Control Science and Engineering
2018; 2(1): 1-15
http://www.sciencepublishinggroup.com/j/cse
doi: 10.11648/j.cse.20180201.11

Science Publishing Group

Methodology Article

Modelling of Steam Turbine Generators from Heat Balance Diagram and Determination of Frequency Response

Sumanta Basu

Department of Electrical and I&C Engineering, L & T-MHPS Boilers Private Limited, Faridabad, India

Email address:
sumanta.basu@lntmhps.com

To cite this article:
Sumanta Basu. Modelling of Steam Turbine Generators from Heat Balance Diagram and Determination of Frequency Response. *Control Science and Engineering*. Vol. 2, No. 1, 2018, pp. 1-15. doi: 10.11648/j.cse.20180201.11

Received: July 21, 2018; **Accepted**: August 8, 2018; **Published**: September 5, 2018

Abstract: In the power system, apart from ensuring the availability of Power, maintaining the power system frequency is of utmost important. The intent is to ensure stabilized frequency to the consumers at all times and maintain load frequency control of the power grid which requires necessarily the power load operators and regulators to manage generation and distribution services efficiently to maintain reliability of the power system frequency. In an interconnected power system the power load demand varies randomly which impacts both the frequency and tie-line power interchange. Hence, it is necessary to develop a methodology to make decisions synchronously and automatically by all grid connected generating units. The load frequency control along with restricted governor mode control address this issue and minimizes the deviations in the power grid frequency and tie-line power interchange bringing the steady state errors to zero and maintaining the balance between demand and supply in real time. Restricted governor mode control is a primary frequency control but with inclusion of a dead band of governor not exceeding + / - 0.03 Hz where primary control is blocked by the governor dead band unlike free governor mode. This ripple factor of + / - 0.03 Hz prevents continuous hunting in the governor due to very small frequency variation. Restricted governor mode control does not act in proportion to the frequency deviation like free governor and is not strictly a frequency controlling mode, rather this mode restrict sudden and large frequency deviation with an additional step load disturbance during drop of normal running frequency under contingency control which operate along with load frequency controller enhancing the generation of power. In order to ensure the same, the precision Restricted Governor Mode Control is necessary simultaneously for all the power grid connected generating stations and to define the methodology close to accurate derivation of the various parameters for the modelling of turbine is necessary. This paper describe the procedure for deriving the parameters of a steam turbo generator model of a typical 660 MW Ultra-supercritical machine from heat and mass balance diagram and the conceptual load frequency control with restricted governor mode control. The main focus of the work is to determine the various time constants and finding the frequency response of a typical steam turbine generator based on a realistic mathematical model using the heat and mass balance data with some thermodynamic assumptions. The simulated model response for various scenarios are also presented in this paper.

Keywords: RGMO, FGMO, HBD, HP, IP, LP, LFC

1. Introduction

In the power system operation, maintaining the Grid frequency by load frequency control is a challenge and requires necessarily the power load operators and regulators to manage generation and distribution services efficiently to maintain reliability of the power system frequency. In an interconnected power system, as generation and load demand varies randomly, both area frequency and tie-line power interchange vary. The Operating point of actual power system changes continuously and randomly with time and experience deviations in nominal system frequency and scheduled power exchanges to other areas that yield undesirable effects. The ability of the generation side to follow the fast changing load is limited due to physical / technical consideration and causes imbalance between the actual and the scheduled generation quantities. This action leads to a frequency variation.. Hence, it is necessary to develop a Synchronous methodology to measure the frequency without measurement delays and make decisions synchronously. For practical purpose it is prudent to consider asynchronous methodology which incorporates frequency measurement delay including boiler-turbine-generator response and asynchronous decentralized decision making. The only way to regulate frequency is to maintain the balance between demand and supply in real time. The load frequency control with free governor or restricted governor mode control address the issue and minimizes the deviations in the area frequency and tie-line power interchange and ensure their steady state errors to be zero by regulating frequency to maintain the balance between demand and supply in real time. In recent years from the year 2010 onwards the Indian Electricity Grid Code has been amended few times to address the governor control as a primary level control which shall act as a first line of defence against sudden frequency rise\fall The system deviates from nominal frequency and generation units deviate from their respective schedules, in response to changes in load. Conventionally, a secondary level control like load frequency control (LFC) is recommended to bring frequency back to nominal value. Implementation of a successful secondary control mechanism is still awaited under present circumstances and various amendments are done to mitigate the issues [7]. Emergency condition arises during transient disturbances due to a tripping of a generator or a loss of load block causing the frequency changes due to the mismatch in load and generation. The drop in operating level of the frequency depends on the instance of starting point of disturbance as well as the system inertia. It is the system inertia, which provides the initial ability of the power system to oppose change in the frequency [33]. A suitable mathematical representation of power units and their controls is required to carry out power system dynamic studies for successful result oriented implementation [30] [34]. The goal of this paper is to illustrate the process of deriving parameters for a Ultra-supercritical 660 MW steam turbine, single reheat steam turbine using data from heat and mass balance diagram. The time constants for Steam chest, Reheater and Crossover are calculated at different MW load for this purpose. Once all the parameters are calculated, they are fed into the model and the frequency response due to load change is observed. PI Controllers are properly tuned to give the best results. The MW loads considered for the study are being 30%, 50%, 60%, 80%, 100% and 105% of 660 MW. The heat balance diagram (HBD) of various loads are shown in the Figure 14 to Figure 19. Matlab and Simulink is used in the development of mathematical model and the simulation study.

2. Steam Power Plant Process Flow Diagram

Steam units in a power plant mainly consist of a boiler, re-heaters, turbine sections, condensers, pumps, and a heat regenerative cycle which includes feed water preheaters and

Feed water pumps. In a typical steam unit cycle, the steam produced with high pressure enters the high pressure (HP) turbine after passing main control valves. Then the HP turbine exhaust passes through re-heater in Steam Generator and subsequently to intermediate-pressure (IP) and then through cross over low-pressure (LP) turbines until it finally reaches the condenser. In HP, IP, and LP turbines, there are extraction points from which steam is fed to the heat regenerative cycle of feed water preheaters. During plant operation, steam expanding through the low-pressure turbine is directed into the condenser and is condensed. Mechanically coupled HP, IP, and LP turbines provide the mechanical power which is converted into electrical energy in the generator. Then the condensed water is pumped by the condensate extraction pump (CEP) to the low pressure (LP) heat regenerative cycle. In this cycle, until the condensate is directed to the steam generator, it passes through gland steam condensers (GSCs), low pressure heater and then to Deaerator. Then feed water pump (FWP) takes suction from Deaerator and feed to high pressure heater. A detailed plant flow diagram is as shown in Figure 1.

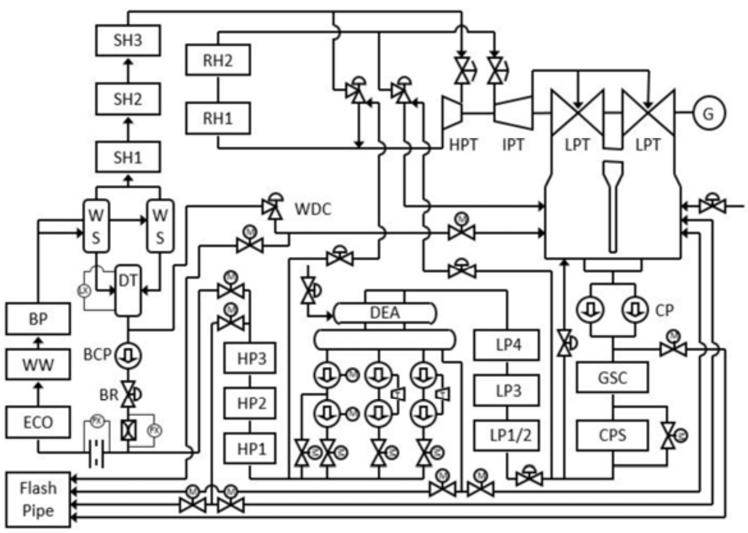

Figure 1. *Process Flow Diagram.*

3. Modelling of Thermal Areas

3.1. Generator Load Model

The generator model is characterized by the following equation

$$\Delta f(s) = \frac{\Delta Pm - \Delta PL}{2H} \tag{1}$$

And the load can be defined by the equation

$$\Delta Pg = (\Delta PL + D\Delta f) \tag{2}$$

where ΔP_L (s) is frequency independent load component and $D\Delta f$ (s) is the frequency sensitive load component where (ΔP_g – ΔP_L) is the increment in the power input to the generator –load system, Pr is the rated capacity of the turbo generator, f_0 is the scheduled system frequency, H is the inertia constant, $\Delta P_g = \Delta P_m$ is the change in turbine mechanical power output and ΔP_L is the change in electrical power i.e the load increment. D is the damping constant defined by the change in the power consumption in the power grid load with frequency expressed as% change in load divided by the% change in frequency.

The generator-load has a transfer function

$$Pg(s) = \frac{1}{2H+D} \tag{3}$$

where power system time constant

$$Tp = \frac{2H}{Df0} \tag{4}$$

and gain of the power system is

$$K_p = \frac{1}{D} \tag{5}$$

3.2. Governor Model

The function of the governing system of steam turbine generator is to regulate or adjust continuously of governing /steam admission control valve, when the turbo-generator is on bars, by controlling the steam inflow to the turbine. The dynamic response of governing control is achieved by various control logics to operate the control valves in the turbine. Stop valves are provided in the governing system before the steam admission control valve to protect the turbine in case of unsafe conditions by blocking the steam flow into the turbine. In an Electro Hydraulic governing system, Halls probes/ Linear variable differential transmitters / pulse generators etc. are used to sense the speed, position of control valves, control circuits to process the signals, computing error and electro hydraulic converters / amplifiers and a hydraulic actuator to drive the control valves.

We use speed and frequency interchangeably since they describe proportional quantities. The speed-versus-power output governing characteristic has droop, which means that a

Decrease in speed should accompany an increase in load, as depicted by the straight line of Figure 3. The per-unit droop or speed regulation of the generating unit is defined as the magnitude of the change in steady-state speed, expressed in per unit of rated speed, when the output of the unit is gradually reduced from 1.00 per-unit rated power to zero. A 5% regulation means that a 5% change in frequency causes a 100% change in power generation. Suppose that the unit is supplying output power P_{g0} at frequency f_0 when the load is increased to Pg = $P_{gO} + \Delta P_g$, as shown in Figure 3. As the speed of the unit decreases, the speed governor allows more steam from the boiler through to the turbine to arrest the decline in speed. Equilibrium between input and output power occurs at the new frequency f = (fo + Δ f) as shown. According to the slope of the speed-output characteristic given the frequency change (in Hz) is $\Delta f = - R \Delta P_g$ where R is called the droop or speed regulation. An isolated turbine generator would continue to operate at the reduced frequency f except for the supplementary control action or the secondary control of the governor. The governor control mechanism can parallel-shift the regulation characteristic to the new position shown by the dashed line of Figure3. Effectively, secondary control of the governor supplements the action of the governor by changing the speed setting to allow more prime-mover energy through to increase the kinetic energy of the generating unit so that it can again operate at the desired frequency f_o while providing the new output P_g. The speed governor has a transfer function

$$G(s)gov = \frac{1}{R\,(1+STgov)} \tag{6}$$

Where T_{gov} is the governor time constant.

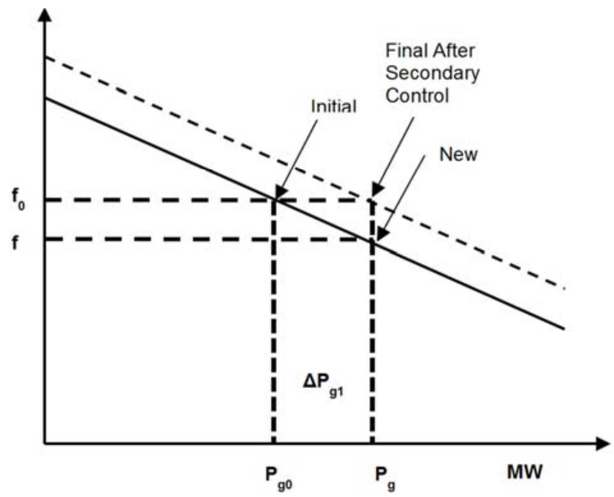

Figure 3. *Governor Characteristics.*

3.3. Turbine Model

A steam turbine converts stored energy of steam of high pressure and temperature into rotating energy. The source of heat in our case is boiler. A variety of steam turbine configurations have been developed depending on unit size and steam conditions. A turbine with multiple sections may be tandem-compound or cross-compound. In our case tandem-compound single reheat Ultra-supercritical turbine is considered. between high pressure exhaust and intermediate pressure turbine, and between the intermediate pressure and low pressure turbine lies the crossover. The steam chest and inlet piping to the first turbine cylinder and re-heaters and crossover piping introduce delays between valve movement and change in steam flow. The reheat turbine model shown in Figure 5 has a transfer function

$$G(s) = \frac{(F_{HP}+F_{IP}+F_{LP})+S(F_{HP}T_{RH}+F_{IP}T_{CO}+F_{HP}T_{CO})+S^2(F_{HP}T_{CO}T_{RH})}{(1+ST_{SC})(1+ST_{RH})(1+ST_{CO})} \quad (7)$$

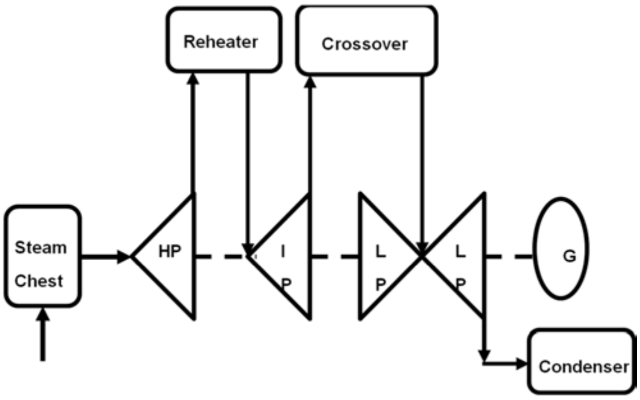

Figure 4. *Tandem Compound Single Reheat turbine.*

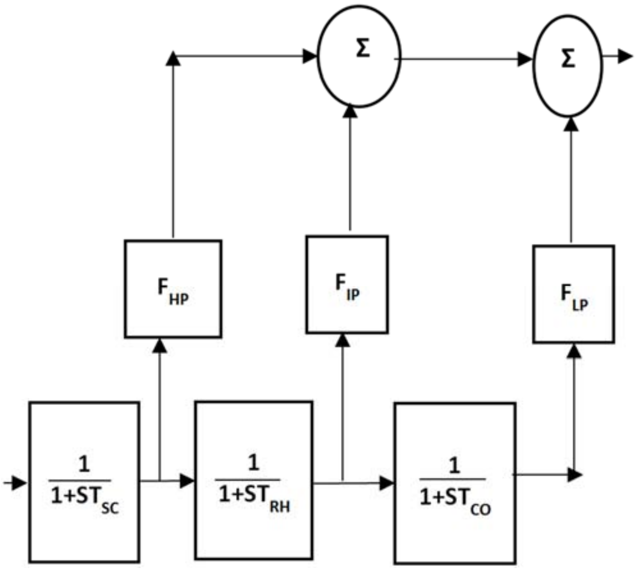

Figure 5. *Turbine Model.*

Where $F_{HP}+F_{IP}+F_{LP}=1$ and F_{HP}, F_{IP}, F_{LP} are the fraction of the power generated in the high pressure turbine, intermediate pressure and low pressure turbine respectively which can be obtained by using the enthalpy and steam flow data available in the heat balance diagram. T_{RH}, T_{CO}, T_{CH} are the time constant for steam chest, re-heaters and crossovers section of the steam turbine respectively and can be derived from the HMBD applicable for this model.

4. Derivation of the Turbine Time Constants

The study case is a 660 MW tandem compound single reheat Ultra-supercritical unit. The HBD represents the heat balance map of the unit cycle. In this map, thermodynamic data including pressure (kgf/cm2), enthalpy (kcal/kg), mass flow (T/h), and temperature (DegC) of nearly all sections of the cycle are given. Temperature control loop maintains the input steam of HP and IP turbines to have constant temperature. Also, there are three extraction outlets in the HP turbine, five in the IP turbine, and six in the LP turbine. There are also gland steam fed into some sections. The heat regenerative cycle consists of one gland steam condenser, five low-pressure feed water preheaters (HTR-1 to HTR-5), and three high-pressure feed water preheaters (HTR-7 to HTR-9). In this relatively complex cycle, we are interested in the thermodynamic data of the reheater, HP, IP, LP turbines, and extraction pipes for calculating the turbine model parameters. The following physical unit conversion factors are considered for all calculation: 1 kgf/cm2 = 98.07 kPa; 1 kg/hr = 0.0002778 kg/sec; 1 kcal/kg = 4.186kJ/kg

4.1. Derivation of Steam Chest Time Constant

Let us assume a steam vessel and using the continuity equation to derive the time constant.

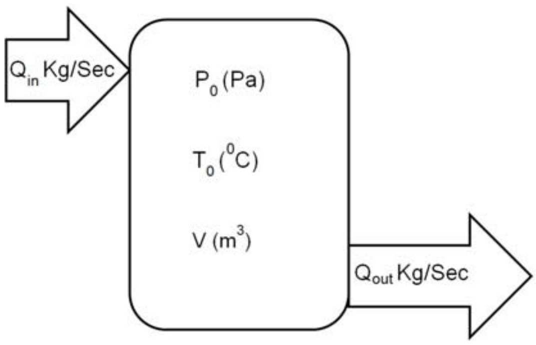

Figure 6. *Vessel Model.*

Q_{in} and Q_{out} are the inlet and outlet mass flow of the vessel, V being the volume of the vessel and p being the density. The continuity equation suggests that for a vessel, the mass flow rate of steam is equal to the difference between the inlet and the outlet flow.

Let us assume t is the time constant of the vessel steam flow in seconds, Q_0 is the steady state mass flow out of the vessel, P_0 is the steady state vessel pressure, T_0 is the vessel temperature that is assumed constant and V is the volume of the vessel.

Vessel pressure, temperature, and mass flow data can be extracted from the HMBD of the unit.

$$Qin - Qout = \frac{dm}{dt} \quad (8)$$

$$\frac{Qout}{Q0} = \frac{P}{P0} \quad (9)$$

$$Qin - Qout = \frac{dm}{dt}$$

$$= \frac{Vdp}{dt}$$

$$= V\frac{dP}{dt}x\frac{dp}{dP}$$

$$= V\left(\frac{dQout}{dt}\right)x\left(\frac{P0}{Q0}\right)x\left(\frac{dp}{dP}\right)$$

$$= V\left(\frac{P0}{Q0}\right)\left(\frac{dp}{dP}\right)\left(\frac{dQout}{dt}\right)$$

$$= t(\frac{dQout}{dt})$$

Where the vessel time constant t can be expressed as

$$t = V(\frac{P0}{Q0})(\frac{dp}{dP})$$

$$t = KV(\frac{P0}{Q0}) \quad (10)$$

Vessel factor $K = \left(\frac{dp}{dP}\right)$ where K is the density change due to pressure changes at constant temperature and V is the volume of the vessel. For per unit mass, the density of steam $p = \frac{1}{v}$

Where, v is the specific volume of the steam at constant temperature. Hence, K can be expressed as

$$K = \frac{\frac{1}{v2}-\frac{1}{v1}}{P2-P1} \quad (11)$$

The turbine steam chest volume covers the volume of HP turbine and IP turbine stop valve, governing and overload valve at the HP and IP turbine inlet. From the heat balance diagram at 100% load shown in the Figure 15, it is found that at HPT inlet the steam parameters are

P_{SC} = 270.0 kg/cm2 = 26477.82 kPa

Q_{SC} = 1849134 kg/hr = 513.6483333 kg/sec

T_{SC} = 600°C

From tabulated data of steam table at T_{SC} = 600°C, the following specific volumes are extracted

P_2 = 30000 kPa, V_2 = 0.011446 m3/kg

P_1 = 20000 kPa, V_1 = 0.01818 m3/kg

Where P_2 and P_1 are the boundary pressures at T_{SC} from steam table. Specific volumes are interpolated from available data. Then from equation (11) the value of K_{sc} is calculated as K_{SC} = 0.003236127 sec2/m2. For the turbine under consideration, the steam chest volume calculated as V_{SC} = 4.55265215 m3 which leads finally the steam chest time constant from equation (10) as t_{SC}= 0.138458597 sec2/m2. Similarly, we can calculate the time constant of steam chest for different MW load conditions from other HBD and the equations (10) and (11) as shown in Table 1 and Table 2.

Table 1. *660 MW Steam Turbine Parameters.*

Steam Turbine Parameters				
Turbo Generator Load		**Pressure**	**Flow**	**Temperature**
(MW)	**(%)**	**(Kgf/cm^2)**	**(Kg/Hr)**	**(Celcius)**
198	30	108	625911	565
330	50	139.4	917165	600
396	60	164.9	1093233	600
528	80	216.7	1459346	600
660	100	270	1849134	600
693	105	270	1960251	600

Table 2. *660 MW Steam Chest Time Constant at different Loads.*

Steam Chest Time Constant			
Turbo Generator Load		**Ksc**	**Time Constant t_{SC}**
(MW)	**(%)**	**(Kg/m^3)/Kpa**	**(Seconds)**
198	30	0.002956529	0.819933708
330	50	0.002816499	0.688034571
396	60	0.002972196	0.720561091
528	80	0.003236127	0.772345396
660	100	0.003236127	0.759462444
693	105	0.003236127	0.716412249

4.2. Derivation of Reheater Time Constant

The Reheater section in the boiler under consideration covers the area starting from the HP turbine outlet, cold reheat pipe, primary re-heater inlet header, primary re-heater bank, terminal, outlet header, primary re-heater to secondary re-heater, secondary re-heater inlet header, secondary re-heater bank, outlet header and hot reheat pipe up to IP turbine inlet. The volume of the total re-heater section is calculated as V= 450.44 m^3.

From the heat and mass balance diagram at 100% load shown in Figure 15, it is found that at re-heater inlet the steam parameters are

P_{RH} = 49.6 kg/cm2 = 4864.0736 kPa

Q_{RH} = 1518342 kg/hr = 421.7616667 kg/sec

T_{RH} = 600°C

From tabulated data of steam table at T_{RH} = 600°C, the following specific volumes are obtained

P_2 = 5000 kPa, V_2 = 0.07869 m3/kg

P_1 = 4000 kPa, V_1 = 0.09885 m3/kg

P_2 and P_1 are the boundary pressures at T_{RH} from steam table. Specific volumes are interpolated from available data in the steam table and the value of K_{RH} is calculated from the equation (10) and (11) as K_{RH} = 0.002591757 sec2/m^2. For the re-heater under consideration with total volume V_{RH} = 450.44 m3 finally, the re-heater time constant is calculated as t_{RH} = 13.46369583 sec2/m2.

Similarly, the time constant of re-heater for different MW load conditions are calculated from the HBD and the equations (10) and (11) as shown in Table 3 and Table 4.

Table 3. *660 MW Steam Turbine Reheater Parameters.*

Reheater Steam Parameters				
Turbo Generator Load		**Pressure**	**Flow**	**Temperature**
(MW)	**(%)**	**(Kgf/cm2)**	**(Kg/Hr)**	**(Celcius)**
198	30	17.3	545611	530
330	50	26.1	789568	600
396	60	30.7	932193	600
528	80	40	1220920	600
660	100	49.6	1518342	600
693	105	52.4	1610421	600

Table 4. *660 MW Steam turbine Reheater Time Constant.*

Reheater Time Constant			
Turbo Generator Load		**K_{RH}**	**Time Constant t_{RH}**
(MW)	**(%)**	**(Kg/m3) / Kpa**	**(seconds)**
198	30	0.002911205	14.67890699
330	50	0.002797203	14.70390995
396	60	0.00256179	13.43408491
528	80	0.00256179	13.36436518
660	100	0.002591757	13.46369583
693	105	0.002627575	13.54406349

4.3. Derivation of Turbine Crossover Time Constant

The crossover pipe is located between the IP and LP turbine. From the heat balance diagram at 100% load shown in Figure 15, the following parameters are obtained as

P_{CO} = 8.23 kg/cm2 = 807.08318 kPa

Q_{CO} = 1225821 kg/hr = 340.5058333 kg/sec

T_{CO} = 600°C

From tabulated data of steam table at T_{CO} = 600°C, the specific volumes are obtained

P_2 = 1000 kPa, V_2 = 0.270205 m3/kg

P_1 = 800 kPa, V_1 = 0.33925 m3/kg

P_2 and P_1 are the boundary pressures at T_{CO} from steam table. Specific volumes are interpolated from available data in the steam table and the value of K_{CO} is calculated from the equation (10) and (11) as K_{CO} = 0.003766075 sec2/m^2. For the crossover area for the steam under consideration the total volume V_{CO} = 107 m3. Finally, the crossover time constant is calculated as t_{CO} = 0.091586213 sec2/m2.

Table 5. *660 MW Steam turbine Crossover Steam Parameters.*

Crossover Steam Parameters				
Turbo Generator Load		**Pressure**	**Flow**	**Temperature**
(MW)	**(%)**	**(Kgf/cm2)**	**(Kg/Hr)**	**(Celcius)**
198	30	3.09	470251	289.8
330	50	4.54	673655	338.1
396	60	5.42	783924	334.8
528	80	6.19	1006356	329.6
660	100	8.23	1225821	324
693	105	8.64	1287558	323.3

Similarly, the time constant of crossover area for different MW load conditions are calculated from the HMBD and the equations (10) and (11) as shown in Table 5 and Table 6.

Table 6. *660 MW Steam turbine Crossover Time Constant.*

Crossover Time Constant			
Turbo Generator Load		**K_{CO}**	**Time Constant t_{CO}**
(MW)	**(%)**	**(Kg/m3) / Kpa**	**(seconds)**
198	30	0.004036285	1.00187911
330	50	0.003846242	0.979173618
396	60	0.003708024	0.968439662
528	80	0.00373245	0.867236969
660	100	0.003766075	0.955138868
693	105	0.003766075	0.954642316

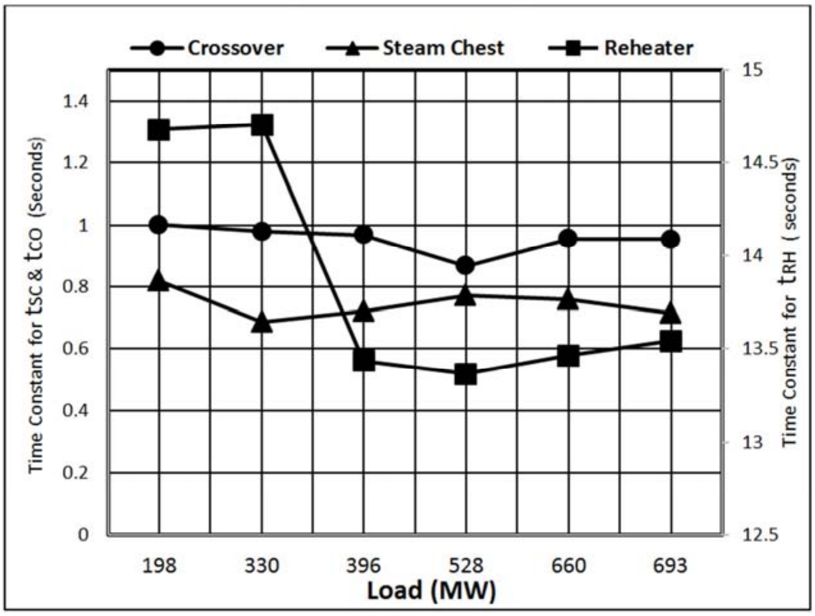

Figure 7. *Variation of HP/IP/LP Turbine Time Constant with MW Load.*

5. Derivation of Power Fractions of Turbine

Power fractions determination of HP, IP and LP turbine section requires calculating each turbine's thermodynamic work. Thus from heat balance data, the thermodynamic work can be calculated as follows.

$$P = Qin\ x\ Hin - \sum_{i=1}^{n} Qi\ x\ Hi \qquad (12)$$

Where Q_{in} is the mass flow rate, H_{in} is enthalpy and n is the number of extraction points.

In case of HP turbine, the power is calculated at 100% load from heat and mass balance diagram with number of extraction point n=3 and P_{hp}

= [1849134 x 831.2 – (144842 x 753.9 + 153184 x 728 + 1518342 x 728)] x 0.0002778 Kg/Sec x 4.186 KJ / Kg

= 245268.0527 KJ/sec or KW

Similarly, at 100% load the power of IP turbine and LP turbine power are calculated with the number of extraction point n=5 and n=6 respectively as follows.

P_{ip} = [1518342 x 876.1–(88514 x 822.6 + 45479 x 770.6 + 104842

x 770.6 + 79627 x 742.2 + 1225821 x 742.2)] x 0.0002778 Kg/Sec x 4.186 KJ/Kg

= 200773.2826 KJ/sec or KW

P_{lp} = [1225821 x 742.2 – (82385 x 695.6 + 41277 x 643.7 + 43950 x 617.6 +

21977 x 588.7 + 518953 x 564.3 + 518953 x 572.3)] x 0.0002778 Kg/Sec x 4.186 KJ/Kg

= 227909.0672 KJ/Sec or KW

The power fractions of each of the HP, IP and LP turbine can then simply calculated by the following equation and tabulated in Table 7, 8 and 9.

$$Fhp = \frac{Php}{Php+Pip+Plp} \tag{13}$$

$$Fip = \frac{Pip}{Php+Pip+Plp} \tag{14}$$

$$Flp = \frac{Plp}{Php+Pip+Plp} \tag{15}$$

Table 7. *660 MW HP turbine Power Fraction Parameters.*

HP Turbine Power				
Turbo Generator Load		**Power**	**Power Fraction**	**Power Fraction**
(MW)	**(%)**	**(MW)**		**(%)**
198	30	86.846972	0.422730994	42.2730994
330	50	129.002877	0.381040337	38.1040337
396	60	151.846029	0.374792441	37.4792441
528	80	198.256714	0.367568149	36.7568149
660	100	245.268053	0.363925968	36.3925968
693	105	245.68811	0.347677815	34.7677815

Table 8. *660 MW IP turbine Power Fraction Parameters.*

IP Turbine Power				
Turbo Generator Load		**Power**	**Power Fraction**	**Power Fraction**
(MW	**(%)**	**(MW)**		**(%)**
198	30	62.858208	0.305964758	30.5964758
330	50	102.10129	0.301580173	30.1580173
396	60	121.300953	0.299399864	29.9399864
528	80	160.108616	0.296841536	29.6841536
660	100	200.773283	0.297905131	29.7905131
693	105	220.40398	0.311897764	31.1897764

Table 9. *660 MW LP turbine Power Fraction Parameters.*

LP Turbine Power				
Turbo Generator Load		**Power**	**Power Fraction**	**Power Fraction**
(MW)	**(%)**	**(MW)**		**(%)**
198	30	55.737461	0.27134248	27.134248
330	50	107.450218	0.31737949	31.737949
396	60	132.000006	0.325807695	32.5807695
528	80	181.008701	0.335590315	33.5590315
660	100	227.909067	0.338168901	33.8168901
693	105	240.56247	0.340424421	34.0424421

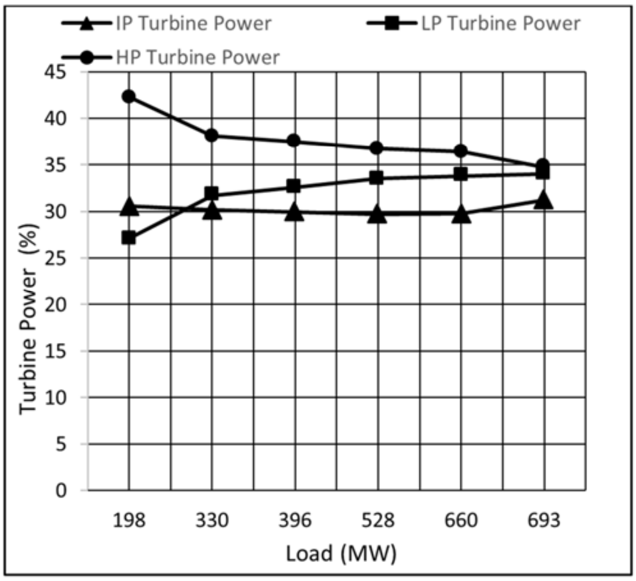

Figure 8. *Turbine Fractional Power Variation with MW Load.*

The correct transfer function of the turbine under consideration is derived under various MW load condition in the form as

$$G(s) = \frac{As^2+Bs+1}{(Xs^3+Ys^2+Zs+1)} \tag{16}$$

Where at 30% load and 100% load of the 660 MW turbine under consideration the values of the parameters A, B, X, Y and Z can be calculated from the equation (1) and Table 2, 4, 6, 7, 8, 9 as shown in the Table 10. It implies that the dynamic model of the turbine varies with the MW load of the machines as shown in Table 10.

Table 10. *Turbine Transfer Function Parameters.*

Turbo Generator Load						
MW	**198**	**330**	**396**	**528**	**660**	**693**
%	**30**	**50**	**60**	**80**	**100**	**105**
A	6.2092	5.4861	4.8761	4.2601	4.67998	4.4954
B	6.9382	6.2712	5.6879	5.4885	5.53193	5.3386
X	12.022	9.9061	9.3746	8.9515	9.76646	9.263
Y	27.52	25.188	23.388	22.582	23.8103	23.317
Z	16.498	16.371	15.123	15.004	15.1783	15.215

6. Frequency Response of Turbo-Generator System

6.1. Load Frequency Control Response

There are many load frequency control methods developed for controlling Frequency of power system. This include flat frequency control (FFC), tie-line bias control (TBC) and flat tie-line control (FTC). In FFC, some generators absorb load change and other generators are operated at base load. The reason is that the operating efficiency at base load is maximum but the disadvantage is the power system becomes more prone to transient disturbances due to lesser number of generating station for load change absorbers. The widely used methods are in TBC, where all the power systems in the interconnected areas regulate the frequency regardless of where the frequency change originates. In FTC, the change in frequency is of a particular control area is taken care of by the generators of that control area thereby maintaining the tie-line loading and frequency thereof.

In a single area power system consists of a electrohydraulic governor, a steam turbine, and a generator with feedback of regulation. System also includes step load change input to the generator. The objective of load frequency controller is to exert the control of frequency response and at the same time real power exchange through outgoing transmission line. The load frequency control strategies is based on the conventional linear Control theory. These controllers may be unsuitable in some operating conditions due to the complexity of the power systems such as nonlinear load characteristics and variable operating points. The power system static and dynamic properties must be well known to design an efficient controller.

The change in frequency is detected by a reliable and accurate frequency sensor. The load frequency controller amplify error frequency error signal corresponding to the change in load and send command signal to the electro-hydraulic governor of the turbine-generator set to control the steam admission valve mechanism. Any increment or decrement in torque because of any frequency change balances the output of governor, which will compensate the value of frequency error signal. The process continues till the steady state error of frequency or load becomes zero with the help of a simple proportional-integral controller. In order to reduce the frequency deviation to zero a reset action in proportional-integral controller sets the load reference point to change the speed set point which forces the final frequency deviation to zero. The controller parameters are tuned to achieve a satisfactory transient response of the system.

6.2. Load Frequency Control with Different Governor Mode

The load frequency control with governor can be achieved with either with turbine in free governor mode or with restricted governor mode, the later comes into effect during emergency condition of frequency disturbance only.

6.2.1. Free Governor Mode

It is necessary in power system to ensure the stable operation of the power generating unit and to avoid tripping of the generating unit due to fluctuation in the power system frequency from steady state value of 50 Hz, all utilities prefer to operate in the restricted frequency bands with a dead band in the governor operation as primary frequency control from 47.5 Hz to 51.50 Hz. The emergency unloading of the turbo generator happens only when frequency goes above 51.50 Hz. In case of isolation of any control area, followed by severe frequency decay, under frequency load shedding through df/dt protective relays occurs which brings up frequency above 52 Hz once again leading to tripping of some other control area on high frequency. The extent of disturbance in the power system depends on the system inertia which provides the initial ability of the power system to oppose change in the frequency. High system inertia means frequency will fall slowly and vice versa, during any system contingency. Higher system inertia provides more time to the governors to respond to a change in frequency and hence is desirable.

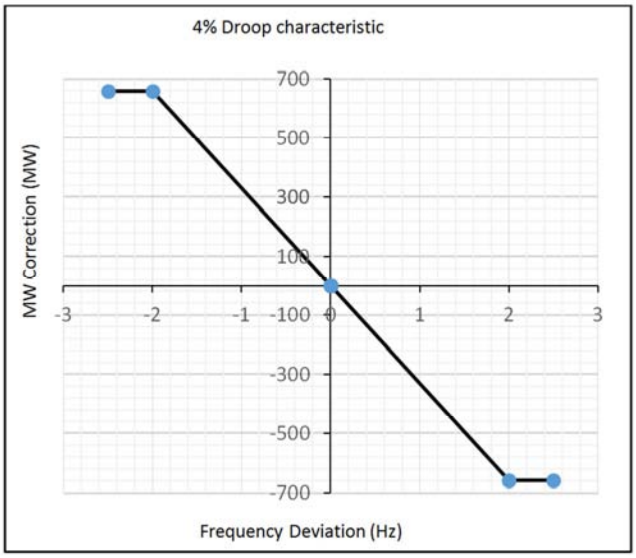

Figure 9. *MW Load Correction with Frequency Variation.*

The governor control responding in the entire frequency range eliminating the dead band is known as free governor mode of operation (FGMO) and it is basically the primary frequency control with droop. With free governor control on generating units, tripping on high frequency would be avoided during power system disturbances as load generation balance can be attained at a faster rate. It is perceived that FGMO is the fastest method to tackle the power system frequency fluctuation particularly during high frequency regime. More the number of constituents generating stations under FGMO, more is the stability of the power system frequency. The objective of FGMO is expected to take care wide frequency variation during power system frequency disturbance.

6.2.2. Restricted Governor Mode

This is also primary frequency control but with inclusion of a dead band of governor not exceeding + / - 0.03 Hz where primary control is blocked by the governor dead band unlike FGMO control. This ripple factor of + / - 0.03 Hz prevents continuous hunting in the governor due to very small frequency variation. Restricted governor mode of operation(RGMO) does not act in proportion to the frequency deviation like FGMO and is not strictly a frequency controlling mode, rather this mode restrict sudden and large frequency deviation with an additional step load disturbance during drop of normal running frequency under contingency control which operate along with load frequency controller enhancing the generation of power.

For any fall in frequency, the power generation shall increase as per Generator droop characteristics up to maximum of 5% of the instantaneous load limited to 105% of turbo generator's maximum continuous rating. This requires primary control reserves of 5% to be carried on by all power generating unit. The reference frequency is set at 50.0 Hz considering the ripple factor of +/- 0.03 Hz and the frequency dead band from 49.97 Hz to 50.03 Hz. The MW load correction for different frequency bands will be as follows:

(i) Case (1) Frequency < 49.97 Hz

For any fall in grid frequency, generation from the unit should increase by a load correction factor called as RGMO load bias as per droop characteristics up to a maximum of 5% of the instantaneous generation subject to ceiling limit of 105% of the rated capacity of the turbine. The RGMO load bias component is calculated by

$$\Delta P = \frac{\Delta f * Pr}{f0 * R} \tag{17}$$

For a machine with rated capacity of P_r = 660 MW, governor droop of R= 4%, last stored frequency = 49.98 Hz and Instantaneous frequency = 49.95 Hz, $\Delta P_{(RGMO)}$ = 9.9 MW.

When the RGMO control mode is initiated for the first time, no frequency correction is done instantaneously and the instantaneous frequency is memorized. During the next scan cycle, the absolute difference between the current frequency and the previously stored frequency parameter is calculated. In case the operating frequency is less than 50.0 Hz and there is a fall in frequency from previously stored value by more than 0.03 Hz, then a RGMO step load bias component equivalent to a load jump up to maximum of 5% of the instantaneous load limited to ceiling of 105% of maximum continuous rating will be done. The frequency value at the instant of load jump is again memorized. The iteration process is in a loop. For operating frequency less than 50 Hz, if the frequency improves / increases more than the previously stored value in next scan cycle, but still less than 50 Hz, previously stored frequency is updated and over-written with the new frequency value. The turbine inlet pressure falls under such circumstances due to the sudden load jump to stabilize the frequency.

The second RGMO step load component equivalent to another load jump does not take place until the turbine inlet pressure regains 5% throttle margin. Once the target load through RGMO action is achieved, the unit generation reference set point is updated to the new set parameter as (previous generation reference set point + RGMO load component).

If the turbine upstream live steam pressure drops more than pre-defined parameter, say 3%, in a stipulated time between 5 sec to 10 sec, then it is logically declared that RGMO control is not sustainable and accordingly the turbine MW load set point is brought back to its earlier set point with 1% ramp down gradient up to turbine's minimum technical load of 55% of load.

(ii) Case (2) 49.97 Hz < Frequency < 50.03 Hz

This is the dead band and no step load correction takes place within this band due to frequency deviation eliminating the possibility of governor hunting due to small frequency variation.

(iii) Case (3) Frequency > 50.03 Hz

Load correction shall be as per generator droop in this frequency range.

7. Simulation Results

The MATLAB simulation is done with turbine model corresponding to two different MW load of 100% and 30% with parameters as shown in Table 8. for free governor mode and for restricted governor mode.

Steam turbine generator model parameters used for the dynamic analysis are shown in Table 11. When a step load variations are applied in two identical turbine model with system parameters corresponding to 100% and 30% MW load for FGMO and RGMO case and the simulation results are shown below in the following figures.

Table 11. *660 MW Turbine Model Parameters at 30% and 100% Load.*

Comparison of Turbine Model Parameters of single area system		
	30% load	**100% load**
Tgov	**5 s**	**5 s**
T_{RH}	14.678 s	13.463 s
T_{CO}	1.001 s	0.955 s
T_{CH}	0.819 s	0.759 s
F_{HP}	0.422	0.363
F_{IP}	0.305	0.297
F_{LP}	0.271	0.338
Tp	10 s	10 s
K_p	60	60
H	5	5
R	5%	5%
D	1.5	1.5

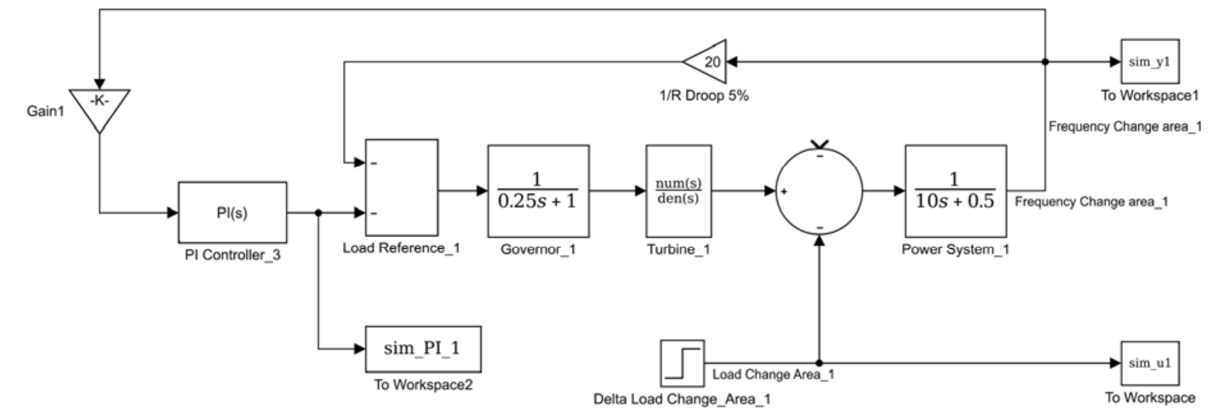

Figure 10. *Turbo generator model in FGMO.*

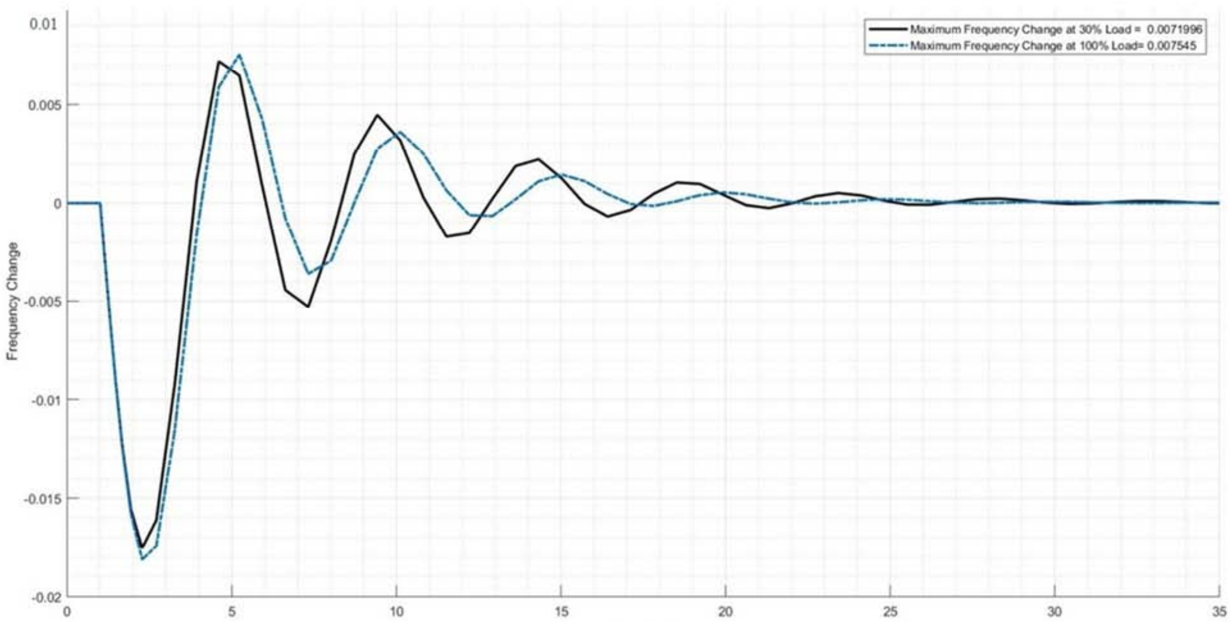

Figure 11. *Frequency Response Of FGMO.*

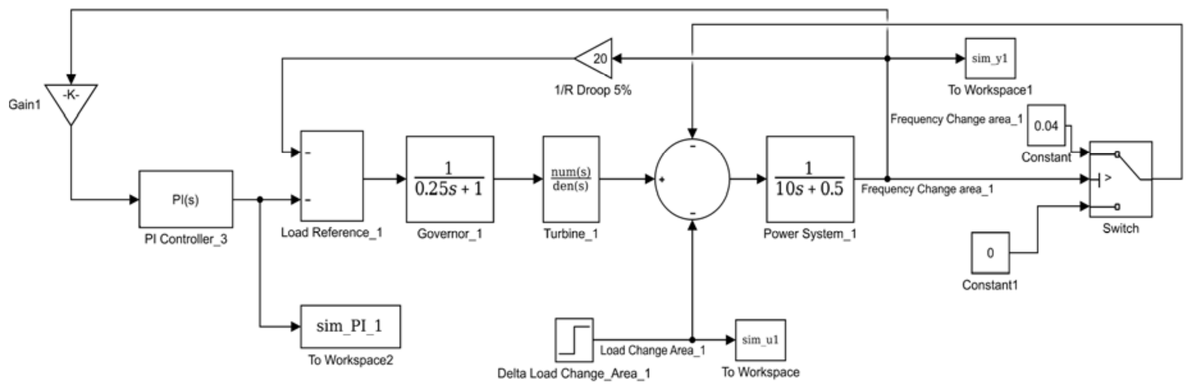

Figure 12. *Simplified Turbo generator model in RGMO.*

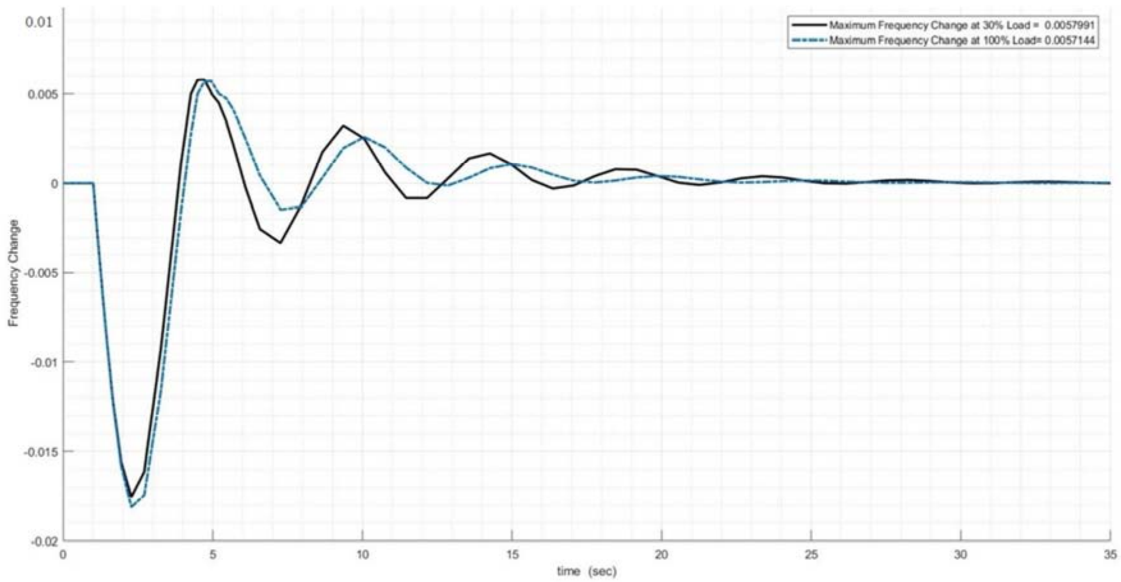

Figure 13. *Frequency Response of RGMO.*

8. Conclusion

The paper describes the methodology to estimate various dynamic parameters by a realistic approach towards steam turbine generators by simply using the heat and mass balance diagram data of a typical 660 MW steam turbine and finding the load dependent frequency response.

It is evident from the analysis that the steam turbine dynamic model parameters change with MW load of the machine. Steam turbine generator model parameters used for the dynamic analysis are the turbine time constants and power fractions. The power output of HP, IP and LP turbines at 100% rated condition are contributing 36.39, 29.79 and 33.81% of total power output respectively. As the MW load decreases, contribution of LP turbine in total power output decreases while that of HP and LP turbines increases. At 30% load HP, IP and LP turbine contributions are 42.27, 30.59 and 27.13% which means that LP turbine contribution has been decreased by 6.68% while that of HP and IP turbine have been increased by 5.88% and 0.8% respectively. It is concluded that the power fractions of HP, IP and LP turbines varies considerably with the MW load of the machine.

It is also observed that the steam turbine time constant depends on the MW generation of the plant. The time constant for steam chest varies in the range of 0.688–0.819 s, for re-heater the range is 13.364-14.678 s, and that for the crossover is 0.867-1 s for a typical 660 MW machine. In this case at 30 and 100% generation levels, the calculated values of time constants are (0.819, 14.678 and 1.001 s) and (0.759, 13.463 and 0.955 s), respectively. Hence, the value of the turbine time constant should be selected based on the MW generation of the machine instead of arbitrarily selecting within the any defined range. Since the value of the steam turbine time constant influence the dynamic performance of the entire power system model, therefore, correct value of the time constant at a particular MW load should be calculated using the mathematical procedure presented in this paper. It is to be noted that the steam chest and cross over time constant almost remains the same for all generation levels of the machine and in partial MW generation only RH time constant needs to be recalculated.

The simulation results show that the power system frequency stabilizes faster leading to zero steady state error in case of 100% machine load than in case of 30% load. The maximum and minimum frequency deviation remain almost same in both the cases.

The response of the simplified turbo-generator model for frequency regulation by restricted Governor Mode Control explained in this paper shows that the maximum frequency deviation under load throw off, outage of generating station or rejection of loads is less in case of load frequency control with restricted governor mode than in case of free governor mode. More the number of constituent power generating unit under load frequency control with RGMO, more is the stability of the power system. The concern is that the cost of carrying the 5% primary control reserves for all the units of the synchronous system and whether it is required to be followed for all the units compared to the actual requirement of primary control reserve based on the synchronous system capacity. The rate of frequency decline from the instant of disturbance like loss of generation or loss of MW load depends on the system inertia or load damping. Governor droop control restores the frequency towards normal operating frequency in FGMO but frequency stabilizes with an offset. The RGMO control tends to reduce the offset as compared to FGMO control. This methodology can be fine-tuned further along with the precise boiler control for grid connected power generating machines in managing the distribution services efficiently maintaining power system frequency.

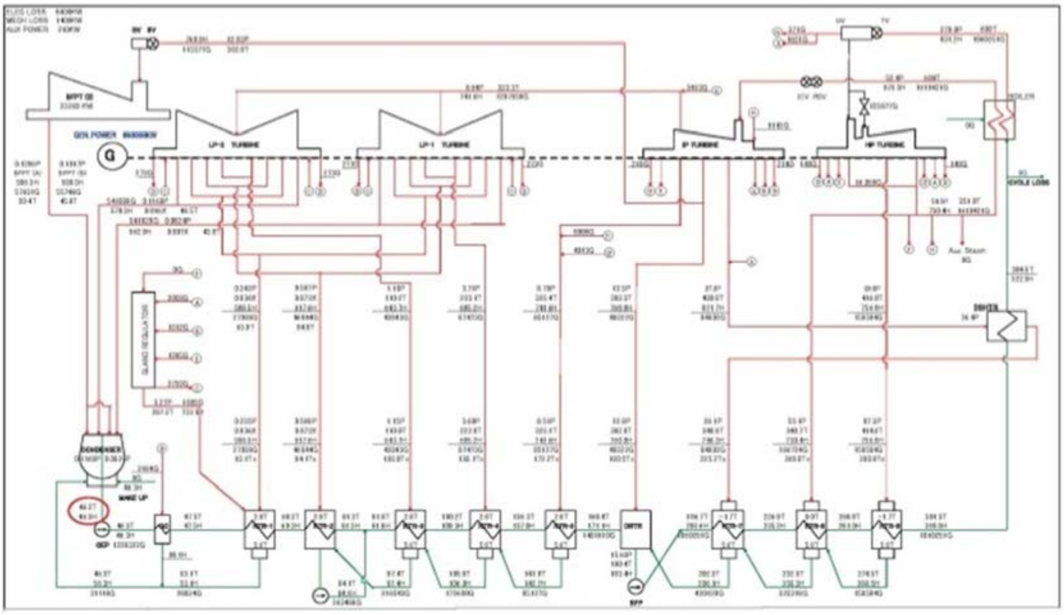

Figure 14. *Heat Balance Diagram for 105% rated Load.*

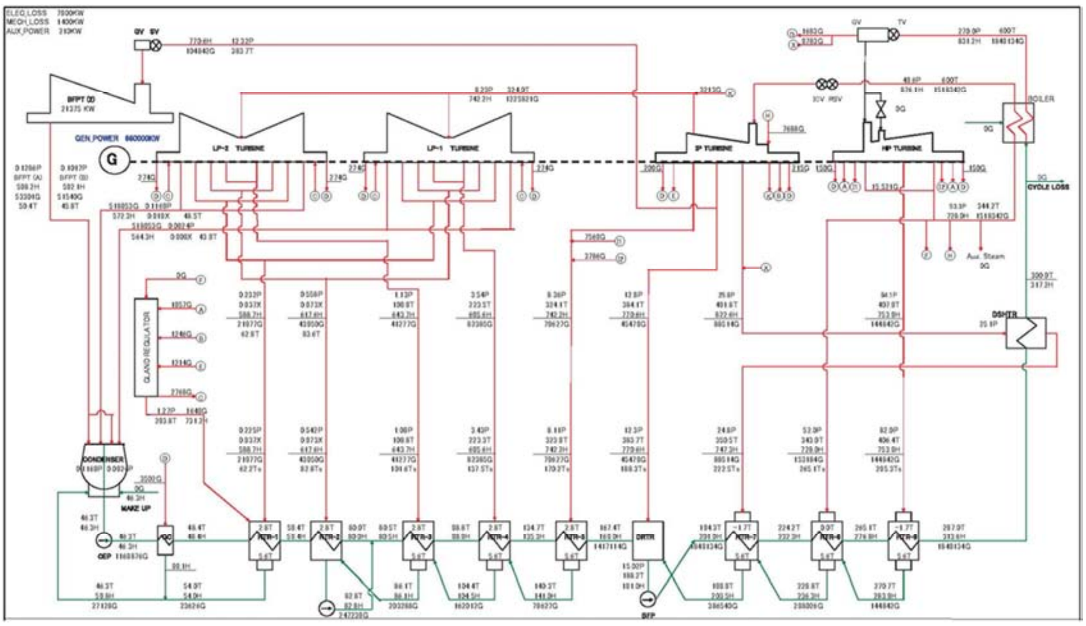

Figure 15. *Heat Balance Diagram for 100% rated Load.*

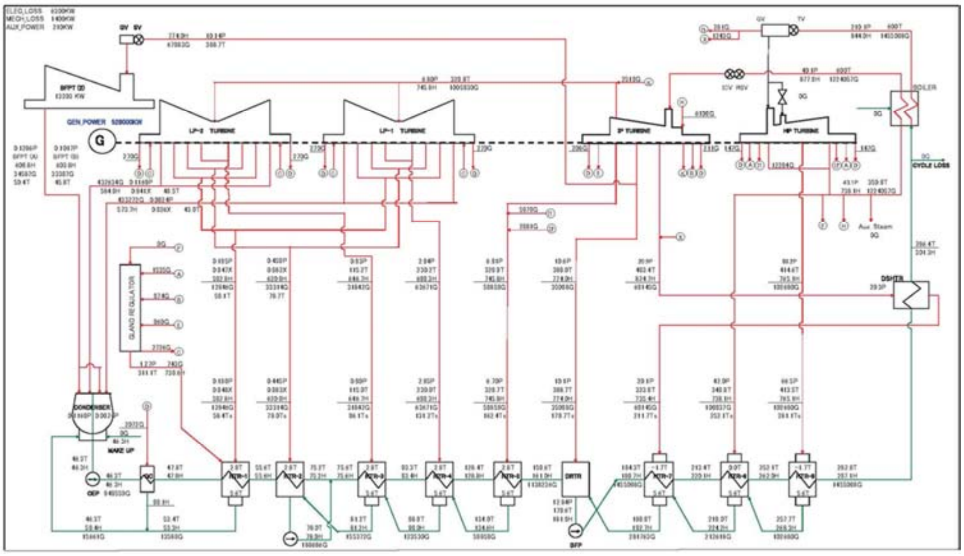

Figure 16. *Heat Balance Diagram for 80% rated Load.*

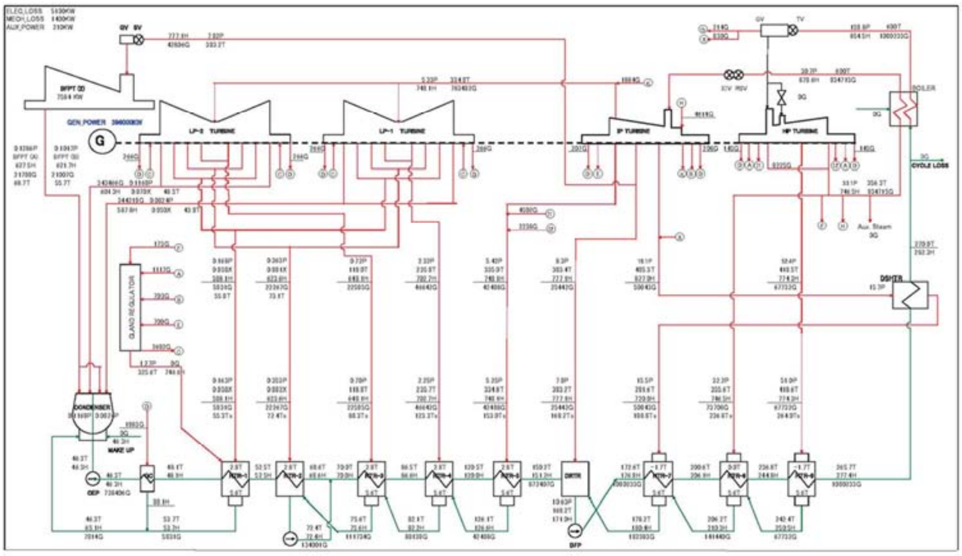

Figure 17. *Heat Balance Diagram for 60% rated Load.*

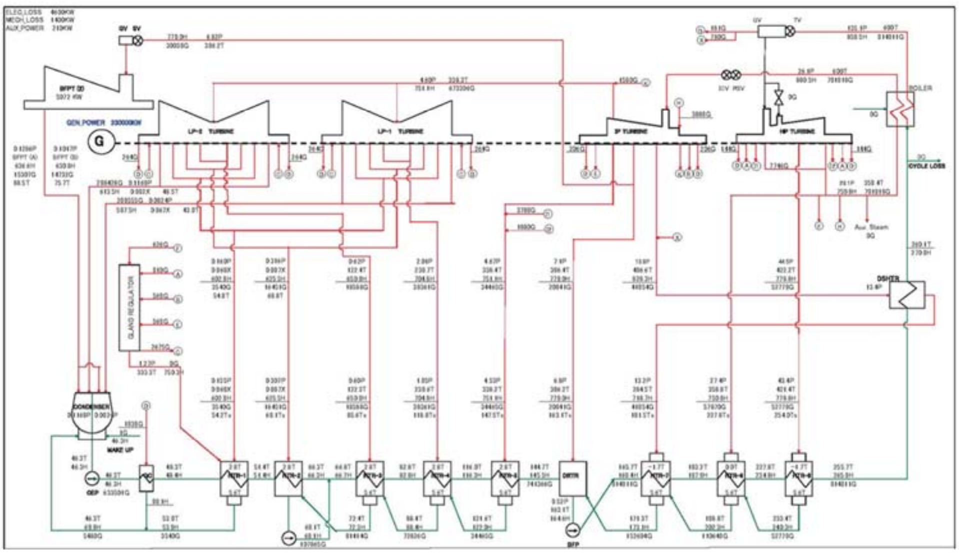

Figure 18. *Heat Balance Diagram for 50% rated Load.*

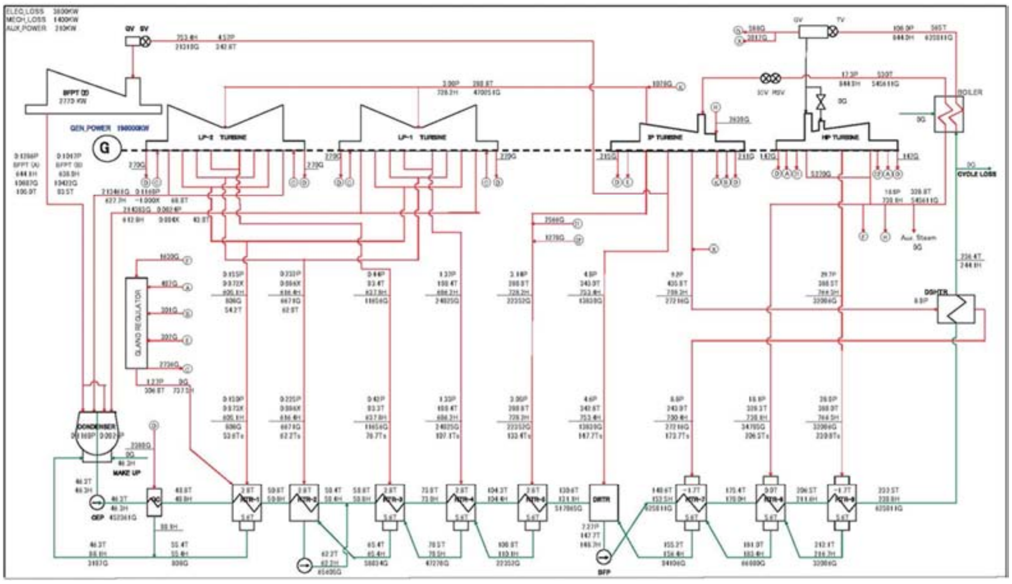

Figure 19. *Heat Balance Diagram for 30% rated Load.*

Acknowledgements

The author would like to gratefully acknowledge his Organizations M/s L&T-MHPS Boilers Pvt. Ltd, India towards designing the load frequency control scheme and meaningful system solutions towards transient power system disturbance that form the content of this paper.

References

[1] IEEE Committee Report: 'Dynamic models for steam and hydro in power system studies', IEEE Trans. Power Appar. Syst., 1973, 92, (6), pp. 1904–1915.

[2] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 published in Part III, Section 4 No. 115 of the Gazette of India (Extraordinary) dated 28.4.2010.

[3] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 First Amendment Regulations dated 06.03.2010.

[4] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 Second Amendment Regulations dated 07.01.2014.

[5] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 Third Amendment Regulations dated 10.08.2015.

[6] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 Fourth Amendment Regulations dated 29.04.2016.

[7] Central Electricity Regulatory Commission (Indian Electricity Grid Code) Regulations, 2010 Fifth Amendment Regulations dated 12.04.2017.

[8] Power System Analysis-Mcgraw-Hill College by Hadi Saadat.

[9] Deterministic Sizing of Frequency Bias Factor of Secondary Control by Andreas Ritter (EEH-Power System Laboratory, Swiss Federal Institute of Technology, Zurich).

[10] Power System Analysis- Mcgraw-Hill series Authored by John J. Grainjer and William D. Stevenson, Jr.

[11] Study of Damping Power in Interconnected Power System by Moustafa Ali Swidan, Iowa State University.

[12] Suppression of Short Term Disturbances from Renewable Resources by Load Frequency Control Considering Different Characteristics of Power Plants, IEEE P Power & Energy Society General Meeting, pp. 1–7, Jul. 2009. Oba, G. Shirai, R. Yokoyama, T. Niimura, and G. Fujita.

[13] P. Kundur, Power System Stability and Control, 1st ed., New York: McGraw-Hill, 1993.

[14] "A Genetic Algorithm Solution to the Governor-Turbine Dynamic Model Identification in Multi-Machine Power Systems" George K. Stefopoulos, Student Member, IEEE, Pavlos S. Georgilakis, Member, IEEE, Nikos D. Hatziargyriou, Senior Member, IEEE, and A. P. Sakis Meliopoulos, Fellow, IEEE. 44th IEEE Conference on Decision and Control, and the European Control Conference 2005 Seville, Spain, December 12-15, 2005.

[15] "Modelling of hydraulic governor-turbine for control stabilization" Yin Chin Choo, Kashem M. Muttagi, M. Negnevitsky @ EMAC 2007 pp C681-C698 2008.

[16] Operation Hand Book-Union for the Co-ordination of Transmission of Electricity.

[17] Frequency response characteristics of an interconnected power system-A case study of regional grids in India by S. K. Soonee and S. C Saxena, Power Grid Corporation of India Ltd. India.

[18] R. Oba, G. Shirai, R. Yokoyama, T. Niimura, and G. Fujita,"Suppression of Short Term Disturbances from Renewable Resources by Load Frequency Control Considering Different Characteristics of Power Plants", IEEE Power & Energy Society General Meeting, pp.1–7, Jul.2009.

[19] C. Zhao, U. Topcu and S. H. Low, "Frequency-based load control in power systems," Technical Report, California Institute of Technology, 2011.

[20] Comparing and Evaluating Frequency Response characteristics of Conventional Power Plant with Wind Power Plant Thesis for the Degree of Master of Science in Engineering (MSc Eng.), Mohammad Bhuiyan and Sundaram Dinakar Division of Electric Power Engineering Department of Energy & Environment Chalmers University of Technology Goteborg, Sweden, June'2008.

[21] Dr. T. K. Sengupta, "Studies on assessment of power frequency in interconnected grid–its computer based control & protection", 2008, thesis paper in JU.

[22] Prof. Prabhat Kumar, Ibraheem, "Dynamic performance evaluation of 2-area interconnected power system–a comparative study", IEEE-trans, August 14, 1996.

[23] Fosha C., Elgerd O. I.: 'The megawatt-frequency control problem: a new approach via optimal control theory', IEEE Trans. Power Appar. Syst., 1970, PAS-89, (4), pp. 563–577.

[24] Concordia C., Kirchmayer L. K.: 'Tie-line power and frequency control of electric power systems–part II', Power Appar. Syst. III. Trans. Am. Inst. Electr. Eng., 1954, 73, (1), pp. 133–146.

[25] Sharma Y., Saikia L. C.: 'Automatic generation control of a multi-area ST–thermal power system using Grey Wolf optimizer algorithm based classical controllers', Int. J. Electr. Power Energy Syst., 2015, 73, pp. 853–862.

[26] K. Sheng, X. Zhu, H. Ni et al., "Simulation and model validation of steam turbine and its governing system [J]", *Electric Power*, vol. 46, no. 12, pp. 52-58, 2013.

[27] Y. Tian, J. Guo, Y. Liu et al., "A mathematical model of reheat turbine for power grid stability calculation [J]", *Power system technology*, vol. 31, no. 5, pp. 39-44, 2007.

[28] X. Zhu, K. Sheng, L. Liu, "Intelligent parameter identification of steam turbine and its governing systems based on multi-algorithm [J]", *Power system protection and control*, vol. 41, no. 20, pp. 138-143, 2013.

[29] Modelling of Primary Frequency Control and Effect Analyses of Governing System Parameters on the Grid Frequency, Zhixin Sun, Institute of Turbomachinery, Xi'an Jiaotong University www.geos.ed.ac.uk/ccs/Meetings/Zhixin.pdf.

[30] Mathematical modelling and simulation of the behaviour of the steam turbine, The 7th International Conference Interdisciplinarity in Engineering (INTER-ENG 2013), Mircea Dulaua, *, Dorin Bicab, b Department of Electrical and Computer Engineering, "Petru Maior" University of Tîrgu-Mureş, 1 N. Iorga st., 540088.

[31] Pan J et al. A new non-linear model of steam turbine unit for dynamic analysis of power system. IEEE International Conference on Power System Technology. Hangzhou; 2010; p. 1–6.

[32] Inoue T et al. A thermal power plant model for dynamic simulation of load frequency control. IEEE Power Systems Conference and Exposition. Atlanta; 2006; p. 1442–1447.

[33] Frequency response Characteristics of an Interconnected Power System-A case study of Regional Grids in India, S. K. Soonee and Samir Chandra Saxena, Power System Operation Corporation Limited, India https://www.researchgate.net/publication/237465388.

[34] Mathematical model of a steam turbine for the thermal diagnostics system by Henryk Rusinowski, Institute of Thermal Technology, The Silesian University of Technology, Gliwice, Poland and Marcin Plis, Institute of Thermal Technology, The Silesian University of echnology, Gliwice, Poland, IEEE 2016 17th International Carpathian Control Conference (ICCC).