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A Hybrid Price-based Demand Response Program for the Residential Micro-grid

Houman Jamshidi Monfared^a, Ahmad Ghasemi^a, Abdollah Loni^b, Mousa Marzband^b

^a*Dept. of Electrical and Computer Engineering, Jundi Shapur University of Technology, Dezful, Iran*

^b*Dept. of Maths, Physics and Electrical Engineering, Northumbria University Newcastle, Newcastle upon Tyne NE1 8ST, UK*

Abstract

During the past two decades, focusing on providing solutions to boost the efficiency of power systems, as well as optimal consumption management has been attracting a good deal of attention. Demand Response (DR) programs, as the main part of Demand Side Management(DSM), have always been among the appropriate ways to persuade consumers to alter consumption patterns. In the main, the implementation of DR programs is carried out by price-based and incentive-based strategies. In this paper, first, a brief overview of the smart grid principles on retail electricity pricing is presented. Then, a hybrid price-based demand response (HPDR) for a residential Micro-grid is proposed, which is more adaptable to pricing principles compared to other existing models. Moreover, to increase the accuracy of the proposed model, the uncertainty regarding decision variables and parame-

Email address: aghasemi@jsu.ac.ir Corresponding author (Ahmad Ghasemi)

ters including the generation units, load dispatch in the Micro-grid is considered.

Finally, the obtained results demonstrate the effectiveness of the proposed model,

and show a decrease in Peak-to-Valley (PtV) index by almost 12%, as well as an

increase in social welfare indicator, power sale at peak times, and Coefficient of

Variation Percentage (CVP) respectively, by approximately 18%, 24% , and 25% in

comparison with other methods.

Keywords: Demand Response, Retail Electricity Pricing, Residential Micro-grid,

Load Pattern Modification.

Nomenclature

Acronyms

CPP	Critical Peak Pricing
CVP	Coefficient of Variation Percentage
DG	Distributed Generation
DR	Demand Response
DSM	Demand Side Management
EIA	Energy Information Administration
FR	Fixed Rate
GSP	Grid Supply Point
HPDR	Hybrid Price-based Demand Response
LCOE	Levelized Cost of Energy
MG	Micro-grid
MT	Microturbine
PAR	Peak to Average Ratio
PtV	Peak-to-Valley
PEM	Point Estimate Method
PV	Photovoltaic
REP	Retail Electricity Pricing
RTP	Real Time Pricing
SG	Stochastic Generation
TOU	Time of Use
TPEM	Two-Point Estimate Method
UG	Upstream Grid
WT	Wind Turbine

Indices

i, j	number of buses, $i, j \in \{2, \dots, 33\}$, $\{i = 1 \text{ is GSP}\}$
t, h	Planning Horizon (time interval), $t, h \in \{1, 2, \dots, 24\}$
G	Total amount of power generated by DGs
D	Active power demand - D_0 is the consumer load before applying DR

Constant Values

$P_{D,i}^t$	Consumed load of i^{th} bus at time t after applying DR (MW)
$P_{D_0,i}^t$	Consumed load of i^{th} bus at time t before applying DR (MW)
$P_{SG,i}^t$	Active power generated by SG of i^{th} bus at time t (MW)
$P_{DG,i}^{\max}$	Maximum amount of active power generated by DG of bus i (MW)
$P_{DG,i}^{\min}$	Minimum amount of active power generated by DG of bus i (MW)
$Q_{D,i}^t$	Total reactive power injected into the i^{th} bus at time t (MW)
$Q_{DG,i}^t$	Total reactive power generated by DG of i^{th} bus at time t (MW)
$V_i^{\max}$	Maximum amount of i^{th} bus voltage
$V_i^{\min}$	Minimum amount of i^{th} bus voltage
Y_{ij}^t	Admittance between buses i and j
θ_{ij}	Admittance angle between buses i and j
S_{GSP}^t	Amount of apparent power of GSP at time t
$S_{GSP}^{\max}$	Maximum amount of apparent power of GSP
S_{ij}^t	Capacity of transmission line between buses i and j at time t
$S_{ij}^{\max}$	Maximum amount of transmission line Capacity between buses i and j at time t
P_{Loss}^t	Total amount of active power losses of MG at time t
Q_{Loss}^t	Total amount of reactive power losses in MG at time t
$e_{D,i}^t$	Self-elasticity of consumer at time t
$e_{D,i}^{t,h}$	Cross-elasticity of consumer at time t
ρ_{D_0}	base energy price (\$/MWh)
$\rho_{D,i}^t$	Nodal hourly price announced to consumers at time t
$\rho_{GSP,i}^t$	Forecasted daily wholesale market price in bus i at time t

$C_{SG,i}^t$	Cost of generated power by SG in bus i at time t (\$/MWh)
$C_{DG,i}^t$	Cost of generated power by DG in bus i at time t (\$/MWh)
$SUC_{DG,i}$	Cost of turning on DG in bus i (\$)
$SDC_{SG,i}$	Cost of turning on SG in bus i (\$)
$RUP_{DG,i}$	Maximum amount of ramp up regarding DG generation in bus i
$RDN_{DG,i}$	Maximum amount of ramping down DG generation in bus i
$MUP_{DG,i}$	Minimum length of time that DG is on in bus i
$MDT_{DG,i}$	Minimum length of time that DG is off in bus i

Decision Variables

$P_{G,i}^t$	Total amount of active power injected into bus i at time t
$P_{DG,i}^t$	Amount of active power generated by DG in bus i at time t
$P_{DG,i}^{t+1}$	Amount of active power generated by DG in bus i at time t+1
$P_{GSP,i}^t$	Amount of active power exchanged between MG and UG at time t
$Q_{G,i}^t$	Total amount of reactive power injected into bus i at time t
$Q_{DG,i}^t$	Amount of reactive power generated by DG in bus i at time t
$Q_{GSP,i}^t$	Amount of reactive power exchanged between MG and UG at time t
V_i^t	Amount of voltage at bus i at time t
δ_i^t	Voltage angle at bus i at time t

Binary Decision Variables

$L_{DG,i}^t$	Binary decision variable regarding dispatchable DG unit start
$M_{DG,i}^t$	Binary decision variable regarding dispatchable DG unit shut
$N_{DG,i}^t$	Binary decision variable regarding dispatchable DG unit status

1. Introduction

The growing population of the world on one hand, and the increase in per capita electricity consumption in most countries, on the other hand, has led the demand side management to become more important. Demand response, known as an impressive method of demand side management, is one of the most effective ways to shift customers' peak so that it can shift customer's consumption from hours with higher prices to hours with lower prices [1]. In order to implement the modern methods of demand response, electricity sales tariffs must be designed for consumers in a way that both maximizes the economic interest of consumers and changes the consumption pattern. For this purpose, the incentive mechanisms are mainly composed of two categories. The first category occurs at peak times when the energy providers try to reduce the consumers' demand by offering incentive programs. The second category is to prevent the occurrence of supply-demand imbalance as far as possible. Therefore, increasing the diversity in the programs of demand response has led to a variety of diversification and pricing options for retail electricity. The purpose of this paper is to evaluate the efficiency of the most important new methods of retail pricing with regard to technical, economic and social welfare indicators. To this end, an optimization framework for the management of

energy is being developed for a residential micro-grid with distributed generations, in which there is the possibility of implementing a variety of pricing options.

Let's begin by looking at the several conducted research in this scope. In recent years, significant efforts have been made to implement the programs of demand response and electricity pricing methods in the context of smart grid. In reference [2], an elementary and simple concept of Time-of-Use (TOU) pricing model has been outlined for the first time. The principle of allocating costs to a tariff plan, and the dependence of these costs on different conditions, has been given in [3]. The real-time pricing (RTP) and the imposition of various tariffs over a very short period of time in an electricity market has been performed in [4]. RTP has been used as one of the newest pricing methodologies for retail electricity in [5] and in a residential MG. The pricing methods that are dependent on the technical characteristics of the system are also presented in some previous studies. For example, a CPP method is presented in [6]. In [7–9], a mathematical model of DR program has been presented to investigate the effect of tariffs on customer consumption during peak times and off-peak consumption. Considering that the DR programs are mainly made by the energy policymakers such as National Grid, an appropriate DR program not only reduces the peak times but also leads to reaching more profit for the residential consumers. Hence, the policymakers should propose incentive programs to encour-

age the consumers for participating in the proposed programs.

In order to evaluate the customer satisfaction of the proposed tariff plan, a social welfare index is considered in [10]. Applying new pricing methods in a MG can be done with different goals. For example, in [11], a TOU tariff plan has been applied to residential customers to maximize the profitability of the utility grid, regardless of the uncertainty caused by generation units. Gradually, with the development of the use of renewable energy sources such as wind and solar as a source of electrical energy, power networks have faced with major challenges [12, 13]. The non-dispatchable generations of renewable energy sources has caused micro grids, which are a small part of power systems, to face the uncertainty in predicting the generation [14]. Therefore, it is necessary to consider the uncertainty associated with the price, load and generation of renewable energy sources. In [15], an optimal electricity pricing strategy is proposed with the aim of maximizing the profit of the utility grid and, taking into account the constraints regarding customer welfare. Changes in the structure of a pricing plan can affect the consumption pattern of customers, these methods, which are generally called special and innovative methods, are typically applied to residential customers because of benefiting greater flexibility [16]. In [17], the novel methods of retail electricity pricing have been introduced, but the efficiency of these methods has not been studied in a near-reality model.

Thus, in this paper, a new optimization framework is introduced, aimed at maximizing the profit of MG, in conditions, on which new and varied retail electricity pricing methods have been implemented. In addition, in order to consider the customer's welfare, the indicators presented in [10] are taken into account. It should be pointed out that this MG has dispatchable and non-dispatchable generations. To bring the model closer to reality, the uncertainty associated with load, generation, and prices has also been considered. Also, all technical constraints and points related to the MG in real situation, such as load dispatch, and etc. will be considered. The contribution of this paper are as follows:

- Providing a hybrid price-based method (HPDR) to enhance the effectiveness of demand response programs, from consumers point of view.
- To evaluate the adaptation of HPDR method to consumer expectations, new indicators such as the indexes of simplicity, Peak-to-Valley (PtV), Peak-to-Average Ratio (PAR), Social Welfare, Coefficient of Variation Percentage (CVP), and Load Profile have been utilized.

The remainder of this paper is organized as follows: In Section 2, a brief overview of the existing models of retail electricity pricing and then, the proposed idea are presented. In Section 3, the implementation of the proposed algorithm is presented.

In Section 4, the results obtained from the proposed approach are shown. This section consists of the case study, numerical results, simulation and comparison of results, technical and economic indicators. Finally, the conclusion is given.

2. Description of General Idea

2.1. Principles of REP Methods

The main objective of the implementation of new REP methods is to improve the demand curve and bring it closer to a flat load profile. This important issue is done by allocating more prices at on-peak hours and lower prices to off-peak hours of consumption. According to the definition given in [17], each pricing plan should follow a principle that includes two groups of social acceptability and cost-related principles. The social acceptability principles include transparency and comprehensiveness of the tariff, simplicity and easy implementation and having minimum volatility of cost. The cost-based principles consist of two principles of cost recovery and cost causality [17]. In another definition, the principles of electricity tariff design can be categorized into five main categories of economic efficiency, justice, revenue stability, payment stability and customer satisfaction [18]. Although the principles outlined above have distinct differences to each other, many of them have similar concepts. In general, it can be said that the more a method of electricity re-

tail pricing is consistent with each of the principles mentioned, it is a more useful and efficient method [19]. Also, due to the contradiction in some principles, when designing a pricing method, there should be a compromise between the principles mentioned. According to the principles mentioned, each of the new REP methods has different structure and features. The main features and the extent of matching each of the new methods of REP with the principles of tariff design are described briefly in the following:

- **FR Pricing Method:** This method is highly popular among companies and residential customers due to the lack of massive changes in tariff rates [19]. But it does not include many production to consumption costs of electricity [19].
- **TOU Pricing Method:** In this pricing method, a tariff is set for each time period. This method, although largely consistent with the principle of simplicity and transparency, cannot fully reflect the cost of electricity in the long term [20].
- **RTP Method:** In this pricing plan, the price rate changes on an hourly basis. Therefore, it can cover all the costs of network changes, but due to constant price changes and complexity, this method has a little social acceptance

among customers [21].

2.2. Description of the Proposed Method (HPDR)

In addition to the above-mentioned methods, ideas for combining some of the pricing methods have also been presented in some of the past papers [22]. In this paper, a tariff plan, namely "HPDR", has been proposed that is a combination of TOU and RTP methods, which can be seen in Fig. (1). In more detail, the prices applied at off-peak and mid-peak hours are equal to the rates offered by TOU method. Also, the prices at on-peak hours are the same with the prices of RTP method during the same hours. This method seems to have the benefits of both TOU and RTP methods.

Fig. 1 : Placed Here

3. Mathematical Implementation of the Problem

The new model for optimizing the short-term/daily utilization of a residential MG is proposed in order to implement and compare the efficiency of various new methods of REP. The optimization model applied in this paper, shown in Fig. (2), aims to maximize and minimize the profitability of the UG and consumers costs, respectively. Moreover, the uncertainties issues related to the generations of WT and PVs, as well as wholesale market prices in this MG are considered using TP

in [22], [23]. As shown in Fig. 2, prior to HPDR unit, the data collected by PV power station, WT, MT, and energy prices are estimated by TPEM. Indeed, the HPDR unit is responsible for assigning a level of price to the consumer power consumptions at each hour (mentioned in subsection 2.2). Finally, the objective function; aimed at achieving the highest profit and the lowest cost of MG and consumers, respectively; is maximized by applying the optimization methods.

Fig. 2 : Placed Here

The optimization model envisaged in this paper is aimed at maximizing the profit of the residential MG and taking into account the potential of customer responsiveness to the prices sent by the MG. In this MG, an economic model of the load is used to express the relationship between customer responsiveness to daily delivery prices. In addition, all technical and operational constraints regarding DGs (both dispatchable and non-dispatchable), customer welfare, and distribution network structure have been considered.

3.1. DR Model

The consumers in the MG can change their consumption pattern, and thereby reduce their bill by participating in DR programs. The residential consumers have more flexibility than industrial and commercial consumers [22]. In this section, a

comprehensive economical model has been applied for DR based on load characteristics, including price flexibility and demand profiles [11]. Eq. (1) presents an economical model of DR for D consumer at time t [11].

$$P_{D,i}^t = P_{D_0,i}^t \cdot [1 + \frac{e_{D,i}^t \cdot [\rho_{D,i}^t - \rho_{D_0}]}{\rho_{D_0}} + \sum_{h=1, h \neq t}^{24} e_{D,i}^{i,h} \cdot \frac{\rho_{D,i}^t - \rho_{D_0}}{\rho_{D_0}}] \quad (1)$$

3.2. The Objective Function

The objective function of the problem is maximizing the MG profit, which is in fact equal to the difference in the amount of revenues and costs. The cost function includes the cost of generating the power of dispatchable DGs, the cost of power exchanges with the wholesale electricity market/UG, and the cost of generating the power with renewable energy sources. The revenue function also includes the amount of power sold to final consumers. Moreover, the variable sign of P_{GSP}^i represents the purchase or sale of power with the upstream network at time t. The positive/negative sign of this variable means that the MG has purchased/sold the power from/to its upstream network. The functions of profit, revenue and cost, respectively are defined in Eqs. (2),(3), and (4) as follows:

$$\text{Max } \sum_t [\text{Revenue}^t - \text{Cost}^t] \quad (2)$$

$$\text{Revenue}^t = \sum_t [(P_{D,i}^t \cdot \rho_{D,i}^t) - (P_{GSP,i}^t \cdot \rho_{GSP,i}^t)] \quad (3)$$

$$\begin{aligned} \text{Cost}^t = \sum_{DG} \left[(C_{DG,i}^t \cdot P_{DG,i}^t \cdot L_{DG,i}^t) + (SUC_{DG,i} \cdot M_{DG,i}^t) \right. \\ \left. + (SDC_{DG,i} \cdot N_{DG,i}^t) \right] + \sum_{SDG} C_{SG,i}^t \cdot P_{SG,i}^t \end{aligned} \quad (4)$$

3.3. Technical and economical constrains

In general, the constraints that should be considered during optimization of the problem are divided into three categories. The first set of constraints is related to the limits of the distribution network of AC load. The second category includes the constraints on the power balance of the results obtained from the optimization problem. The third category ultimately covers the limits of dispatchable DGs.

Distribution Network Constrains

The Eqs. regarding AC load dispatch in each bus at time t are as follows:

$$P_{G,i}^t - P_{D,i}^t = \sum_{\forall j} |V_i^t| \cdot |V_j^t| \cdot |Y_{ij}^t| \cdot \cos(\theta_{ij} + \delta_j^t - \delta_i^t) \quad (5)$$

$$Q_{G,i}^t - Q_{D,i}^t = \sum_{\forall j} |V_i^t| \cdot |V_j^t| \cdot |Y_{ij}^t| \cdot \sin(\theta_{ij} + \delta_j^t - \delta_i^t) \quad (6)$$

In the above Eqs., the values of $P_{G,i}^t$ and $Q_{G,i}^t$ are calculated as follows:

$$P_{G,i}^t = P_{GSP,i}^t + P_{DG,i}^t + P_{SG,i}^t \quad (7)$$

$$Q_{G,i}^t = Q_{GSP,i}^t + Q_{DG,i}^t + Q_{SG,i}^t \quad (8)$$

Eq. (9) is the voltage constrain of each bus.

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

Eq. (10) indicates the capacity constraint of the transformer in the connection point of MG with the UG.

$$S_{GSP}^t \leq S_{GSP}^{\max} \quad (10)$$

Eq. (11) shows that the maximum amount of transitional power of Lines.

$$S_{ij}^t \leq S_{ij}^{\max} \quad (11)$$

Power Balance Constrains

Eqs. (12) and (13) are the constraints related to active and reactive power balance per hour.

$$\sum_{DG} P_{DG,i}^t + \sum_{SDG} P_{SDG,i}^t + P_{GSP,i}^t = \sum_D P_{D,i}^t + P_{Loss}^t \quad (12)$$

$$\sum_{DG} Q_{DG,i}^t + \sum_{SDG} Q_{SDG,i}^t + Q_{GSP,i}^t = \sum_D Q_{D,i}^t + Q_{Loss}^t \quad (13)$$

In the above-mentioned Eqs., the values of P_{Loss}^t and Q_{Loss}^t are obtained from the following Eqs:

$$p_{Loss}^t = 0.5 \times \sum_{ij} \left| \left[(V_i^t)^2 + (V_j^t)^2 \right] \cdot Y_{ij} \cos(\theta_{ij}) - \left[2 \times V_i^t \cdot V_j^t \cdot Y_{ij} \cdot \cos(\theta_i^t) \cdot \cos(\delta_i^t - \delta_j^t) \right] \right| \quad (14)$$

$$Q_{Loss}^t = 0.5 \times \sum_{ij} \left| \left[(V_i^t)^2 + (V_j^t)^2 \right] \cdot Y_{ij} \sin(\theta_{ij}) - \left[2 \times V_i^t \cdot V_j^t \cdot Y_{ij} \cdot \sin(\theta_i^t) \cdot \cos(\delta_i^t - \delta_j^t) \right] \right| \quad (15)$$

DGs Constrains

Eqs. (16), (17), and (18) are the constrains related to dispatchable DGs.

$$P_{DG,i}^{\min} \leq P_{DG,i}^t \leq P_{DG,i}^{\max} \quad (16)$$

$$P_{DG,i}^{t+1} - P_{DG,i}^t \leq RUP_{DG,i} \quad (17)$$

$$P_{DG,i}^t - P_{DG,i}^{t+1} \leq RDN_{DG,i} \quad (18)$$

Where $RUP_{DG,i}$ and $RDN_{DG,i}$ are ramp up and down of DG i (kW/min). The maximum ramp up and down rates are considered as 12% MW and 10% MW of DG generation per hour, respectively (See Table 1 and 2).

Eqs. (19) and (20) indicate the physical constrains associated to each DG.

$$\left\{ \begin{array}{l} \sum_{h=1}^{MUT} L_{DG,i}^{t+h-1} \geq MUP_{DG,i}, \quad \forall M_{DG,i}^t = 1, \quad \sum_{h=1}^{MDT} (1 - L_{DG,i}^{t+h-1}) \\ \sum_{h=1}^{MUT} L_{DG,i}^{t+h-1} \geq MDT_{DG,i}, \quad \forall N_{DG,i}^t = 1 \end{array} \right. \quad (19)$$

$$M_{DG,i}^t - N_{DG,i}^t = L_{DG,i}^t - L_{DG,i}^{t-1}, \quad M_{DG,i}^t + N_{DG,i}^t \leq 1 \quad (20)$$

4. Results and discussion

4.1. Case Study

In this paper, as shown in Fig. 3, a residential radial MG having IEEE 33-bus [23] connected to the UG has been considered. The load of this MG is fed by a number of MTs as dispatchable generation units and by WT and two PVs as non-dispatchable generation units. The target network is a 33 KV network, which has been reviewed and analyzed with considering some changes. The MG has been connected to the UG by a distribution transformer with a capacity of 50 MVA in Bus No. 1 (GSP). Three MTs have been considered as a dispatchable generation source at buses 16, 22, and 30. Moreover, two PVs and a WT, as non-dispatchable renewable units are located at buses 9, 26 and 21, respectively.

Fig. 3 : Placed Here

It should be pointed out that the MG is fully equipped with smart devices including smart meter, smart home appliances, EMS, and energy storage. The responsibility and whole intellectual property of WT, PVs and MTs connected to the MG are delegated to the local aggregator/central controller. The MG receives the estimated daily prices in the wholesale electricity market through the secure internet gateway. The daily consumption profile and the generation amount of WT and PVs are obtained by forecasting the weather conditions and historical data, which is beyond the scope of our discussion in this paper.

4.2. Numerical Studies

The generation cost of each DG is based on the LCOE published by the Energy Information Administration (EIA) in 2017 [24]. The cost of LCOE is calculated based on the cost of installation, exploitation, and maintenance as well as the useful life of each DG unit [25]. Information related to the dispatchable and non-dispatchable DGs, as well as the predicted daily generation of WT and PVs, are presented in Tables 1 to 4, respectively, as follows:

Table 1 : Placed Here

Table 2 : Placed Here

Table 3 : Placed Here

Table 4 : Placed Here

The consumers' buildings belonging to the residential sector are grouped in 32 buses of MG (except bus number 1), which are also visible in Fig. (3). The flexibility of buildings varies over one day or one season and has a different value for each time period. In this paper, the flexibility of buildings for various time periods has been extracted from residential customers in Ontario's Canadian electricity market on a summer day [26], which are visible in Table (5).

Table 5 : Placed Here

Fig. (4) shows the average value of daily energy market estimated prices for the Ontario Electricity Market in August 6, 2016 [27]. The value of the base price of energy in the desired numerical studies is assumed to be (101 \$/ MWh), which is the average of the estimated prices of the wholesale market on the same day [27]. Also, the load profile of Ontario electricity market on the target day, on a smaller scale and with a slight change in the adaptation to the test micro grid is shown in Fig. (5) [28].

Fig. 4 : Placed Here

Fig. 5 : Placed Here

The fixed price in the FR method is equal to the average daily wholesale market prices. Also, the prices of RTP are equal to the daily prices of the wholesale market per hour. Fig. (6) shows the price changes graph in each of the pricing methods.

Fig. 6 : Placed Here

4.3. Simulation and Comparison of Results

DGs Generations

As shown in Fig. (7), the generation of DG No. 1 at 6 o'clock in the morning is zero. The reason for this is that at this hour, the estimated electricity purchase price from the wholesale market (83\$/MWh), is lower than the average cost of generating electricity by DG No. 1 (85\$/MWh). As a result, the MG purchases the power from the UG. Because in the rest of the day, the average cost of generating DGs is lower than the estimated price of the wholesale market, so other DGs have their maximum generation. For the same reason, the generation of DGs NO. 2 and 3 are maximum, which can be seen in Fig. (8).

Fig. 7 : Placed Here

Fig. 8 : Placed Here

Load profile of consumers

Regarding Fig. (9), making the use of new REP methods in the context of the DR

program, causes the load profile to be flattened before the DR is applied. Also, these methods reduce the consumption of the customer at the peak hours. Of course, this reduction is different for REP methods. For example, HPDR method, in comparison with other methods of REP, has the largest share of reducing energy consumption during peak hours.

Fig. 9 : Placed Here

Power exchanges between MG and UG

Fig. (10) shows the electricity exchange of MG with the UG at a daily time interval. In this figure, the positive/ negative values mean the purchase/sale of power from/to the UG. According to the chart, when the price is fixed (FR method), the MG has sold the power to the UG during peak hours of consumption, but it has bought the power out of consumption peak hours. However, after utilizing DR programs generally at consumption peak hours overnight, the HPDR method has a larger share of power sales to the UG.

Fig. 10 : Placed Here

4.4. Technical Indicators

In order to demonstrate the effectiveness of each of the REP methods, plus HPDR, the indicators including technical, economic and social have been considered. The technical indicators include the PtV distance of load profile, as well as

the PAR. Also, the economic indicators examined include the total profit of MG, the total customer bill and the social welfare index. Simplicity index has also been considered as a social indicator for different pricing methods [10, 15]. Finally, the CVP index has been investigated for the purpose of evaluating the uncertainty related to the input parameters on the objective function (Eq. (2)).

PtV distance of load profile

The PtV distance of consumption load profile for each REP method has been shown in Fig. 10. According to this diagram, applying the new pricing methods in the context of the DR program leads to reducing the peak of daily load profile. Also, HPDR method also reduces the PtV distance more than the other methods.

Fig. 11 : Placed Here

PAR coefficient of load profile

Fig. (12) demonstrates the peak to average ratio regarding the daily load profile of consumers consumption in each of REP methods. The smaller the value of the PAR coefficient, the changes in the consumption load profile a REP method are also lower and, as a result, the load profile is flatter. According to Fig. (12), the rate of changes in the load profile in the RTP method is lower than the other methods. Also, the HPDR method has a better PAR ratio than TOU and FR methods.

Fig. 12 : Placed Here

4.5. Economic Indicators

Total profit of MG

According to Fig. (13), the FR method has less profit than the other methods because it considers lower costs of production to consumption than them. Similarly, the RTP method will also result in a higher profit margin for the MG due to the shortage of time interval for changing the price level and, as a result, including more costs. The total profit of MG for each of the REP methods, with different flexibility coefficients for customers, has been shown in Fig. (13). By increasing the flexibility coefficient of the customer in each of the methods, the amount of profit will also increase slightly. In the FR method, the profit of MG is equal to the constant value (\$ 9862).

Fig. 13 : Placed Here

Total customer bill

Figure (14) demonstrates the total customer bill in different REP methods. In general, applying the new pricing methods reduces the total amount of customers' bills relative to the FR method. Also, in the HPDR plan, the total customer bill is close to the TOU method and it is much less and more appropriate than the RTP method.

Fig. 14 : Placed Here

Social Welfare Index

The social welfare index has been investigated to evaluate the efficiency of each REP method in this paper. This index is also known as the surplus of total profit, is defined as the total profit of the customer and the seller [10]. In this paper, the social welfare index is calculated as a total increase in the profit of MG and reduction of the customer bill. Increasing the net profit of MG is the difference in the profit of MG after applying DR compared to pre-applying it in each REP method. Also, the reduction of a customer bill is calculated as a difference in customer bill, in the DR mode, compared to the state of pre-applying the DR. This index has been investigated for various flexibility in Fig. (15). According to Fig. (15), the HPDR scheme has better social welfare than other methods. It should be noted that although the RTP method has a greater profit than the HPDR, the total customer bill in this method is greater than the HPDR, and therefore, in general, the social welfare of HPDR method is higher than other methods.

Fig. 15 : Placed Here

Social Acceptability Index

In this paper, the simplicity index has been expressed in Eq. (21) to examine the simplicity of each REP schemes for customers.

$$\text{Simplicity Index} = \frac{1}{|\sum_{t=1}^{24} [\text{average of daily prices}] - [\text{prices per hour}]|} \quad (21)$$

In general, the more a pricing method has fewer changes in the hourly prices, it will be more in line with the simplicity principle for the customers. According to Fig. (16), the TOU method has a lower amount of variation in applied prices, and its simplicity index is higher. The RTP method also has the slightest simplicity for the customer due to high changes per hour. Although the HPDR has less simplicity than the TOU method, it is simpler than RTP, and thereby does not have problems related to its social unacceptability.

Fig. 16 : Placed Here

Uncertainty rate and CVP index As noted in the previous sections, in this paper, the uncertainty related to the generation of renewable units, as well as the prices of the wholesale market and the consumed load have been estimated. In this section, the permeability amount of each REP methods from uncertainty have been investigated. To this end, in this section, the CVP index for net profit of MG has been calculated and compared when applying any of the REP methods. This random and probable index is calculated from Eq. (22):

$$\text{CVP Index} = \frac{\text{Standard Deviation}}{\text{Mean}} \times 100 \quad (22)$$

The results for each of the REP methods have been shown in Fig. (17). The HPDR scheme has less permeability than existing uncertainties in the MG than in other methods.

Fig. 17 : Placed Here

In this part, a overview of results comparison derived from Figs. (11) to (17) is illustrated in the following table:

Table 6 : Placed Here

5. Conclusion

In this paper, a new optimization framework has been proposed to investigate and compare the new REP methods in the context of residential MG. In general, the more a pricing plan is applied in less time intervals, the larger net profit for the MG is due to consider the greater cost of production to consumption. For this reason, the RTP method has a higher total MG profit than other methods, although this is the most complicated tariff plan because of hourly price changes. The total MG profit for RTP, HPDR, and TOUs is \$ 15623, \$ 13600, and \$ 11988, respectively.

In addition, the total customer bill for HPDR methods is \$ 47000, and TOU is \$ 46860, which is significantly lower than the RTP (\$ 47700), and FR (\$ 48160). Moreover, the HPDR scheme has a better social welfare index than other methods. The percentage of social welfare index for HPDR, RTP and TOU are 39, 32 and 25 percent, respectively. In the investigated methods, the HPDR has reduced the peak value of the load profile, which had an initial value of 28 MW, to the amount of 17.4 MW. This value for TOU and RTP methods is equal to 21 MW and 19.9 MW, respectively. Also, the highest amount of power sold to the UG is related to the HPDR and is equal to the value of 6.5 MW. This value for RTP and TOU methods is equal to 5 MW and 4.1 MW.

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Figure 1: A schematic of HPDR method

Figure 2: Flowchart of Proposed Algorithm.

Figure 3: The structure of proposed MG

Table 1: Characteristics of Dispatchable DGs (MTs)

DG No.	Bus No.	$P_{DG,i}^{\min}$	$P_{DG,i}^{\max}$	$C_{DG,i}^{\max}$	SUC	SDC	$RUP_{DG,i}$	$RDN_{DG,i}$
1	16	0	7	85	20	25	0.84	0.7
2	22	0	5	70	20	25	0.6	0.5
3	30	0	5	75	30	25	0.6	0.5

Table 2: Characteristics of Non-dispatchable DG (Renewable Generation Units)

Type of SDG	BusNo.	$P_{SDG,i}^{\min}$ (MW)	$P_{SDG,i}^{\max}$ (MW)	$C_{SDG,i}^{\max}$ (\$/MW)	$RUP_{DG,i}$	$RDN_{DG,i}$
WT	21	0	9	45	1.08	0.9
PV 1	9	0	2	53	0.24	0.2
PV 2	26	0	2	53	0.24	0.2

Table 3: Elasticity of residential consumers for different time periods

Time period of consumer self – elasticity	On – peak	Mid – peak	Off – peak
On-peak [7 to 11] & [17 to 19]	-0.150	0.080	0.070
Mid-peak [11 to 17]	0.080	-0.140	0.050
Off-peak [19 to 7]	0.070	0.050	-0.120

Table 4: Amount of Power Generated by PV 1 and 2

Generation Hours	PV1		PV2	
	Average Value (MW)	Standard Deviation	Average Value (MW)	Standard Deviation
9	0.2	0.01	0.15	0.01
10	0.4	0.02	0.4	0.02
11	0.6	0.03	0.65	0.04
12	0.8	0.01	0.8	0.02
13	0.9	0.01	0.9	0.02
14	1.1	0.02	1.2	0.01
15	1	0.03	1.1	0.02
16	0.9	0.01	0.9	0.03
17	0.8	0.02	0.9	0.01
18	0.6	0.03	0.7	0.02
19	0.4	0.01	0.45	0.02
20	0.2	0.02	0.3	0.01

Figure 4: The average value of daily estimated prices of wholesale market

Table 5: Characteristic of Power Generated by WT

GenerationHours	WT	
	Average Value (MW)	Standard Deviation
[1, 4]	4	0.28
[5, 8]	4.5	0.2
[9, 12]	6.2	0.23
[13, 16]	5.4	0.4
[17, 20]	6.6	0.32
[21, 24]	7.5	0.26

Figure 5: The daily load profile consumed in each time interval

Figure 6: Changes in hourly prices applied in each of the pricing methods

Figure 7: Generation amount of DG 1 when applying any of the pricing methods

Figure 8: Generation amount of DGs 2 and 3 when applying any of the pricing methods

Figure 9: load profile when applying each REP methods

Figure 10: Electricity exchange of MG with the UG

Figure 11: PtV distance of load profile in each of REP methods

Figure 12: The value of the PAR coefficient in each of the pricing methods

Figure 13: Total profit of MG considering the flexibility coefficient changes for each REP method.

Figure 14: Total customer bill considering the flexibility coefficient changes for each REP method.

Figure 15: The percentage of social welfare index in each of the REP methods

Figure 16: The simplicity index for the customers in each of the REP methods

Figure 17: Uncertainty rate and CVP index in each of the REP methods

Table 6: A summary of results comparison between the retail electricity pricing (REP) methods

HPDR / Other Methods	FR	TOU	RTP
PtV distance of load profile	↑ 42%	↑ 20%	↑ 11%
PAR coefficient of load profile	↑ 6%	↑ 3%	↓ 4%
Total profit of MG	—	↑ 17%	↓ 14%
Total consumer bill	↑ 3%	↓ 4%	↑ 2%
Social Welfare indicator	—	↑ 62%	↑ 18%
Simplicity index	—	↑ 8%	↓ 2%
CVP index	↑ 53%	↑ 40%	↑ 25%

The potential referees are listed below:

- **Prof. Ali Reza Seifi**, Department of Electrical and Computer Engineering,
Shiraz University, E-mail: seifi@shirazu.ac.ir
- **Prof. Seyed Masoud Moghaddas-Tafreshi**, Department of Electrical Engineering, Khajeh Nasir Toosi University of Technology, E-mail: tafreshi@eetd.kntu.ac.ir
- **Prof. Elaheh Mashhour**Prof. Elaheh Mashhour, Department of Electrical Engineering, Shahid Chamran University of Ahvaz, E-mail: e.mashhour@scu.ac.ir