

COMPARATIVE ANALYSIS OF TRANSIENT OPERATION OF TWO DIFFERENT EMBEDDED GAS TURBINE POWER PLANTS

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Abstract – Traditionally, the generation and transmission of electrical power has been associated with large fossil fuelled / nuclear power stations exporting power at extra high voltages via overhead transmission lines to downstream consumers. The configuration of these “typical” electrical networks is now changing with the prospect of large amounts of generation being connected at the medium voltages associated with the distribution networks. These new schemes are known as embedded generation schemes and common practice at this moment in time is to configure the open cycle gas turbine (OCGT) into a combined heating and power (CHP) plant. From a power system stability perspective it is more advantageous to configure the gas turbine into a combined cycle gas turbine (CCGT) power plant. The studies presented in this paper compare the transient performance of the standard OCGT plant with the CCGT plant when connected to the medium voltage distribution network, and when isolated from the network.

Keywords: *Gas Turbine, Embedded Generation, Power System Stability, Distribution Network, Power System Modelling*

1 INTRODUCTION

Embedded generation schemes are becoming an important issue in the design and operation of interconnected power systems in the United Kingdom. Their growth is set to increase considerably in future years due to initiatives in place to reduce harmful gaseous emissions into the atmosphere. Therefore modelling and simulation of these plants is becoming of primary concern in order that their performance can be evaluated both running in parallel with the utility grid (generator parallel operation) and isolated from the utility grid (generator island operation) [1].

The design features of gas turbine power plant make it extremely suitable for use in embedded generation schemes. With respect to steam turbines there is no need for the bulky steam generation equipment, this allows the gas turbine to be of a modularized, lightweight design resulting in shorter construction times and lower capital costs. The start up time for a gas turbine is approximately 2 – 3 minutes allowing rapid restoration of electrical power during outages [2].

This paper investigates the transient stability of the two gas turbine power plants connected to the medium voltage distribution network. Various studies have been carried out on open cycle gas turbine (OCGT) and com-

bined cycle gas turbine (CCGT) plants connected directly to the transmission network [3] and in industrial co-generation schemes [4].

Various contingencies are carried out with an emphasis on the generator island operation. Presently in the United Kingdom embedded generation schemes are not required to operate isolated from the utility grid [5]. However, due to possible future large quantities of embedded generation connected to the distribution network it is envisaged that this scenario may well be changed. Past work on modeling of generator island operation schemes is minimal so it was considered very useful to concentrate studies in this area.

The main aim of this study was to produce detailed models of both OCGT and CCGT power plants using the Matlab toolbox Power System Blockset (PSB). Simulations are carried out for selected contingencies pertinent to embedded generation schemes and comparisons then made between the two plants. In addition the stability margins for a specific contingency are calculated for each plant.

2 TEST SYSTEM MODELLING

2.1 Mechanical System Modelling

2.1.1 The Open Cycle Gas Turbine Plant

Figure 1 shows a simple schematic representation of a single shaft open cycle gas turbine [2].

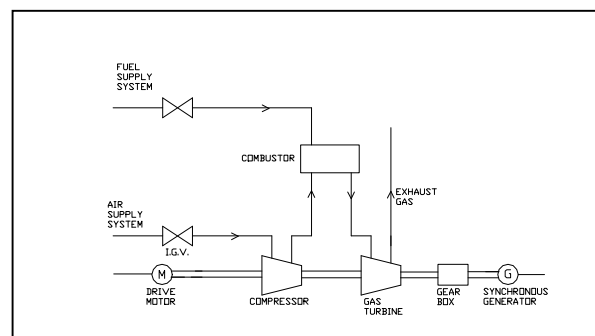


Figure 1: Single Shaft Open Cycle Gas Turbine (OCGT)

This is the standard gas turbine configuration used for electricity generation. The working fluid (air) is compressed by the compressor and then transported to the combustor. Inside the combustor, the air is mixed with the fuel and the mixture is ignited, causing turbine

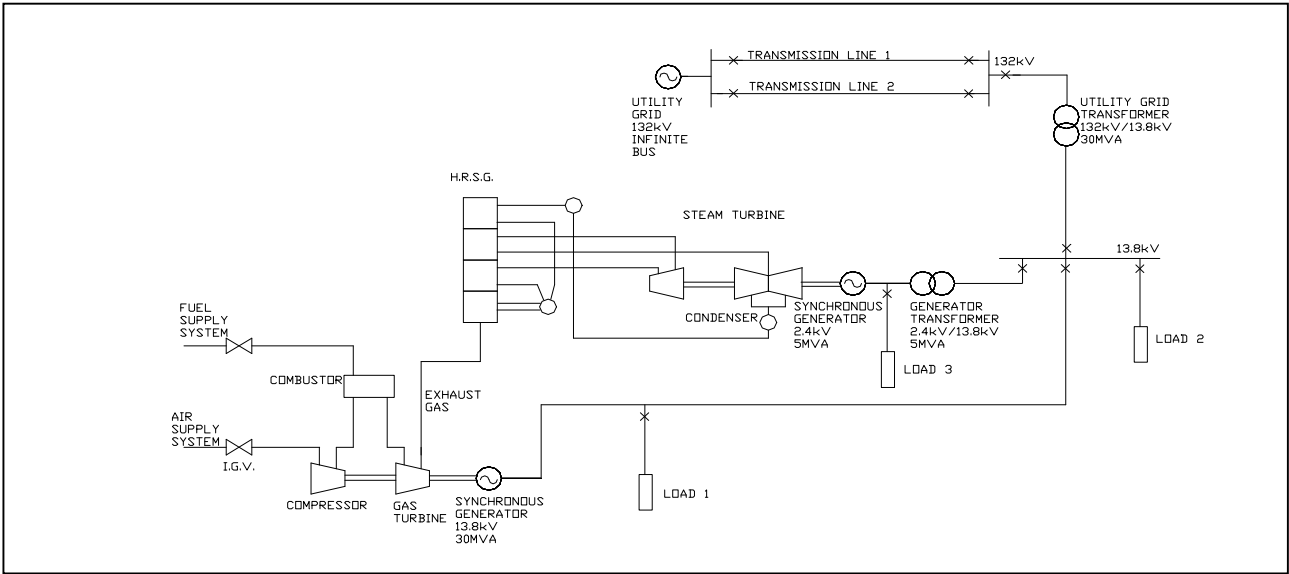


Figure 2: Combined Cycle Gas Turbine (CCGT) Power Plant Connected To The Distribution Network

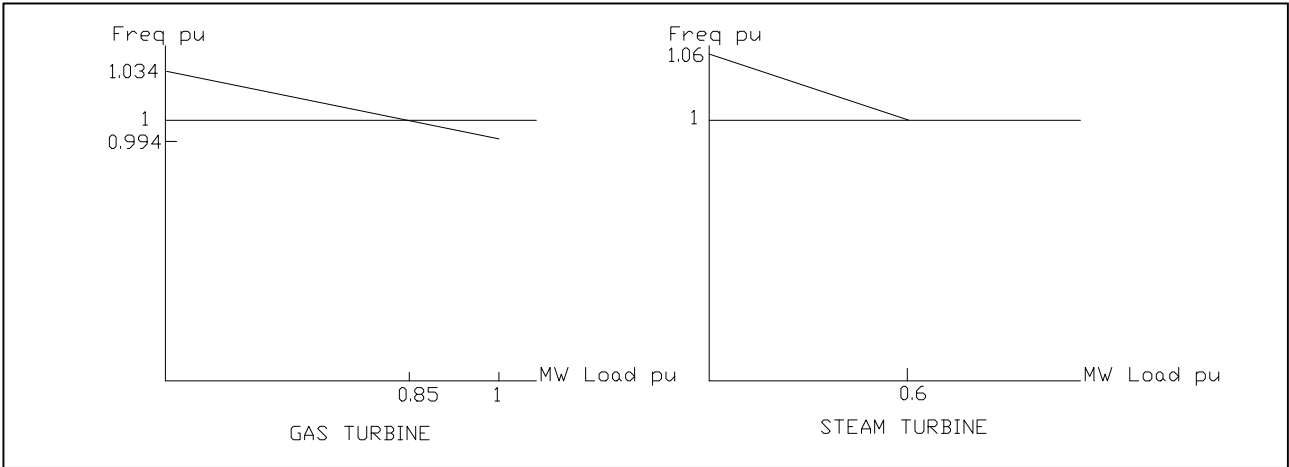


Figure 3: CCGT Gas Turbine And Steam Turbine Droop Settings For Parallel Operation With The Utility Grid

rotation and the production of mechanical power P_m . The exhaust gases are not utilized and are vented to atmosphere. The single shaft gas turbine possesses a large inertia due to the generator, turbine, compressor and drive motor connected via a common shaft. The model used in these simulations is based on [6].

The gas turbine governor utilized is based on whether the generator is running in parallel with or isolated from the utility grid.

When running in parallel with the utility grid the gas turbine is fitted with a droop governor set at 4%, this is essentially a proportional controller with the gain $K_d = 25$.

When running isolated from the utility grid the gas turbine is fitted with an isochronous governor. Isochronous control is used when the gas turbine generator (GTG) is responsible for maintaining the frequency within the desired limits. This is a proportional + inte-

gral (PI) controller which controls the rotor speed in order that the speed error $\Delta\omega_r = 0$.

The complete mathematical model and parameters of the CCGT plant given in [6] are omitted here due to space limitation.

2.1.2 The Combined Cycle Gas Turbine Plant

Figure 2 shows a schematic diagram of a combined cycle gas turbine (CCGT) power plant connected to the distribution network as utilized in these studies. The basic operation of the CCGT plant is similar to the OCGT plant. The fundamental difference between the two plants is associated with the final use of the gas turbine exhaust gases. In an OCGT plant these gases are vented to atmosphere as described above, whereas in the CCGT plant they are fed into a heat recovery steam generator (HRSG). The HRSG is essentially a heat exchanger. A water supply is fed through it and raised in temperature, due to the thermal energy of the exhaust

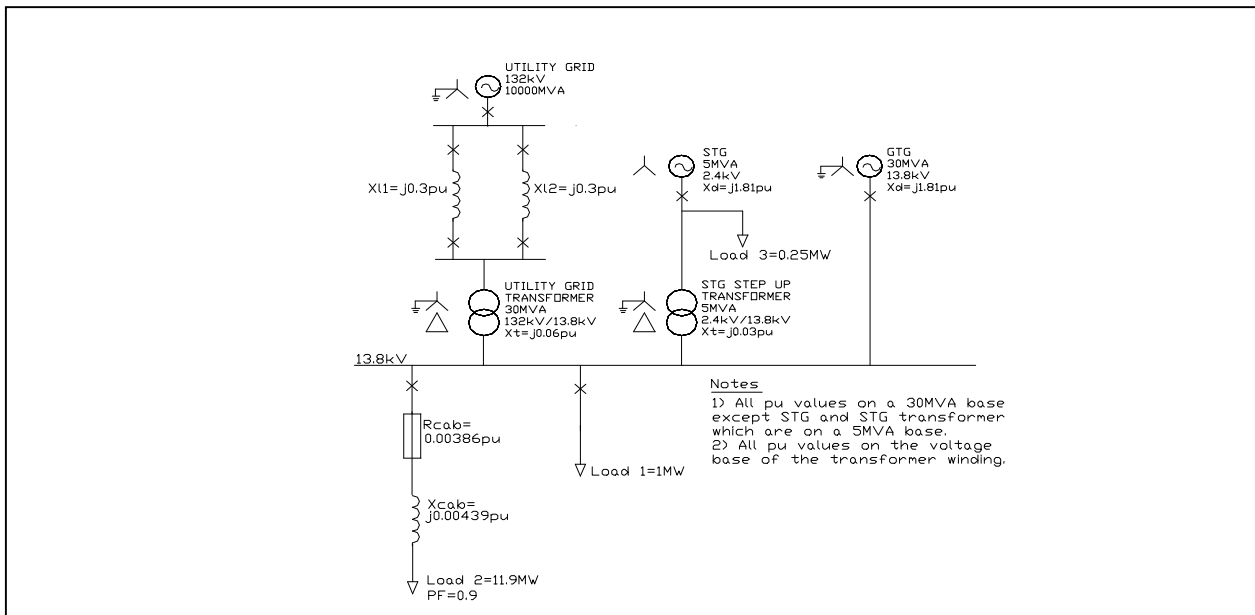


Figure 4: Single Line Diagram Of CCGT Power Plant Operating In Parallel With The Utility Grid

gases, so that the steam is produced. This steam is then fed into a steam turbine generator (STG) and additional mechanical power P_m is produced.

The complete mathematical model and parameters of the CCGT plant given in [3,4] are omitted here due to space limitation.

Figure 3 presents the CCGT plant gas and steam turbine governor droop settings when running in parallel with the utility grid. The GTG was rated at 30 MVA and was set at a droop of 4% and a load reference of 0.85pu (25.5MW). The STG was rated at 5 MVA and was set at a droop of 10% and a load reference of 0.6pu (3MW). This load reference setting was made to limit the steam turbine mechanical power to the upper limit, which was dependent upon the maximum exhaust temperature of the gas turbine. The assumption was made that the gas turbine maximum exhaust gas temperature and flow rate were sufficient to produce 0.6pu mechanical power from the steam turbine. The control systems used to maintain the gas turbine maximum exhaust temperature under varying load conditions are discussed in detail in [3,4].

When isolated from the utility grid the GTG and the STG still had to operate in parallel. The simplest method of configuring the governors of generators operating in parallel is droop-droop operation. If the governors are matched and adjusted so both have the same droop, then each generator would contribute to 50% of the load change. However, due to the load limit imposed on the STG the governors were unable to be matched so this method could not be used. In order to overcome this problem and hold the frequency constant in the islanded system the gas turbine governor was set as an isochronous device. The steam turbine governor remained set at 10% droop with a load reference set

point of 0.6pu. All load variations were thus supplied by the GTG due to the action of the isochronous governor.

2.2 Electrical System Modelling

Figure 4 represents the single line diagram of the CCGT power plant connected to the distribution network and operating in parallel with the utility grid. The diagram is also applicable to the OCGT plant except that the STG is excluded in that case. The GTG and STG are three phase round rotor synchronous generators whose ratings were 60Hz, 13.8kV, 30MVA and 60Hz, 2.4kV, 5MVA respectively. The synchronous generators are represented by 6th order models which have d and q axis stator windings, d axis rotor field and damper windings and two q axis damper windings [7]. Each synchronous generator was equipped with an AC static exciter model IEEE type ST1A potential-source controlled-rectifier [7]. Field current, overexcitation, underexcitation and volt / Hz limiters were not modeled.

The distribution network was rated at 13.8kV and connected to the 132kV utility grid via a 132kV / 13.8kV power transformer and two parallel transmission lines. The utility grid was modeled as a 10GVA source which was essentially an infinite bus.

Three loads were connected to the system. Load 2 = 11.9MW, $\cos\theta = 0.9$, represented the distribution system load and was connected via two parallel, 500m, 240mm², 3 core, 15kV cross linked polyethylene (XLPE) insulated underground cables. Load 1 = 1MW, represented the GTG auxiliary load. Load 3 = 0.25MW, represented the STG auxiliary load. Total OCGT plant local load was 12.9MW, and total CCGT plant local load was 13.15MW.

3 CASE STUDIES

Numerous case studies were carried out in order to compare the transient performance of the OCGT and CCGT plants [1]. The characteristic ones are presented in this section.

3.1 Disconnection From The Utility Grid

A three phase fault lasting $t_c = 150\text{ms}$ was applied at $t = 0.2\text{s}$ to the 132kV utility grid. This resulted in the utility grid being disconnected from the distribution system at $t = 0.35\text{s}$. The GTG governors were then changed from droop to isochronous control in order that the plant could run in island operation, maintaining power to the distribution network loads. During prefault conditions the plants were exporting 15.5MW to the utility grid.

3.2 Comparison Of The Plant Stability Margins With A Variation In Fault Duration Time t_c

The plant stability margins were calculated for each plant whilst operating in parallel with the utility grid. The stability margins were calculated for a three phase fault at load 2. These stability margins were based on the measurement of the fault clearing angle δ_c from the simulation results, for a given fault clearance time t_c . These results were then compared with the calculated critical fault clearing angle δ_{cc} [7] and the stability margin determined.

4 RESULTS OF THE STUDIES

4.1 Disconnection From The Utility Grid

Figures 5, 6 and 7 illustrate the mechanical system dynamics based on case study described in Section 3.1.

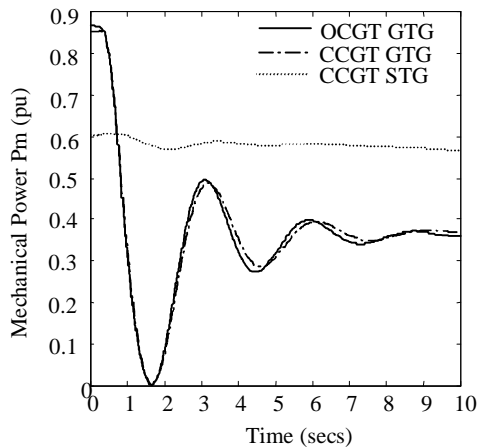


Figure 5: Turbine Mechanical Power P_m

With the three phase fault inception at the utility grid the plants cannot export 15.5MW to the utility grid. This causes an instantaneous reduction in plant active power P_e , the mechanical power P_m (see Figure 5) cannot change instantaneously due to the time lag associated with the gas turbine. The rotor angle deviation δ (see Figure 7) increases due to the inability of the generator

to convert the turbine kinetic energy into magnetic and then electrical energy, which causes the kinetic energy to accelerate the rotor. This also causes the rotor speed ω_r to increase (see Figure 6). At $t = 0.35\text{s}$ the fault is cleared and the utility grid is disconnected, causing the plants to run islanded from the utility grid. The plants are now only supplying the distribution network loads 1, 2 and 3 and the plant active power output alters accordingly. The governor begins responding after approximately $t = 0.5\text{s}$ and reduces the mechanical power P_m . The rotor angle deviation δ begins to follow the mechanical power P_m after approximately 2s, the delay is due to the rotor inertia. The mechanical power P_m of the GTG of each plant is damped until it reaches the new steady state value of 0.38pu (12.9MW). The CCGT plant GTG will eventually supply less active power than the OCGT plant GTG due to the STG contribution. The CCGT STG however, does not make a major contribution to the plant active power reduction due to its governor droop setting of 10%. With the frequency = 1pu the STG active power output is dependent only on its droop governor load reference set point of 0.6pu. This can be seen in Figure 5 for a reduction in total plant load due to the loss of the utility grid. For load additions to the CCGT plant, the GTG will supply the new load due to its fast speed of response. The STG will be unable to contribute due to the long time constant of the HRSG making the STG speed of response very slow relative to the GTG.

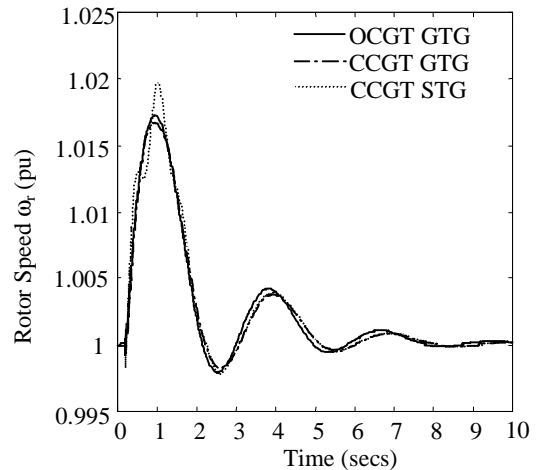


Figure 6: Rotor Speed ω_r

From Figure 6 it can be seen that the generator rotor speed ω_r returns to the predisturbance value of 1pu. At this point the turbine governor has reduced the mechanical power output in order that it equals the new generator island load P_e . From Figure 7 it can be seen that the generator rotor angle deviation δ does not return to the predisturbance value. When the utility grid is disconnected the generator accelerates as previously described. Adopting the equal area criterion [7] it can be seen that rotor angle deviation δ exceeds the maximum transient equilibrium point δ_m and carries on increasing

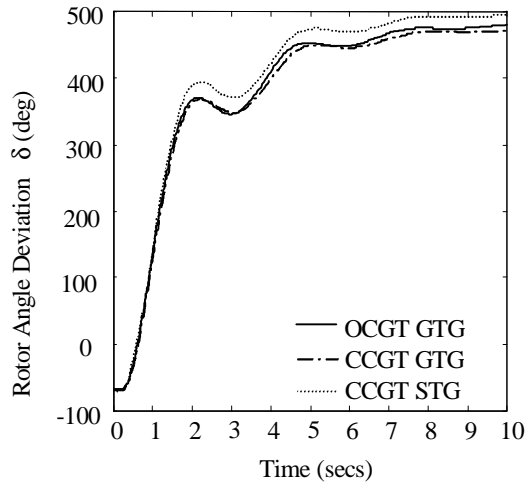


Figure 7: Rotor Angle Deviation δ

until it settles at approximately 555° above the pre-disturbance value. The rotor angle deviation δ can be seen to increase through the half sinusoid generator power angle curves [7] until the governor reduces mechanical power P_m to its new steady state value for the island system. In parallel operation this is equivalent to the generator making 3 pole slips ($3 \times 180^\circ$) with respect to the utility grid. Hence synchronism would be lost with the utility grid and the generator tripped. If the generator was not tripped then synchronism would eventually be regained with the new rotor angle δ settling on the 4th power angle curve. However, in generator island operation the active power output is not determined by the machine rotor angle and the generators' main function is to maintain the system frequency within desired limits. The maximum frequency deviation shown in Figure 6 is +2% and if the generator and distribution system protection does not malfunction then each plant will run successfully during island operation. It should be noted that the relative rotor angle deviation (Figure 7) between the GTG and STG on the CCGT plant is very small indicating that the two generators have remained in synchronism.

Figures 8 and 9 illustrate the electrical system dynamics based on case study described in Section 3.1. The generator terminal voltages (Figure 8) for both plants are severely reduced during fault conditions. Even though the rotor angle and speed variations indicate that mechanically the plant is able to function in islanded operation, the voltage depression could cause undervoltage protection to operate resulting in losing the plant. The potential source controlled rectifier static excitation system is of great benefit on stability and maintaining fault current on a system where the generator terminal voltage is not severely depressed. In the case of an island system however, faults anywhere on the network will cause a large variation in generator terminal voltage and thus as the excitation system receives its power supply directly from the generator terminals problems may often occur. When the fault is

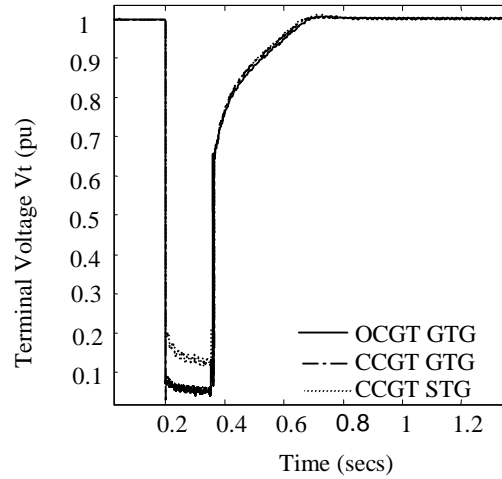


Figure 8: Generator Terminal Voltage V_t

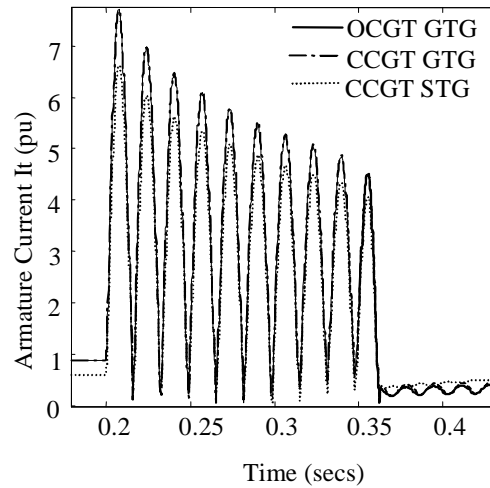


Figure 9: Generator Armature Current I_t

cleared at $t=0.35s$ it can be seen that the terminal voltage is rapidly restored.

It can be seen from Figure 9 that the CCGT plant fault current is much greater than that of the OCGT plant. Although the GTG of each plant produces approximately 8pu fault current (10kA on 30MVA, 13.8kV bases) the STG produces 6.6pu (7.92kA on 5MVA, 2.4kV bases) resulting in the CCGT total fault current being much larger. This would result in the requirement for the electrical equipment on the CCGT plant to be of a greater short time rating and such more expensive.

4.2 Comparison Of The Plant Stability Margins With A Variation In Fault Duration Time t_c

Figure 10 presents the plant fault clearing angle δ_c for a variation in fault clearance time at load 2. Each plant was running in parallel with the utility grid. The fault clearing angles are shown for the GTG on each plant.

The fault clearing angle of the CCGT STG was not included and the assumption was made that it remained in synchronism with the CCGT GTG during the fault conditions.

With fault durations up to 400ms the fault clearing angle (Figure 10) for both plants was very similar. At fault durations above 400ms the OCGT GTG suffered from a larger rotor angle deviation δ . This was mainly due to the fact that the CCGT GTG was operating at a slightly lower pre-fault active power output P_e due to the STG providing 3MW.

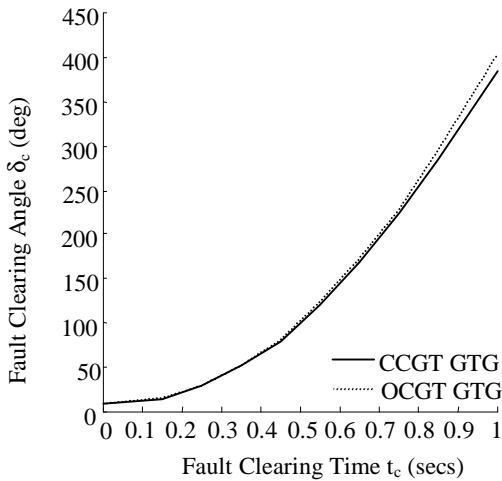


Figure 10: Plant Fault Clearing Angle δ_c For A Variation In Fault Clearance Time t_c (Parallel Operation)

Figure 11 shows the gas turbine governor response as a function of the fault clearing time. It can be seen that the gas turbine governor does not make a significant contribution to stability for fault duration less than 250ms.

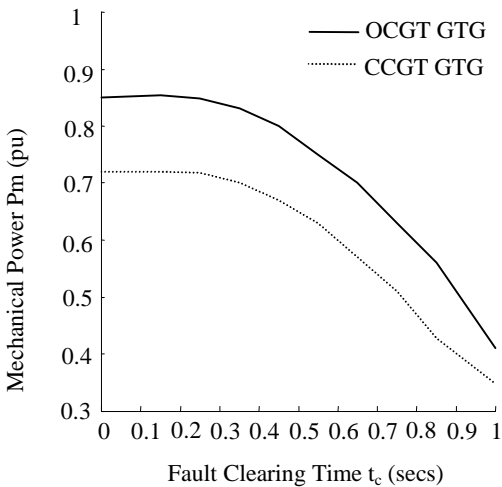


Figure 11: Plant Gas Turbine Governor Response For A Variation In Fault Clearance Time t_c

Figure 12 presents the plant stability margins for the conditions previously described. During pre-fault conditions when the plants are running in the steady state the stability margin is 1pu. It can be seen that the CCGT plant gives slightly better stability margins (dashed curve in Figure 12) for fault clearance times above the critical fault clearance time $t_{cc} = 580$ ms. At the critical fault clearance time t_{cc} the stability margin is 0pu and the rotor angle reaches the unstable maximum transient equilibrium point δ_m [7]. When the GTG reaches this point it begins pole slipping with respect to the utility grid. Pole slipping is an unstable, oscillatory state and indicates that the GTG has lost synchronism with the utility grid (rotor angle instability).

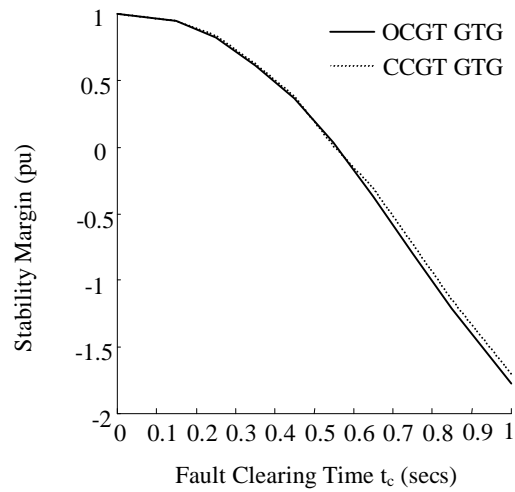


Figure 12: Plant Stability Margins

Figure 13 shows the variation of fault clearing angle δ_c with a fault clearing time t_c for the island system. It can be seen that the rotor angle deviation is much less severe for the CCGT plant at fault clearance times above 460ms. It should be noted that in island operation the generator does not suffer from rotor angle instability, i.e., loss of synchronism with other synchronous machines. Therefore pole slipping is not a problem as there is no danger of oscillations occurring due to the connection of two unsynchronized power supplies. As the rotor angle deviation is improved for the CCGT plant due to the addition of the STG the frequency deviation is not as severe as for the OCGT plant. Frequency deviation is of fundamental importance in an islanded system as there is no external power supply (infinite bus) to hold the frequency constant.

5 CONCLUSIONS

In this study an open cycle gas turbine (OCGT) power plant and a combined cycle gas turbine (CCGT) power plant were modelled using Matlab Power System Blockset (PSB). Transient stability studies were carried

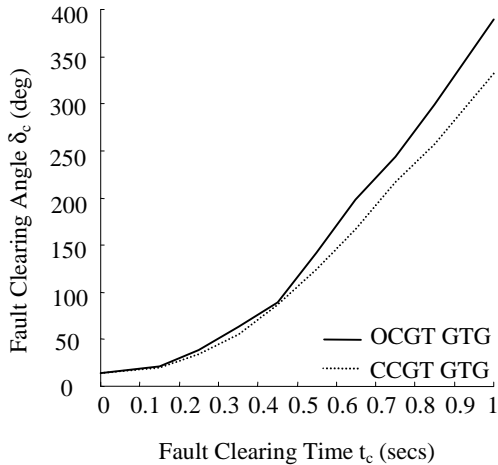


Figure 13: Plant Fault Clearing Angle δ_c For A Variation In Fault Clearance Time t_c (Island Operation)

out to ascertain the relative performances of the plants under varying faulted network conditions. From the results presented in the paper it can be seen that both plants are able to operate correctly when separated from the utility grid for a local load within the plant ratings. These results should be checked against protection characteristics in order to ensure that the plant is not inadvertently disconnected from the distribution network. Protection studies were outside the scope of this paper.

In addition, the stability margins were calculated for each plant for a three phase fault on the distribution network. It can be seen that the CCGT plant offers improved stability margins for parallel operation with the utility grid. In island operation the rotor angle and hence frequency deviation is also improved with respect to the OCGT plant. The main reason for these improved characteristics is the addition of the steam turbine generator (STG) to form the CCGT plant.

It was assumed in the study that the STG exports only 0.1 pu (3MW) of the total GTG power (30MVA). If the STG was designed to produce 0.5 pu (15MW) of the GTG active power (as suggested in some studies [2]) this would clearly give further improvements on the stability margins compared with the standard OCGT plant. In such case however, the system fault levels would be also increased which could mean an increase in the short time withstand levels of the downstream electrical equipment. In addition more complex protection and control schemes would also have to be provided.

6 REFERENCES

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