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Power Control and Ground Fault Simulations for a Distribution System with a Fuel Cell Power Plant

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Abstract

Fuel cell (FC) distributed generation (DG) is gradually becoming more attractive to mainstream electricity users as capacity improves and costs decrease. New technologies including inverters are becoming available to provide a uniform standard interconnection of DGs with an electric power system. Some of the operating conflicts and the effect of DG on power quality are addressed and investigated through simulations on a real distribution network with an FC power plant. The results of these simulations have proved load tracking capability following the real and reactive power change of the load and have shown the flow of overcurrent from an FC power plant during the ground fault of a distribution line.

Key Words : Distributed Generation, Fuel Cell, Utility Grid, Power Conditioning System, Power Control

1. Introduction

Renewable energy sources such as wind-turbines, photovoltaics and fuel cells (FCs) have become more commonplace sources for the production of electricity, fuel, and heat, reflecting the major threats of air pollution, exhaustion of fossil fuels, and the environmental, social and political risks of fossil fuels and nuclear energy. An FC distributed generation (DG) is more attractive than other DGs. It has more potential to save energy and reduce emissions than a micro-turbine DG, and its generation power can be flexibly controlled compared to wind-turbines and photovoltaics.

DG can help to improve power quality and power supply flexibility and expandability, as well as maintain system stability and reduce transmission and distribution costs. There are many issues regarding the interconnection between the utility grid and DG [1]. Presently, IEEE has developed a uniform standard for the interconnection of distributed resources with electric power systems, and requirements relevant to the performance, operation, testing, safety considerations, and maintenance of the interconnection. Most of the issues can be resolved through the design of a power conditioning system (PCS), which controls power flow and quality.

Design of protective relaying systems for a DG

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distribution system is much more complicated because, for example, ways must be found to feed current back into the network through protectors designed for regulating current going the other way. Conversely, when a protector opens a circuit, a distributed generator might continue to feed a sub-distribution system, blowing a fuse, which would then stay open when the larger circuit recloses. Those concerned about the interface of distributed generators on the distribution system have many issues to be clarified.

What has made the concept of distributed power especially attractive is, of course, all the innovative electronics that have lowered the cost of protective relaying, improved remote control, and simplified interfaces between generating resources and the grid. But even so, the difficulties of connecting distributed resources to the grid are not to be underestimated. It is necessary to gain a detailed understanding of the operation issues and the control schemes for a PCS interfaced distributed generation. An appropriate model for the real and reactive powers (PQ) controlled fuel cell will be developed to meet the requirements of the loads in grid-connected operation.

In this paper, some operation issues and the power control of an FC power plant with an inverter controller are investigated to meet the requirements of grid-connected operation. A real distribution network with an FC power plant is simulated for load tracking capability following PQ change and for ground faults.

2. Interface of a Fuel Cell Power Plant to Distribution System

2.1 Operation Issues of DG

Current distribution systems are not designed for two-way power flow. In a radial feeder, power flows unidirectionally from a single source to the loads [2]. The penetration of DG into the feeder can cause a flow reversal. This flow reversal violates the concept of the radial design and can have a significant impact on the operation of the feeder. As a result, utilities have begun to investigate the operating conflicts on their systems.

In general, back-up generation and on-site power supply provided by DG improve the system power quality. However, some issues might arise when distributed generators, with different types and technologies, are interconnected to the utility distribution system. As the level of penetration of DG into the distribution systems increases, the impacts are becoming apparent and can no longer be neglected.

■ Fault Processing

Most distribution systems operate in a radial configuration, in which there is one source and the feeders extend radially from the source [3]. Fault clearing requires then the opening of only one device. With DG, there are multiple sources. Therefore, opening only the utility breaker does not guarantee the fault clearance. Because of the huge infrastructure of existing distribution systems, the DG must adapt to the way the utility works. All DG protection devices must then detect the fault and separate to allow the normal fault-clearing process to proceed.

Due to the fact that many faults are temporary, reclosing is common throughout North America and Asian countries, which enables power to be restored to customers within seconds. DG must disconnect early in the reclose interval to allow time for the arc to dissipate in order to have a successful reclose [2-3].

If DG units are added to the system, the fault current may become large enough that the lateral fuse no longer coordinates with the feeder circuit breaker during a fault. This would lead to unnecessary fuse operations and decreased reliability of the lateral. For inverters, the fault contributions will depend on the maximum current level and duration for which the inverter manufacturer's current limiter is set to respond. On some inverters fault contributions may last for less than a cycle, in other cases it can be much longer.

■ Islanding

Islanding is defined in the IEEE standards [4] as a condition in which a portion of the utility system that contains both load and distributed resources remains energized while isolated from the remainder of the utility system. To prevent islanding, a DG unit operating in parallel with the utility system in a timely manner senses a significant voltage sag or discontinuity of service on the utility side and disconnect from the system. Many utilities have standards which require that this time be about 10 cycles or less for serious feeder disturbances.

Voltage and frequency relays are used as a means of anti-island protection. In most cases, if a generator becomes islanded, it will not be able to meet the sudden change in its load without a significant change in voltage and/or frequency, and relays will trip the unit off line. This type of anti-islanding protection is known as passive protection. Passive protection can be fooled if the generator is able to carry the load of the island without a substantial change in voltage or frequency.

Therefore, as a further safeguard, many smaller inverters today also use what is called active anti-islanding protection. One common active approach is for the inverter to be tuned to operate while islanded at a frequency other than 60[Hz]. Active anti-islanding is more robust than passive, but even this cannot guarantee that an island won't develop in some rare cases. Since islanding can cause severe voltage quality and reliability problems, the proper use and setting of anti-islanding controls is one of the more important issues for DG installations.

■ Voltage Regulation

Radial distribution systems are normally regulated using load-tap-changing transformers at substations, supplementary line regulators on feeders, and switched capacitors on feeders. If a DG unit is applied just in the downstream of a voltage regulator or a load-tap-changing transformer, then the regulation controls will be unable to properly measure feeder demand.

Note that with DG the voltage becomes lower on the feeder because the DG reduces the observed load at the line drop compensator control. This confuses the regulator into setting a voltage lower than is required to maintain adequate service levels at the tail end of the feeder. This is the opposite effect of voltage support, a commonly touted benefit of DG.

DG will also impact losses on the feeder. DG units can be placed at optimal locations where they provide the best reduction in feeder losses. Siting of DG units to minimize losses is like siting capacitor banks for loss reduction. The only difference is that the DG units will impact both the real and reactive power flow. Most generators will be operated between 0.85 lagging and 1.0 power factor, but some inverter technologies can provide reactive compensation.

On feeders where losses are high, a small amount of strategically placed DG with an output of just 10-20[%] of the feeder demand can have a significant loss reduction benefit for the system. Unfortunately, most utilities don't have control over the siting locations, since DG is usually customer owned.

2.2 PCS for a Fuel Cell

A PCS must be introduced to boost and invert the DC voltage of the FCs to AC grid voltage for grid-connected operation. The grid-interactive PCS also controls power flow and quality. Currently, the design of PCSs is based on IGBTs that use PWM technology, and on a DSP processor that enables various control algorithms to be used. Hence, they are capable of generating clean output that meets the IEEE Standards for harmonics.

Fig. 1 shows a block diagram of the FC power plant interfaced with the utility grid via a PCS, which is composed of several boost converters, inverters, and a line filter. The fuel cell stack operates at a low DC voltage ranges. The boost converters are used not only to raise the low DC voltage but also to provide noise isolation and power bus regulation.

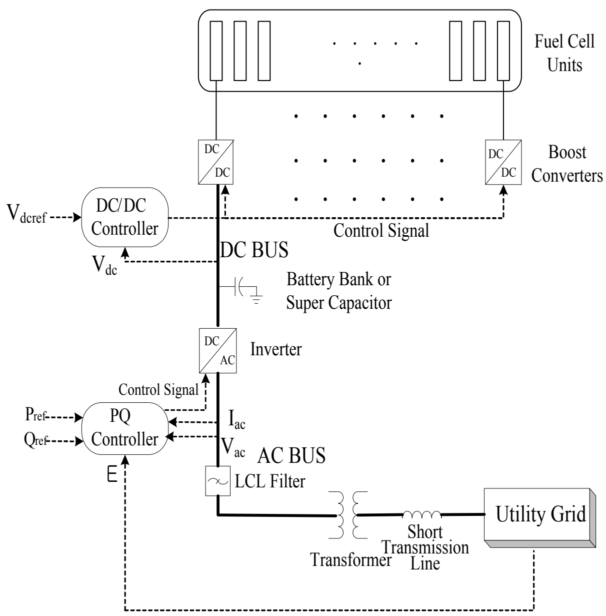

Fig. 1. PCS-based interface to the utility grid

The operation and control of the SCDP is considered to produce the total stack power. First, the simulation model is validated at several steady-state operating points, representative of the assumed range of operation in this part. Setpoint control laws are then derived for the proper regulation of fuel utilization and steam-carbon ratio. Finally, the plant is subjected to cycling load changes, where all control loops are operational [16-17].

The inverter is a low cost inverter switched at the grid-line frequency. New solutions on the market use inverters with IGBT switched typically at 10 to 20[kHz] leading to better power quality performance. An energy storage device, e.g., a battery bank or super capacitor, is used to improve the performance of the FC power system under transient disturbances such as motor starting [5].

In order to lower the transmitted high frequency current ripple caused by the PWM switched operation of the inverter, LC or LCL filters shown in Fig. 2 are inserted between the inverter and the grid. The LC-filter is a second order filter, and its attenuation is 40[dB/decade] over the whole frequency range. The greatest advantages of the LCL filter are low grid distortion and reactive power production, attenuation of 60[dB/decade] for frequency over the resonance frequency, and possibility of a relatively low switching frequency.

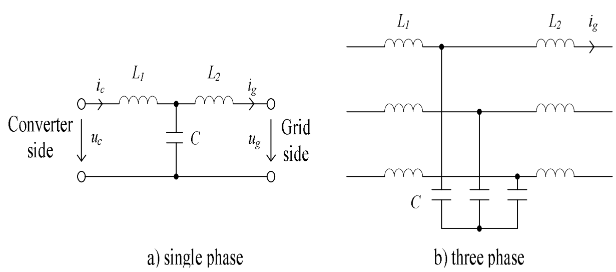

Fig. 2. The LCL line filters

The transfer function of the LCL filter given by the grid side current to the converter side voltage is:

$$G(s)=\frac{I_g(s)}{U_c(s)}=\frac{1}{L_1L_2Cs}\frac{1}{s^2+\omega_{res}^2},\ \omega_{res}=\sqrt{\frac{L_1+L_2}{L_1L_2C}} \quad (1)$$

where ω_{res} is the resonance frequency of the filter. The series resistances of inductors are neglected for simplicity.

It is desirable for the PCS to provide galvanic isolation between the FC terminals and the grid. Hence, the PCS may include an inverter at the output of the FC, followed by a 50 or 60[Hz] transformer, or a switch-mode DC-DC converter at the FC, followed by the grid-connected inverter. A switch-mode DC-DC converter employs high frequencies in the range of 20 to 100[kHz] in order to keep the magnetic components compact.

3. Power Control of an FC Power Plant

3.1 Power Control Scheme

The real and reactive powers in the FC power plant are quantities controlled by means of the inverter. To prevent over-loading of the inverter and the fuel cell power plant, it is important to ensure that load changes are taken up by the inverter in a predetermined manner.

The basic structure of the PQ control in the simplest way is shown in Fig. 3 [6-9], where the AC system has three sinusoidal voltage sources. Two PI controllers would suffice to control the flow of PQ by generating the proper values for two variables of V: the magnitude and δ_V: the phase angle of the inverter output voltage. This control forms the innermost control loop, and is very fast. The inverter and AC system voltage space vectors are obtained from instantaneous voltage measurements and are available locally.

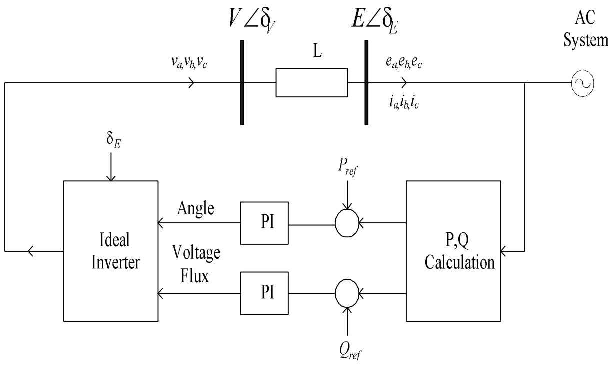

Fig. 3. Basic structure of the PQ control scheme

The voltage source inverter controls both the magnitude and phase of its output voltage. The vector relationship between the inverter voltage and the AC system voltage along with the inductor's reactance determines the flow of real and reactive powers from the FC power plant to the grid. The corresponding mathematical relations for magnitudes of PQ are as follows:

$$P=\frac{VE}{X}sin(\delta_V-\delta_E), \quad (2)$$

$$Q=\frac{V^2}{X}-\frac{VE}{X}cos(\delta_V-\delta_E)=\frac{V}{X}[V-Ecos(\delta_V-\delta_E)] \quad (3)$$

where E and δ_E are the magnitude and the phase angle of the AC system voltage, respectively, and X is the reactance.

Concerning the above expressions, the following points can be raised [5-9]. For small changes in angle, P is predominantly dependent on the power angle difference ($\delta=\delta_V-\delta_E$), and Q is dependent on the voltage magnitude difference ($V-E$). As a consequence, the control of real and reactive power flow is reduced to the control of the power angle and the voltage level of the inverter. Therefore, power angle and voltage level would be the critical variables for real and reactive power flow control. Although the flow of real and reactive power is not completely decoupled, they are independent to a good extent. The control of one has only a minor impact on the other one.

3.2 Simulations of PQ Control

PQ control of an FC power plant is simulated with the Matlab/Simulink model of the Santa Clara Demonstration Project (SCDP) FC power plant. The SCDP model was developed for the commercialization of MCFC technology [10-11]. An inverter Matlab/Simulink model is designed for connection to the original SCDP model and simulated together using the same solver and step size. The inverter model includes PI controllers, PWM generator, and IGBT inverter.

Once the desired PQ values are given, the corresponding control values of voltage and angle are calculated using (2) and (3). These control values of voltage and angle are then converted to d-q component reference voltages, which are regulated with PI controllers. The proportional and the integral gains of PI controllers are determined from simulations through trial and error.

Fig. 4 shows the simulation results for a case study according to the load change of the utility grid. The real power is increased to P=1.0[pu] and the reactive power is changed to Q=2.0[pu] for an inductive load. The corresponding voltage and angle are calculated as V=1.0841[pu], δ=0.2432[rad]. The proportional and the integral gains of PI controllers are 2.6 and 0.00001, respectively. For this case study, the PQ control shows satisfactory results following the real and reactive power change of a load.

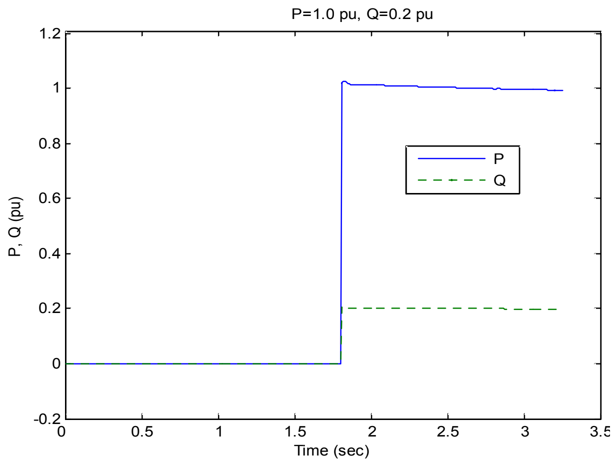

Fig. 4. Simulation result of PQ control

4. Simulations of a Distribution Network

4.1 Simulation Environments

The performance of an FC power plant is simulated through a real distribution network when it is connected to the utility grid. The simulations are performed using the Hypersim software program, which has been developed for power flow simulations based on the Matlab/Simulink software.

The Goyang Branch Office of the Korea Electric Power Corporation (KEPCO), as shown in Fig. 5, is used as the real distribution network for the simulations. In Fig. 5, the FC power plant is assumed to be installed at the section B_03: load center of the distribution line with five sections B_01 - B_05 to compensate the voltage drop effectively.

The maximum capacity of the FC power plant is assumed to be 3,000[kW] considering the regulation of KEPCO: 30[%] of a maximum distribution line capacity. Therefore, FC power plants with two different capacities of 1,000[kW] and 3,000[kW] are supposed to be installed in a 22.9[kV] distribution network.

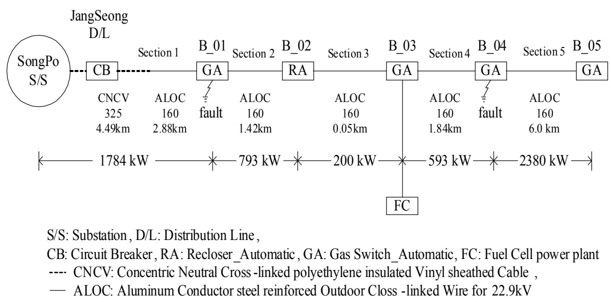

Fig. 5. Diagram of a distribution network model

Distribution line load data are shown in Table 1. Positive sequence and zero sequence impedances are given according to the wire: CN (Concentric Neutral) cable and EW (Extra High Voltage Aluminum Wire for 22.9[kV]). The distribution line is divided into 5 load sections and their power factors are assumed to be 0.9.

Table 1. Distribution line load data

section	P [kW]	Q [kVAr]	power factor
B_01	1784	862	0.9
B_02	793	383	0.9
B_03	200	97	0.9
B_04	593	286	0.9
B_05	2380	1150	0.9
Total	5750	2778	0.9

4.2 Simulations of Load Sharing

The real power of 5,750[kW] is delivered to the circuit breaker (CB) side from the utility in Fig. 5. Some of this power is used through loads between the CB and recloser (RA), with the remainder, 3,173[kW], at the RA side. Load sharing between the FC power plant and distribution line is simulated when the FC power plant begins to supply 1,000[kW] real power at 1[sec].

The simulation results are plotted in Fig. 6. Both 5,750[kW] real power at the CB side and 3,173[kW] real power at the RA side are reduced by 1,000[kW] in Fig. 6 (a). The reactive powers in Fig. 6 (b) are not affected by the FC power plant because the FC power plant supplies real power only. Fig. 6 (c) and (d) show current output from the FC power plant and the voltage variations of the distribution network, respectively.

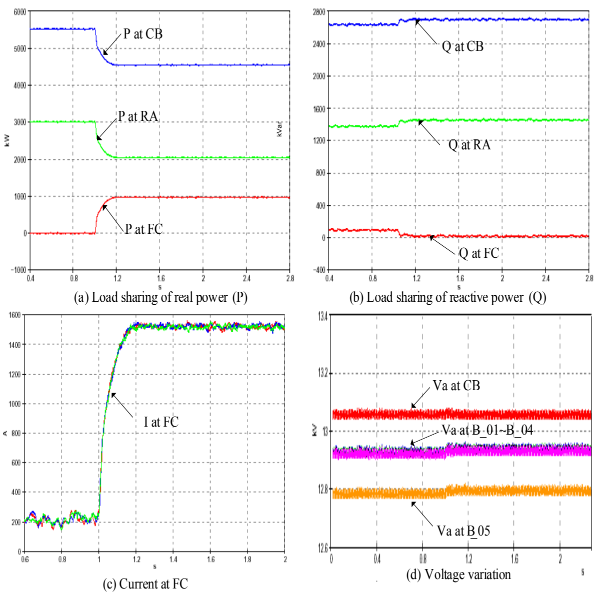

Fig. 6. Load sharing with the FC power plant 1,000[kW]

The voltage variation of this distribution network is investigated through simulations with an FC power plant 3,000[kW] as well as an FC power plant 1,000[kW]. Inverter-based distributed generators can be controlled to supply reactive power for voltage support during the voltage sag. Simulation results of the voltage variation are summarized in Table 2, which shows that the FC power plants make the voltage variation increase slightly. This indicates that the voltage variation due to the FC power can be ignored. All the voltage variations in Table 2 maintain adequate service levels within a 2[%] voltage regulation.

Table 2. Voltage variation due to FC interface

section	without FC [V]	FC 1000[kW] [V]	FC 3000[kW] [V]
Va_B_CB	13,057	13,056	13,060
Va_B_01	12,927	12,932	12,958
Va_B_02	12,924	12,929	12,956
Va_B_03	12,923	12,928	12,955
Va_B_04	12,920	12,925	12,953
Va_B_05	12,783	12,788	12,815

Several simulations of the operation of the distribution network have been performed according to an increasing load and a change of the location of an FC power plant. Fig. 7 shows the simulation results. In Fig. 7 (a), the FC power plant 1,000[kW] is connected at B_01 at t=1[sec] and the load at B_05 is increased by 1,000[kW] at t=2[sec]. The increased load is supplied from a distribution network, while the FC power plant supplies 1,000[kW] continuously. The real power at RA is not changed at t=1[sec], because the FC is interfaced before the point of RA.

In Fig. 7 (b), FC 1,000[kW] at B_05 is connected to the distribution network at t=1[sec], and the load at B_05 is increased by 1,000[kW] at t=2[sec] and decreased at t=3[sec]. The real power at RA is changed similarly to the one at CB, because the FC is interfaced after the point of RA. These simulation results show that the changes of load are followed successfully from the distribution network regardless of the location of the FC power plant.

In Fig. 7 (c), the real power from an FC at B_03 is increased to 3,000[kW] at t=1[sec] and decreased to 1,000[kW] at t=2[sec]. As the real power from the FC is changed, the distribution network adapted to supply the rest of the required power. Fig. 7 (d) shows the case study of an FC failure. An FC is connected to the distribution network at t=1[sec] and disconnected at t=2[sec] due to an FC failure. The distribution network covers the real power lost by the FC failure.

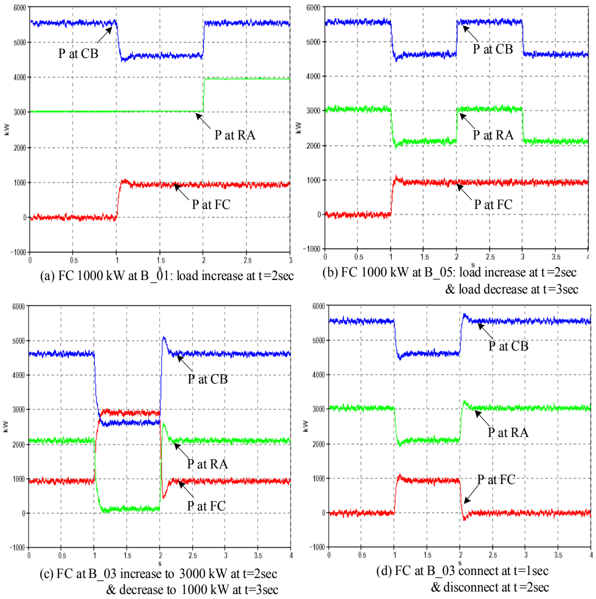

Fig. 7. Increasing the load and changing the location of the FC power plant

The voltage variation of this distribution network was investigated according to the locations of FC 1,000[kW]. Table 3 shows the comparison of the voltage drop in simulations. The voltage drop at B_01 is slightly larger than the one at B_05, because much of the load is connected at B_05.

Table 3. Voltage variation due to locations of the FC power plant

section	FC at B_01 [V]	FC at B_03 [V]	FC at B_05 [V]
Va_B_CB	13,065	13,056	13,067
Va_B_01	12,945	12,932	12,958
Va_B_02	12,942	12,929	12,956
Va_B_03	12,940	12,928	12,955
Va_B_04	12,937	12,925	12,953
Va_B_05	12,770	12,788	12,879

4.3 Simulations of Ground Fault

A ground fault analysis in a real power system model has also been performed using the Hypersim software program to examine the effect on the distribution network. A single line at phase a to ground fault is supposed to occur at B_01. It is assumed that the fault occurred at t=1.5[sec] and cleared at t=1.6[sec] after 0.1[sec].

At the fault point, two different cases have been tested to compare results: without an FC, and with the FC power plant 1,000[kW] at B_03. Important concerns of transients during the fault include PQ, voltage at fault, current at CB, RA and FC, etc. To protect distribution network facilities, the transients have to be sufficiently considered for the design of the breaker and fault processing sequence. With and without the FC power plant 1,000[kW], the transients during the fault at B_01 are shown in Figs 8 and 9, respectively.

Figs. 8 (a) and (b) show the transients of real and reactive power, respectively. The peak of transient values increases close to 4×10^4[kW] and[kVar] temporarily and cleared by the circuit breaker (CB) after 0.1[sec]. Fig. 8 (c) shows the transients of the faulted phase voltage Va in rms value. Va drops to zero at t=1.5[sec] and recovered at t=1.6[sec]. Fig. 8 (d) shows the transients of three phase voltage. The un-faulted two phase voltages Vb and Vc showed as light variations temporarily during the fault and recovered to normal values. Fig. 8 (e) shows the current at CB. The current at the faulted phase increases to 5,000[A] and other two phase currents changes slightly. Fig. 8 (f) shows the transient currents at RA, after the faulted point. The current at the faulted phase Ia drops to zero, because the fault current does not flow through RA. The other two phase current at RA, Ib and Ic, show opposite variation according to the distribution line impedance during the fault.

In Figs. 9 (a) and (b), transients of real and reactive power with the FC power plant 1,000[kW] are similar to the case without an FC power plant. However, the magnitude of transient power at CB decreases slightly compared to the case without an FC power plant. Fig. 9 (c) shows the transients of the faulted phase voltage Va in rms value. Va drops to zero at t=1.5[sec] and recovered at t=1.6[sec]. Figs 9 (d), (e), and (f) show the currents at CB, RA, and the FC power plant, respectively. In Fig. 9 (d), the current at the faulted phase increases to 5,000[A] and other two phase currents increases slightly during the fault. In Fig. 9 (e), the transient currents at RA show slightly different values according to the impedance of distribution line and transformer during the fault. However, magnitudes are much

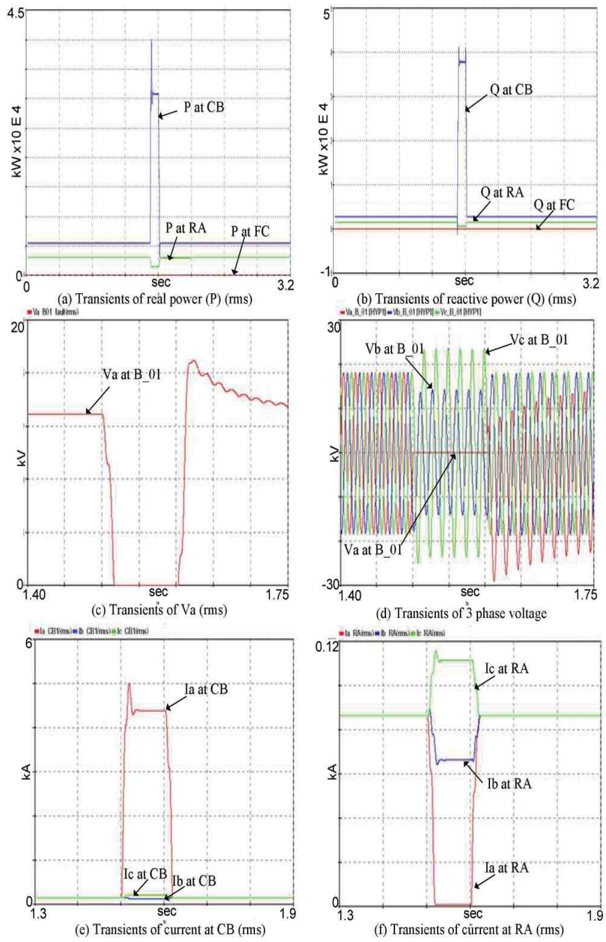

Fig. 8. Transients during fault at B_01 without an FC power plant

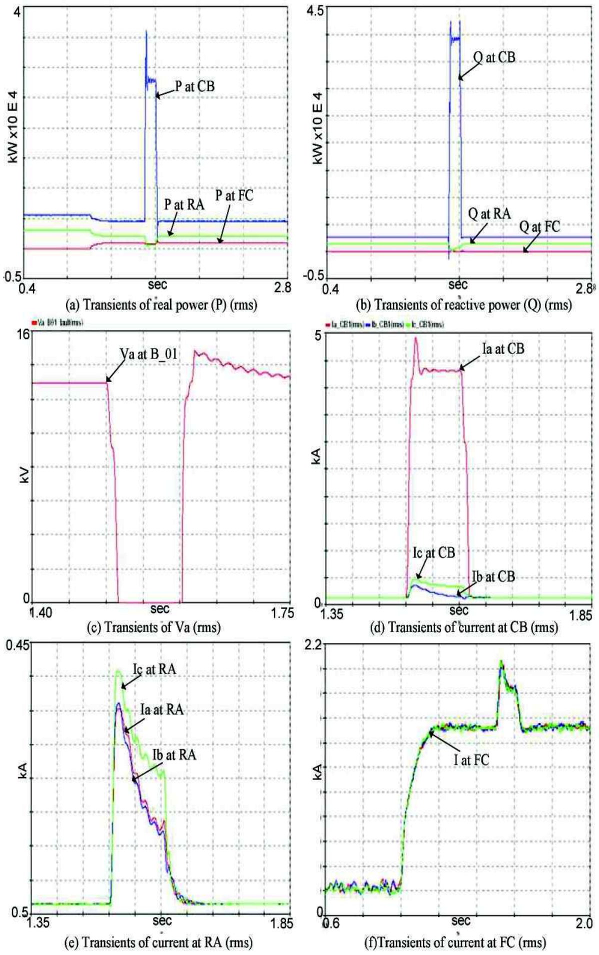

Fig. 9. Transients during fault at B_01 with the FC power plant 1,000[kW]

larger than those without an FC power plant in Fig. 8 (f). This indicates the FC power plant supplies most of the transient currents as shown in Fig. 9 (f) during the fault after the FC power plant is connected at t=1[sec].

In the simulations with line to ground fault, significant impact on the distribution system is not detected in Figs. 8-9. However, ground fault caused an FC power plant to supply overcurrent, which can cause failure in the FC power plant. The FC power plant should in this instance detect the distribution line fault and cut off the supply of power.

5. Conclusions

This study has dealt with the interface of an FC power plant to the distribution network. Operating conflicts and power quality issues were studied to clarify the existing problems. Many of these problems can be solved and improved using inverter technologies including real and reactive power control.

A DG interface model for the utility grid was developed and simulated using Matlab/Simulink for power sharing and fault operation. Simulation results have shown that an FC power plant can track the real and reactive power change of the load. They also have shown that an FC power plant is desirable to cut off the supply of power during ground faults in the distribution line.

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Biography

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Tae-Il Choi received a B. S. degree in Electrical Engineering from Hanyang University, Seoul, Korea, in 1982. He received his M.S. and Ph. D. degrees in Electrical Engineering from the Pennsylvania State University in 1993 and 2008, respectively. Since 1982, he has been working for the Korea Electric Power Corporation as an engineer and manager in Distribution Automation Department of Head Office and the Power Supply or Facility Management Team of B/Os. He is currently a General Manager, Head of Technology Development Team of Smart Grid Office. His research interests include distribution automation, artificial intelligence, distributed generation, and Smart Grid.