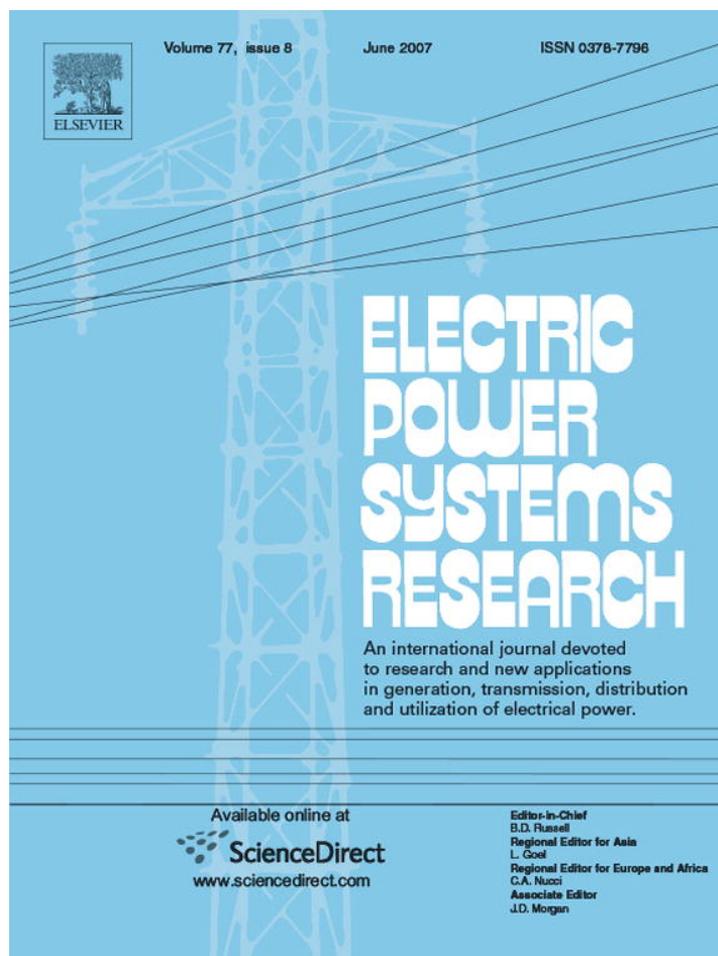


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A new analysis method for early detection and prevention of cascading events

Hongbiao Song^{*}, Mladen Kezunovic

Department of Electrical and Computer Engineering, Texas A&M University, College Station, TX 77843-3128, USA

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Abstract

This paper introduces a new analysis method for early detection and prevention of power system cascading events. It uses the vulnerability index (VI) and margin index (MI) to evaluate the vulnerability and security of the individual system parts, as well as the whole system during an operating state. It identifies the vulnerable parts of the power system using the topology processing and operation index methods. For a given disturbance, it calculates the power flow, evaluates the vulnerability and security, identifies the vulnerable part, finds the transmission line overload and bus voltage problems, and predicts the possible successive events. The approach defines the control means using the following methods for early detection and prevention of cascading events: network contribution factor (NCF), generator distribution factor (GDF), load distribution factor (LDF), and selected minimum load shedding (SMLS). This approach has been tested using the IEEE RTS-96 24-bus system and promising results have been obtained. The proposed approach allows the power system operator to detect initial stages of cascading events and assert actions that will prevent such events from unfolding.

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1. Introduction

Power system cascading event is quite often a very complex phenomenon with low probability of occurrence but potentially catastrophic social and economical impacts. There are many cascading events resulting in large area blackouts worldwide, such as, 1965 US-Northeastern blackout, 1977 US-New York blackout, 1978 France blackout, 1996 US-Western blackouts, 2003 US-Northeastern blackout, 2003 Italy blackout, 2005 Russia-Moscow blackout, etc. [1–7]. Variety of research efforts are aimed at understanding and finding ways to prevent or mitigate cascading events: study of the cascade model, dynamic decision-event tree analysis, wide area backup protection, relay hidden failure analysis, special protection scheme, self-healing system with the aid of multi-agent technology, etc. [8–12]. The mentioned techniques are still far from being an established practice in solving the cascading event problem.

In general, cascading event is not a sudden event that human being cannot prevent or mitigate. Normally there are two stages of a cascading event [13]. First, there is a period of slowly evolving successive events that can be approximated with steady state analysis. The system operating conditions may get worse with several new disturbances following one another. Second, after succession of several major disturbances, there is a fast transient process resulting in cascading events and finally the system collapses. When the total system collapse starts, normally it is too late to stop it. However, much can be done during the slow steady state successions at the first stage.

Early proper control actions at the steady state stage can prevent the possible cascading event. For example, on 3 July 1996, the Western Coast system operators manually shed load to avoid the possible cascading event when conditions were similar to 2 July [4]. On 26 August and 30 October 1996, the appropriate steady state control by system operators of New York Power Pool prevented the possible cascading event if the next worst contingency had occurred [4]. One thousand and five hundred mega Watts load shedding within Cleveland-Akron area before the tripping of Sammis-Star line could have prevented the blackout [5].

^{*} Corresponding author. Tel.: +1 979 847 9069; fax: +1 979 845 9887.

E-mail addresses: songjefferson@neo.tamu.edu (H. Song), kezunov@ece.tamu.edu (M. Kezunovic).

Steady state method was used successfully to simulate the cascading sequence of 2003 US-Northeastern blackout using rough information [14]. It was also used by the task force to benchmark the pre-cascade conditions of the Northeastern power system and conclude that the system was secure at 15:05EDT before the loss of Harding-Chamberlin line [5]. A similar method was used to simulate terrorist attack plan to find the vulnerability of the system [15].

This paper aims at early detection and prevention of cascading event using steady state analysis method at its initial steady state stage. This method can be implemented to work automatically with or without operator supervision, and can serve as a decision-support tool for real time operation or operator training purpose.

The framework of the proposed method is as follows. First, the power system is monitored to see whether there are any events or changing conditions during the system normal operation. Second, the system conditions are evaluated by computing the vulnerability index and margin index. Those indices can give specific quantitative measure of system vulnerability and security margin. Third, if the system is determined to be secure (not vulnerable), the monitoring of the system continues. Otherwise, the vulnerable parts of the system and vulnerable conditions are identified, the possible voltage and overload problems if those vulnerable conditions occur are predicted, the suitable control means to prevent or mitigate the problems are identified, and the control means are activated when needed.

Section 2 presents the comprehensive vulnerability index and margin index to evaluate the power system operation. Section 3 gives methods of topology processing and operation index to identify the vulnerable parts of the power system. Section 4 introduces the fast network contribution factor (NCF) method and uses it to predict the line overload and bus voltage problems for a given network event or assumed contingency. Section 5 provides the steady state control scheme based on network contribution factor (NCF), generator distribution factor (GDF), load distribution factor (LDF), and selected minimum load shedding (SMLS) methods to prevent and mitigate possible cascading event. Section 6 presents the study results. Section 7 concludes the paper.

2. Evaluation of the power system operation

Power system operators need to know as precisely as possible the security condition of the system operation. Thus they can take some control actions when the system security is being or has been threatened.

Security of a power system refers to the degree of risk in its ability to survive imminent disturbances (contingencies) without interruption of customer service. Stability of a power system refers to the continuance of intact operation following a disturbance [16]. Vulnerability can be taken as a measure opposite to security. The system is vulnerable if contingencies lead to an interruption of service to a part or the entire system. The element is vulnerable if contingencies or changing conditions lead to violation of the element limit, outage or mal-function of the element.

Before the power system faces interruption of service or the element faces outage or mal-function, some indices can be used to represent the degree of vulnerability and security. Vulnerability index (VI) and margin index (MI) are proposed to represent comprehensive and quantitative vulnerability and security information of the individual part and whole system [17]. Given a system with m generators, n buses, p lines and q loads, we define the vulnerability index (VI) and margin index (MI) sets as follows

A. Vulnerability index and margin index for generators:

$$VI_{Pg,i} = \frac{W_{Pg,i}}{2N} \left(\frac{Pg_i}{Pg_{i,max}} \right)^{2N}, \quad (1)$$

$$VI_{Qg,i} = \frac{W_{Qg,i}}{2N} \left(\frac{Qg_i}{Qg_{i,max}} \right)^{2N}, \quad (2)$$

$$VI_{gen_loss,i} = W_{gen_loss,i} k_{gen_loss,i}, \quad (3)$$

$$VI_{gen} = \sum_{i=1}^m (VI_{Pg,i} + VI_{Qg,i} + VI_{gen_loss,i}), \quad (4)$$

$$MI_{Pg,i} = 1 - \frac{Pg_i}{Pg_{i,max}}, \quad (5)$$

$$MI_{Qg,i} = 1 - \frac{Qg_i}{Qg_{i,max}}. \quad (6)$$

B. Vulnerability index and margin index for buses:

$$VI_{V,i} = \frac{W_{V,i}}{2N} \left(\frac{V_i - V_i^{sche}}{\Delta V_{i,lim}} \right)^{2N}, \quad (7)$$

$$VI_{Loadab,i} = \frac{W_{Loadab,i}}{2N} (r_{Loadab,i})^{2N}, \quad (8)$$

$$VI_{load_loss,i} = W_{load_loss,i} k_{load_loss,i}, \quad (9)$$

$$VI_{bus} = \sum_{i=1}^n (VI_{V,i} + VI_{Loadab,i} + VI_{load_loss,i}), \quad (10)$$

$$MI_{V,i} = 1 - \left| \frac{V_i - V_i^{sche}}{\Delta V_{i,lim}} \right|, \quad (11)$$

$$MI_{Loadab,i} = 1 - r_{Loadab,i}. \quad (12)$$

C. Vulnerability index and margin index for branches:

$$VI_{Pf,i} = \frac{W_{Pf,i}}{2N} \left(\frac{Pf_i}{S_{i,max}} \right)^{2N}, \quad (13)$$

$$VI_{Qf,i} = \frac{W_{Qf,i}}{2N} \left(\frac{Qf_i}{S_{i,max}} \right)^{2N}, \quad (14)$$

$$VI_{Qc,i} = \frac{W_{Qc,i}}{2N} \left(\frac{Qc_i}{Q_{\Sigma}} \right)^{2N}, \quad (15)$$

$$VI_{line_ang,i} = \frac{W_{line_ang,i}}{2N} \left(\frac{La_i}{La_{i,max}} \right)^{2N}, \quad (16)$$

$$VI_{\text{Relay},i} = \frac{W_{\text{Relay},i}}{2N} \left(\left(\frac{1}{d_{\text{sr},i}} \right)^{2N} + \left(\frac{1}{d_{\text{rs},i}} \right)^{2N} \right), \quad (17)$$

$$VI_{\text{line_loss},i} = W_{\text{line_loss},i} k_{\text{line_loss},i}, \quad (18)$$

$$VI_{\text{line}} = \sum_{i=1}^p (VI_{\text{Pf},i} + VI_{\text{Qf},i} + VI_{\text{Qc},i} + VI_{\text{line_ang},i} + VI_{\text{Relay},i} + VI_{\text{line_off},i}), \quad (19)$$

$$MI_{\text{Sf},i} = 1 - \frac{Sf_i}{S_{i,\text{max}}}, \quad (20)$$

$$MI_{\text{line_ang},i} = 1 - \frac{La_i}{La_{i,\text{max}}}, \quad (21)$$

$$MI_{\text{Relay},i,\text{sr}} = d_{\text{sr},i} - K_{z,i,\text{sr}} \left| \sin \left(\frac{\pi}{2} - \alpha_i + \theta_{d,\text{sr}} \right) \right|, \quad (22)$$

$$MI_{\text{Relay},i,\text{rs}} = d_{\text{rs},i} - K_{z,i,\text{rs}} \left| \sin \left(\frac{\pi}{2} - \alpha_i + \theta_{d,\text{rs}} \right) \right|, \quad (23)$$

where VI_{xx} is the vulnerability index for different parameters, xx represents Pg, Qg, gen_loss, V, etc.; MI_{xx} the margin index for different parameters; W_{xx} the weighting factor for different parameters; $k_{\text{x_loss},i}$ —0: no loss, 1: completely loss, 0–1: loss ratio, x represents gen, load, line; $N=1$ in general; $r_{\text{Loadab},i}$ the bus i loadability; $r_{\text{Loadab},i} = Z_{\text{th},i}/Z_{L0,i}$; $Z_{\text{th},i}$ the Thevenin equivalent system impedance seen from bus i ; $Z_{L0,i}$ the equivalent load impedance at bus i at steady state; Pf_i , Qf_i , Sf_i the real, reactive and apparent power of line i ; Qc_i the line i charging; Q_{Σ} the total reactive power output of all generators, or total reactive power supply of the whole system; La_i the bus voltage angle difference at line i ; $La_{i,\text{max}}$ the bus voltage angle difference limit at line i ; $d_{\text{sr},i}$, $\theta_{d,\text{sr}}$ the magnitude and angle of normalized apparent impedance seen by distance relay from the sending to receiving end of line i ; α_i the impedance angle of line i ; $K_{z,i,\text{sr}}$, $K_{z,i,\text{rs}}$ the zone setting of line i ; $MI_{\text{Relay},i,\text{sr}}$, $MI_{\text{Relay},i,\text{rs}}$ are the distance from the apparent impedance seen by transmission line distance relay to the relay protection zone circle, zero or negative value means the apparent impedance is at or within the protection zone circle.

D. Vulnerability index for the whole system:

The aggregate system vulnerability index (VI) can be presented by

$$VI = W_{\text{gen}} VI_{\text{gen}} + W_{\text{bus}} VI_{\text{bus}} + W_{\text{line}} VI_{\text{line}}. \quad (24)$$

The larger the vulnerability index value, the more vulnerable the system condition.

We can learn about the system-wide vulnerability and security of individual system elements from different VI and MI values computed for various system conditions.

E. Discussions about vulnerability index and margin index:

System performance index (PI) was originally proposed for automatic contingency selection by ranking transmission line outages and generator outages in [18]. It only considers

the influences of line/generator outages on bus voltage and line real power flow, similar to Eqs. (7) and (13).

Current power systems are being operated closer to its security limit due to economic reasons. The influences of more parameters must be considered. The proposed vulnerability index and margin index are more comprehensive and modeling more parameters than traditional performance index. We just give some simple explanations for some new parameters, such as loadability, line charging, bus voltage angle difference, distance relay, etc.

To maintain the scheduled voltage, loadability and reactive power supply need to be considered besides the voltage magnitude. Loadability is often associated with voltage stability limit. There are good methods and references for loadability analysis in [19]. Loadability is computed in this paper by using the Thevenin equivalent impedance method [20].

The line charging influence is also considered by the proposed vulnerability index. Some lightly loaded lines with high charging capacitance may contribute significantly to the reactive power and voltage support. Their outages may decrease the reactive power support or need generators to generate more reactive power. Outages of several lightly loaded transmission lines may reduce the system security, which was one of the key factors in the 10 August 1996 US-Western blackout [4].

The bus voltage angle difference at each line is also an important index. We can see this from the line power flow and apparent impedance seen by line distance relay. For example, from the simplest lossless line model (represented with L only), real power flow through the transmission line can be represented by

$$P_{\text{sr}} = \frac{V_s V_r}{x_{\text{sr}}} \sin \theta_{\text{sr}}, \quad (25)$$

A larger bus voltage angle difference means larger power transfer through that line.

If the lossless line model or short line model (represented with R and L) is used, we can find that the normalized apparent impedance is only associated with the bus voltages along the line:

$$Z_{d,\text{sr}} = \frac{V_s}{I_{\text{sr}}} = \frac{V_s}{(V_s - V_r)/Z_{\text{sr}}}, \quad (26)$$

$$\bar{Z}_{d,\text{sr}} = \frac{Z_{d,\text{sr}}}{Z_{\text{sr}}} = \frac{V_s}{V_s - V_r} = \frac{|V_s|}{|V_s - V_r|} \angle \theta_{d,\text{sr}} = d_{\text{sr}} \angle \theta_{d,\text{sr}}. \quad (27)$$

The larger the bus voltage angle difference, the smaller the normalized apparent impedance, the more possible the case that the apparent impedance may fall into the distance relay backup zone (zone 3 or 2 acting as backup) during non-fault conditions such as power swing, overload and low voltage. The heavy loading and low voltage condition caused the Sammis-Star 345-KV line distance relay “see” a zone 3 fault and trigger the 14 August 2003 Northeastern blackout [5].

The selection of the weighting factors can be based on the power system operating practice. If the operators are more concerned with one part, they can give larger value for that part. For example, important tie-lines can be assigned larger values than other transmission lines. Larger generators can be given larger values than smaller generators.

Vulnerability index and margin index can be used for contingency ranking. They can also be used to judge whether the system condition is vulnerable or not. For example, for a normal ($N - 1$ secure) operating state, we can increase the system loading till it is “ $N - 1$ insecure”. Define the system vulnerability index value at this point as the threshold for vulnerable criterion. If the system vulnerability index value is larger than this threshold, the system is vulnerable. This threshold will also change with the changes in the network topology and generation/load pattern. The fast network contribution factor (NCF) method will be used to approximate power flow results and calculate the vulnerability index and margin index.

3. Identification of vulnerable parts in the system

After the system operating condition is identified as being vulnerable by examining the vulnerability index and margin index, the topology processing method and operation index method can be used to identify the vulnerable parts of the system.

The single-line connection, single-line connected load bus, and double-line connection can be identified from the topology processing method through bus-branch incidence matrix A . The operation index method, including network contribution factors, contingency stiffness index, and distance relay margin index, can be obtained by the base power flow condition and network information.

3.1. Single-line connection

If one line is out, one or several buses will be isolated from the main part of the system. This specific line is called single-line connection, as represented with the line $i - j$ in Fig. 1a and lines $i - j$ and $j - k$ in Fig. 1b. Those single-line connections are used to identify single-line connected load buses and avoid $N - 1$ analysis at those lines.

3.2. Single-line connected load bus

If the load bus is connected by one single-line, as represented with the bus j in Fig. 1a and bus k in Fig. 1b, or if it is connected by more than one line but all of them are single-line connections, as represented with the bus j in Fig. 1b, the load bus is called single-

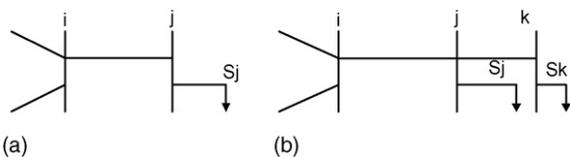


Fig. 1. Single-line connection and its connected load bus.

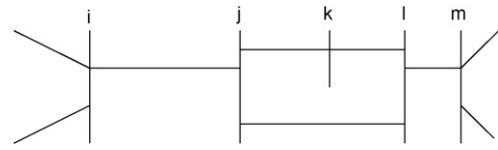


Fig. 2. Double-line connection.

line connected load bus. For those single-line connected load buses, the maximum load is limited by the voltage drop along the line. This method is used for voltage control and selected minimum load shedding (SMLS).

3.3. Double-line connection

If two lines are out, one or several buses will be isolated from the main part of the system. Those two specific lines are called double-line connections. We can see them represented in Fig. 2 where the outage of lines $j - k$ and $k - l$ isolates the bus k , and outage of lines $i - j$ and $l - m$ isolates buses j, k and l . They are used to identify single-line connections after one line outage and avoid the $N - 2$ analysis at those two-line outage combinations.

3.4. Network contribution factor method

Flow network contribution factor (FNCF) and voltage network contribution factor (VNCF) are further defined in [17]. They are obtained from the base flow condition and network information. After a network parameter variance, such as admittance/topology change due to line on/off, admittance change due to TCSC on/off, topology/admittance/shunt change due to SVC on/off, etc., the approximate real power (or bus voltage) variance of branch (or bus) k equals to the product of FNCF (or VNCF), admittance (or voltage) of branch (or bus) k and admittance variance of branch (or bus) i :

(1) Single parameter variance:

For admittance variance Δy_i of a single branch i , flow network contribution factor (FNCF) $N_{f,k}$ is as follows for branch $k, k \neq i$:

$$N_{f,k} = -[A_{1k} \ \cdots \ A_{nk}]X_1K_i; \quad (28)$$

for branch $k, k = i$:

$$N_{f,k} = \sum_{j=1}^n \frac{A_{ji}E_j\theta_j}{y_i} - [A_{1i} \ \cdots \ A_{ni}]X_1K_i. \quad (29)$$

The branch k real power variance is

$$\Delta P_{f,k} = N_{f,k}y_k\Delta y_i. \quad (30)$$

For shunt parameter variance $\Delta y_{bs,i}$ of a single bus i , voltage network contribution factor (VNCF) $N_{v,ki}$ is as follows for bus k :

$$N_{v,ki} = X_{2,ki}. \quad (31)$$

Bus k voltage variance can be obtained by

$$\Delta E_k = N_{v,ki}E_k\Delta y_{bs,i}, \quad (32)$$

where A is the bus-branch incidence matrix, y_k the branch k admittance, E_j, θ_j the magnitude and angle of bus j voltage, Y_1 the negative imaginary part of primitive branch admittance matrix, and B'' is the reduced admittance matrix from fast decoupled power flow method:

$$K_i = [A_{1i} \ \cdots \ A_{ii} \ \cdots \ A_{ni}]^T \sum_{j=1}^n A_{ji} E_j \theta_j,$$

$$X_1 = (A(Y_1 + \Delta Y_1)A^T)^{-1}, \quad X_2 = (B'')^{-1}.$$

For fast approximation, we can use the base network matrix:

$$X_1 = (AY_1A^T)^{-1}.$$

(2) Multi-parameter variance:

For multi-parameter variance, here we only take variance of two parameters as a simple example. For parameter variance of branches i, j , line k real flow variance is

$$\Delta P_{f,k} = N_{f,k} y_k \left(\Delta y_i + \frac{K_j}{K_i} \Delta y_j \right). \quad (33)$$

For parameter variance of buses i, j , bus k voltage variance is

$$\Delta E_k = N_{v,ki} E_k \Delta y_{bs,i} + N_{v,kj} E_k \Delta y_{bs,j}. \quad (34)$$

The variance of bus voltage angle can also be obtained by

$$\Delta \theta = -X_1 (A \Delta Y_1 A^T) \theta. \quad (35)$$

The approximate variance for line k reactive power flow is

$$\Delta Q_{f,k} \approx P_{f,k} \Delta \theta_k. \quad (36)$$

By using the FNCF and VNCF, we can find variance of the line flow and variance of the bus voltage due to network parameter change. Thus, line overload and bus low voltage problems due to parameter change can be predicted.

3.5. Contingency stiffness index

The contingency stiffness index is proposed to represent the maximum disturbance at buses directly affected by a line outage contingency, normalized by the bus equivalent admittance [21]. It is also used in this paper to identify vulnerable lines whose outages may impact the security of the system. For the outage of line k connecting buses i and j , it is defined as

$$SI_k = \max \left\{ \frac{S_{ij}}{Y_i^{eq}}, \frac{S_{ji}}{Y_j^{eq}} \right\}, \quad (37)$$

where S_{ij}, S_{ji} are the apparent power flow at the two ends of line k and Y_i^{eq}, Y_j^{eq} are the equivalent admittance of buses i and j .

The contingencies with the stiffness index values higher than a pre-determined threshold need more attention. It is used for selection of vulnerable parts.

3.6. Distance relay margin index

Eqs. (22) and (23) define the distance relay margin indices from both ends of the line. If either one is negative, that means, the apparent impedance falls into the relay protection zone.

4. Prediction of the overload and voltage problems

For a given network event or assumed network contingency, we can first use fast network contribution factor (NCF) method to get approximate power flow results. Then associated margin and vulnerability indices can be obtained. If the operation condition is judged vulnerable, the vulnerable elements will be identified by the topology processing and operation index methods. Line overload or voltage problems can be predicted by the flow and voltage network contribution factor method. The final results will be verified by the full ac power flow method. If the contingency is a loss of generator or load, new ac power flow needs to be run instead.

5. Control methods and automatic control scheme

If line overload and/or low voltage problems occur after the event, associated control needs to be taken to solve such problems. The proposed steady state control scheme is based on methods of network contribution factor (NCF), generator distribution factor (GDF), load distribution factor (LDF) and selected minimum load shedding (SMLS). GDF and LDF are proposed in [22] for supplemental charge allocation in the transmission open access. In this paper, they are used for line overload relief based on their contribution to the line flow. Here we give the brief description of those methods and related automatic control scheme.

5.1. Network contribution factor (NCF) and NCF control

For a given system, there are some available network control means, such as line switching, TCSC control, SVC control, shunt capacitor/reactor switching, etc. For the line overload problem, choose Eq. (30) or (33) to get the wanted overload relief. For the bus voltage problem, choose Eq. (32) or (34) to get the bus voltage adjustment.

5.2. Generator distribution factor (GDF) and GDF control

Let the gross nodal power P_i^g flowing through node i (when looking at the inflows) be defined by

$$P_i^g = \sum_{j \in \alpha_i^u} |P_{ij}^g| + P_{Gi} \quad \text{for } i = 1, 2, \dots, n, \quad (38)$$

where α_i^u is the set of nodes supplying power and directly connected into node i and P_{Gi} is the power generation injected into node i . Rewrite it as

$$A_u P_{\text{gross}} = P_G, \quad (39)$$

where A_u is the upstream distribution matrix with its (ij) th element defined by

$$[A_u]_{ij} = \begin{cases} 1 & \text{for } i = j \\ -\frac{|P_{ji}|}{P_j} & \text{for } j \in \alpha_i^u, \\ 0 & \text{other} \end{cases}$$

where P_{ji} is the real power flow from node j to node i in line $j-i$ and P_j is the total real power injected into node j . Then we have

$$P_i^g = \sum_{k=1}^n [A_u^{-1}]_{ik} P_{Gk} \text{ for } i = 1, 2, \dots, n. \quad (40)$$

Finally the contribution of each generator k to line $i-j$ flow can be calculated by

$$P_{ij}^g = \sum_{k=1}^n D_{ij,k}^g P_{Gk} \text{ for } j \in \alpha_i^u, \quad (41)$$

$$D_{ij,k}^g = \frac{P_{ij}^g [A_u^{-1}]_{ik}}{P_i^g}. \quad (42)$$

$D_{ij,k}^g$ can be called the generation distribution factor (GDF). They are always positive or zero. For the line $i-j$ overload problem, simply choose the most and least contributing generator pair, decrease the output of the most contributing generator and increase that of the least contributing one. The generator adjustment amount will be restricted by generator upper/lower limit and the line transfer limit. When those limits are hit and the line overload problem still exists, the second most and least contributing generator pair will be chosen till the overload problem is solved.

5.3. Load distribution factor (LDF) and LDF control

Similarly, let the gross nodal power P_i^n (looking from out-flows) be defined by

$$P_i^n = \sum_{j \in \alpha_i^d} |P_{ij}^n| + P_{Li} \text{ for } i = 1, 2, \dots, n, \quad (43)$$

where α_i^d is the set of nodes supplied directly from node i and P_{Li} is the load at node i . Similarly, rewrite it as

$$A_d P_{\text{net}} = P_L, \quad (44)$$

where A_d is the downstream distribution matrix with its (ij) th element defined by

$$[A_d]_{ij} = \begin{cases} 1 & \text{for } i = j \\ \frac{-|P_{ji}|}{P_j} & \text{for } j \in \alpha_i^d, \\ 0 & \text{other} \end{cases}$$

$$P_i^n = \sum_{k=1}^n [A_d^{-1}]_{ik} P_{Lk} \text{ for } i = 1, 2, \dots, n. \quad (45)$$

Finally the contribution of each load k to line $i-j$ flow can be calculated by

$$P_{ij}^n = \sum_{k=1}^n D_{ij,k}^n P_{Lk} \text{ for } j \in \alpha_i^d, \quad (46)$$

$$D_{ij,k}^n = \frac{P_{ij}^n [A_d^{-1}]_{ik}}{P_i^n}. \quad (47)$$

$D_{ij,k}^n$ can be called the load distribution factor (LDF). They are also always positive or zero. If the load can be reduced by an agreement, it can be taken into the LDF control. For the overload line, simply choose one or several most contributing loads to shed to solve the overload problem.

5.4. Selected minimum load shedding (SMLS)

If the power flow diverges due to a line outage but without loss of system integrity, normally some load shedding scheme needs to be activated to make the power flow converge. If the power flow converges, some bus voltages are lower than their lower limits. Load shedding also needs to be taken if other control means cannot solve the problem. The followings are the steps for SMLS.

- Step 1: Check whether the system has single-line connected load buses or not. If bus j is the single-line connected load bus, calculate the approximate line voltage drop:

$$dV_{ij} \approx P_{ij} R_{ij} + Q_{ij} X_{ij}, \quad (48)$$

where P_{ij} , Q_{ij} are the real and reactive part of line $i-j$ flow and R_{ij} , X_{ij} are the resistance and reactance of line $i-j$.

If $dV_{ij} > dV_{ij,\text{lim}}$, check whether there is shunt reactor or capacitor at this bus. If there is a shunt reactor, switch off the shunt reactor to increase the bus voltage. If there is a shunt capacitor, switch on the capacitor. Then recalculate the dV_{ij} . If the voltage difference is still larger than the limit, shed the load at this bus:

$$k_{\text{ratio}} = \frac{dV_{ij,\text{lim}}}{dV_{ij}}, \quad (49)$$

$$k_{\text{shed}} = 1 - k_{\text{ratio}}. \quad (50)$$

After the load shedding at single-line connected load buses is performed, run power flow. Check whether power flow converges or not. If it diverges, increase the load shedding ratio.

Otherwise, check whether there is low voltage problem. If yes, go to Step 2. If no, stop.

- Step 2: Check whether the low voltage bus is single-line connected load bus, and if so, continue load shedding at this bus. If it is not a single-line connected load bus, choose the neighboring buses and voltage sensitive buses to shed their loads to bring the bus voltage within the limit.
- Step 3: Choose the control area or system-wide load shedding based on an available control scheme.
- Step 4: Compare different load shedding results, and choose the minimum load shedding as the final control means.

5.5. A scheme for detection and prevention of cascading events

The conventional approach is for the lines experiencing overload conditions for a long time to be tripped off by relays. Under

frequency load shedding will be activated when the demand is larger than supply and the system frequency keeps decreasing. So will the under voltage load shedding during low voltage conditions if there exists such control scheme.

During the stressed system conditions, if the line outage decreases the security level and causes more cascading events and low voltage problem, that line should not be tripped. Other overload relief means should be activated. For the line overload problem, we first use the steady state control based on network contribution factor (NCF) and generator distribution factor (GDF) methods. If these two methods cannot solve the overload condition, load control based on load distribution factor (LDF) method and selected minimum load shedding (SMLS) will be taken. For the low bus voltage problem, the selected minimum load shedding will be undertaken instead of the control area or system-wide load shedding.

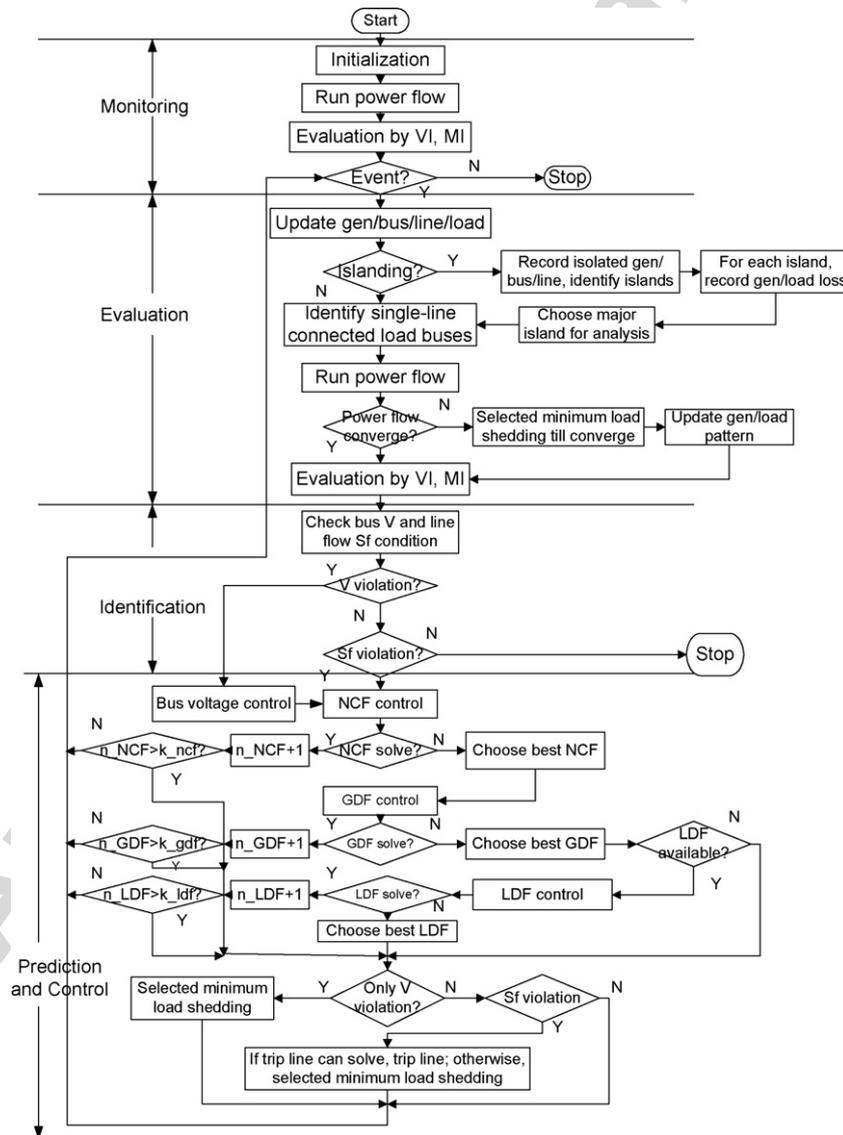


Fig. 3. Flowchart of the control scheme.

The basic procedure is explained as follows

- (1) Initialize the computation.
- (2) Run the base power flow.
- (3) Evaluate system vulnerability and security by VI and MI indices.
- (4) Check whether an event has occurred or not. If no event occurs, stop; if an event occurs, update system information.
- (5) Check whether system islands have been formed or not. If system islands are not formed, go to Step 8.
- (6) Otherwise, identify the islands, record isolated bus/generator/branch, and record generator/load loss in each island.
- (7) Choose major island for analysis, update system information.
- (8) Identify the single-line connected load buses.
- (9) Run the power flow.
- (10) If power flow converges, go to Step 12.
- (11) Otherwise, use selected minimum load shedding (SMLS) scheme to make power flow converge, and update generator/load pattern.
- (12) Evaluate vulnerability and security by VI and MI.
- (13) Check whether there is any bus voltage V and line flow S_f violation. If there is no V violation, go to Step 15.
- (14) Otherwise, activate bus voltage control.
- (15) Check whether there is line flow violation, if not, stop.
- (16) Otherwise, execute associated NCF control to solve the violation problem.
- (17) If NCF method solves the problem, $n_NCF = n_NCF + 1$, if $n_NCF < k_NCF$, go to Step 4, else, go to Step 19; if NCF does not solve the problem, choose the best available NCF control.
- (18) Execute GDF control. If GDF method solves the problem, $n_GDF = n_GDF + 1$, if $n_GDF < k_GDF$, go to Step 4, else, go to Step 19; if GDF does not solve the problem, choose the best available GDF control, go to Step 19.
- (19) Check whether LDF control is available or not. If not, go to Step 20; otherwise, check if LDF method solves the problem, if yes, $n_LDF = n_LDF + 1$, if $n_LDF < k_LDF$, go to Step 4, else, go to Step 20; if LDF does not solve the problem, choose the best available LDF control, go to Step 20.
- (20) Final control. If the original violation is only V violation, use the selected minimum load shedding scheme to bring V within limit; otherwise, check whether removing overloaded line can solve the overload problem or not, if yes and there is no other violations, remove the line; otherwise, use the selected minimum load shedding scheme to eliminate any violation.

Note: k_NCF , k_GDF and k_LDF are pre-defined numbers. If n_NCF , n_GDF and n_LDF are larger than those values, the final control is used. Otherwise, the associated NCF, GDF and LDF control are used.

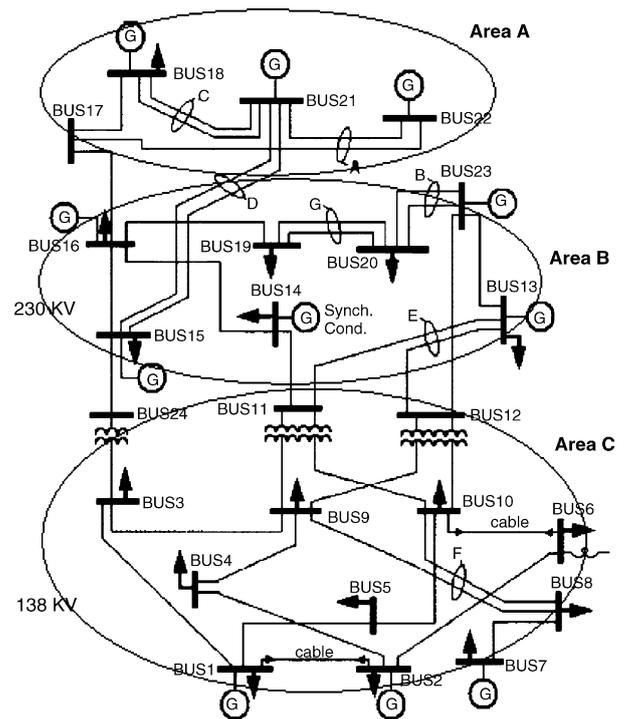


Fig. 4. IEEE one area RTS-96 24-bus system.

6. Implementation study results

We use the IEEE one area RTS-96 24-bus system as the study system [23]. Fig. 4 gives the system configuration.

For the vulnerability index calculation, we simply assign all weights as 1, the line bus voltage angle difference limits as 40° , PQ bus voltage magnitude limits as 1.0 p.u., the base power as 100 MVA. Then we sum all individual vulnerability index values of generators, buses and lines and get the separate summary of vulnerability index values.

Bus voltage magnitude lower limit is 0.9 p.u. The transmission line thermal limit is assumed to be the line rate A setting in the standard IEEE power flow data. Bus voltage drop limit along the transmission line is 0.10 p.u. For the margin index, we just choose margin indices of generator real and reactive power outputs, bus voltage, bus loadability, line flow, line angle difference, and line distance relay for simple demonstration.

Here we give three study cases. The Case 1 is the outage of special cable line L10 (B6–10). There will be a serious low voltage problem if the compensation reactor at bus 6 is not switched off. In reality, the system cannot operate at such a low voltage level. That means, voltage collapse may happen and the system may have cascading event if no appropriate control is taken. The Case 2 is the outage of lines L6 (B3–9) and L27 (B16–17) which results in power flow divergence. Voltage collapse and cascading event may happen before the power flow divergence. The Case 3 is the outage of lines L25 (B15–21) and L26 (B15–21) which results in an overload on two other lines. System islanding and cascading event may occur if there is no appropriate control. The proposed automatic cascading event prevention and mitigation scheme gives very good results for these cases.

Table 1
Vulnerability and margin indices of different conditions

| | Case 1A | Case 1B | Case 1C | Case 1D | Case 1E |
|-----------|---------|---------|---------|---------|---------|
| VI values | 7.863 | 23.369 | 12.122 | 14.773 | 12.059 |
| MI values | 4.063 | 3.619 | 3.800 | 3.981 | 3.807 |

6.1. Case 1: outage of cable line L10 (B6–10)

If the reactor at bus 6 is not switched off, the bus 6 voltage magnitude is 0.6726 p.u. Load shedding is taken to increase the bus 6 voltage. Even if 99% of the total system load is shed, the bus 6 voltage magnitude is still as low as 0.8701 p.u. If the reactor at bus 6 is switched off, its voltage magnitude is 0.8555 p.u. If 16.2% of the total system load, that is, 461.7 + j93.96 MVA, is shed, the bus 6 voltage magnitude is increased to 0.90 p.u.

The new control scheme first finds that bus 6 is a single-line connected load bus by L5 (B2–6). Second, it searches whether there is an available shunt reactor or capacitor at that bus. Then it finds and switches off the shunt reactor. Third, it calculates the approximate voltage drop along this single-line L5 (B2–6) based on the original load level at bus 6. $dV_{26} = P_{26}R_{26} + Q_{26}X_{26} = 1.36 \times 0.05 + 0.28 \times 0.192 = 0.122 > 0.10$ p.u. To bring the bus 6 voltage within limit, the selected minimum load shedding (SMLS) is run and shedding 6.84% of the original load at bus 6 can bring the bus 6 voltage be 0.90 p.u. Thus, only 9.3 + j1.92 MVA load is shed. Compared with the total system load shedding of 461.7 + j93.96 MVA obtained by the conventional method, the proposed approach is only about 2.02% of the conventional method.

Table 1 gives a simple summary of vulnerability and margin indices for different conditions. The Case 1A is the base power flow case without L10 outage. The Case 1B is with L10 outage. The Case 1C is the L10 outage with reactor switched off at B6. The Case 1D is the L10 outage, reactor switched off, and 16.2% system load shedding. The Case 1E is similar as the Case 1D but with only 6.84% load shedding at B6. Here we take 100 MVA load loss as 1.00 in the VI calculation.

Table 2
Solution methods for L6 and L27 outages

| | Procedure | Result |
|-----------------|---|--|
| Method 1 | 191.52 + j38.976 MVA system load shedding | Power flow converges, with B3 and B24 voltage as 0.6122 p.u. and 0.6032 p.u. |
| Method 2 | 1311.6 + j266.92 MVA system load shedding | Power flow converges, with B3 and B24 voltage as 0.9135 p.u. and 0.90 p.u. |
| Proposed method | 82.836 + j17.027 MVA load shedding at B3 | Same results as method 2, but only 6.32% shedding amount of method 2 |

Table 3
Solution method for L25 and L26 outages

| | Procedure | Result |
|----------------|---|--|
| Base condition | L28 and L30 overload (7.4453 p.u. and 5.6395 p.u. vs. their 5 p.u. limit) | Outage of L28 and 30, system islanding and cascading; or (698.72 + j142.13) MVA load shedding to save the system |
| Step 1 | Down G10 and up G1 to solve L28 overload; down G8 and up G2 to solve L30 overload | L30 overload solved, L28 overload decreased but not solved because of G1 upper limit |
| Step 2 | Down G10 and up G3 to solve L28 overload | L28 overload decreased but not solved because of L11 transfer limit |
| Step 3 | Down G10 and up G4 to solve L28 overload | Solved |
| Step 4 | Verified with ac load flow | Solved, no violation |

The base Case 1A has the smallest VI and largest MI. The Case 1B has the largest VI and smallest MI. The Case 1C decreases the vulnerability and increases the security level compared with the Case 1B after the shunt reactor is switched off. The Case 1D increases the security level but increases vulnerability because of large load shedding. The Case 1E is the optimal one because it increases the security while requiring a minimum load shedding.

6.2. Case 2: outage of lines L6 (B3–9) and L27 (B16–17)

Power flow diverges because of the outage of those two lines. By the conventional method, after 6.72% of the total system load (191.52 + j38.976 MVA) is shed, the power flow converges. But the bus voltage magnitudes at buses 3 and 24 are 0.6122 p.u. and 0.6032 p.u., respectively. Then 46.02% of the total system load (1311.6 + j266.92 MVA) needs to be shed to make the voltages at buses 3 and 24 to be 0.9135 p.u. and 0.90 p.u., respectively (Table 2).

The new scheme first identifies that bus 3 is a single-line connected load bus although it is connected by two lines. Second, it concludes that there is no available shunt reactor or capacitor at bus 3. Third, it determines that the approximate voltage drop along this line is 0.177 p.u., which is larger than the 0.1 p.u. limit. Fourth, it runs the selected minimum load shedding and finds that if 46.02% of the load (82.836 + j17.027 MVA) is shed at bus 3, the power flow will converge and there is no any limit violation. The amount of load to be shed determined by the new method is only 6.32% of what was determined by the conventional method.

6.3. Case 3: outage of lines L25 (B15–21) and L26 (B15–21)

Assume that line L25 is tripped due to a fault and the parallel line L26 is also tripped due to relay misoperation, which is a possible case. The apparent flows at L28 (B16–17) and L30 (B17–18) are 7.4453 p.u. and 5.6395 p.u., respectively. The two lines will be overloaded because both of their thermal limits are

5.00 p.u. If L28 and L30 are tripped due to an overload, area A will be disconnected from the main part of the system. Before the islanding, there is a total of $7.57 + j1.446$ p.u. flow transferred from area A to area B through three tie-lines: L25, L26 and L28. From the steady state analysis viewpoint, at least 7.57 p.u. of real power generation needs to be reduced at area A to make the balance between power demand and supply. At area B and area C, the load shedding amount of $698.72 + j142.13$ MVA, which constitutes 27.76% of the total load, is needed to make the power flow converge without any limit violation. If we consider the system dynamics, the system may lose the stability and cascading event may occur (Table 3).

The new method first finds the L28 and L30 overload after outage of L25 and L26. Second, it tries to use the NCF and GDF control methods to solve the overload problem instead of tripping L28 and L30. Since there is no available NCF method to solve the problem, GDF control method is used. GDF method finds two generator pairs which contribute most and least to the overload of L28 and L30, respectively, G10 (at B22) and G1 (at B1) for L28, and G8 (at B18) and G2 (at B2) for L30. In Step 1, GDF control chooses to increase the real power output of G1 and decrease that of G10 by the same amount to solve the L28 overload. GDF control increases the real power output of G2 and decreases that of G8 to solve the L30 overload. The outputs of G1 and G2 can only be increased to their upper limits 2.304 p.u. By this step, the flow at L30 is 4.7971 p.u. and the overload is solved. But the flow at L28 is 6.332 p.u., which is still larger than 5.00 p.u. thermal limit. In Step 2, generator pair G10 (at B22) and G3 (at B7) is chosen to solve the L30 overload. There is a thermal limit of 1.75 p.u. at L11 (B7–8) connecting G3. Thus the increase of G3 has a limit. By taking this step, the flow at L28 is brought to 5.764 p.u., which is still larger than 5.00 p.u. limit. In Step 3, generator pair G10 and G4 (at B13) is chosen and L28 overload is finally solved. By applying the steady state analysis method, the overload problem is solved by using the NCF and GDF methods. The possible cascading event is prevented.

7. Conclusion and future work

This paper proposes a new approach to detect and prevent a cascading event at its initial stage that can be assessed using the steady state analysis method. For each operating state, the system vulnerability and security are evaluated based on the vulnerability and margin indices. The vulnerable parts of the system can be identified based on the topology processing and operational index methods. The next possible event can be predicted based on the analysis. If there are any problems of system islanding, transmission line overload, bus voltage violation, or distance relay misoperation, new control means based on network contribution factor (NCF), generator distribution factor (GDF), load distribution factor (LDF), and selected minimum load shedding (SMLS) methods will be taken to prevent the possible cascading events. Case studies using the IEEE test system show good results.

The proposed approach is based on the steady state analysis method. It gives an understanding how a cascading event progresses in its early stage and provides control means for

preventing further unfolding of the cascade. The power system cascading events are very complex and a comprehensive analysis needs also to consider the system dynamics, which will be included in the future work.

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Hongbiao Song (S'04) received his B.S. and M.S. degrees in electrical engineering from North China Electric Power University, China in 1999 and 2002, respectively, and currently is a Ph.D. candidate in electrical engineering at Texas A&M University. His research interests are power system analysis, simulation, stability, control, cascading events, protection, substation automation, intelligent systems.

Mladen Kezunovic (S'77–M'80–SM'85–F'99) received his Dipl. Ing. degree from the University of Sarajevo, the M.S. and Ph.D. degrees from the University of Kansas, all in electrical engineering, in 1974, 1977 and 1980, respectively. He is the Eugene E. Webb professor and director of Electric Power and Power Electronics Institute at Texas A&M University, College Station, where he has been since 1987. His main research interests are digital simulators and simulation methods for relay testing as well as application of intelligent methods to power system monitoring, control, and protection. Dr. Kezunovic is a fellow of the IEEE and member of CIGRE-Paris.

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