Scenario-Based Probabilistic Multi-Stage Optimization for Transmission Expansion Planning Incorporating Wind Generation Integration

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Abstract: Integrated transmission expansion planning (TEP) and generation expansion planning (GEP) with Wind Farms (WFs) is addressed in this paper. The optimal number of expanded lines, the optimal capacity of WFs installed capacity, and the optimal capacity of wind farms lines (WFLs) are determined through a new TEP optimization model. Furthermore, the optimum capacity additions including conventional generating units is obtained in the proposed model. The Benders decomposition approach is used for solving the optimization problem, including a master problem and two sub-problems with internal scenario analysis. In order to reduce the computational burden of the multi-year and multi-objective expansion planning problem, a multi-stage framework is presented in this paper. The uncertainties of wind speed and system demand along with contingency scenarios lead to a probabilistic optimization problem. Moreover, in the proposed model, the planning time horizon is divided into three predefined stages. This multi-stage approach is used to increase the proposed model accuracy in a power system with a high level of wind power penetration. Hence, in this paper a scenario-based probabilistic multi-stage model for transmission expansion planning is proposed, incorporating optimal WFs integration. It is recognized that high wind penetration increases the transmission expansion investment cost, but based on the reduction of the investment cost of conventional units, the total system cost will be smaller. This result emphasizes the main advantage of wind generating system over the conventional generating system. This planning methodology is applied to the modified IEEE 24-bus test system and simplified Iran 400-kV real system to show the feasibility of the proposed algorithm.

Keywords: Benders Decomposition; Multi-objective Optimization; Multi-stage Programming; Transmission Expansion Planning; Wind Farm Integration.

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Nomenclature

Indices:

d	Index of day
itr	Index of iteration
i	Index of network bus
j	Index of Wind Turbine Generator (WTG)
k	Index of conventional unit
l	Index of transmission line
m	Index of contingency
m_g	Index of generating unit contingency
m_l	Index of transmission line contingency
t	Index of year
s	Index of scenario
w	Index of WF

Sets:

I	Number of network buses
J_w	Number of WTGs in the w^{th} WF
K	Number of conventional units
L	Number of transmission lines
M	Number of contingencies
S	Number of scenarios
T	Planning time horizon
W	Number of WFs

Constants:

d_l	Length of l^{th} new transmission line
$D_{i,d}$	Peak demand of i^{th} bus at d^{th} day
$f_l^{\max}$	Maximum transfer capacity of l^{th} line
$f_l^{\min}$	Minimum transfer capacity of l^{th} line
$G_{k,d}$	Output power of k^{th} conventional unit at d^{th} day
$IEAR$	Interrupted Energy Assessment Rate
ICL	Annual investment cost of transmission line

ICL_w	Annual investment cost of w^{th} WFL
IC_w	Annual investment cost of w^{th} WF
$LS_i^{\max}$	Maximum allowed load shedding at i^{th} bus
$\bar{n}_{l,t}$	Maximum number of new lines can be added in parallel to the l^{th} line at t^{th} year
$P_k^{\min}$	Minimum output power of k^{th} conventional unit
$P_k^{\max}$	Maximum output power of k^{th} conventional unit
$P_{j,w}^{rated}$	Rated power of j^{th} WTG of w^{th} WF
$V_{j,w}^{rated}$	Rated speed of j^{th} WTG of w^{th} WF
V_{ci}	Cut-in speed of wind turbine
V_{co}	Cut-out speed of wind turbine
$W_{pen}^{\max}$	Maximum allowed wind penetration
$WLC_w^{\max}$	Maximum capacity of WFL of w^{th} WF
$WP_w^{\max}$	Maximum output power of w^{th} WF
WS_d	Wind peak speed at d^{th} day
Δt_{ts}	Time step of classified load duration curve

Variables:

C_w	Installed capacity of w^{th} WF
$f_{l,d}$	Power flow of l^{th} transmission line at d^{th} day
ICW	Total WFs investment cost
$ICLW$	Total WFLs investment cost
LMP_i	Local Marginal Price at i^{th} bus
$LS_{i,d}$	Load shedding of i^{th} bus at d^{th} day
n_l	Status of the l^{th} new transmission line [0,1]
W_{pen}	Wind penetration
WLC_w	WFL capacity of w^{th} WF
WPD_i	Wind power delivery at i^{th} bus

$WP_{j,w,d}$ Output power by j^{th} WTG of w^{th} WF at d^{th} day

$WP_{w,d}$ Wind generation of w^{th} WF at d^{th} day

1. Introduction

The expansion planning problem can be categorized into three general groups as, centralized, semi-centralized, and decentralized planning. Different modelling viewpoints are highly dependent on the economic issues and the competition in the long-term market. The expansion planning problem in traditional power systems has been highly investigated in the literature [1].

According to Ref. [2], a planning includes three parts as the value of the input data, data processing, and results. The input data are the load demand and the data of candidate generating units for the system expansion, the geographical and environmental information of the candidate locations, and the reserve requirements.

Data processing stage also comprises three parts as operating costs, investment costs and the budget needed for constructing units and energy transfer which eventually results in the optimal model. The above-mentioned planning generally encounters several problems due to the coordinated planning, the regional and local issues which lead to high computational burden, information deficiency regarding the coordinated planning and the solution infeasibility. Therefore, this type of planning has been less investigated [3]. The objective function of such planning model aimed at minimizing the total cost while disregarding the generating unit location. In other words, it assumes the generating units and local demands on a single bus. The objective function includes the installation cost and operating costs including the fixed costs and variable costs and also, the load curtailment costs.

The concept of the integrated planning has changed with the power systems restructuring. Ref. [4] presented a decentralized planning model in which the decision making structure is based on the centralized and decentralized model. In addition, the load demand uncertainty has been modelled using the Markov chain and the price uncertainty has been characterized as the function of the ratio of the load to the maximum available capacity over different periods.

Ref. [5] developed a market-oriented coordinated long-term planning problem. In this model, the participants in the energy market and transmission services propose their expansion plans to the system operator while optimizing their own objective function. In this respect, the system operator selects the most compromise plan with respect to the system stability, reliability, and security issues. This reference used the marginal capacity payment mechanism beside the price signal which is an effective tool to identify the weak points of the system for the investment. This framework sought to absorb investment for the reinforcement of the transmission system. However, the most important shortcoming of this type of planning framework is that increasing the number of participants in the market would equalize the price in the system and mitigate the profit of the participants [6].

A sustainable approach considering an integrated multi-period model for generation and transmission expansion planning problem has been addressed in [7] to consider the socio-environmental impacts of the power system, including greenhouse gas emissions, noise pollution and social expectations. In addition, a bi-level clustering framework based on objective-based scenario selection has been addressed in [8]. In the mentioned model, the variables of investment problem as well as the decision variables of power flow studies have been selected as the clustering variables. The bi-level expansion planning using K-means clustering approach has been addressed in [9] in which the investment decisions of wind farms have been considered as the clusters.

Ref. [10] developed a framework to optimize the profit of each generating unit considering the bilateral and multilateral contracts for trading electrical energy and also haggling issues which are the function of the price [11]. This is done by allocating a fraction of the supplied load of the load duration curve at base, off-peak and peak levels to the power producers [12].

A semi-competitive expansion planning model has been proposed in [13]. The players achieve the equilibrium in the profit after several rounds of profit maximization. A multi-period and multi-objective DG expansion planning based on game theory approach has been addressed in [14]. The proposed structure guarantees the commercial benefits for conventional generation units in the deregulated markets. A joint operation and planning structure for micro-grids expansion planning incorporating the effects of the energy storage devices in line with wind power generations has been addressed in [15].

Wind turbines were considered as distributed generation connected to the distribution network as micro-scale generation, but in recent years, these turbines in large scale are integrated to the transmission network as WFs [16]. So, in this case, the uncertainty of the wind generation is more important and should be considered in the various power system studies such as GEP and TEP studies [17].

Moreover, the low capacity factor (CF) of WFs rather than the conventional generation is an effective parameter in the network expansion planning. The capacity of WFLs is affected by the law CF of WFs [18]. The integrated TEP and GEP problem should be solved considering the optimal capacity of WFs and WFLs in the power system with high level of wind penetration.

In [19], a multi-period co-optimized GEP and TEP problem was discussed considering a proliferation of demand-side resource, uncertain renewable energy variations, and load fluctuations in the long term planning horizon. A bi-level evolutionary optimization for integrated TEP and GEP has been addressed in [20]. In this reference, the impact of optimizing the generation concerning capacity and location both to reduce the transmission investment and increasing the reliability of network have been discussed. In [21], an IGDT-based model for TEP considering was presented. In this paper, transmission lines arrangement, conventional generation capacity, WFs capacity, and WFLs rating were optimized simultaneously. In [22], the wind power uncertainties considered in TEP based on the chronological evaluation method. In this study the multi-period DC optimal power flow considering the generators ramping limits was applied.

The proposed model in this paper is formulated as a probabilistic and multi-Stage model. In recent years, the probabilistic method has been implemented in transmission and generation expansion planning studies [23] and [24]. Also, in [21] and [25] a multi-stage planning horizon approach considered for more accuracy in the result of the model.

The novel contribution of this paper is to present an improved multi-stage TEP model considering WFs and WFLs optimal integration. A scenario-based probabilistic optimization based on wind speed and system demand uncertainties along with contingency scenarios is presented. In this paper the following solution steps are completed simultaneously:

a) Determining WFs optimal installed capacities;

b) Determining optimal WFLs transfer rates;

c) Presenting an improved TEP model based on a probabilistic optimal power flow (OPF) and probabilistic DC-load-flow (DC-OPF).

To sum up, compared to other studies, in this paper simultaneous transmission expansion planning problem and wind generation integration problem, including wind farms and their lines optimum capacity, are solved. The structure of the paper is arranged as follows. In section 2, load and wind uncertainties, contingency scenario generation and reduction, WF costs, WFL capacity factor, and probabilistic model for solving TEP are reviewed. In section 3, the problem formulation and methodology are discussed. The proposed planning methodology is applied to the Modified IEEE 24-bus test system in section 4 and four different scenarios are implemented on the test system. The conclusions are given in section 5.

2. Background

2.1. Load and wind uncertainties model

The uncertain load, $\overline{D}$, is modelled using the time series method and Normal probability distribution function. Moreover, the uncertain predicted wind generation, $\overline{WP}$, is modelled using the time series method and Weibull distribution [21].

2.2. *Contingency* scenario generation and reduction

Since the failure of power system equipment is always probable, based on the transmission lines, generating units, and other important equipment failure rates, the probability of single and double contingencies are calculated, and related scenarios are generated. Because of large number of these scenarios, the scenario optimal reduction method based on time series is employed to moderate the number of the desired scenarios [26]. The selected scenarios will serve as inputs to the proposed model.

2.3. WF costs

By considering the maintenance and operation costs as parts of the investment cost, ICW and ICWL of WFs and WFLs should be minimized as follows:

$$Min\ ICW = \sum_{t=1}^{T}\sum_{w=1}^{W} IC_{w,t} \times C_{w,t} \tag{1}$$

$$Min\ ICLW = \sum_{t=1}^{T}\sum_{w=1}^{W} ICL_{w,t} \times WLC_{w,t} \times d_{w} \tag{2}$$

Consequently, to determine the optimal solution, the objective function of wind generation system is defined as the sum of WF and WFL investment costs. With regard to the WF uncertain output power, the optimal capacity of the WF lines (WFL) should be determined. Taking the WFL transfer rating equal to the WF installed capacity will cause an overestimate planning and extra system cost. On the other hand, decreasing the WFL capacity would reduce the delivered power of the WF to the system, and hence impose serious problems in the outcome of the WF and the system reliability. In this regard, the cost-reliability analysis is used to determine the optimal WFL capacity. Furthermore, the wind farm line capacity factor (WFL-CF) is used in case study and analysis, which is expressed based on the optimal WF and WFL capacity as follows. The WFL-CF is the average power delivered to the grid, divided by the average power generated. Let's take a 5 MW wind turbine. If it delivers power at an average of two megawatts to the grid, then its WFL-CF is 40%.

$$WFL-CF_{w} = \frac{Optimal\ capacity\ of\ w^{th}\ WFL}{Optimal\ capacity\ of\ w^{th}\ WF} \tag{3}$$

2.4. TEP model

Following to generation source expansion in network, the transmission lines ~~are~~ may be congested. In case of congestion of transmission network, new lines should be added to the power grid to maintain the desired security level. This transmission network expansion should satisfy both the economic and security issues of the system. From economical point of view, the minimization of new transmission lines investment cost is regarded as the main goal as follows:

$$Min \sum_{t=1}^{T}\sum_{l=1}^{L} n_{l,t} \times ICL_{l,t} \tag{4}$$

From security point of view, the minimization of the system load shedding in the normal and contingency conditions (n-1 and n-2) is implemented in the proposed model. The IEAR is considered equal to 5 $/kWh [22].

$$Min \ \mathrm{IEAR} \times \sum_{t=1}^{T}\sum_{i=1}^{I}\sum_{d=1}^{365} LS_{t,i,d} \tag{5}$$

2.5. Probabilistic model for solving TEP

One of the most common probabilistic methods for analysing scenario-based problems is the Monte Carlo simulation. This approach is computationally large demanding and time consuming [27]. In order to achieve an approximate yet accurate method that can decrease computational burden, appropriate probabilistic DC-OPF models are used as effective tools for probabilistic analysis [28] and [29]. Due to the fact that the transmission network is considered in this study, so power flows are calculated based on the branch reactances. Based on the high x / R ratio of the transmission network, the resistance of lines have been omitted and the values of the reactances have been considered based on the IEEE standard network data and the real Iran grid.

3. Problem Formulation

In the proposed model, a multi-objective optimization is used to consider economical and security issues in the integrated GEP and TEP problem incorporating optimal WFs integration. To solve this multi-objective optimization problem, an appropriate and accurate formulation should be presented.

Benders decomposition is applied to bond the master problem and the sub-problems [30–32]. The master problem considers the total WF and WFL investment cost, the investment cost of new added lines, and the system load shedding cost in the power system normal state with no contingencies.

Congestion cost minimization is regarded as the first sub-problem; whereas, the second sub-problem deals with the system load shedding in the contingency conditions.

3.1. *Master Problem*

The objective function of the master problem is defined as the total wind and transmission cost (TWTC) which is described in (6). TWTC includes four terms:

- WF investment cost (ICW) (according to equation 1)

-WFL investment cost (ICLW) (according to equation 2)

- Transmission expansion cost (according to equation 4)

- Load shedding cost in contingencies scenarios (according to equation 5)

Min

$$TWTC = \underbrace{\sum_{t=1}^{T}\sum_{w=1}^{W} IC_{w,t} \times C_{w,t}}_{WF\text{ investment cost}} + \underbrace{\sum_{t=1}^{T}\sum_{w=1}^{W} ICL_{w,t} \times WLC_{w,t} \times d_{w}}_{WFL\text{ investment cost}} \\ + \underbrace{\sum_{t=1}^{T}\sum_{l=1}^{L} n_{l,t} \times ICL_{l,t}}_{TEP\text{ cost}} + \underbrace{\mathrm{IEAR} \times \sum_{t=1}^{T}\sum_{i=1}^{I}\sum_{d=1}^{365} LS_{t,i,d}}_{Load\ shedding\text{ cost}} \tag{6}$$

The wind generation and power system constraints of this optimization problem are given in (7)-(13).

- Load Balance based on DCLF:

Power balance equation is one of the most important constraints in both operation and planning problem. In the presence of wind power generation, the operation may be faced with load shedding. The DC load flow formulation is derived from a reasonable linear approximation between the real bus injected powers and phase angle of bus voltages. To reduce the load shedding costs, this issue should be taken into consideration. Moreover, the load shedding due to the contingent events in the planning stage should be minimized, specifically for n-1 and n-2 contingencies. The generalized load and generation balance equation considering the total wind and conventional generation with the total demand considering load shedding is as follows:

$$\sum_{i=1}^{I} P_{i,d} + \sum_{w=1}^{W} WP_{w,d} - \sum_{i=1}^{I} \overline{D}_{i,d} - \sum_{i=1}^{I} LS_{i,d} = \sum_{l=1}^{L} f_{l,d} \tag{7}$$

The load balance equation considers the transmission network and the net power injected to each bus.

- Transmission line constraint:

The transmitted power through existing and new transmission lines should be less than the maximum loading of the corresponding transmission line. This constraint is valid for both normal and contingent events in the planning study stage. However, in the operating situation, the short-term overloads would be allowed, in the planning stage, the overloading of transmission lines are not allowed. Based on this constraint, the power flow rate of each corridor should not be more than total existing and new added transmission lines capacity.

$$f_l \le (n_l^0 + n_l).f_l^{\max} \tag{8}$$

- Conventional unit generation constraint:

The conventional power generating units have a predefined operating region. In this paper, the DC-OPF problem considers the permissible operating regions of the conventional generating units. Power production limit of the thermal plants is stated as:

$$P_k^{\min} \le G_k \le P_k^{\max} \tag{9}$$

- Load curtailment:

It is evident that for some contingent events, there is no more option for the operator to serve the demands without load shedding. The amount of load shedding can be modelled as a positive slack variable in the mathematical problem formulation to guarantee the load balance equation. However, the load shedding cost should be considered as much as high to be avoided for normal conditions. It is noteworthy that the amount of load shedding for n-1 and n-2 contingency can be used for the reliability calculations like expected energy not served, EENS. Theoretically, the maximum load shedding level is the maximum demanded load at each bus. Equation (10) states the load shedding as a positive decision variable in this study.

$$0 \le LS_i \le LS_i^{\max} \tag{10}$$

- Number of new lines:

The transmission capacity addition is limited due to the physical and economical points of view. Hence, for a given corridor, the maximum number of new transmission lines can be added is limited. The mathematical representation of this constraint is as follows:

$$0 \le n_{l,t} \le \overline{n}_{l,t} \tag{11}$$

- Wind penetration constraint:

Similar to the new transmission lines, there are some techno-economical constraints for the wind power capacity additions. The maximum permissible wind capacity addition is addressed in (12).

$$0 \le W_{pen} \le W_{pen}^{\max} \tag{12}$$

- WF generation constraint:

  Power production limits of wind farms are also limited. Since the wind power generation is volatile and intermittent due to the wind speed nature, the extracted power from each wind turbine needs to be modelled accordingly. Equation (13) states that wind power generation is limited.

$$0 \le \overline{WP} \le C_w \tag{13}$$

Furthermore, from the system security point of view, constraints (14)-(18) should be satisfied in the m^{th} (including m_l^{th} and m_g^{th}) contingency condition:

- Load Balance based on DCLF:

$$\sum_{i=1}^{I} P_{i,d}^{m} + \sum_{w=1}^{W} WP_{w,d} - \sum_{i=1}^{I} \overline{D}_{i,d} - \sum_{i=1}^{I} LS_{i,d}^{m} = \sum_{l=1}^{L} f_{l,d}^{m} \tag{14}$$

- Transmission line constraint:

$$f_l^m \le (n_l^0 + n_l - 1).f_l^{\max}, \quad l = m_l \tag{15}$$

$$f_l^m \le (n_l^0 + n_l).f_l^{\max}, \quad l \ne m_l \tag{16}$$

- Conventional unit generation constraint:

$$P_k^{\min} \le G_k^m \le P_k^{\max} \qquad (17)$$

- Load curtailment:

$$0 \le LS_i^m \le LS_i^{\max} \qquad (\cancel{5}18)$$

3.2. Multi-stage planning

In this study, the multi-stage planning is used. Based on the definition of multi-stage planning, in the proposed model, the planning time horizon is divided into specified stages. As indicated in figure 1, the initial data for the first year of each stage is obtained from the result of the previous stage [21]. The planning time horizon is assumed to be 9 years divided into three 3-year stages.

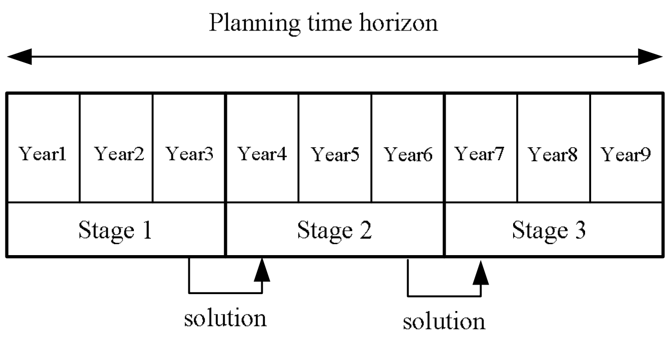

Fig. 1. *Proposed multi-stage approach*

3.3. First sub-problem

In order to optimize the TEP problem in the planning time horizon, the transmission congestion cost is calculated based on the transmission line power flows for each stage without the lines capacity constraint in (8). In the sub-problem, if according to generation expansion in the network, transmission lines are congested, an appropriate cut is generated and sent to the master problem to add the new lines to the network and check the congestion accordingly.

This annual congestion cost is obtained by using the marginal cost of network buses considering daily peak loads as follows:

$$Min \quad Cost_{cong} = \sum_{l=1}^{L} \sum_{d=1}^{365} f_{d,l} (LMP_{l,d,s} - LMP_{l,d,r}) \tag{19}$$

where, $LMP_{l,d,s}$ and $LMP_{l,d,r}$, the Lagrange multipliers of the probabilistic DC-OPF problem [33], are the bus marginal cost of two sides of each line.

Moreover, based on the uncertain parameters in the proposed probabilistic model, the PDF of annual congestion cost is extracted. So, the first sub-problem can be written as the average of this congestion cost:

$$\begin{aligned} &Min \\ &Average\ (Cost_{cong}) \\ &s.t. \\ &Constraints\ (7) - (13)\ \ excluding\ (8) \end{aligned} \tag{20}$$

The constraints of this sub-problem are the same as the master problem constraints excluding the line flow limits. The relaxation of line flow constraints in this optimization problem allows the transmission line flows to exceed the nominal transfer rates. These outrages indicate that the obtained solution from the master problem must be changed. According to this sub-problem, the master problem solution is evaluated considering the minimized congestion cost. If this sub-problem solution differs from the master problem solution, then appropriate Benders cuts based on the outraged power flows will be generated and sent to the master problem, iteratively.

3.4. Second sub-problem

In the master problem and first sub-problem of the proposed model, the economical objective functions considering the system constraints in the normal and contingency conditions are investigated. Therefore, it is necessary to enter a security objective function to the model in the second sub-problem. The total cost of system load shedding in the contingency scenarios, LS_{cont}, should be minimized:

$$\begin{aligned} &Min \\ &LS_{cont} = IEAR \times \sum_{m=1}^{M} \sum_{i=1}^{I} \sum_{d=1}^{365} LS_{m,i,d} \\ &s.t. \\ &Constraints\ (7) - (13) \end{aligned} \tag{21}$$

In this sub-problem, if the load curtailment takes places in the contingency conditions, an appropriate cut is generated and sent to the master problem to add the new lines to the network and check the network expansion and congestion accordingly. This sub-problem conveys the model solution to the optimal solution by considering the minimum system curtailed load. If this minimization problem generates different solution from the master problem and first sub-problem solution, subsequently, proper cuts from this sub-problem will be created.

3.5. Methodology

Indeed, to achieve the optimal solution, the presented model has been formulated as MILP problem and the Benders cuts have been used to decrease the convergence time. Besides, the equilibrium of generation and consumption has been adjusted using load curtailment. The first sub-problem cut is related to congestion of transmission network and regarded as feasibility cut, and the second cut is about optimizing the load curtailment and defined as optimality cut. To solve this problem, GAMS software has been used, which Stopping criteria and convergence condition have been mentioned in the section 4.

Initially, for each stage, uncertain parameters including the annual wind speed in the desired wind sites and the system demand are forecasted using time series method. For each uncertain input variable, an appropriate PDF is fitted using the forecasted data. Moreover, the contingency scenarios generated by the scenario reduction approach are entered to the solving algorithm [30]. Afterward, a DC-OPF problem without wind generation integration is solved. The load duration curve is used [25].

$$\Delta t_{ts} = round\,(2^{0.5(1+ts)}) \tag{22}$$

The flowchart of the proposed methodology, given in Fig. 2, is explained as follows:

a. Initializing section: in this part, the scenarios are generated and reduced, the proposed uncertain inputs are introduced, and the initial DC-OPF is performed.

b. Master problem: after the initialization, the main probabilistic optimization problem is solved (minimizing TWTC). Consequently, the optimal solution (WFs and WFLs capacities and new added lines) are obtained and sent to the first sub-problem.

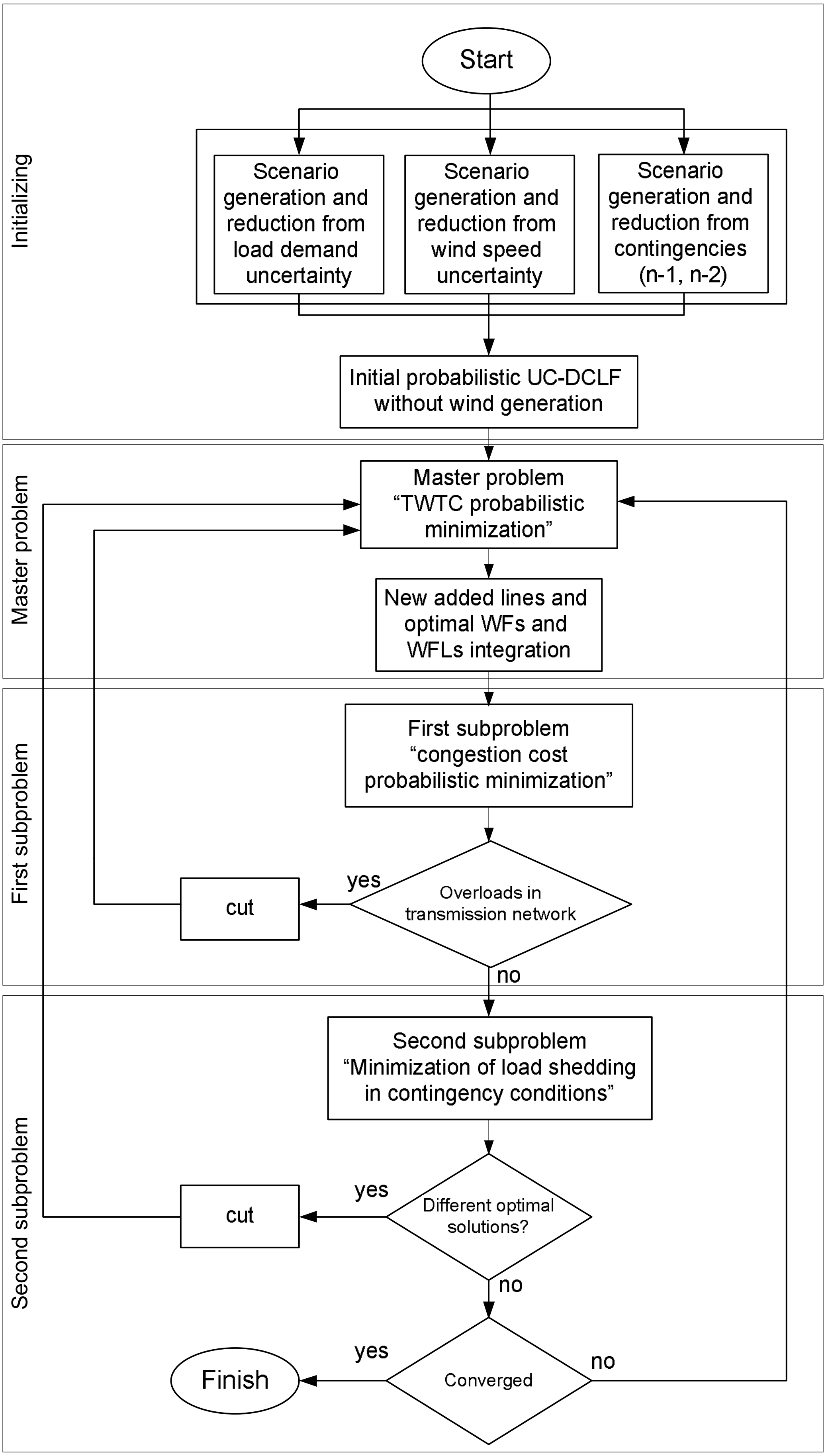

Fig. 2. *Flowchart of proposed methodology for each* stage

c. First sub-problem: subsequent to the master problem solution, this sub-problem is solved (minimizing average congestion cost). According to the solution of this sub-problem, Benders cuts based on the lines overloading will be sent to the master problem if needed; otherwise the solving process will go to the second sub-problem. The first sub-problem cut will be generated based on the lines overloading and will be sent to the master problem if needed. So, this cut is regarded as feasibility cut because return the impossibility of the obtained transmission expansion plan to the master problem. In the first cut, if due to the addition of generation in the grid, network lines are congested, a physical cut from the first sub-problem is sent to the master problem to add the new lines to the network and congestion is checked again.

d. Second sub-problem: after solving the master problem and first sub-problem, the algorithm will proceed to the second sub-problem (minimizing system load shedding). Similar to the first sub-problem, Benders cuts based on the load shedding will be sent to the master problem if needed. The second sub-problem cut will be generated based on the optimal load shedding in contingencies and will be sent to the master problem if needed. Therefore, this cut is defined as optimality cut as return the optimal value of load shedding in contingencies to the master problem. In the second cut, if the load shedding occurs in the scenarios of contingencies, the optimal values of load curtailments are entered into the master problem as optimal values based on the cost of unsupplied load penalty to check the network expansion and congested lines again.

4. Case Study

In this section, the proposed TEP scenario based model is applied to the modified IEEE 24-bus test system and simplified Iran 400 kV real system to assess the validity of the proposed method. In these cases, the piecewise transmission line cost model considered is given by [22].

$$ICL = \begin{cases} 18(\$/\mathrm{MW/km/yr}), & \text{if } \mathrm{f_l} \le 200\,\mathrm{MW} \\ 21(\$/\mathrm{MW/km/yr}), & \text{if } 200\,\mathrm{MW} \le \mathrm{f_l} \le 400\,\mathrm{MW} \\ 30(\$/\mathrm{MW/km/yr}), & \text{if } 400\,\mathrm{MW} \le \mathrm{f_l} \end{cases} \tag{23}$$

Moreover, in order to appropriate and comprehensive analysis, four different scenarios have been considered for wind penetration at each stage as follows:

- Scenario 1: TEP and GEP with no wind generation integration,
- Scenario 2: TEP and GEP with maximum of 5% wind penetration at each stage,
- Scenario 3: TEP and GEP with maximum of 15% wind penetration at each stage,
- Scenario 4: TEP and GEP with maximum of 25% wind penetration at each stage.

In Scenario 1, the system demand is supplied by means of conventional generating units completely. In Scenario 2, the allowable wind penetration in the system is limited to 5% in each stage of the planning horizon. This penetration level has been considered 15% and 25% for Scenarios 3 and 4, respectively. The annual load growth rate and discount rate are considered to be 8% and 10%, respectively.

The optimization problem is solved employing the mixed-integer linear programming (MILP) module of the GAMS/CPLEX optimization package. In fact, to guarantee the optimal solution, the model has been presented as MILP model and the Benders cuts have been used to reduce the computational load. Moreover, considering that the balance of generation and demand has been corrected with the load shedding, the optimization problem will definitely reach the optimal solution and this solution will be achieved when no load curtailment appears on the network. Furthermore, according to the duality theory, the main problem and its dual are interdependent in this case, and the problem is converged exactly.

There are several commonly used gap functions that can be used in convergence test. The first one is based on the difference of the candidate solution and the base solution. Also, the condition of route choice can be checked directly. There are two additional important values we need to introduce to complete our description of branch-and-bound approach. First observe that, once we have an incumbent, the objective value for this incumbent, assuming the original MIP is a minimization problem, is a valid upper bound on the optimal solution of the given MIP. That is, we know that we will never have to accept an integer solution of value higher than this value. Somewhat less obvious is that, at any time during the branch-and-bound search we also have a valid lower bound, sometimes call the best bound. This bound is obtained by taking the minimum of the optimal objective values of all of the current leaf nodes. Finally, the difference between the current upper and lower bounds is known as the gap. While the gap is zero, solution has been reached to the optimal answer. In this study, GAMS software has been used and stopping criteria and convergence condition for this iterative process is defined based on the TWTC, as follows. In this study, ε is considered 0.001 [24].

$$\frac{TWTC_{itr} - TWTC_{itr-1}}{TWTC_{itr}} \le \varepsilon \tag{23}$$

4.1. Modified IEEE 24-bus test system

The modified IEEE 24-bus test system is shown in figure 3. The total generation capacity of this system is 3105 MW from 26 units and the total peak demand is 2850 MW [34]. Four wind sites in this network are considered for wind generation integration. Also, the maximum capability for installing WF for each wind site is 500MW. The daily real wind data in Iran is taken into account [35].

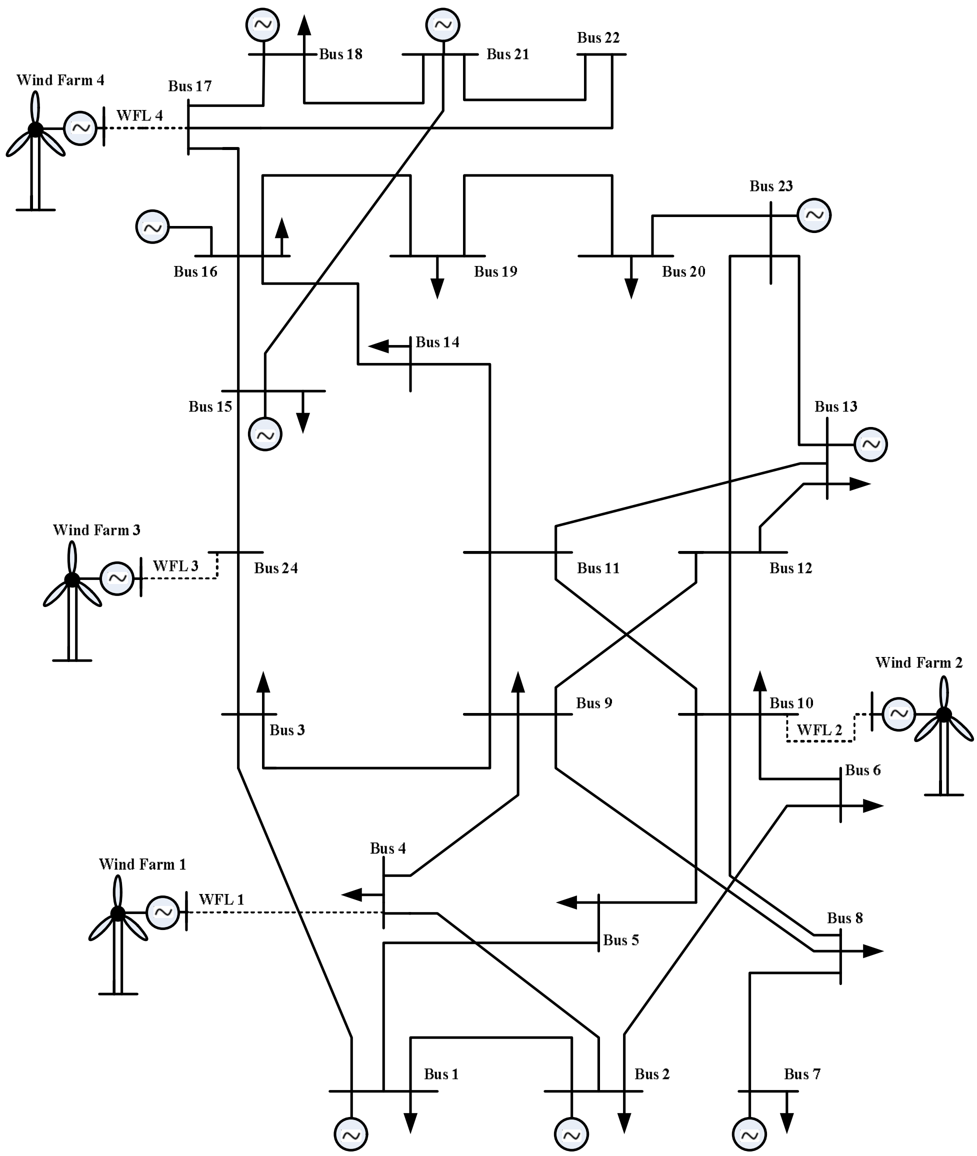

***Fig. 3.** Modified IEEE 24-bus test system*

The simulations result including the optimal WFs installed capacity, optimal WFLs transfer rate, wind penetration, installed capacities of conventional units, new added lines to the power grid, and TWTC for each stage of all scenarios are summarized in Table 1. In this paper, wind penetration at each stage, i.e., W_{pen}, is calculated based on the total WFs capacities only at that stage, whereas the overall wind penetration at each stage is obtained from the sum of WFs capacities at that stage and the previous stages.

Table 1 The optimal solution for each stage of different scenarios for IEEE 24-bus test system

Stage	WFs optimum installed capacity (MW)				WFLs optimum capacity (MW)				W_{pen} (%) at each stage	Conv. units installed capacity (MW)	Number of Congested lines		New added lines	TWTC (M$)
	WF1	WF2	WF3	WF4	WFL1	WFL2	WFL3	WFL4			before TEP	after TEP		
Scenario 1: Wind Penetration 0%														
stage 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	688.4	3	-	1-5, 2-7, 4-15, 7-8, 11-14, 20-22	36
stage 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1255.6	3	-	1-5, 2-7, 11-14, 15-16	23.2
stage 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2359.6	4	-	1-5, 3-24, 5-9	16.3
Scenario 2: Wind Penetration 5%														
stage 1	51.3	66.5	31.5	65.2	38.1	57.7	27.1	44.7	5.0	620.7	4	-	1-5, 2-7, 3-24, 11-14, 15-16, 20-22	40.8
stage 2	47.1	76.5	39.1	66.6	36.3	65.2	32.2	49.1	4.3	1187.2	4	-	1-5, 2-7, 11-12, 15-24	24.4
stage 3	41.7	63.1	27.2	56.2	30.4	59.5	23.9	41.2	3.5	2234.2	5	-	1-5, 5-9	11.7
Scenario 3: Wind Penetration 15%														
stage 1	121.1	190.4	92.5	207.2	94.2	174.5	85.1	145.1	15.0	496.9	6	-	1-5, 2-7,3-24, 7-8, 10-20,15-16	46.3
stage 2	86.5	121.4	86.6	168.7	65.6	109.1	68.3	117.2	10.9	1114.0	6	-	1-5, 2-7, 3-11, 5-9, 11-24	33.9
stage 3	64.7	125.5	82.1	179.8	48.1	104.1	66.7	134.1	8.8	2031.0	6	-	2-7, 3-24	17.5
Scenario 4: Wind Penetration 25%														
stage 1	195.1	278.4	162.5	314.0	146.3	228.3	130.0	226.1	25.0	162.9	6	-	1-5, 2-7,3-24, 7-8, 10-20,15-16	55.0
stage 2	145.2	201.4	110.6	225.3	108.9	165.1	88.5	162.2	17.2	864.5	7	-	1-5, 3-11, 5-9, 11-24,15-16	40.6
stage 3	161.4	242.2	104.6	179.5	121.1	198.6	83.7	129.2	15.9	1199.6	9	-	1-5, 2-7, 3-24	29.7

As shown in table 1, by adding new lines to the network, the loading of congested lines return to the normal condition (less than 100%) and there is no congested line in the network. In this simulation, TWTC contains the WFs and WFLs investment costs, TEP investment cost, congestion cost, and load shedding cost. In order to compare the results of different scenarios as well as to analyze the effects of wind penetration in the power system, the investment cost of conventional units (ICCU) should be considered in the system total cost additionally; since by varying the wind generation level, the conventional units generating level and consequently their investment costs change as well.

Hence, the variation of ICCU can be regarded as an appropriate economic criterion for comparing the advantages and disadvantages of wind and conventional generations. The installed capacity of conventional units in the planning period is determined according to the optimal WFs installed capacities and wind sites CFs at the peak load level.

It can be seen in Table 1 that if the wind penetration of the system is enhanced, the optimal WFs capacity and consequently WFLs capacity will increase. Using the results of this table, it can be shown that the WFL-CFs in this system vary in the range of 70% to 87% depending on the inherent characteristics of wind sites and how they are connected to the transmission network (i.e., the WFLs transfer ratings). The WFL-CF of each WF for each stage in the different scenarios is illustrated in the bar diagram of Fig. 4.

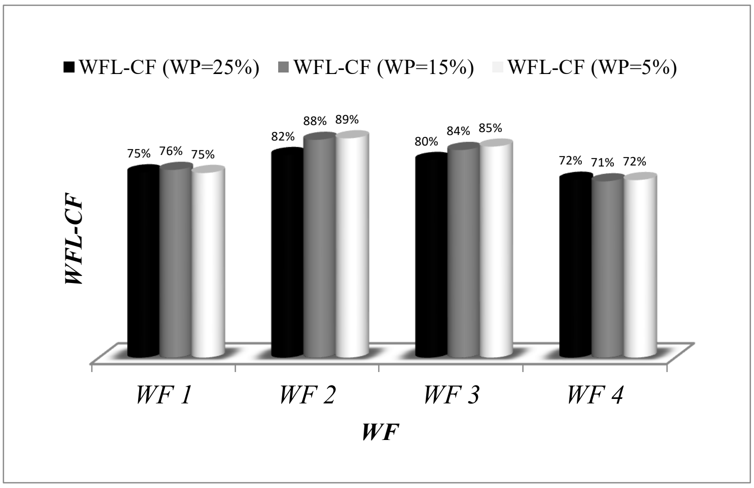

Fig. 4. *WFL-CF of each WF in different scenarios for IEEE 24-bus test system*

In Table 2, the total system cost (TSC) consisting of TWTC and ICCU is given separately for each stage of different scenarios. The ICCU for all types of conventional units is assumed to be 200 $/kW/year generally [36].

Table 2 The system costs for each stage of different scenarios for IEEE 24-bus test system

Stage	Line investment cost	Wind system investment cost	Congestion cost	Load shedding cost	Conv. units investment cost	Total system cost
	LIC(M$)	WSIC(M$)	CC(M$)	LSC(M$)	ICCU(M$)	TSC(M$)
Scenario 1: Wind Penetration 0%						
stage 1	33.5	0	1.8	0.7	137.7	173.7
stage 2	20.4	0	2.1	0.7	251.1	274.3
stage 3	13.4	0	2.3	0.6	471.9	488.2
Total	67.3	0	6.2	2.1	860.7	936.3
Scenario 2: Wind Penetration 5%						
stage 1	36.2	2.4	1.4	0.8	124.1	164.9
stage 2	19.8	2.4	1.4	0.8	237.5	261.8
stage 3	7.8	2.0	1.2	0.7	446.9	458.5
Total	63.8	6.8	3.9	2.3	808.5	885.2
Scenario 3: Wind Penetration 15%						
stage 1	33.6	6.6	3.9	2.2	99.4	145.7
stage 2	24.4	4.9	2.9	1.7	222.8	256.7
stage 3	8.3	4.8	2.8	1.6	406.2	423.7
Total	66.3	16.3	9.5	5.5	728.4	826.0
Scenario 4: Wind Penetration 25%						
stage 1	35.5	9.4	6.4	3.7	32.6	87.5
stage 2	26.1	6.9	4.8	2.8	172.9	213.5
stage 3	12.3	8.4	5.7	3.3	239.9	269.7
Total	73.9	24.7	16.9	9.8	445.4	570.7

As the result of lower total investment and operation cost of wind resources compared to the conventional units, the reduction of conventional installed capacities are causing decrease in the TSC. The pattern of the TSC variation (including ICCU) with respect to the wind penetration level of each scenario is demonstrated in Fig. 5.

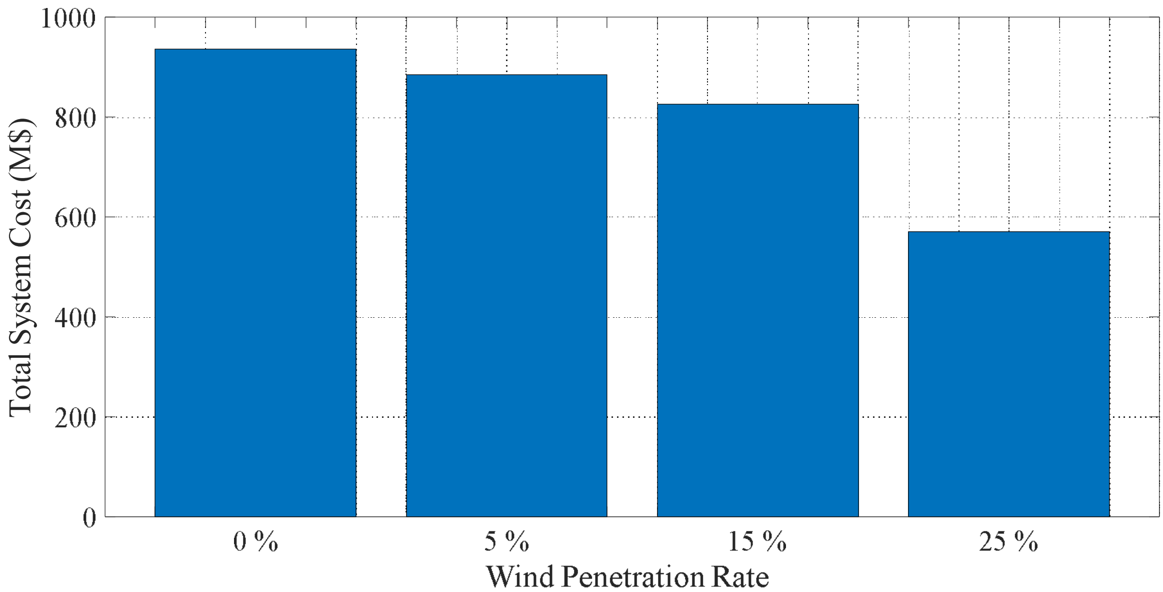

Fig. 5. *Pattern of changing TSC for IEEE 24-bus test system*

The optimal obtained transmission expansion plans in different scenarios reveal that enhancement of wind penetration level in the system needs more number of new lines to be added to the transmission network in the planning period in order to guarantee the required level of system security due to the intermittent and uncertain nature of wind generation. So, it can be said that high wind penetration increases the transmission expansion investment cost, but based on the reduction of the ICCU, as the conventional units' investment cost reduces more, the total system cost will be smaller. This result emphasizes the main advantage of wind generating system over the conventional generating system.

4.2. Simplified Iran 400 kV real system

In this section, the proposed scenario-based TEP model is applied to the simplified Iran 400 kV system shown in Figure 6 to assess the validity of the proposed method. This system has 52 buses, 101 lines, the total generation capacity of 40GW from 28 units, and total demand of 33GW in peak hours [37]. The state-owned TAVANIR Company is the owner and the planner of the transmission network.

Iran Grid Management Company (IGMC) which was established in 2003 serves as the network Independent System Operator. Four actual wind sites namely Manjil, Binaloud, Lootak, and Takestan have been considered, and it has been assumed that there are wind generation expansion feasibilities in these sites. In addition, it has also been assumed that new transmission lines can be added in all the existing and new corridors shown by dashed lines in Figure 6.

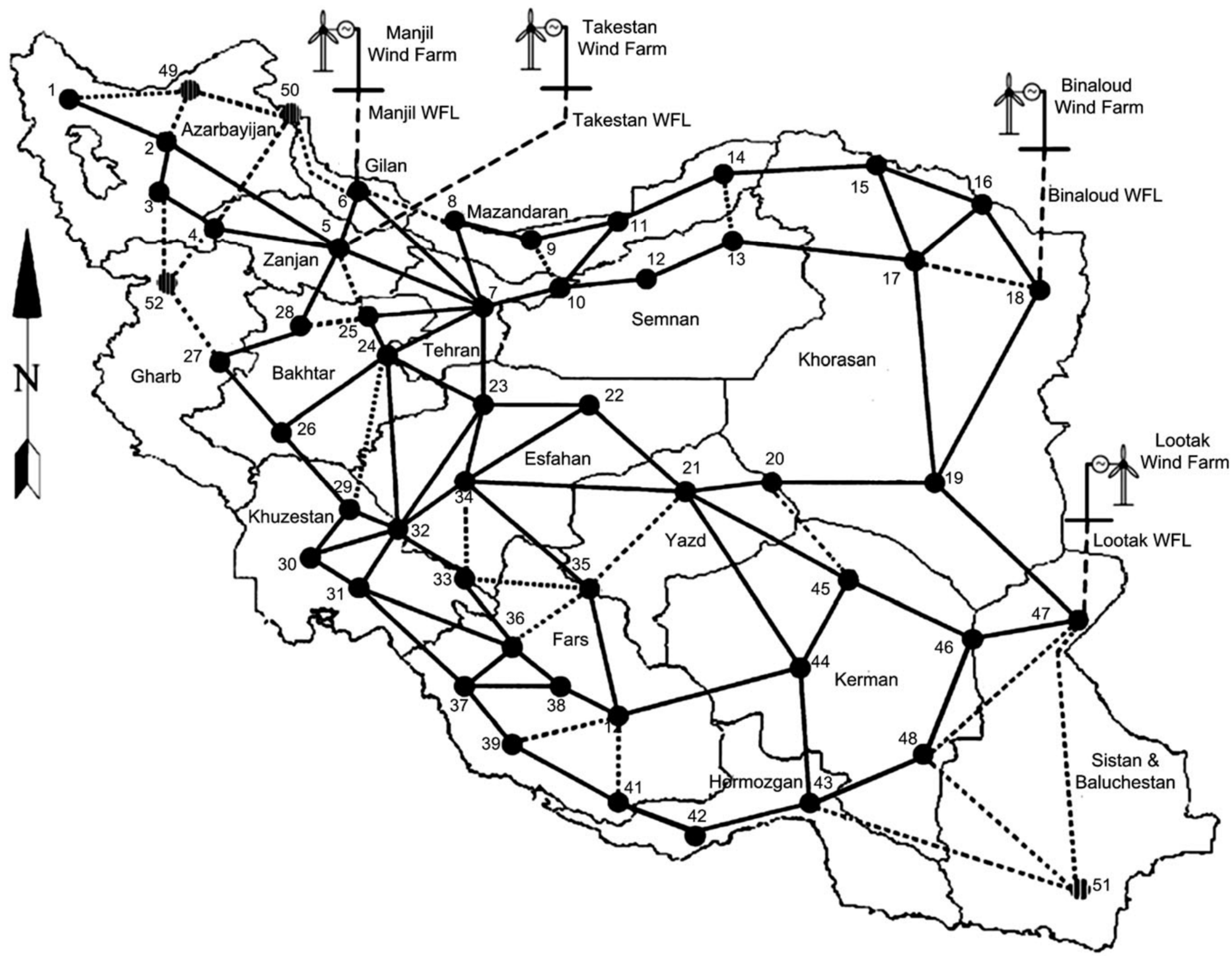

Fig. 6. Simplified Iran 400 kV real system

In this study, the capacity of each wind site has been predefined based on the system wind penetration constraint. The wind sites generation capacity at each stage and the distance between each WF and its related network bus are given in [21]. Real wind data in Iran are used for the considered wind sites [33].

The simulations result including the optimal WFs installed capacity, optimal WFLs transfer rate, wind penetration, installed capacities of conventional units, new added lines to the power grid, and TWTC for each stage of all scenarios are summarized in Table 3. Considering the abovementioned description, wind penetration at each stage, i.e., W_{pen}, and overall wind penetration at each stage is indicated.

Table 3 The optimal solution for each stage of different scenarios for simplified Iran 400 kV system

Stage	WFs optimum installed capacity (MW)				WFLs optimum capacity (MW)				W_{pen} (%) at each stage	Conv. units installed capacity (MW)	Number of Congested lines		New added lines	TWTC (M$)
	WF1	WF2	WF3	WF4	WFL1	WFL2	WFL3	WFL4			before TEP	after TEP		
Scenario 1: Wind Penetration 0%														
stage 1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	13688.0	4	-	6–8	147.6
stage 2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	14783.0	4	-	13–14	91.6
stage 3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	15965.7	4	-	-	66.0
Scenario 2: Wind Penetration 5%														
stage 1	289.8	195.2	99.4	100.0	237.6	179.6	78.5	86.0	5.0	13687.3	5	-	6–8	167.3
stage 2	295.3	195.6	98.2	97.2	265.8	162.3	81.5	78.7	4.9	14096.7	5	-	13–14	96.4
stage 3	287.3	189.7	94.3	96.7	227.0	159.3	87.7	80.3	4.4	15297.7	7	-	13-50	47.4
Scenario 3: Wind Penetration 15%														
stage 1	811.4	478.2	248.5	250.0	714.1	435.2	196.3	215.0	15.0	11899.8	4	-	6–8	189.8
stage 2	745.2	389.1	203.7	226.9	678.1	307.4	169.1	190.6	11.8	13218.1	6	-	13-14, 13-50	133.9
stage 3	712.3	365.8	210.5	217.2	577.0	332.9	183.1	197.7	10.4	14459.9	7	-	47-48	70.9
Scenario 4: Wind Penetration 25%														
stage 1	1241.5	779.5	355.4	362.5	1055.3	631.4	319.8	286.4	25.0	10949.1	7	-	6–8	225.5
stage 2	1089.3	742.5	365.1	321.7	860.5	608.9	328.6	241.3	20.5	12264.4	7	-	13-14, 13-50, 17-18	160.4
stage 3	987.1	713.5	312.2	294.5	839.0	542.3	249.8	238.5	16.9	13658.4	8	-	25-28, 47-48	120.3

As investigated in this table, since new lines are added to the grid based on TEP, loading of congested lines come back to the acceptable region [38]. In this simulation. In order to compare the results of different scenarios as well as to analyze the effects of wind penetration in the power system, the investment cost of conventional units (ICCU) should be considered in the system total cost additionally; since by varying the wind generation level, the conventional units generating level and consequently their investment costs change as well.

It is indicated in Table 3 that if the wind penetration of the system is enhanced, the optimal WFs capacity and consequently WFLs capacity will increase. Using the results of this table, it can be shown that the WFL-CFs in this system vary in the range of 78% to 87%. The WFL-CF of each WF for each stage in the different scenarios is illustrated in the bar diagram of Fig. 7.

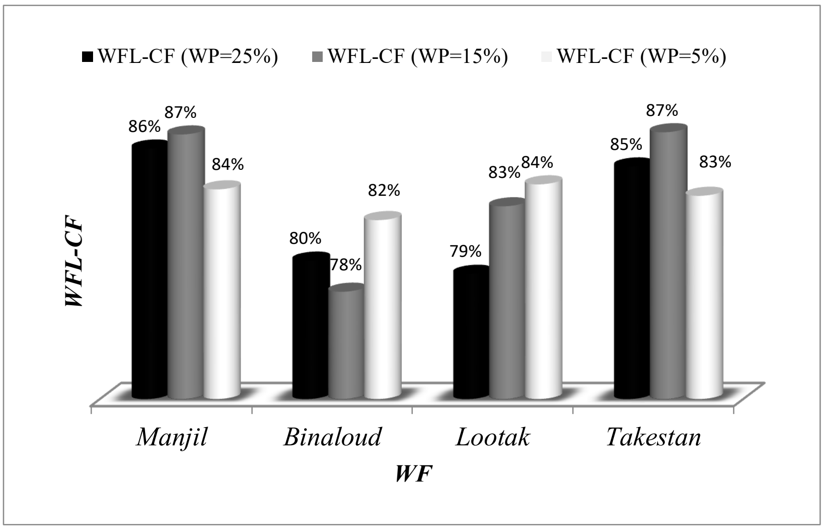

Fig. 7. *WFL-CF of each WF in different scenarios for simplified Iran 400 kV system*

The WFL-CF of Manjil and Takestan is higher than other WFs because the transmission network in the vicinity of these WFs is very tight and also these WFs are closer to load centers compared to Binaloud and Lootak WFs. Therefore, the energy produced by Manjil and Takestan farm is not subject to curtailment due to transmission system congestion as much as other sites are and it can easily be delivered to the network. In other words, transmission constraints limit the generation capability of Binaloud and Lootak sites.

In Table 4, the total system cost (TSC) consisting of TWTC and ICCU is given separately for each stage of different scenarios. Similar to IEEE test system, the ICCU for all types of conventional units is assumed to be 200 $/kW/year [34].

Table 4 The system costs for each stage of different scenarios for simplified Iran 400 kV system

Stage	Line investment cost	Wind system investment cost	Congestion cost	Load shedding cost	Conv. units investment cost	Total system cost
	LIC(M$)	WSIC(M$)	CC(M$)	LSC(M$)	ICCU(M$)	TSC(M$)
Scenario 1: Wind Penetration 0%						
stage 1	137.4	0.0	7.3	2.9	564.6	712.1
stage 2	83.6	0.0	8.5	2.9	1029.5	1124.5
stage 3	54.9	0.0	9.3	2.5	1934.8	2001.5
Total	275.9	0.0	25.1	8.6	3528.9	3838.5
Scenario 2: Wind Penetration 5%						
stage 1	147.0	9.7	5.5	3.4	492.7	658.2
stage 2	80.4	9.7	5.5	3.4	942.9	1041.8
stage 3	31.7	8.1	4.7	2.9	1774.2	1821.6
Total	259.0	27.4	15.4	9.7	3209.7	3521.2
Scenario 3: Wind Penetration 15%						
stage 1	130.7	27.2	15.8	8.6	399.6	581.8
stage 2	94.9	20.2	11.7	6.6	895.7	1029.1
stage 3	32.3	19.8	11.3	6.2	1632.9	1702.6
Total	257.9	67.2	38.5	21.4	2928.2	3313.1
Scenario 4: Wind Penetration 25%						
stage 1	140.6	38.4	25.9	15.5	135.3	355.7
stage 2	103.4	28.2	19.4	11.8	717.5	880.2
stage 3	48.7	34.3	23.1	13.9	995.6	1115.5
Total	292.6	100.8	68.4	41.2	1848.4	2351.4

As the result of lower total investment and operation cost of wind resources compared to the conventional units, the reduction of conventional installed capacities are causing decrease in the TSC. The pattern of the TSC variation (including ICCU) with respect to wind penetration level of each scenario is demonstrated in Fig. 8.

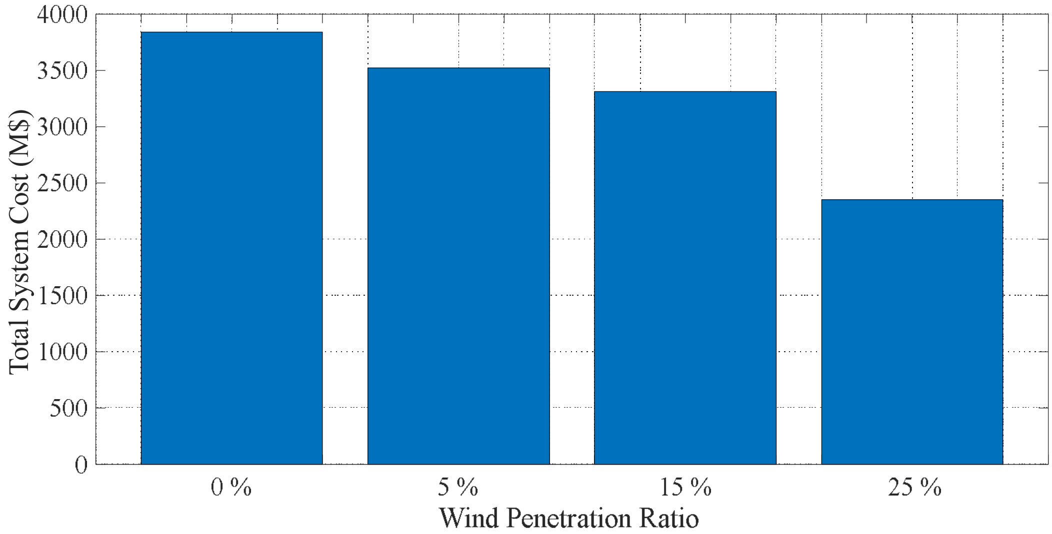

Fig. 8. *Pattern of changing TSC for simplified Iran 400 kV system*

The optimal obtained transmission expansion plans in different scenarios reveal that enhancement of wind penetration level in the system needs more number of new lines to be added to the transmission network in the planning period in order to guarantee the required level of system security due to the intermittent and uncertain nature of wind generation [39]. So, it can be said that high wind penetration increases the transmission expansion investment cost, but based on the reduction of the ICCU, as the conventional units' investment cost reduces more, the total system cost will be smaller. This result emphasizes the main advantage of wind generating system over the conventional generating system.

5. Conclusion

This paper presents a comprehensive TEP and GEP model incorporating optimal wind generation integration to power systems. In comparison to the existing studies, in this paper a novel model is presented to solve simultaneous transmission expansion planning problem and wind generation integration problem, including wind farms and their lines optimum capacity. Considering the wind speed and load demand uncertainties, the *n-1* and *n-2* contingencies are handled through a scenario-based probabilistic optimization problem. The Benders decomposition approach is used to bond a master problem and two sub-problems. This multi-stage approach is used to increase the accuracy of the proposed model. In the proposed multi-stage model, the economic and security aspects of the system are involved in the objective functions. Based on the model outputs, the newly added lines to the network and the optimal WFs and WFLs capacities are determined. The WFL-CF of WFs are adjacent to the transmission network is higher than other WFs because these WFs are closer to load centers. Therefore, output power of these WFs is not subject to restriction owning to transmission system congestion. According to the obtained results, with the increase of the wind penetration in the system (5% to 25%), because of the probabilistic and uncertain nature of wind generation, the investment cost of TEP increases (about 13%), but due to the reduction of the conventional units' investment cost (about 43%), the total system cost decreases (around 34%). Hence, based on the TSCs of scenario 1 (Wind Penetration =0) and scenario 4 (Wind Penetration =25%), this paper has successfully demonstrated that an appropriate expansion of network and generation in association with optimal WFs and WFLs expansion, along with the system security requirements, imposed a lower TSC (around 40%) compared to a conventional generation expansion problem.

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