PSS TUNING OF A RADIALLY CONNECTED HYDRO POWER PLANT OF EASTERN INDIA USING SMIB MODEL AND PHASE COMPENSATION TECHNIQUE

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Abstract—**Power systems are very often exposed to large disturbances such as loss of load, loss of transmission lines, and loss of large generating units. Now the main challenge in operating large power system is that running all the generators synchronously even after these disturbances. Generally following a large disturbance different generators respond differently to the disturbance and low frequency oscillation among the generators comes into the picture. Hydro power plants are generally located to very remote hilly area and connected to the electrical grid via long radial transmission lines. Small signal stability issue is sometimes get triggered following some disturbance or during system wide inter-area oscillation. In this paper a radially connected hydro generating station "A" of Sikkim having 3X170 MW installed capacity is studied. Generating station is connected to the grid at a pooling station via two 400 kV twin moose lines. Machine is currently equipped with static excitation and one simple Power system stabilizer model at the site. However excitation system has the provision of activating complex stabilizer model also. Analyzing various past disturbances and low frequency events in the Indian power grid it is found that the performance of the above mentioned generators in damping the local and inter-area oscillation is poor and ranges between 0 to 7 % damping for all the modes. This paper aims at improving the damping of oscillation to 15-25%.**

Keywords— PSS, PMU,NERC, eigenvalue

I. INTRODUCTION

Indian power system consists of a large number of generators connected via strong meshed transmission network and serving load situated far away from them. Indian power system is divided into five control region both from electrical and geographical point of view. Five regions are strongly interconnected via 400 kV and 765 kV transmission network. Inter-area oscillations in such system are also a common phenomenon apart from local mode of oscillation. Tuning of PSS requires information about the grid also, which are sometimes not available to the generators. Use of PSS to damp both local as well as inter-area oscillation is well known. However effectiveness of the PSS in damping oscillation depends on its proper tuning. A good amount of research work in done for PSS design and lot of literature made available in the past few decades [1]–[12], [18], [19], [13]. PSS design basis concept was presented in the classic paper by deMello et al. [1] for a SMIB system. In this approach, PSS transfer function provide proper phase-compensation to the transfer function of GEP (i.e., the ratio of electrical torque developed on the shaft of the generator and the AVR voltage reference input).

Adequacy of GEP transfer function computed for SMIB model in a multi-machine environment for PSS design is proved by theoretical analysis by Lam et al. [5]. Investigation done by Gibbard [8], Gurrala [9], and Marco [12] are guided by frequency analysis as mentioned in [5]. Gibbard [8] observes that the phase response of $\frac{\Delta V_t}{\Delta V_{ref}}$ closely replicates $\frac{\Delta P}{\Delta V_{ref}}$ transfer function phase response when all rotor shat dynamics are ignored. It is shown, Phase compensation requirement as calculated by P-Vr closely matches with the method of residue. However, for a large interconnected power system this method of PSS design does not ensure good performance. In [9], a decentralized PSS design technique is proposed using local plant measurement; wherein, system dynamics of the i^{th} machine in an interconnected multi-machine power system is linearized by taking secondary bus voltage of the step-up transformer as reference. However magnitude and phase response of the modified GEP transfer function differ markedly from P-Vr transfer function as synthesized in [13]. Recently in [12], for PSS design a phase compensation technique is proposed for machine in a multi-machine environment, by varying external reactance of generator connected to infinite bus. Authors have used a synthetic system, wherein the maximum value of external reactance is calculated by the lowest desired values for inter-area frequencies, while the minimum is set by the reactance of the step-up transformer of generating unit. However, this optimization routine is fairly time consuming for large interconnected network like India, particularly under numerous generation dispatch scenario.

This paper is organized as follows: In Section II Theoretical back ground of Power system modeling and power plant model validation are discussed. In section III proposed PSS tuning method is presented. Section IV describes PSS tuning and finally Section V draws the conclusion

II. THEORITICAL BACKGROUND

A. *Modelling of Power plant "A" along with SMIB model of the Grid:*

Generator, generator terminal LV bus, generating transformer, HV plant bus, outgoing transmission line up to next substation is modeled in PSS@E as per the manufacturer's data. In figure 1 the model is shown. From pooling station there is lots of other connectivity, however those are not exclusively modeled and equivalent impedance is modeled in the form of a line from the polling station to the Grid where a large equivalent generator connected to replicate the rest of the grid. Now the value of the equivalent impedance is calculated as follows:

$$X_{grid} = \frac{1}{\text{Short circuit level of Pooling station}} \quad (1)$$

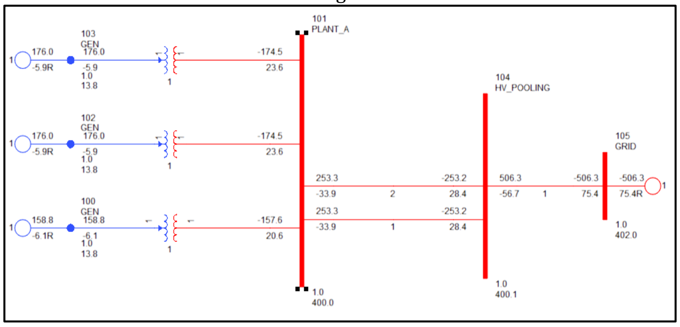

Figure 1: PSS@E load flow model

B. *Dynamic Modeling of Power plant and its Validation:*

Dynamic model of the plant is represented by GENSAL for generators, ST7C for exciter, IEEEST for PSS and HYGOV for turbine and governor.

In line with NERC reliability standard PLAYBACK model is introduced recently in PSS@E. The basic idea of playback is to replicate the system behavior in simulation by using PMU voltage and frequency measurement. Then validation of the plant model is done by comparing the simulated and measured active and reactive power of the plant.

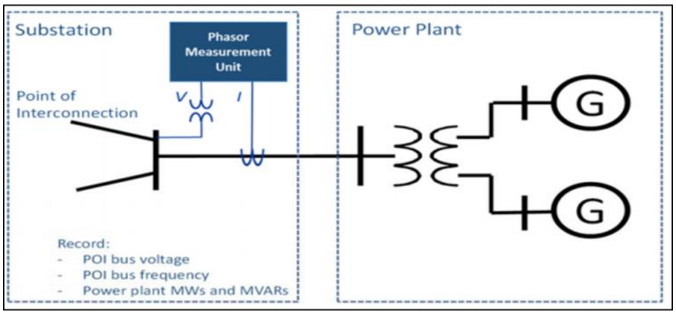

Figure 2: Model validation setup as per NERC guideline

As shown above in figure 2 the rest of the grid is replicated using voltage and frequency of the point of interconnection bus and validation is done by comparing active and reactive power measurement. Measurement during a nearby fault to the plant "A" is used for playing back. At the time of the disturbance only two units were running in plant A.

Results of dynamic simulation are shown below in figure 3 and 4. From the plot we can see simulated and measured active and reactive power matching closely with the measured one. However there is little less damping is observed in simulated active power oscillation. Overall the response is matched and dynamic model of the plant is validated.

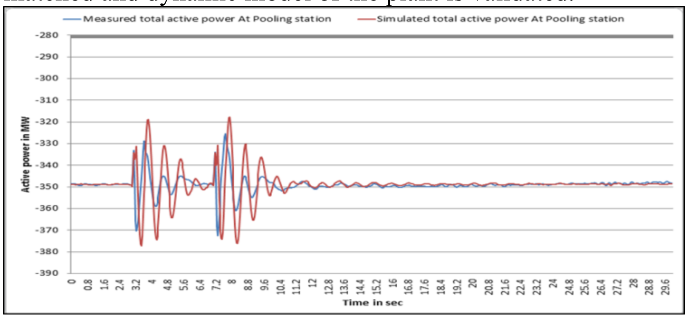

Figure 3: Comparison of measured and simulated active power flow

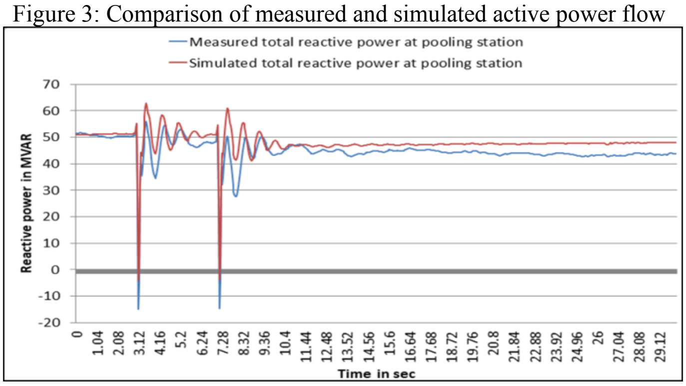

Figure 4: Comparison of measured and simulated reactive power flow

Also using prony analysis of the measured active power in MATLAB local mode frequency and damping are determined. Also using the validated dynamic model of the plant eigen values are calculated using PSS@NETOMAC. Comparisons of both the results are as follows:

Table 1: Comparison of local mode of frequency and damping

Tool used	**Local Mode frequency**	**Damping**
MATLAB Prony analysis of Measured signal	1.22	11.03%
PSS@NETOMAC eigen value analysis of plant	1.236	11.75%

The above results shows that model used are representing the actual plant quite accurately and can be used for PSS tuning.

C. *State Space Modeling of Power system and linearized SMIB model:*

A state space modeling of the power system is needed to study its small signal stability behaviour. The power system is consists of various synchronous generator, transmission links, excitation system of the generator along with automatic voltage regulator (AVR) and power system stabilizer etc. The differential equations of IEEE Model 1.0 for a synchronous alternator equipped with a static excitation system are given as follows:

$$\dot{\delta} = \omega_B S_m \quad (2)$$
$$\dot{S_m} = (T_m - T_e - DS_m)(2H)^{-1} \quad (3)$$
$$\dot{E'}_q = \left((X_d - X'_d)i_d + E_{fd} - E'_q\right)T'_{do}{}^{-1} \quad (4)$$
$$\dot{E}_{fd} = (K_e(V_{ref} + V_{pss} - V_t)i_d - E_{fd})T_e{}^{-1} \quad (5)$$

Where $T_{elec} = E'_q i_q + i_d i_q (X'_d - X_q)$

The algebraic equations of the stator are as follows

$$V_q + R_a i_q = E'_q + X'_d i_d \quad (6)$$
$$V_d + R_a i_d = -X_q i_q \quad (7)$$

III. PROPOSED METHOD

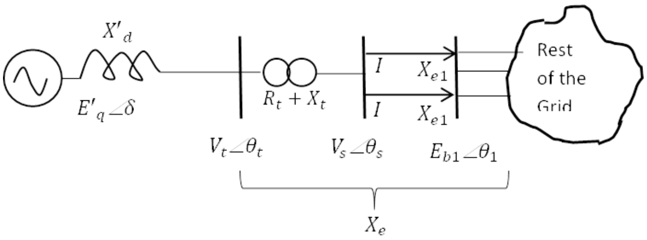

Figure 5: Reduced network model of plant A with connectivity up to next bus

The rotor angle with respect to the high voltage bus of transformer ($V_s\angle\theta_s$) is termed as $\delta_s = \delta - \theta_s$. The angle $\delta_s$and voltage E'_q are calculated as per (10) and (7), respectively [3]:

$$\delta_s = \tan^{-1}\frac{P_s(X_q + X_t) - Q_s(R_t + R_a)}{Q_s(X_q + X_t) + P_s(R_t + R_a) + V_s^2} \quad (8)$$

$$E'_q = X_t^{-1}(X_t + X'_d)\sqrt{V_t^2 - \left(\frac{X_q V_s Sin\delta_s}{X_t + X_q}\right)^2} - X_t^{-1}X'_d V_s cos\delta_s \quad (9)$$

The standard linearized model of SMIB system, popularly known as Heffron-Phillip's model (K-constant), was introduced first in [14]. A modified Heffron-Phillip's model (G-constant [9]) has been developed for multi-machine power system. Following the same line of investigation further development was done and A-constants [15] are proposed recently for interconnected power systems. The major difference between the A-constant and G-constant is that calculation of A-constant accounts the non-stiffness of the secondary bus voltage phasor. However the A-constants are calculated taking absolute infiniteness of the grid.

In this paper following the same line of investigation as used in [15], SMIB model of the units of plant "A" (3X170 MW) of eastern region of India are built. However here some modification is introduced to account for the finiteness of the grid. Based on the fault level of the remote end substation X_{grid} is added between the infinite bus and the remote bus and this impedance is added to the equivalent impedance as calculated in [15]. Then a new set of B-constants are calculated using the modified equivalent impedance.

While calculating the constant for linearized SMIB model transmission line losses are neglected. For building the SMIB model of the generators of plant A first load flow is solved in PSS@E for an all India load flow model and from there remote end bus voltages and angles are noted. Now as there is only one remote bus so calculation of the B-constants is as follows:

$$X_{grid} = calculated\ based\ on\ fault\ level\ of\ remote\ bus \quad (10)$$
$$X_e = \frac{X_{e1}}{2} + X_{grid} \quad (11)$$
$$E_b = obtained\ from\ PSS@E\ load\ flow\ solution \quad (12)$$
$$\theta_b = obtained\ from\ PSS@E\ load\ flow\ solution \quad (13)$$
$$\alpha_i = \theta_s - \theta_b \quad (14)$$
$$i_q = \frac{E_b \sin(\delta - \theta_b)}{(X_q + X_t + X_e)} \quad (15)$$
$$i_d = \frac{(E_b\cos(\delta - \theta_b) - E'_q)}{(X'_d + X_t + X_e)} \quad (16)$$
$$V_q + jV_d = (i_q + ji_d)(R_e + jX_e) + E_b\angle - \delta_b \quad (17)$$

$$B_1 = E_{q0}E_{b0}\cos\delta_{bo}(X_q + X_e)^{-1} + (X_q - X'_d) * E_{b0}i_{q0}sin\delta_{b0}(X_{d'} + X_e)^{-1} \quad (18)$$
$$B_2 = \frac{(X_q + X_e)i_{q0}}{(X'_d + X_e)} \quad (19)$$
$$B_3 = \frac{(X'_d + X_e)}{(X_d + X_e)} \quad (20)$$
$$B_4 = \frac{(X_d - X'_d)E_{b0}\ sin\delta_{b0}}{(X'_d + X_e)} \quad (21)$$
$$B_5 = -\frac{E_{b0}}{V_{t0}}\left(\frac{X'_d V_{q0}}{X'_d + X_e}\sin\delta_{b0} + \frac{X_q V_{d0}}{X_q + X_e}\ cos\delta_{b0}\right) \quad (22)$$
$$B_6 = \frac{X'_d V_{q0}}{(X'_d + X_e)V_{t0}} \quad (23)$$
$$B_{v1} = (X_q + X_e)^{-1}E_{q0}sin\delta_{b0} - (X_q - X'_d) * (X'_d + X_e)^{-1}i_{q0}\ cos\delta_{b0} \quad (24)$$
$$B_{v2} = -\frac{(X_d - X'_d)}{(X'_d + X_e)}\cos\delta_{b0} \quad (25)$$
$$B_{v3} = \frac{1}{V_{t0}}\left(X'_d V_{q0}(X'_d + X_e)^{-1}\cos\delta_{b0} - X_q V_{d0}(X_q + X_e)^{-1}sin\delta_{b0}\right) \quad (26)$$

Where $E_{q0} = E'_{q0} - (X_q - X'_d)i_{d0}$

IV. PSS TUNING USING PROPOSED METHOD

A. Building GEP and complete generator transfer function:

Based on the B-constants a detailed model is built in SIMULINK and from the SMIB model GEP transfer function can be determined as shown in the figure 6:

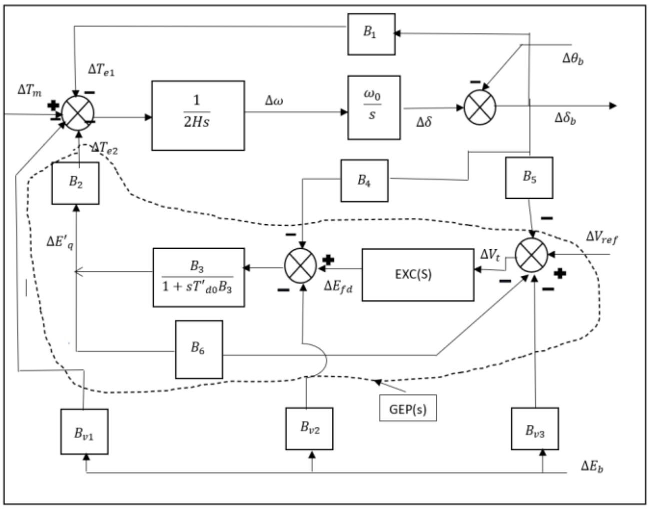

Figure 6: Linearized SMIB model of the generating unit

The above block diagram represents the SMIB model of the generator in a multi machine environment. Derivation of this SMIB model and significance of all the component of the diagram are described in [16] and [17]. The part inside the dotted curve represents the GEP transfer function.

GEP transfer can be expressed as below [16]:

$$GEP(s) = \frac{B_2 B_3 EXC(s)}{(1 + sT'_{do}B_3) + B_3 B_6 EXC(s)} \tag{27}$$

Where EXC(s) is the exciter transfer function.

For getting the GEP frequency response bode plot tool in SIMULINK is used. Signal just before the first summing junction is chosen as input port and the output port is just after the field circuit.

After that using control system linear analysis tool the bode transfer function is generated. The transfer function is as follows:

$$GEP(s) = \frac{4.366S^2 + 218.2S + 43.66}{S^3 + 50.2S^2 + 55.91S + 9.136} \tag{28}$$

The transfer function is a 3rd order transfer function.

The frequency response of the GEP as generated by bode plot tool is shown in the figure 7. In the figure both the phase and gain plot is shown.

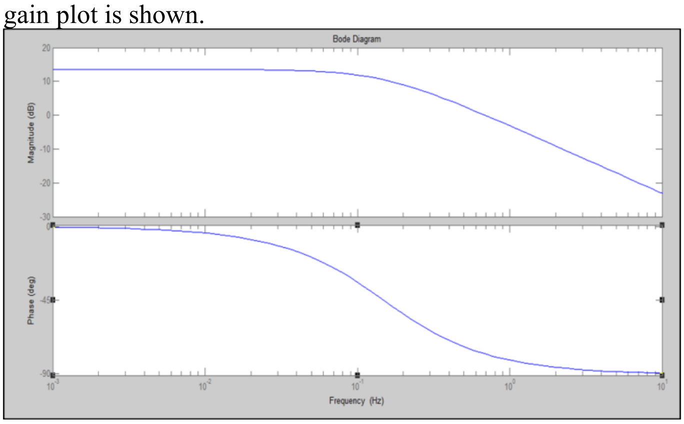

Figure 7: Bode plot of GEP

From the figure 4.4 it is seen that the phase lag of the GEP is asymptotically becoming 90 degree after 1 Hz frequency. Around frequency of local mode GEP is having phase lag very near to 90 degree. From the gain plot it is seen that the corner frequency is around 0.1 Hz.

B. PSS parameter tuning:

In IEEEST there are two lead/lag block and one washout block. Only the lead/lag block will be tuned following the methodology as mentioned in the [9]. Local mode of oscillation is around 1.22 Hz, so time constants are adjusted in such a way that the phase of compensated GEP around local mode of oscillation lies below 50°.Around 30° phase margin is considered to be good for the compensated GEP. The phase lag of around 40° is selected at local mode, so that required degree of tolerance to allow for uncertainties in machine modeling can be accommodated. Following the [9] method T_1 to T_4 are calculated as below:

$$\alpha = \frac{T_2}{T_1} = \frac{1 - \sin\left(\frac{\beta}{m}\right)}{1 + \sin\left(\frac{\beta}{m}\right)} \tag{29}$$

$$\beta = Required\ Phase\ Compensation \tag{30}$$

$$T_1 = \frac{1}{\Omega_i \sqrt{\alpha}} \tag{31}$$

$$T_2 = T_2 \alpha \tag{32}$$

The comparison of the phase plot of compensated and non-compensated system is shown in the figure 8 below. From the plot of figure 8, it can be seen that in frequency range of interest phase lag of the compensated system is flat and is around 40° as desired. Also root locus is drawn for the system to get the critical gain of the system. From root locus it is seen that as gain increased there is no branch crossing the imaginary axis from left to right. So any gain can be used theoretically, however there is practical limitation of 150. High gain causes excessive VAR modulation during large generation rejection and that's why gain is not altered.

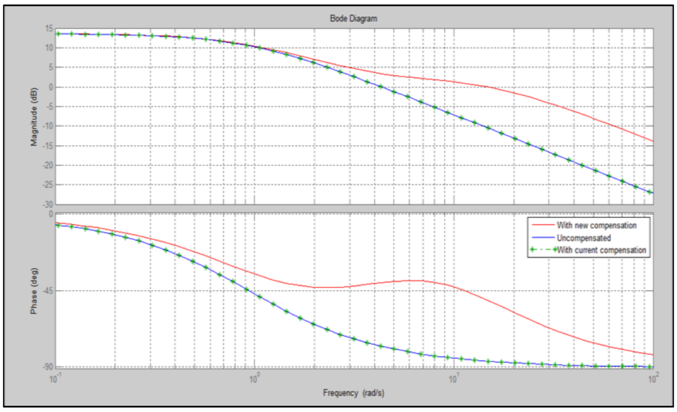

Figure 8: Comparison of Bode plot of compensated system with new and old parameters and, uncompensated system

V. PERFORMANCE COMPARISON

A. Step response testing:

The simulation load flow model is as shown in figure 1.

In PSS@E first the load flow is solved for initializing the dynamic simulation. Then using dynamic simulation engine of

PSS@E simulation is done. After initialization, for 5 sec system is run without any external disturbance. This is called flat run and this verifies the correctness of the dynamic modeling. During these 5 secs of flat run if the power system parameters like voltage, frequency, power output of the generators etc. remain fixed then the modeling is correct and further disturbance can be introduced in the system to check system response.

So at t=5 sec the reference voltage input of the exciter is raised by 5% of the generator connected at bus 102 as shown in Figure 1 in chapter 3. Then the simulation is run for 30 sec without any further disturbance applied to the system.

In PSS@E there is facility to record various power system signals and plot them to see the system response. So the response of the system during the step input to the generator connected at bus 102 is plotted below in the figure 9:

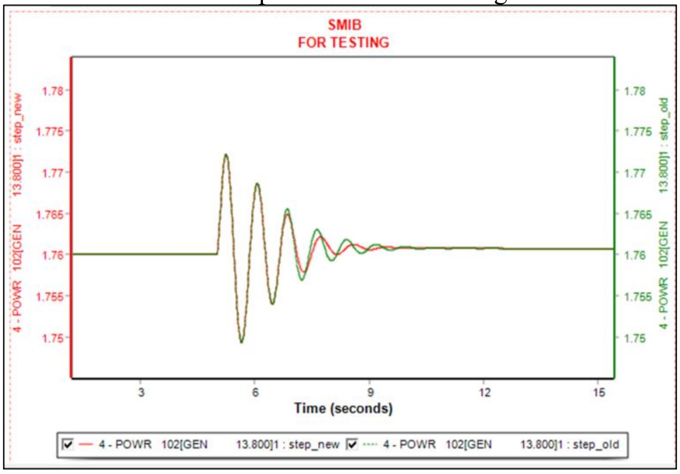

Figure 9: Comparison of Step response of generators with old new parameters for active power output of generator

The red curve in figure 9 is the power output of the units with new PSS parameters and green one is with old parameters. Due to step change in voltage reference, there is an oscillation in the output power of the generator. However as there is no change in mechanical power input to the generator so the power output again settled to the same value. There is slight improvement in damping of the oscillation with new PSS parameters.

B. Response to line tripping:

In PSS@E first the load flow is solved for initializing the dynamic simulation. Then using dynamic simulation engine of PSS@E simulation is done. After initialization, flat run for 5 sec without any external disturbance is executed.

At t=5 one of the transmission line connecting (circuit 1) the Power plant A to the pooling station is tripped and simulation is run for 30 sec.

Response of the generator connected to the bus 102 is them plotted in PSS@E and shown below in figure 10

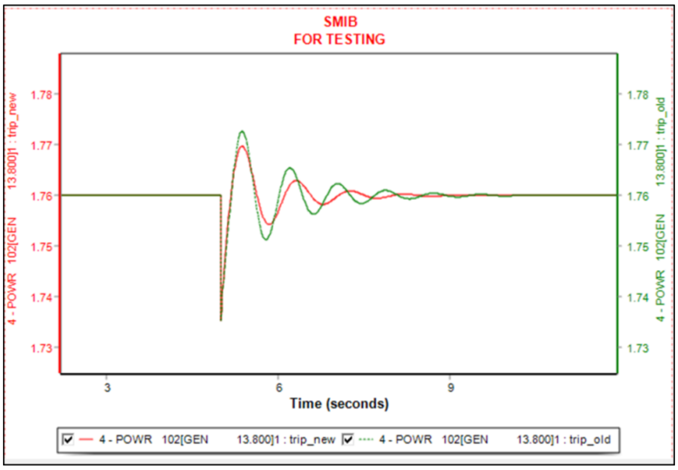

Figure 10: Comparison of response of generators with old new parameters to line tripping for active power output of generator

The red curve in figure 10 is the power output of the units with new PSS parameters and green one is with old parameters. As the oscillation of the output power of the generators are settled faster with new PSS parameter parameters, so there is increase in damping with new PSS parameters, it establishes increase in damping with new parameters.

Response of other generators of the power plant is similar.

Using PSS@NETOMAC local mode and damping is calculated with tuned PSS and compared with the existing one as follows:

Table 2: Comparison of local mode frequency and damping with new and old PSS parameters

PSS parameters	Local Mode frequency	Damping
With old parameter	1.23	11.75%
With new parameters	1.18	17%

VI. CONCLUSION

Critical activity of PSS tuning for a 510 MW (3X170 MW) hydro power plant located at Sikkim in eastern region of India is attempted in this paper and improvement obtained. With some modification A-constants method [15] is followed for building the SMIB model of the power plants in a multi-machine power system. PSS@E is used for getting the steady state load flow information then using those information B-constants are calculated in MATLAB, GEP model is built in SIMULINK and phase compensation is done using MATLAB program.

Improvement after tuning the PSS is verified using time domain step response and line switching simulation. Results of line switching shows good amount of improvement.

Another important work done in this paper is that actual plant model is built from the manufacturers data and then validated using PSS@E playback feature with the help of PMU data. As accurate plant model is necessary for PSS tuning of a power plant, so the parameters calculated in this paper could be used in the field.

Performance of the PSS with new parameters may be tested against some inter-area oscillation using PSS@E playback feature to ensure proper inter-area mode damping. With higher penetration of electronics-based resources in the grid, grid may experience forced oscillation with higher frequency (5-20 Hz). Therefor in future multi-band PSS4B could be used to improve the performance of the generators for a wide band of frequency to cope with such high frequency oscillation.

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