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Security-based Congestion Management by Means of Demand Response Programs

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Abstract— This paper evaluates using of Demand Response (DR) programs for congestion management as well as reducing the risk of supplying the loads. For this purpose, a coordination process between GENCOs and the ISO is considered. In the proposed approach, the coordination is modeled as a two-stage process. At first, GENCOs apply a priced-based unit commitment and submit their bids to the ISO for maximizing their profits. Then, ISO clears the market using certain demand response programs for maximizing social welfare and minimizing the risk of supplying loads. After the market clearing, if transmission flow violations were monitored, the process would provide a signal to GENCOs and DR program participants to reschedule their initial bids. Numerical studies based on IEEE 57-bus system are performed for the evaluation of the proposed method.

Index Terms— Auction-based power market; Congestion Management (CM); Demand Response (DR); Power system deregulation; Security-Constrained Unit Commitment (SCUC)

I. NOMENCLATURE

A. Constants

B_{nm}	Susceptance of line *nm*
N	Total number of buses
N_D	Number of demands
N_G	Number of generators
N_L	Number of lines
$\Pr_i$	Probability of outage of responsible demand *i*
$\Pr_j$	Probability of outage of generator *j*
$P_{j,\max}$	Maximum generation of generator *j*
$\Pr_p$	Probability of outage of line *p*
$P_{p,\max}$	Maximum line flow of line *p*
m_j	0/1 variable, 1 if outage of generator *j* results load inadequacy and 0 otherwise
s_i	0/1 variable, 1 if outage of responsible demand *i* results in load inadequacy and 0 otherwise
u_j	0/1 variable, 1 if generator *j* is running and 0 otherwise
$u_{p,q}$	0/1 variable, 1 if flow of line *p* increases by the outage of line *q* and 0 otherwise
$u_{j,t}$	0/1 variable, 1 if generator *j* production increases by outage of generator *t* and 0 otherwise

B. Optimization variables

$A(i)$	Incentive of DR program in i-th hour ($/MWh)
CSI_p	Contingency sensitivity index of line *p*
CSI_j	Contingency sensitivity index of generator *j*
$D_0(i)$	Demand in i-th hour before DR program (MWh)
$D(i)$	Demand in i-th hour after DR program (MWh)
$E(i)$	Self elasticity of the demand in i-th hour
$E(i,j)$	Cross elasticity of the demand between i,j-th hours
k_r	Risk coefficient
N_{reD}	Number of responsible demands
N_{Di}	Number of blocks requested by demand *i*
N_{Gj}	Number of blocks offered by generator *j*
$r_0(i)$	price in i-th hour before DR program ($/MWh)
$r(i)$	Price in i-th hour after DR program ($/MWh)
P_{jt}	Generation of generator *j* by outage of generator *t*
P_{pq}	Line flow of line *p* by outage of line *q*
$P_{Di,k}$	Power block *k* that demand *i* is willing to buy at price $r_{Di,k}$ up to a maximum of $P_{Di,k}^{\max}$
P_{Di}	Power consumed by demand *i*
$P_{Gj,l}$	Power block *l* that generator *j* is willing to sell at price $r_{Gj,l}$ up to a maximum of $P_{Gj,l}^{\max}$
P_{Gj}	Power produced by generator *j*
P_{Gj}^A	Active power produced by generator *j* as determined by the auction dispatch
P_{Di}^A	Active power consumed by demand *i* as determined by the auction dispatch
P_{Gn}^A	Total active power generation at bus *n* as determined by the auction dispatch
P_{Dn}^A	Total active power consumption at bus *n* as

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determined by the auction dispatch

$P_{Di,k}^{\max}$ Size of the power block k that demand i is willing to buy at price $r_{Di,k}$

$P_{reDi,k}^{\max}$ Size of the power block k offered by responsible demand i at price $r_{reDi,k}$

$P_{Gj,l}^{\max}$ Size of the power block l offered by generator at price $r_{Gj,l}$

$P_{Gj}^{\max}$ Maximum power output of generator j. It is assumed that $P_{Gj}^{\max} = \sum_{l=1}^{N_{Gj}} P_{Gj,l}^{\max}$

$P_{Gj}^{\min}$ Minimum power output of generator j

$P_{nm}^{\max}$ Transmission capacity limit of line nm

ΔP_{Gj}^{up} Increment in the schedule of generator j

ΔP_{Gj}^{down} Decrement in the schedule of generator j

ΔP_{reDi}^{down} Decrement in the schedule of responsible demand i

ΔP_{Gn}^{up} Total increments of active power generation in bus n

ΔP_{Gn}^{down} Total decrements of active power generation in bus n

ΔP_{Dn}^{down} Total decrements of active power consumption in bus n

r_{j}^{up} Price offered by generator j to increase its schedule, for congestion management purposes

r_{j}^{down} Price offered by generator j to decrease its schedule, for congestion management purposes

r_{i}^{down} Price offered by responsible demand i to decrease its schedule for congestion management

$w_{p,q}$ Weight of increasing in flow of line p by line q outage

$w_{j,t}$ Weight of increasing of generator j production by generator t outage

C. Sets

D_n Set of index of demands in bus n

G Set of index of all generators

G_n Set of index of on-line generators

reD Set of index of all responsible demands

d_n Voltage angle of bus n

Ω_n Set of index of buses connected to bus n

II. Introduction

In deregulated environment, generation, transmission, and distribution are unbundled from each other. All deregulated power market participants have open access to a transmission network. The Independent System Operator (ISO) takes a key role in the electricity market. The market requires a centralized control to keep the power system operation in light of security, economic, and reliability criteria [1,2]. Conventionally, a major task of system operators under the restructured system is to operate and maintain the system security providing a minimum operation and maintenance (O&M) cost to maximize the social welfare [3].

Congestion management of transmission network is an essential and important task in the operation of an electric power system. Transmission congestion occurs when overloads in transmission facilities are appeared. In traditional vertically integrated systems the system operator knows the marginal cost of production of each generating unit and an optimal power flow (OPF) tool was used to re-dispatch these units to avoid transmission congestion in a least-cost manner. Congestion management has become more important and difficult in the emerging deregulated electricity markets as the number and magnitude of power transactions increase.

The objective of security-constrained unit commitment (SCUC) is the coordination between GENCOs and the ISO. SCUC schedules unit commitment based on generation bids to ensure the transmission flow security in steady-state and n-1 contingency cases. SCUC decomposes the problem into a master problem and a sub-problem. The master problem solves a unit commitment (UC) with all unit constraints and without network limits. In this stage, GENCOs submit their bids to the ISO for market clearing process. After running the market, ISO obtains the transmission information from TRANSCOs [4].

In cases of transmission limit violation, the ISO sends rescheduling signals to GENCOs. Consequently, GENCOs submit their reschedule bids to ISO. In this way, the ISO will be able to alleviate congestion in least cost manner. This two stages procedure is used in NEPOOL, IMO, and UK markets [5].

In this paper, Emergency Demand Response Program (EDRP) and Day Ahead Demand Response Program (DADRP), as two main alternatives of DR programs, are used in the SCUC to meet transmission capacity limits and mitigate transmission congestion in a least-cost manner in a way that the risk of supplying the loads becomes minimum. In this approach, instead of re-dispatching the generation units which was proposed by other researchers [6,7], EDRP and DADRP are implemented in order to relieve the congestion.

Here, the customer response is modeled base on demand elasticity, for which a new economic load model is used [8]. Finally, a comparison between presence and absence of DR programs in this market clearing procedure is provided. The comparison highlights specifically the differences between i) the total operating cost of power market with and without DR programs which is strongly related to the market price, ii) the added costs of congestion management with and without DR programs, and iii) the Loss Of Load Probability (LOLP) index for power system with and without DR programs. This work makes it possible to evaluate the impact of DR programs on economic and reliability efficiency of the power market.

Numerical studies are conducted using IEEE 57-bus system to evaluate the performance of proposed method.

The remaining of the paper is organized as follows. Section III reviews different congestion management methods briefly. Section IV provides definitions and descriptions of DR programs. Section V explains the formulation of congestion management problem based on EDRP and DADRP implementation and the auction-based generation dispatching procedure. Section VI presents the numerical results of the case study. Finally, in Section VII conclusions are presented.

III. Congestion Management Methods

Transmission system congestion occurs when available, low cost supply cannot be delivered to the load locations due to transmission thermal, voltage, or stability limitations. Congestion could result in preventing new contracts, infeasibility to fulfill the existing contracts, monopoly of prices in some regions of power systems and damages to system components [5]. Therefore, the system operator needs an efficient, non-discriminatory mechanism to solve the congestion problem.

In the literature several approaches have been reported, so far, for congestion management [2,9,10]. Some of these approaches are addressed in the following:

1) The first method is generation re-dispatch. At first, sufficient numbers of the least expensive generators are selected to meet system predicted demands and the market-clearing price is determined by the most expensive bid that has been accepted. Next, ISO will evaluate if transmission constraints would occur under the unconstrained dispatch. If there are constraint violations, ISO would execute a generation re-dispatch [10]. Generation re-dispatch may create additional costs which are defined as the congestion costs [11].
2) In second method, the spot market is split into price areas to deter congestion. Once congestion is predicted, ISO will split its grid and carry out a zone-based market dispatch. The spot price in each area is determined such that the expected transmission between two areas equals the Total Transfer Capability (TTC) of the tie lines. As a result, the spot price in the surplus area will be reduced and the spot price in the deficit area will be increased [11].
3) In third method, in order to induce efficient use of both transmission grids and generation resources by providing correct economic signals, a nodal price is used, which is the marginal cost of supplying the next increment of electric energy at a specific bus. Each participant is paid or charged according to its nodal price [12].
4) In the last method, all trades are based on the bilateral or multilateral contracts. These financial arrangements are of no concern to the ISO but, all parties are required to submit the details of their contract transactions to the ISO. Therefore, during the balancing market, ISO uses participants' Offer/Bid pairs to relieve congestion.

In this paper an approach, which is based on incorporation of DR programs in re-dispatching method, is proposed for congestion management. The proposed method is compared with the previous re-dispatch approach [6,7] from economical and reliability view points.

IV. Economic Load Model

A. Definition

To have a complete competitive market, there should be enough motivations for customers to participate in power market operation. DR programs have created such opportunities for customers to be as players in the market [13,14].

Several DR programs have been developed and implemented in different markets. Federal Energy Regulatory Commission (FERC) has categorized DR programs into two groups namely, "time based" and "incentive based" programs [13]. In this paper, we have focused on Emergency Demand Response Program (EDRP) and Demand-Bidding Program (DBP) which are two of the incentive-based programs [14].

In EDRP, large consumers who intend to reduce or cut a portion of their electricity demand, based on ISO announcements, will participate in this program. The ISO will pay them a significant amount of money as an incentive. It is obvious that customers will participate in this program, voluntarily [13].

There are two forms of DBP programs. The first incorporates demand bids directly into the optimization and scheduling process. In programs such as Day-Ahead Demand Response Program (DADRP) customers typically bid a price at which they would be willing to curtail their load and the level of curtailment in MW on a day-ahead basis. If these bids are selected during the security constrained dispatch process, customers must execute the curtailment in the next day. If they do not reduce their load, they are subjected to a penalty [13].

Hereinafter, those customers who participate in DR programs (both EDRP and DADRP) are referred to as "responsible demands".

B. Mathematical formulation

In order to formulate the participation of customers in DR programs an economic load model, which represents the change of the customer's demand with respect to changing of the electricity price and the incentive given to the consumers, is used [8]. This model is represented as following:

$$D(i)=\left\{D_0(i)+\sum_{j=1}^{24}E(i,j).\frac{D_0(i)}{r_0(j)}.[r(j)-r_0(j)+A(j)]\right\}.$$
$$\left\{1+\frac{E(i)[r(i)-r_0(i)+A(i)]}{r_0(i)}\right\} \quad (1)$$
$$i=1,2,...,24$$

The above equation shows how much should be the customer's demand in order to achieve maximum benefit in a 24 hours interval. Further details are available in [8].

V. Formulation of Congestion Management Based on Generation Re-Dispatching and DR Programs Implementation

A. Auction-based market-clearing with DR programs (DADRP program)

As it was mentioned earlier, customers can bid a price at which they would be willing to curtail their loads on a day-ahead auction dispatch (DADRP). This can be calculated according to (1). So, a modified formulation of auction-based market clearing with DADRP program which takes into account the effect of risk can be formulated as [6]:

$$Min: \sum_{j=1}^{N_G}\sum_{l=1}^{N_{Gj}}(r_{Gj,l}.P_{Gj,l})-\sum_{i=1}^{N_D}\sum_{k=1}^{N_{Di}}(r_{Di,k}.P_{Di,k}) \quad (2)$$
$$+\sum_{i=1}^{N_{reD}}\sum_{k=1}^{N_{Di}}(r_{reDi,k}.P_{reDi,k})+k_r.RC(UCR)$$

Subject to:

$$0\le P_{Di,k}\le P_{Di,k}^{\max}\quad \forall i=1,...,N_D,\forall k=1,...,N_{Di} \quad (3)$$

$$0\le P_{Gj,l}\le P_{Gj,l}^{\max}\quad \forall j=1,...,N_G,\forall l=1,...,N_{Gj} \quad (4)$$

$$u_j P_{Gj,l}^{\min}\le \sum_{l=1}^{N_{Gj}}P_{Gj,l}\le u_j P_{Gj,l}^{\max}\quad \forall j\in G \quad (5)$$

$$0\le P_{reDi,k}\le P_{reDi,k}^{\max}\quad \forall i=1,...,N_{reD},\forall k=1,...,N_{reDi} \quad (6)$$

$$\sum_{i=1}^{N_D}\sum_{k=1}^{N_{Di}}P_{Di,k}-\sum_{i=1}^{N_{reD}}\sum_{k=1}^{N_{Di}}P_{reDi,k}=\sum_{j=1}^{N_G}\sum_{l=1}^{N_{Gj}}P_{Gj,l} \quad (7)$$

$$UCR=\sum_{j=1}^{N_G}(m_j.\Pr_j)+\sum_{i=1}^{N_{reD}}(s_i.\Pr_i) \quad (8)$$

$$u_j, m_j, s_i\in\{0,1\}\qquad \forall j\in G, \forall i\in reD \quad (9)$$

The objective function (2) represents the producer surplus minus the consumers payment plus the cost of responsible demands (i.e., negative of the net social welfare) and cost of the unit commitment risk (UCR). The first term of (2) is the sum of accepted generation bids times their corresponding bid prices. The second term is the sum of accepted demand bids times their corresponding bid prices. The third term takes into account the cost of responsible demands. And the forth term is the reliability cost. The Reliability Cost (RC) is the cost of loss of load because the generation units or responsible demands cannot be committed to a system and this will result in to load inadequacy.

It should be noted that producer bids are considered convex and monotonically increasing; and consumer bids, are concave and monotonically decreasing.

The block of constraints (3) specifies the sizes of the demand bids. The block of constraints (4) limits the sizes of the generation bids, while (5) ensures that every generator if running, runs between its minimum and its maximum power output. The block of constraints (6) specifies the sizes of responsible demand bids. Constraint (7) states that the production should be equal to the demand balance, considering the responsible demands, (8) defines the unit commitment risk. It should be noted that risk of system has two terms. The first term is arisen of generators outage, but the second term arises of responsible demands failure. Constraint (9) is the binary variables declaration.

B. Congestion management by generation and demand re-dispatch (EDRP program)

In the previous section the bids were determined without taking into account the limited capacity of the transmission network. To manage congestion due to generation and demand re-dispatch, the amount of demand reduction by EDRP program is calculated. In this approach, the demand reduction and equivalent incentive which are determined by (1), are supposed to be as the demand bid in auction-based congestion management formulation.

The congestion management due to generation and demand re-dispatch is formulated as below:

$$Min: \sum_{j\in G}(r_j^{up}\,\Delta P_{Gj}^{up}+r_j^{down}\,\Delta P_{Gj}^{down})+$$
$$\sum_{i\in reD}(r_i^{down}\Delta P_{reDi}^{down}) \quad (10)$$

Subject to:

$$P_{Gn}^A+\Delta P_{Gn}^{up}-\Delta P_{Gn}^{down}-P_{Dn}^A+\Delta P_{Dn}^{down}$$
$$-\sum_{m\in\Omega_n}B_{nm}(d_n-d_m)=0\quad \forall n=1,...,N \quad (11)$$

$$-P_{nm}^{\max}\le B_{nm}(d_n-d_m)\le P_{nm}^{\max}\quad \forall n=1,...,N,\forall m\in\Omega_n \quad (12)$$

$$u_j P_{Gj}^{\min}\le P_{Gj}^A+\Delta P_{Gn}^{up}-\Delta P_{Gj}^{down}\le u_j P_{Gj}^{\max}\quad \forall j\in G \quad (13)$$

$$\Delta P_{Gn}^{up}=\sum_{j\in G_n}\Delta P_{Gj}^{up}\qquad \forall n=1,...,N \quad (14)$$

$$\Delta P_{Gn}^{down}=\sum_{j\in G_n}\Delta P_{Gj}^{down}\qquad \forall n=1,...,N \quad (15)$$

$$\Delta P_{Dn}^{down}=\sum_{i\in D_n}\Delta P_{reDi}^{down}\qquad \forall n=1,...,N \quad (16)$$

$$P_{Gn}^A=\sum_{j\in G_n}P_{Gj}^A\qquad \forall n=1,...,N \quad (17)$$

$$P_{Dn}^A=\sum_{i\in D_n}P_{Di}^A\qquad \forall n=1,...,N \quad (18)$$

The objective function (10) is the sum of the amounts received (or paid) by the generators or responsible demands for altering their output as compared to the original auction schedule.

The set of constraints (11) enforces power balance at every bus, and the set of constraints (12) enforces line capacity limits, both using dc load flow model. The set (13) guarantees that the rescheduled generators stay within their respective maximum and minimum power outputs. Constraints (14) and (15) relate power increments and decrements in buses and generators. Also Constraint (16) is similar to (15) but applied for responsible demands. Constraint (17) states that the power generation in every bus is the sum of the production of all generators in that bus. Constraint (18) is similar to (17) but referring to the demands.

VI. NUMERICAL STUDIES

A case study based on the IEEE 57-bus system is presented in this section. Topology, line, generator, and demand data can be found in [15]. It is considered that every generator bids at its marginal costs. This simple bidding criterion is used for simplicity, because it does not affect the comparison process.

A. DR programs implementation

A typical load curve of a real world network is selected to test and analyze the effect of EDRP and DADRP programs [8]. For each load bus, the load curve is normalized to its standard value [15]. The load curve is divided into three intervals; low load period (00.00 to 9:00), off-peak period (10:00 to 19:00), and peak period (20:00 to 24:00).

The price of electrical energy in DR programs formulation is assumed to be equal to 50 \$/MWh.

The elasticities of the load are shown in Table 1. In this study the elasticities of all load buses are assumed to be equal. For different load elasticities the results are nearly similar, but calculations will be more complicated.

TABLE 1
SELF AND CROSS ELASTICITIES

	Peak	*Off-Peak*	*Low*
Peak	-0.1	0.016	0.012
Off-Peak	0.016	-0.1	0.01
Low	0.012	0.01	-0.1

In this study, 3 values of incentive are assumed for DR programs. Where, the incentive in EDRP and DADRP programs is assumed to be 20, 40, and 60 \$/MWh for all customers [16]. The load curves before and after implementation of two mentioned DR programs for incentive equal to 20\$/MWh is represented in Figure 1.

In this study, 10 load buses are chosen as the candidates of responsible demands. These buses are selected according to "Generation Shift Factor (GSF)", which identifies those buses which have the most affects on transmission line loading [17]. Demand values of responsible demands due to different incentives are shown in Table 2. As it was mentioned before, in this study the peak load period is considered from 20 to 24 hours, accordingly a considerable peak load reduction is achieved by DR programs implementation for that period.

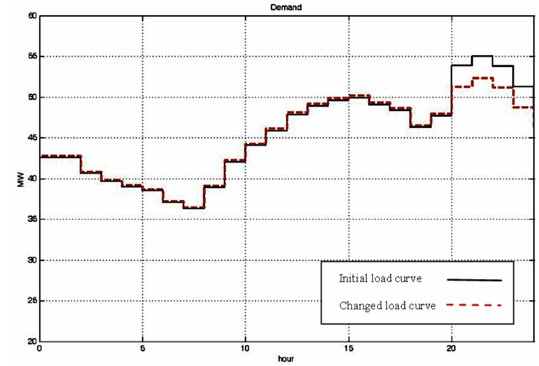

Fig. 1. The load curve before and after DR program implementation, by incentive equal to 20 \$/MWh for bus 1.

TABLE 2
DEMANDS OF RESPONSIBLE DEMANDS DUE TO DIFFERENT INCENTIVES (MW)

Responsible demand number	*Bus number*	*Initial demand*	*20 \$ incentive*	*40 \$ incentive*	*60 \$ incentive*
1	3	41	38.95	36.9	34.85
2	8	150	142.5	135	127.5
3	9	121	114.95	108.9	102.85
4	12	377	358.15	339.3	320.45
5	13	18	17.1	16.2	15.3
6	14	10.6	10.07	9.54	9.01
7	18	27.2	25.84	24.48	23.12
8	27	9.4	8.93	8.46	7.99
9	29	17	16.15	15.3	14.45
10	38	14	13.3	12.6	11.9

B. Auction-based market-clearing with and without DR programs

The auction dispatch clears the generators production by using the initial demand values according to (2)-(9) and by omitting the terms which are related to responsible demands. Here, the calculations are according to consideration of Risk Cost (RC) as following [18]:

$$RC(UCR) = UCR \times 10^7 + 5 \times 10^4 \qquad (19)$$

The risk coefficient (k_r) is considered to be 0.1; such a value for k_r is rational for networks of lower risk [19].

The auction dispatch with DADRP program clears the generators production values according to (2)-(9). The results of numerical studies for cases without DR program, with only DADRP program, and combined DADRP and EDRP programs are presented in Tables 3 and 4. It should be noted that for the third case, the DADRP is implemented for the first 4 responsible demands and EDRP is performed for the remaining 6 responsible demands. It is worth to mention that for implementation of DADRP, responsible demands bid in the day ahead market, but EDRP program is implemented for congestion management after the day ahead market is cleared.

C. Congestion management by generation and demand re-dispatch

The numerical study is extended to consider the re-dispatching of generation and consumption, the result of which is represented in Tables 5 and 6. Note that up and down re-dispatching prices for generators are considered to be equal to generation cost differences of generators in two different generation levels. The costs of load reduction are calculated according to Table 2.

TABLE 3
PRODUCTION OF GENERATORS IN THE AUCTION MARKET (MW)

Generator number	*Bus number*	*Without DR*	*With DADRP*	*With combination of DADRP and EDRP*
1	1	139.46	137.45	137.69
2	2	81.93	66.29	68.18
3	3	43.28	42.65	42.73
4	6	81.93	66.29	68.18
5	8	486.87	479.83	480.68
6	9	81.93	66.29	68.18
7	12	335.4	330.55	331.14

TABLE 4
AMOUNT OF ACCEPTED REDUCTION OF RESPONSIBLE DEMANDS IN THE AUCTION MARKET (MW)

Responsible demand number	*Bus number*	*Without DR*	*With DADRP*	*With combination of DADRP and EDRP*
1	3	0	3.21	3.21
2	8	0	11.75	11.76
3	9	0	9.48	9.49
4	12	0	29.52	29.56
5	13	0	1.41	0
6	14	0	0.82	0
7	18	0	2.13	0
8	27	0	0.72	0
9	29	0	1.33	0
10	38	0	1.1	0

Simulation results, which contain total cost of operation, cost of re-dispatch, and LOLP in 4 states of the system, are presented in the following figures.

As it was mentioned earlier, a comparison between four conditions is performed. In the first condition, there is no any DR program, in the second condition just DADRP is executed, in the third condition just EDRP is performed, and in the last condition both of DADRP and EDRP programs are conducted.

Amount of LOLP, total cost of market operation ($/h), and re-dispatch cost ($/h) in each of these four conditions are shown in Figure 2-4.

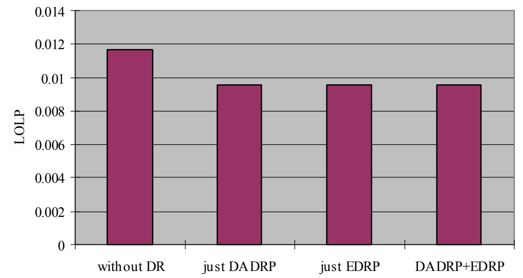

Fig. 2: Amount of LOLP in each of four DR program conditions.

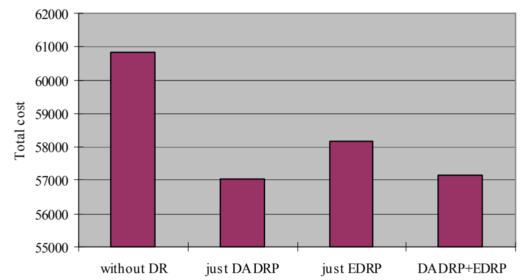

Fig. 3: Total cost of market operation in each of four DR program conditions.

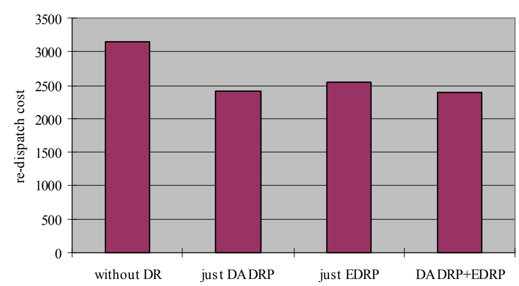

Fig. 4: Re-dispatch cost in each of four DR program conditions.

TABLE 5
GENERATION INCREMENT AND DECREMENT FOR ALL GENERATORS DUE TO CONGESTION MANAGEMENT (MW)

Generator number	*Bus number*	*Without DR*		*With EDRP*		*With combination of DADRP and EDRP*	
		Increment	*Decrement*	*Increment*	*Decrement*	*Increment*	*Decrement*
1	1	0	0	0	0	0	0
2	2	0	0	0	0	0	0
3	3	0	0	0	0	0	0
4	6	0	0	0	0	0	0
5	8	0	38.04	0	38.03	0	19.78
6	9	18.07	0	9.16	0	29.84	0
7	12	19.98	0	0	0	0	0

TABLE 6
DECREMENTIN OF CONSUMPTION FOR RESPONSIBLE DEMANDS DUE TO CONGESTION MANAGEMENT (MW)

Generator number	*Bus number*	*Initial demand*	*Without DR*	*With EDRP*	*With combination of DADRP and EDRP*
1	3	41	0	0.19	0
2	8	150	0	0	0
3	9	121	0	9.63	11.76
4	12	377	0	17.52	0
5	13	18	0	0.8	0.8
6	14	10.5	0	0.36	0.36
7	18	27.2	0	0	0
8	27	9.3	0	0	0
9	29	17	0	0	0
10	38	14	0	0.37	0.37

Investigation of above results reveals that by using DR programs in addition of decreasing in total cost of market operation, the cost of re-dispatch and also LOLP of the system are improved.

VII. Conclusion

Transmission congestion management is a challenging issue in deregulated power systems and usually the system operator is faced with this problem. Many approaches have been proposed and applied to address this problem. In this paper, DR program as a new procedure for congestion management was discussed.

In this regard, auction-based dispatch method, which is adopted in some electricity markets and as a relatively simple procedure was considered. Then, two different types of this method were compared from economical and reliability view points. In the first type, the congestion was relieved just by increment and decrement of initial production of generators, which was determined in market auction. In another type, congestion was relieved by decrement in initial production of generators and reduction of demands, which was achieved by EDRP and DADRP implementation.

Comparison of these two auction-based mechanisms was performed on IEEE 57-bus system. The results indicate that the congestion management by generation and demand re-dispatch can considerably reduce the congestion costs and LOLP. It was shown that the demand response programs can play a major role in competitive electricity markets, particularly in case of congestion management.

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