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Power Exchange for Frequency Control (PXFC)

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Abstract:

This paper concerns markets for balancing power supply and demand in real-time. Two qualitatively different market mechanisms are of interest (1) primary electricity market(s) for supplying anticipated demand and (2) a frequency control market for ensuring that system frequency remains within prespecified limits as demand deviates in real-time from its anticipated pattern. We suggest that both types of markets are necessary for ensuring that frequency remains within its technically acceptable limits as power is provided competitively. In particular, we develop one possible structure of a Power Exchange for Frequency Control (PXFC) that ensures frequency quality in a general primary electricity market comprising both bilateral and spot sub-markets.

I. Introduction

This paper concerns rules, responsibilities and rights for creating an effective Power Exchange for Frequency Control (PXFC). The main function of this market is to ensure sufficient provision of power for balancing supply/demand mismatches created in the primary Power Exchanges (PXs) for electricity so that system frequency remains within the prespecified technical constraints. We propose controls contracts that are designed to move the responsibility for frequency control away from the system operator and towards the individual participants.

One could argue that the operating objectives of today's power systems under normal conditions[1] are well understood. Automatic generation control (AGC), in particular, is known as a very effective simple closed-loop control scheme for balancing power in real time.

This paper states reasons for replacing present cost-based AGC scheme by a market structure for purchasing and selling frequency control as a well-defined commodity. In this paper we refer to this market as a Power Exchange for Frequency Control (PXFC) and develop its basic structure.

II. Principles of Balancing Power and Frequency Regulation

Consider in this part of the paper the simplest electric power system structure consisting of a single control area. At present sufficient power is planned and operated by a single control center for meeting customers' needs in the area under the direct jurisdiction of a control area. The operation of the existing plants consists of two distinct processes:

1. Unit commitment and economic dispatch are performed to supply the anticipated load in the least-cost way.
2. The deviations in load from its expected values are supplied by very few flexible power plants participating in frequency control (or AGC).[2]

In today's industry, only two types of power balancing are in place: (1) the open-loop scheduling for the anticipated demand pattern, and (2) automated regulation of the actual, real-time power imbalance caused by deviations in demand and (rarely) generation from their scheduled (anticipated) values. The longer-term operating efficiency and cost optimization in real-time is achieved by performing economic dispatch every 5-15 minutes, as the information about system loads becomes available through a SCADA system. Usually there is no explicit cost optimization for regulation since these units are chosen for their technical characteristics.

The economic dispatch is done under the assumption that system frequency is regulated tightly and that real power output is a fully controllable quantity by each power plant. In reality, however, power generated by a generator-turbine-governor (G-T-G) unit is determined by a three-way relation (droop characteristic [3], [4])

$$\omega_{Gi} = (1 - \sigma_{Gi} d_{Gi})\omega_{Gi}^{ref} - \sigma_{Gi} P_{Gi} \qquad (1)$$

where $\sigma_{Gi} = -\frac{\partial \omega}{\partial P_{Gi}}$[3] is the droop defining sensitivity of the system frequency $\frac{\omega}{2\pi}$ with respect to the change in power generated by the plant P_{Gi}, assuming that the set

[1]Demand as expected and no equipment outages.

[2]The distinctions between frequency control (FC), load frequency control (LFC), and automatic generation control (AGC) could become critical in the competitive industry, depending on the market structures in place. For example, LFC and FC are the same in an industry where loads are the primary cause of imbalance. In the new industry, supplier could create an un-expected power balance when committed to an energy–and not power–contract, as explained later in this paper.

[3]All symbols in this paper represent *deviations* in variables of interest from the nominal operating point, and not their actual values. For example, ω stands for frequency deviation away from 60Hz$\times 2\pi$ [4].

point value of the governor ω_{Gi}^{ref} remains constant and d_{Gi} is the effective damping coefficient of the entire G-T-G unit.[4] This relation basically says that the output of power plants not participating in LFC increases automatically as the system frequency decreases; this is a direct result of the primary governor control.

In today's industry it is not essential to *unbundle* actual power output into (1) the component caused by the frequency changes resulting from systemwide power imbalances and (2) component directly controllable by each G-T-G unit. In a competitive environment, however, it is important to relate cause and effect, and it is potentially useful to rewrite (1) as

$$P_{Gi}(\omega) = P_{Gi}^{c} - \frac{1}{\sigma_{Gi}}\omega = P_{Gi}^{c} - \beta_{Gi}\omega \tag{2}$$

where

$$P_{Gi}^{c} = \frac{(1-\sigma_{Gi}d_{Gi})\omega_{Gi}^{ref}}{\sigma_{Gi}} \tag{3}$$

and

$$\beta_{Gi} = \frac{1}{\sigma_{Gi}} \tag{4}$$

P_{Gi}^{c} is the component of power generated under the direct control of each power plant, determined by adjusting the set point value ω_{Gi}^{ref}. In today's industry only AGC unites adjust this value. The remaining component $\beta_{Gi}\omega$ depends on everyone else's activities and it reflects how a governor changes P_{Gi} to stabilize system frequency ω to its set point value ω_{Gi}^{ref}.

A. Regulatory and Industry Efforts

The implementation of competitive electricity markets requires a variety of services which may not be provided efficiently unless rules are established for defining the rights and responsibilities of system users to purchase or provide these services.[5] The requirements for some of these services, such as load following and frequency control, vary with the electricity market dynamics. Neither FERC nor NERC efforts have led to any means of differentiating tariffs as a function of the impact of specific market users on the overall market dynamics, and, consequently on the amount of ancillary services needed. In other words, a group of residential customers and an arc furnace pay the same for these services as long as their contracts for capacity are identical.

It has been only recently that several ISO's in forming have proposed markets for frequency control [9]–[11]. Moreover, the load following service is becoming competitive through creation of short-term hourly markets, as in the California ISO [12]. This indirectly leads to changing the FERC pro forma tariffs, but the approval of these changes remains on a case by case basis. An overall understanding of the criteria necessary to be met in order to create markets for ancillary services is needed.

In this paper we critically assess market structures for load following and frequency control that have been proposed and explain some missing necessary features. We show how our market structure for power balancing and frequency control overcomes the fundamental problem related to the unobservability of components associated with particular submarket functions.

III. Ensuring Physically Deliverable Power Contracts

Many questions regarding the performance of a competitive market for ancillary services cannot be answered without addressing the structure of the electricity markets.

For this discussion it is important to note that the primary electricity market responds only to anticipated (whether longer or shorter range forecast) demands, and not to very short term fluctuations, which indicate that real time supply/demand imbalance, and which cannot be ignored.

In this paper we develop a framework for the frequency control market as a separate market from the primary electricity markets, to emphasize the fact that this is a *closed-loop* market which responds to deviations in supply/demand imbalances from their values anticipated in the main electricity markets. We propose that this market lends itself to an entirely decentralized implementation and, as such, it does not require centralized control through an ISO to function.[6]

In the general market structure considered as a background for this paper, we assume power can be traded in three separate submarkets, (1) the long-term bilateral, (2) spot market(s) and (3) the proposed frequency control market.

The droop characteristics of a power plant defined in (1) above is a strong complicating factor when power provision and frequency control are attempted through market means. How can generators be contracted to provide control generation if they do not have full control over their own power outputs? (Recall from (2) that only its portion P_{Gi}^{c} is fully controllable.) In a regulated industry this problem is less critical because generators participating in frequency regulation are directly controlled by a system operator in charge of *both* scheduling power for the expected demand and ensuring sufficient power for frequency control. In a competitive industry, the market(s) must be carefully structured to ensure that such

[4]Throughout this paper we interchangeably use the term system frequency ω, or power plant frequency ω_{Gi}; in quasi-steady state operating mode the two are assumed to be indistinguishable with the present measurement equipment.

[5]In Order No. 888, FERC proposed a list of ancillary services essential for facilitating open access to the transmission system[5]. As a follow-up to FERC's Order, NERC formed an Interconnected Operations Services Task Force (IOS), which produced a list of the industry's recommendations for unbundling system services under competition [6].

[6]This statement assumes that market rules are followed; ISO may still have an essential supervisory role.

necessary services will be provided efficiently. The question is whether it is possible to have several submarkets providing the anticipated demand in an open-loop mode, and an additional closed-loop frequency control market, *all without any direct involvement of an ISO.*

Recall from equation (2) above that power produced by any given plant can be decomposed into the part fully controllable by the producer P^c_{Gi} and the component which varies with the system conditions $\beta_{Gi}\omega$. Similarly, each load is characterizable as

$$P_{Lj}(\omega) = P^c_{Lj} + \beta_{Lj}\omega \tag{5}$$

where P^c_{Lj} is the load component independent of system frequency (that is, other system users' activities) and the remaining component changes as a function of system frequency. This formula represents the well-known self-stabilizing character of loads in today's industry; the power demanded naturally decreases as the frequency decreases, leading to smaller demand shortage, and, therefore, increasing system frequency [3], [15].

A major complication with loads, compared to generator characteristics, is that no aggregate load is capable itself of consuming pre-specified P^c_{Lj} exactly; instead, the load varies constantly around its mean value within a band $\pm\Delta P_{Lj}(t)$. Depending on the level of aggregation and the type of loads represented by a load serving entity, LSE, this behavior could be characterized through the type of contract shown in Fig. 1. Notice that while in today's industry load characterization is not explicit, such characterizations by the LSEs of the future will be particularly important for efficient frequency regulation.

Therefore, in the new industry each generation serving entity (marketer), GSE, should be responsible for specifying only $P^c_{Gi}(t)$ and not the actual $P_{Gi}(t)$ for the entire long-term contract duration. Similarly, each LSE requests a delivery of $P^c_{Lj}(t)$ from the primary electricity market. Since load inherently deviates from its intended level, the band of expected deviations, $\Delta P_{Lj}(t)$, also must be part of the contract, and each LSE must purchase on the frequency control market frequency control service to compensate for their likely deviations.

Specifying power contracts in terms of P^c_{Gi} and P^c_{Lj} ensures that all that can be controlled by the system users themselves is specified. This, in turn, ensures that the power contracts specified in the primary markets can be physically delivered independent from the others.

This type of contract is *the key* to designing decentralized submarkets for balancing power and ensuring efficient frequency control.

IV. Power Exchange for Frequency Control (PXFC)

In this section we define basic rules, responsibilities and rights of the participants in the proposed PXFC. We describe why this is sufficient for ensuring efficient frequency control in a general primary market structure, restricted only by the requirement that contract specifications be as proposed.

To start with, participation of all system users is *mandatory.* For an electric power system to operate as an AC grid, the frequency must be controlled tightly.[7]

It is relatively straightforward to show that it is not possible to meet frequency specifications strictly through primary electricity markets. As shown below, electric supply and demand may balance in these markets, but the equilibrium frequency will deviate from the desired 60Hz making participation in the PXFC mandatory.

A. Participation in the PXFC

In principle all system users, GSEs and LSEs deviate from their commitments in the primary markets, and therefore they all need to purchase frequency control service through the PXFC.

It has been suggested in several recent references [16], [17] that each system user should control its own frequency and that only minimal [17] (or, equivalently system [18], [19]) frequency control should be provided as a system service.

Different consumers may need to purchase more frequency control than others. For example, an arc furnace creates more unexpected power imbalances than a residential customer, and should, therefore, pay more for the system frequency control commodity. Also, some GSEs would be willing to meet their power contracts committed into the primary markets very closely, and some will anticipate significant deviations.

A meaningful PXFC should capture these distinctions among system users and the tariffs for system control should further reflect these differences. Possibly the simplest way to achieve this is by establishing a mandatory contract format which in a transparent way provides the information to the PXFC coordinator about each system user's need for system frequency control.

B. Power Contract Format

In order to develop a meaningful market for frequency control we suggest that, at least, each contract on the daily market should specify anticipated power requirement as a function of time, *and* an estimate of the expected band of superimposed fringe fluctuations. We demonstrate in this paper that this is sufficient for developing a well-defined control market. A representative contract curve is shown in Fig. 1.

Significant reasons may be cited for and against requiring that primary level of regulation be acquired locally (within a control area) or from the larger network. On balance, it could well be that economic efficiency (lower overall cost) will drive the industry toward local supply of regulating energy.

[7] We do not study the question of adequate technical specifications, this is a separate and very difficult subject. The allowable frequency deviations are assumed to be given. The only objective is to ensure these are met.

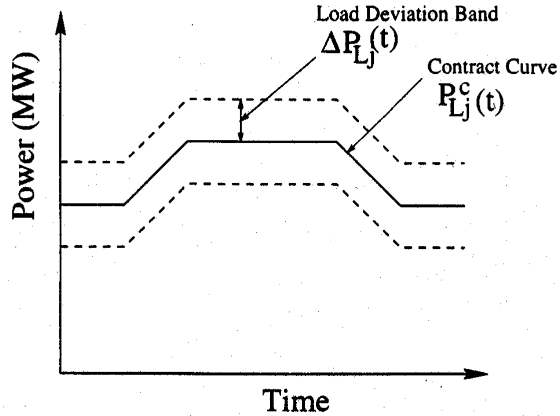

Fig. 1. Recommended Structure of Long-Term Contracts

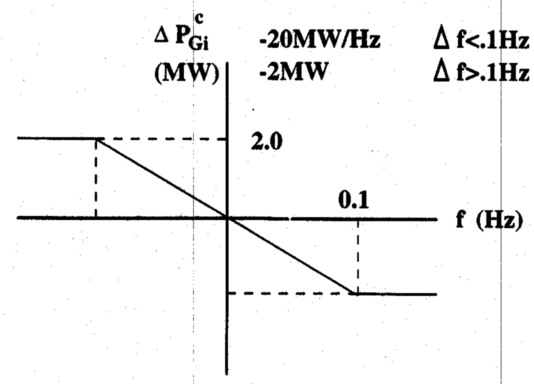

Fig. 2. Structure of Contracts Traded on the Control Market

In any event, since no amount of regulating effort can provide perfect matching of load and generation, a certain amount of default regulation will always have to be provided by the network operator as a system-specific service.

If no restrictions are placed on the source of regulation, central coordination will be required, and all system users, GSEs and LSEs, who do not choose to self-provide their regulation, will be required to provide information to the frequency control market as a prerequisite to connecting to the system. The general information would be in the form shown in Fig 2. All LSEs would be expected to specify a non-zero band $\pm\Delta P_{Lj}(t)$; generators not participating in the frequency control market would be required to provide information about their their power $P^c_{Gi}(t)$ to be produced under the long-term bilateral contracts.

This information can, in turn, be used by the system (or frequency control market) operator to estimate the maximum cumulative power mismatch which must be compensated through purchasing control on this market. Using this estimate, a coordinator of the Power Exchange for Frequency Control can decide how much power to purchase for control. In the remainder of this paper we describe how is this done.

C. Who Provides Service to the PXFC?

In today's industry only a handful of generators participate in AGC. The key issue in the development of an effective PXFC is to ensure the participation of an adequate number of generators in this service, so that no unit can exert frequency control-related market power, thus moving the system away from optimal operating conditions.

Not all units, however, meet the technical characteristics required to participate in a frequency control market. The most significant restrictions are generator location and ramping time. While the value of location and speed of generators have long been generally known to the system operators, there are no readily available measures of their values. Moreover, there is no quantitative relation known between the boundaries of a control area and the technical specifications of the power plants within the area for effective frequency control. In this paper we define these missing relations after introducing a frequency control market.

Power producers selling their services to the frequency control market are required to provide a different type of contractual specification. A system user participating in the frequency control market sells an obligation to adjust its directly controllable power P^c_{Gm} in response to frequency deviations, within a preset band of power, according to

$$P^{control}_{Gm}[kT_s] = P^c_{Gm}[(k+1)T_s] - P^c_{Gm}[kT_s] = G_{Gm}\omega[kT_s] \quad (6)$$

for some

$$P^{c,min}_{Gm} < P^c_{Gm} < P^{c,max}_{Gm} \quad (7)$$

This contract specification is sketched in Fig. 2.

D. Meeting the Control Objective

The function of the PXFC is to guarantee that frequency remains close to 60Hz at all times. We write this system-wide control objective as:

$$\omega^{min} < \omega < \omega^{max} \quad (8)$$

How then can the purchase of controls contracts on the PXFC, as defined above, guarantee that this objective is met? To answer this question we first re-derive the control objective in terms of load/generator power imbalance. Due to the droop characteristic, the net real power injected at the generators will always match the net power extracted at the loads:

$$\sum_m P_{Gm}(\omega) - \sum_i P_{Li}(\omega) = 0 \quad (9)$$

Therefore the popular notion that system frequency deviates because of a mismatch in power between load and generation is not quite accurate. In order to observe this imbalance we have to disregard the droop characteristic and consider only the controllable part of the power output (P_{Gi}^c and P_{Li}^c). This gives us a linear relationship between the cumulative mismatch in load and generation and the deviation in system frequency from 60Hz:

$$\omega = (1/(\beta_G + \beta_L))(\sum_m P_{Gm}^c - \sum_i P_{Li}^c) \qquad (10)$$

Where $\beta_G = \sum_m \beta_{Gm}$ and $\beta_L = \sum_i \beta_{Li}$. We also define P_{imb} such that:

$$\omega = (1/(\beta_G + \beta_L))P_{imb} \qquad (11)$$

Having derived the relationship between power imbalance and frequency deviation we can now rewrite the control objective (8) in terms of power imbalance:

$$P_{imb}^{min} < P_{imb} < P_{imb}^{max} \qquad (12)$$

Where $P_{imb}^{min} = (\beta_G + \beta_L)\omega^{min}$ and $P_{imb}^{max} = (\beta_G + \beta_L)\omega^{max}$. On the actual system the generators are required to have the controllable portion of their power output track a contract curve, while the load is allowed to deviate within specified margins. The power imbalance on the system will therefore be due to unpredicted deviations of the loads (and imperfect generator controls). Since only generators participating in the PXFC will respond to this imbalance we assume that P_{Gi}^c is as specified by the contract curve for all non participating generators.[8] Participating generators will respond according to the control law specified in the previous section. Furthermore we introduce the notation P_{Li}^{dev} to denote the deviation of the i'th load from the contract curve. Under these assumptions, the power imbalance of the closed loop system will be given by:

$$P_{imb} = \sum_m P_{Gm}^{control} - \sum_i P_{Li}^{dev} \qquad (13)$$

Using the control law defined in (6) this expression becomes:

$$P_{imb} = \sum_m G_{Gm}\omega - \sum_i P_{Li}^{dev} \qquad (14)$$

We now substitute equation (11) for ω,

$$P_{imb} = (\sum_m G_{Gm})(1/(\beta_G + \beta_L))P_{Li}^{dev} - \sum_i P_{Li}^{dev} \qquad (15)$$

This relation clearly spells out how control gains must be set in order to balance the overall system. By selecting gains such that

$$\sum_m G_{Gm} = (\beta_G + \beta_L) \qquad (16)$$

[8]Otherwise, high penalties for not meeting contractual obligations should be in effect.

the net imbalance will be reduced to zero and system frequency will be at nominal. This simple constraint on the sum of the control gains therefore spells out the steady state requirement for balancing frequency on the system. When auctioning off control contracts, the PXFC will need to match the sum of droop constants for all loads and generators in its area.

E. How Much Control Capacity?

So far we have shown how to specify the gain on the control contracts traded on the PXFC. We still have to determine how to set $P_{Gm}^{c,min}$ and $P_{Gm}^{c,max}$ for each contract. To do this the power exchange uses the information provided in the bands around the bilateral contract curve. An upper bound on the maximum cumulative imbalance on the system is:

$$P_{imb} < \sum_i \Delta P_{Li} \qquad (17)$$

A simple and safe strategy would be for the system operator to purchase sufficient control capacity to cover this worst case scenario. Specifically, if the unit clearing price for a control contract is given by P_{FC} and m contracts are purchased, the mandatory charge to each LSE i for frequency control will be given by:

$$MFCC_i = (m \times P_{FC})(\Delta P_{Li}/(\sum_j \Delta P_{Lj})) \qquad (18)$$

If this charge is passed on to all LSEs, the total amount of money paid to the PXFC is:

$$\sum_i MFCC_i = m \times P_{FC} \qquad (19)$$

This is exactly equal to the amount paid by the PXFC to the generators participating in frequency control, so the market recovers its full cost while providing individualized economic feedback to the load serving entities.

Clearly, assuming that the deviations of the loads are fully correlated and purchasing control capacity equal to the sum of the contract bounds is overly conservative. In order to improve on this strategy the PXFC needs some measure on the degree to which the deviations of the loads will cancel each other. This other limiting case is given when the loads can be modeled as independent identically distributed (IID). Under this assumption the necessary control capacity, based on the standard deviation of the cumulative disturbance, is given by:

$$\sum_m (P_{Gm}^{c,max} - P_{Gm}^{c,min}) = (2/\sqrt{n})\sum_i \Delta P_{Li} \qquad (20)$$

This clearly is a significant improvement in the economic efficiency of the controls market. In a market with hundreds of LSEs, the necessary capacity may be reduced by a factor approaching ten. According to the pricing scheme provided in (19) these savings will be directly passed on to the loads.

This stochastic analysis sets bounds on the effect of the correlation between individual load deviations on overall volatility. To define this impact over the full range of load correlations, we introduce the Λ function. $\Lambda(cov(P^c_{L1},...,P^c_{Ln}))$ determines the proportional relation between the sum of the deviation bands and the required amount of control capacity:

$$\sum_m (P^{c,max}_{Gi} - P^{c,min}_{Gi}) = (2 \times \Lambda) \sum_i \Delta P_{Li} \qquad (21)$$

Λ will be a monotonically increasing function of load correlation, starting at $\Lambda = 1/\sqrt{n}$ for IID loads, and bounded by $\Lambda = 1$ for fully correlated loads. The introduction of this function illustrates the necessity for market participants to provide more information, to the extent possible, to market facilitators, such as the PXFC, in order to ensure efficient operation.

F. Dynamic Constraints

So far we have addressed how to select the gain and capacity limits on the control contracts in order to balance real power on the system. These are equilibrium constraints in the sense that they guarantee the sufficient availability and proper application of balancing regulation. In addition, we need to satisfy dynamic constraints to ensure that generators can respond to fast disturbances in real time. We mentioned earlier the value of generator location and ramping rate.

A solution to the problem of determining the relative regulating burdens imposed on the system by various loads is not straightforward. The spectral density of the system load extends far beyond any frequency to which generators can respond. In practice, it has been found effective to remove from system signals, by prefiltering, all frequencies higher than 0.01 Hz, and to assign to regulating generators that portion of the spectrum between 0.001 and 0.01; portions of the spectrum below 0.001 should be assigned to load following generators.

The actual frequency response capabilities of generators could be determined by elaborate, and expensive, field testing, which would put a nearly intolerable burden on many generators, and would certainly greatly diminish the number who would be willing to participate in the market. To avoid this result, all units that bid into the PXFC could be subjected to spot checking of their performance, and disqualified if it were found lacking.

V. Single Area Example

In this section a simple four-bus system, shown in Fig. 3, is used to illustrate theoretical ideas introduced in this paper. The system consists of two generators and two loads. The transmission line parameters are uniform ($r = 0.01 p.u.$, and $x = 0.1 p.u.$); generator parameters are ($\sigma_{G_1} = \sigma_{G_2} = 0.05(\frac{rad/sec}{p.u.})$, $d_{G_1} = 1.0$, and $d_{G_2} = 0.8(\frac{p.u.}{rad/sec})$).

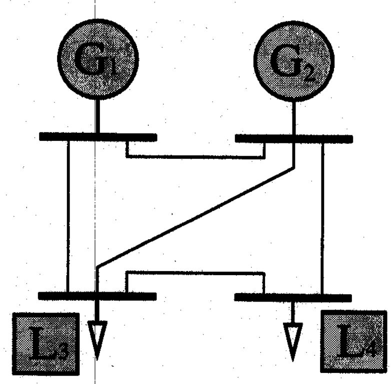

Fig. 3. A simple four-bus system

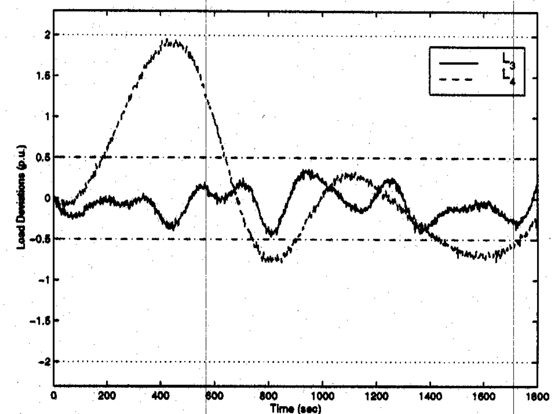

Fig. 4. The deviations from contract curves at L_3 and L_4

For simplicity, the two loads, L_3 and L_4, are assumed not to vary with frequency, and also to be statistically uncorrelated to each other. The two loads are characterized by different deviation bands around their contract curves: L_3 has a ± 0.5 $p.u.$ deviation band; L_4 has a relatively larger, ± 2 $p.u.$, deviation band as shown in Fig. 4.

The set points of generator governors are changed every 30 seconds corresponding to the P^c_{Gm} needed to fulfill the control contracts. Since the droop characteristics, σ_{Gm}, of both G_1 and G_2 are 5% ($\frac{rad/sec}{p.u.}$), based on Equation (16), the total control gains needed for frequency regulation should be

$$\sum_{m=1}^{2} G_{Gm} = \beta_1 + \beta_2 = 2\pi \times 40 \ \ \text{(p.u./Hz)} \qquad (22)$$

In this simulation, we choose $G_{G1} = \frac{2\pi}{3} \times 40$ and $G_{G2} = \frac{4\pi}{3} \times 40$ so that the control gain of G_2 is twice as large as that of G_1. This way G_2 obtains twice as many control contract units as G_1 does. Fig. 5 shows the real power response of G_1 and G_2 participating in PXFC. It shows that G_2 increases (or decreases) twice as

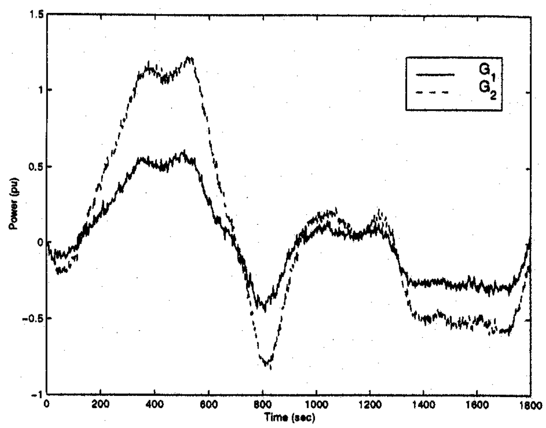

Fig. 5. Real Power Outputs of G_1 and G_2

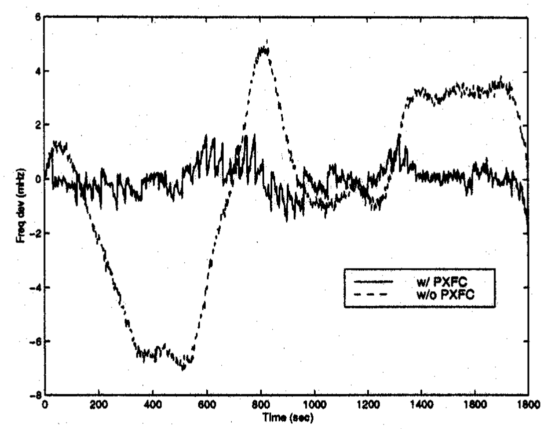

Fig. 6. System Frequency Response with PXFC

much its real power compared with G_1 to balance the system. As mentioned in section IV-F, G_2 must have a fast enough ramping rate in order to qualify to bid for more control contracts and also it needs to reserve more of its real power capability for frequency regulation. Furthermore, since L_4 deviates more from its contract curve, it should take more responsibility for the system frequency deviation than L_3. These verify the charge and payment mechanism described in section IV-E.

Fig. 6 shows system frequency response to the system disturbances. It can be seen that without any coordination the average frequency deviates in an uncontrolled way. In contrast, with the PXFC provided by G_1 and G_2, the system frequency deviation is reduced to less than ± 2 mHz.

VI. Efficiency of the PXFC

Throughout this paper we have focused on the feasibility of a competitive market for closed-loop frequency control. We have shown how the market could ensure the desired control of system frequency by auctioning out a set of long term PXFC contracts which require generators to respond to frequency deviations in a decentralized fashion. The issue which remains to be addressed is the impact of the proposed control market on the economic efficiency of the industry. Will moving from hourly or even intra-hour dispatching of balancing generation to long term contracts result in inefficient allocation of generation? How can generators determine the price of their bids when the long term demand for control generation is highly uncertain?

In order to analyze the short term efficiency of the proposed market structure we have to examine the bidding strategies of individual generators. Recall that each generator has the option of entering into the bilateral, spot and control markets. While each of these markets evolve at different rates each generator has to make a decision at the rate determined by the longest evolving market.

Entering into any long term contract is a clear opportunity cost since it prevents the producer from offering its capacity on the spot market. We would therefore expect the prices in the three markets to stabilize such that the expected profit from allocating generation capacity into each market is identical. The rate at which the market will approach this equilibrium will depend mainly on two factors.

1. The rate at which the market evolves, defined by the length of contracts in the long term markets. The faster generators are able to adapt their bidding strategies, the sooner the market will reach equilibrium conditions.
2. The ability of market participants to estimate load variance. The variance of the load will drive the control market (as well as any bilateral load following contracts). In order to accurately optimize their bidding strategies, generators must be able to estimate this variance.

This is where the proposed control market has its greatest strength. Because of its simple structure the market can be set to operate at almost any rate. The control market also offers a means to relay information about load volatility. The PXFC market coordinator uses the bands on the bilateral contracts to determine the demand for control contracts. If load volatility increases the demand on the control market will increase, however the burden carried by each contract will remain the same. Thus the generator will not have to re-evaluate its bids to the control market every time a new load is added to the system.

VII. PXFC for Multi Control Areas

Creating markets for frequency control in an interconnection comprised of several control areas appears at first sight to be much more complex than the PXFC for an isolated, single control area system described above. To deal with the variety of possible system architectures without creating excessive complexity, it is important to recognize two major facts:

1. The boundaries of a CA are not essential for balancing power in real time, nor for regulating frequency

of the entire interconnection within the prespecified technical limits.

2. It is essential to develop a PXFC in which the control criterion is measured in terms of system frequency deviations and *not* in terms of the traditional area control error (ACE).

In what follows we first describe several conceptual difficulties with using ACE for system frequency control under open access. Next, we suggest that NERC has already moved into the direction of changing the frequency control criterion from ACE-based to CPS1-based [7]; the CPS1 criterion recently recommended by NERC was designed with a different motivation in mind; however, it directly lends itself to being useful for systematic design of a PXFC which is not restricted to a single CA[9]. Once the case is made for a PXFC market creation beyond a single CA/ISO, we describe how it could be implemented. The concepts are identical to the concepts described for a single control area.

VIII. Frequency versus ACE Control Algorithms

In the above proposed PXFC we have, in addition to moving from a centrally dispatched system to a competitive market, also shifted the technical criteria of the control algorithm from the area control error to an algorithm based only on the system frequency. This shift makes the control system more robust to inaccurate tie-line flow schedules. In fact, we will show that the performance of the frequency-based controller is independent from the scheduled flow of base load power. This, in turn, will allow more flexibility in the spot market trade, without having to coordinate last minute changes with the generators participating in frequency control. The market for frequency control presented here has been designed to minimize the need for real time coordination by a system operator.

As shown above, the structure of the contracts guarantees that the system-wide frequency criterion (8) will be met. To further illustrate the advantage of a frequency based control system, let us first consider the potential problems arising under the traditional ACE model.

A. Controlling Frequency with ACE

The area control error is a signal designed to estimate the net power imbalance originating within a specific control area. This is achieved by measuring the frequency deviation in the area, and discounting the effects of tie-line flows. Driving the area control error to zero, therefore, corresponds to balancing real power in each area, which, in turn, guarantees that systemwide frequency will be close to nominal. In the regulated environment the area control error provided an effective means of dividing the task of regulating systemwide frequency among the existing utilities. Using the area control error assured that no utility was forced to react to a disturbance not originating in its native load. Furthermore, since there were relatively few generators participating, maintaining an accurate schedule for tie-line flows was a manageable task.

The deregulation of the electric utility industry provides a drastic change in the conditions under which a frequency control system must operate. With the introduction of independent power producers (IPPs), and a number of aggregators both on the load and generation side, the number of active participants in the market has increased significantly. In addition, the complexity of the market structure is growing. The question is who is responsible for a power mismatch, physically as well as financially, and how the costs of balancing the system should be recovered. If we apply ACE to the deregulated market, we quickly run into a coordination problem.

Each time a trade is completed involving a generator and load in different control areas, the scheduled values of the tie-line flow will change. If trades on the spot market are conducted at an hourly rate, the system operator will be forced to recompute the tie-line schedule, update the operating point for the ACE measurement and re-dispatch this information to generators participating in frequency control each hour. If an update in the schedule is delayed or inaccurate, the controller will be functioning with the wrong operating point, potentially causing it to add a further disturbance rather than balancing the system. We will show the effects of inaccurate scheduling through an example in the next section.

B. Increased Flexibility via the PXFC

We have described how the area control error can be potentially destabilizing in the fast paced deregulated market. How then does the frequency based control system proposed in this paper circumvent this problem? If we examine the structure of the bilateral and controls contracts we see that they are designed to move the responsibility for frequency control away from the system operator and towards the individual participants. Each bilateral contract specifies the magnitude of the maximum potential disturbance which could be caused by the parties of the contract. This is matched by the frequency control contracts which reserve a proportional band of control generation to match the potential disturbance. Assuming that the PXFC coordinator is to be responsible for the purchase of all control contracts and distribute the cost in accordance with deviation bands on load-following contracts, its role is an administrative one. Since control contracts respond only to system frequency, the system operator is not required to provide generators with an update of scheduled tie-line flow. The operating point of the controllers is the nominal frequency, which is fixed at $60Hz$. As a result the frequency-based control algo-

[9]It is our understanding that most of the CAs experimenting with CPS1 use this measure as an accounting mechanism, and not as a tool for real-time frequency control.

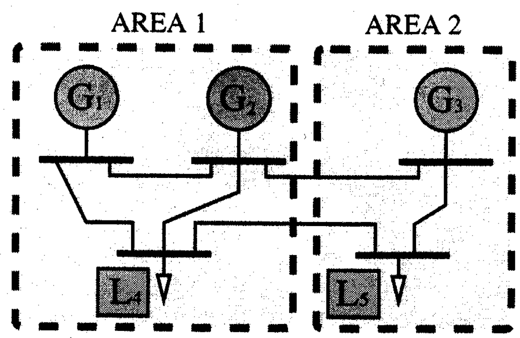

Fig. 7. A 5-bus System for Multi Control Area Simulations

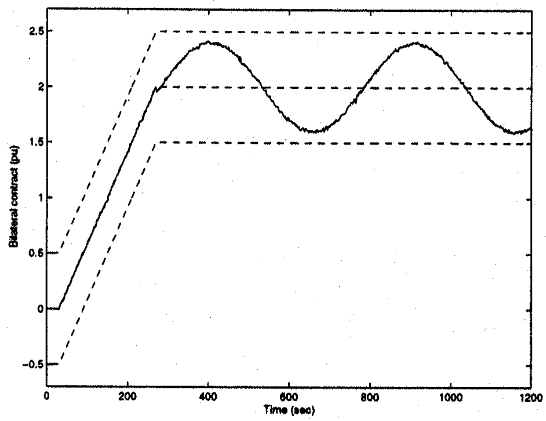

Fig. 8. A Bilateral Contract Between G_2 and L_5

rithm is completely separable from the primary market activities.

IX. Multi-Area Example

To illustrate the differences between a control algorithm based on the area control error and pure frequency control, we have simulated a simple five bus system with three generators and two loads, separated into two control areas (see Fig. 7). All transmission lines parameters and generator data are the same as those of the 4-bus example and G_3 has the same parameter as G_2.

Assume a single bilateral contract between generator G_2 and load L_5. The contract is a nominal contract curve bounded by upper and lower limits on load deviations. The actual load is set to deviate from the contract curve sinusoidally, but it remains within the contractual bounds. The complete setup of the contract and the actual load is shown in Fig. 8.

A. *Uncontrolled Frequency Response*

In order to have point of comparison for the performance of the control system we begin by simulating the system in the absence of any AGC. In this case system frequency will deviate freely in proportion to the net real

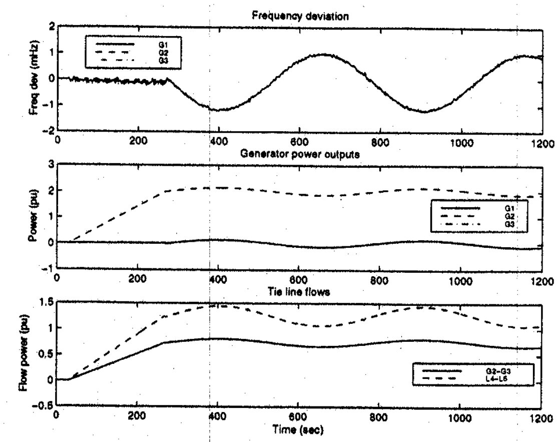

Fig. 9. Uncontrolled Frequency Response

power imbalance. The magnitude of the deviation will depend on the natural response of the system as described earlier in this paper. We can also see how the output of the generators varies slightly in inverse proportion to frequency. This is due to the droop characteristic of the generators. An increase in system frequency will cause a decrease in net power output, and vice versa. The uncontrolled system response is shown in Fig. 9.

B. *ACE versus Frequency Control*

We now consider the response of the system with a controller based on the area control error. In order to illustrate the effects of an error in tie-line scheduling on system performance, we will consider two instances. The first will assume a perfect schedule for the tie-line while the second assumes an approximate schedule.

We now simulate the closed-loop response of the system controlled by the area control error using first the exact and then the approximate tie-line schedule. As can be seen by comparing Fig. 10 and 11, the impact of the scheduling error is quite significant. The maximum frequency deviation increases from less than $1mHz$ for the perfect schedule to almost $4mHz$ for the approximate schedule. It is interesting to note that such a significant deterioration in performance occurred strictly due to an approximation error. If, instead, there had been a failure to add or remove several transactions from the schedule, the impact would have been disastrous.

We now simulate the system driven by the same disturbance but with our proposed frequency-based controller. From the perspective of the controls market there is a single control contract offered by G_3. The system response illustrated in Fig. 12 shows that the deviations in frequency are the same as in the case of the ACE based controller with perfect scheduling. This illustrates how shift from ACE to frequency-based control provides for increased robustness without any deterioration in performance.

An additional advantage of the new control law is that

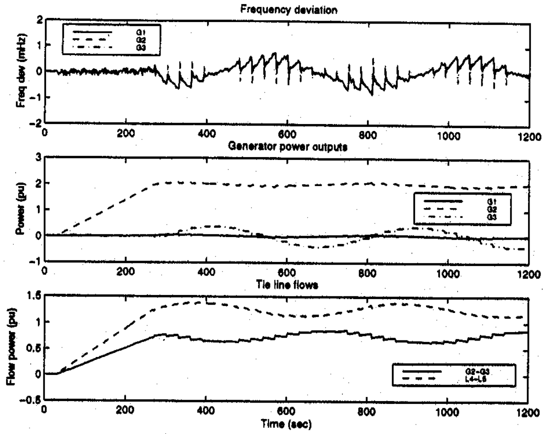

Fig. 10. System Response for Perfect Tie-line Flow Scheduling

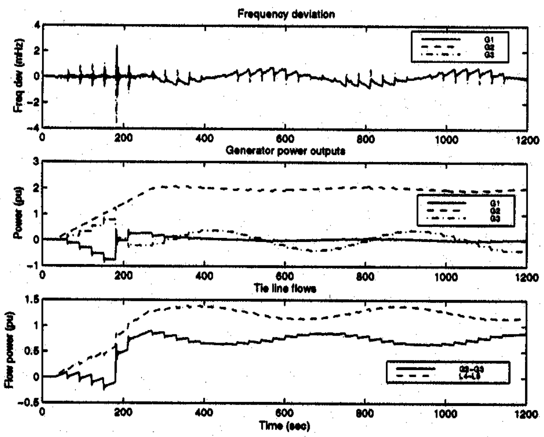

Fig. 11. System Response for Approximate Tie-line Flow Scheduling

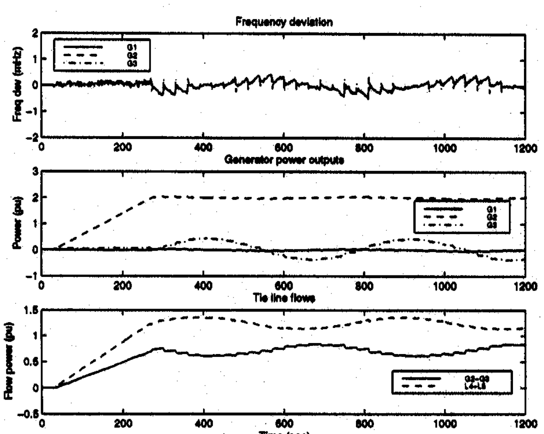

Fig. 12. System Response for Frequency Based Control

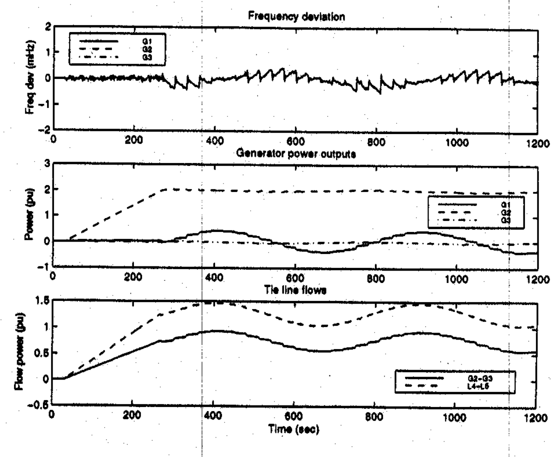

Fig. 13. System Response after the Control Contract of G_3 is shifted to G_1

it lends itself easily to the inter-area trade of control generation. Suppose that generator G_1 is able to offer the same control contract as G_3 at a lower bidding price. Fig. 13 shows the system response after the control contract has been shifted from generator G_3 to generator G_1. As we can see, there is no noticeable deterioration in the performance of the control system.

X. Conclusions

This paper proposes a power exchange market structure for frequency control necessary to balance power imbalances created through the primary electricity market activities. It is shown that it is theoretically possible to balance power and guarantee frequency quality through a very simple market structure. If the rules, rights and regulations for primary markets are well structured, it is possible to establish a market-based provision of frequency regulation in which the role of an ISO would be mainly supervisory.

This proposed scheme allows different load, with different characteristics and variability, to be charged differently – according to their actual impact on the system. This property of the PXFC is very appealing as a way to promote economic efficiency.

This scheme, of course, will not work perfectly. For implementation, and moving it toward real policy, there would need to be some enforcement or monitoring to make sure people do not misrepresent their load/generator characteristics, and so avoid actually paying for their true impact on the system. There will probably need to be some form of sanction or penalty for players who significantly and/or repeatedly make contracts, for example, with a deviation band more narrow than their true deviation.

Also, the robustness of the proposed market to the accuracy at which generator and load droop characteristics are known will have to be studied further to gain confidence in the proposed concept.

Nevertheless, it is somewhat exciting to have reached the point which indicates that market forces could balance power in real time with minimal coordination. This is conceptually possible because system frequency is more or less the same everywhere and, therefore, the actual location of power imbalance becomes secondary.

In the context of an open access comprised of several control areas, the conclusion is that when the ACE is replaced by the frequency criterion the fundamental role of control area is also lost; in an open access market boundaries between control areas are no longer relevant (nor legal) as power is traded within the interconnection. The PXFC proposed described in detail for a single control area is shown to be directly generalizable to the multi control area open systems, as well.

XI. Acknowledgments

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XIII. BIOGRAPHIES

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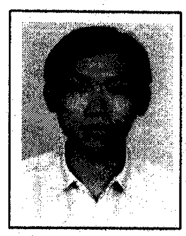

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Lester H. Fink retired in 1997 as Executive Vice President of KEMA Consulting. Earlier, he conducted and managed plant and system control research at the Philadelphia Electric Company (1950-74), developed and managed the national Systems Engineering for Power program at the U.S. Energy Research and Development Administration, engaged in contract research and consulting in the private sector (1970-1997), and served as adjunct professor at the University of Pennsylvania, Drexel University, and University of Maryland (passim). His publications include three U.S. patents (two on power system control) and over fifty papers. He is Life Fellow of IEEE and ISA, a member of CIGRE, and received the Meritorious Service Award of the U.S. Department of Energy.

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