A NEW APPROACH FOR RESERVE MARKET CLEARING AND COST ALLOCATING IN A POOL MODEL[*]

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Abstract– A new approach for optimal reserve determination and cost allocation in the pool-based and disaggregated market model using a well-being framework is presented in this paper. In the proposed method, customers have the chance to specify the risk level which they are willing to accept. Firstly, the energy market is cleared, and afterwards the reserve market is cleared such that the required risk levels of different customers are satisfied. Then, according to the required risk levels and the provided reserve, the cost of reserve is allocated between the different customers with different reliability requirements. For fairly managing the shortage between different customers in the real time operation by the system operator, the *Interruption Factor* is introduced for the first time in this paper. Although from the economic point of view reliability is a public good, using the concept of the interruption factor, different customers with different reliability requirements can be differentiated. Finally, the proposed method is applied to the IEEE-RTS to examine the applicability and effectiveness of the proposed method.

Keywords– Deregulation, reserve market, cost allocation, public good, pool model, well-being

1. INTRODUCTION

Power systems are undergoing restructuring. One significant change in the deregulated power industry is establishing power markets and introducing competition. Deregulation has been taken into practice in different forms in most countries and is under study in others. In the new environment, a vertically integrated utility (VIU) is divided into its three main components, including: Generation companies (Genco), Transmission companies (Transco), and Distribution companies (Disco). The purpose of restructuring is different in the various countries, but the most common is to increase efficiency. Increasing efficiency as a result of competition is one of the most important objectives of deregulation. Competition can facilitate efficiency, price transparency and also supply-demand satisfaction.

In this new environment, there are energy and various ancillary services markets. Ancillary services are necessary for the reliable and secure operation of power systems [1]. There are different types of ancillary services such as spinning reserve (SR), non-spinning reserve, voltage and reactive support, black start, and etc [1]. Energy and ancillary services are normally separated in the new environment and different entities are responsible for providing these commodities. In some power markets, energy and ancillary services are cleared by a single entity, while in others, different entities are responsible for procuring energy and ancillary services.

Reliability in an electrical power system can be considered in two aspects: security and adequacy. Adequacy is the ability of an electric system to supply the aggregate electrical demand and energy requirements of their customers at all times. Security, however, is the ability of the system to withstand sudden disturbances such as electric short circuits, or the unanticipated loss of system elements such as generating units or transmission lines [2]. In the networked industries such as electricity, once a consumer

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demands reliability all other consumers benefit from the added reliability without having to pay for it. Therefore, as stated in [3], security is a public good.

In [4] an approach for procuring operating reserve, including contract-based and pool-based has been presented using an insurance policy. In [5] a method has been presented to schedule generating units so that a given risk index is met. The optimal value of this risk index was determined by cost-benefit analysis. Using the correlation between capacity and reliability, a scheme for the procuring and pricing of operating reserve in the deregulated environment has been proposed in [6]. In [7], customers in the bilateral model can purchase spinning reserve according to their needs using a well-being framework. A novel pool-based market-clearing algorithm, which is based on the deterministic/probabilistic criterion for application in the electricity market, has been proposed in [8]. Energy and reserve are solved simultaneously and units are committed such that the loss of load probability (*LOLP*), or the expected energy not supplied (*EENS*), is smaller than the predetermined value. An integrated energy and spinning reserve market model has been presented in [9], in which market dispatch is carried out so that the total payment, including both energy and spinning reserve and also expected energy not served (*EENS*) is minimized.

In this paper, a method for a reserve (ten minute operating reserve) clearing market in the disaggregated and pool framework is presented. A disaggregated framework has some advantages and disadvantages versus the aggregated one. Lower complexity and transparency of clearing results are the advantages of a disaggregated framework. Aggregated market clearing behaves as a "black box" in which justifying and explaining schedules and prices are very difficult [10]. In this paper, the required reserve is determined using the well-being framework. The well-being framework is first proposed for vertically integrated utilities and works very well in this environment [11-15]. In the proposed method, different customers achieve the different reliability levels by preparing different capacities of reserve. After clearing the energy and reserve markets, the costs of these commodities are allocated between different customers according to their energy and reliability requirements. For fairly managing the shortage between different customers in the real time operation by the system operator, the *Interruption Factor* is introduced for the first time in this paper.

This paper is organized as follows: in section 2 the well-being framework is reviewed. In section 3, the proposed method is presented, and the simulation results are given in section 4. In section 5, concluding remarks and discussions concerning the proposed method have been presented.

2. WELL-BEING FRAMEWORK

The concepts of the PJM method for solving a unit commitment problem were illustrated in [16]. In this probabilistic method, the system performance is identified as being in either the comfort or at the risk domains for a given load and committed units. This is a pure probabilistic method and doesn't give any information about the degree of the system comfort. To solve this problem, a well-being framework has been introduced in [11], which includes deterministic considerations into the probabilistic indices for monitoring the system well-being. This model is shown in Fig. 1.
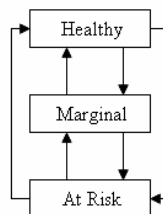

Fig. 1. Well-being framework

The definitions of these three states are as follows [11]:

Healthy: A system operates in the healthy state when it has enough reserve to withstand the deterministic criterion, i.e. any single unit outage.

Marginal: A system operates in the marginal state when it does not have sufficient margin for withstanding specified deterministic criterion.

At Risk: A system operates in the risk state when the system load is higher than or equal to the operating capacity.

According to the above definitions, the total system state probabilities can be expressed as follows:

$$P_H + P_M + P_R = 1 \tag{1}$$

Where, P_H, P_M, and P_R are probabilities of the system in the healthy, marginal and at risk states, respectively. The operating criterion which can be used in the unit commitment are, satisfying an acceptable risk level, satisfying an acceptable healthy level or both. Selecting an operating criterion depends on the required reliability level. If a single criterion is adopted, the goal is to satisfy the following condition:

$$P_R \leq SSR \tag{2}$$

Here, SSR stands for the maximum system's specified risk. Therefore, according to (2), the generating units are committed so that the probability of system risk is not higher than the system's specified risk, which is determined by the system operator. If multiple criteria are adopted, the following constraints should be satisfied.

$$P_R \leq SSR \quad \text{and} \quad P_H \geq SSH \tag{3}$$

The above inequalities mean that generating units should be committed such that, not only the probability of risk is smaller than the *SSR*, but also, the probability of a healthy state is higher than the *SSH (*system's specified healthy). The values of *SSR* and *SSH* are determined by the system operator.

3. PROPOSED METHOD

As stated before, the well-being framework has been proposed for the vertically integrated utilities and works very well in this environment. In these systems, the system operator owns the system and determines the *SSR* and *SSH* for the entire system. In this situation, the total system has a single risk and healthy state probability. But, as stated earlier, such systems have low efficiency. Deregulation and restructuring are introduced to overcome this problem and its objective is to allow customers to choose their suppliers based on price and reliability [17]. Therefore, the well-being framework needs to be modified for implementing in this new environment. In [7] the well-being framework was used in the bilateral model. In the proposed method, the well-being framework is used in the pool-based model. The risk part of well-being is considered in this paper. In the proposed framework, customers have a chance to choose their required risk levels.

a) Market model

The market structure that is used in this paper is a disaggregated pool model. In this market the energy and reserve are respectively cleared by the market operator (MO) and the system operator (SO). In some power markets such as the Spanish electricity market, the system operator and the market operator are separate entities [18], while in others such as Texas, both functions are performed by a unique entity [19]. Generators submit their offer curves for energy and reserve to the market. These curves must be

monotonically increasing functions of price. Customers submit their energy requirements and the required risk levels to the market operator and the system operator, respectively.

It is assumed that customers have the ability to choose their desired risk levels. The clearing process for energy and reserve has two steps. At first, based on the generators' offers and the customers energy requirements, the market operator clears the energy market and the cost of energy is allocated. Then, according to the reliability of the committed units in the energy market, the system operator procures reserve such that the required risk levels of all customers are satisfied and the cost of the procured reserve is allocated between customers with different reliability requirements. After clearing the reserve market, the interruption factor is calculated. Using the interruption factor, the reliability can be fairly managed between different customers in the real time operation.

b) Clearing mechanism

Assume that the number of customers which are participating in the market is N. These customers have to submit their energy requirement as $l_1, l_2, \ldots, l_N$ to the market and for each hour of a specified day. For simplicity, the loads are considered inelastic with respect to the price. Furthermore, customers have a chance to choose their reliability level. One of the reliability indexes in the power system is risk. Therefore, customers can send their acceptable risk level as $R_1, R_2, \ldots, R_N$, to the market. This means that customers 1 and 2 prefer to have a risk level lower than R_1 and R_2 respectively.

On the other hand, generators submit their offer curves to the market. The curve is separated for energy and reserve, and it is necessary to submit a curve for each of them and for every hour of a day. For clearing the energy market, the aggregated load curve and aggregated generators' offer curves are intersected and the market clearing price (*MCP*) is derived from this intersection. The payment mechanism, which is considered in this paper for generators and customers are pay-as-bid (*PAB*) and uniform, respectively. Therefore, for energy cost allocation, the total payment should be calculated and allocated uniformly according to customers' energy requirements. For example, if the total cost of energy providing in an hour is *TCEM*, then the energy cost of customers 1 (EC_1) and 2 (EC_2) are as follows:

$$EC_1 = l_1 \frac{TCEM}{l_1 + l_2 + \ldots l_N} \qquad EC_2 = l_2 \frac{TCEM}{l_1 + l_2 + \ldots l_N} \qquad (4)$$

After clearing and cost allocating of the energy market by the market operator, the reserve market is cleared by the system operator and the reserve cost is allocated between different customers according to their reliability requirements. Suppose that the required risk levels of customers are as follows:

$$R_N \leq R_{N-1} \leq \ldots \leq R_2 \leq R_1 \qquad (5)$$

Assume that all customers can be classified into M ($M \leq N$) classes as listed in Table 1, each class consisting of customers having the same required risk level. The amount of load in each class (L_i) can be calculated as follows:

$$L_i = \sum_{j=N_{(i-1)}+1}^{N_i} l_j \qquad i = 1,2,\ldots,M \qquad (6)$$

Our proposed algorithm for clearing the reserve market will be implemented through the following steps (consider the flowchart in Fig. 2):

Step 1: Determine the number of customer class; in the worst case this number is equal to the number of customers (*N=M*).

Step 2: Set the initial reserve cost (RC_0) and the initial provided reserve (PR_0): $RC_0 = 0, PR_0 = 0$. Set $i = 1$.

Step 3: Set the initial reserve cost associated to each risk level: $RC_{k,0} = 0$ for $k = 1$ to *M*.

Step 4: Calculate the risk using the capacity outage probability table

Step 5: If the ith risk level is satisfied (risk is smaller than the R_i) go to Step 8

Step 6: Procure reserve from the reserve market (using the merit order method) such that the ith risk level is satisfied and compute the reserve cost for satisfying the ith risk level (RC_i).

Step 7: RC_i is allocated uniformly between those classes which submit the risk level equal to or smaller than R_i using the following relationship:

$$RC_{K,i} = \begin{cases} L_K \cdot \dfrac{RC_i}{\displaystyle\sum_{j=i}^{M} L_j} & i \le K \le M \\[6pt] 0 & 1 \le K < i \end{cases} \tag{7}$$

where, $RC_{K,i}$ is the share of Kth class in the reserve cost for satisfying the ith risk level.

Step 8: Calculate the expected energy not supplied (*EENS*) for the ith level as $EENS_i$

Step 9: $i \leftarrow i + 1$

Step 10: if $i \le M$ go to Step 4

Step 11: Determine the total reserve cost of each class as $RC_i = \displaystyle\sum_{j=1}^{M} RC_{i,j}$ and for *i*=1 to *M*. After calculating the reserve cost corresponding to each class, then the reserved cost associated to each customer in the class can be calculated uniformly according to their energy requirements.

Table 1. Customers classification according to their required risk levels

Class	Customers No.		Required risk level
	From	To	
1	1	N_1	R_1
2	$N_1 + 1$	N_2	R_2
.	.	.	.
.	.	.	.
.	.	.	.
$M-1$	$N_{(M-2)} + 1$	$N_{(M-1)}$	R_{M-1}
M	$N_{(M-1)} + 1$	$N_M = N$	R_M

The expected energy not supplied (*eens*) corresponding to each class can be computed as follows:

$$eens_1 = L_1 \frac{EENS_1}{\displaystyle\sum_{i=1}^{M} L_i}, \quad eens_2 = L_2 \frac{EENS_2}{\displaystyle\sum_{i=2}^{M} L_i}, \dots,$$

$$eens_{(M-1)} = L_{(M-1)} \cdot \frac{EENS_{(M-1)}}{\displaystyle\sum_{i=M-1}^{M} L_i}, \quad eens_M = EENS_M \tag{8}$$

Where, $eens_i$ is the expected energy not supplied corresponding to the ith class. Then, the interruption factor corresponding to each risk level is computed as follows:

$$IF_1 = \frac{eens_1}{\sum_{i=1}^{M} eens_i}, \quad IF_2 = \frac{eens_2}{\sum_{i=1}^{M} eens_i}, \quad ..., IF_M = \frac{eens_M}{\sum_{i=1}^{M} eens_i} \tag{9}$$

Here, IF_i is the interruption factor corresponding to the ith class. The interruption factors are used by the system operator when the system encounters a generation deficiency because of the outage of the generating units. Suppose that in the real time operation one or more generation are tripped, and the maximum available generation will be less than the system load. This deficiency will be allocated between each class using the following rule:

$$\text{Deficiency= available generation} - \text{system load}$$

$$IP_i = IF_i Deficiency \tag{10}$$

where, IP_i is the interrupted portion (in megawatt) of the ith class. It is clear that with having the interrupted portion of each class, the interrupted portion of each customer in the same class can be calculated uniformly according to their energy requirements.

4. SIMULATION RESULTS

a) Basic study

The IEEE-RTS [20] is used to examine the applicability of the proposed method. This system has 24 buses, 11 generator buses, 13 load buses, 33 transmission lines, and 5 transformers. The total number of generating units is 32, ranging from 12 MW to 400 MW. The total system generation is 3405 MW and the system annual peak load is 2850 MW. The generation data and the system priority loading order for the IEEE-RTS are given in the appendix. For the sake of simplicity, total load buses are divided into four main distribution companies. The peak loads of these companies are given in Table 2. The system lead time is assumed one hour.

According to the proposed method, customers can chose their required risk levels. Suppose that these customers submit their risk levels as shown in Table 3 to the system operator. It is clear that the customers who need a higher reliability level submit the lower risk level. In this case study, customers B and C submit the same required risk level. Therefore, these four customers can be classified into three classes. Customers A and D belong to class 3 and 1, respectively. Class 2 is constituted by customers B and C.

For simulating the proposed method, it is assumed that the load is varied from 40% up to 70% of the peak load. The number of committed units in the energy market clearing for these ranges of loads is shown in Table 4. After the clearing of the energy market by the market operator, the reliability of the committed units is submitted to the system operator. Then, the system operator provides a reserve so that the risk of each class is satisfied. The clearing results of the reserve market and the participation of each class are presented in Table 5.

For clarifying, suppose that the system load level is 1710 MW. From Table 4, units 1-9 are committed in the energy market. The risk of these committed units in the energy market is 0.0067901. It can be seen from Table 3 that the highest required risk level is 0.01 and this is higher than the risk of the committed units. Therefore, buying a reserve from the reserve market is not necessary. The system operator procures a reserve from the reserve market, such that the next risk level is satisfied. For satisfying the 0.005 risk level, it is necessary to buy a 30 MW reserve from the reserve market. According to Eq. (6), the share of classes 2 and 3 are 14.86 MW and 15.14 MW, respectively. After clearing the reserve market and calculating the share of customer classes 2 and 3, the system operator procures reserve so that the risk of

the system is lower than the risk level which is determined by the customer in class 3. In this step, the system operator buys a 148 MW reserve from the reserve market and all costs of this reserve should be paid by the customers in class 3 (customer A). The total procured reserve for satisfying this required risk level is 178 MW, and the share of classes 1, 2 and 3 are 0 MW, 14.86 MW, and 163.16 MW, respectively. It is clear that the reserve cost associated with class 2 should be allocated between customers B and C according to their load level.
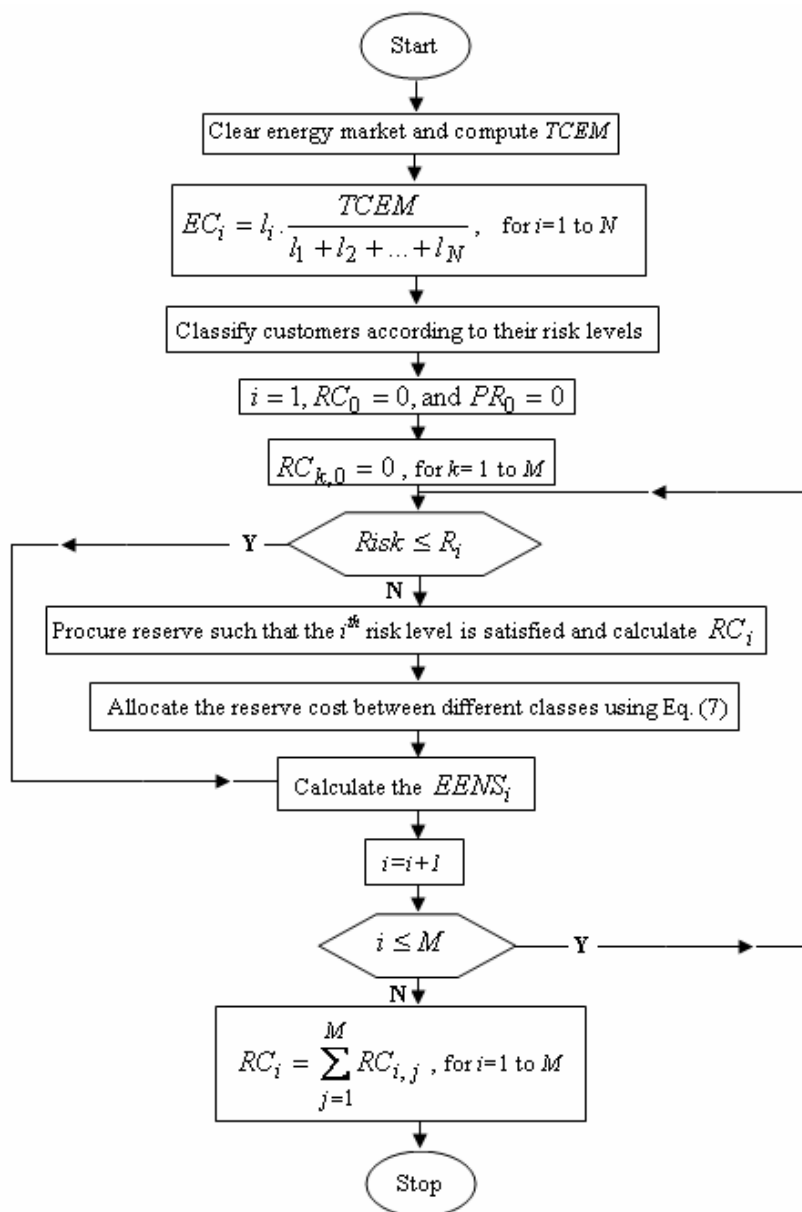
Fig. 2. Flowchart of proposed reserve clearing mechanism

Table 2. Customer peak load

Customer	Peak load (MW)
A	962
B	700
C	244
D	944

Table 6. EENS, *eens*, and IF factors corresponding to the each class

System load	$EENS_1$	$EENS_2$	$EENS_3$	$eens_1$	$eens_2$	$eens_3$	IF_1	IF_2	IF_3
1140	3.7985	2.2720	1.0981	1.2582	1.1253	1.0981	0.3614	0.3232	0.3154
1425	4.8450	3.0848	1.3982	1.6048	1.5278	1.3982	0.3542	0.3372	0.3086
1710	6.0448	3.9690	1.4105	2.0022	1.9658	1.4105	0.3723	0.3655	0.2622
1995	7.2425	3.3277	1.5679	2.3989	1.6481	1.5679	0.4272	0.2935	0.2793

Table 7. Effect of ORR on the procured reserve (MW)

Percentage increase in the ORR	Total procured reserve (MW)	Participation of class 3 (MW)	Participation of class 2 (MW)	Participation of class 1 (MW)
%10	178	163.14	14.86	0.0
%20	212	197.14	14.86	0.0
%30	278	197.3	80.7	0.0
%40	278	197.3	80.7	0.0
%50	295	197.64	81.13	16.23

5. CONCLUSION

A new approach for clearing the reserve market and cost allocating in the pool-based and the disaggregated model is presented in this paper. In the proposed method, customers have the chance to choose their required risk levels. That is, the customers send their energy requirement and required risk level to the market. The reserve market is cleared such that the submitted risk levels are satisfied. After clearing the reserve market, the cost of the reserve is allocated between the different customers according to their requested reliability levels. In the proposed method an interruption factor for managing the shortage between different customers in real time is introduced for the first time. Although from an economic viewpoint reliability is a "public good", by using the proposed interruption factor, deficiency in the real-time operation can be fairly distributed between different customers by the system operator. The proposed method has been applied to the *IEEE-RTS* and the simulation results, which ascertain the effectiveness and efficiency of the proposed method, has also been presented. Considering the healthy part of a well-being framework and also considering cost/benefit analysis are under study.

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APPENDIX

Generation unit data for IEEE-RTS

Priority order	Unit type	P_{max} (MW)	P_{min} (MW)	Ramp rate (MW/Min)	λ (f/yr)	Cost parameter		
						A	B	C
1-4	Hydro	50	0	10	4.42	0	0.5	0
5-6	Nuclear	400	200	0	7.96	216.576	5.345	0.00028
7	Thermal	350	150	9	7.62	388.250	8.919	0.00392
8-10	Thermal	197	80	6	9.22	301.233	20.023	0.00300
11-14	Thermal	155	60	5	9.13	206.703	9.2706	0.00667
15-17	Thermal	100	40	3	7.3	286.241	17.924	0.00220
18-21	Thermal	76	25	2	4.47	100.439	12.145	0.01131
22-26	Thermal	12	5	1	2.98	30.396	23.278	0.13733
27-30	Thermal	20	6	4	19.47	40	37.554	0.18256
31-32	Hydro	50	0	10	4.47	0	0.5	0