Electric Power Systems Research 79 (2009) 734–739

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Evaluating operational risk in a power system with a large amount of wind power

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ARTICLE INFO

Article history:
Received 25 June 2007
Received in revised form 6 April 2008
Accepted 13 October 2008
Available online 28 November 2008

Keywords:
Operational reserve
Operational risk
PJM model
Wind power generation

ABSTRACT

Reserve definition is a compromise between economic issues (additional capacity costs) and reliability (risk of loss of load due to outages of the generators), generally approached by deterministic criteria (e.g. the percentage rule defined by UCTE in Europe) and probabilistic methods like PJM (Pennsylvania–New Jersey, Maryland) and its enhancements, based on the concept of risk. With wind power generation increasing in power systems worldwide, these operational issues gain a renewed interest due to the volatile nature of this kind of energy. The aim of this paper is therefore to address this issue from a risk evaluation point of view, showing that it is possible to extend classical probabilistic methods to this new situation, by introducing a detailed Markov model of wind parks that accounts both for machine failures and different wind power levels.

This evaluation, where wind generation fluctuation and uncertainty is included, can be helpful for transmission system operators (TSO), when defining the reserve requirements for the next hours. In fact, the results obtained for the risk can be used by TSO to check if the reserve levels that results from traditional deterministic rules are acceptable or need to be increased.

1. Introduction

Among the renewable energy resources used to generate electricity, wind power has become the fastest growing technology in the last decade. This increased amount of wind power in the total production mix has, however, consequences in operational reserve planning, due to the volatility of the natural resource.

The needs of reserve considers a compromise between economic (additional capacity costs) and reliability issues (risk of loss of load). Deterministic criteria are appealing because of their simplicity and transparency, but it is generally recognized that the use of probabilistic methods to evaluate the risk associated with a specific unit commitment (or dispatch) is a more reliable way of supporting reserve definition. The volatile nature of wind energy brings a renewed interest in these operational issues. For instance, UK Energy Research Centre's is concerned with the costs and impacts of intermittency at the British electricity network [1]. Also in the Netherlands researchers studied the integration of wind power in their electricity networks from this point of view [2].

In this framework, conservative deterministic rules also emerged that may become an obstacle to a greater use of renewable energy. In some cases, additional reserve corresponding to a high percentage of the existing wind power is required, leading to expensive operating configurations that are not always justified.

In this paper, we address this issue from a risk evaluation point of view, showing that it is possible to extend classical probabilistic methods to this new situation, just by introducing a detailed model of wind parks that accounts both for machine failures and different wind levels. The present paper develops previous work on this subject by the authors in a conference [3], by including transitions from any level to the "no wind" state, in order to include situations of sudden loss of wind, transitions between non-adjacent wind levels and excessive wind.

The methodology, where wind generation fluctuation and uncertainty is included, can be helpful for transmission system operators (TSO), when defining the reserve requirements for the next hours. In fact, the results obtained for the risk can be used by TSO to check if the reserve levels that results from traditional deterministic rules (e.g. UCTE rule or N-1 security) are acceptable or need to be increased.

The extension of classical probabilistic methods to include wind power was addressed by different authors. Milligan [4] developed a method to incorporate wind power variability into system reliability calculations. The method consists of calculating the LOLP in an hourly basis using a sliding window technique, which provides information about the probabilities of various wind output

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doi:10.1016/j.epsr.2008.10.006

levels (assuming a one hour duration for each level). Later, the same author [5,6] developed a chronological approach that assesses the fraction of system reserve that can be allocated to wind parks.

Doherty [7] proposed a methodology for the analysis and provision of system reserve levels. The level of reserve depended on a reliability criterion based on the LOLP. Load and wind forecast errors are incorporated in the model, and the algorithm calculates the reserve level that corresponds to a specified probability of loss of load. Dany [8] quantified the technical consequences of high wind penetrations in Europe on primary, secondary and long–term reserve.

In a different framework, Sayas [9] presented models and techniques to evaluate the reliability of distribution networks containing embedded wind generation. The methodologies reflect stochastic processes involving state space representation based on Markov chains for reliability evaluation. These models inspired us to develop the present methodology, first with transitions only between adjacent wind levels [3] and now considering sudden loss of wind, transitions between non-adjacent wind levels and excessive wind.

The structure of this paper is the following. The basic methodology is described (Section 2), as an extension of the modified PJM method. Section 3 describes the wind power availability Markov model of the generation offered by a wind park. An illustrative example with a small power system is presented in Section 4, followed by some comments on decision aspects of the reserve planning exercise (Section 5). The conclusions and references complete the paper.

2. Methodology

The operating reserve is the stand-by capacity that must be kept ready to generate energy to provide for unplanned outages of generating units [10]. For this reserve, risk represents the probability of failing to satisfy the load in the short term, as the result of loss of generation due to forced outages. It is assumed that during the study time period, the system operator cannot start non-spinning reserve units. He can only count on existent reserve in the generation units that are synchronized. We call this period the lead time (LT).

A more close view of this situation recognizes that the operator may decide to launch (in the beginning of the lead time), either rapid start units (gas turbines or hydro units) or hot reserve units, in order to cover part of the operating risk.

In either case, we can state the problem as the calculation of the risk of not serving the load during the lead time. The risk may then be compared with a standard defined by the utility or by a regulatory authority, in order to check whether or not it is necessary to increase the number of committed units in that situation. Since our method is build over PJM, we begin by reviewing its main concepts and procedures.

2.1. PJM method

The traditional PJM method [11] evaluates the risk of the committed generation just satisfying or failing to satisfy the forecasted load during the LT. Load is generally considered constant during LT.

Since LT is normally small (typical values of 1–4 h), it is accepted that no repair is concluded during the lead time, so the unavailability of a unit is given by

$$P(\text{unit } k \text{ out during LT}) = 1 - e^{-\lambda_k \mathrm{LT}} \quad (1)$$

This probability is known as the outage replacement "rate" (ORR), because of the similarity with the forced outage "rate" used in static reserve studies. The PJM method then builds a generation model similar to the one used to calculate LOLP or LOLE, creating a capacity outage table where the units' states (operating or failed) and the corresponding probabilities (1-ORR and ORR) are combined.

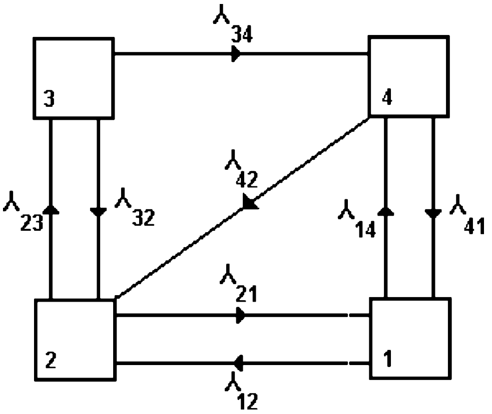

Fig. 1. Four-state model for rapid start units [11].

The risk value for a given load can therefore be deduced directly from the capacity outage table, just by checking the smallest outage level that leads to loss of load and taking the corresponding cumulative probability.

It is important to point out that, with this procedure, we are calculating approximate values of the probabilities over time (for a specific point of time, LT), which is very different from using the FOR to calculate the long-term probability of a given state of the system.

2.2. Modified PJM model

As stated before, the risk of failing to satisfy the load during LT can be reduced by the use of rapid start units (such as gas turbines and hydro units) or hot reserve units. The modified PJM model [11] includes this situation, after a detailed modeling of these units that leads to the characterization of different states, with the corresponding probabilities.

Fig. 1 shows the model for a rapid start unit (RSU), with the following four states: (1) in service, (2) ready for service, (3) fails to start, (4) failed. The unit is normally in state 2, waiting for a start order. Of course, when asked to start, we expect the RSU, if it doesn't fail to start, to be in service at a time T1 < LT.

This model, along to an estimation of the probability of failing to start Pf, is used to calculate the availability of the RSU at T1 (when it is supposed to be in service) and at LT (the lead time). Details of the entire procedure can be seen in [11], but we will give here a sketch of the rest of the process.

The modified PJM method then calculates two risk components:

(a) *Risk index in the first period (0, T1)*: The generation model is formed using only the on-line generation with ORR values calculated from 0 to T1. Reserve units are neglected in this period. We will call this component Ra.
(b) *Risk index in the second period (T1, LT)*: Two generation models are formed, for the beginning and end of the period, using the adequate values of the unavailability of the RSU. Two risk indices are obtained, the risk component for this period being the difference between them: $\mathrm{Rb} = R(\mathrm{LT}) - R(\mathrm{T1+})$

The overall risk will then be, in this case, $R = \mathrm{Ra} + \mathrm{Rb}$.