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Congestion Free Operation of Competitive Energy Market

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Abstract: *The competition and deregulation of electricity markets has increased competition and electricity may be produced and consumed in amounts that would cause the transmission system to operate beyond transfer limits-the system is congested. Hence, congestion management is a fundamental transmission problem. Congestion can be alleviated by adopting suitable solutions. In some inevitable cases moderating the congestion by the load shedding is only the solution which is not economically good in practice. Hence, this paper addresses a solution for congestion management, i.e optimal re-dispatch. The validations of this solution in real time during abnormalities like (N-1) line outages are also considered. To predict the effects of line outages, the required amount of load curtailment is going to optimize with optimal re-dispatch method. The approaches are analyzed with IEEE-14 bus system.*
Keywords: *Congestion management, Contingency, Day-ahead market, Load curtailment, Optimal re-dispatch*

I. Introduction

The electricity industry throughout the world, which has long been dominated by vertically integrated utilities, is undergoing enormous changes. Restructuring has necessitated the decomposition of the three components of electric power industry: generation, transmission, and distribution. An independent operational control of transmission grid in a restructured industry would facilitate a competitive market for power generation and direct retail access. The independent operation of the grid cannot be guaranteed without an independent entity such as the Independent System Operator (ISO). The ISO is required to be independent of individual market participants, such as transmission owners, generators, distribution companies, and end-users. 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. The total generation schedules and dispatch will decided by ISO from 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 marking in the bidding process and his influence in the future market is described in [2].

In order to achieve market goals, several models for the market structure have been considered. In single auction pool based model only GENCOS submit their bids to ISO. In double auction model both GENCOS and DISCOS submit their bids to ISO. Bilateral model contracts are negotiable agreements on delivery and receipt of power between two traders. Hybrid model combines various features of previous two models. Congestion management is one of the most challenging operational problems in deregulated power systems. Transmission networks are one of the main sources of difficulties on fair implementation of electricity restructuring. With open access transmission in deregulated environment, poorly scheduled generation patterns and load patterns from competitive bidding, will be seen more and more often which results transmission line overloads. Transmission congestion may be defined as the condition where more power is scheduled or flows across transmission lines and transformers than the physical limits of those lines (or) it is the operating condition in which there is no enough transmission capacity to implement all the traded transactions simultaneously due to some un expected contingencies. Transmission line overload may prevent the existence of new contracts, lead to additional outages, increase the electricity prices in some regions of the electricity markets, and can threaten system security and reliability. Hence an effective control action strategy is necessary to reduce the line overloads to the security limits in the minimum time. There are significant congestion management schemes suitable for various electricity market structures are described in. Congestion 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 [3, 4].

Contingency analysis is abnormal condition in electrical network. It put whole system or a part of the system under stress. It occurs due to sudden opening of a transmission line. Generator tripping. Sudden change in generation. Sudden change in load value. Contingency analysis provides tools for managing, creating, analyzing, and reporting lists of contingencies and associated violations [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. An IEEE 14-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 and contingency , load curtailment, bid curtailment methods for keeping the security margin in the transmission system while maximizing social welfare are included.

This paper is organized as follows: Following the introduction, different market models are described in section II. Then in section III day-ahead market organization is described. In section IV various congestion relief schemes are described. The results with Variable Bid Curtailment (VBC) for congestion relief methods in real time are carried out are given in section V. Section VI follows the conclusion.

II. Market models

2.1. Pool Co market

A pool Co is defined as a centralized market place that clears the market for buyers and sellers. An ISO within a Pool Co would implement the economic dispatch and produce a single (spot) price to a competitive level that is equal to the marginal cost of most efficient bidders. Generally this market may be operated in two modes i.e. single auction or double auction. In single auction market, the bids received from the GENCOs only and are stacked in increased order of prices. The market will cleared at the intersection point of stacked bid curve and forecasted demand. The highest accepted sell bid price at required demand will treat as *Market Clearing Price (MCP)* [6]. In double auction market, the bids from DISCOs are also considered for market clearing and these bids are stacked in decreased order of prices. The intersection point of these two bid curves will settle the market.

2.2. Bilateral contracts market

Bilateral contracts are negotiable agreements on delivery and receipt of power between two traders. These contracts set the terms and conditions of agreements independent of the ISO. However, in this model the ISO would verify that a sufficient transmission capacity exists to complete the transactions and maintain the transmission security. The bilateral contract model is very flexible as trading parties specify their desired contract terms. However, its disadvantages stem from the high cost of negotiating and writing contracts, and the risk of the credit worthiness of counter parties.

2.3. Hybrid market

The hybrid market combines various features of the previous two markets. In the hybrid market, the utilization of a Pool Co is not obligatory, and any customer would be allowed to negotiate a power supply agreement directly with suppliers or choose to accept power at the spot market price. In this market, pool Co would serve all participants who choose not to sign bilateral contracts.

Here single auction pool Co market is chosen. I.e. only GENCOs submit their bids to ISO. 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 [7].

III. Day-ahead market organization

In many real markets there is a day-ahead market (DA). Most transactions are cleared in the DA market for each hour of the next day. The selling bids are ordered by increasing prices, and the demand bids are ordered by decreasing prices, resulting in an aggregated supply curve and an aggregated demand curve. The intersection of these curves determines the market clearing price (that of the last accepted selling bid).The day-ahead (DA) market is organized as a sequence of twenty-four independent hourly single auctions. The bid prices decided by each GENCO are generally given by

$$: \lambda_{i,j} = 2\,\gamma_i\,P_{i,j} + \beta_i \text{ (Rs./MWhr)} \qquad (1)$$

Where a_i and b_i are cost coefficients of generator i.

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

$$: \text{Minimize } C_t(m) = \lambda_{\mathbf{MCP}}\,P_g \qquad (2)$$

Subjected to equality constraint

$$: P_g = P_d = \sum_{a=1}^{N}\sum_{i=1}^{n}\sum_{j=1}^{k} P_{i,j}^{a} \qquad (3)$$

The total generation of unit i will be calculated by

$$: P_{g,i} = \left\{ \sum_{j=1}^{k} P_{i,j} \right\} \leq P_{i,max} \qquad (4)$$

The total generation of an area 'a' will be calculated by

$$:P_{g,a} = \sum_{i=1}^{n} P_{g,i} \qquad (5)$$

The profit for an N^th area GENCO company will given by

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

$$:= \sum_{i=1}^{n}\ \sum_{j=1}^{k}\ \left(\bar{\lambda}i, j\ \bar{P}i, j\right) \qquad (7)$$

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

The percentage of market share of each GENCO is in an area 'a' will be given by

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

IV. Congestion management schemes

4.1. Technical methods

1) Out aging of congested lines
2) Transformer tap changers
3) Operation of FACTS devices

4.2. Non-technical Methods

4.2.1. Market-based

4.2.1.1. Auctioning: In auctioning the available capacity of a normally constrained path is auctioned by the ISO receiving bids from parties willing to use the path. The lowest marginal bid accepted becomes the price for transmission on the path.

4.2.1.2. Market Splitting: In market splitting the market is first settled without constraints applied. If the resulting schedules cause congestion on some line(s) the market is then split and settled separately with the transfer limit applied.

4.2.1.3. Counter trading: Counter trading is a modified form of re-dispatching the difference being that up and down regulation power is obtained from the market.

4.2.1.4. Re-dispatching: In this method the market is settled without the constraints of the transmission system being applied. If congestion occurs the ISO re-dispatches the generation in such a way that congestion is gotten rid of. The ISO directly commands generators to up regulate or down regulate without the use of the market [8].

4.2.1.5. Load curtailment: By managing load, congestion can also be effectively relieved.

4.2.1.6. Nodal pricing: In the nodal pricing scheme every bus in the grid is treated as zone. The Locational Marginal Price (LMP) for each bus is determined by the ISO.

4.2.1.7. Zonal pricing: In Zonal pricing system buses with similar LMPs are aggregated into zones. The market is first settled constrained free. In
the case that congestion occurs the ISO receives supplementary bids for increase and decrease of generation.

4.2.2. Non-market based

1) Pro rata
2) First come, first serve

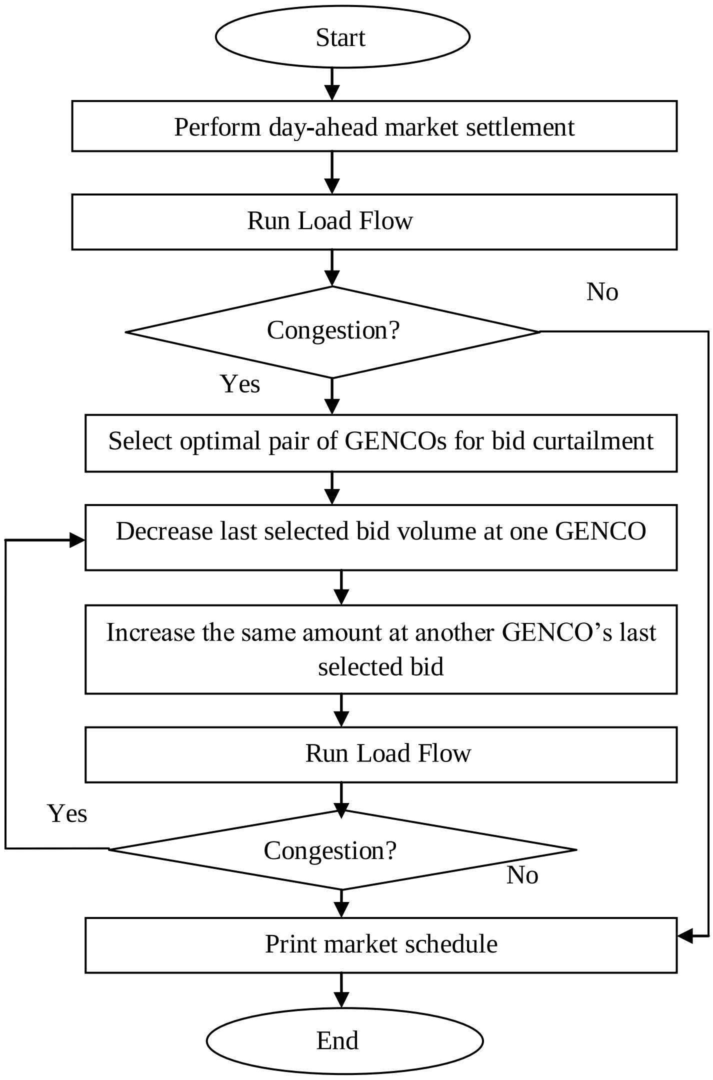

Fig 1: Flow chart of optimal re-dispatches method

The market settlement process has been carried out as explained in [9]. The spot trading session of National Power Exchange Limited (NPEX) generally starts at 10:00AM and ends at 12:00PM.

As the single auction pool market is considered only GENCOs submit their bids to ISO. The bids are presented in the following Table 1 and the forecasted load which should be considered as trading power at each hour is given in Table 2.

Table 1: GENCO's Submitted Bids

Generator I	Block J	Block Size P_{ii}(MW)	Unit Price λii (Rs./MWhr)
1	1	100	208.5
	2	75	358.5
	3	125	608.5
2	1	20	161.5
	2	100	841.5
	3	30	1045.5
3	1	10	600.0
	2	5	850.0
	3	5	1100.0

The bids submitted by the each GENCO are divided into blocks. Here bids are divided into three blocks. Table 2 shows the Load Scaling Factor (LSF) for 24 hours.

Table 2: Load Scaling Factors for 24 hours

Hour	LSF	Hour	LSF	Hour	LSF
1	0.80	9	1.00	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	0.90	21	0.91
6	0.85	14	0.88	22	0.89
7	0.92	15	0.86	23	0.79
8	1.00	16	0.87	24	0.79

The allocated schedules by ISO for the bids submitted by the GENCOs for 24 hours are as in Table 3.

Table 3: Schedule of generation over 24 hours period

Hour	Generator		
	1	2	3
1	1.86	0.20	-
2	1.84	0.20	-
3	1.84	0.20	-
4	1.85	0.20	-
5	1.79	0.20	0.10
6	1.91	0.20	0.10
7	2.10	0.20	0.10
8	2.29	0.20	0.10
9	2.28	0.20	0.10
10	2.19	0.20	0.10
11	2.148	0.20	0.10
12	2.09	0.20	0.10
13	2.03	0.20	0.10
14	1.97	0.20	0.10
15	1.94	0.20	0.10
16	1.95	0.20	0.10
17	1.92	0.20	0.10
18	1.99	0.20	0.10
19	2.12	0.20	0.10
20	2.11	0.20	0.10
21	2.07	0.20	0.10
22	2.00	0.20	0.10
23	1.84	0.20	-
24	1.84	0.20	-

The generation schedule in Table 3 is in p.u. on a 100MVA base. The forecasted peak load on the system is 259 MW for base load and this may considered as variable in each trading hour.

V. Results

5.1. Congestion results

5.1.1. Base case

In this case for the given schedules by running load flow congestion existence is checked and congestion relief is done by Load Curtailment and Variable Bid Curtailment (VBC) i.e. Re-dispatch. By running load flow along with the power flows the system performance index and the losses are also taken. As generator 1 is taken as slack bus it should take care of the loss compensation. For this case the Load Curtailment (LC) is taken as zero. Table 4 shows the results for congestion checkup.

Table 4: Congestion checkup

Hour	PG1	PG2	PG3	PI	Loss	Congestion
1	196.127	20	0	4.9198	8.927	Yes
2	193.296	20	0	4.5664	8.686	Yes
3	193.296	20	0	4.5664	8.686	Yes
4	193.296	20	0	4.5664	8.686	Yes
5	187.912	20	10	3.9043	8.122	Yes
6	199.219	20	10	5.2696	9.069	Yes
7	219.151	20	10	8.5987	10.8713	Yes
8	242.164	20	10	14.357	13.164	Yes
9	242.164	20	10	14.357	13.164	Yes
10	230.626	20	10	11.1747	11.986	Yes
11	227.752	20	10	10.4778	11.702	Yes
12	219.151	20	10	8.5987	10.871	Yes
13	213.437	20	10	7.5078	10.337	Yes
14	207.738	20	10	6.5337	9.818	Yes
15	202.055	20	10	5.6663	9.315	Yes
16	204.895	20	10	6.0872	9.565	Yes
17	202.055	20	10	5.6663	9.315	Yes
18	207.738	20	10	6.5337	9.818	Yes
19	224.881	20	10	9.8171	11.421	Yes
20	222.014	20	10	9.1913	11.144	Yes
21	216.292	20	10	8.0379	10.6023	Yes
22	210.586	20	10	7.0067	10.076	Yes
23	193.296	20	0	4.5664	8.686	Yes
24	193.296	20	0	4.5664	8.686	Yes

5.1.2. Load curtailment

All hours are congested so congestion has to relieve. Below Table 5 gives the results of congestion relief by Load Curtailment. In this case Load Curtailment is increased until the congestion is relived. The corresponding Performance Index (PI) and losses are tabulated in Table 5.

Table 5: Congestion relief by Load Curtailment

Hour	LC	PG1	PG2	PG3	PI	Loss
1	0.22	146.793	20	0	1.122	5.18
2	0.22	144.627	20	0	1.0257	5.031
3	0.22	144.627	20	0	1.0257	5.031
4	0.22	144.627	20	0	1.0257	5.031
5	0.18	147.133	20	10	1.1214	5.108
6	0.22	146.8	20	10	1.1086	5.086
7	0.28	146.634	20	10	1.1023	5.076
8	0.34	145.97	20	10	1.0772	5.033
9	0.34	145.97	20	10	1.0772	5.033
10	0.31	146.634	20	10	1.1023	5.076
11	0.3	147.354	20	10	1.13	5.122
12	0.28	146.634	20	10	1.1023	5.076
13	0.27	145.141	20	10	1.0465	4.981
14	0.25	145.97	20	10	1.0772	5.033
15	0.23	146.579	20	10	1.1002	5.072
16	0.24	146.302	20	10	1.0897	5.054
17	0.23	146.579	20	10	1.1002	5.072

18	0.25	145.97	20	10	1.0772	5.033
19	0.3	145.417	20	10	1.0566	4.998
20	0.29	146.053	20	10	1.0803	5.039
21	0.27	147.16	20	10	1.1225	5.109
22	0.26	145.583	20	10	1.0628	5.009
23	0.22	144.627	20	0	1.0257	5.031
24	0.22	144.627	20	0	1.0257	5.031

5.1.3 Re-dispatch

By adjusting the generation schedules at generating stations the congestion can be relived. The results are tabulated in Table 6. In this case also the Load Curtailment (LC) is taken as zero.

Table 6: Congestion relief by re-dispatch

Hour	PG1	PG2	PG3	PI	Loss
1	154.739	59.8	0	7.3393	7.339
2	154.314	57.5	0	1.3272	7.204
3	154.314	57.5	0	1.3272	7.204
4	154.314	57.5	0	1.3272	7.204
5	154.052	52.6	10	1.3172	6.862
6	155.846	61.7	10	1.3968	7.396
7	159.093	77.6	10	1.5832	8.413
8	162.799	95.9	10	1.8807	9.699
9	162.799	95.9	10	1.8807	9.699
10	160.98	86.7	10	1.7206	9.04
11	160.428	84.5	10	1.6805	8.878
12	159.093	77.6	10	1.5832	8.413
13	158.214	73	10	1.5258	8.114
14	157.24	68.5	10	1.4695	7.82
15	156.378	63.9	10	1.4228	7.538
16	156.808	66.2	10	1.4455	7.678
17	156.378	63.9	10	1.4228	7.538
18	157.24	68.5	10	1.4695	7.82
20	159.536	79.9	10	1.6141	8.566
21	158.653	75.3	10	1.5538	8.263
22	157.674	70.8	10	1.4948	7.964
23	154.314	57.5	0	1.3272	7.204
24	154.314	57.5	0	1.3272	7.204

5.2. Contingency results

For contingency case only the peak load hour is considered. Here the peak load hour is 8^{th} hour. So, the following results are for the hour 8.

The following table 7 gives the results for contingency i.e. outage of a line which may leads to congestion for peak hour in this hour the Load Scaling Factor (LSF) is one.

Table 7: Contingency results

LO	PG1	PG2	PG3	PI	Loss
1.2	276.928	20	10	193.2217	47.931
1.5	250.003	20	10	101.5821	21.003
2.3	250.982	20	10	13.5972	21.984
2.4	244.027	20	10	11.1422	15.027
2.5	243.009	20	10	10.0584	14.009
3.4	242.328	20	10	16.5452	13.328

4.5	244.779	20	10	26.5906	15.779
4.7	242.452	20	10	14.9202	13.452
4.9	242.205	20	10	14.8142	13.205
5.6	245.208	20	10	22.6431	16.208
6.11	242.323	20	10	14.6394	13.323
6.12	242.41	20	10	14.8709	13.41
6.13	243.148	20	10	14.8875	14.148
7.8					
7.9	242.538	20	10	15.0988	13.538
9.10	242.303	20	10	14.359	13.303
9.14	242.677	20	10	15.1147	13.677
10.11	242.202	20	10	14.463	13.202
12.13	242.172	20	10	14.414	13.172
13.14	242.293	20	10	14.4314	13.293

The results of congestion relief due to contingency for the worst case with Load Curtailment (LC) and Re-Dispatch are given in the Table 8 and Table 9.

Table 8: Congestion relief by Load Curtailment for worst contingency

LO	LC	PG1	PG2	PG3	PI	Loss
1.2	0.53	97.261	20	10	0.9907	5.537

Table 9: Congestion relief by re-dispatch for worst contingency

LO	PG1	PG2	PG3	PI	Loss
1.2	99.951	150	18.2	1.7776	9.151

Below is the graphical representation of Performance Index (PI) for all line outages. The Performance Index (PI) for the line outage 1.2 is high, so it is considered as the worst contingency case. The case which is having high Performance Index (PI) is taken as worst contingency case. The Performance Index (PI) of 1.2 outage is 193.2217 that is observed in Fig 2 given below.

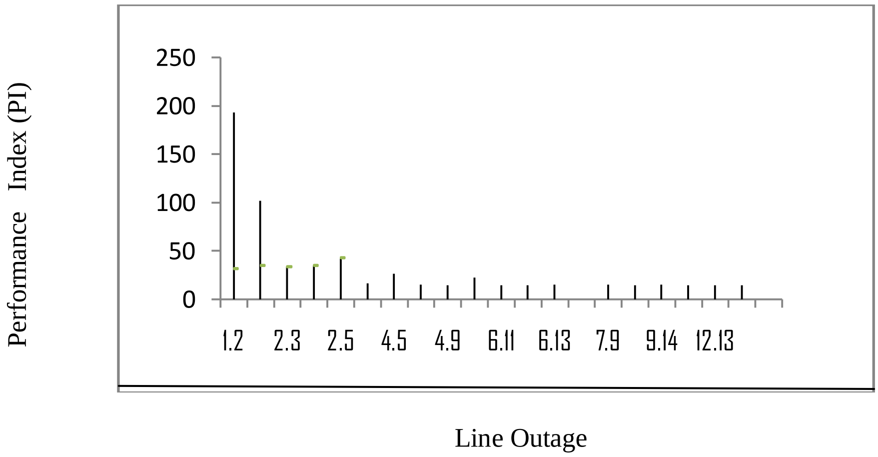

Fig 2: Performance Index for line outages

In the case of Re-Dispatch the Load Curtailment is taken as zero. The Fig 3 is the graph for the Performance Index (PI) for base, Load Curtailment and Re-Dispatch cases.

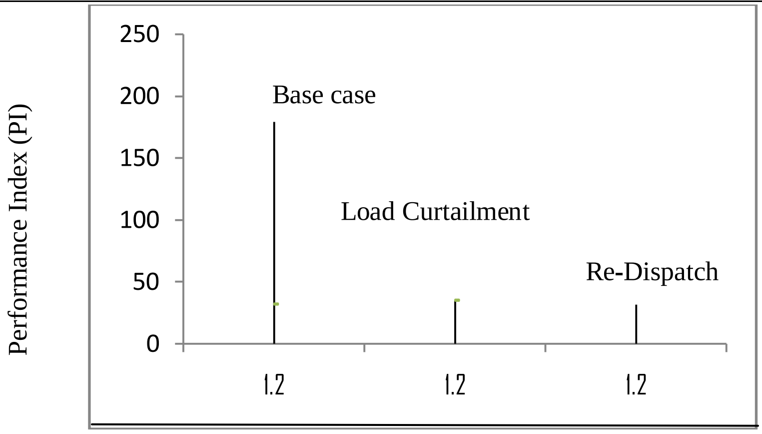

Fig 3: Performance Index (PI) for base case and after load curtailment and re-dispatch

When observed the Fig 3 the Performance Index (PI) is decreased with Load Curtailment and Re-Dispatch by that the contingency is relived.

5.3. Production Cost for congestion and contingency

Production cost is calculated by using two methods.

1) Pay As Bid (PAB) method

2) System Marginal Price (SMP) method

5.3.1. Pay As Bid method

Table 10: Total production cost for congestion

Hour	Base Case	Load Curtailment	Re-Dispatch
1	63,823.28	40,855.29	77,195.63
2	62,100.62	40,078.77	75,107.81
3	62,100.62	40,078.77	75,107.81
4	62,100.62	40,078.77	75,107.81
5	64,824.45	46,977.18	76,890.54
6	71,704.76	46,857.80	85,191.34
7	83,833.38	46,798.28	99,735.24
8	97,836.79	46,560.24	116,463.29
9	97,836.79	46,560.24	116,463.29
10	90,815.92	46,798.28	108,069.38
11	89,067.09	47,056.40	106,020.18
12	83,833.38	46,798.28	99,735.24
13	80,356.41	46,263.04	95,549.21
14	76,888.57	46,560.24	91,413.29
15	73,430.46	46,778.57	87,233.36
16	75,158.60	46,679.26	89,322.96
17	73,430.46	46,778.57	87,233.36
18	76,888.57	46,560.24	91,413.29
19	87,320.08	46,361.99	103,924.48
20	85,575.51	46,590	101,829.50
21	82,093.68	46,986.86	97,642.05
22	78,621.58	46,421.50	93,504.32
23	62,100.62	40,078.77	75,107.81
24	62,100.62	40,078.77	75,107.81

Following Fig 4 shows the graphical representation of total production Re-Dispatch for congestion case and its relief cases

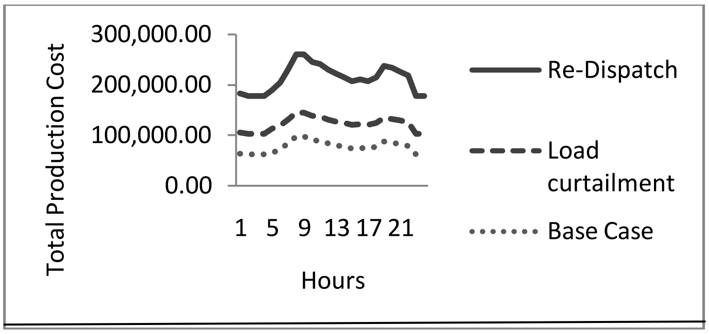

Fig 4: Total production cost graph for congestion

Table 11: Total production cost for contingency

Line outage	Base Case	Load curtailment	Re-Dispatch
1.2	118,949.91	29,509	153,354.78
1.5	102,606.82	29,660.28	154,709.49
2.3	103,202.54	51,848.83	116,824.49
2.4	98,970.42	51,867.47	111,195.13
2.5	98,350.97	51,682.13	110,336.42
3.4	97,936.58	45,587.63	118,699.33
4.5	99,428.02	40,915.30	126,767.12
4.7	98,012.04	44,595.73	116,332.20
4.9	97,861.74	46,567.41	116,338.10
5.6	99,689.07	45,980.19	146,985.40
6.11	97,933.54	46,581.03	116,748.88
6.12	97,986.48	46,595.37	116,643.42
6.13	98,435.55	46,691.81	117,275.03
7.8			
7.9	98,064.37	46,600.39	154,126.10
9.1	97,921.37	46,585.34	116,468.76
9.14	98,148.95	46,636.96	116,650.42
10.11	97,859.91	46,565.62	116,567.77
12.13	97,841.66	46,561.32	116,465.80
13.14	97,915.29	46,576.73	116,646.19

Following Fig 5 shows the graphical representation of total production cost of Base Case, Load Curtailment and Re-Dispatch for contingency case.

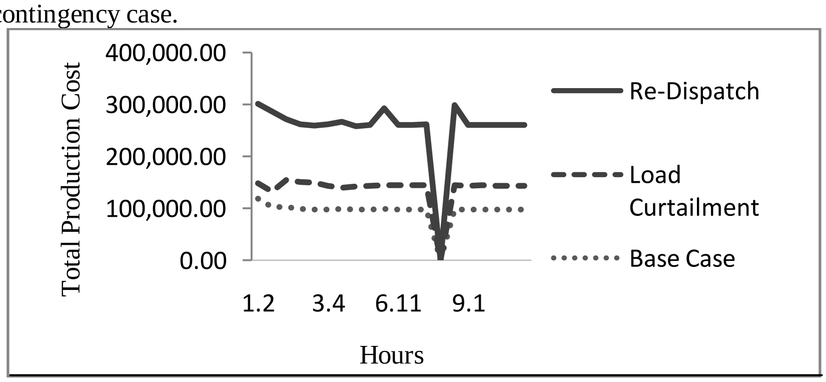

Fig 5: Total production cost for contingency case

5.3.2. System Marginal Price method

Table 12: Total production cost for congestion

Hour	Base Case	Load Curtailment	Re-Dispatch
1	185,780	65,967.50	163,717.50
2	185,780	65,967.50	163,717.50
3	185,780	65,967.50	163,717.50
4	185,780	65,967.50	163,717.50
5	191,780	71,967.50	169,717.50
6	191,780	71,967.50	169,717.50
7	191,780	71,967.50	169,717.50
8	191,780	71,967.50	169,717.50
9	191,780	71,967.50	169,717.50
10	191,780	71,967.50	169,717.50
11	191,780	71,967.50	169,717.50
12	191,780	71,967.50	169,717.50
13	191,780	71,967.50	169,717.50
14	191,780	71,967.50	169,717.50
15	191,780	71,967.50	169,717.50
16	191,780	71,967.50	169,717.50
17	191,780	71,967.50	169,717.50
18	191,780	71,967.50	169,717.50
19	191,780	71,967.50	169,717.50
20	191,780	71,967.50	169,717.50
21	191,780	71,967.50	169,717.50
22	191,780	71,967.50	169,717.50
23	185,780	65,967.50	163,717.50
24	185,780	65,967.50	163,717.50

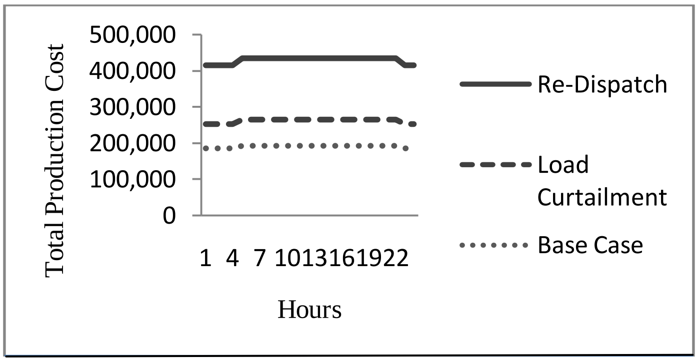

Fig 6: Total production cost for congestion case

Table 13: Total production cost for contingency case

Line outage	Base Case	Load curtailment	Re-Dispatch
1.2	191,780	30,080	178,765
1.5	191,780	30,080	178,765
2.3	191,780	71,968	289,530
2.4	191,780	71,968	289,530
2.5	191,780	71,968	289,530
3.4	191,780	71,968	169,718
4.5	191,780	71,968	169,718
4.7	191,780	71,968	169,718
4.9	191,780	71,968	169,718
5.6	191,780	71,968	127,830
6.11	191,780	71,968	169,718
6.12	191,780	71,968	169,718
6.13	191,780	71,968	169,718

7.8			
7.9	191,780	71,968	178,765
9.10	191,780	71,968	169,718
9.14	191,780	71,968	169,718
10.11	191,780	71,968	169,718
12.13	191,780	71,968	169,718
13.14	191,780	71,968	169,718

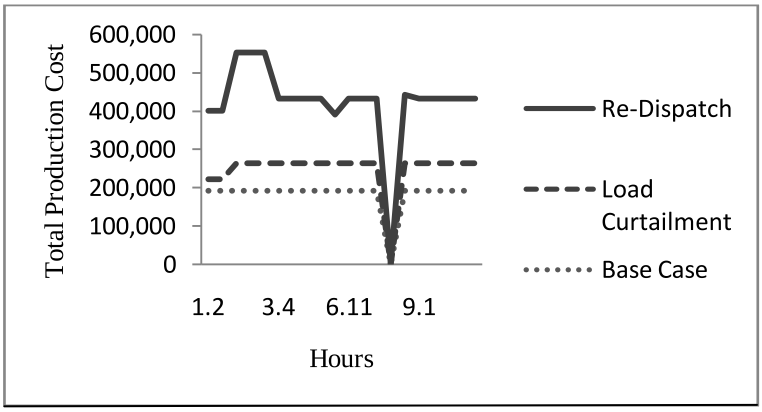

Fig 7: Total production cost for contingency case

VI. Conclusion

In order to operate the competitive energy market efficiently as well as network with security margin, congestion relief techniques are becoming popular day by day. In this paper, a brief review of the transmission congestion management methods has been reported. The competitive energy market is considered as day-ahead market operation. At first stage, the unconstrained market schedule is determined for the period of 24 hours. For this schedule, the overloading condition is verified with NR method and also we have computed performance index to identify overloading severity. In the second stage, congested hours are rescheduled. We have adopted load curtailment and re-dispatch methods for congestion relief in the network. Based on the minimum absolute MW mismatch with re-dispatch to the market schedule, the optimal generator is identified to increase/decrease its bids volume. The market economic inefficiency is determined using two congestion cost calculation methods. Compare with system marginal price method, the pay-as-bid pricing method is given low economic risk. The reduced load on the system for secured operation showed the need of alternative long-term congestion relief methods also. Finally this paper described the new methodology for generator selection to alter its schedule for congestion relief with re-dispatch approach.

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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
k Number of selected blocks in offer bid (DA)
n Number of generating units in one area
N Number of areas (GENCOs)
Pg,i Total generation of unit i, in MW
Pg,a Total generation in area a, in MW
Pd,a Total demand in area a, in MW
Pg System total generation, in MW
Pd System total load, in MW
Pi,j Offer quantity of block j of unit i, in MW
Pi,min Minimum generation of unit i, in MW
Pi,max Maximum generation of unit i, in MW
λij 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
λMCP Market Clearing Price, in Rs./MWhr
$PMCQ$ 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
$Ct(m)$ Total system production cost at mth hour, in Rs.
$\%Cpr,N(m)$ Percentage of Nth GENCO profit at mth hour.
$\%MSa$ Percentage of market share of an area a