

# **Baseline-Constrained Demand Response and Expansion Planning of Hybrid Battery–Hydrogen Storage in PV- Dominated Power Systems**

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## **Abstract**

High photovoltaic (PV) penetration creates midday surplus generation, steep evening ramps, and persistent renewable curtailment, increasing the need for coordinated short- and long-duration flexibility resources. This paper proposes a two-stage mixed-integer planning framework for battery energy storage systems (BESS) and hydrogen energy systems (HES) in a PV-dominated transmission network. In the first stage, the hydrogen subsystem is optimized independently to determine the baseline electrolyzer schedule and the associated hydrogen infrastructure required to satisfy hydrogen demand. In the second stage, the power system and hydrogen system are co-optimized. Demand-response compensation is applied only to downward deviations from the baseline electrolyzer schedule, while shifted load, newly installed electrolyzer capacity, newly added hydrogen storage, and fuel-cell operation are not compensated as demand-response resources. The model includes DC network constraints, PV generation, battery storage, hydrogen transportation, and degradation of batteries, electrolyzers, and fuel cells over a 25-year planning horizon represented by four seasonal days. The framework is applied to the IEEE 24-bus system with six 400 MW PV plants. In the degradation-aware setting, the HES-only flexibility case reduces total cost by 10.4% and PV curtailment by 65.0% relative to the base case but increases emissions by 27.0%. The coordinated hybrid BESS-HES case provides the best

overall performance, reducing total cost by 15.7% and PV curtailment by 90.5%, while limiting the emissions increase to 6.3% relative to the base case and lowering emissions by 16.3% relative to the HES-only case. The results also show that degradation shifts the optimal battery design toward lower power and higher energy capacity and reduces electrolyzer degradation cost by 47.3% in the hybrid case compared with the HES-only case. These findings demonstrate that baseline-constrained hydrogen demand response provides a more realistic basis for long-term PV-dominated grid planning than treating all hydrogen flexibility as uniformly compensable.

## **Keywords**

Hydrogen energy systems, demand response, battery energy storage, power system planning, process optimization.

## **1. Introduction**

Power systems with high photovoltaic (PV) penetration require flexibility not only to absorb midday surplus generation, but also to manage rapid evening ramps, congestion, reserve needs, and renewable curtailment. As conventional synchronous generation is displaced by variable renewable resources, the central planning challenge shifts from supplying energy alone to coordinating energy, flexibility, and infrastructure over long horizons (Xu et al., 2024), (Elsir et al., 2022), (Gabrielli et al., 2018), (Elsir and Al-Awami, 2020), (Mohandes et al., 2019). This challenge becomes more pronounced when flexibility must be delivered under transmission constraints and when different storage technologies interact with both electricity and hydrogen demand.

Battery energy storage systems (BESS) and hydrogen energy systems (HES) are increasingly recognized as complementary flexibility options. Batteries are well suited for fast-response, short-duration balancing, PV smoothing, and intra-day arbitrage, whereas hydrogen is more suitable for long-duration shifting, seasonal balancing, and geographically distributed energy transfer (Elsir et al., 2023), (Reuß et al., 2017), (Elsir et al., 2025), (Demir and Dincer, 2018), (Bockris, 2013), (Elsir et al., 2024). In an integrated setting, batteries can address short-cycle variability while hydrogen systems can absorb sustained PV surplus, store it over longer periods, and release it later through fuel cells or other downstream uses. This complementarity makes coordinated battery–hydrogen planning particularly relevant for PV-dominated systems.

However, integrating hydrogen flexibility into power-system planning raises an important modeling problem. In practice, hydrogen demand is often served by a pre-existing production schedule that reflects the technical and economic requirements of the hydrogen subsystem itself. When this schedule is exposed to the power system, the planner may choose to reduce or shift baseline electrolyzer consumption to support grid operation. At the same time, the planner may also invest in new electrolyzer units, new hydrogen storage, and fuel cells to create additional flexibility. If all electrolyzer consumption is treated uniformly, then demand-response compensation can be incorrectly extended to newly installed hydrogen infrastructure, creating distorted incentives and overstating the economic value of hydrogen flexibility. A realistic planning model should therefore distinguish between inherited electrolyzer commitments and newly installed hydrogen assets.

A second challenge concerns the scope of integrated planning. Hydrogen production, storage, transport, and utilization interact across different spatial and temporal layers. These interactions are difficult to represent in long-term optimization models if detailed electrochemical or process-level formulations are used. The planning model must therefore remain sufficiently simple to be computationally tractable, while still capturing the dominant techno-economic features of electrolysis, hydrogen storage, fuel-cell conversion, transportation, and their interaction with the transmission grid (Meng et al., 2023), (Elsir and Al-Sumaiti, 2025), (Oyewole et al., 2024; Pan et al., 2020), (Samir et al., 2026). The same requirement applies to batteries, whose operational value depends on endogenous sizing and repeated cycling over the planning horizon.

A third challenge is lifecycle realism. Batteries, electrolyzers, and fuel cells all degrade with use. Throughput, switching, and repeated cycling affect both feasible operation and long-term economics (Ahmadian et al., 2017), (Wu et al., 2008; Zerrougui et al., 2025), (Son et al., 2021). Ignoring these effects can bias the comparison between

short-duration and long-duration flexibility options, especially in systems where high PV penetration causes frequent cycling and repeated schedule adjustments. A coordinated model should therefore account for degradation consistently across the active technologies.

These considerations motivate a planning framework that answers three related problem statements. First, how should a PV-dominated transmission system coordinate battery and hydrogen flexibility when hydrogen production is anchored by a baseline standalone schedule? Second, how can demand-response compensation be restricted to genuine deviations from that baseline rather than being applied to all hydrogen assets indiscriminately? Third, how does this selective treatment affect the optimal expansion of electrolyzers, hydrogen storage, fuel cells, and batteries under network, transport, and degradation constraints? To address these questions, this study develops a two-stage optimization framework in which the hydrogen subsystem is first optimized independently to determine a baseline electrolyzer schedule, after which the power system and hydrogen system are co-optimized with selective demand-response compensation.

### **1.1 Objectives**

The objectives of this study are fourfold. First, it aims to develop a tractable transmission-level planning model that coordinates PV generation, battery storage, electrolyzers, hydrogen storage, hydrogen transportation, and fuel cells within a unified optimization framework. Second, it seeks to represent hydrogen demand response in a selective manner by compensating only downward deviations from the baseline electrolyzer schedule obtained from a standalone hydrogen optimization, while leaving shifted load and newly added hydrogen capacities uncompensated. Third, it aims to determine the optimal mix of battery and hydrogen flexibility resources by treating additional electrolyzer capacity, hydrogen-storage capacity, and fuel-cell investment as endogenous decision variables. Fourth, it evaluates how this formulation affects total cost, curtailment, emissions, and infrastructure expansion in a PV dominated IEEE 24-bus system over a long-term planning horizon.

## **2. Literature Review**

The literature on hybrid battery–hydrogen systems can be grouped into several closely related streams. A first stream focuses on operational coordination and energy management. Rule-based, metaheuristic, and supervisory control studies consistently show that batteries are better suited for short-cycle balancing, while hydrogen becomes attractive for sustained surplus absorption and long-duration storage (Kafetzis et al., 2020), (Zhang et al., 2022), (Qamar et al., 2024), (Le et al., 2023). These studies establish the physical complementarity between batteries and hydrogen, but they usually operate over short horizons, assume fixed capacities, and do not address transmission-level infrastructure planning.

A second stream emphasizes uncertainty-aware scheduling, market participation, and multi-objective operation. Stochastic and multi-objective formulations have shown that hybrid storage can reduce operating cost, improve renewable utilization, and support flexible operation under uncertain conditions (Aaslid et al., 2022), (Eghbali et al., 2022), (Karimi, 2024), (Cicek, 2023), (Mahdavi et al., 2026), (Habibifar et al., 2025). This line of work highlights the operational value of combining batteries and hydrogen, yet it remains largely focused on short-term scheduling and does not fully address long-horizon investment decisions, network-wide infrastructure expansion, or the separation between inherited and newly installed hydrogen flexibility.

A third stream studies detailed hydrogen-system design, component modeling, and hydrogen-centered technoeconomics. Electrolyzer and fuel-cell representations have been refined substantially in recent years, and hydrogen storage and transport alternatives have been analyzed in terms of efficiency, cost, and deployment pathways (Makhsoos et al., 2025), (Meng et al., 2023), (Oyewole et al., 2024), (Samir et al., 2026). These studies are valuable for characterizing hydrogen technologies, but many remain either process-oriented or site-specific, and therefore do not directly resolve how hydrogen should be coordinated with battery flexibility inside a network-constrained power system.

A fourth stream addresses degradation and lifecycle performance. The literature shows that batteries, electrolyzers, and fuel cells are all sensitive to throughput, switching, and operating range, and that ignoring degradation can materially alter dispatch and investment conclusions (Ahmadian et al., 2017), (Son et al., 2021), (Abdalla et al., 2025), (Wu et al., 2008), (Zerrougui et al., 2025), (Yang and Lee, 2026), (Ahmadi et al., 2022), (Shi et al., 2025). Existing

studies provide important degradation insights, but degradation is often modeled for only one technology, applied in short-term control settings, or excluded from transmission-level co-planning. As a result, the relative economic roles of battery and hydrogen flexibility are not always compared on a consistent lifecycle basis.

A fifth stream moves closer to integrated planning by combining hybrid storage, optimization, and larger-scale system representation. Recent studies have considered microgrids, industrial hydrogen hubs, energy hubs, and off grid systems with endogenous sizing of batteries and hydrogen components (Rozzi et al., 2025), (Rezaei and Gray, 2025), (Kalhor et al., 2026). These contributions improve the understanding of investment trade-offs between electricity storage and hydrogen storage, but they typically remain limited in at least one of four dimensions: transmission-network representation, hydrogen transportation, consistent multi-technology degradation, or the economic interpretation of hydrogen demand response.

Across these streams, one modeling gap remains particularly important for coordinated planning. The existing literature generally treats electrolyzer flexibility as a single undifferentiated resource. In practice, however, a portion of electrolyzer demand may correspond to an inherited hydrogen-production schedule that is already required to satisfy hydrogen demand, while another portion may arise from newly installed assets chosen by the power-system planner. If these two components are not separated, demand-response compensation can be assigned too broadly and can unintentionally reward new hydrogen investments as if they were contracted flexibility. The literature also provides limited treatment of planner-owned fuel-cell flexibility under this selective compensation logic.

Accordingly, there is a need for a transmission-level planning model that simultaneously: represents PV-driven flexibility needs, coordinates batteries and hydrogen as complementary resources, captures hydrogen transportation and storage expansion, accounts for degradation consistently, and distinguishes between baseline electrolyzer commitments and newly added hydrogen capacity. The present study addresses this need by introducing a two-stage framework in which the hydrogen subsystem first determines a baseline electrolyzer schedule, after which the coordinated model allows selective schedule adjustment and endogenous hydrogen expansion under network and degradation constraints.

### 3. Model Formulation

A two-stage mixed-integer framework is used to coordinate hydrogen and battery flexibility in a PV-dominated transmission grid. The first stage solves the hydrogen subsystem independently and provides a baseline electrolyzer schedule together with the corresponding baseline electrolyzer and hydrogen-storage capacities. The second stage co-optimizes the power system and the hydrogen system. In this coordinated stage, compensated demand response is restricted to downward deviations from the baseline electrolyzer schedule, while newly installed electrolyzer capacity and newly added hydrogen-storage capacity are treated as endogenous expansion decisions without demand-response compensation.

#### 3.1 Baseline decomposition and selective demand response

The total electrolyzer and hydrogen-storage capacities are decomposed into baseline and additional components as:

$$N_e^{\text{elz}} = N_e^{\text{elz},0} + N_e^{\text{elz},+}, \quad R_e^g = R_e^{g,0} + R_e^{g,+}, \quad R_k^d = R_k^{d,0} + R_k^{d,+}. \quad (1)$$

The baseline electrolyzer schedule is adjusted through compensated reduction and uncompensated shifted load, while the total coordinated electrolyzer power includes an additional block associated with new electrolyzer investment:

$$P_{s,e,t}^{\text{elz,B}} = P_{s,e,t}^{\text{elz},0} - L_{s,e,t}^{\text{elz,red}} + L_{s,e,t}^{\text{elz,sh}}, \quad (2)$$

$$P_{s,e,t}^{\text{elz}} = P_{s,e,t}^{\text{elz,B}} + P_{s,e,t}^{\text{elz,N}}, \quad (3)$$

$$C_{s,e,t}^{\text{DR,elz}} = c_e^{\text{elz}} L_{s,e,t}^{\text{elz,red}}, \quad (4)$$

$$C_{s,e,t}^{\text{sh,elz}} = 0. \quad (5)$$

Equations (2)-(5) define the core economic distinction of the model: only reductions from the inherited electrolyzer schedule are compensated, whereas the shifted portion is not compensated as in Eq. (5), and any newly installed electrolyzer capacity contained in  $P_{s,e,t}^{\text{elz,N}}$  remains outside the DR payment mechanism.

### 3.2 Electrolyzer, hydrogen, and fuel-cell operation

The baseline and new electrolyzer blocks obey the same physical operating logic. For  $q \in \{B, N\}$ , the operating power is bounded by the production, standby, and idle states as:

$$P_e^{\text{elz}} L_{s,e,t}^q + P_e^{\text{elz, stb}} St_{s,e,t}^q \leq P_{s,e,t}^{\text{elz,q}} \leq \bar{P}_e^{\text{elz}} L_{s,e,t}^q + P_e^{\text{elz, stb}} St_{s,e,t}^q, \quad (6)$$

$$-P_e^{\text{RD, elz}} L_{s,e,t}^q \leq P_{s,e,t}^{\text{elz,q}} - P_{s,e,t-1}^{\text{elz,q}} \leq P_e^{\text{RU, elz}} L_{s,e,t}^q, \quad (7)$$

$$L_{s,e,t}^q + St_{s,e,t}^q + Id_{s,e,t}^q = 1, \quad (8)$$

$$0 \leq \bar{P}_e^{\text{elz}} N_e^{\text{elz,+}}, \quad 0 \leq P_{s,e,t}^{\text{elz,B}} \leq \bar{P}_e^{\text{elz}} N_e^{\text{elz,0}}. \quad (9)$$

and hydrogen production is linked to total electrolyzer power by:

$$H_{s,e,t}^{\text{elz}} = \eta_e^{\text{elz}} C F_e^{\text{elz}} P_{s,e,t}^{\text{elz}}. \quad (10)$$

Hydrogen is loaded into the carrier, stored, transported, and released according to:

$$H_{s,e,t}^{\text{LOHC}} = \eta_e^+ \xi_e H_{s,e,t}^{\text{elz}}, \quad P_{s,e,t}^{\text{LOHC}} = \gamma_e^+ H_{s,e,t}^{\text{elz}}, \quad (11)$$

$$S_{1,e,1}^g = \rho_e^g R_e^g, \quad S_{s,e,1}^g = S_{s-1,e,T}^g, \quad (12)$$

$$S_{s,e,t}^g = S_{s,e,t-1}^g + H_{s,e,t}^{\text{LOHC}} - H_{s,e,t}^{\text{toHT}}, \quad (13)$$

$$S_{1,k,1}^d = \rho_k^d R_k^d, \quad S_{s,k,1}^d = S_{s-1,k,T}^d, \quad (14)$$

$$S_{s,k,t}^d = S_{s,k,t-1}^d + \sum_r H_{s,k,r,t}^{\text{imp}} + H_{s,k,t}^{\text{rel}} - H_{s,k,t}^{\text{dem}} - \sum_{f \in \mathcal{F}(k)} H_{s,f,t}^{\text{fc}}, \quad (15)$$

$$\sum_i H_{s,i,r,t}^{\text{exp}} \leq \bar{H}_r^{\text{exp}} \sum_{(i,j) \in \mathcal{A}} x_{s,i,j,r,t}, \quad (16)$$

$$\sum_j H_{s,j,r,t}^{\text{imp}} \leq \bar{H}_r^{\text{imp}} \sum_{(i,j) \in \mathcal{A}} x_{s,i,j,r,t}, \quad \sum_i H_{s,i,r,t}^{\text{exp}} = \sum_j H_{s,j,r,t}^{\text{imp}} \quad (17)$$

Fuel cells are modeled as endogenous planner-owned assets:

$$H_{s,f,t}^{\text{fc}} = \kappa_f^{\text{fc}} P_{s,f,t}^{\text{fc}}, \quad (18)$$

$$P_f^{\text{fc}} L_{s,f,t}^{\text{fc}} + P_f^{\text{fc,0}} St_{s,f,t}^{\text{fc}} \leq P_{s,f,t}^{\text{fc}} \leq \bar{P}_f^{\text{fc}} L_{s,f,t}^{\text{fc}} + P_f^{\text{fc,0}} St_{s,f,t}^{\text{fc}}, \quad (19)$$

$$-P_f^{\text{RD, fc}} L_{s,f,t}^{\text{fc}} \leq P_{s,f,t}^{\text{fc}} - P_{s,f,t-1}^{\text{fc}} \leq P_f^{\text{RU, fc}} L_{s,f,t}^{\text{fc}}, \quad (20)$$

$$L_{s,f,t}^{\text{fc}} + St_{s,f,t}^{\text{fc}} + Id_{s,f,t}^{\text{fc}} = 1. \quad (21)$$

Equations (6)-(21) describe the physical operation of the hydrogen subsystem. The electrolyzer equations apply equally to the inherited and added blocks, the storage equations capture generation-side and demand-side hydrogen inventories over representative seasons and hours, and the transport equations enforce truck-capacity and mass-balance consistency. Standard arc-feasibility and MTZ subtour-elimination constraints are also used in the routing subproblem. Fuel cells supply electricity from stored hydrogen but, as shown in Eq. (21), they are not treated as demand-response compensated resources.

### 3.3 Battery storage, PV generation, and network constraints

Battery storage is represented by a standard state-of-charge recursion:

$$SOC_{s,m,t+1} = SOC_{s,m,t} + \eta_m^{\text{ch}} P_{s,m,t}^{\text{ch}} - \frac{P_{s,m,t}^{\text{dis}}}{\eta_m^{\text{dis}}}, \quad (22)$$

$$0 \leq P_{s,m,t}^{\text{ch}}, \quad P_{s,m,t}^{\text{dis}} \leq \bar{P}_m^b, \quad 0 \leq SOC_{s,m,t} \leq \bar{E}_m^b, \quad (23)$$

$$\sum_{s,t} P_{s,m,t}^{\text{ch}} = \sum_{s,t} P_{s,m,t}^{\text{dis}}. \quad (24)$$

Photovoltaic generation is bounded by seasonal availability factors,

$$0 \leq P_{s,v,t}^{\text{pv}} \leq a_{s,v,t}^{\text{pv}} \bar{P}_v^{\text{pv}}, \quad P_{s,v,t}^{\text{pv, curt}} = a_{s,v,t}^{\text{pv}} \bar{P}_v^{\text{pv}} - P_{s,v,t}^{\text{pv}}. \quad (25)$$

and the transmission network is represented by a DC power-flow approximation,

$$P_{s,bn,t} = B_{bn}(\delta_{s,b,t} - \delta_{n,t}), \quad -\bar{P}_{bn} \leq P_{s,bn,t} \leq \bar{P}_{bn}. \quad (26)$$

The nodal balance is enforced by:

$$\sum_{g \in \mathcal{G}(b)} P_{s,g,t}^{\text{th}} + \sum_{c \in \mathcal{C}(b)} P_{s,c,t}^{\text{cc, net}} + \sum_{v \in \mathcal{V}(b)} P_{s,v,t}^{\text{pv}} + \sum_{f \in \mathcal{F}(k)} H_{s,f,t}^{\text{fc}} + \sum_{m \in \mathcal{M}(b)} (P_{s,m,t}^{\text{dis}} - P_{s,m,t}^{\text{ch}}) + L_{s,b,t}^{\text{sh}} - D_{s,b,t} - \sum_{e \in \mathcal{E}(b)} P_{s,e,t}^{\text{elz}} - \sum_{e \in \mathcal{E}(b)} P_{s,e,t}^{\text{LOHC}} \sum_{k \in \mathcal{K}(b)} P_{s,k,t}^{\text{deh}} = \sum_{n \in \mathcal{N}(b)} P_{s,bn,t}. \quad (27)$$

and spinning reserve adequacy is imposed as:

$$T_{s,t}^{\text{SR}} \geq \rho \sum_b D_{s,b,t}. \quad (28)$$

Equations (29)-(31) couple the electrical system with the battery and hydrogen subsystems. Battery charging and discharging, fuel-cell injections, electrolyzer power consumption, LOHC conversion loads, and PV curtailment all enter the nodal balance, allowing the optimization to determine how short-duration and long-duration flexibility reshape the net load and the use of the transmission network.

### 3.4 Degradation and objective function

To preserve tractability, degradation of electrolyzers, fuel cells, and batteries is represented through linear throughput- and cycle-based terms:

$$Q^u = \sum_{s,t} q_{s,t}^u, \quad \chi^u = 1 - a^u Q^u - \phi^u, \quad (29)$$

$$C^{\text{deg},u} = c_{\text{thru}}^u Q^u + c_{\text{start}}^u \sum^u + c_{\text{cycle}}^u \mathcal{E}^u, \quad C^{\text{deg}} = \sum_{u \in \{\text{elz}, \text{fc}, \text{b}\}} C^{\text{deg},u}. \quad (30)$$

The total system cost is minimized as:

$$\min C^{\text{tot}} = C^{\text{eng}} + C^{\text{SR}} + C^{\text{CO}_2} + C^{\text{HT}} + C^{\text{cap}} + C^{\text{deg}} + \sum_{s,e,t} C_{s,e,t}^{\text{DR,elz}} \quad (31)$$

$$+ VOLL \sum_{s,b,t} I_{s,b,t}^{\text{sh}} + c^{\text{curt}} \sum_{s,v,t} p_{s,v,t}^{\text{pv,curt}}.$$

Equations (29)-(31) collect the planning objective. The total cost includes generation, reserve procurement, emissions, hydrogen transportation, capital expenditures, degradation, compensated demand response, load shedding, and PV curtailment. The DR term includes only baseline electrolyzer adjustments and battery DR; there is no payment associated with newly added electrolyzer capacity, additional hydrogen storage, or fuel-cell operation.

## 4. Simulation Setup

The model is tested on the IEEE 24-bus Reliability Test System (Ordoudis et al., 2016), which provides the transmission network, thermal-generation data, and line parameters. The renewable supply is represented by photovoltaic generation. Six PV plants of 400 MW each are connected to six buses, producing the midday surplus and evening ramping conditions that motivate the use of battery and hydrogen flexibility. The hydrogen subsystem contains six production sites, 25 distributed demand nodes, generation-side hydrogen storage, demand-side hydrogen storage, and truck-based hydrogen transportation. Battery storage is allowed at 17 candidate buses, while fuel cells, new electrolyzer capacity, and new hydrogen-storage capacities are optimized systematically. Four representative seasonal days are used to approximate the 25-year planning horizon: winter, spring, summer, and autumn, each represented by 24 hourly periods and weighted by the number of days in the corresponding season. The input data therefore consists of hourly electric load, hourly hydrogen demand, and hourly PV availability for each representative season (see Figure 1). This time reduction preserves the dominant operating conditions that drive PV curtailment, electrolyzer rescheduling, storage cycling, hydrogen transport utilization, and fuel-cell dispatch while keeping the mixed-integer model computationally tractable.

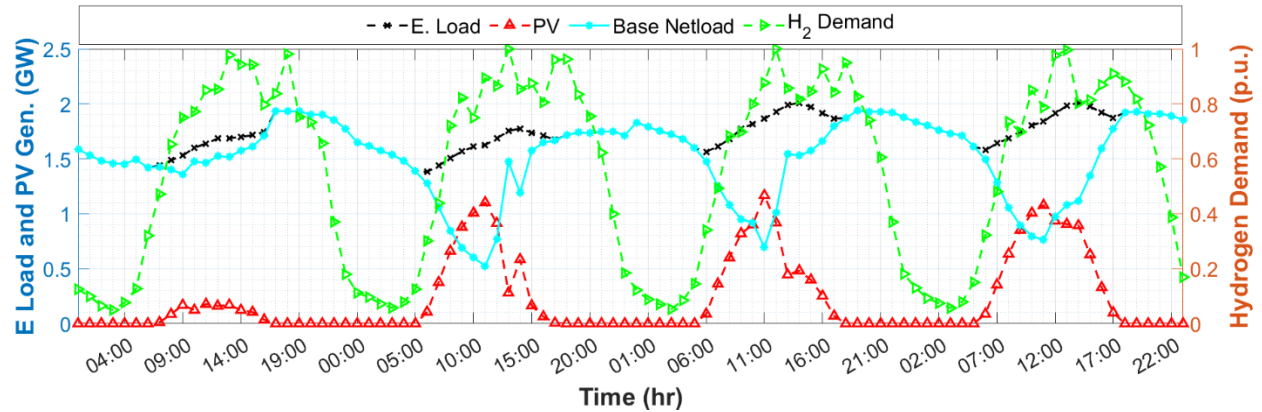


Figure 1. Representative seasonal input profiles used in the optimization. The figure shows the hourly electric load, PV generation availability, baseline net load, and hydrogen demand used for the four representative seasonal days.

The main pattern to note is the midday PV surplus followed by evening net-load recovery, which motivates the coordinated use of battery and hydrogen flexibility.

The numerical experiments are organized around three cases. In the first case, neither batteries nor hydrogen assets provide demand response, and the hydrogen system follows the baseline schedule obtained from the standalone hydrogen optimization. In the second case, hydrogen demand response is activated without battery installation, and compensated adjustments are limited to reductions from the baseline electrolyzer schedule; shifted load remains uncompensated and all newly added hydrogen capacities remain outside the DR-payment mechanism. In the third case, battery and hydrogen demand response are both activated under the same selective compensation rule. In all cases, the standalone hydrogen problem is solved first to determine the baseline electrolyzer schedule and baseline hydrogen capacities, after which the integrated power-hydrogen planning model is solved.

## 5. Results and Discussion

Table 1 reports the absolute planning and economic results for the three cases under degradation-agnostic and degradation-aware settings, while Table 2 summarizes the percentage changes of the principal indicators in Cases 1 and 2 relative to the base case. Relative to the base case, activating hydrogen flexibility alone (Case 1) reduces total system cost by 10.6% without degradation and 10.4% with degradation. The main source of this improvement is the strong reduction in renewable curtailment, which falls by 62.6% and 65.0%, respectively, while renewable generation increases by 22.4% and 25.5%. However, this benefit is accompanied by higher emissions: Case 1 raises total emissions by 19.9% in the degradation-agnostic setting and by 27.0% in the degradation-aware setting. This behavior is consistent with the larger hydrogen infrastructure adopted in Case 1, where the electrolyzer count doubles from about 4,732 to 9,464 cells and HES capital cost increases by approximately 102.6% without degradation and 100.0% with degradation.

The coordinated hybrid case provides the best overall performance. Compared with the base case, Case 2 lowers total cost by 17.9% without degradation and 15.7% with degradation, while renewable curtailment is reduced by 91.8% and 90.5%, respectively. The hybrid configuration also outperforms the HES-only case: relative to Case 1, total cost decreases by 8.1% without degradation and 5.8% with degradation, while curtailment drops by 78.2% and 73.0%. In emissions terms, Case 2 is also preferable to Case 1, cutting total emissions by 14.9% in the degradation-agnostic setting and by 16.3% in the degradation-aware setting. Relative to the base case, the emissions change in Case 2 is limited to +2.0% without degradation and +6.3% with degradation, which is substantially smaller than the increase observed in the HES-only case. This indicates that combining BESS with hydrogen flexibility reduces the need for carbon-intensive balancing while preserving the curtailment-reduction benefits of hydrogen.

Table 1. Summary of planning and economic results across the studied cases

| Metric                                         | Unit               | Case 0  |         | Case 1  |         | Case 2  |         |
|------------------------------------------------|--------------------|---------|---------|---------|---------|---------|---------|
|                                                |                    | Deg.=0  | Deg.=1  | Deg.=0  | Deg.=1  | Deg.=0  | Deg.=1  |
| System-wide economic and environmental results |                    |         |         |         |         |         |         |
| Total Cost                                     | M\$                | 9,201.9 | 9,215.2 | 8,225.0 | 8,253.4 | 7,558.3 | 7,771.9 |
| Emissions                                      | M Tons             | 97.35   | 92.50   | 116.77  | 117.49  | 99.34   | 98.31   |
| Emissions Cost                                 | M\$                | 1,060.2 | 1,007.3 | 1,271.6 | 1,279.5 | 1,081.8 | 1,070.6 |
| Energy Cost                                    | M\$                | 3,815.5 | 3,695.2 | 4,033.2 | 4,030.1 | 3,654.3 | 3,696.4 |
| SR Cost                                        | M\$                | 433.7   | 410.0   | 523.3   | 523.3   | 454.6   | 453.5   |
| HTS Cost                                       | M\$                | 1,129.1 | 1,127.5 | 1,099.9 | 1,099.9 | 1,099.9 | 1,099.9 |
| Hydrogen-system investment results             |                    |         |         |         |         |         |         |
| CAPEX HES                                      | M\$                | 170.4   | 170.3   | 345.2   | 340.6   | 340.7   | 340.6   |
| AWE Nc                                         | #                  | 4,732   | 4,731   | 9,464   | 9,462   | 9,464   | 9,461   |
| PEMFC Nc                                       | #                  | ---     | ---     | 125     | 0       | 0       | 0       |
| H2 Storage                                     | m³ LOHC            | 3,059.3 | 3,180.7 | 3,059.3 | 3,180.7 | 3,059.3 | 3,060.8 |
| HES Salvage Value                              | M\$                | 11.6    | -15.9   | 23.5    | -4.3    | 23.2    | 8.7     |
| Battery-system investment results              |                    |         |         |         |         |         |         |
| CAPEX BESS                                     | M\$                | ---     | ---     | ---     | ---     | 791.4   | 918.4   |
| BESS Power Capacity                            | MW                 | ---     | ---     | ---     | ---     | 526.3   | 477.3   |
| BESS Energy Capacity                           | MWh                | ---     | ---     | ---     | ---     | 1,065.3 | 2,304.5 |
| BESS Salvage Value                             | M\$                | ---     | ---     | ---     | ---     | 53.9    | 62.6    |
| Degradation cost components                    |                    |         |         |         |         |         |         |
| AWE Degradation Cost                           | \$/Day/Season/Cell | ---     | 35,421  | ---     | 35,421  | ---     | 18,654  |
| AWE Throughput Cost                            | \$/Day/Season/Cell | ---     | 1,886   | ---     | 1,886   | ---     | 1,886   |
| AWE Cycle Cost                                 | \$/Day/Season/Cell | ---     | 33,534  | ---     | 33,534  | ---     | 16,768  |
| AWE Start Cost                                 | \$/Day/Season/Cell | ---     | 0.23    | ---     | 0.45    | ---     | 0.22    |

| Metric                 | Unit               | Case 0 |        | Case 1 |        | Case 2 |        |
|------------------------|--------------------|--------|--------|--------|--------|--------|--------|
|                        |                    | Deg.=0 | Deg.=1 | Deg.=0 | Deg.=1 | Deg.=0 | Deg.=1 |
| PEMFC Degradation Cost | \$/Day/Season/Cell | ---    | ---    | ---    | 0      | ---    | 0      |
| PEMFC Throughput Cost  | \$/Day/Season/Cell | ---    | ---    | ---    | 0      | ---    | 0      |
| PEMFC Cycle Cost       | \$/Day/Season/Cell | ---    | ---    | ---    | 0      | ---    | 0      |
| PEMFC Start Cost       | \$/Day/Season/Cell | ---    | ---    | ---    | 0      | ---    | 0      |
| BESS Degradation Cost  | \$/Day/Season      | ---    | ---    | ---    | ---    | ---    | 31,026 |
| BESS Throughput Cost   | \$/Day/Season      | ---    | ---    | ---    | ---    | ---    | 3,275  |
| BESS Cycle Cost        | \$/Day/Season      | ---    | ---    | ---    | ---    | ---    | 27,431 |
| BESS Start Cost        | \$/Day/Season      | ---    | ---    | ---    | ---    | ---    | 320    |

Table 2. Percentage changes in the principal indicators relative to the base case

| Metric               | Case 1 vs Base case |         | Case 2 vs Base case |         |
|----------------------|---------------------|---------|---------------------|---------|
|                      | Deg.=0              | Deg.=1  | Deg.=0              | Deg.=1  |
| Total cost           | -10.6%              | -10.4%  | -17.9%              | -15.7%  |
| Emissions            | +19.9%              | +27.0%  | +2.0%               | +6.3%   |
| Renewable generation | +22.4%              | +25.5%  | +32.8%              | +35.6%  |
| PV curtailment       | -62.6%              | -65.0%  | -91.8%              | -90.5%  |
| Energy cost          | +5.7%               | +9.1%   | -4.2%               | +0.0%   |
| HES CAPEX            | +102.6%             | +100.0% | +99.9%              | +100.0% |

Degradation has a limited impact on the aggregate results of the base and HES-only cases, increasing total cost by only 0.15% in Case 0 and 0.35% in Case 1. Its impact is more visible in the hybrid case, where total cost rises by 2.8%. This difference is mainly associated with the battery investment response. In Case 2, degradation increases BESS capital cost by 16.0%, reduces installed battery power by 9.3%, and increases installed battery energy capacity by 116.3%, indicating a shift toward lower-power and longer-duration battery operation. At the same time, the degradation-aware hybrid case substantially reduces electrolyzer wear relative to the degradation-aware HES-only case: the total AWE degradation cost drops by about 47.3%, driven primarily by a 50.0% decrease in the electrolyzer cycle-degradation component. This confirms that battery support relieves cycling stress on the hydrogen production system. Note that, negative salvage values indicate cases where degradation-related cost offsets exceed the residual asset value at the end of the planning horizon. The nonzero PEMFC investment in Case 1 without degradation disappears once degradation or battery support is considered, indicating that the hybrid configuration and lifecycle penalties reduce the economic value of fuel-cell expansion.

The market indicators are consistent with these trends. A seasonal weighted average of the daily-average LMPs shows that Case 1 increases the average price level by 13.3% without degradation and 14.2% with degradation relative to the base case, whereas Case 2 decreases it by 5.9% and 29.2%, respectively. Relative to the HES-only case, the hybrid configuration lowers the weighted average LMP by 16.9% without degradation and 38.0% with degradation. Finally, the compensated hydrogen demand-response signal becomes weaker once degradation is considered. In both Case 1 and Case 2, DR revenues fall to zero in the degradation-aware runs, indicating that the optimal solution no longer relies on compensated baseline electrolyzer reductions and instead shifts toward infrastructure sizing and dispatch adjustments. Overall, the results show that hydrogen flexibility is highly effective for reducing PV curtailment, but the coordinated hybrid portfolio provides the best balance among cost, emissions, curtailment, and asset utilization. Figures 2(a) and 2(b) show the hourly net-load profiles for the three cases without and with degradation, respectively. Figure 2(a) shows that the base case maintains positive net load throughout the day in all seasons under the degradation-agnostic setting. The minimum net load remains between 622MW and 1,197MW, while the daily peak

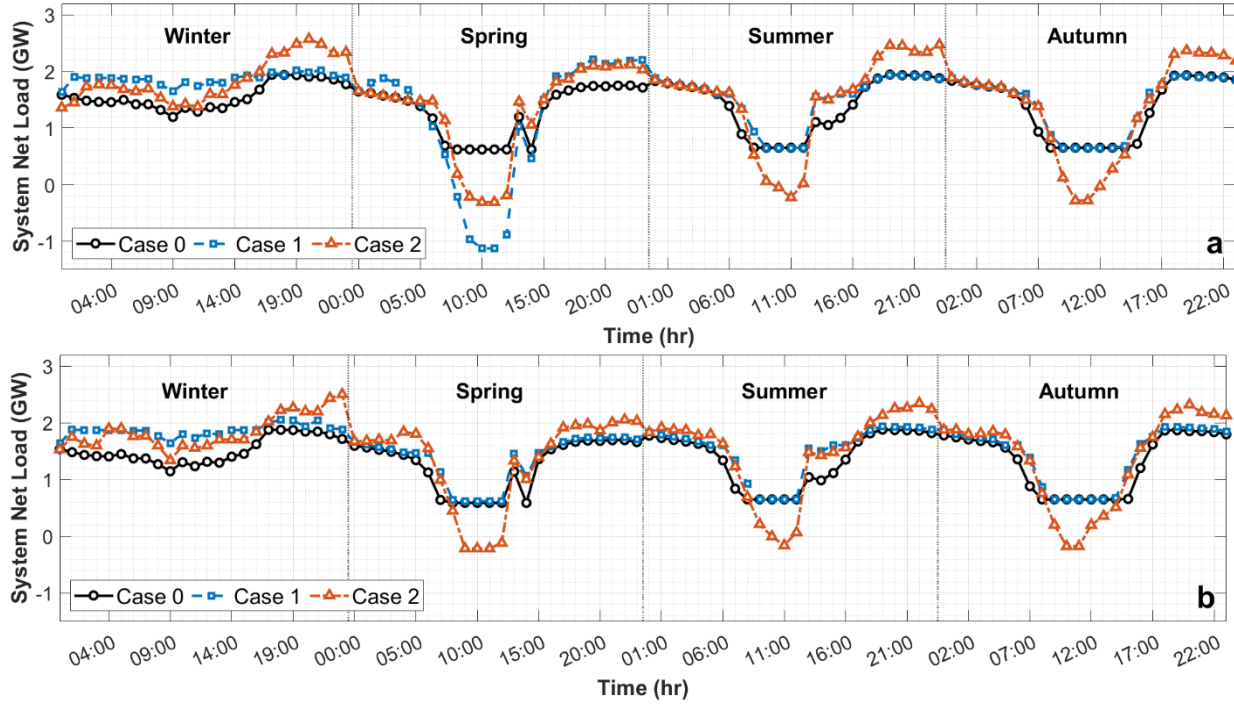


Figure 2. Hourly system net-load profiles for Cases 0-2 under degradation-agnostic (a) and degradation-aware (b) settings.

The figure highlights how HES-only flexibility deepens the spring midday trough, while the coordinated BESS-HES case produces the strongest redistribution of net load across the day and the largest reshaping of evening peaks.

ranges from 1.75~GW in spring to 1.94~GW in summer. The HES-only case produces the strongest midday reduction in spring, where the minimum net load drops from +622MW in the base case to 1,127MW, corresponding to a 1.75GW downward shift, while the spring peak rises by 26.6% from 1,753MW to 2,220MW. In winter, the HES-only case mainly lifts the daytime valley and increases the peak more moderately, by 4.4%. The hybrid HES+BESS case yields the largest inter-hour reshaping of the net-load profile. Without degradation, it drives the midday net load negative in spring, summer, and fall, with minimum of -311MW, -226MW, and -281MW, respectively, while increasing the seasonal peaks by 20.9% in spring, 27.3% in summer, 22.6% in fall, and 32.7% in winter relative to the base case. It also shifts the daily peak toward later hours, reaching 20:00 in winter and 23:00 in summer.

Figure 2(b) shows the corresponding degradation-aware results. In the base case, degradation reduces the seasonal peaks by about 3.1% in all four seasons, with the winter, spring, summer, and fall peaks falling from 1,939, 1,753, 1,943, and 1,933MW to 1,879, 1,698, 1,883, and 1,873MW, respectively. The corresponding midday minima are also slightly lower, by about 4.0% in winter and 4.9% in spring. For the HES-only case, the aggressive spring reshaping is largely removed: the spring minimum returns to +622MW and the spring peak decreases by 21.1% relative to the no-degradation HES-only case, from 2,220MW to 1,750MW. In summer and fall, the HES-only case changes the profile much less, with peak changes remaining within about  $\pm 3\%$ . The hybrid case remains the most effective for reshaping the net load, but it becomes less aggressive under degradation. The magnitude of the negative midday trough is reduced by 31.6% in spring, 29.9% in summer, and 37.8% in fall relative to the no-degradation hybrid case, while the seasonal peaks decline by about 2.0% to 5.1%.

Figures 3(a) and 3(b) show the hourly locational marginal price (LMP) profiles for the three cases without and with degradation, respectively. Figure 3(a) shows that the base case exhibits the strongest price volatility in the degradation-agnostic setting, particularly in the PV-rich seasons. Case 0 produces repeated zero-price periods during midday, with 6 zero-price hours in spring, 5 in summer, and 7 in fall, while the evening peaks reach \$59.69/MWh in summer and \$54.45/MWh in fall. Activating HES flexibility alone (Case 1) reduces the duration of zero-price periods to 4, 4, and

5 hours in spring, summer, and fall, corresponding to reductions of 33.3%, 20.0%, and 28.6%, respectively. However, the HES-only case generally raises the average price level relative to the base case, by 28.6% in winter, 14.4% in

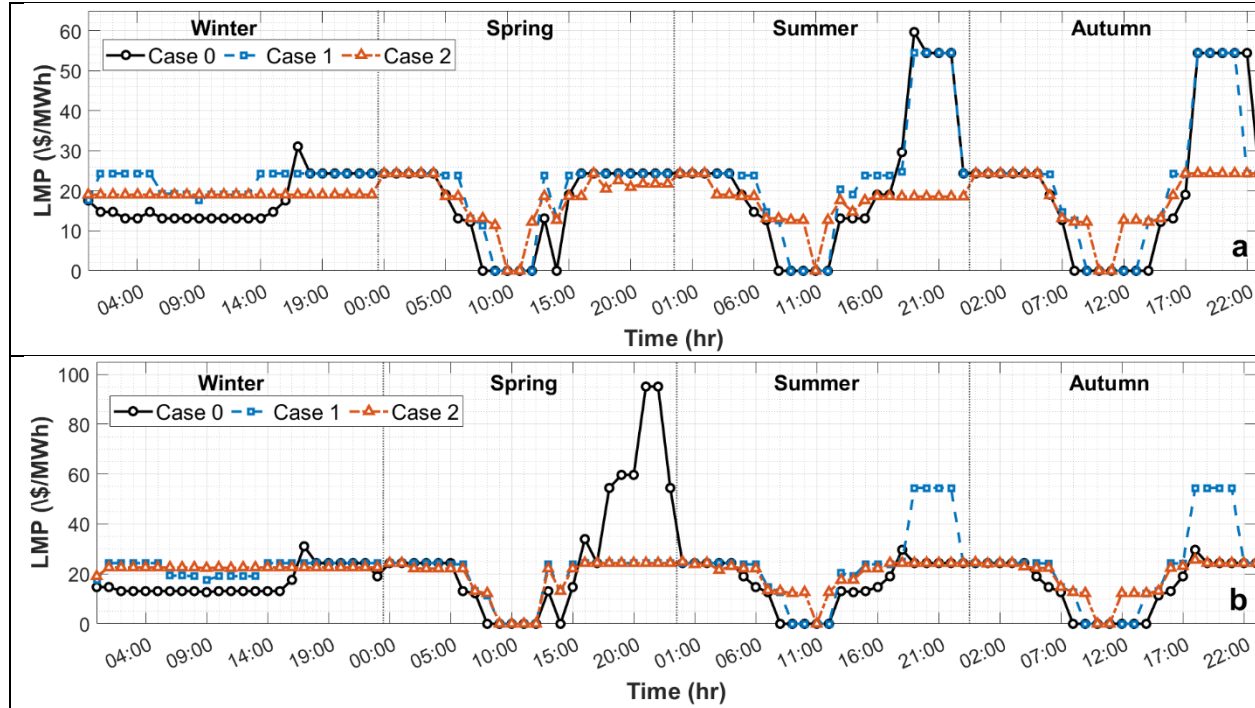


Figure 3. Hourly locational marginal price (LMP) profiles for Cases 0–2 under degradation-agnostic (a) and degradation-aware (b) settings.

The figure shows how hydrogen flexibility reduces the duration of zero-price midday periods, while the coordinated BESS–HES case provides the strongest smoothing of evening price peaks and the most uniform intraday price profile. In spring, 10.0% in summer, and 3.7% in fall. The hybrid case (Case 2) provides the strongest price smoothing. In the no-degradation setting, it reduces the number of zero-price hours to 2 in spring, 1 in summer, and 2 in fall, equivalent to reductions of 66.7%, 80.0%, and 71.4% relative to the base case. It also sharply lowers the evening peaks, cutting the summer peak from \$59.69 to \$24.34/MWh, corresponding to a 59.2% reduction, and the fall peak from \$54.45 to \$24.34/MWh, corresponding to a 55.3% reduction. In winter, the hybrid case completely flattens the LMP profile at about \$19.03/MWh throughout the day.

Figure 3(b) presents the degradation-aware LMP results. In this setting, the HES-only case remains almost unchanged, whereas the base and hybrid cases show more visible price shifts. The degraded base case develops a pronounced spring evening spike, with the maximum LMP rising to \$95.10/MWh, while still maintaining 6 zero-price hours around midday. Both Case 1 and Case 2 eliminate this extreme behavior and cap the spring peak at \$24.34/MWh, which corresponds to a 74.4% reduction relative to the degraded base case. In summer and fall, the degraded hybrid case continues to smooth prices more effectively than the HES-only case, reducing the summer peak from \$54.45 to \$24.84/MWh, or 54.4% relative to Case 1, and the fall peak from \$54.45 to \$25.63/MWh, or 52.9% relative to Case 1.

## 6. Conclusion

This paper presented a two-stage planning framework for coordinated battery and hydrogen flexibility in PV-dominated power systems. The proposed formulation distinguishes between the baseline electrolyzer schedule obtained from a standalone hydrogen optimization and the additional hydrogen flexibility installed by the coordinated planner. This distinction is important because only reductions from the inherited electrolyzer schedule are compensated as demand response, whereas shifted load, new electrolyzer capacity, added hydrogen-storage capacity, and fuel-cell operation are treated as endogenous planner-owned assets without demand-response payments. By

combining this selective compensation rule with network constraints, hydrogen transportation, and degradation-aware modeling, the framework provides a tractable and economically consistent basis for long-term planning.

The numerical results show that hydrogen flexibility alone can substantially reduce system cost and PV curtailment, but it does so at the expense of higher emissions. In the degradation-aware setting, the HES-only case lowers total cost by 10.4% and PV curtailment by 65.0% relative to the base case, while increasing emissions by 27.0%. The coordinated hybrid BESS--HES case achieves the best overall balance, reducing total cost by 15.7% and PV curtailment by 90.5%, while keeping the emissions increase limited to 6.3% relative to the base case and reducing emissions by 16.3% relative to the HES-only case. The hybrid case also produces the strongest smoothing effect on locational prices and the largest reduction in electrolyzer cycling stress. The degradation results confirm that lifecycle effects materially influence optimal planning decisions. In particular, degradation shifts the battery investment toward lower power and higher energy capacity, and the hybrid case reduces total electrolyzer degradation cost by 47.3% relative to the HES-only case. These findings indicate that combining battery and hydrogen resources does not merely improve operational flexibility; it also moderates the long-term wear of the hydrogen subsystem. These results indicate that planners should treat inherited hydrogen obligations and newly installed hydrogen flexibility separately, since bundling them under a single DR compensation rule can overstate the economic value of hydrogen expansion. Future work can extend the framework by incorporating uncertainty in PV generation and hydrogen demand, and additional market products such as reserve and ancillary-service revenues.

## **Acknowledgements**

This research was funded by Khalifa University of Science and Technology under Project code KU-INT-FSU-2024-8474000723-016. The authors also acknowledge the support of the Advanced Power and Energy Center (KU-APEC), and the Research and Innovation Center on CO<sub>2</sub> and Hydrogen (KU-RICH Center), Khalifa University of Science and Technology.

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