TRANSMISSION CONTRACT FOR RISK-HEDGING AND RELIABILITY IMPROVEMENT IN DEREGULATED POWER SYSTEM

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Abstract – In the present paper, the authors propose a new market scheme, transmission contract for risk-hedging and reliability improvement. The proposed transmission contract is a product of the agreements between Generation Company, Transmission System Operator, Distribution Company and large consumer through the market competitive mechanism conducted by Transmission System Operator. The objective of the proposed contract is to help market participants hedge their physical and financial risks in the deregulated power system. From the generator viewpoint, similar to bilateral contract and capacity market, the proposed scheme results in a certain income and reduces the uncertainty of share of demand in the spot market. From the consumer viewpoint, the proposed contract can hedge the risks caused by the volatility of the spot price. Furthermore, for the consumer, whose load needs high reliable electricity, the proposed contract gives a guaranty that his/her load will always be supplied or otherwise he/she will receive a compensation for the service interruption. Simulation is carried out using the modified IEEJ West 10-machine system to show the performance of the proposed contract.

Keywords: Deregulation, Monte Carlo Simulation, Reliability, Risk, Service Interruption, Transmission Contract, Transmission System Operator

1 INTRODUCTION

Deregulation of electric power industry has created a competitive open market environment. Deregulation involves the unbundling of electric utility services resulting in a disaggregating into generation, transmission and distribution. Responsibility of these operations is put on generation companies (GENCOs), transmission companies (TRANSCOs) and distribution companies (DISCOs) with a central coordinator, called an independent system operator (ISO), whose role is to balance supply and demand in the real time and to maintain the system reliability and security. In some markets, ISO and TRANSCOs have been included into one organization (for example, NGC of the England & Wales power pool), who acts as a market and transmission system operator. In contrast, in some markets, the responsibilities of ISO and TRANSCOs are separated [1, 2].

Before the deregulation, generation, transmission and distribution systems are operated by the same organization, who is obligated to prepare new generation and transmission facilities to meet demand in the future. The investment cost is recovered by the electricity price. This resulted in an investment that has no risk.

However, after the deregulation, there is no such kind of obligation. From the viewpoint of investors, they will decide on their own, according to their business expectations, whether they want to build a facility or not. The existence of risk aversion in the potential investors in new generation has become a very important problem nowadays. For instance, the investor may be afraid that the new generating unit will only generate for a few hours a year due to the uncertainty in share of demand. To make an incentive for new entrant generator, the provision of some additional income (e.g., a capacity payment) is needed. On the other hand, from the viewpoint of DISCO/large consumer, gaming, market power and transmission network topology can result in a very high electricity price especially in the spot market. Also, in some market, the responsibility for reserve corresponding to equipment unavailability is not clear; therefore the probability of interruption increases. According to these, DISCO and large consumer have to find the way to protect themselves against high prices and service interruptions. In other words, participants in the power markets face two types of risk: physical and financial risks. Physical risk refers to the possibility of having service to a consumer interrupted. Financial risk is derived from uncertainty about future prices.

Up until now, several methods have been employed to hedge these risks. These methods are price cap, capacity market, bilateral contract, financial transmission right (FTR), transmission congestion contract (TCC).

Price cap can help DISCO/large consumer avoids the risk from high spot price. However, it cannot provide a good economic signal for investment in the future.

The capacity market can provide a certain income for generator and make an incentive for new investment. However, from the viewpoint of consumer, he/she sees no real product in exchange for the capacity that he/she has to purchase. Besides, because each consumer has a different preferred reliability level; it is not fair if all consumers pay the same price for capacity.

Bilateral contract can help GENCO hedge the risk due to the uncertainty of share of demand in the spot market. At the same time, it also helps DISCO/large consumer hedge the risk from the volatility of price in the spot market. However, if the bilateral contract is only the agreement between GENCO and DISCO/large consumer, it can only reduce the financial risk and some parts of physical risk. Without additional cost to transmission service provider, there is no guarantee for power or compensation for service interruption when transmission line is unavailable or congested.

Financial Transmission Right or Transmission Congestion Contract helps DISCO/large consumer reduces the financial risk of high price caused by the congestion. However, the supply reliability is not considered.

A new market approach that integrates the functions of price cap, capacity market and bilateral contract has been presented in [3]. It results in a stabilization of the income of GENCO and provides a clear incentive for new generation investment. However, only the relation between GENCO and DISCO/large consumer has been mentioned while the relation between market participants and transmission network has been ignored.

In this paper, in addition to [3], the function of FTR/TCC and the relation between transmission system and market participants are taken into account. The proposed scheme is denoted as transmission contract for risk-hedging and reliability improvement in the deregulated power system. The objective of the proposed contract is to introduce a new market scheme that can reduce financial and physical risks of participants in the power market.

2 ELECTRICITY MARKET STUDIED

We assume that ISO and TRANSCO are integrated into one organization called Transmission System Operator (TSO). Under this scheme, TSO acts as a market and transmission system operator at the same time.

To simplify the problem, we assume that, there is no direct contract between GENCO and DISCO/large consumer. Without transmission contract, every transaction must be done in the spot market. It should be noted that the proposed contract can be applied to the market where the bilateral contract is exist.

For the spot market, generally it can be broadly classified into two types: nodal price and uniform price based markets. In this paper, the nodal price based spot market will be used. However, the proposed contract can be applied to uniform price based spot market without difficulty. To do this, we just only change the market clearing algorithm and the congestion management method, for example, the uplift in the former England and Wales electricity market [4]. Detail of the spot market clearing process can be described as follows.

2.1 Bidding Strategy of GENCO

In order to show the performance of the proposed transmission contract using the index, Expected Energy Not Supplied (EENS), we assume that there is only inelastic load in the market. As a result, only bidding from generation part is considered.

The bidding strategy of GENCO is modeled based on real strategy of GENCO in market in New England [5]. According to the historical data, the bidding can be divided into two parts. In the first part, GENCO bids based on the real marginal cost of the generating unit. Usually, this strategy is applied from 0 MW to about 80% of generator capacity. In the second part, GENCO

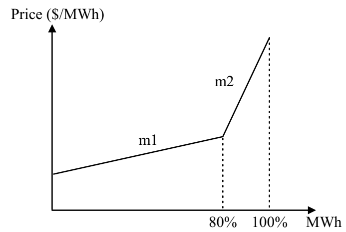

Figure 1: Bidding strategy of GENCO in the spot market

will bid extremely high for the rest of capacity. Bidding strategy can be showned as in Figure 1. Slopes *m1* and *m2* are used to represent the bidding strategies of the first and second parts, respectively.

2.2 Dispatched Power and Nodal Price Calculation

After receiving the bidding information from GENCO, TSO calculates the dispatched power of each generating unit by solving the optimization problem with the objective to maximize the social welfare subject to supply-demand balance and transmission line capacity constraints. However, because the demand is price inelastic. Maximizing the welfare is the same as minimizing the cost of production. This optimization problem can be shown mathematically as in (1) to (3).

$$\min \sum_{p=1}^{NG} \left(BP_p \cdot g_p \right) \tag{1}$$

$$\sum_{p=1}^{NG} g_p = D \tag{2}$$

$$LF_q \leq LF_{q\max} \quad , \quad q = 1,\dots,Q \tag{3}$$

where g_p and BP_p are the dispatched power and bid price of power from p-th generating unit, NG is the number of generating units, D is the demand, LF_q and LF_{qmax} are line flow and capacity of line q, respectively, Q is the number of transmission lines.

In this paper, DC power flow method is employed and the transmission loss is neglected. Linear Programming (LP) is used to solve the above optimization problem. The nodal price is determined from the Lagrange multipliers of equality and inequality constraints.

2.3 Redispatch process

If there is unavailability of generation and/or transmission facility, TSO will redispatch the outputs of generating unit and load. We assume that TSO has right to ask GENCO to produce more or less than the original dispatched power. However, TSO must compensate GENCO who is asked to produce less than the original dispatched power and pay additional cost (reserve cost) to GENCO who is asked to produce more than the original dispatched power. In contrast, GENCO whose unit is not available must pay penalty to TSO. The cost per MWh of compensation, reserve and penalty are assumed to be *sp*, *rp* and *sp*, respectively. Here, *sp* and *rp* are the spot price and reserve price, respectively.

On the other hand, for DISCO/large consumer whose load is curtailed due to facility unavailability, he/she will receive interruption compensation (η) from TSO.

The objective of redispatch is to minimize the curtailment and cost of redispatch (compensation/reserve to generator, income/payment of energy from/to generator/load, interruption compensation to load).

3 PROPOSED TRANSMISSION CONTRACT

3.1 Basic Concept

The revenue of TSO will come from transmission usage charge. TSO will use this revenue to keep the reliability of transmission network and protect consumer from service interruption at one level. In the spot market, TSO will treat all participants equally and by the same set of participation rules and standards. Therefore, the probability of outage depends only on the network topology and operating point of power system. However, some consumers have higher interruption cost load (premium load) compared with other consumers' load. Hence, they have to find a way to protect their loads, especially premium load from the interruption because the current uniform reliability is not sufficient for them.

In this paper, the authors propose a kind of contract conducted by TSO. The proposed contract provides choices for consumers to select their own reliability levels. It functions like reliability insurance to protect consumers from the physical risk or service interruption. Moreover, not only the physical risk, but also the proposed contract functions like price cap or FTR/TCC to protect consumer from the financial risk caused by gaming and/or transmission line congestion.

The participants in the contract are GENCO (supply-side participant), DISCO and large consumer (demand-side participant). The advantages of participant from the proposed contract can be summarized as follows.

For Demand-side participant

1. By joining the proposed contract, every time when the spot price is higher than the predefined strike price, the participant pays at the spot price, but receives the difference from TSO. Every time the spot price is lower than the strike price, the participant pays at the spot price. In other words, the proposed contract acts as a price cap which limits the price at which the participant purchases at the maximum value of strike price.

2. By joining the proposed contract, the participant will be protected from the service interruption or otherwise receive outage compensation caused by the unavailability of generation and/or transmission facility. This can be regarded as the insurance for reliability.

In exchange for these advantages, the demand-side participant has to pay special money (premium) to TSO. This premium is different from one to one depending on the required reliability level of individual participant.

For Supply-side participant

Similar to a bilateral contract, joining the proposed contract means that he/she can sell the energy during the validated period of the contract. This advantage reduces risk from the uncertainty of share of demand in the spot market. However, the price is limited at the strike price.

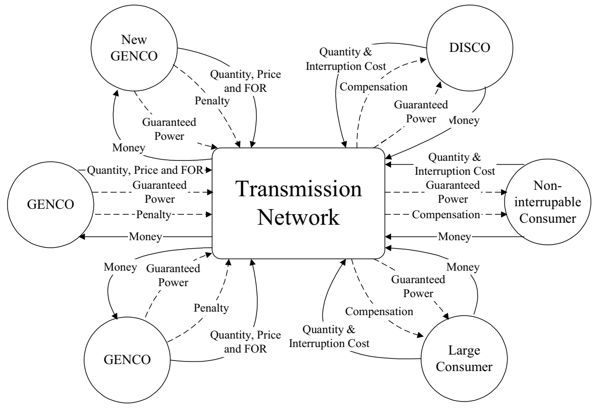

Figure 2: Relation between TSO and participants

Moreover, a special penalty (contract penalty) is applied to the participant, whose unit is not available during the actual delivery period. This contract penalty ($/MWh) is determined in advance by the TSO. Obviously, this penalty will strengthen generating capability to be available all the time and improves the system reliability. To compensate the opportunity loss of selling energy when the spot price is higher than the strike price and the penalty from the unavailability of generating unit, supply-side participant will receive a premium. This can be regarded as a capacity reservation payment which similar to capacity market (installed capacity market). It is a certain money that participant receives in advance before the actual transaction. Therefore, this provides an incentive for investment of new generating unit.

The proposed contract consists of two periods. The first one is the financial period which is started, for example 2 or 3 years, before the actual delivery of energy. In this period, TSO determines the premium based on the information, submitted by participants. Information consists of the premium bid from the supply-side participant, preferred outage compensation and participated quantity from demand-side participant. The second period is the physical delivery period. During this period, the supply-side participant must provide the amount of energy, written in the contract, all the time during the validated period. However, if he/she cannot produce power, he/she must pay the contract penalty to TSO. From the viewpoints of the demand-side participants, they will pay for energy by the price that is not higher than the strike price. Additionally, they will receive compensation every time when energy is not delivered to them. The relations between participants and TSO in the first and second periods are represented by the hard and broken lines in Figure 2, respectively.

3.2 Premium Determination Algorithm

Premium is classified into 2 types: premium of supply-side and premium of demand-side participants. Both of them are calculated in the first period of the contract.

Premium of Supply-side participant

Premium of supply-side participant is computed based on the auction mechanism where the transmission line capacity constraints are taken into account. This can be written mathematically as in (4) to (6).

$$\min \quad \sum_{i=1}^{N} \left(gpr_i \cdot G_i \right) \tag{4}$$

$$\sum_{i=1}^{N} G_i = \sum_{j=1}^{M} L_j \tag{5}$$

$$LF_q \le LF_{q\max} \quad , \quad q = 1, \ldots, Q \tag{6}$$

where gpr_i and G_i are the premium price per MW and amount of participated power of i-th supply-side participant. L_j is the amount of participated power of j-th demand-side participant, N and M are the number of supply-side and demand-side participants.

In this paper, LP is employed to solve this problem. Every successful supply-side bidder will receive premium equal to his/her bid.

For i-th supply-side participant, his/her premium bid consists of two parts: the first part is the forecasted opportunity loss when he/she succeeds in the auction and the spot price is higher than the strike price (*EOC*). The second part is the predicted contract penalty that he/she has to pay when he/she cannot provide energy according to the contract (*ESPEN*). If GENCO owns one generating unit, premium bid is calculated from

$$gpr_i = EOC_i + ESPEN_i \tag{7}$$

$$EOC_i = \int_{sp>s} (1 - FOR_i) \cdot (sp - s) dt \tag{8}$$

$$ESPEN_i = \int (FOR_i \cdot pen) dt \tag{9}$$

where FOR_i is the forced outage rate of generating unit of i-th participant, pen is the contract penalty that the participant must pay when his/her generating unit is out of service, s is the strike price, sp is the spot price.

If a supply-side participant owns more than one generating unit, a set of premium bid blocks should be submitted. The premium bid can be determined based on the capacity outage probability table (COPT) [6]. For i-th GENCO, the premium bid price of p-th block can be calculated from

$$gpr_{ip} = EOC_p + ESPEN_p \tag{10}$$

$$EOC_p = \frac{\sum_{l=1}^{L} \left(pr_l \cdot \int_{sp>s} (sp - s) \cdot \min(AC_l, P_p) dt \right)}{P_p} \tag{11}$$

$$ESPEN_p = \frac{\sum_{l=1}^{L} \left(pr_l \cdot \int pen \cdot \max(0, P_p - AC_l) dt \right)}{P_p} \tag{12}$$

where EOC_p, $ESPEN_p$ and P_p are the forecasted opportunity loss, predicted penalty and participated power of p-th block, respectively. L is the number of states from COPT, AC_l and pr_l are the available capacity and probability of stage l, respectively.

Premium of Demand-side participant

After the premium of supply-side participant has been determined, TSO will conduct Monte Carlo simulation taking into account facility availability and calculates the premium of demand-side participant. Calculation process is described step by step as follows:

1. Start from the first scenario $k = 1$

2. For each scenario, the bidding strategies *m1* and *m2* are randomly generated. According to the historical data [5], *m1* and *m2* are represented using Weibul and Normal distributions, respectively.

3. Spot market is cleared using method in Section 2.

4. Generation and transmission availabilities are randomly generated based on availability data.

5. If there is unavailability of generation and/or transmission facility, system will be dispatched. When there is transmission contract, the calculation method for GENCO compensation/reserve and interruption compensation is different from Section 2.3.

Suppose that the amount of participated power from i-th generator and j-th customer are G_i and L_j MW, respectively. One scenario (line's unavailability) causes changes of generator output ($\triangle g_i$) and curtailment of load ($\triangle l_j$) as shown in Figure 3. Here, g_{ri}, l_{rj}, g_{rinew} and l_{rjnew} are the operating point of generator and load before and after this scenario occurs, respectively.

For cases 3a and 3b, to maintain system security, TSO asks generator to reduce its output from g_{ri} to g_{rinew}. TSO must compensate GENCO, the difference between revenue of selling the power before and after the unavailability of line. The compensation for cases 3a and 3b are computed from (g_{ri} – G_i) * sp) + (G_i – g_{rinew}) * min(sp,s) and ($\triangle g_{ri}$ * sp), respectively.

In contrast, if TSO asks generator to produce more than the original scheduled output, TSO has to pay the cost of reserve ($\triangle g_{ri}$ * rp) to GENCO. In this paper, we assume that the rp = 2*sp.

On the other hand, the compensation for demand-side participants' outages for case 3d and 3e are calculated from $\triangle l_j$ * η_j and (l_{rj} – L_j) * η_j + (L_j – l_{rj} + $\triangle l_j$) * σ_j , respectively. Where η_j is the compensation for interruption in \$/MWh for load that is not in the contract, σ_j is the preferred interruption compensation of j-th demand-side participant.

Similar algorithm can be applied to solve the problem when the generation facility is unavailable.

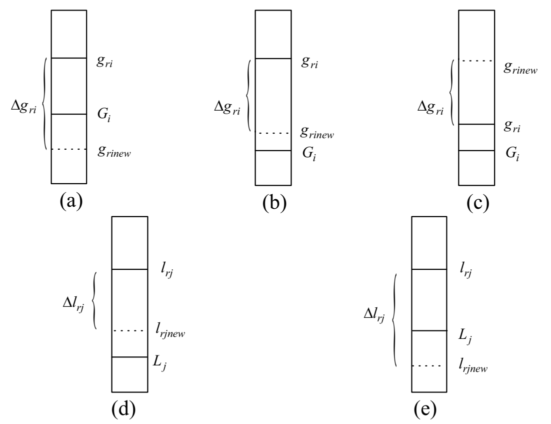

Figure 3: Redispatch process

Financial relations between TSO and participants during the redispatch process are summarized in Tables 1 and 2. Actually, there are many kinds of redispatch process in the real market. In this paper, a simple rule is used as one example. However, another kind of redispatch rule can be applied as well.

Table 1: Revenue per 1 MWh that GENCO receives from the redispatch process

	In the Spot Market	In the Contract
Dispatched Up	*rp*	*rp*
Dispatched Down	*sp*	min*(sp,s)*
Unavailable	*-sp*	*-pen*

Table 2: Compensation per 1 MWh that DISCO or large consumer receives from the redispatch process

	In the Spot Market	In the Contract
Interruption	η	σ

6. From step 5, SC_i, SE_i, $SPEN_i$, LE_j, $LCom_j$ and TRR are determined using (13) to (18)

$$SC_i = gpr_i \cdot G_i \tag{13}$$

$$SE_i = g_i \cdot \min(sp,s) \tag{14}$$

$$SPEN_i = G_i \cdot pen \tag{15}$$

$$LE_j = l_j \cdot \min(sp,s) \tag{16}$$

$$Lcom_j = EENS_j \cdot \sigma_j \tag{17}$$

$$TRR = RC + OC + SPEC - SPER - SPPEN - TCNC \tag{18}$$

where SC_i, SE_i and $SPEN_i$ are premium payment, energy payment and penalty of i-th supply-side participant, LE_j and $LCom_j$ are energy income and outage compensation of j-th demand-side participant, TRR is the additional cost of TSO from conducting the contract, RC and OC are reserve and opportunity loss compensation to generator, $SPEC$ and $SPER$ are energy payment and energy revenue of TSO to/from the spot market, $SPPEN$ is the penalty from generator in the spot market, $TCNC$ is the expected cost of TSO when there is no contract, g_i and l_j are amount of power that i-th supply-side participant provides and j-th demand-side participant consumes, respectively, $EENS_j$ is the expected energy not supplied of contract load of j-th demand-side participant.

7. The premium of demand-side participant (lpr) is determined by equalizing the expected revenue and the cost of TSO as follows:

$$E(RV) = E(TC) \tag{19}$$

$$E(RV) = \sum_{j=1}^{M}\left(LC_j + LE_j\right) + \sum_{i=1}^{N} SPEN_i \tag{20}$$

$$E(TC) = \sum_{j=1}^{M} LCom_j + \sum_{i=1}^{N}\left(SC_i + SE_i\right) + TRR \tag{21}$$

where RV and TC are revenue and cost from conducting the contract of TSO. LC_j is the premium income from j-th demand-side participant and can be represented as

$$LC_j = (L_j \cdot lpr_j) \tag{22}$$

The participant who submits high compensation for interruption needs high reliability. Therefore, this participant should pay premium higher than participant who prefers lower reliability level. The relation between preferred interruption compensation (σ) and the premium (lpr) when the generator/transmission is unavailable is shown in (23).

$$lpr_1 : lpr_2 : \ldots : lpr_M = \sigma_1 : \sigma_2 : \cdots : \sigma_M \tag{23}$$

8. Repeat from Step 2 to 7 until the number of scenarios is reached. The final premium is calculated from

$$lprj = \sum_{k=1}^{K}\left(lpr_{jk} \cdot \gamma_k\right) \tag{24}$$

where γ_k is the probability that scenario k occur, K is the number of scenarios. Obviously if every scenario has same probability, the final premium is the average premium from all scenarios.

Premium calculation flowchart is shown in Figure 4.

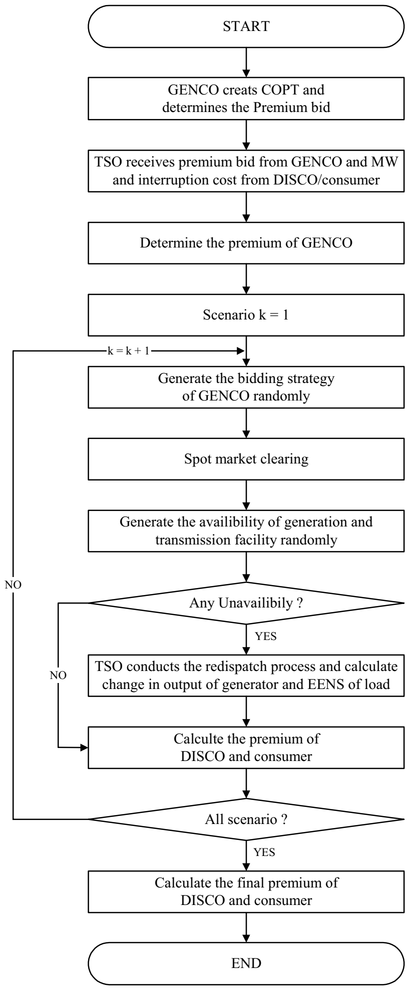

Figure 4: Premium determination flowchart

4 SIMULATION

The modified IEEJ West 10-machine system [7] in Figure 5 has been used for study. This system consists of 10 GENCOs (G1 to G10) and 17 DISCOs/large consumers (L1 to L17). The number of total generating units is 165. The number of transmission lines is 32. Generator and line data are shown in Tables 3 and 4.

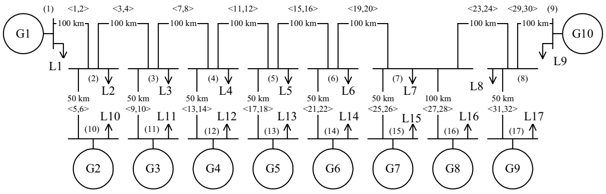

Figure 5: Modified IEEJ West 10-machine system

Table 3: Generating Unit Data

GENCO	Capacity (MW)	Number of Units	FOR
G1	1000	12	0.070
	750	2	0.090
G2	1000	9	0.075
G3	1000	9	0.080
G4	700	12	0.070
	200	3	0.100
G5	700	12	0.075
	200	3	0.080
G6	700	12	0.075
	200	3	0.070
G7	700	12	0.090
	200	3	0.060
G8	250	18	0.090
G9	700	12	0.065
	200	3	0.010
G10	700	35	0.075
	500	5	0.090

Table 4: Transmission Line Data

Line	Fr	To	x (p.u)	Capacity (MW)	Availability
1,2	1	2	0.0630	1500	0.99
3,4	2	3	0.0630	1500	0.99
5,6	2	10	0.0315	3000	0.99
7,8	3	4	0.0630	1500	0.99
9,10	3	11	0.0315	3000	0.99
11,12	4	5	0.0630	1500	0.99
13,14	4	12	0.0315	3000	0.99
15,16	5	6	0.0630	1500	0.99
17,18	5	13	0.0315	3000	0.99
19,20	6	7	0.0630	1500	0.99
21,22	6	14	0.0315	3000	0.99
23,24	7	8	0.0630	1500	0.99
25,26	7	15	0.0315	3000	0.99
27,28	7	16	0.0630	1500	0.99
29,30	8	9	0.0630	1500	0.99
31,32	8	17	0.0315	3000	0.99

The period of the contract is one year (8760 hours). DISCO/large consumer has 5 load patterns. The numbers of hours of all patterns are 2190, 2190, 2190, 2140 and 50 hours, respectively. For each pattern, suppose that 75 percent of loads are the premium loads and are participated in the proposed contract. The preferred outage compensations of L1 and L9 are $200/MWh, preferred interruption compensations of L2 to L8 are $180/MWh. And the preferred interruption compensations for the rest DISCOs/large consumers are $140/MWh. Similarly, assume that all GENCOs submit premium bids with the quantity up to 75 percent of their available capacities. However, we assume that GENCOs commit their generating units according to the load level. That means all 165 generating units are not available all the time. The available capacities of GENCOs and levels of load of DISCOs/large consumers are showed in Table 5. The first and second patterns have been computed based on the night-time load data, while

Table 5: Load and Available generation capacity (in MW)

Participant	Pattern 1	Pattern 2	Pattern 3	Pattern 4	Pattern 5
G1	8000	10000	12000	13500	13500
G2	6000	7000	9000	9000	9000
G3	6000	7000	9000	9000	9000
G4	4900	6300	9000	9000	9000
G5	4900	6300	9000	9000	9000
G6	4900	6300	9000	9000	9000
G7	4900	6300	9000	9000	9000
G8	3750	3750	4500	4500	4500
G9	6300	6300	9000	9000	9000
G10	16500	20700	23500	27000	27000
L1	3750	4500	8160	10200	12000
L2	1000	1200	2380	2975	3500
L3	1000	1200	2380	2975	3500
L4	1000	1200	2380	2975	3500
L5	1000	1200	2380	2975	3500
L6	1000	1200	2380	2975	3500
L7	1500	1800	3570	4462.5	5250
L8	1000	1200	2380	2975	3500
L9	16500	19800	19244	24055	28300
L10	2600	3120	3740	4675	5500
L11	2600	3120	3740	4675	5500
L12	2600	3120	3740	4675	5500
L13	2600	3120	3740	4675	5500
L14	2600	3120	3740	4675	5500
L15	2200	2640	3740	4675	5500
L16	1700	2040	1870	2337.5	2750
L17	2600	3120	3740	4675	5500

the third, fourth and fifth patterns have been computed based on the day-time load data. The fifth pattern is used here to represent the rare (but possible) case when the load is extremely high, for examples, when there is a special event or a very hot day in the mid-summer. The strike price and contract penalty are $60/MWh and $100/MWh, respectively. The outage compensation in the spot market (η) is zero.

For each supply-side participant, the algorithm in Section 3.2 can be used to calculate the premium bid. Here, for the example, we will show how G1 computes his/her premium bid for the load pattern 1. Assume that for load pattern 1, G1 has 8 generating units available. Every unit has 1000 MW capacity and the forced outage rate is 0.07. Assume that G1 submit the premium bid up to his/her 75% of available capacity (= 6000 MW in this case). Suppose that G1 expects that the number of hours that he/she can succeed in the auction and the spot price is higher than the strike price is 164 hours (from 2190 hours). Then, the algorithm in Section 3.2 is used to determine the premium bid. The premium bid prices and quantities of G1 are shown in Table 6. Premium bids of other GENCOs can be considered similarly.

On the other hand, Monte Carlo Simulation with 5000 scenarios has been used to determine the premium of demand-side participants. The final premiums of L1

Table 6: Premium bids of G1 for Load pattern 4

Block	Quantity (MW)	Price ($/MW)
1	1200	6569.62
2	1200	6570.13
3	1200	6570.28
4	1200	6620.91
5	1200	7140.59

and L9 are 43.26 thousand dollars per MW. The premiums of L2 to L8 are 38.93 thousand dollars per MW. And the premiums for the rest are 30.28 thousand dollars per MW. The simulation results with and without transmission contract are compared in Table 7. TC is the total consumption cost which is calculated from the energy cost, outage cost, outage compensation and premium cost. P-EENS and T-EENS are the EENS of premium and total loads, respectively.

From the simulation results, the overall cost can be reduced using the proposed contract. The energy cost is reduced because the proposed contract functions as a price cap while the outage cost is reduced because the proposed contract functions as reliability insurance.

If we consider P-EENS of L10 to L16, it seems like reliability of their premium loads are worse than the case without contract. This is because they summit lower preferred interruption compensations compared with other DISCOs/large consumers. However, they will receive the outage compensation. If we consider the overall cost, the case with contract is still better. It should be noted that they can improve their premium load reliability by submitting higher preferred interruption compensations.

From the last row of Table 7, it can be seen that not only the reliability of participated load, but also the reliability of overall load has been improved. This implies that the generated energy is increased. From the GENCO viewpoint, this is the benefit because he/she can sell more energy.

In the next simulation, the effect of transmission line availability on system reliability and TSO revenue has been investigated. We used the results from the previous simulation and assumed that the income from demand-side participants' premiums of TSO is fixed. The transmission line availability has been improved by 25, 50 and 75 percents. Figure 6 shows the result. Obviously, total EENS and revenue of TSO can be improved by improving the availability of transmission line.

Table 7: Comparison result between case with and without transmission contract

	With Contract			Without Contract		
	TC	P-EENS	T-EENS	TC	P-EENS	T-EENS
L1	2838	0.0	1927.0	3316	10.7	1879.3
L2	835	0.0	22.2	983	21.1	32.4
L3	838	0.0	13.4	983	9.5	16.1
L4	856	0.0	29.8	994	24.6	50.3
L5	858	0.0	12.9	991	45.9	66.9
L6	858	0.0	27.0	996	33.2	60.0
L7	1286	0.0	59.2	1494	28.8	72.1
L8	861	0.0	61.9	1004	58.2	122.3
L9	11736	0.0	479.0	13429	8.5	650.5
L10	1432	47.2	104.2	1704	4.7	9.4
L11	1447	14.5	38.2	1708	2.3	10.0
L12	1494	12.3	55.3	1734	9.6	30.3
L13	1498	14.4	48.4	1738	7.0	16.9
L14	1501	7.9	32.5	1740	6.0	12.2
L15	1433	11.8	34.7	1672	9.4	17.8
L16	820	4.6	11.7	938	3.0	6.8
L17	1497	45.2	179.5	1749	73.9	154.6
Sum	**32088**	**157.8**	**3136.9**	**37175**	**356.4**	**3208.0**

* TC is in million dollars, P-EENS and T-EENS are in GWh

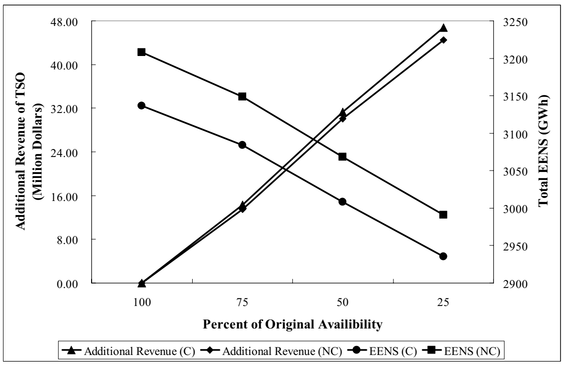

Figure 6: Effect of transmission line availability

Besides, the improvement of case with contract (C) is better than the case without contract (NC). This makes an incentive for transmission reliability improvement.

5 CONCLUSTION

In this paper, the authors have proposed a new market scheme for risk-hedging and reliability improvement in the deregulated power system. The proposed contract functions as bilateral contract, price cap and capacity market simultaneously. Simulation has been conducted to show the performance of the proposed contract, particularly from the participant viewpoint. The effect of transmission line availability has been also investigated.

From the simulation results, it can be concluded that the proposed contract provides benefit for participant, compared with the case without contract. From the GENCO viewpoint, he/she can sell more energy. From DISCO/large consumer viewpoint, his/her service interruption can be reduced. Furthermore, from the viewpoint of TSO, the proposed contract provides an incentive for transmission line reliability improvement.

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