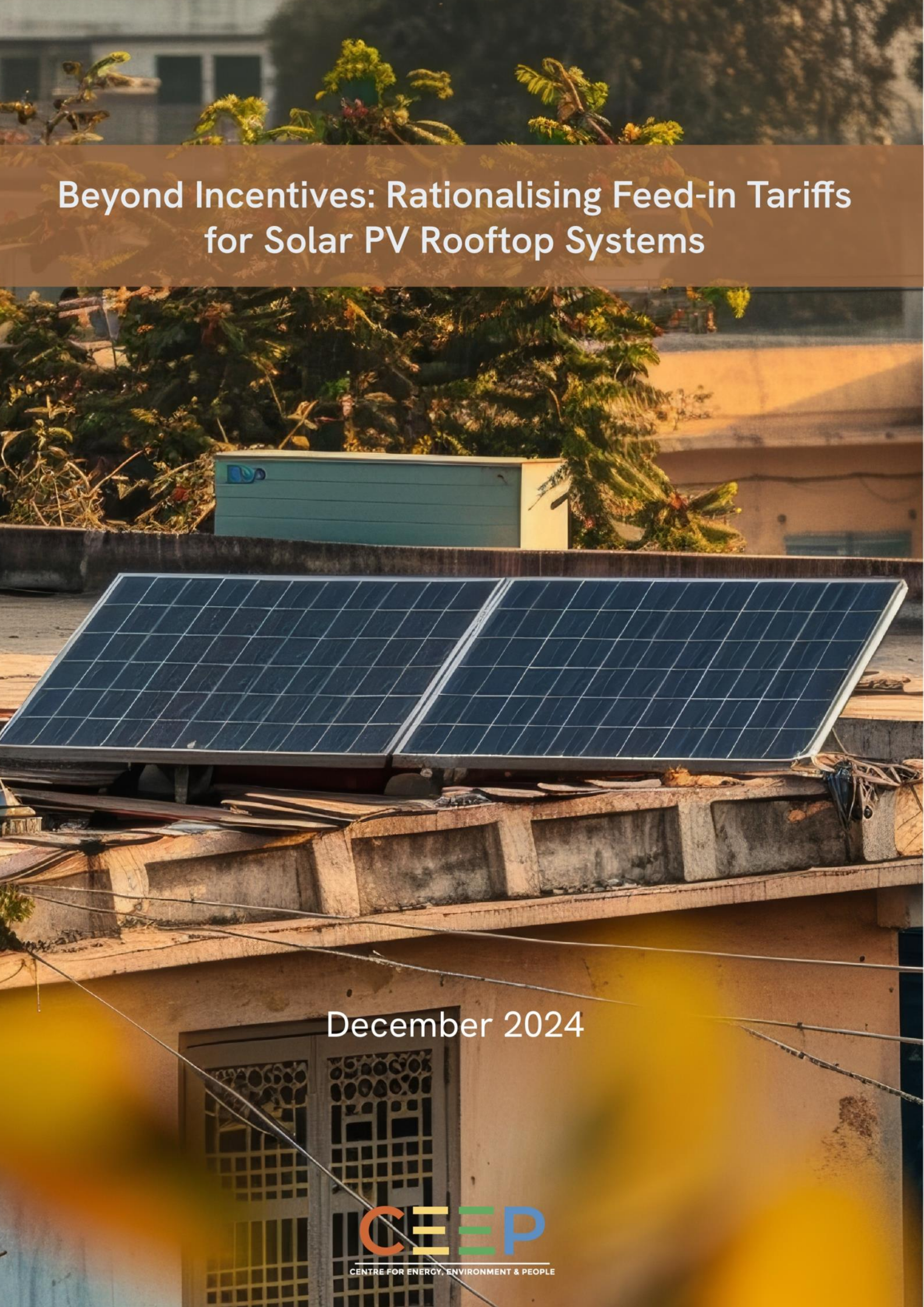
Beyond Incentives: Rationalising Feed-in Tariffs for Solar PV Rooftop Systems



December 2024

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Cover image: AI (Freepik), refined by CEEP

December 2024

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Abbreviations

ABR	Average Billing Rate
ACS or ACoS	Average Cost of Supply
APPC	Average Power Procurement Cost
ARR	Aggregate Revenue Requirement
AVVNL	Ajmer Vidyut Vitran Nigam Ltd.
CapEx	Capital Expenditure
CEA	Central Electricity Authority
CEEP	Centre for Energy, Environment & People
CEEW	Council on Energy, Environment and Water. India.
Cr.	Crore (1,00,00,000 or 10 million)
DISCOM	Distribution Company
FY	Financial Year (April 1st - March 31st)
JdVVNL	Jodhpur Vidyut Vitran Nigam Ltd
JVVNL	Jaipur Vidyut Vitran Nigam Ltd.
kW	Kilowatt
kWh	Kilowatt-hour
LC	Landed Cost
MU	Million Units or (Million kWh)
MW	Megawatt
NDC	Nationally Determined Commitments
O&M	Operations & Maintenance
PPA	Power Purchase Agreement

RE	Renewable Energy
RERC	Rajasthan Electricity Regulatory Commission
REP	Renewable Energy Portfolio
RoE	Return on Equity
RTS	Rooftop Solar
SERC	State Electricity Regulatory Commission
SPVRT	Solar Photovoltaic Rooftop
TPP	Total Power Portfolio
Δ	Delta

Executive Summary

Rajasthan's Solar Photovoltaic Rooftop (SPVRT) systems possess immense potential in India's transition to clean energy. To facilitate this, schemes like the PM Suryaghar Yojana promote residential rooftop solar adoption by subsidising up to 60% of installation costs for households and offering up to 300 units of free electricity monthly. While such schemes provide substantial benefits to consumers, the financial impacts of feed-in tariffs[1] (FiTs) on distribution companies (DISCOMs) like Jaipur Vidyut Vitran Nigam Ltd (JVVNL) are often understated.

This report examines the optimisation of FiTs and incentive structures for SPVRT systems in Rajasthan, focusing on their financial, operational, and regulatory impacts on JVVNL.

The methodology is divided into three parts. The first part focuses on analysing JVVNL's tariff schedule to evaluate the recovery of fixed costs under the current net-metering framework. The second part involves a comparative analysis of tariffs and landed costs of power procurement across different consumer categories, including domestic, non-domestic, industrial, and mixed load users. It evaluates the landed costs of SPVRT systems, utility-scale renewable energy, and the total power portfolio of JVVNL, considering components like power purchase costs, transmission charges, and distribution losses.

A key finding suggests the cost recovery challenges. The analysis reveals substantial fixed-cost under-recovery in current SPVRT net-metering structures, where displaced high-demand electricity generation by SPVRT systems reduces DISCOM revenue without proportionate fixed-cost reductions. Tariff distortions and ineffective cost-reflective pricing contribute to this gap, with approximately 53.1% of total electricity supply costs being fixed and only 10.5% of revenue being currently realised through fixed charges. This gap in cost recovery impacts JVVNL's ability to support the necessary infrastructure.

A Delta analysis reveals that while SPVRT systems offer cost advantages in some consumer categories, these benefits are counterbalanced by revenue losses. SPVRT systems reduce landed costs for high-consumption industrial and non-domestic categories by INR 1.67–2.57/kWh compared to JVVNL's average cost. However, the net impact remains negative due to unrecovered fixed costs. The findings further highlight that, except for bulk supply categories, the net costs associated with SPVRT's adoption are favourable under an optimised tariff framework, with cost savings of up to INR 2.06/kWh in the domestic category.

To safeguard DISCOMs' financial health, the report recommends incentivising low-consumption consumers due to their cost advantages and addressing fixed-cost under-recovery by narrowing the gap between fixed costs and revenue realisation through fixed charges. Implementing a structured framework for determining prosumer incentives and levies is suggested to ensure a gradual transition and stakeholder alignment. With SPVRT systems demonstrating distinct cost advantages over utility-scale renewable energy, policies should prioritise them to lower energy

[1] A feed-in tariff (FIT) is a government policy that compensates renewable energy producers at a fixed, premium rate for the electricity they send to the grid.

transition costs. Regulatory authorities are encouraged to incorporate grid balancing costs into incentives progressively and adopt a rational feed-in tariff framework for excess energy outside banking arrangements, moving away from current benchmarking practices.

1. Introduction

As of June 2023, India's renewable energy capacity was over 150 GW, with cumulative solar capacity surpassing the 70 GW milestone. As part of its Nationally Determined Contributions (NDC) commitments, India aims to achieve about 50% cumulative electricity generation capacity from non-fossil fuel-based energy resources (MoEFCC, 2022). Consequently, India is expected to commission 280 GW of cumulative solar capacity by 2030.

The clean energy transition is changing the fundamental paradigms of electricity generation, consumption and management. As a result, the fundamental cost structures of the power sector are also witnessing a significant shift due to the integration of variable renewable energy. Costs related to digitalisation (smart grids), evacuation and transmission infrastructure for low Capacity Utilisation Factor (CUF) technologies[2], grid management (forecasting and scheduling) and ancillary services shall become increasingly critical with higher integration of renewable energy.

In the emerging energy landscape, distributed solar – including Solar PV Rooftop (SPVRT) systems- offers unique advantages over large-scale wind and solar energy. For instance, tail-end generation doesn't require massive investments in transmission infrastructure and completely avoids transmission and distribution losses. Moreover, it democratises energy transition by enabling households, enterprises, industry and various facilities to participate in it and accrue benefits from it.

Despite the evident benefits, the progress of rooftop solar adoption has remained laggard because of many challenges. As Rooftop Solar (RTS) displaces demand from high-consumption and high-paying consumers across different consumer categories, it is often perceived to have a detrimental impact on distribution company finances. Some of these issues are legitimately intertwined with the inefficiencies in tariff design and cross-subsidy. Further, as the cost structure of the power sector evolves with the clean energy transition, they need to be appropriated, accounted and reflected in tariff design and regulations for the promotion of rooftop solar.

This report analyses some of the fundamental inefficiencies in tariff design and accounting of costs/benefits in determining incentives for power procured from rooftop solar. The framework that evolves in the process is proposed to develop a smooth roadmap for designing incentives to promote distributed renewable energy and accelerate the clean energy transition.

2. Literature Review

Owners or facilities with grid-connected solar rooftop systems are often identified as *Prosumers*. By definition, prosumers are agents that both consume and produce electricity. This differentiates them from traditional electricity consumers as prosumers have inherent attributes that result in costs and benefits to the electricity grids. A fair incentivisation of SPVRTs requires careful evaluation of this, along with their impact on the distribution company.

[2] Wind and solar energy

Grid-connected SPVRTs supply in-firm[3] power to the grid during sunshine hours. This distributed source of generation acts as a tail-end generator, eliminating transmission distribution losses. Distribution companies also don't bear any wheeling charges for electricity procured through SPVRTs. These benefits are unique to distributed tail-end generators.

However, distribution companies have to provide banking services for power procured through a net-metering mechanism. Similarly, they also have invested in grid flexibility and ancillary services for grid balancing. The latter is a consequence of overall renewable integration and not just SPVRT systems. The process of determination of incentives or feed-in-tariff for SPVRT systems is akin to the determination of retail electricity tariff to meet the annual revenue requirement of distribution companies. Consequently, we propose an adherence to tariff rationalisation principles for the determination of feed-in-tariff for SPVRT systems. Tariff rationalisation and its principles are briefly discussed in the following section.

Tariff rationalisation may be defined as an exercise or a process of redesigning tariff structure and determining rates for service to maximise the collective utility of the stakeholders (Rodríguez Ortega et al., 2008). Measuring collective utility with various stakeholders is a challenging task. An alternative approach for such an exercise may be based on certain principles and objectives to define a subject strategy or methodology for similar outcomes. Given the complex nature of this task, electricity regulators typically deploy a principle-based approach to design and determine electricity tariffs.

Principles for tariff rationalisation are implicitly articulated in the Electricity Act 2003, Tariff Policy and Tariff Regulations (The Electricity Act, 2003). However, this leads to varying interpretations and laxity in acknowledging and applying these principles, resulting in various inefficiencies and distortions in electricity tariffs. Some common regulatory principles adopted by regulators in India and other parts of the world are listed below (Reneses & Ortega, 2014), (Joint Electricity Regulatory Commission (JERC), 2020), (Rodríguez Ortega et al., 2008), (A.F Mercados EMI, 2015):

I. **Sustainability:** The tariffs shall allow recovery of prudent costs and a reasonable return on capital, wherein various tariff components must add up to the total revenue requirement to be covered.

II. **Productive Efficiency:** Regulators shall aim to deliver electricity services to consumers at the lowest possible cost while minimising the total system cost through efficient investments, reduction of operational costs, and coordinated investments in transmission and generation.

III. **Allocative Efficiency:** The tariff regime shall incentivise efficient utilisation of the grid through effective peak management and encouraging system flexibility.

IV. **Cost Reflectiveness**: Consumers shall be charged in accordance with the costs of the services they receive and account for space-time differentiation.

[3] Also referred as 'variable energy', attributed to supply which can't be ramped up or down as per grid requirements.

V. **Transparency**: The methodology and results of tariff allocations shall be published and available to network participants, whose bills should clearly state each charged component. (A.F Mercados EMI, 2015, p.35).

VI. **Non-discrimination:** All users that belong to a specific category and demand the same network services should be charged the same, irrespective of the end-use of the electricity. (A.F Mercados EMI, 2015, p.35).

VII. **Equity:** Lifeline access to electricity shall be delivered to all users, and hence disadvantaged users or groups may be charged a preferential (discounted) electricity tariff. (National Electricity Policy, 2005).

VIII. **Simplicity:** The methodology for determining electricity tariff and its results (i.e., tariff rates) shall be easy to understand. (A.F Mercados EMI, 2015, p.35).

IX. **Stability:** The methodology used for tariff design should be stable to minimise regulatory uncertainty. (A.F Mercados EMI, 2015, p.36).

X. **Consistency:** Tariff regulation shall comply with the law of the land and the concerned policies. (Reneses & Ortega, 2014).

We apply the aforementioned principles to determine prudent feed-in-tariffs (FiT) for SPVRT systems, and the methodology for the same is discussed in Chapter 3 of this research paper. FiT based on the cost-benefit analysis of the SPVRT system ensures non-discrimination, cost-reflectiveness, transparency and sustainability. It allows distribution companies to recover prudent costs while preventing the socialisation of costs amongst other electricity consumers[4]. The latter delivers equity in FiT design. The proposed methodology captures the benefits of SPVRT systems vis-à-vis procurement for large-scale utility projects.

The proposed framework shall primarily serve as a guide towards equitable and sustainable FiT, defining a clear and informed pathway for FiT rationalisation, delivering consistency and stability. A gradual and defined transition can aid in avoiding shocks and shall be more amenable to the SPVRT industry and future prosumers.

To propose a sustainable FiT, it becomes pertinent to understand the issue of revenue erosion under current incentivisation schemes.

Satchwell et al. (2015) quantify the financial impact of SPVRT on utility shareholders and ratepayers. The findings suggest that consumer-side PV typically results in a reduction of utility revenues that exceeds the reduction in utility costs, leading to a phenomenon termed "revenue erosion." This erosion occurs because consumers with PV can avoid fixed infrastructure charges, which causes utilities to lose revenue while their costs remain relatively constant. As utility sales decline due to the adoption of customer-sited PV, the average retail rates can increase since the fixed costs of utilities are spread over a smaller consumer base. The paper notes that these impacts

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[4] Consumers who don't have grid synchronised SPVRT systems.

can vary significantly based on the specific circumstances of the utility and does not specify the consumer base.

Burger et al. (2020) and Kim et al. (2023) look at different case studies in the US and South Korea to ascertain the effects of this revenue erosion and the consumer segments it burdens. Under the default flat tariff in Chicago, findings by Burger et al. (2020) show that non-solar consumers in the lowest income quintile may see their electricity expenditures increase significantly by as much as 80% as solar adoption grows.

In the case of South Korea, Kim et al. (2023) quantify that every 1% increase in residential PV penetration results in a 0.83% increase in missing network revenue for utilities. The paper emphasises that lower usage tier consumers (typically economically disadvantaged) disproportionately subsidise the adoption of PV (typically adopted by higher usage tier consumers) due to the incentive structure of the net-metering or gross metering programs. It indicates that as PV penetration increases, the socialisation of these network costs becomes more pronounced.

In the Indian context, the adoption of SPVRT at a utility level has been plagued with concerns about revenue losses. A study by Singh et al. (2019) to evaluate the status and challenges of the Solar Rooftop Programme in India, particularly from the perspective of DISCOMs, states that they feel policies and tariff structures are mostly consumer-oriented and do not adequately consider the financial and operational challenges faced by them. They also expressed that while solar rooftops could help optimise power procurement and reduce costs, the existing fixed charges under Power Purchase Agreements (PPAs) still pose a financial strain.

Across the literature, findings stress the need for regulators and utilities to consider new support mechanisms and feed-in-tariff designs that address both the financial viability of utilities and the equitable treatment of all consumers.

Common sentiment across the renewable energy sector states that the relative cost of generating power is lower in large-scale renewable energy projects (Dobrotkova et al., 2018), (Vickerman, 2023). However, these cost comparisons rarely include network charges such as transmission and distribution losses and associated wheeling charges.

Currently, power procurement from utility projects is subsidised because of waivers on wheeling charges. However, as the share of variable renewable energy increases in the energy mix, it shall be increasingly difficult for the government to waive wheeling charges. Hence, from a long-term perspective, landed costs of power should be considered by including wheeling charges and other allied costs such as transmission and distribution loss.

While Thapar (2022) attempts to compare the Levelised Cost of Energy (LCOE) for a 100 MW centralised solar project with a 1 MW decentralised plant, the analysis does not truly inform the long-term policy and regulatory choices between distributed and utility-scale solar PV because of three key reasons. Firstly, SPVRTs are typically much smaller than 1 MW, and hence the LCOE economics of a 1 MW asset are not suitable in this matter. Secondly, the landed cost of power from behind-the-meter PV is a function of the feed-in-tariff, which in turn is a function of the tariff schedule of each distribution company. Thirdly, the landed cost of power from utility PPAs is a function of transmission and distribution costs.

This report discusses the costs associated with power procurement for a distribution company, specifically focusing on the different sources from which power is procured, including overall power portfolios, renewable energy portfolios, and SPVRT.

3. Methodology

Tariff rationalisation is a process of trade-offs between the ten fundamental principles discussed in Chapter 2. For instance, deviating from the principle of cost-reflectiveness and prioritising equity, Below Poverty Line (BPL) and low-consumption households typically benefit from discounted electricity tariffs. Tariff slabs also follow a similar rationale, while deviating from the principle of simplicity. Consequently, a tariff schedule shall have a certain degree of complexity and inefficiencies that result from trade-offs between different rationalisation principles. In worst-case scenarios, the degree of complexity can be very high, and many inefficiencies in tariff design may neither be apparent nor intended.

To explore a framework for sustainable and equitable FiT, our methodology is segregated into three distinct analyses. In the first part, we evaluate the tariff schedule of Jaipur Vidyut Vitran Nigam Ltd. (JVVNL) for the four primary consumer categories - domestic, non-domestic, industrial and mixed-load consumers. Thereafter, we evaluate the cost-benefits of SPVRT systems. We compare the cost of power procurement of distribution companies for the overall portfolio, large-scale renewable energy and SPVRT systems. In the third part, we consider grid balancing costs for renewable energy. Energy banking costs were excluded from the analysis for a lack of access to relevant data. Finally, we add up costs and benefits from the three-part analysis to present the net costs/benefits of SPVRT systems for respective categories in comparison to the overall power procurement portfolio and large-scale renewable energy procurement.

Key data sets used for analysis are: (a.) JVVNL's True-up Data for FY 2021-22, (RERC, 2023) (b.) Annual Revenue Requirement (ARR) of JVVNL for FY 2023-24, (RERC, 2023) and (c.) Investment Plan of JVVNL for FY 2023-24. (RERC, 2023). The outcomes of the analysis are a function of various costs incurred by the distribution company and hence are dynamic. Significant changes are likely to be observed in the course of the clean energy transition.

Cost of Supply of Electricity & Revenue from Retail Electricity Supply

Aggregate Revenue Requirement (ARR) refers to the costs pertaining to the licensed business which are permitted, in accordance with the tariff regulations, to be recovered from the tariffs and charges determined by the Commission (Law Insider, 2023). Based on ARR estimates, the commission determines the tariff schedule for the retail supply of electricity. Tariff regulations define prudent fixed and variable costs that may be recovered through tariff rates as determined for different categories. Electricity tariffs follow a two-part tariff regime, consisting of fixed charges[5] that are a function of the consumer's sanctioned load and energy charges that are a function of actual energy consumed by the consumer during the billing period.

Part of the fixed costs is often recovered through energy charges. This increases the affordability of electricity tariffs for low-consumption consumers. For enterprises that incur electricity as a major input cost, this aids them in better management of costs across seasonality and any downturns in business activity. However, this also implies that prosumers unfairly benefit from this, as distribution companies are unable to recover fixed costs proportional to generation in the case of net-metering[6].

Cost of Supply of Electricity

Tariff petition and determination of retail electricity tariff for JVVNL is governed by Rajasthan Electricity Regulatory Commission, Regulations, 2019, wherein various cost components and their benchmarks are well-defined. These include power purchase costs, operation & maintenance expenses, terminal benefit expenses, interest on loans, finance charges & lease rental, working capital, depreciation, insurance expenses, rebate and return on equity. DISCOM's Net Aggregate Revenue Requirement is determined after adjusting non-tariff income and income from wheeling charges. The list of cost components is discussed in Annexure 1, and their aggregate values are presented in Annexure 2 and Figure 1 below.

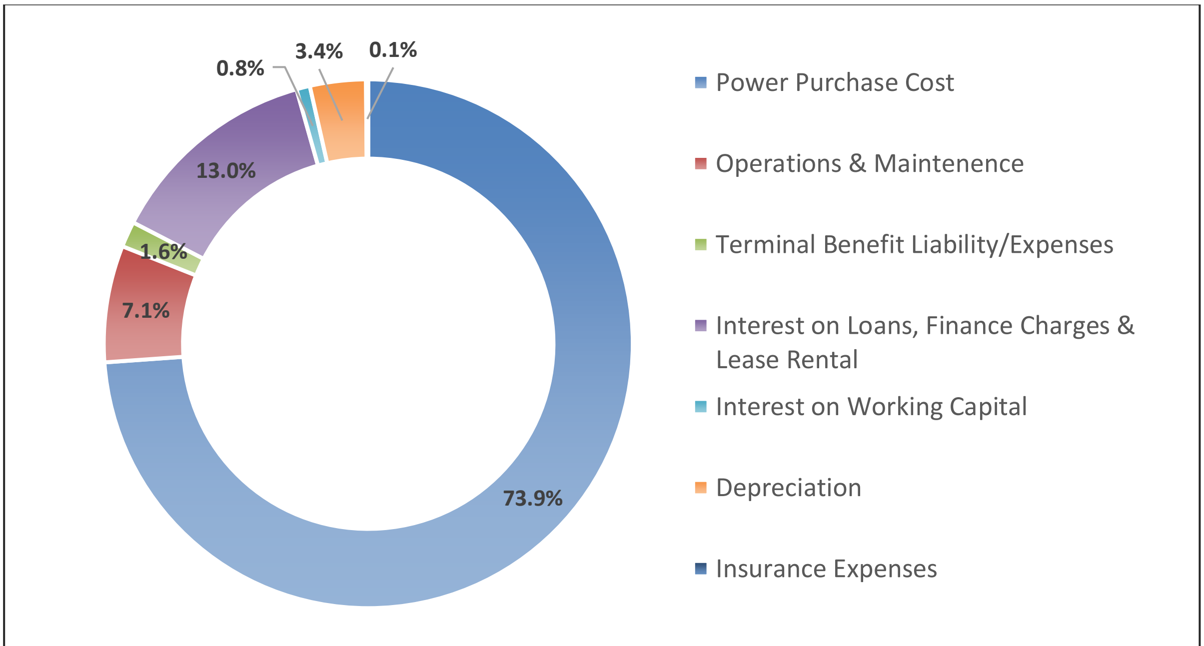

Figure 1: Cost components of retail electricity supply

[5] Fixed charges are recurring charges to be paid for each billing period irrespective of consumer's electricity consumption.
[6] Solar generation is directly adjusted against the electricity consumption in the bill.

Revenue from Retail Electricity Sales

Electricity tariffs are designed as two-part tariffs with fixed charges and energy charges. Correspondingly, the revenue of distribution companies can be segregated into revenue from fixed charges and energy charges. The segregation is not presented in the FY24 tariff petition filed by the distribution company, and the same is estimated using data from JVVNL's True-up petition for FY22. Since there is no change in the energy schedule across the reference period, we assume that the average per unit revenue from energy charges for each category in FY24 shall be the same as the realisation as per the JVVNL's True-up petition for FY22.

We estimate the revenue from fixed charges and energy charges for FY24 based on the average revenue per unit realised from energy charges for respective categories (refer to Annexure 3 and Annexure 4). A significant gap is observed in the ratios of fixed costs to variable costs for retail electricity supply vs revenue from fixed charges to energy (variable) charges (Figure 2). This implies that distribution companies are recovering a significant portion of their fixed costs from energy charges. They produce electricity to meet their energy demand and, consequently, withdraw less electricity from the distribution company. In the case of a net-metering arrangement, this leads to failure to recover fixed costs in proportion to the number of units of electricity generated by the prosumer (or rooftop solar).

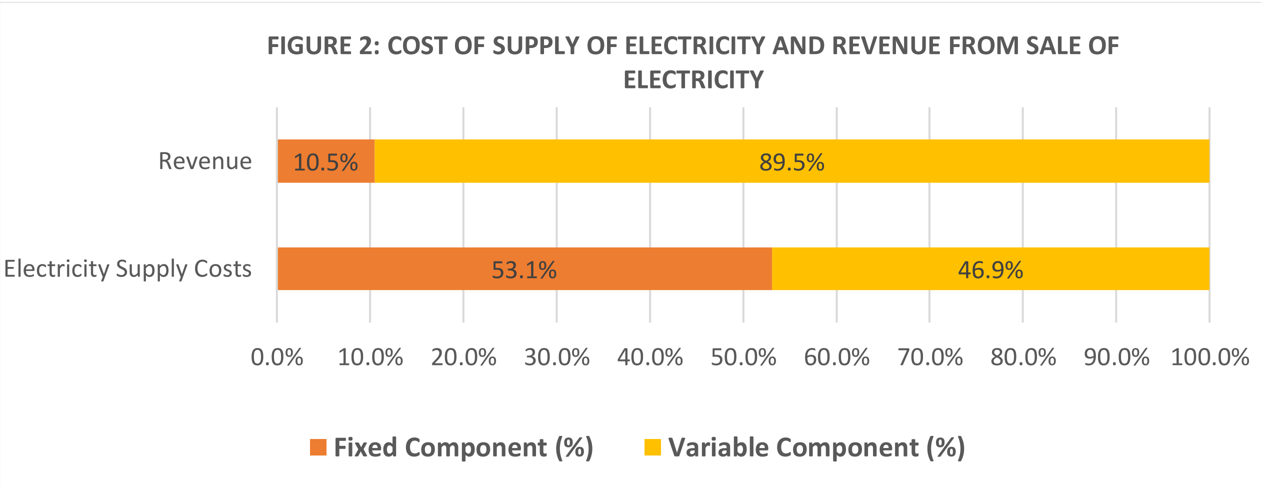

Figure 2: Cost of supply of electricity and revenue from the sale of electricity

The methodology to estimate the under-recovery of fixed costs for every unit of electricity generated by prosumers under the net metering arrangement is discussed in Section 3.1.

3.1. Under Recovery of Fixed Costs in Net Metering Arrangement

In an ideal scenario, all fixed costs shall be recovered through the fixed charges, and the same applies to variable costs and energy charges. However, it may be noted that regulators deviate from this to ensure affordability for low consumption periods and cycles. Explain the average billing rate and the consequences of a low affordability rate.

We estimate the Average Billing Rate (ABR, B_{av}) or average revenue realisation for JVVNL (excluding distribution franchisee sales) as, *Equation 1: Average billing rate for JVVNL*

$$B_{av} = \frac{Total\ Revenue\ from\ existing\ tariff}{Approved\ sales\ adjusted,\ less\ DF\ sales}$$

Consequently, distribution franchisee sales are also excluded from the Annual Revenue Requirement (ARR) for the analysis since distribution franchisees are required to make separate capital investments as per their investment plan. The same are not accounted for in the investment plans submitted by distribution companies.

We also estimate the fixed costs and variable costs per unit of electricity demand from the ARR data presented in the tariff petition to RERC for FY24 (RERC, 2023). A slight difference was observed in the Annual Revenue Requirement (INR 7.7/unit) to the Average Billing Rate (INR 7.67 /unit). Fixed costs and variable costs are thereby normalised to the Average Billing Rate using the unitary method. We identify the same as 'fixed cost normalised to ABR (B_{Fav})' and 'variable charges normalised to ABR (B_{Eav})'. (Annexure 5)

Next, we estimate revenue realisation from fixed charges and energy charges separately for each consumer category for FY24. In the absence of this break-up in the tariff petition, the same is estimated using JVVNL's True-up data for FY22. Since the tariff schedule remains unchanged during the period, it is safe to assume that no significant changes in average revenue realisation from energy charges shall be observed. Consequently, the average revenue realised (B_i) for consumer category C_i and the average revenue realised from energy charges (E_{Bi}) for consumer category C_i are computed below:

Equation 2: Average Billing Rate for Consumer C_i

$$B_i = \frac{Total\ Revenue\ for\ C_i}{Total\ Units\ Sold\ to\ C_i}$$

Equation 3: Average per unit revenue realised from Energy Charges (E_{Bi})

$$E_{Bi} = \frac{Total\ Revenue\ from\ Energy\ Charges\ for\ C_i}{Total\ Units\ Sold\ to\ C_i}$$

Consequently, average revenue realised from fixed charges (F_{Bi}) for consumer category C_i may be estimated as,

Equation 4: Average revenue realised from fixed charges F_{Bi} for consumer category C_i

$$F_{Bi} = B_i - E_{Bi}$$

Average variable and fixed charges to be recovered from each consumer category based on fixed and variable costs normalised to the average billing rate for each consumer category are estimated by adjusting the same for applicable cross-subsidy charges.

Equation 5: 'Average fixed cost' implication for category C_i

$$B_{Fi} = B_{Fav} \times (1 + S_i)$$

Equation 6: 'Average variable cost' implication for category C_i

$$B_{Ei} = B_{Eav} \times (1 + S_i)$$

where S_i is the cross-subsidy applicable for category C_i (Annexure 6)

Under-recovery of fixed costs (F_{Ui}) for prosumers of consumer category C_i for each unit of electricity generated is estimated as below:

Equation 7: Under-recovery of fixed costs for every unit of electricity generated by prosumers

$$F_{Ui} = B_{Fi} - F_{Bi}$$

3.2. Landed Cost and Δ (Delta) Analysis

A distribution company procures long-term, medium-term and short-term power through various resources. Landed power procurement costs of a distribution company are a summation of power purchase costs, transmission costs, transmission losses, distribution costs and distribution losses (Equation 8). This section compares the landed costs of power procurement through (a.) overall power portfolio, (b.) renewable energy (utility-scale) portfolio, and (c.) solar-rooftop systems or prosumers belonging to different consumer categories. Since the distribution network is common to all three, its cost is not considered as part of the analysis. Secondly, since rooftop solar is a tail-end system, transmission costs, transmission losses and distribution losses are considered zero for them.

Equation 8: Landed costs for the distribution company

$$LC_{Portfolio} = PC_j + C_{TD}$$

where,

PC_j is the power purchase costs for the respective portfolio, where *'j'* represents the following: (a.) Total Power Portfolio of JVVNL, (b.) Renewable Energy Portfolio of JVVNL, (c.) Prosumers of domestic category, (d.) Prosumers of non-domestic category, (e.) Prosumers of small industry category, (f.) Prosumers of medium industry category, (g.) Prosumers of large industry category, and (h.) Prosumers of mixed load category.

C_{TD} = {Transmission Charges + Transmission Losses + Distribution Losses}

Transmission charges (T_C) are wheeling charges borne by the distribution company for the respective portfolio.

Equation 9: Transmission charges borne by JVVNL

$$T_C = \frac{Transmission\ Charges}{Estimated\ Energy\ Sales}$$

As a current practice, since transmission costs are not segregated for the overall portfolio and renewable energy, they are considered to be the same as the former for the latter.[7]

Transmission and distribution losses are estimated as the per-unit losses incurred by the distribution company for the procurement of power for the respective portfolio. Per cent losses, as approved by the regulator, are considered, and the quantum of losses in million units is obtained from the JVVNL's tariff petition for FY24 (RERC, 2023). The quantum of losses for the renewable energy portfolio is estimated using the unitary method, proportional to renewable energy procured vs overall energy procured. The value of losses is estimated as a factor of the average power procurement cost for the respective portfolio.

Power Purchase Costs for Solar Rooftop Systems

Under the net-metering arrangement, the electricity produced by solar rooftop systems typically displaces the demand for electricity from the distribution company. In the case of the export of electricity, it is adjusted in the electricity bill against the electricity imported from the distribution company, subject to energy banking regulations.

Consultation with solar players suggests that solar rooftops can displace 60-80% of the electricity demand of a facility. Consequently, for the simplification of analysis, we assume that 100% of electricity demand is displaced by solar rooftops for a prosumer. This assumption is critical for domestic and non-domestic consumer categories with telescopic tariff slabs. Further, the following slabs are considered for respective categories as per the tariff schedule:

A. Domestic: General Domestic - 3, with a total consumption of 500 units per month

B. Non-domestic: LT-NDS - Type 4, with a total consumption of 500 units per month

The aforementioned categories are considered for the simplicity of analysis and are based on the hypothesis that consumers with high electricity consumption are major adopters of solar rooftop systems. Consequently, the power purchase rate for these respective sub-category prosumers shall be equal to their average billing rate after adjustment for fixed costs recovered from energy charges. This ensures appropriate accounting of energy charges since fixed cost implications have been calculated separately in the previous section.

Hence, the average power purchase cost from solar rooftop systems ($PC_{SPVRT,Ci}$) for different consumer categories C_i may be estimated as below:

Equation 10: Average power purchase cost from prosumers

$$PC_{SPVRT,Ci} = T_{av,Ci} - F_{Ui}$$

where,

$T_{av,Ci}$ is the average billing rate for consumer category C_i

[7] It may be noted that transmission cost for large scale renewable energy procurement is likely to increase significantly in the future because of lower capacity utilisation factors of wind and solar, as compared to thermal power plants.

F_{Ui} is the under-recovery of fixed costs for consumer category C_i

Thereafter, landed costs for respective power procurement portfolios are considered and prosumers belonging to respective consumer categories are calculated using Equation 8.

Δ (Delta) Analysis

After computing landed costs for respective portfolios, we compute the relative landed costs with respect to the overall power purchase portfolio, Δ_j, as below:

Equation 11: Relative landed cost for the distribution company

$$\Delta_j = LC_j - LC_{TPP}$$

where,

Δ_j is the relative landed costs with respect to the overall power purchase portfolio

LC_j is the landed cost for *'j'*, where *'j'* represents the following: (a.) Total Power Portfolio of JVVNL, (b.) Renewable Energy Portfolio of JVVNL, (c.) Prosumers of domestic category, (d.) Prosumers of non-domestic category, (e.) Prosumers of small industry category, (f.) Prosumers of medium industry category, (g.) Prosumers of large industry category, and (h.) Prosumers of mixed load category.

LC_{TPP} is the Landed cost for Total Power Portfolio of JVVNL.

The delta analysis represents the additional cost JVVNL is bearing for purchasing power from different agencies discussed in the analysis. A negative cost shall represent net savings for the distribution company for every unit of power purchased or procured. Consequently, the same may be considered while designing prudent incentives for the SPVRT system under a net-metering or gross-metering regime.

3.3. Energy Banking and Balancing Costs

Electricity generated by Solar PV systems is variable and in-firm. This means that the electricity generation varies with the time of the day and weather conditions, and secondly, it can't be ramped up or down as per requirements. The former creates a need for balancing resources for grid integration of solar energy (SPVRT and utility-scale solar) and managing the electricity grid within technical parameters. The latter requires banking services so that surplus power created at any point in time can be fed into the grid and adjusted against consumption at a later period.

Uttar Pradesh Electricity Regulatory Commission, in its draft CRE (Captive and Renewable Energy Generating Plant) Regulations of 2019, defines banking of energy as - "Banking of power is the process under which a Generating Plant supplies power to the grid not with the intent of selling it to either the third party or to a Licensee, but to exercise its eligibility to drawback this power from the grid for its own use as per the conditions provided in these Regulations." Banking charges are levied upon the renewable energy (RE) generator for the energy banked and are paid to the distribution company and determined by the State Electricity Regulatory Commissions (SERC). These are typically paid in kind or cash, depending on the state regulations (CEEW, 2021). In the case of SPVRT systems, banking charges may be attributed to the differential in power purchase at the time of injection and the time of drawl. The computation requires facility-level granular injection and drawl data for a large representative sample and power purchase cost for the corresponding blocks. Due to the unavailability of such data, the energy banking costs are excluded from the scope of work, although they are included in the broader framework for the determination of incentives or levies for SPVRT systems as per the mandate of the electricity regulators.

Grid balancing costs are costs associated with maintaining a real-time balance between electricity demand and supply to ensure that the grid operates within the technical parameters. Traditionally, grid balance was maintained by ramp-up or ramp-down of electricity generation. With the increasing penetration of renewable energy and decreasing availability of firm power through thermal resources, distribution companies must trade in ancillary services markets or invest in infrastructure to provide grid balancing services. Such services are typically offered by gas-powered thermal stations, hydropower, and energy storage systems.

For our analysis, we assume that all energy storage investments are dedicated to grid balancing, and hence, their levelised costs over total renewable energy generation are considered as the grid balancing cost.[8] It may also be noted that balancing costs shall become prominent with the increasing penetration of renewable energy. We have considered the Central Electricity Authority's (CEA) report on Optimal Generation Mix for 2029-30 Version 2.0 for our analysis (Central Electricity Authority, 2023). Benchmark cost for energy storage projects is computed as the mean of energy storage costs for different storage periods ranging from two hours to six hours of energy storage. The cost of pumped hydro projects is also taken from the same report.

For the analysis, we assume that total energy storage capacity is commissioned in a single year and the cost of investments is annualised over a 14-year and 40-year period for battery energy storage and pumped hydro projects, respectively. The costs are annualised assuming a 10.5% cost of capital, and levelised over total renewable energy generation.

3.4. Computing Incentives for SPVRT

To map prudent incentives for SPVRT systems, the costs and benefits estimated in previous sections can be aggregated. This includes under-recovery of fixed costs, the relative cost of power purchase from a prosumer in comparison to the total power portfolio and grid balancing costs. The methodology for the same is discussed for Gross Metering and Net Metering arrangements separately.

Gross Metering

Under a gross-metering arrangement, all power generated by a SPVRT system is directly fed into the electricity grid, and the prosumer is compensated at a fixed price determined by the

[8] This approach is not necessarily the most appropriate. Still, it strives to arrive at a certain understanding of balancing costs. The approach for estimating balancing costs may be revised or evolved based on regulatory guidelines (when available) and the availability of data to estimate the same.

appropriate regulatory authority. Since there is no displacement of consumer electricity demand, the issue of under-recovery of fixed costs does not arise in this matter. Consequently, relative power purchase costs and balancing costs are additional costs that are borne by the distribution company.

Consequently, we propose that FiT under gross-metering arrangement shall be computed as below:

Equation 12: Feed-in-Tariff for gross metering arrangement

$$FiT\ for\ Gross\ Metering = APPC + C_{TD} + C_{GB}$$

where,

FiT is Feed-in-Tariff

APPC is Average Power Procurement Cost of Total Power Portfolio

C_{TD} = {Transmission Charges + Transmission Losses + Distribution Losses}

C_{GB} is grid balancing cost

Net Metering

Net metering allows for the banking of power for the consumers for periods[9] as defined in the regulations. The prosumer is charged for the net import of electricity from the distribution company. Since it directly displaces electricity demand, this leads to under-recovery of fixed costs as discussed in Section 3.1. Hence, the net burden or advantage to distribution companies under a net metering arrangement may be computed as a summation of under-recovered cost, relative landed cost and balancing costs for prosumers of different consumer categories.

Equation 13: Cost to distribution companies under the net-metering arrangement, C_N

$$C_N = F_{Ui} + \Delta_j + C_{GB}$$

Where,

F_{Ui} is the under-recovery of fixed costs for net metering consumer

Δ_j is the relative landed costs with respect to the overall power purchase portfolio

C_{GB} is grid balancing cost

4. Summary of Results

As discussed in Section 3, a significant distortion is observed between the ratio of fixed cost and variable costs when compared to the revenue realised from fixed charges and energy charges. Fixed costs account for 53.1% of the total cost of electricity supply, whereas fixed charges account for only 10.5% of the revenue realisation (Figure 2). The breakdown of average per unit revenue realisation across selected categories is presented in Figure 3.

[9] Monthly or annual

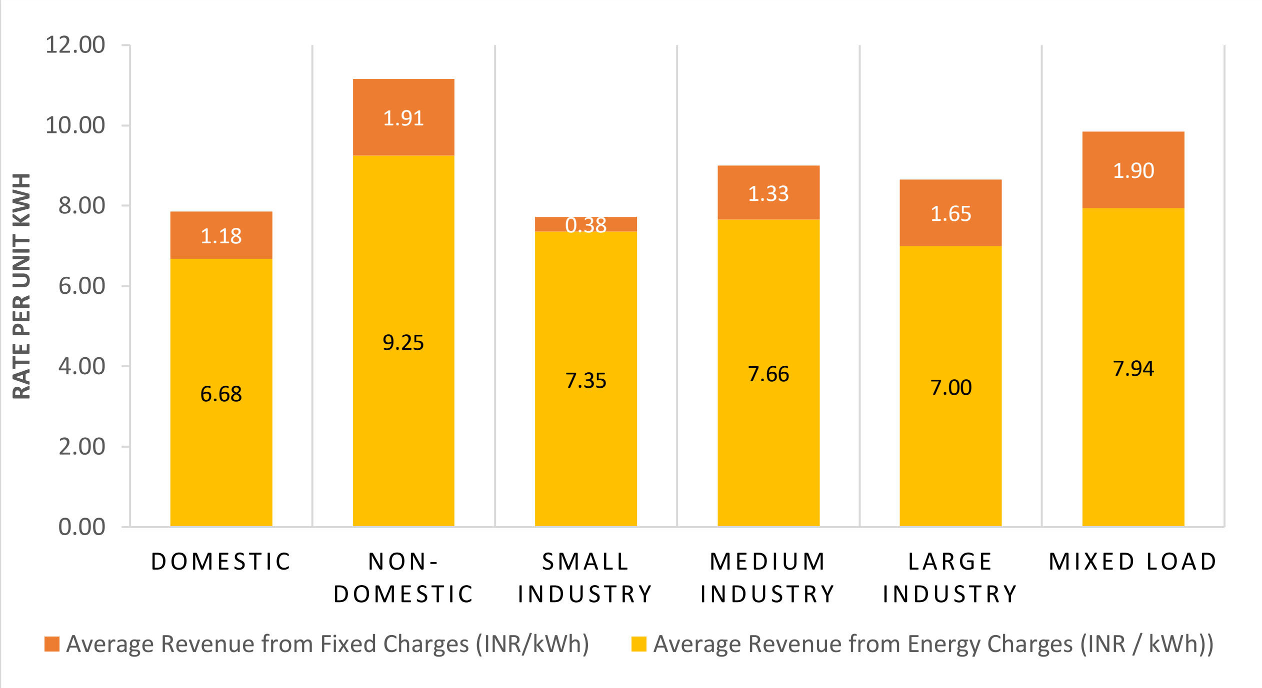

Figure 3: Category-wise per unit revenue realisation (Source: Author's Analysis)

Based on cross-subsidy adjusted fixed costs to be recovered from prosumers of respective consumer categories, the under-recovery of fixed costs for every unit of electricity generated is estimated and presented in Table 1 below:

Table 1: Under-recovery of fixed cost in Net Metering arrangement)

Categories	F_{Bi}	Cross Subsidy Rate	B_{Ei}	F_{Ui}
Domestic	1.18	-2.75%	3.69	-2.60
Non-Domestic	1.91	38.12%	5.20	-3.45
Small Industry	0.38	-4.52%	3.60	-3.33
Medium Industry	1.33	11.23%	4.19	-2.98
Large Industry	1.65	7.00%	4.03	-2.50
Mixed Load	1.90	3.02%	3.88	-2.10

In the landed cost analysis, transmission and distribution (T&D) costs are estimated for the total power portfolio (TPP) and renewable energy portfolio (REP). This included wheeling charges and the value of transmission and distribution losses. The values are presented in Table 2.

Table 2: Transmission and Distribution costs for power procurement (Source: JVVNL's True-up Data for FY 2021-22, (RERC, 2023))

Portfolio	Transmission Charges (INR/unit)	Cost of Transmission Losses (INR/unit)	Cost of Distribution Losses (INR/unit)	Summation of Costs (INR/unit)
TPP	0.65	0.28	0.71	1.64
REP	0.65	0.26	0.67	1.58

Power is purchased from different generation resources at prices as per power purchase agreements. Short-term power is purchased at market-discovered prices. Average power purchase prices for TPP and REP are calculated from the Tariff Order of JVVNL and approved ARR requirements (Annexure 4).

For power purchased under the net-metering arrangement, for consumer categories with telescopic tariff, the average billing rate is estimated based on assumptions discussed in Section 3.2. This applies to domestic and non-domestic categories. For the remaining categories, the highest applicable electricity tariff is considered for the analysis. The values of applicable prosumer tariffs are presented in Annexure 7. This value is adjusted with under-recovery since it is already accounted for separately (Section 3.1).

Thereafter, we estimate the landed costs of power purchase by adding T&D costs to respective power purchase portfolios. Lastly, relative landed costs are calculated for JVVNL with respect to its total power purchase portfolio (Annexure 7, Figure 4).

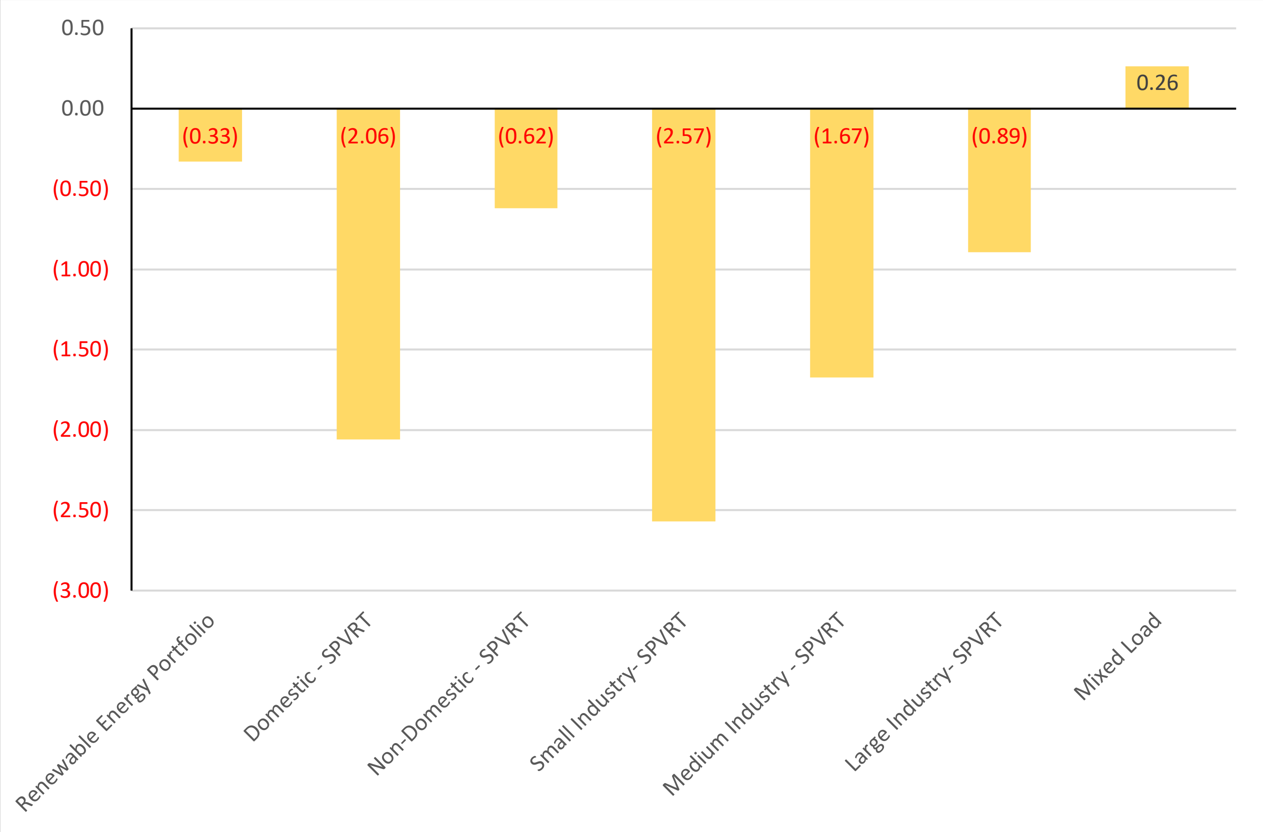

Figure 4: Delta analysis for landed cost of power

It is distinctly observed that, except for the mixed load category, the landed cost for different prosumer categories is cheaper than the TPP portfolio. The cost advantage of a minimum of INR 0.89 per kWh and a maximum of INR 2.57 per kWh is observed for large industries and small industries, respectively. Further, a health cost advantage of INR 2.06 per kWh is also observed for prosumers of the domestic category. It may also be noted that since the domestic category has a telescopic tariff, the cost advantage for prosumers with lower electricity consumption shall be much higher.

The balancing costs for renewable energy are computed as per the methodology discussed in Section 3.3, and the same is estimated to be INR 0.79 per kWh for the year 2030.

Finally, we compute the FiT for gross metering arrangement and net-metering arrangement as discussed in Section 3.4 Since renewable energy penetration is relatively low at present, we estimated the same to be INR 4.90 per kWh and INR 5.69 per kWh, respectively.

While SPVRT systems offer a clear cost advantage in comparison to TPP and REP, under the net-metering arrangement, the distribution company end up incurring a net loss, particularly because of the under-recovery of fixed costs. This cost may be recovered through a Net-Metering levy for every unit generated by SPVRT systems. This, however, shall not apply to units exported to the grid and compensated at a price determined by the regulatory authority. The computed net-metering levy, with and without consideration of balancing cost, is presented in Table 3.

Table 3: Computation of net-metering levy

	Fixed cost under recovery (INR/unit)	Delta (INR/unit)	Balancing Costs (INR/unit)	Net Metering Levy (INR/unit)	Net Metering Levy (INR/unit) w/o Bal.Cost
Domestic - SPVRT	-2.60	-2.06	0.79	1.32	0.54
Non-Domestic - SPVRT	-3.45	-0.62	0.79	3.62	2.83
Small Industry - SPVRT	-4.08	-2.57	0.79	2.29	1.51
Medium Industry - SPVRT	-3.14	-1.67	0.79	2.25	1.46
Large Industry - SPVRT	-2.47	-0.89	0.79	2.36	1.58
Mixed Load / Bulk Supply	-3.33	0.26	0.79	4.38	3.60

5. Recommendations: Roadmap for Prudent Incentivisation of SPVRT Systems

Distributing solar offers many advantages compared to the procurement of power from thermal electricity generation assets and utility-scale solar projects. Tail-end generation avoids wheeling costs, transmission losses and distribution losses. At the same time, the current regulatory framework does not measure the additional costs for integrating renewable energy and procuring variable renewable energy from prosumers. Consequently, distribution companies perceive a negative impact on their cash flows and balance sheets. As the penetration of distributed SPVRT systems increases, the concern of socialisation of costs amongst electricity consumers shall also increase. This shall especially disadvantage low-income households, as they are unable to adopt SPVRT systems because of space and capital constraints.

It may also be noted that as penetration of renewable energy, especially wind and solar, increases, associated costs with wheeling of power shall increase significantly because of the low capacity utilisation factor of wind and solar energy systems. Even with energy storage, it is unlikely that the capacity utilisation will reach the levels of power procurement from thermal electricity generation assets. Consequently, incentivising and promoting the distribution of renewable energy and tail-end generation needs to become a key policy priority.

Balancing the trade-offs between promoting distributed SPVRT systems, ensuring the sustainability of distribution companies, and preventing the socialisation of costs amongst economically weaker consumers requires a nuanced understanding of the costs and benefits of distributed RE. Some of these are carefully measured through the framework proposed in Section 3 of this report, while there's also a definitive possibility for further evolution of the framework.

Leveraging such a framework in the decision-making process may enable the regulatory authorities to devise roadmaps for incentivising distributed RE. Such roadmaps shall allow for the tapering of incentives as we move towards high renewable energy penetration and avoid sudden shocks to distributed renewable energy markets and aspiring consumers.

Some of the key recommendations that emerge from this analysis are discussed below:

- Low-consumption consumers offer more advantages in terms of the cost of procurement of power, and hence, they may be incentivised through additional incentives.
- Reducing the gap between fixed costs and revenue realisation through fixed charges shall be a key measure to reduce the under-recovery of fixed costs from prosumers. This shall also have a positive overall impact on the distribution company's cash flows.
- Integrating an appropriate framework for the determination of incentives/levies on prosumers shall allow for a gradual transition and build consensus amongst stakeholders.
- Distinct cost advantage is observed for SPVRT systems when compared to the procurement of power from utility-scale renewable energy projects, and hence, policies need to prioritise the former to reduce the cost of energy transition.
- The regulatory authorities may gradually include the cost of grid balancing in the design of incentives to reflect the state of renewable energy penetration and increase the incentives for distributed renewable energy in the short and medium term.
- The framework used for computing feed-in-tariff for the gross-metering arrangement may be used to determine tariffs for any excess energy fed into the electricity grid outside the banking arrangement. This shall be a more rational framework in comparison to the current practice of benchmarking the feed-in tariff to the average price discovery of five MW utility-scale solar projects.

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Annexure 1 : Cost Components of ARR

S.No.	Cost Component	Particulars
1	Power Purchase Cost	Power from RVUNL, short term sources/ energy exchanges, Transmission Charges (PGCIL, RVPN, RLDC, SLDC)
2	Capital Expenditure & Capitalisation	Sub Transmission & Dist, Rural Electrification Works, RAPDRP-A, Smart Metering, RDSS, Administrative Building Works, E-Power, DDUGJY (Post Saubhagya), Others
3	Operations and Maintenance	Employee Expenses, Repair and Maintenance (R&M), Administration and General Expenses (A&G)
4	Terminal Benefit Expenses/Liability	Gratuity (service gratuity, retirement gratuity/ death gratuity and residuary gratuity) and pension
5	Interest on Loans, Finance Charges & Lease Rental	Interest on LTL, Security Deposit, UDAY Loans, Regulatory Assets and Financing Charges & Lease Rental
6	Interest on Working Capital	Interest on O&M expenses, Maintenance Spare, Receivables
7	Depreciation	Depreciable amount of an asset over its useful life
8	Insurance Expenses	Amount of expenditure paid to acquire an insurance contract
9	Rebate Allowed	Refund offered to a consumer
10	Return on Equity	Annual Return (Net Income)/Total Shareholders' Equity

Annexure 2 : Costs and adjustments considered in ARR

Cost Component	Costs (in INR Crores)	% of ARR
Power Purchase Cost	19,089	73.9%
Operations & Maintenance	1,844	7.1%
Terminal Benefit Liability/Expenses	406	1.6%
Interest on Loans, Finance Charges & Lease Rental	3,370	13.0%
Interest on Working Capital	213	0.8%
Depreciation	882	3.4%
Insurance Expenses	35	0.1%
Rebate	0	0%
(Return on Equity) ROE	0	0%
Aggregate Revenue Requirement	**25,839**	100%
Less: Non-tariff income	250	
Less: Income from Wheeling Charges, Cross Subsidy Surcharge, and Additional Surcharge	4	
Net Aggregate Revenue Requirement	**25,585**	

Source: Petition No. RERC 2066/22, 2067/22, 2068/22 Table 46, Page 119-120

Annexure 3 : JVVNL true-up data for FY22

Categories	Units Sold (in MU) (A)	Fixed Charges (B)	Energy Charges (C)	Fuel Adjustment Charges (E)	Total Charges (in INR Crores) (F)	ABR (G = F /A)	Energy Charge per Unit (H = C/A)
Domestic	5,270	1,005	3,519.00	82.05	4,605.79	8.74	6.68
Non-Domestic	2,057	446	1,902.44	34.32	2,382.49	11.58	9.25
Small Industry	349	59	257.01	5.51	321.05	9.19	7.35
Medium Industry	792	153	606.93	12.19	771.94	9.74	7.66
Large Industry	6,444	642	4,509.43	102.46	5,253.52	8.15	7.00
Mixed Load/Bulk Supply	154	17	122.10	2.36	140.98	9.17	7.94

Source: For FY22 JVVNL True-up Data, Form D 2.1 Revenue from Sale of Power

Annexure 4 : JVVNL revenue projections and break-up estimate for FY24

Categories	Revenue from Existing Tariff FY24 (Cr) (I)	Approved Energy Sales (MU) (J)	DF Sales (MU)	Energy Sales, Less DF Sales (MU) (L = J - K)	Estimated revenue from Energy Charges FY24 (Cr) M = L x H	Est. revenue from Fixed Charges FY24 (Cr) N = I - M
Domestic	5,604	8,044	912	7,132	4,762	842
Non-Domestic	2,919	2,870	254	2,616	2,420	499
Small Industry	337	453	17	436	321	16
Medium Industry	786	922	48	874	669	117
Large Industry	7,101	8,733	521	8,212	5,747	1,354
Mixed Load/Bulk Supply	190	236	43	193	153	37

Source: RERC Petition 2066/2022, 2067/2022, 2068/2022, Table 88 Page 166, Table 40 Page 112, Table 41 Page 113

Note: Data point ‘H’ in cell ‘M’ is extracted from Annexure 3.

Annexure 5 : Average Cost of Supply (ACoS)

Estimated Sales (in MU)	33,559
Variable Cost (in Cr)	12,643
Fixed Costs (in Cr)	12,942
Net ARR (in Cr)	25,585
Distribution Franchise (DF) Sales*	1,897
DF Income (in Cr)	1,200
Estimated Sales (less DF) (in Cr); A	31,662
Cost, Less DF Income (in Cr); B	24,385
Average cost of supply (INR/unit) (Ax10/B)	7.7
Per unit variable cost (INR/unit)	3.77
Per unit fixed cost (INR/unit)	3.86
Net ARR per unit of electricity demand	7.62
Average Billing Rate	7.67
Adjusted variable costs to be recovered from Tariffs	3.79
Adjusted fixed costs to be recovered from Tariffs	3.88

Annexure 6 : Cross-subsidy and Adjusted Cost of Supply (AdCoS)

Categories	Av Billing Rate from Energy Charges (INR/kWh)	Av Revenue from Energy Charges (INR/kWh)	Av Revenue from Fixed Charges (INR/kWh)	Cross-subsidy (INR/kWh)
Domestic	7.46	6.68	1.18	-2.75%
Non-Domestic	10.60	9.25	1.91	38.12%
Small Industry	7.33	7.35	0.38	-4.52%
Medium Industry	8.54	7.66	1.33	11.23%
Large Industry	8.21	7.00	1.65	7.00%
Mixed Load/Bulk Supply	7.91	7.94	1.90	3.02%

Average Billing Rate	7.67 INR/kWh
Adjusted variable costs to be recovered from Tariffs	3.79 INR/kWh
Adjusted fixed costs to be recovered from Tariffs	3.88 INR/kWh

Annexure 7 : Delta analysis for landed cost of power

Portfolio	Prosumer Tariff (INR/kWh)	T&D Costs (INR/unit)	Landed Costs (INR/unit)	Delta Analysis (INR/unit)
Total Power Portfolio	6.23	1.64	5.69	0.00
Renewable Energy Portfolio	8.52	1.58	5.36	(0.33)
Domestic - SPVRT	6.45	0.00	5.35	(0.33)
Non-Domestic - SPVRT	7.00	0.00	5.50	(0.19)
Small Industry- SPVRT	7.30	0.00	3.12	(2.57)
Medium Industry - SPVRT	8.05	0.00	4.02	(1.67)
Large Industry- SPVRT	6.23	0.00	4.80	(0.89)
Mixed Load	8.52	0.00	5.95	0.26

Annexure 8 : Estimation of grid balancing cost

Balancing Resources	Installed Capacity FY30 (MW)	Benchmark CapEx Costs (Cr/MWh)	O&M Fixed Costs (Cr/MW)	Lifetime (years)	Total CapEx (Cr)	Total O&M Fixed Costs (Cr)	Yearly Fixed Cost Implication (Cr)	Total Yearly Implication (Cr)
Pumped Storage Power Plants (PSP)	18,969	8	0.4	40	1,51,752	7,588	16,040.72	23,628.32
Battery Energy Storage Systems (in MWh)	2,08,250	1.22	0.01	10	2,54,950	2,550	34,527.15	37,076.65
					Total		**50,567.87**	**60,704.97**
Cost of Capital	10.50%					Projected RE Generation in 2030 (BU)		771.26
						Balancing Costs (INR/unit)		**0.79**