DESIGN OF FREQUENCY REGULATION SERVICE MARKET BASED ON PRICE AND DEMAND ELASTICITY BIDS

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Abstract – -- In this paper, an attempt has been made to establish a market mechanism for primary and secondary frequency regulation services in the restructured power system environment. The concept of *elasticity of offer price* and *elasticity of offer quantity* has been proposed. Such a design of offer structure helps the providers to respond to the system requirements based on the market price variations in real-time. Optimization models are proposed for auctions that incorporate service provider maximum regulation constraints and Independent System Operator (ISO) requirements for total regulation while minimizing the total procurement cost of the ISO. The selected service providers in each area receive a uniform market price and regulation services are activated by frequency deviation linked- or Area Control Error (ACE) linked-price signals. The dynamic performances of the "elasticity" based services are analyzed through the simulation of a two-step load perturbation to examine their regulation capabilities.

Keywords: Ancillary services, deregulation, frequency regulation, market design

NOMENCLATURE

i	index referring to ancillary service provider
j	index referring to control area (j = A, B)
UP	superscript for up-regulation
DN	superscript for down-regulation
f	system frequency, Hz
D_{PR}	area primary regulation requirement, p.u.MW/Hz
D_{SR}	area secondary regulation requirement
K_P	plant gain, Hz/p.u.MW, K_P=1/D and D is load-frequency constant, p.u.MW/Hz
K_r	high-pressure turbine power fraction
M_{PR}	upper bound on primary regulation, p.u.MW/Hz
M_{SR}	upper bound on secondary regulation
P_{PR}	primary regulation market price, \$/MWh-Hz
P_{SR}	secondary regulation market price, (\$/MWh)/MWh
T_g	time constant of speed governor, s
T_P	plant time constant, s, T_P=2H/fD where H is the inertia-constant, p.u.MW·s
T_r	reheat time constant, s
T_R	time constant of the hydro governor, s
T_1	time constant of the hydro governor, s
T_2	time constant of the hydro governor, s
T_t	steam-chest time constant, s
T_w	water starting time constant, s
U_{PR}	binary variable for selection of primary regulation
U_{SR}	binary variable for selection of secondary regulation
Δf	incremental frequency deviation, Hz
ΔP_D	incremental load demand change, p.u.MW
ΔP_g	incremental generation change, p.u.MW
ΔP_C	incremental consumption change, p.u.MW
ΔP_{TIE}	incremental change in tie-line power, p.u.MW
ΔX_E	incremental governor valve position change
$\Delta\rho$	ACE linked pricing signal for control, \$/MWh
γ_{PR}	primary regulation quantity offer, p.u. MW/(\$/MWh)
γ_{SR}	secondary regulation quantity offer, p.u. MW/(\$/MWh)
η_{PR}	primary regulation price offer, \$/MWh-Hz
η_{SR}	secondary regulation price offer, (\$/MWh)/MWh

1 INTRODUCTION

As a primary requirement in electrical power systems, the system frequency should be maintained at the nominal (60 Hz or 50 Hz) or within a narrow margin around the nominal for satisfactory system operation. The system frequency is dependent on the real power balance and any mismatch between the generation and demand results in frequency deviation. When the demand exceeds the supply, it is reflected by a drop in frequency. The speed governors of the generators respond to this drop by increasing their output instantaneously. This increase in generation together with some frequency sensitive load reduction helps arrest any further fall in the frequency, and is known as *primary regulation*. With primary regulation only, a change in system load will result in a steady-state frequency deviation in the system.

Restoration of the frequency to its nominal value requires a supplementary control action for adjusting the generation reference set point of selected generators, and is referred to as *secondary regulation*. This can be performed through manual adjustment (as in the Nordic countries) or Automatic Generation Control (AGC).

Primary and secondary regulations together comprise the system frequency control. Traditionally, all generators with speed governors participate in primary regulation while some selected generators participate in secondary regulation. In deregulated power systems, new paradigms for control are evolving and several of them are being managed through the ancillary services markets.

Since the generation and transmission activities operate as separate businesses, the Independent System Operator (ISO) has no direct control over generators and therefore has to procure frequency control services from them (or even from loads). In such an environment, design of proper pricing mechanism for frequency regulation services is extremely important for proper operation of the power system.

Frequency control as an ancillary service in deregulated power systems has been discussed in some of the research literature. Early in 1989, real-time pricing for the control of frequency and tie-line deviations was proposed [1]. These prices were derived from the frequency deviation and obtained through dynamic analysis of the system. Higher the frequency deviation, more would the pricing penalty be. In [2], the technical issues associated with *load frequency control* (LFC) in deregulated environment were identified and two possible solutions- the charged LFC and bilateral LFC, were proposed.

The objective of frequency control is to restore both the system frequency to nominal and the *area control error* (ACE) to zero. This can be implemented by AGC. A modified AGC scheme was suggested for price-based market operation in [3]. The AGC simulator could be applied to both pool and bilateral markets. Reference [4] follows the ideas of [3] and formulates an AGC system taking into account the effect of bilateral contracts by using the disco participation matrix. With the application of adaptive control, a new AGC scheme based on an online identification of the control area dynamic response was designed for the Spanish system in [5].

In the North American power systems, NERC guidelines provides for Control Performance Standard (CPS) based on ACE to evaluate the frequency control performance [6]. Reference [7] analyzes and compares the CPS indices used in North America, with the Regulating Help Indicator (RIH) and Indicator of Regulating Trajectory Tracking (IRTT) used in Europe and concludes that both are essentially similar and belong to the same family. All three indicators use the sign of the Δf to indicate the error direction. RIH, IRTT and CPS are respectively the expression of zero, first, and second moment of the frequency error term. Reference [8] also analyzes the CPS criteria and constructs the general criteria for frequency control performance assessment.

Reference [9] considers simultaneously energy, AGC, synchronized spinning reserve and non-synchronized reserves and provides an optimization model that enables a generator to allocate its power among these various markets to maximize its profit.

An automatic balance service market that can act as an effective tool for system frequency control in deregulated systems was presented in [10]. It was proposed that the participants in the market would respond to frequency linked price signals and provide regulation services. The present paper extends the work reported in [10] to construct price and demand elasticity based offer structure for both primary and secondary regulation services. The selected service providers are activated by frequency- or ACE-linked price signals and respond in real-time.

2 DESIGN OF FREQUENCY REGULATION MARKETS

The proposed market structure for frequency regulation service and the time-frame for operation will be described in detail in this section and is depicted in Figure 1. The proposed market operates in three stages- the first stage involves receiving offers and market settlement, the second stage involves real-time invocation of the services through actuating signals and the third stage deals with post-operational calculation of payoffs.

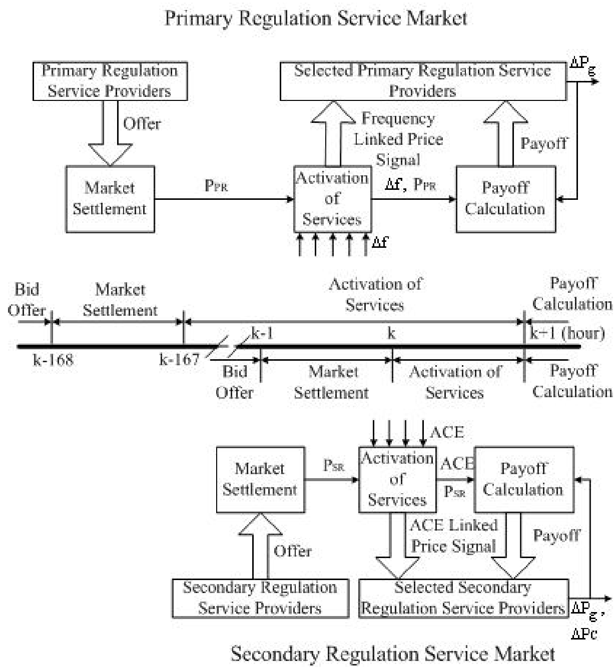

Figure 1: Primary and secondary regulation market structure and operation

The regulation service providers submit their offers which include price and quantity. For primary regulation, D is assumed constant which implies that loads do not participate in primary regulation but only offer for secondary regulation services. In primary regulation service, the regulation quantity R (in MW/Hz) of a generator is determined after the auction. The selected generators will adjust R_i to their appropriate values, while generators not selected will operate with "locked" governors and thereby not provide primary frequency regulation. In this way, generators can offer for both primary and secondary regulation, but in different time-frames. The primary regulation market operates on a weekly basis and the price remains constant for the whole week. The generators will adjust R_i weekly. However, the secondary regulation market is an hourly market where prices change hourly and generators adjust their governor set points hourly.

For example, for the service provided during the hour *k* to *k+1* (see Figure 1), primary regulation service providers will submit their offers one week in advance, *i.e.*, at hour *k-168*, and the market will be settled at hour *k-167*. The duration of the service provided by the selected generators will be of one week from hour *k-167* to hour *k+1*. The secondary regulation service providers will submit their offers one hour before the actual delivery. Hence, they will offer at hour *k-1* for the service delivered from hour *k* to hour *k+1*. The ISO determines the uniform market prices for each service provision according to the system regulation requirement and received offers by executing an optimization procedure.

Once this is complete, the selected generators are activated in real-time by price signals derived from the system frequency deviation or ACE. Finally, at the end of a given period payoffs are calculated using the market price, actual frequency deviation, and actual generation or demand change.

2.1 Primary Regulation Service

The objective of primary regulation is to keep the frequency deviation within acceptable bounds when disturbances occur.

2.1.1 Structure of Primary Regulation Offers

It is proposed here that the generators will offer for primary regulation service based on their droop characteristics. The offer from a generator *i* comprises a quantity offer $\gamma_{PR,i}$ and a price offer $\eta_{PR,i}$. However, unlike the conventional offer structure, $\gamma_{PR,i}$ is the *elasticity of quantity* per unit market price of primary regulation offered by generator *i* while $\eta_{PR,i}$ is the *elasticity of price* per unit of frequency deviation. A comparison of classical and proposed regulation structures is shown in Figure 2. The product, $\gamma_{PR,I} \times \eta_{PR,I}$ is equivalent to the classical value of $1/R_i$.

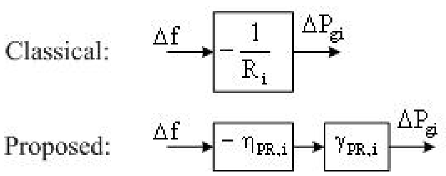

Figure 2: Classical and proposed primary regulation structures

Example: Consider a 300 MW generator that offers its services at a price of 1 \$/MWH for a 0.1 Hz change in system frequency. Further, for every 1% increase in market price it is willing to increase its generation by 2%. If the energy price is 50\$/MWh and system base is 2000 MVA, the primary regulation offer in terms of price and demand elasticity, can be written as-

$$\eta_{PR,i} = \frac{1\$/\text{MWh}}{0.1\text{Hz}} = 10\frac{\$/\text{MWh}}{\text{Hz}}$$

$$\gamma_{PR,i} = \frac{2\% \cdot 300\text{ MW}/2000\text{ MVA}}{1\% \cdot 50\$/\text{MWh}} = 0.006\ \frac{\text{p.u.MW}}{\$/\text{MWh}}$$

From the above it can be stated that the generator's *elasticity of price* is 10\$/MWh per Hz, and the *elasticity of quantity* is 0.006 p.u.MW, per unit of primary regulation price. Therefore, this is a typical offer structure from the generator.

Also note that since there is a limitation in the regulation capability of each generator, it is necessary for the ISO to incorporate an upper bound on regulation, $M_{PR,i}$.

Once all the generators have submitted their offers, the ISO organizes the offers in increasing order of their prices and the highest priced offer to intersect with the primary regulation requirement to determine the market price (P_{PR}).

2.1.2 Procurement of Primary Regulation Service

Considering that the ISO receives *N* offers from the participating generators and the uniform market price after settlement is P_{PR}, the ISO's objective in procurement of the primary regulation service is to minimize P_{PR}, while satisfying all regulation constraints.

The constraints in this optimization problem can be stated as follows:

i) System-wide regulation requirement: The ISO is required to maintain at all times a minimum amount of primary regulation capability at its disposal. This quantity is equal to the classical $\sum 1/R_i$, which is usually pre-determined and known from system studies.

$$\sum_{i=1}^{N} U_{PR,i} P_{PR} \gamma_{PR,i} \geq D_{PR} \tag{1}$$

ii) Upper limit on generator's regulation capacity: Each primary regulation service provider (generator) is also a competitive market participant. A part of its capacity is committed for scheduled generation and a part of it for the service. This constraint ensures that the regulation service from the generator is within the required limits.

$$U_{PR,i} P_{PR} \gamma_{PR,i} \leq M_{PR,i} \quad \forall \quad i = 1,\ldots,N \tag{2}$$

iii) Market price for primary regulation: This constraint ensures that the selected offer prices are less than or equal to the uniform market price, which is the highest accepted offer price.

$$U_{PR,i} \eta_{PR,i} \leq P_{PR} \qquad \forall \quad i = 1,\ldots N \tag{3}$$

2.1.3 Real Time Simulation of Primary Regulation Service

After the market settlement, the uniform market price P_{PR} is determined and sent to the selected generators. The regulation service will be activated in real-time when there is a deviation in frequency, through the frequency-linked price signal P_{PR}.

2.1.4 Payoff Calculation

After real-time, the payoffs to the service providers can be calculated by

$$Payoff_i = \sum_{i=1}^{N} (CP_i + P_{PR} * |\Delta f| * |\Delta P_{gi}|) \tag{4}$$

In (4), CP_i is the availability price of capacity. Even if there is not any frequency deviation in real time, the selected generators can still receive this portion of payoff for the provision of on call capacity. The term $P_{PR} * |\Delta f| * |\Delta P_{gi}|$ is the payoff for actual primary frequency regulation service. Since Δf and ΔP_{gi} are continuous and time-varying, the payoff has to be calculated from discrete sampled values of the two signals. Assuming k to be the number of samples in a period of time, the payoff function can be re-written as:

$$Payoff_i = \sum_{i=1}^{N} CP_i + \sum_{k=0}^{K} \sum_{i=1}^{N} (P_{PR} * |\Delta f_k| * |\Delta P_{gi,k}|) \qquad (5)$$

2.2 Secondary Regulation Service

The objective of secondary regulation service is to restore the system frequency to nominal after the disturbance.

2.2.1 Structure of Offers

In this proposed market, both generators and customers can offer for secondary regulation service based on their ability to respond quickly (*within about 10 minutes*) by increasing / decreasing the generation or consumption.

For up-regulation service, the generators offer to increase their generation while the customers offer to reduce their consumption. And for down-regulation service, the generators offer to decrease their generation while the customers offer to increase their consumption. The up-regulation offer from generator i comprises $\eta_{SR,i}^{UP}$, the *elasticity of price per unit of ACE* and *elasticity of quantity* $\gamma_{SR,i}^{UP}$ *(as in primary regulation).*

<u>Example:</u> A 1000 MW generator offers to provide secondary regulation at a price of 0.4\$/MWh for each MW of ACE change. Also it offers that the generation would respond by a 3% change for a 1% increase in market price. For an energy market price of 50\$/MWh, system base of 2000 MVA, the offer can be formulated as-

$$\eta_{SR,i} = 0.4 \frac{\$/\text{MWh}}{\text{MWh}}$$

$$\gamma_{SR,i}^{UP} = \frac{3\% * 1000\text{MW} / 2000\text{MVA}}{1\% * 50\$ / \text{MWh}} = 0.03 \frac{\text{p.u.MW}}{\$/\text{MWh}}$$

From the above it can be stated that generator's *elasticity of price* is 0.4 \$/MWh per unit ACE change and *elasticity of quantity* is 0.03 p.u.MW per unit of price change. Customers can also offer in the same structure. This is a typical offer for secondary regulation.

Also to be noted that since there is a limitation in the regulation capability of each generator or customer, it is necessary for it to supply an upper bound on regulation, $M_{SR,i}^{UP}$.

Similarly, generator i (or customer i) can offer for down-regulation based on $\gamma_{SR,i}^{DN}$, $\eta_{SR,i}^{DN}$ and upper bound $M_{SR,i}^{DN}$. Both the generators and customers are considered as secondary frequency regulation service providers.

2.2.2 Procurement of Secondary Regulation Service

The objective of the ISO managing the secondary regulation market is to minimize the uniform market price P_{SR}. The constraints in this optimization problem are similar to those of primary frequency regulation:

i) System-wide regulation requirement:

$$\sum_{i=1}^{N} U_{SR,i}^{UP/DN} P_{SR}^{UP/DN} \gamma_{SR,i}^{UP/DN} \ge D_{SR}^{UP/DN} \qquad (6)$$

ii) Upper limit on a provider's regulation capacity:

$$U_{SR,i}^{UP/DN} P_{SR}^{UP/DN} \gamma_{SR,i}^{UP/DN} \le M_{SR,i}^{UP/DN}, \quad i = 1,\ldots, \text{N} \qquad (7)$$

iii) Market price for secondary regulation:

$$U_{SR,i}^{UP/DN} \eta_{SR,i}^{UP/DN} \le P_{SR}^{UP/DN}, \qquad i = 1,\ldots, \text{N} \qquad (8)$$

2.2.3 Real Time Simulation for Secondary Regulation

After the market settlement, a uniform market price P_{SR} is determined and sent to the selected providers. The secondary regulation service will be activated in real-time through the price signal $\Delta\rho$, when there is a non-zero ACE.

The dynamic model of the two-area hydro-thermal system, with the selected generator dynamics incorporated, is shown in Figure 3.

2.2.4 Payoff Calculation

After real-time, with *MP*, the spot market price of energy, known as a priori, and the time-varying *ACE* and $\Delta P_{gi,k}$ (or $\Delta P_{Ci,k}$ for customers) the payoffs to the secondary regulation service providers can be calculated as follows:

<u>For generator:</u>

$$Payoff_i = \sum_{k=0}^{K} \sum_{i=1}^{N} (MP + P_{SR} * ACE) * \Delta P_{gi,k} \qquad (9)$$

<u>For customer:</u>

$$Payoff_i = -\sum_{k=0}^{K} \sum_{i=1}^{N} (MP + P_{SR} * ACE) * \Delta P_{Ci,k} \qquad (10)$$

3 CASE STUDY

A two-area interconnected hydro-thermal power system is used to demonstrate the proposed model for the various cases. The dynamic model of the two-area hydro-thermal system, with the selected generator dynamics incorporated, is shown in Figure 3.

3.1 Market Settlement

By using the optimization model described in Section-2, the market was settled. We consider that four generators in area-A and three generators in area-B are selected for primary regulation service. All the four selected generators in area-A receive the uniform market price of 8.5\$/MWh-Hz. The uniform market price in area-B is 8.8\$/MWh-Hz. The selected generators in both areas are shown in Table 1.

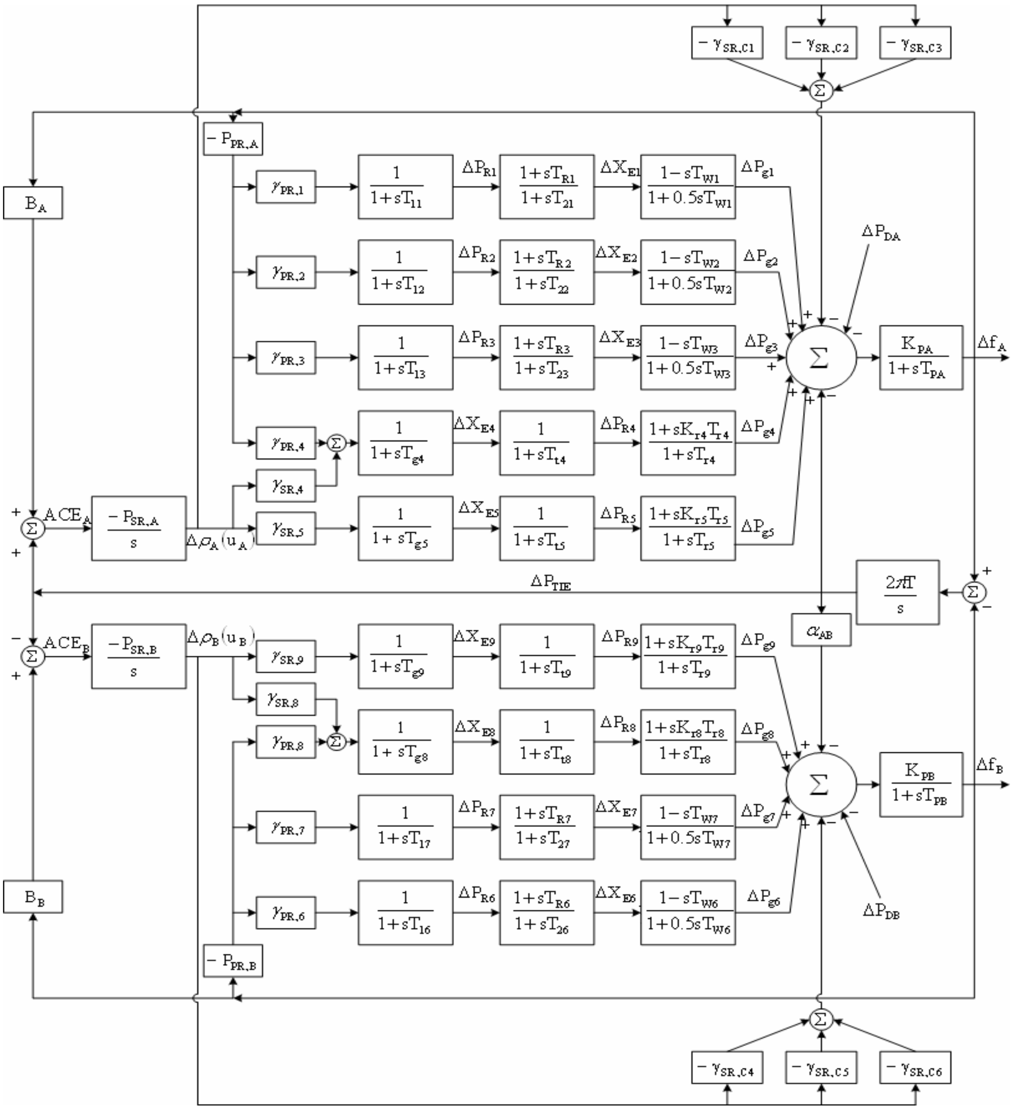

Figure 3: Dynamic model of primary and secondary frequency regulation

Area-A	Gen i	1	2	3	4
	Quantity $\gamma_{PR,i}$, p.u.MW/($/MWh)	0.004	0.008	0.015	0.012
Area-B	Gen i	6	7	8	
	Quantity $\gamma_{PR,i}$, p.u.MW/($/MWh)	0.012	0.011	0.015	

Table 1: Selected Primary Service Providers in Both Areas

The total primary regulation quantity procured by the ISO in each area is 0.33 p.u.MW/Hz and the total secondary up- and down-regulation procured is 0.035 and 0.03 respectively.

After the market settlement, all the secondary service providers in both areas are shown in Table 2. The market price in area-A for up- and down-regulation are 0.27 ($/MWh)/MWh and 0.25 ($/MWh)/MWh, respectively. The up-regulation market price in area-B is 0.30 ($/MWh)/MWh and the down-regulation market price is 0.29 ($/MWh)/MWh.

Area-A	Provider i		4	5	C1	C2	C3
	Quantity $\gamma_{PR,i}$, p.u.MW/($/MWh)	Up	0.03	0.01	0.02	0.04	0.03
		Down	0.04	0.03	0	0.02	0.03
Area-B	Provider i		8	9	C4	C5	C6
	Quantity $\gamma_{PR,i}$, p.u.MW/($/MWh)	Up	0.02	0.04	0.02	0.03	0.01
		Down	0.01	0.03	0.04	0.02	0.01

Table 2: Selected Secondary Service Providers in Both Areas

3.2 Dynamic Simulation

The system dynamic performances with the proposed frequency regulation services based on "elasticity" offers are examined through the simulation of a small perturbation model of the two-area hydro-thermal system. The transfer-function model of the system is developed in state-space form by linearizing the system around a nominal operating point (Figure 2). The model can be written as follows:

$$\frac{d\underline{X}}{dt} = A\underline{X} + \Gamma \underline{p} \quad (11)$$

In (11) $\underline{X}$ is the state-vector and $\underline{p}$ is the perturbation vector. The matrices A and Γ are state and perturbation matrices respectively, of appropriate dimensions, and depend on the system parameters and operating conditions.

It is observed from Table 3 that in area-A Gen-1, -2 and -3 provides primary regulation only; Gen-4 provides both primary and secondary regulation, while Gen-5 provides secondary regulation only. They are depicted in the transfer-function model (Figure 3). Similarly for area-B, Gen-6 and -7 provide primary regulation only, Gen-8 provides both primary and secondary regulation while Gen-9 provides secondary regulation only, and these have been shown in Figure 3. Also observe that there are three "loads" selected in each area for secondary regulation, which have been appropriately represented in Figure 3.

The system dynamic performance is studied with the above model, using the selected primary and secondary regulation service providers, for various disturbance conditions.

A two-step load perturbation is considered in area-A. The first step is a 1% increase in demand at t = 0 s and the second step is a 2.5% increase in demand at t = 10 s.

Figure 4 shows the dynamic frequency response for the two-step load perturbation in area-A. Figure 5 shows the plot of generation responses from Gen-1, -2, and -3 providing only primary regulation services. Figure 6 shows output responses of Gen-4 which provides both primary and secondary regulation services and Gen-5 which provides only secondary regulation service. Figure 7 shows the responses from customer C1, C2, and C3 which provide only secondary regulation services.

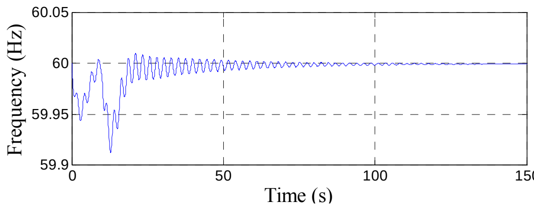

Figure 4: Frequency response in area-A following the step load changes

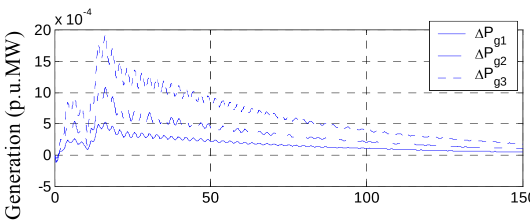

Figure 5: Primary regulation of Gen-1, -2, and -3 after the step load changes

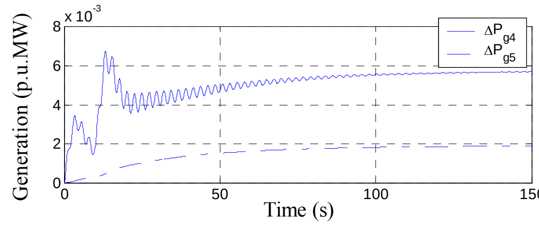

Figure 6: Primary and secondary regulation of Gen-4 and secondary regulation of Gen-5 following the step load changes

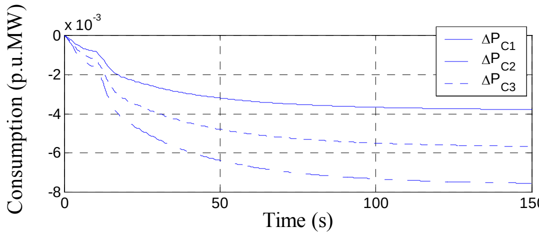

Figure 7: Secondary regulation responses of customer C1, C2, and C3 following the step load changes

Then the same two-step load perturbation is considered in area-B.

Figure 8 shows the dynamic frequency response for the two-step load perturbation in area-B. Figure 9 shows the plot of generation responses from Gen-6, and -7 providing only primary regulation services. Figure 10 shows output responses of Gen-8 which provides both primary and secondary regulation services and Gen-9 which provides only secondary regulation service. Figure 11 shows the responses from customer C4, C5, and C6 which provide only secondary regulation services.

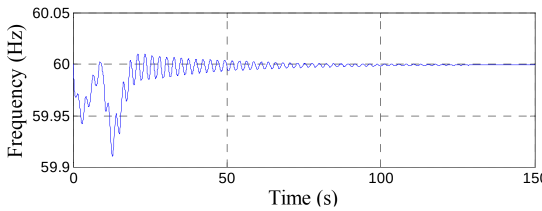

Figure 8: Frequency response in area-B following the step load changes

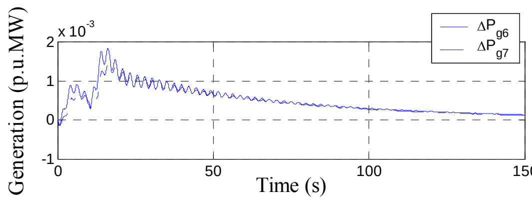

Figure 9: Primary regulation of Gen-6, and -7 after the step load changes

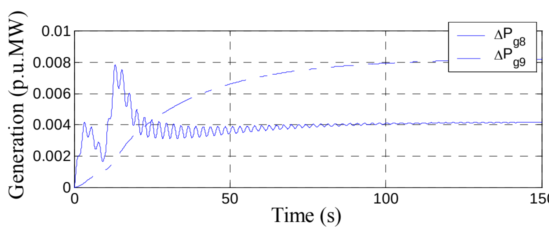

Figure 10: Primary and secondary regulation of Gen-8 and secondary regulation of Gen-9 following the step load changes

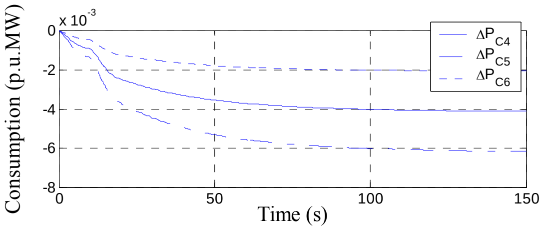

Figure 11: Secondary regulation responses of customer C4, C5, and C6 following the step load changes

It is seen from Figure 4 and Figure 8 that the frequency deviation is within 0.1 Hz and the system frequency is restored to the nominal after the perturbation in both scenarios. The selected services providers adjust their output in proportion to their offer quantities.

3.3 *Calculation of Payoffs*

The payoffs to the participating services providers under the two-step load perturbation in area-A are shown in Table 3. It can be observed that secondary regulation service providers from area-A are paid significantly higher than the other area providers. This is because the step load changes take place in area-A and the secondary control effort is essentially from this area's providers.

Area-A	**Generator**					**Customer**			
Provider *i*	1	2	3	4	5	C1	C2	C3	Total
Primary, $	0.71	1.41	2.66	2.13	-	-	-	-	6.91
Secondary,$	-	-	-	18.92	6.27	13.08	26.17	19.63	84.07
Area-B	**Generator**					**Customer**			
Provider *i*	6	7	8	9		C4	C5	C6	Total
Primary, $	2.20	2.03	2.75	-		-	-	-	6.98
Secondary,$	-	-	2.47	1.00		1.39	0.69	0.35	5.90

Table 3: Payoffs for Step Load Changes in Area-A

The payoffs to the participating services providers under the two-step load perturbation in area-B are shown in Table 4. However, the secondary regulation service providers from area-B are paid significantly higher than the providers from area-A in this case because the perturbation takes place in area-B and the secondary control effort is essentially from this area's providers.

Area-A	**Generator**					**Customer**			
Provider *i*	1	2	3	4	5	C1	C2	C3	Total
Primary, $	0.69	1.38	2.61	2.08	-	-	-	-	6.76
Secondary,$	-	-	-	2.42	1.01	0	0.70	1.04	5.17
Area-B	**Generator**					**Customer**			
Provider *i*	6	7	8	9		C4	C5	C6	Total
Primary, $	2.16	2.00	2.70	-		-	-	-	6.86
Secondary,$	-	-	13.92	27.18		14.40	21.59	7.20	84.29

Table 4: Payoffs for Step Load Changes in Area-B

4 CONCLUSION

This paper establishes a primary and secondary frequency regulation service auction mechanism that is based on price and demand elasticity offers. Such a design helps the providers accurately estimate their capability to provide the services depending on the market price. Optimization models are proposed for both primary and secondary regulation services. Furthermore, a comprehensive dynamic model of a two-area interconnected hydro-thermal power system with multiple generators in each area together with provision for customers providing secondary regulation service has been developed. Simulations have been carried out considering a two-step load perturbation to examine the primary and secondary frequency control capabilities of the selected providers. Finally, a comprehensive payoff calculation exercise is carried out to determine the payoff to each service provider.

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