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LONG RANGE GENERATION EXPANSION PLANNING FOR INTERCONNECTED SYSTEMS

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Summary

Summary - Long range generation expansion planning problem, particularly for interconnected system planning, has received considerable attention because both the generation capacity installations and the fuel costs can be saved by regulating the power exchanges of inter-lines and sharing common reserve of the interconnected systems. Up to now, although several successful methods and packages have been proposed, these methods were originally developed for the isolated systems without network constraints (i.e. single bus model). The representation of network constraints of interconnected system in generation planning studies introduces an additional degree of complexity, especially in calculating reliability indices and production costs for a given trial plan. This report describes a new approach for generation expansion planning of interconnected systems subject to power flow constraints. The proposed approach is based on the Benders Decomposition technique . That is, the large scale generation expansion planning is divided into one master problem which is a linear problem for optimal power exchange plan on inter-lines, and several subproblems which represent a set of smaller scale isolated system generation expansion planning. Power exchanges between systems are calculated by using Linear Programming in master problem. On the other side, generation expansion plans are determined by the conventional approach in subproblems. Since the large scale interconnected system planning is decomposed into several smaller scale isolated system plannings, both computation time and memory can be largely saved. In addition, the generation capacity installations and the fuel costs can be also expected to reduce by regulating the power exchanges and sharing common reserve of the interconnected system. Several examples were shown in the report.

Keywords : generation expansion planning, Benders decomposition, interconnected system, isolated system, power exchange, equivalent load curve, load duration curve

1 Introduction

Up to now, several successful methods and packages have been proposed for long range generation expansion planning problem, such as [1,2,3,4] and [5,6], however, these methods or packages were originally developed for the isolated systems without network constraints (i.e. single bus model). The representation of network constraints of interconnected system in generation planning studies introduces an additional degree of complexity, especially in calculating reliability indices and production costs for a given trial plan. For example, in the isolated system planning, the reliability indices and production costs can be analysed independently by using load duration curve. In contrast, in the interconnected system (multi-area system) planning, the reliability indices and production costs have to be determined by original time-depend demand of each area and power exchange of inter-lines. Since the load correlations of each area and inter-line constraints should be taken into consideration in the planning, the load duration curve cannot be directly used in the production cost simulation. Therefore, the generation planning of interconnected system is complex and more complicated than that of the isolated systems.

In order to overcome the above difficulties and deal with a realistic generation planning, this report presents a practical and effective methodology which aims at minimizing the sum of capital and operating costs subject to network constraints, reliability constraints and available resources for the interconnected systems generation expansion planning. The proposed approach is based on the Benders Decomposition technique [7]. As shown in Fig.1, the large scale generation planning is divided into one master problem which is used to generate trail solutions for optimal power exchange plan, and several subproblems which are composed of smaller scale isolated system generation planning. Power exchanges between each system are calculated by using Linear Programming in master problem. On the other side, generation expansion plans are determined by the conventional approach in subproblems. In such a way, Power exchanges and generation expansion plans are successively processed by solving master problem and subproblems, respectively. Finally the optimal interconnected systems generation expansion planning can be obtained when the convergence conditions have been met. Since the large scale interconnected system planning is decomposed into several smaller scale isolated system planning, both computation time and memory can be largely saved. In addition, the generation capacity installation and the fuel cost can be also expected to reduce because of benefits of interconnected system on economy and security, compared to the isolated system. The key point in this research is that the power exchange calculations and the load correlation considerations are undertaken by allocating hourly loads to appropriate areas. In other words, since the hourly generations are stochastic values and the hourly loads are certain values, in order to avoid the complex probability treatments of generations, inter-lines allocate the hourly loads of areas instead of allocating the generations of areas. As shown in this paper, the proposed approach is efficient and effective for interconnected systems, and especially suitable for parallel computation.

2 Formulation of Generation Planning for Interconnected Systems

Optimal long range generation planning problem for interconnected system could be formulated as a nonlinear mixed integer programming problem.

$$\text{Min} \quad Tcost = \sum_{i=1}^{N} \sum_{h=1}^{H} [F_{i.h}(G_{i.h}) + V_{i.h}(P_{i.h}, T_{i.h}) + U_{i.h}(P_{i.h}, T_{i.h}, \pi_{i.h})] \qquad (1)$$

$$s.t. \qquad T_{i.hmin} \leq \boldsymbol{T}_{i.h} \leq T_{i.hmax} \tag{2}$$

$$UE_{i.h}(\boldsymbol{P}_{i.h}, \boldsymbol{T}_{i.h}) \leq EUE_{i.h} \tag{3}$$

$$LOLP_{i.h}(\boldsymbol{P}_{i.h}, \boldsymbol{T}_{i.h}) \leq ELOLP_{i.h} \tag{4}$$

$$\boldsymbol{G}_{i.hmin} \leq \boldsymbol{G}_{i.h} \leq G_{i.hmax} \tag{5}$$

$$0 \leq \boldsymbol{P}_{i.h} \leq \boldsymbol{G}_{i.h} \tag{6}$$

$$(i = 1, \cdots, N; h = 1, \cdots, H)$$

Reserve margin constraint in each area (7)

Spinning reserve constraint in each area (8)

Units cumulative number constraint in each area (9)

Site capacity and emission constraint in each area (10)

Must-run and retirement units constraint in each area (11)

Fuel and water availability constraint in each area (12)

Maintenance Scheduling in each area (13)

where,

$Tcost$: total capital and operating costs in planning horizon

i: area index; N : number of areas

h : period index; H:number of periods in planning horizon (e.g. assume 1-year to be divided into 12 periods, then $H = 30 \times 12$ periods for 30-year horizon)

$F_{i.h}$: fixed costs (capital and fixed $O\&M$) ($)

$V_{i.h}$: variable costs (Fuel and variable $O\&M$) ($)

$\boldsymbol{G}_{i.h}$: vector of unit capacities [MW]

$\boldsymbol{P}_{i.h}$: vector of unit output levels [MW]

$\boldsymbol{T}_{i.h}$: vector of Power exchange between area-i and other areas [MW]

$U_{i.h}$: ($= \pi_{i.h} \cdot UE_{i.h}$) Penalty of expected unserved energy

$\pi_{i.h}$: short-term marginal cost [$/MWH]

$UE_{i.h}$: expected unserved energy (EUE)[MWH]

$EUE_{i.h}$: desired reliability (EUE) level [MWH]

$ELOLP_{i.h}$: desired LOLP level [Day/Year]

$\boldsymbol{G}_{i.hmin}, \boldsymbol{G}_{i.hmax}, \boldsymbol{T}_{i.hmin}, \boldsymbol{T}_{i.hmax}$: Lower and upper limits on unit capacities and power flow of inter-line (MW)

Therefore, the best possible long range plan for expanding an interconnected system's generating capacity to meet increasing demand can be obtained by minimizing total costs subject to the above overall constraints (Eqn.(2) ~ Eqn.(13)).

3 Solution of Optimal Generation Planning for Interconnected Systems

3.1 Decomposition

The proposed approach for solving problem Eqn.(1) ~ Eqn.(13) is based on the generalized Benders decomposition which divides the problem into one master problem and several subproblems. Generalized Benders decomposition presents how to coordinate solutions between the master problem and subproblems, so that the solution obtained with the decomposed method would be the same as that from the integrated method.

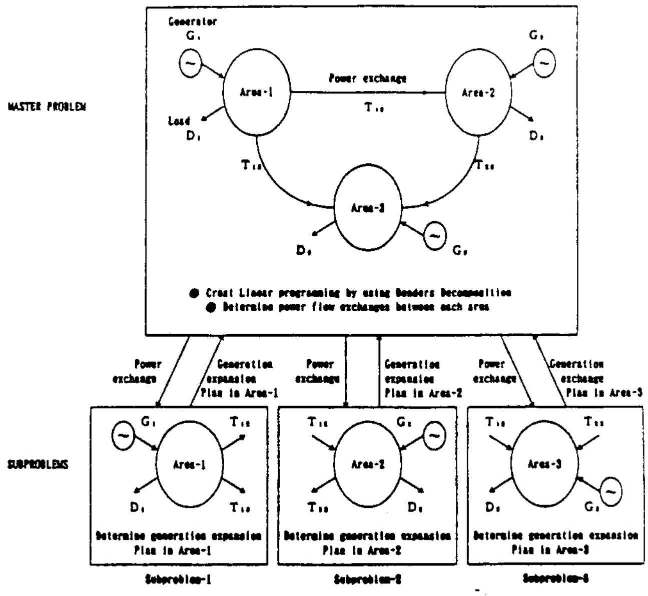

Figure 1: Concept of generation planning for interconnected systems based on Benders decomposition

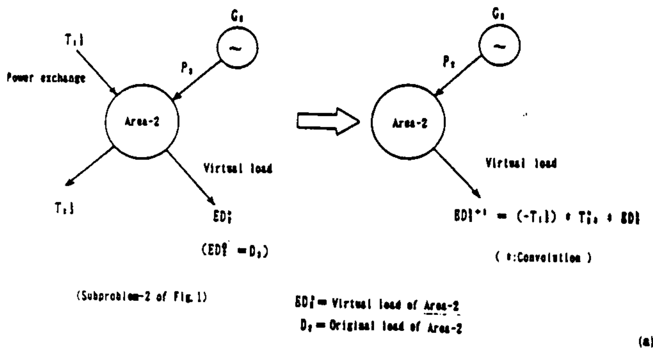

Figure 2: Virtual load from convolution in subproblems

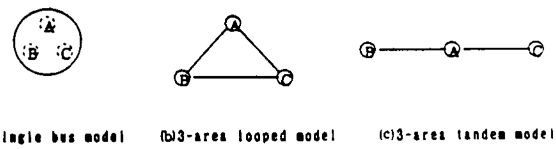

Figure 4: Systems for the simulation

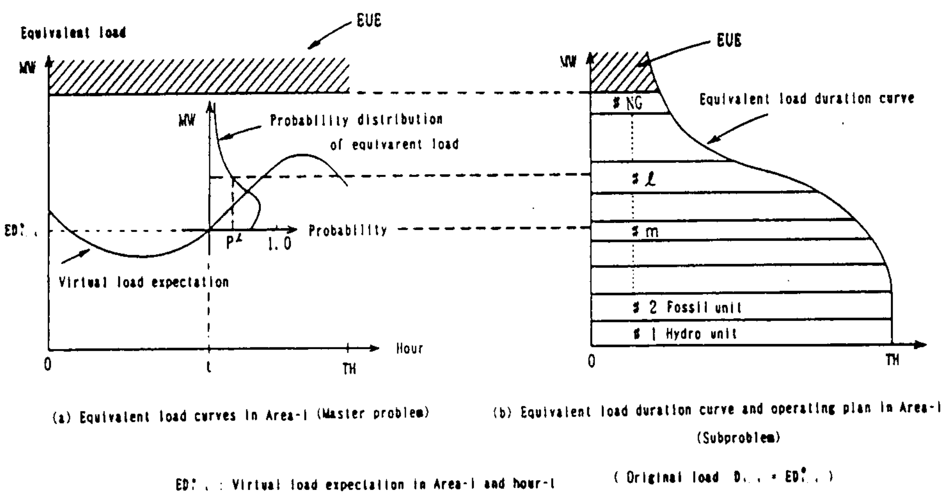

Figure 3: Relation between equivalent load curve of Master problem and equivalent load duration curve of Subproblem

Each subproblem is made up of the isolated system generation planning for the corresponding area using equivalent load duration curve, while the power exchanges among all areas are fixed.

[Subproblem-i] ($i = 1, \ldots, N$; $T_{i.h}$:fixed)

$$\text{Min} \quad \sum_{h=1}^{H}[F_{i.h}(G_{i.h}) + V_{i.h}(P_{i.h}, T_{i.h}^{k}) + U_{i.h}(P_{i.h}, T_{i.h}^{k}, \pi_{i.h})] \tag{14}$$

$$s.t. \quad Eqn.(3) \sim Eqn.(13) \tag{15}$$

where, $T_{i.h}^{k}$: trial solution of power exchanges in iteration-k obtained in master problem

Obviously, each subproblem is smaller scale generation planning problem which determines generation expansion plan ($G_{i.h}$) and operating plan ($P_{i.h}$). Take the subproblem-2 of Fig.1 for example, since the power exchanges between areas are fixed, the virtual load ED_2^k and the power exchanges (T_{12}^k, T_{23}^k) can be convoluted into the virtual load ED_2^{k+1} of iteration-$k+1$ in area-2 for hour-t of period-h as depicted in Fig.2 (the indices h and t have been dropped in Fig.2 for clarity of notation). Here the virtual load is to combine the original load and power exchanges into one equivalent-effect load in the concerned area. Therefore, each subproblem becomes an independent generation planning and can be independently calculated by using conventional generation planning packages. In this research, Dynamic Programming is used to solve the subproblems. Furthermore, the hourly virtual load curves decided in Fig.2 are transferred to the master problem for the calculation of the power exchanges on inter-lines.

On the other hand, the master problem is used to generate trail solution of power exchange plan considering time-depend demands (or hourly virtual load curves) and network constraints, while the generation expansion plan and operating plan are held as constants.

[Master problem] ($G_{i.h}, P_{i.h}, \pi_{i.h}$: fixed)

$$\text{Min} \quad z \tag{16}$$

$$s.t. \quad z \geq \sum_{i=1}^{N}\sum_{h=1}^{H}[F_{i.h}(G_{i.h}^{k}) + V_{i.h}(P_{i.h}^{k}, T_{i.h}) + U_{i.h}(P_{i.h}^{k}, T_{i.h}, \pi_{i.h}^{k})] \tag{17}$$

$$(k = 1, 2, \ldots, K)$$

$$T_{i.hmin} \leq T_{i.h} \leq T_{i.hmax} \tag{18}$$

where,

k :iteration index, K : number of iteration

$G_{i.h}^k, P_{i.h}^k, \pi_{i.h}^k$:trial solution in iteration-k in subproblems

z :lower bound on optimal total cost

Eqns.(17) are composed of K equations and their right-hand sides are upper bounds on optimal total cost. As each trial solution is generated, a new constraint are added to the master problem. Consequently the master problem increases in size as the algorithm proceeds.

3.2 Algorithm for solving subproblems

Since the power exchanges are fixed, as mentioned before, each subproblem is the generation expansion planning of the isolated system which can be solved by the conventional approaches. DP program is applied to deal with the subproblems in this research. In the calculation of production costs, the unit loading order is defined as the economic merit order in which the

Table 1: Existing fossil and nuclear plants parameters

Area	Item		Nuclear	Coal	Oil	Combined cycle	Gas turbine
A	Installed capacity	MW	600	600	200	100	50
	Minimum operating capacity	MW	600	180	75	30	10
	Number of units		1	4	13	11	10
	Forced outage rate	%	1.5	4	4	5	5
	Spinning reserve	%	0	20	20	20	30
	Maintenance periods	Days/Year	50	45	30	30	15
	Maintenance class size	MW	600	600	200	100	50
	Heat rate at minimum operating level	kcal/kWh	2806	2688	2529	2324	3906
	Average incremental heat rate	kcal/kWh	—	1998	2024	1861	2806
	Fuel cost	¢/10^6kcal	538	780	1496	1604	1604
	Fixed O&M cost	$/kW・Month	0.58	7.5	4.83	2.33	1.17
	Variable O&M cost	$/MWh	0.5	5	1	1	1
B	Installed capacity	MW	600	250	200	100	50
	Minimum operating capacity	MW	600	75	50	30	10
	Number of units		0	8	16	4	18
	Forced outage rate	%	1.5	4	4	5	5
	Spinning reserve	%	0	20	20	20	30
	Maintenance periods	Days/Year	50	40	30	30	15
	Maintenance class size	MW	600	250	200	100	50
	Heat rate at minimum operating level	kcal/kWh	2806	2867	2774	2324	3908
	Average incremental heat rate	kcal/kWh	—	2092	2097	1861	2806
	Fuel cost	¢/10^6kcal	538	780	1468	1604	1604
	Fixed O&M cost	$/kW・Month	0.58	8.33	5.33	2.33	1.17
	Variable O&M cost	$/MWh	0.5	6	6	1	1
C	Installed capacity	MW	600	200	100	100	20
	Minimum operating capacity	MW	600	50	25	30	4
	Number of units		0	9	8	0	15
	Forced outage rate	%	1.5	4	4	5	5
	Spinning reserve	%	0	20	20	20	30
	Maintenance periods	Days/Year	50	30	21	30	14
	Maintenance class size	MW	600	200	100	100	20
	Heat rate at minimum operating level	kcal/kWh	2806	2966	2688	2324	3908
	Average incremental heat rate	kcal/kWh	—	2197	2044	1861	2806
	Fuel cost	¢/10^6kcal	538	780	1468	1604	1604
	Fixed O&M cost	$/kW・Month	0.58	8.75	5.58	2.33	1.25
	Variable O&M cost	$/MWh	0.5	6	1	1	1

Table 2: Existing hydro plant parameters

Area	Item		Plant parameters			
A	Installed capacity	MW	970 ($50^{MW} \times 5 + 60^{MW} \times 12$)			
	Minimum operating capacity	MW	100			
	Annual energy to be generated	GWh	2343.6			
			Period 1	Period 2	Period 3	Period 4
	Maximum available generation	MW	460	605	945	605
	Minimum available generation	MW	100	125	225	125
	Available energy	GWh	410.4	529.2	874.8	529.2
B	Installed capacity	MW	460 ($50^{MW} \times 2 + 30^{MW} \times 12$)			
	Minimum operating capacity	MW	40			
	Annual energy to be generated	GWh	1047.6			
			Period 1	Period 2	Period 3	Period 4
	Maximum available generation	MW	220	290	450	290
	Minimum available generation	MW	40	50	90	50
	Available energy	GWh	183.6	237.6	388.8	237.6
C	Installed capacity	MW	390 ($30^{MW} \times 3 + 25^{MW} \times 12$)			
	Minimum operating capacity	MW	60			
	Annual energy to be generated	GWh	1166.4			
			Period 1	Period 2	Period 3	Period 4
	Maximum available generation	MW	240	315	390	315
	Minimum available generation	MW	60	75	90	75
	Available energy	GWh	226.8	291.6	356.4	291.6

Table 3: Capital parameters for alternative generating units

Area	Plant type	Depreciable unit cost ($/kW)		Plant life	Interest during construction (%/Year)	※ Construction lead times (Year)	Annual escalation ratio for capital costs (%/Year)	
		Domestic	Foreign	(Year)			Domestic	Foreign
A	Nuclear	460	1840	25	5	8	3	3
	Coal	360	1440	25	5	5	3	3
	Oil	288	1152	25	5	5	3	3
	Combined cycle	140	560	25	5	5	3	3
	Gas turbine	90	360	10	5	2	3	3
	Hydro	—	—	—	—	—	—	—
B	Nuclear	460	1840	25	5	8	3	3
	Coal	400	1600	25	5	5	3	3
	Oil	320	1280	25	5	5	3	3
	Combined cycle	140	560	25	5	5	3	3
	Gas turbine	90	360	10	5	2	3	3
	Hydro	—	—	—	—	—	—	—
C	Nuclear	460	1840	25	5	8	3	3
	Coal	400	1600	25	5	5	3	3
	Oil	320	1280	25	5	5	3	3
	Combined cycle	140	560	25	5	5	3	3
	Gas turbine	90	360	10	5	2	3	3
	Hydro	600	2400	40	5	8	3	3

※ Construction lead times for 30-year planning

Table 4: Peak load of every area and period

Area	Year	Peak load (MW)			
		Period 1	Period 2	Period 3	Period 4
A	1991	5870	5597	6825	5324
	1992	6163	5876	7166	5590
	1993	6471	6170	7525	5869
	1994	6795	6479	7901	6163
	1995	7134	6803	8296	6471
B	1991	5024	4851	5775	4678
	1992	5275	5094	6064	4912
	1993	5539	5348	6367	5157
	1994	5816	5616	6685	5415
	1995	6107	5896	7020	5686
C	1991	2295	2160	2700	2025
	1992	2479	2333	2916	2187
	1993	2677	2519	3149	2362
	1994	2891	2721	3401	2551
	1995	3122	2939	3673	2755

units are loaded in order of increasing operating costs. The obtained generation expansion plans ($G_{i.h}$), operating plans ($P_{i.h}$) and marginal costs ($\pi_{i.h}$) are transferred to the master problem to create a new constraint.

3.3 Algorithm for solving master problem

The master problem is to determine the power exchanges on inter-lines while the generation plans ($G_{i.h}$), operating plans ($P_{i.h}$) and $\pi_{i.h}$ are held as constants.

In order to cope with the network constraints and load correlation problems, the hourly load curve is used in master problem in contrast to the load duration curve. That is, each year is split into several periods, and each day in one period is further divided in many hours subperiods. For instance, number of total periods is $H = 30 \times 12$ periods for 30-year planning if each year is split into 12 periods. Take a typical day from one period, then the day is represented by $T = 24$ hourly time-depend load curve in which the hourly loads are certain values rather than stochastic values in this paper. By the convolutions shown in Fig.2, the hourly virtual load curve can be calculated.

Fig.3(a) indicates a set of hourly **equivalent load curves** of master problem in area-i and period-h which are convoluted by the hourly virtual load (shown in Fig.2) and operating unit outages (including both forced outages and maintenance outages) in every hour, in contrast to **equivalent load duration curve** which is convoluted by the load duration curve and operating unit outages. That is, hourly equivalent load is calculated by convolution between the corresponding hourly virtual load and unit outages. Therefore, each hourly equivalent load has an probability distribution owing to the unit outages. Fig.3(b) is the operating plan and the equivalent load duration curve in area-i and period-h of the subproblem.

Since the generations of each area are the stochastic values due to the forced outages, and the hourly loads of each area are certain values, in order to avoid the complex probability calculations of the generating units, the power exchanges are taken as the allocations of hourly loads instead of the generations. That is, the treatments of the load correlations and the power exchange calculations are undertaken by allocating the hourly loads to appropriate areas according to the evaluations of economy and reliability. The obtained power exchanges then are transferred to each subproblem to continue iterative calculation until the convergence condition has been met and the algorithm is terminated.

In this section, since we introduce the equivalent load curves into master problem, which not only link the simulation of subproblems and master problem, but also retain the load correlation characteristics, the power flow exchanges can be properly evaluated in relative easy way. It is evident that the computations can be largely decentralized and done in parallel for each of the smaller independent subproblems if any parallel computing hardware is available.

4 Computational Experience

The proposed approach has been implemented and tested on 3 model systems illustrated in Fig.4 for 5-year planning and 30-year planning respectively.

4.1 5-year planning example

Assume inflation rate to be 10%, discount rate to be 10% and escalation rate to be 3%. Table 1 and Table 2 illustrate the existing fossil, nuclear and hydro power plant parameters respectively. The concerned planning model currently has 120 existing units, and six types of alternative units are available for installation in each year. The capital parameters for alternative generating units are shown in Table 3. Assume that the inter-lines have the same transmission capacities and ignore the transmission losses. Let construction lead time for all alternative units be 2 years for simplification in 5-year planning. Split 1 year into 4 periods, then Table 4 depicts peak loads in every area and period.

Table 5 is the simulation results for 8 cases in which cases 5, 7, 9 are the same case.

CASE1 is the simulation based on the single bus model of Fig.4(a) in which the three areas are aggregated into one area without network constraints. Therefore, this case is the most economic and total cost is minimum among the eight cases shown in Table 5.

On the other hand, CASE2 is based on independent three-area model without inter-line between each other (i.e. with 0 MW capacity inter-lines). Consequently the total cost is the most expensive.

CASE3 $\sim$ CASE5 are the simulation to test the affection from the capacity changes of inter-lines from 100 MW to 500 MW using the looped model of Fig.4(b). Obviously, the total costs are gradually decreased with the inter-line capacities increasing which enables more power exchanges on economy and security to be available.

CASE6 $\sim$ 8 are the tests to check the influence of reliability levels, where the model of Fig.4(b) is used. According to the results shown in Table 5, the generation plans become more economic as the reliability levels (LOLP) are set to be larger in amount.

Finally, the influence of the system structure is also investigated in CASE9 $\sim$ 10. CASE9, CASE10 use the models of Fig.4(b), Fig.4(c) respectively. By comparing to the two cases, the total cost of CASE10 is more than that of CASE9 because the transmission capability of the tandem model is less than that of the looped model.

According to the results, it has be found that the expected equivalent peak loads in each area gradually reduce, as the capacities of inter-lines become larger. In other words, since original peak loads do not occur in the same time depending on load correlations among 3 areas, load patterns would become flat shaved by the power exchanges duo to the system interconnection. Therefore, the fuel and capital costs of the interconnected system are saved, compared to the isolated system.

Table 6 shows the generation expansion plans. The number shown in this table is the cumulative number of units to install. Comparing to the plan of the independent system (CASE2). It is evident that the plan for the interconnected system (CASE5) saves 1 coal, 1 oil, 1 combined cycle, 1 gas turbine unit respectively, and the 7.9% of total cost is diminished. In addition, the computer used in this research is FACOM M-770/30. For the calculation of CASE5, it cost 22 minutes CPU time.

4.2 30-year planning example

To verify the proposed approach in more realistic way, a simulation of 30-year planning is undertaken using the looped model of Fig.4(b). As same as the 5-year planning, units parameters are presented in Table 1, Table 2 and Table 3. The construction lead times of alternative units are from 2 years to 8 years as shown in Table 3. The optimal results are shown in Table 7.

From the results, it has been found that the total cost for the interconnected system is cheaper than that of the independent system because the expected equivalent load becomes flat due to the power exchanges, and the reliability is also improved at the same time.

The above results have shown that the proposed approach is efficient and effective for the generation planning of interconnected system.

Table 5: Calculation results for 5 years planning

Case No.	Model system	Line capacity [MW]	LOLP [Day/Year]	Total cost (k $) Area-A	Area-B	Area-C	Total
1	Single bus model	——	2	——	——	——	13.416.478
2	3-area independent system	0	2	6.153.668	6.201.337	3.185.173	15.540.178
3	Influence from inter-lines capacities (3-area looped model)	100	2	6.162.868	5.583.081	3.183.294	14.929.242
4		300	2	6.256.261	5.110.779	3.193.632	14.560.671
5		500	2	6.314.770	4.950.071	3.206.197	14.471.037
6	Influence from reliability levels (3-area looped model)	500	0.2	7.812.133	5.746.921	3.415.913	16.974.997
7		500	2	6.314.770	4.950.071	3.206.197	14.471.037
8		500	20	5.637.984	4.874.212	2.817.016	13.329.212
9	Influence from system structure (3-area looped model)	500	2	6.314.770	4.950.071	3.206.197	14.471.037
1 0	(3-area tandem model)	500	2	6.301.806	5.398.658	3.123.156	14.823.621

Table 6: Generation expansion plans for each system

Area	Year	3-area independent system (CASE2)						Line capacity 100MW (CASE3)						Line capacity 500MW (CASE5)					
		Nuclear	Coal	Oil	Comb	G/T	Hydro	Nuclear	Coal	Oil	Comb	G/T	Hydro	Nuclear	Coal	Oil	Comb	G/T	Hydro
A	1991	0	0	0	0	0		0	0	0	0	0		0	0	0	0	0	
	1992	0	0	0	0	0		0	0	0	0	0		0	0	0	0	0	
	1993	0	0	0	0	1		0	0	0	1	0		0	0	0	0	0	
	1994	0	0	0	4	1		0	0	0	4	0		0	0	0	4	1	
	1995	0	0	1	6	1		0	0	1	6	0		0	0	1	6	1	
B	1991	0	0	0	0	0		0	0	0	0	0		0	0	0	0	0	
	1992	0	0	0	0	0		0	0	0	0	0		0	0	0	0	0	
	1993	0	0	0	0	0		0	0	0	0	0		0	0	0	0	0	
	1994	0	0	0	2	1		0	0	0	1	0		0	0	0	0	0	
	1995	0	1	1	2	1		0	0	1	2	1		0	0	0	1	1	
C	1991	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	1992	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	1993	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	2	0	0
	1994	0	0	1	2	1	0	0	0	1	2	0	0	0	0	1	2	0	0
	1995	0	0	1	4	1	1	0	0	1	4	0	1	0	0	1	4	0	1
Total		0	1	3	12	3	1	0	0	3	12	1	1	0	0	2	11	2	1

Table 7: Calculation results for 30 years planning

Item		3-area independent system	3-area looped system
Total cost	k $	93.083.995	91.601.711
Capital cost	k $	44.869.012	43.610.810
Operating cost	k $	22.951.887	23.042.293
O&M cost	k $	25.263.007	24.948.588
LOLP	Da;/Year	1.054	1.081

5 Conclusions

An integrated methodology for the generation planning of interconnected systems is described by using Generalized Benders Decomposition theory. The method has several characteristics summarized as follows;

I. Large scale interconnected system generation planning problem is divided into one linear master problem and many small scale generation planning problems which can be solved by the conventional approaches in relative easy way.

II. The method contains an effective treatment of the network constraints and the load correlations among all areas. Furthermore the outages of inter-lines can be taken into account in the calculation.

III. The proposed algorithm is suitable for parallel computation.

The test results has been presented to demonstrate the overall effectiveness of the method. In order to incorporate the transmission lines expansion planning and multi-area maintenance scheduling[8] into the generation planning of interconnected systems, further research work is undertaking and will be presented when this work is finished.

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