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Maintenance Priority Index of Overhead Transmission Lines for Reliability Centered Approach

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Abstract – Overhead transmission lines are crucial components in power transmission systems. Well-designed maintenance strategy for overhead lines is required for power utilities to minimize operating costs, while improving the reliability of the power system. This paper presents a maintenance priority index (MPI) of overhead lines for a reliability centered approach. Proposed maintenance strategy is composed of a state index and importance indices, taking into account a transmission condition and importance in system reliability, respectively. The state index is used to determine the condition of overhead lines. On the other hand, the proposed importance indices indicate their criticality analysis in transmission system, by using a load effect index (LEI) and failure effect index (FEI). The proposed maintenance method using the MPI has been tested on an IEEE 9-bus system, and a numerical result demonstrates that our strategy is more cost effective than traditional maintenance strategies.

Keywords: Maintenance priority index, Overhead transmission line, Maintenance strategy, Reliability centered approach

1. Introduction

During the last two and half decades, the electric power industry all over the world has undertaken significant restructuring. Power transmission utilities need to reduce the operation costs such as the maintenance cost, the repair cost and the electrical supply cost. Meanwhile, they have to maintain sustaining system reliability, which is a critical factor for the power system. Well-designed maintenance strategy for transmission equipment is required for this purpose [1, 2]. One of crucial components in power transmission systems is overhead lines on which periodic maintenance to be called Time-based maintenance (TBM) is commonly applied. As an example, Korea Electric Power Corporation (KEPCO) conducts routine inspections every two years and detailed maintenance every five years [3]. However, even though this approach is easy to schedule and results in high system availability, it may not be cost effective. Maintenance scheduling techniques involving condition monitoring have been proposed in [4-6]. These include condition-based maintenance (CBM), which maintains system reliability while reducing maintenance costs. CBM is driven by the actual condition of an overhead line, but it does not take into account on how the system is impacted by the failure of that line [7-9].

In recent years, Reliability-centered maintenance (RCM) has been employed for enhancing physical condition of the overhead line in the whole system. Most researches have been proved that RCM is more cost effective than the traditional approach [10-13]. However, in a realistic system it may be difficult to apply the RCM framework without quantifying the impact of components on system reliability. In order to evaluate this impact effectively, several techniques have been tried out in this task. In [14], the important indices could be used to measure component reliability. A fundamental characteristic of these indices is focused on two-state systems (serial and / or parallel couplings between two nodes), which is based on probability techniques, but it is difficult to apply for electric power networks. In [15, 16], the interruption cost based importance index and the maintenance potential were presented in electrical networks. These indices are traditionally based on analytical technique which uses total interruption cost instead of probabilities for the sensitivity studies in [14]. These methods could be also developed for the network structure which is composed with several load points and distribution systems. However, when there are more complicated systems with repairable components and time varying failure rates, it is not easy for these indices to solve with analytical techniques. To solve this problem, Monte Carlo simulation technique was presented in the distribution system [17]. However, the above importance indices do not provide accurate information about main-

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tenance priority because the importance of components is not always to be criteria of maintenance priority. Therefore, the maintenance priority should be considered both the state and importance of each component. An approach of prioritizing distribution maintenance considered both were presented in [18]. However, the authors only analyze the application of system reliability with the traditional indices, rather than evaluating the developed measures. In spite of performed research in this area, more accurate and robust methods are still required.

In this paper, a maintenance priority index (MPI) of overhead transmission lines is proposed. The MPI is composed with the condition of the overhead line at an arbitrary time through the state index and its criticality to the transmission system via the proposed importance indices. The main contributions of this work are the development of new importance indices that are suitable for transmission systems. The previous importance indices are applicable for two-state systems, simple systems having a few load points or distribution systems. Although these existing importance indices are surely suitable for those systems, these are not capable to apply for transmission systems. Since transmission systems are the meshed network system, these existing indices based on the interruption cost could not be evaluated. Unlike distribution system, one component' failure in transmission systems hardly affect to the system outage. Even though system total generation cost probably increases due to one component's failure, it is very rare that outage cost is occurred. In an effort to improve this problem of existing indices, new importance index for transmission components (especially overhead transmission lines) is proposed by using load effect index (LEI) and the failure effect index (FEI). In overhead transmission lines, uncertainties are widely classified into loads and failures. In order to evaluate the importance of transmission overhead lines by load uncertainty, the LEI is presented. The amount of increased power flow at transmission line between two buses is the criterion to determine the importance of transmission lines in a situation of load growth. In the case of a line failure, the generation cost from contingency factors is another measure of the transmission line's importance. For this, The FEI is also presented as an importance index. The MPI can be easily achieved for cost-effective maintenance strategy as reliability centered approach, by combining each state and the proposed importance indices of overhead lines. Consequently, these proposed indices can be used as an indicator of importance of overhead transmission line associated with load growth and transmission line failure.

The remaining parts of the paper are organized as follows. Section 2 presents the state index for overhead lines. Section 3 provides the proposed importance indices used to evaluate the overhead transmission lines. Section 4 proposes the MPI for cost-effective maintenance strategy of the transmission system. Section 5 describes a case study and compares our approach to the previous maintenance methods. Section 6 outlines our conclusions.

2. State Index of Overhead Transmission Line

2.1 State Index (SI)

The state of an overhead line changes for many reasons, such as aging and accidents. These cause the line condition to deteriorate and may even make the line fail. Fig. 1 shows the state model of overhead lines [19]. The operating condition of the line is divided into several states, and the probabilities of transition from one to another are exponentially distributed. As shown in Fig. 1, D1 and D2 are deterioration states in which the overhead line ages over time or its condition deteriorates. F is the failure state where the line is out of service. State transitions are governed by transition rates λ_1, λ_2, λ_3, … λ_6, which may be interpreted as the reciprocals of the mean times spent in the deterioration states. Maintenance activities M cause a transition from failed and deteriorated states to the normal state N at repair rates μ, μ_1, and μ_2. Besides overhead line maintenance is controlled by the maintenance decision $d_j(t)$ of line j at time t. Here, $d_j(t)$ presents whether doing maintenance or not at time t. In this paper, the current state of the overhead line is assumed to be observed by a real-time sensor S without error.

The state index (SI) of the overhead line can be evaluated as follows:

$$SI_j(t) = \begin{cases} 0........if \;\; overhead \;\; line \;\; state \;\; is \;\; N \\ 0.5.....if \;\; overhead \;\; line \;\; state \;\; is \;\; D1 \\ 0.75...if \;\; overhead \;\; line \;\; state \;\; is \;\; D2 \\ 1........if \;\; overhead \;\; line \;\; state \;\; is \;\; F \end{cases} \quad (1)$$

where $SI_j(t)$ is the state index of the jth overhead line at time t. This value can take on values of 0.0, 0.5, 0.75, and

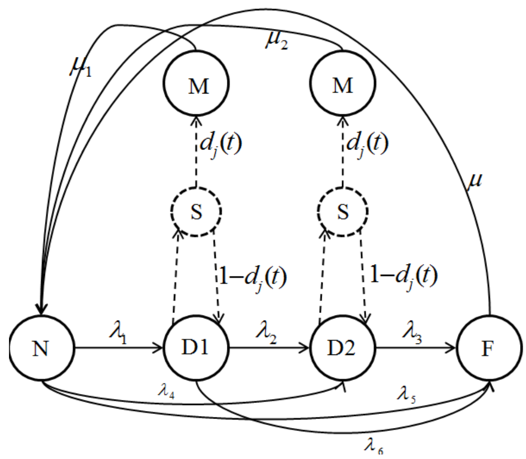

Fig. 1. The state model of the overhead line

1.0 for states N, D1, D2, and F, respectively. These values are not rigidly fixed; transmission utilities could adjust the exact value of $SI_j(t)$ according to the actual state of the overhead line.

2.2 State definition of overhead transmission line

The state model of the overhead transmission line needs to be tailored to the specific line characteristics. The selection of the deterioration states may vary from one utility to another. The deterioration states are defined based on inspection methods and criteria used by transmission utilities [20]. Table 1 shows a summary of the reasonable assumptions for the state model used in this study. The sag behavior of the overhead line, the temperature and tension of this are used to determine each state because it indicates line aging and change of the surrounding environment [21], [22]. Line's tension is strongly related the behavior of sag, although this is one of the factor that decide the state of the overhead line. That is why the tension of the overhead line is neglected in this paper. The temperature of the overhead line is not strictly proportional to the sag behavior. This is used as one of criteria indicating the line state. However, precise values of the line temperature are not presented because the proper line temperature is different according to voltage level of the overhead line. Sag in excess of the normal state indicates an accident such as the impact of a falling tree or excessive line age. We define the state of the overhead line as D1 when the line sag increases by 1~2 meter or the line temperature is abnormal. D2 is also defined when the sag increases by more than 2 meter or the line temperature is too high. Table 1 shows also the transition and repair rates for each state. Because obtaining an accurate value is impossible due to limitations of historical data, we have assumed reasonable values for the transition rate. Transition rate is closely related to mean time to transition. For example, when average life of a transmission line is 50years, mean time to failure from normal state is 50years and transition rate from normal state to failure gets 0.02. In this way, we have assumed that mean time to failure, mean time to transition from normal state to D1, from D1 to D2 and D2 to failure are 50 years, 20years, 20years and 10years respectively. On the basis of this assumption, we derived the transition rates as shown in Table 1.

Table 1. State criteria, transition rate and repair rate of the overhead line

Temperature	Sag [meter]	State	Transition rate [f / year]		Repair rate [f / hour]	
Normal	< 1	N	λ_1	0.05	μ	0.006
			λ_2	0.05		
Abnormal	1 ~ 2	D1	λ_3	0.1	μ_1	0.021
			λ_4	0.02		
Too high	> 2	D2	λ_5	0.02	μ_2	0.021
			λ_6	0.025		

3. Proposed Importance Indices of Overhead Transmission Line

An importance of overhead line is requested for planning effective maintenance of power transmission systems. The indices of overhead transmission line proposed in this paper focus on the load growth analysis and contingency analysis. In the case of load growth, the amount of increased line flow between two buses is the criterion to determine the importance of overhead line. Then, to quantify this value, the LEI are used as an importance index. In the case of a line failure, the generation cost or occasionally outage cost from contingency factors are another measure of the overhead line's importance. For this, The FEI is also presented as an importance index. Once the proposed importance indices of overhead transmission line have been determined, it is reasonable that transmission utilities refer to these indices for the maintenance action, and they can reduce additional costs.

3.1 Load Effect Index (LEI)

Load growth will increase the flow on some overhead lines, while decreasing or not affecting the flow on others. In our work, the critical overhead lines under highly stressed operating conditions can be chosen on the basis of a prediction of a potential vulnerability of the system when there is a possibility that the power flow can increase much more than others for a specific load growth, and then the LEI is calculated as follow:

$$LEI_{i,j} = \frac{IF_{i,j}}{NF_j} \text{ [p.u.]} \tag{2}$$

where $LEI_{i,j}$ is the i^{th} load effect index of the j^{th} overhead line. $IF_{i,j}$ is the power flow on the j^{th} overhead line when the i^{th} load is increased, and NF_j is the j^{th} line power flow in steady state. The LEI of the j^{th} overhead line for the average value of all loads is given by:

$$LEI_j = \frac{1}{N}\sum_{i=1}^{N} LEI_{i,j} \text{ [p.u.]} \tag{3}$$

where N is the number of loads.

3.2 Failure Effect Index (FEI)

Overhead line faults adversely affect the power flow on other lines and the generation cost, and then these situations may cause large-scale blackout. Thus the importance of overhead lines should be also related to the impact of their failure. In general, the importance of an overhead line depends on its location. Since the failure of significant overhead lines has a huge impact on the transmission system, these effects can be evaluated, which is based on the amount of increased generation cost and interruption costs in a contingency situation. The FEI of the j^{th} overhead line is computed as follow:

$$FEI_j = \frac{IC_j}{NGC} \ [\text{p.u.}] \tag{4}$$

where FEI_j is the failure effect index of the j^{th} overhead line. IC_j is the increased cost due to the j^{th} line fault and NGC is the generation cost in normal state. As shown in (4), this equation is calculated by dividing the increased cost due to the j^{th} overhead line fault by the generation cost in normal state.

4. Transmission Line Maintenance Priority Index for Overhead Transmission Lines

As mentioned earlier, the maintenance of overhead lines depends on their condition and relative importance. When two overhead lines, i.e. line A and line B, are equally important, if the line A is deteriorating faster than the line B, then the line A can obtain a higher maintenance priority. On the other hand, when the two lines have the same physical condition, if line A is more important than the line B, the maintenance priority of line A can be higher. Accordingly, the transmission utility has to consider both the state and importance of each line for developing reliable maintenance strategy. To that end, the MPI is defined as follow:

$$MPI_j(t) = SI_j(t) \times \{(\alpha \times LEI_j) + (\beta \times FEI_j)\} \tag{5}$$

where $MPI_j(t)$ is maintenance priority index of the j^{th} overhead line at time t. α and β are weighting factors, respectively. The maintenance decision $d_j(t)$ of line j at time t is given by:

$$d_j(t) = \begin{cases} 1 \ \cdots\cdots \ if\, MPI_j(t) \geq MCI \\ 0 \ \cdots\cdots \ if\, otherwise \end{cases} \tag{6}$$

By using (5), the transmission utility observes the condition of the overhead line using a sensor, and the each state of the overhead line at an arbitrary time is determined. The transmission utility sets the maintenance priority of each line when $MPI_j(t)$ is greater than the maintenance criteria index (MCI). If the value of MCI is too small, unnecessary maintenance will occur, and the operating costs will be high. Whereas, if the value of MCI is too large, the overhead lines will be out of order and bring about the adverse effect on system reliability. Thus, an appropriate MCI value is very important for optimal maintenance strategy. After that, the development of MPI can be easily achieved for cost-effective maintenance strategy of the transmission system, by combining each state and importance index of overhead lines.

5. Numerical Results

The validity of the proposed method was tested on the IEEE 9-bus system and the IEEE 30-bus system. First of all, in order to verify clearly the effectiveness of the one, the IEEE 9-bus system was employed. The IEEE 30-bus system was used to demonstrate the adequacy to larger practical system. The results were then compared to the conventional time-based maintenance strategies and conditional-based maintenance strategies.

5.1 The IEEE 9-bus system results

The IEEE 9-bus system consists of three generators, nine transmission lines, and three loads as illustrated in Fig. 2. The bus data and the line parameter related to the test system are shown in Table 2 and Table 3, respectively. Table 4 shows the generation, outage and the overhead line cost data that are the maintenance costs and the repair costs. With this cost data, the annual operation cost could be calculated. First of all, the total operation cost is obtained by summation of the maintenance costs, the repair costs,

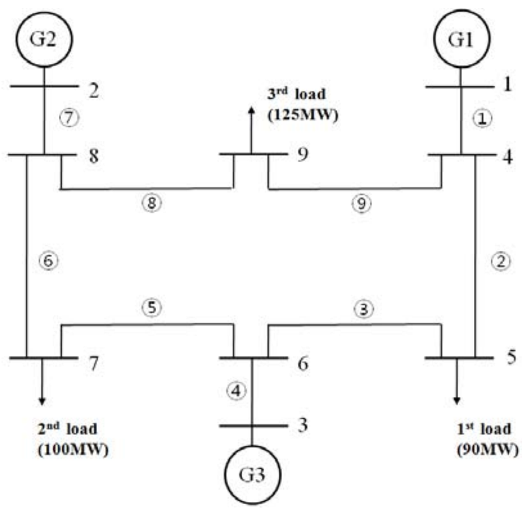

Fig. 2. IEEE 9-bus test system

Table 2. The bus data for the IEEE9-bus test system

Bus number	Type	PG(MW)	PL(MW)
1	Slack	0	0
2	Generator	163	0
3	Generator	85	0
4	Load	0	0
5	Load	0	90
6	Load	0	0
7	Load	0	100
8	Load	0	0
9	Load	0	125

Table 3. The line parameter the IEEE9-bus test system

From	To	R	X	(MW)
1	4	0	0.0576	250
4	5	0.017	0.092	250
5	6	0.039	0.17	150
3	6	0	0.0586	300
6	7	0.0119	0.1008	150
7	8	0.0085	0.072	250
8	2	0	0.0625	250
8	9	0.032	0.161	250
9	4	0.01	0.085	250

Table 4. Generation, outage and the overhead line cost data

Generation Cost ($/hour)	1st generator (#1 bus)	$0.11P^2 + 5P + 150$
	2nd generator (#2 bus)	$0.085P^2 + 1.2P + 600$
	3rd generator (#3 bus)	$0.1225P^2 + P + 335$
Maintenance Cost ($/hour)	-	2000
Repair Cost ($/hour)	-	5000
Outage Cost ($/MWh)	-	100

Table 5. LEI of each overhead line in IEEE9-bus test system

Line No.	$LEI_{1,j}$	$LEI_{2,j}$	$LEI_{3,j}$	NF_j(MW)	LEI_j
#① Line	1.0343	1.03	1.0479	89.80	1.0389
#② Line	1.1451	1.0415	0.9338	35.22	1.0401
#③ Line	1.0724	0.9738	1.0420	54.96	1.0294
#④ Line	1.0273	1.03	1.0372	94.19	1.0315
#⑤ Line	0.9589	1.1133	1.0288	38.22	1.0337
#⑥ Line	1.0252	1.0922	0.9822	61.93	1.0311
#⑦ Line	1.0270	1.0304	1.0378	134.32	1.0317
#⑧ Line	1.0386	0.9767	1.0858	72.11	1.0177
#⑨ Line	0.9635	1.0298	1.1209	54.28	1.0381

the generation costs, and the outage costs for each overhead line during the simulation period. Finally, the total operation cost is normalized by simulation years and that is the annual operation cost. The generation cost in normal state, NGC, per hour in the test system was 5296.69$/hr with a total load of 315 MW. The buses are numbered 1-9, while ①-⑨ indicate the overhead line numbers. The #5 bus load, #7 bus load, and #9 bus load are designated by the 1st load, 2nd load, and 3rd load, respectively.

Table 5 shows the LEI calculated by using (2) and (3) when all loads are increased by 10% in the IEEE 9-bus test system. Here the $LEI_{1,j}$ represents the index of j^{th} overhead line when the 1st load increases. Similarly, the $LEI_{2,j}$ and $LEI_{3,j}$ are values when the 2nd load and 3rd load increase by 10%, respectively. That is, 1st load increases from 90MW to 99MW; 2nd load increases from 100MW to 110MW; and finally 3rd load becomes from 125MW to 137.5MW. The fifth column indicates the NF_j and the sixth column presents the LEI_j. As shown in Table 5, when the 1st load increases, the volume of which #② line is affected is largest. #⑤ line is strongly influenced by the increase of 2nd load. Moreover #⑨ line is seriously affected by the increase of 3rd load. Consequently, it is clear that #② line is the crucial line because the LEI of #② line is higher than other lines.

Table 6. FEI of each overhead line in IEEE9-bus test system

Fault line No.	IC_j ($/hour)	FEI_j
#① Line failure	31,500	5.947
#② Line failure	5331.18	1.0065
#③ Line failure	5381.71	1.0161
#④ Line failure	31,500	5.947
#⑤ Line failure	5330.70	1.0064
#⑥ Line failure	5392.57	1.0181
#⑦ Line failure	31,500	5.947
#⑧ Line failure	5426.34	1.0245
#⑨ Line failure	5410.08	1.0214

Table 6 shows the IC and FEI at each overhead line calculated by using (4) when the overhead line fault occurs. As shown in Fig. 2, overhead lines ①, ④, and ⑦ are critical for transmission system operation. If those lines are out of order, then the power flow solution may not converge. The volume of power outage is 315 MW occurs when overhead lines ①, ④, and ⑦ are out of order. Then IC_1, IC_4, and IC_7 are equal to 31,500 $/hr, which is based on outage cost of 100 $/MWh shown in Table 4.

In order to find the optimal MCI value, a sequential Monte Carlo simulation was used for state transition of overhead lines over time [23]. The MCI value can be changed by depending on the transition rate of each unit, cost, and simulation time because the simulation method, which is based on probability techniques. First of all, the transmission utilities have to calculate the optimal MCI of each system by adjusting the simulation time and probability parameters appropriately. Fig. 3 shows the annual operation costs for each MCI.

We assumed that alpha(α) and beta(β) are the same value as '1' in order to show effectiveness of the proposed method easily. It is necessary to compute optimum values for alpha and beta according to transmission operator or transmission utility. However, since we focused on suggestion of the MPI, we leaved this problem to transmission utility. In this simulation, the annual operation cost over 50 years is lowest when maintenance is based on MCI = 1.055 for each overhead line. It means that the proposed method recommended the maintenance criteria index value (1.055) to transmission utility operating overhead lines in IEEE9-bus system. The transmission utility will maintain overhead lines based on the MCI not by time-based maintenance schedule any more. In that, it will only execute a proper maintenance on overhead lines whose MPI is more than the recommended MCI .

When the MCI is less than 1.055, the annual operation costs have highly values. It means that unnecessary maintenance action occur during sustaining system reliability. On the other hand, if the MCI is too large, the overhead lines will be out of order due to short maintenance.

In the end, it is clear that there are the adverse effects on system reliability by increasing the generation costs or outage costs.

Table 7 shows the comparison with the annual operation costs between TBM, CBM, and the proposed method. For the sake of a fair comparison, the same conditions are selected, which correspond to the simulation times.

From Table 7, it can be seen that the annual operation costs of TBM is obviously highest values, comparing with the maintenance strategies. Because of that TBM involves the unnecessary expense, which is based on the maintenance costs to ensure the reliability. Besides, TBM is not considered the actual condition of overhead lines. On the other hand, CBM is only driven by the actual condition. According to the importance in transmission system, the maintenance actions could be different even though each state of overhead lines is same. However, CBM is surely carries out the maintenance action to equipment when each state turns into specified state. Thus, the annual operation cost of CBM is more than that of the proposed method, while the annual operation cost of CBM is even less than that of TBM. It should be noted that the proposed maintenance method is more cost effective than previous methods such as TBM and CBM. Moreover, by using the MPI, transmission utilities can easily achieve optimal maintenance action to evaluate the impact on system reliability.

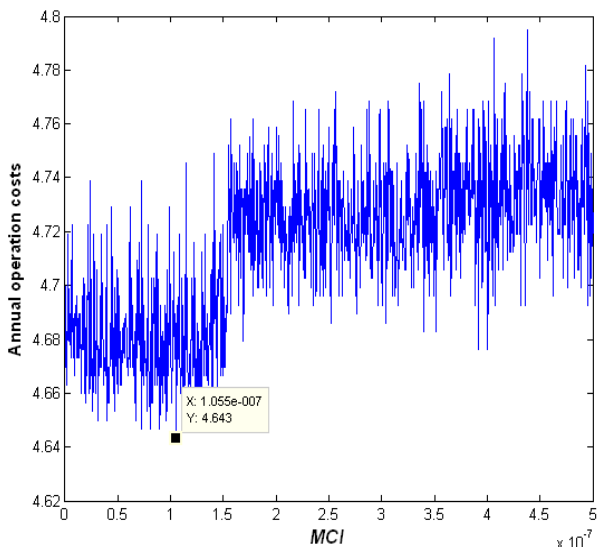

Fig. 3. Annual operation costs versus MCI for the overhead line in IEEE9-bus test system

Table 7. Comparison with Annual operation costs according to maintenance methods

Maintenance method		Annual operation cost ($/year)
TBM	every 2 years	48,589,004.4
	every 3 years	47,859,004.4
	every 5 years	47,275,004.4
CBM	Maintenance at D1	46,487,514.2
	Maintenance at D2	46,474,682.1
Proposed method	MCI = 1.055	46,432,306.1

5.2 The IEEE 30-bus system results

The IEEE 30-bus system has 6 generators, 41 lines. The test data (bus data, line parameters, and generation cost) for these two test systems are taken from the MATPOWER toolbox [24].

Table 8 and Table 9 show the LEI and FEI for the

Table 8. LEI of each overhead line in the IEEE 30-bus system

Line No.	NF_j(MW)	LEI_j	Line No	NF_j(MW)	LEI_j
#1	21.04	1.0418	#22	7.2	1.0328
#2	20.5	0.9829	#23	3.93	1.0545
#3	18.63	0.9592	#24	-5.58	0.9715
#4	17.88	0.9801	#25	7.85	0.9805
#5	14.36	0.9779	#26	7.27	0.9709
#6	21.66	0.9648	#27	-4.43	1.0604
#7	17.58	0.9891	#28	-5.06	1.0335
#8	14.25	0.9781	#29	-21.97	1.0164
#9	8.7	1.0498	#30	-10.92	1.025
#10	23.82	0.9991	#31	-4.46	1.0743
#11	7.27	0.933	#32	2.03	1.1589
#12	4.15	0.9339	#33	-11.18	1.0052
#13	0	0	#34	3.54	1.0051
#14	7.27	0.9329	#35	-14.96	1.0049
#15	11.03	0.9139	#36	-11.45	1.066
#16	-16.2	1.082	#37	6.16	1.005
#17	4.68	1.0053	#38	7.1	1.0051
#18	6.07	1.0013	#39	3.68	1.005
#19	5.31	1.052	#40	-6.29	1.0266
#20	-1.55	1.0042	#41	-5.05	1.1144
#21	1.76	1.1455	-	-	-

Table 9. FEI of each overhead line in the IEEE 30-bus system

Fault line No.	IC_j (hour/$)	FEI_j	Fault line No.	IC_j (hour/$)	FEI_j
#1	577.95	1.0018	#22	577.8	1.0016
#2	579.1	1.0038	#23	577.15	1.0005
#3	577.98	1.0019	#24	577.57	1.0012
#4	578.71	1.0032	#25	596.81	1.0345
#5	578.11	1.0021	#26	577.5	1.0011
#6	578.19	1.0023	#27	576.94	1.0001
#7	577.12	1.0004	#28	577.84	1.0016
#8	578.12	1.0021	#29	578.63	1.003
#9	580	1.0054	#30	577.16	1.0005
#10	742.83	1.2876	#31	576.05	0.9985
#11	577.03	1.0002	#32	577.44	1.001
#12	576.91	1	#33	573.91	0.9948
#13	490.37	0.85	#34	490.37	0.85
#14	577.03	10.0002	#35	573.93	0.9949
#15	578.73	1.0032	#36	690.75	1.1974
#16	490.37	0.85	#37	577.91	1.0018
#17	577.45	1.001	#38	578.31	1.0025
#18	577.53	1.0011	#39	577.66	1.0013
#19	577.72	1.0014	#40	740.1	1.2829
#20	576.87	1	#41	574.68	0.9962
#21	577.07	1.0003			

Table 10. Comparison with Annual operation costs according to maintenance methods

Maintenance method		Annual operation cost ($/year)
TBM	every 2 years	13,813,556.4
	every 3 years	10,893,556.4
	every 5 years	8,557,556.4
CBM	Maintenance at D1	5,557,436.6
	Maintenance at D2	5,253,775.7
Proposed method	MCI=2.16	5,053,556.0

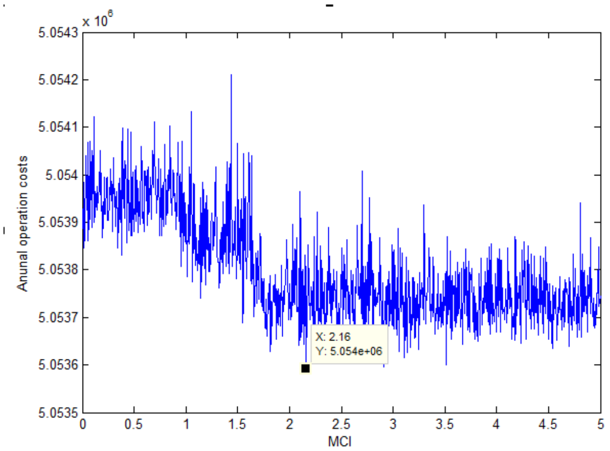

Fig. 4. Annual opertaion costs versus MCI for the overhead line in IEEE30-bus test system

overhead lines of IEEE 30-bus test system. Since the evaluation process of LEI_j is already shown in IEEE 9-bus case, the detailed evaluation process such as obtaining $LEI_{i,j}$ was shortened in this section.

Fig. 4 shows the annual operation costs for IEEE 30-bus system with each MCI. In this simulation, the annual operation cost over 50 years for IEEE 30-bus system is lowest when maintenance is based on MCI = 2.16.

Table 10 shows the comparison with the annual operation costs between TBM, CBM, and the proposed method.

As shown in Table 10, the proposed maintenance method is more cost effective than previous methods such as TBM and CBM. This results shows that the proposed method is still effective for larger practical system.

6. Conclusion

This paper proposed an effective reliability-centered maintenance strategy in overhead transmission lines. Unlike existing maintenance methods of overhead lines, our maintenance strategy, based on MPI, not only considers the physical condition of overhead lines but also demonstrates the importance of system reliability. The MPI can be easily achieved for cost-effective maintenance strategy by combining each state and importance index of overhead lines. Especially, the proposed importance index on MPI (LEI and FEI) also enables overhead transmission lines to be estimated their importance of system reliability. The validity of the proposed method has been tested on an IEEE 9-bus system. According to the proposed maintenance strategy, the transmission utility observes the condition of the overhead line using a sensor in order to define each state and evaluate its MPI. The priority for maintenance of overhead lines is determined whose MPI is greater than the MCI, by calculating through a sequential Monte Carlo simulation. Obtained results have been presented and compared with those of TBM and CBM, simple application of our method that shows reasonable results of the proposed strategy, because of cost effectiveness in the reliability approach. In addition, the system information obtained by using MPI of each overhead line can provide useful guidelines to the transmission utilities, when their maintenance strategy is developed for transmission planning. The research work is under way in order not only to develop better reliability centered approach in large scale power system, but also to find a suitable weighting factor, thereby combining incommensurable objectives such as LEI and FEI.

Appendix

In order to further evaluate previously developed and proposed indices, a small system is analyzed. The system topology is depicted in Fig. 5. The model assumes faultless automatic breakers, which isolate failures without affecting the rest of the network. The components in the test system have exponentially distributed failure and repair times. The data are presented in Table 11 and Table 12.

One of the previously developed importance indices is the failure criticality index (I^{FC}). This was developed in order to obtain a reliability index from existing reliability simulation routines. The basic idea is to divide the number

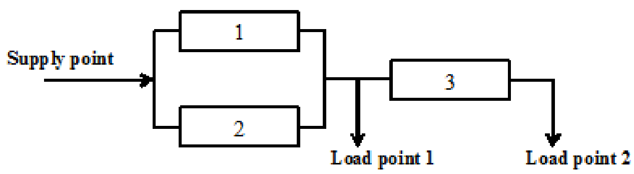

Fig. 5. Test system.

Table 11. Component reliability input data for the test system

Component number	Failure Rate [failures/year]	Mean Down Time [h/failures]	R[Ω]	X[Ω]	Cap. [MW]
#① Line	0.02	480	0	0.5	150
#② Line	0.03	480	0	0.5	150
#③ Line	0.01	6	0	0.5	250

Table 12. Load point input data

Load point	MW	$/MW	$/MWh	$/inter.	$/hour
LP1, LP2	100	15	60	1500	6000

of system failures caused by component i in (0,t) by the total number of system failures in (0,t) [25], as follows:

$$I_i^{FC} = \frac{n_i}{N} \tag{7}$$

where n_i is the number of system failures caused by component I, and N is the total number of system failures. Another importance index derived from simulations is the index (I^M), which calculates customer interruption costs. I^M is calculated by assigning the total interruption cost caused by an interruption to the component identified as the final cause of the interruption. The accumulated cost over time for the component is then divided by the total simulation time. This index is defined as follows [16]:

$$I_i^M = \frac{K_i}{T}\ [\$/yr] \tag{8}$$

This includes the assumption of independent components with exponentially distributed failure and repair times. The applied simulation technique is event-driven.

The proposed importance index is applied to the test system to determine whether or not reasonable results can be obtained. The LEI is calculated by increasing the load by 10%, and the FEI is calculated by inducing component faults. In this case, the NGC is assumed to be 7000 [$/hr].

Table 13 compares the results for the previously developed and proposed indices.

It can be seen that all of the indices produce similar results in this test system (a simple distribution system). Component no. 3 is consistently the most important piece of equipment in the test system, and no. 1 and no. 2 have similar importance values. Thus, the proposed importance index provides reasonable results for the test system, in comparison with the existing indices.

Table 13. Comparison of the previously developed and proposed indices for the test system

	I^{FC}		I^M	Proposed index (LEI + FEI)
	LP1	LP2		
#① Line	0.492	0.0031	78.32	1.6357
#② Line	0.506	0.0033	80.1	1.6357
#③ Line	0.0029	0.9936	380.26	2.1714

Table 14. Comparisons of the previously developed and proposed indices for the IEEE 9-bus system.

	I^{FC}	I^M	Proposed index (LEI + FEI)
#① Line	0.3000	36.247	6.9859
#② Line	0	0	2.0466
#③ Line	0	0	2.0455
#④ Line	0.3666	44.301	6.9785
#⑤ Line	0	0	2.0400
#⑥ Line	0	0	2.0492
#⑦ Line	0.3333	40.274	6.9787
#⑧ Line	0	0	2.0422
#⑨ Line	0	0	2.0595

In order to compare these indices in a transmission system, the IEEE 9-bus system is again employed; the simulation results are presented in Table 14. Table 4 lists the cost data used in the simulation, and the failure rates and repair times are given in Table 1

As Fig. 2 indicates, overhead lines ①, ④, and ⑦ are critical for transmission system operation, and these lines have higher importance values than the other lines. However, the existing importance indices (I^{FC}, I^M) are not able to distinguish between the other overhead lines, because they are all assigned a value of zero. Thus, failure of overhead lines other than ①, ④, and ⑦ does not lead to system failure or any curtailment of the load, and these results are expected to occur in other transmission systems. Therefore, overhead line maintenance based on these existing indices only depends on the physical condition or maintenance period of the lines. On the other hand, the proposed importance indices (LEI + FEI) has the ability to distinguish the importance of overhead transmission lines whose failures do not lead to system failure. One reason for this is that we use the increased cost (IC) due to a line fault instead of an interruption cost. IC becomes an interruption cost if a system failure occurs, or an increased generation cost if there is no system failure, even though an overhead line is out of order. Another reason is that we consider the LEI of an overhead line as an importance index. Since the LEI represents the importance of an overhead line when all loads are increased, it is suitable for transmission systems.

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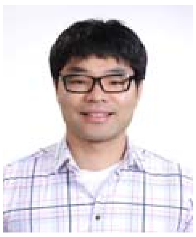

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