Techno-Economic Evaluation of PV-Hydrogen Systems with BESS and Heat Pumps

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Introduction

Photovoltaic hydrogen production is widely used for renewable energy storage, but stable output often demands oversized PV capacity, causing energy waste[1]. Battery storage systems (BESS) help but face cost and efficiency limits [2]. Heat pumps, as flexible long-term storage, offer added benefits when optimized to local conditions[3].

This study explores integrating heat pumps with BESS in PV-hydrogen systems and evaluates economic performance across locations (Guiyang, Shanghai, Xinjiang), tariffs (flat vs. TOU), and operation modes (off-grid, nighttime grid, full grid)

System Structure and Simulation Scenarios

The integrated PV-Hydrogen-Heat Pump (PV-HP-Hydrogen) system includes a PV array with controller, battery (BESS), PEM electrolyzer with heat exchangers, and a heat pump (HP) connected via a DC bus. A closed-loop thermal cycle transfers waste heat from the electrolyzer to the HP.

This study simulates 36 configurations across three Chinese cities (Guiyang, Shanghai, Xinjiang) with varying solar irradiance. Two tariff structures (Flat Rate and Time-of-Use) and three operation modes (Off-grid, Night Grid-Assisted, Full Grid-Connected) are analyzed. The TOU pricing follows Shanghai's seasonal rates, with higher peak prices in summer.

Control strategies manage energy dispatch while maintaining battery SOC between 35–90%. The system evaluates how geography, pricing, and configuration affect hydrogen cost and energy utilization efficiency.

Mathematical Modeling

The system model comprises photovoltaic (PV) generation, a proton exchange membrane (PEM) electrolyzer, battery energy storage (BESS), and a heat pump (HP). All models are implemented in MATLAB/Simulink with hourly simulation resolution.

PV model:Uses the Incremental Conductance (IC) method for MPPT; irradiance and temperature drive power output.

PEM Electrolyzer Model: Cell voltage includes reversible, activation, ohmic, and concentration overpotentials; hydrogen output is dynamically calculated.

Battery Model: SOC-based control governs charge/discharge; battery degradation is not considered.

Heat Pump Model:The HP is modeled with a constant coefficient of performance (COP = 3.5), converting surplus PV power into thermal energy via the PEM cooling water loop. The refrigerant evaporation and condensation temperatures are set at 16 °C and 65 °C, respectively. Heat exchange rates are adjusted by dynamically regulating the water-side flow rates of the evaporator and condenser. The model assumes a quasi-linear relationship between flow rate and heat exchange strength, enabling fast thermal response under variable loading.

Eonomic Inidcators

The economic evaluation includes three key indicators: Levelized Cost of Hydrogen (LCOH), Net Present Value (NPV), and Dynamic Payback Period.

LCOH (Levelized Cost of Hydrogen):Average cost per kg of hydrogen produced over the system's lifetime, considering capital cost, O&M cost, and annual hydrogen yield. A lower LCOH indicates better cost-effectiveness.

NPV (Net Present Value):Net benefit from all discounted cash flows, including hydrogen and heat sales, minus total investment. A positive NPV implies long-term profitability.

Dynamic Payback Period:The earliest year when cumulative discounted cash flow offsets initial investment.

The heat pump's benefit is calculated as the avoided cost of surplus PV electricity, benchmarked against the levelized PV generation cost. This includes both upfront investment and ongoing maintenance.Additionally, the inclusion of heat pump enhances energy self-utilization and provides an auxiliary revenue stream from thermal energy recovery.All indicators are applied to 36 system configurations across different component sizes, regional solar resources (Guiyang, Shanghai, Hami), and electricity pricing strategies (flat vs. TOU)

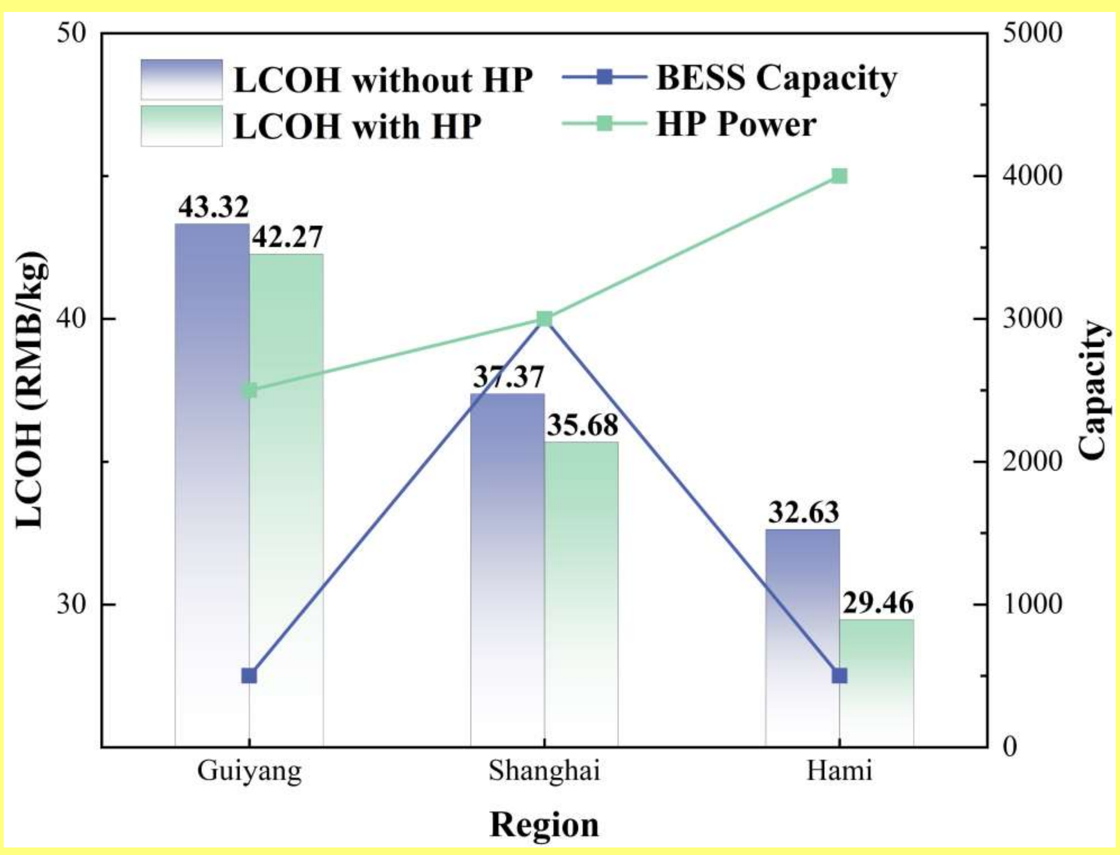

Fig. 1. Best LCOH and Optimal Configuration under 51 PV Capacity (Flat-Rate Pricing) before and after HP Integration.

Results and Discussion

LCOH UNDER SYSTEM CONFIGURATION

Fig. 1 compares optimal LCOH in Guiyang, Shanghai, and Hami under flat-rate pricing, before and after heat pump (HP) integration. LCOH reductions of 2.42%, 4.52%, and 9.72% were observed, with optimal setups varying by region. Guiyang favored smaller BESS and HP due to limited PV. Hami achieved the best performance with minimal BESS and large HP, leveraging abundant solar. Shanghai required larger BESS to smooth fluctuations. Overall, HP integration reduces LCOH across regions, but optimal component sizing depends on local solar conditions.

ECONOMICS BY OPERATION MODE

Fig. 2 compares LCOH and NPV for Guiyang, Shanghai, and Hami under three operation modes: off-grid, night grid-assisted, and full grid-integrated. In Guiyang, LCOH dropped from 42.27 to 35.00 and 33.31 RMB/kg, but only Full mode yielded a positive NPV. Shanghai also favored Full mode, with the lowest LCOH (31.22 RMB/kg) and NPV of 11,095 RMB. In contrast, Hami achieved best results under Night mode, with the lowest LCOH (22.79 RMB/kg) and highest NPV (29,636 RMB). These results show that Full mode is more effective in low-irradiation regions by increasing grid utilization, while Night mode better suits high-sunlight areas by making efficient use of surplus PV during off-peak hours. Tailoring the operation mode to regional solar conditions is crucial for maximizing hydrogen system profitability.

PAYBACK PERIOD DISTRIBUTION

Dynamic payback periods were evaluated across operation modes, tariffs, and PV ratios in Guiyang, Shanghai, and Hami. Guiyang achieved 10–12 years only under Night/TOU with high PV ratios. Hami reached payback in nearly all cases, with 7 years as best under Night/TOU. Shanghai showed 9–11 years under TOU and larger PV setups. Off-grid mode generally failed to reach recovery. TOU pricing outperformed flat-rate in all regions, especially where irradiation is lower. These results confirm the importance of adapting system configuration and pricing policy to regional solar conditions for economic viability.

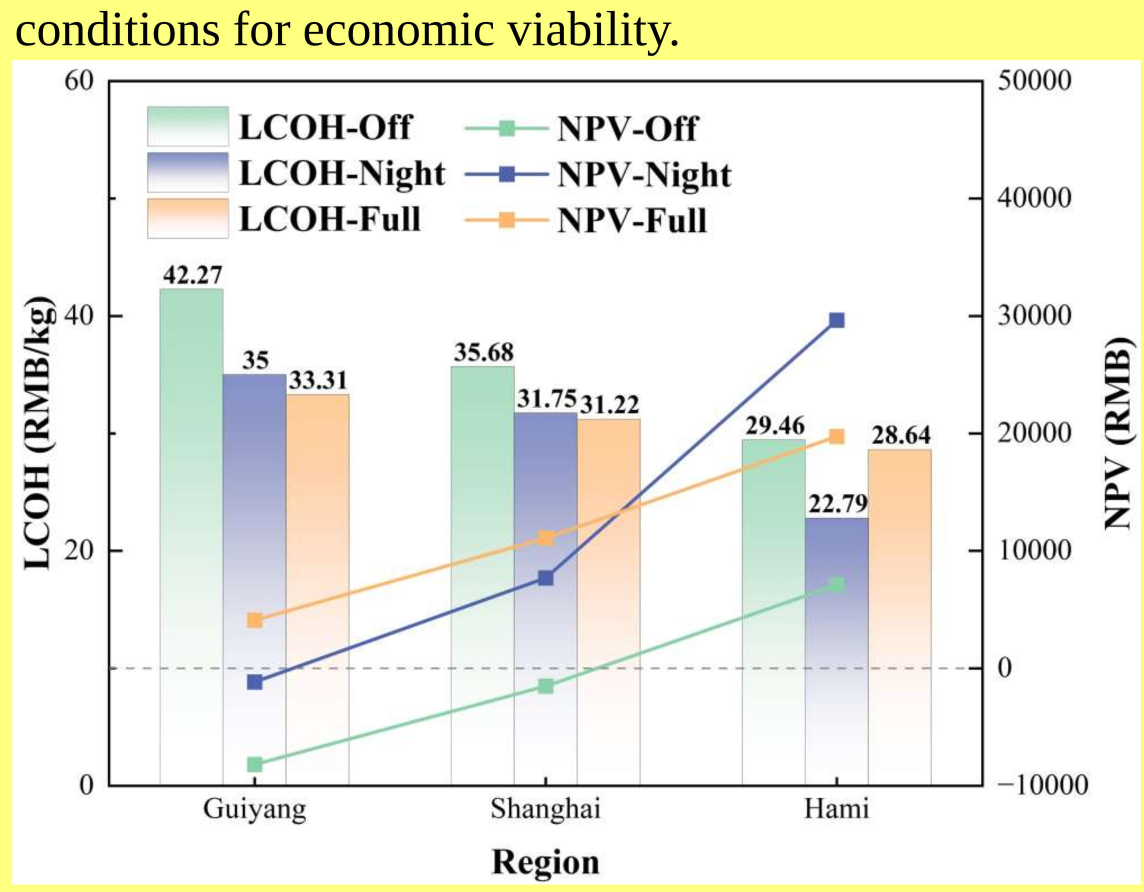

Fig. 2. LCOH and NPV Comparison under Off-Grid, Nighttime Grid-Assisted, and Full Grid-Integrated Modes (Flat-Rate Pricing)

PV ratio	Mode	Guiyang FR	Guiyang TOU	Shanghai FR	Shanghai TOU	Hami FR	Hami TOU
3:1	Off	>15	>15	>15	>15	13	13
	Night	>15	11	14	9	9	7
	Full	15	12	12	10	9	8
5:1	Off	>15	>15	>15	>15	12	12
	Night	>15	10	12	8	9	7
	Full	13	11	11	9	9	8
7:1	Off	>15	>15	>15	>15	12	12
	Night	15	10	12	9	10	8
	Full	13	10	11	9	10	8

years

Fig. 3. Payback Periods across Operation Modes, Tariff Strategies, and PV Capacities in Guiyang, Shanghai, and Hami.

Conclusions

Heat pump integration reduces LCOH across all regions, with optimal configurations varying by solar availability.Full grid mode improves economics in low-irradiation areas, while night-assisted mode performs best under high PV surplus.TOU pricing consistently enhances economic returns compared to flat-rate.Dynamic payback analysis confirms that combining appropriate PV sizing, tariff strategy, and operation mode is key to achieving viable and cost-effective hydrogen production..

References

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