Turkish Journal of Electrical Engineering & Computer Sciences

http://journals.tubitak.gov.tr/elektrik/

Research Article

Turk J Elec Eng & Comp Sci
(2014) 22: 909 – 923

doi:10.3906/elk-1202-57

Reliability-based generation resource planning in electricity markets

Maziar Mirhosseini MOGHADDAM[1,*], **Mohammad Hossein JAVIDI**[2], **Mohsen Parsa MOGHADDAM**[3], **Majid Oloomi BUYGI**[2]

[1]Department of Electrical Engineering, Lahijan Branch, Islamic Azad University, Lahijan, Guilan, Iran
[2]Department of Electrical Engineering, Ferdowsi University of Mashhad, Mashhad, Iran
[3]Department of Electrical Engineering, Tarbiat Modares University, Tehran, Iran

Received: 13.02.2012 • **Accepted:** 19.01.2013 • **Published Online:** 17.06.2014 • **Printed:** 16.07.2014

Abstract: This paper proposes a reliability-based competitive generation resource planning model in electricity markets. The Monte Carlo simulation method is applied to consider random outages of generation units and transmission lines as well as load uncertainty. In order to determine the optimal plan for installation of candidate generating units, the decisions of generation companies (GenCos) and the independent system operators (ISOs) are investigated. The method is based on an iterative process for simulating interactivity among ISOs and GenCos and is repeated until security and reliability constraints assumed by the ISO are fulfilled. In the proposed model, the ISO utilizes a new mechanism for capacity payments such that each GenCo will receive its incentive credits based on its role in improvement of system reliability. In other words, GenCos play indirect roles in system reliability enhancement. Simulation results confirm efficacy of the proposed generation expansion planning model when considering uncertainties in electricity markets.

Key words: Competitive electricity market, generation resource planning, mixed integer programming, Monte Carlo simulation, random outages and uncertainty, system reliability

1. Introduction

Generation expansion planning (GEP) has historically addressed the problem of identifying technology as well as optimal size for generating units, sites, and the period when new capacities should be constructed to ensure installed generation capacity would adequately meet scheduled demand growth.

In conventional capacity planning algorithms for new generation resources, the lowest cost of operation and fulfillment of a pre-specified system reliability level are the major purposes of the utility [1–3]. On the other hand, in competitive electricity markets the objective of generation companies (GenCos) in generation resource planning is to maximize total expected profit over a planning horizon. In contrast with GenCo objectives, market operators or independent system operators (ISOs) are responsible for satisfying system adequacy and reliability requirements. The coordination of the 2 different objectives is essential in generation resource planning. However, achieving an equilibrium point such that GenCo profits are maximized and the reliability of the system is maintained with an acceptable cost may become complicated.

The problem of generation resource planning in competitive electricity markets has been investigated in many studies. Optimization techniques applied to the problem of generation expansion planning such as expert systems, fuzzy logic, neural networks, analytic hierarchy process, network flow, the decomposition method, simulated annealing, and genetic algorithms were discussed in [4], and the merits and demerits of each of

*Correspondence: m.mirhosseini@liau.ac.ir

technique were examined. A noncooperative game theoretic model for generation expansion planning that used a Cournot model of oligopoly behavior was presented in [5]. This work mainly focused on GEP in a pool-dominated electricity market. Fu et al. in [6] proposed an optimal generation resource planning approach considering the security network for modeling the interaction between single a GenCo and the ISO. However, the competition among GenCos was not considered. Buygi et al. proposed a market-based transmission expansion planning approach that facilitates market competition by enabling a flat price profile throughout the transmission network [7]. The flatness of locational price, which means lack of congestion, was taken as the proper criterion for measuring the degree of competitiveness of the transmission network. To determine the optimal investment in new generation in both centralized and decentralized environments, Botterud et al. presented optimal investment planning that incorporates uncertainties in demand and future electricity prices [8]. This approach used stochastic dynamic optimization. A security-based competitive generation resource planning model was proposed in [9] such that the impact of transmission security is incorporated in a multi-GenCo framework. The solution approach is based on Lagrangian relaxation and Benders decomposition techniques. Kaymaz et al. [10] modeled the GEP as a Cournot competition game to study the interaction between competition and transmission congestion in power generation expansion. In [11], an interrelated tri-level optimization model was utilized to achieve optimum decisions in expansion in the generation of the generation capacity and transmission network. In [12], a stochastic multiobjective optimization framework was presented for transmission expansion planning with steady-state voltage security management using AC optimal power flow.

In this paper a new model for generation expansion planning in a competitive market environment is presented. In this model, forced outages of generation units and transmission lines as well as load uncertainties are taken into account. The Monte Carlo simulation method is used to analyze uncertainties related to long-term resource planning. In the proposed model, an iterative process between GenCo and ISO is utilized such that GenCos are competing to maximize their profits. Then the ISO receives the results of GenCo expansion plans and sends corrective signals to GenCos in order to manage system security and reliability. This process is repeated until the security and reliability constraints defined by the ISO are fulfilled.

Different mechanisms and models have been used to design and implement electricity markets. Pool-Co is one of the straightforward structures for implementation of competitive electric markets [13]. In this model, each GenCo offers its bid and corresponding generation quantity to the ISO. The ISO then schedules the generation and computes the spot market prices [14]. Competition among GenCos is simulated by nodal prices or locational marginal prices (LMPs), which are calculated by the ISO and introduced into the investment decisions of each GenCo. LMPs for a given operating point are obtained via optimal power flow (OPF). LMPs are the Lagrange multipliers or shadow prices of the DC power flow constraints.

In this paper a Pool-Co market structure is adopted; outage probability of generating units and transmission lines, modeling inaccuracies in long-term load forecasting, and bid prices of generation units are considered, and probability distribution function of LMPs is computed for peak load of planning horizon using Monte Carlo simulation. Then the mean of the LMPs is given to GenCos to be considered in generation resources planning.

In electricity markets the ISO is responsible for the security of system operations. The responsibility would include coordination between capacity expansion and network security constraints. The ISO role in resource planning is assumed to be limited to ensure that capacity expansion plans do not endanger system reliability.

In this paper it is assumed that the ISO has a proper incentive mechanism to encourage GenCos to invest in those locations where investment results in reducing the total risk to the system. Using this incentive mechanism increases the total reliability of the system and can also supplement generator incomes in a competitive market. This capacity revenue allows a regulatory body or the ISO to set prices at acceptable levels and yet motivates generators to make proper investment decisions.

The paper is organized as follows. Section 2 describes the proposed model and solution methodology. Section 3 provides formulation of planning problems in detail. Section 4 presents case studies from a 6-bus system over a 10-year planning period. The conclusions drawn from the study are provided in section 5.

2. Model overview

The process of resource capacity planning, as shown in Figure 1, is composed of 3 subproblems including: the planning problem for GenCos, the problem of optimal operation for ISOs, and reliability assessment. GenCos receive revised signals of reliability and price from loops responsible for calculating system reliability and energy price.

In this process, the ISO calculates the values of LMPs for different years in the planning horizon by considering available units and forecasted future load, and then future predicted prices are conveyed to investors. Investors propose their optimum plans based on the prices given. Consequently, the ISO declares new energy prices or LMPs correlated to proposed expansion plans within the planning horizon. Finally, investors amend their plans based on final proposed new prices and send them to the ISO again. This repetitive process continues unless investor plans remain unchanged in 2 repetitions of the cycle.

In order to calculate prices, the load duration curve (LDC) for various years is estimated by the ISO. This curve is divided into some constant load levels. In these calculations uncertainties in various parts of the LDC are taken into account. Bid prices of generation units determine probability density functions of bid prices of generating units. The ISO estimates these functions considering prior information from generating units, generation expansion plans, and the existing status of the network. In addition, the probability density functions of bid prices of new units are estimated for different parts of the LDC in various years of the planning horizon by considering their technology, positions in the network, and generation expansion plans.

If generation expansion plans are less than the demanded capacity for network adequacy during planning, the ISO will estimate a bid probability density function with a greater average value resulting in market price growth. Higher prices can provide a proper incentive for investors to expand their plans in the next cycle of the proposal amendment process, which can, in turn, fulfill adequacy of the network capacity. In contrast, if the generation plans exceed network adequacy, the ISO will estimate a bid probability density function with a lower average value, which means a lower market price. As a result, in planning the amendment process investors will withdraw low-profit plans.

The proposed formulation also considers uncertainties related to optimal operation and reliability. As shown in Figure 1, the analysis process in Monte Carlo produces a set of scenarios based on outage probability of generating units, transmission lines, and load uncertainty. All scenarios are assumed to have equal probabilities sampled from a set of independent and identical distributed random variables. It is also assumed that the outage characteristics for all units and lines and capacity of candidate units are identified by the ISO. The proposed model assumes that the ISO compensates part of the cost of expected energy not supplied (EENS) for the system through a capacity payment to encourage GenCos to invest in places where investment will result in reduction of system risk.

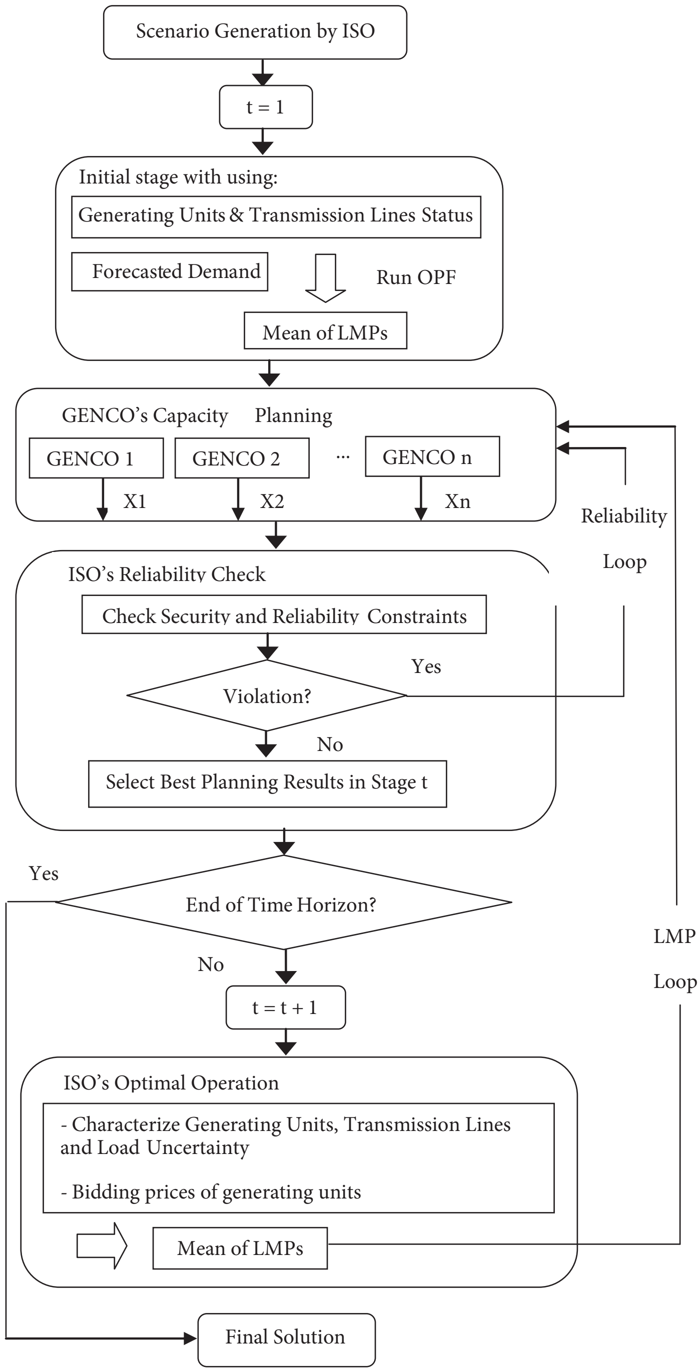

Figure 1. Proposed structure for generation capacity expansion planning.

3. Problem formulation

The generation capacity planning algorithm consists of 3 subproblems (Figure 1). These subproblems include: the GenCo planning problem, ISO reliability assessment, and ISO optimal operation problem.

3.1. Formulation of GENCO planning

Under the market competitive environment the GEP problem is maximization of total expected profit over the planning horizon for each GenCo while satisfying system adequacy constraints. An economic discount rate is used to convert revenues and expenses occurring at different times to their equivalent values at a common reference time (net present value). In this paper the discount rate is assumed to be equal for all GenCos. The optimum decision problem for GenCo h is formulated as follows:

$$\begin{aligned} Max\ \ PF_h = \ \ & [\sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{i\in EGh} DT_d \times (\lambda_{ihdt}\times P_{EG,ihdt} - OC_{ihdt}) \times \tfrac{1}{(1+r)^{t-1}} \\ & + \sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{j\in CGh} DT_d \times (\lambda_{jhdt}\times P_{CG,jhdt} - OC_{jhdt}) \times \frac{X_{jht}}{(1+r)^{t-1}} \\ & - \sum_{t=1}^{T}\sum_{j\in CGh} IC_{jht} \ \times \frac{X_{jht}}{(1+r)^{t-1}} \\ & + \sum_{t=1}^{T}\sum_{d=1}^{Nd}\sum_{j\in CGh} DT_d \times [DEPNS_{jhdt} \times (UEC - \lambda_{jhdt}) \ \times X_{jht}] \end{aligned} \tag{1}$$

where

$$DEPNS_{jhdt} = EPNS_{-jhdt} - EPNS_{jhdt} \tag{2}$$

S.t.

$$ICAP_{jht} = \max\left(\sum_{d=1}^{N_d} P_{CG,jhdt} \times X_{jht}\right) \qquad \forall j\ \ \forall t \tag{3}$$

$$\sum_{j\in CGh} ICAP_{jht} \le MCI_{ht} \qquad \forall t \tag{4}$$

$$\sum_{j\in CGh} IC_{jht} \times X_{jht} \le UCI_{ht} \qquad \forall t \tag{5}$$

$$TICAP_{h,t} = TICAP_{h,t-1} + \sum_{j\in CGh} ICAP_{jht} \qquad \forall t \tag{6}$$

$$0 \le P_{EG,ihdt} \le P_{EG,ih}^{\max} \qquad \forall d\ \ \forall t \tag{7}$$

$$0 \le P_{CG,jhdt} \le P_{CG,jh}^{\max} \qquad \forall d\ \ \forall t \tag{8}$$

The objective function of the problem is presented as the sum of 4 terms in Eq. (1), in which the first 2 terms are the present value of operating profit of existing and candidate units, respectively. Energy prices of existing and candidate units are obtained from the optimal operation subproblem in section 3.3. The third term represents the present value of the annual investment cost for candidate units, and the capacity payment paid to each candidate unit by the ISO for its contribution to system reliability is indicated by the fourth term. To calculate the operating profits of GenCos, LDC is estimated for each year over the planning horizon, and each curve is divided into multiple constant-load blocks.

In this formulation, T and *Nd* are the number of planning years and subperiods in LDC. The duration of step d in LDC is DT_d, and i and j are indexes for existing and candidate generating units, respectively. *EGh* and CGh are sets of existing and candidate units of GenCo h in year t, respectively. P_{EG} and P_{CG} represent the amount of dispatched capacity of existing and candidate units, respectively, λ represents mean of nodal energy price, and r represents economic discount rate. The mean of nodal energy prices for the existing and candidate units are determined by considering network component outages as well as uncertainty in load and bidding prices of the GenCos in each year of the planning horizon. Furthermore, generating operation cost and annual generation investment cost are represented by OC and IC in the planning horizon, respectively. The decision variable of X is a binary variable that shows installation status of candidate units of different GenCos in each planning year. Values 1 and 0 are the installed and uninstalled values, respectively. UEC is cost of the expected unserved energy. For the purpose of long-term price forecasting, this cost will not be the same as the value of lost load (VOLL), because the duration of load blocks is too long to use VOLL. If VOLL is used as the cost of expected energy not supplied (EENS), it may result in very high prices over long periods and potentially overestimate GenCo expected revenues [15]. Hence, it is appropriate to use a value smaller than VOLL: UEC. Referring to Eq. (2), DEPNS represents the impact of each candidate unit on reduction of EPNS of the system. In this equation the amount of EPNS before installation of each candidate unit ($EPNS_{-jhdt}$) is subtracted from its amount after installation of the candidate unit ($EPNS_{jhdt}$). The amount of EENS at each stage is equal to EPNS multiplied by duration of load block. The EPNS value is obtained from the optimal operation subproblem in section 3.3.

Every GenCo operates independently to maximize its own profit, and there are no coupling constraints among GenCos and the investment problem. Therefore, generation expansion planning is decomposed into several mixed-integer programs. Constraint (3) shows the amount of installed capacity (ICAP) of each candidate unit in year t. Constraint (4) expresses the maximum installed capacity for the GenCos (MCI) in each planning year. This restriction is imposed on GenCos by the ISO to prevent market power. Constraint (5) defines the investment budget limitations related to each GenCo. UCI is the maximum value specified for the capital investment of the GenCos in each planning year. Constraint (6) preserves the installation status of generation units of each GenCo. TICAP is the total installed capacity in each planning year. Constraints (7) and (8) are capacity limits for the existing and candidate generation units, respectively.

3.2. ISO reliability check subproblem

When the GenCos have specified their generation investment plans, the plans are sent to the ISO to check for violations in the security and reliability constraints of the system in any year of the planning horizon. The constraints that are checked by the ISO include reserve margins and the level of expected energy not supplied. The details of these constraints are described as below.

The reserve margin level of generation in the system corresponding to peak loads in year t, can be performed using (9). In this relation, $MR_t^{\min} MR_{\min}^t$ and MR_t^{max} are the percentages of the minimum and maximum reserve margins in year t, respectively, and D_t is average peak of the load. NG is the number of GenCos, and the value of subscript index d is equal to 1, which indicates the first part of LDC. This means that during computing the reserve margin in each year of the planning horizon, the peak annual demand is considered:

$$\left(1 + MR_t^{\min}\right) \times D_t \leq \sum_{h=1}^{NG} \left(\sum_{j \in EGh} P_{EG,idht} + \sum_{j \in CGh} P_{CG,jdht} \right) \leq \left(1 + MR_t^{\max}\right) \times D_t \;\; \forall t \;, \quad d = 1 \tag{9}$$

Constraint (10) is used to investigate the level of system risk in which $EENS_t^{max}$ represents the maximum of

EENS in year t which admits the nonserved load due to outages of generating units:

$$EENS_{dt} \leq EENS_t^{\max} \qquad \forall t \quad \forall d \tag{10}$$

In the planning algorithm, equivalent LDC is calculated considering proposed GenCo plans for installation and their outage probabilities. With respect to this, the EENS value is calculated.

If there is at least one violated constraint, energy prices will increase by a specific level and will be sent to the GenCos as a corrective signal for plan revisions. This strategy represents the typical behavior of a power market where, in the case of any existing limitation on available resources with respect to demand, bid prices of generating units tend to rise. Consequently, nodal energy prices (LMPs) grow in the market environment. This iterative process between GenCos and the ISO continues until all constraints by the ISO are fulfilled.

3.3. ISO optimal operation subproblem

This subproblem is performed by the ISO to determine energy prices (LMPs) for the GenCos. In each planning year the mean of LMPs at different buses are computed during peak load for various scenarios obtained from outages of generating units and transmission lines as well as load uncertainty. By considering the given standard deviation, bid price for each existing and candidate unit is defined as a specific normal distribution function such that the minimum obtained value from this normal distribution, with error probability $<0.1\%$, is more than the operation cost of the unit. The objective of the optimal power flow (OPF) problem is to minimize the total cost of operation, which includes the cost of running generating units and load curtailment costs based on the submitted bids for generation and demand [9]. Furthermore, assuming inelastic demand, the objective function is generation cost minimization equal to the maximization of social welfare. Solution of the optimum exploitation in year t for each bidding strategy in generating units and assumed scenarios s can be performed by running the DC OPF below:

$$Min \quad HSC(\mathbf{P}_G, \mathbf{P}_D) = \mathbf{C}_G^T \mathbf{P}_G - \mathbf{C}_D^T \mathbf{P}_D \tag{11}$$

S.t.

$$\mathbf{B}_s \delta_s = \mathbf{P}_{G,s} - \mathbf{P}_{D,s} \qquad \forall s \tag{12}$$

$$-\mathbf{P}_l^{\max} \leq \mathbf{H}_s \delta_s \leq \mathbf{P}_l^{\max} \qquad \forall s \tag{13}$$

$$\mathbf{P}_{G,s}^{\min} \leq \mathbf{P}_{G,s} \leq \mathbf{P}_{G,s}^{\max} \qquad \forall s \tag{14}$$

$$\mathbf{P}_{D,s}^{\min} \leq \mathbf{P}_{D,s} \leq \mathbf{P}_{D,s}^{\max} \qquad \forall s \tag{15}$$

In this problem, the capacities of the existing and candidate units dispatched in the vector of power generations are decision variables. The objective function (11) minimizes the hourly social cost (HSC). The first term of the objective function represents the cost needed to operate generators, which is calculated by multiplying vector of generator bids ($\mathbf{C_G}$) by vector of active power generations ($\mathbf{P_G}$). The second term of (11) represents the load curtailment cost, which is calculated by multiplying vector of load bids ($\mathbf{C_D}$) by vector of active loads ($\mathbf{P_D}$). Constraint (12) shows the DC optimal power flow equations. In each scenario s, $\mathbf{B}_s$ and δ_s represent linearized Jacobian matrix and vector of bus angles, respectively. $\mathbf{P}_{\mathbf{G},s}$ and $\mathbf{P}_{\mathbf{D},s}$ stand for vector of active power generations and active loads, respectively, in assumed scenario s. Constraint (13) represents the line flow limits of the network. $\mathbf{H}_s$ represents matrix of linearized line flows in assumed scenario s. $\mathbf{P}_\mathbf{l}^\mathbf{max}$ is vector of line limits. Constraints (14) and (15) show generation limits and load limits, respectively.

To calculate amount of EPNS in each load block, it is assumed that each load can be modeled with a fix load, which is never curtailed, and an imaginary generator. Loads will be curtailed if the re-dispatch of real generation cannot eliminate transmission overload. Then the amount of power dispatched by an imaginary generator is equal to amount of load curtailed and EPNS.

Case studies

The 6-bus system shown in Figure 2 is used to analyze the effectiveness of the proposed model. The algorithm is applied to the system for a 10-year planning horizon to show the effectiveness of the proposed model. Generator data, transmission line data, and load forecasts over the planning horizon are shown in Tables A.1–A.4 in Appendix A. GenCo A has 3 existing units and 5 candidate units. GenCo B has 1 existing unit and 8 candidate units. The candidate-generating units have differences based on their locations, operating costs, investment costs, and forced outages rates. Hence, these factors will affect investment decisions over the planning horizon. The loads are located at buses 3, 4, and 5.

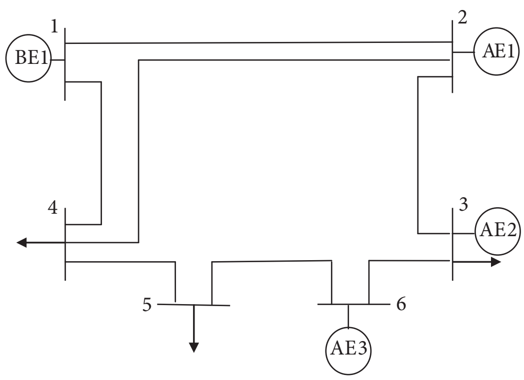

Figure 2. Diagram of 6-bus system.

Two thousand random scenarios are generated using a Monte Carlo simulation where each scenario represents outages status of generating units and transmission lines. The peak demand at the initial year is 25 MW, and the average peak-load growth rate is 5% per year. The uncertainty in the forecasted peak load is assumed to be presented by the 7-stepped normal distribution shown in Figure 3, where class intervals in the distribution have probabilities of $p_{-3} = 0.006$, $p_{-2} = 0.061$, $p_{-1} = 0.242$, $p_0 = 0.382$, $p_{+1} = 0.242$, $p_{+2} = 0.061$, and $p_{+3} = 0.006$. The standard deviation of this distribution is assumed to be 1% of the forecast peak load. The modified load duration curve is shown in Figure 4. The discount rate is assumed to be equal to 5%. In each year it is assumed that the accepted reserve margin level is 10%–40% of average of peak load, and the maximum acceptable EENS is 1% of the average peak load of the system. It is also assumed that the capacity that can be installed by each GenCo should not exceed 50% of the total capacity of candidate units during each planning year. The maximum value specified for the capital investment of each GenCo is equal to the investment costs of the most expensive unit in each planning year. Moreover, it is supposed that UEC is equal to 250\$/MWh. Bid prices of the existing and candidate units are assumed to have normal distribution functions with the unit standard deviation. According to the characteristics of normal distribution function, in order to have pragmatic random bid prices greater than operating costs of the units, the average amount of bid price function should be 6.6$/MWh more than the operating costs of generating units. One thousand scenarios are generated by using the defined bid prices of generating units. In system simulation, for each scenario that is determined from bid prices of generating units, the total scenario determined from uncertainty of network components is considered. The bid prices are listed in Table A.4 in Appendix A.

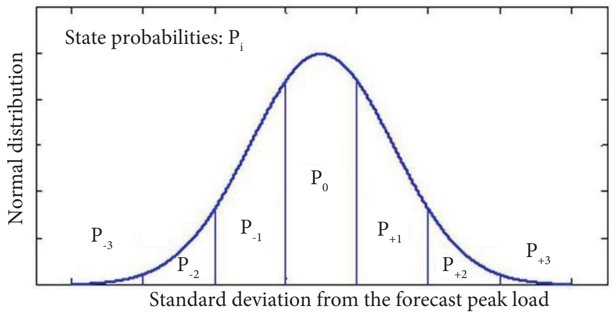

Figure 3. Seven-step approximation of the normal distribution.

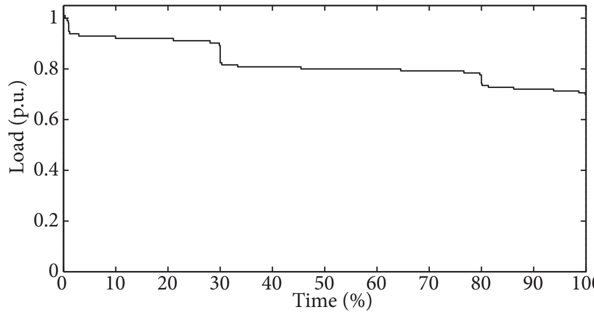

Figure 4. Modified load duration curve with 1% uncertainty.

The general algebraic modeling system (GAMS) and MATLAB are both applicable programs for solving optimization problems. In order to optimize the generating resource planning, the existing link between GAMS and MATLAB software has been utilized [16]. Simulations of GenCo planning optimization and the reliability check were performed in GAMS, and the optimal operation subproblem was simulated in MATLAB.

The 4 test cases shown in Table 1 are investigated. Case 1 is a deterministic case, and cases 2, 3, and 4 are stochastic ones. In case 2, generation expansion planning is considered without any changes in transmission capacity. In case 3, it is assumed that the capacity of line 2–3, which is congested during planning, is increased from 7 MW to 14 MW in order to examine its impact on congestion mitigation. In case 4, the impact of EENS cost changes on case 2 is examined. In this case the cost of EENS was changed from 250$/MWh to 400$/MWh.

Table 1. Candidate unit installation status over 10-year planning horizon.

Year	Case 1	Case 2	Case 3	Case 4
1	-	B2	B8	B2, B4
2	-	B8	A4	
3	B2, B8	-		B8
4	-	B4	B4	
5	-	-		
6	B4	B1		B1
7	-	B3	A5	
8	B1	-		A5
9	A5	-	B2	
10	-	-		B7

Table 1 shows the results of candidate unit installation in case 1, in which generating units B8 and B2, which have small capacity and low investment costs, are installed in planning year 3. The main reason for installation of these units is to maintain the reserve margin within the permitted levels considering capacity payments. Generating units B4, B1, and A5 with capacity of 3 MW are installed in later planning years. These units are installed according to their operating and investment costs to minimize the social cost and maintain the minimum reserve margin level.

In case 2, generation resources planning is determined by considering the outages of generating units and transmission lines together with uncertainty of load along the planning horizon. Table 1 shows that generating units B2 and B8 are installed in planning years 1 and 3, respectively, due to the capacity payment by the ISO and price level changes. In addition, the B4, B1, and B3 generating units are installed in later planning years. These results illustrate that in case 2 some changes in installation status of generating units helped to achieve the assumed constraints of reliability defined by the ISO. Candidate generation units B4 and B1 are installed sooner in comparison with case 1, in which network uncertainties are not considered. On the other hand, generating unit B3 (5 MW) is replaced with A5 and is installed in planning year 7. Among 5 MW generating units B3 has greater investment costs than B7. However, as it has an effective role in network risk reduction, it received a larger capacity payment from the ISO and was installed instead of B7, as shown in Table 2.

Table 2. The capacity payments offered to candidate generating units in GenCos A and B by the ISO in each planning year (in thousands of dollars).

	ID	Yr1	Yr2	Yr3	Yr4	Yr5	Yr6	Yr7	Yr8	Yr9	Yr10
A	A1	746.8	819.1	457.7	626.3	409.5	698.6	361.2	264.9	337.2	554.1
	A2	657.5	770.8	385.4	578.2	337.3	674.5	313.5	264.9	216.8	505.9
	A3	650.4	770.8	192.7	505.9	433.6	626.3	457.7	264.9	216.8	819.1
	A4	385.4	722.7	144.5	385.4	337.3	385.4	264.9	264.9	144.5	554.1
	A5	626.3	819.1	505.9	626.3	457.7	891.3	650.4	264.9	313.2	674.5
B	B1	987.7	794.9	216.8	481.8	794.9	819.1	0	0	0	0
	B2	534.9	0	0	0	0	0	0	0	0	0
	B3	1012	963.6	891.3	1012	794.9	915.4	1036	0	0	0
	B4	987.7	843.1	433.6	794.9	0	0	0	0	0	0
	B5	1180	1084	409.5	867.2	794.9	1060	409.5	264.9	264.9	843.1
	B6	1060	1060	361.3	602.2	457.7	987.6	323.2	264.9	216.8	770.8
	B7	915.4	939.5	204.9	578.2	337.3	819.1	313.2	264.9	192.7	722.7
	B8	505.9	514.1	0	0	0	0	0	0	0	0

Table 2 shows the capacity payment offered by the ISO to each candidate unit according to their share in system EENS reduction in case 2 over the planning horizon. When a candidate unit is installed in year t, incentives will not be paid to them in year $t + 1$ by the ISO.

Figure 5 shows the changes in transmitted flow through the lines during the planning horizon in case 2. During the planning horizon transmission line T2 is always congested and lines T3 and T6 are gradually becoming congested. Candidate generating unit installation B3 mitigates the congestion level in line T6. The capacity of the lines in this condition is 7 MW.

In case 3 it is supposed that the capacity of line T2 has increased from 7 MW to 14 MW. By increasing the capacity of line T2, the amount of total energy not supplied during the planning horizon will decrease from 38.6 MWh to 34.64 MWh. Table 1 represents unit installation status in case 3. Enhancement of transmission capacity and congestion mitigation in line T2 resulted in access to generating units B8 and A4, which have a lower social price due to investment and operation costs in the initial years. In later years, units B4, A5, and B2 are installed to minimize social cost and maintain reliability constraints within admissible levels. Changes proposed in the following years are due to a modified power dispatch, compared with case 2.

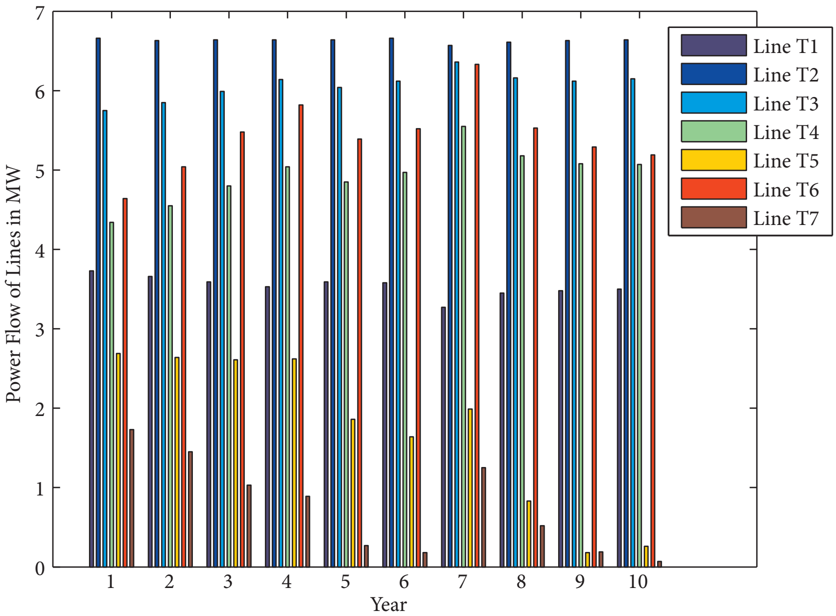

Figure 5. Power flow of transmission lines over the planning horizon.

Figure 6 shows a comparison among mean values of LMP changes at bus 3 for cases 1, 2, and 3. Mean LMP change in case 1, where uncertainties are not considered, has low values in primary years; in later years to maintain the reserve margin at its allowed level, energy prices increase. This has also resulted in the installation of low-social-cost candidate units. The ISO tendency to maintain the risk of the system considering component outages in cases 2 and 3 could lead to the operation of more expensive units and an increase in energy prices over the planning horizon. The lower price level in case 3 compared with case 2 is due to mitigation of congestion in line T2.

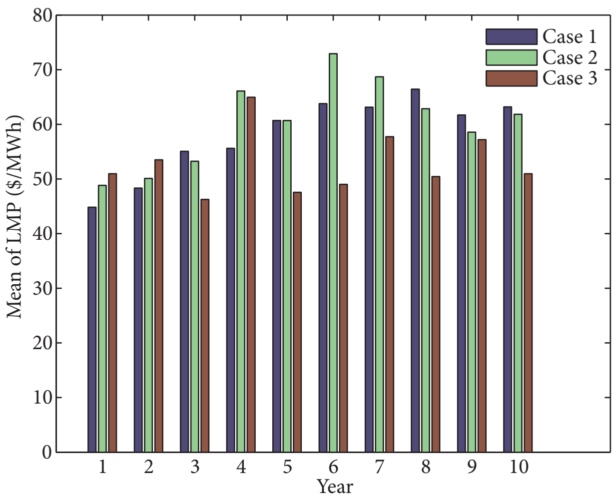

Figure 6. Mean of LMP at bus 3 over the planning horizon.

In case 4 the impact of EENS cost change from 250$/MWh to 400$/MWh on candidate unit installation status is investigated. Change in the EENS cost affects capacity payment value. Increasing the amount of capacity payment offered by the ISO encourages GenCos to invest in network capacity enhancement. A comparison between the results of cases 4 and 2 shows that generating unit B4 is installed in planning year 1 instead of year 4, and installation of generating unit B8 is postponed from planning year 2 to year 3. In addition, generating units A5 and B7 are substituted with generating unit B3. In comparison with other 5 MW units, generating unit B7 has the lowest investment cost.

4. Conclusions

In this paper we proposed a new formulation for stochastic long-term generation capacity planning. In our approach, outages of generating units and transmission lines are considered using a Monte Carlo simulation. An iterative process has been adopted for modeling interactions among GENCOs and the ISO in competitive electricity markets. Since the ISO or the regulator is ultimately responsible for enhancement of reliability and decreasing the risk level of the system planning process, the ISO intends to create appropriate incentives for GENCOs based on their role in enhancing system reliability. In this work, an appropriate method has been chosen to model this payment. The advantage of the proposed approach is that it can provide reliable decision conditions for participants planning long-term capacity expansion. Numerical results confirm the effectiveness of the proposed model by exploring the effects of system component outages on the generation capacity expansion schedule. The proposed framework could be expanded by applying other related constraints such as fuel, emissions, and the constraints of hydrothermal units in long-term resource planning.

Appendix

A. Case study data for the 6-bus system

Table A1. Load blocks in base year.

Subperiod	1	2	3	4
Duration (%)	1	29	50	20
Load (MW)	25	23	20	18

Table A2. Peak load in base year at different buses.

Bus	1	2	3	4	5	6
Load (MW)	0	0	N∼(10,0.01)	N∼(7.5,0.01)	N∼(7.5,0.01)	0

Table A3. Transmission line data.

Line	From	To	Capacity (MW)	FOR (%)	X (%)
T1	1	2	10	0.1	0.170
T2	2	3	7	1.0	0.037
T3	1	4	7	1.0	0.258
T4	2	4	7	1.0	0.197
T5	4	5	7	1.0	0.037
T6	5	6	7	1.0	0.140
T7	3	6	7	1.0	0.018

Table A4. Generation data.

Unit	Bus	Capacity (MW)	FOR (%)	Operating cost ($/MWh)	Bid ($/MWh)	Investment cost (million $)
AE1	2	10	3	25	N∼(31.6,1)	Existing unit
AE2	3	5	3	35	N∼(41.6,1)	Existing unit
AE3	6	5	3	37	N∼(43.6,1)	Existing unit
A1	1	10	3	22	N∼(28.6,1)	10
A2	1	7	3	30	N∼(36.6,1)	5.6
A3	2	5	5	35	N∼(41.6,1)	3
A4	2	3	3	40	N∼(46.6,1)	0.9
A5	4	3	5	40	N∼(46.6,1)	1.2
BE1	1	10	3	25	N∼(31.6,1)	Existing unit
B1	3	3	2	40	N∼(46.6,1)	1.35
B2	3	2	1	55	N∼(61.6,1)	0.4
B3	5	5	5	35	N∼(41.6,1)	3.5
B4	5	3	3	40	N∼(46.6,1)	1.05
B5	6	10	3	22	N∼(28.6,1)	11
B6	6	8	3	29	N∼(35.6,1)	6.8
B7	6	5	5	35	N∼(41.6,1)	2.5
B8	6	2	1	55	N∼(61.6,1)	0.3

Nomenclature

Indices

t index for year
h index of GenCo
i index for existing generating unit
j index for candidate generating unit
d index for subperiod
s subscript index for scenario
EG subscript index for the existing generating units
CG subscript index for the candidate generating units

Parameters

T number of years in the planning horizon
NG number of GenCos
Nd number of subperiods in load duration curve
EGh set of existing generating units in GenCo h
CGh set of candidate generating units in GenCo h
DT_d duration of step d in load duration curve
D_t average peak of load in year t
r economic discount rate
λ_{ihdt} locational marginal price for existing unit i of GenCo h at subperiod d in year t
λ_{jhdt} locational marginal price for candidate unit j of GenCo h at subperiod d in year t
OC_{ihdt} operating cost of existing unit i of GenCo h at subperiod d in year t
OC_{jhdt} operating cost of candidate unit j of GenCo h at subperiod d in year t
IC_{jhdt} investment cost of candidate unit j of GenCo h in year t
UEC cost of the expected unserved energy
$EPNS_{-jhdt}$ and $EPNS_{jhdt}$ expected power not supplied before and after installation of candidate unit j of GenCo h at subperiod d in year t, respectively

$DEPNS_{jhdt}$	reduction in EPNS due to installation of candidate unit j of GenCo h at subperiod d in year t
$ICAP_{jht}$	installation capacity of candidate generating unit j of GenCo h in year t
MCI_{ht}	the maximum installed capacity for GenCo h in year t
UCI_{ht}	the maximum capital investment for GenCo h in year t
$TICAP_{h,t}$	total installed capacity of GenCo h in year t
$P_{EG,ih}^{\max}$	maximum capacity of the existing unit i of GenCo h
$P_{CG,jh}^{\max}$	maximum capacity of the existing unit j of GenCo h
$MR_t^{\min}$	$MR_{\min}^t MR_{\min}^t$ the minimum reserve margins in planning year t
$MR_t^{\max}$	the maximum reserve margins in planning year t
$EENS_{dt}$	expected energy not supplied at subperiod d in year t
$EENS_t^{\max}$	maximum EENS in year t

Decision variables

$P_{EG,\,iht}$	dispatched capacity of the existing unit i of GenCo h at subperiod d in year t
$P_{CG,\,jht}$	dispatched capacity of the candidate unit j of GenCo h at subperiod d in year t
X_{jht}	installation status of candidate unit j of GenCo h in year t; 1 if installed, otherwise 0

Matrices and vectors

$\mathbf{P_G}$	vector of active power generations
$\mathbf{P_D}$	vector of active loads
$\mathbf{C_G}$	vector of generator bids
$\mathbf{C_D}$	vector of load bids
$\mathbf{P_l^{max}}$	vector of transmission line limits
$\mathbf{P}_{\mathbf{G},s}$	vector of active power generations in scenario s
$\mathbf{P}_{\mathbf{D},s}$	vector of active loads in scenario s
$\mathbf{P}_{G,s}^{\max}$	vector of maximum active power generations in scenario s
$\mathbf{P}_{G,s}^{\min}$	vector of minimum active power generations in scenario s
$\mathbf{P}_{D,s}^{\max}$	vector of maximum active loads in scenario s
$\mathbf{P}_{D,s}^{\min}$	vector of minimum active loads in scenario s
$\mathbf{H}_s$	matrix of linearized line flows in scenario s
$\mathbf{B}_s$	linearized Jacobian matrix in scenario s
δ_s	vector of bus angles in scenario s

References

[1] M. Ventosa, M. Rivie, A. Ramo, A. Garcia-Alcalde, "An MCP approach for hydrothermal coordination in restructured power markets", Proceedings of IEEE Power Engineering Society Summer Meeting, Vol. 4, pp. 16–20, 2000.

[2] T. Bjorkvoll, S. Fleten, M. Nowak, A. Tomasgard, "Wallace S. Power generation planning and risk management in a liberalized market", Proceedings of IEEE Porto Power Technology, Vol. 1, pp. 1–6, 2001.

[3] J. Bloom, "Long-range generation planning using decomposition and probabilistic simulation", IEEE Transactions on Power Apparatus and Systems, Vol. 4, pp. 797–802, 1982.

[4] J. Zhu, M.Y. Chow, "A review of emerging techniques on generation expansion planning", IEEE Transactions on Power Systems, Vol. 12, pp. 1722–1728, 1997.

[5] A.S. Chuang, F. Wu, P. Varaiya, "A game-theoretic model for generation expansion planning: problem formulation and numerical comparisons", IEEE Transactions on Power Systems, Vol. 16, pp. 885–891, 2001.

[6] Y. Fu, Z. Li, M. Shahidehpour, "Profit-based generation resource planning", IMA Journal of Management Mathematics, Vol. 15, pp. 273–289, 2004.

[7] M.O. Buygi, G. Balzer, H.M. Shanechi, M. Shahidehpour, "Market-based transmission expansion", IEEE Transactions on Power Systems, Vol. 19, pp. 2060–2067, 2004.

[8] A. Botterud, M.D. Ilic, I. Wangensteen, "Optimal investments in power generation under centralized and decentralized decision making", IEEE Transactions on Power Systems, Vol. 20, pp. 254–263, 2005.

[9] J.H. Roh, M. Shahidehpour, Y. Fu, "Security-constrained resource planning in electricity markets", IEEE Transactions on Power Systems, Vol. 22, pp. 812–820, 2007.

[10] P. Kaymaz, J. Valenzuela, C.S. Park, "Transmission congestion and competition on power generation expansion", IEEE Transactions on Power Systems, Vol. 22, pp. 156–163, 2007.

[11] M.M. Moghaddam, M.H. Javidi, M.P. Moghaddam, M.O. Buygi, "Coordinated decisions for transmission and generation expansion planning in electricity markets", European Transactions on Electrical Power, DOI: 10.1002/etep.1671, 2012.

[12] T. Akbari, A. Rahimi-Kian, M.T. Bina, "Security-constrained transmission expansion planning: a stochastic multi-objective approach", International Journal of Electrical Power and Energy Systems, Vol. 43, pp. 444–453, 2012.

[13] H. Rudnick, R. Varela, W. Hogan, "Evaluation of alternatives for power system coordination and pooling in a competitive environment", IEEE Transactions on Power Systems, Vol. 1, pp. 605–613, 1997.

[14] F. Schweppe, R. Bohn, R. Tabors, M. Caramanis, Spot Pricing of Electricity, fifth printing, Boston, Kluwer Academic Publishers, 2002.

[15] J.H. Roh, M. Shahidehpour, L. Wu, "Market-based generation and transmission planning with uncertainties", IEEE Transactions on Power Systems, Vol. 24, pp. 1587–1598, 2009.

[16] M.C. Ferris, "MATLAB and GAMS: interfacing optimization and visualization software", Mathematical Programming Technical Report 2011 [Online], Available: http://www.gams.com/dd/docs/tools/gdxmrw.pdf.