Abstract—Because of their deployment in dispersed locations on the lowest-voltage portions of the grid, photovoltaic (PV) systems pose unique challenges to power system engineers. Computer models that accurately simulate the relevant behavior of PV systems would thus be of high value. Also, the development of islanding detection and the optimization of maximum power point trackers are challenges in the development of PV inverters that carry relatively high development costs. To address these needs, a MATLAB/Simulink model of a single-phase grid-connected photovoltaic inverter has been developed and experimentally tested. The model development and comparisons of model output with observed inverter behavior are discussed in this paper. It is demonstrated that the model works quite well in predicting the general behaviors of single-phase grid-connected photovoltaic systems, and is thus well-suited for use by power system engineers.

Index Terms—photovoltaics; inverters; islanding detection; modeling and simulation

I. INTRODUCTION

PHOTOVOLTAIC (PV) systems produce electricity without producing CO₂. This property has led to worldwide government policies aimed at increasing the deployment of “grid-connected” or “utility interactive” PV systems that are connected with, and can export power to, utility power networks. PV systems are usually deployed in a highly dispersed mode, in the lowest voltage portions of the grid (down to 120 VAC), and they present unusual challenges for power system engineers tasked with understanding how high penetration levels of PV in industrial parks or ‘solar subdivisions’ might impact system operations. A well-verified computer model would be of great help in this task.

A suitable model must reasonably simulate the inverters’ means of islanding detection. Islanding detection is discussed thoroughly in the literature [1,2], and applicable utility interconnection standards, such as IEEE-1547, UL-1741, and IEC-62116, require that a grid-connected PV inverter be able to detect and prevent unintentional islanding [3-5]. The standards suggest the use of a specific test to demonstrate that a PV inverter can meet this requirement and be certified as a “non-islanding inverter”, but this test is difficult and somewhat expensive to perform, in spite of its conceptual simplicity. Modeling could also be of great utility in understanding the results of anti-islanding tests.

In addition to the anti-islanding controls, the operation of the maximum power point tracker (MPPT) can strongly affect stability and must also be properly simulated, along with the large buffer capacitor usually used at the DC inputs of PV inverters.

PV system models for use in power system simulations have been reported by other authors [for example, 6]. Although useful in some circumstances, most either resort to full switching models of the converter, which are not suitable for high-penetration case studies, or they do not model the MPPT and anti-islanding controls in sufficient detail to accurately simulate the performance and functionality of today’s inverters.

To address these needs, a computer model of a single-phase PV inverter has been developed in the MATLAB/Simulink environment. The model was designed to accurately represent the behaviors of a PV inverter that are most relevant at the system level, especially islanding detection and MPPT. Its primary value is thus to the power system engineer, and secondarily to the power electronics designer. The model was experimentally verified in collaboration with the Distributed Energy Technologies Laboratory (DETL) at Sandia National Laboratories, Albuquerque, NM.

II. DESCRIPTION OF THE MODEL

A. Specification of programming environment and goals

Many excellent power systems modeling packages exist—MATLAB/Simulink’s SimPowerSystems, EMTDC, PSCAD, EMTP-RV, and many others. The choice of which to use for
this work ultimately hinged on the need to flexibly simulate a variety of controls aspects, using a package that was in widespread use in industry and academia. For that reason, the MATLAB/Simulink package was chosen.

There was also considerable discussion about whether a physical model or a behavioral model made more sense. A physical model such as might be produced in a SPICE simulator would give better numerical accuracy, but would be highly specific to a particular inverter. Since the model needed to be broadly applicable for system studies, the model developed is a behavioral model.

In order to meet the needs described earlier, a number of important aspects of PV inverters need to be modeled with reasonable accuracy. Chief among them are:

- islanding detection behavior;
- action of the MPPT;
- output impedance;
- dynamic behavior of the means of synchronizing the PV inverter output to the grid voltage;
- response to grid voltage and frequency fluctuations.

B. Overview of the model

The system being modeled is shown in Figure 1. It consists of a PV array feeding an H-bridge inverter (switches S1-S4) that in turn feeds current into the utility voltage \( V_u \) through an interconnecting inductance \( L_{eq} \). The “eq” subscript indicates that this is an equivalent inductance, including effects from output filters and transformers and possibly the utility source impedance. The power output of single-phase inverters oscillates at 120 Hz, and thus a large buffer capacitor \( C_b \) must be included between the (DC) PV array and the H-bridge to filter out this 120-Hz power ripple.

The model includes:

- Six islanding detection algorithms:
  - Sandia Frequency Shift [7]
  - The classical linear instability method (CLIM) as implemented in the Teslaco PV inverter [8,9]
  - Sandia Voltage Shift [2]
  - Rate of change of frequency (RoCoF) [10]
  - Impedance detection [1,2]
  - Frequency bias [7]
- Two I-V curve based models of a PV array
- A Laplace-domain representation of an L-C lowpass output filter

The model is contained in a Simulink masked block. From the mask’s pop-up menus, the user can set the relevant parameters. The user may use either of the first two islanding prevention methods along with any combination of the last four (the first two islanding prevention methods cannot be modeled simultaneously).

C. The PV array model

Modeling the PV array in simulations of this type is difficult. The physical I-V relationship based on the Shockley equation requires parameters that are almost never available to power electronics or power system engineers. A better choice might be some type of mathematical curve fit, but a literature search quickly revealed that some of the available curve fits to the PV I-V curve are still quite cumbersome to use in this application.

The approach adopted here was to give the user two options for modeling the PV array. The first is a simplified approach based on a “unit” I-V curve shown in Figure 2. The “unit curve” looks approximately like the I-V curve for a single PV cell, except for the fill factor of 0.682 which is more representative of the entire array.

This “unit” curve is scaled to any arbitrary system size by entering the open-circuit voltage at standard test conditions (STC) and the nominal STC power of the array. If it is desired to change the I-V curve to more closely represent a particular array, this can be readily done by changing the vectors used in the lookup table. Changing irradiance conditions can also be approximately modeled.

This approach can be useful for many system-level applications, but it has one important drawback: it fixes the fill factor (FF). The FF affects MPPT performance, and in reality depends on temperature and irradiance. Thus, a second PV array modeling option is included: the model can accept I-V curve data from the program “Sandia IVTracer2”, which generates highly accurate I-V curves from a database of measured parameters on a wide variety of modules. The Simulink model that implements this latter PV array model for
three different irradiances is shown in Figure 3. Sandia IVTracer2 produces voltage and current vectors representing the PV array I-V curves. The user copies and pastes these into the I and V blocks shown. The “Repeating Sequence” block allows simulation of varying irradiance by selecting between the various I-V curves at user-prescribed times. The “Dynamic Lookup Table” accepts the PV array voltage as an input (the computation of which is described below), and its output is the corresponding PV array current. The “Subtract” block implements Kirchhoff’s Current Law at the node at the top of the capacitor in Figure 1; it subtracts the load current from the PV current \((i_1 - i_2)\), so that its output is the current into the capacitor. The capacitor current is used to compute the capacitor voltage via the 1/Capacitance and “Integration by the capacitor” blocks. The capacitor voltage and PV voltage are the same \((v_1\text{ in Figure 1})\), so the capacitor voltage is fed back into the I-V lookup table. In physical inverters, the measurement of the PV array voltage would be filtered, and this is simulated by the “var-per-RMS” block.

D. The MPPT

A block diagram of the perturb-and-observe (P&O) MPPT is shown in Figure 4 (following page). The instantaneous PV output current \((i_3\text{ in Figure 1, and IPV in Figure 4})\) and point of common coupling voltage \((v_{PCC}\text{ in Figure 1, and VPCC in Figure 4})\) are multiplied to obtain the PV system output power, which is averaged over a time window of one-tenth of the MPPT sampling interval. (Note that IPV and VPCC are in phase, so the average of their product is nonzero.) Digital control is assumed, so the PV power passes through a zero-order sampling block that uses a user-defined MPPT “decision interval”—in other words, this is the interval between points at which the P&O MPPT “decides” whether to increment or decrement the PV power. The “Transport Delay” block holds the sampled power for one sampling interval, so that the “Subtract” block subtracts the present power reading from the previous, to get the algebraic sign of the change in power. That sign is used to set a flag in the block labeled “Convert CtZ block output”; if the change in power is positive (output of “Compare to Zero” block is 1), the flag is set to +1, and if negative or zero (output of “Compare to Zero” block is 0), the flag is set to -1. The flag then multiplies a user-settable MPPT increment, which in turn is added to the present PV current (current flowing from the combination of PV array and capacitor) to increment or decrement it as appropriate.

E. The anti-islanding methods

A block diagram of one of the anti-islanding mechanisms included in the model is given in Figure 5 (following page). Islanding would occur if any part of a utility system that was disconnected from the main utility voltage source were still energized by a PV system (or other distributed energy resource). Consider the block diagram shown in Figure 6, which shows a grid-tied photovoltaic inverter (the dashed box), the utility voltage source, and a local load, usually modeled as a parallel RLC circuit. When the switch is in position “a”, the inverter’s terminal voltage is essentially independent of the inverter’s output current (neglecting the effects of the utility source impedance). When islanding begins and the switch moves to position “b”, the inverter’s terminal voltage is the result of the Ohm’s Law response of the local load to the inverter’s output current.

Most of the time, the PV system’s output current will be different than that drawn by the load at the nominal utility voltage, and in that case the change in switch position results in a detectable voltage change. However, if the PV output and load demand are closely balanced, then there is not enough change in the inverter’s terminal voltage to indicate the onset of islanding, and the inverter can run on.

Anti-islanding, or loss-of-mains, algorithms are used to prevent undesired islanding. Six anti-islanding methods are available in the model. One passive method is modeled: rate of change of frequency or “RoCoF”, which is a traditional method used in utility systems. The other five methods are active. The model subsection shown in Figure 4 implements SFS and frequency bias, and is implemented in the phase-locked loop (PLL) that produces the sinewave reference for the inverter’s output current. (Note that not all inverters use a PLL; some use the utility waveform as a template. However, this difference should result in only minor changes in dynamic behavior.) Over/undervoltage and over/underfrequency relaying are also modeled.

F. Modeling of the power stage

The model would not be useful for system simulations if a full switching model of the power stage were used, because simulation times and data file sizes would be excessive. Instead, an average model of the power stage was used, and for the hysteresis-controlled H-bridge, this model is merely a gain. The sine wave reference to which the gain is applied is altered to simulate the various anti-islanding methods as described above. However, the scaling factor needs to account for the MPPT and its interaction with the power-limited PV array and the large buffer capacitor.

Some MPPTs maximize the output (AC) power, while others monitor the PV input (DC) power. Either approach should work, but direct control over the PV power should lead to a more steady PV input for reasons that will become clear shortly. Therefore, in this model, the output power of the inverter is measured and maximized. Since the output current \((i_3\text{ in Figure 1})\) feeds into an essentially constant voltage source, increasing \(i_3\) will always result in an increase
Figure 3. Block diagram of the PV array model. Note that “Iout” is the inverter output current and is an input here.

Fig. 4. Perturb-and-observe maximum power point tracker. Signal propagation is from right to left (the inputs are at the right).

Figure 5. SFS waveform generator. Signal propagation is from right to left (the input is at the right).
in output power. Thus, the MPPT will command ever-increasing currents until the process becomes limited by the gain of the power stage. At that point, even though the MPPT commands an increase in current, the output power will actually decrease, the output power will fall, and the P&O MPPT will reverse direction. The gain of the power stage is clearly a function of \( v_{1} \), and it is necessary to determine what that functional dependency is. There are two ways to approach this problem. The first is to recognize that the H-bridge inverter is a buck-type converter. If one considers a PWM buck DC-DC converter, the relationship of output current to input voltage can be determined as follows:

\[
\frac{v_{o}}{v_{i}} = D = \frac{Zi_{o}}{v_{i}} \\
i_{o} = v_{i} \frac{D}{Z}
\]

(1)

where the input voltage \( v_{i} \) is the converter’s input voltage, \( v_{o} \) is the converter’s output voltage, \( i_{o} \) is the output current, \( Z \) is the impedance of the load fed by the converter, and \( D \) is the duty ratio. The output current is proportional to the input voltage. In the present case, there is no impediment but rather a nonideal voltage source (the impedance is in series with a voltage source), the determination of \( Z \) is nontrivial, and \( D \) would not be constant.

Another approach would be to consider that in the hysteresis-controlled H-bridge inverter, the current \( i_{3} \) in Figure 1 is controlled using the H-bridge to apply \( \pm v_{1} \) at \( v_{2} \), thereby controlling the time rate of change of the current through \( L_{eq} \). Consider the case in which the PV array is nearing maximum power operation after starting from zero current. The current \( i_{3} \) is increasing, and the voltage \( v_{1} \) has fallen to the point at which the converter cannot further increase the amplitude of the current. This case will appear approximately as shown in normalized form in Figure 6, which shows the sine wave reference used by the hysteresis controller, the hysteresis boundaries, and a linear approximation to the sine wave at \( t = 0 \). The PV voltage becomes so low that the current through \( L_{eq} \) “ramps” at approximately the same rate as the reference sine wave, and the bridge does not switch at all during the first portion of the sine wave. Under this condition, near the beginning of the sine wave (\( t = 0 \)), the derivative of \( i_{3} \) can be expressed as:

\[
\frac{di_{3}}{dt} = \frac{v_{2} - v_{U}}{L_{eq}} \approx \omega I_{3m} \cos \omega t
\]

(2)

where \( \omega \) is the frequency of \( v_{U} \) (rad/sec), and \( I_{3m} \) is the maximum value of \( i_{3} \) (A). The approximation is acceptable near the beginning of the cycle of the sine wave, and as long as the hysteresis bandwidth is small. Combining these equations and considering the case of \( t = 0 \) allows a calculation of the maximum amplitude of the current as a function of the PV voltage:

\[
I_{3m} = \frac{v_{PV}}{\omega L_{eq}}
\]

(3)

This calculated value of \( I_{3m} \) will actually be above the true value, but the relationship again supports the notion that it is physically reasonable to make the converter gain proportional to \( v_{i} \), with the constant of proportionality being somewhat less than that given by Equation (3). The approach followed in the model being discussed here was to normalize \( I_{3m} \) by its maximum value, which would be attained if the PV array reached its open-circuit voltage \( V_{OC} \), and multiply by a gain constant \( K \):

\[
I_{3m,norm} = K \frac{v_{1}}{V_{OC}}
\]

(4)

Now, explicit knowledge of \( L_{eq} \) is not required. A value of \( K = 3 \) has proven to be reasonable for most system level work, but if higher accuracy is desired, the value of \( K \) can be adjusted until the maximum power increment specified by the user is of the appropriate size, near the beginning of a simulation started from zero initial conditions.
III. MODEL VALIDATION

The validity of the model has been tested by comparing against experimentally-obtained data from the Distributed Energy Technologies Laboratory (DETL) at Sandia National Laboratories. A number of test cases have been examined, a few of which will be presented here. At this time, most of the available data are suitable for evaluating the general system-level behavior of the model, but detailed internal data on the converters tested were not generally available.

A. Effect of MPPT decision rate on MPPT stability

The model was tested to see whether the general behavior of the MPPT was correct. It has been observed that some PV inverters exhibit considerable low-frequency ripple because of the time lag required for the PV array + capacitor to reach its new operating point when the MPPT perturbs the operating state. This can reduce steady-state MPPT efficiency and lead to undesired shutdowns during changing irradiance conditions, but it can also reduce run-on times during islanding tests. Figure 7 shows an experimentally-measured example. There is approximately a 40-watt (0.3%) MPPT ripple in this example, at a frequency of about 0.15 Hz. The general downward slope is due to changing irradiance.

![Figure 7. Experimentally measured MPPT power ripple.](image)

The model was tested to see whether it correctly predicted this behavior. A representative example is shown in Figure 8. In this simulation, the PV array’s maximum power was 1265 W, irradiance was fixed, and the size of $C_b$ was 40 mF. The heavy trace was produced using an MPPT decision rate of 2 Hz (MPPT decision interval of 0.5 sec), and the lighter trace was produced using an MPPT decision rate of 5 Hz. If the MPPT samples too quickly, the low-frequency oscillation evident in Figure 7 begins to appear; that is, the model predicts the onset of undesired oscillation as the MPPT decision rate is increased. If the rate increases too far—in this case, 10 Hz was sufficient—the MPPT becomes unstable. Similar behavior could be observed if the MPPT decision rate were fixed but the buffer capacitor size was increased.

![Figure 8. Effect of MPPT decision rate on PV output power, for fixed capacitor size and MPPT increment.](image)

B. Anti-islanding method nondetection zones and behavior as a function of load quality factor

The modeled islanding prevention schemes have been thoroughly tested by comparison with both earlier theoretical work and laboratory results. In general, the anti-islanding models appear to work well, predicting general behaviors and nondetection zones (NDZs) reasonably accurately.

Figure 9 shows the results of one set of tests to determine the NDZs predicted by theory (phase criteria [12]) and by the model. The purpose of the test was to see how accurately the model predicted the location of the edge of the nondetection zone. The SFS gain was 0.05, the load was a parallel $RLC$ with $R = 11.8 \Omega$, and the MPPT was turned “off”. Figure 9 shows generally reasonable agreement, but there are two discrepancies apparent: the model NDZ is slightly shifted downward from the theoretical one, and the trend in the model’s lower boundary appears to be inverted from expectations. The downward shift is attributed to the fact that the model’s simulated inverter output current lags the
voltage by about two degrees. That phase shift comes from the inverter’s output low-pass filter, which was left as-is because it and its phase shift are representative of “real-world” inverters.

The reason for the lower boundary discrepancy appears to lie within the phase-locked loop (PLL) used to synchronize the inverter’s current reference wave to the utility voltage. The \( Q \) factors of loads toward the left side of Figure 9 are very high, resulting in an inevitable phase “glitch” upon loss of utility. The PLL senses this phase jump and adjusts its frequency in an attempt to maintain phase lock, resulting in a frequency transient that includes an overshoot. For \( L \) values of 300 \( \mu \)H and 100 \( \mu \)H (the left-most two values in Figure 9), the overshoot for \( C_{\text{nom}} \) values less than 0.9875 is large enough to result in an overfrequency trip. The same effect does not appear for the upper boundary because of the asymmetry of the frequency trip limits; the PLL transient exceeds the 60.5 Hz limit on the high side but does not quite reach the 59.3 Hz limit on the low side.

\[ C_{\text{nom}} \]

C. Using the model to understand an observed interaction between islanding prevention and MPPT functions

This test was described in an earlier paper [13]. The model was used to help explain an experimental observation that a particular commercially-available PV inverter did not island when its MPPT was active, but islanded readily for certain loads when the inverter deactivated its MPPT due to excessive temperature or input power. The model demonstrated that the reason was that the MPPT was marginally stable, so that when the utility was lost, the actual mechanism by which islanding was detected was that the perturbation caused by the anti-islanding algorithm destabilized the MPPT, eventually leading to an input low voltage cutoff.

\[ SFS \]

\[ SVS \]

\[ MPPT \]

\[ \text{SFS gain} = 0.0185 \]

\[ \text{SVS gain} = 0.01 \]

\[ \text{MPPT decision interval} = 0.25 \text{ s} \]

\[ \text{MPPT gain increment} = 2 \]

\[ \text{impedances, and the parameters were set as follows:} \]

\[ V_{u,\text{nom}} = 240 \text{ Vrms} \]

\[ R = 5.76 \Omega \]

\[ L = 6.1115 \text{ mH} \]

\[ C = 1.1513 \text{ mF} \]

\[ \text{MPPT decision interval} = 0.25 \text{ s} \]

\[ \text{MPPT gain increment} = 2 \]

\[ \text{SFS gain} = 0.0185 \]

\[ \text{SVS gain} = 0.01 \]

Then, a number of simulations were run to study the effects of varying several parameters. One of the most interesting results was obtained when varying the time at which the utility was disconnected over the range of 2 to 4 sec. The results of this set of simulations are shown in Figure 11. The horizontal axis variable in Figure 11 is the time at which the utility was disconnected, with \( t = 0 \) being the start of the simulation. Note that a number of closely-spaced simulations were run near 3 sec, to investigate the effect of cutting the utility off at different points in the sine wave. Figure 11 suggests that the point of disconnection within the sine wave made only a small difference, but when a larger time step was used, corresponding to different locations within the interacting cycles of SFS, SVS, and the MPPT, it was found that the run-on time variation due only to changing the utility cutoff time varied by almost a factor of three, from 0.65 s to 1.93 s. The maximum run-on time predicted by the model is reasonably close to that measured in the experiments. Figures 10 and 11 suggest that all of the run-on times found during the experiment are characteristic of the

![Figure 10. Average run-on times for four SFS inverters at full power (experimental result).](image-url)
IV. CONCLUSION

The model presented here appears to simulate the anti-islanding and maximum power point tracking behaviors of typical inverters quite well. It has proven useful in understanding behaviors seen in the lab, and will be useful in studying a variety of high-penetration cases.

Future work includes the addition of a model of a transformerless two-stage power circuit using a boost MPPT; improvements to the somewhat clumsy user interface; and porting the models into an EMTP-based simulator to make them available to a wider audience.

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