Cost of Capital for Indian Renewable Energy Projects: A Review of Methodologies, Risk Drivers, and Policy Evolution

Discussion Paper

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Abstract

India's renewable energy sector faces financing challenges that could undermine its 2030 targets, prompting this review of cost of capital dynamics across utility-scale solar and wind projects to address gaps in understanding how financing costs evolve with market maturation and policy intervention. We synthesize evidence from six estimation methodologies, analyse risk drivers through four comprehensive studies, and trace policy evolution across fifteen years, revealing a fundamental tension in cost of capital research where approaches requiring actual project finance data provide high precision, but limited scalability compared to survey methods and financial market proxies that sacrifice accuracy for broader coverage. Historical trends document a complete financing cycle rather than steady improvement, with multiple estimation methods showing WACC compression of 300-400 basis points from 2012-2020 driven by market maturation, followed by 320 basis points expansion through 2024 as global monetary conditions tightened, while wind's historical financing premium over solar has disappeared entirely as both technologies now access identical debt pricing ranges of 8.5-9.75%. Risk analysis across multiple studies consistently points to power purchase agreement counterparty concerns as the most significant financing barrier, reflecting deeper structural problems within India's electricity distribution system where companies face persistent financial distress, accumulating debt of ₹6.84 trillion despite repeated policy interventions, though currency risk has become less material as domestic financial institutions developed greater comfort with renewable energy financing. Policy evolution through four distinct phases successfully tackled many project-level risks, introducing competitive auctions that drove tariff reductions exceeding 80%, yet these technical achievements have been undermined by persistent systemic challenges, with over 50 GW of successfully auctioned capacity now stalled as distribution companies delay signing power purchase agreements, revealing that while India has solved many financing and technical barriers, fundamental distribution sector problems continue to constrain growth, leading us to identify four research priorities: quantifying grid integration financial implications, developing bankability frameworks for storage technologies, evaluating risk mitigation effectiveness, and creating energy policy uncertainty indices.

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1 India's Renewable Energy Ambition: Targets, Investment, and the Cost of Capital

1.1 India's Renewable Energy Targets and Investment Landscape

India's energy transition trajectory represents one of the most ambitious decarbonization agendas globally, reshaping the nation's approach to power sector development. The commitment to achieve 500 GW of non-fossil fuel capacity by 2030, first articulated at COP26, has evolved from an aspirational target into a systematic policy framework embedded within national energy planning instruments. The 14th National Electricity Plan (NEP-14) operationalizes this vision through a comprehensive roadmap targeting 596 GW of renewable energy capacity by 2032, representing 68.4% of total installed capacity and fulfilling 44% of electricity demand. This strategic architecture encompasses 365 GW of solar capacity, 122 GW of wind power, 47 GW of Battery energy storage systems (BESS) with 236 GWh storage capacity, and 26.7 GW of pumped storage plants, reflecting an integrated approach to variable renewable generation and grid stability enhancement (Das 2025).

India's recent performance trajectory continues to demonstrate substantial momentum toward these objectives. As of November 2025, renewable energy installed capacity reached approximately 243 GW, comprising solar (147 GW), wind (55 GW), bioenergy (11 GW), small hydro (5 GW), and large hydro (25 GW), positioning India well as the fourth-largest renewable power market globally. An additional 135 GW of renewable capacity is under various stages of implementation or tendering. Calendar year 2025 has seen about 32 GW of renewable capacity added, marking a 6% increase over 2024's installations, with auction activity surpassing 80 GW by November. Tariff competitiveness remains strong, with record-low bids continuing around ₹2.44–₹2.55/kWh (≈ 29–31 USD/MWh) for utility-scale solar, confirming the sustained cost advantage of clean energy technologies (MNRE, 2025).

According to the latest BNEF (2025) survey, debt costs for greenfield solar and wind projects range between 8.5-9.75%, representing only a modest 9-64 bps increase compared to their 2022 survey. This compares favourably with broader economy-wide bank lending rate increases of 131-314 bps over the same period, suggesting that renewable energy financing has remained relatively less impacted from macroeconomic rate pressures.

This trend reflects the sector's evolution toward what may be considered a lower-risk lending category in infrastructure finance, potentially comparable to secured lending segments such as home loans due to the tangible, long-lived nature of renewable energy assets and predictable revenue streams from Power Purchase Agreements (PPA). The sector's operational track record and improving regulatory frameworks have contributed to improved risk perception among lenders.

However, the scale of financial mobilization required presents challenges that extend beyond mere capital availability. Realizing NEP-14 targets necessitates a cumulative investment of USD 300 billion by 2032, demanding annual financing growth from USD 13.3 billion in FY 2024 to USD 68 billion by 2032-a consistent 20% annual escalation in capital flows (Das 2025). The financing gap reflects not just scale constraints but structural challenges in how capital markets assess and price renewable energy investments. Despite impressive capacity additions and competitive tariffs, the disconnect between current investment flows and projected requirements suggests that financial market development, risk perception, and capital allocation mechanisms may prove more binding than technological readiness or cost competitiveness.

1.2 Role of Cost of Capital in Achieving Clean Energy Goals

The Cost of Capital (CoC) emerges as the critical variable determining whether India's renewable energy ambitions translate into actual deployment. While conventionally measured as the Weighted Average Cost of Capital (WACC), CoC in practice reflects a complex interplay of factors that vary significantly across projects, technologies, and market conditions. Recent global evidence shows substantial heterogeneity in renewable energy financing costs, with variations often exceeding differences in natural resource quality or technology costs. For capital-intensive renewable projects where upfront investments dominate lifecycle costs, even modest variations in CoC can determine project viability. The challenge for India lies not just in accessing capital, but in achieving financing costs that enable systematic scaling while providing adequate returns to the diverse investor base required to meet deployment targets.

CoC serves as a composite variable that inherently captures and synthesizes multiple risk factors including technology performance, counterparty creditworthiness, regulatory stability, and execution capabilities. This makes it a particularly valuable parameter for understanding how different policy interventions or market conditions affect overall investment attractiveness.

Understanding and accurately measuring CoC for renewable energy projects presents methodological challenges that complicate both academic research and policy design, even as market participants themselves develop sophisticated risk assessment capabilities. While experienced financiers in India's increasingly mature renewable energy sector generally understand project-specific risks and price them accordingly, this specialized knowledge remains largely inaccessible to researchers, policymakers, and new market entrants who require transparent benchmarks. The confidential nature of project finance structures creates particular challenges for energy system modelers attempting to forecast deployment pathways, regulators designing tariff mechanisms, and development institutions crafting risk mitigation instruments.

Renewable energy projects exhibit heightened sensitivity to CoC fluctuations due to their cost structure, characterized by high upfront capital expenditure and relatively lower operational costs over project lifespans. This creates a "leverage effect" where changes in financing costs translate into disproportionate impacts on the levelised cost of electricity (LCOE)[1]. Analysis indicates that a 400 basis points (bps) increase in CoC could potentially delay India's 500 GW target by approximately 100 GW, while a 200 bps variation could alter annual generation costs by ₹270-320 billion (US$2.98-3.54 billion).

The evolving risk landscape presents both challenges and opportunities for achieving optimal financing conditions. While some risk categories have been successfully addressed through market maturation and policy intervention, new complexities continue to emerge as the sector scales and integrates with grid infrastructure. This dynamic risk environment underscores the importance of systematic analysis to understand how financing costs respond to different policy interventions and market conditions.

1.3 Scope and Objectives of the Review

This review focuses specifically on the cost of capital for large-scale solar photovoltaic and onshore wind projects in India, addressing a critical gap in the literature where existing studies either examine global patterns with limited India-specific analysis or focus on broader renewable energy portfolios without the granular assessment required for informed policy and investment decisions. The scope is deliberately circumscribed to utility-scale projects financed through project finance structures, reflecting the dominant financing mechanism for India's renewable energy expansion and ensuring comparability with international best practices.

The review paper pursues three primary objectives. First, it provides an evaluation of methodological approaches employed in the literature for estimating cost of capital in the Indian renewable energy context, assessing the appropriateness, limitations, and comparative advantages of different estimation techniques ranging from reverse-engineering auction results to asset pricing models and expert elicitation methods. This methodological evaluation

[1] LCOE is the average net present cost to build and operate a power plant over its lifetime, divided by its total lifetime energy output.

directly addresses the measurement challenges identified earlier and the persistent problem of data scarcity in project finance.

Second, this study integrates existing empirical and qualitative literature to analyse the risk determinants of the cost of capital in the Indian renewable energy sector, specifically examining how distinct risk categories differentially impact project bankability and financing costs. This synthesis distinguishes between well-documented risks that have characterized the sector since its inception and emerging risk factors identified in recent studies, arising from market evolution, technological advancement, and policy changes.

Third, the review identifies gaps in current research and knowledge, encompassing methodological limitations, data availability constraints, and insufficient analysis of policy intervention effectiveness. This gap analysis provides a foundation for developing a forward-looking research agenda that addresses the evolving needs of India's renewable energy financing landscape and supports evidence-based policy design for achieving the 2030 renewable energy targets.

1.4 Paper Structure and Contribution

The paper is structured in six main sections following this introduction. Section 2 critically reviews methodological frameworks for cost of capital estimation, comparing six primary approaches from deal-level data elicitation to reverse-engineering auction results, and providing guidance for method selection in data-constrained environments. Section 3 synthesizes historical trends in cost of capital evolution and credit rating improvements as evidence of systematic de-risking. Section 4 examines the drivers of cost of capital and risk premia, analysing how various risk factors influence financing costs through synthesis of four comprehensive studies employing different methodological approaches. Section 5 traces policy interventions and market maturation through a four-phase journey from 2010-2025, analysing how policy evolution has systematically addressed different categories of investment risks while identifying persistent structural challenges. Section 6 consolidates findings, identifies critical research gaps across methodological, empirical, and policy dimensions, and outlines future research priorities to support India's 2030 renewable energy targets.

This review makes three distinct contributions to the renewable energy finance literature. First, it provides a synthesis of methodological approaches specifically applied to cost of capital estimation in the Indian renewable energy sector, offering practical guidance for method selection in emerging market contexts where data constraints significantly influence analytical approaches. Second, it systematically categorizes risk factors based on their evolution over time - distinguishing between successfully mitigated risks, persistent challenges, and emerging second-generation complexities - providing a framework for understanding how renewable energy financing risks evolve with market maturation. Third, it identifies critical knowledge gaps that have limited policy effectiveness assessment, providing a roadmap for future research priorities to support evidence-based intervention design for achieving national renewable energy objectives.

2 Methodological frameworks for CoC estimation

2.1 Overview of Estimation Frameworks

The estimation of the CoC for renewable energy projects reflects both the evolution of financing practices in the sector and the confidential nature of project finance transactions in general. While renewable energy financing has matured considerably over the past decade, the confidential nature of project finance structures, combined with the absence of publicly traded securities for individual projects, creates data availability constraints that have shaped the development of estimation methodologies in the literature (B. Steffen 2020). As Steffen notes, "financing models used by companies are confidential, making it almost impossible to know or to verify the actual values used by project developers," with cost of capital typically considered a trade secret.

The WACC serves as the primary metric, combining cost of equity and debt weighted by their market values and adjusted for taxes. Despite data constraints, researchers have used approaches to overcome these limitations, resulting in a methodological landscape that offers multiple pathways for CoC estimation, each with distinct advantages depending on the analytical context and available information.

IEA Cost of Capital Observatory (IEA 2025) states the importance of accurate CoC estimation given the fact that financing costs constitute the largest component of LCOE for utility-scale renewable projects, particularly in emerging markets and developing economies (EMDEs) where cost of capital can be at least double that observed in advanced economies (IEA 2025). This sensitivity makes precise CoC estimation essential for investment decisions, policy design, and achieving cost-competitive renewable energy deployment.

In the Indian context, extensive auction-based procurement systems and evolving financial markets provide specific opportunities for certain estimation techniques while creating constraints for others.

2.2 Methodological Approaches

The methodological landscape can be structured around four general approaches based on the type of information used (B. Steffen 2020): methods that gather new data at the project level (elicitation and surveys) versus those using readily available data from other areas (auction replication and financial market analysis). This classification indicates fundamental trade-offs between precision and scalability, with each approach offering distinct advantages depending on data availability, market characteristics, and objectives.

Within this framework, project-level data gathering encompasses both direct elicitation of actual financing terms from confidential deal documentation and structured surveys of market participants. The readily available data approaches include reverse-engineering cost estimates from competitive auction results and various financial market analysis techniques. This latter category proves particularly diverse, spanning market-based debt pricing models that leverage corporate bond yields and credit spreads, equity pricing approaches using both traditional CAPM and multi-factor models, and certainty equivalent methods that build up risk premiums through systematic scenario analysis. Table 1 details these six specific methodologies, mapping each method to its corresponding data sources and analytical mechanics, providing a comparative guide for selecting the appropriate estimation tool based on specific research contexts and constraints.

Table 1: Review of Cost of Capital Estimation Methodologies in the Literature

Methodology	Description	Key Strengths	Key Limitations	Reference
Elicitation of Project Finance Data	This methodology involves the direct collection of detailed financial components from confidential project deals, utilizing term sheets,	• Provides highly granular, actual transaction data eliminating guesswork.	• Significant data confidentiality barriers require extensive relationship building with financial institutions.	Lorenzoni and Bano (2009) used this approach for Italian market with granular investor data; Shrimali et al.

	financing agreements, and bank documentation. Its implementation requires access to actual transaction data from financial institutions or project developers who are willing to share commercially sensitive information.	• Captures real market conditions and deal-specific risk assessments. • Most accurate for specific projects as it reflects actual investor decisions. • Avoids systematic bias from proxy inferences.	• Naturally limited sample sizes due to sensitivity pertaining to transaction data. • Extremely time-intensive data collection process. • Fundamentally difficult to scale for cross-country analysis due to varying legal frameworks. • Restricted to countries with substantial numbers of comparable, accessible projects. • External validity concerns as project finance CoC is inherently asset-specific. • Challenging to assess whether individual deals represent typical market conditions.	(2013) for Indian wind/solar through developer interviews;

Survey of Expert Estimates	This approach utilizes structured interviews with market participants—including project developers, banks, equity investors, and industry consultants to estimate typical market CoC rather than relying on project-specific data. These primary insights are often supplemented with archival information derived from press releases and industry publications.	• Significantly more scalable across multiple geographies than deal elicitation. • Effectively captures current market sentiment and forward-looking expectations • Particularly valuable for all emerging as well as developed markets • Provides accessible pathway for initial CoC estimates in data-scarce environments • Enables systematic tracking of financing trends over time • Can engage broader set of market participants than those involved in specific deals	• Inherently subjective estimates introducing potential interviewer and respondent bias • Significant representativeness concerns depending on participant selection • Particularly problematic in less mature markets where low consensus exists and participants may provide "gut feeling" estimates rather than data-based assessments • Vague selection criteria can substantially increase estimate uncertainty	Ardani, Davidson, et al. (2013) and Ardani, Seif, et al. (2013) conducted a comprehensive study of 70 US market participants; Kumar, Anisuzaman, and Das (2017) conducted expert interviews with one country expert for each country, and archival information ; Wood and Ross (2012) compiled data for national authorities for an IEA task, using elicited financial data from real projects and/or

				expert interviews; BNEF (2025)'s recent survey of 22 Indian wind/solar stakeholders for debt funding attractiveness
Reverse-Engineering from Auctions	This method involves the backward calculation of the implied CoC by analysing competitive PPA auction results using detailed LCOE models. It exploits publicly available bid data and commodity pricing for equipment components, treating the CoC as the primary unknown variable in replicating the economics of winning bids..	• Generates CoC estimates reflecting actual competitive conditions. • Uses entirely verifiable public data ensuring transparency and replicability • Provides estimates representative of specific auction rounds when all awarded PPAs systematically analysed • Offers empirical method to triangulate and validate expert interview estimates	• Limited to markets with active competitive PPA auction systems • Estimation precision critically depends on quality and completeness of available non-financing data • Inherently country-specific application requiring deep understanding of local auction mechanisms and cost structures • Cannot capture off-market or bilateral deal structures	Apostoleris et al. (2018) analysis on solar projects auctioned in Middle East; Dobrotkova, Surana, and Audinet (2018) conducted a comprehensive study across 13 developing countries which was motivated by investigating record-breaking low solar auction bids and

		• Assumes that equipment costs are largely transparent global commodities		their underlying economics; Egli et al. (2023) used the method to assess 133 German projects
Market Pricing Models - Cost of Debt	Cost of debt can be estimated using various approached using market data - corporate bond yields, project finance markups, or country risk adjustments. Asset pricing theory assumes that debt costs reflect systematic risk factors including credit risk, liquidity premiums, and country-specific factors. Approaches include: (1) Corporate bond yield method using comparable companies with similar credit ratings and secondary	• Enables cross-country analysis using standardized frameworks. • Leverages easily accessible financial market data. • Systematic approach accounting for country and credit risks. • Computed through firm's financial statements and financial securities such as bonds, loans, CDS etc. • Can capture both backward-looking (accounting) and forward-looking (secondary markets) conditions	• Appropriateness of market proxies for project finance bank debt questionable. • Corporate bonds may not reflect project finance risk profiles. • Strong assumptions about risk transferability from public to private markets. • Limited availability of project-specific bank margins, CDS data, lack of syndicated loan deals and swap premiums especially in countries like India.	Werner and Scholtens (2017) use medium-term corporate bond yield indices to estimate the cost of debt for wind projects; Partridge (2018) estimates the cost of debt using utility bond spreads over the risk-free rate, plus an assumed premium for renewable energy projects.; Kitzing

	market bond spreads using real-time trading data to calculate spreads over risk-free rates reflecting current market pricing; (2) Project finance markup method calculating $C_d = r_f + p_{swap} + BM$, where r_f is risk-free rate, p_{swap} is swap premium, and BM is bank margin; (3) Country risk adjustment method using $C_d = r_f + CDS + PS$ where CDS represents credit default swap spreads and PS denotes project-specific spreads; (4) Accounting cost of debt calculated as interest expense divided by outstanding debt from financial statements; (5) Syndicated loan analysis	• Can be applied consistently across multiple markets. • Builds on established corporate finance/asset pricing literature. • Allows for sensitivity analysis using market parameters. • Transparent methodology with verifiable data sources.	• Accounting data reflects past financing conditions with potential lags. • Secondary market analysis limited to markets with active bond trading.	and Weber (2015) adds archival estimates of swap premia and bank margins to the German government bond yield, mirroring bank SPV loan pricing but relying on margin and swap data that are often hard to obtain; To estimate the cost of debt, Angelopoulos et al. (2016) use the German government bond as the European risk-free rate and add (i) the 10-year CDS spread of the country and (ii) a

	using databases like LPC DealScan to analyse loan spreads for specific sectors and technologies. Asset pricing theory assumes debt costs reflect systematic risk factors including credit risk, liquidity premiums, and country-specific factors.			"renewable energy project spread" to capture project-specific risks; Zhou et al. (2023) comprehensive study using four approaches - accounting cost of debt, secondary market bond spreads, and syndicated loan transactions for global energy sector analysis.
Market Based Models - Cost of Equity (CAPM and Multi-Factor Models)	Application of asset pricing models using two approaches: Ex-post models based on historical returns including (A) The foundational Capital Asset Pricing Model calculates	• Robust cross-country comparative analysis using standardized frameworks. • Accounts for systematic risk factors affecting securities returns.	• Strong assumptions about risk transferability from public to private/project finance markets. • Estimation precision depends on	K. Singh, Singh, and Prakash (2022) employed CAPM and Fama-French 3-factor and 5-factor models for to estimate the cost of

	expected return as $C_e = r_f + \beta(r_m - r_f)$ where r_f represents the risk-free rate, β measures systematic risk relative to market portfolio, and $(r_m - r_f)$ denotes the market risk premium; (2) Fama-French multi-factor models incorporates size premium SMB (Small Minus Big market capitalization) and value premium HML (High Minus Low book-to-market ratio). The five-factor model adds profitability factor RMW (Robust Minus Weak profitability) and investment factor CMA (Conservative Minus Aggressive investment behavior) to better explain	• Leverages accessible financial market data most of which is publicly available from listed companies' financials. • Extensive theoretical foundation and empirical literature for listed company valuations. • Ex-ante models inherently forward-looking reflecting investor expectations regarding transition risks. • Suitable for broad studies comparing costs across countries and regions • Consistent methodology applicable across different markets. • Multi-factor models address CAPM limitations by capturing size, value,	appropriateness of chosen market proxies. • Complex challenges transferring insights from liquid to illiquid assets. • Limited empirical support for CAPM as demonstrated by Fama and French especially in emerging markets like India. • Same proxies typically used for different technologies may not account for project/technology related risks. • Multi-factor models require additional data and may exhibit parameter instability. • Ex-ante models dependent on analyst coverage and	equity of Indian energy and infrastructure sectors; Angelopoulos et al. (2016) start from a market-based WACC estimate and then consult 80 experts, asking whether, in which direction, and by roughly how much actual market conditions deviate from that estimate; Donovan and Nuñez (2012) derives estimates from financial market data using CAPM, adjusted for downside beta in

	cross-sectional return variations. (B) Ex-ante models using current stock prices and analyst forecasts including (3) Implied cost of equity approaches following different approaches that calculate forward-looking cost of equity from current stock prices, future cash flows, and analyst earnings forecasts. These models solve for the discount rate that equates current stock price with the present value of expected future cash flows, effectively reverse engineering the cost of equity that market participants are implicitly using. The approach averages estimate from	profitability, and investment effects. • Allows sensitivity analysis and scenario modelling using market parameters.	forecast accuracy, limited to publicly listed companies	emerging markets.; Partridge (2018) uses estimates from financial market data for wind projects located in Denmark, India and the USA; Gebhardt, Lee, and Swaminathan (2001), Easton (2004), Ohlson and Juettner-Nauroth (2005), and Claus and Thomas (2001) developed ex-ante valuation models to estimate implied cost of equity capital using current stock prices and analyst earnings forecasts rather

	multiple models to reduce model-specific biases and provides market-based expectations of required returns rather than relying on historical price movements.			than historical stock returns.
Certainty Equivalent Method	This method quantifies risk premiums through the systematic comparison of projected cash flows under different probability scenarios, typically contrasting the P50 expected outcome against the P90 conservative estimate. By utilizing Monte Carlo simulation frameworks, it determines the additional compensation that investors require for bearing project-specific uncertainties. The approach	• Direct, transparent quantification of specific risk factors affecting cost of capital. • Clear risk attribution identifying primary uncertainty/risk drivers. • Systematically accounts for tail risks overlooked in point estimates. • Transparent build-up from base rate plus explicit premiums. • Allows sensitivity analysis of individual risk components	• Requires extensive detailed risk scenario modelling and probability assumptions. • Highly sensitive to assumptions about correlation between various risks and distribution assumed for each risk factors. • May not reflect actual investor behaviour and risk tolerance. • Resource-intensive requiring detailed scenarios	Das (2025) conducted a comprehensive exercise for Indian RE projects using Monte Carlo simulations incorporating commissioning delays, technology performance risks, and market price uncertainties

	ultimately builds the total CoC by adding these explicit risk premiums to a base rate.	• Incorporates project-specific risks missed by asset pricing methods. • Framework for understanding risk-return trade-offs.	for each risk being considered. • Difficulty validating probability and correlation assumptions. • Risk of double-counting factors across categories especially correlated risks	

2.3 Methodological Insights and Applications

2.3.1 Methodology Selection Trade-Offs

a) **Method Selection Constraints:** A fundamental tension shapes all cost of capital estimation: the more accurate you want to be, the narrower your analytical scope must become. This isn't merely a technical limitation-it reflects the inherent nature of project finance data and the efforts required to access it. Consider elicitation of project finance data, which provides the most precise estimates available. To access actual deal terms, researchers must cultivate deep relationships with banks, developers, and equity investors who guard this information zealously. The process is intensely personal (unless driven by regulators) and time-consuming. This approach yields exceptional accuracy for specific projects but scaling it across multiple markets or technologies becomes prohibitively resource intensive. Hence, most comparative research-studies examining cost differences across countries, technologies, or time periods-gravitates toward survey methods or financial market proxies. These approaches sacrifice precision for breadth, allowing researchers to generate estimates across dozens of markets rather than deep insights into a few. It's a trade-off that shapes what we think we know about renewable energy finance.

b) **Data Availability Drives Methodology Selection:** More problematic is how data accessibility often determines method selection rather than analytical appropriateness. Researchers don't always choose the best tool for the job-they choose the tool that works with available data. Consider why reverse-engineering studies dominate the research focussed on estimation of CoC for solar PV. It's not because auction data suits solar projects better, but because solar equipment costs are transparent and auction mechanisms are well-documented. Module prices trade like commodities with clear global benchmarks, making reverse-engineering method more feasible than other. Research papers estimating cost of capital for wind projects more frequently employ financial market analysis methods because longer operational histories provide better proxies for asset pricing models. The concern is that these methodological patterns create false impressions about technology-specific risks. If solar studies consistently use auction reverse-engineering while wind studies rely on financial market proxies, observed cost differences might reflect methodological artifacts rather than genuine economic distinctions. When policymakers see different cost estimates for solar versus wind projects, they need to understand whether those differences reflect actual financing costs or simply different analytical approaches driven by data availability.

2.3.2 Systematic Biases and Implementation Challenges

a) **Method Implementation in Regulatory Tariff Setting:** Regulators consistently set allowed returns above academic method estimates, with these premiums varying systematically across technologies. K. Singh, Singh, and Prakash (2022) found Indian regulators using CAPM set returns higher than estimated costs of equity, with minimal gaps for conventional generation but substantial spreads for renewables. This suggests standard academic methods may systematically underestimate practical cost of capital requirements for regulatory applications.

b) **Selection Bias in Deal Data**: Elicitation of project finance data faces systematic bias where publicly available deals may not represent typical transactions. Financial institutions preferentially share data on less commercially sensitive deals, potentially overrepresenting older transactions, less competitive markets, or projects with unusual risk profiles while the most current, competitively priced deals remain confidential.

c) **Expert Biases**: Survey of expert estimates participants face conflicting commercial incentives where developers and lenders may provide optimistic estimates to encourage policy support, while consultants may bias toward client interests. Triangulation across participant types proves more valuable than increasing sample sizes within single stakeholder categories.

d) **Regulatory vs. Commercial Applications**: Regulators require legal defensibility and procedural transparency beyond technical accuracy, favouring analysis of financial market data and reverse-engineering from auctions due to publicly observable data. Private investors benefit from Elicitation of Project Finance Data not only for accuracy but for competitive market intelligence gained through the data gathering process.

2.3.3 Methodology Selection Guidelines based on Application

a) **Policy Analysis**: For relatively quick assessment across multiple markets, survey of expert estimates or analysis of financial market data provide necessary scalability despite precision limitations. Rather than applying expensive deal elicitation methods everywhere, policymakers can first use expert surveys to identify which specific markets or technologies show unusually high or uncertain cost estimates, then focus detailed deal analysis only on those priority cases that warrant the additional resources.

b) **Investment Decisions**: Market-specific investment decisions justify resource-intensive elicitation of project finance data combined with expert estimates from experienced local participants, particularly in emerging markets where using listed utility companies as proxies for CAPM calculations may be inadequate because domestic utilities often face fundamentally different regulatory frameworks, currency exposures, and political risks than renewable projects in developed economies.

c) **Academic Research**: Analysis of financial market data and reverse-engineering from auctions offer transparency and replicability advantages, though the field needs systematic validation studies that compare these methods against actual deal outcomes. Currently, researchers often assume that consistent results across methods indicate accuracy, but consistency doesn't guarantee correctness without verification against real transaction data.

d) **Emerging Markets**: Standard CAPM calculations assume liquid secondary markets where utility stock prices accurately reflect incremental project risks, but many emerging markets have thinly traded utility stocks with prices impacted by regulatory environment. Expert surveys face the opposite problem - local participants may have limited experience with international project finance structures, leading to either overly conservative estimates based on domestic banking practices or overly optimistic assessments that ignore specific regulatory enforcement risks. The certainty equivalent method addresses both issues by explicitly modeling political, regulatory, and currency risks as probability distributions, but successful implementation requires deep understanding of how to identify and quantify diverse risk factors, establish realistic probability ranges for each risk, and most critically, model the correlations between risks - such as how political instability simultaneously increases currency devaluation risk, regulatory change risk, and contract enforcement risk in ways that compound rather than offset each other.

3 Historical Trends in Cost of Capital for Indian RE Sector

- *Multiple estimation methodologies consistently document a complete financing cycle: 300-400 bps WACC compression from 2012-2020 driven by market maturation, followed by 320 bps expansion through 2024 reflecting global monetary tightening and post-pandemic policy normalization.*

- *Wind's historical financing premium over solar has completely disappeared, with both technologies now accessing debt capital within identical 8.5-9.75% ranges.*
- *Despite facing over 670 bps financing cost versus developed markets, India maintains competitive positioning relative to other emerging economies and achieves superior energy pricing through resource quality and execution efficiency.*

3.1 Cost of Capital Evolution/Trend

India's renewable energy cost of capital evolved broadly through two phases over the past decade, as evidenced by data from multiple estimation methods. Understanding this evolution requires recognizing that different methodologies can yield varying results, though consistent patterns across methods strengthen confidence in underlying trends.

The 2010-2020 period shows substantial cost compression across all data sources. Project finance elicitation by Shrimali et al. (2013) documented the baseline CoC, with both solar and wind projects facing 12% debt costs and 16% equity returns in 2010-2011. By 2020, IRENA's comprehensive survey (IRENA 2023) data indicated solar WACC had declined to 7.08% and wind to 8.38%. This reduction of approximately 300-400 bps represents significant decline in the risk pertaining to Indian RE sector.

Multiple methodological approaches corroborate this trend. Auction replication studies by Dobrotkova, Surana, and Audinet (2018) showed solar WACC declining from 14.2% in 2013 to 13.7% by 2015 (**Error! Reference source not found.**). Financial market analysis by Partridge (2018) found wind WACC relatively stable at 10.8-10.9% during 2015-2017 (Figure 2). Survey-based estimates from Kumar, Anisuzaman, and Das (2017) placed solar WACC at 10% in 2016. While absolute WACC estimates vary across methods due to different time periods and technological focus, the consistent evidence of declining financing costs validates the broader de-risking trend.

The compression accelerated during 2020-2021, benefiting from global monetary accommodation. Central banks worldwide implemented aggressive rate cuts in response to the COVID-19 pandemic, with India's Reserve Bank reducing the repo rate by 115 bps between March and May 2020 to support economic recovery. India's 10-year G-Sec yield fell to approximately 6.2%, creating favourable base conditions for infrastructure financing. This period likely represented the sector's lowest-ever financing costs.

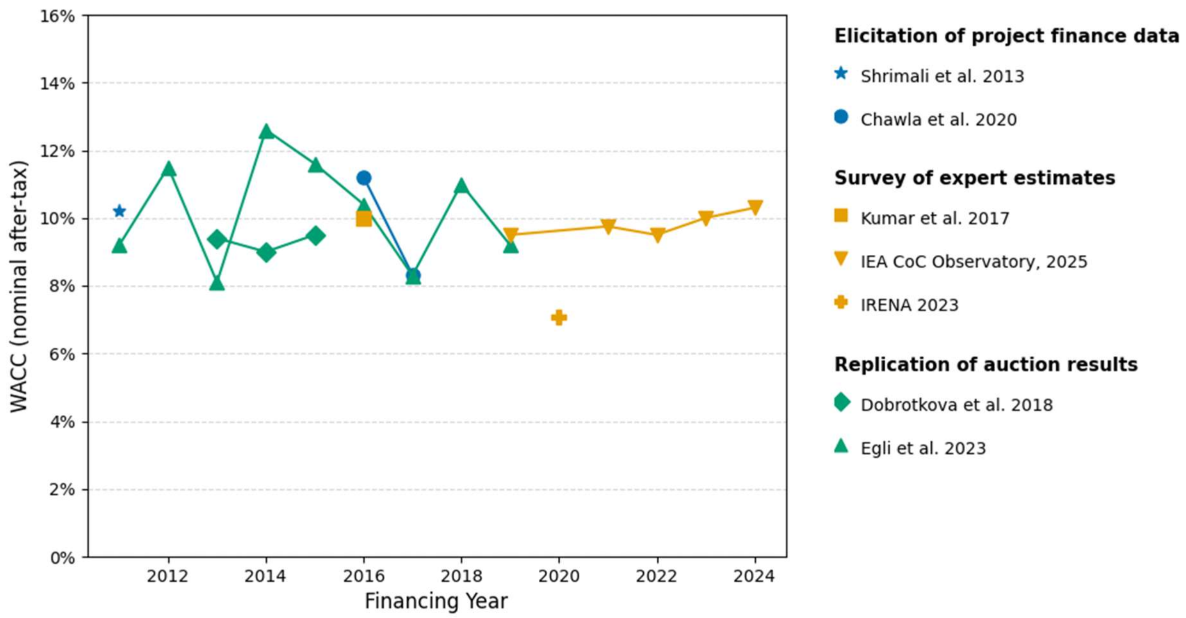

Figure 1: Historical WACC of Indian solar projects estimated through various methodologies

Post-2022 developments reveal market complexity. IEA (2025) surveys indicate solar WACC rising to 9.5-9.75% during 2019-2022, then potentially higher by 2024. However, BNEF (2025) reports debt costs remaining stable at 8.5-9.75% for both technologies. This divergence between total WACC increases and stable debt costs suggests differential risk pricing between debt and equity markets.

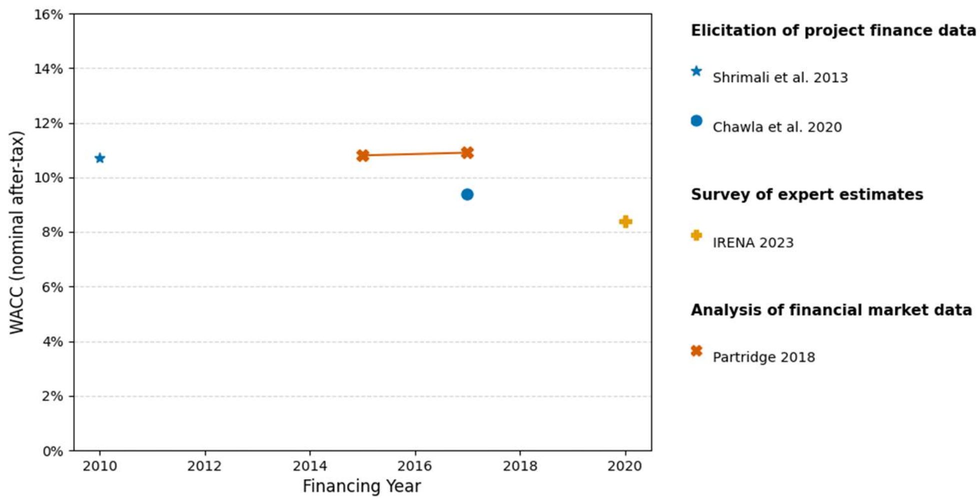

Figure 2: Historical WACC of Indian onshore wind projects estimated through various methodologies

Furthermore, the financing data demonstrates significant convergence in risk perception between solar and wind technologies. Historically, onshore wind projects commanded 50-100 bps premiums over solar due to their operational complexity and moving parts, but recent market intelligence report by BNEF show identical debt pricing ranges for both technologies. This convergence reflects domestic lenders now consider both the generation technologies equally reliable infrastructure assets.

Independent validation of these financing trends emerges from systematic credit rating analysis by V.P. Singh, Nair, and Raja (2021). The authors examined 244 projects' credit rated between 2011-2020 and find that solar projects underwent dramatic transformation from universally sub-investment grade ratings in 2012 to approximately 90% investment grade status by 2020, with over 60% achieving 'A' ratings or higher. Wind projects followed a different trajectory, achieving near-universal investment grade status earlier by 2016, though with less pronounced improvement thereafter. The timeline of these rating upgrades aligns closely with observed WACC compression trends, particularly during the 2015-2018 period when policy innovations such as SECI's credit enhancement intermediation model became operational.

3.2 Comparison with Global RE Markets

Indian solar projects operate under substantially higher financing costs compared to their developed market counterparts, though this disadvantage has not undermined their competitive position in energy pricing. Cross-country comparative analysis shows significant and persistent cost of capital gaps between emerging and developed economies. German solar projects, for instance, achieved remarkably low 1.6% WACC in 2017, while Indian projects faced 8.3% WACC during the same period—a differential of 670 bps that underscores the magnitude of emerging market risk premiums. This pattern extends across developed markets, with US solar projects maintaining WACC levels of 3.0-3.1% during 2017-2018, compared to India's broader range of 8.3-11.0% during the same timeframe (Figure 3).

When positioned within the emerging market context, however, India demonstrates relatively competitive financing conditions. Chinese solar projects experienced WACC levels of 8.4-8.7% during 2017-2019, closely paralleling India's performance and suggesting similar risk perception among international investors. In contrast, Brazilian and South African solar projects consistently commanded financing costs exceeding 10% with considerably greater volatility, indicating that India's financing environment reflects broader emerging market dynamics rather than country-specific institutional weaknesses. These financing cost differentials carry substantial implications for project economics, particularly given renewable energy's capital-intensive nature where financing typically represents 60-70% of total levelized electricity costs. Despite this structural disadvantage, India maintains remarkable competitiveness in delivered energy costs through complementary advantages across multiple dimensions. IRENA (2023) data demonstrates that Indian solar projects achieve levelized costs of $0.038/kWh despite higher financing costs, substantially undercutting US levels of

$0.070/kWh and European Union averages of $0.059/kWh. This competitive position stems from India's unique combination of exceptional solar resource quality with capacity factors reaching 19-22%, significantly lower capital expenditures averaging $525/kW compared to $1,100/kW in developed markets, and streamlined development processes that reduce final levelized cost of solar.

Recent data indicates renewed volatility in India's renewable energy financing costs. Solar WACC reached a historical low of 7.08% in 2020 according to IRENA's comprehensive survey but has since risen to 10.3% by 2024 based on IEA Cost of Capital Observatory data. This 320 bps increase reflects global monetary tightening and renewed risk aversion following the post-pandemic policy normalization. Despite higher financing costs, India's renewable projects maintain competitive energy pricing due to superior resource quality and lower capital expenditures compared to developed markets.

Onshore wind financing CoC data (Figure 4) shows similar cost reduction trends as solar, though with limited data availability reflecting market intelligence gaps. Indian wind projects maintained WACC levels of 9-11% during 2015-2017, consistent with the historical 50-100 bps premium over solar projects. This premium has now disappeared entirely. BNEF (2025) survey reports identical debt pricing ranges of 8.5-9.75% for both wind and solar greenfield projects, marking a significant shift in lender risk perception between the two technologies.

The persistence of emerging market risk premiums reflects systematic factors beyond renewable energy-specific considerations, including currency volatility, regulatory frameworks, and sovereign risk perceptions. While these differentials constrain India's cost reduction potential, the data demonstrates that superior project economics through resource quality and execution efficiency can maintain competitive energy pricing despite financing disadvantages.

The financing story of the past decade shows a complete cycle, not just steady improvement. Different research methods all point to the same pattern: costs fell dramatically from over 12% in 2012 down to just 7.08% in 2020, then climbed back to 10.3% by 2024. That 320 bps increase tells us that 2020 was a turning point, not a permanent new normal.

The most notable change is how wind and solar financing converged. Wind projects used to carry a premium because lenders saw them as riskier. That premium is gone now. Both technologies get the same debt terms, which signals that lenders view them as equally reliable infrastructure investments.

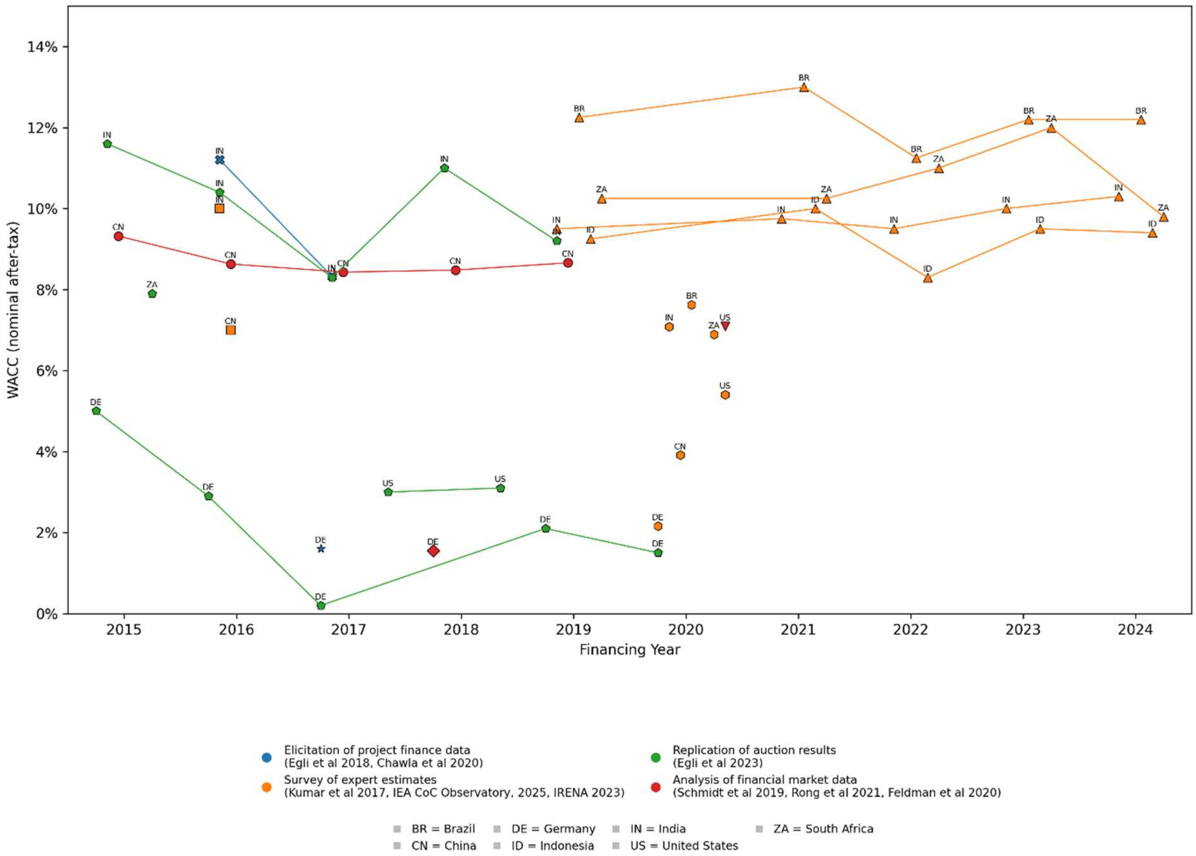

Figure 3: WACC Estimates of Solar PV Projects Across Countries (Source: [B.E. Steffen, Florian; Gumber, Anurag; Dukan, Mak; Waidelich, Paul (2025)](); [IEA (2025)]())

India still pays more for capital than developed markets do. But the country maintains competitive electricity prices anyway. Superior solar resources and lower development costs make up for the financing disadvantage. When different research approaches all show the same trends, we can be confident these patterns reflect real market changes rather than measurement quirks.

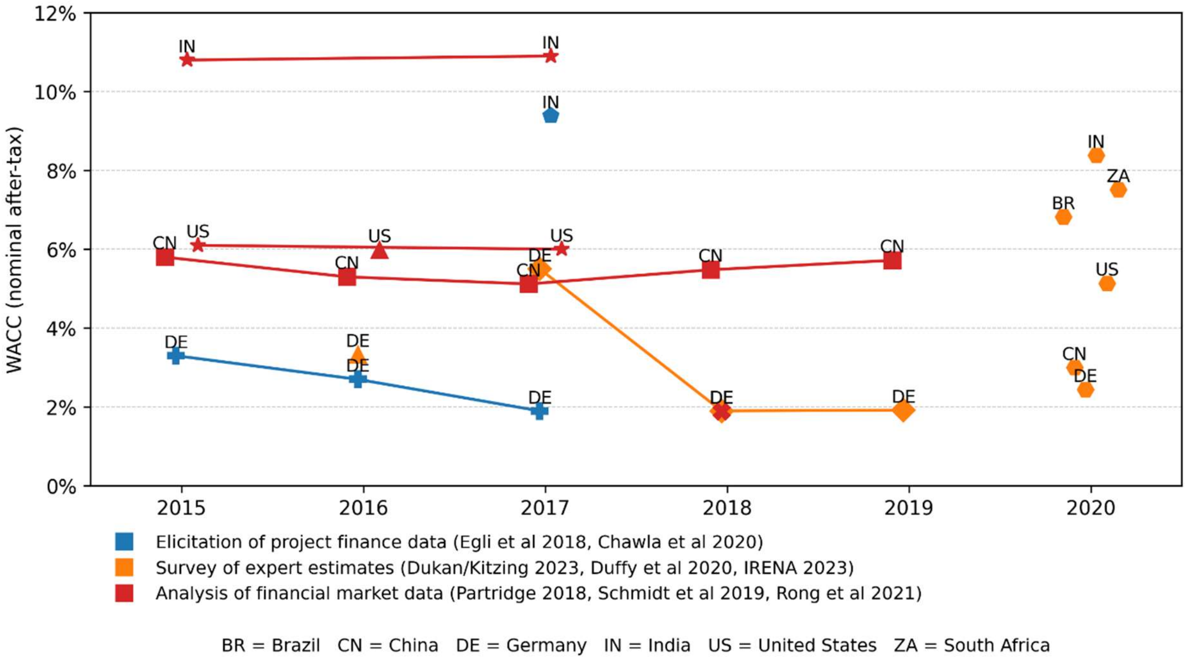

Figure 4: WACC Estimates of Onshore Wind Projects Across Countries (Source: [B.E. Steffen, Florian; Gumber, Anurag; Dukan, Mak; Waidelich, Paul (2025)](#)*)*

The recent cost increases highlight how global financial conditions still matter a great deal. At the same time, the sector faces new complexities. Traditional approaches to managing project risks may not work as well for hybrid projects that combine multiple technologies. These emerging challenges, along with ongoing power sector issues, will likely shape how financing costs evolve going forward.

4 Drivers of Cost of Capital and Risk Premia in the Indian RE Sector

- *PPA counterparty risk consistently emerges as the dominant financing concern across all studies, reflecting that DISCOM financial distress creates a fundamental structural barrier to renewable energy investment.*
- *Currency risk has become less material as domestic financial institutions have developed greater comfort with renewable energy financing, though foreign capital remains necessary for India's climate finance requirements.*
- *New project types like FDRE introduce complex risk categories including demand fulfillment penalties, market price exposure, and battery replacement uncertainties that traditional risk assessment frameworks do not address.*

Understanding the factors that drive financing costs is essential for both investors and policymakers seeking to reduce barriers to renewable energy deployment. India's renewable energy sector faces a unique combination of country-specific challenges and broader emerging market risks that collectively determine project bankability and cost of capital. Several comprehensive studies have examined these risk drivers across different time periods, each employing distinct methodologies to quantify their relative impact on financing costs.

The Table 2: Cost of Capital Risk Drivers in Indian Renewable Energy ProjectsTable 2 draws from four comprehensive studies selected for their detailed examination of how various risk factors drive cost of capital in India's renewable energy sector - either through quantitative assessment or systematic ranking. These studies represent the most rigorous available research that goes beyond general risk identification to actually measure or quantify the relative impact of different risk categories on financing costs. BNEF (2025) provides market participant perspectives through systematic surveys, Shrimali (2021) offers quantitative analysis using financial market proxies combined with expert interviews/surveys, the IEA Cost of Capital Observatory (IEA 2025) an initiative from the International Energy Agency (IEA), World Economic Forum, ETH Zurich and Imperial College London - provides comparative international assessment through its dashboard of financing cost data, analytical tools for risk quantification, and Das (2025) from Ember presents detailed risk premium quantification using certainty equivalent methodology.

The comparison across these four studies reveals several clear patterns in renewable energy financing in India. PPA counterparty risk emerges as the top concern across all methodologies - whether through market participant surveys (BNEF 2025), quantitative financial analysis , international comparative assessment (IEA 2025), or detailed risk premium modelling simulation exercise (Das 2025). All these studies consistently indicates that DISCOM financial distress represents a key persistent barrier to scaling renewable energy investment.

The studies also capture temporal shifts in risk perception. The difference between Shrimali (2021) quantification of currency risk (2.66% country premium) and BNEF (2025) observation of reduced currency materiality reflects India's transition toward domestic financing ecosystems. This shift demonstrates that targeted policy interventions can alter risk profiles within relatively short timeframes.

The methodological diversity across studies provides complementary insights. BNEF (2025) captures current market sentiment through participant surveys, while Das (2025) conducts simulation based modelling to provide detailed quantification of existing as well as emerging risks like FDRE project complexities that may not yet be fully reflected in market pricing. Shrimali (2021) mixed-method approach offers historical perspective on systematic risk drivers, while the IEA (2025) CoC Observatory provides international context that helps distinguish India-specific challenges from broader emerging market patterns.

Table 2: Cost of Capital Risk Drivers in Indian Renewable Energy Projects

Risk Factor	BNEF (2025) **Survey Results**	Shrimali (2021) **Mixed-Method Approach**	IEA (2025) **CoC Observatory Assessment**	Das (2025) **- Risk Premium Analysis**[2]
PPA Counterparty	Market participants consistently rank counterparty risk as the most significant concern, with particular emphasis on DISCOM payment delays averaging 6+ months across most states. Key concerns include contract renegotiation attempts following Andhra Pradesh and Punjab precedent, and stark financing advantages for federal agencies due to sovereign backing. Gujarat represents the only state exception due to strong financial position. This factor received the highest average rating of 4.61/5, ranking	Analysis identifies counterparty risk as the largest single contributor, representing 22-27% of total debt risk premium. The study quantifies debt cost impacts at 1.47% for renewable energy projects and 2.04% for fossil fuel projects, with state DISCOM financial distress creating continued liquidity constraints for standalone projects. This results in higher debt service reserve requirements and elevated credit risk premiums across the power sector.	The Observatory framework identifies counterparty risk as a critical barrier in emerging markets, emphasizing that state utility financial health is fundamental to renewable energy investment viability. Payment delays and contract sanctity concerns create systemic risks that require policy intervention beyond project-level mitigation strategies.	The study's lifecycle analysis identifies "offtake risk due to PPA renegotiation, curtailment and payment delays" across the entire 2–25 year operational phase as a sustained threat to project cash flows, with DISCOMs' accumulated debt of ₹6.84 trillion (US$ 76 billion) reinforcing chronic payment uncertainty.

[2] Risk quantification primarily reflects new-age FDRE projects incorporating oversized generation and storage requirements. Traditional solar/wind projects may exhibit different risk profiles.

	first among all identified cost drivers.			
Execution/Regulatory Risk (Commissioning Delays)	External financiers consistently rate execution risk higher than developers themselves, reflecting the control differential between parties. Primary concerns include land acquisition delays, grid connectivity bottlenecks, environmental clearance procedures, and coordination challenges between state and central approval processes. Survey participants identified five main delay causes: contract signing delays, commissioning transmission grid substations, rising equipment prices, land acquisition complications, and labor shortages. This factor	The paper incorporates execution challenges within the permits risk category as part of broader institutional risk assessment. Regulatory approval delays and environmental clearance bottlenecks are embedded within the institutional framework, with analysis showing that public sector inefficiencies in permit administration create systematic delays affecting project IRRs through extended construction timelines and additional	The Observatory identifies regulatory risk as the top concern for India's cost of capital reduction. The assessment emphasizes single-window clearance systems and regulatory standardization as key policy interventions, with institutional capacity building identified as a fundamental requirement for sustainable cost reduction.	Development phase risk contributing ~80 bps premium.[3] Includes "delay in land aggregation and power evacuation" and "delay in PPA execution" as critical development bottlenecks. CEA data shows average commissioning delays of 17 months (P50) extending to 26 months (P90)[4].

[3] Risk premiums traced from Ember waterfall analysis (Chart 1) showing cost of capital build-up from 4.2% (best-in-class) to 9.9% for new-age FDRE projects. Individual risk contributions estimated as incremental basis point additions from the waterfall structure.
[4] P50 represents median/average scenario with 50% probability of meeting or exceeding estimates; P90 represents conservative scenario with 90% probability - used by risk-averse lenders for credit risk assessment.

	achieved an average rating of 4.00/5, ranking second among all cost of capital drivers.	financing costs during the development phase.		
Site Resource Quality	Market participants demonstrate increasing sophistication in resource evaluation, with assessment methodologies shifting from annual yield calculations to hourly output analysis for complex projects requiring supply during peak demand hours or specific dispatch profiles. International investors apply stricter evaluation standards based on their global portfolio experience with resource forecasting errors, while domestic participants show growing awareness of resource quality's financing implications. Survey responses indicate that focus should be on expected hourly output rather than just annual resource potential, reflecting	The study encompasses resource quality within the broader resource/technology risk category, addressing resource volume uncertainty, technology performance risks, and construction/operational challenges. While ranked with lower materiality compared to counterparty and grid risks, resource assessment accuracy directly impacts debt capacity determination through DSCR (Debt Service Coverage Ratio) calculations and P-value exceedance probabilities used by lenders to stress	The Observatory acknowledges technology risk within its framework but ranks it lower than institutional factors based on cross-country analysis. Resource assessment standardization and technology performance validation are identified as market development requirements rather than primary cost drivers, though they remain important for project-level economics.	Operational generation risk contributing ~50 bps premium. Shortfall in electricity generation identified as moderate operational risk. Analysis of 24 PV plants (5 GW capacity) shows over 75% generating at or above P90 estimates, indicating relatively lower risk profile as per the study.

	increasing grid sophistication requirements and demand-supply matching needs. This factor received an average rating of 3.89/5, ranking third among identified cost drivers.	test the revenues from a project.		
Currency/ Macro-economic Risk	The survey methodology does not directly measure currency risk, suggesting reduced materiality for the predominantly domestic financing ecosystem that has evolved in India's renewable energy sector. Market participants apparently do not consider currency exposure material enough for explicit measurement in current risk assessment frameworks, reflecting the sector's transition from international capital dependence to domestic financing sources and reduced foreign equipment procurement. As the most recent survey in the	The paper includes macroeconomic and currency risk as systematic factors encompassing exchange rate volatility and country risk premium components. Quantified impact: 2.66% country risk premium for India versus developed markets, representing baseline macroeconomic risk adjustment requirements reflecting India's macroeconomic fundamentals relative to developed markets.	The Observatory's dashboard ranks currency risk as the second concern for India in its global comparison framework, reflecting international capital provider perspectives on emerging market investments. Through its case studies section, foreign exchange hedging market development and local currency financing availability are identified as key policy priorities for emerging market renewable energy scaling initiatives	While the study classifies currency fluctuation and rupee depreciation as 'sector-wide risks' distinct from project-specific factors , it explicitly excludes them from its detailed bottom-up risk quantification exercises. Instead of calculating a specific currency risk premium, the methodology incorporates these macroeconomic factors through a baseline 'country risk premium' derived from secondary market sources

	literature, it is particularly indicative of this evolving financing landscape in India's renewable energy sector.		based on successful risk mitigation examples from other countries.	to establish a best-in-class cost of capital
Grid/Transmission Risk/Deviation Settlement Mechanism (DSM)	The survey does not directly isolate grid transmission as a separate risk factor, though transmission grid substation commissioning delays were identified as one of five primary execution risk drivers. Market participants evaluate transmission infrastructure availability through project location assessment methodologies, where infrastructure access significantly affects development timelines and commissioning risks.	Analysis identifies grid and transmission risk as second-largest contributor to cost premiums, representing 14% of total risk premium across both renewable and fossil fuel sectors. Quantified impact: 0.93% debt cost penalty for renewable energy and 1.05% for fossil fuel projects from grid/transmission constraints. Limited transmission capacity creates curtailment risks affecting project economics through reduced off-take certainty.	The Observatory's country-specific risk assessment does not identify transmission network among the top three priority risks for India, focusing instead on regulatory (top risk), currency (second risk), and bankability (third risk) concerns. While transmission challenges are acknowledged in the broader framework, they are not highlighted separate risk categories in the assessment.	Operational scheduling risk contributing ~60 bps premium. DSM penalties from stricter forecasting requirements. Revenue losses expected to increase 60-70% under new DSM regulations effective December 2024.

Equipment Suppliers	Equipment procurement has become more challenging due to fast-evolving import policies and restrictions, including 40% import tax on modules and ALMM (Approved List of Models and Manufacturers) requirements. Banks now spend more time and money evaluating new Indian suppliers, engaging independent third-party factory inspectors and internal technical experts, which has occasionally slowed credit approval processes. Despite widespread industry concerns about new solar module suppliers, the situation is expected to improve within two years as sufficient domestic modules become financed. This factor received an average rating of 3.39/5, with most respondents scoring equipment suppliers at 3-4 for bankability, suggesting IPPs	The paper incorporates equipment considerations within the broader resource/technology risk category, addressing hardware purchase and manufacturing risks along with equipment quality and warranty concerns.	The IEA observatory does not identify equipment supplier or supply chain risks among the primary risk categories assessed for cost of capital drivers in emerging markets.	Technology and cost uncertainties span both construction and operational phases. Panel-related risks (~80 bps) reflect both cost volatility from policy changes and performance concerns, with 40% of TOPCon/HJT modules showing >5% UV performance degradation and 20% price increases following ALMM implementation requirements. Battery energy storage system (BESS) cost uncertainties contribute an additional ~30 bps premium due to evolving technology standards and procurement complexities for Firm and Dispatchable

	are consciously selecting reputable suppliers.			Renewable Energy (FDRE) projects.
Political Risk	The survey does not directly assess political risk as a separate factor. Political considerations may be embedded within other risk categories such as counterparty risk assessment (particularly regarding state DISCOM reliability) and execution risk evaluation (including regulatory approval processes), but political risk was not explicitly measured or discussed as an independent cost driver in the survey framework.	The paper encompasses political risk through country and state-specific governance characteristics and legal framework stability assessment. Institutional quality is identified as a foundational factor affecting all other risk categories through regulatory efficiency and contract enforcement capabilities.	The Observatory's country-specific risk assessment does not identify political risk among the top three priority risks for India, which are regulatory (top risk), currency (second risk), and bankability (third risk).	

The comparative analysis shows several key implications for renewable energy financing. PPA counterparty risk consistently dominates across all methodologies and time periods, indicating DISCOM financial distress represents a fundamental structural barrier rather than a cyclical issue. The evolution from currency risk materiality in Shrimali (2021) to its reduced prominence in BNEF (2025) demonstrates growing domestic financing capacity, though currency risk remains relevant given India's ongoing foreign capital requirements for meeting ambitious climate targets. Meanwhile, FDRE projects introduce entirely new risk architectures that aren't captured in traditional frameworks, suggesting financing challenges will continue evolving as project structures become more sophisticated. The methodological diversity across studies provides complementary insights, with no single approach capturing the complete risk picture.

The evidence suggests that effective risk mitigation requires coordinated intervention across multiple areas. While addressing DISCOM financial health remains a policy priority given its consistent ranking, the emergence of second-generation complexities around grid integration and storage lifecycle management indicates that new challenges will require policy responses as traditional risks are resolved.

Moving beyond episodic analysis requires integrated data infrastructure building on existing platforms like Stefan's database, IEA Cost of Capital Observatory, and BNEF surveys. A "survey of surveys" approach using standardized templates could harmonize data collection while maintaining each source's unique strengths. This should include standardized risk taxonomies that capture both traditional risks and emerging complexities, quantitative policy uncertainty indices tracking regulatory changes and payment delays, and systematic risk premium monitoring that captures emerging risks before they fully materialize in market pricing.

Such coordinated monitoring would leverage existing institutional capabilities while creating the consistency needed to inform both investment decisions and policy interventions as the sector continues evolving toward more complex project structures. The current evidence base provides valuable insights but lacks the consistency and continuity needed for systematic risk monitoring that could guide renewable energy scaling efforts.

5 Policy Interventions and Market Maturation: A Four-Phase Policy Journey

The systematic risk reduction in the RE's CoC documented in Section 3's historical trends reflect policy evolution that has gradually influenced the ranking of various risk factors identified in Sections 4. India's utility-scale renewable energy transformation represents one of the most comprehensive clean energy transitions in contemporary energy transition policies evolution. The journey showcases a narrative of iterative learning where each policy intervention generated new challenges that required increasingly sophisticated solutions.

The journey from 2010 to 2025 can be understood through four distinct phases, each characterized by evolving policy priorities, institutional innovations, and market responses that highlights the relationship between state intervention and market forces in driving technological transformation. This policy trajectory demonstrates clear learning patterns where initial interventions created unintended consequences that necessitated subsequent adaptations. Most significantly, while policies have successfully addressed project-level risks, they have struggled with systemic off-taker challenges that remain the primary constraint on sector scalability.

The comprehensive policy landscape (Table 3) that enabled this transformation is detailed in Appendix 7, which provides an overview of major large-scale renewable energy policies, DISCOM reform, and grid infrastructure policies introduced between 2010-2023. In this section, we examine how these policies evolved through four distinct phases, analyzing their effectiveness in mitigating specific cost of capital drivers while identifying persistent structural challenges that continue to influence investment decisions.

5.1 Phase 1: Market Creation Through Price Guarantees (2010-2015)

The challenge facing policymakers in 2010 was clear: renewable energy technologies were uneconomical. Solar power costs exceeded ₹ 10/kWh (US$0.11/kWh) while coal-fired generation remained below ₹ 3/kWh (US$0.03/kWh), primarily due to nascent stages of technology in India, thus requiring substantial government intervention. The policy response prioritized investment certainty over cost efficiency in recognition that emerging technologies require patient capital and protected markets to achieve viability.

The Jawaharlal Nehru National Solar Mission (JNNSM), launched in January 2010, employed state-determined feed-in tariffs (FiT) that guaranteed developers 25-year PPA at fixed, preferential rates. This mechanism provided what private investors needed: revenue certainty in an otherwise risky and unproven sector. The wind energy projects, already more established, benefited from a different but equally effective set of incentives.

Accelerated Depreciation (AD) allowed high-tax-paying corporations to front-load depreciation benefits. Thapar, Sharma, and Verma (2016) quantified AD's effectiveness in the wind sector. The scheme reduced effective promoter investment by 76%, cutting equity requirements from ₹ 19 million (US$0.21 million) to ₹ 4.5 million (US$0.05 million) per MW through tax offsets. The government collected ₹ 10.84 million (US$0.12 million) per MW in lifetime taxes while providing effective support of only ₹ 0.35 per kWh, making the scheme net revenue-positive. Carbon abatement costs reached US$6.5 per tonne CO2 equivalent, well below IEA benchmarks of US$67 per tonne. During 2003-2010, this mechanism enabled 70% of wind capacity additions.

Another scheme called generation-based incentives (GBI) provided direct payments of ₹ 0.50 per unit of electricity generated. GBI demonstrated superior economic efficiency compared to capital subsidies. While government support equalled ₹ 5.2 million (US$0.06 million) per MW (NPV basis), tax collections from the same projects reached ₹ 11 million (US$0.12 million) per MW over their lifetime. The effective per-unit subsidy was only ₹ 0.14 per kWh over 20 years, achieving carbon displacement at under US$3 per tonne CO2 equivalent. This performance-based approach attracted Independent Power Producers, with over one-third of wind capacity developed under the IPP model by 2016 (Thapar, Sharma, and Verma 2016).

However, empirical analysis by Shrimali, Pusarla, and Trivedi (2017) provided empirical evidence on drawback of the AD scheme: wind plants under AD achieved plant load factors (PLF) at least 3 percentage points lower than those under GBI, suggesting that the focus on tax benefits may have compromised generation efficiency. This finding highlighted the trade-off between deployment effectiveness and operational performance, as developers prioritizing tax advantages under AD appeared less focused on maximizing actual power generation compared to GBI recipients whose returns were directly tied to generation output.

This phase successfully mitigated technology and resource risks through guaranteed feed-in tariffs, while domestic incentives like AD and GBI helped Indian banks develop comfort with renewable energy financing, reducing foreign capital dependency. Long-term policy commitments provided political certainty for investors. The high guaranteed tariffs, while effective for risk mitigation, added fiscal burden to already financially distressed distribution companies, intensifying counterparty risk concerns that would persist throughout subsequent phases.

These supply-side incentives were coupled with demand-side mandates through Renewable Purchase Obligations (RPOs), which required distribution companies to procure specified percentages of their electricity from renewable sources. This double intervention of subsidizing supply while mandating demand for the clean power, reflected how uneconomic was renewable power that policymakers had to confront.

Performance data from this phase revealed impressive capacity growth. The National Solar Mission's initial 20 GW target was achieved four years ahead of schedule, prompting an ambitious revision to 100 GW in 2015. Wind installations grew from 16 GW in FY 2011 to 23.45 GW by FY 2015, demonstrating consistent market response to policy incentives. Yet this success carried significant costs that would reshape future policy design. The high guaranteed tariffs imposed fiscal stress on already struggling distribution companies, creating what would become the sector's most persistent challenge: ensuring the financial viability of off-takers (Chawla 2016).

This phase successfully established renewable energy markets through comprehensive risk mitigation, but the high costs of guaranteed pricing created fiscal sustainability challenges that necessitated fundamental policy restructuring in subsequent phases.

5.2 Phase 2: Price Discovery and De-risking through Institutions (2015-2019)

By 2015, a disconnect had emerged between administered FiT prices and declining technology costs. Global solar module prices were falling rapidly, yet India's FiT remained fixed at levels that no longer reflected economic reality. This created windfall profits for developers while imposing unsustainable burdens on distribution companies, a classic case of policy inertia undermining market efficiency.

The transition to competitive e-reverse auctions beginning in 2015 for solar and 2017 for wind represented more than procedural change. It constituted a fundamental shift from price-setting to price-taking, allowing market forces to determine project economics. The response was dramatic: solar tariffs fell by over 80%, reaching a record low of ₹ 2.44/kWh (US$0.027/kWh) at the Bhadla Solar Park auction in May 2017. Wind power experienced similar declines, dropping from the FiT range of ₹ 4-6/kWh (US$0.044-0.066/kWh) to a low of ₹ 2.43/kWh (US$0.027/kWh) in a Gujarat auction by December 2017 (Dutt 2018).

Early auction results documented by Thapar, Sharma, and Verma (2016) showed solar tariff reductions of 32% in Batch-I and 43% in Batch-II of the National Solar Mission. The bundling mechanism addressed solar power's cost disadvantage by pairing it with cheaper coal power. Given solar's 19% capacity utilization versus coal's 95% PLF, each unit of solar power (₹ 17.91/kWh (US$0.20/kWh)) was bundled with five units of coal power (₹ 3/kWh (US$0.03/kWh)), creating a weighted average of ₹ 5.50/kWh (US$0.06/kWh) that utilities could afford. Auction-discovered discounts further reduced this to ₹ 4.53/kWh (US$0.05/kWh), making expensive solar technology economically viable for power procurement.

Participation requirements including bank guarantees and ₹ 30 million (US$0.33 million) per MW minimum net worth filtered out speculators, resulting in high project completion rates unlike failed auctions in other markets.

Success in cost reduction created new challenges that revealed the complexity of transitioning from regulated to market-based mechanisms. "Winner's curse" dynamics emerged, where developers submitted financially unsustainable bids banking on future cost reductions. Research by Bose and Sarkar (2019) found completion rates of only 58.6% for solar capacity awarded in 2017 auctions. The simultaneous introduction of auctions and withdrawal of traditional incentives disrupted established business models for wind projects where equipment manufacturers were also primary developers, leading to a 60% decline in capacity additions following the 2017 transition (Rao 2021).

Recognizing that low tariffs alone were insufficient if developers faced substantial ground-level and financial risks, policymakers introduced central government backed institutional architecture to de-risk the renewable energy projects. The Solar Park scheme, launched in December 2014, offered developers pre-developed land parcels complete with grid evacuation facilities in a "plug-and-play" model designed to reduce project gestation periods and local clearance risks. Though targets expanded from 20 GW to 40 GW, implementation remained constrained by persistent land acquisition challenges (Astrea Legal Associates, 2024).

More transformative was the emergence of central intermediary institutional setup. SECI and NTPC (Please See Box 1) began acting as intermediaries, signing PPAs with developers while executing back-to-back Power Sale Agreements with distribution companies. This architectural innovation effectively insulated developers from the poor credit ratings of individual DISCOMs as the SECI and NTPC absorbed counterparty risk. Credit rating agencies consistently noted that SECI PPAs significantly lowered risk perception for investors and lenders, enabling access to lower-cost finance that made ultra-low auction tariffs economically viable (V.P. Singh, Nair, and Raja 2021).

Box 1: Empirical Evidence of Central Intermediation Effectiveness

Ryan (2022) provides comprehensive quantitative assessment of counterparty risk impacts using auction data from India's solar procurement spanning 2012-2020. The study exploits institutional variation where identical projects face different risk levels depending on whether procurement occurs through state utilities or central government intermediation.

The analysis reveals that average state counterparty risk increases solar prices by 10% compared to central procurement, representing two-thirds of typical winning bid markups. This risk premium stems from strategic renegotiation behaviour rather than financial weakness, as evidenced by firms operating thermal plants in the same state showing reduced solar risk exposure due to stronger bargaining positions against potential contract disputes.

Central government intermediation through SECI and NTPC completely eliminates this risk premium, achieving 6% lower bid prices through sovereign credit backing. This validates the federal intermediation model where government agencies absorb DISCOM payment risks and provide creditworthy contracts to developers.

The study also documents the failure of ceiling price policies adopted from 2018-2020, which reduced capacity procurement by 16% while achieving minimal cost reductions of only 1%. This counterproductive outcome occurred as ceiling prices reduced auction participation, causing remaining bidders to increase markups toward ceiling levels.

The findings demonstrate that while project-level risks can be mitigated through institutional design, persistent DISCOM financial distress requires federal intermediation to achieve optimal renewable energy financing costs.

On the other hand, the persistent failure of demand-side mechanisms during this period offered sobering lessons about institutional design. Despite legal mandates, RPOs suffered widespread non-compliance across most states due to weak enforcement mechanisms and DISCOM financial constraints. The Renewable Energy Certificate (REC) market, after brief initial activity, effectively collapsed as certificate inventories flooded the market and prices fell to floor levels (Sawhney (2022);

Shrimali, Tirumalachetty, and Nelson (2012)). These failures showed that policies designed by the central government often struggle when they depend on state governments to enforce rules against
central government often struggle when they depend on state governments to enforce rules against
their own cash-strapped electricity companies.

This phase successfully addressed counterparty risk through central intermediaries (SECI/NTPC) that absorbed DISCOM credit risk via back-to-back agreements, while competitive auctions achieved dramatic cost reductions exceeding 80% for solar. Solar Parks targeted execution risks through "plug-and-play" models. However, demand-side mechanisms including RPOs and RECs failed due to weak enforcement and DISCOM financial constraints, while over-aggressive auction bidding created new execution challenges with completion rates dropping to 58.6% for some solar projects.

This phase achieved remarkable cost reductions through competitive price discovery while creating institutional mechanisms that effectively transferred counterparty risk from developers to creditworthy central entities. However, the failure of demand-side mechanisms highlighted the limits of central policy design when implementation depends on financially constrained state-level institutions.

5.3 Phase 3: Grid Integration and Supply Chain Security (2019-2023)

As renewable energy achieved cost competitiveness, policy attention shifted to what scholars term "second-generation" challenges. These are the technical and economic complexities created by success itself. The influx of intermittent solar and wind generation began straining grid stability. Distribution companies and grid operators found themselves struggling to manage variable renewable energy, particularly during evening peak demand when solar generation ceased but electricity demand peaked.

Advanced Auction Designs: Policy responses evolved toward sophisticated auction designs that valued reliability alongside cost. The National Wind-Solar Hybrid Policy, introduced in 2018, leveraged the complementary characteristics of wind and solar resources. Solar generates during the day while wind often peaks at night and during monsoon seasons, producing more consistent power output and higher capacity utilization factors. Round-the-Clock tenders, first introduced by SECI in 2019, represented further innovation by requiring developers to guarantee power supply at high annual capacity utilization factors, typically 80% or higher, with penalties for non-compliance. These tenders allowed combinations of renewable sources with energy storage or bundling with conventional thermal power to achieve firm, dispatchable renewable electricity (Thayillam, Gulia, and Garg 2021).

Developer response to these advanced tender designs proved positive. Market data shows hybrid tender shares grew from 16% in FY2020 to 43% in FY2024 while maintaining competitive tariffs comparable to standalone projects (Sharma et al. 2024). The first RTC auction discovered competitive first-year tariffs of ₹ 2.90/kWh (US$0.03/kWh) with escalation clauses, proving that firm, dispatchable renewable power could be delivered at reasonable cost. Successful commissioning of complex projects like ReNew Power's 3.3 GW RTC project, which combines wind, solar, and battery systems to achieve 80% Plant Load Factor, provided proof-of-concept for these sophisticated tender specifications.

Transmission Bottlenecks: Simultaneously, the concentration of renewable deployment in resource-rich states overwhelmed existing transmission infrastructure, creating bottlenecks, curtailment, and stranded assets. The Green Energy Corridor scheme achieved substantial physical progress with over 9,136 circuit-kilometers constructed under Phase I, yet struggled with persistent delays in land acquisition and right-of-way clearances (Power Grid Corporation, 2025). Despite ISTS charge waivers that successfully encouraged participation in national-level tenders, over 50 GW of renewable capacity remained stranded due to inadequate transmission infrastructure. Annual transmission additions consistently fell short of targets since FY2019 (Sharma et al. 2025).

Manufacturing Policy: Supply chain vulnerabilities prompted comprehensive industrial policy intervention. With over 80-90% of solar components imported from China, creating both geopolitical and price risks, the government implemented a strategy combining protection and incentives. Basic Customs Duty of 40% on modules and 25% on cells, effective from April 2022, provided trade protection. The Approved List of Models and Manufacturers effectively mandated domestic sourcing for government-supported projects by limiting approved suppliers predominantly to domestic producers. Production Linked Incentive schemes provided direct financial incentives based on sales of high-efficiency modules produced in India.

Phase 3 successfully addressed grid integration challenges through advanced auction designs (hybrid and RTC tenders) that required firm, dispatchable renewable power, while manufacturing policies (BCD, PLI, ALMM) reduced equipment supply chain dependency on imports. However, transmission bottlenecks persisted with over 50 GW of capacity stranded despite Green Energy Corridor investments. Manufacturing policies increased project costs by ₹ 0.40-0.52/kWh and created domestic supply risks as manufacturers prioritized exports over local demand.

Industry data suggests this policy package supported significant manufacturing expansion. PLI schemes attracted committed investments exceeding ₹480 billion (USD 5.3 billion) for 48.4 GW manufacturing capacity, projecting over 38,500 direct jobs, with domestic capacity crossing 100 GW in 2025. However, trade-offs became apparent as Basic Customs Duty (BCD) increased project costs by an estimated ₹ 0.40-0.52/kWh (Bridge to India, 2021). An unexpected consequence emerged as Indian manufacturers increasingly prioritised export markets, particularly the United States, potentially creating domestic supply shortfalls despite expanded capacity (IEEFA, 2024).

This phase tried to address grid integration challenges through advanced auction designs to deliver firm renewable power, while industrial policy aimed to achieve manufacturing scale-up albeit with higher domestic costs and unexpected export orientation that threatened domestic supply security.

5.4 Phase 4: Addressing Systemic Off-taker Risks (2021-2025)

The evolution toward addressing systemic risks reflects a mature understanding that generation sector success remains fundamentally constrained by distribution sector distress. The failure of the Ujwal DISCOM Assurance Yojana (UDAY), launched in 2015, provided crucial policy learning. Despite having state governments assume DISCOM debt, the scheme failed to enforce necessary structural reforms. Financial data shows that by fiscal 2020, DISCOM debt had returned to pre-UDAY levels while overdue payments to power generators escalated from ₹ 170.30 billion (US$1.88 billion) in August 2017 to ₹ 949.20 billion (US$10.49 billion) by August 2021. This pattern underscores that financial bailouts without operational improvements are unsustainable (PRS India, 2021; CRISIL, 2020).

The Revamped Distribution Sector Scheme (RDSS), launched in July 2021 with an outlay of ₹ 3.03 trillion (US$33.5 billion), incorporated these lessons through a "reforms-based, results-linked" framework. Unlike UDAY's unconditional bailout approach, RDSS ties financial assistance to achievement of pre-agreed performance benchmarks. These include reducing Aggregate Technical & Commercial losses to 12-15% and eliminating gaps between Average Cost of Supply and Average Revenue Realised by 2024-25. The scheme's centerpiece, a national smart metering program, aims to improve billing and collection efficiency through technological intervention.

Early implementation data presents a mixed picture. Physical progress has been slower than anticipated, with industry reports showing only 28% advancement for loss reduction works and under 10% for smart metering by mid-2025 (Power Line, 2025; Indian Infrastructure, 2025). Financial turnaround remains elusive. DISCOM collective net worth remained negative at ₹ -1.73 trillion (US$19.12 billion) while accumulated losses reached ₹ 6.92 trillion (US$76.50 billion) in 2023-24, pointing to persistent underlying unsustainability.

Complementing structural reforms, the Late Payment Surcharge Rules of 2022 introduced automated enforcement mechanisms that mark an evolution from passive credit enhancement to active penalty imposition. These rules mandate that payment failures trigger power exchange access restrictions and graded supply regulation, creating direct consequences for non-payment behaviour (CRISIL Intelligence, 2025).

Paradoxically, the very success of auctions in reducing tariffs has created new market frictions. Ultra-competitive pricing led to tender undersubscription, with 8.5 GW of capacity finding no bidders in 2024 due to increasingly complex tender designs and developer viability concerns. More concerning, over 50 GW of successfully auctioned capacity remains stalled as distribution companies delay signing

Power Sale Agreements, anticipating further tariff declines. These emerging challenges risk undermining 2030 targets by creating uncertainty for developers and potentially deterring investment in what had become a predictable, auction-driven market. Analysis by Ember suggests that these systemic risks could jeopardize India's 500 GW renewable energy target by as much as 100 GW, underscoring the critical importance of resolving offtaker challenges (Das 2025).

The government, during 2021-2025, attempted systematic counterparty risk resolution through RDSS reforms-based approach (learning from UDAY's failure) and Late Payment Surcharge Rules for automated enforcement. However, DISCOM financial distress persisted with negative collective net worth of ₹ 1.73 trillion and slow reform implementation. Over 50 GW of auctioned capacity remains stalled due to delayed PSA signing, while ultra-competitive pricing created new market frictions with 8.5 GW finding no bidders in 2024.

This fourth phase exposes the centrality of distribution sector reform to renewable energy success. While India has achieved remarkable technological and cost breakthroughs, the persistence of DISCOM financial distress threatens to constrain future growth despite policy innovations. The ultimate test of India's renewable energy transition may depend less on technological advancement than on successful implementation of distribution sector reforms that have proven stubbornly resistant to policy intervention.

India's renewable energy policies successfully reduced solar tariffs by 80% and created a functioning auction market, yet 50 GW of awarded capacity remains stalled. Each policy phase solved immediate risks while DISCOM financial distress persisted unchanged from 2010 to 2025. The sector's technical success has outpaced institutional capacity to manage power purchase obligations, making distribution reform rather than technology advancement the critical bottleneck for achieving 2030 targets.

6 Conclusion: Research Gaps and Future Directions

This review provides a comprehensive synthesis of cost of capital dynamics in India's renewable energy sector, offering insights for diverse stakeholders involved in the country's clean energy transition. For policymakers, the analysis demonstrates that financing costs represent a policy lever with measurable impacts on deployment capacity, as evidenced by modelling studies. For investors and developers, the systematic evaluation of methodological approaches provides guidance on risk assessment while the identification of persistent versus emerging risk factors enables more informed policy design as well as investment decisions.

The review assesses six distinct approaches to cost of capital estimation, presenting their comparative advantages and limitations in India's data-constrained environment. This analysis addresses a gap in the literature where methodological choices often reflect data availability constraint, providing researchers and practitioners with guidance on selecting appropriate estimation techniques based on specific contexts and objectives. The integration of these methodological insights with empirical evidence on risk factors helps understanding how financing costs evolve with market maturity and policy intervention.

The analysis of various risks impacting cost of financing of renewable energy projects shows a pattern of successful mitigation in some categories while highlighting persistent and emerging challenges. Technology performance risks have been reduced, evidenced by the transformation of solar projects from universally sub-investment grade in 2012 to over 90% investment grade by 2020. Counterparty risks have been partially mitigated through institutional innovations like SECI's intermediation model, though state DISCOM financial distress remains a significant persistent challenge. Market creation risks have been addressed through the transition from feed-in tariffs to competitive auctions, achieving over 80% cost reductions while maintaining deployment momentum.

However, the sector now faces second-generation complexities that require new risk mitigation instruments, market reforms and policy responses. Emerging risks include grid integration challenges from tightening deviation settlement mechanisms, storage lifecycle uncertainties in hybrid projects, supply chain constraints beyond traditional module procurement, and execution delays from land aggregation and transmission infrastructure bottlenecks. These evolving risks interact with persistent challenges in ways that compound their individual impacts, creating systematic exposures that affect entire project portfolios rather than isolated assets.

India's policy journey through four distinct phases reveals both remarkable achievements and persistent limitations. The transition from market creation to competitive procurement, grid integration, and systematic risk management shows clear institutional learning over time. Policies have successfully tackled project-specific risks and driven down costs to globally competitive levels. However, the ongoing financial troubles of state distribution companies continue to constrain the sector's growth, highlighting that piecemeal reforms are insufficient. What's needed now are comprehensive structural changes rather than incremental adjustments.

Designing these structural changes requires better understanding of how financing costs respond to different policy interventions and emerging market conditions. Current knowledge gaps limit policymakers' ability to craft effective reforms and constrain investors' capacity to assess evolving risks. Without clearer evidence on what drives financing costs and how different approaches affect investment decisions, the sector risks repeating past policy failures.

Four priority research themes emerge as important for supporting India's continued renewable energy scaling:

Grid Integration Financial Assessment: Quantify cost implications of evolving grid requirements. This includes assessing how deviation settlement mechanism changes affect project economics and understanding storage integration costs in hybrid projects.

Emerging Technology Bankability: Develop financing frameworks for standalone battery storage and complex hybrid structures. These technologies need clearer risk assessment methods to attract investor confidence.

Risk Mitigation Instrument Evaluation: Test whether RDSS reforms and Late Payment Surcharge Rules actually reduce financing costs compared to earlier policies. This requires systematic measurement rather than assumptions about policy effectiveness.

Energy Policy Uncertainty Index: Create a composite measure tracking policy volatility across multiple dimensions. Include regulatory changes, market implementation gaps, trade policy shifts, and institutional factors. This index would help quantify how policy uncertainty affects financing cost premiums across different project types.

These research priorities address knowledge gaps that constrain investment decision-making and policy effectiveness, providing a foundation for evidence-based interventions to achieve India's 2030 renewable energy targets while establishing frameworks applicable to other emerging market contexts.

7 Appendix

Table 3: Key Renewable Energy Policies in India (2010-2024)

Scheme/Initiative	Launched/ Proposed	Objective	Key Features	Beneficiaries	Expected Outcomes	Geographic Focus	Implementation Agencies
Jawaharlal Nehru National Solar Mission (JNNSM)	2010	Market creation for solar power	Feed-in Tariffs, 25-year PPAs at fixed rates	Solar developers	Solar capacity	Nation wide	MNRE
Accelerated Depreciation for Wind	2010	Incentivize wind investments	Front-loaded depreciation benefits	Corporate investors	Wind capacity	Nation wide	Ministry of Finance
Generation-Based Incentives (Wind)	2010	Support wind generation	₹ 0.50 per unit generated	Wind developers	Wind generation	Nation wide	MNRE
Renewable Purchase Obligations (RPOs)	2010	Mandate renewable procurement	Specified % procurement requirements	RE generators	Demand creation	State level	State Electricity Regulatory Commissions
Development of Solar Parks and Ultra Mega Solar Power Projects	2014	Develop large-scale solar projects	Pre-developed land, plug-and-play model	Solar developers	Solar capacity	Nation wide	MNRE
Wind Power Programme	2014	Promote wind power generation	Wind farms, incentives	Wind developers	Wind capacity	Nation wide	MNRE
Competitive E-Reverse Auctions	2015 (Solar), 2017 (Wind)	Price discovery through competition	Market-based tariff determination	Developers, DISCOMs	Cost reduction	Nation wide	SECI, NTPC
Ujwal DISCOM Assurance Yojana (UDAY)	2015	Financial turnaround of DISCOMs	Debt restructuring, state	DISCOMs	Financial stability	Nation wide	Ministry of Power

			government support				
National Smart Grid Mission	2015	Modernize power grid	Smart grids, technology upgrades	Power utilities	Grid reliability	Nation wide	Ministry of Power
Green Energy Corridors Phase I	2015	Strengthen transmission for RE	Transmission infrastructure development	Grid operators	RE evacuation	Specific regions	MNRE, Power Grid Corporation
National Wind-Solar Hybrid Policy	2018	Promote wind-solar hybrid systems	Grid-connected hybrid systems	Energy producers	Optimized transmission infrastructure	Nation wide	MNRE
Round-the-Clock (RTC) Tenders	2019	Firm dispatchable RE power	80% capacity utilization guarantee	Developers, grid operators	Grid stability	Nation wide	SECI
Green Energy Corridor Phase II	2021	Integrate RE into grid	Enhanced transmission infrastructure	Grid operators	RE capacity	Rural areas	MNRE, Power Grid Corporation
Production Linked Incentive (PLI) Scheme for Solar PV	2021	Domestic manufacturing incentives	Sales-based financial incentives	Solar manufacturers	Import reliance	Nation wide	MNRE
Basic Customs Duty on Solar Components	2022	Protect domestic manufacturing	40% on modules, 25% on cells	Domestic manufacturers	Manufacturing growth	Nation wide	Ministry of Finance
Approved List of Models and Manufacturers (ALMM)	2022	Mandate domestic sourcing	Restricted supplier list for govt projects	Domestic manufacturers	Local procurement	Nation wide	MNRE

Revamped Distribution Sector Scheme (RDSS)	2022	DISCOM financial stability	Performance-linked financial assistance	DISCOMs	DISCOM viability	Nation wide	Ministry of Power
Late Payment Surcharge Rules	2022	Enforce payment discipline	Automated penalties, supply restrictions	RE generators	Payment security	Nation wide	Central Electricity Regulatory Commission
Enhanced Solar Park Development Program	2023	Accelerate solar park development	New parks, enhance existing ones	Solar developers	Solar capacity	Specific regions	MNRE
National Offshore Wind Energy Projects	2023	Develop offshore wind projects	Technological advancements	Offshore wind developers	RE generation	Coastal regions	MNRE

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