Transmission Switching in Expansion Planning

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***Abstract*—Transmission switching (TS) is introduced to add flexibility to the transmission and generation capacity expansion planning problem. TS could improve the performance of the capacity expansion planning model and reduce the total planning cost. The capacity expansion planning problem is decomposed into a master problem and two subproblems. The master problem utilizes the candidate set for additional generating unit and transmission capacity investments to find the optimal plan throughout the planning horizon. The subproblems use the optimal plan, apply transmission switching to relieve any transmission flow violations, and calculate the optimal dispatch of generating units. The transmission network contingencies are also considered in the subproblems. The case studies exhibit the effectiveness of the proposed expansion planning approach.**

***Index Terms*—Benders decomposition, mixed integer linear programming, transmission and generation capacity expansion planning, transmission switching.**

NOMENCLATURE

Indices:

b	Index for a load block.
C	Index for a candidate generating unit or transmission line.
E	Index for an existing generating unit or transmission line.
h	Index for a bus.
i	Index for a generating unit.
j	Index for a transmission line.
t	Index for a year.
$\wedge$	Index for the known variables.

Sets:

J_h	Set of transmission lines connected to bus h.
I_h	Set of generating units connected to bus h.

Parameters:

CI	Investment cost for candidate generating unit or transmission line.
Cap	Capacity of candidate generating unit or transmission line.
d	Discount rate.
DT_{bt}	Duration of the load block b in year t.
GCI_t	Capital generating unit investment in year t.
GCT_i	Required time for the construction of unit i.
GUC_t	Maximum added generating capacity in year t.
GUN_t	Maximum number of generating units added in year t.
LCI_t	Capital transmission line investment in year t.
LCT_j	Required construction time for the transmission line j.
LUC_t	Maximum transmission line capacity to be added in year t.
LUN_t	Maximum added number of transmission lines in year t.
NB	Number of load blocks.
NCG	Number of candidate generating units.
NCL	Number of candidate transmission lines.
NEG	Number of existing generating units.
NEL	Number of existing transmission lines.
NH	Number of buses.
NT	Number of years.
OC_{ibt}	Operating cost of the generating unit i at load block b in year t.
PD_{hbt}	Load demand at bus h at load block b in year t.
UX_{ibt}	Contingency state of the generating unit i at load block b in year t.
UY_{jbt}	Contingency state of the transmission line j at load block b in year t.
γ_j	Susceptance of the transmission line j.
ε	Small positive and predefined threshold.

Variables:

PG_{ibt}	Dispatched capacity of the generating unit i at load block b in year t.
PL_{jbt}	Power flow on the transmission line j at load block b in year t.
$SL_{hbt,1}$, $SL_{hbt,2}$	Nonnegative slack variables for power mismatch at bus h at load block b in year t.
X_{it}	Investment state of the generating unit i in year t.
Y_{jt}	Investment state of transmission line j in year t.
Z_{jbt}	Switching state of the transmission line j at load block b in year t.
δ_{mbt}	Voltage angle of bus m at load block b in year t.
λ, μ, π	Dual variables.

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I. Introduction

SWITCHING of power system elements can help ISOs maintain the system security and reduce operation costs. In comparison with existing control methods such as generating unit rescheduling or load shedding [1], [2], transmission switching (TS) can provide additional economical advantages. Several TS approaches were presented in the literature to encompass various operational modes of power systems. In [3], TS was used as a corrective action to mitigate transmission flow violations. In [4]–[7], TS was used to model the power system security in contingency cases. TS was used in [8] as a congestion management tool. However, TS can provide economic benefits which was first introduced in [9] in a market context. The application of TS in reducing the production cost was investigated in [10], and was further developed in [11] to examine the effects of network topology changes on nodal prices, load payments, generation revenues, congestion costs, and flowgate prices. In [12], a model was proposed to add contingencies to the model in [10]. These studies indicated that the switching could provide additional control actions for voltage stability, congestion management, transmission loss reduction, production cost minimization, and the enhancement of system security. However, the TS applicability to the power system planning was not addressed.

Power system planning is the science of determining the optimal place, size, and time for adding new resources to power systems. Previous studies investigated generation and transmission expansion planning methodologies in competitive market environments. The most common planning methods are based on mathematical optimization such as branch and bound, linear programming, and Benders decomposition [13]–[21]. Also heuristic approaches, such as genetic algorithms, fuzzy-sets, simulated annealing, expert systems, and game-theoretic methods [22]–[30], were used to solve the expansion planning problem. The market-based planning in power systems considers economics, security, and reliability constraints and analyzes the risk of planning strategies based on uncertainties [31]–[35]. Using Lagrangian relaxation and Benders decomposition, the impact of transmission security on generation resource planning was discussed [36]. The coordination of transmission expansion planning with the competitive generation capacity planning was presented in [37]. In [38], a very constructive proposal was offered on the interaction of generation and transmission investments in transmission planning. In [39], the long-term transmission expansion planning problem in a competitive pool-based electricity market was modeled. In this model, a number of scenarios based on the future system demand were defined and the optimal expansion planning was simulated by the maximization of the aggregated social welfare. A bilevel model for transmission expansion planning within a market environment was proposed in [40]. The minimization of the network investment was considered in the upper level, while the lower level included pool trading constraints.

The objective of a generation company (GENCO) or a transmission company (TRANSCO) is to maximize its profit over the planning horizon. However, when the ISO performs the planning, the objective will be replaced by the minimization of investment and operating costs. In this paper, it is assumed that the GENCOs and TRANSCOs have already submitted their candidate expansion proposals to the ISO. The ISO will solve the expansion planning problem to satisfy the system constraints based on the candidate set of components submitted by the participating companies.

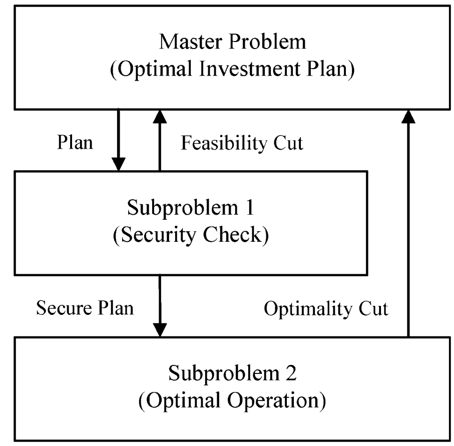

Fig. 1. Proposed expansion planning using TS.

This paper presents a TS coordinated expansion planning model. The planning is a long-term problem that is solved over an extended period of time. TS is a short-term operation problem. The two problems are solved separately, considering the associated time periods. The important point is to link these two problems in a way that the impact of TS on planning can be observed. This task is accomplished by using the security check and the optimal operation subproblems in Fig. 1. The TS application could reduce the total planning cost and possibly defer the planning of the candidate units and transmission lines. In this situation the transmission congestion in the system can vary. A corrective/preventive scheme is used to handle transmission line and generating unit contingencies. The security check subproblem performs corrective actions, while the preventive actions are considered in the master problem. Our proposed approach uses a deterministic criterion to consider contingencies. A future stochastic market-based expansion planning study will explore the effect of random outages of generating units and transmission lines in addition to the long-term load forecast errors, where the Monte Carlo simulation will be used to identify scenarios and the proposed deterministic model will be solved in each scenario.

The rest of the paper is organized as follows. Section II presents the model outline of the proposed approach, while Section III formulates different parts of it. Section IV conducts the numerical simulations and in detail discusses a six-bus, the IEEE 118-bus, and an 1168-bus systems. Finally, concluding remarks are presented in Section V.

II. Proposed Model Outline

Fig. 1 depicts the proposed coordinated generation and transmission expansion planning model. The objective of this problem is to minimize the investment cost, for new generating units and transmission lines, in addition to operating costs. This objective is subject to different security-based planning and operation constraints.

In this paper, Benders decomposition is used to decompose the expansion planning problem. Benders decomposition is mathematically sound and can easily be applied to large-scale systems. The optimality of Benders decomposition as well as its applicability to power system problems in practical cases are discussed in [41]–[44]. Also in [2], the practical applications of Benders decomposition are discussed in detail, where it is explained that the most suitable approach to solve the multi-period expansion planning problem is to use the Benders decomposition. The Benders decomposition provides the iterative solution of the mixed integer linear programming (MIP) problem in a distributed manner. The decomposed planning model includes the optimal investment plan as the master problem, and the security and the optimal operation of the system as the two subproblems. The master problem utilizes the candidate set of generating units and transmission lines to find the optimal investment plan. The security check subproblem examines this plan for satisfying the base case and the security constraints. The optimal operation subproblem inspects the operating cost of the plan. TS is used in the security check and the optimal operation subproblems to enhance the feasibility and the optimality of the proposed problem, respectively. Integer linear programming (ILP) is used to model the master problem, while the subproblems are LP models. A typical set of planning constraints includes

- capital investment funds;
- projected resource and line capacity;
- maximum number of generating units and transmission lines to be added;
- construction time of the candidate investments.

A typical set of operation constraints includes

- power balance;
- transmission line flow limits;
- generation limits.

The approach is presented as follows.

A. Master Problem

The master problem calculates the investment plan for generating units and transmission lines based on the initial set of candidates when considering generation and transmission expansion constraints. The lower bound for the original MIP planning problem is determined by the value of the master problem objective at each iteration. The variables in the master problem are binary and constraints are linear. So the master problem is in the ILP format.

B. Subproblems

The investment plan calculated in the master problem is submitted to the subproblems. The security check subproblem checks whether the proposed plan satisfies the operation constraints. This subproblem would satisfy the power balance at every bus while preserving base case and contingency constraints. If any of the constraints are violated, a feasibility cut is formed and added to the master problem for the solution of the next iteration of the expansion planning problem. This iterative process will continue until a secure plan is achieved.

The optimal operation subproblem is used to check the minimum cost of solution. This subproblem checks the optimality by calculating the upper bound of the original MIP planning problem's objective function and comparing it with its lower bound, which is already calculated in the master problem. If the proposed plan is not optimal, Benders cuts will be formed and added to the master problem for solving the next iteration.

C. TS

TS is used in both subproblems to minimize the operating costs as well as the transmission security violations. The TS binary variables are determined in the master problem and treated as constants in the subproblems. The utilization of TS states in the proposed cuts will help utilize candidate generating units and transmission lines in the planning options. The switchable line states appear as variables in the master problem, but they are governed by dual values in the subproblems.

D. Cuts

In the proposed approach two types of cuts are used. The first one is a feasibility cut which is generated in the security check subproblem. The feasibility cut indicates that the security violations can be mitigated by readjusting the investment plan in each planning year as well as the state of switchable lines in the operation periods. This cut represents the coupling of the proposed investment plan and adjustments in the state of switchable lines. The dual variables in the feasibility cut are the incremental reduction in the load balance violations. The second one is an optimality cut that is generated in the optimal operation subproblem. The optimality cut would limit the range of master problem objective to make it closer to the objective function of the original MIP planning problem. The optimality cut indicates that the objective value of the expansion planning problem can be decreased by modifying the investment plan in addition to the state of switchable lines. Similar to the feasibility cut, this cut represents the coupling of adjustments in the proposed investment plan and the state of switchable lines. The dual variables in the optimality cut are the incremental reduction in the objective function of the optimal operation subproblem.

E. Solution Procedure

The binary switching variables in the master problem are governed by Benders cuts generated in the subproblems. On the other hand, the switching variables affect the investment plans. So the solution of the larger time scale is guided by the smaller time scale problem, and the solution of the smaller time scale problem is guided by the cuts produced at each iteration. The planning solution procedure is given as follows.

1) Solve the planning master problem by considering candidate generating units and transmission lines. There will be no Benders cut in the first iteration of the master problem.
2) Given the proposed plan in the master problem, check the feasibility of system constraints. If the subproblem is feasible, proceed to Step 3. Otherwise, form the Benders cut and return to the master problem.
3) Minimize the operating cost by considering the system constraints. Compare the solution value, i.e., an upper bound, with the objective of master problem, i.e., a lower bound. If the difference is larger than a predefined threshold, form the Benders cuts and return to the master problem for the next iteration. Otherwise, consider the proposed plan as optimal.

III. Problem Formulation

The objective of the expansion planning problem is to minimize the total cost of the system while satisfying the system security and reliability constraints. The total cost includes the investment cost of new generating units and transmission lines plus the system operating cost. This objective is formulated as (1), and is subject to planning and operation constraints:

$$\begin{aligned} MinPP = &\sum_{t=1}^{NT}\sum_{i=1}^{CG}\frac{CI_{it}\left(X_{it}-X_{i(t-1)}\right)}{(1+d)^{(t-1)}} \\ &+\sum_{t=1}^{NT}\sum_{j=1}^{CL}\frac{CI_{jt}\left(Y_{jt}-Y_{j(t-1)}\right)}{(1+d)^{(t-1)}} \\ &+\sum_{t=1}^{NT}\sum_{b=1}^{NB}\sum_{i=1}^{NG}\frac{DT_{bt}OC_{ibt}PG_{ibt}}{(1+d)^{(t-1)}}. \end{aligned} \tag{1}$$

The solution of this problem would determine the size, the location, and the time for adding new generating units and transmission lines in an economical way that ensures the system capability to meet the anticipated load growth in the future. Using the Benders decomposition, the problem is decomposed into a master problem and two subproblems. The master problem provides the optimal plan and the subproblems provide solutions for the security check and the optimal operation.

A. Optimal Plan

The objective of the optimal investment planning problem is to minimize the investment cost of new generating units and transmission lines:

$$\begin{aligned} &MinMP \\ &MP \geq \sum_{t=1}^{NT}\sum_{i=1}^{CG}\frac{CI_{it}\left(X_{it}-X_{i(t-1)}\right)}{(1+d)^{(t-1)}} \\ &\qquad +\sum_{t=1}^{NT}\sum_{j=1}^{CL}\frac{CI_{jt}\left(Y_{jt}-Y_{j(t-1)}\right)}{(1+d)^{(t-1)}}. \end{aligned} \tag{2}$$

This objective is subject to the planning constraints (3)–(12). The generating unit constraints include capital investment funds in a planning year (4), anticipated resource capacity in a planning year (5), maximum number of generating units to be added at a planning year (6), and the construction time of the candidate investment (7). Similarly, the transmission line constraints are capital investment funds in a planning year (9), anticipated transmission line capacity in a planning year (10), maximum number of transmission lines to be added at a planning year (11), and the construction time of the candidate investment (12). Constraint (3) specifies that once a generating unit is in place, its investment state will be 1 in the following years. The same constraint exists for transmission lines, which is presented by (8):

$$X_{i(t-1)} \leq X_{it} \quad (i=1,\ldots,NCG)(t=2,\ldots,NT) \tag{3}$$

$$\sum_{i=1}^{CG} CI_{it}\left(X_{it}-X_{i(t-1)}\right) \leq GCI_t \quad (t=1,\ldots,NT) \tag{4}$$

$$\sum_{i=1}^{CG} Cap_i\left(X_{it}-X_{i(t-1)}\right) \leq GUC_t \quad (t=1,\ldots,NT) \tag{5}$$

$$\sum_{i=1}^{CG}\left(X_{it}-X_{i(t-1)}\right) \leq GUN_t \quad (t=1,\ldots,NT) \tag{6}$$

$$X_{it} = 0 \; if \; t < GCT_i \quad (i=1,\ldots,NCG)(t=1,\ldots,NT) \tag{7}$$

$$Y_{j(t-1)} \leq Y_{jt} \quad (j=1,\ldots,NCL)(t=2,\ldots,NT) \tag{8}$$

$$\sum_{j=1}^{CL} CI_{jt}\left(Y_{jt}-Y_{j(t-1)}\right) \leq LCI_t \quad (t=1,\ldots,NT) \tag{9}$$

$$\sum_{j=1}^{CL} Cap_j\left(Y_{jt}-Y_{j(t-1)}\right) \leq LUC_t \quad (t=1,\ldots,NT) \tag{10}$$

$$\sum_{j=1}^{CL}\left(Y_{jt}-Y_{j(t-1)}\right) \leq LUN_t \quad (t=1,\ldots,NT) \tag{11}$$

$$Y_{jt} = 0 \; if \; t < LCT_j \quad (j=1,\ldots,NCL)(t=1,\ldots,NT). \tag{12}$$

The master problem will determine the optimal investment plan and the lower bound for the original MIP planning problem. The optimality cuts will help minimize investment and operation costs in the master problem. The states of switchable transmission lines are also examined in this problem. Here, the Benders cuts provide the state of switchable lines to the master problem.

B. Security Check

Given the proposed plan in the master problem, as well as the state of switchable lines, the security check subproblem minimizes the potential system violations. This task is accomplished by introducing slack variables in the power balance equation at each bus. The objective is to minimize the sum of nonnegative slack variables:

$$Min\; v_t = \sum_{b=1}^{NB}\sum_{h=1}^{NH}(SL_{hbt,1}+SL_{hbt,2}) \tag{13}$$

$$\begin{aligned} &\sum_{i\in I_h} PG_{ibt}^{E} + \sum_{i\in I_h} PG_{ibt}^{C} - PD_{hbt} - \sum_{j\in J_h} PL_{jbt}^{E} \\ &\quad - \sum_{j\in J_h} PL_{jbt}^{C} + SL_{hbt,1} - SL_{hbt,2} = 0 \\ &\quad (h=1,\ldots,NH)(b=1,\ldots,NB)(t=1,\ldots,NT). \end{aligned} \tag{14}$$

Equation (14) shows the power mismatch at bus h. In this equation, existing and candidate lines are shown with superscripts E and C, respectively. Set J_h includes the lines connected to bus h which are labeled as either the "to bus" or the "from bus" in the set.

This problem is subject to existing and candidate generating unit and transmission line constraints. These constraints represent the capacity of existing and candidate generating units (18), (19), existing transmission line flows (20)–(23), candidate transmission line flows (24)–(27), and phase angle of reference bus (28):

$$X_{it} = \hat{X}_{it} \quad (i=1,\ldots,NCG)(t=1,\ldots,NT) \tag{15}$$

$$Y_{jt} = \hat{Y}_{jt} \quad (j=1,\ldots,NCL)(t=1,\ldots,NT) \tag{16}$$

$$Z_{jbt} = \hat{Z}_{jbt} \quad (j=1,\ldots,NEL)(b=1,\ldots,NB) \quad (t=1,\ldots,NT) \tag{17}$$

$$0 \leq PG^{E}_{ibt} \leq PG^{\max,E}_{i} UX^{E}_{ibt} \quad (i=1,\ldots,NEG) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{18}$$

$$0 \leq PG^{C}_{ibt} \leq PG^{\max,C}_{i} X_{it} UX^{C}_{ibt} \quad (i=1,\ldots,NCG) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{19}$$

$$PL^{E}_{jbt} - \gamma_j \left(\delta^{E}_{mbt} - \delta^{E}_{nbt}\right) - M^{E}_{j}(1-Z_{jbt}) - M^{E}_{j}\left(1-UY^{E}_{jbt}\right) \leq 0 \quad (j=1,\ldots,NEL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{20}$$

$$PL^{E}_{jbt} - \gamma_j \left(\delta^{E}_{mbt} - \delta^{E}_{nbt}\right) + M^{E}_{j}(1-Z_{jbt}) + M^{E}_{j}\left(1-UY^{E}_{jbt}\right) \geq 0 \quad (j=1,\ldots,NEL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{21}$$

$$PL^{E}_{jbt} \leq PL^{\max,E}_{j} Z_{jbt} UY^{E}_{jbt} \quad (j=1,\ldots,NEL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{22}$$

$$-PL^{E}_{jbt} \leq PL^{\max,E}_{j} Z_{jbt} UY^{E}_{jbt} \quad (j=1,\ldots,NEL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{23}$$

$$PL^{C}_{jbt} - \gamma_j \left(\delta^{C}_{mbt} - \delta^{C}_{nbt}\right) - M^{C}_{j}(1-Y_{jt}) - M^{C}_{j}\left(1-UY^{C}_{jbt}\right) \leq 0 \quad (j=1,\ldots,NCL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{24}$$

$$PL^{C}_{jbt} - \gamma_j \left(\delta^{C}_{mbt} - \delta^{C}_{nbt}\right) + M^{C}_{j}(1-Y_{jt}) + M^{C}_{j}\left(1-UY^{C}_{jbt}\right) \geq 0 \quad (j=1,\ldots,NCL)(b=1,\ldots,NB)(t=1,\ldots,NT) \tag{25}$$

$$PL^{C}_{jbt} \leq PL^{\max,C}_{j} Y_{jt} UY^{C}_{jbt} \quad (j=1,\ldots,NCL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{26}$$

$$-PL^{C}_{jbt} \leq PL^{\max,C}_{j} Y_{jt} UY^{C}_{jbt} \quad (j=1,\ldots,NCL) \quad (b=1,\ldots,NB)(t=1,\ldots,NT) \tag{27}$$

$$\delta_{ref} = 0. \tag{28}$$

In the above formulation, the constraints on candidate generating units and transmission lines include the associated binary variable, which is already determined in the master problem. The state of switchable transmission lines is included in the existing transmission flow constraints (20)–(23). So, whenever a transmission line is switched off its associated switchable state is zero and the transmission line will be completely removed from the network. A subset of existing transmission lines is usually considered as switchable. Therefore, for the remaining and nonswitchable lines the switching state (binary variable) will be equal to 1 in the expansion planning problem. The transmission line j is between buses m and n with a transmission flow from bus m to bus n. In constraints (20), (21), (24), and (25), a large constant value, i.e., M, is used to satisfy the relaxation of associated constraints when they would be eliminated. This disjunctive parameter would be larger than a minimum value and should not be very large. The solution of the planning problem is sensitive to the value of this parameter, where in [45] it is shown that large values of disjunctive parameter could limit the validity of the Benders decomposition results. In [21], an effective approach is presented to calculate this parameter, where the disjunctive parameter is increased along the Benders iterations. However in this paper, it is assumed that the disjunctive parameter of each line has a constant value, which is equal to its minimum allowable value. In the Appendix, the minimum allowable values of disjunctive parameters are calculated for transmission lines.

The security check subproblem is solved for the base case and contingencies. During the contingencies, transmission lines can operate at their emergency ratings. So, PL_j^{max} will be adjusted accordingly. The contingency state of the element that is on outage will be zero. In the base case, this parameter will be one. The security check subproblem performs corrective actions to mitigate the violations. Those contingencies that cannot be mitigated with corrective actions are dealt with by preventive actions in the next iteration of the master problem.

If the proposed objective is zero, the problem will proceed to the optimal operation subproblem. Otherwise, the Benders cut (29) will be formed and added to the master problem for the next iteration:

$$v_t + \left\{ \sum_{i=1}^{CG} \lambda_{it}(X_{it} - \hat{X}_{it}) + \sum_{j=1}^{CL} \mu_{jt}(Y_{jt} - \hat{Y}_{jt}) + \sum_{j=1}^{NS} \sum_{b=1}^{NB} \pi_{jbt}(Z_{jbt} - \hat{Z}_{jbt}) \right\} \leq 0 \tag{29}$$

where λ, μ, and π are dual values of constraints (15), (16), and (17), respectively. This cut points out that the stated violations could be mitigated by changing the investment plan in addition to the state of switchable lines. In fact, this cut calculates the capacity signals for the investment of new generating units and transmission lines in case the existing ones cannot satisfy the system feasibility. The Benders cut will be formed for each violated case and added to the master problem. The iterative procedure continues until a secure plan that satisfies the system feasibility is achieved in the base case and contingencies.

C. Optimal Operation

After satisfying the feasibility of the plan due to system constraints, the optimal operation will check the optimality of the solution cost. The objective of the optimal operation problem is to minimize the operating cost for every year and load block as

$$Min\ w_{bt} = \sum_{i=1}^{NG} \frac{DT_{bt} OC_{ibt} PG_{ibt}}{(1+d)^{(t-1)}}. \tag{30}$$

This objective is subject to (15)–(28). The problem is solved for the base case in which contingency parameters are equal to 1. The solution provides the upper bound of the objective function of expansion planning. This upper bound is used to check the optimality of the solution. So the stopping criterion is defined based on this solution. If the proposed plan is not optimal, a Benders cut will be formed and added to the master problem for the next iteration. The proposed Benders cut (31) would restrict the lower bound of objective function in the master problem. Here, λ, μ, and π are dual values of (15), (16), and (17), respectively.

The iterative process between the master problem and subproblems will continue until an optimal solution of the expansion planning problem is calculated. The problem feasibility is ensured via the security check subproblem, while the optimality is guaranteed by comparing the solutions of the master problem and the optimal operation subproblem at each iteration. The solution of the master problem is the lower bound of the optimal solution. The upper bound of the optimal solution is found by using the results of optimal operation subproblem. The optimal solution is obtained when lower and upper bounds are close enough. These bounds are utilized to form an effective convergence criterion in (32):

$$MP \geq \sum_{t=1}^{NT}\sum_{b=1}^{NB}\hat{w}_{bt} + \sum_{t=1}^{NT}\sum_{i=1}^{CG}\frac{CI_{it}\left(X_{it}-X_{i(t-1)}\right)}{(1+d)^{(t-1)}} + \sum_{t=1}^{NT}\sum_{j=1}^{CL}\frac{CI_{jt}\left(Y_{jt}-Y_{j(t-1)}\right)}{(1+d)^{(t-1)}} + \sum_{t=1}^{NT}\sum_{i=1}^{CG}\lambda_{it}(X_{it}-\hat{X}_{it}) + \sum_{t=1}^{NT}\sum_{j=1}^{CL}\mu_{jt}(Y_{jt}-\hat{Y}_{jt}) + \sum_{t=1}^{NT}\sum_{j=1}^{NS}\sum_{b=1}^{NB}\pi_{jbt}(Z_{jbt}-\hat{Z}_{jbt}) \quad (31)$$

$$\frac{PP-MP}{PP+MP} < \varepsilon. \quad (32)$$

The planning stage is performed yearly while the operation stage is carried out for load blocks. The contingencies would last for the entire load block in a year. However, there are no limitations on the length of load blocks which can be chosen as any period of time from hours to months. The choice will be a tradeoff between the accuracy and the simplicity in the execution of the proposed model. However, the choice of load blocks would play an important role in the proposed model. This issue will be addressed in our future study.

IV. Numerical Simulations

Three case studies consisting of a six-bus system, the IEEE 118-bus system, and an 1168-bus system are analyzed. The proposed method was implemented on a 2.4-GHz personal computer using CPLEX 11.

A. Six-Bus System

The six-bus system is shown in Fig. 2. A ten-year planning horizon is considered. The system data for generating units and transmission lines are given in Tables I and II, respectively. In Table III the forecasted yearly peak load is listed. This load is distributed at the rate of 40%, 30%, and 30% among buses 3, 4, and 5, respectively. To simplify the calculations, four load blocks are considered annually. The duration and quantity of load blocks in the first year are given in Table IV. The load blocks in subsequent years will change in proportion to those in Year 1. A set of four candidate generating units and four candidate transmission lines are considered as planning options in Tables I and II. The construction time for generating units is considered to be three years, while it is less than one year for the transmission lines. It is assumed that there are no annual limitations on capital investments or the number of generating units and transmission lines. The discount rate is assumed to be

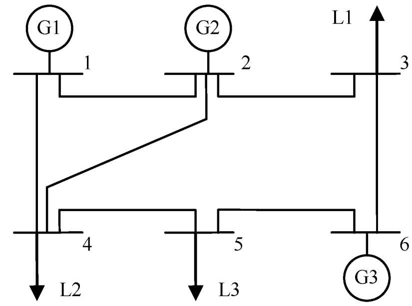

Fig. 2. Six-bus system.

TABLE I
GENERATING UNIT DATA OF SIX-BUS SYSTEM

Unit No.	Bus No.	Generating Capacity (MW)	Investment Cost ($/kW)	Operation Cost ($/MWh)
1	1	100	Existing	15
2	2	100	Existing	18
3	6	50	Existing	23
4	1	100	200	15
5	2	80	270	21
6	2	60	250	24
7	3	20	250	24

TABLE II
TRANSMISSION LINE DATA OF SIX-BUS SYSTEM

Line No.	From Bus	To Bus	X (p.u.)	Capacity (MW)	Investment Cost ($/kW)
1	1	2	0.17	80	Existing
2	2	3	0.037	70	Existing
3	1	4	0.258	140	Existing
4	2	4	0.197	100	Existing
5	4	5	0.037	50	Existing
6	5	6	0.14	140	Existing
7	3	6	0.018	130	Existing
8	1	2	0.17	80	20
9	2	3	0.037	70	24
10	1	4	0.258	140	30
11	5	6	0.14	140	14

TABLE III
YEARLY PEAK LOAD FORECAST OF SIX-BUS SYSTEM

Year	1	2	3	4	5
Peak (MW)	209	225	231	243	269
Year	6	7	8	9	10
Peak (MW)	297	307	315	324	330

0. Three transmission lines 1–4, 2–4, and 4–5 are considered as switchable in the following four planning cases:

Case 1) Base case planning
Case 2) Transmission line 5–6 outage in load block 3 of year 4
Case 3) Generating unit 3 outage in load block 1 of year 6
Case 4) Simultaneous outages considered in Cases 2 and 3

The cases are discussed next.

TABLE IV
LOAD BLOCKS IN THE FIRST YEAR **AUTHOR: PLEASE CITE TABLES V-VIII IN THE BODY OF THE PAPER.**

Block	1	2	3	4
Duration (h)	87	2541	4380	1752
Load (MW)	209	192	167	150

TABLE V
CANDIDATE UNIT INSTALLATION YEAR OF SIX-BUS SYSTEM

Candidate Unit	Case 1	Case 2	Case 3	Case 4
4	-	5	6	6
5	-	-	-	-
6	5	-	-	-
7	8	-	5	5

Case 1: The ten-year expansion planning is considered without considering the TS. According to this plan, line 2–3 is installed in the first year. Also, generating units 6 and 7 are added in years 5 and 8, respectively. At the first year, existing units 1,2,3 try to satisfy the system load while maintaining the feasibility of transmission flows. Here, cheaper units 1 and 2 are dispatched at their maximum capacity and the remaining load is supplied by unit 3. However, due to the congestion of line 2–3, unit 2 cannot increase its generation to its capacity. So the more expensive unit 3 would increase its generation, which increases the operating cost. Accordingly, the candidate line 2–3 is installed at the first year. This installation leads to an increase in the transmission capacity between buses 2 and 3, which allows unit 2 to increase its generation to its capacity in subsequent years.

The new system topology satisfies the system load while the system load is less than the total installed capacity in the system, i.e., years 1–4. In year 5 the system would need to install a new generation capacity to help satisfy the additional load. So, unit 6 is placed at bus 2 which can transfer more power in conjunction with the installation of line 2–3. Two options (i.e., either candidate unit 5 or 6) are available for the installation of a unit in bus 2. Unit 5 is more economical while unit 6 requires a less investment cost. Considering the remaining five years, the algorithm chooses unit 6. Similarly in year 8, another unit is installed. The cheapest generating candidate from the operation viewpoint is unit 4, and the one from the planning viewpoint is unit 7. However, considering the remaining two years in the planning horizon, unit 7 is selected as being more economical. In this case, unit 5 is not a good option since the larger generation in bus 2 may lead to the congestion on line 2–3. The total cost in this case is \$366.3 M.

The TS application in Case 1 will result in a different expansion plan, where unit 4 is installed at year 5 and lines 2–3 and 1–4 are installed at years 1 and 9, respectively. The installation of line 2–3 at year 1 will again relieve the congestion on line 2–3 and increase the dispatchability of units at buses 1 and 2. At year 5, unit 4 is chosen when the system needs to install additional generation capacity. This unit is the most economical candidate unit from operation viewpoint. With the installation of unit 4 at bus 1, most of the system load will be supplied. The additional dispatch at bus 1 would lead to an increase in line flows with a possible congestion. TS is used to mitigate the congestion. For example when the load in year 5 is higher than 215 MW, the

TABLE VI
CANDIDATE UNIT INSTALLATION YEAR OF SIX-BUS SYSTEM USING TS

Candidate Unit	Case 1	Case 2	Case 3	Case 4
4	5	5	6	6
5	-	-	-	-
6	-	-	-	-
7	-	-	5	5

TABLE VII
CANDIDATE LINE INSTALLATION YEAR OF SIX-BUS SYSTEM

Candidate Line	Case 1	Case 2	Case 3	Case 4
1-2	-	-	6	-
2-3	1	1	1	1
1-4	-	7	6	6
5-6	-	4	-	4

TABLE VIII
CANDIDATE LINE INSTALLATION YEAR OF SIX-BUS SYSTEM USING TS

Candidate Line	Case 1	Case 2	Case 3	Case 4
1-2	-	-	-	-
2-3	1	1	1	1
1-4	9	7	6	6
5-6	-	4	-	4

feasibility constraints cannot be satisfied. The constraints are satisfied with the switching of line 2–4. Here, the total cost is dropped by 5.56% to \$345.9 M.

Case 2: In this case, the outage of line 5–6 in year 4 is considered. Similar to Case 1, line 2–3 is installed at year 1. With the possible outage of line 5–6, the installation of candidate line 5–6 will be necessary. Furthermore, the candidate line 1–4 is installed in year 7 with the largest investment cost among candidate lines. However, the line will enhance the dispatch of energy generated by cheap units at bus 1. The total cost in this Case is \$347.9 M which is higher than that in Case 1.

Using TS, a similar expansion plan is proposed, i.e., the installation of unit 4 at year 5 and lines 2–3, 1–4, and 5–6 in years 1, 7, and 4, respectively. The line switching does not change the proposed plan in this case. However, the total cost is reduced to \$346.4 M. The lower total cost is mainly due to the switching of line 2–4. When the line is switched off, the flows on lines 1–2 and 1–4 will be less dependent on one another. So both lines can transfer more power, which would result in the additional dispatch of units at bus 1. Since the cheapest units are at bus 1, the additional dispatch of these units will reduce the total cost.

Case 3: The outage of unit 3 at year 6 would change the proposed plan in Case 1. Like previous cases, new generation capacity is added at year 5. The proposed plan requires the installation of unit 7 at year 5 and subsequently unit 4 at year 6. The installation of unit 4 would increase the installed capacity. Also, unit 7 is added to satisfy the loads in buses 3 and 5. The installation of unit 7 is a preventive action to handle the outage of unit 3. The installed lines are 1–2, 2–3, and 1–4 in years 6, 1, and 6, respectively. Line 2–3 is installed to increase the dispatchability of units at buses 2 and 3, while lines 1–2 and 1–4 are installed to enhance the dispatchability of units at bus 1. The TS application would eliminate the previous installation of line 1–2 at year 6. The previous line flow violations that required the installation

TABLE IX
CANDIDATE UNIT DATA OF IEEE 118-BUS SYSTEM

Unit No.	Bus No.	Generating Capacity (MW)	Investment Cost ($/kW)	Operation Cost ($/MWh)
1	10	200	15	250
2	12	200	15	250
3	25	200	15	250
4	26	200	15	250
5	80	200	15	250
6	89	200	15	250
7	18	100	18	120
8	32	100	18	120
9	55	100	18	120
10	56	100	18	120
11	62	100	18	120
12	74	20	38	50
13	74	20	38	50
14	90	20	38	50
15	103	20	38	50
16	103	20	38	50

of line 1–2 are alleviated by the switching of lines 2–4 and 4–5. The total cost is $350.6 M, which is 0.4% cheaper when using TS. This improvement is due to the elimination of candidate line 1–2 in the planning horizon as well as a decrease in the operating cost. This study demonstrates that the application of TS could result in a similar but cheaper expansion planning.

Case 4: The expansion plan will not be influenced by TS when considering simultaneous outages of line 5–6 in year 4 and unit 3 in year 6. The expansion plan includes the installation of unit 4 at year 6, unit 7 at year 5, and lines 2–3, 1–4, and 5–6 at years 1, 6, and 4, respectively. The installation of unit 7 is a preventive action for the possible outage of unit 3, while the installation of line 11 is a preventive action for the possible outage of line 5–6. The TS application will not alter the proposed expansion plan, but will reduce the total cost by 0.5%. The candidate unit and line installation years of these four planning cases are summarized in Tables V–VIII.

B. IEEE 118-Bus System

A modified IEEE 118-bus system is used to study the expansion planning problem with TS. The system has 118 buses, 54 units, and 186 branches. The data are given in motor.ece.iit.edu/data/Planning_118.xls. The candidate units and lines data are presented in Tables IX and X, respectively. The load growth rate is at 7%. The following three cases are analyzed:

Case 1) Base case planning
Case 2) Effect of discount rate on the planning solution
Case 3) Effect of the number of switchable lines on the planning solution

In Cases 1 and 3, the discount rate is assumed to be 10%, while in Case 2 the discount rate is changed to investigate its effect on the planning solution. In Cases 1 and 2 the effect of TS on planning is analyzed, where ten lines are considered as switchable. The list of these switchable lines is presented in Table XI. In Case 3 the planning problem is solved for a variable number of switchable lines.

TABLE X
CANDIDATE TRANSMISSION LINE DATA OF IEEE 118-BUS SYSTEM

Line No.	From Bus	To Bus	X (p.u.)	Capacity (MW)	Investment Cost ($/kW)
1	30	38	0.054	100	30
2	77	82	0.0853	100	30
3	110	111	0.0755	100	30
4	20	21	0.0849	100	30
5	17	113	0.0301	100	30

TABLE XI
SWITCHABLE LINE DATA OF IEEE 118-BUS SYSTEM

Switchable Line No.	Line No.	From Bus	To Bus	X (p.u.)	Capacity (MW)
1	30	23	24	0.0492	100
2	54	30	38	0.0540	100
3	65	47	49	0.0625	100
4	115	70	75	0.1410	100
5	151	80	97	0.0934	100
6	159	99	100	0.0813	100
7	164	100	104	0.2040	100
8	78	54	56	0.0096	100
9	90	60	61	0.0135	500
10	184	12	117	0.1400	100

Case 1: The base case planning for the IEEE 118-bus system is solved as a coordinated generation and transmission expansion planning problem. At first we disregard the TS option. The proposed plan is shown in Tables XII and XIII for unit and line installations, respectively. In the first four years of planning, loads are satisfied and there is no need to install any new units or lines. The installed generation capacity of the system is 5850 MW. In these four years, the congestion occurs in lines 8 and 96. However at year 5, due to the congestion in line 38 the system cannot satisfy its load, though the system has enough installed capacity. To alleviate this congestion and transfer the required power to the loads, the candidate units 2 and 4 are installed. The installations will mitigate the congestion of lines 8, 96, and 38 and the system will be able to meet the load. At the subsequent years 6 and 7, candidate units 5 and 3 are installed, respectively.

The installation of unit 5 at year 6 offers physical and economical advantages. On the other side, the installation of unit 3 at year 7 will mitigate the congestion in lines 31, 38 and 51. The candidate units 2, 4, and 5 represent expensive investments, but are necessary to provide sufficient generation capacity and transmission flow feasibility. Also the candidate line 1 is installed at year 7 to mitigate the congestion. Accordingly, there will be no need to install new components at year 8. However, at year 9 the candidate unit 9 is installed and subsequently the units 8, 10, 12, 13, and 14 are installed at the last planning year. Also, the candidate line 5 is installed to increase the transfer capacity of the system. Considering the results, we conclude that the system is well-designed and the transmission lines offer a sufficient capacity to transfer the generated power most often.

TS provides quite different results. The candidate units 5 and 3 are installed one year earlier. The candidate units 4 and 8 are not installed and instead units 1 and 11 are installed at years 7 and 10, respectively. Also, the installation of unit 9 is delayed

TABLE XII
CANDIDATE UNIT INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 1

Candidate Unit	Ignoring TS	Considering TS
1	-	7
2	5	5
3	7	6
4	5	-
5	6	5
6	-	-
7	-	-
8	10	-
9	9	10
10	10	10
11	-	10
12	10	10
13	10	10
14	10	10
15	-	-
16	-	-

TABLE XIII
CANDIDATE LINE INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 1

Candidate Line	Ignoring TS	Considering TS
1	7	-
2	-	-
3	-	-
4	-	-
5	10	-

by one year, while the installation of other candidate units is remained the same, i.e., unit 2 is installed at year 5 and units 10, 12, 13, and 14 are installed at year 10. Accordingly, the generation investment cost is decreased by 0.35%. The use of TS eliminates the line investment in this case, as shown in Table XIII. Also, TS enhances the power transfer capability by allowing existing transmission lines to transfer additional power. Here, the lines 7, 8, 9, and 36 are congested at years 7 to 10. Also line 96 is congested at years 1 to 5. The TS applications at certain load blocks will mitigate the congestions and enhances the system feasibility. Accordingly, the operating cost of the system is slightly increased. However, the proposed TS plan will reduce the total cost by 0.04%. As noted in the Introduction, TS may defer generation and transmission investments. Considering the obtained results, the installation of candidate unit 9 is deferred, while the candidate units 3 and 5 are installed earlier than the base case solution.

Case 2: The sensitivity of the proposed plan to the discount rate is investigated. Generally, the discount rate is used in the calculation of the net present value and capacity payment for new generating unit and transmission line investments. It is clear when the discount rate is higher the investment candidates with higher capital costs become inferior. In the real world, investors may use different discount rates in their planning studies which would depend on their financial situation and business strategies. However, in this case the discount rate is assumed to be the same for all candidate units and lines. The discount rates of 10%, 5%, and 0% are considered. The candidate units and lines are the same as those of Case 1.

TABLE XIV
CANDIDATE UNIT INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 2

Candidate Unit	Discount Rate (%)		
	10	5	0
1	7	-	-
2	5	4	4
3	6	-	-
4	-	5	4
5	5	6	4
6	-	-	-
7	-	10	4
8	-	10	4
9	10	9	4
10	10	9	4
11	10	10	4
12	10	10	4
13	10	10	4
14	10	10	4
15	-	-	-
16	-	-	-

The plan with a 10% discount rate was obtained in Case 1. By decreasing the discount rate to 5%, it is expected that the candidate units with higher capital costs, i.e., units 1 to 6, become inferior. So, units 1 and 3 are not installed and installation of unit 5 is delayed by one year. However, Table XIV shows that cheaper units are installed in this case, in which the units 7 and 8 are installed at year 10 and units 9 and 10 are planned at year 9. In addition, similar to the 10% discount solution, there would be no need to install new transmission lines when TS is applied and the discount rate is 5%. Accordingly, the investment cost and total planning cost are increased by 14.4% and 0.63%, respectively.

If we further decrease the discount rate and set it to zero, a quite different investment plan, as shown in last column of Table XIV, will be obtained. The discount rate of 0% means that there is no difference on the installation year of the candidate unit or line, since the investment cost will not change with time.

From the optimization viewpoint, all units are installed at the first year that they are required. Again using TS, there is no requirement for new transmission line investments, since TS satisfies the system feasibility. In comparison with the 10% discount rate, the investment cost and the total planning cost are increased by 47.8% and 1.36%, respectively, when the discount rate is assumed to be zero.

Case 3: In order to examine the impact of TS on the planning results more comprehensively, the expansion planning problem in Case 1 is solved for a variety of switchable lines. The number of switchable lines is varied here form 0 to 40, which 0 means that no line in the system has the switching capability, and 40 means that more than one fifth of transmission system is considered as switchable. Discount rate of 10% is considered for all cases.

The installation year of candidate units as a function of the number of switchable lines is shown in Table XV. The investment plan is a function of the number of switchable lines. However, no transmission line is installed when TS is applied. The investment cost is shown in Fig. 3. This figure shows that the investment cost is a function of the number of switchable lines.

TABLE XV
CANDIDATE UNIT INSTALLATION YEAR FOR IEEE 118-BUS SYSTEM IN CASE 3

Candidate Unit	Number of Switchable Lines				
	0	10	20	30	40
1	-	7	5	5	7
2	5	5	7	7	5
3	7	6	6	6	-
4	5	-	-	-	6
5	6	5	5	5	5
6	-	-	-	-	-
7	-	-	-	-	-
8	10	-	-	-	-
9	9	10	10	10	10
10	10	10	10	10	10
11	-	10	10	10	10
12	10	10	-	10	-
13	10	10	10	10	-
14	10	10	10	10	10
15	-	-	-	-	-
16	-	-	-	-	-

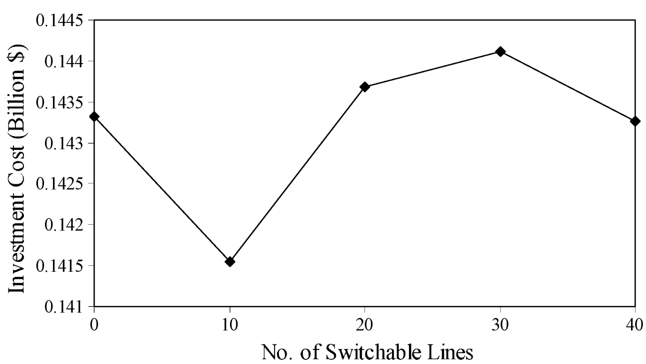

Fig. 3. Investment cost in Case 3.

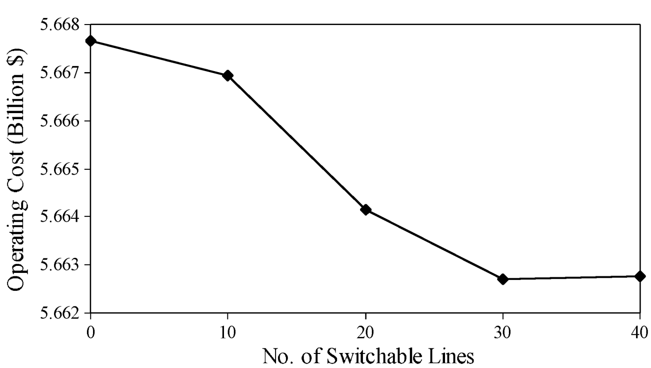

Fig. 4. Operating cost in Case 3.

In the case of the no line switching capability, the investment cost includes the installation costs of units and lines; however, with the TS capability, the investment cost is only that of unit installations.

The operating cost of the system is shown in Fig. 4. By increasing the number of switchable lines from 0 to 30, the operating cost is decreased. However, the operating cost of the 40 switchable lines is higher than that of 30.

So, by increasing the number of switchable lines the operating cost of the system does not decrease monotonically.

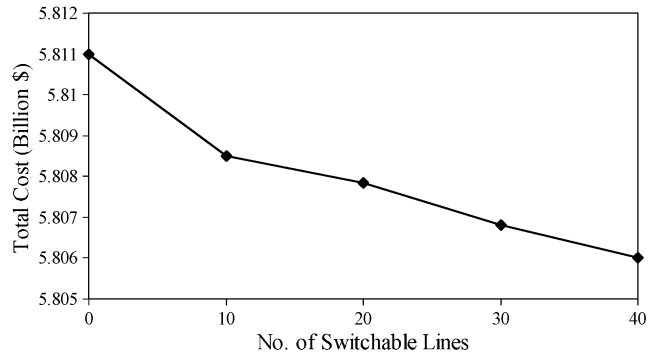

Fig. 5. Total planning cost in Case 3.

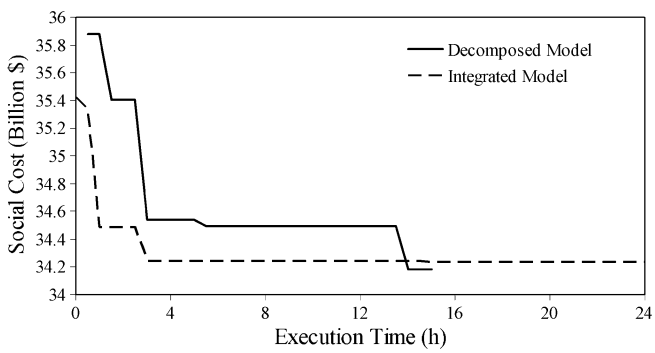

Fig. 6. Comparison of integrated and decomposed planning models.

The objective of the investment planning problem is to minimize the total planning cost, which is the sum of the investment and the operating costs. The total cost is depicted in Fig. 5. As expected, by increasing the number of switchable lines, the total cost is decreased uniformly. The reduction in the total planning cost for 10, 20, 30, and 40 switchable lines, as compared to the case with no switching, is 0.043%, 0.054%, 0.072%, and 0.086%, respectively. These increments would amount to large savings in the case of large-scale power systems.

C. 1168-Bus System

As a large-scale power system, the 1168-bus system is used to compare the effectiveness of the proposed decomposition approach with that of the integrated model. This system has 149 units, 1474 branches, and 568 demand sides. Twenty units are considered as candidate investments. The discount rate for candidate units is assumed to be 10%. The transmission flow limit is increased to alleviate the need for any transmission expansions. To obtain the solution in a reasonable time a planning horizon of three years is considered. One hundred transmission lines are assumed to be switchable. The total planning costs as a function of execution time is depicted in Fig. 6. The solution of the integrated model is achieved using the CPLEX, where the total planning cost is the best current integer solution of the problem. In the decomposed model the total planning cost is the upper bound of the MIP planning problem, i.e., current solution of the decomposed problem.

As shown in Fig. 6, the integrated model finds a better solution initially, and is better than that of decomposed model for the next 14 h. Also, it reaches a near optimal solution in just 3.5 h. However, this near optimal solution cannot be improved further.

On the other hand, the decomposed model would require an additional computation time but is able to reach a cheaper solution. After 15 h, the solution of the decomposed model is 0.17% better than that of the integrated model. We continued with the execution of the two models for another 12 h and learned that the solution of the integrated model did not change. However, the duality gap of the CPLEX solution continued to drop which is because of the increment in the best current node of the solution.

V. Conclusions

The TS application was investigated in the expansion planning of power systems. The expansion planning problem was decomposed into a master problem and two subproblems. The master problem found the optimal expansion plan by considering candidate units and lines. The subproblems utilized the proposed plan to satisfy the feasibility and check the possibility of optimal operation. The TS application for enhancing the system security and economics was considered in the subproblems while the role of TS for enhancing the expansion plan was taken into account in the master problem. The proposed approach was analyzed further through numerical examples introduced in the paper. The proposed TS approach can be utilized as an ISO model for coordinating the transmission expansion planning with the competitive generation capacity planning by representing an iterative process for representing the interactions among generation companies, transmission companies and the ISO, while considering the switching capability of lines.

Appendix

Suppose that we have the following conditional statement:

$$\text{If } \nu = 1 \text{ then } \sum_i a_i x_i = b \tag{A1}$$

where v is a binary variable, x_i is a continuous variable, and a_i and b are constant parameters. To model this statement in MIP format, (A2) and (A3) are used:

$$\sum_i a_i x_i - b \leq M(1-v) \tag{A2}$$

$$\sum_i a_i x_i - b \geq m(1-v). \tag{A3}$$

Similarly, if we have the following conditional statement:

$$\text{If } \nu = 0, \text{ then } \sum_i a_i x_i = b. \tag{A4}$$

We can represent (A5) and (A6) in the MIP format:

$$\sum_i a_i x_i - b \leq Mv \tag{A5}$$

$$\sum_i a_i x_i - b \geq mv. \tag{A6}$$

The constant values M and m are disjunctive parameters of the associated inequality constraint. Usually, M would not be less than a specific value which is given as

$$M = \max\left\{\sum_i a_i x_i - b\right\}. \tag{A7}$$

Similarly, m should not be larger than a specific value

$$m = \min\left\{\sum_i a_i x_i - b\right\}. \tag{A8}$$

So, M and m are upper and lower bounds of the expression $\sum_i a_i x_i - b$, respectively.

These MIP representations of conditions can simply be extended to cases with more than one binary variable. The proposed formulations for line flows, considering the installation state and switching state as binary variables, are obtained similarly. So, disjunctive parameters of line flow constraints are

$$M_j^E = 2PL_j^{\max,E} \tag{A9}$$

$$m_j^E = -2PL_j^{\max,E} \tag{A10}$$

$$M_j^C = 2PL_j^{\max,C} \tag{A11}$$

$$m_j^C = -2PL_j^{\max,C}. \tag{A12}$$

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