A NOVEL APPROACH FOR SOCIAL WELFARE MAXIMIZATION IN DAY-AHEAD MARKET DURING CONGESTION PERIOD

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Abstract: *In the competitive electricity market, congestion is an indicator of the need of transmission system reconfiguration by compensation devices or its expansion with new lines erection. Market economic inefficiency can be avoided by the suitable Congestion Management (CM) technique during peak hours' in Day-Ahead (DA) market settlement. In some inevitable cases, moderating the congestion by load shedding is the only solution which is not good in practice. Hence this paper addresses a solution, i.e. Variable Bid Curtailment (VBC) for the minimization of absolute re-dispatch due to Optimal Power Flow (OPF) method. The objective function aims to the minimum bid curtailment and energy production cost while maximizing the Social Welfare (SW). The IEEE-9 bus test system is used to show the effectiveness of the proposed methodology.*

Key words: *Day-Ahead market (DA), Social Welfare (SW), Congestion management, Optimal Power Flow (OPF), Variable Bid Curtailment (VBC) method*

1. Introduction

The restructuring process in power system is continuing from the past two decades by the expectation of competition among generation companies together with open access to the transmission system will lead to lower electricity prices and better service for customers. By this modern trend and practice, electricity market unbundling into Generating Companies (GENCOS), Transmission Companies (TRANCOS) and Distribution Companies (DISCOS) and these entities are independent. Due to the economies of scale inherent in the transmission system the TRANCOS are natural monopolies and operate under the authority of a regulator known as Independent System Operator (ISO). The role of an ISO in a competitive market environment would be to facilitate the complete dispatch of the power that gets contracted among the market players. Managing dispatch is one of the important control activities in this competitive electricity market. The total generation schedule and dispatch will decided by ISO form the bids submitted by GENCOS and DISCOS. The framing of ground rules by system operators to prevent the bad use of the market by participants in order to achieve their maximum profit are discussed in [1]. The different methods of bidding of strategic bid, multipart bid, iterative and demand side bid are also explained in this literature review. The importance of decision maker in the bidding process and his influence in the future market is described in [2]. In [3], a new stochastic programming methodology is proposed to determine the optimal bidding strategies for the day-ahead market.

In a single or double action pool based electricity market, the market price and hence the schedule of generation is determined by ISO from the bids submitted by the GENCOS and DISCOS. This market settlement may give most economical schedule if system is not subjected to congestion problem. Hence the issue of transmission congestion is more pronounced in this competitive environment. Electrical markets will not be able to operate at its competitive equilibrium with congestion in the system.

Real-time transmission congestion can be defined as the operating condition in which there is not enough transmission capability to implement all the traded transactions simultaneously due to some unexpected contingencies. It may be alleviated by incorporating line capacity constraints in the dispatch and scheduling process. In order to alleviate congestion, some cheap generators have to reduce their dispatch and some expensive generators in the congested zone have to increase their dispatch. This will impose additional cost to the market participants. The minimization of re-dispatch in the pool therefore ensures that the deviation from the economical settlement of the market is minimized [4, 5].

This study aims at investigating the changes in generation schedule levels when taking into account transmission network loadability consideration in the market settlement scheme. The study is based on a Day Ahead Market (DAM) framework for a single action pool electricity market. An IEEE 9-bus test system is used in the study in which three separate cases are analyzed, i.e., hourly based market settlement in over 24 hour period, re-dispatch scheduled in case of congestion, bid curtailment method for keeping the security margin in the transmission system while maximizing social welfare are included. Finally this paper gives an idea about preventive & corrective control actions taking in the event of congestion by ISO in a day-ahead market.

This paper is organized as follows: Following the introduction, different market models are described in section II. Then in section III, the day-ahead market operation is discussed in detail. The case study with day-ahead market operation is described briefly in section IV. Applications of proposed *Variable Bid Curtailment (VBC)* and *Optimal Power Flow (OPF)* for congestion relief methods in real time are carried out and simulation results are given in section V. Finally, brief conclusions are deduced.

2. Market Models

A. Pool based market

This model is a centralized market which clears the market for buyers and sellers of electricity. Generally this market may be operated in two modes i.e. single action or double action. In single action market, the bids received from the GENCOS only and are stacked in increased order of prices. The market will cleared at the intersecting point of stacked bid curve and forecasted demand. The highest accepted sell bid price at required demand will treat as *market clearing price* [6]. In double action market, the bids from DISCOS are also considered for market clearing and these bids are stacked in decreased order of prices. The intersecting point of these two bid curves will settle the market. The detailed market operation with case study will explain in next upcoming sections.

B. Bilateral market

Another way to classify the market structure is based on the rules adopted for the transmission access. A bilateral model is also defined as third party access model because companies that are not utilities access to the transmission network. In this market, single or multiple contracts between seller buses to buyer buses are permitted without sacrificing the system security. The prices of transaction powers in this market model are independent of ISO actions. The transactions are also known as *point to point transactions*. In the situation of congestion, the ISO limits the quoted volume less or equal to the Available Transmission Capacity (ATC) [7].

C. Hybrid Market

The hybrid model combines the various features of the previous two market models. The participation of a GENCO in the Pool is not compulsory. Some GENCOs will therefore have contracts and they can trade the excess capacity on the pool market. GENCOs without contracts submit their sell bids to the pool market. The customers therefore have a choice to settle a power supply agreement directly with suppliers or may choose to accept the spot market price [8, 9]. This market model is the closest to the established markets for other goods and services.

In all the market mechanisms the ISO has to execute the schedules and ensure the reliability and security as well as handling the emergencies like congestion in the system.

3. Day-Ahead Market Operation

Market Clearing Process

The day-ahead (DA) market is organized as a sequence of twenty-four independent hourly single auctions, under the uniform pricing rule. The bid prices decided by each GENCO are generally given by

$$\lambda_{i,j} = 2a_i P_{i,j} + b_i \ (Rs./MWhr) \tag{1}$$

where a_i and b_i are cost coefficients of generator *i*. The total amount of bids is set to the maximum generation capacity in that particular area. The Independent System Operator (ISO) collects and processes the energy offers submitted by all the GENCOS' and computes the quantities and the price that clear the market for each trading interval. Since the auctions of different hours are cleared independently from each other, in the upcoming case study we will consider the energy auction of a particular hour only.

The optimization problem of DA for a particular hour will carried out by ISO as follows:

$$Minimize\ \ C_t(m) = \lambda_{MCP} P_g \tag{2}$$

Subject to equality constraint

$$P_g = P_d = \sum_{a=1}^{N} \sum_{i=1}^{n} \sum_{j=1}^{s} P_{i,j}^{a} \tag{3}$$

The total generation of unit *i* will calculate by

$$P_{g,i} = \left\{ \sum_{j=1}^{s} P_{i,j} \right\} \leq P_{i,max} \tag{4}$$

The total generation of an area *a* will calculate by

$$P_{g,a} = \sum_{i=1}^{n} P_{g,i} \tag{5}$$

The profit for an *Nth* area GENCO company will given by

$$C_{pr,N}(m) = \lambda_{MCP} P_{i,max} - \sum_{i=1}^{n} \sum_{j=1}^{S} \left(\lambda_{i,j} P_{i,j}\right) \tag{6}$$

$$= \sum_{i=1}^{n} \sum_{j=1}^{S} \left(\bar{\lambda}_{i,j} \bar{P}_{i,j}\right) \tag{7}$$

$$= \sum_{i=1}^{n} \sum_{j=1}^{S} \left(\lambda_{MCP} - \lambda_{i,j}\right)\left(P_{i,max} - P_{i,j}\right) \tag{8}$$

The percentage of market share of each GENCO or in an area *a* will given by

$$\%MS_a = \left(\frac{P_{g,i}}{P_d}\right) * 100\ \% \tag{9}$$

4. Case Study

In this study, the market settlement process has been carried out as explained in [10]. The spot trading session of National Power Exchange Limited (NPEX) generally starts at 10:00 AM to 12:00 PM of previous day (D-1) to the actual scheduled day (D). The trading will be done for 24 separate hour period throughout the following delivery day (D). In the case study of upcoming section, the quotation method have been selected as single sided close bid action with uniform market clearing price i.e. *System Marginal Price method (SMP)* for all buyers and sellers. The selected system consisting of three generators and each one treated as one GENCO company. The complete information about IEEE 9-Bus system is available in [11]. The bids of each GENCO's are framed in Table 1.

Gen i	Block j	Block Size P_{ij} *(MW)*	Unit Price λ_{ij} *(Rs./MWhr)*
1	1	20	5.4
	2	50	6.0
	3	80	6.6
	4	100	7.0
2	1	30	6.3
	2	60	11.4
	3	90	16.5
	4	120	21.6
3	1	40	10.8
	2	60	15.7
	3	80	20.6
	4	90	23.05

Table 1: GENCOs' Submitted Bids

The forecasted peak load on the system has been taken of 315 MW for base load and this may considered as variable in each trading hour. The market is cleared at the price of 10.8 Rs./MWhr for the base case load of 315 MW. It can observe in the Fig. 1.

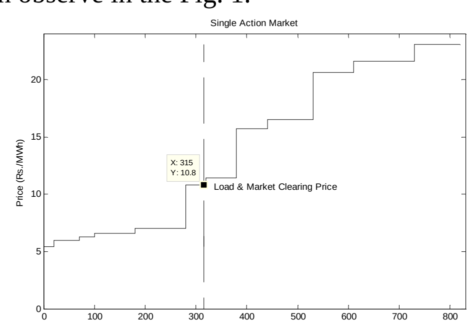

Fig. 1. Bids stacked in increased order

The vertical broken line indicates the total load at hour eight. From Fig. 1, the accepted bids to be the first block from all the GENCOS and including one, the second, third & fourth blocks from GENCO-1. The price would be that of the highest accepted bid i.e. Rs. 10.8/MWhr. The total cost would then be Rs.3402/hr. The market driven schedule is 250MW for GENCO-1, 30MW for GENCO-2 and 35MW for GENCO-3. This schedule is verified for congestion in the network with Newton Raphson method. The result provided 5.223MW loss and generally these losses will take up by the regulation market. In this case, the losses are also assigned to the last selected bid's GENCO. This causes to increase the generation schedule up to 40.223MW at GENCO-3. But the selected bid of GENCO-3 is only 40MW and the excessive loss should be assigned to the next cheapest bid of GENCO-2. This results to the new market settlement with market clearing price at Rs.11.4/MWhr for the required demand of 320.223MW. The market driven schedule is 250MW for GENCO-1, 30.223MW for GENCO-2 and 40MW for GENCO-3. The total cost would then be Rs.3650.5/hr which is greater than to previous case without considering losses. This process is carried out for over the 24 hour period. The forecasted load which should be considered as trading power at each hour is given in Table 2.

Hour	LF	Hour	LF	Hour	LF
1	0.8	9	1	17	0.86
2	0.79	10	0.96	18	0.88
3	0.79	11	0.95	19	0.94
4	0.79	12	0.92	20	0.93
5	0.81	13	0.9	21	0.91
6	0.85	14	0.88	22	0.89
7	0.92	15	0.86	23	0.79
8	1	16	0.87	24	0.79

Table 2: Loading factors in different hours

5. Congestion Management

Congestion management (CM) includes both the congestion relief actions and the associated pricing mechanisms [12]. A brief discussion on these methods is also given in [13]. In this paper, a novel method *Variable Bid Curtailment (VBC)* has been proposed.

a. Verification for congestion

After the Market settlement, the ISO checks the feasibility of the scheduled generation by carrying out a load flow. By considering line loadings in MVA, the load flow is carried out using NR method for each hour to check the feasibility of the generation schedule as carried out in the previous section. The results for the load flow for hour eight are shown in Table 3 for all lines. We have congestion on line 1-4 whilst all the other lines are below their capacity. In the load flow, GENCO-2 is taken as the slack bus and takes up the losses.

Line #	% of MVA Loading		
	Market	VBC	OPF
1-4	**101.48**	**99.99**	36.28
4-5	43.10	42.56	14.17
5-6	25.16	24.63	38.18
3-6	13.38	13.36	32.28
6-7	36.78	35.94	25.70
7-8	19.2	19.65	25.61
8-2	13.03	14.21	53.85
8-9	7.05	6.19	29.12
9-4	56.43	55.58	25.01

Table 3: GENCOs' Submitted Bids

b. Congestion relief using Variable Bid Curtailment

The complete procedure of *VBC* method in the form of flow chart has been given in Fig. 2. In our case study, the variable pair of blocks $(P_{i,p}{}^{a}, P_{i,q}{}^{b})$ is fourth block of GENCO-1 for decrement and first block of GENCO-3 for increment in generation during congested hours of 8^{th} &9^{th} hours. Similarly for the remaining congested hours, second block of GENCO-2 is selected for the increment in generation. The over loading of transmission lines has been relieved due to VBC method and the results can also be observe from Table 3.

c. Congestion Relief using Optimal Power Flow Method

The optimal power flow (OPF) method [11] is also carried out for congestion relief in the network. The results obtained from the case study which is also given in Table 3, we can conclude that the OPF method has given very high production cost compared with variable bid curtailment method. The observable thing in OPF method is that the all transmission lines are moderated power flow very significantly. Coming to variable bid curtailment, the procedure is carried out not only to relief the congestion as well as to operate the system very close to the market clearing point.

6. Market Optimization using VBC method

The new objective function for market settlement during congestion period has changed to

$$Minimize\ \ C_t(m) = \lambda_{MPC} P_g \qquad (10)$$

where λ_{MPC} is the market price at congestion period. The selection of variable bids for curtailment will become optimal if this market price is same as previous market clearing price at no congestion in the network. The algorithm will search for variable bids for curtailment which minimizes congestion cost as well as alleviation of congestion.

If $(P_{i,p}{}^{a}, P_{i,q}{}^{b})$ is the pair of variable selected bids, then the generation at ith bus in area a and at jth bus in area b will become

$$P_{g,i}{}^{a} = \left\{ \sum_{j=1}^{s-1} P_{i,j} + (1+\tau)P_{i,k} \right\} \leq P_{i,max} \quad (11)$$

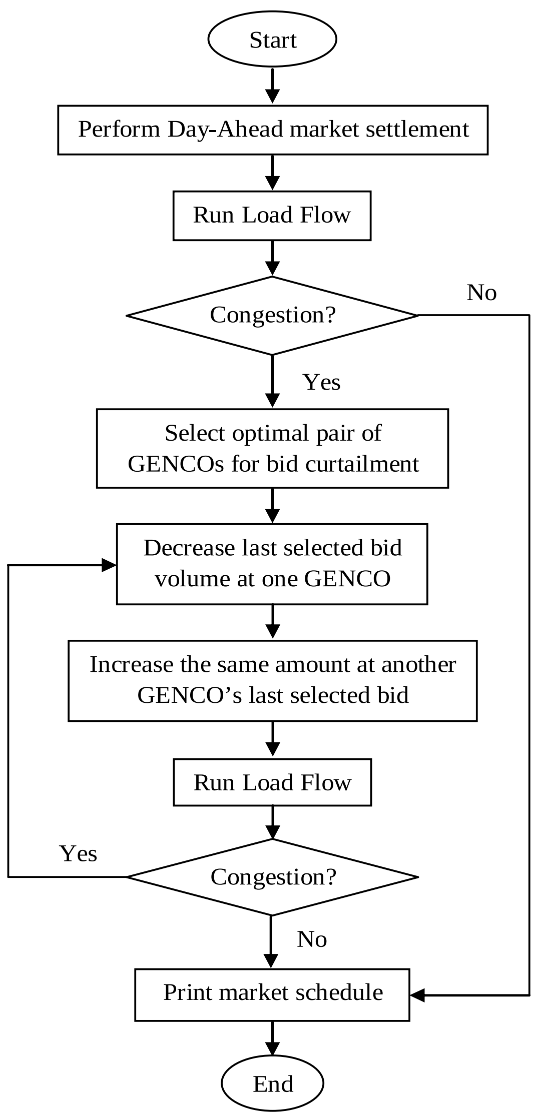

Fig. 2. The flow chart of Variable Bid Curtailment method for Congestion relief

$$P_{g,j}{}^{b} = \left\{ \sum_{j=1}^{s-1} P_{j,j} + (1-\tau)P_{j,k} \right\} \leq P_{j,max} \quad (12)$$

Here τ is the curtailment factor which causes to increase generation at ith bus in area a, similarly to decrease generation at jth bus in area b. This τ will vary up to congestion free in the network. So this method will change the market settlement at new operating point.

The social welfare in terms of savings in production cost will calculate by

$$C_{SW}(m) = C_{t,OPF}(m) - \lambda_{MPC} P_g \quad (13)$$

The generation schedule for congested hours with variable bid curtailment (VBC) and actual market driven schedule considering transmission losses at GENCO-1 & 3 are given in Table 4. The market driven schedule at GENCO-2 is 30MW and it changed to 33.62MW during the congested hours 8 & 9 due to VBC method and it remains same i.e. 30MW for the remaining congested hours due to VBC method also.

Hour #	GENCO-1		GENCO-3	
	Market	VBC	Market	VBC
7	250	247.36	15.13	17.62
8	250	246.43	40.22	40
9	250	246.43	40.22	40
10	250	246.9	27.65	30.59
11	250	247	24.52	27.36
12	250	247.36	15.13	17.62
13	250	247.5	8.89	11.24
14	252.52	247.76	0	4.76
16	249.52	247.82	0	1.59
18	252.83	247.76	0	4.76
19	250	247.15	21.39	24.08
20	250	247.26	18.26	20.85
21	250	247.45	12.01	14.41
22	250	247.6	5.77	8.03

Table 4: Generation Schedule for various methods

The production cost for various methods during congestion hours are given in Table 5. The production cost during hour sixteen shows that congestion problem severity on market operation. Because of the congestion in the network, ISO reduced the last selected block of generator 1 and increased the same at generator 3 caused to increase market clearing price

Rs.10.8/MWhr from Rs.7/MWhr hence the total generation cost of the system has increased in significantly.

This result clearly indicating the need of transmission network's reconfiguration in the deregulated power system using compensation devices (Flexible Alternating Current Transmission devices, i.e. FACTS devices) [14, 15]. The market share and profit of each GENCO companies at hour eight is given in Table 6. The results in Table 6 clearly indicating the necessity of optimal bidding strategies of GENCOs' for gaining profit as well as good amount of market share in the Day-Ahead market's competition [16-18].

Hour #	Production Cost (Rs.)			SW (Rs.)
	Market	VBC	OPF	
7	3187	3786	4695	1510
8	3651	3649	5297	1648
9	3651	3649	5297	1648
10	3323	3321	4990	1669
11	3289	3287	4915	1628
12	3187	3186	4695	1510
13	3120	3118	4552	1434
14	3224	3051	4412	1361
16	**1957**	**3018**	4343	1326
18	3224	3051	4412	1361
19	3255	3253	4841	1588
20	3221	3220	4768	1548
21	3154	3152	4624	1471
22	3086	3085	4482	1397

Table 5: Production Cost & Social Welfare

GENCO#	Market Share	Profit	
		DA	VBC
1	78.07 %	33 %	32.8 %
2	9.43 %	4.2 %	4.207 %
3	12.5 %	0.7 %	0.7 %

Table 6: Market share & Percentage of profit

7. Conclusions

The severity of congestion in the transmission network and its impact on market settlement in day-ahead electricity market has been reviewed in this paper. Two different methods are applied for congestion relief. One is optimal power flow method which has been proved once again increment in production cost due to its application. The second is variable bid curtailment method, which keeps system operating point near to the market settlement during congestion period also. The case study carried out on IEEE – 9 bus test system and the results obtained are validates this approach for congestion relief as well as for Social Welfare maximization in real time.

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Nomenclature

i	Index of generating unit
j	Index of block (step)
k	Index of last selected bid
p	Index of increment block
q	Index of decrement block
b	Number of blocks in offer bid
s	Number of selected blocks in offer bid
n	Number of generating units in one area
N	Number of areas (GENCOs)
$P_{g,i}$	Total generation of unit *i,* in MW
$P_{g,a}$	Total generation in area *a,* in MW
$P_{d,a}$	Total demand in area *a,* in MW
P_g	System total generation, in MW
P_d	System total load, in MW
$P_{i,j}$	Offer quantity of block *j* of unit *i,* in MW
$P_{i,min}$	Minimum generation of unit *i,* in MW
$P_{i,max}$	Maximum generation of unit *i,* in MW
λ_{ij}	Marginal cost of step *j* of unit *i*, in Rs./MWhr
$\lambda_{ij,min}$	Minimum marginal cost of step *j* of unit *i*, in Rs./MWhr
$\lambda_{ij,max}$	Maximum marginal cost of step *j* of unit *i*, in Rs./MWhr
λ_{MCP}	Market Clearing Price, in Rs./MWhr
P_{MCQ}	Market Clearing Quantity, in MW
$P_{i,p}{}^{a}$	Increment block *p* of unit *i* in area *a*, in MW
$P_{i,q}{}^{a}$	Decrement block *q* of unit *i* in area *a*, in MW
$\bar{P}_{i,j}$	Available capacity of unit *i*, in MW, if *jth* block is cleared in market
$\bar{\lambda}_{i,j}$	Residual marginal price (RMP) of unit *i*, in Rs./MWhr, if *jth* block is cleared in market
$C_t(m)$	Total system production cost at *mth* hour, in Rs.
$\%C_{pr,N}(m)$	Percentage of Nth GENCO profit at *mth* hour.
$\%MS_a$	Percentage of market share of an area *a*