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OPTIMAL CONTROL OF A HYBRID POWER SUPPLY SYSTEM WITH RESERVE PROVISION

This paper develops a model for the optimal control of a hybrid power supply system intended for day-ahead operational scheduling under time-of-use tariffs and stochastic uncertainty in generation and demand. A consistent formulation of active power flows, energy balance, and state-of-charge dynamics of the energy storage system is proposed, taking into account conversion efficiencies, technological constraints, and reserve requirements for critical loads. Particular attention is given to the integration of an energy storage degradation model that captures both cycle-induced and calendar aging. The proposed representation enables the evaluation of capacity fade costs without significantly increasing the computational complexity of the optimization problem. The objective function is formulated to jointly minimize electricity purchase costs, account for revenues from energy sales, penalize energy not supplied and generation curtailment, and incorporate degradation-related costs of the storage system. Numerical simulations performed for representative seasonal operating conditions demonstrate that the baseline control strategy is effective under accurate forecasting; however, it exhibits high sensitivity to photovoltaic generation forecast errors. The control strategy proposed in this study ensures a reduction in unserved energy, facilitates the formation of an energy reserve, and decreases both total and specific electricity supply costs, particularly during the winter season and under adverse weather conditions. The obtained results confirm the importance of incorporating degradation effects and uncertainty-related risks into the optimal control framework of hybrid power supply systems.

Ключові слова: hybrid energy supply system, microgrid, energy storage systems, optimal control, photovoltaic power plant.

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ОПТИМАЛЬНЕ КЕРУВАННЯ ГІБРИДНОЮ СИСТЕМОЮ ЕЛЕКТРОЗАБЕЗПЕЧЕННЯ З РЕЗЕРВНИМ ЗАБЕЗПЕЧЕННЯМ

У статті розроблено модель оптимального керування гібридною системою електрозабезпечення, призначену для добового планування режимів роботи за умов тарифної диференціації та стохастичної невизначеності генерації та навантаження. Запропоновано узгоджений опис потоків активної потужності, енергетичного балансу та динаміки стану заряду установки зберігання електроенергії з урахуванням коефіцієнтів корисної дії, технологічних обмежень і вимог до резервування енергії для критичного навантаження. Особливу увагу приділено інтеграції моделі деградації установки зберігання електроенергії, яка враховує циклічне та календарне старіння і дає можливість оцінювати вартість втрати ресурсу без істотного ускладнення оптимізаційної задачі. Сформульовано цільову функцію, що поєднує витрати на купівлю електроенергії, доходи від продажу, штрафи за недовідпуск електроенергії й обмеження генерації, а також витрати, пов'язані з деградацією накопичувача. На основі чисельного моделювання для характерних сезонних режимів показано, що базова стратегія керування є ефективною за умов точного прогнозування, проте демонструє високу чутливість до похибок прогнозу генерації сонячної електростанції. Запропонована у роботі стратегія керування забезпечує зменшення обсягів недовідпуску електроенергії, формування енергетичного резерву та зниження сумарних і питомих витрат на електропостачання, особливо в зимовий період і за несприятливих погодних умов. Отримані результати підтверджують доцільність урахування деградації та ризиків невизначеності під час оптимального керування гібридними системами електрозабезпечення.

Keywords: гібридна система енергозабезпечення, мікромережа, установки зберігання електроенергії, оптимальне керування, сонячна електростанція.

Introduction. The intensive integration of distributed energy resources, primarily photovoltaic (PV) generation, fundamentally alters the operating conditions of distribution networks and increases the controllability requirements for local energy systems. In grid-connected microgrids and local power supply systems, the variability of renewable generation is superimposed on the stochastic nature of demand, necessitating a systematic coordination of technical constraints, economic factors, and reliability indices, both in day-ahead scheduling and real-time operation. Recent studies [1–4] emphasize that a key component of such systems is an optimal energy management framework that coordinates generation, load, and energy storage according to predefined optimality criteria.

This study considers a hybrid power supply system comprising a photovoltaic power plant, an energy storage system (ESS), an external utility grid, and aggregated loads connected at a common coupling point. This architecture is representative of a wide range of practical applications, including self-consumption maximization, peak demand reduction, and electricity cost optimization. A generalized approach to selecting energy sources for combined power supply systems of industrial and local facilities enables the formulation of universal mathematical control problems suitable for practical implementation using standard optimization techniques [1, 5, 6].

A significant methodological challenge lies in the simultaneous consideration of short-term operational effects—driven by tariff structures and forecast errors—and long-term consequences of ESS operation associated with degradation (aging) and resource depletion. In recent years, the integration of storage lifetime characteristics into optimal control problems has been recognized as a prerequisite for sound techno-economic justification of system operating modes [7, 8].

For grid-connected systems, centralized optimization formulations retain substantial practical value, as they provide coordinated solutions over a defined planning horizon. At the same time, contemporary research highlights the limitations of purely centralized schemes, including vulnerability to central node failures and high communication requirements. This has stimulated the development of hybrid architectures that combine optimal planning with a degree of autonomy at the execution stage [3, 5].

Applied research demonstrates that control problems with linear power balance equations and linearized constraints can be effectively formulated as linear programming (LP) or mixed-integer linear programming (MILP) problems. A key advantage of MILP is the ability to employ binary variables to represent mutually exclusive operating states (e.g., ESS charging/discharging modes)

without compromising computational tractability over day-ahead horizons [9].

A notable trend is the transition from purely economic criteria to integrated approaches in which network technical constraints and ESS resource indicators are incorporated within a unified control framework. Examples include algorithms that jointly optimize active and reactive power, achieving a balance between modeling accuracy and computational complexity [9].

From a long-term efficiency perspective, ESS operating strategies should be determined not only by instantaneous tariff conditions but also by life-cycle costs, in which degradation plays a decisive role. Studies addressing aging-aware control show that incorporating degradation costs into the objective function or constraints helps prevent excessive cycling and operation in unfavorable state-of-charge (SoC) regions [7, 8].

Linearized degradation models suitable for integration into MILP formulations are regarded as an effective compromise. In particular, piecewise-linear approximations of cycle-induced and calendar aging factors have been proposed, compatible with rolling-horizon control algorithms [10, 11]. Another research direction combines degradation modeling with uncertainty-aware control methods, balancing the risk of premature wear against power supply reliability requirements [12]. Data-driven approaches have also been developed, where degradation is estimated using neural networks. Although these models more accurately capture physicochemical processes, their integration into classical optimization frameworks remains challenging [13].

For hybrid systems with a significant share of PV generation, forecast uncertainty in both generation and demand constitutes a critical factor. Neglecting this uncertainty may lead to violations of technological constraints and reduced actual economic performance. In response, stochastic and robust optimization methods have gained widespread adoption [14, 15].

Risk-oriented metrics, such as Conditional Value-at-Risk (CVaR), provide an effective tool for addressing uncertainty. This metric enables the minimization of expected losses in worst-case scenarios and can be reformulated in a linear form suitable for optimization [16]. Alternatively, chance-constrained formulations ensure that reliability requirements are satisfied with a prescribed confidence level.

Recent developments include the integration of risk-based criteria into rolling-horizon control schemes, combining planning robustness with operational adaptability—an approach particularly relevant for commercial microgrids [17]. However, there remains a need for a coherent methodology that integrates risk-aware control with detailed ESS degradation models within a unified mathematical framework.

Based on the conducted analysis, mixed-integer linear programming remains a relevant and effective approach for day-ahead scheduling because it can guarantee a global optimum while representing binary operational decisions. At the same time, there is a need for optimization-oriented ESS degradation models that capture resource depletion costs without introducing excessive computational burden. To address PV generation forecast uncertainty in a practical day-ahead setting, this work combines a deterministic

MILP scheduling model with an ESS degradation cost representation and evaluates operational robustness under stochastic PV forecast scenarios. Accordingly, the objective of this paper is to develop a mathematical model for the optimal control of a hybrid power supply system that integrates an ESS degradation model and supports scenario-based assessment of uncertainty impacts.

Mathematical Model of Hybrid Power Supply System Control. The mathematical formulation is developed in discrete time. The planning horizon of duration $T = N\Delta t$ is divided into N equal intervals with discretization step Δt (h). Time intervals are indexed by $k \in \mathcal{T} = \{0, 1, \dots, N - 1\}$. All active power flows are defined with respect to the point of common coupling (PCC) with the utility grid, which enables the formulation of a unified system-level balance equation without excessive detailing of the internal network topology.

The fundamental constraint of the model is the active power balance at the PCC. For each time step k , it is expressed as:

$$P_k^{pv} + P_k^{dis} + P_k^{g+} = (P_k^{load} - P_k^{ls}) + P_k^{ch} + P_k^{g-} + P_k^{loss}, \quad (1)$$

where P_k^{pv} (kW) is the controlled power generated by the photovoltaic plant; P_k^{dis} (kW) is the ESS discharging power; P_k^{g+} (kW) is the imported grid power; P_k^{load} (kW) is the load demand; P_k^{ls} (kW) is the curtailed (unserved) load; P_k^{ch} (kW) is the ESS charging power; P_k^{g-} (kW) is the exported grid power; and P_k^{loss} (kW) represents aggregate system losses. Equation (1) enforces instantaneous energy equilibrium.

To preserve linearity, which is critical for computationally efficient optimization, power losses are approximated by a linear function of the principal energy flows:

$$P_k^{loss} = \alpha^{pv} P_k^{pv} + \alpha^{uze} (P_k^{ch} + P_k^{dis}), \quad (2)$$

where α^{pv} and α^{uze} are dimensionless loss coefficients associated with the PV subsystem and the ESS power conversion chain, respectively. These coefficients are obtained from equipment specifications or statistical identification. The adopted linearization ensures adequate accuracy while significantly simplifying the computational procedure.

The PV output is upper-bounded by the available resource \hat{P}_k^{pv} (kW), determined from solar irradiance forecasts. The actual dispatched power is limited by inverter capabilities:

$$0 \leq P_k^{pv} \leq \min\{\hat{P}_k^{pv}, P^{pv,max}\}, \quad (3)$$

where $P^{pv,max}$ (kW) is the rated installed PV capacity. In case of surplus generation, renewable curtailment may occur:

$$P_k^{cur} = \hat{P}_k^{pv} - P_k^{pv}, \quad P_k^{cur} \geq 0, \quad (4)$$

where P_k^{cur} (kW) denotes the unused renewable potential.

The interaction with the utility grid is subject to interconnection capacity limits:

$$0 \leq P_k^{g+} \leq P^{g+,max}, \quad 0 \leq P_k^{g-} \leq P^{g-,max}, \quad (5)$$

where $P^{g+,max}$ and $P^{g-,max}$ (kW) are the maximum allowable import and export powers. To prevent physically inconsistent simultaneous import and export, a binary variable $y_k^g \in \{0, 1\}$ is introduced:

$$P_k^{g+} \leq y_k^g P^{g+,max}, \quad P_k^{g-} \leq (1 - y_k^g) P^{g-,max}. \quad (6)$$

The ESS model is based on the stored energy state E_k (kWh). The state-of-charge dynamics are described by:

$$E_{k+1} = E_k + \eta^{ch} P_k^{ch} \Delta t - \frac{1}{\eta^{dis}} P_k^{dis} \Delta t, \quad (7)$$

where η^{ch} and η^{dis} denote the charging and discharging efficiencies. The admissible energy range is constrained by technological limits:

$$E^{\min} \leq E_k \leq E^{\max}, \quad (8)$$

where E^{\min} and E^{\max} are selected to mitigate accelerated battery degradation. Power limits are imposed as:

$$0 \leq P_k^{ch} \leq y_k^b P_k^{ch,max}, \quad (9)$$

$$0 \leq P_k^{dis} \leq (1 - y_k^b) P_k^{dis,max},$$

where $y_k^b \in \{0,1\}$ prevents simultaneous charging and discharging. The optimization cycle is completed by specifying the initial condition $E_0 = E^{init}$ and terminal constraint:

$$E_N \in [E^{end,-}, E^{end,+}]. \quad (10)$$

System reliability requirements include maintaining an energy reserve to supply critical load P_k^{crit} for a prescribed duration T^{res} :

$$E_k \geq E_k^{res}, \quad E_k^{res} = P_k^{crit} T^{res}. \quad (11)$$

To account for economic wear, a surrogate linear degradation model is introduced, capturing both cycling and calendar aging effects. An auxiliary variable U_k (kWh) represents the magnitude of energy throughput:

$$U_k \geq |E_{k+1} - E_k| \Rightarrow U_k \geq E_{k+1} - E_k, \quad (12)$$

$$U_k \geq -(E_{k+1} - E_k).$$

The total degradation cost is then defined as:

$$C_k^{deg} = c^{cyc} U_k + c^{cal} E_k \Delta t, \quad (13)$$

where c^{cyc} and c^{cal} are specific cost coefficients associated with cycle-induced and calendar aging, respectively.

The optimal control problem is formulated as the minimization of total operational cost:

$$\min J = \sum_{k \in T} [c_k^{imp} P_k^{g+} - c_k^{exp} P_k^{g-} + c^{ls} P_k^{ls} + c^{cur} P_k^{cur}] \Delta t + \sum_{k \in T} C_k^{deg}, \quad (14)$$

where c_k^{imp} and c_k^{exp} denote time-varying import and export tariffs, while c^{ls} and c^{cur} are penalty coefficients for load shedding and PV curtailment, respectively.

Owing to its linear structure with binary operational variables, the proposed mathematical model is well suited for mixed-integer linear programming, enabling efficient computation of optimal day-ahead schedules while ensuring a balanced trade-off among economic efficiency, supply reliability, and long-term asset sustainability.

Numerical Simulation and Analysis of Results. Numerical experiments were conducted using a model hybrid power supply system operating under a dynamic electricity pricing scheme. The system parameters correspond to a medium-scale industrial facility. The installed photovoltaic capacity is $P^{pv,max} = 110$ kW, while the energy storage system (ESS) has a nominal capacity of $E^{\max} = 240$ kWh, with maximum charging and discharging power of 60 kW and a round-trip efficiency of $\eta^{ch} \eta^{dis} = 0.88$.

The simulation period covers representative seasonal conditions (winter and summer peaks), enabling evaluation of the proposed control algorithms under substantially different PV generation profiles. PV output forecasts were derived from meteorological data, whereas load profiles were based on actual consumption records of the facility (Figs. 1–3). Fig. 1 illustrates the daily PV generation profiles. Fig. 2 presents the active load demand curves. Fig. 3 shows the time-varying electricity purchase tariff.

In the first stage of the study, the performance of the optimal control framework was analyzed using a baseline strategy (Fig. 4). The primary objective of the algorithm was to maximize PV self-consumption and shift demand from peak-price hours to low-tariff nighttime periods.

The results indicate that the optimal controller initiates ESS charging during periods of surplus PV generation (10:00–15:00) and during low-tariff nighttime hours (23:00 and 03:00). This enables discharging during the evening peak period (16:00–22:00), when electricity prices reach 7–8 UAH/kWh. Under favorable weather conditions, the strategy achieves a self-sufficiency ratio of approximately 65.5% in summer.

Fig. 5 shows the daily active power balance calculated for winter period.

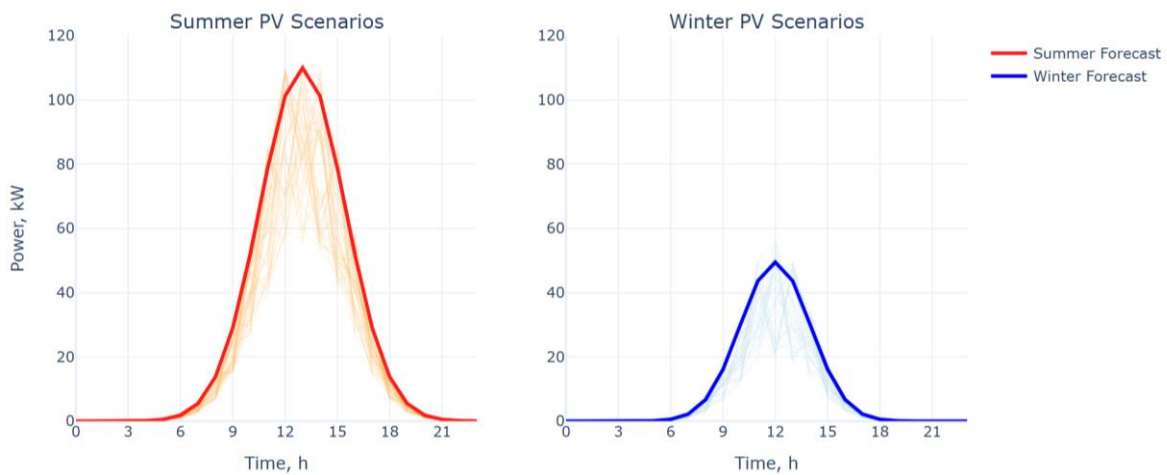


Fig. 1. PV generation profiles

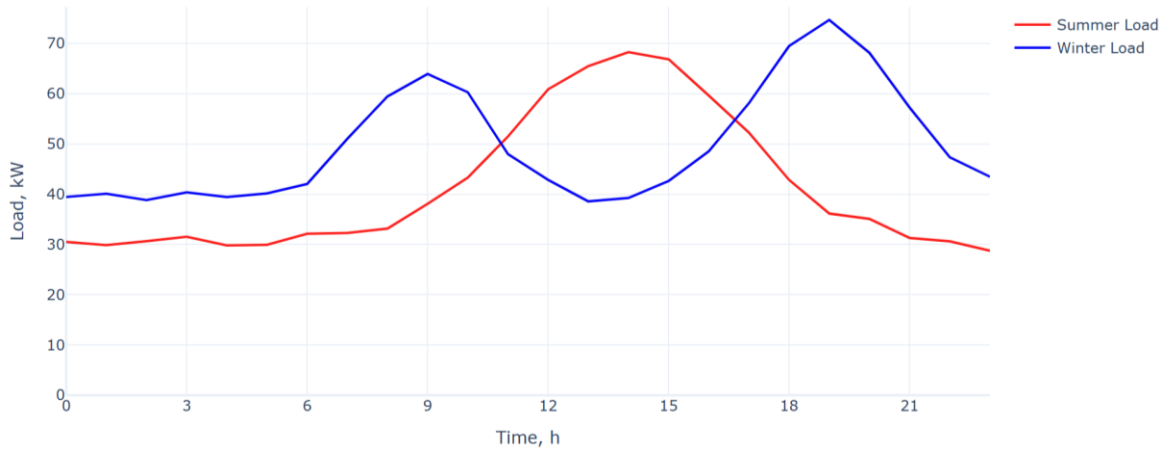


Fig. 2. Active load demand curves

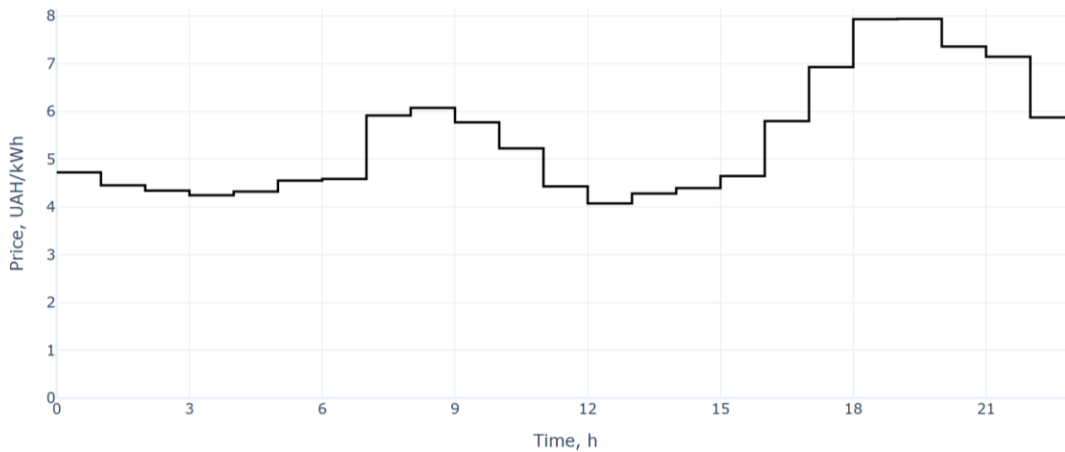


Fig. 3. Electricity purchase tariff

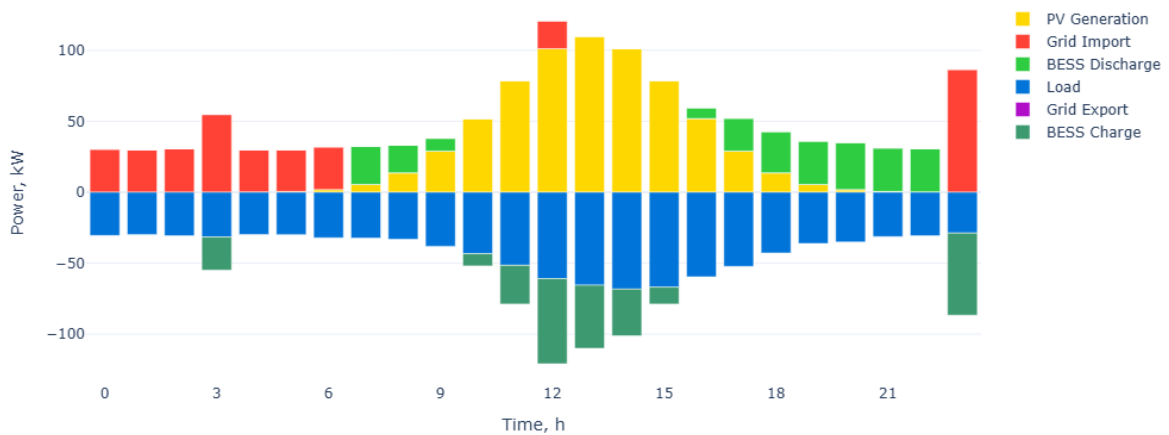


Fig. 4. Optimal daily active power balance for summer period

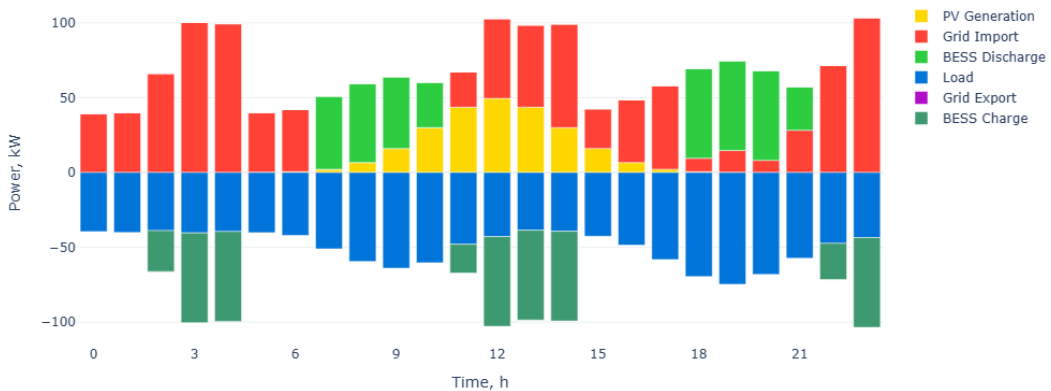


Fig. 5. Optimal daily active power balance for winter period

The results indicate that, in winter, the optimal controller charges the BESS primarily during low-tariff nighttime hours (approximately 02:00–04:00) and, to a limited extent, during the short interval of PV availability around midday (11:00–14:00). The stored energy is then discharged during the evening peak (approximately 18:00–21:00) to reduce grid import when tariffs are highest. Owing to the substantially lower winter PV output and the shorter generation window, the contribution of PV to load supply is limited. Consequently, the self-sufficiency ratio decreases to about 17.3% in winter.

A critical issue concerns the inclusion of battery degradation cost in the objective function. A comparative analysis of control strategies was therefore conducted. The baseline approach often leads to excessive cycling for marginal arbitrage gains, whereas the reserve-oriented strategy rationalizes battery utilization. The simulation results are summarized in Table 1.

Table 1 – Impact of Control Strategy on Performance Indicators

Control Strategy	Load Shedding, kWh	Total Cost, UAH	Specific Cost, UAH/kWh
Baseline	66.69	21 578	19.97
With reserve provision	52.52	17 335	16.05

The proposed strategy maintains a higher SoC level during midday (12:00–16:00), thereby forming an energy buffer. In contrast to the baseline strategy, which tends to discharge the battery earlier to free capacity, the reserve-

oriented approach accounts for the risk of sudden PV generation drops. This allows the system to avoid imbalance penalties and reduces the specific electricity cost by approximately 19.6%.

To assess robustness against forecast errors, a scenario-based analysis was performed using 50 stochastic realizations. The resulting cost distributions for both strategies are presented in Fig. 6. The analysis demonstrates a significant advantage of the reserve-oriented strategy, particularly in winter. Under adverse winter conditions, the average total cost was reduced from 24 199 UAH to 12 949 UAH. This improvement is primarily achieved through minimizing load shedding penalties, as curtailed energy decreased from 64.26 kWh to 26.61 kWh. The narrower cost distribution in Fig. 6 indicates that the reserve-oriented strategy exhibits lower sensitivity to PV forecast errors. During the summer season, the cost reduction ranges from 10–20% depending on weather conditions, while in winter the economic effect is amplified due to avoided high-cost electricity purchases during peak periods under generation shortfalls.

The State of Health (SoH) trajectories were obtained by propagating the battery capacity fade over time using the degradation model, where the yearly SoH reduction is computed from the optimized operating profiles by accumulating cycling-related and calendar-related degradation costs and then converting the resulting cumulative capacity loss into a SoH percentage referenced to the initial capacity. Fig. 7 illustrates the long-term impact of the proposed reserve provision strategy on battery lifetime.

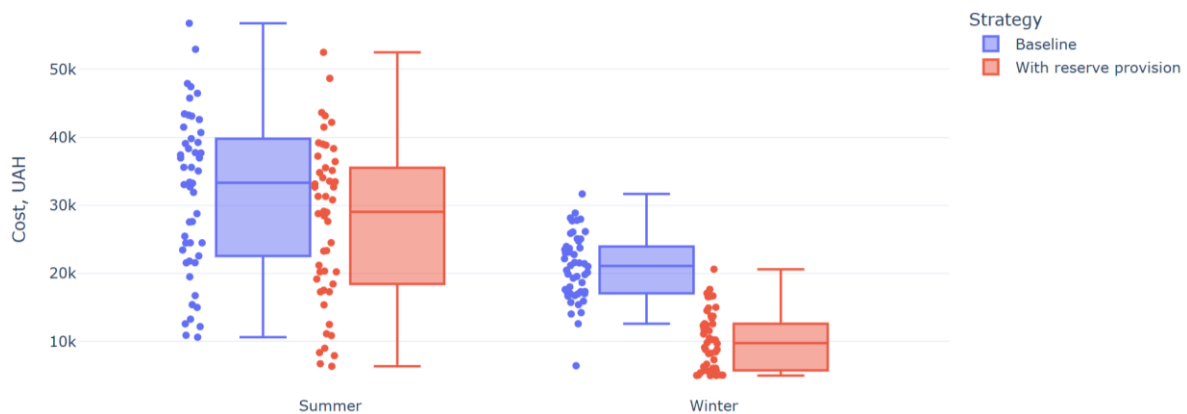


Fig. 6. Cost distribution across different seasons and control strategies

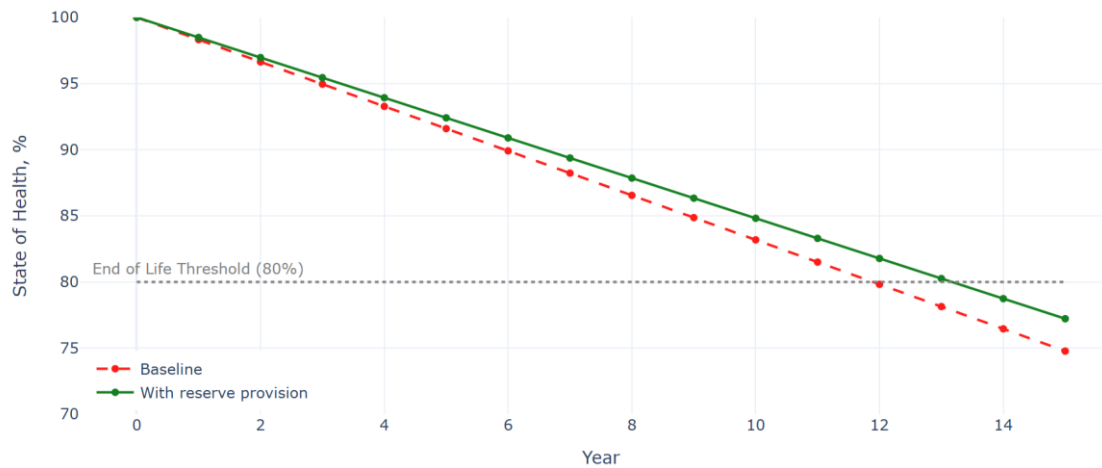


Fig. 7. Projected battery state of health degradation

The baseline schedule exhibits a faster, near-linear decline in SoH, reaching the commonly used end-of-life threshold of 80% at approximately year 12. In contrast, operation with reserve provision slows degradation, keeping SoH higher throughout the horizon and postponing the 80% threshold crossing to roughly year 13, with a SoH of about 77% after 15 years. This behavior is consistent with a reduction in cumulative battery stress. Maintaining an energy reserve limits deep discharge events and high-utilization cycles, thereby lowering effective cycling intensity and extending usable service life while still ensuring the required reliability margin.

Overall, the proposed model enhances power supply reliability by reducing the probability of unserved energy while simultaneously improving the economic performance of the hybrid power supply system.

Conclusions. This paper presents and investigates a mathematical model for the optimal control of a hybrid power supply system intended for day-ahead operational scheduling under time-of-use tariffs and stochastic uncertainty in generation and demand.

A comprehensive formulation of active power flows, system-level energy balance, and ESS state-of-charge dynamics has been developed, incorporating conversion efficiencies, power limits, reserve energy requirements for critical loads, and mutually exclusive operating modes. The proposed model is well suited for centralized optimal control over a day-ahead planning horizon.

Within a unified optimization framework, an ESS degradation model accounting for both cycle-induced and calendar aging has been integrated. It has been demonstrated that incorporating degradation cost into the objective function significantly affects optimal charging and discharging schedules, reducing excessive cycling and promoting more rational utilization of battery resources without compromising supply reliability.

The numerical results confirm that the baseline control model performs effectively under accurate forecasts; however, it exhibits high sensitivity to photovoltaic generation forecast errors, particularly during winter conditions. The application of a reserve-oriented and risk-aware control strategy enables the formation of an energy buffer, reduces the amount of unserved load, and lowers total electricity supply costs.

Future research should focus on extending the proposed framework by incorporating network constraints and integrating day-ahead scheduling with real-time rolling-horizon control.

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