Economic Expansion Planning of Sub-Transmission Grid and Regional Virtual Power Plant

SEYED MASOUD MOGHADDAS TAFRESHI[1] **AND MOHAMMAD NAVIDI**[2]

[1,2]*Department of Electrical Engineering, Faculty of Engineering, university of Guilan, Rasht, Guilan province, Iran*
[*]*Corresponding author: tafreshi@guilan.ac.ir*

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This paper addresses a multi-objective approach for simultaneous dynamic expansion planning of conventional sub-transmission grid and Regional Virtual Power Plant (RVPP). In such a feed-in tariff electricity market, it will assist RVVP's stakeholders in deciding whether or not they should invest in new equipment's installation. A Multi-Objective Particle Swarm Optimization (MOPSO) algorithm as a heuristic optimization method is proposed to eliminate the conventional centralized planning, which has led to competition between Regional Electric Company (REC) and RVPP for power delivery in sub-transmission system. Two objective functions are considered for simultaneous expansion planning of these two systems. The first one takes the minimum cost of the REC, as the sub-transmission grid operator, into account while the other one considers profit maximization for RVPP. To achieve the goals, MOPSO algorithm is employed to find the best expansion of REC and best location and capacity of RVPP's resources. Having solved the proposed multi-objective optimization problem, a Pareto front is determined to show the trade-off between REC and RVPPs' contributions in joint optimal expansion planning of conventional sub-transmission grid and the RVPP. To demonstrate the applicability and effectiveness of the proposed approach, a realistic sub-transmission system in Guilan Province, Iran is used as a test system, and the results are evaluated accordingly.

keywords: *Sub-transmission network, Regional Virtual Power Plant, Simultaneous expansion planning, Multi-objective optimization*

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NOMENCLATURE

Indices

t Time subscript index, $t = \{1, \cdots, T\}, T$: Number of planning horizon year.

i Transmission subscript index, $i = \{1, \cdots, NTS\}, N_{TS}$: The number of transmission substation.

j, $j\prime$ Sub-transmission subscript index, $j, j\prime = \{1, \cdots, N_{SS}\}, N_{SS}$: The number of sub-transmission substation.

n Time duration subscript index, $n = \{1, \cdots, N_{LD}\}$ In this paper, there are six load levels

k The number of source' s subscript index in Each RVPP, $k = 1, \ldots, K$,

K The number of RVPP' s internal resources

τ Guaranteed year subscript index, $\tau = \{1, \cdots, T_G\}$

T_G The number of years that power will be purchased

Pop Population subscript index, $Pop = 1, \ldots, Popsize$

$Iteration$ Iteration subscript, $Iteration : 1, \ldots, MaxIteration$

Parameters

$SLLC$ Sub-transmission Line Loss Cost

$UGEC$ Upstream Grid Energy Cost(Paid by REC)

$SSEC$ Sub-transmission Substation Expansion Cost

$SLEC$ Sub-transmission Line Expansion Cost

$RVPPEC$ RVPP Energy Cost(Paid by REC)

ir Interest rate

LC Loss cost factor $(/MWh) Theresistanceofsub - transmissionlinealongtheijpath (Ohm/km)$

L_{ij} The total length of the sub-transmission line along the ij path (km)

I_{ij} Current flowing through the lines in ij path (A)

$T_{(.)}$ Time duration of each load level

$\prod^{G}$ Electricity price for energy purchasing from upstream utility (Transmission grid)

$\prod^{k}$ Electricity price for energy purchasing from RGES' s resources

$EC_{TS}(S_{TS}^{old}, S_{TS}^{new})$ The cost of upgrading the capacity of transmission substation j from S_{TS}^{old} to S_{TS}^{new}

$EC_{SS}(S_{SS}^{old}, S_{SS}^{new})$ The cost of upgrading the capacity of sub-transmission substation i from S_{SS}^{old} to S_{SS}^{new}

$EC_{SL}(S_{SL}^{old}, S_{SL}^{new})$ The cost of upgrading the capacity of sub-transmission line i from S_{SL}^{old} to S_{SL}^{new}

$EC_{TSL}(S_{TSL}^{old}, S_{TSL}^{new})$ The cost of upgrading the capacity of transmission line j from S_{TSL}^{old} to S_{TSL}^{new}

rf The reserve factor of substation which is a number between 0 up to 1

LF_k The lifetime of kth resources of RVPP

IC_k Installation cost of kth sources of RVPP

OC_k Operation cost of the kth sources of RVPP

DV_k Depreciation value of kth resources of RVPP

P_{tr} Total power transaction between the considered region and other regions

P^{RVPP} Generated power by RVPP' s resources

S_j^{LP} The power demand of the jth load point

Variables

P^{G} Imported power into sub-transmission(upstream) grid from the transmission grid

P^{k} Purchased power from the kth sources of RVPP

$a^{SL}, a^{TSL}, a^{TS}, a^{SS}, \gamma^{LP}$ Binary variables

1. INTRODUCTION

In conventional sub-transmission system expansion planning problems, the subject matter is to determine the type and quantity of substations and lines to be set up over each year of an extended planning horizon. However, government's financial limitations, environmental concerns, low system-wide energy efficiencies, passive defense problems, and a small share of the private sector in energy infrastructure investments are several facts that necessitate offering new models for energy system planning. Although by incorporating distributed generations (DG) into the energy mix, several issues as mentioned earlier can be addressed, stochastic nature of some DGs, especially renewable-based sources, can create uncertainty in energy supply act. Also, the increasing penetration level of DGs causes difficulties in observability and controllability of the energy systems [1]. In order to facilitate efficient planning and operation of distributed energy resources (DERs) within the system while meeting technical and economic objectives, regional energy aggregator such as VPP can be employed. In this paper, RVPP aggregates a portfolio of DERs, storage units, and responsive loads in a specific region and could play a significant role in increasing system flexibility, innovation, and autonomy. However, well planning of the RVPP throughout the system to provide the required functionalities is a must [2,3]. As mentioned later, extensive works have been carried out in the literature regarding the optimal expansion planning in transmission, sub-transmission, and distribution systems. Some tackle the planning process considering a static problem, while others address it in the form of a dynamic problem. Although an extensive amount of research has been reported in literature quantifying and optimizing the benefit of using an integrated regional energy system [4–8], only a few research has been focused on developing a multi-objective optimization model for simultaneous expansion planning of sub-transmission grid and integrated energy system. Some studies have considered only conventional planning with or without considering DG units [9–16] and several kinds of research considered aggregated expansion planning system separately from generation expansion planning (GEP) and transmission expansion planning (TEP) in power system [17–21]. However, power sectors are not separable in a vertically integrated utility system [22–26], and a modern power market includes generation units, transmission network, and RGES. Ref [26] proposed a model which planned the deployment of microgrids (MG) in the network and addressed the effect of MG with GEP and TEP under uncertainties while minimizing the total investment and operational costs. This research has mainly considered power expansion planning to minimize the total operation, investment, and load shedding costs of the system for MG investment as an option to conventional GEP and TEP problem. However, in practical, the owners of GENCOs, TRANSCOs, and MGs make decisions on the new component deployment that can maximize their own profits in such a competitive electricity market [27,28]. Ref. [29] and [30] consider only demand response aggregator in GEP and TEP, respectively. Ref [31] proposed a model for considering congestion and investment reduction in TEP. Ref [32] presented a security-constrained co-planning of transmission line expansion and energy storage. A bi-objective robust model for network expansion planning (NEP) considering the integration of the microgrid aggregators is proposed in [33,34]. However, all of them did not consider economic expansion planning of the sub-transmission system with the presence of conventional expansion planning and VPP. Also, the cost of expansion planning of conventional sub-transmission grid and profit of each agent of VPP is a great concern to investors. The main motivation of this paper is to develop a new model for REC and VPP 's investors to find optimal installation, size and time for REC to conventional sub-transmission expansion planning and VPP in the feed-in tariff market while maximizing their profits. Therefore, this paper enhances the long term VPP planning approach presented in [1], [5], [9], [33] and [35] by finding Pareto front for REC and RVPP expansion planning in feed-in tariff market. To achieve the goals, MOPSO algorithm is employed to find the best expansion of REC and best location and capacity of RVPP's resources in each year of the planning horizon. The proposed features are a tradeoff between REC' s cost and RVPP's profit. The main contributions of this paper can be outlined as the following:

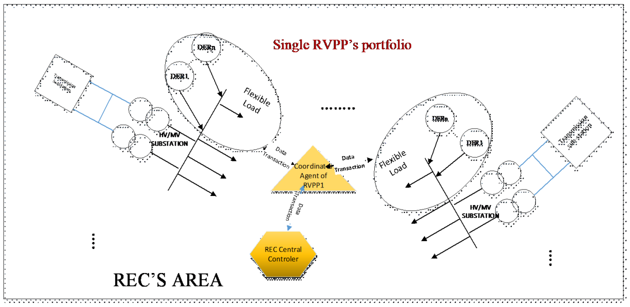


Fig. 1. Single line diagram of the proposed integrated sub-transmission grid and multiple RVPPs

- Proposing a new integrated model for TEP and GEP planning with the presence of Regional Virtual Power Plant (RVPP).
- Determining the optimal contribution of the REC and RVPP in sub-transmission expansion planning utilizing evolutionary multi-objective optimization techniques.

The remainder of this paper is organized as follows. Section 2 describes and formulates the objective functions of a government power utility(REC) and RVPP's owners. The multi-objective particle swarm optimization (MOPSO) method and solution procedure are described in Section 3 to solve the proposed expansion planning problem. The approach is then tested on a real network, and its effectiveness in different experiments is validated in Section 4. Discussion on results is described in Section 5. Finally, Section 6 concludes the paper.

2. PROBLEM STATEMENT

In simultaneous expansion planning of sub-transmission network and agent-based RVPPs, the aim is to optimally determine the expansion plan of both conventional sub-transmission system and RVPP. Fig.1 illustrates the proposed single-line diagram of an integrated sub-transmission network and RVPP where they can transact energy with each other. In this study, interactions between RVPP and REC is incorporated in our simulations. To formulate the simultaneous expansion planning problem, it is initially necessary to define the objective function for key players. REC aims at minimizing expansion and operation costs concerning the network security, while RVPP seek to maximize their profits with respect to network and other relevant constraints. These inherently conflicting objectives will yield a multi-objective optimization problem which is detailed in the following sections.

A. Model of sub-transmission substation's load

In addition to the transmission network, which supplies the load of sub-transmission system, RVPP as local energy networks, can also be involved in energy provision process. However, modeling of the substation's loads through peak value is not sufficient, and there is a need to consider the annual load durations as well. In this paper, the loads of substations are modeled as a three-level approximation of load duration curve (LDC) as shown in Fig. 2. This curve can be obtained from the power consumption history [35].

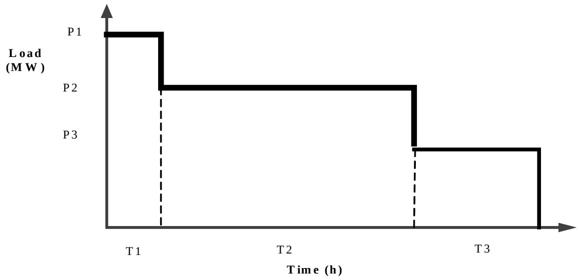


Fig. 2. . Load-duration curve of sub-transmissions' loads

B. REC objective function

The objective function of REC is to minimize the total cost of the system subject to different constraints. This objective function can be considered as the combination of cost components according to Eq. (1):

$$OF_1 = Min\left\{SLLC + UGEC + SSEC + SLEC + RVPPEC\right\} \tag{1}$$

In the above cost function, economic evaluation is made based on five terms considering their net present values. SLLC is the transmission, and sub-transmission lines losses cost as below:

$$SLLC = \sum_{t=1}^{T}(1+ir)^{-t}\left(\begin{array}{l}\sum\limits_{i=1}^{N_{TS}}\sum\limits_{j=1}^{N_{SS}}\sum\limits_{n=1}^{N_{LD}} T_n \times LC \times L_{ij}^{SL} \times R_{ij}^{SL} \times I_{ij_n}^2 \\ +\sum\limits_{i=1,i\neq j}^{N_{SS}}\sum\limits_{j=1,j\neq i}^{N_{SS}}\sum\limits_{n=1}^{N_{LD}} T_n \times LC \times L_{ij}^{SL} \times R_{ij}^{SL} \times I_{ij_n}^2\end{array}\right) \tag{2}$$

The power losses in service transformers are neglected in this study as they are relatively low compared to the line losses. UGEC is the cost of the purchased power from the utility (i.e., transmission network), which can be calculated based on (3). Generally, it is the REC which pays for the energy imported from the transmission network, which is changing over time based on the LDC. This cost is typically higher in peak hours and lower at other times. The cost of providing energy by the transmission network is given by:

$$UGEC = \sum_{t=1}^{T}(1+ir)^{-t}\sum_{i=1}^{N_{TS}}\sum_{n=1}^{N_{LD}} P_{int}^{G} \times T_{nt} \times K_{int}^{G} \tag{3}$$

It should be noted that P_{int}^{G} is an independent variable, which will be determined after the optimization process. SSEC is the transmission and sub-transmission substation expansion cost as (4):

$$\begin{aligned} SSEC = {} & \sum_{t=1}^{T}(1+ir)^{-t}\sum_{i=1}^{N_{TS}}\alpha_{it}^{TS} \times EC_{TS,i}(S_{TS,it}^{old}, S_{TS,it}^{new}) \\ & + \sum_{t=1}^{T}(1+ir)^{-t}\sum_{j=1}^{N_{SS}}\alpha_{jt}^{SS} \times EC_{SS,j}(S_{SS,jt}^{old}, S_{SS,jt}^{new}) \end{aligned} \tag{4}$$

SLEC is the expansion cost for sub-transmission lines, as stated in (5):

$$SLEC = \sum_{t=1}^{T}(1+ir)^{-t}\sum_{i=1}^{N_{TS}}\sum_{j=1}^{N_{SS}}\alpha_{ijt}^{SL}\times EC_{SL,ijt}(S_{SL,ijt}^{old},S_{SL,ijt}^{new}) + \sum_{t=1}^{T}(1+ir)^{-t}\sum_{i=1,i\neq j}^{N_{TS}}\sum_{j=1,j\neq i}^{N_{TS}}\alpha_{ijt}^{TSL}\times EC_{TSL,ijt}(S_{TSL,ijt}^{old},S_{TSL,ijt}^{new}) \quad \textbf{(5)}$$

RVPPEC is the cost of energy provision paid by the REC to the RVPP:

$$RVPPEC = \sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\sum_{t=1}^{T}\sum_{\tau=1}^{TG_{kt}}(1+ir)^{-\tau}\sum_{n=1}^{N_{LD}}P_{t\tau n}^{k_i}*\Pi_{\tau n}^{k}*T_{n\tau} \quad \textbf{(6)}$$

Counter τ also denotes the number of energy guaranteed purchase year. TG is the total number of guaranteed purchase year, which in our case study is considered as five and ten years for fossil DG and PV resources, respectively. After elapsing this time, the produced energy by RVPP's units is purchased by REC according to the price of the upstream network.$\prod_{n\tau_k}^{k}$ is the price of purchased power from the kth of the source of RVPP in the nth time duration of the τ^{th} year.

B.1. REC constraints

Transmission and sub-transmission lines thermal capacity

The loading of transmission and sub-transmission lines must be lower than their thermal capacity as formulated in Eq. (7) - (8):

$$\left|I_{ij}^{SL}\right| \leq 0.8\left|I_{ij,\max}^{SL}\right| \;\; ; \; \forall i\in\{1,2,...,N_{SS}\}, \forall j\in\{1,2,...,N_{TS}\} \quad \textbf{(7)}$$

$$\left|I_{ij}^{TSL}\right| \leq 0.8\left|I_{ij,\max}^{TSL}\right| \;\; ; \; \forall i\in\{1,2,...,N_{TS}\}, \forall j\in\{1,2,...,N_{TS}\}, i\neq j \quad \textbf{(8)}$$

In this paper, it is assumed that the maximum permitted current of each transmission and sub-transmission line is 80 % of lines thermal capacity.

Sub-transmission substations thermal capacity

The loading of sub-transmission substations must be lower than their thermal capacity as Eq. (9):

$$\sum_{j=1}^{N_{LP}}\gamma_{ij}^{lp}S_j^{LP} \leq (1-rf_1)\times S_i^{SS,\max} \;\; ; \; \forall i\in\{1,2,...,N_{SS}\} \quad \textbf{(9)}$$

According to Eq.9, the allocated load to each substation is lower than the capacity of that substation. However, Considering the reserve factor results in higher network reliability [34].

Transmission substations thermal capacity

The load of transmission substations must be lower than their thermal capacity as expressed by Eq. (10):

$$\sum_{j=1}^{N_{SS}}\gamma_{ij}^{SS}S_i^{SS} \leq (1-rf_i)\times S_i^{TS,\max} \;\; ; \; \forall i\in\{1,2,...,N_{TS}\} \quad \textbf{(10)}$$

where γ_{ij}^{SS} is binary variable set to 1 if the sub-transmission substation j is supplied from the ith transmission substation, and 0 otherwise.

Limitation of RVPP's capacity

In design of sub-transmission networks in the presence of distributed generation, it is tried to provide the majority of the needed energy from transmission network via a sub-transmission system, not from RVVP' s units [34]. Therefore, in this study, the maximum amount of power generated by RVPP is considered, according to Eq. (11):

$$S_{VPPi} \leq 0.5S_i^{TS.\max} \quad \textbf{(11)}$$

where $S_i^{TS.\max}$ is maximum transformers capacity of each sub-transmission substation determined in the expansion planning phase.

Power balance constraint

In each time interval and each LDC segment, the constraint indicated below must be respected:

$$\sum_{k=1}^{K}P_k^{VPP} + Ptr = \sum_{i=1}^{I}P_{Load_i} + P_{Loss} \quad \textbf{(12)}$$

where $P_k^{VPP]}$ is generated power of all DERs inside VPP in each time. Ptr is transaction power with other networks.

C. RVPP objective function

In order to maximize its profit, RVPP determines the right size of the resources in the local area considering time duration, investment and operation cost of resources, guaranteed power purchase rate (or feed-in-tariff), guaranteed purchase time, geographic potentials such as irradiation and wind characteristics and flexible load behaviors. In fact, having had forecasted load increment in each load point in the planning horizon, RVPP will determine needed types of resources in all sub-transmission substations to maximize its utility as below:

$$OF_2 = Max\left\{\begin{array}{l}\sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\sum_{t=1}^{T}\sum_{\tau=1}^{TG_{kt}}(1+ir)^{-\tau}\sum_{n=1}^{N_{LD}}P_{t\tau n}^{k_i}*\Pi_{\tau n}^{k}*T_{n\tau}\\ +\sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\sum_{t=1}^{T}\sum_{\tau=TG_{kt}+1}^{LF_k}(1+ir)^{-\tau}\sum_{n=1}^{N_{LD}}P_{t\tau n}^{k_i}*\Pi_{\tau n}^{k}*T_{n\tau} - \sum_{t=1}^{T}(1+ir)^{-t}\sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\\ -\sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\sum_{t=1}^{T}\sum_{\tau=1}^{TG_{kt}}(1+ir)^{-\tau}\sum_{n=1}^{N_{LD}}OC_{k_{it_\tau}} -\\ \sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\sum_{t=1}^{T}\sum_{\tau=TG_{kt}+1}^{LF_k}(1+ir)^{-\tau}\sum_{n=1}^{N_{LD}}OC_{k_{it_\tau}} + \sum_{i=1}^{N_{TS}}\sum_{k=1}^{K}\sum_{t=1}^{T}(1+i\end{array}\right. \quad \textbf{(13)}$$

C.1. Constraints of RVPP

Operational constraint of RVPP's resources

The generation of each unit within the RVPP must be less than its capacity.

$$0 \leq P_{kn}^{RVPP} \leq S_{kn}^{RVPP} \;\; ; \;\; k = 1.2.\ldots.K \;\; ; \;\; n = 1.2.\ldots.nlp \quad \textbf{(14)}$$

whereP_{kn}^{RVPP} and S_{kn}^{RVPP} are the generated power and nominal power of the kth resource of each RVPP in the nth level of LDC (MW). In this study, flexible loads have also been considered as RVPP resources, so the same constraint as in (14) will be applied to show the range in which responsive loads could react.

Limitation of feeding the load by RVPP units

In simultaneous expansion planning of sub-transmission networks and RVPP's resources, there are some network limitations, and it is tried to provide some of the required energy from transmission network via sub-transmission system, not from RVPP's units [35]. Therefore, in this study, the maximum amount of power generated by RVPP's unit is considered according to Eq. (C.1):

beginequation $\sum_{k=1}^{K} P^{RVPP}_{kn_t} \le \lambda S_t$; $k = 1.2.\ldots.K$; $t = 1.2.\ldots.T$; $n = 1.2.\ldots.N_{LP}$

Where St is the total load of the sub-transmission system in year t and the nth level of LDC (in MW). In Eq. (C.1), K is the total number of RVPP's units. λ is a number between zero and one.

3. SOLUTION PROCEDURE

A. Multi Objective Partial Swarm Optimization [37–41]

Multi-objective optimization is a class of problems with solutions, which can be evaluated along with two or more incomparable or conflicting objectives. Solving multi-objective optimization problems can be done in several ways. The simplest is to construct a single meta-objective function by taking a weighted sum of the individual objectives. Such an approach is limited, however, as it is limited to a convex subset of all non-dominated solutions. This exclusion may skip over important representative candidate solutions that would be relevant to the end user. A better approach, adopted in the evolutionary computation literature, is to a Pareto rank candidate solution, and keep an archive of all non-dominated such. In this way, it' s possible to explore the entire Pareto front without any priori knowledge about the problem. Such approaches have been explored in the context of other population-based approaches, such as particle swarm optimization (PSO), and it is the current state of the art in multi-objective optimization with PSO. So, in MOPSO, there is an archive of non-dominated solutions found at each iteration. The MOPSO steps are:

1. Initialize the swarm and archive
2. For each particle in the swarm:
   (a) Select a leader from the archive
   (b) Update velocity
   (c) Update position
3. Initialize the swarm and archive
4. For each particle in the swarm:

Finally, after determined iteration, the non-dominated solutions store in the archive. Further explanations of the MOPSO algorithm are given in Reference No. [37–41].

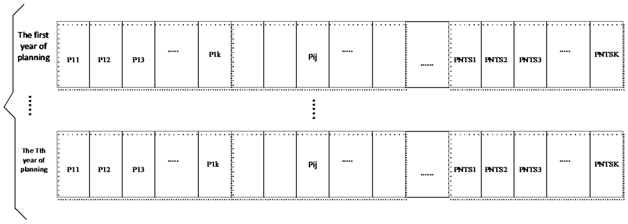


Fig. 3. configuration of population construction

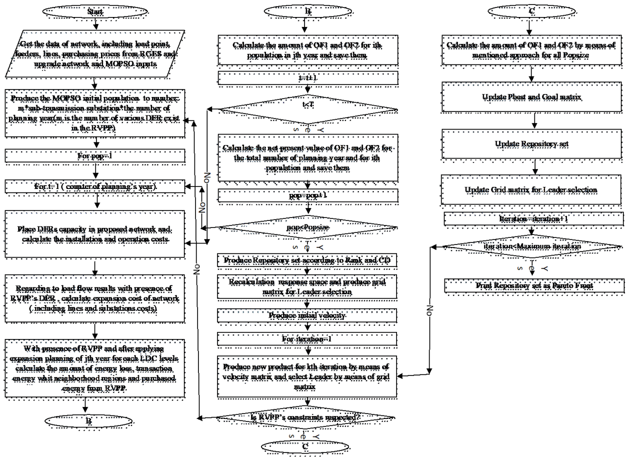


Fig. 4. flowchart of the proposed method

B. solution procedure description

In simultaneous expansion planning of sub-transmission grid and RVPP, REC as a sub-transmission expansion planner chase the following two purposes; one is to minimize the cost of traditional sub-transmission expansion planning, and the other is maximizing the profits of RVPP's investors to encourage them to invest in this sector. Problem variables are the amount of capacity of dispersed generation sources, which is considered to be between zero and 50 percent of the capacity of the sub-transmission substation transformers. After allocating distributed generation capacity of each sub-transmission substation (load point center), using Eq (12). The amount of power required to buy from the upstream network is extracted. Then, considering the Eqs. 7 - 10 , the expansion planning of lines and substations are identified. Ultimately, OF1 and OF2 are calculated, and the process will be repeated for the next chromosome. Finally, the non-dominated answers will be saved in the archived file, and using them Pareto-Front will be obtained. Fig.3 shows the general structure of chromosomes coded in PSO, where P_{ij} is a variable showing the allocated power to the source of RVPP in the sub-transmission substation, Here, it is assumed that RVPP's resources inject power to the electrical network only in the sub-transmission substations. Moreover, because of different tariffs of purchasing energy in low, mid, and peak load levels, the proposed optimization problem is solved for any of the mentioned load levels. At first, the program is run for the peak load level. In this load level, the cost of lines and substation expansion and investment cost of RVPP' s resources is determined. It is obvious that the tariff of energy purchased from RVPP's resources in this load level is the highest. After that, the program will be run for mid and low load levels. REC guarantee the purchasing energy from RVPP's resources. Energy purchasing from the upstream grid is done via REC participation in the wholesale market. In this paper, the average price of energy at each load level is considered. In Figure 4, the flowchart of the proposed method is shown.

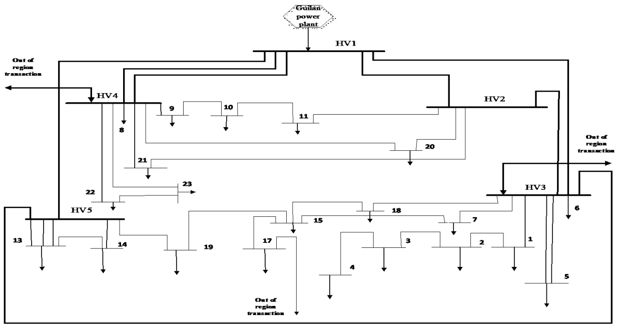


Fig. 5. Single-line diagram of the real test network

4. RESULTS

To evaluate the effectiveness of the proposed approach, the real sub-transmission system of Guilan Regional Electrical Company located in the north of Iran is used as a test case. This electrical network includes twenty-three 63/20 kV sub-transmission substations. In this research, it is assumed that all load points are located in the existing sub-transmission substations. The 63/20 kV substations are fed by five 230/63 kV transmission substation. The single line diagram of the test network is depicted in Figure 5, and its details are given in Appendices A and B. The annual load growth in all levels of LDC is assumed to be 7%. Each sub-transmission line has a capacity of 50 MW. The reserve factor for the lines and substation are considered 20% and 30% respectively [34], and the maximum constructible circuits of the lines at the corridors is 4. Also, it is assumed that each DG unit has the size of 1 MW to be installed in each sub-transmission substation.

The number of study years in the examined expansion planning problem is 5. Other required parameters are given in Table 1. In this case study, it is assumed that RVPP has only two resources; DG and DR units, but in general, RVPP can have various types of DERs that are dependent on geographic and another potential of the intended region.

To study the effects of RVPP in sub-transmission expansion planning, two different cases are considered as follows: Case 1(Conventional case): There are no installed RVPP units in the local area and the whole load of the sub-transmission system is provided by the transmission network. This case represents the conventional sub-transmission network model, where there is no contribution from local energy sources. Also, the optimal expansion planning model for such a network will primarily targets OF_1 as an objective. Case 2: Represents a situation where both the conventional system and RVPP' agents can actively participate in energy provision services. Also, RVPP's agents (here only DG and DR agents are considered) could contribute to the sub-transmission expansion planning process through optimal management of their supply/demand side assets. Such an optimal expansion planning model necessitates a two-objective optimization process where OF_1 and OF_2 are taken into consideration at the same time. In Table 2 and 3, required data for the technical and economic evaluation of sub-transmission expansion planning model and MOPSO parameters are depicted, respectively. Real information about GREC's network is used for both case studies. Also, a practical framework is developed using digital simulation and electrical network calculation program (DIgSILENT) with an integrated interface to an optimization engine to better match the examined system into the real case and help to explore the system performance more in detail.

Table 2. Technical and economic data used to create the sub-transmission expansion planning model

Parameter	Value[36]
Secondary voltage of sub-transmission substation (KV)	20
Maximum capacity of each MV feeder (MVA)	7
Cost of transformer capacity increment($/MVA)	12500
Cost of each MV bay installation(with maximum capacity of 7 MW)($)	2850
Cost of each HV (63 kV) bay installation(with maximum capacity of 50 MVA) ($)	285000
Cost of 63 kV overhead line extension with 50 MVA capacity($/km)	80000
Cost of 230 KV overhead line extension with 250 MVA capacity ($/km)	200000

Table 3. MOPSO Parametersl

Parameter	Value[37]
Number of iteration	100
Number of population	20
Repository size	10
Inertia coefficient	0.5
Mutation rate	0.5
C1	1.5
C2	2

5. DISCUSSION

Results of the optimal expansion planning in each case study are shown in Table 4 in terms of different objectives and cost/benefit components. As it can be seen, incorporation of RVPP's resources in the expansion planning model could not only decrease overall system losses but also mitigate the cost of lines and substations expansion as well as the purchased energy from transmission network. It can be observed from simulation results that the main cost component in a conventional expansion planning (case 1) relates to the UGEC (Figure 6). The results of the second case study are tabulated in other rows of Table 4. By solving the proposed two-objective optimization problem using MOPSO algorithm, a set of non-dominated solutions are found. The Pareto front of optimal solutions for the mentioned problem which are stored in a finite-sized repository is shown in Figure 7. As observed, the proposed multi-objective optimization model yields a true and well-distributed set of Pareto-optimal solutions giving the system planers (e.g. REC and RVPP owners) various options to select an appropriate expansion plan according to economic and/or technical considerations. As an illustrative example, in Guilan regional network which is the real test case of

Table 1. Technical and economic data for study

Parameter	Notation	Value	Parameter	Notation	Value
Interest rate (%)	ir	7	Duration of day peak load(h)	T_n	600
Number of planning years	t	5	Duration of day mid load(h)	T_n	2260
The annual growth rate of the guaranteed purchase (%)	ir	7	Duration of day low load(h)	T_n	1000
Maximum allowed voltage drop	$\Delta V\%$	5	Transmission electricity price in the peak-load level (/MWh$)	K^G_{int}	50
Maximum RVPP's resources penetration (%)	λ	50	Transmission electricity price in the mid-load level (/MWh$)	K^G_{int}	30
Installation cost of DG units (/MW$) [36]	IC	200000	Transmission electricity price in the low-load level (/MWh$)	K^G_{int}	20
Operating cost of DG units (/MWh$) [36]	OC	25	Cost of DR in the peak-load level(/MWh$)[36]	$K^i_{nt\tau}$	80
RVPP electricity price in the peak-load level (/MWh$)	$K^i_{nt\tau}$	70	Cost of DR in the mid-load level(/MWh$)[36]	$K^i_{nt\tau}$	40
RVPP electricity price in the mid-load level(/MWh$)	$K^i_{nt\tau}$	40	Cost of DR in the low-load level(/MWh$)[36]	$K^i_{nt\tau}$	30
RVPP electricity price in the low-load level (/MWh$)	$K^i_{nt\tau}$	30	Penalty cost of load loss in sub-transmission (/MWh$) [36]	LC	15.22
Duration of night peak load(h)	T_{nt}	400			
Duration of night mid load(h)	T_{nt}	3000			
Duration of night low load(h)	T_{nt}	1500			

this study, the total cost of given expansion plans could be very different according to several factors such as large-scale land acquisitions and leases, weather conditions and legal considerations. These factors can push an expansion plan to a highly expensive and time-consuming point or even on the verge of infeasibility. Getting back to the results shown in Table 4, it is understood that, although the first point in the Pareto set, here named as Pareto 1, has the least cost for REC, it denotes the most extended lines expansion plan, which enforces the least profit for RVPP accordingly. On the other hand, Pareto 2, shows a situation where the expansion plan results in maximum OF2 for the RVPP and low SLEC and SSEC. In Pareto 2, SLLC is also minimum, which is well for REC. Thus, this Pareto point can be a candidate choice for REC and RVPP owners from an economic perspective. Besides, in this Pareto point, DR contribution is the highest. In addition, Pareto 6 and 8, have lower SLEC, SSEC and SLLC, and higher OF2 simultaneously in comparison with other Pareto points. Pareto 7 has maximum loss cost, lines, and substations expansion costs and less profit for RVPP, which is not favorable for RVPP and GREC. Totally, considering REC and RVPP conditions, SSEC, SLEC, SLLC, and UGEC indices are minimum in Pareto 2 and 6, that is considerable for GREC and OF2, which are maximum in those Pareto points. Therefore, they can be acceptable answers for REC and RVPP. As seen in Pareto 6, which has the highest DR revenue, there are lowest SLEC, SSEC and SLLC that is a logical result.

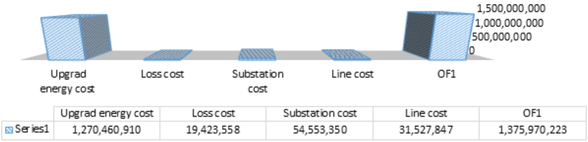


Fig. 6. Conventional planning cost components

Fig. 8 shows a comparison between the expansion costs of substations and lines as well as the loss cost in a conventional expansion planning model and the simultaneous one (conducted for Pareto 6). It is observed that a joint expansion planning model could decrease the costs of lines and substations expansion and losses in comparison with a conventional model, by 84%, 82.5%, and 47%, respectively.

Table 4. Summary of simulation results

Price in $	OF1	OF2	Line cost (SLEC)	Substation cost(SSEC)	DG installation cost(IC)	DG operation cost(OC)	Loss cost(SLLC)	Upgrad energy cost(UGEC)
Base case	1,375,970,223	0	31,527,847	54,553,350	0	0	19,423,558	1,270,460,910
Pareto 1	1,072,055,851	296,085,956	12,201,400	18,790,700	34,200,000	20,673,600	11,638,323	678,462,873
pareto 2	1,350,667,583	784,678,092	4,989,500	9,739,100	93,200,000	69,389,400	10,331,732	343,351,851
Pareto 3	1,197,353,829	524,463,564	8,767,800	10,426,600	63,800,000	44,895,000	10,854,441	534,146,423
Pareto 4	1,170,092,505	481,197,266	5,630,850	10,489,100	61,800,000	41,610,000	11,179,400	558,185,887
Pareto 5	1,140,231,562	425,220,462	52,161,450	11,526,600	51,200,000	33,594,600	11,133,416	601,897,299
Pareto 6	1,327,332,171	743,740,896	4,989,500	9,551,600	92,200,000	67,276,200	10,313,150	399,090,222
Pareto 7	1,092,861,517	330,116,226	13,072,650	19,578,200	38,800,000	24,090,000	11,277,738	655,751,199
Pareto 8	1,309,658,188	714,690,282	4,989,500	9,176,600	87,400,000	62,809,200	10,596,335	420,025,270
Pareto 9	1,213,933,558	544,180,454	8,554,645	10,864,100	66,800,000	45,814,800	10,830,974	418,684,582
Pareto 10	1,156,721,359	442,476,104	8,556,800	18,603,200	53,200,000	35,959,800	10,915,061	568,990,395

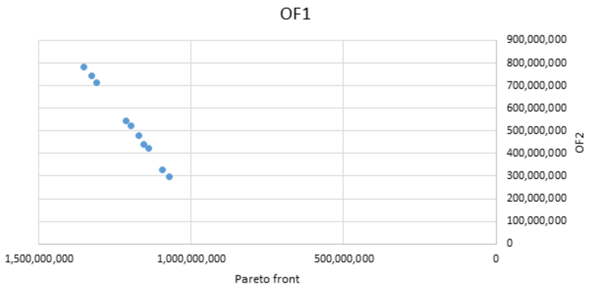
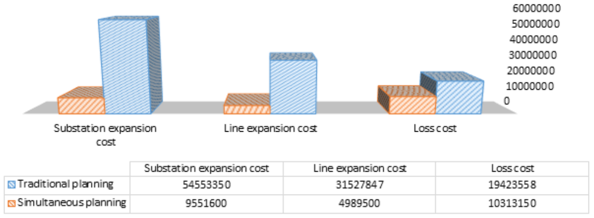


Fig. 7. Pareto front diagram



	Substation expansion cost	Line expansion cost	Loss cost
▨ Traditional planning	54553350	31527847	19423558
▨ Simultaneous planning	9551600	4989500	10313150

Fig. 8. substation and line expansion cost and loss cost comparison in conventional and simultaneous planning

6. CONCLUSION

In this paper, an efficient expansion planning model of electricity networks at sub-transmission level was proposed, based on the Regional-based virtual power plant (RVPP) concept. A regional-based VPP could participate in sub-transmission grid expansion planning and contribute to energy provision services over the long-run period. The proposed model, with all system constraints was expressed as an optimization problem with multiple conflicting objectives and different cost-profit components. Through a real test system and using computer simulations in two different cases, the effectiveness of the proposed approach was demonstrated. The results showed that simultaneous expansion planning of sub-transmission grid Regional-based VPP could decrease loss cost, lines and substation expansion cost and total cost of given REC, while preserving the profits for all agents of RVPP. As future work, the reliability and resiliency indices of the sub-transmission grid with the presence of RVPP can be investigated.

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