

Coordinated AVR and Tap Changing Control for an Autonomous Industrial Power System

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Abstract

This study investigates a strategy of voltage and reactive power control for an autonomous industrial power system including distributed generators and loads. The investigation is based on time domain simulation and aims to define the main functions for the power management system (PMS) that will govern the operation of the power system. Inter-bus transformers (IBTs) are used to limit the fault level but will affect the sharing of the total load reactive power between distributed generators. Generator AVR and on-load tap changing (OLTC) of the IBTs, both supervised by the PMS, are used together to regulate the local load voltages and at the same time to allow reactive power flow through the IBTs for the purpose of equalized sharing. A coordinated strategy is obtained. The knowledge gained from this study can be useful in future cases.

1. Introduction

Isolated, autonomous electrical power systems are often found in process industry, for example in an iron and steel or petrochemical complex. Grid connection may be too costly such as on offshore oil rigs or the grid may not be able to provide the quality and reliability of supply required by the industrial customer. The design and operation of isolated, autonomous power systems have to address technical issues that are not common to conventional substations connected to the utility grid. For instance, the short circuit level can be high due to low impedance and local generation

present in the system. Because both generators and loads are distributed to separate busbars, control of load voltages may conflict with the desired sharing of reactive power between generators involving VAr flow through impedance branches. Such issues are considered in design but must be dealt with during operation, usually by a computerised power management system (PMS) which also provides other control, monitoring and protection functions [1].

Figure 1 shows in general a power management system providing supervisory control in a stand alone industry power system. Load busbar voltages, system frequency and the operating conditions of the generators are acquired and used to activate switching actions, and set references for generator AVRs, governors and the tap positions of some transformers that can be changed on-load. The control objectives of the power management system are to satisfy the load voltage and frequency requirements while maintaining power system components within specifications.

Achieving control objectives using a PMS requires understanding of the system behaviour subject to disturbances and control actions. It is important to form an overall control strategy regarding the requirements. The strategy is then verified and detailed towards implementation. This paper presents a simulation study performed as part of such a development procedure.

Each industrial power system has its own characteristics. This study focuses on the voltage and reactive power control in a system found in the petrochemical industry and it is the control requirements caused by the expansion of an existing system that are considered. In the expanded system, inter-bus transformers (IBTs) between local substations will be used to limit potential fault current. Sharing of load reactive power according to generator MVA ratings is desired to maximize the margin of AVR response when regulating the local load busbar voltage in fast transients. Transformer impedance and reactive power flow give rise to the inherent conflict of trying to achieve voltage and reactive power control simultaneously. In addition to generator AVR, a minimum number of on-load tap changes (OLTC) to the IBTs are required. This paper investigates

how such control means can be used within a PMS to achieve the control objectives.

The model components used in this study are not themselves original. The contribution of this paper is to illustrate the origin of the power system control requirements and put forward a coordinated AVR and OLTC control strategy. Analysis, backed by simulation results, shows how to achieve the control objectives in a PMS. The study provides new insight and ideas that can be useful to the design of future industrial power systems and their PMS.

2. Power System and Control Requirements

The existing power system is simplified as shown in Figure 2. It consists of two substations which are linked at 33 kV voltage level through a short cable run with a circuit breaker at each end. Each substation has generators and loads connected to the 33 kV busbar. The local generation capacity and load power are in the range of 60 MVA to 180 MVA, and are detailed in the Appendix. Significant reactive power is demanded by loads of an industrial nature, e.g. induction motors and thyristor converters or variable speed drives. The frequency of the system is maintained by the governors of all the generators operating in droop mode. Since the loads are all supplied from the two 33 kV busbars which are directly connected, all generators can share the responsibility of load bus voltage regulation. The load reactive power can be shared according to generator MVA ratings by means of ‘q-axis droop’ [2].

As industrial production increases, there is the need to increase the generation capacity. If new generators were added to the two existing substations, this would cause the short circuit level to exceed the interrupting capabilities of the circuit breakers in the system. A highly inductive circuit is associated with a high peak make duty due to the large d.c. offset which takes long time to decay. As a result, it was decided to build a new substation associated with the new production line or load, shown as SS3 in Figure 3. The original interconnection between Substations SS1 and SS2 is broken up and the three substations are all linked to a 132 kV busbar through three pairs of inter-bus

transformers with large impedance to limit the fault current. If a short circuit fault occurs in any part of the system, the fault current fed by at least two substations will be limited by some of the IBTs. The tap positions on the high voltage side of the IBTs can be changed on-load. If two IBTs in a substation are both on line, their tap positions are always the same and changed together to avoid circulating current. The configuration shown in Figure 3 is an option that can be adopted in other designs in the future. Real parameters of Substation SS3 and the identical inter-bus transformers are also given in the Appendix, as for Substations SS1 and SS2.

Each substation can include different types of generators and each generator is equipped with an AVR. The AVR regulates the 11 kV terminal voltage. However the AVR reference is set by the PMS according to the corresponding 33 kV load busbar voltage, as illustrated in the next section.

Sharing the load reactive power between the generators means flow of reactive, as well as real, power in reversible direction through the IBTs, which is permitted in this configuration. The special requirements on the tap changing mechanism to allow reversible power flow are discussed in [3]. This however causes significant voltage drops across the relatively large IBT impedance. The load voltages at the 33 kV busbars are consequently affected. It is necessary to use the on-load tap changing function of the IBTs and the AVRs of the generators together to achieve the load voltage control and reactive power sharing between the generators, requiring a coordinated control strategy. The development and validation of such a strategy are the principle aims of this study.

The load voltages are to be controlled within $\pm 1\%$ of the nominal value (33 kV). The 132 kV busbar voltage is also to be controlled within a $\pm 5\%$ tolerance. The IBT tap ratio can be changed in either the positive or negative direction by 8 steps, each moving further away from the nominal tap by 1.25%. Tap changing relies on mechanisms that are slow and can wear out after extensive use. Therefore a control objective is to reduce the number of tap changes for a given scenario of disturbance. Since IBT tap positions are discrete, there is the risk of hunting in which the tap

oscillates between two positions. This must be avoided by appropriate design.

3. Control Strategy

In order to understand the proposed control strategy it is necessary to point out that the autonomous industrial system concerned is subject to a different set of constraints and control options to those experienced by public distribution networks. This is primarily because public distribution networks have load customers directly connected to them and often they do not have local generation and therefore reactive power sharing between distributed generators is not an issue. The autonomous industrial system concerned has specific control facilities available, such as, access to local generator AVR. This control facility is often unavailable in public distribution networks where local voltage regulation is likely to be achieved using AVC relays [4] or in some circumstances static VAR compensators. This study investigates the feasibility of a new control strategy using generator AVR and OLTC of the IBTs, which if successful will be cost effective as no additional hardware is required. The control specifications of an autonomous industrial system as described in this paper are also different from those in a public distribution network [5].

The generator AVR operates in a continuous manner to adjust the excitation, which will in turn affect the terminal voltage and the reactive power produced by the generator. Given the IBT tap positions, the fast response of the AVR is utilized to ensure the quality of load voltage control. The $\pm 1\%$ voltage variation permitted on the 33 kV busbars can however be used as the first means of reactive power sharing control. This is shown in Figure 4 for any of the three substations. The reference of the 33 kV load busbar voltage is set in the tolerance band so that it will reduce the difference between the VAR sharing of the substation, in terms of MVar per MVA of generator capacity, and that of the overall system. The VAR controller shown in Figure 4 which sets the reference value of the corresponding 33 kV busbar voltage is driven by the following error.

$$\Delta Q = \left(\frac{MVar}{MVA} \right)_{overall} - \left(\frac{MVar}{MVA} \right)_{substation} \quad (1)$$

where the generated MVar is measured on the 33 kV side of the substation.

The voltage regulator shown in Figure 4 responds to the 33 kV busbar voltage error and sets the demand for the generator AVR to regulate its terminal voltage (11 kV). Both the VAr regulator and voltage regulator can be implemented in proportional and integral algorithms that will eliminate any steady state error and the 33 kV load busbar voltage will be kept in the $\pm 1\%$ tolerance band.

As described above, the tap positions of the IBTs can be controlled to achieve two objectives:

- to maintain the 132 kV busbar voltage within $\pm 5\%$ of the nominal value, and
- to drive, in a differential mode, the reactive power towards equal sharing according to the generator MVA capacities of the substations.

It is noted that the system is off grid so load customers are not affected in the same way as in grid connection. The major factors determining the voltage tolerance band of the 132 kV busbar where no load is connected are the equipment voltage ratings rather than customer requirements [5].

A control loop would be required in the PMS that controls the IBT taps in order to maintain the voltage at a particular 33 kV substation where the local generation is off line. This control mode regarding the local load fed from generators in the other two substations through IBTs is conventional for transformer fed substations and therefore has not been included in this study. As on-load tap changing of an IBT is much slower than the response of the generator AVR, it is desired that tap changing control is only enabled and executed when the AVR response has reached the steady state. In the simulation model, this is taken into account by introducing time delays in the tap changing control algorithm, as described later. Following the change of a tap position, further AVR

response would be activated. Through the combined use of generator AVR and IBT on-load tap changing, the 33 kV busbar voltages will remain within the $\pm 1\%$ tolerance band while in the steady state the total load reactive power will be shared by the three substations according to their generator MVA capacities. In the steady state, the 33 kV busbar voltages are largely determined by IBT taps.

Figure 5 shows the structure of the control logic for the IBT tap positions. The error of the 132 kV busbar voltage and/or the unequal reactive power sharing between substations are detected and used to drive the tap positions moving in the desired directions, resulting in reduction of the errors. As shown in the figure, the movement of a tap in an IBT is the result of two actions which aim to regulate the 132 kV busbar voltage and equalize the generator reactive power according to the MVA rating. The 132 kV busbar voltage drives a common mode motion in which all IBTs move their taps in the same direction. The unequal reactive power sharing between the substations drives the tap positions to change in a differential mode. Based on the relationship in the power system, the control logic should satisfy the following conditions, which has been represented using proper signs in Figure 5.

- If the 132 kV busbar voltage is lower than the tolerance band, the control tends to increase the tap positions of all IBTs and vice versa.
- If the reactive power from a substation is to be decreased, this requires the tap position of the IBTs in the corresponding substation to be reduced and vice versa.

In these statements, increasing the tap position means that the number of turns on the high voltage (132 kV) side of the IBT becomes larger.

It is important to set appropriate tolerance bands for the common and differential modes of the tap position control algorithms. While the voltage tolerance band is set as $\pm 5\%$ of the nominal, the

tolerance band for reactive power sharing must consider the discrete nature of the tap positions and this should be set to avoid a hunting scenario in which the tap keeps moving between two positions.

Figure 6 shows the equivalent circuit of the system shown in Figure 3 with all reactances referred to the 132 kV side. X_{SS1} , X_{SS2} and X_{SS3} are the reactances of Substations SS1, SS2 and SS3 respectively, each including the generators (using synchronous reactance) and the 11 kV/33 kV step-up transformers. X_{T1} , X_{T2} and X_{T3} are the equivalent reactances of the parallel IBTs in the three substations. The off nominal tap positions of the IBTs are represented using ideal transformers which can then have non-unity ratios. The load impedances are ignored. It can be shown that the change of reactive power caused by 1.25% of IBT ratio variation in one substation, measured at the local 33 kV busbar can be calculated as

$$\Delta Q_{SS1} = \frac{(0.0125 \times 132 \text{ kV}) \times 132 \text{ kV}}{(X_{SS1} + X_{T1}) + (X_{SS2} + X_{T2}) // (X_{SS3} + X_{T3})} \quad (2)$$

$$\Delta Q_{SS2} = \frac{(0.0125 \times 132 \text{ kV}) \times 132 \text{ kV}}{(X_{SS2} + X_{T2}) + (X_{SS1} + X_{T1}) // (X_{SS3} + X_{T3})} \quad (3)$$

$$\Delta Q_{SS3} = \frac{(0.0125 \times 132 \text{ kV}) \times 132 \text{ kV}}{(X_{SS3} + X_{T3}) + (X_{SS2} + X_{T2}) // (X_{SS1} + X_{T1})} \quad (4)$$

where expressions in the form of $X_1 // X_2$ means the parallel equivalent of X_1 and X_2 , i.e.

$$X_1 X_2 / (X_1 + X_2).$$

It is apparent that the change of reactive power caused by one step of IBT tap position depends on the operational condition of the system, with maximum sensitivities occurring at lowest impedances in the circuit, i.e. when all the generators and transformers are in operation. From the impedance data given in the Appendix, the maximum change of the reactive power caused by a single tap change of IBTs as measured in the corresponding substations are

$$\Delta Q_{SS1_max} = 2.86 \text{ MVar}$$

$$\Delta Q_{SS2_max} = 2.87 \text{ MVar}$$

$$\Delta Q_{SS3_max} = 3.06 \text{ MVar}$$

The tolerance band in IBT tap position control for reactive power sharing must be greater than the maximum of these values. To provide sufficient margin, a band has been set to be ± 6 MVar and this has been taken into account in terms of the MVar/MVA calculation which drives the differential mode of tap position control as shown in Figure 5.

4. Simulation Models

Synchronous generators are usually modelled in two alternative approaches: 1) an equivalent circuit model using a constant e.m.f. behind the synchronous or transient reactance; 2) a full model including stator and rotor windings with coupling which governs the development of e.m.f. and torque of the machine [6]. It was discovered in initial simulations that the first approach is oversimplified and the voltage dip or rise in the system following a major disturbance predicted using synchronous reactance is excessive. It is necessary to use a transient model in which the transient reactance is significantly lower than the synchronous reactance. The second approach is computationally intensive in the present study where many generators are included and the transients concerned last for minutes rather than seconds.

If a conventional transient model were used, e.g. a constant transient e.m.f., E' , behind the transient reactance, it would not allow investigation into the response of the excitation voltage which is dictated by the AVR output. In the present study, it is essential to guarantee that the AVR and exciter outputs will be within the limits. Furthermore, a conventional transient model would cause the reactive power flow in the system to be more sensitive than it is to the change of IBT tap position since the circuit reactance is too low.

The adopted transient generator model is shown in Figure 7 as an equivalent circuit. It appears similar to a conventional transient model. However, the transient e.m.f. is not constant as determined by the pre-event load flow condition. Instead, E' is dynamically updated during the transient. The updating algorithm is given below in Eq. (5) [7], and depends on the exciter output and the reactive component of the generator output current. As a result, the model is able to represent the AVR or exciter limits and the steady state response of the reactive power will be that determined by the excitation voltage E_f and synchronous reactance.

$$T'_{do} \frac{d}{dt} E' = E_f - E' - I_d(X - X') \quad (5)$$

where T'_{do} is the open circuit transient time constant. X and X' are the synchronous and transient reactances of the generator, taking the average of d and q axis values as an approximation.

The AVR modelled conforms to an IEEE Type II standard [8]. The output limits of the main regulator are [-39, 40 pu] while the output of the exciter is limited to [0, 4.7 pu]. Actual control block gains and time constants are used which are also typical as for a 40-50 MVA generator.

The generator transformers are modelled in terms of the winding leakage reactance and resistance, and the mutual coupling between the primary and secondary windings. The inter-bus transformers further feature on-load tap changing. Each IBT is then modelled as a conventional transformer with nominal ratio in cascade with an ideal transformer having the off nominal ratio 1:a where 'a' is adjustable [9] from the controller point of view.

The control algorithms, as outlined in Figures 4 and 5, are implemented in a coordinated manner as they would be in a PMS. The generator excitation control is executed continuously while the IBT OLTC control is modelled as described in [10]. The time scale for updating the local AVR settings

is short (20 ms) while the tap positions are changed in a time scale up to 10 seconds.

In order to avoid unnecessary tap changes, the IBT tap control logic is blocked for 10 seconds after the disturbance. This allows the AVR response, which is automatically initiated and typically has a decaying time constant of 2~3 seconds [11], to settle down. Once the tap position is set, it is held there for at least 10 seconds before the next change of tap position can take place. For example, in line with Figure 5, Figure 8 expands the control logic that the IBT tap position in a substation changes to balance reactive power sharing in the overall system. This corresponds to a differential mode component in Figure 5. The input on the left hand side is the deviation of reactive power sharing (per MVA) as calculated in Eq. (1). In the simulated cases which will be described in the next section, the control logic is manually blocked for 10 seconds following the occurrence of the disturbance. In practice, the power management system would detect the initial transient of a disturbance. Alternatively the 'd/dt' rate in the AVR response would be measured to check whether a new steady state has been reached. Time delay and logic comparison can be used jointly to define the holding time for the set tap position.

It is clear that the IBT tap position control logic described here can be modified to include the reactive power constraint imposed by the generator performance chart. This has been considered in the simulated cases.

5. Case Studies

Two representative disturbances are considered in this section using real system parameters. One causes long term effect to the system while the other has temporary effect during transient. The first case study investigates the system response following an incident of tripping a heavily loaded generator. This will cause the distribution of real and reactive power in the system to change. Simulations show how the PMS achieves the control objectives of maintaining the load busbar voltages and sharing of load reactive power according to generator MVA capacities.

Before the disturbance, all generators in Substations SS2 and SS3 are in operation. In Substation SS1 one generator has already been shut down. A further generator is tripped at SS1 at $t=80$ s in the simulated response shown below. It is assumed that every substation has only one inter-bus transformer in operation.

Figure 9 shows the real power from generators in the three substations. The lost generator power is picked up by all the remaining generators in the system according to the governor droop characteristics. Figure 10 shows the voltage amplitude at the 33 kV busbars of the three substations. The voltages all drop with the maximum dip occurring in SS1 where the tripped generator was connected. The AVRs of all generators respond to the voltage decrease and it takes 5-10 seconds for all the 33 kV busbar voltages to return to the $\pm 1\%$ tolerance band around the nominal value (33 kV, which is used as the base voltage for the per unit value).

The changes to the generator excitation also cause the reactive power output of the generators to change, as shown in Figure 11. The remaining generator in Substation SS1 initially produces more reactive power as its excitation increases in response to the 33 kV busbar voltage dip. After the delay of 10 seconds, the PMS instigates the first tap change of IBTs in order to begin rebalancing of the reactive power sharing. The change of IBT tap positions is plotted in Figure 12. The reactive power of the remaining generator in Substation SS1 is above the limit (30 MVar) for about 50 seconds. This is regarded as acceptable after checking the transient thermal capability of the generator. If necessary, the process of rebalancing the generator reactive power can be accelerated upon detecting the violation of the steady state performance chart regarding reactive power.

The second case studied is direct-on-line starting (with no load) of a 6 MVA induction motor which is fed from the 33 kV busbar of Substation SS2 through a 33 kV/11 kV step-down transformer having a leakage reactance of 0.1 pu. Typical parameters are used also for the induction motor in this study. All generators in Substations SS1 and SS3 are in operation but only one is in Substation

SS2, SS1 and SS3 each has an IBT on-line while SS2 has two to allow power to be imported from Substations SS1 and SS3. Figure 13 shows the response of 33 kV busbar voltages. The disturbance is again applied at $t=80$ s.

It is observed that voltage dips are caused due to the large reactive current drawn by the motor during start up. The voltage recovers and overshoots when the start up is over. Figure 14 shows that the generator AVR's respond to the voltage variations and the excitation voltage of the generator in Substation SS2 reached upper limit (4.7 pu). Figure 15 shows the response of the generator reactive power in the three substations, driven by the AVR's. This has the effect to attenuate the voltage variations on the load busbars as shown in Figure 13. The time delay and tolerance band in the IBT tap control algorithms are set to avoid any unnecessary change of tap as implied by the results shown in Figure 16.

The 132 kV busbar voltage remains very stiff in all cases studied. Loads on the 33 kV busbars consist of induction motors and variable speed drives for gas compressors and pumps which can ride through the voltage disturbances shown in the simulation results [5].

6. Conclusion

This paper has described the requirements of voltage and reactive power control in an industrial power system subject to expansion. A control strategy is developed which achieves the target control requirements. Time domain simulations demonstrate that coordinated control of generator AVR's and on-load tap changing of inter-bus transformers can be used to keep the load busbar voltages within the tolerance band of $\pm 1\%$ around the nominal value while the load reactive power is shared by generators according to their MVA ratings even subject to disturbances. A control tolerance of ± 6 MVar for a substation is determined to prevent the tap from hunting between different positions. Simulations verify the PMS supervisory control strategy which is shown to be suitable for the particular system. The methods outlined in this paper can also be applied to other

industrial systems where the PMS must control the voltage via both AVRs and IBT tap changers.

7. Acknowledgement

The authors thank Ken Smith of Mott-MacDonald, Phil Wearon of Shell Global Solutions and Nigel Harmen of Snamprogetti for advice and useful discussions.

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9. Appendix: System Parameters (pu values are based on machine ratings)

Substation SS1

Generator: 3x44.9 MVA, 11 kV, $X=2.22$ pu, $X'=0.338$ pu, $R_a=0.005$ pu, $T'_{do}=6.212$ s

Transformer: 3x50 MVA, 11.5/34.5 kV, total leakage reactance=5.72%,
total winding resistance=0.0291 pu

Static Load: 85.6 MW, 47 MVar, 33 kV

Substation SS2

Generator: 1x44.9 MVA, 11 kV, $X=2.22$ pu, $X'=0.338$ pu, $R_a=0.005$ pu, $T'_{do}=6.212$ s

2x42.55 MVA, 11 kV, $X=2.05$ pu, $X'=0.21$ pu, $R_a=0.005$ pu, $T'_{do}=10.66$ s

Transformer: 3x50 MVA, 11.5/34.5 kV, total leakage reactance=5.72%,
total winding resistance=0.0291 pu

Static Load: 59.1 MW, 37 MVar, 33 kV

Substation SS3

Generator: 4x42.55 MVA, 11 kV, $X=2.36$ pu, $X'=0.23$ pu, $R_a=0.0058$ pu, $T'_{do}=7.8$ s

Transformer: 4x50 MVA, 11.5/34.5 kV, total leakage reactance=5.72%,
total winding resistance=0.0291 pu

Static Load: 108 MW, 52.4 MVar, 33 kV

IBT Parameters

50 MVA, 33/132 kV (nominal),
total leakage reactance=14.5%,
total winding resistance=0.0049 pu

List of Figures

Figure 1 Industrial Power System with PMS

Figure 2 Existing System Configuration

Figure 3 Expanded System Configuration

Figure 4 33 kV Busbar Voltage Control

Figure 5 Control of Reactive Power Sharing between Substations and 132 kV Busbar Voltage

Figure 6 Simplified Equivalent Circuit

Figure 7 Transient Generator Model

Figure 8 Differential On-load Tap Position Control of IBT

Figure 9 Response of Generator Real Power – Case 1

Figure 10 Response of 33 kV Busbar Voltages (pu) – Case 1

Figure 11 Response of Generator Reactive Power – Case 1

Figure 12 Response of IBT Ratio – Increment off Nominal – Case 1

Figure 13 Response of 33 kV Busbar Voltages (pu) – Case 2

Figure 14 Response of Generator Excitation Voltages (pu) – Case 2

Figure 15 Response of Generator Reactive Power – Case 2

Figure 16 Response of IBT Ratio – Increment off Nominal – Case 2

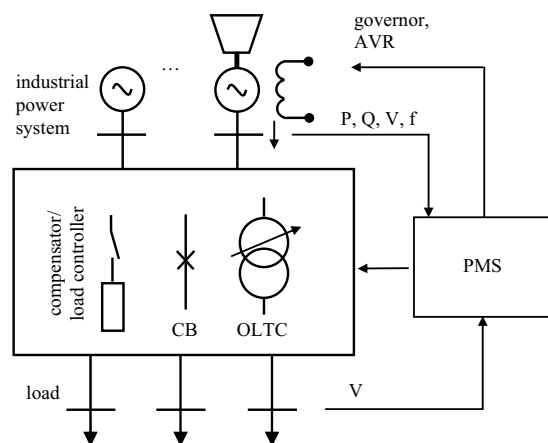


Figure 1 Industrial Power System with PMS

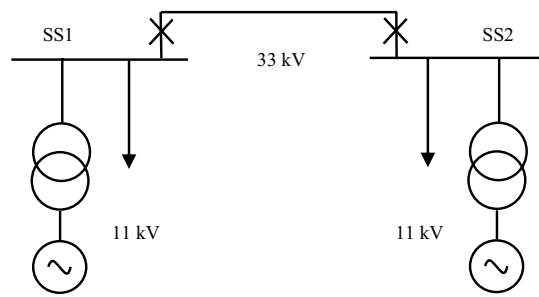


Figure 2 Existing System Configuration

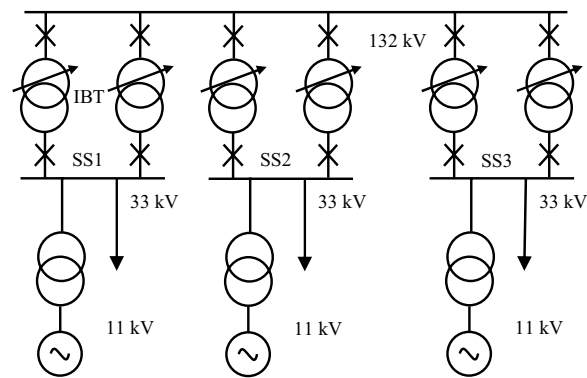


Figure 3 Expanded System Configuration

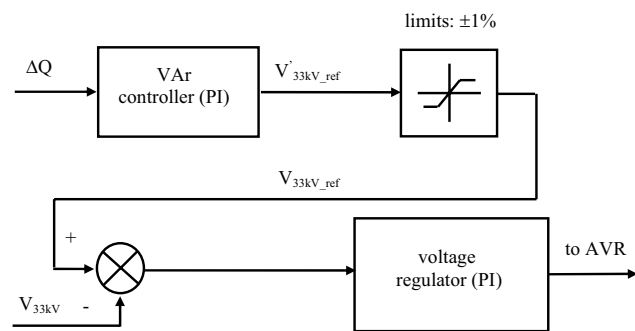


Figure 4 33 kV Busbar Voltage Control

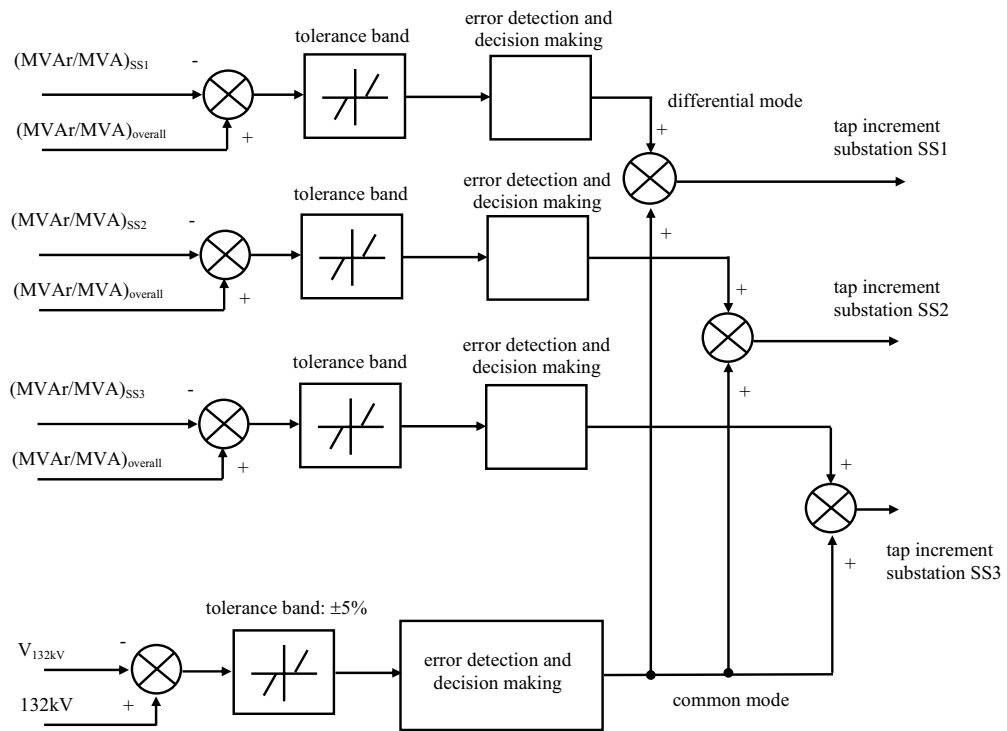


Figure 5 Control of Reactive Power Sharing between Substations and 132 kV Busbar Voltage

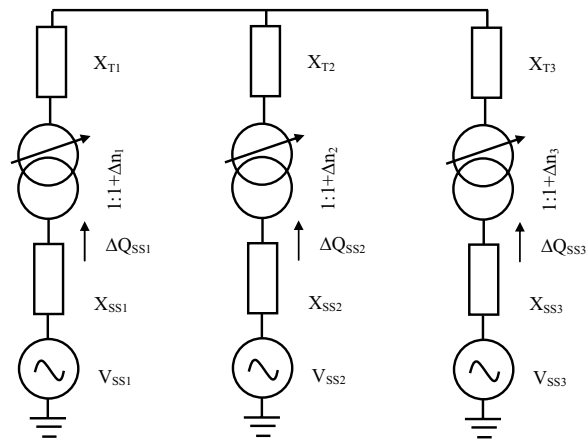


Figure 6 Simplified Equivalent Circuit

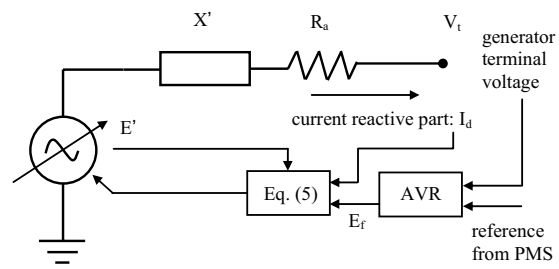


Figure 7 Transient Generator Model

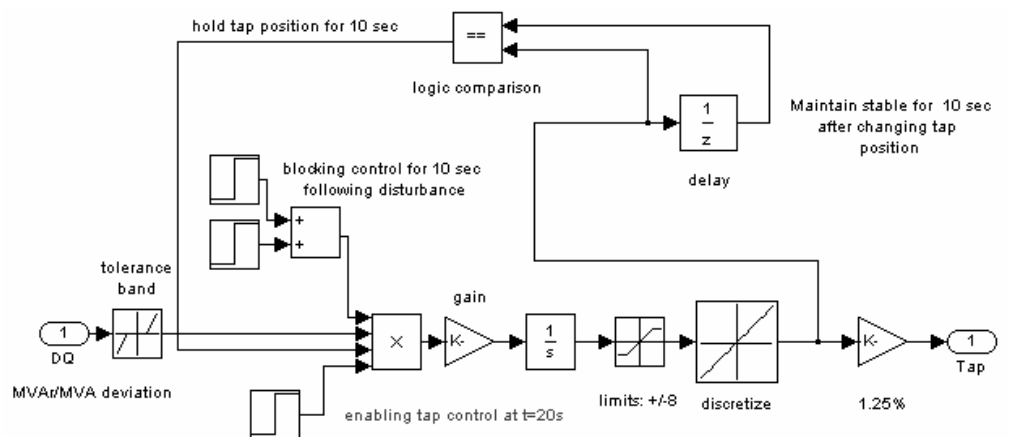
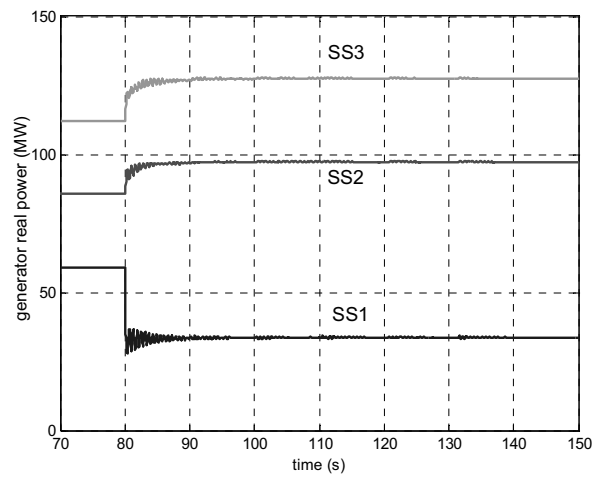


Figure 8 Differential On-load Tap Position Control of IBT



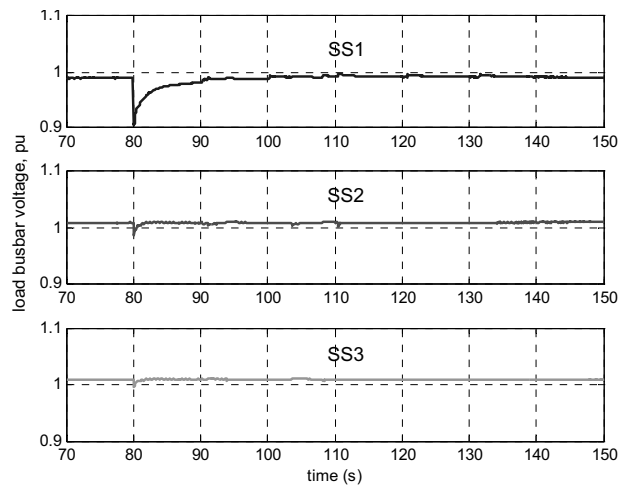


Figure 10 Response of 33 kV Busbar Voltages (pu) – Case 1

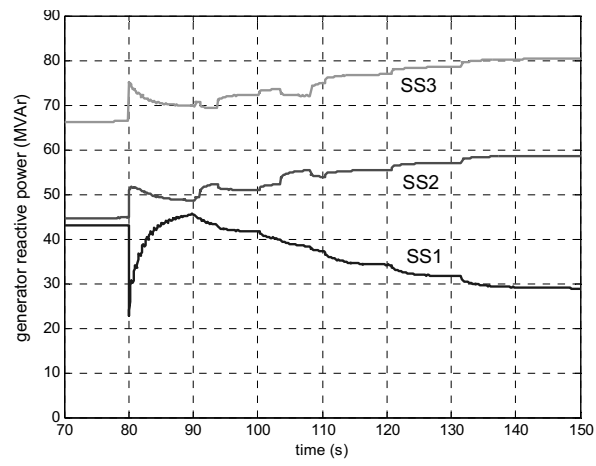


Figure 11 Response of Generator Reactive Power – Case 1

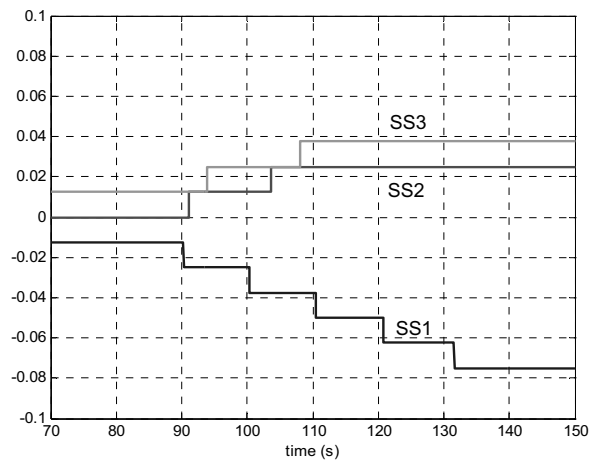


Figure 12 Response of IBT Ratio – Increment off Nominal – Case 1

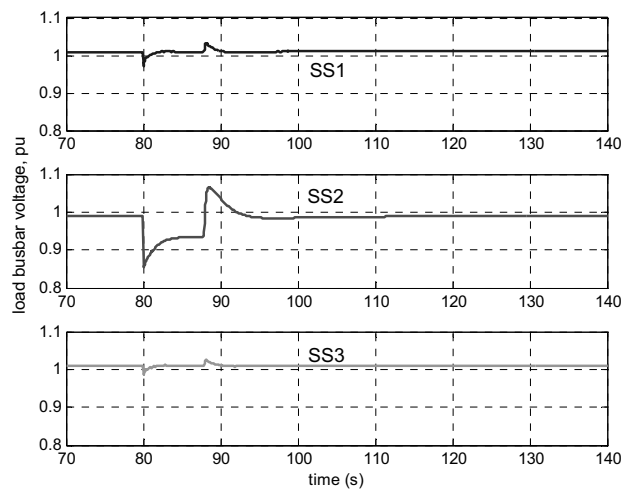


Figure 13 Response of 33 kV Busbar Voltages (pu) – Case 2

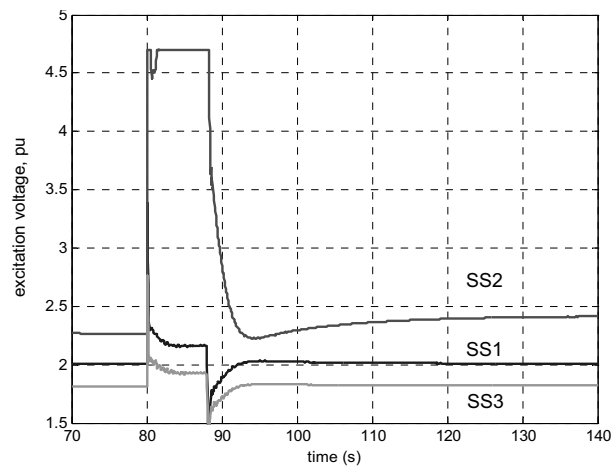


Figure 14 Response of Generator Excitation Voltages (pu) – Case 2

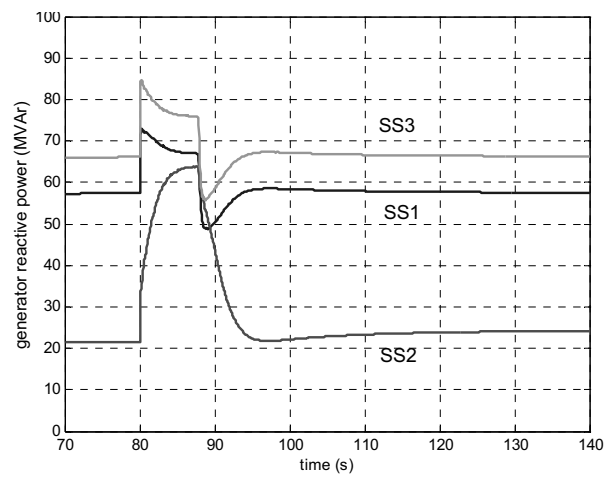


Figure 15 Response of Generator Reactive Power – Case 2

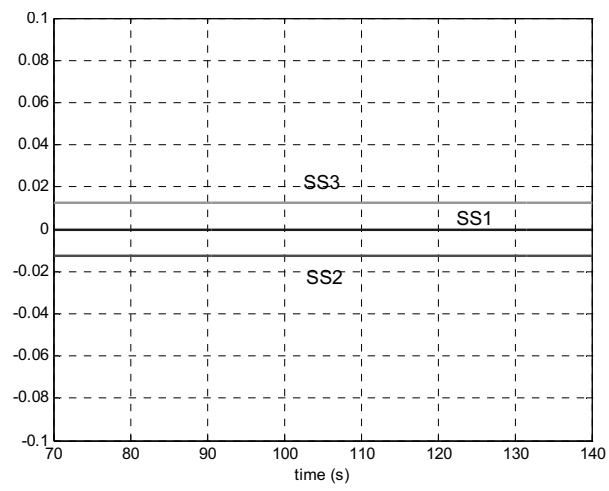


Figure 16 Response of IBT Ratio – Increment off Nominal – Case 2