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Multi-Stage Transmission Network Planning Considering Transmission Congestion in the Power Market

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Abstract: The uncertainty of generation and load increases in the transmission network in the power market. Considering the transmission congestion risk caused by various uncertainties of the transmission network, the optimal operation strategies of the transmission network under various operational scenarios are decided, aiming for the maximum of social benefit for the evaluation of the degree of scenario congestion. Then, a screening method for major congestion scenario is proposed based on the shadow price theory. With the goal of maximizing the difference between the social benefits and the investment and maintenance costs of transmission lines under major congestion scenarios, a multi-stage transmission network planning model based on major congestion scenarios is proposed to determine the configuration of transmission lines in each planning stage. In this paper, the multi-stage transmission network planning is a mixed integer linear programming problem. The DC power flow model and the commercial optimization software CPLEX are applied to solve the problem to obtain the planning scheme. The improved six-node Garver power system and the simplified 25-node power system of Zhejiang Province, China are used to verify the effectiveness of the proposed multi-stage planning model.

Keywords: multi-stage transmission network planning; power market; transmission congestion; scenario screening

1. Introduction

Nowadays, China's power market system is in the accelerating progress of changing from monopoly and regulation to competition [1,2]. The processes of generation, transmission, distribution, and sales in the power market are separated, and the behaviors of multiple participants are becoming more independent and complex [3–5]. At the same time, with the energy structure transition and the development of a smart grid in China [6,7], the uncertainty of a transmission network further increases, which generates many new operational scenarios [8–10]. When the transmission capacity of the network is insufficient, the power flow through the transmission line is limited due to the physical constraints of a secure and stable operation, and the transmission congestion then takes place [11,12]. Users in transmission congestion areas have to buy more expensive electricity, which makes the locational marginal price (LMP) higher than the system marginal generation cost and increases the operation cost of transmission network. The transmission congestion limits the role of transmission network in optimizing the allocation of network resources and improving the energy efficiency in the power market [13]. It is necessary to study the transmission network planning problem considering transmission congestion in the power market.

In recent years, research work has been carried out on transmission network planning of the power market. In the power market, the power price is quoted by generators and users according to their generation costs and consumption benefits, which forms correct price signals and guides the optimal allocation of network resources [14,15]. Based on the game theory [16,17], the transmission network planning method considering the behavior of generators and the planning decision of the transmission network is studied. In [18,19], a transmission network expansion planning model and a coordinated generation and transmission planning model are established, considering the maximum of social welfare and generators' benefit. In [20], considering the influence of short-term bidding strategies and long-term network expansion planning of generators, a four-level planning model of generation bidding, market settlement, generation planning, and network planning of the power market is proposed. The transmission network planning method based on game theory reflects the behavior strategy of generators in the power market and balances the interests of the multiple market participants [21]. However, the research work above does not consider the impact of generators' market power on the transmission network. When the transmission capacity of transmission network is limited, generators can artificially create transmission congestion to increase revenue, which leads to the rise of electricity price and the failure of electricity effective distribution [22]. In the power market, the LMP is used to measure the value of electric energy at different positions in the power system under various operation scenarios and reflect the severity of transmission congestion [23–25]. In [26], a novel evaluation method for operation efficiency of the transmission network is proposed based on LMP. A security-constrained unit commitment model considering the impact of mobility of battery-based energy storage transportation system is proposed in [27] to reduce the overall cost of power delivery by transporting the electricity from low LMP areas to high LMP areas. A two-stage algorithm is proposed in [28] to analyze the effect of carbon emission quota allocation on the LMP of day-ahead electricity markets. In [29], a novel electricity market-clearing mechanism based on locational marginal prices is proposed considering the uncertainties of generation and load. The above studies indicate the guiding role of LMP in congestion management from the perspective of network operation and power market. However, the role of LMP in guiding transmission network planning and evaluating the corresponding benefit in alleviating transmission congestion under various operation scenarios is not exerted fully and needs further research.

In the power market, the transmission congestion risks should be mitigated through transmission network planning [30,31]. In [32], the transmission cost allocation is considered for the proposed tri-level transmission network planning model, which effectively defers the expansion planning and reduces the investment cost. In [33], the transmission network is co-optimized with the merchant electrochemical storage in the market environment, which helps to present the interaction between the transmission network expansion planning and the storage configuration. In [34], a multi-objective transmission network planning model is established with minimum investment, congestion, and risk costs. The transmission network planning based on probabilistic analysis should be studied considering the uncertainties of natural environment, generators, loads, and policies on power generation, transmission, and demand side. In [35], the point estimation method and the Monte Carlo method are jointly applied to describe the uncertainty of intermittent energy and load of the transmission network with high proportion of wind power. Then, a multi-objective transmission network expansion planning model considering the investment cost, risk cost, and congestion cost of the transmission network is established. In [36,37], the stochastic programming theory and scenario analysis method are used to describe the uncertainty of power generation, investment, and load demand of the transmission network on a long-time scale, as well as the uncertainty of distributed generation and load on a short-time scale. Then, the joint planning models of transmission network and energy storage are established. However, the transmission network planning method based on uncertainty theory is time consuming in computation. Only a few types of uncertain risk sources are taken into consideration and their correlations are not involved. The transmission network model based on scenario analysis describes the uncertainties as multiple individual probabilistic scenarios, which reduces the difficulty of solving while considering the coupling of uncertain risks [38]. The uncertainties of renewable generation and load demand are represented by a set of scenarios through rough fuzzy clustering in the flexible transmission network expansion planning of [39]. In [40], the scenario identification index is defined to determine the important scenarios for solving the stochastic transmission expansion planning problem with N-1 contingency analysis. In [41], the concept of an extreme scenario of wind power is proposed and a two-stage transmission network planning model based on Benders decomposition is then established. In [42], a scenario-based transmission expansion planning model is established considering the massive scenarios based on the proposed cost-oriented dynamic scenario clustering method. However, the current researches do not consider the transmission congestion scenarios caused by multiple uncertainties from power market. Thus, it is necessary to carry out the network planning considering transmission congestion scenarios to improve the economy of the transmission network planning scheme in the power market.

Aiming at the above problems, a multi-stage transmission network planning method considering transmission congestion in the power market is presented in this paper. With the goal of maximizing social benefit, the optimal dispatch problem under each operation scenario is simulated and solved. Based on the shadow price theory, a novel screening method for major congestion scenarios is proposed to provide planning scenarios for the transmission network planning. A multi-stage planning model for a transmission network considering transmission congestion is established, with the maximum difference between the social benefits and the investment and maintenance costs of transmission line under severe congestion scenarios. The proposed model based on DC power flow is a mixed integer linear programming problem, which is solved by the commercial optimization software CPLEX. The validity of the proposed model is verified through the case study based on the improved six-node Garver power system and simplified 25-node power system of Zhejiang Province, China.

2. Transmission Congestion Scenario Screening Based on Shadow Price Theory

The location and severity of transmission congestion are related to the operational scenarios in the transmission network. It is necessary to focus on the operational problems under transmission congestion scenarios in the planning decision-making process to improve the efficiency and economic benefit of planning. With the development of the power market, the operational scenarios of the power system tend to be diversified and complicated, which brings great challenges to the search for major congestion scenarios with planning value. In this section, the optimal operation of transmission network in the power market is discussed with the goal of the maximization of social benefit. In transmission network operation and planning, the DC power flow model is used to obtain the LMP within the acceptable range, assuming that the voltage variance and line losses are neglected [22,43]. Considering the node power balance constraint, power flow constraint, line capacity constraint, generator output constraint, and power loss constraint, the active power of generators and users' load under various transmission network scenarios are decided to decompose the LMP. Based on the shadow price theory, the index for transmission congestion degree evaluation and the screening method of major congestion scenario are proposed.

2.1. Economic Dispatching Model of Transmission Network in the Power Market

To realize the economic allocation of electricity energy considering the interests of generators and users in the power market, the economic dispatching model of the transmission network aims at maximizing the social benefit C^{sb}. The objective function includes the generation cost of generator and users' benefit, which is expressed as:

$$\max C^{sb} = \sum_{i\in\Omega_{node}} P_i^{load} c_i^{load} - \sum_{i\in\Omega_{node}} \sum_{g\in\Omega_i^{gen}} P_{i,g}^{gen} c_{i,g}^{gen}. \tag{1}$$

The constraints of the transmission network economic dispatching model are presented as follows:

1. Node power balance constraint

$$\sum_{g\in\Omega_i^{gen}} P_{i,g}^{gen} + \sum_{ij\in\Omega_i^{line}} P_{ij}^{line} = P_i^d. \tag{2}$$

2. Power flow constraint

$$P_{ij}^{line} = \sum_{k\in L_{ij}} P_{ij,k}^{line} = \sum_{k\in L_{ij}} n_{ij,k}B_{ij,k}(\theta_i - \theta_j). \tag{3}$$

3. Line capacity constraint

$$-n_{ij,k}S_{ij,k}^{\max} \le P_{ij,k}^{line} \le n_{ij,k}S_{ij,k}^{\max}. \tag{4}$$

4. Generator power constraint

$$P_{i,g}^{gen,\min} \le P_{i,g}^{gen} \le P_{i,g}^{gen,\max}. \tag{5}$$

5. Phase angle constraint of equilibrium node

$$\theta_{\mathrm{ref}} = 0. \tag{6}$$

6. Power losses constraint

$$\left(1-\varepsilon_i^{ENS}\right)P_i^d \le P_i^{load} \le P_i^d. \tag{7}$$

2.2. LMP Decomposition Based on Shadow Price Theory

The LMP in the transmission network is defined as the marginal cost or revenue when the unit load demand of the node changes [44]. In the power market, LMP can provide price signals for market participants, realize fair trade, help transmission companies to solve transmission congestion problems, and guide transmission network planning [45]. When solving the optimal power flow economic dispatching problem of the transmission network, the extended Lagrangian function is constructed to calculate the Lagrangian multiplier of each constraint, which represents the shadow price of the network resources (i.e., lines and generators) associated with the constraint [46,47]. The expression of the extended Lagrangian function is expressed as follows:

$$\begin{aligned} L = & \sum_{i\in\Omega_{node}} P_i^{load} c_{load}(P_i^{load}) - \sum_{i\in\Omega_{node}} \sum_{g\in\Omega_i^{gen}} P_{i,g}^{gen} c_{gen}(P_{i,g}^{gen}) + \sum_{i\in\Omega_{node}} \lambda_i \left(\sum_{g\in\Omega_{gen,i}} P_{i,g}^{gen} - P_i^d \right) \\ & + \sum_{i\in\Omega_{node}} \sum_{k\in L_{ij}} \mu_{ij} \left(P_{ij}^{line} - \sum_{k\in L_{ij}} n_{ij,k}B_{ij,k}(\theta_i-\theta_j) \right) \\ & + \sum_{i\in\Omega_{node}} \sum_{k\in L_{ij}} \overline{\nu_{ij,k}} \left(P_{ij,k}^{line} - n_{ij,k}S_{ij,k}^{\max} \right) + \sum_{i\in\Omega_{node}} \sum_{k\in L_{ij}} \underline{\nu_{ij,k}} \left(-n_{ij,k}S_{ij,k}^{\max} - P_{ij,k}^{line} \right) \\ & + \sum_{i\in\Omega_{node}} \sum_{g\in\Omega_{gen,i}} \overline{\tau_{i,g}} \left(P_{i,g}^{gen} - P_{i,g}^{gen,\max} \right) + \sum_{i\in\Omega_{node}} \sum_{g\in\Omega_{gen,i}} \underline{\tau_{i,g}} \left(P_{i,g}^{gen,\min} - P_{i,g}^{gen} \right) \\ & + \pi\theta_{ref} + \sum_{i\in\Omega_{node}} \overline{\omega_i} \left(P_i^{load} - P_i^d \right) + \sum_{i\in\Omega_{node}} \underline{\omega_i} \left[\left(1-\varepsilon_i^{ENS}\right)P_i^d - P_i^{load} \right] \end{aligned} \tag{8}$$

The partial derivatives of the extended Lagrange function for each node is expressed as follows:

$$\frac{\partial L}{\partial P_i^{load}} = c_{load}(P_i^{load}) + P_i^{load}\frac{\partial c_{load}(P_i^{load})}{\partial P_i^{load}} - \lambda_i + \sum_{k\in L_{ij}} \mu_{ij}\frac{\partial P_{ij}^{line}}{\partial P_i^{load}} + \sum_{k\in L_{ij}} \left(\overline{\nu_{ij,k}} - \underline{\nu_{ij,k}}\right)\frac{\partial P_{ij,k}^{line}}{\partial P_i^{load}} + \overline{\omega_i} - \underline{\omega_i}. \tag{9}$$

Based on the Karush-Kuhn-Tucker (KKT) optimality condition [48,49], the LMP of node i is expressed as:

$$\begin{aligned} LMP_i^{load} &= c_{load}(P_i^{load}) + P_i^{load}\frac{\partial c_{load}(P_i^{load})}{\partial P_i^{load}} \\ &= \lambda_i - \sum_{k\in L_{ij}} \mu_{ij}\frac{\partial P_{ij}^{line}}{\partial P_i^{load}} - \sum_{k\in L_{ij}}\left(\overline{\nu_{ij,k}} - \underline{\nu_{ij,k}}\right)\frac{\partial P_{ij,k}^{line}}{\partial P_i^{load}} - \overline{\omega_i} + \underline{\omega_i} \end{aligned} \tag{10}$$

It can be seen that the LMP at load node includes the electric price at the reference node, Lagrange multipliers of the line congestion constraint, and the power losses constraint. The Lagrange multiplier represents the increment of the objective function C^{sb} when the kth circuit of transmission corridor ij expands unit capacity. When the capacity of transmission lines is insufficient and the power flow exceeds the maximum limit, the Lagrange multipliers $\overline{\nu_{ij,k}}$ and $\underline{\nu_{ij,k}}$ are not all zero. The larger $\overline{\nu_{ij,k}}$ or $\underline{\nu_{ij,k}}$ is, the more serious the transmission congestion problem is, and the better the effect of line expansion is on alleviating transmission congestion.

The partial derivatives of the extended Lagrange function for each generator is expressed as follows:

$$\frac{\partial L}{\partial P_{i,g}^{gen}} = -c_{gen}(P_{i,g}^{gen}) - P_{i,g}^{gen}\frac{\partial c_{gen}(P_{i,g}^{gen})}{\partial P_{i,g}^{gen}} + \lambda_i + \sum_{k\in L_{ij}} \mu_{ij}\frac{\partial P_{ij}^{line}}{\partial P_{i,g}^{gen}} + \sum_{k\in L_{ij}}\left(\overline{\nu_{ij,k}} - \underline{\nu_{ij,k}}\right)\frac{\partial P_{ij,k}^{line}}{\partial P_{i,g}^{gen}} + \sum_{g\in\Omega_{gen,i}}\left(\overline{\tau_{i,g}} - \underline{\tau_{i,g}}\right). \tag{11}$$

Therefore, the LMP of generator g connected with node i, including the reference node price, the line congestion constraint shadow price and the generator output constraint shadow price, is expressed as:

$$\begin{aligned} LMP_{i,g}^{gen} &= c_{gen}(P_{i,g}^{gen}) + P_{i,g}^{gen}\frac{\partial c_{gen}(P_{i,g}^{gen})}{\partial P_{i,g}^{gen}} \\ &= \lambda_i + \sum_{k\in L_{ij}} \mu_{ij}\frac{\partial P_{ij}^{line}}{\partial P_{i,g}^{gen}} + \sum_{k\in L_{ij}}\left(\overline{\nu_{ij,k}} - \underline{\nu_{ij,k}}\right)\frac{\partial P_{ij,k}^{line}}{\partial P_{i,g}^{gen}} + \sum_{g\in\Omega_{gen,i}}\left(\overline{\tau_{i,g}} - \underline{\tau_{i,g}}\right) \end{aligned} \tag{12}$$

The shadow prices of network resources in the economic dispatch problem of the transmission network are related to the Lagrange multipliers of constraints in the optimal power flow model, the marginal cost of generation, the marginal benefit of electricity consumption, and the flow transferring relativity factor. By decomposing the LMP at each node, the value of network resources is effectively evaluated to guide the planning and use of power network resources in the power market.

2.3. Screening of Transmission Network Congestion Scenarios

Since the new electric power restructuring, the trading volume of electricity within and across provinces in China continues to increase. The influence of the power market on the planning and operation of transmission network is expanding day by day. In addition to the traditional risk sources in the transmission network such as the integration of renewable energy, load fluctuation, and equipment failure [50], new risk sources from the power market such as plant-grid separation, electricity price fluctuation, and direct transaction between generators and users increase the risk degree of the transmission network congestion and the difficulty for transmission companies to coordinate generation and network resources. Generating as many transmission network operation scenarios as possible based on scenario analysis methods and taking them into consideration in planning decision help to fully simulate various potential congestion risks of transmission network, which ensures the economy of the planning scheme. However, the more scenarios there are, the more variables and constraints will be in the planning model, which most likely leads to the dimension disaster and reduces the solving efficiency. Scenarios such as the maximum load, high probability, and failure scenarios are set artificially in the existing transmission network planning method, which cannot objectively evaluate the severity of the congestion problem under various operation scenarios, leading to the neglect of potential congestion scenarios.

Under the transmission congestion scenario, there is a price difference between the two ends of the transmission line, which results in transmission congestion surplus. The transmission congestion surplus is related to the shadow prices (i.e., Lagrange multipliers) μ_i, $\overline{\nu_{ij,k}}$ and $\underline{\nu_{ij,k}}$ in the optimal power flow model, and the flow transferring relativity factor $H_{ij} = \frac{\partial P_{ij}^{line}}{\partial P_i^{gen}} = \frac{\partial P_{ij}^{line}}{\partial P_i^{load}}$. Assuming that the network frame is determined, the μ_i, $\overline{\nu_{ij,k}}$ and $\underline{\nu_{ij,k}}$ can be used to reflect the severity of the transmission congestion. Therefore, an evaluation index for transmission congestion degree is proposed based on the shadow price. Further, a novel screening method for major congestion scenario is proposed to guide transmission network planning considering transmission congestion.

$$\begin{aligned} \eta_s &= p_s \varphi_s \\ &= p_s \sum_{i \in \Omega_{node}} \sum_{ij \in \Omega_{line}, i} \sum_{k \in L_{ij}} (\mu_{s,ij} + \overline{\nu_{s,ij,k}} + \underline{\nu_{s,ij,k}}) \end{aligned} \tag{13}$$

The proposed transmission congestion degree of scenario comprehensively considers the two dimensions (i.e., probability and impact) of the risk. It objectively describes the transmission congestion risk of the scenario and reflects the influence of the operation scenario on the network planning. The scenario with sufficient planning value should be added into the planning scenario set Ω_{plan}, which is expressed as:

$$\Omega_{plan} = \{s* | \eta_{s*} \geq \eta_0\}. \tag{14}$$

According to (14), the scenario with a transmission congestion degree greater than the transmission congestion threshold η_0 is the major congestion scenario and is included into the planning scenario set; otherwise the scenario is the minor congestion scenario and does not need to be considered in the planning problem. The transmission congestion scenario screening provides actual transmission congestion information for the transmission network planning based on the simulation results of transmission network operation, which helps to achieve better planning results.

3. The Network Planning Model Considering Transmission Congestion

In order to improve the ability of transmission network planning model to mitigate the risk of transmission congestion, transmission network planning considering major congestion scenarios is carried out according to the optimized dispatching results of operation scenarios and the screening results of congestion scenarios based on the economic dispatching model. Then, the major congestion scenario is evaluated and screened again based on the current planning scheme. After iterative optimization planning, the optimal multi-stage network frame planning scheme is obtained.

3.1. Multi-stage Planning Model of Transmission Network Considering Major Congestion Scenarios

The transmission network planning model proposed in this paper starts from the point of view of the transmission company, which undertakes social responsibility while deciding the time and circuit number of transmission corridors to be built in the transmission network planning. For multi-stage transmission network planning, the net present value of the total cost in the planning period considers the time benefit, assuming that all cost components occur at the end of each planning stage. The objective function of the planning model includes transmission line investment cost, transmission line maintenance cost and social benefits of the transmission network under major congestion scenario, which is expressed as follows:

$$\begin{aligned}\max_{\Omega_{dec}} C^{total} &= \sum_{t=1}^{N_{plan}}\left[\zeta_t\left(T_{hr}\sum_{s\in\Omega_{plan,t}} p_s C_s^{sb} - C_t^{om}\right) - \sigma C_t^{inv}\right] \\ &= \sum_{t=1}^{N_{plan}}\left[\zeta_t\left(T_{hr}\sum_{s\in\Omega_{plan,t}} p_s\left(\sum_{i\in\Omega_{node}} P_{s,i}^{load} c_{s,i}^{load} - \sum_{i\in\Omega_{node}}\sum_{g\in\Omega_i^{gen}} P_{s,i,g}^{gen} c_{s,i,g}^{gen}\right) - \sum_{i\in\Omega_{node}}\sum_{ij\in\Omega_{line,i}}\sum_{k\in L_{ij}} c_{ij,k}^{om} n_{t,ij,k}\right),\right. \\ &\left. -\sigma\sum_{i\in\Omega_{node}}\sum_{ij\in\Omega_{line,i}}\sum_{k\in L_{ij}} c_{ij,k}^{inv} x_{t,ij,k}\right]; \quad \Omega_{dec} = \left\{P_{s,i}^{load}, P_{s,i,g}^{gen}, n_{t,ij,k}, x_{t,ij,k}\right\}\end{aligned} \tag{15}$$

$$\zeta_t = (1+r)^{-t\times\frac{T_{plan}}{N_{plan}}}, \tag{16}$$

$$\sigma = \frac{r(1+r)^{T_{line}}}{(1+r)^{T_{line}} - 1}. \tag{17}$$

Constraints of the transmission network planning model are presented as follows:

1. Constraints on the number of new lines

Each transmission corridor allows the construction of a limited number of transmission lines, i.e.,

$$0 \le \sum_{t=1}^{N_{plan}}\sum_{k\in L_{ij}} x_{t,ij,k} \le \overline{x_{ij}}. \tag{18}$$

2. Timing constraints of transmission line construction

For the kth candidate circuit of transmission corridor ij, once the construction is selected, it cannot be dismantled, i.e.,

$$n_{t-1,ij,k} \le n_{t,ij,k}. \tag{19}$$

3. Constraints on the annual cost of transmission network investment

There are budgetary constraints on the investment costs of transmission lines at each planning stage, i.e.,

$$C_t^{inv} \le C_t^{\mathrm{bud}}. \tag{20}$$

4. Constraints on the security operation of transmission network

The transmission network planning scheme should satisfy the security operation constraints (2)–(7).

3.2. Iterative Solution Process of Transmission Network Optimization Planning

The iterative solution process of the transmission network planning method proposed in this paper is shown in Figure 1. The initial transmission network and investment parameters and the power market bidding parameters are input into the bi-level collaborative planning as basic data. Before each iteration of transmission network planning, it is necessary to solve the economic dispatch problem under each operation scenario based on the existing network information to evaluate the transmission congestion degree of each operation scenario. Then, the scenarios with high transmission congestion degrees (i.e., major congestion scenarios) are included into the planning scenario set Ω_{plan} and feed back to the upper level. In this way, the process of feedback from the operator to the planner in the actual transmission network planning is simulated, so that the transmission network planning considering the major congestion scenario can be carried out by the upper level. The planning model takes the planning scenario set for optimization. A new generation of the target network frame is obtained for re-evaluating the transmission congestion risk in the next iteration. When no new line investment is made or there is no major congestion scenario with the congestion degree higher than the transmission congestion threshold, the planning model stops the optimization progress and outputs the final transmission network planning scheme. In this paper, the transmission network planning model gives priority to mitigate the operational risk of the major congestion scenario in each generation solution. The planning scenario set changes dynamically with the update of the network configuration scheme, which reflects the change of transmission congestion risk with the transmission line investment. In summary, the proposed model improves the planning efficiency and simulates the interaction between network planning and operation.

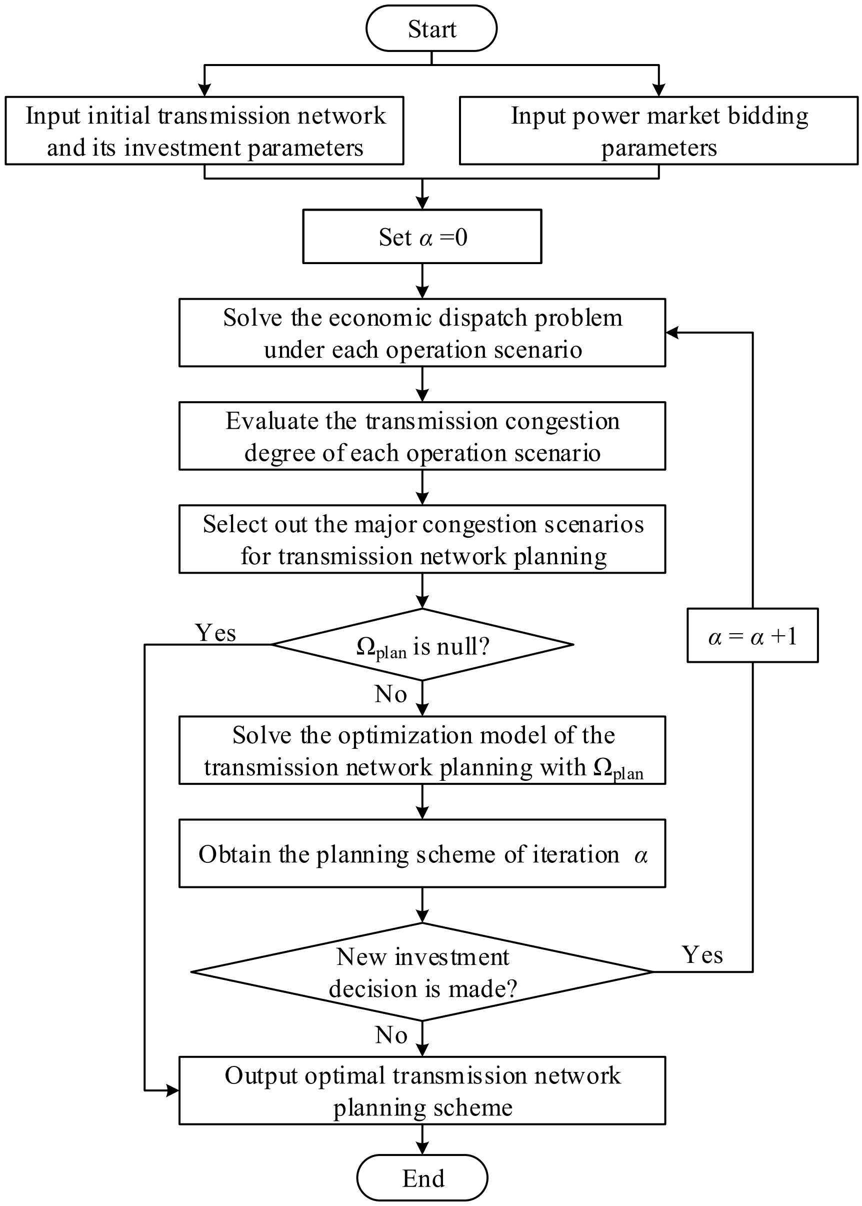

Figure 1. Bi-level collaborative planning process of transmission network.

The specific iterative solution process of the proposed bi-level collaborative planning model is as follows:

1. Input the initial transmission network and its investment parameters, and the power market bidding parameters.
2. Set the initial value of iteration time $\alpha = 0$.
3. Solve the economic dispatch problem of transmission network to obtain the optimal economic dispatch scheme under each operation scenario.

4. Evaluate the transmission congestion degree of each operation scenario.
5. Select out the major congestion scenarios for transmission network planning, which composes the planning scenario set Ω_{plan}.
6. If the planning scenario set Ω_{plan} is null, return to step 9; otherwise transmit the planning scenario set Ω_{plan} to the optimization model of transmission network planning.
7. Solve the optimization model of the transmission network planning and obtain the transmission network planning scheme considering major congestion scenarios.
8. If new investment decision is made, set $\alpha = \alpha$+1 and return to step 2; Otherwise return to step 9.
9. Output the optimal scheme and its benefit of transmission network planning.

4. Case Studies

The following two case studies, i.e., the improved six-node Garver power system and the simplified 25-node power system of Zhejiang Province, China, are employed for verifying the effectiveness of the proposed planning method. It is assumed that the network planning cycle is 15 years, consisting of five planning stages. The load growth rate of each stage is 5%. The capital recovery cycle of the new transmission line is 25 years. The discount rate is assumed to be 8% to calculate the annual cost of transmission line investment in the planning horizon. Moreover, it is assumed that each generating unit quotes according to its marginal cost and the bid of the load demand is based on its actual benefit of electricity. The reactive power compensation equipment is configured at nodes to provide enough reactive power for balance. The proposed multi-stage transmission network planning model considering transmission congestion is a mixed integer linear programming model, which can be effectively solved through the commercial solver CPLEX [51,52] in MATLAB.

4.1. The Improved Six-Node Garver Power System

4.1.1. Parameters of Case Studies

The shown in Figure 2 contains six nodes and 15 transmission corridors. The parameters of transmission corridors are shown in Table 1. It is noted that all cost components of the improved six-node Garver power system are in US dollars. The maximum number of circuits for each transmission corridor is three. In order to simulate the characteristics of the power market, the user side loads are quoted in stages, and the loads at each node are divided into five segments. Each segment is given a different power purchase price. The output range and power supply price of different types of generating units are different. The parameters of generating units and loads are shown in Table 2. Table 3 presents 10 types of load scenarios including ideal state, high load in developed areas, and low load in the whole network during holidays, etc. At the same time, 16 scenarios are used to simulate the changes of generator caused by equipment failures, changes of power generation prices, market policies, and other influences. The transmission congestion threshold η_0 is 0.3.

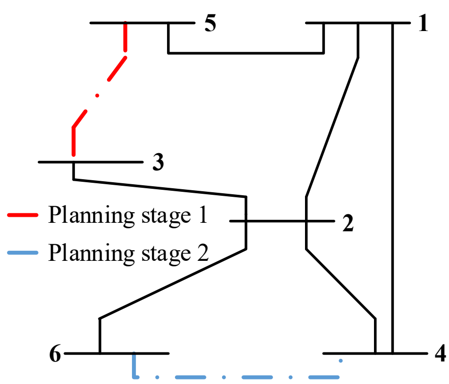

Figure 2. Topology diagram and planning scheme in the improved six-node Garver power system.

Table 1. Parameters of transmission line in the improved six-node Garver power system.

Corridor	From	To	Reactance (p.u.)	Line Capacity (MW)	Investment Cost ($\times 10^6$ $)	Number of Existing Lines	Length (km)
1	1	2	0.40	80	40	1	20
2	1	3	0.38	80	38	0	19
3	1	4	0.60	64	60	1	30
4	1	5	0.20	80	30	1	15
5	1	6	0.68	56	68	0	34
6	2	3	0.20	80	20	1	10
7	2	4	0.40	80	40	1	20
8	2	5	0.31	80	31	0	15.5
9	2	6	0.30	80	30	1	15
10	3	4	0.59	65.6	59	0	29.5
11	3	5	0.20	80	20	1	10
12	3	6	0.48	80	48	0	24
13	4	5	0.63	60	63	0	31.5
14	4	6	0.30	80	30	1	15
15	5	6	0.61	62.4	61	0	30.5

Table 2. Parameters of generating units in the six-node Garver power system.

Node	Generator No.	Capacity (MW)	Minimum Output (MW)	Power Supply Price ($/MWh)
1	G1	250	225	10
2	G2	150	0	20
3	G3	120	60	18
	G4	80	0	22
4	-	-	-	-
5	G5	120	60	17
	G6	100	50	12
6	G7	100	0	20
	G8	100	50	15
	G9	250	100	19
	G10	80	0	21

Table 3. Parameters of load nodes in the improved six-node Garver power system.

Node	Power Purchase Price ($/MWh)	Load Demand (MW)									
		Scenario									
		1	2	3	4	5	6	7	8	9	10
1	30,28,26,24,23	120	96	84	120	120	84	108	108	108	120
2	30,29,27,25,23	120	96	84	120	120	84	108	108	108	120
3	34,32,30,28,25	200	160	140	260	200	200	180	140	180	220
4	32,30,27,26,24	150	120	105	150	150	150	135	105	135	150
5	34,30,26,25,24	170	136	119	170	221	170	119	153	119	187
6	34,30,26,25,24	130	104	91	130	130	130	91	117	91	130

4.1.2. Results of the Proposed Model

The transmission planning scheme for the improved six-node Garver power system and its costs are shown in Figure 2 and Table 4, respectively. Before planning, each operation scenario of transmission network is simulated, and 23 major congestion scenarios of the transmission network are screened out. The information of major congestion scenarios is shown in Table 5.

Table 4. Planning cost in the improved six-node Garver power system.

Type	Cost
Line investment cost (C^{inv})/10^6 \$	20.6093
Line maintenance cost (C^{om})/10^6 \$	4.0995
Social benefit (C^{sb}) before planning/10^9 \$	1.6648
Social benefit (C^{sb}) after planning/10^9 \$	1.7026

Table 5. Major congestion scenarios in improved six-node Garver power system.

Scenario	Planning Stage	Probability	Degree of Transmission Congestion	
			Before Planning	After Planning
73	1	1.50%	0.63	0
1	5	2.40%	0.61	0
71	5	1.50%	0.58	0.19
3	1	2.40%	0.47	0
1	3	2.40%	0.46	0
1	4	2.40%	0.46	0
71	4	1.50%	0.44	0.22
2	4	2.40%	0.44	0
10	5	1.44%	0.43	0.18
71	3	1.20%	0.38	0.23
61	5	1.50%	0.38	0
80	5	0.90%	0.37	0.26
10	4	1.44%	0.37	0
21	5	1.20%	0.35	0.15
80	4	0.90%	0.35	0.13
41	5	0.45%	0.32	0.15
81	5	0.75%	0.31	0.17
2	2	2.40%	0.31	0
2	3	2.40%	0.31	0
3	5	2.40%	0.31	0
21	4	1.20%	0.31	0
11	5	1.20%	0.31	0
81	2	0.75%	0.30	0.16

As can be seen from Table 5, the problem of transmission network congestion is not only affected by load demand growth, but also by coal control policy (scenarios 73, 71, and 80), gas generator price rise (scenario 81), large power input from upper voltage grid due to medium and long-term contracts (scenario 61), and drought or flood seasons (scenarios 21 and 11). In scenario 73, under the influence of the coal control policy, the output level of coal power of nodes 3 and 5 is reduced, the power flow of transmission corridors 11 and 14 exceed the maximum limit in the planning stage 1, and the nuclear power with low electricity price at node 6 cannot be delivered. In order to satisfy the load demand of power users, gas generators with high electricity price are dispatched. Under scenario 1, due to the lack of capacity to meet the demand growth in power transmission, loss of load appeared at node 4 and node 1 in planning stages 3 and 5, respectively. The loss rate of node 4 in planning stages 3 to 5 is 6.0%, 6.0%, and 9.2%, respectively, and that of node 1 in the planning stage 5 is 6.0%. Scenario 1 in planning stages 3 to 5 are added to the planning scenario set. Under scenario 81, the power supply prices of gas generators 2, 4, and 7 increase, which is higher than the quoted prices of some users at each node, resulting in loss of load. The loss of load rates of nodes 1 to 4 are 18.0%, 12.0%, 6.0%, 24%, and 14.6%, respectively. The transmission congestion fails to make full use of the low electricity price in the power system, and limits the social benefit to reach the optimal.

From Figure 2, The proposed planning model decides to build one new circuit for transmission corridor 11 and one new circuit for transmission corridor 14 in planning stage 2. The loss of load at each node in the target transmission network disappears. The degrees of transmission congestion in all scenarios are less than the threshold η_0. In Table 4, the social benefit (C^{sb}) represents the sum of social benefit under all operation scenarios, which is obtained based on the simulation results considering universal scenarios. The social benefits of each planning stage increased by 0.6037 M$, 4.4072 M$, 6.4967 M$, 9.8945 M$, and 16.4156 M$, respectively. After deducting the cost of transmission line planning and investment, the power network planning scheme obtained by the model can still bring the whole society with 13.1088 M$.

To sum up, the proposed multi-stage transmission network planning model considering transmission congestion can effectively alleviate the problem of transmission congestion caused by the development of power network load and the change of power market through the optimal planning of transmission line, which improves the economic benefit of transmission network operation in the planning cycle.

4.1.3. Influence of Different Transmission Congestion Thresholds on the Planning Scheme

To analyze the impact of different transmission congestion threshold η_0 on the planning scheme, η_0 is set to 0.1, 0.2, 0.25, 0.3, 0.35, and 0.4, respectively. The planning schemes and costs are shown in Table 6 and Figure 3. As the transmission congestion threshold η_0 increases, the screening of major congestion scenarios tends to be loose; and the types of scenarios included in the planning scenario set increase, which changes the results of transmission network planning. When η_0 = 0.4, nine major congestion scenarios are considered in the transmission network planning. Compared with the planning scheme when η_0 = 0.3, the line expansion decision of transmission corridor 14 is delayed by one planning stage. Although the line investment cost and maintenance cost are reduced by 2.8103 M$ and 0.0945 M$, respectively, the social benefit is lost at the same time by 3.786 M$, indicating the problem of insufficient transmission line investment. When η_0 = 0.1, the number of major congestion scenarios for transmission network planning is 297. Compared with the planning scheme when η_0 = 0.3, the line investment cost and maintenance cost of the resulting planning scheme are increased by 24.3564 M$ and 0.6529 M$, respectively. The social benefit is increased only by 1.6596 M$, and the total social benefit is reduced instead. Therefore, when carrying out the transmission network planning considering the transmission congestion scenario, it is necessary to determine the reasonable transmission congestion threshold to prevent the problem of insufficient or excessive investment to realize the optimal benefit of transmission network planning.

Table 6. Comparison of transmission network planning schemes under different transmission congestion thresholds.

η_0	Number of Severely Congestion Scenarios	Planning Scheme	Solution Time/s
0.1	297	9(1), 11(1), 14(1), 14(2), 6(5)	347.1317
0.2	90	11(1), 14(1), 6(5), 14(5)	42.0618
0.25	50	11(1), 14(1), 6(5)	35.8863
0.3	23	11(1), 14(2)	22.6523
0.35	13	11(1), 14(2)	20.5243
0.4	9	11(1), 14(3)	19.0354

Note: In the third column, the numbers outside and inside the bracket indicate the indices of expended transmission corridors and the planning stages of the planning scheme, respectively.

The solution time of the planning model under different major congestion scenarios is shown in Figure 4. In Figure 4, as the number of severe congestion scenarios increases, so does the numbers of decision variables and constraints, which leads to the dimensionality disaster with exponential multiplication of computation. If the scale of the transmission system is further expanded, the solving difficulty will continue to increase, which makes it difficult for the model to be applied. Therefore, through the major congestion scenario screening method proposed in this paper, the optimal scheduling simulation under each operation scenario is carried out. According to the predetermined transmission congestion threshold, the major congestion scenario is screened in advance to obtain the planning scheme. The demand of network planning is achieved efficiently under the large scale and complex operational scenarios of the current transmission system.

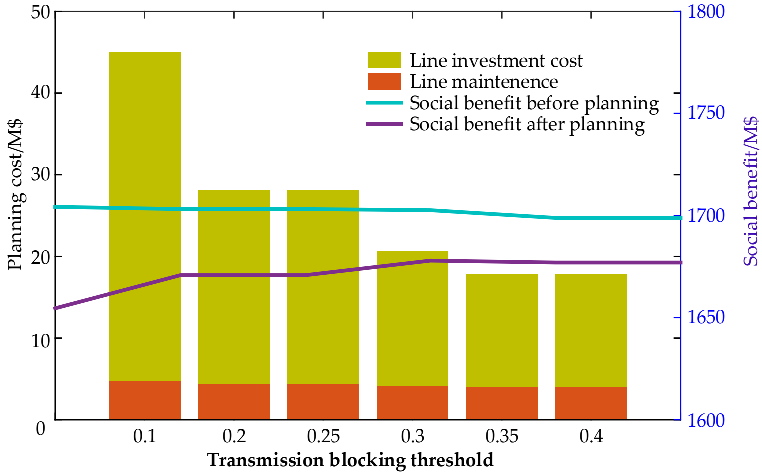

Figure 3. Planning costs under different transmission congestion thresholds.

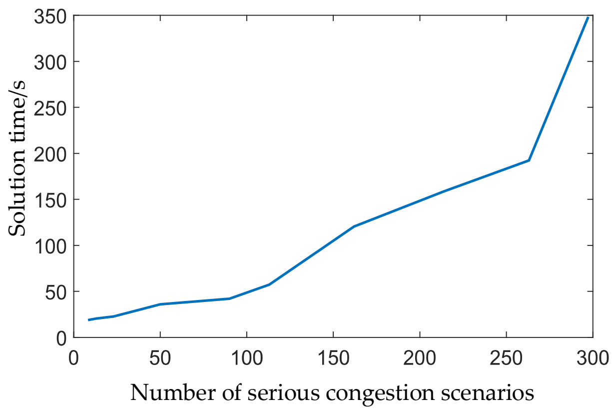

Figure 4. Solution time of the planning models with different major congestion scenarios.

4.2. Simplified 25-Node Power System of Zhejiang Province, China

The simplified 25-node power system of Zhejiang province, China is used for further analysis and verification. The power system consists of three 1000 kV nodes, 22,550 kV nodes, and 36 transmission corridors. The maximum number of lines that can be built for each transmission corridor is three. The topology of the simplified 25-node system of Zhejiang province, China is shown in Figure 5. Parameters of transmission corridors, load demands and generators in the power system are shown in Tables 7–9. It is noted that all cost components of the simplified 25-node power system of Zhejiang province, China are in Chinese Yuan (CNY). According to the actual situation of Zhejiang power market, each load node uses a unified piecewise quotation. The purchase price of each section is 316 CNY/MWh, 538 CNY/MWh, 730 CNY/MWh, and 946 CNY/MWh, respectively. The planning result when $\eta_0 = 7.5$ and its costs are shown in Figure 5 and Table 10.

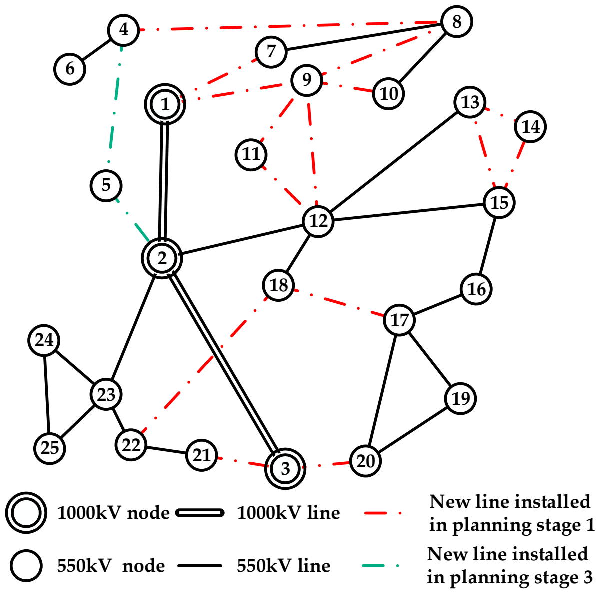

Figure 5. Topology and planning results of 25-node power system of Zhejiang province, China.

Table 7. Parameters of transmission corridors in simplified 25-node power system of Zhejiang province, China.

Corridor	From	To	Reactance (p.u.)	Capacity (MW)	Investment Cost ($\times 10^6$ CNY)	Number of Existing Lines	Length (km)
1	1	2	0.00463	7500	/	2	100
2	2	3	0.00281	7500	/	2	100
3	2	5	0.00812	2200	348	2	87
4	5	4	0.00145	2200	56	2	14
5	4	8	0.00762	2300	312	2	78
6	1	7	0.0013	3000	80	2	20
7	7	8	0.00294	2200	120	2	30
8	1	9	0.00425	4300	328	2	82
9	9	8	0.00297	2700	124	2	31
10	8	10	0.00585	1800	244	2	61
11	9	10	0.00594	1800	240	2	60
12	9	11	0.0034	3200	160	2	40
13	9	12	0.00194	3600	80	2	20
14	11	12	0.00221	3200	104	2	26
15	2	12	0.00717	2700	294	2	73.5
16	12	13	0.00613	2700	254.8	2	63.7
17	13	14	0.00437	3700	180	2	45
18	14	15	0.00276	2300	164	2	41
19	13	15	0.00538	2800	210	2	52.5
20	12	15	0.00608	3100	280	3	70
21	12	18	0.00478	2900	200	2	50
22	17	18	0.01215	2700	500	2	125
23	16	17	0.006	2700	250	2	62.5
24	15	16	0.00522	2900	210.8	2	52.7
25	18	22	0.00487	4300	220	2	55.0
26	2	23	0.01004	2700	416	1	104
27	23	24	0.00504	2300	224	2	56
28	24	24	0.00868	2700	368	2	92
29	23	25	0.00658	2900	272	2	68
30	22	31	0.00569	2800	224	2	56
31	21	3	0.00018	2200	6.68	2	1.67
32	3	20	0.01035	2200	400	2	100
33	17	20	0.00487	2800	202	1	50.5
34	17	19	0.00614	3700	255.6	2	63.9
35	19	20	0.00269	2400	114	2	28.5
36	4	6	0.0037	2200	149.6	2	37.4
37	22	23	0.0019	2200	102	4	25.5

Table 8. Parameters of load demand in simplified 25-node power system of Zhejiang province, China.

Node	Load Demand (MW)									
	Scenario									
	1	2	3	4	5	6	7	8	9	10
1	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0
4	2782	2504	2226	1947	1669	1391	2226	2226	2226	2782
5	4790	4311	3832	3353	2874	2395	3832	3832	3832	4790
6	90	81	72	63	54	45	72	72	72	72
7	5318	4786	4254	3722	3191	2659	4254	4254	4254	4254
8	9793	8814	7834	6855	5876	4897	7834	7834	7834	7834
9	10,146	9131	8116	7102	6087	5073	8116	8116	8116	8116
10	132	119	106	92	79	66	106	106	106	106
11	0	0	0	0	0	0	0	0	0	0
12	8754	7879	7003	6128	5252	4377	7003	7003	6128	7003
13	2533	2280	2026	1773	1520	1266	2026	2026	1773	2026
14	142	126	111	95	79	126	126	111	126	0
15	13,656	12,290	10,925	9559	8194	6828	9559	10,925	9559	13,656
16	1689	1520	1351	1182	1013	845	1182	1182	1182	1351
17	6256	5630	5005	4379	3754	3128	4379	4379	5005	5005
18	4981	4483	3985	3487	2989	2491	3487	3985	3985	3985
19	857	771	686	600	514	429	600	514	686	686
20	9740	8766	7792	6818	5844	4870	6818	5844	7792	7792
21	2032	1829	1626	1422	1219	1016	1422	1626	1626	1626
22	0	0	0	0	0	0	0	0	0	0
23	1762	1586	1410	1233	1057	881	1233	1410	1410	1410
24	1165	1049	932	816	699	583	816	932	932	932
25	2539	2285	2031	1777	1523	1270	1777	2031	2031	2031

The social benefit surplus is the value of the total social benefit under all scenarios deducting the transmission line investment and maintenance costs, which represents the net benefit of the transmission network planning. It can be seen from Table 10 that the social benefit surplus is 16.6 × 10^6 CNY, indicating that the economics of the transmission network operation is effectively improved through the proposed planning method. The information of major congestion scenarios before planning is shown in Table 11. It can be seen from Figure 5 and Table 11 that the power system is mainly faced with three types of transmission congestion scenarios, including reduction of hydraulic generator output due to drought/flood seasons, limited power generation of coal power due to coal control policy, and large power input due to medium and long-term contracts. Under scenario 71, because of the coal control policy, some coal power units at nodes 13 and 15 are shut down, and their output is halved. Due to the power flow violation of transmission corridors 12 and 14, the electricity power at node 11 cannot be sent out, resulting in loss of load at nodes 15, 16, and 17. The shadow price of scenario 71 before planning reaches 1363.6, which is higher than the shadow price of scenario 1 (φ_1 = 1016.8). However, as the probability of scenario 71 is smaller than that of scenario 1, the degree of transmission congestion of scenario 1 is still higher than that of scenario 71. Figure 6 shows the active power of each transmission corridor under scenario 1 before and after the planning. Under scenario 1, the overall load level in this region is relatively high, and the transmission corridors 5, 6, 9, 11, 14, and 32 are congested, resulting in the failure of the electricity with low electricity prices being sent out from nodes 1, 3, 4, and 11. According to the planning result, new transmission lines are built in the above transmission corridors 5, 6, 9, 11, 14, and 32. The transmission capacity of the transmission corridor is improved, and the social benefit in this scenario is increased from 23.3 × 10^6 CNY to 24.3 × 10^6 CNY.

Table 9. Parameters of generators in simplified 25-node power system of Zhejiang province, China.

Generator	Node	Price (CNY/MWh)	Maximum Output (MW)	Minimum Output (MW)	Type
1	6	367	1800	900	Pumped storage
2	7	547	1141	0	Gas generator
3	8	405.3	1320	528	Coal power
4	8	415.3	2178	1089	Nuclear power
5	8	607	4078	0	Gas generator
6	9	547	1356	0	Gas generator
7	10	405.6	4056	2028	Nuclear power
8	12	385.3	2000	800	Coal power
9	12	367	1200	600	Pumped storage
10	12	607	904	0	Gas generator
11	13	385.3	1320	528	Coal power
12	13	547	680	0	Gas generator
13	13	607	788	0	Gas generator
14	14	385.3	2780	1112	Coal power
15	15	385.3	2400	960	Coal power
16	15	547	1131	0	Gas generator
17	16	385.3	2400	960	Coal power
18	17	385.3	2000	800	Coal power
19	18	367	1500	750	Pumped storage
20	18	607	186	0	Gas generator
21	19	385.3	630	252	Coal power
22	20	405.3	2520	1008	Coal power
23	20	385.3	2000	800	Coal power
24	20	607	342	0	Gas generator
25	24	405.3	2520	1008	Coal power
26	25	547	1323	0	Gas generator
27	20	519.6	200	100	Hydropower
28	20	656.8	600	300	Hydropower
29	21	412.4	305	152.5	Hydropower
30	25	386.3	320	160	Hydropower
31	1	369	6000	1800	Power from external regions
32	3	360	6000	1800	Power from external regions
33	4	369	6000	1800	Power from external regions
34	5	369	5000	1500	Power from external regions
35	8	358	5000	1500	Power from external regions
36	11	339	7500	2250	Power from external regions
37	22	358	1000	300	Power from external regions
38	22	301	7500	2250	Power from external regions

Table 10. Costs of the planning scheme in 25-node power system of Zhejiang province, China.

Type	Cost
Line investment cost (C^{inv})/10^6 CNY	1826.7
Line maintenance cost (C^{om})/10^6 CNY	271.5
Social benefits (C^{sb}) under severe congestion scenarios/10^9 CNY	14,807.6
Social benefit (C^{sb}) surplus after planning/10^6 CNY	16.6

Table 11. Major congestion scenarios in 25-node power system of Zhejiang province, China.

Scenario	Planning Stage	Probability	Degree of Transmission Congestion	
			Before Planning	After Planning
1	5	1.6%	16.3	0.5
71	5	1.0%	13.6	0.0
2	5	2.4%	12.5	1.6
1	4	1.6%	12.2	1.3
21	5	0.8%	10.2	0.0
61	5	1.0%	10.2	0.3
1	3	1.6%	9.1	0.8
71	4	1.0%	9.1	1.0
72	5	1.5%	9.0	1.0
62	5	1.5%	7.5	1.0

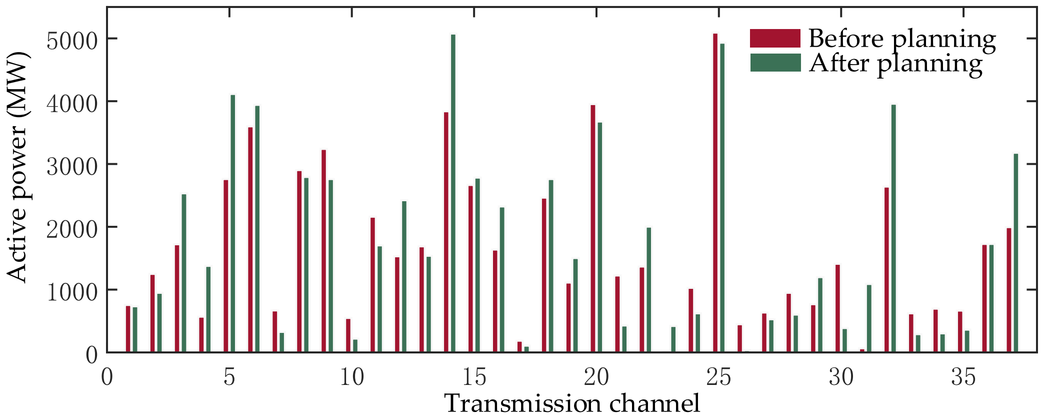

Figure 6. Active power of each transmission corridor under scenario 1.

The generating power of each generator under scenario 21 is presented in Figure 7. Under scenario 21, nodes 20, 21, and 25 (i.e., the area with rich water resources in southwest Zhejiang) are reasonably affected by climate or generating unit scheduling. The hydropower output is less than the expected value. So, the power transmitted to node 16, 17, and 19 in southeast Zhejiang area is reduced, while the transmitted power of transmission corridor 32 reaches the upper limit. Therefore, the power from node 3 cannot be transmitted to southeast Zhejiang. Loss of load appeared at node 16, 17, and 19, with a loss rate of 12%, 18%, and 18%, respectively. At the same time, in order to meet the demand of high quoted power load, the gas generators at node 20 are called up to 342 MW. Under this circumstance, the power system is in the non-optimal operation mode. After planning, the loss of load at nodes 16, 17, and 19 disappeared; the output of node 3 increased by 1908.0 MW; and the social benefit under this scenario increased from 23.1×10^6 CNY to 24.4×10^6 CNY.

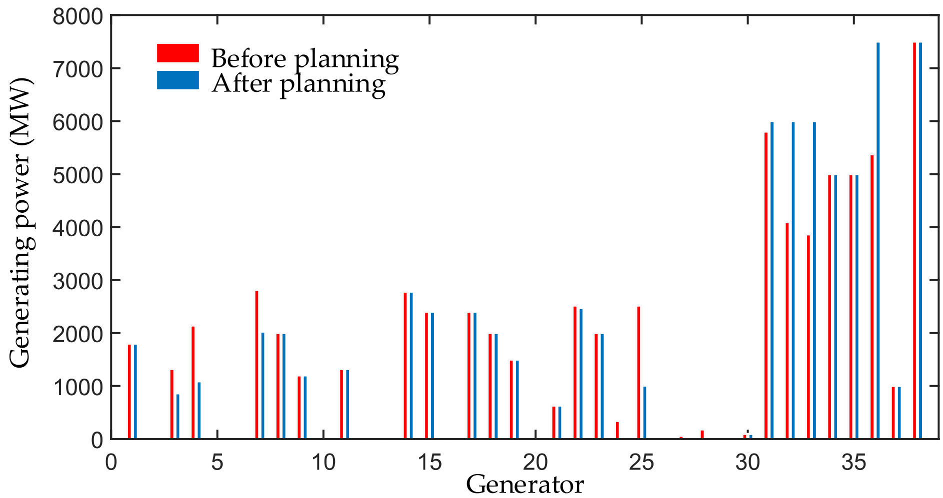

Figure 7. Generating power of each generator under scenario 21.

The proposed bi-level transmission network planning model can be used in the actual transmission network system. By analyzing the major congestion scenarios obtained in the planning, it can effectively help the power system planners to identify the power system congestion risk sources and guide the expansion construction of transmission network.

5. Conclusions

The economic scheduling of transmission network is simulated to evaluate the congestion degree of each scenario and screen out the severely congested ones. A multi-stage transmission network planning model considering transmission congestion is then established. The main conclusions are as follows:

(1) Aiming at the new risks of transmission congestion in the power market, such as the fluctuation of generator quotation, the preemption of transmission medium and long-term contract, a major congestion scenario screening method based on shadow price theory is proposed, which effectively evaluates the congestion risks, screens out major congestion scenarios and provides guidance for multistage planning of transmission network.

(2) When carrying out transmission network planning with as many operating scenarios as possible, the proposed screening method of transmission network congestion scenarios effectively identifies the major congestion scenarios that need to be considered. Through the iterative optimization of transmission network planning, the optimal planning scheme is obtained to alleviate the transmission congestion risk. The proposed screening method effectively improves the efficiency of solving, prevents the dimension disaster problem, and can successfully be applied to the actual power system.

(3) Different settings of transmission congestion threshold will affect the transmission network planning results. A reasonable determination of transmission congestion threshold through sensitivity analysis can prevent the over-investment of transmission lines and reduce the difficulty and solution time.

The proposed transmission network planning model aims at maximizing the social benefit considering different scenarios, which fully describe the uncertain bidding strategies of generators and users. However, it does not take the interests of independent agents into full consideration. In fact, there is a game relationship among the independent agents in the power market, which requires multiple optimization objectives to be considered in the transmission network planning model. Future work should be concentrated on establishing the multi-objective planning model of transmission network considering multi-agent game behavior and the interests of all independent agents to improve the economy of the planning result.

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Nomenclature

(1) Indices and Sets

g	Index for generators.
i, j	Indices for nodes.
k	Index for circuits of transmission corridor.
s	Index for scenarios.
t	Index for planning stages.
α	Index for iterations.
Ω_{node}	Set of transmission network nodes.
Ω_i^{gen}	Set of generators connected with node i.
$\Omega_{\text{plan},t}$	Set of planning scenarios in planning stage t.
$\Omega_{\text{line},i}$	Set of transmission corridors starting from node i.
Ω_{dec}	Set of decision variables.
L_{ij}	Set of transmission circuits of transmission corridor ij.

(2) Parameters

$B_{ij,k}$	Susceptance of the kth circuit of transmission corridor ij.
C^{total}	Surplus of social benefits.
C_s^{sb}	Social benefit under operation scenario s.
C_t^{inv}	Investment cost of transmission line in planning stage t.
C_t^{om}	Maintenance cost of transmission line in planning stage t.
C_t^{bud}	Largest budget for the investment and maintenance of transmission lines in planning stage t.
$c_{ij,k}^{inv}$	Unit investment cost of the kth circuit of transmission corridor ij.
$c_{ij,k}^{\text{om}}$	Unit maintenance cost of the kth circuit of transmission corridor ij.
$c_{i,g}^{gen}$	Electricity price of generator g connected with node i.
c_i^{load}	Power purchase price at node i.
H_{ij}	Flow transferring relativity factor of transmission corridor ij.
LMP_i^{load}, $LMP_{i,g}^{gen}$	LMPs of node i and generator g connected with node i, respectively.
N_{plan}	Number of planning stages.
$P_{i,g}^{gen,\min}$, $P_{i,g}^{gen,\max}$	Minimum and maximum power of generator g connected with node i, respectively.
p_s	Probability of scenario s.
r	Discount rate.
$S_{ij,k}^{\max}$	Maximum transmission power of the kth circuit of transmission corridor ij.
T_{hr}	Load duration of each planning stage.
T_{plan}	Years of the planning cycle.
T_{line}	Years of the transmission line capital recovery cycle.
$\overline{x_{ij}}$	Upper limit of the number of transmission line ij that can be constructed.
ε_i^{ENS}	Maximum load loss rate of node i.
μ_{ij}	Lagrange multiplier of the power flow constraint of power transmission corridor ij.
λ_i	Lagrange multiplier of the power balance constraint of node i.
$\overline{\nu_{ij,k}}$, $\underline{\nu_{ij,k}}$	Lagrange multipliers of the upper and lower limits of capacity constraints of the kth circuit of transmission corridor ij, respectively.
$\overline{\tau_{i,g}}$, $\underline{\tau_{i,g}}$	Lagrange multiplier of the upper and lower limits of power constraints of generator g connected with node i, respectively.
π	Lagrange multiplier of the phase angle constraint at equilibrium node.
$\overline{\omega_i}$, $\underline{\omega_i}$	Lagrange multipliers of the upper and lower limits of power losses constraint at node i, respectively.
η_0	Threshold of transmission congestion degree.
η_s	Transmission congestion degree of scenario s.
σ	Line investment recovery coefficient.
φ_s	Shadow price of scenario s.
ζ_t	Discount coefficient.

(3) Variables

P_i^{load}	Load power of node i.	$x_{t,ij,k}$	Binary investment decision variable of the kth circuit of transmission corridor ij in planning stage t.
$P_{i,g}^{gen}$	Power of generator g connected with node i.	$n_{t,ij,k}$	Binary state decision variable of the kth circuit of transmission corridor ij in planning stage t.
P_{ij}^{line}	Power flow of transmission corridor ij.	θ_i, θ_j	Voltage phase angles of node i and node j, respectively.
P_i^d	Load demand at node i.	θ_{ref}	Voltage phase angle of the equilibrium node.

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