Abstract—Grid connection of many small-scale renewable energy resources, such as photovoltaics, requires an inverter. The way in which this inverter is controlled, is important in respect to safety and voltage quality. Control of such an inverter for Distributed Generation is designed and tested. This is performed on a 3 kW three-phase transformerless lab setup. In addition the inverter is also used as an Uninterruptible Power Supply in case of power outages.

I. INTRODUCTION

An inverter which is used as a combined distributed generator (DG) and uninterruptible power supply (UPS), needs both operation management and voltage or current control. Different operating modes will normally require different control methods. A DG must produce a sinusoidal current, and current-control is therefore often a natural choice [1]. Operation as an UPS, on the other hand, must produce a sinusoidal voltage, and requires voltage control. A voltage controlled inverter connected to the grid can produce large harmonic currents in case of a polluted non-sinusoidal voltage. An inverter which acts as a combined DG and UPS needs to meet this challenge. Therefore, in addition to developing an operation management strategy, a solution to this challenge will be shown.

The method for a combined UPS and DG inverter which will be presented here is based on a method used in active filters [2, 3]. A more detailed explanation for measurement of the 5th and 7th grid voltage harmonics is given in [4]. By controlling the inverter using this information, the grid current can be close to sinusoidal independently of the grid voltage quality. A similar approach will be used here, simplified and adapted to DG. It can reduce the grid current harmonic distortion for voltage-controlled inverters. The lab setup is shown in fig. 1.

II. INVERTER CONTROL METHOD

A. State estimator

A common method of synchronizing a DG to the grid is the use of a phase-locked loop (PLL). The PLL will only track the first harmonic. An alternative method is by use of 50 Hz oscillators running synchronously with the grid [2, 3, 4]. Such a resonance can be modeled using e.g. an LC parallel circuit shown in the right side of fig. 2. This can be expressed in unforced state space form:

\[
\dot{x} = Ax
\]

\[
\begin{bmatrix}
  v_g \\
  i_g
\end{bmatrix} = \begin{bmatrix}
  0 & -1 \\
  1 & L_{g50}
\end{bmatrix} \begin{bmatrix}
  v_g \\
  i_g
\end{bmatrix}
\]

(1)

A negligible resistance at 50 Hz can be paralleled with the capacitor, and series connected with the inductor. It will cancel any offset in the oscillation due to initial conditions. In order to synchronize the phase and amplitude of the LC circuit to the grid, feedback with a magnitude G is used:

\[
\hat{x} = (A - G \cdot C) \hat{x} + G \cdot y
\]

(2)

Fig. 2. The grid estimator structure. \(C_{g50}, L_{g50}, R_{e1}, R_{e2}\) are not physical components, but they represent the part of the observer which replaces the PLL. They are scaled so that the resonant frequency equals 50 Hz.
It is not necessary to measure the current through \( L_{g50} \), but measuring the voltage over \( C_{g50} \) is enough to make the system observable. Eqn. 2 expresses a state estimator for the grid voltage. It can be implemented in software by discretizing the continuous time model. The state space matrix \( A \) of the continuous time model can be transformed to the \( z \)-plane state space matrix \( A' \) using an indefinite series approximation of the exponential function for a matrix:

\[
A' = e^{A_T} = I + \sum_{n=1}^{\infty} \frac{(A \cdot T)^n}{n!} (3)
\]

In order to give a sufficient approximation to the indefinite series, 70 iterations were performed in Matlab. This digital oscillator can easily be included in the state estimator for the LCL-filter shown in fig. 2 and 3. The measured parameters are the current through \( L_{11} \), the voltage over the filter capacitor \( C_f \), and the grid voltage over \( C_{g50} \). The state space model for the combined grid and LCL-filter can be modeled as:

\[
\begin{bmatrix}
    v_c \\
    i_{l1} \\
    i_{l2} \\
    \psi_g \\
    \lambda_e
\end{bmatrix} =
\begin{bmatrix}
    -\frac{1}{L_{11}} & 0 & 0 & 0 \\
    \frac{1}{L_{11}} & 0 & 0 & 0 \\
    0 & 0 & -\frac{1}{L_{12}} & 0 \\
    0 & 0 & \frac{1}{R_g C_{g50}} & -\frac{1}{C_{g50}} \\
    0 & 0 & 0 & -\frac{1}{L_{g50}}
\end{bmatrix}
\begin{bmatrix}
    v_c \\
    i_{l1} \\
    i_{l2} \\
    \psi_g \\
    \lambda_e
\end{bmatrix} +
\begin{bmatrix}
    0 \\
    \frac{1}{L_{11}} \\
    0 \\
    0 \\
    0
\end{bmatrix} u
\]

(4)

The grid voltage estimator can also include harmonics such as the 5th and 7th, using separate oscillators at 250 Hz and 350 Hz. By superposition these three frequencies improve the tracking capability. The filter capacitor voltage over \( C_f \) can then track the grid voltage to a greater extent compared to only 50 Hz tracking. It improves the grid current total harmonic distortion (THD).

### B. Operation monitoring

Today most DG operates without any communication for control. They basically contain two operating modes: Grid-connected and grid-disconnected. Transitions between these two modes are locally controlled based on measured parameters such as voltage and frequency [5, 6].

If islanding is not a problem, a grid-connected inverter has the capability of supporting the grid voltage e.g. by producing reactive power, or harmonic currents. An islanding condition would then be harder to detect. The responsibility of islanding detection could be put on a communication channel instead. This is shown in [7, 8]. By expanding the number of operating modes to three, one can accept a less reliable communication channel in order to enhance the operation freedom. This is shown in fig.4.Maintaining the same level of security independently of the communication reliability can be obtained by having a safe no-communication mode (mode 1 in fig. 4). If communication fails, the system falls back to this mode.

In mode 1, non-islanding inverter control, reactive power must be zero. The active power flow is controlled inversely of the typical droop control for load sharing. In order to make an islanded grid unstable, a small (islanded) grid frequency drop will be amplified by the inverter (positive feedback). This will cause the island frequency to exceed the predefined frequency tolerances, and thus an islanded situation will be detected.

These fail-safe and gracefully degradable operating mode transitions enable the best of new and old technology, whilst avoiding too expensive investments in secure communication. In practice the fail-safe mode transitions are based on a decision table. It also contains a list of preferred operating modes. A similar approach can be found in [9].
The list will often be identical for all modes, but in some cases it may depend on current operating mode. This may be desirable e.g. if extra security is needed, or if the operating mode transitions are complicated. This is the case for the local inverter control described in fig. 9.

Every operating mode has its own conditions, which is simply given by a string of status bits. It starts with the least preferred mode and checks whether the conditions are met or not. It does so for every mode until it finds a mode whose conditions are not met. The last good mode will then be the current operating mode. This is implemented in a binary format, in order to make this easy to implement in a Digital Signal Processor (DSP). The equation that must be satisfied for any mode is:

\[
\text{status} \land \text{Requirement}\_\text{mode} = \text{Requirement}\_\text{mode} \quad (5)
\]

This is in fact a decision table, because the requirements can be ordered in a table. Decision tables are not the best representation for reading. On the other hand it is very efficient when programming a DSP or a microcontroller. This is shown in fig. 5.

The first status bit from the left may represent "grid frequency OK". The second bit may be "grid voltage OK". Let’s say the third is "communication OK". The fourth may be "DC voltage OK". The error mode 0 (UPS) does not have any requirements in this example. The degraded mode 1 (non-islanding) needs both the "frequency OK" and the "voltage OK" bits to be set, in addition to the "DC voltage OK" bit. If any of these bits are not set, the system will stay in the error mode 0. A preferred mode 2 (voltage support) will in addition need the communication bit to be set. For the example in fig. 5, this status bit is not set. Therefore the system will stay in mode 1, grid connected and controlled to avoid islanding by local measurements only.

### III. EXPERIMENTAL SETUP

A three-phase lab test setup as shown in fig. 1 was connected to the grid. A harmonic spectrum analyzer was used to measure the voltage and current between two of the phases, in order to evaluate the THD at 3 kW of power. The UPS functionality was also tested using a 3-phase diode rectifier load. Operating mode transitions were also verified.

The inverter was controlled using a Texas Instruments TMS320F2812 DSP. The inverter was a 3-phase voltage source inverter (VSI) with a DC voltage of 340 V. Line voltage was 230 V. The neutral wire was not connected. The switching frequency was 10 kHz. The bandwidth (-90° phase) of the filter capacitor voltage estimator was 1.99 kHz. From reference to filter capacitor voltage, the state feedback loop had a bandwidth of 1.41 kHz, in order to damp the LC filter resonance frequency at maximum 1.28 kHz.

The grid estimator was implemented using a separate oscillator for each of the axes in the αβ-plane. This is partially shown in the appendix. This made it possible to track an unbalanced grid, and it would be easier to adapt to different directions of rotation. Relevant variables internally in the DSP state estimator are shown for the α-axis in fig. 6-8.

![Fig. 4. Operating modes overview](image)

**Fig. 4. Operating modes overview**
IV. RESULTS

In order to evaluate the effect of the 5th and 7th harmonic estimators, current THD was measured both with and without harmonic estimators. The background grid voltage THD was increased from 0.5% to 1% by connecting a 3-phase diode rectifier load. The results from measurements using a harmonic analyzer function in Labview are summarized in table 1.

Table 1: Current THD with and without harmonic estimators

<table>
<thead>
<tr>
<th></th>
<th>VTHD</th>
<th>ITHD</th>
<th>ITHD, 5th</th>
<th>ITHD, 7th</th>
</tr>
</thead>
<tbody>
<tr>
<td>With harmonic estimators</td>
<td>1.14%</td>
<td>3.82%</td>
<td>2.72%</td>
<td>0.58%</td>
</tr>
<tr>
<td>Without harmonic estimators</td>
<td>1.07%</td>
<td>5.39%</td>
<td>3.67%</td>
<td>2.79%</td>
</tr>
</tbody>
</table>

These results prove the beneficial effect of harmonic estimators at the 5th and 7th harmonic. The improvement is depending much on the level of voltage pollution, and in which frequencies the distortion is.

The local control was tested by connecting and disconnecting the grid. Operating mode transitions between local modes were tested. The modes are shown in fig. 9, which is a detailed version of fig. 4.
V. DISCUSSION

The concept of harmonic voltage estimator can enable the use of voltage-controlled grid connected inverters that meet today's standards. This is useful for a combined UPS and DG inverter.

The concept presented is originally made for current-control in active filters. The concept presented in [1] is perhaps more useful for current-control in DG because of simplicity. The presented approach makes more use of the voltage-control capability, which is needed for the UPS functionality. It makes it easier to satisfy the standards concerning harmonics, which is 5 % THD for voltage and current at rated power [5, 6].

The 18-state estimator requires a large amount of memory. All matrix multiplications were done using Texas Instruments IQ20-format. This could have been optimized using an assembly routine instead. This was not done. Instead artificially sparse matrixes were used. Because new DSP designs have a continuously improving performance, the execution time and memory will not be a problem in the future for this method. The state estimator with fixed feedback gain G is also simpler than a Kalman observer used by [2, 3]. It is possible to analyze and design using standard methods like pole placement, which is especially convenient to combine with state feedback.

The state estimator is suitable for a system which has small frequency deviations. The frequency is stable enough in grid connected generators, but not necessarily on board ships. For offshore installations and ships, the frequency changes so much that a PLL is probably more useful.

Today's standards are not suited for harmonic reduction. When many inverters are located close, they tend to interact in a way making large voltage distortions [1, 10]. This will probably lead to changes concerning the regulations. In that case, the current distortion standards may be redefined. This may be in favor of voltage-controlled inverters or current-controlled inverters with some harmonic separation. Changes in these regulations will hopefully make better use of the inverter control capabilities, and not only try to make it look like a negative resistor electrically.

B. Operation management

The system has a well defined implementation for the transitions between the different operating modes. The presented system can run in grid-interactive mode, and in standalone mode. The operating mode transition in case of errors worked as assumed, making the system gracefully degradable.

C. Further work

Testing with a shorted grid should be done before using this in a commercial product. A solid-state switch would be preferred over the relay currently used for grid disconnection, in order to improve the speed. Non-islanding techniques should also be implemented and verified with different loads.

VI. CONCLUSION

A. State estimator

The tested estimator makes it easier to alternate from standalone to grid-interactive mode and still meet the standards concerning harmonics. A grid voltage estimator with 5th and 7th harmonics gives a better current THD compared to only a first harmonic estimator.

B. Operation management

The system has a well defined implementation for the transitions between the different operating modes. The presented system can run in grid-interactive mode, and in standalone mode. The operating mode transition in case of errors worked as assumed, making the system gracefully degradable.

C. Further work

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APPENDIX

The state space model was first developed in the continuous time plane. It can be expressed as a state space model as shown in the forced eqn. 6. The A-matrix is shown in the unforced eqn. 7.

The upper left part models the physical LCL output filter. Here the following values are used: $C_f = 30 \mu F$, $L_{f1} = 0.75 \text{ mH}$, and $L_{f2} = 1.65 \text{ mH}$. The nominal DC voltage is 340 V. The lower right part is the grid estimator, which has a separate oscillator for each axis. Every second state is not measured, but only necessary to keep the $\alpha$-axis independent from the $\beta$-axis. This gives good tracking capability in case of unsymmetrical voltages.

The harmonic oscillators can be zeroed easily in the discrete version of this A-matrix. This can be done to reduce the voltage THD, if the current THD is of little interest. The discrete version was used for design of the feedback gains using pole placement.
\[ \dot{x} = A \cdot x + B \cdot u \] (6)

\[ \begin{bmatrix} \dot{v}_{C\alpha} \\ \dot{v}_{C\beta} \\ \dot{i}_{E\alpha} \\ \dot{i}_{E\beta} \\ \dot{i}_{L\alpha} \\ \dot{i}_{L\beta} \\ \dot{v}_{g30\alpha} \\ \dot{v}_{g30\beta} \\ \dot{v}_{g35\alpha} \\ \dot{v}_{g35\beta} \\ \dot{v}_{g25\alpha} \\ \dot{v}_{g25\beta} \\ \dot{v}_{g25\beta} \\ \dot{v}_{g30\alpha} \\ \dot{v}_{g30\beta} \end{bmatrix} = \begin{bmatrix} \frac{1}{L_{c\alpha}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & \frac{1}{L_{c\beta}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & \frac{1}{L_{e\alpha}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & \frac{1}{L_{e\beta}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & \frac{1}{L_{l\alpha}} & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{l\beta}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g30\alpha}} & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g30\beta}} & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g35\alpha}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g35\beta}} \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \end{bmatrix} \begin{bmatrix} v_{C\alpha} \\ v_{C\beta} \\ i_{E\alpha} \\ i_{E\beta} \\ i_{L\alpha} \\ i_{L\beta} \\ v_{g30\alpha} \\ v_{g30\beta} \\ v_{g35\alpha} \\ v_{g35\beta} \\ v_{g25\alpha} \\ v_{g25\beta} \\ v_{g25\beta} \\ v_{g30\alpha} \\ v_{g30\beta} \end{bmatrix} + \begin{bmatrix} \frac{1}{L_{c\alpha}} & \frac{1}{L_{c\beta}} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & \frac{1}{L_{e\alpha}} & \frac{1}{L_{e\beta}} & 0 & 0 & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & \frac{1}{L_{l\alpha}} & \frac{1}{L_{l\beta}} & 0 & 0 & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g30\alpha}} & \frac{1}{L_{g30\beta}} & 0 & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g35\alpha}} & \frac{1}{L_{g35\beta}} & 0 \\ 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \frac{1}{L_{g25\alpha}} & \frac{1}{L_{g25\beta}} \end{bmatrix} \begin{bmatrix} 250 \ 350 \ 50 \end{bmatrix} \begin{bmatrix} R_{c\alpha} C_{c\alpha} \ R_{c\beta} C_{c\beta} \\ R_{e\alpha} C_{e\alpha} \ R_{e\beta} C_{e\beta} \\ R_{l\alpha} C_{l\alpha} \ R_{l\beta} C_{l\beta} \\ R_{g30\alpha} C_{g30\alpha} \ R_{g30\beta} C_{g30\beta} \\ R_{g35\alpha} C_{g35\alpha} \ R_{g35\beta} C_{g35\beta} \\ R_{g25\alpha} C_{g25\alpha} \ R_{g25\beta} C_{g25\beta} \end{bmatrix} \] (7)

ACKNOWLEDGMENT

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REFERENCES


