Final Report for YAP including Task 6

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

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

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Executive summary

Task 1: Assessment of energy storage applications in power utilities

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. The assessment and the benchmarking activity consider technical as well as economic and financial aspects of proposed solutions and configurations.

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. 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, Flywheels, Synchronous Condensers and Batteries.

Variable Renewable Energy (VRE) Sources can assist with frequency control through their output being remotely controlled when VRE plants are backed off from their full instantaneous maximum capacity via a remote setpoint, they can also provide primary frequency response to high frequencies and their ramp rate can be limited. Fly Wheels can provide primary frequency control. Various islands off the coast of Australia have installed flywheels as a form of energy storage to complement wind and solar PV systems. The costs for Fly Wheels is US$ 2,600 / kW installed. The most feasible current battery technologies are Sodium Sulphur (NaS) and Lithium-ion (Li-ion). 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. The capital costs for Li-ion batteries is US$375 / kWh. The cost of inverter is estimated to be US$500 / kW.

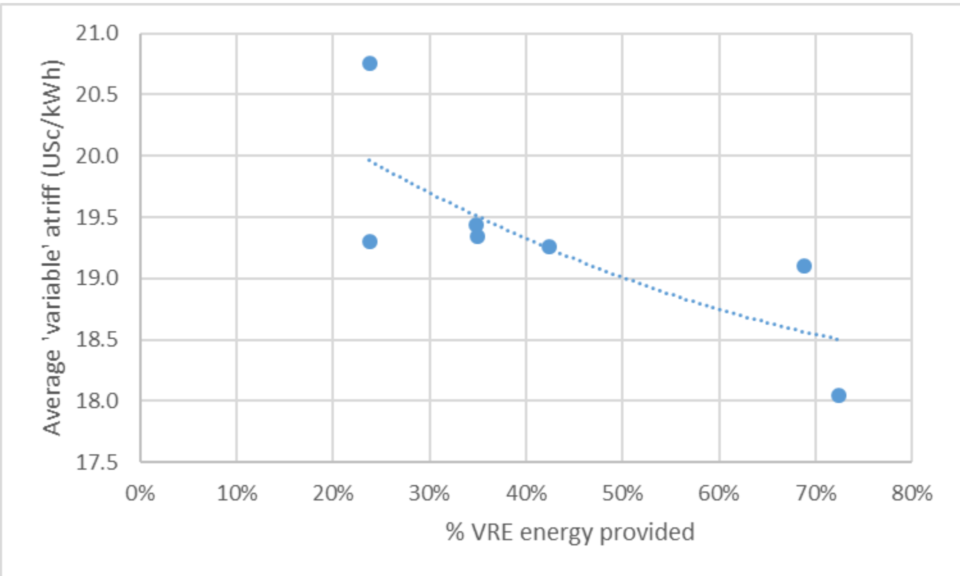
The Generation Dispatch Analysis Tool was used to determine the techno-economic impact of various scenarios for YAP.

The studies performed were installing a 0.5 MW / 3 MWh battery to improve primary frequency control. Then to increasing PV 2 MW with assistance of 0.5 MW / 3 MWh on AGC as proposed by FSM Energy Master Plan Study, April 2018. The final study is 4MW of PV and with assistance of 2 MW / 10 MWh battery on AGC also as proposed by FSM Energy Master Plan Study, April 2018

The studies show that the system is currently experiencing quite high frequency variations due to the current installed wind and PV variations and installing a 0.5 MW / 3 MWh battery will assist with frequency control and should be done as the first step.

To increase to 1 -2 MW of PV the inverter size on the battery should be increased to 1 MW.

There is steady decline in the variable’ component of the tariff from 20 to 18.5 USc/ kWh as VRE is increased from 20% of energy to 70% of energy provided by VRE. The ‘variable’ component of the tariff which includes diesel fuel, additional PV and additional battery costs as shown in the figure below.



The studies were performed with diesel unit D3 as the last unit on at a minimum generation level of 250 kW. Diesel units D1 and D2 have a minimum level of 500 kW and this results in significant spilling of wind and solar power and increases the overall ‘variable’ component of the tariff.

The simulations show that installing 4 MW of PV with 2 MW / 10 MWh of battery with the current demand will decrease the ‘variable’ component of the tariff which includes diesel fuel, additional PV and additional battery costs by 6% if diesel units are allowed to go off. This case needs further studying to determine what is required to have all diesel units off. It is recommended that these studies are repeated with the new demand, PV & battery costs in a few years’ time to determine the next optimal step.

Task 2: Assessment of the needs for Supervisory control and data acquisition (SCADA) and Energy Management System (EMS)

YAP has a SCADA system provided by VERGNET which has network visibility of network backbone. The SCADA system does the generation control including control of VERGNET wind turbines, PV plants and determines spinning reserve for diesel generation.

The next proposed stage is the extension of the SCADA visibility to include the reclosers on the MV feeders and deploy some DMS functions including load flow, short circuit analysis, distribution load forecasting and emergency / block load shedding application. 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. A cost estimate for such an upgrade is provided in the report.

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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 Counties" project.

The assignment consists for YAP of two tasks and each section of this report corresponds to a specific task.

The first 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.

The second 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: Assessment of energy storage applications in power utilities

2.1 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. The assessment and the benchmarking activity considers technical as well as economic and financial aspects of proposed solutions and configurations.

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.

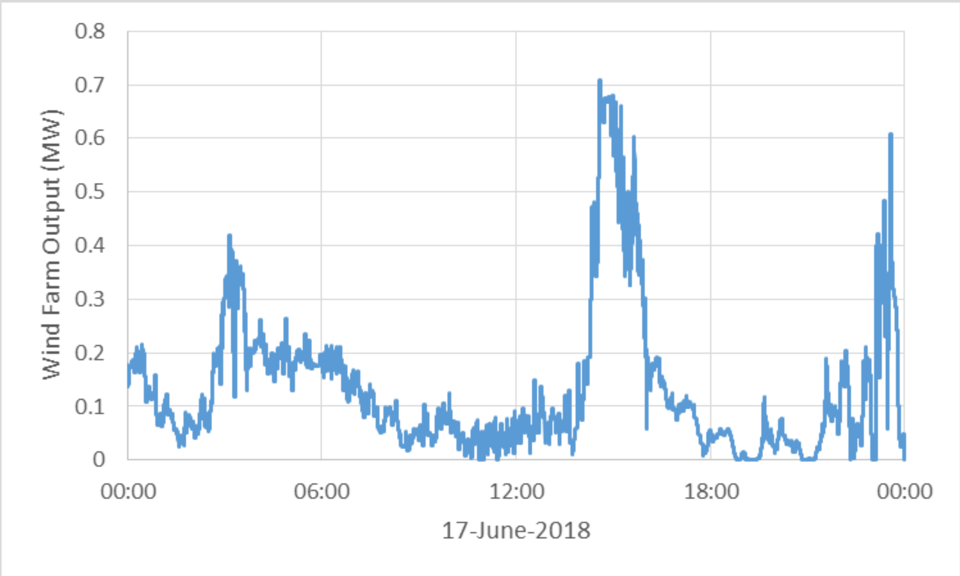
Fast frequency response within seconds or even fractions of a second can also be obtained from non-traditional sources including lithium-ion batteries, flywheels, and demand-response with thermal storage. Each of these sources can react to restore the balance of power but each has its limitations. Batteries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

2.1.1 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 2-1 shows the intermittent output from a wind turbine measured every second over the course of a day at YAP.

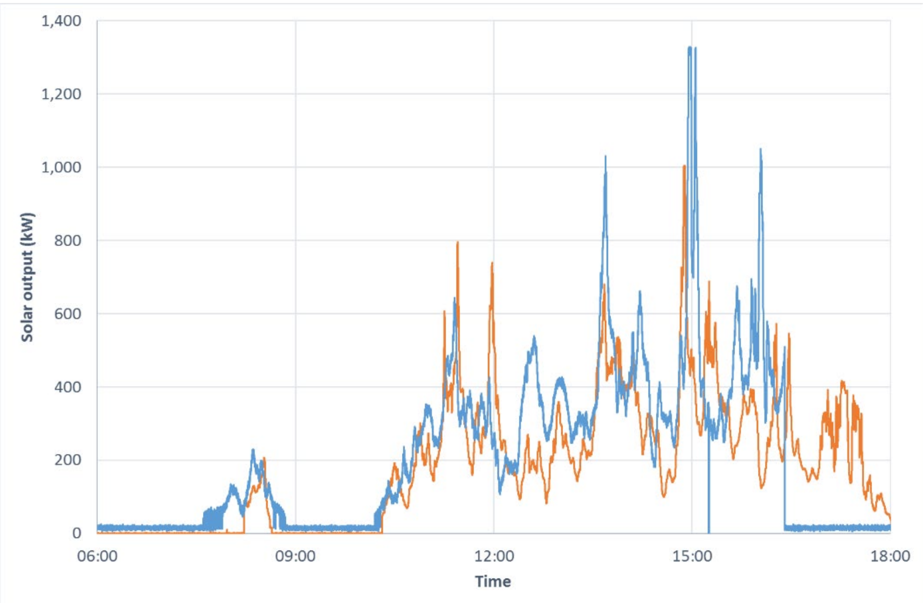
Figure 2-1. Wind power for recorded on 17 June 2018 at YAP



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.

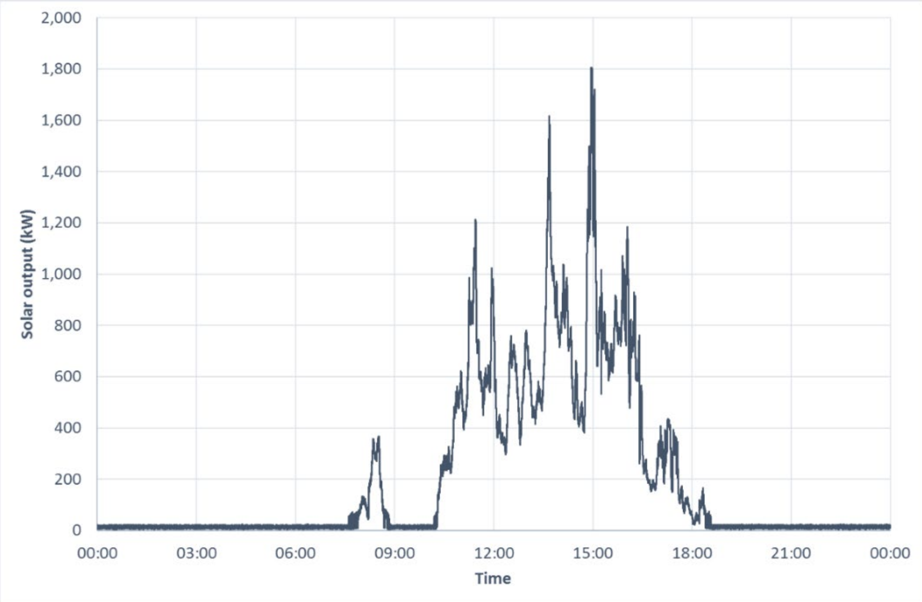
Figure 2-2 shows the individual outputs (measured at one second intervals) from two solar PV plants that are approximately 1 km apart.

Figure 2-2. 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 2-3) 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 2-3. Combined output of two solar plants 1 km apart (Source: Project confidential).



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

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

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

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

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

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

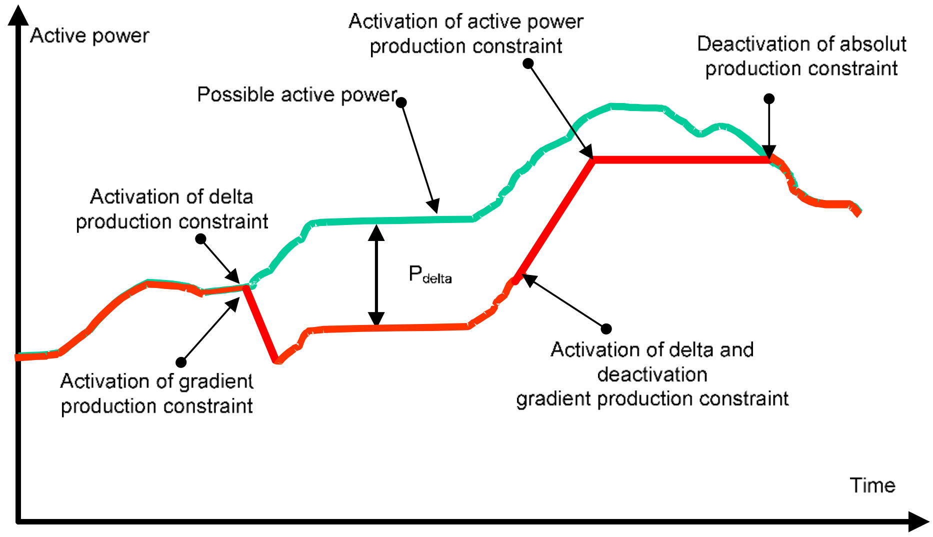
At present, a number of non-traditional sources are commercially available for frequency control/support and these sources include the use of Variable Renewable Energy (VRE) Sources, Fly-wheels, Synchronous Condensers and Batteries. More details of each of these resources and associated costs are as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

2.1.2 VRE enhanced frequency control provision and calculation of costs

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

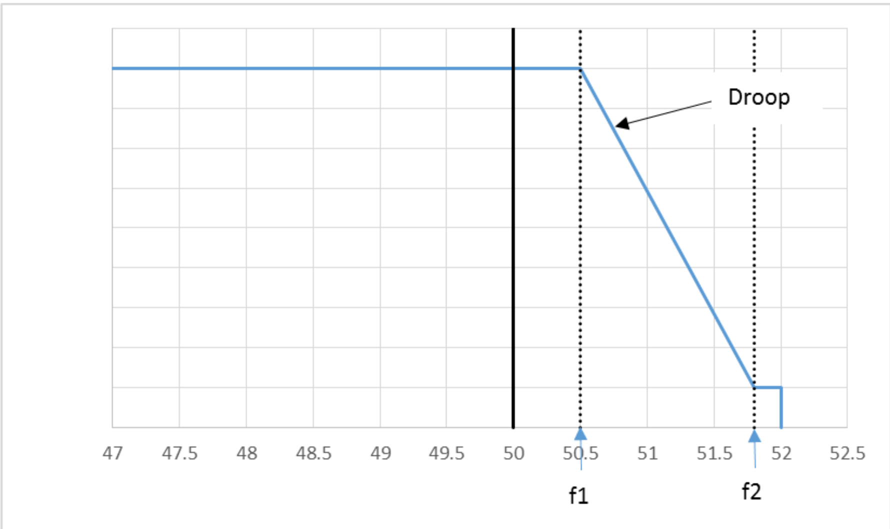
Option 1: The VRE plants are backed off from their full instantaneous maximum capacity, i.e. their outputs are limited. This is technically possible if the VRE plant control system can accept a set point from a central control system or a control philosophy is adopted in which the inverter is kept at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



Option 2: <u>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.

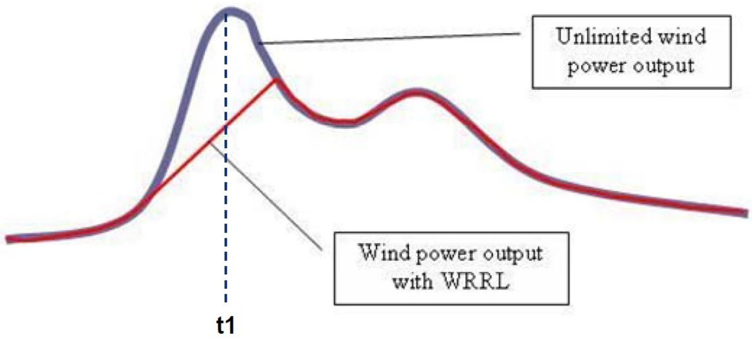
Figure 2-5 Typical VRE high frequency response only



Option 3: <u>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. 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 2-6 Wind power output with wind ramp rate limit (WRRL)1



2.1.3 Fly Wheel and calculation of costs

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

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

Beacon Power has a demonstration plant in Hazle, PA, USA which consists of 200 flywheels each with a max power rating of 100 kW, 25 KWh, as shown in Figure 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.

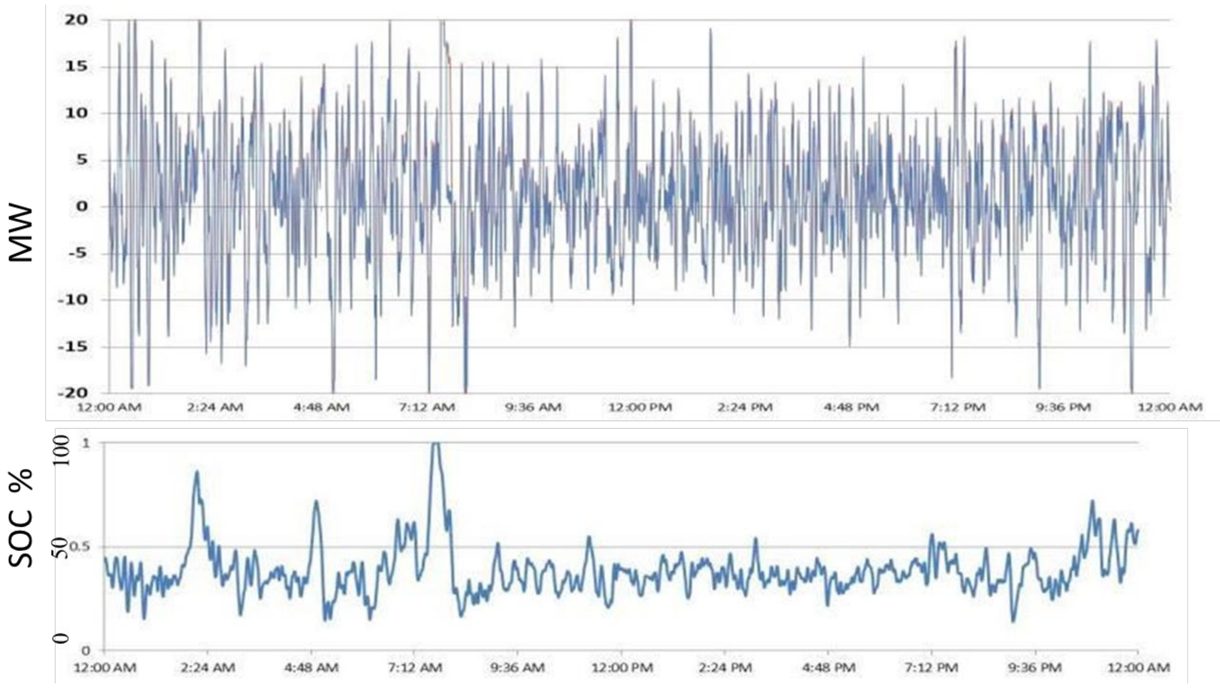
Various islands off the coast of Australia have installed flywheels as a form of energy storage to complement wind and solar PV systems. For example, the Flinders Island Hybrid Energy Hub features a single 900 kW wind turbine and 200 kW solar array. The storage systems include a 750 kW/300 kWh battery 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 2-7 Beacon Power installation in Hazle, PA, USA flywheel performance and state of charge (SOC)



2.1.4 Synchronous Condensers and calculation of costs

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

For Ireland, DNV KEMA notes that the conversion of non-profitable or deactivated power station is currently seen as the most cost-effective option for applying synchronous condensers[4]. Making an accurate cost calculation in general is not possible however, because depending on the existing installation the project will differ from unit to unit. Investments are relatively low when most of the existing infrastructure can be utilised (e.g. Step-up transformer, network infrastructures, buildings, auxiliary equipment and machinery, substations, etc.). In addition, the excitation and control and excitation itself may be changed, depending on the specific machine. The costs shown are therefore only a very rough indication.

General specifications:

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

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

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

2.1.5 Batteries and calculation of costs

The most feasible current battery technologies are Sodium Sulphur (NaS) and Lithium-ion (Li-ion) [5]. The latter has a far smaller power to energy ratio and therefore can be used for frequency response. Li-ion is thus a cheaper alternative as opposed to NaS regarding frequency response services. For peak shaving, however, and ultimately energy storage, NaS batteries are considered to be the better technology at the moment, having a power to energy ratio of approximately 1:8.

The proposed batteries have the following general characteristics:

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

The capital costs for Li-ion batteries is US$750 / kWh[6] and for NaS US$2,200 /kWh[7]. The cost of inverter is estimated to be US$1,000 / kW[8].

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

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

The estimated capital cost for batteries for YAP of 0.5 MW with 3 MWh is $ 0.25 m for inverters and $1.125 m for batteries a total of $1,377,000. For a ten year life time of batteries and inverter, with a 2% interest on debt and fixed O&M of US$7.5 / kW[11], the annualised cost is $157,047 as shown by annuity calculator below:

Annuity Payout Calculator

Installed Capacity	500	kW
	0.5	MW
Capital Expenditure	$ 1,377,000	USD
	$ 1	m USD
Fixed Opex	$ 3,750	USD/year
Variable Opex	$ -	USD/hour
Energy Availability	99%	%
	-	USD/year
Life of the Plant	10	Years
Interest on Debt	0%	%
Interest on Equity	2%	%
Debt to Equity Ratio	0	%
WACC	2.00%	

Annual Payments		
Capital Payment	$ 153,297	USD
Fixed Opex	$ 3,750	USD
Variable Opex	$ -	USD
Total	$ 157,047	USD

Inputs in yellow

The estimated capital cost for batteries for YAP of 2 MW inverter and with 10 MWh of batteries is $4,760,000 with an annualised cost is $544,914 as shown by annuity payment calculator below:

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

Annuity Payout Calculator

Installed Capacity	2000	kW
	2	MW

Capital Expenditure	$ 4,760,000	USD
	$ 5	m USD

Fixed Opex	$ 15,000	USD/year

Variable Opex	$ -	USD/hour
Energy Availability	99%	%
	-	USD/year

Life of the Plant	10	Years

Interest on Debt	0%	%
Interest on Equity	2%	%
Debt to Equity Ratio	0	%
WACC	2.00%	

Annual Payments		
Capital Payment	$ 529,914	USD
Fixed Opex	$ 15,000	USD
Variable Opex	$ -	USD
Total	$ 544,914	USD

Inputs in yellow

2.2 Generation Dispatch Analysis Tool (GDAT)

2.2.1 Introduction to GDAT

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

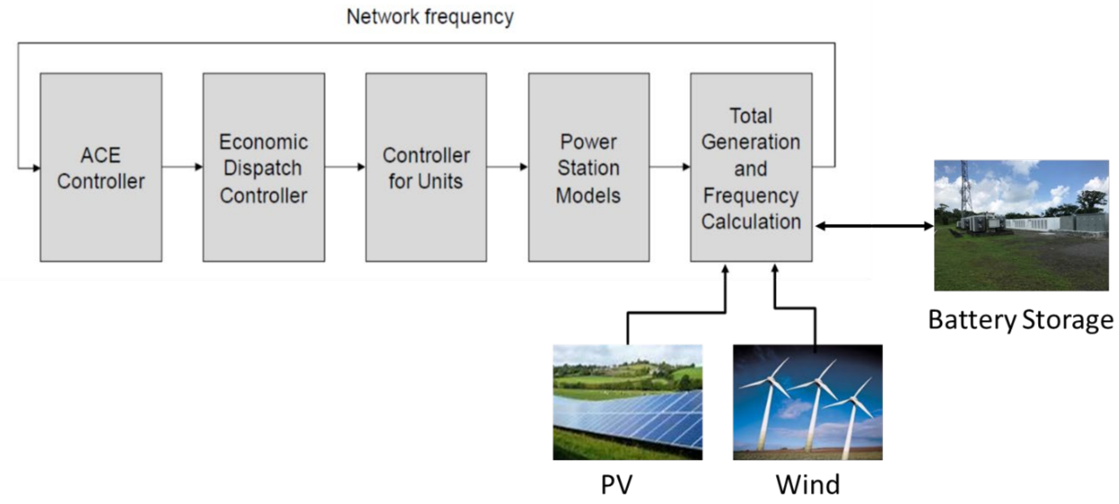
The Generation Dispatch Analysis Tool is used for four main purposes

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

The Generation Dispatch Analysis Tool was developed in 1998 for the optimisation of Automatic Generation Control settings for improved secondary frequency reserve, economic dispatch and interchange power control. From 2007 the tool has been refined for intermittent resources management and used for minute to minute wind farm integration studies in Mauritius and small island systems. The Generation Dispatch Analysis Tool has also been used for system operation studies and system operator audits in South Africa, Tanzania, Thailand and Abu Dhabi. Each of these systems are also analysing the impact of future renewable energy plants on minute to minute dispatch, as shown in Figure 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.

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

Figure 2-8 ***Generation Dispatch Analysis Tool with wind and solar inputs added***



The studies undertaken 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 from the data provided for the island and typical parameters for the power plants. Additional constraints including spinning reserve, storage capability are also included. For YAP, 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.

2.2.2 Input data to GDAT for YAP studies

The models developed for YAP are based on 1 -2 second data records received for June 2018. The real time wind and PV data is the total each of the categories and therefore the model uses 1 wind farm and 1 PV power plant, 2 PV plants are provided for future studies. The Solar PV is then scaled according to the FSM master plan of 2018[12].

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.

[12] Energy Master Plans for the Federated States of Micronesia Final Report (Appendices), April 2018

Table 2-1: Generation and GDAT name for Generation Plants

Name	Capacity (kW)	Type	GDAT name
CAT G1	1650	Cat Diesel	D1
CAT G2	1650	Cat Diesel	D2
CAT G3	830	Cat Diesel	D3
W1	825	Wind	W1
PV1	220	PV	PV1
PV2	20	PV	PV2

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

Table 2-2: YAP generation parameters

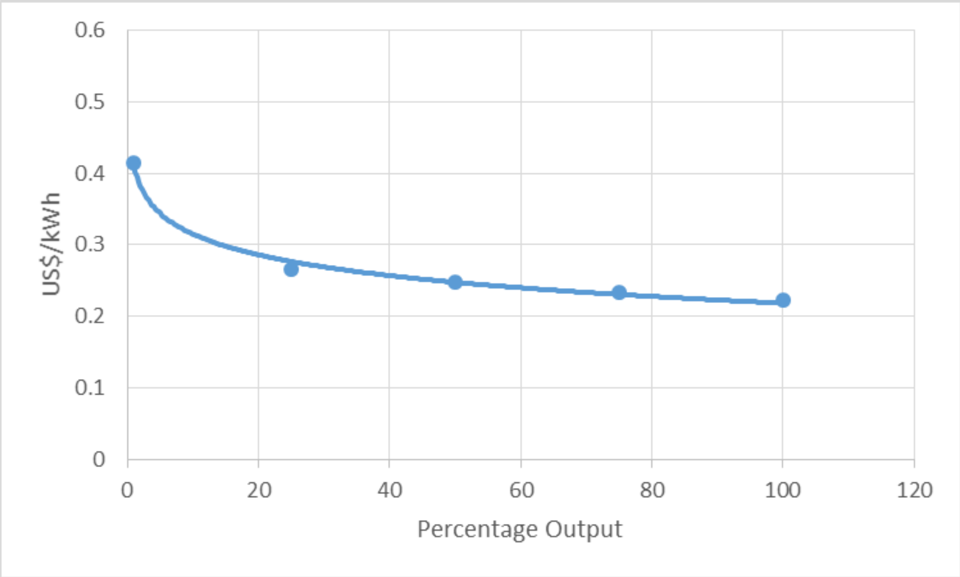
Overview Batch

Unit Name	D1	D2	D3	W1	PV1	PV2	B1
Model type	Diesel	Diesel	Diesel	Wind	Solar	Solar	Battery
MCR	1.6500	1.6500	0.8300	0.8250	0.0200	0.0200	0.5000
Unit Inertia	0.4500	0.4500	0.4500	0	0	0	0
Ramp Rate	1.6500	1.6500	0.8300	60	30	30	10
Maximum Generation	1.6500	1.6500	0.8300	0.8250	1	1	0.5000
Minimum Generation	0.5000	0.5000	0.2500	0	0	0	0
Spinning Capability	1.6500	1.6500	0.8300	0.8250	1	1	0.5000
Nonspinning Capability	1.6500	1.6500	0.8300	0.8250	1	1	0.5000
AGC On	☑	☑	☑	☑	☑	☑	☐
Model Name	DEGOV1	DEGOV1	DEGOV1	RecordedData	RecordedData	RecordedData	Battery
Frequency deadband	1.0000e-03	1.0000e-03	1.0000e-03	1	1	1	1
Lower frequency limit	-1	-1	-1	-1	-1	-1	-1
Upper frequency limit	1	1	1	0	0	0	1
Droop (R)	0.0800	0.0800	0.0800	0.0400	0.0400	0.0400	1.0000e-03

The fuel cost curve that plots power against US$/kWh for CAT units, as shown in Figure 2-9 below, is based on diesel generator's design performance[13]. The cost curve was drawn for a fuel cost of US$ 0.83 per litre[14].

[13] Genset spec sheet – C23.pdf and Genset spec sheet – 3516C 1650kW.pdf
[14] Spreadsheet provided by YAP - Expenses & Sales.xlsx

Figure 2-9 CAT diesel units cost curve



The key parameters for the AGC controller are shown in Figure 2-10 below, for the purpose of the analysis, the demand is assumed to be the same as generation. The demand was calculated by summing the generation. The other parameters selected are described in the appendix. For YAP the simulation is run every second for a day.

Figure 2-10 GDAT controller parameters

Sample Time	4
Frequency error gain	0.019
Controller deadband	0.001
Controller proportional gain	0.1
Controller integral gain	0
Controller derivative gain	0
agcControllerType	1

The VRE power output dates chosen were 16 June 2018, 17 June 2018, 7 July 2018, 14 Feb 2019 and 17 Feb 2019 from recorded data. The 16 June, as shown in Figure 2-11, which was a relatively sunny day with significant variability and the same for wind farm output. The 17 June, as shown in Figure 2-12, which was a typical partially cloudy day in the pacific islands with constant drops in PV power plus a sudden increase in wind power just after a drop in PV. The 7 July, as shown in Figure 2-13, has a windy day with lots of variability and a relatively sunny day in terms of PV output. The 14 Feb 2019 is both a sunny and windy day both with lots of variability. The 17 Feb 2019 is a day with varying wind with a few periods of low wind and a few periods when there is full cloud cover.

Figure 2-11 Recorded 'normalised' one second Wind and PV output for 16 June 2018

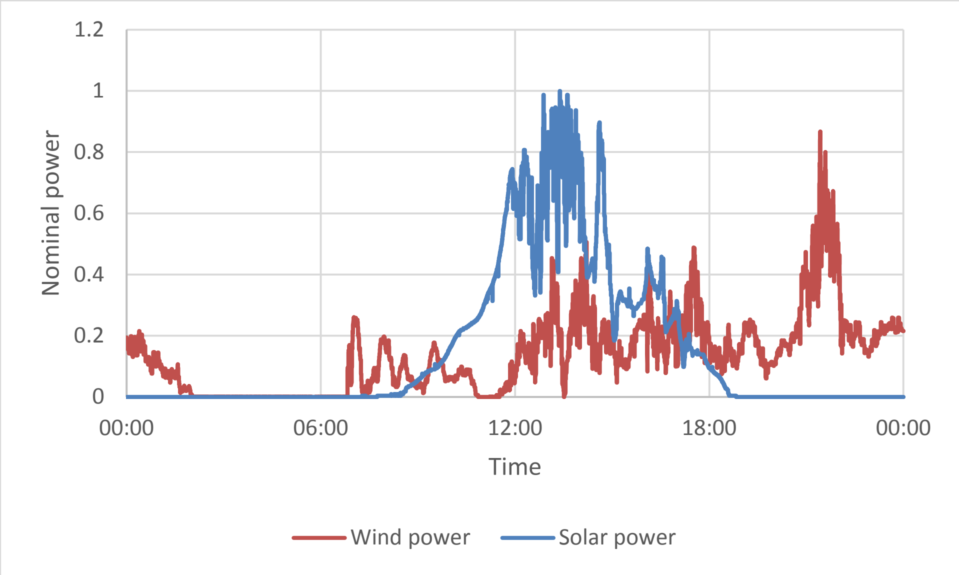


Figure 2-12 Recorded 'normalised' one second Wind and PV output for 17 June 2018

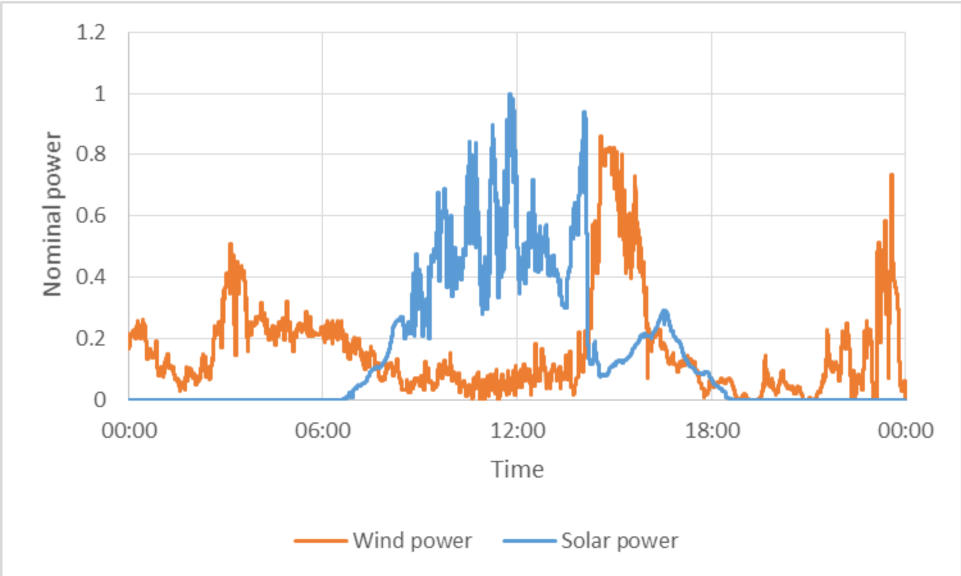


Figure 2-13 Recorded 'normalised' one second Wind and PV output for 7 July 2018

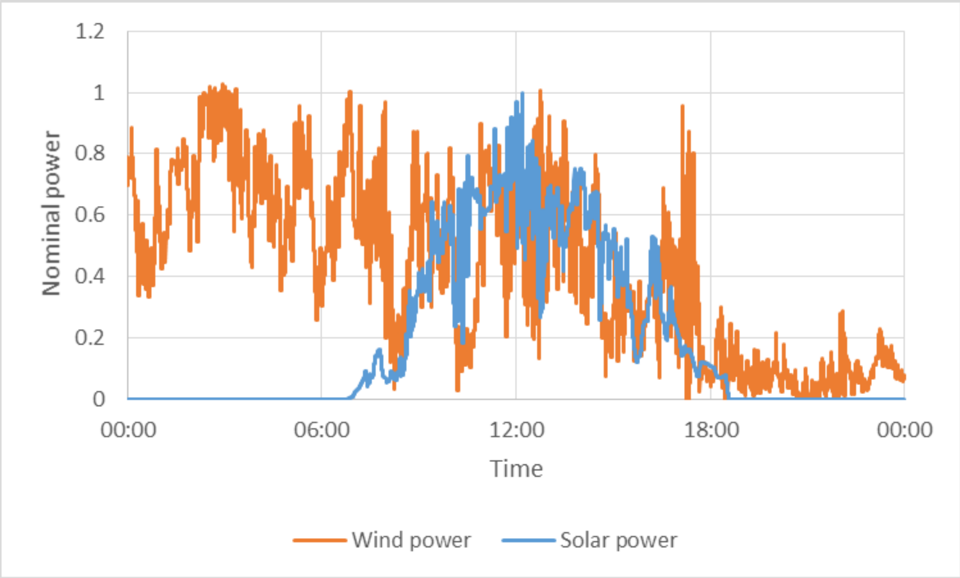


Figure 2-14 Recorded 'normalised' one second Wind and PV output for 14 Feb 2019

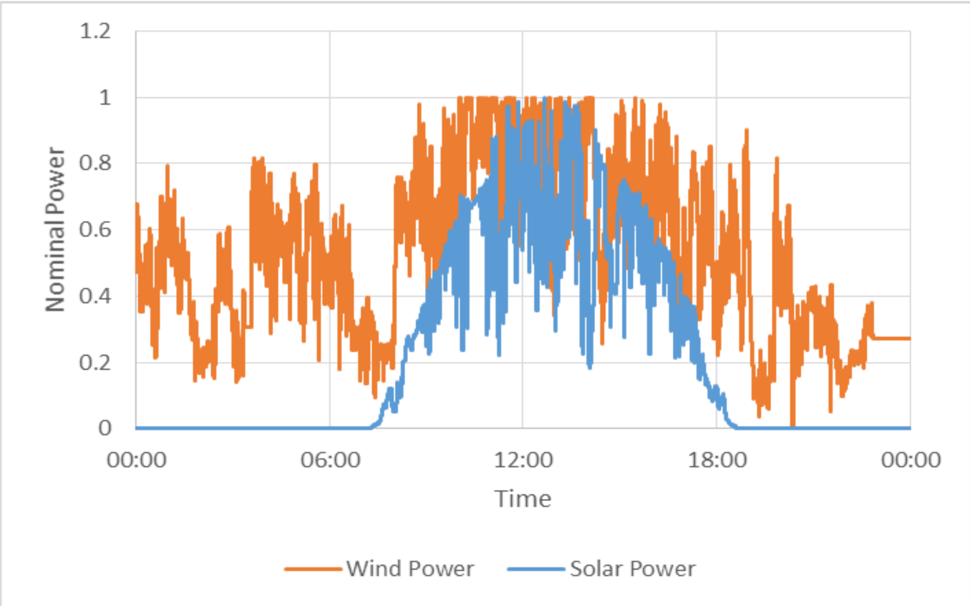
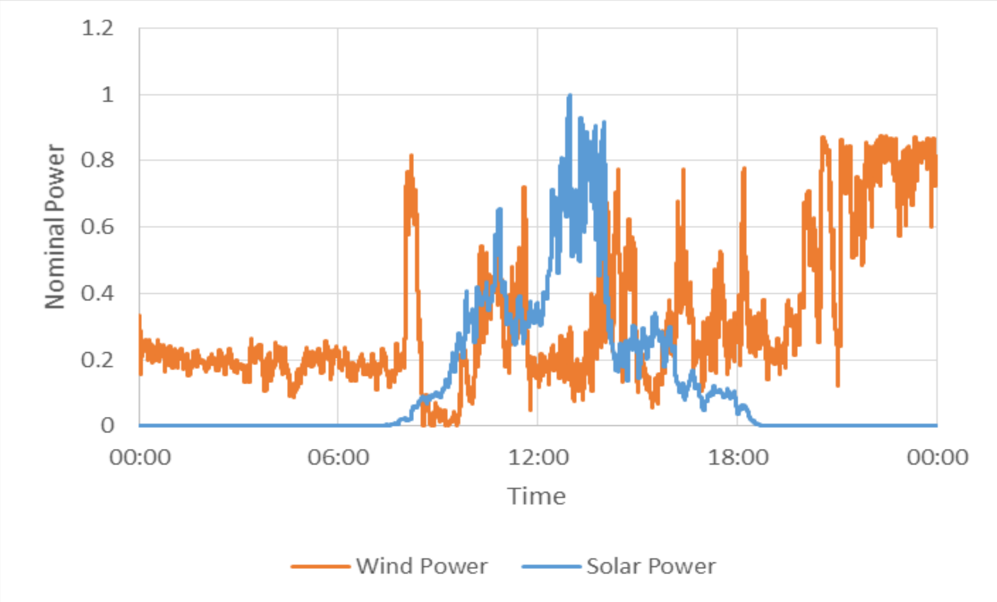


Figure 2-15 Recorded 'normalised' one second Wind and PV output for 17 Feb 2019



2.3 Results of Generation Dispatch Analysis Tool (GDAT)

The following analysis was carried out on the GDAT tool:

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

The summary of the simulations with various changes to input parameters is shown in Table 2-3.

Table 2-3 Simulations performed

						Controller status	
Case Number	**Simulation period**	Wind Installed (MW)	PV installed (MW)	% peak	**RVE data date**	**VRE**	**Battery**
Base 1	Weekend – VRE 16 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov
1	Weekend – VRE 16 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
2	Weekend – VRE 16 June	0.825	1	107%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
3	Weekend – VRE 16 June	0.825	1	107%	16 June 2018	AGC	1 MW / 3 MWh on Gov & AGC
4	Weekend – VRE 16 June	0.825	2	166%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
5	Weekend – VRE 16 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC
6	Weekend – VRE 16 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 2	Weekend – VRE 17 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov

7	Weekend – VRE 17 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
8	Weekend – VRE 17 June	0.825	1	107%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
9	Weekend – VRE 17 June	0.825	1	107%	16 June 2018	AGC	1 MW / 3 MWh on Gov & AGC
10	Weekend – VRE 17 June	0.825	2	166%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
11	Weekend – VRE 17 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC
12	Weekend – VRE 17 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 3	Weekend – VRE 7 July	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov
13	Weekend – VRE 7 July	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
14	Weekend – VRE 7 July	0.825	1	107%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
15	Weekend – VRE 7 July	0.825	1	107%	16 June 2018	AGC	1 MW / 3 MWh on Gov & AGC
16	Weekend – VRE 7 July	0.825	2	166%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
17	Weekend – VRE 7 July	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC
18	Weekend – VRE 7 July	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 4	Weekday – VRE 16 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov
19	Weekday – VRE 16 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
20	Weekday – VRE 16 June	0.825	1	107%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
21	Weekday – VRE 16 June	0.825	1	107%	16 June 2018	AGC	1 MW / 3 MWh on Gov & AGC
22	Weekday – VRE 16 June	0.825	2	166%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
23	Weekday – VRE 16 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC
24	Weekday – VRE 16 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 5	Weekday – VRE 17 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov
25	Weekday – VRE 17 June	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
26	Weekday – VRE 17 June	0.825	1	107%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
27	Weekday – VRE 17 June	0.825	1	107%	16 June 2018	AGC	1 MW / 3 MWh on Gov & AGC
28	Weekday – VRE 17 June	0.825	2	166%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
29	Weekday – VRE 17 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC
30	Weekday – VRE 17 June	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 6	Weekday – VRE 7 July	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov
31	Weekday – VRE 7 July	0.825	0.22	61%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC

32	Weekday – VRE 7 July	0.825	1	107%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
33	Weekday – VRE 7 July	0.825	1	107%	16 June 2018	AGC	1 MW / 3 MWh on Gov & AGC
34	Weekday – VRE 7 July	0.825	2	166%	16 June 2018	AGC	0.5 MW / 3 MWh on Gov & AGC
35	Weekday – VRE 7 July	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC
36	Weekday – VRE 7 July	0.825	4	284%	16 June 2018	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 7	Weekend – VRE 14 Feb	0.825	0.22	61%	14 Feb 2019	AGC	0.5 MW / 3 MWh on Gov
37	Weekend – VRE 14 Feb	0.825	0.22	61%	14 Feb 2019	AGC	0.5 MW / 3 MWh on Gov & AGC
38	Weekend – VRE 14 Feb	0.825	1	107%	14 Feb 2019	AGC	0.5 MW / 3 MWh on Gov & AGC
39	Weekend – VRE 14 Feb	0.825	1	107%	14 Feb 2019	AGC	1 MW / 3 MWh on Gov & AGC
40	Weekend – VRE 14 Feb	0.825	2	166%	14 Feb 2019	AGC	0.5 MW / 3 MWh on Gov & AGC
41	Weekend – VRE 14 Feb	0.825	4	284%	14 Feb 2019	AGC	2 MW / 10 MWh on Gov & AGC
42	Weekend – VRE 14 Feb	0.825	4	284%	14 Feb 2019	AGC	2 MW / 10 MWh on Gov & AGC – diesel off
Base 8	Weekday – VRE 17 Feb	0.825	0.22	61%	17 Feb 2019	AGC	0.5 MW / 3 MWh on Gov
43	Weekday – VRE 17 Feb	0.825	0.22	61%	17 Feb 2019	AGC	0.5 MW / 3 MWh on Gov & AGC
44	Weekday – VRE 17 Feb	0.825	1	107%	17 Feb 2019	AGC	0.5 MW / 3 MWh on Gov & AGC
45	Weekday – VRE 17 Feb	0.825	1	107%	17 Feb 2019	AGC	1 MW / 3 MWh on Gov & AGC
46	Weekday – VRE 17 Feb	0.825	2	166%	17 Feb 2019	AGC	0.5 MW / 3 MWh on Gov & AGC
47	Weekday – VRE 17 Feb	0.825	4	284%	17 Feb 2019	AGC	2 MW / 10 MWh on Gov & AGC
48	Weekday – VRE 17 Feb	0.825	4	284%	17 Feb 2019	AGC	2 MW / 10 MWh on Gov & AGC – diesel off

2.3.1 Base Case 1 & Simulation cases 1 – 6 Weekend with VRE from 16 June 2018

Base Case 1: Weekend - Simulation of original day from 16 June 2018

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 2-16 shows the simulation of generation unit outputs for the Saturday 16 June 2018. This is the base case for these simulations where we can compare techno-economic impact of cases 1 to 5. The simulated frequency, as shown in Figure 2-17, shows the expected frequency variations without any frequency deviations which is reasonably the same as the recorded frequency.

The frequency excursions are just within the acceptable limits of 59.5 – 60.5 Hz showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-16 Simulated generation on Saturday 16 June 2018 with current installed VRE

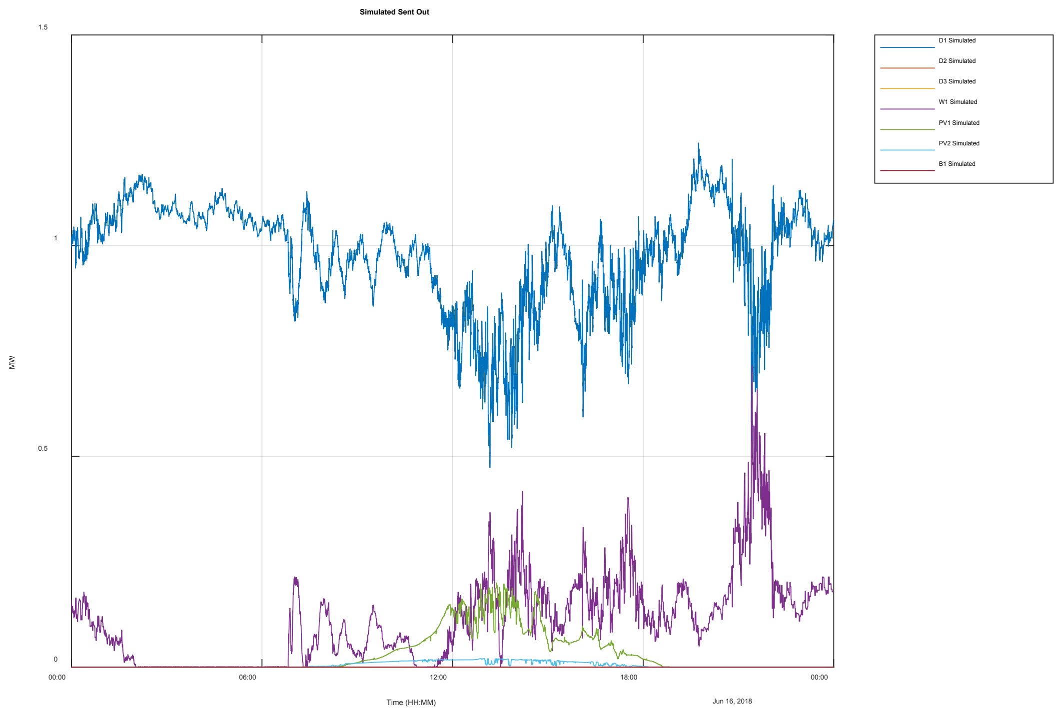
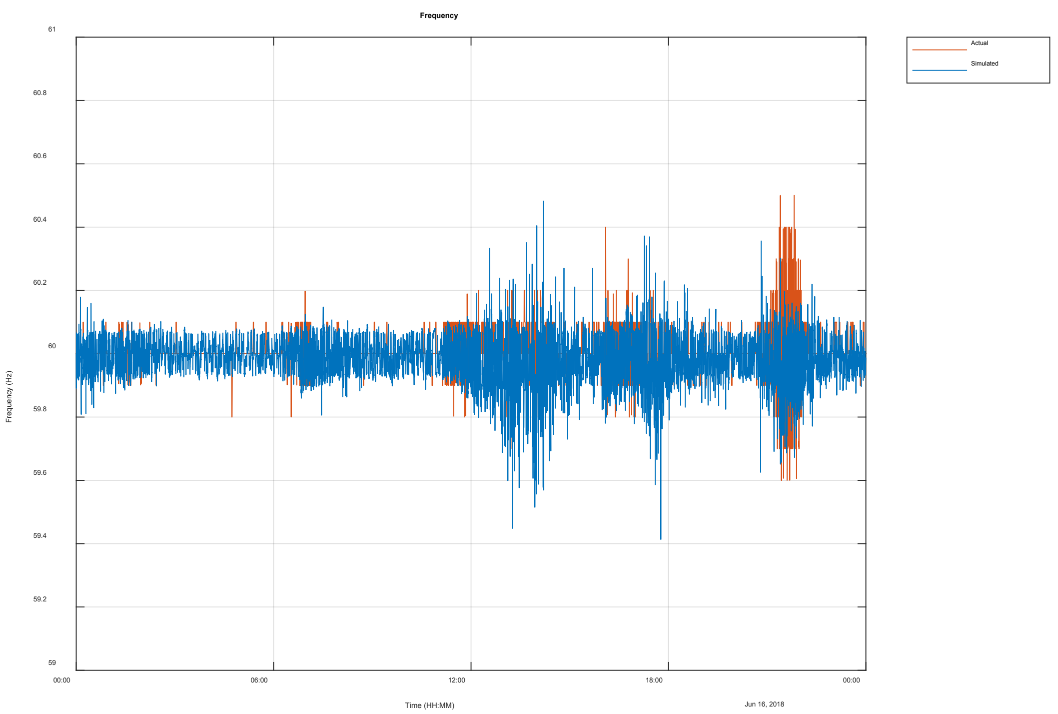


Figure 2-17 Simulated frequency on Saturday 16 June 2018 with current installed VRE

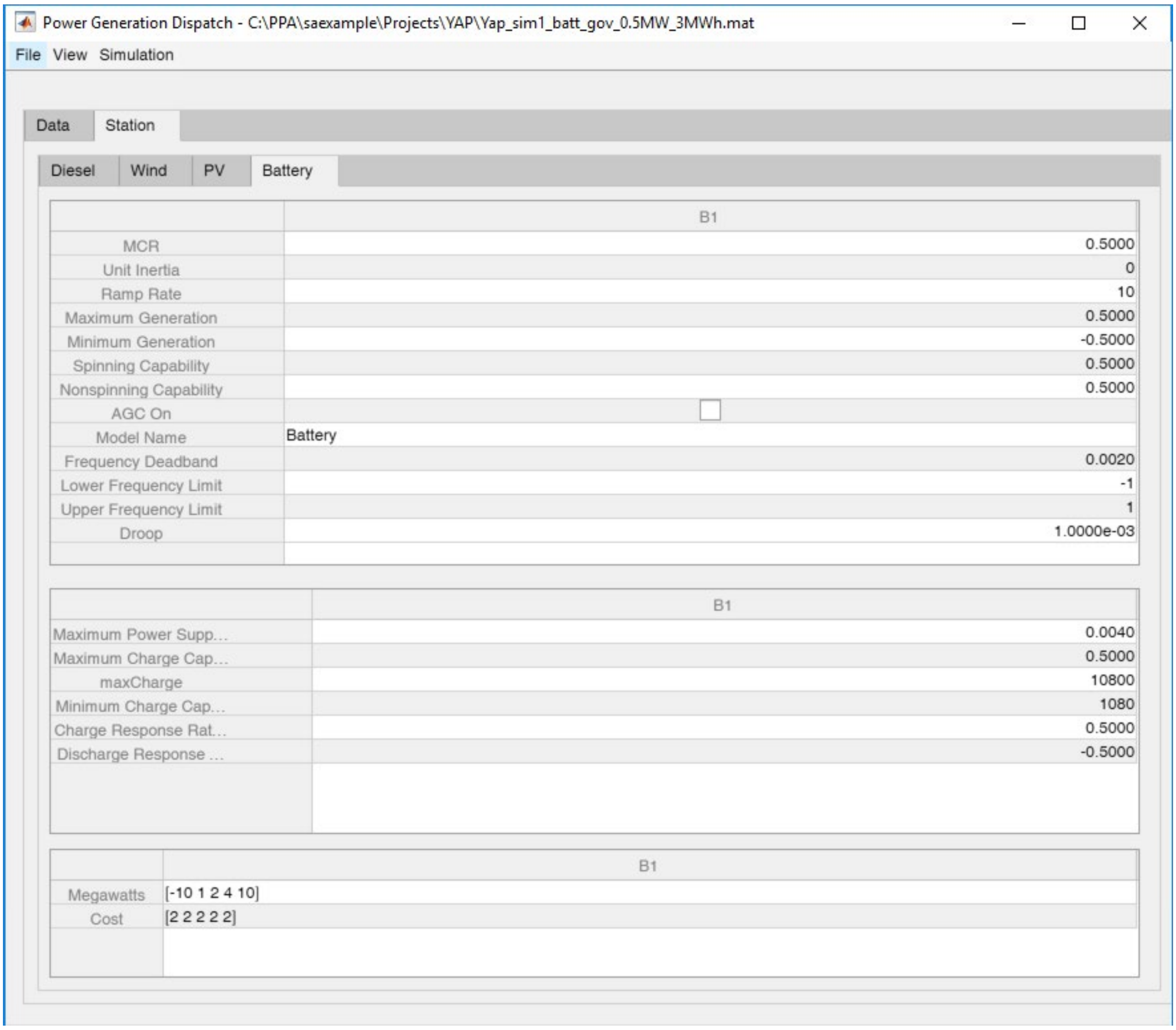


Case 1: Weekend – Base case 1 with 0.5 MW / 3 MWh battery on primary frequency control

Batteries can be used for primary frequency control only and thus only respond to frequency variations. For these simulations, the battery control parameters are in Figure 2-18. The deadband is set to 0.1 Hz and thus the battery will respond to frequency variations outside of this range and droop is set to 0.1 %, thus a 0.1% change in frequency will result in 100% change in power. Thus the battery will go from zero output to full output if the frequency drops from 59.9 to 59.85 Hz and similarly will go to from 0 to full charge with a frequency variation from 60.1 to 60.15 Hz.

A 0.5 MW / 3 MWh battery costs US$ 157,046 per annum or US$ 430.26 per day.

Figure 2-18 Battery parameters when on primary frequency control only



Case 1 is the simulation of base case 1 with 0.5 MW / 3 MWh battery as proposed by the proposed FSM study. The battery is initially added for primary frequency control only as there is no excess VRE energy to charge the battery. The battery output varies up to 0.3 MW showing this is adequate for primary frequency control, as shown in Figure 2-19. The frequency is improved and well within the acceptable limits of 59.5 to 60.5 Hz, as shown in Figure 2-20.

Figure 2-19 Simulated battery output on weekend with base case 1 with 0.5 MW / 3 MWh battery on primary frequency control

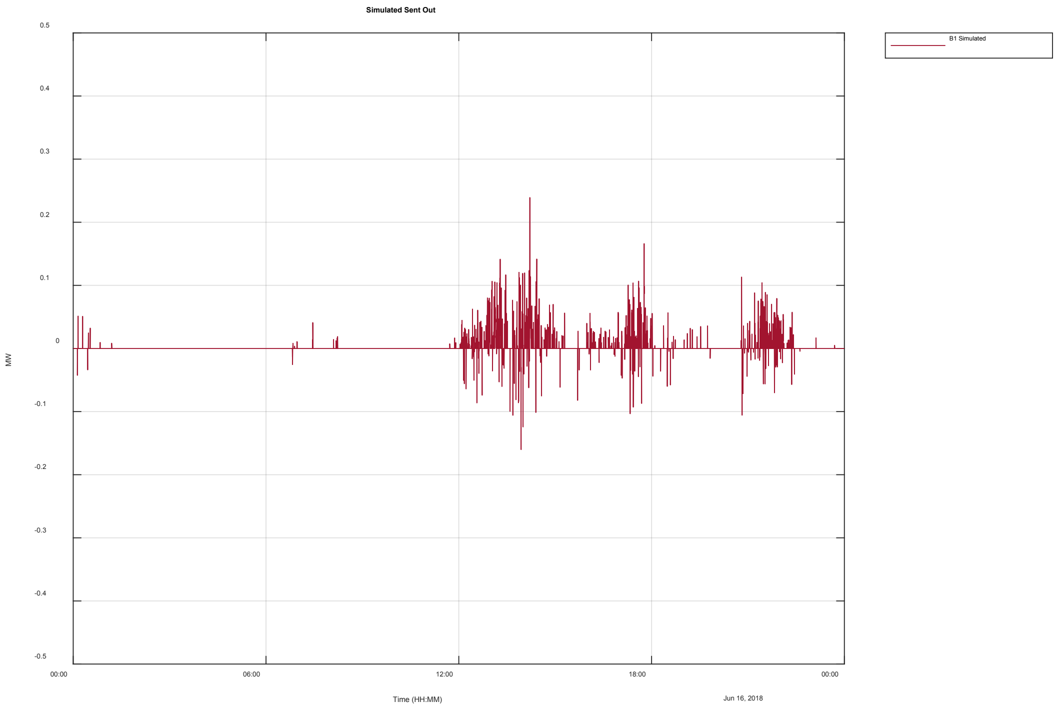
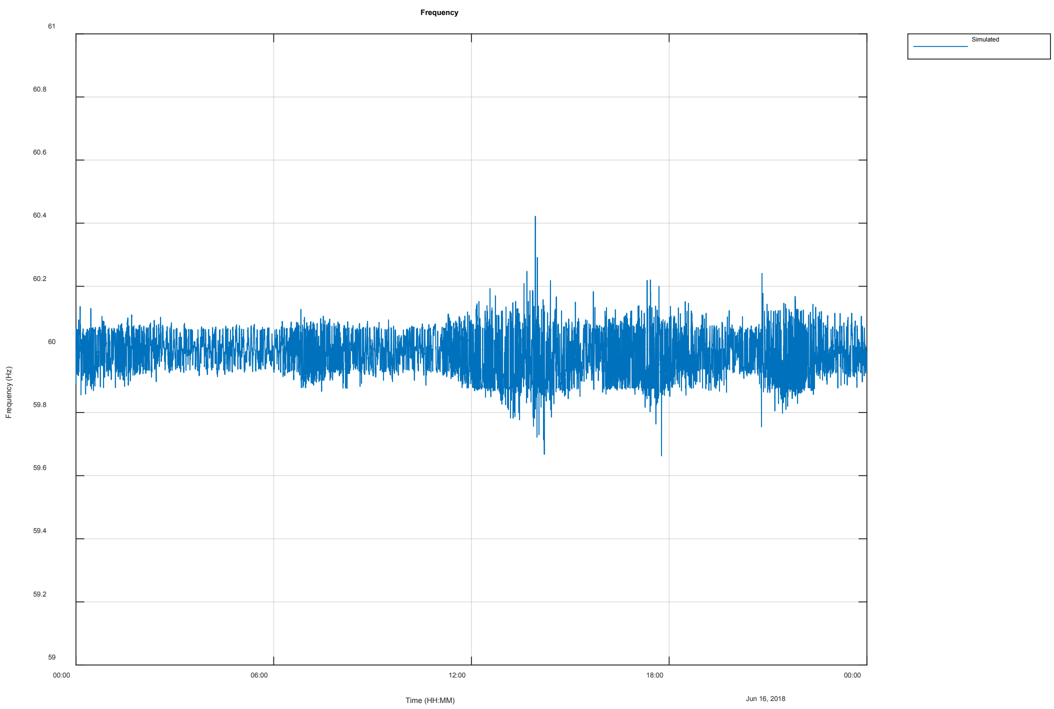


Figure 2-20 Simulated frequency on weekend with base case 1 with 0.5 MW / 3 MWh battery on primary frequency control



<u>Case 2: Weekend – 1 MW of PV and 0.5 MW / 3 MWh battery on AGC</u>

Case 2 is with 1 MW of PV and the 0.5 MW / 3 MWh battery on AGC. The batteries also provide primary frequency control as for the simulations above. The philosophy for the batteries under AGC control is:

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

The simulated frequency is not within acceptable limits when 0.5 MW battery is on primary frequency control and AGC, as shown in Figure 2-21. There are more than a few occasions during the period when the battery is fully utilised and the response is not enough to prevent frequency excursion, as shown in Figure 2-23. When the diesel generation is at minimum generation it does not contribute to frequency control thus the poor frequency during this period. Fuel costs decrease 11% from base case 1 from $5,761 to $5,054. The battery charges from 20% to around 45%, as shown in Figure 2-24. A net loss of US$ 111 is calculated for the simulation day including the PV and battery costs.

Figure 2-21 Simulated frequency for weekend with 1 MW of PV and 0.5 MW / 3 MWh battery on AGC

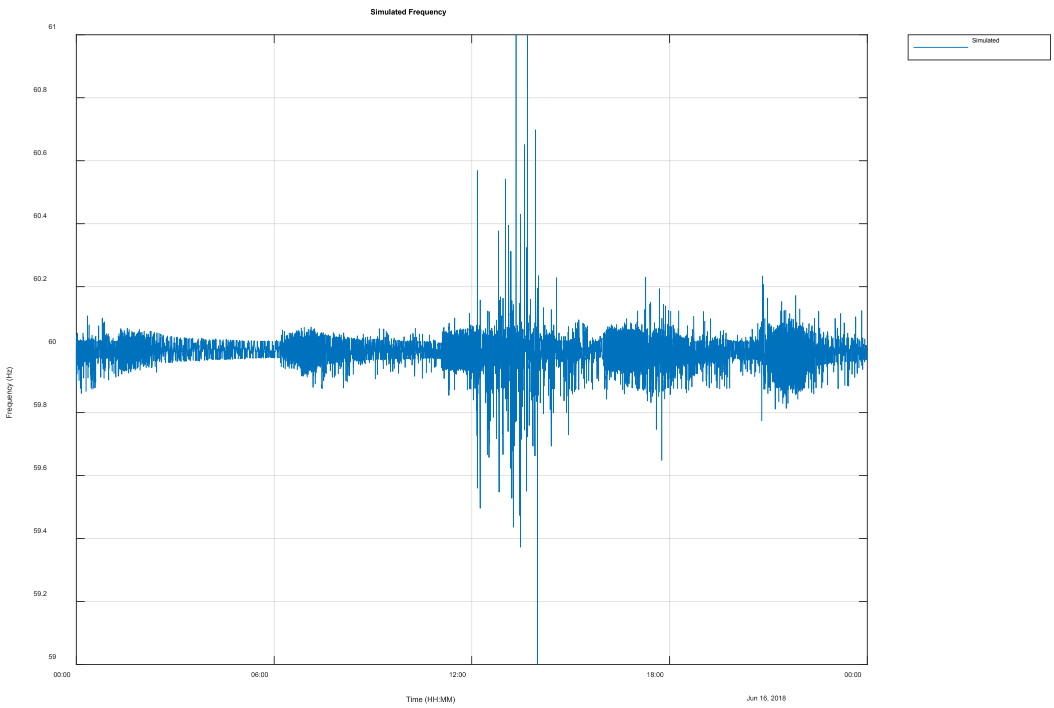


Figure 2-22 Simulated generation for weekend with 1 MW of PV and 0.5 MW / 3 MWh battery on AGC

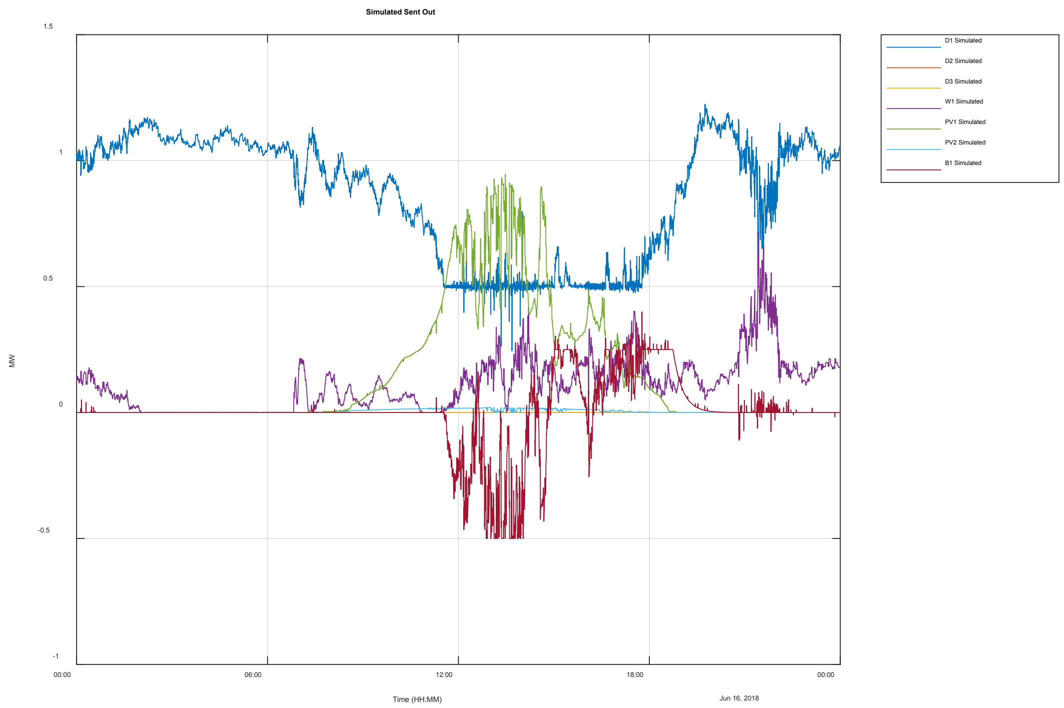


Figure 2-23 Simulated battery power for weekend with 1 MW of PV and 0.5 MW / 3 MWh battery on AGC

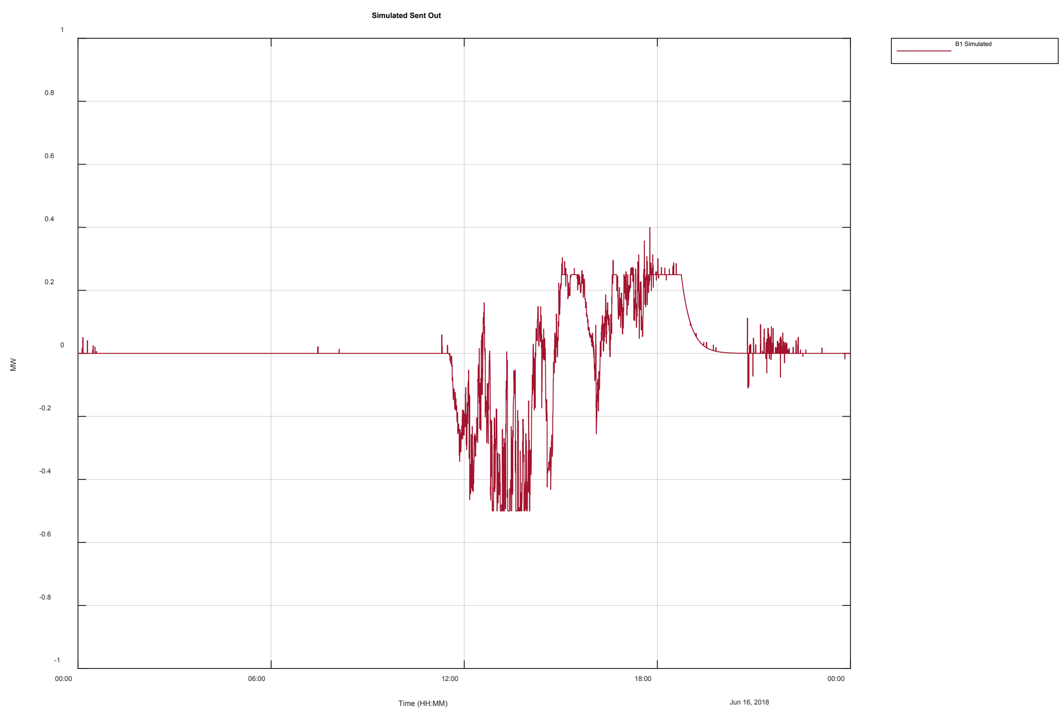
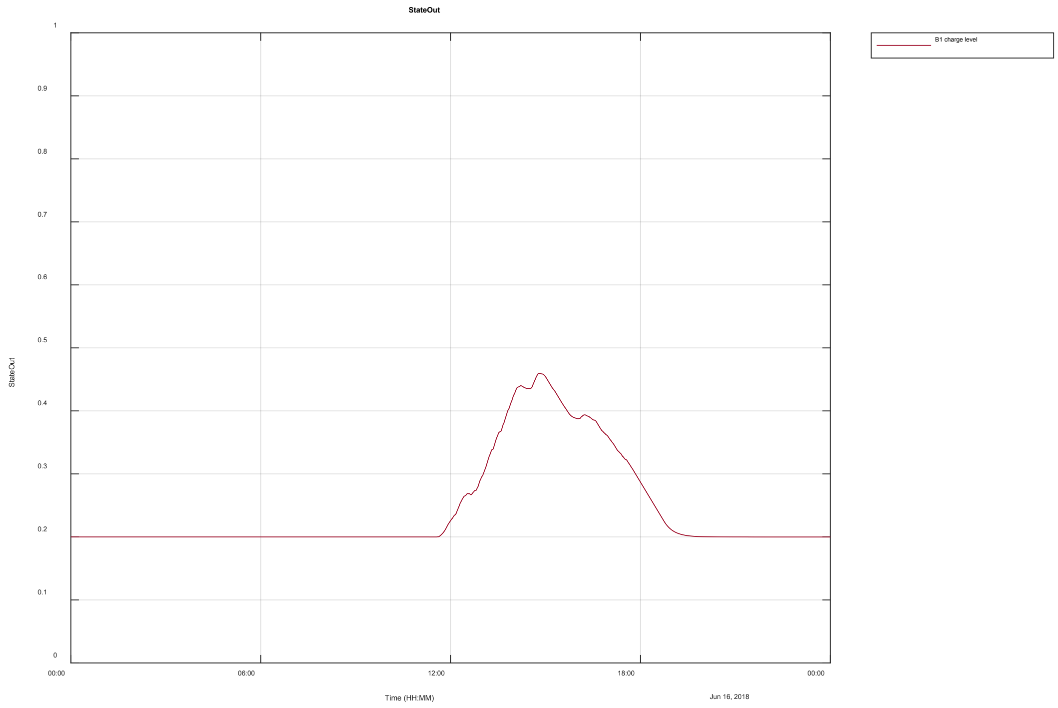


Figure 2-24 Simulated battery charge for weekend with 1 MW of PV and 0.5 MW battery on primary frequency control



Case 3: Weekend – 1 MW of PV and 1 MW / 3 MWh battery on AGC

Case 3 the PV1 power plant is same as case 2 with an increase in inverter size to 1 MW to curtail the large frequency excursions. Diesel unit 1 provides the secondary control under AGC to perform the control assisted by a 1 MW battery on AGC, as shown in Figure **2-25**. The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in Figure 2-26. The battery full range is not fully utilised to control the frequency and so battery size is fine for frequency control for this simulation case, as shown in Figure **2-27**.

Nearly all the available energy from the 1 MW of PV as per the case 2 but a higher net loss of US$ 186 for the simulation day accounting for the bigger inverter.

Figure 2-25 Simulated generation for weekend with 1 MW of PV and 1 MW / 3 MWh battery on AGC

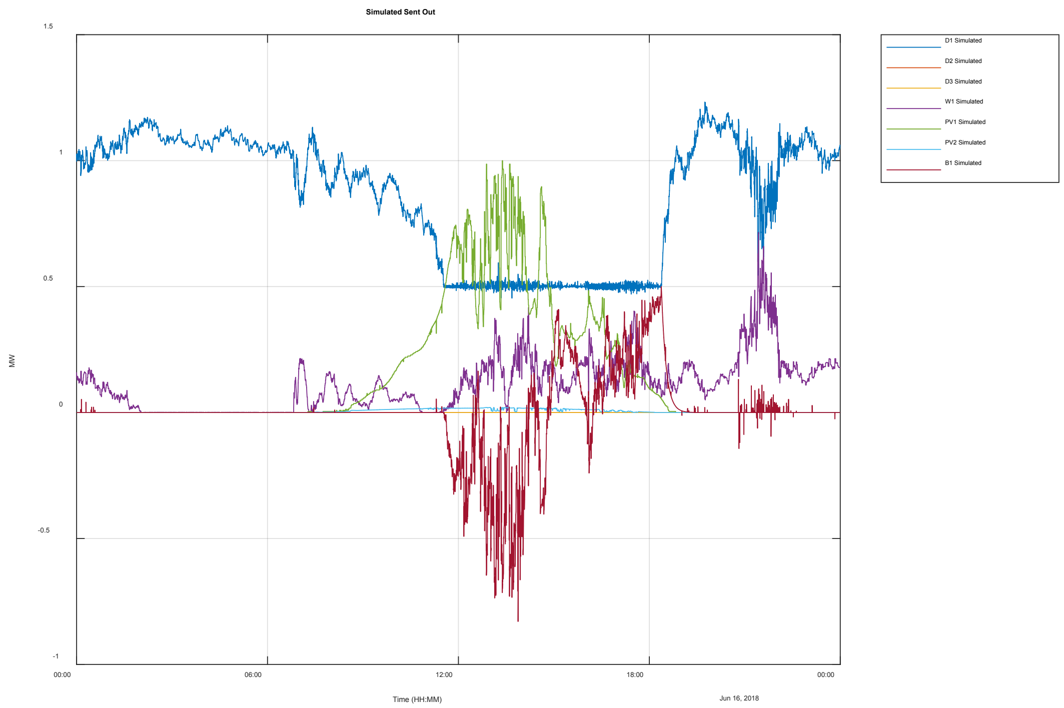


Figure 2-26 Simulated frequency for weekend with 1 MW of PV and 1 MW / 3 MWh battery on AGC

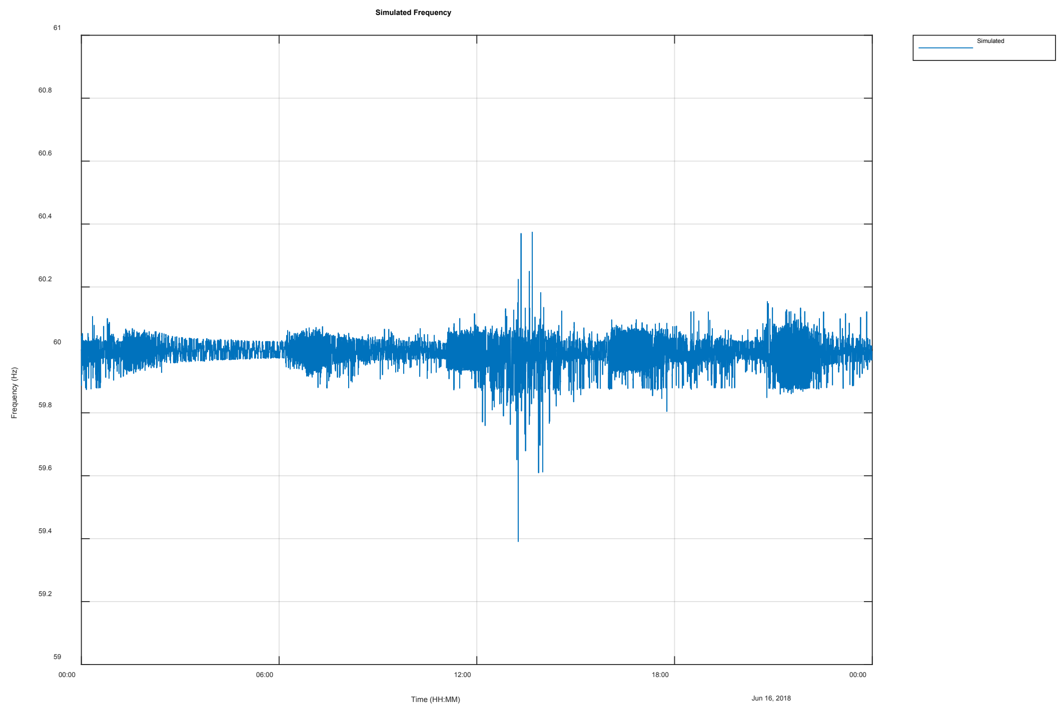
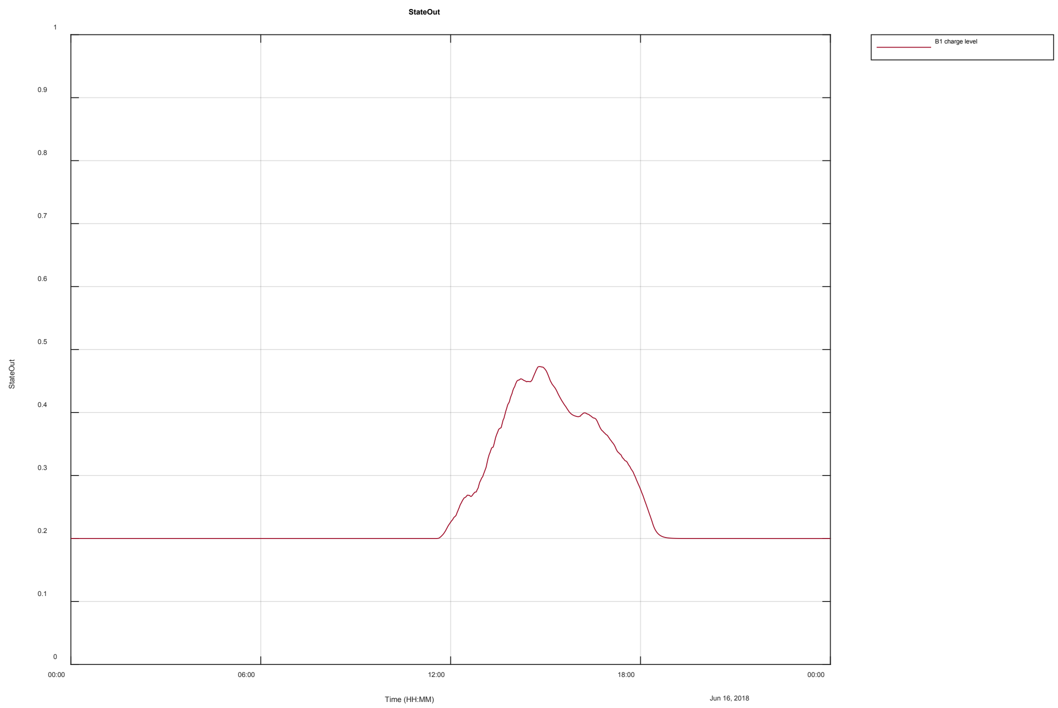


Figure 2-27 Simulated battery output for weekend with 1 MW of PV and 1 MW / 3 MWh battery on AGC



<u>Case 4: Weekend – 2 MW of PV and 0.5 MW / 3 MWh battery on AGC</u>

Case 4 is simulating the same as Case 2 but now with assistance of 2 MW of PV on PV1. Figure 2-31 shows the frequency is better than the case for a 1 MW PV with the same battery. This is due to the curtailment of PV power peaks but the troughs are higher making the change in PV power less and subsequent frequency control better. The simulated PV power is curtailed 16.8%.

Figure 2-29 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery 90% charge level, as shown in Figure 2-30, by 17:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until charge level is 20% which is around 02:00 the next day. The simulated diesel generator 1 output is at minimum generation for most of the period from 10:30 Hrs to 18:00 Hrs, as shown in Figure 2-31.

The fuel costs for Case 4 is $ 4,572 compared to $ 5,054 for Case 2. This reduction is due to an increase PV output of 2.4 MWh which is used to charge the batteries and is later discharged instead of using diesel power. This case only has a net loss of $ 10 for the simulation day which is less than the loss for case 2.

Figure 2-28 Simulated frequency for weekend when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.

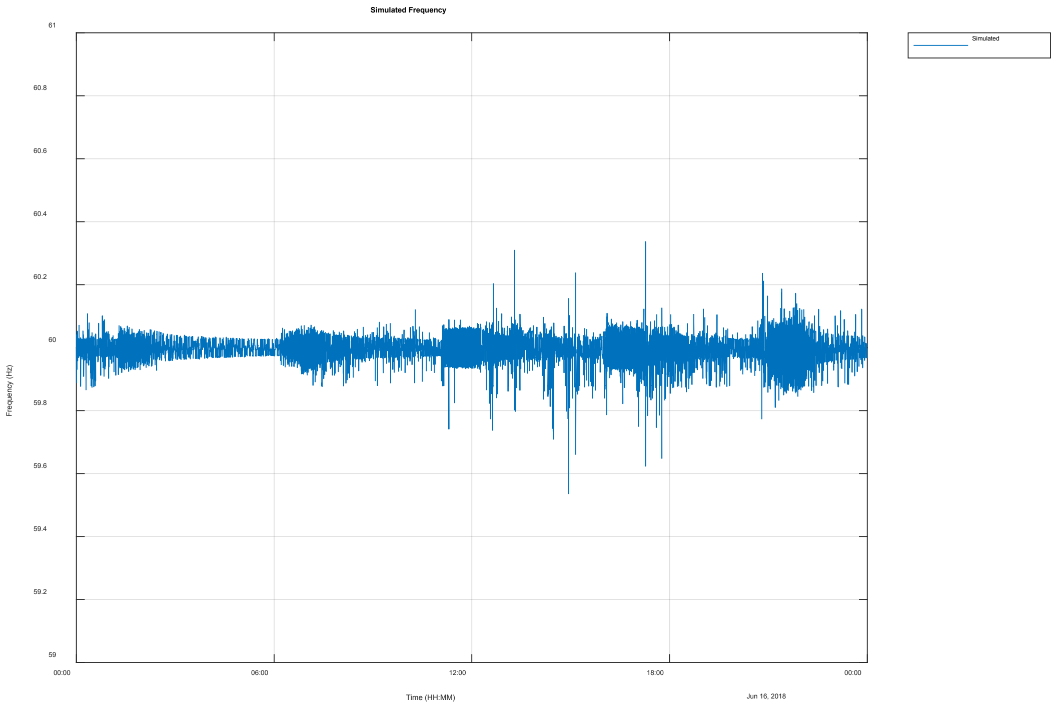


Figure 2-29 Simulated battery output for weekend when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.

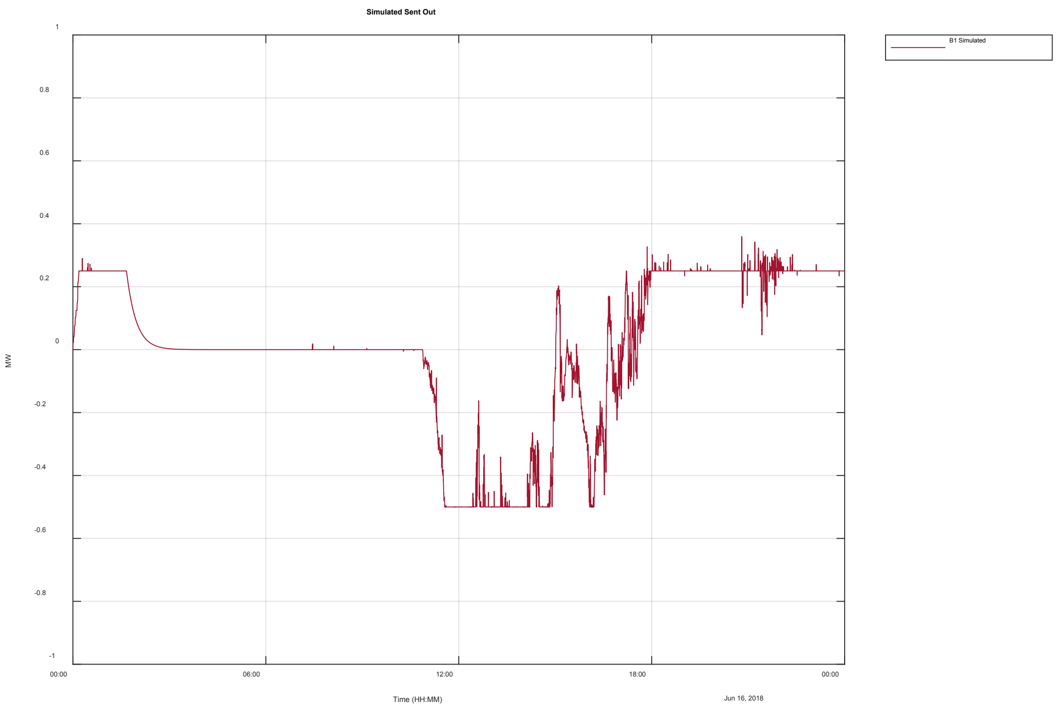


Figure 2-30 Simulated battery charge level for weekend when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.

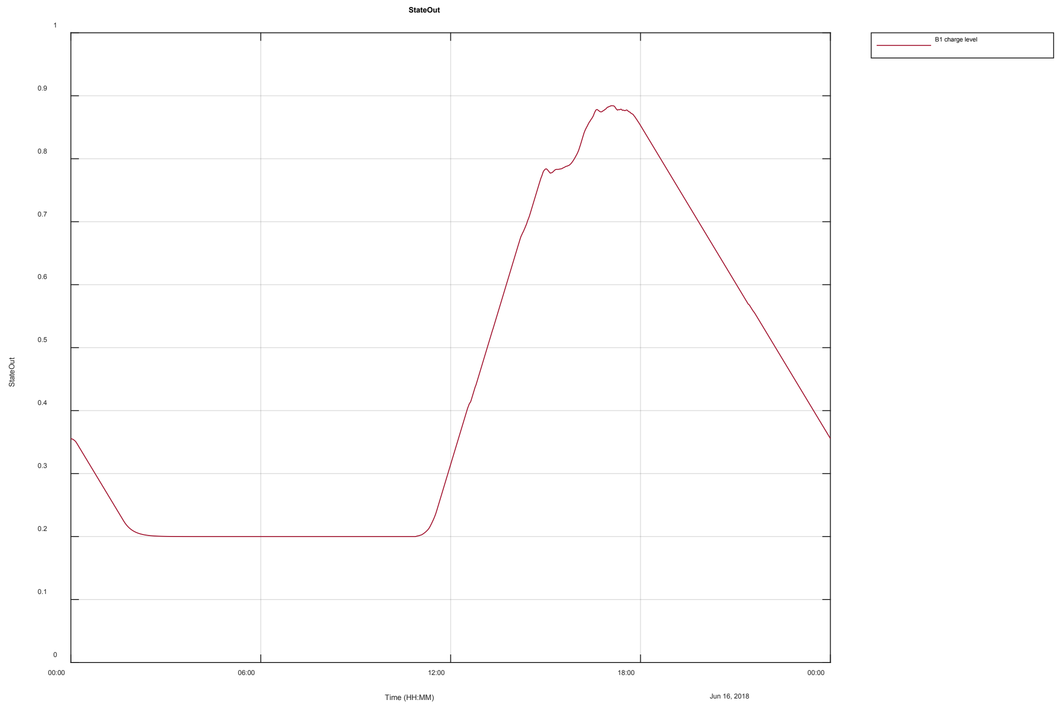
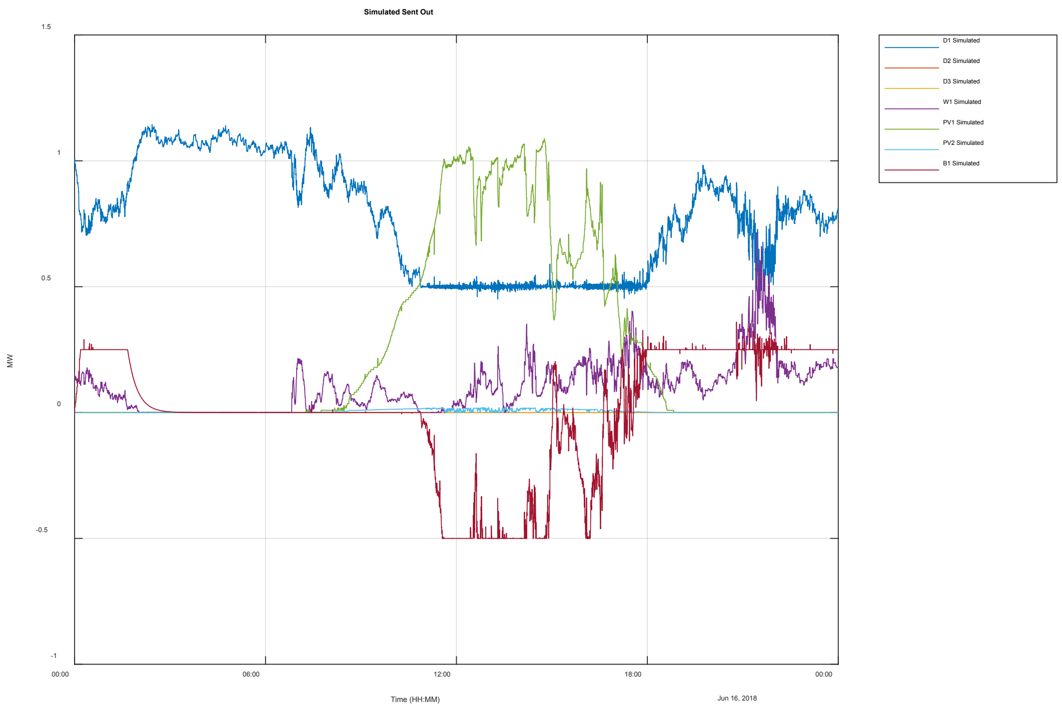


Figure 2-31 Simulated generator outputs for weekend when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.



Case 5: Weekend – 4 MW of PV and 2 MW / 10 MWh battery on AGC

Case 5 is simulating the next stage of the proposed by FSM Energy Master Plan Study, April 2018 with 4 MW of PV and 2 MW / 10 MWh battery on AGC. D3 is kept on at minimum generation of 0.25 MW instead of keeping D1 or D2 units with a higher minimum generation on. The simulated frequency is within acceptable limits even, as shown in Figure 2-32. There are a few frequency excursions which means the inverter size is adequate could be bigger as it is often at full charge MW output level, as shown in Figure **2-33**. Figure 2-34 shows the battery fully discharges around 03:00 and the diesel unit is only above minimum generation from 03:00 to 10:00.

The energy not utilised is 1.7 MWh or 9.3% of energy lost. This case has a net saving of $ 140 for the simulation day.

Figure 2-32 Simulated frequency for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

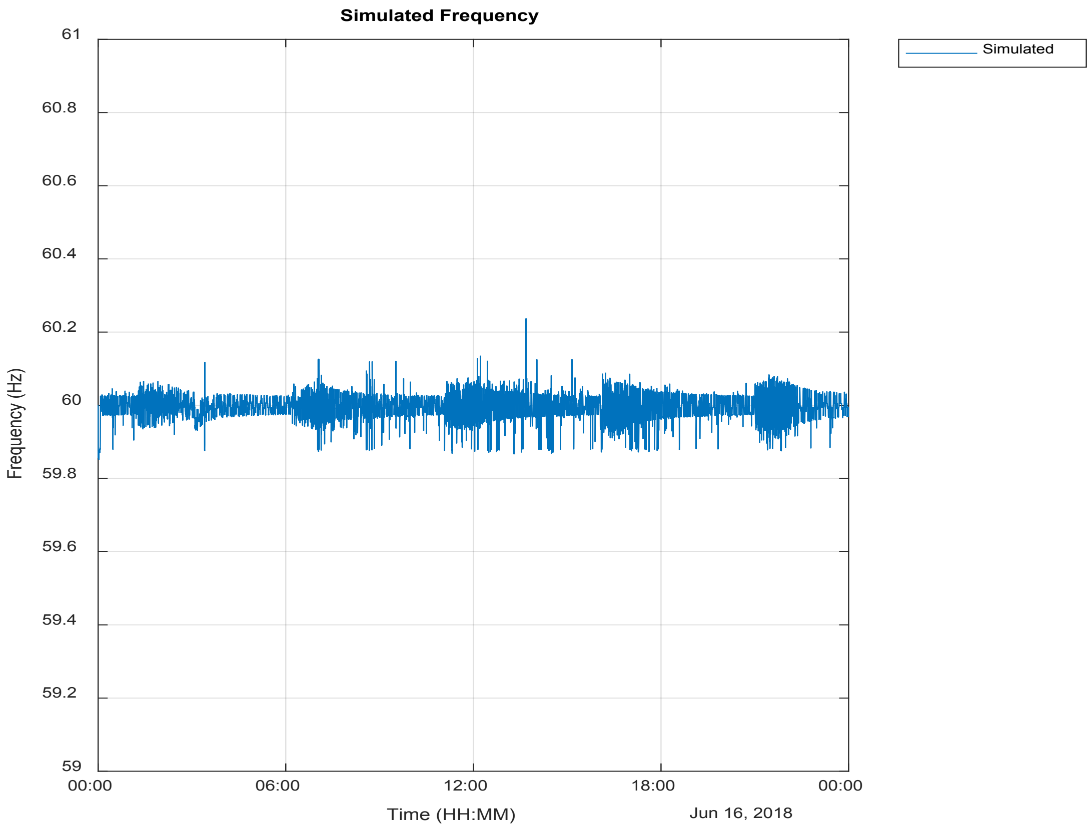


Figure 2-33 Simulated generation for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

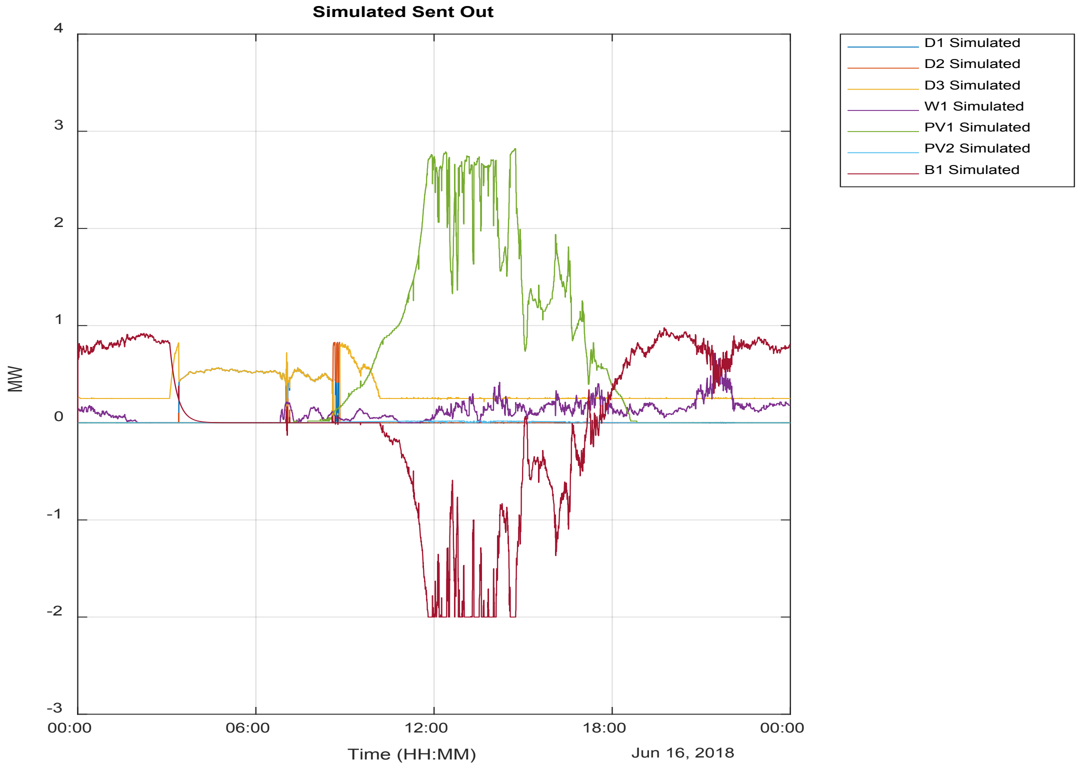
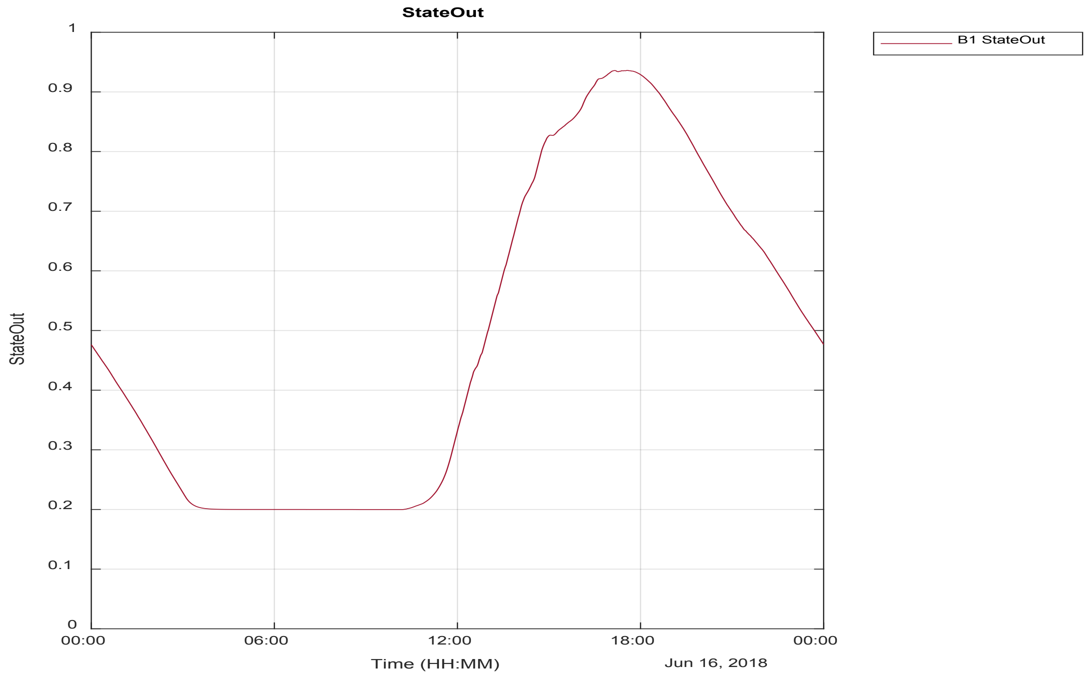


Figure 2-34 Simulated battery charge for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.



Case 6: Weekend – 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off

Case 6 is simulating the same as Case 5 but now the diesel allowed to go off.

Figure 2-35 shows the when generation simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost 80% charge level, as shown in Figure 2-36, by 12:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until midnight. No diesel is required from 11:00 until midnight except for a few times when battery is not sufficient. The battery output in the simulation is only allowed to go to 1 MW which is just not sufficient to meet the demand, as shown in Figure 2-37. Figure 2-38 shows the simulated frequency and when the PV is at its peak output and the battery is charging there is no sufficient control range to control the frequency. The frequency excursions are with the range of 59.5 to 60.5 Hz but the deviations are too big and too often, so the simulation shows a higher level of battery inverter is required.

The fuel costs for Case 6 is $ 2,550 an extra saving of $ 46 for the simulation day compared to Case 5. This case has a net saving of $ 186 for the simulation day.

Figure 2-35 Simulated generation output for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

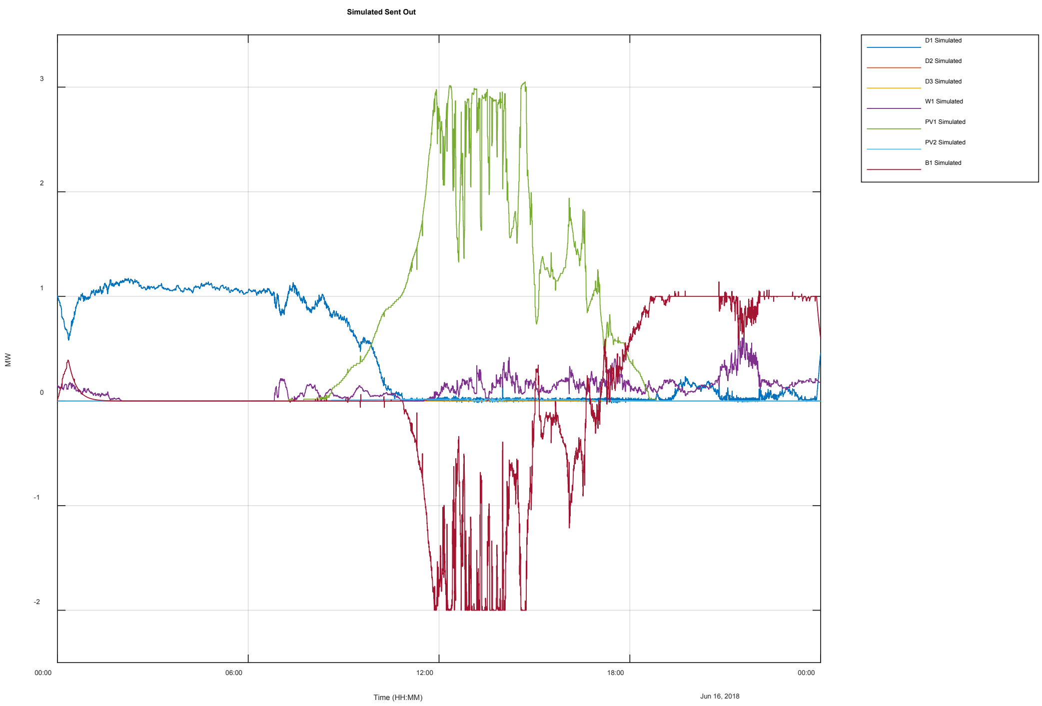


Figure 2-36 Simulated battery charge level for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

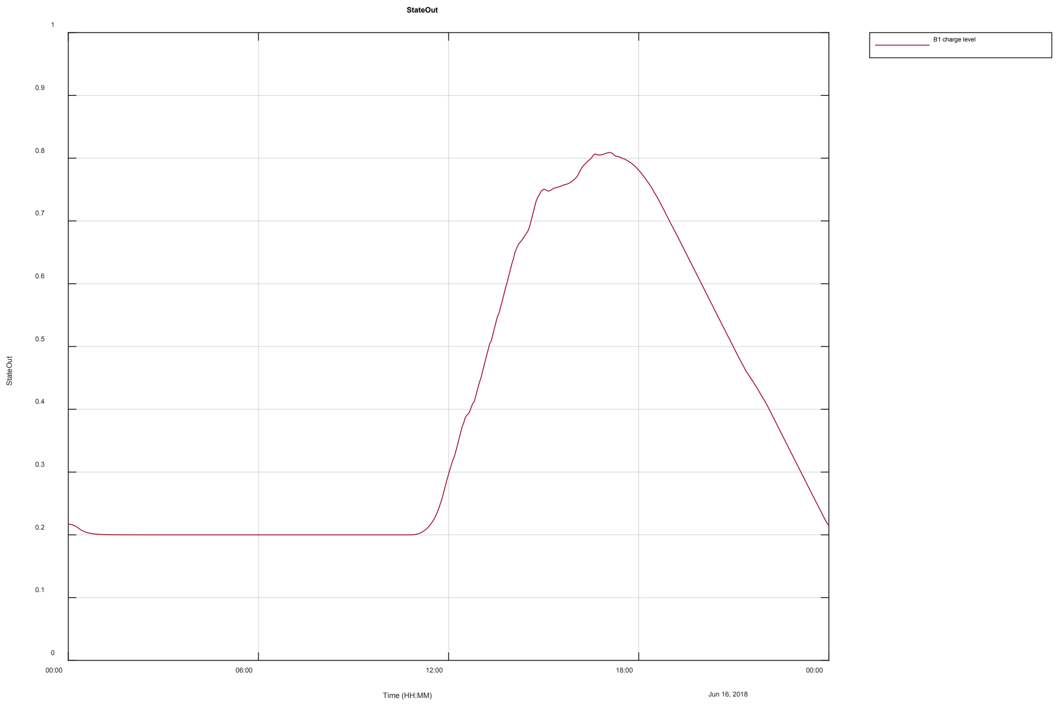


Figure 2-37 Simulated battery output for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

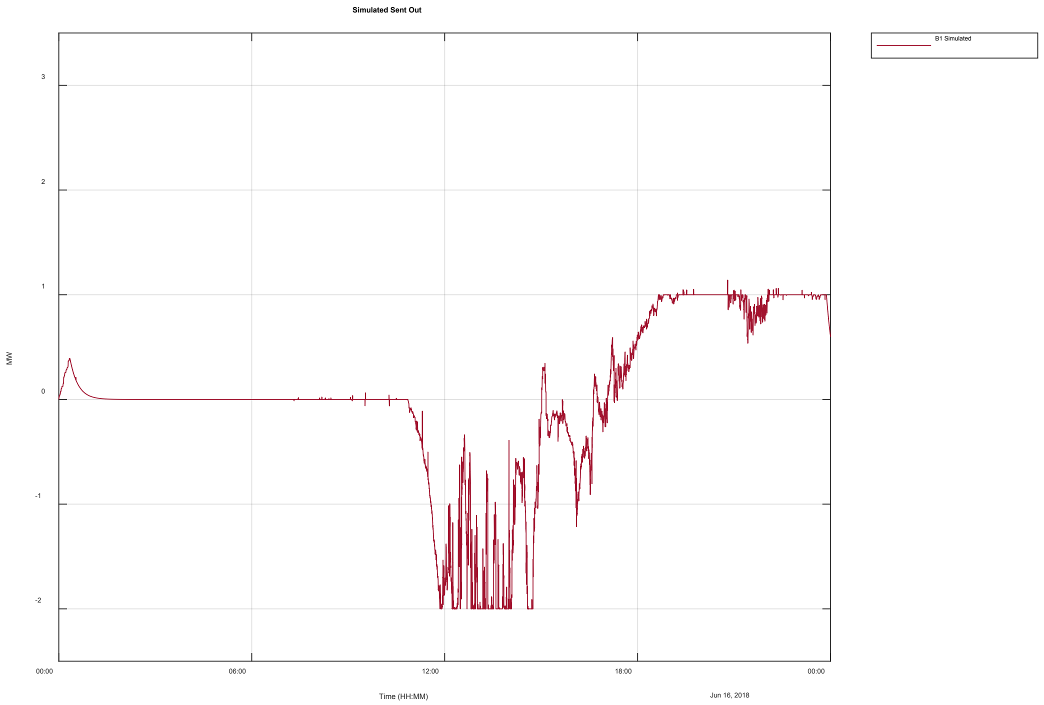
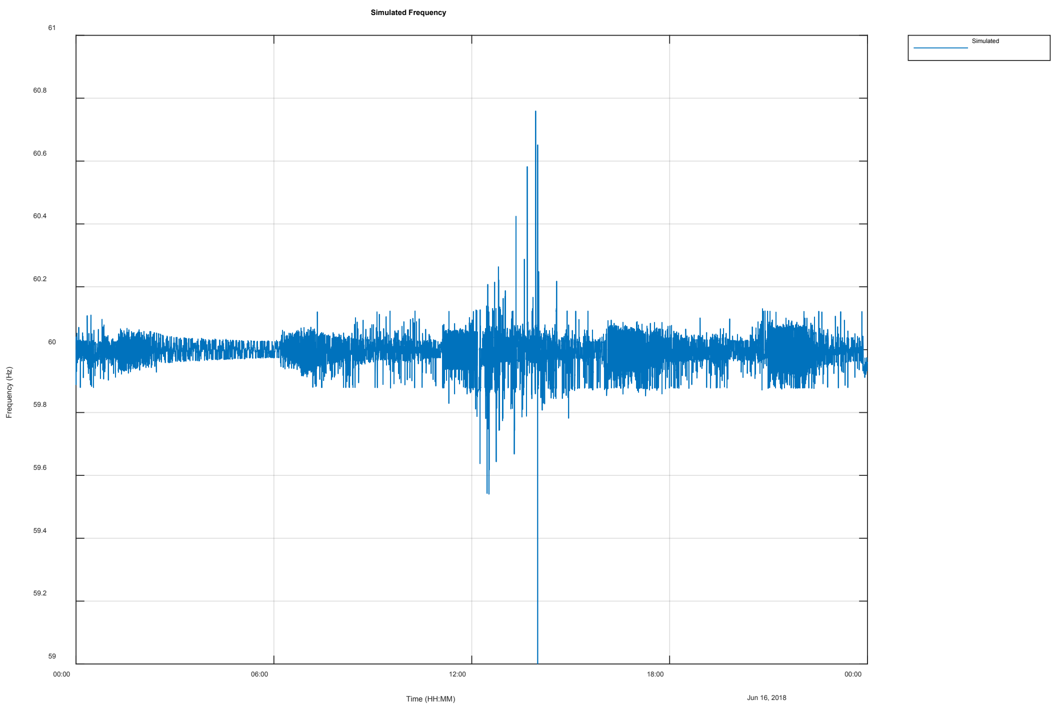


Figure 2-38 Simulated frequency for weekend when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.



2.3.2 Base Case 2 & Simulation cases 7 – 12 Weekend with VRE from 17 June 2018

<u>Base Case 2: Weekend - Simulation of original day from 17 June 2018</u>

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 2-39 shows the simulation of generation unit outputs for the Sunday 17 June

2018. This is the base case for these simulations where we can compare techno-economic impact of cases 7 to 12. The simulated frequency, as shown in Figure 2-40, shows the expected frequency variations without any frequency deviations which is reasonably the same as the recorded frequency.

The frequency excursions are just within the acceptable limits of 59.5 – 60.5 Hz showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-39 Simulated generation on Sunday 17 June 2018 with current installed VRE

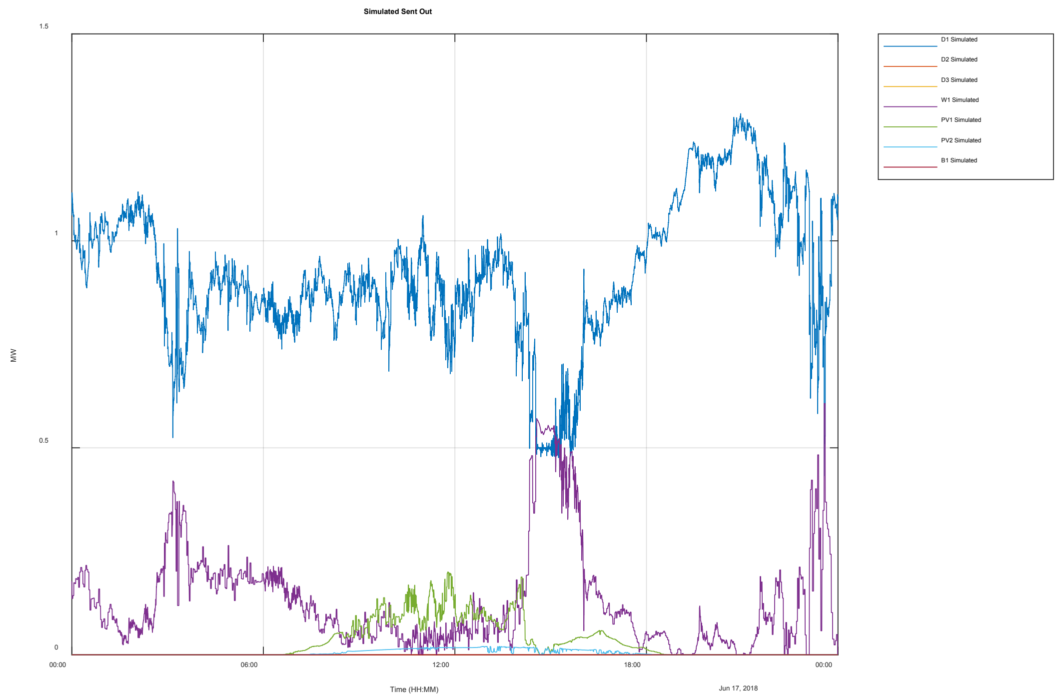
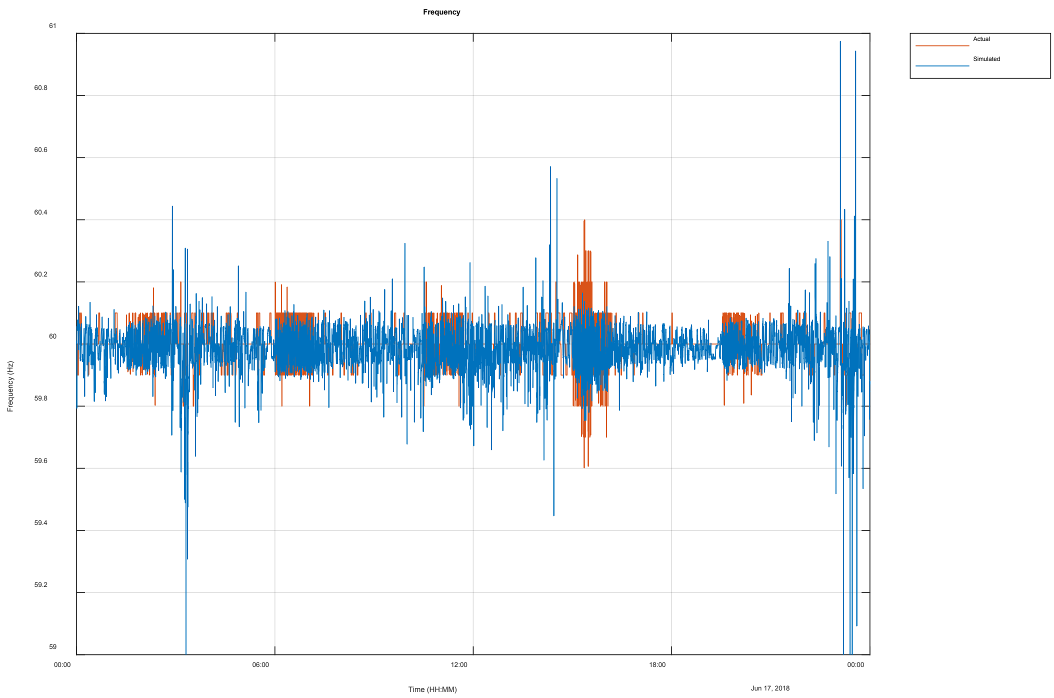


Figure 2-40 Simulated frequency on Sunday 17 June 2018 with current installed VRE



<u>Case 7 - 12: Weekend – Repeat of cases 1-6 with data on Sunday 17 June 2018.</u>

Cases 7 – 12 is the repeat of the simulations for a typical weekend but with data recorded on Sunday 17 June 2018. The simulated frequency is within an acceptable range for case 7 with 0.5 MW / 3 MWh battery added except for a few occasions when wind power varies dramatically, as shown in Figure 2-41. Case 8 with 1 MW of simulated PV with a 0.5 MW / 3 MWh battery on AGC results in too many frequency variations outside the acceptable limits of 59.5 to 60.5 Hz as was for case 2, as shown in Figure 2-42. Case 9 with 1 MW of simulated PV with a 1 MW / 3 MWh battery on AGC results in an acceptable frequency control, as shown in Figure 2-43. Case 10 with the 2 MW of PV and 0.5 MW / 3 MWh battery on AGC has a very a poor frequency control, as shown in Figure 2-44, which is not the same as for case 5, this suggests that the 0.5 MW inverter is too small.

Cases 11 & 12 with 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off has similar results to cases 5 & 6 except for frequency control is unacceptable, as shown in Figure 2-45.

Figure 2-41 Case 7 - Simulated frequency on weekend with 0.5 MW / 3 MWh MW battery on AGC.

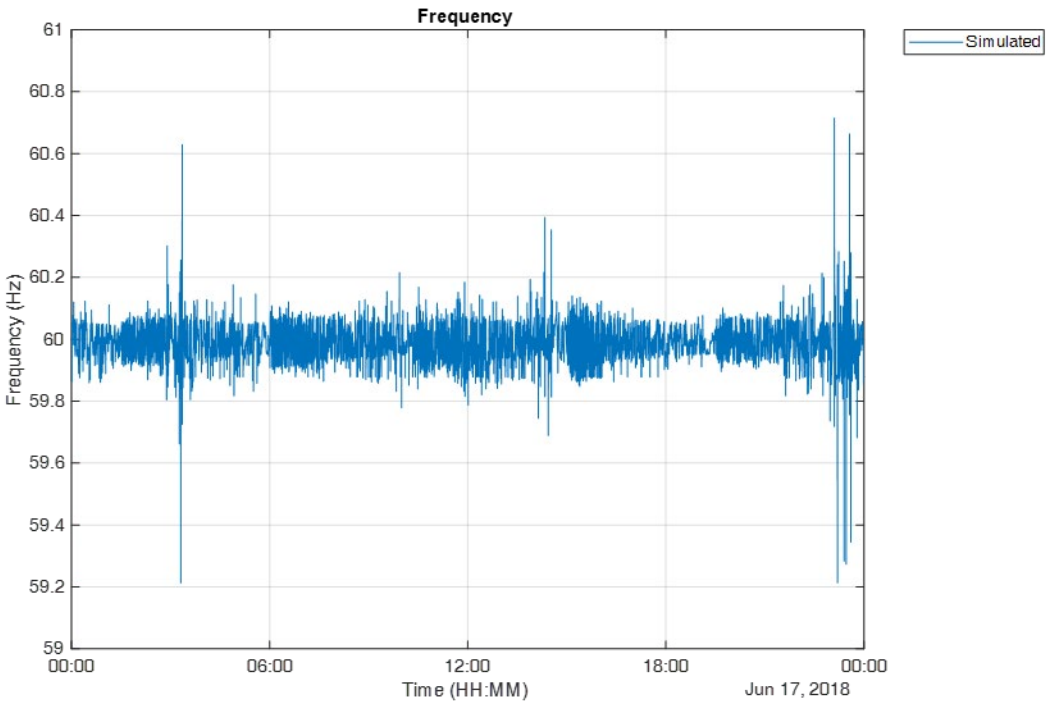


Figure 2-42 Case 8 - Simulated frequency on weekend with 1 MW PV and 0.5 MW / 3 MWh MW battery on AGC

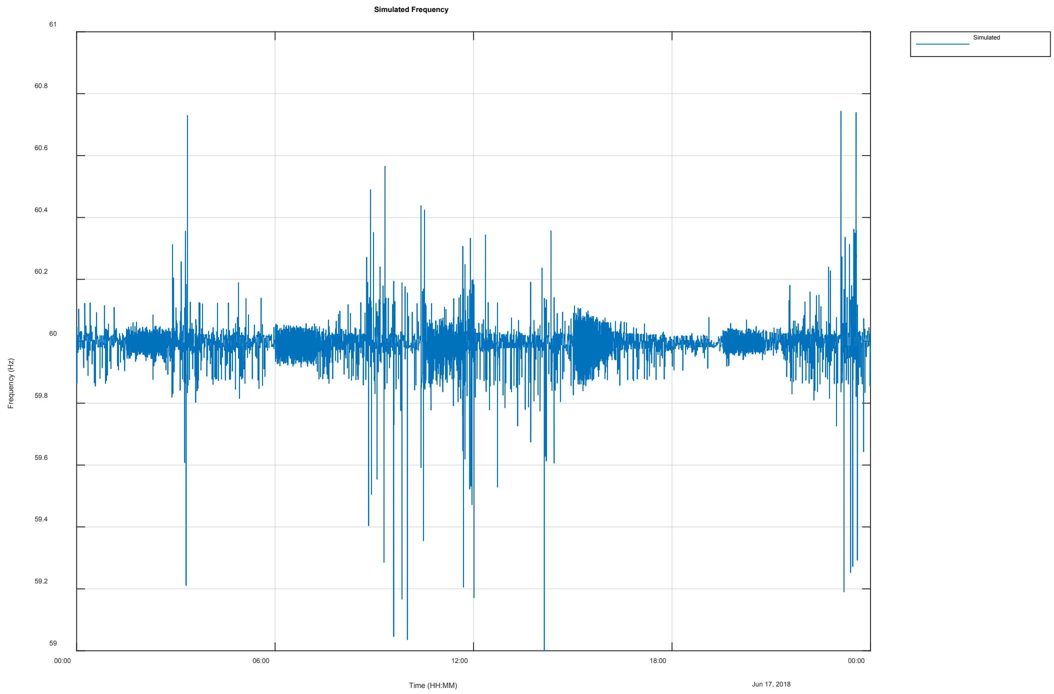


Figure 2-43 Case 9 - Simulated frequency on weekend with 1MW PV and 1 MW / 3 MWh MW battery on AGC

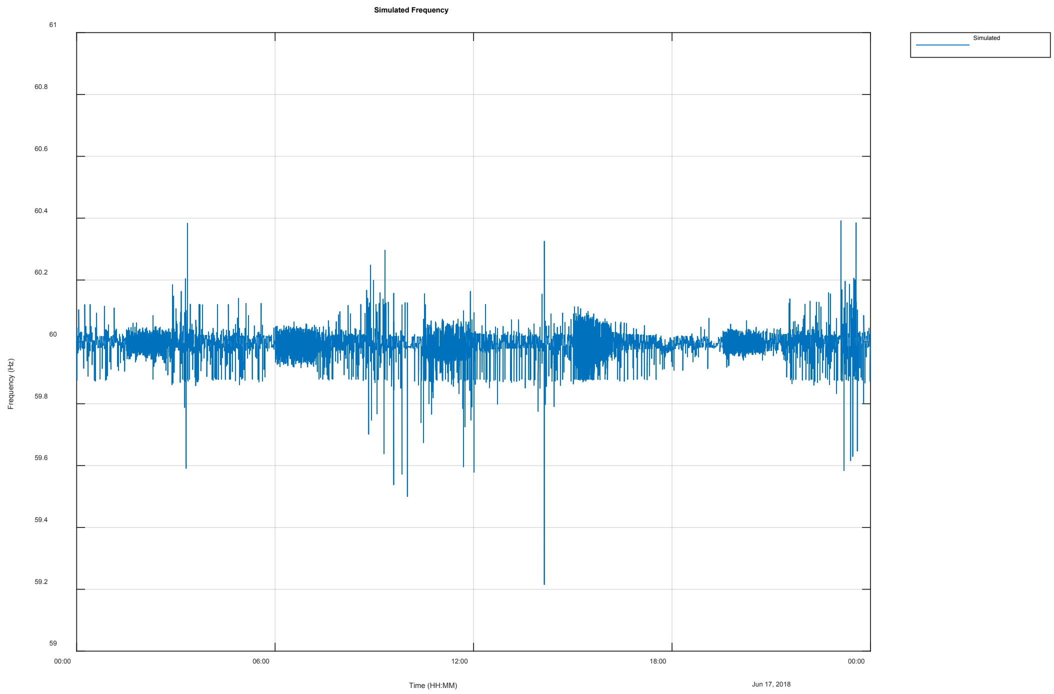


Figure 2-44 Case 10 - Simulated frequency on weekend with 2 MW PV and 0.5 MW / 3 MWh MW battery on AGC

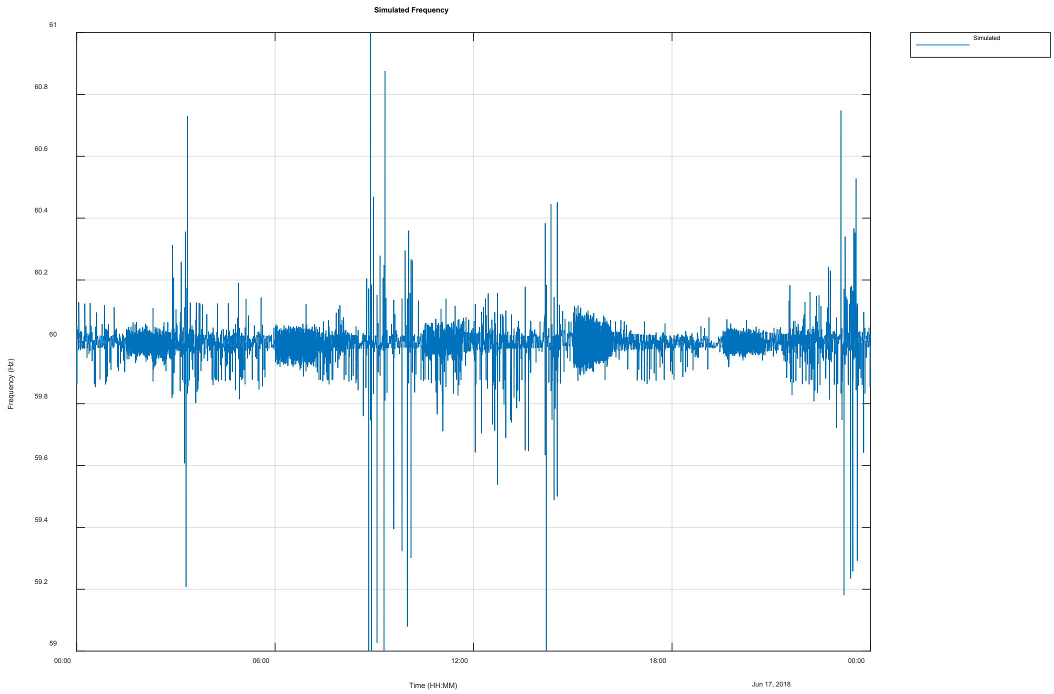
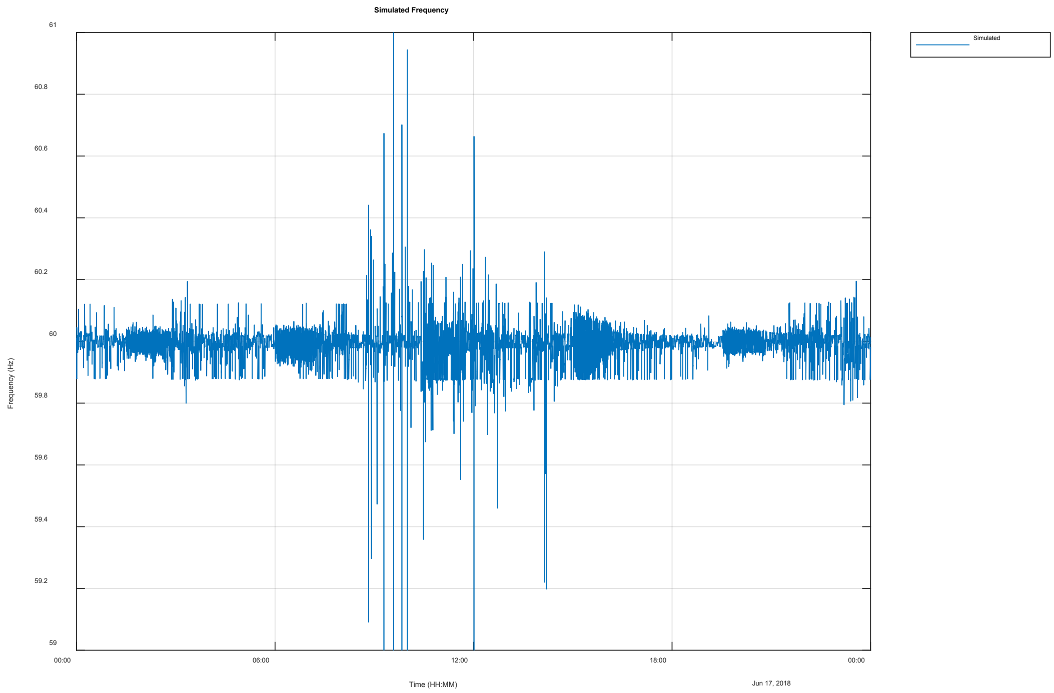


Figure 2-45 Case 12 - Simulated frequency on weekend with 4 MW PV and 2 MW / 10 MWh MW battery on AGC and diesel allowed off



2.3.3 Base Case 3 & Simulation cases 13 – 18 Weekend with VRE from 7 July 2018

Base Case 3: Weekend - Simulation of original day from 7 July 2018

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data except with the increase of the wind power from 2 – 3 turbines. Figure 2-46 shows the simulation of generation unit outputs for the Sunday 7 July 2018. This is the base case for these simulations where we can compare techno-economic impact of cases13 to 18. The simulated frequency, as shown in Figure 2-47, shows the expected frequency variations which are much greater than recorded on the actual day with the increase in wind power and quite a few variations outside the acceptable limits of 59.5 – 60.5 Hz showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-46 Simulated generation on Sunday 7 July 2018 with wind power increased from 2 to 3 turbines

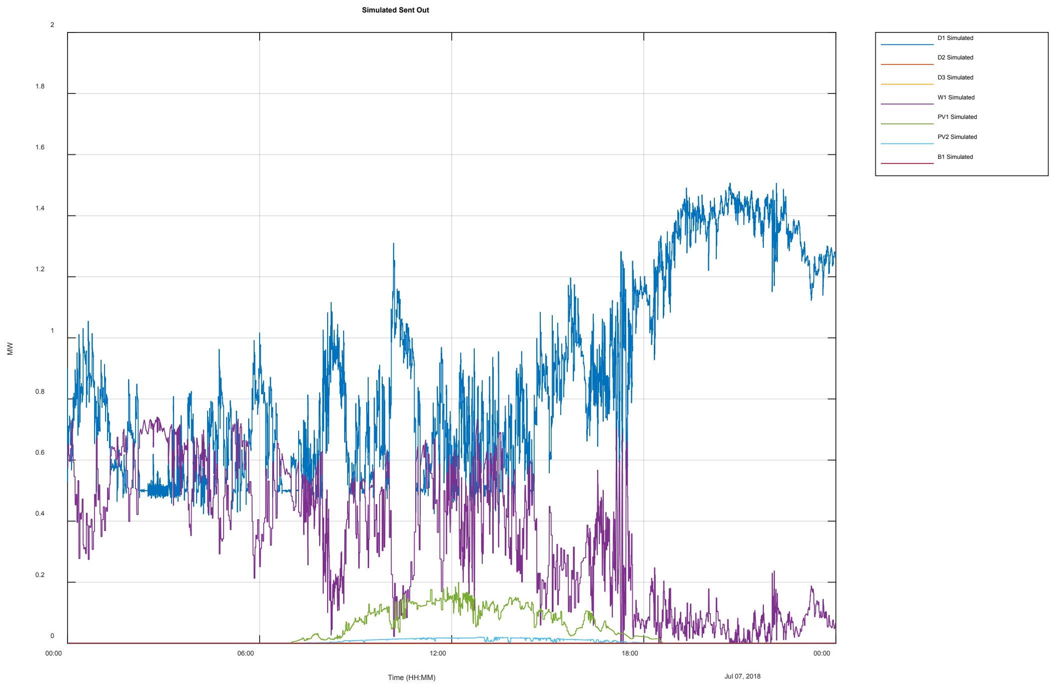
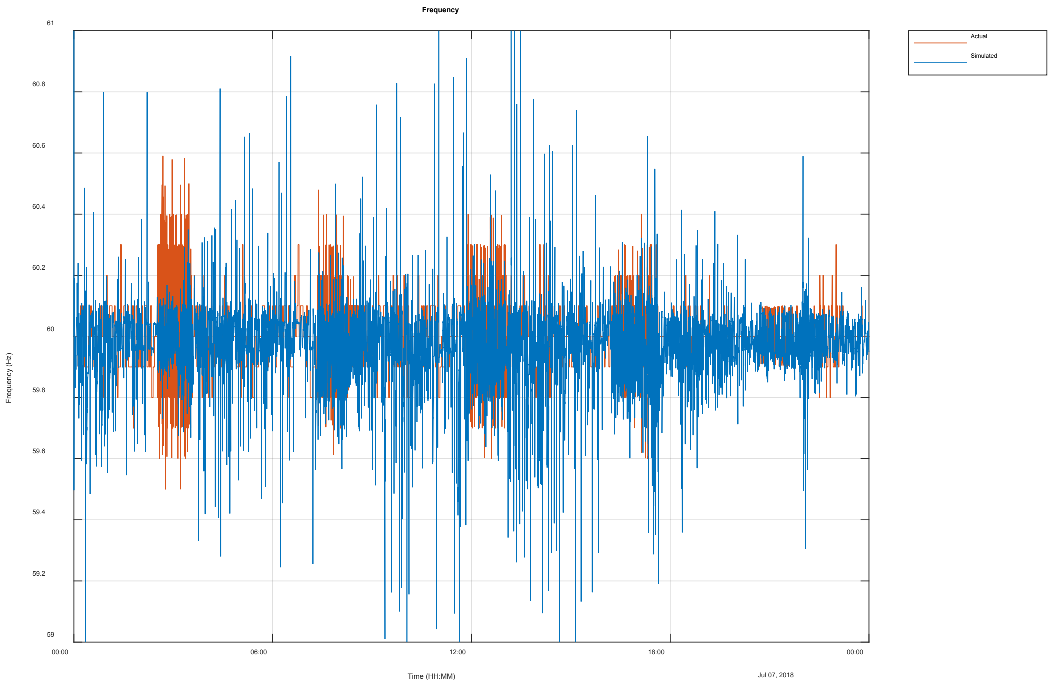


Figure 2-47 Simulated frequency on Sunday 7 July 2018 with wind power increased from 2 to 3 turbines



Case 13 - 18: Weekend – Repeat of cases 1-6 with data on Sunday 7 July 2018.

Cases 13 – 18 is the repeat of the simulations for a typical weekend but with data recorded on Sunday 17 June 2018. The simulated frequency is as with the previous cases is often outside the acceptable range with a 0.5 MW inverter and the frequency control is only acceptable with a 1 MW inverter, Case 15 with 1 MW of simulated PV with a 1 MW / 3 MWh battery on AGC results in an acceptable frequency control, as shown in Figure 2-48.

Cases 17 & 18 with 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off has similar results to cases 5 & 6 and frequency control is acceptable, as shown in Figure 2-49.

Figure 2-48 Case 15 - Simulated frequency on weekend with 1 MW PV and 0.5 MW / 3 MWh MW battery on AGC

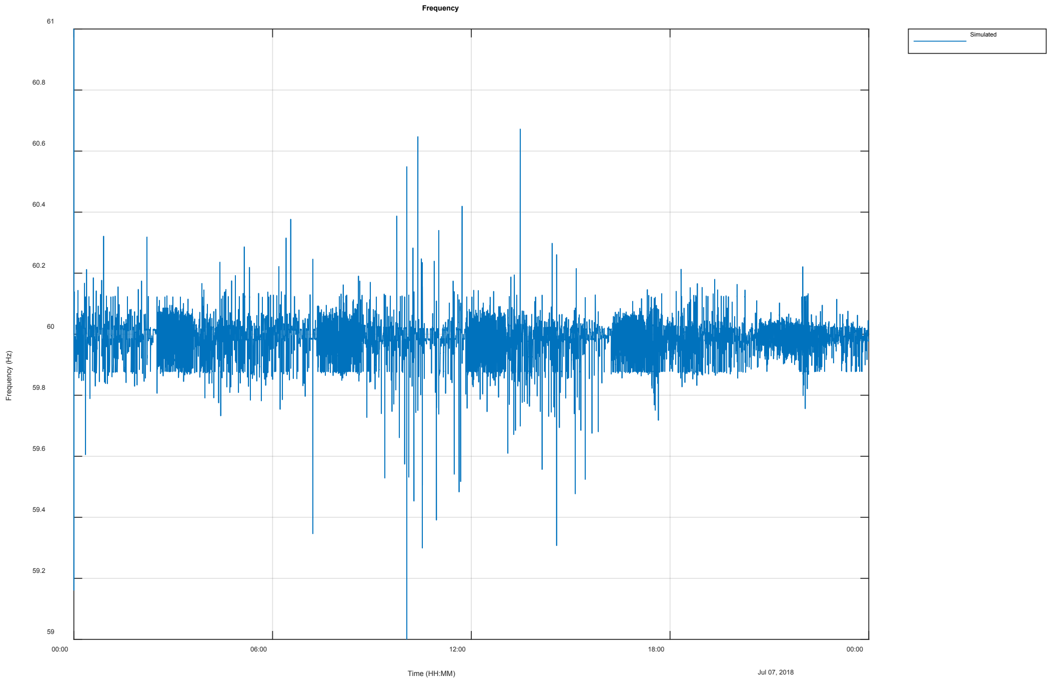
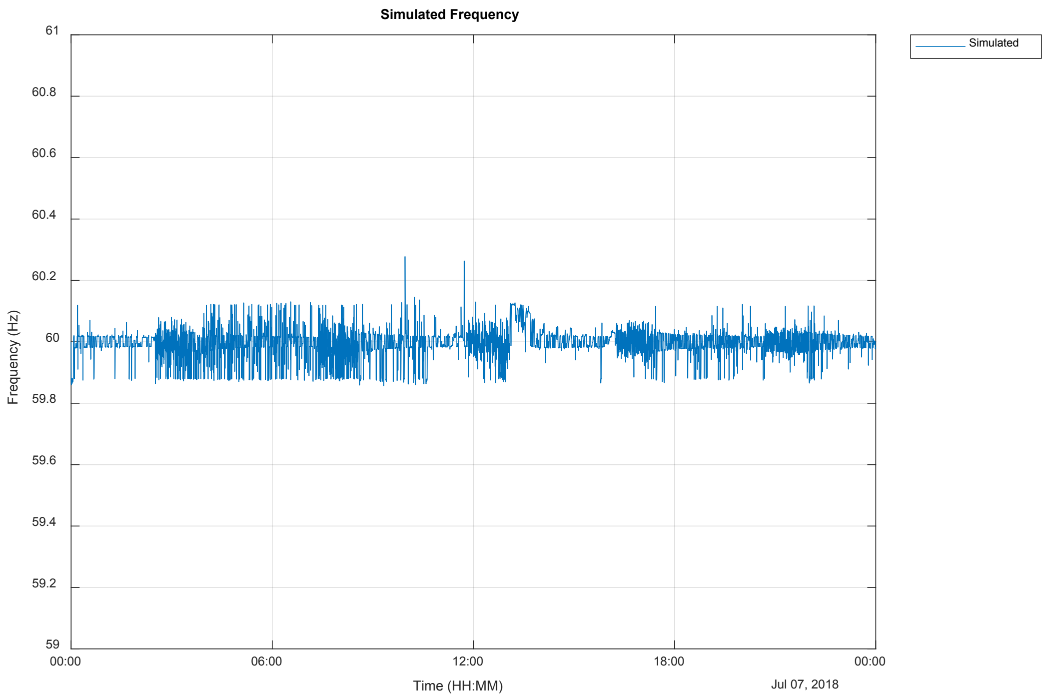


Figure 2-49 Case 17 - Simulated frequency on weekend with 4 MW PV and 2 MW / 10 MWh battery on AGC.



2.3.4 Base Case 7 & Simulation cases 37 – 42 Weekend with VRE from 17 Feb 2019

Base Case 7: Weekend - Simulation of original day from 17 Feb 2019

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 2-50 shows the simulation of generation unit outputs for the Sunday 17 Feb 2019. This is the base case for these simulations where we can compare techno-economic impact of cases 37 to 42. The simulated frequency, as shown in Figure 2-51, shows the expected frequency variations which are similar to the recorded variations on the actual day and mainly within acceptable limits of 59.5 – 60.5 Hz but showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-50 Simulated generation on Sunday 17 February 2019

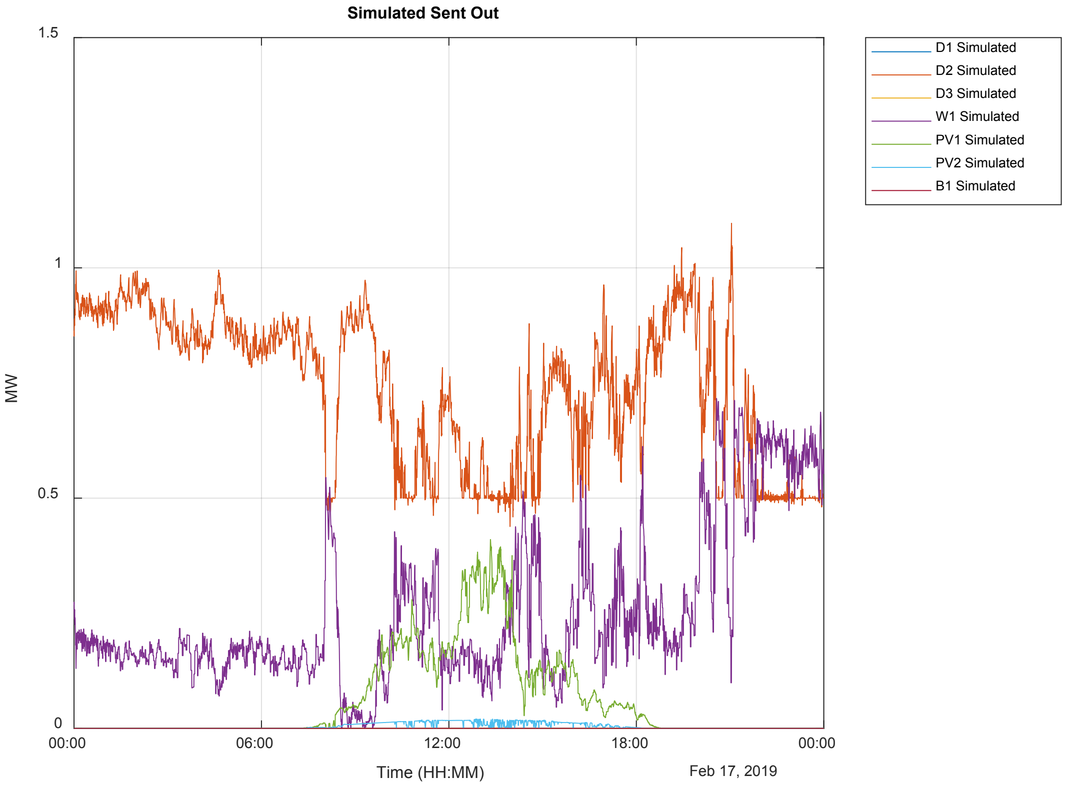
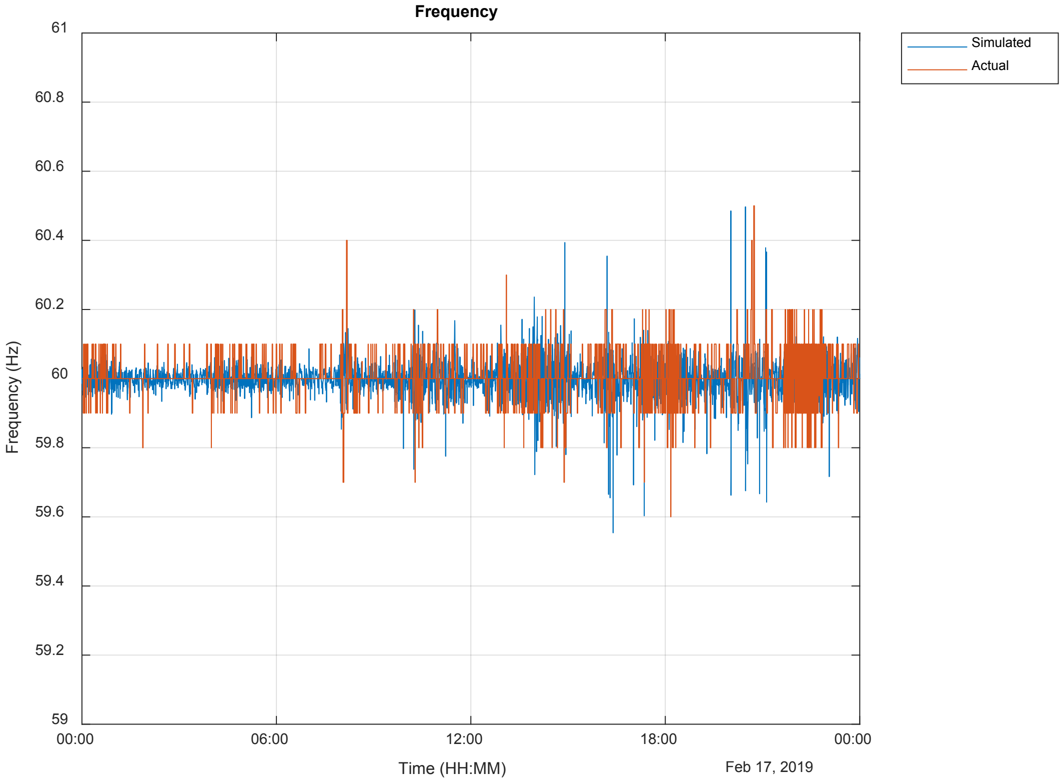


Figure 2-51 Simulated frequency on Sunday 17 February 2019



<u>Case 37 - 42: Weekend – Repeat of cases 1-6 with data on Sunday 17 February 2019.</u>

Cases 37 – 42 is the repeat of the simulations for a typical weekend but with data recorded on Sunday 17 February 2019. The simulated frequency is within the acceptable range with a 0.5 MW inverter which is unlike the previous cases with a 0.5 MW inverter, as shown in Figure 2-52.

Cases 41 & 42 with 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off has similar results to cases 5 & 6 and frequency control is acceptable, as shown in Figure 2-53.

Figure 2-52 Case 39 - Simulated frequency on weekend with 1 MW PV and 0.5 MW / 3 MWh MW battery on AGC

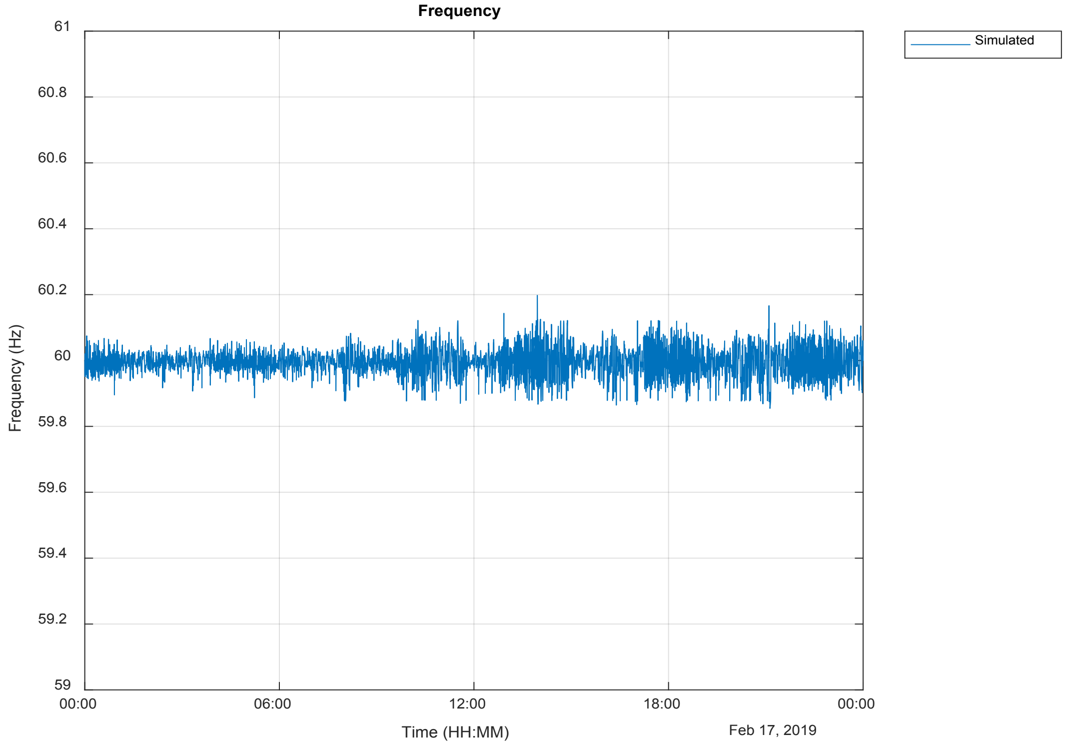
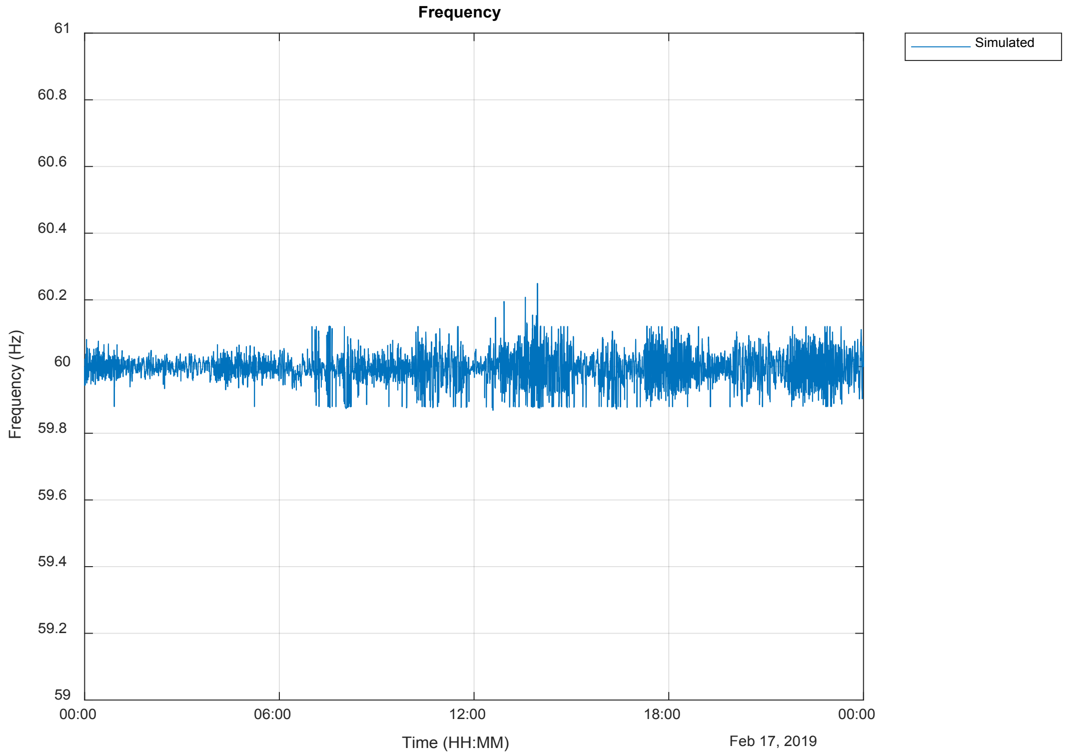


Figure 2-53 Case 41 - Simulated frequency on weekend with 4 MW PV and 2 MW / 10 MWh battery on AGC.



2.3.5 Summary of weekend economic results

The daily diesel fuel savings for each of the comparative cases is very similar as shown in Table 2-4. Table 2-5 shows the total 'variable' costs which is the simulated diesel fuel costs, the daily PV costs for the simulated additional PV and the additional battery costs for the installed batteries. Table 2-6 is the percentage increase in the above costs from the original base case. The increasing to 2 MW of PV with the 0.5MW / 3MWh battery increases costs an average of 1.2%. The increase to from 4 MW of PV with the 2MW / 10MWh battery decreases costs for all cases from 3.3 – 6.8 % if all diesel units are allowed to off.

Table 2-4 Weekend - Comparison of daily fuel saving with different PV and battery input data

Simulation description	Case 1 - 6 diesel savings	Case 7 - 12 diesel savings	Case 13 - 18 diesel savings	Case 37 - 42 diesel savings
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	0	0	8	0
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	617	662	835	426
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	629	665	844	438
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	1,099	1,179	1,055	807
4 MW PV, 0.825 MW wind, D3 on, & 2MW / 10MWh battery on AGC	3,075	3,184	3,068	2,593
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	3,121	3,309	3,557	2,797

Table 2-5 Weekend - Comparison of daily fuel, battery and additional PV costs with different PV and battery input data

Simulation description	Case 1 - 6 Fuel, battery and additional PV costs	Case 7 - 12 Fuel, battery and additional PV costs	Case 13 - 18 Fuel, battery and additional PV costs	Case 37 - 42 Fuel, battery and additional PV costs
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	6,101	5,795	5,494	4,845
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	5,781	5,433	5,032	4,572
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	5,857	5,517	5,110	4,647
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	5,681	5,300	5,280	4,497
4 MW PV, 0.825 MW wind, D3 on, & 2MW / 10MWh battery on AGC	5,530	5,126	5,266	4,386
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	5,485	5,001	4,777	4,181

Table 2-6 Weekend - Comparison of daily percentage change in daily fuel, battery and additional PV costs with different PV and battery input data

Simulation description	Case 1 - 6 % change	Case 7 - 12 % change	Case 13 - 18 % change	Case 37 - 42 % change
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	7.6%	8.0%	8.3%	9.7%
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	1.9%	1.3%	-0.8%	3.6%
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	3.3%	2.8%	0.8%	5.3%
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	0.2%	-1.2%	4.1%	1.9%
4 MW PV, 0.825 MW wind, D3 on, & 2MW / 10MWh battery on AGC	-2.5%	-4.5%	3.8%	-0.7%
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	-3.3%	-6.8%	-5.8%	-5.3%

2.3.6 Base Case 4 & Simulation cases 19 - 24 Weekday with VRE from 17 June 2018

Base Case 4: Weekday - Simulation of original day from 16 June 2018 with demand data from 18 June 2018

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 2-54 shows the simulation of generation unit outputs with demand from 18 June 2018. This is the base case for these simulations where we can compare techno-economic impact of cases 19 - 24. The simulated frequency, as shown in Figure 2-55, shows the expected frequency variations without any frequency deviations which is reasonable for the amount of VRE.

The frequency excursions are just within the acceptable limits of 59.5 – 60.5 Hz showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-54 Simulated generation on weekday with current installed VRE recorded on Saturday 16 June 2018

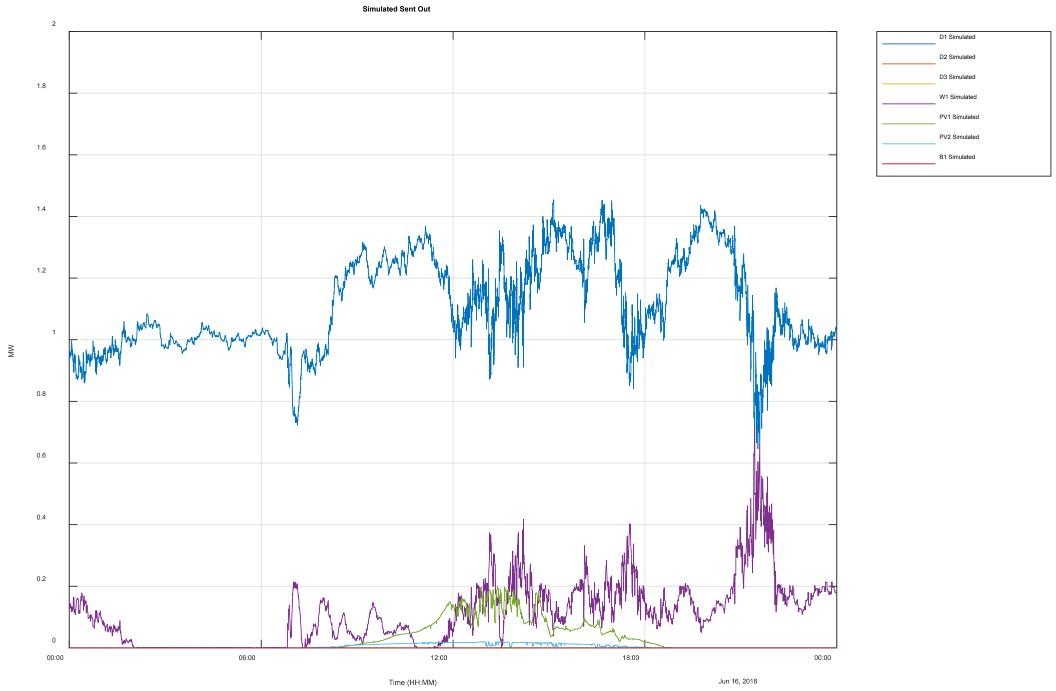
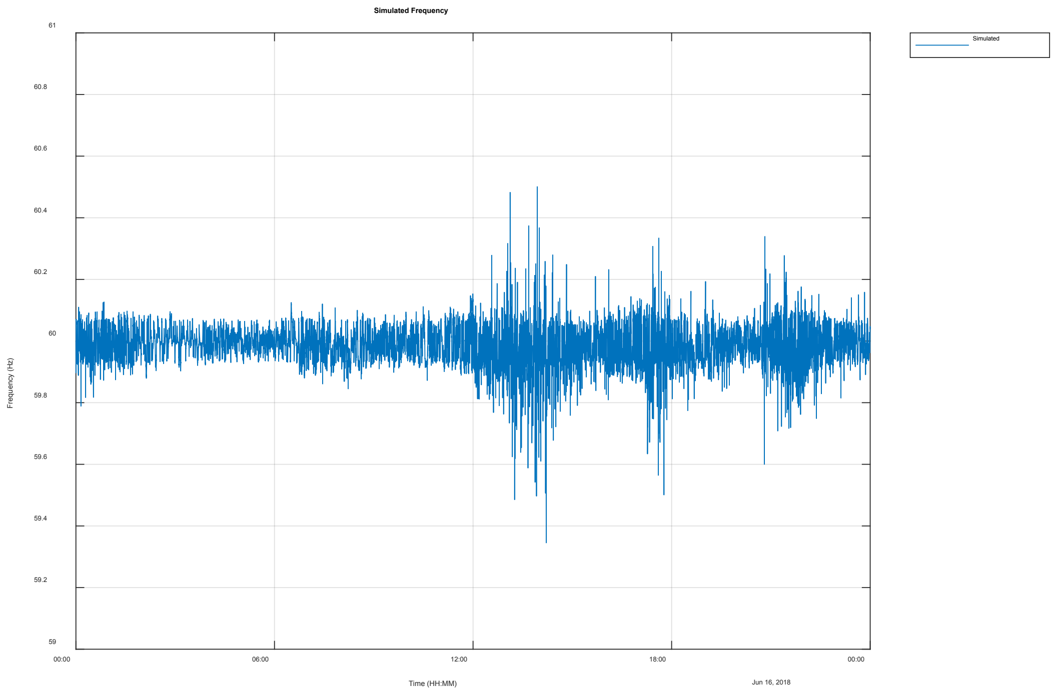


Figure 2-55 Simulated frequency on weekday with current installed VRE



Case 19: Weekday - with current installed VRE with 0.5 / 3 MWh battery on primary frequency control

Case 19 is the simulation of base case 1 with 0.5 MW / 3 MWh battery as proposed by the proposed FSM study. The battery is initially added for primary frequency control only as there is no excess VRE energy to charge the battery. The battery output varies up to 0.2 MW showing this is adequate for primary frequency control, as shown in Figure 2-56. The frequency is improved and well within the acceptable limits of 59.5 to 60.5 Hz, as shown in Figure 2-57.

Figure 2-56 Simulated battery output on weekday - base case 4 with 0.5 MW / 3 MWh battery on primary frequency control

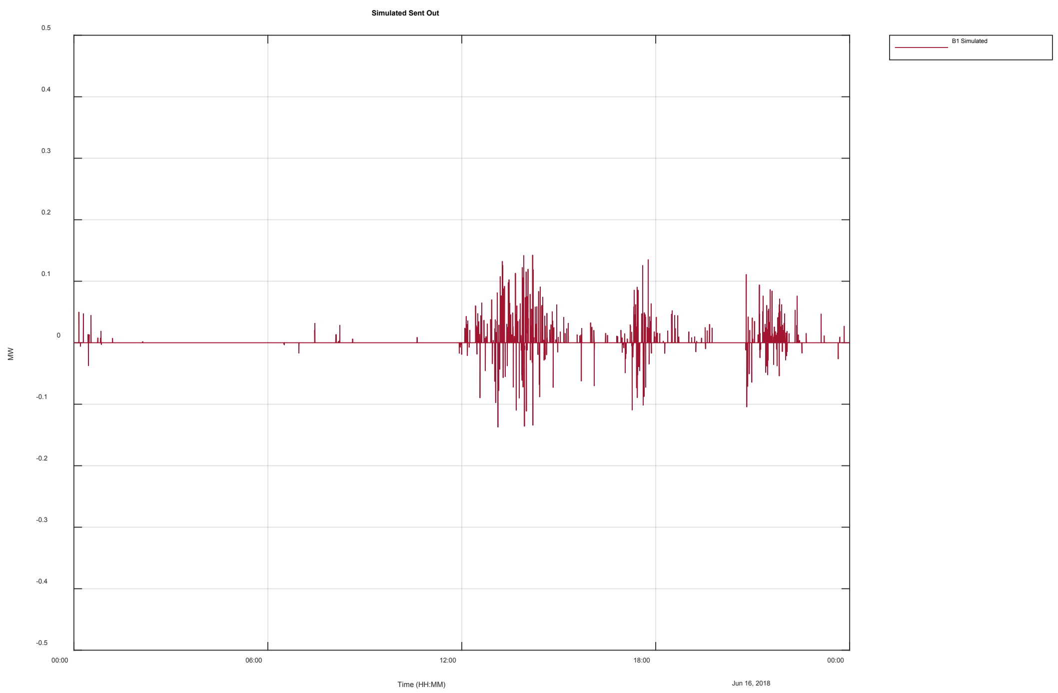
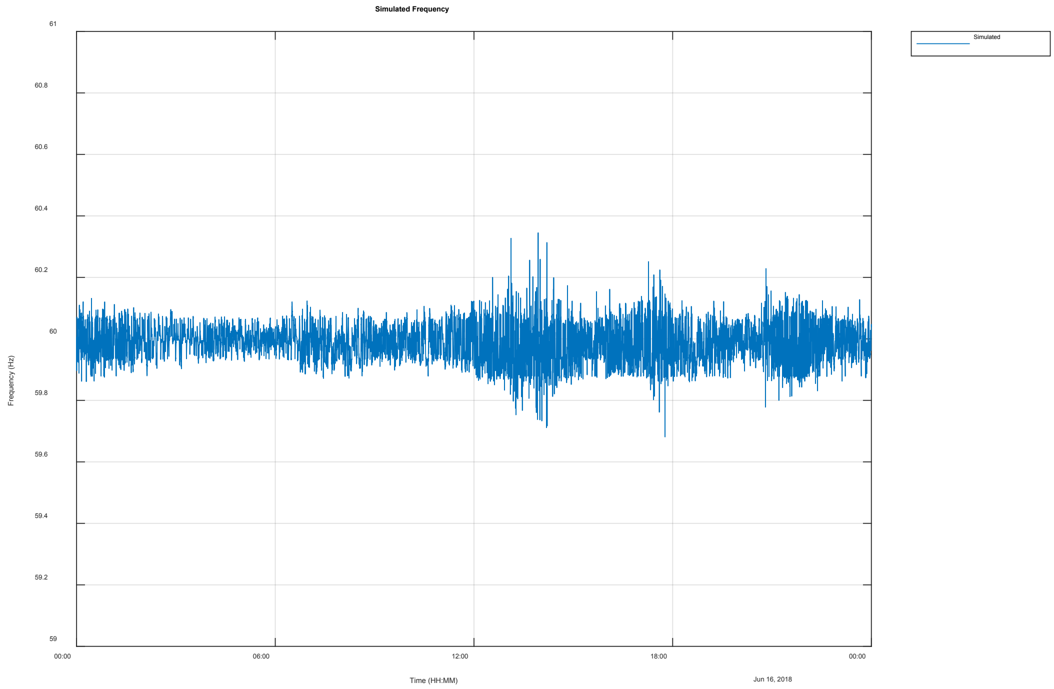


Figure 2-57 Simulated frequency on weekday - base case 4 with 0.5 MW / 3 MWh battery on primary frequency control



<u>Case 20: Weekday - 1 MW of PV and 0.5 MW / 3 MWh battery on AGC</u>

Case 20 is with 1 MW of PV and the 0.5 MW / 3 MWh battery on AGC. The batteries also provide primary frequency control as for the simulations above.

The simulated frequency is not within acceptable limits when 0.5 MW battery is on primary frequency control and AGC, as shown in Figure 2-58. There are more than a few occasions during the period when the battery is fully utilised and the response is not enough to prevent frequency excursion, as shown in Figure 2-59. When the diesel generation is at minimum generation it does not contribute to frequency control thus the poor frequency during this period. Fuel costs decrease 9% from base case 1 from $6.324 to $5,732. The battery hardly charges from 20%, as shown in Figure 2-60. A net cost of US$ 135 is calculated for the simulation day including the PV and battery costs.

Figure 2-58 Simulated frequency for weekday with 1 MW of PV and 0.5 MW / 3 MWh battery on AGC

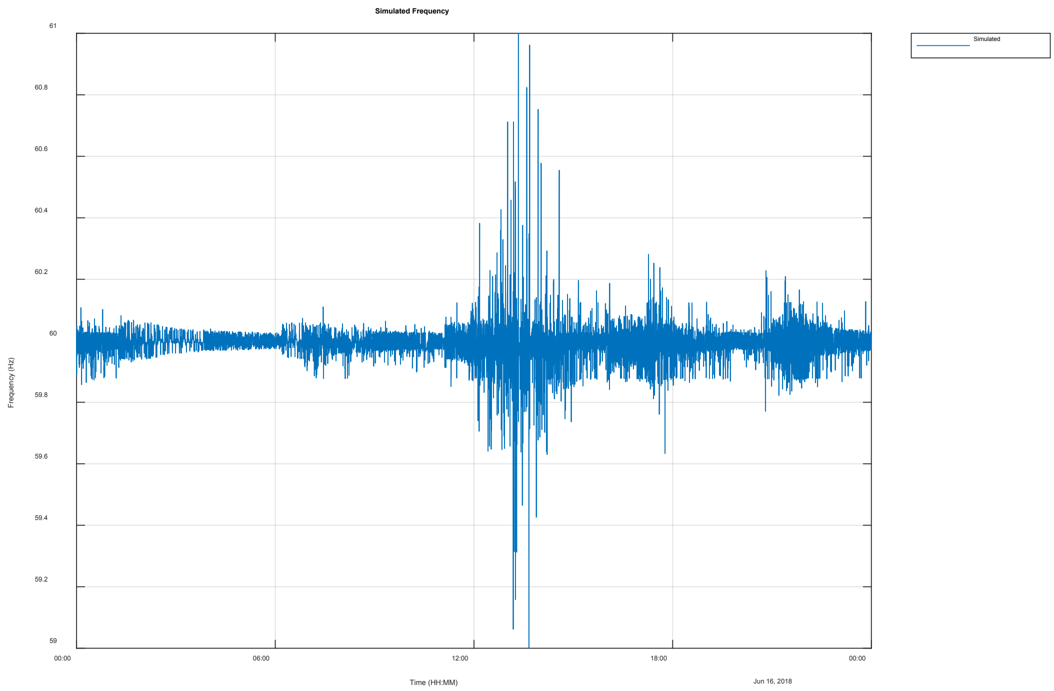


Figure 2-59 Simulated battery power for weekday with 1 MW of PV and 0.5 MW / 3 MWh battery on AGC

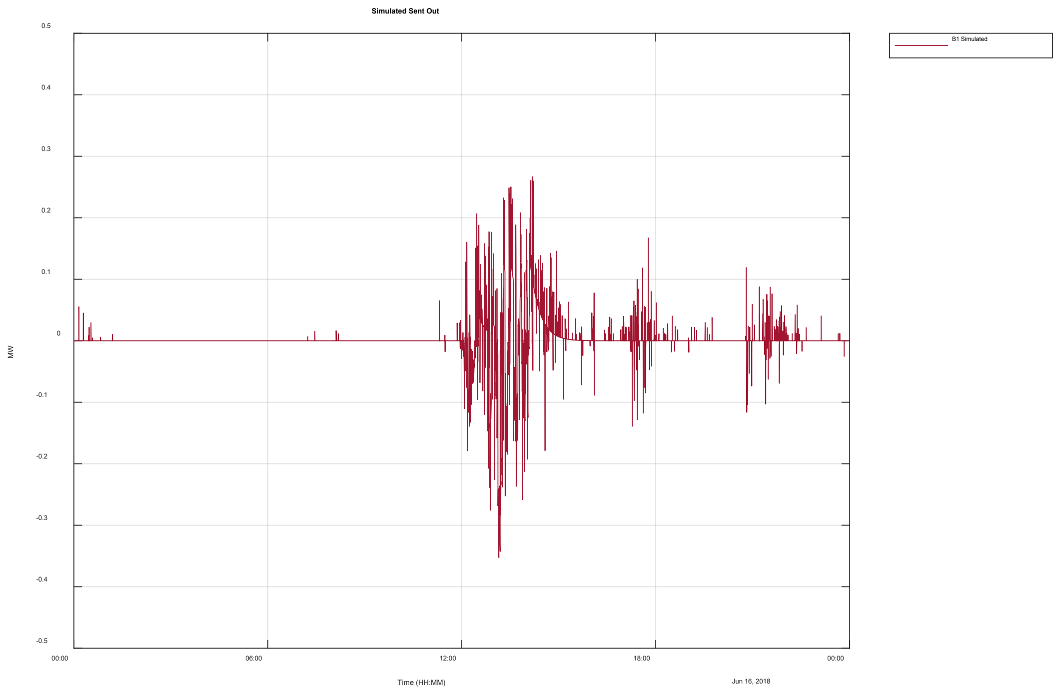
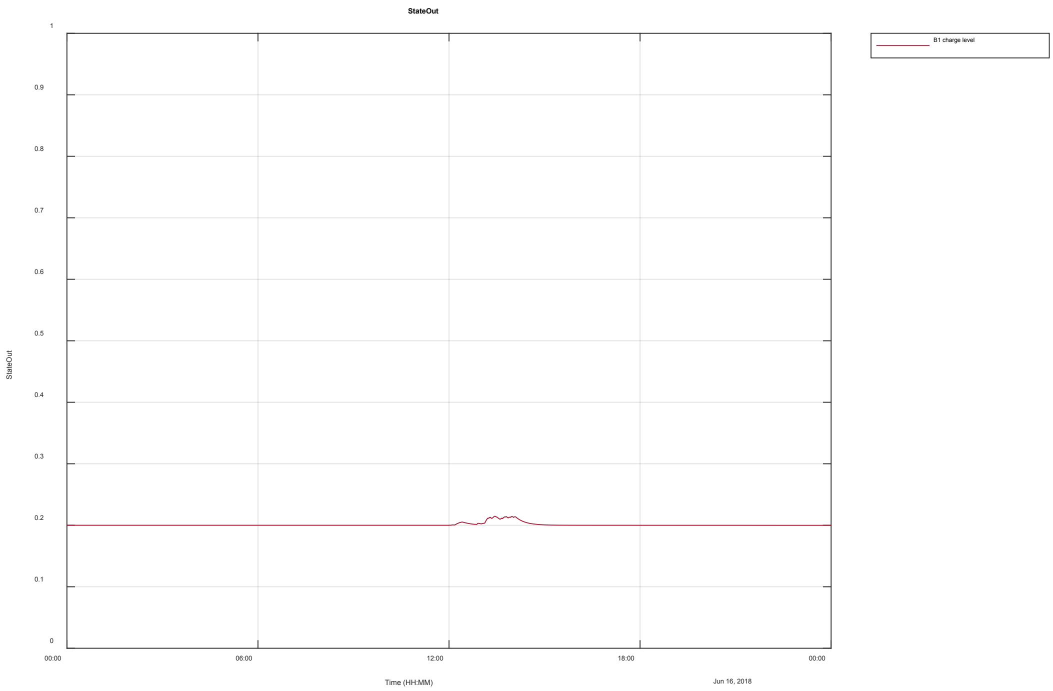


Figure 2-60 Simulated battery charge for weekday with 1 MW of PV and 0.5 MW / 3 MWh battery on AGC



Case 21: Weekday – 1 MW of PV and 1 MW / 3 MWh battery on AGC

Case 21 the PV1 power plant is same as case 20 with an increase in inverter size to 1 MW to curtail the large frequency excursions. Diesel unit 1 provides the secondary control under AGC to perform the control assisted by a 1 MW battery on AGC, as shown in Figure 2-61. The frequency is acceptable control well within the range of 59.5 to 60.5 Hz, as shown in Figure **2-62**. The battery full range is hardly utilised to control the frequency as in the previous simulation case, as shown in Figure 2-63.

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Nearly all of the available energy from the 1 MW of PV as per the case 20 but a higher net loss of US$ 223 for the simulation day accounting for the bigger inverter.

Figure 2-61 Simulated generation for weekday 1 MW of PV and 1 MW / 3 MWh battery on AGC

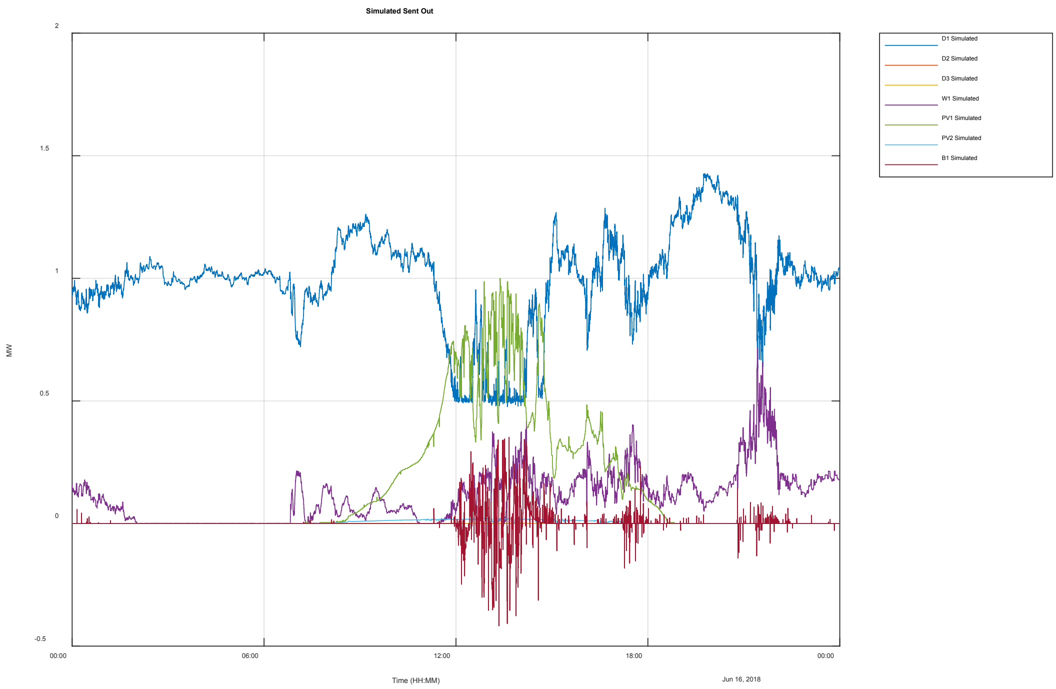


Figure 2-62 Simulated frequency for weekday with 1 MW of PV and 1 MW / 3 MWh battery on AGC

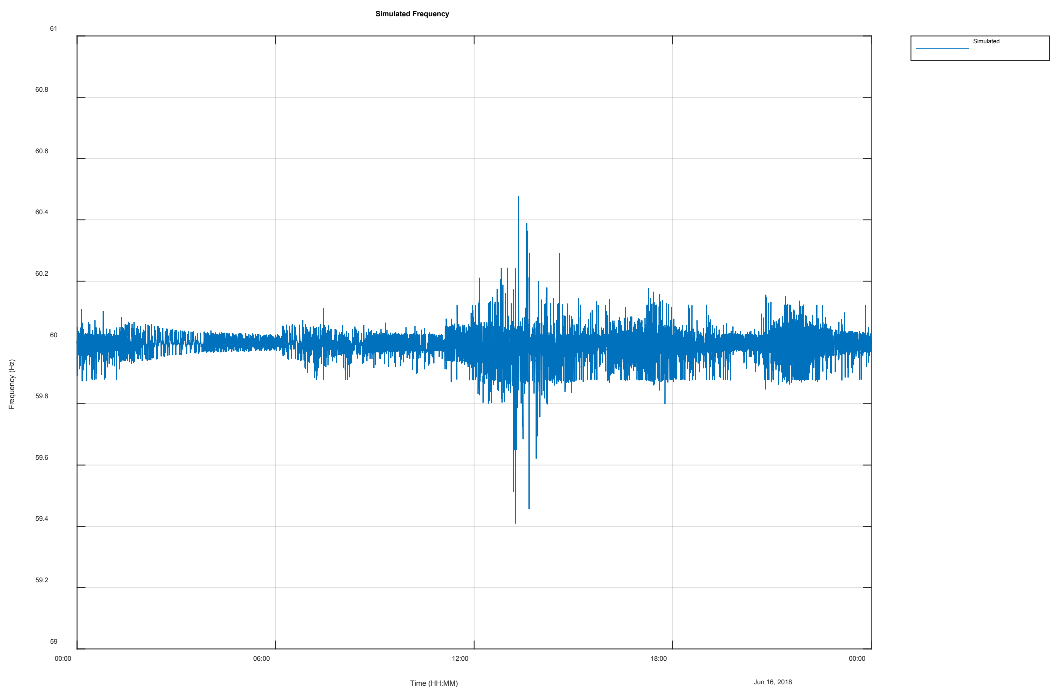
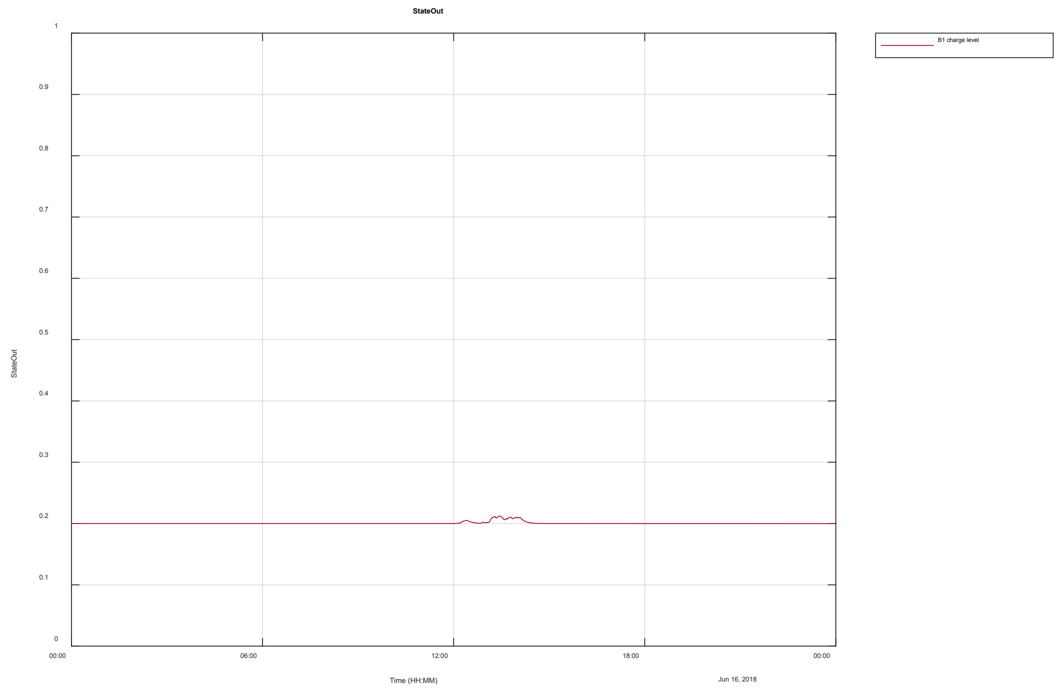


Figure 2-63 Simulated battery output for 1 MW of PV and 1 MW / 3 MWh battery on AGC



<u>Case 22: Weekday – 2 MW of PV and 0.5 MW / 3 MWh battery on AGC</u>

Case 22 is simulating the same as Case 20 but now with assistance of 2 MW of PV on PV1. Figure 2-64 shows the frequency is better than the case for a 1 MW PV with the same battery. This is due to the curtailment of PV power peaks but the troughs are higher making the change in PV power less and subsequent frequency control better. The simulated VRE power is curtailed 8.4%.

Figure 2-65 shows the when battery simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery 60% charge level, as shown in Figure 2-66, by 14:00. The batteries then discharge instead of using diesel generation from 16:00 Hrs until charge level is 20% which is around 20:00. The simulated diesel generator 1 output is at minimum generation for most of the period from 11:30 Hrs to 18:00 Hrs, as shown in Figure 2-67.

The fuel costs for Case 22 is $ 5,074 compared to $ 5,732 for Case 20. This reduction is due to an increase PV output of 3.1 MWh which is used to charge the batteries and is later discharged instead of using diesel power. This case has a net saving of $ 141 for the simulation day which is better than the calculated loss for case 20.

Figure 2-64 Simulated frequency for weekday when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.

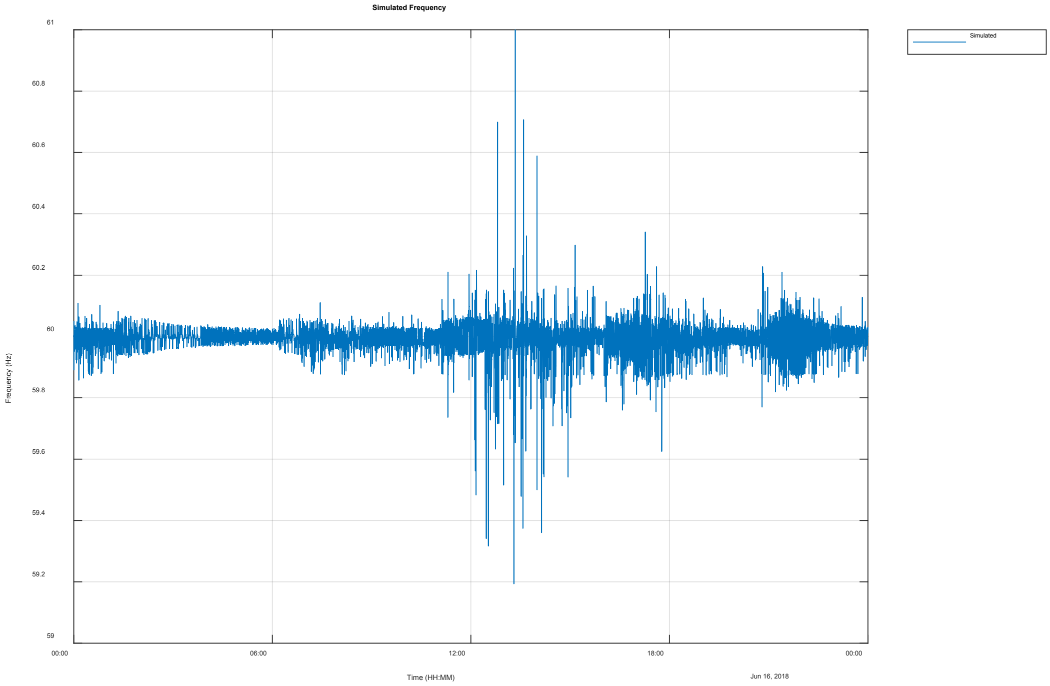


Figure 2-65 Simulated battery charge level for weekday when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.

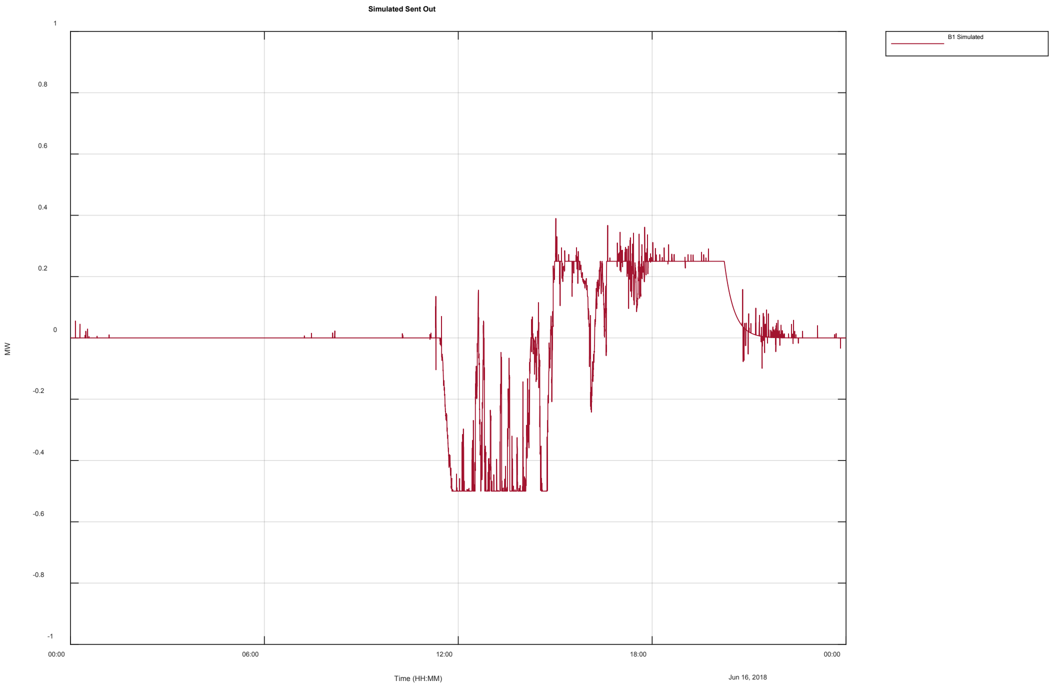


Figure 2-66 Simulated battery charge level for weekday when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.

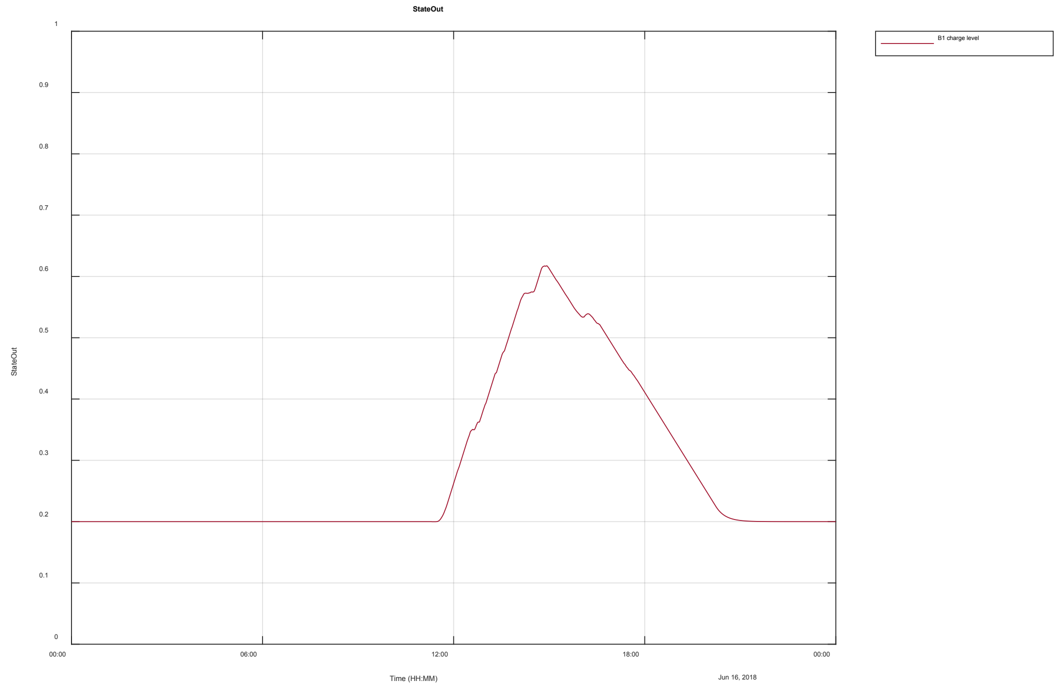
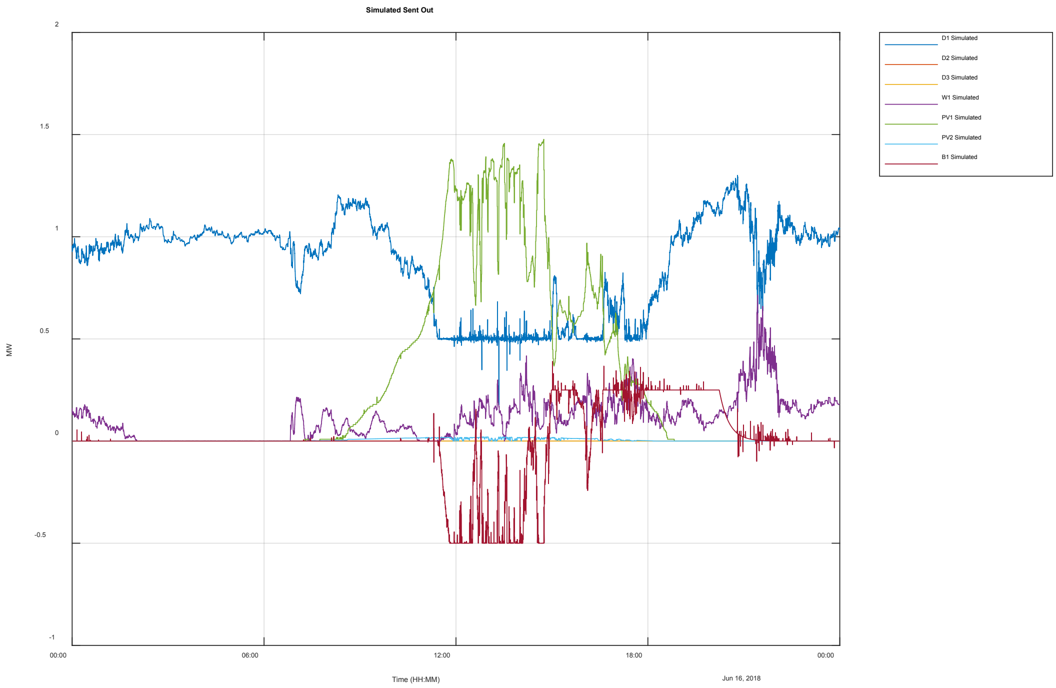


Figure 2-67 Simulated generator outputs for weekday when 0.5 MW / 3 MWh battery provides both primary frequency control and AGC with 2 MW of PV.



Case 23: Weekday – 4 MW of PV and 2 MW / 10 MWh battery on AGC and D3 on

Case 23 is simulating the next stage of the proposed by FSM Energy Master Plan Study, April 2018 with 4 MW of PV and 2 MW / 10 MWh battery on AGC. D3 is used as it has a minimum generation lower than the D1 & D2. The simulated frequency is within acceptable limits even when the last unit is off, as shown in Figure 2-68. There are a few frequency excursions which means the inverter size is adequate could be bigger as it is often at full charge MW output level. Figure 2-69 shows the battery fully discharges around 00:00 and the diesel unit is only above minimum generation from 00:00 to 10:00, as shown in Figure 2-70.

The energy not utilised is 1.1 MWh or 6.3% of energy lost. This case has a net profit of $ 107 for the simulation day.

Figure 2-68 Simulated frequency for weekday when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

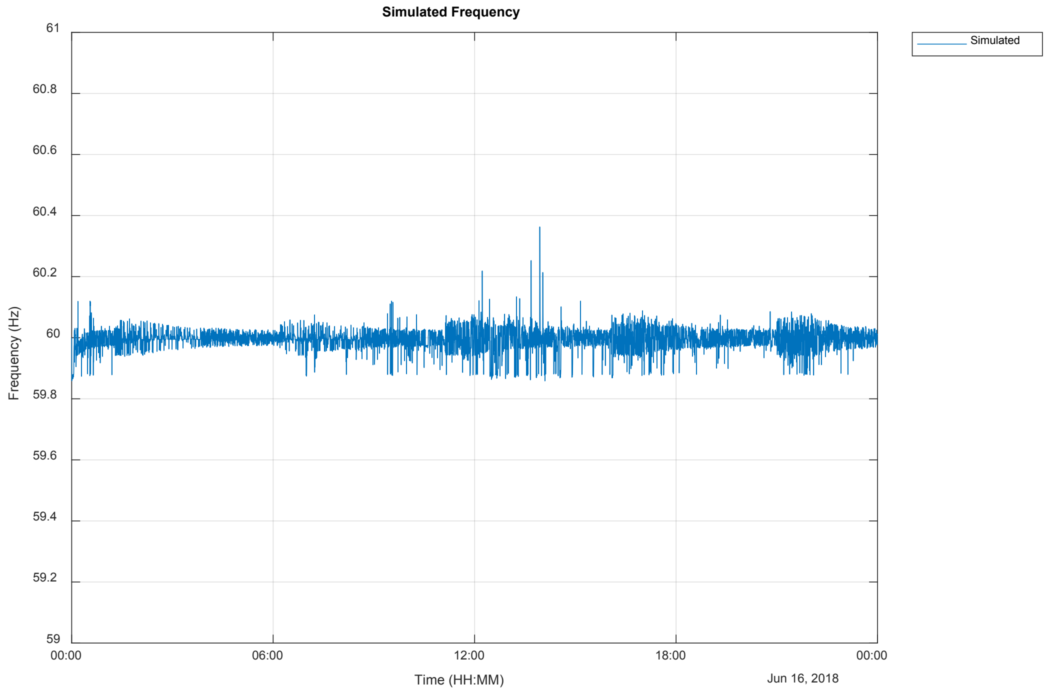


Figure 2-69 Simulated battery charge for weekday when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

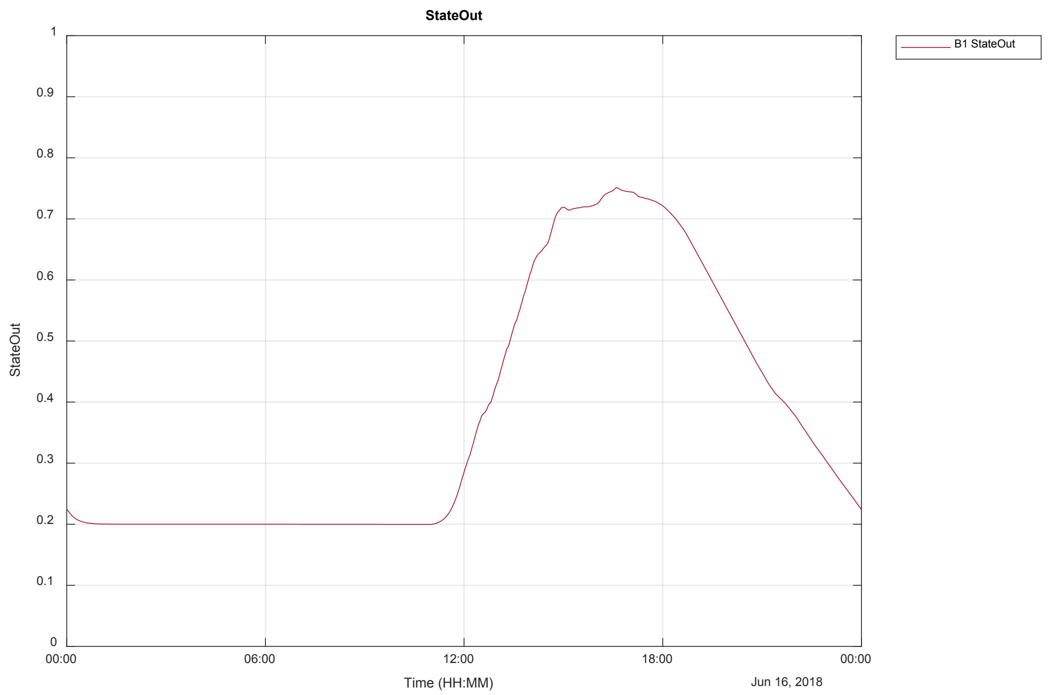
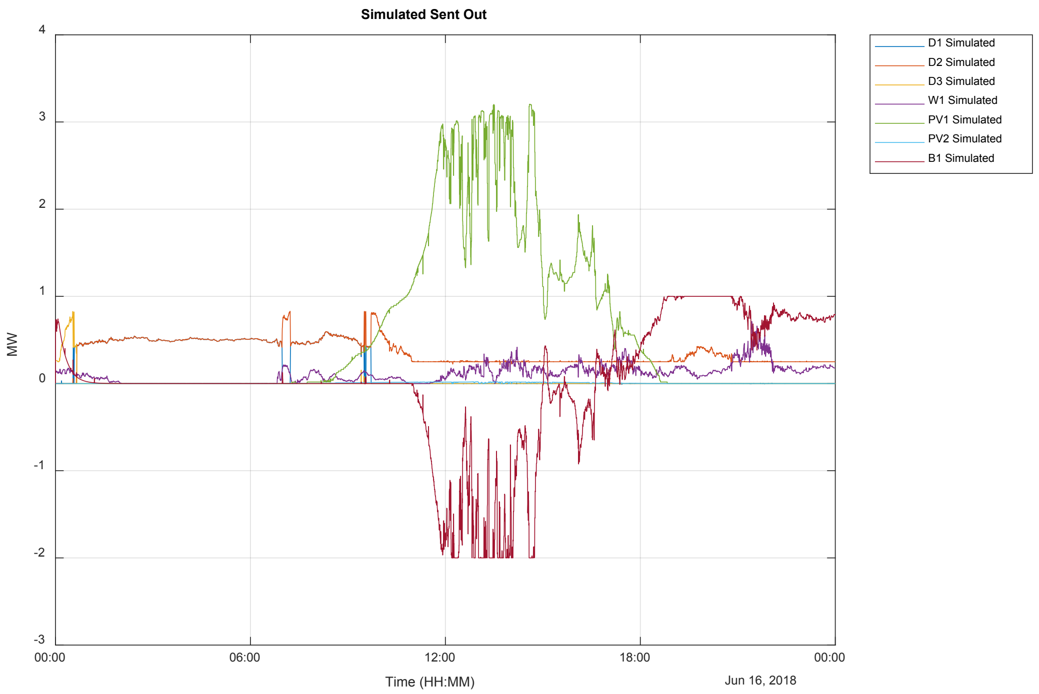


Figure 2-70 Simulated generation output for weekday when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.



Case 24: Weekday – 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off

Case 24 is simulating the same as Case 23 but now the diesel allowed to go off.

Figure 2-71 shows the when generation simulated outputs when put on primary frequency control and AGC, the batteries use the excess PV to charge the battery almost 65% charge level, as shown in Figure 2-72, by 12:00. The batteries then discharge instead of using diesel generation from 17:00 Hrs until midnight. No diesel is required from 11:00 until 22:30 except for a few times when battery is not sufficient. The battery output in the simulation is only allowed to go to 1 MW which is just not sufficient to meet the demand, as shown in Figure 2-73. Figure 2-74 shows the simulated frequency and when the PV is at its peak output and the battery is charging there is no sufficient control range to control the frequency. The frequency excursions are with the range of 59.5 to 60.5 Hz but the deviations are too big and too often so the simulation shows a higher level of battery inverter is required.

The fuel costs for Case 24 is $ 3,220 an extra saving of $ 195 for the simulation day. This case has a net profit of $ 170 for the simulation day.

Figure 2-71 Simulated generation outputs for weekday when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

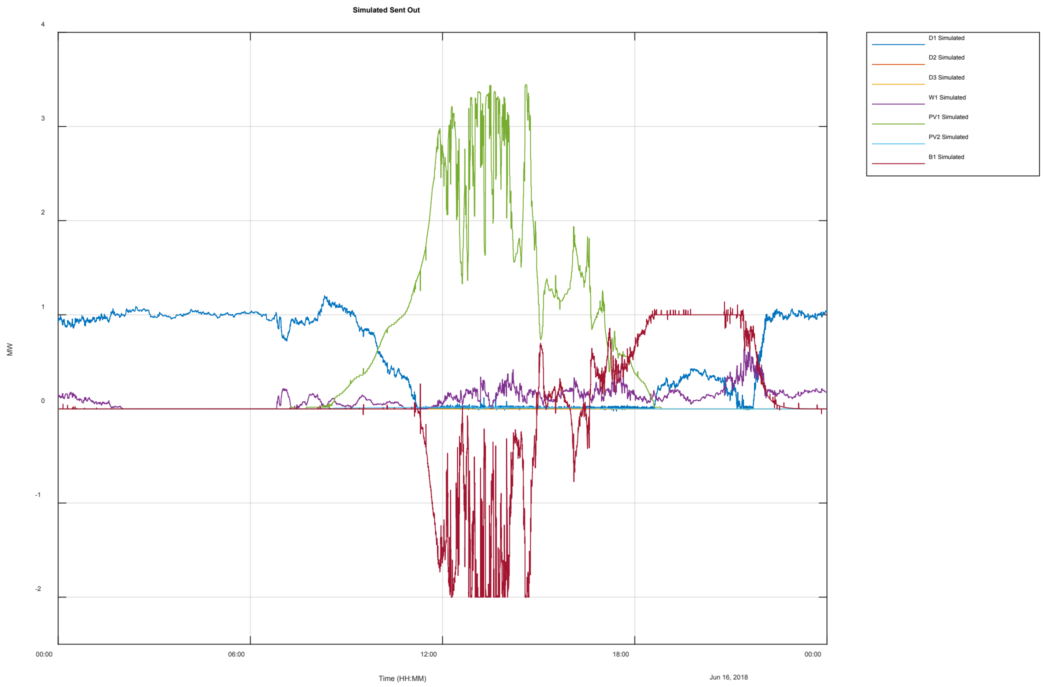


Figure 2-72 Simulated battery charge level for weekday 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

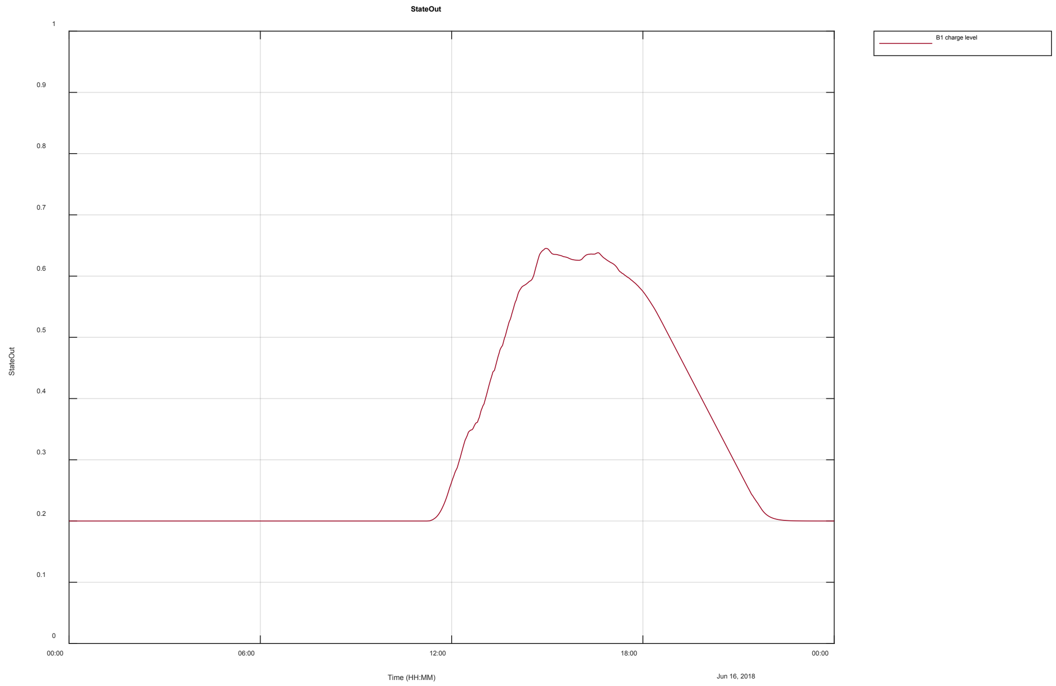


Figure 2-73 Simulated generator outputs for weekday when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.

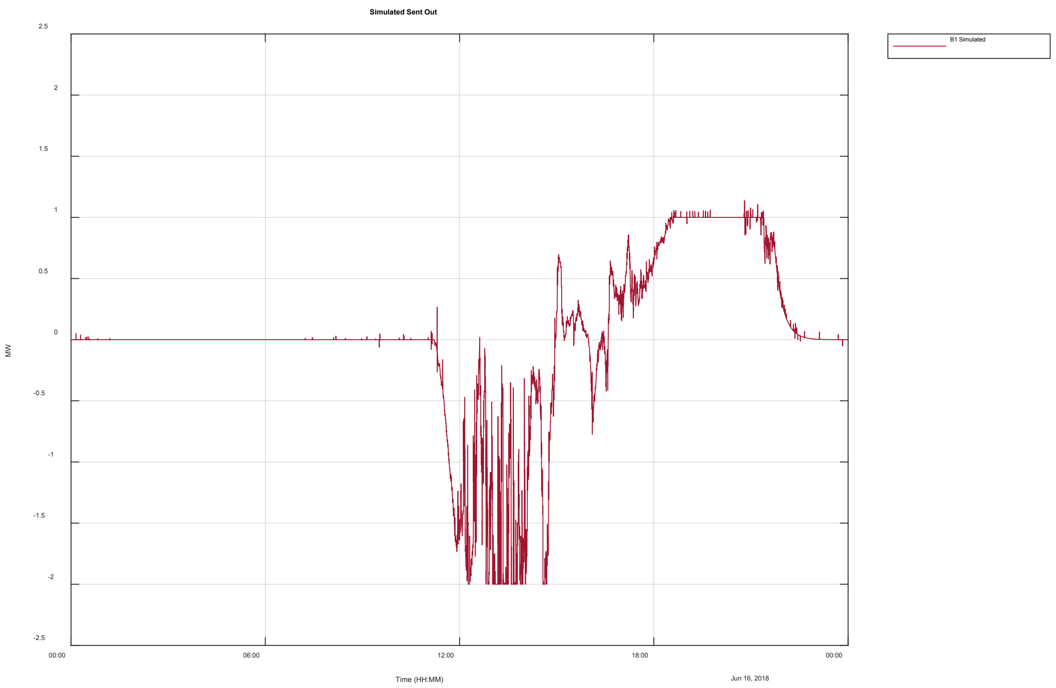
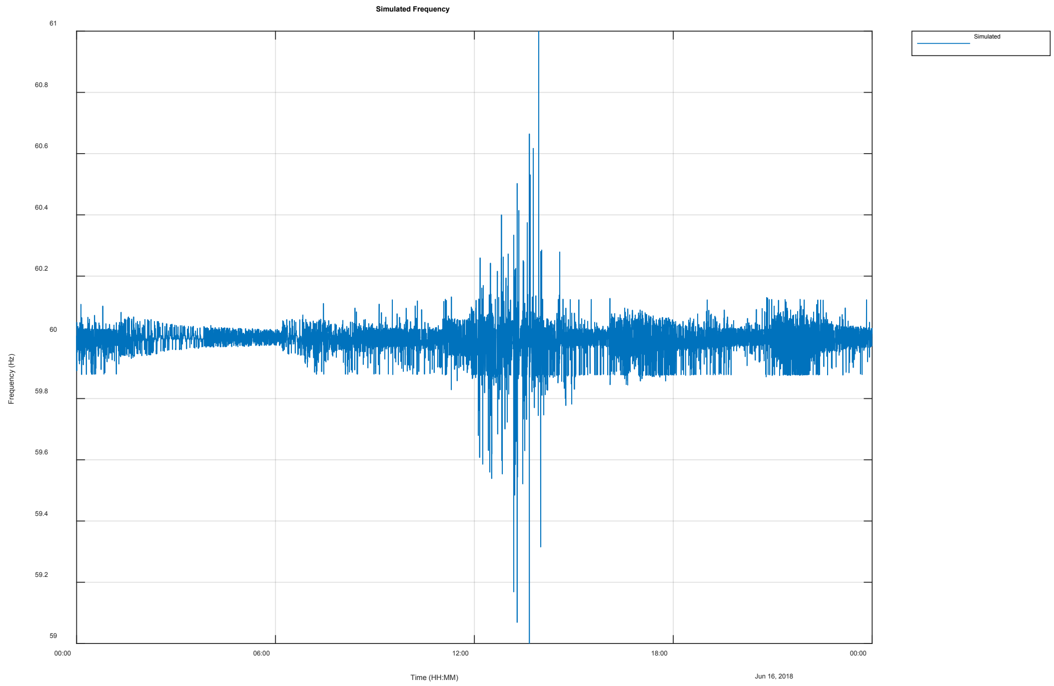


Figure 2-74 Simulated frequency for weekday when 2 MW / 10 MWh battery provides both primary frequency control and AGC with 4 MW of PV.



2.3.7 Base Case 5 & Simulation cases 25 – 30 Weekday of 18 June with VRE from 17 June 2018

Base Case 4: Weekday - Simulation of original day from 17 June 2018 with demand data from 18 June 2018

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 2-75 shows the simulation of generation unit outputs for a typical week day, with VRE from 17 June 2018. This is the base case for these simulations where we can compare techno-economic impact of cases 25 to 30. The simulated frequency, as shown in Figure 2-76, shows the expected frequency variations which has a few deviations outside the acceptable range of 59.5 – 60.5 Hz.

Figure 2-75 Simulated generation on weekday with current installed PV

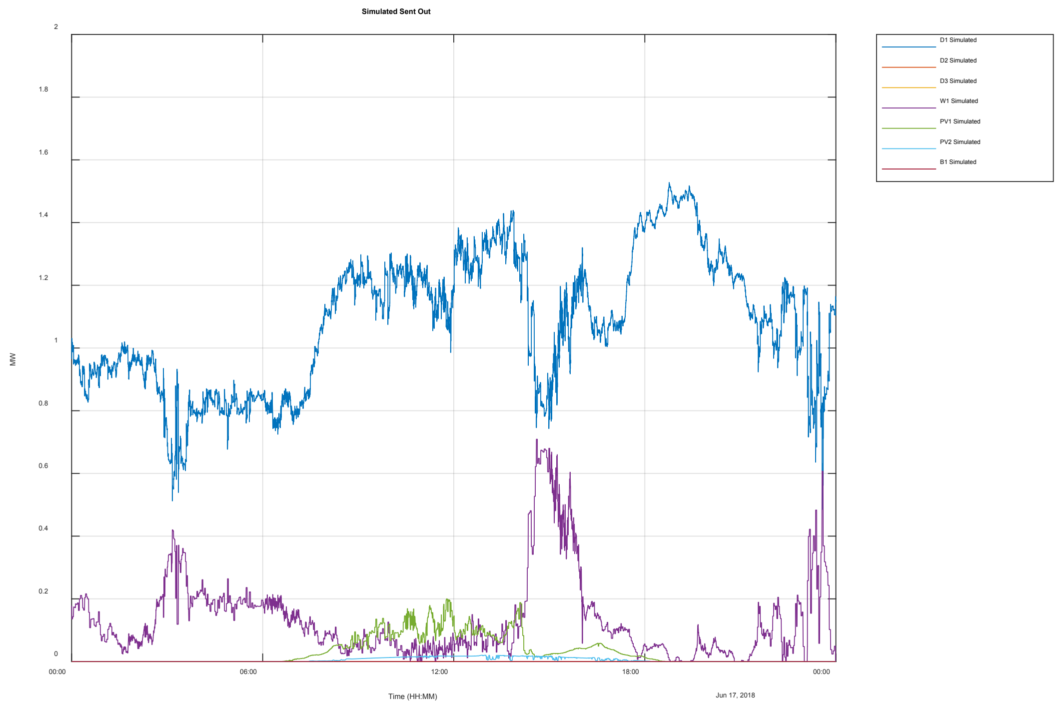
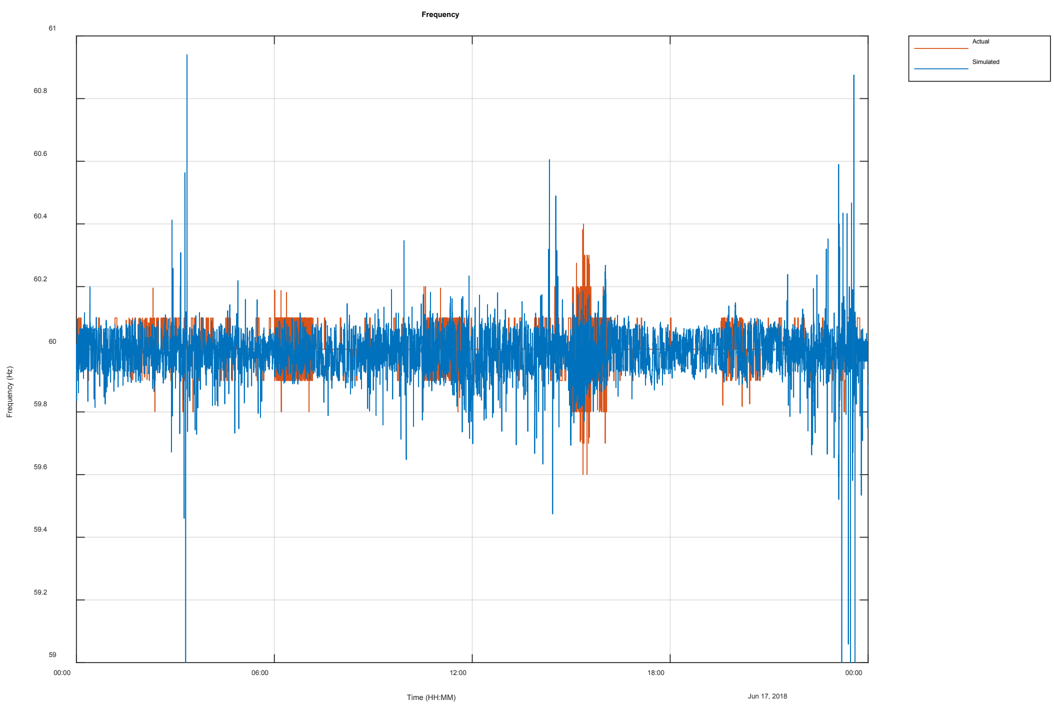


Figure 2-76 Simulated frequency on weekday with current installed PV



<u>Cases 25 - 30: Weekday – Repeat of cases 19 - 24 with VRE from 17 June 2018.</u>

Cases 25 – 30 is the repeat of the simulations for a typical weekday but with data recorded on Sunday 17 June 2018. The simulated frequency is within an acceptable range for case 25 with 0.5 MW / 3 MWh battery added except for a few occasions when wind power varies dramatically, as shown in Figure 2-77. Case 26 with 1 MW of simulated PV with a 0.5 MW / 3 MWh battery on AGC results in too many frequency variations outside the acceptable limits of 59.5 to 60.5 Hz as was for case 20, as shown in Figure 2-78. Case 27 with 1 MW of simulated PV with a 1 MW / 3 MWh battery on AGC results in an acceptable frequency control, as shown in Figure 2-79. Case 28 with the 2 MW of PV and 0.5 MW / 3 MWh battery on AGC has a same frequency control with a few excursions, as shown in Figure 2-80, which still suggests that the 0.5 MW inverter is too small.

Cases 11 & 12 with 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off has similar results to cases 5 & 6 except for frequency control has too many frequency excursions, as shown in Figure 2-81.

Figure 2-77 Case 25 - Simulated frequency on weekday with 0.5 MW / 3 MWh MW battery on AGC

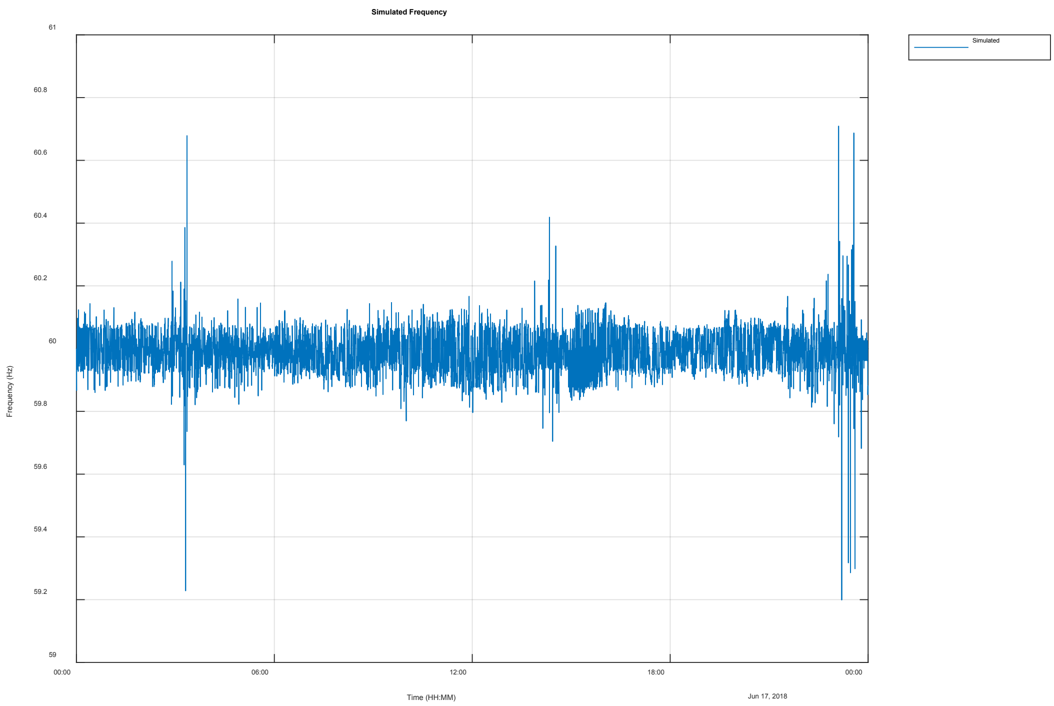


Figure 2-78 Case 26 - Simulated frequency on weekday with 1 MW PV and 0.5 MW / 3 MWh MW battery on AGC

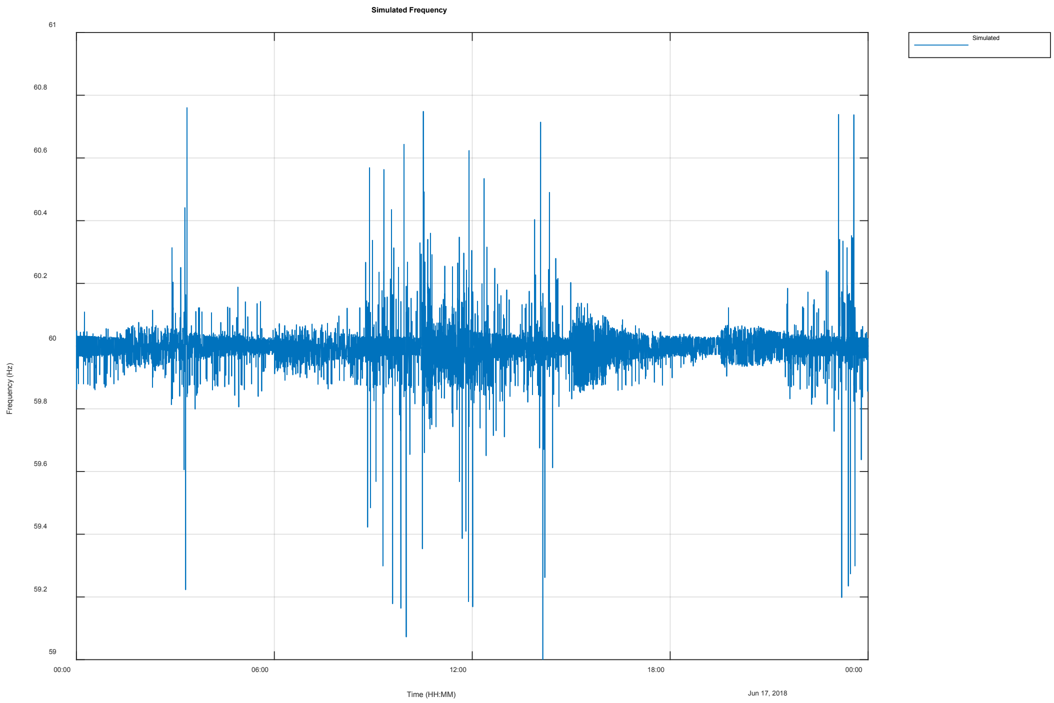


Figure 2-79 Case 27 - Simulated frequency on weekday with 1MW PV and 1 MW / 3 MWh MW battery on AGC

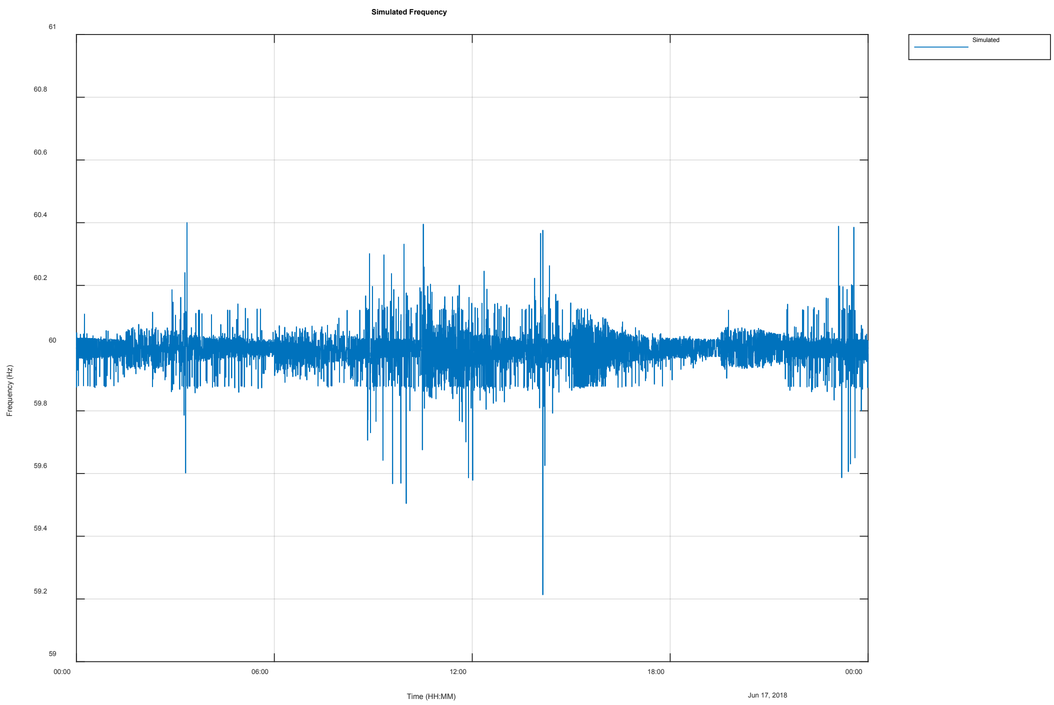


Figure 2-80 Case 28 - Simulated frequency on weekday with 2 MW PV and 0.5 MW / 3 MWh MW battery on AGC

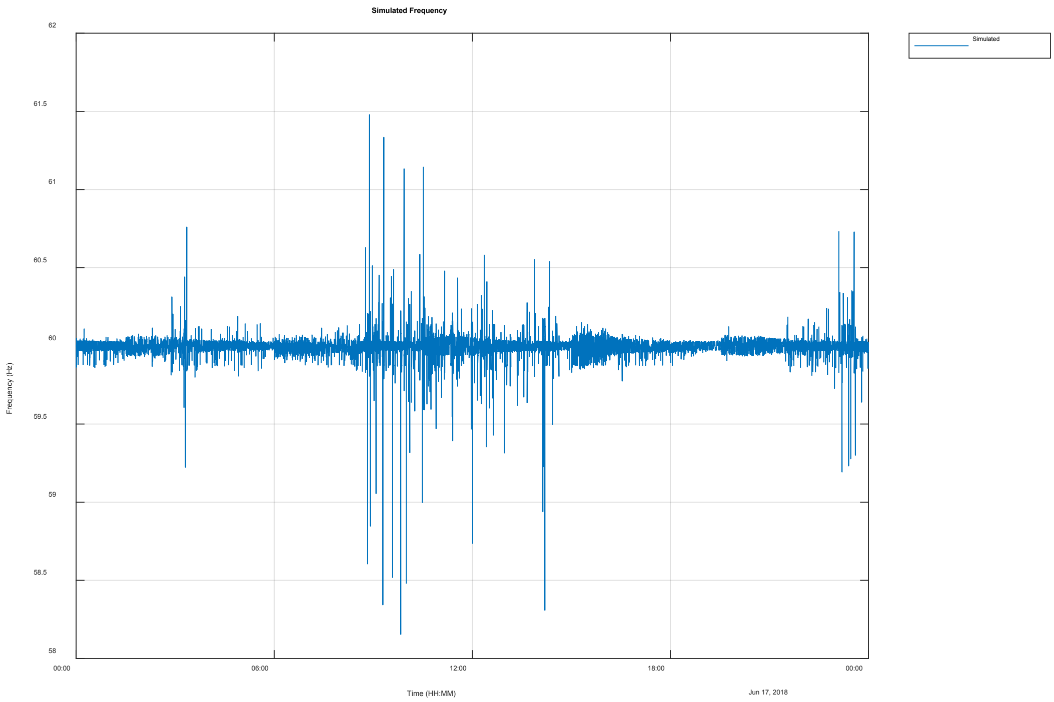
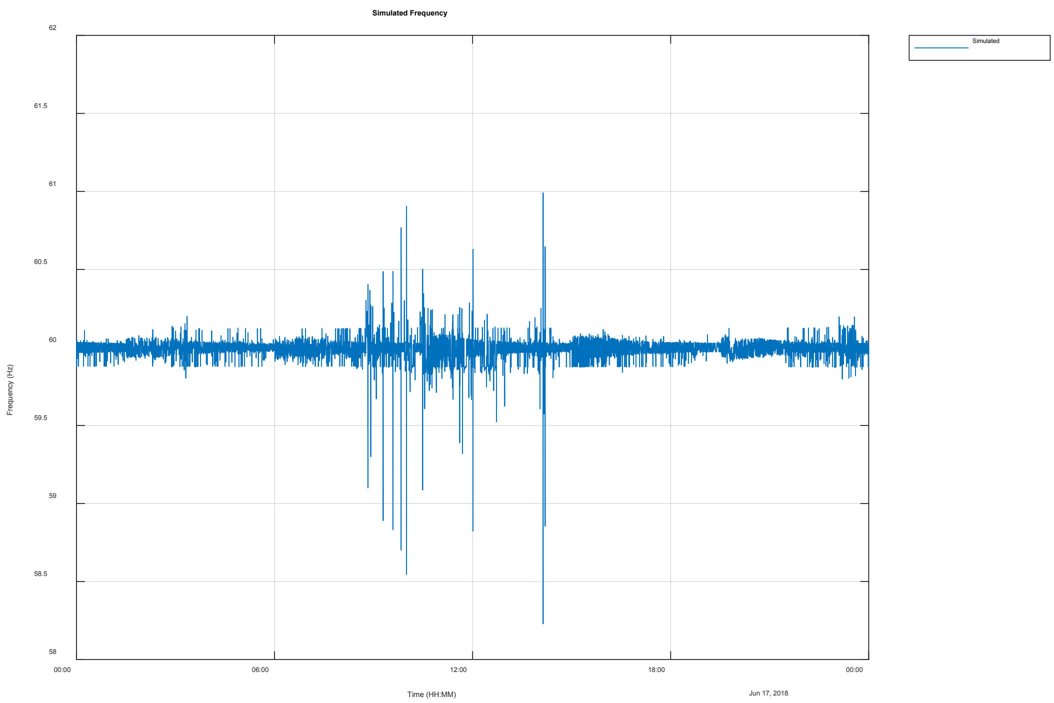


Figure 2-81 Case 30 - Simulated frequency on weekday with 4 MW PV and 2 MW / 10 MWh MW battery on AGC and diesel allowed off



2.3.8 Base Case 6 & Simulation cases 31 – 36 Weekday with VRE from 7 July 2018 and demand from 18 June 2018

Base Case 3: Weekday - Simulation of original day from 7 July 2018

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data except with the increase of the wind power from 2 – 3 turbines. Figure 2-82 shows the simulation of generation unit outputs for the Sunday 7 July 2018. This is the base case for these simulations where we can compare techno-economic impact of cases 31 to 36. The simulated frequency, as shown in Figure 2-83, shows the expected frequency with quite a few variations outside the acceptable limits of 59.5 – 60.5 Hz showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-82 Simulated generation on 18 June 2018 with VRE data from 7 July 2018 with wind power increased from 2 to 3 turbines

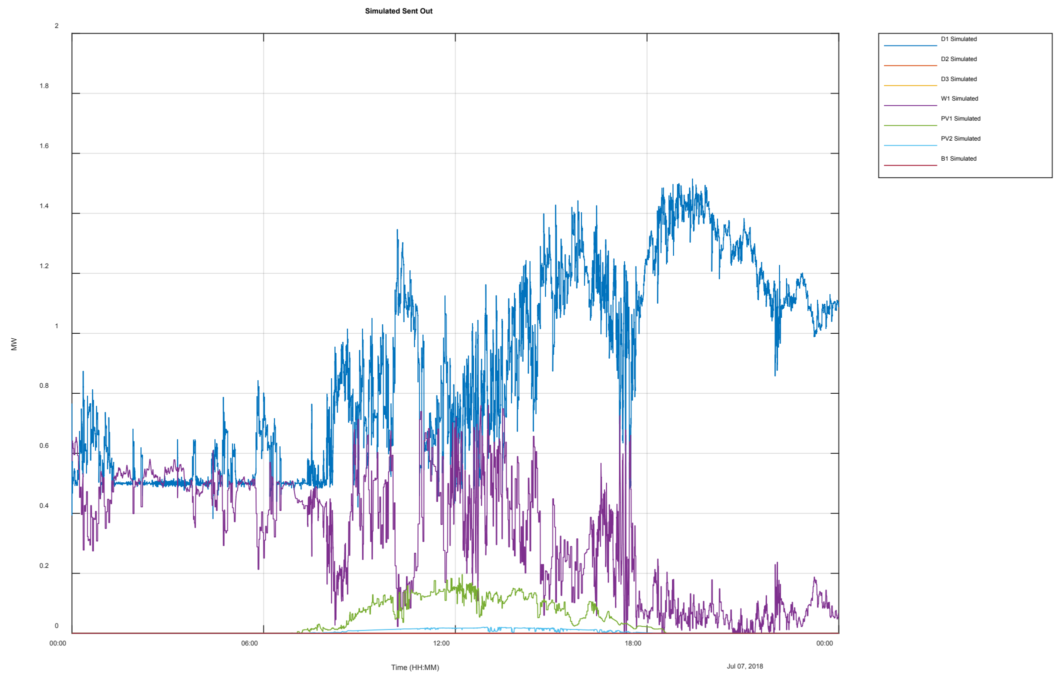
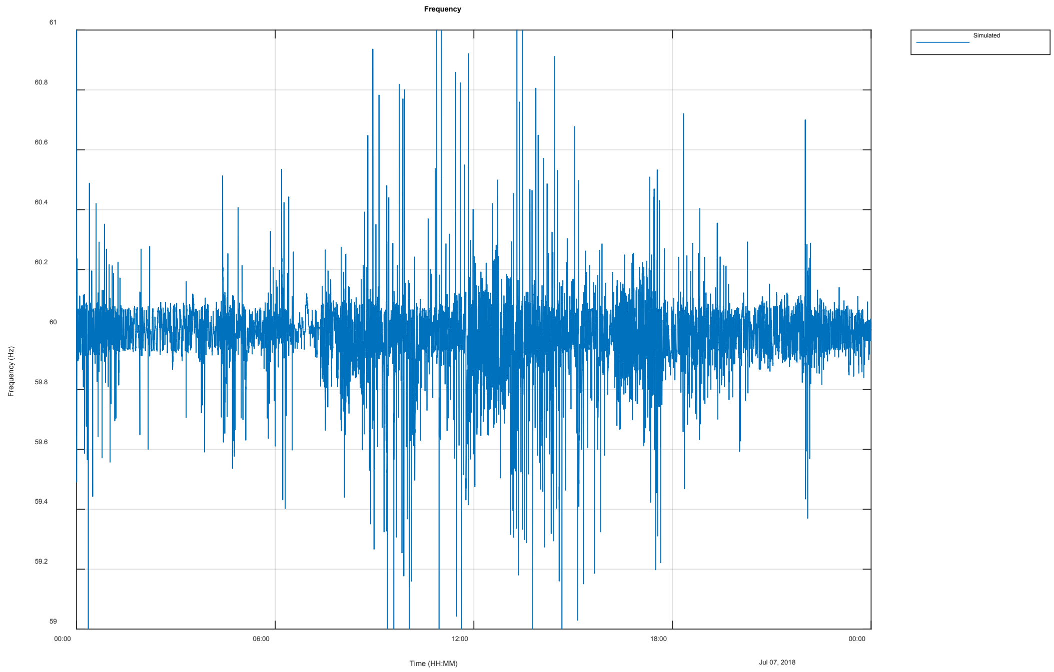


Figure 2-83 Simulated frequency on 18 June 2018 with VRE data from 7 July 2018 with wind power increased from 2 to 3 turbines



<u>Case 31 - 36: Weekday – Repeat of cases 19 - 24 with data on Sunday 7 July 2018.</u>

Cases 31 – 36 is the repeat of the simulations for a typical weekday but with VRE data recorded on 7 July 2018. The simulated frequency is as with the previous cases is often outside the acceptable range with a 0.5 MW inverter and the frequency control is only acceptable with a 1 MW inverter, Case 33 with 1 MW of simulated PV with a 1 MW / 3 MWh battery on AGC results in an acceptable frequency control, as shown in Figure 2-84.

Cases 35 & 36 with 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off has similar results to cases 5 & 6 and frequency control is acceptable, as shown in Figure 2-85.

Figure 2-84 Case 33 - Simulated frequency on weekday with 1 MW PV and 1 MW / 3 MWh MW battery on AGC

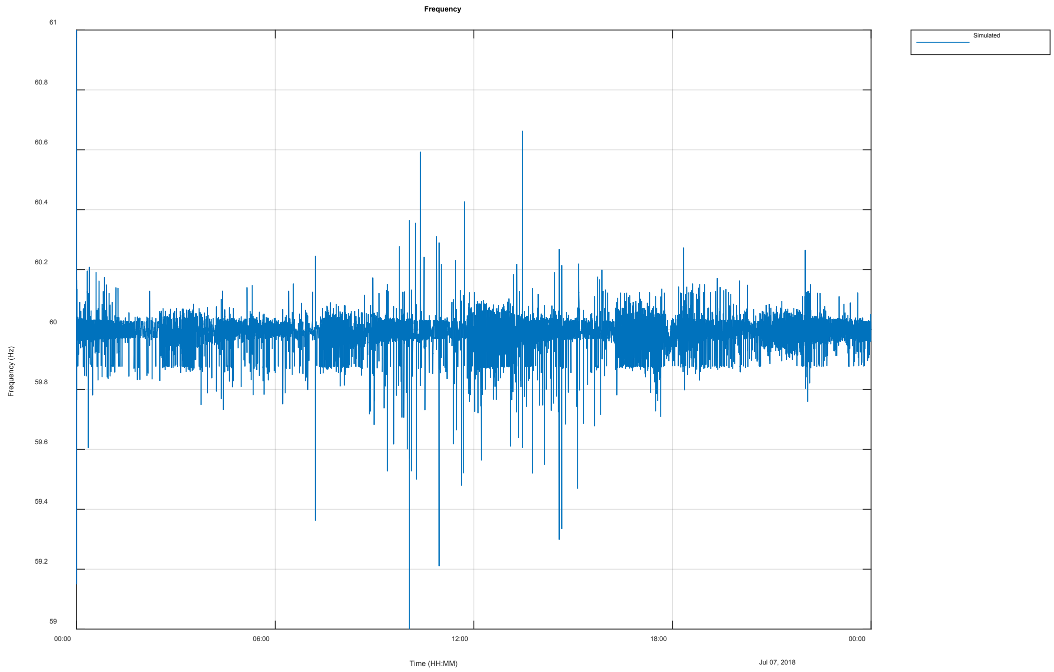
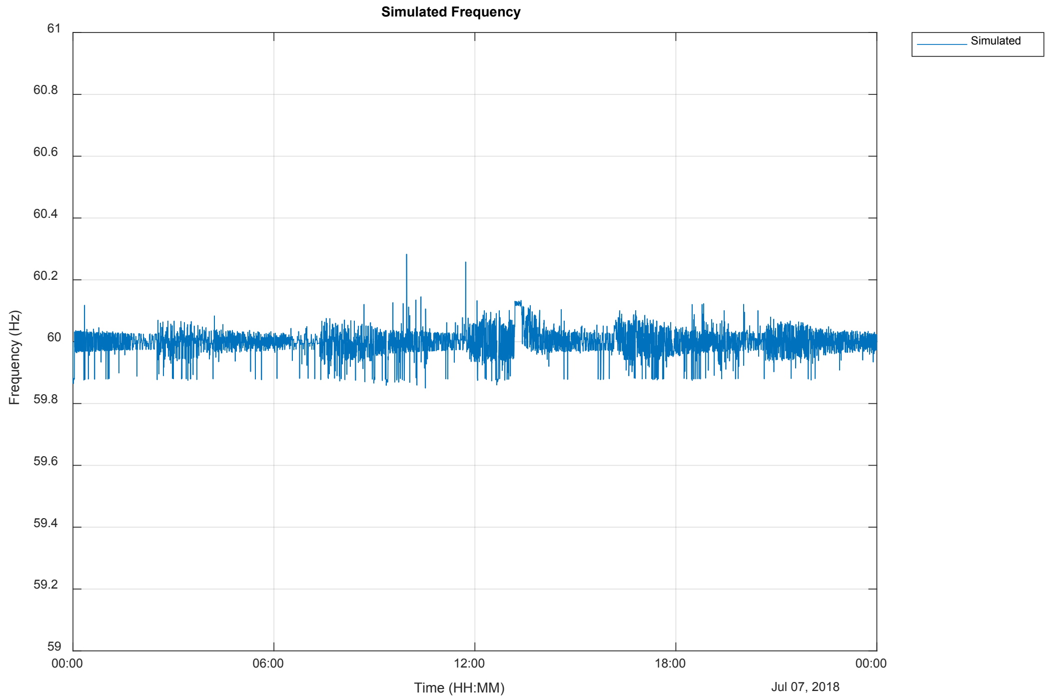


Figure 2-85 Case 35 - Simulated frequency on weekday with 4 MW PV and 2 MW / 10 MWh battery on AGC.



2.3.9 Base Case 8 & Simulation cases 43 – 48 Weekday with VRE from 14 Feb 2019

<u>Base Case 8: Weekday - Simulation of original day from 14 February 2019</u>

The original case is simulated to see if the GDAT model is a reasonably representative of the actual recorded data. Figure 2-86 shows the simulation of generation unit outputs for the Thursday 14 Feb 2019. This is the base case for these simulations where we can compare techno-economic impact of cases 37 to 42. The simulated frequency, as shown in Figure 2-87, shows the expected frequency variations which are similar to the recorded variations on the actual day and mainly within acceptable limits of 59.5 – 60.5 Hz but showing very little room to increase VRE without requiring batteries for frequency control.

Figure 2-86 Simulated generation on weekday of 14 Feb 2019

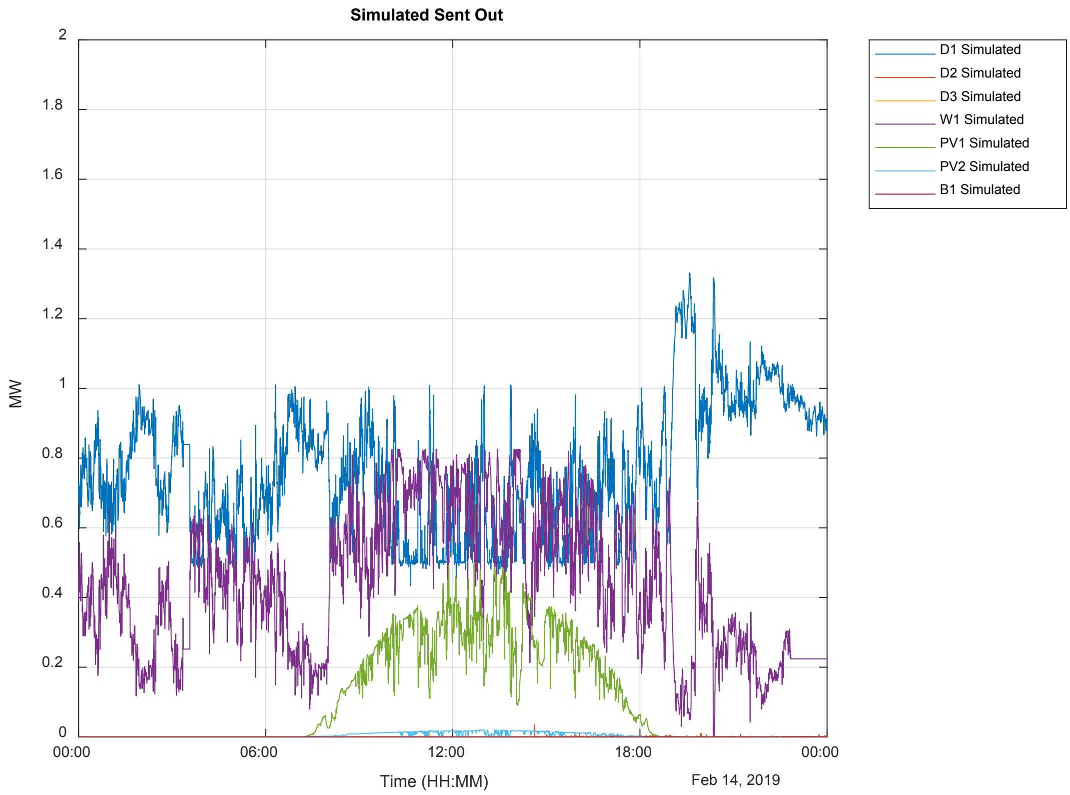
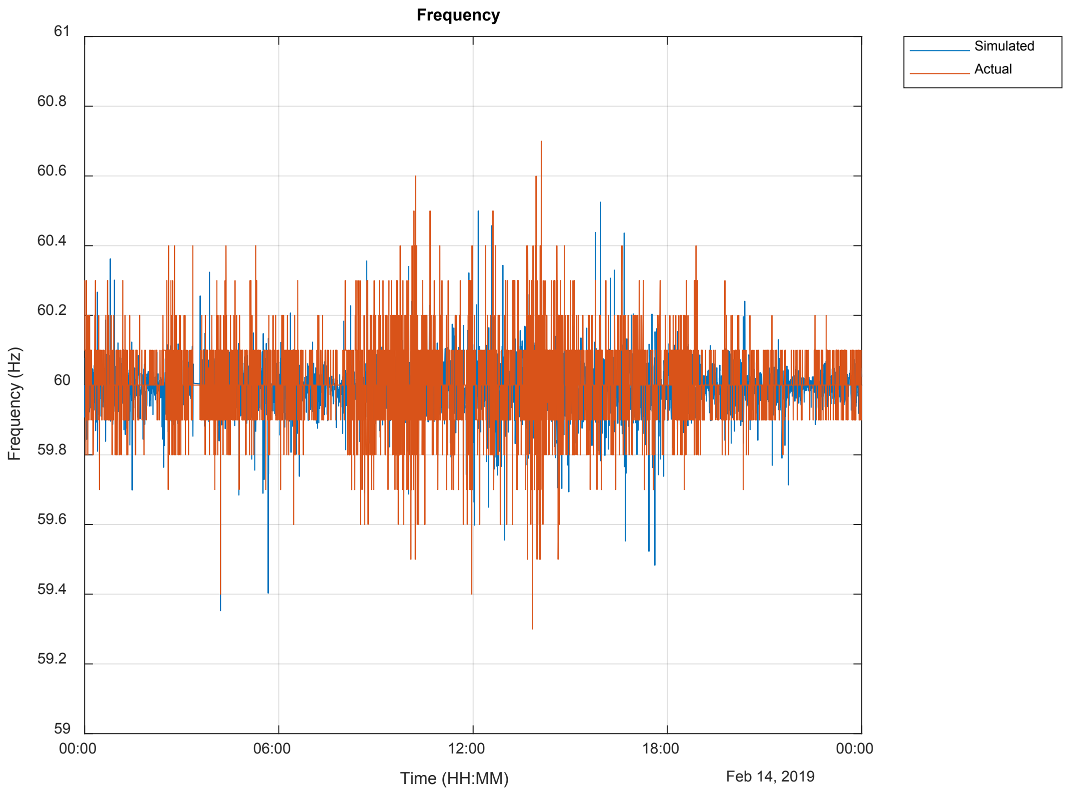


Figure 2-87 Simulated frequency on weekday of 14 Feb 2019



<u>Case 43 – 48: Weekday – Repeat of cases 19 - 24 with data on Thursday 14 Feb 2019.</u>

Cases 43 – 48 is the repeat of the simulations for a typical weekday but with VRE data recorded on 14 Feb 2019. The simulated frequency is as with the previous cases is often outside the acceptable range with a 0.5 MW inverter and the frequency control is only acceptable with a 1 MW inverter, Case 45 with 1 MW of simulated PV with a 1 MW / 3 MWh battery on AGC results in an acceptable frequency control, as shown in Figure 2-88.

Cases 47 & 48 with 4 MW of PV and 2 MW / 10 MWh battery on AGC and all diesel off has similar results to cases 5 & 6 and frequency control is acceptable, as shown in Figure 2-89.

Figure 2-88 Case 45 - Simulated frequency on weekday with 1 MW PV and 1 MW / 3 MWh MW battery on AGC

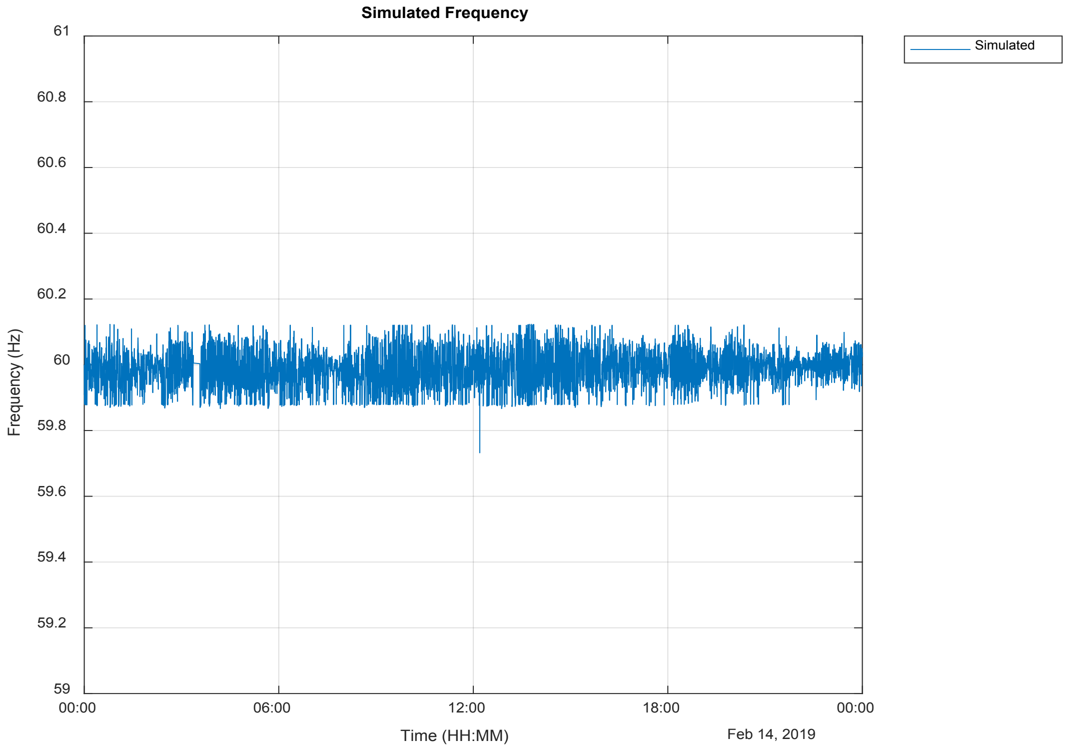
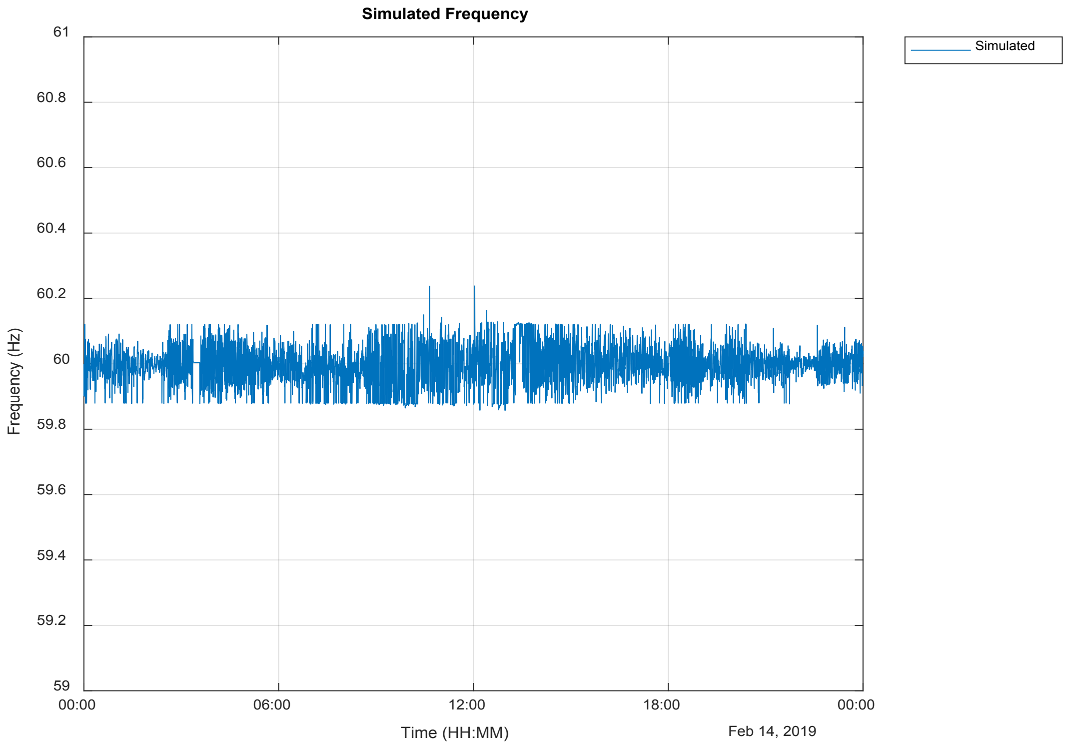


Figure 2-89 Case 47 - Simulated frequency on weekday with 4 MW PV and 2 MW / 10 MWh battery on AGC.



2.3.10 Summary of weekday economic results

The daily diesel fuel savings for each of the comparative cases is very similar as shown in Table 2-7. The wind power is more on 7 July therefore there is more PV power that is unused which increases the overall costs. Table 2-8 shows the total 'variable' costs which is the simulated diesel fuel costs, the daily PV costs for the simulated additional PV and the additional battery costs for the installed batteries. Table 2-9 is the percentage increase in the above costs from the original base case. The increasing to 2 MW of PV with the 0.5MW / 3MWh battery increases costs an average of 0.3%. The increase to from 4 MW of PV with the 2MW / 10MWh battery decreases costs for all cases from 2.7 – 14.6 % if all diesel units are allowed to off.

Table 2-7 Weekday - Comparison of daily fuel saving with different PV and battery input data

Simulation description	Case 19 - 24 diesel savings	Case 25 - 30 diesel savings	Case 31 - 36 diesel savings	Case 43 - 48 diesel savings
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	-1	0	10	0
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	592	612	931	570
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	593	1,140	1,006	1,174
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	1,250	1,368	1,282	1,189
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	3,042	3,196	3,473	1,407
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	3,104	3,203	4,017	3,422

Table 2-8 Weekday - Comparison of daily fuel, battery and additional PV costs with different PV and battery input data

Simulation description	Case 19 - 24 Fuel, battery and additional PV costs	Case 25 – 30 Fuel, battery and additional PV costs	Case 31 - 36 Fuel, battery and additional PV costs	Case 43 - 48 Fuel, battery and additional PV costs
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	6,756	6,613	5,533	4,547
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	6,460	6,304	4,978	5,386
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	6,547	5,864	4,991	5,037
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	6,183	5,938	5,097	5,109
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	6,217	5,951	4,909	5,312
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	6,154	5,945	4,365	5,376

Table 2-9 Weekday - Comparison of daily percentage change in daily fuel, battery and additional PV costs with different PV and battery input data

Simulation description	Case 19 - 24 % change	Case 25 - 30 % change	Case 31 - 36 % change	Case 43 - 48 % change
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	6.8%	7.0%	8.2%	9%
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	2.1%	2.0%	-2.6%	2%
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	3.5%	-5.2%	-2.4%	3%
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	-2.2%	-3.9%	-0.3%	8%
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	-1.7%	-3.7%	-4.0%	9%
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	-2.7%	-3.8%	-14.6%	-6%

2.4 Financial Assessment of incorporating Storage

The simulations economic results are shown in Table 2-10. The results are the calculated daily fuel consumed for the simulation case which is based on the fuel cost curve, as shown in 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 base case for each day, which sets the benchmark for further studies.

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

Table 2-10 Summary of economic results of simulations

No	Sim date	PV Installed (MW)	Diesel fuel costs	% fuel to base	Diesel MWh	Wind MWh	PV MWh	RVE max	Energy spilt	% reduction	Comments
Base 1	Weekend – VRE 16 Jun 2018	0.22	5,671	100%	22.4	2.5	0.8	3.35	0.0	0.0%	Base case
1	Weekend – VRE 16 Jun 2018	0.22	5,671	100%	22.4	2.5	0.8	3.35	0.0	0.0%	0.5 MW / 3 MWh B1 on gov
2	Weekend – VRE 16	1	5,054	89%	19.6	2.5	3.7	6.33	0.1	2.0%	0.5 MW / 3 MWh

	Jun 2018										B1 on AGC & gov
3	Weekend – VRE 16 Jun 2018	1	5,042	89%	19.6	2.5	3.7	6.33	0.1	1.4%	1 MW / 3 MWh B1 on AGC & gov
4	Weekend – VRE 16 Jun 2018	2	4,572	81%	17.6	2.3	6.1	10.14	1.7	16.8%	0.5 MW / 3 MWh B1 on AGC & gov
5	Weekend – VRE 16 Jun 2018	4	2,596	46%	10.4	2.4	13.7	17.77	1.7	9.3%	2 MW / 10 MWh B1 on AGC & gov
6	Weekend – VRE 16 Jun 2018	4	2,550	45%	10.5	2.5	14.0	17.77	1.3	7.2%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 2	Weekend – VRE 17 Jun 2018	0.22	5,365	100%	21.1	2.9	0.8	3.75	0.0	0.0%	Base case
7	Weekend – VRE 17 Jun 2018	0.22	5,365	100%	21.1	2.9	0.8	3.75	0.0	0.0%	0.5 MW / 3 MWh B1 on gov
8	Weekend – VRE 17 Jun 2018	1	4,703	88%	18.1	3.0	3.8	6.75	0.0	-0.3%	0.5 MW / 3 MWh B1 on AGC & gov
9	Weekend – VRE 17 Jun 2018	1	4,699	88%	18.1	3.0	3.8	6.75	0.0	-0.4%	1 MW / 3 MWh B1 on AGC & gov
10	Weekend – VRE 17 Jun 2018	2	4,186	78%	16.0	2.7	6.4	10.59	1.4	13.2%	0.5 MW / 3 MWh B1 on AGC & gov
11	Weekend – VRE 17 Jun 2018	4	2181	41%	8.4	2.9	14.2	18.27	1.1	6.3%	2 MW / 10 MWh B1 on

											AGC & gov
12	Weekend – VRE 17 Jun 2018	4	2,056	38%	7.8	3.0	14.5	18.27	0.8	4.1%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 3	Weekend – VRE 7 Jul 218	0.22	5,071	100%	19.7	8.1	1.0	9.36	0.2	2.3%	Base case
13	Weekend – VRE 7 Jul 218	0.22	5,064	100%	19.6	8.1	1.0	9.36	0.2	2.5%	0.5 MW / 3 MWh B1 on gov
14	Weekend – VRE 7 Jul 218	1	4,237	84%	15.8	8.4	4.7	13.01	0.0	-0.3%	0.5 MW / 3 MWh B1 on AGC & gov
15	Weekend – VRE 7 Jul 218	1	4,227	83%	15.7	8.4	4.7	13.01	-0.1	-0.7%	1 MW / 3 MWh B1 on AGC & gov
16	Weekend – VRE 7 Jul 218	2	4,017	79%	15.0	6.8	7.3	17.69	3.5	20.1%	0.5 MW / 3 MWh B1 on AGC & gov
17	Weekend – VRE 7 Jul 218	4	3,068	39%	7.7	7.2	15.0	27.05	4.9	18.2%	2 MW / 10 MWh B1 on AGC & gov
18	Weekend – VRE 7 Jul 218	4	1,515	30%	5.7	7.7	16.4	27.05	2.9	10.8%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 4	Weekday – VRE 16 Jun 2018	0.22	6,324	100%	25.6	2.5	0.8	3.35	0.0	0.0%	Base case
19	Weekday – VRE 16 Jun 2018	0.22	6,326	100%	25.6	2.5	0.8	3.35	0.0	0.0%	0.5 MW / 3 MWh B1 on gov

20	Weekday – VRE 16 Jun 2018	1	5,732	91%	22.8	2.5	3.7	6.33	0.1	1.4%	0.5 MW / 3 MWh B1 on AGC & gov
21	Weekday – VRE 16 Jun 2018	1	5,732	91%	22.8	2.5	3.7	6.33	0.1	1.4%	1 MW / 3 MWh B1 on AGC & gov
22	Weekday – VRE 16 Jun 2018	2	5,074	80%	19.7	2.4	6.9	10.14	0.9	8.4%	0.5 MW / 3 MWh B1 on AGC & gov
23	Weekday – VRE 16 Jun 2018	4	3,282	52%	13.1	2.5	14.2	17.77	1.1	6.3%	2 MW / 10 MWh B1 on AGC & gov
24	Weekday – VRE 16 Jun 2018	4	3,220	51%	12.2	2.5	14.3	17.77	0.9	5.2%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 5	Weekday – VRE 17 Jun 2018	0.22	6,182	100%	25.0	3.0	0.9	3.83	0.0	0.0%	Base case
25	Weekday – VRE 17 Jun 2018	0.22	6,182	100%	25.0	3.0	0.9	3.83	0.0	0.0%	0.5 MW / 3 MWh B1 on gov
26	Weekday – VRE 17 Jun 2018	1	5,570	90%	22.1	3.0	3.8	6.87	0.1	1.4%	0.5 MW / 3 MWh B1 on AGC & gov
27	Weekday – VRE 17 Jun 2018	1	5,042	82%	22.1	3.0	3.8	6.87	0.1	1.4%	1 MW / 3 MWh B1 on AGC & gov
28	Weekday – VRE 17 Jun 2018	2	4,815	78%	18.6	3.0	7.2	10.77	0.6	5.2%	0.5 MW / 3 MWh B1 on AGC & gov
29	Weekday –	4	2,986	48%	11.3	3.0	14.6	18.56	1.0	5.2%	2 MW / 10

	VRE 17 Jun 2018										MWh B1 on AGC & gov
30	Weekday – VRE 17 Jun 2018	4	2,979	48%	11.2	3.0	14.7	18.56	0.9	4.8%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 6	Weekday – VRE 7 Jul 2018	0.22	5,112	100%	20.0	7.7	1.0	8.69	0.0	0.0%	Base case
31	Weekday – VRE 7 Jul 2018	0.22	5,103	100%	20.0	7.7	1.0	8.69	0.0	0.0%	0.5 MW / 3 MWh B1 on gov
32	Weekday – VRE 7 Jul 2018	1	4,181	82%	15.7	8.4	4.7	12.35	-0.7	-5.9%	0.5 MW / 3 MWh B1 on AGC & gov
33	Weekday – VRE 7 Jul 2018	1	4,106	80%	15.6	8.4	4.7	12.35	-0.8	-6.1%	1 MW / 3 MWh B1 on AGC & gov
34	Weekday – VRE 7 Jul 2018	2	3,830	75%	14.2	7.2	7.5	17.05	2.3	13.7%	0.5 MW / 3 MWh B1 on AGC & gov
35	Weekday – VRE 7 Jul 2018	4	1,639	32%	6.1	7.4	16.1	26.45	2.9	11.1%	2 MW / 10 MWh B1 on AGC & gov
36	Weekday – VRE 7 Jul 2018	4	1,095	21%	4.1	8.0	17.7	26.45	0.8	3.0%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 7	Weekend – VRE 17 Feb 2019	0.5	4,415	100%	17.1	5.4	1.4	7.20	0.4	4.9%	Base case
37	Weekend –	0.5	4,414	100%	17.1	5.5	1.4	7.20	0.3	4.1%	0.5 MW / 3

	VRE 17 Feb 2019										MWh B1 on gov
38	Weekend – VRE 17 Feb 2019	1	3,989	90%	15.2	5.7	3.0	8.73	0.0	0.4%	0.5 MW / 3 MWh B1 on AGC & gov
39	Weekend – VRE 17 Feb 2019	1	3,976	90%	15.2	5.7	3.1	8.73	0.0	0.0%	1 MW / 3 MWh B1 on AGC & gov
40	Weekend – VRE 17 Feb 2019	2	3,608	82%	13.5	5.3	5.1	11.79	1.3	11.3%	0.5 MW / 3 MWh B1 on AGC & gov
41	Weekend – VRE 17 Feb 2019	4	1,822	41%	6.9	5.6	11.7	17.91	0.6	3.4%	2 MW / 10 MWh B1 on AGC & gov
42	Weekend – VRE 17 Feb 2019	4	1,617	37%	6.9	5.7	11.9	17.91	0.4	2.1%	2 MW / 10 MWh B1 on AGC & gov – diesel off
Base 8	Weekday – VRE 14 Feb 2019	0.5	4,547	100%	17.3	10.3	2.5	12.82	0.0	0.0%	Base case
43	Weekday – VRE 14 Feb 2019	0.5	4,542	100%	17.3	10.3	2.5	12.82	0.0	0.0%	0.5 MW / 3 MWh B1 on gov
44	Weekday – VRE 14 Feb 2019	1	3,939	87%	14.8	10.3	5.2	15.36	-0.2	-1.1%	0.5 MW / 3 MWh B1 on AGC & gov
45	Weekday – VRE 14 Feb 2019	1	3,923	86%	14.6	10.5	5.2	15.36	-0.4	-2.6%	1 MW / 3 MWh B1 on AGC & gov
46	Weekday – VRE 14 Feb 2019	2	3,706	81%	13.8	9.2	7.4	20.45	3.8	18.5%	0.5 MW / 3 MWh B1 on

											AGC & gov
47	Weekday – VRE 14 Feb 2019	4	1,691	37%	6.3	9.0	15.6	30.61	6.0	19.8%	2 MW / 10 MWh B1 on AGC & gov
48	Weekday – VRE 14 Feb 2019	4	989	22%	4.1	9.7	17.2	30.61	3.7	12.0%	2 MW / 10 MWh B1 on AGC & gov – diesel off

The simulations show that it is possible to increase the PV energy penetration up to 2 MW on top of the existing wind power with a 0.5 MW / 3 MWh battery but it would be better to increase the inverter size to 1 MW or more. The inverter size of 2 MW is also too small for PV of 4 MW.

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

Table 2-11 and Table 2-12 show the estimated annual costs for each option studied. This is the taking the average 3 weekend cases * 2 *52 plus the average of the 3 weekday cases * 5 * 52.

The average diesel costs for the 8 base cases is 19.3 USc/kWh.

Installing a 0.5 MW / 3 MWh battery increases the estimated annual costs by US$ 156,616, a 8% increase on the ‘variable’ component of the tariff from the 20.8 USc/kWh.

All the cases with diesel unit D3 left on at a minimum generation level of 250 kW have a tariff variance around 1%. The strategy for increasing PV based on the cases reviewed show that there is significant savings in diesel with a minimal impact on the tariff. It is recommended that an inverter of 1 MW with the 3 MWh battery be installed to manage frequency control and thereby increase system security.

The final solution in the FSM study of 4 MW of PV with 2 MW / 10 MWh battery shows a 6% reduction in variable component of the tariff when all diesel units are allowed to go off. This case needs further studying to determine what is required to have all diesel units off.

Figure 2-90 shows a steady decline in the tariff as VRE is increased from 20% of energy to 70% of energy provided by VRE.

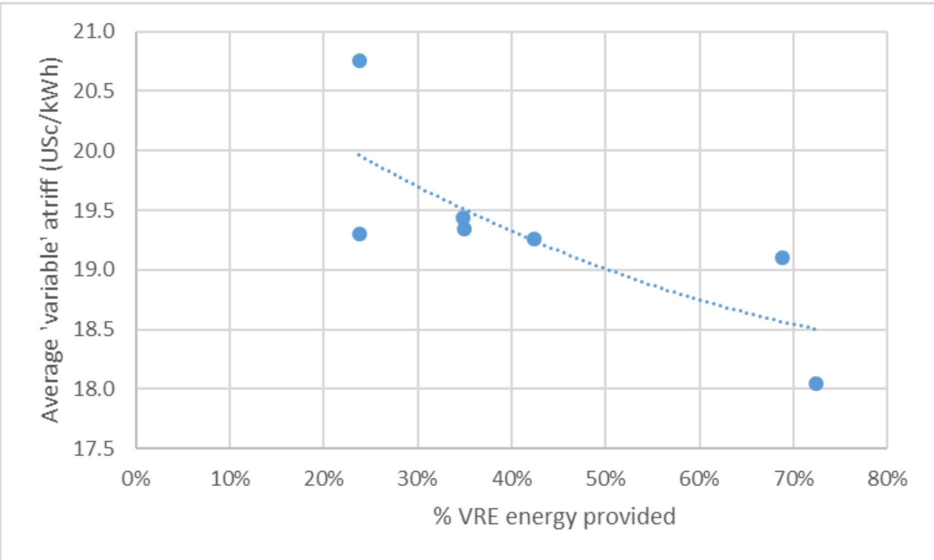
Table 2-11 Estimated annualised solar and battery costs and fuel costs

Description	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated additional battery costs (pa)	Estimated nett saving (pa)
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	61%	1,060	0	156,616	-155,556
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	107%	244,352	108,427	156,616	-20,691
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	107%	285,543	108,427	188,445	-11,328
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	166%	415,838	262,149	156,616	-2,928
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	284%	1,126,788	569,595	543,421	13,772
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	284%	1,234,708	569,595	543,421	121,692

Table 2-12 Estimated annualised total costs and increase / decrease in costs

Description	Estimated total diesel plus additional PV and battery costs (PA)	Estimated total diesel plus additional PV and battery costs (USc/kWh))	% increase from base cases
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	2,129,902	20.8	8%
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	1,995,036	19.4	1%
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	1,985,673	19.3	1%
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	1,977,273	19.3	0%
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	1,960,573	19.1	-1%
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	1,852,654	18.1	-6%

Figure 2-90 Average variable tariff as VRE energy is added



2.5 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 2-13 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 2-13 Average Supply Costs (US Cents/kWh)[15]

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

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

Table 2-14: Average Supply costs versus Tariffs for 2017 in US c/kwh[16]

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

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

In the case of Yap option with 4MW PV, 0.825 Mw wind and 2 MW/10 MWH battery on AGC substituting all of the diesel generation would have the biggest impact on the variable costs. The total decrease in total variable costs from the base case scenario would be 13%. Variable costs meaning fuel costs plus annualised costs of PV and battery. This is used to estimate the incremental system cost in each case.

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

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

Table 2-15: Yap - Estimated annual total variable costs and percentage savings

Description	% peak	Estimated diesel savings (pa)	Estimated additional PV costs (pa)	Estimated total diesel plus additional PV and battery costs (USc/kWh))	% increase from base cases
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	61%	1,060	0	20.8	8%
1 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	107%	244,352	108,427	19.4	1%
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	107%	285,543	108,427	19.3	1%
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	166%	415,838	262,149	19.3	0%
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	284%	1,126,788	569,595	19.1	-1%
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	284%	1,234,708	569,595	18.1	-6%

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 2-16: Estimated Impact on Supply Costs and Tariff (in 2017 annualised figures)

Description	Total 'variable' costs	Average 'variable' costs USc/kWh	% decrease in total costs from base cases	2017 Supply Cost USc/kWh	New Supply Cost	2017 Tariff Usc/kwh	New Tariff
0.22 MW PV, 0.825 MW wind & 0.5 MW/ 3 MWh Batt on gov	2,288,887	25.150	10%	53.08	49.56	45.07	41.55
MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	2,148,774	23.610	3%	53.08	50.01	45.07	42.00
1 MW PV, 0.825 MW wind & 1 MW / 3MWh battery on AGC	2,127,459	23.376	2%	53.08	49.57	45.07	41.56
2 MW PV, 0.825 MW wind & 0.5MW / 3MWh battery on AGC	2,103,870	23.117	1%	53.08	50.07	45.07	42.06
4 MW PV, 0.825 MW wind & 2MW / 10MWh battery on AGC	2,347,602	25.795	13%	53.08	49.21	45.07	41.20
4 MW PV, 0.825 MW wind, 2MW / 10MWh battery on AGC & diesel off	2,003,892	22.019	-4%	53.08	75.10	45.07	67.09

The best-case scenario as described above would have a net impact on the tariff of nearly US cents 4/kwh (from US cents 45.07/kwh to US cents 41.20/kwh). This is well below the average supply costs of around US cents 54/kwh for the years 2012-2017.

2.6 Recommendations for application of storage

The studies show that the system is currently experiencing quite high frequency variations due to the current installed wind and PV variations and installing a 0.5 MW / 3 MWh battery will assist with frequency control and should be done as the first step.

To increase to 1 -2 MW of PV the inverter size on the battery should be increased to 1 MW.

There is steady decline in the variable' component of the tariff from 20 to 18.5 USc/ kWh as VRE is increased from 20% of energy to 70% of energy provided by VRE. The 'variable' component of the tariff which includes diesel fuel, additional PV and additional battery costs.

The studies were performed with diesel unit D3 as the last unit on at a minimum generation level of 250 kW. Diesel units D1 and D2 have a minimum level of 500 kW and this results in significant spilling of wind and solar power and increases the overall 'variable' component of the tariff.

The simulations show that installing 4 MW of PV with 2 MW / 10 MWh of battery with the current demand will decrease the 'variable' component of the tariff which includes diesel fuel, additional PV and additional battery costs by 6% if diesel units are allowed to go off. This case needs further studying to determine what is required to have all diesel units off. It is recommended that these studies are repeated with the new demand, PV & battery costs in a few years' time to determine the next optimal step.

3 Task 2: Assessment of the needs for Supervisory control and data acquisition (SCADA) and Energy Management System (EMS)

3.1 Background: SCADA Systems

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

Main functions of the SCADA are:

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

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

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

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

Those aspects 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.

3.2 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.

3.2.1 Data Acquisition

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

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

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

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

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

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

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

3.2.2 Communications

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

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

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

The operation of the SCADA system is dependent on reliable communication from each station to the central control station. International best practice recommends that Power Utilities establish their own communication network and not be dependent on public Telecommunication operators. A Telco's objective is different to earn revenue from selling bandwidth, whereas a Power Utility has to ensure the reliability of the power network. We 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 situation creates a dependency between the supplier of the RTU's that should be the same (or compatible) with the SCADA system if you want to avoid that an RTU supplier shall emulate the SCADA protocol with the information provided by the supplier. This situation is changing but some of those protocols are still in service due to extended usable life of RTU's.

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

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

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

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

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

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

3.2.3 Information validation

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

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

Those alarms are registered and presented to the operator.

3.2.4 Alarms subsystem

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

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

Some systems use Alarms Intelligent Processors (AIP) or Intelligent Observation Systems (IOS) that study, concentrate and 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.

3.2.5 Monitoring and trending

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

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

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

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

Ref: REE (www.ree.es)

3.2.6 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 and efficient control of the network conditions.

3.2.7 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.

3.3 Added applications

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

For that reason and around the SCADA a big set of applications has been developed being today the master stone 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.

3.4 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:

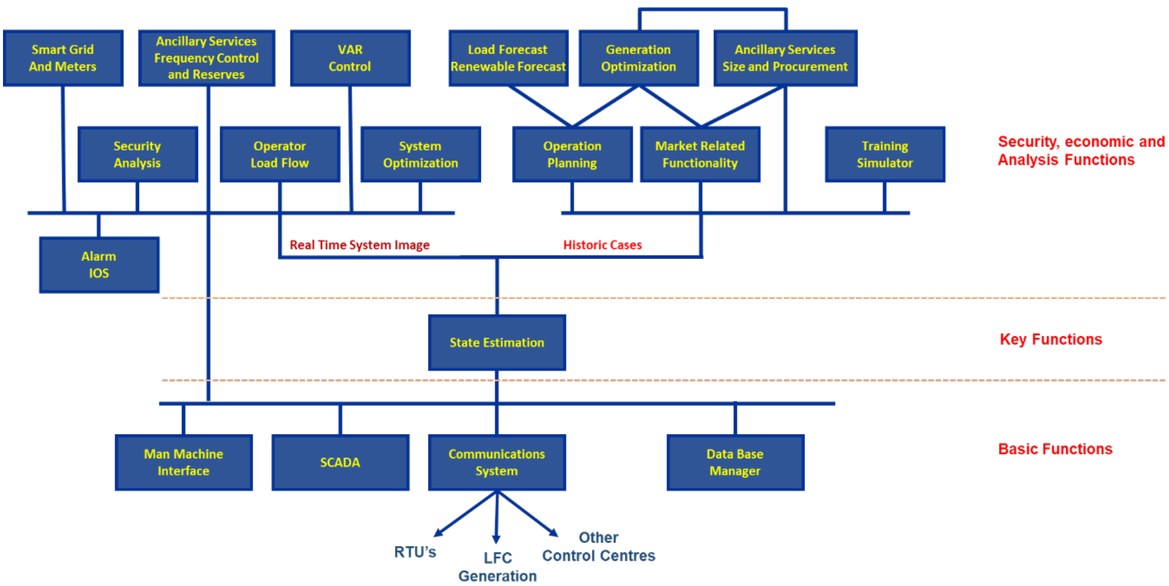
a. **Energy Management System (EMS)** oriented to generation and transmission systems. The main characteristics of those systems are those that are the relatively big size in generation and load, small or medium number of substations and extra high number of controlled elements, with the system fully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

3.4.1 EMS System

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



Briefly, the following applications are oriented to:

3.4.1.1 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 than any value in the system, as example a Voltage at 220 kV, the value sent to Control Centre is 220 kV, but the real value could be any value between 198 and 222 kV. Same error or higher is expected with flows and current readings.

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

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

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

The result is the most probable coherent set of values.

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

This is calculated in the 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 the application to reach a solution.

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

3.4.1.2 Load Flow

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

3.4.1.3 Optimal Load Flow.

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

3.4.1.4 Ancillary Services requirements

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

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

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

3.4.1.5 Security Analysis

It is the suite of applications oriented to verify that the Security Criteria are fulfilled any time, during operation planning or in Real Time. Perhaps the most known application is the Contingency Analysis (CA), where all the conditions included in the security criteria are tested during operation planning and in Real Time.

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

3.4.1.6 Forecast Applications

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

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

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

3.4.1.7 Generation schedule

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

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

3.4.1.8 Generation Control

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

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

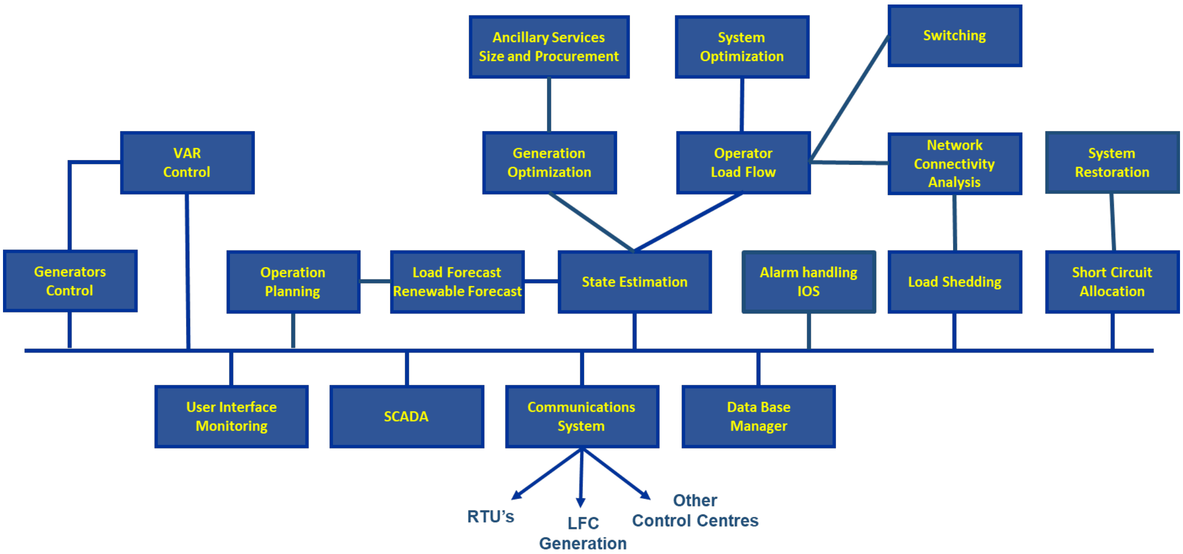
Ref: https://www.winsted.com/resources/case-studies/university-virginia/

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

3.4.2 DMS System

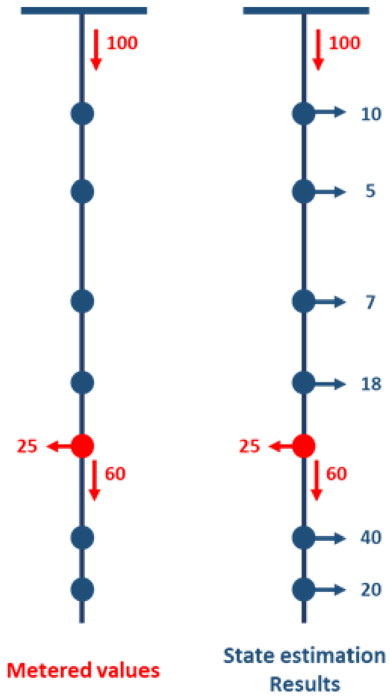
The Distribution Management System is more oriented to distribution networks management. For networks operated as radial, the applications are completely different to the case of meshed networks.

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



The main applications are:

3.4.2.1 State Estimation (SE).



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

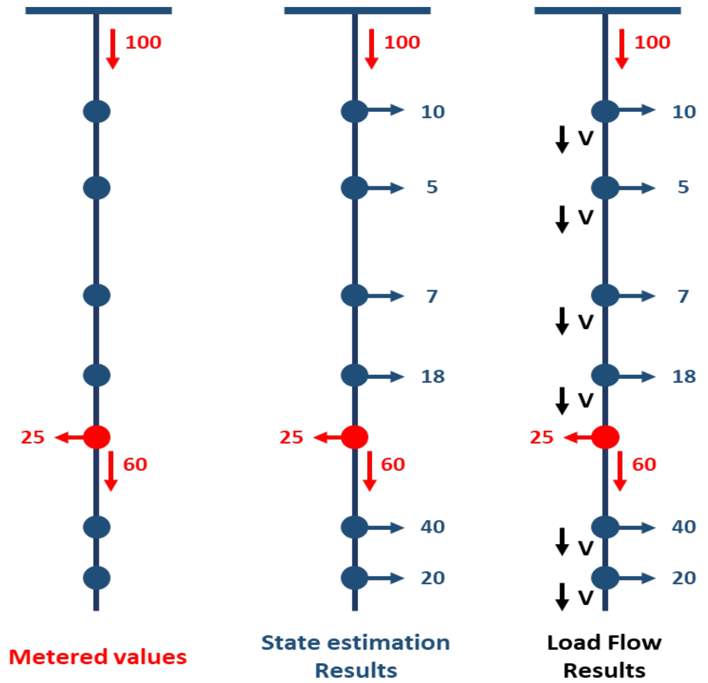
Even though we may not be able to directly observe the state, it can be inferred from a scan of measurements which are assumed to be synchronized. The system appears to be progressing through a sequence of static states that are driven by various parameters like changes in load profile. The outputs of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

3.4.2.2 Load Flow Applications (LFA).

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

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

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



3.4.2.3 Generation Control.

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

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

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

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

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

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

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

3.4.2.4 Network Connectivity Analysis (NCA)

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

3.4.2.5 Switching Schedule & Safety Management.

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

3.4.2.6 Voltage Control

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

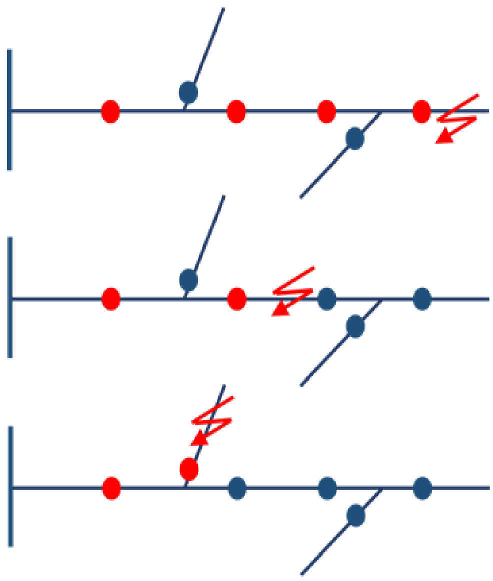
- ✓ Reactive power generation or absorption in generators (VAR control)
- ✓ Modifying the transformer’s ratio, changing in cold or in hot. In this last case, also known as Load Tap Changing, where the transformer is in service, the number of changes per day is normally limited.

- ✓ There are also autotransformers that has a rate very close to 1,00 which means that the voltage variation is small and are used only for voltage control in the same voltage level.
- ✓ Use of external control elements like shunt devices (batteries or reactors) or advanced voltage controllers like SVC's or STATCOM's

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

3.4.2.7 Short Circuit Allocation.

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



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

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

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

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

3.4.2.8 Load Shedding Application (LSA)

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

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

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

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

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

3.4.2.9 Fault Management & System Restoration (FMSR).

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

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

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

3.4.2.10 Distribution Load Forecasting (DLF)

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

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

The traditional energy balance equation is:

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

Where: CG is the Conventional Dispatchable Generation

LO is the total Load (Estimated)

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

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

RE is the Renewable Generation (Forecasted with error)

ERE is the Embedded Renewable Generation (Estimated)

The same balance equation could be written as:

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

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

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

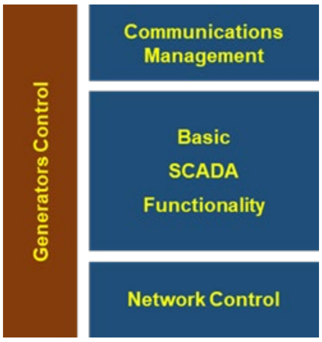
Those forecasts shall be calculated for at least two different time horizons:

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

3.4.2.11 Load Balancing via Feeder Reconfiguration (LBFR)

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

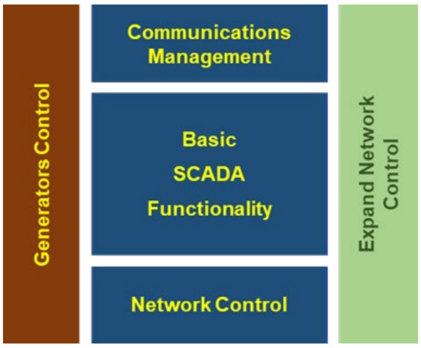
3.4.3 Requirements of the Distributions Systems



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

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

3.4.3.1 Network Control and Monitoring



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

Capacity to control a wall system will be appreciated

3.4.3.2 Quality Assurance

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

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

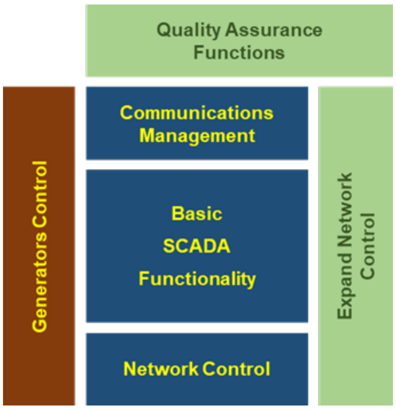
   The main problem to face for continuity of service is the external incidents into the network, such as; lightning, storms, high speed winds, car accidents, vegetation… There are only limited ways to avoid the existence of those incidents, but they can be mitigated using more secure network elements.

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

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

There are non external factors that impact into those quality aspects. Operation planning, normally for the day ahead, is the operation time where those aspects shall be considered and the resources existing made available for operation

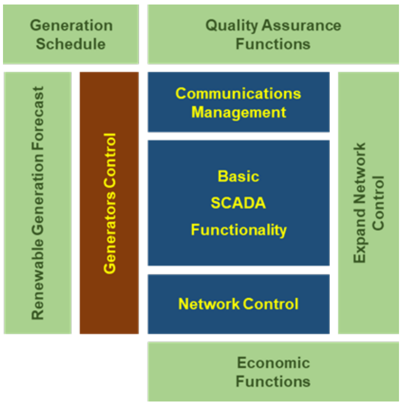
Some applications to control those aspects, together with the Reserves size and allocation, which do not directly impact into quality, but in case of other incidents, will help to limit the extent and magnitude of the incident and eventually reduce the restoration time.



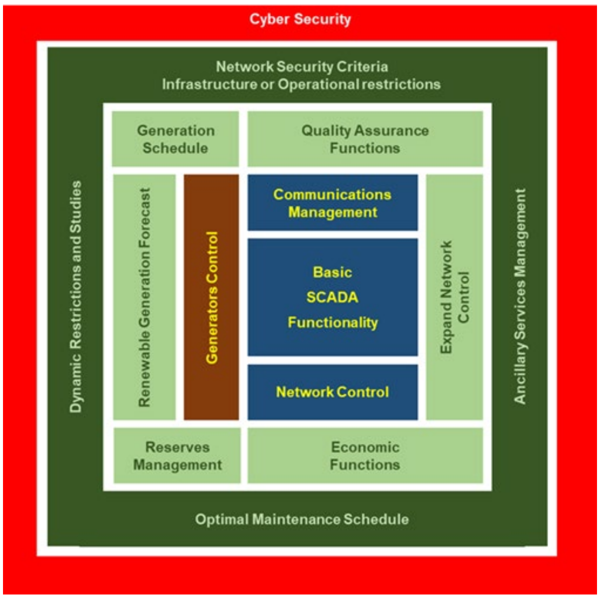
3.4.3.3 System Economic Optimization

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

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



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



3.4.4 Recommendation between EMS and DMS

Both are highly powerful tools, but considering:

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

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

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

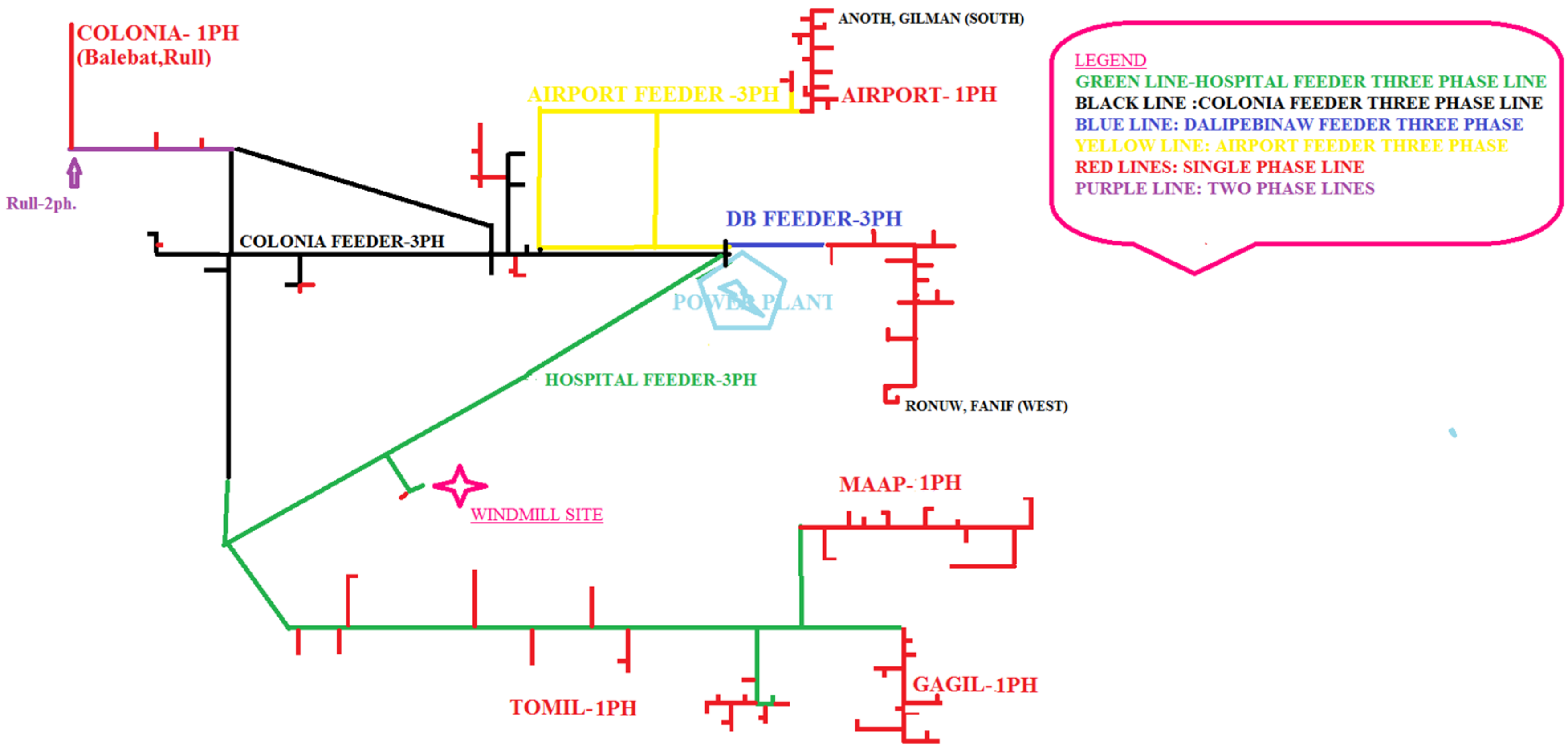
3.5 Yap State Public Service Corporation (YSPSC) System

3.5.1 Network and available Operation Systems

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

Concept	Value	Unit
Peak Load	2.300	kw
Energy served per year	10.226	Mwh
Generators Conventional	5	
Wind Generators Renewable	3	
PV Generators Renewable	3	
Conventional Installed power	2,8	Mw
Renewable Installed power	0,3	Mw
Available SCADA for Generation Control	Yes	
Controls some breakers	No	
Operated Radial	Yes	
Number of feeders	4	

YAP single line diagrams



An existing power station SCADA System controls the frequency and co-ordinates units in Diesel groups.

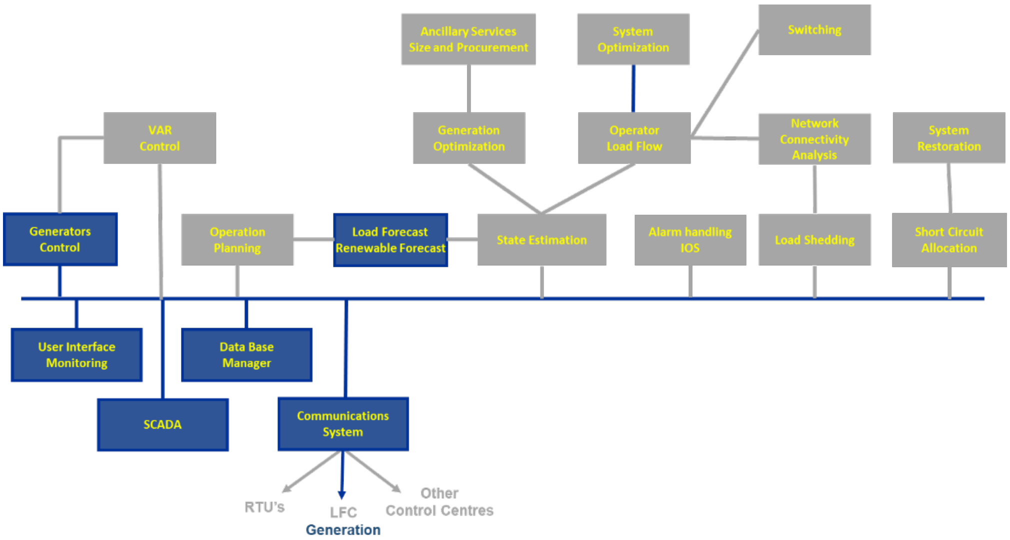
Functionality is limited to:

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

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

c. No additional functionalities available in top of the SCADA

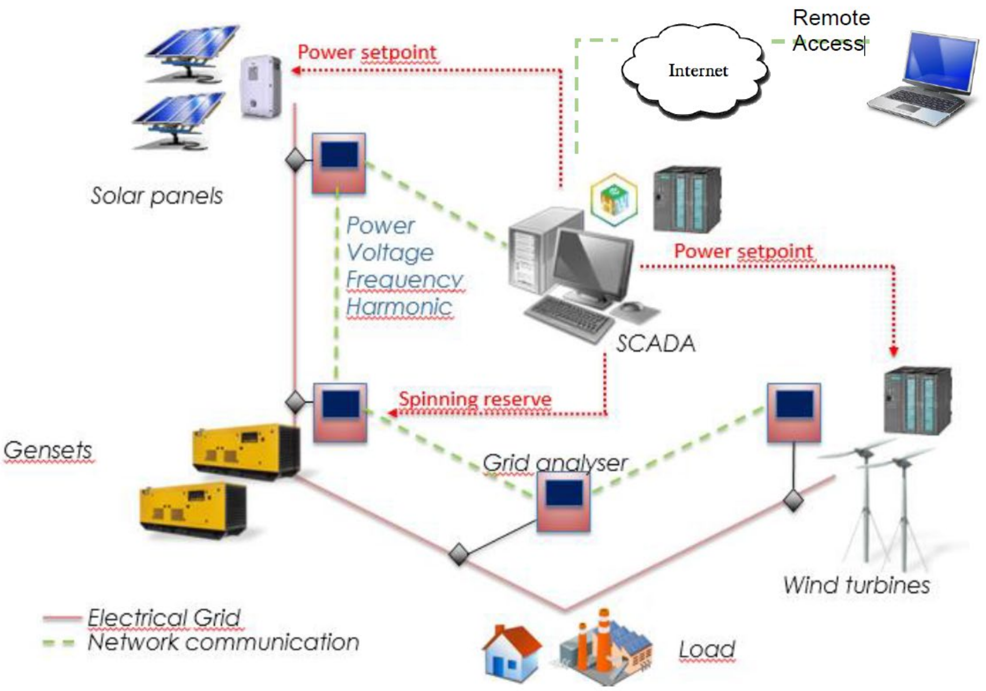
The figure shows the actual SCADA configuration:



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

The VERGNET SCADA system is a software is capable of real time plant monitoring, operational data storage, faults notifications and advanced reports generation. Furthermore, this SCADA system allows users some controls over the wind turbines and meteorological logger, solar inverters, diesel gensets, High Voltage Station. The VERGNET SCADA system is able to monitor and control VERGNET wind turbines, solar inverters and provides spinning reserve to diesel units[18].

[18] Vergnet SCADA System Manual for YAP, IN 60-00-00-30, 16 Nov 2017



3.5.2 Applications Proposal

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

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

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

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

In the following points the possible expansions and the recommended one will be developed.

3.5.3 Functionality proposal

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

3.5.3.1 Quality improvement

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

Specifically:

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

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

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

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

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

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

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

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

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

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

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

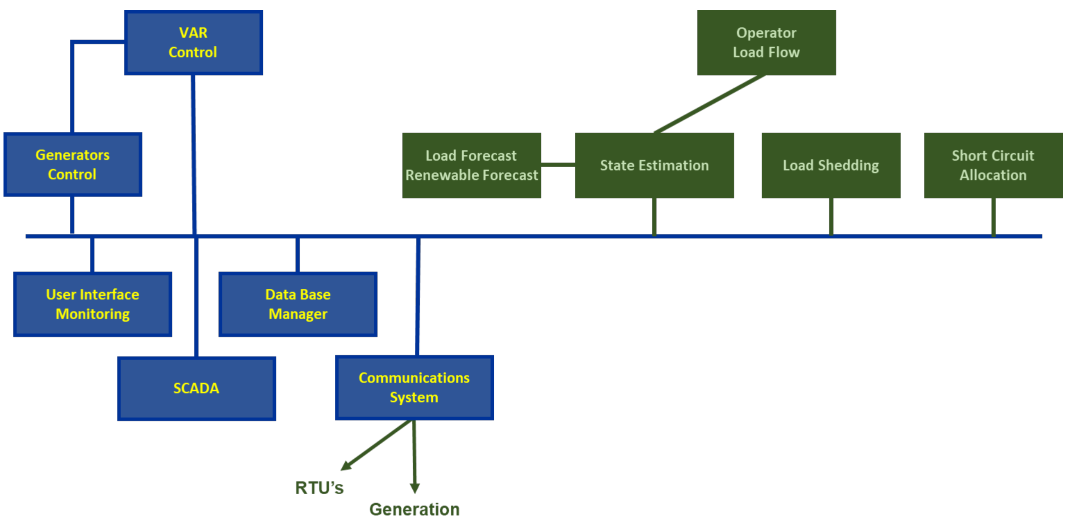
d. Shunt devices (reactance's)

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

A weight methodology will determine the optimal solution.

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

The functionality, after this phase shall be:



3.5.3.2 Economic Optimization and technical loss reduction

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

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

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

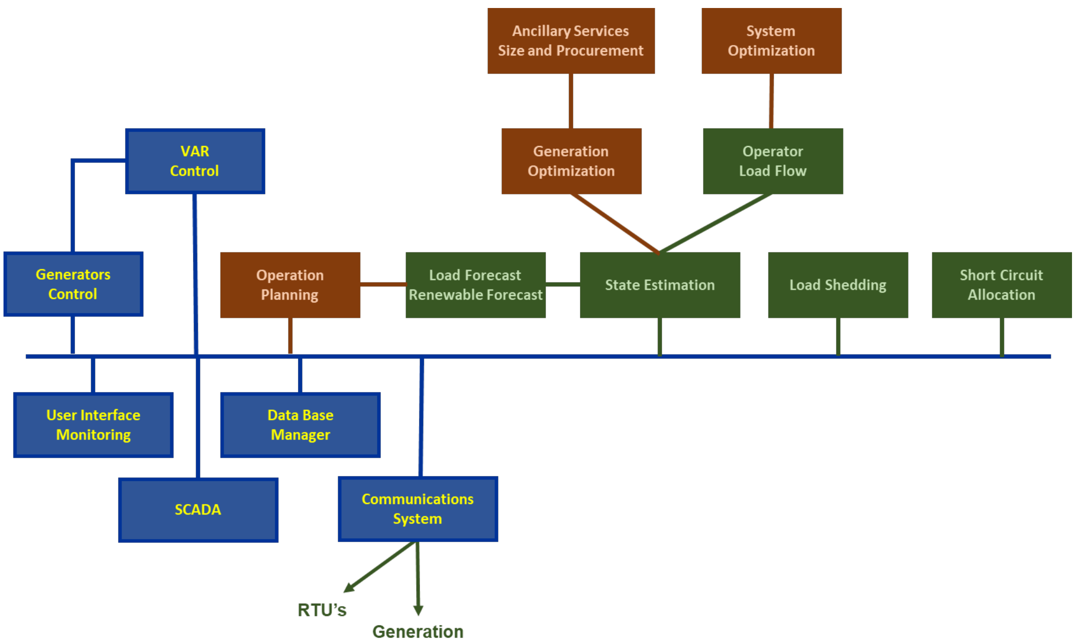
2. **Generation optimization**. After the load and Renewable forecast, we have the amount of energy to be produced by the conventional generation. The split of this generation among the different groups or energy sources will define the optimal generation profile, considering the energy costs, including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

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



3.5.3.3 Functionality not recommended

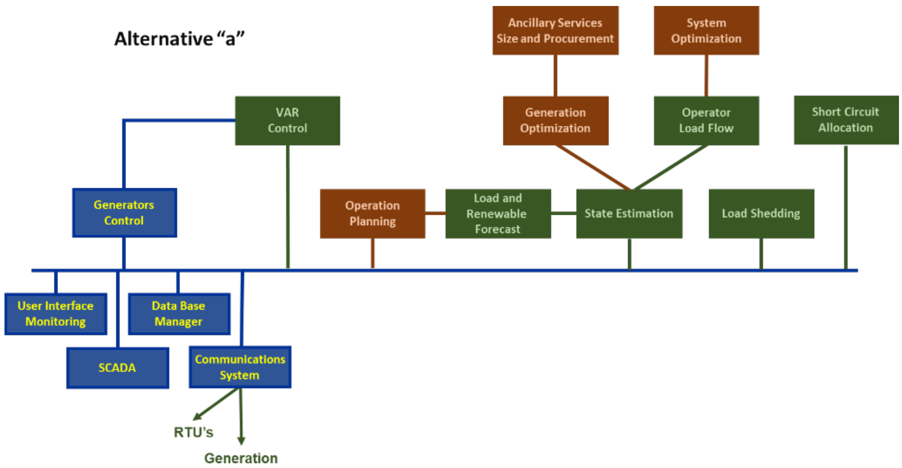
Some functionality is more oriented to much larger systems, where an operator cannot have a detailed knowledge of the full grid. This is not the case observed in the YAP electricity system. These functions are not recommended.

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

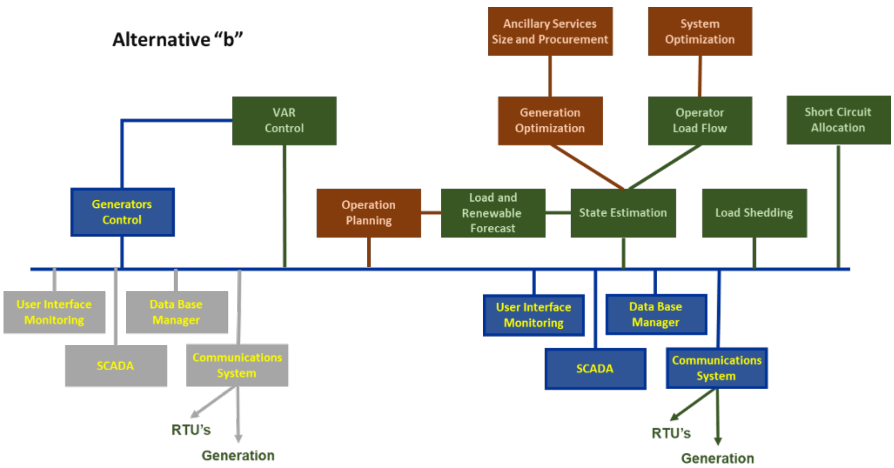
3.6 Architecture Potential alternatives

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

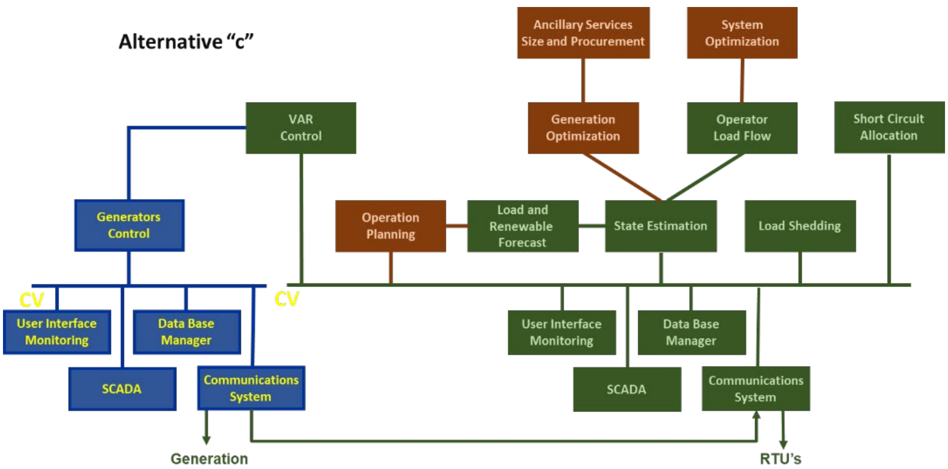
a. Use the actual SCADA system that is available in the YAP system for diesel generation control (blue blocks in the following figures) and expand its functionality with the one required for distribution network control (green blocks at first step, and brown in second).



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



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



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

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

Considering those aspects and because:

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

- Due to the capacity to cooperate between the different utilities in the region, as will be explained below

Considering those reasons, we recommend the alternative “c”

3.7 Additional elements to install in the network

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

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

3.7.1 Remote Terminal Units (RTU’s)

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

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

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

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

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

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

Considering the topology of the network in YAP, to start with, the number of RTU’s shall be between 3 and 6.

3.7.2 Capacity to modify the system topology

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

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

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

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

3.7.3 Communications and protocols

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

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

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

3.7.4 Cyber Security

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

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

3.8 Procurement, Training and Commitment

The activity of procurement will consist of:

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

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

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

3.8.1 Procurement

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

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

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

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

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

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

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

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

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

Some location specific aspects can be included, as options.

3.8.2 Training

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

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

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

But there are additional aspects that shall be considered:

- ✓ The minimum number of people assigned to SCADA in each utility. As administrators, should ideally be between 2 and 3, due the fact that there are unavoidable vacation or illness periods and the risk that one may decides to try other working options. However, in the Pacific Islands, staff resources are usually limited, so other options are:
- ✓ Sharing the trained resources among the different utilities, considering the capacity to be connected from distance, with secured communications, will reduce the number of formed administrators to 1 or 2 per utility.
- ✓ On the other hand, organize training courses for 2 or 3 people many times, in different locations, is an expensive scenario, compared with a single session for 10 to 16 administrators in the same location. Similarly, valid for users training

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

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

3.8.3 Commissioning

Includes all tests for acceptance and the installation on site.

Tests are commonly divided in two:

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

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

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

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

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

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

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

3.9 Cost Benefit Analysis (CBA)

The Cost Benefit Analysis must include the following aspects:

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

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

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

3.9.1 Installation financial cost

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

Those costs shall include:

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

3.9.2 Operational costs

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

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

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

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

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

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

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

3.9.3 Benefits

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

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

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

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

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

3.9.3.1 From the utility perspective.

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

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

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

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

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

3.9.3.2 From the society perspective.

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

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

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

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

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

3.10 SCADA Conclusions and Recommendations

Considering the aspects expressed above, we recommend:

- ✓ Establish one topology based on the maintenance of the existing SCADA to control the conventional generation.
- ✓ Implement a new SCADA system for network control
- ✓ Functionality regarding the Quality of Service will be in the first phase. When this phase will be consolidated, then a second phase with the Economic Optimisation and Losses Reduction will be implemented.

- ✓ Together with the first phase, the commitment and test of at least 4 RTU's.
- ✓ For `procurement, training, commitment, test and commercial operation we recommend achieving an agreement with other utilities to reduce the investment and operational costs.
- ✓ To calculate the Cost Benefit Analysis, we recommend considering the investment and financial costs for an expected life of 10 years, the operative costs for the same period and the social benefits attached to the reduction of blackouts in extension and duration.

3.10.1 Recommendation for staged implementation and roadmap: Yap

An existing SCADA System controls the frequency and the generating units in the Diesel groups. Based on the limited information available to us, we understand that the SCADA functionality includes:

a. Visibility and control of the diesel generation units
b. Visibility and control of the wind generation units
c. Visibility and control of the PV plants
d. Basic control (switching) of some feeder heads.
e. 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: Maintain 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 (diesel, wind and PV plants) which is existing.	Extend the SCADA to include the reclosers on the MV network. Implement level 1 DMS functions (as listed below) to optimise the operation of the power network	Implement additional DMS functions (as listed below) Extend the SCADA visibility to the LV network using SMART meter technology
Objectives (benefits)	Monitor the status of the main substation and the status of generation from a central SCADA Operate the power network (i.e. perform switching) from a central control station to improve restoration and 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 Improve grid security with emergency / block load shed capability	Support the implementation of virtual power plants to improve balancing of supply and demand Improve the control of the microgrid by supporting energy storage capabilities Reduce distribution system losses through volt/var optimisation Reduce demand and energy consumption through conservation voltage regulation

The scope of each stage proposed is detailed here below.

Stage 1: Basic SCADA

The basis SCADA recommended for this stage is existing. This includes SCADA visibility of the diesel generation plant, Wind generation and PV plants including visibility of the main substation 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) at the main substation
    - Basic power flow measurands (e.g. amps, MW, MVAR and voltages) at key network positions
    - Tap positions of major transformers
    - Alarm signals limited to common / grouped alarms
- Provide remote control capability of:
    - Open / close of switches (breakers and isolators)
    - Set generator setpoints and limits
    - Raise / lower transformer tap positions
- Visualise the status of the power network including topology processing to indicate the energized / de-energized / earthed parts of the network.
- 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 reclosers on the MV feeders and deploy some DMS functions listed below:

- 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

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

- Volt/var optimization module

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

- Conservation voltage reduction

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

- LV visibility

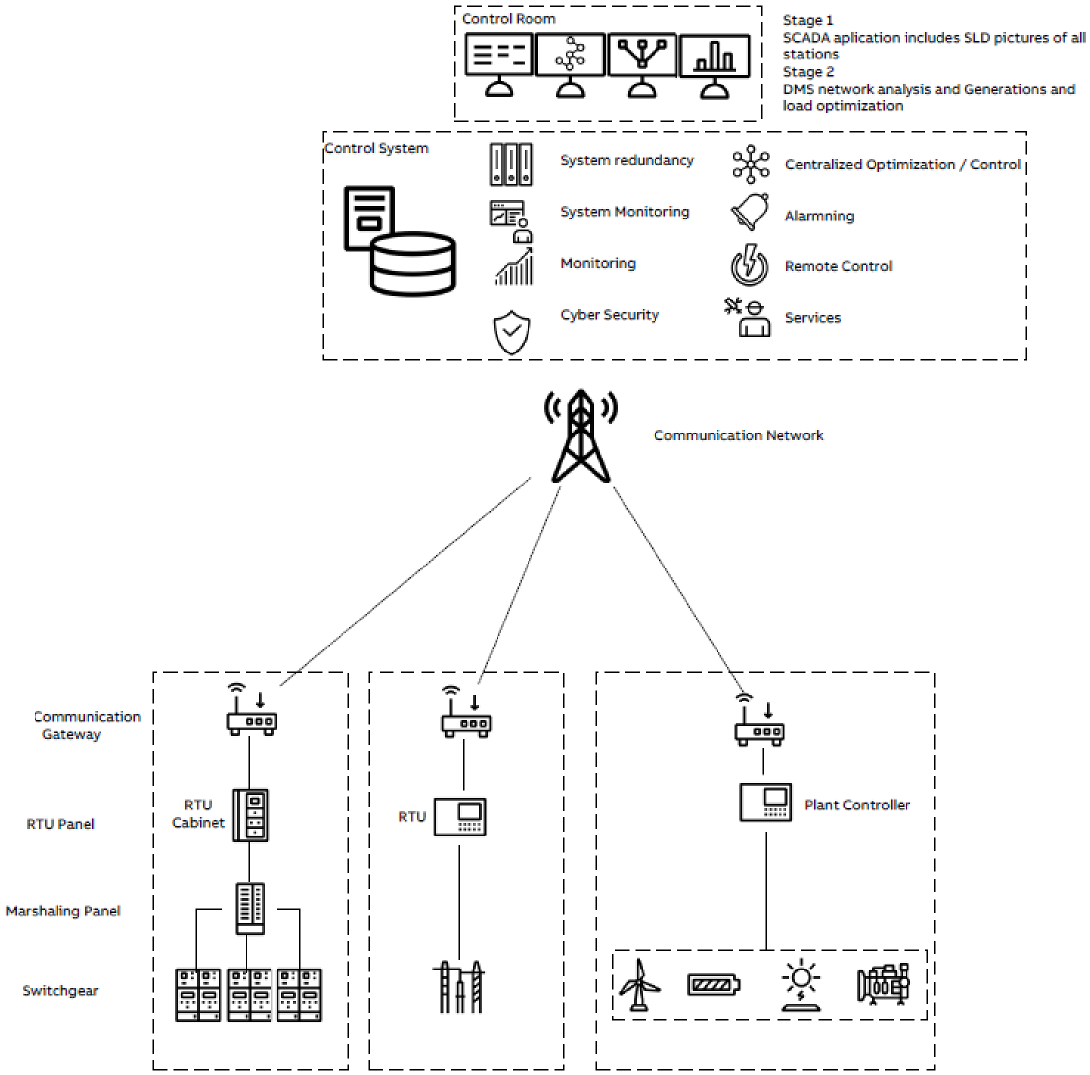
  Extending the LV visibility up to the customer can be achieved with the deployment of SMART meters with bi-directional communication. This can automate outage notification, identify voltage violations and support future volt/var optimization and conservation voltage reduction. This implementation will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

- State Estimator

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

The conceptual design of the SCADA Control System is described in Figure 3-1. The VERGNET SCADA system already provides most of this structure.

Figure 3-1: Conceptual design of the SCADA Control System



The conceptual design solution of the communication network is described in **Figure 3-2**.

Figure 3-2: Concept communication network diagram for YAP network

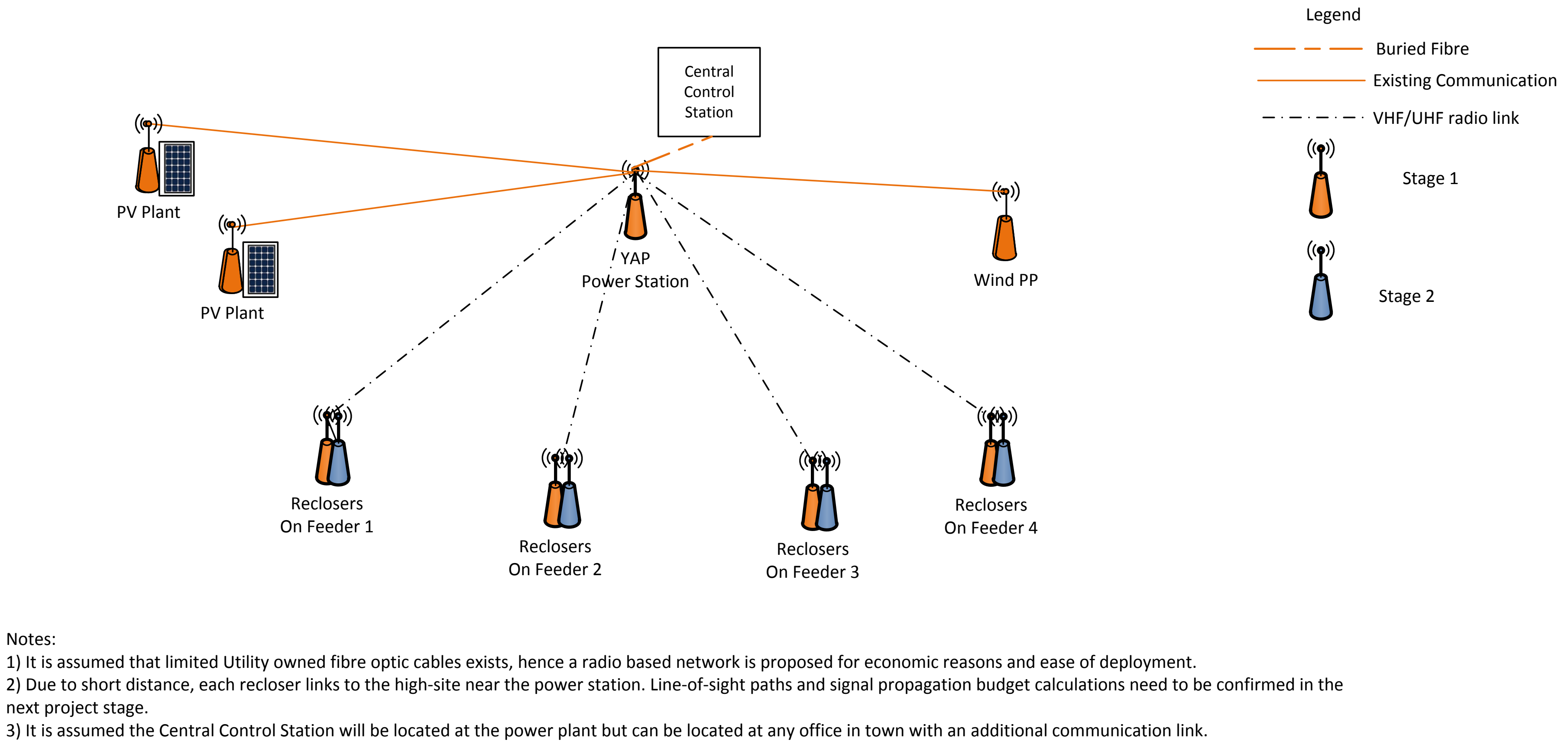


Figure 2: Concept communication network diagram for YAP network

3.10.2 Cost Estimate

The estimated cost to implement stage 1 and 2, based on the scope as described above is indicated in Table 3-1below.

Table 3-1: Estimated cost for stage 1 and 2 for YAP

	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	$ 5,000	$ 5,000	
- Weather station					1	lot	$ 5,000	$ 5,000	To improve future load forecasting
Software licences					1	lot	$ 20,000	$ 20,000	
Design and engineering					1	lot	$ 40,000	$ 40,000	
Installation and commissioning					1	lot	$ 20,000	$ 20,000	
Substations									
Hardware									
- RTUs: Main power plant									It is assumed this is existing
- RTUs (Reclosers)					25	each	$ 5,000	$ 125,000	Provisional qty for telemetry of switches on back
- RTUs (PV & Wind sites)									It is assumed this is existing
- Transducers					15	each	$ 2,000	$ 30,000	Provisional estimate subject to site audit
- Communication equipment: Central Station					1	each	$ 20,000	$ 20,000	
- Communication equipment: Stations					25	each	$ 5,000	$ 125,000	
- Auxiliary DC system					25	each	$ 2,000	$ 50,000	Provisional estimate subject to site audit
Design and Engineering					1	lot	$ 20,000	$ 20,000	
Installation, adaptation and commissioning					25	each	$ 5,000	$ 125,000	Provisional estimate subject to site audit
								$ -	
Travel and accommodation					1	lot	5.0%	$ 31,600	
Project overheads					1	lot	5.0%	$ 31,600	
Contingency					1	lot	15.0%	$ 94,800	
								$ -	
				$ -				$ 790,000	

It is assumed that the existing SCADA is not capable to provide the DMS functions, and the SCADA needs to be extended with a back-end system. This has been provided for in stage 2 as indicated.

Indeed, as I identified by YAP, radio-based communication network is susceptible to interference during weather conditions, and the availability is less than fibre optic networks. The retro fit installation of fibre optic cables after the power cables/lines has already been installed requires more detailed study. This can be done during the project implementation phase by considering any existing fibres, routing of fibre, trenching works required, servitudes for overhead ADSS etc. The costs would depend on whether overhead or buried fibre is used and the route lengths.

The telemetry of Reclosers can be omitted if the Reclosers installed does not support supervisory signals and controls.

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: Description of GDAT model

Appendix 2: Description of Scada and EMS

Appendix 1: 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

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Approved by

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History

Issue	**Date**	**Author**	**Description**
Ver 1.0	06 June 18	Graeme Chown, Grant Grobbelaar and Jason Miskin	Pacific Island model description

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.

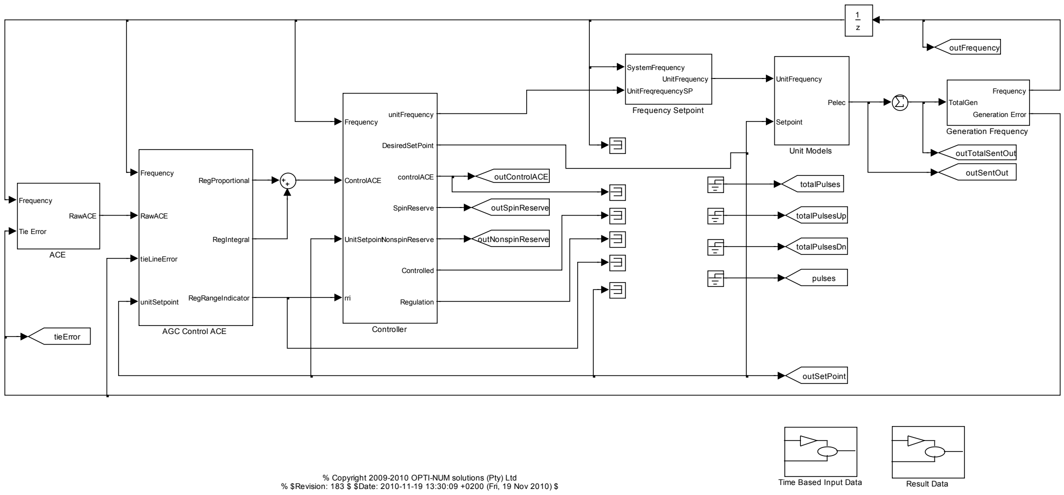


Figure B1: MATLAB AGC Model.

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.

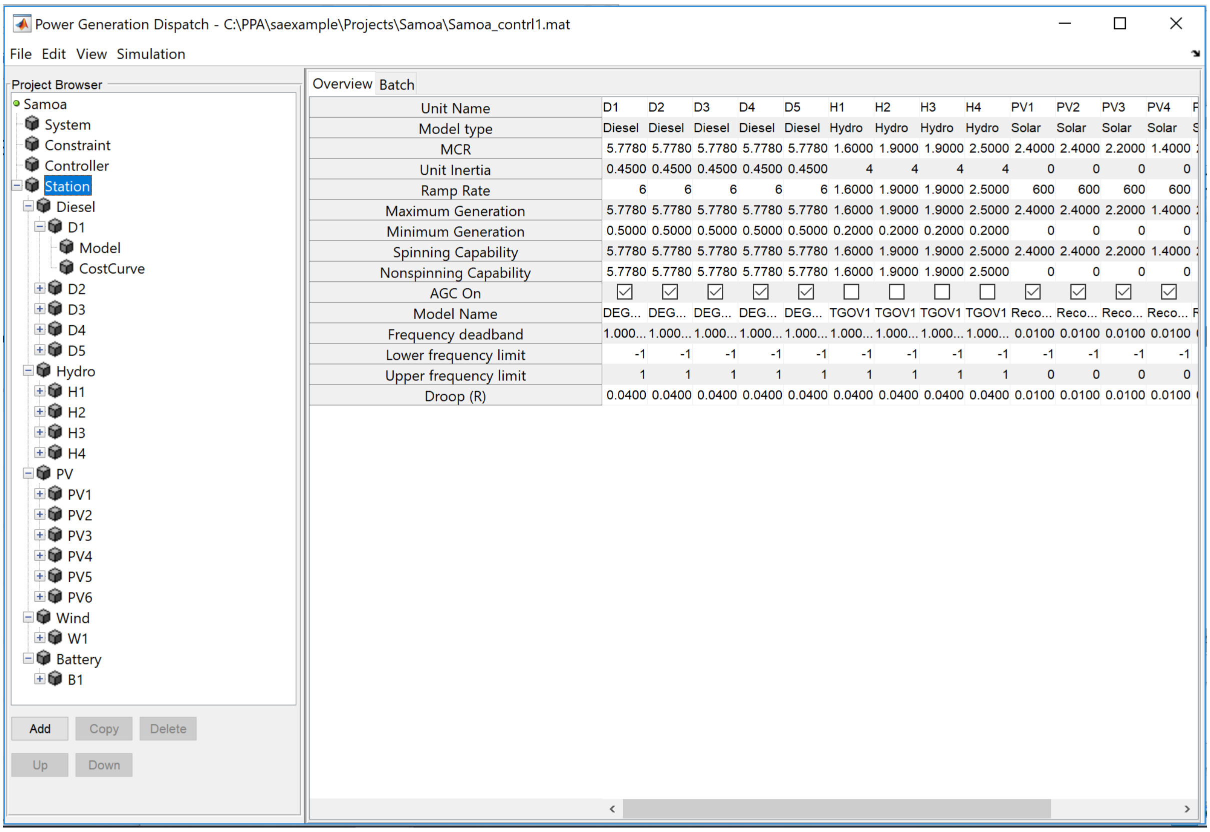


Figure B2: GDAT Model Input Data GUI.

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.

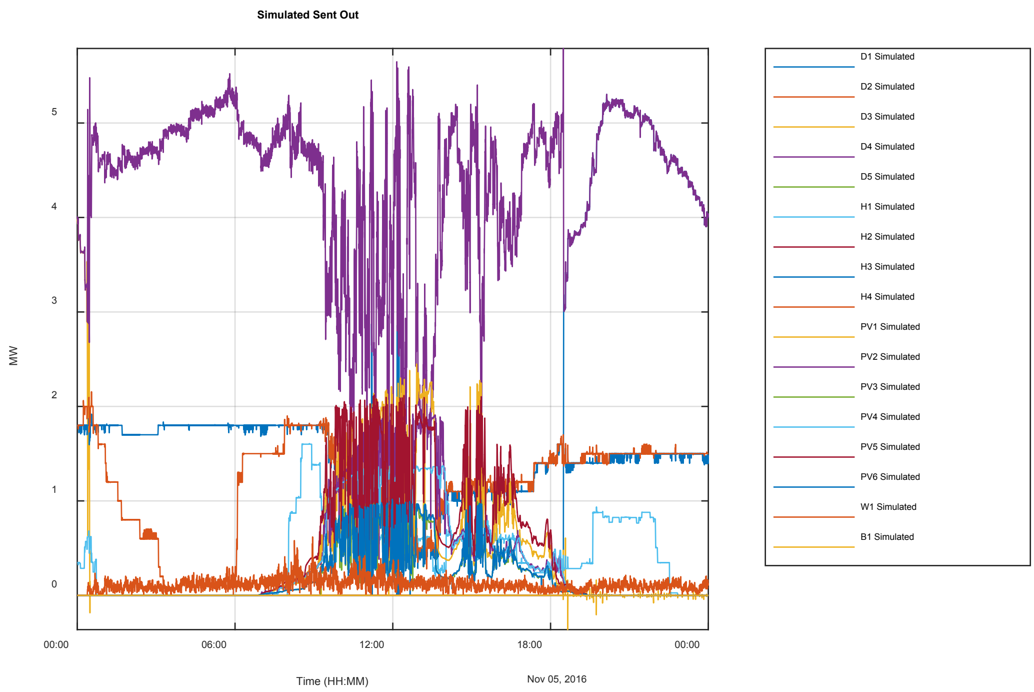


Figure B4: Simulated Sent Out (MW) Plot.

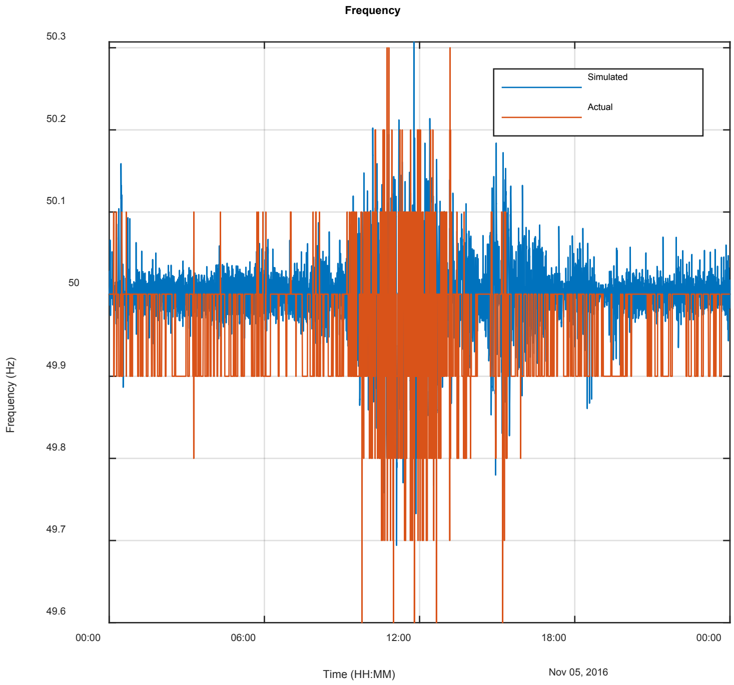
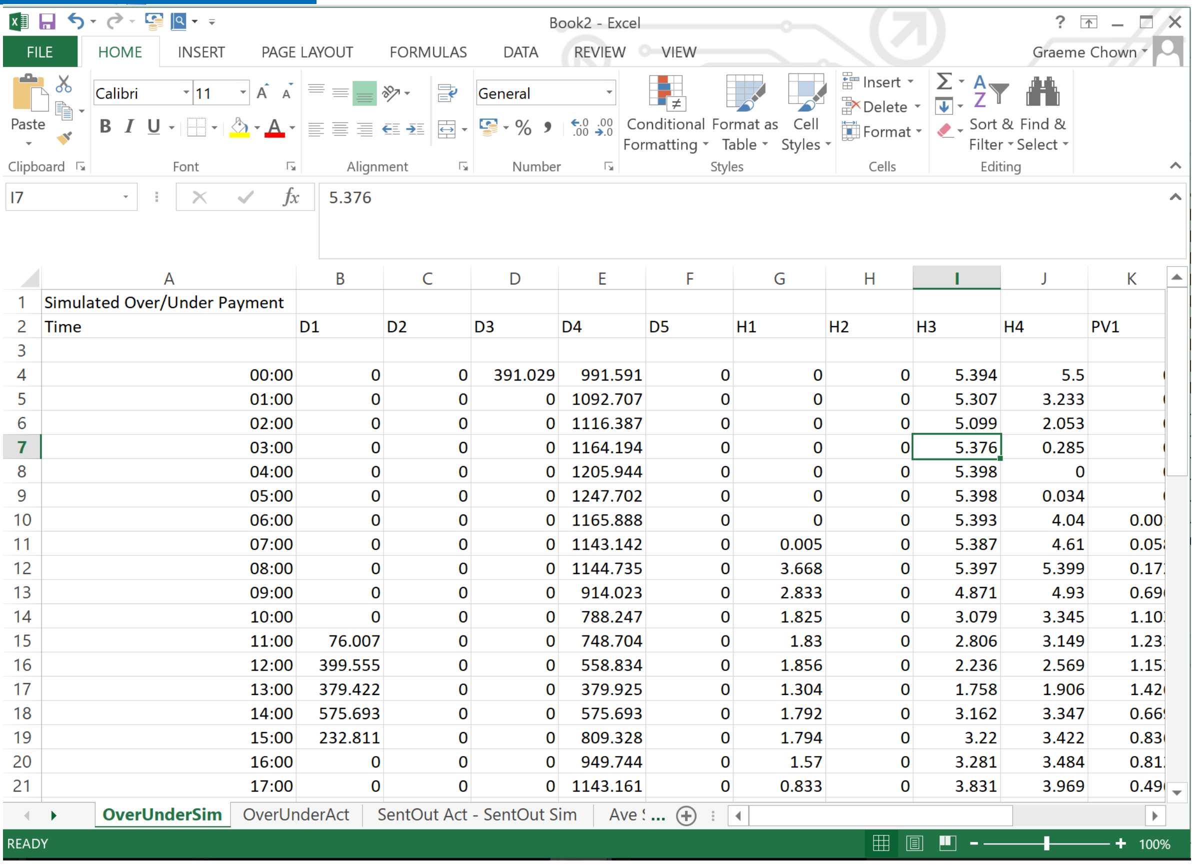


Figure B5: Simulated Frequency (blue) vs. Actual Frequency (orange) Plot.



	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).

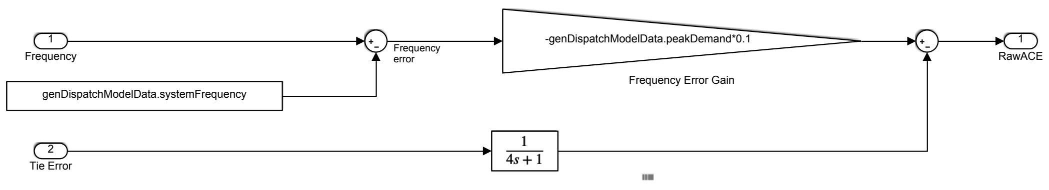


Figure B7: ACE Module.

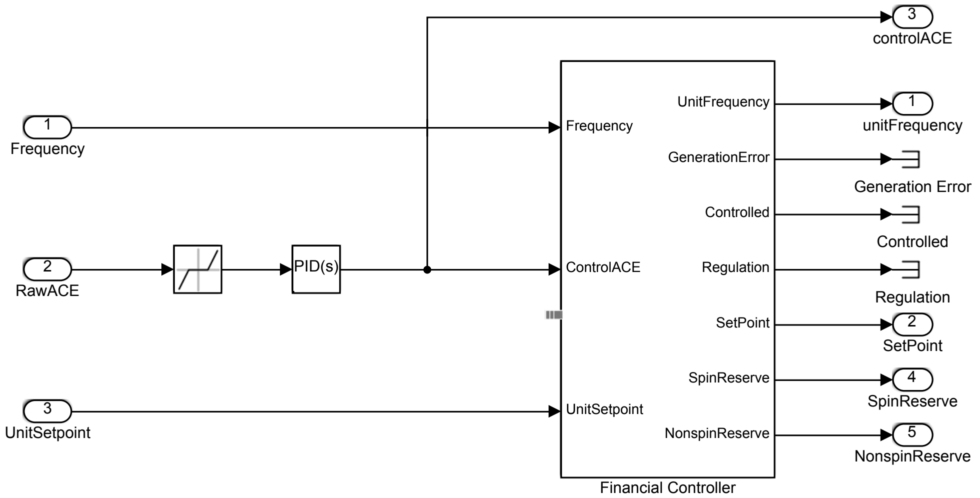


Figure B8: Controller Module.

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.

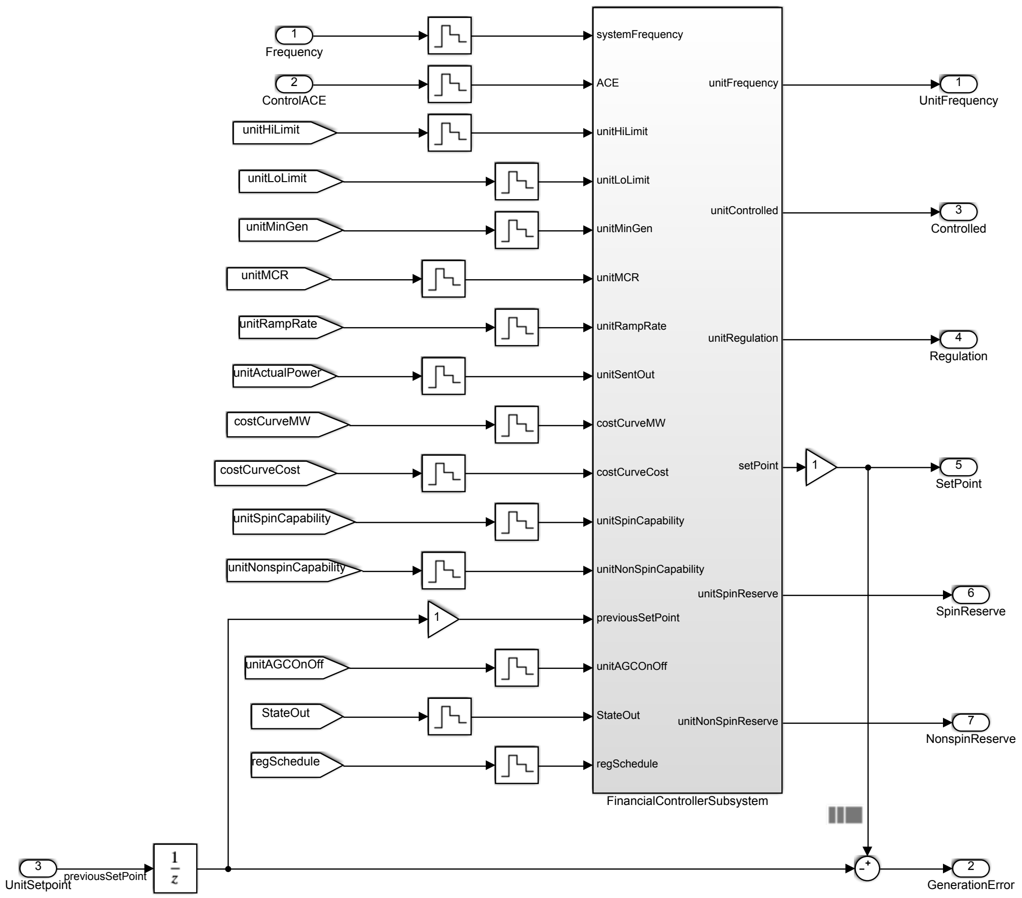


Figure B9: Financial Controller.

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.

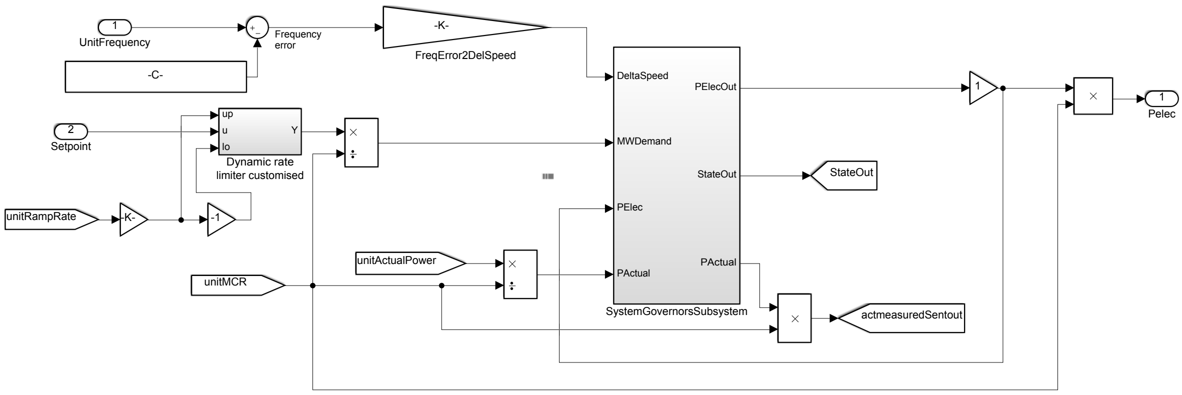


Figure B10: Unit Models Module.

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.

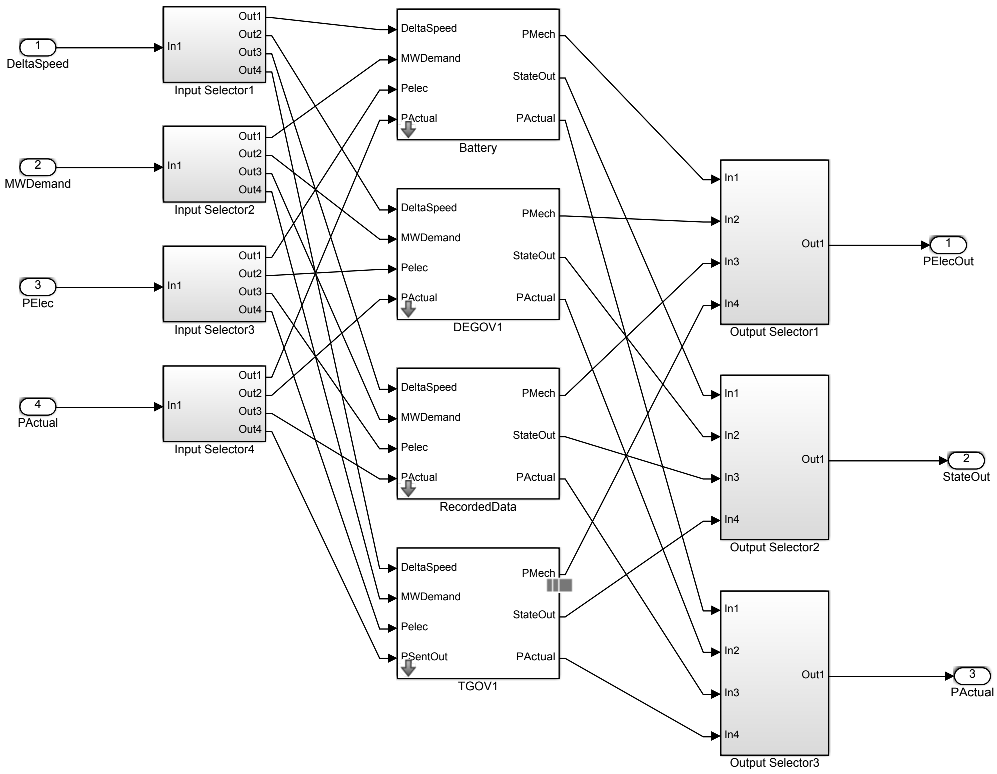


Figure B11: Aggregated System Governor Models.

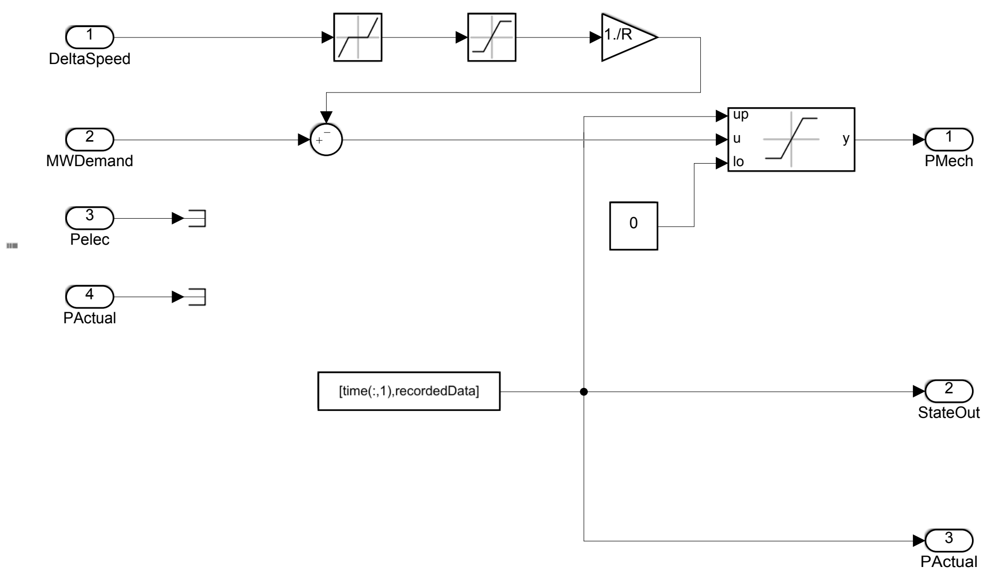


Figure B12: Recorded Data – used for Wind and Solar model.

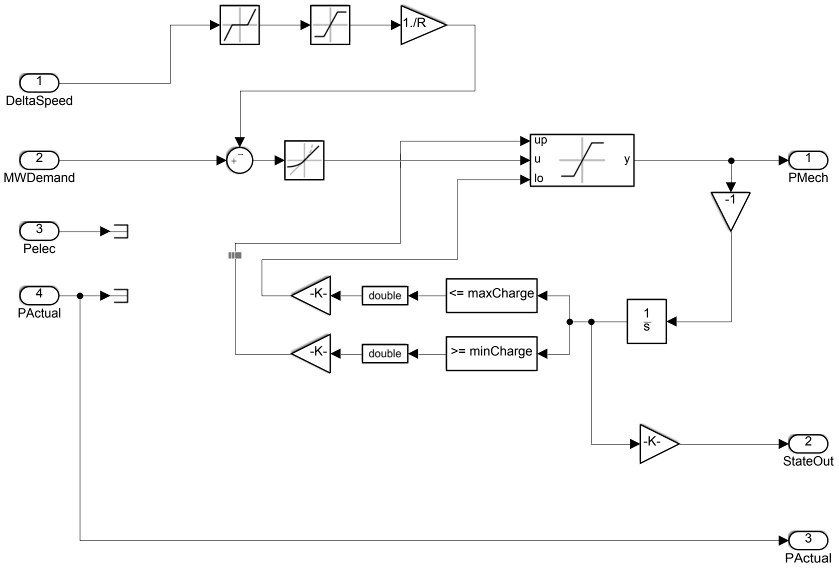


Figure B13: Battery Model.

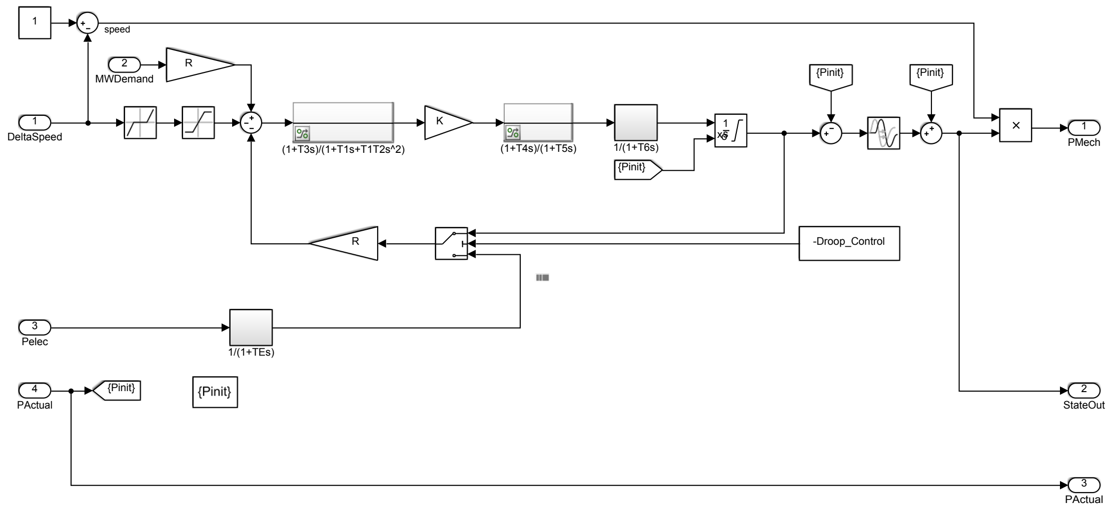


Figure B14 DGOV1 controller with lead lag (PID) controllers deactivated

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.

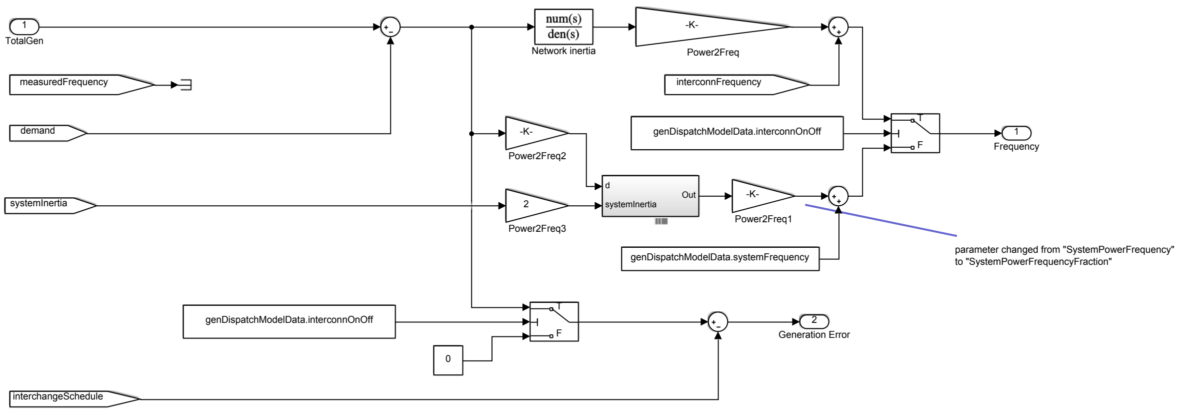


Figure B15: Generation Frequency Model.

Appendix 2: Description of Scada and EMS

Ricardo Energy & Environment

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 <u>Data Acquisition</u>

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.

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.

Communications Management

Basic SCADA Functionality

Network Control

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:

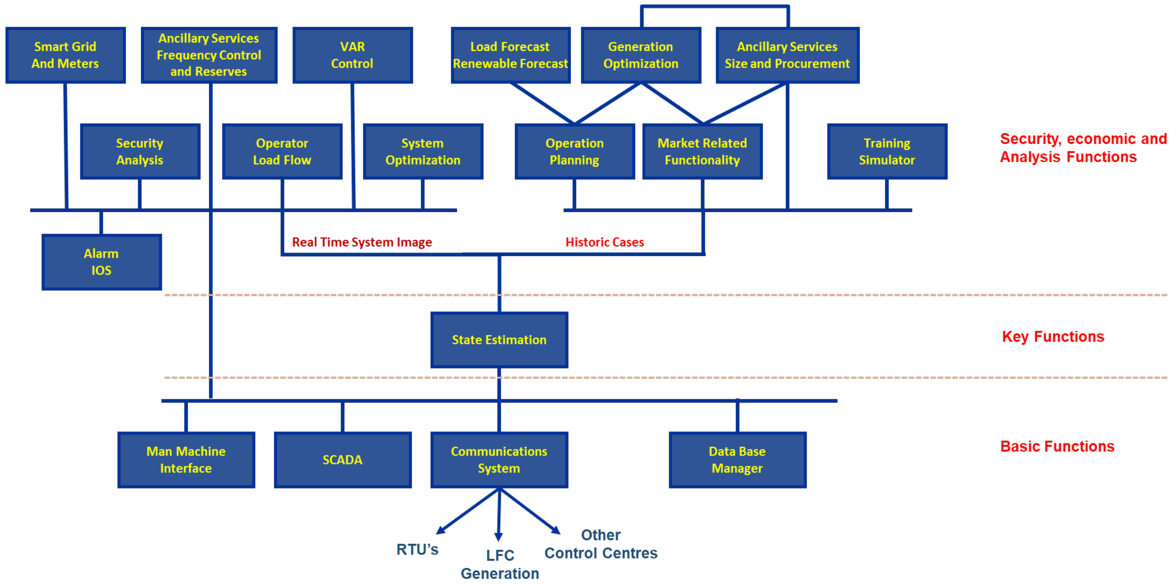
a. **Energy Management System (EMS)** oriented to generation and transmission systems. The main characteristics of those systems are those that are the relatively big size in generation and load, small or medium number of substations and extra high number of controlled elements, with the system fully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

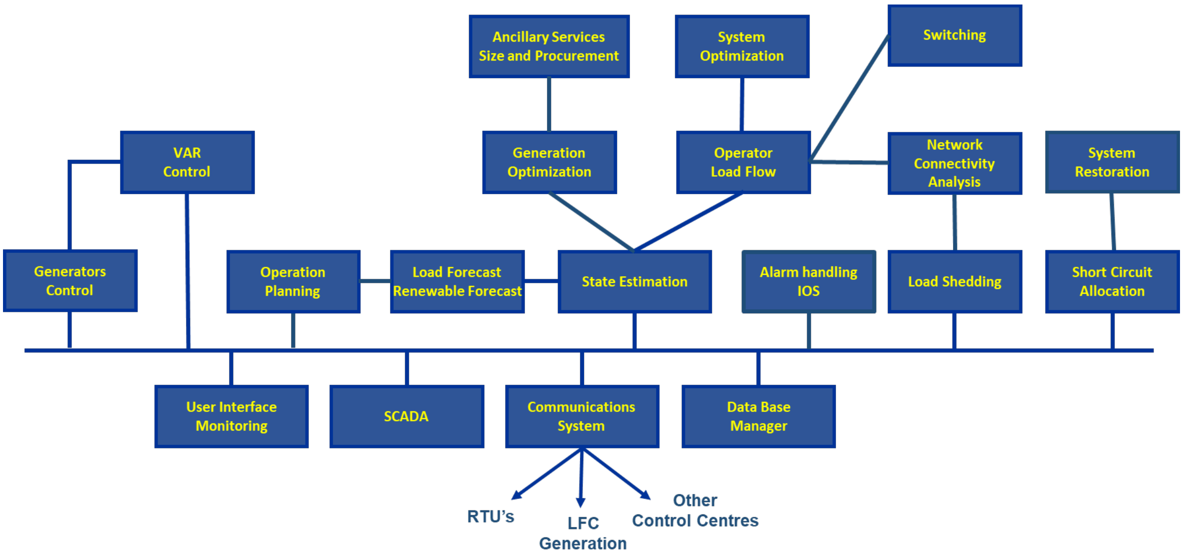
This control philosophy is extended to most large power plants from Nuclear Plants to Coal, Gas or hydro units. It is not a simple application. To control a unit or a power plant, a group of applications are run in a coordinated mode and these allow operators to control a variety of assets, from the 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.

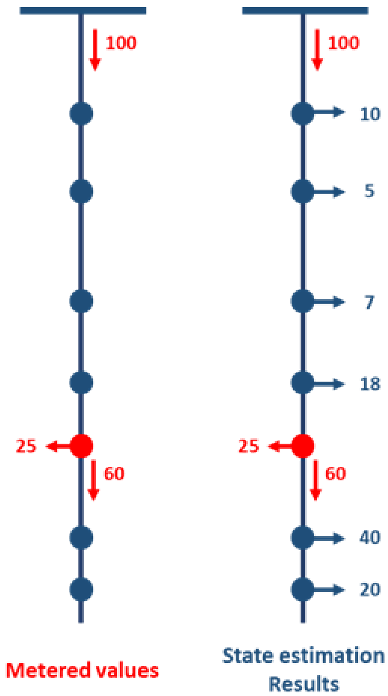
The functionality of applications are similar than in case of Energy Management System (EMS) but the methodology and mathematical approach are quite different.

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.

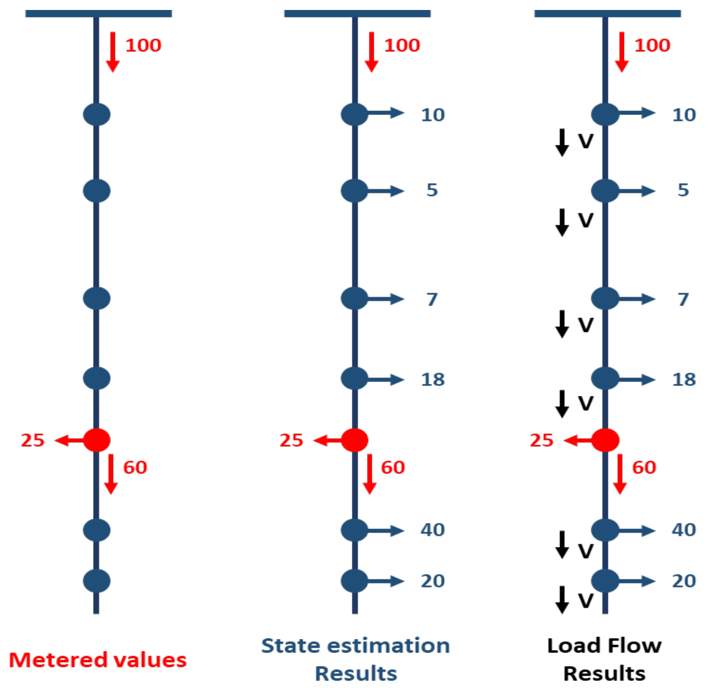
1.4.2.2 Load Flow Applications (LFA).

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.

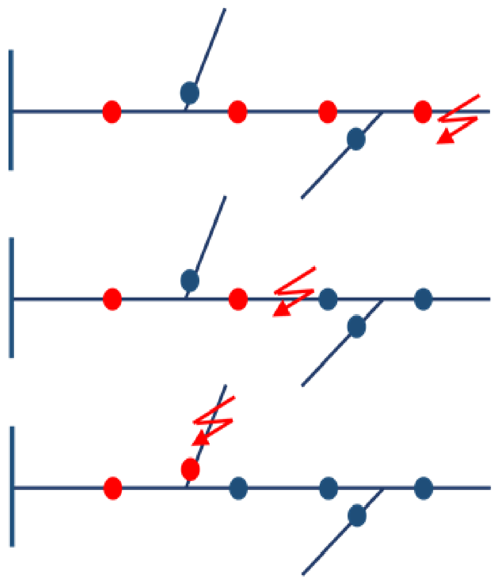
- ✓ Autotransformers: These transformers could have a turns-ratio that is very close to 1.00, which means that the voltage variation is small and these are used only for voltage control at the same voltage level.

- ✓ 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:

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

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

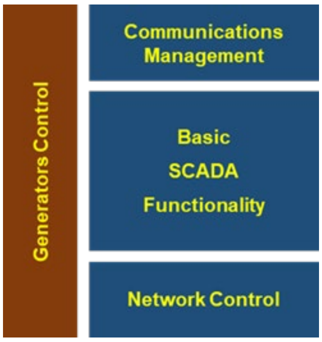
- ✓ Load + Losses forecast, this will require a cleaned historic load data base.
- ✓ Renewable or non-dispatchable generation, which could be estimated globally on the island or independently for solar or wind parks.

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 <u>Requirements of the Distributions Systems</u>

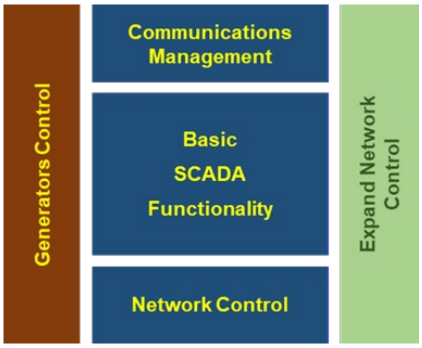
For the Distribution Systems such as the one in Chuuk or as seen in the other islands, the following three requirements have been identified:

- 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:

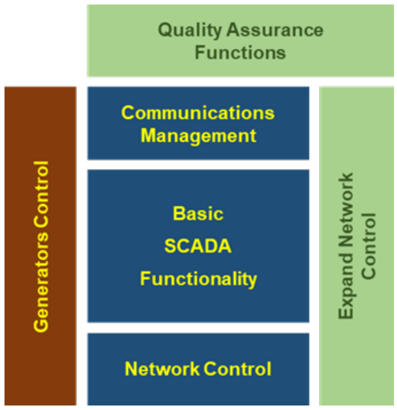
1. **Service Continuity**: The first challenge is to maintain the service under different situations and circumstances.

   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.

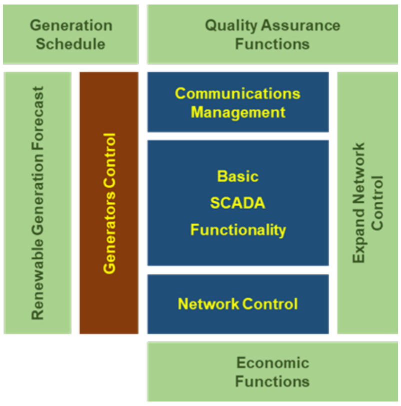
2. **Quality of the supply**: The quality of supply is maintained by managing the main parameters such as the frequency, voltage and harmonics.

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.

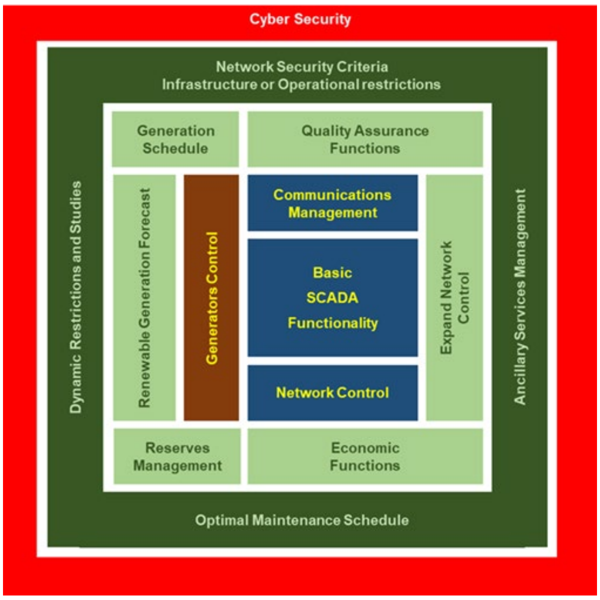


1.4.3.3 System Economic Optimization

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.

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