

OPTIMAL ECONOMIC OPERATION OF A HYBRID POWER SYSTEM CONSIDERING BATTERY ENERGY STORAGE SYSTEM COSTS AND HYDROGEN-BASED ENERGY RESOURCES

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Abstract - To address operational instability arising from the variability of renewable energy sources in the economic dispatch of renewable-energy-integrated power systems, this study proposes a coordinated cost optimization framework incorporating biomass generation units, battery energy storage systems (BESS), and hydrogen-based generation units. Within the proposed framework, hydrogen is modeled as a flexible and dispatchable supplementary energy source, while the impact of BESS sizing is systematically investigated under three distinct capacity scenarios to support optimal investment and operational planning. The model is validated on the standard IEEE 9-bus test system over a 24-hour scheduling horizon. Simulation results demonstrate that the coordinated operation of biomass generation, BESS, and hydrogen-based generators not only enhances overall economic performance but also effectively mitigates power fluctuations, thereby significantly improving the operational flexibility and reliability of the system. The findings provide a quantitative and robust decision-support framework for economic operation planning and optimal dispatch of future renewable-based power systems.

Key words - Battery energy storage system; biomass power plant; economic dispatch; hybrid energy system; hydrogen energy

1. Introduction

Modern power systems are undergoing a profound transformation driven by the increasing integration of distributed energy resources, stringent carbon emission reduction targets, and the growing demand for enhanced reliability of electricity supply. In this context, hybrid power systems have emerged as a critical system architecture, enabling the efficient utilization of local energy resources while significantly improving system flexibility and operational autonomy [1], [2]. However, the development of hybrid power systems also introduces specific operational challenges. The inherent uncertainty and intermittency of renewable energy sources, combined with load variability, have substantially increased the complexity of the economic dispatch (ED) problem - a fundamental task that aims to optimally allocate generation outputs to meet demand at the minimum operational cost [3].

In this study, a day-ahead economic dispatch framework is formulated over a 24-hour scheduling horizon, explicitly incorporating the operational constraints of energy storage systems. Previous research on ED in hybrid power systems has evolved along multiple

directions, ranging from conventional models dominated by thermal generation units [4], [5] to studies integrating BESS for peak shaving, load shifting, and increasing renewable energy utilization [6] - [8]. More recently, hybrid modeling frameworks that combine multiple generation sources and storage technologies have attracted significant attention for the simultaneous optimization of multiple operational objectives [9], [10]. In such frameworks, BESS is commonly analyzed as a fast-response balancing resource; however, its economic effectiveness is highly sensitive to system sizing and operational strategies [11], [12]. In parallel, hydrogen has emerged as a flexible and clean energy vector. Within the scope of this paper, hydrogen-based generators are modeled as dispatchable generation units fueled by externally supplied hydrogen, without explicitly modeling the power-to-hydrogen (P₂H) conversion process. Nevertheless, a large portion of existing studies still focus on a single storage technology or capacity optimization problems, without clearly quantifying the trade-off between investment costs and the operational flexibility gained under controlled operating conditions.

To address these gaps, this study proposes a novel economic dispatch model for hybrid power systems with the following main objectives and contributions. First, a coordinated economic dispatch framework is developed that explicitly integrates three key components: a biomass power plant as the baseload generation source, hydrogen-based generators as flexible resources, and BESS, within a unified cost objective function. Second, a comprehensive cost formulation is constructed, incorporating biomass fuel costs, hydrogen procurement costs based on time-of-use (TOU) electricity pricing, and amortized BESS investment costs directly linked to its rated power and energy capacity. Third, the impacts of three different BESS sizing levels on total system operating cost and load-following flexibility are quantitatively analyzed through direct comparisons under identical generation configurations and load profiles. Fourth, an optimal storage configuration that balances economic efficiency and operational flexibility is identified, providing a practical reference for BESS capacity selection in hybrid power systems. The proposed model is solved using the Differential Evolution (DE) algorithm and validated on the standard IEEE 9-bus test system.

The results and analyses not only elucidate the fundamental trade-off between storage sizing and system performance, but also provide valuable practical insights for planners and operators in selecting appropriate storage capacities for hybrid power systems, based on a balanced consideration of cost constraints and operational flexibility requirements.

2. Research Methodology

2.1. Hybrid Power Systems Modeling

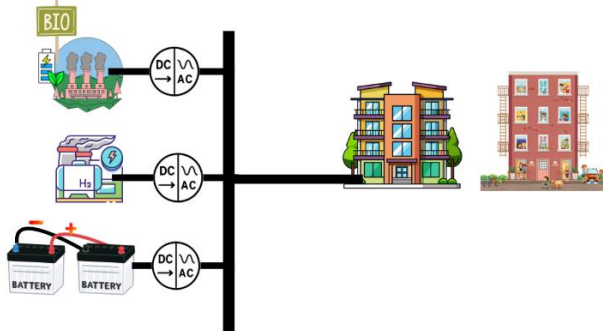


Figure 1. Hybrid power systems with BESS and Hydrogen Resources

A hybrid power system may consist of various generation sources combined with energy storage systems and load demands [13]. In this study, the proposed hybrid power system architecture is mapped onto the standard IEEE 9-bus test system to evaluate its operational performance and to validate the developed optimization framework. The relatively large generation capacities are a direct consequence of adopting this benchmark network, which is designed with a simulated peak load of approximately 700 MW. Therefore, the installed generation levels reflect the characteristics of the selected test system rather than representing a small residential-scale power system. In this context, the studied system refers to a coordinated operational framework integrating biomass generation, hydrogen-based energy resources, and a battery energy storage system (BESS), implemented on the benchmark platform to analyze economic–operational trade-offs within a sufficiently complex and nonlinear optimization environment. Owing to the scalability of the proposed formulation under proportional power adjustments, uniform down-scaling of generation and load would not alter the qualitative characteristics of the optimal solution or the observed economic trends.

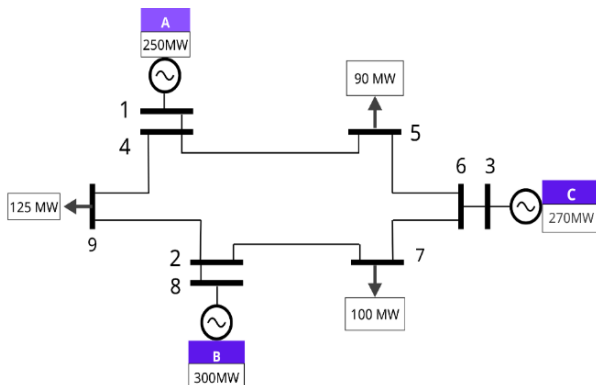


Figure 2. IEEE 9-bus test system

The IEEE 9-bus system comprises three generating units, three loads, and nine buses, and is widely employed in power system research to validate analysis and optimization methodologies. In this work, the technical parameters of the generating units, together with the quadratic fuel cost coefficients a , b , and c , are adopted from [14], thereby ensuring academic continuity with prior studies and enhancing the credibility of the developed economic operation model.

Table 1. Generation Data

Bus	1	2	3
MW Limit	250	300	270
MVAR Limit	± 300		

Table 2. Fuel cost coefficients of the system

Generator	A	B	C
a (\$/MW ² h)	0.1100	0.0850	0.1225
b (\$/MWh)	5.0	1.2	1.0
c (\$/h)	150	600	335

To represent daily demand variability, a 24-hour load profile is adopted, as illustrated in Figure 3. The profile captures hourly power demand variations and forms the basis of the economic dispatch problem with the participation of flexible resources such as hydrogen-based generators and BESS [15].

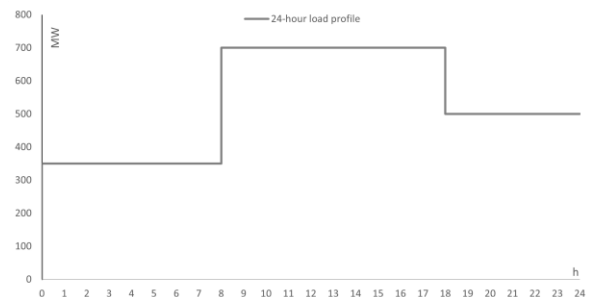


Figure 3. 24-hour load profile

The three generators of the IEEE 9-bus system are modeled as biomass-based power plants within the proposed hybrid power system architecture. Hydrogen-based generators and a BESS are additionally integrated to enhance dispatch flexibility and evaluate their economic contribution. To facilitate the integration of hydrogen-based generation while maintaining overall supply–demand balance, the capacity of Generation Unit A is adjusted to 150 MW. This modification preserves the total installed capacity structure while creating sufficient dispatch margin for hydrogen participation, enabling assessment of hydrogen as a supplementary low-carbon energy source.

The economic operation problem is formulated to minimize the total system operating cost over a 24-hour horizon, subject to power balance and operational constraints of all generation units. The optimization procedure is detailed in the following subsection.

2.2. Mathematical Modeling

2.2.1. System Cost Function Formulation

a. Biomass Power Plant Model

Based on previous studies [16], [17], the operating cost

of the biomass power plant is represented by a quadratic cost function with respect to the generated power, expressed as follows:

$$\sum_i^{n_G} C_{Bi} = \sum_i^{n_G} a_i P_{Bi}^2 + b_i P_{Bi} + c_i$$

Constraint Functions:

$$\sum_i^{n_G} P_i = P_D + P_L$$

$$P_{i\min} \leq P_i \leq P_{i\max}$$

where, $C_{Bi,t}$ denotes the operating cost of biomass unit i at time t ; $P_{Bi,t}$ is the output power of biomass unit i at time t ; a_i, b_i, c_i are the fuel cost coefficients of unit i ; P_i represents the power output of generator i ; P_L denotes the transmission line losses; P_D is the total system load demand; $P_{i\min}$ and $P_{i\max}$ are the minimum and maximum power outputs of generator i , respectively.

Under stable conditions, the typical composition of landfill gas (LFG) consists of approximately 55% CH₄, 40% CO₂, and 5% N₂ by volume, according to the EPA AP-42 documentation [18]. The presence of such a high CO₂ fraction not only lowers the calorific value but also deteriorates combustion kinetics. To address this issue, as suggested by the reviewer, the revised manuscript clarifies that hydrogen blending is essential to compensate for these limitations, thereby improving flame stability and enabling efficient operation of the proposed system.

b. Co-firing of hydrogen and biomass emissions using a gas turbine engine

In this study, a co-firing configuration of hydrogen and biomass exhaust gases is implemented using a gas turbine engine (GTE), where hydrogen is procured from the energy market and CH₄ is derived from biomass-related emissions. According to [19], the cost of hydrogen-based generation is formulated as follows:

$$F_H = \sum_{i=1}^T \sum_{i=1}^{N_h} \alpha_{H,t} H_{i,t}^\phi$$

where, F_H denotes the total cost of hydrogen generators over the scheduling horizon T ; T and N_h represent the time horizon (e.g., 24 h, 1 year, ...) and the number of hydrogen generators, respectively; $\alpha_{H,t}$ is the hydrogen price under the TOU tariff at time t ; and $H_{i,t}$ denotes the amount of hydrogen consumed at time t .

The TOU tariff is defined based on the study in [20] as follows:

Table 3. Time of use tariff at time t

Time Period (hours)	Time Frame	Electricity Price (\$/MW·h)
Peak	8:00–12:00, 17:00–21:00	120
Normal	13:00–17:00, 22:00–23:00	63
Off-peak	0:00–7:00	40

c. Integration of Battery Energy Storage Systems (BESS)

The integration of BESS into power systems provides long-term economic benefits through operating cost

reduction, load balancing, and increased utilization of renewable energy resources. To evaluate the investment effectiveness of BESS, the investment cost must be calculated based on the rated power and the required energy capacity. The investment cost formulation of BESS is expressed as follows [21]:

$$IC_{BESS} = PC_{BESS} \cdot P_{BESS}^{\max} + EC_{BESS} \cdot E_{BESS}^{\max}$$

where, PC_{BESS} and EC_{BESS} denote the investment costs of BESS rated power and energy capacity per MW and per MWh, respectively; and P_{BESS} and E_{BESS} represent the rated power and rated energy capacity of the BESS, respectively.

The BESS investment cost is determined based on its rated power and rated energy capacity, multiplied by the corresponding unit costs. The charging and discharging power of the BESS is constrained by its maximum rated power, which is associated with the optimal sizing configuration. The BESS operates as a load during charging and as a generator during discharging. Furthermore, it is assumed that the BESS power is considered negative during the charging mode and positive during the discharging mode. These operational constraints are expressed as follows:

$$+ P_{BESS}^{\min} \leq P_{BESS}(t) \leq P_{BESS}^{\max}$$

$$+ E_{BESS}^{\min} \leq E_{BESS}(t) \leq E_{BESS}^{\max}$$

$$+ E_{BESS}(t) = E_{BESS}(t-1) - P_{BESS}(t) \times \delta t$$

Economic Optimization Objective Function of the System:

$$\min \left(\sum_1^{n_G} C_{Bi} + \sum_1^{N_H} F_H + \sum IC_{BESS} \right)$$

2.2.2. Total Operating Cost of the System

$$F = \sum_i^{n_G} C_{Bi} + \sum_i^{n_H} F_H + \sum IC_{BESS} \\ = \left(\sum_i^{n_G} a_i P_{Bi}^2 + b_i P_{Bi} + c_i \right) + \left(\sum_{i=1}^T \sum_{i=1}^{N_h} \alpha_{H,t} H_{i,t}^\phi \right) \\ + \left(PC_{BESS} \cdot P_{BESS}^{\max} + EC_{BESS} \cdot E_{BESS}^{\max} \right)$$

2.3. Solution Algorithm (DE)

The proposed economic dispatch problem involves multi-period decision variables coupled through battery operational dynamics and time-varying hydrogen fuel costs under TOU pricing. The inter-temporal coupling is governed by the BESS charging and discharging power balance across consecutive time intervals, while respecting energy capacity and operational constraints. In addition to operational costs, the objective function incorporates amortized BESS investment costs associated with its rated power and energy capacity. This formulation results in a joint operation–sizing optimization framework, which significantly enlarges the search space and increases computational complexity. Although individual generation cost functions are quadratic, the coordinated 24-hour scheduling introduces nonlinear and inter-temporal

constraints due to the coupling between charging/discharging decisions and energy balance over time. To effectively handle this complex, nonconvex optimization structure, DE, a population-based and derivative-free algorithm with strong global exploration capability, is adopted [22].

In contrast, gradient-based methods such as Sequential Quadratic Programming (SQP) may converge to local optima in highly nonlinear search spaces. Deterministic solvers based on Mixed-Integer Linear Programming (MILP) typically require linearization of nonlinear components, which may reduce model fidelity. Furthermore, metaheuristic approaches such as Particle Swarm Optimization (PSO) can suffer from premature convergence in high-dimensional optimization problems.

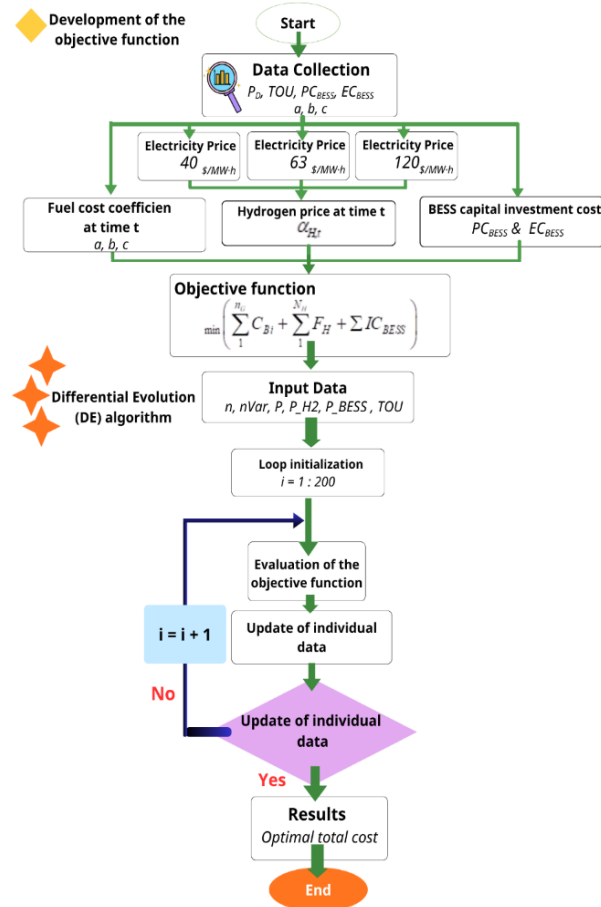


Figure 4. Flowchart of the proposed algorithm

2.4. Research Scenarios

To evaluate the impact of BESS sizing on the economic operation efficiency and operational flexibility of a hydrogen-integrated hybrid power system, this study develops three simulation scenarios based on the standard IEEE 9-bus system over a 24-hour operating horizon. All scenarios adopt the same generation system structure, consisting of three biomass power plants mapped from the generators of the IEEE 9-bus system, combined with hydrogen-based generators and a BESS.

The differences among the scenarios lie in the rated power and energy capacity of the BESS, which are

configured at three representative levels corresponding to different storage scales in the hybrid power system. Specifically, the first scenario (Case 1) considers a small-scale BESS with a rated power of 50 MW and an energy capacity of 100 MWh, representing localized support and short-term load balancing. The second scenario (Case 2) corresponds to a medium-scale BESS with a rated power of 100 MW and an energy capacity of 200 MWh, enabling deeper participation of the BESS in intra-day power dispatch. The third scenario (Case 3) examines a large-scale BESS with a rated power of 200 MW and an energy capacity of 600 MWh, representing a storage system capable of long-duration load support and significantly enhanced operational flexibility of the hybrid power system.

Across all three scenarios, system parameters - including biomass fuel cost coefficients, the 24-hour load profile, the hydrogen TOU tariff, and operational constraints - are kept identical to ensure fairness in comparison. The economic dispatch problem is solved using the DE algorithm with the objective of minimizing the total operating cost of the hybrid power system over the 24-hour period, including biomass fuel costs, hydrogen procurement costs, and amortized BESS investment costs. The comparative analysis of the scenario results enables a clear quantitative assessment of the relationship between BESS sizing, total system cost, and the economic operation performance of the hybrid power system.

3. Results and Discussion

3.1. Simulation Results

a. Case 1: P=50 MW, E=100 MWh

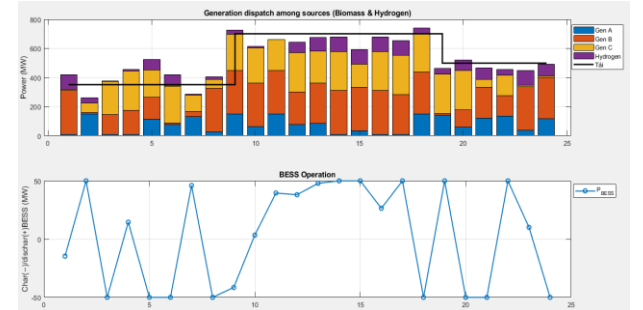


Figure 5. Results for the Small-Scale BESS Case

Case 1 (P = 50 MW, E = 100 MWh): The optimization results obtained using the DE algorithm indicate that the system achieves a minimum total operating cost of 88.81×10^6 USD, with a stable and well-behaved convergence trend across generations. Biomass-based units serve as baseload generators, ensuring reliable and continuous power supply. Hydrogen-based generation enhances operational flexibility during peak demand periods. Meanwhile, the small-scale BESS primarily provides short-term power balancing, mitigating load fluctuations, while its capability for long-duration energy shifting remains limited due to capacity constraints.

b. Case 2: P=100 MW, E=200 MWh

Case 2 (P = 100 MW, E = 200 MWh): The DE-based optimization converges to a total operating cost of 114.03

$\times 10^6$ USD, Biomass units continue to act as baseload sources, supplying the majority of demand. Hydrogen generators contribute to peak-load support and enhance dispatch flexibility. With the increased capacity, the BESS plays a more active role, providing both short-term balancing and partial energy shifting, thereby improving overall operational flexibility compared to the smaller BESS case.



Figure 6. Results for the Medium-Scale BESS Case

c. Case 3: P=200 MW, E=600 MWh

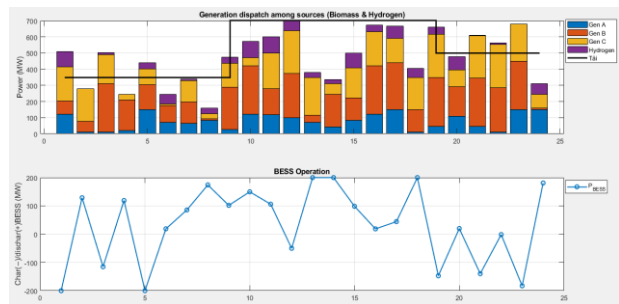


Figure 7. Results for the Large-Scale BESS Case

Case 3 (P = 200 MW, E = 600 MWh): The DE algorithm converges to a total operating cost of 126.37×10^6 USD, Biomass units remain the dominant baseload generators supplying the majority of demand. With the larger storage capacity, the BESS plays a more pronounced role, actively charging and discharging to perform both short-term balancing and energy shifting, while hydrogen generators further enhance dispatch flexibility during peak-load periods.

3.2. Cost Comparison among the Scenarios

Table 2 summarizes the total operating costs of the hybrid power system under three scenarios with different BESS sizes. The results indicate that the total operating cost increases as the BESS capacity is expanded, with Case 1 yielding the lowest cost and Case 3 exhibiting the highest cost. This trend demonstrates that increasing the energy storage capacity does not necessarily lead to improved economic efficiency of the hybrid power system.

Table 3. Total operating cost of the system

Case	BESS	Total Cost (USD)
1	Small	88.81×10^6
2	Medium	114.03×10^6
3	Large	126.37×10^6

In Case 1, the BESS mainly provides short-term power balancing support, while biomass plants and hydrogen-based sources undertake the primary energy supply

function, thereby maintaining a low overall operating cost. As the BESS capacity increases in Case 2, operational flexibility is improved; however, the additional investment and operating costs associated with the BESS lead to a moderate increase in the total system cost. In Case 3, although the large-scale BESS significantly enhances power regulation capability and reduces fluctuations of the main generation sources, the capital investment and storage-related losses constitute a substantial share of the objective function, resulting in a pronounced increase in total operating cost. However, under higher electricity price variability or increased renewable penetration, a larger BESS may become economically advantageous due to improved energy arbitrage and utilization of surplus generation. Lower battery investment costs would further enhance its economic viability.

These results indicate the existence of an optimal BESS size for the hybrid power system, at which the trade-off between operational flexibility and economic efficiency reaches a balanced optimum.

4. Conclusion

This study proposes an economic dispatch model for a hybrid power system that integrates biomass-based generation units, hydrogen-based generators, and a battery energy storage system within a coordinated framework. A mathematical optimization model is formulated with the objective of minimizing the total operating cost, including biomass fuel costs, hydrogen procurement costs under TOU pricing, and allocated BESS investment costs. The optimization problem is solved using the DE algorithm and validated on the standard IEEE 9-bus test system over a 24-hour scheduling horizon, considering three different BESS sizing scenarios.

The identification of the optimal configuration in this study is not based solely on a single cost indicator but is conducted through a multi-criteria techno-economic evaluation process. To determine the preferred option, three key criteria are defined and quantitatively assessed: (i) overall economic performance, (ii) the operational flexibility threshold, and (iii) system reliability. A configuration is considered optimal only when it simultaneously satisfies these technical criteria while maintaining an acceptable cost level. Accordingly, Scenario 1 is not identified as the optimal solution because it fails to meet the technical requirements in terms of flexibility and reliability, despite achieving the lowest total cost (88.81×10^6 USD). With a capacity of 50 MW / 100 MWh, the system is only capable of short-term load balancing and does not provide sufficient storage capacity to effectively implement energy-shifting strategies between low-price and high-price periods under the TOU tariff (40–120 USD/MWh). In contrast, Scenario 2 is selected as the preferred configuration because it achieves a “balanced optimum” between cost and technical performance. With a capacity of 100 MW / 200 MWh, the BESS can participate more actively in energy dispatch, significantly improving operational flexibility and reserve capability, while the total cost increases by only

approximately 28.4% compared with Scenario 1. Meanwhile, Scenario 3, although further enhancing operational flexibility, leads to a substantial increase in total cost to 126.37×10^6 USD due to higher investment costs and additional storage losses, thereby reducing the overall economic efficiency. Therefore, Scenario 2 is identified as the optimal configuration because it simultaneously satisfies both the technical and economic criteria of the system.

Future research may extend the proposed model by incorporating uncertainty modeling, battery degradation effects, and the integration of additional renewable energy sources, thereby further enhancing the practical applicability and robustness of the framework.

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