

Optimized Integral Gain Controllers for Price Based Frequency Regulation of Single Area Multi-Unit Power System

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Abstract: This Paper deals with the Price Based Load Frequency Control (PBLFC) using optimizedgain of integralcontroller with three different system marginal cost cases of single area four generator schemes. Case one having System Marginal Cost (SMC) value more than the nominal Unscheduled Interchange (UI) rate. Case two having system marginal cost value less than the nominal UI rate. Case three illustrates about the peak load condition following sudden loss of large generation to see whether PBLFC can handle such event or not. Particle Swarm Optimization (PSO) technique has been used to optimize gain of integral controllers in case one and two. An attempt has been made to achieve effective system frequency response using optimized gain controllers and also to explore the change in profit earned by Generation Companies (Gencos) in both the cases. For the analysis, UI rate of the year 2012, issued by Central Electricity Regulation Commission (CERC, INDIA) is used.

Index Terms: Load Frequency Control, Unscheduled Interchange (UI), Deregulated Electricity Market, Particle Swarm Optimization.

1. Introduction

Load Frequency Control (LFC) is one of the most important Ancillary Service (AS) brought in after deregulation of electricity market. Frequency regulation means control of grid frequency within its prescribed Normal Operating Band (NOB) by maintaining a proper balance between generation and load on a minute-to-minute basis. Also, to make settlement of real- time imbalance between demand and supply in deregulated electricity market, frequency is the index for real time price of power. The most important technical parameters for frequency related ancillary services are the deployment times. The maximum amount of time that can elapse between the requests from the System Operator (SO) and the beginning of the response by the service provider will be called the "deployment start". "Full availability" is the maximumtime that can elapse between the moment when the provider receives the request and the moment at which it delivers its full response. Lastly, "deployment end" is the maximum amount of time during which the service must be provided starting from the time of the request.

The accuracy of the frequency measurement is another important issue because it affects the efficiency of the control and the payments to the producers. If the instrumentation at a generating unit overestimates the frequency, its response to frequency deviations will be inadequate and the generating unit may be paid more than what it deserves. However, it is generally in the interest of electricity producers to measure frequency accurately so that they can argue more persuasively with the SO in case of any dispute [1]. As the restructuring of electricity supply industry has caused the task of frequency regulation to be seen as an ancillary service, SO provides three

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levels of system frequency control services, to maintain the balance between load and generation. The three levels are:

- A primary regulation service from generating units that respond to frequency changes within a few seconds;
- A secondary regulation service from generating units that respond to signals from the Independent System Operator(IS0) within 5 to 10 minutes;
- A secondary regulation service from loads that respond to signals from the ISO within 5-10 minutes.

A detailed discussion on load frequency control issues in power system operation after deregulation has been reported in [2-3]. The LFC schemes discussed in [4-10] are specially designed for deregulated market considering different types of possible transactions with optimized integral controller and with two or multi area system. General purpose multi area LFC for deregulated electricity market has been discussed in [11-12]. A centralized controller is often considered to be difficult to implement in large size power systems. The advantage in use of a decentralized controller is to reduce complexity and, make its implementation more practical for deregulated electricity market. A decentralized load frequency control has been reported in [13, 14]. Further decentralized controls with advance controller for deregulated electric power system have been proposed in [15-18]. Fuzzy based LFC for competitive electricity market have been discussed in [19-20]. Frequency linked market based real time pricing scheme is another approach for load frequency control in deregulated environment. Various frequency linked price based models have been reported in [21-28].Frequency linked UI mechanism for Indian power system have been discussed in [29-31] Also based on UI mechanismconceptprice based frequency regulation models have been investigated and reported in [32-33].

2. Role Of Ui Mechanism As Frequency Control In Indian Context

In the year 2002, Indian power engineers have introduced frequency dependent three part tariff system known as Availability Based Tariff (ABT). The first part of ABT being a fixed component which is linked to the availability of generating stations, second part is a variable component linked to the energy charges for scheduled interchange and third part is a frequency dependent component linked with the Unscheduled Interchange (UI).In case there are deviations from schedule, this third component of ABT comes into picture. This scheme encourages the re- dispatching of the generating units in real time based on prevailing UI charge to restore the frequency to nominal value of 50Hz.Now a days Indian power industry follows competitive power system structure where both the suppliers and beneficiaries are free to declare their capacity/requirement and their deviation from schedule is treated as per UI mechanism. This 'Unscheduled Interchange (UI)'is dealt commercially as a manual control on a post-facto basis using a 'regional pool settlement' system [29-31]. Also, as the UI mechanism based pricing signal linked to the system frequency can be transmitted across the grid at the same speed as the dynamics to be controlled, it provides the faster automatic LFC compare to manual UI based control for the Indian electricity grid without employing a vast set of inputs, processing software and last mile connectivity to the generators [32-33]. The station operator has only to compare his own variable cost and current pool price (based on UI curve), to decide whether the generation should be changed, and in which direction. The whole design

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encourages the utilities to conserve when in surplus so as to provide for when in shortage and thus smoothing the frequency curve. The system operator and plant operators are empowered to contribute in the grid frequency control, which can made the system self-healing and self-correcting. The utilities can deviate from these schedules, as long as the deviation does not cause a transmission constraint or a grid contingency. However in case of contingency, the schedule can be revised by system operator. The UI mechanism thus ensures that the parties are perpetually encouraged to deviate in the direction beneficial for the interconnection, i.e. towards enhancing overall improvement in the frequency. The curve of UI rate v/s frequency for the year 2012 has been issued by Central Electricity Regulation Commission (CERC) and till date it is in practice for UI mechanism [34].

ABT Control Loop Scheduled Generation UI Nominal **S1** Frequency **S2** Rate + S3 Incremental Cost ΔP_d S5 (gce) ΔP_1 Κ gre G G, Δf ΔP_{tie} **Primary Control Loop** ΔP_v

3. Basic Scheme of Price Based Load Frequency Control

Figure 1. Provision of Frequency Regulation ServicebyA Generator (ABT based frequency control loop) [32].

A mathematical framework for the provision of price based frequency regulation service by a generator, shown in Figure 1.has been first investigated and reported in Ref. [32]. Primary control loop of this scheme responds to a change in frequency instantaneously by using Free Governor Mode of Operation (FGMO), and other secondary control loop, operates automatically following UI signal available in real time, if there is a requirement of more generation that cannot be met through FGMO operation. Feedback signal of this scheme, known as Generation Control Error (GCE) is the difference of incremental cost of generator responding to load change and UI price at the same instant.



Figure 2. ABT Based Frequency Control Loop with Modified GCE Algorithm [33]

For above mentioned mathematical framework, authors in Ref.[33] have commented that for scheduled power of given set of generators if system marginal cost would be greater or lesser than the nominal UI rate (UI rate corresponds to nominal frequency) then unscheduled interchange of power would be there though there is no change in scheduled power and load. So, as the modification to rectify the shortcomings of the proposed model discussed in [32], authors in [33] have developed a new algorithm for computing Generation Control Error (GCE) instead of computing same for each generator in a simple manner as shown in Figure 1. A new strategy is developed in which no action is taken by generators if all the loads and other generators stick to their respective schedules, which may reduce unnecessarily UI, among generators. Control scheme with modified GCE signal has been shown in Figure 2. The same modified control scheme have been used in this present work.

4. Particle Swarm Optimization

Particle Swarm Optimization (PSO) is a population (swarm) based stochastic optimization algorithm which is first introduced by Kennedy and Eberhart in year 1995 [35]. The basic PSO is developed from research on swarm such as fish schooling and bird flocking. A new parameter called inertia weight is added. Particle swarm optimization uses particles which represent potential solutions of the problem. Each particles fly in search space at a certain velocity which can be adjusted in light of proceeding flight experiences. The projected position of ithparticle of the swarm S_i, and the velocity of this particle V_i at (k+1)th iteration are defined as per the following two equations.

$$V_{i}^{k+1} = W * V_{i}^{k} + C_{1} * \text{Rand}_{1} () * (P_{\text{besti}} - S_{i}^{k}) + C_{2} * \text{Rand}_{2} () * (G_{\text{best}} - S_{i}^{k})$$
(1)

$$S_{i}^{k+1} = S_{i}^{k} + V_{i}^{k+1}$$
(2)

$$W = Wmax - \frac{Wmax - Wmin}{Itermax} \times Iter$$
(3)

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Where,

i = 1...n, size of the swarm, $S_i=i^{th}$ particle of swarm, V_i =velocity of i^{th} particle,

 C_1 and C_2 = positive constants,

Rand₁ and Rand₂ are random numbers which are uniformly distributed in [0, 1],

k = iteration number, W = inertia weight,

 P_{besti} = best previous position (the position giving the best fitness value) of the ith particle, and

 G_{best} = best particle among all the particles in the swarm.

5. System Modeling

It is assumed that generators of single area are generating power at scheduled value and frequency of the grid at its scheduled frequency 50Hz. Now for any case, when step load $\Delta P_d(P \text{ MW})$ occurs in the system, which results in deviation in the supply frequency Δf .

$$S1 (f) = \Delta f + f^0 Hz.$$
(4)

At this frequency S1 (f) corresponding, the UI price signal S2 (ρ) (INR/MWh) [34] is calculated by equations (5) to (9).

If $S1(f) > 50.2$ Hz.	
S2 (ρ) = 0 INR/MWh	
	(5)
If $50 \text{ Hz} < \text{S1}$ (f) $\leq 50.2 \text{ Hz}$.	
S2 (ρ) = 8250*(S1 (f)) INR/MWh	
	(6)
If 49.8 Hz $<$ S1 (f) \leq 50Hz	
S2 (ρ) = 1650+14250*(50-f) INR/MWh	(7)
If $49.48 \text{ Hz} < S1 \text{ (f)} \le 49.8 \text{ Hz}$	
S2 (ρ) = 4500+14062.5*(49.8-f) INR/MWh	(8)
If S1 (f) \leq 49.48 Hz	
S2 (ρ) = 9000 INR/MWh	(9)

This UI price signals S2 (ρ) is compared with incremental cost signal S4 (γ) which generate signal S5. Incremental cost signal S4 (γ) is given by the following equations;

$$S4 (\gamma) = 2*c*S3+b \quad INR/MWh$$
(10)

Where c and b are incremental cost co-efficient, which depends upon the type of plant. Now S3 (Pg) is given by following

$$S3 (Pg) = Pg^0 + \Delta Pg \qquad MW \tag{11}$$

Where, ΔPg is change in turbine generator output and Pg^0 is an initial scheduled power of generator.

Further S2 (ρ) and S4 (γ) signal is compared with following condition to generate Generation Control Error (GCE), S5 (gce) INR/MWh, for each generator which is as per the control scheme shown in Figure 2.

If S4 (γ) > ρ^0 ; yes then go to (13), (12)No, then go to (ii) If S2 (ρ) > S4 (γ); yes then go to (14) (13)No, then go to (i) S5 (gce) = S2 (ρ) - S4 (γ); (14)If S2 (ρ) < ρ^0 ; yes then go to (15) (i) No, then go to (16) S5 (gce) = S2 (ρ) – ρ^{0} ; (15)S5 (gce) =0;(16)If S2 (ρ) < S4 (γ); yes then go (14) (ii) No, then go to (iii) If S2 (ρ) > ρ^{0} ; yes then go to (15) (iii) No, then go to (16).

6. Steady State Frequency Error Equation

As per GCE algorithm derived by equation no. (12) to (16) each generator may get a change in error signal as follows.

1: Δ gce = $\Delta \rho - \Delta \gamma$, "Or" 2: Δ gce = $\Delta \rho$, "Or" 3: Δ gce = 0

Now, for change in real time price $\Delta \rho$ corresponding to the change in frequency Δf is given by equation,

 $\Delta \rho (s) = -K_U \Delta f(s)$ (17) $K_U = \text{slope of UI curve and its value corresponds to UI price } \rho^0$ = 14250 INR/MWh.Hz

Where, $\rho^0 = UI$ rate corresponds to $f^0=50$ Hz. = 1650 INR/ MWh[34]

The marginal cost of generation, γ is related to the real time turbine generator power output. For each generator overall cost of generation is given by quadratic equation as follows.

$$C_i(P_{gi}) = a_i + b_i P_{gi} + c_i P_{gi}^2 \quad INR/h$$
(18)

Then, marginal cost of generator is given by equation (19).

$$y_{i} = \frac{d_{ci}}{d_{P_{gi}}} (P_{gi}) = 2c_{i}P_{gi} + b_{i} \qquad \text{INR/MWh}$$
(19)

Where $i = i^{th}$ generator number

Now, the change in marginal cost $\Delta \gamma$ (i) with change in turbine generator output ΔP_{gi} is given by equation.

$$\Delta y_i(s) = 2 c_i \Delta P_{gi}(s) \tag{20}$$

The speed changer setting of each generator follows the Δ gce signal which will be first amplified and then it is integrated.

1: For S5 (gce) signal from equation number (14) steady state frequency error equation is given by following relation.

$$\Delta f(s) = -\frac{\frac{P}{s(Ms+D)}}{1 + \frac{1}{Ms+D} \left\{ \sum_{i=1}^{n} \frac{S + K_{U}K_{Ii}R_{i}}{R_{i}(S + 2C_{i}K_{Ii})} \right\}} Hz$$
(21)

$$\Delta f^{ss} = \lim_{s \to 0} [S\Delta f(s)] = -\frac{P/_D}{1 + \frac{1}{D} \left(\sum_{i=1}^{n} \frac{K_U}{2C_i} \right)} Hz$$
(22)

$$\Delta f^{ss} = -\frac{P}{D + K_{U} \sum_{i=1}^{n} \frac{1}{2C_{i}}} Hz$$
(23)

2: For S5 (gce) signal, from equation number (15) steady state frequency error is given by following relation.

$$\Delta f(s) = -\frac{\frac{P}{s}}{\frac{Ms+D+\sum_{i=1}^{n} \left\{\frac{K_{U}K_{Ii}}{s} + \frac{1}{R_{i}}\right\}} Hz$$
(24)

$$\Delta f^{ss} = \lim_{s \to 0} [s \,\Delta f(s)] = -\frac{P \,x \,S}{MS^2 + DS + \left\{\sum_{i=1}^{n} \frac{S + K_U K_{I\,i} R_i}{R_i}\right\}} Hz$$
(25)

$$\Delta f^{ss} = 0 \qquad Hz \tag{26}$$

Where, P =Step load change in MW.

c_i = Incremental cost co-efficient of ith generator in INR/MW²h

The proposed price based load frequency control scheme has been simulated and tested using an isolated area system having a capacity of 5000 MW supplied by four generating stations following generation scheduling as per economic load dispatch criteria [33]. Figure 3 shows the detail schematic of four generators single area with UI based secondary control. As soon as load demand changes each generator at the same instant respond to change their generation as per the error signals receives from their GCE block to smooth out the grid frequency. So required objective function for PBLFC is the minimization of Generation Control Error (GCE) of all generators after the disturbance. Optimization of gain of integral controller for proposed scheme is obtained using Integral Square Error (ISE) criterion.

7. Test System Investigated



Figure 3. Price Based Model for Single Area Four Generator System [33]

Generalized objective function used for single area scheme is,

$$j = \min \sum_{i=1}^{n} gce_i^2$$
(27)
Where i= 1...n generators,

The necessary relevant datais givenin Appendix. All models are created using MATLAB-SIMULINK environment.

8. Simulation Result and Analysis

80 BR

. 60

> 40 60 time t in seconds

igure 5(c). case1: Δ gce₃ V/S Time

For case-I, the system marginal cost is more than the nominal UI rate, hence all generators receive the positive GCE signal, resulting in steady state frequency error. Figure 4(a) shows, the steady state frequency error is - 0.02 Hz. Figure 4(b) shows that UI rate settles at the value equals to SMC of new most economic point, higher than the nominal UI rate. Figure 5(a-d) shows, response of change in GCE of all the four generators, with and without optimization case. Figure 6(a) and 6(b) shows response of change in generation of all the generators following merit order dispatch for without and with optimization of integral gain controllers' case. Also in this case generator one is running at its full capacity so it does not increase its generation but generators two and three are partly loaded and hence they share the increment in load as per their economic schedule criteria. Generator four does not contribute for secondary control, but it shares generation, which is due to its primary or FGMO control.





/s2 80

00 dce7

8 40

40 60 time t in seconds

Figure 5(d). case1: ∆gce₄ V/S Time

100



Figure 5. With and without PSO, time response for Case 1 (a) - (d) gce for generator 1-4



Figure 6. Case 1, change in Pg₁ to Pg₄ (a) without PSO, (b) with PSO optimized integral controllers



Figure 7. With and without PSO, time response for Case 2 (a) Frequency, (b) UI Rate

For case–II, the system marginal cost is less than the nominal UI rate hence all generators receive the positive S5 (gce) = S2 (ρ) - ρ 0 signal, resulting in zero steady state frequency error. Figure 7(a) shows change in frequency with respect to time for without and with optimized case. Also, it has been revealed from Figure 7(b) that final value of UI rate settled at 1650INR/MWh (corresponds to f⁰). Figure 8 (a-d) shows the response of change in GCE error of individual generator with respect to time for with

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and without PSO optimized integral gain controllers' case. Figure 9(a). and Figure 9(b) shows change in generation for all generators following merit order dispatch without and with integral gain controllers' case. Since generator one and two are partly loaded, they share the increment in load as per their economic scheduling criteria while generator three and generator four contribute to a small amount of generation which is due to their primary or Free Governor Mode Operation (FGMO) action.



Figure 8. With and without PSO, time response for Case 2 (a) - (d) gce for generator 1-4



Figure 9. Case 2, change in Pg₁ to Pg₄ (a) without PSO, (b) with PSO optimized integral controllers

With optimum integral gain controllers for the case I and II, stabilization of steady state frequency is achieved faster than the un-optimized gain controller cases. It is shown in Figure 4(a) and Figure 7(a).respectively.

Figure 5 and Figure 8.reveals that with optimized integral gain controller, time response of GCE of each generator has been improved and the peak magnitude of GCE is reduced for each generator compared to un-optimized gain controller case respectively.

Case–III is simulated as peak loaded system to a loss of 400 MW power generation. As shown in Figure 10(a). , frequency error for this case is found to be - 1.00 Hz, and it mainly depends upon load frequency component D. As the steady state frequency error is very high and beyond unacceptable limit, SO has to take emergency measures to restore the frequency back to within permissible range. So, system operator can seek for on the spot energy integration option like distributed generation, captive power etc. In Figure 10(b)., UI rate reaches to its maximum limit of 9000 INR/MWh. In this case generator one, two and three are running at full capacity and generator four has only 300 MW surplus capacities to respond to change in load. So generator four responds to initial fall in frequency by increasing its generation up to 300MW and thereby running at its full capacity, which is shown in Figure10(C).Still there is 100 MW gap between generation and demand, which could be further met by load reduction due to load frequency response. Figure 10(d) shows the time response of change in net load change ΔP_{dr} .



Figure 10. Case 3, Sudden Loss of Generation (a) change in Frequency (b) UI Rate (c) Change in Pg (d) change in Pdr

Profit earned by various Gencos:

Time	ne Avg. Change			Avg. Change Average change in gen. (MW)			Profit (Rs.)				
in seconds	Hz	in (UI)	∆Pg1	$\Delta Pg2$	$\Delta Pg3$	$\Delta Pg4$	Gen1	Gen2	Gen3	Gen4	
0-900	49.9825	1899.20	0	46.3111	41.8964	10.0271	0	21988.51	19892.41	4760.867	
901-1800	49.9840	1877.90	0	46.5867	42.2245	9.5894	0	21871.29	19823.35	4501.984	
1801-2700	49.9840	1877.90	0	46.5867	42.2245	9.5894	0	21871.29	19823.35	4501.984	
2701-3600	49.9840	1877.90	0	46.5867	42.2245	9.5894	0	21871.29	19823.35	4501.984	
			Total				0	87602.38	79362.45	18266.82	

Table 1-A (Case1, without PSO)

	Table 1-B(Case1, with PSO)										
Time	Time Avg.		А	Average change in gen. (MW)				Profit (Rs.)			
in seconds	Freq. Hz	e in (UI)	∆Pg1	$\Delta Pg2$	$\Delta Pg3$	$\Delta Pg4$	Gen1	Gen2	Gen3	Gen4	
0-900	49.9836	1883.8	0	48.3350	43.3580	6.6437	0	22763.37	20419.45	3128.851	
901-1800	49.9839	1879.0	0	48.4063	43.4450	6.5414	0	22738.86	20408.29	3072.823	
1801-2700	49.9839	1879.0	0	48.4063	43.4450	6.5414	0	22738.86	20408.29	3072.823	
2701-3600	49.9839	1879.0	0	48.4063	43.4450	6.5414	0	22738.86	20408.29	3072.823	
			Total				0	90979.95	81644.32	12347.32	

Table 2-A (Case2, without PSO)

Time	Avg. Frea.	Change	Aver	age change	in gen. (N	IW)		Profit	(Rs.)	
in seconds	Hz	in (UI)	∆Pg1	$\Delta Pg2$	∆Pg3	$\Delta Pg4$	Gen1	Gen2	Gen3	Gen4
0-900	49.9996	1656.10	47.8952	43.9801	5.0669	1.4561	19799.88	18208.86	2097.82	602.86
901-1800	50.0000	1650.00	47.9844	44.1043	4.9617	1.3165	19793.57	18193.02	2046.70	543.06
1801-2700	50.0000	1650.00	47.9844	44.1043	4.9617	1.3165	19793.57	18193.02	2046.70	543.06
2701-3600	50.0000	1650.00	47.9844	44.1043	4.9617	1.3165	19793.57	18193.02	2046.70	543.06
			Total				79180.59	72787.93	8237.92	2232.03

Table 2-B (Case2, with PSO)

Time	Avg. Freg.	Change	Ave	Average change in gen. (MW)				Profit (l		
in seconds	Hz	in (UI)	∆Pg1	$\Delta Pg2$	ΔPg3	∆Pg4	Gen1	Gen2	Gen3	Gen4
0-900	49.9998	1653.60	49.4508	48.8506	2.1349	1.0913	20473.87	20194.84	882.5677	451.1434
901-1800	50.0000	1650.00	49.6174	48.9440	2.0610	1.0106	20467.18	19793.57	850.1625	416.8725
1801-2700	50.0000	1650.00	49.6174	48.9440	2.0610	1.0106	20467.18	19793.57	850.1625	416.8725
2701-3600	50.0000	1650.00	49.6174	48.9440	2.0610	1.0106	20467.18	19793.57	850.1625	416.8725
			Total				81875.4	79575.53	3433.06	1701.76

It has been seen fromtable of profit earned by various Gencos in both the case that with optimized K_i gain, unnecessary UI exchange is reduced between GENCOs and utilities. It can also be observed that all the generators participate in their merit order dispatch with their optimum level generation.

9. Conclusions

The important conclusions drawn from this paper are that, through frequency linked UI component, generator or GENCOs can earn profit by redespatching power in real time at their most economic point. The secondary control through UI does not Shital M. Pujara, et al.

drive the frequency error to zero but it depends upon the cost co-efficient of participating generators and also on the slope of the UI curve at nominal UI rate. The work carried out in this paper reveals to implement PBLFC for Indian electricity market, as UI based automated control involves less response time compared to existing manual UI based control to improve grid frequency profile. The PSO technique used to optimize the gain of integral controllers of individual machine improves the response of frequency and helps in saving unnecessary UI exchange between Gencos and utilities too. Simulation of the system under study of case three is to find out the effect of a sudden loss of large generation on proposed scheme. Results of the same show that contingency has been arisen due to large frequency drop (e.g. -1 Hz), and hence SO must have to take emergency action and has to revise the whole schedule of generation. Also the real time price signal obtained in generation deficient situation described in case three, will encourage the other high cost sources of generations like natural gas based plant, captive generation plant and renewable energy source plants in the system to begin supplying energy into grid at the time of contingency too.

APPENDIX

Table 3. Generator Data									
Daramatars		Gene	rators						
1 al aniciel s	G1	G2	G3	G4					
Capacity(MW)	1500	1500	1000	1000					
b(INR/MWh)	800	1000	1600	2000					
c(INR/MW ² h)	0.3	0.3	0.4	0.4					

Table 4. System Data						
M(MW-s/Hz)	1000					
D(MW/Hz)	100					
$F^{0}(Hz)$	50					
$\Delta P_{d}(MW)$	100					

	Machine 1	Machine 2	Machine 3	Machine 4
Droop R	6%	6%	6%	6%
Governor time constant T_{sg} sec.	0.3	0.3	0.3	0.3
Turbine time constant T_t sec.	0.5	0.5	0.5	0.5

Table 5. Droop, Governor and Turbine Time Constant:

Case	System Marginal Cost (SMC) (INR/MWh)	Generator 1 MW(P _{g1} ⁰)	Generator 2 MW(P _{g2} ⁰)	Generator 3 MW(P _{g3} ⁰)	Generator 4 MW(P _{g4} ⁰)
Case1	1850	1500	1416.66	312.5	0
Case2	1500	1166.66	833.33	0	0
Case3	2560	1500	1500	1000	700

Table 6. Different Case Data

Table 7.	PSO Optimization Data:
C ₁ ,C ₂	2
W _{min}	0.4
W _{max}	0.9
No. of Particles	100
No. of iterations	10

Γa	ıbl	e a	8. 3	Integral	Controll	ler C	bain	with	and	with	hout	PS	50
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	Un-optimized value of KIi
Case1:SMC=1850INR/MWh	$KI_1 = 0.002, KI_2 = 0.002, KI_3 = 0.002, KI_4 = 0.0004$
Case2::SMC= 500INR/MWh	$KI_1 = 0.009, KI_2 = 0.008, KI_3 = 0.009, KI_4 = 0.0009$
	Optimized value of KIi
Case1:SMC=1850INR/MWh	$KI_1 = 0.0061, KI_2 = 0.0093, KI_3 = 0.0091, KI_4 = 0.0004429$
Case2::SMC= 500INR/MWh	KI ₁ =0.0150,KI ₂ =0.0153,KI ₃ =0.000644,KI ₄ =0.000819

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