Journal of Electrical Engineering & Technology, Vol. 3, No. 2, pp. 199~206, 2008 **199**

An Approach to Optimal Dispatch Scheduling Incorporating Transmission Security Constraints

Koo-Hyung Chung†, Dong-Joo Kang*, Balho H. Kim, Tai-Hoon Kim§, and Tae-Kyoo Oh§§**

Abstract – The introduction of competition in electricity markets emphasizes the importance of sufficient transmission capacities to guarantee effective power transactions. Therefore, for the economic and stable electric power system operation, transmission security constrains should be incorporated into the dispatch scheduling problem. With the intent to solve this problem, we decompose a dispatch scheduling problem into a master problem (MP) and several subproblems (SPs) using Benders decomposition. The MP solves a general optimal power flow (OPF) problem while the SPs inspect the feasibility of OPF solution under respective transmission line contingencies. If a dispatch scheduling solution given by the MP violates transmission security constraints, then additional constraints corresponding to the violations are imposed to the MP. Through this iterative process between the MP and SPs, we derive an optimal dispatch schedule incorporating the post-contingency corrective rescheduling. In addition, we consider interruptible loads as active control variables since the interruptible loads can participate as generators in competitive electricity markets. Numerical examples demonstrate the efficiency of the proposed algorithm.

Keywords: Benders Decomposition, Interruptible Load, OPF Transmission Security Constraints, Post-contingency Corrective Rescheduling

1. Introduction

Securing transmission capacities is one of the important issues in competitive electricity markets since competition might cause transmission-related problems such as the load flow increase on long-range tie lines between supply and demand areas, the loop flow appearance, the decrease of transmission reserve and stability margins, and so on. Therefore, transmission security constraints should be incorporated into the dispatch scheduling problem to guarantee effective power transactions [1].

Several optimal power flow (OPF) algorithms considering contingency constraints have been proposed with the intent to solve this problem. In general, adding contingency constraints yields more conservative operation of the electric power system. Contingency constrained OPF algorithms proposed by Ref. [2-6] can be preventative implements for stable power system operations since they incorporate additional constraints to allow feasibility under the contingency condition. However, they have no ability to control system configurations for adjusting the post-contingency condition. OPF algorithms which have post-contingency corrective rescheduling capabilities are proposed at Ref. [7-10]. When taking into account corrective capabilities, each post-contingency scenario is modeled as an optimization problem, causing the global formulation to become a high-dimension optimization problem. This is the reason that the introduction of decomposition techniques is required.

However, in the previous studies, the interruptible loads are thought of as passive elements only in order to ensure the solution feasibility, especially in relation to the active power flows. This is not suitable for competitive electricity markets where participants can use the interruptible loads as a manner for their profit maximization. With the intent to solve this problem, we propose a transmission security constrained dispatch scheduling algorithm that can guarantee the solution feasibility and incorporate each interruptible load capacity. Based on Benders decomposition, the proposed algorithm separates the dispatch scheduling problem by a 2-level optimization problem: a master problem (MP) and a set of subproblems (SPs). The MP solves the base-case OPF problem while the SPs inspect the feasibility of OPF solution under respective

---

† Corresponding Author: Electricity Market Technology Research Group, KERI (Korea Electro-technology Research Institute), Korea. (kchung@keri.re.kr)

* Electric Power Technology Team, KERI (Korea Electro-technology Research Institute), Korea. (djkang@keri.re.kr)

** Dept. of Electrical Engineering, Hongik University, Seoul, Korea. (bhklim@wow.hongik.ac.kr)

§ Dept. of Multimedia Engineering, Hannam University, Daejeon, Korea. (taihoonn@hannam.ac.kr)

§§ Electricity Market Technology Research Group, KERI (Korea Electro-technology Research Institute), Korea. (tkoh@keri.re.kr)

Received 28 August, 2007; Accepted 6 January, 2008

transmission line contingencies. If a dispatch scheduling solution given by the MP violates transmission security constrains, then additional constraints, known as Benders cut, corresponding the violations are imposed to the MP. This iterative process continues until a least-cost dispatch schedule with the post-contingency corrective capability is derived.

2. Problem Formulation

The general contingency constrained dispatch scheduling problem is formulated as follows:

$$\begin{array}{ll} \textit{minimize} & f(x_0) \\ \textit{subject to} & g(x_0)=0 \\ & g(x_k)=0 \;\; \textit{for} \;\; k=1,\cdots,N_c \\ & h(x_0)\le 0 \\ & h(x_k)\le 0 \;\; \textit{for} \;\; k=1,\cdots,N_c \\ & |x_0-x_k|\le \Delta x_k \;\; \textit{for} \;\; k=1,\cdots,N_c \end{array} \qquad (1)$$

where,

k	index of each one of post-contingency scenarios
N_c	set of all post-contingency scenarios
x_0	control variables under base-case scenario
x_k	control variables under post-contingency scenario k
$g(x_0), h(x_0)$	set of operational constraints under base-case scenario
$g(x_k), h(x_k)$	set of operational constraints under post-contingency scenario k
Δx_k	allowable rescheduling capabilities for control variables when the contingency k occurs.

$f(x)$ is defined as the sum of the production costs for all generating units. The objective of the contingency constrained dispatch scheduling aims to the least-cost active power generation at the base-case condition.

$$f(P_G^0)=\sum_{i=1}^{N_g}F_i(P_{Gi}^0) \qquad (2)$$

where,

i	index of each generating unit
N_g	set of all generating units
$F_i(\bullet)$	production cost function of the generating unit i
P_{Gi}^0	generation of the generating unit i under base-case scenario.

Equality constraints $g(x_0)$ and $g(x_k)$ correspond to the power flow equations at the base-case scenario and post-contingency scenario k, respectively.

$$P_{Gi}^0-P_{Di}^0-V_i^0\sum_{j=1}^{N}V_j^0(G_{ij}^0\cos\theta_{ij}^0+B_{ij}^0\sin\theta_{ij}^0)=0 \qquad (3)$$

$$Q_{Gi}^0-Q_{Di}^0-V_i^0\sum_{j=1}^{N}V_j^0(G_{ij}^0\sin\theta_{ij}^0-B_{ij}^0\cos\theta_{ij}^0)=0 \qquad (4)$$

$$P_{Gi}^k-P_{Di}^k-V_i^k\sum_{j=1}^{N}V_j^k(G_{ij}^k\cos\theta_{ij}^k+B_{ij}^k\sin\theta_{ij}^k)=0 \quad \textit{for} \;\; k=1,\cdots,N_c \qquad (5)$$

$$Q_{Gi}^k-Q_{Di}^k-V_i^k\sum_{j=1}^{N}V_j^k(G_{ij}^k\sin\theta_{ij}^k-B_{ij}^k\cos\theta_{ij}^k)=0 \quad \textit{for} \;\; k=1,\cdots,N_c \qquad (6)$$

where,

P_{Gi}^0, P_{Gi}^k	active power generation at bus i under base-case and post-contingency scenario k
Q_{Gi}^0, Q_{Gi}^k	reactive power generation at bus i under base-case and post-contingency scenario k
P_{Di}^0, P_{Di}^k	active power demand at bus i under base-case and post-contingency scenario k
Q_{Di}^0, Q_{Di}^k	reactive power demand at bus i under base-case and post-contingency scenario k
V_i^0, V_i^k	voltage magnitude at bus i under base-case and post-contingency scenario k
θ_i^0, θ_i^k	voltage angle at bus i under base-case and post-contingency scenario k
G_{ij}^0, G_{ij}^k	line conductance between bus i and j under base-case and post-contingency scenario k
B_{ij}^0, B_{ij}^k	line susceptance between bus i and j under base-case and post-contingency scenario k.

Inequality constraints $h(x_0)$ and $h(x_k)$ limit the values of system control variables and functions at the base-case scenario and post-contingency scenario k, respectively.

$$P_{Gi}^{\min}\le P_{Gi}^0\le P_{Gi}^{\max} \qquad (7)$$

$$P_{Gi}^{\min}\le P_{Gi}^k\le P_{Gi}^{\max} \;\; \textit{for} \;\; k=1,\cdots,N_c \qquad (8)$$

$$Q_{Gi}^{\min}\le Q_{Gi}^0\le Q_{Gi}^{\max} \qquad (9)$$

$$Q_{Gi}^{\min}\le Q_{Gi}^k\le Q_{Gi}^{\max} \;\; \textit{for} \;\; k=1,\cdots,N_c \qquad (10)$$

$$|I_{ij}^0|\le I_{ij}^{\max} \qquad (11)$$

$$\left|I_{ij}^k\right| \le I_{ij}^{\max} \quad for \quad k = 1,\cdots,N_c \tag{12}$$

$$V_i^{\min} \le V_i^0 \le V_i^{\max} \tag{13}$$

$$V_i^{\min} \le V_i^k \le V_i^{\max} \quad for \quad k = 1,\cdots,N_c \tag{14}$$

where, I_{ij}^0 and I_{ij}^k are the apparent power flow between bus i and j at the base-case and post-contingency scenario k, respectively.

Ramping constraints between base-case and post-contingency conditions $|x_0 - x_k| \le \Delta x_k$, called coupling constrains, define the allowable rescheduling capabilities for the control variables, especially for the generating units. Therefore, the generating units can adjust their output within the limits of allowable rescheduling capability when contingency k occurs.

$$\left|P_{Gi}^0 - P_{Gi}^k\right| \le \Delta P_{Gi}^k \quad \text{for} \quad k = 1,\cdots,N_c \tag{15}$$

3. Transmission Security Constrained Dispatch Scheduling Problem Incorporating Interruptible Loads

Previous corrective rescheduling OPF algorithms incorporate the interruptible loads but they are subordinate only for the solution feasibility [7-10]. In the competitive electricity markets, practical interruptible capabilities should be imposed to load demands as generation capacities since the interruptible loads can be a mean to maximize the market participant's profit. In addition, some of the algorithms based on DC network model only deal with the interruptible loads in relation to the active power flows. However, the effectiveness of load interruption by the reactive power flow as well as the active power flow should be incorporated in the practical power system operation since the load interruption might be frequently occurred to maintain the voltage stability in the system rather than the thermal limit of transmission lines. Therefore, we also consider load demands as control variables for the dispatch scheduling problem. This might make the computation speed slow. However, as the interruptible loads are practically small parts of the entire loads, the defect can be thought to be acceptable.

Interruptible loads are usually paid in proportion to the amount of active power interruption. This is the reason that interruptible loads can be regarded as generating units. Therefore, the objective function (2) can be revised as follows:

$$f(P_G^0, P_L^0) = \sum_{i=1}^{N_g} F_i(P_{Gi}^0) + \sum_{j=1}^{N_d} CP_{Dj}(P_{Dj}^{req} - P_{Dj}^0) \tag{16}$$

where,

N_d	set of all interruptible loads
CP_{Dj}	unit payment for active power interruption at bus j
P_{Dj}^{req}	active load demand at bus j
P_{Dj}^0	actual active load supply at bus j under base-case scenario.

Therefore, the difference between P_{Dj}^{req} and P_{Dj}^0 is defined as the actual active power interruption at bus j.

As the actual load supplies are treated as the control variables, the active/reactive loads at the equality constraints (3)-(6), that is the power flow equations, are not fixed parameters any longer. In addition, the following limits on the active power interruption should be incorporated with previous operational constraints described at (3)-(15).

$$P_{Di}^{req} - PL_i^{\max} \le P_{Di}^0 \le P_{Di}^{req} \tag{17}$$

$$P_{Di}^{req} - PL_i^{\max} \le P_{Di}^k \le P_{Di}^{req} \quad for \quad k = 1,\cdots,N_c \tag{18}$$

where,

$PL_i^{\max}$	maximum active power interruption at bus i
P_{Di}^k	actual active load supply at bus i under post-contingency scenario k.

It is noted that we curtail the same proportion of the reactive load and the active load to keep the power system operation at a constant power factor. This assumption makes the reactive power interruptions as the dependent variables on the active power interruptions:

$$Q_{Di}^0 = P_{Di}^0 \cdot \frac{Q_{Di}^{req}}{P_{Di}^{req}} \tag{19}$$

$$Q_{Di}^k = P_{Di}^k \cdot \frac{Q_{Di}^{req}}{P_{Di}^{req}} \quad for \quad k = 1,\cdots,N_c \tag{20}$$

where,

Q_{Di}^{req}	reactive load demand at bus i
Q_{Di}^0, Q_{Di}^k	actual reactive load supply at bus i under base-case and post-contingency scenario k.

In addition, the interruptible loads can be controlled as generating units within the maximum power interruption. Therefore, they also have coupling constraints as in Equation (15).

$$\left|P_{Di}^{0} - P_{Di}^{k}\right| \le P_{Di}^{req} - PL_{i}^{\max} \quad for \quad k = 1,\cdots,N_c \tag{21}$$

However, the centralized scheme for solving this dispatch scheduling problem under the n-1 contingency conditions has considerable computational burdens since a lot of constraints are added according to the number of contingencies to be considered. In addition, its convergence property might be graded with the addition and existence of coupling constraints. This is the reason that we introduce Benders decomposition to solve the transmission security constrained dispatch scheduling problem.

4. Application of Benders Decomposition

If we remove the coupling constraints, then the transmission security constrained dispatch scheduling problem can be separated into one MP for the base-case condition and several SPs for respective N_c contingencies. Benders decomposition can be an effective implementation for this 2-level optimization scheme [13]. However, additional constraints, called Benders cuts, should be incorporated into the MP for relaxing the coupling constraints. Benders cuts include information on the effects of given MP solution on the feasibility of respective SPs.

4.1 Formulation of Subproblems

SPs for the transmission security constrained dispatch scheduling are defined for respective contingencies. Therefore, when we consider N_c contingency conditions, there are independent N_c and SPs. SP for the post-contingency scenario k is formulated as follows:

$$\begin{aligned} \text{minimize} \quad & e^T s_k \\ \text{subject to} \quad & g(x_k) = 0 \\ & h(x_k) \le 0 \\ & \left|x_0^m - x_k\right| - s_k \le \Delta x_k \\ & s_k \ge 0 \end{aligned} \tag{22}$$

where, $e = [1,\cdots,1]$. The parameter x_0^m represents the control variable values derived from the MP at m-th iteration and s_k is the penalty variables to measure the incurred violation of the corrective rescheduling at the post-contingency scenario k. These penalty variables also act as the slack variables to guarantee the feasibility of a SP.

If the objective function value of (22) is zero, it means that the power system has sufficient corrective rescheduling capabilities associated with the post-contingency scenario k. However, the non-zero value of the objective function means that the system operation based on the dispatch schedule derived from the MP does not deal with the contingency condition. In this case, the penalty variable values and Lagrange multipliers associated with the coupling constraints are sent to the MP in order to improve the base-case solution. This information as to how much the dispatch schedule derived from the MP affects the k-th SP solution making sure of rescheduling power system operation to minimize the objective value of the SP.

4.2 Formulation of Master Problem

The objective of the MP is to obtain the optimal dispatch schedule at the base-case condition. The MP is formulated as follows:

$$\begin{aligned} \text{minimize} \quad & f(x_0) \\ \text{subject to} \quad & g(x_0) = 0 \\ & h(x_0) \le 0 \\ & s_k + \lambda_k (x_0 - x_0^m) \le 0 \quad for \quad k = 1,\cdots,N_c \end{aligned} \tag{23}$$

where, λ_k is the Lagrange multipliers associated with the coupling constraints from the k-th SP solution. The last constraints of (23) represent the Benders cuts that link the SP solution to the MP solution in order to improve the optimal base-case dispatch schedule.

4.3 Solution Procedure

This proposed algorithm for solving the transmission security constrained dispatch scheduling problem needs initial points for the control variables. The initial points can be obtained from the base-case OPF without the last constraints of (23). For a dispatch schedule given by the MP, we check the feasibility of the SPs. Once a violation is detected in the SPs, Benders cut associated with the corresponding constraint is generated and added into the MP. With this Benders cut, the MP improves the base-case solution which is provided to re-check the feasibility of the SPs. This iterative process between MP and SPs continues until the objective function value for all the SPs becomes zero.

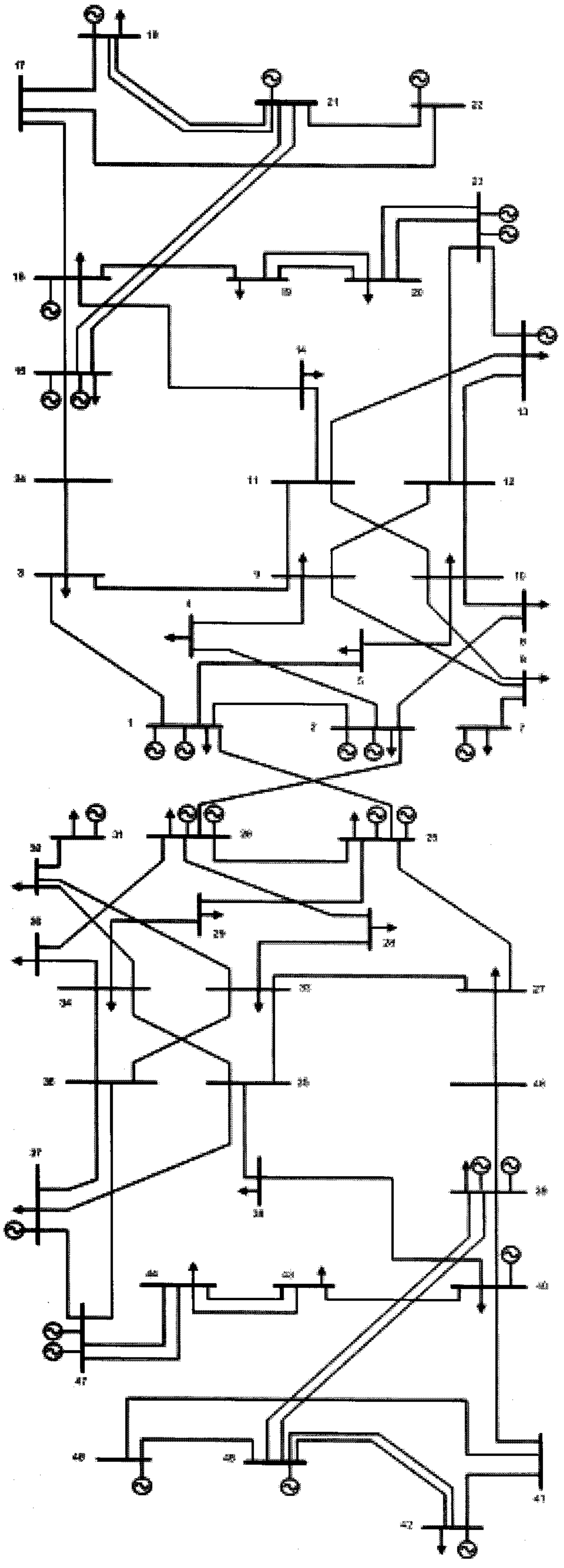


Fig. 1. 48-bus test system

Table 1. Description of generation units

Unit No.	Bus No.	$P^{min}(MW)$	$P^{max}(MW)$	$\Delta P(MW)$
1	1	32.0	40.0	2.00
2	1	30.0	150.0	7.50
3	2	32.0	40.0	2.00
4	2	30.0	150.0	7.50
5	7	75.0	300.0	15.00
6	13	200.0	600.0	30.00
7	15	12.0	60.0	3.00
8	15	54.3	155.0	7.75
9	16	54.3	155.0	7.75
10	18	100.0	400.0	20.00
11	21	100.0	400.0	20.00
12	22	300.0	0.0	15.00
13	23	100.0	310.0	15.50
14	23	140.0	350.0	17.50
15	25	32.0	40.0	2.00
16	25	30.0	150.0	7.50
17	26	32.0	40.0	2.00
18	26	30.0	150.0	7.50
19	31	75.0	300.0	15.00
20	37	200.0	600.0	30.00
21	39	12.0	60.0	3.00
22	39	54.3	155.0	7.75
23	40	54.3	155.0	7.75
24	42	100.0	400.0	20.00
25	45	100.0	400.0	20.00
26	46	300.0	0.0	15.00
27	47	100.0	310.0	15.50
28	47	140.0	350.0	17.50

Table 2. Description of load demands

Bus No.	$P_D(MW)$	$Q_D(MVar)$	$PL^{max}(MW)$
1	76.0	36.8	3.80
2	68.0	32.9	3.40
3	126.0	61.0	6.30
4	52.0	25.2	2.60
5	50.0	24.2	2.50
6	96.0	46.5	4.80
7	88.0	42.6	4.40
8	120.0	58.1	6.00
9	122.0	59.1	6.10
10	136.0	65.9	6.80
13	186.0	90.1	9.30
14	136.0	65.9	6.80
15	222.0	107.5	11.20
16	70.0	33.9	3.50
18	234.0	113.3	11.70
19	128.0	62.0	6.40
20	90.0	43.6	4.50
25	114.0	55.2	5.70
26	102.0	49.4	5.10
27	189.0	91.5	9.45
28	78.0	37.8	3.90
29	75.0	36.3	3.75
30	144.0	69.7	7.20
31	132.0	63.9	6.60
32	180.0	87.2	9.00
33	183.0	88.6	9.15
34	204.0	98.8	10.20
37	279.0	135.1	13.95
38	204.0	98.8	10.20
39	333.0	161.3	16.65
40	105.0	50.9	5.25
42	351.0	170.0	17.55
43	192.0	93.0	9.60
44	135.0	65.4	6.75

Table 3. Generation output by OPF and transmission security constrained dispatch scheduling

Unit No.	OPF (MW)	Transmission security constrained dispatch scheduling				
		Base-case (MW)	Contingency 01-25 (MW)	Contingency 02-06 (MW)	Contingency 25-27 (MW)	Contingency 02-26 (MW)
1	40.00	40.00	38.00	38.00	40.00	38.00
2	150.00	150.00	142.50	142.50	142.50	142.50
3	40.00	40.00	38.00	40.00	40.00	38.00
4	150.00	150.00	142.50	150.00	150.00	142.50
5	137.37	148.39	133.39	142.86	152.37	133.39
6	267.76	318.99	288.99	288.99	288.99	288.99
7	43.10	15.00	18.00	12.00	18.00	18.00
8	155.00	80.77	88.52	73.04	88.52	88.52
9	155.00	155.00	147.25	147.25	147.25	152.40
10	331.27	331.27	311.27	311.27	311.27	311.27
11	315.30	315.30	296.51	295.30	295.30	295.30
12	300.00	300.00	285.00	285.00	300.00	285.00
13	310.00	310.00	294.50	294.50	294.50	294.50
14	350.00	350.00	332.50	332.50	332.50	332.50
15	32.00	32.00	32.00	32.00	34.00	34.00
16	48.53	48.53	56.03	41.03	41.03	56.03
17	32.00	32.00	32.00	34.00	34.00	34.00
18	43.06	49.38	52.83	56.61	41.88	50.54
19	147.12	149.98	164.74	164.76	155.87	134.98
20	200.00	206.74	200.02	235.69	200.00	236.26
21	40.25	40.25	37.25	37.25	43.25	43.25
22	155.00	155.00	147.25	147.25	153.76	155.00
23	155.00	155.00	147.25	155.00	153.76	155.00
24	316.46	321.91	341.46	341.45	329.96	336.44
25	299.39	304.80	324.35	284.80	284.80	284.80
26	300.00	300.00	285.02	300.00	295.31	285.00
27	310.00	310.00	310.00	310.00	303.46	310.00
28	350.00	350.00	350.00	350.00	343.46	332.50

5. Computational Results

The proposed algorithm is tested on a 48-bus system modifying the IEEE RTS 24-bus test system. The 48-bus test system has 28 generating units, 34 loads and 78 transmission lines. Tables 1 and 2 show detailed characteristics for the generating units and loads. Post-contingency scenarios used in this study are 4 major line outages: line 1-25, line 2-6, line 2-26, and line 25-27. It is noted that we can freely select post-contingency scenarios regardless of the number and/or the location of contingencies.

Tables 3 and 4 compare the solution from the proposed algorithm to the conventional OPF with the rescheduling results of the generating units and interruptible loads at respective post-contingency scenarios. These results show that the levels of post-contingency corrective rescheduling for generating units and interruptible loads are differently associated with respective contingencies. Fig. 2 also shows the convergence property through the iterative process between MP and SPs. In this study, the optimal solution needs 3 iterations.

6. Conclusions

The introduction of competition in electricity markets emphasizes the importance of sufficient transmission capacities to guarantee effective power transactions. Therefore, for the economic and stable electric power system operation, transmission security constrains should be incorporated into the dispatch scheduling problem. However, the centralized scheme for solving this dispatch scheduling problem under the n-1 contingency conditions has considerable computational burdens since a lot of constraints are added according to the number of contingencies to be considered. In addition, its solution convergence might decline due to the addition and existence of coupling constraints. This is the reason that we introduce Benders decomposition to solve the transmission security constrained dispatch scheduling problem because Benders decomposition is a natural way to transform the complicated optimization problem into the 2-level structure between a MP and SPs.

In addition, interruptible loads should be incorporated into the post-contingency corrective rescheduling as active control variables since market participants can use their interruptible loads as a manner for their profit maximization. With the intent to solve this problem, we also propose a transmission security constrained dispatch scheduling algorithm that can guarantee the solution feasibility and incorporate each interruptible load capacity. We will implement a dispatch scheduling model that is more delicate and applicable to real power system operations by considering dynamic stability constraints as well as these static security constraints.

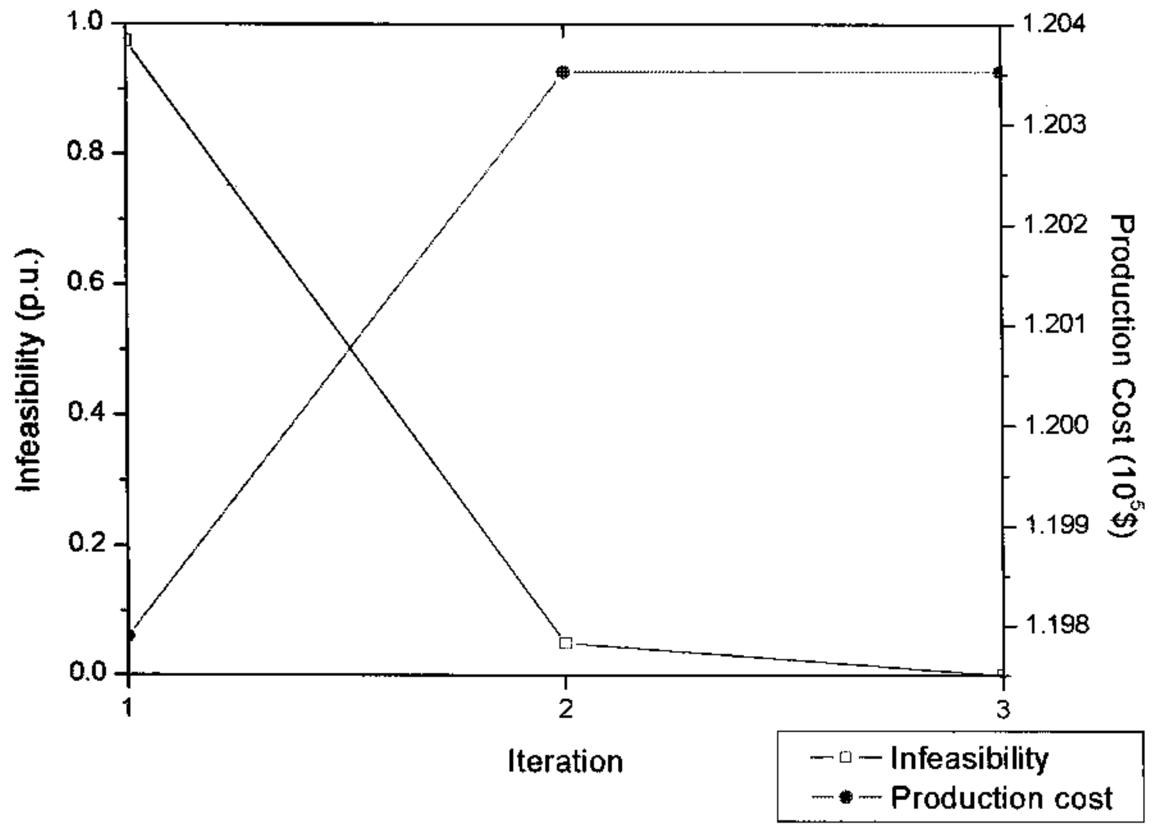


Fig. 2. Infeasibility between MP and SPs and its objective function value by iterations.

References

[1] J. Wood and B. F. Wollenberg, *Power Generation, Operation and Control*, Wiley, New York, 1984.

[2] D. W. Ross, et al., "Dynamic economic dispatch of generation," *IEEE Trans. on Power Apparatus and System*, PAS-99, no. 6, pp. 2060-2068, 1980.

[3] A. J. Svoboda, et al., "Short-term resource scheduling with ramp constraints," *IEEE Trans. on Power System*, vol. 12, no. 1, pp. 77-83, 1997.

[4] P. P. J. van den Bosch, "Optimal dynamic dispatch owing to spinning-reserve and power-rate limits," *IEEE Trans. on Power Apparatus and System*, PAS-104, no. 12, pp. 3395-3401, 1985.

[5] Y. Fukuyama, et al., "An application of neural network to dynamic dispatch using multiprocessors," *IEEE Trans. on Power System*, vol. 9, no. 4, pp. 1737-1743, 1994.

[6] G. Irisarri, "Economic dispatch with network and ramping constraints via interior point methods," *IEEE Trans. on Power System*, vol. 13, no. 1, pp. 236-242, 1998.

[7] A. Monticelli, M. V. F. Pereira, and S. Granville, "Security-constrained optimal power flow with post-contingency corrective rescheduling," *IEEE Trans. on Power Systems*, vol. 2, no. 2, pp. 175-182, 1987.

[8] B. Stott, O. Alsac, and A. Monticelli, "Security analysis and optimization," *Proceedings of the IEEE 75*, no. 12, 1987, pp. 1623-1644.

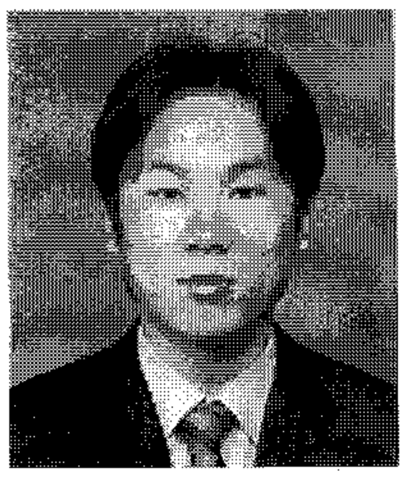
[9] H. Y. Yamin, L. Al-Tallaq, and S. M. Shahidehpour, "New approach for dynamic optimal power flow using benders decomposition in a deregulated power market," *Electric Power Systems Research*, vol. 65, pp. 101-107, 2003.

[10] O. R. Saavedra, "Relaxed approach for the parallel solution of security-constrained dispatch with post-contingency rescheduling," *IEE Proceedings-Generation, Transmission, and Distribution*, vol. 150, no. 3, 2003, pp. 291-296.

[11] K. H. Chung, C. J. Lee, J. H. Kim, D. Hur, B. H. Kim, and J. B. Park, "Development of customer oriented load management software for savings on utility bills in the electricity market," *Journal of Electrical Engineering & Technology*, vol. 2, no. 1, pp. 42-49, 2007.

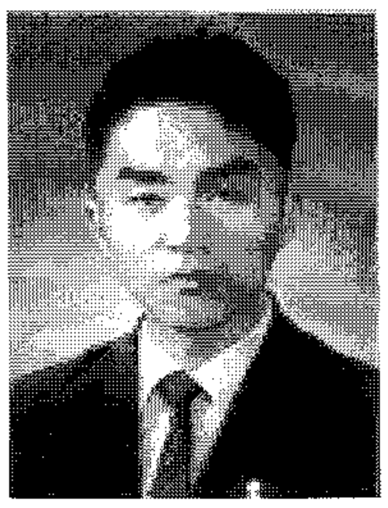
[12] K. H. Chung, J. H. Kim, and B. H. Kim, "Development of the load curtailment allocation algorithm for load aggregator in emergency demand response," *Transactions of KIEE*, vol. 53A, no. 8, pp. 466-471, 2003.

[13] L. S. Lasdon, *Optimization theory for large systems*, Macmillan, New York, 1970.



Koo-Hyung Chung

He received his B.S., M.S., and Ph.D. degrees from Hongik University, Seoul, Korea, in 2001, 2003, and 2007, respectively. He is currently working for the Electricity Market Technology Research Group in KERI. His research interests include optimization modeling and game theory for electricity market analysis, public pricing, and power system operation & planning.



Dong-Joo Kang

He received his B.S. and M.S. degrees from Hongik University, Korea, in 1999 and 2001, respectively. He has been with KERI since 2001. His interests include analysis of power industry restructuring, application of game theory analysis to power transactions, and development of an electricity market simulator.

Balho H. Kim

He received his B.S. degree from Seoul National University, Korea, in 1984, and his M.S. and Ph.D. degrees from the University of Texas, Austin in 1992 and 1996, respectively. He was with KEPCO (the Korea Electric Power Corporation) from 1984 to 1990 and joined Hongik University in 1997 where he is presently Associate Professor of Electrical Engineering. His research fields include distributed optimal power flow, public pricing, B/C analysis, and power system planning and operation.

Tai-Hoon Kim

He received his M.S. and Ph.D. degrees in Electrics, Electronics & Computer Engineering from Sungkyunkwan University, Korea. After working with the Technical Institute of Sindoricoh for two years as a Researcher and then at the Korea Information Security Agency as a Senior Researcher for two and a half years, he worked at DSC (Defense Security Command) for about two years. He then spent half a year at Ewha Women's University as a Research Professor, and now he is a Professor at Hannam University.

Tae-Kyoo Oh

He received his B.S. in Electrical Engineering from Seoul National University, Korea, and his M.S. and Ph.D. degrees in Electrical Engineering from Iowa State University, USA. From 1987 to 2002, he was a Primary Researcher and a Department Manager in the Power System Research Laboratory at KERI, and for a time he took the position of President of the Electrical Testing & Research Laboratory, a branch office of KERI located in Uiwang-city. He is now Chief of the Electricity Market Technology Research Group and an Expert Adviser of KERI.