Coordination of Short-Term Operation Constraints in Multi-Area Expansion Planning

Amin Khodaei, *Member, IEEE*, Mohammad Shahidehpour, *Fellow, IEEE,* Lei Wu, *Member, IEEE*, and Zuyi Li, *Senior Member, IEEE*

***Abstract*—This paper presents a comprehensive expansion planning algorithm of generation and transmission components in multi-area power systems. The objective is to minimize the total system cost in the planning horizon, comprising investment and operation costs and salvage values subject to long-term system reliability and short-term operation constraints. The multi-area expansion planning problem is decomposed into a planning problem and annual reliability subproblems. The planning decisions calculated in the planning problem would also satisfy the short-term operation constraints. A detailed model of thermal and hydro units is considered using the mixed-integer programming (MIP) formulation. In addition, a multi-state representation for the expansion planning of renewable energy units is explored. The proposed approach considers customers' demand response as an option for reducing the short-term operation costs. The planning problem solution is applied to the annual reliability indices subproblems which examine system reliability indices as a post-processor. If the reliability limit is not satisfied, additional reliability constraints will be introduced which are based on the sensitivity of system reliability index to investment decisions. The new reliability constraints are added to the next iterations of the planning problem to govern the revised plan for the optimal expansion. Numerical simulations indicate the effectiveness of the proposed approach for solving the operation-constrained multi-area expansion planning problem of practical power systems.**

***Index Terms*—Multi-area expansion planning, coordinated transmission and generation expansion planning, coordinated long-term and short-term planning, renewable generation planning, demand response, reliability constraints.**

NOMENCLATURE

Indices:

a	Index for area
b	Index for load blocks
f, v	Superscripts for fixed and variable O&M costs
g, p	Superscripts for generating and pumping modes of pumped-storage unit
h	Index for period
i	Index for generating units
l	Index for transmission line
m	Index for bus
n	Index for fuel type
s	Superscript for units in a group
t	Index for year
$\wedge$	Index for calculated variables

Sets:

A	Set of system components in an area
CG	Set of candidate generating units
CH , CT	Set of candidate hydro and thermal units
CL	Set of candidate transmission lines
EG	Set of existing generating units
EH , ET	Set of existing hydro and thermal units
EL	Set of existing transmission lines

Parameters:

B	Bus-line incidence matrix
BL	Bus load percentage
CC	Capital cost
d	Discount rate
DB	Percentage of responsive load
DR	Demand response bid
DT	Duration time
E	Energy limit of pumped-storage unit
EL	Emission limit
EM	Emission rate
FL	Fuel limit
FP	Fuel price
OM	O&M cost
PD	Load demand
r	Unit spinning reserve
R	System spinning reserve requirement
T	Number of years in the scheduling horizon
T^{com}	Commissioning year
T^{Re}	Retirement year
x	Reactance of line
η	Efficiency of pumped-storage unit
κ	Coefficient of present-worth value
γ	Salvage factor
ϑ	Ratio of hours in a load block to the hours in the associated period

Variables:

CU	Curtailed load
F	Fuel function
I	Commitment state

A. Khodaei, M. Shahidehpour, and Z. Li are with Electrical and Computer Engineering Department, Illinois Institute of Technology, Chicago, IL 60616 USA (e-mail: akhodaei@iit.edu; ms@iit.edu; lizu@iit.edu). L. Wu is with Electrical and Computer Engineering Department, Clarkson University, Potsdam, NY 13699 USA (e-mail: lwu@clarkson.edu).

IC	Total investment cost
$LOLE$	System loss of load expectation
OC	Total operation cost
P	Unit generation
PL	Line flow
PN	Unit generation associated with a specific fuel type
Q^g	Generating power of pumped-storage unit
Q^p	Pumping power of pumped-storage unit
SP	Energy of pumped-storage unit
ST	Stored power of large reservoir unit
SV	Total salvage value
u^g	Generating state of pumped-storage unit
u^p	Pumping state of pumped-storage unit
y	Line investment state
z	Unit investment state
θ	Voltage angle
ξ	Fuel permission state

I. Introduction

POWER system expansion planning determines the optimal size, time and location of additional generating units and transmission lines for facilitating economic, secure, and reliable operations of a power grid [1]-[3]. Various optimization techniques were considered which shared a common objective: minimize planning and operation costs over the planning horizon. These techniques include mathematical or heuristic approaches to the expansion planning problem [4]-[12].

In the traditional integrated resource planning approaches, a vertically integrated utility would utilize an integrated approach to determine the preferred plan for the installation of new resources. However, the market-based expansion planning considers self-interested participants, coordinates the participants' planning strategies, and analyzes the associated risks based on prevailing uncertainties [13],[14].

In multi-area power systems, the coordination between the generation and transmission expansion planning would become more critical as it could enhance the reliability of individual areas as well as that of the entire system. The transmission cost represents a small portion of the total cost of delivering electricity to multi-area consumers. However, any transmission investment could yield benefits much more than its planning cost in such cases. To encourage the participation in expansion planning opportunities, power market authorities identify long-term demand forecasts, pinpoint potential resource planning alternatives, and demonstrate revenue options for participants in such ventures. The multi-area resource planning proposals are studied and analyzed by the market authorities with respect to cost and reliability for the optimal development of additional generation and transmission capacity in the multi-area expansion planning horizon [15]-[18].

Although market-based planning is applicable to restructured power systems, the coordinated expansion planning of generation and transmission is exercised in many parts of the world. The reasons for utilizing a coordinated approach are twofold: first, the governments in many countries would still have jurisdictions over power system planning criteria, in which a full privatization in the generation sector is not conceivable and the transmission sector is excluded from any privatization. In other words, the private sector follows tight regulations on generation and transmission planning, and a state entity is overseeing the expansion planning. Second, power systems are often operated and controlled by a single entity in certain countries which are irrespective of individual asset ownerships in the grid. Hence, independent planning decisions are made by market participants who may not have much authority on the daily operation and control of interconnected power systems. The coordinated planning of power systems is exercised primarily for balancing the generation and load, delivering appropriate responses to system events, and preventing unintentional islanding of large interconnections.

A coordinated multi-area expansion planning of transmission and generation components in power systems is proposed in this paper. The approach considers the short-term power system operation strategies in multi-area expansion planning which could reduce the impact of outages, promote affordable and stable market prices, and encourage investments on cleaner and more efficient power plants. A computationally viable approach is developed for considering multi-area system reliability constraints in multi-area expansion planning, where annual reliability subproblems are introduced. The system reliability criterion would be checked in the subproblems and, if not met, additional multi-area reliability constraints are considered and added for revising the power system investment decisions and improving the system reliability to desired levels. The solution of the proposed coordinated model provides annual multi-area plans in the multi-year planning horizon including generation and transmission expansion plans, and advises system planners on the optimal size, location, installation time, and fuel type of new generating units based on transmission limitation, reliability requirements, system operation criteria, and additional economic and environmental constraints.

The proposed multi-area expansion planning algorithm is applicable to both traditional unbundled power systems and the market-based environment. In the market-based environment, the proposed approach is an ISO model which would simulate the interactive coordination of transmission and generation expansion planning [19],[20]. The generation and transmission companies would individually submit their candidate lists of new components to the system operator. It is the responsibility of the system operator to optimally determine appropriate candidates for the least-cost planning while considering long-term reliability and short-term operation constraints. The approach considers the impact of additional renewable energy sources and consumers' hourly demand response on enhancing the long-term planning decisions in multi-area power systems.

The rest of the paper is organized as follows. Section II presents the model outline of the proposed approach, while Section III presents the detailed formulation. Section IV presents illustrative examples to show the proposed model applied to a practical power system. Discussion on the features of the proposed model and concluding remarks are provided in

Sections V and VI, respectively.

II. Multi-Area Expansion Planning Model

Fig. 1 depicts the proposed multi-area expansion planning model. For large-scale applications, the multi-area expansion planning problem is decomposed into a planning problem and annual reliability subproblems for each year which are treated as a post- processor for the planning problem. The planning problem minimizes the total system cost, comprising planning for new resources and operation costs for the entire system, while considering prevailing unit and system constraints. Planning costs include investment costs and salvage values. Operation costs include fuel costs and operation & maintenance (O&M) costs of thermal, hydro and renewable units.

In Fig. 1, the planning problem is formulated and solved by commercial solvers as an integrated MIP problem. A decomposition could otherwise be applied to reduce the execution time of the proposed planning problem and ensure its applicability to practical systems [18],[21]. The decomposition would separate the planning problem into a master problem, a reliability check subproblem (which checks the transmission network constraints in the proposed plan) and an optimal operation subproblem (which finds the optimal system operation based on the proposed plan). Whenever the reliability or optimality check fails, proper cuts are generated in the corresponding subproblems and added to the next iteration of master problem. This iterative process continues until a secure and optimal expansion planning solution is achieved.

The planning problem finds the least-cost set of candidate generating units and transmission lines to be added to the multi-area system in order to meet load forecasts and satisfy prevailing constraints. Considering the power system operation in the multi-area expansion planning problem, the proposed model provides at each period the solution for generating unit dispatch, capacity factor, fuel consumption, fuel consumption cost, fixed and variable O&M costs, and the cumulative emission level for each unit along with the multi-area network flows.

In Fig. 1, the solution of the planning problem is applied to annual Reliability subproblems for calculating the system reliability index, i.e. loss of load expectation (LOLE). If the stated annual reliability criterion is not satisfied in the subproblems, a reliability constraint based on the sensitivity of LOLE to the current investment decisions is generated and added to the next iteration of the planning problem. This new reliability constraint will govern the investment plan of subsequent iterations to achieve the desired system reliability requirement. The iterative process in Fig. 1 will continue until the reliability criterion is satisfied in the entire planning horizon.

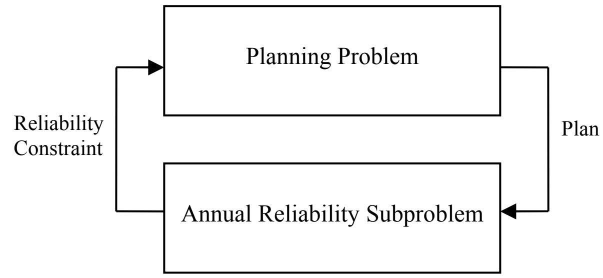

Fig. 1 Proposed multi-area expansion planning model

The multi-area investments are analyzed on an annual basis, i.e. each planned candidate unit or line would be considered for the installation at the beginning of each year. For the system operation, however, every year is decomposed into periods, and each period includes several load blocks. The load duration curve (LDC) method is utilized to consider system load variations and construct load blocks at each period. This long-term option is a practical version of considering hourly chronological loads with an acceptable level of accuracy. The number and the duration of load blocks will represent a tradeoff between the accuracy and the computation burden in the proposed model.

Various types of generators including thermal units (coal, gas, and nuclear), hydro units (run-of-river, large reservoir, and pumped-storage), and renewable units are modeled in this study. Renewable units are modeled as multi-state units to facilitate the system reliability calculation while assuring the modeling accuracy.

The load forecast at every block in every period of the planning horizon will be met by proper multi-area system expansion planning and operation decisions. The system reserve requirements are modeled considering the reserve capability of individual thermal and hydro units.

III. Formulation of Multi-Area Expansion Planning

The proposed multi-area expansion planning minimizes the total system cost throughout the planning horizon (1). The investment cost required for the installation of new generating units and transmission lines is a function of the capital cost ($/MW) and the available capacity for investment (2). The capacity of individual candidate units and lines is fixed. Operation costs include fuel costs of thermal units, O&M costs of thermal, hydro and renewable units, and demand response of curtailable loads (3). The cost of demand response (i.e., negative generation) is the demand response bid multiplied by the curtailed load, which is paid to consumers for load management. The salvage value (or the residual value) is the future value in terms of percentage of depreciation of the initial investment. In our proposed model, salvage value is the value of installed resource at the end of the planning horizon (4). A higher salvage factor for a commodity indicates a lower depreciation by the end of the planning horizon. The objective is evaluated in terms of discounted costs, in which the discount rate is incorporated in the present-worth value of cost components. A higher discount rate in (5) would affect the investment as resources with higher investment costs become inferior. To calculate the salvage value, κ_t is replaced with

κ_T to reflect the commodity value at the end of the planning horizon. T represents the number of planning years.

$$Min \;\; IC + OC - SV \tag{1}$$

$$\begin{aligned} IC = &\sum_t \sum_{i \in CG} \kappa_t CC_i P_i^{\max} (z_{it} - z_{i(t-1)}) \\ &+ \sum_t \sum_{l \in CL} \kappa_t CC_l PL_l^{\max} (y_{lt} - y_{l(t-1)}) \end{aligned} \tag{2}$$

$$\begin{aligned} OC = &\sum_t \sum_h \sum_b \sum_{i \in \{ET,CT\}} \sum_n \kappa_t DT_{bht} FP_{it}^n F_{ibht}^n \\ &+ \sum_t \sum_h \sum_b \sum_i \kappa_t DT_{bht} OM_i^v P_{ibht} \\ &+ \sum_t \sum_h \sum_b \sum_i \kappa_t OM_i^f P_i^{\max} I_{ibht} \vartheta_b \\ &- \sum_t \sum_h \sum_b \sum_m \kappa_t DR_{mht} CU_{mbht} \end{aligned} \tag{3}$$

$$\begin{aligned} SV = &\kappa_T \sum_t \sum_{i \in CG} \gamma_{it} CC_i P_i^{\max} (z_{it} - z_{i(t-1)}) \\ &+ \kappa_T \sum_t \sum_{l \in CL} \gamma_{lt} CC_l PL_l^{\max} (y_{lt} - y_{l(t-1)}) \end{aligned} \tag{4}$$

$$\kappa_t = \frac{1}{(1+d)^{t-1}} \qquad \forall t \tag{5}$$

The proposed multi-area expansion planning objective is subject to the following practical constraints:

A. System Operation Constraints

The load balance constraint (6) requires that the power generated in an area plus the net power injected by transmission lines satisfy the area load minus the curtailed load. The system reserve requirement (7) ensures that the reserve provided by thermal and hydro units satisfies the system spinning reserve requirement. The load curtailment limit (8) ensures that the load curtailment is limited to the designated responsive loads.

$$\sum_{i \in A_a} P_{ibht} + \sum_l B_{a,l} PL_{lbht} = \sum_{m \in A_a} PD_{mbht} - \sum_{m \in A_a} CU_{mbht} \qquad \forall a, \forall b, \forall h, \forall t \tag{6}$$

$$\sum_{i \in \{ET,CT\}} r_i P_i^{\max} I_{ibht} + \sum_{i \in \{EH,CH\}} (P_i^{\max} - P_{ibht}) I_{ibht} \ge R_{bht} \qquad \forall b, \forall h, \forall t \tag{7}$$

$$CU_{mbht} \le DB_{mht} PD_{mbht} \qquad \forall m, \forall b, \forall h, \forall t \tag{8}$$

B. Commissioning Time and Installation Constraints

A commissioning time is imposed before any new installations for exchanging the planning information between multi-area system operators and generation and transmission investors. This time is required to obtain necessary approvals on planning and detailed engineering design and construction work, which is dependent on the type and the size of the new installations. A candidate unit or transmission line cannot be installed before its commissioning time is elapsed (9)-(10). Once a candidate generating unit or transmission line is installed, its investment state will be fixed as 1 for the remaining years in the planning horizon (11)-(12). Generating units cannot be committed or dispatched until they are installed (13). A retired generating unit cannot be operated any longer (14).

$$z_{it} = 0 \qquad \forall i \in CG, \forall t < T_i^{\mathrm{com}} \tag{9}$$

$$y_{lt} = 0 \qquad \forall l \in CL, \forall t < T_l^{\mathrm{com}} \tag{10}$$

$$z_{i(t-1)} \le z_{it} \qquad \forall i \in CG, \forall t \tag{11}$$

$$y_{l(t-1)} \le y_{lt} \qquad \forall l \in CL, \forall t \tag{12}$$

$$I_{ibht} \le z_{it} \qquad \forall i \in CG, \forall b, \forall h, \forall t \tag{13}$$

$$I_{ibht} = 0 \qquad \forall i \in EG, \forall b, \forall h, \forall t > T_i^{\mathrm{Re}} \tag{14}$$

C. Thermal Units Constraints

Thermal units are subject to limits on min/max capacity, fuel, emission, and scheduled maintenance. The commitment status of thermal units is considered as part of the min/max capacity limit (15), for an accurate modeling of unit commitment in multi-area power system operations. The proposed multi-area model supports any number of fuel types for new and existing generating units. Thermal units might use alternate or standby fuels as long as the primary fuel is used up. The unit generation dispatch is the sum of its generation by each fuel type (16). Each fuel type would satisfy its min/max limits (17). For the primary fuel, $\xi_{it}^1 = 1$. Likewise, the fuel permission state of the next fuel type would be set to 1 by (18) for switching to the next fuel type. The fuel function of a generating unit is obtained based on min/max heat values and heat rate of the generating unit. The total annual emission of each thermal unit is restricted by (19). Scheduled maintenance would limit the unit commitment and dispatch (20). In addition, group limits are considered which would represent multi-area expansion planning constraints such as total fuel and emission limits of a system (21)-(22).

$$P_i^{\min} I_{ibht} \le P_{ibht} \le P_i^{\max} I_{ibht} \qquad \forall i \in \{ET,CT\}, \forall b, \forall h, \forall t \tag{15}$$

$$P_{ibht} = \sum_n PN_{ibht}^n \qquad \forall i \in \{ET,CT\}, \forall b, \forall h, \forall t \tag{16}$$

$$FL_{it}^{n,\min} \xi_{it}^n \le \sum_h \sum_b DT_{bht} F_{ibht}^n \le FL_{it}^{n,\max} \xi_{it}^n \qquad \forall i \in \{ET,CT\}, \forall n, \forall t \tag{17}$$

$$\sum_h \sum_b DT_{bht} F_{ibht}^n \ge FL_{it}^{n,\max} \xi_{it}^{n+1} \qquad \forall i \in \{ET,CT\}, \forall n, \forall t \tag{18}$$

$$\sum_h \sum_b \sum_n EM_i^n DT_{bht} PN_{ibht}^n \le EL_{it}^{\max} \qquad \forall i \in \{ET,CT\}, \forall t \tag{19}$$

$$\sum_h \sum_b DT_{bht} P_{ibht} \le P_i^{\max} \Big(\sum_h \sum_b DT_{bht} - SM_i * 24\Big) \qquad \forall i \in \{ET,CT\}, \forall t \tag{20}$$

$$\sum_h \sum_b \sum_{i \in S} \sum_n EM_i^n DT_{bht} PN_{ibht}^n \le EL_t^{s,\max} \qquad \forall t \tag{21}$$

$$FL_t^{s,\min} \le \sum_h \sum_b \sum_{i \in S} \sum_n DT_{bht} F_{ibht}^n \le FL_t^{s,\max} \qquad \forall t \tag{22}$$

D. Hydro Units Constraints

Three types of hydro units including run-of-river, large reservoirs, and pumped-storage are modeled in our algorithm. For run-of-river hydro units, min/max generation capacity limits and min/max energy limits per period are shown in (23) and (24), respectively. The run-of-river hydro unit has no storage, so $ST_{iht} = 0$.

Existing large reservoir hydro units are modeled by (23)-(27). Similar to run-of-river hydro units, (23) defines min/max capacity limits and (24) defines min/max energy limits available per period. The stored energy is restricted by the reservoir storage capacity (25). The stored energy at various periods is coupled so that the energy is not consumed before it is stored (26). The total stored energy at the end of each planning year is zero (27), i.e. the stored energy annually is converted into generation. For large-reservoir hydro candidate units, (24)-(25) are replaced with (28)-(29) to incorporate the investment variable z_{it}.

$$P_i^{\min} I_{ibht} \le P_{ibht} \le P_i^{\max} I_{ibht} \quad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{23}$$

$$E_{ih}^{\min} \le \sum_b DT_{bht} P_{ibht} + ST_{iht} \le E_{ih}^{\max} \qquad \forall i \in EH, \forall h, \forall t \tag{24}$$

$$-ST_{ih}^{\max} \le ST_{iht} \le ST_{ih}^{\max} \qquad \forall i \in EH, \forall h, \forall t \tag{25}$$

$$0 \le \sum_{h'<h} ST_{ih't} \le ST_{ih}^{\max} \qquad \forall i \in \{EH, CH\}, \forall h, \forall t \tag{26}$$

$$\sum_h ST_{iht} = 0 \qquad \forall i \in \{EH, CH\}, \forall t \tag{27}$$

$$E_{ih}^{\min} z_{it} \le \sum_b DT_{bht} P_{ibht} + ST_{iht} \le E_{ih}^{\max} z_{it} \qquad \forall i \in CH, \forall h, \forall t \tag{28}$$

$$-ST_{ih}^{\max} z_{it} \le ST_{iht} \le ST_{ih}^{\max} z_{it} \quad \forall i \in CH, \forall h, \forall t \tag{29}$$

Pumped-storage hydro units are modeled by (30)-(38). A pumped-storage unit has three operation modes which are generating, pumping, and idling modes. The pumped-storage unit is a load when in pumping mode (30). Generating and pumping modes are subject to min/max capacity limits (31) and (32). At each time point, the unit can only be operated at one of its modes, which is denoted by (33). If $u_{ibht}^p = 1$, the unit is pumping, and if $u_{ibht}^g = 1$, the unit is generating. If both binary variables are zeros, the unit is in idling mode. The constraint is further extended to consider the relationship of operation modes and the investment status of candidate units (34). The stored energy is calculated based on the energy stored at pumping mode minus the energy consumed in the generating mode (35). The stored energy is less than the maximum storage capacity (36). The stored energy in blocks is coupled so that the energy can only be consumed after it is stored (37). The total stored energy by the end of each period is zero (38).

$$P_{ibht} = Q_{ibht}^g - Q_{ibht}^p \qquad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{30}$$

$$Q_i^{g,\min} u_{ibht}^g \le Q_{ibht}^g \le Q_i^{g,\max} u_{ibht}^g \qquad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{31}$$

$$Q_i^{p,\min} u_{ibht}^p \le Q_{ibht}^p \le Q_i^{p,\max} u_{ibht}^p \qquad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{32}$$

$$u_{ibht}^p + u_{ibht}^g \le 1 \qquad \forall i \in EH, \forall b, \forall h, \forall t \tag{33}$$

$$u_{ibht}^p + u_{ibht}^g \le z_{it} \qquad \forall i \in CH, \forall b, \forall h, \forall t \tag{34}$$

$$SP_{ibht} = \eta_i DT_{bht} Q_{ibht}^p - DT_{bht} Q_{ibht}^g \qquad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{35}$$

$$-SP_i^{\max} \le SP_{ibht} \le SP_i^{\max} \qquad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{36}$$

$$0 \le \sum_{b'<b} SP_{ib'ht} \le SP_i^{\max} \qquad \forall i \in \{EH, CH\}, \forall b, \forall h, \forall t \tag{37}$$

$$\sum_b SP_{ibht} = 0 \qquad \forall i \in \{EH, CH\}, \forall h, \forall t \tag{38}$$

E. Renewable Unit Constraints

A large integration of intermittent renewable sources could challenge the reliability of multi-area power systems. The significant challenge appears in expansion planning when the additional renewable sources must guarantee a reliable supply of energy to loads [22]. The generation pattern for each renewable unit is determined by its forecasted value. Thus, the generation value is considered as constant in the load balance equation. Several approaches can be applied to renewable unit generation forecast. For instance, wind speed can be forecasted by historical data or simulated by the Weibull probability distribution function; the generation pattern for wind generating units would then be obtained by applying the wind speed quantity to the power curve of each wind turbine [23].

The renewable energy forecast would also define the pattern for the availability of such units. To consider intermittent units in reliability assessments, their respective generation output should remain above a particular minimum generation level for a specified time period (i.e., persistence time.) A persistence time is assumed for each generation level of a unit. Each minimum generation level is compared to the forecasted renewable generation pattern. The periods are identified in which the forecasted renewable generation is higher than the minimum generation level and continues for at least the persistence time. The sum of all such periods divided by the total generation time for a renewable unit would represent the associated availability of the given generation level. This procedure will be repeated for all generation levels between the min and max generation to determine a generation model for an intermittent generating unit. The renewable unit would be represented as a multi-state unit with a given availability for each state. These states are applied in the reliability calculation using the same method as that for non-intermittent generating units [24].

F. Transmission Network Constraints

The multi-area power system is partitioned into geographical areas, which are connected through transmission lines. The existing line flows are modeled by (39)-(40). For candidate lines, however, the power flow depends on the installation state of the line (41)-(42). If the line is not installed, (41) is relaxed and (42) sets the line flow to zero. Once a line is installed, it will no longer be treated as a candidate line. The voltage angle of the area incorporating slack bus is set to zero (43).

$$PL_{lbht} = \sum_a B_{l,a} \theta_{abht} \Big/ x_l \qquad \forall l \in EL, \forall b, \forall h, \forall t \tag{39}$$

$$-PL_l^{\max} \le PL_{lbht} \le PL_l^{\max} \quad \forall l \in EL, \forall b, \forall h, \forall t \tag{40}$$

$$\left| PL_{lbht} - \sum_a B_{l,a} \theta_{abht} \Big/ x_l \right| \le M(1 - z_{lt}) \qquad \forall l \in CL, \forall b, \forall h, \forall t \tag{41}$$

$$\left| PL_{lbht} \right| \le PL_l^{\max} z_{lt} \qquad \forall l \in CL, \forall b, \forall h, \forall t \tag{42}$$

$$\theta_{abht} = 0 \qquad \forall a = \text{Ref}, \forall b, \forall h, \forall t \tag{43}$$

G. Multi-Area System Reliability Criterion

Once the multi-area expansion planning decisions are made in the planning problem, the new topology with generating unit and transmission line investments is sent to the subproblems where annual LOLEs are calculated as a post-processor. The LOLE calculation utilizes the component forced outage rate [17]. If the system LOLE in a year is larger than the LOLE limit, a reliability constraint is generated in the subproblem and added to the next iteration of the planning problem. The reliability constraint is based on the sensitivity of changes in the system LOLE with respect to changes in each investment decision (44)-(48).

$$\Delta LOLE_{at} = \sum_{i \in CG} \left(LOLE^{(1)}_{at,i} - LOLE^{(0)}_{at,i} \right) \Delta z_{it} + \sum_{l \in CL} \left(LOLE^{(1)}_{at,l} - LOLE^{(0)}_{at,l} \right) \Delta y_{lt} \quad \forall a, \forall t \tag{44}$$

$$\Delta z_{it} = z_{it} - \hat{z}_{it} \qquad \forall i \in CG, \forall t \tag{45}$$

$$\Delta y_{lt} = y_{lt} - \hat{y}_{lt} \qquad \forall l \in CL, \forall t \tag{46}$$

$LOLE^{(1)}_{at,i}$ is for an installed unit *i* and $LOLE^{(0)}_{at,i}$ is for a candidate generating unit *i*, which is not installed. Here, $LOLE^{(1)}_{at,i} - LOLE^{(0)}_{at,i}$ represents the incremental change in the LOLE of area *a* when the investment decision for unit *i* is changed. Similarly, $LOLE^{(1)}_{at,l} - LOLE^{(0)}_{at,l}$ represents the change in the LOLE of area *a* when the investment decision for line *l* is changed. The reliability constraint (47) will be included in the next planning iteration.

$$L\hat{OLE}_{at} + \Delta LOLE_{at} \le LOLE^{\text{target}}_{at} \qquad \forall a, \forall t \tag{47}$$

IV. Numerical Simulations

The proposed multi-area expansion planning model is applied to a power system with 43 thermal units, 9 hydro units, and 2 renewable units. The system is partitioned into 7 areas interconnected by 8 tie-lines. Transmission congestion in each single area is ignored.

A set of 23 candidate units (including 16 thermal and 7 hydro units) and 4 candidate lines are considered in Fig. 2. A 20-year planning horizon is considered. Each planning year is divided into six 2-month periods, and six load blocks are considered in each period. Load blocks equally divide the loads between min/max values in each period, and the duration of each block is determined accordingly. The quantity and duration of load blocks may change in each period within each year. The planning is performed annually while the operation is carried out for each load block.

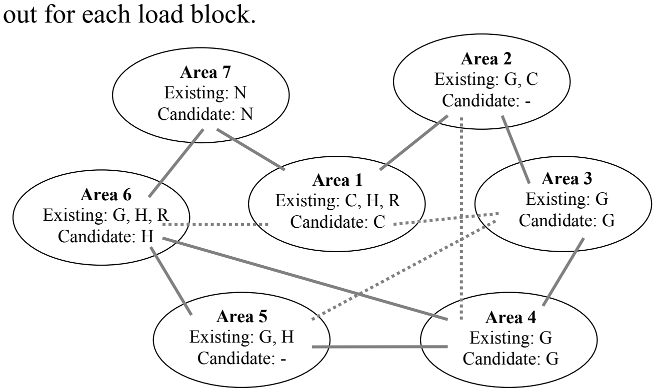

Fig. 2 Multi-area system (C: coal, G: gas, N: nuclear, H: hydro, R: renewable).

In the proposed multi-area model, there are no limitations on annual investments or the number of units and lines that could be installed annually. The discount rate is 5%. The spinning reserve requirement is 5% of the load in each block. The initial multi-area system load is 8,976 MW with an average load growth rate of 2.6%. The initial available generation capacity is 20,430 MW, which decreases due to the retirement of units. By the end of the planning horizon, 11 units will be retired, which reduce the generation capacity to 17,980 MW. LOLE of one day per year is considered as the reliability criterion in all areas. The proposed multi-area expansion planning method is implemented on a 2.4-GHz personal computer using CPLEX 11.0 [25].

These cases are discussed as follows:

Case 1: The 20-year generation expansion planning is performed in each area without considering any transfer capability among multi-areas. The expansion planning candidates in Tables I and II are intended to ensure an adequate supply of load in each area and satisfy the area reliability criterion. In Case 1, each area in Fig. 2 would supply its own load and satisfy its reliability requirements without any regards to the overall system reliability. As a result, less economical units 4-6 (in area 3) are installed, which result in higher investments and operation costs.

TABLE I
CANDIDATE UNIT INSTALLATION YEAR

Candidate Unit	Type	Area	Capacity (MW)	FOR	Case 1	Case 2	Case 3
1	Gas	3	240	0.04	-	11	11
2	Gas	3	240	0.04	-	6	6
3	Gas	3	240	0.04	-	-	-
4	Gas	3	350	0.04	1	20	-
5	Gas	3	350	0.04	1	-	20
6	Gas	3	350	0.04	1	-	-
7	Gas	4	750	0.04	20	15	15
8	Gas	4	750	0.04	1	15	17
9	Gas	4	750	0.04	3	-	-
10	Coal	1	1000	0.06	-	-	2
11	Coal	1	1000	0.06	-	-	-
12	Coal	1	1000	0.06	1	-	-
13	Nuclear	7	1000	0.04	1	1	1
14	Nuclear	7	1000	0.04	1	1	1
15	Nuclear	7	1000	0.04	-	1	1
16	Nuclear	7	1000	0.04	1	1	1
17	Hydro	6	50	0.01	1	1	1
18	Hydro	6	250	0.01	1	1	1
19	Hydro	6	380	0.01	1	1	1
20	Hydro	6	275	0.01	1	1	1
21	Hydro	6	400	0.01	1	1	1
22	Hydro	6	400	0.01	1	1	1
23	Hydro	6	400	0.01	1	1	1

TABLE II
CANDIDATE LINE INSTALLATION YEAR

Candidate Line	From Area	To Area	Capacity (MW)	FOR	Case 1	Case 2	Case 3
1	1	6	2000	0.002	-	-	4
2	1	3	2000	0.002	-	-	1
3	3	5	2000	0.002	-	-	1
4	2	4	2000	0.002	-	-	-

TABLE III
INSTALLED CAPACITY IN EACH AREA AND THE SYSTEM (MW)

	Case 1	Case 2	Case 3
Area 1	4380	3380	4380
Area 2	4200	4200	4200
Area 3	3450	3230	3230
Area 4	4850	4100	4100
Area 5	2850	2850	2850
Area 6	3705	3705	3705
Area 7	4000	5000	5000
System	27435	26465	27465

The installed area capacity and LOLEs at the end of the planning horizon are shown in Tables III and IV, respectively. The total system cost is $505.16B and the investment cost is only 4.62% of the total system cost.

TABLE IV
LOLE IN EACH AREA AND THE SYSTEM (DAY/YEAR)

	Case 1	Case 2	Case 3
Area 1	0.00326	0.05431	0.00345
Area 2	0.28790	0.28790	0.28790
Area 3	0.11476	0.68759	0.68759
Area 4	0.00704	0.10360	0.10360
Area 5	0.69304	0.69304	0.68604
Area 6	0.00001	0.00001	0.00001
Area 7	0.64735	0.04164	0.04164
System	-	0.000008	0.0000011

TABLE V
SUMMARY OF SYSTEM COSTS

	Case 1	Case 2	Case 3
Investment Cost ($Billion)	23.311	21.110	25.517
Operation Cost ($Billion)	482.275	299.958	289.181
Salvage Value ($Billion)	0.422	0.402	0.474
Total Planning Cost ($Billion)	505.164	320.666	314.224

Case 2: A multi-area generation planning model with transmission network constraints is considered. Table IV shows that all areas have met the given reliability criterion. Here, areas with higher levels of reliability would assist those with generation shortfalls. Compared to Case 1, an economical unit is installed at area 7 instead of less economical units at areas 3 and 4. The assisting area 7 would compensate the capacity deficiency in other areas and reduce the overall generation dispatch cost. In Table V, the total system planning cost for investment and operation is $320.66B, which shows a 36.52% reduction as compared to that in Case 1. Here, both investment and operation costs are reduced.

Case 3: The coordination between the generation and transmission planning is considered in the constrained multi-area power systems. Candidate lines 1, 2 and 3 are installed which would mitigate the congestion in line 1-2 and facilitate the dispatch of economical units in area 1. By installing the candidate line 1, area 1 would also install and utilize the economic unit 10. As a result, area 1 would meet its reliability requirement without any support from area 7 and would also support other areas to compensate their capacity deficiency. Table V shows that the total system cost is $314.22B, which is 37.80% lower than that of Case 1, and 2.01% lower than that of Case 2. The transmission investment cost in this case is $2.57B, which represents a small portion of the total cost of multi-area expansion planning. Table V also shows that the proposed solution reduces the operation cost by about $10.77B as compared with that in Case 2 which yields higher benefits than its investment cost. The annual installed capacity in Cases 1, 2 and 3 are shown in Fig. 3 in which a higher installed capacity is required in Case 1 for maintaining the same level of reliability. The installation of unit 10 in Case 3 would result in a higher installed capacity as compared to that in Case 2; however, the installation would provide significant economical benefits by low cost power generation.

The effect of renewable sources is further studied by adding 9 candidate wind units to area 4. All candidate wind units are installed at the first year of planning. However, additional non-wind units would be installed to alleviate the intermittency issue of wind units. The additional units may not be economically justifiable; however, they would be required for maintaining the area reliability. The total operation cost after the installation of wind units drops to $287.83B, which is 8.39% lower than that in Case 3. However, the investment cost increases by 9.34% with the installation of additional thermal units for managing the wind generation intermittency.

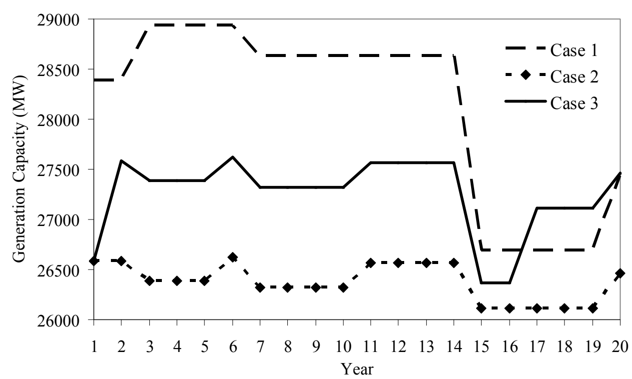

Fig. 3 Generation capacity

In Case 3, if the emission constraint on coal units is further considered, more gas units will be installed in the multi-area system. The additional gas units will result in a higher installed capacity and a lower LOLE. Most of the installed gas units are located in area 4 so the candidate line 4 will be installed to mitigate transmission congestion. The installation of gas units will increase the system operation and investment costs, but will lower the emission and facilitate the installation of intermittent wind generating units.

In Cases 1-3, the multi-area expansion planning is performed annually while the operation is carried out for load blocks. There are no limitations on load block durations which could extend from hours to months. The choice will be a tradeoff between the accuracy and the computation time in the proposed model. However, the duration of load blocks could play a key role when considering the short-term system operation. To address this issue in the multi-area expansion planning, annual peak loads are considered in which short-term operation constraints are ignored. In this case, the minimum LOLE requirement in areas 2 and 5 would not be met despite the possibility of receiving assistance from other areas and considering additional generating unit installations. The investment cost of generating units would be 6.67% higher when the short-term operation constraints are not considered.

Case 4: Gas-fired generating units have become favorable commodities in power systems because of their economic benefits, operation flexibility, and low environmental impacts. Gas-fired units provide a linkage between natural gas and electric power systems. Therefore, limitations on natural gas supply might affect power system operations. To consider the interdependency of gas and electricity, an annual gas supply limit of 150 mmscfd is considered in this case. Here, gas supply in years 2 and 3 (164.88 and 213.14 mmscfd, respectively) is insufficient which is compensated by coal units. All the candidate lines are installed to enhance the coal unit dispatch located in area 1. The total system cost is 0.66% higher than that in Case 3 which is due to the installation of more expensive coal units.

V. Discussions

The specific features of the proposed multi-area expansion planning model are listed as follows:

- Lower investment costs: Fewer units are to be installed for reliability requirements because the interconnected areas would maintain a desired level of reliability in the multi-area system.
- Lower operation costs: The interconnected areas would facilitate the economic transfer of low cost generation to areas with higher load demands.
- Accurate models: Load blocks are used for load modeling (instead of peak loads), and comprehensive models are considered for generating units and transmission lines in the short-term system operation.
- Practical results: The multi-area generation and transmission coordination is considered in operation and planning stages. Moreover, reliability requirements are considered based on random outages of generating units and transmission lines.
- Computation efficiency: The reliability requirements are incorporated in the multi-area expansion planning model by introducing annual reliability subproblems in Fig. 1. The proposed decomposition will reduce the size of the coordinated problem and add minute computation burdens to the multi-area expansion planning problem.

VI. Conclusions

An efficient and comprehensive multi-area model for the coordinated expansion planning with the consideration of system reliability constraints was proposed. The multi-area expansion planning problem was decomposed into a planning problem and annual reliability subproblems for each year. The planning problem found the expansion plan by considering candidate units and lines. The subproblems utilized the proposed plan to calculate the system annual reliability index and compared it to the target value. In case of violations, reliability constraints were formed and added to the next iteration of the planning problem. A complete formulation of this multi-area model was presented, incorporating models for thermal, hydro and renewable units, along with a multi-area transmission network, so that the readers can replicate the model. The proposed multi-area model was analyzed further through numerical simulations, where it was shown that the solution of the coordinated multi-area expansion planning is applicable to practical power systems. The coordinated multi-area expansion planning enhanced the solutions by considering the impact of transmission constraints on system adequacy and reliability, and further guaranteed a reliable and optimal solution.

References

[1] M. Shahidehpour, “Global broadcast - transmission planning in restructured systems,” *IEEE Power Eng Mag.*, vol. 5, no. 5, pp. 18-20, Sep./Oct. 2007.

[2] S. de la Torre, A. J. Conejo, and J. Contreras, “Transmission expansion planning in electricity markets,” *IEEE Trans. Power. Syst.*, vol. 23, no. 1, pp. 238-248, Feb. 2008.

[3] L. P. Garces, A. J. Conejo, R. Garcia-Bertrand, and R. Romero, “A bilevel approach to transmission expansion planning within a market environment,” *IEEE Trans. Power Syst.*, vol. 24, no. 3, pp. 1513-1522, Aug. 2009.

[4] J. Choi, A. A. El-Keib, and T. Tran, "A fuzzy branch and bound-based transmission system expansion planning for the highest satisfaction level of the decision maker," *IEEE Trans. Power Syst.*, vol. 20, no. 1, pp. 476-484, Feb. 2005.

[5] J. Choi, T. Tran, A. A. El-Keib, R. Thomas, H.S. Oh, and R. Billinton, “A method for transmission expansion system expansion planning considering probabilistic reliability criteria," *IEEE Trans. Power Syst.*, vol. 20, no. 3, pp. 1606-1615, Aug. 2005.

[6] O. B. Tor, A. N. Guven, and M. Shahidehpour, “Congestion-driven transmission planning considering the impact of generator expansion,” *IEEE Trans. Power Syst.*, vol. 23, no.2, pp. 781-789, May. 2008.

[7] S. Binato, M. V. Pereira, and S. Granville, “A new Benders decomposition approach to solve power transmission network design problems,” *IEEE Trans. Power Syst.*, vol. 16, no. 2, pp. 235-240, May 2001.

[8] P. Sánchez-Martín, A. Ramos, and J. F. Alonso, “Probabilistic midterm transmission planning in a liberalized market,” *IEEE Trans. Power Syst.*, vol. 20, no. 4, pp. 2135-2142, Nov. 2005.

[9] E. L. Silva, H. A. Gil, and J. M. Areiza, “Transmission network expansion planning under an improved genetic algorithm,” *IEEE Trans. Power Syst.*, vol. 15, no. 3, pp. 1168-1175, Aug. 2000.

[10] A. S. D. Braga and J. T. Saraiva, “A multiyear dynamic approach for transmission expansion planning and long-term marginal costs computation,” *IEEE Trans. Power Syst.*, vol. 20, no. 3, pp. 1631-1639, Aug. 2005.

[11] J. Contreras and F. F. Wu, “Coalition formation in transmission expansion planning,” *IEEE Trans. Power Syst.*, vol. 14, no. 3, pp. 1144-1152, Aug. 1999.

[12] T. De la Torre, J. W. Feltes, T. G. S. Roman, and H. M. Merril, “Deregulation, privatization, and competition: transmission planning under uncertainty,” *IEEE Trans. Power Syst.*, vol. 14, no. 2, pp. 460-465, May 1999.

[13] M. O. Buygi, M. Shahidehpour, H. M. Shanechi, and G. Balzer, “Market based transmission expansion planning: stakeholders' desires,” in Proc. 2004 *IEEE Int. Conf. on Electric Utility Deregulation, Restructuring and Power Technologies*, vol. 2, pp. 433-438.

[14] J. H. Roh, M. Shahidehpour, and Y. Fu, “Security-constrained resource planning in electricity markets,” *IEEE Trans. Power Syst.*, vol. 22, no. 2, pp. 812-820, May 2007.

[15] B. Alizadeh and S. Jadid, “Reliability constrained coordination of generation and transmission expansion planning in power systems using mixed integer programming,” *IET Gen. Trans. Distr.*, vol. 5, no. 9, pp. 948-960, Sep. 2011.

[16] M. O. Buygi, G. Balzer, H. M. Shanechi, and M. Shahidehpour, “Market-based transmission expansion planning”, *IEEE Trans. Power Syst.*, vol. 19, no. 4, pp. 2060-2067, Nov. 2004.

[17] R. Billinton, and R.N. Allan, *Reliability of Power Systems*, second edition, New York: Plenum Publishing, 1996.
[18] A. Khodaei, M. Shahidehpour, and S. Kamalinia, “Transmission switching in expansion planning,” *IEEE Trans. Power Syst.*, vol. 25, no. 3, pp. 1722-1733, Aug. 2010.
[19] O. B. Tor, A. N. Guven and M. Shahidehpour, “Promoting the Investment on IPPs for Optimal Grid Planning,” *IEEE Trans. on Power Systems*, vol. 25 no. 3, pp. 1743-1750, Aug. 2010.
[20] J. H. Roh, M. Shahidehpour, and Y. Fu, “Market-based coordination of transmission and generation capacity planning,” *IEEE Trans. Power Syst.*, vol. 22, no. 4, pp. 1406-1419, Nov. 2007.
[21] A.J. Conejo, E. Castillo, R. Mínguez, and R. García-Bertrand, *Decomposition Techniques in Mathematical Programming*, Springer, 2006.
[22] S. Kamalinia, M. Shahidehpour, and A. Khodaei, “Security-constrained expansion planning of fast-response units for wind integration,” *Elect. Power Syst. Res.*, vol. 81, no. 1, pp. 107-116, Jan. 2011.
[23] M. R. Patel, *Wind and Solar Power Systems*, CRC Press, 1999.
[24] R. N. Allan, P. Djapic, and G. Strbac, “Assessing the contribution of distributed generation to system security,” *Int. Conf. on Prob. Meth. App. Power Syst.*, pp. 1-6, 2006.
[25] ILOG CPLEX, ILOG CPLEX Homepage 2009 [Online]. Available: http://www.ilog.com.

Biographies

Amin Khodaei (M’11) received the B.S. degree from the University of Tehran, Iran, in 2005, the M.S. degree from the Sharif University of Technology, Tehran, Iran, in 2007, and the Ph.D. degree from the Illinois Institute of Technology (IIT), Chicago, in 2010, all in electrical engineering. He is currently a Senior Research Associate in the Electrical and Computer Engineering Department, Illinois Institute of Technology. His research interests include operation and economics of power systems.

Mohammad Shahidehpour (F’01) is the Bodine Chair Professor and Director of Robert W. Galvin Center for Electricity Innovation at IIT. Dr. Shahidehpour is the recipient of the Honorary Doctorate for the Polytechnic University of Bucharest in Romania. He is the recipient of 2011 Technologist of the Year Award from the Illinois Technology Association, Engineer of the Year Award from the IEEE/PES Chicago Section, and the Innovation Award from the Association of Electrical and Computer Engineering Department Heads in the United States.

Lei Wu (M’07) received his B.S. in Electrical Engineering and M.S. in Systems Engineering from Xi’an Jiaotong University, China, in 2001 and 2004, respectively, and Ph.D. degree in EE from IIT in 2008. Presently, he is an Assistant Professor in the ECE Department at Clarkson University. His research interests include power systems operation and economics.

Zuyi Li (SM’09) received the B.S. and M.S. degrees from Shanghai Jiaotong University, Shanghai, China, in 1995 and 1998, respectively, and the Ph.D. degree from IIT, Chicago, in 2002, all in electrical engineering. Presently, he is an Associate Professor in the ECE Department at IIT. He is the Co-PI of $40M grants and contracts on energy and sustainability. Dr. Li is the coauthor of *Market Operations in Electric Power Systems* (New York: Wiley, 2002).