# EFFECTS OF ANCILLARY SERVICE MARKETS ON FREQUENCY AND VOLTAGE CONTROL PERFORMANCE OF DEREGULATED POWER SYSTEMS

By

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To the Faculty of Washington State University:

The members of the Committee appointed to examine the thesis of JYOTIRMOY ROY find it satisfactory and recommend that it be accepted.

________________________________________
Chair

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# Abstract

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In this thesis we have presented different ancillary service markets for frequency and voltage control and analyzed the effect of such markets on the control performance of power systems.

First we have created different market structures for balancing (regulation) markets. Since the automatic generation control (AGC) to control frequency is quite standardized, we do not change the control but only the market structures and study their effect on frequency control performance. We have shown that by changing the market structure and incorporating generator ramp rates into the market design, a more desirable control performance can be achieved.

Next, we have shown that provision for bilateral load following is viable within the conventional AGC framework. In this arrangement the market has not been changed, rather the control has been modified to accommodate the market. We have shown that the proposed method exhibits faster frequency response than separate third party frequency control.

Finally we have looked at the feasibility of VAr markets. For voltage/VAr control, secondary control methods are still evolving and there are few markets in operation. So we have proposed a new control method as well as market structures. In a

comparative study for feasibility of generator VArs we have shown that it is difficult to avoid locational advantage (and hence, market power) for certain generators.

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## Dedication

*This work is dedicated to my parents*

# Chapter 1. Introduction

## *1.1 General*

Ancillary services are those necessary to sustain the basic operation of power systems provided by generators and transmission control equipment. While the number of potential services is large, the following services are recognized in the major power systems as ancillary services and are asked from those who are capable of providing them:

- Energy imbalance equalization
- Frequency regulation
- Spinning reserve generation
- Supplementary reserve generation
- Reactive power supplied from generators
- Black start

The function of the frequency regulation service is to maintain the frequency of the system at the specified value. At the heart of frequency regulation is the Automatic Generation Control (AGC). Whenever there is a random variation in system load, the frequency and tie line interchanges deviate from its scheduled value. It is the AGC that senses the deviations and brings the values of frequency and tie line interchange back to normal by re-dispatching the generators under control. For safe operation of the power system, voltage at the network buses is required to be within certain admissible limits. The objective of secondary voltage control is to maintain the voltage over the network within these limits by managing the reactive power supplied by generators.

In a deregulated environment generation, transmission and distribution systems are owned by separate organizations. Competitive markets have been developed where Load Serving Entities (LSE) can buy energy from Independent Power Producers (IPP).

Similar markets exist for ancillary services but the structures of such markets vary widely influenced by rules and regulations of the region. More often than not, these markets are designed to maximize the financial interest of certain parties, seldom paying attention to the engineering capabilities of the underlying power system. Here, in this work, we have shown that taking the engineering aspects of the network components into account may improve control performance of the system, which often influences the financial aspects in direct or indirect fashion.

## *1.2 Thesis Objective*

In this thesis we have focused our attention on balancing markets, which includes regulation and load following, and secondary voltage control markets to analyze the effect of different markets for these ancillary services on control performance of the power system. The primary objective is broken down into the following subtasks:

1. Studying the existing frequency and voltage control markets and the measure of control performance
2. Identifying the attributes that influences control performance of the system and possible improvements
3. Analyzing short and long term impacts of market structures under discussion

## *1.3 Thesis Outline*

This thesis is organized in three chapters as follows:

In Chapter 2 we have analyzed the influence of regulation market structures on frequency control performance of a system. We have presented comparative studies to examine whether existing markets should be changed and exploiting available control options can result in a more desirable performance. In a separate section we have presented a method to unify the responsibility of regulation and load following under classical Automatic Generation Control (AGC). The method described here uses the AGC system to dispatch both regulation and load following in real-time. Subsequently, feasibility of a competitive market for load following is discussed.

In Chapter 3 we have looked into secondary voltage control. In an attempt to capture the impact of VAr markets and associated secondary voltage control methods on voltage control capability in terms of controllability, performance and economics of the system, two methods of automatic secondary voltage control have been looked into in this work, voltage control by adjusting the reference voltage of generators and voltage control by adjusting the reactive power injection at the generator bus. Feasibility of competitive markets in VAr using the above mentioned generation based voltage control methods have been examined thereafter.

Appendix A illustrates the reduced WECC model which has been used for the simulations. Appendix B elucidates the method of dividing the network into a number of voltage-control areas.

# Chapter 2. Effect of Balance Markets on Frequency Control Performance

## *2.1 Preface*

Regulation is one of the ancillary services (AS) traditionally provided by the generating units, under the jurisdiction of a balancing area (BA), to continually compensate for the difference between load and generation. After the advent of deregulation, there has been much effort to form competitive markets for regulation. These markets have usually been markets for capacity reserves and have variously been called regulation, balancing, load-following, frequency control or even combined with spinning reserve markets. For simplicity we call it the regulation market throughout this paper. While the method of frequency control and load following has to be precisely defined within an interconnection, the structures of the regulation markets vary greatly. In North America, some regulation reserve markets have been developed for secondary control. The payment is for capacity made available, up and down, fully dispatchable within 10 minutes [1], the energy supply being compensated at spot market rates. In some areas there is no separate regulation market and part of the spinning reserve is used for secondary frequency control. In England and Wales, where automatic secondary control is not used, there is a power exchange system with a 30-minute short-term market for balancing, operating one hour ahead of real time. There, only a few generators are called upon for frequency response replacing free governor action by all generators. Likewise, regulation markets exist in Australia, Nordic countries, continental Europe, China and other countries; however, the frequency performance standards are influenced heavily by regional policies and grid rules [1].

To design such markets financial factors have so far played more important roles than technical considerations. Besides there are other issues, which have come into discussion recently [2]-[4], e.g. the problems of involving more suppliers in the market or allocating payments to the participants which reflect the impact of each participant in the market. There also has been lack of insight about how solutions to such problems are going to affect the system as a whole.

In this chapter we present a comparative analysis on the models of regulation markets. We assume that the balancing authority has secondary control or Automatic Generation Control (AGC), i.e. uses tie-line bias control. We also put forward a systematic control strategy to improve the frequency response.

In the next section the market models have been described. Section 2.3 has a brief description of the traditional AGC. In section 2.4 a case study on WECC 225-bus model has been presented and the effects of the markets on its control performance have been compared vis-à-vis.

## 2.2 Regulation Market

All markets can be designed with many variations and regulation markets are the same. To show how such variations can affect system performance we first lay out the structure of three example regulation markets in this section. These three are briefly described below.

A. A flat-rate regulation market – This is the most common type of regulation market that exists (the California market is described in [5]). The features are as follows:
   - 10-minute regulation market, i.e. any spinning unit under AGC control can bid the capacity it can make available in 10 minutes.
   - No distinction according to ramp rates of the generators.
   - Uniform second price payment i.e. all qualified suppliers are paid at the rate of Market Clearing Price (MCP).

B. A price based regulation market – The generators are paid based on the performance in the market.

- 5-minute or 10-minute regulation market
- Generators are categorized as fast or slow as per the ramp rates.
- The fast ramp generators are paid according to the regulation MCP whereas slow ramp generators are paid according to their bid price as long as it is less than the regulation MCP.

C. A response based regulation market – Two separate markets for fast ramp regulation and slow ramp regulation.

- 5-minute market for fast ramp regulation
- 10-minute market for slow ramp regulation.
- Generators are allowed to participate in the respective market which its ramp rate corresponds to.
- Generators are paid at the rate of clearing price of the market they participate into.

All the generators participating in the regulation markets mentioned above are required to meet certain technical and operating requirements. Primary control by governor action is mandatory for participation. The full response of the bid capacity is required to be delivered in the dispatch interval (10 or 5 minutes as applicable). Thus the regulation bid capacity of each supplier is dependent on its ramp rate. This last point is very important since this establishes the connection between market outcome and consequent control performance.

To bid (as shown in Figure 2-1) in the markets, each supplier specifies three quantities in the bid: 1) capacity, 2) price in \$/MWh, and 3) operational ramp rate in MW/min. The markets are cleared for every dispatch interval during the trading interval ahead of real time.

The market may be formulated as single auction power pool (Figure 2-2) where only suppliers bid in the market or double auction power pool, where suppliers' bids are cleared against customers' offers [6]. We assume single auction pool for all markets considered.

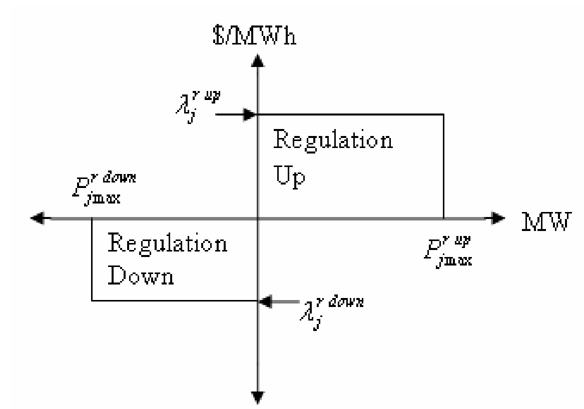


**Figure 2-1: Regulation market bid.**

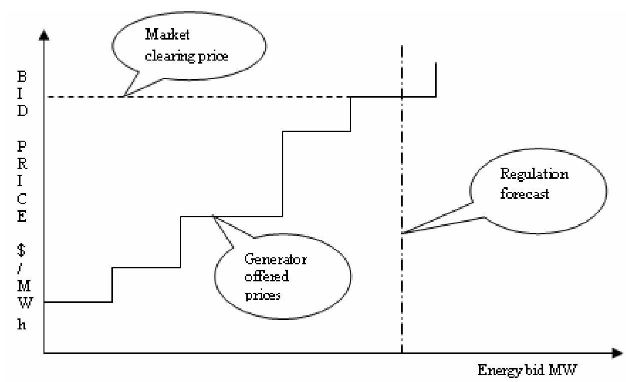


**Figure 2-2: Market clearing in single auction pool**

Type A market is most straightforward and followed at many places of North America and North Africa. The simple nature of such a market makes it attractive; however there is good reason for suppliers not to participate in such market as it does not differentiates among the participants and pays a flat price irrespective of their performance. Type B market on the other hand solves that problem and introduces the performance based pricing. The qualified generators receive market payment at the rate of their bid price except the fast ramp generators which are paid at the rate of MCP. Since the MCP is the maximum possible payment available in auction market, recipients get away with an amount of incentive for their service. Type C market is somewhat similar to the contingency reserve market, only the control here is on a longer time frame. The separation of fast and slow ramp generators makes it possible to call upon the appropriate service depending on the magnitude of the disturbance. It is also possible to use a combination of these services for cost effectiveness. There is no need of added incentive since separate markets would take care of it automatically.

## 2.3 Frequency Control

The function of the regulation market is to select a set of generators to provide the service and to allocate the amount of regulation each are supposed to provide at the time of need. The real-time regulation would be performed by Automatic Generation Control (AGC) to keep the frequency of the system within safe operating limits and the interchanges between the areas at the scheduled value.

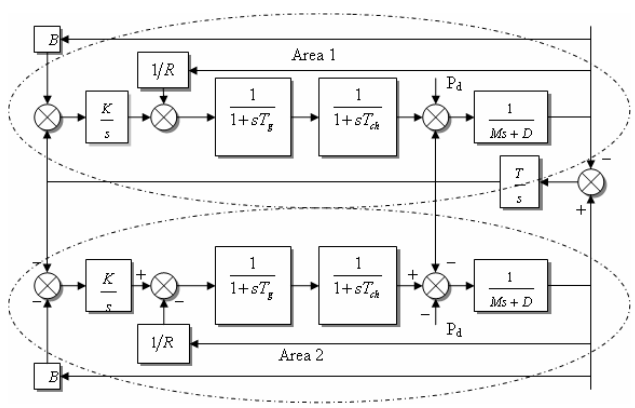


**Figure 2-3: Classical ACG for two control areas**

For the purpose of modeling it is assumed that the generators in a control area are tied together closely, electrically. As a result they oscillate together under minor disturbances. If the deviations in frequency and load are small enough, each control area can represented as the linear approximation [7] as shown in the Figure 2-3.

While modeling the individual generators (Figure 2-4), it is to be remembered that there are limits on the rate at which generators can move their output due to thermal and mechanical stress on the equipments. The ramp rate of hydro units are of the order of 100% of the rated capacity within minutes. However, the ramp rates of thermal units are limited and thermal turbines can be approximated as shown in Figure 2-5.

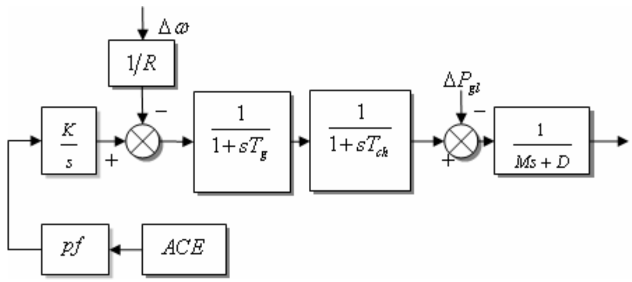


**Figure 2-4: Model of generator with classical AGC**

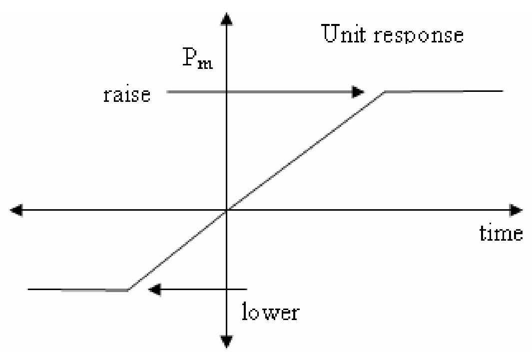


**Figure 2-5: Output of rate limited units**

We define the performance vector η to express the frequency control performance of the markets described earlier as:

$$\eta = \begin{bmatrix} \Delta f_{max} \\ t_s \\ t_c \end{bmatrix} \qquad (1)$$

Where, $\Delta f_{max}$ is the maximum deviation of system frequency after the disturbance, $t_s$, settling time is the time taken by AGC to bring the frequency back within safe limits, and

$t_c$, crossover time is the time taken by ACE to cross zero for the first time after the disturbance.

## *2.4 WECC Case Study*

The proposed markets have been simulated on a reduced WECC model with 225 buses where the California ISO (CAISO) and LADWP are represented in more detail than the rest. The network has been divided into three balancing areas (BA1 to BA3), which are summarized below in Table 2-I. All three areas are interconnected to each other with tie lines.

The markets are set up on area BA3 where all of the 40 generators submit their bid in the regulation market. The market goal is to procure 600MW up and 200MW down regulation capacity at a total load of 25000MW for the hour. The bid prices have been obtained from the generator cost curves which are of the form $C\left(P\right)=a+bP+cP^2$ and the dispatch level as per the Optimal Power Flow (OPF).

It may be pertinent to mention here that in reality the bids submitted by the participants depend on a large number of market factors. Also, the payment of bid price instead of the clearing price may change the way suppliers submit bids. Our assumption of bid price being same as the marginal cost of generation irrespective of the market is solely to present a comparative idea about the impact of different market structures in a common framework.

*a) Market Settlement*

*i) Type A and B 10-minute markets*

The outcome of settlement for 10-minute regulation market of type-A and type-B are same as far as the generators and contracted quantities are concerned. As expected the market payment for type-B is less than that of type-A. The final contracts are shown in

Table 2-II. It can be observed that the procurement resulted in 6 contracts; the effective ramp rate of the system is 61 MW/min.

**Table 2-I: Summary of control area parameters**

| Area code | No. of generators | H (p.u) | D (% per 1% f) |
|---|---|---|---|
| BA1 | 13 | 1685 | 1.06 |
| BA2 | 9 | 637 | 0.26 |
| BA3 | 40 | 1076 | 0.91 |

*ii) Type B 5-minute market*

The settlement of the type-B 5-minute regulation market is shown in Table 2-III for the same market goal. 15 generators are contracted for regulation which is noticeably higher than the earlier case. The reason of higher number of generators being accepted in a 5-minute market is due to the fact that in a market with shorter dispatch interval the generators are able to bid less for a given ramp rate. The effective ramp rate for the system resulting from the market is 140 MW/min.

**Table 2-II: 10-min market – Regulation contracts and prices**

| Gen# | Cost of generation (c, b, a) | Contracted Regulation | |
|---|---|---|---|
| | | Up/Down (MW) | Ramp rate (MW/min) |
| 6 | (0.00378, 20, 0 ) | 70, 0 | 7 |
| 8 | (0.00224, 20, 0 ) | 90, 0 | 10 |
| 15 | (0.00343, 20, 0 ) | 80, -80 | 8 |
| 16 | (0.00768, 20, 0 ) | 80, -80 | 8 |
| 17 | (0.00193, 20, 0 ) | 200, -40 | 20 |
| 20 | (0.030600, 20, 0) | 80, 0 | 8 |

ISO's burden from these contracts

| | |
|---|---|
| Total payment | Type A: 23226.00 $/h |
| | Type B: 23113.20 $/h |
| Clearing Price Up | 38.71 $/MWh |
| Clearing Price Down | 22.03 $/MWh |

*iii) Type C market*

Type C market is comprised of a 5-minute fast ramp market and a 10-minute slow ramp market. The markets are settled separately each procuring half of the regulation goal. The separate markets for fast ramp regulation and slow ramp regulation are shown in the Table 2-IV and Table 2-V. The two markets separately result in 8 contracts and total market payment is 23200.50 $/h.

**Table 2-III: 5-min market – Regulation contracts and prices**

| Gen# | Cost of generation (c, b, a) | Contracted Regulation Up/Down (MW) | Contracted Regulation Ramp rate (MW/min) |
|---|---|---|---|
| 4 | (0.00487, 20, 0 ) | 100, 0 | 20 |
| 5 | (0.00591, 20, 0 ) | 15, 0 | 3 |
| 6 | (0.00378, 20, 0 ) | 35, 0 | 7 |
| 8 | (0.00224, 20, 0 ) | 30, 0 | 10 |
| 9 | (0.00223, 20, 0 ) | 30, 0 | 6 |
| 15 | (0.00343, 20, 0 ) | 40, -40 | 8 |
| 16 | (0.00768, 20, 0 ) | 40, -40 | 8 |
| 17 | (0.00193, 20, 0 ) | 100, -100 | 20 |
| 20 | (0.0306, 20, 0) | 40, -20 | 8 |
| 23 | (0.00395, 20, 0 ) | 40, 0 | 8 |
| 24 | (0.00222, 20, 0 ) | 25, 0 | 5 |
| 25 | (0.01017, 20, 0 ) | 40, 0 | 8 |
| 28 | (0.00595, 20, 0 ) | 30, 0 | 6 |
| 29 | (0.00769, 20, 0 ) | 20, 0 | 20 |
| 35 | (0.04504, 20, 0 ) | 15, 0 | 3 |

| ISO's burden from these contracts | |
|---|---|
| Total payment | 23541 $/h |
| Clearing Price Up | 39.70 $/MWh |
| Clearing Price Down | 22.03 $/MWh |

It is important to note here that the number of contracted generators changes as the market structure changes. The appropriateness of any particular market model for a region depends on certain factors. Apart from economic policies mandated by the market operator and regulatory organization, availability of resources and willingness of suppliers would play an important role to decide the right choice of market for a particular region. It can be seen by comparing the 5-minute and 10-minute markets of type-A and type B that a shorter dispatch interval results in an increase in the number of generators participating in AGC. Now, a direct impediment to form a 5-minute regulation market may simply be bid insufficiency, since everyone bids into the market only what they can deliver in 5 minutes. In such a scenario a reasonable choice would be to keep a 10-minute market overall and add a premium to the single market's regulation price for capacity that can be delivered in 5 minutes.

**Table 2-IV : 5-minute fast ramp regulation market**

| Gen # | Cost of generation (a, b, c) | Contracted Regulation Up/Down (MW) | Ramp rate (MW/min) |
|---|---|---|---|
| 4 | (0.00487, 20, 0 ) | 100, 0 | 20 |
| 8 | (0.00224, 20, 0 ) | 30, 0 | 10 |
| 17 | (0.00193, 20, 0 ) | 100, -100 | 20 |
| 30 | (0.00600, 20, 0 ) | 70, 0 | 20 |

| ISO's burden from these contracts | |
|---|---|
| Total payment | 11700.30 $/h |
| Clearing Price Up | 39.70 $/MWh |
| Clearing Price Down | 22.03 $/MWh |

**Table 2-V : 10-minute slow ramp regulation market**

| Gen# | Cost of generation (a, b, c) | Contracted Regulation Up/Down (MW) | Ramp rate (MW/min) |
|---|---|---|---|
| 6 | (0.00378, 20, 0 ) | 60, 0 | 3 |
| 15 | (0.00343, 20, 0 ) | 80, -80 | 8 |
| 16 | (0.00768, 20, 0 ) | 80, -20 | 8 |
| 20 | (0.0306, 20, 0) | 80, 0 | 8 |

| ISO's burden from these contracts | |
|---|---|
| Total payment | 11500.20 $/h |
| Clearing Price Up | 38.71 $/MWh |
| Clearing Price Down | 22.03 $/MWh |

Besides, there are more choices available for controlling these generators to optimize the system frequency response. In the next section we will observe how these different markets and control systems can affect the system performance.

*b) Performance consideration*

Generators selected in the market as described above provide regulation and the AGC assigns regulation load to each selected generator according to some preset participation factors (pf) or regulation factors. There may be four ways to determine these participation factors.

- Equal participation factor for all units
- Proportional to ramp rate of the units
- Proportional to bid capacity of the units
- Inversely proportional to marginal cost of generation

The following cases demonstrate ways to determine participation factors and corresponding system response for a load disturbance of 1 p.u in BA3.

*i) Type A & Type B 10-min markets*

10-minutes markets of both type A and B have essentially same performance for the reason that the contracted generators are same in both cases. Depending on the method of determining the regulation participation the system response can vary. The following Table 2-VI summarizes the response of 10-minute market with four control schemes mentioned above that choose the participation factors differently.

**Table 2-VI: Performance comparison of four controls**

| Participation | $\Delta f$ (%) | $t_s$ (s) | $t_c$ (s) |
|---|---|---|---|
| Equal | -0.1445 | 350 | 112 |
| Ramp rate | -0.13 | 185 | 96 |
| Bid capacity | -0.13333 | 225 | 92 |
| 1/Marginal cost | -0.14167 | 350 | 110 |

Noticeably, frequency response is best when the participation factors are proportional to ramp rate. The reason is, with such participation factor every generator is moved by an amount which is equal to $ramp\ rate \times dispatch\ interval$.

*ii) Type B 10-min & 5-min markets*

The different dispatch interval of the markets result in a difference in number of generators contracted and amount of service bought from each of them. A 10-minute market yields 6 contracts whereas a 5-minute market yields 15 contracts. Consequently the effective ramping capacity of the system is higher after the later comes into effect. As can be seen from the Figure 2-6, Figure 2-7, Figure 2-8 and Figure 2-9, the frequency response of the 5-minute market is faster for all the four participation methods.

The amount that a generator can bid in the market depends on the ramp rate of the generator. In case every generator gets its full bid capacity accepted in the market, 2nd and 3rd participation factors are essentially same. But a generator's bid may be partly accepted in the market. In that case the control system with 2nd participation method would be different than 3rd participation method.

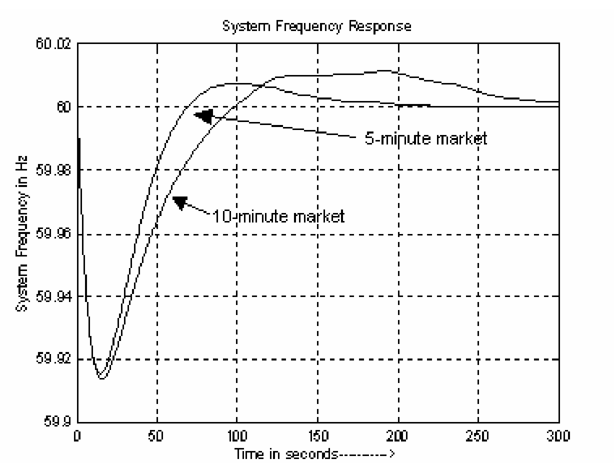


**Figure 2-6: Frequency response with equal pf**

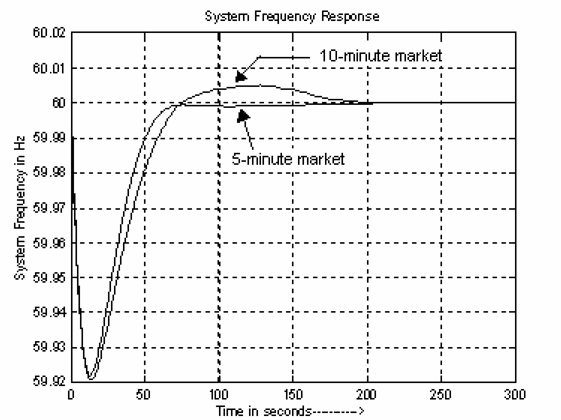


**Figure 2-7: Frequency response with pf proportional to ramp rate**

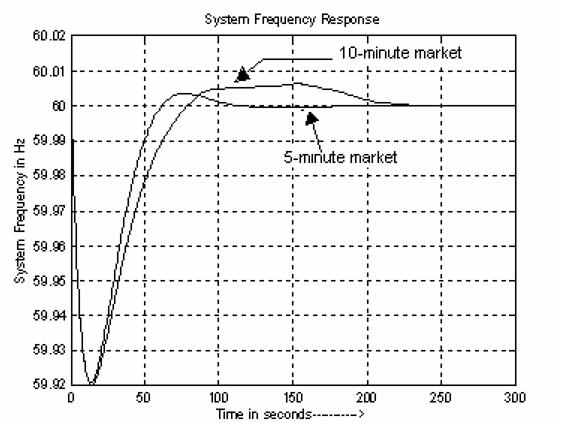


**Figure 2-8: Frequency response with pf proportional to bid capacity**

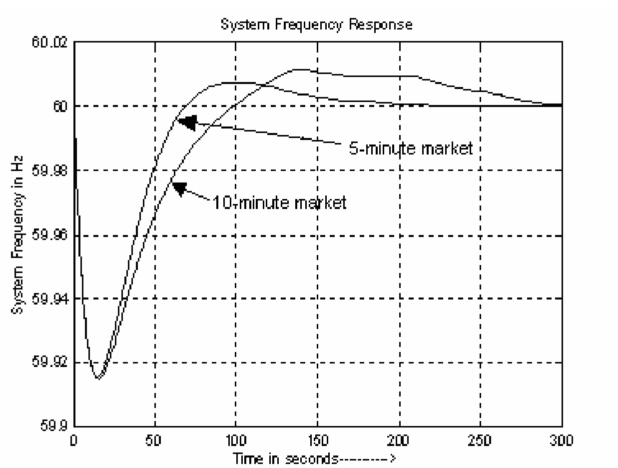


**Figure 2-9: Frequency response with pf inversely proportional to marginal cost**

The Table 2-VII shows the summary of the effect of four participation methods on a 5-minute market.

**Table 2-VII: Performance comparison of four controls**

| Participation | $\Delta f$ (%) | $t_s$ (s) | $t_c$ (s) |
|---|---|---|---|
| Equal | -0.14167 | 220 | 76 |
| Ramp rate | -0.13 | 150 | 100 |
| Bid capacity | -0.13333 | 175 | 76 |
| 1/ Marginal cost | -0.14167 | 221.1 | 78 |

The crossover time is important in systems where ACE is expected to change signs within a certain time. In North America, NERC imposes statistical bounds on the value of ACE and the operators are responsible to maintain the values within these limits.

*iii) Type C market*

Unlike the previous two markets, type-C has separate markets for fast ramp and slow ramp regulation. To procure a certain amount of regulation from such a market one has to decide how much of fast and slow service are to be bought. Then there are multiple options available as to how to use them in time of need. For the purpose of our study we have procured half of the regulation from each of the fast and slow markets. While using the resources to follow the load we have looked into four scenarios using:

- Fast ramp only
- Slow ramp only
- Fast and slow together
- Immediate use of fast, then slow service

For a load disturbance of 1p.u, it is possible to bring the frequency back to normal with fast generators alone, as shown in Figure 2-10 and Figure 2-11a.

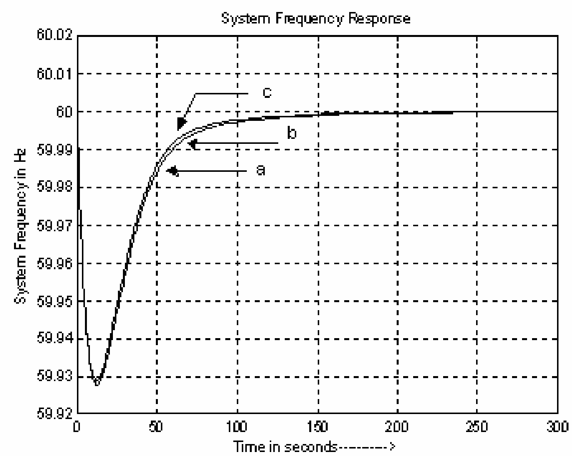


**Figure 2-10: Regulation response with fast generators only with: a. Equal participation, b. Ramp rate based participation, c. Bid capacity based participation**

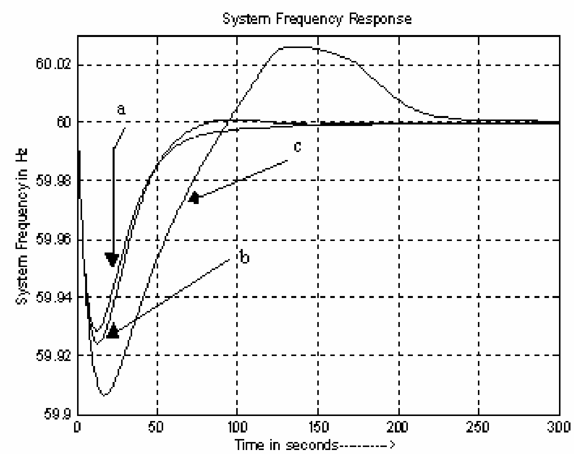


**Figure 2-11: Regulation response with a. only fast, b. 50-50 fast & slow, c. only slow generators**

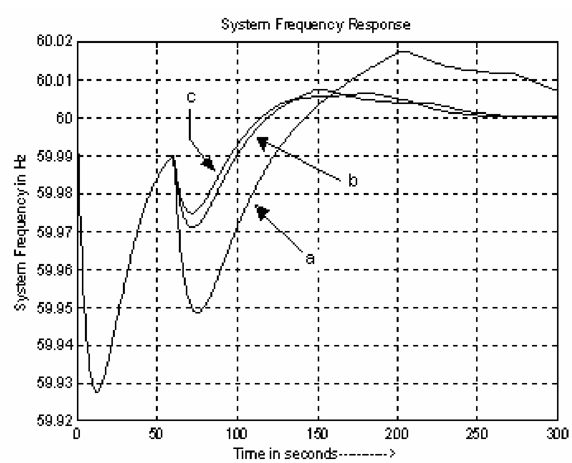


**Figure 2-12: Regulation with fast response for 1minute and thereafter, a. slow only response b. 25% fast–75% slow combination, c. 50% fast–50% slow response**

If only slow generators are used instead, the recovery of frequency is very slow and takes a long time to settle down (Figure 2-11c). But combined together the fast and slow generators can recover the frequency quickly and smoothly (Figure 2-11b). The latter response is almost the same as in Figure 2-11a. which only uses the fast response generators.

In a typical case the operator may not wish to exhaust the fast service completely and call the slow resources to take up the remaining of the regulation load. Though the fast market is designed to sustain the service for 5 minute, for the simulation purposes some part of the fast resources are relieved after 1 minute of the occurrence of the disturbance. Figure 2-12 shows that a. if only slow generators are used for regulation after 1 minute the frequency response is quite slow, b. and c. if a combination fast and slow generators are used, is possible the recover the frequency within the dispatch interval. The response of case c. is smoother than that of b. because of more fast generators.

Together these cases show that the structure of the regulation market has a direct effect on the control performance of the system. Since the maximum amount of regulation that a generator can deliver in the market depends directly on its ramping capability, the amount of service (capacity) bought in the market also affects the system response. The more the procurement, the more would be the number of generators taking part in regulation, and better would be the frequency response. An increased participation of the generators with faster ramp rates can also be achieved by reducing the dispatch interval. The added advantage is more competition and less stress on generators.

Also it is necessary to incorporate some payment method which would reflect the effect of each supplier on the system performance. Splitting up the payment according to the ramp rates of the generators as in the type-B market can solve that issue.

Forming separate markets for fast ramp and slow ramp regulation service can open up a lot of possibilities. Not only does it differentiate among the suppliers as per their rate of response, but also the payment is decided in an easy and competitive manner.

It is necessary to say that the right choice of market will somewhat depend on the idiosyncrasies of a particular geographical region, e.g. availability of resource or capacity. Once a suitable market has been formed there are also certain choices available for control to optimize the performance. In a type-C market it is necessary to decide how much of fast and slow service to be procured and the historical profile of use of regulation in the area under consideration will play an important role in that division. Apart from that it is also possible to decide on the amount of each service to be used depending on the magnitude of the disturbance.

## *2.5 Remarks*

In this section we have demonstrated that the structure of the regulation market has a direct effect on the control performance of the system. Three different market structures were chosen to demonstrate the varying control performance on a reduced WECC system. Although the first market structure is similar to what is used by the California ISO today, the other two were chosen somewhat arbitrarily to show that control performance can be improved by providing more incentives for generators with better response (ramp) rates. However, the actual market structure will have to take into account the actual response rates of available generators. For example, whether a 5-min regulation market can actually be developed depends on the types and capacities of generators willing to be part of such a market. We do show that price based or ramp rate based regulation markets can be formed to:

i) Increase competition
ii) Encourage generators with incentive
iii) Explore more control options to optimize performance

Existing regulation markets are flat priced and does not recognize the difference among suppliers or reward them appropriately. As the regulation market provides control, we believe that such markets should make the necessary changes that are needed to elicit the best control performance possible.

## 2.6 Accommodating Third Party Load Following into Classical AGC

Regulation and load following, both addresses the time varying characteristics of balancing the generation and load under normal operating condition. While regulation matches the generation with minute-to-minute load change, load following uses the generation to meet hour-to-hour and daily variations of load [8]. Though restructured markets after deregulation recognize regulation and energy, load following is not a recognized service.

In a restructured power system independent competitive generating units are allowed to enter into bilateral transactions with Load Serving Entities (LSE) and industrial consumers. When these loads come online, Area Control Error (ACE) detects the change and accordingly units are dispatched by AGC. However, if the loads ramp up too fast, ACE becomes too large and it takes a long time for the frequency to recover. Hence, the larger the variation in load, the more it endangers the dynamic stability of the system. Also as an aftereffect of large values of ACE future regulation estimates are increased, which in turn increases the cost of procurement. For that reason it is desirable to quantify the load following requirement and keep the regulation procurement as low as possible.

Recent impetus for facilitating load following as an ancillary service has led to the conception of a new “AGC like” scheme [9] where a decentralized market for this ancillary service has been proposed, suggesting procurement of load following through bilateral contracts. Thus ISO is relieved from this burden and ultimate responsibility for performance is moved to the supplier.

In an alternative approach, load following can still be procured in a bilateral market while ISO will control response of each supplier to ensure acceptable performance. To incorporate this centralized control over bilateral exchange it is necessary to integrate third party load following with the usual AGC. In the next section we present a method to provide load following service in the existing framework of AGC by changing the method of calculation of ACE and unit error. Then a comparative study between the proposed method and the separate third party control shows the effectiveness of this method in terms of control performance of the system.

### *2.6.1 AGC with Third Party Load Following*

Let us consider a power system where control areas are connected via tie lines. In classical AGC system the ACE after a disturbance is calculated from the change in scheduled interchange flows and frequency [7], [10] as follows:

$$ACE = \Delta P_{Tie} + B\Delta\omega$$

The change in tie line flow is nothing but the difference between the generation and load in the area given by:

$$\Delta P_{Tie} = \sum \Delta P_G - \sum \Delta P_L$$

The control signal to a unit is then given by:

$$u_t = pf \times (ACE_t + \int_0^{t-1} ACE_\tau d\tau)$$

The participation factors *pf* are empirical for a particular system.

Let us now assume that generators inside the control area enter into bilateral contracts with loads. For any generator with real power output $P_{Gi}$ and bilateral load $P_{Bi}$ the instantaneous unit control error (CE) is:

$$CE_i = P_{Gi} - P_{Bi} + \left( D_i + \frac{1}{R_i} \right) \Delta\omega$$

If the generator also takes part in regulation with a participation factor *pf* the instantaneous unit control error would be:

$$CE_i = P_{Gi} - \left(P_{Bi} + pf \bullet P_R\right) + \left(D_i + \frac{1}{R_i}\right)\Delta\omega$$

Now, taking sum over all the control errors inside the area we get:

$$\sum_{area} CE_i = \sum_{area} P_{Gi} - \left(\sum_{area} P_{Bi} + \sum_{area} pf \times P_R\right) + \sum_{area}\left(D_g + \frac{1}{R_g}\right)\Delta\omega$$

$$\sum_{area} CE_i \approx \sum_{area} P_{Gi} - \left(\sum_{area} P_{Bi} + \sum_{area} pf \times P_R\right) + \left(D_{area} + \frac{1}{R_{area}}\right)\Delta\omega$$

Hence $$\sum_{area} CE_i \approx \Delta P_{Tie} + B\Delta\omega$$

The signal to a participation unit can be written as: $u_t = CE_t + \int_0^{t-1} CE_\tau d\tau$

It can be seen that the ACE for an area in classical AGC system is equivalent to the sum of all the unit control errors in that area. Consequently it is possible to dispatch the bilateral load along with the regulation load simultaneously without changing the AGC control structure. Although it would be necessary to calculate the control error for each and every generator in that area and all the transactions with the generators have to be accounted for. It is also possible for the generators to take part in contracts across the control area boundary as would be demonstrated in the following simulation results.

### *2.6.2 Case Study*

The control scheme has been simulated on an experimental three-area system as shown in Figure 2-13. The areas have two, three and four generators respectively. The summary of the three balancing areas are shown in Table 2-VIII. Bilateral contract of generator G3 is in area 3.

The frequency response of the system has been shown in Figure 2-14. For the sake of comparison the response of third party control [9] on the same system is also shown. It can be seen that the proposed scheme bring the frequency back to normal effectively. Comparing the response times of the two schemes mentioned, it can be seen that load following AGC is faster.

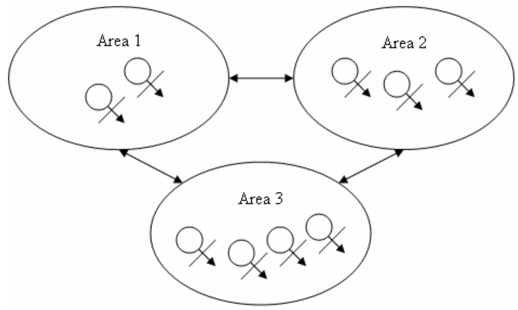


**Figure 2-13: 3-area system connected via tie lines**

In the proposed method there is no ACE since CE is calculated for each supplier and close to the aggregated value of bilateral and regulation load. Figure 2-15 and Figure 2-16 demonstrates that the maximum values of CE and ACE are, in fact, comparable. Hence, such a scheme, if implemented, can be configured to perform within the NERC specified control performance criteria.

**Table 2-VIII : Summary of three balancing areas**

| | Area 1 | | Area 2 | | | Area 3 | | | |
|---|---|---|---|---|---|---|---|---|---|
| Generators | G1 | G2 | G3 | G4 | G5 | G6 | G7 | G8 | G9 |
| AGC | ✓ | ✓ | ✓ | × | ✓ | × | ✓ | ✓ | ✓ |
| Bilateral Load | 0 | 0.2 | 0.1 | 0 | 0.2 | 0 | 0 | 0.1 | 0.1 |
| Reg. load | 0.5 | | 0.2 | | | 0 | | | |
| Reg. pf | 0.5 | 0.5 | 0.5 | 0 | 0.5 | 0 | 0.33 | 0.33 | 0.33 |

Another advantage of AGC with third party load following is that a generator which takes part in bilateral contract can participate in regulation too. In area 1 two generators are on AGC and one of them has bilateral load. In Figure 2-17, it shows that with third party control the regulation load is supplied solely by G1 since G2 has a bilateral load. But with load following AGC the regulation load is shared by both G1 and G2 depending on their regulation participation factor (Figure 2-18). The bilateral load is served by G2 alone. Hence, load following AGC helps more generators to take part in regulation making the frequency response faster.

Figure 2-19 and Figure 2-20 show the area 2 generations under the two different control schemes. The regulation load is supplied only by G3 in Figure 2-19 but in Figure 2-20, the regulation is shared by G3 and G5 since G4 is not on AGC. In both cases G3 serves a bilateral load in area 3. Figure 2-21 and Figure 2-22 show the generation response in area 3. In all instances the generators which are not on AGC reduce their output to zero at the steady state.

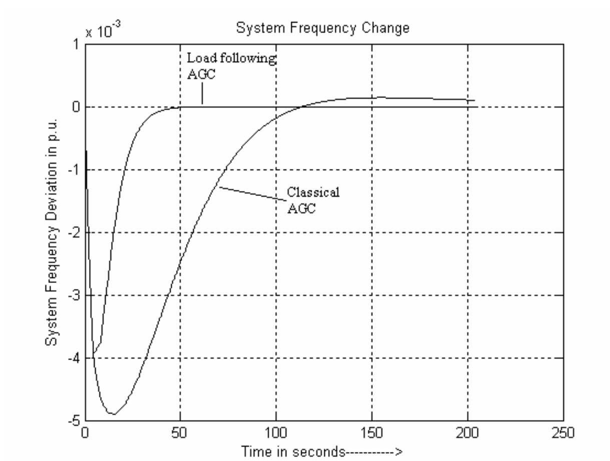


**Figure 2-14: Frequency response a) classical AGC and third party control b) load following AGC**

It is imperative for implementation of such control that all the generators entering in a bilateral contract should be on AGC even if they are not taking part in regulation. That implies almost all the generators in the network should have the communication facility to receive command from AGC.

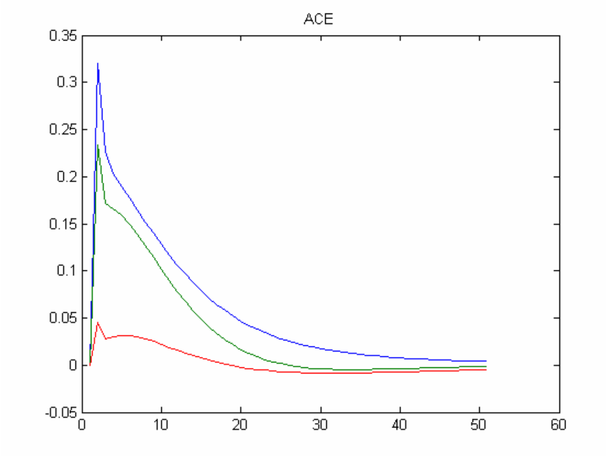


**Figure 2-15: ACE for three areas with classical AGC and third party control**

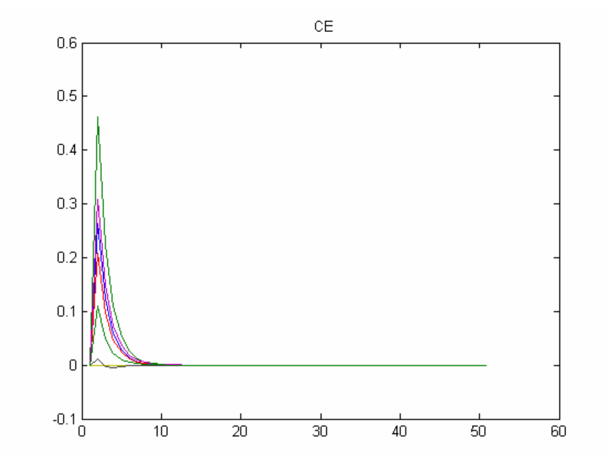


**Figure 2-16: CE for 10 generators with load following AGC**

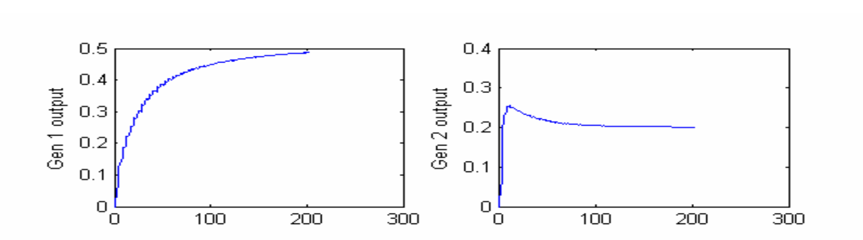


**Figure 2-17: Area 1 generation – third party control**

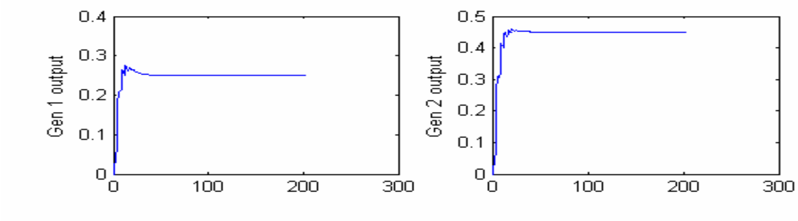


**Figure 2-18: Area 1 generation – load following AGC**

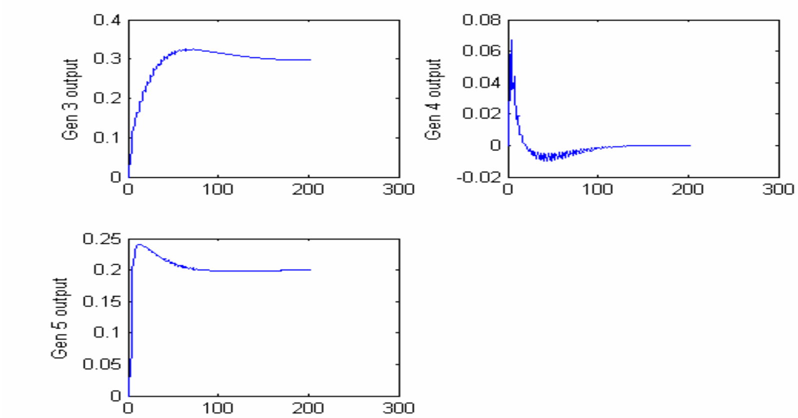


**Figure 2-19: Area 2 generation – third party control**

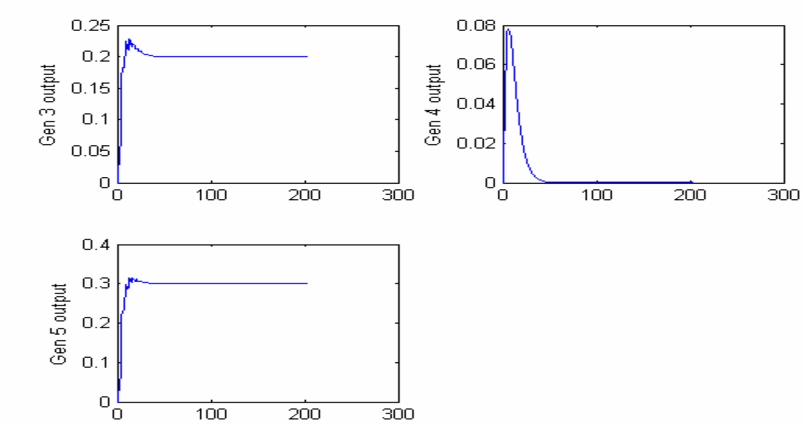


**Figure 2-20: Area 2 generation – load following AGC**

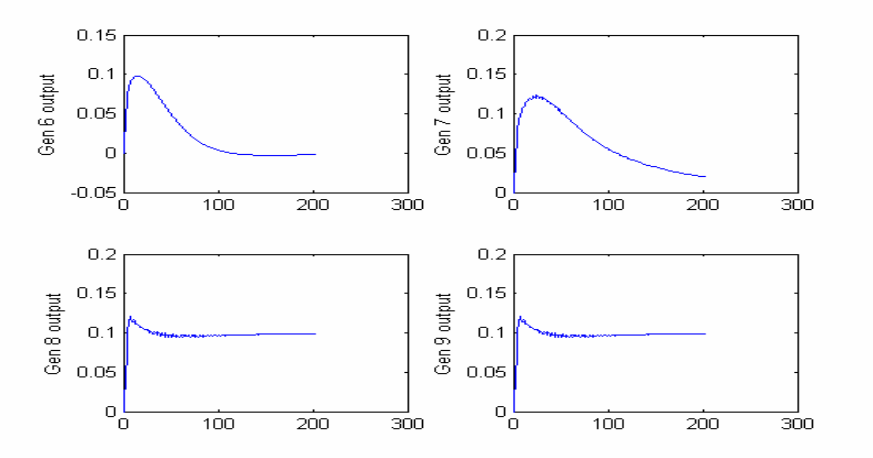


**Figure 2-21: Area 3 generation – third party control**

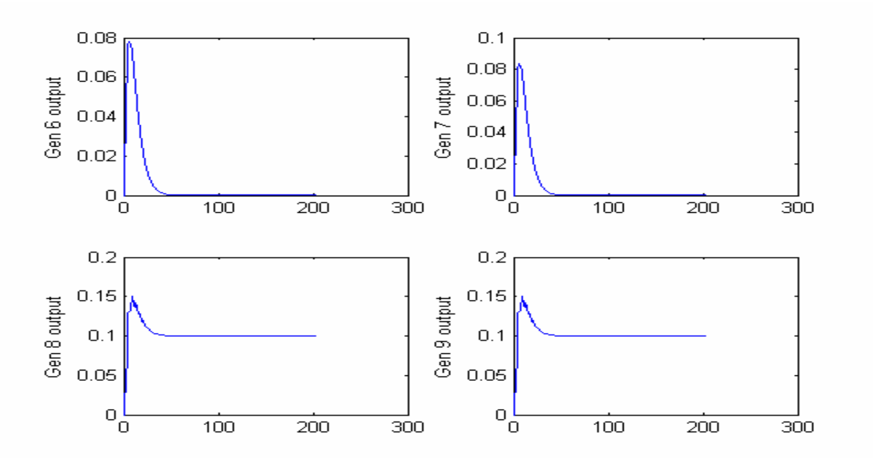


**Figure 2-22: Area 3 generation – load following AGC**

## *2.6.3 Remarks*

The results of the experiment described above show that proposed load following AGC scheme can be used for frequency control. With bilateral load following integrated with the AGC, frequency can be brought back to desired value faster than separate third party control and with reasonable smoothness. Both regulation and bilateral loads can be served with such a control without the need of additional control hardware. Since every transaction is cleared by the System Operator, such scheme does not bring any additional burden, rather it becomes convenient to monitor the performance of individual service providers and maintain the power quality.

It is to be noted that by fixing the participation factor at a proper value the regulation participation of a generator in the system can still be controlled. The local control loop for third party control would force the output of a generator at its contracted value. Consequently the generators entering into bilateral contracts would not be able to participate significantly in regulation. Such restrictions are not present when bilateral load following is integrated with the AGC. As a result a supplier can take part in both markets if it wishes to do so. The ways in which the regulation participation can be determined is discussed in detail in the previous section.

In case a generator enters into a bilateral contract with a load outside the territory of the control area it has to be under control of the AGC of the area where the load is situated. In that case it would be expected that the generator would not take part in regulation in the home control area, because that would create conflict among two AGC signals.

The necessity to recognize load following as an ancillary service has already been discussed and addressed in the literature. The current deregulated market does not recognize load following. As a result the operation and maintenance cost for dispatching the units to follow the ramping loads accrue on the price on energy. Hence it is necessary to define and quantify load following service in the new market system and that will help to procure this service in a competitive manner and reduce overall price of energy. With the proposed scheme a load following market can be formed where the service would be procured as bilateral contracts between the supplier and load, yet the ultimate responsibility for performance would be on the hand of ISO or the equivalent authority. Alternatively a short term load following market may also be developed in this framework. Generators can competitively bid for a certain amount of load following service in such a market and ISO can procure the service for a given market goal.

# Chapter 3. Feasibility of VAR Markets for Secondary Voltage Control

## *3.1 Preface*

From the system perspective, the task of voltage control can be organized into a three level hierarchy, primary, secondary and tertiary. The primary voltage control is essentially a local control whose objective is to keep the voltage at the local bus at specified value using the automatic voltage regulator (AVR) of the generating unit. The secondary voltage control, often automatic centralized control, coordinates the actions of the voltage regulators of the generating units in a region of the network, and targets to keep the voltages at multiple buses in that region at the proper level. The tertiary control is manual control used to coordinate and optimize the reactive power flow across networks. The overall task of all three controls is to maintain a proper voltage level over the network, to reduce congestion and to minimize transmission losses.

The provision of primary voltage control is compulsory in most power systems all over the world as it is necessary as part of the connection requirement to the grid (just as the primary frequency control by generator governor is mandatory). In some regions (Europe, China) secondary voltage control is being used sometimes even with a tertiary control that coordinates the secondary [11-12]. This service is sometimes paid a regulated price or via bilateral contract, but there has never been a competitive market for it. Secondary voltage control, on the other hand, is not a compulsory service and has been implemented in only a handful of European countries [13]-[15]. The system operator or ISO determines the reserve requirement and procures the reactive power resources through bilateral contracts or pay as bid contracts.

In recent works to investigate the feasibility of voltage control ancillary service markets it has been shown that area voltage control is especially suitable to form competitive markets for secondary voltage control due to its relatively local nature [16]. To implement such control, the network has been divided into a number of independent and uncoupled regions, called Voltage Control Areas (VCA) [17]. The voltage profile inside the VCA is then maintained by controlling the voltage reference set point of the generators in that region.

Here through experiments we have shown that formation of a VAr market is possible with a similar method of voltage control by adjusting the reactive power generation at the units. The difference of this method from the earlier scheme is that a direct VAr set point is sent to the unit instead of voltage reference. In a case study of the same power system mentioned earlier, the feasibility of VAr markets with both types of control methods has been investigated side by side.

Apart from the voltage control methods described earlier, which are devoted means of secondary control, voltage at the load buses in a radial network can also be controlled by using automatic tap changing transformers. In modern power systems transformers on the load buses are under the direct control of the ISO and when voltage variation at the load buses are relatively small these are corrected by coordinated adjustment of tap changers. Due to limited capability transformer tap control may be used only as the preliminary tool of voltage control after a substantial disturbance occurs. The responsibility then can be taken over by the other specialized secondary voltage control. Before we turn our attention to area wise voltage control, application of a centralized tap changer control has been explained and demonstrated in the next section. In section 3.3 voltage support by area voltage control methods have been elucidated in detail.

## 3.2 Voltage support by Transformer Tap Control

### 3.2.1 Problem formulation

The centralized control of tap changers in a network is shown in Figure 3-1. With controllable transformer buses present in the system, all the buses in the system can be categorized into three basic types, viz. PV or generator buses, PQ or load buses and TC or transformer controlled buses. Table 3-I shows the known and unknown variables for each type of bus. TC buses are similar to PQ buses except the voltage is fixed at upper or lower limit and the tap ratio is varied to keep the voltage constant at that value. Consequently the tap ratio is unknown at a TC bus.

**Table 3-I: Known and unknown variable at different buses**

| Bus type | PV | PQ | TC |
|---|---|---|---|
| Known | P, V | P, Q | P, Q, V |
| Unknown | δ, Q | δ, V | δ, t |

The desired tap ratio can be calculated by solving the power flow. For each bus the power flow equations are given by:

$$P_i = P_{gi} - P_{Li} + \sum_{j=1}^{N} V_i Y_{ij} V_j \cos\left(\delta_i - \delta_j - \theta_{ij}\right)$$

$$Q_i = Q_{gi} - Q_{Li} - \sum_{j=1}^{N} V_i Y_{ij} V_j \sin\left(\delta_i - \delta_j - \theta_{ij}\right)$$

The Jacobean is calculated as:

$$J = \begin{bmatrix} \frac{\partial P}{\partial \delta} & \frac{\partial P}{\partial V} & \frac{\partial P}{\partial t} \\ \frac{\partial Q}{\partial \delta} & \frac{\partial Q}{\partial V} & \frac{\partial Q}{\partial t} \end{bmatrix}$$

The system operator has to monitor all the transformer buses for violation. When a violation occurs the controller will determine desired tap ratio and send it as a control signal to the respective bus.

It is important to note here that this type of control can have cascaded effects on the network. Change in tap ratio at one transformer can trigger voltage events at some neighboring buses. Consequently a number of complete control cycles may be needed before the all buses are at proper voltage level.

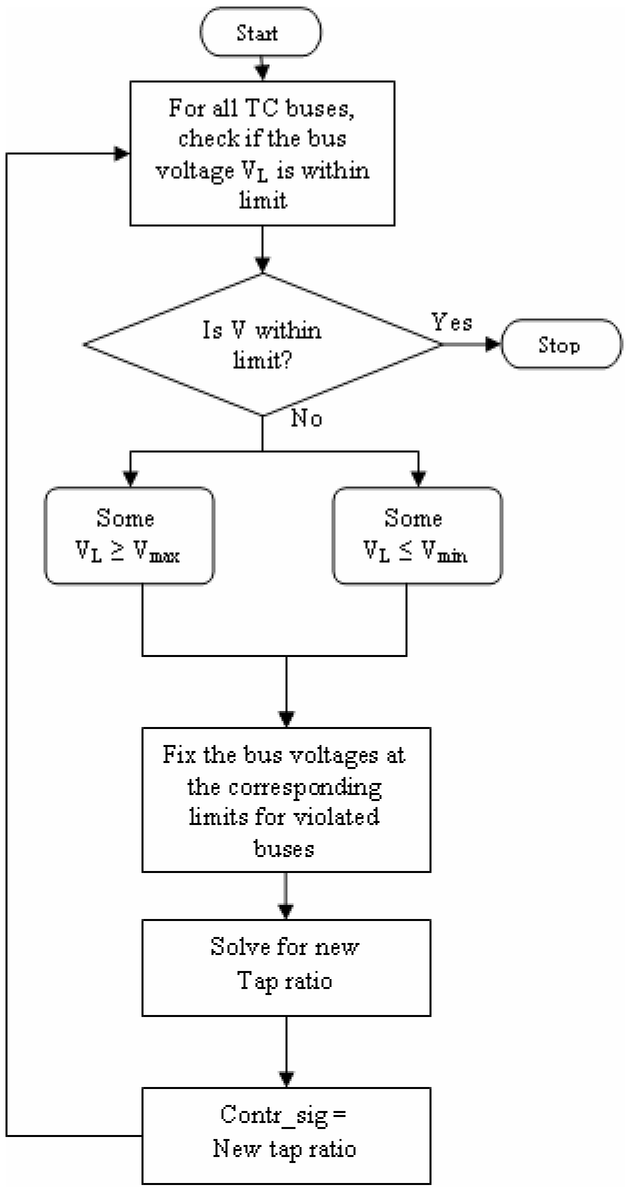


**Figure 3-1: Automatic adjustment of tap changers**

There are also upper and lower limits on tap ratios of a transformer. Naturally, voltage control capability of this scheme is limited by the range of the tap changer. Hence such scheme can not be expected to take up the absolute responsibility of voltage control in a network, rather it can work as a preliminary control which would come into effect before other secondary voltage control are deployed. For example, once the system is perturbed and the voltages at the load buses fall outside the reliability limits, tap changer control may be deployed to correct the voltages at the buses which are equipped with tap changing transformers, and then the reactive injection at the generator buses can be controlled to correct the remaining violations.

### *3.2.2 Case study*

The control method has been tested on the same WECC 225-bus model that has been mentioned in the frequency control sections. For the sake of convenience the admissible limits are assumed to be $V_{\max} = 1.06$ and $V_{\min} = 0.94$ .

Table 3-II shows the load buses which are outside the admissible range at the steady state condition and the voltage after the tap changers have been modified. The initial and final values of the tap ratios at the transformer are shown in Table 3-III.

**Table 3-II: Buses voltages before and after tap changer control**

| Bus No | Initial | Final |
|---|---|---|
| 55 | 0.935 | 0.94 |
| 61 | 0.93 | 0.94 |
| 67 | 1.076 | 1.047 |
| 68 | 1.073 | 1.06 |
| 71 | 1.069 | 1.059 |
| 143 | 0.932 | 0.942 |
| 146 | 0.923 | 0.94 |
| 184 | 0.935 | 0.942 |
| 187 | 0.917 | 0.94 |

The limited voltage control capability of tap changers makes it suitable for small voltage variation at the load buses. If the voltage variation is large more dedicated voltage control methods like the ones described in the subsequent sections are necessary to take over the control. Hence it can act as the preliminary tool to condition the network for reactive injection control or voltage reference control.

**Table 3-III: Tap ratios before and after the control action**

| From bus | To bus | Tap ratio | |
|---|---|---|---|
| | | Initial | Final |
| 52 | 51 | 1.0017 | 1.001 |
| 53 | 51 | 1.0017 | 1.001 |
| 54 | 51 | 1 | 1.001 |
| 54 | 51 | 1 | 1.001 |
| 56 | 55 | 1.0106 | 0.934 |
| 56 | 55 | 1.0106 | 0.934 |
| 60 | 61 | 1.0133 | 1 |
| 68 | 67 | 0.9873 | 1.002 |
| 69 | 68 | 1.0238 | 1.07 |
| 69 | 68 | 1.0238 | 1.07 |
| 72 | 71 | 1.0234 | 1.022 |
| 140 | 143 | 1 | 0.993 |
| 145 | 146 | 1 | 0.942 |
| 151 | 187 | 1 | 0.929 |
| 151 | 187 | 1 | 0.929 |
| 151 | 187 | 1 | 0.929 |
| 183 | 184 | 1 | 0.983 |
| 183 | 184 | 1 | 0.983 |

### *3.2.3 Remarks*

The purpose of the above example is to demonstrate that small voltage disturbances in a network load buses can be eliminated by systematic control of transformer tap changers. The control of these transformers is under direct supervision of ISO. However, no market formation is feasible since transformers in a network are owned by the transmission companies.

## 3.3 Voltage support by Area Voltage Control

Unlike AGC in previous sections, voltage control is almost always done locally (i.e. primary control) and only a few regions, mainly in Europe and China, have implemented secondary control. It is unlikely that an auction market can be set up with only primary control (although bilateral contracts are common), so we assume secondary control in our control schemes here. In this section we show that voltage control performance will be affected by two factors:

- Methods of control implementation
- Methods of setting up the market

### A. Methods of control

Method of control may typically be either manual or automatic. In the scope of this discussion, we shall focus our attention on the automatic control of reactive power dispatch level of the generators on the network. The automatic area voltage control can be implemented by:

- Adjusting the voltage reference set point of the controlling units
- Adjusting the VAr injection at the point of dispatch of the generator

*Scheme 1:*

The control method and logic of voltage reference adjustment is well discussed in [16]. For the sake of simplicity it is assumed that voltage control areas (VCA) can be formed in a network that are largely uncoupled and have little effect on the voltage at the buses in the neighboring VCA s. To make sure that an acceptable voltage profile is maintained throughout the network all the load (PQ) buses are continuously monitored and if the voltage at a monitored bus falls outside the permissible limits the controller would automatically generate an appropriate error signal proportional to the violation.

When there are violations at multiple buses the largest violation would set the error signal.

$$\varepsilon = \max(V_i - V_{limit}), \quad i = 1 \ldots N_{PV}$$

The error signal is then converted to appropriate control signal with the help of a set of weighting factors and used to adjust the voltage references of the generators.

*Scheme 2:*

This control scheme (shown in Figure 3-2) determines the error in the same way. The control signal is generated from the error signal by using the sensitivity of the controlling units towards the error signal. Assuming there are $N_G$ number of controlling units in the VCA and violation $\Delta V$ at bus $i$ to be the maximum magnitude amongst all the violations in the area, the control signal for each generator can be formed as:

$$cs_j = \Delta V \Big/ \left( \frac{\partial V_i}{\partial Q_j} \right), \quad j = 1 \ldots N_G$$

The value of the reactive sensitivity can be used from the ones derived for separation of VCA s [17]. The new level of reactive power generation at controlling unit $j$ can be expressed as:

$$Q_{g_{j\,new}} = Q_{g_{j\,old}} + K_j * \frac{\Delta V}{\left( \partial V_i \big/ \partial Q_j \right)}$$

The participation of each controlling unit can further be controlled by another set of weighting / participation factors $K_j$, which can be determined based on the individual characteristics of each generators inside the area. As the quantity $cs_j$ may not be essentially zero, the K factors for units outside a VCA can be made zero to prevent them from participating in the control action. It is also possible to distribute the responsibility of control over a multiple VCA s by setting nonzero values to the participation factors.

Though the end results of both control schemes are maneuvering of reactive reserve, scheme 2 has some transparency in term of VAr, since the operating target of the controlling unit would always be explicitly defined. The reactive generation level of the unit is not known beforehand when the controlling quantity is the voltage reference.

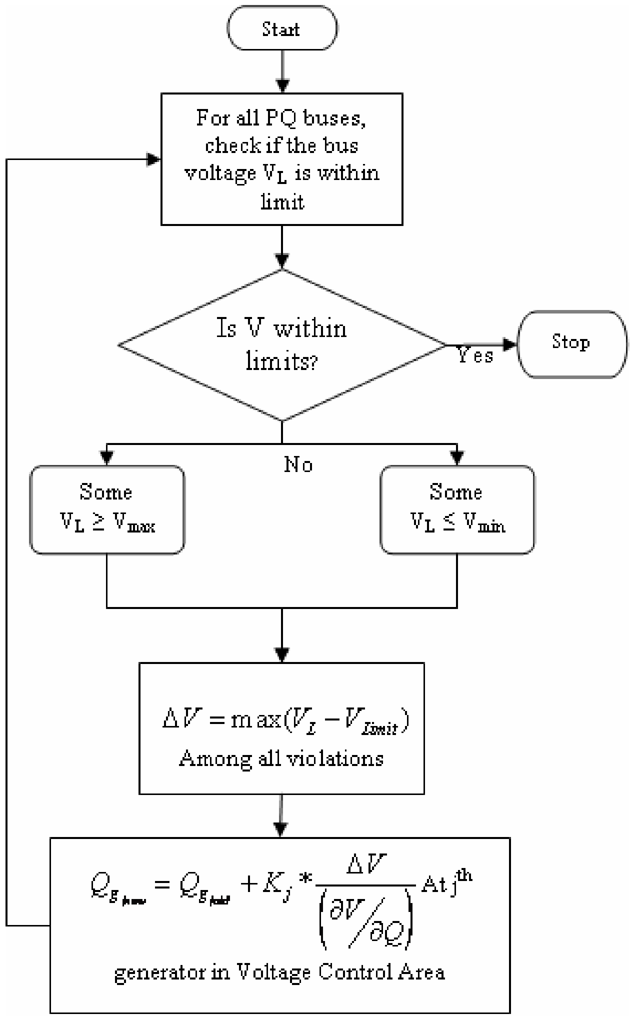


**Figure 3-2: Automatic adjustments of reactive injection**

### *B. Ancillary Market*

The payment expectation of a generator in an ancillary VAr market comprises of two components (Figure 3-3).

- A cost component proportional to capacity made available
- A second order cost component to account for the lost opportunity

As a requirement for connection to the grid generators are required to be able to operate within a specified power factor limits while serving the load. This usually is not considered as an ancillary service, and no payment is associated with it.

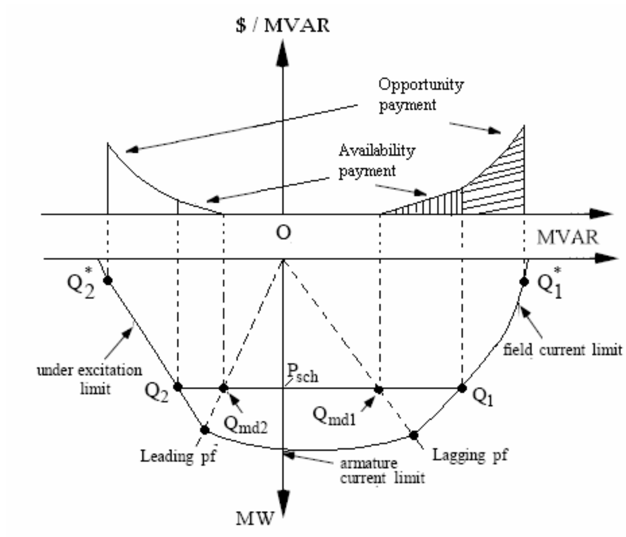


**Figure 3-3: Ancillary service zone and payment**

Following this payment method a VAr market can be set up on top of the above mentioned control scheme as follows.

*Voltage control market* – For the control scheme 1 the reactive power level of the generator is not known beforehand. Hence voltage levels can be determined from the generator capability curve and payment would be for the VAr needed to maintain the reference voltage so that the reactive power in within the ancillary service range.

*VAr control market* – For the control scheme 2, the reactive power output is explicitly specified. Hence a direct VAr market can be formed with payment for maintaining the VAr output of the generator in the ancillary service range.

Procurement from these markets can be decided by a regular auction method within each VCA. It may be desirable to coordinate the voltages across the VCAs through a modified Optimal Power Flow [18], sometimes called tertiary control, but we do not consider this in our experiments here

## 3.4 Case Study

Proposed control schemes were tested on the reduced WECC model described earlier. Among 225 buses represented in the system 40 are generators. As an initial condition all the load buses except the boundary buses are held between the permissible values of $V_{\max} = 1.08\, p.u.$ and $V_{\min} = 0.985\, p.u.$ respectively. To implement area voltage control the network has been divided in 24 VCAs. The simulations are focused on the central California region, VCA#16 consisting of 37 buses, 8 of which are controlling units. The names and types of the buses are shown in Table 3-IV. Using summer 2004 loading data as the base case the load profile of the entire network was increased by 10%. The voltage reference $V_{ref}$ at the controlling units and the reactive power injection MVAr values at the steady state are shown in the Table 3-V. The voltage at load buses #121, #133, #195, #199 and #204 are found to be 0.978, 0.962, 0.936, 0.925 and 0.949 respectively. Initially 0.925 drives the control. Starting from this condition control has been implemented to bring the voltage back within admissible range. First automatic voltage reference correction of controlling units (A) has been used, and then area voltage control with automatic reactive injection adjustment (B) has been implemented.

*A. Voltage reference adjustment*

The voltage sensitivity to reactive injection at the 8 controlling units for the 5 load buses are shown in the Table 3-VI. It can be seen that Gen #110, #198 and #218 are most influential. Hence natural participation factors of these units are higher than the others in a perturbation.

**Table 3-IV: VCA#16 bus type and location**

| Bus # | Type |
|---|---|
| 110 | Gen. Bus |
| 111 | Load Bus |
| 116 | Gen. Bus |
| 117 | Load Bus |
| 118 | Gen. Bus |
| 119 | Load Bus |
| 121 | Load Bus |
| 122 | Load Bus |
| 132 | Load Bus |

| Bus # | Type |
|---|---|
| 133 | Load Bus |
| 134 | Load Bus |
| 173 | Load Bus |
| 192 | Load Bus |
| 193 | Load Bus |
| 195 | Load Bus |
| 198 | Gen. Bus |
| 199 | Load Bus |
| 202 | Load Bus |

| Bus # | Type |
|---|---|
| 204 | Load Bus |
| 210 | Gen. Bus |
| 211 | Load Bus |
| 212 | Load Bus |
| 213 | Load Bus |
| 214 | Load Bus |
| 215 | Load Bus |
| 216 | Load Bus |
| 217 | Load Bus |

| Bus # | Type |
|---|---|
| 218 | Gen. Bus |
| 219 | Gen. Bus |
| 220 | Load Bus |
| 221 | Load Bus |
| 222 | Load Bus |
| 223 | Load Bus |
| 224 | Load Bus |
| 225 | Load Bus |
| 226 | Gen. Bus |

**Table 3-V: Steady state condition after the perturbation**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.013 | 36.52 |
| 116 | 1.05 | 948.64 |
| 118 | 1.035 | 1504.01 |
| 198 | 1.035 | 366.87 |
| 210 | 1.035 | 290.76 |
| 218 | 1 | 613.35 |
| 219 | 1.007 | 835.99 |
| 226 | 1.035 | 129.17 |

**Table 3-VI: Voltage to reactive injection sensitivity**

| | Bus #121 | Bus #133 | Bus #195 | Bus #199 | Bus #204 |
|---|---|---|---|---|---|
| Gen #110 | 0.021 | 0.017 | 0.036 | 0.029 | 0.028 |
| Gen #116 | 0.005 | 0.001 | 0.024 | 0.021 | 0.022 |
| Gen #118 | 0.005 | 0.001 | 0.024 | 0.021 | 0.022 |
| Gen #198 | 0.017 | 0.012 | 0.048 | 0.038 | 0.037 |
| Gen #210 | 0.006 | 0.001 | 0.04 | 0.035 | 0.039 |
| Gen #218 | 0.014 | 0.012 | 0.023 | 0.018 | 0.017 |
| Gen #219 | 0.008 | 0.003 | 0.028 | 0.025 | 0.026 |
| Gen #226 | 0.009 | 0.005 | 0.027 | 0.023 | 0.024 |

From a control point of view there are three cases that can be considered.

*Case A.1. All units are used for control together*

The new steady state condition is shown in Table 3-VII when all of the 8 generators are used for control by adjusting voltage set point. The voltages at all the 5 load buses are now within the admissible range. The weighting factor used for all 8 units is 1. Total reactive power generated is 20102.71 MVAr and the reactive power generated by the controlling units is 4828.78 MVAr. It can be seen that the reactive power produced by the controlled units have increased from 2531.81 MVAr while total reactive power is less than 22703.35 MVAr without voltage control.

**Table 3-VII: Case A.1. Voltage reference adjustment at all 7 units**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.073 | 193.99 |
| 116 | 1.1 | 831.37 |
| 118 | 1.095 | 1458.68 |
| 198 | 1.095 | 489.15 |
| 210 | 1.095 | 299.42 |
| 218 | 1.06 | 600.45 |
| 219 | 1.067 | 826.73 |
| 226 | 1.095 | 128.99 |

*Case A.2. Most influential units are used first*

Now, initially three most influential units #110, #198, #218 are used to control the voltage. When these units reach maximum voltage limit other less influential units are used. The participation factors for all units are 1. The steady state values of  and reactive power MVAr are shown in Table 3-VIII. The total reactive injection is 20229.98 MVAr. Total reactive power generated by the controlled units is 5024.42 MVAr.

*Case A.3. Less influential units are used first*

Units #116, #210, #219 and #226 are used for control initially, all with weighting factor 1. After these units reach their maximum voltage limit other units are called upon for control. The steady state values of voltage reference and reactive power injection at the generators are shown in Table 3-IX. Total reactive injection in this case is 20039.68 MVAr. Reactive power generated by the controlling units is 4980.99 MVAr.

**Table 3-VIII: Case A.2. Voltage reference adjustment of most influential units**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.1 | 212.4 |
| 116 | 1.1 | 736.03 |
| 118 | 1.065 | 810.57 |
| 198 | 1.095 | 457.11 |
| 210 | 1.1 | 287.85 |
| 218 | 1.1 | 1056.69 |
| 219 | 1.1 | 1343.78 |
| 226 | 1.1 | 76.56 |

**Table 3-IX: Case A.3. Voltage reference adjustment of less influential units**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.1 | 205.41 |
| 116 | 1.06 | 688.36 |
| 118 | 1.084 | 1310.21 |
| 198 | 1.1 | 463.68 |
| 210 | 1.084 | 316.43 |
| 218 | 1.1 | 1321.98 |
| 219 | 1.056 | 603.23 |
| 226 | 1.084 | 115.12 |

These three cases above show that as more reactive power is generated inside an area to counteract a voltage disturbance, total reactive power consumption of the system is reduced. For example, in absence of voltage control the generators inside VCA #16 supply 2531.81 MVAr. When voltage control is used total VAr consumption of the system for all three cases is less than this value. The reason is intuitive; higher availability of reactive power inside an area reduces the need to transport it from units far from the area, thus reducing absorption and loss over the network. Again, use of the most influential units first result in reduced reactive injection inside the VCA than using less influential units, which is justified, since more influential units would improve the voltage at the neighboring buses more effectively, i.e. at the cost of less reactive power.

*B. Reactive injection adjustment*

Now, control scheme 2 is used to manage the same disturbance. To implement the control the sensitivity of each unit towards the voltage variation, which drives the control, is determined. The sensitivities of the 8 controlling units inside VCA#16 towards a voltage variation at bus #195 are 0.036, 0.024, 0.024, 0.048, 0.04, 0.023, 0.028 and 0.027 respectively. Then K is chosen accordingly for three scenarios.

*Case B.1. All units are used for voltage control*

All units are used simultaneously for voltage control by adjusting reactive injection. Table 3-X shows the new steady state voltage reference and reactive injection at the generators with K values of 1 for all 8 controlling units. The voltages at all the five load buses are within limits and the new reactive injection is 19971.47 MVAr compared to the reactive injection of 22703.35 MVAr before voltage control. Less amount of reactive injection indicates less congestion and lower loss. The reactive power generated by the controlled units is 4974.69 MVAr.

*Case B.2. Most influential units are used*

Units #110, #198 and #218 are used for voltage control. The K values for these three units are 2.5 and others are 0. Due to higher participation factors these units increase their reactive injection more than others. The steady state voltage and reactive injections at the generators are shown in Table 3-XI. Total amount of reactive injection in this case is 20191.96 MVAr. The reactive power generated inside the VCA is 4460.75 MVAr. On contrary to A.2, voltage control is possible by adjusting the reactive injection of the most influential units only. Higher reactive injection inside the VCA result in an over all lower reactive power consumption in this case.

**Table 3-X: Case B.1. Reactive injection adjustment at all units**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.1 | 204.91 |
| 116 | 1.1 | 723.99 |
| 118 | 1.075 | 914.43 |
| 198 | 1.1 | 452.46 |
| 210 | 1.1 | 290.76 |
| 218 | 1.1 | 1025.29 |
| 219 | 1.1 | 1286.3 |
| 226 | 1.1 | 76.55 |

**Table 3-XI: Case B.2. Reactive injection adjustment at most influential units**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.1 | 209.9 |
| 116 | 1.1 | 869.01 |
| 118 | 1.075 | 1146.08 |
| 198 | 1.1 | 465.07 |
| 210 | 1.072 | 251.34 |
| 218 | 1.1 | 765.46 |
| 219 | 1.062 | 618.82 |
| 226 | 1.1 | 135.07 |

**Table 3-XII: Case B.3. Reactive injection adjustment at less influential buses**

| Bus No | $V_{ref}$ | MVAr |
|---|---|---|
| 110 | 1.085 | 10.28 |
| 116 | 1.1 | 724.59 |
| 118 | 1.075 | 931.71 |
| 198 | 1.075 | 348.36 |
| 210 | 1.1 | 277.28 |
| 218 | 1.1 | 1213.66 |
| 219 | 1.1 | 1289.53 |
| 226 | 1.1 | 76.54 |

*Case B.3. Least influential units are used*

In this case the less influential units at bus #116, #210, #219 and #226 have K value 2.5 and two of the most influential units #110 and #198 have K values 0.5 and 2.5 respectively. The steady state voltage and reactive power injection at the generating units are shown in Table 3-XII. Noticeably most of the reactive power is produced by the less influential units. As in this case it is not possible to rectify all the voltage violations by adjusting the less influential units. Hence some of the most influential units have also been called upon to correct the violations. Total reactive injection in this case is 20085.04 MVAr. Reactive power generated inside the VCA is 4871.95 MVAr.

Comparing the total VAr consumption in B.1, 2 and 3 it can again be observed that overall power consumption of the system is reduced as the generators close to the perturbed buses increase reactive power injection. In B.1, generators in VCA #16 supply 4974.69 MVAr to achieve overall consumption of 19971.47 MVAr, whereas in B.2, supply in the VCA is 4460.75 MVAr for a total consumption of 20191.96 MVAr. When a system is divided into a number of areas and using types of voltage control methods described here, it may be particularly helpful for system operator to utilize the above mentioned knowledge for reserve requirement planning.

## 3.5 Impact Analysis

***Controllability***

The type of voltage control scheme dictates the way reactive resources can be controlled and to the extent they can be controlled. In case A.2 all of three most influential units are used first to correct the low voltages at the load buses. But as these generators reached their maximum reference voltage level, it was necessary to call upon the other less influential units for control. In case B.2, direct reactive set points were sent and these three units turned out to be sufficient to provide the VAr needed for the situation. Comparing the examples A.2 and B.2, in both of the cases most influential units are used to control the voltage, but clearly the later is advantageous because the reactive power to be produced by the units were predefined by the control. When controlling by the reference voltage, no control action can be taken on a generator once their voltage reaches maximum limit, but when units are controlled by direct VAr adjustment, the reactive output level of the generator is precisely known and it is the responsibility of the local primary control to produce it in whichever way is convenient. Hence there is certain amount of advantage in terms of control that can be gained from such a scheme. Also this gives the operator flexibility to use the resources which he thinks best from reliability or economic point of view.

The conventional way of allocating the reactive power to a unit is through OPF. But it is necessarily a manual control. In real-time the voltage incident may occur in dynamic range i.e. within a few seconds. The discussed methods of secondary voltage controls are automatic and can perform in real-time like automatic generation control (AGC). So the operator has some time to react and move the point of operation in safe zone.

***Performance***

It is evident from all the examples above that the more the number of controlling units in a VCA is used to control a voltage event the lower is the total consumption of reactive power and loss. In case B.1 all 8 generators have been used at once and the total reactive injection is 19971.47 MVAr. In B.2 and B.3, generators are used according to the sensitivity and the total reactive power injections are 20191.96 MVAr and 20085.04 MVAr respectively. In A.1, A.2 and A.3, all the eight units have been used. In A.3, practically all the units except two have reached the maximum voltage level. Naturally A.3 results in least system VAr consumption amongst those three cases. Hence involving more generators inside a VCA reduces the overall reactive injection because when generators close to the perturbed buses are able to supply the necessary reactive power, the need for transporting reactive power into the area is minimized and absorption and transmission loss is decreased.

While comparing the control performances of the methods described in this paper it should be mentioned that scheme 2, i.e. voltage control with direct VAr adjustment is better in terms of control, since reactive generation of each controlling unit is precisely known and hence total power consumption and VAr reserve can managed with relative ease. However, such control, being based on OPF, will behave conservatively and try to keep voltage levels close to lower limits. Scheme 1 i.e. generator voltage adjustment, on the other hand, may be more likely to maintain a better voltage profile by pushing the voltage at controlling units at higher value.

***Economic consideration***

The secondary voltage control methods discussed earlier are particularly suitable for creating competitive markets for VAr. For control scheme 1 a voltage control market can be formed where suppliers would bid reactive capacity and will be paid according to uniform clearing price calculated by OPF. The real time control of units will, however, be in voltage. Necessary measure has to be taken to operate the units within market awarded reactive limits. Similar VAr market can be formed for control scheme 2 as well.

While considering competitive markets for voltage control it is to be kept in mind that unlike frequency, voltage behavior of a network is locally influenced. Naturally, some of the generators may be absolutely necessary for voltage support due to their locational advantage. For example in almost all the cases described here, generator #110 has to be used to rectify all the bus voltages. In cases A.2 and A.3 it is necessary to involve both types of generators in control. In real market such units would be aware of their advantage and given the profit seeking nature of market participants, may try to influence the clearing price. If that be the case, market power may be unavoidable. One way to avoid that situation may be to split the market. Some amount of service can be made mandatory and the ISO can go into long term bilateral contracts with the generators and then create a short term market for the balance quantity.

It is also to be noted that the availability of the resources would not only be affected by its location in the network, but also by the market that it participates in. If a market fosters competition and involves more generators to procure the goal, it is better for the performance and thus minimizes congestion and loss. Importance has to be given on the performance considerations, not only the cost and a trade off have to be made to maintain a balance between to two.

## *3.6 Remarks*

In this chapter we have presented a comparative study of area voltage control schemes. Control of voltage is possible by adjusting the reactive power injection at the generators. Compared to controlling the voltage reference of a unit, this scheme provides the operator with better controllability over the reactive resources while being equally effective in reducing the congestion and loss. A competitive VAr market seems feasible in this control framework.

To achieve a better performance in terms of voltage profile, the market should make sure that sufficient amount of service is procured. For that purpose it may be necessary to involve more number of service providers. Consequently some resources may turn out to be crucial for control and stability of the system. In a spot market these resources may acquire market power.

# Chapter 4. Conclusion

In this work we have demonstrated that the structure of ancillary service markets affect system performance. Those ancillary services that provide control, like the regulation market to control frequency and the VAr market to control voltage, are particularly important to design properly so that the desired control performance is obtained at the best price. This means that the structure of the ancillary markets should be such that those generators that can contribute more towards better control should be encouraged by the proper incentives. In the case of the regulation market this usually means the recognition that generating units with faster response (ramp) rates are more important to load balancing and frequency control. In the case of VAr markets, the speed of response is not as important as the location of the units and their VAr production capacities, i.e. voltage control is more sensitive to the electrical proximity of the VAr sources.

We chose a simple experiment to show that the regulation market has a direct effect on the control performance of the system. Three different market structures were chosen to demonstrate the varying control performance on a reduced WECC model: the first is similar to what is used by the California ISO today but the other two were chosen somewhat arbitrarily to provide more incentives for generators with better response (ramp) rates. In the second structure we develop a second bid market for 5-minute capacities in addition to the existing 10-minute capacity market. The 5-minute market can be used for better control than the 10-min market and at the same time these faster generators can be rewarded with higher prices. In the third structure we form separate markets for fast and slow units based on ramp rates.

We have also presented a comparative study of two different area voltage control schemes to demonstrate feasibility of voltage control by adjusting the reactive power injection from the generators. A competitive VAr market seems feasible in either of these control frameworks. To achieve better performance in terms of the voltage profile, the market has to procure sufficient amount of reactive power reserve. A market for VArs for that purpose will provide the option to choose amongst resources. Unlike frequency control which is controlled very close to 60Hz, voltages are controlled within a band so that the robustness of the voltage profile maintained determines the VAr resources utilized. However, it is shown that just as in the regulation market certain generators provide better voltage control because of their location and VAr capacities and either scheme used in this paper will provide market incentives to the more effective generators.

This work shows that ancillary markets should be structured to reward those properties of the generator that better helps the ancillary service. It should however be made very clear that it may not always be possible to create such a market and there has to be enough generators in the market with similar capabilities to generate competition. For example, if there are only one or two generators with fast ramp rates in a balancing area of largely slow thermal units, these fast units will have too much market power in a spot market that incentivizes ramp rates. Similarly, if there are not enough generators near a load center to control the voltage, the few nearby generators will exercise too much market power to develop a viable VAr market.

# Appendix

## A. WSCC 225-bus model

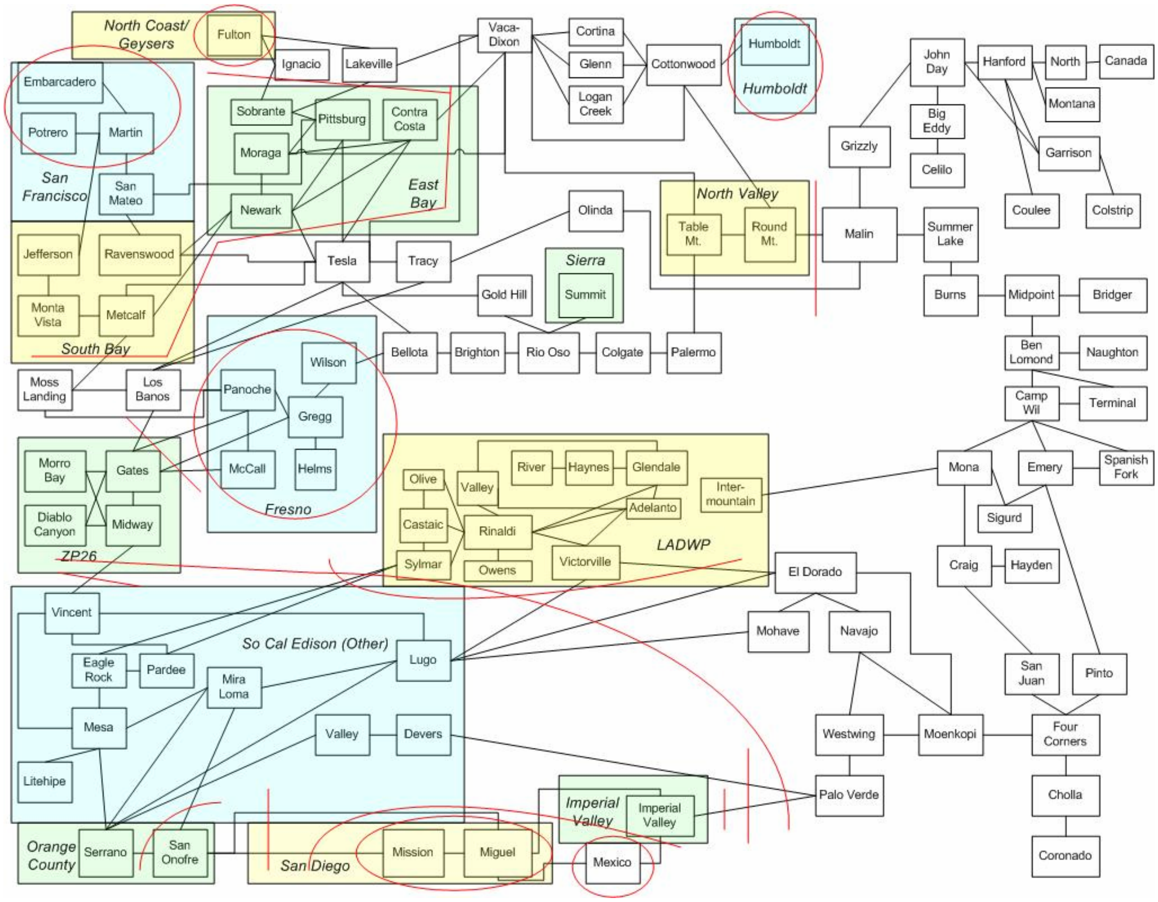


**Figure A-1:** Major substations of WSCC reduced model (courtesy CAISO)

## B. *Voltage Control Area*

A power system can be divided into a number of voltage control areas consisting of coherent buses and reactive resources able to sustain the reactive requirement of the area. The systematic method to determine such VCA s has been described in [18]:

1. Calculation of electrical distance between all the nodes of a system
2. Identification each area using topological classification within the border of the network

The electrical distance between the buses in a network can be derived from $\left[\partial P/\partial\theta\right]$, which is a part of the Jacobean matrix J. Since we are interested in the reactive power sensitivity of the buses, it is necessary to obtain $\left[\partial Q/\partial V\right]$ and the $\left[\partial Q/\partial V\right]$ part of the Jacobean does not include generator buses, the complete matrix can be derived from $\left[\partial P/\partial\theta\right]$ as follows:

$$\frac{\partial Q_i}{\partial V_j} = \frac{\partial P_i}{\partial \theta_j}, \qquad \text{for} \qquad i \neq j$$

$$\frac{\partial Q_i}{\partial V_i} = Q_i - B_{ii}V_i^2, \qquad \text{for} \qquad i = j$$

Hence, the sensitivity $\left[\partial V/\partial Q\right] = \left[\partial Q/\partial V\right]^{-1}$ is the measure of propagation of voltage variation following a reactive power injection at the bus. The magnitude of voltage coupling between two buses can be quantified by the maximum attenuation of voltage variation between these two buses:

$$\Delta V_i = \alpha_{ij}\Delta V_j$$

The attenuation is given by:

$$\alpha_{ij} = \left(\frac{\partial V_i}{\partial Q_j}\right) \Big/ \left(\frac{\partial V_j}{\partial Q_j}\right)$$

The attenuation matrix thus obtained is non-symmetric. To ensure positivity and symmetry the electrical distance between any two nodes $i$ and $j$ is calculated as:

$$D_{ij} = D_{ji} = -\log_{10}\left(\alpha_{ij} \cdot \alpha_{ji}\right)$$

Once the electrical distance between any two nodes of the network has been defined VCA s can be formed by grouping the electrical distance into certain ranges. Starting from a generator bus, all the buses whose electrical distances from that bus is less than the range is included in one area. A number of areas can be formed like this until every bus belongs to at least one area. In case a bus belongs to more than one area some judgment is to be used to classify it in any one area.

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