Control of a Microgrid in Islanded and Grid-Connected Modes

Authored by: Bradley Baxter

Academic Supervisor: Dr. Gregory Crebbin
Declaration of Originality of Research

I certify that the research described in this report has not already been submitted for any other degree.

I certify that to the best of my knowledge, all sources used and any help received in the preparation of this dissertation have been acknowledged.

Signed: ________________________________
Abstract

Microgrids are small electrical power distribution networks that can be connected to a main utility power grid, or can operate in disconnected or islanded mode. They offer a potential solution to the world’s reliance on fossil fuel sourced electrical energy generation. They can improve energy security and reliability for customers connected to the microgrid. Microgrids usually incorporate distributed energy sources, including renewable sources. Many of the renewable sources are interfaced with power electronics which must be able to operate in conjunction with traditional forms of generation such as synchronous generators. Control of power electronic interfaced energy sources can pose challenges for coordinated control of the microgrid as a whole. The control systems main function is to ensure supply to critical loads is maintained, particularly when in islanded mode. This study investigated several strategies for control and management of a microgrid, including taking over voltage and frequency control in islanded mode.

The distributed nature of energy sources that usually makes up a microgrid favours a control system with minimal communication infrastructure and that for the most part operates autonomously in both a grid connected and islanded mode. The current study investigated the general concepts for control of both centralised and decentralised configurations of a microgrid and the problems associated with each. In-depth investigations and simulations were carried out on two decentralised control strategies, a pure droop control method and an angle-frequency droop control method.

The pure droop controller had the ability to autonomously perform equal power sharing and maintain stability in islanded mode of operation, but resulted in permanent steady state frequency offset. The angle-frequency droop also operated autonomously but with improved power sharing and frequency regulation.

The investigation used the MATLAB® environment to perform calculations and carry out simulations of the proposed systems over a range of grid connected and islanded mode scenarios. Performance measures such as power sharing accuracy, disturbance transient behaviour and islanded-grid connection transition were used to assess the suitability of each control scheme.

The P-f droop control has been widely reported on and has been proven to work over a range of conditions. The angle-frequency droop is a new proposal to improve the performance of a microgrid in islanded mode. Results demonstrated that both methods of control performed well in islanded mode. The angle-frequency droop had a slight increase in power sharing accuracy and superior frequency regulation. However it would appear that several design flaws may need addressing before the angle-frequency droop can be implemented as a truly decentralised topology.
Acknowledgements

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<th>Acronym</th>
<th>Definition</th>
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<tbody>
<tr>
<td>AC</td>
<td>Alternating current</td>
</tr>
<tr>
<td>DC</td>
<td>Direct current</td>
</tr>
<tr>
<td>DG</td>
<td>Distributed generator</td>
</tr>
<tr>
<td>HV</td>
<td>High voltage (greater than 35kV)</td>
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<tr>
<td>IEC</td>
<td>International Electrotechnical Commission</td>
</tr>
<tr>
<td>IGBT</td>
<td>Insulated gate bipolar transistors</td>
</tr>
<tr>
<td>LV</td>
<td>Low voltage (less than 1kV)</td>
</tr>
<tr>
<td>MG</td>
<td>Microgrid</td>
</tr>
<tr>
<td>MGCC</td>
<td>Microgrid central controller</td>
</tr>
<tr>
<td>MGCS</td>
<td>Microgrid control switch</td>
</tr>
<tr>
<td>MOSFETS</td>
<td>Metal oxide semiconductor field effect transistors</td>
</tr>
<tr>
<td>MPP</td>
<td>Maximum power point</td>
</tr>
<tr>
<td>MS</td>
<td>Micro source</td>
</tr>
<tr>
<td>MV</td>
<td>Medium voltage (1kV to 35kV)</td>
</tr>
<tr>
<td>PCC</td>
<td>Point of common connection</td>
</tr>
<tr>
<td>P-f</td>
<td>Power-frequency</td>
</tr>
<tr>
<td>PID</td>
<td>Proportional-Integral-Derivative</td>
</tr>
<tr>
<td>PLL</td>
<td>Phase lock loop</td>
</tr>
<tr>
<td>PQ</td>
<td>Active and reactive power</td>
</tr>
<tr>
<td>PV</td>
<td>Photovoltaic</td>
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<td>SG</td>
<td>Synchronous generator</td>
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1 Introduction

The global community is facing the economic, environmental, and political consequences of a high dependence on fossil fuel energy. In response, most countries are expecting to increase the share of electrical energy produced from renewable sources. This includes Australia, with a 20% target by 2020 [1], [2]. Most renewable forms of energy are distributed rather than centralised, and in many cases are located closer to customer loads [1]. Trends have already emerged whereby more energy is produced locally. In large part this is driven by the increased uptake of small to medium sized renewable energy generation sources such as wind, solar, micro hydro, and biogas [3]. When spread across a network these distributed energy sources are known as distributed generators (DGs). When combined with other distributed energy resources the integration of renewable energy resources has the potential to offer benefits to both energy consumers and the power utilities [1].

Presently the low penetration of DGs has had minimal impact on the overall operation of the electrical power distribution grid (“the grid”). However it is expected that the uptake of DGs connected at the distribution level will continue to increase [3]. With many DGs powered by renewables, the energy produced is intermittent and when the renewable energy source is high, power will flow from the distribution level to the transmission level. The grid has not been designed or constructed for this mode of operation [2] and so new methods are needed for controlling these generators so that grid stability and power quality is not adversely affected [4]. It is not technically possible to extend communications to the potentially millions of DGs in a network [2]. If DGs are to benefit consumers and utilities, there must be some means of coordinated control. One promising solution is the concept of a Microgrid (MG).

A MG is defined by the Microgrid Exchange group as “a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or islanded mode” [5]. Whilst technically a MG can be entirely off grid [6], most interest is for systems that are able to operate in either grid connected or off grid ‘islanded’ modes [7]. MGs can range in size from a few kW to several MW, and are transforming distribution networks from passive to active networks with bidirectional power flows [6].
At a distribution level, a commercial MG of typically less than 10MW capacity would appear as a single controllable unit to the network operator [8]. The level of control that the utility may have will vary depending on the MG configuration; it may be as simple as disconnecting or reconnecting the microgrid or a higher level of control that is able to control the flow of active or reactive power to enable active participation in grid voltage and frequency support [6]. It would also help the utility or network operator by reducing transmission losses [8], [7], [9]. A MG could delay or eliminate the need for costly bulk power transmission upgrades and installations [10], reduce peak loads, and lower emissions [3].

A MG also offers potential advantages to the local consumer by improving reliability [11]. This can help consumers save money from downtime during power outages and by lowering energy costs [5]. A MG even has the potential to generate revenue and create jobs. It also gives consumers greater control over how their energy is generated and how much power they are allowed to consume, thereby giving them a greater degree of energy independence.

Although the potential advantages are clear, there are still many challenges to face. Many of the DGs in a MG would consist of intermittent renewable energy sources [11] which, in many cases, would require energy storage devices which are currently expensive [6]. Many DGs are also interfaced with power electronic converters to produce the frequencies and voltages required by the grid. Power electronic converter systems do not have natural inertia, like traditional synchronous generators (SGs) and thus do not as easily ride through large disturbances such as sudden load changes and faults [11]. The fault current of power electronic converters are also much lower than SGs so there are difficulties in fault detection and isolation [8]. The lack of inertia and the intermittency of renewables also introduce many technical challenges for controlling large numbers of DGs so that stability is maintained. There are also challenges in optimising DG sizing and placement to assist with maintaining stable and efficient microgrid operation [9], [3]. Currently there is a lack of technical experience in managing such issues [3].

Of most importance for a MG is the ability to maintain the voltage and frequency within acceptable limits when in islanded mode. Many control strategies have been proposed to achieve this and to a certain extent the control system that is implemented will depend on the MG system requirements. A MG can be operated in two ways, centralised or decentralised.
A centralised system can have better frequency regulation, although this approach requires a communications system which is not only more complex to install but is also expensive and is not easily expanded. A decentralised approach is in many ways more desirable when generators are distributed. A decentralised system does not require a complex and expensive communications system and is much more easily expanded. One drawback is that frequency regulation is not as good as the centralised approach [12] and the extent of load flow control is limited, which may lessen the appeal to a utility operator.

The ideal control system for a MG would be one that does not have a single point of failure, is easily expanded, has good frequency and voltage regulation, transitions seamlessly between islanded and grid connected modes, maintains stable operation under a range of conditions, and has accurate power sharing between DGs. This thesis will focus on the control systems for a MG with multiple DGs that enable grid connected and islanded modes of operation. Some of the more commonly proposed strategies will be investigated. This investigation will culminate in the simulation and analysis of an angle-frequency droop control system that is a compromise between many of the desired characteristics of a MG control system.
2 Microgrid overview

A MG has two distinct modes of operation: a grid-connected mode, and an off-grid islanded or emergency mode [7]. When grid-connected, the MG imports power whenever there is a shortfall of energy generation and exports power whenever excess energy is generated. When grid connected, there is little concern regarding energy shortfalls or surpluses [10].

When the MG becomes disconnected from the main grid, the DGs must be capable of supplying the load demand and maintain acceptable voltage and frequency limits. Traditionally, DGs connected to non-dispatchable renewable energy sources will deliver maximum power to the grid, usually at close to unity power factor [2]. Dispatchable generators such as synchronous generators (SGs) and energy storage units, which were idle in grid-connected mode, will be brought online to meet the energy shortfall. As the penetration of renewable forms of energy generation increase, a momentary or prolonged oversupply of power is possible. The control of active and reactive power for both non-dispatchable and dispatchable energy sources becomes critical in maintaining voltage and frequency stability in islanded mode [1].

In situations where the DGs cannot meet demand, load shedding will be required. In circumstances where this is possible, MG loads are classified as critical or non-critical. Critical loads require reliable energy sources with good power quality, while the non-critical loads can be shed when required [10]. A hierarchical approach may be implemented so that loads are classified from least to most critical and shed in order of priority as required [13].

If a system failure or fault causes a black out, then the system must be able to restore itself, in what is known as a black start.

For MGs to reach their full potential they must play a supportive role for the power quality of the utility. Systems that benefit the utility the most will be able to adjust active and reactive power flow. When this level of control is implemented, a MG can be intentionally islanded or can be called upon to increase power by the utility when demand is high, which will help support the utility’s frequency, reduce congestion and reduces transmission losses. The MG could also be called upon to produce more reactive power in order to provide voltage support for the utility.
The role of a MG in grid connected and islanded modes can be summarised in the following dot points [6]:

- **Grid connected mode**
  - Frequency control support
  - Voltage control support
  - Congestion management
  - Reduction of grid losses
  - Improvement of power quality (voltage dips, flicker, compensation of harmonics)

- **Islanded mode**
  - Black start
  - Frequency control
  - Voltage control

The DGs of a MG can be comprised of many energy sources. These can include combined heat and power plants (CHP), solar photovoltaic (PV) arrays, biodiesel and diesel generators, wind turbines, gas micro turbines, micro hydro turbines, geothermal plants, batteries, ultra-capacitors and tidal or wave plants [1]. The DGs are connected to a local distribution network along with MG loads. The MG is connected to the utility grid via a MG control switch (MGCS) at the point of common connection (PCC). A possible configuration of a MG is shown in Figure 1.

![Figure 1: Possible MG configuration](image-url)
2.1 Inverters

Many of the key technologies that will make MGs possible are interfaced with converters/inverters [6]. This is shown in Figure 1. These inverters are power electronic devices that use semiconductor devices such as insulated gate bipolar transistors (IGBTs) and metal oxide semiconductor field effect transistors (MOSFETs) to convert the voltages and currents produced by the energy source into the sinusoidal voltages and frequencies required for grid connection. Some of the energy sources, such as PV arrays, fuel cells and batteries, require only single stage conversion from direct current (DC) to alternating current (AC). Other energy sources, such as wind turbines and micro turbines, which may produce high frequency voltages, require a two stage conversion. In other words from AC to DC and then back to AC. Utility frequencies are typically 50Hz or 60Hz. The voltage will vary but will normally be at LV (less than 1kV) or MV (1kV to 35kV) levels.

Inverters can be categorised into two modes of operation, PQ or V-f (often referred to as voltage source inverters (VSIs)).

- **PQ inverter mode**: A PQ inverter controls the real and reactive power by adjusting the magnitude of the output real and reactive current. A PQ inverter essentially operates as a voltage controlled current source [13].

- **Voltage source inverter (VSI) mode**: A VSI reproduces the behaviour of a traditional SG. It controls the voltage and frequency at the output terminals, in effect operating as a voltage source [13], [7].

In both modes, a pulse-width modulation (PWM) process is used whereby a series of pulses are generated by switching IGBTs or MOSFETs on and off. The pulses can be filtered to give a good approximation of a sine wave. This process has its challenges and can introduce harmonics into the system. This level of control is not the focus of this report.

The mode of inverter operation will depend on the chosen MG control strategy, and may change depending on whether the MG is operating in a grid connected or islanded mode.
2.2 Microgrid control

A control system is required to maintain stable operation at all times. At a minimum, the control system must enable disconnection and reconnection to the main grid, maintain voltage and frequency levels in islanded mode of operation, and must be able to facilitate a black start after a system failure [14]. A minimum requirement to achieve this level of coordination would be to have at least one DG within the MG that can control the voltage and frequency [15].

Selecting an appropriate control strategy for MG operation will depend on many factors. The main drivers for a MG installation are economic, technical, environmental or a combination of each [6]. These factors will influence the control strategy and will need to give consideration to issues such as load sensitivity [16], the number of DGs in the MG, power quality requirements, ownership of the MG and DGs, distances between DGs, the existing communication infrastructure [10], each DG’s energy source, and whether the MG is predominately an exporter or importer of energy [15].

The principle method used for maintaining stability in a MG is some form of droop control. Active power-frequency (P-f) and reactive power-voltage (Q-V) droop controls are the most common methods of control [1]. The P-f and Q-V droops are the basic principle that enables multiple synchronously rotating machines to control power sharing and maintain voltage and frequency stability [17]. The droops are expressed as linear relationships between active power and frequency, and between reactive power and voltage.
2.2.1 Droop control

The relationship between active power and frequency, and reactive power and voltage can be understood by investigating a two bus analogy of a synchronous generator connected to a transmission network. The power produced at the terminal of the generator for a two bus system can be expressed as:

\[ P = \frac{E}{R^2 + X^2} \left( XV \sin \delta + R(E - V \cos \delta) \right) \]  
\[ Q = \frac{E}{R^2 + X^2} \left( -RV \sin \delta + X(E - V \cos \delta) \right) \]

In the equations, \( \delta \) is the voltage angle which is often referred to as the power angle. The equations are easiest to derive when setting the generator terminal as the reference, meaning it has a voltage angle of zero. However, only the angle difference between the two busses is important. A positive value for \( \delta \), assumes the generator bus voltage leads the receiving end voltage.

Figure 2 depicts a generator delivering power to the grid in a high voltage (greater than 35kV) transmission network. High voltage (HV) networks have a low R/X ratio, meaning that R is much smaller than X, so line resistance can be ignored. From equation (1) and (2) the active and reactive power flow from the generator can be expressed as:

\[ P = \frac{VE \sin \delta}{X} \]  
\[ Q = \frac{E^2 - VECos \delta}{X} \]

![Figure 2: Generator connected to infinite bus (the grid)](image)
Assuming $\delta$ is small then $\cos \delta \approx 1$ and $\sin \delta \approx \delta$, so equations (3) and (4) simplify to [18]:

$$
\delta \approx \frac{PX}{VE}
$$

(5)

$$
E - V \approx \frac{QX}{E}
$$

(6)

Therefore the reactive power $Q$, can be controlled by the difference in voltage between $E$ and $V$, and the active power $P$, by the voltage angle $\delta$. For this reason $\delta$ is often referred to as the power angle. The voltage angle $\delta$, is related to angular frequency $\omega$ (in radians per second) and therefore electrical frequency $f$ (in hertz) by equation (7).

$$
\delta = \int \Delta \omega \, dt = \frac{1}{2\pi} \int \Delta f \, dt
$$

(7)

When combined with the P-f droop (shown in Figure 3a), the relationship outlined above allows equal power sharing between SGs, in what is known as self-synchronising-torque. A change in load will cause a frequency variation at the terminal of each SG. Active power will flow from regions of higher frequency to regions of lower frequency. Frequency variations within the network will eventually drift to an average steady state value [6]. The new steady state frequency will be proportional to the change in power, as shown in Figure 3a.

![Figure 3: P-f and Q-V droops](image)

Figure 3: P-f and Q-V droops [4]
Figure 4 illustrates a simplified utility network with two generators of similar power ratings using equivalent droops. At steady state, each generator will deliver equal power and have the same voltage angle with respect to the load bus. In a scenario where the load at the common bus increases, initially some of the kinetic energy stored in the spinning rotor of the synchronous generator will be converted into electrical energy, causing the rotor speed to decrease. The rotor speed is related to the electrical frequency. The change in rotor speed is detected by the governor’s control system and in response the mechanical power to the SG is increased. If mechanical power was not increased the rotor speed and electrical frequency would continue to decrease and the system would become unstable. For an ideal (lossless) system, mechanical power is equal to electrical power. The governor is controlled by the P-f droop shown in Figure 3a, so that at steady state the network will operate at a reduced frequency. When the load decreases the process is reversed [19].

The change in voltage angle ($\delta$) is a result of the change in frequency. This is outlined in equation (7). Therefore the voltage angle of the SGs can be controlled by changing the frequency, which will in turn, result in a variation to the SGs active power flow, in proportion to the P-f droop curve [17]. That is why the traditional method uses frequency to control the active power flow [17], [20].

Q-V droops are used to regulate reactive power and voltage. A SG’s voltage is controlled by varying the excitation current of the rotor. Controlling the voltage with a Q-V droop helps to maintain voltage stability in a network and prevent large circulating current between generators [19]. Large utility networks tend to have high impedance between generators, so circulating currents are somewhat impeded. In a MG, the impedance between DGs is much lower. If some form of voltage control was not employed there would be a significant risk that current oscillations large enough to exceed the ratings of DGs would occur [3], [6]. The Q-V droop is a means of preventing this.

\[ E_1 \delta_1 = X_1 \quad V_1 = 0 \quad X_1 = X_2 = E_2 \delta_2 \]

Figure 4: Two bus HV network [17]
MGs will likely be dominated by power electronic interfaced energy sources such as inverters. Unlike SGs, inverters do not have a natural connection between frequency and active power. To achieve stable operation with multiple DGs, a coordinated control system must be implemented [21]. Controlling the inverters so that they mimic the characteristics of a SG with P-f and Q-V droop controls is one way to maintain voltage and frequency stability, as well as facilitating power sharing between DGs. For a PQ inverter, these droops are implemented as $P(f)$ and $Q(V)$ functions, whereas a VSI uses $f(P)$ and $V(Q)$ droops.

### 2.2.1.1 PQ Inverter with droop control

A SG would use the rotor speed as the frequency input for the P-f droop controller and the response could directly influence the system frequency. A PQ inverter does not set the frequency, but rather measures the grid frequency using a phase lock loop (PLL) and then operates at that measured frequency. The inverter will adjust its power accordingly, by comparing the measured frequency to a reference (nominal grid frequency) value. A graphical representation of this is shown in Figure 3a. Mathematically this is represented as:

$$P(f) = P_o - (f_{set} - f)k_f$$

(8)

Where $P_o$ is the power delivered by the inverter at setpoint frequency $f_{set}$. $k_f$ is the gradient of the droop, which determines how much the power $P$ will change in response to a change in frequency $f$.

When a Q-V droop is used, the PQ inverter measures the terminal voltage and compares this to the reference value. The reactive power is adjusted by altering the reactive component of the inverter current [13]. This reactive power adjustment is expressed by equation (9). A graphical representation of the Q-V droop is shown in Figure 3b.

$$Q(V) = Q_o - (V_{set} - V)k_v$$

(9)

Where $Q_o$ is the reactive power delivered/consumed by the inverter at setpoint voltage $V_{set}$. $k_v$ is the gradient of the droop, which determines how much the reactive power $Q$ will change in response to a change in voltage $V$.

Measuring the frequency accurately in a real system can be difficult. Active power is much easier to measure in comparison. A control system that uses active and reactive power measurement to control voltage and frequency is the VSI or V-f inverter [6].
2.2.1.2 VSI with droop control

A VSI with droop control uses the same relationships as shown in Figure 3, but this time the active and reactive VSI output power are measured. From the measured active power the VSI frequency is generated and from the measured reactive power the VSI voltage is produced. In this respect the VSI operates like a SG. The mathematical representation for the conventional VSI droop controls are given by equations (10) and (11) [18].

\[ f(P) = (P_o - P)K_p - f_{set} \]  \hspace{1cm} (10)

where \( K_p \) is the gradient of the droop, which determines how much the frequency will change in response to a change in power \( P \).

\[ V(Q) = (Q_o - Q)K_q - V_{set} \]  \hspace{1cm} (11)

where \( K_q \) is the gradient of the droop, which determines how much the voltage will change in response to a change in reactive power \( Q \).

2.2.1.3 Reverse droop control

The droop control is based on the assumption that the line resistance is much less than the reactance and therefore active power flow is predominately a function of the voltage angle. This is the case for HV lines, but it is not so for LV and MV networks. Table 1 shows typical line parameters for LV, MV, and HV lines [22].

<table>
<thead>
<tr>
<th>Type of line</th>
<th>( R ) (( \Omega /km ))</th>
<th>( X ) (( \Omega /km ))</th>
<th>( R/X )</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low voltage</td>
<td>0.642</td>
<td>0.083</td>
<td>7.7</td>
</tr>
<tr>
<td>Medium voltage</td>
<td>0.161</td>
<td>0.190</td>
<td>0.85</td>
</tr>
<tr>
<td>High voltage</td>
<td>0.06</td>
<td>0.191</td>
<td>0.31</td>
</tr>
</tbody>
</table>

For a LV network the relationships between power, voltage, frequency and reactive power is reversed. This can be seen by analysing a generator connected to an infinite bus through a predominately resistive LV line as shown in Figure 5.
From equations (1) and (2) with reactance ignored and assuming $\delta$ is small so that $\sin\delta \approx \delta$ and $\cos\delta \approx 1$, the power produced by the generator is expressed as:

$$P = \frac{E(E - V)}{R}$$  \hspace{1cm} (12)

and

$$Q = -\frac{VE}{R} \delta$$ \hspace{1cm} (13)

Therefore the terminal voltage $E$ can be regulated by controlling the active power $P$ or vice versa, and the reactive power $Q$ can be controlled by the voltage angle $\delta$ or vice versa. From this relationship it would appear $P$-$V$ and $Q$-$f$ droop curves are more suited. This is known as reverse droop. The droop curves for this method are shown in Figure 6.

![Figure 6: Reverse droop curve [15]](image)

Simulations from [22] and [6] show that while reverse droops are an acceptable control method in LV networks, it would not be compatible with MGs containing SGs or interconnected to HV networks. The reverse droop is also not an economical means of controlling voltage due to high losses in the distribution lines [6], [22]. Simulations show that conventional droop can be scaled down to LV levels without too many adverse effects. Conventional droops would not have the ability to directly control the voltage. However given that reverse droops are not an economical means of controlling the voltage, the sizing and placement of DGs within the LV network becomes more important [22].

A solution to these problems has been proposed by [2], in which a control system that incorporates virtual reactance at the terminals of the VSI is used. The idea behind this method is to emulate the higher reactance of MV and HV distribution lines. This report will focus on MV MGs, where the X/R ratio is not high enough to inhibit voltage control.
2.2.2 Levels of control

There are three levels of control that can be implemented in a MG system. They are arranged as a hierarchical structure from primary to secondary and then to a tertiary level. The droop control is a form of primary control and is essential for maintaining stability. Secondary and tertiary levels of control are optional in a MG network and are used to improve power quality, efficiency and economics performance [23]. In general:

- **Primary Control**: Responsible for power reliability
- **Secondary Control**: Responsible for power quality
- **Tertiary Control**: Responsible for optimal economic performance [12].

2.2.2.1 Primary control

Primary control is the most basic level of control and is concerned foremost with power reliability, load sharing and stability within a network [12], [23]. For a MG, primary control in grid-connected mode will ensure DGs are operating at their setpoint values. When the MG is islanded the primary control ensures the voltage and frequency are maintained within acceptable limits and that the load is shared proportionally between DGs. Most commonly, primary control is decentralised and is performed locally at each DG. In less common designs, primary control can be centralised. In such systems redundancy is reduced and complex control loop communication systems with high bandwidth are required [18]. Primary control normally results in variations to the voltage and frequency setpoints. Secondary control is used to correct this [24].

2.2.2.2 Secondary control

Secondary control is optional and typically requires a communications system, although this system can be much slower than would be required for primary controls [3], [23]. In general, secondary control has been used for correcting deviations in voltage and frequency [24]. In a MG, secondary control could be extended to have other functions such as power correction, harmonic compensation and voltage imbalance correction [24], [16]. The type of secondary control will depend on the overall system requirements.

For control systems using droop control, if a DG is required to deliver a fixed real or reactive power during islanded mode, the secondary controller is used to shift the droop curve vertically, so that the DG output returns to real and reactive power setpoints. This is shown in Figure 7 [16].
Where frequency or voltage regulation is important a secondary controller that moves the droop horizontally can be used [4]. Moving the droop curve horizontally will enable the system to restore to the setpoint frequency and/or voltage, as shown in Figure 8.

2.2.2.3 Tertiary control
Tertiary control also requires a communications system and is the slowest control level. Tertiary control is used to operate a system in a way that optimises the economic performance of the MG [23]. It basically regulates power flows in grid connected or islanded modes so that all DGs operate at equal marginal cost [3], [23].
2.2.3 Microgrid configuration

Microgrids require an overall coordinated control to ensure reliability and optimal operation [3]. This means that DGs throughout the grid must adjust their operating point so that voltage and frequency are stabilised within constraints and seamless transfers between operating modes can be achieved. In general the MG control can use either a centralised or decentralised approach [23], [3].

- **Centralised configuration**: The MG operating points are determined by a MG central controller (MGCC) and sent via communication systems to some or all DGs and potentially to some of the loads throughout the network. For systems where the primary control is performed by the MGCC, high speed high bandwidth communications infrastructure is required. More commonly, centralised control is used for secondary and tertiary control, alleviating the need for high bandwidth communications. For these systems the primary control is the responsibility of the DGs [23], [3].

- **Decentralised configuration**: The operating points of DGs and loads are independently determined, normally via a virtual communication system such as the system frequency or from local measurements of voltages and power flow [23]. Decentralised control removes the need for communication links, which increases the system reliability and reduces costs [23]. This autonomous mode of control enables DGs and loads to have plug-and-play capabilities, which enables MG systems to be easily and inexpensively expanded.

The centralised and decentralised configurations are implemented under two main modes of operation, master slave/single master or multi master.

2.2.3.1 Master slave/single master operation

For single master operation, all the inverters can operate in PQ mode when grid connected, as the grid will control the voltage and frequency. When the MG becomes islanded, a single master inverter will switch to VSI mode to provide the voltage and frequency reference, the remaining DGs continuing to operate in PQ mode [13]. Where a SG is used, it would take the place of the VSI. The system can operate in either a centralised configuration as in Figure 9, or a decentralised configuration such as the pure droop and infinite bus control modes.
2.2.3.1.1 Centrally controlled

There are several variations of a centrally controlled single master operation.

In master slave operation, a single VSI acts as the voltage and frequency reference with all other inverters operating in PQ current source mode. The load is equally shared across each inverter such that the current produced from the master is used as a reference for the PQ inverters. The operating current is communicated to them in real time. This configuration is only possible with high speed communication links. It is therefore difficult to expand, and is not really suitable for distributed generation [6]. Master slave operation may be suitable for a small installation and has previously been used for uninterruptable power supply applications [6].

The need for high speed communications can be eliminated and a high degree of control maintained, when some of the DGs perform primary control independent of the MGCC. An example of this is a system known as ‘multi agent PQ’. In this system all non-dispatchable DGs remain in PQ mode delivering maximum power. When islanded, a storage device(s) shifts to droop control, regulating the voltage and frequency. The storage device(s) is the only DG with primary control. The MGCC is used for secondary control and operating points for each of the remaining DGs are sent out in 30sec intervals [15].

An example of a centrally controlled single master MG is shown in Figure 9 [25], [7].

![Figure 9: Example of a centrally controlled single master MG [25], [7]](image-url)
2.2.3.1.2 Pure droop control

If all DG units in a system determine their own real and reactive power, the need for communications can be eliminated. This is the principle behind the decentralised control known as ‘pure droop’. In this mode each DG, including the master, has an inbuilt generation profile determined by $P$-$f$ and $Q$-$V$ droop curves. The master VSI sets the voltage and frequency based on its droop and the PQ inverters determine the active power from the system frequency set by the master VSI and the reactive power from the local voltage measurements. The pure droop system is easily expanded as it gives equal priority to all DGs and can operate without communication links. This ability to simply add or removed hardware is often referred to as a plug-and-play [4]. In pure droop, DGs adopt droop control in both grid-connected and islanded modes. The output power is constant when the MG is grid-connected because the grid sets the frequency (with very little variation). When islanded, the master VSI uses droops to control the frequency and voltage [15]. This control strategy does not facilitate secondary control and will only be acceptable if the loads are compatible with fluctuating voltages and frequency, for example constant impedance loads and loads with front end electronics [15]. The principle of the pure droop control is outlined in Figure 10. At steady state each DG will operate at the same frequency, the operating voltage will differ depending on the location within the MG.

![Diagram of Pure Droop curves for a three DG MG](image)

**Figure 10:** Pure Droop curves for a three DG MG
2.2.3.2.1 Infinite bus model

A second decentralised approach for single master is the ‘infinite bus model’. This technique relies on the master VSI absorbing excess power or producing the shortfall of active and reactive power required by the MG. All remaining DGs continue to operate in PQ mode delivering maximum power [10]. Therefore the master VSI must be appropriately sized and have sufficient storage to perform this task [4]. It is probably the worst choice as the master VSI is solely responsible for energy storage and load following, but may be suitable for very small systems [15].

2.2.3.2 Multi master operation

A multi master configuration does not rely on a single DG to control the voltage and frequency when the MG is islanded and therefore has built in redundancy. A multi master configuration can have all DGs acting as masters or can use a combination of master generators (VSI or SG) and PQ inverters. The multi master configuration can also have operation modes that allow decentralised or centralised control. Many of the multi master configurations share similarities with single master operation.

2.2.3.2.1 Centrally controlled

The centrally controlled multi master system uses several VSIs operating at predefined voltage and frequency, determined by the MGCC. The principle is almost identical to the centrally control single master system. One advantage is that battery interfaced VSIs can be distributed throughout the network [7]. A combined VSI-PQ multi master centrally controlled MG is shown in Figure 11 [25], [7]. Compared with single master, the centralised control for multi master requires a higher level of communication between master VSIs. This adds complexity, although it does have the advantage of in built redundancy as the system will continue to operate if one of the master VSIs goes off-line [4].

![Figure 11: Centrally controlled combined VSI-PQ multi master MG [25], [7]](image-url)
2.2.3.2.2 Pure droop

The pure droop control for multi master is almost identical to the single master mode. All DGs are able to regulate their power outputs in grid-connected and islanded mode by using individual droop controls. Multi master pure droop systems are well suited to systems with multiple integrated, renewable energy/storage generators spread throughout a MG. When implemented in this way the load will be shared equally across all DGs regardless of the available renewable resource [15].

2.2.3.2.3 Angle droop

The relationship between power and voltage angle was described in section 2.2.1 and summarised by equation (5). Unlike SGs, VSI can directly and almost instantaneously change their voltage angle; therefore active power flow can be regulated directly by altering the voltage angle. It has been demonstrated that power sharing between DGs can be achieved by using angle droops [26], [1]. Using angle droops can eliminate the need for secondary control as the frequency deviations are much smaller than for P-f droops, whilst maintaining the same stability margins [26], [1]. The angle droop is implemented as a decentralised multi master configuration, although there is a need for GPS communications for angle referencing [26].

2.2.3.2.4 Hybrid angle-frequency droop

A combined angle-frequency droop has been proposed by [27] and has advantages over the method outlined in the previous section. It is a decentralised multi master approach, so it does not need a communications system. It does not have a single point of failure and so has added redundancy, and it has plug-and-play ability. It also does not suffer from a permanent frequency offset typical of most decentralised configurations and so does not require secondary frequency control. DGs with storage can be spread throughout the network and DGs remain in VSI mode in both grid-connected and islanded mode, so inverter control reconfiguration is not required [27].

Other benefits of hybrid angle-frequency droop are:

- SG controllers can be adapted to be compatible
- Improved dynamic performance due to multiple degrees of freedom in control loops
- Seamlessly transitions between grid-connected and islanded modes
- Seamless operation with out-of-phase reclosing to utility grid
- Its ability to emulate the beneficial performance of a SG such as power dampening and virtual inertia [27].
3 Investigation and comparison of P-f droop and angle-frequency droop control

The remainder of the report will investigate and compare the dynamic and steady state performance of a conventional decentralised pure droop controller and an angle-frequency droop controller for a MG.

Control loops will be adapted from [27], starting with the simpler P-f/Q-V droop control topology. The angle-frequency droop will build on the P-f droop to highlight its advantages. The control topology will be analysed for transient behaviour, frequency and voltage regulation, and power sharing accuracy for grid connected and islanded modes of operation. The initial aim of this process will be to replicate results obtained from [27] so a better understanding of the control system can be gained. This will included testing the compatibility of the control topologies with parallel operation of a SG, response to load changes in islanded mode, grid reconnection dynamics and the system stability when a VSI is disconnected.

The greater understanding of the angle-frequency droop controller will be used to explore scenarios not covered in [27]. Possible reconfigurations that could improve the MG performance as well as the potential issues that could be encountered by such a control system will be investigated. This will include examining black start scenarios, utility grid frequency variations, and load changes not explored in [27].

The purpose of the simulations is to test the suitability of the control technique for an off-grid or permanently islanded MG. Therefore, as a starting point, it is assumed that for all simulations the DGs are able to meet the total power demand. Details such as battery state of charge and the variability of renewables will not be considered in the simulation.

The angle-frequency droop method takes advantage of the fact that inverters can instantaneously change their voltage angle. The system is presented as an autonomous decentralised system, and whilst it does not use a traditional communication system it does require GPS signals for angle referencing [28]. How this is implemented is outside the scope of this report. The angle-frequency droop method will be simulated on a MG in both grid-connected and islanded modes.
3.1 Simulation platform

All simulations will be carried out on the MATLAB® software package using the Simulink™ extension. The controllers are modelled with components from the Simulink™ library. All electrical components are modelled using Simscape™ and SimPowerSystems™ library components. Calculations used to assist in design parameters are carried out using MATLAB® scripts and transferred to the Simulink™ components for simulation.

MATLAB® (matrix laboratory) is a high-level language environment used for numerical computations developed by MathWorks. Simulink™ is a graphical block diagramming tool that operates in integration with MATLAB® and is used extensively for control theory. Simscape™ and SimPowerSystems™ are component libraries in the Simulink™ environment used for simulating physical systems such as mechanical, hydraulic and electrical systems. Simscape™ components are used for measuring electrical signals such as currents, voltages, active power and reactive power. The SimPowerSystems™ has components for electrical power systems and is used to model voltage sources, VSIs, SGs, loads, transmission lines and transformers.

Details of the MG components and generator models developed in Simulink™, SimPowerSystems™ and Simscape™ environments, which were used for simulation can be found in the Appendix A.
3.2 VSI and SG off grid microgrid

The effectiveness of the decentralised pure droop controller and angle-frequency droop controller was assessed by simulations carried out on a MG with a VSI and SG as shown in Figure 12. Both DGs were rated at 600kVA and operate at 4.14kV. The voltage was stepped up through transformers to the 13.8kV of the distribution system. Each DG has its own local load and a shared common load connected at the PCC. A shunt capacitor is also connected to the PCC to assist with voltage regulation. As the network operates at a MV level, the resistance and reactance of the distribution lines and transformer needed to be considered in the design of the angle-frequency droop controller.

![Figure 12: Five bus off-grid microgrid, with SG and VSI [27]](image-url)
3.3 Multi VSI microgrid

Some of the advantages a VSI has over a SG are that they are able to quickly self-synchronise with an out of phase re-closure to the utility grid [27]. Therefore, an independent controller that is needed to perform synchronisation before a SG can be reconnected to the utility grid can be eliminated. A larger VSI only MG shown in Figure 13 and was used to determine how well the angle-frequency droop performs during MGCS re-closure. Several other large scale disturbances were also examined to analyse the dynamic behaviour of the VSI without the natural inertia of a SG present.

The microgrid was connected to the utility grid via a 69-13.8kV step down transformer and a MG control switch (MGCS). The MGCS was used to connect and disconnect the MG from the utility network. The MG contained three DGs, which were all rated at 4.14kV, with power ratings of 3.7 MVA, 4MVA and 3.2MVA respectively. The voltage was stepped up through transformers to the 13.8kV of the distribution system. Each DG had its own local load connected on the HV side of the transformer. A shared common load was connected at the PCC. A shunt capacitor is also connected to the PCC to assist with voltage regulation in islanded mode.
3.4 P-f droop controller

3.4.1 Voltage source inverter

The VSI controller used for the P-f droop controlled MG is similar to those proposed in [6], [29] and [27], which varies slightly from the traditional VSI droop detailed in section 2.2.1.2. The VSI was modelled using an average-model of an H-bridge inverter from the SimPowerSystems™ library. This model generates a three phase voltage at the terminals of the VSI, from a reference input sine wave such as \( e(t)_{\text{ref}} \) shown in Figure 14. The average model does not require a PWM signal that normally controls switching of the IGBTs or MOSFETS of the H-bridge rectifier. This enables longer sample times and a faster simulation. The resulting voltage wave of the average model does not contain harmonic components.

The VSI controller is divided into two control loops, the P-f (or P-\( \omega \)) droop and the Q-V droop, as shown in Figure 14. When delivering setpoint active power the VSI operates at setpoint frequency. When a change in electrical power occurs, an error is caused from the difference between setpoint and measured active power. The instantaneous active power mismatch results in an error \( \Delta \omega \), which is passed through the frequency droop which ultimately results in an angular frequency and therefore electrical frequency variation, proportional to the angular frequency droop \( K_\omega \).

![Figure 14: VSI P-f and Q-V droop controller](image)

This P-f (or P-\( \omega \)) droop controller shown in Figure 14 varies slightly from conventional VSI droops. It uses the droop function similar to that of a PQ inverter described by equation (8), although the droop is still a \( f(P) \) or a \( \omega(P) \) function. It also includes the voltage angle \( \delta \) in the controller, which is calculated by integrating the angular frequency over time, as was outlined in equation (7). This extra term helps to achieve more precise power sharing after a transient event [22].
The steady state frequency of the controllers P-f droop is expressed as:

\[ f - f_{set} = \frac{P - P_{set}}{K_f}, \text{ or } \omega - \omega_{set} = \frac{P - P_{set}}{K_\omega} \tag{14} \]

where \( K_f \) determines the gradient of the P-f droop and is calculated such that:

\[ K_f = -\frac{\Delta P_{max}}{\Delta f_{max}} \tag{15} \]

and \( K_\omega = K_f / 2\pi \)

The term \( \Delta P_{max} \) is determined by the power rating of the inverter. The selection of the variable \( \Delta f_{max} \) is a trade-off between power sharing accuracy and frequency regulation. Larger values of \( \Delta f_{max} \) will improve the power sharing accuracy between DGs and improve the system stability, at the expense of poorer frequency regulation [27].

The Q-V droop is used for voltage control and to prevent circulating reactive currents between DGs. The voltage controller for this system uses a setpoint reactive power of zero. Therefore the droop expressed by equation (11) is simplified to:

\[ E = E_{set} - Q K_Q \tag{16} \]

where \( K_Q \) determines the gradient of the Q-V droop such that:

\[ K_Q = \frac{\Delta E_{max}}{Q_{max}} \tag{17} \]

The reactive power \( Q_{max} \) is an inverter limitation and the voltage \( \Delta E_{max} \) is a design constraint (normally limited to within ±5% of the nominal voltage). The system designer must therefore determine values of \( K_f \) and \( K_Q \) so that a suitable transient response, power sharing accuracy, and frequency and voltage regulation are achieved [27].
The inputs to the controller $P'(t)$ and $Q'(t)$ are the filtered instantaneous three phase active and reactive powers. The library component selected from Simscape™ to measure real and reactive power uses the instantaneous current and voltage to calculate the instantaneous active and reactive power. A balanced three phase system at steady state will return a constant power value, however transient conditions will cause some DC offset in the AC current as a result of the line reactance. This produces a ripple in the active and reactive power outputs of the power meter. Small load power imbalances between phases will also cause such ripples. If these ripples are not filtered out the VSI controller will react in such a way that the system can quickly become unstable. The need for power filtering to prevent the resonance impact at the output of VSI terminals was discussed in [18] and [6]. The filters were designed to filter out small power oscillations and the high harmonics content from switching of MOSFETs or IGBTs in the H-bridge of the VSI. Harmonics were not an issue when using the average model of an H-bridge inverter, although ripple frequencies twice the fundamental frequency (60Hz) did occur in transient conditions. A low pass filter can be applied to block the problematic frequencies, which in the frequency domain can be expressed as the first order transfer function given in equation (18), where $\omega_c$ represents the cut off frequency.

$$P'(s) = \frac{\omega_c}{s + \omega_c}P; \quad Q'(s) = \frac{\omega_c}{s + \omega_c}Q$$

(18)

When re-arranged, the first order transfer functions of equation (18) above represents the time lag functions used to model the time lags of mechanical torque and excitation that are indicative of the response of a SG. In the frequency domain they are given by equation (19), where $\tau$ represents the time constant. Whilst there is no difference between equations (18) and (19)(i.e. $\tau = 1/\omega_c$) how they are represented can indicate the function they are trying to model. For example, using the transfer function as shown in (19) in a VSI controller would indicate the transfer functions is used to try and smooth the response to fast and non-linear current changes [29] as would result from the characteristic time lags of a SG.

$$P'(s) = \frac{1}{\tau_{mech-torq}s + 1}P; \quad Q'(s) = \frac{1}{\tau_{excite}s + 1}Q$$

(19)

Sometimes both transfer functions are used, for example [6] uses two transforms in series, one representing a low pass filter and the other a first order time lag. The transfer function could be represented by equation (20), however, looking at this transfer function in a controller diagram may not be immediately indicate the reasoning behind its use.
\[ P'(s) = \frac{1}{\frac{\tau_{mech} - \text{torq}}{\omega_c} s^2 + \left(\frac{1}{\omega_c} + \tau_{mech}\right)s + 1} \]

(20)

By choosing suitable filter parameters, the dynamic response of the VSI can be improved.
3.4.2 Synchronous generator

The synchronous generator is modelled using the ‘simplified synchronous machine’ from the SimPowerSytem™ library. The mechanical system for the SG is described by equation (21).

$$\Delta \omega_{\text{rotor}}(t) = \frac{1}{2H} \int (T_{\text{mech}} - T_e) dt - K_d \Delta \omega_{\text{rotor}}(t)$$ \hspace{1cm} (21)

Where the torque ($T$) is related to power such that:

$$T_m \approx \frac{P_m}{\omega_{\text{rotor}}}, \quad T_e \approx \frac{P_e}{\omega_{\text{rotor}}}$$ \hspace{1cm} (22)

A basic P-f (or P-$\omega$) droop controlled governor for the SG is shown in Figure 15. The SG has been modelled as a two pole machine so that the rotor speed measurement $\omega_{\text{rotor}}$ does not require further processing, as at steady state $\omega_e = \omega_{\text{rotor}}$. The mechanical power delivered to the SG is derived from the P-f droop such that at the setpoint power the generator operates at nominal frequency. When a change in electrical power occurs, the rotor speed will change as described by equation (21). The resulting error $\Delta f$ in the controller causes the mechanical power to change until a steady state condition is reached, such that $P_{\text{mech}} = P_e$. The rotor frequency and therefore the electrical frequency will end up at a new operating steady state frequency proportional to the load change.

![Figure 15: Generator P-f droop controller [19]](image)

In reality, the mechanical power delivered to the SG would not change instantly [19]. This can be modelled by including a first ordered transfer function in the Simulink™ controller model, as is shown (faded component) in Figure 15. The time constant for the governor controller has not been considered for the MG simulations.

When stator losses are ignored (i.e. electrical power equals mechanical power) the steady state change in frequency of the SG is given by:
\[ \Delta f = \frac{P_{\text{set}} - P_e}{K_f} \]  

(23)

As with the VSI, the gradient of the droop \( K_f \), is determined by equation (15), where the controller gain \( K_\omega = K_f / 2\pi \).

The simplified model of the SG in MATLAB\textsuperscript{®} has a single input for the voltage reference point. This means control of the excitation currents normally used for SG voltage control did not need to be modelled. The same voltage droop controller used for the VSI voltage control was directly implemented into the SG controller.
3.5 Angle-frequency droop controller

The angle frequency droop was adapted directly from [27]. It adds a cascaded angle-droop to the P-f droop controller of the previous section. The angle-frequency droop takes advantage of the fact that VSIs can directly control the voltage angle. It was shown in equation (5) that when the voltage angle \( \delta \) is small the active power can be controlled directly by changing the voltage angle itself. For the conventional droop the change in \( \delta \) occurs from the change in angular frequency \( \omega \). A VSI has the ability to change the voltage angle almost instantaneously. However the active power flow is a result of the difference in voltage angle. Using Figure 16 as an example, the active power flow is a result of the voltage angle difference between the VSI and the PCC (\( \delta_{tVSI} - \delta_{tPCC} \)). The VSI has no control over the voltage angle \( \delta_{tPCC} \) so a GPS system would be required for angle referencing [26]. The VSI controller is therefore used to change the angle \( \delta_{tVSI} \) with respect to the angle \( \delta_{tPCC} \), which from here on will be assumed as the reference phasor with angle zero.

The relationship between active power and voltage angle is a non-linear one, however it can be shown using line impedance and VSI ratings from Figure 13 that the expected operating range of the VSI will be in a linear section of the power curve (where the active power is less than 1 per unit).

Unlike the frequency droop, which does not have a direct physical correlation between frequency and active power, the power flow resulting from the angle droop has a direct nonlinear correlation that is predominantly a function of the grid impedance. Consider the two bus analogy of a MV network shown in Figure 16, delivering power to an infinite bus. Figure 17a shows the steady state active power, reactive power and VSI voltage vs voltage angle for a P-\( \delta \)/Q-V droop. Over the full angle range, the relationship is clearly non-linear; however the VSI will operate in the small portion of the curve where the real power is less than or equal to 1 pu, as shown in Figure 17b. In this graph the power vs. angle is very close to being perfectly linear. Therefore, an angle droop can be implemented which will deliver power very close to that for the angle droop given by equation (24).

![Diagram](image.png)

*Figure 16: Generator connected to infinite bus in a MV network*
\[ \delta = \delta_{\text{set}} - K_d (P - P_{\text{set}}) \]  

where \( \delta_{\text{set}} \) is the voltage angle when operating at setpoint power \( P_{\text{set}} \) and \( K_d \) is the inverse of the gradient of the slope for the power v. voltage angle line shown in the right graph of Figure 7.

If the power sharing between DGs is controlled by an angle droop described by equation (24), then the angular frequency can be maintained at the setpoint value after a change in active power has occurred [28]. Combining the angle droop with a frequency droop will allow frequency setpoint restoration, with the added advantage of having more degrees of freedom within the controller. This enables a more controlled transient response to large scale disturbances [27].
3.5.1 Voltage source inverter

The angle-frequency droop controller for a VSI is shown in Figure 18 [27]. The controller includes both an angle and a frequency droop, but the angle droop is the foremost power sharing droop. The frequency droop provides dampening to reduce frequency oscillations. The cascading of the droops also introduces a virtual inertia similar to the inertia observed in a SG, which helps to reduce angle oscillations in transient conditions [27].

![Figure 18: VSI angle-frequency droop controller [27]](image)

The VSI controller shown in Figure 18 is mathematically represented such that:

\[
\int \left\{ \left[ K_d (\delta_{set} - \delta) - \Delta \omega \right] K_\omega + P_{set} - P \right\} dt = \Delta \omega \tag{25}
\]

At steady state the active power is expressed by:

\[
P = P_{set} + K_\omega K_d (\delta_{set} - \delta) \tag{26}
\]

where \( \delta_{set} \) is the setpoint angle \((\delta_{t,VSI} - \delta_{t,PCC})\). Therefore, the steady state power is a function of the difference in voltage angle \((\delta_{set} - \delta)\) and the angle and frequency droop constants \((K_\omega \times K_d)\). (The derivation of equation (26) is outlined in the Appendix A).
3.5.2 Synchronous generator

Importantly, the SG controller can also be modified to include the angle droop to allow parallel operation with angle-frequency droop controlled VSIs. Unlike a VSI, the voltage angle of a SG cannot be changed instantly. However, adding the angle droop to the SG controller enables the frequency to return to the setpoint after a load change, whilst still preserving autonomous power sharing capabilities. The SG angle-frequency controller is shown in Figure 19 [27]. Unlike the P-f droop, the angle-frequency droop for the SG requires both the rotor speed and active power measurements.

![Figure 19: SG angle-frequency droop controller [27]](image)

The SG angle-frequency droop controller is expressed mathematically such that:

\[
P_{\text{mech}} = K_\omega K_d (\delta_{\text{set}} - \delta) - K_\omega \Delta \omega - P_e \tag{27}
\]

At steady state:

\[
P_e = K_\omega K_d (\delta_{\text{set}} - \delta) - P_{\text{mech}} \tag{28}
\]

The gain \(K_d\) is the active power-angle droop and also serves as a dampener to prevent angle/frequency oscillations [27]. For the network shown in Figure 12 consisting of two equally rated DGs, \(K_\omega\) and \(K_d\) will be identical for both control loops.
3.5.3 Determining the setpoints

For the angle-frequency droop to deliver setpoint active power requires setting the appropriate setpoint angle reference. This entails knowing the voltage angle with reference to the PCC when the VSI is delivering setpoint active power. For the two bus analogy shown in Figure 16, the solution can be solved using the active and reactive power flow equations (1) and (2). However, calculating the angle \( \delta \) becomes somewhat more complicated when additional DGs, distribution lines, and loads are added. Deriving an equivalent two bus Thevenin equivalent network for each DG becomes quite challenging for a network such as the one shown in Figure 13. An alternative approach to deriving the Thevenin equivalent circuit is to use Kirchhoff’s Current Law (KCL) to develop a system of equations to solve for the VSI operating voltage and angles. Solving the KCL equations requires an iterative approach, which can be developed into an algorithm to be used by computer software, such as MATLAB® to solve for each variable.

To implement KCL, the network was simplified by representing the network using per unit values for all network elements and replacing all DGs and loads with current sources, as shown in Figure 20. An equation can be expressed for each of the buses in the network using KCL, for example bus 1 can be represented as:

\[
I_1 = -I_2 \quad \rightarrow \quad I_1 = \frac{V_4 - V_1}{z_{12}} \quad \rightarrow \quad I_1 = V_{4y_{12}} - V_{1y_{12}} \tag{29}
\]

where \( y \) is the per unit admittance \( \left( \frac{1}{z} \right) \).

Figure 20: KCL per unit model of seven bus microgrid
When KCL is applied to each bus, the resulting set of equations can be represented in matrix form such that:

\[
\begin{bmatrix}
I_1 \\
\vdots \\
I_7
\end{bmatrix} = 
\begin{bmatrix}
y_{11} & \cdots & -y_{17} \\
\vdots & \ddots & \vdots \\
-y_{17} & \cdots & y_{77}
\end{bmatrix}
\begin{bmatrix}
V_1 \\
\vdots \\
V_7
\end{bmatrix}
\]

(30)

where all diagonal components are given by \( y_{kk} = \sum_{n=1}^{N} y_{kn} \) and \( I_k \) is given by:

\[
I_k = \frac{(P_k + jQ_k)^*}{V_k^*}
\]

(31)

where \( * \) denotes the complex conjugate.

Substituting this relationship into the matrix leads to an expression for the voltage at each bus, which forms the basis for the iterative scheme. The bus voltage is represented by the equation:

\[
V_k = \frac{1}{y_{kk}} \left( \sum_{n=1}^{N} -y_{kn}V_n + \frac{(P_k + jQ_k)^*}{V_k^*} \right)
\]

(32)

A Gauss-Seidel approach was applied to solve the system of equations until convergence was achieved. Each bus was given an initial guess, in this case \( 1\angle 0 \, \text{pu} \). The program solves each bus voltage consecutively using two iterations for each bus to account for the real and imaginary part of the bus voltage, then updates the voltage after each iteration. In grid connected mode of operation the PCC was held at \( 1\angle 0 \, \text{pu} \), and the desired output power for each of the three DGs was used for \( P_{k=1,2,3} \) (i.e. the desired active power delivered to bus 1, 2 and 3). The voltage controlled buses of the three DGs required an additional iteration to update the reactive power and voltage magnitude. i.e.:

\[
V_{k=1,2,3} = K_Q \times \text{Imag} \left[ P_k - V_k^* \left( y_{kk}V_k + \sum_{n=1}^{N} y_{kn}V_n \right) \right] \times e^{j \angle (V_k(i-1))}
\]

(33)

where \( K_Q \) is the voltage droop gain and \( i \) is the \( i^{th} \) iteration.
Once the system of equations had converged the voltage angle $\delta_{k=1,2,3}$ was used as the setpoint angle $\delta_{set}$ for the VSI controller. The system of equations was solved again for the system when in islanded mode, with the desired operating point of the DGs. To solve the system of equations when in islanded mode it was assumed the distribution lines were lossless. Therefore in the case of the desired 4:5:6 power sharing ratio of the three DGs of the MG shown in Figure 13 it can be assumed that:

$$P_{DG[2,1,3]} = \frac{P_{load}}{15} \times [4,5,6]$$  \hspace{1cm} (34)

The new voltage angle $\delta_{k=1,2,3}$ was used to calculate the VSI angle droop gain $K_d$ so that the desired power sharing between DGs could be attained. The expression for $K_d$ is given by:

$$K_d = n \times \frac{\Delta P}{K_\omega \Delta \delta}$$  \hspace{1cm} (35)

where $n$ is any multiple. A higher multiple of $n$ will increase dampening which reduces the size of the oscillations.

The $MATLAB^\text{®}$ code for the Gauss-Seidel solver is outlined in Appendix B.
3.6 Results

3.6.1 P-f droop control, five bus VSI and SG microgrid

The P-f droop controlled system was tested on the network presented in [27] as shown in Figure 12. For this simulation the aim was to replicate results obtained from [27]. The parameters $K_{\omega}$ and $K_Q$ were taken directly from [27]. Selecting the filter coefficients were carried out using a trial an error approach, [6] suggested values for frequency filtering. However decoupling time lags expressed in the frequency domain by equation (19) were used in series with the low pass frequency filters. For simplicity only a single first order transfer function was used to perform frequency filtering and introduce a time lag. The optimal coefficients found from the trial and error approach are shown in Table 2.

The transient response of the pure droop was analysed by varying the common load from 180kW to 450kW at t=4seconds. Figure 21 shows the power and frequency responses of each DG. The DGs exhibited fairly good power sharing. There was a slight imbalance after the load increase due to losses in the stator windings of the SG. The transient response was fairly subdued with a small overshoot in active power with a steady state settling time of just under 0.2 seconds. The new steady state frequency settled just below 59.8 Hz.

![Figure 21: DGs active power and frequency response to a common load increase (P-f droop)](image-url)
Table 2: SG parameters and P-f droop controller settings

<table>
<thead>
<tr>
<th></th>
<th>DG1 (SG)</th>
<th>DG2 (VSI)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stator resistance</td>
<td>0.2Ω</td>
<td>–</td>
</tr>
<tr>
<td>Stator impedance</td>
<td>2mH</td>
<td>–</td>
</tr>
<tr>
<td>Power setpoint: $P_{\text{set}}$</td>
<td>320 kW</td>
<td>320 kW</td>
</tr>
<tr>
<td>Power droop: $K_\omega \left[ \frac{W}{\text{rad} \cdot \text{s}^{-1}} \right]$</td>
<td>$-10^5$</td>
<td>$10^5$</td>
</tr>
<tr>
<td>Voltage droop: $K_E \left[ \frac{V}{\text{V} \cdot \text{Ar}} \right]$</td>
<td>$2 \times 10^{-5}$</td>
<td>$2 \times 10^{-5}$</td>
</tr>
<tr>
<td>Low pass active power filter: $\omega_{C_P} [\text{rad} \cdot \text{s}^{-1}]$</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Low pass reactive power filter: $\omega_{C_Q} [\text{rad} \cdot \text{s}^{-1}]$</td>
<td>10</td>
<td>10</td>
</tr>
</tbody>
</table>
3.6.2 Angle-frequency droop control, five bus VSI and SG microgrid

The angle-frequency droop controller was also implemented into the MG network shown in Figure 12, to assess the parallel operation with a SG. The droop coefficients $K_Q$, $K_\omega$ and $K_d$ were taken directly from [27]. So that an accurate comparison could be made to the pure droop system, filter coefficients were left unchanged. The parameters are shown in Table 3.

Figure 22 shows the power and frequency responses of the two SGs to a common load increase from 180kW to 450kW at t=4seconds. The angle-frequency droop control system was slower to reach the new steady state, with a settling time just under 0.5 seconds. The magnitude of overshoot was not greatly affected and improved power sharing accuracy between DGs was also observed. The main benefit of the angle-frequency droop controller was that the frequency returned to 60Hz after the load change.

Figure 22: DGs active power and frequency response to a common load increase ($\delta$-f droop)
Table 3: SG parameters and angle-frequency droop controller settings

<table>
<thead>
<tr>
<th></th>
<th>DG1 (SG)</th>
<th>DG2 (VSI)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stator resistance</td>
<td>0.2Ω</td>
<td>–</td>
</tr>
<tr>
<td>Stator impedance</td>
<td>2mH</td>
<td>–</td>
</tr>
<tr>
<td>Power setpoint</td>
<td>320 kW</td>
<td>320 kW</td>
</tr>
<tr>
<td>Power droop: $K_\omega \left[ \frac{W}{\text{rad} \cdot \text{s}^{-1}} \right]$</td>
<td>$10^5$</td>
<td>$10^5$</td>
</tr>
<tr>
<td>Voltage droop: $K_E \left[ \frac{V}{V\text{Ar}} \right]$</td>
<td>$2 \times 10^{-5}$</td>
<td>$2 \times 10^{-5}$</td>
</tr>
<tr>
<td>Angle droop: $K_d \left[ \text{s}^{-1} \right]$</td>
<td>10</td>
<td>10</td>
</tr>
<tr>
<td>Low pass active filter: $\omega_{C_P} \left[ \text{rad} \cdot \text{s}^{-1} \right]$</td>
<td>200</td>
<td>200</td>
</tr>
<tr>
<td>Low pass reactive power filter: $\omega_{C_Q} \left[ \text{rad} \cdot \text{s}^{-1} \right]$</td>
<td>10</td>
<td>10</td>
</tr>
</tbody>
</table>

A microgrid with a SG would require a synchronisation controller to synchronise the MG to the utility grid before reconnection took place. This would require some form of central controller which would be responsible for ensuring the voltage magnitudes, frequency, phase sequence and phase angles are synchronised before reconnection. This process may take several seconds to minutes [3]. One of the benefits of a VSI is its ability to self-synchronise to the grid without any external reference [30]. This means a VSI-only MG can reconnect to the grid autonomously [31]. This aspect of the controller is analysed for the seven bus VSI only MG.
3.6.3 Angle-frequency droop control, seven bus VSI microgrid

To analyse the suitability of this control system the MG shown in Figure 13 was subjected to a scenario of major disturbances:

- The MG was initially in a grid connected mode
- $t = 0.4 \text{ seconds}$: The MG was disconnected from the main grid and the DGs must increase power to meet the load demand
- $t = 0.6 \text{ seconds}$: DG2 was disconnected requiring DG1 and DG3 to increase power to supply the loads
- $t = 0.8 \text{ seconds}$: DG2 was reconnected
- $t = 1.0 \text{ seconds}$: The MG reconnects to the utility grid.

Figure 23 shows the DGs power and frequency response to each disturbance using angle droops with the same order of magnitude as those presented in [27]. The frequency was returned to the setpoint value of 60Hz throughout the simulation, with some large short term deviations after each disturbance. The transition from grid connected to islanded mode was seamless, with only the smallest of oscillations observed. The large disturbance of disconnecting DG2 resulted in small short lived oscillations with only a small amount of active power overshoot. The reconnection of DG2 caused the largest oscillations, which briefly resulted in massive overshoots in both reactive and active power, which would exceed the rating of the DGs. Both active and reactive power are shared proportionally in both grid connected and islanded mode. The active power is delivered at setpoint values when grid connected and very close to the system design values when islanded. Reactive power was delivered with the same sign under all steady state conditions, which indicates the voltage controller was preventing circulating reactive currents.

Increasing the dampening in the controller by increasing the angle droop $K_d$ by three orders of magnitude vastly improved the performance. There was an observed reduction in overshoot and a reduction in time taken to reach steady state frequency. DG1 did still exceed its power rating, though only for a brief instant and only marginally. The DGs response with increased dampening is shown in Figure 24.

The angle-frequency droop controller settings for each simulation are shown in Table 4.
Figure 23: DGs active power, reactive power and frequency response (Simulation 1)

Figure 24: DGs active power, reactive power and frequency response (Simulation 2)
Table 4: DG angle-frequency droop controller settings

<table>
<thead>
<tr>
<th></th>
<th>DG1</th>
<th>DG2</th>
<th>DG3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Angle setpoint: $\delta_{set}$</td>
<td>15.39°</td>
<td>18.02°</td>
<td>12.39°</td>
</tr>
<tr>
<td>Power setpoint: $P_{set}$</td>
<td>2.43 MW</td>
<td>2.86 MW</td>
<td>1.90 MW</td>
</tr>
<tr>
<td>Power Droop: $K_\omega \frac{W}{rad\cdot s^{-1}}$</td>
<td>1e5</td>
<td>1e5</td>
<td>1e5</td>
</tr>
<tr>
<td>Voltage droop: $K_E \frac{V}{VAr}$</td>
<td>2.5e-4</td>
<td>2x10^-5</td>
<td>3e-4</td>
</tr>
<tr>
<td>Low pass active power filter: $\omega C_P \ [rad \cdot s^{-1}]$</td>
<td>120</td>
<td>120</td>
<td>120</td>
</tr>
<tr>
<td>Low pass reactive power filter: $\omega C_Q \ [rad \cdot s^{-1}]$</td>
<td>120</td>
<td>120</td>
<td>120</td>
</tr>
<tr>
<td>Angle Droop: $K_d \ [s^{-1}](Simulation \ 1/Simulation \ 2)$</td>
<td>87/87e3</td>
<td>82/82e3</td>
<td>91/91e3</td>
</tr>
</tbody>
</table>

During the simulation the voltage at the terminals of each VSI was maintained within acceptable limits for an Australian public network (adapted from international standards) of between 90% and 106% of the nominal voltage [32]. This was a result of the voltage droop, which limited the steady state voltage level. The high line impedance between DGs and the PCC required voltage support in the form of a shunt capacitor to regulate the voltage at the PCC in an islanded mode. Using the shunt capacitor reactance suggested in [27] resulted in the PCC voltage falling to an unacceptable level of 0.88pu when DG2 was disconnected. This is shown in Figure 25a. This was corrected by increasing the size of the shunt capacitor by 2.5MVAr to 4MVAr (as is shown in Figure 13 after correction). As a result and as shown in Figure 25b, the voltage was maintained within five percent of the nominal voltage. The additional reactance did not affect the MG or DG stability. However, there would be some risk of exceeding voltage limits if there was a sudden loss of load under islanded conditions. A controlled shunt capacitor may be a better solution.
3.6.3.1 Complications of angle-frequency droop control

There were several scenarios that caused problems with the angle-frequency droop as it stands. These issues are outlined below, along with some suggestions for possible solutions. The work carried out to rectify the problems experienced was minimal and further investigation would be required before any credible solutions could be found.

3.6.3.1.1 Load shedding

Both the P-f droop and angle frequency droop have assumed that the VSI is able to meet the load demand. If the variability of the renewable energy source and battery state of charge were to be considered, then load shedding would be a reasonable consideration for maintaining stability when generation capacity is reduced. The P-f droop has the advantage of using frequency as a virtual communications network. There are scenarios where system frequency thresholds can be used to autonomously shed non-critical loads, if the loads themselves can measure the system frequency [13]. The angle-frequency droop, which has no frequency offset after a transient event, does not appear to have an obvious means of facilitating autonomous load shedding.

3.6.3.1.2 Local load loss

This control system does suffer from some inaccurate power sharing when a large variation in power at the local load between the point of common connection (PCC) and VSI occurs. For DG1, if the local load is completely disconnected the VSI power deviates by 210kW from its setpoint value. To maintain a high level of power sharing accuracy a local communication system could be implemented. The system configuration could still be classified as decentralised as communications would only be required between the VSI and its local load. Furthermore only a slow communications network would be required. The examples shown in Figure 26 are for the system without communications (Figure 26a) and with a communications system between the load and VSI (Figure 26b). For demonstration purposes only, the load power was sent to the VSI every 0.1 seconds. A Gauss-Seidel solver was used to calculate and update the setpoint voltage angle in the VSI controller. To test the effectiveness of the local communications system, a simulation was carried out, whereby the MG remains in a grid connected mode and at $t = 0.2\text{seconds}$ the local load is disconnected and reconnected 0.2 seconds later at $t = 0.4\text{seconds}$. Figure 26 highlights how the local communications network combined with the Gauss-Seidel solver corrects the active power deviation.
So far the simulations have ignored the fact that power produced from renewable sources fluctuates. If in a grid-connected mode the VSI operated at setpoint power, even when the renewable source was low, the battery would discharge and may not have sufficient capacity to supply loads in an islanded scenario. It has not been explored in detail how this controller would be implemented with renewable energy sources. However it can be seen that a simple communications system with a simple solver could be used to update the setpoints $P_{\text{set}}$ and $\delta_{\text{set}}$, so that only the available power from a renewable source was delivered when in a grid connected mode.

3.6.3.1.3 Unbalanced loads

All simulations have assumed balanced three phase loads. When the network becomes unbalanced in an islanded mode, small power and angle oscillations were observed. Figure 27 shows the response when at $t = 0.5$ seconds, a 500kW load is added to phases a and b. This was also shown in the results presented by [27]. The system does maintain stability, albeit with small on-going oscillations. In this instance the largest power oscillations were 100kW in magnitude with frequency of 0.06Hz, and voltage oscillations of less than 1.5V in magnitude.
Figure 27: Frequency and active power response to a 250kW per phase unbalanced common load

Unbalanced systems were outside the scope of work for the current study and [27]. However it was suggested that a negative sequence control loop within a non-linear voltage controller could prevent such oscillations [27]. Even with the oscillations present in [27], stability was not compromised and voltage variations were within acceptable limits for an unbalanced system [27]. Without knowing the specific IEC limits, it cannot be determined whether the simulation carried out in this report stays within an acceptable range. However the results are comparable to those presented in [27].

The International Electrotechnical Commission (IEC) publishes standards for emission limits for a range of LV, MV and HV systems. For a MV network voltage ripple is limited to 0.3% [33]. Therefore, the voltage ripple observed for the unbalanced load was well within limits. To ensure all the observed steady state and transient voltage/current behaviour was also within the limits specified by the IEC standards, would require a detailed analysis of the voltage/current harmonics, as well as analysis of positive, negative and zero sequence voltage/current. Details for how this should be carried out are given in the IEC 6100 standards. This is outside the scope of this report.

3.6.3.1.4 Grid frequency variations

The above simulations were carried out on the assumption the utility grid frequency was maintained at a constant 60Hz. Even a strong electrical grid such as the European interconnected grid permits steady-state frequency deviations of up to 200mHz [17]. When the grid frequency was increased by 50mHz, the VSI active power very quickly decreased. This occurs as a result of the VSIs automatically synchronises with the grid [30] and as the set point angular frequency is fixed, to maintain the grid frequency the voltage angle is constantly decreasing.

This can be understood more clearly by investigating equation (36).
\[ \omega_{grid} = \frac{d(\omega_{VSI} t + \delta(t))}{dt} \]  

If both \( \omega_{grid} \) and \( \omega_{VSI} \) (i.e. \( \omega_{set} + \Delta \omega \) at steady state) are constant but different:

\[ \omega_{grid} = \omega_{VSI} + \frac{d(\delta(t))}{dt} \]  

Then \( \delta \) must be a time varying function. The effect of this is shown in Figure 28. As the voltage angle \( \delta \) decreases linearly over time, so too does the VSI power.

The VSI is able to determine the grid frequency internally. Therefore, a Proportional-Integral-Derivative (PID) controller was implemented with a similar function of a PLL (follow the grid frequency). In this case the PID controller was used to update the setpoint angular frequency \( \omega_{set} \). Figure 29 shows that the PID frequency controller worked quite well in grid-connected mode. The problem with this addition was that when the MG was islanded each VSI tried to synchronise with the other. The MG frequency soon becomes unstable, as shown in Figure 30.
If there was a way that the VSI could detect when the MG was islanded, the PID frequency controller could be switched in and out accordingly. The challenge is implementing an islanding detection system without a communication system, so that the benefit of the decentralised angle-frequency droop is maintained.

### 3.6.3.1.5 Black starts
Performing a black start where all DGs and loads are connected instantaneously results in extremely large voltage, frequency, and power oscillations. The voltage and currents observed in the simulation would be far too large for the power electronics of a VSI. The idealised VSI used for simulations permitted such large currents and voltages. A more detailed VSI model with a non-ideal DC voltage source would not allow such large swings. It is not well understood what the actual real world outcome of this would be and although a stable steady state is eventually achieved, clearly the oscillations required to reach steady state are unacceptably large. This is shown in Figure 31.

![Figure 31: DGs frequency and active power in an uncontrolled black start](image)

A sequence of control actions for a MG black start has been outlined in [6] and [34]. In this sequence of actions it is assumed that bidirectional communication between DGs and loads is present. It also assumes the MG can be broken into a number of smaller MGs, that can in turn operate in an islanded mode, before being synchronised together to form the complete MG. The basic sequence of actions is:

- Disconnect all loads
- Build smaller islanded MGs with controllable DGs
- Synchronise smaller islanded MGs
- Connect controllable loads
- Connect non-controllable DGs
- Increase load
- MG utility synchronisation and connection [34].
Without the extent of control proposed in [34] a black start control action was adapted from [34] and [6] for the angle-frequency droop controlled MG. The strategy simulated would require some form of communication between a MGCC and the DGs and loads. The sequence simulated was as follows:

- **Energising distribution lines and transformer**: Each DG was connected consecutively to the MG, to energise the distribution lines and transformer. With the average based VSI used in the simulation, each DG was able to provide the inrush currents for transformer energisation. A voltage ramp function should be used for this process to protect the power electronics of the inverter [34].
- **Load connection**: With the network energised each load was connected, starting with the smallest of the DGs local loads and ending with the largest. The PCC load and shunt capacitor were connected simultaneously and were the final loads to be connected.
- **Reconnection to utility grid**: The MG could now be reconnected to the utility grid.

Figure 32 shows the DGs response to the applied black start procedure and apart from some short term frequency variations the system was well regulated throughout.

![Figure 32: DGs frequency and active power for a sequential black start](image-url)
4 Conclusion and future work

In this report some of the control strategies used for MG grid-connected and islanded modes of operations were presented. Simulations were carried out for a multi master decentralised pure P-f droop controlled MG, and a multi master decentralised angle-frequency droop controlled MG. These control strategies are suitable for systems with dispatchable DGs spread throughout a MG.

The P-f droop controller adapted from [27] was simulated on a MV MG with two DGs, a SG and a VSI. The DGs responded adequately to a load change at the PCC with fairly accurate power sharing between DGs. Some losses in the stator winding did mean that there was a very slight mismatch in power sharing between the DGs. Being a multi master decentralised system, no secondary control was used and as such, a permanent frequency offset resulted from the load change. Adding a secondary angle droop to form an angle-frequency droop controller improved the frequency regulation such that the frequency returned to the setpoint in a little over 0.5 seconds for a 270kW load increase at the PCC.

The angle-frequency droop control scheme was expanded to a larger MG network with three VSI and four loads. The MG also had a connection to the utility grid via a MGCS at the PCC. The simulation demonstrated the many benefits of the proposed control system. The DGs displayed good power sharing in both grid connected and islanded modes of operations, displayed excellent frequency regulation in islanded mode, and with the assistance of a shunt capacitor could regulate voltage within acceptable limits of between 0.9 to 1.06pu. The VSIs ability to self-synchronise with the utility grid made for seamless transitions between islanded and grid-connected modes. The multi-master configuration also added redundancy to the system as the system could continue to run in an islanded mode if one of the DGs failed.

Both the P-f droop and the angle-frequency droop have plug-and-play ability. The angle-frequency droop however requires GPS angle referencing which would add a level of complexity to the setup. The angle-frequency droop controller also requires setpoint calculations, which could become quite complex as the system expands. Therefore the pure droop would be more easily implemented and may be a better option for situations where frequency regulation is not important.

The angle-frequency droop, whilst displaying very good power sharing and frequency regulation for specific situations, would need some more refinement to perform well under all conditions. One of the advantages of the angle-frequency droop is that it can be used as a decentralised system. One scenario where this appeared to be a problem was during a black start event. An uncontrolled black
start was unacceptable. A controlled sequential black start performed well, but would likely need some form of communications system.

The angle-frequency droop does require a secondary control level for frequency regulation, as the frequency is well regulated autonomously, although a lack of communication immediately eliminates the possibility of tertiary control. The angle-frequency droop does suffer from inaccurate power delivery when large load variations occur between the DG and the PCC. A communications system could improve the accuracy of power sharing. It was shown that to achieve high power sharing accuracy only a local communications system between the DG and local load would be needed.

Another problem where a communications system would be an obvious solution is to address the problems experienced with changing grid frequencies. The angle-frequency droop controller did not manage changes in the utility frequency very well. A small variation to the control system could overcome the problem in a grid-connected mode, but introduced other problems when the system was islanded. A communications system with a signal to change control modes of the VSI would overcome these difficulties. This is not to say a decentralised approach could not be implemented, but it would need more research for how this could be achieved.

The other problem requiring further research is how to improve the controller response to unbalanced loads in an islanded mode. An unbalanced load introduced small voltage, frequency and power oscillations. Although the system remains stable it is not a desirable response.

Even if fixes for the control problems could be easily implemented, there are many aspects that could be further investigated. If connected to a renewable source the angle-frequency droop controller could be integrated with MPP trackers and or battery charge controllers. Investigations would need to be carried out on how this could be achieved.

Problems outlined with the ability of MGs using inverters to detect and ride through faults could be further explored. This would require more detailed modelling of the inverter itself and the connected DC or high frequency AC source.

In conclusion, the pure-droop is a proven control system that despite shortfalls in frequency regulation performs well under many circumstances. The angle-droop is a promising solution for better frequency regulation of a decentralised system, however some issues need to be addressed before it can be fully implemented.
Bibliography


Appendix A: Simulink™, Simscape™ and SimPowerSystems™

**VSI simulation settings**

The average model of the H-bridge rectifier uses a three phase reference to produce an AC voltage, where:

\[ v_{an}(t) = \frac{V_{dc}}{2} \times u_{ref,\phi}(t) \rightarrow U_{ref} = u_{ref,\phi1}, u_{ref,\phi2}, u_{ref,\phi2}. \]

An ideal voltage source was used as the DC source.

**VSI P-f droop controller**
The P-f droop controller for the VSI is shown in Appendix Figure, which is expressed mathematically by:

\[
\Delta \omega = \int_0^t K_p (-K_f \Delta \omega + P_{set} - P) \, dt
\]  
\( (38) \)

\[
\frac{d\Delta \omega}{dt} = K_p K_f \Delta \omega + K_p P_{set} - K_p P
\]  
\( (39) \)

At steady state:

\[
\frac{d\Delta \omega}{dt} = 0 = -K_p K_f \Delta \omega + K_p P_{set} - K_p P
\]  
\( (40) \)

\[
\omega = \omega_{set} + \Delta \omega \rightarrow \Delta \omega = \omega - \omega_{set}
\]  
\( (41) \)

\[
P = K_p P_{set} - K_f \Delta \omega = P_{set} - K_f (\omega - \omega_{set})
\]  
\( (42) \)

The instantaneous frequency is given by the expression:

\[
\omega_{grid} = \frac{d(\omega t + \delta)}{dt}
\]  
\( (43) \)

At steady state:

\[
\frac{d\delta}{dt} = 0 \text{ and } \omega = \text{constant} \quad \therefore \omega_{grid} = \omega
\]  
\( (44) \)

**VSI angle-frequency droop controller**

[Diagram of VSI angle-frequency droop controller]
The VSI controller shown in Appendix Figure 4 is mathematically represented such that:

\[
\int \{(K_d(\delta_{set} - \delta) - \Delta \omega)K_f + P_{set} - P\}K_p \, dt = \Delta \omega 
\]

(45)

\[
\frac{d\Delta \omega}{dt} = K_pK_fK_d(\delta_{set} - \delta) - K_pK_f\Delta \omega + (P_{set} - P)K_p
\]

(46)

\[
\omega = \Delta \omega + \omega_{set} \rightarrow \Delta \omega = \omega - \omega_{set}
\]

(47)

At steady state:

\[
\frac{d\Delta \omega}{dt} = 0 = K_pK_fK_d(\delta_{set} - \delta) - K_pK_f\Delta \omega + (P_{set} - P)K_p
\]

(48)

\[
P = P_{set} + K_fK_d\delta_{set} - K_fK_d\delta - K_f\Delta \omega
\]

(49)

\[
\omega = \frac{P - P_{set} - K_fK_d(\delta - \delta_{set})}{-K_f} + \omega_{set}
\]

(50)

\[
\omega = \omega_{set}, \quad \text{and} \quad \Delta \omega = 0 \rightarrow \int \Delta \omega \, dt = \delta
\]

(51)

\[
\omega_{grid} = \frac{d(\omega t + \delta)}{dt} = \omega
\]

(52)

\[
P = P_{set} + K_fK_d(\delta_{set} - \delta)
\]

(53)
Appendix Figure 5: Angle-frequency droop with PID PLL for frequency following (Simulink™)

The angle-frequency droop with added frequency PLL used to follow variations in grid frequency.

Synchronous generator

Appendix Figure 6: Synchronous generator (SimPowerSystems™)
To simplify the calculation further $K_d$ was set to 0, therefore:

$$\Delta \omega(t) = \frac{1}{2H} \int \frac{P_m}{\omega} - \frac{P_e}{\omega} \, dt \rightarrow \frac{d \Delta \omega}{dt} = \frac{1}{2H} \left( \frac{P_m}{\omega} - \frac{P_e}{\omega} \right)$$  \hspace{1cm} (54)

At steady state:

$$0 = \frac{1}{2H\omega} (P_m - P_e) \rightarrow P_e \approx P_m$$  \hspace{1cm} (55)

The three phase voltage $V_{LL} = E$ of the input to the synchronous generator block.
**P-f droop**

Appendix Figure 8: Synchronous generator P-f droop controller (Simulink™)

**Angle-frequency droop**

Appendix Figure 9: Synchronous generator angle-frequency droop controller (Simulink™)
Test microgrid in MATLAB®

Appendix Figure 10: Seven bus microgrid (SimPowerSystems™)

Appendix Figure 11: Powergue settings (SimPowerSystems™)
The Powergue function block is required to carry out simulations using library components from SimPowerSystems™ and Simscape™.

**Appendix Figure 12:** Solver settings (Simulink™)

*Voltage angle, current, voltage, and Power measurements*

![Voltage angle, current, voltage, and Power measurements](image)

**Appendix Figure 13:** Phase angle measurement (Simulink™)

**Appendix Figure 14:** Voltage, current, active power and reactive power measurements (Simscape™)

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Appendix B: MATLAB® Gauss-Seidel solver code

The Gauss-Seidel solver was developed to determine the setpoint voltage angle and the angle-droop gain $K_d$.

clc clear all

%-------------------------------- Desirable DG grid connected power -----------------------------
P_1_g=2.43e6;
P_2_g=2.86e6;
P_3_g=1.9e6;
%-------------------------------- Desirable DG islanded power -------------------------------------
P_1_i=2.6e6;
P_2_i=3.12e6;
P_3_i=2.08e6;
%-------------------------------Load Power----------------------------------------------------------
S_4=2.4e6+0.6e6.*1i;
S_5=2e6+0.4e6.*1i;
S_6=1.4e6+0.7e6.*1i;
S_7=2e6-4e6.*1i;
%-------------------------------Base values-----------------------------------------------------------
S_base=10e6;
V_base1=4140;
V_base2=13.8e3;
%-------------------------------Voltage and frequency droop values----------------------------------
k_1=2.5e-4/(4140)*S_base;
k_2=2e-4/(4140)*S_base;
k_3=3e-4/(4140)*S_base;
k_f=10^5;
%-----------------------------------Y-bus matrix in Per-unit-------------------------------------
y11=(.2713+1.0210.*1i)^-1;y12=0;y13=0;y14=(.2713+1.0210.*1i)^-1;y15=0;y16=0;y17=0;
y21=0;y22=(.2713+1.0210.*1i)^-1;y23=0;y24=0;y25=(.2713+1.0210.*1i)^-1;y26=0;y27=0;
y31=0;y32=0;y33=(.2713+1.0210.*1i)^-1;y34=0;y35=0;y36=(.2713+1.0210.*1i)^-1;y37=0;
y41=(.2713+1.0210.*1i)^-1;y42=0;y43=0;y44=(.2713+1.0210.*1i)^-1*(.0737+0.0992.*1i)^-1; y45=0;y46=0;y47=(.0737+0.0992.*1i)^-1; y41=0;y42=0;y43=0;y44=(.2713+1.0210.*1i)^-1*(.0737+0.0992.*1i)^-1; y45=0;y46=0;y47=(.0737+0.0992.*1i)^-1; y41=0;y42=0;y43=0;y44=(.2713+1.0210.*1i)^-1*(.0737+0.0992.*1i)^-1; y45=0;y46=0;y47=(.0737+0.0992.*1i)^-1; y41=0;y42=0;y43=0;y44=(.2713+1.0210.*1i)^-1*(.0737+0.0992.*1i)^-1; y45=0;y46=0;y47=(.0737+0.0992.*1i)^-1; y41=0;y42=0;y43=0;y44=(.2713+1.0210.*1i)^-1*(.0737+0.0992.*1i)^-1; y45=0;y46=0;y47=(.0737+0.0992.*1i)^-1;
%-------------------------------Per unit calculation----------------------------------------------
P_1pu_g=(P_1_g)/S_base;
P_2pu_g=(P_2_g)/S_base;
P_3pu_g=(P_3_g)/S_base;
P_1pu_i=(P_1_i)/S_base;
P_2pu_i=(P_2_i)/S_base;
P_3pu_i=(P_3_i)/S_base;
S_4pu=S_4/S_base;
S_5pu=S_5/S_base;
S_6pu=S_6/S_base;
S_7pu=S_7/S_base;
%----------operating voltage initial guess---------------------------------------------------------
V_1=1;V_2=1;V_3=1;V_4=1;V_5=1;V_6=1;V_7=1;
Q_1pu=0;Q_2pu=0;Q_3pu=0;
for n=1:100
n=n+1;
%-------------------grid-connected---------------------------------------------------------------
V_1=1;y11.*conj(P_1pu_g*Q_1pu)./(conj(V_1)+y14.*V_4);
V_1=1;y11.*conj(P_1pu_g*Q_1pu)./(conj(V_1)+y14.*V_4);
Q_1pu=1i.*imag(P_1pu_g-Q_1pu)./(conj(V_1)+y14.*V_4);
V_1=abs(1-Q_1pu.*K_1).*exp(1i.*angle(V_1));
V_2=1;y22.*conj(P_2pu_g*Q_2pu)./(conj(V_2)+y25.*V_5);
V_2=1;y22.*conj(P_2pu_g*Q_2pu)./(conj(V_2)+y25.*V_5);
Q_2pu=1i.*imag(P_2pu_g-Q_2pu)./(conj(V_2)+y25.*V_5);
V_2=abs(1-Q_2pu.*K_2).*exp(1i.*angle(V_2));
V_3=1;y33.*conj(P_3pu_g-Q_3pu)./(conj(V_3)+y36.*V_6);
V_3=1/y33.*(conj(P_3pu_g+Q_3pu)./conj(V_3)+y36.*V_6);
V_3=abs(1-Q_3pu.*k_3).*exp(1i.*angle(V_3));
V_4=1/y44.*(-conj(S_4pu_)./conj(V_4)+y41.*V_1+y47.*V_7);
V_4=1/y44.*(-conj(S_4pu_)./conj(V_4)+y41.*V_1+y47.*V_7);
V_5=1/y55.*(-conj(S_5pu_)./conj(V_5)+y52.*V_2+y57.*V_7);
V_5=1/y55.*(-conj(S_5pu_)./conj(V_5)+y52.*V_2+y57.*V_7);
V_6=1/y66.*(-conj(S_6pu_)./conj(V_6)+y63.*V_3+y67.*V_7);
V_6=1/y66.*(-conj(S_6pu_)./conj(V_6)+y63.*V_3+y67.*V_7);

end

V_grid=[V_1;V_2;V_3;V_4;V_5;V_6;V_7];
Q_grid=[imag(Q_1pu);imag(Q_2pu);imag(Q_3pu);imag(S_4pu);imag(S_5pu);imag(S_6pu);imag(S_7pu)];
V_grid_solved=abs(V_grid)
angle_grid_solved=angle(V_grid)*180/pi
Q_grid_solved=Q_grid

for n=1:100
n=n+1;
V_1=1/y11.*(conj(P_1pu_i+Q_1pu_)./conj(V_1)+y14.*V_4);
V_1=abs(1-Q_1pu_.*k_1).*exp(1i.*angle(V_1));
V_2=1/y22.*(conj(P_2pu_i+Q_2pu_)./conj(V_2)+y25.*V_5);
V_2=abs(1-Q_2pu_.*k_2).*exp(1i.*angle(V_2));
V_3=1/y33.*(conj(P_3pu_i+Q_3pu_)./conj(V_3)+y36.*V_6);
V_3=abs(1-Q_3pu_.*k_3).*exp(1i.*angle(V_3));
V_4=1/y44.*(-conj(S_4pu_)./conj(V_4)+y41.*V_1+y47.*V_7);
V_4=1/y44.*(-conj(S_4pu_)./conj(V_4)+y41.*V_1+y47.*V_7);
V_5=1/y55.*(-conj(S_5pu_)./conj(V_5)+y52.*V_2+y57.*V_7);
V_5=1/y55.*(-conj(S_5pu_)./conj(V_5)+y52.*V_2+y57.*V_7);
V_6=1/y66.*(-conj(S_6pu_)./conj(V_6)+y63.*V_3+y67.*V_7);
V_6=1/y66.*(-conj(S_6pu_)./conj(V_6)+y63.*V_3+y67.*V_7);
V_7=1/y77.*(-conj(S_7pu_)./conj(V_7)+y47.*V_4+y57.*V_5+y67.*V_6);
V_7=abs(V_7);
end

V_island=[V_1;V_2;V_3;V_4;V_5;V_6;V_7];
Q_island=[imag(Q_1pu);imag(Q_2pu);imag(Q_3pu);imag(S_4pu);imag(S_5pu);imag(S_6pu);imag(S_7pu)];
V_island_solved=abs(V_island)
angle_island_solved=angle(V_island)*180/pi
Q_island_solved=Q_island

delta_a1=(angle_grid_solved(1)-angle_island_solved(1));
delta_a2=(angle_grid_solved(2)-angle_island_solved(2));
delta_a3=(angle_grid_solved(3)-angle_island_solved(3));
delta_p1=(P_1pu_i-P_1pu_g).*S_base;
delta_p2=(P_2pu_i-P_2pu_g).*S_base;
delta_p3=(P_3pu_i-P_3pu_g).*S_base;
k_d1=delta_p1./(k_f.*delta_a1*pi/180);
k_d2=delta_p2./(k_f.*delta_a2*pi/180);
k_d3=delta_p3./(k_f.*delta_a3*pi/180);