Electric Power Systems Research 81 (2011) 107–116

Contents lists available at ScienceDirect

Electric Power Systems Research

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

Security-constrained expansion planning of fast-response units for wind integration☆

Saeed Kamalinia, Mohammad Shahidehpour*, Amin Khodaei

Electrical and Computer Engineering Department, Illinois Institute of Technology, United States

ARTICLE INFO

Article history:
Received 18 June 2010
Received in revised form 18 July 2010
Accepted 20 July 2010
Available online 14 August 2010

Keywords:
Wind generation (WG)
Fast-response generating units
Generation expansion planning
Security-constrained unit commitment (SCUC)

ABSTRACT

This paper proposes a stochastic expansion planning of fast-response thermal units for the large-scale integration of wind generation (WG). The paper assumes that the WG integration level is given and considers the short-term thermal constraints and the volatility of wind units in the planning of fast-response thermal units. The new fast-response units are proposed by market participants. The security-constrained expansion planning approach will be used by an ISO or a regulatory body to secure the optimal planning of the participants' proposed fast-response units with the WG integration. Random outages of generating units and transmission lines as well as hourly load and wind speed forecast errors are modeled in Monte Carlo scenarios. The Monte Carlo simplification methods are introduced to handle large-scale stochastic expansion planning as a tradeoff between the solution accuracy and the calculation time. The effectiveness of the proposed approach is demonstrated through numerical simulations.

1. Introduction

The increasing socio-environmental concerns have persuaded governments to support large integrations of renewable generation in power systems by introducing mandatory Renewable Portfolio Standards (RPS) or equivalent policies [1]. The large integration of intermittent wind generation (WG) in power systems has necessitated the inclusion of more innovative and sophisticated approaches in power system operation and planning [2].

In this paper, the intermittency refers to a situation where the power output of WG is less than a minimum amount over an extended time. While the volatility points out to smaller WG fluctuations in a shorter time. A major challenge in power systems is to determine the optimal availability of reserves to compensate WG uncertainties. Without a sufficient supply of reserves, the power system may not be able to provide short-term ramping support to contain large WG variability. However, the real-time allocation of a large sum of reserves may not be feasible when considering the economics and the security of power systems. Here, the allocation of excessive thermal reserves could further increase the operating costs while thermal reserves supplied by remote generating units may not be readily accessible due to transmission constraints.

The deterministic allocation of thermal reserves (e.g., largest generation unit in the system or certain percentages of load and WG) may offer a sub-optimal solution. Large integrations of intermittent WG could further contribute to the vulnerability of power systems [3–5]. Hence, it is necessary to apply stochastic optimization methods to address major WG integration concerns such as the coordinated expansion of WG and fast-response generation units, uncertain nature of systems with WG units, and short-term operating constraints of power systems.

The operation planning of WG integration is proposed in Ref. [6]. The reliability of composite generation and transmission system with a large-scale WG integration is investigated in Ref. [7]. The Monte Carlo simulation is used in Ref. [8] to investigate the effect of wind and load forecast errors on the power system expansion planning.

However, only a few studies in the literature considered the complicated operation issues in the WG expansion planning problem. The problem in Ref. [9] provides a nonlinear wind-thermal model and applies the evolutionary programming to large-scale power systems. A coordinated wind-thermal dispatch is presented in Ref. [10] by applying the direct search method to the WG integration. A combination of branch and bound and dynamic programming is considered in Ref. [11] for a coordinated economic dispatch of wind and thermal units in isolated power systems. The impact of transmission lines on the WG expansion is discussed in Ref. [12]. The approach considers additional zonal reserves because of the WG uncertainty. The incorporation of the WG model in the optimal economic dispatch is discussed in Ref. [13]. The study in Ref. [14] considers the short-term operation along with the long-term

☆ This work is supported in part by DOE grants DE-EE 0002979 and DE-EE 0001380.000 and the NSF grant ECCS-0801853.

* Corresponding author.
E-mail address: ms@iit.edu (M. Shahidehpour).

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doi:10.1016/j.epsr.2010.07.017

planning, where renewable energy resources are operated along with conventional generating systems to satisfy certain objectives. A comprehensive study of the operation of power systems when considering the WG integration is presented in Ref. [15]. The study shows that, at the present time, frequency control is not a significant challenge when integrating WG into large power systems. However, such issues will become more of a challenge for systems with large penetrations of WG. Recently, North American Electric Reliability Corporation (NERC) released a report on the planning and the operation of power systems with large sums of WG [16].

This paper proposes a stochastic expansion planning of fast-response thermal units for the large-scale integration of WG. The level of WG integration is assumed to be given. The site and the year of installation of fast-response units are proposed by the participants. The ISO does not plan any generating units. Rather the ISO would acknowledge and optimize the proposed planning of fast-response units that would provide both the reserve capacity and the fast ramping required for large WG integrations. The fast-response units in the paper assumed to have the ability to reach their maximum capacity in a short period. The inclusion of the hourly unit commitment is essential when considering the WG variations and ramping constraints. The paper considers the short-term thermal constraints and the volatility of wind units in the planning model and applies a decomposition model for utilizing the hourly unit commitment states. Random outages of generating units and transmission lines as well as load and wind speed forecast errors are modeled in scenarios using the Monte Carlo simulation. The Monte Carlo simplification methods are introduced to handle large-scale the stochastic expansion planning as a tradeoff between accuracy and calculation time. The proposed stochastic generation expansion planning approach would inherently form a large-scale optimization problem and a decomposition method is used to alleviate the calculation burdens. The application of mixed-integer programming (MIP) presents attractive features including a fast convergence, simplicity of the model, linearity of constraints, and the ability to handle large-scale problems [17]. The approach can be used by an ISO or a regulatory body to secure the optimal planning of fast-response units proposed by market participants while considering the large-scale WG integration. The contribution of the paper is to consider and utilize new fast-response generating units in power systems that would accommodate large WG integrations. The impact of WG dispersion (i.e., centralized or distributed) on the power system operation and planning is investigated. The planning problem, when considering the WG uncertainty, would present a large-scale problem with major computation burdens. Several improvements in decomposition and modeling are considered in this paper to make the proposed approach more practical.

Other alternatives such as the demand response and the application of storage systems may accommodate the WG uncertainty. However, such alternatives are usually available in small quantities as compared with large WG variations in power systems [18,19]. The application of responsive demands may incur additional investments on communication facilities between the supply and the demand [20].

The rest of this paper is organized as follows. Section 2 describes the modeling of uncertainties in the proposed model. Section 3 presents the framework and the decomposition procedure applied to the model. Section 4 provides a detailed formulation of the problem and the solution methodology. Section 5 presents and discusses the case studies for a six-bus system and the IEEE 118-bus system over a 10-year planning period. The conclusions drawn from the case studies are provided in Section 6.

2. Uncertainty in power system planning

The uncertainty can be categorized into (1) the participant level uncertainty which includes fuel availability and emission costs, discount rates, investment costs, competition, etc., and (2) the ISO level uncertainty which includes random component outages and load and wind forecast errors. The financial risks are usually included in the market participant portfolio optimization [21]. As this paper assumes that the investors have already submitted their expansion planning proposals to the ISO, the participant level uncertainty is not considered. Accordingly, the ISO's uncertainty is considered in scenarios to maintain the reliability index at an acceptable level. The ISO assumes the stochastic behavior of power systems corresponding to component outages and load and wind forecast errors by deploying an optimal level of generation reserves. The embedded expansion planning risk, assumed to be undertaken by the ISO, is modeled in Section 4 by adding the cost of imaginary units to the ISO's objective function.

The Monte Carlo (MC) simulation method is adopted to simulate random characteristics of power systems. The proposed stochastic planning model would consider multiple scenarios in the Monte Carlo simulation [23,24]. To address the uncertainty of WG, we assume the wind power is subject to a Weibull distribution. The detailed modeling of WG uncertainty with a Weibull distribution is provided in Refs. [13,22]. The Monte Carlo simulation will generate a large number of scenarios considering wind speed forecast errors. In each scenario, the hourly WG is considered to be given.

To consider random outages of generators and transmission lines, we use UX and UY vectors in the Monte Carlo simulation, which $UX_{iht} = 1$ indicates that the ith generator is available in year t and scheduling period h while $UX_{iht} = 0$ indicates otherwise. Likewise, $UY_{jht} = 1$ indicates that the jth transmission line is available in year t and scheduling period h while $UY_{jht} = 0$ indicates otherwise [23].

To consider load forecast errors, the annual peak load forecast is expressed as the base load times the annual growth rate. The annual growth rate consists of an average growth rate and a random component. Normally distributed random components are assumed to be added to the average growth rates in order to reflect an uncertain economic growth or weather changes in the load forecast [24]. The hourly load at each bus is then determined based on the annual system peak load using given load distribution factors.

Each scenario is assigned a probability of occurrence, PRs, that is one divided by the number of generated scenarios. The number of scenarios has a substantial impact on the computational requirements for solving scenario-based optimization models. Therefore, using an effective scenario reduction method could be very essential for solving large-scale systems [25]. The reduction technique is a scenario-based approximation with a smaller number of scenarios and a reasonably good approximation of original system. Therefore, we determine a subset of scenarios and a probability measure based on the subset that is the closest to the initial probability distribution in terms of probability metrics. The General Algebraic Modeling System (GAMS) is used in this study. GAMS provides a tool called SCENRED for scenario reduction and modeling random data processes. These scenario reduction algorithms provided by SCENRED determine a scenario subset (of prescribed cardinality or accuracy) and assign optimal probabilities to the preserved scenarios [26].

3. Planning model description

Fig. 1 depicts the proposed planning model. The Benders decomposition is used to decompose the planning problem into the optimal investment plan as master problem, and

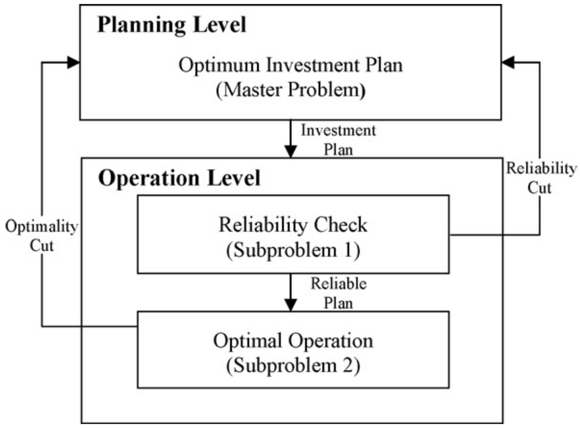

Fig. 1. The ISO's proposed planning framework.

the reliability and the optimal operation as two subproblems. The optimality of Benders decomposition as well as its applicability to power system problems is discussed in Refs. [27–30].

It is assumed that the level of wind integration is already known by the ISO. The large WG integration could aggravate the reliability of power systems if non-wind units cannot adequately support WG variations. The fast-response units are planned in this study to tackle such uncertainties. On the other hand, the emission associated with fast-response gas units may negatively contribute to the overall goal of WG expansion. Therefore, the proposed study would determine the optimal mix of generation which would also satisfy the system reliability.

In Fig. 1, the candidate set of fast-response generating units is provided to the ISO by market participants. Although, the ISO is not making any investment decisions, it would maintain the system reliability along with the minimum social cost (i.e., total operation and investment cost) to enhanced the market operation. The optimal investment plan of the new generating units is determined in the ISO's master problem. The objective of the master problem is to minimize the total investment cost of new generating units while considering the planning constraints. The planning constraints include capital investment funds, the maximum number of units, and the construction time of candidate units. The lower bound of the objective function is also obtained in the master problem and used further to check the optimality of the proposed plan. In addition to the planning constraints, the cuts generated in the subproblems are considered in the master problem. All binary variables are considered in the master problem and all constraints are linear. The master problem is a mixed-integer linear programming (MILP) problem. Commitment states are adjusted in the master problem through the cuts provided by reliability and optimal operation subproblems.

The reliability check subproblem examines the plan proposed by the master problem for the feasibility of system reliability constraints. This subproblem would satisfy the power balance in every bus while preserving the transmission security and physical constraints of generating units. In the case of feasibility violations, a reliability cut will be formed and added to the master problem for solving the next iteration of the planning problem. This iterative process will continue until a reliable plan is calculated. Once the system reliability is feasible, the optimal operation subproblem will consider the optimality of the proposed plan. The iterative process will continue until the given convergence criterion is satisfied.

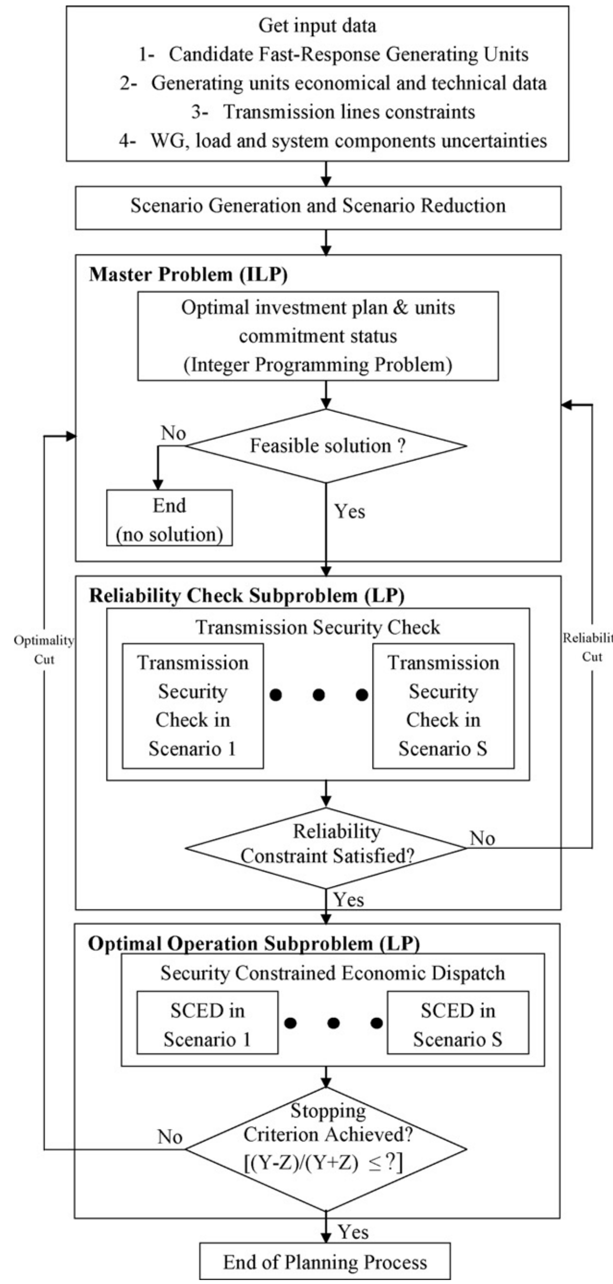

Fig. 2. Flowchart of the ISO's proposed planning problem.

4. Formulation and solution methodology

The ISO's proposed objective of security-constrained planning is to minimize the total cost of planning (1) while satisfying the planning and the operation constraints:

$$Y = \sum_{t=1}^{NT}\sum_{i=1}^{NG}\frac{PIC_{it}(GX_{it}-GX_{i(t-1)})}{(1+d)^{(t-1)}} + \sum_{s=1}^{NS}PR_s\sum_{t=1}^{NT}\sum_{h=1}^{NH}\sum_{i=1}^{NG}\frac{DT_{ht}PO_{iht}P_{ihts}}{(1+d)^{(t-1)}} \quad (1)$$

Fig. 2 depicts the flowchart of the decomposed planning problem. The solution steps are listed as follows:

Step 1 (scenario generation): We assume that the list of fast-response thermal units is provided by the participants as an input data to the ISO. The initial information provided to the ISO includes investment candidate units of individual participants, forced outages of generating units and transmission lines, as well as load and wind speed forecast errors. A set of scenarios is created using the Monte Carlo simulation. The stochastic long-term planning problem is inherently large. So, the scenario reduction is utilized to establish a tradeoff between the execution time and the accuracy of the long-term planning solution.

Step 2 (master problem): The proposed model consists of an MILP master problem and two LP subproblems. The master problem provides the optimal investment plan, while the subproblems provide the reliability check and the optimal market operation. The optimal investment plan is determined in the master problem, where the objective is to minimize the investment cost of new fast-response generating units (2).

Min Z

$$Z \geq \sum_{t=1}^{NT}\sum_{i=1}^{NG}\frac{PIC_{it}(GX_{it}-GX_{i(t-1)})}{(1+d)^{(t-1)}} \tag{2}$$

This objective is subject to planning constraints for new units, which include the construction time (3), the installation status (4), and the commitment state of such fast-response units (5):

$$GX_{it} = 0 \text{ if } t < CT_i \tag{3}$$

$$GX_{i(t-1)} \leq GX_{it} \tag{4}$$

$$I_{iht} \leq GX_{it} \tag{5}$$

The master problem solution consists of the optimal investment plan, commitment state of new units, and the lower bound of the planning objective function. At the first iteration there are no system constraints on commitment states of the units; so random values are assigned to these variables. However, in the subsequent iterations the Benders cuts from the reliability check and the optimal operation subproblems establish the constraints on the unit states. The proper initial values for *I* could reduce the solution time. If an infeasibility problem occurs (i.e., no solution is found in Fig. 2), the ISO would consider preventive actions including load curtailments or the additional incentives provided to participants for extra capacity expansions.

Step 3 (reliability check subproblem): After determining the optimal plan, $G\hat{X}_{it}$, and commitment states, $\hat{I}_{iht}$, of generating units in the master problem, the reliability check subproblem will minimize the system violations based on the master solution. Slack variables are considered in the power balance constraint, where the objective (6) is to minimize these slack variables. The objective function (6) is subject to nodal power balance constraint (7), generating unit installation status (8), commitment states (9) which are determined in the master problem, generating limits (10), DC power flow (11), transmission lines limits (12), and ramping constraints (13) and (14):

$$Min \quad W_{ts}^{r} = \sum_{h=1}^{NH}\sum_{b=1}^{NB}(SL_{bhts,1}^{r} + SL_{bhts,2}^{r}) \tag{6}$$

S.t.

$$P_{hbts} - \sum_{j\in J_b} PL_{jbts} + SL_{bhts,1} - SL_{bhts,2} = PD_{bhts} \tag{7}$$

$$GX_{its} = G\hat{X}_{it} \quad \lambda_{its} \tag{8}$$

$$I_{ihts} = \hat{I}_{iht} \quad \mu_{ihts} \tag{9}$$

$$P_{\min,i} I_{iht} UX_{ihts} \leq P_{ihts} \leq P_{\max,i} I_{iht} UX_{ihts} \tag{10}$$

$$PL_{jhts} - \frac{\theta_{jmhts}-\theta_{jnhts}}{x_j} = (1-U_{jhts})M \tag{11}$$

$$|PL_{jhts}| \leq PL_{\max,j} UY_{jhts} \tag{12}$$

$$\begin{aligned} P_{ihts} - P_{i(h-1)ts} &\leq [1 - I_{ihts}(1 - I_{i(h-1)ts})]RU_i \\ &\quad + I_{ihts}(1 - I_{i(h-1)ts})P_{\min,i} \end{aligned} \tag{13}$$

$$\begin{aligned} P_{i(h-1)ts} - P_{ihts} &\leq [1 - I_{i(h-1)ts}(1 - I_{ihts})]RD_i \\ &\quad + I_{i(h-1)ts}(1 - I_{ihts})P_{\min,i} \end{aligned} \tag{14}$$

The stochastic planning solution would satisfy the long-term reliability index, i.e., loss of energy probability (LOEP). A Benders cut at iteration *r* is generated and the corresponding reliability signal is sent to the master problem when the LOEP at hour *h* in year *t* is larger than the target LOEP. LOEP is applied as a constraint to limit the amount of unsupplied hourly load. The yearly sum would satisfy the annual LOEP. However, the benefit of using the hourly index is that it would prevent any large-scale load shedding at certain hours. The LOEP at hour *h* in year *t* is calculated by dividing the expected generation deficit, $SL_{bhts,1}^{r}$, in (6) by the expected load at hour *h* in year *t*. The reliability constraint in (15) would also enforce generation surplus, $SL_{bhts,2}^{r}$, to be zero. If either constraint in (15) is not satisfied, the Benders cut (16) will be generated:

$$\begin{cases} \sum_{h=1}^{NH}\sum_{b=1}^{NB} SL_{bhts,2}^{r} = 0 \\ \sum_{s=1}^{NS}\left(PR_s \sum_{b=1}^{NB} SL_{bhts,1}^{r}\right) / \sum_{s=1}^{NS}(PR_s L_{hts}) \leq \text{LOEP}_{ht} \end{cases} \tag{15}$$

$$\begin{aligned} &\sum_{s=1}^{NS}(PR_s W_{ts}^{r}) + \sum_{s=1}^{NS}\sum_{i=1}^{NG} PR_s \lambda_{its}(GX_{its} - G\hat{X}_{it}) \\ &+ \sum_{s=1}^{NS}\sum_{i=1}^{NG}\sum_{h=1}^{NH} PR_s \mu_{ihts}(I_{ihts} - \hat{I}_{iht}) \leq \sum_{s=1}^{NS}\sum_{h=1}^{NH} \text{LOEP}_{ht}\cdot PR_s \cdot L_{hts} \end{aligned} \tag{16}$$

The Benders cut (16) represents the coupled information on the existing unit commitment state and the candidate unit installation status. The cut indicates that the violation can be mitigated by readjusting the master's investment plan in year *t*.

Step 4 (optimal operation subproblem): The objective of the optimal operation subproblem is to maximize the social welfare based on submitted bids for generation and demand. The social welfare is defined as the difference between consumption payments, based on accepted bids, and production costs. Security-constrained economic dispatch (SCED) is utilized to model the optimal operation subproblem which checks the optimality of the proposed solution.

When the power demand is inelastic, the objective function is to minimize the system cost for the given investment plan and the unit commitment state (17). In some scenarios, generating unit and transmission line outages can cause solution infeasibility. To calculate the price in such cases, imaginary generating units (IMP) are assumed to supply the deficient energy at high prices as represented below. The energy supplied by the IMPs represents the expected unsupplied energy (EUE):

$$\begin{aligned} Min \quad V_s^q &= \sum_{t=1}^{NT}\sum_{h=1}^{NH}\sum_{i=1}^{NG}\frac{DT_{ht}PO_{iht}P_{ihts}}{(1+d)^{(t-1)}} \\ &+ \sum_{t=1}^{NT}\sum_{h=1}^{NH}\sum_{b=1}^{NB}\frac{DT_{ht}IMC_{bht}IMP_{bhts}}{(1+d)^{(t-1)}} \end{aligned} \tag{17}$$

S.t.

$$\sum_{i=1}^{NG}P_{ihbts} + \sum_{b=1}^{NB}IMP_{bhts} = \sum_{b=1}^{NB}PD_{bhts} \tag{18}$$

$$\mathbf{A}\cdot\mathbf{P} - \mathbf{B}\cdot\mathbf{PD} + \mathbf{IMP} \le \mathbf{K}\cdot\mathbf{PL} \tag{19}$$

$$0 \le IMP_{bhts} \quad \forall b \tag{20}$$

The optimal operation objective is subject to physical constraints, which are similar to the reliability check subproblem (8)–(14). The solution of this subproblem provides the upper bound of the objective function in the master problem. This upper bound is used to check the optimality of the solution. If the proposed plan is not optimal, the Benders cut (21) will be formed and added to the master problem for the next iteration.

$$\begin{aligned} Z \ge &\sum_{s=1}^{NS}PR_sV_s^q + \sum_{t=1}^{NT}\sum_{i=1}^{NG}\frac{PIC_{it}(GX_{its}-GX_{i(t-1)s})}{(1+d)^{(t-1)}} \\ &+ \sum_{s=1}^{NS}PR_s\sum_{t=1}^{NT}\sum_{i=1}^{NG}\lambda_{its}(GX_{its}-G\hat{X}_{it}) \\ &+ \sum_{s=1}^{NS}PR_s\sum_{t=1}^{NT}\sum_{h=1}^{NH}\sum_{i=1}^{NG}\mu_{ihts}(I_{ihts}-\hat{I}_{iht}) \end{aligned} \tag{21}$$

The important feature of the Benders decomposition is the availability of upper and lower bounds to the optimal solution at each iteration. These bounds are used as an effective convergence criterion. The convergence criterion is given as

$$\frac{Y-Z}{Y+Z} < \varepsilon \tag{22}$$

where ε is a small positive number which shows the predefined threshold to accept the solution as optimal.

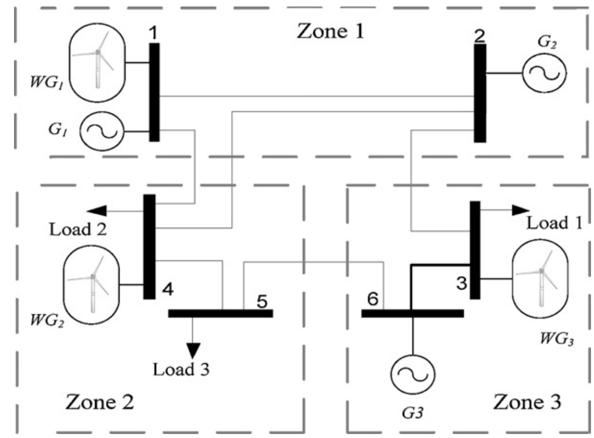

Fig. 3. Six-bus system.

Table 1
Existing generator data.

Generator	Capacity (MW)	Ramp up/down (MW/h)	Operating cost coefficient ($/MWh)
G_1	250	20	13.5
G_2	100	30	22.6
G_3	50	20	17.6

5. Numerical simulations

In this section, two case studies are presented. In Section 6.1, different aspects of centralized and distributed WG expansion are investigated.

Two case studies consisting of a six-bus system and the IEEE 118-bus system are analyzed to illustrate the performance of the proposed method. The model is implemented on a 2.4-GHz server with a 64 GB of memory with the CPLEX solver. Using the six-bus system, centralized and distributed WG expansions are discussed. The IEEE 118-bus system is selected to investigate the effect of transmission constraints on the proposed expansion planning model. This study will consider the planning of fast-response thermal generating units for a given level of WG integration.

5.1. Six-bus system

This system is shown in Fig. 3 [31]. Based on wind speed forecasts, three wind zones are defined in the system with the WG capacity factors of 47%, 39% and 32%, respectively. The capacity factor of a WG is the ratio of the actual available wind power generation over a given period (e.g., 1 year) to its output if it had operated at full nameplate capacity the entire time. A 10-year planning horizon is considered for this study. The system data are given in Tables 1 and 2. The base-case annual peak load forecast is listed in Table 3. This load is distributed with the ratio of 50%, 30% and 20% among buses 3, 4 and 5, respectively. It is assumed that the load has the same distribution factor in the

Table 2
Transmission line data.

Line number	From bus number	To bus number	Reactance (Ω)	Capacity (MW)
1	1	2	0.17	200
2	2	3	0.137	100
3	1	4	0.258	100
4	2	4	0.197	100
5	4	5	0.137	100
6	5	6	0.14	100
7	3	6	0.118	100

Table 3
Forecasted annual peak load of six-bus system.

Year	1	2	3	4	5	6	7	8	9	10
Peak load (MW)	256	262	269	276	283	290	297	304	312	320

Table 4
Candidate fast-response generating units in six-bus system.

Bus number	Capacity (MW)	Ramp up/down (MW/h)	Operating cost coefficient ($/MWh)	Investment cost (k$/MW)
1	30	30	18.3	1050
2	30	30	20.9	959
3	30	30	22.5	847
4	30	30	24.55	780.5
5	30	30	26.4	700
6	30	30	28.1	577.5

entire planning period. The annual peak load forecast is the base load (i.e., 256 MW) times the annual growth rate (i.e., 2.5% per year). The random component of the peak load and energy demand growth rate is assumed to have a normal distribution with a zero mean and standard deviation of 0.01. The hourly load distribution factor and the hourly wind generation forecast are provided in http://motor.ece.iit.edu/data/6bus_Hourly_Data.xls.

Table 4 shows the candidate generating unit data. The hourly cost of wind generation is negligible. The WG capacity is 120 MW which is centralized (i.e., Case 1) and distributed (Cases 2–4). Five cases are studied as follows:

Case 1: Planning with WG centered at bus 1.
Case 2: Planning with WG distributed at buses 1, 3 and 4.
Case 3: WG in Case 2 with the outage of line 5–6 in year 8.
Case 4: WG in Case 2 with the outage of unit 3 in year 8.
Case 5: WG in Case 2 with the simultaneous outages in Cases 3 and 4.

Case 1: In this case, the proposed WG capacity is aggregated at bus 1 located in zone 1 with the best wind speed pattern. In this case a 120 MW WG with a capacity factor of 47% is added in the first year of planning period at bus 1. The shortcoming of such a plan is that large wind speed variations at bus 1 may not be compensated by other generating units. The proposed method is used to find the results shown in Table 5. WG and the cheaper existing unit 1 are committed at all hours while the existing unit 2 is used at peak hours to satisfy the remaining load and minimize the operating cost. The total investment and operating costs are $178.15M while the operating cost is $73.75M. In this case, at the beginning, the candidate unit 1 is installed at bus 1 and the candidate unit 3 is introduced at bus 3 which is the system's largest load center. The other three candidate units in Table 5 are added in later years when the WG capacity and loads are increased. Another significant deficit of such centralized solution could be the lack of enough transmission access [32].

Case 2: We disaggregate the WG capacity in Case 1 to represent three WG units located at different zones as depicted in Fig. 3. Each WG has a capacity of 40 MW and the WG capacity factor in the two remote areas, i.e., zones 2 and 3, are less than that in zone 1 (i.e., site in Case 1). Table 6 shows the candidate unit installation year. Similar to Case 1, candidate units 2 and 3 are installed in years 5 and 1, respectively. However, the installation of candidate unit 1 at bus 1 is delayed until year 7. The average generation of WG_1 located at bus 1 is 9 MW (i.e., 22.5% of WG_1 capacity) while there is no congestion on lines 1 and 3. The reason the low-cost WG_1 is dispatched below its capacity factor in some periods is the system ramping constraint. Therefore, after the installation of the fast-response unit in year 7, the average generation of WG_1 increases to 17 MW (i.e., 42.5% of WG_1 capacity). This amount is less than WG_1 capacity factor (i.e., 47%), which is due to transmission and operating constraints (i.e., thermal generating units min generation limit, system ramping and min on/off constraints, etc.). Compared to Case 1, the total investment and operating costs decrease to $142.91M while the operating cost increases to $80.07M.

Table 5
Candidate fast-response unit installation year: Case 1.

Unit	1	2	3	4	5	6
Year	1	5	1	5	7	–

Table 6
Candidate generating units installation year: Case 2.

Unit	1	2	3	4	5	6
Year	7	5	1	–	–	–

In Case 2 the total WG utilization decreases by 24% as compared to Case 1, which is because of the lower capacity factor in zones 2 and 3. A lower WG utilization would result in the dispatch of more expensive thermal units and the increase in operating costs. If we could set the capacity factor of zones 2 and 3 to be the same as that in zone 1 (i.e., 47%) the operating cost would decrease to $71.95M. Fig. 4 depicts operation and investment costs as a function of WG capacity. The initial point in Fig. 4 is associated with the current level of WG penetration. Here, the operation cost would decrease as the investment cost on fast-response generating units increases. Based on social cost results, it is concluded that the optimal increase in WG capacity is 20% (i.e., it would result in the minimum social cost).

While zones 2 and 3 have lower WG capacity factors, the dispersion of WG in the three locations would cause a significant decrease in the total cost and a more utilization of available low-cost WG. The reason for such cost reductions is that the intermittency of WG in one zone may be compensated by available WGs in the other zones. Accordingly, a smaller fast-response generation capacity would be needed for reliability purposes.

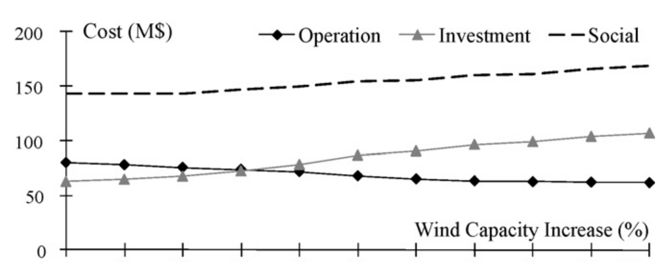

Fig. 4. System operation cost and fast-response unit investment cost vs. WG capacity.

Table 7
Candidate generating units installation year: Case 3.

Unit	1	2	3	4	5	6
Year	7	5	1	10	8	–

Table 8
Candidate generating units installation year: Case 4.

Unit	1	2	3	4	5	6
Year	7	5	1	8	–	–

Case 3: The outage of line 5–6 at the peak-load period in the year 8 is considered in this case. Similar to Case 2, the candidate generating units 3, 2 and 1 are installed in years 1, 5 and 7, respectively as shown in Table 7. In addition, as a preventive action, candidate units 5 and 4 are installed in years 8 and 10, respectively. The outage of line 5–6 decreases the transmission access between zones 2 and 3. Therefore, the addition of candidate units 4 and 5 would be necessary at zone 2. Compared to Case 2, the total cost has increased to $163.65M.

Case 4: The outage of unit 3 in the peak-load period in the year 8 would change the plan proposed in Case 2. New generating units 3, 2 and 1 are again added in years 1, 5 and 7, respectively as shown in Table 8. In addition, the installation of candidate unit 4 in year 8 is a preventive action to compensate the possible outage of unit 3. This preventive action increases the planning cost to $154.94M and the operating cost to $80.08M.

Table 9
Candidate generating units installation year: Case 5.

Unit	1	2	3	4	5	6
Year	7	7	1	8	8	–

Case 5: Simultaneous outages of line 5–6 and generating unit 3 at peak and off-peak periods in the year 8 are considered respectively. Similar to previous cases, the candidate unit 1 is installed in year 1. Candidate units 4 and 5 are installed in the year 8 as shown in Table 9 to compensate the system's possible outage. The total cost increases to $164.31M, which is the highest among all the cases, while the operating cost does not change significantly as compared to Cases 4 and 5.

5.2. IEEE 118-bus

A modified 118-bus system in Fig. 5 is used in this case. The test data and the single line diagram are provided in http://motor.ece.iit.edu/data/IEEE118bus_data_figure.xls. The system has 54 units, 186 branches, 14 capacitors, 9 tap-changing transformers, and 91 demand sides. The peak load of initial year is 3733 MW. The system is tested in a 10-year time horizon to

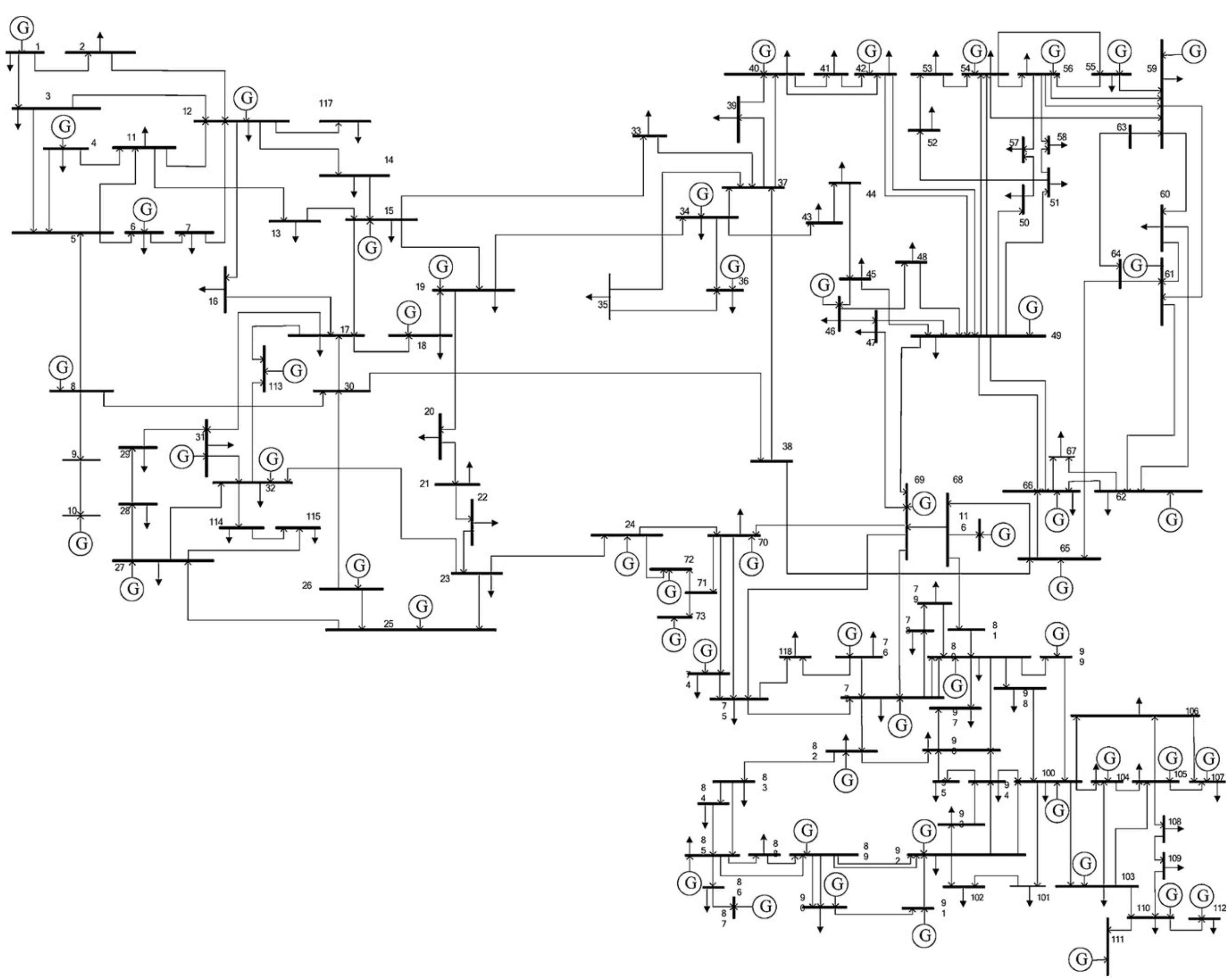

Fig. 5. One-line diagram of IEEE 118-bus system.

Table 10
WG data and network connection year.

WG	Bus number	Capacity (MW)	Wind capacity factor (%)	Network connection year
1	1	150	39	1
2	2	200	37	3
3	3	250	36	5
4	11	250	35	7
5	13	300	34	9

demonstrate the stochastic long-term planning solution. The average annual peak load growth rate is assumed to be 5%. The random component of the peak load and energy demand growth rate is assumed to have a normal distribution with a zero mean and standard deviation of 0.01. The discount rate is 10% which is used in the calculation of net present value of new generating units and the operating cost of existing units during the planning period. The convergence criterion ε is 0.1%. The planning period includes hours in which the WG variation is significant. The target LOEP is 5% at all hours. Five WGs are to be connected to the grid, which is based on the predefined schedule given in Table 10. The candidate fast-response generating unit data are presented in Table 11.

The low-discrepancy Monte Carlo simulation method is used to create 1000 scenarios, each representing possible component outages, load forecast errors, and wind speed volatilities. The computation time for the scenario-based problem depends on the number of scenarios. Therefore, using the scenario reduction method, the number of scenarios is reduced from 1000 to 10 as a tradeoff between the computation time and the solution accuracy. Table 12 shows the scenario weights after the reduction. We consider four test cases categorized into deterministic (Cases 1 and 2) and stochastic (Case 3 and 4) cases as follows.

Case 1: Transmission-constrained deterministic case.
Case 2: Deterministic case without transmission constraints.
Case 3: Transmission-constrained stochastic case.
Case 4: Stochastic case without transmission constraints.

Table 13 shows the installation year of candidate units. In Case 3, the candidate unit 5 is installed in year 5 to handle uncertainties. Compared to Case 1, the candidate generating units 2 and 9 are installed a year earlier in Case 3. Additional fast-response generating unit would have to be installed earlier in the stochastic cases (Cases 3 and 4) as compared to the deterministic cases (Cases 1 and 2). This is because of the random outages of generation units and transmission lines as well as load and wind forecast errors.

Table 14 shows the planning and operating costs in four cases. The costs in Case 3 are higher than those in Case 1 by $43.287M and $2.871M, respectively. The costs are higher when uncertainties are considered as additional generating units and transmission lines would be installed. The operating and planning costs could be decreased when transmission constraints are relaxed (Cases 2 and 4). Here, the system can handle more WG variations if a sufficient transmission access is available. Therefore, a coordinated generation-transmission planning would be necessary for a high integration of WG.

The CPU time is about 5 h for one scenario in Case 3 (i.e., the most computationally intensive case). Table 15 lists the computation time for different convergence criteria. With the possible short-cuts introduced in Section 6, the CPU time could be further reduced to less than 2 h.

Table 12
Weight of each scenario after scenario reduction (%).

Scenario	1	2	3	4	5	6	7	8	9	10
Weight	5.3	0.1	0.1	0.1	61.2	3.9	4.4	0.1	5.0	19.8

Table 13
Candidate unit installation year.

Unit number	1	2	3	4	5	6	7	8	9	10
Case 1	8	8	9	–	–	1	1	1	7	8
Case2	–	–	–	–	–	1	1	6	–	–
Case 3	8	7	9	–	5	1	1	1	6	8
Case 4	–	–	–	–	5	1	1	6	–	–

Table 14
Total planning and operating costs.

Case	Planning cost (billion$)	Operating cost (billion$)
Case 1	2.149	1.516
Case 2	1.834	1.489
Case 3	2.192	1.518
Case 4	1.877	1.490

Table 15
Computation time for one scenario in each iteration.

Convergence criterion value (%)	Computation time for one scenario (h)
0.001	5.41
0.01	5.29
0.05	5.21
0.1	4.93
10	4.57

6. Discussions and conclusions

A stochastic planning method is proposed for the fast-response generating units in power systems with large WG integrations. In this paper, we assume that market participants would individually submit their candidate list of units to the ISO. It is the responsibility of the ISO to determine which candidates would violate the system reliability by considering the power system constraints. In this

Table 11
Candidate fast-response generating units in 118-bus system.

Unit number	Bus number	Capacity (MW)	Ramp up/down (MW/h)	Operating cost coefficient ($/MWh)	Investment cost (Thousand $/MW)
1	35	100	100	17.5	1050
2	41	100	100	18	945
3	45	100	100	18.5	840
4	60	100	100	19.5	735
5	75	100	100	20	630
6	94	150	150	13.5	945
7	95	150	150	14.5	875
8	96	150	150	15.5	770
9	98	150	150	16	665
10	118	150	150	16.5	595

paper, the ISO does not make any investments. Rather it maintains the reliability of the system. Although, the proposed expansion model is for fast-response units, the same approach can be utilized for the capacity expansion planning of any kind of generating units or transmission lines. The Monte Carlo simulation and the scenario reduction techniques are applied for representing the random outages of generating units and transmission lines, and load and wind speed forecast errors. Scenarios would add a dimension to the planning problem that could make the large-scale expansion planning problem more complex and computationally impractical. Hence, the Benders decomposition is utilized for the decomposition of the problem into tractable easy-to-solve subproblems at each period.

The numerical experiments show that the fast-response units can improve the reliability of power systems in the case of large integration of volatile WG. The merits of proposed stochastic approach include the provision of reliable decision signals to planners and regulators on the long-term capacity expansion planning. It is also observed that the transmission access has a significant impact on the generation expansion especially when there is a large wind integration. The results show that a coordinated generation-transmission planning can significantly improve the WG integration.

A few short-cuts are introduced to speed up the solution. These short-cuts are listed as follows:

- Limit the hours under study: power systems may not face large wind variations on the hourly basis. Wind variations at many hours may also be compensated by the existing generation redispatch. So, we could select certain hours for analyses at which the incremental wind generation in two subsequent hours is larger than a percentage of the generation at the given hours. To ensure the capacity adequacy, the peak load hours are always added to the study.
- Limit the committable units: generating units may be classified as always ON, always OFF and committable units [33]. Intrinsically, peak loads will utilize Always OFF units and base loads utilize Always ON units. We determine the status of committable units by iterations between the master and the subproblems.

Appendix A. List of symbols

b	index of bus
t	index of planning year
h	index of subperiod
i	index of generating unit
j	index of transmission line
s	index of scenario
r,q	index of iteration number

Parameters and variables

CT_i	construction time of candidate unit i
d	discount rate
DT_{ht}	duration of subperiod h in year t, e.g., 1 h
Gx_{its}	installation status of generating unit i in year t and scenario s, 1 if installed, otherwise 0
I_{ihts}	commitment state of generating unit i in subperiod h of year t in scenario s, 1 means on and 0 means off
j_b	preserved set of branches connected to bus b
IMP_{bhts}	dispatched capacity of imaginary unit at bus b in subperiod h of year t in scenario s
IMC_{bht}	cost of imaginary unit at bus b in subperiod h of year t
L_{hts}	load in subperiod h of year t in scenario s
LOEP	target LOEP, reliability criterion
NB	number of buses
NT	number of years
NG	number of generating units
NH	number of subperiods
NS	number of scenarios
PIC_{it}	investment cost of unit i at year t
PD_{bhts}	load at bus b in subperiod h at year t in scenario s
PR_s	probability of scenario s
PL_{jhts}	real power flow of transmission line j in subperiod h of year t in scenario s
P_{ihts}	generation dispatch of unit i in subperiod h of year t in scenario s
PO_i	operating cost of generating unit i
RU_i, RD_i	ramping up/down limit of unit i
SL^r_{bhts}	slack variable for bus b in subperiod h of year t in scenario s
UY_{jhts}	transmission lines availability status of transmission line j subperiod h of year t in scenario s, 0 if in outage, otherwise 1
UX_{ihts}	generators availability status of unit i in subperiod h of year t in scenario s, 0 if in outage, otherwise 1

Matrices and vectors

A	bus-unit incidence matrix
B	bus-load incidence matrix
IMP	dispatched capacity of imaginary unit vector
K	bus-branch incidence matrix
P	real power output vector
PD	load vector

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