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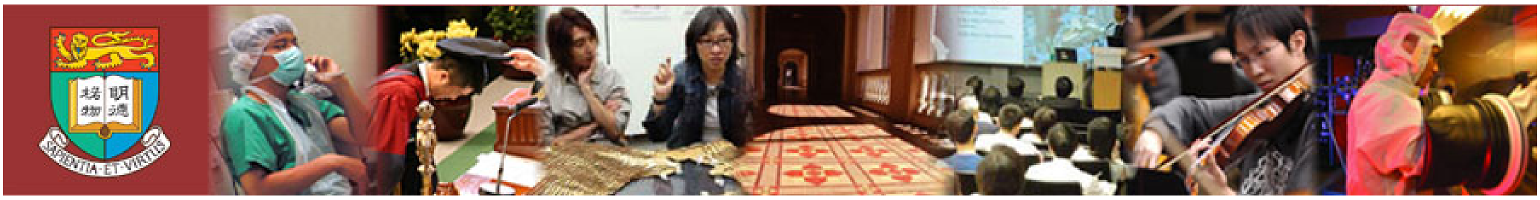

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PRICING FOR SYSTEM SECURITY

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Abstract

Security in power systems refers to the ability of the system to withstand imminent disturbances (contingencies). Maintaining security is an issue which must be addressed at the system level. It is shown in this paper, however, that it is possible to maintain system security in an operating environment with many participants (power companies, independent power producers, co-generators, consumers) each attempting to optimize their own benefit, through pricing incentives and appropriate information exchange. Rates for power generation/consumption and for an offer to use during a contingency, as well as information on the probability distribution of contingency need for each participant, are derived so that individual optimization will lead to the socially optimal solution in which system security is optimized and the aggregate benefit is maximized.

Keywords: Demand-side management, spot pricing, power system security, real-time pricing, power system reliability.

I. Introduction

The ultimate nightmare in power system operation is the occurrence of a widespread blackout like the one in New York in 1977, which causes tremendous economic losses to society and severe equipment damage to the utility [1]. The initiating event of such a blackout is typically a disturbance on the system, for example, lightning on a transmission line or failure of a generator. Disturbances occur frequently in power systems. Redundancy in generation and transmission facilities is built into the interconnected power system to make sure most disturbances can be tolerated. It is only when the effect of a disturbance cannot be contained and it causes overload and subsequent disconnection of equipment in other parts of the interconnected system that cascading outages occur.

Stringent planning and operating guidelines are set up to avoid cascading outages [2]. Planning engineers and system dispatchers strive to make sure that the system is planned and operated according to these *reliability criteria*. The criteria are expressed in two related forms, one being primarily for the generation system and the other being primarily for the transmission system. The former is a requirement on generation reserve, over and above the forecasted load demand. The latter is a requirement that the system should be able to withstand and survive a set of possible disturbances in the form of generation and transmission outages, which are called (credible) *contingencies*. This aspect of a system's capability is usually referred to as *security*. In other words, a system is secure if it is able to withstand a set of credible contingencies. In system operation, concern for security always comes first, and only when the system is secure does one consider economic dispatch. If the current operating point would not survive one of the credible contingencies, then the operating point is changed by redispatching generation or load to make it survivable, even at the expense of economy. This is called security control or preventive control [3]. Security requires the system to have enough controllable resources such as spinning reserve and direct load control to be able to steer the system to normal operation should a contingency occur.

System security is a concept that is particular to interconnected power systems. It is not determined by the capacity of individual generators, loads, or transmission lines. It is a property that has to be considered at the system level. There is usually more than one redispatch of

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generation and consumption which would maintain security. Different combinations requiring different contributions from individual generators and consumers may result in the same level of security. In the traditional situation where the utility is operated as a monopoly, security control is executed by the dispatchers exercising their authority to dictate the power output of each generator. The interesting research problem of how the dispatchers should set these outputs has been extensively studied over the past 15 years (see, for example, the extensive bibliography in [3]).

However, this traditional model of power systems operation is loosing its validity. Economic and technological changes have resulted in increasing numbers of generators which are owned and operated by entities other than the utility. These include independent power producers and co-generators. Further, changes in communiations technology will make it possible for some consumers to rapidly respond to system conditions. Both this type of consumer and non-utility generators should be considered as part of the security control problem.

One approach to security control is to maintain more or less the existing operating paradigm. Producers and consumers other than the utility are required to make available additional capacity for the utility to use to maintain security. This leads to such concepts as stand-by capacity requirement and dispatchability capability. This approach essentially requires the independent power producers and consumers to surrender their autonomy so that the utility has the authority to make decisions regarding system security. This would not lead to an economically efficient solution since the decisions would not take into account the cost structures of each participant. It may also raise the issue of fairness in light of the nonuniqueness of solutions to the security control problem. Moreover, it would be difficult to continue this paradigm when there is no single dominant player in the system.

In this paper we propose an alternative approach to maintaining system security—through inducement and cooperation. Each participant, be it a power company, an independent power producer, a co-generator or a consumer, is allowed to make its own decision concerning the most beneficial way to generate or consume electricity, as well as the amount to contribute for maintaining system security. However, we show that through pricing incentives and information on system needs, it is possible to achieve a socially optimal level of system security. The proposed approach assumes an operating paradigm that is characterized by decentralized decision-making. A discussion of the new paradigm is presented in the next section.

The research reported in this paper extends the work of Schweppe et al [4] who first proposed the use of pricing to maintain system security [4, pp. 214-222]. Using the approach of our earlier work [5], we have developed a probabilistic framework for calculating and achieving a socially optimal level of security, which properly allocates the burden of maintaining security to participants. The security/economy trade-off is thus resolved.

II. A Decentralized Operating Paradigm

In this paper, no distinction is made between those who consume and those who produce electrical energy. Each entity that engages in the generation or consumption of electrical energy or in the operation of a power system is referred to as a *participant*. These include electric utilities, independent power producers, co-generators and consumers. It is also assumed that there is one body responsible for setting prices for electricity and for publishing forecasts. This body is referred to as the *price setter* and its objective is to coordinate the interactions of the participants, producing a socially optimal outcome.

The operating decisions of each participant have two effects. First, they determine the actual level of operation of the participant at the present (operations) time. Secondly, according to how the participant's plant has been configured, the staffing levels and other such present time decisions, different levels of response to possible future system contingencies will be possible. For example, a production facility with co-generation might be configured so that the production facility could be rapidly by-passed, leading to a quick increase in electrical output. Another example might involve maintaining a higher level of storage, enabling a rapid reduction in electrical load demand without damaging the production facility. Thus each participant determines at the operation times the additional power that it *could* supply in the event of a contingency, either by reducing demand or increasing its electrical output. This amount is referred to as the *contingency offering*, and must be determined in conjuction with the other operations decisions. In the event of a contingency occurring, the amount of additional support from each participant is limited by its contingency offering.

The socially optimal solution for the actual level of generation/consumption of each participant at the present time is well-known - spot pricing at short-run marginal cost. The rest of this section will be devoted to the discussion of (i) what constitutes a socially optimal solution for participants' contingency offerings and (ii) how to induce the participants to offer that. It should be mentioned, however, a unified approach, encompassing both decisions, is actually adopted in the mathematical derivation in this paper.

In order to achieve a socially optimal coordination of operating decisions, it is necessary to account for the costs and benefits of all participants. There are three types of costs which are particularly relevant to security control. These are:

- The cost of a participant being prepared to respond to a contingency. This might, for example, include increased fuel costs associated with maintaining a spinning reserve or the costs of maintaining a higher storage level. These costs are actually incurred at the operations time.
- The cost to a participant of actually responding to a system contingency by reducing demand or increasing electrical output. These costs are only incurred in the event of a contingency.
- System collapse costs which arise if the security control fails to avert a system collapse. These costs are borne by society as a whole and include the effects of a failure of the entire supply system.

The objective is to achieve a socially optimal set of contributions to security control. That is, it is desired to encourage a contingency offering and, in the event of a contingency, actual support from each participant which minimizes the total social costs. The social costs can be thought of as the sum of three terms:

- the sum of each participant's costs associated with their contingency offering
- the sum of each participant's expected cost of responding to a contingency (i.e. the sum of the actual response costs weighted by the probability of the contingency occurring)
- expected system collapse costs (i.e. the product of the probability that the system will collapse and the actual cost of a collapse).

By minimizing these costs, the optimal economic trade-off between level of security and the cost of maintaining it will be found.

One possible approach could be based on issuing real time prices which rise during contingencies, thereby encouraging increasing generation and reduced load demand. During normal state operation, probabilistic forecasts of future prices would be required to obtain appropriate levels of preparedness (i.e. contingency offerings). These forecasts would need to account for the probability of each contingency. Each participant would respond to these forecasts by minimizing its costs which would be the sum of:

- the cost of its contingency offering and
- the expected actuation costs minus the income earned from the contingent spot prices. Here the expectation is over the probability distribution of the price forecast.

The main disadvantage of this approach arises because serious contingent events occur quite infrequently. Thus the price setter would have no opportunity to develop knowledge of the way in which the system contingency offerings would vary with price forecasts. Price setting and forecasting would therefore occur without feedback and could be quite inaccurate.

In this paper, we propose a different arrangement which avoids this problem by establishing contractual obligations for contingency offerings. At the operations time, each participant is shown a price for contingency offerings and a forecast of the probability of various levels of actual support that might be asked for. This probabilistic forecast would be parametrized by the level of contingency offering. The meaning of a given level of offering is that, should a contingency occur, any level of system support up to that level of contingency offering may be taken from the participant. Thus, while the participant determines its own level of potential contribution, the system operator determines the actual contribution level in the event of a contingency.

Each participant will respond to the price for contingency offerings and the forecasts of usage of contingency response by choosing its own level of contingency offering. It will aim to maximize its own profits, which can be written as the sum of:

- income from the sale of the contingency offering (i.e. the product of the price and the size of the contingency offering)
- minus the cost of preparing the plant to offer that level of contingency offering
- minus the expected cost of actually supplying system support, where the expectation is over the probability and size of the support, as determined by the forecast.

Clearly, the price and forecast of usage should be designed to encourage socially optimal levels of contingency offerings. The main advantage of this scheme is that the price (and forecast) setter has feedback on the levels of contingency support before a contingency occurs and can therefore adjust the price if there is either too little or an excess of system support. Thus there is a closed loop in the price setting process.

The main result of this paper shows that there is indeed a price that can be set for contingency offerings and a forecast for actual contingent usage that encourages each participant to make a socially optimal contingency offering (i.e. offerings which minimize the total social costs). In Section III of this paper, the above notions of interactions between participants and the price setter are made precise. The main pricing result is stated in Section IV and proved in the Appendix.

It is shown that the price for each unit of contingency offering should be set equal to the incremental effect on expected contingency costs, i.e. the derivative with respect to contingency offering level of the sum of

- expected system collapse costs (i.e. the product of the actual system collapse costs and the probability that the system will collapse), and

- the sum of each participants expected costs of actually responding to a contingency.

It is shown that a forecast for actual contingency usage is also necessary in order to induce socially optimal response. The forecast shows the participant how the probability of various levels of actual contingent support will change as a function of his/her contingent offering.

III. Mathematical Formulation

1. Preliminaries

Let the set of participants in the power system be represented by the index set J. Thus each $j \in J$ is either an electric utility, an independent power producer, a cogenerator or a consumer. Let the symbol ω_0 represent normal (non-contingent) operation and Ω represent the set of contingencies. For each participant $j \in J$, let y_j represent j's net level of injection of electrical energy into the system. Thus if j is a consumer y_j is negative and $-y_j$ is j's level of power consumption. If, on the other hand, j is a net producer of electrical energy, then y_j is positive and equal to j's level of power generation. (See [5] for further details.) Further let z_j represent j's contingent offering being the largest injection that the participant is prepared to offer. The difference between z_j and y_j might represent additional generation (spinning reserve) or consumption reduction (load management). Contingency offering is the limit set by the participant that can be taken should a contingency happen. In the following to simplify presentation, we assume that $z_j > 0$, implying a net injection and that the actual injection is somewhere between 0 and z_j. The results apply equally well to net consumers. Let the actual amount taken from participant j, when a contingency $\omega \in \Omega$ indeed occurs, be represented by $\zeta_j(\omega)$. Thus $\zeta_j(\omega)$ is the actual value of y_j after the contingency. Under that $z_j > 0$, we have

$$0 \le \zeta_j(\omega) \le z_j \qquad (1)$$

We define the J-vectors y, z, ζ to be the vectors of y_j, z_j, ζ_j.

Whether a contingency is survivable depends on the contingency ω and the system's ability to settle into a stable operating point after redispatch of generation and consumption. Survivability also requires that the new operating point does not cause equipment overload and abnormal voltages. For each contingency, the ability of the system to survive will depend on the level of support available to it. We may use a vector relationship to represent this, i.e., the system survives if and only if

$$S(\zeta(\omega), \omega) \lneqq 0 \ . \qquad (2)$$

The exact form of the above inequality can be derived from transient stability and load flow considerations [6,7]. Now we can define the set of *survivable contingencies* $\Omega_s(z)$, for a given z, as follows:

$$\Omega_s(z) = \{\omega \in \Omega : \exists\, \zeta(\omega) \text{ such that } \qquad (3)$$
$$0 \le \zeta_j(\omega) \le z_j \ \varsigma j\,,$$
$$S(\zeta(\omega), \omega) \lneqq 0\} \ .$$

For a given set of contingency offering z and a survivable contingency $\omega \in \Omega_s(z)$, the choice of $\zeta(\omega)$ is determined by the system dispatcher. When the choice is not unique, the system dispatcher may make the decision based on a reasonable criterion. One example of such a criterion is to maximize overall benefits of the participants, the detail of which will be discussed at the end of the next subsection after the appropriate terms are defined. At any rate, since the actual amount taken from a participant $\zeta_j(\omega)$ during a contingency depends on the contingency ω, as well as the contingency offerings z, let us use the function Φ to explicitly represent this dependency, i.e.,

$$\Phi_j(z, \omega) = \zeta_j(\omega) \ . \qquad (4)$$

2. Socially Optimal Solutions

To introduce the socially optimal solution $(\hat{y}, \hat{z})$, we need to define participants' benefit and cost terms. The cost of electricity is first separated from the other price-independent benefit and cost components of the participants. To simplify presentation, costs are all absorbed as negative benefits, so that a benefit term refers to the gross benefit minus (price-independent) cost. For example, for an industrial consumer "gross benefits" might include income earned from the sale of goods produced (except electrical energy) while "cost" would include the cost of purchasing all labor and raw materials (except electrical energy).

For each participant $j \in J$, define:

$b_j(y_j, z_j)$ = benefit for j if there is no contingency

$\beta_j(z_j, \zeta_j)$ = benefit for j if the system takes contingency response ζ_j when j offered z_j.

Thus $b_j(y_j, z_j)$ is the "normal" level of benefits (minus costs) and the net revenue for j would, with probability p_0, be $b_j(y_j, z_j)$ minus what is paid for electrical energy, plus what is earned from the sale of electrical energy. In general, $\beta_j(z_j, \zeta_j)$ will be negative, representing the cost to j of j's response.

For the set of contingencies Ω, define:

$P(\cdot)$ = probability measure on $\Omega \cup \{\omega_0\}$

$p_0 = P(\{\omega_0\})$, i.e., the probability of normal (non-contingent) operation.

For a given set of contingency offerings z, the probability that the system is secure can be obtained as:

$$R(z) = \int_{\Omega_s(z)} dP(\omega) \ . \tag{5}$$

Therefore, $(1 - R(z))$ is the probability, given the contingency offering z, that the system will not be secure, i.e., it is the probability that the system will collapse. Let the social cost of system collapse be denoted by K_{out}.

The socially optimal solution $(\hat{y}, \hat{z})$ is defined as an operating point for which the expected total benefit of all participants is maximized, the expected cost of system collapse is minimized, all participants are operating under their respective limits, and the power generation and consumption in the system are balanced.

The limits imposed by participant j's plant can be written as a set of inequalities:

$$h_j(y_j, z_j) \leqq 0 \ . \tag{6}$$

For example, a consumer's level of demand is limited by the capacity of its plant. The power balance may be represented by the load flow equations. However, for simplicity, here the power balance is written simply as

$$Y_{non} + \sum_{j \in J} y_j = 0 \tag{7}$$

where Y_{non} includes other generation-consumption and transmission losses. The results presented below can very easily be generalized by replacing equation (7) with a full set of power flow equations and inequalities representing line flow and bus voltage limits.

With the notation introduced above, the socially optimal solution $(\hat{y}, \hat{z})$ is the solution of the following optimization problem.

$$\max \{ \sum_{j \in J} p_0 b_j(y_j, z_j) - (1 - R(z)) K_{out} \tag{8}$$
$$+ \int_{\Omega_s(z)} \sum_{j \in J} \beta_j(z_j, \Phi_j(z, \omega))\, dP(\omega):$$
$$h_j(y_j, z_j) \leqq 0, \ \varsigma j \in J \ ,$$
$$Y_{non} + \sum_{j \in J} y_j = 0\} \ .$$

The first term in the objective function in equation (8) is the expected participant's benefits associated with "normal" (non-contingent) operation. The second term is the expected social costs of a system collapse while the third term is the negative of the expected participant's costs of responding to a survivable contingency.

Note that the costs of electricity are not present in the objective function in (8), this is because the revenue from the sale of electricity by the producers (negative costs to producers) is equal to the what the consumers have to pay (costs to consumers), so the net cost from a societal point of view is zero. It is just a transfer payment.

Returning to the selection of $\zeta(\omega)$ by the system dispatcher during a contingency ω, a socially optimal selection $\Phi(z, \omega)$ may be obtained from the solution of the following optimization problem:

$$\max \{ \sum_{j \in J} \beta_j(z_j, \zeta_j(\omega)): 0 \leq \zeta_j(\omega) \leq z_j, \varsigma j, \tag{9}$$
$$S(\zeta(\omega), \omega) \leqq 0\} \ .$$

In the above formulation the dispatcher selects the contingency requirement (generation or load reduction) from each participant in such a way that the sum of the benefits of *all* participants is minimized. In other words, the dispatcher's objective is to achieve a socially optimal solution under the circumstance.

3. Participant's Decision Making

Each participant is operating in a decentralized environment. He/she decides on the amount y_k to be generated or consumed and the amount z_k to offer to the system to assist in maintaining system security. The decision is made purely to maximize his/her own benefit.

We assume that each participant receives from the system the following information:

(i) $\pi_k(y_k, z_k)$ = the price for electricity if participant k generates (consumes) y_k and offers z_k for contingencies;

(ii) $F_k(\eta_k | z_k)$ = probability that the system will take contingency support $\zeta_k = \eta_k$ from participant k if z_k was offered.

For participant k, the decision-making problem is to maximize its own expected net benefit. This can be stated as the selection of $(\hat{y}_k, \hat{z}_k)$ to solve:

$$\max \{ p_0 b_k(y_k, z_k) - \pi_k(y_k, z_k) \tag{10}$$
$$+ \int_0^{z_k} \beta_k(z_k, \zeta_k)\, dF_k(\zeta_k | z_k): h_j(y_k, z_k) \leqq 0\} \ .$$

The objective function in (10) represents the expected net benefit (i.e., benefit-cost) and it has three terms. The second term is the cost of electricity $\pi_k(y_k, z_k)$. The first and the third terms together represent the expected benefit. The first one is the benefit for k if there is no contingency, $b_k(y_k, z_k)$, and it is weighted by its probability p_0. The third term is the expected benefit for k if there is a contingency. The benefit during a contingency depends on how much ζ_k is taken from k by the system. Since participant k receives the information on the probability distribution of how much the system will take from k if he/she offers z_k, $F_k(\zeta_k | z_k)$, the expected benefit can be calculated from the integral $\int_0^{z_k} \beta_k(z_k, \zeta_k)\, dF_k(\zeta_k | z_k)$. Moreover, participant k's decision should be made within its plant limitation, i.e., $h_j(y_j, z_j) \leq 0$.

IV. Security Pricing

In this section we will show that it is possible to achieve the socially optimal solution through participants' decentralized decision making if each participant receives proper pricing signals reflecting security needs and some additional information related to system security. The result will first be presented as a theorem, whose proof is in the Appendix, and the discussion of its interpretation will follow.

We need to introduce more notation. Consider a fixed participant $k \in J$, and define for each z_k and y_k,

$$\hat{Z}^k(z_k) = (\hat{z}_1, \cdots, \hat{z}_{k-1}, z_k, \hat{z}_{k+1}, \cdots, \hat{z}_J) \quad (11)$$

$$\hat{Y}^k(y_k) = (\hat{y}_1, \cdots, \hat{y}_{k-1}, y_k, \hat{y}_{k+1}, \cdots, \hat{y}_J) \quad (12)$$

which are the vectors of contingent offerings and non-contingent injections (generation-consumption) if everyone except participant k makes socially optimal choices. Define

$$\hat{\Omega}_s^k(z_k) = \Omega_s(\hat{Z}^k(z_k)) \quad (13)$$

which is the set of contingencies which are survivable. For each $j \in J$ including k itself, and for each $\omega \in \hat{\Omega}_s^k(z_k)$ define

$$\hat{\phi}_{j|k}(z_k, \omega) = \Phi_j(\hat{Z}^k(z_k), \omega) \quad (14)$$

which is the optimal utilization of participant j's contingent offering if ω occurs and the vector of all participants' offerings is $\hat{Z}^k(z_k)$. Define

$$\hat{\beta}_{J|k}(z_k) = \sum_{j \neq k} \int_{\hat{\Omega}_s^k(z_k)} \beta_j(\hat{z}_j, \hat{\phi}_{j|k}(z_k, \omega))dP(\omega) \quad (15)$$

$$\hat{\lambda}_k = \left[K_{\text{out}} \frac{\partial R(\hat{Z}^k)}{\partial z_k} + \frac{\partial \hat{\beta}_{J|k}}{\partial z_k} \right] \Bigg|_{z_k = \hat{z}_k} . \quad (16)$$

Their meaning will be explained after we introduce the following theorem.

Theorem. Suppose that participant $k \in J$ is shown price and forecasts given by

$$\pi_k(y_k, z_k) = -\hat{\theta} y_k - \hat{\lambda}_k z_k \quad (17)$$

$$F_k(\zeta_k | z_k) = P(\{\omega \in \hat{\Omega}_s^k(z_k) : \hat{\phi}_{k|k}(z_k, \omega) \leq \zeta_k\}), \quad (18)$$

where $\hat{\theta}$ is the shadow price of eq. (7) or the short run marginal cost of the system, then individual participant's decision making as determined by the solution of (10) will be socially optimal: i.e.,

$$\tilde{y}_k = \hat{y}_k \quad (19)$$

$$\tilde{z}_k = \hat{z}_k . \quad (20)$$

The theorem states that it is sufficient for each participant to be given:

- a pricing structure for electricity
- a forecast of contingency need.

The price of electricity has two components, one for the participant's generation or consumption, and one for his/her contingency offering. The rate charged for generation/consumption is the short-run marginal cost ($\hat{\theta}$) of the system, which is consistent with previous results [4,5]. The rate charged for participant k's contingency offering z_k can be viewed as the marginal contingency cost ($\hat{\lambda}_k$). It has two components (see. Eq. (16)):

(1) Incremental effect of z_k on the expected cost of system collapse. This component is evaluated by first considering the effect of the change in contingency offering from the optimal z_k on the probability of system collapse $(1 - R(z))$ assuming all other participants will offer the optimal $\hat{z}_i$, and then considering the cost of system collapse K_{out}.

(2) Incremental effect of z_k on the expected costs of all other participants. This component is evaluated by again assuming all other participants will offer the optimal $\hat{z}_i$, and considering the effect of the change in participant k's contingency offering from the optimal $\hat{z}_k$ on the change in the expected total costs (negative benefits) of all other participants.

It should be noted that in the first term, an increase in contingency offering will reduce the probability of collapse while in the second term, one participant's increase in offering will result in a reduction of response costs for all other participants.

The forecast of contingency need from participant k is the probability of the amount actually needed from participant k if he/she offers z_k. More precisely, it is expressed in terms of the conditional probability that given that participant k offers an amount z_k, the probability distribution of the amount the system will need from participant k assuming all other participants will offer the optimal $\hat{z}_i$.

V. Conclusion

In this paper a decentralized operating environment is assumed in which all participants including power companies, independent power producers, co-generators, and consumers attempt to optimize their own benefits of electricity utilization or generation. Through pricing and forecast information, the end result is that they cooperate to maintain system security.

The main result of this paper shows that there is indeed a price that can be set for contingency offerings and a forecast for actual contingent usage that encourages each participant to make a socially optimal contingency offering (i.e. offerings which minimize the total social costs).

It is shown that the price for each unit of contingency offering should be set equal to the incremental effect on expected contingency costs, i.e. the derivative with respect to contingency offering level of the sum of

- expected system collapse costs (i.e. the product of the actual system collapse costs and the probability that the system will collapse), and
- the sum of each participants expected costs of actually responding to a contingency.

It is shown that a forecast for actual contingency usage is also necessary in order to induce socially optimal response. The forecast shows the participant how the probability of various levels of actual contingent support will change as a function of the contingent offering.

The proposed approach has the following characteristics:

- Decision making is decentralized;
- Supply-side and demand-side are treated equally;
- Utilities, other producers, and consumers cooperate in system operation;
- Security-economic tradeoff is incorporated;
- Information technology is used to assist power system operation.

The implementation of the proposed approach requires a communication, computing, and control (3C) system capable of calculating the needed pricing and forecasting information and transmitting to the participants [8]. The amount of data communication may exceed the capability of existing energy management systems [9]. Detailed implementation issues need to be explored and are outside the scope of this paper.

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Appendix

Proof of Theorem

Define $\hat{y}_j, \hat{z}_j, \hat{\theta}_j, \hat{\gamma}_j$ for $j \in J$ to be the (assumed unique) solutions of the Kuhn-Tucker equations for equation (8): $\varsigma k \in J$

$$p_0 \frac{\partial b_k}{\partial y_k} + \gamma_k^T \frac{\partial h_k}{\partial y_k} + \theta = 0 \tag{23}$$

$$\begin{aligned} p_0 \frac{\partial b_k}{\partial z_k} &+ K_{out} \frac{\partial R}{\partial z_k} + \frac{\partial}{\partial z_k} \int_{\Omega_s(z)} \beta_k (z_k, \Phi_k(z,\omega))\, dP(\omega) \\ &+ \frac{\partial}{\partial z_k} \int_{\Omega_s(z)} \sum_{j \neq k} \beta_j (z_j, \Phi_j(z,\omega))\, dP(\omega) \\ &+ \gamma_k^T \frac{\partial h_k}{\partial z_k} = 0 \end{aligned} \tag{24}$$

$$\gamma_{k,l} = \begin{cases} 0 & \text{if } h_{k,l}(y_k, z_k) < 0 \\ \geq 0 & \text{if } h_{k,l}(y_k, z_k) = 0 \end{cases} \tag{25}$$

$$Y_{non} + \sum_{j \in J} y_j = 0 \,. \tag{26}$$

Define $\tilde{y}_k, \tilde{z}_k, \tilde{\gamma}_k$ to be the (assumed unique) solutions of the Kuhn-Tucker equations for equation (10):

$$p_0 \frac{\partial b_k}{\partial y_k} + \gamma_k^T \frac{\partial h_k}{\partial y_k} - \frac{\partial \pi_k}{\partial y_k} = 0 \tag{27}$$

$$\begin{aligned} p_0 \frac{\partial b_k}{\partial z_k} &+ \frac{\partial}{\partial z_k} \int_0^{z_k} \beta_k (z_k, \zeta_k)\, dF_k(\zeta_k \mid z_k) \\ &+ \gamma_k^T \frac{\partial h_k}{\partial z_k} - \frac{\partial \pi_k}{\partial z_k} = 0 \end{aligned} \tag{28}$$

$$\gamma_{k,l} = \begin{cases} 0 & \text{if } h_{k,l}(y_k, z_k) < 0 \\ \geq 0 & \text{if } h_{k,l}(y_k, z_k) = 0 \end{cases} \tag{29}$$

It follows from equations (14) and (18) that for $z = \hat{Z}^k(z_k)$

$$\int_{\Omega_k(z)} \beta_k(z_k, \Phi_k(z, \omega))\, dP(\omega) \qquad (30)$$
$$= \int_0^{z_k} \beta_k(z_k, \zeta_k)\, dF_k(\zeta_k \mid z_k)\,.$$

Thus, substituting equations (17) and (18) into equations (27) to (29) and comparing the resulting equations to equations (23) to (25) for k shows that $\hat{y}_k$, $\hat{z}_k$ and $\hat{\gamma}_k$ satisfy equations (27) to (29). ∎

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Discussion

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Kaye, Wu, and Varaiya are concerned with the problem of maintaining power system security in electric systems where there are many independent participants (including both producers and consumers) who might contribute to security. Their paper describes the pricing incentives that might induce these participants to behave in an optimal manner. Using a single-period model, the paper demonstrates that, in an optimal pricing regime, power system participants should be paid one price for their actual power output and another price for their "contingency offering" (i.e., the output that they promise to provide upon request). The paper finds that the price for actual output is the shadow price of the power balance equation. Because the paper assumes constant transmission losses, it finds that this price is the same for all participants. The paper finds that the price for contingency offerings varies by participant: each participant's price reflects the benefits that that participant's offering confers upon all other participants.

We believe that Kaye, Wu, and Varaiya address issues that will become increasingly important as the decentralization of the power supply industry proceeds. We generally concur with their results.

We note that similar results have been developed in the past. In reference 4 (page 216), for example, Schweppe, Caramanis, Tabors, and Bohn derive a two-part optimal price, with one part being a "security control implementation price". In EPRI project RP 2996-1, Caves, Kirsch, and Schoech also find a two-part price: the price for actual output depends upon multi-period dispatch, and varies by participant according to the participant's electrical location and according to the uncertainty in the participant's prospective output; while the contingency offering price, which is the same for all participants, is the market clearing price that is required to bring forth an adequate aggregate quantity of contingency offerings. The new element in Kaye, Wu, and Varaiya's results seems to be that the contingency offering price depends upon the benefits that each participant's offering confers upon all other participants, regardless of whether the others are demand-side or supply-side participants.

We caution that all of the foregoing results -- including those by Kaye, Wu, and Varaiya -- assume perfect information. That information includes: advance knowledge, by system dispatchers, of which contingencies are survivable; advance knowledge, by each participant, of individual costs and benefits without contingencies and for each potential contingency response requirement; and advance knowledge, by each participant, of the probabilities that each potential contingency response might be called by system dispatchers. Furthermore, prices must be simultaneously set for all participants. In a theoretical model, these information requirements can be overlooked. For practical implementation, however, these requirements must be addressed. Fortunately, the evidence is that real markets operate well enough even though participants have imperfect knowledge of their own benefit functions, and even though prices are more or less simultaneously set for all participants. The information problems that are peculiar to electric power system decentralization are therefore those that are best analyzed at the system dispatch level: the problem of identifying important contingencies; and the problem of identifying probabilities of occurrence of various system configurations.

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Closure was not provided by the author.