MAINTENANCE SCHEDULING APPROACH

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الخلاصـة :

تُقـدم هذه الورقة أسلوبا بسيطا وذا كفاءة في جدولة الصيانة الوقائية لأنظمة التوليد مبنيا على معامل للاعتمادية يُعرف بـ « معامل اعتمادية الطاقة » . وهذا المعامل قد اختير من بين عدة معاملات للاعتمادية ، لأن هناك معلومات مهمة لها تأثير على جدولة الصيانة كانتاج الوحدة من الطاقة والطاقة غير المتاحة وتكاليفها يمكن تقييمها مباشرة باستخدام نفس الطريقة التي يمكن بها استنباط معامل اعتمادية الطاقة دون أن يكون هناك مجهودا يذكر في الحسابات . ولكي يتم التحقق من الأسلوب المطور فقد جرى تطبيقه على نظام الـ IEEE-RTS والنظام الكهربائي للموحدة الوسطى (SCECOc) . وتم الحصول على النتائج المتوخاة .

ABSTRACT

This paper proposes a simple and efficient technique of preventive maintenance scheduling for generating systems, based on a reliability index called "Energy Index of Reliability, EIR". The EIR has been chosen among other reliability indices since other important information affecting the maintenance schedule such as unit energy production, unserved energy, and their costs can be directly evaluated using the same algorithm used for the EIR evaluation without extra computational efforts. To substantiate the methodology proposed, applications to the IEEE Reliability Test System (IEEE–RTS) and to the Saudi Consolidated Electric Company in the central region (SCECOc) as a practical system model have been conducted and the desired results obtained.

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INTRODUCTION

Due to the critical importance of the electric energy and the rising cost of its production, power utilities are compelled to minimize energy production cost while, in the mean time, operating within sufficient reserve margin to ensure an acceptable level of system reliability. Therefore, prevention of power system failures is of paramount importance during the design and operation of the system. A well-planned preventive maintenance schedule can have a significant effect on the achievement of this goal.

Units under maintenance are usually not available to the system during maintenance periods. The total installed capacity is, therefore, decreased which may contributes to a lower system reliability level which may lead to more power outages and energy interruptions. Scheduling maintenance should, therefore, be permitted taking into account system ability to meet adequately all load levels all the time.

Preventive maintenance is a regular routine of planned checkups and repair of generating equipment. It is required in order to reduce the probability of capacity shortage and improve the overall reliability level of power system. The maintenance scheduling specifies the period of the year each generating unit is to be taken out of service for preventive maintenance, taking into account the imposed load levels, reserve capacity, maintenance requirements and the forced outages of the units.

A BRIEF BACKGROUND

Several techniques have been proposed for preventive maintenance scheduling. The approximate calculation of the effective load-carrying capability (ELCC) of a generating unit [1] was useful in the classical maintenance scheduling approach [2] which is based on levelizing the reserve throughout the year. The ELCC replaces the unit ratings in the reserve leveling portion of the classical method. This technique converts the reserve levelizing method into one that levelizes the risk throughout the year. The loss-of-load expectation method (LOLE) is used to compute these risks. Levelizing the LOLE is superior to levelizing reserve and has recently received considerable attention. Dillon *et al.* [3] considered that the gross reserve of the system during any period of maintenance (say a week) is the total installed capacity minus the peak load forecast for that period. This has to be achieved under several complex, complicated, and improperly structured constraints, which will greatly restrict the choice of scheduling times. Stremel [4] and also Chen and Toyoda [5] have proposed a new goal for maintenance scheduling which minimizes the total LOLE throughout the year instead of levelizing it. A much more efficient approach has recently been described in [6], where a load model is constructed for each interval in which the effect of units on maintenance is included by a deconvolution procedure. The modified load models for all intervals are combined to render a composite load model for the year from which the annual indices are computed.

A maintenance scheduling optimization has been attempted [7] taking into account both production cost and reliability consideration. Dynamic programming has been used to solve the optimal maintenance scheduling problem. It was concluded, however, that the production cost is very flat around the optimum supporting the theory that maximizing reliability tends to minimize production cost and, therefore, reliability is the most effective objective function for maintenance scheduling. One aspect of the cost which is not considered in [7] that might alter the conclusion is the overlooking of the outages cost, *i.e.* the cost of the expected energy not being served (EENS) by the supply [8–13].

RELIABILITY INDICES

Two fundamental indices used in generating system reliability analysis are the LOLE [14] and the Expected Energy Not Served, EENS [15]. The LOLE denotes "the expected number of days on which the system demand is not totally satisfied due to capacity deficiencies in the generation system". The EENS is defined as "the expected amount of energy not being served by the system considered due to capacity deficiency".

Because of its simplicity, the LOLE is a widely adopted and used reliability index in power system planning and operation. Although the application of EENS requires more computational effort, utilization of this index is now increasing since it is considered to have more significance than the LOLE as it gives a measure of severity of deficiency rather than only the average amount of time that deficiency will exist. EENS could be normalized by dividing it by the total energy demanded and subtracted from one to give the Energy Index of Reliability (EIR) and this will be discussed in the following section.

ENERGY-BASED RELIABILITY INDICES

Although the LOLE is considered as the most popular reliability index, however, the EENS is now receiving more attention and will possibly replace the LOLE because of its physical significance, in that, power systems are energy systems. It is useful therefore to evaluate relevant energy indices for the studied systems, these include EENS and the Energy Index of Reliability (EIR). An additional advantage given by energy based evaluation methods is that the energy served by each unit can be evaluated for system reliability/cost assessment [16, 17]. Therefore, the above mentioned indices can be derived as follows:

Referring to Figure 1, the expected energy delivered by unit 1 is given by

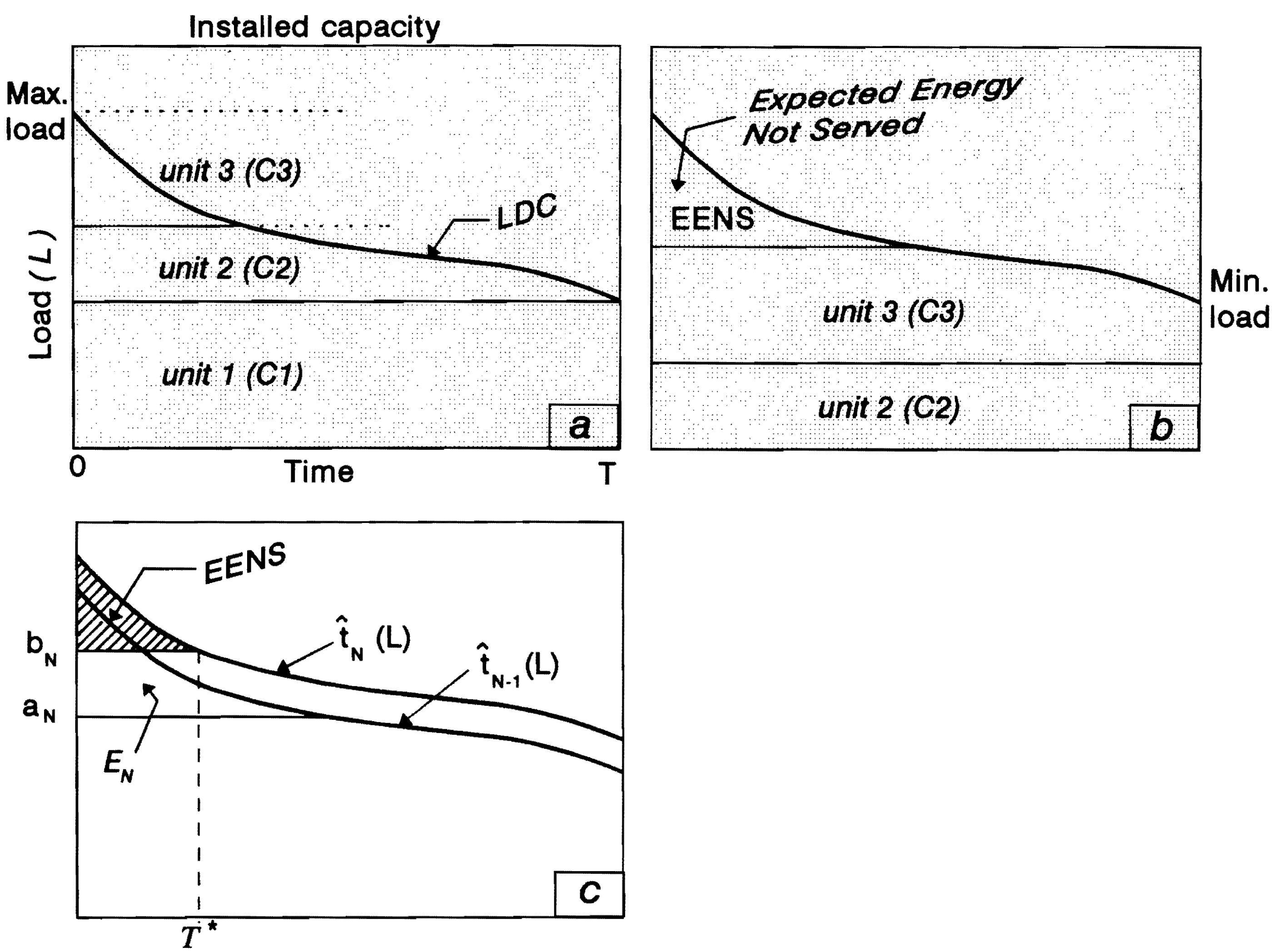

Figure 1. (a) Units Loading with Unit 1 in Service; (b) Units Loading with Unit 1 on Outage; (c) Modified Load Duration Curve for the Last Two Units to be Loaded.

$$E_1 = p_1 \int_0^{C_1} t(L)dL \tag{1}$$

representing the area occupied by unit 1 beneath the LDC. In calculating the energy served by the second unit, two components are considered. First, when unit 1 is available (with probability of p_1), unit 2 will be loaded to supply system load between the levels c_1 and c_1+c_2. Second, when unit 1 is on outage (with probability of q_1), unit 2 will occupy the lowest position under the LDC, supplying system load between the levels 0 and c_2. The expected amount of energy served by unit 2 is

$$E_2 = p_2 \left[p_1 \int_{c_1}^{c_1+c_2} t(L)dL + q_1 \int_0^{c_2} t(L)dL \right]. \tag{2}$$

Recognizing that

$$\int_0^{c_1} t(L)dL = \int_{c_1}^{c_1+c_2} t(L - C_1)dL$$

which acts to shift the LDC up by the amount c_1. Now, Equation (2) becomes

$$E_2 = p_2 \int_{c_1}^{c_1+c_2} \left[p_1 t(L) + q_1 t(L - C_1) \right] dL . \tag{3}$$

The influence of the availability of unit 1 on the operation of unit 2 may be reflected through modifying the load duration curve. A "Modified load duration curve, MLDC" is defined as follows:

$$\hat{t}_1(L) = p_1 t(L) + q_1 t(L - C_1). \tag{4}$$

Substituting Equation (4) into Equation (3), yields

$$E_2 = p_2 \int_{c_1}^{c_1+c_2} \hat{t}_1(L)dL \tag{5}$$

which has a form similar to Equation (1).

To evaluate the expected energy served by unit 3, the effects of outages of both units 1 and 2 must be considered (since position of unit 3 under the LDC depends on the availability of units 1 and 2). The MLDC, $t_1(L)$ incorporates the effect of forced outage of unit 1. Unit 3 is, therefore, loaded according to this curve if unit 2 is available. If unit 2 is not available, the MLDC, $t_1(L)$ is shifted upward by c_2 and used, that is,

$$E_3 = p_3 \left[p_2 \int_{c_1+c_2}^{c_1+c_2+c_3} \hat{t}_1(L)dL + q_2 \int_{c_1+c_2}^{c_1+c_2+c_3} \hat{t}_1(L - C_2)dL \right]. \tag{6}$$

Defining the MLDC for unit 2

$$\hat{t}_2(L) = p_2 \hat{t}_1(L) + q_2 \hat{t}_1(L - C_2). \tag{7}$$

Substituting Equation (7) into Equation (6), yields

$$E_3 = p_3 \int_{c_1+c_2}^{c_1+c_2+c_3} \hat{t}_2(L)dL . \tag{8}$$

Now, comparing Equations (1), (5), and (8), the following recursive formula can be used for evaluating the expected energy served by each unit n

$$E_n = p_n \int_{a_n}^{b_n} \hat{t}_{n-1}(L)dL, \quad n = 1, 2, \ldots, N \tag{9}$$

where

$$a_n = \sum_{i=1}^{n-1} C_i, \quad b_n = \sum_{i=1}^{n} C_i$$

and

$$\hat{t}_n(L) = p_n \hat{t}_{n-1}(L) + q_n \hat{t}_{n-1}(L - C_n).$$

For unit 1, the MLDC and LDC are identical, that is,

$$\hat{t}_0(L) = t(L). \tag{10}$$

After the expected energies for all units in the system have been evaluated using the recursive formula (Equation (9)), the final MLDC, $t_N(L)$ includes the forced outage effects of all units and consequently contains additional information about the system. Referring to Figure 1, T^* is the number of days that the equivalent load equals or exceeds the system capacity, commonly known as the LOLE for the power system and it is given as:

$$\text{LOLE} = \hat{t}_N(b_N) = T^*. \tag{11}$$

The shaded area shown in Figure 1, defined by $t_N(L)$ and total system capacity b_N, represents the expected energy not served (EENS) and can be defined as:

$$\text{EENS} = \int_{b_n}^{\infty} \hat{t}_N(L)dL. \tag{12}$$

In generation planning and operation, it is often useful to find the ratio between the energy not served and the total energy demanded by the system, because this provides a reliability index that does not depend on particular system characteristics. Hence, it can be compared with those of other systems with different generating capacity and different load demand. To express the EENS in per unit ($\text{EENS}_{p.u.}$), EENS is divided by the total energy demanded (*TED*) during the time period considered and as follows:

$$\text{EENS}_{p.u.} = \frac{\text{EENS}}{\text{TED}}. \tag{13}$$

The $\text{EENS}_{p.u.}$ is usually very small because the energy curtailed is a small fraction of the total energy demanded, therefore, another energy index known as the "energy index of reliability (EIR)" is an extended form of the EENS and can be expressed as

$$\text{EIR} = 1 - \text{EENS}_{p.u.}. \tag{14}$$

SCHEDULED MAINTENANCE

When a unit is on maintenance, it is usually not available to serve energy. This increases the system risk. It is generally agreed [8, 9] that a realistic method of incorporating scheduled maintenance is to divide the year into intervals during which the units on planned outage remain unchanged. The generation system and load models are then developed for each interval and convoluted to yield interval indices which can be aggregated to produce annual indices. Therefore, the main objective of the maintenance scheduling programme is to schedule maintenance in a way that minimizes the annual risk. This can be achieved by levelizing the risk throughout the year. For maintenance scheduling, the year is divided into an integer number of intervals (usually weeks). The maintenance requirement of each unit is an integer number of the selected interval. The generating units should be loaded according to a loading priority order based on their least operating costs.

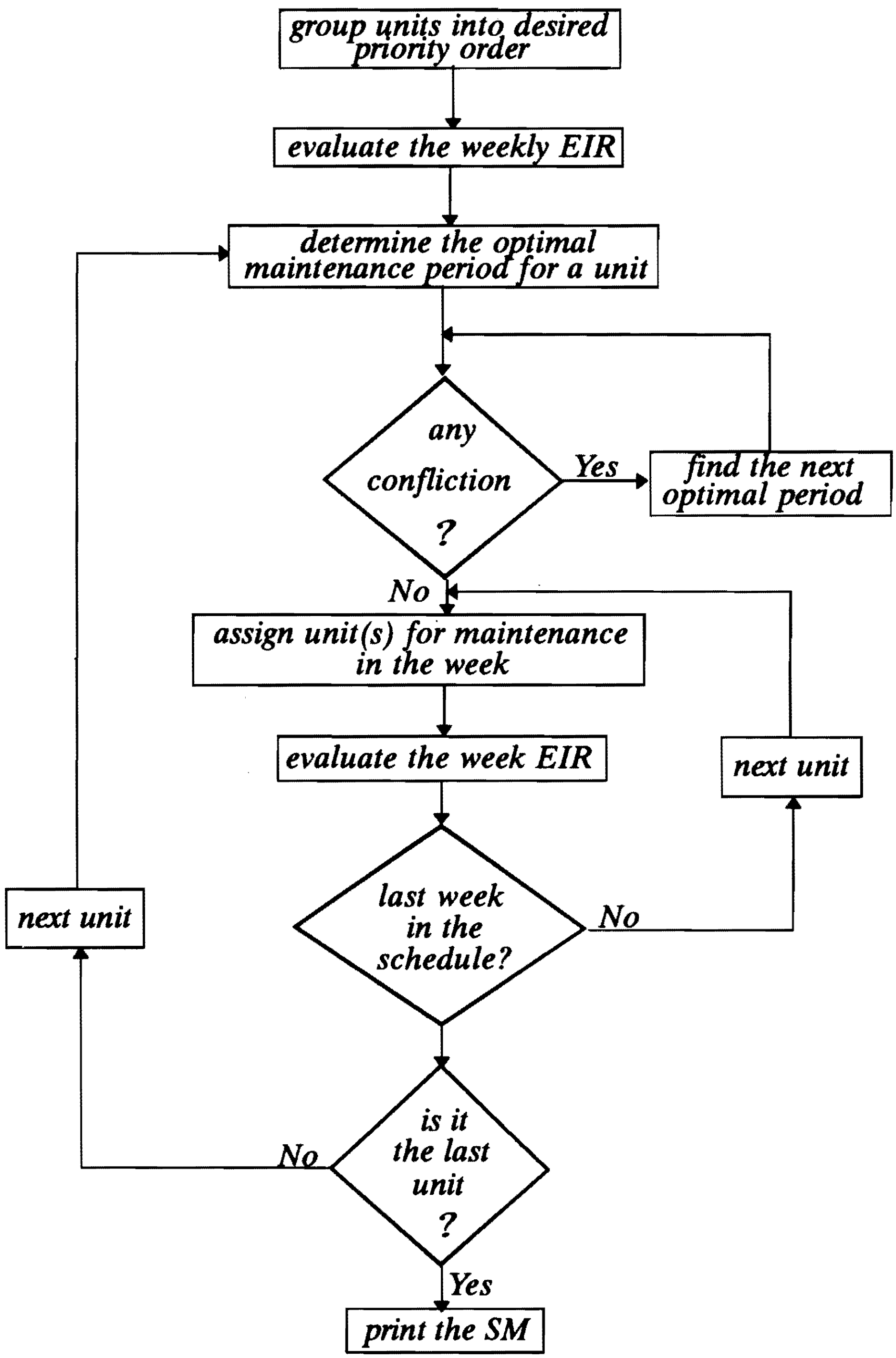

Figure 2. Flow Chart for the Proposed Method.

In this paper, a maintenance scheduling method based on levelizing the EIR is proposed. The proposed method avoids the time-consuming convolution of the load model and the capacity model for each interval. In fact, the proposed method requires approximately the same computational effort for inclusion of scheduled maintenance as presented by the deconvolution method [6] or by the approximate method [18]. The basic concept of the suggested method is to arrange individual generating units or group of units in increasing order of flexibility in the maintenance schedule. In this way, the units or group of units that are the most difficult to schedule because they need longer maintenance and/or they have a larger capacity that may increase the system risk when they are on outage, are considered first. The remaining units, easier to schedule, are considered subsequently. To ensure that the unit(s) being out of service for maintenance will not cause any capacity deficiency, the maintenance schedule is specified to be in the most convenient period(s) of the year where the peak demands are low and no confliction with other system constraints. The procedure is shown in the flow chart of Figure 2.

SYSTEMS STUDIED

The proposed method, based on the EIR levelization approach, has been applied to the IEEE Reliability Test System (RTS) and to the Saudi Consolidated Electric Company in the central region (SCECOc). The basic procedure of this method is to arrange individual generating units or group of units in an increasing order of flexibility in the maintenance schedule. In this way, the units or group of units that are large and/or most difficult to schedule because they need longer maintenance periods, thus increasing the system risk when they are on outage, are considered first. The remaining easier to schedule units are considered subsequently.

Application to the IEEE–RTS

For evaluation of the proposed method, The IEEE–RTS as described in [19] and extended in [20] has been used. The generating system contains 32 units with a total capacity of 3405 MW. The units capacities range from 12 to 400 MW (see Table 1). The RTS load model (see Table 2) gives data on weekly peak demands. The annual peak occurs in week 51. If week 1 is taken as January, Table 2 describes a winter peaking system. If week 1 is taken as a summer month, a summer peaking system can be described.

To test the methodology proposed, Table 3 shows a comparison in calculated reliability indices for the IEEE–RTS with that obtained in references [6, 20]. It reveals some resemblance in the results that may substantiate the techniques developed in this paper.

Table 4 shows the maintenance schedule for the IEEE–RTS using the proposed method compared to the method based on levelizing the LOLE [20]. It can be seen that the proposed method gives different maintenance activities in several weeks. Both methods, however, did not allow maintenance in weeks 1, 2, 19, 23–25, and 45–52. Figure 3 shows a comparison of reserve capacity before and after maintenance using the LOLE levelization technique [20] and the proposed technique. Figure 4 shows the profile of the weekly EIR before and after performing the preventive maintenance. It is noted that the two biggest units, which have the capacity of 400 MW, have been scheduled for maintenance in the highest EIR period.

Application to the SCECOc System

The generation system for SCECOc system has 7 power plants with 71 gas turbine units. The total installed capacity is 3050 MW. There are three tie lines connecting SCECOc to SCECOe with a total import power ranging from 500 to 1100 MW. Details of system data are shown in Tables 6 and 7.

Table 7 shows the preventive maintenance schedule for the SCECOc using the proposed method. Figure 4 shows the profile of weekly EIR before and after performing the preventive maintenance, while Figure 5 shows the capacity reserve for the system before and after maintenance. In this system the maximum unit outage for maintenance occurred in weeks 30–39 corresponding to the minimum demand time, while no maintenance was allowed for weeks 1–15, 51 and 52 which are the weeks of peak demand. More units could have been scheduled during minimum demand period if the available crew constraints is not considered leading to a more levelized EIR.

Table 1. IEEE–RTS Generating Unit Data.

Unit size MW	Type of unit	Number of units	MTTR hrs.	MTTF hrs.	Forced outage rate	Scheduled Maintenance weeks/year
12	Oil 3	5	60	2940	0.02	2
20	GT	4	50	450	0.10	2
50	Hydro	6	20	1980	0.01	2
76	Coal 3	4	40	1960	0.02	3
100	Oil 2	3	50	1200	0.04	3
155	Coal 2	4	40	960	0.04	4
197	Oil 1	3	50	950	0.05	4
350	Coal 1	1	100	1150	0.08	5
400	Nuclear	2	150	1100	0.12	6

MTTR = mean time to repair
MTTF = mean time to failure
Forced outage rate = MTTR/(MTTR + MTTF)

Table 2. IEEE–RTS Weekly Peak Demand.

Week No.	Demand MW	Week No.	Demand MW	Week No.	Demand MW	Week No.	Demand MW
1	2451	14	2138	27	2152	40	2063
2	2565	15	2055	28	2326	41	2118
3	2502	16	2280	29	2283	42	2120
4	2377	17	2149	30	2508	43	2280
5	2508	18	2385	31	2058	44	2511
6	2397	19	2480	32	2212	45	2522
7	2371	20	2508	33	2280	46	2591
8	2297	21	2440	34	2078	47	2679
9	2109	22	2311	35	2069	48	2537
10	2100	23	2565	36	2009	49	2685
11	2038	24	2528	37	2223	50	2765
12	2072	25	2554	38	1981	51	2850
13	2006	26	2454	39	2063	52	2713

Table 3. Comparison of Calculated Reliability Indices for the IEEE–RTS.

Reliability index	Physical unit	Proposed method	Reference [6]	Reference [20]
LOLE	days/year	1.45674	2.66659	1.36886
EENS	MWh	1176	2092	1176
EIR	–	0.99993	–	0.99992

Table 4. The IEEE–RTS Maintenance Schedule.

Weeks	Units on Maintenance							
	LOLE Levelization Reference [20]				EIR Levelization Proposed method			
1, 2	none				none			
3	76				12			
4	76				12	12		
5	76				12			
6	155				155			
7	155				155	76		
8	197	155			155	76	50	
9	197	155	20	12	197	155	76	50
10	400	197	20	12	400	197	76	
11	400	197	155		400	197	76	50
12	400	155	20	20	400	197	76	50
13	400	155	20	20	400			
14	400	155			400	197		
15	400	197	76		400	197	155	
16	197	76	50		197	155		
17	197	76	50		197	155		
18	197				155			
19	none				none			
20	100				none			
21	100	50			50	12	12	
22	100	50			50	12	12	
23–25	none				none			
26	155	12			20	12		
27	155	100	50	12	100	76	20	
28	155	100	50		100	76	12	
29	155	100			100	76	76	
30	76				76			
31	350	76	50		197	155	76	50
32	350	76	50		197	155	50	
33	350	20	12		197	155		
34	350	76	20	12	197	155	155	100
35	400	350	76		400	155	100	20
36	400	155	76		400	155	100	20
37	400	155			400	155	50	
38	400	155	50	12	400	350	50	
39	400	155	12		400	350		
40	400	197			400	350		
41	197	100	50	12	350	100		
42	197	100	50	12	350	100	20	20
43	197	100			100	20	20	12
44	none				12			
45–52	none				none			

Table 5. SCECOc System Power Plants Data.

Power plant	Unit size (MW)	FOR (pu)	No. of maintence crew	No. of units	Scheduled maintenance weeks/year
PP2	18.0	0.78	1	1	11
				4	2
PP3	46.5	0.72	2	3	6
				3	4
				1	5
				1	3
				1	0
PP4	20.0	0.91	1	4	2
PP4X	39.0	0.91	1	1	8
				1	6
				3	4
PP5	44.5	0.87	2	3	10
				1	8
				2	2
				3	0
PP7	47.0	0.84	4	1	11
				6	10
				9	4
PP8	49.0	0.86	5	9	10
				6	2
				5	1

Table 6. SCECOc Weekly Peak Demand.

Week No.	Demand	Week No.	Demand	Week No.	Demand	Week No.	Demand
1	3820	14	2972	27	2455	40	2556
2	3771	15	2851	28	2525	41	2963
3	3860	16	2816	29	2646	42	2004
4	3689	17	2514	30	1875	43	2945
5	3786	18	2402	31	1995	44	3017
6	3668	19	2340	32	1835	45	3001
7	3603	20	2256	33	1964	46	3467
8	3448	21	2152	34	1931	47	3370
9	3520	22	2145	35	1822	48	3356
10	3168	23	2174	36	1914	49	3358
11	3020	24	2226	37	1931	50	3718
12	3042	25	2669	38	1940	51	3801
13	3032	26	2635	39	1998	52	3620

Table 7. SCECOc Maintenance Schedule.

Weeks	Number of units on maintenance						
	PP2	PP3	PP4	PP4X	PP5	PP7	PP8
1–15			none				
16						1	
17, 18		1				1	
19	1	1			1	2	1
20	1	1		1	1	3	1
21	1	1		1	1	3	2
22–25	1	2		1	1	3	4
26–28	1	1		1	1	3	4
29	1	1	1	1	2	3	4
30–36	1	1	1	1	2	3	5
37	1	1		1	2	4	5
38, 39		1		1	2	4	5
40		1		1	2	4	4
41		1		1	1	4	4
42–45		1		1	1	4	2
46, 47		1			1	3	2
48		1			1	3	1
49, 50		1				2	
51, 52				none			

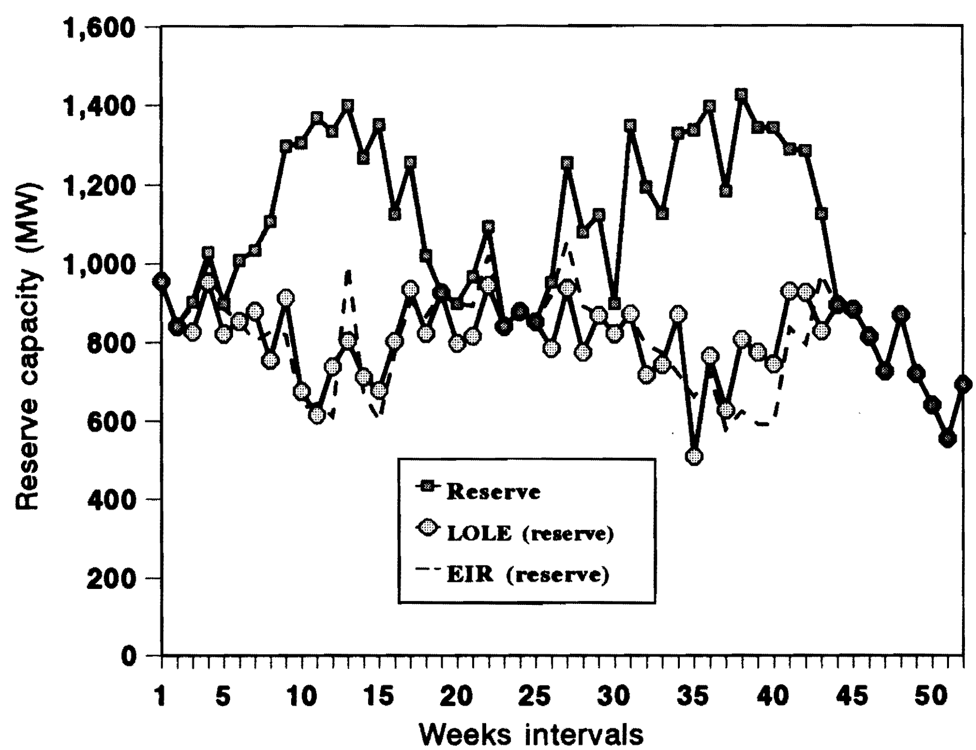

Figure 3. Comparison Between LOLE [20] and the EIR Proposed for the RTS Scheduled Maintenance.

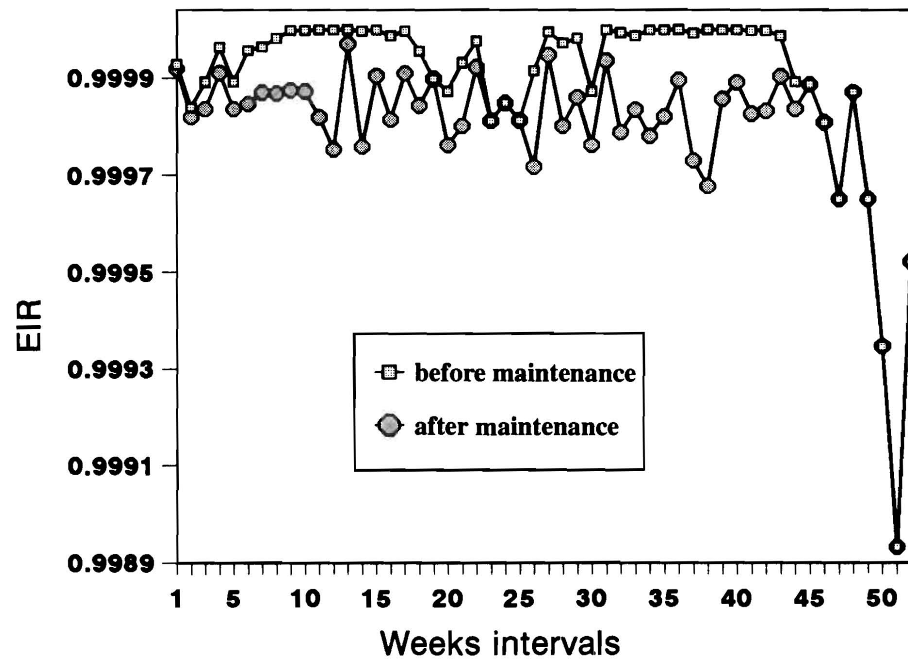

Figure 4. The EIR Before and After Scheduled Maintenance for the IEEE–RTS.

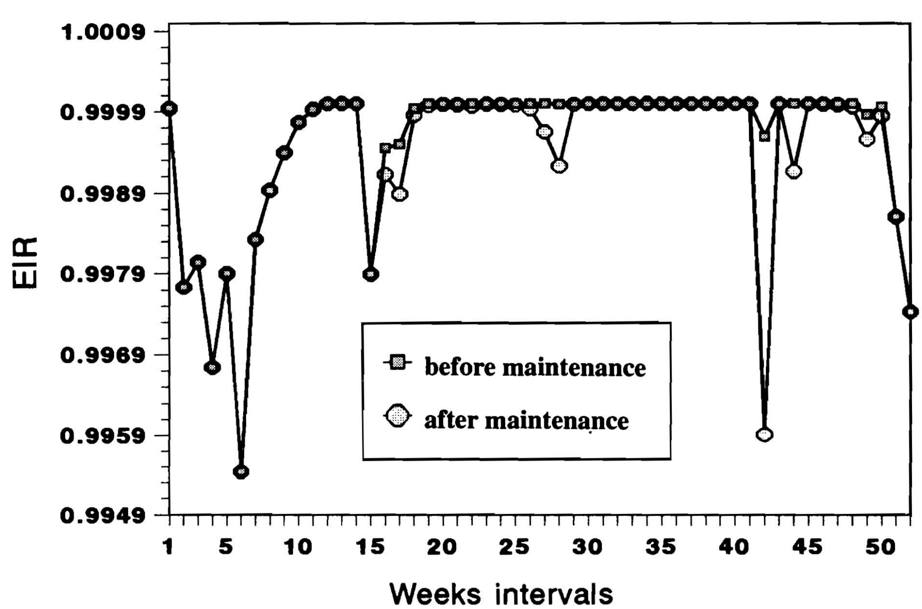

Figure 5. The EIR Before and After Scheduled Maintenance for the SCECOc System.

CONCLUSION

An efficient and practical method for maintenance scheduling of generating units based on a reliability index levelizing known as the Energy Index of Reliability, EIR has been proposed and presented. This method has been applied to the IEEE–RTS and to the SCECOc system. The main advantage of this method over the currently used one (*i.e.* the LOLE), is that the EIR adopted is an energy based index that measures the severity of deficiency rather than only the amount of time that a deficiency may exist. The proposed method can be further implemented to obtain an optimum maintenance scheduling from both economical and reliability point of view without major computational efforts since in the process of obtaining the EIR, the expected energy of all units available in the system and the EENS are calculated. Using units production cost together with the outage cost, the preventive maintenance scheduling will be transformed to levelizing the overall cost (*i.e.* production and reliability costs).

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