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Area equivalents for spinning reserve determination in interconnected power systems

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A R T I C L E I N F O

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A B S T R A C T

The current study applies the cost-benefit analysis method to determine the optimal amount of spinning reserve. However, it is difficult for the method to handle large size problem, like large interconnected power systems with several control areas, directly. Therefore, this paper proposes a power system equivalent for the original system to reduce the complexity of the original problem. According to the proposed algorithm, each area of the system is first modeled by an equivalent system, obtained by the REI (radial – equivalent – independent) method, and an interconnected REI equivalent is obtained for the original interconnected system. A cost-benefit analysis is then performed to determine the spinning reserve requirements of both the original and equivalent systems. The cost-benefit algorithm considers either the SCUC (security constrained unit commitment) or the SCED (security constrained economic dispatch). Finally, the proposed interconnected REI equivalent is evaluated by comparing the spinning reserve of each control area in the original system with that in the equivalent system. Numerical studies are performed on two IEEE test systems.

1. Introduction

According to NERC (North American electric reliability corporation), security, as a part of reliability, refers to the ability of the power system to withstand unexpected disturbances [1]. By this definition, it is not possible to maintain system security unless there are sufficient spinning reserves. Calculating the amount of spinning reserve needed in a power system is, however, a challenging task. This paper focuses on spinning reserve calculation in interconnected power systems.

Different methods for determining spinning reserve requirements have been proposed in previous studies. For example [2], describes an offline cost-benefit method, which is based on the cost of reserve provision and the benefit derived from its availability to determine the required spinning reserve. In Ref. [3], LOLP (Loss Of Load Probability) is used in a hybrid deterministic-probabilistic approach to set the optimal amount of reserve. A fixed amount of reserve is imposed by some market operators on the basis of operator experience [4]. Some other markets use the deterministic methods, based on N-x criterion [5]. The Ref. [6] employs probabilistic indices to set the reserve requirements. The probabilistic approach is also used in Ref. [7] to determine the reserve requirements in Denmark. In Ref. [8], reserve calculation in a joint energy and spinning reserve markets is discussed. Integration of aggregated loads in reserve provision is discussed in Ref. [9], while load participation in the German balancing mechanism is studied in Ref. [10]. The combined deterministic-probabilistic method and the cost-benefit method are utilized to allocate the spinning reserve among generation units in Ref. [11]. The same method is used in Ref. [12] to determine the reserve value considering different reliability preferences. In the use of these methods mentioned above, however, there is a tradeoff between accuracy and computational complexity. This means that, on the one hand, some of these methods, such as the experimental ones, do not require great computational capacity, and thus give fast results, which are, nevertheless, not based on accurate analyses. On the other hand, those involving systematic procedures may provide more reliable results, but they require complicated mathematic calculations. The cost-benefit method, for instance, solves a mathematical optimization problem at the expense of high computational complexity, which in turn may jeopardize the efficiency of the method when it is applied to large power systems.

Application of the cost-benefit method for spinning reserve determination in an interconnected power system is even more

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Nomenclature

Constants

A	total number of areas
G	total number of generators
K	total number of considered contingencies
L	total number of lines
N	total number of buses
T	total number of time intervals

Sets

G_a	sets of all generators in area a
BG_a	sets of all border generators (generators connected to the border buses) in area a
L_i	sets of all lines connected to bus i
N_a	sets of all buses in area a
BN_a	sets of all border buses in area a

Variables

$C_k(t,i,k)$	generation operation cost in time t and in bus i for contingency k
$C_n(t,i)$	generation operation cost in time t and in bus i for normal state of system
$C_{sd}(t,i)$	shut-down cost in time t and in bus i
$C_{su}(t,i)$	start-up cost in time t and in bus i
$D_k(t,i,k)$	demand value in time t and in bus i for contingency k
$D_n(t,i)$	demand value in time t and in bus i for normal state of system
$ENS_k(t,i,k)$	energy not supplied in time t and in bus i for contingency k
$P_k(t,l,k)$	transferred power in time t and in line l for contingency k
$P_n(t,l)$	transferred power in time t and in line l for normal state of system
$P_k(t,i,k)$	generated power in time t and in bus i for contingency k
$P_n(t,i)$	generated power in time t and in bus i for normal state of system
$R_k(t,i,k)$	generated reserve in time t and in bus i for contingency k
$R_a(t,k)$	reserve amount of area a in time t for contingency k
$R_a(t)$	reserve amount of area a in time t
S_i	apparent power in load bus i
S_j	apparent power in generation bus j
$y^{sd}(t,i)$	binary variable equal to 1 if generator of bus i has a shut-down in time t and 0 otherwise
$y^{su}(t,i)$	binary variable equal to 1 if generator of bus i has a start-up in time t and 0 otherwise
$\theta_n(t,i)$	voltage angle in time t and in bus i for normal state of system
$\theta_k(t,i,k)$	voltage angle in time t and in bus i for contingency k
$y^u(t,i)$	binary variable equal to 1 if generator of bus i in time t is on and 0 otherwise
V_i	voltage in bus i
$V_{i,k}$	voltage in bus i for contingency k
$\lvert V_i \rvert$	voltage magnitude in load bus i
$\lvert V_j \rvert$	voltage magnitude in generation bus j
$\lvert V_{N+1} \rvert$	voltage magnitude in new generator bus
$\lvert V_{N+2} \rvert$	voltage magnitude in new load bus
$Y_{N+2,i}$	admittance between former load bus i and new load bus
$Y_{N+1,i}$	admittance between former generator bus i and new load bus
$Y_{E,E}$	part of Y_{New} matrix corresponding to all essential buses
$Y_{E,N}$	part of Y_{New} matrix corresponding to the connections between essential and non-essential buses
$Y_{N,E}$	part of Y_{New} matrix corresponding to the connections between non-essential and essential buses
$Y_{N,N}$	part of Y_{New} matrix corresponding to all non-essential buses
Y_{New}	the $(N+2) \times (N+2)$ admittance matrix obtained by adding two new load and generator buses to the original system
$Y_{Reduced}$	the new admittance matrix obtained for essential buses after removing the non-essential buses by network reduction method

Parameters

$b_1(i)/b_2(i)$	cost function coefficients for generator of bus i
π_k	probability of contingency k
π_n	probability of normal state of system
$\overline{P}(i)$	maximum generation for generator of bus i
$\underline{P}(i)$	minimum generation for generator of bus i
$\overline{P}(l)$	capacity of line l
$c^{sd}(i)$	shut-down cost for generator of bus i
$c^{su}(i)$	start-up cost for generator of bus i
$\tau^{on}_{max}(i)$	maximum on time for generator of bus i
$\tau^{on}_{min}(i)$	minimum on time for generator of bus i
$\tau^{off}_{max}(i)$	maximum off time for generator of bus i
$\tau^{off}_{min}(i)$	minimum off time for generator of bus i
$v^{ll}(t,i)$	value of lost load in time t and in bus i
$W_{i,j}$	admittance value between buses i and j in SCUC- and SCED- based cost-benefit method

Indices

a	index of areas running from 1 to A
k	index of contingencies running from 1 to K
l	index of lines running from 1 to L
i	index of buses running from 1 to N
i_l	index of buses connected to line l running from 1 to N
j	index of buses running from 1 to N
j_l	index of buses connected to line l running from 1 to N
t	index of time intervals running from 1 to T

Abbreviations

EENS	expected energy not served
ENTSO-E	European network of transmission system operators for electricity
LOLP	loss of load probability
MIP	Mixed integer programming
NERC	North American electric reliability corporation
REI	radial − equivalent − independent
SCUC	security constrained unit commitment
SCED	security constrained economic dispatch