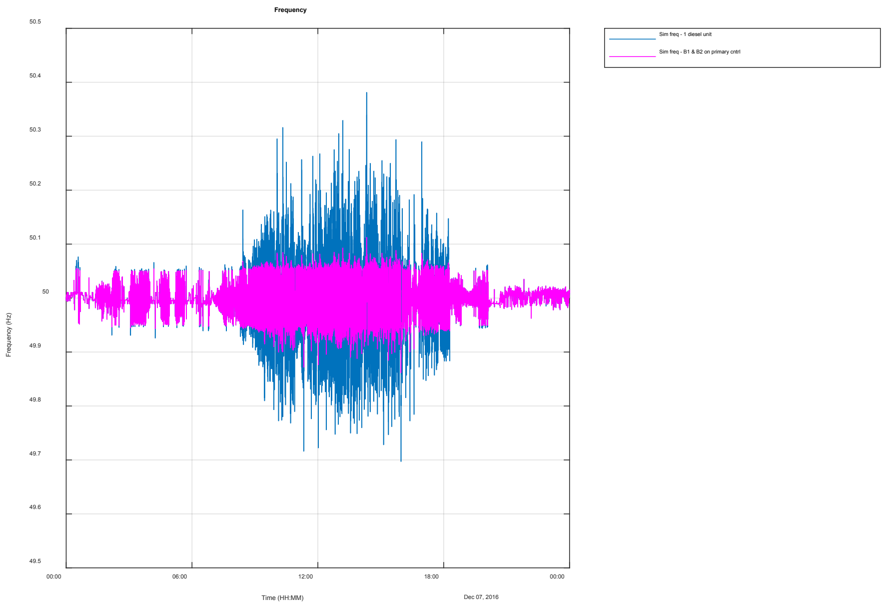


Case 12: 7 December 2016 - Batteries B1 & B2 on primary frequency control

The simulated frequency excursions when battery B2 is on primary frequency control only are removed when both batteries are on primary frequency control only, Figure 2-43. The batteries output only reaches half of the ±8 MW available capacity and hence there is space for more VRE to be added, Figure 2-44. The diesel fuel costs of $65,873 are the more or less same as for case 10 of $65,872.

The case where the batteries are on AGC and charged and discharged on a regular basis is not economically viable as there is not any surplus VRE. Any charging will use more diesel power and this is increases the fuel cost by 5% due to inefficient battery cycle and thus not recommended.

Figure 3-43 Simulated frequency for 7 December 2016 with one diesel units controlling frequency with and without both batteries on primary frequency control



<u>Case 13: 7 December 2016 - Doubling the installed VRE with Batteries B1 & B2 on primary frequency control</u>

This case is a repeat of Case 5 but now for 7 December.

The simulation reduces the VRE power plants when there is surplus power and the diesel generator is at minimum power. The VRE is reduced from 122.8 MWh to 119.8 MWh, a 2.4% reduction, essentially making the annualised cost from VRE 2.4 % more expensive if the reduction was required every day.

The MW output from the batteries is not fully utilised even when the VRE is doubled, Figure 2-44, thus the simulations indicate there is room to increase VRE power even further without the requirement for more batteries on primary frequency control. For case 14 the VRE is tripled.

Figure 2-45 shows the diesel units output and the simulation shows quite a long period when a single unit is at minimum generation, however there is no real surplus available to charge and discharge the batteries.

Figure 3-44 Simulated B1 & B2 battery output for 7 December 2016 when both batteries are providing primary frequency control and VRE doubled.

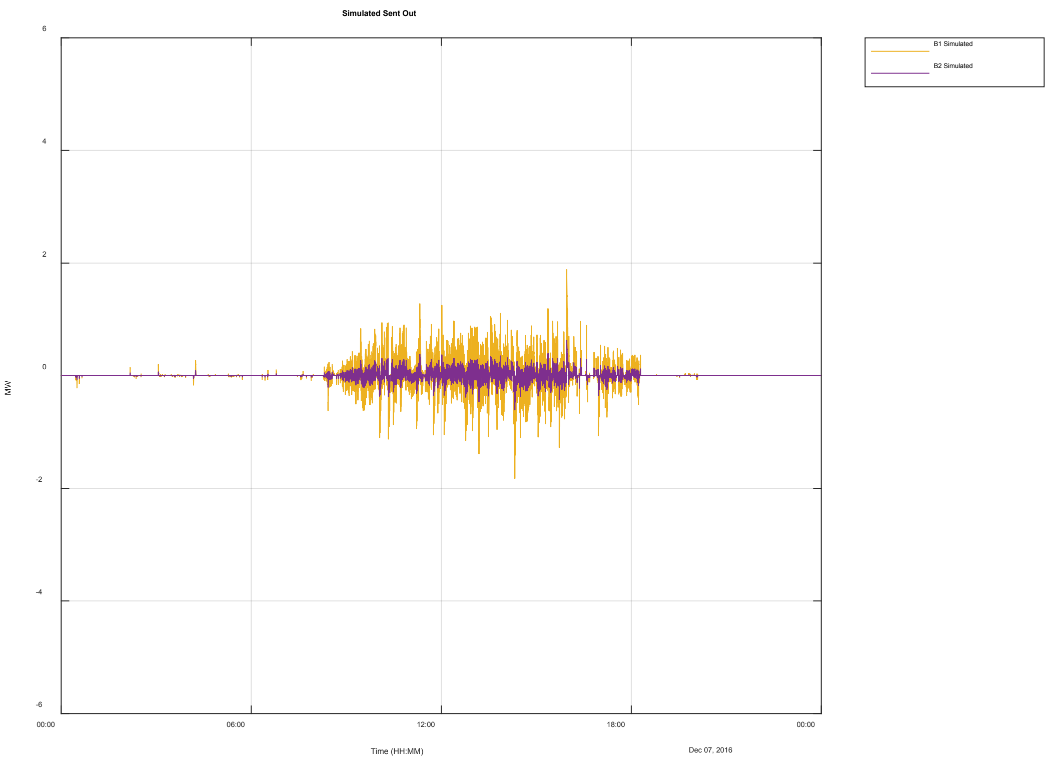
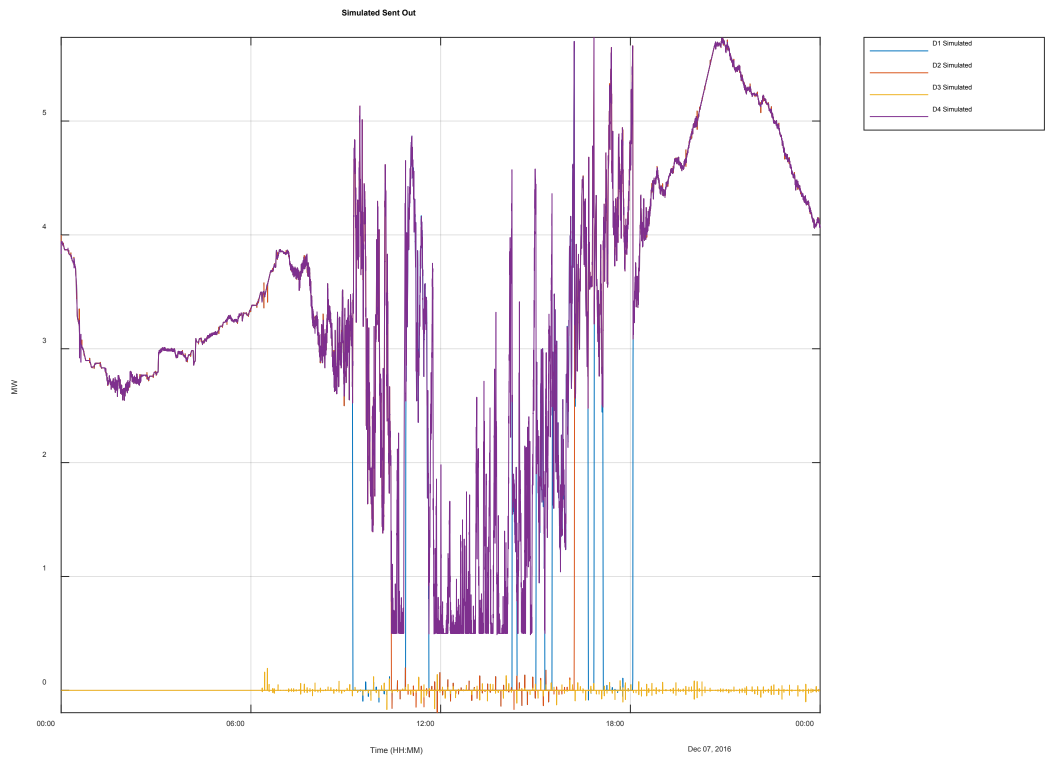


Figure 3-45 Simulated diesel units output for 7 December 2016 when both batteries are providing primary frequency control and VRE doubled.



<u>Case 14: 7 December 2016 - Tripling the installed VRE with Batteries B1 & B2 on primary frequency control</u>

This case is a repeat of Case 13 but now the VRE is tripled. The simulated frequency is within acceptable limits even when the VRE is tripled, shown in Figure 2-46.

The MW output from the batteries is almost fully utilised when the VRE is tripled, shown in Figure 2-47, thus the simulations indicate this is the maximum VRE with the current 8 MW of batteries on primary frequency control.
The VRE is reduced from 184.2 MWh to 147.0 MWh, a 20.2% reduction, essentially making the annualised cost from VRE 20.2 % more expensive if the reduction was required every day. This case requires further studying using batteries on AGC and maximising surplus energy. For case 15, the batteries are put on AGC to see what further optimisation is possible.

Figure 2-48 shows the diesel units output and the simulation shows quite a long period when a single unit is at minimum generation, so this is a potential case to see if it's possible to take all diesel units off. Case 16 will investigate this possibility further.

Figure 3-46 Simulated frequency for 7 December 2016 when both batteries are providing primary frequency control and VRE tripled.

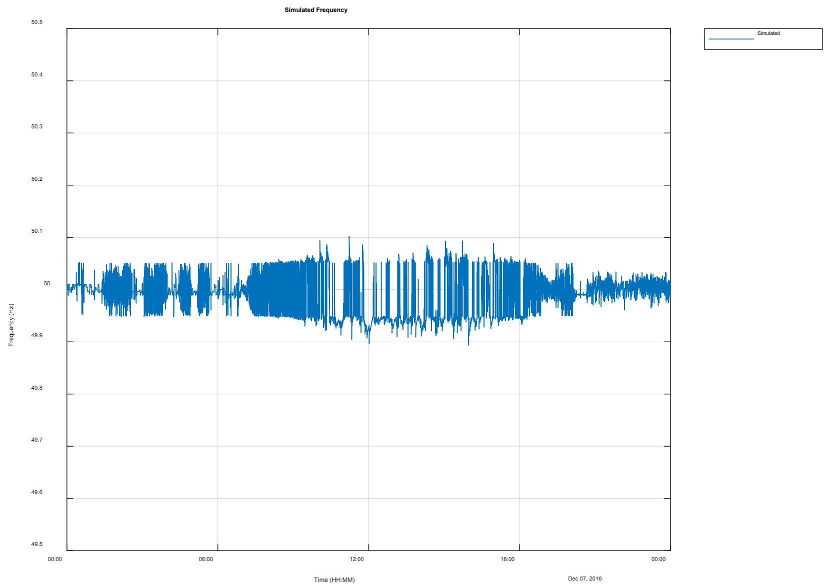


Figure 3-47 Simulated B1 & B2 battery output for 7 December 2016 when both batteries are providing primary frequency control with VRE tripled.

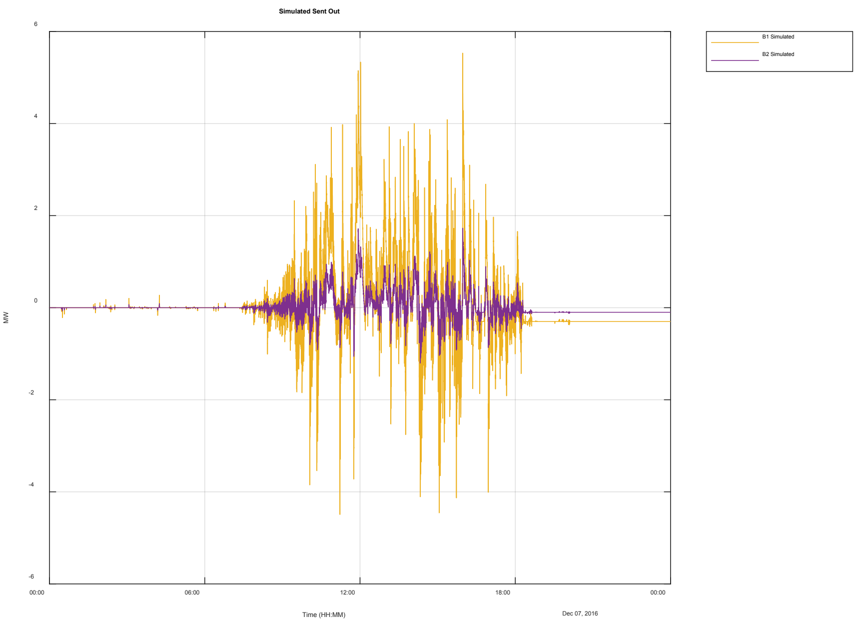
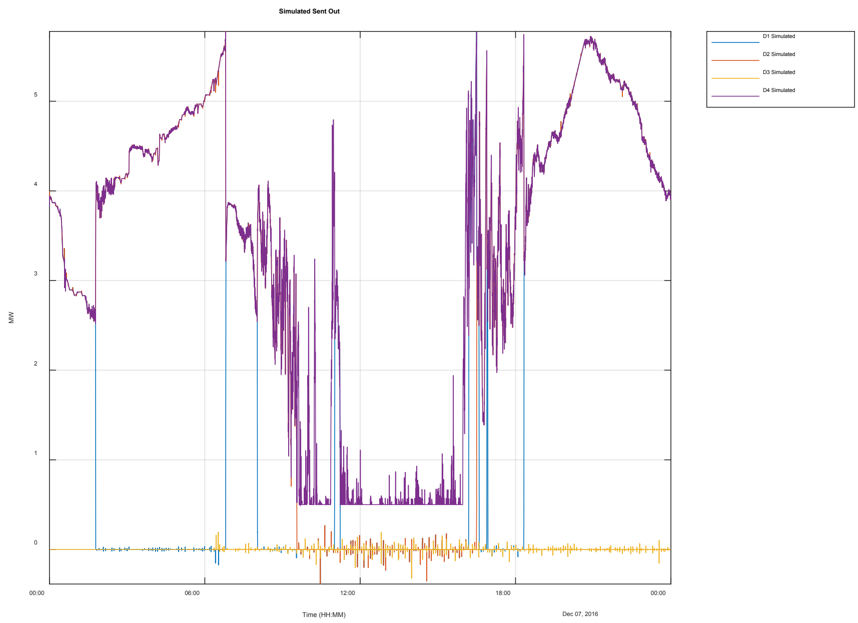


Figure 3-48Simulated diesel units output for 7 December 2016 when both batteries are providing primary frequency control with VRE doubled.



<u>Case 15: 7 December 2016 - Tripling the installed VRE with Batteries B1 & B2 on primary frequency control and AGC</u>

As for Case 6 when 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
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 VRE available – when VRE exceeds demand minus diesel generation minimum demand
4. The charge discharge level is limited by the AGC controller to ensure frequency is controlled at the same time as optimising the energy available – essentially system security before economics

Figure 2-49 shows the frequency control is worse when the batteries are charging, but the frequency variations are still acceptable. In this period there are a few high frequencies which are not significant but could be reduced if VRE ramp rate up is dynamically decreased.

Figure 2-50 shows the batteries are using their full range to control the frequency and even with this the batteries are charging to full output, set as 95%, by 13::00 Hrs, Figure 2-51. This indicates that more storage can be applied when the VRE is tripled but this is a weekend low demand period.
The last diesel unit is at minimum output from 13:00 Hrs to 15:00 Hrs, Figure 2-52, and during this time the battery and VRE do control the frequency satisfactorily apart from the high frequencies noted above.
The fuel savings is $3,110 for the week day when compared to Case 14 when the batteries are not utilised. For this simulation, the VRE is curtailed by 23.8 MWh or 12.9 % of its potential output.

Simulating a case where all diesel units are allowed to go off did not result in any diesel units going off due to spinning reserve constraints. If the spinning reserve requirement was reduced the unit would have gone off-line for 4 hours saving 4 MWh of diesel usage and around $500 per sunny week day.

Figure 3-49 Simulated frequency for 7 December 2016 when both batteries are providing both primary frequency control and AGC with VRE tripled.

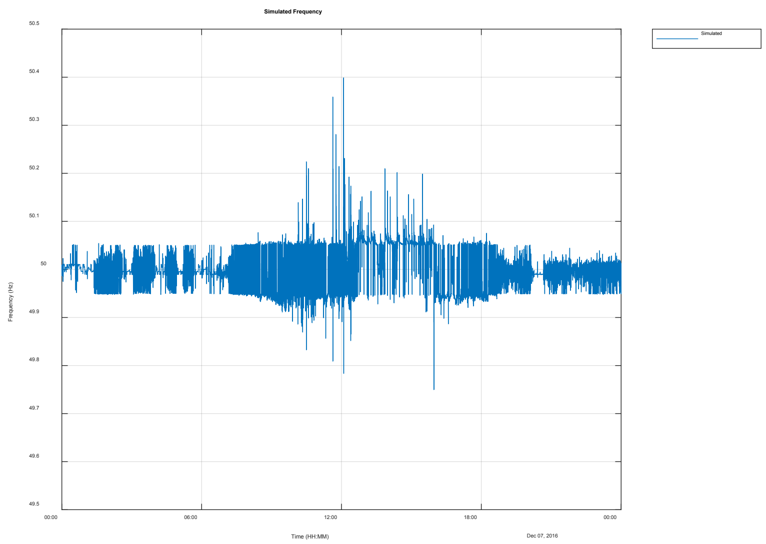


Figure 3-50 Simulated B1 & B2 battery output for 7 December 2016 when both batteries are providing both primary frequency control and AGC with VRE tripled.

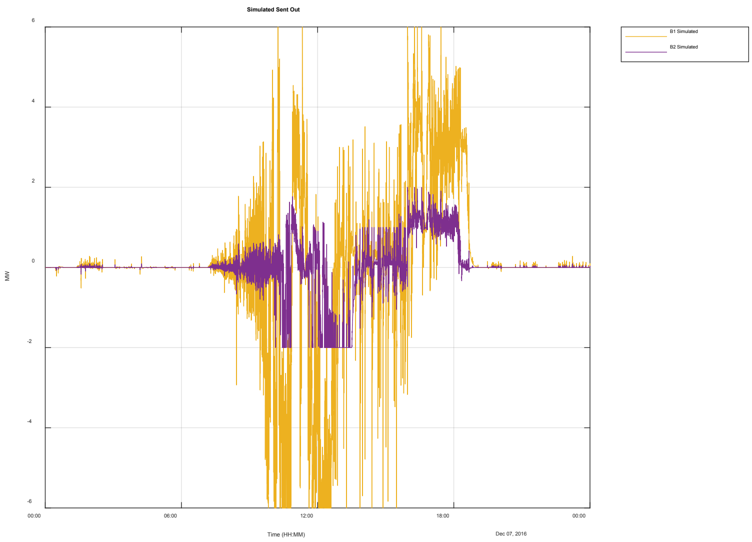


Figure 3-51 Simulated B1 & B2 battery charge level for 7 December 2016 when both batteries are providing both primary frequency control and AGC with VRE tripled.

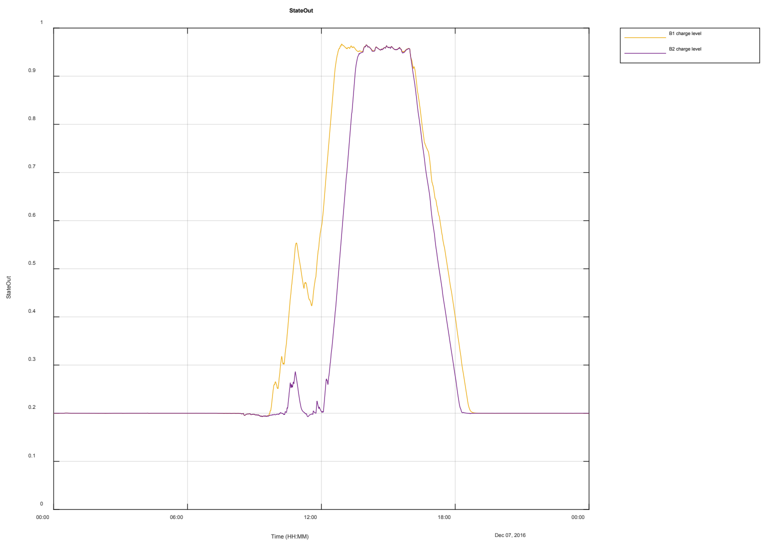
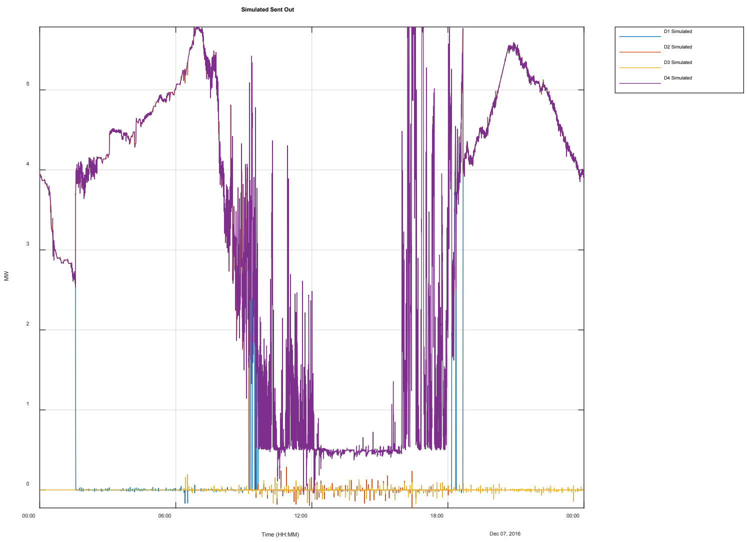


Figure 3-52 Simulated diesel unit outputs for 7 December 2016 when both batteries are providing both primary frequency control and AGC with VRE tripled.



3.4 Financial Assessment of incorporating Storage

The simulations economic results are shown in Table 2-7. The results are the calculated daily fuel consumed for the simulation case which is based on the fuel cost curve, Figure 2-9 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 first simulation for each day, which sets the benchmark for further studies.

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

Table 3-7 Summary of economic results of simulations

No	Sim date	VRE Installed (MW)	Diesel fuel costs	% fuel to sim 1 / 10	Diesel MWh	VRE MWh	VRE max (MWh)	VRE MWh reduced	% reduction	Comments
Base	05-Nov-16	12.6	31,849	99%	130.2	46.4	46.4	0.0	0.0%	
1	05-Nov-16	12.6	32,116	100%	131.0	46.6	46.6	0.0	0.0%	Base case validation
2	05-Nov-16	12.6	32,984	103%	131.0	46.6	46.6	0.0	0.0%	Two units running
3	05-Nov-16	12.6	32,180	100%	131.0	46.6	46.6	0.0	0.0%	B1 on gov
4	05-Nov-16	12.6	32,138	100%	131.0	46.6	46.6	0.0	0.0%	B1&B2 on Gov
5	05-Nov-16	25.2	25,142	78%	101.6	75.0	93.2	18.2	19.5%	B1&B2 on Gov
6	05-Nov-16	25.2	22,269	69%	94.1	87.4	93.2	5.8	6.2%	B1 & B2 on AGC
7	05-Nov-16	37.8	23,655	74%	93.6	83.6	93.2	9.6	10.3%	B1&B2 on Gov

8	05-Nov-16	37.8	20,669	64%	83.1	94.3	139.8	45.5	32.5%	B1 & B2 on AGC
9	05-Nov-16	37.8	19,860	62%	80.3	97.0	139.8	42.8	30.6%	B1 & B2 on AGC All diesel off
Base	07-Dec-16	12.6	66,560	101%	274.8	61.4	61.4	0.0	0.0%	
10	07-Dec-16	12.6	65,872	100%	270.9	61.4	61.4	0.0	0.0%	Base case validation
11	07-Dec-16	12.6	65,871	100%	270.9	61.4	61.4	0.0	0.0%	B1 on gov
12	07-Dec-16	12.6	65,873	100%	270.9	61.4	61.4	0.0	0.0%	B1&B2 on Gov
13	07-Dec-16	25.2	51,528	78%	210.2	119.8	122.8	3.0	2.4%	B1&B2 on Gov
14	07-Dec-16	37.8	45,118	68%	184.8	147.0	184.2	37.2	20.2%	B1&B2 on Gov
15	07-Dec-16	37.8	42,008	64%	171.9	160.4	184.2	23.8	12.9%	B1 & B2 on AGC

The simulations show that it is possible to increase the renewable energy penetration by three times the current installation without a negative impact on frequency control.

The technical ability to take off all diesel units needs further analysis.

Table 2-8 shows a summary of a few key cases in order to get an idea of how much batteries already installed in Samoa are saving in terms of initially using the batteries only for system security and frequency control and then secondly the additional utilising the storage available in the batteries.

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.

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

No	VRE % of peak	Diesel fuel costs	fuel savings	$/kwh	% fuel to sim 1	Diesel MWh	NRE MWh	VRE max MWh	VRE reduced	% reduction	Additional PV energy costs	net saving
1	63%	32,116	0	0.245	100%	131.0	46.6	46.6	0.0	0.0%	0	0
5	63%	25,142	6,974	0.247	78%	101.6	75.0	93.2	18.2	19.5%	4,660	2,314
6	126%	22,269	9,847	0.237	69%	94.1	87.4	93.2	5.8	6.2%	4,660	5,187
7	189%	23,655	8,461	0.253	74%	93.6	83.6	93.2	9.6	10.3%	4,660	3,801
8	189%	20,669	11,447	0.249	64%	83.1	94.3	139.8	45.5	32.5%	9,320	2,127
9	189%	19,860	12,256	0.247	62%	80.3	97.0	139.8	42.8	30.6%	9,320	2,936
10	63%	65,872	0	0.243	100%	270.9	61.4	61.4	0.0	0.0%	0	0
13	126%	51,528	14,344	0.245	78%	210.2	119.8	122.8	3.0	2.4%	6,140	8,204
14	189%	45,118	20,754	0.244	68%	184.8	147.0	184.2	37.2	20.2%	12,280	8,474
15	189%	42,008	23,864	0.244	64%	171.9	160.4	184.2	23.8	12.9%	12,280	11,584

Doubling the VRE power plants and keeping the batteries on primary frequency control will save US$2,314 for a weekend day and a simulated saving of US$8,204 for the week day. Tripling the VRE power plants gives a saving of US$ 3,801 for a weekend day and US$8,474 for the week day. There are diminishing returns as the VRE is increased from 2 to 3 times as there is significant curtailment when the VRE is greater than the demand minus the minimum generation of the last diesel unit online.

Utilising the existing storage in the batteries already installed saves an additional US$ 2,400 per day. This needs to be checked with more data to ensure this is still a secure solution.

Switching the last unit off during the day saving 0.5 MWh per hour will realise more savings US$ 800 for a weekend day and US$500 for the week 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.

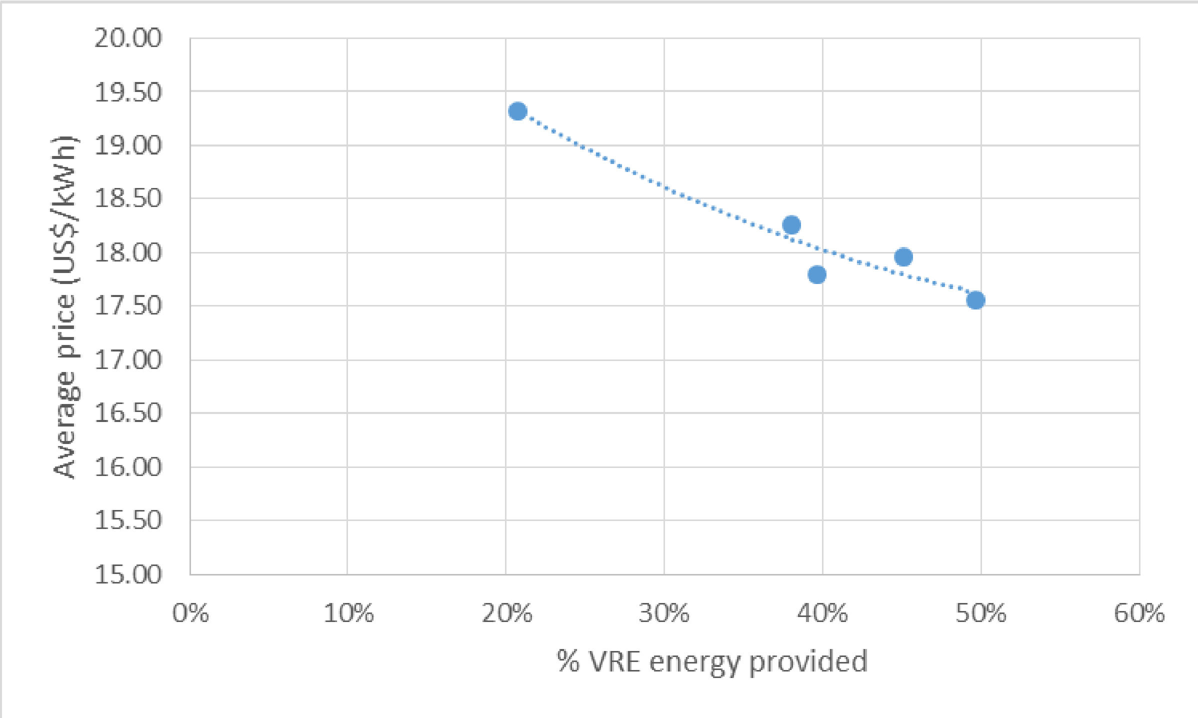
Annualising the Solar costs and fuel savings by simply taking the weekend results multiplied by 2 days and 52 weeks and the week day results multiplied by 5 days and 52 weeks gives a very rough estimate of the potential annual savings shown in Table 2-9. The annualised savings when using batteries for frequency control alone are less the annualised costs of the batteries estimated as $1.8m.

Using the existing storage to its maximum by charging the batteries whenever there is surplus energy shows an additional estimated savings of between US$ 0.4 m to US$ 0.6 m per annum.

Table 3-9 Estimated annualised Solar Costs and fuel savings

Description	VRE Installed (MW)	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated nett saving (pa)
Batteries on primary frequency control only	25.2	126%	4,454,736	2,081,040	2,373,696
Batteries on primary frequency control and AGC	25.2	126%	4,753,528	2,081,040	2,672,488
Batteries on primary frequency control only	37.8	189%	6,275,984	3,677,440	2,598,544
Batteries on primary frequency control and AGC	37.8	189%	7,395,128	4,162,080	3,233,048

Figure 3-53 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

3-10 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 3-10: Average Supply Costs (US Cents/kWh)[9]

		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 3-11: Average Supply costs versus Tariffs for 2017 in US c/kwh[10]

		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 Samoa, the following scenarios have been presented and as shown in the last column of Table 3-12, the option with of 37.8 MW PV and B1 & B2 battery capacity on primary frequency control and AGC would have the biggest impact on the variable costs. The total decrease in total variable costs from the base case scenario would be 9%. Variable costs meaning fuel costs plus annualised costs of PV and battery. This is used to estimate the incremental system cost in each case.

9 PPA Benchmarking Report Fiscal year 2017 (published September 2018)

10 PPA Benchmarking Report Fiscal year 2017 (published September 2018)

Table 3-12: Samoa - Estimated annual total variable costs and percentage savings

Description	VRE Installed (MW)	% peak	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total 'variable' costs from base cases
Batteries on primary frequency control only	25.2	126%	19,130,239	18.261	5%
Batteries on primary frequency control and AGC	25.2	126%	18,831,447	17.799	8%
Batteries on primary frequency control only	37.8	189%	18,905,391	17.964	7%
Batteries on primary frequency control and AGC	37.8	189%	18,270,887	17.565	9%

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 3-13: 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
Batteries on primary frequency control only	19,130,239	18.261	5%	28.22	27.31	42.15	41.23
Batteries on primary frequency control and AGC	18,831,447	17.799	8%	28.22	26.80	42.15	40.72
Batteries on primary frequency control only	18,905,391	17.964	7%	28.22	26.96	42.15	40.89
Batteries on primary frequency control and AGC	18,270,887	17.565	9%	28.22	26.64	42.15	40.56

The best-case scenario as described above would have a net impact on the tariff of more than US cents 1.5 /kwh (from US cents 42.15/kwh to US cents 40.56/kwh). This is close to the average supply costs of around US cents 41/kwh for the years 2012-2017.

3.6 Recommendations for application of storage

The installation of the current batteries will improve the security of supply and storage will only be required once the actual VRE exceeds the demand at the time. The current installed battery installation will allow for the VRE to be at least doubled and even tripled without the need for extra batteries for frequency control. The simulation studies show the system is secure. The simulations show that storage will be utilised on the weekends when the current VRE is doubled in size and on the week days when the current VRE is tripled.

Using the existing storage to its maximum by charging the batteries whenever there is surplus energy shows an additional estimated savings of between US$ 0.4 m to US$ 0.6 m per annum. The risk occurs when the battery is charging, as it is not available to control high frequency incidents and these have to thus be controlled by VRE units on AGC as diesel units are either at minimum or off.

The recommendation for Samoa in the short term to medium term is to increase VRE with the existing storage. Additional storage without more than doubling the existing VRE will not improve security of supply or have any savings in diesel fuel consumption.

Once the VRE is increased to double the current installation then these studies would need to be repeated on the new demand and measured variability 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 Electric Power Corporation (Samoa) and this is available in Appendix A 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 Background: SCADA Systems

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

Main functions of the SCADA are:

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

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

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

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

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

5.2 SCADA Systems Basic activity

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

5.2.1 Data Acquisition

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

a. Analogue values like Voltage, Current or Power (active or reactive). Those values captured from the field in analogue ways are converted into digital in counts values (±0 – 2000), transmitted in digital format and, at reception are transformed to engineering values (Volts, Amperes etc.). Also, could be included in this type the number of a tap or the actual value of a meter.
b. Position or digital values like open/close, active/non-active are collected and sent to the Control Centre as 0 or 1. These values represents either the status of a breaker or an isolator or if an alarm is activated or not.
c. Values of meters or similar, presented in a higher precision than a normal Analogue value.

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

This communication is demanded by the control center, which is normally done on a timely basis (scan). In case of alarms, the RTU may initiate the communication with the control center, requesting to establish a communication and to be interrogated.

Size and capacity of an RTU can be adjusted to the needs, from a simple RTU to collect one value to an RTU to collect and operated a big substation, using in each case the appropriate technology. Even Programmable Logic Controller (PLC[11]) have been used in small systems.

5.2.2 Communications

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

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

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

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

The protocols used can be divided in four main groups:

a. For many years, the SCADA suppliers have imposed proprietary protocols, used exclusively in their own installations. This creates a dependency that the supplier of the RTU that should be the same (or compatible) with the SCADA system. This could be avoided by ensuring that an RTU supplier emulates the SCADA protocol with the information that is provided by the supplier. This situation is changing but some of those protocols are still in service due to long usable life of RTUs.

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

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

d. The Internet Protocol (IP) is the principal communications protocol used establish Internet, which uses source and destination addresses. Its routing function enables internetworking and is useful for connecting the RTUs in the Field and with the Control Centre.

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

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

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

5.2.3 Information validation

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

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

Those alarms are registered and presented to the operator.

5.2.4 Alarms subsystem

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

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

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

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

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

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

The historical of alarms cannot be deleted.

5.2.5 Monitoring and trending

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

a. Contains the last values received from the field. Could be considered an image of the network in a certain time and under known conditions. This image of the system can be saved, manually or automatically for subsequent studies, of this situation or as representative of some similar network conditions in the future.
b. Selected values could be individually monitored, so in a particular Data Base each selected value received from this source or calculated with digital and/or received values, is saved on a dedicated Data Base and presented as a tabular or as a graphic trend.

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

5.2.6 Supervisory Control

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

Those orders are typically:

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

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

5.2.7 Resume of Basic Functionality

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

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

5.3 Added applications

SCADA has been used to control electricity systems. SCADA systems were first implemented in the transmission systems and were commercially available and in the late 60's and early 70's. For the electricity system, SCADA very soon became the most effective control tool to improve system information and control and, at the same time, reduce operative costs.

For these reasons, around the world, SCADA applications have been developed and they form an important part of an efficient and safe control system.

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

5.4 EMS versus DMS

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

a. **Energy Management System (EMS)** oriented to generation and transmission systems. The main characteristics of those systems are those that are the relatively big size in generation and load, small or medium number of substations and extra high number of controlled elements, with the system fully meshed, operated with almost all breakers closed.
b. **Distribution Management Systems (DMS)** oriented to distribution systems operated radially, without forming loops in the system, with a high number of stations controlling a small

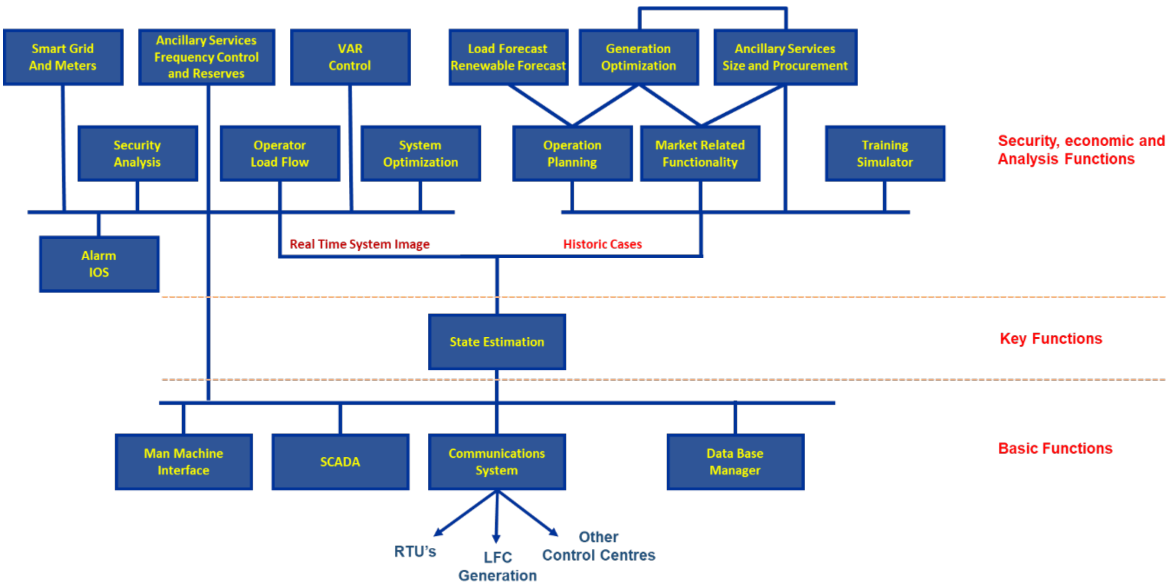
number of elements on each station. Operation must be done by opening and closing elements of the network, in most cases passing thorough zero voltage.

The Samoan power network backbone consisting of 33kV network resembles more a Distribution network than a Transmission network. The deployment of the Control System therefore requires consideration of DMS rather than EMS functions.

5.4.1 EMS System

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

Figure 5-1: EMS functionalities supported by the SCADA System



Briefly, the following applications are oriented to:

5.4.1.1 State Estimation

Normally values are measured with a certain level of error introduced by measurement or when transformed from analogue to digital format. It is acceptable that, in the best of cases, the error will be around 1.0 %. This means that any value in the system would have some element of error. For example, the voltage measurements show that voltage at a node is 220 kV, which means that the value sent to the control centre is 220 kV, but the real value could be any value between 198 and 222 kV. The same error is expected in other readings that are obtained for power and current measurements.

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

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

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

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

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

5.4.1.2 Load Flow

Once the state estimator is well tuned and available, then its solution could be used as input for the load flow studies. It is possible to run the load flow, based on information available in the network model and the information available for the generation and load connected to each node. The model calculates the real voltages and flows on each node or network element at real time or in study mode. In addition to this, the load flow will simulate any new situation, which could have modified generation or load profiles or the network topology. This load flow study results, based on simulations, would show the system conditions such as voltage and power flows.

5.4.1.3 Optimal Load Flow.

In this case, the inputs are the same as in above but in addition, the results will show the optimal values for some control elements values such as reactive generation, shunt devices or tap changes. It could be proposed that these devices are changed, after evaluating the need for change in control and considering the cost of changing the asset. On similar lines, system losses will also have a cost. The control function will display the cost of an optimal set of control elements and the motive would be to reduce losses with a minimum cost. The use of different costs for each action will reflect the system control priorities.

5.4.1.4 Ancillary Services requirements

Two of the most important aspects of system security are:

- The **Load Frequency Control (LFC)**, is the application in the system that controls directly the governors of the dedicated generating units in an automated closed loop. The application increases or reduces the actual generation to maintain the frequency stability. The LFC sends a signal to raise/lower or fix a set point and this is also known as Automated Generation Control (AGC).
- **Voltage control**, especially with the integration of renewable generation parks has become an important requirement to maintain the power quality. In many parts of the world, the new renewable generation plants have had limited contribution to voltage stability as compared to the conventional units. The voltage control could be achieved by use of modern tools such as shunt devices, VAR systems, SVC and STATCOM units.

5.4.1.5 Security Analysis

The security analysis applications are oriented to verify that the security criteria are fulfilled any time, during operation planning or in real-time. Perhaps the most known application is the Contingency Analysis (CA), which has all the conditions included in the security criteria and these are tested during operation planning and in real-time.

This suite of functions is basic to determine the capability of the system to survive any contingency included in the security criteria stablished in the grid codes or in the regulations.

5.4.1.6 Forecast Applications

Load demand forecast and Renewable Generation forecasts applications normally provide forecasts at park level for wind and solar generation. The forecast is done for longer term, which is used for planning and at a year-to-year level to guarantee the availability of resources.

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

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

5.4.1.7 Generation schedule

Using the load and RE forecasts as inputs, the generation schedule be developed. In the generation schedule, the generation needs are estimated for the day ahead or in Real Time for the near future.

The schedule also verifies the needs for controls and the availability on the system for different types of reserves, according to the security constraints.

5.4.1.8 Generation Control

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

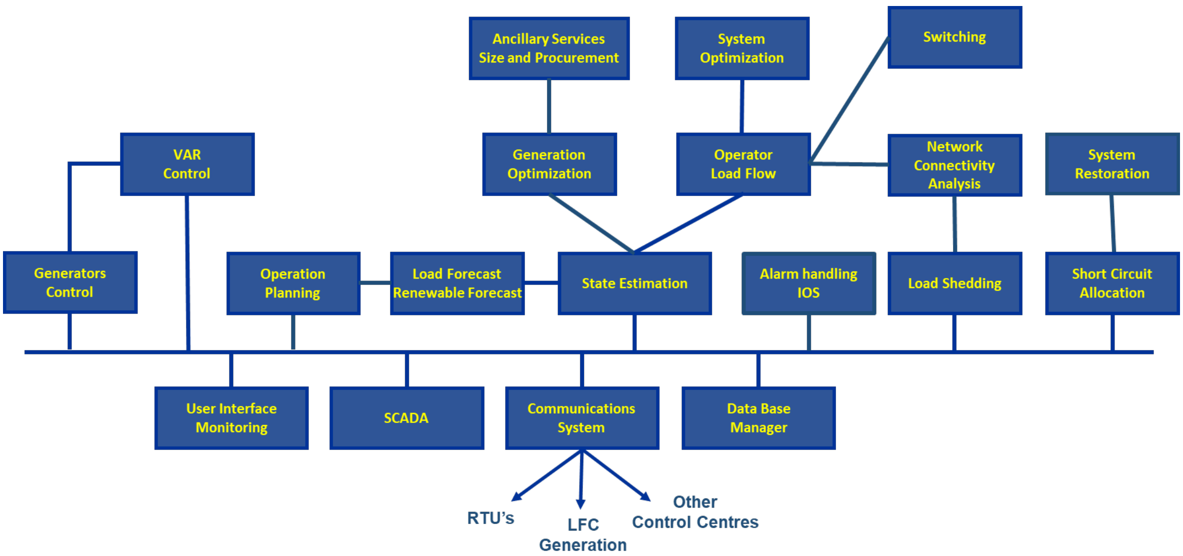
This control philosophy is extended to most large power plants from Nuclear Plants to Coal, Gas or hydro units. It is not a simple application. To control a unit or a power plant, a group of applications are run in a coordinated mode and these allow operators to control a variety of assets, from the high voltage park to any kind of fuel based plants. Those applications facilitate the control of many generating units, which are controlled from a centre located outside of the plant itself, reducing the operating costs considerably.

5.4.2 Distribution Management System (DMS) System

The Distribution Management System is more oriented to manage distribution networks. For radial networks, the applications are completely different than those for the meshed networks.

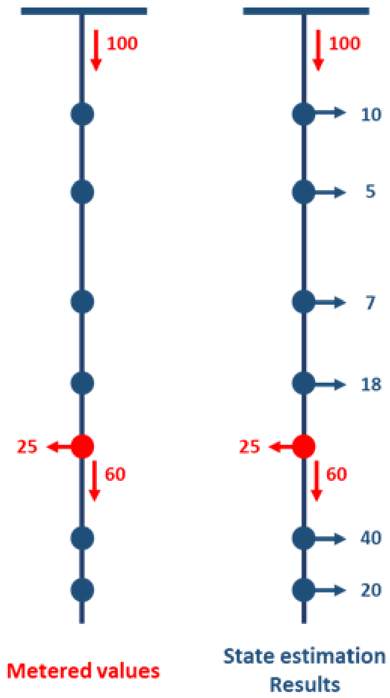
The functionality of applications are similar than in case of Energy Management System (EMS) but the methodology and mathematical approach are quite different.

Figure 5-2: Functionality of DMS applications



The main applications are:

5.4.2.1 State Estimation (SE).



The state estimator is an integral part of the overall monitoring and control systems for transmission networks. It is mainly designed to provide a reliable estimate of the system values. The state estimators could calculate various system variables with high confidence despite the facts that their measurements may be corrupted by noise or could be missing or inaccurate.

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

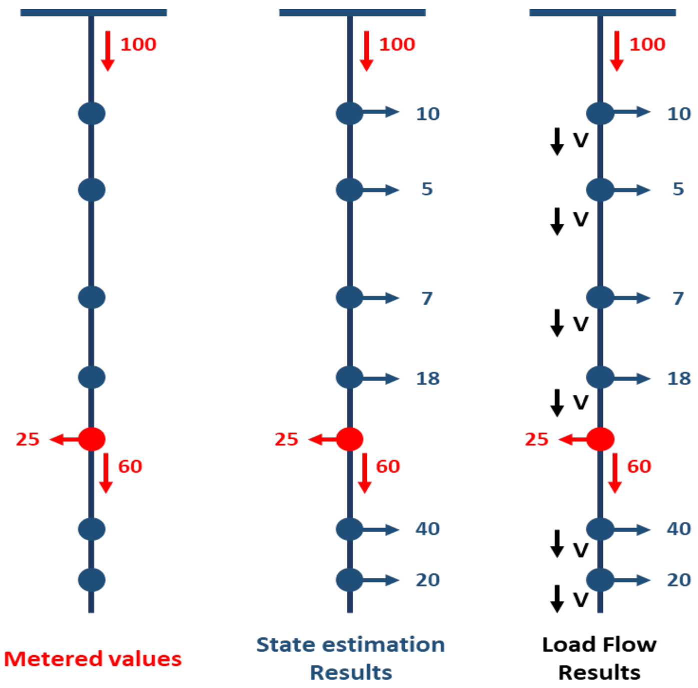
5.4.2.2 Load Flow Applications (LFA).

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

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

For a better understanding of the combined use of those two applications, an example is shown in the figure below. The figure shows a scheme that represents a feeder with only the metered information and a second scheme that uses the State Estimation, which estimates the load in the transformer stations without this information. The third example shows the results obtained after running the load flow, which calculates all flows and voltages. The estimated values will probably to some extent modified by the load flow due to the results of losses calculation in each feeder section. The accuracy of the results will be a function of the accuracy of the State Estimator.

Figure 5-3: Example of a State Estimator



5.4.2.3 Generation Control.

A generator embedded in the distribution networks normally has a power capacity that is compatible with the feeder where it is connected to. The generators embedded in the distribution networks would be significantly smaller than units connected into the transmission grid. These groups will be easy to operate and at the same time support network security, frequency and voltage maintenance. The big control panels filled with push buttons and analogic measures in the past, have now been substituted by digital systems that provide much better capabilities to operate the generator and monitor system values.

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

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

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

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

- ✓ **Manually**: The Control Centre or the Generation Operator controls the frequency by transferring instructions directly to generators or to operators to manually increase or reduce generation. This control system gives a pour quality on frequency control. This methodology is used in some isolated systems.
- ✓ **Automated**: The computer controls the deviation of the frequency, generates the raise / lower signals to the generators control elements to maintain the frequency precisely to set point. Even some dispatches take the responsibility to control the hour deviation and set the frequency monthly to correct the “electric hour” (Laufenburg). This control method produces a very precise frequency control but is much more expensive to implement. This is the common control methodology used across Europe and USA. Its main advantage is that it allows fair interchanges.

5.4.2.4 Network Connectivity Analysis (NCA)

By analysing the network information obtained through the SCADA system, NCA considers the position of all switching elements and assists the operator by illustrating the state of the distribution network, which includes the information for the radial mode, loops and parallels in the network.

5.4.2.5 Switching Schedule & Safety Management.

Control engineers prepare switching schedules to isolate and disconnect a section of a network in which the work has to be done. The Distribution Management System (DMS) validates the possible working schedules based on the results of the network model. When the required section of the network has been isolated, the DMS allows a Permit To Work (PTW) document to be issued. After its cancellation, when the work has been finished, the switching schedule then facilitates restoration of the normal running arrangements.

5.4.2.6 Voltage Control

Voltage could be controlled in the system, using:

- ✓ Reactive power generation or absorption in generators (VAR control)
- ✓ Tap Changers - Modifying the transformer’s ratio, changing taps with temperature variations. In this last case, also known as Load Tap Changing, where the transformer is in service, the number of changes per day is normally limited.
- ✓ Autotransformers: These transformers could have a turns-ratio that is very close to 1.00, which means that the voltage variation is small and these are used only for voltage control at the same voltage level.
- ✓ Use of external control elements like shunt devices (batteries or reactors) or advanced voltage controllers like SVC’s or STATCOM’s.

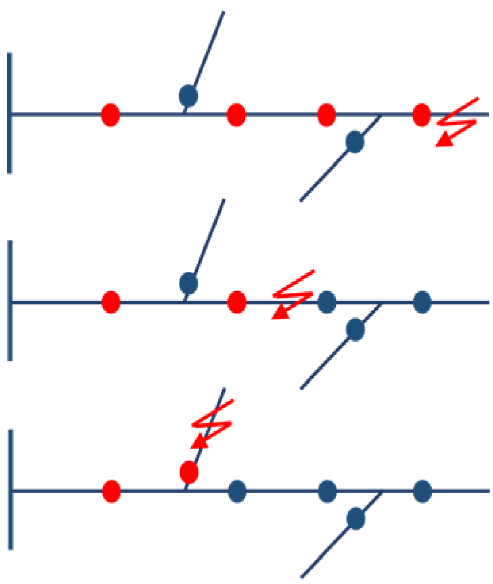
Most of those elements can be automated, controlling the voltage in the connection point.

5.4.2.7 Short Circuit Allocation.

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

Short circuit allocation is based on the use of short-circuit current elements in the network that simply detects and communicate the fault details to the control centre.

The following graphic shows its application to determine the short circuit allocation. The blue dots represent the locations with a short circuit pass detector and the red dots represent the locations with elements that detected the passing of the current.



For each location of the short circuit in the network (feeder), there is a different configuration of elements which detects the pass of the short-circuit current and in consequence, the short circuit location itself which will allow the operator to perform actions for restoring the system immediately.

The detectors shall be capable of communicating with the control centre (could be based on a Power-line communication (PLC) or General Packet Radio Services (GRPS) communication systems) or incorporating the signal into an RTU that collects other types of information.

5.4.2.8 Load Shedding Application (LSA)

One of the key aspects of an electric system control is to maintain the equilibrium between load and generation. In order to control the generation to match the demand, operation planning could be done on a day-ahead based or real-time adjustments could be made.

But at times when the demand increases or decreases significantly or at times when key generation units' trip, the balance between supply and demand is lost. The system reacts by modifying the system frequency that must be corrected by increasing (or reducing) the generation in other units. The problem becomes more critical when the generation margins have been exhausted. In this case, the only solution is to reduce the load and this is known as load shedding.

This reduction or Load Shedding could be done manually or could be automated using a Load Shedding Application (LSA). This is the most common method is to reject some load from the system when the frequency reaches unacceptable levels. The load shedding with the double objective to protect the generators and to stabilize the network, which makes the restoration easy and faster.

The load shedding is normally "triggered" by a protection system that scans the frequency or the frequency variations. Once the frequency is recorded lower than acceptable values, the protection system trips some feeders to reduce the load reduction. In a system normally there are a few frequency levels defined to reduce the load (between 3 and 5) and at each frequency level, a certain amount of load is rejected (from 15% to 25%).

5.4.2.9 Fault Management & System Restoration (FMSR).

Some incidents in the network are, because of the way they are caused, impossible to avoid or reduce. For example, it is difficult to avoid the damage that could be caused by storms or other weather conditions but the quality of service could be improved by ensuring faster restorations.

Fault Management & System Restoration (FMSR) applications tend to reduce the restoration time by automating a part of the restoration process. This functionality requires an excellent electric model and intensive information compilation. Is especially useful for those utilities that have by law, for safety purposes, limited the time to test lines or cables (some countries have this limitation in 1 minute). Once the allowed time has elapsed, in order to test a cable, the operators have to be physically present at the fault location, to verify there is no danger to the public during the test.

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

5.4.2.10 Distribution Load Forecasting (DLF)

As mentioned in the previous section, one of the main aspects is to ensure the balance between generation and load. The system load includes the client's consumption and the system's technical and nontechnical losses.

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

The traditional energy balance equation is:

DG + RE + IB = LO + SL

Where: DG is the Conventional Dispatchable Generation

LO is the total Load (Estimated)

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

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

RE is the Renewable Generation (Forecasted with error)

ERE is the Embedded Renewable Generation (Estimated)

The same balance equation could be written as:

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

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

- ✓ Load + Losses forecast, this will require a cleaned historic load data base.

✓ Renewable or non-dispatchable generation, which could be estimated globally on the island or independently for solar or wind parks.

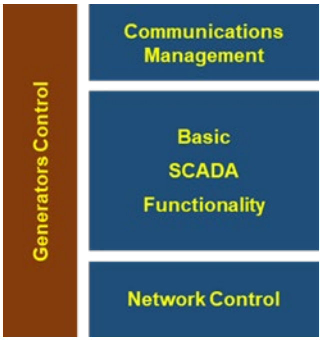
Those forecasts shall be calculated for at least two different time horizons:

✓ Day (or week ahead) for operation planning.

✓ Minutes or hours ahead for real time security analysis performance calculation.

5.4.2.11 Load Balancing via Feeder Reconfiguration (LBFR)

The Load Balancing via Feeder Reconfiguration involves automating the decision process to decide the network configuration from the network topology, deciding the status of all embedded isolators or breakers (open or close) which for big systems may represent thousands of different configurations. The application will develop an optimal solution to manage the network.



5.4.3 Requirements of the Distribution Systems

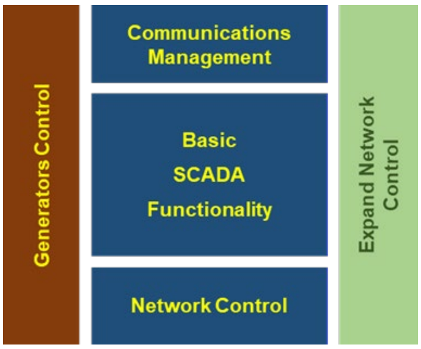
For the Distribution Systems such as the one in Samoa or as seen in the other islands, the following three requirements have been identified:

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

5.4.3.1 Network Control and Monitoring

For network control and monitoring:

- SCADA systems normally provides enough information for system monitoring and control
- The user interface should be simple and capable to show the network at different levels depending on the real-time requirements
- The options for zoom, panning and clustering should be available in the system.
- The capacity for supervisory control shall be protected in a two steps operation (i.e. selection and execution)



5.4.3.2 Quality Assurance

Maintaining a good quality of service is essential for any distribution system. This could be considered under two aspects:

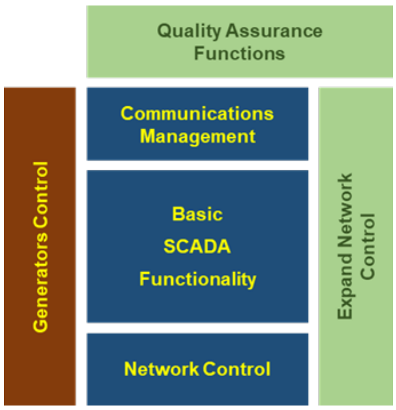
1. **Service Continuity**: The first challenge is to maintain the service under different situations and circumstances.

   The continuity of services could be affected by external incidents into the network, such as; lightning, storms, high-speed winds, car accidents and vegetation. There are only limited ways to avoid the existence of those incidents, but they can be mitigated using more secure network elements.

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

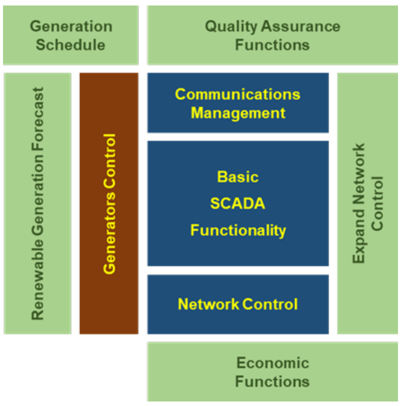
2. **Quality of the supply**: The quality of supply is maintained by managing the main parameters such as the frequency, voltage and harmonics.

Normally external factors do not affect the quality aspects. Operation planning process, which is normally done for a day in advance, considers the resources existing or made available for operation. Some applications are available to control those aspects, together with the reserves capacity and allocation, which does not directly impact the quality, but in case of other incidents, such capacity will help to limit the extent and magnitude of the incident and eventually reduce the restoration time.

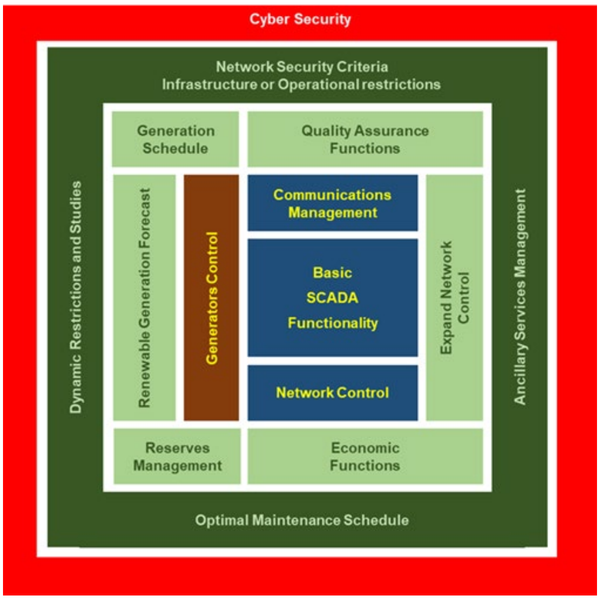


5.4.3.3 System Economic Optimization

Apart from ensuring continuity of supply and quality of power, it is important that the network is managed in the most economical way. Firstly, to run the power system in the most economical way, the generation schedule should be optimised. Once the generation is optimised, the network operator's main aspect is to reduce system losses. The SCADA application provides tools to control network losses and ensures optimal switching in the network to reduce feeder losses.



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



5.4.4 Recommendation between EMS and DMS

Both are systems have powerful tools, but considering:

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

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

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

5.4.5 Recommendation between EMS and DMS

Both are systems have powerful tools, but considering:

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

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

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

5.5 Network and Available Operation Systems

The salient points of the electricity system in Samoa are summarised in the table below:

Concept	Value	Unit
Peak Load	22	MW
Energy generated per year	128,373	MWh
Generators Conventional	10	
Generators Renewable	7	
Conventional Installed power	32.0	MW
Renewable Installed power	14.6	MW
Available SCADA for Generation Control	Yes	
Controls some breakers	Yes	
Operated Radial	Yes	
Number of feeders	3	

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

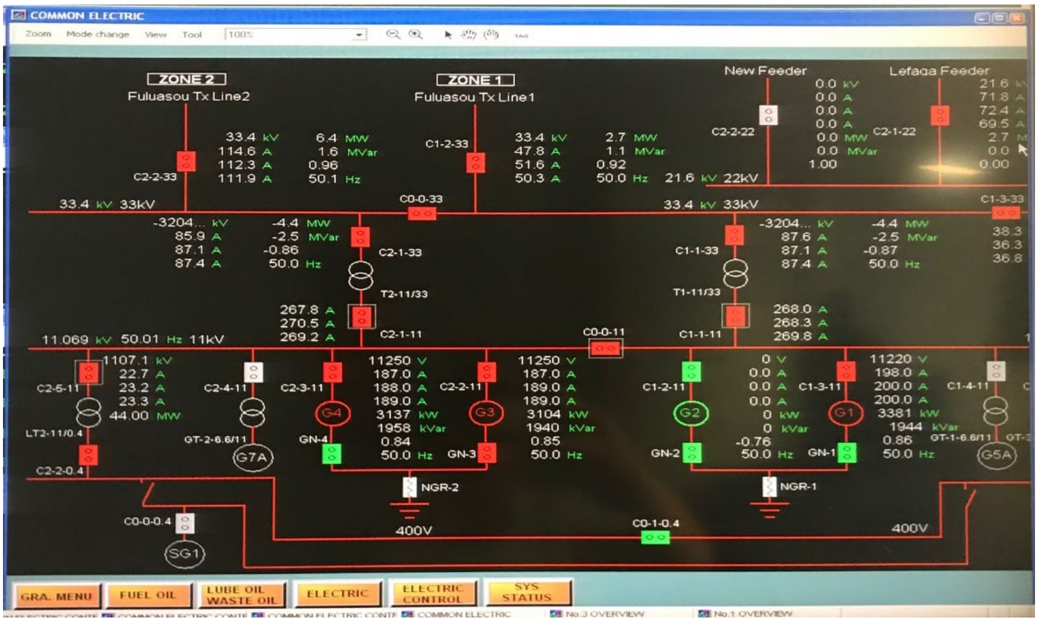
Functionality is limited to:

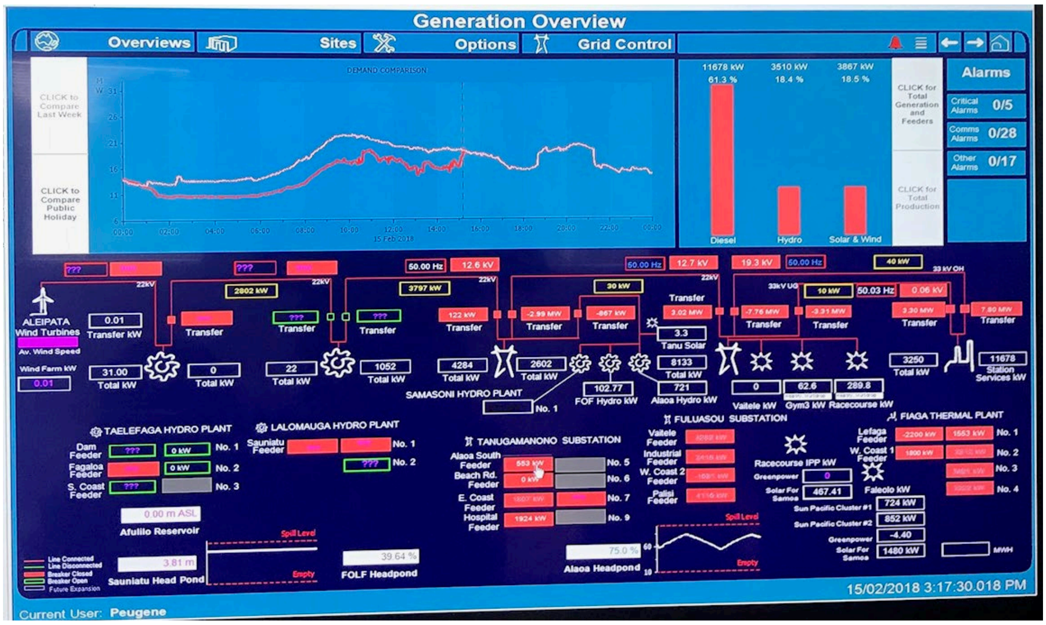
a. Full control of the generation units, which includes some options to optimise of the generation assigned to each unit.

b. Basic control (switching) of some feeder heads. There are plans to expand the basic control functionalities to some other substations

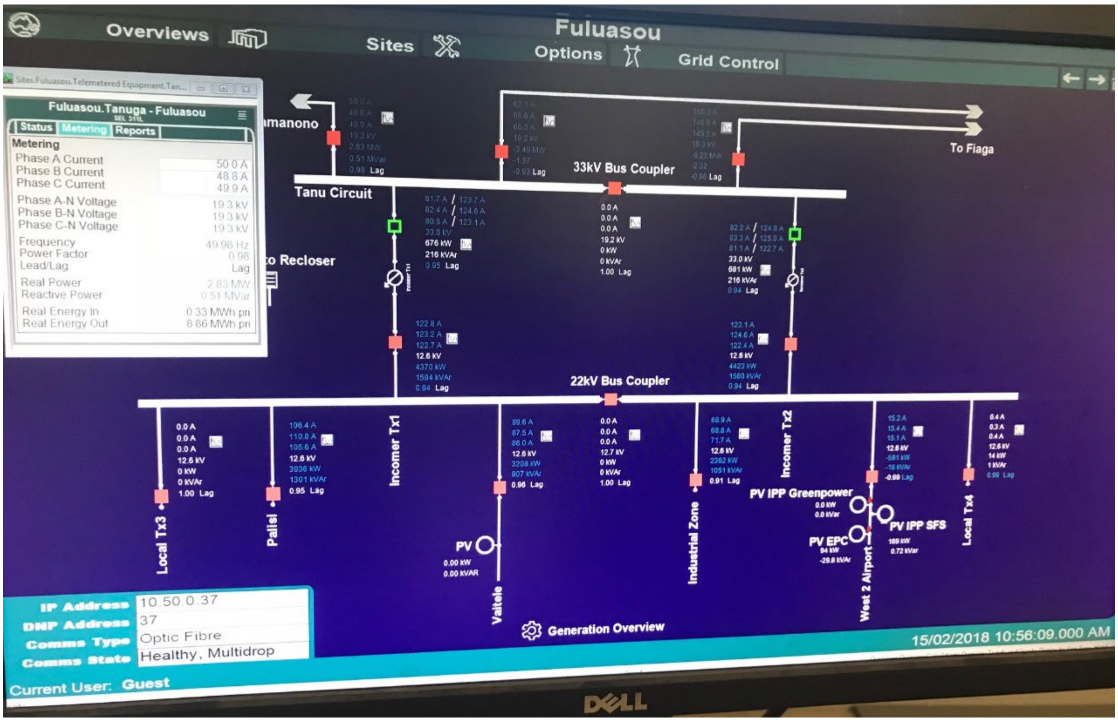
c. No additional functionalities available on top of the SCADA

The current SCADA system has full monitoring and control of the Fiaga diesel generators. It also monitors the major wind, solar and hydro power plants. New micro grid controller was being commissioned and this will have full control of all 'major' power plants.



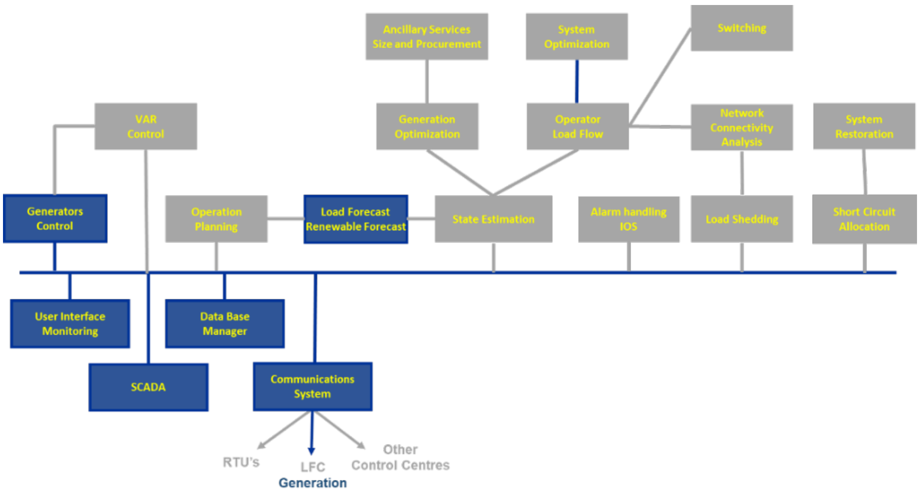


The current SCADA also monitors most of the existing backbone substations and lines. There is a fibre optic link to these substations either in place or planned to in place soon. There is no remote control of breakers except for SCADA system installed at Fiaga substation.



The figure below shows the actual SCADA configuration in blue boxes:

Figure 5-4:SCADA Configurations



Battery & 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.

5.6 Applications Proposal

There are plans to expand the functionality of the SCADA to improve the network system operation. Any expansion can be made in different ways, one way could be to implement one functionality at a time or the other way could be to implement a few functionalities at a time.

The latter option has the advantage that that all functionality will be available as soon as possible. The first option delays the full functionality but allows users to gain in-depth knowledge as it is done on a step by step basis. The training of operators and users is important and the second option allows operators to acquire knowledge about one functionality before implementing other functions.

In the following sections, the options to expand and the recommended for the EPC system have been presented.

5.6.1 Priorities

Through discussions with the EPC staff, the following priorities for improvements were identified:

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

5.6.2 Functionality proposal

The functionalities are proposed in two sections, the first section is oriented to the quality of service and the second section is oriented for economic optimisations of the network or to reduce losses.

5.6.2.1 Quality improvement

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

Specifically:

1. **Short circuit allocation**. Once installed in the network, short circuit current detectors such as an overcurrent relay could be used to send information about circuit parameters to the control centre.

   If the locations with the short circuit current detectors have RTUs, it can be used to include this signal and this signal would be transmitted just as any other signal in the RTU communications. As an alternative, for those measurement points, which do not have an RTU 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 it reaches a value where the units will have to be disconnected for security reasons. If this point is reached, the 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, in which the 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.

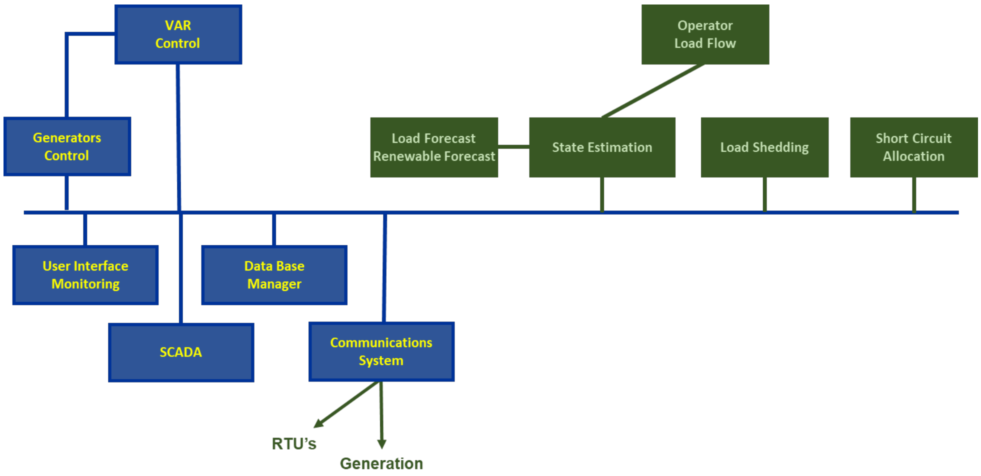
4. **Operator Load Flow**. This calculates intermediate voltage and flows between the locations where the actual load flows are not measured. It is obvious that in any distribution system it is not practical to install a measurement device at each location, to measure all loads in the system, but for forecasting, flow control (considering the different cables/lines capacity), operation planning and voltage control, such information is required.

5. **Voltage and VAR control.** The 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.** Forecasts could be developed to project some values not only based on the historical cleaned database, but also by variable parameters such as temperature, solar insolation and other weather conditions. These values are needed for generation optimisation.

The functionalities, after implementing these phases are shown (green boxes) in the figure below:



5.6.2.2 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. The electrical resistance of any network depends on the quality of infrastructure and characteristics of the lines or cables. But the current flows depending on the network topology. The system losses could be reduced by modifying the network topology, moving loads from one feeder to another or making some loads in parallel.

   This function together with other applications such as voltage management will determine the network topology with minimum losses.

   Just after implementation, the capability to apply this functionality (topology modification) could not be high enough, but following applications can also be used to select the optimal planning options, which will enable the use of this function for planning and managing the current conditions.

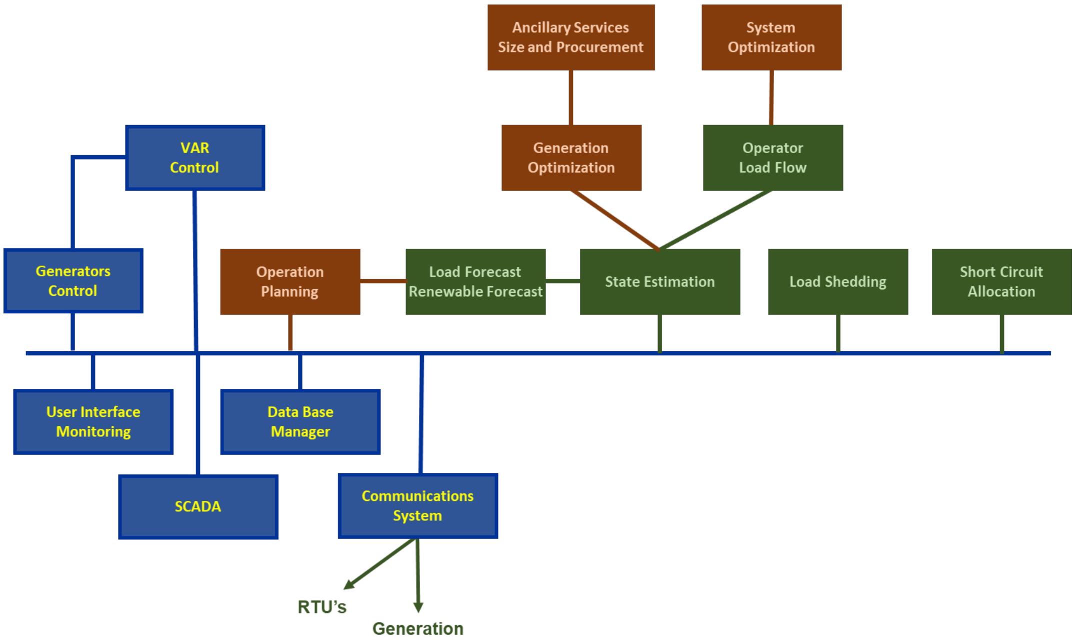
2. **Generation optimization**. Once the load that could be supplied by the renewable sources is identified, the amount of energy that has to be produced by the conventional generation is determined. The split of this generation among the different groups or energy sources will define the optimal generation 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 Samoa system is not inside the definition of “transmission interconnected systems” but is also true that to operate a system like Samoa requires consideration of the need for Ancillary Services

   The evaluation of the needs of ancillary services includes reserves of different types or the voltage control requirements. The evaluation of ancillary services must be allocated and monitored in real Time.

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

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



5.6.2.3 Functionalities not recommended

Some functionality is more oriented for much larger systems, where an operator cannot have a detailed knowledge of the full grid. This is not the case in the Samoa electricity system.

The following functions are not recommended.

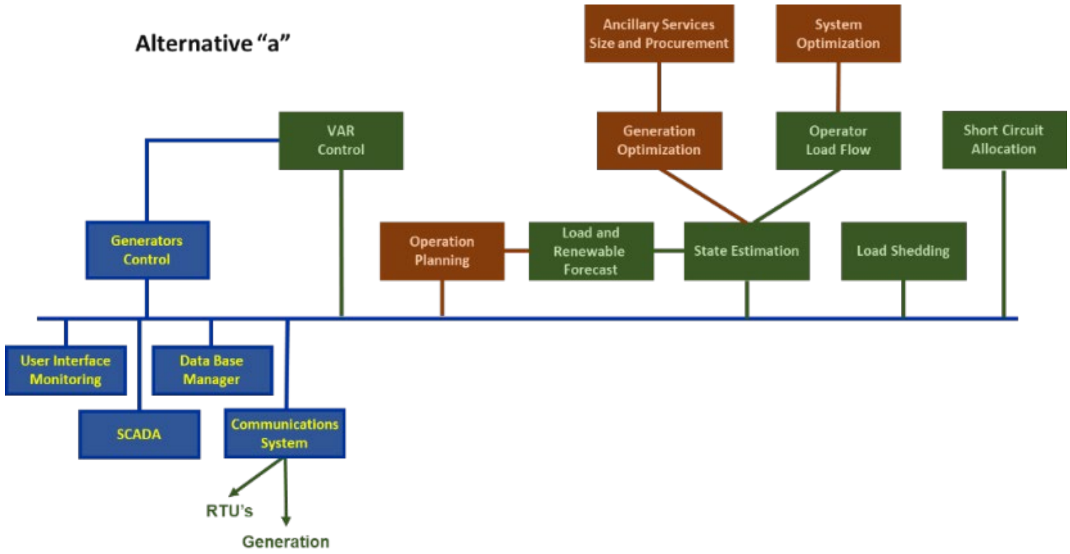
1. **Switching**: This functionality proposes a sequence of network operations to restore the system, after an incident, or to prepare the isolation of a network section for maintenance purposes.
2. **Network connectivity:** This functionality analyses the system topology watching for loops or parallel sections, which may produce a loss on protections selectivity.
3. **System restoration:** After an incident, these applications calculate the sequence of operations for optimal restoration of areas in a blackout.
4. **Intelligent Alarm Operation:** Alarms are raised in the RTUs or at the control centre if some of the values received are not within 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.

5.7 Architecture Potential alternatives

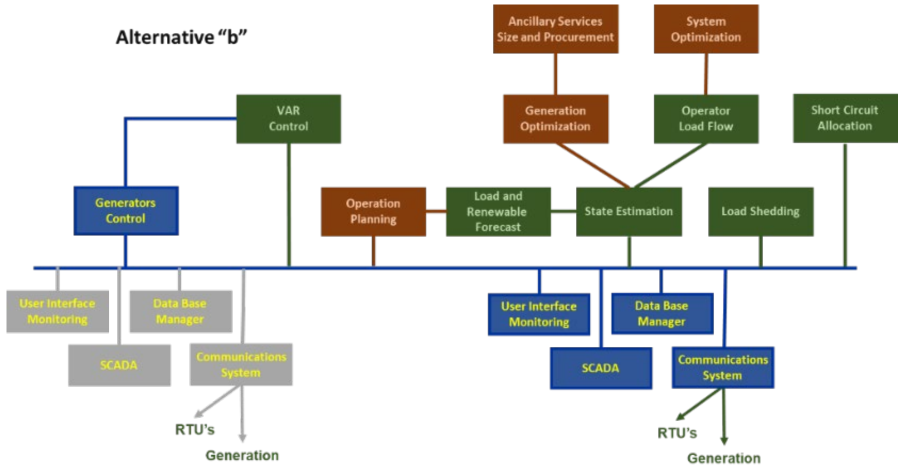
Assuming that the system functionality is the one selected, there are few potential architectures of the system with their own pros and cons.

The following alternatives apply:

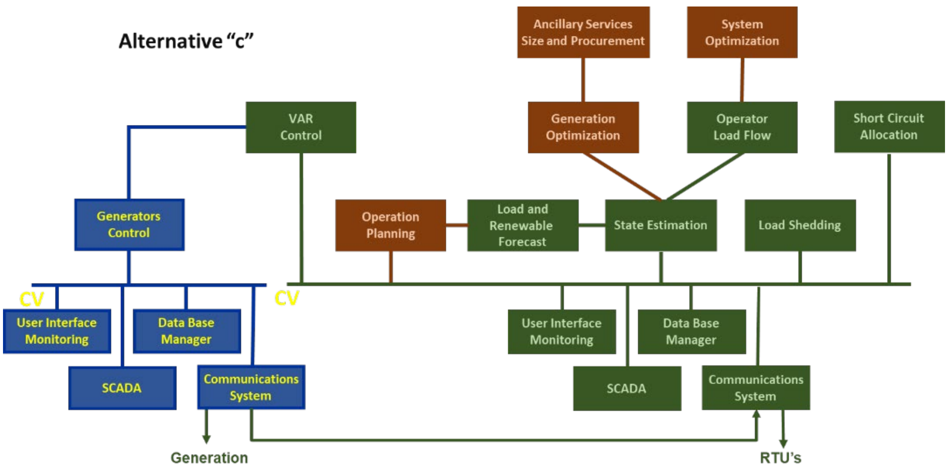
a. Use the actual SCADA system that is available in the Samoa system for diesel generation control (blue blocks in the following figures) and expand its functionality with the one required for distribution network control (green blocks in the first phase, and brown in second).



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 taken into consideration, before making the final decision:

- The alternative “a” will require additional functionalities 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 modifications of the existing controls of the generators, especially if the software versions of network applications (operating system, database) are not compatible with the existing system since they were 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, which is currently working in a satisfactory condition.
- Alternative “c” requires new hardware and will become a separate system. This option maintains the generators control as it is.

These aspects have been considered because:

- It is mandatory to maintain the generators control provided by the supplier of the generators that are working satisfactorily, and we do not want to disturb this and take extra risks.
- There are costs to program and adopt new functions and introduce them in a working system and these also have a certain level of risk
- The actual cost of hardware has been reduced for equipment with some functionalities
- There could be an option to cooperate with the different utilities in the region and this has been explained in the section below.

Considering those reasons, we recommend the alternative “c”

5.8 Additional elements to install in the network

To enable the functionality proposed to use their full capability, some additional elements should be installed in the network:

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

5.8.1 Remote Terminal Units (RTUs)

RTUs are the terminals that send monitored information to the SCADA, 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, relay 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 Samoa, to start with, the number of RTU’s shall be between 6 and 10.

5.8.2 Capacity to modify the system topology

One of the advantages of the SCADA system is to intervene and modify some of the main parameters of the network, like the topology. By opening and closing some of the isolators or breakers the power flow directions could be changed as such switching could modify feeder configurations. 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 that has had a blackout, the topology changes may reduce the area that has been affected.

5.8.3 Communications and protocols

All communications available technologies could be used and these could be from PLC to Optical Fibre going through radio or GPRS sim cards. A standard set of 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 and steps should be taken to maintain cybersecurity.

5.8.4 Cyber Security

As in any other control centre, the cyber security is important 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.

5.9 Procurement, Training and Commissioning

The procurement activities will consist of:

- designing the system including the functionality,
- preparing technical specifications
- preparing 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
- Evaluating bids and deciding the winning offer and contract negotiation and signature

Once the supplier has been accepted and before the commissioning of assets, the training process shall start where the personnel will be trained in the administration and maintenance of the system that would by the network operators.

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

5.9.1 Procurement

The preparation of specifications and procurement activity can be very time consuming and in consequence has a high cost associated with it. In the case of where the utilities carry out their procurement individually, this activity will need to be repeated for each utility that wishes to establish a network control as designed above.

For efficient 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.

The utilities collaborating in this process should be able to benefit from time and cost savings:

- ✓ One core technical specification should be valid for all systems. This will reduce the number of specifications and contractual conditions to be prepared.
- ✓ The individual price obtained for a 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.

5.9.2 Training

As part of the contract, the two training activities should be developed for different staff:

- ✓ **Training for administrators**: This training is specially oriented on maintenance of system hardware and software, particularly the application of new versions, and the ordinary system maintenance, population and expansion of Data Bases, RTUs and the communication systems. Resolution of any kind of problems, with the objective to maintain the system operation.
- ✓ **Users training**: This training is to prepare the potential operators that perform and execute all applications of the system, included supervisory control or those involved in preparing reports.

This is knowledge that should be acquired by the utility staff members and must be retained.

But there are additional aspects that shall be considered:

- ✓ The minimum number of people assigned to SCADA in each utility. It is ideal to have 2 to 3 staff members as administrators, due the fact that there are unavoidable vacation or illness periods and the risk that one may decide leave his/her job.

However, in the Pacific Islands, staff resources are usually limited, so other options are:

- ✓ Sharing the trained resources among the different utilities, considering the ability to work remotely, with secured communications, will reduce the number of formed administrators to 1 or 2 per utility.
- ✓ On the other hand, organising training courses for 2 or 3 people (both for administrators and users) many times, in different locations, is an expensive scenario, compared with a single session for 10 to 16 administrators in the same location.

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

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

5.9.3 Commissioning

Includes all tests for acceptance and the installation on site.

Tests are commonly divided into two types:

- **Factory Acceptance Test (FAT)** where the supplier executes the tests and these are witnessed by the client. All functionality is tested. During this test, no real data will be available, but the data could be simulated and loaded on the system from another computer that simulates the field information. Unless the results of FAT are satisfactory, the Site Acceptance Test should not be carried out.
- **Site Acceptance Tests (SAT):** In these tests, the system is tested by the clients in their own facilities, with real data, and these tests must be witnessed by the supplier. With the acceptance of SAT, the system is accepted, and this is usually when the guarantee period starts.

As mentioned before, if there is a collaboration agreement between several utilities, the supplier can run a single FAT process, which has a cost, instead of independent FAT for each individual system. Such cooperation between utilities will reduce the testing costs, without reducing its effectiveness, which will reduce the global costs for the supplier and in consequence the overall cost for the utilities.

On the other hand, SAT must be carried on each system independently. In the initial tests, the problems are detected and resolved and normally the remaining tests are carried out easily as the utility would have already accepted key results.

Hence it is recommended that the utilities implementing SCADA should, where possible, have a joint agreement between them to conduct such tests.

All aspects commented in the previous points regarding the development of cooperation between utilities are aimed at:

- ✓ Simplifying all activities related to the commissioning 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 to day operation.
- ✓ Maintaining the utility's financial independence and its juridical personality.

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

5.10 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 lifetime for the system, for reasons of CBA calculation is set at 10 years.

The results of the analysis shall report if the operation is economically and financially sustainable.

5.10.1 Installation financial cost

The installation cost corresponds to the cost of the procurement, site works, testing, training and commissioning of the SCADA system.

These costs shall include:

- ✓ The SCADA hardware and software
- ✓ Commissioning of the system, including training and test. Exclude decoration of the Control Centre.
- ✓ For the study a total of 7 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.

5.10.2 Operational costs

The operational cost would include the cost of 1 or 2 additional staff who would be employed during the useful life of the system. This assumes that the administrators of the actual system for generation control will also be the administrators of the Network SCADA system.

In addition to this, 1 additional full-time staff would be required if the utilities decide to collaborate and 2 additional full-time staff would be required in a scenario where utilities do not collaborate. The main reason for this is to ensure that the knowledge about the system remains / is available by the staff of the company and an expert is available or is available on call on a 24 X 7 basis. If we assume that only 1 additional full-time staff would be required then it would not be possible to guarantee that the staff would be available on all days due to vacations or sick leave.

So, in this case, a minimum of 2 operational experts are required at all times. But if financially viable, more experts are recommended.

On the other hand, if the utilities decide to collaborate, the third staff member could act as a reserve for substitution in other utilities as and when needed for a limited time. In case of a consortium, the number of staff members required will be 3 needed minus 1, the actual number of experts and minus 1, evaluated as the assistance between partners in the consortium, which makes 1 new employee.

No termination costs should be considered. From our past experience, we understand that once the useful life of the equipment is over either for the 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.

5.10.3 Benefits

The improvements that can be incorporated 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. It is difficult to evaluate the reduction in blackouts and evaluate the benefit of this reduction. The benefits are tangible in some aspects related with a non-supplied energy and for maintaining the image of the utility in any scenario. The first benefit can be quantitatively calculated but the second benefit can only be explained in qualitative terms.

5.10.3.1 From the utility perspective.

It is obvious that the utility suffers in its image from blackouts.

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

- There is the cost of energy that is 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.

Those costs can be considered as “cost of unsupplied energy”, which can be evaluated by utilities. Perhaps the average is considering 10 times of the cost of the most popular tariff.

5.10.3.2 From the social perspective.

It is true that the cost impact of a blackout to the civil society is high, which is in form of loss of production and commercial activities that have to be stopped. The other costs could be that related to the damage of some goods at home, food wastage due the loss of refrigeration, loss of capacity to recover electronic communication means (TV, Laptops, smartphones…), hotel image in front of their clients may indirectly cause economic losses.

All these aspects are not included in the cost of a blackout but their impact on the country’s economy is much higher than the impact on the utility’s financial situation.

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

5.11 SCADA Conclusions and Recommendations

Considering the aspects expressed above, we recommend:

- ✓ Establish one topology based on keeping the existing SCADA to control the conventional generation.
- ✓ Implement a new SCADA system for network control
- ✓ Functionality that improves the Quality of Service should be implemented in the first phase. When this phase is successfully completed, then a second phase that focusses on the Economic Optimisation and Losses Reduction will be implemented.
- ✓ Together with the first phase, the commissioning and test of 3 to 5 RTU’s

- ✓ For procurement, training, commissioning, test and commercial operation, we recommend achieving agreements and/or procurement arrangements with other utilities in order to reduce the investment and operational costs.
- ✓ To calculate the Cost Benefit Analysis, we recommend considering the investment and financial costs for an expected life of 10 years, the operative costs for the same period and the social benefits attached to the reduction of blackouts in extension and duration.

5.11.1 Recommendation for staged implementation and roadmap: Samoa (Upolu Island)

The SCADA system existing which provides visibility of the generating units and controls the network frequency. Based on the information available to us, we understand that the SCADA functionality includes:

a. Visibility of the hydro units (control functions is to be upgraded soon once hydro governor controls are updated)

b. Visibility and control of the diesel generation units

c. Visibility and control of the wind generation units

d. Visibility and control of some of the PV plants

e. Visibility and control of the Tesla batteries

f. Basic control (switching) of some feeder heads.

g. No additional functionalities available on top of the SCADA

Similar to the approach recommended for the other islands, 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	Maintain the SCADA capabilities of the Power generating units (hydro, diesel, wind and PV plants) and main substations which are existing.	Extend the SCADA to include the 11kV substations and any remaining 33kV & 22 kV substations and renewable generation plants 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 generation and the main substations from a central SCADA. Operate the power network and dispatch generation from a central control station to provide power balancing, improve restoration and enhance safety	Improve the scope of visibility and improve detection of outages, alarms and voltage violations 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	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

		Improve grid security with emergency / block load shed capability	through conservation voltage regulation

The scope of each stage proposed is detailed below.

Stage 1: Basic SCADA

The basis SCADA recommended for this stage is existing. This includes SCADA visibility of the hydro plants, diesel generation plants, and main wind generation and PV plants including visibility of the main substations from the existing SCADA. We recommend that it be confirmed that the following capabilities are available with the existing SCADA, and if not, that the SCADA be extended to include these:

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

Note: The cost estimate assumes this SCADA functionality is existing in stage 1

Stage 2: Extend SCADA and deploy level 1 DMS functions

During this stage we recommend the extension of the SCADA visibility to include the 11kV substations and any remaining 33kV & 22 kV substations and renewable generation plants, extend the signals that are monitored and deploy some DMS functions listed below:

- Extend the signals monitored in the following areas:
    - Include additional stations (11kV,22kV, 33kV networks) and remaining renewable generation
    - Include additional power flow measurands at more network points
    - Include additional alarm signals to monitor individual alarms (subject to availability of alarm signals)

- Load flow study module:
  This will enable load flow studies to be done via the SCADA system considering the actual network condition or simulated network conditions. Network overload and voltage violations can be studied for different operation conditions and by simulating different network topologies (e.g. tripping of generators / transformers with or without PV plant being available).

- Short circuit calculation
  This module is an extension of the load flow study module to determine the minimum and maximum fault levels at different network positions and operating conditions. This information is important to validate the ratings of equipment and for protection co-ordination studies.

- Distribution load forecasting
  With this module the historical load profile and generation output data is used in combining with the weather forecast for short term load forecasting. The forecast of the available

renewable capacity is considered to improve the scheduling and most economic dispatch of generation.

- Emergency / block load shed application:
  In the situation where insufficient generation capacity is available to meet the demand, the emergency / block load shed application will provide the ability to block load shed on a rotational basis to avoid inadvertent tripping of generators on overload. This improves the network security.

Note: The capabilities of the existing SCADA to provide these functions need to be confirmed. It may be required to supplement the SCADA with an additional system to provide these DMS functions. This has been provided for in the cost estimate.

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

- Network model

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

Future Stage: Deploy level 2 DMS functions supporting other technologies

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

- Virtual power plants module

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

- Microgrid Energy Storage module

  The introduction of energy storage capabilities will improve the control of a microgrid forming by islanding parts of the network and improve 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

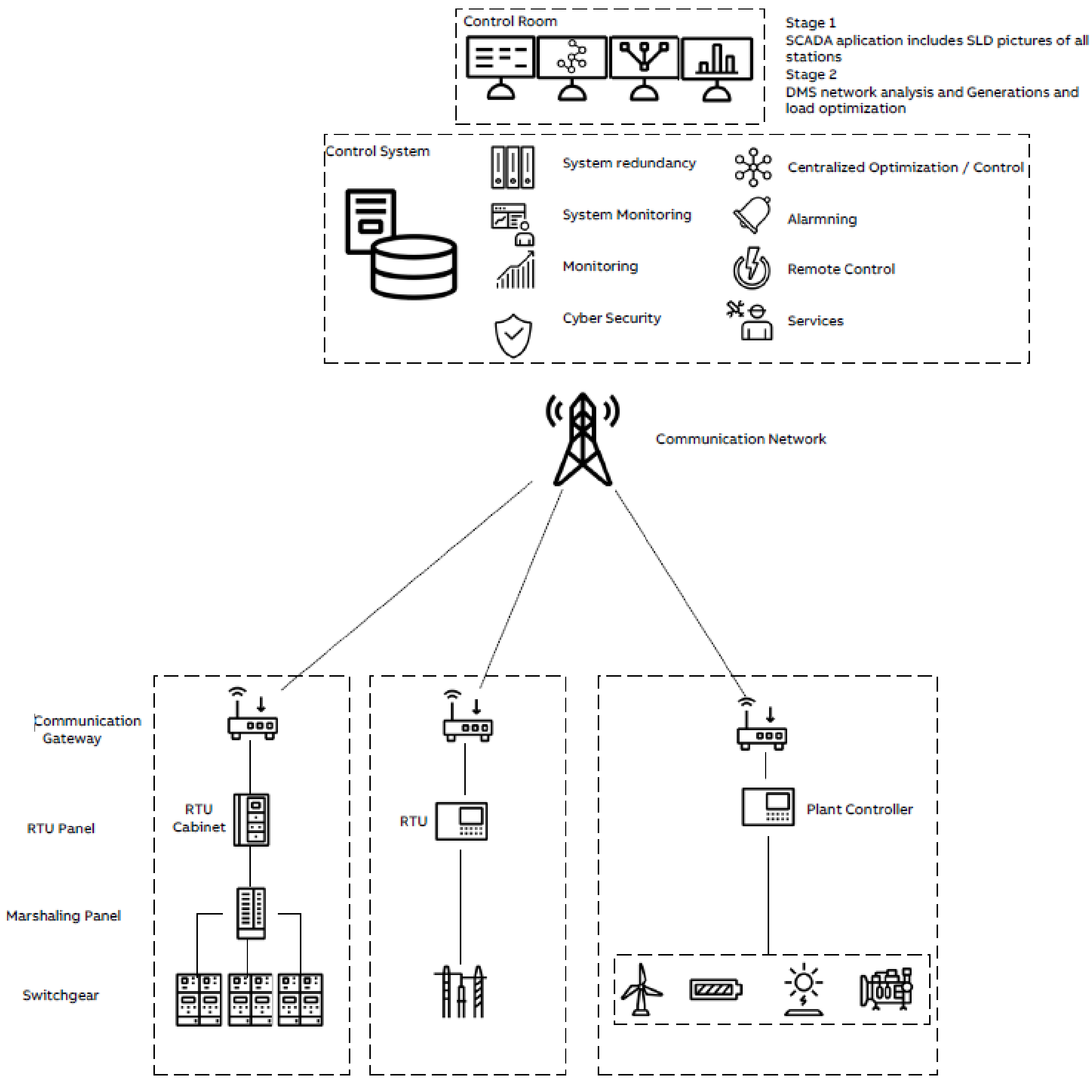
  Extending the LV visibility up to the customer can be achieved with the deployment of SMART meters with bi-directional communication. This can automate outage notification, identify voltage violations and support future volt/var optimization and conservation voltage reduction. This implementation will 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 4-5.

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



The conceptual design solution of the communication network is described in Figure 1-1: Single line diagram for the Upolu power system Figure 4-6. The existing communication network needs to be considered when designing the communication network (This information was unavailable to use at the time of writing this report).

Figure 5-6: Concept communication network diagram for Samoa network

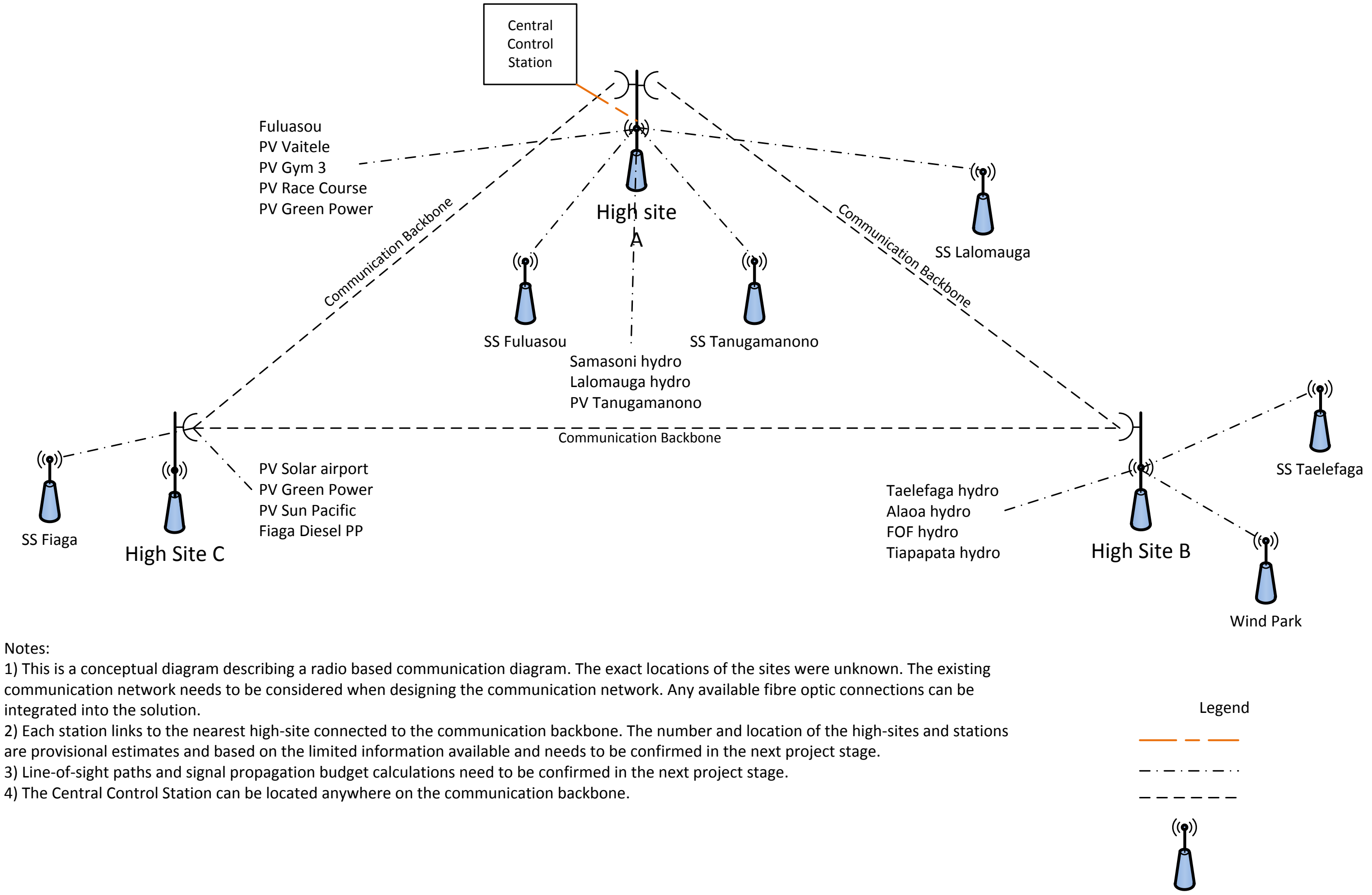


Figure 2: Concept communication network diagram for Samoa (Upolu island) network

5.11.2 Cost Estimate

The estimated cost to implement stage 1 and 2, based on the scope as described above and the conceptual design solution described in the appendix, is indicated in Table 4-1 below.

Table 5-1 Estimated cost for stage 2 for Samoa (Upolu island)

	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	It is assumed that the existing SCADA is not
- Servers					2	each	$ 10,000	$ 20,000	capable to provide the DMS functions, and
- Workstations					2	each	$ 3,500	$ 7,000	needs to be extended with a back-end system
- UPS					1	each	$ 5,000	$ 5,000	Limited capacity assuming standby generator
- Fibre Communication					1	lot	$ 10,000	$ 10,000	
- Weather station					1	lot	$ 5,000	$ 5,000	To improve future load forecasting
Software licences					1	lot	$ 40,000	$ 40,000	
Design and engineering					1	lot	$ 40,000	$ 50,000	
Installation and commissioning					1	lot	$ 30,000	$ 30,000	
Substations									
Hardware									
- RTUs: Main substation									It is assumed this is existing
- RTUs: Other station					25	each	$ 20,000	$ 500,000	Number of stations and scope to be confirmed
- Transducers					50	each	$ 2,000	$ 100,000	Provisional estimate subject to site audit
- Communication equipment: Backbone					3	each	$ 50,000	$ 150,000	Subject to existing comms
- Communication equipment: Main stations									It is assumed this is existing
- Communication equipment: Other stations					25	each	$ 5,000	$ 125,000	Provisional estimate subject to site audit
- Auxiliary DC system					25	each	$ 10,000	$ 250,000	Provisional estimate subject to site audit
Design and Engineering					1	lot	$ 60,000	$ 60,000	
Installation, adaptation and commissioning					25	each	$ 15,000	$ 375,000	Provisional estimate subject to site audit
								$ -	
Travel and accommodation					1	lot	5.0%	$ 87,100	
Project overheads					1	lot	5.0%	$ 87,100	
Contingency					1	lot	15.0%	$ 261,300	
								$ -	
				$ -				$ 2,177,500	

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 for Renewable Power Plants and Battery Storage Plants

Electric Power Corporation
Samoa

Grid Connection Code for Renewable Power Plants and Battery Storage Plants

Version 0.2

May 2019

Enquiries: The secretariat,

EPC, Samoa

Telephone:

Version control

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

1 Objectives

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

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

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

2 Scope

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

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

(a) *Photovoltaic*

(b) *Wind*

(c) *Battery Storage*

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

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

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

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

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

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

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

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

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

3 Definitions and Abbreviations

Active Power Curtailment Set-point

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

Available Active Power

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

Curtailed Active Power

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

Electric Power Corporation

Means the Electric Power Corporation established under the Electric Power Corporation Act 1980.

Rated power

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

Rated wind speed

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

Renewable Power Plant

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

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

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

PV Power Plant (*PVPP*)

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

Wind Power Plant (*WPP*)

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

Battery Storage Power Plant (*BSPP*)

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

Renewable Power Plant (*RPP*) Controller

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

***RPP* Generator**

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

Voltage Ride Through (*VRT*) Capability

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

4 Tolerance of Frequency and Voltage Deviations

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

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

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

4.1 *Normal Operating Conditions*

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

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

(3) The nominal frequency of the *Electric Power Corporation*'s network is 50 Hz and is normally controlled within the limits of 49.5 to 50.5 Hz.

(4) All *Renewable Power Plants* facilities shall be capable of remaining connected to the network and operate within the frequency range of 47.0 to 52.0 Hz.

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

(6) Tripping times for when frequency goes outside of the normal operating range of 49.0 to 51.0 Hz shall be agreed with *Electric Power Corporation*. *Electric Power Corporation* shall co-ordinate such settings to minimise the risk of cascade tripping and network collapse.

(7) All *Renewable Power Plants* shall be capable of continuous operation, at up to 100% active power output, within a frequency range of 49.0 to 51.0 Hz and voltage range of 10% either side of nominal voltage.

(8) The active power output from all Type B and C *Renewable Power Plants* shall not decrease by more than a proportionate decrease when the frequency varies within the range of 47.0 to 49.0 Hz.

(9) When the frequency on the *Electric Power Corporation*'s network is higher than 52.0 Hz for longer than 4 seconds, the *Renewable Power Plant* may be disconnected from the grid.

(10) When the frequency on the *Electric Power Corporation*'s network is less than 47.0 Hz for longer than 200ms, the *Renewable Power Plant* may be disconnected.

(11) The *Renewable Power Plant* shall remain connected to the *Electric Power Corporation*'s network for a rate of change of frequency of up to and including 1.0 Hz per second measured over a rolling window of 500 ms, provided that the network frequency remains within the range of 47.0 to 49.0 Hz.

4.1.1 Synchronising to the *Electric Power Corporation's* network

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

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

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

(c) frequency in the *Electric Power Corporation*'s network is within the range of 49.0 Hz and 50.2 Hz.

(d) removal of the synchronisation block signal received from the *Electric Power Corporation SCADA* system

4.2 *Abnormal Operating Conditions*

4.2.1 Tolerance to sudden voltage drops and peaks

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

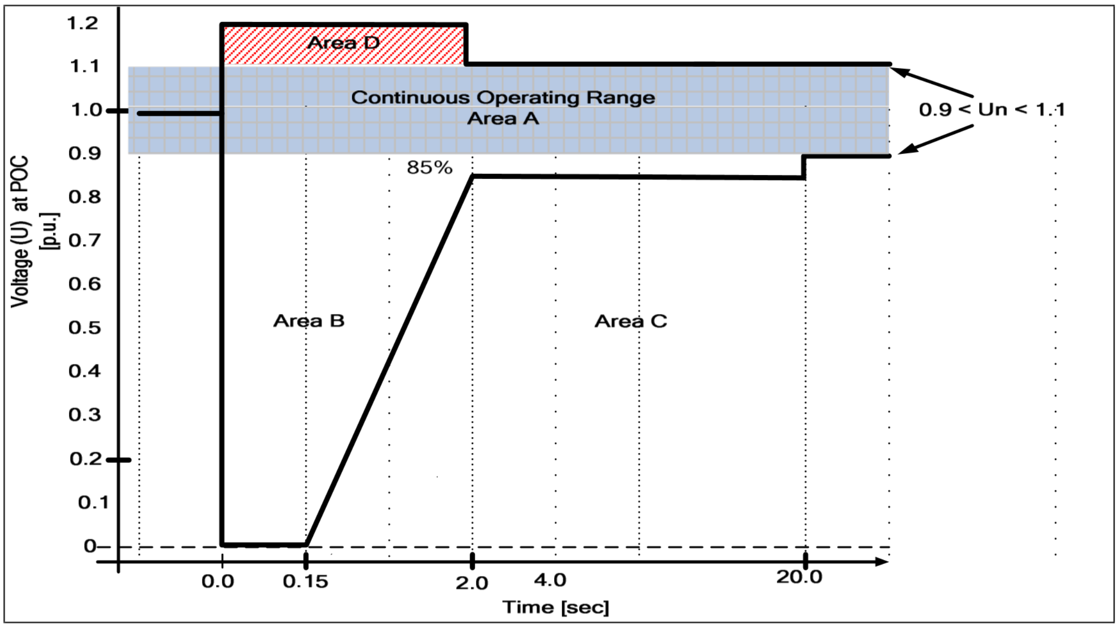
(2) The *Renewable Power Plant* shall be designed to withstand voltage drops and peaks, as illustrated in Figure 1 and supply or absorb reactive current within the transient design ratings of the plant.

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

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

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

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



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

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

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

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

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

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

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

5 Frequency Response

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

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

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

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

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

(4) It shall be possible to set the frequency response control function for all frequency points shown in Figure 2. It shall be possible to set the frequencies f_{min}, f_{max}, as well as f_1 to f_5 to any value in the range of 47 - 52 Hz with a minimum accuracy of 10 mHz.

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

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

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

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

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

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

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

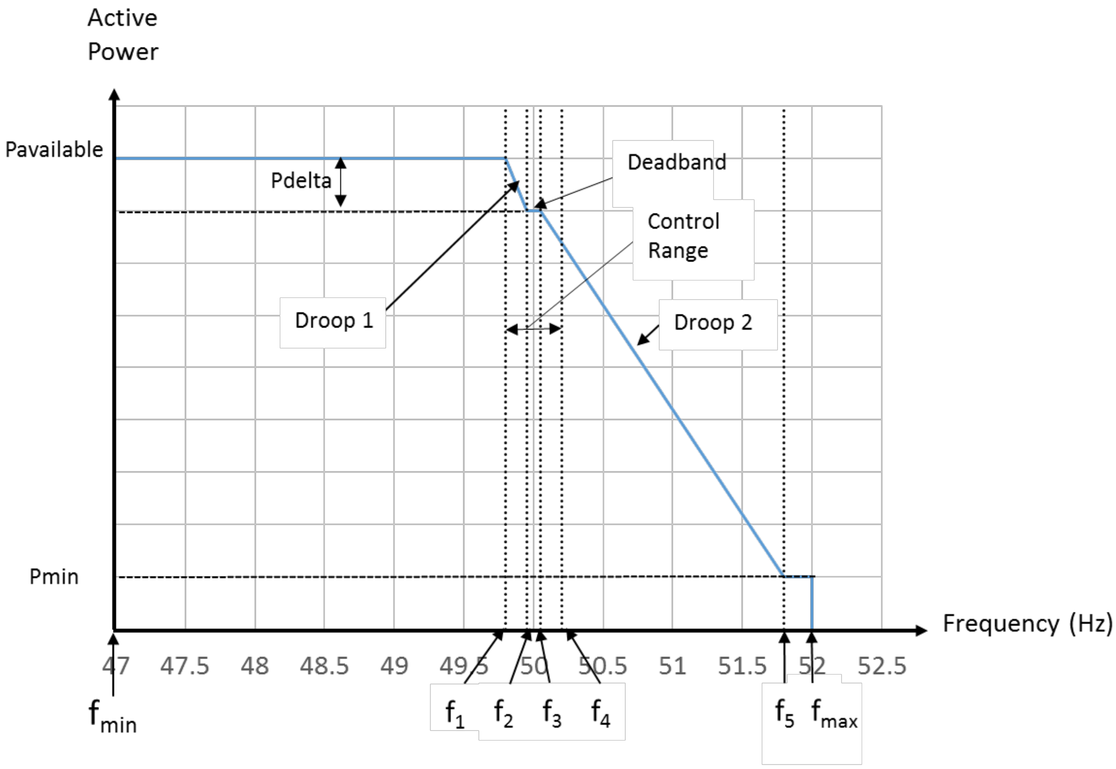


Table 1: Frequency Default Settings

Type	Type A PVPP & WPP	Type B & C PVPP & WPP	Type A, B & C BSPP	Unit
f_{min}	47.0	47.0	47.0	Hz
f_{max}	52.0	52.0	52.0	Hz
f_1	47.0	49.0	49.8	Hz
f_2	47.0	49.5	49.9	Hz
f_3	50.5	50.5	50.1	Hz
f_4	51.0	51.0	50.2	Hz
f_5	52.0	52.0	52.0	Hz
P_{Delta}	0	As agreed with *EPC*	100	%

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

(1) The Electric Power Corporation shall give the Renewable Power Plants owner/operator a minimum of 2 weeks if changes to any of the frequency response parameters (i.e. f_1 to f_5) are required. The *Renewable Power Plant* owner/operator

shall confirm with the Electric Power Corporation that requested changes have been implemented within two weeks of receiving the Electric Power Corporation's request.

5.3 Synthetic Inertia

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

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

6 Reactive Power Capabilities

6.1 Type A *Renewable Power Plants*

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

6.2 Type B & C *Renewable Power Plants*

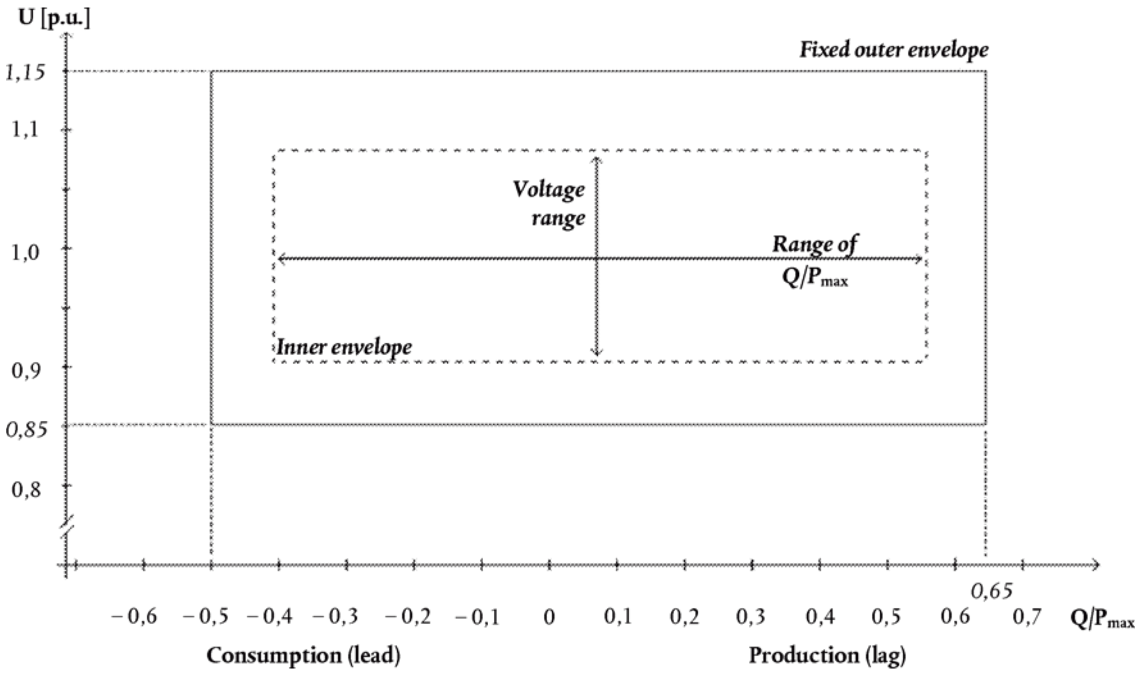
(1) *Type B* & C *Renewable Power Plants* shall be designed with the capability to operate in a voltage (V), power factor or reactive power (Q or *MVA*r) control modes as described in section 7 below. The actual operating mode (V, power factor or Q control) as well as the operating point shall be agreed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

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

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

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

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



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

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

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

7 Reactive Power and Voltage Control Functions

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

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

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

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

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

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

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

(d) a stator current limiter;

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

(a) Voltage control

(b) Power Factor control

(c) Q control

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

7.1 Reactive power (Q) Control

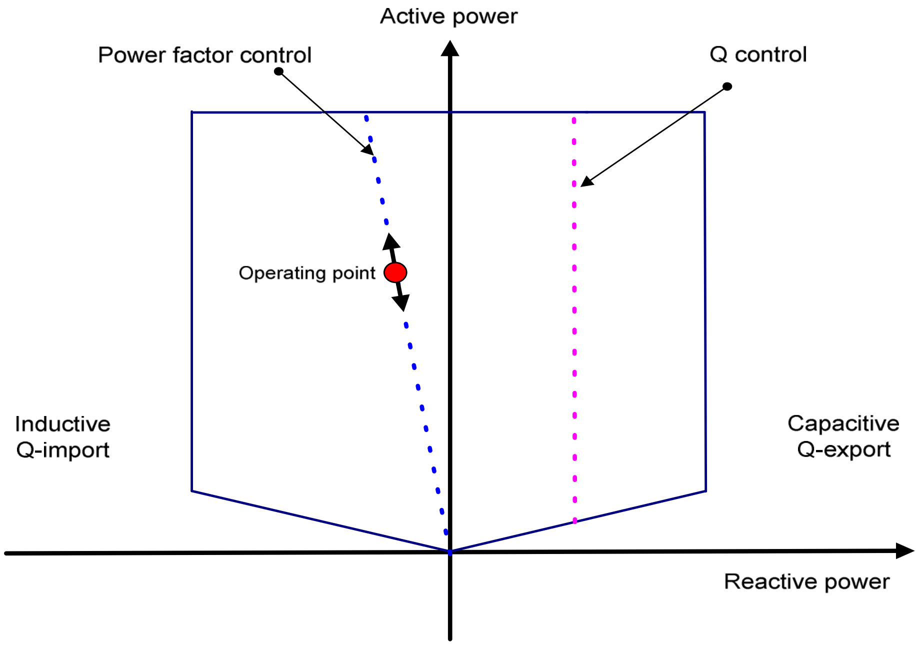
(1) Q control is a control function controlling the reactive power supply and absorption at the point of connection to the grid independently of the active power and the voltage. This control function is illustrated in Figure 4 as a vertical line.

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

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

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

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



7.2 Power Factor Control

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

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

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

7.3 Voltage Control

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

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

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

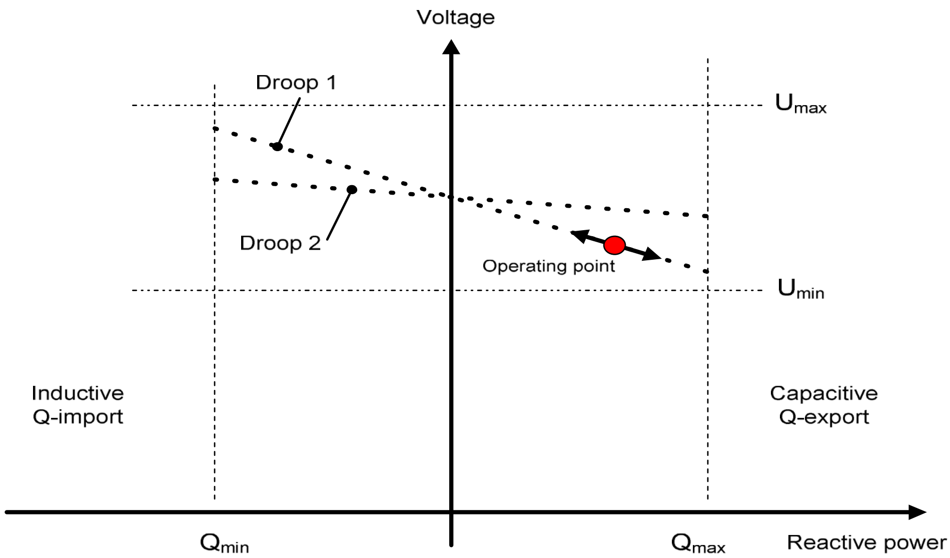
(4) The individual *Renewable Power Plant* shall be able to perform the control within its dynamic range and voltage limit with the *droop* configured as shown in Figure 5. In

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

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

(6) Overall voltage coordination shall be handled by the *Electric Power Corporation*.

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



8 <u>Power Quality</u>

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

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

(a) voltage fluctuations:

(i) rapid voltage changes

(ii) flicker

(b) high-frequency currents and voltages:

(i) harmonics

(ii) inter-harmonics

(iii) disturbances greater than 2 kHz.

(c) unbalanced currents and voltages:

(i) deviation in magnitude between three phases

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

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

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

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

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

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

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

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

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

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

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

9 Islanding

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

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

10 Protection and Fault levels

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

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

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

(4) Protection schemes may cover the following aspects:

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

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

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

11 Active Power Constraint Functions

(1) This section shall apply to Types B and C *Renewable Power Plants.*

(2) For system security reasons it may be necessary for the *Electric Power Corporation* to curtail the *Renewable Power Plant's* active power output.

(3) The *Renewable Power Plants* shall be capable of:

(a) operating the plant at a reduced level if active power has been curtailed by the *Electric Power Corporation* for system security reasons and for frequency control.

(b) receiving a telemetered MW Curtailment set-point sent from the *Electric Power Corporation.*

(4) The *Renewable Power Plants* shall be equipped with constraint functions, i.e. supplementary active power control functions. The constraint functions are used to avoid imbalances in the *Electric Power Corporation's* network or overloading of the network in connection with the reconfiguration of the network in critical or unstable situations or the like, as illustrated in Figure 6.

(5) Activation of the active power constraint functions shall be agreed with the *Electric Power Corporation*.

The required constraint functions are as follows:

(a) Absolute production constraint

(b) Delta production constraint

(c) Power gradient constraint

(6) The required constraint functions are described in the following sections.

11.1 Absolute Production Constraint

(1) An Absolute Production Constraint is used to constrain the output active power from the *Renewable Power Plants* to a predefined power MW limit at the point of connection to the grid. This is typically used to protect the network against overloading and for frequency control.

(2) If the setpoint for the Absolute Production Constraint is to be changed, such change shall be commenced within 1 second and completed not later than 2 seconds after receipt of an order to change the setpoint.

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

11.2 Delta Production Constraint

(1) A Delta Production Constraint is used to constrain the active power from the *Renewable Power Plants* to a required constant value in proportion to the possible active power.

(2) A Delta Production Constraint is typically used to establish a control reserve for control purposes in connection with primary frequency control.

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

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

11.3 Power Gradient Constraint

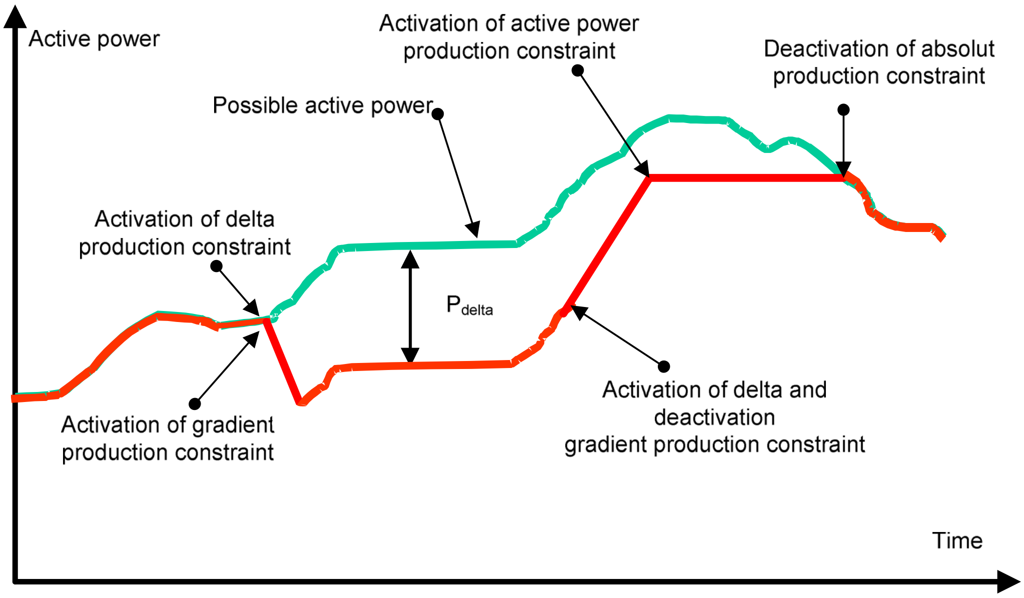
(1) A Power Gradient Constraint is used to limit the maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the setpoints for the *Renewable Power Plant.* A Power Gradient Constraint is typically used for reasons of system operation to prevent changes in active power from impacting the stability *of the* network.

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

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

(4) The active power constraint functions are illustrated in **Figure 6**.

Figure 6: Active power control functions for a Renewable Power Plant



12 Control Function Requirements

(1) *Renewable Power Plants* shall be equipped with the control functions specified in Table 4. The purpose of the various control functions is to ensure overall control and monitoring of the *Renewable Power Plant's* generation.

(2) The *Renewable Power Plants* control system shall be capable of controlling the ramp rate of its active power output with a maximum MW per minute ramp rate set by the *Electric Power Corporation*.

(3) These ramp rate settings shall be applicable for all ranges of operation including positive ramp rate during start up, positive ramp rate only during normal operation and negative ramp rate during controlled shut down. They shall not apply to frequency regulation.

(4) The *Renewable Power Plants* shall not perform any frequency response or voltage control functions without having entered into a specific agreement to this effect with the *Electric Power Corporation*.

(5) The specifications and regulation functions specified shall comply with the international standard IEC 61400-25-2.

Table 4: Control functions required for *Renewable Power Plants*

Control function	**Type A**	**Type B**	**Type C**
Frequency control	X	X	X
Absolute production constraint	-	X	X
Delta production constraint	-	X	X

Control function	Type A	Type B	Type C
Power gradient constraint	-	X	X
Q control	-	X	X
Power factor control	-	X	X
Voltage control	-	X	X

13 Signals, Communications & Control

(1) All signals shall be made available at the *point of connection to the grid* by the *Renewable Power Plants*.

13.1 Signals from the *Renewable Power Plants* available at the point of connection to the grid

(1) This section shall apply to *Renewable Power Plants* of *Type B and C*.

(2) Signals from the *Renewable Power Plants* to the *Electric Power Corporation* shall be broken up into a number of logical groups depending on functionality.

(3) The following signal list groups shall apply:

(a) ***Signals List #1*** *– General*

In addition, *Renewable Power Plants* shall be required to provide certain signals from Signals Lists 2, 3, 4 and 5. These lists relate to:

(b) ***Signals List #2*** *– Renewable Power Plant Availability Estimate;*

(c) ***Signals List #3*** *– Renewable Power Plant MW Curtailment data;*

(d) ***Signals List #4*** *– Renewable Power Plant frequency response settings*

(e) ***Signals List #5*** *– Renewable Power Plant meteorological data.*

13.1.1 Signals List #1 – General

(1) The *Renewable Power Plants* shall make the following signals available at the *Electric Power Corporation* designated *communication gateway equipment* located at the *plant's* site:

(a) Actual sent-out (MW) at the point of connection to the grid

(b) Active Power Ramp rate of the entire *Renewable Power Plant*

(c) Reactive Power Import/Export (+/-*MVAr*) at the point of connection to the grid

(d) Reactive power range upper and lower limits

(e) *Power Factor*

(f) *Voltage output*

(g) *Echo MW set point*

(h) *Echo MVAr set point*

(i) *Echo Voltage set point*

13.1.2 Signals List #2 – *Renewable Power Plants* Current Availability Estimates

(1) The *Renewable Power Plants* shall make available the following signals at the *Electric Power Corporation* designated *communication gateway equipment* located at the *plant* site:

(a) Current available maximum MW updated every second.

(b) Current available *MVA*r updated every second.

13.1.3 Signals List #3 – *RPP* MW Curtailment Data

(1) The *Renewable Power Plants* shall make the following signals available at a designated *communication gateway equipment* located at the *plant's* site:

(a) *Plant* MW Curtailment facility status indication (ON/OFF) as a double bit point. This is a controllable point which is set on or off by the *Electric Power Corporation*. When set "On" the *plant* shall then clarify and initiate the curtailment based on the curtailment setpoint value below.

(b) Curtailment in progress digital feedback. This single bit point will be set high by the *plant* while the facility is in the process of curtailing its output.

(c) *Plant's* MW Curtailment Set-point value (MW- feedback).

(2) In the event of a curtailment, the *Electric Power Corporation* will pulse the curtailment setpoint value down. The *plant's* response to the changed curtailment value will be echoed by changing the corresponding echo MW value. This will provide feedback that the *plant* is responding to the curtailment request.

13.1.4 Signals List #4 – Frequency Response System Settings

(1) The *Renewable Power Plants* shall make the following signals available at a designated communication gateway equipment located at the *plant's* site:

(a) *Frequency Response System* mode status indication (ON/OFF) as a double bit point

13.1.5 Signals List #5 – Renewable Power Plants Meteorological Data.

(1) *Renewable Power Plants* shall make the following signals available at the *Electric Power Corporation's* designated communication gateway equipment located at the *plant* site:

(a) Wind speed (within 75% of the hub height) – measured signal in meters/second (for *WPP only*)

(b) Wind direction within 75% of the hub height) – measured signal in degrees from true north(0-359) (for *WPP only*)

(c) Air temperature- measured signal in degrees centigrade (-20 to 50)

(d) Air pressure- measured signal in millibar (800 to 1400).

(e) Air density (for *WPP only*)

(f) Solar radiation (for *PVPP only*)

(2) The meteorological data signals shall be provided by a dedicated Meteorological Mast located at the *plant's* site or, where possible and preferable to do *so*, data from a means of the same or better accuracy.

(3) Energy resource conversion data for the facility (e.g. MW/ wind speed) for the various resource inputs to enable the *Electric Power Corporation* to derive a graph of the full range of the facilities output capabilities. An update will be sent to the *Electric Power Corporation* following any changes in the output capability of the facility.

13.2 Update Rates

(1) Signals shall be updated at the following rates:

(a) Analog Signals at a rate of 1 second

(b) Digital Signals at the rate of 1 second.

(c) Meteorological data once a minute

13.3 Control Signals Sent from *Electric Power Corporation* to the *Renewable Power Plants*

The control signals described below shall be sent from *Electric Power Corporation* to the *Type B and C Renewable Power Plants*. The *plants* shall be capable of receiving these signals and acting accordingly.

13.3.1 Active-Power Control

(1) An *Active-Power Control* setpoint signal shall be sent by *Electric Power Corporation* to the *Renewable Power Plant's* control system.

(2) This setpoint shall define the maximum Active Power output permitted from the *plant*. The *plant's* control system shall be capable of receiving this signal and acting accordingly to achieve the desired change in Active Power output.

(3) The *Renewable Power Plants* shall make it possible for the *Electric Power Corporation* to remotely enable/disable the Active-Power control function in the plant's control system.

13.3.2 Connection Point CB Trip facility

(1) A facility shall be provided by the *Electric Power Corporation* to facilitate the disconnection of the *plant*. It shall be possible for Electric Power Corporation to send a trip signal to the circuit breaker at the *HV* side of *the point of connection to the grid.*

13.3.3 Synchronisation block signal

(1) A Synchronisation block signal shall be sent by *Electric Power Corporation* to the *Renewable Power Plant's* control system to prevent the *Renewable Power Plant* from synchronising when system conditions dictate this.

13.4 *Renewable Power Plants* MW availability declaration

(1) The *Renewable Power Plant* shall submit *plant's* MW availability declarations whenever changes in MW availability occur or are predicted to occur. These declarations shall be submitted by means of an electronic interface in accordance with the requirements of *Electric Power Corporation's* data system.

13.5 Data Communications Specifications

(1) The *Renewable Power Plant* shall have external communication gateway equipment that can communicate with a minimum of two simultaneous SCADA Masters, independently from what is done inside the *plant*.

(2) The location of the communication gateway equipment shall be agreed between affected participants in the connection agreement.

(3) The necessary communications links, communications protocol and the requirement for analogue or digital signals shall be specified by the *Electric Power Corporation* as appropriate before a connection agreement is signed between the *plant* and the *Electric Power Corporation*.

(4) *Active Power Curtailment* or *Voltage Regulation* facilities at the *plant* shall be tested once a quarter. It is essential that facilities exist to allow the testing of the functionality without tripping the actual equipment.

(5) Where signals or indications required to be provided by the *plant* become unavailable or do not comply with applicable standards due to failure of the *plant* equipment or any other reason under the control of the *plant owner/operator*, the *plant owner/operator* shall restore or correct the signals and/or indications within 24 hours.

14 Testing and Compliance Monitoring

(1) All *Renewable Power Plants* shall demonstrate compliance to all applicable requirements specified in this grid connection code and any other applicable code or standard, before being allowed to connect to the network.

(2) The *plant* shall review, and confirm to the *Electric Power Corporation*, compliance by the *plant* with every requirements of this code.

(3) The *Renewable Power Plant* shall conduct tests or studies to demonstrate that the *plant* complies with each of the requirements of this code.

(4) The *Renewable Power Plant* shall continuously monitor its compliance in all material respects with all the connection conditions of this code.

(5) Each *Renewable Power Plant* shall submit to the *Electric Power Corporation* a detailed test procedure, emphasising system impact, for each relevant part of this code prior to every test.

(6) If *Renewable Power Plant* determines, from tests or otherwise, that the *plant* is not complying with one or more sections of this code, then the *plant owner/operator* shall (within 1 hour of being aware):

(a) notify the *Electric Power Corporation* of that fact,

(b) advise the *Electric Power Corporation* of the remedial steps it proposes to take to ensure that the relevant *plant* can comply with this code and the proposed timetable for implementing those steps,

(c) diligently take such remedial action to ensure that the relevant *plant* can comply with this code; the *plant owner/operator* shall regularly report in writing to the Electric Power Corporation on its progress in implementing the remedial action, and

(d) after taking remedial action as described above, demonstrate to the reasonable satisfaction of the *Electric Power Corporation* that the relevant *plant* is then complying with this code.

(7) The *Electric Power Corporation* may issue an instruction requiring the *plant* to carry out a test to demonstrate that the relevant *plant* with the code requirements. A *plant* may not refuse such an instruction, provided it is issued timeously and there are reasonable grounds for suspecting non-compliance.

(8) The *plant* owner/operator shall keep records relating to the compliance of the *plant* with each section of this grid connection code, or any other code applicable to that *plant*, setting out such information that the *Electric Power Corporation* reasonably requires for assessing power system performance, including actual *plant* performance during abnormal conditions. Records shall be kept for a minimum of 5 years (unless otherwise specified in the code) commencing from the date the information was created.

15 Reporting to Electric Power Corporation

(1) The *Renewable Power Plant* shall design the system and maintain records *such* that the following information can be provided to the *Electric Power Corporation* on a monthly basis in an electronic spread sheet format:

(a) Non-renewable/supplementary fuel used by the power plant.

(b) Actual hourly availability and output energy to the grid that occurred and the average primary resource for that hour.

(c) Actual hourly electricity imports from all sources as applicable.

(d) Any curtailed energy during the month.

(2) These reports are to be submitted before the 15th of the following month to *Electric Power Corporation* via an email.

(3) These reports should also include details of incidents relating any unavailability of the network which prevented the *plant* from generating.

(4) The *Electric Power Corporation* requires suitable and accurate dynamic models, in the template specified by the requesting party applying for a connection to the *network*, in order to assess reliably the impact of the *plant* proposed installation on the dynamic performance and security and stability of the power system.

(5) The required dynamic models must operate under RMS simulation to replicate the performance of the *plant* or individual units for analysis of the following network aspects:

(a) *Plant's* impact on network voltage stability

(b) *Plant's* impact on Quality of Supply at *point of connection*

(c) *Plant's* impact on network protection co-ordination

(d) *Plant's FRT* (Fault Ride Through) capability for different types of faults and positions (h) *plant's* response to various system phenomena such as:

(i) switching on the network

(ii) power swings

(iii) small signal instabilities

(6) *Plant's* data exchange shall be a time-based process.

(a) **First stage** (during the application for connection)

(i) The following information shall be submitted by the *plant owner/operator* to the *Electric Power Corporation*, as applicable:

- Physical location (including the GPS coordinates)

- Site Plan
- Number of wind turbines or *units* to be connected
- MW output per turbine or *unit*
- Initial phase MW value
- Final phase MW value and timelines
- Any other information that the service provider may reasonably require

(ii) For the detailed *plant* design, the *Electric Power Corporation* shall make available to the *plant owner/operator* at least the following information:

- *Point of connection* to the grid including the nominal voltages,
- Expected fault levels,
- The network service provider's connection between the Point of connection to the grid and the *plant*,
- The busbar layout of the point of connection to the grid and *point of connection* substations,
- The portion of the network service provider's grid that will allow accurate and sufficient studies to design the *plant* to meet the Grid Code. This information shall include:
    - Positive and zero sequence parameters of the relevant network service provider's transmission and distribution, transformers, reactors, capacitors and other relevant equipment
    - The connection of the various lines transformers, reactors and capacitors etc.

(b) **Second stage** (after detailed *plant* designs have been completed but before commissioning the *plant*)

(i) During this stage, the *plant* shall provide information on:

- Selected *plant* technology data.
- Fault ride through capability and harmonic studies test report
- Generic test model and dynamic modelling data per wind turbine or *unit* as from the type approval and tests result

(c) **Third stage** (after commissioning and optimisation of the *plant*)

(i) During this stage, the *plant* is compelled to provide information on:

- A validated *plant's* electrical dynamic simulation model using commissioning test data and measurements

- Test measurement data in the format agreed between the *plant* and the Electric Power Corporation, as applicable.

(7) The dynamic modelling data shall be provided in a format as may be agreed between the *plant owner/operator* and the Electric Power Corporation, as applicable.

(8) In addition, the *Renewable Power Plant* Generator shall provide the Electric Power Corporation with operational data as prescribed in **Appendix 4**.

16 Appendix 1 - *Wind Power Plants*

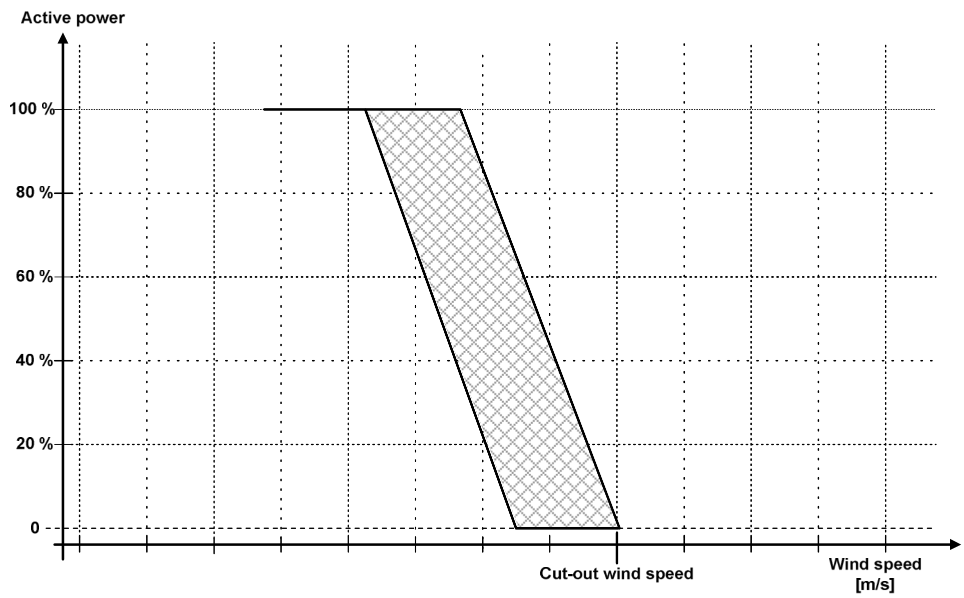
16.1 High Wind Curtailment

(1) It shall be possible to continuously downward regulate the active power supplied by the *plant* to an arbitrary value in the interval from 100% to at least 40% of the rated power. When downward regulation is performed, the shutting-down of individual wind turbine *generator* systems is allowed *so* that the load characteristic is followed as well as possible.

(2) The *Wind Power Plant* shall stay connected to the *network* at average wind speeds below a predefined cut-out wind speed. The cut-out wind speed shall as a minimum be 25 m/s, based on the wind speed measured as an average value over a 10-minute period. To prevent instability in the *network*, the *Wind Power Plant* shall be equipped with an automatic downward regulation function making it possible to avoid a temporary interruption of the active power production at wind speeds close to the cut-out wind speed.

(3) Downward regulation shall be performed as continuous or discrete regulation. Discrete regulation shall have a step size of maximum 25% of the rated power within the hatched area shown in Figure 7. When downward regulation is being performed, the shutting down of individual wind turbine *generator* systems is allowed. The downward regulation band shall be agreed with the *Electric Power Corporation* upon commissioning of the wind power plant.

Figure 7: Downward regulation of active power at high renewable speeds



17 Appendix 2 - *Photovoltaic Power Plants*

No special requirements for solar PV except the general requirement specified in this code.

Appendix 3 - *Battery Power Plants*

No special requirements for *Battery Power Plants* except the general requirement specified in this code.

18 Appendix 4 - Documentation

18.1 Master Data

Description	**Text**
Identification:	
Name of *electricity supply undertaking*	
Plant name	
ID number	
Planned commissioning	
Technical data:	
Manufacturer	
Type designation (model)	
Type approval	
Approval authority	
Installed kW (*rated power*)	
Cos φ (*rated power*)	
Cos φ (20% *rated power*)	
Cos φ (no load)	
3-phase short-circuit current immediately in front of the *power plant* (RMS)	
Point of connection	
Voltage level	

Description	Text
Plant address:	
Contact person (technical)	
Address1	
House number	
Letter	
Postal code	
BBR municipality	
X/Y coordinates	
Title number	
Owners' association on titled land	
Owner:	
C ID number	
Company name	
Contact person (administrative)	
Address1	
House number	
Letter	
Floor	
To the right/left	
Postal code	
Email address	

18.2 Technical Documentation

18.2.1 Step-Up Transformer

Description	Value
Make	
Type	
Comments	

Description	Symbol	Unit	Value
Nominal apparent power (1 p.u.)	S_n	*MVA*	
Nominal primary voltage (1 p.u.)	U_p	kV	
Nominal secondary voltage	U_s	kV	
Coupling designation, eg Dyn11	-	-	
Step switch location	-	-	Primary side ☐ Secondary side ☐
Step switch, additional voltage per step	du_{tp}	%/trin	
Step switch, phase angle of additional voltage per step:	phi_{tp}	degree/step	
Step switch, lowest position	n_{tpmin}	-	
Step switch, highest position	n_{tpmax}	-	
Step switch, neutral position	n_{tp0}	-	
Short-circuit voltage, synchronous	u_k	%	
Copper loss	P_{cu}	kW	
Short-circuit voltage, zero system	u_{k0}	%	
Resistive short-circuit voltage, zerosequence system	u_{kr0}	%	
No-load current	I_0	%	
No-load loss	P_0	%	

18.2.2 Single Line Diagram Representation

(1) This applies to all *Renewable Power Plants* of Type B and C.

(2) A single-line diagram representation of the plant shall be created, with indication of *point of connection to the grid,* metering points, including settlement metering, limits of ownership and operational supervisor limits/limits of liability. In addition, the type designation for the switchgear used shall be stated *so* as to make it possible to identify the correct connection terminals.

(3) In instances when a single-line diagram representation is included in the grid use agreement between the *Renewable Power Plant* and Electric Power Corporation, the grid *connection agreement* can be enclosed as documentation.

18.2.3 PQ Diagram

(1) This applies to all *Renewable Power Plants* of Type B and C.

19 Appendix 5 – Compliance test specifications

19.1 Introduction

This section specifies the procedures to be followed in carrying out testing to verify compliance with this *Code.*

19.2 Test procedures

19.3 *Renewable Power Plants* protection function verification

Parameter	Reference	Description
Protection function and settings	Section 9	**APPLICABILITY AND FREQUENCY** All new *Renewable Power Plants* coming on line or at which major refurbishment or upgrades of protection systems have taken place. **Routine review:** All *plants* to confirm compliance every six years. **PURPOSE** To ensure that the relevant protection functions in the *Renewable Power Plants* are coordinated and aligned with the system requirements. **PROCEDURE** *1.* Establish the system protection function and associated trip level requirements from the *Electric Power Corporation.* *2.* Derive protection functions and settings that match the *Renewable Power Plant* and system requirements. *3.* Confirm the stability of each protection function for all relevant system conditions. *4.* Document the details of the trip levels and stability calculations for each protection function. *5.* Convert protection tripping levels for each protection function into a per *unit* base. *6.* Consolidate all settings in a per *unit* base for all protection functions in one document. *7.* Derive actual relay dial setting details and document the relay setting sheet for all protection functions. *8.* Document the position of each protection function on one single line diagram of the generating *unit* and associated connections. *9.* Document the tripping functions for each tripping function on one tripping logic diagram. *10.* Consolidate detail setting calculations, per unit setting sheets, relay setting sheets, plant base information on which the settings are based, tripping logic diagram, protection function single line diagram and relevant

		protection relay manufacturers' information into one document. *11.*Submit to the *Electric Power Corporation* for its acceptance and update.
Protection function and settings (cont.)	Section 9 (cont.)	**Review:** 1. Review Items 1 to 10 above. 2. Submit to the *Electric Power Corporation* for its acceptance and update. 3. Provide the *Electric Power Corporation* with one original master copy and one working copy. **ACCEPTANCE CRITERIA** All protection functions are set to meet the necessary protection requirements of the *plant* with a minimal margin, optimal fault clearing times and maximum plant availability. Submit a report to the *Electric Power Corporation* one month after commissioning and six-yearly for routine tests.

19.3.1 *Renewable Power Plants* protection integrity verification

Parameter	Reference	Description
Protection integrity	Section 9	**APPLICABILITY AND FREQUENCY** All new *Renewable Power Plants* coming on line and all other *power stations* after major works of refurbishment of protection or related plant. Also, when modification or work has been done to the protection, items 2 to 5 must be carried out. This may, however, be limited to the areas worked on or modified. **Routine review:** All *plants* on: item 1 below: Review and confirm every 6 years Item 2, and 3 below: at least every 12 years. **PURPOSE** To confirm that the protection has been wired and functions according to the specifications. **PROCEDURE** 1. Apply final settings as per agreed documentation to all protection functions. 2. With the *unit* off load and de-energized, inject appropriate signals into every protection function and confirm correct operation and correct calibration. Document all protection function operations. 3. Carry out trip testing of all protection functions, from origin (e.g. Buchholz relay) to all tripping output devices (e.g. HV breaker). Document all trip test responses. 4. Apply short-circuits at all relevant protection zones and with *generator* at nominal speed excite *generator* slowly, record currents at all relevant protection functions and confirm correct operation of all relevant protection functions. Document all readings and responses. Remove all short-circuits. 5. With the *Renewable Power Plants* at nominal production. Confirm correct operation and correct calibration of all protection functions. Document all readings and responses.

		Review: Submit to the *Electric Power Corporation* for its acceptance and update. **ACCEPTANCE CRITERIA** All protection functions are fully operational and operate to required levels within the relay *OEM* allowable tolerances. Measuring instrumentation used shall be sufficiently accurate and calibrated to a traceable standard. Submit a report to the *Electric Power Corporation* one month after test.

19.3.2 - *Renewable Power Plants* active power control capability verification

Parameter	Reference	Description
Active power control function and operational range	Section 10 depending on Type	**APPLICABILITY** All new *Renewable Power Plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the active power control capability specified is met. **PROCEDURE** The following tests shall be performed within an active power level range of at least 0.2p.u.or higher 1. The *plant* will be required to regulate the active power to a set of specific setpoints within the design margins. 2. The *plant* will be required to obtain a set of active power setpoints within the design margins with minimum two different gradients for ramping up and two different gradients for ramping down. 3. The *plant* will be required to maintain as a minimum two different set levels of spinning reserve within the design margins. 4. The *plant* will be required to operate as a minimum to limit active power output according to two different absolute power constraint set levels within the design margins. 5. The *plant* will be required to verify operation according to as a minimum two different parameter sets for a frequency response curve within the design margins. **ACCEPTANCE CRITERIA**

		1. The *plant* shall maintain the set output level within ±2% of the capability registered with the *Electric Power Corporation* for at least one hour. 2. The *plant* shall demonstrate ramp rates with precision within ±2% of the capability registered with the *Electric Power Corporation* for ramp up and down. 3. The *plant* shall maintain a spinning reserve set level within ±2% of the capability registered with the *Electric Power Corporation* for at least one hour. 4. The *plant* shall maintain an absolute power constraint set level within ±2% of the capability registered with the *Electric Power Corporation* for at least one hour. 5. The *plant* shall demonstrate that the requested frequency response curves can be obtained. Submit a report to the *Electric Power Corporation* one month after the test.

19.3.3 *Renewable Power Plants* reactive power control capability verification

Parameter	Reference	Description
Reactive power control function and operational range	Sections 6 and 7 depending on Type	**APPLICABILITY** All new *Renewable Power Plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the reactive power control capability specified is met. **PROCEDURE** The following tests shall be performed within a minimum active power level range of at least 0.2 p.u. or higher 1. The *plant* will be required to regulate the voltage at the point of connection to the grid to a set level within the design margins. 2. The *plant* will be required to provide a fixed Q to a set level within the design margins. 3. The *plant* will be required to obtain a fixed PF within the design margins. **ACCEPTANCE CRITERIA** 1. The *plant* shall maintain the set voltage within ±5% of the capability registered with the *Electric Power Corporation* for at least one hour. 2. The *plant* shall maintain the set Q within ±2% of the capability registered with the *Electric Power Corporation* for at least one hour. 3. The *plant* shall maintain the set PF within ±2% of the capability registered with the *Electric Power Corporation* for at least one hour.

		Submit a report to the *Electric Power Corporation* one month after the test.

19.3.4 *Renewable Power Plants* power quality calculations

Parameter	**Reference**	**Description**
Power quality calculations for:	Section 8 depending on Type	**APPLICABILITY** All new *plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: Confirm compliance every 6 years. **PURPOSE** To confirm that the limits for all power quality parameters specified is met. **PROCEDURE** The following tests shall be calculated within a minimum active power level range from 0.2p.u. to 1.0p.u.
1. Rapid voltage changes		1. Calculate the levels for rapid voltage changes are within the limits specified over the full operational range.
2. Flicker		2. Calculate the flicker levels are within the limits specified over the full operational range.
3. Harmonics		3. Calculate the harmonics are within the limits specified over the full operational range.
4. Inter-harmonics		4. Calculate the interharmonics are within the limits specified over the full operational range.

5. High frequency disturbances		5. Calculate the disturbances higher than 2 Hz are within the limits specified over the full operational range. **ACCEPTANCE CRITERIA** 1. The calculations shall demonstrate that the levels for rapid voltage changes are within the limits specified over the full operational range. 2. The calculations shall demonstrate that the flicker levels are within the limits specified over the full operational range. 3. The calculations shall demonstrate that the harmonics are within the limits specified over the full operational range. 4. The calculations shall demonstrate that the interharmonics are within the limits specified over the full operational range. 5. The calculations shall demonstrate that the disturbances higher than 2 Hz are within the limits specified over the full operational range Submit a report to the *Electric Power Corporation* one month after the test.

19.3.5 *Renewable Power Plants* fault ride through simulations

Parameter	Reference	Description
Simulations of fault ride though voltage droops and peaks.	Section 4	**APPLICABILITY** All new *plants* coming on line and after major modifications or refurbishment of related plant components or functionality. **Routine test/reviews**: None. **PURPOSE** To confirm that the limits for all power quality parameters specified is met. **PROCEDURE** By applying the electrical simulation model for the entire *plant* it shall be demonstrated that the *plant* performs to the specifications. 1. Area A - the *plant* shall stay connected to the network and uphold normal production. 2. Area B - the *plant* shall stay connected to the network. The *plant* shall provide maximum voltage support by supplying a controlled amount of reactive power within the design framework offered by the technology, see Figure 1. 3. Area C - the *plant* is allowed to disconnect. 4. Area D - the *plant* shall stay connected. The *plant* shall provide maximum voltage support by absorbing a controlled amount of reactive power within the design framework offered by the technology, see Figure 1. **ACCEPTANCE CRITERIA** 1. The dynamic simulations shall demonstrate that the *plants* fulfils the requirements specified. Submit a report to the *Electric Power Corporation* three month after the commission.

Appendix 2 Description of GDAT model

Description of Measurement of Real-time Dispatch Performance Program

June 2018

Document Status

Title: Description of Generation Dispatch Analysis Tool for Pacific Islands

Reference:

Issue: Version 1.0

Date: 26 June 2018

Electronic Doc Ref: Description of GDAT model v1.0.pdf

Approved by

History

Issue	**Date**	**Author**	**Description**
Ver 1.0	06 June 18	Graeme Chown, Grant Grobbelaar and Jason Miskin	Pacific Island model description

Name of Client **Pacific Power Association**
Assignment Name: Assessment of Variable Renewable Energy (VRE) Grid Integration, and Evaluation of SCADA and EMS system design in the Pacific Island Counties

Executive Summary

This document contains the description of the Generation Dispatch Analysis Tool which is designed to simulate frequency control over a typical day / week, analyse various scenarios including wind, solar power and storage, evaluate different control strategies, determine spinning reserve requirements and audit system dispatch.

For the Pacific islands the model is developed specifically test the impact of increasing wind and solar. Mitigation strategies to control frequencies using battery power firstly to improve frequency control and secondly to act as a storage.

This document provides the details of the program and how to run simulation studies.

1 Introduction

The Generation Dispatch Analysis Tool (GDAT) is a product in MATLAB© & Simulink© that has been developed by Dr Graeme Chown with assistance from Optinum Solutions.

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
6. System Operator dispatch audit

The key features of the tool are:

1. Easy interface to input data
2. Automatic generation of code for the options chosen in the input data
3. Automatic saving of results
4. Graphical user interface to view results
5. Automatic generation of key performance statistics

This document is a description of the main features of the GDAT model, how to input data, run simulations and view results.

2 Description of GDAT model components

2.1 Overview of model components

Figure B1 shows the AGC model as built using MATLAB and Simulink. As shown, the model is made up of six different blocks (or modules), and each block is further made up of additional blocks and/or subroutines also built using MATLAB and Simulink. The following are the main modules of the MATLAB AGC model:

- ACE (Area Control Error): This is the first module and calculates the raw ACE. The ACE is calculated from the frequency difference between target and actual frequencies.

- Controller: This module calculates the amount of control needed. Considering the financial components, the module calculates the desired generation for all the units under AGC control.
- Frequency Setpoint: This module determines which units are on governing and should receive the actual system frequency; otherwise frequency is set to nominal for units not on governing.
- Unit Models: This module contains the models for all the units and produces the electrical power output for each unit.
- Generation Frequency: This module receives the sum of all the electrical power outputs from all the generating units to give the total generation. The Generation Frequency module compares the actual generation to the demand and then generates the frequency.

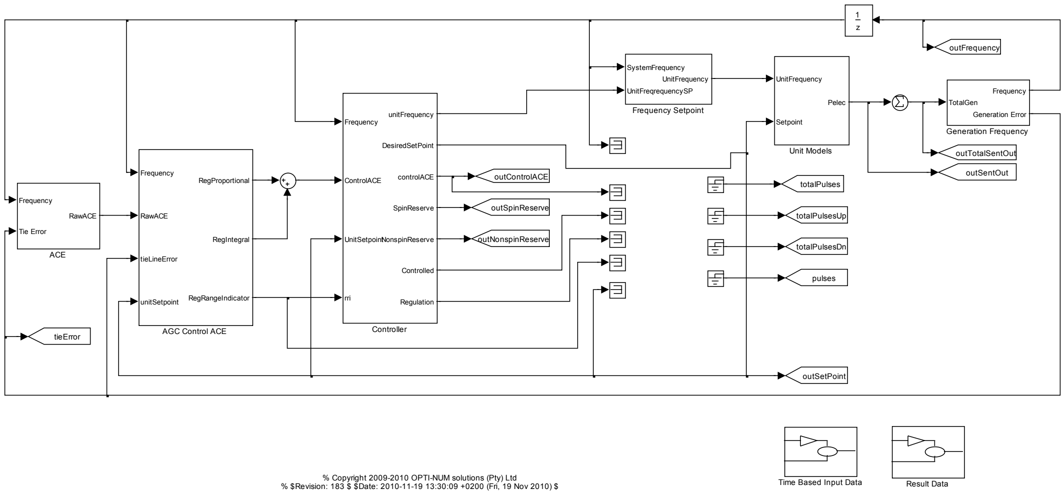


Figure B1: MATLAB AGC Model.

Two additional modules can be seen, viz. Time Based Input Data and Result Data. The Time Based Input Data is where the time based data is developed for use in the model. The Result Data is where the results are stored for later use, e.g. plotting.

The details of each module are further described in the sections to follow. In addition, a description of the model's entry point is described – the Power Generation Model Graphical User Interface (GUI).

2.1.1 GDAT Model Input Data

Figure B2 shows the GDAT Graphical User Interface – the entry point of the MATLAB GDAT Model. All the information required for the studies is entered via this Graphical User Interface, i.e. external data files, generating units and their associated dynamic models and cost curves, AGC parameters, etc.

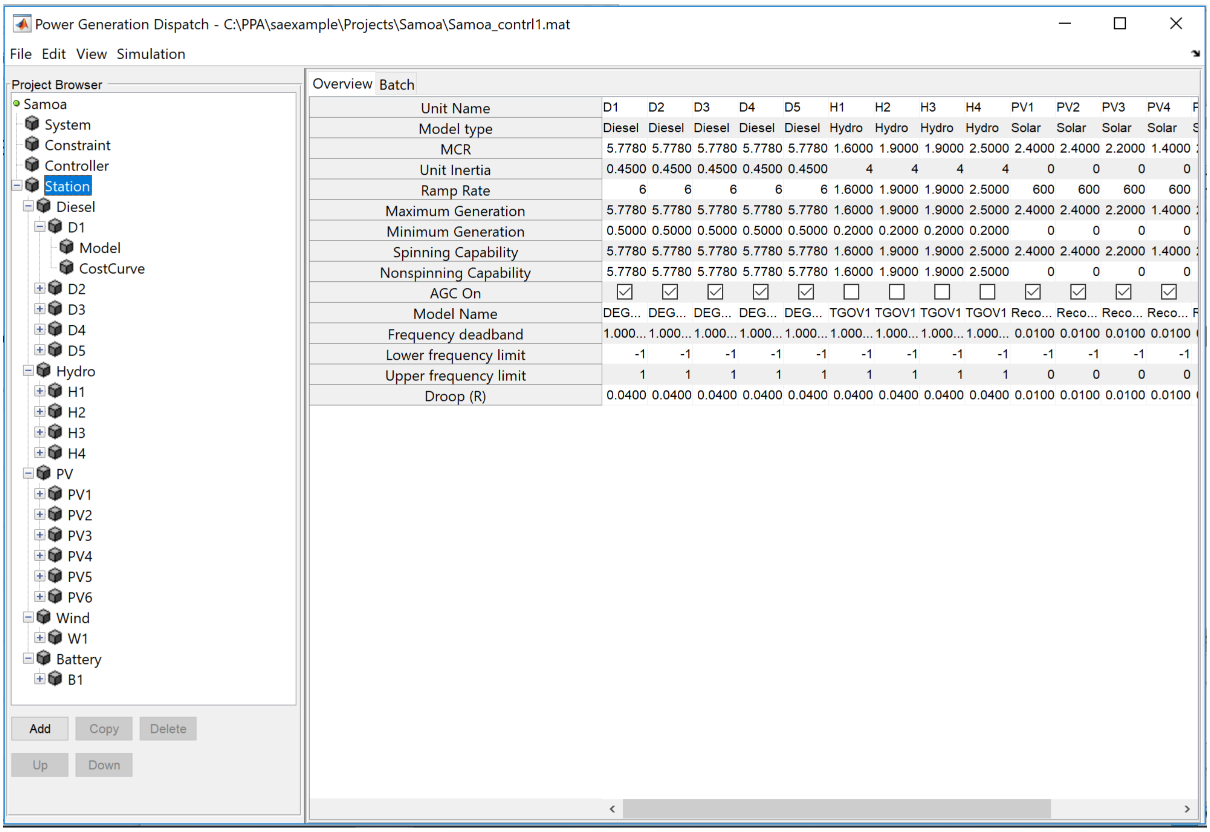


Figure B2: GDAT Model Input Data GUI.

2.1.2 GDAT Model Output (Plotting)

Figure B3 show the GDAT Simulation Results plotter which allows the user to plot simulation results. The interface allows for the plotting of important variables for analysis, viz. electrical power outputs of generating units, system frequency and other variables, e.g. ControlACE, SpinReserve, TotalGen, etc.

Figure B3: GDAT Simulation Results Plotter.

Figure B4 shows, for example, a plot of the Actual Sent Out (MW) for all the units modelled. Figure B5 shows Simulated Frequency (HZ) and Actual Frequency (Hz) plots.

The GDAT Simulation Results interface also has a “Tabulate” button (top right corner) which can be used to automatically generate Excel spreadsheets that compare variables based on the actual and simulated values. For example, the Excel spreadsheet calculates the cost of the original dispatch and shows the difference between the actual dispatch costs and the simulated dispatch costs. This difference is on an hourly and totals basis to enable easy identification of the difference between simulated and actual results. Figure B6 shows an example of the Excel spreadsheet.

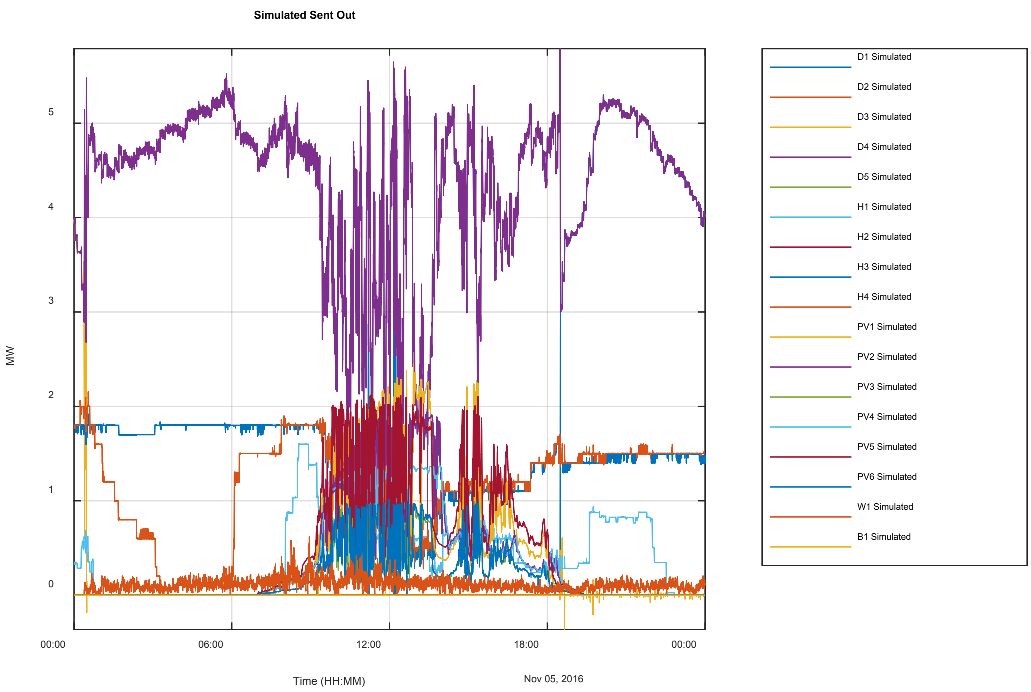


Figure B4: Simulated Sent Out (MW) Plot.

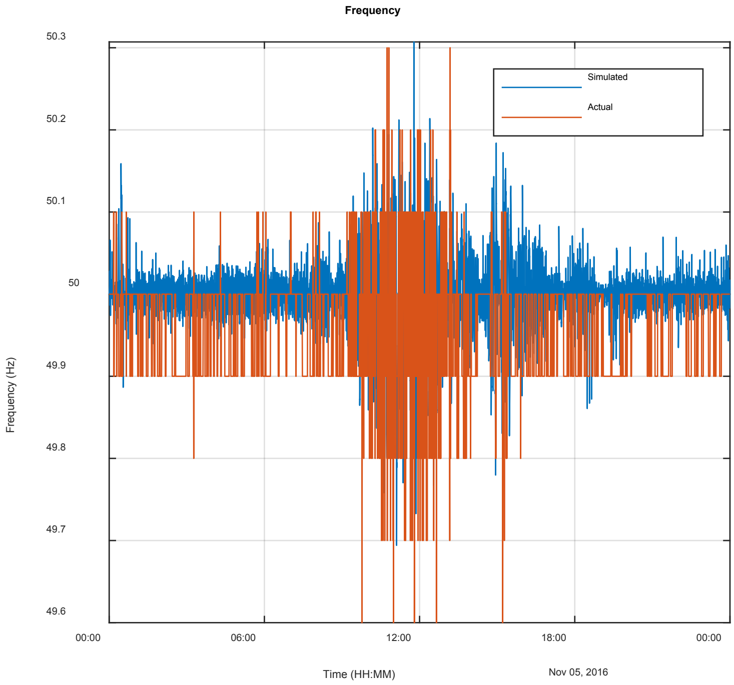
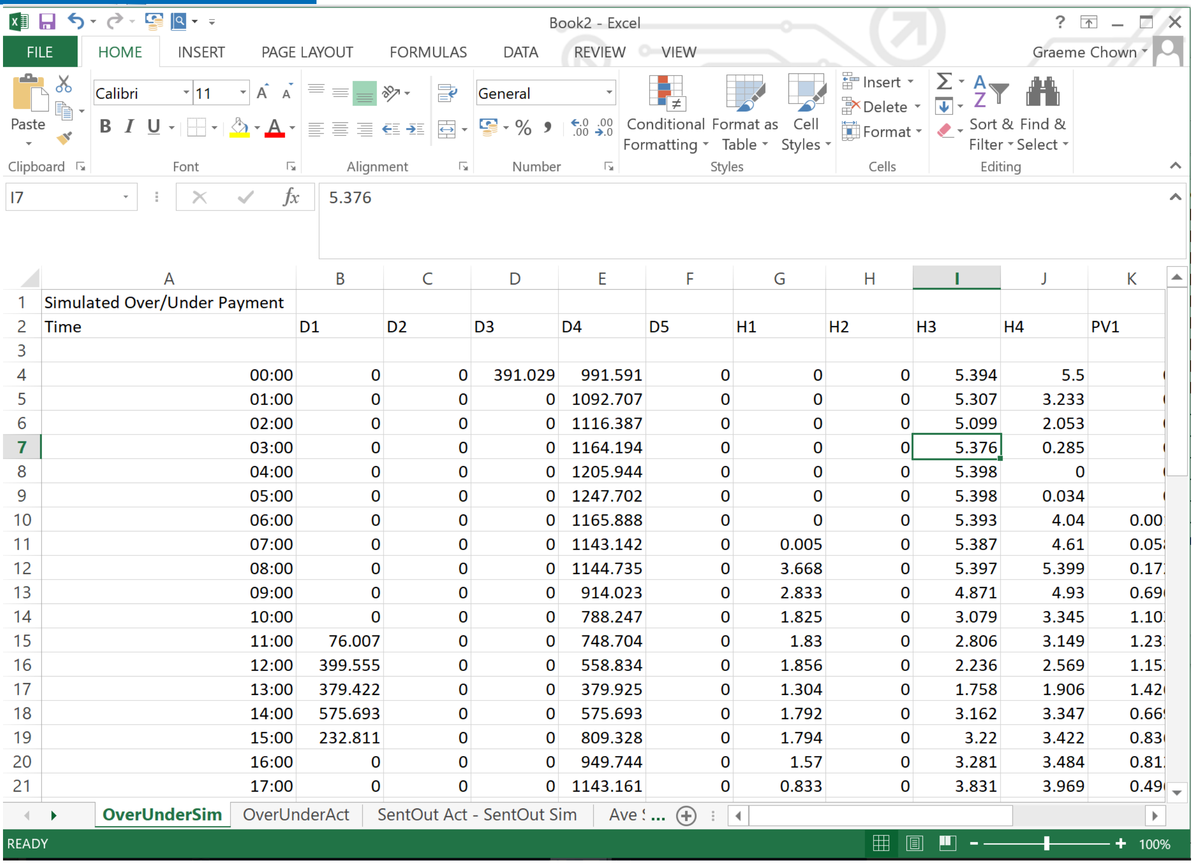


Figure B5: Simulated Frequency (blue) vs. Actual Frequency (orange) Plot.



	A	B	C	D	E	F	G	H	I	J	K
1	Simulated Over/Under Payment										
2	Time	D1	D2	D3	D4	D5	H1	H2	H3	H4	PV1
3											
4	00:00	0	0	391.029	991.591	0	0	0	5.394	5.5	
5	01:00	0	0	0	1092.707	0	0	0	5.307	3.233	
6	02:00	0	0	0	1116.387	0	0	0	5.099	2.053	
7	03:00	0	0	0	1164.194	0	0	0	5.376	0.285	
8	04:00	0	0	0	1205.944	0	0	0	5.398	0	
9	05:00	0	0	0	1247.702	0	0	0	5.398	0.034	
10	06:00	0	0	0	1165.888	0	0	0	5.393	4.04	0.00
11	07:00	0	0	0	1143.142	0	0.005	0	5.387	4.61	0.05
12	08:00	0	0	0	1144.735	0	3.668	0	5.397	5.399	0.17
13	09:00	0	0	0	914.023	0	2.833	0	4.871	4.93	0.69
14	10:00	0	0	0	788.247	0	1.825	0	3.079	3.345	1.10
15	11:00	76.007	0	0	748.704	0	1.83	0	2.806	3.149	1.23
16	12:00	399.555	0	0	558.834	0	1.856	0	2.236	2.569	1.15
17	13:00	379.422	0	0	379.925	0	1.304	0	1.758	1.906	1.42
18	14:00	575.693	0	0	575.693	0	1.792	0	3.162	3.347	0.66
19	15:00	232.811	0	0	809.328	0	1.794	0	3.22	3.422	0.83
20	16:00	0	0	0	949.744	0	1.57	0	3.281	3.484	0.81
21	17:00	0	0	0	1143.161	0	0.833	0	3.831	3.969	0.49

Figure B6: Excel Spreadsheet Example.

2.1.3 GDAT Model: ACE and Financial Controller

This section provides details of the following MATLAB GDAT model: ACE and Financial Controller.

Figure B7 shows a picture of the ACE module which calculates the raw ACE. The raw ACE is the calculation of the MW shortfall or surplus and is used in the Controller to determine the amount of MWs required to control the frequency. The bias used for raw ACE calculation is 10% of the maximum demand per 1 Hz frequency change, this is the international standard for the bias.

The model has the capability to be a part of an interconnection but this is not used for Pacific Islands – this is set by interconnect on/off flag set to false.

The raw ACE is fed into a PID (proportional-integral-derivative) controller (Financial Controller module) and the output of the controller is the control ACE (Figure B1).

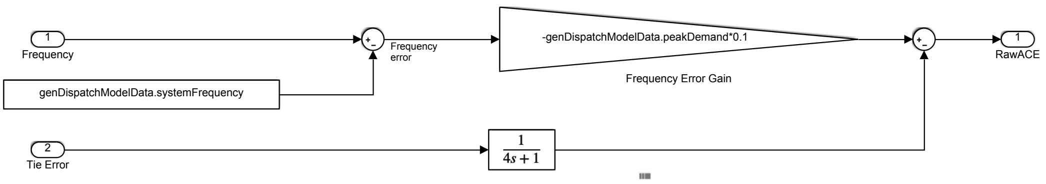


Figure B7: ACE Module.

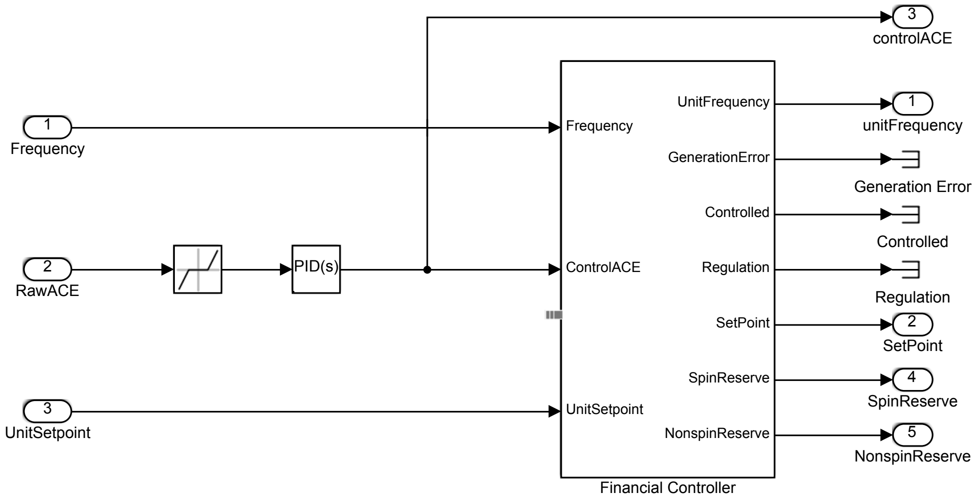


Figure B8: Controller Module.

The Controller (Figure B8) is designed to control the frequency at nominal (50 or 60Hz) by determining a new desired set point for generating units on AGC based on the Financial Controller routine. If the frequency is below nominal the controller will increase unit setpoints and visa-versa if the frequency is higher than nominal the controller will reduce unit setpoints.

The inputs to the Financial Controller (Figure B9) are as follows:

1. Frequency,

2. Control ACE which is from the output of the PID controller,

3. Current MW output (or where the unit is currently),
4. Maximum and minimum MW which determines the range where the unit can be controlled,
5. Unit ramp rate determines how much the unit can move for the period,
6. Unit spin and non spin capability which is the maximum MWs that can be allocated to spinning and non spinning reserve for each unit,
7. Unit AGC on/off which determines whether the unit can be controlled or not,
8. Elbow and price which determines the cost for the unit, and
9. Previous set-point which is where the current unit was controlled on the previous cycle.

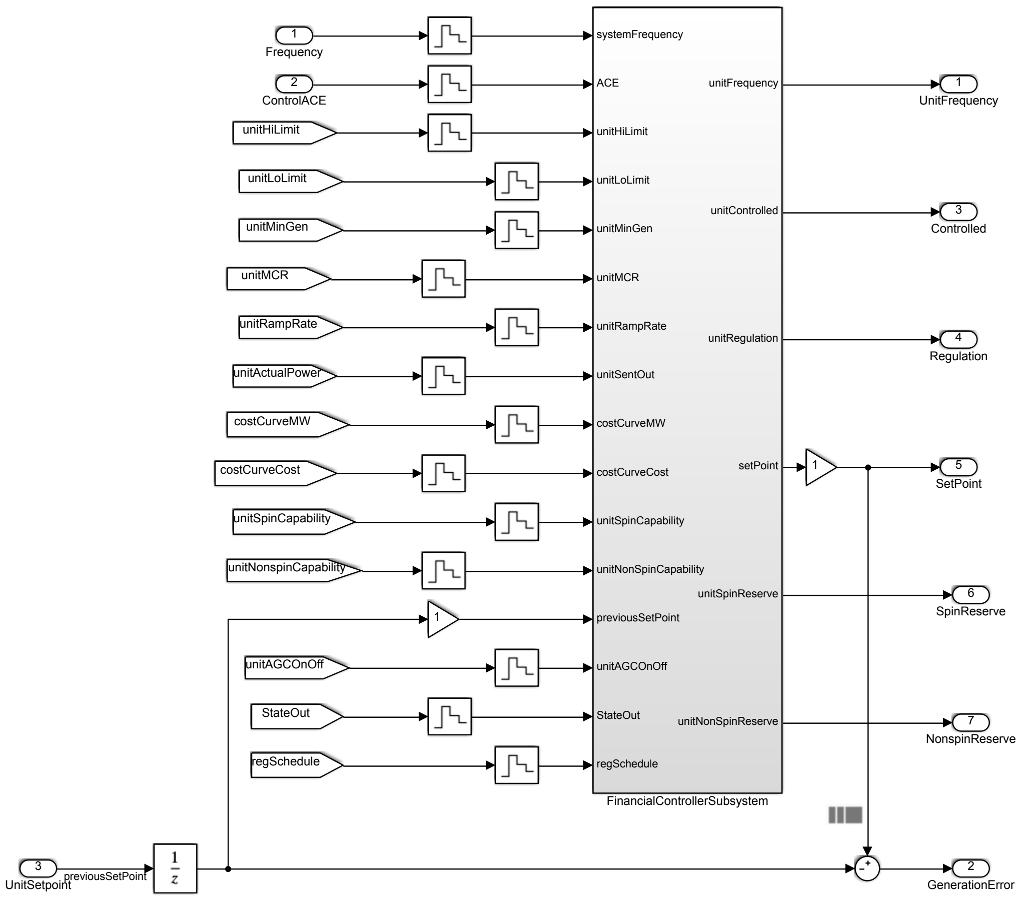


Figure B9: Financial Controller.

The financial controller dynamically calculates the system inertia. A unit is online if it is > min generation limit of the unit. Inertia of each unit is an input parameter into the model. A factor of 0.2 is added to the system inertia to account for induction motors in the system which also contribute to the system inertia.

The units are broken into three categories in the financial controller to ensure best economic dispatch:

- Wind and Solar
- Storage
- Non renewable

The financial controller has two control options, namely controller 1 and controller 2.

<u>Controller 1 set by parameter agcControllerType = 1 in GUI</u>

Controller 1 dispatches all units under AGC at an equal level. This controller is designed to reflect the current Pacific Islands practice of operating units in a group at the same dispatch level. This philosophy maximises security as it keeps an equal percentage level of spinning reserve on each unit.

The controller has the following other features:

1. Dynamic spinning reserve requirement calculated as the minimum spinning reserve requirement plus 30% of renewable power being produced, to ensure sufficient spinning reserve to cater for momentary dips in wind and solar units

2. Reducing wind and solar units if their output is higher than the technical capability of the existing synchronised units. This is calculated as required generation (current plus ACE) > renewable current power maximum output + synchronised units minimum generation level.

3. Pre-allocation to increase wind and solar units below their maximum capacity as determined a dynamic high limit capability limit sent by the wind and solar units and if there is room to move non-renewable units down

4. Charging of battery units set on AGC up to 95% if there is surplus wind and solar units generation. There is a high limit from when charge is 90% = -100% minimum setpoint proportionally down to a charge of

95% == 0% minimum setpoint. This allows 5% for primary frequency control high frequency incidents.

5. Discharging of battery units on AGC down to 20% before utilising diesel units. There is a high limit from when charge is 25% = 100% maximum setpoint proportionally down to a charge of 20% == 0% maximum setpoint. This allows 10% for primary frequency control low frequency incidents as the battery can only be discharged to 10%.

6. Keep primary frequency control only batteries (that is AGC off) above 50% charge by charging them at 5% of high limit

7. Switch off non-renewable and AGC on units if spinning reserve is double the requirement. The remaining non-renewable units must also be able to provide spinning reserve.

8. Switch on non-renewable and AGC on units if spinning reserve drops below target level.

9. A new setpoint is derived for non-renewable and AGC on units based on ACE plus current generation. The setpoint is apportioned proportionally to each units MCR. The amount the setpoint can change is then limited to the unit ramp rate.

Controller 2 set by parameter agcControllerType = 2 in GUI

Controller 2 derives a new setpoint for all units that are on AGC using MATLAB's optimiseCost function.

The following additional feature are put into the optimise function:

1. Spinning reserve requirement

2. Unit high and low limit

3. Unit cost as derived from the cost curve

2.1.4 GDAT Model: Unit Models

The Unit Models module contains all the governor models of all the generating units considered for the studies. The model parameters are in per unit and as a result each MW Demand is divided by the maximum continuous rating to obtain a per unit input into the models (Figure B10). Similarly the frequency is divided by 50.

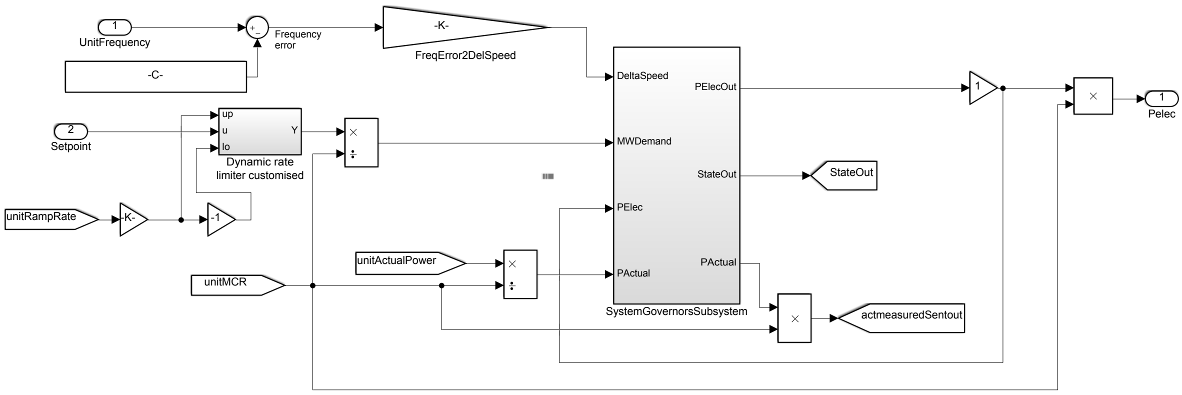


Figure B10: Unit Models Module.

Figure B11 shows the aggregated system governor models. Based on Figure B11 the study considers five kinds of governor models, three of which are standard models, namely DGOV1, HYGOV1 and TGOV1. Two additional models were created to represent wind and solar units (Figure B12) and batteries (Figure B13) respectively.

The recorded data model is used for the replaying nominal of the wind and solar recorded multiplied by wind or solar farm size. This does allow for scaling of the wind and solar unit by just adjusting the MCR. The model also has the facility to time shift the wind and solar data using parameter Time Shift. The recorded data the delta speed / frequency coming into the model and the primary frequency response can be set-up. Typically this will be a reduction in the output for frequencies greater than 0.5 Hz from nominal. The setpoint comes from the financial controller and this is limited to the level recorded on the day.

The battery model has the same primary frequency response and setpoint features as the recorded data. The battery has a charge recorder and the state of the charge is outputted as state. The state of charge is used in the financial controller to determine whether the battery can be charged / discharged. If the battery is fully charged the setpoint in is limited to zero and the same for when fully discharged.

DGOV1 controller has been simplified by removing the two lead lag controllers (PID) (shaded in Figure B14) and making this a simple PI controller. None of the diesel power stations logics and parameters provided had the differential activated so this is consistent with the diesel units performance.

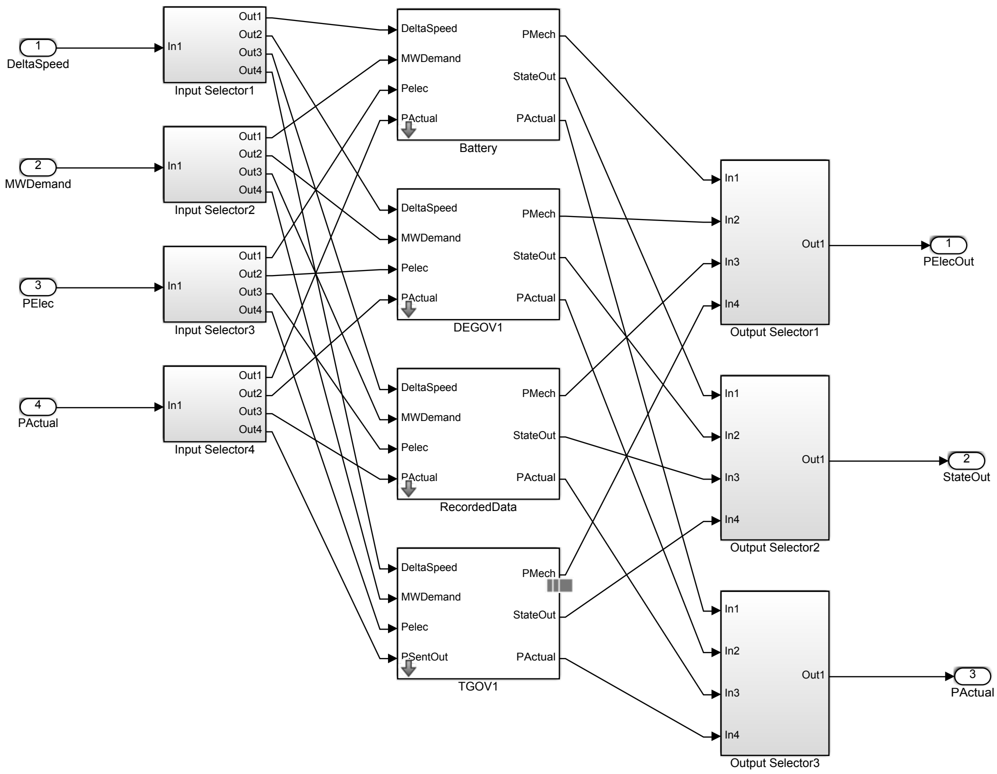


Figure B11: Aggregated System Governor Models.

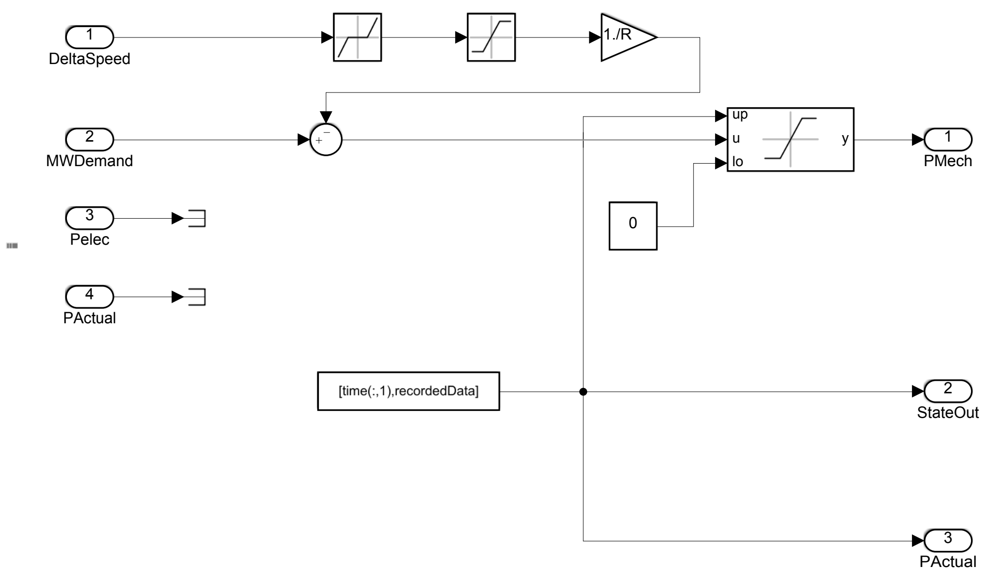


Figure B12: Recorded Data – used for Wind and Solar model.

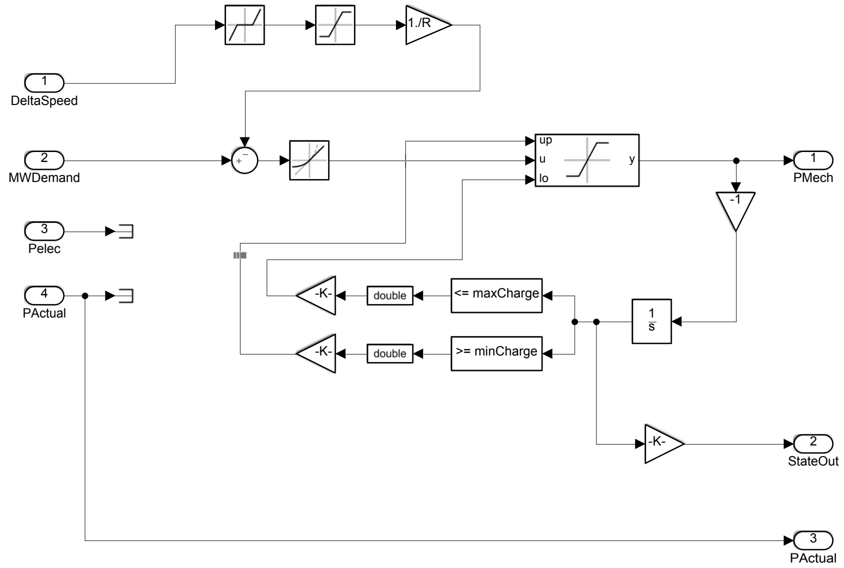


Figure B13: Battery Model.

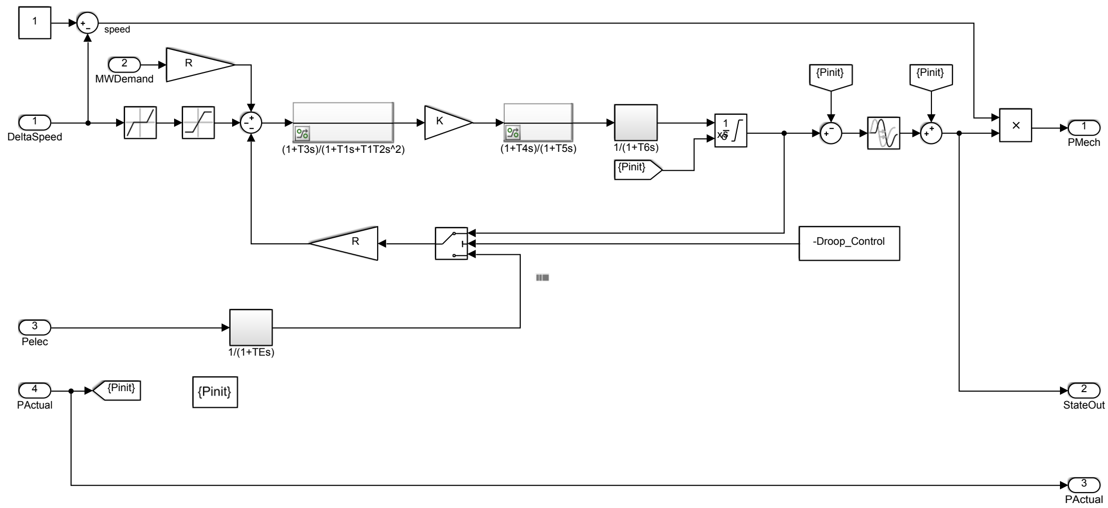


Figure B14 DGOV1 controller with lead lag (PID) controllers deactivated

2.1.5 GDAT Model: Generation Frequency Module

The total load is calculated to be the total generation that was recorded by the SCADA system plus load frequency support when the frequency was not at nominal 50 Hz – Figure B15. The difference between the simulated generation and load determines the new frequency. The simulated frequency error is a function of the network inertia which is dynamically calculated by the units online (see financial controller) and the load frequency support. The frequency error is added to nominal 50 Hz to give the final simulated frequency.

The model is further adapted to be able to operate in an interconnected system and calculate tie line error and interconnection frequency.

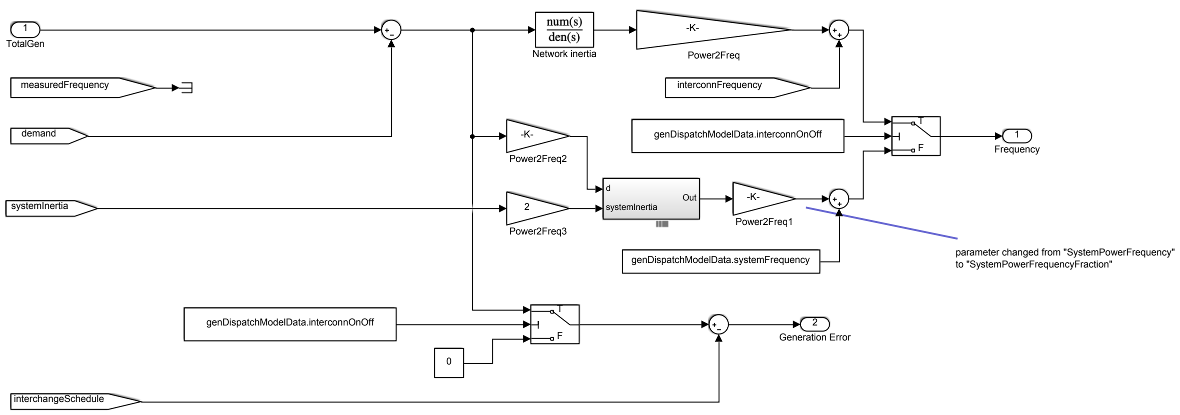


Figure B15: Generation Frequency Model.

Appendix 3 Description of SCADA and EMS

Description of SCADA and Energy Management System (EMS)

1.1 Background: SCADA Systems

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

Main functions of the SCADA are:

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

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

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

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

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

1.2 SCADA Systems Basic activity

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

1.2.1 Data Acquisition

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

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

b. Position or digital values like open/close, active/non-active are collected and sent to the Control Centre as 0 or 1. These values represents either the status of a breaker or an isolator or if an alarm is activated or not.

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

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

This communication is demanded by the control center, which is normally done on a timely basis (scan). In case of alarms, the RTU may initiate the communication with the control center, requesting to establish a communication and to be interrogated.

Size and capacity of an RTU can be adjusted to the needs, from a simple RTU to collect one value to an RTU to collect and operated a big substation, using in each case the appropriate technology. Even Programmable Logic Controller (PLC[1]) have been used in small systems.

1.2.2 Communications Management

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

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

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

The protocols used can be divided in four main groups:

a. For many years, the SCADA suppliers have imposed proprietary protocols, used exclusively in their own installations. This creates a dependency that the supplier of the RTU that should be the same (or compatible) with the SCADA system. This could be avoided by ensuring that an RTU supplier emulates the SCADA protocol with the information that is provided by the supplier. This situation is changing but some of those protocols are still in service due to long usable life of RTUs.

b. Some general-purpose protocols like Modbus or DNP (Distributed Network Protocol) are quite efficient for use in the Electricity Networks control, at different levels. Despite

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

the age of these protocols, they are still in use (Modbus was created at the end of 70's), with good results.

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

d. The Internet Protocol (IP) is the principal communications protocol used establish Internet, which uses source and destination addresses. Its routing function enables internetworking and is useful for connecting the RTUs in the Field and with the Control Centre.

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

1.2.3 Information validation

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

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

Those alarms are registered and presented to the operator.

1.2.4 Alarms subsystem

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

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

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

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

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

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

The historical of alarms cannot be deleted.

1.2.5 Monitoring and trending

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

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

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

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

1.2.6 Supervisory Control

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

Those orders are typically:

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

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

Communications Management

Basic SCADA Functionality

Network Control

1.2.7 Resume of Basic Functionality

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

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

1.3 Added applications

SCADA has been used to control electricity systems. SCADA systems were first implemented in the transmission systems and were commercially available and in the late 60's and early 70's. For the electricity system, SCADA very soon became the most effective control tool to improve system information and control and, at the same time, reduce operative costs.

For these reasons, around the world, SCADA applications have been developed and they form an important part of an efficient and safe control system.

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

1.4 EMS versus DMS

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

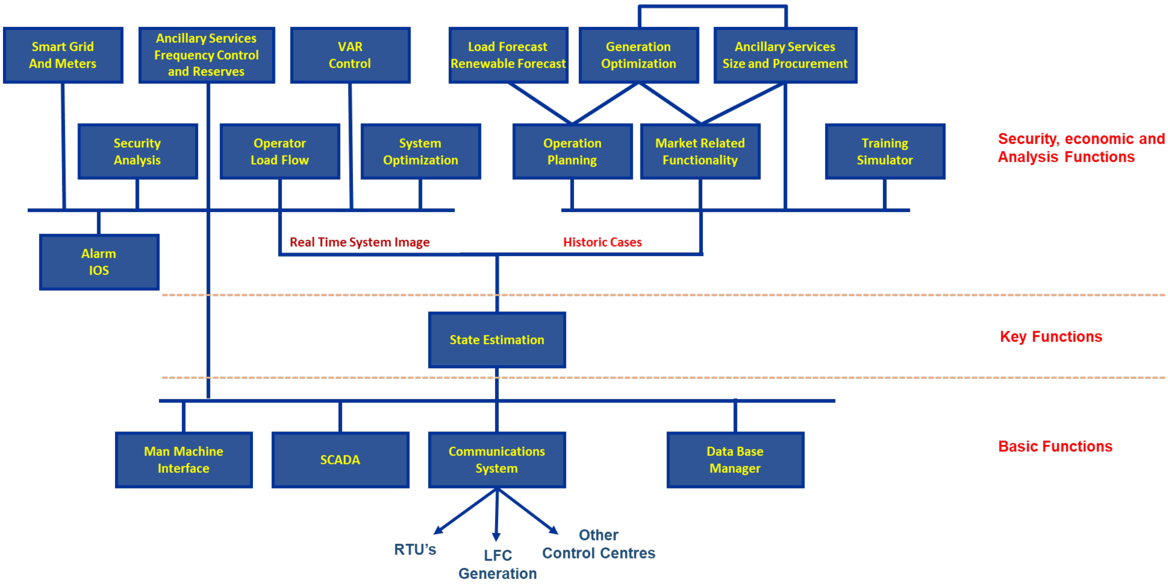
a. **Energy Management System (EMS)** oriented to generation and transmission systems. The main characteristics of those systems are those that are the relatively big size in generation and load, small or medium number of substations and extra high number of controlled elements, with the system fully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

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

1.4.1 EMS System

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

Figure Error! No text of specified style in document.**-1: EMS functionalities supported by the SCADA System**



Briefly, the following applications are oriented to:

1.4.1.1 State Estimation

Normally values are measured with a certain level of error introduced by measurement or when transformed from analogue to digital format. It is acceptable that, in the best of cases, the error will be around 1.0 %. This means that any value in the system would have some element of error. For example, the voltage measurements show that voltage at a node is 220 kV, which means that the value sent to the control centre is 220 kV, but the real value could be any value between 198 and 222 kV. The same error is expected in other readings that are obtained for power and current measurements.

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

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

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

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

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

1.4.1.2 Load Flow

Once the state estimator is well tuned and available, then its solution could be used as input for the load flow studies. It is possible to run the load flow, based on information available in the network model and the information available for the generation and load connected to each node. The model calculates the real voltages and flows on each node or network element at real time or in study mode. In addition to this, the load flow will simulate any new situation, which could have modified generation or load profiles or the network topology. This load flow study results, based on simulations, would show the system conditions such as voltage and power flows.

1.4.1.3 Optimal Load Flow.

In this case, the inputs are the same as in above but in addition, the results will show the optimal values for some control elements values such as reactive generation, shunt devices or tap changes. It could be proposed that these devices are changed, after evaluating the need for change in control and considering the cost of changing the asset. On similar lines, system losses will also have a cost. The control function will display the cost of an optimal set of control elements and the motive would be to reduce losses with a minimum cost. The use of different costs for each action will reflect the system control priorities.

1.4.1.4 Ancillary Services requirements

Two of the most important aspects of system security are:

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

- **Voltage control**, especially with the integration of renewable generation parks has become an important requirement to maintain the power quality. In many parts of the world, the new renewable generation plants have had limited contribution to voltage stability as compared to the conventional units. The voltage control could be achieved by use of modern tools such as shunt devices, VAR systems, SVC and STATCOM units.

1.4.1.5 Security Analysis

The security analysis applications are oriented to verify that the security criteria are fulfilled any time, during operation planning or in real-time. Perhaps the most known application is the Contingency Analysis (CA), which has all the conditions included in the security criteria and these are tested during operation planning and in real-time.

These suite of functions are basic to determine the capability of the system to survive to any contingency included in the security criteria stablished in the grid codes or in the regulation laws.

1.4.1.6 Forecast Applications

Load demand forecast and Renewable Generation forecasts applications normally provide forecasts at park level for wind and solar generation. The forecast is done for longer term, which is used for planning and at a year-to-year level to guarantee the availability of resources.

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

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

1.4.1.7 Generation schedule

Using the load and RE forecasts as inputs, the generation schedule be developed. In the generation schedule, the generation needs are estimated for the day ahead or in Real Time for the near future. The schedule also verifies the needs for controls and the availability on the system for different types of reserves, according to the security constraints.

1.4.1.8 Generation Control

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

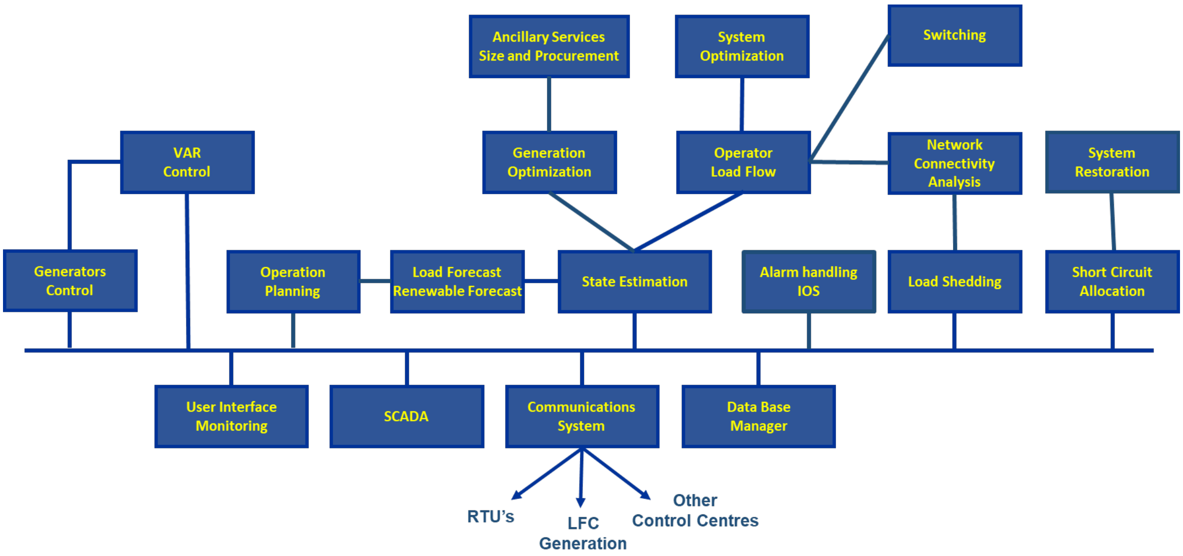
This control philosophy is extended to most large power plants from Nuclear Plants to Coal, Gas or hydro units. It is not a simple application. To control a unit or a power plant, a group of applications are run in a coordinated mode and these allow operators to control a variety of assets, from the high voltage park to any kind of fuel based plants. Those applications facilitate the control of many generating units, which are controlled from a centre located outside of the plant itself, reducing the operating costs considerably.

1.4.2 Distribution Management System (DMS) System

The Distribution Management System is more oriented to manage distribution networks. For radial networks, the applications are completely different than those for the meshed networks.

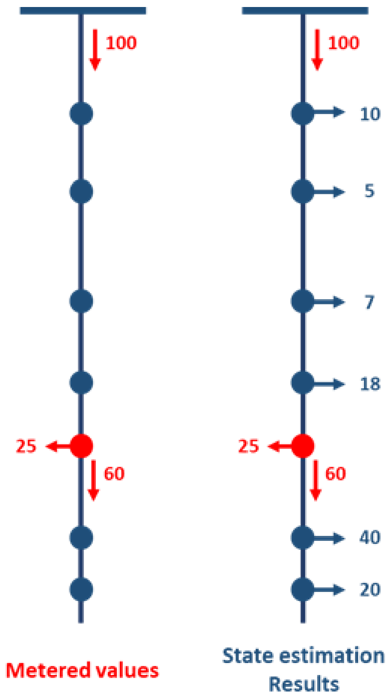
The functionality of applications are similar than in case of Energy Management System (EMS) but the methodology and mathematical approach are quite different.

Figure Error! No text of specified style in document.**-2: Functionality of DMS applications**



The main applications are:

1.4.2.1 State Estimation (SE).



The state estimator is an integral part of the overall monitoring and control systems for transmission networks. It is mainly designed to provide a reliable estimate of the system values. The state estimators could calculate various system variables with high confidence despite the facts that their measurements may be corrupted by noise or could be missing or inaccurate.

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

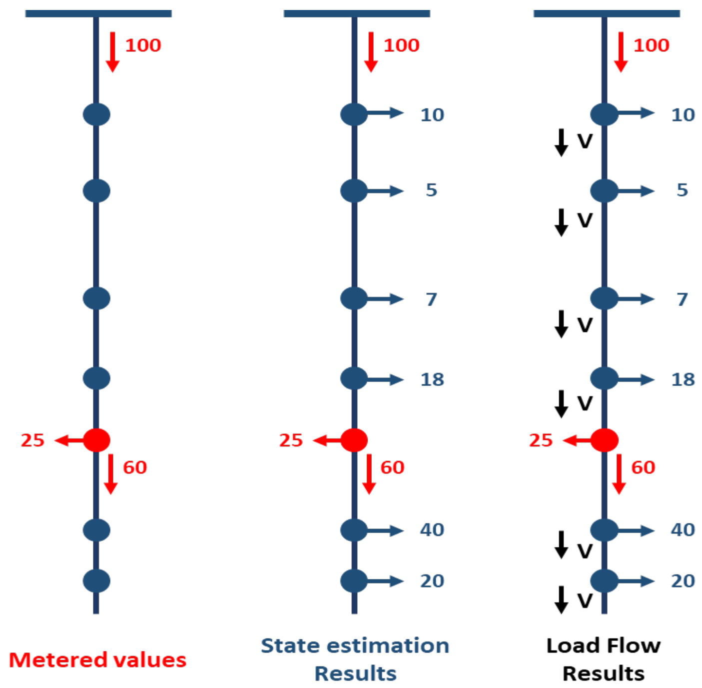
1.4.2.2 Load Flow Applications (LFA).

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

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

For a better understanding of the combined use of those two applications, an example is shown in the figure below. The figure shows a scheme that represents a feeder with only the metered information and a second scheme that uses the State Estimation, which estimates the load in the transformer stations without this information. The third example shows the results obtained after running the load flow, which calculates all flows and voltages. The estimated values will probably to some extent modified by the load flow due to the results of losses calculation in each feeder section. The accuracy of the results will be a function of the accuracy of the State Estimator.

Figure Error! No text of specified style in document.**-3: Example of a State Estimator**



1.4.2.3 Generation Control.

A generator embedded in the distribution networks normally has a power capacity that is compatible with the feeder where it is connected to. The generators embedded in the distribution networks would be significantly smaller than units connected into the transmission grid. These groups will be easy to operate and at the same time support network security, frequency and voltage maintenance. The big control panels filled with push buttons and analogic measures in the past, have now been substituted by digital systems that provide much better capabilities to operate the generator and monitor system values.

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

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

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

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

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

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

1.4.2.4 Network Connectivity Analysis (NCA)

By analysing the network information obtained through the SCADA system, NCA considers the position of all switching elements and assists the operator by illustrating the state of the distribution network, which includes the information for the radial mode, loops and parallels in the network.

1.4.2.5 Switching Schedule & Safety Management.

Control engineers prepare switching schedules to isolate and disconnect a section of a network in which the work has to be done. The Distribution Management System (DMS) validates the possible working schedules based on the results of the network model. When the required section of the network has been isolated, the DMS allows a Permit To Work (PTW) document to be issued. After its cancellation, when the work has been finished, the switching schedule then facilitates restoration of the normal running arrangements.

1.4.2.6 Voltage Control

Voltage could be controlled in the system, using:

- ✓ Reactive power generation or absorption in generators (VAR control)

- ✓ Tap Changers - Modifying the transformer’s ratio, changing taps with temperature variations. In this last case, also known as Load Tap Changing, where the transformer is in service, the number of changes per day is normally limited.

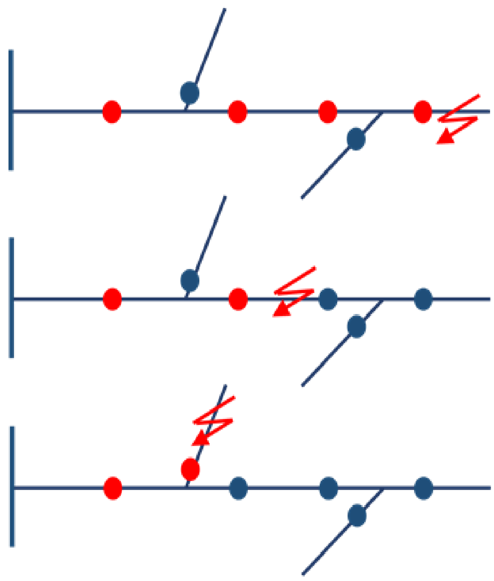
- ✓ Autotransformers: These transformers could have a turns-ratio that is very close to 1.00, which means that the voltage variation is small and these are used only for voltage control at the same voltage level.

- ✓ Use of external control elements like shunt devices (batteries or reactors) or advanced voltage controllers like SVC's or STATCOM's.

Most of those elements can be automated, controlling the voltage in the connection point.

1.4.2.7 Short Circuit Allocation.

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



Short circuit allocation is based on the use of short-circuit current elements in the network that simply detects and communicate the fault details to the control centre.

The following graphic shows its application to determine the short circuit allocation. The blue dots represent the locations with a short circuit pass detector and the red dots represent the locations with elements that detected the passing of the current.

For each location of the short circuit in the network (feeder), there is a different configuration of elements which detects the pass of the short-circuit current and in consequence, the short circuit location itself which will allow the operator to perform actions for restoring the system immediately.

The detectors shall be capable of communicating with the control centre (could be based on a Power-line communication (PLC) or General Packet Radio Services (GRPS) communication systems) or incorporating the signal into an RTU that collects other types of information.

1.4.2.8 Load Shedding Application (LSA)

One of the key aspects of an electric system control is to maintain the equilibrium between load and generation. In order to control the generation to match the demand, operation planning could be done on a day-ahead based or real-time adjustments could be made.

But at times when the demand increases or decreases significantly or at times when key generation units' trip, the balance between supply and demand is lost. The system reacts by modifying the system frequency that must be corrected by increasing (or reducing) the generation in other units. The problem becomes more critical when the generation margins have been exhausted. In this case, the only solution is to reduce the load and this is known as load shedding.

This reduction or Load Shedding could be done manually or could be automated using a Load Shedding Application (LSA). This is the most common method is to reject some load from the system when the frequency reaches unacceptable levels. The load shedding with the double objective to protect the generators and to stabilize the network, which makes the restoration easy and faster.

The load shedding is normally “triggered” by a protection system that scans the frequency or the frequency variations. Once the frequency is recorded lower than acceptable values, the protection system trips some feeders to reduce the load reduction. In a system normally there are a few frequency levels defined to reduce the load (between 3 and 5) and at each frequency level, a certain amount of load is rejected (from 15% to 25%).

1.4.2.9 Fault Management & System Restoration (FMSR).

Some incidents in the network are, because of the way they are caused, impossible to avoid or reduce. For example, it is difficult to avoid the damage that could be caused by storms or other weather conditions but the quality of service could be improved by ensuring faster restorations.

Fault Management & System Restoration (FMSR) applications tend to reduce the restoration time by automating a part of the restoration process. This functionality requires an excellent electric model and intensive information compilation. Is especially useful for those utilities that have by law, for safety purposes, limited the time to test lines or cables (some countries have this limitation in 1 minute). Once the allowed time has elapsed, in order to test a cable, the operators have to be physically present at the fault location, to verify there is no danger to the public during the test.

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

1.4.2.10 Distribution Load Forecasting (DLF)

As mentioned in the previous section, one of the main aspects is to ensure the balance between generation and load. The system load includes the client’s consumption and the system’s technical and nontechnical losses.

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

The traditional energy balance equation is:

DG + RE + IB = LO + SL

Where: DG is the Conventional Dispatchable Generation

LO is the total Load (Estimated)

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

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

RE is the Renewable Generation (Forecasted with error)

ERE is the Embedded Renewable Generation (Estimated)

The same balance equation could be written as:

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

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

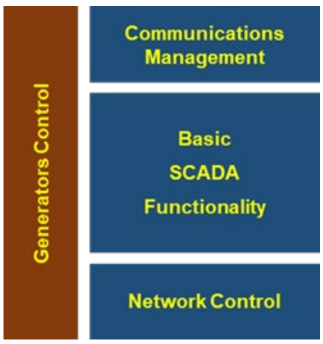
- ✓ Load + Losses forecast, this will require a cleaned historic load data base.
- ✓ Renewable or non-dispatchable generation, which could be estimated globally on the island or independently for solar or wind parks.

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

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

1.4.2.11 Load Balancing via Feeder Reconfiguration (LBFR)

The Load Balancing via Feeder Reconfiguration involves automating the decision process to decide the network configuration from the network topology, deciding the status of all embedded isolators or breakers (open or close) which for big systems may represent thousands of different configurations. The application will develop an optimal solution to manage the network.



1.4.3 Requirements of the Distributions Systems

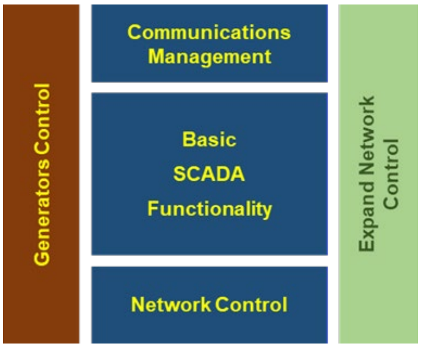
For the Distribution Systems such as the one in Chuuk or as seen in the other islands, the following three requirements have been identified:

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

1.4.3.1 Network Control and Monitoring

For network control and monitoring:

- SCADA systems normally provides enough information for system monitoring and control
- The user interface should be simple and capable to show the network at different levels depending on the real-time requirements
- The options for zoom, panning and clustering should be available in the system.
- The capacity for supervisory control shall be protected in a two steps operation (i.e. selection and execution)



1.4.3.2 Quality Assurance

Maintaining a good quality of service is essential for any distribution system. This could be considered under two aspects:

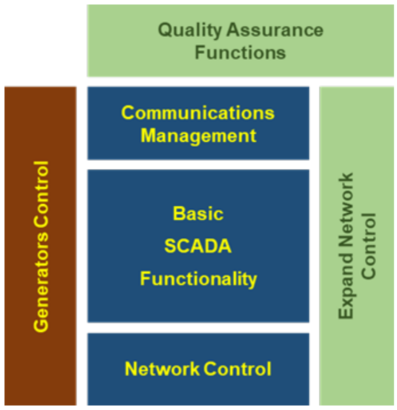
1. **Service Continuity**: The first challenge is to maintain the service under different situations and circumstances.

   The continuity of services could be affected by external incidents into the network, such as; lightning, storms, high-speed winds, car accidents and vegetation. There are only limited ways to avoid the existence of those incidents, but they can be mitigated using more secure network elements.

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

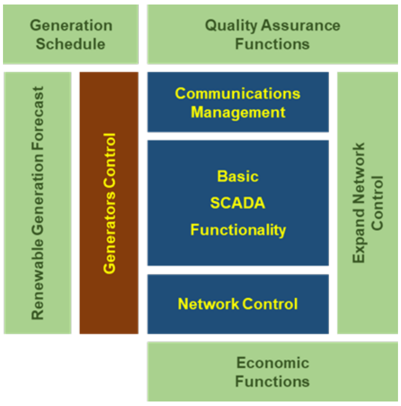
2. **Quality of the supply**: The quality of supply is maintained by managing the main parameters such as the frequency, voltage and harmonics.

Normally external factors do not affect the quality aspects. Operation planning process, which is normally done for a day in advance, considers the resources existing or made available for operation. Some applications are available to control those aspects, together with the reserves capacity and allocation, which does not directly impact the quality, but in case of other incidents, such capacity will help to limit the extent and magnitude of the incident and eventually reduce the restoration time.

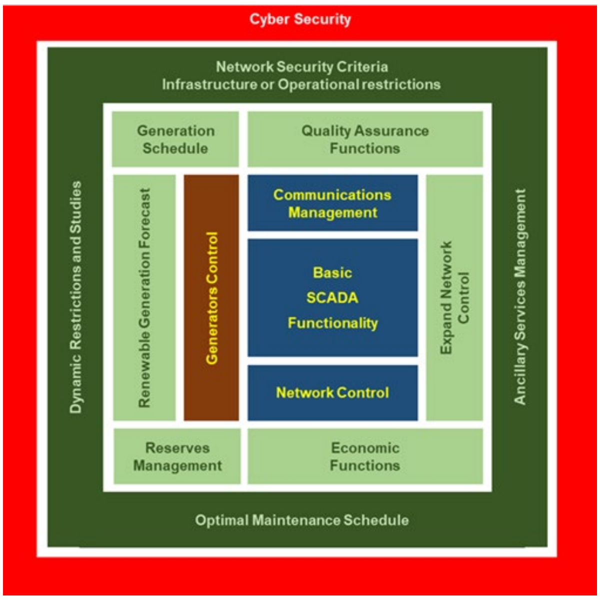


1.4.3.3 System Economic Optimization

Apart from ensuring continuity of supply and quality of power, it is important that the network is managed in the most economical way. Firstly, to run the power system in the most economical way, the generation schedule should be optimised. Once the generation is optimised, the network operator's main aspect is to reduce system losses. The SCADA application provides tools to control network losses and ensures optimal switching in the network to reduce feeder losses.



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



1.4.4 Recommendation between EMS and DMS

Both are systems have powerful tools, but considering:

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

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

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

1.4.5 Recommendation between EMS and DMS

Both are systems have powerful tools, but considering:

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

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

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

Ricardo
Energy & Environment

The Gemini Building
Fermi Avenue
Harwell
Didcot
Oxfordshire
OX11 0QR
United Kingdom

t: +44 (0)1235 753000
e: enquiry@ricardo.com

ee.ricardo.com