

Multi-Period Integrated Framework of Generation, Transmission, and Natural Gas Grid Expansion Planning for Large-Scale Systems

Fatemeh Barati, Hossein Seifi, *Senior Member, IEEE*, Mohammad Sadegh Sepasian, Abolfazl Nateghi, Miadreza Shafie-khah, *Member, IEEE*, and João P. S. Catalão, *Senior Member, IEEE*

Abstract—In this paper, a multi-period integrated framework is developed for generation expansion planning (GEP), transmission expansion planning (TEP), and natural gas grid expansion planning (NGGEP) problems for large-scale systems. New nodal generation requirements, new transmission lines, and natural gas (NG) pipelines are simultaneously obtained in a multi-period planning horizon. In addition, a new approach is proposed to compute NG load flow by considering grid compressors. In order to solve the large-scale mixed integer nonlinear problem, a framework is developed based on genetic algorithms. The proposed framework performance is investigated by applying it to a typical electric-NG combined grid. Moreover, in order to evaluate the effectiveness of the proposed framework for real-world systems, it has been applied to the Iranian power and NG system, including 98 power plants, 521 buses, 1060 transmission lines, and 92 NG pipelines. The results indicate that the proposed framework is applicable for large-scale and real-world systems.

Index Terms—Generation expansion planning, multi-period, natural gas grid expansion planning, transmission expansion planning.

NOMENCLATURE

A	Incidence matrix.
$c_{i,j}$	Construction cost of new electric transmission line between buses i and j .
CI_i	Investment cost of unit i .
d	Annual discount rate.
D_t	Total electric demand at time t .

D_k	Internal diameter of pipe between nodes.
f_{gas}	Vector of mass flow rates through branches.
$f_{k,i,j}^{gas}$	Pipeline flow rate, SCF/h.
$f_{i,j,t}^{ele}$	Electric flow between buses i and j at time t in normal condition.
$f_{i,j,t}^{ele,cg}$	Electric flow between buses i and j at time t in normal condition.
F_k	Pipeline friction factor.
FC_i	Fixed cost of unit i .
$g_{j,t}$	Electric generation at bus j .
G	Gas specific gravity (air = 1.0, gas = 0.6).
$H_{k,i,j}$	Compressor horsepower.
L_k	Pipeline length between nodes, miles.
MC	Marginal cost of unit i .
$n_{i,j,t}$	Number of total lines (new and existing) between buses i and j at time t .
N	Number of units (new and existing).
OC	Outage cost factor of units.
p_i	Pressure at node i , psi.
p_0	Standard pressure, psi.
$r_{k,t}$	Virtual generation to calculate transmission loss.
R_{min}, R_{max}	Minimum and maximum of reserve margin.
S	Confluence matrix of nodes and branches.
T	Number of periods in study horizon.
T_0	Standard temperature, °R.
T_{ka}	Average gas temperature, °R.
U_t	Vector of new units at time t .
$U_{max,t}$	Maximum generation capacity that can be added at time t .
w	Vector of gas injection at each node.
w_S	Vector of gas suppliers.
w_L	Vector of gas demands.
X_t	Vector of all new and existing units at time t .
$X_{i,t}$	Cumulative capacity of unit i at time t .
z_{ki}	Compressibility factor of gas.
Z_a	Average gas compressibility factor.
α	C_p/C_v ratio.

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F. Barati is with the Iran University of Science and Technology, Tehran, Iran. H. Seifi and A. Nateghi are with Tarbiat Modares University, Tehran, Iran. M. S. Sepasian is with Power and Water Industry University, Tehran, Iran. M. Shafie-khah and J. P. S. Catalão are with the University of Beira Interior, Covilha, Portugal, with INESC-ID, Lisbon, Portugal, and with IST, University of Lisbon, Lisbon, Portugal (e-mail: catalao@ubi.pt).

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χ	Factor of loss cost.
$\gamma_{i,j}$	Susceptance of new line between buses i and j .
η_k	Compressor efficiency.
θ_i	Electric voltage angle of bus i , rad.
δ_i	Salvage factor of unit i .
ε	Pipeline efficiency.

I. INTRODUCTION

AMPLE natural gas (NG) resources in a lot of countries have caused gas-fired power plants to be permanently the main reason of growth of NG consumption. The consumption can keep growing because of the excessive amount of unexplored NG reserves, which leads to an increase in NG infrastructures' investments. In this context, generation expansion planning (GEP) plays a significant role as a link between electric and NG networks. On one hand, although different algorithms have been reported to solve GEP, e.g., linear programming (LP) [1], [2], dynamic programming (DP) [3], genetic algorithm (GA) [3]–[6], particle swarm optimization (PSO) [7], and tabu search (TS) [8], the NG system has not been taken into account in the mentioned reports. On the other hand, to solve transmission expansion planning (TEP), although many approaches such as mathematical-based [9]–[11] and meta-heuristic algorithms [12]–[17] have been applied, GEP has been rarely considered.

In previous reported researches, GEP, TEP, and NG grid expansion planning (NGGEP) have been mainly considered as three independent problems. In other words, in order to solve one of these problems, the two other expansions have been totally ignored or considered with significant simplifying assumptions. For instance, in some works (e.g., [12] and [17]) in order to solve TEP, the location and size of power plants have been considered as known and pre-specified.

Moreover, constraints and expansions of NG network have not been addressed. Reference [18] has indicated that, if GEP and TEP can be fairly formulated in a combined form, the results would be more satisfactory in comparison with their separate solutions. In this context, a probabilistic model for combined GEP and TEP has been reported in [19]. In [20], coordination of GEP and TEP in a competitive electricity market has been studied using bi-level models. In [21], a tri-level model has been proposed to solve decentralized GEP and centralized TEP in electricity markets. With combined formulation of GEP and TEP, an obvious cost would be the fuel cost, which is location dependent. It mainly consists of generation cost and cost of supplying the fuel. If NG is considered as the dominant fuel, the cost of supplying the fuel can be the piping cost. In some reports (e.g., [18]), this cost has been assumed to be relative to the distance of generation node and main refinery or NG center. The assumption is not strictly valid as the plant is supplied through a nearby NG grid with its own load flow constraints [22]. It should be noted that, before the present paper, some works have presented the combined model of power plants, electric network, and NG grid (e.g., [22]–[26]), but mainly in operational studies.

In [23], a joint operator of NG and electric systems has been proposed to minimize operation costs considering constraints

of both systems. In [22], a short-term security constrained unit commitment (SCUC) problem has been proposed considering the NG network. In [24], an integrated model based on SCUC problem has been reported to assess the effect of the interdependent infrastructures on operation study. The impact of NG limitations on medium-term hydro-thermal scheduling has been presented in [25] and [26]. However, most of the reports are presented in operation horizons and the planning problem has been rarely addressed.

Since GEP and especially TEP can significantly affect NG network, planning of power system and NG grid can be simultaneously accomplished. On this basis, in [27], an integrated GEP and TEP model has been proposed considering constraints of fuel transportation; however, expansion planning of NG network has not been taken into account. In [28] and [29], an integrated expansion planning of both power and NG systems has been proposed. The integrated model has focused on the composition of electricity generation in GEP problem and NG dispatch. However, some simplifications due to the linearization of the model have been considered that can reduce the precision of TEP. Moreover, contingencies have not been considered in both electric and NG expansion planning problems.

In [30], a single-period integration of GEP and TEP has been proposed by considering NGGEP. However, a very simple model of GEP has been employed by considering some specific scenarios of generation. On this basis, many significant features of GEP such as the investment cost, maintenance and outage costs, the salvage value, and reserve constraint have not been considered. In addition, because of several simplifications in the model and in the optimization method, the presented model in [30] cannot be utilized for large-scale real-world systems and multi-period modeling.

In order to overcome all the mentioned drawbacks, in this paper, a three-stage TEP is proposed, including forward, backward, and decrease stages, to verify candidate branches in normal and contingency states. Furthermore, since NG load flow has the most significant influence on the computation time in large-scale systems, a new solution method has been developed to solve the NG load flow faster than the conventional one. Moreover, a novel combined framework of multi-period “GEP + TEP + NGGEP” is developed to achieve:

- generation requirements (placement and sizing);
- transmission requirements (type and ends of lines);
- NG grid requirements to supply the new power plants and NG demand.

The structure of the paper is as follows. Formulation of NG grid and the proposed NG load flow model are presented in Section II. The proposed multi-period framework is introduced in Section III. Numerical results are presented in Section IV. Finally, Section V provides concluding remarks.

II. NATURAL GAS GRID MODELING

A. Basic Principles

The gas flow rate, f_{kij} , through a long gas pipeline, k , with sending and receiving nodes, i and j , respectively, can be given by [24]

$$f_{k,i,j}^{gas} = 3.2387 \times S_{i,j} \times \frac{T_0}{p_0} \sqrt{\frac{S_{i,j} (p_i^2 - p_j^2) D_k^5}{F_k G L_k T_{ka} Z_a}} \quad (1)$$

where

$$S_{i,j} = \begin{cases} -1, & p_i - p_j < 0 \\ +1, & p_i - p_j \geq 0. \end{cases}$$

Friction factor, F_k , depends on flow region. For fully turbulent flow region in high-pressure grid (i.e., Reynolds number $\gg 400$), friction factor is given by [24]

$$F_k = \frac{0.032}{D_k^{\frac{1}{3}}}. \quad (2)$$

B. Node Balance Equation

The node balance in a matrix form can be formulated by

$$A f^{gas} + w = 0 \quad (3)$$

where array of matrix A , $A_{i,k}$, is given by

$$A_{i,k} = \{+1, -1, 0\} \quad (4)$$

and w is given by

$$w = \begin{cases} w_S & \text{if } w > 0 \\ w_L & \text{if } w < 0. \end{cases} \quad (5)$$

If $w > 0$, the respective node is a generation (refinery) node. Otherwise ($w < 0$), the node would be a load (consumption) one.

C. Compressor Equation

The objective of the compressor is to increase the pressure in pipelines. In this paper, it is assumed that $T_0 = 60^\circ_F = 520^\circ_R$, $p_0 = 14.65 \text{ psia}$, and the heat leakage of compressor is considered negligible. Therefore, it can be formulated as follows [31], [32]:

$$p_j = p_i \cdot \left(1 + \frac{H_{k,i,j}}{B_k f_{k,i,j}^{gas}} \right)^{\frac{1}{z_{ki}(\alpha-1/\alpha)}} \quad (6)$$

where p_i and p_j are the pressure of input and output gas flow, respectively. $H_{k,i,j}$ is the actual adiabatic (zero heat transfer) compressor horsepower that is located through the gas pipeline k , with the sending and the receiving nodes, i and j , respectively. B_k is given by

$$B_k = \frac{3554.58 T_{ka}}{\eta_k} \left(\frac{\alpha}{\alpha - 1} \right). \quad (7)$$

D. Proposed Natural Gas Load Flow Method

The main equation of the NG load flow, i.e., (1), is nonlinear. Solving the equation in each iteration of the proposed framework dramatically increases the computation time. In order to

overcome the problem, a new approach is proposed and explained as follows.

Two major variables are related to each node, namely, pressure and flow rate. In the proposed solution method, one of the generation nodes is considered as slack node and the other generation nodes are assumed as load nodes with pre-specified flow rates.

Therefore, the flow rate of the slack node and pressure of the remaining nodes would be unknown to be determined. On this basis, if N_p and N_l denote the number of generation and load nodes, respectively, we would have:

- Known: $f_{N_p+1}^{gas}, f_{N_p+2}^{gas}, \dots, f_{N_p+N_l}^{gas}$
- Unknown: $p_{N_p+1}, p_{N_p+2}, \dots, p_{N_p+N_l}$

Based on this, the flow rate of the slack node can be determined as follows:

$$w_S = \sum_{i=N_p}^{N_p+N_l} f_i - \sum_{j=2}^{N_p} w_j. \quad (8)$$

After obtaining the pressures, the flow rates through the pipelines can be easily determined using (1).

Various constraints should be observed throughout the solution process.

Constraints of node pressure and NG flow are presented in (9) and (10), respectively:

$$p_i^{\min} \leq p_i \leq p_i^{\max} \quad (9)$$

$$-f_{k,i,j}^{gas,\max} \leq f_{k,i,j}^{gas} \leq f_{k,i,j}^{gas,\max}. \quad (10)$$

Constraints of gas supply and gas demand are presented in (11) and (12), respectively:

$$w_S^{\min} \leq w_S \leq w_S^{\max} \quad (11)$$

$$w_L^{\min} \leq w_L \leq w_L^{\max}. \quad (12)$$

III. PROPOSED FRAMEWORK

A. GEP Approach

The multi-period GEP problem employed in this paper can be formulated as follows:

$$Cost_{GEP} = \sum_{t=1}^T I(U_t) + M(X_t) + O(X_t) - S(U_t) \quad (13)$$

where $I(U_t)$ is the investment cost of new units constructed at time t , $M(X_t)$ and $O(X_t)$ are maintenance and outage costs of all new and existing units, respectively, and $S(U_t)$ is salvage value of new units constructed at time t . The mentioned terms can be calculated by (14)–(18):

$$X_t = X_{t-1} + U_t \quad (14)$$

$$I(U_t) = (1 + d)^{-2t} \sum_{i=1}^N C I_i \cdot U_{i,t} \quad (15)$$

$$S(U_t) = (1+d)^{-2T+2t-2} \sum_{i=1}^N CI_i \cdot U_{i,t} \cdot \delta_i \quad (16)$$

$$M(X_t) = (1+d)^{1.5+2t-2} \sum_{i=1}^N (X_t \cdot FC_i + MC_i) \\ + (1+d)^{2.5+2t-2} \sum_{i=1}^N (X_t \cdot FC_i + MC_i) \quad (17)$$

$$O(X_t) = OC \cdot ((1+d)^{1.5+2t-2} + (1+d)^{2.5+2t-2}). \quad (18)$$

The objective should be minimized considering the following constraints:

$$0 \leq U_t \leq U_{\max,t}. \quad (19)$$

Equation (19) denotes the upper construction limit, so the construction capacity in each year must be lower than $U_{\max,t}$. In addition, each unit should be able to supply a certain amount of reserve. Therefore, a reserve margin is considered by

$$D_t \cdot (1 + R_{\min}) \leq \sum_{i=1}^N X_{i,t} \leq D_t \cdot (1 + R_{\max}). \quad (20)$$

B. TEP Approach

The multi-period TEP approach employed in this paper consists of a three-stage hybrid algorithm as follows:

- 1) Backward stage: In this stage, the system security is assured in normal condition.
- 2) Forward stage: In this stage, the system security is assured for contingency conditions ($N-1$ criteria), provided that the candidates already verified in the backward stage are assumed “in”.

In each of the above stages, some high capacity elements can be verified. On this basis, in the last stage of the hybrid algorithm, we have:

- 3) Decrease stage: It is checked if lower capacity elements (e.g., single-circuit transmission line, instead of a double circuit one) on the same corridors can keep system security. In that case, lower capacity ones are selected.

In the first two stages, the basic evaluation function that should be optimized in each step is as follows:

$$\text{TEP Evaluation Function} = \text{Cost}_{TEP} \\ + a(\text{Constraints Violations}) + b(\text{Islanding Conditions}) \quad (21)$$

where Cost_{TEP} is the cost of investment and losses and can be formulated by (22), a and b denote very large numbers, $bgga$, $a = 10^6$, and $b = 10^{12}$:

$$\text{Cost}_{TEP} = \sum_{t=1}^T \left[(1-d)^{t-1} \sum_{i,j} c_{i,j} n_{i,j,t} + \chi \sum_k r_{k,t} \right]. \quad (22)$$

Based on (21), the solutions would end up at minimum cost, while no constraint is violated and no islanding occurs. In the last stage, the evaluation function is basically the second term (constraint violation) that would be checked.

In order to consider electric constraints, power flow formulations are applied by (23) and (24):

$$S_t f_t + g_t + r_t = d_t \quad (23)$$

$$f_{i,j,t}^{ele} - \gamma_{i,j} \left(\sum_{m=0}^t n_{i,j,m} \right) (\theta_{i,t} - \theta_{j,t}) = 0 \quad (24)$$

where $0 \leq r_t \leq d_t$.

The constraints of electric flows are checked in both normal and contingency states based on the capacity of electric branches. The constraints are respectively presented by (25) and (26):

$$- \left(\sum_{m=0}^t n_{i,i,m} \right) f_{i,j}^{ele,\max} \leq f_{i,j,t}^{ele} \leq \left(\sum_{m=0}^t n_{i,i,m} \right) f_{i,j}^{ele,\max} \quad (25)$$

$$- \left(\sum_{m=0}^t n_{i,i,m} \right) f_{i,j}^{ele,\max} \leq f_{i,j,t}^{ele,Cg} \leq \left(\sum_{m=0}^t n_{i,i,m} \right) f_{i,j}^{ele,\max}. \quad (26)$$

Lower and upper limits of electric generation in each bus are given as follows:

$$g_{j,t}^{\min} \leq g_{j,t} \leq g_{j,t}^{\max}. \quad (27)$$

Constraint of the number of lines that can be added to corridor $i-j$ at time t and at the whole study horizon are given by (28) and (29), respectively:

$$n_{i,j,t}^{\min} \leq n_{i,j,t} \leq n_{i,j,t}^{\max} \quad (28)$$

$$\sum_{t=1}^T n_{i,j,t} \leq n_{i,j}^{\max}. \quad (29)$$

C. Combined Model

The combined model is an optimization problem that minimizes the total cost, given by

$$\text{Cost}_{Total} = \text{Cost}_{TEP} + \text{Cost}_{NGGEP} + \text{Cost}_{GEP} \quad (30)$$

where Cost_{TEP} is the electric grid cost, consisting of costs due to transmission expansion and electric system losses, Cost_{NGGEP} is the gas grid expansion cost, and Cost_{GEP} is the generation expansion cost due to the power plants.

In order to find the economic solution, the problem can assign generations to some nodes. Based on this, the added generations to candidate buses are determined as optimization variables. This is due to the fact that generation allocation affects both electric expansion requirements and gas grid expansion. It should be mentioned that if the type and capacity of required generation are considered to be fixed and pre-specified, Cost_{GEP} will be fixed and case-independent, so that it can be omitted from the optimization process.

The flowchart of the proposed framework is illustrated in Fig. 1. In the proposed framework, it is noted that the number of candidates for a practical electric grid is higher than the respective gas grid and the hybrid approach is well suited for large-scale systems. The middle block is used to calculate the

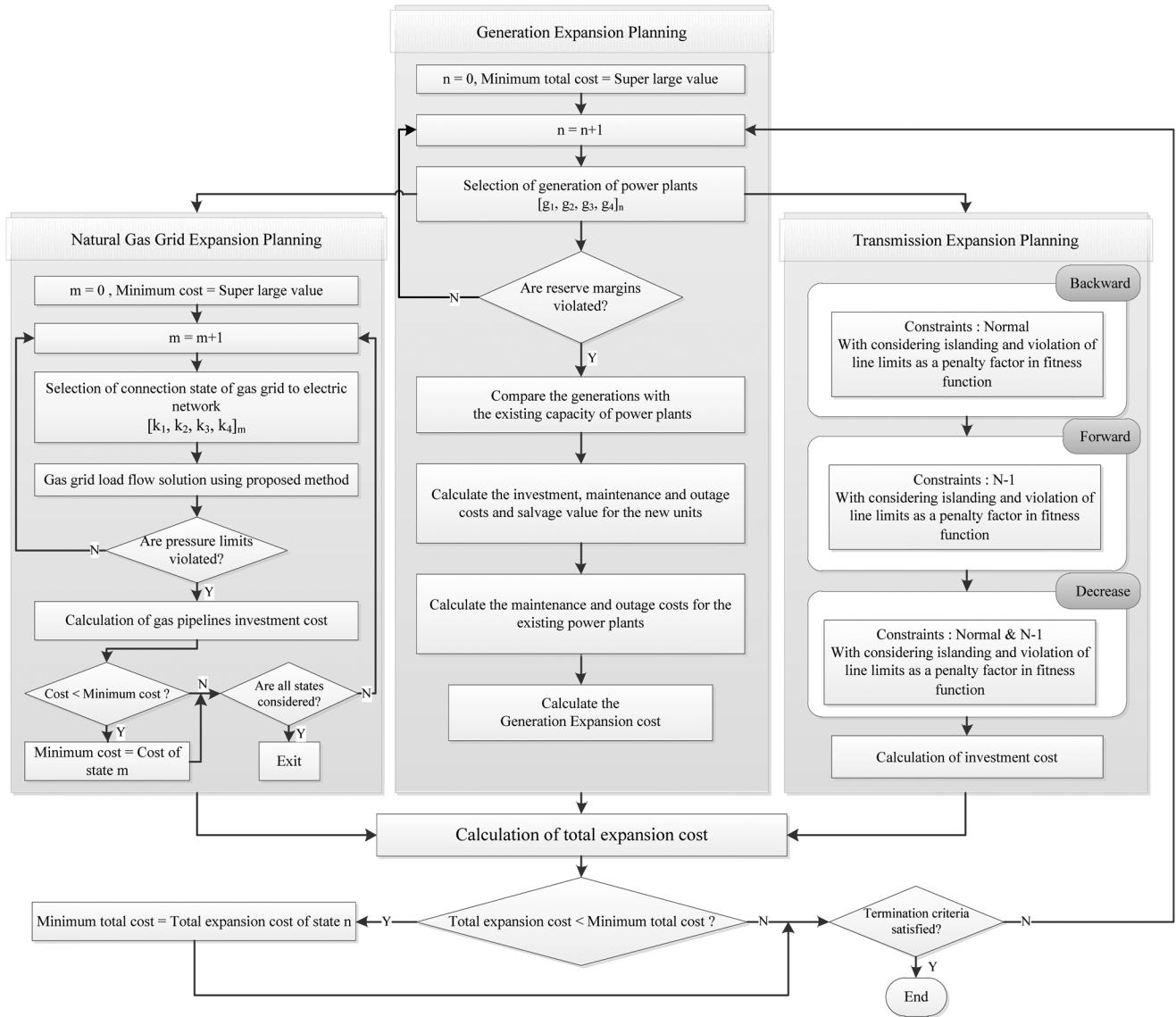


Fig. 1. Flowchart of the proposed framework.

GEP cost considering the reserve constraint. The right block corresponds to the solution process for the electric network, while the left block covers the NG grid so that the power plants requirements are satisfied and the nodes pressure and pipelines capacities are not violated.

Initially, some candidates should be assigned in terms of both electric grid elements (i.e., generation units and transmission lines) and NG pipelines. Then, the appropriate candidates should be verified using an optimization method. Reference [8] has shown that methods based on metaheuristic techniques can be the best option for solving the expansion planning problems in real-world power systems.

Additionally, in [33], it has been shown that GA can manage TEP better than most mathematical methodologies due to the non-convexity and nonlinearity of the mixed-integer problem. On this basis, and due to the high level of nonlinearity and discrete nature of the optimization problem, GA has been utilized

as the solution tool. The fitness (evaluation) function as given in (31) is used:

$$\text{Evaluation Function} = \frac{1}{\text{Cost}_{Total} + \sum a_i \text{Constraints}_i} \quad (31)$$

where a_i is arbitrarily chosen very high so that the solution would end up with no constraint violation. Iterations are generated using GA by selecting the generation value of power plants, and then the expansion costs in the three mentioned blocks are calculated. Therefore, in any iteration, GA compares the value of the evaluation function with the previous iteration, and if the evaluation value is increased, the minimum total cost will be replaced with the new one.

As shown in Fig. 1, the convergence of the framework is checked by the convergence of the minimum total cost. It means that, after considerable amount of iterations, if no better result is obtained, then GA will terminate the iterations.

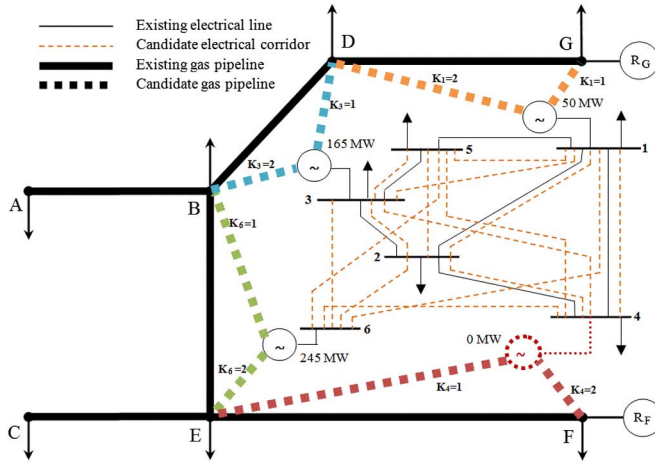


Fig. 2. Combined electric and NG systems for the Garver case study.

IV. NUMERICAL STUDIES

For the assessment of the proposed framework, two case studies have been performed, including the Garver test system [22] and the Iranian power and NG system as a practical large-scale system.

The platform that has been utilized to assess the proposed flowchart is a 64-bit Workstation having two Xeon E5-2687W 8C 3.10-GHz processors with 256 GB of RAM.

A. Garver Test System

The first system under study is the Garver test system [22] that has been modified to cover the proposed GEP+TEP+NGGEP framework as depicted in Fig. 2.

A 7-node NG grid, with 2 gas generation nodes (i.e., nodes F and G) and 5 gas load nodes (i.e., A to E), has been considered. The base electric data are provided in Tables I and II. It is assumed that the loads are increased by 50% (see Table II). Moreover, it is assumed that new generation can be added to both existing generation buses (buses 1, 3, 6) and a new bus (bus 4). Details of gas grid are provided in Tables III and IV.

B. Applying the Proposed NG Load Flow to the Garver Test System

In this section, the proposed NG load flow approach is described and assessed using the above-mentioned test system. Using (8), the flow rate of the slack node (i.e., node G) can be determined as

$$w_S = \sum_{i=A}^S f_i - w_F. \quad (32)$$

Once w_S is known, the pressure of the next connecting node to slack node (i.e., node D) can be calculated as follows:

$$p_D = \sqrt{p_S^2 - \frac{f_{S,D}^2}{C_{k_{S,D}}^2}} \quad \text{if } f_{S,D} > 0 \quad (33)$$

$$p_D = \sqrt{p_S^2 + \frac{f_{S,D}^2}{C_{k_{S,D}}^2}} \quad \text{if } f_{S,D} < 0. \quad (34)$$

 TABLE I
LINE DATA FOR GARVER ELECTRIC TEST SYSTEM

	End buses	Resistance (pu)	Reactance (pu)	Investment Cost (\$)	Capacity (MW)
Existing lines	1-2	0.10	0.40	0	100
	1-4	0.15	0.60	0	80
	1-5	0.05	0.20	0	100
	2-3	0.05	0.20	0	100
	2-4	0.10	0.40	0	100
	3-5	0.05	0.20	0	100
Candidate lines	1-2	0.10	0.40	40	100
	1-3	0.09	0.38	38	100
	1-4	0.15	0.60	60	80
	1-5	0.05	0.20	20	100
	1-6	0.17	0.68	68	70
	2-3	0.05	0.20	20	100
	2-4	0.10	0.40	40	100
	2-5	0.08	0.31	31	100
	2-6	0.08	0.30	30	100
	3-4	0.15	0.59	59	82
	3-5	0.05	0.20	20	100
	3-6	0.12	0.48	48	100
	4-5	0.16	0.63	63	75
	4-6	0.08	0.30	30	100
5-6	0.15	0.61	61	78	

 TABLE II
BUS DATA FOR GARVER ELECTRIC TEST SYSTEM

Bus	Current year			Horizon year	
	Max generation (MW)	Generation Price (\$/MWh)	Demand (MW)	Max generation (MW)	Demand (MW)
1	150	10	80	200	120
2	-	-	240	-	360
3	360	20	40	450	60
4	-	-	160	460	240
5	-	-	240	-	360
6	600	30	0	750	0

 TABLE III
GAS PIPELINE DATA FOR GARVER ELECTRIC TEST SYSTEM

End substations		Capacity (kcf/psia)
from	to	
A	B	50.6
B	D	40
D	G	50.1
C	E	43.5
B	E	37.5
E	F	45.3

 TABLE IV
GAS SUBSTATION DATA FOR GARVER TEST SYSTEM

Substation	Station type	Flow (SCF/hr)	Pressure (psia)	Pressure (psia)	
				Min	Max
A	Constant flow	4000	-	75	200
B	Constant flow	1000	-	120	200
C	Constant flow	4000	-	75	200
D	Constant flow	-	-	120	200
E	Constant flow	-	-	120	200
F	Constant flow	-4000	-	120	200
G	Constant pressure	-	200	75	200

Once p_D is determined, the p_B as the pressure of connecting node to node D will be determined. The steps are repeated until all pressures are obtained. Afterwards, the flows through the pipelines will be calculated using (1). The results of the proposed NG load flow method have been presented in Tables V

TABLE V
OBTAINED NG SUBSTATIONS' PRESSURE USING
THE PROPOSED NG LOAD FLOW

NG Substation	Pressure (psia)
A	90.36
B	120.06
C	77.19
D	173.32
E	120.06
F	149.03
G	200

TABLE VI
OBTAINED NG PIPELINES' FLOW USING THE PROPOSED NG LOAD FLOW

End substations		Flow (SCF/hr)
from	to	
A	B	-4000
B	D	-5253.3
D	G	-5253.3
C	E	-4000
B	E	253.3
E	F	-3746.7

TABLE VII
INVESTMENT COST OF CANDIDATE PIPELINES (MILLION \$/km)

Diameter	8	10	12	16	20	24	30
Investment cost	0.28	0.47	0.68	1.12	1.83	2.58	4.17

and VI. It should be noted that, in order to assess the accuracy of the proposed method, the obtained load flow results have been compared with those of nonlinear equations. The comparison showed that both results are completely the same, but the computation time of conventional nonlinear model (0.39 s) is much more than that of the proposed method (just 0.008 s). Since the NG load flow is the engine of the proposed framework and its equations must be repeatedly solved during the framework process, using the proposed NG load flow method can play a significant role in decreasing the computation time without losing accuracy, especially in large-scale systems.

C. Applying the Proposed Framework to the Garver Test System

The interface between electric and gas grids is the set of power plants. Fig. 2 also shows the candidate pipelines for supplying the power plants. Moreover, it is assumed that, in terms of the transmission lines candidates, new lines (a maximum of 4 in each corridor) may be constructed in parallel with existing lines. As already described, the aim is to allocate new generations in such a way that requirement cost (both in terms of pipelines and transmission lines) is minimized, while loads are adequately satisfied and various constraints are met. In order to fulfill this idea, some cost terms are used as the input parameters. The investment cost of transmission lines is considered to be 240 000 \$/km, whereas for any additional path it is 150 000 \$/km. The cost of losses is considered to be 1.5 \$/kW and the investment cost for power plants is assumed to be 530 000 \$/MW.

TABLE VIII
CAPACITY OF CANDIDATE PIPELINES (MILLION m³/MONTH)

Diameter Length	8	10	12	16	20	24	30
10	1.7	2.8	4.1	6.7	11	15.5	25
20	1.2	2.2	3.4	6.2	10.2	14.6	24
30	1	1.8	2.8	5.1	9.2	14	23.1
40	0.9	1.5	2.4	4.4	8	12.7	22.2
50	0	1.4	2.1	3.9	7.1	11.3	20.3
60	0	0	1.9	3.6	6.5	10.4	18.5
70	0	0	0	3.3	6	9.6	17.1
80	0	0	0	0	5.6	9	16
90	0	0	0	0	0	8.4	15.1
100	0	0	0	0	0	0	14.3

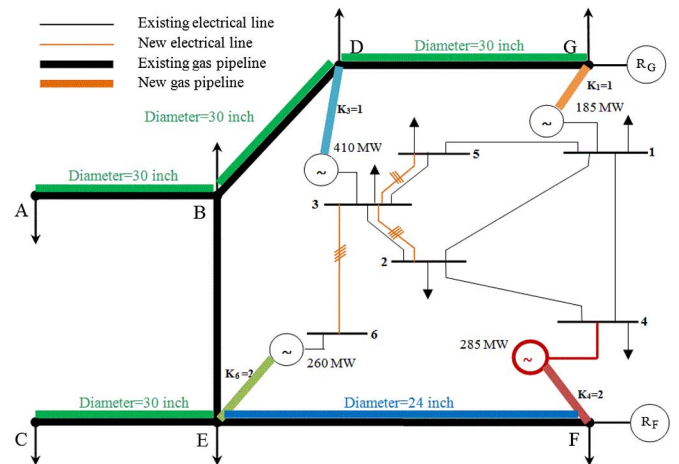


Fig. 3. Solution result for Garver case study (colored lines represent new lines and units).

The investment cost and capacity of candidate pipelines is presented in Tables VII and VIII, respectively. The solution of the problem is depicted in Fig. 3.

As can be seen in Fig. 3, among eight candidate pipelines for connecting the electric system to the gas network, four pipelines have been selected. In addition, because of the increase of gas demand due to generation units' consumption, most of the existing pipelines should be enhanced.

It should be mentioned that the proposed framework selects the candidate pipelines with the shortest distance to generation units, except the connection of the gas pipeline to the generation unit at bus 3. The reason is that, if a shorter pipeline ($K_3 = 2$) had been selected, pipeline B-E would have been enhanced instead of pipeline B-D. Since the distance between gas substations B and E (i.e., pipeline B-E) is more than that between gas substations B and D (i.e., pipeline B-D), the optimal solution is to connect generation unit 3 to gas substation D (further gas substation) to avoid enhancing the longer existing gas pipeline between gas substations B and E. In addition, three new corridors have been selected for the electric network. Two of these corridors (i.e., lines between buses 2-3 and 3-6) include 4 lines, and one of them (i.e., line between buses 3-5) includes 3 lines. Furthermore, the candidate generation unit at bus 4 has been selected to generate with the nominal capacity of 285 MW. The generation capacity of the existing generation units is also increased to cover the demand grow in the horizon year.

TABLE IX
CHARACTERISTICS OF IRANIAN NG SYSTEM

Main pipeline	Diameter (inch)	Capacity (million m ³ /day)	Length (km)	Number of compressor stations	
				Existing	approved
Bidboland-Astara	42 & 40	46 & 32	1103	10	-
Kangan-Qazvin	56	80	1039	8	-
Asalouye-Kangan-Saveh-Rasht	56	90	1267	9	-
Asalouye-Parsian-Neyzar-Saveh	56	110	1145	3	7 ⁽¹⁾
Asalouye-Aghajari	56	95	504	5	-
Asalouye-Bidboland-Ahvaz	56	110	610	5	-
Asalouye-Sarkhoun-Iranshahr	56	110	902	2	7 ⁽²⁾
Asalouye-Parsian-Naeen-Tehran	56	110	1050	10	-
Asalouye-Ahvaz-Dehgolan-Bazargan	56	110	1863	17	-
Kangan-Petaveh-Isfahan	56	70	632	3	-
Saveh-Hamedan-Bijar-Takab-Miandoab	48 & 40	50 & 40	470	3	-
Tehran-Semnan-Sabzevar-Sangbast	48 & 42	50 & 30	905	3	-
Sangbast-Dolatabad (Turkmenistan)	48	50	120	-	1 ⁽³⁾
Chahbouk (Turkmenistan)-Khangiran-Mashhad-Neka-Ghouchan	48	50	450	6	-
Qazvin-Tabriz-Bazargan	48 & 40	50 & 40	2000	5	2 ⁽⁴⁾
Gilan-Tabriz	30	21	343	4	-
Sarkhoun-Kerman	24	11	415	1	2 ⁽⁵⁾

⁽¹⁾ Seven compressor stations approved for year 2014 stand on branches Fars-Kheirgou, Khanj-Fars, Fars-Jahrom, Fars-Arsanjan, Fars-Safashahr, Fars-Abadeh, and Isfahan-Shahreza.

⁽²⁾ Seven compressor stations approved for year 2015 in order to export NG to India and Pakistan.

⁽³⁾ One compressor station approved for year 2014 in order to export NG to Turkmenistan.

⁽⁴⁾ Two compressor stations approved for 2014 stand on branches Marganlar-Azarbaijan and Zanjan-Qazvin.

⁽⁵⁾ Two compressor stations approved for 2013 stand on branches Hormozgan-Abshirin and Kerman-Sirjan.

D. Applying the Proposed Framework to the Iranian Power and Natural Gas Systems

The case study of this paper is the 521-bus Iranian power system with 92 existing power plants and 1060 branches (total length of about 43 000 km) [34].

Seven of the power plants are hydro and the rest are thermal. In addition, six new thermal power plants are considered for the horizon year (2016).

The power system is modeled in voltage levels of 400 and 230 kV (155 of the buses are at 400 kV and the rest are at 230 kV) and with the maximum demand of 49 931 MW for the horizon year. Moreover, this case study includes 50 main NG pipelines, which feed 43 existing thermal power plants, with 42 sub-branches considered to feed the other thermal power plants (total length of about 9433 km). The total NG consumption is 490.8 million m³/day, including the consumption of thermal

TABLE X
NUMBER OF PLANNING PERIODS FOR IRANIAN POWER AND NG SYSTEMS

Year	2010	2011	2012	2013	2014	2015	2016
Maximum electric demand (MW)	39662	42329	43459	44371	46284	47447	49931
Maximum NG demand (million m ³ /day)	490.8	500.9	515.7	532.1	546.5	559.1	570.8

TABLE XI
SOLUTION RESULT FOR IRANIAN POWER AND NG SYSTEMS (TWO PERIODS)

Case	GEP+TEP	NGGEP	GEP+TEP+NGGEP
GEP cost (million \$)	1113.00	-	975.00
TEP cost (million \$)	164.93	-	205.07
NGGEP cost (million \$)	-	384.56	420.85
Total cost (million \$)	1277.93	384.56	1601.12
Computation time (sec)	401	22	678

power plants, considering 66 NG substations [35]. The mentioned NG substations are used to model 13.122 million urban NG consumers and 24 million m³ NG exports for each day. In order to solve this case study, 72 candidate electric transmission lines and 21 candidate pipelines have been considered.

It should be noted that, in this paper, allocation/sizing of compressors is not implemented.

Regarding Table IX, it is assumed that the existing compressors are referring to the gas network in the year 2010 and the approved compressors by the National Iranian Gas Company (NIGC) are increasing the compressing capabilities of the network until the horizon year (2016). The details of the Iranian NG system are presented in Table IX [36].

In order to investigate the effect of the number of planning periods on computational tractability, the proposed framework has been applied to three cases, including a two period (i.e., 2013 and 2016), a three period (i.e., 2012, 2014, and 2016), and a six period (2011–2016) planning. The year of 2010 is considered as the initial stage (i.e., stage 0). The details of the mentioned periods are presented in Table X.

In order to compare the integrated framework with the separated method, the expansion planning method with and without considering the NG grid has been applied to a two period planning. The expansion cost of the separated NGGEP is equal to 384.56 million \$.

The expansion cost without NGGEP (i.e., integrated GEP and TEP) is equal to 1277.93 million \$, whereas by considering the NGGEP (i.e., integrated GEP, TEP, and NGGEP), it is equal to 1601.12 million \$; that is 61.37 million \$ (about 3.7% of total cost) less than the sum of the separated expansion costs. Details of the results have been presented in Tables XI and XII.

Regarding the solution results, the investment is shared more in TEP than in NGGEP. The reason is that the electric loads are supplied by the power plants via the transmission network. If the electric loads are supplied by enhancement in NG network, an investment in GEP is also needed to construct the new power plants, converting the NG to electricity to supply the loads. In other words, most of the NG pipeline capacities are over the power plant capacities connected to them. On this basis, any enhancement in NG network can cause a requirement of enhancement in connected power plants capacities.

TABLE XII
DETAILED RESULT FOR IRANIAN POWER AND NG SYSTEMS (TWO PERIODS)

Case	GEP+TEP			NGGEP			GEP+TEP+NGGEP		
	2013	2016	Total	2013	2016	Total	2013	2016	Total
Number of verified power plants	2	4	6	-	-	-	1	4	5
Total capacity of verified power plants (MW)	630	1420	2050	-	-	-	350	1480	1830
Number of verified transmission lines	10	18	28	-	-	-	12	20	32
Total length of verified transmission lines (km)	356	539	895	-	-	-	354	652	1006
Number of verified NG pipelines	-	-	-	3	4	7	2	5	7
Total length of verified NG pipelines (km)	-	-	-	153	169	322	111	211	322

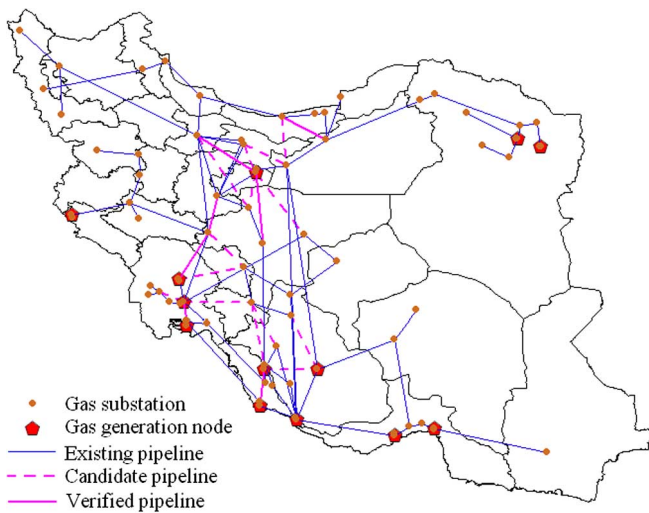


Fig. 4. Existing, candidate, and verified NG pipelines for Iranian NG system (two periods).

In this case study, there is no need to enhance the existing NG pipelines. However, seven new NG pipelines are required to feed the new thermal power plants and the new NG substations, as illustrated in Fig. 4. Moreover, 32 of the candidate transmission lines (total length of about 1006 km) have been verified, as illustrated in Fig. 5.

As it can be seen in Table XII, six thermal power plants have been verified by using the separated model, while applying the integrated framework causes only five thermal power plants to be verified. However, the number of electric transmission lines and the cost of NGGEP have been increased, because by applying a new NG pipeline with higher capacity, the size of one of the verified power plants can be increased and the demand requirement can be supplied by expanding the electric transmission lines.

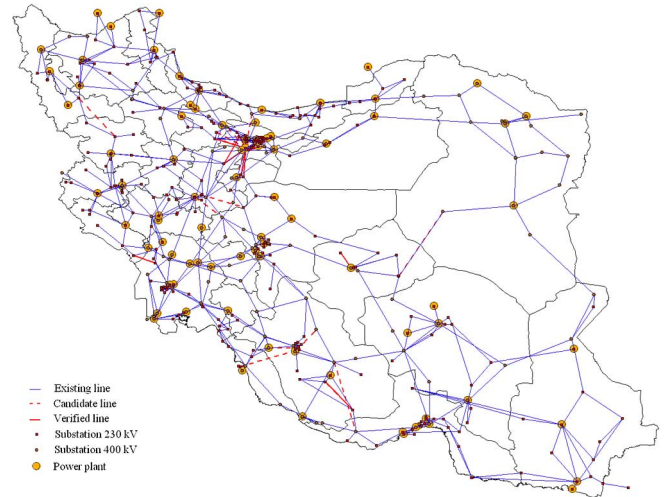


Fig. 5. Existing, candidate, and verified transmission lines for Iranian power system (two periods).

TABLE XIII
DETAILED RESULT OF THE PROPOSED FRAMEWORK FOR IRANIAN POWER AND NG SYSTEMS (THREE PERIODS)

Period	2012	2014	2016	Total
Number of verified power plants	1	1	3	5
Total capacity of verified power plants (MW)	350	420	1060	1830
Number of verified transmission lines	3	11	18	32
Total length of verified transmission lines (km)	171	230	605	1006
Number of verified NG pipelines	2	2	3	7
Total length of verified NG pipelines (km)	111	72	139	322

TABLE XIV
SOLUTION RESULT OF THE PROPOSED FRAMEWORK FOR IRANIAN POWER AND NG SYSTEMS (THREE PERIODS)

Case	GEP+TEP+NGGEP
GEP cost (million \$)	975.00
TEP cost (million \$)	205.07
NGGEP cost (million \$)	384.56
Total cost (million \$)	1564.63
Computation time (sec)	1105

Tables XIII and XIV present the obtained results from a three period planning. As can be seen in Table XIV, the total cost is less than the one in the two period planning, because the capacity of one of the verified NG pipelines in 2012 is less than that in 2013.

This NG pipeline supplies the load of a new NG substation in 2012. Since a part of this NG substation's load will be fed by the second NG pipeline in 2014, a lower capacity can be sufficient for the first pipeline. It should be mentioned that the second NG pipeline is not verified for 2013 and, consequently, a higher capacity for the first pipeline is required. Similarly, a lower capacity for the mentioned NG pipeline has been verified for the six period planning.

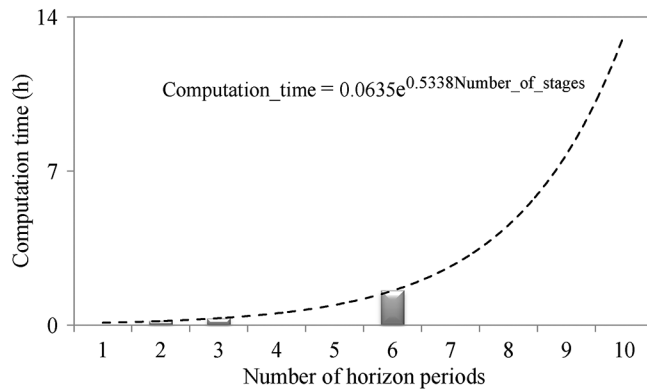


Fig. 6. Effect of number of horizon periods on the computation time.

According to Table XIV, the computation time of the three period planning is approximately 63% more than the one in the two period planning.

Fig. 6 compares the computation times of two, three, and six period planning cases. The fitted curve shows that by increasing further the number of periods, especially between six and ten period planning, the computation time will be exponentially increased. The computation time for solving the integrated problem by the proposed framework can be considered acceptable for planning studies. Hence, the results indicate that the proposed method is applicable for large-scale real-world systems and multi-period modeling.

V. CONCLUSION

Although GEP and TEP have been typically treated separately, a combined modeling may improve the results significantly. Moreover, the generation plants were supplied through an NG grid with its own potentials and limitations. Hence, an integrated GEP+TEP+NGGEP framework was proposed and formulated in this paper for large-scale systems. The proposed framework was applied to a real-world power and NG system. The results indicated that the proposed method was indeed useful for large-scale systems. Optimal allocation of compressors and electric substations is a topic for future work.

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Fatemeh Barati was born in Ahwaz, Iran, in 1983. She received the B.Sc. degree from Zanjan University, Zanjan, Iran, in 2005, the M.Sc. degree from Tarbiat Modares University, Tehran, Iran, in 2009, and she is currently pursuing the Ph.D. degree in Iran University of Science and Technology (IUST), Tehran, Iran.

Her research interests include power system planning, distributed generation issues, and renewable energy.



Hossein Seifi (SM'01) was born in Shiraz, Iran, in 1957. He received the B.Sc. degree from Shiraz University, Shiraz, Iran, in 1980 and the M.Sc. and Ph.D. degrees from the University of Manchester Institute of Science and Technology, Manchester, U.K., in 1987 and 1989, respectively.

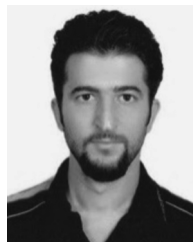
He then joined Tarbiat Modares University, Tehran, Iran, where he is currently a Full Professor and, at the same time, is the Head of the Iran Power System Engineering Research Center (IPERC). His research interests include power system planning

and operational issues.



Mohammad Sadegh Sepasian was born in Tehran, Iran, in 1967. He received the B.Sc. degree from Tabriz University, Tabriz, Iran, in 1990 and the M.Sc. and Ph.D. degrees from Tehran University and Tarbiat Modares University, Tehran, Iran, in 1993 and 1999, respectively.

Currently, he is an Assistant Professor with Power and Water University, Tehran. His research interests include power system planning as well as distribution system planning issues.



Abolfazl Nateghi was born in Zanjan, Iran, in 1983. He received the B.Sc. and M.Sc. degrees from Zanjan University, Zanjan, Iran, in 2005 and 2007, respectively, and the Ph.D. degree from Tarbiat Modares University, Tehran, Iran, in 2014.

His research interests include power system planning, distributed generation issues, and transformer design.



Miadreza Shafie-khah (S'08–M'13) received the M.Sc. and Ph.D. degrees in electrical engineering from Tarbiat Modares University, Tehran, Iran, in 2008 and 2012, respectively.

He is currently pursuing his postdoctoral studies in the laboratory of Sustainable Energy Systems with Prof. J. P. S. Catalão, University of Beira Interior (UBI), Covilha, Portugal. His research interests include power market simulation, market power monitoring, power system optimization, operation of electricity markets, price forecasting, and smart grids.



João P. S. Catalão (M'04–SM'12) received the M.Sc. degree from the Instituto Superior Técnico (IST), Lisbon, Portugal, in 2003, and the Ph.D. degree and Habilitation for Full Professor ("Agregação") from the University of Beira Interior (UBI), Covilha, Portugal, in 2007 and 2013, respectively.

He is currently a Professor at UBI, Director of the Sustainable Energy Systems Lab, and Researcher at INESC-ID. He is the Primary Coordinator of the EU-funded FP7 project SiNGULAR ("Smart and Sustainable Insular Electricity Grids Under Large-Scale Renewable Integration"), a 5.2 million euro project involving 11 industry partners. He has published more than 95 journal papers, 175 conference proceedings papers and 12 book chapters, with an *h*-index of 21 (according to Google Scholar), having supervised more than 25 post-docs, Ph.D., and M.Sc. students. He received the 2011 Scientific Merit Award UBI-FE/Santander Universities and the 2012 Scientific Award UTL/Santander Totta. His research interests include power system operations and planning, hydro and thermal scheduling, wind and price forecasting, distributed renewable generation, demand response, and smart grids. He was the Editor of the book entitled *Electric Power Systems: Advanced Forecasting Techniques and Optimal Generation Scheduling* (Boca Raton, FL, USA: CRC, 2012), translated into Chinese in January 2014. He is currently editing another book for CRC Press entitled *Smart and Sustainable Power Systems: Operations, Planning and Economics of Insular Electricity Grids*, forthcoming in 2015.

Prof. Catalão is an Editor of the IEEE TRANSACTIONS ON SMART GRID, an Editor of the IEEE TRANSACTIONS ON SUSTAINABLE ENERGY, and an Associate Editor of *IET Renewable Power Generation*. He was Guest Editor-in-Chief for the Special Section on "Real-Time Demand Response" of the IEEE TRANSACTIONS ON SMART GRID, published in December 2012, and he is currently Guest Editor-in-Chief for the Special Section on "Reserve and Flexibility for Handling Variability and Uncertainty of Renewable Generation" of the IEEE TRANSACTIONS ON SUSTAINABLE ENERGY.