

Article

D-distance Risk Factor for Transmission Line Maintenance Management and Cost Analysis

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Abstract: In this paper, a D-distance risk factor was proposed to prioritize high-voltage transmission lines from high to low risk in transmission line maintenance and renovation management. Various conditions and importance assessment criteria together with the weighting and scoring method were proposed to calculate both the renovation and importance indices of transmission lines. The scores of different test methods and visual inspection were differentiated from zero to five as end-of-life to very good condition to evaluate the condition of the line and its components. Additionally, the scores of different importance criteria were modified to assess the line importance from low to high importance. Moreover, the analytic hierarchy process was applied to determine the important weight of all test methods and importance criteria, which were evaluated by utility experts. The renovation and importance indices were combined in a risk matrix to finally determine the risk of the line by using the D-distance technique. Later, the risk of every transmission line was plotted in a risk matrix to prioritize and manage maintenance tasks. Finally, a maintenance cost was analyzed by applying the D-distance risk factor and compared with the replacement cost of a new transmission line for maintenance planning and cost minimization. Twenty out of 115, 230 and 500 kV transmission lines fleet in Thailand were practically analyzed with actual data. The results were realistic to feasibly implement in a transmission system for sustainable management.

Keywords: D-distance factor; importance index; renovation index; risk factor; risk matrix; weighting and scoring technique



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1. Introduction

Nowadays, thirty-five percent of high-voltage transmission lines (HVTLs) in Thailand and several worldwide are aged and mostly more than 30 years old. Ageing and deterioration as well as harsh environmental conditions and electrical stress on HVTL components cause unexpected failures and supply interruption leading to system reliability problems [1–4]. Consequently, there is a concrete requirement to effectively assess HVTL conditions to manage the reparation, replacement, or renovation tasks of transmission lines as well as to manage operational risks to improve the system operating performance and reliability [5–7]. To reach this goal, different approaches were proposed to cope with the risk assessment of HVTLs and manage maintenance tasks [7–12]. In addition, some risk factors were also intensively investigated for condition assessment and risk management [13–15]. Based on the acquired condition and risk, different maintenance strategies were proposed for effective HVTL maintenance management [16–19]. Moreover, economic crisis has forced the power supply industry to maintain acceptable power quality and reliability under the minimum cost of operation and maintenance [20,21]. Therefore, an asset management strategy of HVTLs in Thailand is proposed in this paper to effectively cope with maintenance management and investment planning problems in the country.

According to the critical components in HVTLs discussed in [22–24], the major components of 115, 230 and 500 kV transmission lines in Thailand were practically divided into eight major groups consisting of conductor, conductor accessory, insulator, steel structure, foundation, lighting protection, tower accessory and right of way, as shown in Table 1. Sub-components of each major group were also clarified according to transmission utility maintenance tasks and inspection strategies during on-site testing and visual inspection. The major components with their renovation indices, as a percentage of conductor (%CRI), conductor accessory (%CARI), insulator (%IRI), steel structure (%SSRI), foundation (%FRI), lighting protection (%LPRI), tower accessory (%TARI) and right of way (%RWRI), are illustrated in Figure 1. The risk of HVTLs was assessed by considering two aspects. The first is the overhead line condition evaluated in the actual system based on their historical test data and presented in forms of renovation index. The second aspect is to assess the importance of the overhead line to the electrical network, named as the importance index. For renovation index calculation, various testing methods [23–27] together with practical testing experience and visual inspection of a Thailand’s transmission utility [28] were determined as methods for condition assessment with a comprehensive, detailed clarification of aging and degradation characteristics and the scoring of degradation levels as basic input for the renovation index calculation. For importance index determination, the significant impact factors encountered during transmission system operation were considered, such as the percentage of line loading (MVA), system usage, operating voltage level (kV), contingency of HVTL, statistical failure, age of HVTL, as well as pollution, public image, and human impact in various locations along the HVTL were thoroughly considered. Some significant criteria were mentioned in [29–31]. The weighting and scoring method (WSM) was applied in this research to calculate both renovation indices of sub-components, components and the overall transmission line as well as for the importance index as it is a simple, clear and transparent method in any calculating steps. The analytical hierarchy process (AHP) method [32–34] was applied to identify the utility-consensus weight of any sub-components, components, testing methods and importance criteria for HVTL assessment.

Table 1. HVTL components and sub-components.

| Group | Component | %LRI | Sub-Component |
|-------|----------------------|-------|--|
| 1 | conductor | %CRI | conductor |
| 2 | conductor accessory | %CARI | joint, compression dead end, damper, spacer, parallel glove clamp (PGC) |
| 3 | insulator | %IRI | insulator |
| 4 | steel structure | %SSRI | steel structure, anchor and guy |
| 5 | foundation | %FRI | concrete foundation, grillage foundation, stub |
| 6 | lightning protection | %LPRI | overhead/optical ground wire and fittings, marker ball, grounding system |
| 7 | tower accessory | %TARI | danger sign, tower number sign, phase plate |
| 8 | right-of-way | %RWRI | right-of-way |

The risk assessment procedure with the D-distance risk factor was proposed and is illustrated in Figure 2. The steps for the condition and importance evaluating method and equations are also expressed. After the evaluation, both the line renovation index (%LRI) and importance index (%IMI) were coordinated and plotted in a risk matrix in Figure 2, which was classified into nine groups. The D-distance risk factor was determined by using a proposed D-distance method to measure the risk. Finally, transmission utility could make an appropriate decision on an HVTL maintenance strategy, renovation, or new investment for replacement planning.

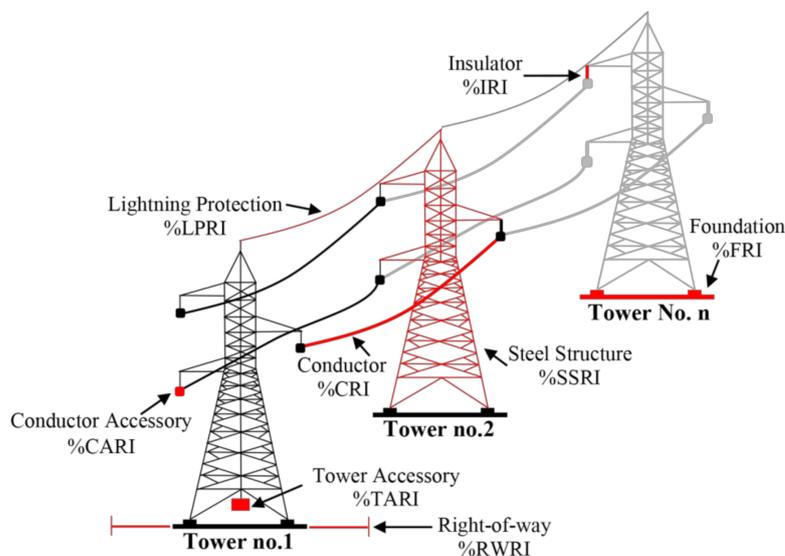


Figure 1. High-voltage transmission line components for condition assessment.

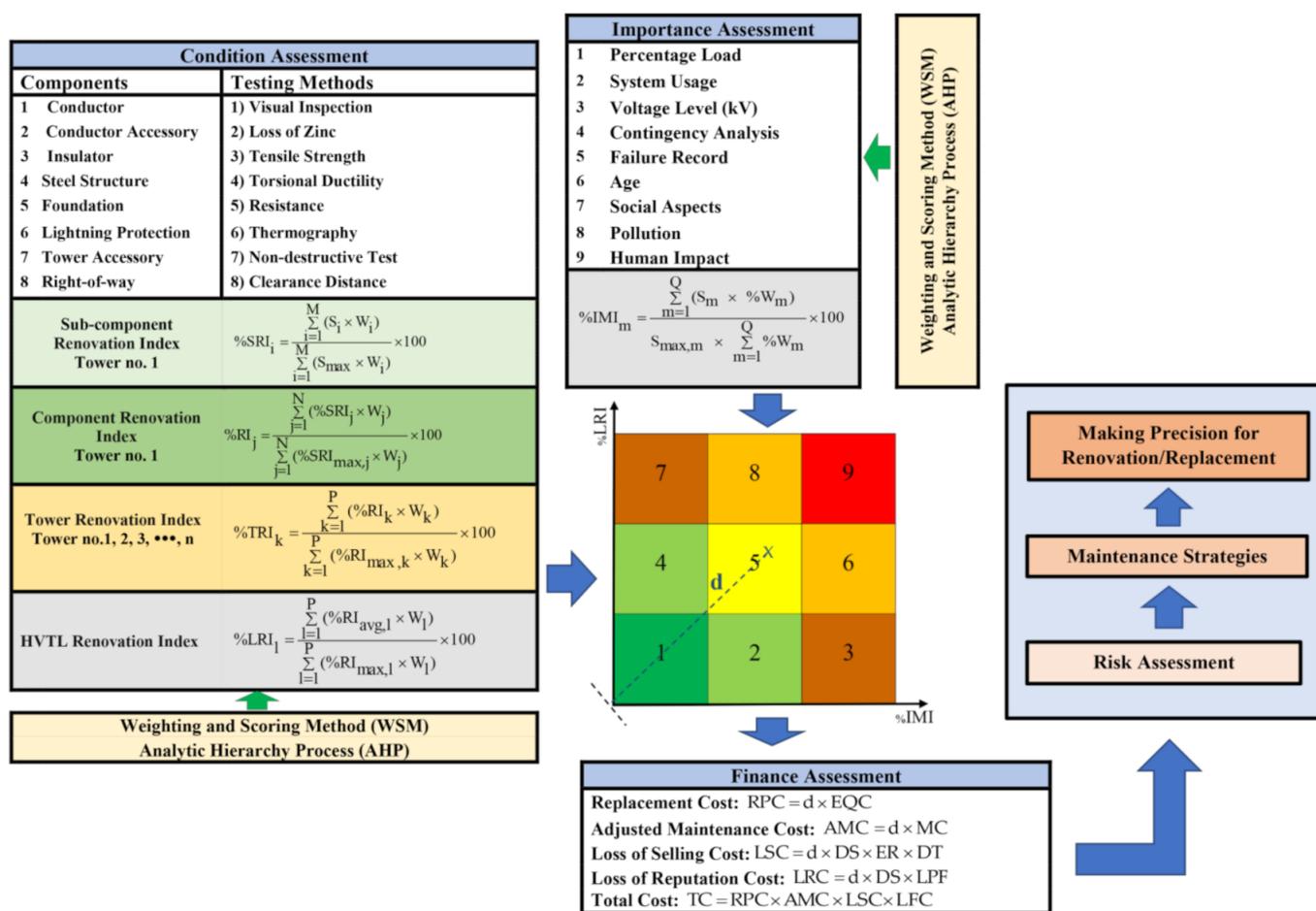


Figure 2. Risk assessment for maintenance strategy flowchart.

2. D-distance Risk Factor

In Figure 3, the risk was calculated from %LRI and %IMI by coordinating them in the risk matrix. Points x_1 and x_2 as well as y_1 and y_2 identified a boundary of low, moderate, and high levels in the renovation and importance indices.

The ranges for x_1 , x_2 , y_1 and y_2 could be adjusted by the utility depending on the experiences and historical data. The risk of HVTL was identified by using distance “ d ”, named “D-distance risk factor”, measured from the point coordinated by %LRI and %IMI perpendicular to a 45° line, as illustrated in Figure 3. The angles θ_1 and θ_2 of 45° mean that the condition or renovation requirement and importance of HVTLs play equal significance for this utility. The “ d ” distance was calculated by using (1) and (2).

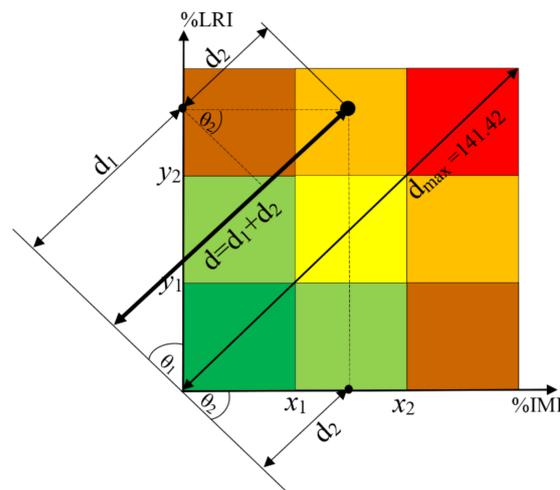


Figure 3. Risk matrix with D-distance risk factor “ d ”.

$$d = \frac{(d_1) + (d_2)}{d_{\max}} \quad (1)$$

$$d = \frac{(\%LRI \times \sin\theta_1) + (\%IMI \times \sin\theta_2)}{d_{\max}} \times 100 \quad (2)$$

where d is the perpendicular distance from %LRI to 45° line, d_1 is the perpendicular distance from %LRI to 45° line, d_2 is the perpendicular distance from %IMI to 45° line, d_{\max} is the maximum D-distance in the risk matrix, x is the value of %LRI as a percentage line renovation index, y is the value of %IMI as a percentage line importance index, θ_1 is the angle between the y -axis and 45° line and θ_2 is the angle between the x -axis and 45° line.

In Figure 3, there are nine clusters of risk in the risk matrix from the lowest risk in cluster 1 represented by the green color to the highest risk in cluster 9 represented by the red color. The renovation index, importance index, overall risk and required maintenance task for each cluster are detailed as follows.

In cluster 1, equipment has a good condition with low importance. The corrective maintenance strategy should be applied with this minimum risk cluster. The damage could be corrected when equipment was broken. The visual inspection and corrective maintenance (CM) by routine inspection was introduced.

In cluster 2, equipment has a good condition with moderate importance. Time-based maintenance (TBM) based on a planning schedule should be applied.

In cluster 3, equipment has a good condition with high importance. The TBM with condition-based maintenance (CBM) should be applied. Condition monitoring should probably be considered based on cost analysis.

In cluster 4, equipment has a moderate condition with low importance. The normal maintenance or CM could be applied.

In cluster 5, equipment has a moderate condition with moderate importance. Then, preventive maintenance (PM) was suggested. However, if the system is working properly, regular maintenance or TBM could be applied.

In cluster 6, equipment has a moderate condition with high importance. The CBM is strongly recommended to trace the change in condition or renovation requirement, and the proper remedy could be executed in time.

In cluster 7, equipment has a poor condition with low importance; then, repairing or renovation when fault without blackout was requested.

In cluster 8, equipment has a poor condition with moderate importance; then, intensive maintenance, repair or refurbishment or renovation should be carried out based on the economic suitability or available budget or repair, renovation, or refurbishment according to economic consideration.

In cluster 9, equipment encounters the worst condition with the highest importance leading to the highest risk. Then, the utility must immediately consider a short-term repair, renovation, or refurbishment.

3. Condition Assessment

In Figure 4, various testing methods and visual inspection techniques for renovation index assessment of HVTL components are proposed.

The application of WSM was used to calculate the renovation index. The WSM method considered a score representing the actual condition and weight indicating importance of considered components and criteria, i.e., score of the testing method, was categorized into six levels, namely, "0" for very good, "1" for good, "2" for satisfy, "3" for moderate, "4" for degradation and "5" for reaching the end-of-life condition. The weight of testing method was assigned by the AHP method. The percentage renovation index of sub-component (%SRI) was determined by using (3).

$$\%SRI_i = \frac{\sum_{i=1}^M (S_i \times W_i)}{\sum_{i=1}^M (S_{\max,i} \times W_i)} \times 100 \quad (3)$$

where i is the index of the sub-component, M is the total number of testing methods of the sub-component, S_i is the score of each testing method, $S_{\max,i}$ is the maximum score of each testing method and W_i is the weight of each testing method.

Next, the renovation index of the component (%RI) was determined by using (4). For example, to determine %CARI, the percentage renovation index of five sub-components in the conductor accessory group, namely, spacer, damper, joint, dead end and PGC, should be previously calculated in advance. Thereafter, %CRI, %IRI, %CARI, %FRI, %SSRI, %LPRI and %RWRI were finally calculated in this step.

$$\%RI_j = \frac{\sum_{j=1}^N (\%SRI_j \times W_j)}{\sum_{j=1}^N (\%SRI_{\max,j} \times W_j)} \times 100 \quad (4)$$

where j is the index of the component, N is the total number of sub-components in each component, %SRI $_j$ is the percentage renovation index of each sub-component, %SRI $_{\max,j}$ is the maximum percentage renovation index of each sub-component and W_j is the weight of each sub-component.

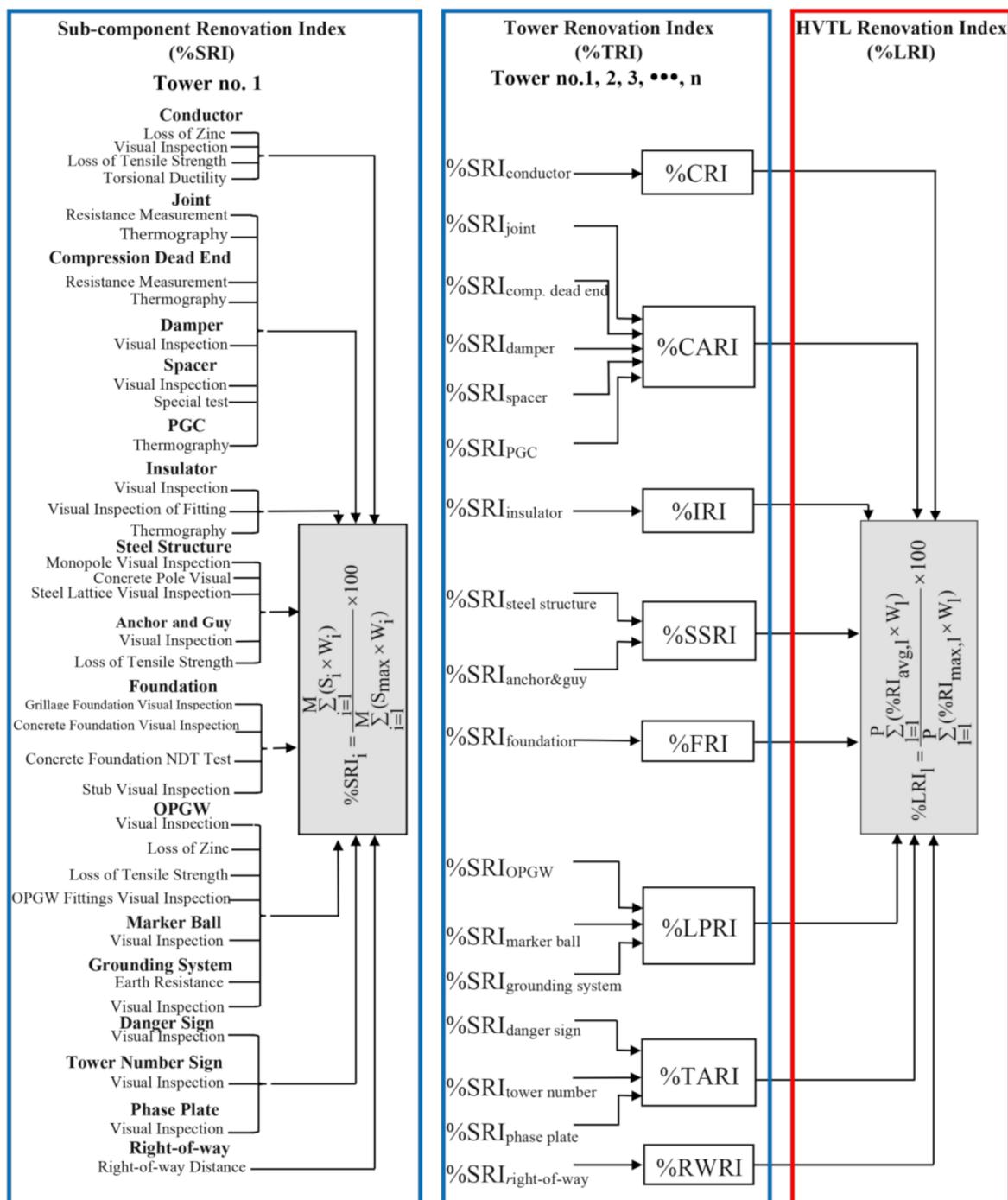


Figure 4. Structure for condition assessment of HVTL procedure.

Then, the tower renovation index (%TRI) was determined by using (5).

$$\%TRI_k = \frac{\sum_{k=1}^P (\%RI_k \times W_k)}{\sum_{k=1}^P (\%RI_{max,k} \times W_k)} \times 100 \tag{5}$$

where k is the index of the tower, P is the total number of components in each tower, $\%RI_k$ is the percentage renovation index of each component, $\%RI_{\max,k}$ is the maximum percentage renovation index of each component and W_k is the weight of each component.

Finally, the transmission line renovation index ($\%LRI$) was determined by using (6). The average renovation index of all components was applied in this step.

$$\%LRI_l = \frac{\sum_{l=1}^P (\%RI_{\text{avg},l} \times W_l)}{\sum_{l=1}^P (\%RI_{\max,l} \times W_l)} \times 100 \quad (6)$$

where l is the index of the line, P is the total number of components of each tower, $\%RI_{\text{avg}}$ is the average percentage renovation index of each component, $\%RI_{\max}$ is the maximum percentage renovation index of each component and W_l is the weight of each component.

4. Importance Assessment

The importance criteria are presented and shown in Table 2, consisting of the percentage of line loading (MVA), system usage, voltage level (kV), contingency analysis, statically failure record, age, public image, pollution, and human impact. The determination of assigned scores and weights of all criteria are presented in Table 2. Line loading considered the maximum percentage of the highest power flow compared to the MVA rating of the line. The higher the line loading percentage, the greater the expected impact on customers in the case of line outage. System usage was also important regarding the type of usage, i.e., connection to power plant, tie transmission line, rapid load shedding scheme and radial or loop line, which could cause a severe impact on the electrical system. The voltage level was considered as it implied the power transfer capability of such transmission line in an electrical transmission system, i.e., at the 500 kV level, the HVTL would have more power transfer capability and a greater impact on the system than the 115 kV line when fault occurred. Contingency related to the redundancy of the HVTL affected the system availability and reliability of the electrical supply system. Moreover, the age of the transmission line could reflect the invisible deterioration, which could subsequently cause a higher probability of power outage. Age could imply an old design and obsolete technical specifications or lower performance for current operating conditions. The importance index ($\%IMI$) was calculated by using (7). Similarly, the WSM was applied in the calculation.

$$\%IMI_m = \frac{\sum_{m=1}^Q (S_m \times \%W_m)}{S_{\max,m} \times \sum_{m=1}^Q (\%W_m)} \times 100 \quad (7)$$

where m is the index of importance, Q is the total number of importance criteria, S_m is the score of each importance criterion, $S_{\max,m}$ is the maximum score of each importance criterion and W_m is the weight of each importance criterion.

AHP [32,33] is a multi-criteria decision-making method. It was applied to determine importance the weight of each testing method, assessment criterion, component, and sub-component to avoid conflict among people as experts working with the transmission system in the utility. These experts have intensive experience and deep knowledge in transmission system construction, operation, and maintenance engineering. They were invited to share diverse opinions in weight determination based on their valuable experience and responsibility in the utility. An inquiry form based on the AHP method was developed in MS Excel file and distributed to experts to share their opinions in weight determination to obtain the utility-consensus value. Finally, the final weights were calculated by using the geometric mean technique. Eventually, this WSM and the overall process were well accepted by all departments without any disagreement.

Table 2. Importance criteria of transmission system.

| Criteria | Score Sm from 0 to 4 | | | | | %Wm |
|---|----------------------|--|-------------------|----------------|--|--------------|
| | Very Low (0) | Low (1) | Moderate (2) | High (3) | Very High (4) | |
| percentage line loading (MVA) | 0–20 | 21–30 | 31–40 | 41–50 | >50 | 14 |
| system usage | | no tie line | | radial line | tie line/rapid load shedding/generator connected | 11 |
| voltage level (kV) | | ≤115 | | 230 | 500/300 DC | 5 |
| contingency analysis statistically failure (event/year) | non | | N-2 | | N-1 | 10 |
| age (years) | 0 | | 1–5 | 6–10 | >10 | 6 |
| public image | 10–0 | 20–11 | 25–21 | 30–26 | >30 | 32 |
| pollution (>20% of total length) human impact | normal province | rice field/agricultural area normal line | plant burn/firing | bird droppings | industrial estate/big province/tourist/business area coastal area/industrial estate compact line | 7 5 10 |

5. Cost Analysis

Maintenance costs of the transmission line, including the replacement cost, adjusted maintenance cost, loss of selling cost and loss of penalty fee cost, were determined and subsequently used to multiply with the D-distance risk factor, as shown in (8) to (11), which revealed the actual maintenance cost based on actual risk. Finally, the total maintenance cost could be expressed as shown in (12). With this calculated total maintenance cost, the utility could properly plan the annual budget for the maintenance, renovation, or replacement of the HVTL.

$$RPC = d \times EQC \quad (8)$$

$$AMC = d \times MC \quad (9)$$

$$LSC = d \times DS \times ER \times DT \quad (10)$$

$$LRC = d \times DS \times LPF \quad (11)$$

$$TC = RPC + AMC + LSC + LFC \quad (12)$$

where RPC is the replacement cost, EQC is the equipment cost, MC is the maintenance cost, AMC is the adjusted maintenance cost, LSC is the loss of selling cost, DS is the MW sold, ER is the electricity selling rate, DT is the down time for repair, LRC is the loss of reputation cost, LPF is the utility penalty fee in the case of power interruption and TC is the total cost.

6. Results and Discussion

After a clear procedure for the HVTL was established, risk assessment was set up, and the asset management program for the HVTL at the 115, 230 and 500 kV levels was developed. It is currently used by Thailand's transmission system utility for recording technical and financial data, testing and inspection results and condition and importance evaluation results. All mentioned data with maintenance costs were recorded in a central database. At present, the actual technical and testing data of the HVTL can be quickly retrieved from the database, and further analysis can be performed regarding the results shown in this section.

6.1. Risk Analysis

The renovation and importance indices calculations are clearly demonstrated in this section. All actual testing and visual inspection results were used in this analysis. A pilot 115 kV TL#1 was selected as an example. In Table 3, the calculation of the conductor renovation index or %CRI is expressed as 75%. In the group of conductors, it only consists of a conductor by itself. By using (3), there were four test methods for the conductor; the weight percentage of each method was equally assigned as 25%. By using (4), %CRI could

be obtained as 75%, while the %RI of other components was similarly calculated and is presented in Table 4. Next, the %TRI of tower No.1 (Tower#1) was determined by using (5) and was equal to 63.45%, as shown in Table 4. Then, the %RI_{avg} of all components in 103 towers of HVTL No.1 (TL#1) was further used to calculate the %LRI of TL#1 by applying (6). The %LRI of TL#1 was equal to 66.21%, as shown in Table 5. Simultaneously, the %IMI of the 115 kV TL#1 was similarly calculated by applying (7) with the actual importance data, as presented in Table 6, which was equal to 67.75%. After obtaining both indices, the %D-distance of the 115 kV TL#1 risk could be determined by (2) as 80.60%. Finally, the %LRI and %IMI of twenty transmission lines in Thailand were successfully determined. The percentage D-distance risk factor relevant to the %LRI and %IMI of individual line was further investigated, as shown in Table 7, and plotted in the risk matrix, as shown in Figure 5. The obtained D-distance from the risk matrix was used to manage the risk by classifying the obtained risk into four levels from very high to low risk. Therefore, different actions could be performed according to these risks, as shown in Table 8.

Table 3. %CRI of conductor of 115 kV TL#1, tower# 1.

| Testing Method | %W _i | %S _i | %W _i × %S _i | %CRI |
|--------------------------|-----------------|-----------------|-----------------------------------|------|
| visual inspection | 25 | 5 | 125 | 75% |
| loss of zinc | 25 | 3 | 75 | |
| loss of tensile strength | 25 | 4 | 100 | |
| torsional ductility | 25 | 3 | 75 | |

Table 4. %TRI of 115 kV TL#1, tower# 1.

| Tower | Component | %RI _j | %W _j | %TRI _{#1} |
|---------|----------------------|------------------|-----------------|--------------------|
| Tower#1 | conductor | %CRI = 75% | 25.31 | 63.45% |
| | conductor accessory | %CARI = 40% | 2.91 | |
| | insulator | %IRI = 24.62% | 10.48 | |
| | steel structure | %SSRI = 80% | 15.48 | |
| | foundation | %FRI = 90% | 19.06 | |
| | lightning protection | %LPRI = 18.82% | 16.89 | |
| | tower accessory | %TARI = 40% | 3.10 | |
| | right-of-way | %RWRI = 100% | 6.77 | |

Table 5. %LRI of 115 kV TL#1.

| Line | Component | %RI _{avg,l} | W _i | %LRI |
|-------------|----------------------|-------------------------------|----------------|--------|
| 115 kV TL#1 | conductor | %CRI _{avg} = 62.89% | 25.31 | 63.45% |
| | conductor accessory | %CARI _{avg} = 40% | 2.91 | |
| | insulator | %IRI _{avg} = 24.62% | 10.48 | |
| | steel structure | %SSRI _{avg} = 77.86% | 15.48 | |
| | foundation | %FRI _{avg} = 96.99% | 19.06 | |
| | lightning protection | %LPRI _{avg} = 39.59% | 16.89 | |
| | tower accessory | %TARI _{avg} = 31.07 | 3.10 | |
| | right-of-way | %RWRI _{avg} = 94.17 | 6.77 | |

Table 6. %IMI of HVTL 115 kV TL# 1.

| Importance Criteria | Data | S_m | $\%W_m$ | $S_m \times W_m$ | %IMI |
|----------------------|-------------------|-------|---------|------------------|--------|
| loading percentage | 58.6 | 2 | 14 | 28 | 67.75% |
| system usage | tie line | 4 | 11 | 44 | |
| voltage level | 115 kV | 1 | 5 | 5 | |
| contingency analysis | non | 0 | 10 | 0 | |
| failure record | 6 event/year | 3 | 6 | 18 | |
| age | 31 years | 4 | 32 | 128 | |
| social aspects | big province | 4 | 7 | 28 | |
| pollution | plant burn/firing | 2 | 5 | 10 | |
| human impact | normal line | 1 | 10 | 10 | |

Table 7. Assessment results of 20 HVTLs.

| HVTL's Name | Age (y) | %LRI | %IMI | %D-distance |
|--------------|---------|-------|-------|-------------|
| 115 kV TL#1 | 51 | 66.21 | 67.75 | 80.60 |
| 115 kV TL#2 | 28 | 20.06 | 39.50 | 35.84 |
| 115 kV TL#3 | 30 | 17.92 | 51.50 | 41.77 |
| 115 kV TL#4 | 32 | 15.78 | 70.25 | 51.76 |
| 115 kV TL#5 | 50 | 41.52 | 51.50 | 55.97 |
| 115 kV TL#6 | 30 | 21.44 | 58.50 | 48.10 |
| 115 kV TL#7 | 39 | 25.64 | 71.50 | 58.45 |
| 230 kV TL#8 | 55 | 37.17 | 66.75 | 62.53 |
| 230 kV TL#9 | 21 | 5.46 | 26.25 | 19.08 |
| 230 kV TL#10 | 35 | 25.01 | 57.50 | 49.65 |
| 230 kV TL#11 | 30 | 21.06 | 67.00 | 52.98 |
| 230 kV TL#12 | 43 | 67.18 | 48.25 | 69.45 |
| 230 kV TL#13 | 2 | 5.46 | 7.75 | 7.95 |
| 230 kV TL#14 | 26 | 22.94 | 61.00 | 50.51 |
| 500 kV TL#15 | 20 | 7.51 | 33.75 | 24.83 |
| 500 kV TL#16 | 28 | 58.59 | 19.10 | 46.74 |
| 500 kV TL#17 | 19 | 19.10 | 70.50 | 53.91 |
| 500 kV TL#18 | 36 | 18.12 | 38.75 | 34.22 |
| 500 kV TL#19 | 13 | 5.49 | 29.75 | 21.20 |
| 500 kV TL#20 | 26 | 17.25 | 30.00 | 28.43 |

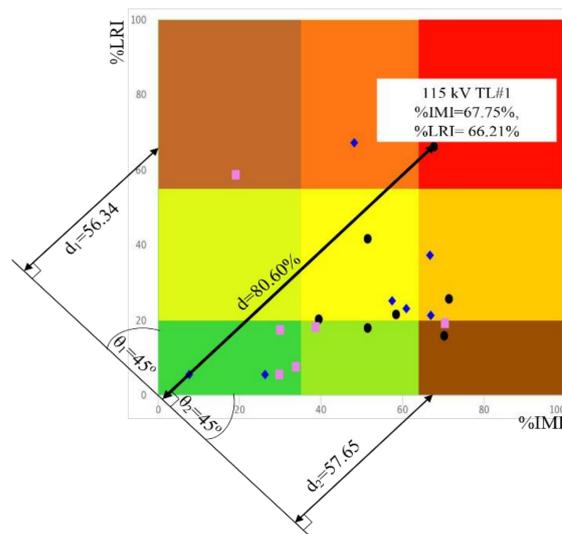


Figure 5. Risk assessment matrix and D-distance.

Table 8. Range of risk management from D-distance.

| %D-distance | Risk | Requirements | Suggested Action |
|-------------|-----------|--------------|----------------------|
| >80.1 | very high | 1st priority | urgent action |
| 60.1–80 | high | 2nd priority | short-term planning |
| 30.1–60 | medium | 3rd priority | medium-term planning |
| 0–30 | low | 4th priority | long-term planning |

6.2. Cost Analysis

The cost analysis of HVTLs was further analyzed after obtaining the D-distance value. The maintenance budget could be effectively planned according to the actual condition or renovation requirement and risk of HVTLs. To demonstrate the implementation of the proposed method, a double circuit 230 kV HVTL with a 1×1272 MCM ACSR conductor was chosen as an example due to its complete information of the actual maintenance cost. The cost included the replacement cost, adjusted maintenance cost, loss of selling cost and loss of supply penalty fee cost per kilometer. As shown in Table 9, the investment cost of this 230 kV HVTL was 4285.06 THB/m. The maintenance cost of the line was also obtained, which was further used to compare with the investment of the new line in order to analyze the breakeven point to install the new line instead of continuing to conduct maintenance tasks for the lines. The inflation rate, MW loss of sale, down time of outage, electricity rate and loss of reputation rate were also given. Consequently, the total cost consisted of the summation of the replacement cost of equipment (3,762,500 THB/km), maintenance cost (517,000 THB/km), loss of opportunity to sale electricity during outage (2.513 THB/kWh) and reputation cost (0.7 THB/kWh). In addition, all maintenance costs were equal for all of 115, 230 and 500 kV lines. The loss of sale and reputation cost were assumed by using the line loss of 100 MW in 3 h. The cost of loss was increasing due to the 3% inflation rate.

Table 9. Maintenance cost of 115, 230 and 500 kV HVTL (kTHB/km).

| Group | 115 kV | | 230 kV | | 500 kV | |
|--|--------------------|-------|---------------------|-----|---------------------|------|
| | EQC | MC | EQC | MC | EQC | MC |
| conductor | 508 | 43 | 900 | 50 | 1500 | 100 |
| conductor accessory | 65.5 | 35 | 67.5 | 40 | 120 | 70 |
| insulator | 50.18 | 130 | 72 | 150 | 100 | 200 |
| steel structure | 1600 | 100 | 1800 | 114 | 2600 | 2300 |
| foundation | 600 | 95 | 750 | 100 | 1000 | 200 |
| lightning protection | 130 | 35 | 150 | 40 | 300 | 100 |
| tower accessory | 4.8 | 4.8 | 5 | 5 | 10 | 10 |
| right-of-way | 15 | 15 | 18 | 18 | 25 | 25 |
| sum | 2973.48 | 457.8 | 3762.5 | 517 | 5655 | 3005 |
| total maintenance cost (EQC + MC) | 3431.28 | | 4279.5 | | 8660 | |
| HVTL Information | 115 kV | | 230 kV | | 500 kV | |
| investment of new line (THB/km) | 3508.28 | | 4285.06 | | 10,949.71 | |
| ACSR conductor, double circuit | 2×795 MCM | | 2×1272 MCM | | 4×1272 MCM | |
| inflation rate: <i>IR</i> (%) | 3 | | 3 | | 3 | |
| demand of sale: <i>DS</i> (MW) | 100 | | 100 | | 100 | |
| down time: <i>DT</i> (hrs) | 3 | | 4 | | 5 | |
| electricity rate: <i>ER</i> (THB/kWh) | 2.977 | | 2.513 | | 2.479 | |
| loss of penalty fee: <i>LPF</i> (THB/kW) | 0.5 | | 0.7 | | 0.9 | |

As presented in Table 10, the result showed that TL#1 encountered the highest risk with a D-distance of 80.60%, represented in red color, as it was located near seashore with poor pollution resulting from salt spray due to strong winds. This led to poor conditions of

the insulator, conductor, foundation, etc. By using (8) and (9), the replacement cost and maintenance cost of TL#1 at the age of 51 years, which were determined by multiplying the D-distance with its relevant cost, were equal to 2396.68 and 368.99 kTHB/km, respectively. Similarly, by using (10) and (11), the loss of sale and reputation cost were equal to 719.85 and 40.30 kTHB/km, respectively. Therefore, the total cost of this line is 3525.83 kTHB/km, which is nearly equal to the investment cost of a new overhead line—3508.28 kTHB/km. Now, the decision can be easily made to replace this TL#1 with the new one due to the highest risk and maintenance cost. With the D-distance technique, the D-distances and overall costs of 20 HVTLs were successfully calculated. The result showed that five, twelve and three HVTLs were at low, medium, and high risk as represented in Table 10 in green, yellow and orange colors, respectively. From the obtained results, TL#1 has the highest risk at 80.60% D-distance and a high total cost of maintenance at 3525.83 kTHB/km, which is comparable to the investment cost of a new overhead line. Then, the decision should be the immediate replacement of TL#1 by a new line. TL#12 was ranked as having the second highest risk of 69.45% D-distance with 43 years in service. Its total maintenance cost is 3348 kTHB/km, which is slightly lower than the new investment cost of 4279.54 kTHB/km. Short-term planning to replace TL#12 should be performed. From this proposed method of D-distance risk factor and cost analysis, the comprehensive information to support the decision regarding HVTL maintenance or replacement by a new line can be effectively compared based on the actual condition of the HVTL, its importance to the electrical network, its usage risk and total cost comparison. This method was further developed as a systematic evaluation tool for all HVTLs in a utility's network to facilitate the maintenance and renovation tasks.

Table 10. Cost analysis according to D-distance (kTHB/km).

| %D | Age | Line | kV | RPC | AMC | LSC | LRC | TC |
|-------|-----|------|-----|---------|---------|---------|-------|---------|
| 7.95 | 2 | #13 | 230 | 299.05 | 41.09 | 79.90 | 5.56 | 425.61 |
| 19.08 | 21 | #9 | 230 | 717.86 | 98.64 | 191.79 | 13.36 | 1021.65 |
| 21.20 | 13 | #19 | 500 | 1199.05 | 637.16 | 262.82 | 19.08 | 2118.11 |
| 24.83 | 20 | #15 | 500 | 1403.88 | 746.01 | 307.71 | 22.34 | 2479.95 |
| 28.43 | 26 | #20 | 500 | 1607.70 | 854.31 | 352.39 | 25.59 | 2839.98 |
| 34.22 | 36 | #18 | 500 | 1935.02 | 1028.25 | 424.13 | 30.80 | 3418.19 |
| 35.84 | 28 | #2 | 115 | 1065.59 | 164.06 | 320.06 | 17.92 | 1567.62 |
| 41.77 | 30 | #3 | 115 | 1241.99 | 191.22 | 373.04 | 20.88 | 1827.13 |
| 46.74 | 28 | #16 | 500 | 2643.43 | 1404.69 | 579.404 | 42.07 | 4669.59 |
| 48.10 | 30 | #6 | 115 | 1430.21 | 220.20 | 432.89 | 24.05 | 2107.34 |
| 49.65 | 35 | #10 | 230 | 1867.90 | 256.67 | 499.03 | 34.75 | 2658.34 |
| 50.51 | 26 | #14 | 230 | 1900.27 | 261.11 | 507.68 | 35.35 | 2704.42 |
| 51.76 | 32 | #4 | 115 | 1539.16 | 236.97 | 462.30 | 25.88 | 2264.31 |
| 52.98 | 30 | #11 | 230 | 1993.54 | 273.93 | 532.60 | 37.09 | 2837.16 |
| 53.91 | 19 | #17 | 500 | 3048.67 | 1620.03 | 668.23 | 48.52 | 5385.44 |
| 55.97 | 50 | #5 | 115 | 1664.22 | 256.23 | 499.86 | 27.98 | 2448.29 |
| 58.45 | 39 | #7 | 115 | 1737.93 | 267.57 | 522.00 | 29.22 | 2556.73 |
| 62.53 | 55 | #8 | 230 | 2352.58 | 323.27 | 628.52 | 43.77 | 3348.14 |
| 69.45 | 43 | #12 | 230 | 2613.15 | 359.07 | 698.14 | 48.62 | 3718.98 |
| 80.60 | 51 | #1 | 115 | 2396.68 | 368.99 | 719.85 | 40.30 | 3525.83 |

Note: the traffic light color in the above table represents the risk level as green for low risk, yellow for moderate risk and red for high risk.

7. Conclusions

Risk-based maintenance using renovation and importance indices for HVTLs was proposed. The actual testing and visual inspection results obtained from the utility practice during annual on-site HVTL maintenance as well as data for the importance assessment were considered together to determine the risk of HVTL usage. The renovation index referred to the maintenance/renovation/replacement requirement, while the importance index considered the overall impact of HVTLs on electrical systems. The weighting and scoring method was applied to calculate both renovation and importance indices. The

score and its ranges were assigned based on the utility practice and international standard, while all importance weights were assigned by the brainstorming of experts from various departments responsible for HVTLs in a utility with the aid of the AHP method. The maintenance tasks according to the calculated renovation and importance indices were suggested and differentiated into nine clusters in the risk matrix. The input data, including visual inspection, on-site tests and special tests, of 20 HVTLs in 115, 230 and 500 kV transmission networks were applied in this assessment process. With the application of the D-distance risk factor, all HVTLs could be prioritized for maintenance planning and ranked from required urgent action to long-term planning. The results showed that five lines were in a low-risk zone, twelve lines in a medium risk zone, two lines in high-risk zone and one line in a very high-risk zone, respectively. Moreover, in this risk-based analysis, the maintenance costs together with the outage cost of these existing lines was compared with the investment cost of a new line to support the decision-making process in whether to maintain/renovate or construct a new HVTL. From the results, TL#1 has the highest risk of 80.60% D-distance with the total cost of maintenance at 3525.83 kTHB/km. Since the cost of a new overhead line is 3508.28 kTHB/km, the decision can be made easily to replace this TL#1. Presently, the transmission line maintenance department and asset management division can apply the developed procedure and its obtained results for successful maintenance planning in the repair, renovation, or replacement of aged HVTLs according to their actual condition and renovation requirements as well as the available budget.

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