Determining Optimal Buses for Implementing Demand Response as an Effective Congestion Management Method

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***Abstract*—Demand response (DR) can be counted as an effective congestion management method in power systems. However, appointing the optimal buses for the demand response programs (DRPs) implementation is one of the main challenges for the power system operators. In this paper, a new procedure has been developed by which the optimal locations and times of DRPs implementation are determined. Optimal buses are identified based on the power transfer distribution factors (PTDFs), available transfer capability, and dynamic dc optimal power flow problem. Applying the developed method results in reducing lines' congestion, increasing customers, and independent system operator's benefits, improving load curve's characteristics, preventing line outages and black outs, and consequently increasing the network reliability. The proposed method has been applied on the IEEE 39-bus New England test system. Results indicate the effectiveness and practical benefits of the proposed method.**

***Index Terms*—Available transfer capability, congestion management, DDCOPF, demand response, optimal buses, power transfer distribution factors.**

NOMENCLATURE

ATC	Available transfer capability
a_g, b_g, c_g	Generators cost's coefficients
Ben	Benefit function
CBM	Capacity benefit margin
CM	Congestion management
CPP	Critical peak pricing
DDCOPF	Dynamic DC optimal power flow
DED	Dynamic economic dispatch
DER	Distributed energy resources
DG	Distributed generation
DLC	Direct load control
DR	Demand response
DRPs	Demand response programs
DS	Distributed storage
$d_0(.)$	Initial load demand
$d(.)$	Load demand after implementing DR
$d_0^{\max}(.)$	Maximum initial load demand
$d^{\max}(.)$	Maximum load demand
$d^{\min}(.)$	Minimum load demand
Els	Elasticity in the price elasticity matrix
EDRP	Emergency demand response program
ETC	Existing transmission commitments
E_{gen}	Generator existence matrix at each bus
FACTS	Flexible AC transmission system
GSFs	Generation shift factors
G_{shunt}	Amount of consumed power by the shunt elements with the constant impedance
ISFs	Injection shift factors
ISO	Independent system operator
LF	Load factor
MAX_{line}	Maximum line limit
NERC	North American electric reliability corporation
NP	Net profit
N_g	Number of generating units
PC	Peak compensate
PEM	Price elasticity matrix
PTDFs	Power transfer distribution factors
PTV	Peak to valley
$P_{D,t}$	Bus load matrix at the tth hour
$P_{g,t}$	Generated power of the gth generator at the tth hour
$P_g^{\max}$	Maximum limit of the generating power for the gth generator
$P_g^{\min}$	Minimum limit of the generating power for the gth generator
$P_{\text{line},t}$	Power flow at the lth line
$P_l^{\max}$	Thermal limit at the line l
SGs	Smart grids
T	Dispatch interval ($T = 24$)
TOU	Time of use
TRM	Transmission reliability margin
TTC	Total transfer capability
TL_l	Transfer limitation for each line
X_{im}	Element of the bus reactance matrix at the ith row and mth column
x_l	Reactance of the line l between the buses i and j
x_s^i	Series reactance of the ith line
$\rho_0(.)$	Initial electricity price
$\rho(.)$	Electricity price
Θ_t	Line angle difference matrix at the tth hour
$\theta_{i,t}$	Bus voltage angle at the tth hour
θ_i^{ref}	Reference angle
τ^i	Tap ratio

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I. Introduction

ELECTRICITY demand growth in the recent years has caused some problems such as the line congestion, lack of generation capacity, blackouts, electricity price increase, and environmental pollution due to the fossil fuel power plants. Continuing increase of the demand imposes additional costs for constructing new power plants and transmission lines [1]. However, these costs are just for providing electricity in some critical hours in the year. Therefore, it is necessary to apply some methods such as DRPs in order to reduce consumption at the peak hours and consequently alleviate the congestion.

Congestion management (CM) is one of the main issues in the power system operation. CM's methods are mainly divided into two categories namely the preventive and corrective CM methods. Preventive CM methods are based on using the transmission right and available transfer capability (ATC). On the other hand, ATC based methods focus on informing customers to optimally modify their consumption pattern in order to alleviate the congestion and increase their benefits [2], [3]. Demand response (DR) is one of these effective methods by which customers participate in some programs that leads to the load curve's pattern modification. In other words, customers who participate in DRPs can play an important role in CM [4]. But, this goal can be achieved only if DRPs are implemented optimally. So that, the best locations (critical hours) and times (critical hours) for implementing DRPs should be determined by independent system operator. In this paper, a new procedure for the mentioned goals has been developed which is based on the power transfer distribution factors (PTDFs), ATC, and dynamic DC optimal power flow (DDCOPF). Actually, this paper focuses on the role of DRPs in CM and consequently reliability improvement.

ATC is the amount of electrical power (based on MW) which can be transferred from one point or area to the other ones in a safe and reliable manner. ATC is defined by North American electric reliability corporation based on four indexes as given in (1) [5], [6]

$$\mathrm{ATC} = \mathrm{TTC} - \mathrm{TRM} - \mathrm{CBM} - \mathrm{ETC} \tag{1}$$

Total transfer capability (TTC) is the total power which can be transferred from one point to another one in the transmission network without interrupting. Transmission reliability margin (TRM) is the reliability index for covering the transmission network uncertainties. Capacity benefit margin (CBM) is similar to TRM, but it is for covering the power generation uncertainties. Existing transmission commitments is the amount of transferred power from one point to another considering the current contracts. TRM and CBM vary a lot in different systems based on the methodologies of calculation. So, they are usually ignored to reduce the calculation. The ATC calculation based on PTDFs has been presented in [7]–[10] too.

PTDFs determine the sensitivities of different lines power flow changes due to different power transactions in different system buses. After applying DDCOPF and ATC calculation, based on a procedure, the best buses for implementing DRPs are determined. This approach will be explained in Sections II and III. Note that in this paper, for DCOPF calculation, the package of matpower_5.1 software [11] has been used with some modifications to be applied to DDCOPF.

DRPs are implemented based on the different policies. Usually they are implemented to reduce demand at the peak hours and consequently to decrease generation's costs and emission. In other words, if DRPs are implemented intelligently by which the optimal incentives and prices are determined; they can decrease both the supply and demand costs.

Frequency and voltage support of the islanded micro grid by coordinating the distributed energy resources (DERs) and DR have been presented in [12]. The proposed method is based on the real and reactive power sensitivities at different buses in order to minimize the deviation of voltage and frequency. It was shown that DERs and DR could effectively support the voltage and frequency of the islanded micro grid [12].

Modeling the automated residential DR by a dynamic energy management framework has been presented in [13]. The model estimates the residential demand and optimally schedules controllable appliances including the plug-in electric vehicles [13].

Reference [14] introduced DRPs resources' challenges and potential solutions under smart grid (SG). They concluded that DR can be counted as an important ingredient of SGs.

In our previous works, the incentive based [15] and price based [16] DRPs were intelligently integrated with the dynamic economic dispatch problem and it was shown that if the incentives in the incentive based DRPs [15] and also prices in the price based DRPs [16] are determined intelligently, DRPs would be a win-win game both for the supply and demand sides. In other words in this situation, the generation costs are decreased, customers' benefits are increased, and load curve's characteristics are improved simultaneously. In fact, in [15] a procedure for determining the optimal incentives in the incentive based DRPs and in [16], a procedure for determining the optimal prices during different periods in the price based DRPs are developed. Note that in [15] and [16], the transmission line limits and congestion were not taken into account and DR was not considered as a tool for CM. In fact, the effects of DR on the costs reduction and load curve's characteristics improvement were considered in [15] and [16].

In addition to the above benefits for the DRPs implementation, DRP can be implemented to alleviate the network's congestion. But, it is possible just by determining the optimal buses, times, and prices in DRPs.

In [17], two different procedures for CM have been presented. At the first one, the emergency demand response program which is an incentive based DR has been implemented at the system's buses which alleviates congestion. The second approach redispatches the generation units which alleviates the congestion too. The optimization problem is based on the net social welfare maximization. The authors applied their proposed model on the IEEE 30-bus test system and results showed that both of their procedures can alleviate the congestion in the power system.

An agent-based architecture was proposed in [18] for the energy management system. In the presented model, DR and distributed storage contribute to facilitating the power trading between different micro-grids. They also considered the incentive based DRPs in which customers reduce their peak demand during the peak hours.

In [19], an economical comparison between the flexible AC transmission system (FACTS) and DR in improving ATC has been presented. They have applied their proposed system on the IEEE 30-bus test system considering direct load control (DLC) as the DRP. They showed that DLC improves ATC, but is has high additional costs which should be paid as incentives to the customers to motivate them to participate in DLC. So, they concluded that DLC (as a tool for the ATC improvement) should be implemented just in the emergency situations.

Yousefi *et al.* formulated a two-step market clearing scheme by which congestion is managed by DR and FACTS devices [20]. Their procedure is based on the generation companies' and ISO's benefits maximization including the network constraints. They have compared the impacts of different values of DR and FACTS. Finally, they showed that DR and FACTS can effectively alleviate the congestion in the power system.

In the all above mentioned works, DR is implemented to reduce costs and improve the load curve characteristics, or alleviating congestion. But, none of them has introduced a procedure for the optimal implementation of DR for the CM while satisfying the other aims i.e. the cost reduction and reliability improvement. In other words, there is not a complete work by which the optimal buses and times for the implementation of DRPs are determined. If DR is not implemented optimally, it may worsen the congestion (implementation of DR on buses with positive values of PTDFs as will explained in the following). So, it is very important to determine the optimal buses and times for implementation of DR. In fact, optimal implementation of DR in order to satisfy different tasks is a significant role which has been developed in this paper. Actually in this work, a procedure for the mentioned purposes is presented using PTDFs, ATC, and DDCOPF which is fully consistent with the real-world power system conditions and it is a scientific and practical approach.

DRPs are categorized into the incentive based and price based DRPs. Sometimes based on the network's situation and ISO's policies, a combination of these two programs may be implemented [21], [22]. In the price based DRPs, the prices during different periods vary, so it motivates customers to modify their consumption patterns. In the incentive based DRPs, incentives are paid to the customers to reduce or cut their consumption during critical or peak hours. In this paper, a combination of two common price based programs namely the time of use (TOU) and critical peak pricing (CPP) has been taken into account. In the applied program namely TOU-CPP, the prices of electricity vary in different periods based on the amount of consumption. So that, prices in the peak, off-peak, and valley periods are relatively high, average, and low, respectively (like pricing in TOU). Moreover, the price in the critical hour(s) is very high (like pricing in CPP). Therefore, a combination of the mentioned pricing including TOU and CPP (TOU-CPP) pricing is considered in this paper.

The main contributions of this paper are the development of a new procedure for determining the optimal buses and times for the DRPs implementation based on PTDFs, ATC, and DDCOPF and also investigating the effects of DRPs on ATC and lines congestion improvement.

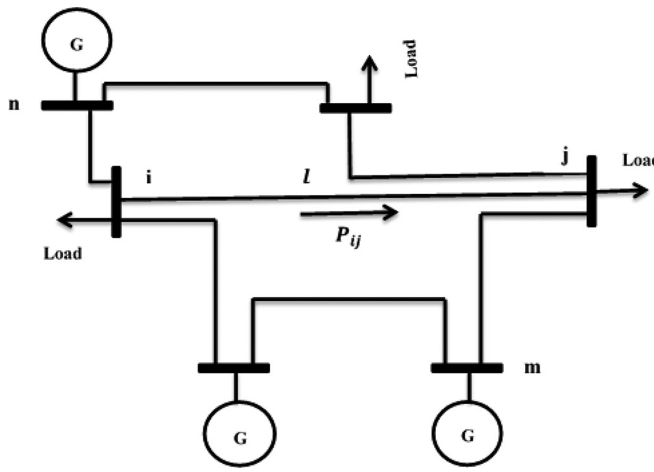

Fig. 1. Typical 6-bus test system.

The rest of this paper is organized as follows. In Section II, the problem formulation and solution methods are developed. In Section III, the numerical simulation and results are presented. Finally, the conclusion is drawn in Section IV.

II. Problem Formulation

To solve the mentioned problem, a procedure is presented as following. First, the method of calculating PTDFs and ATC are presented. Then, the formulation of DDCOPF is developed. Finally, the way of optimal implementation of DR through integration of PTDFs, ATC, and DDCOPF is presented.

A. PTDFs and ATC Calculation

PTDFs are the sensitivities of line flows to the changes in the nodal active power injection. Sometimes these factors are called generation shift factors or injection shift factors especially when the second power extractor node is the reference bus. Therefore, PTDF is as (2) which is the ratio of power flow changes in the line l (between buses i and j) due to the power transaction from the bus m to n [7]–[10] (see Fig. 1). When this factor is relatively high, it shows that the power changes in bus m can effectively change the power flow changes in the line l. Therefore, this bus can be a suitable candidate for the DRPs implementation

$$\mathrm{PTDF}_{l,\mathrm{mn}} = \frac{\Delta P_l}{\Delta P_{\mathrm{bus}}} = \frac{X_{\mathrm{im}} - X_{\mathrm{jm}} - X_{\mathrm{in}} + X_{\mathrm{jn}}}{x_l} \tag{2}$$

The transfer limitation for each monitored line due to the different transactions considering the thermal overload is as (3) which limits ATC

$$TL_l = \begin{cases} \dfrac{P_l^{\max} - P_l}{\mathrm{PTDF}_l}, & \mathrm{PTDF}_l > 0 \\ \infty, & \mathrm{PTDF}_l = 0 \\ \dfrac{-P_l^{\max} - P_l}{\mathrm{PTDF}_l}, & \mathrm{PTDF}_l < 0 \end{cases} \tag{3}$$

Whatever the amount of TL_l is less, the line l will be more constraining. So, ATC can be given as

$$\mathrm{ATC}_l = \min\left(TL_l\right) \tag{4}$$

B. Standard Dynamic DCOPF

A summary of the DDCOPF problem formulations including its constraints are as (5)–(13). It is actually the DCOPF problem [11], [23], [24] which has been extended for the dynamic case

$$\min \sum_{t=1}^{T} \left\{ \sum_{g=1}^{N_g} a_g + b_g P_{g,t} + c_g P_{g,t}^2 \right\} \tag{5}$$

Subject to:

$$P_g^{\min} \le P_{g,t} \le P_g^{\max} \; g = 1,2,\ldots,N_g \tag{6}$$

$$\theta_i^{\text{ref}} \le \theta_{i,t} \le \theta_i^{\text{ref}} \; i \in I_{\text{ref}} \tag{7}$$

$$\mathrm{B}_{\text{bus}}\Theta_t + P_{\text{shift,bus},t} + P_{D,t} + G_{\text{shunt}} - E_{\text{gen}}\, P_{\text{gen},t} = 0 \tag{8}$$

$$P_{\text{shift,bus},t} = (Z_{\text{from}} - Z_{\text{to}})^{\text{Trn}}\, P_{\text{shift,line},t} \tag{9}$$

$$P_{\text{shift,line},t} = P_{\text{line},t} - B_{\text{line}}\Theta_t \tag{10}$$

$$B_{\text{line}} = B_{\text{line-line}}\, (Z_{\text{from}} - Z_{\text{to}}) \tag{11}$$

$$B_{\text{line}}\Theta_t + P_{\text{shift,line},t} - MAX_{\text{line}} \le 0 \tag{12}$$

$$-B_{\text{line}}\Theta_t - P_{\text{shift,line},t} - MAX_{\text{line}} \le 0 \tag{13}$$

where G_{shunt} is the amount of consumed power by the shunt elements with constant impedance, E_{gen} is the matrix of generator existence at each bus (it is one when a generator exists at the related bus and is zero when there is not any). Z_{from} and Z_{to} are the matrixes with the element equal to one when the (a,b) element of Z_{from} and also the (a,c) element of Z_{to} for the line a connecting from buses b to c exists. Otherwise, their elements are zero. $B_{\text{line-line}}$ is a $N_{\text{line}} \times 1$ matrix which its ith element is $\frac{1}{\tau^i \times x_s^i}$.

C. Economic Model of Responsive Load

Elasticity is the sensitivity of the demand respect to the price as (14) [25]–[27]

$$\mathrm{Els}(t,t') = \frac{\rho_0(t')}{d_0(t)} \frac{\partial d(t)}{\partial \rho(t')} \begin{cases} \mathrm{Els}(t,t') \le 0 & \text{if } t = t' \\ \mathrm{Els}(t,t') \ge 0 & \text{if } t \ne t' \end{cases} \tag{14}$$

Self and cross elasticity values can be given as a 24×24 matrix as (15) for the 24 hours. This matrix is called the price elasticity matrix (PEM)

$$\begin{bmatrix} \frac{\Delta d(1)}{d_0(1)} \\ \frac{\Delta d(2)}{d_0(2)} \\ \frac{\Delta d(3)}{d_0(3)} \\ \cdots \\ \frac{\Delta d(24)}{d_0(24)} \end{bmatrix} = \begin{bmatrix} \mathrm{Els}(1,1) & \cdots & \mathrm{Els}(1,24) \\ \vdots & \ddots & \vdots \\ \mathrm{Els}(24,1) & \cdots & \mathrm{Els}(24,24) \end{bmatrix} \times \begin{bmatrix} \frac{\Delta \rho(1)}{\rho_0(1)} \\ \frac{\Delta \rho(2)}{\rho_0(2)} \\ \frac{\Delta \rho(3)}{\rho_0(3)} \\ \cdots \\ \frac{\Delta \rho(24)}{\rho_0(24)} \end{bmatrix} \tag{15}$$

The jth column of PEM represents the price changes in the jth hour on consumption at the other hours. If the elements above the main diagonal are nonzero, it means that customers want to prevent high electricity prices by increasing consumption before the high price hours (peak periods). If the elements below the main diagonal are not nonzero, it means that customers wait for low price hours (valley periods) by procrastinating their consumption at the high price hours [26], [27].

The customer's net-profit is given in (16) which is actually the customer's income because of the electricity consumption and producing their commodities

$$\mathrm{NP}(t) = \mathrm{Ben}(d(t)) - d(t)\,\rho(t) \tag{16}$$

where Ben*(d(t))* is the benefit which customers obtained by consuming power. In fact, it is assumed that *Ben(d(t))* is customer's benefit from the use of electricity during the tth hour. For example, if the load is industrial, consuming power results in producing industrial products. Also, the net profit i.e. NP*(t)* is calculated by subtracting the price of electricity i.e. *d(t)p(t)* from this amount as calculated in (16).

To maximize the customer benefit, the derivative of (16) should be zero

$$\frac{\partial\, \mathrm{NP}(t)}{\partial d(t)} = \frac{\partial\, \mathrm{Ben}(d(t))}{\partial d(t)} - \rho(t) = 0 \tag{17}$$

$$\frac{\partial\, \mathrm{Ben}(d(t))}{\partial d(t)} = \rho(t) \tag{18}$$

Taylor series of *Ben* is as

$$\mathrm{Ben}(d(t)) = \mathrm{Ben}(d_0(t)) + \frac{\partial\, \mathrm{Ben}(d_0(t))}{\partial d(t)} [d(t) - d_0(t)] + \frac{1}{2} \frac{\partial^2\, \mathrm{Ben}(d_0(t))}{\partial d^2(t)} [d(t) - d_0(t)]^2 \tag{19}$$

To get the optimal consumption by which the customers obtain the maximum profit, from (19):

$$\mathrm{Ben}(d(\mathrm{t})) = \mathrm{Ben}(d_0(t)) + \rho_0(t)[d(t) - d_0(t)] + \frac{1}{2} \frac{\rho_0(t)}{\mathrm{Els}(t,t)\, d_0(t)} [d(t) - d_0(t)]^2 \tag{20}$$

Differentiating:

$$\frac{\partial\, \mathrm{Ben}(d(t))}{\partial d(t)} = \rho_0(t) \left(1 + \frac{d(t) - d_0(t)}{\mathrm{Els}(t,t)\, d_0(t)}\right) \tag{21}$$

By combining (21) and (18), for the single-period model of the responsive load:

$$d(t) = d_0(t) \times \left(1 + \frac{\rho(t) - \rho_0(t)}{\rho_0(t)} \mathrm{Els}(t,t)\right) \tag{22}$$

The multi period model is as (23):

$$d(t) = d_0(t) \times \left\{ 1 + \sum_{\substack{t'=1 \\ t' \ne t}}^{24} \mathrm{Els}(t,t') \times \frac{\rho(t') - \rho_0(t')}{\rho_0(t')} \right\} \tag{23}$$

Finally, the complete and combined model including the single and multi- period models of the responsive load is as (24) which is actually sum of (22) and (23)

$$d\ (t) = d_0\ \ (t) \times \left\{ 1 + \sum_{t'=1}^{24} \mathrm{Els}\,(t, t') \times \frac{\rho\,(t') - \rho_0\,(t')}{\rho_0\,(t')} \right\} \tag{24}$$

Based on (24), the demand after DRP depends on the initial demand before implementing DRP ($d_0(t)$), elasticity ($\mathrm{Els}(t, t')$), initial electricity price ($\rho_0(t')$), and secondary prices after DRP ($\rho(t')$). If DRP is not implemented ($\rho(t') = \rho_0(t')$), there is no demand changes ($d(t) = d_0(t)$).

Some factors are defined as following (See (25)–(27)) to show the effects of implementing DRPs on the load curve improvement. Smoothness of the load curve is evaluated by the load factor (See (25)). This factor is ideally 100% which shows that demand is constant and does not change with the time [16]

$$\mathrm{LF}\% = 100 \times \left(\frac{\sum_{t\,=\,1}^{T} d\,(t)}{T \times d^{\max}\,(t)} \right) \tag{25}$$

Peak to valley is another factor which shows the distance ratio between peak to valley as (26)

$$\mathrm{PTV}\% = 100 \times \left(\frac{d^{\max}\,(t) - d^{\min}\,(t)}{d^{\max}\,(t)} \right) \tag{26}$$

Finally, peak compensate is defined as (27) and is the normalized amount of compensated peak after implementing DRPs. In other words, after implementation of DRPs the amount of peak decreases; this factor i.e. peak compensate actually demonstrates the normalized amount of this reduction

$$\mathrm{PC}\% = 100 \times \left(\frac{{d_0}^{\max}\,(t) - d^{\max}\,(t)}{{d_0}^{\max}\,(t)} \right) \tag{27}$$

III. Solution Method

The way of determining the optimal buses for the implementing DR is presented as the following flowchart (see Fig. 2). At first, the initial input data are defined. Then, PTDFs are calculated and the DDCOPF is solved for each hour and the ATC values are determined accordingly. Note that in each hour, the critical lines based on their ATC values are appointed and based on their power flow and related PTDFs, the optimal buses for optimal implementation of TOU-CPP are determined. More details and information are illustrated in Fig. 2.

As shown in Fig. 2, the solution process aims at making ATC positive for all lines at 24 hours. However, it is possible that after solving the problem for T = 24 hours, ATC remains negative for some lines due to the network configuration. For example, if PTDFs (which is unique and different for each network) have positive values for some lines at some hours, this method i.e. implementing DR may not be able in alleviating congestion. In this situation, four ways are proposed as following. (i) Increasing the number of candidate buses for implementing DRPs (if all values of PTDFs are positive or have very small negative values, this method is not efficient). (ii) Using distributed generations (DGs) at the critical buses as negative loads. (iii) Decreasing generation at the critical generation buses (these buses should have positive values of PTDFs). (iv) Doubling or constructing new lines or the critical lines.

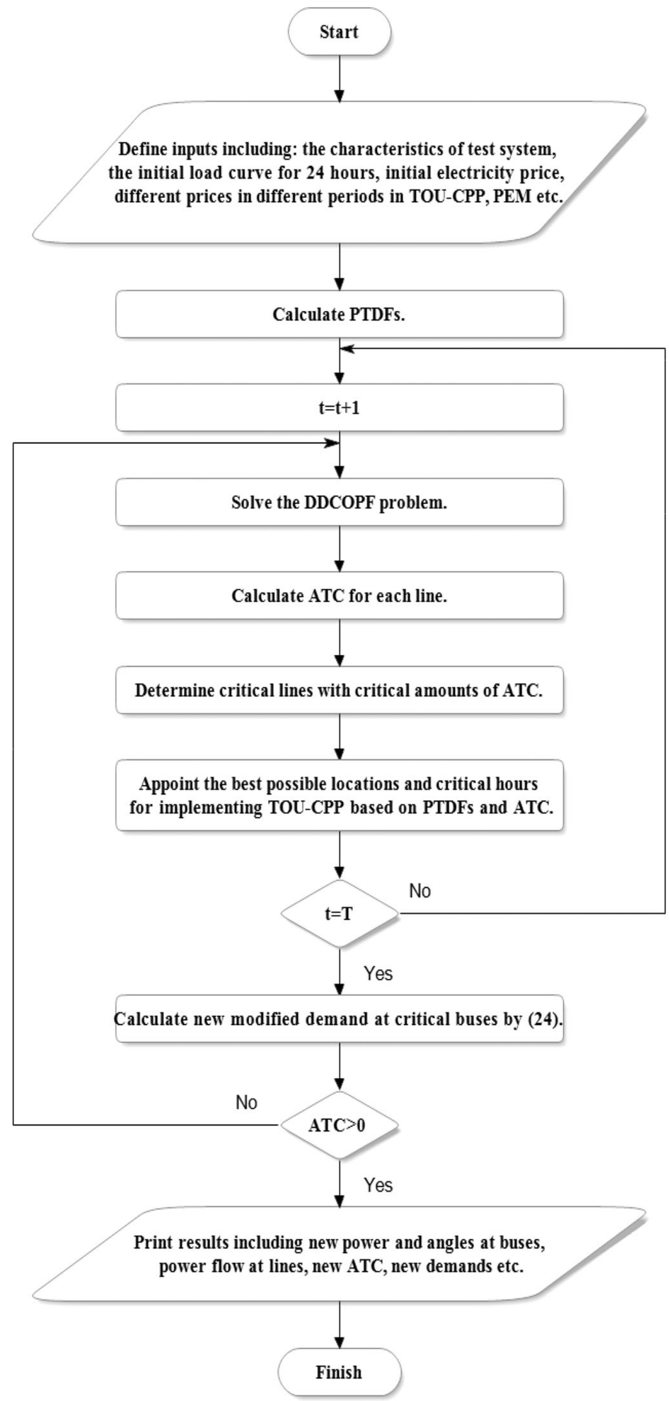

Fig. 2. Solution method's flowchart.

IV. Numerical Simulation and Results

To show the correctness and applicability of the proposed method, it is applied on the IEEE 39-bus New England test system. The system data is extracted from [28]. Note that the amount of load at each bus is increased as 5% and to make the load dynamic for 24 hours, each load bus is normalized for 24 hours based on the Iran's load curve in 2007 [26].

As mentioned before, TOU-CPP has been used as DRP. There are 30 load buses in the 39 bus test system and it is obvious

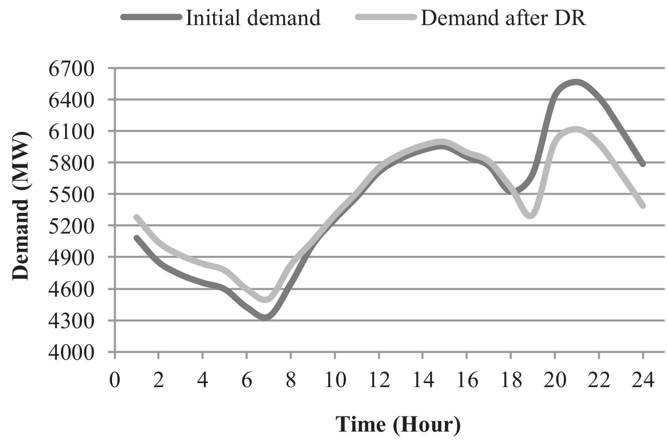

Fig. 3. Daily system's load curve.

TABLE I
EFFECTS OF TOU-CPP ON THE COSTS AND LOAD CURVE'S CHARACTERISTICS

Parameter	Before DR implementation	After DR implementation
Total generation cost ($)	763103.2898	749876.7837
Total generation (MW)	130657.7905	129980.1974
Total saved energy (MWh)	—	677.5931
Load factor %	82.90	88.54
Peak compensate %	—	6.86
Peak to valley %	34.00	26.39

that all customers do not participate in DRP, so it is assumed that TOU-CPP is implemented on just 5 buses among the 30 load buses. These five buses would be determined based on the priorities and calculations which were explained in Sections II and III. Here, these buses are determined as 1, 3, 4, 18, and 26. Because these buses are the most suitable and have the most negative amount of PTDFs among the other buses during the critical hours at the critical lines, (more details will be presented at the following). PEM is also available in [15] and [25]. The daily load curve is divided into the peak (19–24 hour), off-peak (9–18 hour), and valley (1–8 hour) periods (also as shown in Fig. 3). The electricity prices in the valley, off-peak, and peak periods are low, average, and high, respectively. Here, the average electricity price is 15 $/MWh in the off-peak, 12 (15–3) $/MWh in the valley, and 18 (15 + 3) $/MWh in the peak period. In CPP, the electricity price in the critical hour (here hour = 21, see Table II) is very high. Here it is considered to be 50 $/MWh.

The effects of TOU-CPP on the costs and load curve characteristics are given in Table I. From Table I, the total generation cost is decreased by 13226.5061 $ (763103.2898–749876.7837) after implementation of TOU-CPP. It is because of the fact that the demand is decreased by customers at the peak hours (high generation costs) or is shifted to the off-peak and valley periods (less generation costs). Also, the characteristics of the load curve including load factor, peak compensate, and peak to valley are improved after TOU-CPP. Papers [25]–[27] validate our results. Furthermore, the network load curve before and after TOU-CPP is illustrated in Fig. 3. As is clear from Fig. 3, demand at the

TABLE II
ATC VALUES BEFORE AND AFTER IMPLEMENTING TOU-CPP

Line	ATC before DR (MW)	Hour	ATC after DR (MW)	Hour
1	821.3993	23	787.8119	1
2	0.0000	21	473.8198	15
3	690.6366	12	630.7637	1
4	0.0000	21	345.9849	21
5	733.4494	7	663.5745	21
6	0.0000	21	105.8789	15
7	0.0000	21	312.7495	15
8	0.0000	21	117.6947	15
9	0.0000	21	388.9681	21
10	0.0000	21	114.2672	15
11	630.2327	21	650.9581	15
12	586.5088	21	605.7963	15
13	99.6747	21	149.9536	21
14	0.0000	21	65.91193	15
15	586.5088	21	605.7963	15
16	303.7926	21	313.7829	15
17	471.2087	20	436.0038	21
18	0.0000	21	240.5992	15
19	109.4688	21	164.6882	21
20	937.8206	7	920.9591	7
21	0.0000	21	695.9675	21
22	796.7376	21	764.1170	21
23	354.5881	23	340.0888	1
24	302.9993	23	290.6095	1
25	302.9993	23	290.6095	1
26	302.9993	23	290.6095	1
27	175.0000	21	262.1993	21
28	400.9604	22	453.9758	21
29	609.7504	1	583.0137	2
30	815.2317	21	963.1968	21
31	169.6260	23	162.6899	1
32	175.0000	21	262.1993	21
33	248.0000	21	262.1993	21
34	392.0000	12	392.0000	10
35	400.9604	22	453.9758	21
36	1138.3640	12	1134.3430	1
37	259.5962	22	293.9203	21
38	621.9467	21	733.0197	21
39	596.9113	12	594.8031	1
40	0.0000	21	384.9189	1
41	213.0000	21	262.1993	21
42	0.0000	21	384.9189	1
43	388.0340	22	411.5359	15
44	635.2624	22	673.7380	15
45	1062.2300	12	1053.7450	1
46	860.6817	7	874.6465	7

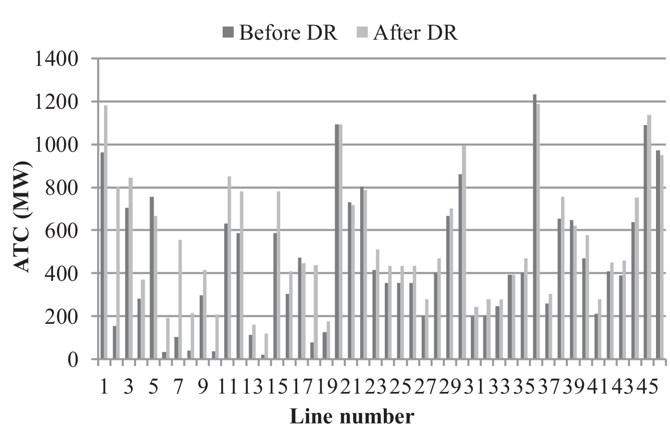

Fig. 4. ATC values at hour = 20.

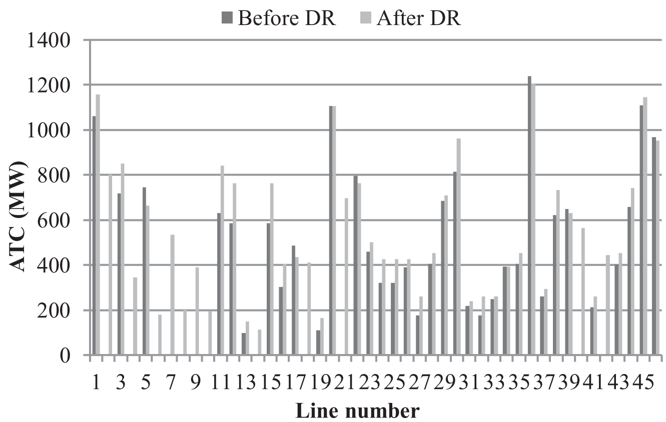

Fig. 5. ATC values at hour = 21.

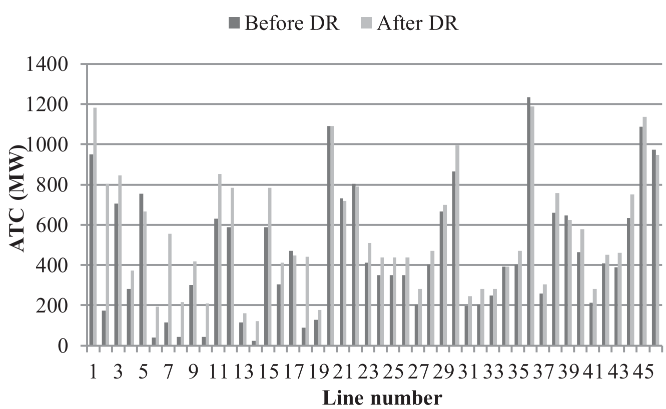

Fig. 6. ATC values at hour = 22.

peak hours is decreased and it is shifted to the valley or off-peak hours.

The minimum values of ATC for each line are given in Table II. From Table II, it can be seen that the hour 21 is the limiting hour for all of the at risk lines with ATCs = 0. After implementing TOU-CPP, ATC at all the mentioned lines are increased and there is no critical line with the critical amount of ATC. Reference [20] validates our results that DR can effectively improve ATC. In fact, the procedure for optimal implementing of TOU-CPP is as following. Based on Table II, the lines with the numbers 2, 4, 6, 7, 8, 9, 10, 14, 18, 21, 40, and 42 are the critical (congested) lines with ATCs = 0 at the hour 21. Therefore, based on the mentioned procedure in Sections II and III, the sensitivity of all the mentioned lines' power flows due to the buses injection are calculated (PTDFs). Then, based on these factors and due to the direction of lines' flow, the most suitable lines for implementing TOU-CPP are determined. The best buses are determined as buses with the numbers 1, 3, 4, 18, and 26. These buses have the most negative amount of PTDFs at the critical hours and also have the most effects on decreasing the congestion (can effectively reduce the congestion at the monitored lines due to TOU-CPP implementation), so the implementing TOU-CPP on them will have the most reduction in the lines congestion and consequently will have most increase in ATCs. Note that the computation time for scenario one i.e. before implementation of DR is 1.6339 seconds and it is 6.7434 seconds for scenario two i.e. after implementation of DR.

The ATC values before and after implementing TOU-CPP for three critical hours i.e. 20–22 are given in Figs. 4–6, respectively. From these figures, it is clear that ATCs for most of the lines (especially those with least amount of ATCs) are increased after optimally implementation of TOU-CPP. It means that optimally implementation of DRPs at suitable buses results in alleviating the congestion in the critical lines at the critical hours. In other words, if DR is implemented optimally (based on PTDFs values, as described in the paper), it can be counted as an economic and suitable method for alleviating the congestion.

V. CONCLUSION

DR can be applied as a powerful CM method in the power system operation. However, this purpose can be achieved just by optimally implementation of DRPs. In this paper, a new procedure for optimal implementation of DRPs was presented based on the PTDFs, ATC, and dynamic DCOPF. In the presented procedure, the optimal buses and times for implementing DRPs are determined. By the proposed method, the congestion is reduced, the ATC values are increased significantly, and consequently the system reliability is improved. TOU-CPP has been used as the DRP which is a price-based one and by changing the electricity's prices during different periods, it motivates customers to modify their consumption patterns. To validate the proposed scheme, it was applied on the IEEE 39-bus New England test system. Results showed effectiveness and applicability of the proposed method.

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