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ASSESSMENT OF SECURITY LEVEL UNDER STRATEGIC BIDDING IN COMPETITIVE ELECTRICITY MARKET ENVIRONMENT

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ABSTRACT

In day-ahead power market auction, the concept of competitive bidding by GENCOs is deflecting the natural market equilibrium point. The changes in market schedule for forecasted demand error as well as bids changes are addressed in this paper. Taking into consideration the effect of competitive bidding, available transfer capability (ATC) is modeled as the largest value of unused transfer power with severe (N-1) contingency criteria that causes no system operating constraints violation. The repeated power flow (RPF) method is used to determine the ATC between a specified seller bus and buyer buses.

Key Words— Day-Ahead market, Competitive bidding, Available Transfer Capability (ATC), Repeated Power Flow (RPF).

INTRODUCTION

The role of Independent System Operator (ISO) in a competitive market environment would be to facilitate the complete dispatch of the power that gets contracted among the market players. The trading of large amount of energy and the increasing load levels day-by-day result overloading of the transmission system. The market driven schedule dispatchable problems due to overloading create many challenging issues to be addressed by the researchers. Based upon the NERC's definition [1], Available Transfer Capability (ATC) is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically it is expressed as follows:

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

The definition of each term as follows: Total Transfer Capability (TTC) is the maximum of power that can be transferred in a reliable manner between a pair of defined source and sink locations in the interconnected system while meeting all of a specific set of defined pre- and post-contingency system conditions. Transmission Reliability Margin (TRM) is the amount of transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission system will be secure. Capacity Benefit Margin (CBM) is the amount of transfer capability preserved for Load Service Entities (LSE's) on the host transmission system where their load is located, to enable an access to generation from interconnected systems to meet generation reliability requirements. Existing Transmission Commitments (ETC) is the amount of electric power which has been already committed or scheduled, i.e. base case load on the system.

TTC is the most important and first term to be determined in the ATC determination. Due to nonlinear nature of the interconnected electric power systems, TTC between two locations and their associated binding constraints depend on the set of operating conditions. The operating conditions represent a single snapshot of the operation of the interconnected network based on the consideration of a number of factors. Generation dispatch, system configuration, base schedule transfers, system contingencies, projected customer demand etc. are the major ones. And similarly, the computation method of ATC should consider limits imposed on the system components such as thermal, voltage and stability limits. However, these limits in the system are mainly dependent on the power injections/ withdrawals, position of load flow controlling devices like transformer tap/phase shifters setting and major disturbances in the system. Whatever the disturbances considered, the ATC value will decrease significantly. The transaction power must be limited to available transfer capability (ATC), if bottlenecks prevent a reliable system operation under consideration of uncertainties. In general, the uncertainties like generator/line outages, uncertainties in load forecast, system operating constraints and simultaneous transactions are major limiting factors to the ATC between specified seller buses to buyer buses. In addition, the competitive environment in day-ahead energy market auction changes the level of power injections/ withdrawals for every trading hour in the system. Under this scenario, the MW flow in a line may increase or decrease. The incremental flow i.e. *stress* which can also causes to congestion. Since ATC is a network capability signal for commercial activities over the network, it is worthwhile to incorporate stress with market participants' strategies in addition to common disturbances while computing ATC to increase the efficient use of the transmission system. In this paper, our aim is to impose unstable market schedule with bids change and load forecast errors while determining the ATC value at every trading hour hence ATC value that reflects the strategic market activities in addition to major contingencies.

In this paper, first we have schedule the generations as per the single sided day-ahead energy auction. The GENCOs strategic bid change and error in forecasted demand (EFD) are considered simultaneously during the market settlement. Later, Repeated Power Flow (RPF) [2] method is adapted to calculated TTC value between any pair of source and sinks locations. The (N-1) contingency incident is imposed for the account of TRM, CBM and finally ATC is determined.

This paper is organized as follows: Following the introduction, day–ahead market settlement is explained briefly in section II. In section III, strategic bidding modeling in competitive market is described. Then in section IV, modeling of different uncertainties are explained. In section V, evaluation of Available Transmission Capability (ATC) is explained briefly. The case study with different bilateral transactions between various sources/sink is carried out and simulation results are given in section VI. Finally, brief conclusions are deduced.

I. DAY–AHEAD MARKET SETTLEMENT

In a day-ahead single sided energy auction, Generators only submit supply offers for each trading interval (hour or half-hour) of the next day to the system (or market) operator. Supply offers can be either "priced," in the form of a set of price-quantity (Rs/MWh–MWh) pairs, or "non–priced," in the form of quantity (MWh) only. The system operator stacks the bids 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.* Since, the supply offers are basically prepared from the marginal cost function; we have followed the scheduling process as similar to economic dispatch (ED) algorithms explained in [3]. The input to the ED problem consists of the bidding curves of each generator instead of their original cost functions.

Generally, the offering strategies by the power producer will change according to the market signal like MCP and cleared quantity to maximize their profits. But, being an objective function of public welfare maximization, Independent System Operator (ISO) will schedule the generators such that which minimizing the total generation cost. The single sided auction market objective function [4] is as follows:

$$\min\left\{MCP \times \sum_{p\in NG} P_{G,p}\right\} \tag{2}$$

Subject to:

$$\sum_{q\in NL} P_{d,q} = \sum_{p\in NG} P_{G,p} \tag{3}$$

where $P_{d,q}$ and $P_{G,p}$ are the active load at bus *q* and generation at bus *p* respectively. *NL* and *NG* are the number of load buses and generator buses in the system respectively.

The schedule at a particular bus *p,* $P_{G,p}$ and MCP by the consideration of error in forecasted demand (EFD) ε, will determined as follows:

$$MCP = \frac{\left\{(1+\varepsilon)\times P_d^{base}\right\} + \sum_{p\in G}\frac{b_p}{2a_p}}{\sum_{p\in G}\frac{1}{2a_p}} \tag{4}$$

$$P_{G,p} = \frac{MCP - b_p}{2a_p} \tag{5}$$

Now considered the effect of generator limits given by the inequality constraint:

$$P_{G,p}^{\min} \le P_{G,p} \le P_{G,p}^{\max} \qquad \forall p \in NG \tag{6}$$

If a particular generator loading $P_{G,q}$ reaches the limit $P_{G,p}^{\min}$ or $P_{G,p}^{\max}$, its loading is held fixed at this value and the balance load is shared between the remaining generators on an equal incremental cost basis.

II. STRATEGIC BIDDING MODELING IN COMPETITIVE POWER MARKET

The strategic bidding is a process of change in bid functions to maximize GENCOs' profit [5, 6]. In a perfect competitive market, the supply curve created by aggregating generator offers should closely approximate the system marginal production cost of generation. Hence the bidding cost function treated as a continuous function and is given by a power producer *p* (or supply curve) is:

$$C_{b,p}(P_{G,p}) = a_{b,p}P_{G,p}{}^2 + b_{b,p}P_{G,p} + c_{b,p} \tag{7}$$

where ($a_{b,p}$, $b_{b,p}$ and $c_{b,p}$) are the bid coefficients and related with the actual cost function coefficients (a_p, b_p and c_p) as follows [7]:

$$\xi_p = \frac{a_{b,p}}{a_p} = \frac{b_{b,p}}{b_p}, \text{ and } c_{b,p} = c_p \tag{8}$$

where ξ_p is the bidding parameter and represents markup above or below the marginal cost that a generator p decide to set its marginal bid in competitive market. Now, the marginal cost function will become as:

$$C_{b,p}(P_{G,p}) = \xi_p a_p P_{G,p}{}^2 + \xi_p b_p P_{G,p} + c_{b,p} \tag{9}$$

Now the modified schedule with the change in bidding parameter by bus p, and MCP will determine as

$$MCP = \frac{\left\{(1+\varepsilon)\times P_d^{base}\right\} + \sum_{p\in G} \frac{b_p}{2a_p}}{\sum_{p\in G} \frac{1}{2\xi_p a_p}} \tag{10}$$

$$P_{G,p} = \frac{MCP - \xi_p b_p}{2\xi_p a_p} \tag{11}$$

Once again, the complete schedule will determine as per previous section. After the market settlement, the ISO checks the feasibility of the scheduled generation by carrying out a load flow. The bidding parameter which causes to threat to the security will reject. Keeping in mind, to prevent the market abuse by power producers with their strategic bidding, the bidding coefficient range should be quantified properly and we have considered it as 0.5 to 2.

III. MODELING OF UNCERTAINTIES

1) *Error in Forecasted Demand (EFD)*

The error, ε in forecasted demand may cause higher or lower to the cleared demand (quantity) at every trading hour in the day–ahead auction. The new demand on the entire system and corresponding load at a bus p will alter as follows:

$$P_d^{new} = P_d^{base}(1+\varepsilon)$$

(12)

$$P_{d,p}^{new} = P_{d,p}^{base} \times (1+\varepsilon) \tag{13}$$

2) *Line outage*

The line between buses p and q having self admittance y_{pq} is to be considered an outage, then the required modification in Y_{bus} is obtained by simply adding another line in parallel to the same line with negative admittance i.e. $-y_{pq}$. The new admittance matrix elements can also be updated as fallows.

$$Y_{pp}^{new} = Y_{pp}^{old} - y_{pq} \tag{14}$$

$$Y_{qq}^{new} = Y_{qq}^{old} - y_{pq} \tag{15}$$

$$Y_{pq}^{new} = Y_{qp}^{new} = Y_{pq}^{old} + y_{pq} \tag{16}$$

3) *Generator Outage*

After scheduling the generation as per Section – II, one of the generators is considered to be outaged. The generator outage is modeled as zero output power and treated as load bus. The required excessive generation on the system is going to supply by the slack bus. In the event of slack bus outage, we have considered next highest capacity generator as the slack bus.

Security Level

The impact of severe outages should be considered while calculating the security constraint ATC. To identify the severity level of any contingency in the network, the Performance Index (PI) method [8] is adopted and is given by

$$PI = \sum_{l} \left(\frac{f_l}{f_{l,\max}} \right)^{2x} \tag{17}$$

where l is the number of transmission lines, f_l is the absolute flow of line l and $f_{l,max}$ is its MVA rating. The higher value of PI for any operating state of the system indicates overloading of one or more transmission lines in the network.

In the event of congestion in the transmission system, the ISO should take necessary preventive actions for security. The literature provided by [9] will give basic idea about existed congestion management techniques. In this paper we have followed by load curtailment and the required load curtailment on the system is modeled as:

$$P_d^{new} = (1-\tau) \times \sum_{p} P_{d,p}^{base} \tag{18}$$

where τ is the load curtailment factor (LCF) which is less than one and the reduced load will compensated by reference bus. At this case ATC will become negative value and it will be equal to the required amount of load curtailment.

$$P_{LC} = P_d^{base} - P_d^{new} \tag{19}$$

IV. EVALUATION OF ATC

1) *Repeated Power Flow method*

At a specified hour with congestion free market schedule, the maximum value of ATC can be obtained using RPF method, as the name implies, finds TTC by successively solving a set of power flow problems. The demand at buyer bus, and the generation at the seller bus are increased in an increment step until any of the operating constraints' violation. In this paper, the voltage limit, thermal limit and generation capacity limits are considered. Finally the ATC will be equal to TTC minus base load at sink bus which can be further useful to bilateral transaction.

2) *Generalized Curve Fitting (GCF) Approach*

Generally, Continuous Power Flow (CPF) method is used to calculate critical loading point or voltage stability margin. Instead of CPF, later, Generalized Curve Fitting (GCF) approach is also used to find critical loading point. The modified approach for GCF is given in [11]. Using GCF, the PV curve is drawn first. The PV curve for sink bus provides the information of drooping nature of voltage under load increment. In order to transfer ATC obtained with RPF method, what should be the voltage at sink bus? This value is determined using GCF approach. The actual value with RPF and obtained value with GCF will compare.

V. CASE STUDY AND RESULTS

The IEEE 14–Bus test system [13] is used to represent the transmission network with same bus data. The network is scheduling with day-ahead market auction. To represent trading quantities over 24 hour period, the forecasted demands in terms of load scaling factors (LSF) are given in Table–I. The market schedule, MCP and corresponding transmission losses are given in Table–I & II. The loss allocation to a generator is the responsibility of market operator and we have assigned to the slack bus. The cost of transmission loss is not considered. Fortunately, for the entire day the system does not subjected to congestion.

TABLE I: MARKET SCHEDULE OVER 24 HOUR PERIOD

Hour #	LSF	Market Schedule				
		PG1	PG2	PG3	PG4	PG5
1	0.80	50.66	65.04	24.21	46.77	20.53
2	0.79	50.20	64.52	24.06	45.67	20.16
3	0.79	50.20	64.52	24.06	45.67	20.16
4	0.79	50.20	64.52	24.06	45.67	20.16
5	0.81	51.11	65.56	24.36	47.87	20.89
6	0.85	53.64	68.44	25.16	50.00	22.91
7	0.92	59.19	74.79	26.94	50.00	27.35
8	1.00	65.54	82.05	28.97	50.00	32.43
9	1.00	65.54	82.05	28.97	50.00	32.43
10	0.96	62.37	78.42	27.96	50.00	29.89
11	0.95	61.57	77.51	27.70	50.00	29.26
12	0.92	59.19	74.79	26.94	50.00	27.35
13	0.9	57.61	72.98	26.43	50.00	26.08
14	0.88	56.02	71.16	25.93	50.00	24.81
15	0.86	54.43	69.35	25.42	50.00	23.54
16	0.87	55.22	70.26	25.67	50.00	24.18
17	0.86	54.43	69.35	25.42	50.00	23.54
18	0.88	56.02	71.16	25.93	50.00	24.81
19	0.94	60.78	76.61	27.45	50.00	28.62
20	0.93	59.99	75.70	27.20	50.00	27.99
21	0.91	58.40	73.88	26.69	50.00	26.72
22	0.89	56.81	72.07	26.18	50.00	25.45
23	0.79	50.20	64.52	24.06	45.67	20.16
24	0.79	50.20	64.52	24.06	45.67	20.16

TABLE II: ECONOMICS & SYSTEM PERFORMANCE OVER 24 HOUR PERIOD

Hour #	MCP	Losses	Hour #	MCP	Losses
1	4.0263	2.4191	13	4.3042	3.0089
2	4.0081	2.3642	14	4.2407	2.8883
3	4.0081	2.3642	15	4.1772	2.7715
4	4.0081	2.3642	16	4.2089	2.8294
5	4.0446	2.4750	17	4.1772	2.7715
6	4.1454	2.7146	18	4.2407	2.8883
7	4.3677	3.1947	19	4.4312	3.3209
8	4.6217	3.7232	20	4.3995	3.2573
9	4.6217	3.7232	21	4.3360	3.0706
10	4.4947	3.4510	22	4.2725	2.9481
11	4.4630	3.3855	23	4.0081	2.3642
12	4.3677	3.1947	24	4.0081	2.3642

1) *Identification of Severe Contingency*

Different approaches are followed to identify the stress level in the system. The PI values are determined for every (N-1) contingency i.e. either generator or line with x = 5 at base case. As per the PI values in Table–III, Generator–4 is considered as severe outage. Similarly, the severe line outage is 7–9. The congested situation i.e. line outage 2–3 is restored with load curtailment. The required LCF is –0.24. Line outage is 7–8 is not considered as per network configuration.

TABLE III
GENERATOR OUTAGES AND SYSTEM PERFORMANCE

Gen #	Losses	PI	Gen #	Losses	PI
1	3.494	0.2158	4	5.819	**0.4441**
2	5.774	0.2770	5	5.596	0.2268
3	5.899	0.4203			

TABLE IV
LINE OUTAGES AND SYSTEM PERFORMANCE

Line	Losses	PI	Line	Losses	PI
1 – 2	5.0364	0.4054	6 – 11	3.9375	0.2904
1 – 5	4.6287	0.2744	6 – 12	3.9666	0.2662
2 – 3	7.8177	**5.6725**	6 – 13	4.7867	0.5177
2 – 4	4.3677	0.3388	7 – 8	Not Considered	
2 – 5	3.9744	0.2307	**7 – 9**	4.5294	**0.5932**
3 – 4	3.8757	0.2399	9 – 10	3.8032	0.2114
4 – 5	4.9404	0.4244	9 – 14	4.0958	0.2163
4 – 7	3.6956	0.2054	10 – 11	3.7924	0.2494
4 – 9	3.7837	0.2517	12 – 13	3.7314	0.2162
5 – 6	3.6860	0.2086	13 – 14	3.8831	0.2817

2) *Identification stress free bidding parameter range*

The simulations are performed with the bidding parameter range of 0.5 to 2.0. The bidding parameter range which causes to stress measured in PI for each generator can easily understood from Fig. 1 and the corresponding variation in losses can observable in Fig. 2. It is cleared that losses are also more when stress is

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high. So the ISO may/ should reject the biding parameter value if it exists in these ranges as a preventive action for security.

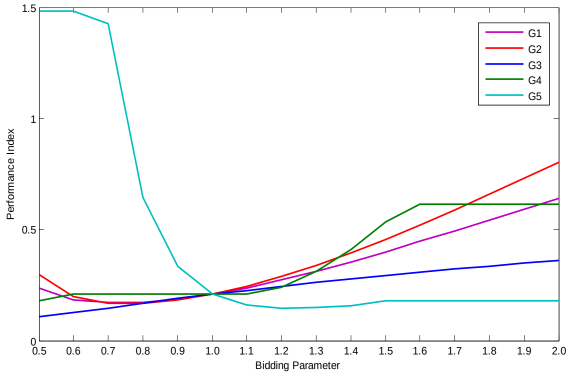

Fig. 1. Performance Index vs. Bidding Parameter

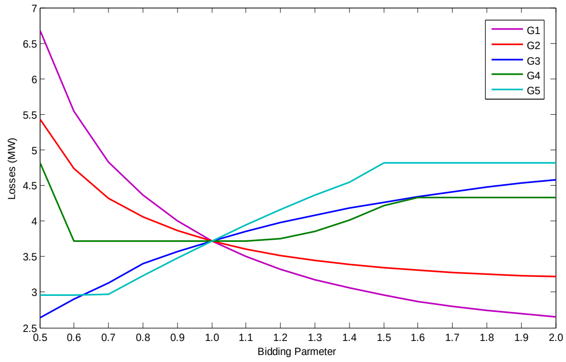

Fig. 2. Transmission Losses vs. Bidding Parameter

3) *ATC Calculation without Uncertainties*

In this section, the ATC values between selected source/sink pairs were determined. The results for base case i.e. peak loading hour without line outages are given in Table–V.

4) *ATC Calculation with Uncertainties*

In this section the following uncertainties are incorporated simultaneously to the base case and results given in Tables VI – VIII respectively.

a) Outage of Line 7 – 9
b) Outage of Generator 4
c) EFD of 0.2 for peak demand

TABLE V: ATC VALUES WITHOUT LINE OUTAGE

Source/ Sink	ATC (MW)	Losses (MW)	PI	LSF	Limiting Factor
1 – 12	33.184	6.1555	1.4124	6.44	Line 6 - 12
2 – 12	33.184	6.1555	1.4124	6.44	Line 6 - 12
3 – 12	33.306	4.6994	1.3466	6.46	Line 6 - 12
6 – 12	0	4.5294	0.5932	1.00	Pg,max
8 – 12	24.827	4.4046	1.6870	5.07	Line 7 – 8

TABLE VI: ATC VALUES WITH LINE 7- 9 AS UNDER OUTAGE

Source/ Sink	ATC (MW)	Losses (MW)	PI	LSF	Limiting Factor
1 – 12	30.866	6.9505	1.8450	6.06	Line 6 - 12
2 – 12	30.866	6.5209	1.8521	6.06	Line 6 - 12
3 – 12	30.927	5.1514	1.7790	6.07	Line 6 - 12
6 – 12	0	4.5294	0.5932	1.00	Pg,max
8 – 12	16.348	4.7596	1.9778	3.68	Line 4 – 7

TABLE VII: ATC Values with Line 7 – 9 & Generator 4 as Outages

Source/ Sink	ATC (MW)	Losses (MW)	PI	LSF	Limiting Factor
1 – 12	13.054	7.3299	1.7606	3.14	Line 5 - 6
2 – 12	13.054	7.0180	1.7622	3.14	Line 5 - 6
3 – 12	13.146	6.3520	1.7092	3.155	Line 5 - 6
6 – 12	0	6.2040	1.0146	1.00	Pg,max
8 – 12	13.481	6.4630	2.6126	3.21	Line 7 – 8

TABLE VIII: ATC VALUES WITH LINE 7 – 9, GENERATOR 4 AS OUTAGES & EFD=0.2

Source/ Sink	LC (MW)	Losses (MW)	PI	LSF	Limiting Factor
1 – 12	-3.133	8.446	2.8748	0.572	Line 5 - 6
2 – 12	-3.140	8.5281	2.8742	0.571	Line 5 - 6
3 – 12	-3.177	8.7420	2.8986	0.566	Line 5 - 6
6 – 12	-10.26	7.7980	2.7620	0.967	Line 5 - 6
8 – 12	-3.411	8.682	2.5567	0.534	Line 5 - 6

From the results obtained in Table–VIII, the system is subjected to congestion at its initial stage. So the ISO will not permit any transactions. And the stress relief is done with load curtailment. We have decreased the load at sink bus and generation at source bus. This method is successfully results in congestion–free state expect for transaction between buses 6 to 12. At this situation, we have reduced the load at all the buses. There

5) *ATC Calculation with Uncertainties and GENCOs' Bidding Parameter Change*

We have imposed the bidding parameter change by each GENCO for the results obtained Table–VIII. From the Fig. 1, it is observable that the GENCO–5 is creating more stress with its bidding parameter value less than 1. Similarly, remaining GENCOs are in the range of beyond 1 creating stress. The results for various GENCOs bidding parameter value (GN_BP) with contingencies i.e. line 7–9 and Generator–4 as well as EFD = –0.2 are considered for the peak load. The results are given in Table–IX.

TABLE IX: ATC VALUES WITH BIDDING PARAMETER CHANGE

BP	Source/ Sink	ATC (MW)	Losses (MW)	PI	LSF	Limiting Factor
G4_ 2.0	1 – 12	28.353	5.537	1.8819	6.81	Line 5 – 6
G2_ 0.5	2 – 12	28.304	6.771	1.9844	6.80	Line 5 – 6
G3_ 1.2	3 – 12	28.255	5.238	1.7267	6.79	Line 5 – 6
G1_ 1.5	6 – 12	0	3.331	0.3762	1.00	Pg,min
G5_ 0.8	8 – 12	11.663	3.606	1.9387	3.39	Line 4 – 7

The results are clearly indicating that the bidding parameter change also causes to alter the ATC value. Similarly, the contingency considerations are also moderating the ATC value. So it is worthwhile to quantify the uncertainties in the system while calculating the ATC value since its going to change the competition as well as system operation state.

6) *Determination of voltage at sink bus using GCF method*

While load increment is continuing, the voltage at bus-12 became very drooping. At loading factor of 33.96, the NR method failed to converge. So this value is considered as critical loading point. Our interest is to trace out the voltage at bus-12 for the load increment of 11.663 MW using GCF approach. The coefficients of the curve are as follows:

p1 = -7.1348e-006, p2 = -0.0014286, p3 = 1.0652.

The actual voltage for the loading of 16.543 MW is 1.043 pu. The same value is traced and can observe in the Fig. 3.

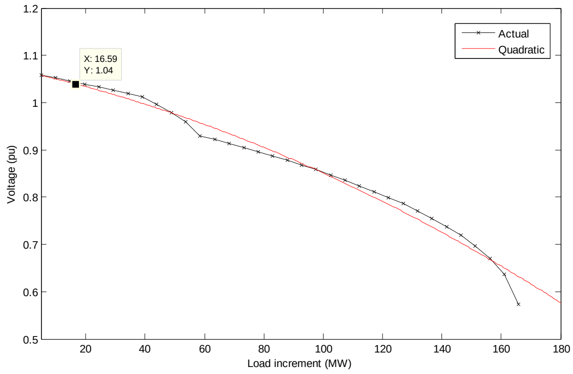

Fig. 3. PV curve at Bus-12

VI. Conclusions

This paper reviews the influence of different uncertainties on the ATC value. In addition to the general contingencies, the stress due to strategic bidding or trading schemes by GENCOs in the competitive market is also modeled and considered. The ATC value between a specified seller bus and buyer bus can vary significantly with the change in bid since it causes to alter the schedule as a result system operating state. The higher value of bidding parameter by a GENCO causes to allocate lower schedule at that generator and ATC value to any bus from that source is increased. Similarly the lower value of bidding parameter results the allotment of higher schedule and so lessening the ATC value from that source. This study is not explored the unit commitment problem during generator outage condition and market economic issues when system is insecure due to congestion during normal/contingency case. This theme will include in the further study of ATC enhancement with optimal FACTS device installation at optimal location.

Appendix – A

Generator Cost Coefficients & MW Limits

Gen #	a_p	b_p	c_p	$P_{G,p}^{\min}$	$P_{G,p}^{\max}$
1	0.0200	2.00	0	10	250
2	0.0175	1.75	0	10	200
3	0.0625	1.00	0	05	065
4	0.0083	3.25	0	05	050
5	0.0250	3.00	0	05	060

APPENDIX - B

TEST SYSTEM LINE LIMITS IN MVA

Sb	Eb	MVA	Sb	Eb	MVA	Sb	Eb	MVA
1	2	200	4	7	50	7	9	60
1	5	110	4	9	50	9	10	50
2	3	110	5	6	70	9	14	50
2	4	80	6	11	30	10	11	50
2	5	70	6	12	30	12	13	50
3	4	50	6	13	50	13	14	50
4	5	100	7	8	60			

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