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Integrated generation-transmission expansion planning considering power system reliability and optimal maintenance activities

Meisam Mahdavi [a], Mohammad S. Javadi [b,*], João P.S. Catalão [b,c]

[a] Bioenergy Research Institute (IPBEN), Associated Laboratory of Ilha Solteira, São Paulo State University, School of Engineering, Ilha Solteira 15385-000, SP, Brazil
[b] Institute for Systems and Computer Engineering, Technology and Science (INESC TEC), Porto, Portugal
[c] Faculty of Engineering of the University of Porto, Porto, Portugal

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ABSTRACT

This paper evaluates lines repair and maintenance impacts on generation-transmission expansion planning (GTEP), considering the transmission and generation reliability. The objective is to form a balance between the transmission and generation expansion and operational costs and reliability, as well as lines repair and maintenance costs. For this purpose, the transmission system reliability is represented by the value of loss of load (LOL) and load shedding owing to line outages, and generation reliability is formulated by the LOL and load shedding indices because of transmission congestion and outage of generating units. The implementation results of the model on the IEEE RTS show that including line repair and maintenance as well as line loading in GTEP leads to optimal generation and transmission plans and significant savings in expansion and operational costs.

1. Introduction

The main task of power-system expansion planning is determining the installation time and place of new lines and units to maximize the system economic welfare [1] while providing safe power demand for customers [2]. Nonetheless, transmission networks are getting old and their components failure rate and outage are increasing [3]. The reduced reliability of the transmission system leads to higher operating costs and economic welfare loss [4]. A way to remove this shortcoming is to replace old transmission lines with new ones, but a full replacement of existing lines is prohibitively expensive. Another way is employing maintenance actions that can diminish and increase equipment failure rates and lifetime, respectively. This poses a challenge for power-system planners because, as previously stated, the lines replacement is expensive and maintaining the aged lines in the system can decrease network reliability, which is necessary for long-term power-system planning [5]. To approach overall optimal investment in the power system, the solutions for transmission expansion planning (TEP) [6,7] and generation expansion planning (GEP) [8] problems must be coordinated. Accordingly, some of the recent methods and models proposed for finding optimal coordinated solutions to the GTEP problem are reviewed in further text.

Barati et al. [9,10] integrated the multi-year GTEP problem with natural gas (NG) system expansion planning, showing that simultaneous expansion of electric network and the gas grid causes more economic expansion plans. The goals were obtaining new generating units, new transmission lines, and NG pipelines at the same time to meet increased power demand. The genetic algorithm (GA) [11] was employed to solve this complex large-scale nonlinear optimization problem.

Hajebrahimi *et al.* [12] formulated a multi-objective GTEP problem considering demand response (DR), wind generation, and network reliability in the energy market. The objectives are capital cost minimization, congestion mitigation, and risk reduction, as well as the incentives maximization for DR participants. Like [9] and [10], the GA was used to solve the proposed nonlinear model and a probabilistic analysis technique called two-point estimation method was used to handle uncertainty of wind generation.

In order to reduce the computational burden and convergence time of multi-objective GTEP problems, Javadi *et al.* [13] incorporated a virtual database and the non-dominated sorting GA-II (NSGA-II) to hedge the repetitive calculations during optimization process. Despite

Abbreviations: AC, Alternating current; DCGA, Decimal codification genetic algorithm; DPSO, Discrete particle swarm optimization; DR, Demand response; GA, Genetic algorithm; GEP, Generation expansion planning; GTEP, Generation-transmission expansion planning; GTEP-M GTEP, considering optimal maintenance activities; LOL, Loss of load; LS, Load shedding; MILP, Mixed-integer linear programming; MTTR, Mean time to repair; NNC, Normalized normal constraint; PSO, Particle swarm optimization; SC, Short-circuit current; TEP, Transmission expansion planning; VOLL, Value of lost load.

* Corresponding author.
E-mail addresses: msjavadi@gmail.com, Mohammad.Javadi@inesctec.pt (M.S. Javadi).

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Nomenclature

Ω^{b}	Set of all buses.
Ω^{c}	Set of all corridors.
Ω^{ec}	Set of existing corridors including lines.
Ω^{gb}	Set of generation candidate buses.
Ω^{lb}	Set of load buses.
Ω^{s}	Set of existing corridors including substations.
$\mathrm{C_{ij}}$	Construction cost of line *j* in corridor *i* ($).
$\mathrm{C^{L}}$	Losses cost per unit of energy ($/MWh).
$\mathrm{C_{i}^{C}}$	Construction cost of a line in corridor *i* ($).
$\mathrm{C_{i}^{R}}$	Replacement cost of a line in corridor *i* ($).
$\mathrm{C_{i}^{S}}$	Construction cost of a substation in corridor *i* ($).
$\mathrm{C_{ij}^{M}}$	Maintenance cost for line *j* of corridor *i* ($).
$\mathrm{C_{ij}^{r}}$	Repair cost for line *j* of corridor *i* ($).
C_{ng}^{G}	Construction cost of a unit of type *g* on bus *n* ($).
$\underline{C}_{ij}^{M}$	Fixed maintenance cost of line *j* in corridor i ($).
$\underline{C}_{ij}^{r}$	Fixed repair cost of line *j* in corridor *i* ($).
D_{n}	Total demand of bus *n* (MW).
f_{i}	Active power of corridor *i* (MW).
f_{nm}	Active power flow between buses *n* and *m* (MW).
FOR_{q}	Forced outage rate (FOR) due to outage of unit *q*.
f_{nm}^{ij}	f_{nm} when line *j* of corridor *i* fails (MW).
f_{i}^{L}	Active losses of corridor *i* (MW).
f_{nm}^{q}	f_{nm} when unit *q* fails.
$\overline{f}_{nm}$	Maximum value of f_{nm} (MW).
H	Planning horizon (yr.).
$\mathrm{K_{ij}}$	Maintenance cost coefficient of line *j* in corridor *i*.
$\mathrm{k^{L}}$	Losses coefficient.
$\mathrm{K_{ij}^{r}}$	Repair cost coefficient of line *j* in corridor *i*.
ℓ_{i}	Length of corridor *i* (km).
LOL_{nq}	LOL due to outage of unit *q* (MW).
$LS_{n,ij}$	LS due to outage of line *j* in corridor *i* (MW).
LS_{nq}	LS due to outage of unit *q* (MW).
Ng	Number of existing generating units.
$\mathrm{n_{i}}$	Number of new circuits in corridor *i*.
$\mathrm{n_{i}^{s}}$	Number of new substations in corridor *i*.
$\mathrm{n_{ij}^{le}}$	Life expectancy of line *j* in corridor *i* (yr.).
$\mathrm{n_{ij}^{l0}}$	Initial life of line *j* in corridor *i* (yr.).
$\underline{\mathrm{n}}_{\mathrm{i}}$	Number of initial circuits in corridor *i*.
$\overline{n}_{i}$	Maximum number of circuits in corridor *i*.
$\underline{\mathrm{n}}_{\mathrm{i}}^{\mathrm{s}}$	Number of initial substations in corridor *i*.
$\overline{n}_{i}^{s}$	Maximum number of substations in corridor *i*.
P_{ng}	Optimal generation of a unit of type *g* on bus *n* ($).
Pr_{ij}	Outage probability of line *j* in corridor *i*.
Pr_{q}	Outage probability of unit *q*.
$\underline{P}_{ng}$	Minimum generation of a unit of type *g* on bus *n* ($).
$\overline{P}_{ng}$	Maximum generation of a unit of type *g* on bus *n* (MW).
R_{i}	Resistance of each circuit per kilometer of corridor *i* (Ω/km).
T_{n}	Number of generating unit of type *g* on bus *n*.
U_{ij}	Unavailability of line *j* in corridor *i*.
x_{ng}	Number of generating units of type *g* on bus *n*.
$\underline{x}_{ng}$	Number of initial generating units of type *g* on bus *n*.
$\overline{x}_{ng}$	Maximum number of generating units of type *g* on bus *n*.
$\mathrm{V_{i}}$	Voltage level of corridor *i* (kV).
$VOLL_{n}$	VOLL on bus *n* ($/MW).
λ_{ij}	Failure rate of line *j* in corridor *i* (1/yr.).
γ_{nm}	Susceptance per kilometer between buses *n* and *m* (Ω^{-1}/km).
τ_{ij}	MTTR of line *j* in corridor *i* (h).
δ_{ij}	Salvage factor of line *j* in corridor *i*.
ς_{ij}	Depreciation coefficient of line *j* in corridor *i*.
$\Delta\theta_{nm}$	Difference of voltage phase angles between buses *n* and *m* (rad).

intensive computations in reliability assessment of composite transmission and generation systems, the proposed virtual database-supported NSGA-II (VDS-NSGA-II) method can solve large-scale GTEP problems efficiently.

Also, Qiu *et al.* [14] solved the GTEP problem considering uncertainties of wind generation and DR. In this model, the total cost of the network was reduced by decreasing lost power due to wind curtailment and by better coordination of demand response with dispatched power. Unlike the studies that use the deterministic security criteria, an insecurity risk approach, quantifying the system security degree considering the probability and the severity of contingencies was proposed in [14] to provide a flexible framework for network planners.

Moreover, Moreira *et al.* [15] minimized the investment cost of new lines and wind units considering uncertainty in load and generation, operating cost of generators, reserve cost [16] and network reliability. In the new expansion planning technique proposed by [15], the expensive cost of reserve resources and construction cost of new transmission lines are balanced in presence of renewable sources and generation and transmission outages.

In addition, Baharvandi *et al.* [17] proposed a robust and stochastic model for the GTEP problem considering load and wind generation uncertainties. To reduce complexity and computational burden of the problem presented in [17], the model was formulated as a mixed-integer linear programming (MILP) problem.

Li *et al.* [18] embedded uncertainties of generation and demand in GTEP formulation by a new scenario generation technique using Benders decomposition. The simulation results show that an appropriate renewable curtailment causes more economic plans for GTEP. Also, Benders decomposition is an efficient computational algorithm to solve the scenario-based GTEP problems.

Later, Zhang and Conejo [19] considered load growth and generation uncertainties besides the availability of equipment in GTEP. In this approach, annual load growth and future generation were considered as long-term uncertainties during planning horizon, while load changes, renewable generation variability, and equipment availability were taken into account as short-term uncertainties during a year.

Furthermore, Saxena and Bhakar [20] evaluated the DR effect on GTEP considering price-based incentives for energy consumers, aiming for minimization of the investment, operation cost, and losses [21]. The results show that including price-based demand response in the GTEP problem leads to an increase in network utilization and thus a significant decrease in the expansion cost of the network.

Javadi and Nezhad [22] minimized expansion and operational costs and expected energy not served (EENS) of the high voltage transmission network of Iran's national power grid (INPG) by integrating renewable energy sources (RESs) into the multi-year and multi-objective GTEP problem. The results obtained by epsilon-constraint optimization method in [22] show that RESs enhance the network reliability and decrease total costs (investment and operation expenses) of transmission and generation systems.

Verástegui *et al.* [23] proposed a robust model for the GTEP problem considering daily load and renewable generation uncertainties by separating investment and operational decisions. The formulation represents a flexible system with many numbers of renewable generation sources. Also, Najjar and Falaghi [24] introduced a new model for GTEP to reduce the short-circuit current (SC) in presence of wind units. The results show that the proposed model not only reduces SC level but decreases the investment cost of generation and transmission systems.

Moreover, Arasteh *et al.* [25] developed a stochastic multi-objective framework for GTEP under uncertain wind power using normalized normal constraint (NNC) method. In this approach, the objectives were minimization of expansion and operation costs and the transmission losses.

Later, Esmaili *et al.* [26] proposed a linear model for dynamic GTEP considering SC, bundled lines, and voltage level. The results demonstrate that neglecting voltage levels, bundled conductors and SC lead to suboptimal planning outcomes. Also, to decrease the computational efforts, the proposed nonlinear model was linearized by an effective linearization method.

Moreover, Wang *et al.* [27] presented a robust flexible model for coordination of wind units with coal-fired power plants in GTEP considering load and wind uncertainties. The results evaluation show that coal-fired power plants are still important electricity suppliers in many countries because high penetration of wind farms into transmission systems resulted in significant wind generation curtailment due to transmission congestion.

$$\begin{aligned}\min J = {} & TC + \sum_{i\in\Omega^s} C_i^S n_i^s + \sum_{n\in\Omega^{lb}} VOLL_n \sum_{i\in\Omega^c}\sum_{j=1}^{n_i+\underline{n}_i} LS_{n,ij} Pr_{ij} + \sum_{i\in\Omega^{ec}}\sum_{j=1}^{\underline{n}_i}\left(C_{ij}^M + C_{ij}^r\right) \\ & + \sum_{n\in\Omega^{lb}} VOLL_n \sum_{q=1}^{Ng}\left(LOL_{nq} + LS_{nq}\right)Pr_q + \sum_{n\in\Omega^{gb}}\sum_{g=1}^{T_n} C_{ng}^G x_{ng} + 8760\sum_{i\in\Omega^c} k^L C^L f_i^L + OC - VTS\end{aligned} \tag{1}$$

Recently, Hamidpour *et al.* [28] presented a flexible AC power flow based MILP formulation for GTEP in presence of wind farms and energy storage systems. The goal was to minimize expansion, operation, and reliability costs under load, energy price, and wind power uncertainties. Also, Khaligh and Buygi [29] performed the simultaneous expansion of electricity and gas networks considering units, lines, and pipelines contingencies. A distributed algorithm based on alternative direction method of multipliers was developed to preserve the privacy of electricity and gas networks for maintaining a coordination link between owners of electricity grid and gas network. Finally, Mahdavi *et al.* [30] included substation expansion costs and the uncertainty of fuel price in expansion planning of Azerbaijan Regional Electric Company of Iran. The results evaluation reveal that the fuel price uncertainties play important role in power system expansion planning that indirectly affect the lines loading and subsequent network configuration through the change of optimal generation of power plants.

However, in all of these works, maintenance impacts on the GTEP problem considering lines loading have not been studied. Reliability is reduced with weak maintenance, while the operational costs will increase considerably if maintenance activities are carried out frequently. Despite an increase in the system overall cost because of an increase in maintenance expenditure, construction of some new lines and costly expansion of the transmission network are avoided [31].

The lines power flow influences transmission reliability through its effect on line failure rates [32]. In simple terms, failure rates of transmission lines are reduced with a decrease in the magnitude of lines current flow, and therefore transmission reliability is improved. Consequently, it is very interesting to consider a lifetime-reliant and loading-dependent model in the GTEP formulation to explicitly optimize maintenance activities in the GTEP solution.

Thus, in the present paper, first, a mathematical model for GTEP problem considering optimal maintenance activities (GTEP-M) is proposed. Then our proposed GTEP-M model is solved by a particle swarm optimization (PSO) and a GA algorithm. Accordingly, the main contributions of the paper are:

- To quantify the economic benefit of line maintenance on GTEP.
- To present a lifetime-reliant and loading-dependent model for GTEP-M.
- To study lines loading effect on the GTEP problem via dependence of line failure rate on its power flow.
- To evaluate the maintenance effects on the reliability of a composite transmission and generation system through relationship of maintenance activities and lines failure rate improvement.

2. Problem formulation

The proposed GTEP-M problem is formulated as follows:

where

$$TC = \sum_{i\in\Omega^c} C_i^C n_i + \sum_{i\in\Omega^{ec}} C_i^R \tag{2}$$

$$Pr_{ij} = U_{ij}\prod_{o=1,o\neq j}^{n_i+\underline{n}_i}\left(1 - U_{io}\right)\prod_{y\in\Omega^c}\prod_{o=1}^{n_i+\underline{n}_i}\left(1 - U_{yo}\right) \quad \forall y\neq i \tag{3}$$

$$U_{ij} = \lambda_{ij}\tau_{ij}\big/\left(1 + \lambda_{ij}\tau_{ij}\right) \tag{4}$$

$$C_{ij}^M = K_{ij}\underline{C}_{ij}^M \tag{5}$$

$$C_{ij}^r = K_{ij}^r\underline{C}_{ij}^r \tag{6}$$

$$Pr_q = FOR_q\prod_{p=1,p\neq q}^{Ng}\left(1 - FOR_p\right)\forall q = 1,\ldots,Ng \tag{7}$$

$$f_i^L = f_i^2\ell_i r_i\big/\left(\underline{n}_i + n_i\right)|V_i|^2 \tag{8}$$

$$OC = \sum_{n\in\Omega^{gb}}\sum_{g=1}^{T_n}\left(a_{ng}G_{ng}^2 + \ b_{ng}G_{ng} + \ c_{ng}\right) \tag{9}$$

$$VTS = \sum_{i\in\Omega^{ec}}\ell_i\sum_{j=1}^{\underline{n}_i}\left[1 - \left(1 - \delta_{ij}\right)\varsigma_{ij}\right]C_{ij}^C \tag{10}$$

$$\varsigma_{ij} = \sum_{Q=1}^{n_{ij}^{l0}+H} 2Q\Big/n_{ij}^{le}\left(1 + n_{ij}^{le}\right) \tag{11}$$

subject to:

$$\sum_{g=1}^{T_n} G_{ng} = D_n + \sum_{m\in\Omega^b} f_{nm} \qquad \forall n\in\Omega^b, m\neq n \tag{12}$$

$$G_{ng} = \left(\underline{x}_{ng} + x_{ng}\right)P_{ng} \tag{13}$$

$$f_{nm} = \gamma_{nm}\Delta\theta_{nm} \tag{14}$$

$$|f_{nm}|\leqslant\overline{f}_{nm} \tag{15}$$

$$\underline{P}_{ng} \leqslant P_{ng} \leqslant \overline{P}_{ng} \tag{16}$$

$$0 \leqslant n_i \leqslant \overline{n}_i - \underline{n}_i \tag{17}$$

$$0 \leqslant x_{ng} \leqslant \overline{x}_{ng} - \underline{x}_{ng} \tag{18}$$

$$0 \leqslant n_i^s \leqslant \overline{n}_i^s - \underline{n}_i^s \tag{19}$$

$$0 \leqslant LS_{n,ij} \leqslant D_n \tag{20}$$

$$\left| f_{nm}^{ij} \right| \leqslant \overline{f}_{nm} \tag{21}$$

$$f_{nm}^{ij} = \sum_{k \in \Omega^{gb}} \widehat{e}_{k,nm}^{ij} G_k + \sum_{u \in \Omega^{lb}} \widehat{h}_{u,nm}^{ij} \left(D_u - LS_{u,ij} \right) \tag{22}$$

The TC in (1) indicates the transmission expansion cost, in which it consists of the investment for construction of new lines and replacement of old lines with new ones (please see (2)). The second part of (1) represents substations construction cost. The third part describes transmission reliability cost (LS due to a line outage), in which the LS probability is calculated by (3). It should be mentioned that calculation method of LS due to a line outage has been completely described in [33]. The fourth one is the transmission system maintenance and repair costs, where (5) and (6) emphasize that these costs are multipliers of their fixed amounts. These multipliers can affect the lines lifetime, failure rate, and MTTR (refer to Sections 2.1, 2.2, 2.3, and 2.4 for more details). The fifth part shows the generation reliability (LOL and LS costs because of unit outage and transmission congestion removal), in which their probabilities are determined by (7). Section 2.6 describes calculation method of LS due to transmission congestion. The sixth one includes the cost for construction of new units at each bus. The seventh part describes the active power losses cost. The active power loss of each corridor (f_i^L) is calculated using (8). The eighth term, described in (9), represents the units operational cost (OC), in which a_{ng} (\$/MW^{2}h), b_{ng} (\$/MWh), and c_{ng} (\$/h) are the cost coefficients for units of type g on bus n. The last term demonstrates the value of the transmission system (VTS) that can be calculated by (10). Also, (11) states that lines lifetime is increased by reducing lines depreciation.

Constrains (12)–(20) show the nodal power-flow balance, power-flow limit of lines, nodal permitted generation of units with the same technology, maximum constructible lines, units, and substations, and LS limitations related to outage of lines, respectively. Also, (21) shows that the power flow of a transmission line must not violate its limit during line outage. In (22), $\widehat{e}_{k,nm}^{ij}$ and $\widehat{h}_{u,nm}^{ij}$ are the ratio of the power flow change on the line connected to both buses n and m to the generation change of bus k and the demand of bus u due to outage of line j in corridor i, respectively. These factors are calculated using the DC power flow for each contingency.

2.1. Maintenance activities with the Line's lives

The relationship of maintenance cost with lines lifetime is described by (23) [31].

$$\vartheta_{ij} = \left(1 - \alpha_{ij}\right)\left(\beta_{ij}\right)^{1/m_{ij}}\left(K_{ij} - 1\right)^{1/m_{ij}} + \left(\alpha_{ij} + H/n_{ij}^{rl}\right) \tag{23}$$

$$m_{ij} = M_{ij} - \left(M_{ij} - 1\right)\alpha_{ij}^{1/2} \tag{24}$$

where $\vartheta_{ij} = n_{ij}^{le}/n_{ij}^{rl}, \alpha_{ij} = n_{ij}^{l0}/n_{ij}^{rl}$, and$\beta_{ij} = \underline{C}_{ij}^{M}/C_{ij}^{r}$. ϑ_{ij}, n_{ij}^{rl}, m_{ij}, and M_{ij} are life coefficient, regular lifetime (yr.), feature constant, and maximum value of m_{ij} for line j of corridor i, respectively.

2.2. Maintenance activities with the Line's failure

Maintenance cost versus the line failure rates are shown in (25) [33].

$$\zeta_{ij} = \left(1 - \alpha_{ij}\right)\left(H/n_{ij}^{rl}\right) - \eta\left(1 - \alpha_{ij}\right)\left(\beta_{ij}\right)^{1/m_{ij}}\left(K_{ij} - 1\right)^{1/m_{ij}} \tag{25}$$

where $\zeta_{ij} = \lambda_{ij}/\lambda_{ij}$ - $\zeta_{ij} = \lambda_{ij}^{M}/\underline{\lambda}_{ij}$ and $\eta = 0.5.\underline{\lambda}_{ij}$ and λ_{ij}^{M} are failure rates of line j in corridor i before and after optimal maintenance actions (1/yr.), respectively. ζ_{ij} is the failure coefficient of line j in corridor i.

2.3. Maintenance activities with the Line's MTTR

The MTTR of a line is extended with an increase in the maintenance cost as shown in (26) [33].

$$\chi_{ij} = \begin{cases} \begin{array}{l} \varpi_1\left(1 - \alpha_{ij}/2\right)\left(\beta_{ij}\right)^{1/m_{ij}}(b-1)^{1/(2m_{ij})} - \\ \quad \varpi_2\left(1 - \alpha_{ij}\right)^2\left(H/n_{ij}^{rl}\right) + \alpha_{ij}/\varepsilon \end{array} & 1 \leqslant K_{ij} \leqslant b \\ \begin{array}{l} \varpi_1\left(1 - \alpha_{ij}/2\right)\left(\beta_{ij}\right)^{1/m_{ij}}\left(K_{ij}-1\right)^{1/(2m_{ij})} - \\ \quad \varpi_2\left(1 - \alpha_{ij}\right)^2\left(H/n_{ij}^{rl}\right) + \alpha_{ij}/\varepsilon \end{array} & b \leqslant K_{ij} \leqslant d \\ \begin{array}{l} \varpi_1\left(1 - \alpha_{ij}/2\right)\left(\beta_{ij}\right)^{1/m_{ij}}(d-1)^{1/(2m_{ij})} - \\ \quad \varpi_2\left(1 - \alpha_{ij}\right)^2\left(H/n_{ij}^{rl}\right) + \alpha_{ij}/\varepsilon \end{array} & K_{ij} \geqslant d \end{cases} \tag{26}$$

where $\chi_{ij} = \tau_{ij}/\underline{\tau}_{ij}$, $\varepsilon = 1$, $\varpi_1 = 10.36$, $\varpi_2 = 2.216$, $b = 2$, and $d = 4.\underline{\tau}_{ij}$ and χ_{ij} are MTTR before optimal maintenance actions (h) and MTTR coefficient of line j in corridor i, respectively.

2.4. Repair activities and the Line's MTTR

To provide a regular life for a line during its operation, specific repair activities are necessary besides maintenance efforts. An increase in maintenance cost leads to a decrease in the number of repairs, and subsequent repair cost. Also, the repair expenses decrease if the fixed repair expenditure is reduced. This reality can be explained by (27).

$$C_{ij}^{r} = \left(\underline{C}_{ij}^{r}/\underline{\mu}_{ij}\right)\mu_{ij} \tag{27}$$

where $\underline{\mu}_{ij}$ and μ_{ij} are the number of repairs per year for line j of corridor i before and after optimal maintenance actions, respectively.

Equation (28) is obtained by replacing $\mu_{ij} = 8760/\tau_{ij}$ and $\underline{\mu}_{ij} = 8760/\underline{\tau}_{ij}$ in (27).

$$C_{ij}^{r} = \left(\underline{C}_{ij}^{r}/\tau_{ij}\right)\underline{\tau}_{ij} = \underline{C}_{ij}^{r}/\chi_{ij} \tag{28}$$

Equation (29) yields by comparing (28) to (6):

$$k_{ij}^{r} = 1/\chi_{ij} \tag{29}$$

This equation shows the relationship between the coefficients of repair cost and MTTR.

2.5. Line loading and the failure rate

The failure rate of a transmission line is reduced with a decrease in the line current magnitude (line loading) [32]. We consider that a transmission line has the lowest and the highest failure rates of λ_{ij}^{M} and $\underline{\lambda}_{ij}$ when its active power flow is zero ($f_i = 0$) and maximum ($f_i = \overline{f}_i$), respectively.

The failure rate can be defined as a linear proportion to the percentage of line loading when the line active power is between its minimum and maximum values. Accordingly, the line loading coefficient of a line in corridor i (ρ_i) is defined as (30).

$$\rho_i = f_i / \overline{f}_i \tag{30}$$

Thus, the relationship between the loading and failure rate of a transmission line can be described by (31).

$$\lambda_{ij} = (f_i / \overline{f}_i)\left(\underline{\lambda}_{ij} - \lambda_{ij}^M\right) + \lambda_{ij}^M \tag{31}$$

2.5.1. LS due to a unit outage

The power flow of some transmission lines increases after a unit outage, which may result in network congestion. In this case, a portion of the loads must be curtailed to alleviate network violations. Different load-shedding schemes can be used to remove network congestion. This paper utilizes the load curtailment based on the minimum amount of load shedding in order to achieve maximum network reliability [34]. The objective function for each contingency state (unit outage) is shown in (32):

$$\min \sum_{n \in \Omega^{lb}} LS_{nq} \tag{32}$$

subject to:

$$0 \leqslant LS_{nq} \leqslant D_n - LOL_{nq} \tag{33}$$

$$\left| f_{nm}^q \right| \leqslant \overline{f}_{nm} \tag{34}$$

$$f_{nm}^q = \sum_{k \in \Omega^{gb}} e_{k,nm}^q G_k + \sum_{u \in \Omega^{lb}} h_{u,nm}^q \left(D_u - LOL_{uq} - LS_{uq}\right) \tag{35}$$

Equation (33) shows the minimum and maximum load shedding due to a unit outage. Constraint (34) declares the power flow limit for contingency states. This equation imposes that power flows on the lines cannot exceed their limits when a single unit outage happens. In (35), $e_{k,nm}^q$ and $h_{u,nm}^q$ are the ratio of the change of the power flow on the line connected between buses n and m to the change of generation of bus k and to the change of demand on bus u, respectively, after the outage of unit q. These factors are determined by the DC power flow for each contingency.

3. Solution methods

The proposed GTEP-M model is a mixed-integer nonlinear optimization problem including discrete variables Ng, n_i, n_i^s, n_{ij}^{le}, and x_{ng} and real variables P_{ng}, $\Delta\theta_{nm}$, $LS_{n,ij}$, and $LS_{n,q}$ as well as non-linear objective function (1), linear equations (2), (3), (5) to (7), (10), (12) to (14), (22), and (35), nonlinear equations (4), (8), (9), (11), (23), (25), (26), (29), and (31), linear constraints (15) to (21), (33), and (34) that can be calculated using nonlinear solvers of classic optimization tools or metaheuristic algorithms. However, calculation of the proposed problem using commercial nonlinear solvers suffers high computational burden, while metaheuristics can solve the problem with lower computational efforts. Among metaheuristic algorithms, GA is a popular method and PSO is commonly employed to solve TEP and GEP problems. The performance of both algorithms has been proven to outperform other metaheuristics in power system expansion planning.

3.1. Discrete particle swarm optimization (DPSO)

Regarding existence of discrete variables in the GTEP-M model, the discrete PSO (DPSO) algorithm was employed to solve the proposed optimization problem. In this method, first, a d-dimension population (d = 5) with different particles positions (36) and velocities (37), is randomly generated subjecting to constraints (12)–(22) and (33) to (35):

$$X = \begin{bmatrix} X_1 & X_2 & \dots & X_i & \dots & X_d \end{bmatrix}^{Transpose} \tag{36}$$

$$V = \begin{bmatrix} V_1 & V_2 & \dots & V_i & \dots & V_d \end{bmatrix}^{Transpose} \tag{37}$$

In the above equations, the position and velocity vectors of the particle d are represented by X_d and Ve_d, respectively, where they include integer variables of the problem and random numbers from 0 to 1, respectively. The decision variables are number of new circuits and substations in each candidate corridor (n_i and n_i^s) for transmission system expansion, number of new generating units on candidate buses (x_{ng}) for expansion of generation system, and life expectancies of old lines in existing corridors (n_{ij}^{le}). Therefore, position vector of each particle, consisting of these integer decision variables is formed as follows.

$$X_d = [NL_d, NS_d, NU_d, LE_d] \tag{38}$$

where

$$NL_d = \left[n_{1d}, n_{2d}, \dots, n_{id}, \dots, n_{|\Omega^c|d}\right] \tag{39}$$

$$NS_d = \left[n_{1d}^s, n_{2d}^s \dots, n_{id}^s, \dots, n_{|\Omega^s|d}^s\right] \tag{40}$$

$$NU_d = \left[x_{11d}, x_{21d}, \dots, x_{n1d}, x_{12d}, x_{22d}, \dots, x_{n2d}, \dots, x_{ngd}, \dots, x_{\left|\Omega^{gb}\right| \max\left\{T_1, T_2, \dots, T_{\left|\Omega^{gb}\right|}\right\} d}\right] \tag{41}$$

$$LE_d = \left[n_{1d}^{le}, \dots, n_{id}^{le}, \dots, n_{|\Omega^{ec}|d}^{le}\right] \tag{42}$$

In (39)–(41), n_{id} and n_{id}^s are the number of new circuits and substations of particle d proposed for corridor i. The quantities x_{ngd} and n_{id}^{le} indicate the number of new units and lines life expectancy of particle d at bus n and corridor i, respectively.

In order to determine the optimal generation of the units at each bus, (9) considering constraints (12)–(16) is minimized using the optimization function of *quadprog* in MATLAB.

Then, the third term of the objective function (1) subjecting constraints (20) to (22) is minimized using the *fmincon* function of MATLAB to calculate load shedding of each bus due to line outages.

After minimizing the (32) considering constraints (33) to (35) using *fmincon* to calculate fifth term of (1), (2)–(11) are computed, and therefore, the objective function (1) is specified. The PSO is based on fitness maximization. For this, (43) converts minimization of the objective function (1) to a maximization process, where parameter A is a large number.

$$F = A/J \tag{43}$$

The fitness values of all initial particles are stored as (44):

$$F = [F_1, F_2, \dots, F_h, \dots, F_d] \tag{44}$$

F_{gbest} is the *global best fitness* or maximum value of (44) and its related particle is known as X_{gp}. Afterwards, X_h (the position of the particle h) is updated as follows:

$$X_h' = X_h + Ve_h' \qquad \forall h = 1, 2, \dots, d \tag{45}$$

$$Ve_{hi}' = fix\left(Ve_h + c_2 r_2 \left(X_{gp} - X_h\right)\right) \tag{46}$$

where $v_{min} \le Ve_h'(s) \le v_{max}$ (s = 1, 2,…, N) and *fix* command rounds each element of vector $Ve_h + c_2 r_2 (X_{gp} – X_h)$ to the nearest integer toward zero. When $Ve_h'(s)$ is bigger or smaller than v_{max} and v_{min}, it is defined as $Ve_h'(s) = v_{max}$ and $Ve_h'(s) = v_{min}$, respectively. When $X_h'(s)$ (for s = 1, 2,…, N) is bigger than the upper bound, $X_h'(s)$ is made equal to the upper bound. $X_h'(s)$ is replaced by zero if $X_h'(s) < 0$. Also, r_2 is a random number from 0 to 1, and c_2 is the velocity coefficient with an amount of 2. Again, the fitness function (43) is evaluated for new particle X_h'.

Then, the new fitness values are arranged as shown in (47).

$$F' = \left[F_1', F_2', \dots, F_h', \dots, F_d'\right] \tag{47}$$

Table 1
Best transmission expansion plan of RTS system in Case 1 for TEP using DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	4–10	1	138	12–16	1	230	15–22	1	230
3–8	2	138	5–7	2	138	12–17	1	230	16–20	1	230
3–10	1	138	7–8	1	138	12–18	1	230	18–22	1	230
4–5	1	138	7–10	1	138	12–20	1	230	18–24	1	230
4–6	2	138	11–12	1	230	12–21	1	230	19–23	2	230
4–7	2	138	12–15	1	230	14–19	1	230	23–24	1	230

Table 2
Expansion and operation costs of RTS system in Case 1 for TEP (million US$).

Methods		DCGA	DPSO
Transmission system expansion cost	Lines construction cost	66.402	66.402
	Lines replacement cost	21.811	21.811
Generating units construction cost		6079.2	5341.6
Expansion cost of substations		0	0
Operation cost of generating units		1611	1632.2
Active losses cost		11.25	9.5406
Load shedding cost because of line and substation outages		0.5879	1.2381
LOL cost		25.85	20.765
Annual maintenance cost		1.838	1.838
Annual repair cost		5.338	5.338
Total cost of power system		7823.3	7100.7

Better *global best fitness* and *global particle* are selected by comparing the maximum value of (47) and its corresponding position vector with those of (44). Then, $F_h{'}$ is compared with F_h, and each particle that is bigger is called a *local best fitness*, and its related particle is called a *local particle* (X_{lp}). Now, $X_h{'}$ (position vector of new particle h) is updated using (48) and (49).

$$X_h'' = X_h' + Ve_h'' \qquad \forall h = 1, 2, ..., d \tag{48}$$

$$Ve_{hi}'' = fix\left(\omega\ Ve_{hi}' + c_1 r_1\left(X_{lph} - X_h'\right) + c_2 r_2\left(X_{gp} - X_h'\right)\right) \tag{49}$$

In (49), $0 < r_1 < 1$, $c_1 = 2$, and ω is inertia weight that is calculated by (50).

$$\omega = 1/(1 + \ln t) \tag{50}$$

In (50), t is the iteration number of PSO algorithm. The process is repeated by evaluating (43) for each particle and is terminated after a finite number of iterations.

3.2. Decimal codification genetic algorithm (DCGA)

Like Section 3.1, decimal codification GA (DCGA) is used here because of discrete decision variables n_i (number of new circuits in each candidate corridor), n_i^s (number of new substations in existing corridor including substation), x_{ng} (number of new generating units on each candidate generation bus), and n_{ij}^{le} (lines' life expectancies in existing

Table 5
Expansion and operation costs of RTS system in Case 2 for TEP (million US$).

Methods		DCGA	DPSO
Transmission system expansion cost	Lines construction cost	73.315	70.262
	Lines replacement cost	0	0
Generating units construction cost		5094	5094
Expansion cost of substations		0	0
Operation cost of generating units		1517.4	1590.4
Active losses cost		10.663	8.743
Load shedding cost because of line and substation outages		1.417	0.6567
LOL cost		20.68	19.377
Annual maintenance cost		2.235	2.325
Annual repair cost		1.468	1.468
Value of transmission system		47.191	47.804
Total cost of power system		6674	6739.5

Table 3
New lifetimes (year), failure rates (1/year), and MTTRs (Hour) in RTS system under Case 2 for TEP based on DPSO.

Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}	Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}
1–2	37	0.2320	0.2381	2959.7	12–23	55	0.2773	0.3415	1638.3
1–3	57	0.2550	0.2735	1389.8	13–23	41	0.3757	0.3894	1738.6
1–5	58	0.1595	0.2218	2147.8	14–16	48	0.2470	0.3179	2241.9
2–4	38	0.3185	0.3454	1430.0	15–16	49	0.2090	0.3097	2581.6
2–6	36	0.4080	0.4402	871.6	15–21	58	0.2255	0.3009	2356.2
3–9	49	0.2660	0.2671	1940.0	15–24	40	0.3212	0.3223	1905.2
4–9	51	0.2160	0.2505	1968.9	16–17	46	0.2392	0.2541	2434.1
5–10	52	0.1983	0.2108	2084.7	16–19	38	0.2777	0.2916	1813.3
6–10	58	0.1850	0.2572	2566.1	17–18	58	0.1760	0.2086	3018.9
7–8	57	0.1500	0.2587	2362.6	17–22	59	0.2473	0.2700	1607.4
8–9	44	0.3447	0.3699	1675.5	18–21	46	0.2392	0.2439	2434.1
8–10	44	0.3153	0.3298	1610.9	19–20	43	0.2787	0.2959	2241.9
11–13	53	0.2533	0.3280	2415.1	20–23	47	0.2267	0.2821	2505.6
11–14	46	0.2665	0.2715	2184.4	21–22	45	0.3150	0.3275	1893.2
12–13	49	0.2533	0.3000	2129.8	–	–		–	–

Table 4
Best transmission expansion plan of RTS system in Case 2 for TEP using DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	5–7	2	138	12–18	1	230	18–22	1	230
3–8	2	138	7–8	1	138	12–20	1	230	18–24	1	230
3–10	1	138	7–10	1	138	12–21	1	230	19–23	2	230
4–5	1	138	11–12	1	230	14–19	1	230	23–24	1	230
4–6	2	138	12–15	1	230	15–22	1	230	–	–	–
4–7	2	138	12–16	1	230	15–23	1	230	–	–	–
4–10	1	138	12–17	1	230	16–20	1	230	–	–	–

Table 6
Best transmission expansion plan of RTS system proposed in Case 3 for TEP using DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	5–7	2	138	12–17	1	230	15–23	1	230
3–8	2	138	7–8	1	138	12–18	1	230	16–20	1	230
3–10	1	138	7–10	1	138	12–19	1	230	18–22	1	230
4–5	1	138	11–12	1	230	12–20	1	230	18–24	1	230
4–6	2	138	14–18	1	230	12–21	1	230	19–23	2	230
4–7	2	138	12–15	1	230	14–19	1	230	23–24	1	230
4–10	1	138	12–16	1	230	15–22	1	230	–	–	–

Table 7
New lifetimes (year), failure rates (1/year), and MTTRs (Hour) in RTS system under Case 3 for TEP based on DPSO.

Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}	Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}
1–2	58	0.1480	0.2182	3.2077	12–23	48	0.3380	0.3825	1.6383
1–3	51	0.3060	0.3223	1.3898	13–23	55	0.2613	0.2835	1.7386
1–5	54	0.1815	0.2355	2.1478	14–16	56	0.1963	0.2684	2.2419
2–4	50	0.2405	0.2966	1.8174	15–16	55	0.1760	0.3127	2.5816
2–6	56	0.2480	0.3516	1.4766	15–21	58	0.2255	0.2967	2.3562
3–9	56	0.2217	0.2257	1.9400	15–24	54	0.2255	0.2288	2.0779
4–9	52	0.2100	0.2462	1.9689	16–17	58	0.1692	0.1813	2.4341
5–10	58	0.1643	0.1792	2.0847	16–19	54	0.1870	0.2224	2.5056
6–10	50	0.2250	0.2723	2.5661	17–18	54	0.1973	0.2143	3.0189
7–8	48	0.1950	0.2714	2.3626	17–22	58	0.2562	0.2775	1.6074
8–9	46	0.3300	0.3594	1.6755	18–21	58	0.1692	0.1704	2.4341
8–10	54	0.2420	0.2656	1.6109	19–20	46	0.2597	0.2782	2.2419
11–13	58	0.2200	0.3071	2.4151	20–23	57	0.1700	0.2480	2.5056
11–14	58	0.1885	0.2148	2.1844	21–22	58	0.2175	0.2394	1.8932
12–13	54	0.2200	0.2775	2.1298	–	–	–	–	–

Table 8
Expansion and operation costs of RTS system in Case 3 for TEP (million US$).

Methods		DCGA	DPSO
Transmission system expansion cost	Lines construction cost	80.162	78.184
	Lines replacement cost	0	0
Generating units construction cost		4171.8	4236.4
Expansion cost of substations		0	0
Operation cost of generating units		1596.6	1562.1
Active losses cost		9.4545	8.274
Load shedding cost because of line and substation outages		0.5827	0.5536
LOL cost		20.998	20.891
Annual maintenance cost		3.0305	3.1508
Annual repair cost		0.7854	0.7854
Value of transmission system		51.872	52.449
Total cost of power system		5831.5	5857.9

corridors). In DCGA, a d-dimension population of different chromosomes is randomly constructed as (51) under constraints (12)–(22) and (33) to (35):

$$Chr = \begin{bmatrix} Chr_1 & Chr_2 & \dots & Chr_i & \dots & Chr_d \end{bmatrix}^{Transpose} \tag{51}$$

In (51), chromosome d is represented by Chr_d and contains integer decision variables.

$$Chr_d = [NL_d, NS_d, NU_d, LE_d] \tag{52}$$

where NL_d, NS_d, NU_d, and LE_d can be calculated by (39) to (42) with this difference that n_{id},n_{id}^{s}, and n_{id}^{le} are the number of new circuits, the number of new substations, and life expectancy of lines in corridor i, respectively, and x_{ngd} is the number of new units at bus n all for chromosome d. The optimal generation of the units is determined by minimization of (9) under constraints (12)–(16) using the *quadprog* function in MATLAB. To determine objective function (1), the third term of (1) subjecting constraints (20) to (22) and objective function (32) with constraints (33) to (35) are minimized, respectively, using the *fmincon* function of MATLAB. Then, more fit chromosomes for reproduction are chosen by selection operator to reproduce each chromosome in proportion to the value of their fitness functions. Similar to PSO, fitness function of GA has inverse proportion to its objective function. After selection of the parent chromosomes, the crossover operator is applied to boundary of two

Table 10
Best generation expansion plan of RTS system in Case 1 for GTEP based on DPSO.

Location	Number	Size	Type
Bus 1	2 Units	20 MW	Combustion Turbine (CT)
Bus 2	2 Units	76 MW	Fossil Steam (FS)
Bus 7	3 Units	100 MW	FS
Bus 13	1 Unit	197 MW	FS
Bus 14	2 Units	20 MW	CT
Bus 16	4 Units	155 MW	FS
Bus 17	2 Units	76 MW	FS
Bus 18	1 Unit	400 MW	Nuclear Steam (NS)
Bus 21	1 Unit	400 MW	NS
Bus 23	4 Units	350 MW	FS

Table 9
Best transmission expansion plan of RTS system in Case 1 for GTEP based on DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	7–8	1	138	12–19	1	230	16–20	1	230
3–8	2	138	7–10	1	138	12–20	1	230	18–22	1	230
3–10	1	138	11–12	1	230	12–21	1	230	18–24	1	230
4–5	1	138	14–18	1	230	12–23	1	230	19–23	2	230
4–6	2	138	12–15	1	230	14–19	1	230	21–23	1	230
4–7	2	138	12–16	1	230	15–22	1	230	22–23	1	230
4–10	1	138	12–17	1	230	15–23	1	230	23–24	1	230
5–7	2	138	12–18	1	230	16–18	1	230	–	–	–

Table 11
Expansion and operation costs of RTS system in Case 1 for GTEP based on DPSO (million US$).

Transmission system expansion cost	Lines construction cost	90.532
	Lines replacement cost	21.811
Generating units construction cost		3364.8
Expansion cost of substations		0
Operation cost of generating units		1618.9
Active losses cost		9.81
Load shedding cost because of line and substation outages		0.6160
LOL cost		17.335
Annual maintenance cost		1.84
Annual repair cost		5.34
Total cost of power system		5130.984

integer variables of each pair with the probability of P_C ($P_C = 0.9$) and the genes (variables) of two chromosomes are swapped. Then, the mutation operator selects some integer numbers of crossed over chromosomes and then randomly changes their values with probability of P_M ($P_M = 0.1$).

The process is iterated by evaluating the objective function (1) and is terminated after a specific number of iterations.

4. Simulation results

The IEEE RTS [35] and the IEEE 118-bus test system [36] were used to verify the proposed model. The maximum number of new circuits and substations and usual life of all lines in each corridor were considered to be 2, 2, and 30 years, respectively, for both case study systems.

4.1. IEEE RTS

All data of this test system is available in [35]. Also, the initial life of the existing lines and VOLLs are presented in Tables A1 and A2 of Appendix, respectively. It should be noted that values of VOLL were adopted from [31]. Also, the MTTR of existing lines before optimal maintenance actions (basic values) are according to Table A3 given in Appendix. The proposed model was studied in three scenarios for H = 15 years.

To show the benefits of solving simulations TEP and GEP problem and importance of maintenance consideration in network expansion planning, first, TEP considering maintenance costs and then GTEP

Table 14
Best generation expansion plan of RTS system in Case 2 for GTEP based on DPSO.

Location	Number	Size	Type
Bus 1	2 Units	20 MW	CT
Bus 2	2 Units	76 MW	FS
Bus 7	3 Units	100 MW	FS
Bus 13	1 Unit	197 MW	FS
Bus 14	2 Units	20 MW	CT
Bus 16	4 Units	155 MW	FS
Bus 17	1 Unit	76 MW	FS
Bus 18	2 Units	400 MW	NS
Bus 21	1 Unit	400 MW	NS
Bus 23	4 Units	350 MW	FS

Table 15
Expansion and operation costs of RTS system in Case 2 for GTEP based on DPSO (million US$).

Transmission system expansion cost	Lines construction cost	94.58
	Lines replacement cost	0
Generating units construction cost		3306.1
Expansion cost of substations		0
Operation cost of generating units		1659.6
Active losses cost		9.79
Load shedding cost because of line and substation outages		0.1
LOL cost		17.2
Annual maintenance cost		2.7
Annual repair cost		1.56
Value of transmission system		49.83
Total cost of power system		5041.8

Table 12
New lifetimes (year), failure rates (1/year), and MTTRs (Hour) in RTS system under Case 2 for GTEP based on DPSO.

Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}	Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}
1–2	59	0.14	0.22	3207.7	12–23	54	0.29	0.36	1638.3
1–3	52	0.30	0.32	1389.8	13–23	55	0.26	0.34	1738.6
1–5	50	0.20	0.25	2147.8	14–16	48	0.25	0.30	2241.9
2–4	45	0.27	0.32	1817.4	15–16	54	0.2	0.31	2483.1
2–6	46	0.35	0.39	1470	15–21	56	0.24	0.31	2356.2
3–9	50	0.26	0.26	1940.0	15–24	57	0.20	0.21	2077.9
4–9	50	0.22	0.24	1968.9	16–17	58	0.17	0.18	2434.1
5–10	52	0.20	0.21	2084.7	16–19	53	0.19	0.20	2505.6
6–10	51	0.22	0.25	2566.1	17–18	50	0.22	0.24	3018.9
7–8	60	0.13	0.25	2362.6	17–22	57	0.26	0.30	1607.4
8–9	47	0.33	0.35	1675.5	18–21	43	0.32	0.35	2536.3
8–10	50	0.2	0.24	1540	19–20	50	0.23	0.26	2241.9
11–13	57	0.23	0.27	2415.1	20–23	60	0.15	0.26	2505.6
11–14	58	0.19	0.23	2184.4	21–22	57	0.22	0.24	1893.2
12–13	53	0.23	0.23	2129.8	–	–	–	–	–

Table 13
Best transmission expansion plan of RTS system in Case 2 for GTEP based on DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	5–7	2	138	12–15	1	230	15–23	1	230
3–8	2	138	5–9	1	138	12–16	1	230	16–18	1	230
3–9	1	138	5–10	1	138	12–17	1	230	16–20	1	230
3–10	1	138	6–8	1	138	12–18	1	230	18–22	1	230
4–5	1	138	6–9	1	138	12–19	1	230	18–24	1	230
4–6	2	138	6–10	1	138	12–20	1	230	19–23	2	230
4–7	2	138	7–8	1	138	12–21	1	230	21–23	1	230
4–8	2	138	7–10	2	138	12–23	1	230	22–23	1	230
4–9	2	138	11–12	1	230	14–19	1	230	23–24	1	230
4–10	2	138	14–18	1	230	15–22	1	230	–	–	–

Table 16
Best transmission expansion plan of RTS system in Case 3 for GTEP based on DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	5–7	2	138	12–16	1	230	16–18	1	230
3–8	2	138	5–9	1	138	12–17	1	230	16–20	1	230
3–9	1	138	5–10	1	138	12–18	1	230	18–22	1	230
3–10	1	138	6–8	1	138	12–19	1	230	18–24	1	230
4–5	1	138	6–10	1	138	12–20	1	230	19–23	2	230
4–6	2	138	7–8	1	138	12–21	1	230	21–23	1	230
4–7	2	138	7–10	2	138	12–23	1	230	22–23	1	230
4–8	2	138	11–12	1	230	14–19	1	230	23–24	1	230
4–9	1	138	14–18	1	230	15–22	1	230	–	–	–
4–10	2	138	12–15	1	230	15–23	1	230	–	–	–

Table 17
New lifetimes (year), failure rates (1/year), and MTTRs (Hour) in RTS system under Case 3 for GTEP based on DPSO.

Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}	Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}
1–2	59	0.14	0.22	3207.7	12–23	54	0.29	0.36	1638.3
1–3	52	0.30	0.32	1389.8	13–23	55	0.26	0.34	1738.6
1–5	50	0.20	0.25	2147.8	14–16	48	0.25	0.30	2241.9
2–4	45	0.27	0.32	1817.4	15–16	52	0.19	0.30	2581.6
2–6	48	0.31	0.37	1476.6	15–21	56	0.24	0.31	2356.2
3–9	50	0.26	0.26	1940.0	15–24	57	0.20	0.21	2077.9
4–9	50	0.22	0.24	1968.9	16–17	58	0.17	0.18	2434.1
5–10	52	0.20	0.21	2084.7	16–19	53	0.19	0.20	2505.6
6–10	51	0.22	0.25	2566.1	17–18	50	0.22	0.24	3018.9
7–8	60	0.13	0.25	2362.6	17–22	57	0.26	0.30	1607.4
8–9	47	0.33	0.35	1675.5	18–21	47	0.23	0.29	2434.1
8–10	55	0.23	0.26	1610.9	19–20	50	0.23	0.26	2241.9
11–13	57	0.23	0.27	2415.1	20–23	60	0.15	0.26	2505.6
11–14	58	0.19	0.23	2184.4	21–22	57	0.22	0.24	1893.2
12–13	53	0.23	0.23	2129.8	–	–	–	–	–

Table 18
Best generation expansion plan of RTS system in Case 3 for GTEP based on DPSO.

Location	Number	Size	Type
Bus 1	2 Units	20 MW	CT
Bus 2	2 Units	76 MW	FS
Bus 7	3 Units	100 MW	FS
Bus 13	1 Unit	197 MW	FS
Bus 14	2 Units	20 MW	CT
Bus 16	4 Units	155 MW	FS
Bus 17	1 Unit	76 MW	FS
Bus 18	1 Unit	400 MW	NS
Bus 21	1 Unit	400 MW	NS
Bus 23	4 Units	350 MW	FS

Table 19
Expansion and operation costs of RTS system in Case 3 for GTEP based on DPSO (million US$).

Transmission system expansion cost	Lines construction cost	93.30
	Lines replacement cost	0
Generating units construction cost		3304.8
Expansion cost of substations		0
Operation cost of generating units		1646
Active losses cost		9.786
Load shedding cost because of line and substation outages		0.0703
LOL cost		17.15
Annual maintenance cost		3.04
Annual repair cost		0.785
Value of transmission system		52.061
Total cost of power system		5022.87

problem in presence of maintenance activities were solved.

4.1.1. TEP considering maintenance

In this section, the TEP problem is optimized for three cases to show importance of optimal maintenance activities in TEP.

Table 20
Loading coefficients in all cases for GTEP based on DPSO.

Corr.	Cases			Corr.	Cases		
	1	2	3		1	2	3
1–2	0.75	0.71	0.70	12–23	0.33	0.33	0.33
1–3	0.08	0.08	0.08	13–23	0.36	0.36	0.36
1–5	0.37	0.36	0.36	14–16	0.43	0.42	0.42
2–4	0.38	0.37	0.37	15–16	0.825	0.79	0.79
2–6	0.45	0.39	0.37	15–21	0.43	0.40	0.40
3–9	0.02	0.02	0.02	15–24	0.05	0.04	0.04
4–9	0.24	0.17	0.17	16–17	0.04	0.06	0.06
5–10	0.09	0.09	0.09	16–19	0.12	0.09	0.08
6–10	0.63	0.39	0.39	17–18	0.32	0.20	0.20
7–8	0.73	0.69	0.69	17–22	0.12	0.11	0.10
8–9	0.27	0.22	0.22	18–21	0.46	0.46	0.46
8–10	0.125	0.12	0.11	19–20	0.21	0.19	0.20
11–13	0.25	0.25	0.25	20–23	0.58	0.58	0.58
11–14	0.19	0.19	0.19	21–22	0.07	0.07	0.07
12–13	0.01	0.01	0.01	Total	8.93	8.16	8.11

- **TEP-Case 1**

The goal is to solve the TEP problem considering only fixed maintenance and repair costs, and power system reliability. The proposed model without optimal generation scenario is applied to the RTS system, and results based on the solution method used are listed in Tables 1 and 2 and Tables A4 and A5 of Appendix. The RTS system has 141 candidate corridors for expansion of transmission network ($|\Omega^c|+|\Omega^s|=141$). Regarding the fact that maximum numbers of constructible circuits and substations in each corridor have been considered 2 ($\overline{n}_i=\underline{n}_i^s=2$) and new corridors have no lines, while existing corridors have one or two line circuits or substations, each corridor can have three integer numbers 0,

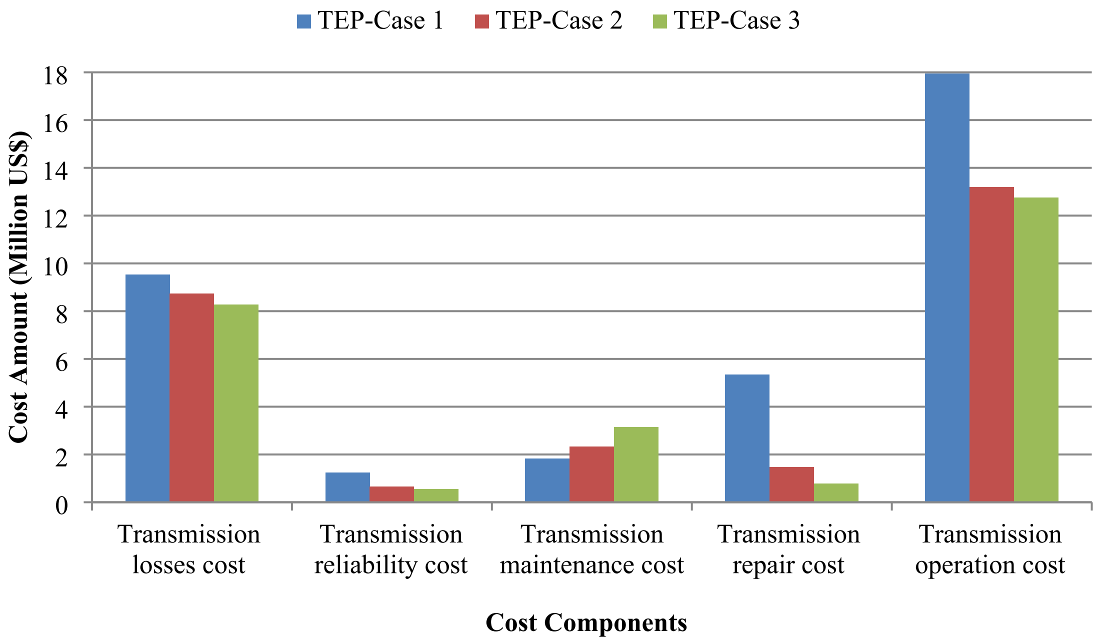

Fig. 1. Components of transmission operation cost for TEP.

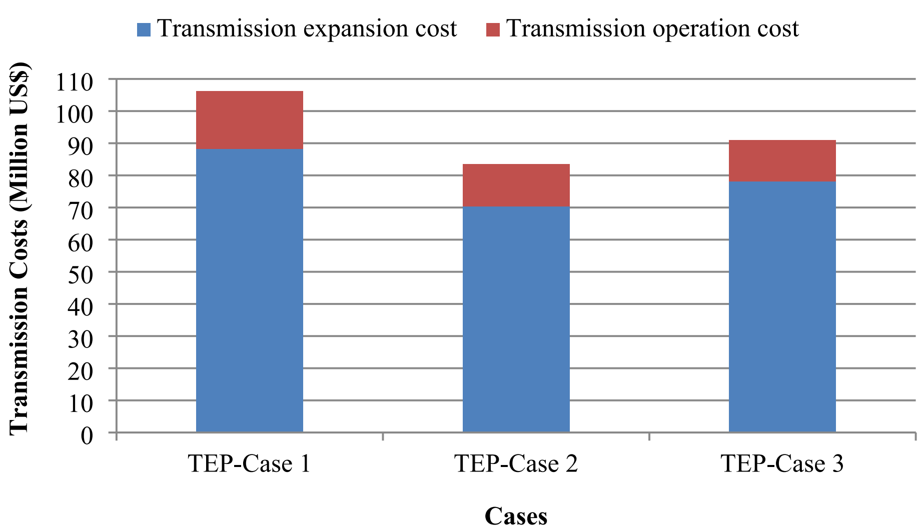

Fig. 2. Transmission costs for TEP.

1, and 2. Also, regarding equality of size of each particle ($|X_d|$) or chromosome ($|Chr_d|$) in DPSO or DCGA to number of candidate corridors ($|NL_d|+|NS_d|=141$) and choosing five individuals for initial population ($d = 5$), the size of search space in both algorithms will be $3^d \times 3^{141} = 3^{146}$. Since the goal is only installation of new lines and substations for network expansion, the number of decision variables are equal to size of chosen particles or chromosomes ($|X_d|=|Chr_d|=|NL_d|+|NS_d|$), i.e. 141.

Tables 1 and A4 list new lines that should be added to the transmission network. Table A5 shows replaced existing lines by new ones because their regular lives are less than their initial lifetimes plus the planning horizon year. Table 2 describes the costs of expansion, operation, losses, and reliability (LS and LOL due to line, substation, and unit outages) when fixed maintenance and repair costs are considered.

- **TEP-Case 2**

In this case, the impact of optimal maintenance activities and line loading effect on the system reliability are considered in TEP. Therefore, the life expectancy of existing lines should be added to decision variables mentioned in TEP-Case 1 (new line circuits). Regarding 29 existing corridors with at least one transmission line in RTS system ($|\Omega^{ec}|=29$), size of each particle and chromosome of TEP-Case 1 should be increased by $|LE_d|$ ($|X_d|=|Chr_d|=|NL_d|+|NS_d|+|LE_d|=141 + 29$). Therefore, number of decision variables is 170 in this case. Each part of particle or chromosome which defined for life expectancy can include integer numbers from usual life (30 yr.) to maximum life expectancy (60 yr.), i.e. 31 numbers. Therefore, the size of search space for both algorithms equals $3^{146} + 31^d \times 31^{29} = 3^{146} + 31^{34}$. The proposed model was implemented on the network under study, and the results are given in Tables 3–5 and Tables A6 and A7 of Appendix. Table 3 represents new lifetimes, failure rates, and MTTRs of existing lines after optimal maintenance activities.

- **TEP-Case 3**

In this case, the effect of optimal maintenance activities on repair cost is considered in the formulation of TEP-Case 2. Therefore, the

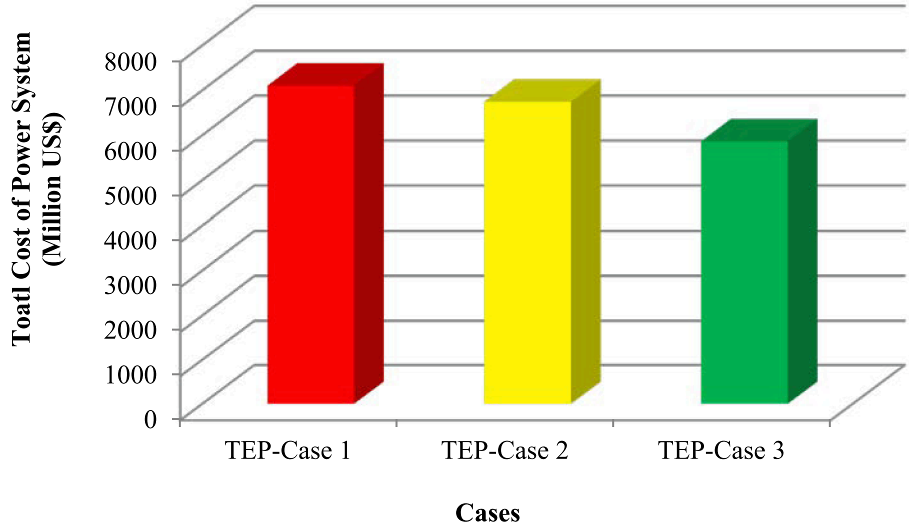

Fig. 3. Total power system cost for TEP.

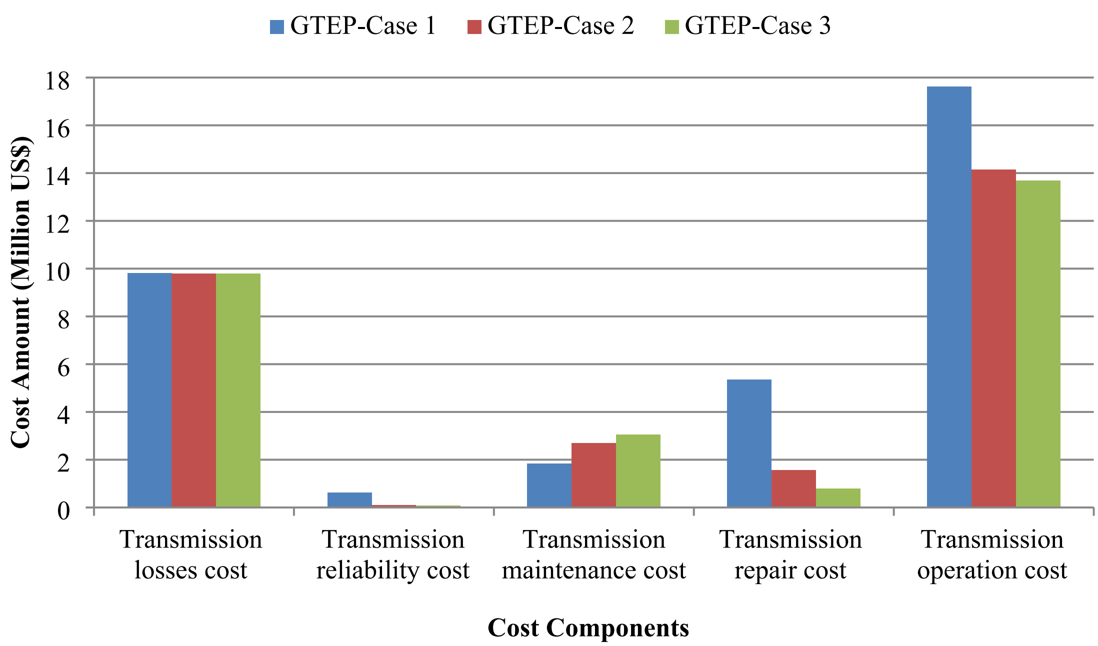

Fig. 4. Transmission operation costs for GTEP.

decision variables and size of search space are the same as those considered in TEP-Case 2. The proposed idea was applied to the test system, and results are provided in Tables 6–8, and A8 and A9 of Appendix.

4.1.2. GTEP considering maintenance

To show important effects of optimal maintenance activities on expansion planning of generation and transmission systems, the GTEP problem is studied under three different cases. As shown in Section 4.1.1, the DPSO performance is better than DCGA method. Also, the results calculated by DPSO were more accurate than DCGA in GTEP problem too. For this, only the best solutions obtained by DPSO are presented here.

- **GTEP-Case 1**

The GTEP problem considering fixed maintenance and repair costs, and network reliability is implemented on RTS system and the results are presented in Tables 9–11. Table 10 includes new generating units that should be installed in the network. Therefore, the length of particles and chromosomes of TEP-Case1 should be extended to include probable locations of new generating units that are equal to number of generation candidate buses ($|\Omega^{gb}|=12$), i.e. 153 ($|X_d|=|Chr_d|=|NL_d|+|NS_d|+|NU_d|=141+12$). Also, maximum six units ($\overline{x}_{ng}=6$) and minimum zero unit can be installed on each generation candidate bus. Accordingly, number of decision variables is 153 and size of search space is $3^{146}+7^{d}\times 7^{12}=3^{146}+7^{17}$. It should be noted that all lines of Table A5 are replaced by new ones due to reasons that mentioned already in TEP-Case 1 section.

- **GTEP-Case 2**

Here, the optimal maintenance activities and line loading impacts on the power system reliability are considered. The results are listed in Tables 12–15. Regarding addition of life expectancy to particle and

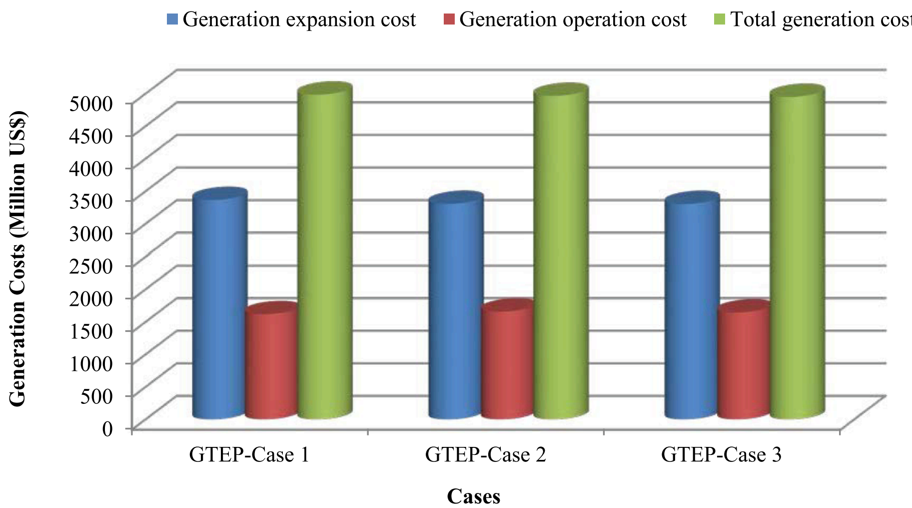

Fig. 5. Expansion and operation costs of generation system for GTEP.

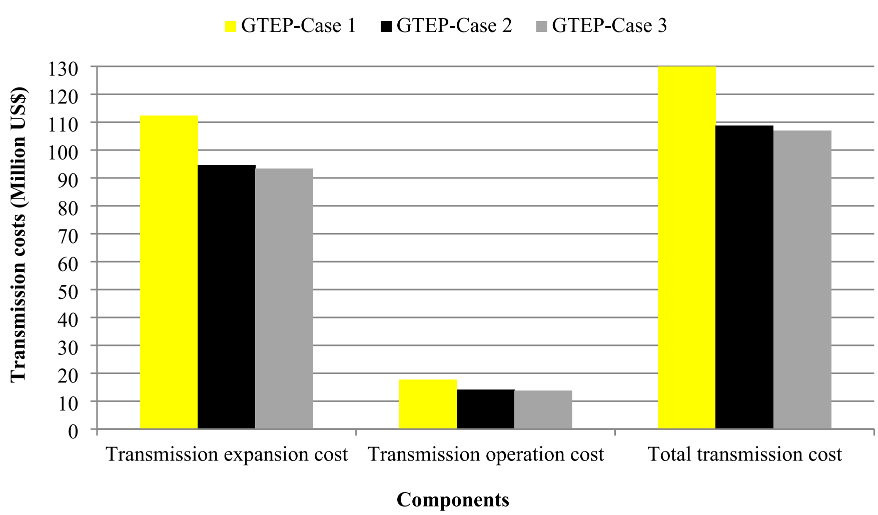

Fig. 6. Transmission costs for GTEP.

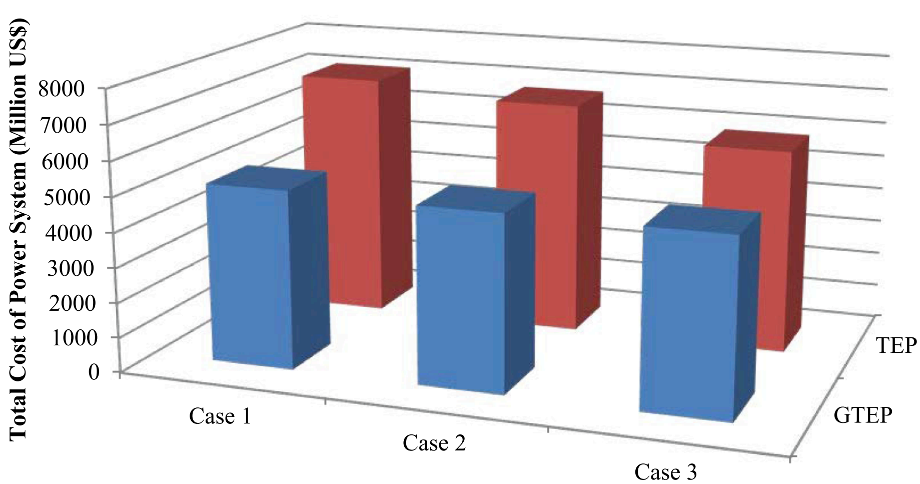

Fig. 7. Total cost for TEP and GTEP.

Table 21
Transmission expansion plan of 118-bus system in Case 1 based on DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
1–3	2	138	23–25	1	138	56–57	2	138	69–77	1	138	80–99	1	138
4–5	1	138	25–27	1	138	51–58	2	138	75–77	2	138	92–102	2	138
6–7	2	138	27–28	1	138	54–59	1	138	77–78	1	138	100–103	2	138
8–9	1	345	28–29	2	138	56–59	2	138	78–79	1	138	100–104	1	138
8–5	2	138/345	30–17	1	138/345	59–60	2	138	77–80	2	138	103–104	1	138
9–10	1	345	29–31	2	138	59–61	1	138	68–81	2	138	104–105	2	138
4–11	1	138	31–32	2	138	60–61	2	138	77–82	2	138	105–106	1	138
5–11	1	138	27–32	1	138	61–62	1	138	82–83	2	138	105–107	1	138
3–12	2	138	15–33	2	138	63–64	2	345	84–85	1	138	109–110	2	138
7–12	2	138	33–37	2	138	64–65	1	345	85–86	2	138	110–111	2	138
11–13	2	138	34–36	1	138	49–66	1	138	86–87	1	138	110–112	1	138
12–14	1	138	40–41	1	138	68–69	2	138/345	85–88	1	138	17–113	1	138
13–15	2	138	43–44	1	138	69–70	2	138	85–89	2	138	32–114	2	138
12–16	1	138	34–43	1	138	70–71	2	138	88–89	2	138	27–115	2	138
15–17	2	138	45–46	2	138	71–72	1	138	90–91	2	138	114–115	1	138
16–17	1	138	46–47	2	138	71–73	1	138	89–92	2	138	68–116	2	345
17–18	2	138	46–48	1	138	70–75	1	138	91–92	2	138	12–117	1	138
15–19	1	138	48–49	2	138	69–75	1	138	92–93	1	138	75–118	2	138
20–21	2	138	49–50	1	138	74–75	1	138	94–95	1	138	76–118	1	138
21–22	2	138	54–56	2	138	76–77	1	138	94–96	1	138	–	–	–

Table 22
Transmission expansion plan of 118-bus system in Case 3 based on DPSO.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
1–2	2	138	23–24	2	138	51–58	2	138	78–79	2	138	95–96	1	138
1–3	2	138	28–29	2	138	54–59	1	138	68–81	2	138	99–100	2	138
4–5	2	138	30–17	2	138/345	59–61	2	138	81–80	1	138/345	92–102	2	138
3–5	2	138	23–32	2	138	60–61	2	138	82–83	2	138	100–103	2	138
6–7	2	138	27–32	1	138	60–62	1	138	85–86	2	138	100–104	2	138
8–9	2	345	15–33	1	138	61–62	1	138	86–87	2	138	103–104	2	138
8–5	1	138/345	35–37	2	138	64–61	2	138/345	85–88	2	138	104–105	2	138
9–10	1	345	34–36	2	138	49–66	2	138	85–89	2	138	108–109	2	138
4–11	2	138	37–39	2	138	62–66	2	138	88–89	2	138	110–111	1	138
5–11	2	138	37–40	2	138	62–67	2	138	89–90	2	138	110–112	2	138
7–12	1	138	40–41	2	138	66–67	2	138	90–91	2	138	17–113	2	138
17–18	2	138	46–47	2	138	69–70	2	138	89–92	2	138	32–114	2	138
18–19	2	138	46–48	2	138	70–71	2	138	91–92	2	138	27–115	2	138
19–20	2	138	47–49	2	138	71–72	1	138	92–93	2	138	114–115	1	138
15–19	2	138	42–49	2	138	71–73	2	138	94–95	2	138	68–116	2	345
20–21	2	138	49–54	2	138	74–75	2	138	82–96	2	138	12–117	1	138
21–22	2	138	54–55	2	138	76–77	2	138	94–96	2	138	76–118	1	138
22–23	1	138	56–57	2	138	69–77	2	138	80–99	1	138	–	–	–

Table 23
Generation expansion plan of 118-bus system in Case 3 based on DPSO and DCGA.

Location	Number	Size (MW)	Type	Location	Number	Size (MW)	Type	Location	Number	Size (MW)	Type
Bus 8	5	5	FS	Bus 46	3	25	FS	Bus 73	5	5	FS
Bus 10	1	150	FS	Bus 49	4	50	FS	Bus 74	3	5	FS
Bus 12	1	100	FS	Bus 54	4	50	FS	Bus 76	3	25	FS
Bus 15	2	10	FS	Bus 55	3	25	FS	Bus 77	3	25	FS
Bus 18	3	25	FS	Bus 56	3	25	FS	Bus 80	1	150	FS
Bus 19	5	5	FS	Bus 59	3	50	FS	Bus 82	3	25	FS
Bus 24	5	5	FS	Bus 61	3	50	FS	Bus 85	1	10	FS
Bus 25	2	100	FS	Bus 62	3	25	FS	Bus 87	1	100	FS
Bus 26	3	100	FS	Bus 65	4	100	FS	Bus 99	2	100	FS
Bus 34	3	8	FS	Bus 66	4	100	FS	Bus 113	1	25	FS
Bus 36	3	25	FS	Bus 69	3	80	FS	Bus 116	1	25	FS
Bus 40	3	8	FS	Bus 70	2	30	FS	–	–	–	–
Bus 42	3	8	FS	Bu 72	2	10	FS	–	–	–	–

chromosome of GTEP-Case 2, number of decision variables will be $|X_d|=|Chr_d|=|NL_d|+|NS_d|+|NU_d|+|LE_d|=141+12+29=182$ and size of search space is $3^{146}+7^{17}+31^{34}$.

- **GTEP-Case 3**

In this case, optimal maintenance activities effect on repair cost is added to the formulation of Case 2. The proposed idea was applied to the test system, and results are provided in Tables 16–20. Table 20 shows loading coefficients of existing lines for all cases. Since only effect of line maintenance on repair cost was added to the problem of GTEP-Case 2, the decision variables and search space are the same as those presented in GTEP-Case 2.

4.1.3. Results analysis for RTS system

To see effect of maintenance on transmission operation costs in TEP, total operation cost of transmission system, including its components is shown in Fig. 1 for TEP problem. It should be noted that these costs were

Table 24
New failure rates of 118-bus system lines for Case 3 based on DPSO (1/yr.).

Corr.	λ_{ij}^{M}	λ_{ij}	Corr.	λ_{ij}^{M}	λ_{ij}	Corr.	λ_{ij}^{M}	λ_{ij}	Corr.	λ_{ij}^{M}	λ_{ij}
1–2	0.4696	0.4696	35–36	0.1834	0.1920	63–64	0.4743	0.5323	91–92	0.5190	0.5196
1–3	0.3261	0.3261	35–37	0.3240	0.3240	64–61	0.0163	0.0167	92–93	0.3187	0.3226
4–5	0.1467	0.1530	33–37	0.3518	0.3644	38–65	1.9860	1.9889	92–94	0.5110	0.5144
3–5	0.3608	0.3781	34–36	0.2520	0.2545	64–65	0.7056	0.8528	93–94	0.3350	0.3370
5–6	0.2996	0.3101	34–37	0.2064	0.2088	49–66	0.3328	0.3395	94–95	0.3166	0.3175
6–7	0.1925	0.1943	38–37	0.0196	0.0197	62–66	0.6635	0.6667	80–96	0.3859	0.3974
8–9	0.7263	0.7512	37–39	0.3684	0.3775	62–67	0.3967	0.4107	82–96	0.2519	0.2596
8–5	0.0140	0.0161	37–40	0.6563	0.6580	65–66	0.0140	0.0151	94–96	0.3652	0.3662
9–10	0.7003	0.7550	30–38	0.8168	1.1364	66–67	0.2784	0.3195	80–97	0.3260	0.3342
4–11	0.2980	0.3110	39–40	0.2995	0.3036	65–68	0.4344	0.4696	80–98	0.3287	0.3401
5–11	0.3289	0.3386	40–41	0.2898	0.2944	47–69	0.5674	0.6508	80–99	0.6381	0.6407
11–12	0.2689	0.2689	40–42	0.6776	0.6776	49–69	0.7837	0.8354	92–100	0.7331	0.7395
2–12	0.3340	0.3417	41–42	0.5580	0.5580	68–69	0.0168	0.0172	94–100	0.2868	0.3191
3–12	0.4418	0.4513	43–44	0.6975	0.7025	69–70	0.3882	0.3889	95–96	0.3594	0.3594
7–12	0.2599	0.2637	34–43	0.5336	0.5445	24–70	0.7585	0.7957	96–97	0.3180	0.3189
11–13	0.3251	0.3386	44–45	0.3398	0.3421	70–71	0.2990	0.2990	98–100	0.5324	0.5410
12–14	0.2738	0.2783	45–46	0.4463	0.4740	24–72	0.5109	0.5212	99–100	0.2421	0.3040
13–15	0.6910	0.7020	46–47	0.4441	0.4455	71–72	0.4139	0.4389	100–101	0.4014	0.4134
14–15	0.5556	0.5642	46–48	0.5320	0.5368	71–73	0.2416	0.2454	92–102	0.3370	0.3370
12–16	0.3742	0.3746	47–49	0.2690	0.2708	70–74	0.4699	0.4910	101–102	0.3239	0.3245
15–17	0.2271	0.2486	42–49	0.6193	0.6216	70–75	0.4981	0.5150	100–103	0.2730	0.2769
16–17	0.4313	0.4674	45–49	0.6077	0.6313	69–75	0.4502	0.4593	100–104	0.5525	0.5604
17–18	0.2595	0.2731	48–49	0.2392	0.2446	74–75	0.3214	0.3214	103–104	0.5298	0.5345
18–19	0.3085	0.3126	49–50	0.2918	0.3436	76–77	0.3918	0.4023	103–105	0.5671	0.5737
19–20	0.3617	0.3672	49–51	0.4677	0.5244	69–77	0.2937	0.3283	100–106	0.6386	0.6540
15–19	0.2348	0.2485	51–52	0.3033	0.3163	75–77	0.5115	0.5269	104–105	0.2475	0.2536
20–21	0.3192	0.3265	52–53	0.5120	0.5162	77–78	0.2110	0.2375	105–106	0.2938	0.3043
21–22	0.4207	0.4207	53–54	0.4029	0.4092	78–79	0.2380	0.2387	105–107	0.4589	0.4798
22–23	0.4810	0.4959	49–54	0.5397	0.6183	77–80	0.2680	0.2716	105–108	0.2599	0.2617
23–24	0.3136	0.3136	54–55	0.2496	0.2570	79–80	0.3223	0.3318	106–107	0.4545	0.4627
23–25	0.3134	0.3415	54–56	0.2434	0.2434	68–81	0.2991	0.2992	108–109	0.2355	0.2355
26–25	0.0182	0.0184	55–56	0.2029	0.2042	81–80	0.0191	0.0191	103–110	0.4105	0.4212
25–27	0.4489	0.4746	56–57	0.4457	0.4485	77–82	0.2911	0.2927	109–110	0.3600	0.3635
27–28	0.4004	0.4004	50–57	0.4607	0.4960	82–83	0.2007	0.2026	110–111	0.4046	0.4046
28–29	0.4057	0.4069	56–58	0.3015	0.3177	83–84	0.2696	0.2696	110–112	0.4062	0.4062
30–17	0.0159	0.0163	51–58	0.3373	0.3416	83–85	0.5092	0.5177	17–113	0.2452	0.2553
8–30	1.0638	1.0864	54–59	0.5913	0.6202	84–85	0.1870	0.1942	32–113	0.5525	0.5544
26–30	1.5788	1.8182	56–59	0.6705	0.7155	85–86	0.4648	0.4707	32–114	0.2157	0.2209
17–31	0.4644	0.4758	55–59	0.5568	0.5872	86–87	0.5320	0.5320	27–115	0.2766	0.2794
29–31	0.2594	0.2611	59–60	0.4334	0.4882	85–88	0.3201	0.3333	114–115	0.1717	0.1740
23–32	0.4313	0.4507	59–61	0.4047	0.4838	85–89	0.4268	0.4392	68–116	0.3541	0.3545
31–32	0.4660	0.4660	60–61	0.1874	0.1924	88–89	0.3244	0.3245	12–117	0.3680	0.3785
27–32	0.2916	0.2926	60–62	0.2988	0.3095	89–90	0.3018	0.3069	75–118	0.2785	0.2816
15–33	0.4047	0.4186	61–62	0.2129	0.2413	90–91	0.3761	0.3796	76–118	0.3415	0.3427
19–34	0.7158	0.7308	63–59	0.0191	0.0197	89–92	0.2655	0.2661	–	–	–

extracted from Tables 2, 5, and 8.

As observed in Fig. 1, the transmission reliability cost, power losses, and repair expenses are reduced if optimal maintenance activities increase. This fact causes a decrease in the total operation cost of transmission system. This means that considering maintenance effect on TEP, results in reduction in lines loading and failure rate. Line flow and failure rate reductions lead to lower power losses and reliability cost. Also, maintenance actions cause lower repair cost. Even total transmission operation costs diminish more effectively if repair activities affected by maintenance plans (TEP-Case 3). Also, to observe the effect of maintenance on transmission expansion costs and therefore total cost of transmission system in TEP, expansion and operation costs of transmission network are illustrated in Fig. 2.

Fig. 2 indicates that both expansion and operation costs of transmission system and therefore total transmission cost are reduced by considering maintenance activities in TEP. However, more reduction is observed in TEP-Case 2, because of lower construction cost of the network proposed in TEP-Case 2 when compared to TEP-Case 3. To find out which expansion plan is more appropriate for TEP, the total power system costs of all TEP cases are compared in Fig. 3.

According to Fig. 3, transmission expansion plan proposed in TEP-Case 3 is less expensive than other cases from the total cost point of view. To find a transmission plan with lower operation cost when TEP and GEP are optimized at the same time, cost components and total operation cost of transmission system are shown in Fig. 4. All these costs were obtained from Tables 11, 15, and 19. Like when only TEP problem was solved, considering maintenance activities in GTEP cause transmission expansion plans with lower operation costs are achieved, especially in GTEP-Case 3. In this case, the load shedding and LOL costs are US$ 0.546 million and US$ 0.185 million lower than the same costs of GTEP-Case 1, respectively. In fact, the reliability costs of GTEP-Cases 2 and 3 were US$ 0.651 million and US$ 0.731 million, respectively, lower than GTEP-Case 1 due to lines failure rate reduction (see Tables 21 and 26 as well as Table IX of [35]) and the transmission system modification. As seen in Tables 11, 15, and 19, the lines construction costs for the plans that consider optimal maintenance activities (GTEP-Cases 2 and 3) are US$ 4.048 million and US$ 2.768 million, respectively, more than those of the configuration proposed by GTEP-Case 1, in which only specific maintenance activities (fixed maintenance cost) are considered. The main reason is that, in GTEP-Cases 2 and 3, more new lines have to be constructed in the network for lines loading reduction and, consequently, decrease in line failure rates. This modification, as seen in Fig. 5, results in an expansion cost for the generation system that was almost US$ 60 million less than the generation cost in GTEP-Case 1.

Also, in GTEP-Case 1, US$ 7.18 million is spent for maintenance and repair of existing lines of the network to provide regular lifetimes for them and keep their failure rates and MTTRs at basic values (see Table I and Table II of [35] for the basic values). Nevertheless, the transmission

Table 25
New lifetimes (yr.) and MTTRs (h) in 118-bus system for Case 3 based on DPSO.

Corr.	n_{ij}^{le}	τ_{ij}	Corr.	n_{ij}^{le}	τ_{ij}	Corr.	n_{ij}^{le}	τ_{ij}	Corr.	n_{ij}^{le}	τ_{ij}	Corr.	n_{ij}^{le}	τ_{ij}
1–2	30	187	8–30	35	147	53–54	35	332	71–73	38	508	80–98	40	393
1–3	32	269	26–30	41	130	49–54	45	277	70–74	35	285	80–99	33	217
4–5	45	1023	17–31	39	262	54–55	43	578	70–75	36	273	92–100	34	187
3–5	37	350	29–31	37	512	54–56	31	360	69–75	36	292	94–100	38	428
5–6	33	263	23–32	34	276	55–56	38	605	74–75	32	273	95–96	31	244
6–7	42	839	31–32	30	188	56–57	34	321	76–77	43	368	96–97	37	397
8–9	35	226	27–32	41	464	50–57	38	266	69–77	45	509	98–100	35	262
8–5	45	15,760	15–33	39	300	56–58	45	496	75–77	41	264	99–100	45	617
9–10	41	293	19–34	35	187	51–58	37	375	77–78	39	800	100–101	36	324
4–11	39	408	35–36	39	663	54–59	37	225	78–79	34	577	92–102	31	453
5–11	37	404	35–37	30	270.4	56–59	38	183	77–80	39	456	101–102	41	417
11–12	30	326	33–37	45	425	55–59	36	234	79–80	34	426	100–103	40	562
2–12	35	417	34–36	36	539	59–60	36	300	68–81	37	427	100–104	35	242
3–12	41	306	34–37	35	655	59–61	39	300	81–80	34	13,763	103–104	36	256
7–12	34	529	38–37	33	13,763	60–61	39	652	77–82	44	493	103–105	34	242
11–13	37	389	37–39	39	330	60–62	37	522	82–83	44	715	100–106	35	209
12–14	42	512	37–40	32	229	61–62	41	635	83–84	31	582	104–105	37	511
13–15	36	188	30–38	45	209	63–59	34	13,763	83–85	34	270	105–106	35	455
14–15	38	221	39–40	37	422	63–64	36	337	84–85	40	817	105–107	42	305
12–16	34	382	40–41	35	461	64–61	40	13,763	85–86	33	170	105–108	45	575
15–17	42	620	40–42	30	129.3	38–65	35	89	86–87	30	165	106–107	44	368
16–17	42	325	41–42	30	157	64–65	37	220	85–88	39	380	108–109	38	521
17–18	38	473	43–44	36	213	49–66	36	395	85–89	40	302	103–110	42	341
18–19	33	476	34–43	33	148	62–66	33	226	88–89	33	243.1	109–110	36	361
19–20	38	339	44–45	37	372	62–67	35	337	89–90	42	466	110–111	30	217
15–19	40	549	45–46	37	283	65–66	45	15,760	90–91	34	365	110–112	30	216
20–21	37	396	46–47	36	293	66–67	44	529	89–92	36	495	17–113	36	530
21–22	30	208.2	46–48	41	296	65–68	42	424	91–92	32	290	32–113	39	221
22–23	34	286	47–49	41	503	47–69	45	263	92–93	40	405	32–114	45	693
23–24	35	455	42–49	42	226	49–69	39	155	92–94	36	254	27–115	40	466
23–25	36	419	45–49	40	287	68–69	39	13,763	93–94	36	388	114–115	42	880
26–25	36	13,763	48–49	43	603	69–70	38	320	94–95	32	475	68–116	31	239.2
25–27	36	293	49–50	44	573	24–70	43	190	80–96	43	374	12–117	44	482
27–28	30	219	49–51	38	262	70–71	32	293	82–96	41	537	75–118	39	568
28–29	33	362	51–52	39	485	24–72	40	299	94–96	36	356	76–118	33	435
30–17	41	13,763	52–53	34	268	71–72	43	348	80–97	37	388	–	–	–

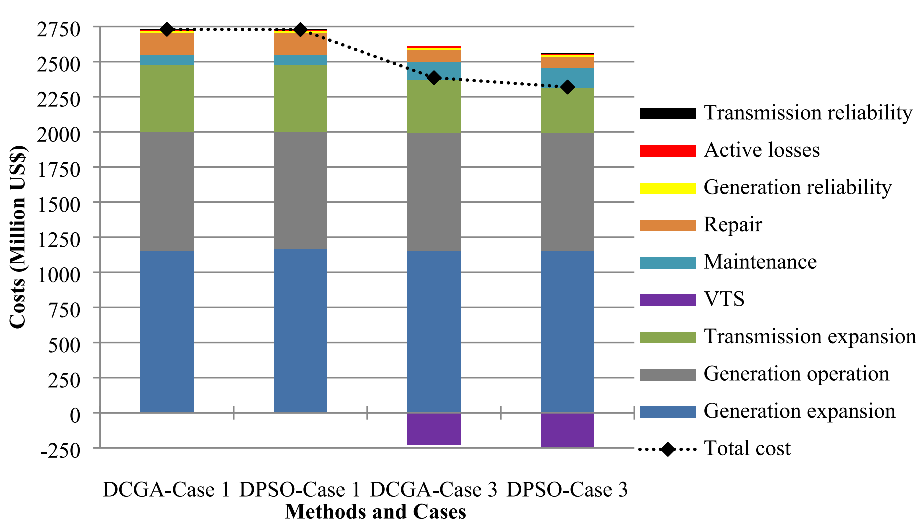

Fig. 8. Expansion and operation costs of 118-bus system for different cases and methods.

system expansion costs in GTEP-Cases 2 and 3 are US$ 17.8 million and US$ 19.043 million, respectively, lower than the corresponded costs in GTEP-Case 1 as shown in Fig. 6. The reason is that, in GTEP-Case 1, the existing lines of 22 corridors must be replaced by new ones because of their initial lives (see Table I for more information), whereas the life expectancies in all of the existing corridors in GTEP-Cases 2 and 3 are extended (Tables IX and XIII). This would increase the transmission system value by US$ 49.83 million and US$ 52.061 million versus US$ 4.26 million and US$ 3.825 million in maintenance and repair costs if the proposed arrangements in GTEP-Cases 2 and 3 are applied, respectively.

Generation and transmission costs shown in Figs. 5 and 6 prove that transmission and generation expansion plans suggested in GTEP-Case 3 are more efficient as it can be seen that applying the plan of GTEP-Case 3 (where optimal maintenance and repair activities are considered) would be less expensive because it would yield US$ 108.114 million savings in total cost of power system. Moreover to show the importance of simultaneously solving TEP and GEP problems, total cost for TEP is compared

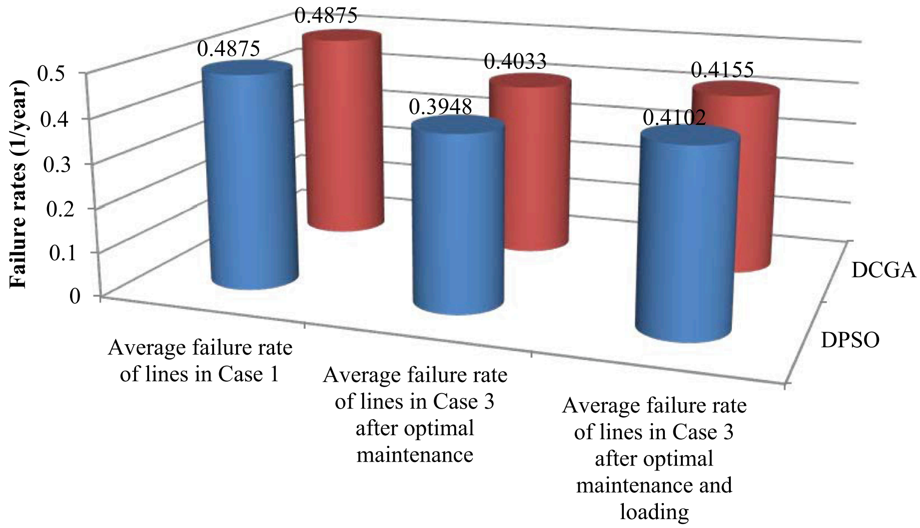

Fig. 9. Average failure rates of lines in 118-bus system.

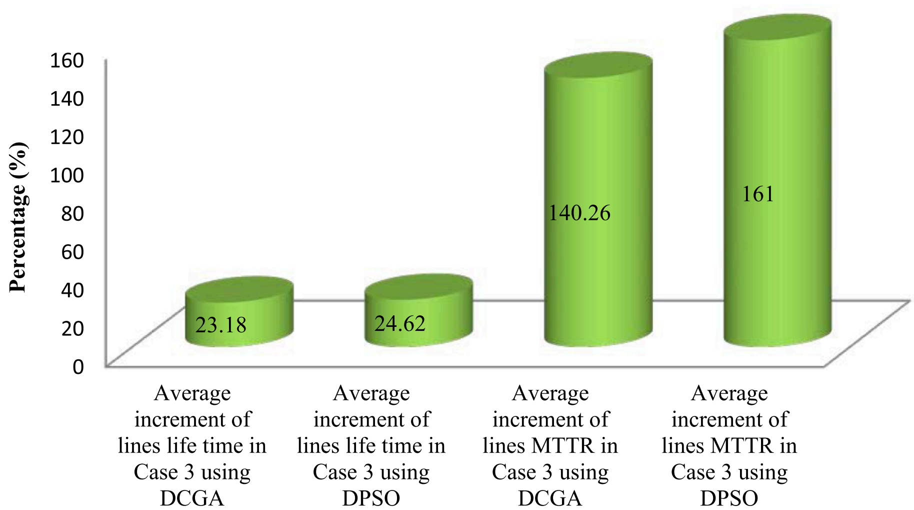

Fig. 10. Increment of average lines life times and MTTRs in 118-bus system.

to that of GTEP in Fig. 7. As observed in Fig. 7, GTEP problem can find more optimal solution for power system expansion planning.

4.2. 118-Bus test system

Regarding better results of Cases 3 compared to Cases 2 and importance of solving GEP and TEP problems at the same time, the proposed GTEP model is applied to 118-bus transmission network under Cases 1 and 3 to show efficiency of the proposed model in larger test systems. In Case 1, the number of decision variables is equal to number of 179 candidate corridors for expansion of transmission network plus 54 candidate buses for generation system expansion, i.e. $|X_d|=|Chr_d|=|NL_d|+|NS_d|+|NU_d|=179+54=233$. Whereas, number of decision variables in Case 3 is equal to that of Case 1 plus life expectancies of 179 existing corridors ($|X_d|=|Chr_d|=233+|LE_d|=233+179=412$). Therefore, regarding four constructible lines or substations in each candidate corridor (five integer numbers) and maximum three installable generating units on each candidate bus (four discrete numbers) as well as maximum life expectancy of 45 years (16 integer numbers between 30 and 45), size of search space for Case 1 is $5^d \times 5^{179} + 4^d \times 4^{54} = 5^{184} + 4^{59}$ and for case 2 is $5^{184} + 4^{59} + 16^d \times 16^{179} = 5^{184} + 4^{59} + 16^{184}$. All data of this actual transmission system are available in [36]. Initial lifetime, MTTR, and failure rate of lines and VOLL of buses are provided in Tables A10 to A13 of Appendix. It should be noted that lines failure rates and MTTRs were calculated according to data presented in [35] and [37] for 138 kV and 345 kV lines. The maximum number of circuits in each corridor is assumed to be 4 and planning horizon is the same as RTS system. Tables 21 to 25 and Figs. 8 to 10 present the results obtained by DCGA and DPSO for this large transmission system.

Comparison of Tables A11 to A13 with Tables 24 and 25 shows increases in lines life time and MTTR and a decrease in lines failure rate after conducting optimal maintenance activities in actual 118-bus transmission system. Figs. 9 and 10 confirm these facts by illustrating significant increases in average line lifetimes and MTTRs and reduction in lines failure rates. As observed in Figs. 9 and 10, solutions obtained by DPSO are slightly better than those calculated by DCGA. Moreover, cost terms shown in Fig. 8 indicates that transmission expansion plans proposed by both methods in Case 3 are less expensive than those introduced by DPSO and DCGA in Case 1 because of considerable reduction in lines replacement cost and repair expenses due to employment of optimal maintenance schemes. Moreover, optimal maintenance activities increase value of transmission system due to increment of lines lifetime, in which this value is considered as a negative cost (profit). Therefore, the expansion plan of Case 3 is more economic and has lower total cost compared to that of Case 1.

5. Conclusion

The paper presents a model based on network reliability for generation-transmission expansion planning, considering line maintenance, repair and loading impacts. The economic benefit of the line maintenance is quantified by calculating the total generation and transmission cost (including both operation and investment costs) with and without optimal maintenance activities. The cost difference between these two cases shows the magnitude of economic benefit. The reliability effect is formulated by the load shedding cost.

Also, the effect of generation reliability on power system expansion planning is computed by the loss of load index. Furthermore, a quantitative relationship among line loading, reliability, and maintenance is presented. Analyzing the results shows the importance of the proposed GTEP-M model mainly due to the fact that the lines that seemed old could still be economical in the long run if the required maintenance and repair actions were carried out timely and properly.

Optimal maintenance activities result in the reduction of total investment and operation cost through deferring construction of new transmission or generation facilities while improving the reliability of the whole system.

CRediT authorship contribution statement

Meisam Mahdavi: Conceptualization, Methodology, Software, Writing – original draft. **Mohammad S. Javadi:** Validation. **João P.S. Catalão:** Investigation, Supervision.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Data availability

Data will be made available on request.

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Appendix A

In this section, network data and some solutions calculated by DCGA are presented (see Tables A1–A13).

Table A1
Initial life of the lines for RTS system (year).

Corr.	n_{ij}^{l0}	Corr.	n_{ij}^{l0}	Corr.	n_{ij}^{l0}	Corr.	n_{ij}^{l0}	Corr.	n_{ij}^{l0}	Corr.	n_{ij}^{l0}
1–2	10	3–9	14	8–9	14	12–23	18	15–24	18	18–21	18
1–3	18	4–9	18	8–10	18	13–23	18	16–17	18	19–20	18
1–5	18	5–10	18	11–13	14	14–16	18	16–19	18	20–23	18
2–4	18	6–10	10	11–14	18	15–16	18	17–18	14	21–22	18
2–6	18	7–8	18	12–13	18	15–21	14	17–22	18	–	–

Table A2
Value of lost loads ($/MW).

Bus	$VOLL_n$	Bus	$VOLL_n$	Bus	$VOLL_n$	Bus	$VOLL_n$	Bus	$VOLL_n$
1	1900	5	1250	9	3100	15	5550	20	2250
2	1700	6	2400	10	3400	16	1750	–	–
3	3200	7	2200	13	4200	18	5850	–	–
4	1300	8	3000	14	3400	19	3250	–	–

Table A3
MTTRs of existing lines (hour).

Corr.	$\underline{r}_{ij}$	Corr.	$\underline{r}_{ij}$	Corr.	$\underline{r}_{ij}$	Corr.	$\underline{r}_{ij}$	Corr.	$\underline{r}_{ij}$
1–2	1825.0	4–9	1216.7	11–13	1095.0	15–16	1327.3	17–22	826.4
1–3	858.8	5–10	1288.2	11–14	1123.1	15–21	1068.3	18–21	1251.4
1–5	1327.3	6–10	1460.0	12–13	1095.0	15–24	1068.3	19–20	1152.6
2–4	1123.1	7–8	1460.0	12–23	842.3	16–17	1251.4	20–23	1288.2
2–6	912.5	8–9	995.5	13–23	893.9	16–19	1288.2	21–22	973.3
3–9	1152.6	8–10	995.5	14–16	1152.6	17–18	1368.7	–	–

Table A4
Best transmission expansion plan of RTS system in Case 1 for TEP using DCGA.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	4–10	1	138	12–16	1	230	15–23	1	230
3–8	2	138	5–7	2	138	12–17	1	230	16–20	1	230
3–10	1	138	7–8	1	138	12–18	1	230	18–22	1	230
4–5	1	138	7–10	1	138	12–20	1	230	18–24	1	230
4–6	2	138	11–12	1	230	12–21	1	230	19–23	2	230
4–7	2	138	12–15	1	230	14–19	1	230	23–24	1	230

Table A5
Replaced lines in RTS system for TEP using DPSO and DCGA.

Corr.	$\underline{n}_i$	V_i (kV)	Corr.	$\underline{n}_i$	V_i (kV)	Corr.	$\underline{n}_i$	V_i (kV)
1–3	1	138	11–14	1	138	16–19	1	230
1–5	1	138	12–13	1	230	17–22	1	230
2–4	1	138	12–23	1	230	18–21	2	230
2–6	1	138	13–23	1	230	19–20	2	230
4–9	1	138	14–16	1	230	20–23	2	230
5–10	1	138	15–16	1	230	21–22	1	230
7–8	1	138	15–24	1	230	–	–	–
8–10	1	138	16–17	1	230	–	–	–

Table A6
Best transmission expansion plan of RTS system in Case 2 for TEP using DCGA.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	5–7	2	138	12–17	1	230	16–20	1	230
3–8	2	138	7–8	1	138	12–18	1	230	18–22	1	230
3–10	1	138	7–10	1	138	12–20	1	230	18–24	1	230
4–5	1	138	11–12	1	230	12–21	1	230	19–23	2	230
4–6	2	138	14–18	1	230	14–19	1	230	23–24	1	230
4–7	2	138	12–15	1	230	15–22	1	230	–	–	–
4–10	1	138	12–16	1	230	15–23	1	230	–	–	–

Table A7
New lifetimes (year), failure rates (1/year), and MTTRs (Hour) in RTS system under Case 2 for TEP based on DCGA.

Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}	Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}
1–2	36	0.2360	0.2390	2732.8	12–23	55	0.2773	0.3306	1638.3
1–3	56	0.2635	0.2828	1389.8	13–23	39	0.3920	0.3995	1429.7
1–5	42	0.2475	0.2775	2147.8	14–16	48	0.2470	0.3044	2241.9
2–4	39	0.3120	0.3413	1587.4	15–16	48	0.2145	0.2957	2581.6
2–6	35	0.4160	0.4446	843.1	15–21	57	0.2323	0.3360	2356.2
3–9	50	0.2597	0.2624	1940.0	15–24	40	0.3212	0.3290	1905.2
4–9	52	0.2100	0.2461	1968.9	16–17	46	0.2392	0.2415	2434.1
5–10	52	0.1983	0.2104	2084.7	16–19	42	0.2550	0.2791	2505.6
6–10	54	0.2050	0.2648	2566.1	17–18	37	0.2880	0.2914	2278.0
7–8	58	0.1450	0.2577	2362.6	17–22	60	0.2385	0.2726	1607.4
8–9	43	0.3520	0.3755	1675.5	18–21	47	0.2333	0.3116	2434.1
8–10	43	0.3227	0.3366	1610.9	19–20	42	0.2850	0.2974	2241.9
11–13	52	0.2600	0.3268	2415.1	20–23	47	0.2267	0.2731	2505.6
11–14	46	0.2665	0.2814	2184.4	21–22	45	0.3150	0.3221	1893.2
12–13	50	0.2467	0.2936	2129.8	–	–		–	–

Table A8
Best transmission expansion plan of RTS system proposed in Case 3 for TEP using DCGA.

Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)	Corr.	n_i	V_i (kV)
2–9	2	138	5–7	2	138	12–17	1	230	15–23	1	230
3–8	2	138	7–8	1	138	12–18	1	230	16–18	1	230
3–10	1	138	7–10	1	138	12–19	1	230	16–20	1	230
4–5	1	138	11–12	1	230	12–20	1	230	18–22	1	230
4–6	2	138	14–18	1	230	12–21	1	230	18–24	1	230
4–7	2	138	12–15	1	230	14–19	1	230	19–23	2	230
4–10	1	138	12–16	1	230	15–22	1	230	23–24	1	230

Table A9
New lifetimes (year), failure rates (1/year), and MTTRs (Hour) in RTS system under Case 3 for TEP based on DCGA.

Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}	Corr.	n_{ij}^{le}	λ_{ij}^{M}	λ_{ij}	τ_{ij}
1–2	58	0.1480	0.2183	3.2077	12–23	48	0.3380	0.3871	1.6383
1–3	52	0.2975	0.3148	1.3898	13–23	56	0.2532	0.2814	1.7386
1–5	54	0.1815	0.2354	2.1478	14–16	56	0.1963	0.2703	2.2419
2–4	55	0.2080	0.2763	1.8174	15–16	56	0.1705	0.3177	2.5816
2–6	53	0.2720	0.3648	1.4766	15–21	56	0.2392	0.2993	2.3562
3–9	53	0.2407	0.2447	1.9400	15–24	56	0.2118	0.2152	2.0779
4–9	50	0.2220	0.2553	1.9689	16–17	41	0.2683	0.2712	2.4341
5–10	58	0.1643	0.1791	2.0847	16–19	50	0.2097	0.2345	2.5056
6–10	51	0.2200	0.2704	2.5661	17–18	51	0.2133	0.2182	3.0189
7–8	49	0.1900	0.2701	2.3626	17–22	58	0.2562	0.2747	1.6074
8–9	50	0.3007	0.3380	1.6755	18–21	55	0.1867	0.1931	2.4341
8–10	58	0.2127	0.2399	1.6109	19–20	46	0.2597	0.2801	2.2419
11–13	58	0.2200	0.3091	2.4151	20–23	58	0.1643	0.2516	2.5056
11–14	58	0.1885	0.2132	2.1844	21–22	51	0.2700	0.2879	1.8932
12–13	52	0.2333	0.2885	2.1298	–	–	–	–	–

Table A10
VOLLs of 118-bus system ($/MW).

Bus	VOLLn	Bus	VOLLn	Bus	VOLLn	Bus	VOLLn	Bus	VOLLn	Bus	VOLLn
1	5414	21	1486	43	1800	59	27,700	85	2400	105	3100
2	2123	22	1062	44	1600	60	7800	86	2100	106	4300
3	4140	23	743	45	5300	62	7700	88	4800	107	2800
4	3185	27	6582	46	2800	66	3900	90	7800	108	200
6	5520	28	1805	47	3400	67	2800	92	6500	109	800
7	2017	29	2548	48	2000	70	6600	93	1200	110	3900
11	7431	31	4565	49	8700	74	6800	94	3000	112	2500
12	4989	32	6263	50	1700	75	4700	95	4200	114	849
13	3609	33	2442	51	1700	76	6800	96	3800	115	2335
14	1486	34	6263	52	1800	77	6100	97	1500	117	2123
15	9554	35	3503	53	2300	78	7100	98	3400	118	3300
16	2654	36	3291	54	11,300	79	3900	100	3700	–	–
17	1168	39	2700	55	6300	80	13,000	101	2200	–	–
18	6369	40	2000	56	8400	82	5400	102	500	–	–
19	4777	41	3700	57	1200	83	2000	103	2300	–	–
20	1911	42	3700	58	1200	84	1100	104	3800	–	–

Table A11
Failure rate of existing lines before maintenance of 118-bus system (1/yr.).

Corr.	$\underline{\lambda}_{ij}$	Corr.	$\underline{\lambda}_{ij}$	Corr.	$\underline{\lambda}_{ij}$	Corr.	$\underline{\lambda}_{ij}$	Corr.	$\underline{\lambda}_{ij}$	Corr.	$\underline{\lambda}_{ij}$	Corr.	$\underline{\lambda}_{ij}$
1–2	0.4696	21–22	0.4207	20–21	0.3958	50–57	0.5882	24–70	1.1378	85–89	0.5793	100–104	0.6474
1–3	0.3261	22–23	0.5486	30–38	1.3173	56–58	0.4862	70–71	0.2990	88–89	0.3604	103–104	0.6090
4–5	0.2366	23–24	0.3360	39–40	0.3713	51–58	0.4181	24–72	0.6578	89–90	0.4374	103–105	0.6469
3–5	0.4472	23–25	0.3776	40–41	0.3396	54–59	0.6984	71–72	0.6209	90–91	0.4290	100–106	0.7483
5–6	0.3328	26–25	0.0200	40–42	0.6776	56–59	0.8560	71–73	0.3084	89–92	0.3198	104–105	0.3068
6–7	0.2637	25–27	0.5408	41–42	0.5580	55–59	0.6708	70–74	0.5507	91–92	0.5388	105–106	0.3443
8–9	0.8511	27–28	0.4004	43–44	0.7863	59–60	0.5221	70–75	0.5726	92–93	0.4327	105–107	0.6651
8–5	0.0200	28–29	0.4316	34–43	0.5928	59–61	0.5325	69–75	0.5424	92–94	0.6157	105–108	0.4192
9–10	0.8827	30–17	0.0200	44–45	0.4212	60–61	0.2465	74–75	0.3214	93–94	0.4036	106–107	0.6651
4–11	0.3921	8–30	1.2467	45–46	0.5533	60–62	0.3370	76–77	0.5876	94–95	0.3287	108–109	0.3006
5–11	0.3885	26–30	1.9900	46–47	0.5351	61–62	0.2985	69–77	0.4738	80–96	0.5788	103–110	0.5949
11–12	0.2689	17–31	0.6110	46–48	0.7062	63–59	0.0200	75–77	0.7171	82–96	0.3531	109–110	0.4337
2–12	0.3739	29–31	0.3063	47–49	0.3770	63–64	0.5715	77–78	0.2512	94–96	0.4400	110–111	0.4046
3–12	0.6194	23–32	0.4920	42–49	0.8976	64–61	0.0200	78–79	0.2715	80–97	0.4041	110–112	0.4062
7–12	0.2964	31–32	0.4660	45–49	0.7442	38–65	2.2232	77–80	0.3526	80–98	0.4462	17–113	0.2954
11–13	0.4030	27–32	0.4088	48–49	0.3588	64–65	0.8747	79–80	0.3677	80–99	0.6511	32–113	0.7270
12–14	0.3968	15–33	0.5325	49–50	0.4270	49–66	0.4010	68–81	0.3708	92–100	0.8362	32–114	0.3479
13–15	0.8326	19–34	0.8388	49–51	0.5970	62–66	0.6771	81–80	0.0200	94–100	0.3661	27–115	0.3755
14–15	0.7093	35–36	0.2413	51–52	0.3791	62–67	0.4649	77–82	0.4524	95–96	0.3594	114–115	0.2418
12–16	0.4082	35–37	0.3240	52–53	0.5840	65–66	0.0200	82–83	0.3120	96–97	0.3942	68–116	0.3663
15–17	0.3292	33–37	0.5674	53–54	0.4722	66–67	0.4327	83–84	0.2626	98–100	0.5960	12–117	0.5232
16–17	0.6251	34–36	0.2897	49–54	0.8705	65–68	0.5950	83–85	0.5809	99–100	0.3906	75–118	0.3396
17–18	0.3313	34–37	0.2418	54–55	0.3744	47–69	0.9152	84–85	0.2408	100–101	0.4836	76–118	0.3557
18–19	0.3282	38–37	0.0200	54–56	0.2434	49–69	1.0312	85–86	0.5164	92–102	0.3459	–	–
19–20	0.4618	37–39	0.4847	55–56	0.2590	68–69	0.0200	86–87	0.5320	101–102	0.4540	–	–
15–19	0.3188	37–40	0.6812	56–57	0.4862	69–70	0.4956	85–88	0.4212	100–103	0.3516	–	–

Table A12
MTTRs of existing lines for 118-bus system (h).

Corr.	τ_{ij}	Corr.	τ_{ij}	Corr.	τ_{ij}	Corr.	τ_{ij}	Corr.	τ_{ij}	Corr.	τ_{ij}
1–2	186.5	23–25	232	44–45	208	63–64	153.3	68–81	236.2	98–100	147
1–3	268.6	26–25	4380	45–46	158.3	64–61	4380	81–80	4380	99–100	224.3
4–5	370.2	25–27	162	46–47	163.7	38–65	39.4	77–82	193.6	100–101	181.1
3–5	195.9	27–28	218.8	46–48	124	64–65	100.2	82–83	280.7	92–102	259.9
5–6	263.2	28–29	202.9	47–49	232.3	49–66	218.5	83–84	333.5	101–102	193
6–7	332.2	30–17	4380	42–49	97.6	62–66	129.4	83–85	150.8	100–103	249.2
8–9	102.9	8–30	70.3	45–49	117.7	62–67	188.4	84–85	363.8	100–104	135.3
8–5	4380	26–30	44	48–49	244.1	65–66	4380	85–86	169.6	103–104	143.9
9–10	99.2	17–31	143.4	49–50	205.2	66–67	202.5	86–87	164.7	103–105	135.4
4–11	223.4	29–31	286	49–51	146.7	65–68	147.2	85–88	208	100–106	117.1
5–11	225.5	23–32	178.1	51–52	231.1	47–69	95.7	85–89	151.2	104–105	285.5
11–12	325.8	31–32	188	52–53	150	49–69	84.9	88–89	243.1	105–106	254.4
2–12	234.3	27–32	214.3	53–54	185.5	68–69	4380	89–90	200.3	105–107	131.7
3–12	141.4	15–33	164.5	49–54	100.6	69–70	176.8	90–91	204.2	105–108	209
7–12	295.5	19–34	104.4	54–55	233.9	24–70	77	89–92	273.9	106–107	131.7
11–13	217.3	35–36	363	54–56	359.9	70–71	292.9	91–92	162.6	108–109	291.4
12–14	220.8	35–37	270.4	55–56	338.2	24–72	133.2	92–93	202.5	103–110	147.2
13–15	105.2	33–37	154.4	56–57	180.2	71–72	141.1	92–94	142.3	109–110	202
14–15	123.5	34–36	302.4	50–57	148.9	71–73	284	93–94	217.1	110–111	216.5
12–16	214.6	34–37	362.2	56–58	180.2	70–74	159.1	94–95	266.5	110–112	215.7
15–17	266.1	38–37	4380	51–58	209.5	70–75	153	80–96	151.3	17–113	296.5
16–17	140.1	37–39	180.7	54–59	125.4	69–75	161.5	82–96	248.1	32–113	120.5
17–18	264.4	37–40	128.6	56–59	102.3	74–75	272.6	94–96	199.1	32–114	251.8
18–19	266.9	30–38	66.5	55–59	130.6	76–77	149.1	80–97	216.8	27–115	233.3
19–20	189.7	39–40	235.9	59–60	167.8	69–77	184.9	80–98	196.3	114–115	362.2
15–19	274.8	40–41	258	59–61	164.5	75–77	122.2	80–99	134.5	68–116	239.2
20–21	221.3	40–42	129.3	60–61	355.3	77–78	348.7	92–100	104.8	12–117	167.4
21–22	208.2	41–42	157	60–62	259.9	78–79	322.7	94–100	239.3	75–118	258
22–23	159.7	43–44	114.3	61–62	293.4	77–80	248.4	95–96	243.8	76–118	246.3
23–24	260.7	34–43	147.8	63–59	4380	79–80	238.3	96–97	222.2	–	–

Table A13
Initial life of the lines for 118-bus system (yr.).

Corr.	n_{ij}^{lo}	Corr.	n_{ij}^{lo}	Corr.	n_{ij}^{lo}	Corr.	n_{ij}^{lo}	Corr.	n_{ij}^{lo}	Corr.	n_{ij}^{lo}	Corr.	n_{ij}^{lo}
1–2	10	20–21	18	37–40	14	50–57	18	24–70	18	85–89	18	100–104	18
1–3	18	21–22	18	30–38	18	56–58	18	70–71	18	88–89	18	103–104	14
4–5	18	22–23	18	39–40	18	51–58	18	24–72	14	89–90	18	103–105	18
3–5	18	23–24	10	40–41	18	54–59	14	71–72	18	90–91	18	100–106	18
5–6	18	23–25	18	40–42	18	56–59	18	71–73	18	89–92	18	104–105	18
6–7	14	26–25	10	41–42	18	55–59	18	70–74	18	91–92	14	105–106	18
8–9	18	25–27	18	43–44	10	59–60	18	70–75	14	92–93	18	105–107	18
8–5	10	27–28	18	34–43	18	59–61	18	69–75	18	92–94	18	105–108	18
9–10	10	28–29	14	44–45	18	60–61	18	74–75	18	93–94	18	106–107	14
4–11	18	30–17	10	45–46	18	60–62	10	76–77	18	94–95	14	108–109	18
5–11	14	8–30	18	46–47	18	61–62	18	69–77	18	80–96	18	103–110	18
11–12	18	26–30	10	46–48	14	63–59	10	75–77	18	82–96	18	109–110	18
2–12	14	17–31	18	47–49	18	63–64	18	77–78	10	94–96	18	110–111	14
3–12	18	29–31	14	42–49	18	64–61	10	78–79	18	80–97	18	110–112	18
7–12	18	23–32	18	45–49	10	38–65	14	77–80	18	80–98	18	17–113	18
11–13	18	31–32	14	48–49	18	64–65	18	79–80	18	80–99	10	32–113	18
12–14	18	27–32	18	49–50	14	49–66	18	68–81	18	92–100	18	32–114	18
13–15	18	15–33	18	49–51	18	62–66	10	81–80	10	94–100	18	27–115	18
14–15	18	19–34	18	51–52	14	62–67	18	77–82	18	95–96	18	114–115	16
12–16	14	35–36	18	52–53	18	65–66	10	82–83	18	96–97	18	68–116	16
15–17	18	35–37	18	53–54	18	66–67	18	83–84	10	98–100	14	12–117	12
16–17	18	33–37	18	49–54	18	65–68	14	83–85	18	99–100	18	75–118	12
17–18	18	34–36	14	54–55	18	47–69	18	84–85	14	100–101	18	76–118	12
18–19	14	34–37	18	54–56	18	49–69	18	85–86	18	92–102	10	–	–
19–20	18	38–37	10	55–56	18	68–69	10	86–87	14	101–102	18	–	–
15–19	18	37–39	18	56–57	14	69–70	18	85–88	18	100–103	14	–	–

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