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Settlement Mechanisms in The Day-Ahead Electricity Market: A Comparative Analysis of European Countries, The United States, and China

Xueshan Lin,[1] Xishuang Wu,[1] Yongjian Li,[1,*] Xin Liu,[2] Jianxiong Shi,[3] Xing Huang,[4,*] and Shaohua Yang[5,*]

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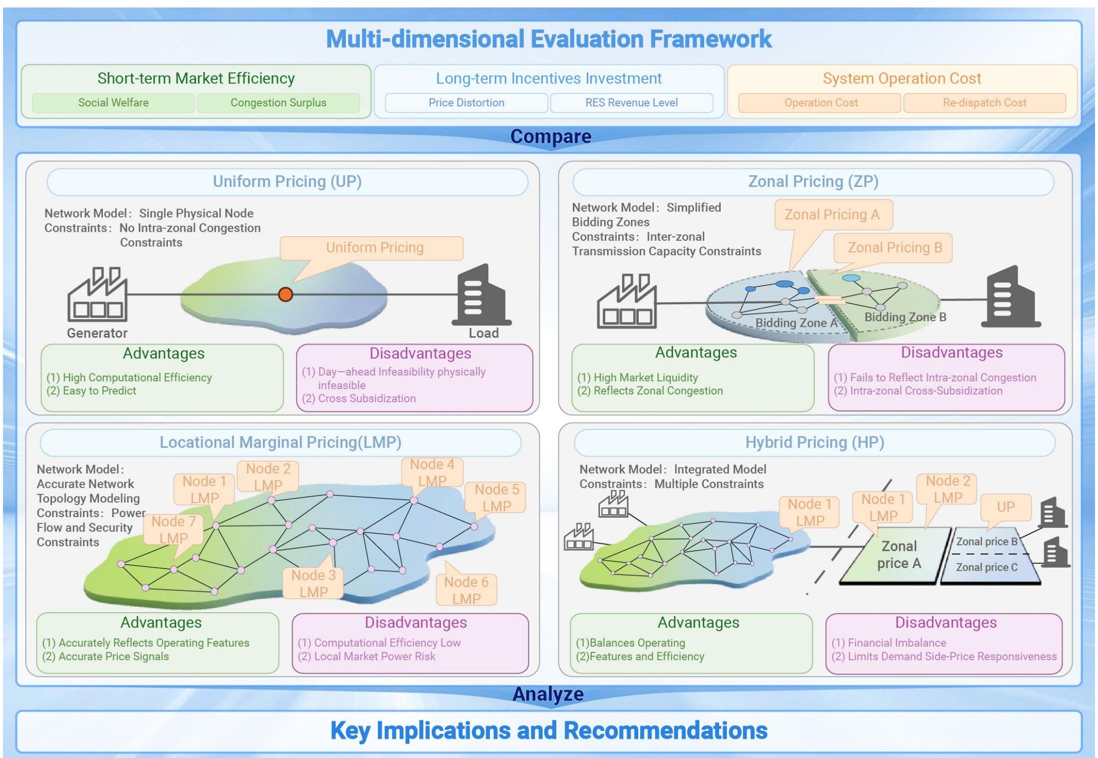
GRAPHICAL ABSTRACT



PUBLIC SUMMARY

- Deep RES integration demands rational DA settlement rules; a 3D framework evaluates UP, ZP, LMP, HP on efficiency, investment incentives and operation costs.
- No universally optimal settlement mechanism; its performance relies heavily on specific power system physical conditions.
- ZP boosts liquidity with adequate transmission capacity, but causes cross-subsidies and higher re-dispatch costs under high RES penetration.
- LMP delivers granular grid constraint signals, reduces renewable curtailment and remarkably raises overall social welfare.
- HP guarantees demand-side price stability for transitional markets; SM design must match grids, resources and market reform stages.

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As the integration of renewable energy sources (RES) deepens, selecting an appropriate day-ahead (DA) market settlement mechanism (SM) becomes critical for balancing system efficiency and economic viability. This paper proposes a multi-dimensional quantitative evaluation framework to assess four typical SMs—Uniform Pricing (UP), Zonal Pricing (ZP), Locational Marginal Pricing (LMP), and Hybrid Pricing (HP)—across three core dimensions: short-term market efficiency, long-term investment incentives, and system operation costs. Through comparative analysis and numerical simulations in typical scenarios, the results show that no universally optimal SM exists independent of the physical system's conditions. Specifically, ZP enhances market liquidity in systems with sufficient transmission capacity but tends to obscure local bottlenecks under high-RES penetration, leading to implicit cross-subsidization and increased re-dispatch costs (RCs). In contrast, LMP internalizes network constraints through granular spatiotemporal price signals, effectively reducing RES curtailment and improving overall social welfare (SW). For transitioning markets requiring demand-side price stability, HP offers a practical compromise. Overall, SM design should be closely aligned with grid topology, resource endowments, and the stage of market reform.

INTRODUCTION

With the ongoing reform of electricity markets and the increasing integration of renewable energy sources (RESs), ensuring the secure, reliable, and economically efficient operation of power systems presents significant challenges.[1,2] In this context, the day-ahead (DA) market settlement mechanism (SM) serves as a crucial interface between physical dispatch and economic transactions. The SM directly determines electricity valuation, thereby affecting short-term resource allocation efficiency, long-term investment incentives,[3] and overall system operating costs.[4-6] Consequently, designing and evaluating an SM tailored to specific national contexts has become an urgent priority for global power market regulators.[7]

To manage network congestion and allocate resources, electricity markets worldwide have evolved SMs tailored to their respective grid structures and resource endowments. Existing literature and market practices typically classify these SMs into four types: 1) Uniform Pricing (UP), which disregards physical network constraints; 2) Zonal Pricing (ZP), which manages critical cross-zonal congestion;[8-10] 3) Locational Marginal Pricing (LMP), which explicitly accounts for physical constraints at all network nodes;[11] and 4) Hybrid Pricing (HP), which applies asymmetric pricing to the supply and demand sides to balance market efficiency and stability.[12]

In recent years, the academic community has extensively examined the differences among the aforementioned SMs.[13,14] For instance, studies based on the European market model show that ZP incurs efficiency losses when addressing intra-zonal congestion.[15] When analyzing actual data from the North American PJM market, LMP offers advantages for guiding the optimal allocation of flexible resources.[16] However, existing reviews and studies predominantly focus on comparison between LMP and ZP,[17-19] with limited attention to other SMs across various scenarios. Moreover, most references rely on single-dimensional indicators, such as SW maximization and operation costs minimization,[20] but lack a multi-dimensional evaluation framework. This limitation may obscure the roles of different SMs in congestion management under real-world system conditions and weaken the assessment of price-signal accuracy.

To address these research gaps, this paper analyzes the applicability of various SMs using a multidimensional quantitative evaluation framework. The main contributions include:

1) Constructing a quantitative evaluation framework for DA market SMs that covers three dimensions: short-term market efficiency, long-term investment incentives, system operating costs, and reveals the impact of different mechanisms on market operation. 2) Analyzing the compatibility of market SMs operating in Europe, the United States, and China,[21-23] this paper analyzes the compatibility of market SMs with resource allocation and regional energy policies. 3) Dividing the market into three typical scenarios: partial congestion, high-RES penetration,[24] and applicability imbalance.[25] The applicability of different SMs will be analyzed separately to provide market recommendations on SM selection.

The remainder of this paper is organized as follows. The existing DA market SMs and their implications are reviewed in Section 2. An evaluation framework encompassing multidimensional quantitative indicators is constructed in Section 3. The existing electricity market SMs and their evolution in Europe, the United States, and China are analyzed in Section 4. In Section 5, based on typical operating scenarios, the applicability of different SMs is evaluated, and corresponding suggestions are provided. Finally, Section 6 concludes the paper by presenting a list of challenges facing SMs and potential directions for future research.

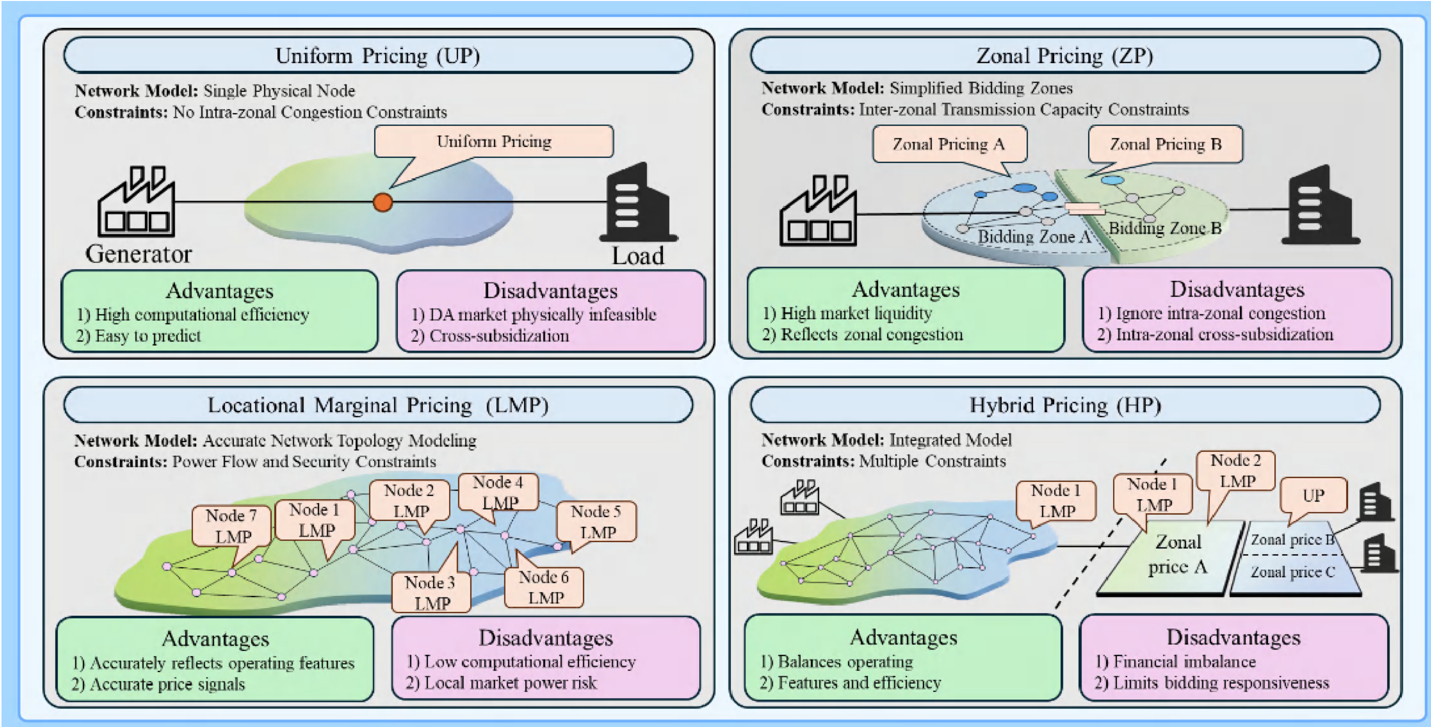

Figure 1. The characteristics of different settlement mechanisms

ELECTRICITY MARKET SMS

Depending on the pricing method and settlement point, SMs can be categorized into UP, ZP, LMP, and HP.[20,26] The characteristics of different SMs are shown in Fig 1. Among these, UP disregards physical network topology to maximize overall market liquidity.[18] By employing a nodal aggregation strategy, ZP strikes a balance between simplifying trading processes and managing macro-level congestion.[27] Conversely, LMP relies on detailed power flow models to reflect the precise marginal value of electricity at specific times and locations.[26] Finally, to mitigate the impact of price volatility on end-users and address supply-demand asymmetry, HP implements distinct pricing strategies across the supply and demand sides.[28]

Uniform pricing

UP is the most typical settlement model in the early stages of electricity market reform.[29] This approach disregards the capacity constraints of transmission components and differences in network topology, simplifying the entire coverage area into a single physical node to maximize unconstrained economic efficiency.[30] Generally, the clearing process only needs to satisfy the system-wide power balance constraint, whose shadow price establishes the system marginal price (SMP). Consequently, regardless of location, a single price is applied to settlement on both the supply and demand sides.[31]

The absence of topological constraints makes this mechanism highly transparent and computationally efficient, thereby facilitating intuitive price forecasting and lowering market entry barriers[2]. Therefore, UP is frequently adopted during the transition from centralized dispatch to market competition, as evidenced by the early British Pool and initial reform pilots in several Chinese provinces.[32,33] However, omitting transmission limits often renders the DA clearing results physically infeasible.[34] To alleviate actual congestion, the system operator must correct these schedules in the real-time market through out-of-merit re-dispatch.[30,35] Furthermore, the resulting congestion management costs are uniformly socialized, which inherently creates cross-subsidies for inefficient units and distorts long-term investment signals for both grid expansion and generation capacity.[36-40]

Zonal pricing

ZP is fundamentally a pricing mechanism based on nodal aggregation, partitioning the system into multiple bidding zones.[8] A representative symmetrical framework is adopted in the Pan-European unified electricity market. This mechanism accounts for inter-zonal capacity transfer constraints and establishes zonal settlement points across different countries. Specifically, cross-border capacity allocation primarily relies on Available Transmission Capacity (ATC) and Flow-Based Market Coupling (FBMC) approaches.[15,41,42]

Although Europe has practically configured its market bidding zones based on national administrative borders rather than physical grid bottlenecks, the debate over optimal zone configuration persists in academia. Static configurations based on administrative boundaries neglect actual network topology and power flow distribution, leading to distorted zonal prices.[43-45] Consequently, intra-zonal congestion induced by RES variability is not adequately captured, leading to implicit cross-subsidies within zones.[8,14] To address this, dynamic configuration methods have been proposed. These approaches employ intelligent algorithms to cluster nodes based on LMPs, thereby dynamically adapting zonal boundaries to reflect real-time grid conditions.[46-49] Ultimately, ZP aims to simplify trading processes and enhance market liquidity for cross-zonal resource allocation. To achieve this, the number of zones and their adjustment frequencies must be minimized.[12] However, this inherent rigidity makes it challenging for ZP configurations to keep pace with the rapid evolution of system operations and shifting resource endowments.[50]

Locational marginal pricing

LMP is a pricing mechanism fundamentally driven by network topology and physical power flow limits.[51] Mathematically, it represents the marginal cost of supplying the next increment of electrical demand at a specific node in an economic dispatch model, which aims to maximize SW or minimize system operation costs.[52] An LMP typically comprises three distinct components: the marginal energy, congestion, and loss components.[53] By integrating these elements, LMP accurately reflects the spatiotemporal marginal value of electricity.[11,54] The fundamental DC optimal power flow (DC-OPF) formulation used to derive LMPs can be expressed as follows:[55]

$$\min \sum_{g\in G} C_g(P_g) \tag{1a}$$

s.t.

$$\sum_{g\in G} P_g + \sum_{r\in R} P_r = \sum_{d\in D} P_d \ (\lambda) \tag{1b}$$

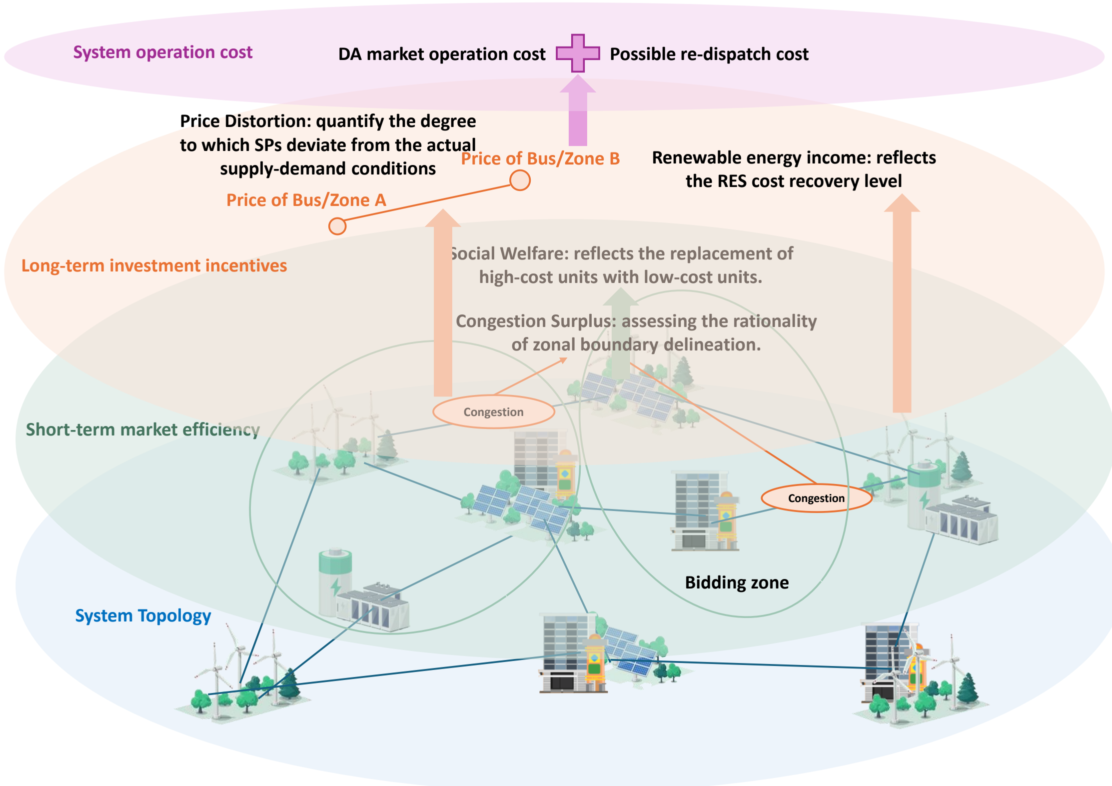

Figure 2. The proposed evaluation framework, mapping economic dimensions to the underlying physical system topology.

$$-F_l^{max} \le \sum_{i\in N} PTDF_{l,i}\cdot\Big(\sum_{g\in G_i} P_g + \sum_{r\in R_i} P_r - \sum_{d\in D_i} P_d\Big) \le F_l^{max}, \forall l \in L(\mu_l^-, \mu_l^+) \quad (1c)$$

$$P_g^{min} \le P_g \le P_g^{max}, \forall g \in G \quad (1d)$$

$$0 \le P_r \le P_r^{max}, \forall r \in R \quad (1e)$$

where, N denotes the set of buses and $i \in N$ represents the bus index; G, R, and D denote the sets of conventional generators, RES units, and loads, respectively; G_i,R_i,and D_i denote the sets of conventional generators, RES units, and loads connected to bus i, respectively; L is a set of power transmission lines; P_g, P_r, and P_d represent the output power of conventional generator g, the output power of RES unit r, and the demand of load d, respectively; $C_g(\ )$ denotes the generation cost function of conventional generator g; $PTDF_{l,i}$ is the Power Transfer Distribution Factor (PTDF) of transmission line l with respect to bus i; F_l^{max} denotes the transmission capacity limit of line l. The constraint (1b) is the system power balance constraints (λ is the corresponding system marginal price); (1c) is the transmission capacity line flow constraints; μ_l^- and μ_l^+ are the corresponding shadow prices associated with the lower and upper transmission limits; (1d) and (1e) are the upper and lower limits of output for conventional generators and RES units.

It should be noted that a complete LMP formulation typically comprises marginal energy, marginal congestion, and marginal loss components. In the DC-OPF model employed in these numerical simulations, network losses are intentionally neglected; therefore, the marginal loss component is not modeled. This is a commonly adopted simplification in comparative market-design studies, as it allows the analysis to isolate the impact of physical congestion management and spatial price differences across different settlement mechanisms without introducing additional nonlinear effects associated with network losses.

LMP can provide market participants with price signals that reflect the characteristics of network topology and power flow distribution. However, due to high price sensitivity, it is prone to triggering strategic behavior by market participants at critical buses, thereby exacerbating market power risks.[56,57]

Hybrid pricing

HP implements distinct SMs on the supply and demand sides to concurrently address generator-side congestion management and load-side price stability.[28] Depending on the specific combinations of mechanisms, HP can be broadly classified into Nodal-Zonal Hybrid (NZH) and Zonal-Uniform Hybrid (ZUH). NZH is predominantly adopted by several ISOs/RTOs in the United States, aiming to balance short-term physical congestion management with long-term market flexibility incentives. Reference[23] indicates that supply-side LMPs effectively capture highly localized system congestion, while demand-side ZP mitigates price volatility and reduces trading complexity.[58] This asymmetric design reflects a pragmatic institutional trade-off between physical accuracy and market stability.[21] Nevertheless, aggregating demand across zones inherently obscures local scarcity signals.[59] Consequently, it dampens price responsiveness and hinders the efficient integration of flexible resources, such as distributed energy storage and demand response.[20,60]

A representative example of ZUH is the Prezzo Unico Nazionale (PUN) in Italy. Under this mechanism, the DA market employed an asymmetric structure featuring ZP for generators and UP for consumers. Although this mechanism effectively smoothed spatial price discrepancies and mitigated procurement risks,[61-63] its inherent asymmetry masked true local scarcity. This misalignment inevitably led to cross-subsidization from low-cost to high-cost regions and generated substantial financial settlement deficits, ultimately compromising overall resource allocation efficiency.[64-66] To restore the temporal and spatial value of electricity, Italy officially abolished the PUN mechanism in 2025 and transitioned the demand side to ZP.[67,68]

ANALYTICAL FRAMEWORK: HOW TO EVALUATE SMS

To further illustrate the applicability of market SMs, this section constructs a multi-dimensional quantitative framework. As illustrated in Figure 2, this framework bridges the fundamental physical system topology and three core economic dimensions: short-term market efficiency, long-term investment incentives, and system operating costs.[69]

Short-term market efficiency

The objective of the electricity market is to achieve optimal resource allocation while satisfying physical constraints.[26,70] Therefore, SW reflects short-term market efficiency, and congestion surplus (CS) quantifies the impact of physical constraints on RCs.[54]

1) Social Welfare

SW is typically defined as the sum of consumer surplus, producer surplus, and CS. It reflects whether the SM can promote the replacement of high-cost units with low-cost units. A larger SW indicates a higher short-term system configuration efficiency. When demand is inelastic, the cost of market operation is usually used to characterize SW. A lower value indicates higher short-term operating efficiency[20]. At any time, the SW can be expressed as:

$$SW_t = \sum_{d\in D} U_d(P^D_{d,t}) - \sum_{g\in G} C_g(P^G_{g,t}) \tag{2}$$

where, D and G are the sets of loads and generators, respectively; $P_{d,t}^{D}$ is the is the load demand of load d at time t ; $U_d(\,)$ is the utility function of the load d; $P_{g,t}^{G}$ is the power output of generator g at time t; $C_g(\,)$ is the generation cost function of generator g which is typically modeled as a quadratic function or a piecewise linear function.[71]

2) Congestion surplus

When there is congestion in the system, price differences between nodes or regions can generate CS. This indicator not only reflects the scarcity of power transmission resources but also serves as a key basis for assessing the rationality of zonal boundary delineation.[72,73] If the explicit CS under the market SM is lower than the actual CS, it cannot accurately reflect market supply and demand conditions, and there is a risk of price deviation.[74,75] By comparing CS across different SMs, price efficiency can be revealed. CS is defined as the difference between demand-side payments and supply-side revenues, expressed as:

$$CS_t = \sum_{d\in D} \lambda^{load}_{d,t} \cdot P^D_{d,t} - \left(\sum_{g\in G} \lambda^{gen}_{g,t} \cdot P^G_{g,t} + \sum_{r\in R} \lambda^{RES}_{r,t} \cdot P^{RES}_{r,t} \right) \tag{3}$$

where, $\lambda_{d,t}^{load}$, $\lambda_{g,t}^{gen}$ and $\lambda_{r,t}^{RES}$ denote the actual settlement prices (SPs) of load d, conventional generator g, and RES unit r at time t, respectively; $P_{d,t}^{D}$, $P_{g,t}^{G}$ and $P_{r,t}^{RES}$ represent denote the electricity demand of load d, the cleared output power of conventional generator g, and the cleared output power of RES unit r, respectively.

Long-term investment incentives

The evaluation of SMs should not be limited to their impact on short-term market efficiency but should also guide future resource allocation. If the SM obscures the true supply-demand conditions, it may provide incorrect investment signals, causing investment decisions to deviate from the optimal allocation.[76] Therefore, this section proposes capturing the degree of deviation in price signals via price distortion and the RES absorption capacity via the RES price level.

1) Price distortion

Price distortion aims to quantify the degree to which SPs deviate from the actual supply-demand conditions. Prices that are too low or too high will cause cross-subsidies among market participants.[77] Since LMP is the most accurate and can reflect the actual supply-demand conditions of different nodes, this paper uses the difference between a node's ZP at a given moment and LMP to intuitively characterize the spatial distribution of price distortion for each node.[78] The price deviation $\Delta\lambda_{i,t}$ of node i at time t is expressed as:

$$\Delta\lambda_{i,t} = \lambda^{Zone}_{z(i),t} - \lambda^{LMP}_{i,t} \tag{4}$$

where, $\lambda_{z(i),t}^{Zone}$ is the unified clearing price of the price zone to which node i belongs during time t; $\lambda_{i,t}^{LMP}$ is the LMP of node i at time t; $\Delta\lambda_{i,t}$'s unit is \$/MWh. When $\Delta\lambda_{i,t} > 0$, it indicates that the ZP overestimates the true value of the electricity at that node; When $\Delta\lambda_{i,t} < 0$, it reflects the cross-subsidy for that node region.

2) Renewable energy income level

With the large-scale integration of RES, there is often a local oversupply during peak power-generation periods, which may lead to low or even negative electricity prices.[79] At this point, it is crucial that SM accurately reflects physical constraints. For instance, in a regional market, if the regional division fails to effectively isolate congestion, it can artificially inflate the SP of RES within the congested areas. This creates artificially high returns, which in the long run will mislead investors and exacerbate the risk of wind and solar power curtailment.[80-82] A reasonable SM should expose this absorption dilemma through price signals and guide the deployment of RES to nodes/zones that need it most. The price level of RES is defined as the ratio of the weighted-average revenue per unit of on-grid electricity to the average market electricity price. MV_{RES}<1 means that RES is facing value deflation. It can be represented as:[83]

$$MV_{RES} = \frac{\sum_{t\in T}\sum_{r\in R} P^{RES}_{r,t} \cdot \lambda_{r,t}}{\left(\sum_{t\in T}\sum_{r\in R} P^{RES}_{r,t}\right) \cdot \bar{\lambda}_{sys}} \times 100\% \tag{5}$$

where, R is the set of RES units, and T denotes the set of scheduling periods; $P_{r,t}^{RES}$ denotes the actual dispatched output power of RES unit r at time t; $\lambda_{r,t}$ denotes the LMP corresponding to RES unit r at time t; $\bar{\lambda}_{sys}$ denotes the system-wide load-weighted average electricity price. A higher value of MV_{RES} indicates that RES units are able to obtain higher market revenues relative to the system average electricity price level.

System operating costs

Although the DA market SM based on pure-economic clearing is highly efficient, it often suffers from physical infeasibility.[30,84] In practice, the scheduling plan is usually revised via the Re-dispatch/Ancillary Service Market after the DA market clears. Therefore, the sum of the electricity purchase cost and RC reflects the system operating cost. In LMP, because the clearing model theoretically accounts for all physical constraints, the RC approaches zero.[20] Under LMP, the DA clearing cost represents the actual system operating cost. In UP or ZP, the closer to purely economic clearing, the lower the DA generation cost, but the higher the RC, and the greater the potential increase in total operating cost.[15,27] The formula for calculating system operating costs is:

$$C_{redispatch} = \sum_{t\in T}\sum_{g\in G} C_g(P^{Feasible}_{g,t}) - \sum_{t\in T}\sum_{g\in G} C_g(P^{Market}_{g,t}) \tag{6}$$

where $C_g(\,)$ is the the generation cost function of conventional generator g; $P_{g,t}^{Feasible}$ is the feasible redispatched output of generator g at time t considering network topology and transmission constraints; $P_{g,t}^{Market}$ is the cleared output of generator g obtained from the initial DA market clearing process; T and G denote the sets of scheduling periods and generators, respectively. The difference in cost between the two operating costs represents the additional RC required to relieve transmission congestion and maintain secure system operation.

SETTLEMENT MECHANISMS IN MAJOR ELECTRICITY MARKETS

SMs implemented across various countries and regions rarely pursue purely theoretical optimal solutions; rather, they are practical outcomes shaped by a combination of resource distribution, network topology, and institutional frameworks.[16,85,86] Below, we analyze the specific SMs and their driving factors in typical markets, including the United States, Europe, and China.[87]

The United States

The delineation of settlement boundaries in the U.S. electricity market is influenced by both historical asset ownership and the physical characteristics of local networks. These delineation approaches generally fall into two categories: asset-oriented and physical-oriented. The former is based on the legacy service territories of vertically integrated utility companies, with prominent examples including PJM, ISO-NE, NYISO, and SPP.[88] The latter primarily relies on identifying critical system congestion and topological features, as exemplified by CAISO and MISO.[89] Furthermore, although ERCOT operates as an independent power grid exempt from federal jurisdiction, its settlement boundary division also follows this physical-oriented logic.[20,90]

The specific SMs within each market footprint are determined by their respective Independent System Operator (ISO) or Regional Transmission Organization (RTO). Markets under the jurisdiction of the Federal Energy Regulatory Commission (FERC) strictly adhere to the core principles of its

Standard Market Design (SMD). Specifically, these markets adopt a two-settlement system (DA and real-time), implement LMP-based congestion management on the supply side, and provide Financial Transmission Rights (FTRs) to hedge congestion risks.[7,91]

Overall, all settlement regions in the United States adopt HP. This asymmetric mechanism simultaneously reflects local system congestion and mitigates demand-side price volatility. Furthermore, to enhance market liquidity and facilitate bilateral financial transactions, various markets have established numerous aggregated trading hubs on the supply side.[92,93] Due to the diverse zoning methodologies mentioned previously, the scope and specific calculation methods for demand-side weighted average prices vary across these markets.[20,94]

1) Asset-oriented markets

The PJM market covers high-density load areas and features a complex network architecture. To manage local congestion risks and improve liquidity in financial transactions, PJM adopts a ZP method based on nodal aggregation on the demand side. The core advantage of this approach lies in simplifying trading processes and maintaining price stability while inherently accounting for underlying congestion management.[93] Specifically, PJM implements differentiated settlement strategies tailored to demand-side characteristics. For discrete, easily separable demand entities, settlement is directly mapped to individual physical nodal LMPs. Conversely, for Load-Serving Entities (LSEs) spanning multiple nodes, PJM establishes specific Pricing Nodes (P-Nodes) and estimates load distribution factors (LDFs). The SP is then calculated as the load-weighted average of the relevant underlying LMPs.[95,96] In addition, post-DA market clearing uplift costs, incurred to maintain system reliability, are assigned to market participants based on the cost causation principle.[97,98]

Unlike PJM's highly granular settlement based on P-Nodes and dynamic distribution factors, the ISO-NE market is primarily guided by system reliability requirements and legacy administrative boundaries. ISO-NE statically aggregates demand-side nodes into distinct Load Zones for settlement.[99] For each Load Zone, the uniform SP is determined by calculating the load-weighted average of all underlying physical nodal LMPs, utilizing either actual or DA-forecasted load shares.[100,101] This aggregation strategy, rooted in fixed reliability boundaries, ensures operational stability and effectively insulates the demand side from drastic price volatility caused by single-node congestion. Furthermore, recognizing fuel supply constraints (e.g., natural gas pipeline limitations), ISO-NE introduced a scarcity pricing mechanism. During reserve capacity shortages, this mechanism elevates real-time LMPs to reflect the true scarcity value of physical resources, thereby guiding market participants to provide available capacity through accurate price signals.[102]

2) Physically oriented markets

In the CAISO market, prices remain relatively balanced within specific zones because the zonal delineations inherently account for critical transmission constraints. Consequently, CAISO employs Default Load Aggregation Points (DLAPs) for demand-side settlement, calculating the regional SP using a load-weighted average of underlying LMPs.[101,103] On the generation side, CAISO has established major trading hubs, such as NP15 and SP15.[104] By aggregating the LMPs of multiple generation nodes, these hubs provide market participants with stable reference prices for medium- and long-term bilateral contracts and financial derivatives.[92]

The MISO market covers a vast geographic footprint, characterized by high but spatially uneven wind power penetration. To manage network congestion and reconcile the diverse interests of member states, MISO delineates load zones and aggregates demand-side settlements based on the footprints of Local Balancing Authorities (LBAs).[105,106] This strategy effectively balances physical network constraints with administrative jurisdictions, maintaining stable demand-side SPs across localized areas.[107] To ensure system reliability, MISO adopts an uplift SM similar to PJM's, allocating actual market operating cost deviations to responsible parties.[61,108]

Europe

The European electricity market adopts ZP, which partitions the geographical footprint into distinct Bidding Zones—historically based more on national administrative borders than physical grid bottlenecks—and treats each zone as a single, unconstrained physical node. In the DA market, the Single Day-Ahead Coupling (SDAC) mechanism is employed across European power exchanges (e.g., EPEX SPOT). This mechanism aggregates bids and offers from various zones and calculates the Market Clearing Price using the EUPHEMIA algorithm, thereby enabling implicit cross-border electricity auctions. Ultimately, SDAC aims to guide power flows from low-price to high-price zones via price signals, optimizing cross-zonal electricity trading.[109]

However, driven by the growing penetration of RES and the rising frequency of inter-zonal transactions, congestion on cross-border transmission lines has become increasingly prominent. To address this challenge and accurately reflect cross-zonal capacity constraints, the European capacity allocation mechanism has progressively evolved from the static ATC approach to FBMC.

Specifically, the ATC method relies on predefined ex-ante scenarios encompassing significant uncertainty. This approach disregards the actual physical power flow distribution governed by Kirchhoff's laws, treating the transmission capacity limit between zones merely as a fixed commercial constraint.[110,111] The fundamental ATC constraint can be formulated as follows:

$$P_{A\to B}^{\min} \le P_{A\to B} \le P_{A\to B}^{\max} \tag{7}$$

where, $P_{A\to B}$ is the planned exchange power from zone A to zone B; $P_{A\to B}^{\min}$ and $P_{A\to B}^{\max}$ are the upper and lower limits of the transmission capacity between zones A and B.

Because the ATC mechanism ignores actual power flow distributions, it obscures the true capacity utilization of inter-zonal transmission branches resulting from cleared commercial transactions. This misalignment can lead to the underutilization of transmission capacity and a consequent loss of SW. Alternatively, it may cause severe physical line congestion, necessitating costly out-of-merit re-dispatch actions and thereby significantly increasing RCs.[112,113]

Therefore, to enhance the accuracy of the clearing process, the Central Western European (CWE) zone pioneered the FBMC framework. Unlike ATC, FBMC no longer prescribes predefined bilateral cross-border transfer capacities. Instead, it explicitly restricts transmission capacity during the market-clearing process using the Remaining Available Margin (RAM) and PTDFs. This approach inherently accounts for the actual physical power flows on critical grid elements during clearing, as described in Equation (8):[114]

$$\sum_{z} PTDF_{z,l} \cdot NPX_z \le RAM_l \tag{8}$$

where, $PTDF_{z,l}$ is the PTDF of the net injected power in the z-th zone to the l-th critical line. NPX_z is the net injection power in the z-th zone; RAM_l is the RAM of the l-th critical branch (CB).

China

China's electricity market currently employs a "dual-track" settlement system, exhibiting distinct transitional characteristics. This system operates a parallel settlement process that accommodates both legacy physical forward contracts and spot-market deviations.[115] To balance system stability with economic efficiency, most pilot provinces have adopted the HP mechanism in their DA markets—specifically, applying LMP on the supply side and ZP or UP on the demand side.[116,117]

This asymmetric design stems from China's unique macroeconomic context. On the demand side, industrial and commercial production activities remain highly sensitive to electricity price volatility, while agricultural and residential sectors rely on strictly regulated, guaranteed tariffs. Conversely, on the generation side, many net power-importing provinces feature complex grid topologies and severe local congestion. Consequently, highly granular price signals (i.e., LMPs) are imperative to guide optimal unit commitment and dispatch, thereby mitigating congestion risks and enhancing operational efficiency.[118,119]

Given the significant spatial disparity in resource endowments across provinces, regional SMs must be tailored accordingly. For instance, in Gansu province—characterized by exceptionally high-RES penetration —the SM must balance the efficient integration of renewable energy with the procurement of adequate system regulation capacity.[120] Therefore, Gansu implements a co-optimized clearing of energy and ancillary services, comple-

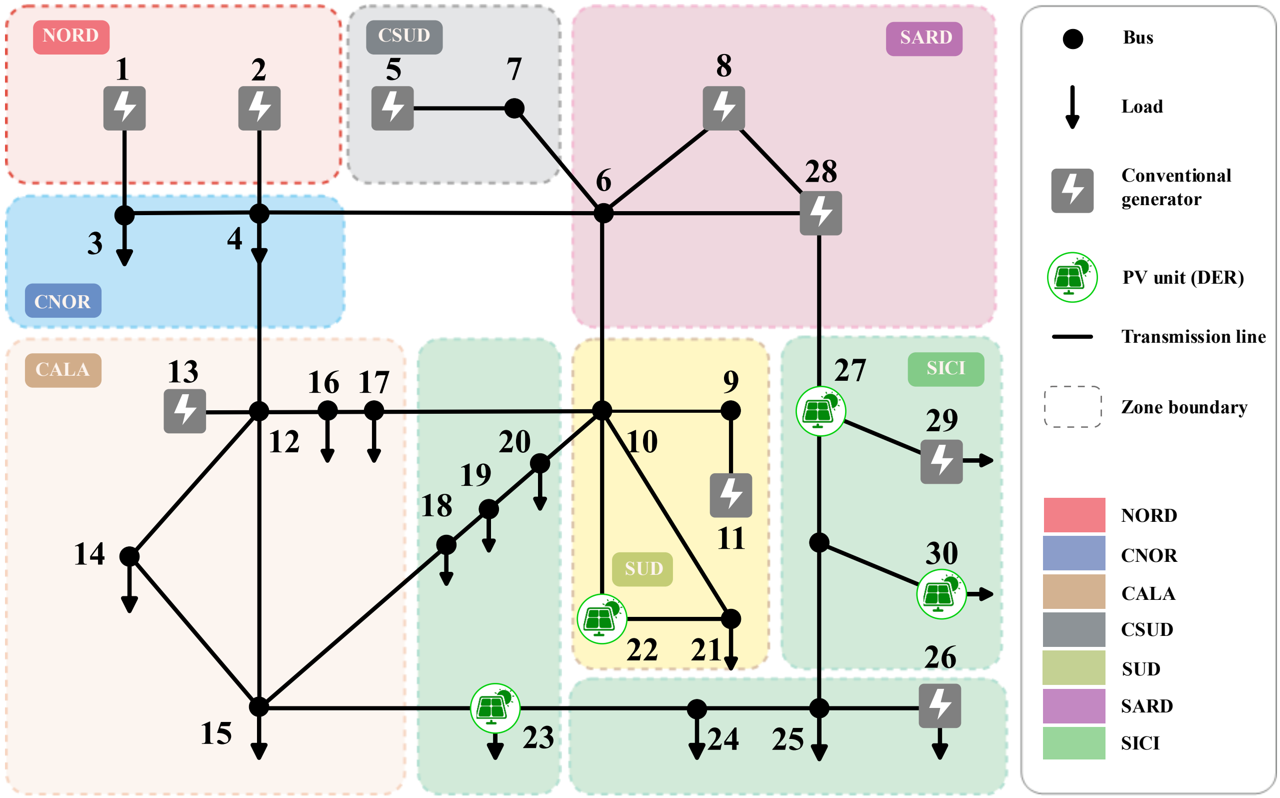

Figure 3. Schematic of the 7-zone test system. Note: Zone NORD represents the heavy load center, and zone SICI indicates the high-RES penetration zone. Zones CNOR, CSUD, and SUD cover the main transmission corridors.

mented by a refined deviation cost-sharing mechanism. This approach effectively mitigates the accumulation of imbalance funds and addresses the inadequate compensation for flexible resources typical of high-RES scenarios. While this hybrid planned-market mechanism successfully marries market stability with resource allocation requirements, its inherent supply-demand asymmetry can generate substantial financial settlement imbalances. Such imbalances distort the true spatiotemporal value of electricity, potentially inducing conflicts between physical dispatch instructions and the commercial interests of market participants.[121,122]

NUMERICAL SIMULATION

Case settings

To comprehensively evaluate the performance and applicability of various SMs, the numerical simulations in this study are designed based on the fundamental market characteristics of Europe and the United States. Accordingly, a custom test system was constructed to encompass diverse network topologies, resource endowments, and bidding zone configurations, as illustrated in Figure 3. It should be noted that to maintain computational efficiency and strictly focus on the fundamental price signals and congestion management of the different settlement mechanisms, the cost functions of conventional generators ($C_g()$) in Equations (1) and (2) are modeled as standard quadratic functions in the simulation. Furthermore, complex integer constraints associated with unit commitment—such as start-up costs, no-load costs, and minimum up/down times—are excluded from this day-ahead market clearing model. This widely adopted simplification ensures that the comparative differences in Social Welfare and Re-dispatch Costs across Cases 1-4 are driven entirely by the spatial pricing of transmission constraints rather than the non-convexities of unit commitment.

It should be explicitly stated that in the simulations for the ZP and HP mechanisms (Cases 2 and 4), the predefined zonal boundaries are assumed to be statically fixed. This static configuration is designed to reflect the current baseline practices in most established zonal markets. However, it is worth noting that if a dynamic zoning approach were adopted—where boundaries are dynamically reconfigured to align with real-time power flow bottlenecks—the severe intra-zonal congestion could be more effectively isolated. As a result, adopting dynamic zoning could partially mitigate the high RCs currently observed under the static ZP mechanism, bridging the efficiency gap between ZP and LMP.

Specifically, a Monte Carlo simulation was used to account for fluctuations in RES generation and changes in demand, yielding 1000 operating states, as shown in Figure 4.

Based on the aforementioned spatial distribution of resources and dynamic grid conditions, the system operating states are clustered into three typical scenarios to comprehensively evaluate the performance of different SMs. It should be explicitly clarified that Scenarios A, B, and C are not intended to represent the most statistically probable operating states among the 1000 samples. Instead, they are selected as representative stress-test scenarios that capture typical extreme boundary conditions. Therefore, their representativeness lies in their ability to reveal the behavior of different settlement mechanisms under severe congestion and supply–demand imbalance, rather than in their occurrence frequency within the Monte Carlo samples.

During specific periods, the southern region (e.g., CALA, SICI, SUD) serves as the primary generation hub, while the northern region (e.g., NORD, CNOR) serves as the primary load center, leading to severe spatial supply-demand imbalances. For instance, in Sample 488, the system net load peaks at 291.80 MW due to extremely low RES output of about 0.78 MW. Consequently, maintaining the supply-demand balance relies heavily on conventional units in the south. This massive south-to-north power transfer causes severe congestion on the CB.

2) Scenario B (High penetration of RES):

This scenario captures periods of high-RES generation and low system demand, resulting in extreme levels of RES penetration. In Sample 321, the system load drops to a trough of 269.05 MW while photovoltaic (PV) output surges to 242.00 MW, achieving an RES penetration of 89.9%. This abundant supply of near-zero-marginal-cost electricity significantly depresses clearing prices, particularly within the SICI region.

3) Scenario C (Imbalance of supply-demand):

Extreme supply-demand dynamics fundamentally disrupt market settlements. During certain periods (such as Sample 615), robust RES generation

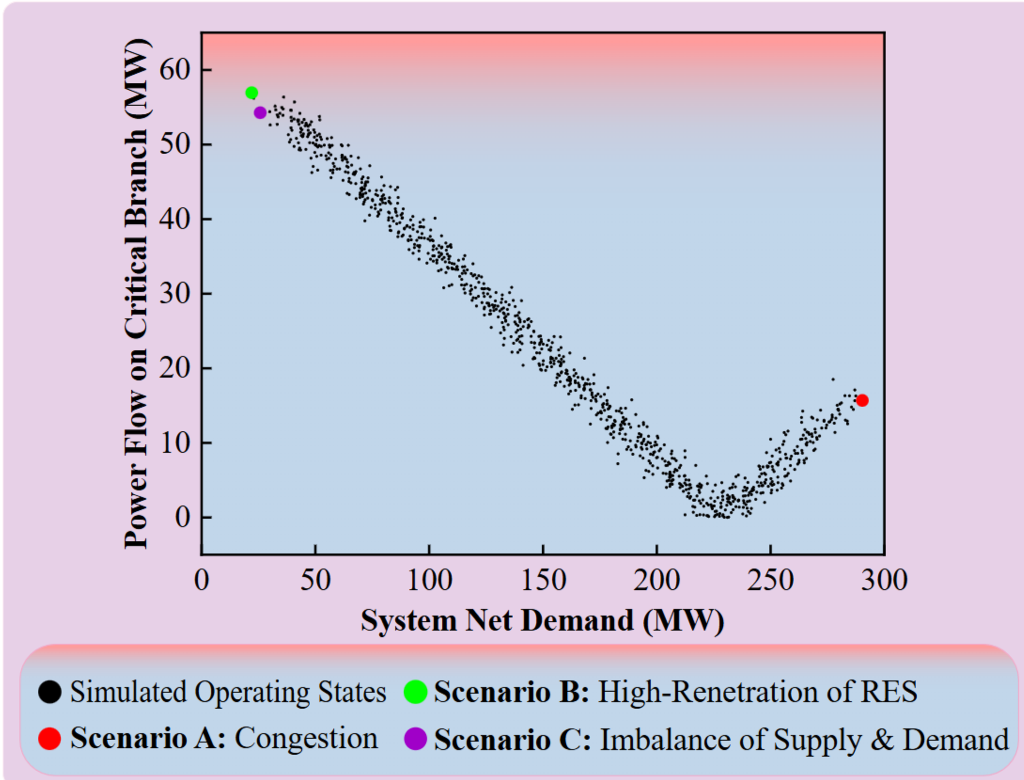

Figure 4. Distribution of system operating states via Monte Carlo simulation and identification of representative scenarios. Note: The x-axis represents the system net demand (MW), and the y-axis denotes the power flow on the CB (MW). Scenarios A, B, and C reflect typical operating states of congestion, high-RES penetration, and supply-demand imbalance, respectively.

Table 1. Settings of the comparison case

Scenario	Case	Settlement Mechanism	Key Features
A	1	UP	Sample: 488 Demand: 291.80MW RES: 0.78MW State: Congestion on the CB (Line 4-12) Concern: Does the SP accurately reflect the severity of congestion?
	2	ZP	
	3	LMP	
	4	HP	
B	1	UP	Sample: 321 Demand: 269.05W RES: 242.00MW State: RES penetration 91.7% Concern: Can the SM's price signals capture the impact of high-RES penetration?
	2	ZP	
	3	LMP	
	4	HP	
C	1	UP	Sample: 615 Demand: 261.7MW RES: 235.9MW State: System-wide oversupply and price collapse Concern: Can the SM effectively reflect extreme global supply-demand imbalances?
	2	ZP	
	3	LMP	
	4	HP	

combined with subdued demand leads to a system-wide oversupply. This extreme imbalance typically triggers market price collapse.

The detailed settings for these three typical scenarios—simulated across the four SMs to analyze short-term market efficiency, long-term investment incentives, and system operating costs—are summarized in Table 1.

Market-clearing price

To illustrate the influence of the different SMs, the distributions of market clearing prices across scenarios A, B, and C are depicted in Figure 5.

In summary, under Case 1 (UP), the same SP is applied to both the supply and demand sides throughout the entire system. Case 4 (HP) applies nodal prices to generators but maintains a unified, load-weighted SP on the demand side. Under Case 2 (ZP), because the RAMs of cross-zonal CBs are enforced, the clearing results exhibit a step-like zonal price profile. Conversely, Case 3 (LMP) strictly accounts for the detailed network topology and individual line capacity limits, resulting in highly granular and pronounced nodal price fluctuations.

Based on the operational characteristics of the different scenarios, the high-RES penetration in Scenario B significantly reduces the system marginal cost due to the near-zero bidding prices of renewable generation. Similarly, the severe system-wide oversupply in Scenario C leads to a drastic collapse in overall market prices. Consequently, both scenarios exhibit significantly lower baseline clearing prices compared to normal operating conditions. However, despite these depressed baseline prices, the acute localized bottlenecks caused by high-RES penetration (Scenario B) and extreme supply-demand imbalances (Scenario C) significantly exacerbate spatial price volatility, lead-

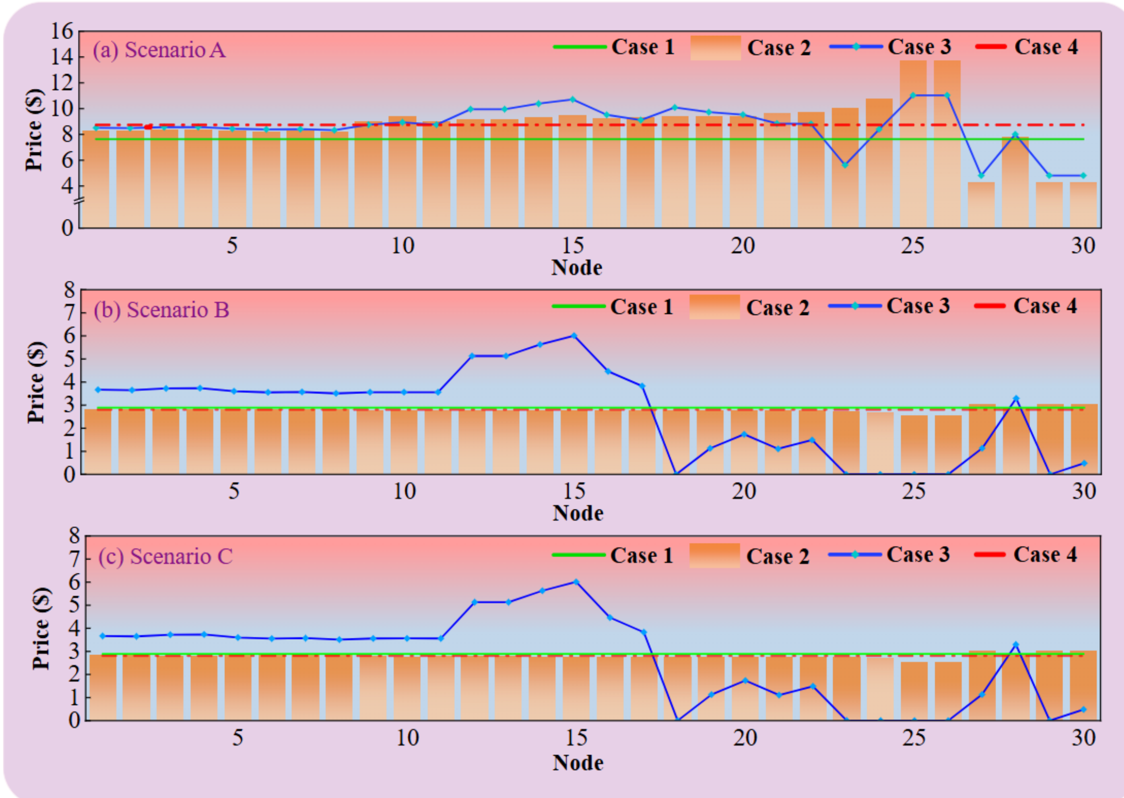

Figure 5. Distribution of market-clearing price

ing to a substantially widened LMP spread in Case 3.

Market performance

To comprehensively evaluate the market performance of the four SMs (Cases 1-4), this section analyzes the simulation results across the three typical operating scenarios (Scenarios A, B, and C) from three dimensions: short-term market efficiency, long-term investment incentives, and system operating costs.

1) Short-term market efficiency

Short-term market efficiency is primarily quantified using two indicators: system-wide SW and CS. The results for the four SMs across the three operating scenarios are illustrated in Figure 6.

Overall, Case 1 delivers the highest SW while the CS remains zero, closely approximating an unconstrained "purely economic dispatch". As spatial network constraints are progressively enforced (Cases 2 and 4), SW gradually decreases while CS emerges and grows. When the transmission capacity limits of all individual lines are strictly enforced (Case 3), SW theoretically reaches its lowest level, CS peaks, and market price spreads widen significantly.

Specifically, in Scenario A (winter evening peak), the entire grid operates under heavy load without PV generation support, making the system heavily reliant on inter-zonal transmission lines. Notably, the SW for Case 3 is \$27,835, which is higher than the \$27,802 observed in Cases 2 and 4. Because Case 3 captures more granular system congestion, its CS reaches \$240.8, significantly higher than the \$90.1 in Cases 2 and 4. In Scenario B, the increased RES penetration enables the SICI region to utilize abundant, low-priced electricity, thereby reducing the SP. However, due to reduced overall system demand and severe cross-zonal transmission congestion on Line 27-28, the SW across Cases 1-4 decreases by approximately 5.1% to 5.6% compared to Scenario A. Ignoring significant internal congestion (Cases 2 and 4) reduces the CS by approximately 94.9% relative to Scenario A. Conversely, when full transmission margins are considered (Case 3), the widened price spread results in a CS that is 81.8% higher than in Scenario A. Scenario C further reflects the impact of extreme supply-demand dynamics on short-term efficiency. Due to the severe system-wide oversupply and subsequent price collapse, effective market trading volume is suppressed, leading to a slight decrease in SW, a further widening of the price spread, and a marginal increase in CS.

Crucially, it is worth noting an apparent theoretical paradox: Case 3 strictly enforces all network constraints; therefore, its SW should theoretically be lower than that of Cases 2 and 4, which relax intra-zonal limits. However, the simulation results demonstrate that Case 3 actually yields a higher SW. This occurs because, under ZP/HP mechanisms (Cases 2 and 4), the system operator must conservatively reduce the cross-zonal ATC to maintain sufficient reliability margins against unmodeled intra-zonal congestion. Conversely, the LMP mechanism (Case 3) explicitly models actual physical power flows based on Kirchhoff's laws, thereby safely maximizing transmission capacity utilization without withholding conservative ex-ante margins.

In summary, for markets characterized by relatively abundant transmission capacity and clearly defined congestion boundaries—such as the Swedish electricity market, which boasts strong cross-border connectivity, abundant flexible hydropower, and a clear north-to-south power flow—a ZP mechanism is suitable for SW maximization. Conversely, for markets facing high-RES penetration, frequent localized congestion, and spatial imbalances—such as the Great Britain market, where wind power accounts for 30% of annual generation—greater emphasis must be placed on improving system deliverability and guiding congestion management via precise price signals; therefore, introducing an LMP mechanism is highly recommended. Finally, for markets requiring a balance between price stability and the gradual strengthening of locational signals, HP serves as an effective transitional mechanism.

2) Long-term investment incentives

a) Price distortion

Price distortion quantifies the deviation between the applied SP and the true spatiotemporal marginal value of electricity (i.e., the LMP), as illustrated in Figure 7. Because Case 1 (UP) yields a single system-wide price with maximum deviation, and Case 4 (HP) simply combines a zonal SP for load and nodal LMPs for generation, analyzing the discrepancy between Case 2 (ZP) and Case 3 (LMP) is sufficient to capture the core dynamics of price distortion without analytical redundancy.

As depicted in Fig. 8, the localized congestion on the CB (Line 4-12) in Scenario A induces notable price deviations across nodes 21 to 26, peaking

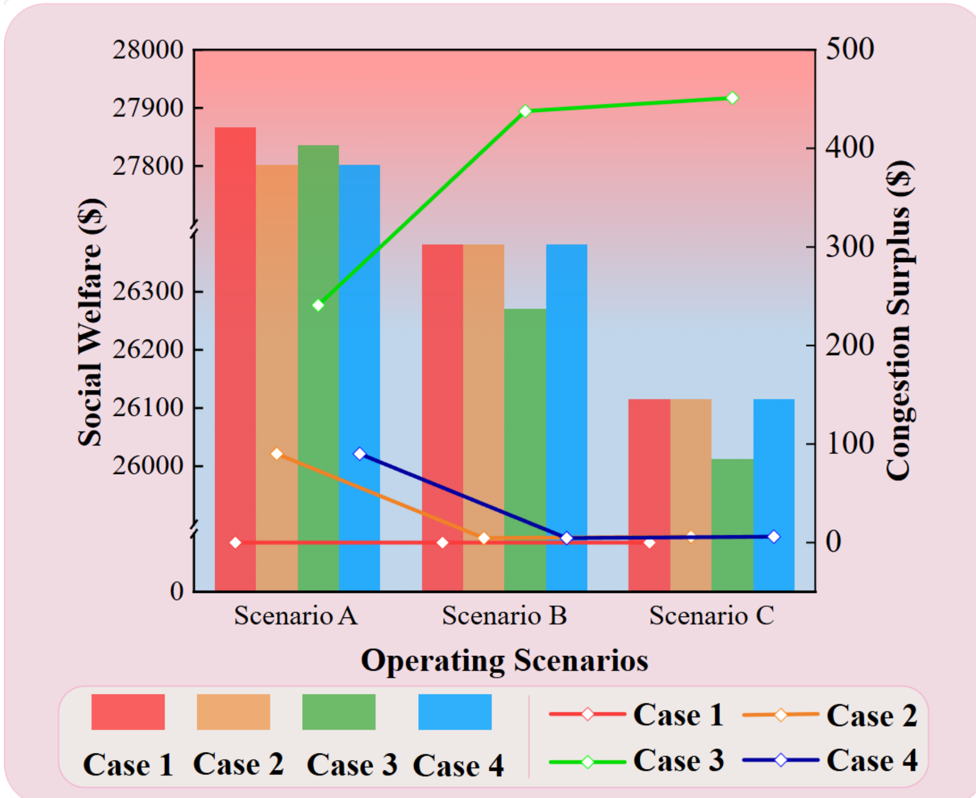

Figure 6. Comparison of short-term market efficiency: SW and CS across different pricing mechanisms. Note: Bar charts (left axis) represent the SW, line charts (right axis) illustrate the CS.

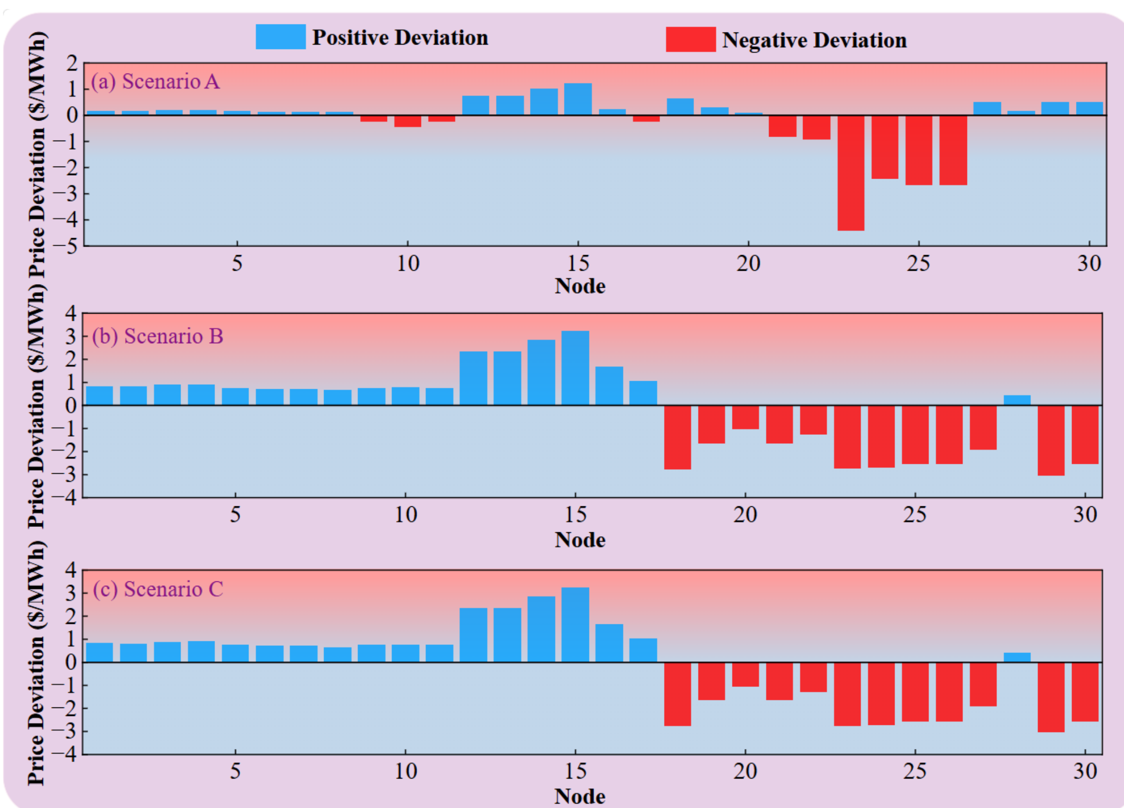

Figure 7. Distribution of the price deviations Note: The y-axis represents the degree of price distortion (ZP in Case 2 compared with LMP in Case 3), and the x-axis denotes the 30 nodes. Blue bars indicate positive deviations, while red bars indicate negative deviations.

at approximately $4.5/MWh at node 23. However, this spatial price distortion becomes markedly more pronounced under the high-RES penetration in Scenario B. Abundant RES generation in the SICI zone drives local marginal costs close to zero. Naturally, market optimization attempts to source this low-cost electricity for the NORD and CNOR load centers. However, binding cross-zonal transmission constraints severely restrict this power flow. Consequently, the load-dense NORD zone is forced to dispatch expensive local conventional thermal units to meet its demand.

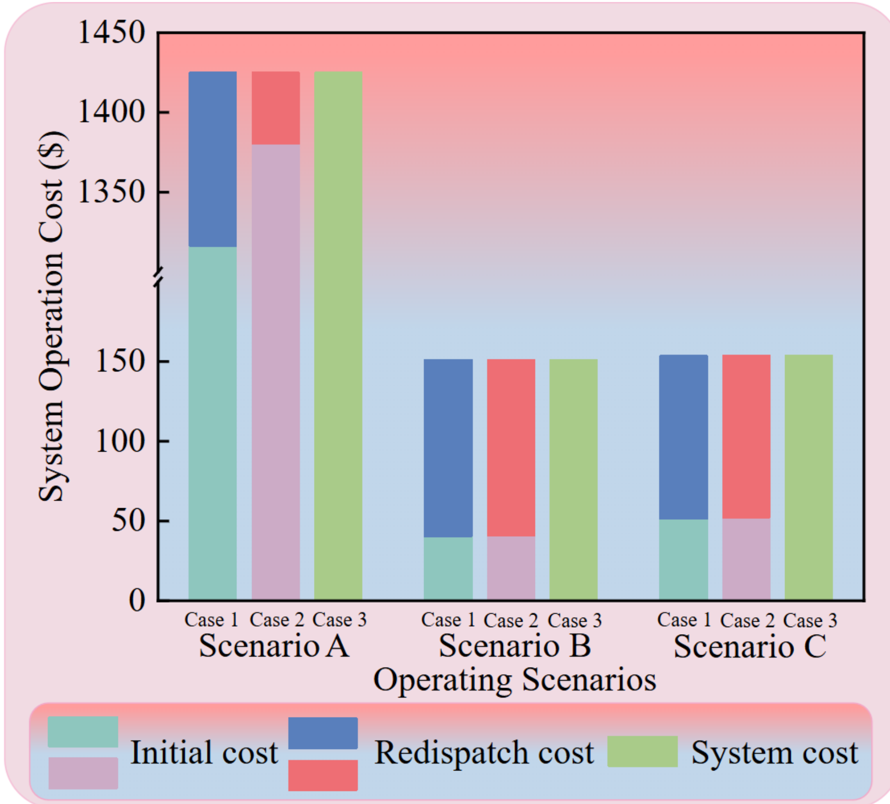

Figure 8. Comparison of system operation costs and RCs under different scenarios. Note: The grouped stacked columns illustrate the system operation costs of Cases 1, 2, and 3 under Scenarios A, B, and C. The lower segment of the column represents the DA market operation cost, while the upper segment indicates the RC.

Table 2. Comparison of RES revenue across different settlement mechanisms

Mechanism	Scenario A ($)	Scenario B ($)	Scenario C ($)	Total Revenue ($)
Case 1	11.53	700.06	692.82	1404.41
Case 2	13.65	677.20	663.06	1353.91
Case 3	12.29	139.76	151.47	303.52
Case 4	13.65	677.20	663.06	1353.91

By averaging these granular locational costs into a single uniform SP, the ZP mechanism inherently masks severe intra-zonal congestion and heavily distorts locational price signals. This averaging effect generates implicit cross-subsidies—both between supply and demand, and across different geographic nodes—which ultimately subvert long-term investment incentives for optimal resource and flexible asset siting. Similarly severe distortion patterns, driven by extreme nodal price divergence, are also observed during the system-wide oversupply events in Scenario C.

Consequently, it is imperative that electricity markets operating under a ZP mechanism undergo regular Bidding Zone Reviews (BZRs). These periodic reconfigurations are essential to ensure that the DA market settlement accurately reflects underlying physical grid bottlenecks, thereby minimizing out-of-market RCs and facilitating economically efficient cross-zonal power flows amid rising RES integration.

b) RES income level

SMs fundamentally shape long-term investment trajectories by influencing RES revenue streams. An optimal SM should organically provide investment disincentives (i.e., depressed revenues) in localized nodes with saturated RES penetration and severe grid congestion. Conversely, in regions with insufficient RES integration or high marginal costs, the SM should provide robust financial incentives to attract capacity. The simulated RES revenue levels across the four SMs under the typical operating scenarios are detailed in Table 2.

In Scenario A, characterized by localized congestion on CBs (e.g., Lines 4-12 and 6-10), the variation in RES revenues across the different SMs remains relatively modest. Case 1 (UP) applies a completely uniform SP, yielding the lowest RES returns ($11.53). In contrast, Case 2 (ZP) and Case 4 (HP) account for the macro-level inter-zonal congestion, allowing RES units in the exporting SICI region to settle at a marginally higher zonal price, thereby capturing slightly higher revenues ($13.65) when supplying the NORD load center.

The revenue disparities become drastically magnified in Scenario B, which features extreme RES penetration. SICI-based RES units dominate the supply mix and export heavily to other zones. Notably, the settlement revenues under Cases 1, 2, and 4 (UP, ZP, and HP) remain artificially buoyant, hovering around $700. In stark contrast, Case 3 (LMP) exposes the severe local oversupply and physical delivery constraints, plummeting RES revenues to a mere $139.76—an approximate 80% reduction. Because Cases 1, 2, and 4 effectively socialize or ignore specific intra-zonal congestion (e.g., Line 4-12 bottlenecks), they artificially inflate cleared transaction volumes and mask local price depressions, thereby implicitly subsidizing RES revenues. A similar pattern of severe revenue divergence is also observed during the system-wide oversupply events of Scenario C.

Ultimately, these simulation results highlight divergent policy applications. In mature markets with high RES penetration and limited transmission flexibility, Case 3 (LMP) is indispensable. By exposing the true marginal value of electricity, LMP penalizes generation at saturated, congested nodes, thereby providing precise locational signals that guide future RES and flexible storage investments toward optimal siting and help prevent the exacerbation of large-scale congestion. Conversely, in transitional markets where accelerating RES deployment is the primary policy mandate, Case 2 (ZP) or Case 4 (HP) can shield renewable developers from harsh nodal price volatility. These mechanisms secure higher, more stable revenues than UP or LMP, thus actively incentivizing continued market participation and capacity expansion.

3) System operation cost

System operating costs comprise DA market clearing costs and subsequent out-of-market RCs. Fig. 8 illustrates the distribution costs under different SMs across the typical scenarios. Because Case 4 (HP) applies the same demand-side zonal boundaries as Case 2 (ZP), their overall cost distributions are highly analogous.

Overall, Case 1 (UP) achieves the lowest DA market operating cost, followed by Case 2 (ZP), while Case 3 (LMP) incurs the highest. However, because UP entirely disregards physical transmission limits during the DA clearing, it generates massive physical infeasibilities, resulting in the highest RC in the real-time market. Conversely, Case 3 (LMP) internalizes all network constraints, yielding zero RC.

In Scenario B, the near-zero marginal cost of abundant RES reduces the baseline system operating cost by approximately 89.4% compared to Scenario A. However, the RC under Case 2 (ZP) spikes significantly, approaching the levels seen in Case 1 (UP). This occurs because the severe congestion in Scenario B is predominantly intra-zonal; thus, the predefined inter-zonal CB limits fail to capture and manage these internal bottlenecks. In Scenario C, the total system operation cost declines further due to the severe price collapse induced by system-wide oversupply, while the RC dynamics mirror those of Scenario B, driven by similar unmanaged intra-zonal congestion.

This cost dichotomy presents significant market risks. When DA clearing ignores physical realities (leading to high RCs), market participants can exploit these discrepancies through strategic bidding—a phenomenon known as "inc-dec" gaming (arbitrage between DA and real-time markets).

It is important to note that the quantitative evaluation framework in this study relies on the assumption of "perfect competition," where generators bid at their true marginal costs. However, when considering potential strategic bidding, the comparative advantages of LMP and ZP become more nuanced. Under the ZP mechanism, because intra-zonal congestion is financially socialized rather than explicitly priced, generators can easily anticipate systemic bottlenecks and engage in systemic "inc-dec" gaming to extract out-of-market profits, thereby severely inflating total system operating costs.

Conversely, while LMP can significantly reduce the arbitrage opportunities between the DA and real-time markets by accurately pricing physical constraints, it can inadvertently expose the system to localized risks. Specifically, at deeply congested nodes, pivotal suppliers may exercise local market power by economic withholding capacity or bidding significantly above marginal costs, knowing that the transmission network cannot import cheaper alternatives.

Ultimately, while both mechanisms are vulnerable to strategic behavior, they require different regulatory responses. The structural flaws of ZP often lead to systemic inefficiencies that are difficult to isolate. In contrast, the high spatiotemporal granularity of LMP provides transparent scarcity signals, making it significantly easier for market monitors to identify the abuse of local market power and implement targeted mitigation measures (e.g., localized bid caps or conduct-and-impact tests).

Therefore, for power grids characterized by high-RES penetration, severe spatial supply-demand imbalances, and frequent congestion, Case 3 (LMP) is superior for mitigating gaming risks and minimizing total system operating costs. Conversely, in systems with ample generation adequacy and robust, unconstrained transmission networks, Case 1 (UP) can maximize market liquidity and lower participation barriers. Finally, during transitional phases—where moderate congestion exists but overall supply-demand dynamics remain relatively balanced— Cases 2 and 4 (ZP and HP) offer a pragmatic compromise between physical accuracy and market liquidity.

Comprehensive evaluation of settlement mechanisms

To comprehensively evaluate the overall performance of the different SMs, this section analyzes 1,000 representative operational scenarios spanning a full year. The evaluation relies on three core metrics that capture actual market performance: 1) Welfare Cost, which measures the apparent short-term efficiency loss when physical network constraints are ignored; 2) Price Distortion, which quantifies the degree to which a specific SP deviates from the actual LMP; and 3) RC, which represents the system expenditures required to eliminate physical network congestion. The aggregated multidimensional performance of the four SMs is illustrated in Fig. 9.

As depicted in Figure 8, Case 1 (UP) yields a normalized value of 1.0 across all three metrics, forming the outermost red boundary. This visually demonstrates that Case 1 incurs the highest degree of market inefficiency and the greatest overall operating costs. Conversely, Case 3 (LMP) achieves a value of 0 for all three indicators. This outcome perfectly aligns with the minimum price deviation and zero-RC paradigm established in Hogan's[54] foundational research, representing the theoretical ideal of electricity market clearing.

Nevertheless, real-world operational uncertainties and diverse macro-policy objectives necessitate selecting an SM that is tailored to a region's specific stage of market development. This pragmatic requirement forms the basis for the subsequent discussion in Section 5.3, which analyzes the applicability of different SMs under diverse, multidimensional market conditions.

CONCLUSION

This paper establishes a multidimensional evaluation framework to quantitatively compare the performance of four typical SMs in the DA market and subsequently proposes adaptive application scenarios. The study reveals that under conditions without severe congestion, the differences in SW across the various mechanisms remain relatively marginal. However, as the penetration of near-zero-marginal-cost RES increases and physical constraints on transmission corridors tighten, the inherent flaws of aggregated clearing models—such as ZP's tendency to mask localized bottlenecks—are significantly amplified. This ultimately leads to inflated RCs and implicit cross-subsidies. Conversely, LMP accurately exposes physical bottlenecks through precise price signals, including extreme negative prices. By effectively mitigating RES curtailment and minimizing re-dispatch actions, LMP optimizes overall SW. Based on this quantitative analysis and logical framework, the following core conclusions are drawn:

First, there is no universally optimal SM design that is detached from physical grid realities; rather, the chosen mechanism must align closely with a zonal-specific market structure and resource endowments. For markets boasting ample transmission capacity margins and zonal boundaries accurately defined by CBs, ZP can sufficiently enhance market liquidity while safeguarding SW. Second, in systems characterized by high-RES penetration and frequent, severe localized congestion, LMP is indispensable for accurately reflecting spatial energy value and ensuring market fairness. Third, for transitional markets or those driven by specific policy mandates, implementing an HP mechanism—featuring supply-side LMP and demand-side ZP or UP—offers a pragmatic compromise. HP simultaneously reflects wholesale electricity scarcity and mitigates retail price volatility for end-users. It is critical to note, however, that while HP serves as an effective transitional mechanism under the current landscape of relatively inelastic demand, its inherent disadvantages will be significantly amplified in the near future. With the rapid proliferation of highly elastic flexible loads—such as virtual power plants (VPPs) and distributed energy storage—active demand-side response requires precise locational scarcity signals to operate optimally. By aggregating the demand side into zonal or uniform prices, HP effectively blinds these emerging flexible resources to actual local bottlenecks. Consequently, they will lack the financial incentive to shift consumption or discharge power to alleviate localized congestion. Therefore, as demand becomes increasingly elastic, policymakers may need to consider that a gradual transition from HP to a finer-grained LMP may become increasingly important to fully unlock the regulatory potential of flexible resources. Furthermore, when adopting a ZP mechanism, regulatory authorities must mandate periodic BZRs to dynamically address shifts in congestion and spillover effects arising from continuous RES integration.

Further research based on this work includes:

1) From the perspective of market investors: Investigating the long-term impacts of DA SMs on capacity expansion planning and the strategic participation of flexible resources (e.g., virtual power plants, energy storage systems, and flexible loads) in market transactions.

2) From the perspective of market design: Exploring the interrelationships between the aforementioned core SMs and supplementary mechanisms (e.g., Pay-for-Performance, Pay-as-Bid, Uplift allocation, and Close-out

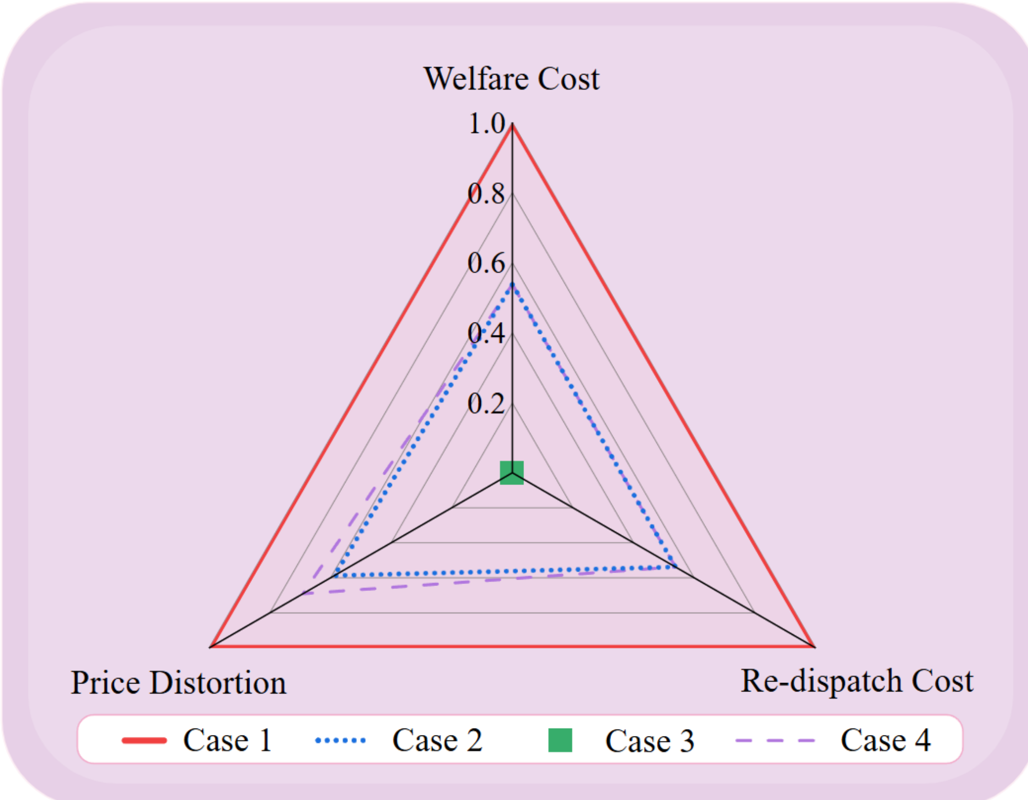

Figure 9. Performance evaluation of Cases 1-4 under 1000 annual samples Note: All feature indicators are normalized, and the area of each region reflects the extent of deviation from the maximum value.

settlements) across different market timeframes to enhance comprehensive risk management.

3) From the perspective of market regulation: Analyzing the incentivizing or mitigating effects of different SMs on the strategic bidding behaviors and potential market power abuse by participants.

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DECLARATION OF INTERESTS

The authors declare no competing interests.

DATA AND CODE AVAILABILITY

Readers may contact the corresponding authors for data upon reasonable request.