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A new multiple line outage identification formulation using a sparse vector recovery technique

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ABSTRACT

This paper develops new methods to estimate the locations of transmission line outages in transmission networks. Two transmission outage models are developed based on DC and AC power flow equations and injected power changes due to line outages. The models are then generalized to include other transmission lines in addition to the outaged lines to provide a full representation of transmission networks. Three methods are developed based on the DC and AC models: Method_1 uses the DC power flow model; Method_2 uses the AC power flow model with zero line resistance; Method_3 uses the AC power flow model with line losses taken into account. A regularized least square based on ℓ_1-norm minimization is developed to solve the models and estimate the locations of outages. Simulation results of the IEEE 39-, 57- and 118-bus systems verify the effectiveness of the developed methods in detecting line outage locations.

1. Introduction

Identification of transmission line outages plays a key role for the reliable and secure operation of electric power systems. This is particularly important for restructured power systems where the independent functioning of different entities and inherent inertia of the decisions made by market participants delay corrective actions. The line outages alter the power flow of the system which may result in overloading of certain transmission lines and their consequent failures. This may lead to major blackouts if the corrective actions are not taken promptly. The North American Electric Reliability Council (NERC) conducted an investigation of the August 14, 2003 blackout to identify the causes of the outage. The lack of situation awareness and deficiencies in visualizing system conditions were recognized as the major reasons [1,2]. The system data are thereafter required to be updated on an hourly basis to enhance the awareness of the system topology [1]. However, the line outage may occur anytime within the one hour interval due to unexpected events such as breaker failures, faults, lightning and tree fallings. Therefore, there is a need for an appropriate algorithm to identify transmission line outages more efficiently and promptly.

Line outage detection has been investigated in several studies [3–10,19–23]. A single-line outage detection method using the voltage angle measurements provided by phasor measurement units (PMUs) was developed in Ref. [3]. The proposed method was then extended to include the pre-outage topology information as well as the real-time PMU measurements for double-line contingencies [4]. A mixed-integer programming approach was proposed in Ref. [5] for single-line outages. The compressive sensing theorem was used in Refs. [6] and [7] for multiple line outages detection. The internal noise term considered for the proposed model adversely affects the performance of the outage detection scheme. Moreover, the methods developed in Refs. [6] and [7] are based on a DC power flow model which is incapable of capturing the true AC nature of PMU measurements and transmission systems. A support vector machine (SVM) technique was presented in Ref. [8] that used the PMU measurements to identify the line outages for single contingencies. These methods increase the computational complexity of the problem as they require an exhaustive search over all possible candidate topologies to obtain the optimal solution. The increased complexity limits the practicality of implementation for higher number of contingencies. A dependency graph approach for fault detection was developed in Ref. [9]. However, assumptions considered for the study such as independency and Gaussian distribution of the

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voltage angles are not practical. A method based on Ref. [4] was introduced in Ref. [10] to locate line outages within a specific area of power systems, but it was limited to single-line outages. A convex-relaxed version of the outage detection problem using a linearized transmission model was proposed in Refs. [19] and [20]. A linearized measurement model, convex relaxation and branch and bound algorithm were used in Ref. [21] to estimate the optimal locations of sensors within a power system for line outage detection purposes. A comprehensive sensing technique based on a DC power flow model was employed in Refs. [22] and [23] to detect line outage locations. Ref. [24] developed a multiclass logistic regression to classify single line outages. However, all these studies are based on a linearized transmission model or linear DC model which neither reflect the actual AC nature of transmission networks nor effectively use the AC PMU measurements. Also, several studies have developed effective algebraic models for fault location detection within distribution networks, but they either estimate the location of single faults [25–29] or multiple faults [30] which cannot be used for line outage detection in general. A near real-time identification algorithm for multiple external line outages, which uses hourly basecase topology information and local voltage phasor angle data, was proposed in Ref. [31]. An algorithm to detect line outages in the transmission system using the bus voltage phasor measurement available from PMUs in conjunction with change in the system topology arising due to line outage was discussed in Ref. [32]. PMUs are assumed to be placed at all buses and then are reduced by removing them from the buses with least priority to arrive at the minimum required number. A computationally efficient optimization technique based on Quantum Inspired Evolutionary Algorithm was proposed in Ref. [33] to solve the multiple line outage identification problem in smart power grids. The proposed algorithm avoids the local optima and is capable of identifying multiple line outages with an acceptable accuracy. A transmission expansion planning (TEP) procedure which employs the ORNL-Pserc-Alaska model was proposed in Ref. [34] for choosing more effective candidate transmission lines to be used in TEP regarding risk of cascading line outages. The results provide motivation for considering the risk of cascading line outages in TEP that afford substantial savings to the society. The study in Ref. [35] proposed a formulation for multi-stage DC-based security-constrained generation capacity expansion planning problem using power transmission distribution factors and line outage distribution factors.

This paper develops new methods to estimate the locations of transmission line outages in a power network. Two transmission line outage models are developed based on DC and AC power flow equations. The models are then generalized to include all transmission lines. A regularized least square problem (LSP) based on ℓ_1-norm is developed to solve the models and estimate the locations of outages. Unlike the other line outage detection methods proposed in the literature, our proposed methods model the actual AC transmission network which in combination with actual measurements capture the actual AC nature of the transmission networks and provide a more accurate representation of power systems. Moreover, our methods have the advantage of easy implementation which can be directly incorporated in state estimation algorithms.

Section 2 explains the methodology based on DC and AC power flow models. It also explains the line outage models and detection algorithm. Simulation results and comparisons between the developed methods are given in Section 3. Conclusions are presented in Section 4.

2. Methodology

Sets of N buses $\mathcal{N}:=\left\{1,\ldots,N\right\}$. and m transmission lines $\mathcal{L}:=\left\{L_1,\ldots,L_m\right\}$ are used to represent a transmission network where $l:=\left\{(i,j)\right\}\subseteq\mathcal{N}^2$ and $l\subseteq\mathcal{L}$.

2.1. DC power flow

DC power flow is an approximation of the AC power flow to facilitate the monitoring of real power systems under normal and contingency conditions. The relation between the powers injected into buses and voltage angles is linear as:

$$P = B\theta \tag{1}$$

where P and θ are the net injected active power and voltage angle for each bus, and B is a constant $\mathcal{N}^2$ matrix given by [11]:

$$B_{ij}=\begin{cases}\dfrac{-1}{x_{ij}}, & i,j\in\mathcal{N}\text{are connected}, i\neq j\\ \displaystyle\sum_k\dfrac{1}{x_{ik}}, & i,k\in\mathcal{N}\text{are connected}, i=j\end{cases} \tag{2}$$

where x_{ij} is the reactance of the line between buses i and $j\in\mathcal{N}$. Using Eq. (1), the voltage angles are calculated by:

$$\theta = B^{-1}P = XP \tag{3}$$

2.2. AC power flow

AC power flow is a complete representation of a transmission network in steady state which provides both voltage magnitudes and angles. The relation between the power injected into each bus and voltage magnitudes and angles is given by:

$$P = real\,(V.I^*) = real\left(V.Y_{Bus}^*V^*\right) = real\left(|V|\measuredangle\theta.Y_{Bus}^*|V|\measuredangle-\theta\right) \tag{4}$$

where, I, Y_{Bus} and $|V|$ are the injected current vector, the network bus admittance matrix and voltage magnitudes, respectively; "*" is the complex conjugate, and "." is defined as the element-by-element product operator [11]. The elements of Y_{Bus} are defined by:

$$Y_{ij}=\begin{cases}-y_{ij} & i,j\in\mathcal{N}\text{are connected}, i\neq j\\ \displaystyle\sum_k y_{ij} & i,k\in\mathcal{N}\text{are connected}, i=j\end{cases} \tag{5}$$