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Transmission Network Expansion Planning Considering Desired Generation Security

Samaneh GOLESTANI, Haidar SAMET

School of Electrical and Computer Engineering, Shiraz University, Shiraz, Iran.
E-mails: samanehgolestani@shirazu.ac.ir; samet@shirazu.ac.ir
Phone: +989127002513

Abstract

Transmission Network Expansion Planning (TNEP) is an important part of power system planning in both conventional and new structured power market. Its goal is to minimize the network construction and operational cost while satisfying the demand increase, considering technical and economic conditions. Planning algorithm in this paper consisted of two stages. The former specifies highly uncertain lines and probability of congestion, considering desired generation security level (e.g. N-2 generation security level). The latter determines the optimal expansion capacity of existing lines. Splitting required capacity for reinforcement of weak lines due to desired generation security level simplifies the TNEP problem. In addition, it monitors the impact of generation uncertainty on transmission lines. Simulation results of the proposed idea are presented for IEEE-RTS-24bus network.

Keywords

Transmission Lines; Power System Planning; Security; Cost

Introduction

Transmission expansion improves the market competitiveness. On the other hand, investments in new transmission equipment are costly and should be undertaken only if they can be justified economically. In order to deliver maximum economic welfare to society, the electricity supply industry should follow the path of least-cost long-term development. This requires a coordinated approach to the optimization of the generation and transmission operation and development. Optimizing the transmission network in isolation from the generation resources would almost certainly not meet the above objective [1]. Before the deregulation of power systems, the vertical integration of electric utilities was considered necessary to ensure an adequate level of coordination.

Among other reasons, competition was introduced in the electricity supply to respond to growing concerns about the inefficiency of established operation and investment practices. One of the consequences of the deregulation process has been the separation of generation from transmission. This separation is indeed frequently considered indispensable to achieve open and non-discriminatory access to the energy market [1].

In this environment, pricing of transmission becomes the key to achieving both efficient operation and least-cost system development of the entire system [1]. Coordinating the investment of transmission and generation, which are now operated as separate entities, is to be achieved through efficient transmission network expansion planning.

TNEP is a basic part of power system planning that determines where, when and how many new transmission lines should be added to the network. Its task is to minimize the network construction and operational cost, while meeting imposed technical and economic constraints. TNEP should satisfy required adequacy of the lines for delivering safe and reliable electric power to load centers along the planning horizon. TNEP is a hard, large-scale combinatorial optimization problem.

After Garver's paper that was published in 1970 [2], much research has been done on the field of TNEP problem. Some of them such as [3, 4] are related to TNEP problem solution method. Some other proposed different approaches for solution of this problem considering various parameters such as uncertainty in demand [5], reliability criteria [6, 7], and economic factors [8]. In addition, some of them investigated this problem and generation expansion planning together [9, 10]. Recently, different methods such as, Bender decomposition [3], HIPER [11], branch and bound algorithm [12], sensitivity analysis [13], genetic algorithm

[14], simulated annealing [15], Tabu search [16] Particle Swarm Optimization [17] and fuzzy [18] have been proposed for the solution of TNEP problem. In all of these methods, the problem has been solved regardless to the influences of generation uncertainty on TNEP problem.

This article proposes a technique to define weak transmission lines in order to facilitate solving TNEP. In essence, it presents a stochastic method, which can be used by vertically integrated utilities as well as the ISOs in electricity markets. In this method, outage of generation as random disturbance is modeled in order to define vulnerable transmission lines. Determining an appropriate capacity for line expansion is the final stage.

Material and Method

In this paper, algorithm of transmission network expansion planning has two stages. The first stage specifies highly uncertain lines and probability of congestion considering the desired generation security (e.g. N-2 generation security). The second stage determines the optimal expansion capacity of existing lines.

Focus of this research is to organize the first stage's algorithm appropriately. Because planning optimal solution for transmission expansion is much easier when the weak lines are highlighted. It allows considering discrete capacity expansion for the highlighted lines. When the line expansion candidate is specified, applicative capacity is not complicated to determine. Any optimization algorithm can manage the second stage. In this research, Genetic Algorithm (GA) was used to solve the problem. Simulation results of the proposed idea are presented for IEEE-RTS-24bus network.

The proposed algorithm was implemented in "MATLAB" program. The program is tested on IEEE 24-bus Reliability Test System (RTS) network. In order to plan future transmission network, the future network condition shall be predicted. In this paper, load growth rate are assumed 10%. It means that each load is 110% of its standard quantity in IEEE-RTS case study. Generator unit location and generator unit forced outage rate are given in Tables 1 and 2 respectively. The other input data are in [19].

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Table 1.Generator unit locations

Bus	**MW / Unit No.**	**Bus**	**MW / Unit No.**
1	20/1, 20/2, 76/3, 76/4	**16**	155/22
2	20/5, 20/6, 76/7, 76/8	**8**	400/23
7	100/9, 100/10, 100/11	**21**	400/24
13	197/12, 197/13, 197/14	**22**	50/25, 50/26, 50/27, 50/28, 50/29, 50/30
15	0/15	**23**	155/31, 155/32, 350/33
18	12/16, 12/17, 12/18, 12/19, 12/20, 155/21		

Table 2.Generator unit forced outage rate

Unit Size MW	Number of Units	Forced Outage Rate
12	5	0.02
20	4	0.10
50	6	0.01
76	4	0.02
100	3	0.04
155	4	0.04
197	3	0.05
350	1	0.08
400	2	0.12

TNEP Problem Formulation

The TNEP objective function can be stated as follows [1]:

$$\min_{P_{pg},T_b}\left(\sum_{p=1}^{np}\tau_p\sum_{g=1}^{ng}C_gP_{pg}+\sum_{b=1}^{nl}K_bl_bT_b\right) \tag{1}$$

where τ_p = Duration of demand period p; P_{pg} = Output of generator g during demand period p; l_b = Length of line b (km); C_g = Operating cost of generator g; k_b = Annuitized investment cost for line b in \$/(MW/km/year); T_b = Capacity of line b

In general, this problem covers several demand periods over a year, and it must satisfy the power flow equations for the intact system and the line capacity limits for each of them. Neglecting losses, these constraints are:

$$A^0F_P^0-P_P-D_P=0 \tag{2}$$

$$F_P^0=H^0(P_P-D_P) \tag{3}$$

$$F_P^0-T\le 0 \tag{4}$$

$$-F_P^0 - T \le 0 \tag{5}$$

where: F_p^0 = Vector of line flows for the intact system during period p; A^0 = Node-branch incidence matrix for the intact system; Pp = Vector of nodal generations for demand period p; D_p = Nodal demand vector for period p; T = Vector of line capacities; H^0 = Sensitivity matrix for the intact system.

Equation (2) is a nodal balance constraint derived from Kirchhoff's current law, which requires that the total power flowing into a node must be equal to the total power flowing out of the node. Constraint (3) relates flows and injections based on Kirchhoff's voltage law. The last two equations represent thermal constraints on the line flows.

All these constraints must also be satisfied for each contingency during each demand period:

$$A^c F_P^c - P_P - D_P = 0 \tag{6}$$

$$F_P^c = H^c (P_P - D_P) \tag{7}$$

$$F_P^c - T \le 0 \tag{8}$$

$$-F_P^c - T \le 0 \tag{9}$$

where A^c = Node-branch incidence matrix for contingency c; F_p^c = Vector of line flows for contingency c during period p; H^c = Sensitivity matrix for contingency c.

Finally, the optimization must respect the limits on the output of the generators:

$$P^{min} \le P_P \le P^{max} \tag{10}$$

where P_p = Vector of nodal generations for demand period p; p_{min} = Lower limit of real power generation; p_{max} = Upper limit of real power generation

Since the object of the optimization is to determine the optimal thermal capacity of the lines, this variable can take any positive value:

$$0 \le T \le \infty \tag{11}$$

TNEP Implement Formulation

The above model calculates the vector of generation dispatch P_p in each demand period, the vector of line flows F_p^0 in each demand period. All other parameters in the above equations are either specified or determined from the network topology and data. Since we have assumed constant generation marginal costs, the optimization problem is linear.

However, because of its size, this problem is usually not solved in its original form. Instead, it is solved using the iterative algorithm [1].

Optimal Power Flow Formulation

The problem must satisfy the power flow equations and the line capacity limits for all demand period.

$$\min_x f(x) \tag{12}$$

Subject to:

$$g(x)=0 \tag{13}$$

$$h(x)\leq 0 \tag{14}$$

$$x^{min} \leq x \leq x^{max} \tag{15}$$

The optimization vector x for the standard AC Optimal Power Flow (OPF) problem consists of the nb×1 vectors of voltage angles Θ and magnitudes V_m and the ng-1 vectors of generator real and reactive power injections Pg and Qg.

$$x = \begin{bmatrix} \Theta \\ V_m \\ P_g \\ Q_g \end{bmatrix} \tag{16}$$

The objective function (12) is simply a summation of individual polynomial cost functions f_p^i and f_Q^i of real and reactive power injections, respectively, for each generator:

$$\min_{\Theta,Vm,Pg,Qg} \left(\sum_{i=1}^{ng} f_p^i(p_g^i) + f_Q^i(q_g^i) \right) \tag{17}$$

The equality constraints in (13) are simply the full set of 2.nb nonlinear real and reactive power balance equations as follows:

$$gp(\Theta,V_m,P_g)=P_{bus}(\Theta,V_m)+P_d - C_g P_g=0 \tag{18}$$

$$g_Q(\Theta,V_m,Q_g)=P_{bus}(\Theta,V_m)+Q_d - C_g Q_g=0 \tag{19}$$

The inequality constraints (14) consist of two sets of nl branch flow limits as nonlinear functions of the bus voltage angles and magnitudes, one for the from-end and one for the to-end of each branch:

$$h_f(\Theta, Vm) = |F_f(\Theta, Vm)| - F_{max} \leq 0 \tag{20}$$

$$h_t(\Theta, Vm) = |F_t(\Theta, Vm)| - F_{max} \leq 0 \tag{21}$$

The flows are typically apparent power flows expressed in MVA, but can be real power or current flows, yielding the following three possible forms for the flow constraints:

$$f(\Theta,Vm)=\begin{cases} S_f(\Theta,Vm), apparent power \\ P_f(\Theta,Vm), real power \\ I_f(\Theta,Vm), current \end{cases} \tag{22}$$

Where If $=Y_f V$, Sf $=|C_f V|$If$*$, Pf = R {Sf} and the vector of flow limits F^{max} has the appropriate units for the type of constraint. It is likewise for Ft (Θ,Vm). The variable limits (15) include an equality constraint on any reference bus angle and upper and lower limits on all bus voltage magnitudes and real and reactive generator injections:

$$\Theta_i^{ref} \le \Theta_i \le \Theta_i^{ref} \tag{23}$$

$$v_m^{i,min} \le v_m^i \le v_m^{max} \qquad i=1\ldots nb \tag{24}$$

$$P_g^{i,min} \le P_g^i \le P_g^{i,max} \qquad i=1\ldots ng \tag{25}$$

$$q_g^{i,min} \le q_g^i \le q_g^{i,max} \qquad i=1\ldots ng \tag{26}$$

TNEP implementation combined with optimal power flow formulations presents the TNEP problem formulation. In general, this problem covers several demand periods over a year, and it must satisfy the power flow equations for the intact system and the line capacity limits for each of them. However to simplify, this paper considers a uniform demand period. Assuming constant generation marginal cost, the optimization is a large-scale linear problem. Therefore, in real size simulations, iterative algorithm is preferred. In order to reduce the size and solve the problem in its original form (1), this paper proposes a two stages algorithm. Considering N-1 generation security at the first stage, weak lines with insufficient capacity limit became highlighted. The first stage algorithm is illustrated in Figure 1. In this paper intrinsic outage rate of transmission lines are neglected.

Proposed approach

After identifying the weak lines and related congestion probability, the second stage finds optimal expansion capacity of those lines. This stage could be solved by any optimization program. Genetic Algorithm is chosen in this paper. See Figure 2.

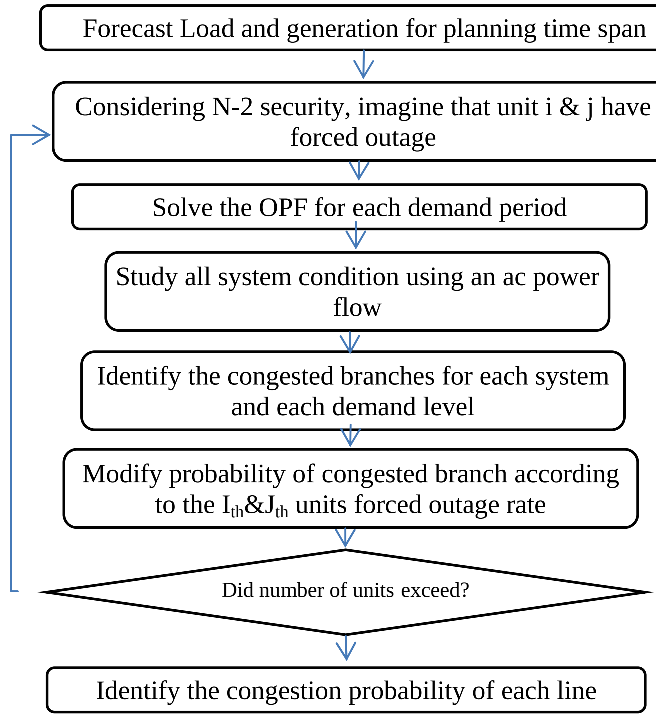

Figure 1. *First stage flowchart*

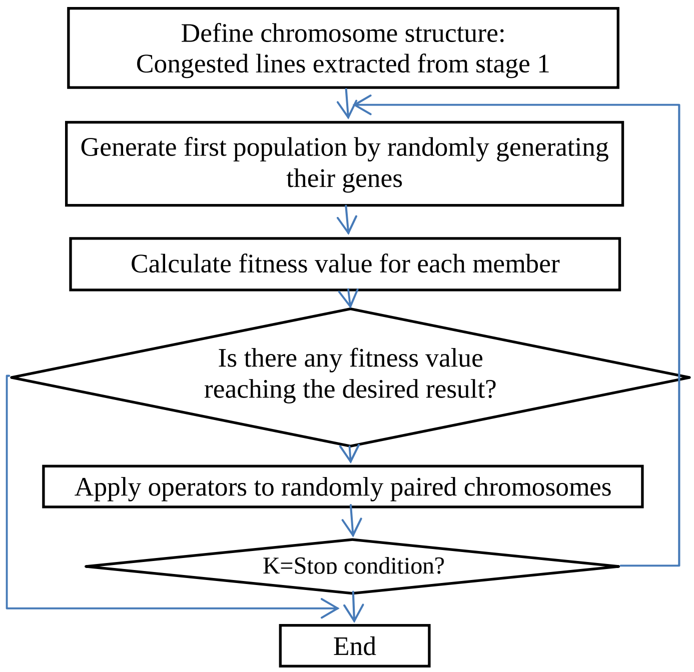

Figure 2. *Second stage flowchart*

Results

In the first stage, assuming unit i & j out of service, OPF determines the network condition. Results of this stage are shown in Table 3.

It illustrates all conditions in which one or two generators are out of service. Since congestions are taken place only in lines number 10 and 11, it is evident that only transmission lines No. 10 & 11 are vulnerable and weak. Therefore, these are the best candidates for expansion investment. Gray cells in Table 3 show that i and j are the same. It means that there is a single contingency in generator units.

Forced outage rate of line b could be calculated by (27). When lack of one or two generator leads to the above-mentioned rate, expanding line No. 10 & 11 leads to N-1 and N-2 generation security respectively. Tables 4 and 5 show the forced outage rate of line No. 10 &11 related to N-1 and N-2 security level. In this paper intrinsic outage rate of transmission lines are neglected.

Table 3. Transmission line contingency for generator unit (N-1) & (N-2) Security

Transmission line contingency (Generator unit j is out of service)	Transmission line contingency (Generator unit i is out of service)																																
j \ i	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**	**25**	**26**	**27**	**28**	**29**	**30**	**31**	**32**	**33**
1	0	10	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	10 11	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
2	10	0	10	10	10	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	10 11	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
3	10	10	10	10 11	10	10	10 11	10 11	10	10	10	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11
4	10	10	10 11	10	10	10	10 11	10 11	10	10	10	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11
5	10	10	10	10	0	10	10	10	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11
6	10	10	10	10	10	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11
7	10	10	10 11	10 11	10	10	10	10	10	10	10	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11
8	10	10	10 11	10 11	10	10	10	10	10	10	10	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11	10 11	10	10	10	10	10	10	10 11	10 11	10 11
9	0	0	10	10	0	0	10	10	0	10	10	10	10	10	0	0	0	0	0	0	10	10	10	10	0	0	0	0	0	0	10	10	10
10	0	0	10	10	0	0	10	10	10	0	10	10	10	10	0	0	0	0	0	0	10	10	10	10	0	0	0	0	0	0	10	10	10
11	0	0	10	10	0	0	10	10	10	10	0	10	10	10	0	0	0	0	0	0	10	10	10	10	0	0	0	0	0	0	10	10	10
12	0	0	10 11	10 11	0	0	10 11	10 11	10	10	10	0	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
13	0	0	10 11	10 11	0	0	10 11	10 11	10	10	10	10 11	0	10 11	0	0	0	0	0	0	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
14	0	0	10 11	10 11	0	0	10 11	10 11	10	10	10	10 11	10 11	0	0	0	0	0	0	0	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11
15	0	0	10	10	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
16	0	0	10	10	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
17	0	0	10	10	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
18	0	0	10	10	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
19	0	0	10	10	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11

	20	0	0	10	10	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	21	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10	10 11	10 11	10 11	0	0	0	0	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11
	22	0	0	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10	10 11	10 11	10 11	0	0	0	0	0	0	10 11	0	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11
	23	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10 11	10 11	10 11
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	25	0	0	10	10	0	0	10	10	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	26	0	0	10	10	0	0	10	10	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	27	0	0	10	10	0	0	10	10	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	28	0	0	10	10	0	0	10	10	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	29	0	0	10	10	0	0	10	10	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	30	0	0	10	10	0	0	10	10	0	0	0	10 11	10 11	10 11	0	0	0	0	0	0	0	0	10 11	10 11	0	0	0	0	0	0	0	0	10 11
	31	0	0	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10	10 11	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11	10 11	0	0	0	0	0	0	0	10 11	10 11
	32	0	0	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10	10 11	10 11	10 11	0	0	0	0	0	0	10 11	10 11	10 11	10 11	0	0	0	0	0	0	10 11	0	10 11
	33	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10	10	10	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11	10 11

Table 4.line forced outage rate related to N-1 unit generation security level

Line	From Bus No.	To Bus No.	Forced Outage Rate
10	6	10	0.0368
11	7	8	0.0352

Table 5.line forced outage rate related to N-2 unit generation security level

Line	From Bus No.	To Bus No.	Forced Outage Rate
10	6	10	0.6865
11	7	8	0.4897

$$FORb_{ij} = \sum_{i=j}^{33}\sum_{j=1}^{33} FOR_{pi} \times FOR_{pj} \qquad Cb_{ij}=1 \tag{27}$$

where FOR_{pi} = Forced Outage Rate of generator unit i during demand period p; FOR_{pj} = Forced Outage Rate of generator unit j during demand period p; FORbij = Forced Outage Rate of line b duo to lack of units i&j

In the second stage, Genetic Algorithm determines the optimal expansion size for lines No. 10 and 11. Test results of this paper have obtained considering population size of 50 for 300 generations with crossover and mutation rate of 0.8 and 0.2, respectively. Normal capacity of line 10 & 11 is 175 MW.

Table 6 illustrates the results of expanding these lines 5, 10 & 15 MW respectively. In each case, the investment cost for extra capacity is calculated. On the other hand, decreased cost of production is presented as “incremental production cost”. Sum of these two recent items makes opportunity cost. Gray row in the above-mentioned table is the result of optimization program. It shall be mentioned that there are some restrictions such as standard line capacity, existing line's condition, in planning optimal capacity for line expansion. These restrictions can be considered when the candid for expansion is definite. In addition choosing a weight factor can simulate the condition of each power system.

It shall be noted that in the above table, number 10 represents transmission lines between bus number 6 and 10. Similarly, number 11 represents transmission lines between bus number 7 and 8.

Table 6. Operating cost for the four-line size example

<table>
<tr><th>Line</th><th>Normal Line max capacity</th><th>Length (km)</th><th>Kc</th><th>Incremental investment cost $/year Base: 175MW</th><th>Production cost $/hr</th><th>Production cost $/year</th><th>Incremental production cost $/year Base: 175MW</th><th>Opp* cost</th></tr>
<tr><td>10</td><td>175</td><td>25.75</td><td rowspan="8">50 $/ (MW. Km. year)</td><td>0</td><td rowspan="2">90384112</td><td rowspan="2">791764822</td><td rowspan="2">0</td><td rowspan="2">0</td></tr>
<tr><td>11</td><td>175</td><td>25.75</td><td>0</td></tr>
<tr><td>10</td><td>180</td><td>25.75</td><td>6437.5</td><td rowspan="2">90377354</td><td rowspan="2">791705617</td><td rowspan="2">-59205</td><td rowspan="2">-46330</td></tr>
<tr><td>11</td><td>180</td><td>25.75</td><td>6437.5</td></tr>
<tr><td>10</td><td>185</td><td>25.75</td><td>12875</td><td rowspan="2">90376451</td><td rowspan="2">791697712</td><td rowspan="2">-67109</td><td rowspan="2">-41359</td></tr>
<tr><td>11</td><td>185</td><td>25.75</td><td>12875</td></tr>
<tr><td>10</td><td>190</td><td>25.75</td><td>19312.5</td><td rowspan="2">90376369</td><td rowspan="2">791696989</td><td rowspan="2">-67833</td><td rowspan="2">-29208</td></tr>
<tr><td>11</td><td>190</td><td>25.75</td><td>19312.5</td></tr>
</table>

*Opp: Opportunity

Discussion

TNEP problem covers several demand periods over specified time span. It attempts to fulfill the power flow equations and capacity limits for each of lines. Assuming constant generation marginal cost, the optimization is a large-scale linear problem. Therefore, in real size simulations, iterative algorithm is preferred. In order to reduce the size and solve the problem in its original form (1), this paper proposes a two stages algorithm. Considering N-1 or N-2 generation security, the first stage specifies weak lines with inadequate capacity limit.

After identifying the weak lines and related congestion probability, the second stage finds optimal expansion capacity of those lines. Genetic algorithm is selected as the optimization program in this paper

Due to condition and main goal of each power network, investment and production costs have deferent importance. By multiplying each of the investment or production cost into a predefined weigh factor, its impact on opportunity cost will be changed. This is one of the advantages of the algorithm. Another advantage is the fact that standard line capacity has taken into account in this algorithm without getting involved in a huge amount of calculation.

Conclusion

Simulation results of the proposed idea for IEEE-RTS-24 bus network shows that dividing TNEP problem into two stages is an efficient procedure. Making decision is easier when the weak lines are highlighted.

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