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Measuring the Long-Term Uncertainty Effect Reduction on Transmission Expansion Planning

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Abstract
Transmission expansion planning (TEP) is known as long-term study, which is related to the generation expansion pattern, i.e. where and how many new generation facilities will be constructed. Recently, some researchers have paid special attention to network reliability and maintainability in TEP design. As such, the uncertainty of generation expansion planning (GEP) can alter the results of TEP. Therefore, the robustness of TEP to the uncertainty of GEP should be investigated in TEP process. This paper aims to define the robustness of TEP to the long-term uncertainties mathematically. To do so, a simple TEP problem is first proposed and then the uncertainty of GEP is applied to the problem by developing a novel uncertainty-oriented TEP objective function as multi-objective optimization. Two objectives of this model are the conventional TEP costs and minimum changes. Then, the model is implemented on the IEEE 24-bus reliability test system (IEEE RTS) for two main items in order to assess the applicability of the proposed method. Furthermore, the effect of the method on undoing the uncertainty of generation mixture is investigated at the plan horizon in TEP. As TEP planning is NP-hard, genetic algorithm (GA) is utilized along with *fminc* optimization function in MATLAB, where the lower levels are resolved using the *quadprog* function in MATLAB. Afterwards, Pareto front of the solutions is analyzed to choose the most possible and economical solution between them. It can be concluded that the uncertain generation expansion would result in drastic economic losses both in the operation stage and in investment cost waste. Eventually, the obtained results confirm the applicability of the proposed model and solution method.

Keywords- Long-term uncertainty, Robustness, Transmission expansion planning, Generation expansion planning.

1. Introduction

From 1970 until now, many studies have been conducted on transmission expansion planning (TEP) (Monticelli et al., 1982; Garver et al., 1970). In this way, some researchers have recently paid special attention to network reliability and maintainability in TEP design. Here, it is worthwhile to mention that TEP is considered as long-term study. Moreover, it is definitely related to the generation expansion pattern, i.e. where and how many new generation facilities will be constructed. As such, it can be said that the uncertainty of generation expansion planning (GEP) can alter the results of TEP. Uncertainty is another characteristic that must be evaluated to distinguish the desired model to dissolve the TEP problem. Considering the uncertainty in the variables of load, production, cost, reliability and/or renewable resources makes the Transmission Network Expansion Planning (TNEP) model uncertain. (UTNEP) (Dalaliyan Miandoab et al., 2024). Ignoring this uncertainty, this is the deterministic TNEP (CTNEP) model. In this matter, several models have been proposed to solve the problem of TEP, STNEP and CTNEP using the DC model (Torre et al., 2008). On the other hand, other methods also employed DC or AC current in active mode (dealing with DTNEP) to generate a realistic assessment of TEP (Buygi et al., 2004).

For instance, Zhao et al. (2009) assessed the uncertainty of the load in terms of LOL in the objective functions and constraints of the problem. Moreover, Yang and Wen (2005) proposed a robust model concerning the Taguchi orthogonal array test (TOAT), the cost of load shedding caused by renewable sources. In addition, Buygi et al. (2006) developed a multi-objective framework based on distributed generation (DG) factors on the market environment and uncertainty of production, load, and market variables. Moreover, they proposed a novel and practical model to deal with the probability density functions of the nodal cost, taking into account the uncertainty of the load as well as the generation of stolen environments including the investment cost of the objective function, the cost of congestion and the operation costs of generators, load reduction, and reliability. Linares (2002) investigated the investment cost and risk in the objective function of a mathematical model taking into account the demand uncertainty. Note that the advantage of this model in planning was to eliminate or minimize the basic concerns caused by poor use of the network, load shedding, and inefficiency in supplying electricity from the cheapest generators (Hooshmand et al., 2012).

Yang and Wen (2005) described a robust mixed multi-level LP (MILP) model through a simple uncertainty model. Fang and Hill (2003) utilized the Benders decomposition (BD) algorithm to decrease the expansion cost of the master problem to the maximum limit set by the slave problem. Besides, a robust model was presented by Akbari et al. (2012) taking into account the uncertainty in load and production in order to minimize the cost of maximum expansion. Furthermore, the proposed model by Yu et al. (2009) provided a probabilistic framework for USTNEP and generation expansion planning based on grid reliability (availability of units and lines) and uncertainty of wind demand and generation. Moreover, a three-level MILP model was presented by Moeini-Aghtaie et al. (2012) models including the power system in normal and emergency states in order to minimize the investment, operation, and capacity imbalance system costs in the high-level problem. It should be mentioned that a medium-level problem is the one with the largest imbalance. It is a precautionary scheme that also evaluates the low-level problem of the operator's best response (Romero et al., 1994).

In addition, Da Silva et al. (2010) described a multi-objective modeling of uncertain DTNEP (i.e. UDTNEP) in the renewable environment based on generation uncertainty. Akbari et al. (2011) developed a robust logic model to develop DTNEP for large capacity systems by considering the operation and leakage costs, demand uncertainty from year to year, and production, in which the transmission and production facilities were stated. Yu et al. (2009) proposed a probabilistic framework for USTNEP and generation expansion planning by considering network reliability (access to units and lines), uncertainty of demand, and wind production.

Mahdavi et al. (2021) investigated the development of transmission lines and substations by considering losses and fuel price uncertainty. The proposed algorithm was the bee colony algorithm, which was an innovative method. They showed that the uncertainty of the burnt price indirectly affected the network load. In other words, with fuel price changes in different non-deterministic scenarios, network operation was changed and therefore a different arrangement for the target year was obtained for different fuel prices. In Alhamrouni et al. (2021) only load uncertainty was proposed and load response programs were utilized to solve it. Also, voltage stability was considered as a technical constraint in the problem. The Bacterial foraging algorithm (BFA) is employed to solve the problem of development of transmission lines. In Mehrtash and Cao (2022), AC load distribution model was considered for the network and then a mixed integer non-linear programming model was developed for it. Then, with the help of Kan's second-order release methods and the release of hardened constraints, a solution method was presented for it. Moreover, a new method for determining the possible solution space (FSA) was developed, leading to faster and more accurate answers by further limiting the range of the solution space. In Lin et al. (2022) a value-oriented development planning model of transmission lines was proposed, in which storage resources with hydrogen storage technology were addressed. The focus of this study was more on storage. In El-Meligy et al. (2022) the changes in transmission line resistance with load change, wire shape change and ambient temperature were investigated in the planning problem of transmission line development. In this way, by changing the resistance value, the capacity of transmission lines and their stability limits were changed. In this reference, the uncertainty of load, production, renewable sources and electricity prices were considered. In Yasasvi et al. (2022) the uncertainty of renewable resources and load was considered in the development of transmission lines. Then, a novel two-level model was proposed based on a dual method to handle the problem. Afterwards, the two-level problem was separated into the main problem and sub-problem using Bandarz separation method, in which the worst-case scenario could be determined and the response of the developed system could be guaranteed under the worst-case scenario (Puvvada et al., 2022).

Recently, Dalaliyan Miandoab et al. (2024) investigated the long-term effect of demand response on the loading rate of the system as well as subsequent line loading influence on line failure rates. Then, the related cost is minimized in the objective of the proposed mixed integer nonlinear planning model.

1.1 The Main Contribution

Eventually, based on what was mentioned above, the main challenge of the TEP problem is uncertainty such as the uncertainty of demand, renewal, and contingencies. On the other hand, the uncertainty of the generation configuration in the preliminary year makes researchers jointly solve TEP and Generation Expansion Planning (GEP). The network topology method was employed by Ugranli et al. (2017) to decrease the planning variables of the long-term multi-stage development of the production and transmission network. This method minimized the production investment costs, lines, and fuel costs. In this study, it was confirmed that the proposed method had good efficiency in solving the integrated development planning for large systems. Karki and Patel (2005) presented a model for planning the integrated development of transmission and generation, considering EENS caused by random outages of generators or lines. Nevertheless, the combination of GEP and TEP leads to a large-scale and complex system. On the other hand, in the market of reforming power, GEP has been changed to Generation Funding by investors instead of the government, so the results of GTEP cannot be established in practice because of the benefits. Borrowers are private investors and they may prefer to invest in technology, the amount, and the areas where they have more return on investment. Therefore, the electricity market has been reformed and the uncertainty of the generation of the integrated generation planning is an important part of the TEP.

Based on the reviewed literature, very little research has been conducted on generational modeling uncertainty in planning. To fulfill this shortcoming, this paper considers this uncertainty by introducing the new hardness. To accomplish this aim, the robustness of TEP to the long-term uncertainties is proposed mathematically.

For this purpose, a simple TEP problem is first developed and then the uncertainty of GEP is applied to the problem by a new uncertainty-oriented TEP objective function as multi-objective optimization including conventional TEP costs and minimum changes. Then, this model is implemented on the IEEE 24-bus reliability test system (IEEE RTS) for two main items in order to assess the applicability of the study method. Note that as TEP planning is NP-hard (Vilaça et al., 2022), GA can be a good solution method because it is known as a strong and capable metaheuristic algorithm to solve Np-hard problems (Ebrahimi et al., 2023), along with *fminc* optimization function in MATLAB, where the lower levels are resolved using the *quadprog* function in MATLAB. Finally, Pareto front of the solutions is analyzed to choose the most possible and economical solution between them. In short, the main contribution of the proposed TEP method is the following innovations:

- Exploring Factors affecting uncertain production in the TEP problem.
- Investigating new robustness against the uncertainty.

This paper is organized as follows: Section 2 provides the principle of basic TEP model. Then, Section 3 presents the proposed approach including its flowchart. Section 4 describes the robust DTEP against long-term uncertainty. Then, Section 5 provides some numerical results to assess the applicability of the proposed approach. Finally, Section 6 brings conclusion.

2. Basic TEP Model

The proposed TEP model is designed to assess the impact of demand on line loading and network reliability. This model is the bi-level programming method, which its objective function is based on the transmission system operator (TSO) related to the transmission infrastructure. It is worthwhile to mention that in realistic markets, congestion savings and DR projects are paid by customers, while reliability costs are paid by the transmission system owner or customers. To present these mentioned conditions, the network load is modeled as an hourly load in the desired year. To achieve a good example of the model, two cases including four scenarios are described. The first case investigates the reliability of TEP without DR whereas DR is added to the model in the second case.

***Sets*:**

Ω^c	Set of all corridors.
Ω^{dt}	All hours corresponding to time *t* in one day.
Ω^{ec}	All corridors that include lines.
Ω^{gb}	Collection of production buses.
Ω^i	All of buses at the beginning and end of the line *i*.
Ω^{lb}	Collection of load buses.
Ω^s	All corridors that include substations.
Ω^t	Time steps.

***Variables and Parameters*:**

a_{ng}, b_{ng}, c_{ng}	Allocated coefficients cost of unit g in bus n.
C_T	Total cost ($).
C_i^C	Cost of building for the line circuit in *i*-th corridor ($).
C_i^S	Cost of building a 138/230 kV substation in *i*-th corridor ($).
C_{ij}^R	The cost of changing line *j* in corridor *i* ($).
C_{co2}	Cost per unit CO2 emission ($/kg).
CO_{2n}	CO_2 emission rate of producing unit at bus *n* (kg/MWh).
$D_n(t)$	Load demand on bus *n* at time *t*-th of plan horizon (MW).
$\hat{e}_{ki}^{xj}$	Changes in the ratio of capacity in corridor *k* to load in bus *i* after the interruption of line *j* in corridor *x*.
f_i	Active capacity flow of corridor *i* (MW).
f_i^L	Active capacity losses of corridor *i* (MW).
f_i^{max}	Maximum capacity of corridor *i* (MW).
$f_i(t)$	Active capacity flow of corridor *i* in *t*-th of plan horizon (MW).
$f_i^{xj}(t)$	Flow of corridor *i* when line *j* in corridor *x* fails at *t*-th plan horizon (MW).

$\overline{f_i^{xj}}$	Maximum values of f_i when line j in corridor x fails (MW).
FOR_{pz}	Forced outage rate of unit p at bus z.
$G_n(t)$	Power generation at bus n in t-th period of plan horizon (MW).
$\hat{h}_{ui}^{xj}$	The ratio of capacity variations in corridor u to generation variations at bus i after outage of line j in corridor x.
$Inc_n(t)$	Incentive for load shifting at bus n in time t ($).
ℓ_i	Length of corridor i (km).
$LMP_n(t)$	Locational marginal price at bus n in t-th period of plan horizon ($/MWh).
$LS_n^{ij}(t)$	Load shedding of bus n because of an outage of line j within corridor i in t-th period of time horizon (MW).
n_i	Number of new circuits in corridor i.
N_{pg}	Number of generation units at bus n in the end of plan horizon.
n_i^{max}	Maximum number of line can be constructed in corridor i.
n_i^{min}	Initial number of circuits in corridor i.
n_{ij}^{l0}	Initial life of line j in corridor i in the beginning of plan horizon.
n_{ij}^{rl}	Regular life of line j in corridor i in the start of plan horizon.
n_i^s	Number of new substations in corridor i.
$P_{ng}(t)$	Power production of unit g at bus n in t-th period of time horizon (MW).
P_{ng}^{min}	Minimum capacity of unit g at bus n (MW).
P_{ng}^{max}	Maximum capacity of unit g at bus n (MW).
Pr_{ij}	Probability of outage of line j in corridor i.
r_{ij}^{cr}	Duration of each failure for line j in corridor i.
r_{ng}^{cr}	Duration of each repair for generation unit g on bus n (h).
T	Plan horizon (year).
U_{ij}	Unavailability of line j in corridor i.
$U_{ng}(t)$	ON/OFF binary variable for producing unit g at bus n in t-th period of time horizon.
v_{ij}	Binary decision variable for replacement of line j in corridor i (If the line is not replaced, its value is 1).
$VOLL_n$	Value of lost load on bus n ($/MW).
VTS	Value of transmission system in the ending of plan horizon.
$\Delta\theta_i(t)$	Voltage phase angle difference in last and first buses of corridor i (rad).
λ_{ij}	Failure rate of line j in corridor i (f/yr.).
λ_{ng}	Number of failures for generation unit g at bus n.
${\lambda_{ij}}^{ini}$	Initial failure rate of line j in corridor i (f/yr.).
$\overline{\lambda_{ij}}$	Threshold failure rate of line j in corridor i (f/yr.).
$\varepsilon_t^n(t)$	The own price elasticity at hour t.
$\varepsilon_t^n(t')$	Cross price elasticity in hour t because of price variations at hour t'.
γ_i	Susceptance of corridor i (Ω^{-1}).
γ_i'	Susceptance per kilometre of a line circuit in corridor i (Ω^{-1}/km).
ζ_{ij}	Aging coefficient.
$\rho_n(t)$	Consumer bid price at bus n in t-th period of time horizon ($/MW).
τ_{ij}	Mean time to repair (MTTR) of line j in corridor i (h).

Upper level (main) problem:

$$\min C_T = \sum_{i\in\Omega^c} C_i^C\, n_i + \sum_{i\in\Omega^s} C_i^S\, n_i^S + \sum_{i\in\Omega^{ec}} \sum_{j=1}^{n_i^{min}} v_{ij} C_{ij}^R + \sum_{i\in\Omega^{lb}} VOLL_n \sum_{t\in\Omega^t} \sum_{i\in\Omega^c} \sum_{j=1}^{n_i+n_i^{min}} LS_n^{ij}(t) Pr_{ij}\, r_{ij}^{cr} + \sum_{t\in\Omega^t} \sum_{i\in\Omega^s} \sum_{m,n\in\Omega^i} f_i(t)[LMP_n(t) - LMP_m(t)] \tag{1}$$

$$v_{ij} = \begin{cases} 1 & for\ \lambda_{ij} \geq \overline{\lambda_{ij}} \\ 0 & ow \end{cases} \text{for } \forall\, i, j \tag{2}$$

$$Pr_{ij} = U_{ij} \prod_{o=1,o\neq j}^{n_i+n_i^{min}\prod} (1 - U_{io}) \prod_{y\in\Omega^c}^{y\neq i\prod} \prod_{o=1}^{n_y+n_y^{min}\prod} \left(1 - U_{yo}\right) \text{for } \forall\, i, j \tag{3}$$

$$U_{ij} = \frac{\lambda_{ij}\tau_{ij}}{1+\lambda_{ij}\tau_{ij}} \text{for } \forall\, i, j \tag{4}$$

$$\lambda_{ij} = \sum_{t\in\Omega^t}^{\sum} \left(\frac{f_i^t}{f_i^{max}\overline{\lambda_{ij}}_{ij}^{ini}{}_{ij}^{ini}}\right. \quad \text{for } \forall\, i, j \tag{5}$$

$$C_{ij}^R = 0.5 C_i^C \text{ for } \forall\, i, j \tag{6}$$

$$VTS = \sum_{i\in\Omega^{ec}} l_i \sum_{j=1}^{n_i^{min}\sum} \zeta_{ij} C_{ij}^C \tag{7}$$

$$\zeta_{ij} = \left(\frac{n_{ij}^{rl}}{2(n_{ij}^{lo}+T)}\right) \times \left(\frac{\overline{\lambda_{ij}}}{\lambda_{ij}}\right) \text{for } \forall\, i, j \tag{8}$$

Subject to:

$$0 \leq n_i \leq n_i^{max_i^{min}} \text{ for } \forall\, i \tag{9}$$

$$0 \leq n_i^s \leq n_i^{max_i^{min}} \text{ for } \forall\, i \tag{10}$$

Equation (1) represents the high-level objective function that should be minimized. In this equation, the first term indicates the cost of building lines; the second term shows new posts; and the third term indicates the cost of replacing existing lines. The cost of replacing existing lines is calculated by Equations (2)-(5) derived by Choi et al. (2005) while Equation (6) was proposed Pereira and Pinto (1985). Note that if the line-breaking rate is greater than the threshold value, the binary decision variable is 1; otherwise, if there is no validation, it is equal to 0.

The fourth term of Equation (1) explains the reliability of the network from the disconnection of the line using Equation (3) (Pereira and Pinto, 1985) and the lower level of LS. The fifth term shows the increase in congestion, in which the LMP values are returned from the OPF in the target year of the low-level problem.

The sixth term in Equation (1) denotes the consumers' cost to encourage them to shift their burden to improve the higher-level goal, i.e. DR encompassing the following sections:
The first is to ensure sufficient participation in this cost and the second is motivation for the participants in this program.

Eventually, the last term of Equation (1) shows the value of the transmission method for the target year provided in Equations (7) and (8). Equation (7) denotes the VTS as a function of line expectation, where the line expectation is defined in Equation (8) (Pereira and Pinto, 1985), which is a function of the line's life in the target year and the line's loss rate. It is noteworthy that in this paper, the line failure rate depends on the line loading, which is determined at a lower level. Furthermore, at higher level of demand, the line load may fluctuate. Therefore, it can be concluded that DR can be effective in cable loading and cable breakage. At higher levels, line load can be controlled by programming to improve the reliability of the transmission network. Finally, High-level constraints Equations (9) and (10) limit the allowed number of new lines and posts.

Lower level problem (sub-problem):

$$LMP_i(t), f_i^l(t), LS_n^{ij}(t) = arg\{ Min \sum_{t\in\Omega^t} \sum_{n\in\Omega^{gb}} \left(a_{ng}P_{ng}^2(t) + b_{ng}P_{ng}(t) + c_{ng}\right) + \sum_{t\in\Omega^t} \sum_{n\in\Omega^{gb}} \sum_{g=1}^{N_{ng}} C_{co_2} CO_{2n}\, P_{ng}(t)\} \tag{11}$$

Subject to:

$$G_n(t) = D_n^{DR}(t) + \sum_{i\in\Omega^n} f_i(t) : LMP_i(t)\ for\ \forall\ n, t \tag{12}$$

$$f_i(t) = \gamma_i \Delta\theta_i(t)\ for\ \forall\ i \tag{13}$$

$$\gamma_i = \ell_i\left(n_i + n_i^{\min}\right)\gamma_i'\ for\ \forall\ i \tag{14}$$

$$U_{ng}(t)P_{ng}^{\min} \le P_{ng}(t) \le U_{ng}(t)P_{ng}^{\max}\ for\ \forall\ n, g \tag{15}$$

$$0 \le LS_n^{ij}(t) \le D_n(t)\ for\ \forall\ i, j, n \tag{16}$$

$$\left|f_i^{xj}(t)\right| \le \overline{f_i^{xj}} \quad \forall i \in \Omega^c, \forall t \in \Omega^t,\ j = 1,\ldots,(n_i + \underline{n_i}) \tag{17}$$

$$f_i^{xj}(t) = \sum_{k\in\Omega^{gb}} \hat{e}_{ki}^{xj}\left(G_k(t)\right) + \sum_{u\in\Omega^{lb}} \hat{h}_{ui}^{xj}\left(D_u(t) - LS_u^{ij}(t)\right) for\ \forall\ i, j, x \tag{18}$$

$$\overline{f_i^{xj}} = \begin{cases} f_i^{\max} & if\ \ j = x \\ f_i^{\max} - \dfrac{f_i^{\max}}{n_i^{\min} + n_i} & ow \end{cases} \quad for\ \forall\ i, j, x \tag{19}$$

Equation (11) shows the OPF sub-objective of 8760 hours in the target year formulated as a unit commitment (UC) problem. In addition, the pollution cost of the generation system is included Equation (11). Constraints Equations (12)-(19) are low-level constraints. Constraints Equations (12)-(15) refer to the load flow equations including load balance load, line flow, sensitivity of each channel and generation limitation. Constraints Equations (16)-(19) are contingency constraints. Constraint Equation (16) limits the maximum load of each bus, Constraint Equation (17) limits the line current after the interruption of the transmission line while Constraint Equation (18) calculates this value using the sensitivity coefficient. Therefore, Equation (19) shows that the power of the channel decreases when the disconnection of the line (e.g. line *j*) falls on the same channel (*i*=*x*), otherwise the maximum power flow of the channel does not change if the line from it falls on other roads. A reliable indicator of the load reduction objective functions is calculated as follows resulting from a line failure.

3. The Proposed Approach

The proposed approach can be illustrated in **Figure 1** including the main following steps:

***Step* 1:** An initial population *X* with *d* chromosomes is constructed randomly considering constrains Equations (14) and (15). Now first and second terms of Equation (1) are available.

***Step* 2:** Considering new configuration, OPF problem Equations (11)-(20) is solved by quadprog in MATLAB using the expressed sequential method. Now using dual variables of Equation (12), fifth term of Equation (1) is calculated.

***Step* 3:** Putting f_i into Equation (5) lines failure rates is obtained then by Equations (8) and (7) VTS (last term of Equation (1)) is calculated.

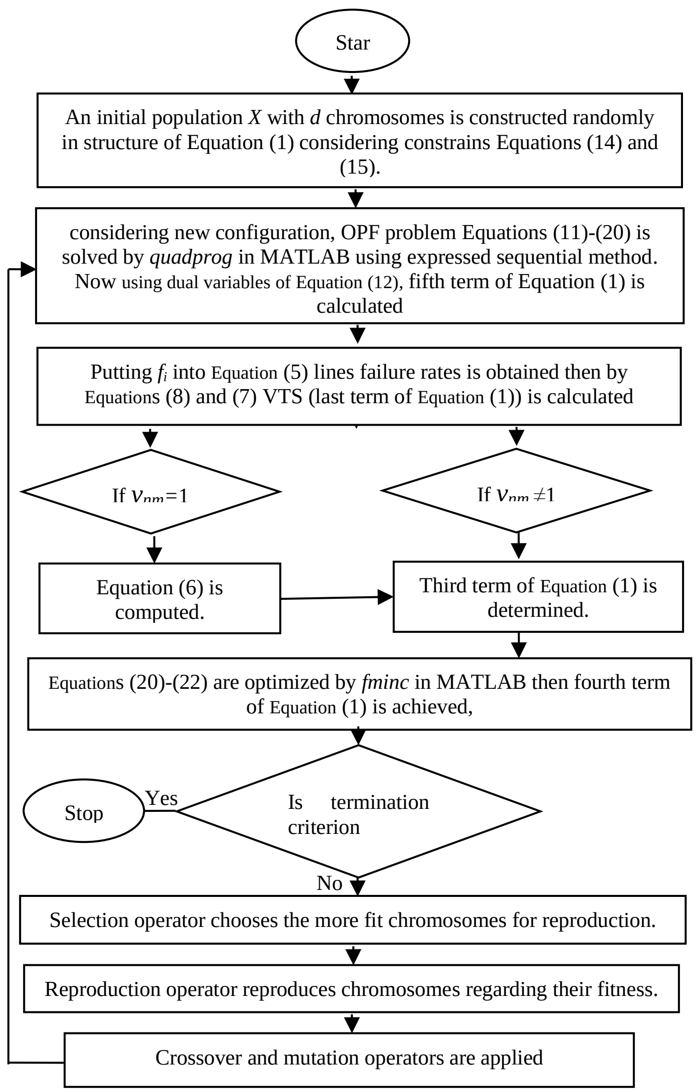

Figure 1. Flowchart of the proposed method.

4. Robust DTEP Against Long-Term Uncertainty

In this section, equations of the proposed problem are provided based on the different components described in the previous section, and then the relationships between them are demonstrated. The suggested system is a two-level model in which the high-level problem is the development objective function, and long-term uncertainty exposure will be applied to this objective function, which is the main innovation of this paper including low level of utilization of developed infrastructure. The objective function can be expressed for each long-term scenario including the annual output adjustment as follows.

$$C_{T,\omega} = \sum_{i\in\Omega^c} C_i^C\, n_{i,\omega} + \sum_{i\in\Omega^s} C_i^S\, n_{i,\omega}^s + \sum_{i\in\Omega^{ec}}^{\Sigma} \sum_{j=1}^{n_i^{min}\Sigma} v_{ij,\omega} C_{ij}^R + \sum_{n\in\Omega^{lb}} VOLL_n \sum_{t\in\Omega^t}^{\Sigma} \sum_{i\in\Omega^c}^{\Sigma} \sum_{j=1}^{n_i+n_i^{min}\Sigma Pr_{ij,\omega}\left(r_{ij}^{cr}\right)} LS_{nt,\omega}^{ij} + \sum_{t\in\Omega^t} \sum_{i\in\Omega^s} \sum_{m,n\in\Omega^i} f_{i,\omega}^t (LMP_{nt,\omega} - LMP_{mt,\omega}) \tag{20}$$

Now, this objective function is modeled for a long-term scenario as well as for one of the time horizons of the study. Note that as the development model is dynamic, the above objective function will be dynamic as well.

$$C_\omega = \sum_{T=1}^{N_T} \zeta_T C_{T,\omega} \tag{21}$$

where, *NT* denotes the number of time horizons of the study. For example, if the study is conducted for the next 15 years, these 15 years are divided into three 5-year horizons, and in each period, the number and corridors of the transmission network development are determined for that period, meaning that by the end of that period, the lines should be determined to be built. It is also the symbol of the conversion factor to the current value for each planning period. Now, the main objective function encompassing the Equation (21) and the innovation of the problem, is delivered in the form of the Equation (22).

$$C_{T,\omega} = \sum_{T=1}^{N_T} \zeta_T \{ \sum_{i\in\Omega^c} C_i^C\, n_{i,\omega,T} + \sum_{i\in\Omega^s} C_i^S\, n_{i,\omega,T}^s + \sum_{i\in\Omega^{ec}}^{\Sigma} \sum_{j=1}^{n_i^{min}\Sigma} v_{ij,\omega,T} C_{ij}^R + \sum_{n\in\Omega^{lb}} VOLL_n \sum_{t\in\Omega^t}^{\Sigma} \sum_{i\in\Omega^c}^{\Sigma} \sum_{j=1}^{n_i+n_i^{min}\Sigma Pr_{ij,\omega,T}\left(r_{ij}^{cr}\right)} LS_{nt,\omega,T}^{ij} + \sum_{t\in\Omega^t} \sum_{i\in\Omega^s} \sum_{m,n\in\Omega^i} f_{i,\omega,T}^t (LMP_{nt,\omega,T} - LMP_{mt,\omega,T}) + \sum_{t=1}^{8760} \sum_{B=1}^{\Omega_b} [\rho_{nt,\omega,T} (D_{nt,\omega,T}^{DR} - D_{nt,\omega,T}) + Inc_{nt,\omega,T}] \} + \Lambda \sqrt{\sum_{i\in\Omega^c} \sum_{\omega_1\in\Omega^\omega} \sum_{\omega_2\in\Omega^\omega} (n_{i,\omega_1,T} - n_{i,\omega_2,T})^2} \tag{22}$$

In the above equation, although the model is dynamic, unlike the stochastic programming method, long-term variables contain a visual indicator; hence, the problem is not solved only in the worst item. Indeed, the problem is solved in each item, and the difference or the sum of the Cartesian distances between the response of each condition and other conditions is added to the objective function with a large sum of fines. Besides, the penalty coefficient will be determined experimentally in the numerical studies section. Obviously, the higher the value of this coefficient, the more coordinated the response to the conditions, and the lower the value, the greater the difference between the responses to the conditions. In the following, the relationship between the variables and the challenges of the problem is presented. The indicator of the appearance and time of the dynamic program is left because of their presence in all the signs. The proposed two-level formula includes two objective functions via two continuous variables. The proposed problem is solved by the genetic algorithm (GA) that is also employed in Jalilzadeh et al. (2008), Kazemi et al. (2008), and Mahdavi et al. (2015), as well as fminc optimization function in MATLAB. The lower levels are resolved using the quadprog function in MATLAB. (**Figure 1**). Note that as TEP planning is NP-hard (Vilaça et al., 2022), GA can be a good solution method because it is known as a strong and capable metaheuristic algorithm to solve Np-hard problems (Ebrahimi et al., 2023).

5. Numerical Results

In the following, the IEEE RTS test methods were applied to represent the suggested configuration due to the availability of all technical data, reliability and maintainability. However, the implementation of the proposed method in large test systems is possible. According to Choi et al. (2005), the maximum number of new lines allowed is considered to be 2 for each route. The maximum number of newlines can be set to 3 or 4 but the computation load increases. It should be mentioned that if the model is effective for IEEE RTS using the maximum number of two new lines allowed, it means that the proposed strategy can be effective for other test studies with a large number of maximum lines that can be built. The developed case is investigated in RTS in 2 scenarios for the 15 years plan.

5.1 Item 1: The TEP Problem with Deterministic Generation Expansion

For this item, the proposed is implemented on IEEE 24 bus RTS test system concerning the generation expansion equal to the 1.1 times of total load growth for the horizon year at the current generation buses. **Table 1** illustrates new transmission lines that can be added to the presented network. Also, new failure rates of present lines are obtained in **Table 2**. Corridors 102 and 123 with start bus of 15 and 18 also end bus of 21 for both, were changed by new lines because of the highest failure rates of lines in these corridors. The objective function terms for this solution are mentioned in **Table 2**.

Table 1. Suggested features for item 1.

Corridor		n_i
SB	EB	
1	7	1
1	8	1
2	3	1
5	9	1
6	10	1
7	9	1
9	11	1
9	12	1
10	11	1
10	12	1
11	17	1
11	18	1
11	20	1
12	14	1
12	19	1
13	16	1
13	18	1
13	20	1
13	22	1
14	18	1
14	23	2
15	22	1
16	22	1
18	23	2
19	22	1
19	23	2
20	22	1

Table 2. The costs of item 1 (million US$).

Cost item	**Cost amount (million US$)**
Installation cost of new lines	78.773
Construction cost of new substations	14
Replacement cost of old lines	5.39
Total Transmission expansion cost	**98.17**
LS Cost of line outages (Transmission reliability Cost)	1.358
Congestion Cost	16.802
VTS	62.28
Total cost	**116.33**

5.2 Item 2: The TEP Problem with Generation Expansion Uncertainty

In this item, 4 scenarios for GEP have been considered. The first scenario is the one considered at Item-1 and the other 3 scenarios are as **Table 3**. Note that generation buses are: 1, 2, 7, 13, 14, 15, 16, 18, 21 and

22 and the load buses are as follows: 1 to 10, 13 to 16 and 18 to 20 (17 buses). Note that all scenarios expand the generation equal to the 1.1 times of total load (10823) at the 15th year which is equal to the 11905 MW.

Table 3. New generation facilities for 3 scenarios.

S1	S2	S3
600	600	1400
600	200	0
0	200	0
500	0	0
0	0	0
0	0	0
900	0	900
0	200	0
500	0	0
0	0	0
0	0	0
0	200	800
0	0	0
0	0	0
600	900	1400
400	400	400
500	0	800
1700	1200	1200
500	0	0
0	0	0
1200	1500	800
0	2300	3600
0	200	800
0	0	0

5.2.1 Transmission Expansion for Scenarios

The total cost of each plan as well as total cost deviation for scenarios defined as the penalty paid to the curtailed load are listed in **Table 4** for four scenarios. The cost items include installation cost of new lines, construction cost of new lines, and substations replacement cost of old lines.

Table 4. The cost of each scenario and total cost deviation for scenarios (million US$).

Cost item	**S1**		**S2**		**S3**		**S4**	
Installation cost of new lines	78.773		88.23		76.56		75.98	
Construction cost of new lines substations	14		14		14		14	
Replacement cost of old lines	5.39		5.39		5.39		5.39	
Total Transmission Expansion cost	**98.17**		**107.62**		**95.95**		**95.37**	
LS Cost of line outages (Transmission reliability Cost)	1.358		1.562		1.782		1.452	
Congestion Cost	16.802		14.83		18.97		17.82	
VTS	62.28		62.28		62.28		62.28	
Total cost of each Scenario	**116.33**		**124.012**		**116.702**		**114.6420**	
Operational Cost Deviation Due to Scenario changes	**S2**	**9.34**	**S1**	**12.23**	**S1**	**14.53**	**S1**	**13.34**
	S3	**11.65**	**S3**	**11.45**	**S2**	**13.21**	**S2**	**14.77**
	S4	**10.49**	**S4**	**13.39**	**S4**	**14.97**	**S3**	**12.58**
Construction Cost Deviation Due to Scenario changes	**S2**	**14.76**	**S1**	**16.98**	**S1**	**19.03**	**S1**	**21.03**
	S3	**18.52**	**S3**	**15.24**	**S3**	**17.98**	**S3**	**19.54**
	S4	**1978**	**S4**	**18.45**	**S4**	**16.65**	**S4**	**18.89**
Total Real Cost	**124.2**		**133.27**		**127.37**		**124.81**	

According to **Table 4**, it can be observed that scenario S2 contains the highest total transmission expansion cost (107.62$). On the other hand, regarding LS cost of line outages (transmission reliability cost), congestion cost, and VTS, scenario S2 contains the highest total cost of each (124.012$). Moreover, regarding operational cost deviation due to scenario changes and construction cost deviation due to scenario changes, this scenario S2 again obtains the total real cost (133.27$).

Note that the deviation among the obtained cost of scenarios is due to a change in the state of the **Table 4**, indicating that the best facility that should be built has such a cost. According to the results of **Table 4**, it can be observed that the uncertain generation expansion would result in drastic economic losses both in the operation stage and in investment cost waste. For example, if a planner considers S1 but earlier in the year S2 has occurred, the difference between the best plan for S2 and S1 can be covered by the same cost. Experimentally this cannot be financed because of the time required for construction but both S2 and S1 indicate the economic investment. For example, if a planner considers S1 but the horizon year S2 has expired, 16.98 (million US$) would be wasted. Nevertheless, the deviation of the operation cost must be paid in the operation stage due to the change in appearance. Finally, the last row shows the expected value of the consideration in each item. Eventually, the obtained results confirm the applicability of the proposed model and solution method.

5.2.2 Robust Transmission Expansion

In the following, the uncertainty of generation mixture is explored using robust transmission expansion at horizon year in TEP. To do so, the cost terms of expansions are listed in **Table 5** including cost of installing new lines, cost of creating new substations, and the replacement cost of old lines. Regarding LS Cost of line outages (Transmission reliability Cost) and congestion cost, it can be observed that scenario S2 obtains the highest total cost (121.284$). According to the obtained results, the differences between cost of the proposed method and the deterministic one studied in the previous section are about 5, 16, 6 and 5 million US$ for S1, S2, S3 and S4 occurrence respectively.

Table 5. Cost terms of expansion by proposed method (million US$).

Cost item	Cost amount (million US$)			
cost of installing new lines	80.773			
cost of creating new substations	14			
Replacement cost of old lines	5.39			
Total Transmission expansion cost	100.163			
LS Cost of line outages (Transmission reliability Cost)	S1	S2	S3	S4
	1.398	1.671	1.801	1.472
Congestion Cost	17.72	15.21	19.32	18.11
VTS	62.28			
Total cost	**119.28**	**117.044**	**121.284**	**119.745**

6. Conclusion and Further Research

This paper assessed the long-term effects of optimal emission uncertainty in the TEP problem. To prevent excessive economic losses, robustness against uncertainty was formulated mathematically along with other cost criteria of the objective function. As such, both the degree of durability and expansion of the minimum cost are achieved. For this purpose, a simple TEP problem was first developed and then the uncertainty of GEP was applied to the problem by new uncertainty-oriented TEP objective function as multi-objective optimization, in which conventional TEP costs and minimum changes in the plan were two objectives. Then, the proposed model was implemented on the IEEE 24-bus reliability test system (IEEE RTS) for two main items in order to assess the applicability of the study method. The genetic algorithm along with fminc optimization function in MATLAB solved the proposed problem. The lower levels were resolved using the quadprog function in MATLAB. As TEP planning is NP-hard, GA can be a good solution method because it is known as a strong and capable metaheuristic algorithm to solve Np-hard problems. Finally, Pareto front of the solutions was analyzed to choose the most possible and economical solution between them. More importantly, the effect of the presented method on undoing the uncertainty of generation mixture was investigated at horizon year in TEP. According to the obtained results, there were differences between the cost of the proposed method and each item's individual cost while the difference between the cost of losses in the item changes could not be compared with the proposed method. Besides, the uncertain generation expansion would result in drastic economic losses both in the operation stage and in investment cost waste. Eventually, the obtained results confirm the applicability of the proposed model and solution method.

For further research, the investigation of investment waste due to changes in conditions and the solution algorithms such as metaheuristic algorithms can be developed for future studies, which were not considered in our investigation.

Conflict of Interest
There is no conflict of interest.

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