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Shan Jin
Iowa State University

Sarah M. Ryan
Iowa State University, smryan@iastate.edu

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We study a tri-level integrated transmission and generation expansion planning problem in a deregulated power market environment. The collection of bi-level sub-problems in the lower two levels is an equilibrium problem with equilibrium constraints (EPEC) that can be approached by either the diagonalization method (DM) or a complementarity problem (CP) reformulation. This paper is a continuation of its Part I, in which a hybrid iterative algorithm is proposed to solve the tri-level problem by iteratively applying the CP reformulation of the tri-level problem to propose solutions and evaluating them in the EPEC sub-problem by DM. It focuses on the numerical results obtained by the hybrid algorithm for a 6-bus system, a modified IEEE 30-bus system, and an IEEE 118-bus system. In the numerical instances, the (approximate) Nash equilibrium point for the sub-problem can be verified by examining local concavity.

Keywords

complementarity problem, equilibrium problem with equilibrium constraints, generation expansion planning, mathematical program with equilibrium contraints, Nash equilibrium, transmission expansion planning

Disciplines

Industrial Engineering | Systems Engineering

Comments

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A Tri-level Model of Centralized Transmission and Decentralized Generation Expansion Planning for an Electricity Market: Part II

Shan Jin and Sarah M. Ryan, *Member*, *IEEE*

Abstract—We study a tri-level integrated transmission and generation expansion planning problem in a deregulated power market environment. The collection of bi-level sub-problems in the lower two levels is an equilibrium problem with equilibrium constraints (EPEC) that can be approached by either the diagonalization method (DM) or a complementarity problem (CP) reformulation. This paper is a continuation of its Part I, in which a hybrid iterative algorithm is proposed to solve the tri-level problem by iteratively applying the CP reformulation of the tri-level problem to propose solutions and evaluating them in the EPEC sub-problem by DM. It focuses on the numerical results obtained by the hybrid algorithm for a 6 bus system, a modified IEEE 30 bus system and an IEEE 118 bus system. In the numerical instances, the (approximate) Nash equilibrium point for the sub-problem can be verified by examining local concavity.

Index Terms—Generation Expansion Planning, Transmission Expansion Planning, Equilibrium Problem with Equilibrium Constraints, Mathematical Program with Equilibrium Constraints, Complementarity Problem, Nash Equilibrium.

I. INTRODUCTION

THIS paper is a continuation of its Part I. There, we formulate a generation and transmission expansion planning problem as a mixed integer tri-level programming problem, with the centralized transmission planning decision in the first level, multi-GENCOs' generation expansion decisions in the second level, and an electricity market equilibrium problem in the third level.

Part I includes a full literature review of the modeling aspects of our formulation. Here, we focus on previous related numerical results. Nanduri et al. [*1*] modeled a two-tier matrix game for a multi-period, multi-GENCO capacity expansion model with an investment game in the upper level and a supply function game in the lower level with consideration of a transmission network. They proposed an algorithm to solve the matrix game to its optimal Nash equilibrium (NE) point, and applied it to a 5 bus system. Wang et al. [2] investigated bi-level games for a multi-GENCO capacity expansion planning problem in which GENCOs make their capacity and bidding decisions in the upper level and ISO clears the market in the lower level, proposed a co-evolutionary algorithm with pattern search, and applied it to an 8 bus network system, to identify the NE solution of the competition. Li et al. [3] and Soleymani et al. [4] modeled bi-level games with GENCOs' bidding decisions in the upper level and the ISO clearing the market in the lower level, for which two iterative methods were illustrated in [3] for an 8 bus system, and a search based algorithm was applied to a 6 bus system in [4]. Ruiz et al. [5] studied a multi-GENCO bi-level bidding problem subject to a market clearing problem in the lower level, and solved it as an EPEC problem, which can be reformulated as a mixed integer linear programming problem. A case study of an IEEE Reliability Test System (RTS) [6] was presented.

When the GENCOs, modeled as Cournot competitors, make their expansion decisions in anticipation of the market clearing results, their decisions are also affected by the transmission capacity. Sauma and Oren [7] modeled a multi-GENCO capacity expansion problem for a restructured electricity market, given various transmission expansion plans, as bi-level games and evaluated the social welfare of the system. An iterative algorithm to solve the bi-level games was illustrated on a 30 bus system. Roh et al. [8] simulated the interactions among GENCOs, TRANSCOs and ISO, and applied an iterative algorithm to a 6 bus system to solve a generation and transmission planning problem. The algorithm first solved resource planning problems of each GENCO and TRANSCO to maximize its profit with forecasted locational marginal price (LMP) and flowgate marginal price (FMP). Within each iteration, an ISO reliability check problem evaluated the system reliability in terms of loss of energy probability and provided capacity signals to the resource planning problem; while an ISO total social cost minimizing problem updated the LMP and FMP and provided price signals to the resource planning problems. Motamedi et al. [9] proposed a framework to consider decentralized GENCOs' reactions to the transmission expansion decision and anticipations of clearing prices from a restructured electricity market, formulated it as a four level model approached by agent-based system and search-based techniques, and applied it to a 5 bus system. Hesamzadeh et al. [10] solved a tri-level transmission augmentation planning problem with strategic generation expansion and operational decisions by a hybrid bi-level /island parallel genetic algorithm, tested on an IEEE 14-bus system. The first level minimizes the social cost including the

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Shan Jin was with Iowa State University, Ames, IA 50010 USA. She is now with Liberty Mutual Insurance Group (email: shan.jin.c@gmail.com).

Sarah M. Ryan is with the Department of Industrial and Manufacturing Systems Engineering, Iowa State University, Ames, IA 50010 USA (email: smryan@iastate.edu).

transmission augmentation cost and the system operational cost. The bottom two levels are bi-level games, in which GENCOs, on the top level, maximize their profits by determining a price and quantity bid pair and expansion level, with anticipation of a social cost minimization problem based on a security constrained economic dispatch model in the bottom level. Pozo et al. [*11*] studied a tri-level generation and transmission model, in which the investment and operational cost is minimized in the first level, the GENCOs maximize profit from expansion in the second level, and a market equilibrium problem with perfect competition among the GENCOs forms the third level. The GENCOs' MPEC problems were combined into a mixed integer linear programming problem by linearization of the nonlinear components in the objective functions and mixed integer reformulation of the equilibrium constraints. The model was tested on a 34-bus realistic power system in Chile. The problem we study is most similar to [7] but we treat the transmission plan as a decision variable in the optimization problem rather than a parameter. Our tri-level model also has a similar structure to the model investigated in [*11*]. However, we consider price-responsive linear demand functions and strategic operational decisions by the GENCOs. The problem structure is also similar to that in [10] but we apply mathematical programming to approach the solution instead of a heuristic. We test the solution accuracy and scalability on a 6 bus system, a modified IEEE 30-bus system, and the IEEE 118 bus system.

The model in our paper has a complicated tri-level structure with an equilibrium bi-level sub-problem and is difficult to solve. Algorithms are first proposed to solve the equilibrium bi-level sub-problem. Because bi-level games can be reformulated into an equilibrium problem with equilibrium constraints (EPEC), two currently available methodologies, diagonalization method (DM) and complementarity problem reformulation (CP), discussed in [12], are applied in Part I to help reformulate and solve the EPEC sub-problem and the tri-level problem. Further, we propose a hybrid iterative algorithm in Part I of the paper to solve the entire tri-level-programming problem by taking advantage of both methods.

In this paper, three case studies are presented to illustrate how the algorithm proposed in Part I works to find the best transmission expansion plan, which can generate the largest net surplus in the system, in anticipation of generation expansion, production and market clearing decisions.

In Section II, the numerical results are presented. Section III concludes the paper.

II. Numerical Results

For illustration, the hybrid algorithm has been applied to a small 6 bus system, a modified IEEE 30 bus test system, and the IEEE 118 bus sytem. In the 6 bus system, all the transmission planning options can be enumerated so that we are able to validate the global optimality of the solution found by the hybrid algorithm. The 30 bus system tests the scalability of the method and allows comparison with previous results in [7]. In the 118 bus system, global optimality among a restricted, realistic, set of transmission expansion options is verified. All the computational results are computed in GAMS23.4, and run on a 3.4GHz Intel Pentium 4 processor with 4 GB of RAM and 64 bit windows 7 system.

A. Six Bus System

For a demonstration case, we present a 6 bus network with three GENCOs on Buses 1, 2 and 6, and three candidate transmission lines shown in Figure 1, where solid lines represent the existing transmission lines and dotted lines represent the candidate lines.

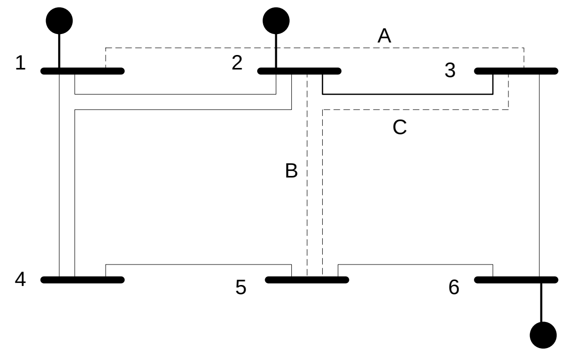

Fig. 1. A 6 Bus Test System with Three Candidate Lines

TABLE I
Model Parameters for Bus Nodes

j	V_j(MW)	c_j^{gexp}($/MW)	c_j($/MWh)	e_j($/MWh/MWh)	U_j(MW)	a_j($/MWh)	b_j($/MWh/MWh)
1	80	10	20	0.0625	1800	100	-1
2	50	10	20	0.0625	1800	100	-1
3	n/a	n/a	n/a	n/a	0	120	-1
4	n/a	n/a	n/a	n/a	0	120	-1
5	n/a	n/a	n/a	n/a	0	120	-1
6	20	6	40	0.2500	1200	100	-1

TABLE II
Model Parameters for Transmission Lines

(i, j)	K_{ij} (MW)	$B_{ij}(\Omega^{-1})$	c_{ij}^{trexp}($/MW)	Line Status
(1,2)	200	5.9	n/a	Existing
(1,3) A	100	30	4	Candidate
(1,4)	50	3.9	n/a	Existing
(2,3)	100	27	n/a	Existing
(2,4)	100	5.1	n/a	Existing
(2,5) B	100	30	4	Candidate
(3,5) C	100	30	4	Candidate
(3,6)	100	55.5	n/a	Existing
(4,5)	50	27.0	n/a	Existing
(5,6)	100	5.1	n/a	Existing

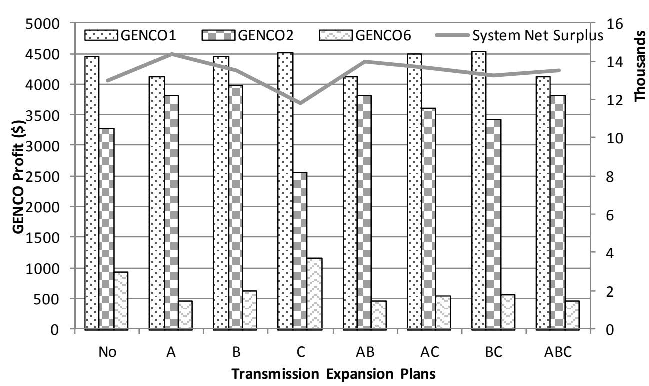

Fig. 2. Net Surplus and GENCOs' Net Profits with Different Transmission Expansion Plans for a 6 Bus System

All the model parameters are presented in Table I and II.

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The three candidate lines are called lines A, B and C. The initial values V_j^{newequ} for the DM algorithm are set to equal their current values V_j.

Each of the eight feasible transmission expansion solutions can be evaluated in the equilibrium bi-level sub-problem by DM. Figure 2 compares the system net surplus and the profit for each GENCO among all the solutions, and it indicates that building transmission line A only is the global optimal solution according to system net surplus.

The iterative results obtained by the hybrid algorithm are presented in Table III. In the first iteration, the master problem identifies building line A only as a promising initial transmission planning decision. Assuming this line is built, DM identifies an (approximate) NE for the multi-GENCO expansion decisions. The lower bound for the upper-level objective value and best found solution are updated, and a cut constraint is added to the master problem to eliminate the current solution of building line A only. The master problem becomes infeasible at its second iteration, which implies that all the other transmission plans other than building line A only cannot produce a net surplus in the master problem higher than 14348.46. Therefore, the algorithm terminates with the best found solution of building line A only, which is the global optimal solution of the original tri-level programming problem, as shown in Figure 2. The hybrid algorithm takes only two major iterations and one DM evaluation to find the optimal solution within 104.41 seconds. In comparison, enumerating all solutions and evaluating each by DM requires a total of 542.82 seconds.

Table IV summarizes the detailed results obtained with different transmission expansion plans, where we can draw the same conclusion from the total net surplus, that the global optimal solution is to build line A only. From Table IV, when there is no transmission expansion, the system experiences congestion in line (2, 3). When one transmission line, A, is built, the congestion is relieved and the electricity price decreases. The GENCOs have less market power to drive a high market price by expanding and generating less. Instead, the GENCOs maximize their profit by making the expansions to sell more power. Therefore, the buyers receive more electricity with lower prices, which results in higher buyer surplus. Compared with plan "None", the buyer surplus and seller surplus both increase. Because the increase in the system surplus is sufficient to cover the cost of building transmission line A and extra generation expansion cost, plan "A" is much more favored than plan "None". Unlike in plan "A", in plans "B" and "C", the network congestion has not been eliminated. Although building only transmission line B leads to a slight decrease in electricity price, and, thus, an increase in both buyer surplus and seller surplus, the overall system net surplus is not as high as in plan "A". In plan "C", the system congestion becomes even worse, which leads to higher electricity prices, and the buyer surplus and seller surplus both decrease. Plans "AB" and "ABC" result in the same generation expansion level, and quantity consumed as plan "A", but at a higher transmission expansion cost. Therefore it is obvious that plan "A" is preferred. Plans "AC" and "BC" generally help to relieve the congestion and increase the system efficiency with a higher system net surplus. However they have higher transmission investment cost and lower increase in system surplus than plan "A".

We observe that the best transmission expansion plan can not only increase the total net surplus but also guide the market participants to achieve a win-win situation in which total buyer and seller surpluses can be increased by 22% and 7%, respectively. The total net surplus increase comes mostly from the increasing total buyer surplus, which is driven by the increasing generation capacity expansions and the lower electricity prices.

B. Modified IEEE 30 Bus Test System

The modified IEEE 30 Bus Test System includes six generators on nodes 1, 2, 13, 22, 23 and 27, thirty-nine transmission lines, and ten candidate transmission lines. Based on the 30 bus case study in [7], the model parameters are set up as shown in Appendix A. Different from [7], we assume a quadratic generation cost function that is not affected by the increasing generation capacity, and we do not consider expanding the capacity of the existing transmission lines. All the GENCOs have the same generation cost function with $c_j = 10$ and $e_j = 0.0625$. The ten candidate lines are labeled as A through J, among which the lines B, E, G, and H are the proposed new lines in [7]. The total number of all transmission expansion options totals $2^{10} = 1024$, which makes evaluation of each by DM computationally prohibitive. The network is in Figure 4, where solid lines represent the existing transmission lines and dotted lines represent the candidate lines.

The larger problem size causes computational difficulty to solve the MINLP master problem at the beginning of each major iteration. Because the purpose of the master problem is to identify a promising transmission planning decision, it can be further relaxed by ignoring equations obtained from the partial derivatives of the Lagrangian with respect to the dual variables; i.e., equations (43) - (54) in Part I of this paper.

The iterative results obtained by the hybrid algorithm are given in Table V. In the fourth major iteration the algorithm finds the optimal solution, which is to build only candidate line H. This result also appears to be consistent with the case study results found in [7]. Except for the adjustment of the parameters due to model differences, the 30 bus case study is the same as the one in [7]. Besides the instance with ten candidate lines, we also examine a 30 bus case study with the four new transmission lines B, E, G, and H, suggested in [*7*], and the results also indicate building line H only. All the 16 feasible transmission expansion solutions can be evaluated in the EPEC sub-problem by DM. Figure 4 compares the system net surplus and the profit for each GENCO given all transmission expansion options, and it indicates that building transmission line D only is the global optimal transmission expansion decision. Although we do not have the DM solutions for all 1024 transmission expansion options to validate the best solution found by the hybrid algorithm, based on the results of the 30 bus instance with four candidate lines in Figure 3, it is very likely that building line H only is the global optimal solution for the tri-level expansion planning problem. The total computational time for the hybrid algorithm is 5591.97 seconds.

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TABLE III
ITERATIVE RESULTS OF THE HYBRID ALGORITHM TO SOLVE A 6 BUS CASE STUDY

Major Iteration	MINLP Master Problem A with CP Reformulation			EPEC Sub-problem B with DM	Adding Constraints	
	Status	$\mathbf{z^{master}}$	**Net Surplus** $\mathbf{F(z^{master}, \Omega^{master})}$	**Net Surplus** $\mathbf{F(z^{master}, \Omega^{sub})}$	**Lower Bound** $\mathbf{F^{best}}$	**Cut Point** $\mathbf{z^{master}}$
1	Feasible	A	15244.07	14348.46	14348.46	A
2	Infeasible					

TABLE IV
DETAILED RESULTS WITH DIFFERENT TRANSMISSION EXPANSION PLANS

		None	A	B	C	AB	AC	BC	ABC
Total Surplus		13502	15908	14690	12561	15908	15509	14921	15908
Total Buyer Surplus		3929	6347	4808	3394	6347	5871	5130	6347
Total Seller Surplus		9202	9561	9861	8596	9561	9638	9791	9561
Total Transmission Rent		371	0	21	571	0	0	0	0
Total Generation Investment Cost		535	1159	800	362	1159	1043	870	1159
Total Transmission Investment Cost		0	400	400	400	800	800	800	1200
Total Net Surplus		12967	14348	13490	11799	13948	13666	13251	13548
Generation Expansion Level, V_j^{new} = Generation Level, y_j	1	99.98	120.36	105.93	98.20	120.36	126.39	117.48	120.36
	2	74.63	120.36	100.09	54.38	120.36	101.51	93.93	120.36
	6	34.86	28.66	26.58	42.68	28.66	30.66	29.34	28.66
Quantity Consumed, q_j	1	27.23	34.90	28.88	26.04	34.90	33.09	30.13	34.90
	2	28.17	34.90	28.90	28.62	34.90	33.09	30.13	34.90
	3	41.39	54.90	48.54	38.98	54.90	53.09	50.13	54.90
	4	45.81	54.90	48.87	42.15	54.90	53.09	50.13	54.90
	5	45.16	54.90	48.86	40.37	54.90	53.09	50.13	54.90
	6	21.71	34.90	28.56	19.10	34.90	33.09	30.13	34.90
Electricity Price, p_j	1	72.77	65.10	71.12	73.96	65.10	66.91	69.88	65.10
	2	71.83	65.10	71.10	71.38	65.10	66.91	69.88	65.10
	3	78.61	65.10	71.46	81.02	65.10	66.91	69.88	65.10
	4	74.19	65.10	71.13	77.85	65.10	66.91	69.88	65.10
	5	74.84	65.10	71.14	79.63	65.10	66.91	69.88	65.10
	6	78.29	65.10	71.44	80.90	65.10	66.91	69.88	65.10
Flow, f_{ij}	(1,2)	31.10	0.66	41.88	37.39	9.10	3.15	48.27	6.89
	(1,3)	0.00	51.87	0.00	0.00	58.41	71.54	0.00	63.41
	(1,4)	41.64	32.93	35.17	34.77	17.95	18.61	39.09	15.17
	(2,3)	**50.00**	43.64	**50.00**	**50.00**	10.91	49.96	49.28	25.55
	(2,4)	27.57	42.48	9.79	13.15	15.60	21.61	9.39	13.88
	(2,5)	0.00	0.00	53.28	0.00	68.06	0.00	53.40	52.92
	(3,5)	0.00	0.00	0.00	28.22	0.00	57.26	-1.35	24.53
	(3,6)	8.61	40.62	1.46	-17.20	14.42	11.14	0.51	9.53
	(4,5)	23.40	20.51	-3.90	5.77	-21.35	-12.88	-1.65	-25.85
	(5,6)	-21.75	-34.38	0.52	-6.38	-8.18	-8.71	0.28	-3.29

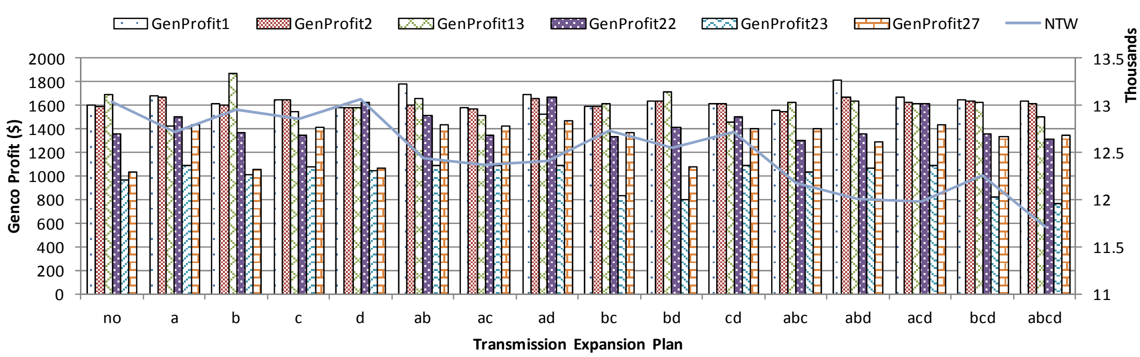

Fig. 3. Net Surplus and GENCOs' Net Profits with Different Transmission Expansion Plans for a modified IEEE 30 Bus Test System

TABLE V
ITERATIVE RESULTS OF THE HYBRID ALGORITHM TO SOLVE A MODIFIED IEEE 30 BUS TEST SYSTEM

Major Iteration	MINLP Master Problem A with CP Reformulation			EPEC Sub-problem B with DM	Adding Constraints	
	Status	$\mathbf{z^{master}}$	**Net Surplus** $\mathbf{F(z^{master}, \Omega^{master})}$	**Net Surplus** $\mathbf{F(z^{master}, \Omega^{sub})}$	**Lower Bound** $\mathbf{F^{best}}$	**Cut Point** $\mathbf{z^{master}}$
1	Feasible	No	13235.34	13038.62	13038.62	No
2	Feasible	B	13057.90	12727.90	13038.62	B
3	Feasible	E	13216.10	12957.11	13038.62	E
4	**Feasible**	**H**	**13246.07**	**13066.56**	**13066.56**	**H**
5	Infeasible					

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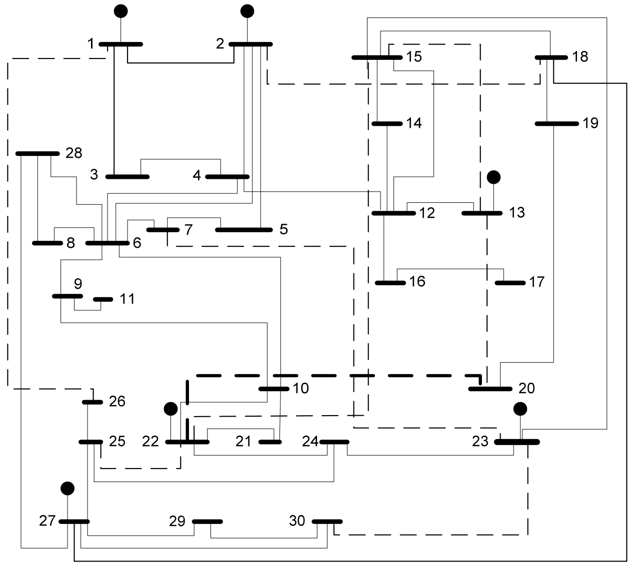

Fig. 4. A Modified IEEE 30 Bus Test System with Ten Candidate Lines

Given expansion on candidate line H, the DM results for the optimal generation capacity vector, V^{new}, are indicated in Figure 5. Based on much computational experience, the optimal solutions usually stabilize within 10 to 15 rounds of iterations, so we set 25 as a maximum number of iteration cycles to terminate the DM algorithm when it is impossible to find an exact NE point. Because there are six different GENCOs making their capacity decisions in each round of iteration, it results in a maximum of 150 MPEC solution iterations.

From Figure 5, since the optimal solution does not converge, we infer existence of a mixed, rather than pure, Nash strategy. The GENCOs' decisions oscillate within a small range of approximately 1%: GENCO 1 slightly adjusts its decision between the values 99.94 and 100.88; GENCO 2 between the values 99.94 and 100.52; GENCO 13 between 77.94 and 78.03; GENCO 22 between 105.24 and 105.87; while both GENCOs 23 and 27 are converged to a capacity of 60 MW each. In this case, we can simply define an approximate equilibrium point by averaging the two capacity values for a generator, so that the optimal generation expansion capacities V_k^{new} , j = 1, 2, 13, 22, 23 and 27, are approximately [100.41, 100.23, 77.99, 105.56, 60, 60] and the generation levels y_j , j = 1, 2, 13, 22, 23 and 27, are the same as their new generation capacities. The net profits for each GENCO are [1586.50, 1583.39, 1581.42, 1632.46, 1050.94, 1076.19], and the total system net surplus is 13066.56.

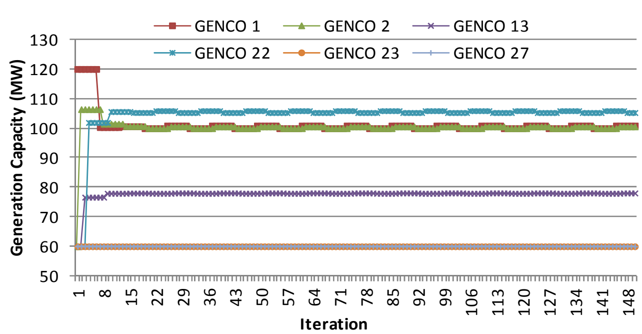

Fig.5. Iteration of Expansion Capacity V^{new} with Transmission Expansion on Line H

C. Nash Equilibrium (NE) Solution Validation

The DM algorithm is applied to iteratively solve each single bi-level programming problem, reformulated as an equivalent mathematical program with equilibrium constraints (MPEC) including equations (2), (3), (18)-(35) for each specific GENCO k, within the EPEC sub-problem B. The (approximate) convergence point is an NE point, where no GENCO can improve its profit by changing only its own capacity expansion decisions while all the other GENCOs' decision remain fixed. To ensure the (approximate) convergence point, each GENCO's MPEC in the DM iteration should be solved to its local optimality. However the objective function (2) of each MPEC in Part I is nonlinear and not ensured to be concave, which implies no guarantee for the global optimality. To validate that the solution found by DM approximates an NE, we must further investigate the objective values of neighboring points.

For each single MPEC, we can reformulate the lower level problem by introducing the binary variables μz and and a big value M, and converting all the equilibrium constraints of the form $0 \le x \perp y \ge 0$ into $0 \le x, 0 \le y, x \le M\mu z, y \le M(1 - \mu z)$ as in our previous paper [13]. Upon this reformulation, the MPEC becomes a single level programming problem with mixed integer linear constraints and nonlinear objective function given by equation (2) in Part I. For GENCO 1, given the optimal solutions of the other GENCOs as the model parameters, we evaluate the net benefits for the neighboring points of the optimal solution, 100.41. Variable V_1^{new} can be fixed to values ranging from its existing capacity, 60, to 120 to investigate the change of the objective values in response to it. Once the variable V_1^{new} is fixed, its optimal generation variable $y_1 = V_1^{new}$ can be determined, since there is no incentive to expand beyond the actual generation level that is needed[1]. In this case, the single level nonlinear mixed integer program (MIP) has been transformed to a single level linear MIP, which can be solved to its global optimality by CPLEX. The only variable involved in the objective function is p. In the case of making no expansion, like GENCO 23 and 27, because V_k^{new} has to be higher than the existing capacity, 60, we evaluate the net profits for the neighboring area by fixing V_k^{new} from 60 to a predetermined higher value. Figure 6 presents the relationship among the objective value, the net profit of GENCO 1, and its capacity decision V_1^{new}. The net profit at the top is an enlargement of the bottom one. It indicates concavity of the GENCO's objective, given in equation (2) of Part I, as a function of V_1^{new} with the global optimal solution between 100 and 101, which is consistent with the approximate optimal point 100.41 found by the DM algorithm. The same test can be applied to each GENCO to validate the global optimality of each GENCO's MPEC

[1] Here, the model is a single period model. However, in a stochastic EPEC, the generation level y in all the scenarios will not necessarily equal the capacity level V^{new}. To validate an (approximate) NE point in the stochastic EPEC case, we can also first fix a GENCO k's capacity level V_k^{new} in a range of values. Given each fixed value V_k^{new}, we can solve for a set of pairs of optimal generation level and dual price $\{y_s(V_k^{new}), p_s(V_k^{new})\}$ under each scenario s, so that we can calculate profit for GENCO k expanding at V_k^{new} in equation (2) in Part I of the paper. We can compare those profits for GENCO k at all the different capacity levels V_k^{new} and find the V_k^{new} with the highest profit.

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problem, which further verifies that the optimal solution found by the DM algorithm is indeed the local NE point of the EPEC sub-problem B.

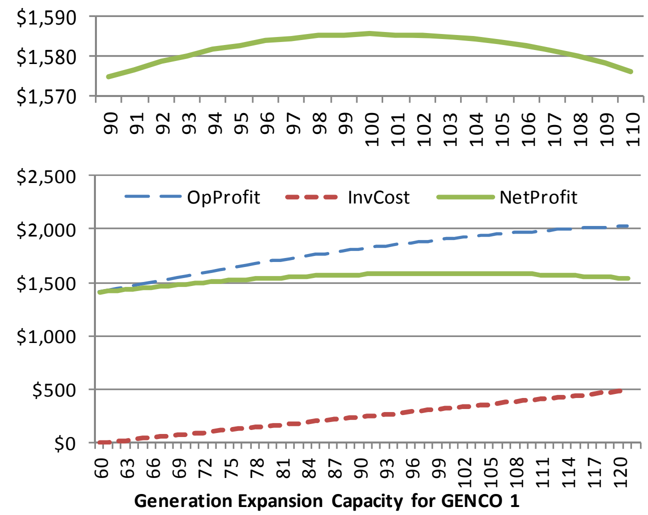

Fig. 6. Investment Cost, Operational Profit and Net Profit by Expansion Capacity V_1^{new}

D. IEEE 118 Bus Test System

The algorithm was also tested on a standard IEEE 118 bus system with 54 generators, 179 existing lines and 4 candidate lines. The candidate lines were selected as likely to help relieve the congestion in the existing system. All the nodes have the same linear demand functions with $a_j = 100$ and $b_j = -1$. The capacities of existing lines are assumed to be K_{ij} =50, and K_{ij} = 100 for the candidate lines. Detailed parameter assumptions for GENCOs and transmission lines are shown in Appendix 5.B of [*14*].

The algorithm identified the best solution at the first major iteration and found two more feasible, though inferior, solutions in the second and third rounds. The best solution returned is to build the transmission lines A, C and D. We observe that even after building three candidate lines, system congestion still exists.

We also obtained the global optimal solution of the 118 bus case study by enumerating all the 16 possible transmission expansion options in Figure 7, and verified that the best solution found by the algorithm turned out to be globally optimal in this instance.

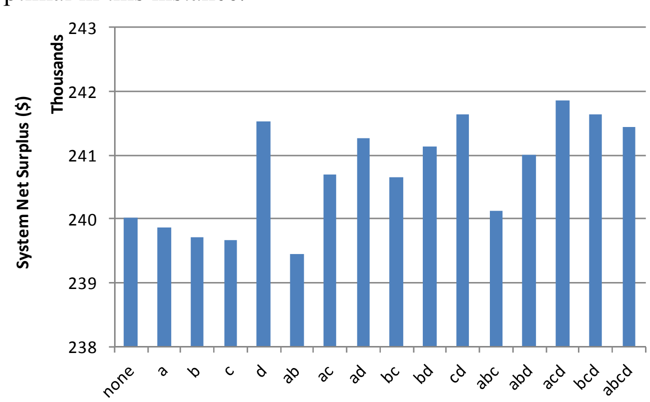

Fig. 7. Net Surplus with Different Transmission Expansion Plans for the IEEE 118 Bus Test System

III. Conclusions

In this paper, we consider an integrated market-based transmission and generation expansion planning problem in a deregulated electricity market environment. The novel tri-level programming model proposed in Part I of the paper includes an equilibrium bi-level sub-problem, also known as an EPEC, which can be solved by either a diagonalization method (DM) or a complementarity problem (CP) reformulation. To approach the tri-level optimization problem, a hybrid iterative algorithm is proposed in Part I of the paper by taking advantage of both methods.

The proposed algorithm has been tested both on three systems. In the smallest instance, where all the feasible transmission expansion solutions can be enumerated, the solution found by the hybrid algorithm has been shown to be globally optimal. The solutions of the 30 and 118 bus systems were also successfully found by the hybrid algorithm. To deal with the cases where a pure Nash equilibrium strategy does not exist, an approximate NE point has been defined. Finally, a method has been proposed to validate the (approximate) NE point found by DM algorithm.

Appendix A.
Model Parameters for Modified IEEE 30 Bus System

TABLE VI
Model Parameters for Bus Nodes

j	V_j(MW)	c_j^{gexp}($/MW)	b_j($/MW/MW)	a_j($/MW)
1	60	8	-1	50
2	60	8	-1	50
3	0	0	-1	60
4	0	0	-1	55
5	0	0	-1	50
6	0	0	-1	50
7	0	0	-1	60
8	0	0	-1	55
9	0	0	-1	50
10	0	0	-1	55
11	0	0	-1	50
12	0	0	-1	55
13	60	8	-1	50
14	0	0	-1	55
15	0	0	-1	55
16	0	0	-1	50
17	0	0	-1	55
18	0	0	-1	50
19	0	0	-1	55
20	0	0	-1	50
21	0	0	-1	50
22	60	8	-1	50
23	60	8	-1	60
24	0	0	-1	55
25	0	0	-1	50
26	0	0	-1	50
27	60	8	-1	50
28	0	0	-1	50
29	0	0	-1	50
30	0	0	-1	55

TABLE VII
Model Parameters for Transmission Lines

(i, j)	K_{ij} (MW)	$B_{ij}(\Omega^{-1})$	c_{ij}^{trexp}($/MW)	Line Status
(1,2)	130	15	n/a	Existing
(1,3)	130	4.92	n/a	Existing
(2,4)	65	5.23	n/a	Existing
(3,4)	130	23.53	n/a	Existing
(2,5)	130	4.71	n/a	Existing

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(2,6)	65	5	n/a	Existing
(4,6)	90	23.53	n/a	Existing
(5,7)	70	7.1	n/a	Existing
(6,7)	130	10.96	n/a	Existing
(6,8)	32	23.53	n/a	Existing
(6,9)	65	4.76	n/a	Existing
(6,10)	32	1.79	n/a	Existing
(9,11)	65	4.76	n/a	Existing
(9,10)	65	9.09	n/a	Existing
(4,12)	65	3.85	n/a	Existing
(12,13)	65	7.14	n/a	Existing
(12,14)	32	3.17	n/a	Existing
(12,15)	32	5.96	n/a	Existing
(12,16)	32	4.16	n/a	Existing
(14,15)	16	2.26	n/a	Existing
(16,17)	16	4.47	n/a	Existing
(15,18)	16	3.64	n/a	Existing
(18,19)	16	6.34	n/a	Existing
(19,20)	32	12.07	n/a	Existing
(10,21)	32	12.07	n/a	Existing
(10,22)	32	5.47	n/a	Existing
(21,22)	32	40	n/a	Existing
(15,23)	16	4	n/a	Existing
(22,24)	16	3.85	n/a	Existing
(23,24)	16	3.01	n/a	Existing
(24,25)	16	2.28	n/a	Existing
(25,26)	16	1.84	n/a	Existing
(25,27)	16	3.74	n/a	Existing
(27,28)	65	2.5	n/a	Existing
(27,29)	16	1.87	n/a	Existing
(27,30)	16	1.3	n/a	Existing
(29,30)	16	1.73	n/a	Existing
(8,28)	32	4.59	n/a	Existing
(6,28)	32	15	n/a	Existing
(1,26) A	100	23.53	4	Candidate
(2,18) B	100	23.53	4	Candidate
(7,23) C	100	23.53	4	Candidate
(13,15) D	100	23.53	4	Candidate
(13,20) E	100	23.53	4	Candidate
(15,22) F	100	23.53	4	Candidate
(18,27) G	100	23.53	4	Candidate
(20,22) H	100	23.53	4	Candidate
(22,25) I	100	23.53	4	Candidate
(23,30) J	100	23.53	4	Candidate

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V. Biographies

Shan Jin received her B.S. degree in computational mathematics from Zhejiang University (ZJU), Hangzhou, China, and her M.S. and Ph.D degree in Industrial Engineering from Iowa State University. In summer 2011 and 2012, she worked as a summer graduate student in Center for Energy, Environmental, and Economic Systems Analysis (CEEESA) at Argonne National Laboratory. Her research interest includes power system planning, electricity markets, and renewable energy. She is currently with Liberty Mutual Insurance Group.

Sarah M. Ryan (M'09) received her Ph.D. degree from The University of Michigan, Ann Arbor. She is currently Professor in the Department of Industrial and Manufacturing Systems Engineering at Iowa State University. Her research applies stochastic modeling and optimization to the planning and operation of service and manufacturing systems.