Turk J Elec Eng & Comp Sci, Vol.18, No.4, 2010, © TÜBİTAK
doi:10.3906/elk-0904-5

Fault detection and identification for voltage sag state estimation in power systems

Jamal BEIZA, Seyed Hossein HOSSEINIAN, Behrooz VAHIDI
Department of Electrical Engineering, Amirkabir University of Technology, Tehran-IRAN
e-mail: hosseinian@aut.ac.ir

Abstract

This paper presents a novel approach for fault detection and identification in order to estimate voltage sag during a fault. One of the best approaches for voltage sag estimation is instantaneous voltage estimation. The approach uses traditional state estimation where redundant measurements are available. The proposed method is used to estimate voltage sag performance during a fault. At the fault duration, the grid topology is changed. In such a case the measurement matrix must be re-determined at the fault duration. The proposed approach is an efficient method for fault detection and identification which is based on residual analysis and topology error detection. The performance of the novel approach is tested on an IEEE 14 bus system and the results are shown.

Key Words: *Fault location, Power system quality, Voltage sag (dip) estimation, State estimation, Residual analysis*

1. Introduction

A fault could be a short circuit that causes voltage sag in power systems. Voltage sag is one of the most aspects of power system quality indices. On the other hand, power system quality is of greater concern to electric utilities and consumers. According to IEEE standard 1346 voltage sag is a decrease in RMS voltage at the power frequency for a duration changing from half a cycle to 1 min. Typical voltage sag values are 0.1 to 0.9 pu [1]. However, any phenomenon that causes an increase in current can be a source of voltage sag. Motor starting, transformer energizing and sudden load changes are the sources of voltage sag. Voltage sags affect sensitive electrical equipments. These equipments are computers, electronic equipments, adjustable AC and DC drives, induction and synchronous motors, contactors and etc [2]. In addition, voltage sag causes customer damage costs. These costs include damage to product, delays in delivery, damage to equipment and processes and reduced customer satisfaction [3]. In order to quantify voltage sag severity two methods including monitoring and stochastic assessment can be used.

There is much research about voltage sag stochastic assessment based on critical distance and fault positions. The probabilistic nature of stochastic methods makes them suitable for long term estimations, but in a specific year, the predicted number of voltage sags can differ substantially from the measurement. In addition, in some cases, historic data are not available when analyzing a part of the system recently introduced or modified [4].

Power Quality (PQ) monitoring is necessary to characterize electromagnetic phenomena at a particular location in a power system. In some cases, the objective of the monitoring is to diagnose power quality problems. In other cases, monitoring may be used in planning the installation of power quality mitigating devices. In addition, economic impacts of power quality problems are significant in many load centers. In addition to resolving equipment disruption, a database of equipment tolerances and sensitivities can be developed from monitored data. Such a database can provide a basis for developing equipment compatibility specifications and guidelines for future equipment enhancement [5].

State Estimation (SE) is one of the essential functions in Energy Management Systems (EMS). Nowadays, in Supervisory Control and Data Acquisition (SCADA) Control Centers (C.C), EMS servers execute real time state estimation. Weighted Least Square (WLS) state estimation algorithm is used to solve the normal equation widely.

In order to have linear measurement equations for voltage estimation, line currents and some bus voltages shall be chosen as the measurements.

Substation Automation (SA) is the first step toward the creation of a highly reliable, self-healing power system that responds rapidly to real-time events with appropriate actions. This system supports the planning and asset management necessary for cost-effective operations. Substation automation was not feasible up to a few years ago. Communication technologies simply were not available to handle the demands imposed by the complexity of SA requirements. However, communication standards have now been developed to be able to address many of these demands [6].

Global Positioning System (GPS) is a Wireless Communication Technology for SA. Substation automation basically consists of implementing Intelligent Electronic Devices (IEDs) using microprocessors to monitor and control the physical power system devices. Recently all substations are based on IEDs with changes in measurement architecture [7].

According to the above issues, there is no concern about Wide Area Monitoring (WAM), clock synchronization and real time implementation challenges.

In the voltage sag state estimation procedure, when a fault is occurred, there is one topology error. It is important to note that the fault status does not change measurement matrix dimensions but changes some elements of the measurement matrix. The main purpose of the paper is to detect and identify fault location for time domain voltage sag state estimation.

The remainder of the paper is organized as follows. In section II, fundamental concepts of state estimation are described. Section III discusses time domain state estimation. In section IV, a fault detection and identification approach is described, which includes time domain measurement matrix and residual analysis. Numerical results are shown in section V. Finally, conclusions are noted in section VI.

2. State estimation

State Estimation (SE) was introduced by Gauss and Legendre in the 18^{th} century. The basic idea was to "fine-tune" state variables by minimizing the sum of the residual squares. This is the well-known least squares (LS) method. The other method is the Weighted Least Square (WLS). The method is used to minimize the weighted sum of the residual squares. WLS calculate the best estimation of states [8]. In fact, the measurement errors are assumed to have a known probability density function. Most of the time, Gaussian (normal) distribution probability density functions with zero mean value and known variance is used. Another objective of SE is detection, identification and suppression of gross measurement errors [9]. In this paper, the aforementioned subject is developed to detect fault location due to voltage sag estimation.

Consider the set of measurements given by vector z [10]:

$$z = \begin{bmatrix} z_1 \\ z_2 \\ . \\ . \\ . \\ z_m \end{bmatrix} = \begin{bmatrix} h_1(x_1, x_2, ..., x_n) \\ h_2(x_1, x_2, ..., x_n) \\ . \\ . \\ . \\ h_m(x_1, x_2, ..., x_n) \end{bmatrix} + \begin{bmatrix} e_1 \\ e_2 \\ . \\ . \\ . \\ e_m \end{bmatrix} = h(x) + e \tag{1}$$

where $h_i(x)$ is the nonlinear function relating i^{th} measurement of the states; x_i is the state; m is the number of measurements; and n is the number of states. Also, x is the system state vector and e is the measurements errors vector. Equation (1) is called the measurement equation.

Regarding the statistical properties of measurement errors, the following assumptions are made:

$$E(e_i) = 0, i = 1, 2, ..., m \tag{2}$$

$$E(e_i e_j) = 0, i = 1, 2, ..., m. \tag{3}$$

Equations (2) and (3) express that the mean values of measurements errors vectors are zero, and also the measurement errors are independent. Hence,

$$Cov(e) = E(e.e^T) = R = diag(\sigma_1^2, \sigma_2^2, ..., \sigma_m^2) \tag{4}$$

where, σ_i is standard deviation for measurement i which is computed to reflect the expected accuracy of the corresponding meter used.

Now, the objective function is defined as follows:

$$\begin{aligned} J(x) &= \sum_{i=1}^{m} (z_i - h_i(x))^2 / R_{ii} \\ &= [z - h(x)]^T R^{-1} [z - h(x)] \end{aligned} . \tag{5}$$

Finally, the weighted least squares state estimation leads to an iterative solution of the following equation (called the Normal Equation (NE)) [10]:

$$G(x^k)\Delta x^k = H^T(x^k) R^{-1} \Delta z^k, \tag{6}$$

where H is measurement Jacobian matrix of $h(x)$, G is Gain matrix and is equal to $H^T R^{-1} H$, k denotes the iteration index

The residual index is

$$r = \Delta z = z - H(x). \tag{7}$$

In conventional power system telemetry stations, both active power and reactive power are analogue measurements. If these parameters are chosen as a set of measurements and bus voltages are chosen as states, then the measurement equation is nonlinear. Decoupled weighted least squares state estimation is introduced to have linear measurement equation [10]. Also, when line currents and some bus voltages are chosen as state variables, measurement equation becomes linear [11].

Linearly,

$$z = Hx + e, \tag{8}$$

and, in this case, the objective function is

$$J(x) = [z - Hx]^T R^{-1} [z - Hx]. \tag{9}$$

In order to have a unique solution, linear equation must be completely determined or over determined. Under such conditions, the system state vector is estimated as [5, 8]

$$x^{\text{estimated}} = G^{-1} H^T R^{-1} z. \tag{10}$$

Network observability analysis must be checked prior to SE. This analysis will be determined if a unique estimate can be found for the system states [10, 12].

In this paper, according to [12] the network observability analysis is done to determine observability of the network.

3. Time-domain state estimation

Time-domain state estimation requires components from time domain modeling and some assumptions in a power system. These assumptions allow the use of single-phase circuit for modeling the power system. If measurement sets are placed on the lines, the main approach for state estimation in the power system is line or branch modeling. In the following, we focus on line modeling for time-domain state estimation.

The pi line model is used to show equivalent circuit for a line in a power system. The standard differential voltage-current relationships for resistor, inductor and capacitor elements can be given by [13]

$$i_{RL}(t) = \frac{1+\alpha}{\frac{2L}{\Delta t} + (1+\alpha)R} v_{RL}(t) + \frac{1-\alpha}{\frac{2L}{\Delta t} + (1+\alpha)R} v_{RL}(t-\Delta t) + \frac{\frac{2L}{\Delta t} - (1-\alpha)R}{\frac{2L}{\Delta t} + (1+\alpha)R} i_{RL}(t-\Delta t) \tag{11}$$

$$i_C(t) = \frac{2C}{\Delta t(1+\alpha)} v_C(t) - \frac{2C}{\Delta t(1+\alpha)} v_C(t-\Delta t) - \frac{1-\alpha}{1+\alpha} i_C(t-\Delta t), \tag{12}$$

where α is the compensating constant factor; $v_{RL}(t)$, $i_{RL}(t)$ are the voltage and current across the series branch; $v_C(t)$, $i_C(t)$ are the voltage and current across shunt branch, respectively; and R, L, C are values of resistance, inductance and capacitance of the line.

Let X_t represents the vector of all bus voltages at time t. Then the measurement equation can be written as

$$Z_t = i_m(t) - i_h(t) = HX_t, \tag{13}$$

where, $i_m(t)$ is the vector of all measurement current at time t. It is necessary to calculate H and $i_h(t)$ that are measurement matrix in time domain and history term of components.

Measurement matrix can be divided into two parts:

$$H = H_{RL} + H_C. \tag{14}$$

Factor H_{RL} is related to series branch and H_C is related to shunt branch. With introducing A as branch-to-node incidence matrix and M as measurement-to-branch incidence matrix, H_{RL} can be given as

$$H_{RL} = M.diag(h).A, \tag{15}$$

where

$$h(i) = \frac{1+\alpha}{\frac{2L_i}{\Delta t} + (1+\alpha)R_i}, i = 1, 2, ..., k \tag{16}$$

where k is the number of network branches and i is the branch number.

If the simplified pi model is used, the capacitor can be neglected in the model. Therefore,

$$H_C = 0 i_h(t) = i_{hRL}(t) = M.diag(h_{RL}).A.X_t + diag(hh_{RL}).i_m(t-1), \tag{17}$$

in which

$$h_{RL}(i) = \frac{1-\alpha}{\frac{2L_i}{\Delta t} + (1+\alpha)R_i}, i = 1, 2, ..., k \tag{18}$$

$$hh_{RL}(p) = \frac{\frac{2L_i}{\Delta t} - (1-\alpha)R_i}{\frac{2L_i}{\Delta t} + (1+\alpha)R_i}. \tag{19}$$

Here, p is the measurement number, which is placed on line i. It can be drawn out from the measurement set placement table. For each instance of simulation, SE is running and bus voltages are estimated according to equation (10).

4. Fault detection and identification approach

SE has typically several functions. One is topology error processing, and can be classified in two categories: Branch status error and configuration error. When a fault occurs, there is one topology error. It is categorized as a branch status error. In the fault status, the measurement matrix dimensions are not changed, but some elements of the measurement matrix are changed. This subject is described as follows.

The measurement matrix at a fault duration is as follows:

$$L_f = \gamma L_{kj}, R_f = \gamma R_{kj}, C_f = \gamma C_{kj}$$

$$H(m,k) = \left(\frac{2\gamma C_{kj}}{\Delta t(1+\alpha)} + \frac{1+\alpha}{\frac{2\gamma L_{kj}}{\Delta t} + (1+\alpha)\gamma R_{kj}} \right) \tag{20}$$

$$H(m,j) = 0. \tag{21}$$

In deriving the matrix, it is assumed there is a fault on a line connecting bus $\#k$ and $\#j$. Figure 1 shows the fault status on a line.

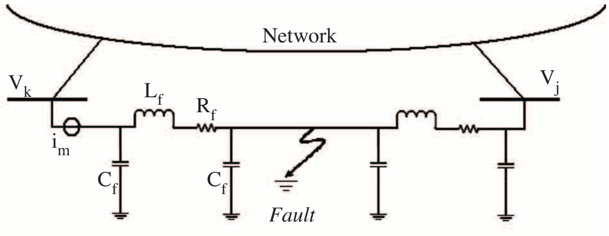

Figure 1. Illustration of a fault status on a line.

The proposed approach combines two test methods for fault detection and identification. The idea derives from the condition that, when there is a fault, there is a single error on network topology at the fault duration. The selected methods are the largest normalized residual test and residual analysis. They are based on residual value and residual mean value, respectively.

The largest normalized residual test can be used to devise a test for identifying and detecting a single error [10]. The test has the following steps:

- Solve WLS and obtain residual vector.
- Compute the normalized residuals as follows:

$$r_i^N = \frac{|r_i|}{\sqrt{\Omega_{ii}}}, i = 1, 2, ..., m \tag{22}$$

where m is the number of measurements and Ω is the residual covariance matrix. If$r_k^N > \delta$, then there is a fault and δ is chosen as a threshold for fault detection.

It is necessary to say that fault location must be determined for solving SE. In other words, the measurement matrix at the steady state period is different from the measurement matrix at the fault duration. In this case, a test method is required to detect and identify the line or branch on which the fault occurs. In addition, there are some cases for which the largest normalized residual test can not uniquely identify an error. An example is when the fault location is near a bus including other connected lines.

The proposed approach uses the residual analysis concept to determine fault location and to rebuild measurement matrix.

The basic point in the fault status is the fact that measurement matrix dimensions are not changed. Therefore, the relation between measurement matrixes in two statues is described as [1, 14]

$$H_{fault} = H_{steady} + E, \tag{23}$$

where, E is the error measurement matrix. In the fault duration, the SE equation is defined as

$$z = H_{fault}x + e = H_{steady}x + Ex + e. \tag{24}$$

Before the fault detection and identification, the residual vector at the fault duration is given as

$$r = z - H_{steady}\hat{x}. \tag{25}$$

Mean and covariance values for residual are expressed as

$$E(r) = (I - K)Ex \tag{26}$$

$$Cov(r) = (I - K)R, \tag{27}$$

where

$$K = H_{steady} G^{-1} H_{steady}^T R^{-1} \tag{28}$$

denotes the hat matrix.

The relationship between residuals and vector line error is expressed as

$$r = Tf, \tag{29}$$

where f is vector line error and T is given by

$$T = (I - K)M. \tag{30}$$

Here, M is the measurement-to-line incident matrix.

According to the co-linearity test which is described in [15], the dot product between T and r is

$$\cos\theta_j = \frac{T_j^T r}{\|T_j\| \, \|r\|}, \tag{31}$$

where, $\|T_j\|$, $\|r\|$ are the largest singular value of T_j, r, respectively.

Line j has a short circuit fault if $\cos\theta_j$ is approximately equal to one. For other lines they are less than one. In this case, the two described methods with power network topology at fault duration can be used to detect and identify fault as fault indices. In the following section the numerical analysis is presented to justify the proposed approach.

5. Numerical analysis

IEEE 14-bus test system with 20 lines is used for time domain simulation [16]. The set of measurements based on the method for observability analysis according to [12] is performed. The method uses triangular factors of singular, symmetric gain matrix to determine the observable islands of a measurement set. The factorization of the gain matrix is computed as [12]:

$$D = L^{-1} G L^{-T}, \tag{32}$$

where, D is a triangular and diagonal matrix and L is a non singular lower triangular matrix.

D is checked to have zero pivots, if not, the test matrixes (W, C from L) are calculated to obtain unobservable islands. IEEE 14-bus test system with measurement set is shown in Figure 2. The mentioned method is done to find a fully observable network. The measurements placement description is illustrated in the appendix.

As mentioned before, bus voltages are selected as the state variables. In this test system there are 18 measurements, therefore, degree of freedom is 4. Time domain simulations are done with 1 ms time step for a 200 ms simulation period. The fault is occurred in the middle of line 4 at time 80 ms. The fault duration is assumed to be 2 cycles. The proposed approach is assessed with above assumption. Two desired indices are measured to determine when they exceed a threshold value.

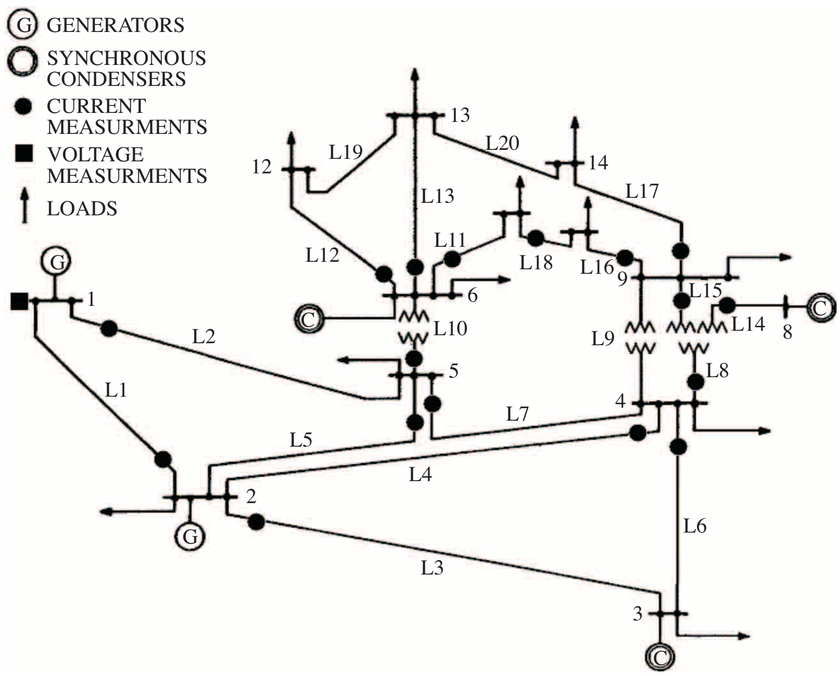

Figure 2. IEEE 14-bus test system with measurement set.

Figure 3 shows the normalized residual index for each measurement when there is no fault in the network and the network is in the steady state conditions. As seen, the threshold value is not crossed and therefore there is no gross error for each measurement. Also, cosine theta indices for each line are shown in Figure 4. All indices are under one that indicates no fault on the lines.

Both criteria show that there is no fault on the grid. When fault is occurred on line 4, all residuals are increased because of error topology due to the short circuit fault. These accretions are illustrated in Figure 5.

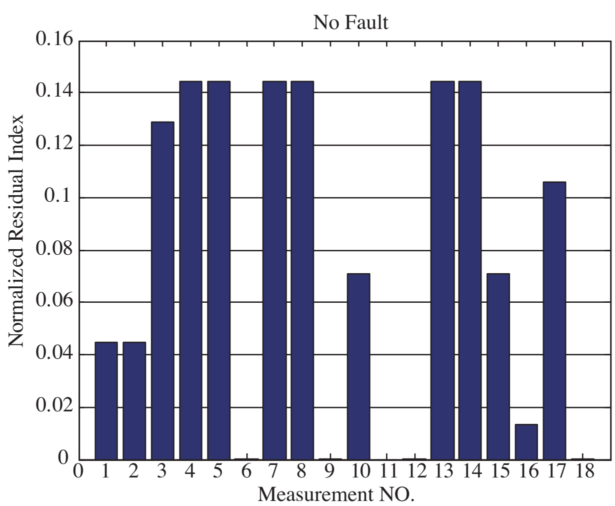

Figure 3. Normalized residual index for each measurement.

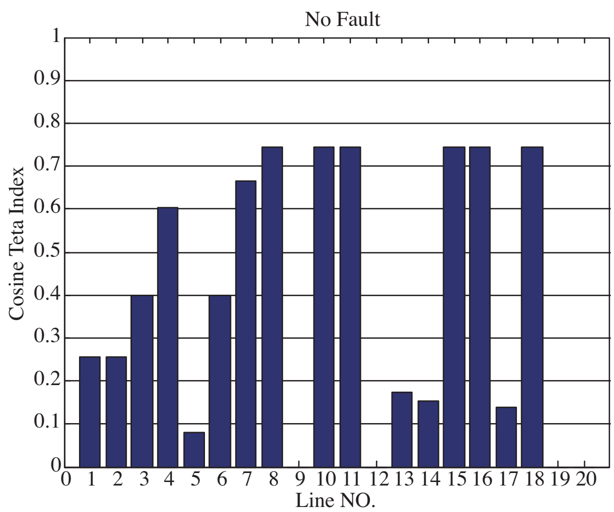

Figure 4. Cosine theta index for each Line.

Start Here Next It is clear that all normalized residual values at the fault status are greater than normalized residual values at the steady state. These increases are very gross and these errors are as large as 100% at least. In fact, it is possible that topology errors are detected from measurement errors due to gross influences.

The measurement errors are neglected in this paper. Generally, normalized residual test determines topology error in the grid, Cosine theta criterion is used to detect and identify fault zone. Figure 6 shows cosine theta index for each line. Cosine theta index for line 4 is one. This case confirms validation of the proposed method.

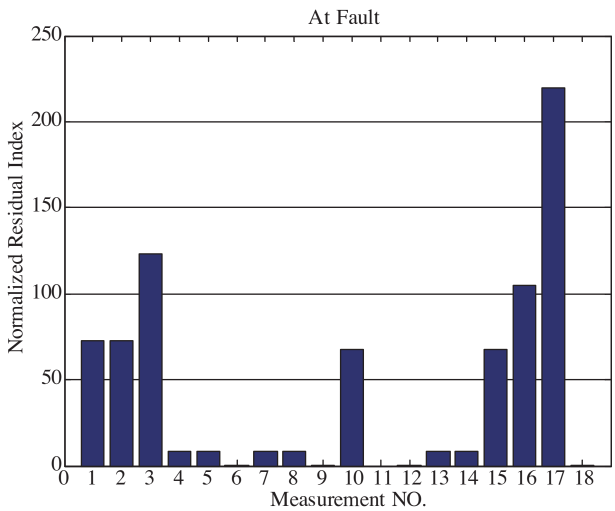

Figure 5. Normalized residual index for each measurement for the fault on line 4.

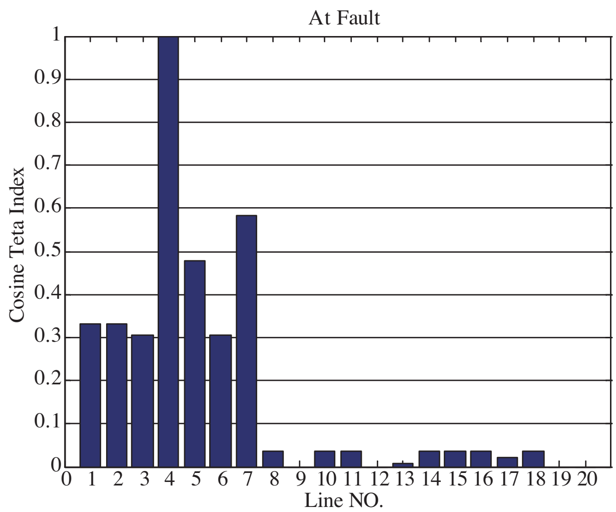

Figure 6. Cosine theta index for each line at a fault on line 4.

6. Conclusion

In this paper, an efficient method is applied to detect and identify fault characteristics. These characteristics include fault location and fault instance which are used to build measurement matrix and to estimate voltage sag. Topology error function of state estimation is used. The current based model allows a linear mapping between the measured variable and the states to be estimated. Residuals analyses are used to obtain criteria threshold. The main advantage of the developed method is the fault detection and identification within just one step time after fault instance. A time-domain measurement model was considered for the voltage state estimation. The approach was tested for IEEE 14 bus system.

Appendix

The measurement placement for IEEE 14-bus is illustrated in Table.

Table. Measurements placement

Measurement #	Placement
1	Line 2
2	Line 1
3	Line 7
4	Line 8
5	Line 10
6	Line 13
7	Line 11
8	Line 15
9	Line 14
10	Line 3
11	Line 12
12	Line 17
13	Line 18
14	Line 16
15	Line 6
16	Line 5
17	Line 4
18	Bus1

References

[1] *IEEE Recommended Practice for Evaluating Electric Power System Compatibility With Electronic Process Equipment* , IEEE Standard 1346, 1998.

[2] M.H.J.Bollen, *Understanding power quality problems: voltage sags and interruptions*. IEEE press series on power engineering, 2000.

[3] Andersson, T., Nilsson D. "Test and Evaluation of Voltage Dip Immunity". Master research work, Department of Electric Power Engineering, Chalmers University of Technology, Gothenburg, Sweden, 2002.

[4] E.Espinosa-Juarez, A.Hernandez, "A Method for Voltage Sag State Estimation in Power Systems" *IEEE Transaction on power delivery, Vol 22, No.4, October, 2007.*

[5] M.Mazadi, S.H.Hosseinian, W.Rosehart, D.T.Westwick, "Instantaneous Voltage Estimation for Assessment and Monitoring of Flicker Indices in Power Systems" *IEEE Transaction on power delivery, Vol 22, No.3, pp.1841-1846, July,2007.*

[6] Guidelines for Implementing Substation Automation Using IEC 61850, the International Power System Information Modeling Standard. Final Report, EPRI, Palo Alto, CA: 2004.1008688.

[7] M.Kenzunovic, "Monitoring of power system Topology in Real – Time" Copyright 2005 IEEE. To appear in the proceedings of the Hawai'i International Conference on System Sciences, HICSS 39, Kauai, Hawaii, Symposium on Electric Power Systems Reliability, January 4-5, 2006.

[8] A. J. Woods and B. F. Wollenberg, Power Generation, Operation and Control. New York: Wiley, 1984.

[9] R.L.Lugtu, D.F.Hackett,K.C.Liu and D.D.Might ”Power System State Estimation :Detection of Topological Errors *“IEEE Transaction on power Apparatus and systems, Vol PASS-99, No.6, pp.2406-2412,Nov/Dec,1980*

[10] A.Abur, A.G.Exposito, *Power System State Estimation: Theory and Implementation.* Marcel Dekker, inc, 2004.

[11] J. A. Arrillaga, N. R. Watson, and S. Chen, Power System Quality Assessment. New York: Wiley, 2000.

[12] B.Gou, A.Abur, “ A Direct Numerical Method for Observability Analysis ” *IEEE Transaction on power systems, Vol 15, No.2, pp:448 – 451, May,2000*

[13] S. H. Hosseinian, “Improvements in simulation methods for power system harmonic and transient studies,” Ph.D. dissertation, Upon Tyne University, Newcastle Upon Tyne, U.K., 1996.

[14] F.F.Wu,W.E.Liu, “Detection of Topology Errors By State Estimation” *IEEE Transaction on power systems, Vol 4, No.1, pp.176-18,3 February,1989.*

[15] K.A.Clements,P.W.Davis, “ Detection and Identification of Topology Errors in Electric Power Systems” *IEEE Transaction on power systems, Vol 3, No.4, November,1988.*

[16] *IEEE 14-Bus Test Case*, [Online]. Available: http://www.ee.washington.edu/research/pstca/pf14/ieee14cdf.txt