IET Smart Grid

Research Article

Assessing the benefits of capacity payment, feed-in-tariff and time-of-use programme on long-term renewable energy sources integration

eISSN 2515-2947
Received on 28th December 2018
Revised 14th July 2019
Accepted on 18th July 2019
E-First on 30th August 2019
doi: 10.1049/iet-stg.2018.0298
www.ietdl.org

Mohammad Sadegh Javadi[1] ✉, Ali Esmaeel Nezhad[2], Miadreza Shafie-khah[3], Pierluigi Siano[4], João P.S. Catalão[5]

[1]*Institute for Systems and Computer Engineering, Technology and Science (INESC TEC), Porto, Portugal*
[2]*Department of Electrical, Electronic, and Information Engineering, University of Bologna, Italy*
[3]*School of Technology and Innovations, University of Vaasa, 65200 Vaasa, Finland*
[4]*University of Salerno, Fisciano (SA), Italy*
[5]*Faculty of Engineering of the University of Porto and INESC TEC, Porto, Portugal*
✉ *E-mail: msjavadi@gmail.com*

Abstract: Recently, demand response programmes (DRPs) have captured great attention in electric power systems. DRPs such as time-of-use (ToU) programme can be efficiently employed in the power system planning to reform the long-term behaviour of the load demands. The composite generation expansion planning (GEP) and transmission expansion planning (TEP) known as composite GEP–TEP is of high significance in power systems to meet the future load demand of the system and also integrate renewable energy sources (RESs). In this regard, this study presents a dynamic optimisation framework for the composite GEP–TEP problem taking into consideration the ToU programme and also, the incentive-based and supportive programmes. Accordingly, the performances of the capacity payment and feed-in tariff mechanisms and the ToU programme in integrating RESs and reducing the total cost have been evaluated in this study. The problem has been formulated and solved as a standard two-stage mixed-integer linear programming model aimed at minimising the total costs. In this model, the ToU programme is applied and the results are fed into the expansion planning problem as the input. The proposed framework is simulated on the IEEE Reliability Test System to verify the effectiveness of the model and discuss the results obtained from implementing the mentioned mechanisms to support the RESs integration.

Nomenclature

Variables

PG	power production of generating units
PL	transmission line flow
OC	operational cost
TC	total cost
Gn, Ln	generation and transmission investment status
δ	bus voltage angle
PD	elastic demanded load
IG	operating status of generating units
INVC, OPC	investment and operational cost

Constant

d	interest rate
E, C	index for existing/candidate assets
b; NB	load block; total load duration curve's blocks
i; NG	index for generation buses; total generation buses
k; NCU, NEU	index for units; total candidate/existing units
j; NCL, NEL	index for branches; total candidate/existing links
l; ND	index for load buses; total load buses
t; NT	index for time; operating horizon
y; NY	index for years; planning horizon
GI, TI	generation and transmission investment cost
CP; FIT	capacity payment; feed-in-tariff
MTGI, MTTI	minimum time for generation/transmission installation
TGI, TTI	maximum generation/transmission investment budget
TGC, TIC	maximum generation/transmission capacity additions
B	susceptance of transmission line
α, β	minimum and maximum reserve margin index
SRU, SRD	shifting ramp up/down
μ	load shifting index in ToU implementation
max, min	maximum and minimum of variables
DT_{by}	time duration in the LDC
IB	total incentive budget
M	a big constant

1 Introduction

1.1 Motivation

The generation expansion planning (GEP) problem is of high significance in electric power systems and implemented to mitigate the operating costs and increase renewable energy penetration in the generation mix. The actions to reduce the greenhouse gas (GHG) emissions and also to reduce the risk due to the fossil fuel price variations have been already begun and they are in process. Various mechanisms such as feed-in tariff (FIT), premium payment, green certificate, renewable quotas obligations and subsidies have been employed in different countries to incentivise the investment in the renewable energy sector [1]. On the other hand, the independent system operator (ISO) focuses on utilising different generation technologies which can lead to cost reduction, stability enhancement, optimal reserve allocation, and eventually, more economic and reliable load demand procurement.

Although the ISO tends to increase the penetration of renewable energies, the uncertainties associated with such generation technologies would be a severe challenge. Besides, the capital cost of renewable energy units is substantial that along with the uncertain power generation decreases the rate of return. However, some other mechanisms have been introduced to support the investment in the generation system expansion, such as the capacity payment (CP). The supporting mechanisms for investment can be considered in two main categories: (i) Installed capacity oriented policy; (ii) Energy production oriented policy. It is noted that either the two mechanisms or each one alone can be applied to a market. Precise determination of the support for the private sector to invest requires a techno-economic analysis. For instance, Poullikkas [2] has used the GEP simulation called 'Wien Automatic System Planning (WASP-IV)' and genetic algorithm to determine the optimal used FIT. Furthermore, the value of lost load and load duration curve (LDC) have been employed in [3].

The experience related to the price increase and market power in restructured power systems have turned into the main factor to support and incentivise the generation investment [4]. Although such mechanisms are effective in increasing the generation capacity, they are less efficient compared to the peak-load demand reduction based policies. Recently, stimulating market demand has been presented as a fundamental method to change the end-users' behaviour [5]. By optimally determining the best generation mix among renewable energies, thermal and nuclear-generating units, the ISO would be able to reduce the cost and enhance the reliability and the service quality without any load curtailment. Thus, it is highly needed to propose a long-term planning framework to assess the impact of incentive-based and supportive mechanisms and the demand response programmes (DRPs) in the presence of renewable energies.

1.2 Literature review

Different models have thus far been proposed for the composite GEP and transmission expansion planning (TEP) problem, such as static models [6–8] and dynamic models [9–11]. Besides, some models are single-objective [12–14] while some of them are multi-objective [15–18]. Asensio *et al*. [19] proposed a sustainable expansion planning in distribution systems and Bagheri *et al*. [20] focused on increasing the renewable energy contribution and ultimately, implementing 100% renewable energies. A multi-objective wind farm integration framework is proposed in [21] taking into account the composite generation and reliability assessment as well as the annualised operating and investment cost evaluation. Javadi and Esmaeel Nezhad [22] present a multi-year, multi-objective framework for integrating renewable energy sources (RESs) into the high voltage transmission network of Iran's National Power Grid. The robust optimisation has also been suggested for the planning problems [23–25]. Demand-side management and DRPs and their impacts on the long-term planning of power systems have been also discussed in the literature. The TEP assessment taking into consideration the feasibility of distributed generation and DRP deployment has been carried out in [26]. Also, Lohmann [27] investigates the role of short-term DRPs in the GEP. The application of the DRPs in the energy trading in the distribution networks in the presence of renewable energies has been discussed in [28] using a bi-level optimisation technique. A decentralised demand response framework has been presented in [29] aimed at minimising the suppliers' and consumers' cost. In this respect, a comprehensive review has been carried out on the DRP in the context of smart grids [30].

1.3 Contributions

This paper presents a dynamic optimisation framework for the composite GEP–TEP problem considering the impact of different incentive-based and supportive policies. Both installed capacity oriented policy and energy production-oriented policy are taken into account in the proposed framework. Besides, a linear optimisation technique has been used to model the performance of time-of-use (ToU) programmes. By utilising this technique, the LDC used in long-term planning is reformed. Accordingly, the output of the presented model would be the input to the expansion planning problem. In fact, the problem has been modelled in a two-stage linear framework in which the master problem includes the decision variables of long-term planning at the first stage and the slave problem includes the operational variables at the second stage. Using this framework, the computational burden of the problem considerably reduces and the rate of convergence substantially improves. Moreover, a feasibility analysis is carried out at the first stage to eliminate the infeasible solutions. Consequently, there would be no need to do the optimality analysis at the second stage. The main contributions of this paper can be briefly stated as follows:

- Proposing a linear model for the ToU programme assessment and extending it to long-term planning.
- Developing a mixed-integer linear programming (MILP) framework for assessing the incentive-based and supportive policies based on both installed capacity and energy production-oriented policies.

1.4 Paper organisation

The remainder of this paper is as follows: Section 2 discusses the incentive-based and supportive policies for the GEP. The composite GEP–TEP problem is proposed in Section 3 and the detailed mathematical model is presented in Section 4. Section 5 includes the simulation results and finally, Section 6 draws some relevant conclusions.

2 Incentive and supportive policies in GEP

Incentive-based and supportive policies have been introduced in many countries to motivate the private sector investment. Among various mechanisms suggested so far, giving a loan, subsidy to provide the required investment sources, guaranteed energy purchase, discount on the fuel price due to higher efficiency than the installed units, and energy purchase from renewable energy units at a higher price compared to the fossil-fuel units are some examples. Accordingly, two categories can be considered for the incentive-based programmes:

(i) Installed capacity oriented policy.
(ii) Energy production oriented policy.

2.1 Installed capacity oriented policy

Installed capacity oriented policies are used to increase the installed generation capacity, ensure the investment absorption in the generation sector, and also to supply a fraction of the investment costs. This type of policies seeks to incentivise the private sector to participate in the energy generation in a way that it would be interesting.

It should be noted that it would be impossible to permanently use all generating units as the amount of the load demand varies over the different hours of a day and also over different months and seasons. Accordingly, in the presence of low-cost base-load generating units, there would be no opportunity for using all generating units. Thus, the investor will face the loss of profit which can negatively affect the performance of the private sector regarding the investment in the power market.

On the other hand, such units must exist in the network to serve the peak load, otherwise, load curtailment may occur. Besides, the investment cost increases due to installing low-cost generating units requiring a substantial initial investment. Therefore, the installed capacity oriented policies are put into action to incentivise the investment and also to reduce the risk due to not participating in the power market caused by the fact that they cannot compete with low-cost units. This policy known as the CP may be paid to the Generation Companies (GenCOs) on an hourly basis, while it is designed based on the installed capacity of the unit independently from the amount of power generation. In this respect, the planning entity considers such a policy to permanently send positive economic signals to the private sector in order to actively participate in the power market. It is worth mentioning that this policy can proceed until the required investment in the generation sector is made. However, it is assumed that this policy will continue to increase the participation factor.

2.2 Energy production oriented policy

Supporting policies based on the amount of power generation are provided to support the efficient power generation and also as a signal to motivate the investors towards low-cost power generation in the market. It is obvious that the investment cost of high-efficiency units would be higher. Thus, there should be sufficient support for the investments in the clean and renewable energies to cover the noticeable investment cost. By mitigating the dependency on fossil fuels in the generation sector, the amount of GHG emissions would be reduced and that fossil fuel can be used in another industrial sector.

Meanwhile, increasing the energy density would be an incentivising action to support the high-efficiency generating units. The FIT can be assigned to the generating units in case of power generation. FIT can be different for various load levels and different seasons. The government can utilise the FIT mechanism in an optimal manner to support the high-efficiency units and renewable energies such that a fraction of the private sectors' cost is compensated. A higher price can be paid to non-fossil-fuel generating units compared to those having GHG emissions. This type of supportive policy can be either temporary or permanent. In this paper, it is assumed that this policy would be valid over the entire planning horizon, but different FITs can be applied proportionally to the amount of the load demand.

3 Dynamic expansion planning model

Generally, the power system expansion planning problems are formulated as optimisation problems with techno-economic constraints. Therefore, two different strategies can be discussed regarding the GEP and TEP problems. The first strategy would be minimising the total cost stated from the ISO's point of view while the second strategy would be proposed from the government's or the private sector's point of view to maximise the profit. However, a more general strategy can be considered for the GEP and TEP problems in which social welfare can be maximised besides taking into account the total system's cost and profit. The only difference between the models relate to the definition of the objective function and some of the constraints. The capital cost in the objective function is the key factor in each of the mentioned models. The main goal of the investor would be managing financial resources and the available budget for purchasing and installing the required assets. Moreover, taking an optimal decision on the type, capacity, and the number of the required generating units would be of great significance ultimately resulting in the total operating cost minimisation. The most important constraint of the presented problem is supplying the future load demand of the system. This constraint should be in accordance with the capacity of the existing units, the hourly load demand, and the required reserve of the system to cope with the scheduled outages and contingencies. The composite GEP–TEP problem is formulated as an optimisation problem with various constraints. The decision variables of the problem can be categorised into three different groups:

- The combination (generation mix) problem
- The design analysis
- The operation analysis

The problem of optimal generation mix problem determines the type of required generation and transmission assets. Hence, with respect to the type of fuel and different available generation technologies, the best generation mix is selected to supply the load demand. The design stage determines the optimal capacity and the number of assets such that the operation of the system would be at the minimum cost and minimum risk considering the hourly, monthly and seasonal load demand.

At the third stage, i.e. the operation stage, the operation of the system would be done to supply the load demand at the minimum cost. However, various objective functions can be represented beside the total cost minimisation, such as emission reduction, reliability enhancement, risk mitigation etc. [31, 32]. The constraints of the problem are also categorised into different types. Some constraints relate to the financial issues and budget limitations and some constraints are technical relating to the technology, capacity, time response, efficiency etc. The power balance constraint is the most vital technical constraint which can be somehow economical, since in case of not supplying the load demand, customers' dissatisfaction may occur. Thus, the power balance constraint would be techno-economic. Another technical constraint of the problem is the determination of the optimal operating points of the assets over the scheduling horizon, i.e. determination of the optimal power generation of units and the power flow of transmission lines and transformers. Since the real-time power balance impacts the system's frequency, it is required to allocate the required reserve to the system to confront the unscheduled conditions. The amount of the reserve depends upon the system conditions and the capacity of the largest generating unit, the failure rate of the generation and transmission assets, and also the reliability considerations. Two types of variables influencing the optimal operating points' determination are either continuous or discrete. For instance, the power flow of transmission lines and the power generation of the units are of continuous types while the tap position of the transformers is a discrete variable. Furthermore, a binary variable is defined to specify the status of the unit. In this respect, this binary variable would be equal to '1' in case the unit is committed, otherwise '0'. Besides, a binary variable can be similarly defined to determine the status of the transmission lines and transformers. Adding these binary variables would turn the presented optimisation problem into a MILP problem.

4 Problem formulation

This paper presents a two-stage model to decompose the variables to generation mix and design variables put in one stage and the operation variables in another stage. It is noted that the generation mix and design variables directly impact the operation stage, but they are independent of the time analysis viewpoint. So, they can be separated from the operation variables. The time independency means that in case of selecting an asset, its availability status would not be a variable any longer in the operation stage and it can be used as an available asset. The mentioned asset can be either used or not used in the operation stage. Accordingly, two binary variables are associated with each asset; one in the design stage and one in the operation stage that in spite of dependence on each other, they are independent of the time viewpoint. The objective function (1) includes the master problem and the sub-problem. The investment cost (INVC) in the objective function comprises the GEP and TEP costs while the operating cost (OPC) relates to the generation costs of the units. Besides, the CP support mechanisms have been presented in the first part and the FIT policies have been proposed in the form of the sub-problem in the second part. The problem formulation for this model is as follows:

$$
\begin{aligned}
&\mathrm{Min\ TC} = \mathrm{INVC} + \mathrm{OPC}\\
&\mathrm{INVC} = \sum_{y=1}^{NY}\sum_{i=1}^{NG}\sum_{k=1}^{NCU}\frac{[\mathrm{GI}_{ki}-\mathrm{CP}_{ki}]\mathrm{PG}_{ki}^{\max,C}(\mathrm{Gn}_{kiy}-\mathrm{Gn}_{ki(y-1)})}{(1+d)^{y-1}}\\
&\qquad + \sum_{y=1}^{NY}\sum_{j=1}^{NCL}\frac{\mathrm{TI}_j\mathrm{PL}_j^{\max,C}(\mathrm{Ln}_{jy}-\mathrm{Ln}_{j(y-1)})}{(1+d)^{y-1}}\\
&\mathrm{OPC} = \sum_{y=1}^{NY}\sum_{b=1}^{NB}\sum_{i=1}^{NG}\sum_{k=1}^{NU}\frac{\mathrm{DT}_{by}[\mathrm{OC}_{kiby}-\mathrm{FIT}_{kiby}]\mathrm{PG}_{kiby}}{(1+d)^{y-1}}
\end{aligned}
\tag{1}
$$

Subject to:

Master Problem Constraints:

$$\mathrm{Gn}_{ki(y-1)} \le \mathrm{Gn}_{kiy},\quad \mathrm{Gn}_{kiy}=0 \quad \text{if } y<\mathrm{MTGI}_{ki} \tag{2}$$

$$\mathrm{Ln}_{j(y-1)} \le \mathrm{Ln}_{jy},\quad \mathrm{Ln}_{jy}=0 \quad \text{if } y<\mathrm{MTTI}_{j} \tag{3}$$

$$\sum_{i=1}^{NG}\sum_{k=1}^{NCU}\mathrm{GI}_{ki}\mathrm{PG}_{ki}^{\max,C}(\mathrm{Gn}_{kiy}-\mathrm{Gn}_{ki(y-1)}) \le \mathrm{TGI}_y \tag{4}$$

$$\sum_{j=1}^{NCL} \mathrm{TI}_j \mathrm{PL}_j^{\max,C}(\mathrm{Ln}_{jy} - \mathrm{Ln}_{j(y-1)}) \le \mathrm{TTI}_y \tag{5}$$

$$\sum_{i=1}^{NG} \sum_{k=1}^{NCU} \mathrm{PG}_{ki}^{\max,C}(\mathrm{Gn}_{kiy} - \mathrm{Gn}_{ki(y-1)}) \le \mathrm{TGC}_y \tag{6}$$

$$\sum_{j=1}^{NCL} \mathrm{PL}_{jy}^{\max,C}(\mathrm{Ln}_{jy} - \mathrm{Ln}_{j(y-1)}) \le \mathrm{TTC}_y \tag{7}$$

Slave Problem Constraints:

$$\mathrm{PG}_{ki}^{\min,E}\mathrm{IG}_{kiby}^{E} \le \mathrm{PG}_{kiby}^{E} \le \mathrm{PG}_{ki}^{\max,E}\mathrm{IG}_{kiby}^{E} \tag{8}$$

$$\mathrm{PG}_{ki}^{\min,C}\mathrm{Gn}_{kiy}\mathrm{IG}_{kiby}^{C} \le \mathrm{PG}_{kiby}^{C} \le \mathrm{PG}_{ki}^{\max,C}\mathrm{Gn}_{kiy}\mathrm{IG}_{kiby}^{C} \tag{9}$$

$$\mathrm{PL}_{jby}^{E} = B_j(\delta_{mby}^{E} - \delta_{nby}^{E}) \tag{10}$$

$$-\mathrm{PL}_j^{\max,E} \le \mathrm{PL}_{jby}^{E} \le +\mathrm{PL}_j^{\max,E} \tag{11}$$

$$\mathrm{PL}_{jby}^{C} - B_j(\delta_{mby}^{C} - \delta_{nby}^{C}) - M_j^C(1 - \mathrm{Ln}_{jy}) \le 0 \tag{12}$$

$$\mathrm{PL}_{jby}^{C} - B_j(\delta_{mby}^{C} - \delta_{nby}^{C}) + M_j^C(1 - \mathrm{Ln}_{jy}) \ge 0 \tag{13}$$

$$-\mathrm{PL}_j^{\max,C}\mathrm{Ln}_{jy} \le \mathrm{PL}_{jby}^{C} \le +\mathrm{PL}_j^{\max,C}\mathrm{Ln}_{jy} \tag{14}$$

$$\delta_{\mathrm{ref}} = 0 \tag{15}$$

$$\begin{aligned} &\sum_{i=1}^{NG}\sum_{k=1}^{NEU} \mathrm{PG}_{kiby}^{E} + \sum_{i=1}^{NG}\sum_{k=1}^{NCU} \mathrm{PG}_{kiby}^{C} = \mathrm{PD}_{lby} \\ &+ \sum_{j=1}^{NEL} \mathrm{PL}_{jby}^{E} + \sum_{j=1}^{NCL} \mathrm{PL}_{jby}^{C} \end{aligned} \tag{16}$$

$$\begin{aligned} (1+\alpha)\sum_{l} \mathrm{PD}_{lby}^{\max} \le & \sum_{i=1}^{NG}\sum_{k=1}^{NEU} \mathrm{PG}_{ki}^{\max,E}\mathrm{IG}_{kiby}^{E} \\ &+ \sum_{i=1}^{NG}\sum_{k=1}^{NCU} \mathrm{PG}_{ki}^{\max,C}\mathrm{Gn}_{kiy}\mathrm{IG}_{kiby}^{C} \\ &\le (1+\beta)\sum_{l} \mathrm{PD}_{lby}^{\max} \end{aligned} \tag{17}$$

$$\begin{aligned} &\sum_{i=1}^{NG}\sum_{k=1}^{NCU} \mathrm{CP}_{ki}\mathrm{PG}_{ki}^{\max,C}(\mathrm{Gn}_{kiy} - \mathrm{Gn}_{ki(y-1)}) \\ &+ \sum_{b=1}^{NB}\sum_{i=1}^{NG}\sum_{k=1}^{NCU} \mathrm{DT}_{by}\mathrm{FIT}_{kiby}\mathrm{PG}_{kiby} \le \mathrm{IB}_y \end{aligned} \tag{18}$$

The investment costs along with the related constraints should be investigated in the master problem. The sub-problem assesses the operating costs of the existing generating units and those determined by the master problem to be added as new generating units.

In this model, the CP policy which is an installed capacity oriented policy has been represented in the first part and indicated by CP_{ki} (\$/kW-year), while the FIT policy has been represented in the third part of the objective function and denoted by FIT_{kiby}. The FIT policy is proportional to the power generated by renewable energy units.

Constraints (2) and (3) relate to the minimum time required to construct the generating units and transmission lines, respectively. These two constraints state that new generating units and transmission lines cannot be added to the network until the minimum required time passes. Constraints (4) and (5) indicate the budget limitation for the investment in the generation and transmission system expansion, while constraints (6) and (7) represent the limitation of the capacity to be added each year.

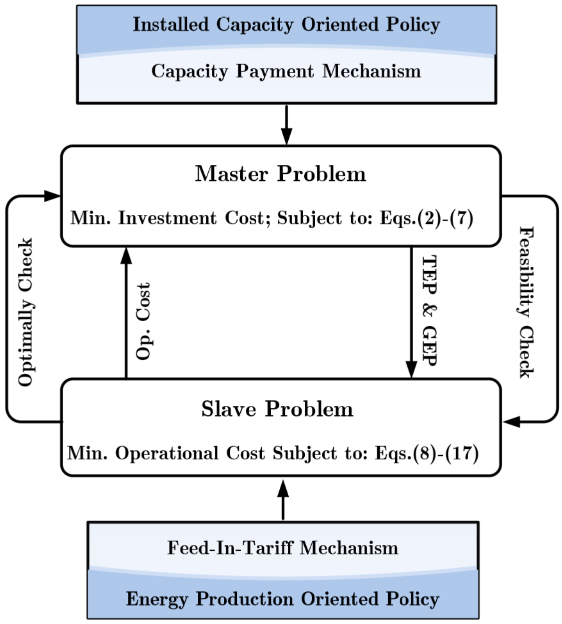

Fig. 1 *Conceptual long-term planning model in the context of the standard two-stage programming*

The operating limitations of the existing and new generating units are included in constraints (8) and (9), respectively. It should be noted that only one binary variable is assigned to each existing unit showing the operating status, while two binary variables are associated with the candidate units; one relates to the planning horizon denoted by Gn_{kiy} and the other one relates to the operation horizon denoted by $\mathrm{IG}^{C}{}_{kiby}$. As it has been previously mentioned, the candidate unit generates power provided that the binary variable of the planning horizon Gn_{kiy} is '1'. The DC power flow equations have been represented in the relationships (10)–(15). In this respect, the value of the parameter M is chosen big enough so that constraints (12) and (13) which include the binary variable relating to selecting the candidate lines in year y is mathematically satisfied [13].

The power flow equations are based on the incidence matrix which has been represented in detail in [33]. It is noted that the bus voltage angle of the reference bus is considered zero as (15). Equation (16) shows the hourly power balance equation taking into consideration the new generating units and transmission lines. This constraint is the most important one in power system studies and this paper discusses the amount of the load demand with and without applying the ToU programme. The ToU implementation based on a simple linear optimisation model is adopted in this paper. The problem formulation and a simple case study are provided in Appendix.

Inequality (17) indicates the lower and upper bounds of the annual increase in the installed generation capacity. In other words, coefficients α and β determine the lower and upper bounds of the required reserve over the planning horizon. The budget limitation of the incentive-based programmes and supportive mechanisms in each year of the planning horizon has been shown in (18). It is evident that the amount of budget allocated by governments to each of the mentioned programmes has an annual limitation denoted by IB_y. In case of only taking the CP strategy, the second part of the inequality on the left-hand side would equal to zero. Also, when considering only the FIT, the first part would be zero. Fig. 1 shows the conceptual long-term planning model proposed in this paper considering both the CP and FIT mechanisms. The problem has been formulated using a two-stage model similar to [13]. As it can be observed from Fig. 1, the planning model includes two stages as the master problem and the slave problem. The master problem determines the expansion plans of the generation and transmission systems. Then, the feasibility criterion of the specified plans is evaluated in the slave problem using the hourly optimal operation sub-problems. The second stage aims to minimise the operating costs of the suggested expansion plans.

Finally, these costs are added to the capital cost of the components planned to be added. The installed capacity-oriented policies are applied in the master problem while the incentive mechanisms for renewable energy productions are applied to the slave problem. It is noteworthy that the ToU programme is employed in the slave problem. As such programmes change the LDC, the slave problem is impacted first which in turn affects the master problem regarding the expansion plans. The presented composite GEP–TEP framework considering the ToU strategy is evaluated in the next section by applying the model on IEEE Reliability Test System (RTS).

5 Simulation results

The test system used in this paper to assess the proposed composite GEP–TEP framework is IEEE RTS including 24 buses, 32 generating units and 38 branches including transmission lines and transformers. The single-line diagram of this test system is illustrated in Fig. 2. The installed generation capacity in the base case is 3405 MW and the maximum load demand is 2850 MW [34]. IEEE RTS is known as a robust system which has so far been frequently used in long-term planning studies. Besides, this system is known as a reference in TEP studies [35]. The best feature of this system is the various generating units with liquid fuel, nuclear units, synchronous condensers as well as hydro units. The voltage levels of the system are 230 and 138 kV, and this system includes various overhead lines as well as cables, transformers and shunt compensators making the system a desirable choice for long-term planning studies. It is noteworthy that the simulations have been done using GAMS software installed on an Intel core i5 Laptop with 4 GB RAM and the problem is solved using CPLEX solver. This paper investigates different cases to evaluate the proposed long-term planning framework. The most important assumptions of the paper are as follows:

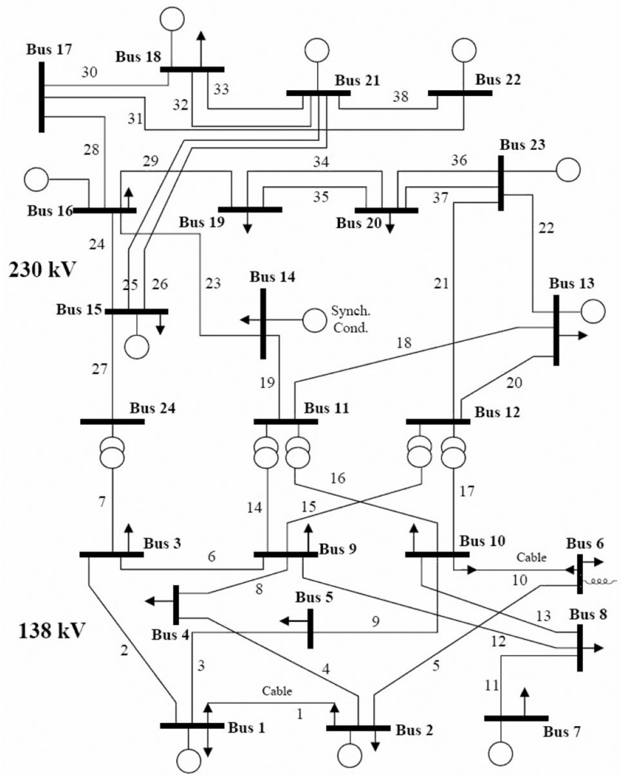

Fig. 2 *Single line diagram of IEEE 24-Bus RTS [34]*

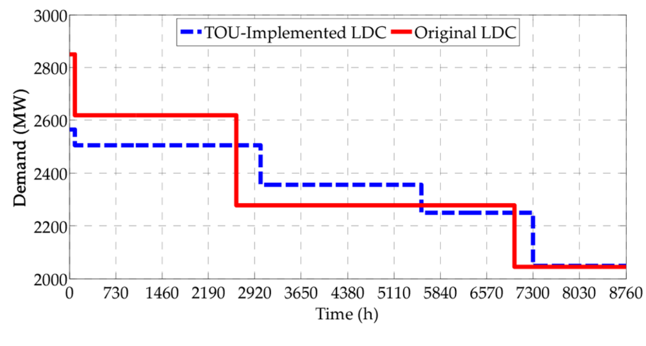

Fig. 3 *Original LDC and the ToU-implemented LDC*

- The planning horizon is 10 years.
- The annual growth of load demand is 7%.
- The load demand of the base year is 2850 MW.
- The minimum required reserve is equal to 10% of the peak load demand of each year.
- The maximum reserve is equal to 50% of the peak load of each year.
- The RES power generation model developed in [16] has been used in this paper.

The LDC is modelled using the linear approximations method in [11] and the number of load levels in the base case is 4. By applying the ToU strategy and using the linearisation technique, the new LDC has been modelled in 5 levels. The maximum permitted load demand to participate in the ToU programme is 10% of the hourly load demand.

Fig. 3 shows the original LDC and the LDC after applying the ToU programme. Table 1 represents the contribution of each bus of the system to the peak load demand of the base year. This load pattern has been used for all hours of the planning horizon taking into account the mentioned LDC. Azami *et al*. [36] contains the data of the existing generating units and transmission lines of the system. The total installed generation capacity in the base year is 3405 MW which can sufficiently supply the 2850 MW load demand. It is noted that 50-MW units are of hydroelectric technology, 400-MW units are of nuclear technology and the remaining are of thermal technology. The operating cost of hydro units is zero and others non-zero.

Table 2 represents the data of candidate units as well as the data of the incentive-based and supportive policies. The data of the candidate transmission lines are shown in Table 3. It is noteworthy that the number of existing and candidate are 38 and 10, respectively.

Incentive-based and supportive policies have been investigated in this case study.

5.1 Case 1: The base composite GEP–TEP

The composite GEP–TEP problem is implemented in the base case disregarding the incentive-based and supportive mechanisms. Accordingly, the ISO implements the expansion planning problem taking into account the real investment and operating costs. In this regard, the optimality of the final plan to be accepted would be the

Table 1 Amount of the peak load of the base year [34]

Bus	Demand, MW	Bus	Demand, MW	Bus	Demand, MW	Bus	Demand, MW
1	108	7	125	13	265	19	181
2	97	8	171	14	194	20	128
3	180	9	175	15	317	21	—
4	74	10	195	16	100	22	—
5	71	11	—	17	—	23	—
6	136	12	—	18	333	24	—

minimum total cost including the total investment and operating costs. Although the investment cost of hydro, PV and wind farms are high and their operating cost is negligible, their short construction time and the effectiveness of investment in such units have caused them to be highlighted in this plan. The contribution of the renewable energies is 350 MW, i.e. ∼14.27% of the newly added capacity. Moreover, the amount of the required reserve for the last year of the planning horizon is 11.8%. The implementation of the ToU strategy has led to 22% reduction in the fossil-fuel type generation investment. Meanwhile, the reserve margin has decreased to 11.4% using the ToU strategy considering 1847 new capacity and the peak load.

5.2 Case 2: applying the installed capacity oriented policy

Considering the installed capacity oriented policy alone leads to more contribution of fossil-fuel generating units. Using this strategy, the GEP costs considerably increase due to payment to all units disregarding their technology. However, having applied the ToU, there would be no need for investment in the generation sector. The required generation capacity to install is 5937 MW while by applying the ToU, it reduces to 5357 MW. The contribution of the renewable energies with and without applying the ToU strategy is 16.98 and 8.19% of the installed capacity, respectively. The simulation results show that reducing the load demand peak using the ToU programme performs better compared to adding renewable energy capacity through supportive mechanisms for investment. The allocated budget before applying the ToU programme is 55.958 M$ while it reduces to 40.25062 M$ by applying the ToU programme. This issue shows that a 10% reduction in the load demand has resulted in a 28% reduction in the required supportive budget.

5.3 Case 3: applying the renewable energy supportive mechanism

The third case relates to considering the incentive-based and supportive mechanisms to more absorb the renewable energy investment by applying the incentive tariffs during the operation. As per kW investment cost of renewable energies is very high, there should be sufficient support to motivate the private sector to invest. The contribution of renewable energies has reached 18.77% of the total capacity additions in this case before applying for the ToU programme, verifying that the mentioned supportive programme can desirably increase the penetration level of renewable energies in the generation mix. The amount of reserve has reached 10.7% before applying the ToU programme and 16.8% after applying the ToU programme in the final year of the planning horizon. The required budget for implementing this mechanism before applying the ToU tariff is 294.8353 M$ and after applying the ToU tariff, it reaches 159.7087 M$. This issue shows that utilising the ToU programme which can reduce the investment costs also reduces the government's payment for supporting renewable energies. However, it should be noted that after applying the ToU programme, the contribution of renewable energies has reduced from 450 to 310 MW, i.e. two-third, while the subsidy allocated for the FIT has decreased to 46%.

5.4 Case 4: applying the supporting mechanisms based on the installed capacity oriented policy and renewable power generation

The last case relates to simultaneously considering the installed capacity oriented policy and incentive-based mechanism for renewable power generation. The simulation results, in this case, would be expected to be close to those of case 2 and case 3. However, renewable energy units would benefit from both the incentive-based and supportive policies. The simulation results show that the installed capacity of renewable energies has reduced from 480 MW before applying the ToU tariff to 380 MW after applying the ToU tariff. This issue shows that by decreasing the peak load demand, the expensive investment in renewable energies would also decrease. It is worth-mentioning that the PV units contribute the most compared to others, which is due to the overlap between the PV power generation and the peak load and off-peak load hours. The amount of reserve before and after applying the ToU tariff is 12.81 and 13.66%, respectively. Besides, the total budget allocated through incentive-based and supportive mechanisms before and after applying the ToU programme is 279.71934 M$ and 97.66957 M$, respectively. Table 4 represents the brief GEP results corresponding to eight different cases studied in this paper. This table depicts the annual added capacity in MW as well as the generation technology. For example, 40 MW thermal

Table 2 Techno-economic data of candidate units

Bus	N_T	Type	GI, $/kW	$PG^{max,C}$, MW	OC, $/MWh	CP, $/kW	FIT, $/MWh	MTGI, Year
1,2	2	T	700	20	19.50	37.5	—	2
1,2	2	T	400	76	24.00	37.5	—	5
3,4,6,8,24	2	W	12,000	50	4.50	37.5	20	2
3,4,6,8,24	2	W	9000	100	9.60	37.5	20	3
3,4,6,8,24	2	P	6000	30	12.30	37.5	20	1
3,4,6,8,24	2	P	3000	50	18.60	37.5	20	2
13,23	2	T	800	197	27.00	37.5	—	3
15,16,20	2	T	1970	155	18.00	37.5	—	4
21,22	3	H	14,550	50	0.00	37.5	20	3

T: Thermal; W: Wind; P: Photovoltaic; H: Hydro.

Table 3 Data of candidate transmission lines

Candidate link	From	To	B_j, pu	P_j^{max}, MW	TI_j, $/MW	$MTTI_j$, Year
39	3	9	8.40	175	186	2
40	3	9	8.40	175	186	2
41	8	9	6.06	175	258	2
42	8	9	6.06	175	258	2
43	15	24	19.27	500	129	3
44	15	24	19.27	500	129	3
45	16	17	19.27	500	108	1
46	16	17	19.27	500	108	1
47	11	21	19.27	500	600	2
48	11	21	19.27	500	600	2

power generation, 100 MW PV power generation and 50 MW wind power generation must be added to the network in the third year of the planning in the base case disregarding the ToU programme. Moreover, Table 5 shows the transmission expansion plans considering different cases. The installation year of each transmission line is provided in the parenthesis, provided that it is needed to be added to the network. Table 6 represents a brief report of the expansion plans; the generation expansion plans as well as the operating costs. Also, the supportive actions made through each of the mentioned mechanisms have been indicated.

The simulation results show that the system reserve disregarding the ToU programme is 20% in the first year. This value would reduce to 11% in the second year with respect to the 7% annual load growth if no generation investment is made. It is noted that in all cases without considering the ToU programme, the first generating unit is planned to be installed in the third year to maintain the 10% minimum reserve. The optimal generation mix of the suggested generation expansion plans is in a way that the new generating unit would be added to the system after the MTGI to supply the required energy. It is noteworthy that a new generating unit must be installed in case the system reserve is below the minimum required value. However, the new capacity to be added to the system would reduce by applying the ToU programme. In the case without the ToU programme implementation, the penetration level of renewable energies increases by considering the FIT supporting mechanism and CP policy. Taking into account these two policies will cause the renewable energies penetration to increase, effectively. Fig. 4 depicts the generation mix of each case based on the installed capacity without the ToU programme implementation.

Applying the ToU programme significantly reduces the transmission system congestion, thus reducing the required new transmission capacity. For instance, the number of required lines in the base case has reduced from 7 to 3. Besides, by simultaneously considering the FIT and CP policies, the number of required lines reduces from 6 to 2 by considering the ToU. Since the amount of

Table 4 Generating units to be added in different cases over the planning horizon

Year	2	3	4	5	6	7	8	9	10
base without TOU	0	T40 + P100 + W50	T237 + H50	T394	T304	T197	T310	T310	T310 + P150
base with TOU	P30	T20	H50	T237	T304	T197 + P50	T217 + P30	T352	T310 + P50
CP without TOU	0	T80 + P100 + W50	T197 + H50	T394 + P30	T304	T197 + H50	T310	T310	T310 + P150
CP with TOU	0	T80	0	T197 + P50 + H50	T501	0	T197 + P60	T352	T465
FIT without TOU	0	T40 + P100 + W50	T197 + P150 + H50	T217	T152 + H50	T349	T372	T310	T310 + H50
FIT with TOU	P30	T40	T40 + P50 + H50	T197 + P30	T501	P50	T197 + P50 + H50	T352	T465
FIT-CP without TOU	0	T40 + P100 + W50	T217 + P100	T197 + H50	T248 + P100	T352 + P80	T352	T310	T310
FIT-CP with TOU	P30	T60 + P100	0	T197 + H50	T304 + P50	P150	T352	T352	T310

T: Thermal; W: Wind; P: Photovoltaic; H: Hydro.

Table 5 Transmission expansion over the planning horizon

Candidate Link	Base without TOU	Base with TOU	CP without TOU	CP with TOU	FIT without TOU	FIT with TOU	CP-FIT without TOU	CP-FIT with TOU
39	(10)	—	(6)	(6)	(10)	(7)	(6)	—
40	(7)	(6)	(7)	(6)	(7)	(6)	(10)	—
41	(9)	(6)	(6)	—	(6)	—	(6)	(10)
42	(6)	—	(9)	(7)	(7)	—	(7)	—
43	(10)	—	(10)	—	(10)	—	(10)	—
44	(10)	—	(10)	—	(10)	—	(9)	—
45	(6)	(5)	(6)	(5)	—	(5)	—	(6)
46	—	—	(6)	(5)	—	(6)	—	—

() indicates installation year of transmission line.

Table 6 Detailed cost analysis of the test system case studies

Case	Base without TOU	Base with TOU	CP without TOU	CP with TOU	FIT without TOU	FIT with TOU	CP-FIT without TOU	CP-FIT with TOU
GEP ($\times 10^9$\$)	2.880841	1.816699	3.416542	1.796704	3.597155	2.491344	2.851061	1.688776
TEP ($\times 10^6$\$)	0.169514	0.085128	0.20945	0.139673	0.140407	0.108997	0.14498	0.052678
OPC ($\times 10^9$\$)	3.258232	3.349926	3.219122	3.449384	3.209941	3.385047	3.23786	3.450478
FIT ($\times 10^6$\$)	0	0	0	0	294.8353	159.7087	226.6119	58.93365
CP ($\times 10^6$\$)	0	0	55.958	40.25062	0	0	53.10744	38.73592
NTC ($\times 10^9$\$)	6.139242514	5.166710128	6.63587345	5.246227673	6.807236407	5.876499997	6.08906598	5.139306678
budget ($\times 10^6$\$)	0	0	55.958	40.25062	294.8353	159.7087	279.71934	97.66957
OF ($\times 10^9$\$)	6.1392	5.1667	6.5799	5.2060	6.5124	5.7168	5.8093	5.0416
iteration	12,053	10,827	12,438	19,164	10,698	14,297	11,275	17,469
solution time, min	9:23	9:28	10:01	10:03	10:12	10:15	10:29	10:32
total cap	5857	5252	5937	5357	5802	5507	5911	5360
reserve, %	11.8	11.4	13.3	13.6	10.7	16.8	12.81	13.66
RES, %	14.27	11.37	16.98	8.19	18.77	14.75	19.15	19.44

OPC = operating cost, NTC = net total cost, OF = objective function.

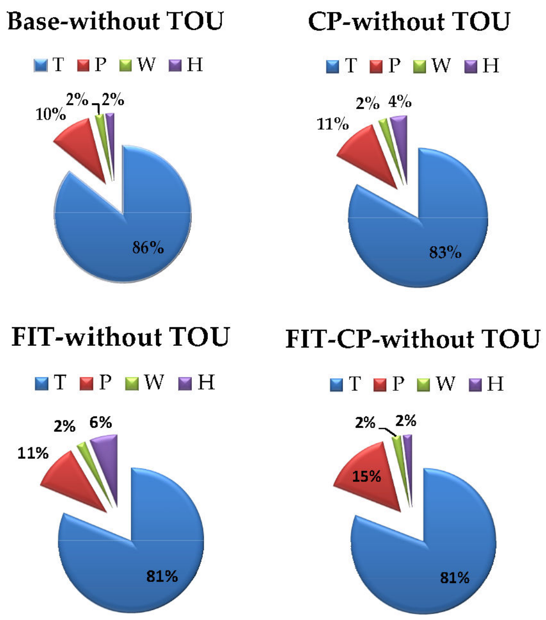

Fig. 4 *Generation mix of the case studies without ToU*

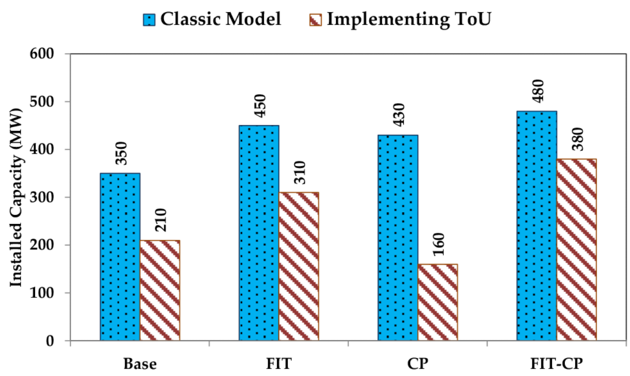

Fig. 5 *Penetration of RESs for different case studies*

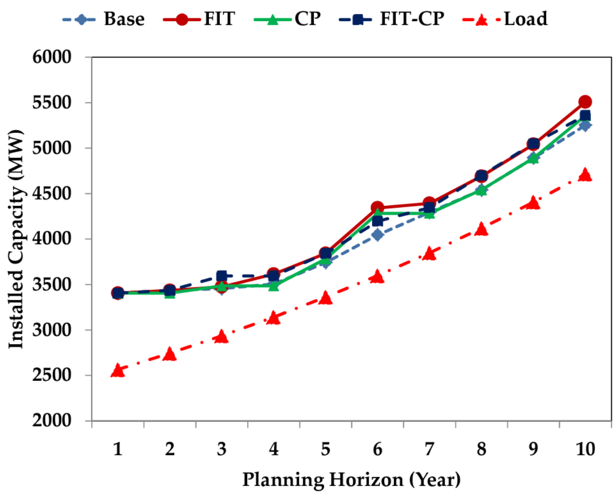

Fig. 6 *Generation expansion capacity considering the ToU programme*

load demand and accordingly, the amount of new generation capacity will be reduced by applying the ToU programme; there would be no need to add new transmission capacity.

Furthermore, the planning entity can defer the transmission system expansion. As the transmission system expansion is done by the government, deferring the new capacity installation would be a positive point.

Fig. 5 depicts the RES penetrations regarding the different case studies. The simulation results show that the incentive-based and supportive policies can effectively contribute to absorbing the investment in the RESs integration. In the base case, the RESs' penetration is 350 MW of the new generation capacity, while the FIT policy increases this amount to 450 MW.

On the contrary, the CP mechanism increases the RESs' penetration to 430 MW which relates to the supportive policy for increasing the capacity additions in this study. Consequently, the planning entity prefers to allocate the budget to the units with low operating costs having the capability to phenomenally generate power throughout the year. Indeed, this policy focuses on the units that can considerably reduce the operating costs of the system. Accordingly, the investment has been made in the RESs integration as well as the low-cost generating units. Although simultaneously applying the CP and FIT mechanisms can increase the RESs' penetration, the impact of the ToU programme on the RESs penetration is much more appreciable. The ToU programme seeks to change the consumption behaviour and supply the load demand by generating units with low operating costs and use highly reliable units to meet the peak load demand. As a result, the reduction in the RESs' penetration is expected. In case of concurrently using both CP and FIT policies, the investment in the RESs integration increases.

It is worth mentioning that without these policies in the base case, the investment is made only to supply the load demand and there would not be any tendency to use renewable energies with low operating costs.

However, by effectively managing the budget allocation using the CP and FIT policies, the added capacity would be focused on integrating high-efficiency generating units with low operating costs. Fig. 6 shows the generation expansion capacity taking into consideration the ToU programme. Furthermore, the load forecast in this state has been also plotted. Accordingly, the amount of reserve in each year can be easily observed. With respect to the minimum reserve requirement which is equal to 10% of the annual peak load demand, it is obvious that the GEP has been carried out in a way not only to satisfy this constraint but also to avoid high investment costs.

6 Conclusion

This paper presented a composite GEP and TEP problem. In this respect, the performances of the CP and FIT mechanisms in the context of the long-term planning of power systems and RESs integration were investigated. Besides, the effectiveness of DRPs in the form of ToU programme in facilitating the system expansion and reducing cost was evaluated. The proposed framework was modelled as a two-stage MILP problem and the following results were obtained.

In the base case without any incentive-based and supportive mechanisms, the contribution of the RESs in the added generation capacity is 14.27%. Besides, applying the ToU programme can reduce the fossil-fuel type generation investment, while the reserve margin in the last year of the planning horizon is 11.4% which is close to the case without the ToU programme. In case the CP mechanism alone is employed, the RESs contribute to the new capacity addition by 16.98% which is 2.71% more than the base case without the ToU programme. The ToU programme can result in a 10% reduction in the load demand, which in turn reduces the required supportive budget by 28%.

When the FIT is utilised to support the RESs integration, the contribution of RESs considerably increases to 18.77% of the total capacity addition. Moreover, applying the ToU programme leads to 5.9% reserve margin increase and also a 45.8% reduction in the total cost. In this case, the RESs contribution to the total added capacity also decreases to 14.75%. In case of simultaneously considering the two policies, the investment in the renewable energies sector is more than others. The RES contribution is 19.15% of the new units disregarding the ToU programme. If the ToU programme is applied, this value increases to 19.44%.

In this regard, the model can be extended to multi-objective optimisation one including several objective functions, such as the emission minimisation, reliability maximisation, voltage stability margin maximisation. The impact of other DRPs on the long-term planning of power systems can be evaluated to more comprehensively investigate the mentioned problem. Also, the strategic behaviour of the generation companies can be discussed.

7 Acknowledgment

J.P.S. Catalão acknowledges the support by FEDER funds through COMPETE 2020 and by Portuguese funds through FCT, under POCI-01-0145-FEDER-029803 (02/SAICT/2017)

8 References

[1] Bausch, C., Mehling, M.: '*Strengthening renewable energy expansion with feed-in tariffs: the German example*' (Friedrich-Ebert-Stiftung, Amman Office, Amman, Jordan, 2013)

[2] Poullikkas, A.: 'An optimization model for the integration of renewable technologies in power generation systems'. World Renewable Energy Congress, Linkoping, Sweden, 2011, pp. 2347–2354

[3] Oren, S.S.: 'Capacity payments and supply adequacy in competitive electricity markets'. The 7th Symp. Specialists in Electric Operational and Expansion Planning, Curitiba, Brazil, 2000

[4] Botterud, A., Doorman, G.L.: '*Generation investment and capacity adequacy in electricity markets*' (Int. Association for Energy Economics, New Orleans, USA, 2008), pp. 11–15

[5] Zhang, F.: 'How fit are feed-in tariff policies? Evidence from the European Wind Market', Policy Research Working Paper 6376, The World Bank, Europe, 2013

[6] Alizadeh, B., Jadid, S.: 'Reliability constrained coordination of generation and transmission expansion planning in power systems using mixed integer programming', *IET Gener. Transm. Distrib.*, 2011, **5**, (9), pp. 948–960

[7] De Mendona, I.M., Junior, I.C.S., and Marcato, A.: 'Static planning of the expansion of electrical energy transmission systems using particle swarm optimization', *Int. J. Electr. Power Energy Syst.*, 2014, **60**, pp. 234–244

[8] Fuerte-Ledezma, L.F., G. Gutirrez, A., Javadi, M.S.: 'Static transmission expansion planning considering uncertainty in demand using BPSO'. North American Power Symp. (NAPS), New York City, USA, 2013, pp. 1–6

[9] Akbari, T., Rahimikian, A., Kazemi, A.: 'Dynamic transmission expansion planning using benders decomposition: a stochastic approach'. 24-th Power System Conf., PSC, Tehran, Iran, 2009

[10] Alizadeh, B., Jadid, S.: 'A dynamic model for coordination of generation and transmission expansion planning in power systems', *Int. J. Electr. Power Energy Syst.*, 2015, **65**, pp. 408–418

[11] Javadi, M.S., Saniei, M., Rajabi Mashhadi, H.: 'An augmented NSGA-II technique with virtual database to solve the composite generation and transmission expansion planning problem', *J. Exp. Theor. Artif. Intell.*, 2013, **26**, (2), pp. 1–24

[12] Sharan, I., Balasubramanian, R.: 'Integrated generation and transmission expansion planning including power and fuel transportation constraints', *Energy. Policy.*, 2012, **43**, pp. 275–284

[13] Khodaei, A., Shahidehpour, M., Kamalinia, S.: 'Transmission switching in expansion planning', *IEEE Trans. Power Syst.*, 2010, **25**, (3), pp. 1722–1733

[14] Murugan, P., Kannan, S., Baskar, S.: 'Application of NSGA-II algorithm to single-objective transmission constrained generation expansion planning', *IEEE Trans. Power Syst.*, 2009, **24**, (4), pp. 1790–1797

[15] Zakerinia, M., Torabi, S.A.: 'Multiobjective power expansion planning in the planning horizon'. 2010 IEEE Conf. on Innovative Technologies for an Efficient and Reliable Electricity Supply (CITRES), Waltham, USA, 2010, pp. 188–194

[16] Javadi, M.S., Saniei, M., Mashhadi, H.R.*, et al.*: 'Multi-objective expansion planning approach: distant wind farms and limited energy resources integration', *IET Renew. Power Gener.*, 2013, **7**, (6), pp. 652–668

[17] Seddighi, A.H., Ahmadi-Javid, A.: 'Integrated multiperiod power generation and transmission expansion planning with sustainability aspects in a stochastic environment', *Energy*, 2015, **86**, pp. 9–18

[18] Shivaie, M., Ameli, M.T.: 'Strategic multiyear transmission expansion planning under severe uncertainties by a combination of melody search algorithm and Powell heuristic method', *Energy*, 2016, **115**, pp. 338–352

[19] Asensio, M., Quevedo, P.M.D., Muñoz-Delgado, G.*, et al.*: 'Joint distribution network and renewable energy expansion planning considering demand response and energy storage—part II: numerical results', *IEEE Trans. Smart Grid*, 2018, **9**, (2), pp. 667–675

[20] Bagheri, A., Vahidinasab, V., Mehran, K.: 'A novel multiobjective generation and transmission investment framework for implementing 100% renewable energy sources', *IET Gener. Transm. Distrib.*, 2018, **12**, (2), pp. 455–465

[21] Javadi, M.S., Razavi, S.-E., Ahmadi, A.*, et al.*: 'A novel approach for distant wind farm interconnection: Iran south-west wind farms integration', *Renew. Energy*, 2019, **140**, pp. 737–750

[22] Javadi, M.S., Esmaeel Nezhad, A.: 'Multi-objective, multi-year dynamic generation and transmission expansion planning- renewable energy sources integration for Iran's National Power Grid', *Int. Trans. Electr. Energy Syst.*, 2019, **29**, (4), p. e2810

[23] Taherkhani, M., Hosseini, S.H.: 'IGDT-based multi-stage transmission expansion planning model incorporating optimal wind farm integration', *Int. Trans. Electr. Energy Syst.*, 2014, **25**, (10), pp. 2340–2358

[24] Mansouri, S.A., Javadi, M.S.: 'A robust optimisation framework in composite generation and transmission expansion planning considering inherent uncertainties', *J. Exp. Theor. Artif. Intell.*, 2017, **29**, (4), pp. 717–730

[25] Roldan, C., Sanchez de la Nieta, A.A., Garcia-Bertrand, R.*, et al.*: 'Robust dynamic transmission and renewable generation expansion planning: walking towards sustainable systems', *Int. J. Electr. Power Energy Syst.*, 2018, **96**, (Supplement C), pp. 52–63

[26] Hejeejo, R., Qiu, J.: 'Probabilistic transmission expansion planning considering distributed generation and demand response programs', *IET Renew. Power Gener.*, 2017, **11**, (5), pp. 650–658

[27] Lohmann, T.: 'Long-term power generation expansion planning with short-term demand response: model, algorithms, implementation, and electricity policies'. Economics and Business. Ph.D, Colorado School of Mines, 2015

[28] Bahrami, S., Amini, M.H., Shafie-Khah, M.*, et al.*: 'A decentralized renewable generation management and demand response in power distribution networks', *IEEE Trans. Sustain. Energy*, 2018, **9**, (4), pp. 1783–1797

[29] Bahrami, S., Amini, M.H., Shafie-khah, M.*, et al.*: 'A decentralized electricity market scheme enabling demand response deployment', *IEEE Trans. Power Syst.*, 2018, **33**, (4), pp. 4218–4227

[30] Siano, P.: 'Demand response and smart grids – a survey', *Renew. Sust. Energy Rev.*, 2014, **30**, pp. 461–478

[31] La Scala, M., Vaccaro, A., Zobaa, A.F.: 'A goal programming methodology for multiobjective optimization of distributed energy hubs operation', *Appl. Therm. Eng.*, 2014, **71**, (2), pp. 658–666

[32] Carradore, L., Bignucolo, F.: 'Distributed multi-generation and application of the energy hub concept in future networks'. 43rd Int. Universities Power Engineering Conf., 2008. UPEC 2008, Padova, Italy, 2008, pp. 1–5

[33] Javadi, M.S.: 'Incidence matrix-based LMP calculation: algorithm and applications', *Int. J. Multidiscip. Sci. Eng.*, 2012, **2**, (5), pp. 48–52

[34] Grigg, C., Wong, P., Albrecht, P.*, et al.*: 'The IEEE Reliability Test System-1996. A report prepared by the Reliability Test System Task Force of the Application of Probability Methods Subcommittee', *IEEE Trans. Power Syst.*, 1999, **14**, (3), pp. 1010–1020

[35] Papalexopoulos, A.: 'Power system expansion planning and pricing in a deregulated environment'. Power Engineering Society Summer Meeting, Chicago, USA, 2002, p. 1168

[36] Azami, R., Javadi, M.S., Hematipour, G.: 'Economic load dispatch and DC-optimal power flow problem- PSO versus LR', *Int. J. Multidiscip. Sci. Eng.*, 2011, **2**, (9), pp. 8–13

9 Appendix

Time-based DRPs are of the most important policies which can sustainably reduce the peak load demand and defer it to other periods both over short-term and long-term horizons. It should be noted that these policies are time-based. The ToU strategy is more efficient in the long-term compared to real-time pricing (RTP), since this programme would be more effective in the long-term to change the behaviour of the consumers over the peak load hours. In this regard, this paper discusses the impact of the ToU tariff on reducing the generation investment costs in the long-term. In this respect, a ToU tariff-based optimisation model is used in this paper taking into account the maximum increase/decrease in the hourly load demand and the maximum hourly load deferral aimed at reducing the total cost while supplying the load demand over the planning horizon. It is noted that load and price elasticity-based models can be simply implemented, but they are associated with two main shortfalls. The first problem relates to the determination of the self and cross elasticity coefficients. The second problem is caused by unguaranteed constant energy consumption after implementing this policy. Since ToU-based models aim at changing the consumption time behaviour, the price elasticity model would not be able to effectively meet this goal. The mathematical model used in this paper is as follows:

$$\text{Min} \sum_{l=1}^{ND} \sum_{b=1}^{NB} \sum_{t=1}^{NT} \text{PD}_{lbt}^{\text{TOU}} \times \text{Tariff}_{\text{t}} \tag{19}$$

Subject to:

$$(1-\mu)\text{PD}_{lbt}^{\text{Original}} \le \text{PD}_{lbt}^{\text{TOU}} \le (1+\mu)\text{PD}_{lbt}^{\text{Original}} \tag{20}$$

$$\text{PD}_{lbt}^{\text{TOU}} - \text{PD}_{lb,t-1}^{\text{TOU}} \le \text{SRU} \tag{21}$$

$$\text{PD}_{lb,t-1}^{\text{TOU}} - \text{PD}_{lbt}^{\text{TOU}} \le \text{SRD} \tag{22}$$

$$\sum_{t=1}^{NT} \text{PD}_{lbt}^{\text{TOU}} = \sum_{t=1}^{NT} \text{PD}_{lbt}^{\text{Original}} \tag{23}$$

where the load demand l at bus b and time t is denoted by PD_{lbt}. Superscripts Original and ToU show the amount of the load demand before and after applying the ToU tariff. Besides, the tariff of energy sale at each hour has been indicated by Tariff_t. The objective function in this state has been defined as minimising the cost of the total energy purchased by the consumers (19). It is worth mentioning that as the amount of flexible load to participate in the DRP is a fraction of the total load demand at each hour, the participation in the ToU programme would be limited. The load demand allowed to increase or decrease at each time is shown by μ. Inequality (20) states the maximum variation of the load demand after applying the ToU policy. Furthermore, it should be noted that the maximum load deferral must be in a way that it does not result in frequency fluctuations in the network. Thus, the amount of load deferral is limited. The maximum load increase and load decrease are shown by shifting ramp-up and shifting ramp-down (SRD), as denoted in (21) and (22), respectively.