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Multi-objective, multi-year dynamic generation and transmission expansion planning- renewable energy sources integration for Iran's National Power Grid

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Summary

The paper presents a multi-year, multi-objective framework for integrating Renewable Energy Sources (RESs) into the high voltage transmission network of Iran's National Power Grid (INPG). The objective functions in this study are the total cost, including the investment cost and operating cost for the planning horizon, and the system reliability. The first objective function is stated from the economic point of view, while the second objective function is considered as a security index in the expansion planning issue. The main purpose of this paper is to increase the RES penetration into the generation mix of INPG. Since the mentioned 230 to 400-kV INPG is a large-scale power system, the problem formulation is investigated in a mixed-integer programming, and then, the developed multi-objective problem has been solved using the augmented epsilon-constraint optimization method. In order to select the executive plan for installation, the fuzzy satisfying decision-making procedure is adopted in this study.

KEYWORDS

epsilon-constraint method, fuzzy satisfying decision making, Iran National Power Grid, multi-objective optimization, multi-year planning, renewable energy integration

Nomenclature

Variables: *PG*, Power generated by generation units; *PL*, Power transmitted throughout transmission lines; *PVG*, Virtual power generation (curtailed load); f, Objective function; *Gn*, Generation unit's decision variable; *Ln*, Transmission line's decision variable; *Z*, Transmission switching status; δ, Bus voltage angle; *C* (*PG*), Operational cost of generation unit; $\mathrm{EENS}_{\mathrm{HL\text{-}II}}$, Expected energy not supplied in composite generation and transmission level

Sets: *b*, Index for load bus; *y*, Index for planning year; *i*, Index for generation bus; *j*, Index for transmission line; *k*, Index for candidate unit; *C*, Index for candidate assets; *E*, Index for existing assets; *NB*, Number of load busses; *NY*, Planning horizon; *NCU*, Number of candidate units; *NCL*, Number of candidate lines; *NG*, Number of generation buses

Parameters: *d*, Annual discount rate; *DT*, Duration of load blocks; *GI*, Generation unit's investment cost; *TI*, Transmission line's investment cost; *MTGI*, Minimum time required for generation unit installation; *MTTI*, Minimum time required for transmission line installation; *TGC*, Maximum annual budget for generation units' investment; *TGI*, Total number of new generation units can be installed for each year; *TTC*, Maximum annual budget for transmission lines' investment; *TTI*, Total number of new transmission lines can be installed for each year; *Max*, Upper bound for variables; *Min*, Lower bound for variable; *PD*, Demand power; ρ, Contingent event's probability; *B*, Susceptance matrix of power grid

1 | INTRODUCTION

Generation and transmission network expansion is one of the most significant parts of the power system planning. Generation expansion planning (GEP) and transmission expansion planning (TEP) are performed to determine the exact installation time and location of the generating units and transmission lines, respectively. A coordinated planning should be implemented in power systems for the assets to meet the future requirements. The expansion planning is done by the system planning entity in traditional power systems where it is in accordance to the system operator (SO) necessities. In such an environment, an entity is supposed to supply the entire budget needed for the system expansion. Besides, planning and operation of the system are exclusively done by the energy supply entity while the coordination between different sectors is done in an integrated fashion.

However, the planning entity and the SO have faced new conditions by the power system restructuring. The competition in the energy generation sector and providing competitive conditions for energy agencies while moving from the monopoly to oligopoly would be the first outcomes of restructuring. The mechanisms used by the supervisory entities at the beginning of the restructuring to facilitate and further expand the competitive conditions would impact the power system operation and investment in the future. The operation and ownership of the existing generating units are given to the private sectors, and the system expansion would be done by these entities after assessing the market conditions and the investment risk in the near future. As a result, the policies of planning entity in the restructured environment will highly affect the investment trend. Although the power flow in the system is independent of the system management structure, different market strategies influence the economic factors of the power flow. Thus, it can change the operation conditions. Furthermore, private sector decision making is affected by the technical, economic, and the security of the system which in turn increase the planning problem complexity. It is worth noting that the inherent features of the electrical energy lead to more conservative viewpoints in the planning stage. As the electrical energy cannot be stored in large scale due to the economic issues, the SO encounters severe challenges at each horizon of the planning regarding the load demand supply at the desired quality and quantity. It is noted that the long-term and short-term planning hierarchy is a function of the previous status of the investment in the power system. Hence, it can be stated that the optimal power system operation requires the optimal system planning in the generation and transmission sectors. Meanwhile, the priorities of both the consumers and the producers should be taken into consideration in the policies. The specific features of the electrical energy along with the time-consuming procedure of the optimal siting and investment in new assets more highlight the necessity for investigating the impact of different mechanisms on the long-term dynamics of the market.

The coordinated GEP-TEP problem is an optimization problem of mixed-integer programming (MIP) type with a dynamic nature over the planning horizon. In this respect, the integer variables relate to the time schedule of installing new assets and also their commitment status. In addition, the continuous variables relate to the power generation and the power flow of lines considered the decision variables. This problem is subject to different, technical, economic, and operation security constraints stated either in linear or nonlinear format. The coordinated GEP-TEP problem is a large-scale one with high complexity where nonlinear constraints and objective functions may lead to non-tractability of the problem. Hence, the DC power flow is generally used in the long-term studies of the power system.

There are so many research works carried out in the area of power system planning. This section only investigates those proposing novel models/techniques for the coordinated GEP-TEP problem. It is worth to note that the TEP is implemented after the GEP. Thus, the first part reviews the GEP-oriented research works, and then, a comprehensive review is done on the TEP problem. Afterwards, the coordinated GEP-TEP problem will be reviewed in detail to shed more light on the significance of this problem.

The main aim beyond the GEP is to provide the system with the required adequacy at the lowest cost. In this regard, various models and optimization algorithms have been presented up to this time to tackle the mentioned problem. These models are developed to determine the amount of power generation, the generation technology, and the installation time such that the minimum cost is achieved for the exclusive owner of the systems (mostly governments). According to the published documents, the oldest research done in the case of long-term expansion planning dates back to 1955 which was in French. Accordingly, it was translated into English in 1957 by Dantzig and Taylor. In the mentioned paper, a linear model with four constraints and five variables was proposed.[1] Hence, it can be stated that this paper presented the application of linear programming (LP) to the GEP problem for the first time. Meanwhile, Dantzig published a paper to indicate the risk due to the non-storable nature of a product using the electrical energy example and LP.[2] The number of constraints and variables of the model was 70 and 90, respectively. In 1972, Anderson showed that the multi-stage sequential decision-making nature of the GEP problem has the same behavior as those solved by the backward methods in the dynamic programming.[3] A linear standard formulation was proposed by Namara[4] in 1976 aimed at minimizing the investment and operating costs. Moreover, it was depicted that increasing the model accuracy, for example by applying the nonlinear behavior of the load duration curve (LDC) would mitigate the convergence speed compared with the LP. As a result, adding the uncertainty to the mentioned nonlinear model would further complicate the problem and even leads to the intractability of the problem. The preliminary models provided appropriate circumstances to overcome the shortcomings in the later research works. Dehghan et al5 proposed a multi-year mixed-integer linear programming model for the GEP under severe uncertainty. In this respect, a consolidated single-stage and two-stage robust optimization framework has been proposed. Zhan et al6 used a multi-stage optimization framework for the GEP considering the wind power uncertainty. In this regard, the impacts of the decisions on the future uncertainties have also been characterized. A unit commitment (UC)-based GEP model has been developed in Hua et al[7] to raise the operational flexibility so that the large penetration of renewable energies can be effectively handled. Besides, an embedded UC-based GEP model is presented in Palmintier and Webster[8] to simultaneously meet the future renewable Portfolio standards, carbon standards, and also the load demand. Besides, Pereira et al9 formulated the GEP problem using an embedded UC to support the generation mix. The future of the system with high renewable energy penetration has also been assessed in Bhuvanesh et al.[10] Manickavasagam et al11 presented the chance-constrained optimization model for the GEP. In this respect, the uncertain parameter in the long-term planning was the load demand. A Benders decomposition-based optimization framework has been suggested in Rebennac,12 while the uncertainty of the water inflow of hydro units has been taken into consideration, and the problem has been solved using a standard stochastic dual dynamic programming algorithm. Koltsaklis and Dagoumas13 has done a comprehensive review on the GEP problem.

The TEP models can be divided into two groups as static and dynamic planning.[14] The system planning entity determines the exact installation corridor and asset type to minimize the transferring energy to the load centers through the static planning. The dynamic planning is implemented in multiple stages while each stage impacts other stages. This method is rarely used and very difficult to implement. There are three questions to answer in the dynamic planning as, how? when?, and where?.

The TEP problem is implemented in traditional power systems to supply the forecasted load demand at the minimum cost, while meeting the system and reliability constraints. The reliability constraints were generally assessed in the context of the $N - 1$ contingency analysis where N is the number of assets.[15,16] Accordingly, the TEP problem was modeled as an optimization problem aimed at minimizing the total cost subject to a set of techno-economic and reliability constraints. These optimization problems have been solved using LP methods,[17-19] nonlinear programming (NLP),[20] and MIP methods.[21,22] LP was first used to solve the TEP problem[15] in 1997 by Garver, where the transmission losses were neglected and the constraints were all linear. It is noted that this method was associated with low accuracy and high convergence speed. The objective function and some of the constraints are nonlinear in the NLP problems, while the algorithm may be trapped into local optimum and the global solution may not be obtained. The key point in such algorithms is to properly set the initial values of the unknown variables. Some of the variables are of binary type in the MIP method. Furthermore, decomposition techniques have been used in addition to classic methods to solve the TEP problem.[23,24] However, the performance of the Benders decomposition technique can be improved using the hierarchical methods as the TEP problem is a non-convex optimization problem. Other methods such as the interior point method as a well-known approach to solve LP and NLP problems and branch-and-bound method which is based on the hierarchical Benders decomposition have also been used to solve the TEP problem.[25] Many other research works have been proposed so far to model and solve the TEP problem among which, Arabali et al26 developed a multi-stage planning framework with three objectives as investment cost minimization, private investment maximization as well as the reliability maximization. In this respect, the non-dominated sorting genetic algorithm (NSGA II) has been utilized to tackle the multi-objective optimization problem. Taking into account the load demand uncertainty, the stochastic problem has been solved in Alaee et al[27] using the shuffled frog leaping algorithm where the reliability cost has been added to the conventional objective function. Short-term uncertainties like the renewable power generation and the long-term uncertainties such as the demand growth and the variations of the production capacity have been addressed in the context of adaptive robust TEP in Zhang and Conejo.[28] The TEP problem under uncertainty was handled in Majidi-Qadikolai and Baldick[29] using a scalable and configurable decomposition method, and Haghighat and Zeng30 proposed a bilevel ACOPF-based TEP model. Comprehensive reviews on the TEP and the challenges of the TEP problem have been carried out in Hemmati et al and Lumbreras and Ramos,[31,32] respectively.

Reliability issues are other important ones in power system that should be considered in the power system studies. In general, reliability is a criterion to evaluate the performance of the system. According to the North America Electric Reliability Council, the power system reliability can be defined as Cassidy et al[33]: The ability of the power system to supply the consumers' load demand with respect to the standards. There is no index that is individually used to evaluate the power system reliability. The reliability indices are categorized into deterministic and probabilistic ones. The deterministic indices are calculated using deterministic parameters from a static viewpoint. The merit of this method refers to the simple calculations while it suffers from the low accuracy due to the fact that unpredictable events cannot be modeled. The probabilistic indices take into consideration the dynamic nature of the system and use statistical methods to consider the future uncertainties. These indices perform better compared with deterministic ones, but suffer from the high computational burden. Such indices measure the frequencies and time duration of the failures. It is worth mentioning that these indices can be used in the long-term planning as much more time is available. On the contrary, deterministic methods are usually used in the operation and management studies. Various expansion plans are proposed to improve the power system reliability categorized into expansion and reinforcement plans. The reinforcement plans generally include replacing existing single-circuit lines with double-circuit ones, and increasing the number of transformers or the transmission voltage level. Through the expansion planning, the planning entity specifies new locations for installing transmission lines or transformers considering the environmental restrictions. So, new transmission corridors would be added to the system. The methods presented for the TEP problem in the first step take into account the adequacy index and disregard the security index. Some references evaluated the power system reliability using the fault tree analysis[34] and probabilistic indices with $N-1$ contingency analysis[35-38] or $N-2$ contingency analysis[39] based on deterministic or probabilistic viewpoints.

It is worth mentioning that all above-cited references proposed an individual framework for the system expansion problem while in practice, these two stages must be implemented in a coordinated fashion. Restructured power systems based on the market are different from those with a traditional structure. In such systems, the generation, transmission, and distribution systems are not vertically integrated any longer. It means that the power flows through transmission lines based on the physical principles and independently of the market conditions. The competition will be among the market players, ie, consumers, producers, and the transmission system. Under such conditions, the decisions made by the consumers over the short-term, mid-term, and long-term horizons would highly affect the planning strategies. As it has been previously described, the proper expansion of the transmission system is of high significance to supply the load demand. The ISO is still the ultimate owner of the existing transmission systems which is due to the strategic role of this sector in the power market. Besides, the private sector rarely tends to participate in the TEP because of its high capital cost and low rate of return. The available transmission capacity in different parts of the system is a strategic factor for investment in the generation sectors. In this situation, the generation sector investors may encounter the transmission capacity hoarding disregarding the reliability issues. It is quite obvious that the investment will be done in the points that face no problem in the energy delivery chain. The transmission line congestion provides some producers with the disruption opportunity. The market power of such producers allows them to cause a monopoly in the power generation which is beyond the competitive conditions. Thus, this issue must be considered in the long-term planning. Promoting the transmission system is a big-budget action. In this respect, when planning to add the transmission capacity to connect new generating units, the future conditions of the power system should be also taken into account to avoid any extra cost in the future. Since the generation sector is highly dependent upon the transmission system, all the three entities must agree for any planning. Independent power producers (IPPs) tend to perform the GEP while the transmission system should be accordingly reinforced. Meanwhile, the ISO as a supervisory entity should assess the proposed plans. These items are barriers for to generation system expansion. Hence, there is a Federal Energy Regulatory Commission in the United States to evaluate the plans and supply the required costs. This procedure is done under the supervision of the ISO. This means that the ISO approves the final plans and IPPs are supposed to confirm their plans before the construction. There is no specific method in the strategy taken by Federal Energy Regulatory Commission. So, the ISO can ask IPPs to supply the required budget for the network promotion. Many research works have been so far devoted to the coordinated GEP-TEP problem. In this respect, Jin and Ryan40,41 present the coordinated GEP-TEP problem while considering the centralized TEP and decentralized GEP through a tri-level model. Furthermore, a tri-level programming framework has been suggested in Hong et al,[42] in which multiple contingencies have been considered along with the load demand uncertainty. The proposed method is based on the Benders decomposition. A composite GEP-TEP problem was implemented in Aghaei et al[43] while the reliability was also considered in the form of EENS cost. A single-objective optimization framework has been developed in Javadi et al[44] for the coordinated GEP-TEP problem using the intelligent particle swarm optimization algorithm. Baringo and Baringo45 proposed a stochastic adaptive robust optimization framework for the composite GEP-TEP framework in which the uncertainty of the load demand the stochastic units have been tackled. A robust framework for the reliability-oriented coordinated GEP-TEP planning using the information-gap decision theory and normal boundary intersection method has been proposed in

Baringo and Baringo.[46] It is noteworthy that the renewable power integration has not been taken into account in the above-mentioned references.

In this respect, this paper implements the coordinated GEP-TEP problem aimed at supplying the future load demand at the lowest cost and desired reliability level as well as interconnecting renewable energy sources (RESs). To this end, the mentioned problem is formulated as a multi-objective mixed-integer linear programming problem solved using the epsilon-constraint technique.[47,48] This model would enable the decision maker to select the most compromise solution among Pareto optimal solutions. The framework is validated by simulating the model using the Iran's 230 to 400-kV National Power Grid as a large-scale real power system. It is noteworthy that the undergoing expansion plans and their expected installation time have also been applied to the model as parameters. The developed dynamic expansion planning model has the capability to be modified and updated with respect to the variations of the load demand, fuel price, and the equipment installation-related issues. As this paper intends to add RESs to the electric power system, the transmission system capacity must accord with the RESs states considering this fact that the power output of the some RESs is volatile. Additionally, adding new transmission capacity and RESs would not certainly improve the system reliability. In this regard, one of the objective functions of the paper is the reliability index, which is finally needed to make a decision regarding the most preferred expansion plan.

The remainder of the present paper has been represented as below:

Section 2 presents the problem modeling. Section 3 describes the multi-objective optimization principles based on the epsilon-constraint method and fuzzy satisfying technique. Section 4 includes simulation results, and finally, some relevant conclusions have been provided in Section 5.

2 | PROBLEM DESCRIPTION

In this section, the problem description in line with the mathematical representation of the proposed model is described. In the proposed model, two different objective functions have been considered. The first objective function relates to the total system cost and includes the total investment costs of new generating units and transmission lines and the total operating cost over the planning horizon. Since the expansion planning model in this study is considered a multi-year dynamic planning one, the total investment cost regarding the installation year for each capacity addition should be evaluated by taking into consideration the annual discount rate. In the second objective function, the minimization of the expected energy not supplied (EENS) corresponding to the network topology is investigated. Due to the dynamic nature of multi-year planning in this study, the aforementioned security issue should be evaluated over the planning horizon. Therefore, the minimization of the EENS over the planning horizon is the same as the maximization of the system reliability. In the following subsections, the mathematical formulation of each objective function and the corresponding constraints are provided.

2.1 | Total investment cost minimization

One of the most important issues in the power system expansion planning problem relates to the capital cost of new capacity additions. In the state of the art viewpoint of expansion planning models, there are different mathematical models proposed in the literature in the context of operation research statement. Almost in all of the proposed models, the investment cost of new assets has been considered in terms of minimization of the cost or maximization of social welfare. From the economic point of view, the capital cost of new installations in the power grids forms a dominant part of the total cost. However, for a remarkable planning horizon, the operating cost over the planning horizon is also considerable, and it should be investigated in the model. In the coordinated GEP-TEP problem, the economic objective function and the corresponding constraints for a multi-year planning horizon can be defined as

$$\begin{aligned}&\text{Min}\\ f_1 = &\sum_{y=1}^{NY}\sum_{i=1}^{NG}\sum_{k=1}^{NCU}\frac{GI_{kiy}\left(Gn_{kiy}-Gn_{ki(y-1)}\right)}{(1+d)^{y-1}}+\sum_{y=1}^{NY}\sum_{j=1}^{NCL}\frac{TI_{jy}\left(Ln_{jy}-Ln_{j(y-1)}\right)}{(1+d)^{y-1}}\\ &+\sum_{y=1}^{NY}\sum_{b=1}^{NB}\sum_{i=1}^{NG}\sum_{k=1}^{NU}\frac{DT_{by}.c\left(PG_{kiby}\right)}{(1+d)^{y-1}}.\end{aligned} \tag{1.1}$$

Subject to:

$$Gn_{ki(y-1)} \le Gn_{kiy},\ Gn_{kiy} = 0\ if\ y < MTGI_{ki} \tag{1.2}$$

$$Ln_{j(y-1)} \le Ln_{jy},\ Ln_{jy} = 0\ if\ y < MTTI_{j} \tag{1.3}$$

$$\sum_{i=1}^{NG}\sum_{k=1}^{NU} GI_{kiy}\left(Gn_{kiy} - Gn_{ki(y-1)}\right) \le TGI_y \tag{1.4}$$

$$\sum_{j=1}^{NL} TI_{jy}\left(Ln_{jy} - Ln_{j(y-1)}\right) \le TTI_y \tag{1.5}$$

$$\sum_{i=1}^{NG}\sum_{k=1}^{NU} PG_{ki}^{\max,C}\left(Gn_{kiy} - Gn_{ki(y-1)}\right) \le TGC_y \tag{1.6}$$

$$\sum_{j=1}^{NL} PL_{jy}^{\max,C}\left(Ln_{jy} - Ln_{j(y-1)}\right) \le TTC_y \tag{1.7}$$

$$\sum_{k=1}^{NEU} PG_{kiby}^{E} + \sum_{k=1}^{NCU} PG_{kiby}^{C} + PVG_{lby} - PD_{lby} = \sum_{j=1}^{NEL} PL_{jby}^{E} + \sum_{j=1}^{NCL} PL_{jby}^{C} \tag{1.8}$$

$$PG_{ki}^{\min,E} \times IG_{kiby}^{E} \le PG_{kiby}^{E} \le PG_{ki}^{\max,E} \times IG_{kiby}^{E} \tag{1.9}$$

$$PG_{ki}^{\min,C} \times Gn_{kiy} \times IG_{kiby}^{C} \le PG_{kiby}^{C} \le PG_{ki}^{\max,C} \times Gn_{kiy} \times IG_{kiby}^{C} \tag{1.10}$$

$$0 \le \sum_{b=1}^{NB} PG_{kiby}^{E} \times IG_{kiby}^{E} \le Energy_{kiy}^{\max,E} \tag{1.11}$$

$$0 \le Gn_{kiy} \times \sum_{b=1}^{NB} PG_{kiby}^{C} \times IG_{kiby}^{C} \le Energy_{kiy}^{\max,C} \tag{1.12}$$

$$PL_{jby}^{E} - B_j\left(\delta_{mby}^{E} - \delta_{nby}^{E}\right) - M_j^{E}\left(1 - Z_{jby}\right) \le 0 \tag{1.13}$$

$$PL_{jby}^{E} - B_j\left(\delta_{mby}^{E} - \delta_{nby}^{E}\right) + M_j^{E}\left(1 - Z_{jby}\right) \ge 0 \tag{1.14}$$

$$-PL_{j}^{\max,E} \times Z_{jby} \le PL_{jby}^{E} \le PL_{j}^{\max,E} \times Z_{jby} \tag{1.15}$$

$$PL_{jby}^{C} - B_j\left(\delta_{mby}^{C} - \delta_{nby}^{C}\right) - M_j^{C}\left(1 - Z_{jby}\right) - M_j^{C}\left(1 - Ln_{jy}\right) \le 0 \tag{1.16}$$

$$PL_{jby}^{C} - B_j\left(\delta_{mby}^{C} - \delta_{nby}^{C}\right) + M_j^{C}\left(1 - Z_{jby}\right) + M_j^{C}\left(1 - Ln_{jy}\right) \ge 0 \tag{1.17}$$

$$-PL_{j}^{\max,C} \times Z_{jby} \times Ln_{jy} \le PL_{jby}^{C} \le PL_{j}^{\max,C} \times Z_{jby} \times Ln_{jy} \tag{1.18}$$

$$-\pi \le \delta_{iby} \le +\pi \quad \delta_{1,by} = 0 \tag{1.19}$$

As it has been stated before, the total cost including the investment cost and the operating cost over the planning horizon should be minimized. The first objective function is aimed at minimizing the total investment cost in the context of the coordinated GEP-TEP as well as the total operating cost over the planning horizon. Since the expansion planning is scheduled as a multi-year planning, the total annual operating cost is considered in the objective function, as well. In this regard, the first objective function consists of three parts, in which the two first items relate to GEP and TEP while the third part is the total operating cost over the planning horizon.

This objective function is subjected to different techno-economic constraints. One of the most critical issues in the new capacity additions is the minimum time required for installing new assets. The construction time needed for the installation of new equipment should be investigated in the planning horizon. Therefore, it is necessary to pass this time interval for generating units and transmission lines, respectively. Constraints (1.2) and (1.3) relate to the installation of new generating units and transmission lines, respectively. These constraints confirm that if the minimum required time for installing the mentioned assets have not been passed, they have not any chance to be installed. The associated binary variables of generating units, Gn_{kiy}, and transmission lines, Ln_{jy}, will be “0” before the installation and they will be “1” after the installation. Equations 1.4 and 1.5 deal with the annual investment budgets for new generating units and transmission lines investments, respectively. In the aforementioned equations, the annual budget limitation for generating units and transmission lines installation are considered TGI_y and TTI_y, respectively. In addition, the same constraints are considered for annual capacity additions to the grid for both generating units as well as transmission lines. Equations 1.6 and 1.7 are considered in this regard. The nodal load balance equation is addressed in Equation 1.8 in which the load unbalance at each bus is modeled by a virtual generator. In other words, the amount of the curtailed load at each bus for each year over the planning horizon is modeled by VPG_{lby} which is a slack positive variable. If the power system faces any load curtailment, this positive variable maintains the nodal load balance which is an equality equation. It is evident that the maximum acceptable load curtailment in the worst case scenario is equivalent to the entire demand load at that bus. The value of the curtailed load is considered to be the value of lost load. In the operation horizon, each generating unit should be operated within the acceptable operating limits. Therefore, Equations 1.9 and 1.10 are considered in this regard. Moreover, the maximum extracted power from both existing and candidate generation units should be less than the maximum extractable power from such units. Equations 1.11 and 1.12 deal with the maximum acceptable power that can be achieved from the existing and candidate generating units in each year of planning horizon, respectively. Equations 1.13 to 1.19 relate to the DC optimal power flow (DCOPF) equations considering the transmission switching actions. More details about these equations are available in Javadi.[49] It is noteworthy that the decision binary variables regarding the long-term planning and short-term operation are addressed by Equations 1.13 to 1.15 and Equations 1.16 to 1.18, respectively. It is evident that the associated binary decision variables for the short-term operation are merely dependent upon the long-term planning decisions. In other words, if the long-term binary variable is “0,” the short-term operation binary variable is not defined. In addition, a security constraint regarding the stability issues is considered in Equation 1.19. This constraint represents the acceptable bounds for the bus voltage angle while the bus voltage angle for the slack bus is assumed to be zero.

2.2 | Expected energy not served minimization

One of the most important issues in the long-term power system planning studies is the reliability assessment of the studied network. Different reliability indices have been addressed in the literature. However, the most practical index for reliability assessment is the EENS at generation and transmission hierarchical level known as $\text{EENS}_{\text{HL-II}}$. In order to calculate the $\text{EENS}_{\text{HL-II}}$, the probability of forced outage occurrence related to each equipment, ie, generating units and transmission lines, is needed. In this study, a two-stage model for each asset is adopted. The availability and unavailability probability of each asset are needed in the two-stage framework. By implementing the DCOPF addressed in the previous section, the amount of load curtailment due to generating units and transmission lines outages can be calculated by considering the presence of a virtual power generator at each bus. Meanwhile, it is also necessary to generate the contingent events for the reliability assessment. In this study, a deterministic model for generating the contingent events and their associated occurrence probabilities are adopted. In order to reduce the computational burden, the contingent events with the probability less than 0.000001 are omitted. Eventually, the problem formulation of the second objective function is as follows:

$$\begin{gathered}\text{Min}\\ f_2 = EENS_{HL-II}.\end{gathered} \tag{2.1}$$

Subject to:

$$EENS_{HL-II} = \sum_{y=1}^{NY} EENS_{HL-II}^{y} \tag{2.2}$$

$$EENS_{HL-II}^{y} = \sum_{c=1}^{NC} \rho^{c} \sum_{l=1}^{ND} \sum_{b=1}^{NB} PVG_{lby}^{c} \tag{2.3}$$

$$\sum_{k=1}^{NU} PG_{kiby}^{c} + PVG_{lby}^{c} - PD_{lby} = \sum_{j=1}^{NL} PL_{jby}^{c} \tag{2.4}$$

$$PG_{ki}^{\min,c} \times IG_{kiby}^{c} \le PG_{kiby}^{c} \le PG_{ki}^{\max,c} \times IG_{kiby}^{c} \tag{2.5}$$

$$PL_{jby}^{c} - B_{j}^{c}\left(\delta_{mby}^{c} - \delta_{nby}^{c}\right) - M_{j}^{c}\left(1 - Z_{jby}^{c}\right) \le 0 \tag{2.6}$$

$$PL_{jby}^{c} - B_{j}^{c}\left(\delta_{mby}^{c} - \delta_{nby}^{c}\right) + M_{j}^{c}\left(1 - Z_{jby}^{c}\right) \ge 0 \tag{2.7}$$

$$-PL_{j}^{\max,c} \times Z_{jby}^{c} \le PL_{jby}^{c} \le PL_{j}^{\max,c} \times Z_{jby}^{c} \tag{2.8}$$

$$-\pi \le \delta_{iby}^{c} \le +\pi \quad \delta_{1,by}^{c} = 0 \tag{2.9}$$

The second objective function is subjected to a huge number of subproblems in order to find the EENS over the planning horizon. The objective function that should be minimized is defined as the total annual $EENS_{HL\text{-}II}$. This objective function should be calculated after determination of the intended plan. Therefore, in the DCOPF subproblems relating to each contingency, the long-term binary decision variables have been determined. For each contingent event with the occurrence probability ρ^{c}, the amount of the curtailed load should be calculated as stated in Equation 2.3. The corresponding probabilistic DCOPF subproblems' constraints are provided in Equations 2.4 to 2.9. It should also be noticed that if the contingent events are associated with the transmission lines outage, the network topology will change. Therefore, the network topology matrix, B_{j}^{c}, should be rearranged according to the change in network topology in such a case.

3 | MULTI-OBJECTIVE OPTIMIZATION

Generally, an optimization problem with two or more objective functions can be mathematically presented as follows[50-54]:

$$\begin{aligned} &\text{Min} \quad F = \left[f_1(X),\ f_2(X),\ \dots\ ,\ f_p(X)\right]^T \\ &\textit{subject to} \\ &g_i(X) < 0, \quad i = 1, 2, \ \dots\ , N_{ueq} \\ &h_i(X) = 0, \quad i = 1, 2, \ \dots\ , N_{eq} \end{aligned} \tag{3}$$

where the number of objective functions, inequality constraints, and equality constraints are denoted by p, N_{ueq}, and N_{eq}, respectively. Besides, the decision vector is indicated by X. It is noted that the objective functions are intended to be either minimized or maximized depending upon the application of the problem and the definition of the objective function. It is noteworthy that solving a multi-objective optimization problem would lead to a set of optimal solutions while a single-objective optimization problem results in a single optimal solution. Indeed, each member of this set would include a pair of values for a bi-objective problem. In this respect, each member of the set of optimal solutions is called Pareto optimal (non-dominated or non-inferior) solution. The key point in the Pareto optimal front is that it is not possible to find a better value for one of the objective functions unless it deteriorates the values of other objective functions.[55] Among the various multi-objective optimization methods proposed thus far, the epsilon-constraint technique has been proved as one of the most efficient ones, particularly compared with the weighting-sum method. Using the weighted-sum method, all objective functions are weighted and merged into one objective function.[56,57] However, a famous optimization method like epsilon-constraint has also two critical shortfalls that need to be taken into account. If there are *P* objective functions, the range of *P-1* objective functions must be specified as these objectives will be assigned to the problem as constraints. This problem has been tackled in this paper by employing the lexicographic optimization technique to optimally determine the range of each objective function. The second shortfall of this multi-objective optimization method relates to the efficiency and the superiority of the obtained solutions. In this regard, the augmented epsilon-constraint technique is used to overcome this shortfall. Thus, this paper employs the augmented epsilon-constraint and lexicographic optimization technique to solve the proposed multi-objective optimization problem with conflicting objective functions. The procedure of the epsilon-constraint method is described in the following, while Aghaei et al, Amjady et al, and Ahmadi et al58-60 include the detailed descriptions. The fundamental of this method is based on assigning one of the objective functions as the main one and all others as constraints to the problem as follows[56,61]:

$$\begin{aligned} &\text{Min} \quad f_1(\overline{x}) \\ &\textit{subject to} \quad f_2(\overline{x}) \le e_2, f_3(\overline{x}) \le e_3 \ , \ \ldots \ , f_p(\overline{x}) \le e_p \end{aligned} \tag{4}$$

where p and $\overline{x}$, respectively, indicate the number of objective functions and the decision variables vector. As it can be observed from the above expression, the objective functions have been all considered to be minimized, and as it has been already mentioned, the ranges of the $p-1$ objective functions should be determined. To this end, the payoff matrix can be utilized to compute these values.

Building the payoff matrix involves several stages while in the first stage, the problem must be solved as a single-objective optimization problem to determine the optimal value of each objective function f_i for p objective functions. In this respect, $f_i^*(\overline{x}_i^*)$ and $\overline{x}_i^*$, respectively, show the optimal value of each objective function and the vector of decision variables that optimize the objective function f_i. Then, the single optimum of other objective functions indicated by $f_1(\overline{x}_i^*), f_2(\overline{x}_i^*), \ldots, f_{i-1}^*(\overline{x}_i^*), f_{i+1}(\overline{x}_i^*), \ldots f_p(\overline{x}_i^*)$ would be calculated using the optimal solution of f_i. Accordingly, the payoff matrix would be derived as follows,[62] where the row i of this matrix is composed of $f_1(\overline{x}_i^*), f_2(\overline{x}_i^*), \ldots, f_i^*(\overline{x}_i^*), \ldots, f_p(\overline{x}_i^*)$.

$$\Phi = \begin{bmatrix} f_1^*(\overline{x}_1^*) & \ldots & f_i(\overline{x}_1^*) & \ldots & f_p(\overline{x}_1^*) \\ \vdots & \ddots & & & \vdots \\ f_1(\overline{x}_i^*) & \ldots & f_i^*(\overline{x}_i^*) & \ldots & f_p(\overline{x}_i^*) \\ \vdots & & & \ddots & \vdots \\ f_1(\overline{x}_p^*) & \ldots & f_i(\overline{x}_p^*) & \ldots & f_p^*(\overline{x}_p^*) \end{bmatrix} \tag{5}$$

The final payoff matrix is a square matrix with p rows and p columns, while the optimum of each objective function f_n is presented in the column n and the range of each objective function is calculated by the minimum and maximum values. The epsilon-constraint method includes several concepts that should be introduced. Assigning all objective functions to be minimized, the *Utopia* point denoted by $f^U$is a point out of the feasible space at which all objective functions take their best possible values as follows:

$$f^U = \left[f_1^U, \ldots, f_i^U, \ldots, f_p^U\right] = \left[f_1^*(\overline{x}_1^*), \ldots, f_i^*(\overline{x}_i^*), \ldots, f_p^*(\overline{x}_p^*)\right]. \tag{6}$$

On the contrary, the point in the objective region at which all objective functions take their worst values is called *Nadir* point, f^N as follows:

$$f^{N}=\left[f_{1}^{N},...,f_{i}^{N},...,f_{p}^{N}\right] \tag{7}$$

where

$$f_{i}^{N}=\underset{\overline{x}}{\mathrm{Max}}\ f_{i}(\overline{x}) \tag{8}$$

subject to $\overline{x}\in\Omega$

and Ω is the feasible region. Besides, *Pseudo Nadir* point is another point relatively similar to the *Nadir* point, and it is presented as

$$f^{SN}=\left[f_{1}^{SN},...,f_{i}^{SN},...,f_{p}^{SN}\right] \tag{9}$$

where,

$$f_{i}^{SN}=\mathrm{Max}\ \left\{f_{i}(\overline{x}_{1}^{*}),...,f_{i}^{*}(\overline{x}_{i}^{*}),...,f_{i}\left(\overline{x}_{p}^{*}\right)\right\}. \tag{10}$$

It is noteworthy that the range of the objective functions will be determined using the *Utopia* and *pseudo Nadir* points as:

$$f_{i}^{U}\leq f_{i}(\overline{x})\leq f_{i}^{SN} \tag{11}$$

The objective space is introduced with the dimension of the objective functions. Using the concepts of these three points, a typical Pareto frontier can be shown as Figure 1.

The ranges of *p − 1* objective functions must be divided into identical intervals by applying the intermediate grid points denoted by (q_2-1), ..., (q_p-1). It should be noted that the first objective function is set as the main one. Thus, $\prod_{i=2}^{p}(q_i+1)$ subproblems must be tackled as follows:

$$\begin{array}{ll}\mathrm{Min} & f_{1}(\overline{x})\\ S.T. & f_{2}(\overline{x})\leq e_{2,n2},\ \ \dots\ ,f_{p}(\overline{x})\leq e_{p,np}\end{array} \tag{12}$$

$$e_{2,n2}=f_{2}^{SN}-\left(\frac{f_{2}^{SN}-f_{2}^{U}}{q_{2}}\right)\times n2,\quad n2=0,1,...,q_{2} \tag{13}$$

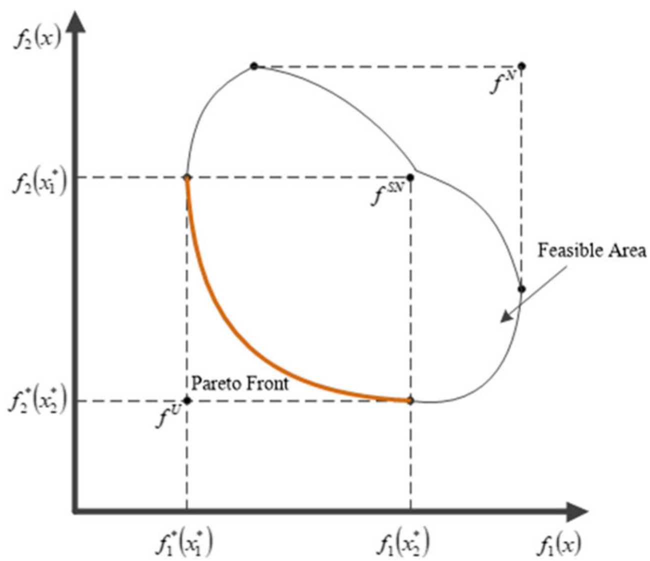

FIGURE 1 Pareto set comprising *Utopia*, *Nadir* and *Pseudo Nadir* points

$$e_{2,np} = f_p^{SN} - \left(\frac{f_p^{SN} - f_p^{U}}{q_p}\right) \times np, \qquad np = 0, 1, \ldots, q_p \tag{14}$$

Using this technique, every subproblem would be subjected to the constraints introduced in Equation 12 beside the constraints of the main problem. By solving each subproblem, the Pareto optimal front will be derived while the infeasible solutions will be denied. The inefficiency of the solutions can be overcome by transforming the objective function constraints in Equation 12 to equalities by adding the slack variable method[56,63] as

$$\begin{cases} \text{Min} \quad \left(f_1(\overline{x}) - r_1 \sum_{i=2}^{P} \left(\frac{s_i}{r_i}\right)\right) \\ subject \;\; to \\ f_i(\overline{x}) + s_{i,ni} = e_{i,ni}, \quad i = 2, \ldots, p \quad \& \quad s_{i,ni} \in R^+ \\ \overline{x} \in \Omega \end{cases} . \tag{15}$$

In this respect, $s_2, \ldots, s_p$show the slack variables introduced to the problem for the constraints in Equation 12. $r_1(s_i/r_i)$ is considered in the second part pf the objective function to avoid the problems caused by the scale of the objectives. Moreover, the ranges of the objective functions are obtained by the payoff matrix ($r_i = f_i^{SN} - f_i^{U}$). Utilizing this technique, the slack variables are scaled to the range of the main objective function. Accordingly, Equation 15 is known as the augmented epsilon-constraint method due to the augmentation of the objective function f_1 by the second part. Mavrotas56 has shown that by using this method, only efficient solutions will be obtained. The flowchart of the presented multi-objective optimization method is demonstrated in Figure 2.[61] The decision maker should select the most desired solution among the obtained non-dominated solutions.

In this regard, the fuzzy satisfying method is used in this paper to select the most compromise solution. Using this method, the first step is to define a linear membership function for each objective function as below[64-67]:

$$\mu_{Fi}(X) = \begin{cases} 1 & F_i(X) \le F_i^{\min} \\ \dfrac{F_i^{\max} - F_i(X)}{F_i^{\max} - F_i^{\min}} & F_i^{\min} \le F_i(X) \le F_i^{\max} \\ 0 & F_i(X) \ge F_i^{\max} \end{cases} . \tag{16}$$

When this function is fully met, its value would be equal to 1, and zero when not satisfied et all. F_i^k andμ_i^k are the values of the objective function i and the membership value of each objective function in the Pareto solution k, respectively. It is worth mentioning that the membership function above is proposed for the objective functions that are set to be minimized. The total membership value,μ^k, determining the most compromise solution is stated as follows:

$$\mu^k = \frac{\sum_{i=1}^{P} w_i \cdot \mu_i^k}{\sum_{k=1}^{M} \sum_{i=1}^{P} w_i \cdot \mu_i^k} \tag{17}$$

where w_i is the weighting factor of the objective function i and it is specified by the decision maker with respect to the requirements of the problem. The decision maker is the planning entity in this paper that should decide on the best expansion plan according to the priorities of the system. It should be noted that the solution with the highest $\mu^k$is selected as the most compromise solution.

4 | SIMULATION RESULTS

This section provides the simulation results for evaluating the proposed model using a high voltage transmission network, ie, Iran's 230 to 400-kV grid. The INPG consists of 17 regional electricity companies (RECs), 28 generation management companies, and 42 distribution companies, and it is categorized as one of the largest power grids in the Middle East. This large-scale power system has extensive fossil-fuel resources located in the south and south-west of this country. This network has some priorities in the integration of renewable resources to the national grid to reduce the

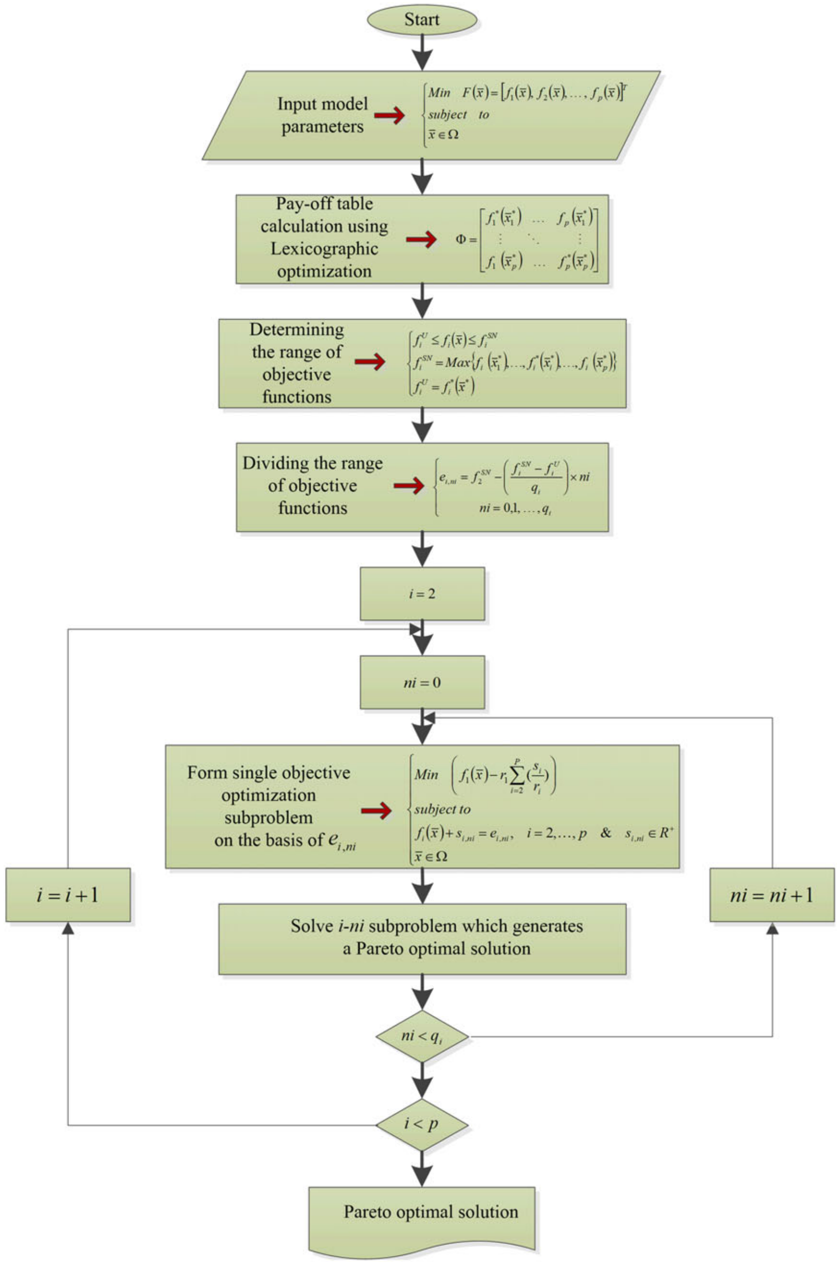

FIGURE 2 The concept of the augmented epsilon constraint technique

interdependencies to the fossil-fuel generation. Moreover, there are different potentials available for investment in the renewable resources in this country. In order to increase the RES penetration to the INPG, some incentive programs have been proposed to encourage the investment in this area. Therefore, the RECs are eager to invest in the renewable energy generations. Among the 17 RECs, the Kish REC is not connected to the INPG, and therefore, this REC is not considered in the planning studies in this research.

As mentioned before, the conventional fossil-fuel resources, like oil and gas, are mostly located in the south and southwest of this country. A massive pipeline network for transferring oil and gas fuels has been investigated, and different petroleum refineries have been constructed during the last decades to supply the required fossil fuels for transportation system, industries, as well as fossil-fuel generating units.

Despite the fact that the fossil fuels are accessible in every part of the country using the pipelines and also by the transportation system, some regions may encounter lack of such fuels over some periods. Thus, the intermediate statement is established for such regions.

As it is obvious from the current status of renewable energy technologies, they are still associated with exorbitant costs with restricted availability. Nevertheless, the interest in renewable energies is experiencing an ever-growing rate to alleviate the dependency on fossil fuels. It should be noted that the availability of wind and solar energy is quite moderate which is only in some parts of Iran due to the geographical reasons. In this respect, the potential of such energies has been estimated over 60 000 MW for each technology.[68] The total installed capacity of the power plants until the year 2018 is 79 611 MW. At the peak hour, the total available and operational power plant capacity was 60 608 MW, including 49 142 MW of thermal and nuclear power generation capacity and 11 466 MW renewable power generation capacity. The simultaneous peak demand for electricity in the year reaches 57 098 MW.

The load demand growth rate for the planning horizon is estimated at 4% per year. Also, it should be noted that the planned capacity of the power plant for installation in this network in 2018 is 2366 MW for conventional fossil-fuel fired technology and 477.57 MW renewable power plants.

The horizon for planning in this study is considered 7 years, starting from 2019 and the target year is 2025. Figure 3 illustrates the INPG network in line with the candidate locations for wind farms and installed refineries. The forecasted loads for this case study are provided in Table 1. The last row of this table includes the simultaneous peak demand at each year.

In this study, there are four subperiods considered corresponding to four seasons. The peak load ratios of the mentioned subperiods are addressed in Table 2. The LDC is approximately modeled with three levels, and the estimated LDC data are provided in Table 3. The data of candidate generating units and transmission lines for the expansion planning study for INPG are provided in Table 4 and Tables 5 and 6, respectively.

Figure 4 illustrates the installed and candidate corridors for new transmission lines installation. For new transmission lines, it is necessary to select the type of transmission lines as well as the reconfiguration of the network topology for the optimal power flow studies.

Since the renewable power generation in INPG has considerable potentials for investment, the integration of such technologies can reduce the fuel and water consumptions. In addition, the wind and solar power technologies are environmentally friendly, and therefore, they can be effective in reducing the greenhouse gas emissions.

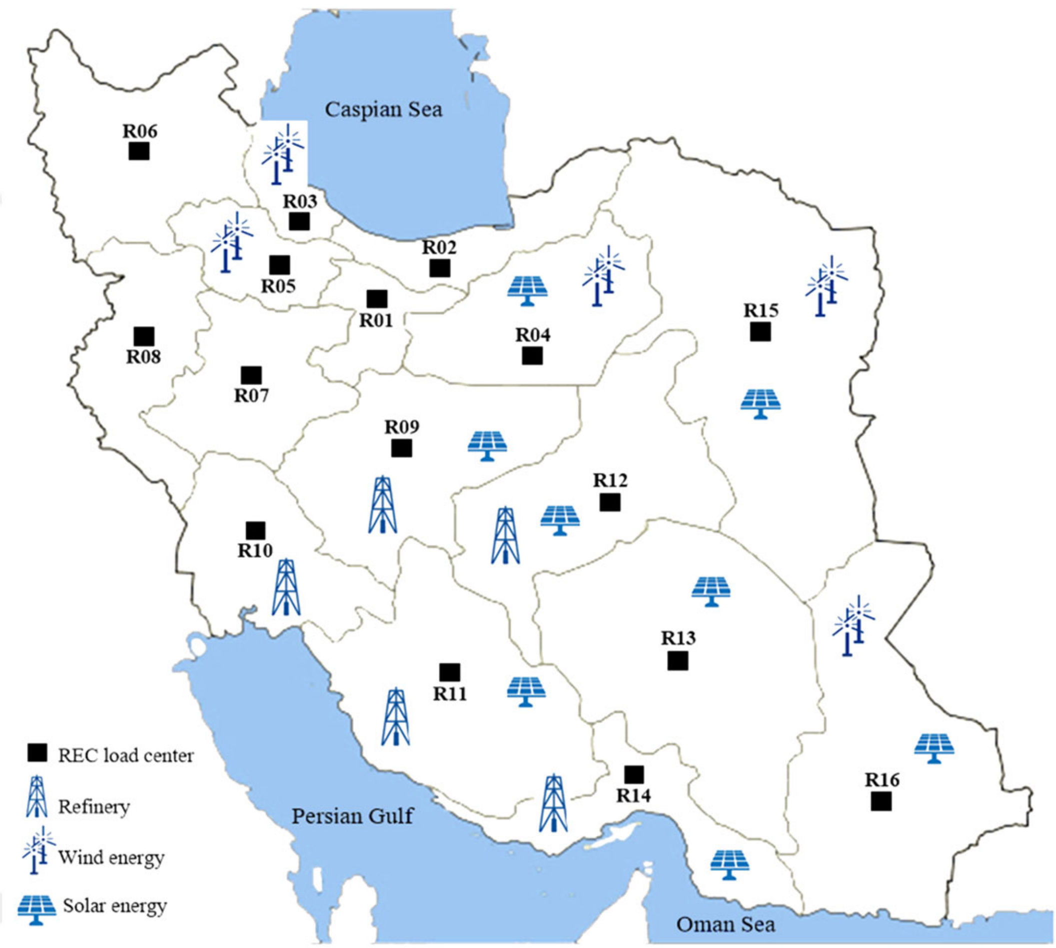

FIGURE 3 Geographic map of RECs in Iran and location of primary energy resources[69]

TABLE 1 The RECs' forecasted for planning horizon [71]

	Forecasted Peak Demand							
REC	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
R01	10 524	11 103	11 674	12 118	12 560	13 028	13 505	13 937
R02	4506	4827	5138	5389	5645	5899	6162	6415
R03	1974	2105	2234	2315	2395	2470	2545	2614
R04	586	615	646	678	711	745	781	818
R05	1567	1664	1759	1831	1903	1975	2050	2119
R06	3618	3836	3987	4122	4217	4352	4468	4593
R07	3522	3720	3892	4012	4131	4240	4291	4445
R08	2695	2892	3082	3236	3393	3549	3713	3866
R09	5503	5823	6094	6283	6468	6626	6758	6868
R10	10 057	10 571	11 219	11 680	12 199	12 737	13 293	13 822
R11	5601	5966	6314	6586	6859	7127	7403	7661
R12	1497	1619	1727	1815	1904	1981	2057	2130
R13	2632	2854	3073	3260	3453	3646	3850	4048
R14	3682	3992	4310	4586	4870	5154	5450	5742
R15	4282	4566	4822	5021	5219	5397	5580	5747
R16	1574	1671	1762	1831	1899	1966	2034	2097
Simultaneous peak	57 098	59 382	61 757	64 227	66 797	69 468	72 247	75 137

TABLE 2 Peak load ratio for each sub-period[70]

Period	**Peak Load Ratio, pu**
1	0.8996
2	1.0000
3	0.8936
4	0.8348

TABLE 3 Linear approximation of INPG's LDC[70]

Level	**Duration, h**	**Load Ratio, pu**
1	438	1.00
2	6570	0.75
3	1572	0.60

In this paper, the integration of RESs and conventional fossil-fuel fired power plants is studied to supply the load in the planning. According to the proposed optimization model in the previous section, two objective functions as the total cost and $EENS_{HL\text{-}II}$ have been investigated in this test system.

The simulation results obtained from the epsilon-constrained method show that for the planning horizon 36 optimal solutions have been obtained. Figure 5 illustrates the optimal Pareto front derived from the epsilon-constraint method. The simulation results confirm that the planning sector needs to consider much more budget for expansion planning to achieve the lower $EENS_{HL\text{-}II}$. Eventually, in order to select the final plan for expansion, it is needed to adopt a decision-making procedure. In this study, the fuzzy satisfying method is accepted. In the next section, the final plan for installation is obtained by implementing this strategy.

TABLE 4 Techno-economic data for generating unit candidates[70]

Attributes	Type of Generation Units						
	S325	G130	CC400	WF30	WF50	SP15	SP20
Size (MW)	325	130	400	30	50	15	20
Minimum time to installation (year)	5	2	5	1	1	1	1
Life time (year)	30	15	30	20	20	15	15
FOR (%)	12.9	10.2	13.67	3.2	3.4	4.5	4.8
Investment cost ($/kw)	800	500	850	1000	950	850	800
Maximum number of units installation in RECs	5	10	3	20	15	20	15

TABLE 5 Techno-economic data for transmission line candidates[70]

Attributes	Type 1	Type 2
Line voltage (kV)	230	400
Type	CANARY	CURLEW
Number of bundle	1	1
Number of circuit	1	1
Resistance (pu/km)	0.000120	0.000035
Reactance (pu/km)	0.000764	0.000260
Nominal transmission line capacity (MW)	397	750
Variable investment cost (k$/km)	42	85
Fix investment cost (k$/km)	500	1600

TABLE 6 Existing and candidate for expansion transmission lines data[70]

Line	Branch		Capacity, MW	Resistance, pu	Reactance, pu	Length, km
	From	To				
1	R01	R02	2443	0.0013	0.0126	161
2	R01	R03	1292	0.0029	0.0334	230
3	R01	R04	1408	0.0029	0.0280	242
4	R01	R05	1528	0.0022	0.0134	202
5	R01	R06	667	0.0085	0.0968	500
6	R01	R07	4932	0.0015	0.0145	233
7	R01	R09	1530	0.0030	0.0246	349
8	R02	R03	397	0.0076	0.0502	308
9	R02	R04	1581	0.0021	0.0203	118
10	R02	R15	878	0.0049	0.0556	562
11	R03	R05	2631	0.0014	0.0121	97
12	R03	R06	939	0.0054	0.0331	305
13	R04	R15	909	0.0045	0.0515	452
14	R05	R06	1098	0.0041	0.0392	322
15	R05	R07	1097	0.0032	0.0371	205
16	R06	R08	397	0.0114	0.0757	414

(Continues)

TABLE 6 (Continued)

Line	Branch From	Branch To	Capacity, MW	Resistance, pu	Reactance, pu	Length, km
17	R07	R08	3632	0.0011	0.0105	206
18	R07	R09	1500	0.0016	0.0181	293
19	R07	R10	3643	0.0011	0.0113	355
20	R08	R10	397	0.0114	0.0757	368
21	R09	R10	5512	0.0006	0.0074	283
22	R09	R11	316	0.0185	0.1227	341
23	R09	R12	1292	0.0024	0.0345	273
24	R10	R11	3225	0.0012	0.0177	382
25	R11	R13	1293	0.0016	0.0283	416
26	R11	R14	1271	0.0180	0.1196	458
27	R12	R13	1868	0.0018	0.0239	300
28	R13	R14	2455	0.0014	0.0160	318
29	R13	R16	836	0.0105	0.0597	473
30	R14	R16	197	0.0442	0.2525	480

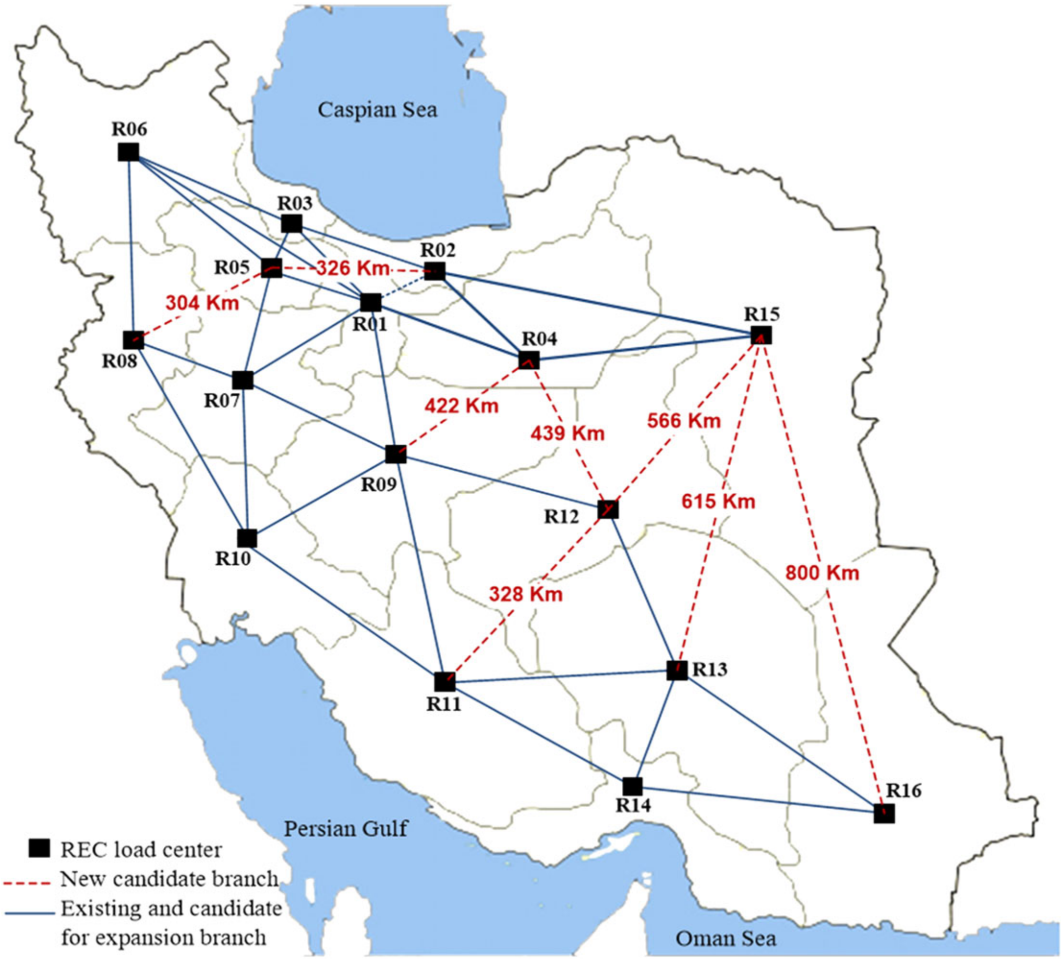

FIGURE 4 Existing and candidate corridors for transmission expansion planning[69]

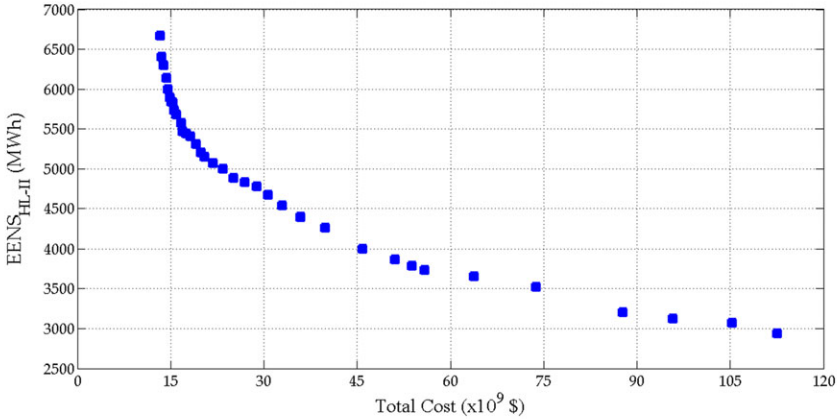

FIGURE 5 Optimal Pareto front obtained by the epsilon-constraint

Since there are two objective functions in this study, the decision maker needs to consider two weighting factors for the corresponding individual membership functions. In this study, the membership functions for EENS$_{HL-II}$ and Total Costs are considered 0.75 and 0.25, respectively. From the point of view of the planning entity, the security issue has much more priority than the total cost. Therefore, the associated weighting factor for the EENS$_{HL-II}$ objective function is considered greater than the total cost. The fuzzy satisfying method for decision-making process by considering the mentioned weighting factors results in the final expansion plan. The performance of the fuzzy method in terms of the membership values of the objectives and the total membership has been demonstrated in Figure 6. As this figure shows, Pareto solution 12 is selected as the most compromise solution as it is associated with the highest total membership value as 0.803043. The total cost and EENS$_{HL-II}$ for the executive plan are \$ 73.815 billion and 3520.44 MWh, respectively.

The final plan based on the mentioned fuzzy satisfying decision-making method is addressed in Table 7. As it can be seen from the obtained results, there are different wind farms, solar panels, as well as other conventional generating units available in the executive plan. In addition, the transmission network needs to be expanded proportionally to integrate the large-scale power plants in this case. It should also be noticed that the scheduled plans for installation are considered in this study. In Table 7, the ongoing projects are bold, and it means that the mentioned generating units will be available for operation over the planning horizon. The total generation capacity at the end of planning horizon is expected to be 127 155 MW. Considering this fact that the forecasted simultaneous peak demand in the last year of the planning is 75,137 MW, there will be enough reserve for supporting the secure operation at the peak hours. It is noteworthy that the penetration of RESs in the generation mix is remarkable.

For TEP, there is no project for installation between the different RECs. Therefore, in the RECs' cut-sets, there is no new transmission line for installation. However, for integrating new generating units and improving the reliability of the entire network, the planning entity has to install six new transmission lines. Among these new installations, the number of new corridors that should be installed is 4. In the selected plan for installation, the R01 should be connected to its neighboring RECs through two transmission lines to R02 and R09. The R04 should be connected to the R09 and R012 by installing two new corridors. The R012 should also be connected to R015 to integrate the new generating units by installing a new corridor. Finally, R05 needs to connect to R08 and transfer the generated power from R08 to the large load centres. The installation year of new transmission lines is addressed in Table 8.

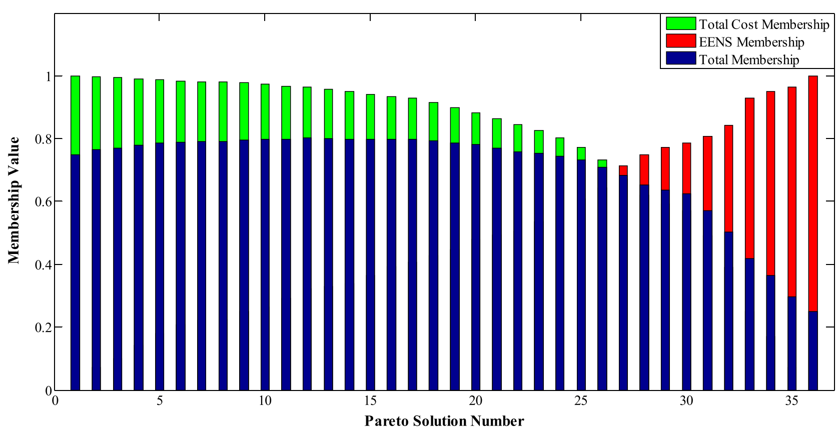

FIGURE 6 The performance of fuzzy satisfying method

TABLE 7 Generation expansion planning over the planning horizon

	2018	2019	2020	2021	2022	2023	2024	2025
R01		**345**	**810** + G130	3xG130	5xG130	3xS325	2xS325 + CC400	3xS325 + CC400
R02	**140**		**160**	2xG130	3xG130	CC400	S325 + CC400	2xS325 + CC400
R03			WF50		WF50	CC400	CC400	2xWF50
R04		**160**	WF30 + 2xSP20	2xWF30 + 2xSP20	2xSP20 + G130	WF30 + 2xG130	WF30 + 3xSP15	3xWF30 + 3xS325
R05		WF30	**320** + WF30	WF50	3xWF50	WF50	2xWF30 + 2xG130	
R06	**506**	**1267**	**467**	2xG130	3xG130	CC400	S325 + CC400	S325
R07	**324**	**762**		G130	2xG130	2xG130	S325	S325
R08	**180**		**320** + G130		2xG130	3xG130	S325 + CC400	2xS325 + CC400
R09	**160**	SP15		2xSP15 + 2xG130		SP20 + CC400	2xSP15 + 2xS325	2xSP20 + 2xS325
R10		**918**	**777** + G130	2xG130	4xG130	4xG130	2xS325 + G130	2xS325 + 2xCC400
R11	**480**			SP20		2xSP15 + S325	S325	2xSP20 + 2xCC400
R12		**17**	SP15 + 3xG130	SP20 + 3xG130	2xSP15 + 3xG130	2xG130	2xSP20 + 2xG130	
R13	**162**	**162**	**160** + 2xG130	3xG130	SP20	SP15 + SP20	S325	2xSP20
R14	**324**	**762**	**638**	4xG130	3xG130	2xCC400	S325 + CC400	2xS325 + 2xCC400
R15	**480**	2xWF30	**307**	SP20 + 3xG130	2xWF30 + 3xG130	SP15 + 2xG130	SP20 + G130	2xWF30 + S325
R16		**160**	**631** + SP20	WF30 + 4xG130	2xSP20 + 5G130	2xWF30 + S325	WF50 + 3xS325	4xSP15 + 3G130

TABLE 8 Transmission expansion planning over the planning horizon

Line	From	To	Year	Type
1	R01	R02	2020	Type 1
2	R01	R09	2021	Type 2
3	R04	R09	2019	Type 2
4	R04	R12	2022	Type 2
5	R05	R08	2022	Type 2
6	R12	R15	2024	Type 2

5 | CONCLUSION

This paper investigated the wind farms interconnection to the INPG in the context of the coordinated GEP and TEP. The problem was presented in a multi-objective optimization framework. The objective functions were the total cost as an economic index and the reliability as a significant technical index. The reliability index was the EENS. For the sake of mitigating the computational burden, all objective functions and constraints were proposed in a linear framework. The multi-objective coordinated GEP-TEP problem was solved using the augmented epsilon-constraint technique. The obtained Pareto optimal front indicated that solving the problem leads to diverse expansion plans where the total cost increased as the EENS reduced, ie, the enhanced reliability. The generation expansion plans that had started to be implemented since the past years were modeled as parameters. However, some units must be constructed over the initial years of the planning horizon. The steam power and combined-cycle units will take longer to construct due to their limitations. Besides, renewable energy based units should also be added over the planning horizon. As the mentioned units were located close to the load centers, the installation of new transmission lines was limited. On the other hand, interconnecting different parts of the system not only reduces the operating costs, but also leads to enhanced reliability. As shown in the simulation results, the total cost of the planning is remarkable which needs a big-budget to be implemented.

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