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Contingency Ranking for Combined Pool/Bilateral Market

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ABSTRACT

This paper proposes novel techniques for including contingencies in combined pool/bilateral dispatch based on continuation power flow for OPF based electricity market computations and for the estimation of a "System-wide" Available Transfer Capability (SATC). The OPF problem formulation includes voltage stability constraints and a loading parameter in order to ensure a proper stability margin for the market solution. Two approaches are proposed: The first technique is by considering of power system contingencies based on the effects of them on Mega Watt Margin (MWM) and maximum loading point is focused in order to analyze the static voltage stability using continuation power flow method and second approach computes an SATC value based on an N-1 contingency criterion for an initial operating condition. By using this approach we solves a reduced number of OPF problems associated with worst contingency cases according to continuation power flow those having lowest SATC value. The study has been carried out on modified IEEE 14 Bus system using Mat lab and results are presented.

***Keywords*: *Available transfer capability, Continuation power flow, Electricity market, N-1 contingency criteria, optimal power flow, Static voltage stability*.**

I. INRTODUCTION

The electric power industry today is under restructuring in response to changes in the law, technology, markets and competitive pressures. Once the primary domain of large vertically integrated utilities was to provide power at regulated rates, the industry now includes companies selling "unbundled" power at rates set by competitive markets. In this environment, more competition will mean lower rates for customers.

Full deregulation is a dynamic concept and bringing radical changes in power system area. The primary objective of a fully deregulated system is to provide customers their choices of utilities. Any electric power generating utility or independent power producer (IPP) would be allowed to enter in a electric power bilateral contract with any customer in a deregulated power system. Allowing generators or IPP to contract directly with customers creates competition on both sides of the transaction. Two different concepts are playing important role in the process of implementation of deregulation is power system area. They are

- Power pool
- Bilateral contracts

Power pool - This is the most common form of market at present due to its simple nature. The generating utilities or IPP and customers both bid for buying and selling power at the power pool. Power pool conducts different types of auction: day a head market, hour a head market, real time market etc.

Bilateral contracts - Generating utilities and customers contract each other for selling and buying power. The seller arranges the transportation of the contracted power over the transmission network. The concept of bilateral contracts allows the customers and generating plants to work according to their policy and does not make them dependent on the everyday bid like the ones in a power pool system.

This paper focuses on combined pool/bilateral markets and proposes a method for the proper inclusion of contingencies and stability constraints through the use of continuation power flow and optimal power flow. As the market participants are increased electricity consumptions are also increased. Electricity consumption increasing affects power system complexity and system works in near instability limit attention to high consumption. When a crisis, regardless its reason, occurs in a power system, voltage drops in a specified bus intensively until leads all the system to instability that yields to voltage collapse. There are two major problems analyzing static voltage stability:

1) Maximum loading point (MLP)
2) Mega Watt Margin (MWM).

For an ideal condition, when system does not experience an event and all components work correctly in system, system can provide maximum loading point and so its corresponding maximum mega watt margin. So to analyze how much power system is utilized safe, it needs to simulate possible contingencies for power system and network performance to be considered for each event. Surveying contingencies to analysis static voltage stability, contingencies ranking are among necessary aspects of voltage safety. Ranking all possible contingencies based on their impact on the system voltage profile will help the operators in choosing the most suitable remedial actions before the system moves toward voltage collapse [1]. In [2], surveying possible contingencies with ranking according to line FVSI indicator is carried out. The method of ranking the possible contingency based on right eigenvector and branch parameter especially in [3] is given. Appearing the artificial intelligence, possible contingency ranking is done based on neural networks [4]-[6], fuzzy logic [7], [8] and genetic algorithm [9]. In this paper applying continuation power flow (CPF) that is based on reformulation of load flow equations applying a continuum parameter, calculating MLP and its corresponding mega watt margin decrease percent in each contingency, we set to ranking of possible contingencies based on the severity of their effect on static voltage collapse.

This paper uses an approach similar to [10], where the authors proposed a technique to account for system security through the use of voltage stability based constraints, and to provide an estimation of the system congestion, through the value of a "System-wide" Available Transfer Capability (SATC) as proposed in [11]. The paper is organized as follows: section 2 presents the necessary and preliminary parts of background material on static voltage stability, the definition of SATC and the proposed contingency ranking method and its corresponding flowchart are also provided. Section 3 discusses a novel technique to account for contingencies in the OPF problem; with particular emphasis on their application to OPF based electricity market models. The applications of the proposed techniques are illustrated in section 4 for a modified IEEE 14 bus system. Finally section 5 discusses the main contributions of this paper.

II. STATIC VOLTAGE STABILITY AND SURVEYING POSSIBLE CONTINGENCIES

A power system could utilize in safe manner when the occurrence of each possible contingency can not to exit system from normal work. Power system works in abnormal manner that variables exit from their allowed limit or the equilibrium between generation and consumption of energy spoils. Each event in power system would change the configuration of network that itself results in contraction of $\lambda - V$ curve and so decrease of MLP and its corresponding MWM. So for an ideal condition when system does not experience a contingency and all components work correctly, system can prepare MLP and Maximum Mega Watt Margin (MMWM). In a power system we encounter with too many contingencies that may results in overload in some of lines and/or bus voltages deviation from their allowed limit so that the position of the weakest bus may change. Figure 1 shows $\lambda - V$ curve with MLP and Megawatt margin in appearing contingencies.

The system may be operating at a stable equilibrium point but a contingency at maximum loading point may land unstable region or where there are no solutions to the system equations. The main reason for low voltage profile for some contingency and therefore smaller MWM is the insufficient reactive power in the vicinity of the low voltage buses [12]-[14]. There are some severities contingencies with very low loading that are a small function of maximum loading, while for some other contingencies, the loading margin is near to its maximum. Contingencies ranking that are considered as necessary aspects of static voltage stability analysis, we can identify more critical contingencies to create preventive and improving strategies to avoid static voltage instability that occurs because of this sever contingency.

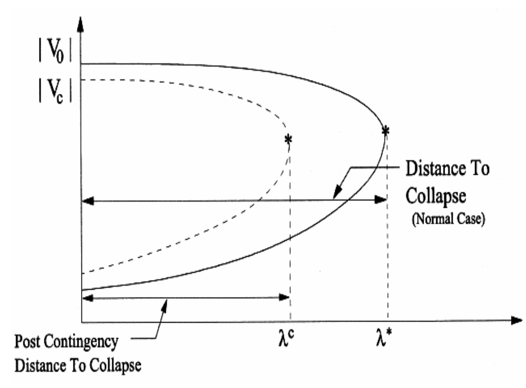


Fig.1: Voltage Collapse Point at Pre-Contingency and Post-Contingency.

A. System available transfer capability

The Available Transfer Capability (ATC), as defined by NERC, is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses [15]. This basic concept is typically associated with area interchange limits used, for example, in markets for transmission rights. In [11], a "System-wide" ATC (SATC) is proposed to extend the ATC concept to a system domain, as follows:

$$SATC = STTC - SETC - STRM \qquad (1)$$

Where

$$STTC = \min\,(P_{\max, I_{\lim}}, P_{\max, V_{\lim}}, P_{\max, S_{\lim}}) \qquad (2)$$

Represents the "System-wide" Total Transfer Capability, i.e. the maximum power that the system can deliver given the security constraints denoted by thermal limits ($I_{\lim}$), voltage limits ($V_{\lim}$) and stability limits ($S_{\lim}$) based on an N-1 contingency criterion. SETC stands for the "System-wide" Existing Transmission Commitments, and STRM is the "System-wide" Transmission Reliability Margin, which is meant to account for uncertainties in system operations. In this paper, the STTC is estimated based on the loading parameter $\lambda_{\max}$, as follows:

$$STTC = (1 + \lambda_{\max})\, T \qquad (3)$$

Where T ($T = \sum_i P_{D,i}$) represents the total transaction level of the system. The SETC is defined as the actual power consumed by loads, i.e. SETC = T, and the STRM is assumed to be a fixed quantity, i.e. STRM = K, where K is a given MW value used to represent contingencies that are not being considered during the STTC computations (e.g. N-2 contingency criteria). Thus the SATC for the continuation power flow can be defined as

$$SATC = \lambda_{\max} T - K \qquad (4)$$

B. Contingency ranking with continuation power flow method

As discussed in pervious section, contingencies ranking are considered as major aspects in surveying contingencies in power system. Processing to contingencies ranking, first we calculate the variables of power system using an analytical method for each event and then the severity of effect in each event are calculated based on an performance indicator that is function of these variables. Figure 2 shows the flowchart of ranking for contingencies. Attention to figure, appearing each contingency (like line outages and/or generation unit outages), the MLP and its corresponding MWM decrease percent would be calculated by continuation power flow method. Arranging MLP as ascending and its corresponding MWM decrease percent as descending, contingencies with lower MLP and higher MWM decrease percent set in higher ranks. MMWM and MWM calculate for system as:

$$MMWM = P_{base,\max} \qquad (5)$$

$$MWM = P_{i+1\max} \qquad (6)$$

Where $P_{base,\max}$ is maximum load active power corresponding with MLP under normal condition and $P_{i+1\max}$ is maximum load active power corresponding with MLP under contingency condition.

The MWM decrease percent is also calculated based on this:

$$\text{MWM decrease percent} = 100 \times [1-(MWM/MMWM)] \qquad (7)$$

In power systems, the numbers of contingencies is dependent the number the elements exposed to failure in the system.

III. CONTINGENCY IN POOL /BILATERAL MARKET

In competitive electricity markets, loads are supplied through a mix of prescheduled firm bilateral contracts and centrally dispatched pool generation. In a mixed pool + bilateral market total power generation p_g is then decomposed into the sum of the following components.

$$P_g = P_g^p + P_g^b \qquad (8)$$

Where P_g is a vector of total real power generation.

P_g^p, P_g^b is a vector of total real power generation for power pool or bilateral transactions.

If a generator has more than one bilateral contract, the total amount of power the generator has to produce could be expressed as

$$P_{gi}^b = \sum_{j=1}^{n} GD_{ij} \qquad (9)$$

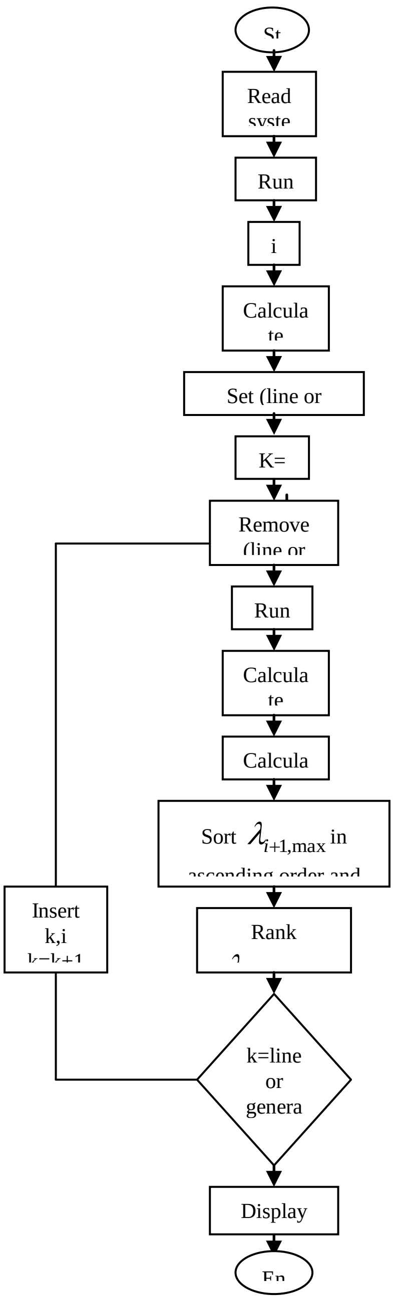
Where GD = {GD_{ij} , i = 1,..., n ; j = 1, ..., n} is the matrix of bilateral contracts delivered at the loads (buses j) from the generators (buses i).

Similarly the total real power demands P_d is decomposed into the sum of the following components.

$$P_d = P_d^p + P_d^b \tag{10}$$

Where P_d is vector of total real power demand.

P_d^p & P_d^b is a vector of real power demand for power pool or bilateral transaction.



On the other hand if one customer has several bilateral contracts with generators, the total power delivered. From those generators could be expressed as

$$P_{dj}^b = \sum_{i=1}^{n} GD_{ij} \tag{11}$$

Note that the component P_g^p supplies both the pool demand P_d^p as well as any transmission losses and congestion re-dispatch due to the combined effect of pool and bilateral demand. In other words, the bilateral generation contracts do not include loss supply, this function being the sole responsibility of the pool.

A. VSC-OPF in pool /bilateral market

The Optimal Power Flow (OPF) of the system with bilateral transactions can be stated as

$$\min_{p_g Q_g} \sum_{i\in G} C(P_{gi}) \tag{12}$$

$$V_{\min} \le V \le V_{\max} \qquad \text{V security limit}$$

$$Q_{G\min} \le Q_G \le Q_{G\max} \qquad \text{Gen Q limit}$$

$$\lambda_{\min} \le \lambda \le \lambda_{\max}$$

$$\left(p_{g,} Q_g\right) \in S,$$

Subject to $\quad P_g \ge P_g^b,$

Where the objective function to be minimized is total generation costs obtained from bidding prices of participated generators, and S is the set of necessary constraints, such as power balanced equations and system operating limits. The inequality constraint, $Pg \ge P_g^b$, is an additional constraint indicating that generators participating in bilateral transactions must generate no less than the amount promised in their bilateral contracts despite of their cost functions. If this constraint is neglected, OPF may yield optimal results that do not agree with bilateral contracts.

The loading margin $\lambda_{\max}$ is also included in the objective function through a properly scaled weighting factor k to guarantee the required maximum loading conditions (k > 0 and k < 1 to avoid affecting market solutions [16]). This parameter is bounded within minimum and maximum limits, respectively, to ensure a minimum security margin in all operating conditions and to avoid "excessive" levels of security. Observe that the higher the value of $\lambda_{\max}$, the more "congested" the solution for the

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system would be. An improper choice of $\lambda_{\max}$ may result in an unfeasible OPF problem if a voltage stability limit (collapse point) corresponding to a system singularity (saddle-node bifurcation) or a given system controller limit like generator reactive power limits (limit-induced bifurcation) is encountered [17, 18]. For the current system equations f and the "critical" system equations $\lambda_{\max}$, the generator and load powers are defined as follows:

$$P_{g,\max} = (P_g^p + P_g^b)\,\lambda_{\max} \qquad (13)$$

$$P_{d,\max} = (P_d^p + P_d^b)\,(1+\lambda_{\max}) \qquad (14)$$

$$Q_{d,\max} = (Q_d^p + Q_d^b)\,(1+\lambda_{\max}) \qquad (15)$$

Where $P_{g,\max}$, $P_{d,\max}$ and $Q_{d,\max}$ stand for maximum generator and maximum active and reactive load powers under loading margin condition $\lambda_{\max}$. It is assumed that the losses associated with the loading level defined by $\lambda_{\max}$ are distributed among all generators; other possible mechanisms to handle these particular losses could be implemented, but they are beyond the main interest of the present paper.

B. Continuation power flow for N-1 contingency

The solution of the continuation power flow for N-1 contingency is used as the initial condition for the technique proposed here to account for an N-1 contingency criterion in electricity markets based on this type of OPF approach. Contingencies are included in continuation power flow by taking out the selected lines when formulating the "critical" power flow equations, thus ensuring that the current solution of the OPF problem is feasible also for the given contingency. Although one could solve one OPF for the outage of each line of the system, this would result in a lengthy process for realistic size networks. The techniques proposed in this paper address the problem of efficiently determining the contingencies which cause the worst effects on the system, i.e. the lowest SATC values, based on the continuation power flow analysis, in the OPF-based market solutions. This method is basically composed of two basic steps.

(1) An N-1 contingency criterion is performed for determining the most critical line outage based on a continuation power flow analysis, using as generator and loading directions the supply and demand bids P_s and P_D determined from the loading margin solution. For the continuation power flow computations, system controls and limits are all considered to properly determine limit conditions due to voltage stability, thermal and/or bus voltage limits.

(2) The line outage that causes the minimum SATC is selected and the power flow equations are modified by taking out this critical line for the solution of the next OPF problem. Observe that the OPF-based solution of the power flow equations and its associated SATC generally differ from the corresponding values obtained with the continuation power flow, since in the OPF problem control variables, such as generator voltages and reactive powers are modified in order to minimize costs and maximize the loading margin $\lambda_{\max}$ for the given contingency.

When removing a line in equations, it is necessary to consider the system effects of a line outage in order to avoid unfeasible conditions. For example, a line outage may cause the original grid to separate into two subsystems, i.e. islanding; in this case, the smallest island may be discarded, or just consider the associated contingency as unfeasible for the given operating conditions.

IV. NUMERICAL EXAMPLE

The study on pool + bilateral transactions is done on an IEEE 14 bus system proposed by MATPOWER with additional bilateral transactions [19]. The optimal power flow (OPF) of the test system is obtained through a program developed by MATPOWER.

There are three bilateral transactions. The details of the transactions are as follows: -

T1: Injection of 20 MW at bus 1 and removal at bus 5.

T2: Injection of 20 MW at bus 2 and removal at bus 14.

T3: Injection of 20 MW at bus 3 and removal at bus 1.

To analyze of static voltage stability to survey contingencies of power system (like the line outages and/or generation unit outages) the continuation power flow for normal system manner is done that all generation units and lines are in the network and in fact no contingencies has occurred in system. Maximum Loading Point is $\lambda_{\max}$ = 1.8. Also load active powers are in base and maximum cases are P_{base} = 334.125MW and $P_{base,\max}$ = 1168.69MW respectively. The weakest bus also is identified bus14 with voltage 0.637P.U.

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A. Single generator unit outages with CPF method

Table I shows the results of single generation units outages applying continuation power flow. As is shown in generation unit outages connected to bus 3 and 6 that loading margin is same for both the generators but total generation capacity is different. Similarly for generation unit outages connected to bus 2 and 8 the loading margin is same for both the generators but total generation capacity is different. Note that in continuation power flow the generation unit connected to bus 1 that is known as slack bus does not exit from network.

Table I: The result of single generation unit outage

Generation unit outage	$\lambda_{\max}$	$P_{G,\max}$	$P_{D,\max}$
Bus 2	0.4	427.2	446.60
Bus 3	0.3	429	414.7
Bus 6	0.3	425.6	414.7
Bus 8	0.4	460.97	446.60

The result of calculation of MWM and SATC or contingencies of generation unit outages is shown in table II. Contingency with lowest SATC and MLP and highest MWM decrease percent are in higher rank in table. In fact, these severe contingencies can cause to lose system stability and preparing insufficient power to avoid static voltage collapse. Attention to table II, the generation unit outage connected to bus 3 and 6 with $\lambda_{\max}$ = 0.3 and MWM decrease percent 18.75% are identified as the most critical contingency between contingencies of other generation unit outages. So in table put in higher rank. As so contingencies of generation unit outage connected to buses 2 and 8 are in lower ranks in table. Figure 2 and 3 show MWM and SATC decrease percent in single generation unit outages.

Table II: The result of MWM(%) for single generation unit outage

Generation unit outage	SATC	MWM (%)	Rank
Bus 3	124.41	18.75	1
Bus 6	124.41	18.75	2
Bus 2	178.64	12.5	3
Bus 8	178.64	12.5	4

B. Single line outages with CPF method

Results of single line outages applying continuation power flow are shown in table III.

Table III: Result of single line outages

Line outage	$P_{G,\max}$	$P_{D,\max}$	$\lambda_{\max}$
Line 1	475.10	382.8	0.2
Line 2	1268.95	829.4	1.6
Line 3	1104.69	861.3	1.7
Line 4	1206.20	893.2	1.8
Line 5	860.0	638	1.0
Line 6	1083	797.5	1.5
Line 7	1010.00	797.5	1.5
Line 8	1039	797.5	1.5
Line 9	1111	861.3	1.7
Line 10	600	510	0.6
Line 11	994	797	1.5
Line 12	1113	861	1.7
Line 13	827	670	1.1
Line 14	416	383	0.2
Line 15	759	638	1.0
Line 16	375.036	350.90	0.1
Line 17	370.85	344.52	0.08
Line 18	1052	829	1.6
Line 19	1178	893	1.8
Line 20	658	574	0.8

The outage of line 17 connected to bus 9 to 14 has lowest MLP 0.08 that in this manner line 17 is identified as the weakest bus. It is also observed that outage of line 16 and 1 connected to bus 9 to 10 and 1to 2 has lowest MLP of 0.1 and 0.2. The results of calculated MWM and SATC for contingencies of line outages are shown in table IV. Attention to table IV, outages of lines 17, 16, 01 and 14 are considered as critical lines and are in higher ranks in table.

The outage of Line 17 with $\lambda_{\max}$=0.08 and MWM decrease percent 61.43% is identified as the most critical line compare to other line outages. Lines 3, 4, 9, 12 and 19 with higher loading point and lower MWM decrease percent are in lower ranks in table. The outage of line 4 with MWM decrease percent 00 % is considered as contingency that has not too much effect on static voltage instability. Fig 4 and 5 show MWM decrease percent and SATC in outage of single line.

Table IV: Contingency ranking for single line outages

Rank	Line outage	SATC	MWM decrease (%)
1	17	27.6	61.43
2	16	35.1	60.70
3	01	76.6	57.14
4	14	76.6	57.12
5	10	306	42.90
6	20	459	35.74
7	05	638	28.57
8	15	638	28.57
9	13	737	24.98
10	11	1195.5	10.77
11	07	1196.3	10.71
12	08	1196.3	10.71
13	06	1196.3	10.71
14	18	1326.4	7.18
15	02	1327	7.14
16	12	1463.7	3.60
17	09	1464.2	3.57
18	03	1464.2	3.57
19	19	1607.4	0.022
20	04	1607.8	0

C. Contingency analysis in VSC OPF market model

In this section, the VSC-OPF problem and the proposed techniques to account for contingencies are applied to a modified IEEE 14bus system. The results of the optimization techniques are also discussed to observe the effect of the proposed method on NCPs and system security, which is represented here through the SATC. All the results discussed here were obtained by using Matlab.

Table V depicts the initial solution of the VSC-OPF problem (12) showing a high total transaction level T with respect to the maximum power limits of all bids, and NCPs, indicating that system constraints, and in particular active power flow limits, effect the market solution. For the sake of comparison, this table also depicts the value of the SATC obtained for this particular operating condition that is under no contingency condition. Table V also shows the payment given to the Independent Market Operator (referred to as Pay_{IMO}), which is computed as the difference between demand and supply payments as follows:

$$Pay_{IMO} = \sum_i C_{Si} P_{Gi} - \sum_i C_{Di} P_{Di} \qquad (16)$$

Where C_{Si} and C_{Di} are vectors of supply and demand bids in \$/MWh, respectively and P_{Gi} and P_{Di} represent bounded supply and demand power bids in MW.

Table V: VSC-OPF without contingencies (λ=1.5)

participant	V(P.U.)	NCP($/MWh)	P_o (MW)	Pay($/h)
GENCO 1	1.06	38.46	214.52	8250.87
GENCO 2	1.04	40.13	40.27	1616.03
GENCO 3	1.03	41.95	97.53	4091.38
GENCO 4	1.04	41.65	82.79	3448.20
GENCO 5	1.05	41.73	86.43	3606.72
ESCO 1	1.01	42.12	71.7	3019.72
ESCO 2	1.01	41.69	41.40	1725.55
ESCO 3	1.02	42.14	00	00
ESCO 4	1.01	42.45	44.25	1878.41
ESCO 5	1.00	42.74	13.50	576.99
ESCO 6	1.01	42.43	5.25	222.76
ESCO 7	0.98	45.71	39.15	1789.55
ESCO 8	0.99	44.31	20.25	897.28
ESCO 9	0.94	47.51	52.35	2487.15
TOTALS	T=287.85 MW , SATC= 431.77 MW Pay_{IMO} =8475.79 $/h			

Table VI: VSC-OPF with contingency on Generators

Parameter	GEN CO 1	GEN CO 2	GEN CO 3	GEN CO 4	GEN CO 5
loading margin $\lambda_{\max}$	1.2	1.3	1.2	1.2	1.3
Total transaction (MW)	230.28	249.47	230.28	230.28	249.47
Pay_{IMO} (\$/h)	7143.65	7174.02	6902.30	6618.45	7279.94
SATC (MW)	276.34	324.31	276.34	276.34	324.22
MWM (%)	21.12	13.53	19.36	19.61	12.78

It is also observed that outage of generator 4 has most effect on the system as the payment given to the Independent Market Operator Pay_{IMO} is low as compare to other generators under their respective loading margin condition. On the same time MWM decrease percent for generator 4 is also high as compare to other generators. From these data of generator outages it can be concluded that outage of generator 1 is having most worst effect on the system since its outage having lowest SATC value and high MWM decrease percent.

It is possible to obtain the solution of VSC-OPF for the outage of each line of the system, but this would result in a lengthy process for realistic size networks. The techniques proposed in this paper address the problem of efficiently determining the contingencies which cause the worst effects on the system, i.e. the lowest SATC values, based on the continuation power flow analysis, in the OPF-based market solutions. From table IV it is clear that outage of line 17,16,1 and 14 causes the worst effects on the system since they have lowest SATC value hence we obtain VSC-OPF solution only for these line outages. Table VII show the result of VSC-OPF solution for outage of line 17,16,1 and 14 respectively.

Table VII: VSC-OPF with contingency on critical lines

Parameter	Line 17	Line 16	Line 1	Line 14
loading margin $\lambda_{\max}$	1.3	1.5	1.5	1.3
Total transaction(MW)	223.47	287.85	287.85	249.47
Pay_{IMO} (\$/h)	7308.75	8408.68	5843.05	7280.31
SATC (MW)	290.51	431.77	431.77	324.31
MWM (%)	22.36	0	0	13.33

Table VII depicts the final VSC-OPF results for the critical line 17,16,1 and 14 outage. The VSC-OPF solution of 16 and 1 presents practically the same total transaction level as provided by the solution without contingencies in Table VI, with 0% MWM decrease percent but with different Pay_{IMO} as expected, since the system is now optimized for the given critical contingency. Observe that the rescheduling of demand bids results also in slightly lower NCPs, as a consequence of including more precise security constraints, which in turn results in a lower Pay_{IMO} value as show in table VII with respect to the one obtained with the standard OPF problem (12) in Table VI. Table VII depicts the final solution obtained with a different inferior limit for the loading parameter, i.e. $\lambda_{\max}$ = 1.3. As expected, the lower maximum security margin leads to a lower T and, with lower SATC value as reported in Table VII, also NCPs are generally lower, which is due to the lower level of congestion of the current solution. Observe that a more secure solution leads to lower costs, because the demand model is assumed to be elastic; hence, higher stability margins lead to less congested, i.e. lower T, and cheaper optimal solutions. Notice that it is not reasonable to set high values for $\lambda_{\max}$, since the resulting security margin already takes into account the most severe contingency, and is thus a conservative estimation of the system stability level.

V. CONCLUSIONS

In this paper, two methods for including contingencies in a VSC-OPF-based market are proposed and tested on a modified IEEE 14 bus system with three transactions in combined pool/bilateral dispatch. Comparisons between the results obtained with the proposed techniques indicate that a proper representation of system security and a proper inclusion of contingencies result in improved transactions, higher security margins and lower prices. The two proposed techniques lead to similar solutions using different strategies. The first method tries to define the worst case contingency by computing MWM decrease percent, while the second approach determining the lowest SATC value whose magnitude indicate which line outages maximally affect the total transaction level and system security. The contingencies with lower loading point, higher MWM decrease percent and lower SATC value dedicates itself higher ranks. By using this approach we solves a reduced number of OPF problems associated with worst contingency cases according to continuation power flow those having lowest SATC value. So with identifying these critical contingencies, we can do works to create preventive and reforming strategies to avoid system static voltage collapse.

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