The Dynamic Utilization of Substation Measurements to Maintain Power System Observability

Y. Wu, *Student Member, IEEE,* M. Kezunovic, *Fellow, IEEE* and T. Kostic, *Member, IEEE*

***Abstract*-- In a power system State Estimator (SE), a Network Topology Processor (NTP) determines the Circuit Breaker (CB) status in real-time to obtain electrical network topology. In a conventional NTP, many substation measurements are simply discarded because their positions in the simplified bus-branch network model are lost. These measurements cannot be used in the network observability analysis and when some of the used measurements are lost, an estimate of system states may not be obtained. This paper proposes an innovative method to utilize these redundant measurements. The new method uses a numerical matrix to represent the physical connectivity of substation devices, and then dynamically searches for solutions to calculate branch and bus injection power flow measurement data using the linear combination of the available substation measurement data. Test cases on IEEE-30 bus system verify that the proposed method is very effective in making the network observable, without the need to install new measurement devices.**

***Index Terms*—energy management systems, network topology processor, observability analysis, state estimation**

I. Introduction

A State Estimator (SE) is an essential application in the Energy Management Systems (EMS). The state estimator estimates the system states, which allows other EMS functions such as security assessment to be reliably deployed in order to analyze contingencies, as well as to predict corrective actions [1].

An important requirement for state estimation is the network observability. Due to the frequent change of network topology, many measurements that provide data to the state estimator may no longer be available in the network model. The previously observable system may turn into unobservable.

An advanced real-time network modeling tool is needed to handle the loss of observability problems. In this paper, a new method to enhance the ability of existing network topology processor (NTP) is proposed. The method tries to recover the network observability by dynamically providing more measurements to the SE.

Section II talks about what an NTP does in the preprocessing of the raw measurement data; section III is a brief introduction to the concept and methods of network observability analysis; section IV explains what the proposed method does to efficiently use the substation measurements in real-time. Tests results are shown in section V. Conclusions are presented in section VI.

II. Conventional Network Topology Processing

In this paper, the term *connectivity* refers to the static physical layout of devices (transmission lines, bus-bars, switches, etc.) in a power system network; the term *topology* refers to the dynamic structure of a network determined upon the status of switches and circuit breakers (CBs). Connectivity is usually fixed over longer periods of time while topology changes relatively frequently over time. The term *node* refers to an electrical node in the detailed substation model; the term *bus* refers to an electrical node in the bus-branch model after the processing of an NTP. A bus usually consists of one or several nodes that are connected by closed CBs or switches.

An NTP takes care of the first stage of data processing in a state estimation function. Its task is to determine the network topology (usually in the form of a bus-branch model) based on the detailed description of network connectivity and the real-time CB status [2-3]. In a conventional NTP, the input data consist of the following.

A. The description of the connectivity of the physical devices in the network

The physical devices include generators, loads, CBs, transmission lines, transformers, current transformers (CTs), voltage transformers (VTs), etc. These devices can be grouped into four categories based on their characteristics that affect the determination of network topology:

1) CBs and other switching devices: these devices have two terminals – a from-node and a to-node. Their states are either open or closed. An open CB corresponds to an open circuit, or an infinite impedance branch; a closed CB corresponds to a short circuit, or a zero impedance branch.
2) Nodal injection devices (generators, loads, etc): these devices have one terminal – the node that they are connected to.

This work was funded by ABB Corporate Research Center in Baden-Daettwil, Switzerland (project CRID 30293).

Y. Wu and M. Kezunovic are with the Department of Electrical and Computer Engineering, Texas A&M University, College Station, TX 77843-3128, USA (e-mails: wuyang@ece.tamu.edu, kezunov@ece.tamu.edu).

T. Kostic is with ABB Switzerland Ltd - Corporate Research in Baden-Daettwil, Switzerland (email: tatjana.kostic@ch.abb.com).

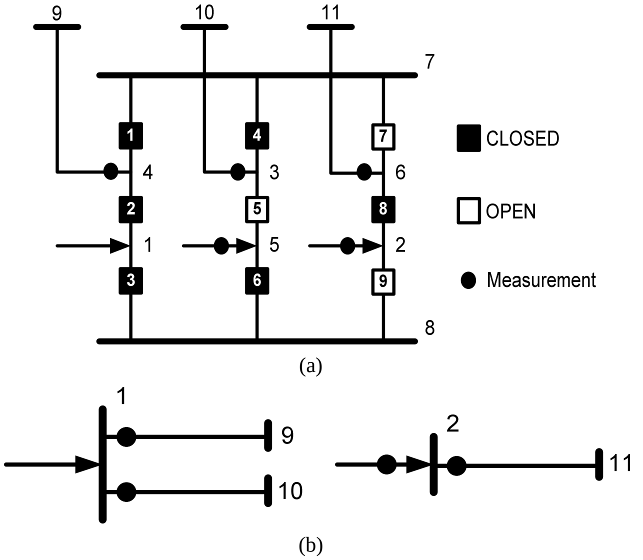


Fig.1: An example of the detailed substation model and the used bus-branch model. (a) Detailed substation model. (b) Used bus-branch model.

3) Transmission lines, transformers: these devices are usually represented by non-zero impedance branches that have two terminals – a from-node and a to-node.
4) Measurements: the commonly used measurements include CB power flow measurements, nodal power flow injection measurements and voltage magnitude measurements.

B. CB Status and analog measurement data

The CB status measurement data are provided to the NTP so that it can merge electrical nodes that are connected by closed CBs into a single bus. After that, the NTP also needs to assign the nodal injection devices and branches available in the detailed substation models to the proper locations in the bus-branch model.

The analog measurement data, such as CB power flows, nodal injection power flows and voltage magnitudes also need to be provided to the NTP. These measurement data need to be processed before they can be used by a state estimator.

Most state estimators that are available in power systems can deal with three types of measurements in the bus-branch network: bus voltage magnitude measurements, bus power flow injection measurements, and branch power flow measurements. Many of the analog measurement data that are gathered by the physical devices in the substations cannot be used directly in the state estimator, since the values that they monitor do not fall in any of these three categories. These values could be combined and new meaningful measurement values could be calculated.

The existing NTPs use the following principles in treating the raw analog measurement data:

1) A nodal voltage magnitude measurement is directly converted to a bus voltage magnitude measurement by mapping the node number to its corresponding bus number in the bus-branch model.
2) A nodal power flow injection measurement is converted to either a branch power flow measurement (if a branch is connected to the node and brings the injection) or a portion of a bus injection power flow measurement (if an injection device is connected to the node and brings the injection). If a bus is composed of several nodes in the detailed substation model, a bus injection measurement is created only if all nodal injection measurements are available.
3) The CB power flow measurements will be used to calculate the nodal injections, if possible. The calculated nodal injections will be further processed in the way described in 2).

An example of how NTP works is shown in Fig. 1. A substation that has nine CBs and eight nodes is shown in Fig. 1(a). Bus 9, 10 and 11 are from external substations. Three injection devices are connected to node 1, 2 and 5. Power flow measurements are installed on three transmission lines, as well as node 2 and 5. Fig. 1(b) shows the used bus-branch model. It can be seen that two buses exist in this substation. Node 1, 3, 4, 5, 7 and 8 are merged into bus 1, and node 2 and 6 become bus 2. The three branch measurements are preserved in the bus-branch model. The nodal injection measurement at node 2 is also preserved. The nodal injection measurement at node 5, however, is eliminated since bus 1's injection equals to the sum of node 1 and 5's injections, and node 1's injection is unknown.

III. NETWORK OBSERVABILITY ANALYSIS

A linear, time-invariant (LTI) system is usually described in the following state space representation:

$$\begin{aligned}\dot{\mathbf{x}}(t) &= \mathbf{A}\mathbf{x}(t) + \mathbf{B}\mathbf{u}(t) \\ \mathbf{y}(t) &= \mathbf{C}\mathbf{x}(t) + \mathbf{D}\mathbf{u}(t)\end{aligned}, \tag{1}$$

where $\mathbf{x}$ is the *state vector;* $\mathbf{y}$ is the *output vector;* $\mathbf{u}$ is the *input* (or *control*) *vector;* $\mathbf{A}$ is the *state matrix;* $\mathbf{B}$ is the *input matrix;* $\mathbf{C}$ is the *output matrix;* $\mathbf{D}$ is the *feedthrough* (or *feedforward*) *matrix*.

In power system state estimation, the state vector $\mathbf{x}$ of the system contains the voltage magnitude and phase angles of buses. The output vector $\mathbf{y}$ (which is often denoted as $\mathbf{z}$ in power system analysis) contains the measurements. Since state estimation is a steady state function, the state vector is constant, and the state matrix and input matrix are both 0, i.e., $\mathbf{A}$=0 and $\mathbf{B}$=0. Also, measurements that are considered in power system state estimation have no feedthrough, i.e., $\mathbf{D}$=0. Thus the power system state estimation problem becomes

$$\mathbf{z} = \mathbf{C}\mathbf{x}\,. \tag{3}$$

Different from the LTI system, the power system is a non-linear system. The output matrix $\mathbf{C}$ is a function of $\mathbf{x}$, and (3) can be represented as:

$$\mathbf{z} = \mathbf{f}(\mathbf{x}). \tag{4}$$

First-order Taylor approximation of (4) yields:

$$\mathbf{H}\cdot\Delta\mathbf{x} = \mathbf{z} - \mathbf{f}\left(\mathbf{x}^0\right) = \Delta\mathbf{z}\,, \tag{5}$$

where $\mathbf{H} = \dfrac{\partial \mathbf{f}(\mathbf{x})}{\partial \mathbf{x}}$, evaluated at some $\mathbf{x}^0$; $\Delta\mathbf{x} = \mathbf{x} - \mathbf{x}^0$.

Equation (5) relates all existing measurements to the state variables, using the first-order Taylor approximation. An estimate for $\Delta\mathbf{x}$ can be obtained as long as the rank of $\mathbf{H}$ is equal to the dimension of $\Delta\mathbf{x}$ or $\mathbf{x}$. Therefore, the necessary and sufficient condition for a power system to be observable is:

$$\operatorname{rank} \mathbf{H} = n \,, \tag{6}$$

where n is the dimension of the state vector $\mathbf{x}$.

It should be noted that the system observability is independent of the branch parameters as well as the operating state of the system. So, all system branches can be assumed to have an impedance of $j1.0$ per unit (p.u.) and all bus voltages can be set equal to 1.0 p.u. for the purpose of observability analysis. It can be shown that in such a power system network, $\mathbf{H}$ can be calculated by:

$$\mathbf{H} = \mathbf{M} \cdot \mathbf{A}^T \,, \tag{7}$$

where $\mathbf{M}$ is the measurement-branch incidence matrix,

$$\mathbf{M}_{ij} = \begin{cases} 1 & \text{If measurement } i \text{ is incident to bus } j \text{ at the "from end".} \\ -1 & \text{If measurement } i \text{ is incident to bus } j \text{ at the "to end".} \\ 0 & \text{If measurement } i \text{ is not incident to bus } j. \end{cases}$$

$\mathbf{A}$ is the branch-bus incidence matrix,

$$\mathbf{A}_{ij} = \begin{cases} 1 & \text{If branch } i \text{ is incident to bus } j \text{ at the "from end".} \\ -1 & \text{If branch } i \text{ is incident to bus } j \text{ at the "to end".} \\ 0 & \text{If branch } i \text{ is not incident to bus } j. \end{cases}$$

The method that uses (6) and (7) to decide whether a network is observable is call the *numerical method*.

Observability analysis can also be carried out by using a *topological method*. If a tree can be formed such that each branch of this tree contains a power flow measurement, then the phase angles at all buses can be determined, i.e. the system will be fully observable. The available measurements should be assigned to the branches according to the following rules:

1) If the branch flow is measured, the branch is assigned to its flow measurement.
2) If an injection is measured at a terminal node of a branch, the branch can be assigned to that injection.
3) Once a branch is assigned to a measurement, it can not ba assigned to any other measurement.

The essential steps of the algorithm can be summarized as follows:

1) First assign all the flow measurements to their respective branches.
2) Then, try to assign the injection measurements in order to reduce the existing forest by merging existing trees. Note that there is no way to predict the correct sequence for processing injections. Implementation of the method requires proper back-up and re-assignment of injections when necessary.

The network observability analysis determines if a state estimation solution for the entire system can be obtained using the available set of measurements, therefore it is a very important component in the EMS and it is usually carried out before the execution of state estimation.

IV. The Dynamic Utilization of Substation Measurements

In a physical substation, CB statuses may be changing relatively frequently, either due to faults, or because of operator commands. The network topology changes accordingly. The changes in topology may have the following potential impacts on the NTP:

1) The merging or splitting of buses may cause some substation measurements to become useless in the changed topology, during the processing of measurement data as described in section II.
2) Some measurements may be disconnected from the rest of the network. For example, when the CBs disconnect a transmission line, the branch power flow measurement on this line is also disconnected and will not appear in the bus-branch model.
3) The total number of available measurements in the bus-branch model may be reduced and the locations of measurements may change, due to the change of network topology.

Because the network observability is highly related to the number and locations of measurements in the network, the network may become unobservable after the change of topology, and therefore an estimation of system states cannot be obtained.

The existing approach to deal with the loss of observability is to suggest new locations for additional measurements [4-6]. However, installing new measurements may be costly and can only be done off-line. A way of utilizing the currently available measurements in the substations to recover the network observability on-line is presented in this section. The new method is called the dynamic utilization of substation measurements. (DUSM).

A. Calculation of inferred substation measurements

Like a conventional NTP, the first step of DUSM is to read in the static connections of devices and CB statuses, and then store the network topology information in an organized way for easier processing.

The devices (CBs, branches, loads, generators, etc.) are grouped into different substations. Each device is assigned a "virtual" measurement that supposes to measure the power flow of this device, and a measurement vector can be as created using the following equation:

$$\mathbf{z}_i = \left[z(\text{device}\,1) \quad z(\text{device}\,2) \quad \cdots \quad z(\text{device}\,\text{n}) \right]^T , \tag{8}$$

where i is the substation number, device 1,2,…n are the devices of substation i, and z(device j) is the power flow measurement of device j.

The following assumptions are made regarding the directions of the measurements:

1) A CB power flow measurement's direction is always the same as the CB's.
2) A branch power flow measurement's direction is always going into the node that the branch is connected to.
3) A power injection measurement's direction is always going into the node that it is connected to, i.e., for a generator, the measurement value is positive; for a load, the measurement value is negative.

If the directions of measurements are different from the

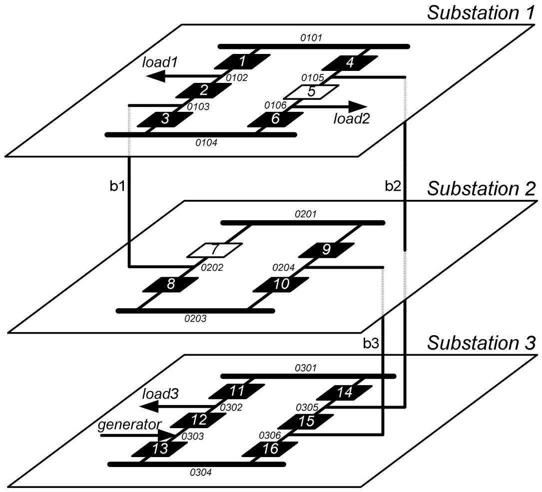


Fig. 2. Sample detailed substation model of a 3-bus system.

above assumptions, they can be easily modified to conform to the assumption by changing the signs of the measurement values.

DUSM uses a three-dimensional incidence matrix **M** to store the topological information, as illustrated in Fig. 2 and Table I. The element of the incidence matrix **M** can be expressed as

$$\mathbf{M}_i(y,x)=\begin{cases}1 & \text{If measurement } x\text{'s direction goes into node } y,\\ -1 & \text{If measurement } x\text{'s direction goes out of node } y,\\ 0 & \text{If measurement } x \text{ is not incident to node } y,\end{cases}$$

where i is the substation number.

According to Kirchhoff's current law, we have

$$\mathbf{M}_i \cdot \mathbf{z}_i = 0\,, \tag{9}$$

where i is the substation number.

In a practical system, some of the elements in $\mathbf{z}_i$ are measured, and others are not. The measured elements can be replaced by their measurement values, while other elements remain as unknown. What we are interested in is to infer as many measurement values as we can by using (9).

It can be seen that an inferred measurement can be calculated when the measurements of all other devices that are connected to the same node are available. This can be illustrated by the following example. In Fig. 2, suppose the power flow of CB8 is measured and its value is z_8. Applying (9) to node 0202, we get

$$\begin{bmatrix}-1 & 0 & 0 & 1 & 0\end{bmatrix}\cdot\begin{bmatrix} z_8 \\ z_{CB9} \\ z_{CB10} \\ z_{b1} \\ z_{b3}\end{bmatrix} = 0\,, \tag{10}$$

or $z_{b1} = z_8$, which means the power flow of b1 equals the power flow of CB8. Now that z_{b1} has been calculated, both z_8 and z_{b1} can be used to calculate other inferred measurements, until no more measurements can be inferred.

TABLE I
TOPOLOGICAL INFORMATION STORAGE FOR FIG. 1
(A) SUBSTATION 1

Substation 1		Devices								
		CB1	CB2	CB3	CB4	CB6	load1	load2	b1	b2
Nodes	0101	-1	0	0	-1	0	0	0	0	0
	0102	1	-1	0	0	0	1	0	0	0
	0103	0	1	-1	0	0	0	0	1	0
	0104	0	0	1	0	1	0	0	0	0
	0105	0	0	0	1	0	0	0	0	1
	0106	0	0	0	0	-1	0	1	0	0

(B) SUBSTATION 2

Substation 2		Devices				
		CB8	CB9	CB10	b1	b3
Nodes	0201	0	-1	0	0	0
	0202	-1	0	0	1	0
	0203	1	0	1	0	0
	0204	0	1	-1	0	1

(C) SUBSTATION 3

Substation 3		Devices									
		CB11	CB12	CB13	CB14	CB15	CB16	generator	Load3	b2	b3
Nodes	0301	-1	0	0	-1	0	0	0	0	0	0
	0302	1	-1	0	0	0	0	0	1	0	0
	0303	0	1	-1	0	0	0	1	0	0	0
	0304	0	0	1	0	0	1	0	0	0	0
	0305	0	0	0	1	-1	0	0	0	1	0
	0306	0	0	0	0	1	-1	0	0	0	1

B. Calculation of bus-branch measurements

Once all possible inferred measurements are obtained, the next step is to calculate the values of the bus voltage magnitude measurements, bus injection power flow measurements and branch power flow measurements.

The calculation of bus voltage magnitude measurements is straight-forward. It can be done by a direct mapping of the substation node to the corresponding bus, as show below:

$$V_i = V_n\,, \tag{11}$$

where n is the node number in the substation model, i is the bus number of n in the bus-branch model.

The calculation of branch power flow measurement uses the following rules:

1) If there is only one branch (single line) between two buses, map the branch measurement in the detailed substation model to the corresponding branch measurement in the bus-branch model by changing the node numbers to the bus numbers.
2) If more than one branch (multiple lines) exists between two buses, sum up all branch measurements in the substation model to get the branch measurement in the bus-branch model.

The bus injection power flow measurement can be calculated by adding all nodal injection measurements in a single merged electrical bus. If any measurement value is unknown after the addition, the injection power flow of this bus cannot be calculated.

C. The applicability in practice

The DUSM algorithm uses the following implicit assumptions:

1) It assumes that the Kirchhoff's current law is applicable, which requires that there is no unknown ground fault or ground leakage current existing in the substation. This is usually true, since firstly, the possibility of ground faults in a substation is low; secondly, in case of a bus ground fault, the bus protection will trip all CBs that are connected to the bus and clear the leakage current.
2) The open CBs are excluded from the topological matrix and the power flows through them are assumed to be zero. This requires that the CB statuses are correctly reported. If the CB status measurements are not accurate enough, the open CBs should still be included in the topological matrix and the power flow through them should be regarded as unknown.

The DUSM algorithm can be implemented as a supplementary function to the substation automation system (SAS), or to the EMS in the control center.

The advantages of implementing DUSM in substations are:

1) More measurements are available in substations than in the control center. In recent digital substations, besides the measurements that are gathered by RTUs, many intelligent electronic devices (IEDs) also record and monitor the status of the substation on-line. Many measurement data can be obtained from the recording of these devices [7].
2) Because of the independent storage of substation topological information, DUSM can be implemented in any number of substations in the system. This adds to the flexibility of implementation. A few substations may be picked up and the effectiveness of the new algorithm may be tested without the need for upgrading the existing EMS software in the control center or SAS software in other substations.

On the other hand, the advantage of implementation in the control center is that the full potential of dynamically creating new measurements for the state estimation purpose can be obtained. The EMS in control center has the access to the topological information from all substations. The installation of the new algorithm will enable the new measurements to be calculated from all the measurements that are transmitted to the control center.

V. TEST CASES

Tests have been run on the IEEE-30 bus system. The data of the IEEE-30 bus system, including the bus-branch diagram, can be obtained from [8].

It was assumed that 31 measurements were already available to the state estimator. The types and locations of these measurements are listed in Table II.

TABLE II
MEASUREMENT PLACEMENT

Measurement	Location
Bus voltage magnitude	4, 16
Branch power flow	29-27, 30-29, 30-27, 25-26, 12-16, 16-17, 1-3, 9-11, 14-12, 12-13, 14-15, 6-8, 28-8, 22-21, 18-19, 17-31
Bus injection power flow	25, 27, 4, 9, 10, 22, 24, 15, 12, 28, 20, 18, 2

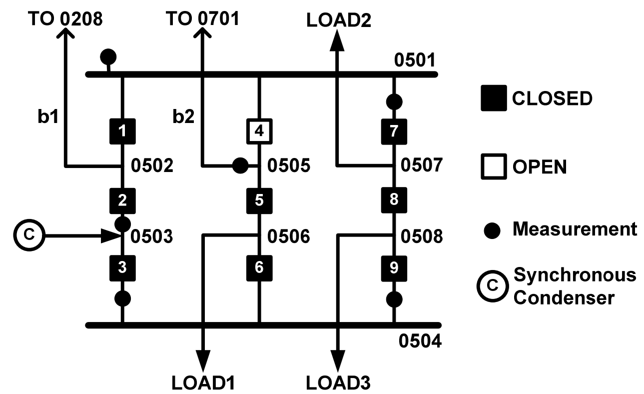


Fig. 3. Detailed substation model of FIELDALE substation in the IEEE-30 bus system.

TABLE III
MEASUREMENT DATA VALUES

Measurement	V_{0501}	P_{CB2}	P_{CB3}	P_{CB7}	P_{CB9}	P_{b2}
Value	1.01	45.4 -*j*13.0	45.4 -*j*22.8	34.0 +*j*6.9	-53.0 -*j*10.7	14.8 -*j*10.6

Furthermore, the detailed breaker-and-a-half configuration was arbitrarily picked to represent the FIELDALE substation (Bus 5) in the IEEE-30 bus system, as shown in Fig. 3. Six measurements were placed in the substation, including one voltage magnitude measurement and five power flow measurements. The measurement values are listed in Table III.

Using the conventional NTP, only two measurements were generated to serve the state estimator. In the bus-branch model, V_{0501} became the voltage magnitude measurement of Bus 5, and P_{b2} became the branch power flow measurement of branch 5-7. The conventional NTP was also able to calculate the injection power flow of the synchronous condenser. However, the injection of Bus 5 could not be calculated since neither of the three loads' power flow could be obtained.

A topological method as mentioned in section III was used to evaluate the observability of the 30-bus network. Adding these two measurements to the system, it was found that the whole network was not totally observable.

TABLE IV
CONVENTIONAL NTP VS. DUSM

Measurement	Conventional NTP	DUSM
V_{bus5}	1.01, equals to V_{0501}.	1.01, equals to V_{0501}.
$P_{5\text{-}2}$	(Unknown)	79.4-*j*6.1, equals to $-P_{CB2}$ $-P_{CB7}$.
$P_{5\text{-}7}$	14.8-*j*10.6, equals to P_{b2}.	14.8-j10.6, equals to P_{b2}.
P_{inj5}	(Unknown)	-94.2+*j*16.7, equals to $-P_{CB2}+P_{CB7}-2P_{CB9}-P_{b2}$.

The same measurement data were then processed by the DUSM algorithm and four measurements were generated: the voltage magnitude measurement of Bus 5, the branch power flow measurement of branch 5-2 and 5-7, and the bus injection power flow measurement of bus 5. A comparison of the different results is shown in Table IV.

With the help of the two extra measurements that were created by DUSM, the whole network became observable, and the state estimation was then able to be executed.

VI. CONCLUSIONS

This paper explains the importance of an advanced network topology processor in preserving as many substation measurements as possible to maintain the network observability. A new method – the dynamic utilization of substation measurements (DUSM) – was presented. Instead of seeking the installation of new measurements in the system, this method tries to calculate meaningful state estimation measurement values by applying the current law that regulates different measurement values implicitly. Its processing is at the substation level and therefore can be implemented in different substations. Test cases on the IEEE-30 system show DUSM's advantage in measurement processing over a conventional network topology processor.

VII. REFERENCES

[1] A. Abur and A. G. Exposito, *Power System State Estimation*, Marcel Dekker, USA, March 2004, p. 5.

[2] A. Monticelli, "Electric power system state estimation," *Proceedings of the IEEE*, Vol. 88, No. 2, pp. 262-282, Feburary 2000.

[3] S. Pandit, S. A. Soman and S. A. Khaparde, "Object-oriented network topology processor," *IEEE Computer Applications in Power*, Vol. 14, No. 2, pp. 42-46, April 2001.

[4] F. H. Magnago and A. Abur, "Unified approach to robust meter placement against bad data and branch outages," *IEEE Trans. on Power Systems*, Vol.15, No. 3, pp. 945-949, August 2000.

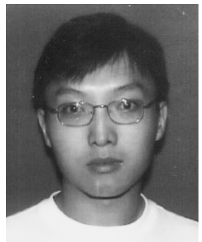
[5] Q. Ding and A. Abur, "An improved measurement placement method against loss of multiple measurements and branches," in *Proceeding of IEEE Power Engineering Society Winter Meeting*, Vol. 1, pp. 27-31, January 2002.

[6] M. K. Celik and W.-H.E. Liu, "An incremental measurement placement algorithm for state estimation," *IEEE Trans. on Power Systems*, Vol. 10, No. 3, pp. 1698-1703, August 1995.

[7] M. Kezunovic, "Future trends in protective relaying, substation automation, testing and related standardization," in *Proceeding of IEEE Transmission and Distribution Conference and Exhibition*, Vol. 1, pp. 598-602, October 2002.

[8] R. Christie. Power Systems Test Case Archive, 30 Bus Power Flow Test Case [Online]. Available: http://www.ee.washington.edu/research/pstca/pf30/pg_tca30bus.htm.

VIII. BIOGRAPHIES



Yang Wu (S'05) received his B.S. and M.S. degrees from Xi'an Jiaotong University, Xi'an, China, both in electrical engineering, in 1999 and 2002 respectively. He has been a Ph.D. student in Texas A&M University since Aug. 2002. His research interests include protective relaying, substation automation and state estimation.

Mladen Kezunovic (S'77, M'80, SM'85, F'99) received the Dipl. Ing. Degree in electrical engineering from the University of Sarajevo, Bosnia-Herzegovina, in 1974, and the M.S. and Ph.D. degrees in electrical engineering from the University of Kansas, Lawrence, in 1977 and 1980, respectively. Currently, he is the Eugene E.Webb Professor and Director of Electric Power and Power Electronics Institute at Texas A&M University. 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 also a Fellow of IEEE and a member of CIGRE-Paris.

Tatjana (Tanja) Kostic (M'95) received her BSEE ('89) and MSEE ('94) from the University of Belgrade, Yugoslavia, and the Dr. of Sc. Techn. degree ('97) from the Swiss Federal Institute of Technology (EPFL), Lausanne, Switzerland. After her post-doc year with Mitsubishi Electric, Amagasaki, Japan, she joined ABB Corporate Research in Switzerland, where she is currently working as a principal scientist in Utility Solutions group. Her research interests include IT applications for power system operation and for utility asset management, standardized utility domain models, object-oriented analysis and design, and artificial intelligence. She is a member of the IEEE PES and Computer societies, a working member of the Cigré WG C2.01, and an IEC expert in TC57 WG14.