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Line Security Evaluation of WANS Considering Protectability of Relays and Vulnerability of Lines

Akhtar Hussain*, Chang-Ju Seok*, Myeon-Song Choi*, Seung-Jae Lee* and Seong-IL-Lim†

Abstract – Maloperation of protective relays is one of the major causes for cascading tripping in WANS. Another line trip followed by a previous line trip may occur due to overloading of the line, because of the load redistribution or unwanted trip of a backup relay due to change in the flow of fault current. Evaluation of each line is required by considering both of these effects. A new index named Line Security Index (LSI) is proposed in this paper which combines both Vulnerability Index (VI) and Protectability Index (PI) to completely evaluate the security of individual lines and their importance in the power grid. Computer simulations have been performed on the Korean power grid data to establish the feasibility of the proposed idea.

Keywords: Distance protection, Power system stability, Protection protectability, Protection vulnerability, Distance relaying

1. Introduction

On one hand, power grids are among the most curtail and essential infrastructures in modern society; while on the other hand, due to an increased demand of power and economic constraints power lines are operating closer to their maximum limits. This makes them more prone and vulnerable to disturbances. When power flows normally all the lines seem to be equally important while in reality some lines are more important and tripping them may result in another line tripping possibly leading to cascading trips and ultimately resulting in large area blackouts or even a complete breakdown of the network. In order to prevent the cascading events and high magnitude blackouts, it is desirable to evaluate all the lines of a power grid and assign some index to each line to indicate the importance of individual lines in a particular network.

Improper functioning of protection relays has been one of the major causes for the cascading events [1, 2, 14]. The maloperation of relays is mainly caused by two potential incidences. One is the overloading of a line due to redistribution of a load after the tripping of a particular line (due to any reason). Another is unnecessary trip of the backup relay because of a change in flow of the fault current after the tripping of a line. Different algorithms for evaluating the vulnerability of power systems and to reduce restoration time have been proposed [3-5, 11, 15].

An algorithm which is computationally non-intensive is required for real time computations of protectability and vulnerability. This is because power networks keep on changing causing these parameters to need to be recalculated over and over. This is another challenge for evaluation of line security in power systems [13].

Overloading of the lines after redistribution of a load has been addressed in [6] and has been named Vulnerability Index (VI). This indicates the risk of a cascading tripping due to an overload after tripping that line.

Only the vulnerability analysis of power systems is not sufficient for a complete evaluation of cascading tripping. Maloperation of relays due to a change in flow of fault current is also a major cause of cascade tripping. Both of these parameters are equally important for security evaluation of power lines. A security index which will combine the effect of both the potential causes of cascading tripping is necessary to identify the importance of the individual lines in a power network.

This paper proposes the Protectability Index for each line to indicate the risk of the maloperation of a relay due to the change in flow of a fault current after tripping of a line. It combines the VI and PI to make a new index for evaluating the security of each line in a given power network and inputs the information into the new Line Security Index (LSI). The Line Security Index caters to both of the major potential causes of cascade trips. It sums the VI index proposed in [6] to the Protectability Index (PI). The paper uses a simple method for real time computation of all the indexes.

2. Protection Vulnerability and Protectability

When the power system is working in normal mode, all the lines seem to be in the same equipotent state. When a

† Corresponding Author: Dept. of Electrical Engineering, Kyungnam University, Korea. (slim@kyungnam.ac.kr)
* Dept. of Electrical and Electronic Engineering, Myongji University, Korea. (hussainakhtar44@yahoo.com, childog84@gmail.com, {mschoi, sjlee}@mju.ac.kr)
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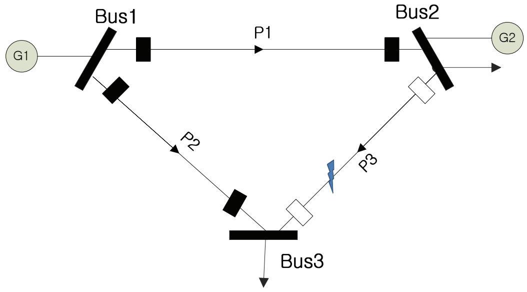

Fig. 1. Example Power System working in normal mode

fault occurs in normal mode, the responsible relays are opened and clear the fault as shown in Fig. 1. With this, it is difficult to identify which line is of more importance in normal mode.

In an actual case, some lines are of more importance than others. Their tripping may result in overloading of other lines and result in cascading tripping. When a line is tripped some of the relays in the network need to be reset to avoid maloperation in case of a fault. So it is essential to identify the importance of individual lines.

When a line is tripped in a power network due to any reason, the load of that line is redistributed to other healthy lines. The amount of load transferred can be easily calculated by using Line Outage Distribution Factor (LODF) [6].

In Fig. 2 P1, P2 and P3, the power flowing through line1, line2 and line3 are in normal mode respectively. When line1 is tripped, its load will be redistributed to line2 and line3. Power flowing through line2 and line3 after tripping of line 1 is P2+ΔP2 and P3+ΔP3 respectively, where Δ indicates the extra load of line1. Due to this extra load, line2 and line3 may get overloaded and trip. This is known as Protection Vulnerability and is addressed in detail in [6]. Protection Vulnerability depends upon the current structure of the power network. It needs to be updated after some interval of time, and LODF is a fast method to do this. Distance relays are major devices used for protection of power networks and their operation is based on some preset values [7-9, 12]. They cannot be reset in real time but their setting values can be calculated. The setting values of each relay can be calculated before and after the tripping of a line and the difference between these two values is used to compute the PI.

When a fault occurs in the normal network, the responsible relays get tripped and the faulty section is isolated from the rest of the network Fig. 3. When the fault occurs after the tripping of a line, the relay mounted on the backup line may maloperate due to a change in the flow of the fault current and this may lead to cascading trips.

After the tripping of a line the setting values of relays in the network need to be updated. Real-time updating of relays is not possible, but those relays which need a reset can be identified. Apparent Factor is required for setting the relays [8] and a fast algorithm for computing Apparent Factor without a fault analysis has been proposed in [10]. The method only needs the Network Impedance Matrix and Certain Line Impedances.

In Fig. 3, the setting value of relay on line2 in normal state is K1. When a fault occurs at line3, then the responsible relays (R2 and R3) will get tripped and clear the fault. When line1 is tripped due to any reason and a fault occurs at the same point, the backup relay, R1, may maloperate, because the fault current flowing through L2 has been increased by ΔF. The R1 setting value should be

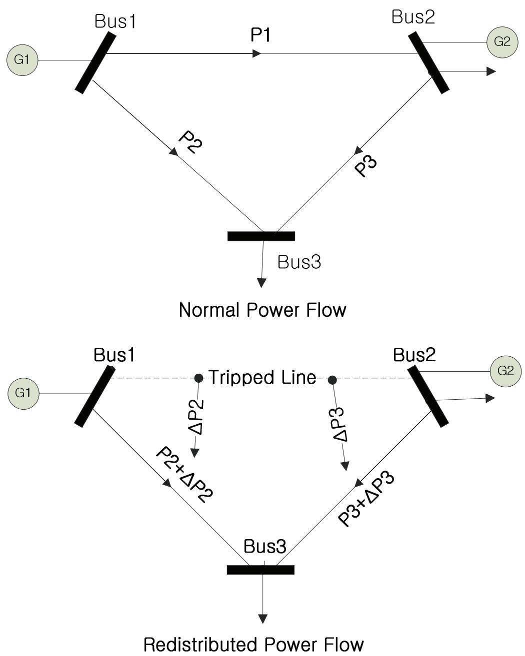

Fig. 2. Power flow in normal state and after line tripping

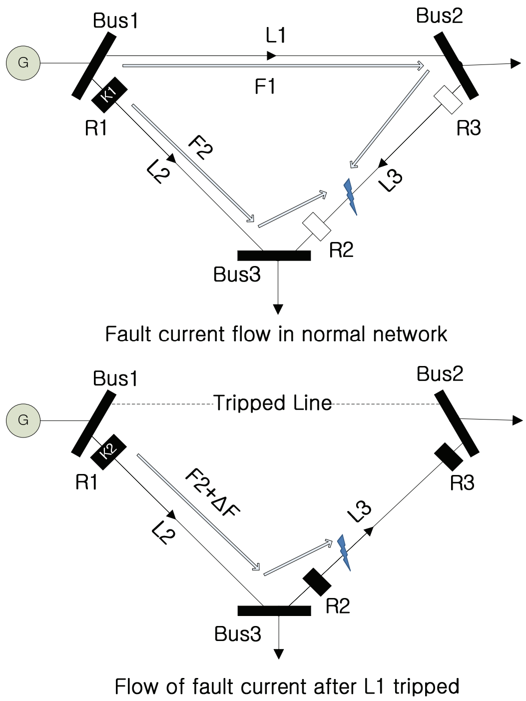

Fig. 3. Flow of fault current before and after tripping of line

changed to K2 after the L1 trip.

In order to analyze the line, the change in power flow ΔP and change in fault current ΔF are required to be known. The following section explains how to calculate these values in real time.

3. Computation of Indexes

3.1 Power flow estimation using LODF

The variation in voltage angle according to the real power variation can be given by:

$$\Delta\theta = \left[X\right]\Delta P \tag{1}$$

LODF is used to estimate the change of the load on a line after the tripping of another line. In Fig. 2, the power flow through Line2 after Line1 that got tripped can be calculated by:

$$P_2^{new} = P_2 + \Delta P_2 \tag{2}$$

Where P_2^{new} is a new power flowing through Line2 after the Line1 outage, P_2 represents the pre-outage power flow of Line2 and ΔP_2 represents the Line1 load which is transferred to Line2. This increase can be written as: $\Delta P_2 = d_{(2,1)} P_1^0$

Eq. (2) can be written as:

$$P_2^{new} = P_2 + d_{(2,1)} P_1^0 \tag{3}$$

Where $d_{(2,1)}$ is the line outage factor, Line2 is monitored after the outage of Line1. P_1^0 is the power flowing through Line1 before its tripping.

The Line Outage Distribution Factor $d_{(l,k)}$ is defined by power flow increase ratio after tripping a line in the network and depends on the network topology and system parameters. This can be calculated in a normal state by using (4) [6], [1].

$$d_{(l,k)} = \frac{\Delta P_l}{P_k^0} = \frac{\frac{x_k}{x_l}\left(X_{(i,n)} - X_{(j,n)} - X_{(i,m)} + X_{(j,m)}\right)}{x_k - \left(X_{(n,n)} + X_{(m,m)} - 2X_{(n,m)}\right)} \tag{4}$$

This shows that $d_{(l,k)}$ represents LODF from line k to line l when k is tripped.

x_l and x_k are reactances of line l and line k respectively.

i and j are bus IDs surrounding the monitoring line (Line2).

m and n are bus IDs surrounding the tripped line (Line1).

$X_{(a,b)}$ is (a,b)th element of X matrix in (1).

Using (4) LODF matrix between all the tie lines in the network can be calculated as follows:

$$d_{N*N} = [d_{(l,k)}] = \begin{bmatrix} -1 & d_{(1,2)} & \cdots & d_{(1,n)} \\ d_{(2,1)} & -1 & \cdots & d_{(2,n)} \\ \vdots & \vdots & \ddots & \vdots \\ d_{(n,1)} & d_{(n,2)} & \cdots & -1 \end{bmatrix}$$

Every time the network structure or network parameters are changed, this matrix needs to be updated.

3.2 Computation of vulnerability index

The Vulnerability Index indicates the risk of cascaded tripping of distance relays due to overload. The setting of distance relays is done by using the blinder, which is determined by the Maximum Load Ability of the line. The proposed method for calculating the Vulnerability Index in paper [6] using this proximity to the relay blinder is used. This paper not only analyzes the direct impact of line tripping but also analyzes the impact of second line tripping such as in Fig. 4. This paper divides the blinder into three zones using the Maximum Load Impedance by utilizing the Boundary Resistance Value of 85% and 125% of Maximum Load Impedance which represent the severity of distance in a relay trip possibility.

First level VI is calculated by applying a weighted value defined for each of the three zones. Second Level Vulnerability is calculated by first calculating the Vulnerability Index for each line by assuming the under observation line while tripped, and then an average of all the values is calculated. For Third Level Vulnerability, it is assumed that another line is tripping while the Under Observation Line has been tripped and the index computes it in the same way. The final VI is computed by summing all the primary, secondary, and tertiary VIs for that line.

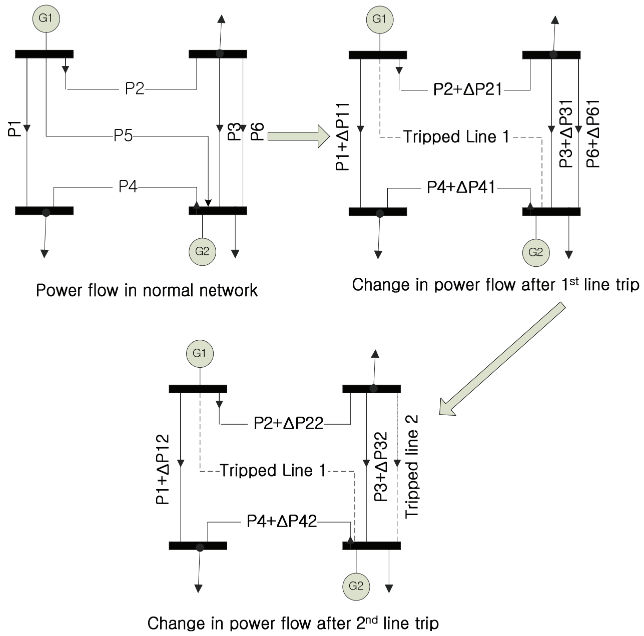

Fig. 4. Computation of secondary and tertiary VIs

3.3 Apparent factor and setting of distance relays

Due to the presence of feed lines in power systems, the distance seen by Distance Relay is known as Apparent Impedance; it differs from the Real Impedance by a factor known as Apparent Factor given as:

$$K_{ijk} = \frac{I_{jk}}{I_{ij}} \tag{5}$$

Here I_{ij} and I_{jk} show the current flowing through protected branch and protective branch respectively shown in Fig. 5.

Calculation of Apparent Factor using the conventional method as in (1) is a time consuming process due to the involvement of fault calculations. A fast algorithm for finding the apparent factor without fault analysis has been proposed in paper [10]. The method only needs the Network Impedance Matrix and certain Line Impedances.

Suppose the current injected from fault node F is I_F which will produce voltage at each node and is given as:

$$V_{iF} = Z_{iF} I_F \tag{6}$$

Z_{iF} is the trans-impedance between node i and F. If normal voltage of node i is $V_{i0,}$ then at fault state, it will be $V_i=V_{i0}+V_{iF.}$ If normal state node voltage is unified in per unit, then $V_{i0}=V_{j0}$, branch currents can be given by (7) & (8) by putting the values of V_{iF} and V_{jF} from (6)

$$\begin{aligned} I_{ij} &= \frac{V_i - V_j}{Z_a} = \frac{\left(V_{i0}+V_{iF}\right)-\left(V_{j0}+V_{jF}\right)}{Z_a} \\ &= \frac{V_{iF}-V_{jF}}{Z_a} = \frac{\left(Z_{iF}-Z_{jF}\right)I_F}{Z_a} \end{aligned} \tag{7}$$

$$I_{jk} = \frac{\left(Z_{jF}-Z_{kF}\right)I_F}{Z_b} \tag{8}$$

Apparent Factor can be computed by using (7) and (8) in the following way:

$$K_{ijk} = \frac{I_{jk}}{I_{ij}} = \frac{\dfrac{\left(Z_{jF}-Z_{kF}\right)I_F}{Z_b}}{\dfrac{\left(Z_{iF}-Z_{jF}\right)I_F}{Z_a}} = \frac{Z_a\left(Z_{jF}-Z_{kF}\right)}{Z_b\left(Z_{iF}-Z_{jF}\right)} \tag{9}$$

Once Apparent Factor is calculated, the setting values for zone 2 of Distance Relay are given as:

(Protected Line Impedance 100%) +
{(50% of shortest Protecting Line Impedence) ×
(apparent factor/2)}

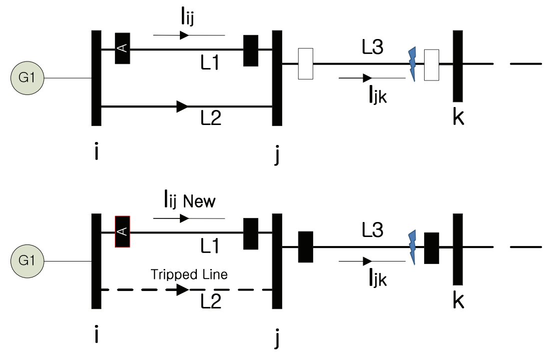

Fig. 5. Updating the relay setting values

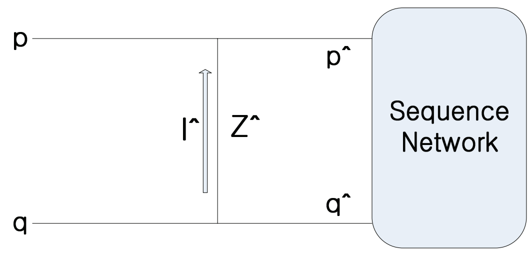

Fig. 6. Computation of new impedance matrix

When line L2 is tripped in Fig. 5, then the setting values of relay need to be reset. For updating the setting values, we use the above mentioned formula. Apparent Factor is a sensitive element in that formula which can be calculated by using (9). The Branch Impedance can be updated by using (12). Fig. 6 shows a network where a branch with impedance $Z^{\wedge}$ is deleted between node p and q. The new impedance matrix can be calculated by using (12):

The voltage at any node i in the network after deleting line between node p and q can be given by:

$$\begin{aligned} V_i^{\wedge} &= z_{i1}^{\wedge} I_i^{\wedge} + \ldots + z_{ip}^{\wedge}(I_p^{\wedge} + I_m^{\wedge}) + z_{iq}^{\wedge}(I_p^{\wedge} - I_m^{\wedge}) + \ldots \\ &= z_{i1}^{\wedge} I_i^{\wedge} + \ldots + z_{ip}^{\wedge} I_p^{\wedge} + z_{iq}^{\wedge} I_p^{\wedge} + \ldots (z_{ip}^{\wedge} - z_{iq}^{\wedge}) I_m^{\wedge} \end{aligned} \tag{10}$$

The new current can be calculated by integrating the polynomials after substituting the new voltage at nodes p and q as $\mathbf{V_p^{\wedge}} = \mathbf{V_q^{\wedge}} - (-\mathbf{Z}^{\wedge})\mathbf{I}^{\wedge}$. Eq. (10) can be written as

$$I^{\wedge} = \frac{\left(z_{q1}^{\wedge} - z_{p1}^{\wedge}\right) I_1^{\wedge} + \left(z_{q2}^{\wedge} - z_{p2}^{\wedge}\right) I_2^{\wedge} + \ldots}{z_{pp}^{\wedge} - z_{pq}^{\wedge} - z_{qp}^{\wedge} + z_{qq}^{\wedge} - Z^{\wedge}} \tag{11}$$

The new impedance matrix can be calculated by substituting (11) into (10): [10]

$$z_{nmNew}^{\wedge} = z_{nm}^{\wedge} - \frac{\left(z_{np}^{\wedge} - z_{nq}^{\wedge}\right).\left(z_{pm}^{\wedge} - z_{qm}^{\wedge}\right)}{z_{pp}^{\wedge} - z_{pq}^{\wedge} - z_{qp}^{\wedge} + z_{qq}^{\wedge} - Z^{\wedge}} \quad (m, n = 1, 2, 3 \ldots. N) \tag{12}$$

When a line is deleted, the new admittance matrix can be calculated by using (12). Once the matrix is known, the new Apparent Factor can be calculated by using (9). Then the new setting Values of Relays can be computed.

3.4 Computation of protectability index

After finding the setting values of relays before and after the tripping of line, the difference between these two values has been analyzed and a new index, Protectability Index (PI) has been proposed. It indicates the risk of cascading tripping due to unwanted tripping of relays due to change in flow of fault current after tripping a line.

In Fig. 3, the setting value of relay in L2 before tripping of L1 is K_1 and the new setting value of relay is K_2 after tripping of L1 and redistribution of load. Then, PI will be calculated by using the weighted protectability defined for the different regions. Fig. 7, which is governed by equation set (13), shows the Protectability Index for each region.

$$PI = \begin{cases} 1 & : K_2 \geq C_u \text{ or } K_2 \leq C_l \\ \dfrac{K_2 - K_1}{C_u - K_1} & : K_2 \geq K_1 \\ 1 - \dfrac{K_1}{K_2} & : K_2 < K_1 \end{cases} \tag{13}$$

Where

C_l - Lower limit for setting value
C_u - Upper limit for setting value.

Abscissa in Fig. 7 shows the new setting values of the relay being observed. Cl is the lower limit for new setting values and Cu is upper threshold for the new setting value. Both the thresholds have been set as 10% of the old setting value of the relay. Since operating current of a relay should be within 10% of the pickup current [16] and relay setting values is function of pickup current.

Similarly PI will be calculated for all other relays, and the final PI for L1 will be the sum of all the individual line PIs.

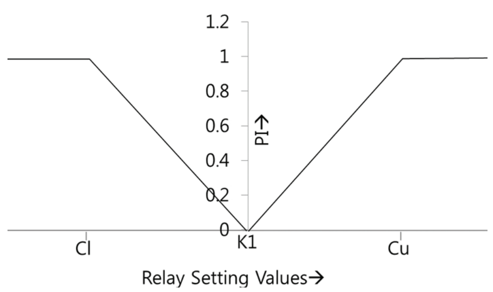

Fig. 7. Weighted Protectability for each region

3.5 Computation of line security index

The vulnerability index is measure of how much other lines become overloaded when a line is tripped due to any reason.

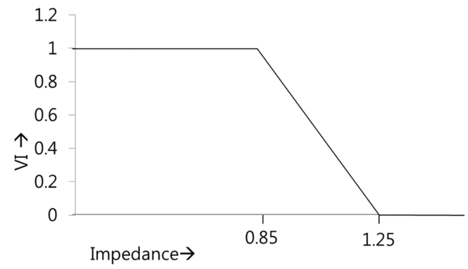

Fig. 8. Weighted Vulnerability for each region

VI has been computed by dividing the relay blinder into three zones by using the maximum load impedance as shown in Fig. 8. The graph show in Fig. 8 is governed by equation set (14).

$$VI = \begin{cases} 0 & : R_{ij} > 1.25 \times R_{\max} \\ \dfrac{R_{ij} - 1.25 \times R_{\max}}{0.4 \times R_{\max}} & : 0.85 \times R_{\max} \leq R_{ij} \leq 1.25 \times R_{\max} \\ 1 & : R_{ij} < 0.85 \times R_{\max} \end{cases} \tag{14}$$

Where

R_{ij} : Load impedance of line between bus i and bus j
$R_{\max}$: Maximum load impedance of the same line

The traditional setting of zone one for distance relay is adopted as 80% of the line considering measurements errors and is based on engineering experience [8]. While setting of zone two is set as 120% of its line by considering the measurement errors. By giving an additional margin of 5%, the VI computed for region one has been set to one, if the line impedance drops by 85% of its maximum impedance i.e. $R_{ij} < 0.85 \times R_{\max}$. Similarly for region three, the VI has been set as zero, if the line impedances crosses 125% of the maximum impedance i.e $R_{ij} > 1.25 \times R_{\max}$. After knowing the boundary conditions the VI for region two has been calculated by formulating a line equation between these two known points, where 0.4 is the slope of that line.

Protectability Index tells about the possibility of falsely tripping the relays planted for protection of the line with a change in the fault current. The weighted protectability for each region has been shown in Fig. 7. In order to analyze a line completely, it is essential to analyze both the indexes.

Line Security Index is the algebraic sum of both the Vulnerability Index and the Protectability Index and is given as $LSI = VI + PI$. The calculated LSI will indicate the importance of each individual line.

The LSI assigned to each line has a physical significance. LSI indicates the probability of total unwanted trippings. PI indicates the probability of unwanted relay operations due to change in the flow of fault current and VI indicates the probability of unwanted trippings due to overloading. Combining both will result in the probability of total unwanted operations when the line under observation is tripped.

In the example system shown in Fig. 3, each line from L1 to L3 will have an LSI. It will indicate the importance of that line. Here, importance of a line means its effect on the remaining system in terms of overloading of lines and/or tripping of other relays. The complete process for computation of LSI is explained by the flow chart shown in Fig. 9.

We can analyze the system and find the relay setting values before and after the line tripping. Once we know the importance of each line by using LSI, we can easily reset the designated relays only. Resetting of the relays in real time is not possible, and it also is difficult to determine which group of relays needs to be reset. By using the proposed LSI in this paper, we can easily find the relays which need to be reset when a particular line is tripped. Due to the simplicity of methods used for calculating, the relay setting values or load distribution the proposed index can be calculated in real time and quickly, if configuration of the network is changed.

The PI and VI values for individual relays are computed by using Figs. 7 and 8 respectively. The computed values using these figures show the probability of tripping of a single relay, so their maximum value is one. While the final PI and VI values show the total number of unwanted trippings due to the backup relay's maloperation and line overloading respectively. If PI for a line is 2, then tripping of that line will result in two unwanted relay trips. The value 2 indicates that probability of false tripping of both the relays is one and one respectively. Similarly 2VI means two unwanted trips due to overloading, with a tripping probability of one for each of the two relays.

Every line will be assigned an LSI using the method depicted in Fig. 9. The value of LSI indicates the probability of unwanted operations. If LSI for a line is 3, it means there is probability of 3 maloperations if the Under Observed Line is tripped. The algorithm has been already realized by Korea Electric Power Corporation (KEPCO).

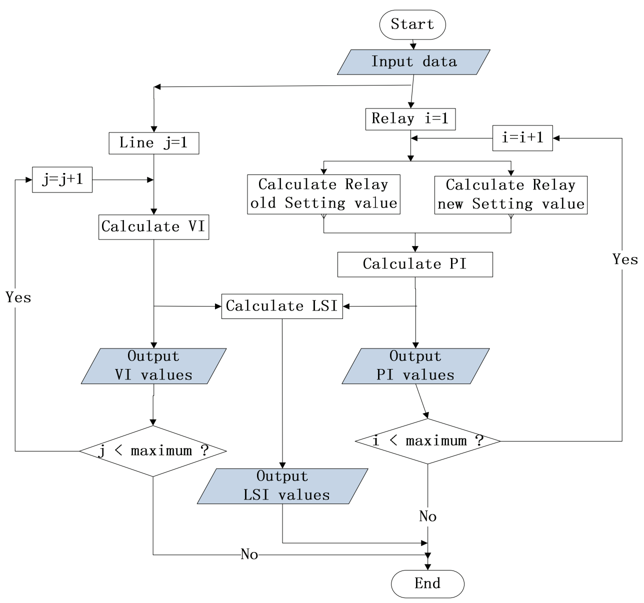

Fig. 9. Flow chart for LSI computation.

4. Test Cases

The test system has been simulated in PSCAD version 3.0 and system parameters have been taken from Korea Electric Power Supply Corporation. The system parameter files have been exported as .txt files. The text files have been used for calculating VI, PI and LSI for each line by making use of the proposed algorithm developed in C++, Visual Studio 2010. The final values of VI, PI, and LSI computed by using the developed algorithm are stored in a text file for analysis of the tested system. The tested system comprises of 259 lines and 1533 buses. The line id ranges from 0 to 258. Fig. 12 shows some part of the tested network. Due to the complexity of network only some part of it is shown. The figure only contains those lines which have a comparatively severe effect on the remaining system from protectability and/or vulnerability point of view.

4.1 Evaluation of VI

For evaluation of VI primary, secondary and tertiary indexes have been summed and the Value of Primary Index is usually zero because the blinder is set in a safe zone initially. The secondary index indicates how much the remaining system will be affected when the line of the given id is tripped and the tertiary indicates the risk of cascade tripping i.e how the remaining system will be affected when another line is tripped given that under observation line has already been tripped.

The final VI is the sum of all the above three indexes. Table 1 shows the results of only those lines which have a significantly higher VI. By analyzing the final VI from Table1, it can be concluded that line 212 is the most important line from a vulnerability point of view. VI is

Table 1. Computation of VI

Line ID	Primary index	Secondary index	Tertiary index	VI
12	0.000	0.366	0.366	0.731
156	0.000	0.129	0.065	0.194
205	0.000	0.362	0.000	0.362
210	0.000	0.374	0.187	0.562
212	0.000	0.684	0.342	0.027

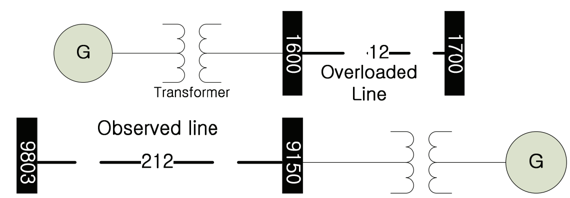

Fig. 10. Significance of VI

computed by tripping Line 212 and then line 115 given that line 212 was already tripped as shown in Fig. 10. Secondary VI for line 212 is 0.684, tertiary is 0.342, and final VI is 1.027 which is greater than one. It means at least one line will get overloaded. In this case line12 is fully overloaded and will be tripped via overloading (because VI>1). A similar interpretation is valid for all the other lines.

Fig. 10 shows the physical significance of VI; VI indicates number of overloaded lines. The VI for line 212 is 1.027 which means one line will get overloaded, line12.

The higher the VI, the more important the line is because when a line with a high VI is tripped, there is more possibility of other lines overloading resulting in false tripping. This may then lead to cascade tripping. Though, tripping lines with lower VI are not likely to cause any significant danger to the system.

4.2 Evaluation of PI

Similarly for computing PI the same system of 259 lines is used. In order to calculate PI, new setting values have been computed for all the connected lines. Setting values before and after the tripping of the line have been used according to Fig. 3. Ultimately, the PI for the relay has been computed by finding the sum of all the individual PI values.

Results of some of the lines which have a higher effect on the setting values of adjacent lines relays are shown in Table 2.

When a fault occurs in line11 in normal state, the responsible relays planted at both the ends of line11 get tripped and the faulty section is isolated as shown in Fig. 11, a section of Fig. 12. However, when line8 is tripped and the fault occurs at the same point on line11, then the backup relays planted on line4 and line5 may maloperate. From tripping line8, all of the fault current will flow through line4 and line5 and these two relays will need to be reset. The PI value is the index for the number of false tripping. For line8, PI is 1.939 which is around 2. With this, two relays will maloperate if line8 is tripped. The two relays are the relays at line4 and line5 as shown in Fig. 11.

Table 2. Computation of PI

Tripped line ID	Protected line	Protective line	Old setting value	New setting value	Single line PI	PI
8	11	4	0.004	0.117	0.969	1.939
		5	0.004	0.117	0.969	
139	149	128	0.020	0.314	0.936	1.877
	128	149	0.026	0.544	0.952	
254	174	169	0.007	0.021	0.648	1.596
	169	174	0.010	0.109	0.945	

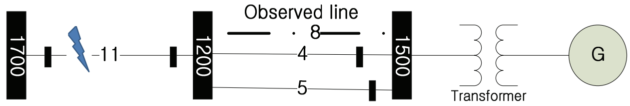

Fig. 11. Significance of PI

By observing the above table, it can be concluded line8 is the most important line from a protectability point of view because its tripping will lead to two false trips (PI≈2).

A similar type of interpretation is valid for all the lines. The higher the PI, the more important the line is. When a line with higher PI is tripped and fault occurs at a protective line, there is more of a chance for falsely tripping the protected line relay. When a line with low PI is tripped, there are less chances of maloperation of the protected line relay.

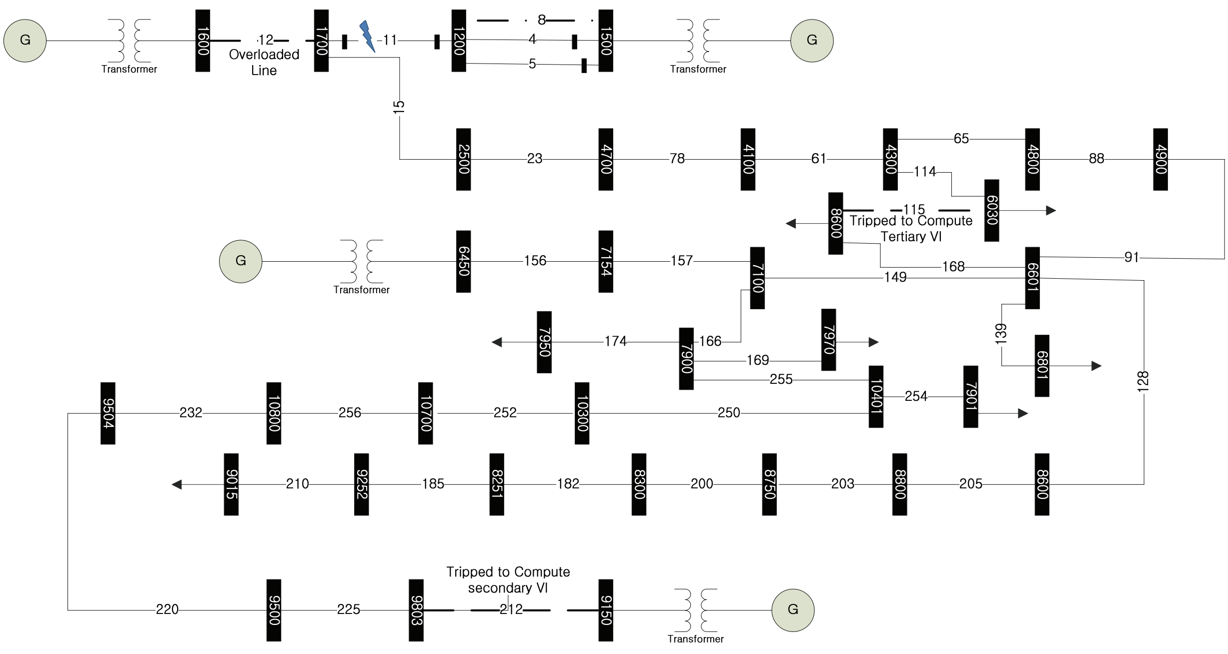

Fig. 12. A Portion of tested network

4.3 Evaluation of LSI

Finally the LSI is computed by summing the VI and PI values. Below Table 3 shows LSIs of only some of the lines whose values are higher. Every line is connected between two busses. From Bus and To Bus in the following table mean the bus names between which the given lines are connected.

Table 3. Computation of LSI

Line ID	From Bus	To Bus	VI	PI	LSI
8	1500	1700	0	1.94	1.94
255	7900	10401	0.17	1.6	1.77
139	6601	6801	0	1.87	1.87
254	7901	10400	0.19	1.6	1.79
205	8600	8800	0.36	1.29	1.65

The importance of a line is given by the number of false trippings which will be caused by that line. LSI indicates total number of false tripping when the given line is tripped. LSI for line8 is around two which means two maloperations. Fig. 13 shows that when line8 is tripped and a fault occurs at line11, two relays (line4 and line5) will maloperate.

The LSI computed has given an importance to each line by considering both protectability and vulnerability. The higher the LSI value the greater the importance of the line is. Tripping of an important line may result in another line tripping. Ultimately, it will result in a cascade tripping and may lead to a huge blackout or complete system breakdown.

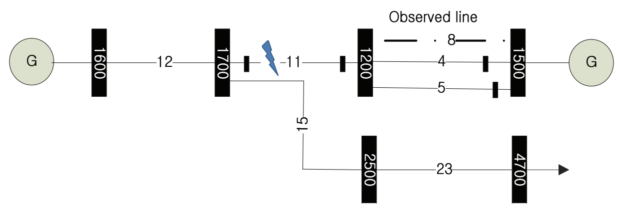

Fig. 13. Significance of LSI

5. Conclusion

Protectability index has been calculated by using the setting values of a relay before and after the tripping of other lines and vulnerability index is same in [6] with different regions and different weightages for each region.

Only VI or PI cannot evaluate the importance of an electrical line completely, so this new index has been proposed. The new index, LSI, is computed with a numerical sum of both VI and PI. VI indicates the probability of number of false operations in a power network due to overloading and PI indicates the probability of number of false trips due to change in the flow of fault current. Their sum will indicate the total number of false operations in a power network. The new proposed method is based on simple and real time application methods. Finally, each index has a physical significance. By observing the index value, number of maloperations can be easily determined. It has been applied to the real system data at the Korean Electrical Power Supply Corp. The proposed method has been realized by KEPCO and has been used for monitoring and analysis of real power systems in Korea. The results have proved it to be an essential index for finding the importance of individual lines before tripping lines as to avoid cascaded line tripping and at long last avoid large scale blackouts.

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Akhtar Hussain received his B.E degree in Telecommunications from National University of Sciences and Technology (NUST) Pakistan in 2011 and M.S in Power Systems from Myongji University, Korea, in 2014. Currently he is working as an associate engineer in SANION; IEDs development company, in Korea. His research interests are power system automation and protection, smart grids and communication in power systems.

Chang-Ju Seok He received his B.S degree in Electrical Engineering from Myongji University Korea in 2012. Currently he is an M.S Student in Myongji University Korea majoring in Power System in Electrical Engineering department. His research interests are automation in power systems and power system protection.

Myeon-Song Choi is a professor at Myongji University, Korea. He received B.S., M.S. and Ph.D. degrees from Seoul National University, Korea in 1989, 1991 and 1996, respectively. He was a visiting fellow at Pennsylvania State University in 1995. His major research fields are power system control and protection including artificial intelligence application.

Seung-Jae Lee has been with the department of Electrical Engineering, Myongji University as a professor since 1988. He is a director of Next-Generation Power Technology Center. He received BS and MS degrees from Seoul National University, Korea in 1979 and 1981 respectively and a Ph.D. from University of Washington, Seattle, USA, in 1988. His main research areas are protective relaying, distribution automation and AI applications to power systems.

Seongil Lim received the B.S., M.S., and Ph.D. degrees from Myongji University, Yongin, Korea, in 1994, 1996, and 2004, respectively. He was with Electric Power Research Institute of KEPCO and then a Visiting Scholar at Iowa State University, Ames, in 2006. Currently, he is an Associate Professor at Department of Electrical Engineering, Kyungnam University, Chanwon, Korea. His research fields are protective relaying, substation automation, and distribution automation.