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PV Hybrid Mini-Grids: Applicable Control Methods for Various Situations

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PHOTOVOLTAIC
POWER SYSTEMS
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PV Hybrid Mini-Grids: Applicable Control Methods for Various Situations

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1. **Foreword**

The International Energy Agency (IEA), founded in November 1974, is an autonomous body within the framework of the Organization for Economic Cooperation and Development (OECD) which carries out a comprehensive program of energy co-operation among its member countries. The European Commission also participates in the work of the IEA.

The IEA Photovoltaic Power Systems Program (PVPS) is one of the collaborative R&D Agreements established within the IEA. Since 1993, the PVPS participants have been conducting a variety of joint projects in the application of photovoltaic conversion of solar energy into electricity. The mission of the IEA PVPS program is: To enhance the international collaboration efforts which accelerate the development and deployment of photovoltaic solar energy as a significant and sustainable renewable energy option.

The IEA PVPS Program aims to realize the above mission by adopting four objectives related to reliable PV power system applications for the target groups of governments, electricity utilities, energy service providers and other public and private users.

- To stimulate activities that will lead to a cost reduction of PV power systems applications.
- To increase the awareness of PV power systems' potential and value and thereby provide advice to decision makers from government, utilities and international organizations.
- To foster the removal of technical and non-technical barriers of PV power systems for the emerging applications in OECD countries.
- To enhance co-operation with non-OECD countries and address both technical and non-technical issues of PV applications in those countries.

The overall program is headed by an Executive Committee composed of one representative from each participating country, while the management of individual research projects (Tasks) is the responsibility of Operating Agents. By mid 2010, thirteen Tasks were established within the PVPS program.

The overall goal of Task 11: "PV Hybrid Systems within Mini-grids" is to promote the role of PV technology as a technically relevant and competitive source in mini-grids. It aims at enhancing the knowledge-base of multi-source power generation systems including PV and associated electric distribution networks. The objectives of the Task are to:

- define concepts for sustainable PV hybrid mini-grids taking into account local factors (specificity of the application, financing regimes, location, others);
- provide recommendations on individual designs (mix of technologies, architecture, size, performances, other) in order to achieve high penetration level of PV as a mean to improve quality, reliability and economics of electrification systems such as mini-grids;
- assess the potential of technologies to be mixed with PV for hybridisation; and,
- compile and disseminate best-practices on PV hybrid power systems.

The current members of the IEA PVPS Task 11 are:

- Australia
- Austria
- Canada
- China
- France
- Germany
- Italy
- Japan
- Malaysia
- Spain
- United States of America

This report gives an overview of control strategies and techniques to maintain frequency and voltage stability in PV hybrid mini-grids. The technical report has been prepared under the supervision of PVPS Task 11 by:

- Luiz Lopes, Concordia University (CAN)
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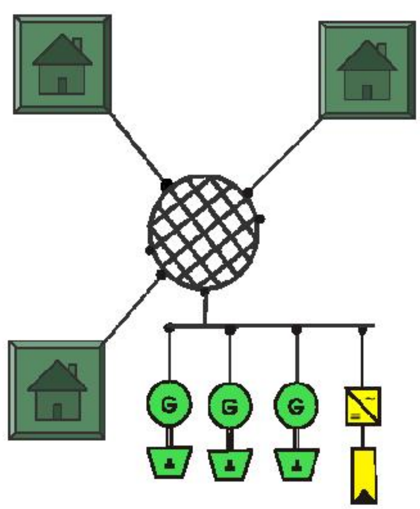
The report expresses, as nearly as possible, the international consensus of opinion of the Task 11 experts on the subject dealt with. Further information on the activities and results of the Task can be found at: http://www.iea-pvps-task11.org and http://www.iea-pvps.org.

2. Executive Summary

IEA PVPS Task 11 explores various design, control, and operational aspects of remote power generation and delivery systems (hybrid mini-grids) that include multiple energy sources to supply community-type loads. The immediate applications are for electrification of non-integrated areas and geographical islands based on renewable energy sources (RES). Traditionally, remote communities worldwide have been supplied electricity by diesel engine-generator sets (gensets). The use of RES can reduce the environmental impact of power generation, displacing diesel fuel and reducing the overall electricity price. When there is high penetration of RES, the inherent fluctuating and intermittent power characteristics of RES and the highly variable load profile of remote communities create significant challenges for the grid forming (master) unit(s) that regulate voltage and frequency. These challenges can be addressed with suitable control strategies which should at one level, (primary control) maintain grid stability by balancing generation and consumption of power and, at the other level, (secondary, or supervisory, control) optimize the generation of all sources and operation of the energy storage units.

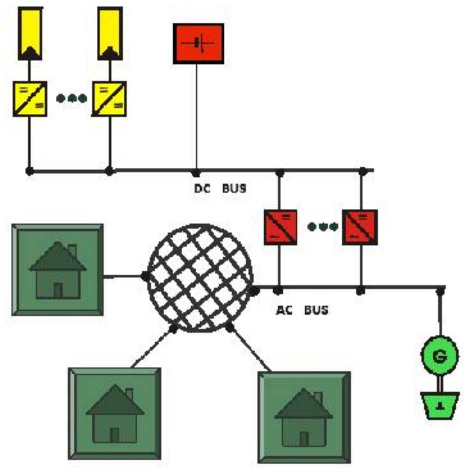
Hybrid mini-grids can be classified in several ways. In this report, a classification scheme based on the nature of the grid forming (master) unit(s), which balance power generation and consumption within the mini-grid, has been selected to discuss available control techniques and future developments. Three classes are discussed. These are:

- The multi-master rotating machine dominated mini-grid, which is a typical configuration for a diesel mini-grid, has multiple ac sources (fossil fuel gensets, PV inverters, and other RES) connected to the mini-grid and simultaneously supplying power. The gensets do the grid forming and the other sources follow the mini-grid voltage and frequency.



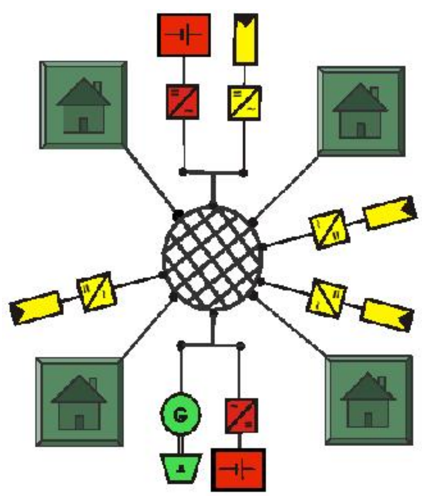
Multi-master rotating machine dominated mini-grid

- The single switched master mini-grid architecture has multiple ac sources connected to the mini-grid (typically battery and PV inverters and a fossil fuel genset), but the grid forming control is switched between the genset and the battery inverter(s). This allows the genset to be turned off. These architectures are typical in village microgrids.



Single switched master mini-grid

- The multi-master inverter dominated mini-grid also has multiple ac sources (fossil fuel gensets, PV inverters, battery inverters, other RES) connected to the mini-grid and simultaneously supplying power, but in this case certain inverters participate in the grid forming along with the gensets. This approach is well suited for mini-grids with many generators distributed throughout the network.



Multi-master inverter dominated mini-grid

2.1. Multi master rotating machine dominated mini-grid architecture

In a typical instance of this architecture, the grid is formed by a diesel power plant consisting of two or more diesel units, with at least one of them operating continuously. Interruptible diesel operation is possible in the presence of adequate amounts of RES and energy storage capacity, leading to one of the other two control architectures previously discussed. However, since battery storage is usually one of the most expensive components of a mini-grid over its life-time, there are cost advantages to eliminating energy storage entirely, or incorporating only short-term storage to assist with transient dynamics of the system. With the diesel genset(s) acting as the grid former, power quality and system stability depend on the ability of the gensets to respond to changes in power balance and other disturbances. The characteristics of the genset governor and excitation systems have a strong influence on this, as do the inertia of the rotating machinery and the response time of the prime mover.

Adding renewable energy sources (RES) to diesel mini-grid systems offers economic and environmental benefits, including considerable fuel savings and carbon dioxide emission reductions. This can be done in a distributed fashion or centralized at a few interconnection points. The latter approach (centralized) may be favourable from the mini-grid control and energy management stand point. On the other hand, distributed integration of RES may help off-set the load locally and reduce distribution losses, since mini-grids are normally implemented at low voltage levels. But distributed systems with high penetration of non-controllable RES can be subject to overvoltages during periods of high generation and low load, particularly if the RESs are placed far from the master diesel power plant. Since reactive power control is less effective in regulating voltage in feeders with resistive characteristics, such as in low voltage (LV) networks, another possible solution is the curtailment of the active power of the RES as a function of the local voltage.

Conventional diesel gensets are not designed to operate for extended periods at loads under about 30% of their rating. This can limit RES penetration since at least one genset must operate to form the grid and it must be loaded at a minimum of 30 - 50 % of its rated capacity. Excess energy from the RES that would reduce genset load must be curtailed or dissipated in dump loads. Gensets suitable for low load operation are now becoming available that reduce this problem. Other steps to maximize RES energy contribution include:

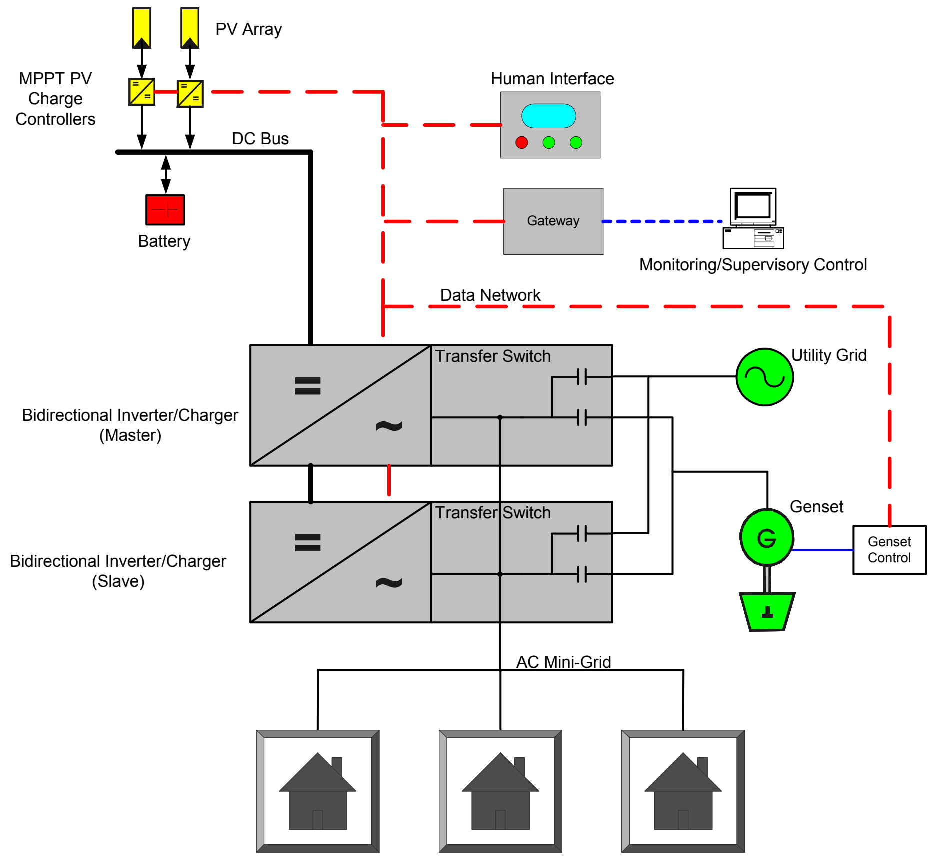
- resizing the gensets in the diesel plant and adopting a genset cycling strategy so that a lower power genset operates when load demand is low and/or RES contribution is high
- ensuring that the gensets are equipped with modern controllers that allow rapid, automatic response to changing load conditions
- upgrading the supervisory control system to manage the RES contribution,

- increasing RES capabilities, in terms of control and communications, including short term storage
- adding an automated demand management system that sheds or adds dispatchable loads (e.g. water pumping, cooling/heating, etc.) as needed

2.2. Single switching master (SSM) mini-grid architecture

This architecture has evolved from smaller PV hybrid systems for solar home applications. Developments in inverter and system technology have resulted in systems that can support village mini-grids. These advances include:

- Introduction of new PV battery charge controllers that incorporate PV maximum power point tracking (MPPT), temperature compensated multi-stage battery charging algorithms, and means to coordinate with the inverter/charger to manage the battery charging process. These MPPT charge controllers may be integrated into the inverter/charger, or remain as separate devices that communicate with the inverter/charger over a data network.
- Introduction of higher power capability for larger systems. This is achieved either through higher capacity inverter/chargers, or by modular systems that allow inverter/chargers to be connected in parallel to increase capacity.
- Introduction of data networks that interconnect system elements (e.g. PV charge controllers, inverter/chargers, generator controls, human interface) to enable system control, energy management, and monitoring.
- Development of control techniques that allow true, bidirectional four quadrant operation of the inverter/charger (rectifier) and fast, smooth transition of the inverter from a voltage source (grid former) to a current source (grid follower). This allows implementation of new operating modes that support both genset operation and interconnection to the central utility grid.



A modern SSM min-grid architecture

In this system, the bidirectional inverter/chargers exercise supervisory control over the system and manage the transitions among operating modes. The operating modes are:

- Autonomous operation with inverter/charger as the grid forming master. Multiple inverters can be paralleled to increase output power capability but their operation is controlled by a master unit to synchronize their ac output waveforms and to share output power.
- Autonomous operation with genset master. The inverter/chargers can be configured to operate as battery chargers which absorb power from the mini-grid only, or they can be configured to provide generator support also, by delivering power to the ac mini-grid under high demand conditions.
- Grid-parallel operation with the central (utility) grid as master. The inverter/chargers can be configured for the following operating modes:
  - battery charging only
  - mini-grid support (no power export to the central grid)
  - grid support with power export
  - peak shaving operation

Since the transfer switches that connect the genset(s) or the central grid to the mini-grid are controlled by the inverter/charger, the transitions between operating modes can usually be made with minimal voltage disturbance since the inverter/charger can synchronize the mini-grid and the source before making the transfer.

The battery energy storage in SSM systems mitigates the effects of rapidly changing RES generation or large load swings on system stability. The battery and the power converters connected to it (PV charge controllers and bidirectional inverter/chargers), act to absorb power from, or deliver power to, the mini-grid to maintain power balance. They also “smooth” the contribution of the PV generators on both a short term and long term basis. PV generators can also be coupled to the ac bus within the mini-grid if a more decentralized system is preferred. The bidirectional inverter/chargers can still smooth the contribution of these generators, but a means to curtail the power input of these generators is needed if the battery becomes fully charged and cannot absorb more energy.

2.3. **Multi-master inverter dominated mini-grid architecture**

This architecture is aimed at decentralized mini-grid applications where new generation sources can be added at locations throughout the mini-grid. A decentralized control structure that does not need high speed communication links is required. In such a case, the droop methods that are widely used for paralleling synchronous generators in conventional power systems have an advantage since they do not require a separate communication channel. For paralleling grid forming inverters, the frequency and magnitude of the reference voltage of each inverter can be made a function of their active and reactive powers according to $f = f_0 - s_{pf}P$ and $V = V_0 - s_{pv}Q$

where P and Q are the measured active and reactive powers injected by the inverter, s_{pf} and s_{pv} are the slopes of the frequency and voltage droop curves ($\Delta f/\Delta P$ and $\Delta V/\Delta Q$) and f_0 and V_0 are the idle frequency and the idle voltage, i.e. the voltage at which the inverter injects no reactive power into the mini-grid,. The latter are usually selected so that frequency and voltage drop by around 1% and 4% at rated values of active and reactive power, respectively. The shares of the variations of the balancing active and reactive powers (ΔP and ΔQ) taken by each grid forming inverter depend on their values of dP and dQ. With identical values, these inverters will share the balancing powers proportionally to their rated capacities.

Besides allowing power sharing coordination of the grid forming inverters without a dedicated communication channel, frequency variation can also be used for energy management. For example, the supervisory control can reduce the idle frequency of a grid forming inverter if its battery needs to be charged. In cases of low load conditions and fully charged batteries, a high mini-grid frequency value can be used to show that there is an excess of power in the system and that generators should curtail output. Likewise, load controllers can disconnect loads in case the grid frequency falls below a certain value.

Load sharing between droop controlled grid forming inverters and gensets has been shown to be feasible with the appropriate settings of the inverters' frequency droops. As for grid-tie operation, where the system frequency is fixed, it has been shown that the inverter power can be controlled by varying the value of the idle frequency, as in the autonomous case. The suitability of droop control for multi-master inverter dominated mini-grids has been demonstrated in pilot projects in Europe and North America.

2.4. **Conclusions and Recommendations**

The primary control strategies reviewed above are capable of regulating mini-grid voltage and frequency to meet current user needs. The choice of strategy employed will depend on the architecture of the mini-grid (centralized or decentralized), the generation mix (diesel dominated or high penetration of renewable sources), and the economics of incorporating auxiliary stabilization mechanisms, such as energy storage systems or dispatchable loads.

These control strategies are typically easiest to implement in lower power, compact mini-grids with centralized generation. As power levels rise, and the grid becomes geographically larger and more dispersed, the challenges increase for the following reasons:

- reduced availability of standard, off the shelf components and systems
- greater challenges with communication among system elements
- greater challenges maintaining voltage regulation throughout the mini-grid

There is a need for more research and commercial development of control systems and components for large, distributed mini-grids.

3. Introduction

IEA PVPS Task 11 explores design, control, and operation aspects of power generation and delivery systems (hybrid mini-grids) that include multiple energy sources to supply community-type loads. The immediate applications are for electrification of remote areas not integrated into the central grid, and geographical islands, using a range of energy generation technologies, particularly renewable energy sources (RES) such as photovoltaics (PV). Traditionally, remote communities worldwide have been supplied electricity almost exclusively by fossil fuel engine-generator sets (gensets). Environmental concerns with fossil fuel based generation sources are some of the drivers to increase RES penetration. In addition, RES contribution can displace fuel and reduce the overall electricity price.

The penetration of renewable energy in a hybrid system can be defined in terms of instantaneous and/or average values [3.1]. In the first case, one considers the ratio of the peak power produced by renewable energy source(s) and the active power consumption of the system loads. This parameter is an indicator of the level of control required to operate the system with good power quality. The average penetration can be obtained by dividing the energy produced by the renewable source(s) by the energy consumed by the primary load, in a month or year. This parameter provides an estimation of possible fuel savings due to the addition of RES. Table 3.1 shows a classification presented in [3.1]. It is assumed that suitable means for balancing the power produced and consumed in the system are in place – this may include control of non-renewable generation sources, energy storage, dispatchable secondary loads, or export to an external grid.

Table 3.1 – Classification of renewable penetration levels.

Class	Penetration	
	Peak Instantaneous	Annual Average
Low	< 50%	< 20%
Medium	50% - 100 %	20% - 50%
High	100% - 400%	50% - 150%

The incorporation of RES into a genset based system at low penetration levels is relatively simple since they can operate as passive generation units, injecting as much power as possible, with no participation in the control strategy. The renewable sources can be seen as “negative loads” that reduce the amount of power demanded from the gensets. However, at high penetration levels, the inherent fluctuating and intermittent power characteristics of RES creates significant challenges for the gensets which act as grid-forming (master) units to balance power and regulate voltage and frequency. Gensets typically operate under operating constraints that keep operation and maintenance costs low while providing power with acceptable levels of quality and reliability. These constraints limit the ability of the gensets to respond to large rapid changes in power supplied to the mini-grid by RES.

The power balance challenge for mini-grids in remote communities is increased by load profiles which are often highly variable, with the peak load as high as 5 to 10 times the average load. Since mini-grids typically represent weak grid conditions (i.e. limited generation capacity and spinning reserve), sudden variations in mini-grid power consumption may deteriorate power quality. This problem is even more critical with high penetration of RES and with the system operating with reduced amounts of rotating masses due to low combined generator inertia.

One alternative for power smoothing in systems with RES and highly variable loads is to use an energy storage system, such as a battery. Energy storage technologies suitable for mini-grid stability control are reviewed in the IEA PVPS Task 11 report *T11-02:2011 - The role of energy storage for mini-grid stabilization*. Energy storage systems are expensive over the life-time of a mini-grid. That is why many mini-grids employ minimal energy storage to enhance short term power balancing capabilities, or use operating and control strategies that do not rely on storage. These may include demand side management (DSM) and actively controlled RES.

Operating a hybrid mini-grid with medium and high penetration of renewable energy typically requires a multi-level control strategy to maintain stability and power quality while also achieving economic, reliability, and environmental objectives. The control strategy of the mini-grid should, at one level, (primary control) maintain grid stability and, at the other level, (secondary, or supervisory, control) optimize the operation of the power sources, energy storage units and controllable loads, if applicable. This report focuses mostly on the short-term power balancing aspects of the control of a hybrid mini-grid in order to maintain grid stability and power quality.

3.1. Overview of stability issues in mini-grids

According to the IEEE / CIGRE Joint Task Force on Stability Terms and Definitions [3.3]: “Power system stability is the ability of an electric power system, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance, with most system variables bounded so that practically the entire system remains intact.” Common physical disturbances in hybrid mini-grids are power imbalances caused by changes in power injected by generation sources or power consumed by loads. To achieve stability, the power injected must be balanced by the power consumed. The Task Force also defines three main types of instability: Rotor angle instability, frequency instability and voltage instability. The majority of the literature on power system stability has focused on rotor angle and voltage stability, with frequency stability often being neglected. A simple reason for this is that most of the world’s power systems are large interconnected networks, where there is plenty of opportunity for power wheeling and therefore sharing of spinning reserve (extra capacity to restore generation/load balance following a generator trip) and unit inertial response.

This results in a stiff system, where a large generation/load imbalance must occur before the frequency will deviate to any significant level [3.3]. This is not necessarily the case for “small” systems, such as mini-grids, which can be defined as one in which any individual generator in-feed represents a substantial portion of the total demand. There, frequency stability is of greater concern, particularly with high penetration of renewable energy.

The response of synchronous generators in conventional power plants to a change in power balance and the resulting frequency deviations can be split up in three phases. In the first phase, following a deviation in the power balance, the rotors of the synchronous generators will release or absorb kinetic energy and as a result the frequency will change. The response is determined by the dynamics of the system and is called “inertial response”. This is of paramount importance, particularly in a small system, as it controls the initial rate of change of frequency. When the frequency deviation exceeds a certain limit, governors will be activated to change the power input to the prime movers. This is the second phase, the primary frequency control. When the power balance is restored with the spinning reserve, there will be still a steady-state frequency deviation. In the third phase, secondary frequency control, the frequency will be brought back to its nominal value. [3.4]

The integration of renewable energy sources such as photovoltaic (PV) and wind, replacing conventional power plants, can create frequency stability issues in small systems. PV systems do not present kinetic energy stored in rotating masses to assist with the inertial response. Besides, they are usually operated at maximum power point, so they cannot assist in the primary frequency control by providing extra power to compensate for a loss of generation or a load increase. Wind energy conversion systems do have stored kinetic energy but their inertial response depends on the nature of the interface to the grid. If a power electronic interface is used to allow variable speed operation of the turbine, a change in system frequency will not be experienced by the turbine, with consequent release/absorption of kinetic energy, unless a supplementary control loop, not standard in small wind turbines, is added for this purpose.

In a small system with significant shares of RES, the initial rate of frequency change is typically greater and a lower value of frequency can be reached in a shorter time than in conventional systems with all generation supplied by rotating machines, possibly resulting in under-frequency load shedding and tripping of PV and wind generators. In such cases, adequate spinning reserve should be available and provided by rotating machines with a sufficient governor response and a high inertia. Gas turbines and diesel gensets can typically provide faster spinning reserve than steam turbines with a consequent reduction in the transient frequency drop [3.5]. The required increase in spinning reserve to compensate for the lack of frequency control support of RES is an important matter even in relatively large isolated grids. For example, in the 2000 MW system in Northern Ireland, consisting mainly of thermal generation (i.e. steam turbines), it has been suggested that for 10% wind power penetration the requirements for spinning-reserve margin and system ramping rates would have to be increased by approximately 25% and 5%, respectively [3.2], [3.6].

An alternative to generation based spinning reserve is the use of energy storage. This is one of the most technologically advanced and long term solutions for frequency stability. A recent installation in Alaska is capable of maintaining an output of 40 MW for 15 minutes until other forms of generation can be started and synchronized [3.2], [3.7]. Another option for isolated systems is load shedding [3.7] but its “cost” to system users, in terms of perceived loss of power quality and reliability, has to be balanced with the cost of providing adequate spinning reserves. It should be noted that in many cases, autonomous diesel-hybrid systems present secondary loads with intrinsic energy storage characteristics, such as water heaters, water pumping, water desalination plants and ice making plants that can be disconnected for some time without major issues for the consumers. Even space heaters and coolers can be disconnected for short periods without noticeable impact.

Ideally, electric power systems would provide reliable and uninterrupted service with constant voltage and frequency to the loads. In practice, voltage and frequency are allowed to vary within a “normal range” giving some flexibility for the system while making sure that the consumer’s equipment operate satisfactorily. According to the IEEE Standard for Interconnecting Distributed Resources with Electric Power Systems (IEEE Std 1547), distributed resources (DRs) smaller than 30 kW should cease to energize the area electric power system (EPS) when the voltage goes out of range, typically 88% to 110% of the nominal voltage and the frequency goes out of range, above 60.5 Hz and below 59.3 Hz [3.9]. The European Standard EN–50160 (European Standard EN–50160, 1994) requires that for a non-interconnected (*i.e.* autonomous) power system, voltage and frequency should be within certain ranges:

1. 230 V ± 10% (*i.e.* 207–253 V) during 95% of a week;
   230 V–15% +10% (*i.e.* 195.5–253 V) during 100% of a week, and

2. 50 Hz ± 2% (*i.e.* 49–51 Hz) during 95% of a week;
   50 Hz ± 15% (*i.e.* 42.5–57.5 Hz) during 100% of a week [3.9]

3.2. Power quality

Power quality in mini-grids is usually dependent on the source(s) acting as the grid forming (master) unit(s), the design of the mini-grid distribution network, and the nature of the loads in the mini-grid. The main factors usually considered are voltage and frequency regulation as well as (voltage) harmonic distortion.

The voltage regulation characteristics of gensets are determined mainly by the type and design of the alternator, usually a wound rotor synchronous generator, and the performance of the automatic voltage regulator. According to [3.11] the steady-state voltage deviation should be better or equal to 5% for units above 10 kVA. The harmonic distortion of the voltage waveform at the output of the genset depends significantly on the quality of the alternator. Good quality genset alternators achieve total harmonic distortion (THD) of well under 5%.

Frequency regulation depends on the characteristics of the governor (speed controller), and on the secondary (supervisory) control system. The governor usually operates in either the isochronous mode, with constant speed and, ideally, constant output frequency or in the droop control mode, where the generator speed and frequency are allowed to vary in a controlled way. In practice, engine gensets vary widely in the quality of their frequency regulation, and the output frequency is often load-dependent even in the absence of a droop control system.

In the droop mode, the generator operates with variable speed (ω) as a function of its output power (P), given by

$$\omega = \omega_{ref} - s_p\left(P - P_{ref}\right)$$

where ω_{ref} and P_{ref} are set-point values of speed and output power and s_p is a slope factor. As the output power of a generator increases, its speed tends to decrease, which facilitates the operation of multiple generators in parallel (See Section 4.2 for a more detailed discussion). Droop control results in short term deviations from nominal frequency but the long term average can be maintained at the nominal frequency by a supervisory controller that changes the ω_{ref} and/or P_{ref} set-points of each generator to bring the grid frequency back to its nominal value.

The power quality of modern power electronic interfaces for RES and energy storage systems is usually excellent, with superior regulation of voltage and frequency and low harmonic distortion. Typical THD levels are considerably less than 5% (2% - 3% is common). Modern inverter/chargers with high frequency PWM control of the output waveform and closed loop control of their output voltage usually have low output impedance. As a result, the voltage regulation can be very good (typical specification is V_{nom} +/- 3%). Figure 3.1 shows the voltage and current waveforms when a modern inverter/charger is step loaded to twice its continuous rated power (its maximum surge power). The ac output voltage drops only 0.6%, from 240Vac to 238Vac. Modern inverter/chargers usually have a crystal controlled time-base that controls the ac output frequency. As a result, frequency regulation is excellent (typical specifications are less than 0.1 Hz deviation from nominal), although there is sufficient long-term drift so that the ac line frequency cannot be relied on for long-term time-measurement applications.

In addition, modern inverter/chargers can provide load support to other lower performing grid-forming sources thus reducing voltage and frequency variations. Even further improvement can be achieved if the power electronic interfaces present active power filtering features. This has been the topic of research [3.12] - [3.14] but is not yet offered in commercial products.

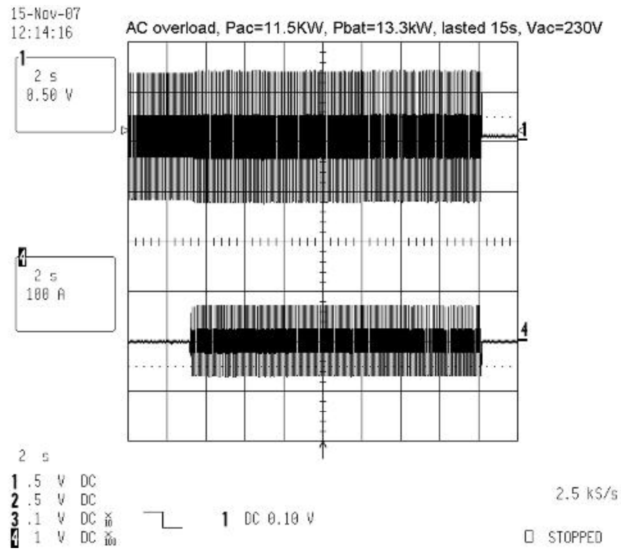


Figure 3.1 – Schneider XW Inverter voltage regulation.
Trace 1: Vac (250V/div);
Trace 4: Iac (50A/div);
Time: (2s/div.)

The design of the mini-grid distribution network primarily affects voltage regulation within the mini-grid due to the effect of line impedances. These effects can be predicted with distribution network design and analysis software but, for hybrid mini-grid applications, the software package should accommodate networks with multiple distributed generation sources.

Load characteristics can have a significant impact on power quality in a mini-grid since the generation sources are typically less “stiff” than those in a large central grid (i.e. they have higher internal impedance and less stored energy). Loads can cause:

- voltage flicker due to rapid fluctuations in load (e.g. a large load cycling on and off), and
- increased voltage harmonic distortion due to non-linear loads drawing non-sinusoidal current (e.g. electronic lamp ballasts for compact fluorescent lamps).

3.3. Classification of mini-grids

Hybrid mini-grids can be classified in several ways. In this report, a classification scheme based on the nature of the grid forming (master) unit(s) has been selected to discuss presently available control techniques and future developments. Three classes will be discussed in subsequent sections. These are:

- The multi-master rotating machine dominated mini-grid (see Figure 3.2), which is a typical configuration for a diesel mini-grid, has multiple ac sources (fossil fuel gensets, PV inverters, and other RES) connected to the mini-grid and simultaneously supplying power [3.15]. The gensets do the grid forming and the other sources follow the mini-grid voltage and frequency.

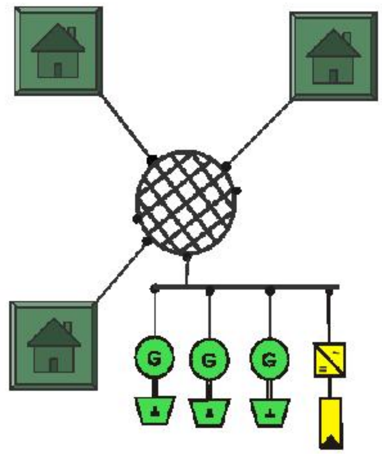


Figure 3.2 – Multi-master rotating machine dominated mini-grid

- The single switched master mini-grid architecture (see Figure 3.3) has multiple ac sources connected to the mini-grid (typically battery and PV inverters and a fossil fuel genset), but the grid forming control is switched between the genset and the battery inverter(s). This allows the genset to be turned off. These architectures are typical in village microgrids.

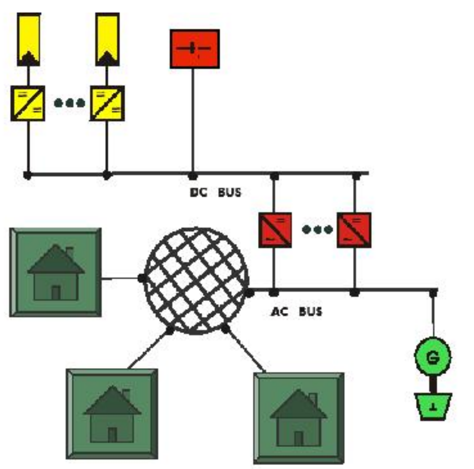


Figure 3.3 – Single switched master mini-grid

- The multi-master inverter dominated mini-grid (see Figure 3.4) also has multiple ac sources (fossil fuel gensets, PV inverters, battery inverters, other RES) connected to the mini-grid and simultaneously supplying power, but in this case certain inverters participate in the grid forming along with the gensets [3.16]. This approach is well suited for mini-grids with many generators distributed throughout the network.

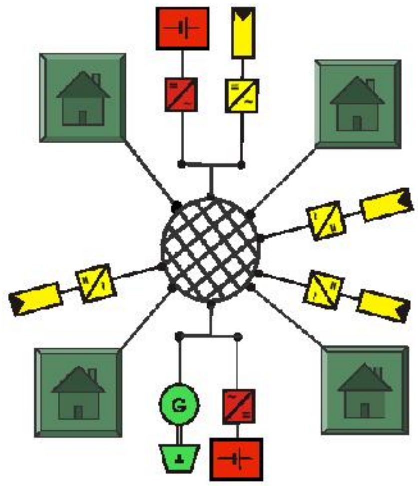


Figure 3.4 – Multi-master inverter dominated mini-grid

The selection of a control strategy depends on the nature of the generation sources in the mini-grid, the level of RES penetration desired and the extent to which generation sources are distributed within the mini-grid. Figure 3.5 illustrates where the different control schemes fit within these criteria.

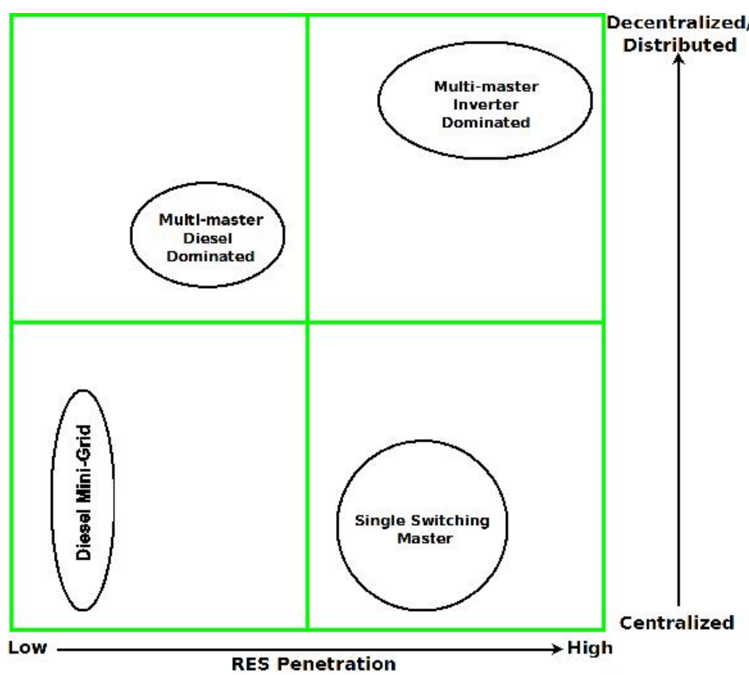


Figure 3.5 – Applicability of control strategies to system architectures

For example, systems with a large diesel generation capacity relative to the RES capacity are well suited for control strategies centered on using the diesel gensets as masters.

The centralized/decentralized character of the hybrid mini-grid architecture also plays a significant part in the control strategies selected and their communication needs/means. In the case of a centralized system, where the energy sources, energy storage, and power conversion equipment are in close proximity, a hard-wired high speed communication channel among power electronic interfaces and gensets can be used with a negligible cost while offering enhanced flexibility and performance with the management of multiple grid forming units. With synchronization signals and current sharing commands, it is possible to operate in several different modes so as to increase efficiency and power quality, reduce cycling of gensets, and optimize the state-of-charge (SoC) of battery storage. In this case, the single changing master architecture is a good choice.

On the other hand, the cost of high speed communication can make it prohibitive for decentralized systems where energy sources, energy storage, and power conversion equipment are dispersed in the mini-grid. In such a case, the coordination of the various system elements can be done by means of droop methods that rely on changes in grid frequency and voltage. A supervisory control, with a slow communication channel, just provides parameter settings for the droop controllers. The multi-master rotating machine dominated architecture or the multi-master inverter dominated architecture are good choices in this case.

4. Multi-master rotating machine dominated mini-grid architecture

4.1. Introduction

In the multi-master rotating machine dominated architecture, one or more rotating-machine alternators maintain an "AC" grid to regulate voltage and stabilize frequency. In the mini-grid context these alternators are typically driven by diesel reciprocating engines (diesel gensets). Figure 4.1 shows a general structure of a diesel dominated renewable mini-grid. It consists of a diesel power plant serving multiple residential and commercial loads. Renewable energy sources (RES) such as solar photovoltaic (PV), small wind turbines, and/or run-off river hydro power sources also supply part of the load when the energy source is available.

At least one of the gensets operates continuously, while the other(s) can be dispatched based on variations in load demand and changes in the RES availability. In most cases, a diesel dominated mini-grid does not have any sort of energy storage (other than the kinetic energy stored in the rotating machines), or only utilizes "short-term" energy storage to assist with transient dynamics of the system. The RES usually operate as passive generation units, injecting as much power as possible, with little or no participation in the control strategy. The renewable sources can be seen as "negative loads" that reduce the amount of power demanded from the gensets.

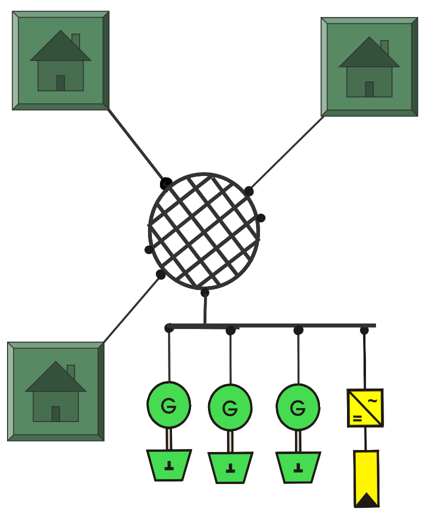


Figure 4.1 – Typical structure of a rotating machine dominated mini-grid

Since the controllers used for the diesel gensets are the primary determinant of control system performance in this architecture, we will first review diesel genset control. We then consider the effects of adding RES to the mini-grid and how the diesel plant can be configured to maximize the penetration of RES.

4.2. Basic diesel genset controls

Figure 4.2 shows a single-shaft genset comprising of a prime mover and a generator. The prime mover is a reciprocating engine that converts chemical energy of the fuel to the kinetic energy of the rotating shaft to drive a rotating electric machine. Normally, a synchronous machine is used as the generation source to convert the mechanical energy to electrical energy based on the interaction of two electromagnetic fields. Induction machines as the generation source are typically impractical for stand-alone operation because they require an excitation source for start-up and a reactive power source during normal generation.

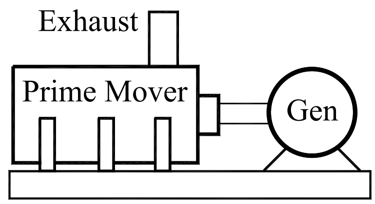


Figure 4.2 – A single-shaft genset

Both the reciprocating engine and the synchronous generator are equipped with several controllers and protection devices to perform the tasks of engine start-up, generator voltage/speed adjustment, frequency stabilization, and/or automatic synchronization with a live mini-grid. In addition, a supervisory control unit is normally used for dispatch functions such as adjusting active/reactive power generation of the genset for operation in parallel with other units and to control load transfer from one unit to another. An overall block diagram of the control units and interconnection signals for a three-phase genset is shown in Figure 4.3. The detailed description of each control unit is provided in the following subsections.

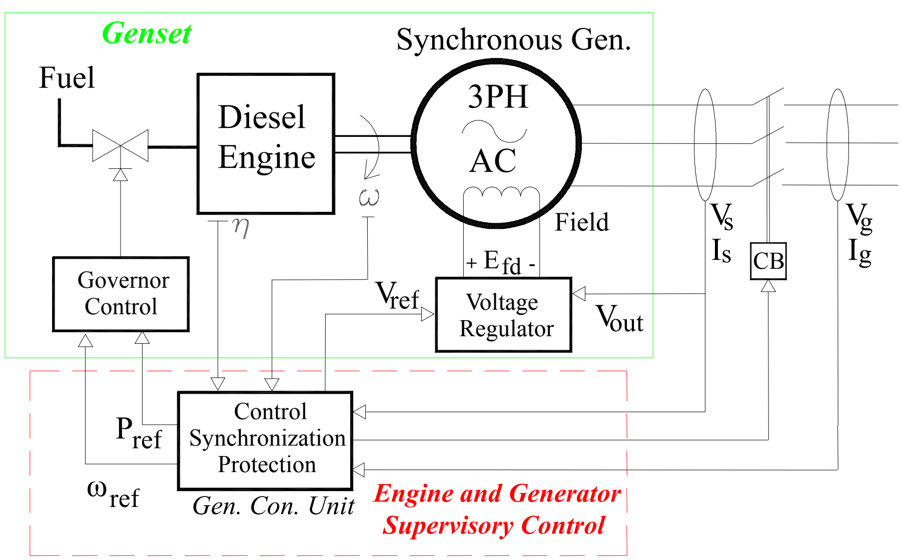


Figure 4.3 – Overall diagram of a diesel genset with governor and excitation systems and supervisory controls

4.2.1. Speed (frequency) governor control

The principal objective of a speed-governor control is to respond to load variations and ultimately adjust the power frequency of the generator. Any deviation in the system frequency and the generator speed is determined by interactions of the electrical torque (T_L), due to the load demand, and the mechanical torque of the generator prime mover (Tm). The aggregate effect of the genset inertia and load inertia also determines the rate of change of the frequency. Figure 4.4 shows a simplified block diagram of the generation controls and the system load representation that determines the frequency dynamics. The generation controls include the governor and the prime mover blocks. The prime mover dynamics are also characterized by the combined control response of a fuel control system (actuator) and the engine. The first is usually represented by a first-order model while the second is dominated by a delay representing the elapsed time between the fuel injection and the actual production of torque by the cylinders.

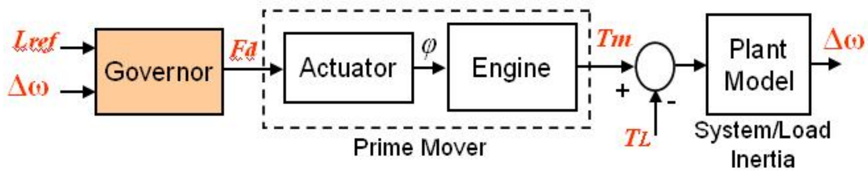


Figure 4.4 – A simplified representation of speed control blocks in interaction with the system

Inputs for the governor control are a reference power (P_{ref}) or load reference set-point (L_{ref}) and engine-generator speed deviation (Δω). The load reference set-point is specified by the engine-generator main controller and synchronization unit as shown in Figure 4.4. The commonly utilized governor control strategies introduced by different manufacturers are described as follows.

Fixed frequency control, also called isochronous-speed control, is commonly used for constant frequency control of a single genset unit or a master unit in a power plant with multiple units operating in parallel. The governor control, often based on a PI (proportional integral) regulator, affects the mechanical power until the generator speed is adjusted to the reference value and Δω is zero.

The isochronous speed control provides a fast frequency response. Figure 4.5 shows speed response of a stand-alone 500 kW diesel generator for a sudden load increase of 150 kW. The maximum frequency deviation (illustrated based on the generator speed variations) is less than 0.4 Hz, while the frequency is adjusted to 60 Hz in less than 3 s.

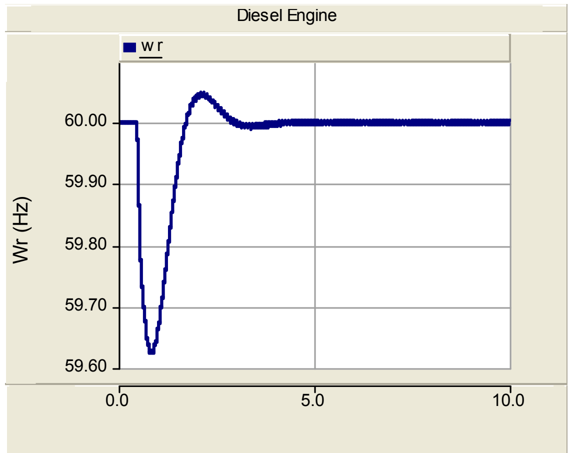


Figure 4.5 – Speed response of a stand-alone generator for a step load change

The second category of frequency control is typically called "speed-droop control" that represents a variable frequency control method. Figure 4.6 shows a basic speed-droop governor control that employs a load adjustment input (L_{ref}), the speed deviation ($\Delta\omega$) signal and a frequency-droop characteristic, represented by the coefficient R, to control the amount of fuel injection [2.1].

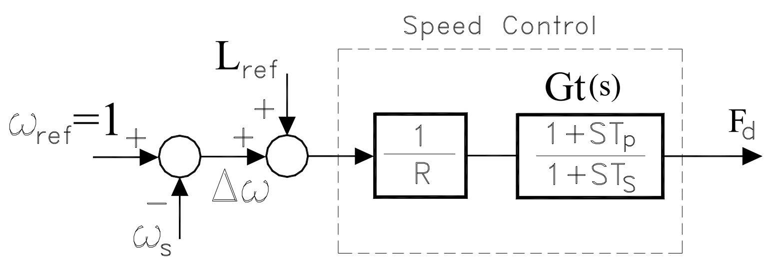


Figure 4.6 – Basic speed-droop governor control block

A typical speed-droop characteristic is shown in Figure 4.7. The characteristic is defined based on the load reference point (L_{ref}) and the slope of the droop curve. Based on this characteristic, the generator speed and power frequency are reduced in response to a load increase (P_1).

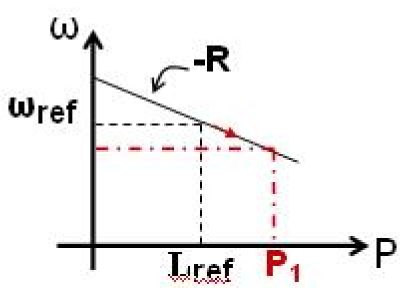


Figure 4.7 – Speed-droop characteristic

The governor control block in Figure 4.6 uses a lead-lag speed compensator Gt(s) to first stabilize the generator speed based on the steady-state droop curve and then eventually recover the frequency by adjusting the droop characteristic. The secondary action of the speed-droop control to adjust the frequency back to ω_{ref} is shown in Figure 4.8 in which the droop curve is shifted up to achieve the reference frequency (ω_{ref}) at the new power output (P_1).

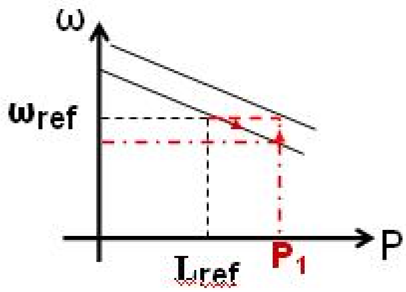


Figure 4.8 – Frequency compensation action with droop characteristic

The frequency-droop control is commonly selected for governor controls to provide power dispatch capability and parallel operation of multiple units (see Section 4.3). It should be noted that the secondary frequency compensation action is typically performed very slowly to allow parallel units to properly respond to the frequency adjustment. Figure 4.9 shows the speed variations of a speed-droop governor control for a sudden increase in load demand.

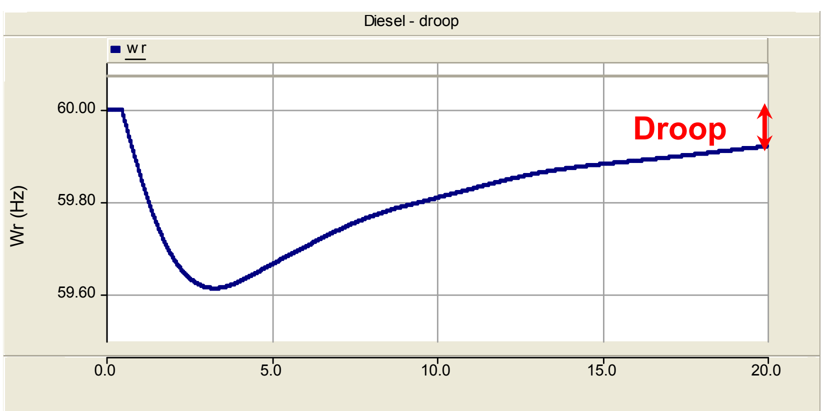


Figure 4.9 – Response of a speed-droop governor to a step load change

4.2.2. Excitation system

A synchronous generator requires an excitation system to power the field winding and regulate the terminal voltage. The excitation system consists of a DC voltage supply source which is controlled by an Automatic Voltage Regulator (AVR) to adjust the generator field voltage and/or the field current according to the variations in the terminal voltage to achieve the desired generator internal voltage.

In general, two main excitation system structures have been introduced by generator manufacturers:

Self-excitation system

A self-excitation system refers to a configuration in which the generator terminal voltage is directly used to supply the field winding. Figure 4.10 shows a self-excitation configuration. In this case, the field voltage is built up from the terminal voltage and controlled by the AVR. Although this configuration simplifies the generator structure and excitation requirements, the generator has slow voltage recovery time and cannot contribute to short-circuit fault for a long period because of the terminal voltage collapse on faults. In addition, the generator does not have black-start capability and may have difficulties during start-up if there is not sufficient residual magnetism in the machine.

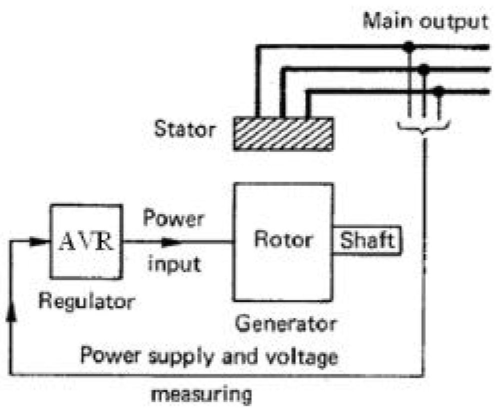


Figure 4.10 - A self-excitation field configuration [4.2]

Separate excitation system

The separate excitation system is powered up by a source independent of the generator terminal voltage. Figure 4.11 shows a typical separate excitation system. Normally, a small permanent magnet generator (pilot exciter) and a main exciter are used to generate large enough internal AC supply. The internal AC source, generated by the main exciter, is regulated by an AVR and supplies the rotor windings using rotating semiconductor rectifiers as part of the rotor. The voltage regulation and control process is as follows. The pilot exciter generates the base voltage for the AVR system. The AVR measures the terminal voltage of the generator and supplies a regulated stator voltage for the main exciter. The regulated voltage is amplified by the main exciter and used to supply the field winding of the main generator.

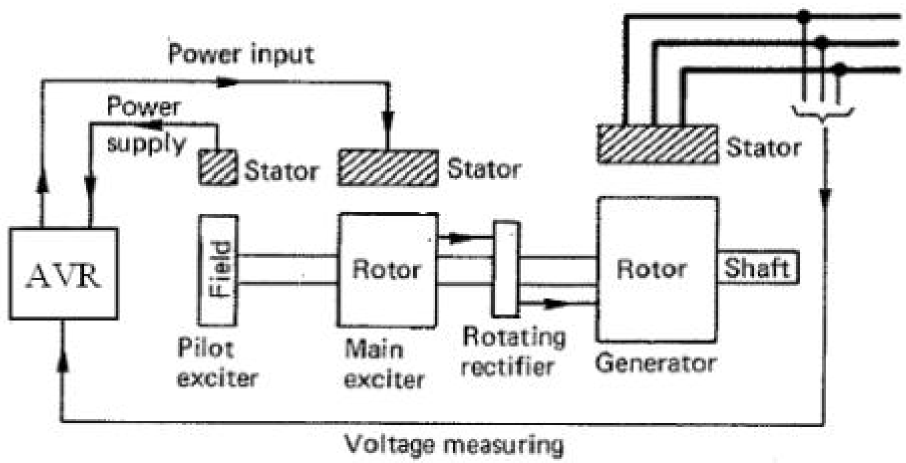


Figure 4.11 - Block diagram of a separate excitation system [4.2]

The separate excitation system can automatically provide voltage build-up for the starting and enhances the steady-state overload capability of the generator. Also, the generator has good performance on fault since the excitation voltage will not collapse by a fault on the terminal. This configuration is very common on gensets used for stand-alone power supply and isolated operation.

Several AVR models are recommended by the IEEE standards according to the type of excitation system and AVR voltage control action, [4.3]. A simple AVR control block is shown in Figure 4.12.

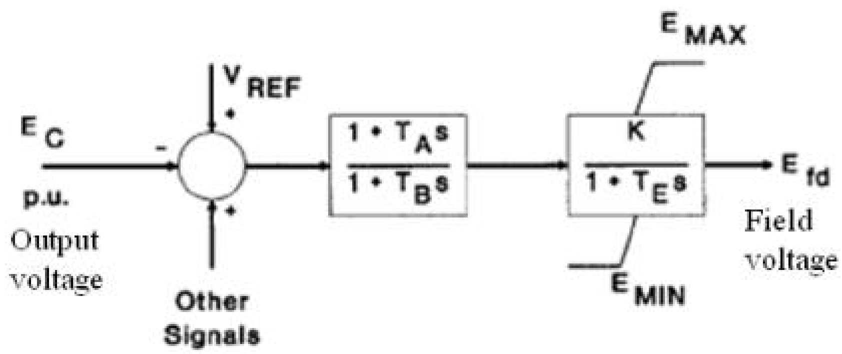


Figure 4.12 – A generic automatic voltage regulator controller [4.3]

The control input for the AVR is a voltage reference set-point (V_{ref}) corresponding to the terminal voltage and/or the reactive power output of the generator. The set-point is normally provided by the supervisory control. The set-point is a constant value if the generator operates in a voltage regulation mode. However, the voltage reference set-point can be varied, for instance by using a power factor controller (PFC) circuit to adjust the reactive power output of the generator to operate at a constant power factor irrespective of the mini-grid voltage variations. Another option is to use voltage droop control to allow parallel gensets to share reactive power variations. The AVR output is either the field voltage, in case of a self-excitation generator, or the base voltage for a main exciter to generate internal voltage for the field as applicable for a separate excitation system.

4.3. Multiple genset control

Multiple gensets connected to the mini-grid must have a means of sharing load in a controlled fashion. This is commonly accomplished through the use of speed (frequency) droop control. Two control options are shown in Figure 4.13. In Figure 4.13 (a), proportional load sharing of two gensets with different power ratings is illustrated. The genset controller droop slopes (m) are chosen so that:

$m_1 * S_1 = m_2 * S_2$ where S_1 and S_2 are the power ratings of the respective gensets

The gensets operate initially at frequency ω_{nom} with output powers of P1 and P3 which reflect their proportional share of the total load. When total load is increased, the gensets follow their individual droop slopes until the sum of their power outputs (P2 + P4) equals the new load demand at the new operating frequency ω_{new}. The new load is still shared proportionally.

Alternately, as shown in Figure 4.13 (b), a droop mode genset can be operated with an isochronous (constant frequency) control genset. The frequency setpoint of the droop control is set to dispatch the genset at the expected base load of the mini-grid at the nominal grid frequency ω_{nom}. The isochronous genset, referred to as the “swing” unit, varies its power output to meet the changing load demand (i.e. it increases power from P1 to P3 as load increases).

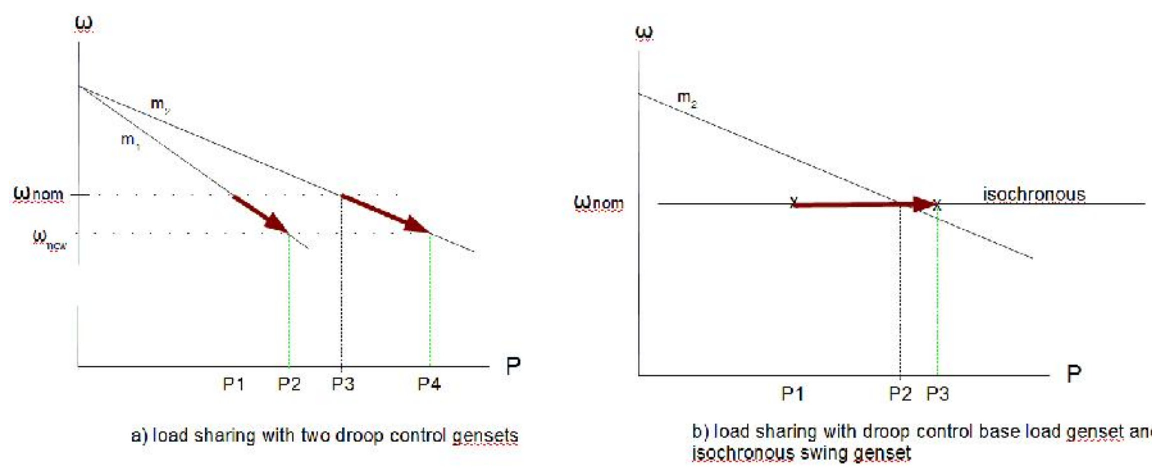


Figure 4.13 – Load sharing control for multiple gensets

These power dispatch and load sharing capabilities for multiple gensets are provided by the genset supervisory control and/or the plant controller, which determine and apply appropriate set-points as the inputs for each genset governor and the excitation system. The governor load reference set-point adjusts the active power output of the generator, while the AVR voltage reference affects the reactive power supply of the unit. Figure 4.14 shows a governor control block that incorporates a power compensation loop for load sharing and uses a proportional-integral plus derivative (PID) controller for the speed regulation [4.1]. The governor control uses a feedback from the active power output of the generator to precisely follow the power dispatch (load reference) set-point.

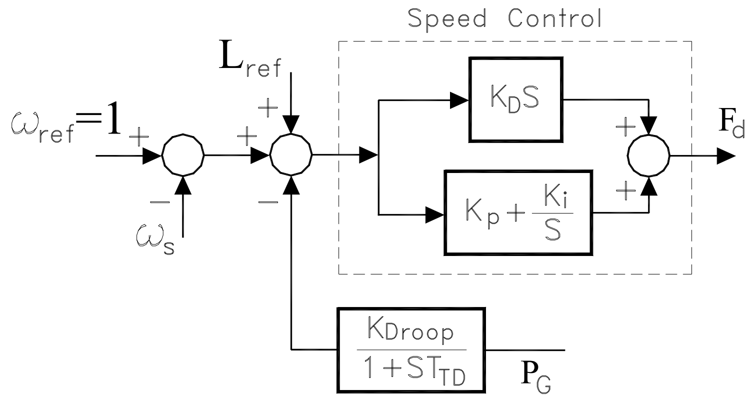


Figure 4.14 – A governor block with load sharing feedback loop

The supervisory control also manages the start-up and synchronization processes of a generator. After adding a new unit to the output bus of the genset plant, the power dispatch set points of all units are re-calculated to share the load among them proportional to their rated capacities. If paralleling and power dispatch is part of regular load cycling among two generators, the load from the unit already in operation is gradually transferred to the newly added genset unit prior to idling the primary unit.

Figure 4.15, as an example, shows the process of paralleling, power dispatch and load transfer among two 925 kW diesel generators as part of a 3-unit diesel plant serving a mini-grid. In this example, primarily, DG1 is supplying the entire load of the mini-grid. At t = 70 s, DG3 is brought online and eventually the load is shared among the two units by changing the load reference set-points of the units. At t = 325 s, it is started to transfer the entire load to DG3 and shut down DG1. The load transfer is completed in about 35 s and DG3 serves the mini-grid.

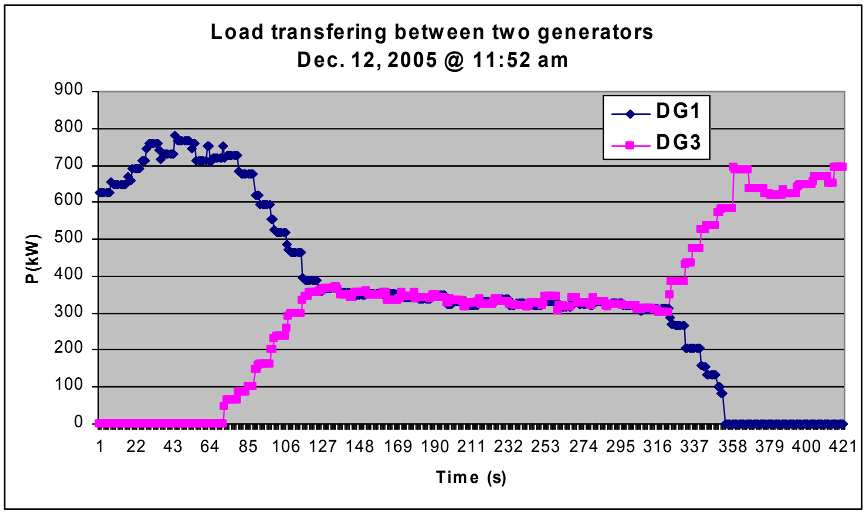


Figure 4.15 – An example of paralleling and load transfer between two diesel generators

Similar to the frequency-active power droop characteristics, some AVR systems incorporate a voltage-reactive power droop (a V-Q droop characteristic) to change reactive power of the unit as a function of the variations in the terminal voltage. The voltage droop simplifies the control avoid circulating currents and also ensures generator operation within a safe operating region during load transients. Figure 4.16 shows a voltage droop characteristic. As the reactive power supplied by the genset increases, the output voltage of the genset is decreased. The voltage droop coefficient is normally determined based on the maximum range of voltage deviation in the system (± ΔV) and the minimum and the maximum reactive power limits ($-Q_m$ and Q_n) of the genset.

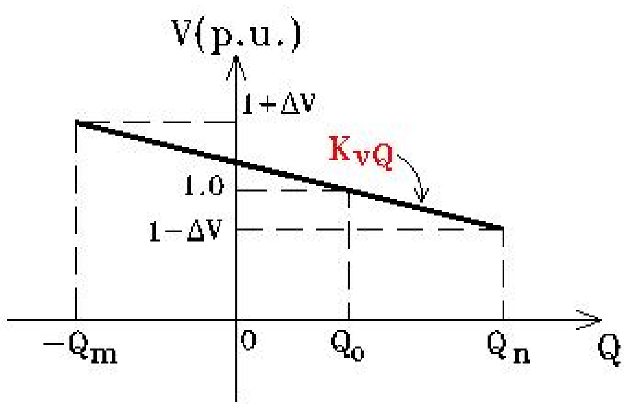


Figure 4.16 – Voltage-reactive power droop characteristic

It should be noted that direct control of the generator terminal voltage is required during the period of genset start-up and synchronization with the live grid. After paralleling, the voltage control is changed to the voltage droop mode for effective reactive power sharing of the load among the parallel units.

4.4. Commercial genset control units

The following are examples of commercial diesel generator controllers, including governor and excitation system controllers, which are representative of current technology.

4.4.1. Caterpillar digital voltage regulator (CDVR) [4.4]

The CDVR is a microprocessor based voltage regulator (Figure 4.17) used to regulate the output voltage of the synchronous alternator in an engine generator set.

Figure 4.17 – Caterpillar digital voltage regulator

The Caterpillar digital voltage regulator has the following features:

- Three control modes:
    - Automatic voltage regulation (AVR)
    - Power factor (PF) regulation
    - Reactive power (VAR) regulation
- Programmable stability settings
- Soft start control with an adjustable time setting in AVR mode
- Dual slope voltage versus frequency (V/Hz) characteristic
- Three-phase or single-phase voltage sensing
- Single-phase current sensing

- Field current and field voltage sensing
- Ten protection functions

4.4.2. Woodward L-series governor [4.5]

The Woodward L-Series governor combines the L-series electric actuator with integrated speed control software to control the speed of a diesel or gaseous engine. The L-Series is a microprocessor-based control that is incorporated into the actuator, creating a single integrated package. This eliminates the need for an additional driver box and speed control box.

The L-Series governor has the following programmable features:

- Speed signal setup parameters
- General setup parameters
    - Fail direction (ccw or cw)
    - Min position direction (ccw or cw)
- Valve position control parameters
- Speed set point setup parameters
    - Functionality settings
    - Idle/Rated 1/Rated 2 speed settings
    - Acceleration and deceleration rates
    - Droop / isochronous
    - Biasing behaviour and rates
- Speed control setup parameters behaviour
    - Start speed settings and rates
    - Engine stopping settings
    - Speed error detection settings
    - Dynamics settings
- Fuel limiting
    - Behaviour
    - Settings and rates
- Discrete output settings
- Discrete input settings
- Fault settings

- Security settings

4.4.3. ComAp – general purpose compact genset controller [4.6]

The ComAp InteliGen is a comprehensive controller for both single and multiple gensets operating in standby or parallel modes. A built-in synchronizer and digital isochronous load sharing controller enable a general solution for gensets operating in a standby mode, island parallel mode and/or parallel operation with the main grid. The controller supports operation of up to 32 gensets as a standard feature. As shown in Figure 4.18, InteliGen NT has a graphic display with user-friendly controls.

Figure 4.18 – ComAp InteliGen NT General Purpose Genset Controller [4.6]

InteliGen provides automatic synchronization and power control through speed regulator at the generator terminal and/or with reference to a remote bus. It also includes basic control features for base load and import/export controls. The integrated Automatic Voltage Regulator unit of the controller can adjust excitation system voltage based on set points for constant voltage or constant power factor. The controller provides all range of measurements for generator and main terminal parameters.

The following fixed and configurable protection functions are provided internally:

- Phase integrated generator protections (V + f)
- IDMT overcurrent + Short-current protection
- Overload protection
- Reverse power protection
- Earth fault protection
- phase integrated mains protections (V + f)
- Vector shift protection

- Additional 160 programmable protections configurable for any measured value to create customer-specific protections.

The InteliGen utilizes CAN bus communication protocol for signal sharing and remote supervisory control.

4.5. Integration of renewable energy sources in diesel mini-grids

Traditionally, remote communities worldwide have been supplied electricity almost exclusively by diesel units, due to the reliability and confidence in the technology. Integration of renewable energy sources (RES) into these fossil fuel based power generation systems can offer attractive economic and environmental merits including considerable fuel savings and carbon dioxide emission reductions. This can be done in a distributed fashion or centralized at a few interconnection points. The latter approach (centralized) may be favourable from the mini-grid control and energy management stand point. On the other hand, distributed integration of RESs may help off-set the load locally and reduce the distribution losses, since the mini-grids are normally implemented at low voltage levels. But distributed systems with high penetration of non-controllable RES can be subject to overvoltages during periods of high generation and low load, particularly if the RESs are placed far from the master diesel power plant. Since reactive power control is less effective in regulating voltage in feeders with resistive characteristics, such as LV ones, a possible solution is the curtailment of the active power of the RES as a function of the local voltage [4.7].

The inherent fluctuating and intermittent power characteristics of RES can pose a significant additional burden on the economical operation of the diesel master unit(s), which already deal with the highly variable nature of load demand in remote community systems, and also have their own operating constraints for safe and reliable operation. These issues are more significant for medium to high penetration depth of RES, especially when neither electric energy storage nor demand side management (controllable loads) are used. The common approach to deal with this issue is to operate the already oversized existing diesel generators (with respect to the load) at no lower than the minimum recommended loading and dissipate the “excess” power produced by RES in dump loads. This limits the potential for high RES penetration.

The minimum loading requirement for diesel gensets arises from several considerations. The most significant is that operation under low load may result in the following damaging conditions [4.8]:

- Wet Stacking – Wet stacking manifests itself in the accumulation of carbon particles, unburned fuel, lube oil, condensed water and acids in the exhaust system. This accumulation is due to incomplete combustion caused by low combustion temperatures.

- Carboning – Carboning is the result of carbon particles deposited on top of the piston rings and in the injectors due to incomplete burning of fuel.
- Fuel Dilution of Lube Oil – Piston rings are designed for optimum sealing under elevated combustion pressures. When these pressures are not achieved due to the application of low loads, the fuel injected into the combustion chamber can get past the piston rings causing a fuel dilution situation in the lubricating oil.
- Water Contamination of Lube Oil – If the lubricating oil does not attain the desirable operating temperature, condensation of water may form in the engine oil pan.
- Piston Detonation – Piston detonation damage is caused by excessive engine idling or low load conditions that lead to localized burning of fuel above the top ring when larger loads are required of the engine.

Operation at light load, to some extent, also reduces the load following capability of the generator. Finally, as illustrated in Table 4.1, the fuel efficiency of a diesel engine drops substantially at low power levels.

Table 4.1 – Fuel consumption for CAT D3512 diesel engine [4.9]

Load (% / kW)	Engine Power (bkW)	Fuel Rate (Litres / hour)	Fuel Efficiency (kWh / litre)
100 / 925.0	983.2	233.0	3.97
90 / 832.5	886.0	209.2	3.98
80 / 740.0	789.8	186.6	3.97
75 / 693.8	742.0	175.9	3.94
70 / 647.5	694.2	165.2	3.92
60 / 555.0	599.0	144.0	3.85
50 / 462.5	504.4	123.0	3.76
40 / 370.0	413.1	102.8	3.60
30 / 277.5	319.6	82.3	3.37
25 / 231.3	272.0	71.9	3.22
20 / 185.0	223.7	61.4	3.01

Recently, some companies such as Danvest Energy A/S (Denmark) [4.10] and Powercorp/D&WS (Australia) [4.11] have announced the availability of gensets that can run efficiently under low load conditions for long periods with minimum carbon build up, and have good load following capability at low load. Another alternative for low load operation is a variable speed genset with a power electronic converter to interface to the grid [4.12]

When adding RES to an existing diesel mini-grid system, increased RES penetration can often be achieved by:

- ensuring that the gensets are equipped with modern controllers that allow rapid, automatic response to changing load conditions,
- adjusting the diesel plant structure by re-sizing of the diesel units to account for the RES contribution (see 4.5.1 below),
- adding a low-load generator unit to the plant,
- implementing appropriate cycling strategies to optimize spinning reserve of the diesel plant (see 4.5.1 and 4.5.2 below),
- upgrading the supervisory control system to manage the RES contribution (see 4.5.3 below),
- increasing RES capabilities, in terms of control and communications,
- including short term storage,
- adding an automated demand management system that sheds or adds dispatchable loads (e.g. water pumping, cooling/heating, etc.) as needed.

4.5.1. Diesel plant structure – selection of size (rating) and number of gensets

Optimal unit sizing of a diesel power plant requires careful consideration of several factors, including detailed analysis of daily and seasonal load fluctuations, annual load growth, and incorporation of practical constraints for feasible and reliable diesel operation. If diesel units are only sized based on peak and/or average load values, on an annual basis, with some safety margins and additional capacity for future expansion, the diesel plant will generally be very oversized. The reason is that remote community loads are normally characterized as being highly variable, with the peak load as high as 5 to 10 times the average load [4.13].

In general, two approaches for diesel plant sizing can be considered:

- Single size gensets; where all units in a plant have the same size, and

- Multiple size gensets; where several units with different sizes are used.

The following example illustrates the challenges of genset sizing for a remote community. Figure 4.19 shows the cumulative load curve for a remote community with population of 700 people. The peak load of the community is 1210 kW and the minimum load is about 202 kW. Also, the average load based on 50% cumulative load level is about 470 kW. In this system, peak load is about 6 times the minimum load. It is not possible to select a single genset to supply the maximum load (1200 kW), while complying with the minimum loading criterion of 40% of the unit rating. The outcome is either an oversized genset that requires addition of a dump load, resulting in significant energy loss, to maintain minimum loading of the unit, or several small gensets which are sized based on the minimum load and operating in parallel to deliver the peak load. For instance, in this case, a 500 kW unit would be a practical genset size in order to achieve minimum load (202 kW) at 40% of the genset capacity. If the single size genset option is chosen, this will result in operating three 500 kW units in parallel during peak load time.

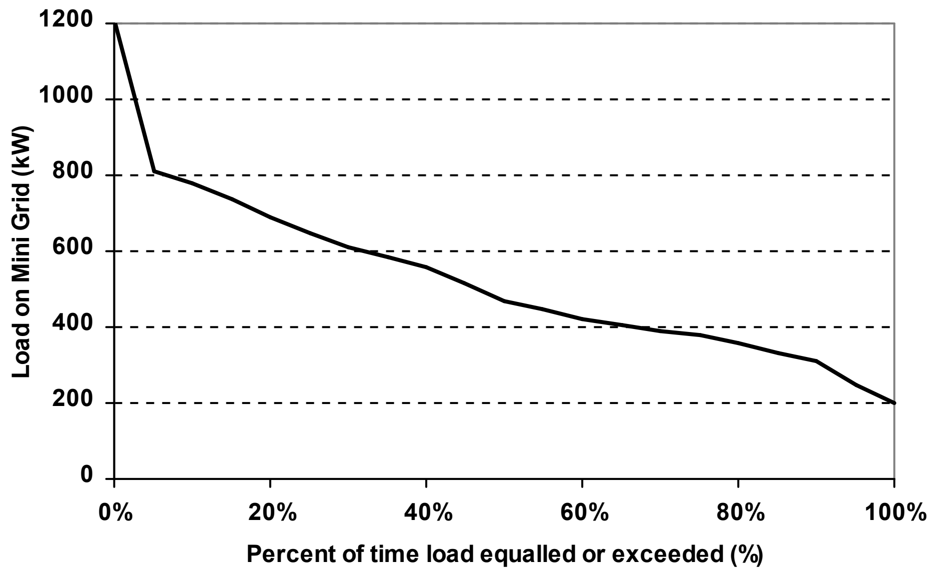


Figure 4.19 – Cumulative load curve for a remote community

In many cases, and in particular when RES are added, it is effective to employ multiple units with different ratings and use a cycling and dispatch strategy to optimize the loading of each unit to achieve maximum fuel efficiency and maximum RES penetration. For example, one study of a wind-diesel mini-grid showed significant performance improvement if a plant with three equal sized 925 kW gensets was replaced with a plant consisting of two 925 kW gensets and one 635 kW genset [4.14]. It should be noted that a minimum operating time (MOT) rule for each genset should be used to avoid short periods of switch on/off and minimize cycling. The use of reduced diesel sizes usually increases the total number of start/stop cycles of the generators, mostly for small MOTs.

In [4.15] an optimal cycling was achieved for MOT greater than 20 minutes. An alternative for this problem might be the use of short term storage units [4.16].

4.5.2. Plant capacity and spinning reserve

A multi-genset plant is normally sized according to the peak load and reliability (redundancy) requirements as well as consideration of the contingency issues and maintenance periods. The following criteria are some basic requirements and examples for sizing a genset plant for continuous, reliable service:

- The plant should have at least two gensets to account for risk of a unit failure and maintenance requirements,
- The average load of the system should be greater than the suggested minimum loading of a single unit (30-50%),
- Combined capacity of the plant, with one unit out of service, should be capable of providing about 110% of the forecast peak load,
- To provide a spinning reserve, each unit in operation should be loaded to no more than 85% of rating before adding the second unit in parallel.

The spinning reserve is considered as the plant capability to cover sudden loss of generation or increase in load. The spinning reserve should be sized properly based on the history of load variations and rate of failure of the generation units to provide enough time for starting up and addition of another unit. If the generation loss or load increase is very large, the spinning reserve also ensures slow fall in frequency in order for automatic load shedding controls to properly operate and drop the load to minimize system disturbances.

The following table shows examples of plant sizing and genset selections that are utilized in some of the remote communities in Canada.

Table 4.3 – Example plant sizing for remote communities in Canada

Community Peak Load	Gen A	Gen B	Gen C	Gen D	Total Size	Plant Rating
610 kW	600 kW	400 kW	1000 kW	-	2000 kW	1000 kW
160 kW	100 kW	100 kW	125 kW	-	325 kW	200 kW
1210 kW	925 kW	925 kW	925 kW	-	2775 kW	1850 kW
919 kW	250 kW	400 kW	600 kW	1000 kW	2250 kW	1250 kW

Table 4.3 shows that plants with multiple size gensets are common among small and large communities. The plant rating in Table 4.3 is calculated based on the total size of genset unit less the largest unit. Normally, a peak load to plant rating ratio of 60% to 80% is used to ensure reliability.

In modern mini-grid systems with computer-based supervisory control, it is possible to actively manage spinning reserve based on actual and predicted load and RES generation [4.17].

4.5.3. Renewable mini-grid supervisory control and operation

For stable operation of a remote mini-grid, especially with medium to high penetration of renewable energy sources, the output power of all units must meet the total load demand of the mini-grid. Otherwise, to match generation and demand, the mini-grid must undergo load and generation balancing processes that can be consist of: load shedding, dump-load or secondary load adjustment, and/or control of dispatchable generation units. In addition, fast and flexible active/reactive power control strategies are required to minimize the impact of mini-grid dynamics due to load variations and RES output fluctuations. Impact of the dynamic phenomena and reaction of the mini-grid supervisory control determine the power quality level of the mini-grid in terms of range of voltage variations and frequency oscillations. The selected power and energy management strategies as part of the mini-grid supervisory control should be able to accommodate both short-term power balancing and long-term energy management.

The short-term power balancing requirements may include:

- Provisions for load following capability, voltage regulation, and frequency control based on load sharing among generation units and/or load control to alleviate power mismatch and maintain voltage and frequency within an acceptable range.
- Provisions for acceptable dynamic response, and voltage/frequency restoration during and subsequent to transients. A determinant factor in this case is the aggregate genset inertia. Short-term energy storage technologies can be used to enhance dynamic response of genset units especially during start-up, ramp-up and ramp-down intervals.
- Provisions to meet power quality constraints of sensitive loads, inclusive of voltage profile, voltage fluctuations, and total harmonic distortion of the mini-grid. The power quality control and enhancement techniques can be applied for specific loads or on part of the mini-grid serving the sensitive loads.
- The longer-term energy management requirements may include:
- Provisions to maintain an appropriate level of reserve capacity while dispatching and/or re-scheduling the operating points of gensets based on an optimization process to:
    a) control the loading of gensets,

b) minimize power loss,

c) maximize power contribution of the renewable-based units, and/or

d) minimize the cost of energy production of gensets.

- Provisions for demand response management including instantaneous load-profile control and proper utilization of controllable loads such as water pump, electric heating and cooling, water desalination, etc.

Figure 4.20 shows a proposed structure for a diesel dominated mini-grid supervisory control based on utilization of several resources including multiple-sized gensets, renewable energy sources and controllable loads [4.18].

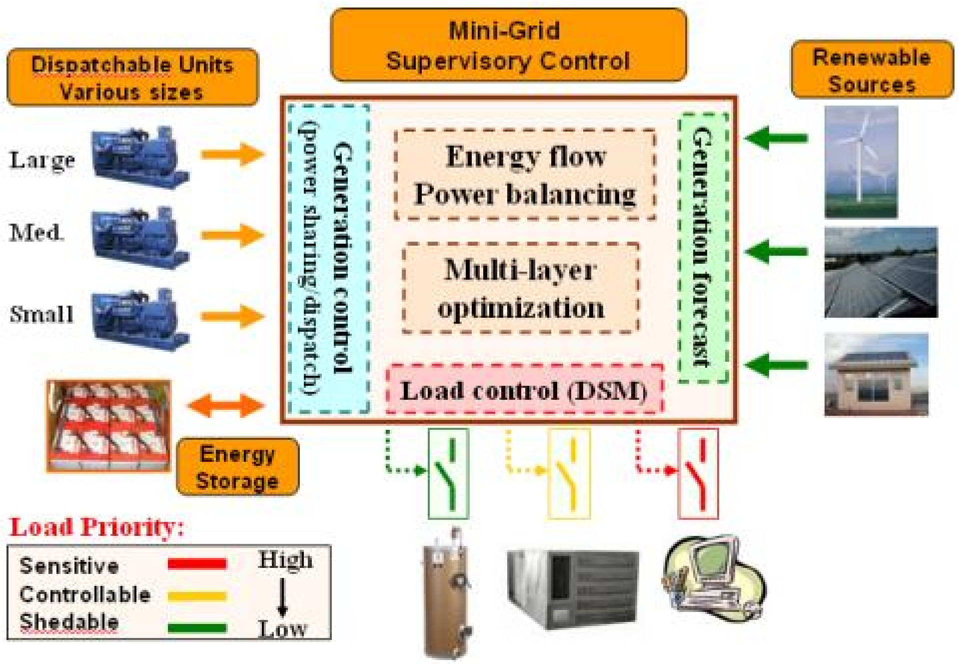


Figure 4.20 – General structure for a diesel dominated mini-grid supervisory control [4.18]

The supervisory control incorporates resource management and optimization strategies to achieve short term and long term energy/power balancing of the remote mini-grid and overcome power fluctuations introduced by intermittent RESs and variable load. The design philosophy of the real-time supervisory control consists of:

- Advanced power sharing and unit commitment among a set of multiple-sized gensets to select appropriate combination of units based on variations in load as well as consideration of minimum loading of the units and spinning reserve requirement,

- Utilization of optimal sized energy storage units to enhance short-term power balancing and/or increase renewable energy contribution,
- Prioritization and advanced control of load to achieve desired load profile and reduce range of load variation.

4.6. Diesel plant protection

Figure 4.21 shows a typical electrical configuration diagram of a genset plant. As an example, interconnection apparatus, protection and control requirements for parallel operation of two generators are illustrated. A multifunctional relay is used to provide the basic mini-grid and interconnection protection requirements. The multifunctional relay primarily controls and/or supervises opening/reclosing of the main circuit breaker (A) and can also be used to perform the task of output measurements for a plant supervisory controller. The supervisory controller coordinates the synchronization process and operation of multiple diesel gensets. The generator protection functions can be part of the supervisory control and/or be provided by individual genset protection devices in coordination with the supervisory control.

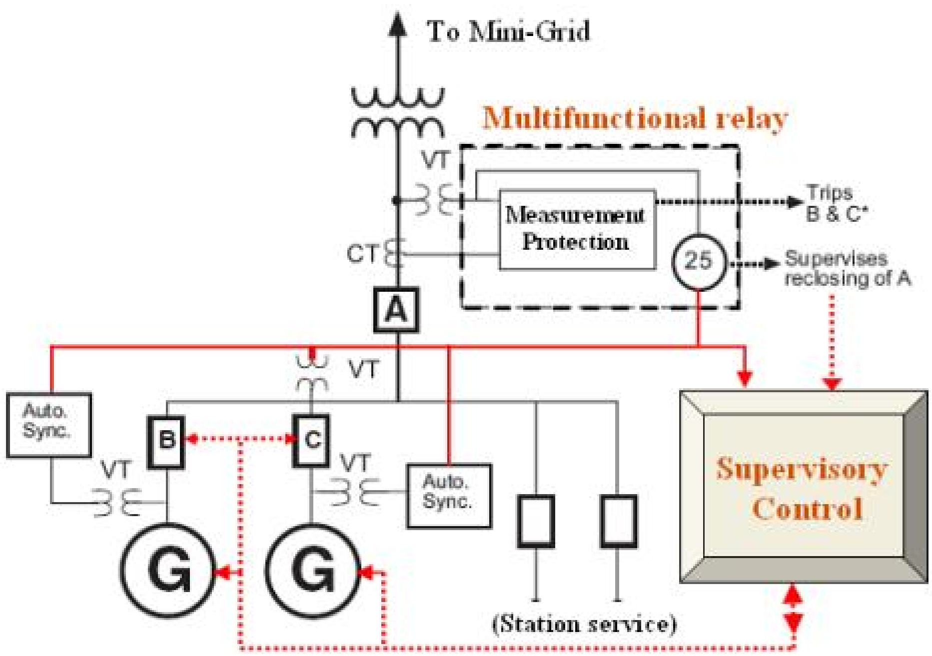


Figure 4.21 – Electrical diagram of a genset plant

4.6.1. Genset operating region

Protection relay settings are often determined by rating constraints and stability limits imposed on the operation of a genset. These constraints determine maximum and minimum values for the generator active and reactive power outputs under various operating conditions. Figure 4.22 shows an operating chart (P and Q region) of a typical genset. A theoretical operating region, surrounded by hatch lines, and a practical operating region (shaded area) are identified in Figure 4.22. The area to the right of the P-axis (positive active and reactive power supply) is considered for generator operation with lagging power factor or reactive power injection. In this area, the generator operation is limited by the stator and rotor maximum current limits. Normally, the generator is oversized compared to the prime-mover. Hence, the active power limit of the prime mover or the genset rating is the limiting factor imposed on the active power output of the generator, as shown in Figure 4.22. Typically, the genset rating is specified for a rated lagging power factor of 0.8. Beyond this power factor, the active power output should be reduced to compensate for additional reactive power supply. The lagging power factor of 0.8 is considered as the boundary of practical operating region.

The genset operation with leading power factor or reactive power absorption is mainly limited by the practical stability constraints due to under-excited field system. The leading kVAr limit in Figure 4.22 specifies the maximum reactive power can safely be absorbed by a generator. A loss of excitation protection is normally used to protect generator in this region.

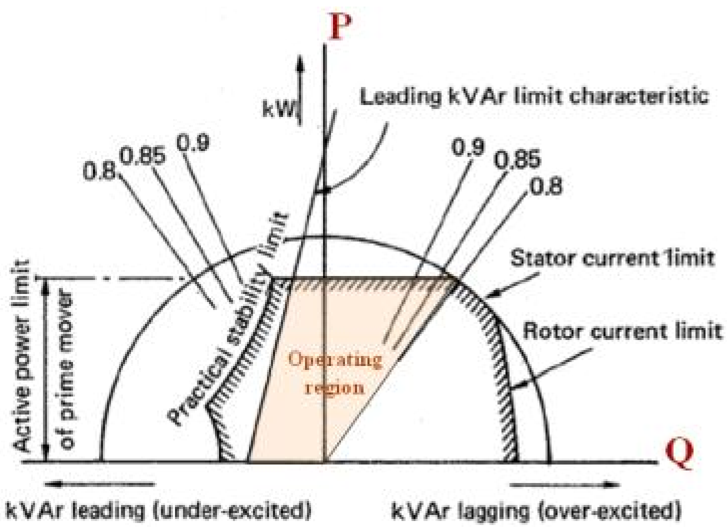


Figure 4.22 – A typical operating chart of a genset

4.6.2. Genset protection

Table 4.4 shows some of the protection functionalities that are normally part of a generator protection device. The protection objective is to assure safe operation of the generator and the prime mover within the limits of the operating region. The protection functions and applicable characteristics may vary based on the generator size, type of the prime mover and number of units in parallel. As shown in Table 4.4, the protection functions are identified by specific numbers, assigned by the ANSI standard that can be selected on any general-purpose multifunctional generator protective device.

Table 4.4 – Generator protection functions

Basic Protection Functions		Specific Protection Functions	
ANSI #	**Protection Function**	**ANSI #**	**Protection Function**
25	Synchronism-Check	46	Unbalanced Current
27	Under Voltage	47	Unbalanced voltage
59	Over Voltage		Negative sequence voltage
81O/U	Over/under frequency	51G	Neutral Ground fault
32	Reverse Power	81R	Rate of change of frequency
50	Instantaneous Over Current	67P	Phase Directional Over current
51	Timed Over Current		
40Q	Loss of Excitation		

4.7. Diesel-hybrid mini-grid case studies

This section describes examples of diesel dominated mini-grid systems that include medium penetration and high penetration of renewable energy sources. The objectives of the case studies are to highlight the mini-grid design and sizing practices as well as control and operation aspects.

4.7.1. A medium voltage, single-phase PV-diesel hybrid mini-grid

The Nemiah Valley in British Columbia, Canada, is home to the Xeni Gwet'in First Nation; it is located 250 km North of Vancouver, and is separated by about 100 km of road from the nearest electricity grid. In 2007 the existing diesel mini-grid serving the Xeni Gwet'in community was upgraded to a diesel-PV hybrid mini-grid.

A line diagram illustration of the de-centralized PV-Diesel hybrid grid is shown in Figure 4.23. The 600 V diesel plant consisted originally of three three-phase 90-kW diesel gensets for supplying the public area load and residential customers, the 30 kW units was added later. All loads are supplied with 120V/240V single-phase 60 Hz. The public area, close to the diesel power plant, is served though underground low voltage lines. It is split in two circuits, one with critical loads is powered 24/7 while the other, fed through a 200 kW distribution transformer, is switched off, manually, during night time and holidays. The residential subdivision is served via an overhead medium voltage (14.4 kV) single-phase distribution line with a total length of 1.5 km with several pole-mounted 25 kVA and 10 kVA distribution transformers at the connection points of the residential houses to the MV grid. It supplies 12 residential houses without PV, 2 houses with 2.8 kW roof-top PV and 4 semi-detached houses with 5.4 kW PV each. The system also includes a 18.6 kW dump load, for providing minimum loading of the gensets when required, but no energy storage (battery) units. The PV systems are owned by the wire owner and pay-as-you-go meters allow the wire owner to collect money up-front using a chip card that can be refilled at the community gas station.

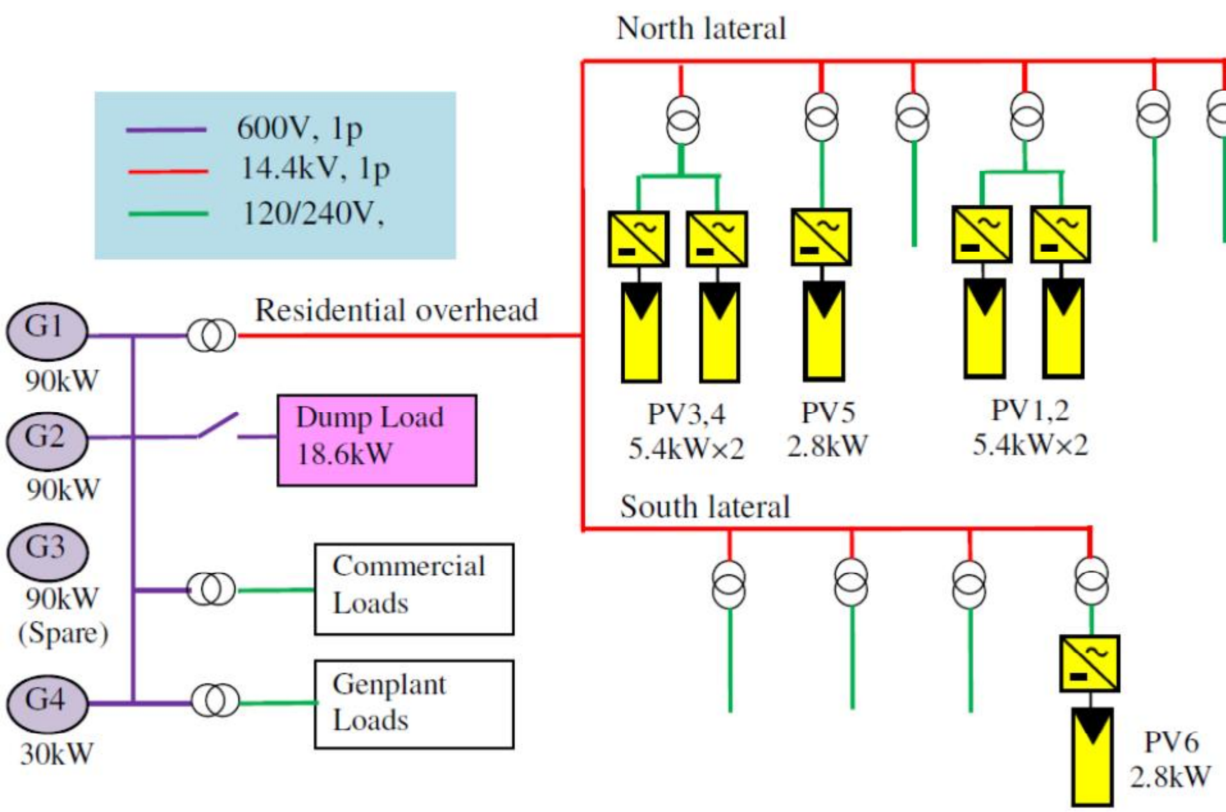


Figure 4.23 – Line diagram of the PV-diesel hybrid mini-grid

The gensets are Simson-Maxwell 95TDS-U36-68 and Simson-Maxwell 30DS-U2F-58 with voltage regulations of +/- 0.5% and +/-1.5% from no-load to full load, respectively. The PV panels are the Day4 – 48MC (180W). The PV inverters are Xantrex grid tie solar inverters GT 5.0-NA-240/108 UL-05 and GT 3.0-NA-DS-240 which operate as current sources and with maximum power point tracking (MPPT). There is no automatic demand side management in use at this time. However, when the non-critical bus of the public area is switched off, the 30 kW genset is used to power the reduced evening and holiday loads. This has proven to be more efficient than using the 90 kW genset with the dump load. The genset controllers, when required, bring in a new genset to supply the load but the selection of the main genset is done manually. There are neither tap-changers nor any other voltage regulation means in the residential subdivision, but over and over-voltages do not occur because of the relatively low power levels that flow in the MV feeder.

The daily load of the mini-grid varies between 10-kW to 50-kW. The peak load normally occurs during the daytime when the public service area is used. As a result, there is a good correlation between sunny hours and maximum consumption times. In the event that the genset output power falls below 1 kW, due to excess PV power generation, the dump load is connected for 1s to cause a sudden frequency variation sufficient to trip the PV inverters. The inverters will attempt to deliver power to the grid again following a “reconnect delay” after the tripping conditions has ceased. This parameter can be set by the user, and a recommended value, according to the CSA C22.2 no. L07.L-0l Section 15.3.4.3, is 5 minutes

The average diesel mini-grid consumption is less than ~750 kWh per day. Each year a projected 30 MWh negative-load provided by the PV panels will result in a diesel savings of approximately 10,000 L. The simple and easy to implement approach presented in this example has created a cost-effective 10 % PV and 90 % diesel electric power generation station that can produce electricity for levelized costs of less than 0.50 US$/kWh [4.19].

A simulation benchmark of the PV-Diesel mini-grid was developed in PSCAD/EMTDC and used to study system transients under various loading and PV generation regimes [4.20]. Figure 4.23 shows the response of the system to variations in the solar irradiance. The total mini-grid load is assumed to be constant at 25 kW, 18 kW in the residential subdivision. At t = 6 s, the solar irradiance starts increasing linearly from 0% until it reaches 90% of its rated value at 12 s. Then, it decreases suddenly to 10% to represent the loss of some PV generation. The results show that the isochronous controller is capable of regulating the mini-grid frequency at rated values during steady-state conditions and that the grid voltage at the output of the diesel power plant and at the end of the distribution does not change significantly. This is achieved despite a power reversal in the distribution feeder when the PV production exceeded the load in the residential subdivision. In general, the simulation results presented in [4.19] showed little impact of the medium penetration PV on voltage/frequency regulation and dynamic behaviour of the diesel generator. Slight changes in the voltage profile and total harmonic distortion (THD) levels for currents and voltages, measured at two-ends of the feeder, are noticeable; however, there is no adverse impact on power quality of the mini-grid.

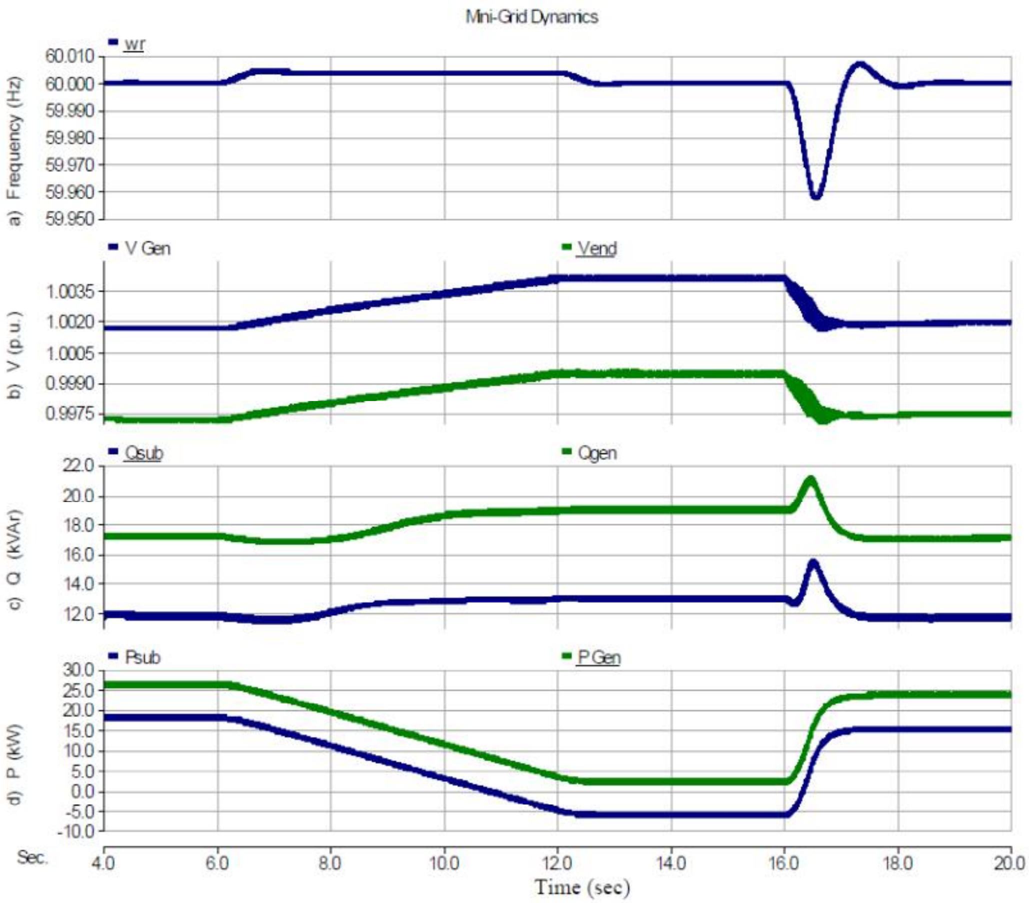


Figure 4.24 – PV-diesel hybrid mini-grid dynamics for changes in the PV power generation.

4.7.2. A wind-diesel hybrid mini-grid

The case study discussed in this section is quite different from the previous one. It concerns a high penetration wind-diesel mini-grid, with centralized generation, (short term) energy storage devices and automated control of the demand for assisting with power balancing and frequency regulation. Wind-diesel systems are relevant to PV since they have pioneered high penetration techniques that can be applied to PV as well. This configuration is typical for larger isolated applications (> 50 kW), and some systems in the MW range have been reported.

A schematic diagram of this system located in Fuerteventura, in the Canary Islands (Spain), and that was developed in the 90's is shown in Figure 4.25 [4.21]. The diesel power plant consists of two gensets, each with a 105 kW diesel engine connected by means of a clutch to a low speed flywheel of 1200 kg/m^2 and a 60 kVA synchronous generator. The diesel power plant was designed to meet a peak summer load of 99.8 kW. The flywheel was sized to supply half peak load during 30 s before the frequency falls below 48 Hz. A three-blade induction generator-based Vestas 27 wind turbine with pitch angle control and rated at 225 kW supplements the diesel power plant. It was sized for a peak summer load when the population of the village would increase from 60 to about 500, due to tourists, but this estimation proved to be excessive and the maximum WT output power has been limited to 130 kW by means of pitch angle control. A 100 kW dump load consisting of resistance blocks from 390W to 50 kW is used to help regulating the frequency and balance power [4.22]. The main loads in the system are a water desalination plant, a cold storage and ice-making plant, a sewage treatment plant, water pumps, public lighting and residential loads.

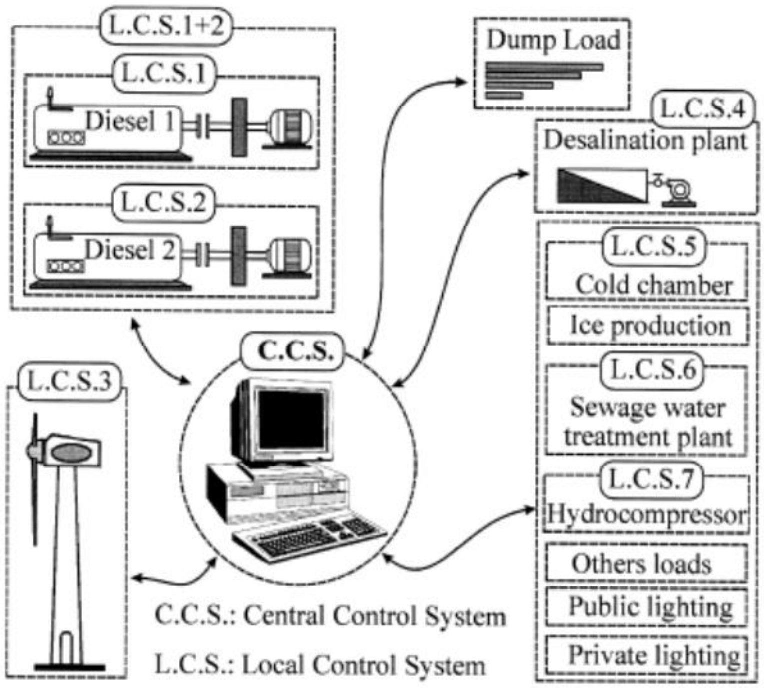


Figure 4.25 – Line diagram of the wind-diesel hybrid mini-grid

The control system of the mini-grid consists of a central controller (CCS), implemented in an industrial type PC, and local controllers (LCSs) in the diesel gensets, wind turbine, desalination plant, sewage treatment plant, cold storage and ice-making plant and water pumping station. The system was designed to operate in three different modes:

a) Diesel only
b) Wind-diesel
c) Wind only

In the first case, when there is no wind, or the wind turbine is unavailable, the diesel gensets supply the load in a conventional way with the governor regulating the frequency and the exciter the output voltage. The number of gensets on depends on the load demand. If it is less than 50 kW, only one genset can be used, allowing the CCS to disengage, via clutch, the diesel engine from the other unit. The synchronous generator of this unit can however, remain connected to the system, as a synchronous condenser to help with voltage regulation and reactive power compensation. Besides, since the flywheel is still connected to the generator, it can also assist with frequency regulation and active power balancing.

When the average wind speed over 10 minutes exceeds the cut-in speed of 4 m/s, the wind turbine is brought on-line starting a wind-diesel operation mode. In such a case, the synchronous condenser provides the reactive power demanded by the induction generator of the wind turbine and the flywheel helps mitigating variations in the frequency caused by the fluctuating power produced by the wind turbine. As the wind speed increases, and the wind turbine power exceeds the forecasted peak load, both diesel engines can be shut down and the system can operate in the wind-only mode. In this case, without the governor(s) of the diesel engine(s) to regulate the frequency, this task is carried out by the dump load along with pitch angle control of the wind turbine. The voltage in the system is still regulated by the synchronous condenser(s). In general, the results with the control strategy employed in this system have been quite satisfactory. In the period from March 1 to October 31, the maximum frequency and voltage variations measured in the system were of 1.72% and 1.81%, respectively. In this same period, the system operated in the wind-only mode for 61.77% of the time and in the diesel-only mode for 16.82% of the time. In fact, once the system worked in the wind-only mode for 91 consecutive hours.

Figure 4.26 shows the variations of the system frequency, load demand, power supplied by the genset and the wind turbine as well as losses in the flywheel, in modes (a) and (b) and also during transitions. In mode (a), diesel-only, the power produced by the genset follows the load and also replenishes the losses in the flywheel. When the wind turbine is brought on-line, the power supplied by the genset is significantly reduced. However, due the fluctuating characteristic of the output power of the wind turbine, the frequency variations increase somewhat, even with the flywheel attempting to regulate the frequency by balancing the active power demand. Similar waveforms are shown in Figure 4.27 for the system operating in modes (a) and (c) and during transitions, for a different time of the day. For the wind-only case, one can see that the dump load is the element that effectively balances the active power in the mini-grid and regulates the frequency. The power it consumes follows closely the variations in the output power of the wind turbine while the flywheel power draw varies very little. In the diesel-only mode, the grid frequency is regulated by the genset and since the load demand is relatively constant, the amount of power consumed by the flywheel is virtually constant.

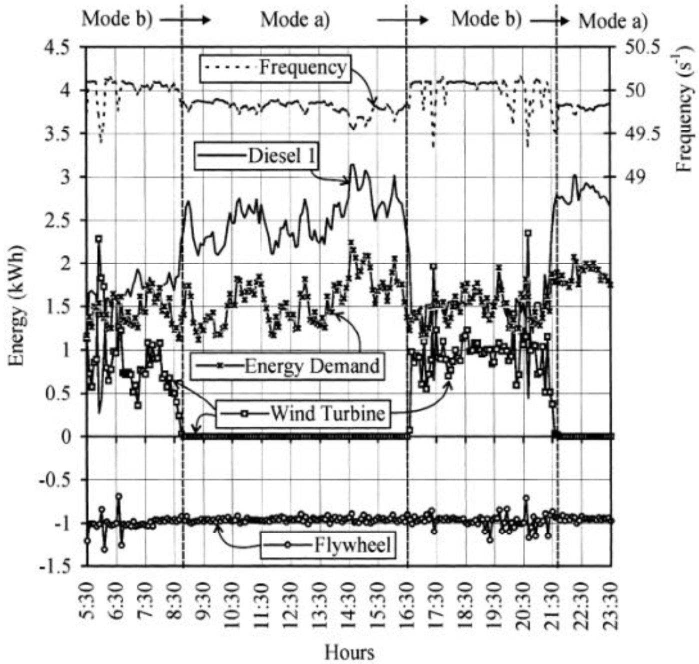


Figure 4.26 – Frequency and power variations in modes (a) and (b) and during transitions [4.20]

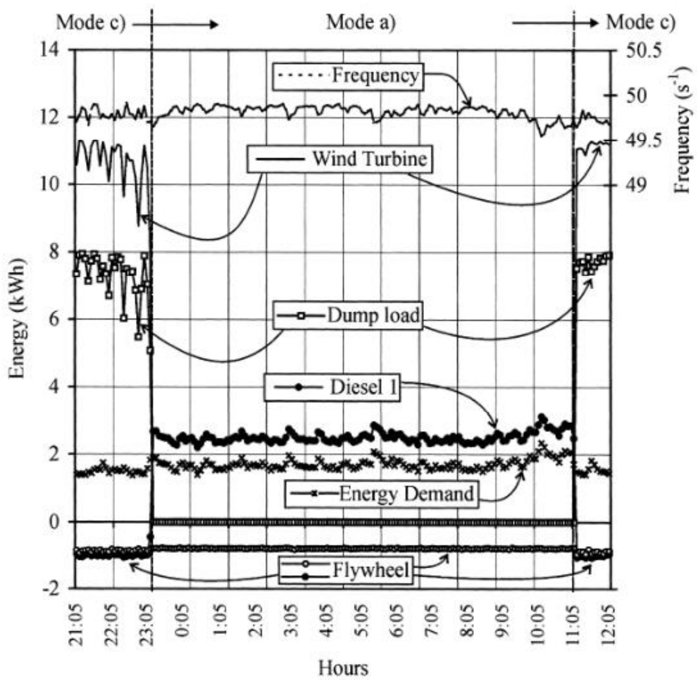


Figure 4.27 – Frequency and power variations in modes (a) and (c) and during transitions [4.20]

4.7.3. King's Canyon PV-Diesel Hybrid

Kings Canyon is an isolated tourist resort in Central Australia's Watarrka National Park, 480 km south-west of Alice Springs. The resort has relied on a diesel genset mini-grid to meet its electricity needs (650 kW maximum demand). Three diesel engine gensets feed an 11 kV three-phase mini-grid that distributes power to hotel rooms, restaurants, staff accommodation, and shops.

In 2003, a centralized 225 kWp PV generator was added to the mini-grid, creating a PV-hybrid system with the diesel gensets continuing to control system voltage and frequency (Figure 4.28). There is no energy storage in the system (other than the inertia of the gensets) and the PV inverters follow the mini-grid voltage and frequency. The PV energy offsets diesel generation and reduces peak demand on the gensets. Peak power demand in the mini-grid closely matches the availability of PV power over the course of a day, with the peak occurring early afternoon.

The PV system is designed to produce approximately 372,000 kWh per annum, which reduces annual diesel fuel consumption by up to 105,000 liters and annual greenhouse gas emissions by 331 tonnes.

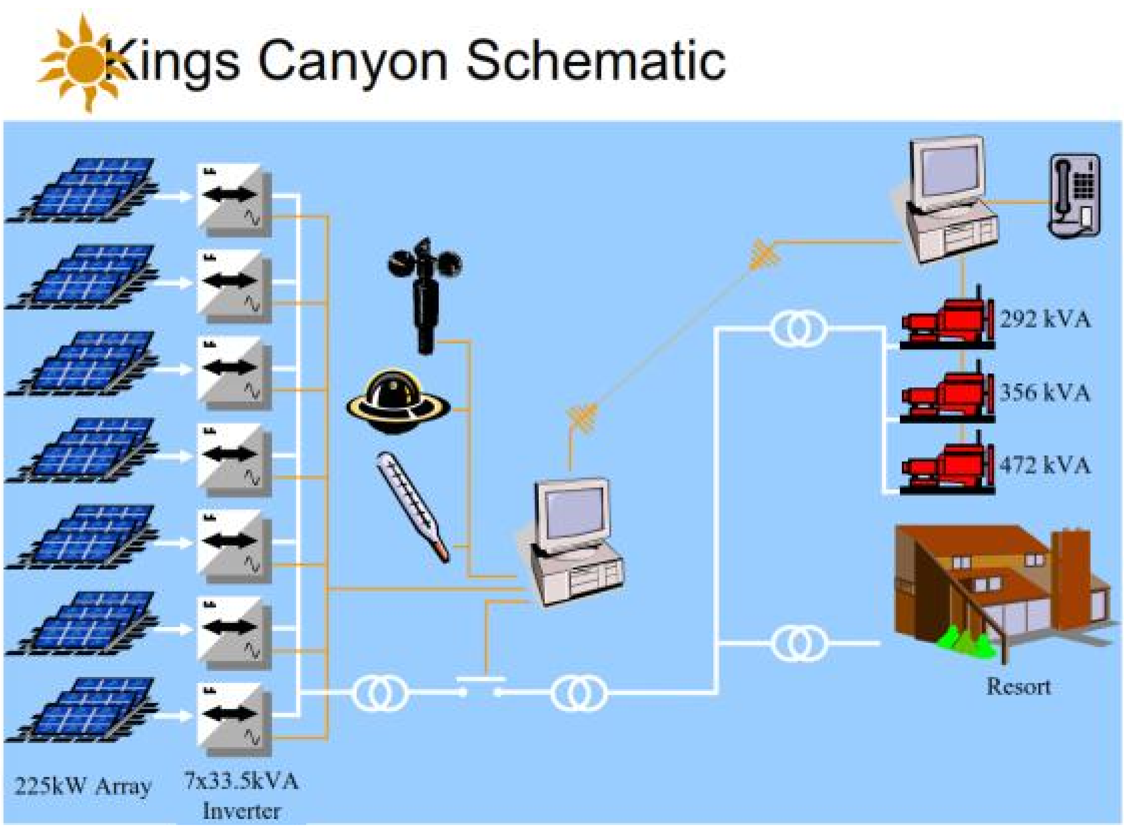


Figure 4.28 – King's Canyon PV-Diesel Mini-Grid [4.23]

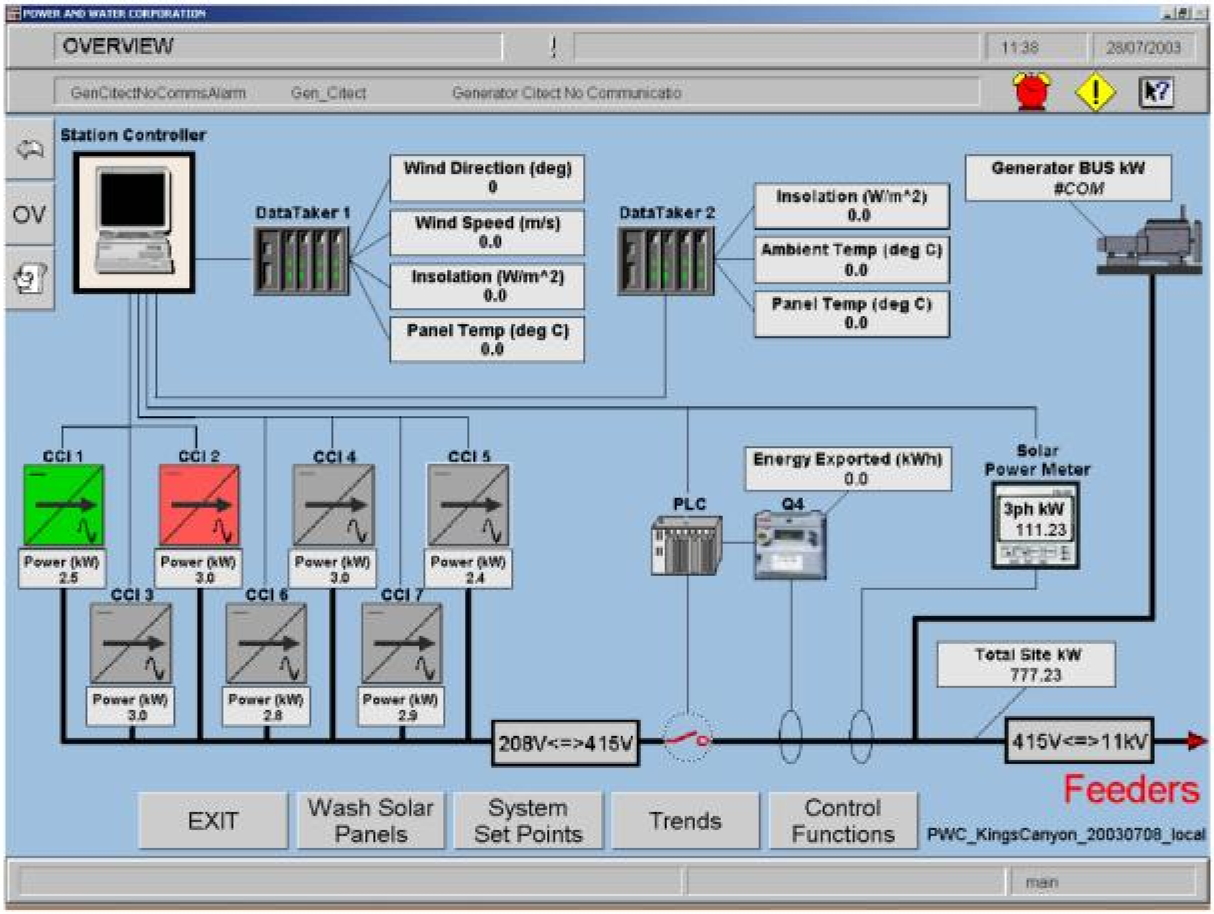


Figure 4.29 – Supervisory Control System [4.23]

The PV plant and the genset plant are several hundred meters apart and have separate controllers but they have a telecommunications link to coordinate their operation. Figure 4.29 shows the supervisory control system for the PV plant. PV generation can be disconnected if required to maintain system stability and the system has a prediction capability to dispatch genset spinning reserve if clouds are expected to reduce PV generation.

5. Single switching master (SSM) mini-grid architecture

5.1. Introduction

The single switched master (SSM) mini-grid architecture (see Figure 5.1) has multiple ac sources connected to the mini-grid (typically battery inverters and a fossil fuel genset), but the grid forming control is switched between the genset and the battery inverter(s). This allows the genset to be turned off and the system to operate only from RES and storage. These architectures are typically used in smaller village microgrids which do not have sufficient base load to support continuous genset operation or multiple genset plants. With sufficient energy storage and PV capacity, very high RES penetration can be achieved. In some systems, the genset is used only as a backup.

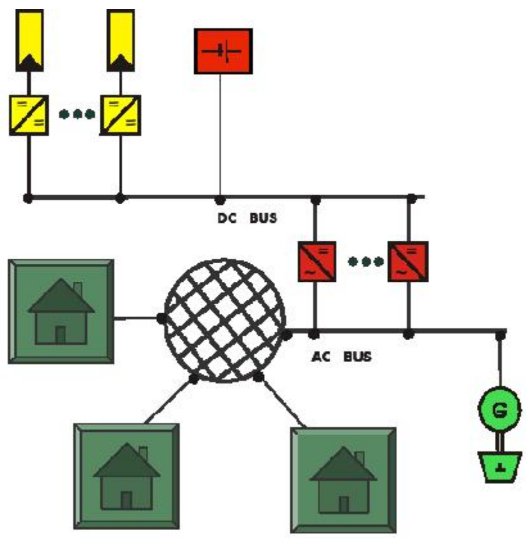


Figure 5.1 – Single switched master mini-grid architecture

This architecture has evolved from small PV hybrid systems suitable for single residences and small buildings. In the mid-1990's, bidirectional inverter/chargers with integrated generator controls and transfer switches came on to the market, enabling relatively straightforward implementation of small PV hybrid systems suitable for single residences and small buildings. A typical system configuration for these residential-scale systems is shown in Figure 5.2.

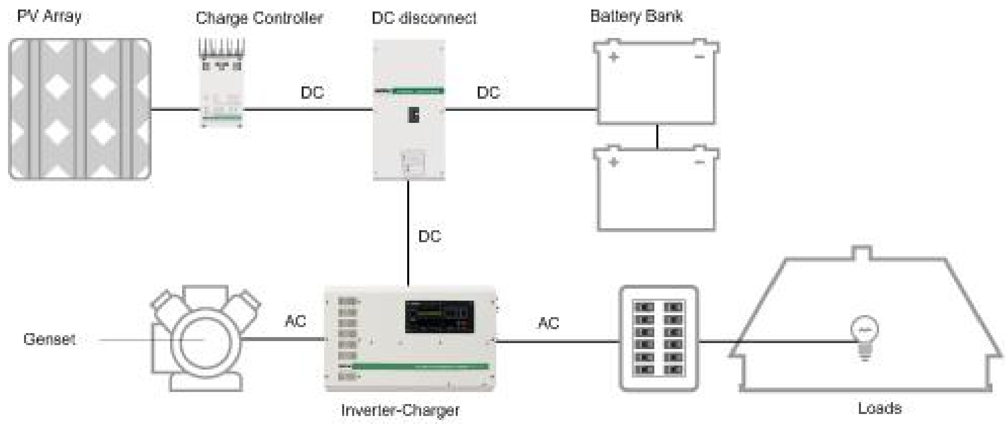


Figure 5.2 – Residential PV-Hybrid System

This can be characterized as a mixed ac/dc bus hybrid system with some energy sources connected to the dc bus and others connected to the ac bus. Usually the PV array is connected to the dc bus via a battery charge controller, which initially was of the series pulse-width modulation (PWM) type. However ac bus connection of PV is also possible with some systems. The engine generator (genset) is connected to the ac bus via a transfer switch integrated into the inverter/charger and the inverter/charger controls the operation of the genset (typically start/stop only).

This is a single switching master (SSM) system. When the genset is not operating, the inverter/charger performs the grid forming function (i.e. controls the ac voltage and frequency). When the genset is operating and connected to the loads, it does the grid forming and the inverter/charger follows (usually operating in battery charger mode).

Over the past decade this technology has advanced substantially, allowing the SSM system to remain competitive with newer approaches, such as the ac bus centric multi-master system discussed in Chapter 6, for small mini-grid applications. Key advances include:

1. Introduction of new PV battery charge controllers that incorporate PV maximum power point tracking (MPPT), temperature compensated multi-stage battery charging algorithms, and means to coordinate with the inverter/charger to manage the battery charging process. These MPPT charge controllers may be integrated into the inverter/charger, or remain as separate devices that communicate with the inverter/charger over a data network.

2. Introduction of higher power capability for larger systems. This is achieved either through higher capacity inverter/chargers, or by modular systems that allow inverter/chargers to be connected in parallel to increase capacity.

3. Introduction of data networks that interconnect system elements (e.g. PV charge controllers, inverter/chargers, generator controls, human interface) to enable system control, energy management, and monitoring.

4. Development of control techniques that allow fast, smooth transition of the inverter from a voltage source to a current source [5.1, 5.2]. This allows implementation of new operating modes that support both genset operation and interconnection to the central utility grid.

These new capabilities allow the implementation of PV hybrid mini-grid systems that are suitable for village electrification and multi-building facilities. Figure 5.3 shows a typical configuration for a mini-grid system that can operate autonomously or interconnected to the central (utility) grid.

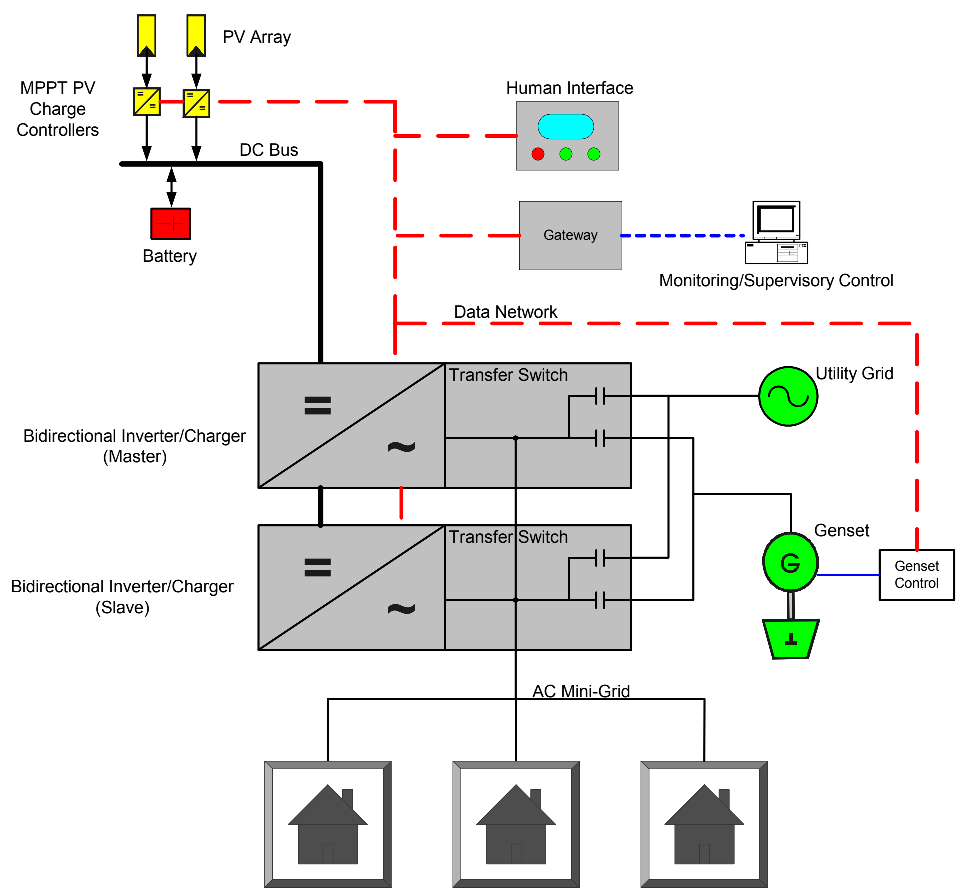


Figure 5.3 – PV Hybrid Mini-Grid with SSM control architecture

The system can operate in three modes:

- Autonomous operation with inverter/charger as the grid forming master. Multiple inverters can be paralleled to increase output power capability but their operation is controlled by a master unit to synchronize their ac output waveforms and to share output power.
- Autonomous operation with generator master. The inverter/chargers can be configured to operate as battery chargers only, or they can be configured to provide generator support by delivering power to the ac mini-grid under high demand conditions.
- Grid-parallel operation with the central (utility) grid as master. The inverter/chargers can be configured for the following operating modes
  - battery charging only,
  - mini-grid support (no power export to the central grid),
  - grid support with power export,
  - or peak shaving operation

The system shown in Fig. 5.3 has all the PV generation connected to a dc bus through PV charge controllers (dc/dc converters). However it is also possible to connect PV directly to the ac mini-grid through dc/ac inverters. The implications of this on control strategy are discussed in Section 5.5.

The various available operating modes allow the implementation of several different supervisory control strategies which can be selected based on performance goals for the system such as lowest cost operation, maximization of renewable energy fraction, high reliability, etc. Section 5.6 presents a case study of a SSM mini-grid and its control strategy.

The battery energy storage in SSM systems mitigates the effects of rapidly changing RES generation or large load swings on system stability. The battery, and the power converters connected to it (PV charge controllers and bidirectional inverter/chargers), act to absorb power from, or deliver power to the mini-grid to maintain power balance. They also “smooth” the contribution of the PV generators on both a short term and long term basis.

5.2. Control of grid forming generators

The grid forming generators control the voltage and frequency in the mini-grid when it is operating autonomously. Non-grid forming generators follow the voltage and frequency set by the grid forming unit(s). As with the conventional electricity distribution grids, it is desirable to maintain the voltage and frequency in the mini-grid within a relatively narrow band.

In present SSM mini-grid systems, standard engine-generator sets (gensets) using conventional isochronous governors and regulators are normally used. Voltage and frequency regulation when the genset is the grid forming master is largely dependent on the characteristics of the generator controls and the characteristics of the electrical machine used in the genset (see Section 5.2 for a more complete discussion). However in some newer systems the inverter can provide additional voltage support to the genset to maintain voltage regulation (see discussion in 5.2.3 below).

Ideally, the inverter grid forming master in the SSM system acts as a stiff voltage source that can deliver and absorb both real and reactive power. Therefore a full bridge inverter topology [5.4] that can operate in all four quadrants is normally employed. Such a topology, as shown in Figure 5.4, employs pulse width modulation (PWM) to efficiently create a regulated sinusoidal voltage at the desired line frequency. Active and reactive power can flow in both directions through the inverter bridge. The output filter components (L_F, C_F) are designed to remove the PWM switching frequency harmonics, which are much higher than the ac line frequency. As a result, the output impedance of the inverter at the ac line frequency can be quite low and it is possible to achieve a good approximation to a four quadrant voltage source for both steady state and transient conditions using an appropriate multi-loop control structure [5.5].

Modern inverter bridge controllers are usually implemented in software on a fast digital processor. Therefore multiple operating modes can be readily implemented, allowing the bridge to operate as a voltage source, when the inverter is grid master, and as a current source when it is following another grid master [5.1, 5.2].

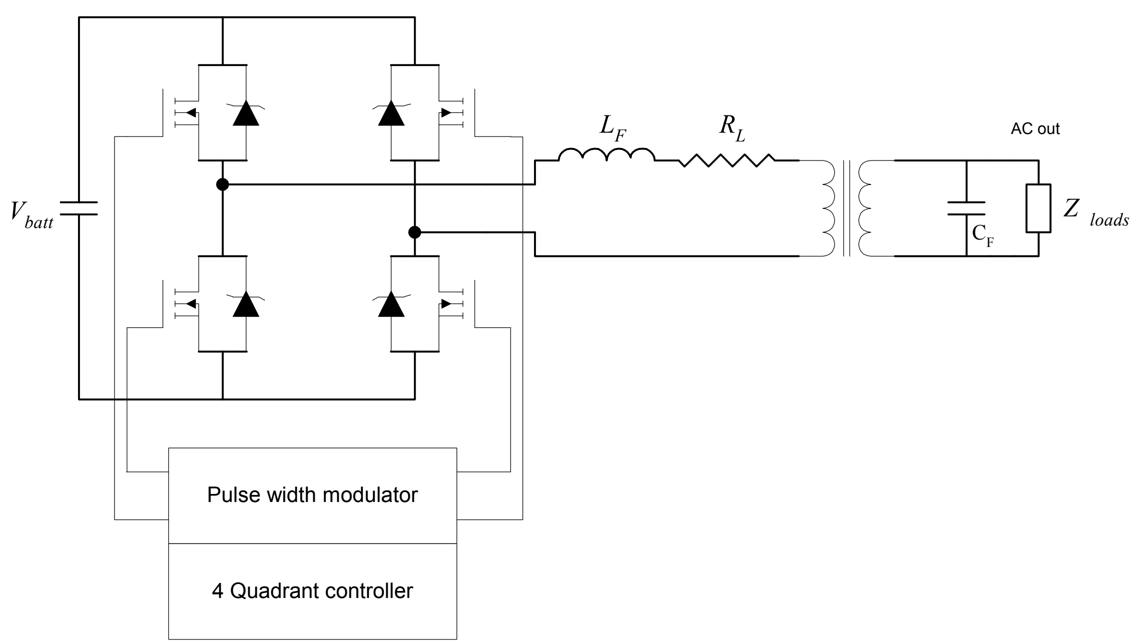


Figure 5.4 – Typical SSM inverter topology - single phase example

In practice the four quadrant capability of the inverter system will be limited by the current (ampere) rating of the inverter and the ability of the battery to deliver and absorb power.

In most present SSM mini-grid systems, the grid forming sources (inverters, genset, central grid connection) are co-located at one facility. Therefore the design of the mini-grid to maintain voltage regulation throughout the mini-grid can follow practices similar to those used to design a standard utility distribution feeder that is fed by a single transformer.

5.2.1. Synchronization and power sharing of inverter/chargers

In SSM mini-grid architectures that use a modular approach to increase inverter power capacity, the grid forming inverters must operate in parallel. In parallel connected voltage source inverters, large circulating currents can flow between units if the output phase, voltage or impedance of the units are mismatched. Since some mismatch is inevitable, a means of minimizing circulating current is essential. Circulating currents can be viewed as equivalent to poor sharing of load current among the parallel inverters. If the parallel units share load current accurately, then circulating currents are minimized. [5.6]

Approaches to controlling the parallel operation of voltage source inverters can be generally divided into:

1. active current sharing methods that rely on synchronization signals and current sharing commands from a master controller that are communicated over some form of communication channel among the inverters [5.7]

2. “droop” methods that rely on changes in grid frequency and voltage to coordinate inverter operation without the need for a separate communication channel. [5.8]

Either approach can be used in the SSM architecture. If there is a need to have widely dispersed grid forming inverters in the mini-grid, the droop methods have an advantage since they do not require a separate communications channel (although in practice a supervisory control channel is usually needed). These methods are discussed in detail in Chapter 4. In the more common situation where grid forming inverters are co-located, the cost of a high speed communications channel among inverters is negligible and the communications channel offers advantages, such as easy configuration of single-phase inverter modules into a three-phase system and more flexibility in operating modes. For instance the Schneider/Xantrex XW system, which uses a communications channel, can operate in two sharing modes.

1. "Team mode" in which only one inverter operates when load demand is low and additional inverters are added to the "team" as load demand increases. The non-active inverters remain in a low-power standby mode that minimizes total inverter losses.

2. Conventional sharing mode in which each inverter shares the load equally at all times – this is more suitable when there is one large load with a high surge demand.

The rationale for implementing a team mode of operation among the parallel inverters is to maximize the power conversion efficiency of the system. The efficiency curve of a single XW inverter/charger unit is shown in Figure 5.5. To maintain system efficiency above the target of 94% when possible, the inverters should be controlled so that each inverter is operating in a window between 0.7kW and 4kW whenever possible. Thus it is not desirable to simply share power equally among the inverters at all times since this could result in unnecessary operation outside the desired power window.

The team mode control operates in a hierarchical fashion. The master operates continuously while slave units are enabled to assist the master based on a ranking system. Through peer-to-peer arbitration slaves self-assign a unique rank, establishing an order in which to assist the master. The highest ranked slave will assist the master once the master is loaded above a pre-defined threshold (e.g. 66% of rated power). If the loading increases further, additional slaves sequentially join in the assist effort with power levels assigned to keep them operating within the desired power window when possible. As the load on the system drops, the first slave to assist will be first to return to standby state, in a first-on, first-off order, allowing more distributed stress among slave units. A load surge beyond the master's surge ability will result in a command to all slave units to assist simultaneously.

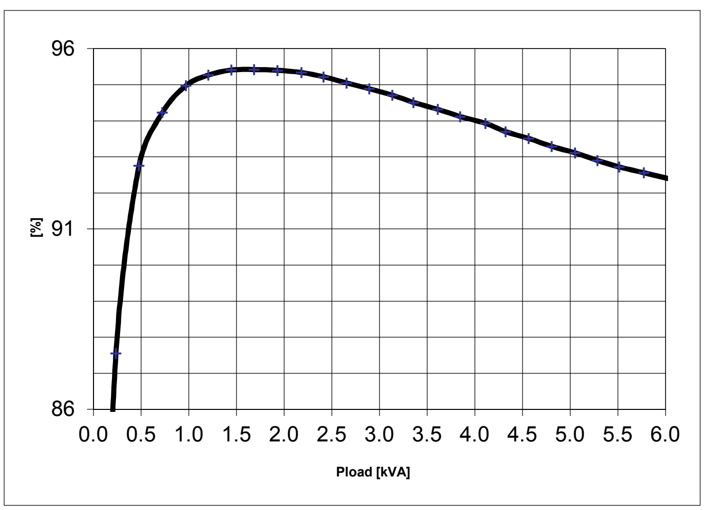


Figure 5.5 – Efficiency curve for single XW inverter/charger (invert mode)
(Source: Schneider/Xantrex)

Successful operation of team mode parallel operation requires fast, transient-free addition of new inverters to the mini-grid. Figure 5.6 shows the relevant waveforms when a new inverter is added. The new inverter is added and is accurately sharing current within two to three cycles and there are no large excursions due to transient circulating currents.

Modern control systems for inverter paralleling usually rely on digital control techniques. Data communication buses and protocols designed for control applications, such as the CAN protocol [5.9], are used to exchange synchronization and current sharing information among the inverters [5.7, 5.10, 5.11, 5.12]. The speed of the data bus, the number of inverters on the data bus, and the other data traffic on the bus can affect the current sharing performance.

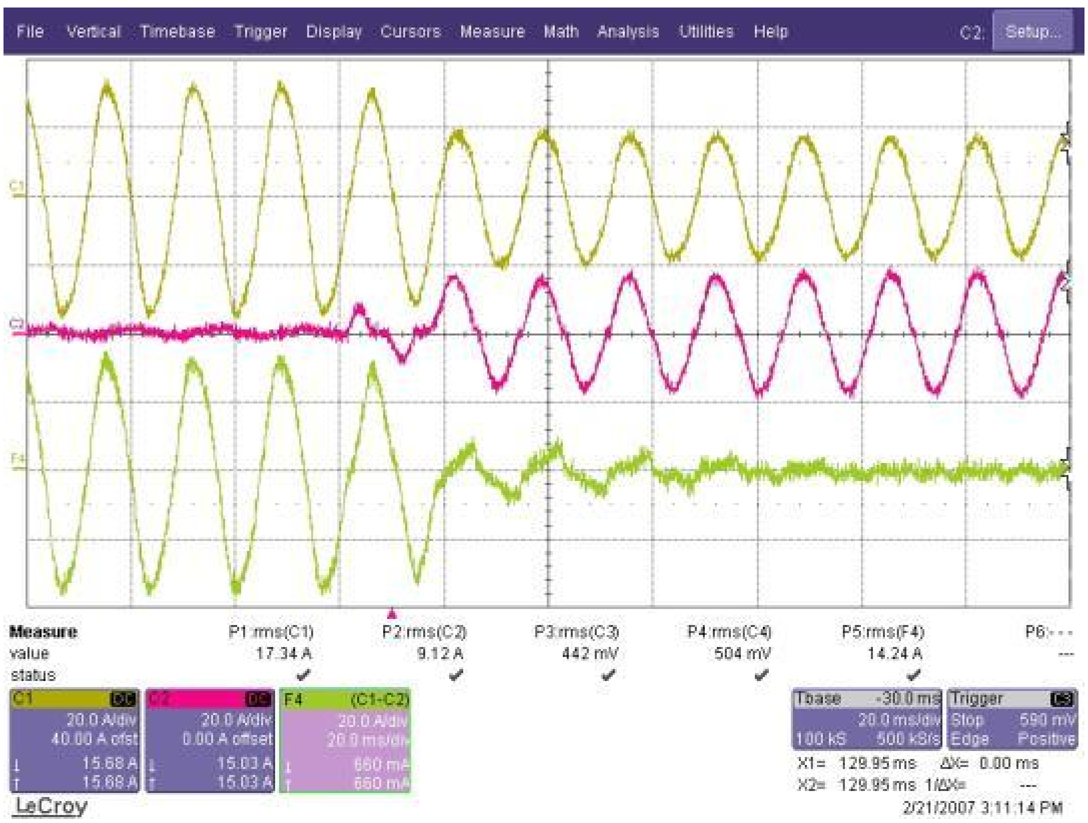


Figure 5.6 – Addition of a new inverter in team mode sharing (Source: Schneider/Xantrex)

C1: Master inverter current (25A/division)
C2: Slave inverter current (25A/division)
F4: Difference between master and slave current (25A/division)

Figures 5.7 and 5.8 illustrate the effects of data bus traffic on current sharing performance of one digital control scheme [5.7]. The figures show current waveforms (simulated in Pspice) for step load changes from no load to 25A rms and then to 50A rms. The top two traces show the individual inverter output currents and the bottom trace shows the difference between the two currents (the circulating current). Figure 5.7 shows the performance when current data is exchanged every 44 milliseconds while Figure 5.8 shows the performance when current data is exchanged every 16 milliseconds.

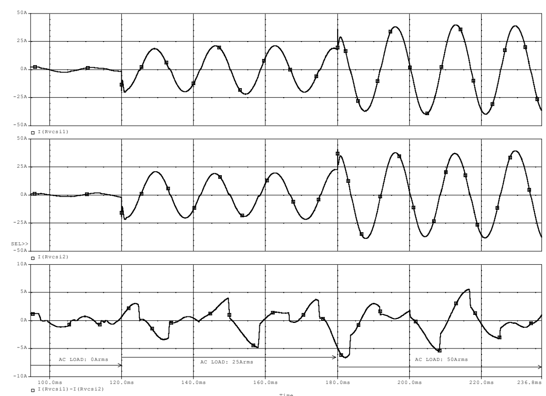


Figure 5.7 – 44 msec data exchange
Circulating current: 1.8 Arms (7%)

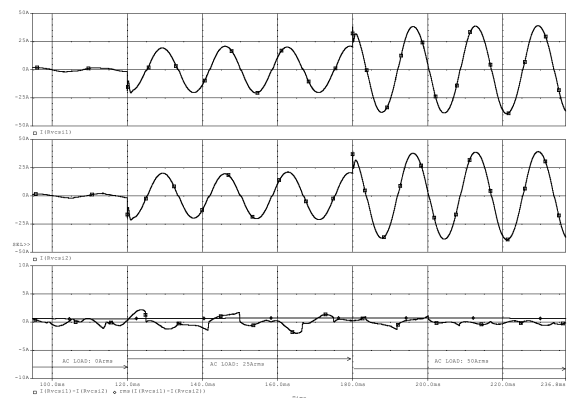


Figure 5.8 – 16 msec data exchange
Circulating current: 0.6A rms (2.5%)

Modern data networking technology is capable of allowing a reasonable number of units to operate in parallel with good sharing. Table 5.1 shows the paralleling capability of some current commercial single phase inverter/charger units.

Table 5.1 – Parallel connection capability of modern inverter/chargers

Inverter/Charger	# units – single phase	# units – three-phase
Xantrex XW	3 (18 kW total)	9 (54 kW total)
SMA Sunny Island	4 (20 kW total)	3 (15 kW total)
Studer Innotec Extender	3 (21 kW total)	9 (63 kW total)
Outback FX/VFX	8 (28.8 kW total)	3 (10.8 kW total)

Technology is available to allow for larger numbers of units to be paralleled if the market shows a preference to implement higher power systems through many parallel units. However cost per watt usually decreases as inverter power rating increases, so the advantages of modularity decline as more units are paralleled (e.g. a 200 kW system consisting of four parallel 50kW units will be less expensive than a 200 kW system consisting of 50 parallel 4 kW units).

Parallel operation of a commercial inverter/charger using digital control and a CAN network for communication is demonstrated in Figure 5.9, which shows current and voltage waveforms with the system operating through a step change in the resistive load.

The current sharing technique also performs well with non-linear loads that draw significant harmonic currents. Figure 5.10 shows current and voltage waveforms with a non-linear load. Circulating current is less than 4% of output current.

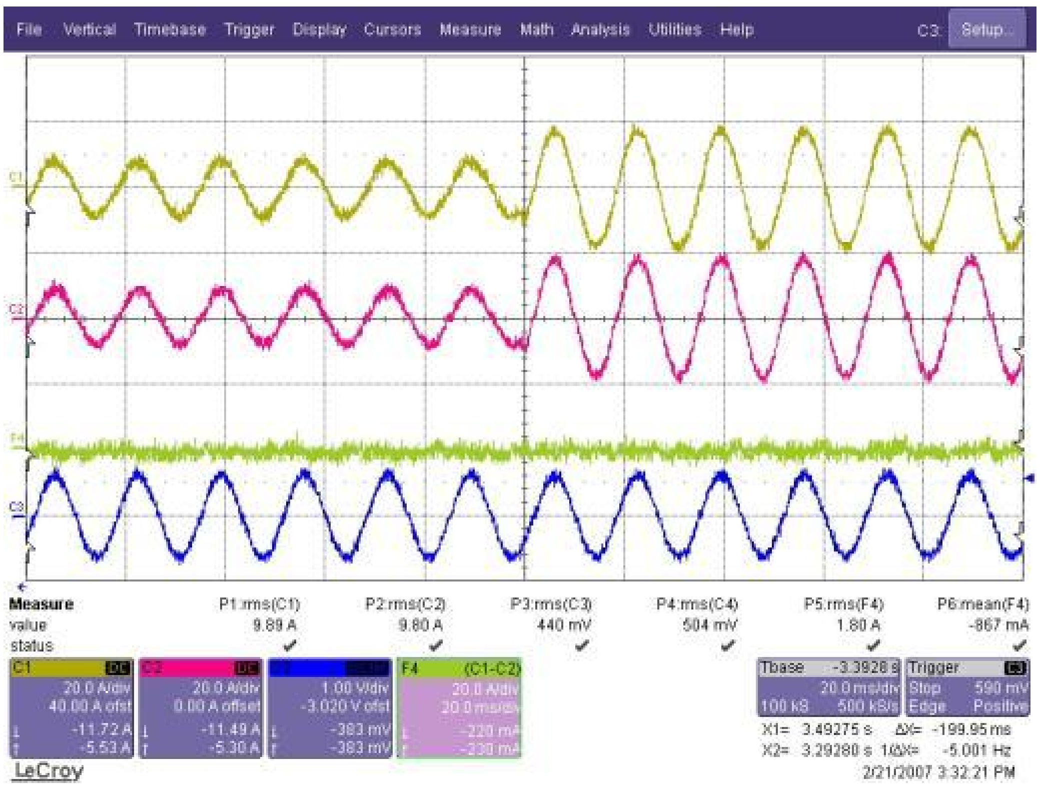


Figure 5.9 – Parallel inverters with step change in load (Source: Schneider/Xantrex)

C1: Inverter 1 output current (20A/division)
C2: Inverter 2 output current (20A/division)
F4: Difference between C1 and C2 (20A/division)
This is the residual circulating current.
C3 : Output voltage (500V/division)

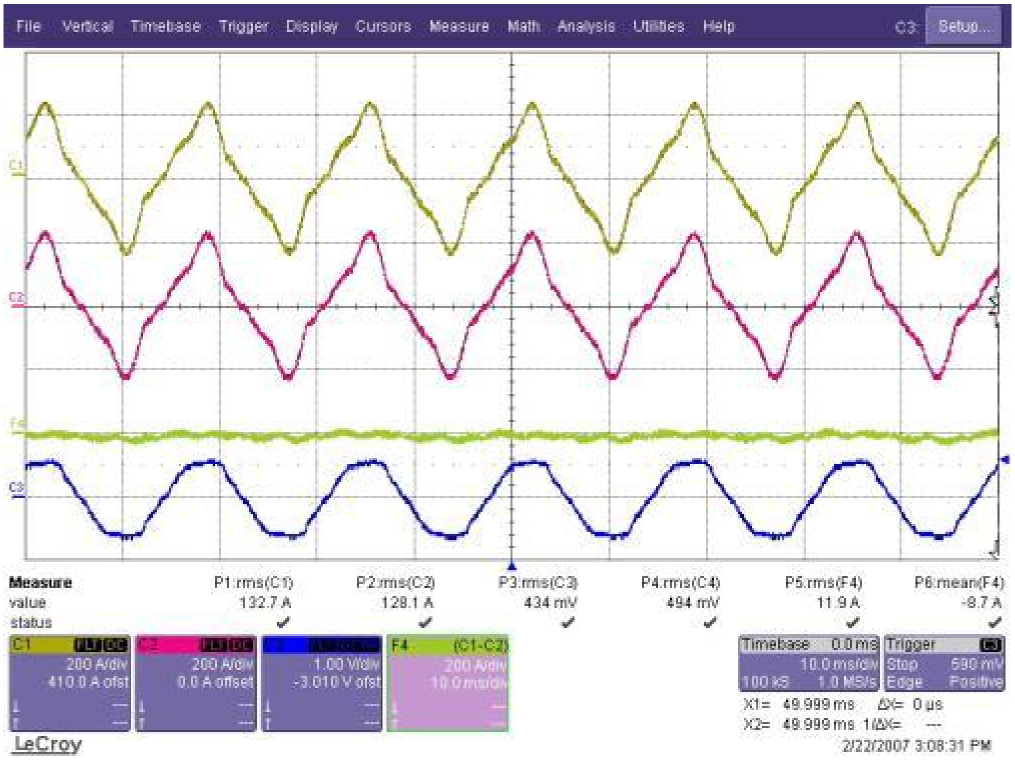


Figure 5.10 – Parallel inverters with non-linear load (Source: Schneider/Xantrex)

C1: Inverter 1 output current (20A/division)
C2: Inverter 2 output current (20A/division)
F4: Difference between C1 and C2 (20A/division)
This is the residual circulating current.
C3 : Output voltage (500V/division)

5.2.2. Transfer between grid forming masters

Achieving smooth transfer between grid forming masters is an important control objective in switching master mini-grid systems. An advantage of the centralized mini-grid architecture is that the powerful controller and integral transfer switches in the inverter/charger can control the transition among grid forming masters. This allows the use of relatively inexpensive gensets that are not equipped with transfer switches, synchronizing controls, or droop-mode operation and also allows smooth transitions between autonomous and grid-connect operation. In a decentralized mini-grid system, where the gensets and the interface to the central grid are not co-located with the grid forming inverter/charger, additional transfer switches and control equipment are needed to manage the connection of these sources to the mini-grid.

For example, the Schneider/Xantrex XW inverter/charger has the ability to manage the connection of two external ac sources as grid forming masters. It allows the user flexibility to prioritize the grid forming master in the event that all power sources are available. In most applications the two power sources are engine generators or the central electricity grid. However other sources, such as microhydro generators or other mini-grids, can be used as long as they have the necessary grid forming capability.

The XW system has considerable flexibility in programming the dispatch (start/stop) of engine gensets. It can dispatch the genset based on

- Battery state of charge
- System power demand
- Availability of the other ac power source (i.e. central grid)
- Time of day
- External relay contact
- Manual input from the user interface

Since the transfer switches for the other grid forming sources are built into the inverter/charger, the inverter/charger controller can sense the magnitude and phase/frequency of the voltages at the inputs to these switches, and the current flowing through the switches. In addition, the controller can be pre-programmed with information about the transfer time of the switches, since they are selected and installed by the inverter manufacturer. This allows very precise control of the transition between grid forming sources.

The transition from the inverter acting as the grid forming master to either the genset or the central grid can be made in an almost seamless fashion. The inverter controller matches the voltage and phase of the inverter to the voltage and phase of the new master and then closes the transfer switch to connect the new master to the mini-grid. The inverter continues to operate in voltage control mode for most of the switching interval, maintaining the mini-grid voltage until the new master is connected. Figure 5.11 shows the current and voltage waveforms for such a transition. The voltage dip at the transfer occurs for only a few milliseconds and there is no phase discontinuity in the voltage or current.

The transition to an inverter master from a genset master or from the central grid is also essentially seamless if it is a controlled transfer. However, if a grid-forming master shuts down unexpectedly (e.g. a central grid blackout) the inverter must first detect the loss of voltage before it can take action. Therefore the transition is not as short. Figure 5.12 shows this case. The inverter/charger takes about 8 milliseconds to detect loss of power and open the transfer switch. This matches the performance of many uninterruptible power supplies and allows the implementation of PV hybrid mini-grids that can provide backup power capability to critical loads.

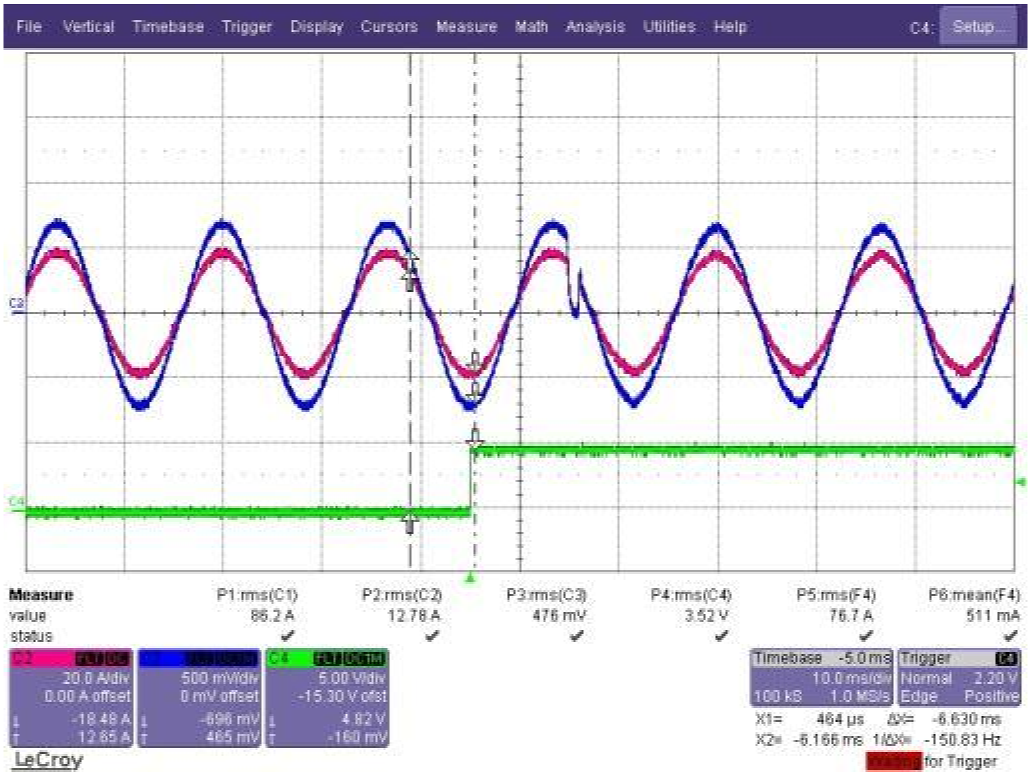


Figure 5.11 – Transition from inverter master to new master (e.g. genset) (Source: Schneider/Xantrex)

C2 (red):	**Load current (20A/division)**
C3 (blue):	**Load voltage (250V/division)**
C4 (green):	**Transfer switch control signal. The low to high transition indicates the moment of activation.**
Time base:	**10 milliseconds/division.**

The transfer switches in one XW inverter/charger unit can be connected in parallel with their counterparts in other parallel units and their switching is coordinated over a CAN data network. Thus the power rating of the transfer switches increases as the power rating of the inverter system increases.

Modern inverter/chargers from several other manufacturers offer similar capabilities, with transfer times below 20 milliseconds. At present, the integrated transfer switches used in the inverter/chargers are electromechanical contactors. The control techniques described are equally applicable to solid-state (static) switches, which would be faster [5.13, 5.14]. Cost and regulatory issues, and lack of market demand for significantly better performance, have discouraged adoption of solid-state switches. However as mini-grids progress to higher power levels, where electromechanical switches become more expensive and slower, static switches will be more attractive.

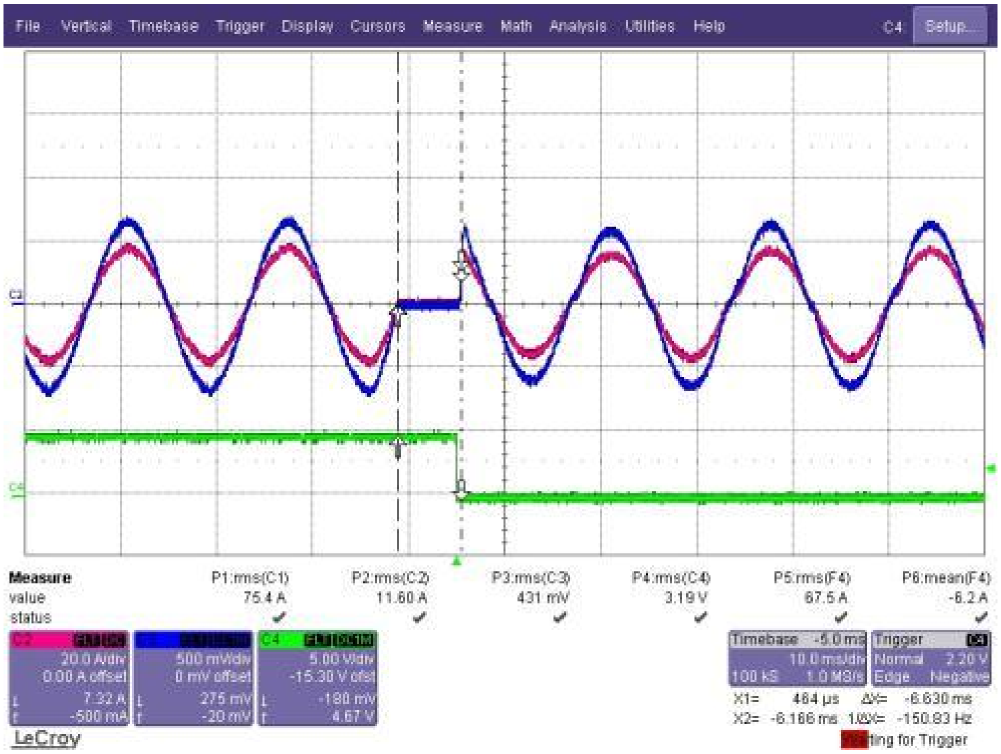


Figure 5.12 – Transfer to inverter master upon loss of grid power (Source: Schneider/Xantrex)

5.2.3. Inverter support of other grid forming masters

The capability to monitor the power (or current) supplied to the mini-grid by the genset or the central grid, and the ability of the inverter/charger to transition to a current source grid-parallel mode, allows the implementation of a number of useful operating modes in which the inverter/charger supports the grid forming master. Typical modes include:

1. *Charger load management*. The battery charger input current is controlled to maintain the current supplied by the genset or grid below a preset threshold. This gives priority to other loads in the mini-grid and ensures that the genset or grid connection is not overloaded. Charger operation can also be programmed for certain times of day only, to take advantage of lower electricity rates in off-peak periods.

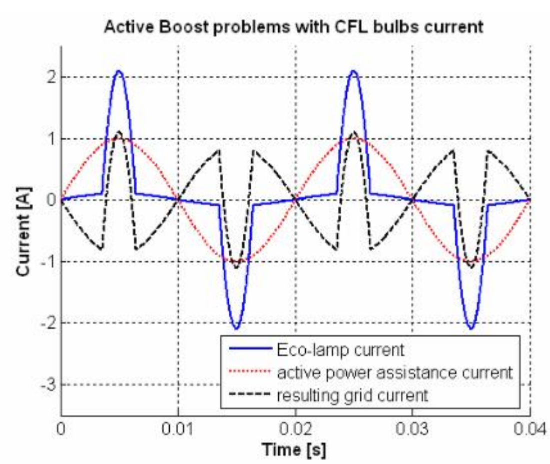
2. *Generator load support*. The inverter supplies current to the mini-grid when the generator current reaches an (adjustable) limit to maintain the generator current at the limit. This allows delivery of the combined power of the genset and the inverter to the mini-grid for high load conditions.

3. *Mini-grid support with no export.* If the battery on the dc bus is charged, the inverter/charger will supply available power from sources (other than the battery) connected to the dc bus to the mini-grid, reducing the power that must be supplied from the main grid. No power will be exported across the transfer switch.

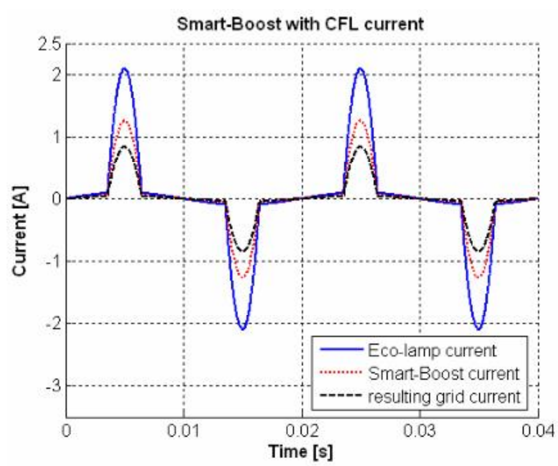
4. *Mini-grid support with export.* If the battery on the dc bus is charged, the inverter/charger will supply available power from sources (other than the battery) connected to the dc bus to the mini-grid. Excess power is exported across the transfer switch to the main grid.

5. *Peak shaving.* In grid connected operation, the inverter supplies current to the mini-grid when the central grid current reaches an (adjustable) limit to maintain the current drawn from the main grid at the limit. This allows peak shaving to reduce loading on the main grid. This mode can be programmed to operate only for periods of the day when electricity costs are high or there is a high load on the main grid.

An interesting example of generator load support is the Studer Xtender series "Smart-Boost" feature that operates the inverter in conventional voltage source mode when it is the grid-forming master, and operates it in bidirectional current assistance mode when another source is the grid-forming master [5.15]. In current assistance mode, the inverter actively follows the line (load) current, injecting both fundamental and harmonic components to support the genset or grid source. This improves overall system performance when the loads are non-linear or have low power factor when compared to the alternative strategy of injecting only fundamental current in phase with the line voltage (see Figure 5.13).



(a)



(b)

Figure 5.13 – (a) Active power assistance (injected current follows line voltage) (b) Current assistance (injected current follows line current) [5.15]

5.3. Control of power quality in SSM mini-grids

Power quality in a SSM mini-grid architecture is dependent on the source acting as the grid forming master, the design of the mini-grid distribution network, and the nature of the loads in the mini-grid. Generally the inverter/charger has very good power quality, with excellent regulation of voltage and frequency and low harmonic distortion. The ability of modern inverter/chargers to provide load support to the other grid-forming sources can improve the power quality of these sources by reducing voltage and frequency droops and harmonic distortion. Even further improvement could be delivered if the inverter/charger implemented active filtering. This has been the topic of research [5.16, 5.17] but is not yet offered in commercial products.

Usually the inverter/charger is programmed to only select sources with acceptable power quality (voltage, frequency, and, in some cases, distortion) and will revert to the inverter as the grid forming master if another source's power quality decreases below acceptable limits. Similarly, if the inverter encounters conditions that affect its ability to maintain power quality (e.g. excessive load, low dc bus voltage), it can dispatch the engine-generator to supply power instead. This ability to rapidly select a new source if there are power quality problems makes the SSM system well suited to mini-grids offering backup or premium power capability.

5.4. Fault Conditions and Protection in SSM Mini-Grids

Fault protection in a mini-grid must:

- reliably detect faults and minimize false trips,
- be sufficiently fast to protect people and equipment, and
- preferably isolate the fault by disconnecting the minimum portion of the mini-grid and therefore the minimum number of users.

Conventional fault protection systems in radial distribution networks assume that high levels of fault current are available at the source (i.e. at the feeder transformer). Fault current levels decline the further the fault is from the source because of the line impedance between the source and the fault. Circuit breakers, other protection equipment, and conductor sizes are coordinated so that the devices further into the network, closer to the fault, trip first (because they have lower fault current trip points). This achieves the goal of isolating the fault while disconnecting the minimum portion of the network.

SSM mini-grid architectures have the advantage that they usually concentrate the electricity sources at one point in the mini-grid, similar to the feeder transformer in a conventional radial distribution network. However, they differ in that fault currents depend on what source is the grid-forming master. When the central grid is the master, available fault current is high and conventional protection techniques can be employed.

However, inverters typically limit short term output currents to no more than two or three times the rated continuous current (see Figure 5.14) and many will rapidly shut down in the event of a line-line or line-ground fault, resulting in no fault current delivery at all. Gensets are also relatively high impedance sources compared to the central grid – fault current of a small genset (<100 kW) may be limited to three times the rated continuous current for a relatively short period (e.g. ten seconds). As a result, conventional circuit protection devices may not work as expected and coordination to ensure that a fault is isolated may not be possible through conventional practices.

As example, in Figure 5.14, the inverter's response to overload is faster than that of a conventional circuit breaker rated close to the continuous rating of the inverter. As a result, the breaker may not trip on a fault. This does not pose a safety hazard (the inverter provides the fault protection), but it does make it difficult to design a protection system that isolates the fault and allows the remainder of the mini-grid to keep operating.

New protection techniques for mini-grids that address these issues are being actively investigated [5.18, 5.19, 5.20]. These include:

- development of inverters with defined fault-ride through capability that will continue to deliver fault current (rather than disconnect) during a fault,
- development of fault detection and isolation techniques that do not depend on high fault current levels.

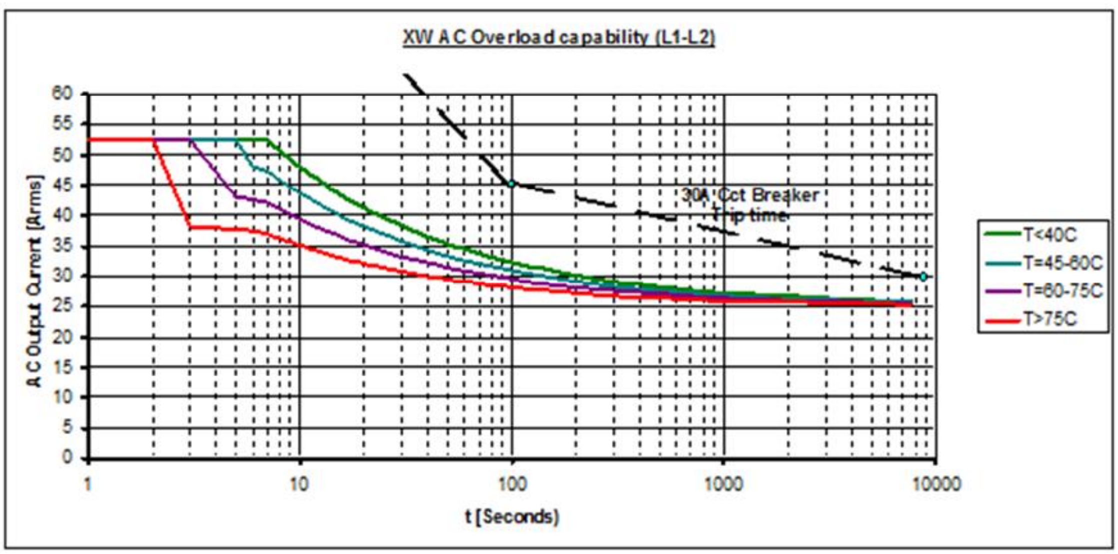


Figure 5.14 – Inverter overload capability vs. time (hard current limit at 2 x continuous) (Source: Schneider/Xantrex)

5.5. Controlling PV Generation

SSM PV hybrid architectures normally employ DC coupling of PV sources in which the PV is coupled to the DC (battery) bus by a dc/dc converter (PV charge controller). The bidirectional inverter/charger couples the DC bus to the mini-grid. However a completely AC coupled architecture is also possible in which the PV is coupled directly to the mini-grid by one or more inverters (see the case study in Section 5.6). PV energy that is not absorbed by loads on the mini-grid can be stored in the battery by the bidirectional inverter/charger. It is also possible to consider mixed systems that have both AC coupled and DC coupled PV generation.

Although it is possible to choose a DC coupled or AC coupled system based on efficiency considerations, this will normally require detailed analysis of the system's components and load profile since neither coupling method is more efficient in all situations [5.21]. However DC coupling generally has cost and performance advantages when the PV generators, battery storage and grid-forming inverters are co-located. AC coupling has advantages when PV generators that are distributed throughout the mini-grid must be integrated into the mini-grid.

Managing PV generation for power balance in DC coupled systems is relatively straightforward since the battery on the DC bus acts as a reservoir to smooth power flow between the PV generator and the mini-grid. If the battery becomes fully charged, and the mini-grid cannot absorb the power from the PV generator, then the PV charge controllers simply reduce the power drawn from the PV generator to maintain the DC bus voltage at its nominal setting.

Managing AC coupled systems to maintain power balance is more complex. The bidirectional inverter must be truly capable of four quadrant operation so that it can smoothly transition from supplying power to the mini-grid to absorbing power from the mini-grid as PV generation varies. Also required is a means of signalling the distributed PV inverters to reduce PV generation if no more energy can be absorbed by the battery.

One method of signalling is for the grid-forming inverter to change the mini-grid frequency as the battery reaches full charge [5.22, 5.23]. The distributed PV inverters detect the change and adjust their output. Alternatively, extra loads could be connected to absorb the excess PV power. As shown in Figure 3.15, this concept can be extended to signal a low battery state-of-charge as well, allowing implementation of load shedding or other demand management strategies.

The SMA Sunny Island inverter (grid-forming) and Sunny Boy inverter (PV inverter) implement this strategy [5.23] – see Section 6.5. – but it has not yet been generally implemented in commercial products. An alternative is to activate the over-frequency protective trip function in commercial PV inverters [5.24]. This results in a cruder on-off control of PV generation but can be effective. Figure 5.16 shows a bidirectional inverter/charger (grid forming master) controlling a conventional PV inverter by activating its over-frequency trip function at 50.2 Hz. Effectively, a low frequency pulse width modulation scheme is implemented to control the battery charging.

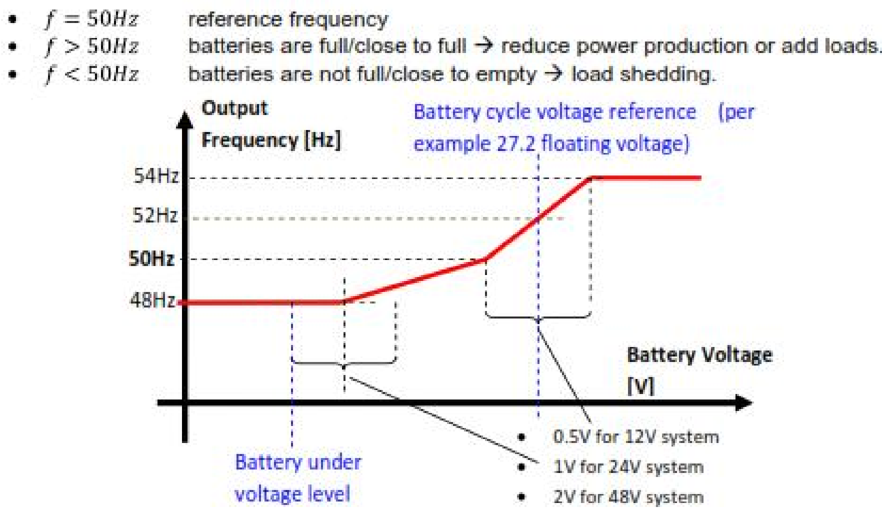


Figure 5.15 – Mini-grid frequency signaling of battery state of charge [5.22]

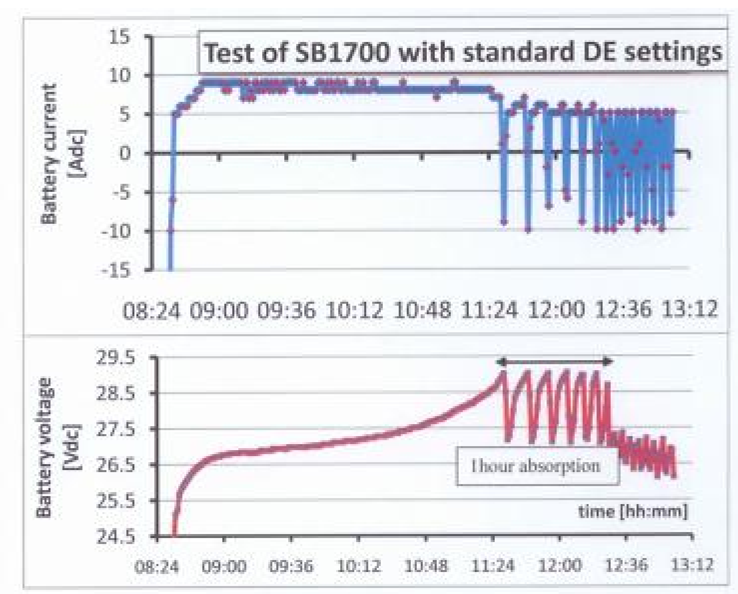


Figure 5.16 – Control of PV inverter using over-frequency trip function [5.24]

5.6. SSM mini-grid on Kapas Island, Malaysia

Malaysia has installed several PV hybrid mini-grid systems in locations that are not suitable for grid extension [5.25]. One recent installation (2007) is on Kapas Island (Pulau Kapas) off the coast of Terengganu [5.26]. The system replaces privately owned diesel genset systems and is owned by Perbadanan Memajukan Ikhtisad Negeri Terengganu (PMINT – Terengganu State Economic Development Corporation). It supplies electricity to tourist resorts and island residents.

Figure 5.17 – PV modules on Kapas Island jetty (Source: Universiti Teknologi MARA)

Figure 5.18 – Cabin for inverters and battery bank. PV array provides shading. (Source: Universiti Teknologi MARA)

The one-line diagram for the mini-grid system is shown in Figure 5.19. The system has a 240 Vdc (nominal) bus for the battery energy storage system and a 415 Vac 3-phase bus to interconnect the generators and loads.

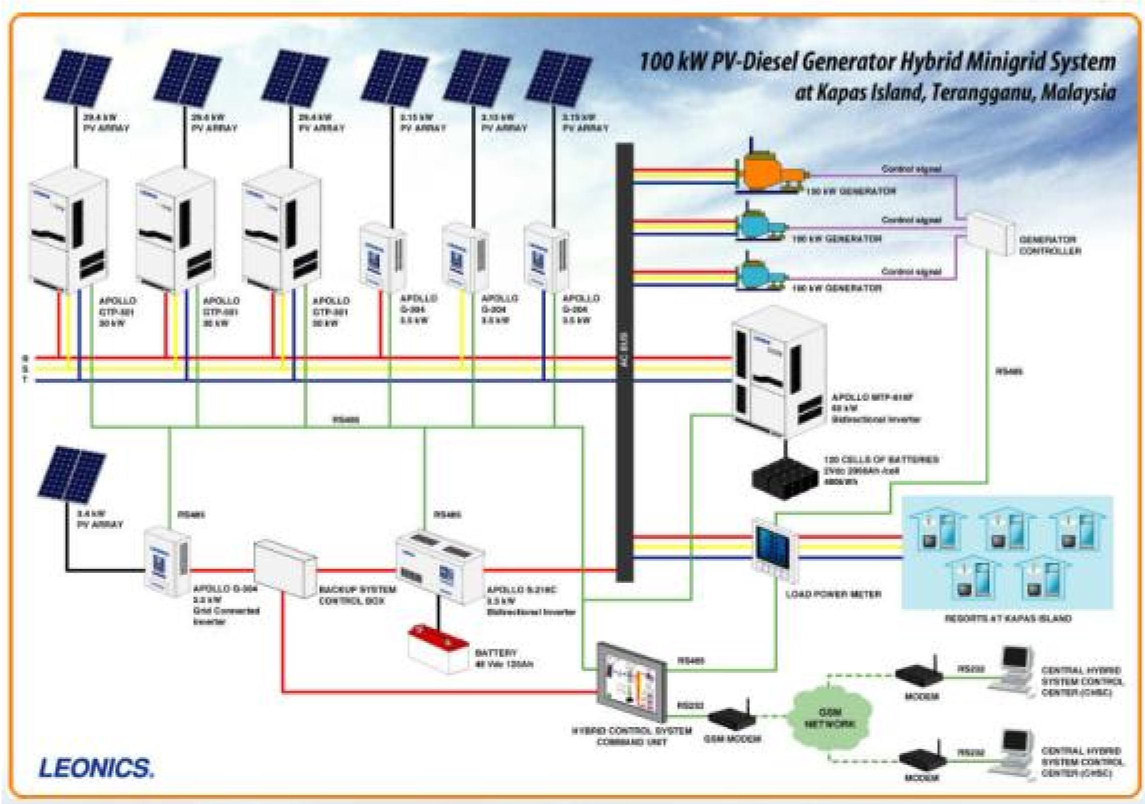


Figure 5.19 – Kapas Island PV-Hybrid mini-grid system
(Source: Leonics Company Ltd.)

Key system components include

a) 100kW Photovoltaic Plant consisting of:
   - 3 PV arrays rated 28.9 kWp each
   - 4 PV arrays rated 3.4 kWp each

b) PV Inverters to AC bus
   - 3 Leonics GTP-501(30kW, 3 phase)
   - 4 Leonics G-304 (3.5kW, 1 phase), 1 for PV Back Up System (UPS)

c) Bi-Directional Inverter (links AC and DC bus)
   - 1 Leonics MTP-616F (60kW, 3 phase)
   - 1 Leonics MTP-615F (45kW, 3 phase) – recently added
   - 1 Leonics S-218C (3.5 kW, 1 phase) for PV Back Up System (UPS)

d) Energy Storage

- 240 Volt DC 480kWh lead-acid battery bank with monitoring system

e) Diesel Generator Plant
   - 2 100 kW Diesel Genset
   - 1 150 kW Diesel Genset

f) Hybrid Control System Command Unit (HCCU) with remote monitoring and control capability

This is a single switching master (SSM) system with the PV generators connected to the AC bus through PV inverters which follow the grid forming masters. The two 3-phase bidirectional inverters (paralleled in a master-slave arrangement) or the diesel gensets act as grid forming masters.

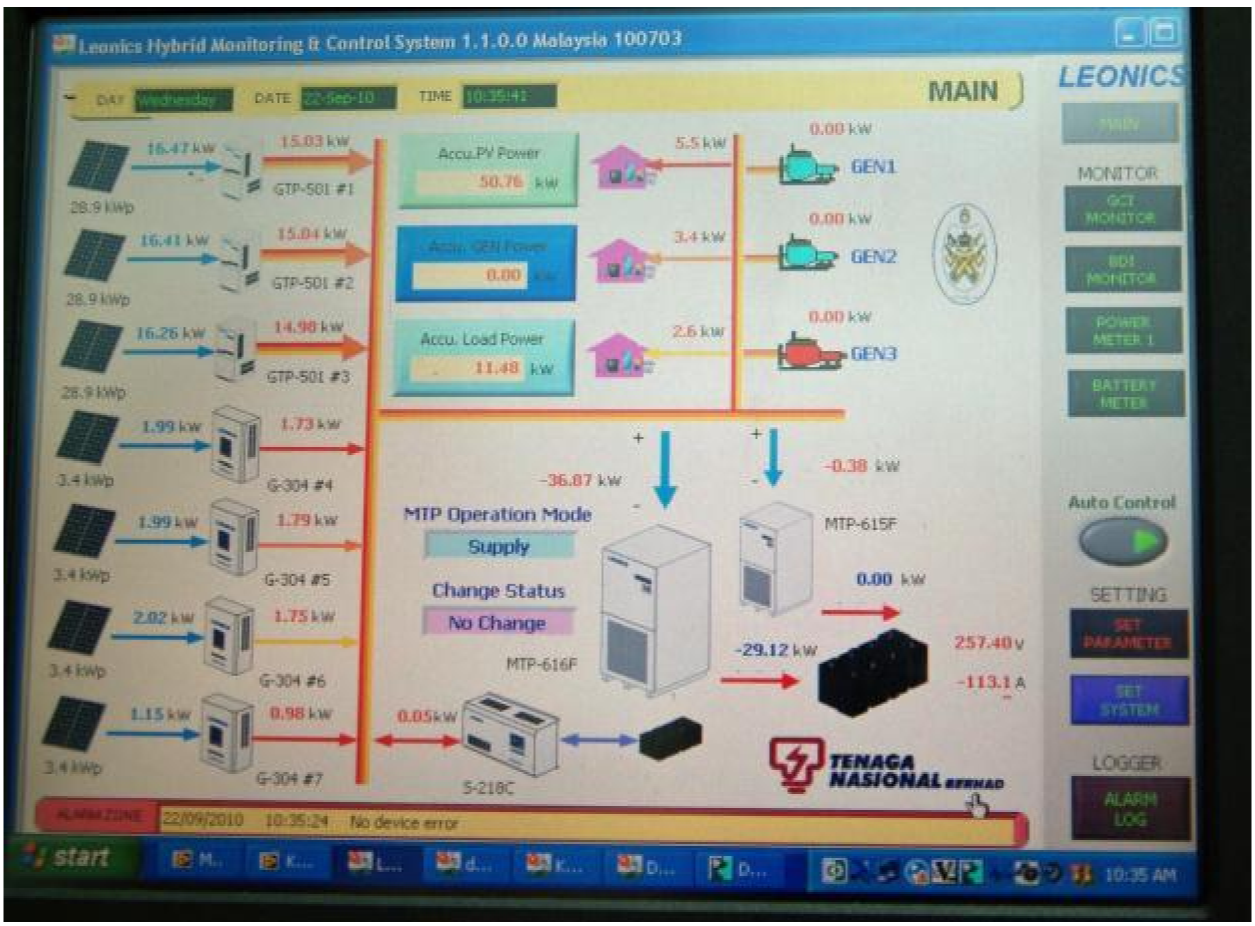


Figure 5.20 – Hybrid Control Unit (HCCU) Display

The Hybrid Control System Command Unit (HCCU) (Figure 5.20) controls the system to achieve the following objectives [5.27]

- Full automatic operation of the system to optimize the usage of PV energy
- Manage PV energy production to avoid reverse power flow to diesel gensets or overcharge of battery bank.
- Use the energy in the battery bank to support peak loads and avoid starting extra gensets, thus reducing fuel consumption.

The system operates in three modes [5.27]

- *Inverter mode*. When battery state of charge > 30% and load power < 90kW the bidirectional inverters act as grid formers and the diesel gensets are off.
- *Charging mode*. When battery state of charge < 30% or load power > 98 kW, the bidirectional inverters act as battery chargers and the diesel plant acts as the grid former.
- *Feeding Mode*. When battery state of charge > 80%, load power > 80% of the rating of the dispatched genset, and there is no PV production, the bidirectional inverters provide peaking support to allow the dispatched genset to operate at peak efficiency.

5.7. Conclusion

Present control technology and commercially available components allow effective implementation of SSM PV hybrid mini-grid systems up to a few hundred kilowatts. There is a limited number of commercial bi-directional inverters with ratings over 100 kW. Introduction of larger three-phase bidirectional inverters, particularly with capability to dispatch and manage multiple gensets, would expand the application of the SSM architecture to larger mini-grids.

6. Multi-master inverter dominated mini-grid architecture

6.1. Introduction

The multi-master inverter-dominated architecture (Figure 6.1) has a decentralized control architecture in which several generating sources distributed within the mini-grid cooperate to act as grid-formers (i.e. control mini-grid voltage and frequency). Generally, most of these sources are interfaced to the mini-grid by power electronic interfaces (inverters), but conventional rotating machine generators using droop control may be integrated as well.

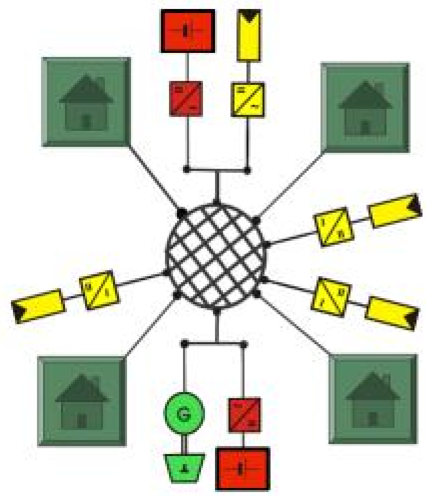


Figure 6.1 – Multi-master inverter-dominated architecture

In order for a mini-grid to operate in a stable fashion, with frequency and voltage regulated within acceptable limits, the active and reactive powers produced and demanded in the system, must be balanced. This can be done by a diesel genset in a diesel-based system. In the absence of a diesel genset and energy storage units and with an excess of active power produced by RESs, controllable loads can balance the active power, and a synchronous condenser can balance the reactive power, as shown in the case studies of Chapter 4. In cases where an energy storage device such as a battery bank and its static dc-ac converter, or inverter, is available, it can operate as a master unit forming the grid. This approach should also increase system efficiency since there will be no losses in the dump loads. It should be mentioned that while an energy storage unit with adequate capacity (kWh) is essential for balancing active power in the long run, reactive power can be supplied or absorbed by the inverter without any significant requirements of storage capacity in the dc side of the inverter. Nonetheless, the inverter has to be rated with appropriate apparent power (VA) to deal the active (W) and reactive (Var) powers required for power balancing.

In principle one grid forming unit can be used. However, for the sake of redundancy, it is often desirable to have multiple grid forming units of different types working in parallel, in a centralized or decentralized manner. Besides, this would allow a mini-grid to be expanded on a step-by-step basis. In the past, this ability has been technically limited by the fact that parallel operation of inverters has been possible only through the so called “master–slave” operation, where the “master” inverter provides the frequency, while the ‘slave’, follows this frequency. In addition, distribution of power between these units has to be organized. This requires careful individual design and also a communication line between these units. Also, it is not easy to integrate conventional rotating machine gensets as parallel grid formers with this scheme.

More recently, inverters that incorporate the frequency vs. active power (f-P) and the voltage vs. reactive power (V-Q) droop characteristics, commonly found in rotating generators, have been developed. This technology should enable the parallel operation of multiple grid forming units at different location on the mini-grid without communication requirements.

6.2. Control strategies for parallel operation of grid forming inverters

For multiple inverters to operate in parallel as grid forming units, it is necessary to make sure that they will be sharing the active and reactive power required for balancing supply and demand in a way that will not overload, and possibly damage, any of them. This is relatively simple to do for rotating generators with speed (frequency) droop governors and Automatic Voltage Regulators (AVR) as seen in Chapter 4. When the active and reactive power demanded by a load varies in a mini-grid served by two or more droop controlled gensets, the load voltage and the grid frequency will change and the system will find a stable operating point with the gensets sharing active and reactive power according to their droop curves. Conversely, standard inverters operate with fixed voltage and fixed frequency and cannot be paralleled without additional measures.

The active and reactive powers that flow between two inductively coupled voltage sources can be calculated by

$$P = \frac{V_1 V_2}{X}\sin(\delta_1 - \delta_2) \text{ and } Q = \frac{V_1}{X}[V_1 - V_2\cos(\delta_1 - \delta_2)] \quad (6.1)$$

Where V is the magnitude of a voltage source, δ is the phase angle and X is the impedance of the inductance between them. Typically the sources present similar magnitudes and the phase difference between them is small. The active and reactive power flows depend primarily on the phase angles between them and on their voltage differences, respectively. These relations reverse for low voltage grids, which tend to present a more resistive characteristic. Nevertheless, the conventional droop logic, discussed in the following section, is still the preferred choice [6.1]. Although crystal based inverters present excellent frequency regulation, small frequency differences integrated overtime result in hazardous angle differences between inverters. While the impedances between rotating generators in conventional systems are relatively large, they are quite small in mini-grids and small differences in voltage magnitudes can lead to circulating reactive currents that can exceed the ratings of the inverters.

Two strategies that enable the parallel operation of inverters for forming the grid are presented below.

6.2.1. Master-slave

The classical approach is the master-slave configuration [6.2, 6.3], shown in Figure 6.2. In this case, one inverter *forms the grid*, regulating the voltage and frequency as an ideal voltage source while one or more slave units *support the grid* by injecting given amounts of active and reactive power as a current source. The supervisory control is responsible for calculating the amounts of power that each unit should inject/absorb and send this information to the inverters via a fast communication channel. This approach is not suitable for decentralized mini-grids because of the additional cost of long high speed communication cables.

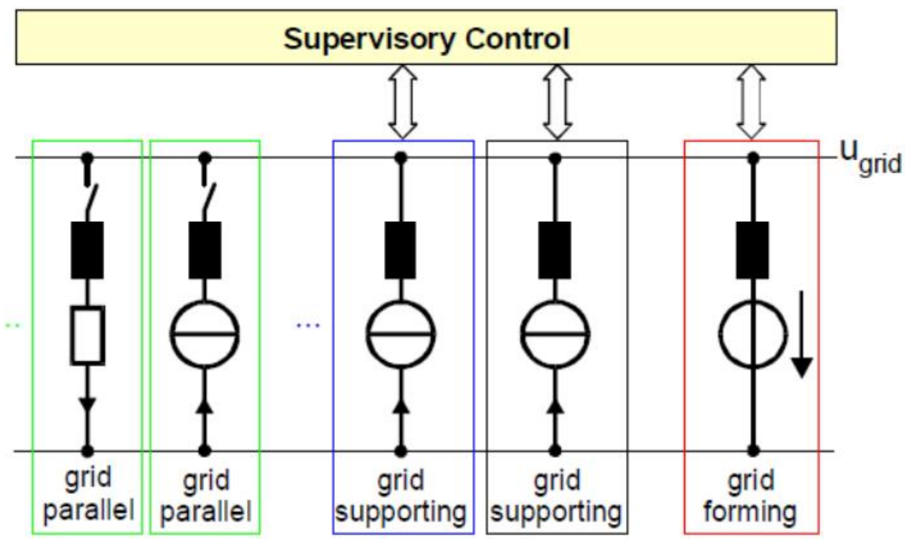


Figure 6.2 – Classical master-slave system consisting of one voltage source, current sources and supervisory control.

6.2.2. Multi-Master

In cases of decentralized mini-grids, the fast communication data network can be avoided if the inverters themselves set their instantaneous active and reactive power. Besides, the mini-grid can be expanded more easily with distributed master inverters and becomes more robust since it can remain in operation even if the supervisory controller fails. This can be done with the frequency-active power (f-P) and voltage-reactive power (V-Q) droop controls that are used in rotating generators. The droop curves are shown in Figure 6.3.

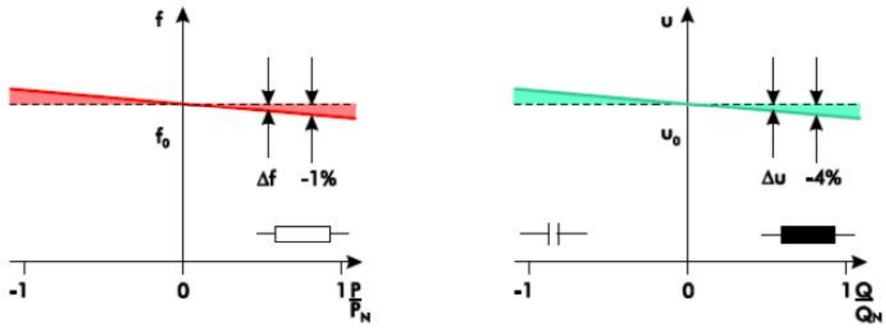


Figure 6.3 – f-P and V-Q droop characteristics

The obvious method for implementing the frequency droop is to use *P* as a function of *f*, measured at the point of connection of the inverter. However, obtaining an accurate measurement of instantaneous frequency in a real system is not straight-forward. Measuring instantaneous real power is easier. Alternatively one can make *f* to be a function of *P*: the VSI output power is measured and this quantity is used to adjust its output frequency of the inverter [6.9]. The droop curves can be therefore represented by

$$f = f_0 - s_{pf}P \text{ and } V = V_0 - s_{pv}Q \qquad (6.2)$$

Where *P* and *Q* are the measured active and reactive powers injected by the inverter, s_{pf} and s_{pv} are the slopes of the frequency and voltage droop curves ($\Delta f/\Delta P$ and $\Delta V/\Delta Q$) and f_0 and V_0 are the idle frequency and the idle voltage, i.e. the voltage at which the inverter injects no reactive power into the mini-grid. The -1% and -4% slopes or droop values shown in Figure 6.3 mean that when the inverter injects rated (1 p.u.) active and reactive power the output frequency of the inverter will be 1% and the voltage magnitude 4% lower than the values of f_0 and V_0. Master inverters of different ratings but with the same slopes, in %, will share the net load variations proportionally to their ratings. The droop parameters can be adjusted by a supervisory controller for frequency and voltage regulation or energy management purposes using a slow communication channel.

For the sake of simplicity, consider a PV mini-grid that operates with a single droop controlled master battery inverter. As the PV power generation and load demand in the mini-grid vary, the active and reactive powers required for power balancing and that flow through the inverter also vary. As a result, the output voltage of the inverter presents variable frequency and magnitude. If there is a shortage of active and reactive powers in the mini-grid, the master inverter has to supply them and its output voltage will present frequency and magnitude values below the idle values, f_0 and V_0. The differences between the actual values of voltage magnitude and frequency and the idle values depend on the amount of active and reactive power demanded from the master inverter and on the slope of the droop curves. The higher the demand of active and reactive power, the lower the values of frequency and voltage magnitude will be. In steady-state, the frequency is the same in all buses of the mini-grid, what cannot be said about the voltage magnitude.

Operation with variable frequency can be advantageous because it allows all components connected to the mini-grid to know if there is a shortage or excess of active power in the system. This allows controllable loads to disconnect if the frequency decreases below certain values, and PV inverters to reduce their active power injection if the frequency exceeds given values. If there are multiple decentralized master inverters, the supervisory controller can charge, or discharge, any of them in a controlled way by setting its idle frequency below, or above, the mini-grid frequency, respectively.

Droop control for parallel operation of inverters was first investigated for distributed uninterruptible power supply (UPS) systems [6.4]. Subsequently several research groups investigated applications in distributed generation [6.5, 6.6, 6.7]. The most extensive work, including experimental verification and demonstration projects, has been by ISET (now IWES) and SMA Regelsysteme Gmbh in Kassel, Germany [6.8, 6.9] and by the CERTS microgrid project in the USA [6.10, 6.11]. The ISET/SMA work is described in detail in the following sections.

The CERTS microgrid concept was developed to facilitate the integration of small (<100 kW) distributed generation sources (microsources) into grid connected and stand-alone (mini-grid) systems. In the CERTS microgrids, each microsource is required to be a complete energy supply, without requiring the addition of other power supply hardware, so that it can be placed anywhere in the system in a plug-and-play approach. They consist of a prime mover, typically microturbines, PV panels, or fuel cells, a short-term energy storage unit and the power electronics and controls required for the microsource to perform properly. The choice and ratings of the energy storage units, usually placed in the internal dc bus of the microsource, depend significantly on the characteristics of the prime mover. While the maximum output power of a PV panel varies with the solar irradiance, a microturbine can increase their output power from idle to full in hundreds of milliseconds, but fuel cells will generally require several tens of seconds to make the same transition. Each microsource presents a controller with a peer-to-peer operation model based on droop control and locally measured quantities that ensures that there are no critical components, such as master unit or communication system, for the operation of the microgrid.

6.3. Implementation of droop control in single-phase inverters

The schematic diagram of one implementation of droop control for single-phase system is shown in Figure 6.4. This approach called *selfsync*™ was implemented in the battery inverter *SunnyIsland*™ from SMA.

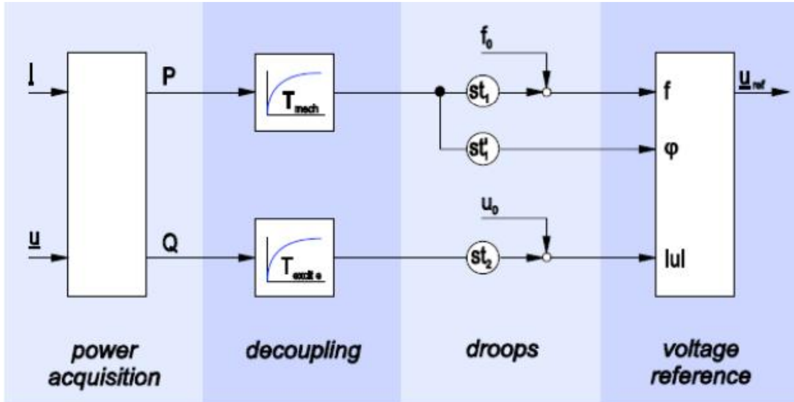


Figure 6.4 – Control approach *selfsync*™ by ISET e.V., Kassel, Germany [6.13].

The first block in the left computes the active and reactive powers, what is not straightforward in single-phase systems since the instantaneous power presents a pulsating component at twice the grid frequency. In such a case, one can use a formulation based on space vector that yields

$$P = 0.5\left(u_\alpha i_\alpha + u_\beta i_\beta\right) \text{ and } P = 0.5\left(u_\beta i_\alpha - u_\alpha i_\beta\right) \qquad (6.3)$$

Where the *α* components are the time-domain waveforms obtained from the actual system and the *β* components, are orthogonal to the first, are obtained using a special filter shown in Figure 6.5 [6.12] tuned at the rated grid frequency . An example of the single-phase *P/Q* computation is shown in Fig. 6.5.

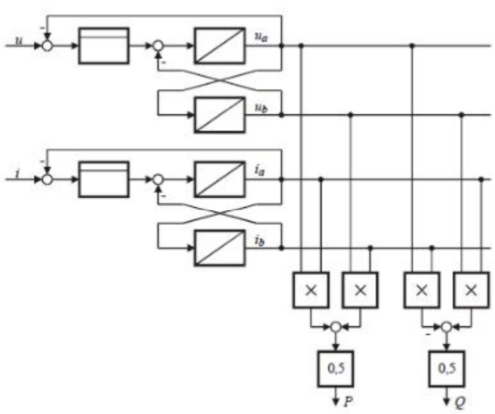


Figure 6.5 – P/Q computation block

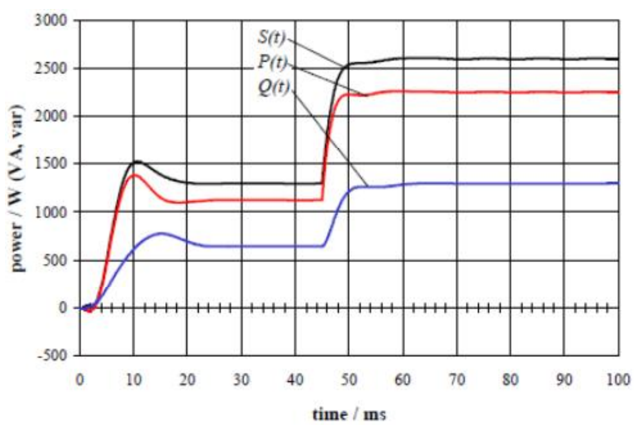


Figure 6.6 – Example of P/Q computation.

One can also see from Figure 6.4 that the reference voltage waveform for the inverter is obtained from the droop equations (6.2). The use of the measured active power to adjust the phase angle of the reference voltage of the inverter helps improve the transient response of the controller [6.13].

6.4. Laboratory verifications

In order to demonstrate the different functions that can be realized using droop and frequency control in a multi-master inverter dominated mini-grid, a specific test system has been set up in the Design Centre for Modular Systems Technology (“DeMoTec”) of the Institut für Solare Energieversorgungstechnik (ISET). In this system, the grid forming task is distributed among two distant inverters which are not linked by any fast communication link. For primary control purposes, the sharing of power between the grid-forming inverters is made possible using the *selfsync*™ algorithm. Concerning the secondary control, a communication environment based on internet and XML-RPC has been set up in order to allow the mini-grid supervisory controller to send control set points to the local generator controllers (Remote Terminal Units - RTUs) of the different power units (Figure 6.7).

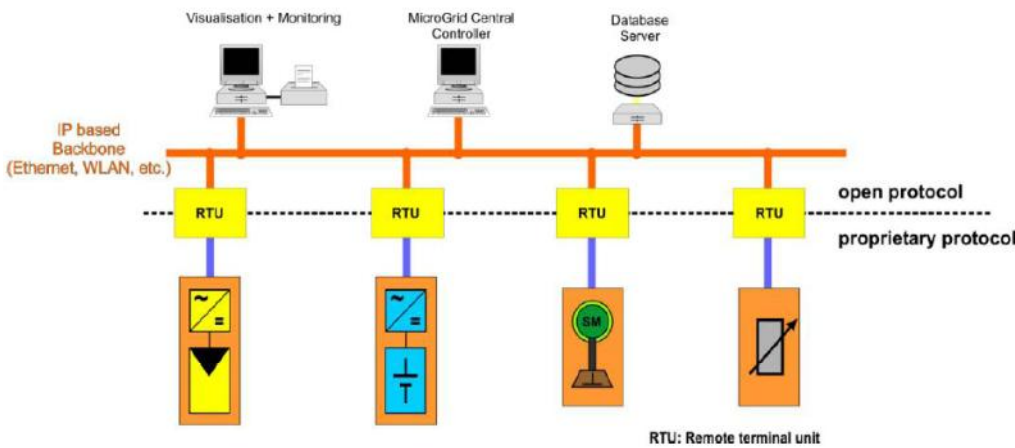


Figure 6.7 – Communications infrastructure in the DeMoTec laboratory

Several critical situations have been studied, which included the transition from interconnected to island operation after a fault on the main grid and the transition from island to interconnected operation (re-connection to mains after fault clearance, mini-grid black start).

6.4.1. Mini-grid test configuration

The three-phase mini-grid under test includes the following components:

- 3 grid forming units (2 battery units and 1 diesel genset).
- 2 renewable energy sources (RESs): PV (inverter) and wind (asynchronous generator).
- Several loads with different priority levels.

- Several automatic switches for sectionalizing the mini-grid into up to 3 island grids, in order to increase the reliability.
- Supervisory control for a fully automatic operation of the mini-grid (disconnection, re-connection, black-start, optimal dispatch).
- Connection to a medium voltage grid via a 100 kVA transformer.
- A 230 mΩ resistance to emulate about 400 meters of a weak low voltage line (NAYY 4*50 SE) between the main mini-grid bus and battery Inverter 1.

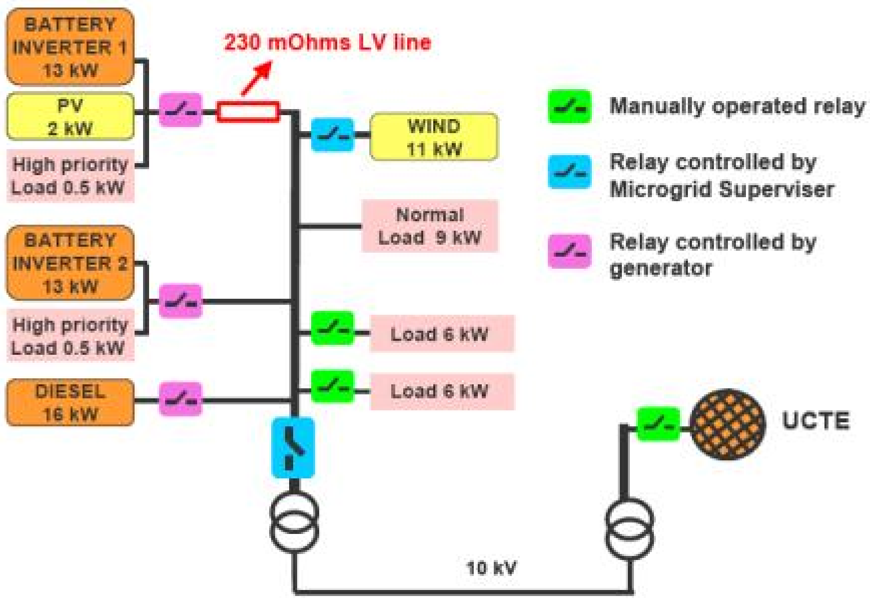


Figure 6.8 – Layout of the mini-grid installed at DeMoTec

6.4.2. Testing the island mode

The island mode of operation has been validated on the DeMoTec mini-grid. The test has demonstrated that two battery inverters with frequency-active power (f-P) droops can share their active power in island mode even if the distance from the main load to each battery inverter is very different. Recall that while the battery inverter 2 and main load are directly connected to the mini-grid bus, there is a 400 m emulated low voltage (LV) line between battery inverter 1 and the mini-grid bus.

In this test, the mini-grid operates initially connected to a main grid. The main grid supplies active power to the mini-grid while the batteries absorb some active power (P_inv1 and P_Inv2 > 0). Figure 6.9 shows that the amount of power absorbed by the inverters is relatively constant while the power supplied by the main grid varies, to balance the variation in the load and power produced by the RESs. The main grid also regulates the system frequency as seen in Figure 6.10.

At t = 2083 s when the grid breaker opens, the battery inverters start to form the grid, balancing the grid and supplying active power to the mini-grid. The power supplied by the inverters is about the same and vary according to the net power demanded by the mini-grid. One can clearly see the correlation between variations of the output power of the battery inverters and the mini-grid frequency (f_MG). The mini-grid frequency increases as the power required from the grid-forming inverters to balance the power produced by the RESs and consumed by the load, decreases. It is evident from these results that the frequency is not regulated and that it reflects the availability of power from the non grid forming units to meet the load demand.

At t = 2400 s, the supervisory controller starts the diesel genset and sets its output power to keep the average power of the battery inverters close to zero, thus increasing the mini-grid frequency. Later on, 6 kW (2 kW per phase) of load is added to the system. Since the genset is controlled with constant power, the battery inverters have to increase their output, what they do, sharing the increase in load demand. After a while, the supervisory controller adjusts the output power of the genset to bring the output power of the battery inverters back to around zero. At t = 2500 s, the 6 kW load is disconnected, leading the battery inverters to absorb active power until the supervisory controller re-adjusts the output power of the genset to bring the output power of the battery inverters back to around zero.

Another interesting strategy that can be used is to turn on the genset only when the SoC of the battery inverter(s) is too low, or if the output power of the battery inverter(s) is too high, close to the rated capacity. Besides, one can regulate the mini-grid frequency by changing the droop set points of the battery inverters.

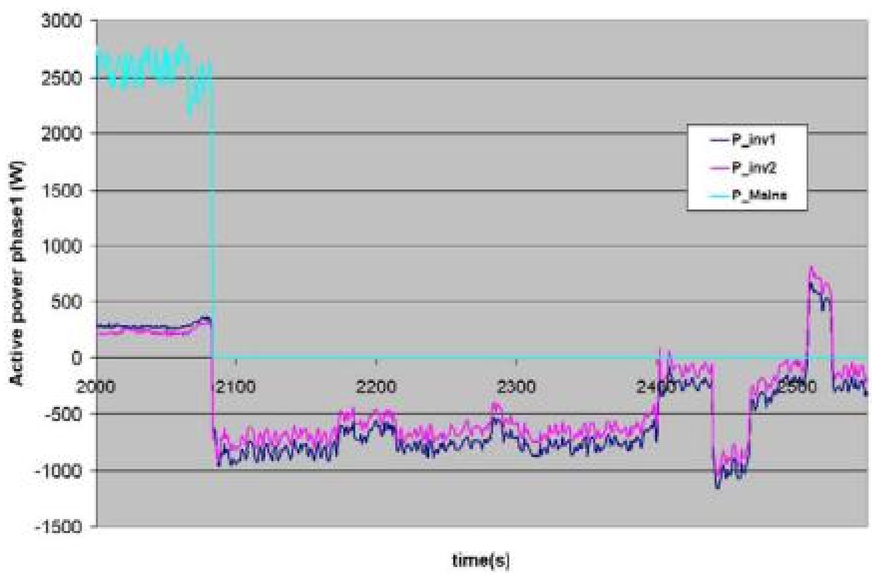


Figure 6.9 – Active power of the battery inverters and main grid during the test.

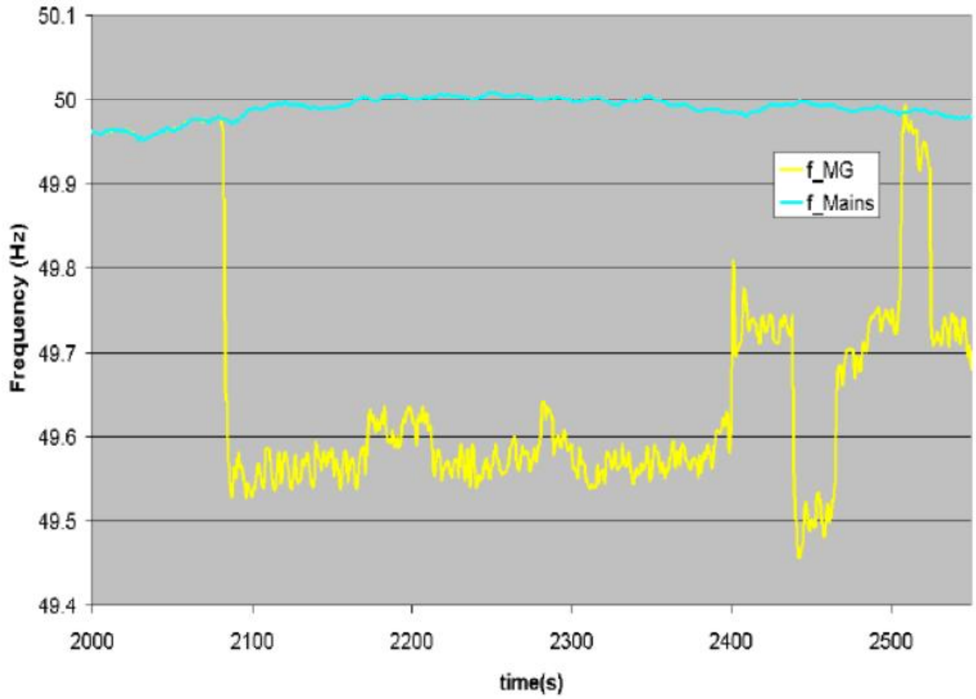


Figure 6.10 – Frequencies of the main grid (f_Mains) and of the mini-grid (f_MG) during the test.

6.4.3. Black start and grid synchronization

Another important aspect to be validated is the transition from islanded system to grid-connected operation. In this test, it is assumed that the mini-grid is disconnected from the main grid and is split in three island systems. Each battery inverter is powering its own grid and the mini-grid bus is de-energized. The first action of the mini-grid supervisory controller is to start the back-up diesel genset, which restores the voltage on the mini-grid bus (light blue line in Figure 6.11). The two battery inverters then automatically synchronize to the mini-grid bus. In order to do this reconnection smoothly, they reduce their frequency, as seen in Figure 6.11. The automatic switches are closed when the phase difference between the voltages in the two sides of the automatic switches is within a small acceptable range. Battery inverter 1 is the first to be connected to the mini-grid bus, and then it is followed by battery inverter 2. For some time, the batteries are charged by the diesel unit as shown in Figure 6.12. After restoration of the main grid, the mini-grid supervisory controller activates the synchronizer of the mini-grid switch and after a few seconds, when the phase difference between the mini-grid and main grid voltages are acceptable, the whole mini-grid is reconnected to the main grid.

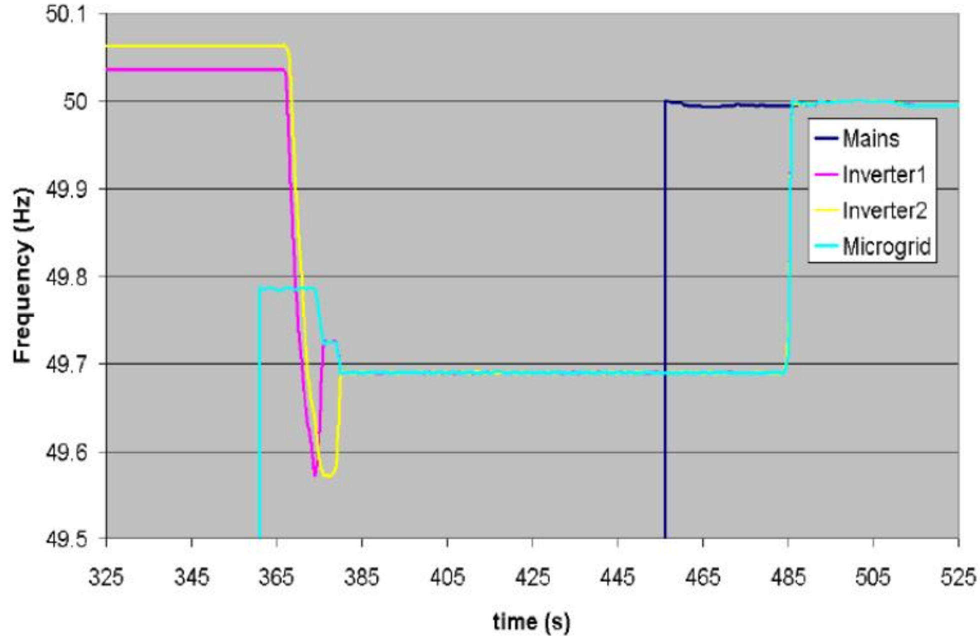


Figure 6.11 – Frequencies of the battery inverters, mini-grid and main grid during the test.

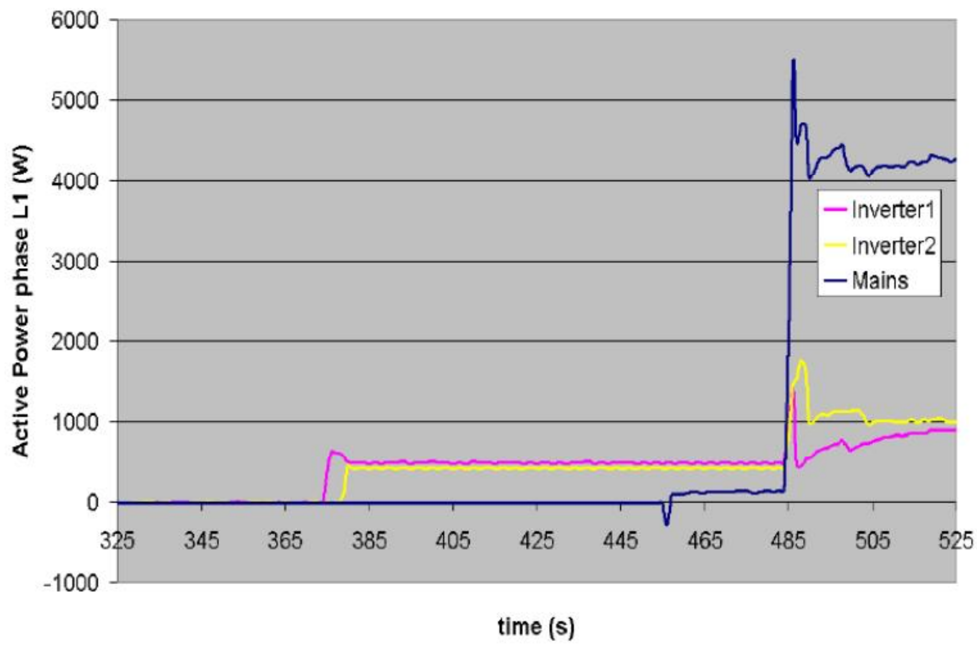


Figure 6.12 – Powers of the battery inverters (absorbed) and main grid (supplied) during the test.

6.5. Pilot mini-grid in Kythnos

The first mini-grid in which variable-frequency inverters supply the loads of several households has been installed on the Greek island of Kythnos, in 2001. 12 houses in a remote valley have been connected to an overhead single-phase 230 V/50 Hz grid. In addition to the power grid, telephone lines have been installed. These are currently being used to obtain readings from the meters of the houses and the PV installations. The system is being monitored, and can be parameterized remotely via a GSM connection (see Figure 6.13) [6.14].

Five PV generators, totalling 11 kW, feed in AC current at different locations. Permanent supply of power and grid stability are guaranteed by a combination of three parallel battery inverters (SMA Sunny Island 4500) along with a 50 kWh lead–acid battery bank, shown in Figure 6.14 and 6.15. The battery inverters employ the f-P and V-Q droop control schemes. The mini-grid frequency varies not only as a function of the net load, but it is also influenced by the state of charge of the battery. As a back-up unit, a small diesel genset has been installed, which is able to feed in up to 5 kW of electrical power on a single phase (see Figure 6.15). The 12 houses are connected to the overhead feeder via power meters and have their current limited by a 6 A fuse [6.14]. Load controllers developed by E-Connect (UK) are able to disconnect the load if the grid frequency falls below 49.14 Hz and reconnect them, in a random order to avoid large load increases, if the frequency has been continuously above 50 Hz for more than two minutes. The PV inverters used in this mini-grid are the SMA Sunny Boy 1100 and Sunny Boy 2500. These PV inverters are able to reduce their output in response to high grid frequency values. The parameters for the PV power intentional de-rating are described in the PV inverter special function “Frequency shift power control” (Figure 6.16).

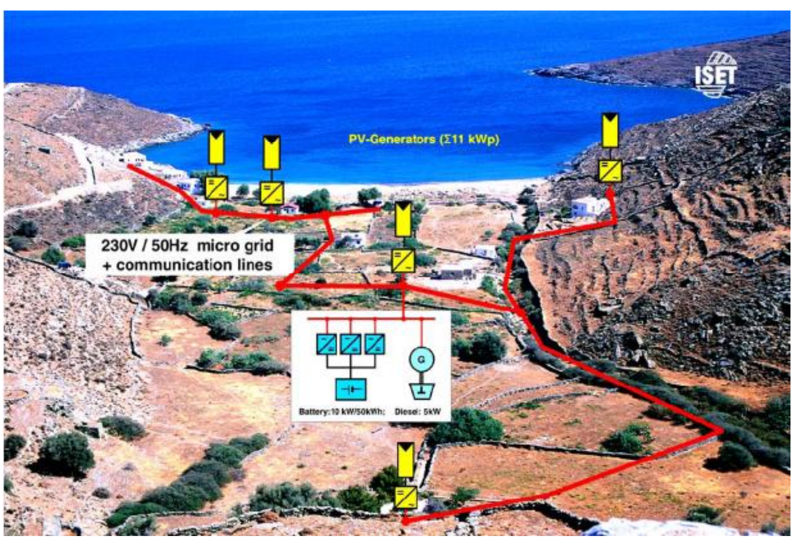


Figure 6.13 – Gaidouromandra photovoltaic mini-grid on the island of Kythnos.

Figure 6.14 – Three battery inverters in parallel forming a single-phase grid.

Figure 6.15 – Battery room (left) and diesel genset (right).

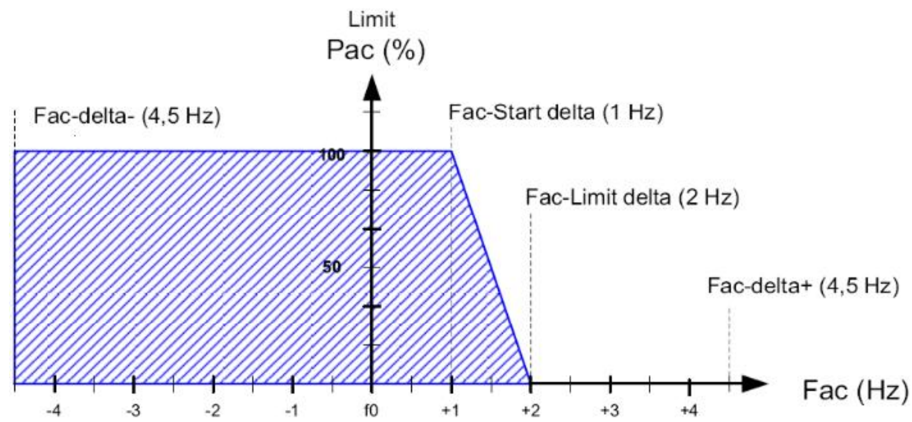


Figure 6.16 – Frequency shift power control for the PV inverters. (Source: SMA AG)

Variation of grid frequency is applied for organizing both primary control of the grid and energy management with distributed sources and loads. The battery inverters are synchronized, and diesel genset applies frequency and voltage droops. This concept allows the provision of high peak power, for the starting of motors and enough short-circuit currents to release circuit breakers. Peak power is shared between all operating battery inverters and the genset, without additional communication requirements. To communicate the information coming from energy management, the set value of the grid frequency varies. The frequency window ranges from 48 Hz to 52 Hz to allow for the operation of usual consumers. A simplified graphical presentation of this dependency is shown in Figure 6.17. It can be seen that at times when the battery needs to be charged, the grid frequency is lowered. If necessary, the diesel genset will be started and, if the frequency drops still further, loads will be disconnected. If the battery is full or needs power limitation according to the implemented charge control, the distributed PV inverters that feed PV power into the AC mini-grid identify a higher grid frequency and continuously limit their power output.

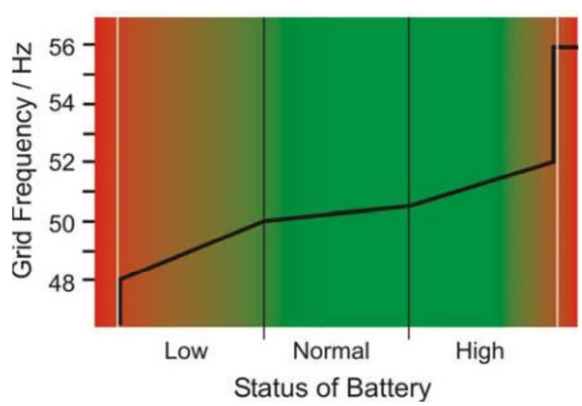


Figure 6.17 – The battery management strategy varies the grid frequency according to the status of the battery.

This variable frequency control used in the mini-grid can be illustrated with the results obtained in a typical clear summer day (Sunday 18.07.2004) when the total horizontal solar radiation was 7.5 kWh/m^2. Figure 6.18 and Figure 6.19 show the evolution of the battery cell voltage, the total PV power (AC) and the grid frequency during this day. At night, the back-up genset is not used, the battery discharges and the cell voltage decreases. From dawn until noon, the PV inverters operate at the maximum power point (100% of MPPT operation), producing a total maximum of 6.8 kW. As the PV and net power in the mini-grid increases, the frequency increases. The batteries get charged with this net power increasing the battery cell voltage at different rates. When the latter reaches the first limit of 2.37 V, the battery inverter increases the grid frequency by 0.5 Hz. A grid frequency over 51 Hz is interpreted by the PV inverters as a signal for limiting their power proportionally to the frequency deviation, what can be clearly seen in Figure 6.19. As long as there is an excess of PV power, the battery inverter will use this control method to charge optimally the battery. After a few boost charges, the battery voltage is set to a floating level of 2.22 volts.

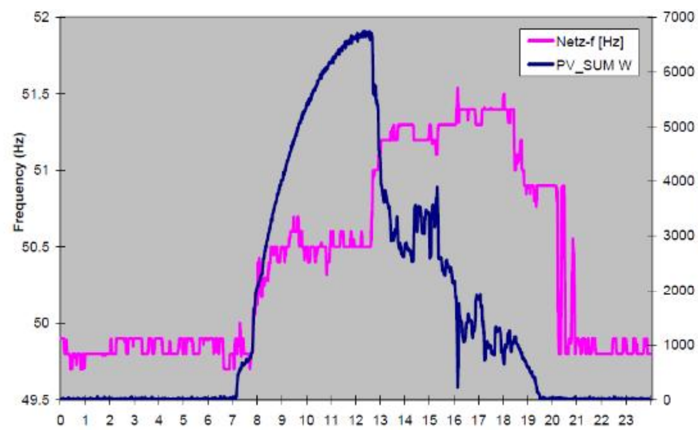


Figure 6.18 – The battery inverter controls the PV power by changing the grid frequency.

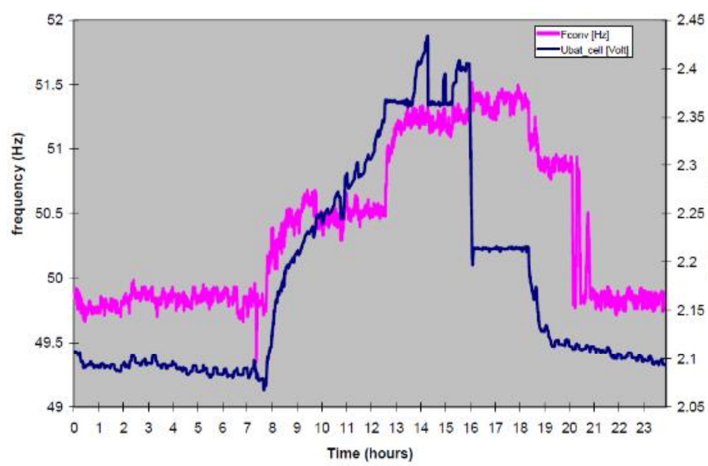


Figure 6.19 – The battery inverter controls the battery charging voltage by changing the grid frequency.

Figure 6.20 shows the daily energy production (PV, genset and battery) and consumption (battery and load) in August 2008. The battery presents negative energy production, around 5 – 10 kWh a day, because of the losses. The amount of energy consumed by the load in the first two weeks of august 2008 was relatively high (over 30 kWh per day). Then, it decreased gradually in the last two weeks to around 10 – 20 kWh a day. The energy generation in the system was mainly from the PV generators and battery while the diesel genset was used only on 13.08.2008 for 3 hours. The highest load in this month was on 12.08.2008 with 37 kWh. Unfortunately, the minimum load of the month could not be calculated due to data missing on 13.08.2008 and 14.08.2008. This is the reason why on these 2 days the energy to the load and energy produced from PV seemed to be the lowest of the month.

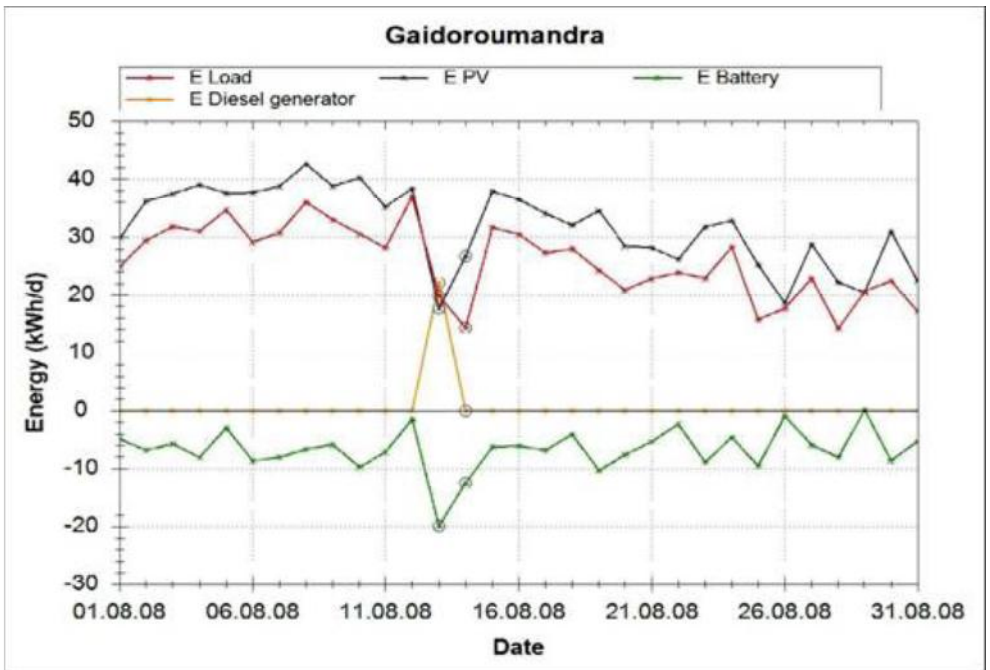


Figure 6.20 – Daily energy production in August 2008.

7. Conclusion and Recommendations

The combination of PV and other generation sources in a hybrid energy system requires coordinated control mechanisms. These can be divided into two levels: One is maintaining grid stability (primary control) and the other is optimising the contribution of all generation sources (secondary/supervisory control). This report has reviewed current strategies for primary control to maintain grid stability, where the grid forming or master unit(s) balance power generation and consumption, thus keeping the voltage and frequency within acceptable ranges.

The main challenges for primary control arise from the fluctuating and intermittent characteristics of PV and the highly variable load profiles typical of mini-grids in remote communities. The choice of control strategy depends significantly on the hybrid system components and the mini-grid architecture. Energy storage units and secondary controllable loads that can be dispatched to assist with power balancing can have a very positive impact on the grid stability. Centralized mini-grid architectures, where generators, energy storage systems and controllable loads are co-located, can use fast communication data networks to manage the contribution of each unit to the power balance. Conversely, in decentralized systems with system components dispersed over relatively large areas, the cost of fast communication networks can be prohibitive. In this case, primary control strategies based on droop methods that rely on changes in grid frequency and voltage to communicate among components are a better option.

The multi-master rotating machine dominated hybrid mini-grid is a common architecture, usually created by the integration of PV generation into an existing diesel-based power system. The diesel power plant usually consists of multiple diesel gensets than can be dispatched according to the expected demand to meet the load demand in an economical way. The diesel gensets are the system masters and the genset controllers implement the control strategy. Typically, they use active power vs. frequency and reactive power vs. voltage droop control to share the short-term load variations proportionally to genset ratings, and keep grid voltage and frequency within prescribed ranges.

In these systems the control challenge increases as the PV penetration increases. At low penetration levels, the PV generators appear as small negative loads and do not have a significant effect on system stability or the dispatch and control strategies for the diesel gensets. To achieve higher PV penetration, changes to the diesel plant are usually required. As a first step, options to resize the gensets and adjust the dispatch strategy to account for the influence of the PV source should be analysed. It may be possible to reduce the number and size of gensets in service at certain times of the day. However, due to the fluctuating nature of PV power, it may be necessary to keep some diesel-based spinning reserve to make sure the load can be met at all times. In addition, conventional diesel gensets are usually constrained to operate at a minimum load no less than 30% - 50% of their rated power. This generally reduces the diesel fuel displacement expected with PV integration.

With fewer gensets in service, the kinetic energy stored in the rotating machines is reduced, which leads to larger and faster frequency variations following a sudden power mismatch due to load or PV power variations. This problem can be mitigated by employing a master genset with fast governor response to ensure good load following capability. Recently, gensets that can run efficiently under low load conditions for long periods with minimum carbon build up, and with good load following capability, have been introduced. With further development and broader distribution of this “low load diesel” technology in world markets, the penetration levels of PV in diesel mini-grids can be improved.

Other possible solutions to the problems of minimum diesel loading and spinning reserve are to use short-term energy storage, or controllable secondary loads, such as water heaters, water pumps and ice making plants. These loads can be turned on or off without major issues for the consumers and so can be dispatched to balance power generation and consumption in the grid. In the absence of dedicated fast communication for dispatch, these loads can be equipped to automatically react, turning on-off or even changing the amount of power they consume as a function of the grid frequency. At present, short term energy storage systems for mini-grid stabilization, or suitable controllers for dispatchable loads, are generally not available as standard, off-the-shelf products. Broader commercialization and distribution of these systems would simplify the implementation of high penetration PV-diesel mini-grids.

The single switching master (SSM) mini-grid architecture is typical of centralized mini-grid systems designed for high PV penetration. The grid forming function is switched between different ac sources, usually an inverter/charger and a diesel genset. The architecture is usually a mixed ac/dc bus configuration, with some energy sources, usually PV and a battery, connected to the dc bus and other sources, such as a diesel genset, connected to the ac bus. Control functions are normally integrated into the inverter/charger, which manages the transition between grid forming masters.

The technology in inverter/chargers for SSM applications has advanced over the past decade to incorporate high speed data networks that interconnect system elements and allow inverters to operate in parallel to achieve higher power levels. Control techniques have advanced to allow smooth transitions among multiple operating modes that support both central-grid-connected and autonomous operation of the mini-grid. However, there is a lack of standard, off-the-shelf, high power inverter/chargers to implement larger (>300 kW) mini-grid systems. There is also a need for standardization of data communication protocols to allow interoperation of components from different manufacturers. Finally, standardized techniques are needed to allow control of decentralized system elements, such as ac coupled PV generators, which may be added to the system.

The multi-master inverter-dominated architecture is a decentralized system in which several generating sources distributed within the mini-grid cooperate to form the grid. Usually, the generating sources are interfaced to the grid via a power electronic converter. Systems usually contain at least one energy storage unit and, due to the distance between generating sources, no fast communication data networks are used for primary control. The sharing of the power balancing effort is done based on locally measured quantities using active power vs. frequency and reactive power vs. voltage droop control. Grid frequency signalling can also be used for energy management functions, shutting down dispatchable loads if there is a shortage of energy and curtailing generator production if there is a surplus of energy.

The multi-master approach is the subject of considerable research since it holds the promise of mini-grids that are easily extended, allow integration of many types of energy sources, and are resistant to single point failures. However, there is, at present, limited field experience with these systems, and a limited selection of commercial, off-the-shelf generating sources suitable for integration into these systems.

The primary control strategies reviewed above are capable of regulating mini-grid voltage and frequency to meet current user needs. The choice of strategy employed will depend on the architecture of the mini-grid (centralized or decentralized), the generation mix (diesel dominated or high penetration of renewable sources), and the economics of incorporating auxiliary stabilization mechanisms, such as energy storage systems or dispatchable loads.

These control strategies are typically easiest to implement in lower power, compact mini-grids with centralized generation. As power levels rise, and the grid becomes geographically larger and more dispersed, the challenges increase for the following reasons:

- reduced availability of standard, off the shelf components and systems
- greater challenges with communication among system elements
- greater challenges maintaining voltage regulation throughout the mini-grid

There is a need for more research and commercial development of control systems and components for large, distributed mini-grids.

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