Multi-energy System Planning Based on Cascade Hydro-Photovoltaic-Pumped Storage Hybrid Generation System

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Abstract. Yalong River in Sichuan, China is a typical cascade hydro-photovoltaic-pumped storage (CHPPS) correlation system. CHPPS correlation system can achieve the objectives of multi-energy complementarities, renewable energy consumption and power supply structure optimization. This paper proposes a novel planning of cascade hydro-photovoltaic hybrid generation with pumped storage generations (PG). Firstly, the concept of comprehensive model of location and capacity for multi-energy system is proposed. With the form of equality constraint, correlation model reflects the space-time complementarities of hydropower (HY) and photovoltaic power (PV). Secondly, the correlation model is derived in detail with the specific form provided. Then, a multi-objective planning model is established with power flow and reliability constraints. Thereafter, a novel solution method that combines the fast non-dominated genetic algorithm (NSGA-II) is developed. An example using the CHPPS based on IEEE 33-node distribution system is demonstrated in this paper. Simulation results show that the proposed model considering the correlation model possesses reasonable investments, good income and excellent water-light complementary ability.

1. Introduction

Under the circumstance of increasing exhausted fossil energy, severe environmental pollutions and the greenhouse effect, it is necessary to improve the integration of renewable energy into the power grid to promote low-carbon energy [1, 2]. However, distributed generation, such as PV, which is the most promising among all renewable resources, can bring changes to power flow distributions, voltage drops and system reliability. It is necessary to plan DGs to distribution network carefully.

In single-layer planning, reference [3] proposes an analytical formulation to calculate the optimal size and identify the corresponding optimum location for DG placement to minimize the total power losses. Reference [4] adopts the genetic algorithm to solve DG arrangements, which include voltage and reliability requirements in the constraints to reduce losses and investment cost of the distribution network. Reference [5] proposes a multi-objective planning model for DGs, which considers influence of load.

In above DG planning research, the planning objectives are mainly investment cost, operation and maintenance costs [4,5], losses [3,5] and reliability [5]. However, the complementarities of different types of DGs are ignored. References [6,7] divide DGs into two types according to reactive power, namely reactive power supplement DGs and reactive power consumption DGs. The relationship between different types of DGs, loss and power factors in a distribution network is analyzed in [6]. The effects on allocation and sizing of different types of DG brought by load level are studied in [7] based on [6]. These references focus on the location and sizing of DGs based on corresponding features but
ignore the reliability of distribution networks. Besides, the randomness of DG output is not considered in these references.

The research on the scheduling strategies when DGs are connected to distribution networks focuses on reducing the risk from DG output fluctuation, which is affected by a variety of random factors. The output has strong intermittency and volatility, and thus DGs must be supported by conventional generation when integrated to the power grid.

HY, one low-cost energy with strong adjustment ability, has the most mature technology and is the most competitive among all clean and renewable energy. HY can complement other DGs such as wind power and PV in time-space distribution. The complementarities improve the utilization of the transmission channel in the dry season, reduce the area occupied by DGs, improve the structure of energy, and achieve a better allocation of power resources.

PG is the most economic power supply in transferring energy from low-use periods to peak-use periods. Due to its quick response characteristics, PG can offset the inherent intermittency in renewable resources. Therefore, PG is increasingly popular in the modern power grid. Reference [8] proposes a coordination methodology for wind power and PG in the day-ahead operation planning considering transmission constraints. A nonlinear function of the thermal power unit starting costs is integrated to [9] on basis of [8], which is then solved by a binary PSO algorithm.

In this paper, the CHPPS correlation model is established on basis of electricity balance and generation models of isolated units. Then a multi-objective planning model is established with power flow and reliability constraints. Thereafter, a novel solution method that combines NSGA-II is developed. Finally, the approach is demonstrated in the IEEE 33-node system.

The remainder of the paper is organized as follows. In section II, the CHPPS correlation model is proposed. Both the model’s physical and mathematic meanings are analyzed. In section III, the process of modeling is deduced in detail. In section IV, a planning model is established. The solutions to the above models are shown in section V. The conclusion is reached in section VI.

2. Overview of market mechanism

2.1. Comprehensive Model of Location and Capacity for Multi-energy System

The comprehensive model contains a correlation equation of generation capacity and location of cascade HY, PV and PG, described in (1). The correlation model reflects the mutual relationship between these stations in planning.

\[
f(I_{1,t}, I_{2,t}, H_{i,t}, P_{ka,s}, A_{j,t}, T_{stc,j}, T_{pv,j}, P_{pv,j}, P_{pg,s,k}) = 0
\]  

(1)

Where \( I_{1,t} \) represents the amount of water from the cascade HY \( i \) at month \( t_1 \), \( H_{i,t} \) represents the net head of the cascade HY \( i \) in month \( t_1 \). \( P_{ca,s} \) represents the rated power of the cascade HY \( i \). \( A_{j,t} \) represents the actual irradiance of PV \( j \) at month \( t_2 \). \( T_{stc,t} \) represents the actual temperature of the PV \( j \) at month \( t_2 \). \( P_{pv,j} \) and \( P_{pg,s,k} \) are the rated power of PV \( j \) and PG \( k \) respectively. \( P_{pg,s,k} \) represents generation power of PG \( k \) in scenario \( s \) at month \( t_2 \).

Eq. (1) is composed of (2). Eq. (2a) is the power correlation equation, which represents the power balance of the three power stations. The annual power generation of each station can be preliminarily calculated with (2a), forming the basis for calculating generation capacity and geographical location.

To obtain the output power of each station, their generation models should be first established. Described in (2b), the generation amount and output power of cascade HY are determined by the water flow in the drainage basin, the net head of the reservoir and the turbine capacity. Described in (2c), the power of PV is decided by irradiation intensity, temperature and the rated power. With the conversion efficiency, the power generation of PG is less than the power consumed when pumping. The annual power consumption of pumped storage is determined by the daily dispatch instruction and the capacity of the PG, provided in (2d).
\[
\begin{aligned}
&f_\mu(P_{\mu_{\text{mix}}}, P_{\mu_{\text{con}}}) = 0 \quad (2a) \\
&f_\mu(I_{\mu_{\text{mix}}}, I_{\mu_{\text{con}}}) = P_{\mu_{\text{con}}} - P_{\mu_{\text{mix}}}, \quad i = 1, 2, \ldots, n_\mu \quad (2b) \\
&f_\mu(T_{\mu_{\text{mix}}}, T_{\mu_{\text{con}}}) = P_{\mu_{\text{con}}}, \quad j = 1, 2, \ldots, n_\mu \quad (2c) \\
&f_\mu(P_{\mu_{\text{out}}}, P_{\mu_{\text{con}}}) = 0 \quad (2d)
\end{aligned}
\]

Where \( P_{\mu_{\text{con}}} \) represents the average power of the cascade HY \( i \) in month \( t_1 \), \( P_{\mu_{\text{mix}}} \) is the maximum output of the PV \( j \) at \( t_2 \) in month \( t_1 \) in scenario \( s \). \( n_\mu \), \( n_\nu \) and \( n_\gamma \) represent total number of HY, PV and PG units respectively.

### 2.2. Correlation model

#### 2.2.1. Electricity balance in CHPPS units

The correlation equation of CHPPS is established according to the power balance in (3).

\[
E_{\text{pv},y} + E_{\text{hy},y} + E_{\text{mg},y} + E_{\text{buy},y} + E_{\text{load},y} = E_{\text{load},y} \quad (3)
\]

Where \( E_{\text{pv},y}, E_{\text{hy},y}, E_{\text{mg},y}, E_{\text{buy},y} \) and \( E_{\text{load},y} \), respectively represent the annual power generation of PV, the power generation of cascade HY systems in the basin, the total annual electricity consumption of the PG, the power generation of original units in distribution network, the annual planned purchase of electricity in the distribution network and the annual electricity consumption of load in the distribution network during planning year \( y \).

Eq. (3) represents the annual electricity balance of the distribution network. Eq. (4)-(9) respectively represent the annual load, the annual power generation of cascade HY, the annual power generation of PV, the annual power generation of PG, the annual power generation of original units in the distribution network, and the annual electricity purchase from the main grid.

\[
E_{\text{pv},y} = \sum_{t_1}^{T_y} \sum_{t_2}^{T_y} \sum_{i}^{n_{\mu_{\text{con}}}} P_{\mu_{\text{con}},i} \Delta t_1 \quad (4)
\]

\[
E_{\text{hy},y} = \sum_{t_1}^{T_y} \sum_{t_2}^{T_y} \sum_{i}^{n_{\mu_{\text{con}}}} \eta_\mu O_{\mu,i}^{\text{hy}} H_{\mu,i} \Delta t_1 \quad (5)
\]

\[
E_{\text{pg},y} = \sum_{t_1}^{T_y} \sum_{t_2}^{T_y} \sum_{i}^{n_{\mu_{\text{con}}}} \sum_{t}^{n_{\gamma_{\text{con}}}} \left( P_{\gamma_{\text{con}},i}^{\text{pg}} - P_{\gamma_{\text{con}},i}^{\text{pp}} \right) \Delta t_1 = (1 - \eta_\nu) \sum_{t_1}^{T_y} \sum_{t_2}^{T_y} \sum_{i}^{n_{\mu_{\text{con}}}} P_{\mu_{\text{con}},i}^{\text{pp}} \Delta t_1 \quad (6)
\]

\[
E_{\text{mg},y} = \sum_{t_1}^{T_y} \sum_{t_2}^{T_y} \sum_{i}^{n_{\mu_{\text{con}}}} P_{\mu_{\text{con}},i}^{\text{pp}} \quad (7)
\]

\[
E_{\text{buy},y} = \sum_{t_1}^{T_y} \sum_{t_2}^{T_y} \sum_{i}^{n_{\mu_{\text{con}}}} P_{\mu_{\text{con}},i}^{\text{pp}} \quad (8)
\]

\[
E_{\text{load},y} = E_{\text{load},y}^{0} e^{(y-1) + c_0} \quad (9)
\]

Where \( T_1 \) and \( T_2 \) represents Scheduling cycle of cascade HY and PV respectively. \( n_{\mu_{\text{con}}}, n_{\nu_{\text{con}}} \) and \( n_{\gamma_{\text{con}}} \) represent number of HY, PV and PG coming into use during planning year \( y \) respectively. \( \Delta t_1 \) is the days in month \( t_1 \). \( \eta_\mu \) and \( \eta_\nu \) represent the unit conversion efficiency of cascade HY and PG respectively. \( O_{\mu,i}^{\text{hy}} \) is the average daily power generation flow of the cascade HY \( i \) in month \( t_1 \). \( P_{\mu_{\text{con}},i}^{\text{pp}} \) and \( P_{\gamma_{\text{con}},i}^{\text{pp}} \) represent the generation power and pumped active power of PG \( k \) in scenario \( s \) at \( t_2 \) in month \( t_1 \). \( n_{\gamma_{\text{con}}} \) is the number of original units in the distribution network during planning year \( y \). \( P_{\gamma_{\text{con}},i}^{\text{pp}} \) is the reactive output of the original unit \( l \) of the distribution network at \( t_2 \) in month \( t_1 \). \( P_{\mu_{\text{con}},i}^{\text{pp}} \) is the power of CHPPS system purchasing from the main network at \( t_2 \) in month \( t_1 \). \( E_{\text{load},y}^{0} \) is the current annual load of electricity. \( b_0 \) and \( c_0 \) are the annual load growth factors.
3. Planning model

3.1. Composition of Planning Problems

The joint planning of CHPPS involves many objective functions and constraints, as shown in figure 1. The objective functions include the minimum amount of abandoned light and water, the minimum investment cost, and the minimum fluctuation power of the CHPPS system to the grid, in (10). The constraints include equality constraints and inequality constraints: 1) Equality constraints are those constraints of the CHPPS correlation model (1) and power flow constraint (10a). 2) The inequality constraints include reliability constraint in (10b) and other inequality constraints in (10c).

![Diagram of Planning of CHPPS System](image)

Figure 1. The analytical diagram of the planning of CHPPS system

\[
\min F(P_{hy}^v, P_{pv}^v, P_{pg}^v) = \left[F_1, F_2, F_3, F_4\right]'
\]

(10)

\[
\text{st.} \begin{cases} 
  h(P_{hy}^v, P_{pv}^v, P_{pg}^v) = 0 \\ 
  g_1(P_{hy}^v, P_{pv}^v, P_{pg}^v) \leq \varepsilon \\ 
  g_2(P_{hy}^v, P_{pv}^v, P_{pg}^v) \leq 0 
\end{cases}
\]

(10a)

(10b)

(10c)

Where \( \varepsilon \) is the reliability index. \( Z_{i,t} \) is the water level of the cascade HY \( i \) in month \( t \). \( a_{i,t} \), \( b_{i,t} \) and \( c_{i,t} \) are discharge flow parameters of the reservoir water level of the cascade HY \( i \). \( a_{i,t} \) and \( c_{i,t} \) are head loss parameters of the cascade HY \( i \). \( S_{i,t} \) is the average daily downflow of the cascade HY \( i \) in month \( t \).

3.2. Planning Objectives

Objective 1 is to minimize water abandoned during the planning year as shown in (11). Objective 2 is to minimize abandoning light in all scenario during the planning year as shown in (12). Objective 3 is to minimize daily power fluctuation as shown in (13). Objective 4 is to minimize the total planning cost as shown in (14).

\[
\min F_i = \min \sum_{i=1}^{n_i} \sum_{j=1}^{n_{ij}} \left(S_{i,j} - Q_{i,j}^g\right)
\]

(11)

\[
\min F_i = \min \left(\sum_{j=1}^{n_{ij}} \max\left(P_{min}^b, \sum_{j=1}^{n_{ij}} P_{max}^b - P_{min}^b, 0\right)\right)
\]

(12)

\[
\min F_i = \min \left(\max F_{hv} - \min F_{hv}\right)
\]

(13)

\[
\min F_i = \min \left(\sum_{j=1}^{n_{ij}} (1+i_j)^{\gamma} C^p + \sum_{j=1}^{n_{ij}} (1+i_j)^{\gamma} \left(\frac{1+i_j}{1+i_j} - 1\right)^{\gamma} C^{f}\right)
\]

(14)
Where \( n_s \) is the number of economic scheduling scenarios. \( n_y \) is the total planning year. \( P_{PV,real,s,t}^{j} \) is the actual output of PV \( j \) in scenario \( s \) at \( t \) in month \( t_1 \). \( i_r \) is the discount rate. \( C^{op} \) and \( C^{pl} \) represent annual operation and planning costs for CHPPS system respectively. \( PEL \) is the operating period of generators.

In (14), the first element on the right side is the dynamic operating cost of the CHPPS system, including the cost of the fuel unit in the original distribution network, the cost of load shedding, and the cost to purchase electricity from the main network, as shown in (15). The second term is the dynamic investment cost, which is generally a linear function of the unit capacity, as shown in (16).

\[
C^{op} = \sum_{t_2} \left( \sum_{s} \sum_{w} P_{PV,real,s,t}^{j} \left( \sum_{k} c^{op}_{k} P_{PV,real,s,t}^{j} + \rho^{op} P_{PV,real,s,t}^{j} \right) \Delta t \right)
\]

\[
C^{pl} = \sum_{s} \sum_{w} \left( \sum_{i} C^{pl,i} + \sum_{k} C^{pl,k} \right)
\]

Where \( C^{op} \), \( C^{pl} \) and \( C^{pl} \) are static investment cost of cascade HY, PV and PG. \( c^{op} \), \( \rho^{op} \) and \( \rho^{op} \) represent unit price of the original distribution network unit running, cutting load and purchasing power from the main network. \( M \) is the number of nodes.

4. Case study

4.1. Parameters of calculation example

In this paper, the proposed model is demonstrated on the IEEE 33-node distribution network. It has planned three cascade HYs, 20 PVs, and 1 PG. The coupling relationship between the hydraulic and electric power of cascade HY groups is shown in figure 2. The unit price for load-cutting is 200$/MWh, the total planning period is 5 years, and the annual growth factor of the load is 5%. The maximum number of accesses to a PV node is 10. The random factors of the distribution network system include the annual temperature prediction error, the daily actual irradiance prediction error and the load prediction error. They all obey the normal distribution, and the standard deviation is 0.1 times of mathematical expectation.

![Figure 2. Hydraulic and electric power in cascaded hydroelectric stations](image)

4.2. Results

In this paper, the optimal planning results of scenarios under the weight of two targets are given in table 1 and 2 and the comprehensive planning results are shown in table 3.

| year | capacity/location of cascade hy | capacity/ bus of pg | amount/bus of pv |
|------|--------------------------------|---------------------|------------------|
| 1    | /                              | 2/9, 1/10, 1/11, 1/15, 1/17, 2/18, 3/19, 4/21, 1/22, 1/29, 5/31 |
| 2    | 25/6                           | 3/10, 3/11, 1/15, 2/18, 1/19, 2/22, 3/29, 2/31 |
| 3    | 45/8                           | 2/9, 2/11, 2/15, 1/18, 2/21, 3/29, 1/31 |
| 4    | 25/7                           | 2/9, 2/10, 2/11, 2/15, 2/17, 1/18, 2/19, 5/22, 3/29, 1/31 |
| 5    | /                              | 2/9, 1/10, 1/11, 1/15, 4/17, 2/18, 1/22, 1/31 |

Table 2. Planning results of scenario 2
Tables 1, 2 and 3 show the planning results of the two scenarios. In scenario 1, the capacity of the cascade HY is large and the amount of water abandonment is small. The HY comes into operation early, which can reduce the cost of the distribution network for electricity purchase from the main power grid. Therefore, the cost decreases during the planning period. The cost of electricity purchased in scenario 1 was 17.9% smaller than that in scenario 2. In scenario 1 with less planning cost weight, the total PV planning capacity is 5.83 MW, which is 1.12 MW higher than that of the scenario 2. Because PG is put into operation early to stabilize the PV and load fluctuations, the amount of discarded light is reduced by 74 MWh. In scenario 2, it is late for PG to come into operation. The original units must suppress the load and the PV output error, so the operating cost of the original unit is large.

### Table 3. Planning results of different scenarios

| scenario | wasted water (m³) | wasted light (MWh) | power fluctuation (MW) | total cost (10^6¥) | investment cost (10^6¥) | operation cost (10^6¥) |
|----------|----------------|-------------------|------------------------|--------------------|------------------------|------------------------|
| 1        | 9              | 11                | 0.6                    | 57052              | 15634                  | 4791                   |
| 2        | 15             | 85                | 5                      | 46805              | 9103                   | 3804                   |

5. Conclusion

In this paper, the concept of CHPPS correlation planning model is proposed, and the concrete model is formed. The multi-objective CHPPS planning model considering multiple scenario is established. The solution method of the model is illustrated by a specific example. The results of the example show that the planning model can choose complementary planning scenarios that meet different optimization objectives by setting different target weights. The results show that the CHPPS planning system can fully consider the complementarity between HY and PV access nodes.

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