Multiobjective Robust Power System Expansion Planning Considering Generation Units Retirement

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***Abstract*—This paper presents a mixed-integer linear robust multiobjective model for the expansion planning of an electric power system. An information-gap decision theory-based framework is proposed to take into account the uncertainties in electrical demand and new power system elements prices. The model is intended to increase the power system resistance against the uncertainties caused by forecast errors. The normal boundary intersection method is used to obtain the Pareto front of the multiobjective problem. Since the planning problem is a large-scale problem, the model is kept linear using the Big M linearization technique that is able to significantly decrease the computational burden. The fuel transportation and availability constraints are taken into account. The model also enables the system planner to build new fuel transportation routes whenever it is necessary. The generating units' retirement is also incorporated into the model, and the simulation results are showed to the advantages of incorporating units' retirement in the power system expansion planning model instead of considering it separately. The proposed multiobjective method is applied to the Garver 6-bus, IEEE 24-bus, and IEEE 118-bus test systems, and the results are compared with the well-known epsilon-constraint method.**

***Index Terms*—Generation expansion planning, information-gap decision theory, mixed-integer linear programming, normal boundary intersection, transmission expansion planning.**

NOMENCLATURE

Indices

f	Index for fuel sources.
i	Index for busses.
t	Index for year of planning horizon.
m	Index for generation technologies.
y	Index for available capacities for generation units.
type	Index for available reactances for each transmission capacity.
tc	Index for available transmission lines capacity.

Parameters

M	Relatively large number.
$B_{\mathrm{tc,type}}^{\mathrm{candidate}}$	Susceptance of candidate transmission lines.
$P_{\mathrm{tc,type}}^{\mathrm{candidate}}$	Capacity of candidate transmission lines in megawatts.
$P_{i,m,y}^{g,ini}$	Capacity of generation units in preexpansion condition.
γ_m	Multiplier for gaseous emission.
$\mathrm{GE}_t^{\max}$	Maximum allowable gaseous emission in year t.
$C_t^{\max}$	Maximum yearly budget in year t.
$\mathrm{load}_{i,t}^{\mathrm{actual}}$	Actual peak load for bus i in year t.
$\mathrm{load}_{i,t}^{\mathrm{forecasted}}$	Forecasted peak load for bus i in year t.
$\mathrm{Pr}_{m,y}^{\mathrm{GEP,actual}}$	Actual price of adding new generation units with technology m and capacity y.
$\mathrm{Pr}_{m,y}^{\mathrm{GEP,forecasted}}$	Forecasted price of adding new generation units with technology m and capacity y.
U	Parameter which bounds the total cost in the robust model.
β_i	Weight factor for objective function i in NBI method.
ρ_k	Possibility of each contingency.
FOR_k	Forced outage rate of the failed generator during contingency k.
$\mathrm{FR}_{f,i,t}^{\mathrm{available}}$	Set of candidate fuel transportation routes.
$\mathrm{Pr}_{m,y}^{\mathrm{GEP}}$	Price of the new generating unit of technology m and capacity y.
$\mathrm{Pr}_{\mathrm{tc,type}}^{\mathrm{TEP}}$	Per kilometer price of building a transmission line with capacity tc and reactance type.
$L_{i,j}$	Distance between bus i and bus j.
α_m	Operation cost multiplier.
Pr_f^{fuel1}	Fuel constant price at fuel source.
Pr_f^{fuel2}	Transportation price for fuel type f.
$D_{f,i}$	Distance between fuel source f and bus i.
d	Discount rate.
$\mathrm{fuel}_{f,i}^{\mathrm{available}}$	Candidate fuel transportation capacities.
$\mathrm{fuel}_{f,i}^{\mathrm{existing}}$	Existing fuel transportation routes capacities.
$\mathrm{FTL}_{f,i}^{\max}$	Fuel transportation route capacity.
$\mathrm{FS}_f^{\max}$	Fuel source f maximum capacity.

Manuscript received June 12, 2016; revised September 3, 2016 and January 8, 2017; accepted February 11, 2017.

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Digital Object Identifier 10.1109/JSYST.2017.2672694

ψ_m	Fuel consumption multiplier for generation technology m.
$\text{load}_{i,t}$	Forecasted peak load in bus *i* in year *t*.
HS_i	Duration of the peak load.
η_m	Contribution factor for generation technology *m*.
MHO_m	Maximum hours of operation for generation technology *m*.
$P_{i,j}^{\text{transmission}}$	Power flow capacity between bus *i* and *j* in preexpansion condition.
$B_{i,j}^{\text{ini}}$	Susceptance matrix in the preexpansion condition.
θ_i^{ini}	Voltage angle in bus *i* in the preexpansion condition.

Variables

$\Delta\theta_{i,k,t}$	Changes in voltage angles during contingency *k* in year *t* compared to preexpansion condition.
$Z_{i,j,k,t}^1$	Auxiliary variable which is defined as the multiplication of $\Delta B_{i,j,t}$and$\Delta\theta_{i,k,t}$.
C_t^{route}	Total cost of building new fuel transportation routes in year *t*.
α_L	Robust region envelope for load.
α_C	Robust region envelope for total cost.
$C_t^{\text{investment},R}$	Total cost when uncertainty in load and generation capacity price is neglected.
$C_t^{\text{investment},D}$	Total cost when uncertainty in load and generation capacity price is considered.
$Z_{i,m,y,t}^2$	Auxiliary variable which is defined as the multiplication of $ug_{i,m,y,t}$ and α_C.
f_i^N	Best possible value for objective function *i*.
f_i^U	Worst possible value for objective function *i*.
$\bar{f}_i(x)$	Normalized value of objective function *i*.
$\bar{\phi}_{mn}$	Normalized values of payoff table.
C_t^{route}	Cost of adding new fuel transportation routes in the system.
$\text{FRC}_{f,i}^{\text{available}}$	Cost of building fuel route between fuel source *f* and generator located at bus *i*.
$uf_{f,i,t}$	Binary variable that is equal to 1, when a new fuel transportation route is added to the system between fuel source *f* and bus *i* in year *t*.
C_t^{GEP}	Total investment cost for new generation units in year *t* of the planning horizon.
$ug_{i,m,y,t}$	Binary decision variable for new generation units.
C_t^{TEP}	Total investment cost for new transmission lines in year *t* of the planning horizon.
$ut_{i,j,\text{tc},\text{type},t}$	Binary decision variable for new transmission lines.
$C_t^{\text{investment}}$	Total investment cost in year *t* of the planning horizon.
$C_t^{\text{operation}}$	Total generation unit's operation cost in year *t* of the planning horizon.
$\text{En}_{i,m,t}$	Energy generated with technology *m* at bus *i* in year *t* of the planning period.
C_t^{fuel}	Total fuel cost in year *t* of the planning horizon.
$\text{FT}_{f,i,m,t}$	Fuel transported between fuel source *f* and generating unit with technology *m* at bus *i* in year *t*.
C^{total}	Total cost.
$\Delta f_{f,i,t}$	Change in the fuel transportation capacity in year *t* compared to preexpansion condition.
TRE_t	Total required energy in year *t*.
$\Delta P_{i,m,y,t}^g$	Generation capacity of the newly installed units.
$P_{i,m,y,k,t}^g$	Power generated by unit at bus *i* with technology *m* and capacity *y* during contingency *k* in year *t* in the peak load condition.
$P_{i,k,t}^{\text{shed}}$	Amount of load shedding in bus *i* during contingency *k* in year *t*.
$P_{i,j,k,t}^{\text{flow}}$	Power flow between buses *i* and *j* during contingency *k* in year *t*.
$P_{i,m,y,t}^{g,\text{plan}}$	Capacity of the generation unit in bus *i*, technology *m*, capacity *y* in year *t*.
$P_{i,j}^{\text{ini,flow}}$	Power flow between bus *i* and *j* in preexpansion condition.
$P_{i,j,k,t}^{\text{flow}}$	Power flow between bus *i* and bus *j* during contingency *k* in year *t*.
$P_{i,j}^{\text{trans}}$	Transmission capacity between bus *i* and bus *j* in preexpansion condition.
$\Delta P_{i,j,t}^{\text{trans}}$	Change in transmission capacity due to newly added transmission lines.
$B_{i,j,t}^{\text{plan}}$	Susceptance matrix in year *t*.
$\theta_{i,k,t}^{\text{plan}}$	Bus voltage angles in year *t*.
$\Delta B_{i,j,t}$	Changes in susceptance matrix in year *t* compared to preexpansion condition.

I. Introduction

The electrical demand is continuously rising in many parts of the world as a result of the economic growth and the increase in the population. Therefore, power system generation should be expanded in order to meet the demand requirements. The increase of power generation means, building new power plants or increasing the capacity of the existing plants by adding new generating units. This can result in higher power flows over transmission lines, and in order to avoid their overloads, it is sometimes necessary to add new transmission capacity [1].

The generation expansion planning (GEP) problem is concerned with the determination of new generating units' location, type, time of installation, and capacity. On the other hand, the transmission expansion planning (TEP) problem deals with adding new transmission lines (and substations). By solving a TEP problem, the capacity, number of bundles, location, and time of installation of new transmission lines should be defined.

The cost of adding new generating units is higher than the TEP cost [1], therefore in older papers, the GEP and TEP problems are solved separately. In [2], it is shown that when generation and transmission expansion planning are simultaneously performed, the total expansion cost is reduced. It should be noted that the cost of the GEP for a large-scale practical power system is very high; therefore, it is essential to find the most economical way to solve the problem.

Several models for the GEP–TEP problem are presented in the technical literature. Alternate current (AC) models use ac power flow to find the power flow over transmission lines. This enables the planner to perform studies, such as reactive power planning, voltage stability analysis, and addition of FACTS devices [3], which can lead to construction of a lower number of transmission lines [4]. Using ac power flow results in a nonlinear model, which is very hard to solve, especially in a large-scale problem such as GEP–TEP problems. To avoid the huge computational burden, usually dc models are used to solve the GEP–TEP problems [5].

An interesting stochastic hybrid algorithm for the ac/dc TEP is presented in [6]. The model takes into account the uncertainty related to generating units' and transmission lines' availability, as well as errors in the load forecasting.

In recent years, since the reduction in greenhouse gases and the consumer welfare have gained more importance, a solution that only minimizes the total planning costs may not be suitable for real power systems. A multiobjective framework is, thus, presented in many papers (see [7]) to solve the hybrid generation and transmission expansion planning problems. The reliability index and emissions are usually considered as additional objective functions in multiobjective models, while other objective functions, such as fuel price volatility [8], congestions [9], etc., are also considered in the technical literature.

Another important issue when dealing with expansion planning problems is its uncertain nature. The GEP–TEP problem is naturally a stochastic optimization problem due to uncertainty in load forecasting, investment prices, fuel prices, availability of generating units and transmission lines, wind power production, etc. There are several methods to deal with uncertainty in optimization problems.

In [10], the information-gap decision theory is implemented together with the epsilon-constraint method [11] to solve the TEP problem. Load and new elements' investment cost are considered as the main sources of uncertainty. The robust region of each uncertainty source is maximized, while the total cost is bounded to a predefined value.

The advent of restructuring is another source of uncertainty in power system expansion planning problem. When considering the electricity market in GEP–TEP models, the problem of market clearing should be incorporated into the model. A three-level-market-based model for the GEP–TEP problem is presented in [12].

The GEP–TEP problem is a nonlinear problem, which is very difficult to solve and may lead to infeasibility. Usually, it is appropriate to eliminate the nonlinear terms and make the model linear. In [13], benders decomposition, allowing solving a mixed-integer linear programming (MILP) master problem, and a linear programming subproblem is used to eliminate the nonlinear term in the model.

The reliability of power systems is another important issue when dealing with expansion planning problems. The outages of generating units and transmission lines are random and cannot be predicted accurately. Therefore, the system should be planned in a manner that the outage of one element does not result in serious problems in terms of involuntary load shedding. In [14], a probabilistic model for GEP–TEP problem has been presented, considering estimated-energy-not-supplied (EENS) as a reliability criterion. EENS is calculated based on known historical forced outage rate (FOR).

A normal boundary intersection (NBI) method is an effective tool to solve multiobjective problems. Information-gap decision theory (IGDT) has not been applied together with NBI method to solve the GEP–TEP problem in the previously published works. In addition, the previous models have not simultaneously considered the generation unit's retirement, fuel constraints, gaseous emission, and estimated load-not-served. All these aspects are of very high importance in the expansion of real power systems and neglecting any of them would not be acceptable. This paper has incorporated all the main aspects of the GEP–TEP problem at the same time.

The main contributions of this paper are as follows.

1) In the prior studies, due to the huge computational burden of the problem, some important aspects of GEP–TEP problem have usually been neglected. In this paper, a comprehensive model taking into account the unit retirement, fuel constraints, reliability, emission, uncertainty, and annual cost at the same time and based on IGDT is presented for the GEP–TEP problem. This is performed through a novel mixed-integer linear formulation which is able to solve the problem while avoiding the in-feasibility.
2) The expansion planning of new fuel transportation routes is incorporated into the model. This enables the system planner to expand the fuel transportation capacity when needed. The addition of new transmission routes is not considered in the previous published works. It is shown in this paper that new fuel transportation routes can eliminate the need for construction of new generation units and decrease the total cost.
3) The retirement of existing generating units during the planning horizon is taken into consideration. The new generating units should simultaneously compensate the load growth and the retirement of existing generating units.
4) A multiobjective framework, based on the NBI method, is presented to maximize the robust region of electrical demand and new generation units and transmission lines prices uncertainty at the same time.

This paper is organized as follows. In Section II, the proposed multiobjective optimization and the NBI method are described in detail. In Section III, the formulation of the multiyear GEP–TEP problem is presented. In Section IV, the solution methodology is described. In Section V, the model is implemented on 6-bus, IEEE 24- and 118-bus test systems, and numerical results are reported. The results show the good performance of the proposed model. Finally, section VI concludes this paper.

II. Multiobjective Optimization Using NBI Method

A. Multiobjective Optimization

In the multiobjective optimization, more than one objective function at the same time should be optimized. A basic multiobjective problem can be expressed as follows [15]:

$$\max\ [f_1(x),\ f_2(x),\ \ldots,\ f_n(x)]$$
$$x \in X \tag{1}$$

where n is the number of objective functions (in this paper, n is equal to 2), f_i is the ith objective function, and x is the set of problem variables.

The objective functions are generally in conflict, i.e., improving one objective results in worsening other objective functions. As a result, instead of one single optimal solution, a set of Pareto optimal solutions would be obtained. In other words, in multiobjective optimization problems, the concept of optimality is replaced with Pareto optimality. Pareto solutions cannot dominate other Pareto solutions in all objective functions. This means the following:

1) each Pareto solution excels other solutions in at least one objective function;
2) there is not a solution that excels in all objective functions.

The image of all the Pareto solutions is called Pareto front. The nature of tradeoff between objective functions is indicated by the Pareto front [15].

B. Normal Boundary Intersection

In this paper, NBI method [16] is proposed to solve the multiobjective optimization problem. A geometrically intuitive parameterization is used in the NBI method to obtain the set of Pareto solutions. Before using the NBI method, a payoff table ϕ should be constructed. A well-designed approach to construct the payoff table is presented in [17]. When every objective function's range gets known by using a payoff table, each objective function should be normalized based on its best and worst values as

$$\bar{f}_i(x) = \frac{f_i(x) - f_i^U}{f_i^N - f_i^U}. \tag{2}$$

Equation (2) makes the criterion space nondimensional and unitless. In the following formulation, the normalized values are denoted with a bar. The elements of each row of the payoff table can be combined to form the convex hull of individual minima (CHIM) as

$$P(\beta_1, \beta_2, \ldots, \beta_n) = \begin{bmatrix} \beta_1\bar{\phi}_{11} + \ldots + \beta_n\bar{\phi}_{1n} \\ \vdots \\ \beta_n\bar{\phi}_{m1} + \ldots + \beta_n\bar{\phi}_{mn} \end{bmatrix} \tag{3}$$

$\sum_{i=1}^{n} \beta_i = 1$ and $\beta_i \geq 0$.

In fact, CHIM is the set of all convex combinations of each objective function's individual global optimum. In the NBI method, the problem is to maximize the distance between the CHIM points and the Pareto solutions. The number of CHIM points is equal to the number of objective functions (n). Therefore, n single-objective subproblems should be solved to maximize the distance between the points obtained by (3) and the Pareto solutions. This can be formulated as

$$\begin{aligned} &\max D \\ &\text{Subject to}: \\ &\phi_n.\beta + D.\hat{n} = F(x) \end{aligned} \tag{4}$$

where $\hat{n}$ is the normal unit vector from the point on the simplex to the *CHIM*, and β is an arbitrary set of n values. A Pareto solution is obtained for each set of β, while it can be changed to get different solutions. The elements of ϕ_n are normalized using (2). Indeed, it is the normalized payoff matrix.

After obtaining the Pareto front, the most preferred solution is selected using fuzzy decision-making (FDM) method. For the detailed descriptions of the FDM, see [18].

III. Mathematical Formulation

In this section, the hybrid linear multiyear generation and transmission expansion model is formulated as a mixed-integer linear optimization problem. First, the least-cost model is introduced and then, the IGDT approach is used to maximize the robust regions for uncertain parameters of the problem while satisfying the system constraints.

A. GEP–TEP Model

Thirty nine credible contingencies are considered in this paper to evaluate the reliability index, including transmission lines' and generation units' outages. The probability of each contingency is calculated based on the FOR of generators as

$$\rho_k = \frac{\text{FOR}_k}{1 - \text{FOR}_k} \prod_{k=1} (1 - \text{FOR}_k) \tag{5}$$

$$\rho_0 = 1 - \sum_{k=1} \rho_k. \tag{6}$$

The objective function is to minimize the total planning costs including fuel cost, operation cost, and investment cost for new generating units, transmission lines, and fuel transportation routes.

The cost related to the addition of new fuel transportation routes in the system can be modeled as follows:

$$\begin{aligned} C_t^{\text{route}} = &\sum_f \sum_i FR_{f,i,t}^{\text{available}} \times FRC_{f,i}^{\text{available}} \\ &\times (uf_{f,i,t} - uf_{f,i,t-1}). \end{aligned} \tag{7}$$

The investment cost of new generation and transmission facilities is modeled through (8) and (9), respectively,

$$C_t^{\text{GEP}} = \sum_m \sum_i \sum_y \text{Pr}_{m,y}^{\text{GEP}} \times (ug_{i,m,y,t} - ug_{i,m,y,t-1}) \tag{8}$$

$$C_t^{\mathrm{TEP}} = \sum_i \sum_{\substack{j \\ j \neq i}} \sum_{\mathrm{type}} \sum_{\mathrm{tc}} \mathrm{Pr}_{\mathrm{tc,type}}^{\mathrm{TEP}} \times L_{i,j} \times (ut_{i,j,\mathrm{tc,type},t} - ut_{i,j,tc,type,t-1}) \quad (9)$$

$$C_t^{\mathrm{investment}} = C_t^{\mathrm{TEP}} + C_t^{\mathrm{GEP}}. \quad (10)$$

Generating units' operation cost is modeled as a linear function of their generated energy as

$$C_t^{\mathrm{operation}} = \sum_i \sum_m \alpha_m \times \mathrm{En}_{i,m,t}. \quad (11)$$

Another component of the expansion cost is that due to fuel consumption in generating units. This represents a considerable amount for thermal units. The fuel cost comprises two parts, the fuel price at the fuel source and the transportation price. The transportation price can be modeled as a linear function of the distance between the fuel source and the generation unit. This can be expressed as follows:

$$C_t^{\mathrm{fuel}} = \sum_f \sum_i \sum_m \mathrm{FT}_{f,i,m,t} \times (Pr_f^{\mathrm{fuel1}} + Pr_f^{\mathrm{fuel2}} \times D_{f,i}). \quad (12)$$

Finally, the total annualized cost is as follows:

$$C^{\mathrm{total}} = \sum_t \frac{(C_t^{\mathrm{fuel}} + C_t^{\mathrm{operation}} + C_t^{\mathrm{TEP}} + C_t^{\mathrm{GEP}} + C_t^{\mathrm{route}})}{(1+d)^t} \quad (13)$$

where d is 0.05. The total annualized cost represents the objective function to minimize while satisfying the problem's constraints.

The change in the fuel transportation capacity can be expressed by

$$\Delta f_{f,i,t} = \mathrm{fuel}_{f,i}^{\mathrm{available}} \times uf_{f,i,t} \quad (14)$$

$$\sum_m \mathrm{FT}_{f,i,m,t} \leq \mathrm{fuel}_{f,i}^{\mathrm{existing}} + \Delta f_{f,i,t}. \quad (15)$$

Each fuel source has a limited capacity. This can be expressed as follows:

$$\sum_i \sum_m \mathrm{FT}_{f,i,m,t} \leq \mathrm{FS}_f^{\max}. \quad (16)$$

Equation (17) shows the fuel transportation constraint

$$\mathrm{FT}_{f,i,m,t} \leq \mathrm{FTL}_{f,i}^{\max}. \quad (17)$$

The total fuel consumption of the power plants should be provided by the fuel sources. This can be formulated as follows:

$$\sum_f \mathrm{FT}_{f,i,m,t} = \psi_m \times \mathrm{En}_{i,m,t}. \quad (18)$$

The right-hand side of (18) is the total fuel consumed by the generating units. It is modeled as a linear function of the generated energy. The left-hand side of the equation is the fuel transferred to the generator at bus i with technology m in year t.

The required energy is a function of the electrical load. The required energy should be lower than that produced by generating units

$$\mathrm{TRE}_t = \sum_i \mathrm{load}_{i,t} \times HS_i \leq \sum_i \sum_m \mathrm{En}_{i,m,t}. \quad (19)$$

In this paper, the peak load conditions are considered. This assumption is made to simplify the model instead of considering several piece-wise linear segments for the electrical load.

The generated energy by new units is limited by the capacity of these units, the contribution factor, and the yearly maximum hours of operation for each technology. The contribution factor is scalar between 0 and 1. It is usually larger for the base load technologies and less than 0.2 for peak load technologies,

$$\eta_m \times \mathrm{MHO}_m \times \Delta P_{i,m,y,t}^g \leq \mathrm{En}_{i,m,t} \leq \mathrm{MHO}_m \times \Delta P_{i,m,y,t}^g. \quad (20)$$

The power balance equation can be written as follows:

$$\sum_y \sum_m P_{i,m,y,k,t}^g - \mathrm{load}_{i,t} + P_{i,k,t}^{\mathrm{shed}} = \sum_j P_{i,j,k,t}^{\mathrm{flow}} \quad (21)$$

$$P_{i,k,t}^{\mathrm{shed}} \leq \mathrm{load}_{i,t} \quad (22)$$

$$P_{i,m,y,k,t}^g \leq P_{i,m,y,t}^{g,\mathrm{plan}}. \quad (23)$$

The transmission power-flow capacity limit in the post-expansion and preexpansion conditions is presented in (24) and (25):

$$-(P_{i,j}^{\mathrm{trans}} + \Delta P_{i,j,t}^{\mathrm{trans}}) \leq P_{i,j,k,t}^{\mathrm{flow}} \leq P_{i,j}^{\mathrm{trans}} + \Delta P_{i,j,t}^{\mathrm{trans}} \quad (24)$$

$$-P_{i,j}^{\mathrm{transmission}} \leq P_{i,j}^{\mathrm{ini,flow}} \leq P_{i,j}^{\mathrm{transmission}}. \quad (25)$$

As seen in (24), the maximum capacity in each corridor is the sum of the capacity of existing lines and the capacity of the added transmission lines. Therefore, the maximum capacity in each corridor changes in each year.

Kirchhoff's second law relates the bus voltage angles to the susceptance of the transmission lines. These can be stated mathematically for preexpansion and postexpansion conditions in (26) and (27), respectively

$$P_{i,j}^{\mathrm{ini,flow}} = B_{i,j}^{\mathrm{ini}} \times (\theta_i^{\mathrm{ini}} - \theta_j^{\mathrm{ini}}) \quad (26)$$

$$P_{i,j,k,t}^{\mathrm{flow}} = B_{i,j,t}^{\mathrm{plan}} \times (\theta_{i,k,t}^{\mathrm{plan}} - \theta_{j,k,t}^{\mathrm{plan}}). \quad (27)$$

By substituting $P_{i,j,k,t}^{\mathrm{flow}}$ and $P_{i,j,k}^{\mathrm{ini,flow}}$ from (26) and (27) in (24) and (25), (28) and (29) are obtained.

$$-(P_{i,j}^{\mathrm{trans}} + \Delta P_{i,j,t}^{\mathrm{trans}}) \leq (B_{i,j}^{\mathrm{ini}} + \Delta B_{i,j,t}) \times (\theta_i^{\mathrm{ini}} + \Delta\theta_{i,k,t} - \theta_j^{\mathrm{ini}} - \Delta\theta_{j,k,t}) \leq P_{i,j}^{\mathrm{trans}} + \Delta P_{i,j,t}^{\mathrm{trans}} \quad (28)$$

$$-P_{i,j}^{\mathrm{transmission}} \leq B_{i,j}^{\mathrm{ini}} \times (\theta_i^{\mathrm{ini}} - \theta_j^{\mathrm{ini}}) \leq P_{i,j}^{\mathrm{transmission}}. \quad (29)$$

By subtracting (29) from (28), (30) is obtained

$$\left| B_{i,j}^{\mathrm{ini}} \times (\Delta\theta_{i,k,t} - \Delta\theta_{j,k,t}) + \Delta B_{i,j,t} \times (\theta_i^{\mathrm{ini}} - \theta_j^{\mathrm{ini}}) + \Delta B_{i,j,t} \times (\Delta\theta_{i,k,t} - \Delta\theta_{i,k,t}) \right| \leq \Delta P_{i,j}^{\mathrm{trans}}. \quad (30)$$

It should be noted that to obtain the values of $B_{i,j,t}^{\text{plan}}$ in each year, its initial value should be added to the changes in suscpetance matrix due to addition of new transmission lines, up to year t. Same process is used to obtain the $\theta_{i,k,t}^{\text{plan}}$. Equation (30) is nonlinear, since it contains the multiplication of two continuous variables $\Delta B_{i,j,t}$ and $\Delta\theta_{i,k,t}$. To eliminate the nonlinearity of the formulation, Big M linearization technique [1] is used in this paper. It can be formulated as

$$Z_{i,j,k,t}^{1} + M.ut_{i,j,\text{tc},\text{type},t} \le M + \Delta\theta_{i,k,t} \times B_{\text{tc},\text{type}}^{\text{candidate}} \quad (31)$$

$$Z_{i,j,k,t}^{1} - M.ut_{i,j,\text{tc},\text{type},t} \ge -M + \Delta\theta_{i,k,t} \times B_{\text{tc},\text{type}}^{\text{candidate}} \quad (32)$$

$$0 \le Z_{i,j,k,t}^{1} + M.\sum_{\text{tc}}\sum_{\text{type}} ut_{i,j,\text{tc},\text{type},t} \quad (33)$$

$$Z_{i,j,k,t}^{1} - M.\sum_{\text{tc}}\sum_{\text{type}} ut_{i,j,\text{tc},\text{type},t} \le 0. \quad (34)$$

Also, (30) is converted to

$$\left| \begin{array}{l} B_{i,j}^{\text{ini}} \times (\Delta\theta_{i,k,t} - \Delta\theta_{j,k,t}) + \Delta B_{i,j,t} \times (\theta_i^{\text{ini}} - \theta_j^{\text{ini}}) \\ + Z_{i,j,k,t}^{1} - Z_{j,i,k,t}^{1} \end{array} \right| \le \Delta P_{i,j}^{\text{transmission}}. \quad (35)$$

Transmission capacity and susceptance of transmission lines change according to (36) and (37), due to the addition of new transmission lines.

$$\Delta P_{i,j,t}^{\text{trans}} = \sum_{\text{tc}}\sum_{\text{type}} ut_{i,j,\text{tc},\text{type},t} \times P_{\text{tc},\text{type}}^{\text{candidate}} \quad (36)$$

$$\Delta B_{i,j,t} = B_{i,j,t}^{\text{plan}} - B_{i,j}^{\text{initial}} = \sum_{\text{tc}}\sum_{\text{type}} ut_{i,j,\text{tc},\text{type},t} \times B_{\text{tc},\text{type}}^{\text{candidate}}. \quad (37)$$

Equation (38) shows the change in generation at bus i resulted by installation of new generating units

$$P_{i,m,y,t}^{g,\text{plan}} - P_{i,m,y}^{g,ini} = ug_{i,m,y,t} \times Pg_{m,y}^{\text{candidate}}. \quad (38)$$

The gaseous emission is modeled as a linear function of power plant-generated energy. This emission should be limited in the whole system

$$\sum_{i}\sum_{m} \gamma_m \times \text{En}_{i,m,t} \le \text{GE}_t^{\max}. \quad (39)$$

The total generation of the system should be equal to total load plus the total load shedding.

$$\sum_{i}\sum_{y}\sum_{m} (P_{i,m,y,k,t}^{g}) - \sum_{i} \text{load}_{i,t} + \sum_{i} P_{i,k,t}^{\text{shed}} = 0. \quad (40)$$

In this paper, estimated load not supplied (ELNS) [19] is used to evaluate the reliability of the system. Maximum allowable ELNS each year is limited by

$$\sum_{i}\sum_{k} \rho_k \times P_{i,k,t}^{\text{shed}} \le 40. \quad (41)$$

To calculate the ELNS, the following procedure must be followed.

1) Each element of the power system, including generation units and transmission lines, has a failure rate. This failure can be expressed in the form of FOR, determined by the system planner based on the historical data.
2) The outage of each element contributes to a certain contingency. It is assumed that in each contingency, only one failure occurs. In other words, the simultaneous outage of more than one element is not considered. This is acceptable, since the probability of occurrence of more than one outage during the peak load condition is negligible.
3) The probability of each contingency is calculated based on FOR, using (5) and (6). In (6), ρ_0 is the probability of a normal condition of the power system. This is the situation where no outage occurred.
4) In each contingency, the model calculates the involuntary load shedding using (21)–(23).
5) The ELNS is calculated by using (41). In this paper, the maximum allowed ELNS in each year is considered to be 40 MW. It should be noted that the amount of the maximum allowed ELNS should be determined for each power system based on its connected load. A more detailed discussion on ELNS calculation in addition to some numerical examples can be found in [19].

Frequency deviation occurs as a result of the imbalance between generation and demand. In power system expansion planning, GEP should be done in a way that the balance between generation and demand in peak load condition is guaranteed even during contingency conditions [20]. Therefore, the frequency deviation in steady-state condition is not considered. Since the problem is solved in a long-term time horizon, some issues such as construction delays, forecast inaccuracy, etc., can result in frequency deviation. The study on transient frequency deviation [21] should be performed after the expansion planning is finished.

The economic constraints should also be considered. There is a constraint related to the maximum budget $C_t^{\max}$ that can be invested during each year by the planner. In fact, this is the only persuasive reason to justify the load shedding. When there is no limit on the yearly budget, no load shedding should be allowed, since the consumer comfort is a very important factor for the system planner

$$C_t^{\text{fuel}} + C_t^{\text{operation}} + C_t^{\text{TEP}} + C_t^{GEP} + C_t^{\text{route}} \le C_t^{\max}. \quad (42)$$

B. IGDT-Based GEP–TEP Model

In the previous section, the uncertainty was disregarded and the forecasted values are assumed perfectly accurate. An envelope bound IGDT [22] together with the NBI method is presented here to incorporate the uncertainty in the model. The model is intended to keep the cost bounded and to satisfy the technical and economic constraints. The main advantages of IGDT over other risk management methods are listed as follows [23].

1) The risk factor is not predetermined.
2) IGDT avoids expansion plans with high total costs.
3) The method is able to find the optimal expansion plan for any budget level, while scenario-based uncertainty methods, such as Monte Carlo simulation [24], require the generation of specific scenarios. This makes the IGDT method suitable for problems with lack of information.

The actual values for uncertain parameters can be either lower or higher than the forecasted values. When the forecasted values are too optimistic, incorporating the uncertainty leads to worse results and, on the other hand, if the forecasted values are too conservative, the uncertainty leads to better solutions compared to deterministic model. Robustness and opportunity are two immunity functions to deal with these conflicting aspects. The problem solution is a function of uncertain variables. Uncertain parameters' upper and lower bounds are as follows:

$$\begin{aligned}&-\alpha_L \le \frac{\text{load}_{i,t}^{\text{actual}} - \text{load}_{i,t}^{\text{forecasted}}}{\text{load}_{i,t}^{\text{forecasted}}} \le \alpha_L\\&\to (1-\alpha_L)\text{load}_{i,t}^{\text{forecasted}} \le \text{load}_{i,t}^{\text{actual}}\\&\le (1+\alpha_L)\text{load}_{i,t}^{\text{forecasted}}\\&\text{while}\\&\alpha_L \ge 0 \qquad (43)\end{aligned}$$

$$\begin{aligned}&-\alpha_C \le \frac{\text{Pr}_{m,y}^{GEP,actual} - \text{Pr}_{m,y}^{GEP,\text{forecasted}}}{\text{Pr}_{m,y}^{GEP,\text{forecasted}}} \le \alpha_C\\&\to (1-\alpha_C)\text{Pr}_{m,y}^{GEP,\text{forecasted}} \le \text{Pr}_{m,y}^{GEP,actual}\\&\le (1+\alpha_C)\text{Pr}_{m,y}^{GEP,\text{forecasted}}\\&\text{while}\\&\alpha_C \ge 0 \qquad (44)\end{aligned}$$

$$\begin{aligned}&-\alpha_C \le \frac{\text{Pr}_{\text{tc,type}}^{\text{TEP,actual}} - \text{Pr}_{\text{tc,type}}^{\text{TEP,forecasted}}}{\text{Pr}_{\text{tc,type}}^{TEP,\text{forecasted}}} \le \alpha_C\\&\to (1-\alpha_C)\text{Pr}_{\text{tc,type}}^{\text{TEP,forecasted}} \le \text{Pr}_{\text{tc,type}}^{\text{TEP,actual}}\\&\le (1+\alpha_C)\text{Pr}_{\text{tc,type}}^{\text{TEP,forecasted}}\\&\text{while}\\&\alpha_C \ge 0. \qquad (45)\end{aligned}$$

In order to solve the robust model, first, the deterministic model should be solved and the total cost in the deterministic case is obtained. Then, an upper bound on the total expansion cost is set based on the deterministic cost. In the formulations (5)–(42), the forecasted load and the investment cost are allowed to increase as

$$\begin{cases}\text{load}_{i,t} \to (1+\alpha_L)load_{i,t}\\ \text{Pr}_{m,y}^{\text{GEP}} \to (1+\alpha_C).\text{Pr}_{m,y}^{\text{GEP}}, \text{Pr}_{\text{tc,type}}^{\text{TEP}}\\ \qquad \to (1+\alpha_C).\text{Pr}_{\text{tc,type}}^{\text{TEP}}.\end{cases} \qquad (46)$$

An additional constraint should be set to the cost, to make the model economically effective while maximizing its robustness. This is shown by (46),

$$C_t^{\text{investment},R} \le (1+U)\cdot C_t^{\text{investment},D}. \qquad (47)$$

Now the problem should be solved to maximize α_L and α_C, which are the robust regions of load and investment cost as follows:

$$\text{Max}\,(\alpha_C, \alpha_L). \qquad (48)$$

Subject to (5)–(42).

The robust region of the load and the investment cost can be tuned by using different values for U.

Substitution of (46) converts (8) and (9), respectively, to (49) and (50),

$$\begin{aligned}C_t^{\text{GEP}} = &\sum_m \sum_i \sum_y \text{Pr}_{m,y}^{\text{GEP}}\\&\times\ (1+\alpha_c).(\text{ug}_{i,m,y,t} - \text{ug}_{i,m,y,t-1}) \qquad (49)\end{aligned}$$

$$\begin{aligned}C_t^{\text{TEP}} = &\sum_m \sum_{\substack{j\\ j\ne i}} \text{Pr}_{\text{tc,type}}^{\text{TEP}} \times L_{i,j}\\&\times\ (1+\alpha_c).(\text{ut}_{i,j,\text{tc,type},t} - \text{ut}_{i,j,tc,\text{type},t-1} \qquad (50)\end{aligned}$$

The multiplication of α_C by $ug_{i,m,y,t}$ and $ut_{i,j,\text{tc},\text{type},t}$ makes the model nonlinear. To eliminate the nonlinearity in the model, same procedure that is used to linearize (30) is followed. Two auxiliary variables are introduced as follows:

$$Z_{i,m,y,t}^2 = \alpha_C \times ug_{i,m,y,t} \qquad (51)$$

$$Z_{i,j,\text{tc,type},t}^3 = \alpha_C \times ut_{i,j,\text{tc,type},t}. \qquad (52)$$

Now to keep the model linear, the following equations should be held:

$$Z_{i,j,\text{tc,type},t}^3 + M\cdot ut_{i,j,\text{tc,type},t} \le M + \alpha_c \qquad (53)$$

$$Z_{i,j,\text{tc,type},t}^3 - M\cdot ut_{i,j,\text{tc,type},t} \ge -M + \alpha_c \qquad (54)$$

$$Z_{i,j,\text{tc,type},t}^3 - M\sum_{tc}\sum_{tp} ut_{i,j,\text{tc,type},t} \le 0 \qquad (55)$$

$$Z_{i,j,\text{tc,type},t}^3 + M\sum_{tc}\sum_{tp} ut_{i,j,\text{tc,type},t} \ge 0 \qquad (56)$$

$$Z_{i,m,y,t}^2 + M\cdot ug_{i,m,y,t} \le M + \alpha_c \qquad (57)$$

$$Z_{i,m,y,t}^2 - M\cdot ug_{i,m,y,t} \ge -M + \alpha_c \qquad (58)$$

$$Z_{i,m,y,t}^2 - M\sum_{\text{tech}}\sum_{g} ug_{i,m,y,t} \le 0 \qquad (59)$$

$$Z_{i,m,y,t}^2 + M\sum_{\text{tech}}\sum_{g} ug_{i,m,y,t} \ge 0. \qquad (60)$$

Besides, (49) and (50) are converted, respectively, to (61) and (62),

$$\begin{aligned}C_t^{GEP} = &\sum_m \sum_i \sum_y \text{Pr}_{m,y}^{GEP}\\&\times\ (ug_{i,m,y,t} - ug_{i,m,y,t-1} + Z_{i,m,y,t}^2 - Z_{i,m,y,t-1}^2) \qquad (61)\end{aligned}$$

$$C_t^{TEP} = \sum_i \sum_{\substack{j \\ j \neq i}} \sum_{\text{type}} \sum_{tc} \Pr_{\text{tc,type}}^{TEP} \times L_{i,j} \times (ut_{i,j,\text{tc,type},t} - ut_{i,j,\text{tc,type},t-1} + Z_{i,j,\text{tc,type,t}}^3 - Z_{i,j,\text{tc,type},t-1}^3). \quad (62)$$

IV. Solution Methodology

The GEP–TEP problem is formulated as a MILP problem. An IGDT-based model is used together with the NBI method to solve the problem. The IGDT is used to take into account the uncertainties associated with load forecast and investment prices. Its task is to determine how much should be spent for a given level of reliability. This will help the decision maker to choose the appropriate level of reliability. This is achieved in this paper by finding α_L and α_C for different values of U. In this paper, the goal is to maximize the robust region for load and investment price simultaneously. These two objectives are in conflict with each other, i.e., increasing α_L will result in reduction in α_C and vice versa. Therefore, it is impossible to find a single solution which maximizes α_L and α_C at the same time. Instead, a set of Pareto optimal solutions is found in this paper using the NBI method. At the end, FDM is used to find the best solution among Pareto solutions.

The procedure of optimal expansion plan derivation is as follows.

1) The nonlinearities of the model are eliminated using the Big M linearization technique.
2) For each contingency, the linearized problem is solved using equations (5)–(42), ELNS and total cost is calculated.
3) The model is modified to an IGDT-based model using the procedure described in Section III-B.
4) For a certain value of uncertainty budget, NBI method is implemented for a specified set of β and a Pareto solution is obtained.
5) For a certain value of uncertainty budget, the epsilon-constraint method is implemented considering α_L as the main objective function and dividing the α_C range according to a desired number of points, and the Pareto front is obtained.
6) Using FDM, the best solutions obtained by the epsilon-constraint method and the NBI method are obtained separately.
7) Steps (4)–(6) are repeated for different values of U.

The flowchart of the solution method is presented in Fig. 1, to better illustrate the procedure.

V. Numerical Results

Hydro, combined-cycle gas turbine, gas turbine, and steam turbine are considered in this paper as available generation technologies. The available capacity of each technology and the corresponding cost per megawatt are provided in Table I. As seen in Table I, building larger plants leads to less ∃/MW cost. Table II shows the available transmission lines' costs and pa-

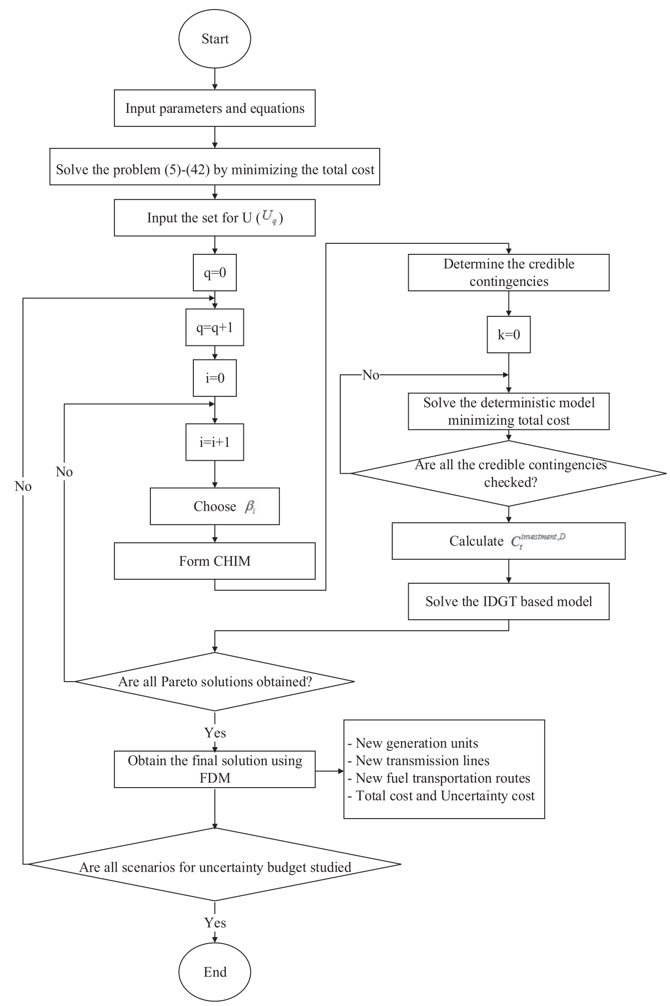

Fig. 1. Flowchart of the proposed IGDT-NBI-based method.

TABLE I
AVAILABLE GENERATION TECHNOLOGIES

Technology	1		2		3	
	Capacity	Cost (∃/MW)	Capacity (MW)	Cost (∃/MW)	Capacity (MW)	Cost (∃/MW)
Hydro	50	62.5	60	70	70	82.6
Steam	75	75	100	95	125	112.5
Gas	30	27	40	34	50	40
Combined	135	148.5	160	168	180	180

TABLE II
AVAILABLE TRANSMISSION DESIGNS

Capacity (MW)	1		2	
	Susceptance	Cost (∃/MW)	Susceptance	Cost (∃/MW)
50	0.128	144.39	0.192	129.95
80	0.192	151.17	0.224	136.05
100	0.224	155.69	0.336	140.12
150	0.392	163.49	0.420	147.14
200	0.420	260.2	0.490	234.18

TABLE III
OPTIMAL EXPANSION PLAN FOR CASE 1

Year	Added elements
t = 1	60MW gas unit at bus 5
	60 MW hydro unit at bus 1
t = 2	60-MW hydro unit at bus 6
t = 3	200-MW combined unit at bus 5
t = 4	200-MW combined unit at bus 4
t = 5	60-MW gas unit at bus 2
	70-MW hydro unit at bus 1
	200-MW combined unit at bus 6
	50-MW transmission line between buses 1 and 2

TABLE IV
OPTIMAL EXPANSION PLAN FOR CASE 2

year	Added elements
t = 1	75-MW steam unit at bus 5
	60-MW hydro unit at bus 1
t = 2	60-MW hydro unit at bus 6
t = 3	200-MW combined unit at bus 5
t = 4	200-MW combined unit at bus 4 fuel route between fuel source 2 and bus 4 with 300 thousand barrel per annum capacity
t = 5	200-MW combined unit at bus 3
	70-MW hydro unit at bus 6
	150-MW transmission line between buses 2 and 3

rameters with different capacities. Tables I and II are taken from [1] with some modifications.

The problem is implemented on three test cases: 6-bus Garver test system [25], 24-bus IEEE test system [26], and IEEE 118-bus test system [27]. The Angular stability limit [28] is set to 45°, which is a practical value for power systems for the test cases. All the simulations are performed in GAMS [29] package, using CPLEX solver.

A. Garver's 6-Bus Test System

The existing generating units in preexpansion state comprise 90-MW gas turbine at bus 1, 60-MW steam turbine at bus 2, and 120-MW steam turbine at bus 3. Generating unit retirement [30] is one of the important issues when dealing with long-term problems. In this paper, it is assumed that 60-, 90-, and 120-MW units are retired in third, fourth, and fifth year of the planning horizon, respectively. The hydro-generation is limited to 200 MW in postexpansion condition.

The model consists of 286 296 rows, 25 291 columns, 761 152 nonzero variables, and 3220 discrete variables. The maximum allowed ELNS in each year is limited to 40 MW.

At first, the problem is solved in two nonrobust cases. In cases 1 and 2, the uncertainty in loads, new generation units, and transmission lines prices is neglected, and the failure of system elements is considered as the only uncertain parameter. The objective function for both the cases is to minimize the total planning cost defined by (16).

In case 1, the constraints on fuel availability and transportation are neglected.

In case 2, the fuel constraints are added to the model.

The optimal expansion plan in cases 1 and 2 is presented in Tables III and IV, respectively. It is clear from Tables III and IV that neglecting the fuel constraints results in more gas-powered generating units. This was expected, since gas-powered units have less efficiency and higher fuel consumption among other generating units. Therefore, when the amount of fuel is limited, the model is inclined to use generating units with less fuel consumption. The total capacities of new generating units in cases 1 and 2 are 910 and 875 MW, respectively, with a 35-MW generation capacity reduction in case 2. This indicates that building new fuel transportation routes can lead to a decreased need for new generating units. The reason is that in case 1, some of fuel capacity of fuel source 2 is not entirely

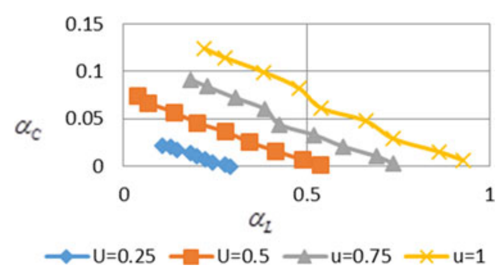

Fig. 2. Pareto front obtained by the NBI method for different values of U.

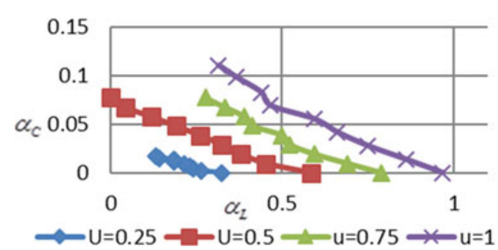

Fig. 3. Pareto front obtained by the epsilon-constraint method for different values of U.

used because of the fuel transportation routes limit. The unused capacity is used, instead, in case 2 by adding a new transportation route.

Therefore, operation hours of the combined-cycle unit increase. A higher number of operational hours for a generating unit means, that for a given generation capacity in megawatts, more energy can be produced by that unit. This results in less need for new generation-capacity installation.

In the next step, the IGDT-based model is used as a multi-objective optimization problem using NBI method. The results are compared to the well-known augmented epsilon-constraint method [31]. Uncertainties in load forecasting and prices are considered as the main sources of uncertainty. The robust region of both uncertainty sources is maximized.

The results for NBI method and epsilon-constraint method for different levels of uncertainty budgets are shown in Figs. 2 and 3. It is clear that higher values of U, results in more values for both α_L and α_C.

The total run-time for construction of Pareto front is 8:05:24 for NBI method, which is considerably less than 23:16:36 of epsilon-constraint method.

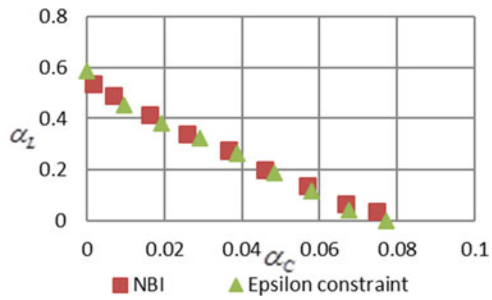

Fig. 4. Comparison between Pareto fronts obtained for $\mathrm{U} = 0.5$.

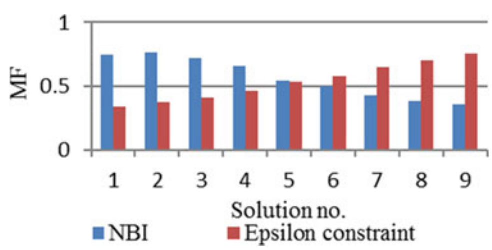

Fig. 5. Comparison between MFs for $\mathrm{U} = 0.75$.

Fig. 4 shows a comparison between the two proposed multiobjective methods for $\mathrm{U} = 0.5$. Fig. 5 shows the membership functions (MF) obtained by FDM for each Pareto optimal solution for different multiobjective optimization methods, while U is 0.75 and 75. The best solution obtained by NBI method is 0.764, while it is 0.741 for epsilon-constraint method, when the weighting factor for both objective functions is considered 1.

As seen in Fig. 4, α_L and α_C are changed in a narrower range, for NBI method. In other words, the NBI method tends to avoid solutions, which have inappropriate values for one objective. This has resulted in a better overall solution in terms of MF, with considerably less run-time (about one-third of the epsilon-constraint method). Therefore, NBI has provided an appropriate tool to solve the multiobjective GEP–TEP problem (which is a very large-scale and time-consuming problem) with less run-time and better solutions.

B. IEEE 24-Bus Test System

The model was also implemented on an IEEE 24-bus test system to show the efficiency of the model on a larger test system. In this section, first, the effect of consideration on the unit's retirement is studied through two different single-objective cases. In the first case, the unit retirement is considered in the model. In the second case, the expansion plan is obtained without the consideration of unit's retirement, and then, the retired units are removed from the power system and a new optimization problem is solved to compensate for the generation unit's retirement. In both cases, electrical demand is considered as the only source of uncertainty and the objective function is to maximize the α_L.

It is assumed in these cases, that the 200-MW unit at bus 7 in the fourth year, a 200-MW unit at bus 18 in the third year, two 50-MW generating units at bus 1 in the second year, 100-MW steam unit at bus 15 in third year, and a 300-MW unit at bus 23 in

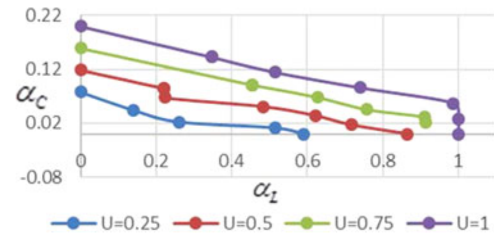

Fig. 6. Pareto front obtained by the epsilon-constraint method for different values of U.

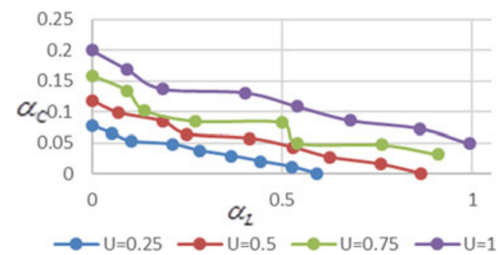

Fig. 7. Pareto front obtained by the NBI method for different values of U.

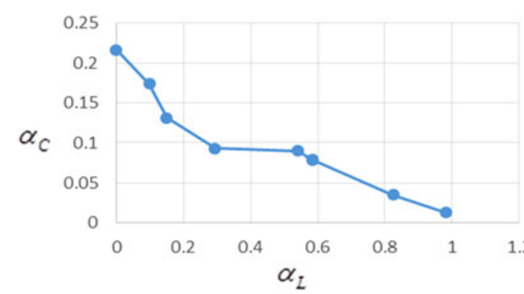

Fig. 8. Pareto front obtained by the NBI method for $U = 0.75$.

the fifth year of the planning horizon will be retired. Therefore, 900 MW of generation capacity in the preexpansion condition is out of service by the end of the planning horizon.

When the unit retirement is neglected, the total expansion cost is 4.82E9. In the next step, as explained earlier, the unit retirement is considered for the postexpansion power system. The simulations resulted in four new 200-MW combined-cycle generation units in buses 1-, 5-, 7-, and 12-, and 60-MW hydro-unit at bus 18. This will lead to 843 million-dollars extra budget to take into account the generation unit's retirement. When the unit retirement is added to the expansion model, the total expansion cost is 5.17E9, which shows an approximately 350 million-dollar increase in the total expansion budget. This shows that incorporating the generation unit's retirement in the expansion model will enable the planner to compensate for the retirement of the generation units.

The multiobjective model is then implemented using α_L and α_C as two objective functions. The number of Pareto solutions in each Pareto front is selected to be 8. The Pareto fronts obtained by the epsilon-constraint method and NBI method for 24-bus IEEE test system are presented in Figs. 6 and 8, respectively.

It should be noted that from the NBI method for each U, all the eight solutions are obtained, while for epsilon-constraint method three solutions for U = 0.25, one solution for U = 0.75 and U = 1, and two solutions for U = 0.75 are repeated. For the 6-bus test system, the epsilon-constraint method did not return infeasible or repetitive solutions. This obviously shows that the NBI method is more efficient in dealing with large-scale optimization problems.

For U = 0.5 the solution with $\alpha_L = 0.6219$ and $\alpha_C = 0.0337$ is selected as the best compromise solution while α_L and α_C for the most preferred solution obtained by NBI method are 0.7591 and 0.015, respectively.

C. IEEE 118-Bus Test System

The IEEE 118-bus test system includes 91 loads, 54 generation units, as well as 186 branches. The annual rise in peak load for all buses is considered 10% each year. Therefore, by the end of the planning horizon, each bus's peak load will increase by 61%. The Pareto front for this case is presented in Fig. 8, when U is 0.75.

Comparing Figs. 7 and 8 shows that the range of α_C and α_L increased in the 118-bus test system. This means that in larger power systems, the robustness of the system would be less dependent on the cost, and that for a certain amount of total budget, the change in expansion decisions can result in a considerable change in robustness against uncertainties. This emphasizes the importance of robustness analysis in large-scale systems.

It is clear from Fig. 8 that α_L changes in a wider range as compared to α_C . For example, to increase α_C from 0.111 to 0.248, α_L decreased from 0.539 to 0.098. Therefore, it is expected that when the weighting factors are equal, the FDM method is inclined to choose solutions with better values for α_L because of its higher sensitivity to changes. The numerical results show that solution with $\alpha_C = 0.0197$ and $\alpha_L = 0.983$ is selected when the weighting factor for both objective functions are equal.

VI. Conclusion

This paper proposed a mixed-integer linear model for coordinated generation and TEP problem. Two sources of uncertainty are considered in this paper; load forecast and prices. In order to deal with the aforementioned uncertainties, a nondeterministic framework based on the IGDT method has been used. The mentioned uncertainties are in conflict with each other; therefore, to simultaneously maximize them, the normal boundary intersection method is used as a powerful and efficient multiobjective optimization method. The model enables the planner to build new fuel transportation routes when it leads to a more robust plan. The model implemented on Garver 6-bus test system, IEEE 24-bus, and IEEE 118-bus test systems. The results showed that the presented method is able to find a better solution in less run-time. It also succeeds to provide optimal solution when epsilon-constraint method returned infeasible or repetitive solutions. Simulation results also showed that the consideration of generation units retirement will decrease the cost needed for the compensation the outage of old generation units significantly.

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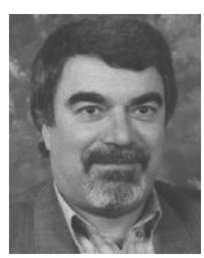

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