ON THE CONTROL AND STABILITY OF GRID CONNECTED PHOTOVOLTAIC SOURCES

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ABSTRACT

A methodology is proposed for the effective integration of photovoltaic (PV) devices into the electric utility distribution network operations. The dispersed PV generator is viewed as an active device used to improve system stability by appropriately modulating the power conditioning unit's output power. Disturbances on the utility system can be damped out by injecting this power into the grid in such a way so that the net effect is a cancellation of undesirable oscillations. The approach is implemented by monitoring the oscillating power and generating control signals which shape accordingly the interface unit's output power. Successful implementation of the scheme relies heavily on the speed and flexibility with which the electronic inverter moves power from the primary source/storage facility to the utility lines. Simulation studies, using the proposed control approach, indicate that application of these policies may result in reduced load following requirements for conventional power generating units, increase the value and acceptability of new energy technologies, and improve power quality and stability of the interconnected system.

INTRODUCTION

In recent years, there has been growing interest in utilizing Photovoltaic (PV) and other Dispersed Storage and Generation (DSG) devices to provide some of the electricity demand [1-3]. Experimental and demonstration PV facilities have been developed worldwide to address basic feasibility concerns. Such systems are usually interfaced with an existing power grid for fuel displacement purposes, as well as for earning some capacity credit. Interest in the use generally of DSGs in electric distribution systems results from a number of technical, economic, and institutional factors. The Public Utility Regulatory Policies Act (PURPA) of 1978 [4] has cleared the way for the guaranteed interconnection of customer-owned generation to electric utility systems. Moreover, small power production represents a potential future alternative to central station generation for the electric utility industry since small DSG devices have a reduced environmental impact, may be constructed and become operational in a relatively short period of time, and produce electricity from available domestic and renewable fuels while located close to load centers. Utility-owned DSGs would present technical intertie problems similar to those of customer-owned equipment.

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The interconnection and operation of dispersed PV devices at the electric distribution level raise numerous planning and operational concerns [5-9]. Electric utilities usually specify PV interface requirements and protection schemes that are capable of responding to all "abnormal" system conditions by disconnecting the dispersed source from their system [10]. This utility philosophy results in increased costs associated with the interconnection hardware and an inefficient utilization of available generated power. Moreover, the value of New Energy Technologies (NET) is further decreased, with a corresponding increase in power production from conventional sources, since this operating philosophy allows for stochastic output power variations from dispersed generators causing excessive ramping of the utilities' regulation units and increasing load-following, spinning reserve, and unloadable generation requirements. Recently, it has been suggested that if NETs are to contribute significantly to the electric energy supply, then methods must be developed for operating these new sources in harmony with the conventional power system [1,11,12].

In a recent paper [13], the authors introduced a new methodology for the effective integration of NET devices into the utility grid. The dispersed generator is viewed as an active device contributing towards the regulation of real and reactive power flow. The proposed control strategies result in reduced load-following requirements for conventional power generating units.

In this paper, the basic dispersed source-utility grid interface philosophy is reviewed and attention is initially focused on the storage requirements for control and stability purposes. Next, the power flow control problem is formulated and the role of the dispersed generator as a power modulating device contributing to the improvement of systems stability is discussed.

INTERFACE CONSIDERATIONS

A. Interface Requirements

Figure 1 shows a block diagram of the proposed system configuration. The primary solar energy source is converted to electrical form. The Power

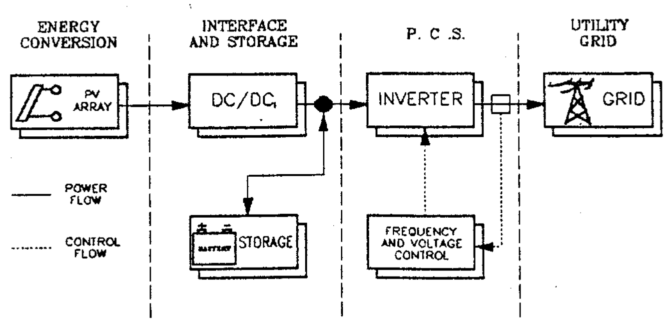


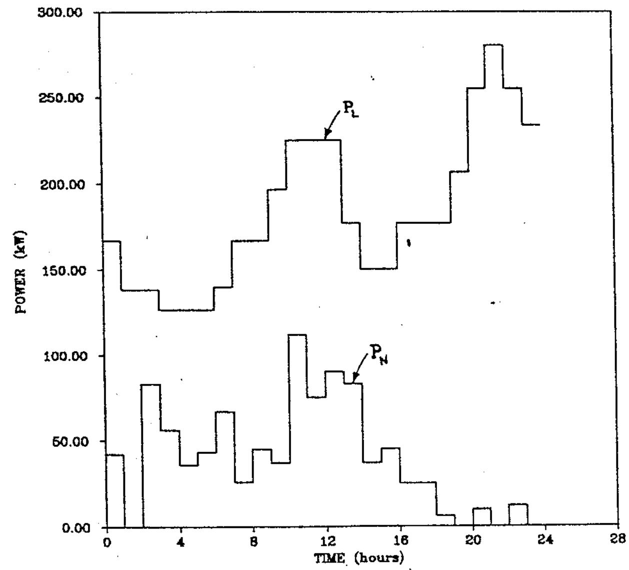
Figure 1. Block diagram of the proposed PV-utility grid system configuration.

Conditioning Subsystem containing the inverter circuit is central to the proposed control and stabilization philosophy. The DC to AC inverter is capable of delivering both real and reactive power to the grid. Reverse flow of power (from the utility lines to the storage device) is also possible and may be desirable under appropriate supply/load management policies. A possible inverter design for control and stabilization purposes may be based upon the principle of self-commutation. Voltage-fed, self-commutated inverters have been developed using techniques of square wave generation with harmonic neutralization, various PWM methods, and high frequency linking of the input to output power flow [11,14-17].

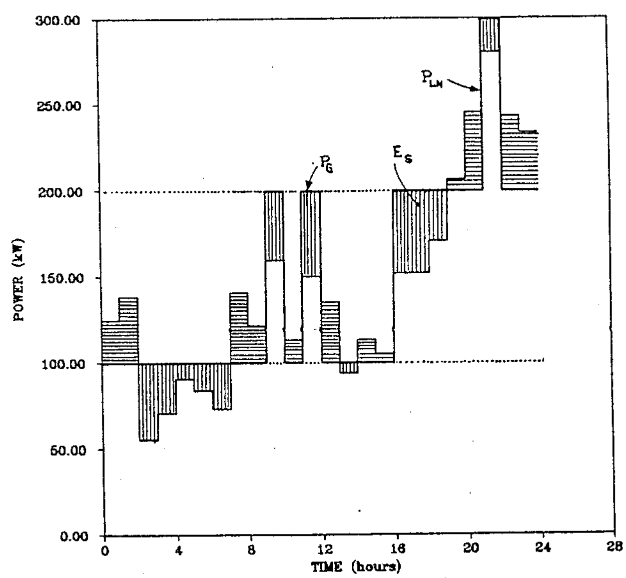
The function of the inverter as a power flow controller may be simply explained as follows: The inverter is considered to be an AC source connected to the utility grid through an impedance buffer. System frequency variations are continuously monitored at the grid bus and a control signal proportional to the frequency variation is used to vary the phase difference between the inverter and grid buses, thus transferring more or less real power to the utility. Control of the amplitude of the inverter output voltage in relation to the grid bus voltage regulates reactive power flow. Under four quadrant P-Q operation, the inverter is absorbing real and reactive power from the grid making them available for storage. The system configuration is complemented with suitable information retrieval/processing and control instrumentation. The characteristics and size of the storage device required to provide the energy called upon by the inverter for control and stability purposes are discussed in the following paragraph.

B. Storage Requirements

A conventional storage facility associated with PV generators is normally designed to accommodate energy requirements for an extended period of time, typically 4-5 days, during which the primary source is unavailable due to cloud cover. In the control configuration examined in this paper, the storage unit serves primarily the purpose of supplying or receiving suitable amounts of energy, over brief periods of time, as dictated by the bidirectional action of the inverter/controller. It is, therefore, considerably smaller in capacity than those storage facilities required for stand-alone operation. Figure 2 is a graphical illustration of the manner in which the storage facility participates in the regulation process. Figure 2(a) depicts the real power demand, for a specific autonomous power system, as a function of time of day (curve P_L). The real power generated by renewable energy sources, i.e., solar photovoltaic and wind converters, is also shown in the figure (curve P_N). Optimum operational considerations dictate that any available power, P_N, from renewable sources must be supplied directly to the power grid. The real power demand is, therefore, the difference P_L-P_N, as shown in Figure 2(b) (curve P_{LN}). This difference is covered by the system's conventional power generation and the storage facility. Operation of the conventional power generating station is programmed on the basis of the following two considerations: (1) as long as the inverter undertakes to regulate the power flow of the system, the conventional unit may be programmed to supply a constant amount of power thus achieving fuel economy while operating at maximum efficiency; (2) if, on the other hand, the conventional station is set to provide, on a continuous basis, a constant average amount of power, then the storage capacity required for control purposes is relatively large and the cost of such a facility becomes prohibitively high.



2(a)



2(b)

Figure 2. An illustration of the storage facility's participation in the regulation process; (a) real power demand P_L, DSG real power output P_N; (b) the difference P_L-P_N.

A compromise between the two contradicting conditions allows for a step mode of operation of the conventional unit, as shown in Figure 2(b) (curve P_G). In this graphical example, the conventional station is operating with step changes in output power of 100 kW. When the difference between the load demand and the generating station's output is greater than 50 kW, the station's power output is increased or decreased by 100 kW, depending upon the sign of the difference P_L-P_G. The remaining power demand (or surplus) P_{LN}-P_G is provided by or directed to the storage unit. The horizontally shaded regions in Figure 2(b) represent energy supplied to the power system from storage, while vertically shaded regions represent energy flowing back into storage. The balance is stored energy and, according to the argument pursued above, must be statistically equal to zero. The capacity of the storage facility is estimated on the basis of the largest amount of energy this unit is called upon to supply at any time.

In the example, Figure 2(b), the estimated storage capacity is E_S = 125 kWh and, therefore, a conventional battery storage with a capacity of 150 kWh is considered to be adequate. For the typical small power system considered here to illustrate the energy requirements concept, the design storage facility is intended to provide an energy demand over a period of a few hours only. Therefore, its size and corresponding cost is miniscule compared to other system components.

A contingency that must be taken into consideration relates to a change in the output power level of the conventional station in the event that an operating state requires an amount of energy greater than 150 kWh.

Given that a storage facility, of an appropriate size as estimated above, is incorporated into the system design, the inverter is ready to undertake the regulation of the system's performance as described in the following paragraphs.

THE CONTROL AND STABILITY PROBLEM

Monitoring of the variations in system frequency (Δf) and utility grid bus voltage ($\Delta|V|$) for the purpose of controlling the phase difference ($\Delta\phi$) between the inverter and grid buses and the amplitude of the inverter output voltage ($\Delta|E|$) - and, correspondingly, the real and reactive power flows - is the classical approach for coping with system load changes. In our case, the speed of response of the inverter's electronic circuitry is the principle factor contributing to a more stable performance of the interconnected system.

The innovation introduced in this paper refers to a further improvement in system stability via monitoring, in addition to Δf and $\Delta|V|$, the real power at the inverter output bus (see Figure 3). A sudden change in load demand results in oscillations of the real power provided by the conventional generating units.

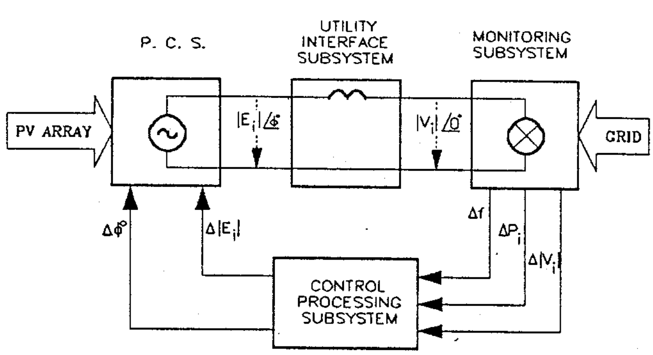


Figure 3. Proposed feedback configuration for stability purposes.

An additional correction in the phase difference $\Delta\phi$ may appropriately modulate the inverter output power so that it is 180° out of phase with the oscillating component. The dispersed source is effectively introducing a damping term to the oscillating dynamics of the system. The net result is a reduction in power oscillations with a consequent improvement in the system's dynamic behavior.

For purposes of analysis, it is assumed that one or more DSGs of the type specified previously, are operating in a coherent power system consisting of diesel-powered generating units, power transmission and distribution facilities, and typical loads. Situations of this category are already in existence in several small islands or isolated communities with WECs clusters and PV arrays operating in parallel with the local power system [18]. For a large power network, the case is considered where the DSGs are supported by a distribution feeder. The configuration of interest is now localized to the feeder under consideration with the system beyond the distribution transformer represented as an infinite bus. Effective voltage regulation is demonstrated for the assumed feeder topology. It is theoretically conceivable that substantial DSG penetrations in the future, with the DSGs distributed throughout the power network, may result in frequency control, voltage regulation, and increased system stability characteristics.

Figure 4 is a logic diagram of the combined dynamics describing the state of the power network, the generator swing equations, the inverter behavior, and the controller relations. The behavior of the transmission lines and the loads is represented by the

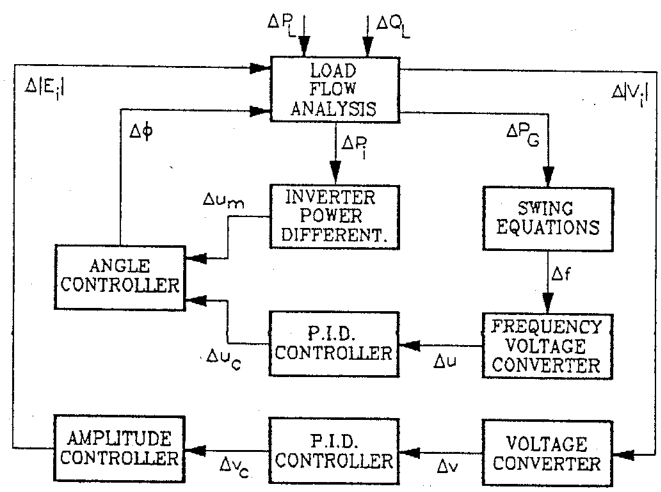


Figure 4. A logic diagram of the combined generator/power network/inverter dynamics.

load-flow equations while the swing equations describe the operation of the conventional units providing power to the network. The feedback loop branches into two main paths: an angle controller and an amplitude controller. The branch of the angle controller has two inputs: one for sensing the frequency (Δf) and the other for monitoring variations in the inverter bus power (ΔP_i). The latter is used to generate the control signal needed to modulate the inverter output power. A change in loading of the system (ΔP_L) results in a corresponding change of the conventional station's real power output (ΔP_G) through the load-flow equations. Consequently, a change in frequency (Δf) occurs. This frequency variation (Δf) is converted to a voltage change (Δu) which feeds the input of a PID controller. The controller, in turn, produces a signal (Δu_c) which modifies, through the angle controller of the inverter, the phase difference ($\Delta\phi$) between the output voltage of the inverter and the voltage at the connecting grid bus. Thus, a change in the inverter's real power output is effected so that it compensates for variations in system loading and assists to return the system frequency to its nominal value. The load change (ΔP_L) also causes a change in ΔP_i. A differentiating unit follows these changes in power and produces a control signal (Δu_m) which, in turn, modulates the phase difference ($\Delta\phi$) with the intent to minimize the oscillating component of ΔP_i resulting in improved system stability.

The feedback branch for the control of the inverter's output voltage is similar to the frequency control branch. Specifically, a change in reactive loading (ΔQ_L) results in a change of the magnitude of the bus voltages and, therefore, of the voltage at the interface bus ($\Delta|V_i|$). This change produces, through the PID controller, a control signal (Δv_c) which activates the circuit regulating the magnitude of the inverter's output voltage ($\Delta|E_i|$). As a consequence of this procedure, the inverter supplies a quantity of reactive power to the grid enough to compensate for ΔQ_L and eliminate the perturbations in $\Delta|V_i|$. The angle and amplitude controllers are represented by first-order transfer functions each, under the assumption that voltage phase and amplitude changes are small. Similar representations using first and second-order dynamics have been suggested by other investigators [19,20]. Under the assumption that the frequency, f, remains fairly constant, the interconnected network is considered to be in the sinusoidal steady-state. Load-flow analysis may, therefore, be used to calculate changes in the grid bus voltage and the power supplied by the generator due to changes in the control variables $\Delta|E_i|$ and $\Delta\phi$.

MATHEMATICAL DESCRIPTION

The operation of the interconnected PV - conventional units - utility grid system may be mathematically represented via appropriate transfer functions. Such a representation of the overall system dynamics is shown in Figure 5. For reasons of simplicity, only one conventional generating unit and one DSG are shown in

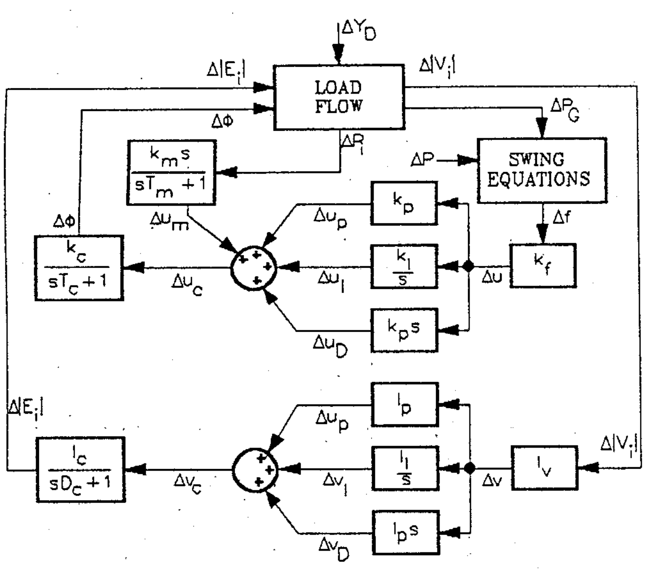


Figure 5. Transfer function representation of the combined dynamics.

the diagram. A multiplicity of these devices has an equivalent transfer function representation. The system's state equations may be expressed directly from the transfer functions of Figure 5. The generator swing equation may be written as

$$\Delta P_T - \Delta P_G = h_o \ddot{\Delta\delta} + D\dot{\Delta\delta} \tag{1}$$

where

$$h_o = \frac{W_k}{\pi f^o}$$

W_k is the kinetic energy of the rotating parts of both the driver and the generator at the nominal rotating frequency (f^o) and D is the damping factor due to the machine damper windings. With $x_1 = \Delta\delta$ and $x_2 = 2\Pi\Delta f$, a state variable formulation of the swing dynamics is expressed as

$$\begin{aligned} \dot{x}_1 &= x_2 \\ \dot{x}_2 &= \frac{1}{h_o}(\Delta P_T - \Delta P_G - Dx_2) \end{aligned} \tag{2}$$

The angle and amplitude feedback dynamics of each one of the inverters (Figure 5) can be written in the following form:

$$\begin{aligned} \dot{x}_3 &= \frac{k_I k_f}{2\pi} x_2 \\ \dot{x}_4 &= \frac{1}{T_c}\left[k_c\left[k_p k_f \frac{x_2}{2\pi} + x_3 - \frac{k_D k_f}{2\pi h_o}(\Delta P_G + Dx_2) + x_7\right] - x_4\right] \\ \dot{x}_5 &= \ell_I \ell_v \Delta|V_i| \\ \dot{x}_6 &= \frac{1}{D_c}\left[\ell_c\left(\ell_p \ell_v \Delta|V_i| + x_5 + \ell_D \ell_v \frac{\Delta|V_i| - \Delta|V_i|^o}{\Delta t}\right) - x_6\right] \\ \dot{x}_7 &= \frac{1}{T_m}\left[k_m \frac{\Delta P_i - \Delta P_i^o}{\Delta t} - x_7\right] \end{aligned} \tag{3}$$

where:

$x_1 = \Delta\delta$

$x_2 = 2\pi\Delta f$

$x_3 = \Delta u_I$ and $x_{3min} < x_3 < x_{3max}$

$x_4 = \Delta\phi$ and $x_{4min} < x_4 < x_{4max}$

$x_5 = \Delta v_I$ and $x_{5min} < x_5 < x_{5max}$

$x_6 = \Delta|E_i|$ and $x_{6min} < x_6 < x_{6max}$

$x_7 = \Delta u_m$ and $x_{7min} < x_7 < x_{7max}$

The input turbine power, P_T, is taken to be constant; therefore, $\Delta P_T = 0$. Steady-state operating conditions are established using the Load Flow algorithm. The transmission line is assumed to be lossy and a sudden change in load demand initiates the post-fault condition. The change in load demand establishes a new initial condition for the load flow equations. The Load Flow algorithm is used to calculate the changes in the grid bus voltage, the electrical power supplied by the conventional generator, and the inverter. The generator swing dynamics are accessed next producing an output change of frequency Δf. Changes in grid voltage $\Delta|V_i|$, frequency Δf, and the real power of the inverter ΔP_i are inputted to the amplitude and inverter angle controller algorithms, respectively. The outputs from these two processes are deviations in the inverter voltage $\Delta|E_i|$ and phase angle $\Delta\phi$. These last two quantities are the inputs to the Load Flow algorithm for the next program iteration.

Figure 6 depicts a single-line diagram of a small autonomous power system consisting of one conventional power generator without any frequency and voltage control capabilities and a rated capacity of 500 kVA, transmission lines, and two identical inverters of the type suggested in the paper, with a rating each of 100

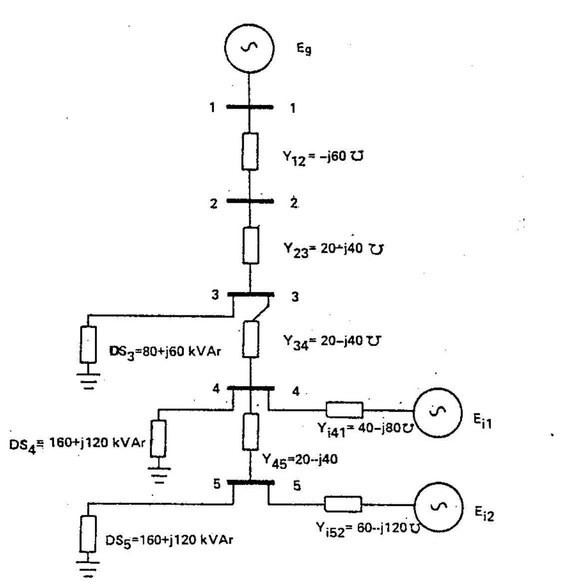


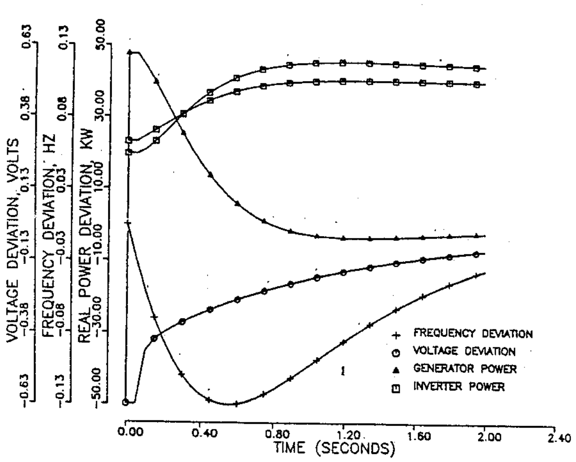
Figure 6. Single-line diagram of the example autonomous power system.

kVA. The system nominal voltage is considered to be 220V. E_g is the emf behind the generator transient reactance and it is assumed to remain constant during the transient state and equal to 220V.

Simulation studies were conducted on the basis of the flow diagram shown in Figure 5. With representative system parameters chosen to reflect actual field conditions, several test runs were executed with various step load changes.

Simulation Results

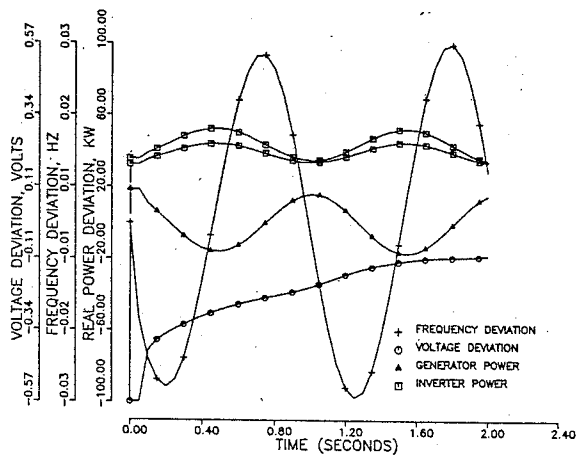
Figure 7(a) shows deviations of the system frequency, bus voltages where the inverters are connected, real power provided by the conventional unit, and real power produced by each inverter, for a 20% step load increase. In this case, the branch monitoring the real power oscillations at the inverter output



7(a)

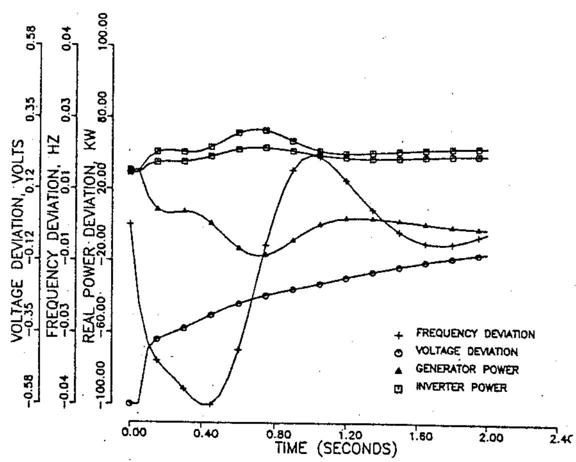
(ΔP_i) is considered to be disconnected ($k_m = 0$). Since the conventional unit supplies a fixed amount of real power, the increase in load is taken up eventually by the inverters, as it is illustrated in the figure. The inverter parameters have been adjusted for optimum response conditions. Indeed, the system reaches steady state in a very short period of time, which is one of the attractive features of the proposed configuration.

Figure 7(b) depicts the response of the same quantities to a similar load disturbance. In this case though, the inverter parameters are purposely assigned values away from the optimum settings. The figure clearly illustrates the sensitivity of the response to the inverter parameters as evidenced by the resulting instability.



7(b)

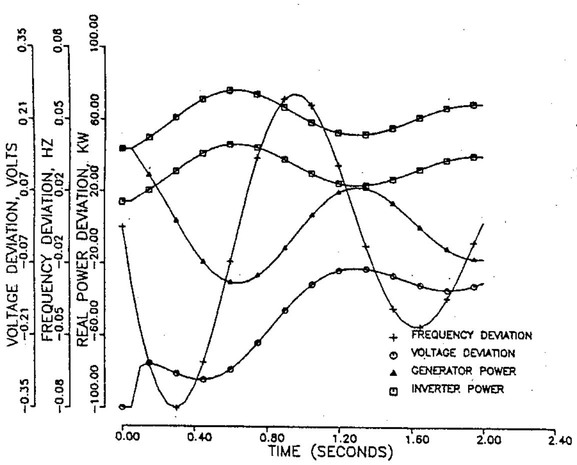
Figure 7(c) shows the behavior of the same quantities as in 7(b) with the difference that the branch monitoring the inverter power (ΔP_i) is now actively engaged. It is evident, from the figure, that the proposed real power control configuration results in a substantial reduction of the oscillating amplitudes, thus improving system stability.



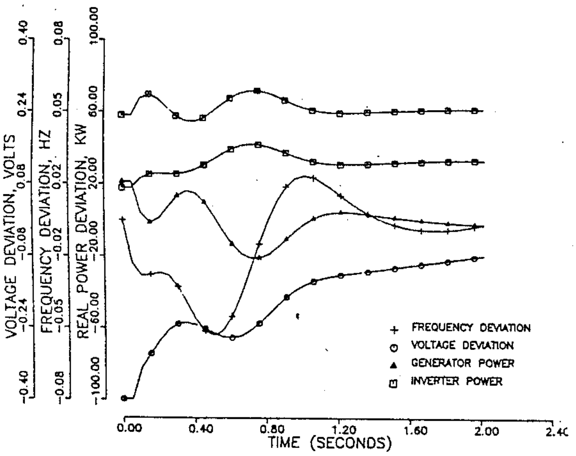
7(c)

Similar quantities, as in Figure 7(b), are plotted in Figure 7(d) after a topological change in the system configuration: one of the inverters is now connected to bus No. 2 instead of bus No. 4 (Figure 6). Instability phenomena are again observed as the inverter power feedback is de-activated. In contrast, Figure 7(e) shows the system response with the ΔP_i loop energized. Improvement in stability is characteristically evident.

A different philosophy of approach is suggested for PV devices connected to a large electric power system. Since in this situation PV penetrations are



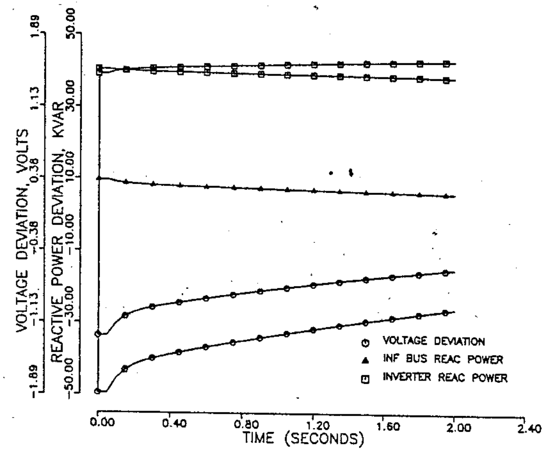
7(d)



7(e)

small, frequency control is, for all practical purposes, impossible. PV devices though, may be effectively utilized for local voltage regulation. One such possible configuration is shown in Figure 4, where the branch: swing equations-f to v converter-PID-angle controller is omitted. Moreover, the conventional generating unit is topologically substituted with an infinite bus (Figure 5). Thus, this network may represent a specific distribution feeder of a large power system. A 20% load change now results in the responses of Figure 7(f). The inverter parameters have again been set to their optimum settings. The system behavior is relatively stable and it returns to a steady state condition in a very short period of time. The real power provided by the inverters remains almost constant while the power system undertakes to supply the increased load demand. The figure shows the deviation of reactive power introduced by the inverters which is necessary for voltage regulation purposes. It is theoretically conceivable that future large DSG penetrations will affect both frequency and voltage control loops if the proposed philosophy is adopted.

Simulation results indicate that implementation of the control and stabilizing strategies involves the utilization of a frequency versus power "drooping" characteristic for each inverter. A permanent load disturbance is shared by the operating power conditioning units according to their capacity. The proposed scheme thus "simulates" the control characteristics of a conventional unit.



7(f)

Figure 7(a)-(f). Deviations of system frequency, bus voltage and real power for a 20% load change under various control policies.

CONCLUSIONS

The proposed control and stabilization methodology constitutes a significant departure from accepted utility practices in the interconnection of dispersed storage and generation devices with the utility grid. A typical dispersed generator, such as a PV array, is viewed as contributing beneficially to the operation of the power system.

Simulation results indicate that the response time of the control elements is extremely short with the overall PV - utility grid - generator system exhibiting stable transient behavior.

Immediate benefits in improved voltage regulation will be realized via implementation of the proposed control strategies even at small PV penetration levels. Future increased penetrations are bound to bring about positive results as far as frequency control and stability improvements are concerned. Most DSG interface devices already utilize appropriate inverter designs for regulating real and reactive power flows. The additional cost and complexity due to the feedback circuitry is minimal. Thus, equipment costs may be kept to an acceptable level while the operation of the devices may be fully automated.

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