Impact of NEPRA Prosumer Regulations 2026: A Case Study for Textile Sector

Alternate
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This study stands as a testament to what can be achieved through shared vision and collaborative effort. We hope its findings and recommendations serve as a catalyst for transformative change and inspire continued progress toward achieving the Sustainable Development Goals (SDGs) and the objective of clean and affordable energy.

Amjad Nazeer
Chief Executive Officer
Alternate Development Services (ADS)
Islamabad, March 2026

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List of Acronyms

ADS	Alternate Development Services
APTMA	All Pakistan Textile Mills Association
ARE Policy	Alternative & Renewable Energy Policy
AMI	Advanced Metering Infrastructure
BESS	Battery Energy Storage System
CBAM	Carbon Border Adjustment Mechanism
CPP	Captive Power Plant
CPPA-G	Central Power Purchasing Agency-Guarantee Limited
CTBCM	Competitive Trading Bilateral Contract Market
DER	Distributed Energy Resource
DG	Distributed Generation
DISCO	Distribution Company
EPA	Environmental Protection Agency
EPP	Energy Purchase Price
EU	European Union
FiT	Feed-in-Tariff
FY	Financial Year
GoP	Government of Pakistan
HCA	Hosting Capacity Analysis
IEA	International Energy Agency
IPP	Independent Power Producer
IRR	Internal Rate of Return
ISMO	Independent System and Market Operator
KPI	Key performance Indicator
kWh	Kilowatt hours
LCOE	Levelized Cost of Electricity
MRV	Monitoring, Reporting & Verification
MW	Megawatt
NAEPP	National Average Energy Purchase Price
NB	Net-Billing
NEPRA	National Electric Power Regulatory Authority
NM	Net Metering
NPV	Net Present Value
O&M	Operation and Maintenance
P2P	Peer-to-Peer
PBP	Payback Period
PLAC	Partial Load Adjustment Charges
PPA	Power Purchase Agreement
PPMC	Power Planning & Monitoring Company
RE	Renewable Energy
ROI	Return on Investment
SME	Small and Medium Enterprise
TEA	Techno-Economic Analysis
TOU	Time-of-Use
VoS	Value-of-Solar
VPP	Virtual Powerplants

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Executive Summary

Pakistan's rapid rooftop solar growth has reached a policy inflection point. Falling panel costs and strong private demand produced many on-site installations; at the same time the power system carries large, fixed obligations (capacity payments to IPPs), aging distribution infrastructure, and operational stresses (grid congestion, the "duck" profile). NEPRA's move from unit-for-unit net-metering to a net-billing settlement changes how exported rooftop energy is valued and therefore has direct commercial consequences for industrial consumers; especially textile mills, which are energy-intensive, exposed to international low-carbon buyers, and highly sensitive to electricity cost volatility.

To quantify the impacts, representative *industrial cases* across three scales are modeled in a case study for evaluating impact of NEPRA Prosumer Regulations 2026 on industrial prosumers; Small (≈380 kWh/day), Medium/pooled SME (≈4,200 kWh/day) and Large (≈10,500 kWh/day); and three demand states (Low, Actual, High). Twelve policy/operational scenarios are tested: net-metering (NM), net-billing (NB), higher retail tariffs, sanctioned-load caps, low/high self-consumption profiles and battery inclusion. Outputs included LCOE (PKR/kWh), annual electricity bill (PKR/yr), NPV, IRR, ROI and simple payback. The aim is to show which design choices materially affect economic viability and near-term cash flows so regulators and industry can choose measures that preserve system stability without killing investment signals.

Key quantitative findings show that *settlement design* dominates economics. Under the legacy net-metering regime, medium and large mills deliver very strong returns in our cases; IRRs typically ~50–58% and simple paybacks around 2.7–3.0 years, with LCOE falling to roughly 6–8 PKR/kWh. Replacing that with a simple net-billing approach (exports credited at a low wholesale/NAEP rate and imports at full retail) materially reduces monthly cash benefits and lengthens paybacks: large mills commonly move into a ~4.2–4.7 year payback range under NB. It was also observed that *demand level* matters; Higher production (Low → Actual → High) improves IRR and shortens payback because the same PV offsets more purchases; but it does not overturn the settlement effect: higher demand under NB can still raise near-term import bills because exports are poorly credited. Representative annual bill examples make this simplistic and clear: the selected large mill's baseline grid exposure was ≈PKR 126M/year; NB reduced cash outflow in some cases to ≈PKR 13.3M but did not create the export value under NM (≈ – PKR 20.7M). NB combined with higher retail tariffs or sanctioned caps can push annual bills back up (≈PKR 24.1M and ≈PKR 27.8M respectively). Battery plus time-differentiated peak credits recovers much of the lost value: NM + battery kept net receipts near ≈ – PKR 19.9M, while NB + battery plus fixed charges largely neutralized benefits (≈PKR 1.95M).

The study showed that *medium mills* (or ***pooled SME aggregations***) are the most resilient: they combine scale economies with flexibility and generally remain profitable across a wide set of scenarios. Large firms can adapt by investing in storage or securing bespoke commercial arrangements but are constrained by sanctioned-load ceilings and transformer limits that remove the oversize lever they previously used to optimize systems. Small firms are most vulnerable: low export credits, explicit fixed charges, or strict sanctioned caps push IRRs down and paybacks into marginal ranges, threatening access to finance and increasing the risk of off-grid or behind-the-meter storage choices.

Technical drivers and policy levers. The principal levers that change outcomes are how exports are credited (retail vs wholesale/VoS/TOU), whether storage dispatch is recognized and remunerated for adoption, sanctioned-load or transformer caps, and the availability of aggregation/VPP frameworks and AMI metering. Blunt measures; across-the-board export cuts or uniform caps; are the cheapest to implement but have large costs: they accelerate behind-the-meter storage or grid defection, reduce system visibility, and lower the national return on distributed energy resources (DER) investment. Conversely, pairing net-billing with time-differentiated credits, clear battery energy storage solutions (BESS) compensation, and aggregation pathways aligns private incentives with system needs (peak shaving, capacity deferral) and recovers much of NM's financial viability.

The study also provided practical implications for stakeholders. Regulators must balance protecting non-solar consumers and DISCO revenue with preserving industrial competitiveness and investment certainty. For industry, investment decisions will now depend more on settlement and storage rules than on panel costs. Medium/pooled SMEs are the best candidates for continued growth in distributed PV; small firms need aggregation and concessional storage finance to stay in the transition. DISCOs should prioritize targeted hosting-capacity analysis, smart inverter controls and staged feeder upgrades rather than blanket caps that penalize productive generation.

Before wide implementation of net-billing, run transparent VoS/TOU and storage pilots on representative feeders and publish results; enable aggregation/VPP pilots and AMI rollout for new >10 kW prosumers; require DISCOs to follow a mitigation ladder (export setpoints, phase balancing, short curtailment, targeted upgrade) and publish transformer HCA and queue data; and design any modest network cost recovery so it is phased and paired with protections for small adopters. These steps let policy address DISCO revenue concerns while keeping industrial investment viable and preserving grid visibility.

To summarize, net-billing can be a defensible policy tool for protecting distribution company finances; but only if implemented as part of a package that pays for the time and flexibility value of distributed resources, recognizes storage, and enables aggregation. Otherwise, the change risks slowing rooftop adoption, encouraging grid defection, and transferring costs onto vulnerable consumers. A measured, evidence-led transition will preserve industrial competitiveness while delivering the system benefits of a more flexible, distributed power system.

1. Introduction and Objectives

Rooftop solar deployment in Pakistan has grown rapidly over the last five years as module costs fell, financing options improved, and early policy support encouraged distributed investment. Cumulative net-metering capacity expanded into the multi-GW range during 2024–25, driven by households, commercial sites and a fast-growing number of industrial prosumers; independent trackers and sector reporting put the country's net-metering additions at multiple gigawatts in 2024–25 [1,2]. The complete timeline of Net metering (NM)'s progress over recent years is captured in **Figure 1**.

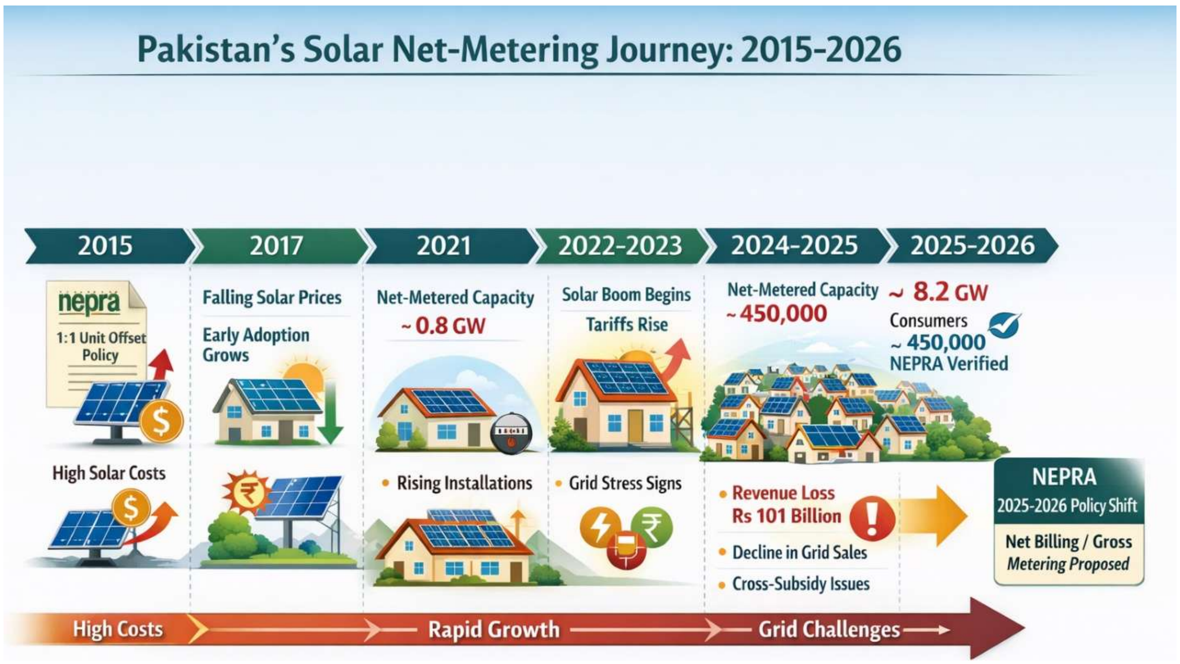


Figure 1*:* Pakistan's Solar Journey from Net Metering to Net Billing [3–6]

In February 2026, the National Electric Power Regulatory Authority (NEPRA) promulgated the **Prosumer Regulations, 2026** which replace the earlier net-metering framework with a net-billing arrangement and update interconnection, metering and settlement rules for distributed generation. The new rules define exports as being credited (or purchased) by licensees at a national average purchase price rather than being netted unit-for-unit against consumption; the formal regulation text and notification are published on NEPRA's website on 9th February 2026 [7,8].

NEPRA and proponents of the change justify the policy shift on system-stability and tariff-equity grounds: rapid prosumer uptake has reduced volumetric sales and, according to regulators, created cross-subsidy and fixed-cost recovery pressures for distribution companies. The draft/regulatory papers and official commentary frame net-billing as a way to preserve DISCO revenue streams and ensure unavoidable network costs are recovered while still allowing prosumers to export surplus energy [7,9].

The reforms produced significant public and industry reaction. Energy analysts, industry bodies and media outlets warned that the switch could slow rooftop deployment and undermine investor confidence because it materially changes the bankability/economic viability that many projects were built on; several outlets reported debates over proposed buy-back/buy-back rates (figures in the low-teens PKR per kWh for exported energy) and the prospect that existing consumers could be shifted to net-billing arrangements. Senior policymakers and commentators have publicly debated the trade-offs between protecting electricity consumers at large and preserving the nascent prosumer market [10,11].

This policy report, prepared for industrial stakeholders, energy researchers and regulators, explains the technical and commercial mechanics of the change, summarizes the likely impacts on industrial prosumers (including LCOE, annual-bill and payback implications), and sets out practical recommendations for a fair, evidence-based transition. Many stakeholders asked for transparent sensitivity modelling by the Power Planning & Monitoring Company (PPMC) and the market operator (ISMO) so that cross-subsidy, tariff and DISCO-revenue outcomes are publicly available before any permanent rule changes are finalized. These analyses will be critical to designing time-differentiated export credits, storage compensation and any graduated fixed-charge mechanism that balance system stability with continued industrial investment [7,12].

1.1. Key objectives of the study

The report is intended to serve the following objectives:

- To clarify the provisions of the 2026 Prosumer Regulations, especially the mechanics of net-billing.
- To explain what is changing from the old net-metering scheme (billing, contract terms, caps).
- To outline sanctioned-load limits and export rules under the new regime.
- To analyze implications for industrial prosumers' billing, cost recovery and investment returns.
- To summarize arguments from NEPRA's public hearing (including PPMC's grid-impact data) and stakeholder responses.
- To analyze the impact of prosumer regulations on industrial prosumers through realistic data and identify the consequences of implementation of these regulations on bulk consumers as well as small & medium enterprises (SMEs).
- To propose actionable recommendations for policymakers, DISCOs and industry to mitigate adverse impacts and improve regulatory outcomes.

2. Background and Context

Most industries in Pakistan rely heavily on a mix of grid supply and captive generation: large factories typically run grid-connected processes during the day and switch to captive gas or diesel plants for evening and backup, while many SMEs depend almost entirely on captive generation when the grid is unreliable. High industrial tariffs (commonly in the PKR 40–50/kWh range) and rising fuel prices make captive power increasingly uneconomic, pushing firms toward on-site solar and hybrid systems to lower operating cost and secure continuity.

This dual pressure; volatile grid reliability plus high energy cost; is the immediate commercial context shaping industrial responses to changes in prosumer regulations. In industrial sectors, the textile sector is the backbone of Pakistan's economy; contributing roughly **8–9% of GDP** and accounting for most merchandise exports; and it employs a very large share of industrial labor, also accounting for the bulk of national exports [13,14]. This scale makes energy costs a critical competitiveness factor: textile processes (spinning, weaving, dyeing, finishing) are energy-intensive and concentrated in regional hubs that together consume a large fraction of industrial electricity [15].

At the system level, this matters because Pakistan's industrial users face volatile supply, frequent outages and high tariffs that materially erode margins. Industrial tariffs and system inefficiencies (high T&D losses) have pushed many mills toward self-generation and rooftop solar to reduce daytime fuel and grid exposure; hybrid PV + captive/grid solutions are now common in large installations. On the trade side, tightening buyer standards and instruments such as the EU's Carbon Border Adjustment Mechanism (CBAM) add a second commercial imperative: low-carbon, documented electricity use (and verifiable Scope-2 accounting) is becoming a condition of market access for export garments and textiles. Together, these economic and regulatory drivers explain why changes to prosumer rules (net-metering → net-billing, sanctioned-load caps, treatment of storage and time-differentiated credits) are material for textile competitiveness and investment decisions.

Rooftop solar deployment in Pakistan accelerated rapidly after 2016-2017 as global PV module prices fell and local demand reacted to chronic reliability problems and rising retail tariffs. Between 2017 and 2025 the on-grid, net-metered rooftop fleet expanded into the multiple-GW range (independent reports placed cumulative net-metered capacity in the ~6–7 GW band by 2024 – 25); while behind-the-meter, off-grid and hybrid installations also grew substantially. This large, distributed uptake changed the shape and timing of net demand on the system: midday solar injections created very low net loads from the utility grid and a steep evening ramp (the so-called "duck curve" as shown in **Figure 2**) in several major industrial hubs, and in some pockets daytime rooftop generation now approaches or exceeds local daytime demand [16–18].

At the same time, cost structure of Pakistan's power-sector remained dominated by fixed payments. A very large share of total system costs, driven by capacity payments, contract obligations and network overheads, is effectively fixed and does not decline with a fall in kWh sales; recent public discussion and regulatory filings characterize roughly three-quarters of system costs as fixed in nature (i.e., not easily recovered through volumetric charges). This combination; falling kWh sales (partly due to prosumers' self-consumption and exports) and a high fixed-cost base; produced acute cross-subsidy and revenue-recovery pressure for distribution companies (DISCOs), contributing to persistent circular-debt dynamics that the government has been addressing through debt restructuring and financing packages [19,20].

Thus, as distributed solar tends to be strongest during daytime, system operators have reported growing operational challenges: very low mid-day dispatch for central plants followed by steep evening ramps, local voltage excursions in heavily penetrated feeder sections, and localized transformer loading concerns where many large generators cluster. Operators and planners (including those working with market operator datasets) have used hourly demand profiles to demonstrate these operational impacts, which require new operational tools (advanced inverter functions, active export control, hosting-capacity analysis) and, where necessary, targeted network reinforcement. Those technical stresses combined with the financial stress on DISCO cash flows are central to the regulatory re-examination of how prosumers are credited for exports [21,22].

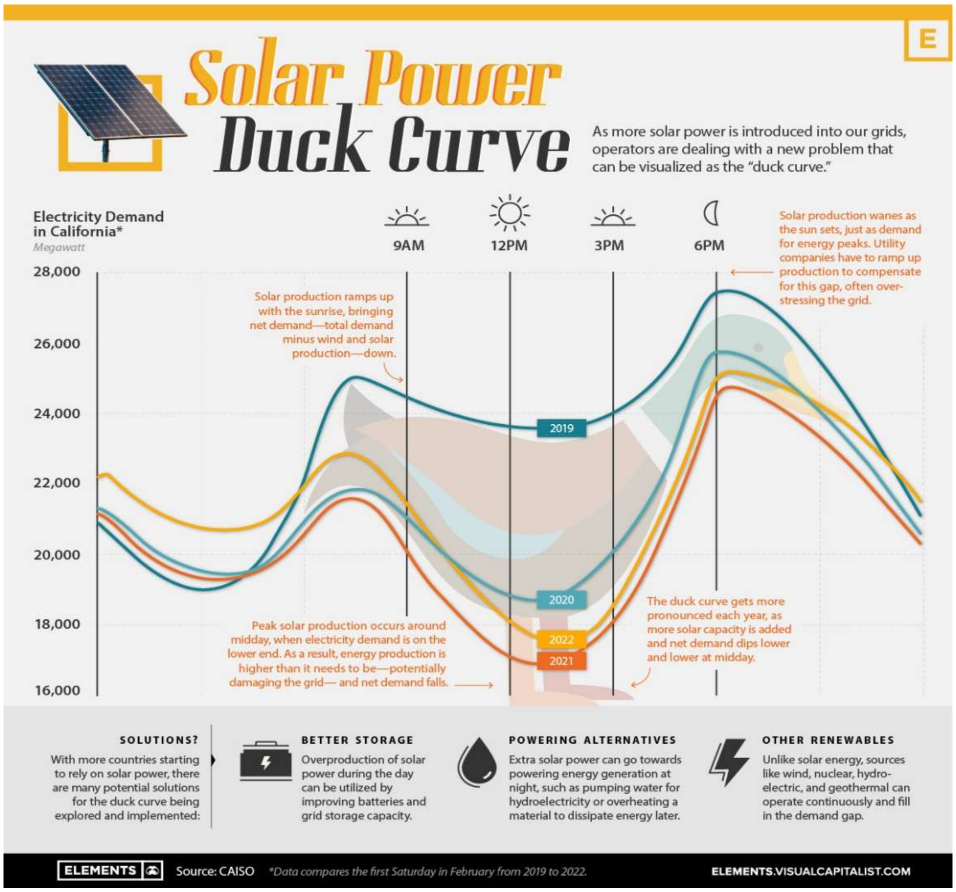


Figure 2: Duck Curve Phenomenon [23]

2.1. Why did NEPRA change the settlement model?

The National Electric Power Regulatory Authority's (NEPRA) decision to move from a unit-for-unit net-metering settlement to a net-billing approach (published in the Prosumer Regulations) reflects two core concerns articulated by regulators:

(a) Protecting non-solar consumers and preserving the ability of DISCOs to recover unavoidable fixed costs, and

(b) Safeguarding operational stability and distribution network strength as distributed generation (DG) penetrations increase.

NEPRA argues that the old net-metering design; appropriate when rooftop solar was nascent; allowed prosumers, particularly higher-tariff commercial and industrial consumers, to avoid paying their proportionate share of capacity and network costs, thereby shifting an increasing recovery burden onto other consumers. The new rules replace kWh-netting with monetary settlement mechanisms that pay for exports at a purchase price rather than offsetting retail purchases unit-for-unit; they also formalize capacity / size limits, metering standards and technical connection conditions [7].

Public observations show that this policy re-direction was pushed by both macro-fiscal pressures (large outstanding sector arrears and circular debt) and short-term operational signals (local over-injection and ramping challenges). The issue was framed as a trade-off between rapid distributed-generation deployment (and the environmental and consumer benefits it yields) and the need to ensure an equitable tariff framework and stable system financing; the local and international coverage influenced the timing and political relevance of the regulatory intervention [24,25].

2.2. Technical drivers: System operation, hosting capacity and inverter roles

From a technical perspective, three interlinked drivers have made the issue urgent for planners:

(1) **Hosting capacity (HC) limits** at the transformer and feeder level; the point beyond which additional exports risk voltage, protection and thermal limits;
(2) **Bidirectional flows and local protection settings** that were not designed for high, synchronous reverse power during daylight; and
(3) **Ramping and reserve requirements** as central dispatch must follow a more variable net-load profile.

These factors require new grid-integration practices: mandatory advanced inverter features (ride-through, volt/VAR support), detailed hosting-capacity analysis (HCA), incorporating diversity and net-export profiles, smart meter roll-out to improve visibility, and inverter or market-level export controls to prevent localized constraint breaches [21]. Where these technical solutions are more cost-effective than blanket limits, targeted upgrades are preferable to blunt sanctioned-load caps; the regulatory framework must therefore incentivize mitigations (inverter settings, phase balancing, time-limited curtailment) before permanent refusals. A brief illustration of hosting capacity is shown in **Figure 3**. The graph shows how a feeder's "performance index" (voltage, protection, thermal limits, etc.) degrades as more distributed generation (DG) is added, and how targeted hosting-capacity (HC) enhancements push the system to tolerate more generation before operation becomes unacceptable. The solid curve is the original performance trajectory: at the red dot the index hits the unacceptable threshold and the feeder's uncontrolled hosting capacity is reached, forcing limits or rejections. The dashed, right-shifted curve shows the same feeder after HC measures (inverter export controls, phase rebalancing, targeted upgrades, advanced protection, etc.), moving the crossing point to the green dot and creating extra headroom (yellow arrow); i.e., additional DG penetration that can be safely accommodated without hitting the operational limit. In short, the figure illustrates that technical mitigations increase usable hosting capacity and are a less-disruptive alternative to blunt caps on new prosumer connections [26].

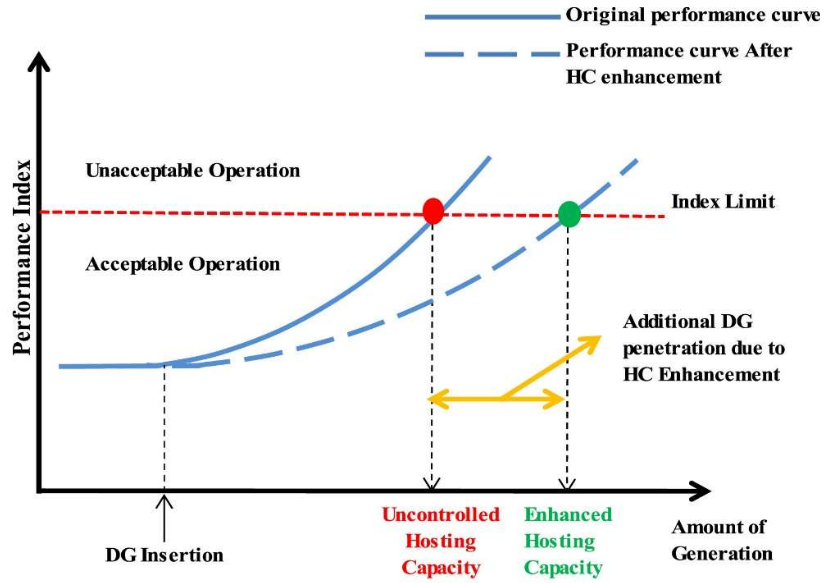


Figure 3: HC concept and the effect of its enhancement [26]

2.3. Economic drivers: Tariffs, cross-subsidy and circular debt

Economically, the net-metering era amplified a distributional tension. High retail tariffs (set to recover capacity charges and other legacy costs) made rooftop investments financially attractive for consumers able to self-consume or export, but as these consumers avoided volumetric charges the remaining pool of customers faced higher per-unit burdens or required explicit budgetary subsidies. Regulators and the Ministry pointed to a growing subsidy and protected-consumer population as reasons to rebalance recovery. The persistence of circular debt; large outstanding payables to generators and among sector entities; added urgency to measures that could stabilize DISCO revenue flows. The government response, including large refinancing packages and IMF-linked reform actions, acknowledged both the need to shore up sector finances and the political sensitivity of tariff changes [19,27].

2.4. Market and policy context: Investment, jobs and trade implications

Beyond domestic tariff fairness and operational stability, there are broader strategic considerations. Industrial adopters view rooftop solar as both an operating-cost hedge and a component of corporate decarbonization strategies (useful for voluntary carbon accounting and for meeting buyer preferences in export markets exposed to carbon border adjustment mechanism (CBAM) in near future). Sudden changes in the return framework raise legitimate questions about stranded investment risk and legal/regulatory predictability; factors that influence the cost of capital and the pace of future deployment. Policy design therefore has implications for industrial competitiveness, trade (e.g., compliance with emerging CBAM-like regimes), local jobs in installation and services, and the pace of the domestic solar supply chain. Press reporting and industry statements made clear that a careful, evidence-based transition (with clear grandfathering and transparent modelling) would reduce investor uncertainty [22,25].

2.5. What empirical evidence has shown so far?

Empirical system data and sector observations converge on a few critical findings:

(1) Distributed PV materially reduces daytime grid demand and shifts the dispatch burden to evening hours, creating higher ramp rates for dispatchable plants;
(2) Where penetration is high on a single transformer or feeder, localized voltage and protection issues have been observed;
(3) Financial transfers embedded in existing tariff structures mean that a rapid adoption of prosumers reduces volumetric revenues while fixed obligations remain, exacerbating financial stress; and
(4) Modest technical interventions (inverter control, AMI, targeted upgrades) coupled with market measures (time-differentiated pricing and storage incentives) can preserve most of the system and social benefits while protecting network finances.

These findings have emphasized calls from professional bodies, academics and market operators for a structured transition rather than an abrupt policy reversal [20,21].

2.6. Methodology of Study and Implications for the remainder of the report

Figure 4 shows the detailed methodology of the study.

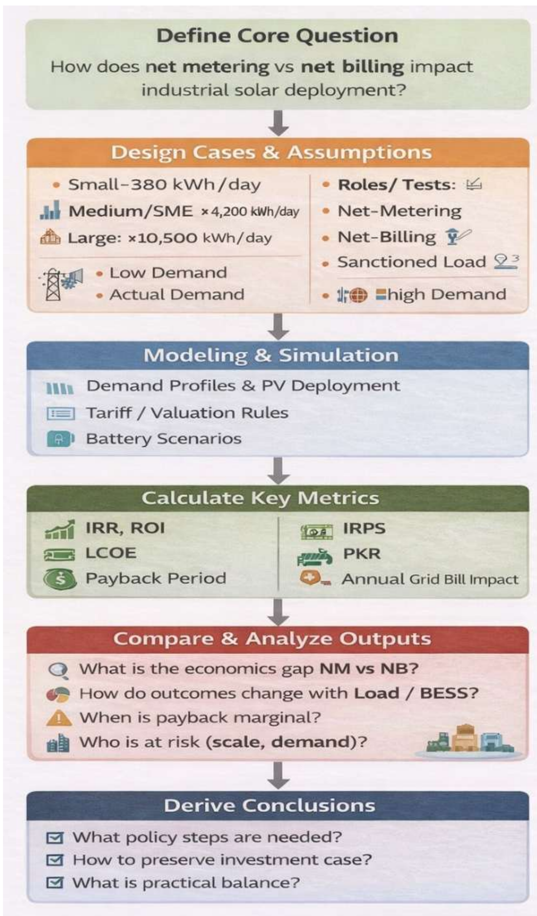


Figure 4: Detailed methodology of proposed study.

The background explained why the policy choice is contentious: the system is no longer at a “nascent” stage, and both technical and economic externalities now matter at scale. The remainder of this report therefore focuses on:

(a) A technical discussion of what changes these regulations offer;
(b) NEPRA hearing overview and response;
(c) Technical capacity limits, what they imply and how;
(d) Quantified techno-economic impacts for representative industrial classes (large, medium, small),
(e) Practical mitigations; technical, commercial and policy; that preserve prosumer value while protecting DISCO finances, and
(f) A recommended sequencing of reforms, which can deliver a balanced outcome.

For regulators and stakeholders, the priority is to align rules with operational realities and to publish the sensitivity analysis for justification needed to make those trade-offs transparent.

3. NEPRA Prosumer Regulations 2026 Overview

In February 2026 NEPRA issued the *Prosumer Regulations, 2026*, a comprehensive reworking of the 2015 net-metering regime. The headline change is legal and commercial: the Regulations formalize a **net-billing** settlement in place of the old 1:1 energy offset. Under the new model, prosumers continue to buy from the grid at the applicable retail tariff but any exported energy is credited (or purchased) by the licensee at the **national average energy purchase price (NAEPP / NAP)** rather than at full retail; the regulation text defines the purchase/credit mechanics and the limited carryover/payment rules that apply to exported energy. The Regulations also tighten interconnection and metering requirements (mandating bidirectional or separate import/export meter configurations), shorten the standard contract term to five years (renewable by consent), and formalize technical and safety obligations for equipment and metering. These core provisions are set out in the formal NEPRA regulation text [7].

Settlement mechanics and export price: The Regulations move the industry from a unit-for-unit offset to separate buy/sell prices: imports are charged at the consumer’s retail tariff while exports are credited at the NAEP. Media reporting and the regulatory text indicate that the practical effect is a large reduction in export compensation versus the old retail offset; figures discussed publicly range in the low-teens PKR per kWh (commonly cited ~Rs.8–11/unit for NAEP or slightly higher for transitional measures, while some reporting referenced higher national average purchase prices depending on the accounting period). The Regulations also prescribe settlement timing (limited carryover of credits and quarterly payouts for net export balances), which changes monthly cash-flow dynamics for prosumers compared with the immediate invoice offset of net-metering. This re-pricing is central to the economic impact on industrial project economic viability and was explicitly discussed in the NEPRA notification and public discussion [28,29].

Grandfathering, contracts and transitional protection: Recognizing the legal and investment implications, the Regulations explicitly **grandfather existing net-metering agreements**; those executed under the 2015 rules remain valid until their contracted expiry, after which renewals fall under the new net-billing provisions, as per amendment issued by

NEPRA on 17th February 2026 after severe public backlash [30,31]. Separately, the Power Division moved quickly to require limited transitional protections for already-registered prosumers (including short interim protections (30 day) reported after the initial notification [32], and complete protection until expiry term after amendment [30]), and NEPRA subsequently acknowledged the need for time-bounded protections as well as protections for prosumers who applied for net metering connection, while the rules are reviewed in the public process (i.e. for applications submitted on or before 8th February, 2026) [33]. These transitional arrangements matter legally and financially because they affect the effective lifetime return assumptions used by projects commissioned under the earlier regime.

System size, sanctioned-load rules and technical limits: A material operational change is the removal of the earlier implicit oversizing allowance; the Regulations tie permitted installed DG capacity to the consumer's **sanctioned load** (i.e., generation cannot exceed sanctioned load). Practically this reduces previously allowed headroom (where some purchasers had installed up to ~150% of sanctioned load under the old model) to a 100% cap unless the regulator notifies otherwise. Regulators, i.e. PPMC and NEPRA and also DISCOs emphasized that this change was motivated by transformer/feeder hosting capacity concerns and the need to avoid uncontrolled reverse power flow; the cap therefore directly constrains prosumers who used oversizing to maximize daytime self-consumption and project economics [34,35].

Metering, technical and interconnection standards: The Regulations require either a single bidirectional metering configuration or separate import/export meters with equivalent measurement accuracy, and prescribe meter types, testing and replacement protocols (e.g., timelines for faulty meter replacement and laboratory verification). They set out licensee responsibilities for interconnection study, safe-connection checks, and the technical protection requirements that equipment must meet. The rules also give licensees specific operational rights (including temporary disconnection for safety/fault reasons) but stop short of fully prescriptive national grid-code changes; instead, they reference adopted standards and allow NEPRA to update technical annexes and metering technology directions by notification. These metering and data-visibility elements (including an emphasis on AMI and accurate export measurement) are designed to reduce meter disputes and improve settlement integrity [8].

Operational controls, hosting capacity and network remedies: Recognizing that distribution networks have local constraints, the Regulations assign licensees authority to assess hosting capacity and to reject or condition connections where technical limits would be exceeded. However, the rules also require defined processes for connection assessment and give licensees discretion to require mitigation (inverter export limits, phase balancing, time-limited curtailment or targeted reinforcement) before rejecting a connection outright. This approach attempts to balance the need for operational security with the goal of allowing economically and technically safe projects to proceed; although stakeholders have argued that the Regulations should be more prescriptive about the mitigation sequence and publication of transformer-level HCA data [7,31].

Consumer protections, dispute resolution and contract terms: The standard contract term under the new Regulations is five years (renewable by mutual agreement), shorter than the seven-year time horizon under many earlier net-metering agreements; this shorter horizon affects long-term financing assumptions and bankability. The Regulations provide for billing and payment rules (including quarterly settlement for export surpluses beyond limited carryover), meter dispute procedures and limited dispute referral paths to the Authority, but they do not set aggressive statutory timelines for dispute resolution; a point raised repeatedly in stakeholder submissions. Stakeholders have also asked NEPRA to require clearer transitional grandfathering for pending applications and to publish modelling showing the aggregate impact of the new settlement on DISCO revenue and cross-subsidies before full implementation [9,30].

Public reaction and policy process: The Regulations provoked broad stakeholder engagement: industry bodies, renewable-energy trade associations, and consumer advocates submitted comments and urged public hearings. Media coverage and industry communiqués highlighted concerns that the shift to net-billing (particularly when combined with lower export prices and sanctioned-load limits) would lengthen paybacks, raise effective LCOE for prosumers, and slow rooftop deployment; while regulators argued that system-level fairness and DISCO financial health required corrective action. Following the public responses, the Power Division requested NEPRA to re-examine aspects of the rules (notably protection for existing licensees, which was ultimately fulfilled a week after submission), and NEPRA has been asked to publish the underlying VoS/PPM modelling to justify chosen purchase prices and to support a transparent rule-making record [34,36].

Practical implications: To summarize, the Prosumer Regulations 2026 tighten technical safeguards, improve metering and clarify settlement mechanics, but they also **fundamentally change the revenue mechanism** for prosumers by replacing 1:1 net (offset) with monetary settlement at NAEPP. For industrial stakeholders (prosumers), this shift lowers export compensation, shortens guaranteed contract prospects, and restricts size; three factors which jointly reduce internal rates of return (IRR) and extend payback unless alternative value streams (time-differentiated credits, storage revenues, aggregation/VPPs) are enabled. Regulators seeking to preserve DER deployment should therefore pair net-billing with explicit pilots for Time-of-Use/VoS, BESS dispatch payments and clear HCA/transparency requirements so the system and investor interests remain aligned.

4. Net Metering → Net Billing: Changes and Mechanics

The *Prosumer Regulations, 2026* replace the familiar 1:1 retail offset model with a two-price monetary settlement that separates imports and exports into distinct transactions. Under the old net-metering regime, every kWh exported effectively cancelled a kWh imported at the same retail price, providing immediate and full monthly bill relief. Under the new approach imports are billed at the consumer's applicable retail tariff while exported energy is purchased by the licensee at the **national average energy purchase price** (NAEPP), which is substantially lower than retail for most industrial tariffs. The legal text and operative clauses formalize this separation, prescribe the measurement/settlement conventions, limit credit rollover and define the contract and metering requirements for prosumers. NEPRA's published regulation text is the primary legal source for these changes. **Figure 5** shows the comparison between existing and newly adopted model [37,38].

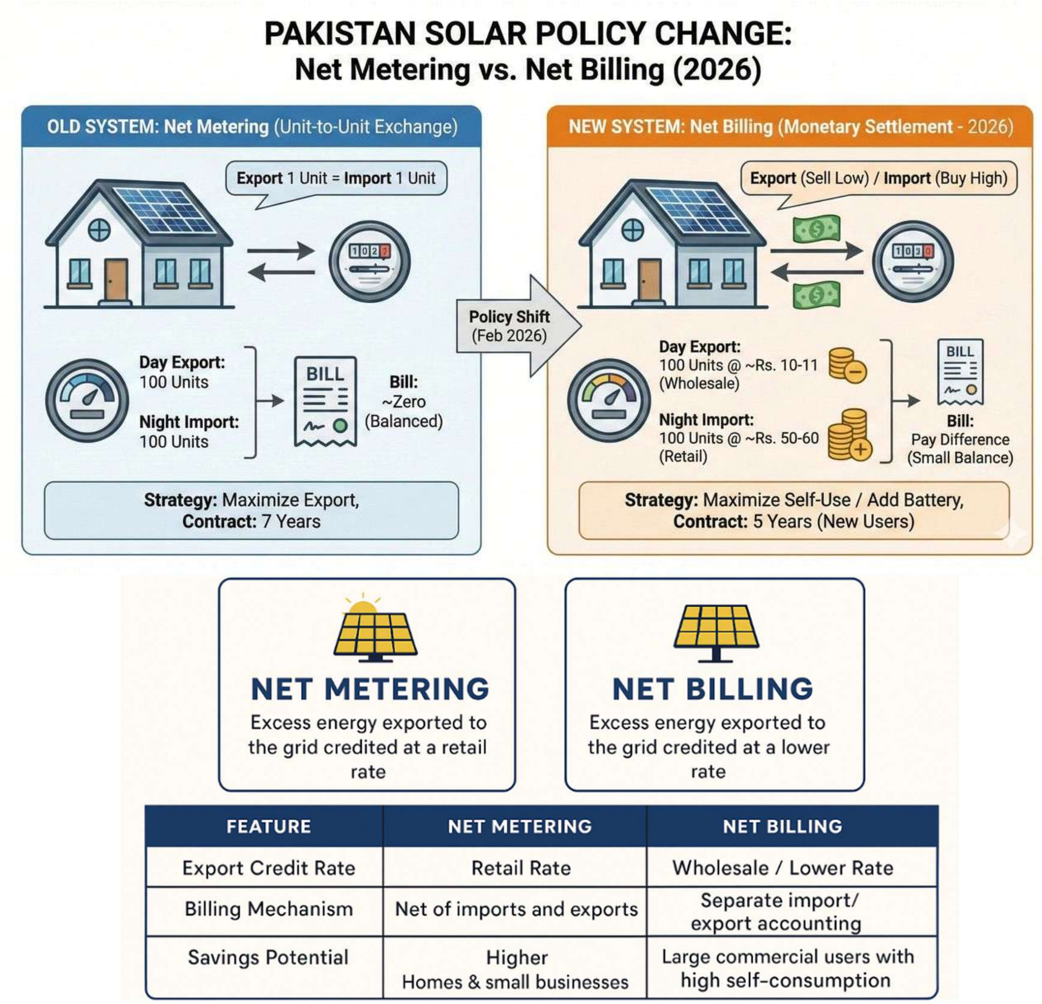


Figure 5: Net Metering vs. Net Billing (Mechanics)

Two concrete and critical commercial effects follow immediately. First, the per-unit monetary value that a prosumer receives for exported solar falls sharply compared with the earlier retail offset. Public reporting around the rule-making process reported export purchase prices discussed in the range of roughly **Rs. 8–13 per kWh** (variously reported as Rs.8–11 per unit), whereas many industrial retail slabs are in the **~Rs. 33–55/kWh** (inclusive of taxes and other fixed charges) band for on-peak imports; creating a large arbitrage gap between import and export settlement that directly reduces realized monthly savings for industrial users. Second, the settlement timing is constricted: carryover of export credits is limited (one month with quarterly payout rules), and contracts for new prosumers are standardized to five years (renewable by mutual consent), shortening the contractual prospect which many investors used when modelling payback and financing. These concrete mechanics have been the subject of extended media and industry concerns and backlash [34,35].

From an industrial perspective, these mechanics change three core investment drivers. The first is monthly cash flow: under net-metering a sizeable export during daylight produced an immediate reduction in the next bill (adjusted quarterly); under net-billing that same export produces only a modest wholesale receipt which has to be paid monthly and does not neutralize the immediate retail cost of imports. The second is the effective revenue scope: shorter contract lengths (five instead of seven years) reduce the net present value available to service debt and raise the perceived regulatory/contractual risk that lenders price into industrial financing. The third is system design flexibility: the new cap tying installed DG to sanctioned load (as discussed in Section 5) removes the simple technique of modest oversizing to increase daytime self-use without additional permitting; an important design lever used by many industrial buyers to lower effective LCOE and improve payback without storage. The combined effect is that many projects which looked profitable or economically viable under full retail offset now show materially longer paybacks or require added investment in storage to retain the same economics [22,25].

Metering and measurement have been upgraded accordingly. The Regulations require bidirectional meters or separate import/export meters with defined accuracy, testing and dispute procedures, and they prescribe the billing procedure; gross imports charged at retail less gross export credits at NAEPP, with the limited rollover and quarterly settlement rules clearly laid out in the rulebook. These metering changes remove the ambiguity inherent in single-balance arrangements and improve settlement integrity, but they also make monthly cash flows more volatile for prosumers who previously used rollover to smooth seasonality. Early public and industry comments have emphasized the need for rapid AMI rollout and clear meter replacement procedures so that disputes do not create additional financial strain during the transition [8,28].

Operational incentives change as well. With export credits low, prosumers' commercial interest shifts strongly toward maximizing on-site self-consumption (to avoid paying retail import rates) and toward investing in battery energy storage solutions (BESS), so that daytime solar can be time-shifted to higher-value evening periods. From a system POV, this is not bad per se; storage can help shave evening peaks; but it is capital-intensive. The obvious policy question is whether the regulator will reward storage services (dispatch payments, capacity credits or value of solar(VoS)/time of use (TOU) differentials), so that storage investments deliver both private return and public system value. Stakeholders and industry groups have called for VoS/TOU pilots and explicit BESS compensation to be run ahead of full NB rollout so that prosumers can see a credible route to recover added storage costs [1,39].

Finally, the regulatory and strategic context matters to industry above bills only. Export remuneration/compensation levels interact with corporate decarbonization strategies and trade compliance (e.g., buyers asking for verifiable Scope-2 reductions). If exported energy is credited only at a low wholesale price and if accounting rules for on-site generation and documented imports/exports are unclear, firms face the dual risk of higher net energy costs plus weaker green credentials simultaneously; a materially adverse outcome for export-facing sectors such as textiles. Industry submissions to the public hearing therefore emphasized clarifications on carbon accounting treatment, explicit grandfathering provisions and transparent sensitivity modelling by planning bodies to show DISCO revenue impacts before permanent changes are made.

In summary, the shift from net-metering to net-billing is a structural change: it replaces a symmetric energy offset with asymmetric buy/sell economics, shortens contractual horizons, constricts metering and capacity rules, and alters operational incentives toward self-consumption and storage. For industrial prosumers this means lower monthly cash relief, longer paybacks unless time/locational value or storage revenues are available, and greater financing and planning uncertainty unless regulators pair net-billing with targeted, pro-investment measures (dynamic credits, BESS recognition and aggregation/VPP access). In short: the shift to net-billing is technically simple and straightforward but commercially transformative; regulators can preserve most industrial value by pairing NB with time/duration-sensitive export credits, storage compensation, aggregation pathways (VPP/P2P pilots) and clear rules for carbon accounting.

5. Sanctioned Load and Export Limits

The *Prosumer Regulations, 2026* tie permitted solar capacity directly to a consumer's sanctioned load: installed distributed generation may not exceed **100% of sanctioned load**, replacing the earlier informal practice that frequently allowed installations up to ~150% of sanctioned load. This change is enforced during the interconnection approval process, where licensees review proposed system design against the sanctioned-load record and may require written permission from **NEPRA** for any capacity beyond the sanctioned level. The stated intent is simple; to limit oversized installations that could cause local protection, voltage and transformer loading issues; but the practical effect is to compress the design space for industrial prosumers who had used modest oversizing as a low-cost method to raise daytime self-consumption and improve project economics [40].

From a technical perspective, sanctioned-load caps interact with two important grid realities. First, **hosting capacity** at transformer and feeder level is a local, measurable limit: beyond a point additional exports may cause reverse power flow, voltage excursions, or thermal stress. Second, many existing distribution protection and control schemes were designed for one-way flows; sudden high reverse flows from rooftop PV systems reveal weaknesses in protection coordination. Regulators and DISCOs therefore argue that restricting installed capacity simplifies operational risk management. Internationally, however, system planners increasingly prefer targeted technical mitigations; advanced inverter settings (volt/VAR, active export control), phase rebalancing, staged reinforcements and a published Hosting Capacity Analysis (HCA); over blunt, system-wide caps because the latter can block technically viable projects and waste private capital. The experience reported in highly penetrated Pakistani hubs (where rooftop solar can exceed local daytime demand) gives observable examples of both phenomena and explains the regulatory caution [22,25].

Policy and economic consequences follow directly. Limiting installation to sanctioned load reduces the daytime export potential of a site and therefore the ability to produce surplus for either retail offset or wholesale sale. For industrial plants which previously relied on oversizing to maximize daytime self-use (for multi-shift operations or daytime-heavy processes), the cap raises effective LCOE and extends payback unless compensating measures (e.g., storage) are deployed. Because NEPRA retains discretion to approve oversize in exceptional cases, the practical pathway to additional capacity is administratively burdensome and uncertain, a constraint for investment. Stakeholders therefore recommend that sanctioned-load constraints be treated as a **last-resort** mitigation, applied only after licensees publish HCA results and have attempted calibrated, lower-cost responses (export setpoints, temporary curtailment windows, targeted transformer upgrades) which preserve project value while addressing safety concerns [8,40]. **Figure 6** shows the technical constraints imposed by Prosumer Regulations on solar systems.

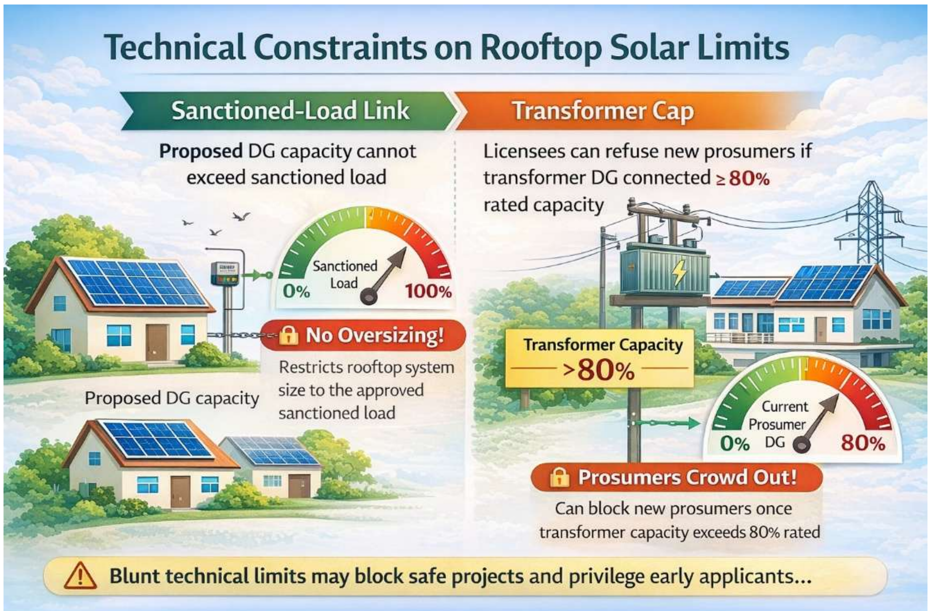


Figure 6: Technical Constraints put forth by Prosumer Regulations 2026

Finally, the sanctioned-load rule shifts the commercial dynamics for system designers. Where oversizing was a low-cost lever to increase yield, the capped envelope makes storage or load-shifting the primary tools for capturing daytime value, at higher capital cost. This encourages two outcomes:

(a) Well-capitalized industrials will add BESS and advanced controls to recover value, and
(b) Smaller firms with tighter capital constraints may defer or abandon projects or attempt informal dispatch workarounds.

Both outcomes matter for system planners: the former delivers useful system services (if compensated), the latter fragments visibility into distributed assets. For these reasons, it should be argued that sanctioned-load limits must be paired with transparent HCA publication, a defined mitigation framework, and a clear, fast administrative pathway for justified oversize approvals [41].

6. Billing, Settlement & Tariff Implications for Industrial Prosumers

Under the new net-billing settlement a prosumer's grid imports are billed at the applicable retail tariff (including time-of-use components), while exports are monetized separately at the **NAEPP.** In reporting by regulatory bodies, the practical effect has been described as a large price spread: many industrial TOU retail rates fall in the **~Rs.37–55/kWh** range for peak imports, whereas the NAEPP used to credit exports is widely reported in the **~Rs.8–11/kWh** band in the new rules; a gap which dramatically reduces the per-unit value a prosumer receives for exports and hence monthly cash relief compared with unit-for-unit netting. This asymmetric settlement is the principal driver of the longer paybacks and lower IRRs as observe for industrial cases under the NB regime (**Section 8**) [24,25].

The Regulations also squeeze the temporal mechanics of settlement. Where legacy net-metering often allowed multi-month rollovers and direct unit offsets that smoothed seasonal and intra-monthly intermittency, net-billing limits this to **one month** (with quarterly cash-out or adjustment for net export balances). Combined with the shortened standard contract length (five years for new agreements versus seven previously), this increases revenue volatility for solar projects and reduces the guaranteed prospect used by lenders for debt service calculations. The upshot is higher financing costs and a higher effective hurdle rate for industrial investments unless alternative value streams (time-differentiated export credits, storage dispatch payments, or aggregation revenues) are explicitly made available [8]. **Figure 7** shows the tariff settlement mechanism under old and new prosumer regulations (PR).

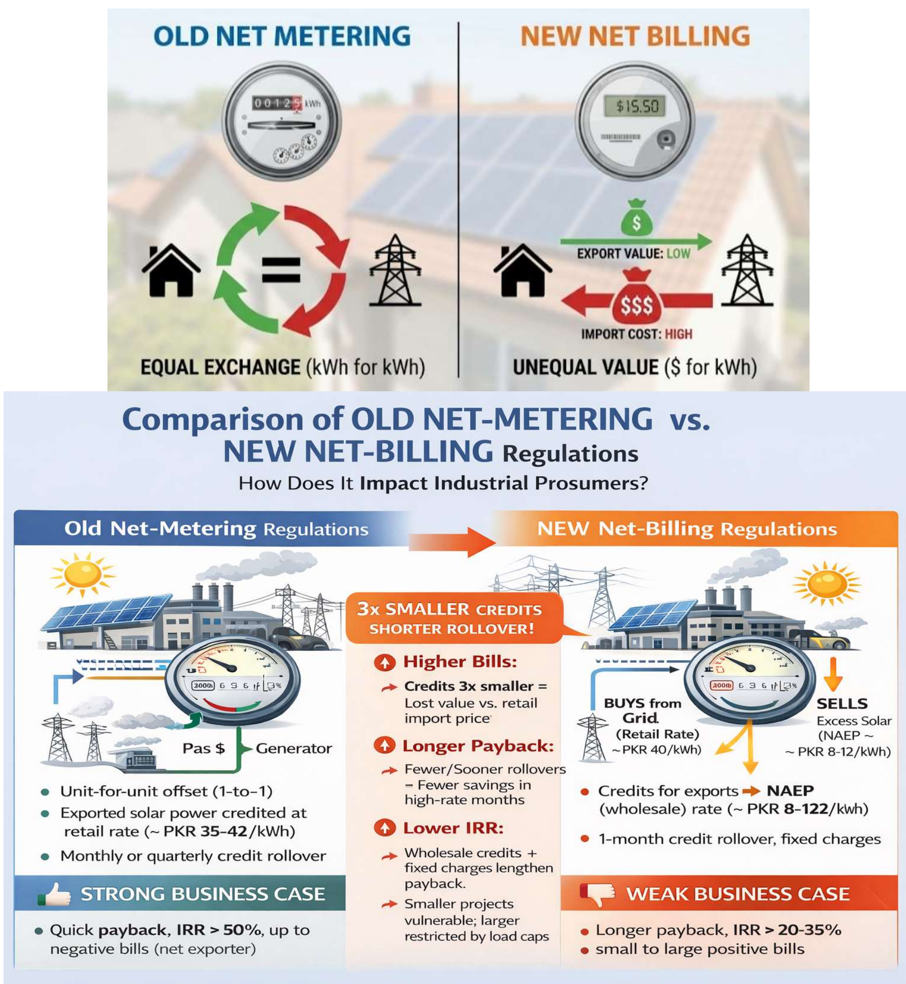


Figure 7*:* Tariff settlement mechanism and likely impact on industrial prosumers

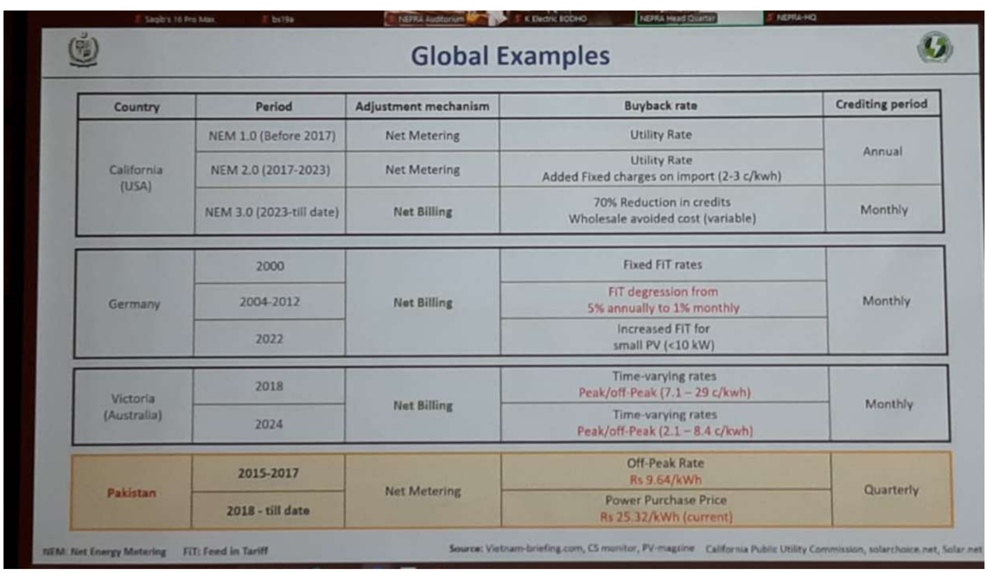
Quantitatively, the reduced export credit raises levelized costs as realized export revenue falls even if technical LCOE remains low. Recent sector modelling (**Section 8** in this report) for representative large industrial sites finds LCOE rising materially when export values are paid at wholesale NAEP rather than retail offset; a change that turns quick 2–3 year paybacks into multi-year returns (4+ years in many NB scenarios). For industrial prosumers, monthly cash-flow effects are as important as lifetime LCOE: under net-metering a prosumer could rely on consistent monthly offsets that substantially reduce monthly bills; under net-billing the same system converts much of that benefit into modest, often quarterly, wholesale receipts; less useful for working capital. This shift incentivizes real-time self-consumption and storage, but those responses carry additional capital and operational costs [40,42].

7. NEPRA Public Hearing: Overview and Response

On 6th February 2026, a public hearing convened by the regulator (i.e. NEPRA) drew a broad cast of participants: government ministries, the Power Division, planning and market bodies, distribution companies, industry groups, consumer advocates and many prosumers. The regulator and the planning office presented modelling and operational data to justify the move to net-billing, most prominently pointing to very rapid rooftop growth and emerging operational stress in several distribution hubs. Officials highlighted aggregated figures showing that on-grid rooftop capacity has grown from negligible levels in 2017 to multi-GW by 2024–25, and that off-grid/hybrid solar capacity is also large and rapidly rising; a scale shift that, they argued, changes the distribution of costs and operational risk across the power system [7].

7.1. Narrative build-up by regulatory bodies and industrial responses

Figures 8-12 show the narrative build-up by regulators in policy change context.



Country	Period	Adjustment mechanism	Buyback rate	Crediting period
California (USA)	NEM 1.0 (Before 2017)	Net Metering	Utility Rate	Annual
	NEM 2.0 (2017-2023)	Net Metering	Utility Rate Added Fixed charges on import (2-3 c/kwh)	
	NEM 3.0 (2023-till date)	Net Billing	70% Reduction in credits Wholesale avoided cost (variable)	Monthly
Germany	2000	Net Billing	Fixed FiT rates	Monthly
	2004-2012		FiT degression from 5% annually to 1% monthly	
	2022		Increased FiT for small PV (<10 kW)	
Victoria (Australia)	2018	Net Billing	Time-varying rates Peak/off-Peak (7.1 – 29 c/kwh)	Monthly
	2024		Time-varying rates Peak/off-Peak (2.1 – 8.4 c/kwh)	
Pakistan	2015-2017	Net Metering	Off-Peak Rate Rs 9.64/kWh	Quarterly
	2018 - till date		Power Purchase Price Rs 25.32/kWh (current)	

NEM: Net Energy Metering   FiT: Feed in Tariff   Source: Vietnam-briefing.com, CS monitor, PV-magzine California Public Utility Commission, solarchoice.net, Solar.net

Figure 8: Global Examples shown by PPMC as an argument for shifting during public hearing

The Power Planning & Monitoring Company (PPMC) and other presenters representing regulatory body (NEPRA) and DISCOs laid out two inter-linked concerns. First, very high daytime solar injections are altering net demand shapes (large midday troughs and steep evening ramps) and in some feeders are approaching or exceeding local daytime demand, producing voltage excursions and localized protection incidents that require technical mitigation. Second, the tariff structure is highly front-loaded with fixed obligations (capacity payments and other fixed costs), so falling volumetric sales; driven in part by prosumer self-consumption and export; mean those fixed costs must be recovered from a shrinking kWh base, increasing cross-subsidy pressure on non-solar consumers. Regulators quantified the alleged transfer from net-metered users to others in per-kWh terms and aggregate rupee figures during the hearing, and argued that a net-billing settlement would reduce that transfer immediately while allowing time for longer-term structural reforms [43,44].

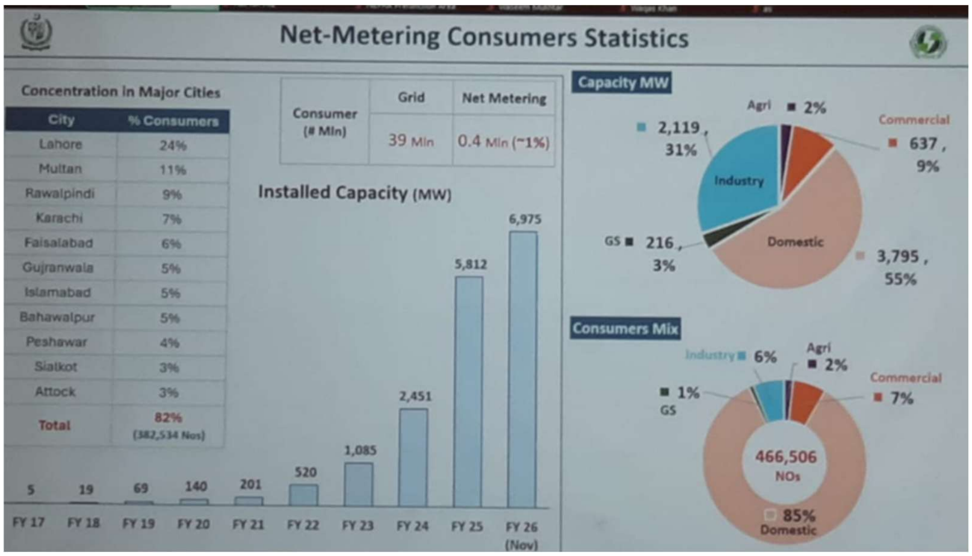
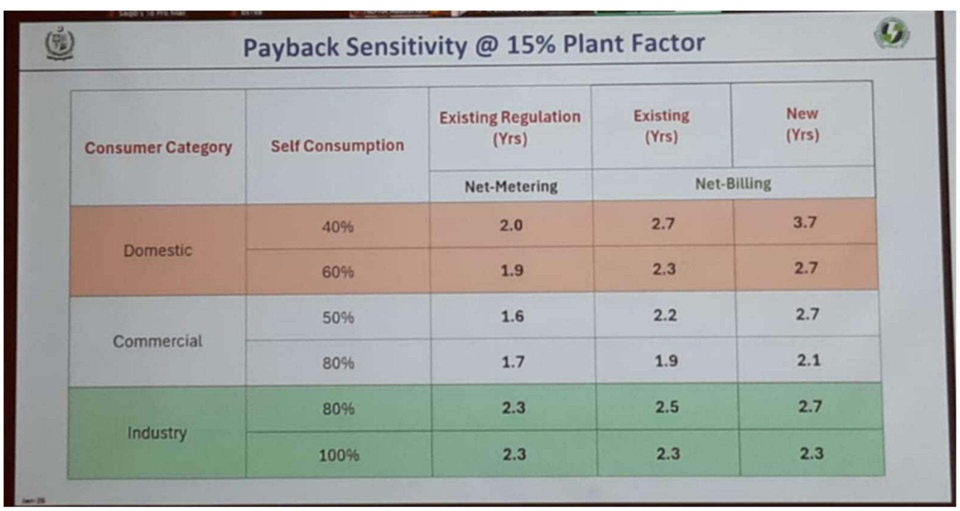


Figure 9: Net-Metering consumer statistics shown by PPMC during public hearing



Payback Sensitivity @ 15% Plant Factor

Consumer Category	Self Consumption	Existing Regulation (Yrs)	Existing (Yrs)	New (Yrs)
		Net-Metering	Net-Billing	
Domestic	40%	2.0	2.7	3.7
	60%	1.9	2.3	2.7
Commercial	50%	1.6	2.2	2.7
	80%	1.7	1.9	2.1
Industry	80%	2.3	2.5	2.7
	100%	2.3	2.3	2.3

Figure 10: Results of Modeling Impact Analysis of Policy shift shown by PPMC during public hearing

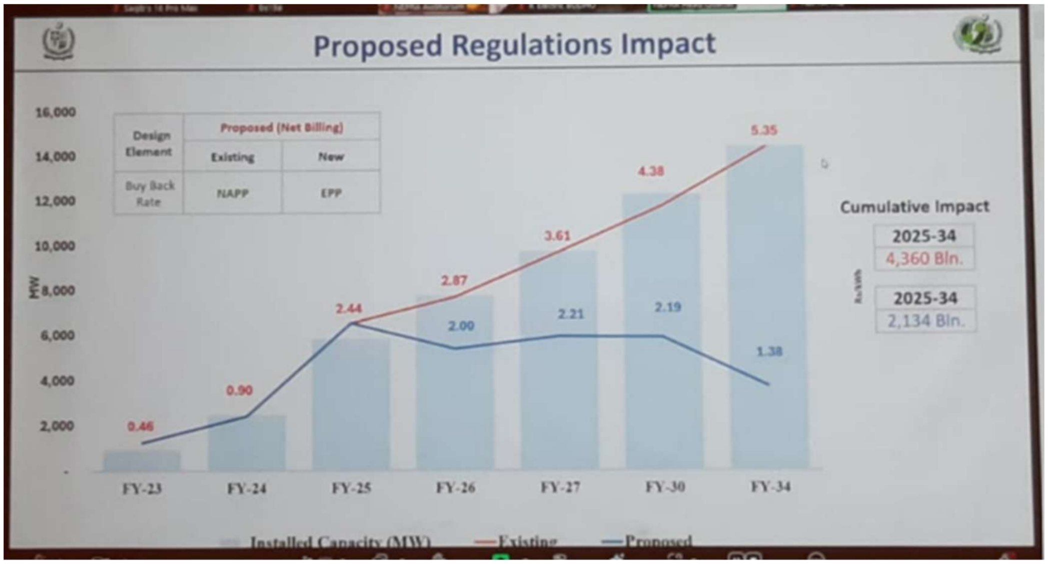


Figure 11: Argument put forth by PPMC during public hearing showing solar prosumers putting extra tariff burden on non-solar consumers

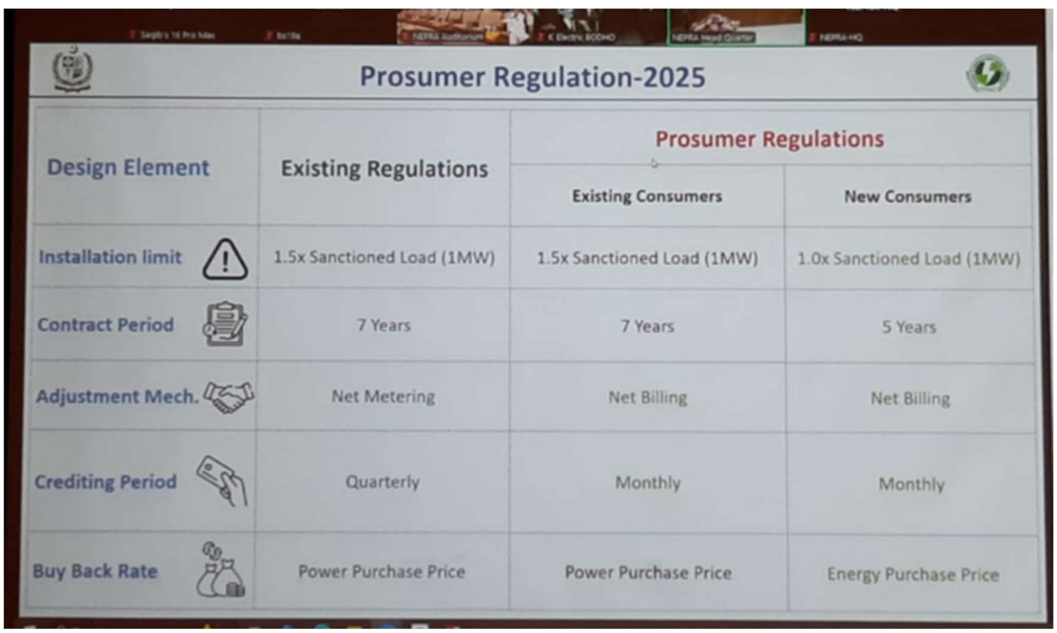


Figure 12: Effect of PR on Prosumers; regulatory and technical scenario (though existing prosumers are fully protected under new amendment)

Industry and trade groups mounted a vigorous rebuttal. Representatives from the private sector; including the Karachi Chamber of Commerce & Industry (KCCI) and textile exporters; questioned the data, demanded independent verification, and argued that sudden changes risked stranded investment and competitiveness impacts. In public statements, KCCI speakers pointed out that distribution companies (and some urban utilities) sell final power at high retail tariffs while purchasing bulk solar at much lower wholesale rates; they warned that penalizing net-metering would simply accelerate behind-the-meter battery deployment and off-grid solutions, shifting foreign-exchange pressure to imports of batteries and inverters. These industry witnesses pressed for more transparent modelling and for transitional measures to protect investors who made decisions under the earlier rules [45,46].

Political responses were immediate and polarized. The parliamentarians present in the hearing described the move as unfair to citizens who had followed government policy and invested accordingly; some lawmakers used strong language, calling the change "daylight robbery" and urging government intervention to protect existing contracts. In parallel, members of the ruling coalition and some regulators argued the reforms were designed to protect the wider consumer base and the financial health of DISCOs. The political pressure quickly produced executive-level engagement: the Prime Minister's office instructed the Power Division to seek a formal review and to ensure protection for existing net-metering contracts while the regulatory process proceeds [47,48].

Technical experts and think tanks offered more nuanced critiques. Several submissions asked for an independent, peer-reviewed Value-of-Solar (VoS) or Time-of-Use (TOU) study before permanently fixing export purchase rates, arguing that a flat national average purchase price understates the locational and temporal value (or disvalue) of exported solar. Academics and system operators urged a staged approach: publish transformer-level Hosting Capacity Analyses (HCA), mandate inverter export controls and phase rebalancing as first-order mitigations and only use caps or refusals where technical fixes are exhausted. Experts also recommend explicitly recognizing hybrid PV+BESS configurations and pilot time-differentiated buyback schemes so that storage can be remunerated for the system services it provides. These requests framed the hearing's technical agenda: the choice is not binary between "protect DISCOs" and "protect prosumers" but about sequencing measures and ensuring transparent, evidence-based trade-offs Pakistan Distributed solar [2,41].

Economic arguments at the hearing centred on the size and incidence of the alleged cross-subsidy. Regulators presented per-kWh figures and aggregate rupee impacts; industry and some independent analysts questioned the assumptions (including load elasticity, displacement effects, and the treatment of capacity payments) and asked for scenario sensitivity runs from **PPMC** and the market operator **ISMO**. Stakeholders requested published modelling that disaggregates regional impacts, shows the effect of dynamic export pricing, and quantifies how BESS deployment would alter both DISCO revenue needs and system operational metrics. In response, NEPRA opened a formal 15-day comment period on proposed amendments (at 17th Feb 2026, grandfathering existing contracts) and said it would consider targeted clauses and additional data publication [46,49].

A pragmatic outcome of the hearing was immediate policy caution: the executive and regulator signaled a willingness to pause full implementation and to refine rules in response to credible data and stakeholder input. That included short-term protections for previously registered net-metering applicants and a commitment by the Power Division to coordinate with NEPRA on transitional arrangements, while asking PPMC and ISMO to make cross-subsidy and tariff-impact analyses public. The public debate ensured the political and technical dimensions remained visible and allowed stakeholders to press for explicit VoS/TOU pilots, clearer grandfathering protections and rapid publication of HCA data.

7.2. Contradictory Elements and Anti-Narrative

NEPRA/PPMC framed the story at the hearing as a simple accounting problem; a small share of net-metered users (hundreds of thousands) is allegedly "burdenizing" non-solar consumers by ~PKR 2–3/ kWh; thereby justifying reduced export credits. While rooftop solar does change volumetric electricity sales, attributing rising tariffs primarily to net-metering relies on several contestable assumptions. Electricity tariffs in Pakistan are shaped by multiple structural drivers including capacity payments, tariff design, fuel-cost adjustments, transmission and distribution losses, and circular-debt recovery mechanisms. Consequently, the regulator's main figures depend heavily on assumptions about rollover treatment, the valuation of exports relative to retail tariffs, and the counterfactual evolution of DISCO costs if rooftop solar had not expanded. Treating net-metering as the dominant driver of cross-subsidy risks oversimplifying the sector's cost structure and may produce counterproductive outcomes; for instance, significantly reducing export credits could accelerate behind-the-meter storage adoption and partial or full grid defection, ultimately reducing grid visibility and planning efficiency.

A particularly important structural factor is the **capacity-payment burden embedded in Pakistan's tariff structure**, which stems from long-term take-or-pay contracts with independent power producers (IPPs). Capacity charges have grown substantially in recent years and now constitute a major share of electricity tariffs; in some recent years the *capacity purchase component has approached roughly 40–60% of the consumer tariff*, reflecting large, fixed obligations that must be paid regardless of actual electricity generation or demand [50,51]. In FY2024-25 alone, projected capacity payments exceeded *PKR 2 trillion*, highlighting the scale of fixed system costs embedded in electricity pricing [52]. When grid consumption declines due to rooftop solar or efficiency improvements, these fixed costs must be recovered from a smaller base of consumers, creating political pressure to modify export compensation mechanisms even though the underlying driver lies in contractual and tariff design structures rather than distributed solar alone Another structural constraint is **grid infrastructure and operational capability**. Pakistan's distribution network faces persistent challenges including ageing transformers, high T&D losses (`17-18% in FY24-25), limited advanced metering infrastructure (AMI), and slow investment cycles within DISCOs. These conditions mean hosting-capacity constraints are often local; at the feeder or transformer level; rather than system-wide [53]. Without targeted hosting-capacity analysis, smart inverter standards, export-control mechanisms, and staged grid upgrades, regulators tend to rely on blunt policy tools such as export caps or reduced compensation rates. Such measures may protect short-term utility revenues but risk slowing distributed energy deployment and discouraging industrial decarbonization investments. **Figure 13** shows the counter-narrative against regulator's core motive behind policy change.

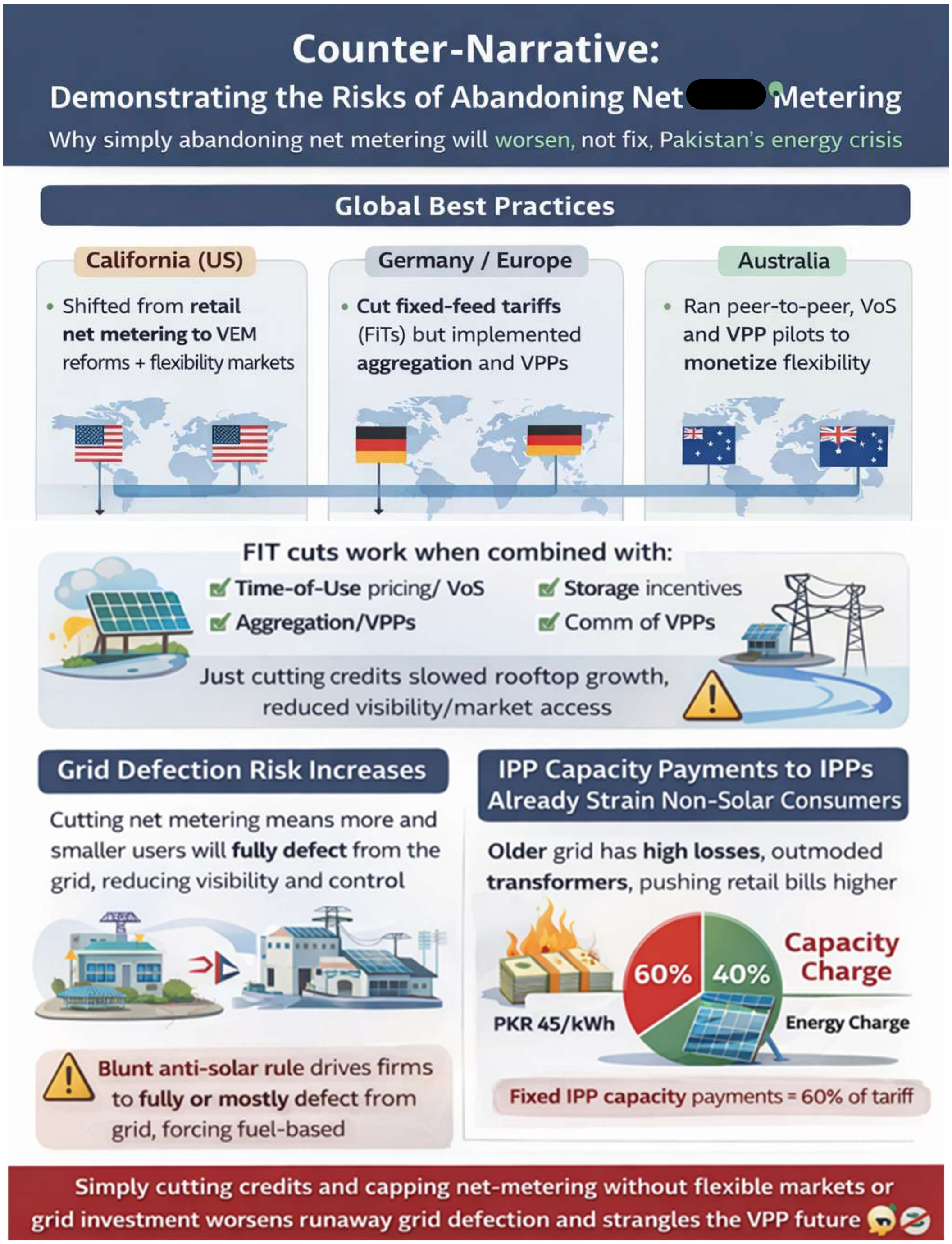


Figure 13: Anti-Narrative to NEPRA/PPMC arguments against Prosumer Regulations 2026

The global lesson is clear and directly relevant: jurisdictions that successfully rebalanced export payments did not simply cut buyback rates; they simultaneously created alternative value streams and market access. For example, **California's transition from retail net-metering to the Net Billing Tariff (NEM 3.0)** reduced export credits by roughly 70–75% and linked compensation to avoided grid costs and time-of-use signals, while simultaneously encouraging storage adoption and flexible consumption patterns [54]. Similarly, **Australia has introduced "two-way tariffs" for distributed solar**, where export compensation varies by time of day and customers may receive higher payments for evening exports while midday exports face lower or even negative prices in order to manage grid congestion and incentivize storage and demand shifting [55,56]. In Europe, several countries including Germany and the Netherlands have gradually reduced feed-in tariffs while developing market-based remuneration, aggregation frameworks, and virtual power plant (VPP) models to integrate distributed energy resources into electricity markets. Likewise, P2P and VPP pilots elsewhere (e.g., Australia, ARENA/Power Ledger pilots) show local value capture can preserve small prosumer economics when settlement, metering and market rules exist [57]**.** In short, an evidence-based alternative path is to commission an independent, transparent PPMC/ISMO sensitivity study, run VoS/TOU + BESS + aggregation pilots, mandate AMI for new >10 kW prosumers, and only then phase any export reforms, while grandfathering committed projects (which was ultimately safeguarded). That sequence protects DISCO finances without killing the investment case for medium and small industry, preserves grid visibility, and aligns Pakistan's policy with international best practice [58].

8. Case Study: Implications on Prosumer regulations on Industrial Sector

This case study quantifies how Pakistan's shift from unit-for-unit **net-metering** to a **net-billing** settlement (and a range of related rule changes) affects industrial prosumers of different scale. Three representative industrial classes are utilized in this study; **Large mills**, **medium mills / aggregated SME dispatch**, and **Small mills**; and for each class, three demand states (Low, Actual, High) are analyzed to capture seasonal/operational variability and the sensitivity of project economics to utilization.

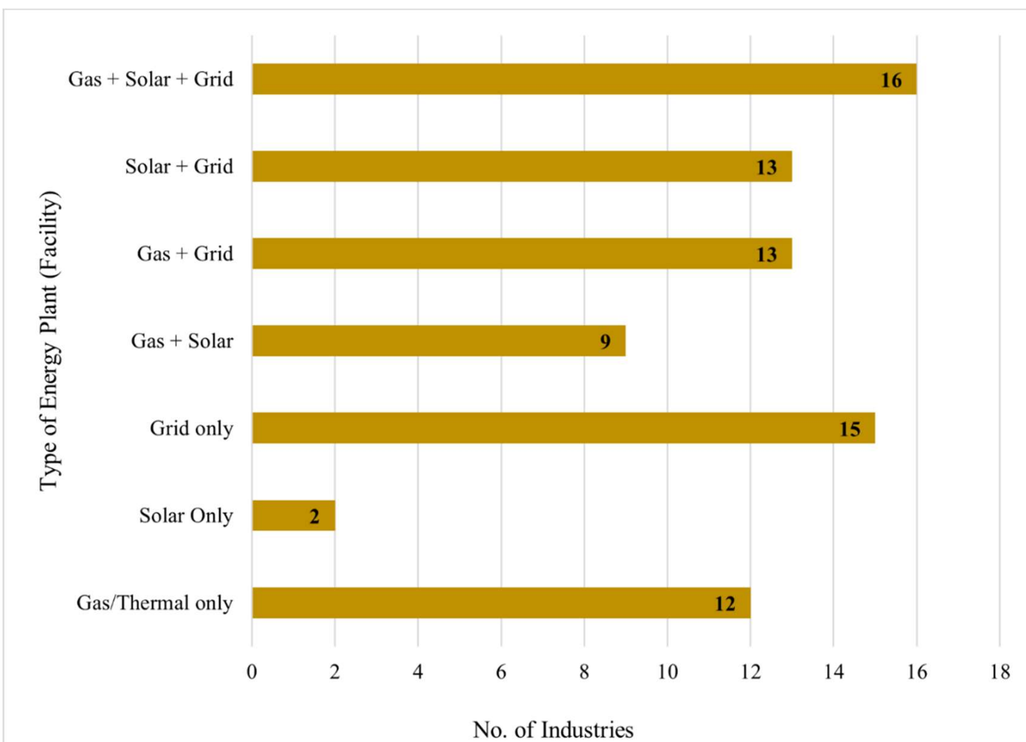


Figure 14: Comparative energy mix profile of Sample Textile industries (from previous study)

The inputs are taken from previous solar mapping study across textile hubs of Faisalabad and Multan. Across data of **80 textile mills** is targeted (50 Faisalabad, 30 Multan) mapped; **62.8 %** rely on captive thermal generation (gas/coal/oil) as primary source as shown in **Figure 14**. The dominance of captive thermal units underscores the urgent need for cleaner alternatives. However, nearly one in three mills has taken the first step into solar, and grid-tied configurations are growing as reliability improves.

In next sections, it is explained that what inputs are used, which scenario cases are run and why, and what is the main aim to measure. A detailed input-parameter table (for modeling assumptions) is also presented as follows.

8.1. What is modeled and why?

Purpose: The analysis isolates how settlement rules, demand level, sanctioned-load ceilings, self-consumption behaviour and battery adoption change five core project outcomes: **IRR**, **ROI**, **simple payback**, **LCOE** and **annual electricity bill**. These metrics together show both lifetime value (LCOE, IRR, ROI) and near-term cash-flow impacts (annual bill, payback), which matter to industrial decision makers and lenders.

Representative industrial classes: Below are chosen because they reflect different technical/financial profiles and policy exposure:

- **Large mills:** high absolute energy demand, can install large PV arrays and (sometimes) battery fleets; sensitive to single-site net-metering ceilings and sanctioned-load rules.
    - Demand: Low = 8,500 kWh/day; Actual = **10,500 kWh/day**; High = 12,500 kWh/day.
    - Typical system: 2,700 kW.
- **Medium mills / pooled SMEs:** the "sweet spot"; enough scale to get good unit economics, but able to use aggregation or pooled dispatch to avoid single-site ceilings.
    - Demand: Low = 3,000 kWh/day; Actual = **4,200 kWh/day**; High = 4,800 kWh/day.
    - Typical system: 1,000 kW.
- **Small mills:** many are capital constrained, single-phase or single-site, and most exposed to fixed charges and capped sanctioned loads.
    - Demand: Low = 250 kWh/day; Actual = **380 kWh/day**; High = 450 kWh/day.
    - Typical system: 80 kW.

Demand levels are chosen to represent realistic operational ranges (low = off-season or reduced production; actual = typical operating level; high = high production/peak season). Comparing these three states isolates how seasonality or growth in production alters project bankability or financial viability.

Scenarios (cases) analyzed: Each case is intended to reflect a policy or operational regime that was either proposed, discussed during the NEPRA hearing, or is a natural technical variant:

1. **Net-Billing (NB) – Nominal (New Regulated scenario)**: new prosumers credited at NAEP (flat wholesale), imports at retail. One-month rollover. (This is the core regulator proposal.)
2. **Net-Metering (NM) – Nominal (Old Scenario)**: legacy 1:1 retail offset model (unit-for-unit), quarterly carryover.
3. **NM (higher retail tariffs)**: net-metering but with higher retail import tariffs (tests tariff shock).
4. **NB (higher retail tariffs)**: net-billing with higher retail import prices.
5. **NB (sanctioned-load cap)**: NB combined with a cap on installed DG tied to sanctioned load (250 kW for large/medium; 20 kW for small).
6. **NM (sanctioned cap)**: net-metering but with the same sanctioned cap (tests cap effect under NM).
7. **NM (low self-consumption / high time-of-use (TOU; on-peak))**: customer exports a large share of generation; high on-peak import share for loads (worst for NB).
8. **NB (low self-consumption / high TOU on-peak)**: NB variant for exported-heavy prosumers — typically poor economics.
9. **NB (high self-consumption / low TOU on-peak)**: high on-site use of generation (best NB outcome).
10. **NM (high self-consumption / low TOU on-peak)**: NM with load profiles that consume most generation on site.
11. **NM + Battery**: NM case with BESS added to shift daytime generation to evening/high value hours.
12. **NB + Battery (+ fixed charges)**: NB with BESS and inclusion of explicit fixed network recovery charge (tests worst-case of NB + fixed charges).

These are shown in **Table 1** below:

Table 1: Cases Analyzed Matrix Design

Case	Metering mechanism	Scenario applicability
1. Net-Billing – Nominal	Net-Billing (bidirectional metering)	All sizes (new regulated NB regime); baseline regulator proposal
2. Net-Metering – Nominal	Net-Metering (1:1 retail offset)	Existing/legacy NM contracts (all sizes within previous NM limits; common reference case)
3. NM – Higher retail tariffs	Net-Metering	NM under tariff shock; mainly industrial (medium/large) sensitivity case

4. NB –Higher retail tariffs	Net-Billing	NB under tariff shock; primarily affects industrial consumers
5. NB + sanctioned-load cap	Net-Billing + capacity cap (sanctioned load)	All sizes with cap enforced (Large & Medium cap = 250 kW; Small cap = 20 kW)
6. NM + sanctioned-cap	Net-Metering + capacity cap	Tests impact of sanctioned caps under NM (all sizes)
7. NM – Low self-consumption / high TOU (on-peak)	Net-Metering	Export-heavy customers / high on-peak import share (worst NM export timing)
8. NB – Low self-consumption / high TOU (on-peak)	Net-Billing	Export-heavy customers under NB (typically poor economics; all sizes)
9. NB – High self-consumption / low TOU (on-peak)	Net-Billing	High on-site consumption profile (best NB outcome; medium/large most relevant)
10. NM – High self-consumption / low TOU	Net-Metering	NM with load profiles consuming most generation on site (favorable)
11. NM + Battery	Net-Metering + BESS	NM with storage (shifts value to peak hours; medium/large and aggregations)
12. NB + Battery + fixed charges	Net-Billing + BESS + explicit fixed recovery charge	Worst-case NB + fixed-charge test (shows impact on small adopters; all sizes)

Why these cases? Together they reproduce the policy levers under discussion (export credit level, carryover window, sanctioned caps, time of use (TOU) variation, and storage) and show which design choices most affect project economic viability/profitability and system outcomes.

What is measured? For each class × demand level × case, following parameters are computed:

- Levelized Cost of Energy (LCOE, PKR/kWh),
- Annual electricity bill (PKR/yr, with sign showing net payment or net receipt),
- Financial metrics: Net Present Value (NPV), Internal Rate of Return (IRR), Return on Investment (ROI), and simple payback (years).

These combined metrics show whether projects are attractive to industry (IRR/ROI), whether they improve monthly cash flow (annual bill), and how quickly capital is recovered (payback).

8.2. Input parameters for Modeling Analysis

Table 2 below lists the core technical and financial parameters used consistently across the cases (unless a scenario explicitly overrides a parameter). Values are chosen to reflect the industrial context (Pakistan) used throughout the analysis.

Table 2: Input parameters for modeled scenarios for comprehensive technoeconomic analysis under various scenarios

Parameter	Value	Source
PV CAPEX (installed, excl. inverter)	PKR 79,240 / kW	Database 2025 / Feasibility Studies [59]
Inverter cost (assumed)	$156 / kW	Database 2025 [60]
PV O&M (model assumption)	1.0% of PV CAPEX / year	Modelling assumption
O&M Cost (industry survey)	2.5% of CAPEX	Industry Surveys (Faisalabad) [61]
Land & Miscellaneous Costs	10% of CAPEX	Assumed
Project lifetime	25 years	Standard assumption
Discount rate / real WACC (used in NPV modelling)	10% nominal	Modelling assumption
Discount rate (standard reference)	11%	Standard discount rate for current year [62]
Inflation Rate	3.20%	Macroeconomic reference / Standard inflation rate for current year [63,64]
Degradation rate	0.5% / year	Modelling assumption
System performance ratio (PR) / system losses	0.78 (≈22% losses)	Modelling assumption
DC:AC ratio	1.15 – 1.25 (typical 1.2)	Modelling assumption
Typical annual yield / used to convert kW → kWh	Input by system & location (daily profiles)	Case inputs / site profiles
Capacity factor (approx.)	~15–18%	Implied by yields used
Baseline grid LCOE (approx.)	PKR 44 – 47 / kWh	User input / modelling baseline
Normal on-peak tariff (modelling)	PKR 42.00 / kWh	Average FESCO 2026 tariffs (User Input) [4,65]
Normal off-peak tariff (modelling)	PKR 33.60 / kWh	Average FESCO 2026 tariffs (User input)
Higher on-peak tariff (stress case)	PKR 56.00 / kWh	Average FESCO 2026 tariffs (User input)

Higher off-peak tariff (stress case)	PKR 42.00 / kWh	Average FESCO 2026 tariffs (User input)
Export credit (NAEP / modelling default)	PKR 11.00 / kWh	NEPRA proposed reduced tariff [66]
Sanctioned export cap (assumed)	Large & Medium: 250 kW; Small: 20 kW	User input
System sizes (typical used in cases)	Large: 2,700 kW; Medium: 1,000 kW; Small: 80 kW	User input
Sensitivities performed	Retail tariffs, sanctioned caps, demand level	Modelling plan
Inverter / export control option	Export limit = inverter rating or setpoint	Modelling assumption
Grid losses (in NM/NB cases)	15%	Assumed for NM/NB modelling
Tax rates	10%	Fiscal assumption
BESS assumptions (Cases 11/12)	Round-trip efficiency 90%; life 15 years; O&M 2% / year of BESS CAPEX	Modelling assumption
Self-consumption profiles	Low SC ≈ 36% ; High SC ≈ 68%	Scenario inputs

Notes on assumptions and provenance:

- Export credit (NAEP) was modelled at PKR 11/kWh for the nominal NB case with sensitivity runs at PKR 8–18 to reproduce discussion ranges from the hearing and earlier tables.
- The performance ratio, degradation and lifetime assumptions are standard practice for utility/industrial PV financial models and were applied consistently across various cases so differences reflect demand, settlement and design choices, not modelling artefacts.

8.3. What is intended to analyze (outputs)

Using these inputs and scenarios for each class × demand level × case, following outputs are produced:

- *Technical outputs*: expected annual generation, energy purchased from grid, energy sold to grid, effective export volumes under sanctioned caps or export setpoints.
- *Economic outputs*: LCOE (PKR/kWh), annual electricity bill (PKR/yr), NPV, IRR, ROI, and simple payback.
- *Comparative policy insight*: identify the parameter sensitivities (which inputs move IRR / payback the most), the classes most exposed to policy change, and policy levers (VoS/TOU, BESS compensation, aggregation, HCA) that restore bankability while protecting DISCO revenues.

8.4. Results & discussion

The quantitative patterns from results are synthesized and practical, policy-relevant conclusions are drawn below. It is also examined how the three demand levels (Low → Actual → High) affect each mill class across the five metrics (IRR, ROI, simple payback, LCOE, annual bill), and then the effects of the **sanctioned-load cap**, **low vs high self-consumption**, and **battery (BESS)** options is discussed. A short vulnerability ranking and operational recommendations are also given.

8.4.1. Comprehensive pattern analysis & policy interpretation for Actual Demand Case

The results are presented in **Figure 15**, **Figure 16** and **Figure 17** (Actual Demand scenarios):

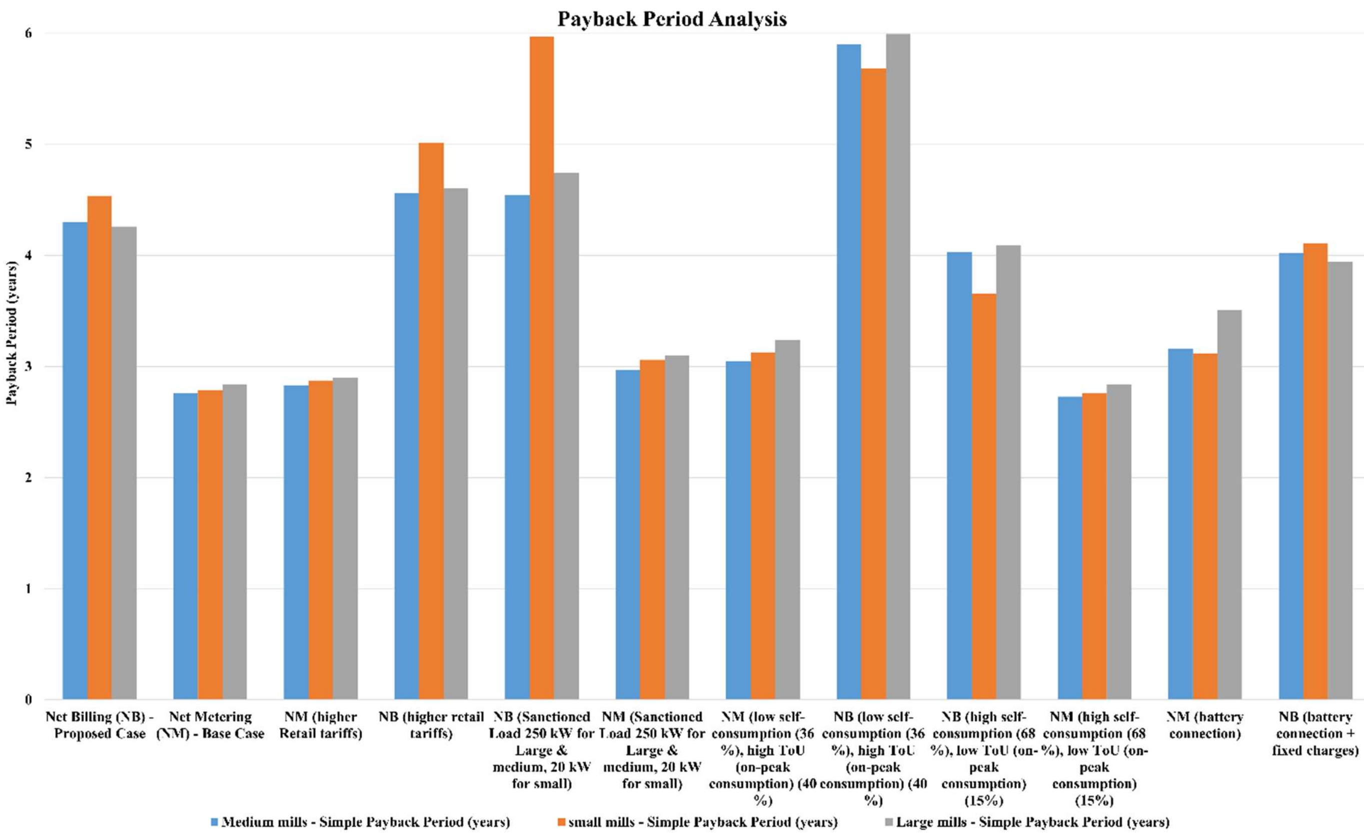


Figure 15: Actual Demand Scenario: Payback Analysis of Modeled Scenarios

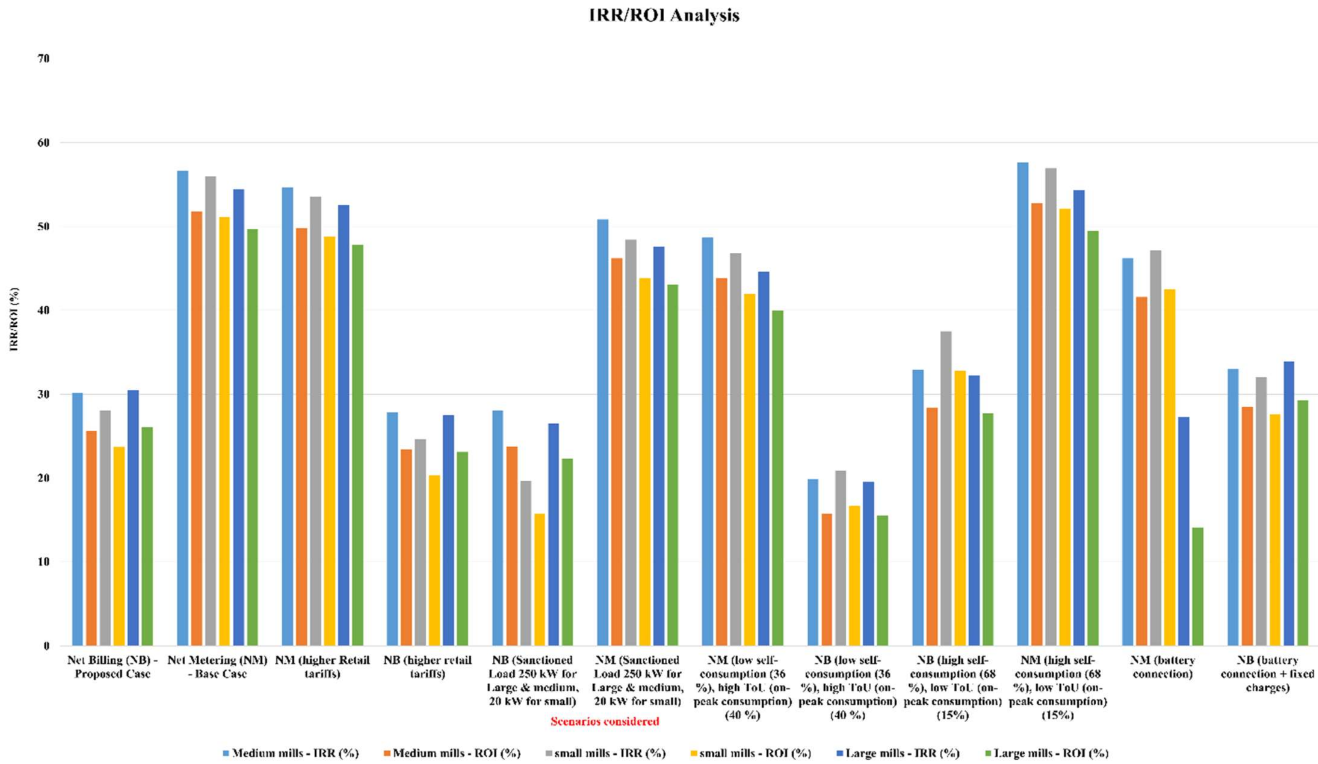


Figure 16: Actual Demand Scenario: Internal Rate of Return/Return on Investment Analysis of Modeled Scenarios

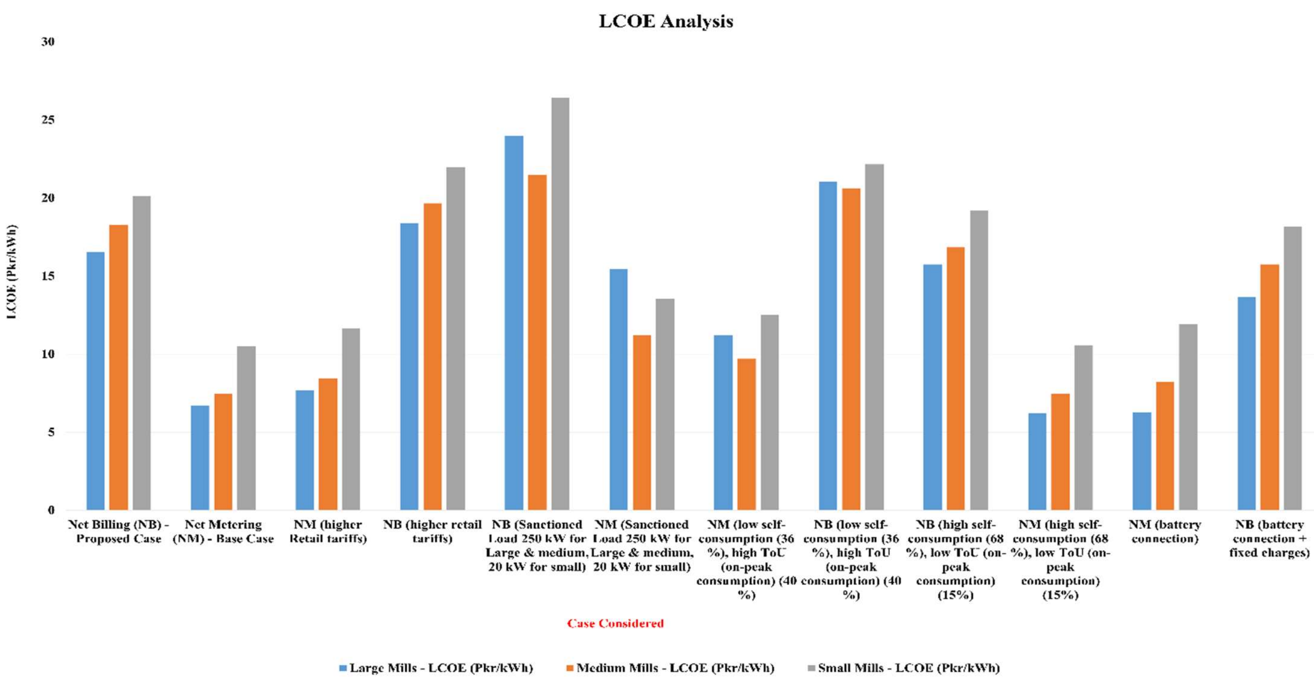


Figure 17: Actual Demand Scenario: LCOE Analysis of Modeled Scenarios

Across the representative industrial classes, the clearest and strongest pattern is the superiority of **Net-Metering** (NM) for project financeability: NM yields the highest IRRs and the shortest payback periods for all three demand classes (medium ≈ 2.7–2.8 yrs, large ≈ 2.8–2.9 yrs, small

≈ 2.8–3.0 yrs). This is because unit-for-unit retail offsets convert exported generation into immediate retail bill avoidance, producing large monthly cash savings that support quick capital recovery. Introducing higher retail tariffs reduces but does not eliminate NM's advantage; NM with higher retail still keeps paybacks inside ~3 years.

By contrast, **Net-Billing** (NB) in its simple (nominal, implemented case by regulator) form moves paybacks into the 4+ year band across classes (≈4.3–4.6 yrs), reflecting reduced export credits and shortened contract horizons; IRRs fall accordingly. NB's adverse effect is most pronounced in scenarios with low self-consumption and high on-peak tariff exposure (cases labeled NB low self-consumption/high TOU): paybacks lengthen to ~5–6+ years and IRRs sink below 20% in some instances, which threatens bankability for smaller firms. NB combined with **sanctioned-load caps** (limiting installed capacity) worsens outcomes for small mills especially (small IRR drops to ~19.7% and payback approaches 6 years), because these firms lose the oversize lever they had used to increase daytime self-use without costly storage.

The role of *self-consumption and TOU profile* is pivotal. High self-consumption and low TOU exposure (i.e., most generation directly consumed on-site during high-use periods) narrows the NB–NM gap: in those cases NB IRRs improve and paybacks fall (e.g., NB high self-consumption, low TOU yields IRRs ~32% and paybacks ~4 yrs). Conversely, when prosumers export a larger share (low self-consumption) and face high on-peak import tariffs, NB penalizes them strongly because exported kWh earn low wholesale credits while imports are costly.

Storage (BESS) *is an effective mitigant but not a critical remedy*. Adding batteries under NM preserves high IRR/payback metrics (NM + battery keeps paybacks near 3 yrs for medium/small), and under NB batteries improve outcomes substantially compared with NB alone, e.g., NB + battery + fixed charges reduce payback to ~4 yrs and IRRs to the low-30% range for many classes. However, batteries add capital cost; under NB the benefit of storage is blunted if fixed charges and low export credits remain, so cost recovery depends on whether regulators provide explicit dispatch compensation or time-differentiated export credits.

Differential impacts by scale: Medium mills (or aggregated SME dispatch pools) show the strongest resilience and often the best economics (medium > large > small). Medium sites combine scale economies with flexibility and typically avoid single-site net-metering ceilings that constrain the very largest. Large mills still perform well under many scenarios but face constraints where the sanctioned-load cap is applied as a breaking snapshot (i.e. 250 kW for our case) and generally ~990 kW maximum DG capacity limits for all NM connections. Small mills are consistently the most vulnerable across NB variants; their paybacks and IRRs are most sensitive to export credit levels, fixed charges and sanctioned caps; without aggregation or subsidized storage finance many small projects risk becoming marginal. Thus, this is key policy takeaway; aggregated units are often most resilient under policy changes.

Policy implications in the NEPRA change context: The NB move will achieve the regulator's short-term objective of lowering cross-subsidy pressure, but the modelling shows it does so at the cost of materially weakening many industrial investment cases; particularly for small and low-self-consumption sites. To avoid suppressing overall rooftop deployment and to keep industry aligned with national decarbonization goals, policy must pair NB with compensatory measures: time-differentiated export pricing (VoS/TOU pilots), explicit BESS dispatch payments, clear and fast rules for aggregation/VPP access, transparent PPMC/ISMO sensitivity models for DISCO revenue impacts and preserving existing project economics. Failure to offer these measures, NB will likely accelerate behind-the-meter battery uptake by large industrial players (which can be system-beneficial if compensated) while pricing out smaller adopters and reducing visible exports; an outcome that complicates both grid planning and equitable tariff recovery.

8.4.2. Comprehensive Discussion and interpretation for Actual Demand Case

A. Core patterns (LCOE and Annual bill behaviour)

1. **Net-Metering (NM) remains the strongest financier for prosumers.** LCOE under NM is lowest across all three classes (Large ≈ 6.7 PKR/kWh; Medium ≈ 7.4 PKR/kWh; Small ≈ 10.5 PKR/kWh), and annual bills are strongly negative for many NM scenarios; a direct reflection of unit-for-unit retail offsets converting exported energy into immediate bill savings. Where NM shows negative annual bills (large and medium), these represent net export values, which materially improves cash flow and payback.
2. **Net-Billing (NB) raises LCOE effectively and reduces monthly cash relief.** Under the NB nominal case, the effective LCOE numbers are much higher (Large 16.55; Medium 18.28; Small 20.13 PKR/kWh) versus NM, and annual bills remain positive, i.e., prosumers still pay net money to the grid, albeit far lower than Base Case grid bills. This shows NB reduces cross-subsidy but also removes most of the bankability or economic viability that NM provided.
3. **Higher retail tariffs and sanctioned caps push annual bills back up.** NB with higher retail tariffs or with the sanctioned-load cap (250/20 kW) further increases LCOE and annual cash outflows for prosumers; sometimes approaching or exceeding the Base Case burden (NB higher retail for large mills: PKR 24.08M annual). The sanctioned cap case is particularly punishing/penalizing for large industrial (here textile) locations, because it removes oversizing headroom and limits daytime export/self-consumption strategies.
4. **Self-consumption profile matters strongly:** Scenarios with **high self-consumption and low TOU** (i.e., the prosumer consumes most generation on-site during valuable periods) show much better outcomes under both regimes. For example, NM high self-consumption yields very low LCOE and large negative annual bills (Large NM high self-consumption: LCOE 6.216; Annual -PKR 26.24M). Conversely, NB with **low self-consumption and high TOU** is worst; large LCOE and very high annual bills (Large NB low self-consumption/high TOU: LCOE 21.056; Annual PKR 54.12M).
5. **Battery (BESS) helps but outcome depends on settlement:** Under NM, adding battery often improves export timing and keeps annual net revenue highly negative (more favorable). Under NB, battery can reduce annual bills but not restore NM-level benefits unless storage dispatch is explicitly remunerated; NB + battery yields modest positive or slightly negative annual bills depending on case (Large NB battery: small

positive PKR 1.13M annual). Batteries also increase project LCOE (added CAPEX) but can improve cash flow timing.

B. Policy-aware interpretation & What the Implications means under Prosumer Regulations 2026

1. **NEPRA's objective vs investor outcomes:** The NB model will reduce the cross-subsidy pressure and produce positive fiscal relief for non-solar consumers (regulatory aim), visible here as NB annual bills being far lower than Base Case. But that comes at the cost of the rapid, visible returns NM delivered to prosumers; NM shows quick, negative-bill outcomes that spurred investment. Policymakers trade lower sectoral subsidy exposure for weaker prosumer economics.

2. **Winners and losers:** Medium-sized mills (and aggregated SME pools) remain relatively tough and resilient under many NB variants: their annual bills under NB are manageable and IRRs in your other tables were still decent. Large mills can remain economic but are sensitive to sanctioned-load caps and high retail adjustments; small mills are the most vulnerable; NB raises their effective LCOE and annual bills more severely relative to NM, and they lack scale to absorb battery costs.

3. **Sanctioned-load caps are blunt and costly:** The NB sanctioned-cap scenario shows LCOE jumps and annual bills for large mills increase substantially (PKR 27.8M); despite NB's aim to protect grid stability. This demonstrates that a blanket cap without effective HCA and mitigation leads to higher consumer bills and weaker investment economics. Targeted technical mitigations (export setpoints, phase balancing, AMI) would be less distortive.

4. **Timing and cash-flow effects matter as much as lifetime LCOE:** Even where lifetime LCOE under NB compares favorably to grid, the monthly cash flows under NB are worse than NM (quarterly payouts, limited carryover), and that affects working capital and bankability. The results reflects that: NB annual bills are positive and sometimes high even when LCOE is competitive, because export credits are low or delayed.

5. **Storage is an important policy lever; if compensated:** BESS can restore a substantial fraction of prosumer value by time-shifting solar into higher-priced hours, reducing reliance on export compensation. However, under NB without explicit dispatch payments or higher on-peak buyback, the economics of storage may not be sufficiently attractive, especially for small mills. Policy should therefore consider explicit BESS compensation or TOU export credits to align private incentives with system needs (peak shaving, capacity deferral).

C. Recommendations & Policy implications from Modeled Results

- If NEPRA implements NB, **pair it with time-differentiated export credits (VoS/TOU)** and explicit storage dispatch payments to restore investment incentives while protecting DISCO revenue.

- Avoid blanket sanctioned-load caps; require HCA and a mitigation ladder so technically viable oversize/connection requests can proceed after targeted remediation.
- Protect small adopters through aggregation/VPP pathways and concessional BESS financing so they remain bankable.
- Publish PPMC/ISMO sensitivity runs showing how NB + TOU + BESS affect DISCO revenue and cross-subsidy incidence before final rule enactment.

8.4.3. Comprehensive Discussion and interpretation for All scenarios at varying demand levels

The modeling results for all industries at varying demand levels are shown in **Figures 18 – 23**. The modeling results derive following implications:

- **Demand level matters.** For the same case, moving from Low → Actual → High demand generally improves IRR/ROI and shortens payback (because more of the generated energy offsets higher volume of purchases). This is especially visible under NM and where self-consumption is high.
- **Net-Metering (NM) dominates financially.** Across demand levels NM gives the lowest LCOE and largest negative annual bills (payments to prosumers), producing the shortest paybacks (≈2–3 yrs for medium/large). NM high-self-consumption cases show particularly strong results.
- **Net-Billing (NB) reduces prosumer cash benefits.** NB nominal produces much higher LCOE and positive annual bills (i.e., prosumers still pay net to grid), and NB worsens substantially under high retail tariffs or low self-consumption (very high annual bills in those scenarios).
- **Sanctioned caps & low self-consumption are punitive.** NB + sanctioned cap or NB + low self-consumption + high TOU produce the worst outcomes (LCOE high and annual bills large), making projects marginal for smaller adopters.
- **Storage improves timing but not always net value under NB.** Adding battery (NB battery case) reduces peak purchases and improves payback/IRR compared with plain NB, but does not restore NM-level surplus unless dispatch/peak credits are available.

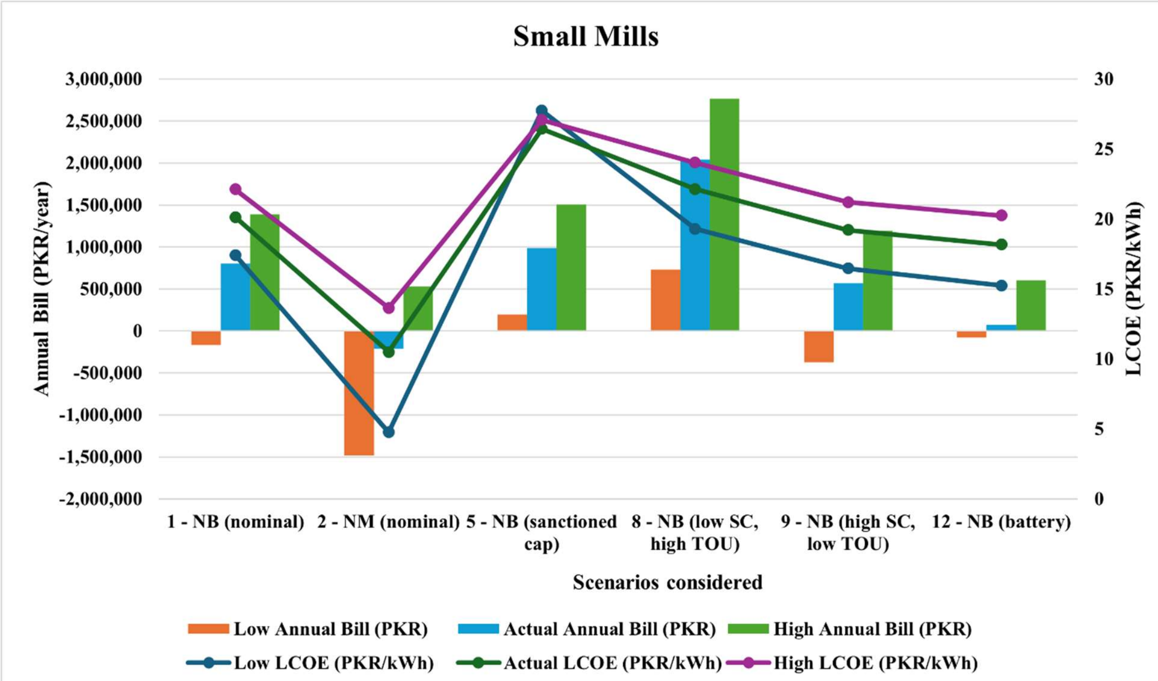


Figure 18: Small Mills: Modeling results for LCOE and Annual Bills

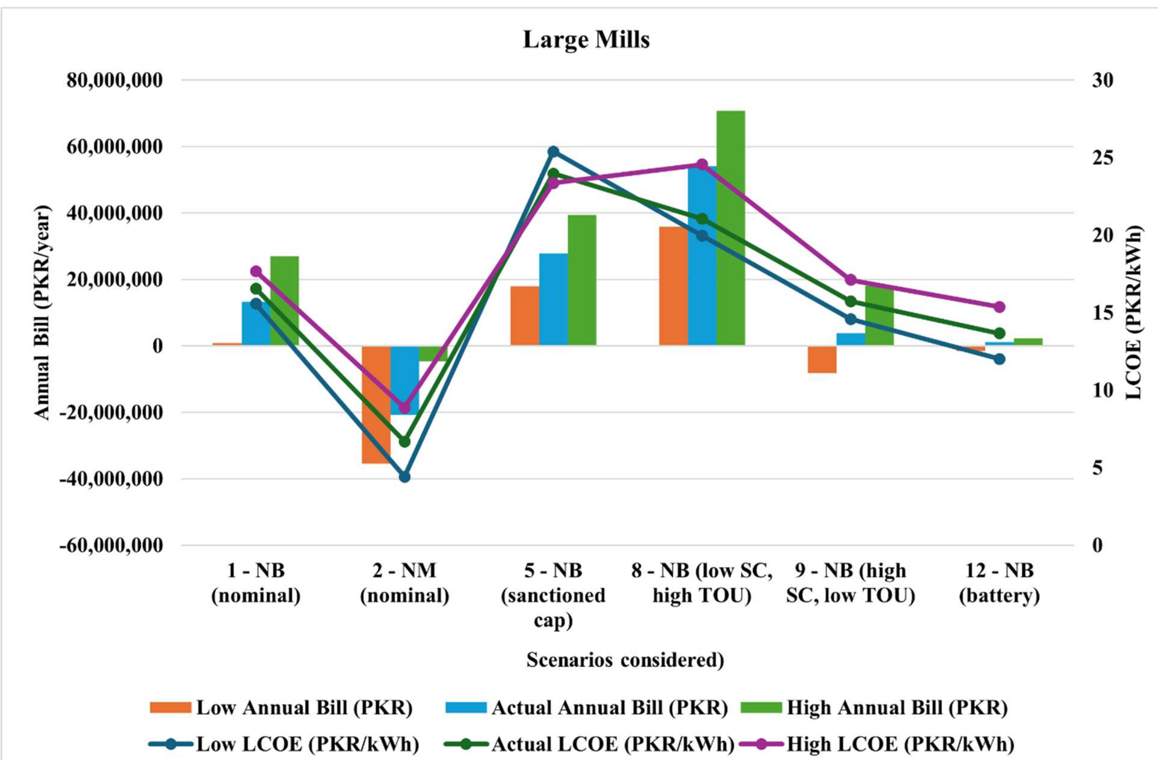


Figure 19: Large Mills: Modeling results for LCOE and Annual Bills

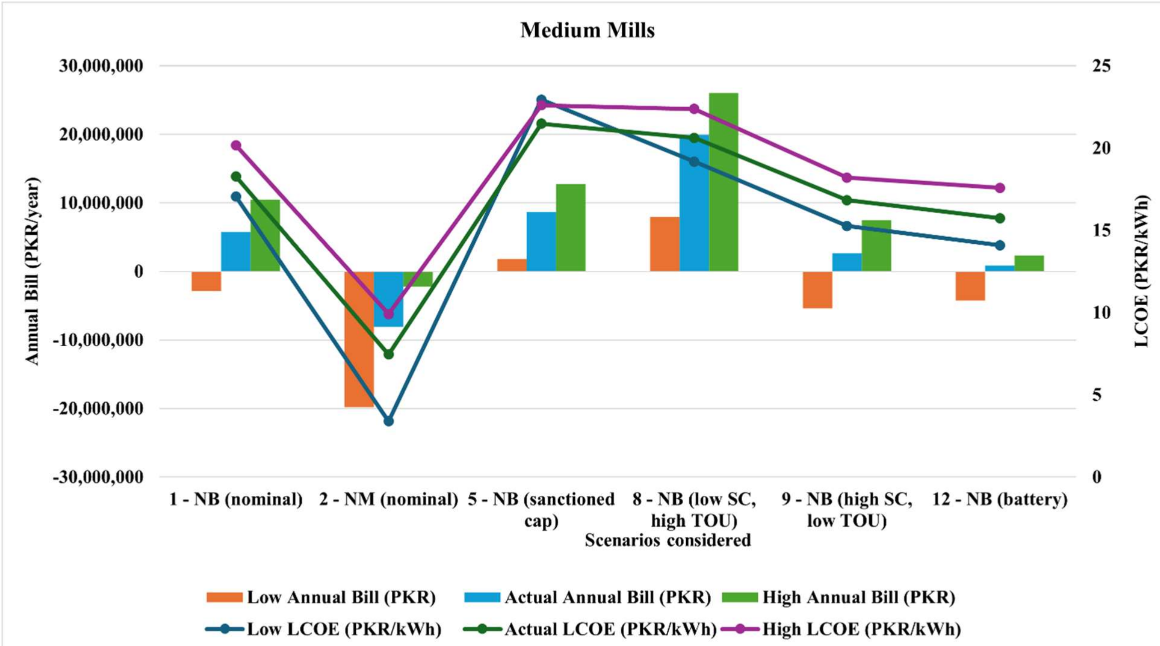


Figure 20: Medium Mills: Modeling results for LCOE and Annual Bills

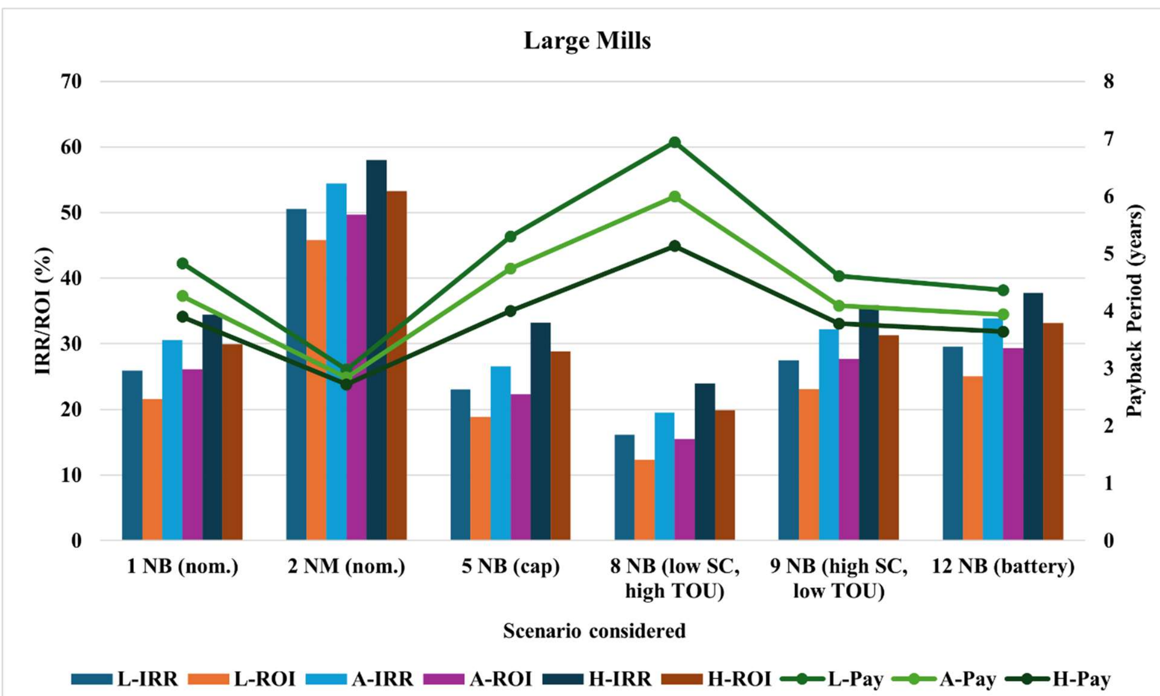


Figure 21: Large Mills: Modeling results for Payback periods and financial returns

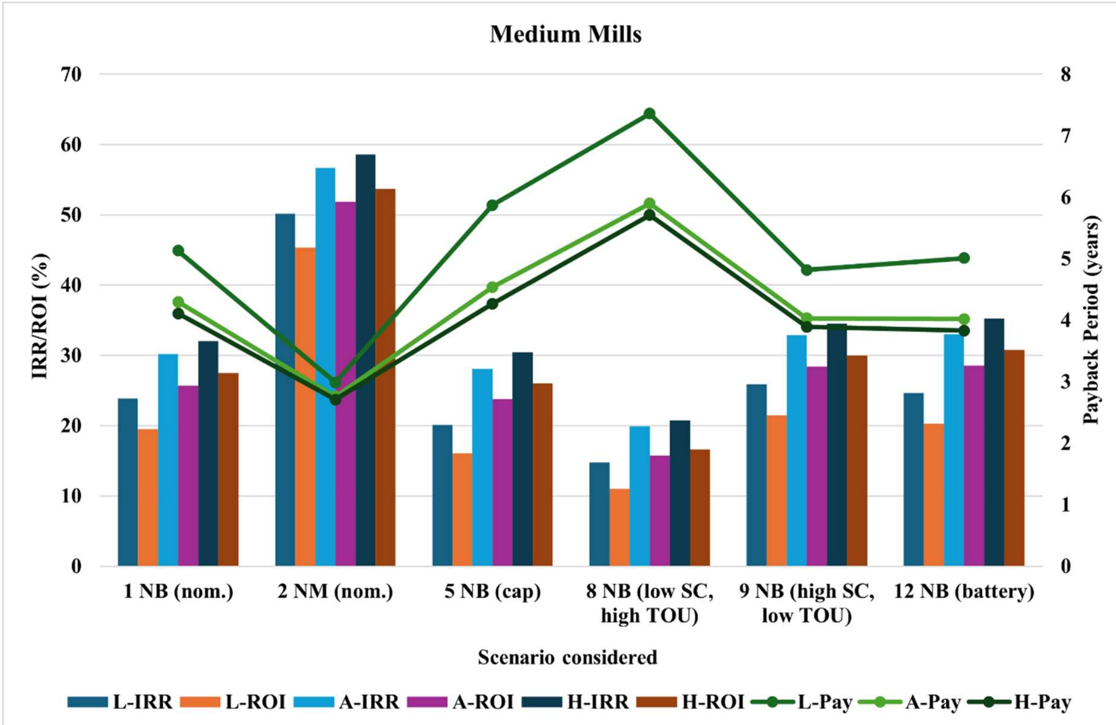


Figure 22: Medium Mills: Modeling results for Payback periods and financial returns

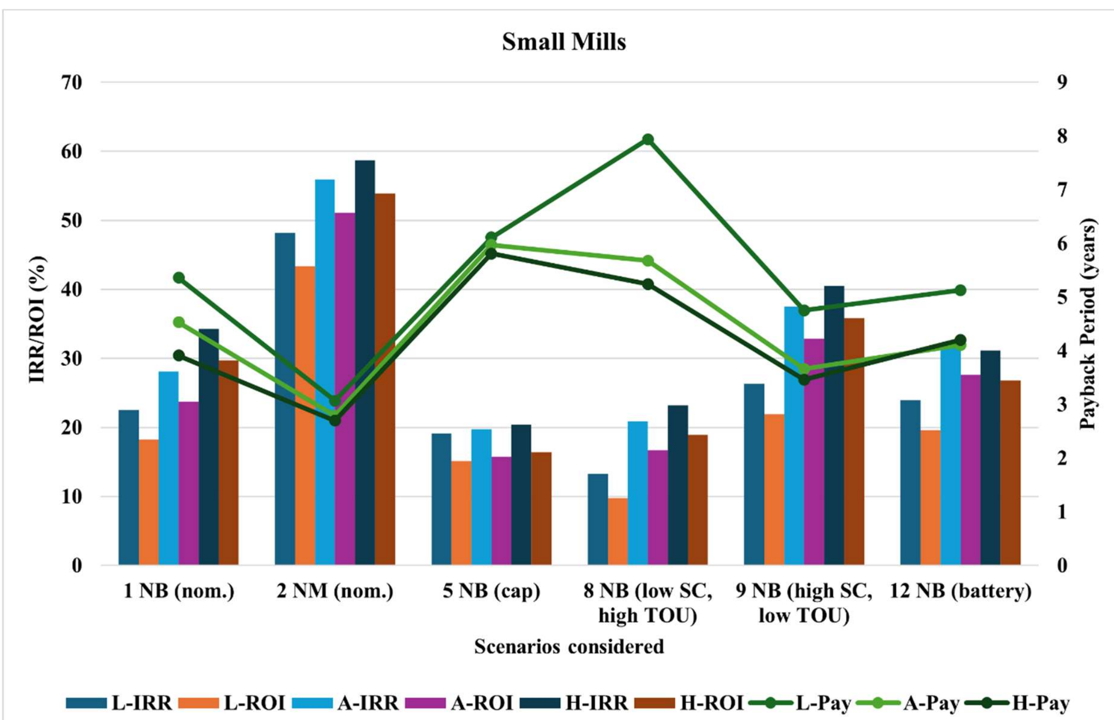


Figure 23: Small Mills: Modeling results for Payback periods and financial returns

Key: L – Low demand, A – Actual demand, H – High demand, Pay – Payback Period.

8.4.4. How demand level (Low → Actual → High) changes the economics: Quantitative summary

A. Large mills (8,500 → 10,500 → 12,500 kWh/day)

- **IRR / ROI / Payback:** NB nominal IRR rises from **~25.9% → 30.5% → 34.4%** as demand climbs; payback shortens from **4.83 → 4.26 → 3.90 years**. NM (net-metering) similarly improves IRR (≈50.5 → 54.5 → 58.0%) and shortens payback (~2.98 → 2.84 → 2.72 yrs).
- **LCOE:** LCOE under both regimes increases slightly with demand (NB: 15.57 → 16.55 → 17.67 PKR/kWh; NM: 4.42 → 6.69 → 8.88 PKR/kWh).
- **Annual bill:** NB annual bill rises strongly with demand (≈ +0.9M → +13.3M → +27.1M PKR) while NM annual net receipts fall in magnitude (i.e., less negative: −35.5M → −20.7M → −4.6M PKR).

Interpretation: higher loads improve project-level returns (IRR up, payback down) because fixed PV output offsets a larger base of purchases and system scale better matches consumption patterns; but higher gross consumption also increases net cash outflows under NB (because imports at retail remain costly). NM retains larger net export benefits at every demand level.

B. Medium mills (3,000 → 4,200 → 4,800 kWh/day)

- **IRR / ROI / Payback:** NB nominal IRR moves **23.9% → 30.2% → 32.0%**, payback shortens **5.13 → 4.30 → 4.11 yrs**. NM IRRs are high throughout (≈50–58%) with paybacks ≈2.7–3.0 yrs.
- **LCOE:** NB LCOE increases modestly (≈17.05 → 18.28 → 20.16 PKR/kWh); NM LCOE remains very low at low demand (3.39 PKR/kWh) and increases with demand.
- **Annual bill:** NB annual bill goes from net credit at low load (−2.9M PKR) to small positive at actual (≈+5.8M) and larger at high (≈+10.5M); NM remains net negative (exports exceed imports).
  Interpretation: medium mills gain significantly as demand rises (similar pattern to large), but because medium sites combine scale and flexible system sizing, they remain the most robust class under both NM and NB.

C. Small mills (250 → 380 → 450 kWh/day)

- **IRR / ROI / Payback:** NB nominal IRR jumps **22.5% → 28.1% → 34.3%**, payback shortens **5.36 → 4.53 → 3.91 yrs**; NM remains very attractive (IRR ≈48–59%, paybacks ≈2.7–3.1 yrs).
- **LCOE:** NB LCOE increases markedly with demand (17.42 → 20.13 → 22.12 PKR/kWh); NM LCOE increases from 4.76 → 10.50 → 13.64 PKR/kWh.
- **Annual bill:** NB annual bill grows from slightly negative at low load (−0.16M PKR) to positive at actual and high load (+0.8M → +1.39M PKR); NM shows net receipts at low load (−1.48M) but converges toward small negative/positive at higher loads.

Interpretation: small mills show the **largest proportional sensitivity** to demand level (largest percent changes in IRR/payback across the three demand states). Changes in demand materially alter small mills' bankability because their fixed cost base and relatively coarse sanctioned/inverter steps mean small shifts in energy balance change outcomes quickly.

Cross-cutting quantitative conclusion: Moving from Low → Actual → High demand generally **improves IRR and shortens payback** for all mill types, because a larger consumption base allows the same PV generation to offset more expensive imports. However, **annual bills under NB** tend to increase with demand (because imports at retail remain expensive and exported credits are low), while **NM** converts increased generation into continued strong net export value; therefore the direction of annual-bill change depends on the settlement regime.

8.4.5. Which mill type is most affected (sensitivity) and which is most resilient?

- **Most affected / most sensitive: Small mills.** They show the largest relative swings across metrics when demand changes and when policy parameters (sanctioned cap, TOU profile, export price) vary. Under punitive NB variants (low self-consumption / high TOU / sanctioned limits) small mills are easily pushed into marginal territory (IRR drops below ~15–20%, paybacks >6 years in worst cases).
- **Most resilient / least impacted: Medium mills (or aggregated SME pools).** They consistently record higher IRRs and lower paybacks than small mills under both NM and NB. Medium mills combine scale economies, ability to install systems near sanctioned limits without being constrained by 1 MW NM ceilings, and more predictable load profiles; these features make them better able to absorb NB's lower export price or short carryover windows.

Large mills sit between these: they are **robust/resilient** financially but **structurally constrained** when sanctioned-load caps bite (those caps remove an oversize lever that large sites previously used), so their outcome depends on cap and self-consumption patterns.

8.4.6. Sanctioned-load cap: Quantitative effect and practical meaning

- **Quantitative effect:** comparing NB nominal vs NB with sanctioned cap (250 kW / 20 kW for small): IRR drops and payback lengthens across classes; the **small mills** experience the largest proportional decline (e.g., small: IRR ~28.1% → 19.7% at Actual load in your tables), large mills see IRR decline (~30.5% → 26.5%), medium mills decline (~30.2% → 28.1%). LCOE increases under the cap because oversizing that improved real production is disallowed; annual bills generally increase. This is because applying sanctioned load limit increases the *curtailment from **<1% to around ~20-30%*** in all scenarios (as shown by excess electricity), i.e. majority of the excess energy is not credited, and system's full utilization is highly compromised, which can be reduced by using BESS solutions, if capital is available.

- **Practical meaning:** The cap is a "blunt instrument" that reduces export potential and punishes sites that previously used modest oversize to increase daytime self-use. It particularly hurts smaller adopters and any industrial site that would otherwise have optimized DC/AC ratios or slightly larger arrays to match daytime processes.

Policy implication: before using caps as the default remedy, regulators should require a mitigation ladder (export setpoints, inverter limits, phase rebalancing, targeted transformer upgrade) and publish transformer-level HCA so only genuinely constrained feeders are restricted.

8.4.7. Low vs high self-consumption cases: how behaviour changes economics

- **Low self-consumption (large exports):** Under NB this is the worst outcome — exported energy is credited at low NAEP so prosumers with low on-site load realise little value for exports. Quantitatively, NB low-SC cases show much lower IRR and longer payback (e.g., Large NB low-SC actual IRR ≈ 19.5% vs NB high-SC actual IRR ≈ 32.2%). Small mills are severely affected.
- **High self-consumption (most generation consumed on-site):** Improves outcomes under NB and NM: IRR and ROI rise and paybacks shorten markedly; because the prosumer avoids paying retail imports instead of relying on low export credits. For example, NB high-SC large IRR ~32.2% vs NB low-SC ~19.5% (actual demand).

Practical takeaway: Policies *encouraging or enabling higher self-consumption* (demand shifting, process scheduling, on-site storage or heat integration) materially improve economics under NB. This is why time-differentiated credits and storage compensation are central to restoring NB bankability or economic viability.

8.4.8. Battery (BESS) viability and its differentiated impact by mill type

- **Quantitative effect:** adding BESS improves IRR and shortens payback across mill types in your tables (e.g., Large: NB nominal IRR 30.5% → NB + battery 33.9% at Actual; payback 4.26 → 3.94 yrs). Annual bill outcomes under NB + battery are markedly better than NB without battery (often cutting bills by tens of millions PKR for large mills in modeled scenarios).
- **Small vs Large:** large and medium mills can absorb BESS capex more easily; small mills often cannot unless concessional finance or aggregation is available. In modeled results, medium and large sectors recover a large share of NB losses by adding batteries; small mills improve but remain sensitive.
- **Value drivers:** BESS is most valuable when it enables shifting generation to *on-peak* hours (high retail price) or avoids expensive imports. Its viability increases if regulators permit explicit dispatch payments or time-differentiated export credits. If NB simply imposes low flat export credits and does not remunerate BESS services, battery ROI depends solely on retail arbitrage and may be marginal for small adopters.

Policy implication: BESS is an effective technical mitigation and commercial hedge for NB; but widespread deployment requires

(a) Access to affordable financing, and
(b) Regulatory identification (VoS/TOU credits, capacity or ancillary service payments) so that the social value of storage accrues to investors.

8.4.9. Final Integrated qualitative assessment under all scenarios

- **Most able to cope / adapt: Medium mills (and SME aggregations).** They show the best blend of IRR, ROI and short payback across NB variants, and they can more easily bundle or aggregate projects to smooth risk. They are thus the logical "sweet spot" for a pro-investment NB transition.

- **Can cope but need conditional support: Large mills.** They remain profitable in most NB settings but are **sensitive** to sanctioned-load caps and regulatory treatment of storage and oversize. Large players can self-finance BESS and negotiate custom commercial arrangements; they need clear rules and a fast path for oversize approvals where technically safe.

- **Most vulnerable: Small mills.** They are hit hardest by NB, carryover limits, fixed recovery levies, and sanctioned caps. Without aggregation, concessional finance for storage, or explicit protection (phased fixed charges), many small projects will see paybacks lengthen and IRRs fall into marginal ranges.

8.4.10. Actionable recommendations according to modeled scenarios

The full set of results informs two decision pathways for regulators and industry:

a) **Protect DISCO financial health** while maintaining investment signals (NB paired with VoS/TOU and BESS payments); or
b) **Preserve prosumer economic viability** (maintain some retail-level offset or longer credits) while introducing targeted technical measures (HCA, inverter controls) to manage grid safety.
c) If NEPRA moves to NB, do it conditionally. Pair NB with a short grandfathering window and pilot a VoS/TOU buyback plus explicit BESS dispatch payments so that NB's loss of export value can be recaptured by time-sensitive credits and storage services. This preserves investment signals while limiting cross-subsidy exposure.
d) Avoid blanket sanctioned-load caps. Require published HCA results and a mitigation ladder before refusing connections. Caps are particularly punitive for small adopters and bluntly reduce national DER yield.
e) Support aggregation and concessional BESS finance. Small mills require pooling solutions (VPP/aggregation) and targeted finance to make BESS viable; otherwise, NB will polarize the market (large players with storage vs marginalized small players).
f) Publish transparent modelling. Require PPMC/ISMO to publish sensitivity modelling showing DISCO revenue effects under NB with and without VoS/TOU and storage payments; this reduces uncertainty and enables evidence-based pilots.

8.4.11. Closing synthesis

Raising demand (Low→ Actual → High) improves project returns (higher IRR, higher ROI, shorter payback) for all mill types because fixed PV generation offsets a larger import base; however, the **settlement rule** determines whether those improved returns translate into positive monthly cash flows. Under net-metering industrial projects show very strong bankability at all demand levels; under net-billing the same projects remain technically attractive in LCOE terms but many lose short-term cash relief; especially small and low-self-consumption sites. Medium mills (or aggregated SMEs) consistently show the greatest resilience and are the best candidates for a managed transition; small mills are most vulnerable and require explicit policy measures (aggregation, concessional BESS finance, phased fixed charges) to avoid being driven off-grid or into marginal economics. Sanctioned-load caps and low self-consumption regimes amplify harm; batteries mitigate much of that harm but only when supported by appropriate market remuneration and finance.

9. Policy Recommendations and Future Directions

The modelling and scenario work above shows a clear, policy-sensitive result: settlement design (how exports are credited and whether storage dispatch is remunerated), sanctioned-load limits, and self-consumption patterns are the dominant determinants of industrial project financial viability; not small changes in PV capital cost. Net-metering delivers the strongest economics (IRRs ≈ 50–58% and paybacks ≈ 2.7–3.0 years for medium/large mills in our cases). Net-billing without compensating measures reduces IRRs and lengthens paybacks (large mills move to roughly 4.2–4.7 years), and small mills are the most vulnerable. Batteries and time-differentiated peak credits can restore much of the lost value, but only if the regulator explicitly recognizes and remunerates those services. The recommendations below are practical, evidence-based, and sequenced so NEPRA, the Power Division, PPMC/ISMO and DISCOs can act immediately and responsibly.

A. Conditional settlement reform (avoid an abrupt investment cliff)

1. **Adopt Net-Billing only conditionally:** NEPRA should not permanently replace net-metering with net-billing without pilots and guardrails. Condition adoption on: (a) a peer-reviewed Value-of-Solar (VoS) / Time-of-Use (TOU) pilot, (b) explicit hybrid PV+BESS dispatch/payment rules, and (c) a short, enforceable grandfathering window of **6–12 months** for projects already contracted or under advanced procurement.
   Rationale: Modelling shows NB can protect DISCO revenues but will materially reduce prosumer bankability unless combined with time/duration value payments and storage compensation.

2. **Run an immediate VoS/TOU pilot (12–24 months) with simple parameters:** Design the pilot to test at-scale dynamic export credits (example pilot peak credit ≈ **PKR18/kWh**) and off-peak/shoulder rates. The pilot should cover representative feeders and include medium, large and small industrial sites with and without storage. Publish methodology, assumptions and interim results.

Rationale: Analysis shows time-differentiated export credits plus BESS materially close the NB–NM gap.

B. Explicitly recognize and remunerate BESS (Technical & commercial rules)

3. **Update grid interconnection and market rules to recognize hybrid PV+BESS:** Amend grid code to permit and standardize BESS participation (dispatch rules, telemetry, verification, compensated services). Adopt modern inverter standards (e.g., IEEE 1547-2018 capabilities: ride-through, controlled export, volt/VAR).
Rationale: Batteries convert otherwise low-valued daytime exports into high-value peak injections; our modelling shows NB + peak credits + BESS restores IRR and payback materially.

4. **Create specific BESS compensation mechanisms:** Define one or more explicit revenue streams for batteries: time-differentiated arbitrage (TOU), peak export credit, or capacity/ancillary service payments. Link payment eligibility to verified dispatch and AMI metering.
Rationale: Without payment, batteries improve technical outcomes but may remain uneconomic for many firms (notably small mills).

C. Protect SMEs and enable aggregation

5. **Authorize and fast-track aggregation / VPP pilots for SMEs:** Allow DISCOs and third-party aggregators to operate time-limited P2P / VPP pilots that let small prosumers pool exports and access storage revenues. Permit simplified settlement and a lightweight registry to measure pooled exports.
Rationale: Medium mills/pooled SMEs are the most resilient; small firms need pooling to reach scale and project economic viability.

6. **Design concessional finance for BESS targeted at SMEs:** Coordinate with development finance institutions to provide low-cost loans or guarantees for BESS paired with SME rooftop PV, conditional on participation in pilots or VPPs.
Rationale: Modelling shows BESS narrows NB losses; small mills cannot otherwise afford the CAPEX.

D. Technical sequencing, transformer hosting and connection rules

7. **Mandate a mitigation ladder before connection refusals:** Require DISCOs to apply, document and publish the following sequence before refusing new prosumer applications:

    (i) Adjust inverter export setpoints/anti-islanding settings,
    (ii) Phase balancing and reconnection checks,
    (iii) Targeted short-term curtailment windows,
    (iv) Temporary or staged connection approvals, and only then
    (v) Targeted transformer upgrade or refusal.

Require public posting of transformer Hosting Capacity Analyses (HCA), connection queues and rejection reasons.
Rationale: Sanctioned-load caps are a blunt tool; our results show caps sharply reduce project value and are often unnecessary if targeted technical mitigations work.

8. **Publish HCA and transformer loading data:** DISCOs must publish feeder and transformer loading, stated HCAs, and expected upgrade timelines. Provide an appeals/grievance mechanism for applicants.
Rationale: Transparency reduces arbitrary refusals and enables prioritized upgrades where the national benefit is highest.

E. Tariff design, fixed charges and sequencing

9. **If a fixed network recovery charge is required, phase it and protect small adopters:** Any fixed charge should be modest, phased-in over multiple years, and accompanied by targeted protections for vulnerable small prosumers (e.g., a lower initial surcharge, discounts for participation in aggregation or BESS pilots).
Rationale: modelling shows fixed charges disproportionately reduce small adopters' IRR and push paybacks into marginal ranges.

10. **Mandate AMI for new >10 kW prosumers and plan phased retrofit:** AMI enables TOU settlement, automated dispatch verification, and reliable aggregation. Sequence: mandatory for new >=10 kW immediately; retrofit existing systems within 3–5 years with cost-sharing mechanisms.
Rationale: accurate metering underpins TOU/VoS schemes and battery remuneration.

F. Transparency, modelling and stakeholder process

11. **Require published sensitivity modelling by PPMC/ISMO before permanent rules:** The planner(s) must release scenario runs showing DISCO revenue impacts, cross-subsidy per kWh, and tariff sensitivity for plausible adoption curves (baseline, medium, high rooftop adoption) and with/without VoS/TOU & BESS. Commission independent peer review.
Rationale: Many hearing objections were data-driven; transparent modelling will resolve technical disputes and reduce regulatory risk.

12. **Hold Another public hearing and phased rule adoption:** Use a *specific grace period* to incorporate industry suggestions, and adopt rules in phases tied to pilot outcomes (e.g., NB allowed in pilot feeders only; nationwide rollout only after VoS/TOU pilot demonstrates outcomes).
Rationale: Predictability and consultation are essential to maintain investor confidence.

G. Implementation, monitoring and enforcement

13. **Define pilot metrics and a decision gate:** For the VoS/TOU + BESS pilots define measurable KPIs (reduction in peak procurement, DISCO revenue shortfall vs baseline, change in prosumer IRR/payback, number of small adopters enabled via aggregation).

After pilot (12–24 months) use KPIs to decide on national rollout or required parameter changes.
Rationale: evidence-based policy reduces chance of unintended consequences.

14. **Require grandfathering and a fair dispute-resolution process:** Provide legally binding grandfathering for projects already contracted or in advanced procurement (6–12 months); create fast-track dispute resolution and interim relief for billing or disconnection disputes.
Rationale: Sudden changes create stranded investment risk & reduce future investment.

H. Quick wins: Actions NEPRA and MoE can take immediately

15. **Immediate publication of HCA sample data and connection queue statistics:** This is low cost and builds trust.
16. **Authorize limited VPP / aggregation pilots and a small BESS subsidy window for SMEs:** This jumpstarts commercially viable aggregation and improves resilience while pilots run.
17. **Issue guidance clarifying how on-site generation will be treated for corporate Scope-2/CBAM accounting:** Certainty here prevents loss of export market competitiveness for textile exporters.

10. Concluding Remarks

NEPRA's shift from unit-for-unit net-metering to a net-billing settlement is a material policy change for Pakistan's industrial prosumers. The empirical findings presented here are unambiguous: settlement rules; not marginal variations in PV system cost; determine whether industrial prosumers remain financially viable under the Prosumer Regulations. The developed modelling case study; covering small, medium (including pooled SMEs) and large mills across low, actual and high demand cases; shows that the settlement rule is the primary driver of project financial reliability and bankability. Under the old net-metering rule industrial projects (particularly medium and large mills) delivered very strong returns and short paybacks; replacing that with a simple net-billing approach, credited at wholesale/NAEPP rates with short rollover, reduces monthly cash savings and lengthens paybacks unless compensating mechanisms are provided. In plain terms: system (components') cost is no longer the binding constraint; how exported energy and storage are paid for is. Net-billing can protect DISCO finances, but only if implemented with carefully designed, evidence-led compensatory instruments: time-differentiated export credits (VoS/TOU), explicit BESS dispatch compensation, aggregation pathways for SMEs, transparent HCA and a mitigation ladder before connection refusals.

Demand level and operational behaviour matter, but they do not overturn the settlement effect. Moving from lower to higher demand reliably improves IRR and shortens payback because the same PV output offsets more costly imports; however, under net-billing higher demand can mean larger net import bills in the near term because imports are charged at retail while exports are paid at a low wholesale rate. Medium mills (or aggregated SME pools) are the most resilient class in our cases: they combine sufficient scale to capture unit-economy benefits while avoiding many single-site size constraints and so remain profitable across more scenarios. Large firms can generally adapt (often by adding storage or negotiating bespoke arrangements), but sanctioned-load caps and blunt transformer limits remove an important design lever and materially raise effective LCOE. Small firms are the most exposed; modest fixed charges, low export credits, or strict caps can push their paybacks into marginal territory and constrain access to finance.

Technical policy choices determine whether net-billing will protect DISCOs without destroying prosumer investment. Our analysis shows that pairing net-billing with time-differentiated export credits (a VoS/TOU pilot), explicit recognition and remuneration of BESS dispatch, and aggregation/VPP access restores much of net-metering's lost value while aligning private incentives with system needs (peak shaving, capacity deferral). By contrast, reducing export credits alone or imposing uniform sanctioned-load ceilings tends to accelerate behind-the-meter storage or partial grid defection, reduce system visibility, and transfer costs unpredictably onto vulnerable non-solar consumers. Grid constraints; local transformer loading, T&D losses, slow DISCO capex cycles and limited AMI; explain why many technical limits are applied; but the right response is targeted hosting-capacity analysis and a mitigation pathway (export setpoints, phase balancing, short curtailment windows, targeted upgrades) rather than blunt nationwide caps.

Practically, a sensible and politically durable pathway is sequenced and evidence-led. First, protect projects already contracted with a short enforceable grandfathering window (6–12 months) to avoid stranded investment and maintain investor confidence. Second, run transparent pilots (VoS/TOU + BESS + aggregation) over 12–24 months on representative feeders, with publicly available key performance indicators (KPIs, i.e. DISCO revenue impacts, peak reduction, prosumer IRR outcomes). Third, mandate operational enablers; AMI for new >10 kW prosumers, updated interconnection rules adopting modern inverter capabilities, and clear BESS dispatch/settlement rules; so the market can monetize flexibility. Fourth, enable SME aggregation and VPP pilots and couple those with targeted, concessional BESS finance so small adopters are not priced out.

Regulators will also need better, more transparent modelling to convince stakeholders. Require PPMC/ISMO to publish sensitivity analyses showing tariff and cross-subsidy impacts under plausible adoption curves and alternative compensation designs. Require DISCOs to publish transformer HCA, connection queues and rejection reasons and to follow the mitigation ladder before refusing applications. If a modest fixed network recovery charge is required, phase it and protect small adopters through temporary concessions or aggregation support rather than sudden, large levies that undermine profit viability. Thus, an immediate peer-reviewed pilots and published sensitivity modelling from PPMC/ISMO is also the need of the hour, and collectively these measures will allow Pakistan to preserve investor confidence while addressing legitimate system and equity concerns. Through this way, NEPRA can protect non-solar consumers and DISCOs without sacrificing the industrial and climate benefits that widespread rooftop solar delivers.

In short, Pakistan can protect distribution company finances and non-solar consumers while preserving the industrial case for distributed solar; but only if net-billing is implemented as part of a package that pays for time and flexibility, recognizes storage, enables aggregation, and sequences reforms around pilots and transparent modelling. Policymakers who move fast without those enablers risk slowing rooftop investment, encouraging grid defection, and shifting costs onto the most vulnerable consumers. A measured, evidence-based transition will keep industrial competitiveness intact while delivering the grid-level benefits of a smarter, more flexible distributed energy system.

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Appendix

A.1. Data Obtained – LCOE and Annual Bill

Table A.1: LCOE and Annual Bill Data for Large Mills (for all cases)

Large Mills	Actual Demand (kWh/day)	Low Demand (kWh/day)	High Demand (kWh/day)	System Cap. (kW)	**Grid System framework**			
	10500	8500	12500	2700				
Case	**Description**	**Load Connected (kWh)**	**LCOE ($/kWh)**	**LCOE (PKR/kWh)**	**Annual Electricity Bill ($/year)**	**Annual Electricity Bill (PKR/year)**	**Energy Purchased (kWh)**	**Energy Sold (kWh)**
0	Base Case	8500	0.162	45.36	$396,806.73	111,105,884.40	3832498	0
		10500	0.159	44.52	$472,389.14	132,268,959.20	4562500	0
		12500	0.166	46.48	$321,222.14	89,942,199.20	3102475	0
1	Net Billing (Gross) - Nominal	8500	0.0556	15.568	$3,235.16	905,844.80	703,740	2,307,029
		10500	0.0591	16.548	$47,548.43	13,313,560.40	953,603	2,001,523
		12500	0.0631	17.668	$96,665.65	27,066,382.00	1,248,399	1,713,514
2	Net Metering - Nominal	8500	0.0158	4.424	($126,691.34)	-35,473,575.20	703,740	2,332,636
		10500	0.0239	6.692	($73,800.97)	-20,664,271.60	953,603	2,043,660
		12500	0.0317	8.876	($16,331.80)	-4,572,904.00	1,248,399	1,747,851
3	NM (higher on-peak tariffs)	10500	0.0274	7.672	($53,169.29)	-14,887,401.20	953,603	2,043,660
4	NB (higher on-peak tariffs)	10500	0.0657	18.396	$86,001.11	24,080,310.80	953,603	1,999,554
5	NB (DG capacity 250 kW)	8500	0.0907	25.396	$63,999.87	17,919,963.60	703,740	697,548
		10500	0.0856	23.968	99,349.83	27,817,952.40	953,603	515,784
		12500	0.0834	23.352	$140,626.43	39,375,400.40	1,248,551	425,346
6	NM (DG capacity250 kW)	8500	0.0548	15.344	$12,031.73	3,368,884.40	703,740	725,739
		10500	0.0551	15.428	$47,076.01	13,181,282.80	953,603	645,743
		12500	0.0574	16.072	$91,505.74	25,621,607.20	1,248,399	465,664
7	NM (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	8500	0.03175	8.89	($20,035.11)	-5,609,830.80	1,631,121	2,822,573
		10500	0.04	11.2	$50,642.35	14,179,858.00	2,038,462	2,661,542
		12500	0.0478	13.384	$71,222.14	19,942,199.20	2,838,462	1,852,555

8	NB (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	8500	0.0713	19.964	$127,948.90	35,825,692.00	1,631,121	2,807,129
		10500	0.0752	21.056	$193,297.30	54,123,244.00	2,038,462	2,639,915
		12500	0.0877	24.556	$252,735.06	70,765,816.80	2,838,462	1,839,555
9	NB (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	8500	0.0521	14.588	($29,096.23)	-8,146,944.40	423,598	2,126,988
		10500	0.0562	15.736	$13,575.98	3,801,274.40	652,009	1,767,387
		12500	0.0611	17.108	$64,877.96	18,165,828.80	978,981	1,465,112
10	NM (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	8500	0.0132	3.696	($149,067.05)	-41,738,774.00	422,931	2,187,748
		10500	0.0222	6.216	($93,714.32)	-26,240,009.60	648,742	1,805,236
		12500	0.0289	8.092	($74,474.50)	-20,852,860.00	858,742	1,564,254
11	NM (battery connection)	8500	0.0124	3.472	($169,458.03)	-47,448,248.40	203,740	1,475,775
		10500	0.0224	6.272	($103,933.53)	-29,101,388.40	373,603	1,219,023
		12500	0.0318	8.904	($35,984.24)	-10,075,587.20	748,399	1,017,348
12	NB (battery connection)	8500	0.0429	12.012	($5,388.05)	-1,508,654.00	203,740	1,475,775
		10500	0.0488	13.664	$4,030.68	1,128,590.40	373,603	1,219,023
		12500	0.0549	15.372	$8,347.52	2,337,305.60	748,399	1,017,348

Table A.2: LCOE and Annual Bill Data for Medium Mills (for all cases)

Medium-sized Mills (or aggregted SME Dispatch)	Actual Demand (kWh/day)	Low Demand (kWh/day)	High Demand (kWh/day)	System Cap. (kW)	**Grid System framework**			
	4200	3000	4800	1000				
Case	**Description**	**Load Connected**	**LCOE ($/kWh)**	**LCOE (PKR/kWh)**	**Annual Electricity Bill ($/year)**	**Annual Electricity Bill (PKR/year)**	**Energy Purchased (kWh)**	**Energy Sold (kWh)**
0	Base Case	3000	0.178	49.84	$159,043.07	44,532,059.60	1,095,000	0
		4200	0.168	**47.04**	$222,660.30	62,344,884.00	1,533,000	0
		4800	0.166	46.48	$254,468.92	71,251,297.60	1,752,000	0
1	Net Billing (Gross) - Nominal	3000	0.0609	17.052	($10,342.26)	-2,895,832.80	244,083	1,095,554
		4200	0.0653	**18.284**	$20,576.40	**5,761,392.00**	397,079	810,550
		4800	0.072	20.16	$37,394.15	10,470,362.00	489,957	684,428

2	Net Metering - Nominal	3000	0.0121	3.388	($70,630.99)	-19,776,677.20	244,083	1,112,480
		4200	0.0266	**7.448**	($28,862.73)	**-8,081,564.40**	397,079	827,476
		4800	0.0354	9.912	($7,824.75)	-2,190,930.00	489,957	701,354
3	NM (higher on-peak tariffs)	4200	0.0302	**8.456**	($20,462.18)	**-5,729,410.40**	397,079	827,476
4	NB (higher on-peak tariffs)	4200	0.07019	**19.6532**	$32,014.78	**8,964,138.40**	397,079	810,131
5	NB (DG capacity 250 kW)	3000	0.0819	22.932	$6,385.19	1,787,853.20	244,083	665,543
		4200	0.0767	**21.476**	$31,048.02	**8,693,445.60**	397,079	541,357
		4800	0.0807	22.596	$45,424.15	12,718,762.00	489,990	478,102
6	NM (DG capacity 250 kW)	3000	0.034	9.52	($31,662.48)	-8,865,494.40	244,083	672,184
		4200	0.04	**11.2**	($4,612.77)	**-1,291,575.60**	397,079	553,138
		4800	0.0458	12.824	$11,035.64	3,089,979.20	489,957	493,295
7	NM (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	3000	0.0203	5.684	($45,863.36)	-12,841,740.80	574,457	1,434,037
		4200	0.0347	**9.716**	$4,696.70	**1,315,076.00**	819,903	1,246,444
		4800	0.0429	12.012	$30,153.56	8,442,996.80	946,727	1,155,569
8	NB (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	3000	0.0685	19.18	$28,326.23	7,931,344.40	574,457	1,419,371
		4200	0.0736	**20.608**	$71,068.76	**19,899,252.80**	819,903	1,231,778
		4800	0.0799	22.372	$92,853.83	25,999,072.40	946,727	1,140,903
9	NB (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	3000	0.0545	15.26	($19,291.23)	-5,401,544.40	143,684	968,974
		4200	0.0601	**16.828**	$9,425.10	**2,639,028.00**	286,255	680,497
		4800	0.065	18.2	$26,703.65	7,477,022.00	395,029	573,450
10	NM (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	3000	0.0122	3.416	($71,979.38)	-20,154,226.40	143,684	985,865
		4200	0.0266	**7.448**	($32,536.78)	**-9,110,298.40**	285,506	692,137
		4800	0.0355	9.94	($11,708.29)	-3,278,321.20	393,263	582,040
11	NM (battery connection)	3000	0.0145	4.06	($72,261.60)	-20,233,248.00	93,150	959,803

		4200	0.0293	**8.204**	($31,076.07)	**-8,701,299.60**	15,587	344,240
		4800	0.0385	10.78	($10,161.33)	-2,845,172.40	93,743	203,397
12	NB (battery connection)	3000	0.0503	14.084	($15,153.60)	-4,243,008.00	93,150	959,803
		4200	0.0562	**15.736**	$2,898.97	**811,711.60**	15,587	344,240
		4800	0.0628	17.584	$8,339.77	2,335,135.60	93,743	203,397

Table A.3: LCOE and Annual Bill Data for Small Mills (for all cases)

Small (relative) Mills	**Actual Demand (kWh/day)**	**Low Demand (kWh/day)**	**High Demand (kWh/day)**	**System Cap. (kW)**	**Grid System framework**			
	380	250	450	80				
Case	**Description**	**Load Connected**	**LCOE ($/kWh)**	**LCOE (PKR/kWh)**	**Annual Electricity Bill ($/year)**	**Annual Electricity Bill (PKR/year)**	**Energy Purchased (kWh)**	**Energy Sold (kWh)**
0	Base Case	250	0.174	48.72	$13,253.59	3,711,005.20	91250	0
		380	0.164	45.92	**$20,145.46**	5,640,728.80	**138700**	0
		450	0.161	45.08	$23,856.46	6,679,808.80	164250	0
1	Net Billing (Gross) - Nominal	250	0.0622	17.416	($588.31)	-164,726.80	20642	85240
		380	0.0719	20.132	**$2,871.37**	803,983.60	**38541**	55690
		450	0.079	22.12	$4,962.95	1,389,626.00	50965	42564
2	Net Metering - Nominal	250	0.017	4.76	($5,300.99)	- 1,484,277.20	20642	86371
		380	0.0375	10.5	**($760.76)**	-213,012.80	**38541**	56821
		450	0.0487	13.636	$1,902.36	532,660.80	50965	43695
3	NM (higher on-peak tariffs)	380	0.0415	11.62	**$23.57**	6,599.60	**38541**	56821
4	NB (higher on-peak tariffs)	380	0.0784	21.952	**$4,395.42**	1,230,717.60	**38541**	55678
5	NB (DG capacity 20 kW)	250	0.0991	27.748	$703.53	196,988.40	20642	52031
		380	0.0944	26.432	**$3,526.74**	987,487.20	**38543**	38848
		450	0.0967	27.076	$5,383.97	1,507,511.60	50975	31773
6	NM (DG capacity 20 kW)	250	0.0387	10.836	($2,328.14)	-651,879.20	20642	52843
		380	0.0484	13.552	**$775.81**	217,226.80	**38541**	39787
		450	0.0558	15.624	$2,913.15	815,682.00	50966	32849
7	NM (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	250	0.0248	6.944	($3,260.54)	-912,951.20	47958	113250
		380	0.0446	12.488	**$2,231.91**	624,934.80	**74883**	93162
		450	0.0544	15.232	$5,211.97	1,459,351.60	90077	82890

8	NB (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	250	0.0689	19.292	$2,618.54	733,191.20	47958	111935
		380	0.0791	22.148	**$7,294.38**	2,042,426.40	**74883**	91847
		450	0.0858	24.024	$9,872.83	2,764,392.40	90077	81286
9	NB (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	250	0.0588	16.464	($1,338.12)	-374,673.60	12363	75024
		380	0.0686	19.208	**$2,028.84**	568,075.20	**30783**	46629
		450	0.0757	21.196	$4,269.78	1,195,538.40	46242	36979
10	NM (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	250	0.0173	4.844	($5,427.21)	-1,519,618.80	12362	76079
		380	0.0377	10.556	**($1,080.53)**	-302,548.40	**30672**	47198
		450	0.0486	13.608	$1,555.83	435,632.40	46071	37271
11	NM (battery connection)	250	0.0263	7.364	($2,480.44)	-694,523.20	6331	61172
		380	0.0426	11.928	**($337.61)**	-94,530.80	**20939**	36699
		450	0.0535	14.98	$693.96	194,308.80	31980	23720
12	NB (battery connection)	250	0.0544	15.232	($272.43)	-76,280.40	6331	59975
		380	0.0649	18.172	**$256.90**	71,932.00	**15949**	30436
		450	0.0723	20.244	$2,147.49	601,297.20	27051	17555

A.2. Comprehensive Technoeconomic Results

Table A.4: Technoeconomic Results for Large Mills (for all cases)

Large-sized Mills						
Case	**Description**	**Load Connected (kWh)**	**NPV ($)**	**IRR (%)**	**ROI (%)**	**Simple Payback Period (years)**
1	Net Billing - Nominal	8500	$2,361,699	25.880%	21.57%	4.827
		10500	$3,050,050	30.542%	26.11%	4.257
		12500	$3,652,864	34.417%	29.91%	3.896
2	Net Metering - Nominal	8500	$4,743,825	50.506%	45.82%	2.979
		10500	$5,315,578	54.453%	49.71%	2.836
		12500	$5,830,174	58.032%	53.26%	2.723
3	NM (higher tariffs)	10500	$5,086,760	52.52%	47.79%	2.903
4	NB (higher tariffs)	10500	$2,623,588.71	27.531%	23.16%	4.604

5	NB (DG capacity 250 kW)	8500	$1,820,415	23.00%	18.90%	5.297
		10500	$2,501,289	26.54%	22.32%	4.742
		12500	$3,274,220	33.24%	28.87%	3.999
6	NM (DG capacity 250 kW)	8500	$3,342,138	41.48%	37.03%	3.408
		10500	$4,103,435	47.62%	43.09%	3.098
		12500	$4,748,679	52.43%	47.82%	2.907
7	NM (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	8500	$3,608,792	41.79%	37.20%	3.390
		10500	$3,990,272	44.60%	39.96%	3.240
		12500	$3,199,285	38.70%	35.20%	3.778
8	NB (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	8500	$1,019,809	16.14%	12.34%	6.937
		10500	$1,476,877	19.54%	15.49%	5.994
		12500	$3,546,623	23.98%	19.90%	5.134
9	NB (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	8500	$2,664,636	27.48%	23.08%	4.609
		10500	$3,377,661	32.21%	27.71%	4.090
		12500	$3,960,231	35.87%	31.30%	3.780
10	NM (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	8500	$4,921,382	50.00%	45.22%	2.998
		10500	$5,485,958	54.31%	49.51%	2.840
		12500	$5,658,977	55.30%	52.13%	2.650
11	NM (battery connection)	8500	$4,880,082	27.32%	15.52%	3.777
		10500	$5,328,472	27.25%	14.07%	3.513
		12500	$5,742,186	27.43%	12.96%	3.194
12	NB (battery connection)	8500	$2,892,408	29.54%	25.06%	4.364
		10500	$3,528,746	33.87%	29.32%	3.941
		12500	$4,097,046	37.78%	33.19%	3.641

Table A.5: Technoeconomic Results for Small Mills (for all cases)

Small-sized Mills						
Case	**Description**	**Load Connected (kWh)**	**NPV ($)**	**IRR (%)**	**ROI (%)**	**Simple Payback Period (years)**
1	Net Billing - Nominal	250	$56,412	22.525%	18.24%	5.360
		380	$93,083	28.103%	23.71%	4.532
		450	$112,000	34.256%	29.72%	3.909
2	Net Metering - Nominal	250	$142,228	48.200%	43.39%	3.073
		380	$170,830	55.947%	51.12%	2.787

		450	$180,933	58.681%	53.85%	2.704
3	NM (higher on-peak tariffs)	380	$162,124	53.59%	48.77%	2.865
4	NB (higher on-peak tariffs)	380	$76,181.20	24.612%	20.31%	5.014
5	NB (DG capacity 600 kW)	250	$43,058	19.10%	15.11%	6.110
		380	$71,311	19.71%	15.74%	5.974
		450	$83,026	20.43%	16.43%	5.810
6	NM (DG capacity 600 kW)	250	$113,902	44.08%	39.50%	3.266
		380	$152,338	48.43%	43.81%	3.063
		450	$171,235	57.70%	52.93%	2.733
7	NM (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	250	$119,477	41.93%	37.15%	3.380
		380	$137,511	46.82%	42.01%	3.134
		450	$144,098	48.60%	43.79%	3.056
8	NB (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	250	$20,424	13.31%	9.73%	7.935
		380	$50,180	20.87%	16.67%	5.682
		450	$59,696	23.20%	18.89%	5.242
9	NB (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	250	$98,700	26.35%	21.89%	4.753
		380	$111,202	37.49%	32.83%	3.660
		450	$124,085	40.50%	35.80%	3.464
10	NM (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	250	$143,637	48.59%	43.79%	3.056
		380	$174,390	56.92%	52.09%	2.756
		450	$184,686	59.60%	54.77%	2.677
11	NM (battery connection)	250	$128,380	25.02%	14.71%	4.226
		380	$164,499	47.14%	42.49%	3.119
		450	$165,802	39.54%	35.04%	3.525
12	NB (battery connection)	250	$71,844	23.91%	19.63%	5.127
		380	$115,869	32.02%	27.58%	4.110
		450	$126,533	31.16%	26.79%	4.195

Table A.6: Technoeconomic Results for Medium-sized Mills (for all cases)

Medium-sized Mills (or aggregated SME Dispatch)						
Case	**Case Description**	**Load Connected (kWh)**	**NPV ($)**	**IRR (%)**	**ROI (%)**	**Simple Payback Period (years)**
1	Net Billing - Nominal	3000	$732,008	23.848%	19.48%	5.129
		4200	$1,167,114	30.152%	25.67%	4.297
		4800	$1,270,145	32.008%	27.50%	4.110
2	Net Metering - Nominal	3000	$1,862,592	50.146%	45.33%	2.993
		4200	$2,166,818	56.662%	51.83%	2.764
		4800	$2,254,666	58.565%	53.73%	2.707
3	NM (higher on-peak tariffs - actual demand)	4200	$2,073,658	54.64%	49.81%	2.829
4	NB (higher on-peak tariffs - actual demand)	4200	$1,040,261.12	27.856%	23.43%	4.561
5	NB (DG capacity 600 kW)	3000	$558,739	20.11%	16.06%	5.868
		4200	$1,059,215	28.09%	23.77%	4.537
		4800	$1,187,680	30.43%	26.05%	4.270
6	NM (DG capacity 600 kW)	3000	$1,491,529	46.06%	41.49%	3.169
		4200	$1,906,821	50.84%	46.22%	2.966
		4800	$2,052,327	54.04%	49.36%	2.850
7	NM (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	3000	$776,246	26.32%	21.79%	4.753
		4200	$1,795,726	48.69%	43.88%	3.052
		4800	$1,678,567	46.02%	41.07%	3.171
8	NB (low self-consumption (36 %), high ToU (on-peak consumption) (40 %)	3000	$303,047	14.74%	10.98%	7.360
		4200	$606,613	19.86%	15.73%	5.904
		4800	$654,557	20.76%	16.58%	5.708
9	NB (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	3000	$831,341	25.88%	21.45%	4.819
		4200	$1,298,123	32.90%	28.36%	4.027
		4800	$1,393,005	34.52%	29.95%	3.887
10	NM (high self-consumption (68 %), low ToU (on-peak consumption) (15%)	3000	$1,877,424	50.46%	45.64%	2.980
		4200	$2,208,518	57.65%	52.82%	2.734
		4800	$2,298,694	59.60%	54.77%	2.677

11	NM (battery connection)	3000	$1,781,305	40.75%	36.13%	3.450
		4200	$2,093,069	46.22%	41.58%	3.161
		4800	$2,182,281	47.79%	43.14%	3.091
12	NB (battery connection)	3000	$914,829	24.63%	20.31%	5.011
		4200	$1,403,741	32.99%	28.50%	4.019
		4800	$1,537,847	35.26%	30.75%	3.828