Power Flow Control of a Single Distributed Generation Unit with Nonlinear Local Load

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***Abstract*— Distributed generation units with small energy sources, such as fuel cells, micro-turbines, and photovoltaic devices, can be connected to utility grid as alternative energy sources besides providing power to their local loads. The distributed generation units are interfaced with utility grid using three phase inverters. With inverter control, both active and reactive power pumped into the utility grid from the distributed generation units can be controlled. Reactive power flow control allows the distributed generation units to be used as static var compensation units besides energy sources. This paper presents a distributed generation unit control technique which provides robust voltage regulation with harmonic elimination under island running mode and decoupled active and reactive power flow control under grid-connected mode. The control technique, which combines discrete-time sliding mode current control, robust servomechanism voltage control, and integral power control, enables seamless switching between island mode and grid-connected mode and guarantees sinusoidal line current waveform under nonlinear local load. The P Q coupling issue is addressed and the stability of the power control loop is proved using Lyapunov direct method.**

I. Introduction

Distributed generation (DG) units interfaced with utility grid with static inverters are being applied and focused increasingly due to the fact that conventional electric power systems are being more and more stressed by expanding power demand, limit of power delivery capability, complications in building new transmission lines, and blackouts. Power quality, safety and environmental concerns and commercial incentives are making alternative energy sources, e.g., fuel cells, photovoltaic devices, wind power, and gas-fired micro-turbines, more desirable. Especially, developments in power electronics and digital control technology are providing more possibility and better flexibility of using these new sources in conventional electric power systems, to not only increase electric energy production but also help to enhance the power system stability via power flow control.

Previous research results have shown that DG could have significant impacts on transmission system stability at heavy penetration levels [1], where penetration is defined as the percentage of DG power in total load power in the system. A DG unit affects the system stability by generating or consuming active and reactive power. Therefore, power control performance of the DG unit determines its impact on the utility grid it connects to. If the power control performance is good, the DG unit can be used as means to enhance the system stability and improve power quality; otherwise it could undermine the system stability.

Control issues of grid-connected inverter systems with local load have been addressed by a number of researches. Chandorkar et al. [2] and Kwon et al. [3] have studied line interactive inverters to be used as uninterruptible power supplies (UPS), where the inverters do not power the local load and the utility mains simultaneously, and therefore do not contribute to transmission system stability. Some past researches on line interactive inverters [4]–[9] only concentrate on current waveform control where power control is not considered. Although current waveform control is one of the goals of the inverter control, power control performance must be addressed before it can be practically connected to any power system.

Liang et al. [10] have presented a power control method for a grid-connected voltage source inverter which achieves good P Q decoupling and fast power response. However, this approach requires knowledge of the value of power system equivalent impedance, which is impractical. Even though the possible error in the power factor angle of the impedance has been considered, it is the magnitude of the impedance that truly causes the sensitivity of P and Q responses, which is however not addressed. Therefore, the effectiveness of the control approach claimed in [10] is undermined.

Illindala et al. [11] have presented a different power control strategy based on frequency and voltage droop characteristics of power transmission, which allows decoupling of P and Q at steady state. However, the presented simulation result does not show a satisfactory performance in response time and control magnitude which could be caused by low feedback gain and implies that higher gain may cause problems.

In this paper, a new solution to the power flow control problem of a grid-connected single DG unit will be proposed. The proposed approach combines voltage regulation plus harmonic minimization under island mode and decoupled P and Q control under grid-connected mode with a nonlinear local load. The proposed control does not require knowledge of the equivalent impedance of the utility grid the DG unit is connected to and yields seamless switching transients between island mode and grid-connected mode, strong P and Q regulation capability, fast enough response, and purely sinusoidal

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line current. The P Q coupling issue will be addressed and a proof of the power loop stability based on Lyapunov's method will be presented.

II. The Control System

The proposed control solution is developed for a grid-connected DG unit shown in Fig. 1. The DG unit consists of a DC bus powered by any DC source or AC source with a rectifier, a voltage source inverter, an LC filter stage, a Δ/Yg type isolation transformer with secondary side filtering. The DG unit has a local load, linear or crest, and is connected to the utility grid through a three-phase triac. The utility grid is modelled as an equivalent three-phase AC source with an equivalent internal impedance.

Under island mode, the inverter conducts voltage control, where the load voltage V_{outABC} should track the given reference. The voltage control goal is strong voltage regulation, low static error in RMS, fast transient response, and low total harmonic distortion (THD). If the voltage of the utility main E_{ABC} is measured and used as the reference, V_{outABC} will be controlled to match E_{ABC} in magnitude and synchronized in phase angle.

Under grid-connected mode, the DG unit conducts power control, where the output active power P and reactive power Q from the DG unit to the utility grid should be regulated to desired values P_{ref} and Q_{ref}. Both P_{ref} and Q_{ref} can be positive or negative, which provides possibility for the DG unit to help with the energy production and stability enhancement of the power system or sustain power supply to local load when it exceeds the capacity of the DG. The control goal of power regulation is stability, low static error, and fast response.

In the switching transient from island mode to grid-connected mode, even though V_{outABC} matches E_{ABC} before the triac is turned on, transient current will still flow due to the change of the circuit topology. The duration of the transient is determined by the power control performance. Due to the matching between V_{outABC} and E_{ABC} and the low equivalent impedance Z, the V_{outABC} transient is mostly negligible and regarded seamless.

A. Voltage and Current Control

For high quality of V_{outABC} with strong regulation, low THD, and overload protection, a dual-loop voltage and current control structure is used as shown in Fig. 2, where the inner loop is for current control and outer loop is for voltage control. A robust servomechanism controller (RSC) is used for voltage control and a discrete-time sliding mode controller (DSMC) is used for current control. The three-phase quantities are transformed from ABC reference frame into a stationary $\alpha\beta$ reference frame. The details of this approach have been given in [12], [13]. Some key points are summarized below for readers convenience.

The DSMC is used in the current loop to limit the inverter current under overload condition because of the fast and no-overshoot response it provides. The RSC is adopted for voltage control due to its capability to perform zero steady state tracking error under unknown load and eliminate harmonics of any specified frequencies with guaranteed system stability. The theory behind the RSC is based on the solution of robust servomechanism problem (RSP) [14] where the internal model principle [15] and the optimal control theory for linear systems are combined. The internal model principle is applied in the DG voltages control by including the fundamental frequency mode and the frequency modes of the harmonics to be eliminated into the controller. The optimal control theory of linear systems is combined in the RSC in order to guarantee the stability of the closed loop system and providing arbitrary good transient response based on desired control priorities.

In a DG unit shown in Fig. 1, most of the voltage harmonics, like the triplen (3rd, 9th, 15th, ...) and even harmonics, are either non-existing or uncontrollable, or negligible in values. Therefore, only the fundamental and the 5th and 7th harmonics are left for the control to handle. Since the overload protection is a strongly desired feature for inverter systems, a DSMC is included in the inner loop to limit the current under overload conditions. With the existence of the DSMC in the inner loop, the RSC in the outer loop are designed taking the dynamics of the DSMC into account, so that the stability and robustness of the overall control system is guaranteed.

1) The discrete-time sliding mode current control: The circuit shown in Fig. 1 is a linear system and can be modelled in state space. The current controller controls the inverter current, i.e., the inductor current. The LC filter can be represented in discrete time

$$\begin{cases} X_i(k+1) = A_i X_i(k) + B_i v_{inv}(k) + E_i i_{out}(k) \\ y_i(k) = C_i X_i(k) \end{cases} \quad (1)$$

where $X_i(k) = \begin{bmatrix} v_{xfm}^T(k) & i_{inv}^T(k) \end{bmatrix}^T$, v_{inv}, and load disturbance i_{out} are all represented in $\alpha\beta$ reference frame. Given inverter current command $i_{ref}(k)$, the DSMC equivalent control law is

$$\begin{aligned} v_{inv,eq}(k) = (C_i B_i)^{-1} [&i_{ref}(k) \\ &-C_i A_i X(k) - C_i E_i i_{out}(k)]. \end{aligned} \quad (2)$$

With inverter control voltage limit v_{max} determined by the DC bus voltage and PWM technique, the actual control voltage becomes

$$v_{inv} = \begin{cases} v_{inv,eq} & \text{if } \|v_{inv,eq}\| \leqslant v_{max}, \\ \frac{v_{max}}{\|v_{inv,eq}\|} v_{inv,eq} & \text{otherwise.} \end{cases} \quad (3)$$

2) The robust servomechanism voltage control: The voltage controller generates current command i_{ref} for the current controller. For the system shown in Fig. 1, considering the dynamics of the DSMC current controller, the overall state space model is

$$X(k+1) = AX(k) + Bi_{ref}(k) + Ei_{out}(k), \quad (4)$$

where $X(k) = \begin{bmatrix} v_{xfm}^T(k) & i_{inv}^T(k) & v_{out}^T(k) & i_{xfm}^T(k) \end{bmatrix}^T$, with all element vectors represented under $\alpha\beta$ reference frame, and i_{xfm} is the transformer secondary current and will be replaced by i_{out} feedback in the control due to the negligible difference.

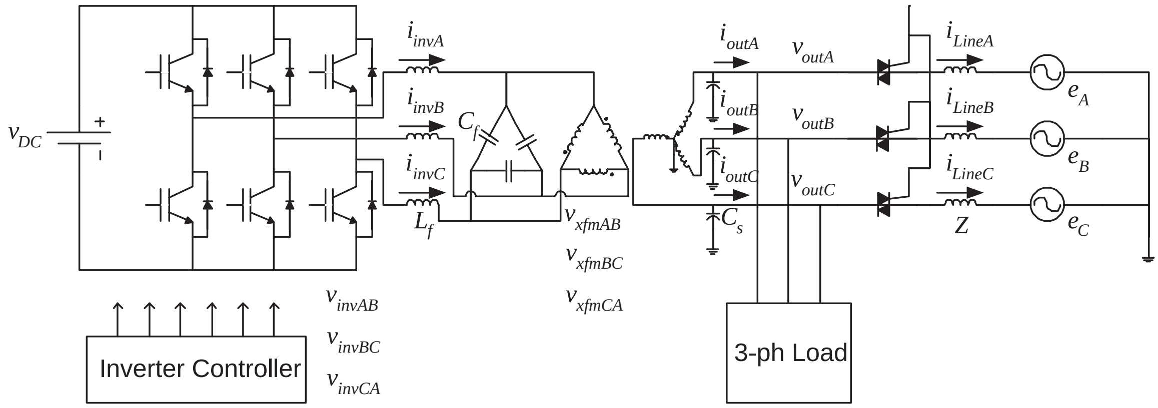

Fig. 1. A grid-connected DG unit with local load.

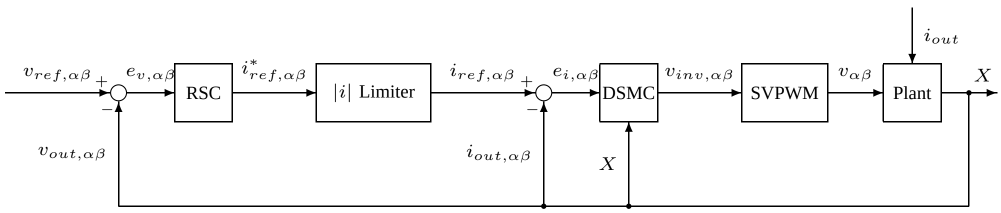

Fig. 2. Control structure for island mode.

An RSC is a combination of a stabilizing compensator and a servo compensator. The stabilizing compensator is the state feedback of (4) times a gain K_0. The servo compensator is a second order filter represented by

$$\eta(k+1) = A_s\eta(k) + B_s e_v(k), \tag{5}$$

where η is the state vector, $e_v(k)$ is the instantaneous voltage regulation error vector, and matrix A_s has poles at specified frequencies to be cancelled from $e_v(k)$, e.g., the fundamental, 5th and 7th harmonics. All quantities are in the $\alpha\beta$ reference frame.

The current command for the current controller can be obtained as

$$i_{ref}(k) = K_0 X(k) + K_1\eta(k), \tag{6}$$

where the gains K_0 and K_1 are obtained by solving the linear quadratic optimization problem of the augmented system of X and η. Therefore, run-time gain calculation is not necessary.

B. Active and Reactive Power Control

Since the DG unit uses a voltage source inverter with a strong voltage control, its output active and reactive power are determined by the unit's output voltage, including magnitude and phase angle, as stated in

$$P = \frac{V_{out}E}{X}\sin\delta, \tag{7}$$

$$Q = \frac{V_{out}^2 - V_{out}E\cos\delta}{X}, \tag{8}$$

where E is the equivalent main voltage, X is the equivalent line reactance where the resistance is ignored, and δ is the power angle. Since the DG unit output voltage control already exists, the task of the power controller is to generate voltage command for the voltage controller based on the desired power values P_{ref} and Q_{ref} and actual values P and Q as illustrated in Fig. 3.

It is apparent that the desired DG output voltage V and the power angle δ can be calculated from (7) and (8) given desired P and Q values and system parameter X. If this is true, the power control problem is solved. However, in practical systems, the above approach is not feasible. Equations (7) and (8) show that both P and Q are sensitive to variation of X since it appears in the denominators and especially when X is small. A large capacity power system is assumed in this research, where the value of X must be small. Practically, the value of X cannot be precisely known and may change due to the operation of the power system. Once an inaccurate value of X is used in the control, the error of X will lead to poor tracking and even instability. Therefore, power control solutions requiring knowledge of X cannot be practically used.

It can be observed from (7) and (8) that both P and Q will be affected by only adjusting one of V and δ, which is so called coupling between P and Q. However, variations of V and δ have different levels of impact on P and Q as described in the following partial derivatives -

$$\frac{\partial P}{\partial \delta} = \frac{V_{out}E}{X}\cos\delta, \tag{9}$$

$$\frac{\partial P}{\partial V_{out}} = \frac{E}{X}\sin\delta, \tag{10}$$

$$\frac{\partial Q}{\partial \delta} = \frac{V_{out}E}{X}\sin\delta, \tag{11}$$

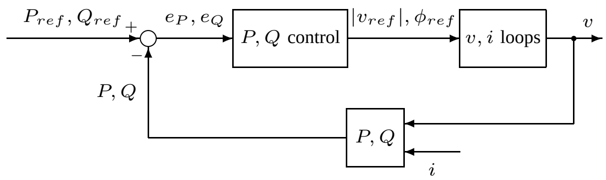

Fig. 3. Control structure for grid-connected mode.

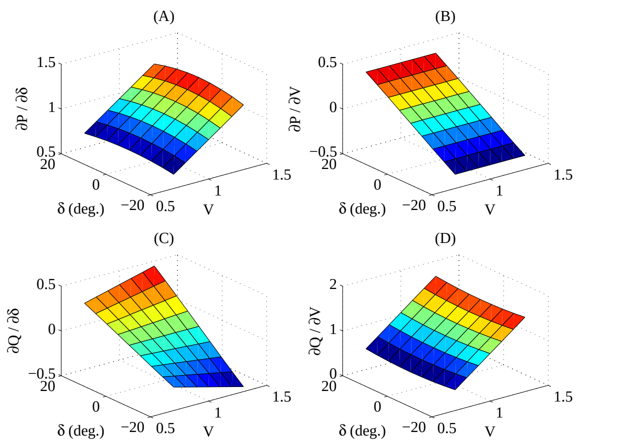

Fig. 4. Sensitivity of P and Q to V and δ variations with normalized V, E, and X: (A) $\frac{\partial P}{\partial \delta}$, (B) $\frac{\partial P}{\partial V}$, (C) $\frac{\partial Q}{\partial \delta}$, (D) $\frac{\partial Q}{\partial V}$.

$$\frac{\partial Q}{\partial V_{out}} = \frac{2V_{out} - E\cos\delta}{X}. \tag{12}$$

These partial derivatives are plotted in three-dimensional manner as shown in Fig. 4 to illustrate the significance of the impacts of V and δ variations on P and Q under different V and δ values. The values of V, E, and X are normalized in Fig. 4 for comparison purposes.

It can be observed from Fig. 4 that, when $|\delta|$ is small and V is close to 1 which is true for large capacity power systems, $\frac{\partial P}{\partial \delta}$ is close to 1 and $\frac{\partial P}{\partial V_{out}}$ is close to 0 and reversely, $\frac{\partial Q}{\partial \delta}$ is close to 0 and $\frac{\partial Q}{\partial V_{out}}$ is close to 1. This fact indicates that P is more sensitive to δ and Q is more sensitive to V_{out} especially when the DG unit is connected to a large capacity system where the power angle δ is usually small. The different levels of sensitivity of P and Q to δ and V_{out} provide a chance to control P and Q relatively independently, not completely independently though.

Based on the above analysis, an integral approach to conduct the power flow control can be developed to control P by adjusting δ and control Q by adjusting V_{out}. If the phase angle associated to the system voltage E is assumed to be 0, $\delta = \phi$ holds, where ϕ is the phase angle associated to V_{out}. The voltage and phase angle references can be generated as

$$\phi_{ref} = \int [K_P(P_{ref} - P) + \omega_n]dt + \phi_0, \tag{13}$$

$$V_{ref} = \int K_Q(Q_{ref} - Q)dt + V_0, \tag{14}$$

where $\omega_n = 2\pi \cdot 60$rad./sec. is the system nominal angular frequency, ϕ_0 and V_0 are the initial voltage and phase angle at the moment that the DG unit is connected to the grid from island running mode. The proposed power controller is illustrated in Fig. 5 where the integration is implemented in discrete-time.

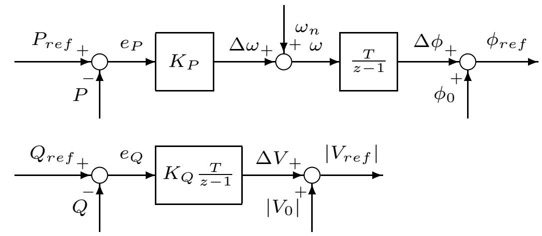

Fig. 5. The power regulator for P and Q.

C. The Stability Issue

In the proposed power regulation approach, P and Q controls are decoupled under steady state due to the integration of the errors. However, in the transient, the P Q coupling cannot be eliminated. Moreover, both P and Q are nonlinear functions of V_{out} and ϕ, which increases the complexity to analyze the system behavior. Due to the coupling issue and the nonlinearity, the stability of the power control must be investigated.

Due to the strong regulation of the DG output voltage V_{out} and its phase angle ϕ, the dynamics of the voltage control loop can be simplified into a first-order system with a transfer function representation

$$\phi(s) = \frac{a_\phi}{s + a_\phi}\phi_{ref}(s), \tag{15}$$

$$V_{out}(s) = \frac{a_V}{s + a_V}V_{ref}(s), \tag{16}$$

where a_ϕ and a_V are the inverses of the time constants of ϕ and V_{out} dynamics. Since the scope of this discussion is about power control stability of a DG unit connected to a large power system, whose time constant is in a range of seconds and much greater than that of the voltage tracking response measured in a range of 0.01 sec. or less, the DG power response has the room to be much slower than the voltage tracking and still fast compared to the power system. Therefore, it is reasonable to ignore the dynamics of the voltage tracking when power control is concerned, i.e. $a_\phi \to \infty$, $a_V \to \infty$, and $\phi \to \phi_{ref}$, $V_{out} \to V_{ref}$.

At the moment that the DG is switched from island mode to grid-connected mode, V_0 and ϕ_0 should match E and ϕ_E, where ϕ_E denotes the phase angle associated to E. Therefore, (13) and (14) can be rewritten into

$$\delta = \int [K_P(P_{ref} - P) + \omega_n]dt, \tag{17}$$

$$\Delta V = \int K_Q(Q_{ref} - Q)dt, \tag{18}$$

where $\delta = \phi_{ref} - \phi_E$ and $\Delta V = V_{ref} - E$. Assuming large capacity power system with small power angle δ, it is

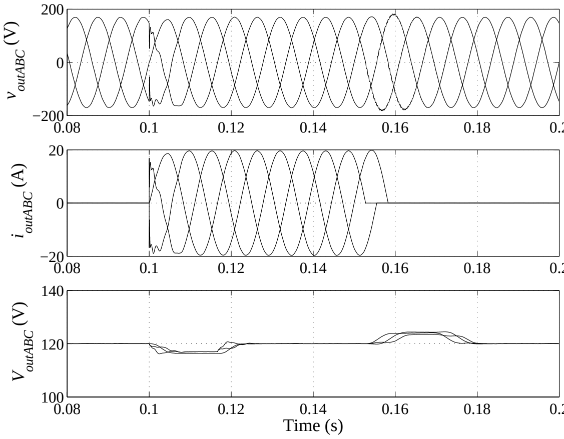

Fig. 6. Transient response of V_{out} in instantaneous and RMS at step load increase from 0 to 100% and decrease from 100% to 0.

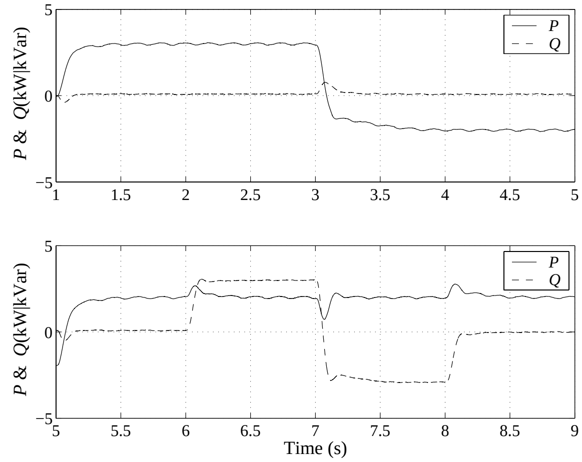

Fig. 7. P, Q regulation under nonlinear local load.

reasonable to have $\sin\delta \approx \delta$ and $\cos\delta \approx 1$. Equations (17) and (18) can be rewritten in differential format

$$\dot{\delta} = K_P(P_{ref} - \frac{EV_{out}}{X}\delta), \tag{19}$$

$$\Delta\dot{V} = K_Q(Q_{ref} - \frac{V_{out}}{X}\Delta V). \tag{20}$$

Since the dynamics of DG voltage tracking is ignored, the stability of the power loop can be evaluated using Lyapunov's direct method where there is no external excitation, i.e., $P_{ref} = 0$ and $Q_{ref} = 0$.

A Lyapunov function can be defined as

$$\xi(\Delta V, \delta) = \frac{1}{2}\Delta V^2 + \frac{1}{2}\delta^2, \tag{21}$$

where $\xi > 0$ holds unless $\Delta V = 0$ and $\delta = 0$. The derivative of the above function is

$$\begin{aligned}\dot{\xi(\Delta V, \delta)} &= \Delta V \cdot \Delta\dot{V} + \delta \cdot \dot{\delta} \\ &= -K_Q\frac{V_{out}}{X}\Delta V^2 - K_P\frac{EV_{out}}{X}\delta^2. \end{aligned} \tag{22}$$

From (22), it can be observed that $\dot{\xi}(\Delta V, \delta) < 0$ holds when $\Delta V \neq 0$ or $\delta \neq 0$, given positive values of K_P, K_Q, E, V_{out}, and X. Therefore, the proposed power control loop is asymptotically stable at vicinity of the equilibrium point $\Delta V = 0$ and $\delta = 0$.

III. Simulation Results

Simulations have been run on a 5kVA DG unit with a topology shown in Fig. 1 connected to a 120V line-to-neutral power system with an equivalent reactance 0.1Ω under a number of difference scenarios as shown below.

A. Island Mode

Under island mode, a 100% step load increase is applied to the DG output terminal. After steady state is reached, the load steps back down to zero. The voltage response under these transients are shown in Fig. 6.

Simulation data shows that the voltage tracking error under steady state is nearly zero and the THD is 0.4%. It can be observed from Fig. 6 that the load disturbance has little impact on V_{out} waveform and the RMS transients last for only 0.02 second with 3% or so peak variations.

B. Grid-connected Mode

Under grid-connected mode, P and Q output to the utility grid need to be controlled for system stabilizing, compensation, or handling local load disturbances. Fig. 7 illustrates the P and Q regulation under various step references under nonlinear local load. It can be observed from Fig. 7 that the settling time is about 0.5-0.8 sec. for P response and 0.3-0.5 sec. for Q response under reference step changes with size of 60%-100% unit rating, which is significantly faster than the work in [11] with much greater step sizes in per unit value. Even though some minor coupling between P and Q is seen in the transients, the steady state decoupling is achieved with the control.

When nonlinear local load exists, the line current i_{Line} is supposed not be affected with the proposed control. Fig. 8 exhibits the current waveforms at three different locations of the system including the line current i_{Line}, the unit output current i_{out}, and the inverter current i_{inv}. The waveforms show that all current harmonics are taken by the DG unit and the system line current is clean. This is because the voltage control loop eliminates the voltage harmonics at the DG output which avoids harmonic current flow to or from the utility grid.

C. The Switching Transients

The transients as the DG unit is switched between island mode and grid connected mode are presented in Fig. 9 and Fig. 10. Both figures show seamless switching as far as the voltage is concerned. The power transient shown in Fig. 9 is caused by the circuit topology change with a nonzero system equivalent impedance Z.

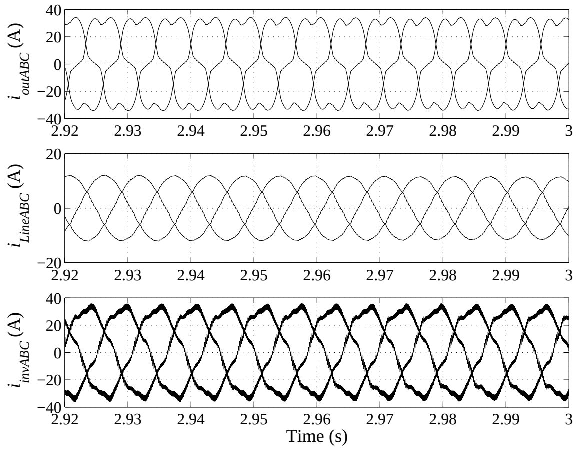

Fig. 8. Current waveforms of DG unit output current i_{out}, system line current i_{Line}, and inverter current i_{inv} under nonlinear local load.

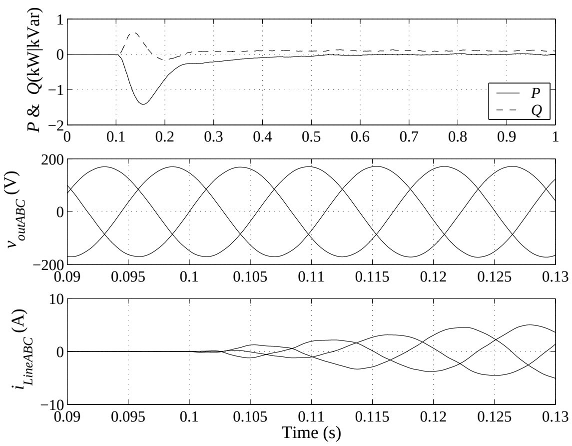

Fig. 9. Transients of P, Q, v_{out}, and i_{out} when the DG unit is switched from island mode to grid-connected mode with zero P_{ref} and Q_{ref}.

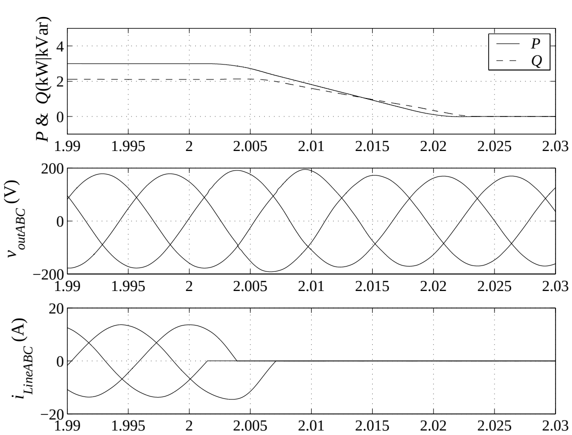

Fig. 10. Transients of P, Q, v_{out}, and i_{out} when the DG unit is switched from grid-connected mode to island mode with nonzero P and Q initial operating condition.

IV. Conclusion

This paper has presented a power flow control approach for a single distributed generation unit connected to utility grid with a nonlinear local load. The proposed control technique combines an independent integral P and Q controller, a robust servomechanism voltage controller, and a discrete-time sliding mode current controller. Simulation results under various scenarios have demonstrated the effectiveness of the proposed technique in power regulation and harmonic elimination of line current. The stability of the power control loop is proved using Lyapunov direct method.

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