Heat and Electricity Supply Chains Expansion Planning Under the Umbrella of Energy Hub: A Case Study of Iran

Hadi Sadeghi¹, Masoud Rashidinejad², Moein Moeini-Aghtaie³, and Amir Abdollahi⁴*

¹,²,⁴ Department of Electrical Engineering, Shahid Bahonar University, PO.Box: 76169-133, Kerman, Iran
¹ Young Research Association
³ Department of Electrical Engineering, Sharif University of Technology, P.O Box: 11365-11155, Tehran, Iran

Abstract

Increases in tightening the correlation of gas and electricity systems (G&ES), affected by diverse factors, ranging from anthropogenic climate change to the advent of new conversion/generation technologies, have remarkably brought the co-expansion of G&ES using a new concept, the so-called Energy Hub (EH), as well as the potential of storage systems into focus. To assess the effectiveness of EH approach and the role of storages in the coordinated plans of G&ES, this paper proposes a comprehensive EH-based planning model for co-expansion of G&ES supply chains with respect to the role of gas storage systems (GSSs). As a mixed-integer linear programming (MILP) problem, the model is applied to a real large-scale case study, i.e. the Iranian G&ES and is solved via the GAMS package. The simulation results reveal that incorporation of the interactions existing between G&ES into their planning problems in the framework of an EH can reach more flexible, realistic and optimal expansion plans compared with their traditional integrated expansion planning methods. Furthermore, findings show that the involvement capacities of GSSs provides the opportunity of optimal matching of demand with supply by increasing the productivity of the gas pipelines, allowing technically and economically sensible long-term management of gas supply systems.

Keywords: Energy hub, Heat, gas and electricity supply chains, Co-expansion planning, Gas storage systems.

* Corresponding author. Tel.:+983433202519; Mobile No. +989131989225, +989177310968, E-mail address: a.abdollahi@uk.ac.ir
Nomenclature

A. Indices

- **i,s,n,b,t** Index corresponding to an infrastructure type, installation area, number of infrastructures, loads-block, and to a planning horizon stage, respectively.
- **S,B,T** Index corresponding to the total number of areas, loads-blocks, and planning horizon intervals, respectively.

B. Superscripts

- **SP** Symbol of gas supply systems.
- **GP** Symbol of gas pipelines.
- **GS** Symbol of gas storage systems.
- **FU** Symbol of gas furnaces.
- **CO** Symbol of gas compressors.
- **HP** Symbol of heat pumps.
- **GPG** Symbol of gas-fired power plants.
- **CHP** Symbol of combined heat and power units.
- **GDG** Symbol of gas-fired distributed generation units.
- **TL** Symbol of transmission lines.
- **RE** Symbol of renewable-based generation units.

C. Constants/parameters

- **C_{inv}** Investment cost.
- **C_{&OM}** Fixed operation and maintenance cost.
- **C_{opr}** Variable operation cost.
- **C_{inc}** Renewables’ incentive-based support scheme cost.
- **µ, λ** Injection and withdrawal cost of gas storage systems, respectively.
- **u, v** Maximum and minimum bounds of gas storage systems, respectively.
- **u^{inj}, v^{inj}** Maximum and minimum injection bounds of gas storage systems, respectively.
- **u^{with}, v^{with}** Maximum and minimum withdrawal bounds of gas storage systems, respectively.
- **p, p** Maximum and minimum power generation capacity, respectively.
- **g, g** Maximum and minimum gas production capacity of gas supply systems, respectively.
- **h, h** Maximum and minimum heat power generation capacity, respectively.
- **δ** Renewable-based distributed generation capacity factor multiplied by 8760.
- **ζ** Electricity-to-gas conversion factor.
- **N** Maximum number of an infrastructure that can be installed during the planning horizon.
- **f_{g}** Maximum flow capacity of a pipeline.
- **τ** Seasonal storage factor.
- **r** Discount year.
- **ρ^{inj}, ρ^{with}** Outlet, inlet pressures of a gas compressor, respectively.
- **φ** Polytropic exponent of the empirical equation of gas compressors’ consumed power.
- **hp** Horsepower of gas compressors.

- **N** Natural gas thermal value.
- **g_e** Natural gas emission factor.
- **η** Efficiency of an infrastructure.
- **P_C** Electrical power consumed by a compressor.
- **G_C** Gas consumed by a compressor.
- **B_{tot}** Total available budget in the base year.
- **EENS** Allowed amount of not served energy.
- **VOLL** Value of lost load.
- **Φ^{E}, Φ^{H}** Duration of electrical, heat, and gas load, respectively.
- **Ω^{G}, Ω^{G}** The amount and duration of gas demand, respectively.
- **Φ^{E}, Φ^{G}** Duration of total gas demand in equivalent gas and heat demand curve.
- **Ω^{E}, Ω^{G}** Electricity and total gas demand (including gas demand of heat loads), respectively.

B. Variables

- **p** Generated power (MWh).
- **g** Produced gas (MM^3/h).
- **h** Produced heat (MMBtu/h).
- **x** Binary decision variable.
- **u^{inj}, v^{inj}** Injection and withdrawal of gas storage systems (MM^3/h), respectively.
- **g_f** Natural gas flow in a gas pipeline (MM^3/h).
- **f_e** Electric flow in a transmission line (MWh).
- **EENS** Expected energy not served (MWh).
- **CR** Curtailed electricity load (MW).

D. Sets

- **I** Set of candidate types corresponding to each infrastructure.
- **I_{N&E}** Set of new-added and existent types of each infrastructure.
1- Introduction

As one of the biggest source of CO$_2$ emission, power plants can play a prominent role in realization of the green economy by modification of their own operation and expansion strategies. The need to apply emission restrictions to the generation sectors has propelled different countries to use energy sources characterized by lower emission. Accordingly, natural gas (NG) will have the main role among fossil fuels in the future of conventional energy systems (ESs) [1]. However, the rotation of visions to the NG energy is not only derived from the climate change. In this context, the need for increasing the capacity of fast-response generation units in parallel with the fast penetration of renewable energy sources (RES), as non-dispatchable and inherently uncertain energy sources, and lower NG price compared with other fossil fuels, in fact, are comprised other well-known factors strengthening the position of NG in the future of energy paradigm. Redundancy of NG natural sources, advances in extraction of NG from unconventional sources in term of the shale gas, and economic features of the gas-fired power plants (GPG), such as lower investment cost as well as shorter installation, have also had an effective role in enhancing the NG position.

All above-enumerated factors, along with decisions of some developed countries, such as Germany and Switzerland, on acceleration of retiring coal-fired power plants and replacing them with gas-fired ones as well as bringing forward nuclear generation phase-out programs in the wake of Fukushima disaster in 2011, have resulted in significantly increasing the interdependency of gas and electricity systems [2, 3]. In doing so, the impact of technological progresses, in particular in the field of distributed energy resources realizing microgrids [4, 5], as well as the advent of diverse energy converters on intensifying this interdependency is undeniable. Gas-fired distributed generations (GDG), power to gas (P2G) storage systems, heat pumps (HPs), and ultimately, CHP units, are some of those technologies which have recently had a fast penetration rate in ESs as the result of global concentrations on energy efficiency (EE) and clean energy production improvements.

Obviously, the widespread penetration of NG-based energy conversion/generation technologies in the generation mix of power and heating systems impresses generation, transmission, and distribution of the most common energy demand forms, i.e. heat and electrical energies. And this has made the need to employ more comprehensive methodologies to plan and analyze today’s ESs, this time, in an integrated manner in term of a multi-energy system to facilitate moving towards green economic realization. This new-emerged viewpoint on ESs, nowadays, is pursued in a framework, the so called “Energy Hub” (EH), providing the opportunity to achieve more optimal
and realistic operation and expansion strategies from all technical, economical, and environmental perspectives [6].

1.1. Literature review

What making the utilization of EH concept imperative in energy systems’ expansion planning (ESEP) problems are not only related to the increased dependencies of ESs on each other. Incremental rate of demand growth along with today’s ESs’ requirements, such as higher EE, better assets management, and more precise planning models owing to tremendous capability enhancement of computer systems as well as soft computing methods realizing the optimization of sophisticated models, from the other hand, in fact, have highlighted the necessity of concentrating on the EH approach. Reviewing the advantages and capabilities originated from this approach in ESs planning, scrutinized in a multitude of studies [3-13], helps to better appreciate this concept.

With or without considering the enumerated factors of increase in today’s interdependencies of ESs, up to now, amalgamated expansion planning of gas and electricity systems (G&ES) has been addressed by a wide range of research works. Accuracy and method of modelling, employed optimization methodologies, and infrastructures considered in expansion planning, can be regarded as the distinctions between the works. Regarding hourly fluctuation of gas and electricity demands in an 11-year horizon, a precise linear dynamic model for expansion planning of Brazilian G&ES is presented in [14]. In an almost similar framework, Barati et al. also addresses simultaneous expansion planning of G&ES in a large-scale and a 7-year horizon [15]. The obtained results from conducted scenarios on the Iranian G&ES illustrate the effectiveness of integrated expansion planning approach compared with separate planning of these systems. The carried out work in [16] determines optimal expansion strategies of integrated gas and electricity distribution networks, and similarly, the findings show that simultaneous planning of the networks can remarkably decrease both operation and investment expenditures of both systems, which in turn, can enhance the social welfare. With emphasis on the importance of NG role in mitigating the share of generation sector in greenhouse gas (GHG) emission, Qui et al. suggest a suitable mixed-integer linear model for integrated expansion planning of G&ES with respect to the combination the relevant energy markets in [17]. Like the results of built frameworks in [18] and [19], exploring optimal capacity expansion strategies of GPGs’ units integrated with gas and electricity transmission networks in the presence of relevant markets’ uncertainties, simulation results of this work enumerate the advantages of integrating G&ES expansion planning problems generally in four cases. The findings, first, demonstrate that the planning integration can lead to capital and operation costs
reduction and so social welfare enhancement. Better identification of infrastructures weakness to meet energy demands in a long-term horizon and so better appreciate the interactions existing between G&ES in order to achieve a better coordination for the relevant decision-making systems are mentioned as the second and third advantages. And, finally, the authors conclude that integrating G&ES expansion planning problems improves EE and assets management. Evaluation of NG network constraints’ impacts on co-optimization expansion planning of power generation and transmission systems [20], and simultaneous expansion planning of gas and electricity transmission networks taking into consideration the interaction between wind and fast-response GPG units [21] are other pursued linchpins in the field of integrated expansion planning of ESs.

From reviewing above-mentioned works, it can be seen that none of them, hereafter called conventional integrated ESEP studies, distinguishes thermal load from total NG demand and considers the capability of converting energy forms to each other to meet end-user demanded energy forms; whereas, the latter is the basic of EH approach [22].

Despite the obviousness of EH approach role in achieving more optimal planning strategies, there is only a few works in the ESEP field that have focused on investigating the effectiveness of EH concept utilization in co-expansion of G&ES. The presented framework in [7], trying to determine optimal expansion strategies of distribution networks, is indeed one the first EH-based ESEP studies. But the role that EH approach in the long-term co-expansion of G&ES, for the first time, is scrutinized in [8]. This works indeed presents a linear and simplified model that only considers main infrastructures and converters of the energy systems, i.e. power generation capacity, gas and electricity transmission corridors, CHP units and gas furnaces, to meet forecasted thermal and electrical loads at minimum cost. The simulated scenarios demonstrate that planning under the umbrella of EH faces with a certain degree of flexibility for energy supply, resulting in less investment and operation costs, more reliability, and higher EE, as outlined in [9-13] addressing operation planning of heat, gas, and electricity systems in the framework of an energy hub.

To explain the flexibility from the viewpoint of EH, the effectiveness of gas storage systems (GSSs) has been less noticed until now, so that only a few recently published articles have incorporated the impact of GSSs into the planning models. In this regard, Wang et al. proposes a bi-level cost-based co-expansion planning model, which considers the interactions between wind units, P2G facilities and GSSs in the expansion planning problem of G&ES [23]. The results show that GSSs have a prominent role in coordinating the ESs by accommodating wind power and balancing temporal energy needs. Findings also reveal that GSSs together with P2G and wind units can make up a promising combination for alleviating the problems arising from the lack of NG. A
similar framework has been pursued in [24], which develops an expansion co-planning model for integrated power and gas systems with respect to NG storage and P2G facilities. From obtained results and provided discussions in this work, it can be inferred that promotion of NG converting and storage systems will be an important step toward realization of green economy and 100% penetration of RES.

Through a more precise co-expansion planning model, reference [25] scrutinizes the importance of GSSs in managing short time uncertainties in developing a long-term expansion plan for both G&ES. By adopting a chance constrained programming approach, the proposed model aims to minimize the investment cost of under-study energy systems infrastructures, while a desired confidence level for meeting future stochastic electricity and NG demands is reached. Experimental results demonstrate that GSSs are efficient in managing short-time stochasticity of the demand pairs in the long-term co-planning of the G&ES and in enhancing the reliability of both ESs. In this work, like all above-reviewed works developing an integrated planning model, the heat demand has been considered in term of NG demand, resulting in elimination of the impacts that some generating/converting technologies such as, HPs and CHPs, can have on expansion strategies from the model.

1.2. Paper aim and structure

As can be seen from the available literature, how the EH approach can improve expansion plans of gas and electricity energy systems by considering all the supply chains’ rings of the carriers demanded by end users, i.e. heat, gas, and electricity, in comparison with the common co-expansion models has been less noticed till now. Hence, to clarify how the EH concept can affect expansion strategies of G&ES in a more real, suitable, and qualified manner, this paper aims to concentrate on coordinated expansion planning of heat and electricity supply chains under the umbrella of energy hub with respect all effective rings of the chains. In doing so, a multiregional, multistage, and matrix-set-based model, formulated in term of a MIPL-based problem, is presented. GPG units, transmission lines, gas pipelines, gas supply systems, gas stations, and gas reservoir systems, along with CHP units, GDG units, gas furnaces, and heat pumps, are included the chains’ rings considered in the expansion planning problem. To achieve more realistic and compatible strategies, the most important effective aspects in planning of under-study energy systems are incorporated into the model faced by a central decision-making authority in a partially deregulated environment. Of these aspects, the contribution of private sector in investing on RES-based units in term of
independent power producers (IPPs), incentive-based energy policies, budget constraint, and climate characteristics affecting RES-based units’ capacity factor are outstanding.

To present the pursued linchpin, the rest of this paper is organized as follows. Through Section 2, prior to formulate the general model of a typical EH, its concept is scrutinized. Construction of the proposed optimization framework is allocated to Section 3. Section 4 deals with the numerical analysis where the pursued framework is implemented on the test systems. And eventually, the drawn conclusion is provided in Section 5.

2- The energy hub: A step toward the sustainable development

Through a multitude of studies, up to now, diverse definitions and models of the EH concept have been presented [6], [4]-[13]. Referring to [6], as one the first articles using the expression of EH, an energy hub is defined as a set of interface equipment between energy sources and end-users. Thus, it can be said that the EH is not a new system or infrastructure among existing ESs. It is indeed a novel and general viewpoint on ESs in planning problems while a minimum dependency between ESs, especially between G&ES, has been always existed and the possibility of converting different forms of energy to each other has been provided by technological progresses since many years ago.

To present an appropriate model of infrastructures supplying NG, thermal, and electrical loads, it is required to focus on the supply chain rings of these carriers. Regarding the structure of a NG system, gas wells, GSSs, pipelines, compressors, and demand-side convertors can be treated as the basic rings of the NG and thermal supply chains. Similarly, power plants, transmission networks, and distribution systems are included the main rings of the electricity supply chain. Now, a comprehensive expansion planning model based on the EH concept is reached, if in modeling energy carrier supply chains, not only all basic rings, but also the interaction between the carriers as well as the possibility of converting them to each other are considered. In other words, neglecting final form of energy demanded as the result of neglecting the possibility of converting energy carriers to each other (in particular in demand side) or eliminating a ring of the supply chain of the demanded carries, can disrupt the realization of EH concept in the planning. For instance, in case of the thermal supply chain, when demanded heat energy is considered in term of an equivalent value of NG demand in the planning process, G&ES cannot be completely modeled in term of an EH. Such consideration indeed causes that the role of some basic rings of the thermal supply chain, such as CHP and HPs, is eliminated from the model, while these energy converters can provide various options to supply the heat demand.
To formulate the EH concept, suppose the sets of \( 1 = (\alpha, \beta, ..., \psi) \) and \( O = (\alpha, \beta, ..., \omega) \) representing final energy forms demanded at the output of an EH and input energy forms, respectively. Regarding the type and number of converters considered within the hub, its performance in changing/converting input energy carries at the output can be mathematically modeled by a matrix, namely mapping matrix, as (1). Each mapping matrix element, named here mapping factor, indeed represents performance efficiency of one of the rings of supply chain. In doing so, if \( P_\alpha \) and \( L_\alpha \) depict electrical energy carrier at the hub input and the relevant load at output, respectively, and the substation transformer is considered as a converter which supplies a part of demanded electrical energy at the output, \( m_{\alpha,\alpha} \) indicates the transformer (substation) efficiency, as a converter with same form of input-output energy. Therefore, for each type of demand at the hub output, all possible load supplying strategies are obtained from summing the multiplication of input carriers to the relevant converters’ efficiencies.

Accordingly, in case of an EH with multiple input-output, the mapping factor of each input carrier at the output will be equal to multiplication of the efficiencies of all converters (rings) existing in the pathway between the input and output. On the other hand, each input carrier can be divided between two or more converters. To determine each converter share of each input carrier, a factor known as dispatch factor, \( \sigma \), is employed. Equation (1) can be consequently rewritten as Eq. (2):

\[
\begin{bmatrix}
L_{n} \\
L_{\beta} \\
\vdots \\
L_{\nu}
\end{bmatrix}
\begin{bmatrix}
m_{\alpha,\alpha} & m_{\beta,\alpha} & \cdots & m_{\psi,\alpha} \\
m_{\alpha,\beta} & m_{\beta,\beta} & \cdots & m_{\psi,\beta} \\
\vdots & \vdots & \ddots & \vdots \\
m_{\alpha,\nu} & m_{\beta,\nu} & \cdots & m_{\psi,\nu}
\end{bmatrix}
\begin{bmatrix}
P_{\alpha} \\
P_{\beta} \\
\vdots \\
P_{\nu}
\end{bmatrix}
= \begin{bmatrix}
P_{\alpha} \\
P_{\beta} \\
\vdots \\
P_{\nu}
\end{bmatrix}; \quad 0 \leq m_{i,j} \leq 1 \quad \forall i \in 1, j \in O
\]

\( c = \{CHP,Fur,TR,...\}; \quad \sum_{i=1}^{M} \sigma_{i \rightarrow k} = \sum_{i=1}^{M} \sigma_{i \rightarrow k}^c = \sum_{i=1}^{M} \sigma_{i \rightarrow k}^w = 1 \)
Regarding the performance efficiency of each ring shown in the figure, meeting output thermal and electrical loads can be formulated as Eq. (4), in which $\eta_{k\rightarrow s}^{GP}$ and $\eta_{k\rightarrow s}^{TL}$ depict the efficiency of gas pipeline and transmission line, respectively, as the losses of these infrastructures can be regarded in term of their efficiencies.

$$\begin{bmatrix}
L_e \\
L_{th}
\end{bmatrix} = M \begin{bmatrix}
P_e \\
P_{th}
\end{bmatrix} : \text{if } \eta_{k\rightarrow s}^{GS} \approx 1; M = \begin{bmatrix}
\eta_{k\rightarrow s}^{ST} \\
\eta_{k\rightarrow s}^{CO}
\end{bmatrix} \begin{bmatrix}
\sigma_{k\rightarrow s}^{GP} \cdot \eta_{k\rightarrow s}^{GP} + \eta_{k\rightarrow s}^{ST} + \sigma_{k\rightarrow s}^{TL} \cdot \eta_{k\rightarrow s}^{TL} + \eta_{k\rightarrow s}^{ST} + \eta_{k\rightarrow s}^{CO} \cdot \eta_{k\rightarrow s}^{GP} \\
\sigma_{k\rightarrow s}^{GP} \cdot \eta_{k\rightarrow s}^{GP} + \eta_{k\rightarrow s}^{ST} + \sigma_{k\rightarrow s}^{GP} \cdot \eta_{k\rightarrow s}^{GP} \cdot \eta_{k\rightarrow s}^{CO} \cdot \eta_{k\rightarrow s}^{GP}
\end{bmatrix}.$$  

(4)

**Fig. 1**

3- Modelling procedure of G&ES co-expansion planning under the umbrella of energy hub

In this section, a multistage, multiregional, and matrix-set based model is proposed to plan expansion strategies of G&ES infrastructures in the framework of EH, so that all capital and operation costs are minimized and meanwhile, the required techno-economic constraints are satisfied. The model, formulated in term of a mixed integer linear programming (MILP) problem, is tailored for a semi-deregulated environment to incorporate the role of RES-based IPPs into the model. Gas supply systems (set of gas wells and refineries), GSSs, gas pipelines, GPGs, and transmission lines are the main infrastructures regarded in generation and transmission sectors. GDG units, gas furnaces, and HPs along with RES-based units (in term of IPPs) are encompassed technology options considered on the demand side to convert input energy carriers into the desirable forms. Different parts of the proposed model are presented in the following.

3-1- Objective function

The objective function (OF) is comprised of the net present value (NPV) of all G&ES costs to be minimized. As can be seen in Eq. (5), the OF has 24 cost terms in (M$) defined by Eq. (6) and Eq. (7) corresponding to the heat and electricity supply chains, respectively. For instance, in case of thermal supply chain, the first term, i.e. $\Gamma_i^H$, depicts investment cost of $n^{th}$ gas supply system from type $i$ in region $s$ and $t^{th}$ stage of the planning horizon.

$$\text{Min } OF = \sum_{t=1}^{T} \sum_{s=1}^{S} \left(1+r\right)^{-t} \left[ \left(\Gamma_1^H + \Gamma_2^H + \cdots + \Gamma_n^H \right) + \left(\Gamma_1^E + \Gamma_2^E + \cdots + \Gamma_n^E \right) \right]$$

(5)
\[
\Gamma^H = \sum_{i \in T^H} \sum_{n = 1}^{N} \left( C_{inv}^{iH} (i, s, n, t) \cdot x^{iH}_n (i, s, n, t) \right) + \sum_{k = 1}^{K} \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \left( 0.5 C_{inv}^{iH} (i, s, k, n, t) \cdot x^{iH}_n (i, s, k, n, t) \right) \\
+ \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \left( C_{inv}^{iG} (i, s, n, t) \cdot x^{iG}_n (i, s, n, t) \right) + \sum_{k = 1}^{K} \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \left( C_{inv}^{iG} (i, s, k, n, t) \cdot x^{iG}_n (i, s, k, n, t) \right) \\
+ \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \sum_{b = 1}^{B} \left[ G(i, s, n, t) \cdot v^{\text{m}} (i, s, n, b, t) \right] + \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \sum_{b = 1}^{B} \left[ G(i, s, n, t) \cdot v^{\text{o}} (i, s, n, b, t) \right] + \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \sum_{b = 1}^{B} \left[ C_{inv}^{iG} (i, s, n, t) \cdot x^{iG}_n (i, s, n, t) \right] \\
+ \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \sum_{b = 1}^{B} \left[ C_{inv}^{iG} (i, s, n, t) \cdot g^{\text{sp}} (i, s, n, b, t) \right] \cdot \Phi^G (s, b, t) \\
+ \sum_{i \in T^{iH}} \sum_{n = 1}^{N} \sum_{b = 1}^{B} \left[ C_{inv}^{iG} (i, s, n, t) \cdot h^{\text{sp}} (i, s, n, b, t) \right] \cdot \Phi^H (s, b, t) \\
\]

\[
\Gamma^E = \sum_{i \in T^E} \sum_{n = 1}^{N} \left( C_{inv}^{iG} (i, s, n, t) \cdot x^{iG}_n (i, s, n, t) \right) + \sum_{i \in T^{iE}} \sum_{n = 1}^{N} \left( C_{inv}^{iG} (i, s, n, t) \cdot x^{iG}_n (i, s, n, t) \right) \\
+ \sum_{i \in T^{iE}} \sum_{n = 1}^{N} \sum_{p = 1}^{P} \left[ G(i, s, n, t) \cdot p^{\text{RE}} (i, s, n, t) \right] \cdot \Phi^E (s, b, t) \\
+ \sum_{i \in T^{iE}} \sum_{n = 1}^{N} \sum_{p = 1}^{P} \left[ C_{inv}^{iG} (i, s, n, t) \cdot p^{\text{sp}} (i, s, n, b, t) \right] \cdot \Phi^E (s, b, t) \\
+ \sum_{i \in T^{iE}} \sum_{n = 1}^{N} \sum_{p = 1}^{P} \left[ C_{inv}^{iG} (i, s, n, t) \cdot p^{\text{sp}} (i, s, n, b, t) \right] \cdot \Phi^E (s, b, t) \\
+ \sum_{i \in T^{iE}} \sum_{n = 1}^{N} \sum_{p = 1}^{P} \left[ C_{inv}^{iG} (i, s, n, t) \cdot p^{\text{sp}} (i, s, n, b, t) \right] \cdot \Phi^E (s, b, t) \\
\]

Investment costs of gas pipelines installed between regions \(s\) and \(k\), \(n^{th}\) GSS from type \(i\) in the relevant region and planning stage, gas furnaces, gas compressors, and of HPs are regarded by \(2^{nd}\)-\(6^{th}\) terms of Eq. (6), respectively. Variable operation cost of GSSs, comprising injection and withdrawal costs, the relevant fixed operation and maintenance (O&M) costs, the O&M cost of gas supply systems, their variable operation costs, and the variable operation costs of gas compressors
are depicted by last five terms, respectively. Similar to Eq. (6), Eq. (7) represents the costs associated with expansion of the NG-based supply chain of electricity carrier. The first four terms show the capital costs of GPG, CHP, and GDG units plus capital cost of transmission lines, respectively. The fifth and sixth terms are indeed the O&M costs of GPG and CHP units, respectively. The costs derived from the considered incentive measure, i.e. feed-in-tariff (FIT), to encourage IPPs to investment on RES-based units and from expected energy not supplied (EENS) during each planning stage are modeled by seventh and eighth terms of Eq. (7), respectively. And, ultimately, operation costs of all generation units are considered by last three terms of aforementioned equation.

3-2- Demand modeling

At the heart of energy systems planning problems is a load duration curve (LDC). The LDC is obtained by sorting the loads from the largest to smallest value, which results in loss of the chronological information. It indeed illustrates the frequency that a particular level of demand occurs in a year. For large-scale and long-term problems, the load duration curve can be simplified using linear approximation. Hence, we have modeled the yearly demand, by three load blocks using the base, intermediate (mid) and peak hours of a typical load-duration curve at each node. And like electricity demand, demand behaviors for the other under-study carries in each regain are modeled as the discretized LDC, as shown in Fig. 2 for NG load. In this figure, the gas supply systems are allocated to meet the base, medium, and peak-load demands during the planning horizon. As for $\Phi^G(s,B)$, $\Phi^G(s,M)$, $\Phi^G(s,P)$, they are the time periods of base, medium, and peak-load demands.

![Fig. 2](image)

3-3- NG system constraints

Regarding the first six terms of Eq. 6, representing the cost terms of gas and heat supply chains, the operation and investment costs of each infrastructure are taken into account when the state of relevant binary variable changes to 1. And this state of each binary variable is not changeable till the end of planning horizon, unless the infrastructure is decommissioned because of the lifetime constraint, if considered. The capital cost of each infrastructure is assumed to be added to the OF at the beginning of the relevant operation period. Furthermore, to compute operation costs in each stage, the number of in-operation infrastructures should be updated. The binary variables are defined by Eqs. (8) and (9); and, for the set of considered NG system infrastructures, constraints on the state of binary variables and updating number of infrastructure are formulated by Eqs. (10)-
(11) and (12)-(13), respectively. Apart from number of infrastructures, the sets encompassing technology types of each infrastructure should be also upgraded, as formulated by Eqs. (14)-(15).

\[
x^{\text{infra}}(i, s, n, t) \in \{0,1\}; t = 1,..., T; s = 1,..., S; \]
\[
n = 1,..., n_{\text{infra}}^{\text{infra}}(i, s, t); \forall i \in I_{N&E}^{\text{infra}}(s, t); \forall \text{infra} \in \{\text{SP, GS, CO, FU, HP}\}. \tag{8}
\]

\[
x^{\text{GP}}(i, s, k, n, t) \in \{0,1\}; t = 1,..., T; s = 1,..., S; k = 1,..., S, k \neq s; \]
\[
n = 1,..., n_{\text{GP}}^{\text{infra}}(i, s, k, t); \forall i \in I_{N&E}^{\text{infra}}(s, k, t). \tag{9}
\]

\[
x^{\text{infra}}(i, s, n, t) \leq x^{\text{infra}}(i, s, n, t+1); t = 1,..., T; s = 1,..., S; \]
\[
n = 1,..., n_{\text{infra}}^{\text{infra}}(i, s, t); \forall i \in I_{N&E}^{\text{infra}}(s, t); \forall \text{infra} \in \{\text{SP, GS, CO, FU, HP}\}. \tag{10}
\]

\[
x^{\text{GP}}(i, s, k, n, t) \leq x^{\text{GP}}(i, s, k, n, t+1); t = 1,..., T; s = 1,..., S; k = 1,..., S; \]
\[
n = 1,..., n_{\text{GP}}^{\text{infra}}(i, s, k, t); \forall i \in I_{N&E}^{\text{infra}}(s, k, t). \tag{11}
\]

\[
n_{\text{infra}}^{\text{infra}}(i, s, t+1) = n_{\text{infra}}^{\text{infra}}(i, s, t) + \sum_n x^{\text{infra}}(i, s, n, t); t = 1,..., T; \]
\[
s = 1,..., S; \forall i \in I_{N&E}^{\text{infra}}(s, t); \forall \text{infra} \in \{\text{SP, GS, CO, FU, HP}\}. \tag{12}
\]

\[
n_{\text{GP}}^{\text{infra}}(i, s, k, t+1) = n_{\text{GP}}^{\text{infra}}(i, s, k, t) + \sum_n x^{\text{GP}}(i, s, k, n, t); \]
\[
t = 1,..., T; s = 1,..., S; k = 1,..., S, k \neq s; \forall i \in I_{N&E}^{\text{infra}}(s, k, t). \tag{13}
\]

\[
I_{N&E}^{\text{infra}}(s, t+1) = I_{N&E}^{\text{infra}}(s, t) \cup \{i\}, \forall i \in I_{N&E}^{\text{infra}}(s), \text{if } x^{\text{infra}}(i, s, n, t) = 1; n = 1,..., n_{\text{infra}}^{\text{infra}}(i); \]
\[
t = 1,..., T; s = 1,..., S; \forall \text{infra} \in \{\text{SP, GS, CO, FU, HP}\}. \tag{14}
\]

\[
I_{N&E}^{\text{GP}}(s, k, t+1) = I_{N&E}^{\text{GP}}(s, k, t) \cup \{i\}, \forall i \in I_{N&E}^{\text{GP}}(s, k), \text{if } x^{\text{GP}}(i, s, k, n, t) = 1; n = 1,..., n_{\text{GP}}^{\text{infra}}(i); \]
\[
t = 1,..., T; s = 1,..., S; k = 1,..., S, k \neq s. \tag{15}
\]

The restrictions on installation time of each infrastructure of the NG system are incorporated into the model as follows.

\[
\sum_n x^{\text{infra}}(i, s, n, t) \leq \bar{N}^{\text{infra}}(i, s, t); t = 1,..., T; s = 1,..., S; i \in I_{N&E}^{\text{infra}}(s); \forall \text{infra} \in \{\text{SP, GS, CO, FU, HP}\}. \tag{16}
\]

\[
\sum_n x^{\text{GP}}(i, s, k, n, t) \leq \bar{N}^{\text{GP}}(i, s, k, t); t = 1,..., T; s = 1,..., S; k = 1,..., S, k \neq s; i \in I_{N&E}^{\text{GP}}. \tag{17}
\]

Gas storage systems, in particular, under-ground storage (UGS) ones, play a prominent role in load meeting during the cold periods of years and in postponing investment costs of NG systems expansion capacity. The operation of GSSs is modeled with respect to their storage volume limit as well as the limitations of NG injection and withdrawal values. A typical representation of an above-ground NG reservoir is illustrated in Fig. 3. As can be seen from this figure, a GSS characterized by a fixed volume in specific pressure, has a minimum (\(\underbar{v}(i)\)) and maximum (\(\overbar{v}(i)\))
capacity storage as well as limit injection ($v^{\text{inj}}$) and withdrawal ($v^{\text{with}}$) volumes per hour. The volume of each GSS in load block $b$ can be expressed as (18) [14]. The constraints on storage capacity and injection/withdrawal processes are also considered by Eqs. (19)-(21).

\[
v(i,s,n,b,t) = v(i,s,n,b-1,t) + \left( v^{\text{inj}}(i,s,n,b,t) - v^{\text{with}}(i,s,n,b,t) \right) \Phi^G (s,b,t); s = 1,...,S;
\]

\[
b = 1,...,B; t = 1,...,T; n = 1,...,n_{sg}^{G}(i,s,t); \forall i \in I_{s}^{G}(s,t).
\]

\[
v(i,s,n,b,t) \leq \tilde{v}(i) \quad \& \quad v(i,s,n,b,t) \geq v(i); s = 1,...,S; b = 1,...,B; t = 1,...,T; n = 1,...,n_{sg}^{G}(i,s,t); \forall i \in I_{s}^{G}(s,t).
\]

\[
v^{\text{inj}}(i,s,n,b,t) \leq v^{\text{inj}}(i); \quad \& \quad v^{\text{inj}}(i,s,n,b,t) \geq v^{\text{inj}}(i); s = 1,...,S; b = 1,...,B; t = 1,...,T; n = 1,...,n_{sg}^{G}(i,s,t); \forall i \in I_{s}^{G}(s,t).
\]

\[
v^{\text{with}}(i,s,n,b,t) \leq v^{\text{with}}(i); \quad \& \quad v^{\text{with}}(i,s,n,b,t) \geq v^{\text{with}}(i); s = 1,...,S; b = 1,...,B; t = 1,...,T;
\]

\[
n = 1,...,n_{sg}^{G}(i,s,t); \forall i \in I_{s}^{G}(s,t).
\]

Fig. 3

Completely modeling the performance of GSSs is contingent upon the consideration of GSSs’ storing capability during base and medium load periods in each stage. In doing so, if $v^{G}(s,b,t)$ depicts the volume of stored NG in region $s$ during the load block $b$, the difference between NG supply capacity plus received volume and the total of transmitted plus consumed capacities, can be stored in the GSS, as follows:

\[
v^{G}(s,b,t) = v^{G}(s,b-1,t) + \left( \sum_{i \in I_{s}^{G}(s,t)} \sum_{n=1}^{n_{sg}^{G}(i,s,t)} (v^{inj}(i,s,n,b,t) - v^{with}(i,s,n,b,t)) \right) \Phi^G (s,b,t);
\]

\[
s = 1,...,S; b = 1,...,B; t = 1,...,T.
\]

\[
v^{G}(s,b,t) \geq \tau(b) \cdot v^{G}(s,b,t); \quad \text{if} \quad \sum_{i \in I_{s}^{G}(s,t)} \sum_{n=1}^{n_{sg}^{G}(i,s,t)} g^{G}(i,n) + P_{g}^{\text{inj}}(s,b,t) \geq \Omega^G (s,b,t); s = 1,...,S; b = 1,...,b^{\text{peak}}; t = 1,...,T.
\]

\[
\frac{v^{G}(s,b,t)}{v^{G}(s,b,t)} \leq \tau(b) \leq 1; s = 1,...,S; b = 1,...,b^{\text{peak}}; t = 1,...,T.
\]

where $P_{g}^{\text{inj}}(s,b,t)$ represents total hourly NG volume injected to region $s$; $\tau(b)$ is the charge coefficient with a positive slope which cause that the GSS is charged during the base and medium-load periods, if the capacity restriction of the relevant gas supply system and the pipeline allows. As a matter of course, increase in the aforementioned coefficient results in variation of the injection variable, i.e. $v^{inj}(i,s,n,b,t)$, in the defined range with respect to the load fluctuations (demands and stations consumption values) of all other regions that along with the region $s$ are jointly supplied by the relevant gas supply system. Accordingly, from the beginning of base-load period, i.e. $b=1$, to the beginning of peak-load period, i.e. $b=b^{\text{peak}}$ in each stage, $\tau(b)$ will vary in direct proportion to the gas demands and increase the volume of stored gas to the highest possible level.
The capacity constraints of gas supply systems, pipelines, and gas compressors are taken into account by Eqs. (25)-(27):

\[
g^{SP}(i,s,n,b,t) \leq \bar{g}^{SP}(i); \quad \& \quad g^{SP}(i,s,n,b,t) \geq \underline{g}^{SP}(i); s = 1,...,S; b = 1,...,B; t = 1,...,T;
\]

\[
n = 1,...,n_{io}^{SP}(i,s,t); \forall i \in I_{N&E}^{SP}(s,t).
\]

\[
f_{g}(i,s,k,n,b,t) \leq \frac{\bar{f}_{g}(i)}{f_{g}(i)}; s = 1,...,S; k = 1,...,S; k \neq s; b = 1,...,B; t = 1,...,T; n = 1,...,n_{io}^{GP}(i,s,k,t); i \in I^{GP}.
\]

\[
\sum_{n=1}^{\sum_{i=1}^{\sum_{i=1}^{n_{io}^{GP}(i,s,t)}}} \sum_{n=1}^{\sum_{i=1}^{n_{io}^{GP}(i,s,t)}} \overline{g}(i,s,k,n,t); s = 1,...,S; k = 1,...,S; k \neq s; b = 1,...,B; t = 1,...,T.
\]

where \(F_{g}(s,k,b,t)\) is total transmitted NG volume from region \(s\) to \(k\), and \(f_{g}(i,s,k,n,b,t)\) is the pipeline gas flow variable which can take positive or negative values with regard to the flow direction [14].

In gas stations, the required electricity for gas compressors is usually supplied by located DG units consuming around 3%-5% of the transmitted gas depending upon the compressor horse power, which in turn is a function of flow rate and the ratio of input-output gas pressures, as shown in an empirical Eq. (28) [17] as:

\[
P_{c}(i,s,k,n,b,t) = \frac{F_{g}(s,k,b,t) \cdot \beta(i,s,n,t) \cdot \varphi \cdot \left(\frac{\rho^{in}(i,s,n,b,t)}{\rho^{in}(i,s,n,b,t)}\right)^{(\varphi-1)} - 1}{\eta^{co}(i)(\varphi-1)};
\]

\(s = 1,...,S; t = 1,...,T; b = 1,...,B; n = 1,...,n_{io}^{CO}(i,s,t); \forall i \in I_{N&E}^{CO}(s,t).
\]

\[
\sum_{n=1}^{\sum_{i=1}^{\sum_{i=1}^{n_{io}^{CO}(i,s,t)}}} \sum_{n=1}^{\sum_{i=1}^{n_{io}^{CO}(i,s,t)}} \overline{g}(i,s,k,n,t); t = 1,...,T; s = 1,...,S; k = 1,...,S; k \neq s; i \in I^{GP}.
\]

where \(\beta(i,s,k,n,t)\) is the participation factor of compressors in boosting the pressure of gas flow transmitted from area \(s\) to \(k\). Consequently, the NG volume consumed by each station is:

\[
G_{c}(i,s,k,n,b,t) = \frac{3.412 \times P_{c}(i,s,k,n,b,t)}{\eta^{DG}(i) \cdot \varphi}; s = 1,...,S; k = 1,...,S; k \neq s; t = 1,...,T;
\]

\(b = 1,...,B; n = 1,...,n_{io}^{CO}(i,s,t); \forall i \in I_{N&E}^{CO}(s,t).
\]

where \(\eta^{DG}(i)\) is the efficiency of GDG located at the station. Note that at given pipelines’ physical characteristics, the parameters \(\rho^{in}, \rho^{in}\), and \(\varphi\) can be estimated. And, here, they are incorporated into the model as constants to keep the linearity [17], [26].

3-4- Electricity system constraints

Regarding the enumerated factors about NG importance, enacted policies about this carrier, and the pursued linchpin, only NG-based generation technologies are considered here as the generation
sector of the electricity system. In doing so, among all conventional generation technology options on the generation side and all non-renewable DG units, gas-fired power plants, in term of combined and open-cycle gas turbine (CCGT and OCGT) units, together with CHP and GDG units are only considered to meet the projected demand. Investing on RES, in term of wind and solar units, is another load meeting option incorporated into the model as an opportunity for IPPs supported by FIT system. In the following, the constraints derived from investing and operating procedures of these generation options are modeled.

In case of the electricity sector infrastructures, definition of the binary variables along with the relevant constraints as well as updating number of infrastructures and upgrading the sets related to the type of technologies in operation, will be like Eqs. (8)-(15). Accordingly, here, transmission lines and the other electricity system infrastructures (infra), defined as the set of \{GPG, CHP, GDG, RE\}, correspond to gas pipelines and the set of NG infrastructures, i.e. \{SP, GS, CO, FU, HP\}, respectively. The bounds on installation time of the electricity infrastructures are also modeled through a way similar to the relevant constraints of the NG sector; and hence, it is avoided writing them here. The capacity bound of infrastructures are regarded as follows.

\[
p^{GPG}(i,s,n,b,t) \leq p_{GPG}(i) \quad \& \quad p^{GPG}(i,s,n,b,t) \geq p_{GPG}(i);
\]
\[
s = 1,..,S; b = 1,..,B; t = 1,..,T; n = 1,..,n^{GPG}_{id}(i,s,t); \forall i \in I^G_{N&E}(s,t).
\]  

(31)

\[
p^{CHP}(i,s,n,b,t) \leq p_{CHP}(i) \quad \& \quad p^{CHP}(i,s,n,b,t) \geq p_{CHP}(i);
\]
\[
s = 1,..,S; b = 1,..,B; t = 1,..,T; n = 1,..,n^{CHP}_{id}(i,s,t); \forall i \in I^C_{N&E}(s,t).
\]  

(32)

\[
p^{GDG}(i,s,n,b,t) \leq p_{GDG}(i) \quad \& \quad p^{GDG}(i,s,n,b,t) \geq p_{GDG}(i);
\]
\[
s = 1,..,S; b = 1,..,B; t = 1,..,T; n = 1,..,n^{GDG}_{id}(i,s,t); \forall i \in I^G_{N&E}(s,t).
\]  

(33)

\[
|f_{r,s}(k,k,n,b,t)| x^{TL}(k,s,k,n,t) \leq \overline{f_{r}}; s = 1,..,S; k = 1,..,S; k \neq s; b = 1,..,B; t = 1,..,T; n = 1,..,n^{TL}_{r,s,b}.
\]  

(34)

As the basic distinction between power industries of different countries, the restructuring has resulted in transforming planning models. In a semi-deregulated structure, the IPPs sell their generation to the utility acting as a government-dependent purchasing agent. Here, to realistically incorporate the role of RES generators in to the model, they are considered as IPPs supported by the FIT mechanism being implemented in some developing countries such as Iran. It is noteworthy that among various FIT models, the fixed premium model is considered here. In this type of FIT system, a technology specific environmental premium (bonus) is paid above the normal electricity price to the renewable energy generators mandated by a regulator and guaranteed for a fixed period of time [27]. From an IPP point of view, investing on RES-based units is contingent upon the
profitability of the project, which in turn, depends on associated capital costs, the estimated capacity factor taking into consideration the geographical features of the region, and the amount of FIT premiums. To model the guarantee on the IPPs’ investment profitability, we have:

\[
C_{ic}^{RE}(i,s,n,t) \cdot p_{RE}^{RE}(i,s,n,t) \cdot \delta(i,s) \geq \left(1 + \%\alpha\right) \left[ r \cdot C_{inc}^{RE}(i,s,n,t) + C_{ops}^{RE}(i,s,n,t) \right]; \quad s = 1,...,S; b = 1,...,B; t = 1,...,T; n = 1,...,n_{cr}^{RE}(i,s,t); \forall i \in I_{N&R&E}^{RE}(s,t).
\]

(35)

Accordingly, IPPs’ income from FIT premiums, i.e. the left side of Eq. (35), in each planning stage should be greater than total costs imposed on IPPs. This is done by \(\alpha\) which indeed is a constant between \(r\) and 1. The RES capital costs are computed in the equivalent annualized form, while the RES projects are mostly funded by (governmental) banks. Furthermore, to provide a trade-off between IPPs profit and paid subsidies by the planning authority threatened by over funding risk, the incentives are considered flexibly, as Eq. (36). The average amount of delivered power by IPPs in region \(s\), planning stage \(t\), and load block \(b\), can be computed as follows.

\[
p_{RE}^{RE}(s,b,t) = \left(\sum_{i=1}^{6} \sum_{j=1}^{6} n_{cr}^{RE}(i,j) \cdot p_{RE}^{RE}(i,s,n,t) \cdot \delta(i,s) / 8760\right); \quad s = 1,...,S; b = 1,...,B; t = 1,...,T.
\]

(37)

Of other main factors affecting expansion plans are budget constraint [28]. Here, to plan expansion strategies as realistic as possible, the constraint on budget is given as follows.

\[
Inv(t) \leq B(t); \quad t = 1,...,T.
\]

(38)

\[
B(t) = (1 + r)B(t-1) - Inv(t); \quad B(0) = B^0; \quad t = 1,...,T.
\]

(39)

\[
Inv(t) = \sum_{j=1}^{6} \Gamma_{j}^{H} + \sum_{q=1}^{4} \Gamma_{q}^{E}; \quad t = 1,...,T.
\]

(40)

Regarding the eighth term of Eq. (7), it is required that the total amount of EENS at each stage, computed by Eq. (41), is limited to a certain value, as Eq. (43). Note that since the values of lost loads in different regions may differ from one another, different EENS caps can be allocated to them by (42).

\[
EENS(s,b,t) = CR(s,b,t) \cdot \Omega_{s}^{b}(s,b,t); \quad s = 1,...,S; b = 1,...,B; t = 1,...,T.
\]

(41)

\[
\sum_{b=1}^{B} EENS(s,b,t) \leq EENS(s,t); \quad s = 1,...,S; t = 1,...,T.
\]

(42)

\[
\sum_{s=1}^{S} \sum_{t=1}^{T} EENS(s,b,t) \leq \overline{EENS}(t); \quad t = 1,...,T.
\]

(43)

3-5- Energy hub constraints
Regardless of energy distribution systems, if each region of under-study system is considered in term of a micro hub (node), the injected amount of each input carrier to each node, i.e. $P_{inj}^{\mu}(s,b,t)$, can be computed by Eq. (44) as follows [8]:

$$P_{inj}^{\mu}(s,b,t) = N_a(s,t) \cdot F_a(s,b,t); s = 1,...,S; b = 1,...,B; t = 1,...,T.$$  \hspace{1cm} (44)

where, $N_a(s,t)$, is the connectivity vector of carrier $\alpha$ for region $s$, and $F_a(s,b,t)$, is corresponding flow vector including lines/pipelines flows. The elements of $N_a(s,t)$, in fact, are the binary variables of transport/transmission infrastructures of carrier $\alpha$. To better appreciate the content of Eq. (44), consider NG carrier; if the set of gas pipelines connected to region $s$ till stage $t$, i.e. $I_{GP}^{NE}(s,k,t)$, is comprised of $q_1$ members, the expanded form of Eq. (44), i.e. Eq. (45), presents the volume of NG hourly injected to node $s$ in load block $b$ as follows:

$$P_{inj}^{\mu}(s,b,t) = N_a(s,t) \cdot F_a(s,b,t) \ast \left[ f_s(1,s,1,n,b,t) ... f_s(1,s,S,n,b,t) ... f_s(q_1,s,1,n,b,t) ... f_s(q_1,s,S,n,b,t) \right] \hspace{1cm} (45)$$

accordingly, the sum of injected and generated/produced amounts of gas and electricity carriers of each node, as a micro hub, achieves total available energy to meet projected loads as:

$$P_e(s,b,t) = N_a(s,t) \cdot F_e(s,b,t) + E(s,t) \ast p_e(s,b,t); s = 1,...,S; b = 1,...,B; t = 1,...,T.$$  \hspace{1cm} (46)

$$P_g(s,b,t) = N_a(s,t) \cdot F_g(s,b,t) + G(s,t) \ast p_g(s,b,t); s = 1,...,S; b = 1,...,B; t = 1,...,T.$$  \hspace{1cm} (47)

where $E$ and $G$ vectors are indeed the number of electricity generation units and gas supply systems in operation, respectively; $p_e$ and $p_g$ are corresponding dispatch vectors at node $s$, at stage $t$, during load block $b$. All vectors $E$, $G$, $N_e$, and $N_g$, are updated each stage with respect to the new-added generation and transmission infrastructures. To better understand aforementioned vectors, consider the electricity carrier and all considered generation options for it in hub $s$. In this hub, if the sets $I_{N&E}^{GP}(s,t)$, $I_{N&E}^{CHP}(s,t)$ and $I_{N&E}^{GDG}(s,t)$, are comprised of $q_2$, $q_3$ and $q_4$ members, respectively, the vectors $E$ and $p_e$ are defined as:

$$E(s,t) = \left[ n_{GP}^{IO}(1,s,t) ... n_{GP}^{IO}(q_2,s,t) ... n_{CHP}^{IO}(1,s,t) ... n_{CHP}^{IO}(q_3,s,t) ... n_{GDG}^{IO}(1,s,t) ... n_{GDG}^{IO}(q_4,s,t) \right]; \hspace{1cm} (48)$$

$s = 1,...,S; t = 1,...,T.$
\[
p_g(s,b,t) = \left[ p^{GPG}_g(1,s,n,b,t) \ldots p^{GPG}(q_2,s,n,b,t) \ldots p^{CHP}(1,s,n,b,t) \ldots p^{CHP}(q_3,s,n,b,t) \right]^T s = 1, \ldots, S; b = 1, \ldots, B; t = 1, \ldots, T. \tag{49}
\]

Similarly, gas supply and storage systems are the elements of vector \( G \). And the production and withdrawal values are corresponding elements of \( p_g \). Consequently, to meet demanded energy forms at each node, the input carries can be converted to each other by the corresponding mapping matrices as follows:

\[
L_g(s,b,t) - CR(s,b,t) - p^{RE}_g(s,b,t) = M_g(s,t) * P_g(s,b,t); s = 1, \ldots, S; b = 1, \ldots, B; t = 1, \ldots, T. \tag{50}
\]

\[
L_{gh}(s,b,t) = M_{gh}(s,t) * P_{gh}(s,b,t); s = 1, \ldots, S; b = 1, \ldots, B; t = 1, \ldots, T. \tag{51}
\]

Since a part of NG volume injected to each node is consumed in the electricity generation mix of that node, the share of thermal loads in injected volume, \( P_{gh}(s,b,t) \), with regard to the predicted NG demand for that node, is given by:

\[
P_{gh}(s,b,t) = P_g(s,b,t) - \Omega^G(s,b,t) - \nu^G(s,b,t) - \left( \sum_{i \in \mathcal{I}^{GCHP}(s,t)} \sum_{n=1}^{\mathcal{I}^{GCHP}(s,t)} G_c(i,s,k,n,b,t) - \sum_{i \in \mathcal{I}^{GCHP}(s,t)} \sum_{n=1}^{\mathcal{I}^{GCHP}(s,t)} p^{GPG}(i,s,n,b,t) \eta^{GPG}(i) \right) \varphi; s = 1, \ldots, S; b = 1, \ldots, B; t = 1, \ldots, T. \tag{52}
\]

4- **Numerical analysis**

In this section, the simulation results obtained from two different scenarios, conducted on a real large-scale case study, are presented and discussed. The scenarios, i.e. S1 and S2, are defined as follows; S1: conventional integrated expansion planning; and S2: EH-based integrated expansion planning. In S1, expansion of G&ES is simultaneously planned regardless of the ability of converting gas and electricity energy carriers to each other to meet heat and electricity demands on the demand side. This state is reached when the rings connecting heat and electricity supply chains to each other on that side are neglected. In doing so, thermal loads are regarded as a part of NG demand and so, some generation/conversion technology options such as GDG and CHP units, gas furnaces and HPs are eliminated from candidate options. Through the S2, the optimal integrated expansion plan of G&ES is scheduled while all considered rings for heat and electricity supply chains are incorporated into the model and the thermal load is excluded from the NG demand.

4-1- **Description of the case study, input data, and assumptions**

To investigate the adequacy of EH approach in the long-term large-scale ESs’ expansion problem, the proposed framework is applied to the Iranian electricity and gas systems, shown in
Fig. 4. Demand growth rate for each region and capacity factors related to the considered RES generators are also presented in this figure. As can be seen from Fig. 4-b, all energy demands are divided between 33 regions. Regardless of energy distribution networks, demands in each node/region are considered as a load point. The exchange rate of energy between the regions can increase by enhancing the capacity of existing transmission infrastructures and/or by implementing new transmission corridors projects. To incorporate the importance of the gas supply systems fed by common gas fields into the problem, the expansion capacities of gas supply systems related to the uncommon ones are assumed to be restricted. Here, the gas refineries located in the region 29 are considered as the supply systems fed by common gas fields. According to the base topology of each under-study energy system, candidate transmission corridors, i.e. new transmission lines and/or pipelines, are also depicted in the figure. More clarifications on this context are also presented in Fig. 4.

The more load blocks the LDC of each carrier has, the more precise models for demands behavior are reached. Hence, each planning stage (year) has been considered here in term of three load periods, i.e. base, medium, and peak, and each period, in turn, are divided into four monthly load blocks, resulting in twelves blocks. The forecasted amounts of demand for each carrier, at each node, during each load block of year 2020, as the base year of planning horizon, i.e. 2021-2030, together with the electrical load shedding price, i.e. VOLL, corresponding to each region, can be found in [29]. The techno-economic data of candidate infrastructures are itemized in Table 1. In this table, an identification code (ID) is allocated to each technology type of infrastructures in order to facilitate the illustration of simulation results. In Table 1, it also should be noted that the polyethylene type of pipelines are starred to show in the other tables; in case of storage systems, the first type, denoted by GS1, refer to the above-ground (spherical tank) NG storage system; GS2-GS4 are UGS systems based on aquifer, salt cavern, depleted field, respectively. The starred operation cost indeed include both operation and O&M costs. Furthermore, in aforementioned table, the first three types of gas-fired DG units, i.e. GDG1-GDG3 are from gas turbine technologies; and the last two types, i.e. GDG4 and GDG5, are from reciprocating engine type of gas-fired based DG technologies. In case of power generation units, the first three types of considered technologies, i.e. GPG1-GPG3, refer to CCGT units; whereas, the last two types, i.e. GPG4 and GPG5, are based on the OCGT technology. Eventually, the investment cost of new electricity transmission corridor projects and any additional path for existing topology are also assumed to be 0.24 M$/km and 0.15 M$/km, respectively [15].
Formulated as a MILP problem, the scenarios were programmed using the GAMS software and optimized via the CPLEX 11.2.0 solver. The simulations were run on a PC powered by a core i3 processor and 3 GB of RAM. Having assumed a cap on the investment budget, i.e. $B^{tot}=85000$ M$, and a 5% discount rate, the solution results of the conducted scenarios are discussed in the following.

4-2- Analysis of the co-expansion planning results

To better highlight the superiority of EH-based expansion planning approach compared with the traditional ESs’ co-expansion planning one, the results of the first scenario are presented here. In doing so, how the coordinated planning scheme leads to more optimized expansion strategies in comparison with the separate planning method are also discussed with respect to the available literature [14–21].

As S1 results summarized in Table 2 demonstrate, total amount of capacities added to the initial generation mix is 5040 MW. Note that in aforementioned table, the highlighted rows refer to the new energy transmission corridors. The NPV of the total cost associated with the added capacities along with installed transmission lines is 4517.91 M$. Feeding aforementioned added electricity generation capacities together with meeting the gas demand in each region of the case study has cost 79856.85 M$ (computed based on the NPV method) for the NG sector. Note that, in the co-expansion planning scenario, the operation cost of new-added GPG units are not taken into account; this cost indeed here lies in the operation cost of gas supply systems.

Table 3 demonstrates the details of IPPs contribution and the amounts of regions’ EENS during the planning horizon. The NPV of total incentives allocated to the RES-based generators, granted a FIT of 105 $/MWh and 122.5 $/MWh for wind and solar types [30], respectively, is 60.687 M$. In this context, as can be seen from Table 3 and Fig. 4, the regions characterized by lower electricity demand growth and higher $\delta$ have been more attractive options for attracting IPPs’ contribution. Nevertheless, the share of RES in meeting the growing demand is negligible which may be derived from being low the VOLL or incentives paid to the renewable generators. It is noteworthy that in the proposed model, the uncertainties associated with operation of the RES-based units are addressed by assuming reasonable values for their utilization hours per year, i.e. 1700 and 1400 hour/year, corresponding to the wind and solar technologies, respectively [31]. Through the S1, the total amount of EENS and the NPV of corresponding VOLLs are 68601 MWh and 67.072 M$,
respectively. The differences between the amounts of EENS in different regions can be derived from the location of GPG units, the profitability of RES-based units for the IPPs, the characteristics of transmission lines, and above all, defined prices for the shed loads.

Table 2

Table 3

As demonstrated by a wide range of research works focusing on integrated expansion/operation planning of G&ES [14-21], [32, 33], the co-planning method reaches more optimal expansion/operation strategies for both G&ES from a general point of view in comparison with the situation in which the strategies of aforementioned energy systems are separately planned. In case of co-expansion planning studies, what makes the simultaneous expansion strategies more optimal, indeed, relates to the utilization efficiency improvement of ESs’ infrastructures, which in turn is the reflection of incorporating the interactions existing between G&ES into the planning. This can be better understood by evaluation of the impacts that electricity expansion plans can have on the NG sector in the co-expansion planning approach and the separate expansion planning method, while the electricity sector can be treated as one of the main NG consumers. As a matter of course, as can be seen from the available literature [14-21], new capacities added to electricity generation mixes through separate expansion planning studies, are only translated to a part of the projected NG demand with a predefined and fixed location for the NG sector. Whereas, in the co-expansion approach, like S1 simulated here, being variable the location and capacity of NG-based generation options makes a level of flexibility for the NG sector and so a compromise between expansion of gas and electricity networks, resulting in achieving more optimal expansion strategies. Accordingly, GPG units, like a support put under a rod, can make an optimal balance between the lengths of pipelines and transmission lines.

In today’s large-scale gas energy systems, the effectiveness of gas storage systems’ role in optimizing the size of gas supply systems and pipelines has been proven, as outlined in [14], [17], [18] and [20]. Here, in order to evaluate the performance of GSS added to the under-study gas system in region 11, it is required that the NG load profile of this region together with the gas flow rate of new gas pipeline, feeding the relevant gas demand in that region, and the generation behavior of the relevant gas supply systems are assessed. In this regard, the NG load profile of region 11, the charging behavior of the GSS added to the aforementioned region, the process of stored gas volume changes, as well as the gas flow rate of 11-16 pipeline, as the only corridor covering NG demand growth of region 11, have been depicted in Fig. 5. The NG load profile of
region 11 is indeed the sum of NG demand, including gas and heat demands, and the amount of gas consumed by the electricity generation capacity added to the relevant generation mix.

Fig. 5

Regarding the arrangement of expanded gas pipelines and implemented transmission line projects, summarized in table 1, it can be observed that the gas and electricity demands of region 11 along with regions 5, 6, 10, 12, 16, 17, 22, 23, 26, and 29, are fed by the gas supply systems added to region 29. To better appreciate the dispatch of supplied gas in region 29, the implemented gas pipeline projects are shown in Fig. 6. From this figure, it is simply found that the 16-11 pipeline, feeding region 11, is originated from the gas supply systems in region 29. Note that, the electricity demands of all above-mentioned regions, expected region 6, are met by the generation capacities added to regions 16, 23, and 29, which in turn are fed by the gas supply systems of region 29. To investigate the impact that the GSS may have onto the gas supply systems, the generation behavior of them together with the sum of total NG demands of all regions covered by them during the operation period of the added GSS are demonstrated in Fig. 7.

Fig. 6
Fig. 7

The trade-off made between gas and electricity sectors in meeting total gas demands (the sum of gas and electricity demands) of the regions covered by the SP added to region 29 is apparent from Fig. 5. As can be seen from this figure, by adding the GSS to region 11, the consumed gas by the added generation mix, i.e. the 80-MW CCGT unit, to this region has decreased to the lowest possible level during the first months of GSS in-operation year, i.e. two first months of the last planning year. During this period, total electrical load of aforementioned region indeed is met by the generation mix of adjacent region, i.e. region 16. At the same time, as observable from Fig. 5-(d), the NG volume delivered to region 11 by 16-11 pipeline is at the highest possible level with respect to the pipeline capacity limit. The decrease in the gas consumption of the electricity generation mix from one hand, and receiving the highest possible NG volume through the pipeline from the other hand, in fact, provide the possibility of storing NG in the GSS in region 11, so that at the end of aforementioned period, the stored gas volume in the GSS reaches 340 MM³. At this time, indeed, the GSS has been fully charged. Following the increase in electrical loads of the regions and so in the gas demands of the generation mixes, as can be seen from Fig. 7, the sum of total NG loads of the regions is more than the maximum installed capacity of SP in region 29, i.e.
6.25 MM³/h (150 MM³/day) during the peak period. This imbalance between NG supply capacity and level of demand is indeed derived from the presence of GSS in region 11. Regarding Figs. 5-(b) and 7-(a), the GSS could result in avoiding more investing in the gas supply systems by meeting a big share of peak NG demand during the withdrawal period in accordance to the total NG demand profile, shown in Fig. 7-(b). Obviously, participation of the GSS in load meeting can lead to better budget allocation and assets management. Another notable point about above-discussed trade-off between gas and electricity generation and demand nodes relates to the shed load in region 12 during the monitored operation period. As can be seen from Fig. 7, the capacity limit of the GSS (or of the relevant feeding gas pipeline) has caused that the whole of NG demand cannot be met by the GSS during the end hours of the peak period at the planned capacity for the SP of region 29. In other words, the comparison of the NG generation level and demand in Fig. 7, when the level of stored NG volume in GSS reach to its own minimum amount, demonstrates that the GSS cannot completely cover the capacity shortage of the gas supply systems of region 29. And, this mismatch has been reflected in electrical load shedding in region 12, which may have the lowest VOLL compared with other regions supplied by the new SP installed in region 29.

4-3- Analysis of the EH-based co-expansion planning results

Main findings of the built framework in this work are analyzed here. As can be inferred from the details provided by Table 4 for S2, the focus on supplying energy demands has been a little shifted from capacity expansion of basic ESs’ infrastructures to employment of small-scale generation and/or conversion technologies in the planned expansion strategy. It is noteworthy that in this scenario, similar to S1, the operation costs of NG-based electricity generation technologies lies in the costs associated with gas supply systems, and hence, they are excluded from the OF. Note that in aforementioned table, the highlighted rows refer to the new energy transmission corridors.

Regarding the provided details in Table 4, at first glance, it may seem that hugely investing in the new heat and electricity supply chain rings, such as CHP units, HPs, and GDG units, through the second scenario has led to more costs compared with S1. Despite the plurality and diversity of added technologies and infrastructures through S2, the NPV of total costs of both under-study G&ES in this scenario equals 83721.54 M$. This cost, together with other expenditures derived from shed loads and IPPs participation, is lower by 772.87 M$ in comparison with the total costs of S1. Analysis of the findings show that various changes in the expansion strategy, affected by a higher level of flexibility provided in load meeting and infrastructures characterized by higher level of EE, could result in this cost saving. Obviously, the source of changes has been the employment
of the EH concept. It should be noted that through the second scenario, all new gas pipelines and transmission lines have been added to the base topology of under-study G&ES through the first planning stage (year 1).

Table 4

From the viewpoint of flexibility, excluding the heat loads from the total NG demand of each region together with more completely modelling the loads’ supply chains can lead to decrease required investment costs in the basic infrastructures of both G&ES. In other words, the reductions in the capacity electricity generation and gas and electricity transmission infrastructure, in fact, are the reflection of investing in the candidate distributed generation/conversion technology options and of separating final forms of energy demanded from each other. And under these circumstances, employing these generators/convertors in some cases can lead to relatively less cost in comparison to the expansion of basic ESs’ infrastructures to meet the projected demands. For instance, in case of gas pipelines capacity, as can be seen from the summarized results in Table 4, incorporation of the HPs role into the under-study supply chains can remarkably reduce the diameter of required gas pipeline projects. As a matter of course, aforementioned technologies along with CHP units provide the possibility of supplying heat loads consisting a big part of NG demands by using both G&ES infrastructures. And, the heat demand can be only met by the pipelines, when this is considered in term of the NG demand. By contrast, when the gas and heat demands are considered separately, in accordance to what exists in the real world, the NG demand in each region has the opportunity of supplying by the pipelines characterized by lower capacity (diameter), if meeting the relevant heat load via the electricity carrier (HPs) is more cost-effective. This subject can be better appreciated in case of the regions having higher heat demand growth rate, e.g. region 4 (see Fig. 4). In this energy hub, through S1, the NG demand, encompassing the heat demand, is met by the GP1 type gas pipeline (9-3 and 3-4 gas pipeline) that costs 0.38 M$/km (see Table 1). Whereas, through S2, the GP1” type of candidate technologies with lower capacity and investment cost has been selected for aforementioned gas pipeline path, resulting in 0.5 M$ cost saving for each kilometer of that path. This reduction in the costs is indeed the reflection of HPs utilization in region 4 for heat demand meeting with the aid of generated power in region 9 (see Table 4). Be noted that the difference between the expansion plan of S1 and S2 for under-study gas system is more originated from the pipelines’ capacity (diameter), while the new topology of NG network and total length of constructed pipelines in both scenarios are almost the same.
From the viewpoint of EE, incorporation of high-efficient generation/conversion technologies, such as CHP units, into the supply chains models of energy carriers demanded by end-users can obviously provide cost saving opportunities for ESs’ planners. Here, to better appreciate this context, compare the planned expansion strategies through both scenarios for meeting all demands of region 32. The peak levels of heat, gas, and electricity in this region during the last planning stage are $2.27 \times 10^6$ MMBtu (equal to $6.648 \times 10^5$ MM³/h gas) $6.22 \times 10^4$ MM³/h, and 46.47 MWh (equal to $80.15 \times 10^{-3}$ MM³/h gas), respectively [29]. As can be seen from the result tables, i.e. Tables 2 and 4, through both simulated scenarios, the gas pipeline with minimum transmission rate among exiting technology options is employed to meet the relevant NG demands. In S1, the delivered gas to aforementioned region is consumed in both gas and electricity sectors, for meeting the NG demand and feeding the new-added 80-MW GPG unit, respectively. In the second scenario, separating heat and NG demand from each other together with consideration of the conversion ability of the demanded energy carriers to each other, as the result of completing the models of under-study supply chains in the EH context, prevent from investing in new generation capacity. Under the new circumstances of the supply chains model, in fact, combination CHP and GDG units are planned to meet heat and electricity demands, resulting in avoiding the investment cost in generation mix and decreasing NG sector operation cost. And, the latter is derived from replacing basic infrastructures, such as power plants mostly characterized by low efficiencies, with high-efficient small-scale generation options.

Regarding the expansion strategies obtained from conducted scenarios, it can be seen that utilization of HP and CHP units has been more attractive than employing gas furnace technologies to meet the heat demand. This may be derived from the high coefficient of performance in HPs and the big difference between capital cost of G&ES infrastructures. As expansion costs of NG systems are very greater than the costs of electricity systems, utilization of FU with NG carrier input for meeting heat demands does not seem more economically.

In the second scenario, the amounts of not served load are 803.52 MWh and 193.44 MWh, related to the regions 18 and 19 in the ninth planning stage, respectively. The total NPV of the shed loads is 1.112 M$. By comparing the total EENS amounts of two scenarios, it can be inferred that the presence of distributed generations in the EH framework can remarkably decrease load shedding by increasing load meeting options. Through S2 also, no IPPs participates in electricity load meeting. The flexibility realizes in load meeting along with the lack of emission cap in the model can be treated as the reasons of this part of S2 expansion strategy.
5- Concluding remarks

With a special emphasis on the importance of courses of action to enhance EE, decline the energy sector impact on climate change, and generally, to modify traditional planning methods to determine more optimal and compatible strategies in ESs’ planning problems, this paper devises an analytical framework to assess the effectiveness of EH approach in co-expansion planning of G&ES. In this regard, after scrutinizing the nature of this approach by using the supply chain concept, and reviewing the chain of events that have increased the dependence of G&ES, a suitable MILP-based model for integrated planning of aforementioned ESs was presented. According to the pursued linchpin in the proposed framework, two planning scenarios were conducted, and optimal expansion strategies obtained from the simulation of each scenario were discussed in depth. The following highlights the main conclusions drawn out of the pursued framework:

1) The EH approach is not a new-invented planning tool for different ESs, but, it is a new look at the co-planning manners for them; as, the concept of ‘multi-carrier energy systems’ is not a new system among energy systems, but, it is a new attitude to integrated planning of ESs.

2) Regardless of the EH concept, the traditional expansion co-planning of G&ES results in more optimal expansion plans compared with the separate planning of these ESs obviously, as outlined in the literature. And, as the electricity demand here will be finally a part of NG demand, this can be derived from variable state of the GPG units’ locations, making the problem more flexible and consequently, providing a trade-off between the lengths of gas and electricity transmission lines.

3) In one step ahead, EH-based expansion co-planning of G&ES, and as a consequence, taking into consideration the conversion ability for final forms of demanded energy carries, offer more options for supplying the loads, increasing flexibility level of the problem once again. And this results in achieving more optimal and realistic expansion strategies compared with the conventional integrated planning method.

4) Gas storage systems can play a prominent role in balancing energy production and demands and in postponing investment costs of NG system expansion capacity.

Regarding the nature of EH approach and the importance of adopting a comprehensive view on ESs in co-planning problems, in the present work, the planning framework was built in the traditional (vertically integrated) structure of the ESs. Obviously, applying the EH approach to the liberalized structure of ESs would be very sophisticated from mathematical perspective, affected by the need for considering the relevant energy markets associated with the data exchanges constraints as well as the conflicts that may exist between independent operators of the systems.
Work in progress thereby aims at proposing an expansion co-planning model applicable to G&ES associated with their markets in a liberalized environment.

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**The caption list of figures**

Fig. 1: A typical gas-electricity energy hub
Fig. 2: The discretized NG load duration curve
Fig. 3: Schematic of a gas storage system
Fig. 4: Existing and candidate infrastructures of Iranian power system (4-a) and NG network (4-b) with demand and RES capacity factor characteristics corresponding to each region.
Fig. 5- (a): Total NG demands (sum of gas and electricity NG demands) of region 11; (b): Injection (charge) and withdrawal (discharge) amounts of the GSS; (c): The volume changes of gas stored in the GSS; (d): The flow rate of 16-11 gas pipeline during the last planning stage (in-operation year of GSS).
Fig. 6: The sketch of NG demand nodes covered by the gas supply systems of region 29.
Fig. 7- (a): Generation behavior of the gas supply systems in region 29; (b): The sum of NG demands of the regions covered by the gas supply systems of region 29 during the last planning stage (in-operation year of GSS).

**The caption list of tables**

Table 1: Techno-economic data of candidate infrastructures for the gas and electricity energy systems.
Table 2: The details of S1 expansion results.
Table 3: IPPs share and the amount of EENS in S1.
Table 4: The details of S2 expansion results.
The work figures:

1. A typical gas-electricity hub

2. Gas wells

3. Gas compressor

4. Gas furnace

5. CHP

6. GDG

7. Heat pumps

8. Substation

9. Gas pipeline

10. Transmission line

11. GPG

12. Gas reservoir

13. Gas wells

Gas flow

Power flow

Thermal flow

Fig. 1

Base load

Medium load

Peak load

Gas demand (MM $^3$)

Fig. 2
The existing transmission corridors connecting the candidate locations (substations) of new generation capacities to each other are considered as the corridors having the capability of adding new paths.

Fig. 3

(a): The electricity system

(b): The natural gas system

Fig. 4
NG demand of region 11 (MM)

NG demand (the sum of heat and gas demands)

NG consumed by the new-added GPG(s)

(a)

Charging behavior of the GSS (MM)

(b)

The stored gas volume in the GSS (MM)

(c)

Gas flow rate of the gas pipeline (NM)

(d)

Fig. 5
Fig. 6

Fig. 7
The work tables:

| Table 1 |
| --- |
| **Gas pipeline** | ID | GP1 | GP2 | GP3 | GP4 | GP5 | GP6 |
| Diameter (inch) | 24 | 30 | 36 | 42 | 48 | 56 |
| $C_{inv}$ (MS/km) | 2.9 | 4.8 | 6.7 | 9.4 | 12.2 | 12.2 |
| Max capacity (Mm$^3$/h) | 0.38 | 0.81 | 1.25 | 168 | 2.04 | 2.73 |
| **Steel** | 2.4 | 3.6 | 5 | 7 | 8.5 | - |
| **Polyeth.** | 0.22 | 0.54 | 0.86 | 1.41 | 1.85 | - |
| **CHP units** | ID | CHP1 | CHP2 | CHP3 | CHP4 | CHP5 | CHP6 |
| Capacity (MW) | 0.5 | 1 | 2 | 5 | 10 | 20 |
| $C_{inv}$ (MS/MW) | 2.1 | 2.08 | 1.96 | 1.85 | 1.8 | 1.5 |
| $C_{dep}$ (S/MWh) | 33 | 32.5 | 32 | 31.7 | 31.1 | 26.9 |
| $C_{O&M}$ (S/MWh) | 12.3 | 11 | 9.81 | 9.44 | 9.25 | 9.1 |
| Eff. | 35 | 35 | 33 | 32 | 28 | 33 |
| Gas-Elec. (%) | 44 | 42 | 41.8 | 41 | 40 | 37 |
| **NG supply system** | ID | SP1 | SP2 | SP3 | SP4 |
| Capacity (Mm$^3$/day) | 125 | 60 | 20 | 10 |
| $C_{inv}$ (MS/MM$^3$/day) | 156.95 | 160.23 | 164.61 | 169.73 |
| $C_{dep}$ (S/MM$^3$/day) | 57.56 | 58.35 | 61.28 | 63.48 |
| $C_{O&M}$ (S/MM$^3$/day) | 51.67 | 43.75 | 30 | 12.5 |
| **Gas reservoirs** | ID | GS1 | GS2 | GS3 | GS4 |
| Capacity (Mm$^3$) | 0.015 | 0.923 | 0.781 | 0.628 |
| $C_{inv}$ (MS/MM$^3$) | 1200 | 5000 | 5000 | 5000 |
| $C_{dep}$ (S/MM$^3$/h) | 250 | 1000 | 1150 | 830 |
| $C_{O&M}$ (S/MM$^3$/h) | 25.6 | 250.1 | 248.3 | 245.6 |
| **Gas compressors** | ID | CO1 | CO2 | CO3 | CO4 |
| Capacity (MW) | 25 | 50 | 75 | 100 |
| Trans. rate (Mm$^3$/h) | 1.24 | 2.92 | 4.58 | 5.83 |
| $C_{inv}$ (MS/MW) | 2 | 3.91 | 3.86 | 3.81 |
| $C_{dep}$ (S/MWh) | 0.91 | 0.90 | 0.88 | 0.88 |
| $C_{O&M}$ (S/MWh) | 252.6 | 250.1 | 248.3 | 245.6 |
| **Heat pumps** | ID | HP1 | HP2 | HP3 | HP4 |
| Capacity (MW) | 10 | 25 | 30 | 50 |
| Perform. coefficient | 3.1 | 3.12 | 3.15 | 3.3 |
| $C_{inv}$ (MS/MW) | 0.91 | 0.90 | 0.88 | 0.88 |
| $C_{dep}$ (S/MWh) | 252.6 | 250.1 | 248.3 | 245.6 |
| **Gas furnaces** | ID | FU1 | FU2 | FU3 | FU4 |
| Capacity (MMBtu/h) | 40 | 50 | 60 | 80 |
| $C_{inv}$ (MS/MMBtu) | 0.045 | 0.043 | 0.039 | 0.035 |
| $C_{dep}$ (S/MMBtu) | 3.1 | 3.31 | 3.9 | 4.5 |
| Eff. (%) | 90 | 90 | 85 | 83 |
| **GDG units** | ID | GDG1 | GDG2 | GDG3 | GDG4 | GDG5 |
| Capacity (MW) | 10 | 25 | 40 | 2 | 3 |
| $C_{inv}$ (MS/MW) | 1.3 | 1 | 0.82 | 1.8 | 1.7 |
| $C_{dep}$ (S/MWh) | 35.5 | 26.1 | 25 | 26.9 | 25.3 |
| $C_{O&M}$ (S/MWh) | 13 | 8.1 | 7 | 11.3 | 10 |
| Eff. (%) | 25 | 34 | 35.5 | 33 | 35 |
| **GPG units** | ID | GPG1 | GPG2 | GPG3 | GPG4 | GPG5 |
| Capacity (MW) | 80 | 120 | 160 | 160 | 200 |
| $C_{inv}$ (MS/MW) | 1 | 0.98 | 0.96 | 0.83 | 0.81 |
| $C_{dep}$ (S/MWh) | 16.1 | 15.3 | 14.5 | 21.6 | 21.6 |
| $C_{O&M}$ (S/MWh) | 43 | 41 | 38 | 159 | 156 |
| Eff. (%) | 55 | 58 | 61 | 41 | 41 |
| Symbol / ID of infrastructures | SP, GS, GPG, & CO | GP & TL |
|-------------------------------|-----------------|---------|
| $I$ | $n$ | $t$ | $I$ | $S$ | $k$ | $n$ | $t$ |
| SP2 | 24 | 1 | 4 | 2 | 9 | 1 | 1 |
| SP2 | 29 | 1 | 4 | 3 | 4 | 1 | 1 |
| SP3 | 13 | 1 | 1 | 3 | 9 | 1 | 1 |
| SP3 | 20 | 1 | 1 | 6 | 12 | 1 | 1 |
| SP3 | 24 | 1 | 1 | 12 | 17 | 1 | 1 |
| SP3 | 29 | 2,1 | 1,1,6 | 1 | 2 | 1 | 1 |
| SP4 | 13 | 1 | 7 | 5 | 6 | 1 | 1 |
| SP4 | 20 | 1 | 7 | 7 | 13 | 1 | 1 |
| SP4 | 29 | 1,1,1 | 4,6,8 | 8 | 15 | 1 | 1 |
| SP4 | 30 | 1,1 | 1,1 | 10 | 16 | 1 | 1 |
| SP4 | 33 | 1,1 | 1,1 | 13 | 18 | 1 | 1 |
| GS3 | 11 | 1 | 10 | 13 | 19 | 1 | 1 |
| GS3 | 3 | 1 | 1 | 14 | 15 | 1 | 1 |
| GS3 | 7 | 1 | 1 | 24 | 25 | 1 | 1 |
| GS3 | 8 | 1 | 1 | 27 | 31 | 1 | 1 |
| GS3 | 11 | 1 | 1 | 27 | 28 | 1 | 1 |
| GS3 | 13 | 1,1,1 | 1,5,8 | 30 | 31 | 1 | 1 |
| GS3 | 16 | 1,1 | 2,5 | 32 | 33 | 1 | 1 |
| GPG1 | 18 | 1 | 1 | GP1 | 11 | 16 | 1 | 1 |
| GPG1 | 19 | 1 | 1 | GP1 | 17 | 23 | 1 | 1 |
| GPG1 | 23 | 1,1 | 4,9 | GP1 | 21 | 24 | 1 | 1 |
| GPG1 | 24 | 1,2,1 | 1,3,3,9 | GP1 | 20 | 21 | 1 | 1 |
| GPG1 | 25 | 1 | 1 | GP1 | 9 | 15 | 1 | 1 |
| GPG1 | 30 | 1,1,1 | 1,4,6,8 | 16 | 17 | 1 | 1 |
| GPG1 | 32 | 1 | 1 | 17 | 22 | 1 | 1 |
| GPG1 | 33 | 1 | 4 | 22 | 29 | 1 | 1 |
| GPG1 | 9 | 1,1,1 | 4,6,8 | 23 | 26 | 1 | 1 |
| GPG1 | 16 | 1,1,1,1 | 1,5,6,9 | 26 | 29 | 1 | 1 |
| GPG2 | 23 | 1,1 | 5,6 | 15 | 21 | 1 | 1 |
| GPG2 | 24 | 1,1,1 | 1,7,8 | 1 | 2 | 1 | 1 |
| GPG2 | 29 | 1 | 1 | 2 | 9 | 1 | 1 |
| GPG2 | 33 | 1,1 | 1,6 | 4 | 9 | 1 | 1 |
| GPG3 | 3 | 1 | 1 | 5 | 12 | 1 | 1 |
| GPG3 | 29 | 1 | 4 | 6 | 12 | 1 | 1 |
| GPG5 | 16 | 1,1 | 3,7 | 6 | 7 | 1 | 6 |
| GPG5 | 23 | 1,1 | 1,1 | 9 | 10 | 1 | 1 |
| GPG5 | 24 | 1 | 5 | 11 | 16 | 1,1 | 1,5 |
| GPG5 | 17 | 1 | 1 | 12 | 17 | 1 | 1 |
| CO1 | 3 | 1 | 1 | 14 | 20 | 1 | 1 |
| CO1 | 12 | 1 | 1 | 15 | 21 | 1 | 1 |
| CO1 | 6 | 1 | 1 | 16 | 17 | 1 | 1 |
| CO1 | 2 | 1 | 1 | 17 | 22 | 1 | 1 |
| CO1 | 13 | 2 | 1,1 | 17 | 23 | 1 | 1 |
| CO1 | 15 | 1 | 1 | 20 | 24 | 1 | 1 |
| CO1 | 31 | 1 | 1 | 20 | 21 | 1 | 1 |
| CO1 | 27 | 1 | 1 | 22 | 25 | 1 | 1 |
| CO2 | 21 | 1 | 1 | 26 | 29 | 1 | 1 |
| CO2 | 26 | 1 | 1 | 27 | 30 | 1 | 1 |
| CO2 | 23 | 1 | 1 | 27 | 31 | 1 | 1 |
| CO2 | 16 | 1 | 1 | 28 | 31 | 1 | 1 |
| NFV of total inv. cost (M$) | 79856.85 | 4517.91 |
| s | EENS t [MWh] | IPPs i | n | t MW |
|---|---|---|---|---|
| 7 | - | 0 Wind | 1 | 8 | 15 |
| 12 | 10 | 45761 | - | 0 | 0 |
| 27 | - | 0 Solar | 1 | 7 | 50 |
| 28 | 9 | 2157 Solar | 1 | 8 | 50 |
| 28 | 10 | 20683 | | | |
| Total | 68601 | 115 |
| Symbol / ID of infrastructures | SP, GS, GPG, & CO | CHP & HP | GP & TL |
|-------------------------------|------------------|---------|---------|
| i | s | n | t | i | s | n | t | i | s | n | t |
| SP2 | 24 | 1 | 4 | 16 | 1 | 1 | GP1 | 11 | 1 | 16 | 2 |
| 29 | 1 | 4 | 27 | 1 | 1 | | | | | |
| SP3 | 13 | 1 | 1 | 23 | 1 | 1 | GP1 | 1 | 2 | 9 | 7 |
| 20 | 1 | 1 | 24 | 1 | 1 | | | | | |
| 24 | 1 | 1 | 31 | 1 | 1 | | | | | |
| 29 | 2,1 | 1,1,6 | 9 | 1 | 1 | | | | | |
| SP4 | 13 | 1 | 1 | 15 | 1 | 1 | GP1 | 6 | 12 | 7 | 13 |
| 20 | 1 | 7 | 21 | 1 | 1 | | | | | |
| 29 | 1,1,1 | 4,6,8,9 | 22 | 1 | 1 | | | | | |
| 30 | 1,1 | 1,6 | 26 | 1 | 1 | | | | | |
| 33 | 1,1 | 1,10 | 18 | 1 | 1 | | | | | |
| 19 | 1,1 | 1,4,8 | 20 | 1 | 1 | | | | | |
| 13 | 1,1 | 1,6 | 24 | 1 | 1 | | | | | |
| 16 | 1,1 | 8,10 | 28 | 1 | 1 | | | | | |
| 24 | 1 | 1 | 30 | 1 | 1 | | | | | |
| 29 | 1,1,1 | 1,3,7 | 18 | 1 | 1 | | | | | |
| 30 | 1 | 1 | 19 | 1 | 1 | | | | | |
| 33 | 1,1 | 1,14 | 29 | 1 | 1 | | | | | |
| GPG1 | 16 | 1,1,1 | 1,2,9 | 19 | 1,1 | 1,5 | GP3 | 20 | 21 | 12 | 17 |
| 24 | 1 | 1 | 20 | 1 | 1 | | | | | |
| 33 | 1 | 6 | 23 | 1,1 | 6,8 | GP5 | 9 | 15 | 14 | 15 |
| 29 | 1,1,1 | 4,5,8 | 27 | 1 | 1 | | | | | |
| 30 | 1 | 4 | 30 | 1 | 1 | | | | | |
| GPG2 | 9 | 1 | 3 | 7 | 1 | 1 | GP2 | 17 | 23 | 7 | 13 |
| 16 | 1,1,1 | 1,2,9 | 19 | 1,1,1 | 1,5 | GP3 | 20 | 21 | 8 | 15 |
| 24 | 1 | 1 | 20 | 1 | 1 | | | | | |
| 33 | 1 | 6 | 23 | 1,1 | 6,8 | GP5 | 9 | 15 | 14 | 15 |
| 29 | 1,1,1 | 4,5,8 | 27 | 1 | 1 | | | | | |
| GPG3 | 30 | 1 | 4 | 30 | 1 | 1 | | | | | |
| GPG4 | 9 | 1,1 | 1,5 | 31 | 1 | 1 | | | | | |
| 16 | 1,1,1 | 3,5,6 | 7 | 1 | 1 | | | | | |
| 23 | 1,1 | 1,7 | 8 | 1 | 1 | | | | | |
| GPG5 | 24 | 1,1,1 | 1,5,8 | 13 | 1 | 1 | 10 | | | | |
| 7 | 1,1 | 1,5 | 23 | 1 | 1 | | | | | |
| 8 | 1,1,1 | 1,4,7 | 24 | 1 | 1 | | | | | |
| 18 | 1,1,1 | 5,7,10 | 25 | 1 | 1 | | | | | |
| 19 | 1,1 | 1,5 | 27 | 1 | 1 | | | | | |
| 20 | 1 | 1 | 3 | 1 | 1 | | | | | |
| 29 | 1 | 9 | 9 | 1 | 1 | | | | | |
| 31 | 1,1,1 | 1,3,6 | 10 | 1 | 1 | | | | | |
| 32 | 1 | 7 | 32 | 1 | 1 | | | | | |
| GDG1 | 23 | 1 | 10 | 33 | 1 | 1 | | | | | |
| 24 | 1 | 10 | 13 | 1,1,1 | 1,4,6 | GP1 | 16 | 20 | 15 | 20 |
| 33 | 1 | 10 | 1 | 1,1,1 | 1,4,7 | | | | | |
| 9 | 1 | 10 | 2 | 1,1,1,1 | 1,3,6,9 | | | | | |
| 32 | 1 | 3 | 4 | 1,1,1 | 1,6,9 | | | | | |
| 18 | 1 | 1 | 5 | 1,1,1 | 1,3,5 | | | | | |
| 24 | 1 | 10 | 6 | 1,1,1 | 1,6 | | | | | |
| 29 | 1 | 9 | 12 | 1 | 1 | | | | | |
| 30 | 1,1 | 8,9 | 14 | 1 | 1 | | | | | |
| 7 | 1 | 10 | 15 | 1,1,1,1 | 1,3,6,9 | | | | | |
| 18 | 1 | 9 | 16 | 1,1,1 | 1,7 | | | | | |
| GDG2 | 19 | 1 | 10 | 17 | 1,1,1 | 4,5 | | | | |
| 31 | 1 | 9 | 21 | 1,1,1 | 1,7 | | | | | |
| 31 | 1 | 9 | 22 | 1 | 1 | | | | | |
| GDG3 | 20 | 1 | 8 | 26 | 1,1,1 | 1,6 | | | | |
| 2 | 1 | 1 | 4 | 1 | 3 | | | | |
| 3 | 1 | 1 | 5 | 1 | 7 | | | | |
| 6 | 1 | 1 | 11 | 1 | 10 | | | | |
| 12 | 1 | 1 | 17 | 1,1,1 | 1,7 | | | | |
| 15 | 2 | 1,1 | 11 | 1 | 4 | | | | | |
| 15 | 1 | 1 | 11 | 1,1,1 | 1,6 | | | | |
| GDG4 | 19 | 1 | 10 | 17 | 1,1,1 | 4,5 | | | | |
| 31 | 1 | 9 | 21 | 1,1,1 | 1,7 | | | | | |
| 31 | 1 | 9 | 22 | 1 | 1 | | | | | |
| GDG5 | 20 | 1 | 8 | 26 | 1,1,1 | 1,6 | | | | |
| 2 | 1 | 1 | 4 | 1 | 3 | | | | |
| 3 | 1 | 1 | 5 | 1 | 7 | | | | |
| 6 | 1 | 1 | 11 | 1 | 10 | | | | |
| 12 | 1 | 1 | 17 | 1,1,1 | 1,7 | | | | |
| 13 | 2 | 1,1 | 11 | 1 | 4 | | | | | |
| 15 | 1 | 1 | 11 | 1,1,1 | 1,6 | | | | |

The NPV of total inv. cost of the connecting rings (M$)

NG system Elec. system
78895.61 4153.44

The NPV of total inv. cost of the supply chains (M$)

CHP units Heat pumps
261.58 410.81

Table 4

The NPV of total inv. cost of the supply chains (M$)
A brief technical biography of the authors

Hadi Sadeghi received his B.Sc. degree in electrical engineering from South Tehran Branch, Islamic Azad University, Tehran, Iran in 2011 and M.Sc. degree in electrical engineering from Shahid Bahonar University of Kerman, Kerman, Iran, 2014, where he is currently working toward the Ph.D degree. His research interests are in operation and expansion planning of energy systems, smart grids and multi-carrier energy systems.

Masoud Rashidinejad received the B.Sc. degree in electrical engineering and M.Sc. degree in systems engineering from the Isfahan University of Technology, Isfahan, Iran, and the Ph.D. degree in electrical engineering from Brunel University, London, U.K., in 2000. Prof. Rashidinejad is a professor with the department of the electrical engineering, Shahid Bahonar university of Kerman, Kerman, Iran. His research interests include power system optimization, power system planning, electricity restructuring, energy efficiency, and energy management in smart electricity grids.

Moein Moeini-Aghtaie received the M.Sc. and Ph.D. degrees from Sharif University of Technology, Tehran, Iran, in 2010 and 2014, respectively, all in electrical engineering. He is currently an assistant Professor in the Department of Electrical Engineering, Sharif University of Technology, Tehran, Iran. His current research interests include reliability and resilience studies of modern distribution systems, especially in the multi-carrier energy environment, and charging management of plug-in hybrid electric-vehicles.

Amir Abdollahi-received the B.Sc. degree in electrical engineering from Shahid Bahonar University of Kerman, Kerman, Iran, in 2007, the M.Sc. degree in electrical engineering from Sharif University of Technology, Tehran, Iran, in 2009, and the Ph.D. degree in electrical engineering from Tarbiat Modares University, Tehran, in 2012. Dr. Abdollahi is currently an Associate Professor with the Department of Electrical Engineering, Shahid Bahonar University of Kerman. His research interests include demand-side management, resiliency, reliability and economics in smart electricity grids.