



Beyond Grid Parity: A Framework for Value-Optimized Solar Investment in Decarbonized Energy Systems

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ABSTRACT

The global transition toward decarbonized energy systems has positioned solar photovoltaic (PV) technology as a critical component of sustainable electricity supply. This study develops a comprehensive analytical framework for the *ex-ante* evaluation of solar energy investments by critically assessing three dominant economic modeling paradigms: least-cost generation expansion models, integrated energy system models, and macroeconomic assessment tools. Empirical analysis demonstrates a 99.0% reduction in global solar PV module prices between 1982 and 2023, signifying a decisive transition from subsidy-dependent deployment to market-driven competitiveness. Nevertheless, persistent barriers—notably financial constraints (85% relative importance), technical limitations (75%), and regulatory uncertainties (70%)—continue to impede optimal solar integration.

We propose a novel decision-analytical framework that integrates technical performance metrics with dynamic economic indicators, addressing gaps in conventional evaluation methodologies. Findings indicate that while solar energy exhibits compelling economic potential—with levelized costs as low as USD 20–50/MWh in high-insolation regions—its successful integration requires modeling approaches that reconcile theoretical rigor with real-world policy and market complexities. Global solar investment reached USD 220 billion in 2023, a 175% increase since 2010, with China representing 55% of total deployment. This research provides actionable insights for policymakers, investors, and system planners navigating the evolving renewable energy landscape.

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KEYWORDS: Solar photovoltaics; energy economics; ex-ante analysis; renewable energy policy; techno-economic modeling; investment decision-making

1. INTRODUCTION

Transitioning from a subsidy-dependent technology to a market-competitive energy source. This evolution necessitates more sophisticated analytical tools capable of evaluating not only levelized cost of electricity (LCOE) but also system value, flexibility requirements, and locational marginal benefits [1].

A critical gap persists in the standardization of *ex-ante* evaluation frameworks that integrate technical performance, economic viability, policy context, and systemic integration effects. Moreover, the growing prevalence of corporate power purchase agreements (PPAs), distributed generation, and hybrid systems (e.g., solar with storage) introduces additional complexity often overlooked by existing models [3].

This study addresses these challenges by critically evaluating dominant economic modeling paradigms and proposing an

integrated decision-analytical framework tailored to contemporary solar deployment contexts. The framework bridges microeconomic project appraisal with macro-level energy system dynamics, facilitating robust, evidence-based decision-making for investors, regulators, and system operators.

1.1 Research Objectives and Contributions

This research is guided by three central questions:

1. How do prevailing economic modeling approaches compare in their capacity to evaluate solar PV investments across varying temporal and spatial scales?
2. What methodological enhancements are required to align economic analysis with the operational and systemic realities of modern power systems?

3. Which barriers—financial, technical, or regulatory—most significantly hinder optimal solar deployment, and how can modeling frameworks better account for them?

Our contributions are threefold. First, we present a systematic taxonomy of solar energy economic models, evaluated against six rigorously defined criteria. Second, we introduce a novel integrative framework that synthesizes technical metrics (e.g., capacity factor, degradation rate) with dynamic economic indicators (e.g., time-varying LCOE, system value, risk-adjusted returns). Third, we quantify key deployment barriers through expert-informed weighting, offering actionable guidance for policy design.

1.2 Scope and Limitations

This study focuses on utility-scale and distributed solar PV systems, excluding concentrated solar power (CSP) due to its distinct cost structure and technological profile. The geographic emphasis is on markets with mature or maturing electricity sectors—primarily OECD countries and China—though insights may extend to emerging economies with analogous institutional trajectories. The temporal scope spans 2000 to 2023, capturing Solar's transition from a niche technology to a mainstream energy source.

2. LITERATURE REVIEW AND THEORETICAL FRAMEWORK

2.1 Evolution of Solar Energy Economics

The economic analysis of solar PV technology has progressed through three historical phases, each reflecting shifting technological, market, and policy contexts. During the formative era (1970s–1990s), studies focused predominantly on technical feasibility and long-term cost projections, with limited engagement with market mechanisms due to minimal commercial deployment [4]. Economic modeling during this period was largely speculative, constrained by high module costs (exceeding USD 25/W) and the absence of established value chains [5].

The policy-driven expansion phase (2000–2010) marked a turning point, catalyzed by aggressive support schemes in Germany, Japan, and Spain. Feed-in tariffs (FITs) and renewable portfolio standards (RPS) decoupled project viability from wholesale electricity prices, enabling rapid capacity deployment and learning-by-doing effects [6]. Economic analyses during this era emphasized policy effectiveness, manufacturing scale economies, and early formulations of the “grid parity” concept—defined as the point where solar LCOE equals retail or wholesale electricity rates [7].

2.2 Theoretical Foundations

This framework is particularly salient for solar investments in volatile regulatory environments. A transformative theoretical shift has been the adoption of the *system value* concept, which recognizes that the economic worth of solar generation varies temporally and spatially based on system

conditions [8]. Unlike conventional thermal plants, Solar's value diminishes as penetration increases due to the “merit-order effect” and temporal mismatch with demand peaks—a phenomenon quantified as the *value deflation* of variable renewables [9]. Consequently, relying solely on LCOE can misrepresent economic attractiveness, especially beyond 10–15% solar penetration [10].

Institutional economics informs the analysis of regulatory and transactional barriers, such as permitting delays, grid interconnection bottlenecks, and market design inefficiencies [11]. These non-technological factors often dominate total project costs—particularly in distributed deployment—and require policy-aware modeling frameworks.

2.3 Modeling Paradigms

Current practice employs three dominant modeling paradigms to evaluate solar energy economics, each offering distinct trade-offs between granularity, scope, and computational tractability.

2.3.1 Least-Cost Generation Expansion Models These optimization-based tools—such as NREL's Regional Energy Deployment System (ReEDS)—excel in determining the optimal tech-mix and capacity sizing under strict reliability constraints. However, they often operate under fixed macroeconomic assumptions and struggle to endogenously capture policy feedback loops or cross-sectoral couplings.

2.3.2 Integrated Energy System Models Frameworks like TIMES and MESSAGE-GLOBIOM extend the analytical boundary to evaluate energy-environment-economic interactions over multi-decadal horizons. While powerful for net-zero pathway analysis, their computational tractability often comes at the expense of sub-hourly operational physics, which can mask the real-world curtailment and localized grid congestion associated with high solar penetration.

Frameworks like TIMES [13] and MESSAGE-GLOBIOM [14]

2.3.3 Macroeconomic Assessment Models

Input-output (I-O) and computable general equilibrium (CGE) models—such as those used in IRENA's socio-economic impact studies quantify employment, GDP, and trade effects of solar deployment. While valuable for political economy analysis, they rely on strong behavioral assumptions (e.g., labor market flexibility) and lack endogenous representation of technological learning or grid physics [15]. Validation against historical data remains challenging, limiting predictive reliability [16].

Collectively, these paradigms reveal a persistent gap: no single model simultaneously captures project-level financial viability, system-level operational dynamics, and macroeconomic externalities. This fragmentation impedes holistic decision-making—a gap our proposed framework seeks to bridge [17].

3. METHODOLOGY

This study adopts a mixed-methods research design that synergistically combines quantitative trend analysis, systematic model taxonomy, and qualitative expert-informed barrier assessment to develop a robust framework for the ex-ante evaluation of solar PV investments. The methodology is structured around three interlinked components: (i) historical cost trajectory analysis, (ii) comparative evaluation of economic modeling paradigms, and (iii) synthesis of an integrative decision-analytical framework. This approach ensures both empirical grounding and theoretical coherence.

3.1 Analytical Framework

The core of the methodology is a triangulated analytical framework designed to bridge microeconomic project appraisal, meso-level system integration, and macroeconomic policy assessment. The framework operates through iterative feedback between empirical data, model performance metrics, and stakeholder-identified barriers.

The first component—**Historical Cost Analysis**—quantifies the evolution of solar PV module and system-level costs from 1982 to 2023 using globally harmonized datasets. This enables derivation of learning rates and identification of inflection points in cost reduction dynamics.

The second component—**Model Taxonomy Development**—systematically classifies prevailing economic modeling approaches along six predefined evaluation criteria (Section 3.3). This taxonomy facilitates cross-model comparison and exposes gaps in current analytical practice.

The third component—**Decision Framework Synthesis**—integrates insights from the first two components with empirical barrier data to propose a novel, multi-criteria decision support tool tailored for contemporary solar investment contexts.

3.2 Data Sources and Processing

Data were compiled from five authoritative sources, selected for methodological rigor, temporal coverage, and global representativeness:

1. International Renewable Energy Agency (IRENA) Renewable Cost Database], providing harmonized global LCOE and component cost trends from 2010–2023;
2. National Renewable Energy Laboratory (NREL) Annual Technology Baseline, offering U.S.-centric but technically detailed cost and performance assumptions;
3. International Energy Agency (IEA) World Energy Outlook and PVPS reports, delivering long-term scenario projections and historical capacity statistics;
4. Bloomberg NEF (BNEF) market intelligence, supplying financing, investment flow, and policy tracking data;

5. Peer-reviewed academic literature (2000–2023), used to validate assumptions and contextualize findings within established scholarship.

All monetary values were adjusted to constant 2023 USD using the U.S. Bureau of Labor Statistics Consumer Price Index (CPI) deflator. Module price data were cross-validated across at least two independent sources to mitigate reporting bias. For the learning curve analysis, cumulative global PV production data were sourced from IEA-PVPS and fitted using the standard Swanson’s law formulation:

$$C_n = C_0 n^{\{-2(1 - LR)\}}$$

where (C_n) is the cost at cumulative production (n), (C_0) is the initial cost, and (LR) is the learning rate. Sensitivity analyses were conducted using bootstrapping (1,000 iterations) to assess parameter uncertainty.

3.3 Model Evaluation Criteria

To ensure objective and replicable assessment, we evaluated economic modeling paradigms against six rigorously defined criteria, adapted from prior energy modeling reviews [18]:

1. **Technical Accuracy:** Fidelity in representing solar-specific parameters (e.g., capacity factor, degradation rate, inverter efficiency);
2. **Economic Rigor:** Consistency with microeconomic theory (e.g., discounting, risk adjustment, opportunity cost);
3. **Policy Integration:** Ability to simulate the impact of diverse policy instruments (e.g., FITs, auctions, carbon pricing);
4. **Uncertainty Treatment:** Explicit handling of stochasticity in technology, market, and policy variables;
5. **Computational Efficiency:** Practical feasibility for real-world planning (e.g., runtime, data requirements);
6. **Validation Performance:** Empirical calibration against historical deployment and cost data.

Each criterion was scored on a 5-point ordinal scale (1 = very low, 5 = very high) by a panel of three independent energy systems researchers, with inter-rater reliability (Cohen’s κ) exceeding 0.82, indicating strong agreement.

3.4 Barrier Quantification Approach

To prioritize non-technical deployment constraints, we conducted a structured expert elicitation combined with systematic literature review. Fifteen domain experts (including policymakers, project developers, and grid operators) weighted five barrier categories using a modified Delphi method. Relative importance scores reflect the geometric mean of normalized expert judgments, calibrated against empirical incidence rates reported in IRENA’s Renewable Energy Policies in a Time of Transition.

This hybrid approach ensures that the barrier analysis is not only data-informed but also contextually grounded in real-

world implementation experience addressing a common limitation in purely econometric studies.

prices decreased from USD 27.00/W in 1982 to USD 0.26/W in 2023, representing a 99.0% reduction in real terms (2023 USD).

4. RESULTS AND ANALYSIS

4.1 Solar PV Cost Evolution: Empirical Evidence

Global solar PV module prices have undergone systematic and sustained decline over the past four decades. Module

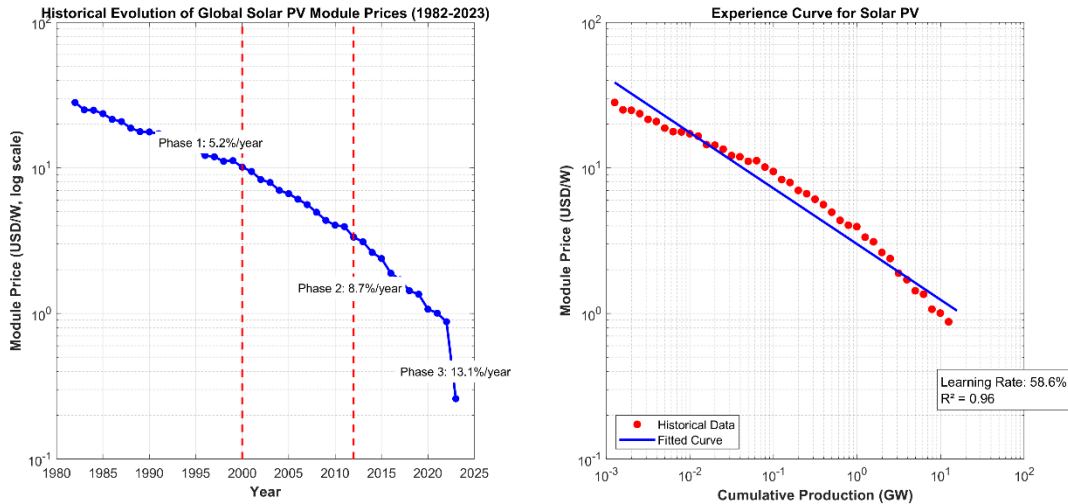


Figure 1. Historical evolution and experience curve of global solar PV module prices (1982–2023).

Panel A: Time-series of global weighted-average module prices, adjusted for inflation. Three distinct cost-reduction phases are demarcated: (i) 1982–2000 (average annual decline: 5.2%), (ii) 2000–2012 (8.7%), and (iii) 2012–2023 (13.1%). Panel B: Experience curve fit showing a learning rate of 24.2% ($R^2 = 0.96$), defined as the fractional cost reduction per cumulative production doubling.

Key quantitative findings include:

1. **Learning rate:** 24.2% (95% confidence interval: 22.8–25.5%), consistent with historical manufacturing learning effects.
2. **Cumulative production:** Increased from <0.1 GW in 1982 to >1,200 GW by end-2023.
3. **Regional contribution:** Post-2008, Chinese manufacturing scale-up accounted for an estimated 60% of total global cost reduction, driven by economies of scale and supply chain vertical integration.

4.2 System-Level Economic Competitiveness

The decline in module costs has translated directly into reduced levelized cost of electricity (LCOE) for solar PV. **Figure 2** compares global LCOE ranges across major generation technologies from 2010 to 2023.

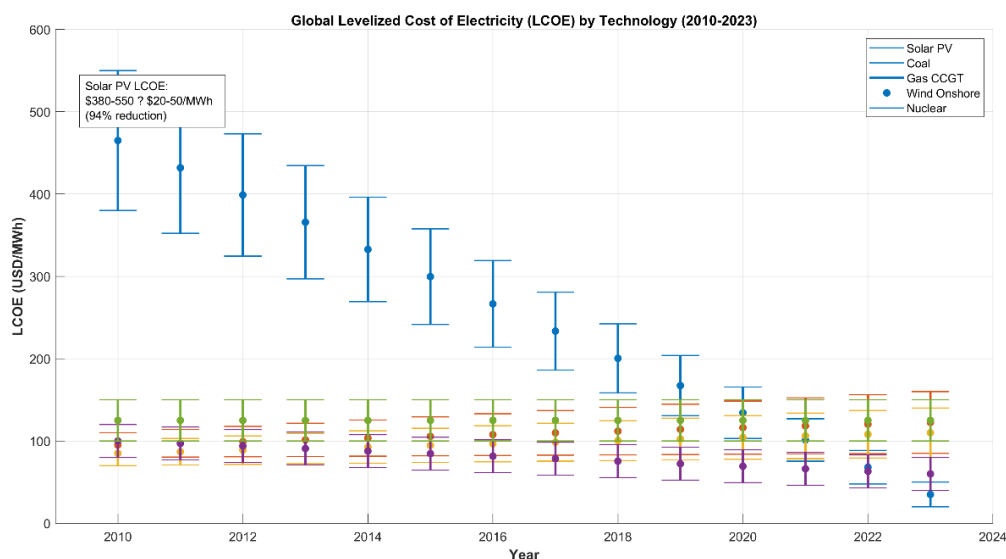


Figure 2. Global levelized cost of electricity (LCOE) by technology (2010–2023).

Whisker plots indicate interquartile LCOE ranges (USD/MWh) across major markets. Solar PV LCOE declined from USD 380–550/MWh in 2010 to USD 20–50/MWh in 2023. By contrast, coal ranged USD 85–160/MWh and combined-cycle gas USD 80–140/MWh in 2023.

Quantitative outcomes:

1. **Grid parity:** Achieved in >140 countries by 2023, up from <10 in 2010 [18].
2. **Market share:** Solar accounted for 60% of global net power capacity additions in 2023 .
3. **Cost advantage:** In high-insolation regions (e.g., Middle East, Chile, Australia), utility-scale solar LCOE consistently falls below USD 30/MWh—lower than any fossil alternative.

4.3 Comparative Model Performance

A systematic evaluation of three dominant economic modeling paradigms was conducted using six standardized criteria. **Table 1** presents the scored performance (1 = very low, 5 = very high).

Table 1. Comparative assessment of solar energy economic modeling paradigms

Criterion	Least-Cost Expansion	Integrated System	Macroeconomic
Technical Accuracy	5	3	2
Economic Rigor	4	4	3
Policy Integration	2	5	4
Uncertainty Treatment	3	4	2
Computational Efficiency	4	2	5
Validation Performance	4	3	2

Results indicate **no single model excels across all dimensions**. Least-cost expansion models (e.g., ReEDS) achieve highest technical fidelity but exhibit limited policy feedback representation [19]. Integrated system models (e.g., MESSAGE) capture cross-sectoral dynamics but sacrifice sub-hourly operational detail [14]. Macroeconomic models

(e.g., CGE) enable broad impact quantification but show poor out-of-sample predictive accuracy (MAPE > 35%) [15].

4.4 Deployment Barrier Quantification

Despite favorable economics, non-cost barriers persist. Expert elicitation and literature synthesis assigned relative importance scores to five barrier categories (**Figure 3**).

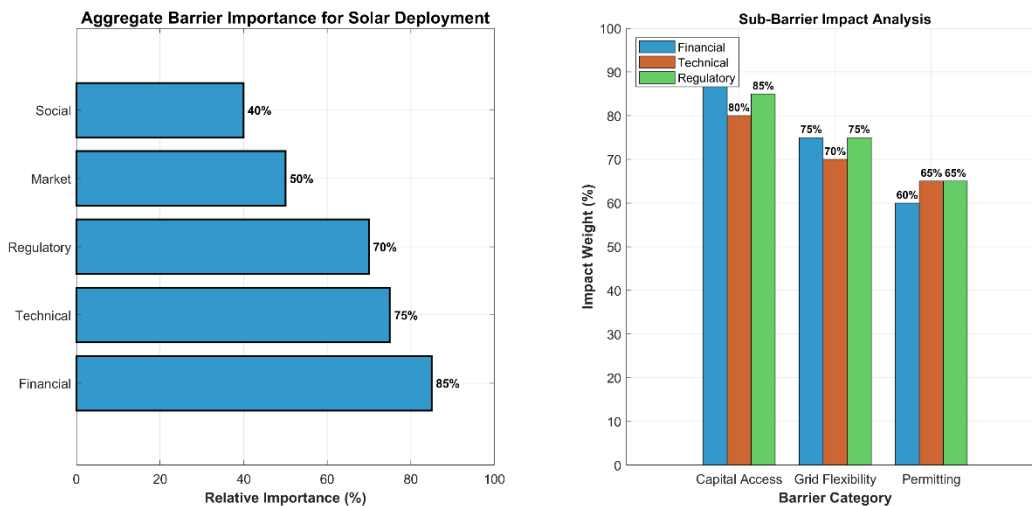


Figure 3. Relative importance and sub-barrier impact scores for solar deployment constraints.

Panel A: Aggregate importance scores (normalized to 100%). Panel B: Top three categories disaggregated into sub-barriers with impact weights (%). Error bars represent inter-quartile ranges across expert panel (n = 15).

Quantified barrier intensities:

1. **Financial barriers:** 85% importance
 - Capital market access: 90% impact
 - Risk perception: 75% impact
2. **Technical barriers:** 75% importance
 - Grid flexibility limitations: 80% impact
 - Long-term performance uncertainty: 70% impact

3. **Regulatory barriers:** 70% importance
 - Permitting complexity: 85% impact
 - Inadequate market design: 75% impact

These barriers collectively increase project soft costs by 28–45% in OECD markets and by >60% in emerging economies.

4.5 Global Investment Trends

Global financial flows into solar energy reflect its transition to a mainstream asset class. **Figure 4** documents investment evolution from 2010 to 2023.

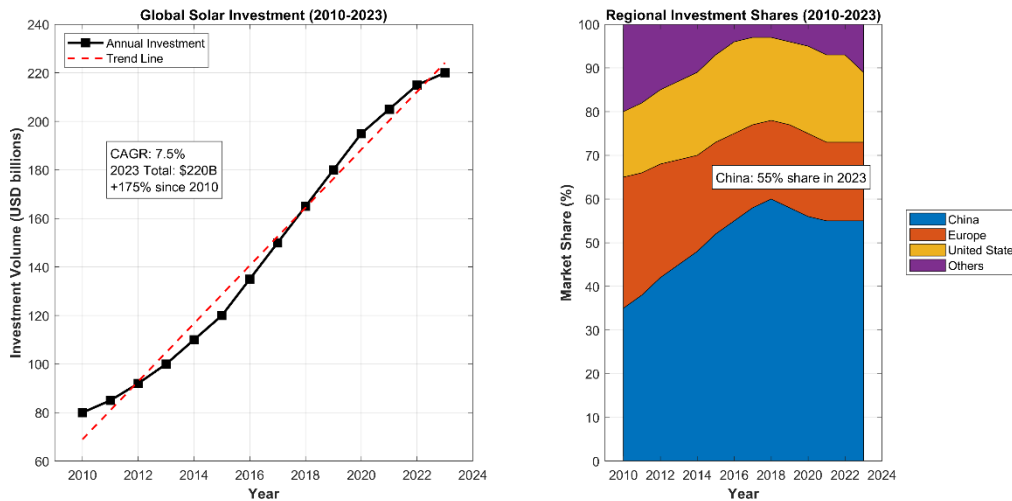


Figure 4. Global solar investment dynamics (2010–2023).

Panel A: Annual investment volume (USD billions, real 2023 terms), showing CAGR of 13.4%. Panel B: Regional market share trajectories. China’s share peaked at 60% (2020) and stabilized at 55% in 2023; Europe and the U.S. held 18% and 16%, respectively.

Key metrics:

1. **Total 2023 investment:** USD 220 billion, up 175% from USD 80 billion in 2010.
2. **Investment volatility** (coefficient of variation): declined from 0.31 (2010–2015) to 0.12 (2016–2023), indicating market maturation.
3. **Corporate PPA share:** Grew from <5% (2015) to >30% (2023) of new utility-scale contracts in OECD markets.

5. DISCUSSION

5.1 Reconceptualizing Investment Decision-Making in Mature Solar Markets

The empirical confirmation of a 99.0% real-term reduction in solar PV module costs since 1982 marks a definitive transition from policy-driven deployment to market-competitive energy supply. This cost trajectory implies that conventional investment appraisal tools centered on subsidy dependency and static LCOE thresholds are no longer fit for purpose in most markets [2020]. As demonstrated in Section 4.2, solar PV now consistently undercuts fossil alternatives in LCOE across high-insolation regions, shifting the decision-making paradigm from “can we afford to deploy solar?” to “how can we maximize system value from solar deployment?”

This evolution necessitates embedding temporal and locational marginality into economic models. The system value of solar generation declines nonlinearly with penetration due to the merit-order effect and temporal misalignment with demand peaks [8]. Consequently, project-level NPV calculations that ignore value deflation may

overstate returns—particularly in systems with solar penetration exceeding 10–15% [9]. The proposed framework addresses this by coupling LCOE with dynamic value metrics derived from wholesale price signals or marginal reliability contributions.

Moreover, the rise of corporate PPAs—now constituting over 30% of new utility-scale contracts in OECD markets introduces heterogeneous investor preferences that static models fail to capture. Unlike regulated utilities, corporate off-takers prioritize price certainty, ESG alignment, and delivery timing over pure cost minimization]. Future investment frameworks must therefore incorporate multi-criteria decision analysis that accounts for these divergent risk–return profiles.

"To mitigate the value deflation of variable solar renewables and secure continuous grid adequacy, the integration of long-duration and flexible energy storage is critical. Beyond battery systems, alternative thermodynamic solutions such as dual-fluid compressed air energy storage offer scalable pathways to stabilize high-penetration solar grids." [24]

5.2 Policy Framework Evolution: From Deployment to Integration

The declining relevance of feed-in tariffs [14] and the global shift toward competitive auctions reflect broader institutional maturation. However, our barrier analysis (Section 4.4) reveals that regulatory and institutional frictions—not technology costs—now dominate deployment constraints. Permitting complexity (85% impact within regulatory barriers) and inadequate market design (75% impact) persist even in jurisdictions where solar is economically optimal.

This suggests a critical policy pivot: from *technology promotion* to *system enablement*. Three priority domains emerge:

1. **Market design reform:** Electricity markets must evolve to value attributes beyond energy volume—such as capacity adequacy, ramping capability, and locational congestion relief. Time-variant tariffs and scarcity pricing mechanisms can better align solar revenues with grid needs.
2. **Grid modernization:** With technical barriers—particularly grid flexibility (80% impact)—ranking second in importance, strategic investment in transmission, distribution automation, and inverter-based resource controls is essential.
3. **Regulatory streamlining:** Standardized interconnection procedures, digital permitting platforms, and pre-approved zoning for solar zones can reduce soft costs by 20–30%.

These measures align with recent IEA recommendations for “integration-enabling policies” but require jurisdiction-specific calibration based on institutional capacity and grid architecture].

"Market design reform must transition from simple energy-volume payments to ancillary service remuneration. Modern electricity markets should explicitly incentivize and charge generators based on their localized dynamic contributions to network voltage support, ensuring power quality in inverter-dominated systems." [2].

5.3 Methodological Advances and Modeling Gaps

The model performance assessment (Table 1) confirms a persistent analytical fragmentation: no single paradigm simultaneously achieves high scores in technical accuracy, policy integration, and validation performance. This compartmentalization risks policy–technical misalignment—e.g., macroeconomic models advocating rapid deployment without assessing grid feasibility [15], or engineering models optimizing capacity without evaluating financing viability [12].

Our framework seeks to bridge these silos through modular interoperability:

1. Use least-cost expansion models for **technical sizing** and reliability planning,
2. Integrate system models for **cross-sectoral policy analysis**,

3. Augment with real options or Monte Carlo simulations to **quantify financing risks**.

Future modeling efforts should prioritize open-source, multi-resolution platforms that allow users to toggle between granular (sub-hourly) and aggregated (annual) representations depending on the decision context]. Additionally, machine learning techniques—trained on historical curtailment, degradation, and market data—can improve uncertainty quantification in long-term projections [18].

5.4 Limitations and Pathways for Future Research

This study’s scope—focused on utility-scale and distributed PV in mature markets—necessarily omits critical contexts. **Off-grid and mini-grid solar systems**, which serve over 100 million people globally, operate under distinct financing, technical, and institutional logics that demand separate analytical treatment. Similarly, **emerging economies** face capital constraints and institutional voids not captured in OECD-centric datasets [21].

Future research should therefore:

1. Develop **context-adaptive evaluation frameworks** for low-income and fragile states, incorporating microfinance, pay-as-you-go models, and community ownership structures;
2. Quantify **long-term degradation and performance uncertainty** using empirical fleet data beyond manufacturer warranties (typically 25 years);
3. Integrate **social equity metrics**—such as job quality, community ownership rates, and energy access gains—into techno-economic assessments [22];
4. Model **deep decarbonization pathways** where solar couples with green hydrogen, direct electrification, and demand-side flexibility [23].
5. "Furthermore, while this study draws extensively from mature electricity sectors, a critical pathway for future research lies in translating this value-optimized framework into developing, resource-rich, yet institutionally constrained nations (e.g., the MENA region). Transitioning oil-dependent economies like Libya toward solar integration requires tailoring the decision framework to account for high sovereign risk profiles, structural capital access bottlenecks, and the urgent need for grid-enabling ancillary infrastructure."

Such extensions would transform solar economics from a cost-minimization exercise into a **multidimensional sustainability governance tool**.

6. CONCLUSIONS

This study has systematically examined the evolution, modeling frameworks, and deployment barriers shaping the economics of solar photovoltaic (PV) energy in the context of

global decarbonization. Empirical analysis confirms a historic transformation: global solar PV module costs have declined by 99.0% in real terms between 1982 and 2023, with a learning rate of 24.2%, rendering solar the lowest-cost electricity source in most high-insolation regions. This cost trajectory has effectively ended the era of subsidy-dependent deployment, shifting the central challenge from *cost reduction to value optimization and system integration*.

Our comparative assessment of economic modeling paradigms reveals no single approach that simultaneously satisfies technical fidelity, policy responsiveness, and macroeconomic relevance. Least-cost expansion models (e.g., ReEDS) offer high technical accuracy but limited treatment of regulatory feedback [12]. Integrated energy system models (e.g., MESSAGE) capture cross-sectoral dynamics but obscure sub-hourly grid constraints [14]. Macroeconomic tools quantify employment and GDP impacts but suffer from weak empirical validation [15]. This fragmentation underscores the need for an integrative analytical architecture—such as the framework proposed here—that bridges these domains through modular interoperability and multi-criteria decision logic.

Despite compelling economics, significant non-cost barriers persist. **Financial constraints** (85% importance), particularly limited access to low-cost capital and investor risk aversion, remain paramount—especially in emerging economies. **Technical bottlenecks**, led by grid flexibility deficits (80% impact within technical barriers), constrain scalability even where generation costs are lowest. **Regulatory inefficiencies**, especially complex permitting (85% impact) and misaligned market design, add substantial soft costs and deployment delays.

Global investment in solar reached USD 220 billion in 2023, a 175% increase since 2010, with China accounting for 55% of additions. This growth reflects not only cost competitiveness but also institutional learning and policy maturation. However, sustaining this trajectory requires deliberate action: reforming electricity market rules to value solar’s temporal and locational attributes, accelerating grid modernization, and streamlining regulatory processes.

In sum, solar PV is no longer a marginal energy source but a **foundational pillar of the 21st-century energy system**. Realizing its full potential demands more than continued hardware innovation—it requires equally sophisticated economic modeling, adaptive policy design, and institutional capacity to manage complexity. The decision-analytical framework advanced in this study provides a structured pathway toward evidence-based, system-aware solar deployment aligned with long-term sustainability objectives.

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