AN ELECTRICITY MARKET ANALYSIS METHOD BASED ON PROBABILISTIC PRODUCTION COSTING TECHNIQUE

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Abstract: This paper presents an efficient algorithm for evaluating the profit and revenue of generating units in a competitive electricity market based on the probabilistic production costing technique. The accurate evaluation of the profit and revenue of generating units for long-term perspectives is one of the most important issues in a competitive electricity market analysis. For efficient calculation of the profit and revenue of generating units under the equivalent load duration curve (ELDC), a new approach to figure out the marginal plants and the corresponding market clearing prices during a time period in a probabilistic manner is developed. The mathematical formulation and illustrative application of the suggested method is presented.

Keywords: Probabilistic Production Costing Technique, Equivalent Load Duration Curve, Expected Profit and Revenue Evaluation, Marginal Plant.

1.INTRODUCTION

The demise of the regulated electricity industry and the emergence of competitive markets is changing the way that electricity is and will be priced and is making increasingly difficult for market participants to appraise the prospects for the future electricity markets (Murray, 1998; Hunt and Shuttleworth, 1996). Due to introduction of competition in the electricity industry, a new framework is required to measure the impact of generator investments in terms of a generation company or regulatory body (Park, *et al*., 2002; Chuang, *et al*., 2001). These economic studies include the evaluation of expected revenue, cost, and profit of generating units and reliability measures during a time period in a long-term perspective.

The probabilistic production costing technique, first introduced by Baleriaux, *et al*. (1967) and Booth (1972) followed by several novel approaches (Stremel, *et al*., 1980; Schenk, *et al*., 1984; Lakshmi, *et al*., 1992), basically employs the equivalent load duration curve (ELDC) framework to consider the probabilistic characteristic of demand expressed in load duration curve (LDC) and the random outage of generating units simultaneously, which is the same as the convolution process of random variables (Wang and McDonald, 1994).

The probabilistic production costing method has been widely applied to electric utility planning, maintenance scheduling, and power system operational problems since it can provide lots of useful information such as the expected generation and cost of each unit, the total operating expense of an alternative, and reliability measures, etc. However, some additional information is required for the application of the production costing technique to competitive market analysis such as market clearing price (MCP), expected revenue and profit of each unit during a time period, etc.

In this paper, we propose an efficient profit evaluation algorithm for each generating unit directly applicable to competitive electricity markets. Also the explicit expression of expected generation of unit-*i* when unit-*j* is the marginal plant is obtained in a recursive form based on the modified probabilistic production costing technique, which can produce the same results from the chronological approach.

The suggested method can dramatically reduce the computation time to obtain the required information such as expected revenue, cost, and profit of each unit when compared to the chronological simulation algorithm (Pereira, *et al*., 1992). Therefore, the method can usefully and efficiently be used in the economic studies of capacity investment and development of maintenance scheduling strategies in competitive electricity market environments.

2. BASIC ASSUMTIONS

2.1 Generator and Demand Model

In this paper, the generators are modeled with 2-state representation (i.e., on-state with full capacity and off-state with zero capacity) and a power system is only composed of thermal generating units without fuel limitations. Also, the operating costs of each generating unit are regarded as constant values whereas the values are varying with the output levels in a real-world problem. The demand elasticity for the market price and the stochastic characteristic of demand are neglected in this paper.

2.2 Market Model

Generally, the electricity market in short-term perspectives can be modeled as a series of auctions for the right to serve the demand among generating units. Also, each auction can be characterized as sealed-bid and uniform priced (Sheble, 1999). However since we are interested in the long-term analysis, the electricity market model should incorporate the random outage of generating units. Therefore, we have assumed that the market clearing features also have the stochastic characteristics reflecting the randomness of generating units.

Also, the offer price of each generator is confined as the constant values with full capacity. The dispatch order among generating units in a LDC is determined by the increasing order of their offer prices, which is very similar to the dispatch situation in the conventional probabilistic production costing techniques.

The market clearing price (MCP) of each auction is determined by the offer price of the marginal generator while the MCP is capped with the pre-determined constant value in the case of the power shortage.

3. THE MATHEMATICAL MODEL

In this chapter, we will describe how to evaluate the expected energy, cost, revenue, and profit of generating units under a LDC. Suppose the market has n generating units and the generating units are indexed by the ascending order of the offer prices. Let the unit-i have the capacity of C_i [MW], the forced outage rate of q_i, the operating cost of oc_i [\$/MWh], and the offer price of op_i [\$/MWh]. We denote the time period of a LDC and the cumulative capacity until unit-i by DT [hours] and x_i [MW], respectively.

Let Π_i be the expected profit of unit-i, then we can decompose this value with respect to the market clearing prices. If we let Π_i^j and Π_i^{cap} be the unit-i's expected profit when the market clearing prices correspond to the offer price of unit-j and the price cap, mcp^{cap}, respectively, then Π_i can be represented by (1).

$$\Pi_i = \sum_{j=1}^{n} \Pi_i^j + \Pi_i^{cap} \tag{1}$$

Since $\Pi_i^j = 0, \forall j < i$, (1) can be rewritten as (2).

$$\Pi_i = \sum_{j=i}^{n} \Pi_i^j + \Pi_i^{cap} \tag{2}$$

Let us define the expected generation of unit-i when unit-j is the marginal one and when the price cap becomes the market clearing price by E_i^j and E_i^{cap} respectively. Then Π_i^j and Π_i^{cap} are represented by (3) and (4) which are composed of the revenue component (i.e., $op_j \cdot E_i^j$ and $mcp^{cap} \cdot E_i^{cap}$) and the cost component (i.e., $oc_i \cdot E_i^j$ and $oc_i \cdot E_i^{cap}$).

$$\Pi_i^j = \left(op_j - oc_i\right) E_i^j \tag{3}$$

$$\Pi_i^{cap} = \left(mcp^{cap} - oc_i\right) E_i^{cap} \tag{4}$$

Therefore, the expected profit can be specified only if we obtain E_i^j and E_i^{cap} for all generating units. Based on the conventional convolution theory, we can consider the random outage characteristics of generating units using equivalent load duration curve (ELDC). Generally, the ELDC is expressed as follows:

$$\begin{aligned} f^{(i)}(x) &= f^{(0)}(x) \oplus G_1 \oplus G_2 \oplus \cdots \oplus G_i \\ &= f^{(i-1)}(x) \oplus G_i \\ &= p_i f^{(i-1)}(x) + q_i f^{(i-1)}(x - C_i) \end{aligned} \tag{5}$$

where

G_i : random variable representing generating unit-i,

$\oplus$: convolution operator,

$f^{(0)}(x)$: original load duration curve.

To develop E_i^j and E_i^{cap} with analytic expressions for all generating units, it is necessary to define a variant of ELDC reflecting the conditional probabilistic situations. To do this, we have defined $f_i^{(j)}(x)$ as the conditional ELDC under the conditions that unit-i is on-state with probability of p_i and that the generators until unit-j are convolved. Then, $f_i^{(j)}(x)$ can be defined as follows:

$$f_i^{(j)}(x) = \begin{cases} p_i f^{(j)}(x) & \text{if } j < i \\ p_i f^{(i-1)}(x) & \text{if } j = i \\ p_i f^{(i-1)}(x) \oplus G_{i+1} \oplus \cdots \oplus G_j & \text{if } j > i \end{cases} \tag{6}$$

When j is smaller than i, unit-i is irrelevant to the convolution process until unit-j. Therefore, $f_i^{(j)}(x)$ becomes $p_i f^{(j)}(x)$. When j is equal to i, the convolution process is repeated until unit-(i-1) and the on-state condition of unit-i is handled by multiplying p_i . Therefore, $f_i^{(j)}(x)$ is expressed as $p_i f^{(i-1)}(x)$. In case j is larger than i, the convolution process is performed by convolving generators until unit-j except unit-i resulting $f_i^{(j)}(x)$ as $p_i f^{(i-1)}(x) \oplus G_{i+1} \oplus \cdots \oplus G_j$.

Based on the conditional ELDC defined in (6), we can acquire the analytic representations for the expected energy of each generating unit in a recursive form. Here, we should note that when E_i^j is assessed, there is no need to convolve unit j, j+1, … , and n since unit-j is the marginal unit and the randomness of unit-j is individually considered by the on-state condition. The E_i^j can be categorized into 3 cases; 1) the case of $j < i$, 2) the case of $j = i$, and 3) the case of $j > i$. In case of $j < i$, the value of E_i^j obviously becomes zero since the dispatch order of unit-i is preceded by unit-j. In case of $j = i$, the E_i^j (i.e., E_i^i) should be calculated based on $f_i^{(i-1)}$ (i.e., $p_i f^{(i-1)}(x)$) since unit-i itself becomes the marginal unit. The resulting expression for E_i^i is given in (7). The first term of the right-hand side in (7) (i.e., $DT\int_{x_{i-1}}^{x_i} f_i^{(i-1)}(x)dx$) is the total expected energy of unit-*i*, and the second term (i.e., $DT \cdot C_i \cdot f_i^{(i-1)}(x_i)$) is the expected energy of unit-*i* when unit-*i* is not the marginal unit. Therefore, by subtracting the second term from the first term, we can obtain E_i^i as (7).

$$E_i^i = DT\left[\int_{x_{i-1}}^{x_i} f_i^{(i-1)}(x)dx - C_i f_i^{(i-1)}(x_i)\right] \quad (7)$$

The shaded triangle in Fig. 1 is the expected energy of unit-*i* when unit-*i* becomes the marginal one under the condition that unit-*i* is on-state.

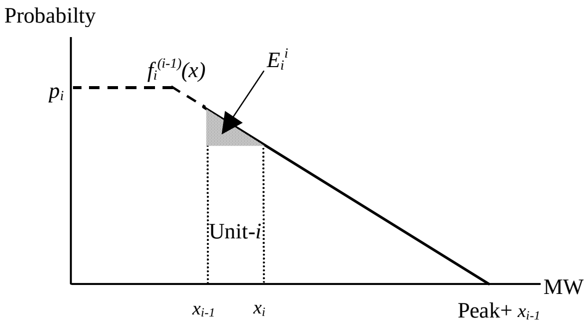

Fig. 1. Conditional ELDC of $f_i^{(i-1)}$ for E_i^i

On the other hand, we should impose one more condition when obtaining E_i^j, where $j > i$, that unit-*j* should also be on-state since otherwise, unit-*j* cannot be the marginal unit. This stochastic situation can be taken care of by $p_j \cdot f_i^{(j-1)}$. The probability with unit-*j* as the marginal unit under the on-state condition of unit-*i* can be expressed by $p_j \cdot \left[f_i^{(j-1)}(x_{j-1}) - f_i^{(j-1)}(x_j)\right]$. Therefore, E_i^j can be calculated as (8).

$$E_i^j = DT \cdot C_i \cdot p_j \cdot \left[f_i^{(j-1)}(x_{j-1}) - f_i^{(j-1)}(x_j)\right] \quad (8)$$

Fig. 2 shows $f_i^{(j-1)}$ where $j > i$ and the shaded rectangular corresponds to the expected energy of unit-*i* when unit-*j* becomes the marginal one under the on-state condition of unit-*i* which is defined by E_i^j.

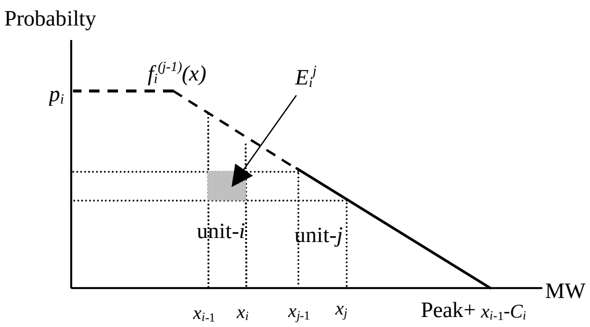

Fig. 2. Conditional ELDC of $f_i^{(j-1)}$ for E_i^j

Finally, in order to evaluate E_i^{cap}, the random outages of all generating units except unit-*i* should be considered. For unit-*i*, only the on-state is our concern since the off-state has no effect on E_i^{cap}. The $f_i^{(n)}$ can deal with this stochastic situation, and, therefore, E_i^{cap} can be obtained as (9).

$$E_i^{cap} = DT \cdot C_i \cdot f_i^{(n)}(x_n) \quad (9)$$

Fig. 3 shows $f_i^{(n)}$ and the shaded rectangular is the expected energy of unit-*i* when the price cap becomes the market clearing price under unit-*i*'s on-state condition which is denoted by E_i^{cap}.

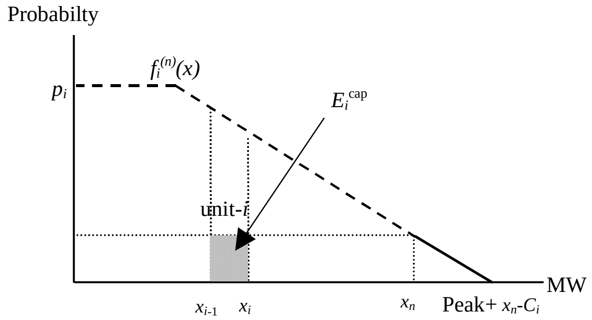

Fig. 3. Conditional ELDC of $f_i^{(n)}$ for E_i^{cap}

Therefore, the generic expression for E_i^j including the price capped situation is;

$$E_i^j = \begin{cases} 0 & \text{if } j < i \\ DT\left[\int_{x_{i-1}}^{x_i} f_i^{(i-1)}(x)dx - C_i f_i^{(i-1)}(x_i)\right] & \text{if } j = i \\ DT \cdot C_i \cdot p_j \cdot \left[f_i^{(j-1)}(x_{j-1}) - f_i^{(j-1)}(x_j)\right] & \text{if } j > i \\ DT \cdot C_i \cdot f_i^{(n)}(x_n) & \text{if } j = cap \end{cases} \quad (10)$$

Consequently, the expected profit of unit-*i* can be obtained by combining (3), (4), and (10).

4. NUMERICAL TESTS

4.1 Simple Test System with 3 Units

Test System Description

The developed algorithm for the evaluation of profit of each unit has been applied to a sample power system with 3 units whose data is described in Table 1. The dispatch order in an electricity market is determined by the offer price given in the 5th column of Table 1.

Table 1. Generator data of test system

Generator Name	Capacity (MW)	FOR	Operating Cost ($/MWh)	Offer Price ($/MWh)
Generator #1	200	0.05	0.024	0.025
Generator #2	200	0.05	0.027	0.028
Generator #3	150	0.10	0.030	0.031

The considered chronological demand during 3 hours is given in Fig. 4 with the base load of 100[MW], the medium of 300[MW], and the peak of 500[MW], respectively.

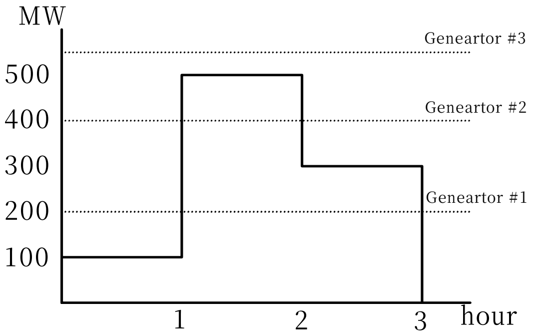

Fig. 4. Chronological demand of test system

Numerical Tests

In this section, we will compute the expected generation, cost, revenue, and profit of each generating unit for the test system using the proposed algorithm. Also, to show the validity of the suggested algorithm, the results of the proposed algorithm are compared with those of the conventional chronological approach (Pereira, *et al*., 1992).

To evaluate the required information in a probabilistic manner using the chronological approach, it is necessary to identify all the possible outcomes as described in Table 2. Each outcome is defined as a state denoted by a row vector whose element (i.e., *i*-th element corresponds to *i*-th generator) has a binary value (here, we denote on-state by 1 and off-state by 0).

Based on the results in Table 2, one can easily obtain the expected generation, cost, revenue, and profit of each generator in each hour. The results are summarized in Table 3.

From now on, we will show the effectiveness and efficiency of the proposed algorithm with the same test system. As we have discussed earlier, all information of each generator in Table 3 can be obtained using (3), (4), and (10). We will only show the details of solution procedures focused on Generator #1. The conditional ELDCs for Generator #1 including the original LDC can be obtained from (6) and depicted in Fig. 5.

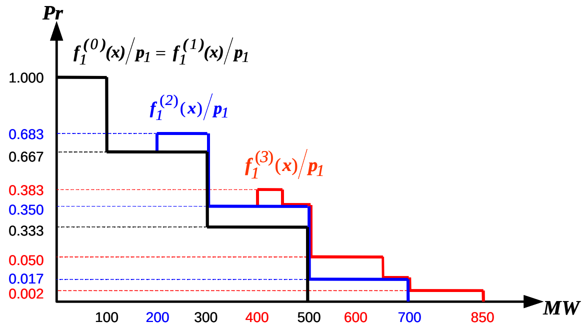

Fig. 5. Conditional ELDCs for Generator #1

The expected generation of Generator #1 (i.e., E_1) is composed of 4 components (i.e., $E_1^1, E_1^2, E_1^3, E_1^{cap}$). Each component can be calculated as follows using (6) and (10).

$$E_1^1 = DT \cdot \left[\int_{x_0}^{x_1} f_1^{(0)}(x)dx - C_1 \cdot f_1^{(0)}(x_1) \right]$$

$$= 3 \cdot 0.95 \cdot \left[100 + 100 \cdot \frac{2}{3} - 200 \cdot \frac{2}{3} \right] = 95\,[\mathrm{MWh}]$$

$$E_1^2 = DT \cdot C_1 \cdot p_2 \cdot \left[f_1^{(1)}(x_1) - f_1^{(1)}(x_2) \right]$$

$$= 3 \cdot 200 \cdot 0.95 \cdot \left[0.95 \cdot \frac{2}{3} - 0.95 \cdot \frac{1}{3} \right] = 180.5\,[\mathrm{MWh}]$$

$$E_1^3 = DT \cdot C_1 \cdot p_3 \cdot \left[f_1^{(2)}(x_2) - f_1^{(2)}(x_3) \right]$$

$$= 3 \cdot 200 \cdot 0.9 \cdot [0.95 \cdot 0.35 - 0.95 \cdot 0.017] = 171\,[\mathrm{MWh}]$$

$$E_1^{cap} = DT \cdot C_1 \cdot f_1^{(3)}(x_3)$$

$$= 3 \cdot 200 \cdot 0.95 \cdot 0.05 = 28.5\,[\mathrm{MWh}]$$

Table 2. State enumerations of the test system

State	Prob.	Hour-1 (100MW)		Hour-2 (500MW)		Hour-3 (300MW)	
		Gener.	MCP	Gener.	MCP	Gener.	MCP
(1,1,1)	0.8123	(100,0,0)	0.025	(200,200,100)	0.031	(200,100,0)	0.028
(1,1,0)	0.0903	(100,0,0)	0.025	(200,200,0)	0.1	(200,100,0)	0.028
(1,0,1)	0.0428	(100,0,0)	0.025	(200,0,150)	0.1	(200,0,100)	0.031
(1,0,0)	0.0048	(100,0,0)	0.025	(200,0,0)	0.1	(200,0,0)	0.1
(0,1,1)	0.0428	(0,100,0)	0.028	(0,200,150)	0.1	(0,200,100)	0.031
(0,1,0)	0.0048	(0,100,0)	0.028	(0,200,0)	0.1	(0,200,0)	0.1
(0,0,1)	0.0023	(0,0,100)	0.031	(0,0,150)	0.1	(0,0,150)	0.1
(0,0,0)	0.0003	(0,0,0)	0.1	(0,0,0)	0.1	(0,0,0)	0.1

Table 3. Expected generation and profit from chronological analysis

	Generator #1				Generator #2				Generator #3			
	H1	H2	H3	Tot.	H1	H2	H3	Tot.	H1	H2	H3	Tot.
Exp. Gen. (MWh)	95	190	190	475	4.75	190	99.75	294.5	0.23	94.39	8.89	103.5
Exp. Rev. ($)	2.38	7.79	5.41	15.58	0.13	7.79	2.89	10.81	0.01	3.83	0.30	4.14
Exp. Cost ($)	2.28	4.56	4.56	11.4	0.13	5.13	2.69	7.95	0.01	2.83	0.27	3.11
Exp. Prof. ($)	0.10	3.23	0.85	4.18	0.01	2.66	0.19	2.86	0.00	1.00	0.03	1.04

Therefore, E_1 becomes 475[MWh] which exactly matches with the results of the chronological approach. Each profit component of Generator #1 (i.e., Π_1^j) can be easily obtained by (3) and (4). That is,

$$\Pi_1^1 = (op_1 - oc_1)\cdot E_1^1 = (0.025 - 0.024)\cdot 95 = 0.095[\$]$$
$$\Pi_1^2 = (op_2 - oc_1)\cdot E_1^2 = (0.028 - 0.024)\cdot 180.5 = 0.722[\$]$$
$$\Pi_1^3 = (op_3 - oc_1)\cdot E_1^3 = (0.031 - 0.024)\cdot 171 = 1.197[\$]$$
$$\Pi_1^{cap} = (mcp^{cap} - oc_1)\cdot E_1^{cap} = (0.1 - 0.024)\cdot 28.5 = 2.166[\$]$$

Therefore, the total profit of Generator #1 becomes 4.18[$] which also exactly matches with the result in Table 3. The profits of Generator #2 and #3 are computed as 2.86[$] and 1.04[$] by the same procedures, which are the same as the results in Table 3. Note that the suggested algorithm can dramatically reduce the number of enumerations for profit evaluation of each generator. For example, the total number of enumerations in this sample study becomes 9 (i.e., 4+3+2) while the chronological approach requires 24 (i.e., 3×2^3). Therefore, one can use the suggested algorithm in the real-world power systems without the computational burden.

4.2 Modified Reliability Test System

Description of System

The generator data of the modified IEEE 24-node Reliability Test System (RTS) (IEEE Committee Report, 1979) are presented in Table 4. The dispatch order among the generators in an electricity market is determined by the offer price presented in the 5th column of Table 4. Note that the price cap of market is 2.0[$/MWh] in case of the power shortage. The chronological demand data has been used from data provided in IEEE 24-node RTS and the annual peak load of this system has been set to 2,000[MW].

Table 4. Generator data of modified IEEE RTS

Generator Name	Capacity (MW)	FOR	Operating Cost ($/MWh)	Offer Price ($/MWh)
Gen. #1	197	0.04	0.69	0.700
Gen. #2	350	0.08	0.70	0.708
Gen. #3	197	0.05	0.70	0.710
Gen. #4	197	0.06	0.71	0.720
Gen. #5	155	0.03	0.79	0.798
Gen. #6	100	0.03	0.79	0.800
Gen. #7	155	0.04	0.80	0.808
Gen. #8	100	0.04	0.80	0.810
Gen. #9	155	0.05	0.81	0.818
Gen. #10	100	0.05	0.81	0.820
Gen. #11	155	0.06	0.82	0.828
Gen. #12	76	0.02	0.90	0.908
Gen. #13	12	0.02	0.90	0.910
Gen. #14	76	0.03	0.91	0.918
Gen. #15	12	0.03	0.91	0.920
Gen. #16	76	0.04	0.92	0.928
Gen. #17	12	0.04	0.92	0.930
Gen. #18	76	0.05	0.93	0.938
Gen. #19	12	0.05	0.93	0.940
Gen. #20	12	0.06	0.94	0.950

Numerical Results

We will compute the expected generation and profit of each generating unit for the modified IEEE 24-node RTS using the proposed algorithm. Also, to show the efficiency and effectiveness of the suggested algorithm, the results of proposed algorithm are compared with those of Monte Carlo Simulation (MCS) (Billinton and Li, 1994) as well as chronological approach. The results are summarized in Table 5.

In Table 5, the results of Monte Carlo Simulation are obtained based on the following procedure:

Table 5. Comparison of simulation results of each method

Generator Name	Chronological Approach		MCS		Proposed Algorithm	
	Exp. Gen. (GWh)	Exp. Prof. (10^3\$)	Exp. Gen. (GWh)	Exp. Prof. (10^3\$)	Exp. Gen. (GWh)	Exp. Prof. (10^3\$)
Gen. #1	1652.15	187.91	1649.14	187.06	1652.15	187.92
Gen. #2	2812.99	278.82	2820.61	279.53	2812.99	278.83
Gen. #3	1632.64	168.96	1636.56	169.13	1632.64	168.96
Gen. #4	1507.06	149.50	1507.34	149.19	1507.06	149.50
Gen. #5	1009.38	31.72	1008.56	31.47	1009.38	31.73
Gen. #6	544.19	19.77	543.32	19.59	544.19	19.77
Gen. #7	656.25	20.49	653.40	20.14	656.25	20.50
Gen. #8	310.12	12.52	308.76	12.32	310.12	12.52
Gen. #9	329.44	13.17	329.36	13.02	329.44	13.18
Gen. #10	126.08	8.07	125.57	7.95	126.08	8.07
Gen. #11	97.67	9.42	96.57	9.22	97.67	9.42
Gen. #12	25.00	2.58	24.63	2.51	25.00	2.58
Gen. #13	2.91	0.41	2.85	0.39	2.91	0.41
Gen. #14	13.39	2.27	13.07	2.20	13.39	2.27
Gen. #15	1.52	0.36	1.48	0.35	1.52	0.36
Gen. #16	6.81	2.08	6.61	2.00	6.81	2.08
Gen. #17	0.76	0.34	0.73	0.33	0.76	0.34
Gen. #18	3.28	1.97	3.19	1.91	3.28	1.97
Gen. #19	0.36	0.32	0.35	0.31	0.36	0.32
Gen. #20	0.31	0.32	0.30	0.31	0.31	0.32

Step 1) Determine operating cycles of each generating unit. The operating cycle is in the form of chronological up-down-up. To obtain sampling values of the TTF (Time-to-Failure) and TTR (Time-to-Repair), we have assumed that operating time is exponentially distributed and repair time is constant value evaluated by multiplying 168 hours (1 week) by FOR.

Step 2) Compute the expected generation and profit of each unit during the sampling year. These values can be obtained by comparing the hourly available capacity model with the chronological load model.

Step 3) Repeat step 1) and 2) until the iteration is approached to the prefixed number of sample year. Note that we have set the number of sample year as 5,000.

Step 4) Compute the average values of expected generation and profit of each unit. These values can be evaluated by dividing summation of expected generation or profit of each sampling year into that of the total number of sample year.

The CPU time of each method is provided in Table 6. The CPU time of proposed method is remarkably low in comparison with those of MCS as well as chronological approach.

Table 6. Comparison of CPU times of each method

	Chronological Approach	MCS	Proposed Algorithm
CPU time (min)	1641	1383	44

As shown in Table 5 and Table 6, we can determine that the results of proposed algorithm are exactly identified with those of the chronological simulation algorithm and the computation time of proposed algorithm can be reduced when compared with those of chronological and MCS.

5. CONCLUSIONS

This paper presents an efficient algorithm for evaluating the profit and revenue of generating units in a competitive electricity market based on a variant of the probabilistic production costing technique. In the suggested algorithm, the expected profit of each unit can be acquired by identifying the marginal plant probabilistically in the viewpoint of the generator. Without any loss of accuracy of the probabilistic chronological method, the suggested method can dramatically reduce the computational complexity. Therefore, the proposed method is adequately applicable to long-term power system planning problems in the competitive electricity market environments.

ACKNOWLEDGEMENT

This work was financially supported by MOCIE through IERC program.

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