A Reliability Based Model for Generation and Transmission Expansion Planning

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ABSTRACT

This paper presents a mixed integer linear multi-objective model based on information gap decision theory (IGDT), which is used to solve coordinated multiyear generation and transmission expansion planning (G&TEP) problems. The model maximizes the robustness of each uncertain parameter while a maximum allowable budget range is set. Fuel transportation price is considered. The results provide a numerical tool for system planner to help him adjust the appropriate level of robustness for each uncertain parameter of the problem. Extra limits on security, gaseous emission, and fuel availability are considered. A multi-objective method called the ε-constraint method is used here to maximize the robust region of load and investment costs simultaneously. The model is implemented on a six-bus Garver test system and 24 bus IEEE test system. The numerical results show the good performance of the model.

Keywords: ε-constraint method, generation expansion planning, IGDT, mixed integer linear programming (MILP), transmission expansion planning.

NOMENCLATURE

Indices

i	index for busses
$tech$	index for available generation technologies
c	index for credible contingencies
t	index for year of planning horizon
s	index for fuel sources
cap	index for available transmission lines capacities
g	index for available generation capacities

Parameters

σ_{tech}	multiplier that relates the energy to operation cost for each technology
$D_{\text{s},i}$	the distance between fuel source s and bus i
$F_{2,s}$	the transportation price between fuel source s and bus i
$F_{1,s}$	the fuel price in fuel source s
ρ_c	possibility of contingency c
d	the discount rate
L_{cap}	the investment cost for transmission lines with capacity cap
$l_{i,j}$	distance between bus i and j
$G_{\text{tech,g}}$	the investment cost for candidate generation technology $tech$ with capacity g
FOR	forced outage rate
$L_{i,t}$	forecasted peak load in bus i in year t
$ELNS_t^{\max}$	maximum allowable ELNS in year t
$PG_{i,\text{tech}}^{initial}$	the total generation installed in pre-expansion conditions in bus i from technology $tech$
$P_{tech,g}^{new}$	the candidate generation capacities
$\theta^{\max}$	maximum allowable value for voltage angle
$\theta^{\min}$	minimum allowable value for voltage angle

M	a relatively large number
X_{cap}^{new}	the reactance matrix of candidate transmission lines
υ_{tech}	linear emission multiplier for technology *tech* α_{tech}
$EM_i^{\max}$	maximum allowable emission in bus i
ψ_{tech}	fuel consumption multiplier for technology *tech*
	maximum fuel capacity of fuel source *s* in year *t*
$T_{s,i}^{\max}$	the fuel transportation capacity between fuel source s and bus *i*
E_{fuel}	a table relating each fuel source to generation units with the same fuel type
	the contribution factor for generation technology *tech*
MH_{tech}	is the maximum operating hours for each technology for a year
$B_{i,j}^{ini}$	initial susceptance matrix
	transmission capacity between bus *i* and *j* in pre expansion condition
CA_{cap}	the candidate transmission capacities for each line
$L_{i,t}^{forecasted}$	forecasted peak load in bus i in year t
$L_{i,\mathrm{t}}^{actual}$	actual peak load in bus i in year t
$C^{inv,\mathrm{forecasted}}$	forecasted investment prices
$C^{inv,actual}$	actual investment prices
U	total budget bound

Variables

$E_{i,\mathrm{tech,c},t}$	energy generated in bus i with technology *tech* during contingency c in year t
$T_{\mathrm{s},i,\mathrm{tech,c},t}$	the amount of fuel transferred from fuel source *s* to bus *i* to be consumed by a generation unit with technology *tech* during contingency *c* in year *t*
C^{inv}	the total investment cost required for installation of new elements
DC	the total cost of planning when the robustness is not taken into consideration
$Y_{i,j,cap,t}$	binary decision variable that is one when transmission lines are planned to be installed in the power system between busses *i* and *j*, with capacity *cap* in year *t*
$Xg_{i,tech,g,t}$	binary decision variables that are one when generation units is planned to be installed in the power system in bus *i*, with technology *tech*, capacity *g* in year *t*
$ELNS$	Estimated Load not Supplied
$PG_{i,\mathrm{tech,g,c},t}$	the generated power of unit in bus *i* with technology *tech* and capacity *g* during contingency *c* in year *t*
$F_{\mathrm{s},t}^{\max}$ $LSH_{i,\mathrm{c},t}$	the amount of load shedding in bus *i* during contingency *c* in year *t*
$P_{i,\mathrm{c},t}^{inj}$	the power injected by bus *i* to the power grid during contingency *c* in year *t*
$PG_{i,\mathrm{tech,g},t}^{capacity}$	the generation capacity in post expansion condition
$\theta_{i,\mathrm{c,t}}$	voltage angles during contingency *c* in year *t*
$X_{i,j,t}$	reactance matrix in year *t*
$\Delta PG_{i,\mathrm{tech,g,t}}$	changes in generation capacity until year t compared to pre expansion condition
$W_{1,i,j,\mathrm{c},t}$	auxiliary variable for big M linearization technique which is equal to $\dfrac{\Delta\theta_{i,\mathrm{c},t}}{X_{cap}^{new}}$
$\Delta B_{i,j}$	change in susceptance matrix until year *t* of the planning horizon due to addition of new transmission lines
$\Delta P_{i,j,t}$	change in transmission capacity until year *t* of the planning horizon due to addition of new transmission lines
α_L	robust region for load
α_C	robust region for investment cost
RC	total cost in robust model
$W_{2,i,j,\mathrm{c},t}$	auxiliary variable for big M technique which is equal to $\alpha_c \times \mathrm{Y}_{i,\mathrm{j,cap},t}$
$W_{3,i,t}$	auxiliary variable for big M technique which is equal to $\alpha_c \times \mathrm{Xg}_{i,\mathrm{tech,g},t}$

I. INTRODUCTION

The power system expansion planning problem consists of two main components.

1) Generation expansion planning (GEP) which is intended to find the best size, location, installation time, and type of generation units while satisfying growing demand and technical generation unit constraints.

2) Transmission expansion planning (TEP), whose goal is to find the optimal way to handle power flow by the installation of new transmission lines and to determine their capacity and reactance (and number of bundles). TEP should also answer the question of when to add new transmission lines.

The problem is usually solved to maximize the long-term reliability criterion or to minimize the total planning cost, which consists of investment cost for new generation units and transmission lines and operation cost. The main component of operation cost for thermal units is the fuel cost [1].

The power system expansion planning problem is intrinsically a large-scale, non-linear, non-convex, and discrete optimization problem. In most cases, the problem should be converted to a linear problem in order to decrease the computational burden. Therefore, the DC model is usually used to model the transmission lines' power flow, since it can model the problem with acceptable precision while making the model much easier to solve compared to complete AC model [2]. This consideration results in neglecting reactive power planning, ohmic losses and voltage stability analysis. In this paper, since such studies are not performed, the use of DC model is suitable.

The power system expansion planning problem is exposed to several sources of uncertainties. The most significant uncertainties in the G&TEP problem are load forecast error [3] and component forced outage, which can be caused by a fault or failure. A good expansion plan has to deal with these uncertainties in an efficient and accurate manner. Several models are presented in the technical literature to solve non-deterministic problems [4]-[6].

The authors proposed a probabilistic model based on 2m point estimate method in [7] to cope with the uncertainty in coordinated multi-objective GEP-TEP problem. A very powerful tool for dealing with uncertainty, especially when historical data are not available or are insufficient, is the information gap decision theory (IGDT) which is introduced in [8]. It maximizes the robustness of solutions against uncertainty. In other words, the solutions have the maximum possible tolerance against uncertainty while providing the desired performance [9].

Robust frameworks [10] can be categorized into three types [11]. In Type I, worst-case uncertainty scenarios are incorporated into the problem. Taguchi’s orthogonal array testing (TOAT) [12] is used for that purpose. In type II [13], for each uncertain parameter an allowable range is specified, and then the problem is solved while the uncertainty is bound in the specified range. In type III, IGDT is used to find the robust solution and the objective function is bounded in a predefined allowable range for a definite uncertainty budget [14].

A multi-objective IGDT-based linear model for TEP problems is presented in [11]. Two sources of uncertainty are considered, investment cost and forecast load, and the epsilon constraint method is used to solve the multi-objective problem of maximizing the robust regions for a specified budget limit. [11] has neglected some important aspects of power system expansion planning problem such as gaseous emission, system security and fuel constraints. It also has not considered the generation expansion planning. In [15] a robust model is introduced to solve TEP problems. Estimated investment cost and forecast system load are considered as sources of uncertainty.

In the present paper, an IGDT-based formulation is presented for solving multi-objective coordinated multi-year generation and transmission expansion planning problems. The main contributions of this paper are as follows.

1) The model propose a method to calculate the required cost for different levels of reliability. This can help the system planner to make a tradeoff between cost and robustness.

2) A comprehensive model for coordinated generation and transmission expansion planning problems considering fuel and emission constraints, system reliability, and emission is proposed in this paper. The presented Mixed model is able to address the most important aspects of expansion planning problem in an efficient way.

3) Fuel transportation and fuel availability constraint are considered in this paper to build a more realistic model for generation and transmission expansion planning. The model takes into account the refinery fuel production constraint and limit on fuel transportation.

The remainder of the paper is organized as follows: The mathematical formulation of the multi-year simultaneous generation and transmission expansion planning problem is presented in Section II. In section II, first the model is described without consideration of robustness and then the robustness is incorporated into the model via IGDT approach. In Section III a description of multi-objective optimization and the epsilon constraint method is presented. Numerical results and some discussion is provided in Section IV. Section V concludes the paper.

II. MODEL CHARACTERISTICS

In this paper the model is first solved without consideration of robustness. Then IGDT is implemented to incorporate the robustness into the model.

A. the model without consideration of robustness

The total planning cost can be expressed as shown in (1) and (2). DC is the total cost of planning when the robustness is not taken into consideration. (1) consists of three sentences. C^{inv} is the total investment cost required for installation of new elements which is formulated in (2).The second sentence is the fuel cost, which is considered non-uniform across the system. d is the discount rate. $T_{s,i,\text{tech},c,t}$ is the amount of fuel transferred from fuel source s to bus i to be consumed by a generation unit with technology *tech* during contingency c in year t. $F_{1,s}$ is the fuel price in fuel source s and $F_{2,s}$ is the transportation price between fuel source s and bus i. As seen in (1) the cost of fuel transportation is proportional to the distance between fuel sources and buses ($D_{s,i}$).The third sentence is allocated to the operation cost, which is modeled as a linear function of energy generated by each generation unit. σ_{tech} is the multiplier that relates the energy to operation cost for each technology. $Xg_{i,tech,g,t}$ and $Y_{i,j,cap,t}$ are the binary decision variables that are one when generation unit and transmission lines are planned to be installed in the power system, respectively. $G_{\text{tech,g}}$ is the investment cost for candidate generation technology *tech* with capacity g. It is assumed that larger generation units have less investment cost per MW. L_{cap} is the investment cost for transmission lines with capacity *cap*.

$$DC = C^{inv} + \sum_t \sum_c \frac{\rho_c}{(1+d)^{t-1}} \times \left(\sum_{tech} \sum_s \sum_i T_{s,i,\text{tech},c,t} \times (F_{1,s} + F_{2,s} \times D_{s,i}) + \sum_{tech} \sum_i \sigma_{\text{tech}} \times E_{i,\text{tech},c,t} \right) \tag{1}$$

$$C^{inv} = \sum_t \left(\sum_i \sum_{tech} \sum_g G_{\text{tech,g}} \times (Xg_{i,\text{tech},g,t} - Xg_{i,\text{tech},g,t-1}) + \sum_i \sum_{j \neq i} \sum_{cap} l_{i,j} \times L_{cap} \times (Y_{i,j,\text{cap},t} - Y_{i,j,\text{cap},t-1}) \right) \tag{2}$$

ρ_c is the probability of each contingency. $E_{i,\text{tech},c,t}$ is the energy generated in bus i with technology *tech* during contingency c in year t. The probability of contingencies can be obtained from the forced outage rate (FOR) of each element. In this paper, the probability of more than one outages at a time is neglected for the sake of simplicity. In addition, the outage of transmission lines outage is neglected since it is relatively rare [16].This assumption leads to much less scenarios. The probability of each contingency is calculated as follows:

$$\rho_c = \frac{FOR_c}{1-FOR_c} \prod_{c=1}^{C} (1-FOR_c), \ \forall c \tag{3}$$

The ELNS (Estimated Load not Supplied) index is used to evaluate the system reliability [17]. To calculate the ELNS the following equations should be used:

$$\sum_g \sum_{tech} PG_{i,\text{tech},g,c,t} - L_{i,t} + LSH_{i,c,t} = P_{i,c,t}^{inj} \quad \forall i, \forall c, \forall t \tag{4}$$

$$PG_{i,\text{tech},g,c,t} \le PG_{i,\text{tech},g,t}^{capacity} \quad \forall i, \forall c, \forall t \tag{5}$$

$$P_{i,c,t}^{inj} = \sum_j \frac{\theta_{i,c,t} - \theta_{j,c,t}}{X_{i,j,t}} \qquad \forall i, \forall c, \forall t \tag{6}$$

$$0 \le LSH_{i,c,t} \le L_{i,t} \quad \forall i, \forall c, \forall t \tag{7}$$

$$ELNS_t = \sum_i \sum_c \rho_c \times LSH_{i,c,t} \le ELNS_t^{\max} \quad \forall t \tag{8}$$

where $PG_{i,\text{tech},g,c,t}$ is the generated power of unit in bus i with technology *tech* and capacity g during contingency c in year t. The amount of $PG_{i,\text{tech},g,c,t}$ is limited to its capacity in (5). The capacity can be changed due to new generation units installation during planning horizon. $L_{i,t}$ is the forecast peak load in bus i for year t. In this paper, the model is based on peak load condition. $LSH_{i,c,t}$ is the amount of load shedding in bus i during contingency c in year t. $P_{i,c,t}^{inj}$ is the power injected by bus i to the power grid during contingency c in year t. (4) is the power balance equation for yearly peak load. (6) is the DC power flow equation that relates the voltage angles to line reactance. (7) shows that the amount of load shedding in each bus cannot be more than load at that bus. The amount of ELNS for each year is constrained by (8).

The power generated by each generation unit is limited to its nominal power output. In this paper, the lower bound of power output is neglected for simplicity.

$$0 \le PG_{i,\text{tech},g,t}^{capacity} = \Delta PG_{i,\text{tech},g,t} + PG_{i,\text{tech}}^{initial}, \quad \forall i, \forall \text{tech}, \forall g, \forall c, \forall t \tag{9}$$

$$\Delta PG_{i,\text{tech},g,t} = Xg_{i,\text{tech},g,t} \times P_{tech,g}^{new} \qquad \forall i, \forall tech, \forall g, \forall t \tag{10}$$

where $PG_{i,\text{tech}}^{initial}$ is the total generation installed in pre-expansion conditions in bus i from technology *tech*. $P_{tech,g}^{new}$ shows the candidate generation capacities.

The voltage angle is limited between minimum and maximum values because of angular voltage stability [18] considerations:

$$\theta^{\min} \le \theta_{i,c,t} \le \theta^{\max} \quad \forall i, \forall c, \forall t \tag{11}$$

(6) is non-linear because of the division of two variables, θ and X, by each other. Therefore, in this paper the big M linearization technique is used to keep the linearity of the model. The following equations should be used:

$$W_{1,i,j,c,t} + M \times Y_{i,j,cap,t} \le M + \frac{\Delta\theta_{i,c,t}}{X_{cap}^{new}} \quad \forall i, \forall j, \forall cap, \forall c, \forall t \tag{12}$$

$$W_{1,i,j,c,t} - M \times Y_{i,j,cap,t} \ge -M + \frac{\Delta\theta_{i,c,t}}{X_{cap}^{new}} \quad \forall i, \forall j, \forall cap, \forall c, \forall t \tag{13}$$

$$W_{1,i,j,c,t} - M \sum_{cap} Y_{i,j,cap,t} \le 0 \quad \forall i, \forall j, \forall c, \forall t \tag{14}$$

$$W_{1,i,j,c,t} + M \sum_{cap} Y_{i,j,cap,t} \ge 0 \quad \forall i, \forall j, \forall c, \forall t \tag{15}$$

where $W_{1,i,j,c,t}$ is an auxiliary variable, M is a very large value, X_{cap}^{new} is the reactance matrix of candidate transmission lines. When $Y_{i,j,cap,t}$ is one, (14) and (15) are converted to (16) and can be neglected. Therefore, only (12) and (13) are considered. On the other hand if $Y_{i,j,cap,t}$ is zero only (14) and (15) are considered. (12) and (13) are converted to (17) in this situation.

$$\begin{cases} W_{1,i,j,c,t} \le M = \infty \\ W_{1,i,j,c,t} \ge -M = -\infty \end{cases} \rightarrow -M \le W_{1,i,j,c,t} \le M \quad \forall i, \forall j, \forall c, \forall t \tag{16}$$

$$\begin{cases} W_{1,i,j,c,t} \le 0 \\ W_{1,i,j,c,t} \ge 0 \end{cases} \rightarrow W_{1,i,j,c,t} = 0 \quad \forall i, \forall j, \forall c, \forall t \tag{17}$$

The amount of gaseous emission is modeled as a linear function of energy generated by generation units as follows:

$$\sum_{tech} \upsilon_{tech} \times E_{i,tech,c,t} \le EM_i^{\max} \quad \forall t, \forall c \tag{18}$$

where υ_{tech} is the emission multiplier and EM_t^{max} is the maximum allowed emission in each bus for each year and in any contingency.

The following equations show the fuel sources and fuel transportation limits. Each fuel source can provide a limited amount of fuel in each year ($F_{tech,t}^{\max}$):

$$\sum_{tech} \sum_{i} T_{s,i,tech,c,t} \le F_{s,t}^{\max}, \quad \forall c, \forall t \tag{19}$$

$$\sum_{tech} T_{s,i,tech,c,t} = T_{s,i}^{\max} \quad \forall s, \forall c, \forall t \tag{20}$$

where $T_{s,i}^{\max}$ is the fuel transportation capacity between fuel source s and bus i. Additionally, each generation unit fuel demand should be met:

$$\sum_{s}^{s \in E_{fuel}} T_{s,i,tech,c,t} = \psi_{tech} \times E_{i,tech,c,t} \quad \forall i, \forall tech, \forall c, \forall t \tag{21}$$

where E_{fuel} is a table relating each fuel source to generation units with the same fuel type. As seen in (19) and (21), the fuel consumption of each generation unit is modeled as a linear function of the unit's generated energy. Energy generation for each generation unit is constrained in (22).

$$\alpha_{tech} \times MH_{tech} \times PG_{i,tech,g,t}^{capacity} \le E_{i,tech,c,t} \le MH_{tech} \times PG_{i,tech,g,t}^{capacity} \quad \forall i, \forall tech, \forall g, \forall t \tag{22}$$

where α_{tech} is the contribution factor for generation technology *tech*. It is a value between zero and one. For base load technologies such as steam power plants it is close to one and for peak load technologies such as gas turbines it is close to zero. MH_{tech} is the maximum operating hours for each technology for a year.

Finally, the power flow constraints can be written as follows [19]:

$$-P_{i,j}^{\max} \le B_{i,j}^{ini} \times (\theta_i - \theta_j) \le P_{i,j}^{\max} \quad existing \ \ lines \quad \forall i, \forall j \tag{23}$$

$$-\Delta P_{i,j,t} \le \Delta B_{i,j,t} \times (\theta_i^{ini} - \theta_j^{ini}) + W_{1,j,i,c,t} - W_{1,i,j,c,t} \le \Delta P_{i,j,t} \quad new \ \ lines \quad \forall i, \forall j, \forall c, \forall t \tag{24}$$

$$\Delta P_{i,j,t} = \sum_{cap} Y_{i,j,cap,t} \times CA_{cap} \quad \forall i, \forall j, \forall t \tag{25}$$

$$\Delta B_{i,j,t} = \sum_{cap} \frac{Y_{i,j,cap,t}}{X_{cap}^{new}} \quad \forall i, \forall j, \forall t \tag{26}$$

$\Delta P_{i,j,t}$ and $\Delta B_{i,j,t}$ are the change in capacity and susceptance of transmission system. CA_{cap} is the candidate transmission capacities for each line. The change in installed generation capacity is shown in (27):
It is obvious that once the decision variables $\mathrm{Xg}_{i,\mathrm{tech,g},t}$ and $\mathrm{Y}_{i,\mathrm{j,cap},t}$ become one they cannot change back to zero.

$$Xg_{i,\mathrm{tc,g},t-1} \leq X\,\mathrm{g}_{i,\mathrm{tc,g},t} \quad \forall i, \forall tc, \forall g, \forall t \tag{27}$$

$$Y_{i,\mathrm{j,cap},t-1} \leq Y_{i,j,\mathrm{cap},t} \quad \forall i, \forall j, \forall cap, \forall t \tag{28}$$

In (27) addition of generation units with different capacities or technology is possible during planning horizon. Same assumption for transmission lines is made in (28).

B. Robust GEP-TEP Formulation

In the model that is described in the previous sub-section, the uncertainty sources were disregarded and only the failure of generation units was considered. In this subsection, an envelope-bound IGDT [9] is used together with augmented-weighted epsilon constraint method to maximize the robustness of the model while keeping the cost, ELNS, emission and fuel consumption within the allowed range. Load forecast and investment costs are considered as two main sources of uncertainty.
Uncertainty in a model can have two different effects. It can make the actual values better than forecast values and, on the other hand, it can be harmful when the uncertain values such as system load are worse than expected. Two immunity functions are used in IGDT to deal with the aforementioned aspects of robustness and opportunity [14].
Any change in uncertain parameters, which are load and investment prices here, lead to different values for total cost. Therefore, the total cost is a function of load and investment costs.
Each uncertain parameter is bounded as follows:

$$-\alpha_L \leq \frac{L_{i,\mathrm{t}}^{actual} - L_{i,t}^{forecasted}}{L_{i,t}^{forecasted}} \leq \alpha_L \quad \rightarrow (1-\alpha_L) \times L_{i,t}^{forecasted} \leq L_{i,\mathrm{t}}^{actual} \leq (1+\alpha_L) \times L_{i,t}^{forecasted} \quad \forall i, \forall t \tag{29}$$

$$-\alpha_C \leq \frac{C^{inv,actual} - C^{inv,\mathrm{forecasted}}}{C^{inv,\mathrm{forecasted}}} \leq \alpha_C \quad \rightarrow (1-\alpha_C) \times C^{inv,\mathrm{forecasted}} \leq C^{inv,actual} \leq (1+\alpha_C) \times C^{inv,\mathrm{forecasted}}, \tag{30}$$

where α_C and α_L are positive variables. As seen in (29) and (30) the robust region of uncertain parameters can be adjusted by using α_C and α_L. First, the model, which is described in the previous subsection, is solved and DC is obtained. Then through the following multi-objective optimization problem α_C and α_L can be obtained for different values of *U*.

$$\mathrm{Max}\ (\alpha_C, \alpha_L) \tag{31}$$

subject to:

$$\mathrm{RC} \leq (1+\mathrm{U}) \times \mathrm{DC} \tag{32}$$

while other problem constraints are set. In the formulation of (1)-(28), the following substitutions should be made:

$$\begin{cases} L_{i,t} \rightarrow (1+\alpha_L) \times L_{i,t} & \forall i, \forall t \\ C^{inv} \rightarrow (1+\alpha_C) \times C^{inv} \end{cases} \tag{33}$$

(32) limits the total cost in the robust model, to a desirable value. By tuning the *U*, the system planner can select different levels of robustness depending on how much he or she is willing to spend on robustness.

As a result, equations (2), (4), (7) are converted to equations (34)-(36) respectively.

$$C^{inv,robust} = \sum_t \sum_c \frac{(1+\alpha_C)}{(1+d)^{t-1}} \times \left(\sum_i \sum_{tech} \sum_g G_{\mathrm{tech,g}} \times (\mathrm{Xg}_{i,\mathrm{tech,g},t} - Xg_{i,\mathrm{tech,g},t-1}) + \sum_i \sum_{j \neq i} \sum_{cap} l_{i,j} \times L_{cap} \times (\mathrm{Y}_{i,\mathrm{j,cap},t} - Y_{i,j,\mathrm{cap},t-1}) \right) \tag{34}$$

$$\sum_g \sum_{tech} PG_{i,\mathrm{tech,g,c},t} - (1+\alpha_L) L_{i,t} + LSH_{i,\mathrm{c},t} = P_{i,\mathrm{c},t}^{inj} \quad \forall i, \forall c, \forall t \tag{35}$$

$$0 \leq LSH_{i,\mathrm{c},t} \leq (1+\alpha_L) \times L_{i,t} \quad \forall i, \forall c, \forall t \tag{36}$$

The multiplication of α_C with $\mathrm{Xg}_{i,\mathrm{tech,g},t}$, $Xg_{i,\mathrm{tech,g},t-1}$, $\mathrm{Y}_{i,\mathrm{j,cap},t}$ and $Y_{i,j,\mathrm{cap},t-1}$ generate four nonlinear terms. To eliminate the non-linearity of the model the big M technique is used again as follows:

$$W_{2,i,j,\mathrm{c},t} + (M \times \mathrm{Y}_{i,\mathrm{j,cap},t}) \leq M + \alpha_c \quad \forall i, \forall j, \forall cap, \forall c, \forall t \tag{37}$$

$$W_{2,i,j,\mathrm{c},t} - (M \times \mathrm{Y}_{i,\mathrm{j,cap},t}) \geq -M + \alpha_c \quad \forall i, \forall j, \forall cap, \forall c, \forall t \tag{38}$$

$$W_{2,i,j,c,t} - M\sum_{cap} Y_{i,j,cap,t} \le 0 \quad \forall i, \forall j, \forall c, \forall t \tag{39}$$

$$W_{2,i,j,c,t} + M\sum_{cap} Y_{i,j,cap,t} \ge 0 \quad \forall i, \forall j, \forall c, \forall t \tag{40}$$

$$W_{3,i,t} + M \times \mathrm{Xg}_{i,\mathrm{tech},g,t} \le M + \alpha_c \quad \forall i, \forall tech, \forall g, \forall t \tag{41}$$

$$W_{3,i,t} - M \times \mathrm{Xg}_{i,\mathrm{tech},g,t} \ge -M + \alpha_c \quad \forall i, \forall tech, \forall g, \forall t \tag{42}$$

$$W_{3,i,t} - M\sum_{tech}\sum_{g} \mathrm{Xg}_{i,\mathrm{tech},g,t} \le 0 \quad \forall i, \forall t \tag{43}$$

$$W_{3,i,t} + M\sum_{tech}\sum_{g} \mathrm{Xg}_{i,\mathrm{tech},g,t} \ge 0 \quad \forall i, \forall t \tag{44}$$

where $W_{2,i,j,c,t}$ and $W_{3,i,t}$ are auxiliary variables defined as follows:

$$\begin{cases} W_{2,i,j,c,t} = \alpha_c \times \mathrm{Y}_{i,j,cap,t} \\ W_{3,i,t} = \alpha_c \times \mathrm{Xg}_{i,\mathrm{tech},g,t} \end{cases} \tag{45}$$

The aim of proposed robust model is to maximize the α_C and α_L. The larger value for α_C and α_L means that the expansion plan can resist more forecast error with predefined level of budget. In other words, larger values of α_C and α_L means more robustness against uncertainties associated with load and investment cost.

III. MULTI-OBJECTIVE OPTIMIZATION USING EPSILON CONSTRAINT METHOD

Problems with more than one objective function are called multi-objective problems [20-22]. Since in this type of problem objective functions are usually in conflict with each other, it is impossible to find a unique solution that optimizes all of the objective functions at the same time. Instead, a set of solutions called the Pareto front is obtained [23-25]. The Pareto front is a set of solutions that can be improved in one objective only when another objective is worsened. In the end, a compromise should be made between different objective functions to obtain the final solution.

A. *Epsilon Constraint Method*

In this paper, an augmented-weighted epsilon constraint method obtained by lexicographic optimization [26] is used to solve the multi-objective problem. One objective function is considered as the main objective function and the other objective functions are treated as extra constraints. The method is detailed below.

B. *Problem Solution Using Epsilon Constraint Method*

The mathematical formulation for a bi-objective GEP-TEP maximization problem can be expressed as follows [27]:

$$\min \left[q_1 \times O_1 + q_2 \times \frac{r_1 \times s_2}{r_2} \right] \tag{45}$$

subject to:

$$e_i = O_i - s_i \quad for \quad i = 1, 2; \tag{46}$$

$$e_i^k = (\mathrm{O}_i^{\min} - \mathrm{O}_i^{\max}) + \frac{r_i^k}{q_i} \tag{47}$$

where O_i is the i^{th} objective function, k is index for grid points. q_i is the importance factor for i^{th} objective function. s_i is the surplus variable for the constraints and r_i is the range of i^{th} objective function. r_i should be obtained before using (45)-(47). Usually a pay-off table is calculated to obtain the range of each objective function. In order to calculate the pay-off table elements (a_{ij}) the following steps should be used [28].

1) The main objective function is selected.
2) The problem is solved as a single objective problem, using main objective function as the only objective function and the first element of the pay-off table (a_{11}) is obtained.

3) To obtain a_{21}, the single objective problem is solved, using second objective function as only objective, while the main objective function is constrained to a_{11} .

4) To obtain a_{22} , the single objective problem is solved, using the second objective function as the only objective

5) To obtain a_{12}, the single objective problem is solved, using the main objective function as only objective, while the second objective function is constrained to a_{22}.

Finally, the difference between the minimum and maximum value of each objective function in the pay-off table gives r_i. The augmented epsilon constraint method divides the range of extra objective functions into n-1 intervals. n is set by the planner. A larger value of n means more Pareto optimal solutions; in other words, larger values of n lead to a more accurate search in Pareto space. Considering the minimum and maximum values of each objective function, n+1 grid points exist for each objective function. In this paper, only one extra objective function is used so the number of Pareto solutions is equal to n+1. This means the single objective problem is solved n+1 times. More detailed discussion on epsilon constraint method can be found in [26], [27]. In this paper FDM (see [29]) is used as a tool for selecting the most preferred solution.

IV. NUMERICAL RESULTS

Some simulation results are presented in this section to verify the good performance of the proposed multi-objective multi- year GEP-TEP model. All simulations of this paper are implemented with a CPLEX 12.3 solver within the GAMS software package [30] on a 2.2-GHz Core i7 with 8 GB RAM platform.

The proposed IGDT-based GEP-TEP model is implemented on the modified Garver's six-bus test system [31] and IEEE 24 bus test system [32]. Discount rate and maximum voltage angle are assumed 5% and 45 degrees, respectively. Candidate generation unit data are presented in Table I. The available capacities for generation and transmission facilities are presented in Tables II and III, respectively.

TABLE I

CANDIDATE GENERATION UNITS DATA

type	σ_{tech}	υ_{tech}	MH_{tech}	α_{tech}	ψ_{tech}
Hydro	8	0	6000	0.3	0.1
Gas	58	0.231	3000	0.1	0.76
Steam	28	0.173	4000	0.7	0.68
Combined	25	0.116	5000	0.8	0.52

TABLE II

AVAILABLE GENERATION UNITS CAPACITY IN MW ($P^{new}_{tech,g}$)

type	1	2	3	4
Hydro	62.5	70	82.5	
Gas	27	34	40	45
Steam	75	95	112.5	127.5
Combined	148.5	168	180	190

TABLE III

AVAILABLE TRANSMISSION LINES CAPACITY IN MW (CA_{cap})

cap	1	2	3	4	5	6	7	8
capacity (MW)	50	80	100	120	150	180	200	225

A. Garver's 6-bus test system

The model consists of 49 blocks of equations, 26 blocks of variables, 805,078 non-zero variables, 297,272 single equations, 25258 single variables and 3100 discrete variables.

Four types of generation units are considered in this paper: steam, hydro, gas and combined cycle power plants. The capacity of all the existing transmission lines is assumed to be 75 MW.

Four fuel sources are considered in this paper. In this paper, first, the robust region of the forecasted load is optimized by considering different bounds on the uncertainty budget (U) and then a multi-objective framework is implemented for optimizing α_c and α_L simultaneously, using the augmented epsilon constraint method. Before that, it is necessary to find the DC by solving the single objective GEP-TEP problem which is defined by (1)-(28). The DC is 747.1 M$ in this case. The optimal plan in this case is presented in Table IV.

Table V shows the optimal robust ranges of α_L for different uncertainty budgets in three cases.

1. There is no limit on annual budget.
2. The annual budget is limited to 200M$ per year.
3. The annual budget is limited to 100 M$ per year.

As seen in table V, an increasing uncertainty budget leads to an increase in α_L until a certain value, which is called UC in this paper. For *U* greater than UC, the value of α_L remains unchanged. The reason is that when the annual budget is limited to a certain amount, for example 200 M$, the total planning cost is limited to one billion dollars (5×200). Therefore, according to (31) the α_L cannot be larger than a maximum amount. Because even if the total expansion cost limit is very large, the annual budget limit will bind the total cost. When the total cost cannot be increased, the α_L will remain unchanged. The value of UC is 0.65 in case 3 and 0.314 for case 2.

As seen in table V, for U=0, α_L is not zero. This means the post-expansion power system is capable of supplying a greater load without increasing the cost but in expense of decreased reliability and emission. Also it can be seen in table that the larger U results in larger ranges for both α_L and α_c.

The investment cost of new generation and transmission facilities can be considerably different from their forecasted values. Therefore, it is necessary to consider this source of uncertainty when dealing with a power system expansion planning problem. The investment cost uncertainty (α_C) is added as an extra objective function in this paper and the bi-objective optimization problem is solved using epsilon constraint method. The α_C range is divided into seven equal intervals to find eight Pareto front solutions for each U.

The results are shown in fig. 1. It can be seen in fig. 1 that by increasing U, which means spending more budget, the robustness of the plan is improved. This means the robust region of each objective function is increased. The system planner has to make a compromise between the total planning cost and robustness of obtained plan against uncertainty but before that, for each U, one solution should be selected as the most preferred solution of the Pareto solutions.

Fuzzy decision-making (FDM) is used in this paper to perform this task. With the use of FDM, the planner can determine the quality of solutions in terms of membership function. In the FDM the planner is able to change the weighting factor for each objective. Higher weighting factors for each objective function means that the objective function has higher priority for the system planner. Table VI shows the total membership functions in two cases:

1) U=0.75 and weighting factors for α_L and α_c of 10 and 1, respectively.

2) U=0.75 and equal weights for α_L and α_c

In Table VI, MF indicates the total membership function of the selected solution obtained by FDM.

The best solution in case 1 has total membership equal to 0.909. This solution has the highest α_L, e.g. 1, which was predictable since we chose a much higher weighting factor for load uncertainty than for investment cost uncertainty. This leads to a relatively low value for α_c (which is zero in this case). Of course, this is not acceptable. Therefore, for a fair decision, the planner should change the weighting factors.

The 8th solution is selected as the best solution in case 2 (α_L =0.377 and α_c =0.881.). This happens because the range of α_C is much less than the α_L range so the investment cost uncertainty trend has more effect on membership function changes. It is seen in Table VI that the selected solution in this case has the most α_c and the lowest α_L.

TABLE IV
OPTIMAL EXPANSION PLAN WHEN IGDT IS NOT CONSIDERED

year	Added elements
t=1	40 MW Gas unit at bus 5, 70 MW Hydro unit at bus 6
t=2	200 MW Combined unit at bus 5
t=3	no addition
t=4	no addition
t=5	200 MW Combined unit at bus 4, 150 MW Steam unit at bus 2

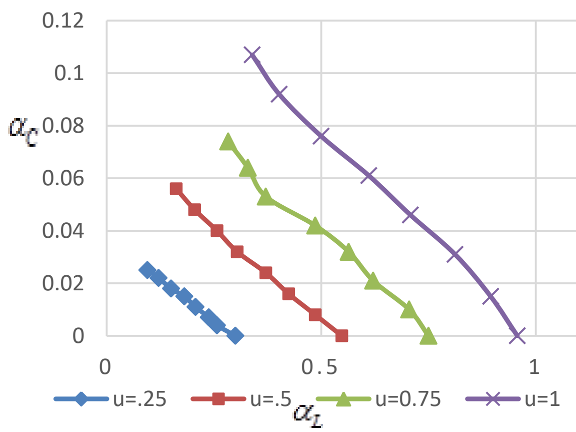

Fig. 1. Pareto optimal solutions obtained by augmented epsilon constraint method for 6 bus test system

The best expansion plan obtained by FDM for U=1 in case 2 is shown in Table VII. The total cost in this case is 1472.4 M$. The highest generation capacity is added to bus 1 (430 MW). The total transmission capacity connected to bus 1 is 225 MW. Therefore, there is a need to connect more transmission lines to bus 1. As seen in Table VII, all the transmission lines are added to bus 1 to make the transmission of the generated load in bus 1 possible.

Comparison of tables VII and IV shows the effect of IGDT on the proposed model. It is obvious that the robust model tends to generate larger generation units and therefore needs more transmission lines to transfer the generated energy to the loads. This leads to more total cost (1472.4-790.8=681.6 M$). This extra budget is spent to decrease the vulnerability of the expansion plan against the forecast error in load and investment cost. In fact, the proposed model enabled the system planner to calculate the required budget for a certain level of robustness. This can considerably help the system planners to decide the level of robustness required for the system.

TABLE V

α_L AGAINST UNCERTAINTY BUDGET FOR DIFFERENT VALUES OF ANNUAL BUDGET

U	case1	case2	case3	U	case1	case2	case3
0	0.043	0.036	0.043	0.6	0.655	0.314	0.624
0.05	0.09	0.081	0.09	0.65	0.719	0.314	0.66
0.1	0.15	0.129	0.15	0.7	0.752	0.314	0.643
0.15	0.214	0.176	0.2	0.75	0.807	0.314	0.652
0.2	0.257	0.224	0.243	0.8	0.842	0.314	0.645
0.25	0.31	0.274	0.292	0.85	0.892	0.314	0.645
0.3	0.36	0.3	0.338	0.9	0.949	0.314	0.66
0.35	0.414	0.314	0.388	0.95	0.948	0.314	0.652
0.4	0.457	0.314	0.44	1	0.948	0.314	0.652
0.45	0.511	0.314	0.471	1.05	0.948	0.314	0.652
0.5	0.555	0.314	0.514	1.1	0.948	0.314	0.64
0.55	0.625	0.314	0.581				

TABLE VI

COMPARISON BETWEEN MEMBERSHIP FUNCTIONS FOR LOAD AND INVESTMENT COST UNCERTAINTY AND TOTAL MEMBERSHIP FUNCTION FOR CASE 1 AND CASE 2

no.	α_c	α_L	total membership in case 1	total membership in case2
1	0	1	0.909	0.5
2	0.119	0.94	0.865	0.53
3	0.25	0.828	0.775	0.539
4	0.381	0.752	0.718	0.566
5	0.5	0.648	0.635	0.574
6	0.631	0.495	0.507	0.563
7	0.762	0.439	0.468	0.6
8	0.881	0.377	0.423	0.629

TABLE VII

OPTIMAL EXPANSION PLAN FOR U=1 AND EQUAL WEIGHTING FACTORS

year	Added element
t=1	160 MW Combined unit at bus 5
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 1, 50 MW Hydro unit at bus 6, 150 MW between bus 1 and bus 4, 180 MW between bus 1 and bus 4
t=5	180 MW Combined unit at bus 1, 2*150 MW between bus 1 and bus 2, 200 MW Combined unit at bus 6, 50 MW Hydro unit at bus 1

B. IEEE 24 bus test system

The model is implemented on IEEE 24 bus test system as a larger system to verify the good performance of the proposed method when the size of the optimization problem is large. 8 Pareto fronts for 4 different values of U are generated using epsilon constraint method. The Pareto fronts in this case are presented in fig. 2.

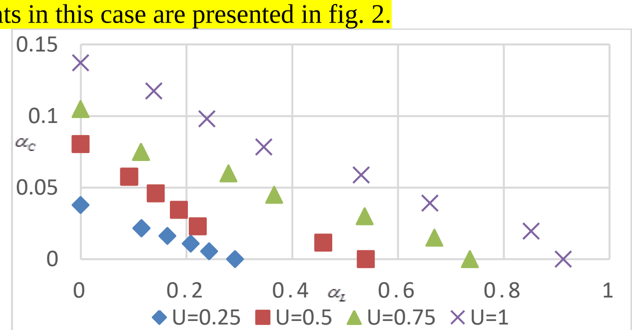

Fig. 2. Pareto optimal solutions obtained by augmented epsilon constraint method for 24 bus test system

As seen in fig. 2, α_L and α_c increase for higher values of *U*. For *U*=0.25, 2 solutions are repeated and 6 distinctive solutions are obtained, for *U*=0.5 and *U*=0.75, one solutions is repeated and for *U*=1 no solutions is repeated. This shows that since for larger values of U the problem is less constrained, therefore the possibility of infeasible or repeated solutions is less. The FDM is used to find the best solution for different values of U. The results are shown in table VIII for two different cases, *A*) when weighting factors are equal, *B*) when the weighting factor for α_C and α_L are 2 and 3, respectively. It can be seen in table VIII that higher weighting factor for α_L in case b, always has led to lower values for α_C.

For more detailed comparison, the best solution obtained in each case for U=0.25 are shown in table IX. In case *B*, the uncertainty in load demand is more important for the system planner, therefore higher values for α_L are obtained. This means the model in this case should provide load demand up to 24.3% more than forecasted. This value is 11.49% for case *A*. To provide more robustness against load forecast inaccuracy, extra generation units should be built in case *B* but since U is equal for both cases, the total expansion cost is the same. Therefore, in case *B*, the model intends to build larger generation units because of their cheaper per MW cost. The numerical results show that in case *B*, 300 MW more generation capacity is built while the average capacity of new generation units is 13.9% higher than case *A*. It is proven that use of larger generation units can decrease the reliability indices [17]. The numerical results show that in case *B*, the average amount of *ELNS* in each year is 26.4 MW more than case *A*.

TABLE VIII
BEST SOLUTIONS OBTAINED BY FDM

U	case A		case B	
	α_c	α_L	α_c	α_L
0.25	0.021579851	0.114926513	0.005501887	0.243087035
0.5	0.057533969	0.091815599	0.011492488	0.458788899
0.75	0.074892457	0.114081996	0.01497851	0.669020338
1	0.117500614	0.138355759	0.019583436	0.851851852

TABLE IX
NEW GENERATION UNITS IN CASE A AND CASE B

year	Case A	Case B
t=1	150 MW steam unit at bus 3, 160 MW combined cycle unit at bus 3, 200 MW combined cycle unit at bus 4, 125 MW steam unit at bus 5, 150 MW steam unit at bus 6, 200 MW combined cycle unit at bus 8, 200 MW combined cycle unit at bus 9, 200 MW combined cycle unit at bus 10, 200 MW combined cycle unit at bus 11, 150 MW steam unit at bus 11, 200 MW combined cycle unit at bus 12, 200 MW combined cycle unit at bus 15, 150 MW steam unit at bus 14, 40 MW hydro unit at bus 16, 150 MW steam unit at bus 17,	200 MW combined cycle unit at bus 3, 125 MW steam unit at bus 4, 125 MW steam unit at bus 5, 200 MW combined cycle unit at bus 6, 200 MW combined cycle unit at bus 8, 200 MW combined cycle unit at bus 9, 60 MW hydro unit at bus 10, 200 MW combined cycle unit at bus 10, 200 MW combined cycle unit at bus 11, , 150 MW steam unit at bus 11, , 150 MW steam unit at bus 12, 60 MW hydro unit at bus 12, 200 MW combined cycle unit at bus 14, 200 MW combined cycle unit at bus 15, 60 MW hydro unit at bus 16, 200 MW combined cycle unit at bus 17
t=2	60 MW hydro unit at bus 19, 60 MW hydro unit at bus 20, 50 MW hydro unit at bus 24 , 60 MW gas turbine at bus 15	30 MW gas turbine at bus 3, 50 MW hydro unit at bus 8, 60 MW gas unit at bus 9, 200 MW combined cycle unit at bus 12, 135 MW steam unit at bus 19, 30 MW gas turbine at bus 24
t=3	60 MW hydro unit at bus 10, 60 MW hydro unit at bus 12 , 60 MW hydro unit at bus 15, 30 MW gas turbine at bus 15	60 MW gas turbine at bus 3, 60 MW hydro unit at bus 15, 160 MW combined cycle unit at bus 16
t=4	60 MW hydro unit at bus 6, 60 MW gas turbine at bus 8, 60 MW hydro unit at bus 9, 70 MW hydro unit at bus 17	60 MW hydro unit at bus 1, 40 MW gas turbine at bus 6, 60 MW gas turbine at bus 10, 135 MW combined cycle unit at bus 11,
t=5	60 MW gas turbine at bus 9, 150 MW steam unit at bus 12, 70 MW steam unit at bus 15, 30 MW gas turbine at bus 3	180 MW combined cycle unit at bus 8

V. CONCLUSION

This paper proposed a mixed integer linear programming (MILP) model for simultaneous GEP-TEP problems. The uncertainties in electricity demand and investment costs are dealt with through a new non-deterministic framework. The proposed framework uses the IGDT method to handle uncertainty. The proposed IGDT-based model enables the planner to effectively tune the robustness degree of the expansion plan by means of changing the uncertainty budget. Since increase in the load robust region leads to decrease in the investment cost robust region, a multi-objective optimization is required to optimize the uncertain parameters robust regions simultaneously. The augmented epsilon constraint method is used in this paper to find the Pareto optimal solutions. The big M linearization technique is used to keep the model linear, which is a very important factor in terms of keeping the computational burden of the problem at a desirable level. Ongoing research work needs to take into consideration the uncertainty caused by integration of renewable energies such as wind power and photovoltaic energy.

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