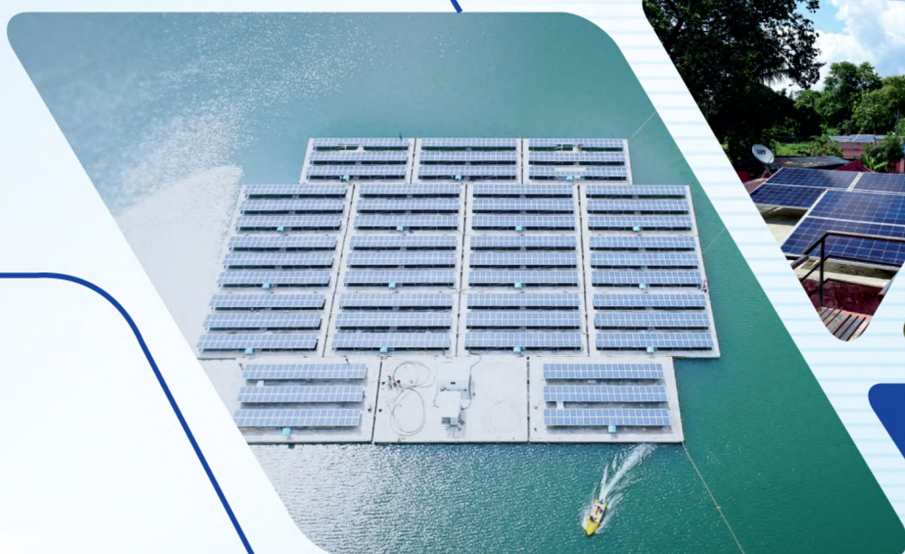
KERALA STATE ELECTRICITY REGULATORY COMMISSION

Regulatory Framework for Renewable Energy

DISCUSSION PAPER



KERALA STATE ELECTRICITY REGULATORY COMMISSION

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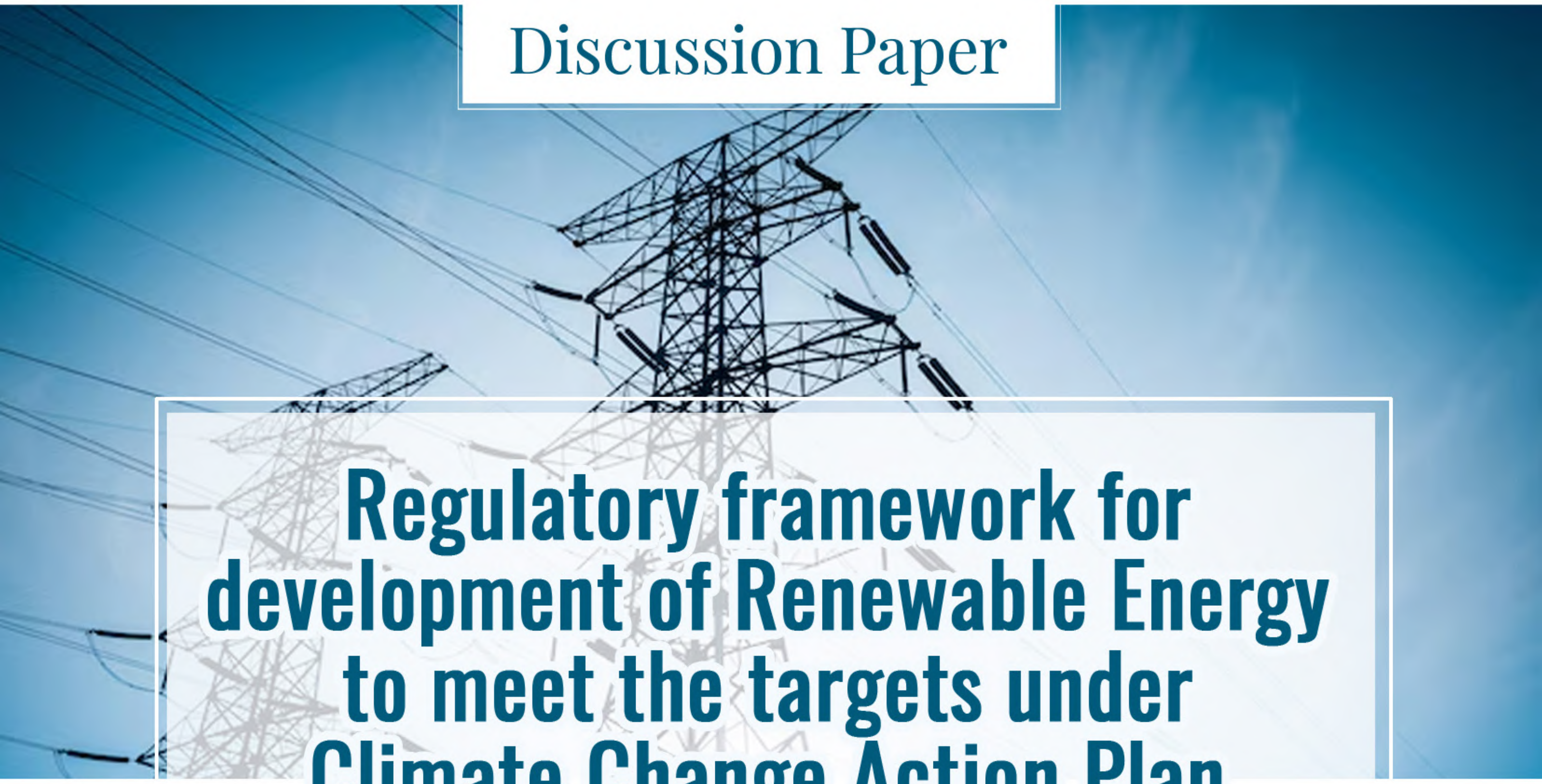


Discussion Paper

Regulatory framework for development of Renewable Energy to meet the targets under Climate Change Action Plan and to facilitate Energy Transition

January 2025

Preface

Section 86(1) (e) of the Electricity Act, 2003 authorizes the State Electricity Regulatory Commission to promote co-generation and generation of electricity from Renewable Sources of Energy by providing suitable measures for connectivity with the grid and sale of electricity to any person and specify for the purchase of electricity from such sources a percentage of the total consumption of electricity within the area of the distribution licensee. Accordingly, the Commission has notified the KSERC (Renewable Energy and Net Metering) Regulations, 2020 on 07th February, 2020. Further, it was amended on 15th July, 2022 and 17th August, 2024. The Control period of the said Regulations is upto FY 2024-25. In view of the approaching conclusion of the current control period, the Commission has resolved to formulate a new regulation for the Control Period commencing from FY 2025-26. This initiative aims to promote renewable energy in Kerala in alignment with the National and State Renewable Energy (RE) targets and Net Zero commitments. To facilitate this, the Commission has undertaken the preparation of a discussion paper to guide the development of the new regulation.

To ensure a comprehensive and informed approach, the Commission constituted an Evaluation Committee on 8th August, 2024. The Committee, comprising of the experts and professionals in the field, has been tasked with studying the renewable energy regulations across regions, identifying the challenges faced by licensees and prosumers, analyzing global trends and emerging technologies, and addressing pressing issues in the renewable energy sector. The Evaluation Committee is chaired by Sri. B Pradeep, Member (Technical), KSERC, and includes the following members:-

(1) Sri. B Pradeep, (Chairman of the Committee);
(2) Dr. Ashok S, Professor, NIT Calicut;
(3) Dr. T Rajeev, Professor, CET, Trivandrum;
(4) Dr C A Babu, Emeritus Professor, CUSAT, Ernakulam;
(5) Dr. Arun Rahul S, Assistant Professor, IIT Palakkad;
(6) Dr. Anand S. R, (Retired Director Transmission, KSEB Ltd), Aluva;
(7) Sri. Ashwin Gambhir, Fellow, Prayas (Energy Group), Pune;
(8) Sri. Bose Jacob, Institute for Sustainable Development and Energy Studies (In-SDES), Shornur;
(9) Sri. Sivaprasad P. V, Consultant (Technical), KSERC;
(10) Sri. Mohanakumar B. V, Consultant (Technical), KSERC;
(11) Sri. Sarma kumar C. S, Fellow, Consultant (Engineering), KSERC (Convenor)

After a series of consultations, deliberations, discussions, presentations, and after perusal and review of; the publications and developments in the Sector globally, nationally and within the State, the Committee has prepared the Discussion paper. This discussion paper forms the foundation for stakeholder engagement and deliberation, aiming to create a robust and forward-looking regulatory framework that addresses the evolving dynamics of the Renewable Energy sector in Kerala. The Commission invites valuable feedback and suggestions from all the stakeholders to shape the Draft Renewable Energy Regulation, for the Control Period from FY 2025-26.

Disclaimer

The issues presented in this discussion paper and the views therein are based on the analysis of the Committee entrusted to prepare the same. Those issues and views do not represent the views of this Commission and are not binding on the Commission. The contents of this discussion paper are circulated among the stakeholders, aiming to initiate informed discussions in a transparent manner and to obtain considered views, as part of evolving a balanced regulatory framework for the upcoming control period commencing from FY 2025 - 26, for the development of Renewable Energy (RE) in the State. The Commission is soliciting inputs from the stakeholders, including those on; realisable RE potential in the State and the Country, challenges and way forward in non-firm RE integration, challenges specific to distributed RE and probable solutions, financing the requirements, recent technical developments, commercial factors, social equity etc. balancing the interests of; the consumers, prosumers, captive generators, Independent Power Producers (IPPs), open access consumers, distribution licensees etc., in this regard.

Acknowledgement

This discussion paper on the ‘regulatory framework for the development of renewable energy in the State of Kerala’ was prepared by this Committee to address the issues prevailing in the State and to suggest the corrective policy measures to be adopted in the RE Regulations to be issued by the State Commission for the control period starting from FY 2025-26. Based on all the technical, regulatory, market aspects of the renewable energy system in the Indian context, viz. the tariff & availability of different systems, supply chain maturity, life cycle & techno economic analysis, legal status and the regulations in force, the Committee has suggested in the paper the needed policy changes in the upcoming regulations in the State, to facilitate the Energy transition under the Climate Change Action Plan.

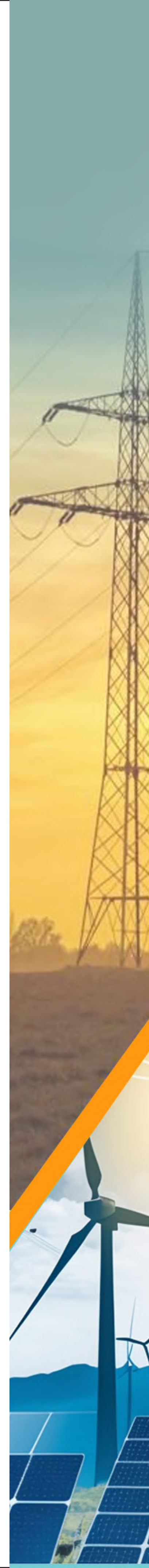
The Committee expresses sincere thanks to the Kerala State Electricity Regulatory Commission, for extending the full support in conducting the various discussion meetings and for providing the related documents & literature, to have informed and authenticated study on the subject, enabling the Committee to prepare this paper.

The Committee acknowledge the contribution given by the following, who have collected and provided the required data for the preparation of this paper: -

(i) Dr. Priyanka Paliwal, Associate Professor, Maulana Azad National Institute of Technology, Bhopal for the presentation on ‘Solar Generation in distribution network voltage support’;

(ii) Sri. Sunil N.X, Deputy Chief Engineer, System Operation Circle, Kalamassery, KSEBL for the presentation of the ‘Study Report of Solar Penetration in LT distribution Network – based on the study conducted by KSEBL’;

(iii) Sri. Justin Joseph, Executive Engineer, TMR Division, KSEBL, Thiruvananthapuram, Sri. A.S Jalesh Kumar, Executive Engineer, Electrical Division, Thiruvananthapuram and their team of officers for downloading and sharing the energy meter data for analysing the ‘Daily load profile of different consumer segments of KSEBL’;



(iv) Sri. Manoj B Nair, AEE, Corporate Planning, KSEBL, for analysing the data from TMR Division and preparing the ‘typical Daily load profile of the different consumer segments’;

(v) The Junior Consultants of the Commission for preparing the comparative data of the existing RE Regulations across various States in India (Annexure B);

(vi) The Interns (Graduate Engineers) of the Commission for preparing Annexure C data, ‘Analysis of payback periods of RTS prosumers in Kerala’, compilation of daily demand data of all the Indian States and identifying the States having complementary demand pattern with Kerala, compilation and analysis of rooftop solar PV related data, RE data, RE regulations in various States etc.;

(vii) Sri. Adarsh G, CMA, Junior Consultants of the Commission, for validating the ‘Analysis of payback periods of RTS prosumers in Kerala’

(viiI) Sri. Arakesh Madhu M. L, Junior Consultant of the Commission for; the preparation of Annexure A data, compiling the report and carrying out all the back-office works connected with the preparation of this paper.

Finally, the Committee would like to thank the various stakeholders in the field, including the various national & international publications in the subject, which have been helpful in the preparation of this paper.

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List of abbreviations used

ACC	Avoided Cost Calculator
AD	Anaerobic Digestion
AEMC	Australian Energy Market Commission
ALMM	Approved List of Models and Manufacturers
APPC	Average Pooled Power Purchase Cost
ARAI	Automotive Research Association of India
ARENA	Australian Renewable Energy Agency
BCD	Basic Customs Duty
BESS	Battery Energy Storage System
BM	Balancing Mechanism
BOOT	Build, Own, Operate and Transfer
BTM	Behind the Meter
CAES	Compressed Air Energy Storage
CAGR	Compounded Annual Growth Rate
CAISO	California Independent System Operator
CAPEX	Capital Expenditure
CCS	Carbon Capture and Storage
CEA	Central Electricity Authority, Ministry of Power
CERC	Central Electricity Regulatory Commission
COP	Conference of the Parties
CPUC	California Public Utilities Commission
CSTEP	Center for Study of Science, Technology and Policy, Bangalore
CUF	Capacity Utilization Factor
DAM	Day Ahead Market
DEBS	Distributed Energy Buyback Scheme
DER	Distributed Energy Source
DESS	Distributed Energy Storage System
DG	Distributed Generation
DISCOM	Distribution Company
DR	Demand Response
DRE	Distributed Renewable Energy

DSO	Distribution System Operators
DT	Distribution Transformer
EDLC	Electric Double Layer Capacitor
EEG	Erneuerbare-Energien-Gesetz
EIA	Environmental Impact Assessments
EPC	Engineering, Procurement, and Construction
EPS	Electric Power Survey
ESO	Energy Storage Obligation
ESS	Energy Storage Systems
EV	Electric Vehicle
FDRE	Firm and Dispatchable Renewable Energy
FiT	Feed in Tariff
FOR	Forum of Regulators
FY	Financial Year
GDP	Gross Domestic Product
GHG	Green House Gas
GNM	Group Net Metering
GoI	Government of India
GoK	Government of Kerala
GWN	Gigawat Hours
HC	Hosting Capacity
HEP	Hydro Electric Projects
HPO	Hydro Power Obligation
HVAC	Heating, Ventilation and Air Conditioning
ICE	Internal Combustion Engines
ICRA	Investment Information and Credit Rating Agency
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronics Engineers
IEEFA	Institute for Energy Economics and Financial Analysis
IEGC	Indian Electricity Grid Code
IFC	International Finance Corporation
IIT	Indian Institute of Technology
IPCC	Intergovernmental Panel on Climate Change
IRE	Intermittent Renewable Energy sources

ISTS	Inter State Transmission System
ITC	Investment Tax Credits
I-THD	Current Total Harmonic Distortion
KSEBL	Kerala State Electricity Board Limited
KSERC	Kerala State Electricity Regulatory Commission
kWh	Kilowatt hour
LADF	Local Area Development Fund
LCoS	Levelized Cost of Storage
LDES	Long Duration Energy Storage
LGB	Load Growth Balance
LHP	Large Hydro projects
MNRE	Ministry of New and Renewable Energy, GoI
MoP	Ministry of Power, GoI
MP	Madhya Pradesh
MRET	Mandatory Renewable Energy Target
MU	Million units
MSW	Municipal Solid Waste
MWh	Megawatt hour
NAPCC	National Action Plan on Climate Change
NCAER	National Council of Applied Economic Research
NEM	Net Energy Metering
NEP	National Electricity Policy
NGHM	National Green Hydrogen Mission
NHPC	National Hydroelectric Power Corporation
NSW	New South Wales, Australia
NTPC	National Thermal Power Corporation
OA	Open Access
OLTC	On-Load Tap Changer
P2P	Peer to Peer
PCC	Point of Common Coupling
PLEXO	Plexus Optimization And Simulation
PM- KUSUM	Pradhan Mantri Kisan Urja Suraksha evam Utthaan Mahabhiyan
POSOCO	Power System Operation Corporation (GRID INDIA)
PPA	Power Purchase Agreement

PPP	Public Private Partnership
PQ	Power Quality
PSP	Pumped Storage Plants
PSU	Public Sector Undertaking
PX	Power Exchange
PV	Photo voltage
RDF	Refuse Derived Fuel
RE	Renewable Energy
REC	Renewable Energy Certificate
REZ	Renewable Energy Zone
RPO	Renewable Power Obligation
RESCO	Renewable Energy Service Company
RTC	Round the clock
RTPV	Rooftop Photovoltaic solar system
RTS	Rooftop Solar
SBD	Standard Bidding Document
SCADA	Supervisory Control And Data Acquisition
SDG	Sustainable Development Goals
SECI	Solar Energy Corporation of India
SEG	Smart Export Guarantee
SIGHT	Strategic Interventions for Green Hydrogen Transition
SLDC	State Load Despatch Centre
SJVN	Satluj Jal Vidyut Nigam
SOP	Standards of Performance
SRES	Small-scale Renewable Energy Scheme
STATCOM	Static Synchronous Compensator
STC	Small-scale Technology Certificates
STOA	Short Term Open Access
TBCB	Tariff Based Competitive Bidding
TERI	The Energy and Resources Institute, New Delhi
TES	Thermal Energy Storage
ToD	Time of Day
ToU	Time of Use

UN	United Nations
UNFCCC	United Nations Framework Convention on Climate Change
UP	Uttar Pradesh
UPS	Uninterruptible Power Supply
URET	Uniform Renewable Energy Tariff
US	United States
USD	United States Dollar
V2G	Vehicle to Grid
VAWT	Vertical Axis Wind Turbines
VGF	Viability Gap Funding
VNM	Virtual Net Metering
VPP	Virtual Power Plants
VRE	Variable Renewable energy
VSM	Voltage Stability Margin
V-THD	Voltage Total Harmonic Distortion
WG	Working Group
WKNCEPPL	West Kallada Non-Conventional Energy Promoters Private Limited
WPO	Wind Power Obligation
WTE	Waste to Energy
€	Euro
$	Dollar
₹	Rupees

Executive Summary

Energy transition is vital for combating climate change, with the energy sector responsible for 73% of global greenhouse gas emissions, primarily from fossil fuels. The shift towards Renewable Energy and electrification of energy end use is accelerating. However, significant challenges remain, including the intermittency of renewable energy, underutilisation of infrastructure, and the imperative for a stable power supply. At COP28 (2023), more than 20 nations committed to tripling nuclear energy capacity by 2050 to complement renewable energy sources. Financing the Energy transition remains contentious, with developing nations seeking $1.3 trillion annually but developed nations committing only a $300 billion target by 2035 at COP29 (2024). Countries have set varied net-zero timelines—India has declared target of net zero by 2070, reduction of emissions intensity of its GDP by 45% by 2030 from 2005 level and achieve about 50% cumulative electric power installed capacity from non-fossil fuel based energy resources by 2030, requiring $150 billion annually for renewable energy expansion. While Kerala targets net zero by 2050 and 100% renewable energy by 2040, necessitating substantial investments in energy infrastructure.

The Electricity Act, 2003 forms the foundation for India's renewable energy regulatory framework as well, empowering both the Central and State Governments to promote renewable energy through policies and mandates. Key provisions include the National Electricity Policy and Tariff Policy, which aim to increase the share of renewable energy in the electricity mix, promote R&D, and encourage private sector participation. The Central Government initiatives to achieve target of 500 GW of renewable capacity by 2030 include; designating Large Hydropower as Renewable Energy and introducing Hydropower Purchase Obligations (HPO) under the Renewable Purchase Obligations (RPO), policies like waiver of Inter State transmission charges for renewables, enabling open access for green energy procurement, Viability Gap Funding for BESS and Offshore wind energy projects, hybrid renewable energy projects, PM Surya Ghar, PM-KUSUM and the National Green Hydrogen Mission, etc. The National Electricity Plan (2022-2032) emphasizes renewable energy as the core of sustainable power generation while addressing challenges like intermittency through smart grids and storage solutions. State Regulations in Kerala, have evolved over time, introducing RPO targets, Net Metering, and differential tariffs to integrate and promote renewable energy effectively. Additionally, the Central Electricity Regulatory Commission (CERC) has streamlined tariff structures, introduced perpetual validity for Renewable Energy Certificates (RECs), and promoted flexible coal-based plant operations to accommodate renewable integration.

Solar power has emerged as the dominant renewable energy (RE) source globally, surpassing wind in capacity and witnessing a rapid expansion driven by falling prices. Reports indicate that global solar capacity reached 2,000 GW by 2024, with rooftop solar comprising 40% of this, showcasing active consumer participation in greening the grid. Overproduction of solar cells and modules in China, which produces five times the combined output of the rest of the world, has driven prices to record lows. Regulatory frameworks in regions like California, United Kingdom, Germany, and Australia have evolved over time to balance rooftop solar adoption with equitable sharing of RE integration costs, emphasizing grid stability, promoting energy storage including home batteries, and market-based mechanisms for energy transactions. Energy Storage Systems (ESS), including battery solutions and Vehicle-to-Grid (V2G) technologies, are being adopted globally to enhance grid resilience, support renewable integration, and stabilize electricity supply.

An overview of state wise regulations on RE in India also indicate an evolution of policies in line with progress in RE technologies and local adoption trends. The Forum of Regulators (FOR), established under the Electricity Act, 2003, has formed a Working Group (WG) to examine renewable energy (RE) policies and regulatory issues with a view to harmonize regulatory approaches. Key interim suggestions of the WG include clearly defining mechanisms like Net Metering, Gross Metering, Net Billing, Behind-the-Meter (BTM), Virtual Net Metering (VNM), and Group Net Metering (GNM) to facilitate energy accounting and billing for Distributed Renewable Energy Systems (DRES). The WG highlights the need for tailored metering/billing systems based on consumer categories to address cross-subsidy variations in tariffs. It also recommends introducing Peer-to-Peer (P2P) energy trading using blockchain technology for domestic consumers, with initial thresholds to regulate adoption. States like UP, Delhi, and Karnataka have issued guidelines for P2P transactions.

As of October 2024, India's renewable energy capacity reached 200

GW, accounting for 46.3% of the total electricity generation capacity of 452.69 GW, with solar leading at 90.76 GW. The RE potential zones identified to meet the target of 500 GW by 2030 are concentrated in eight Indian States, viz, Rajasthan, Andhra Pradesh, Karnataka, Tamil Nadu, Telangana, Madhya Pradesh, Gujarat and Maharashtra. Kerala stands out with its entire state generation solely from RE and for its leadership in rooftop solar (RTS) having an aggregate capacity of 946.9 MW as on October 2024, which constitutes 72% of the State's total solar capacity—far above the global average of 40%. Installed capacity of Rooftop solar constitutes 22% of State's day demand. However, daytime solar generation is not supporting Kerala's peak power demand, unlike in States like Gujarat having peak demand during day time.

Renewable energy sector in India has made significant strides with the Central Government empowering Central PSUs like SECI, NTPC, NHPC, and SJVN as intermediary procurers to streamline bidding for DISCOMs. This has led to greater market efficiency, with large-scale bidding lowering prices. In 2023-24, the country initiated bids for 69 GW, surpassing the 50 GW target, with intermediary procurers playing a key role in expanding the RE market. Apart from the conventional bids, new products like hybrid RE, RE with storage, RTC RE, and FDRE are being introduced to address diurnal and seasonal power variations, providing more reliable energy solutions. These developments enable the States having inadequate RE potential to meet its energy transition goals in an economical manner. Additionally, energy storage systems like BESS, Pumped Storage Plants etc. are vital for achieving India's decarbonization targets.

To meet its ambitious renewable energy goals, Kerala has set higher Renewable Purchase Obligation (RPO) targets than the national mandate but faces challenges in monitoring, compliance, and transparency. Enhanced RPO compliance mechanisms, clearer reporting, and penalties or incentives to meet targets is required to meet the RPO targets. Kerala faces significant challenges in meeting its 50% RPO target by 2029-30, requiring an additional 10,000 MU of renewable energy, primarily from hydro, solar and wind supported by energy storage systems. The higher capital costs of new hydro projects and the very limited reservoir storage capacity are major concerns which need to be addressed. Wind energy growth is also hindered by high tariffs and limited potential in Kerala's challenging terrains. Overcoming these barriers requires substantial investment, technological innovation, and regulatory reforms. The State has pioneered floating solar projects, including one at Banasura Sagar

Dam; but there is an urgent need to address forest related issues and also to evolve innovative models like land pooling as in West Kallada Floating solar project. Kerala needs energy storage systems for meeting diurnal as well as seasonal demand variations. For addressing seasonal demand variations, long duration energy storage PSPs and collaboration with States having complementary demand patterns are required. Other renewable sources, like offshore wind, municipal waste-to-energy and tidal energy, offer potential but are still underdeveloped. Additionally, rising interstate transmission charges, driven by investments in transmission infrastructure and low capacityutilization of renewable plants, present financial challenges, though importing renewable energy remains economically competitive. Achieving a balance between intrastate and interstate renewable energy sourcing is crucial for meeting energy transition goals.

The adoption of Decentralized Renewable Energy (DRE) faces challenges related to grid stability, power quality, and technical integration, especially with the growing penetration of rooftop solar power. Issues include voltage fluctuations, unbalanced reverse power flow, harmonics, and unbalanced loads, which affect grid performance and reliability. For instance, during solar peak hours, significant voltage rises and dips, phase unbalance, and increased reactive power draw result in power quality degradation. The additional costs for mitigating these issues are often overlooked, however, will soon lead to increases in retail tariffs. These costs include, cost of storage, cost of balancing, cost of network modernisation etc and can be clubbed together as cost of RE integration. A balanced framework for an equitable sharing of these costs among all network users including prosumers is to be evolved. The payback period analysis of solar rooftop systems installed by different categories of consumers indicate significantly different compensation under net metering regulation due to the difference in retail tariffs among the categories of consumers. Also, in view of availability of higher compensation to certain categories of consumers, it appears that the global trend of lowering solar prices is not properly reflected in the Kerala market. A recalibration of regulations to ensure efficient functioning of the market is required.

The Renewable Power hosting capacity in Kerala is currently set at 90% of the distribution transformer capacity, but KSEB Ltd has raised concerns about the impact of increased renewable energy (RE) penetration. To address this, several safeguards are proposed, including limiting rooftop solar PV capacity per phase to appropriate capacity, capping reverse power flow as a percentage of the transformer's capacity after conducting studies, and requiring neutral earthing at transformers, poles, and consumer points for system safety. Additionally, solar capacity should align with a consumer's connected load/contract demand, and hybrid/smart inverters with Battery Energy Storage Systems (BESS) would be required for plants above certain capacity to mitigate voltage fluctuations. The limits may be specified after conducting detailed studies. For areas with exhausted hosting capacity, rooftop solar installations can be allowed only through behind-the-meter systems or smart inverters with BESS. Further, inverters with dynamic reactive power support should be incentivized to enhance grid stability, and smart appliances paired with Time-of-Use tariffs can encourage usage during solar hours. As rooftop solar capacity grows rapidly, an updated Time-of-Day tariff design for 2025-2030 is needed, along with strategies for energy storage and efficient consumption. A rationalization of Net Metering policies is also proposed, with options for net billing or gross metering for larger systems. A new banking framework would gradually increase banking charges to encourage self-consumption during solar hours and/or battery storage. Virtual Net Metering and Group Net Metering options can be expanded for community and institutional solar projects. Additionally, prosumers could be offered more options, such as Peer-to-Peer energy trading, Vehicle-to-Grid (V2G) systems, and Demand Response programs. Transition periods for existing consumers will ensure a smoother alignment with new regulations.

The Committee recommends several measures to foster renewable energy (RE) development in Kerala, including integrating the policy suggestions from Chapter 9 into the new RE regulations. To improve grid stability, cost-effective energy storage solutions such as Battery Energy Storage Systems (BESS) and Pumped Storage Plants (PSP) should be implemented. Existing hydropower projects should be optimized by increasing pondage capacity, while new hydroelectric projects should be assessed for viability and cost reductions. The wind energy potential in Kanjikode, Attapady, and Ramakkalmedu, along with offshore wind energy along Kerala's western coast, should be explored using Viability Gap Funding (VGF). Municipalities are encouraged to establish Waste-to-Energy (WtE) plants with PPP models, supported by MNRE funding. The development of green ammonia projects should be promoted to decarbonize industries, while new technologies including small modular nuclear plants should be explored to secure long-term energy supply as coal plants are phased out.

Chapter
1

Introduction

1.1 The Energy Transition

The United Nations (UN) has put in place a broad framework for sustainable development (Sustainable Development Goals: SDGs) which has an inseparable nexus with energy; the innumerable ways in which energy is produced and consumed. As concerns on greenhouse gas (GHG) emissions and climate change have increasingly became reality, energy is often at the heart of the climate action debate and is also recognised as the key to the solution. The International Energy Agency (IEA) estimated global emissions attributable to the energy sector as 73% and the emission contribution within the energy sector, viz power generation, Transport, Industry, Buildings, accounts for 40%, 23%, 23% and 10% respectively. Fossil fuels, such as coal, oil and gas, are the primary sources for energy which causes GHG emissions. Switching energy systems from fossil fuels to renewables to reduce emissions is often recognised as ‘Energy Transition’. While the role of renewables in electricity generation in this transition is well recognised, often, the role of electricity in displacing fossil fuels in energy end use is understated.

The emerging role of electricity in energy transition is emphatically recognised in the recently published World Energy Outlook 2024 by IEA, which notes: ‘Energy System is moving at speed into the Age of Electricity’. Electricity use has grown twice as fast as total energy demand from 2010 to 2023 and between now to 2035, electricity demand is set to grow six times as fast as overall energy demand as a result of factors like; the adoption of electric vehicles, air conditioning use, the digitalisation of the economy, the expansion of Artificial Intelligence etc.

1.2 Challenges in Energy transition

The Energy systems targets for global pathways to limit global warming to within 1.5°C of the pre-industrial levels by 2050[1], includes:

(1) lower the energy use through enhanced energy efficiency;

(2) faster electrification of energy end use;

(3) use of low emission energy sources;

(4) renewable energy supplying 70-85% of electricity in 2050;

(5) increasing the share of nuclear energy;

(6) fossil fuel use with carbon capture and storage; and

(7) sharply reducing coal usage.

With the faster electrification of energy end use, the electricity share in energy demand in buildings is to reach 55 – 75%, transport to increase from less than 5% to 35 – 65% in these projected pathways. Increased use of electricity for heating needs in industry and use of green hydrogen etc. are also envisaged. The annual average additional energy related investments for energy transition is estimated as around 830 billion USD.

The energy transition spreads across the entire value chain, from generation to consumption. Fossil fuels which have been at the core of global economies for more than 150 years need to be replaced by renewable and nuclear. It also requires changes in transmission and distribution technology on account of higher deployment of distributed energy resources (DER) including storage technologies, against the concept of larger power houses and extensive high power transmission system that leveraged on 'economy of sizes'.

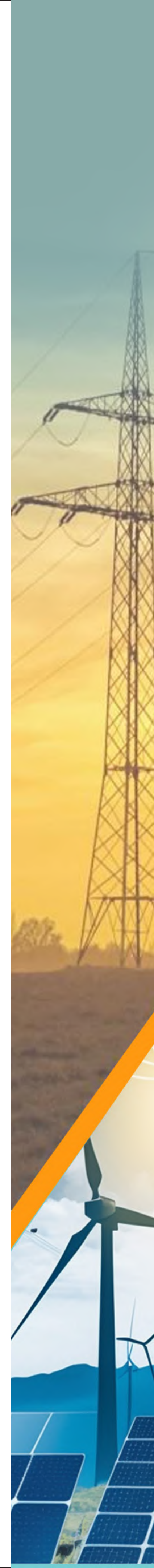
The challenge in integrating the power from renewable energy sources such as; solar, wind etc. is its non-firm nature. 'Non-firm power' means the power generated from renewable sources, the variation of which is dependent upon nature's phenomenon like sun, cloud, wind etc. that cannot be accurately predicted nor be regulated for real time balancing with dynamically varying usage requirements. It is also known as Variable Renewable Energy (VRE) or Intermittent Renewable Energy Sources (IRES) that are not firmly dispatchable due to their fluctuating nature, as opposed to controllable/dispatchable energy sources. This brings to focus the need for deploying Energy Storage Systems (ESS) for integration of VRE into the electrical grid and associated costs. The limited duration of daylight or wind in a day results in low capacity utilisation of the generation and connected transmission networks. Even though the fall in prices of solar and wind generation equipment compensates for the lower capacity utilisation, the underutilisation of transmission systems for centralised renewable energy plants, need for maintaining alternate source of electricity for periods of no sun and no wind has emerged as a cause for serious economic concern.

Meeting the base load of electrical systems while reducing the prominent role of coal and gas plants remains a major challenge in the energy transition. At COP28, held at Dubai, UAE (2023), the debate over nuclear energy as a renewable energy source took centre stage as countries grappled with the balancing of carbon reduction goals and energy security. With nuclear power producing near-zero carbon emissions, it was highlighted as a potential complement to wind, solar, and other renewables, especially for providing reliable, large-scale base load power. In the COP28, more than 20 countries from four continents launched the Declaration to Triple Nuclear Energy. The Declaration recognizes the key role of nuclear energy in achieving global net-zero greenhouse gas emissions by 2050 and keeping the 1.5-degree goal within reach. Core elements of the declaration include working together to advance a goal of tripling nuclear energy capacity globally by 2050 and inviting shareholders of international financial institutions to encourage the inclusion of nuclear energy in energy lending policies. Endorsing countries include the United States, Armenia, Bulgaria, Canada, Croatia, Czech Republic, Finland, France, Ghana, Hungary, Jamaica, Japan, Republic of Korea, Moldova, Mongolia, Morocco, Netherlands, Poland, Romania, Slovakia, Slovenia, Sweden, Ukraine, United Arab Emirates, and United Kingdom.

It is now well understood that the pathways to limit global warming provide stiff challenges and significant additional investments and depend on strong global and national commitments and emergence of new cost-effective technologies.

1.3 Climate financing

The successive UN climate change conferences (Conference of Parties -COPs) find it hard to arrive at consensus on many contentious matters including that on net zero targets and the means of financing the pathways to limit global warming. While there is near total consensus for a global net zero target by 2050, the regional and national targets vary significantly in view of the current development phase of each country. While developing nations need to elevate their population to decent living standards and develop their economies at a faster pace calling for enhanced energy use and requiring a longer time period to achieve net zero, the developed regions have to accelerate their transition to achieve net zero much before 2050. The emerging or developing regions seek a fair share in the global carbon budget and points towards the cumulative emissions already made



by developed regions in excess of their fair shares. In contrast, developed nations seek an immediate reduction in the present level of emissions by developing regions which are having accelerated growth trajectories like India and China. Climate financing, which includes financing for both mitigation and adaptation, has become the core of the debates in the last COPs and remains to be settled.

The recently concluded COP 29 held at Baku, Azerbaijan (2024) saw developing nations seeking an annual climate finance of US$ 1.3 trillion from the developed nations. However, the conference adopted a US$ 300 billion target per year, by 2035. India expressed disappointment over the development and stated that the outcome clearly brings out the unwillingness of the developed country parties to fulfill their responsibilities and is incompatible with the principle of Common but Differentiated Responsibilities (CBDR) and equity.

1.4 Global and Regional targets

In view of the lack of consensus and uncertainties on the pathways as well as the means of financing the climate action, UNFCCC follows a system whereby nations declare their own "Intended Nationally Determined Contributions (INDCs)". Presently, Germany has a net zero target by 2045 and net negative emissions post 2050, US and European Union's net zero target is 2050 and that of China's is 2060. As part of its updated INDC, India has declared targets of net zero by 2070, reduction of emissions intensity of its GDP by 45% by 2030 from 2005 level and achieve about 50% cumulative electric power installed capacity from non-fossil fuel based energy resources by 2030. The cumulative non-fossil generation capacity is targeted as 500 GW by 2030. As per CEA estimates, the power sector investments required till 2030 would be Rs 45 lakh Crores. According to the International Finance Corporation (IFC), India needs more than $10 trillion to achieve "net zero" by 2070. Annual investment to reach the target in 2030 is estimated as $150 billion.

In line with India's INDC, Kerala has declared its targets as part of the Kerala SAPCC 2.0 (State Action Plan on Climate Change 2023-30), wherein net zero is targeted by 2050 and 100% renewable energy use by 2040. It is estimated that Rs 52,238 Cr investment is required till 2030 in energy infrastructure to meet the targets. A 2023 study by NCAER[2] puts the investment requirements in the energy sector at a much higher level of 45 Billion USD and 230 Billion USD respectively for 2025-30 and 2025-50 timeframes, to meet these targets.

Chapter

2

Legal framework in India

Electricity Act, 2003 provides the basic framework for regulating the renewable energy sector as well. While the Central Government has broad powers in framing the policies, the Central and State Regulatory Commissions are mandated to promote renewable energy through various measures[3].

2.1 Role of Government and Electricity Regulatory Commissions

Section 3 (1) of the Electricity Act, 2003 requires the Central Government to formulate, inter alia, the National Electricity Policy and Tariff Policy in consultation with the Central Electricity Authority (CEA) and State Governments for inter-alia, development of the renewable sources of energy. Section 3(4) stipulates that the Central Electricity Authority shall prepare the National Electricity Plan in accordance with National Electricity Policy and notify the plan once in every five years. Sections 79 (4) and 86 (4) of the Act stipulate that, in discharge of its functions the Central and the State Commissions shall be guided by the policies published by the Central Government under Section 3. Section 61 (h) of the Act provides that, while specifying the terms and conditions of determination of tariff, the Commission shall promote co-generation and generation of electricity from renewable sources of energy. Section 86 (1) (e) of the Act further stipulates that the State Commission shall specify purchase of a certain percentage of the power procured by the distribution utilities/ licensees and obligated entities, from renewable energy sources (RPO).

Further, the Act, while casting the responsibility of regulating the sector on the appropriate regulatory commissions, stipulates interalia that it shall;

(1) promote the factors which would encourage competition, efficiency, economical use of the resources, good performance and optimum investments;

(2) safeguard consumers' interest; and

(3) promote the principles rewarding efficiency in performance.

The National Electricity Policy (NEP) published in 2005 by the Ministry of Power, Government of India stipulates the need for fully exploiting the feasible potential of non-conventional energy sources, such as small hydro, wind, bio-mass etc. NEP intends to increase the overall share of non-conventional energy sources in the electricity mix, through private sector participation and suitable promotional measures. Further, it stipulates the need for R&D on Technology Development, and commercialisation of non-conventional energy systems to meet the international standards, specifications and performance parameters[4].

In compliance with Section 3(1) of the Act, the Central Government has notified the revised National Tariff Policy on 28th January, 2016. The Tariff Policy further emphasizes the promotion of renewable energy by mandating that the State Regulators have to ensure a specific percentage of energy is sourced from renewable sources. The policy also supports the development of renewable energy through competitive bidding and tariff determination, ensuring that renewable sources become a significant part of the energy mix. Additionally, the policy allows for differential pricing to encourage investment in renewable technologies until they reach cost parity with conventional energy sources[5].

2.2 Rules and notifications by the Central government

In March, 2019 the Government of India declared large hydro power projects as a renewable source of power. In order to achieve the INDC target of 500 GW by 2030,the Ministry of Power (MoP) vide Order dated 22nd July, 2022 has notified the Renewable Purchase Obligation (RPO) and Energy Storage Obligation trajectory till FY 2029-30. It has also introduced Hydropower Purchase Obligation (HPO) trajectory, to promote hydropower generation in India and also specified that the Large Hydro projects (LHP) which come into commercial operation after 08.03.2019 will be considered to meet the HPO trajectory[6].

The Central Government has waived off Inter-State Transmission System (ISTS) charges applicable to the transmission of electricity generated from hydro, solar, wind sources and energy storage systems like Hydro Pumped Storage Plant (PSP), Battery Energy Storage Systems (BESS) and Green Hydrogen production for specific periods and the same has been recognised by the Central Electricity Regulatory Commission. The Government vide notification dated 29th December, 2022 has notified the procedure for implementation of Uniform Renewable Energy Tariff (URET)[7]. These rules establish a framework for different categories of Central pools, each catering to specific renewable energy sources, including Solar Power, Wind Power, Hydro Power, Solar-Wind Hybrid, Round the Clock Power (Solar - Wind hybrid + Storage), Peaking Power (Solar- Wind Hybrid + Storage), Firm and Dispatchable RE (FDRE) Power, and any other new pool specified by the Central Government. On 06th June, 2022 the Central Government notified the Electricity (Promoting Renewable Energy through Green Energy Open Access) Rules, 2022, allowing any consumer having load demand exceeding 100 kW to avail open access for procuring green energy. It has also introduced the concept of Green Tariff for consumers opting to avail green energy from their DISCOMs.

2.3 National Electricity Plan

The Central Electricity Authority (CEA) has notified the National Electricity Plan (NEP) (Vol-I Generation) for the period of 2022-32 in accordance with Section 3(4) of the Act. The NEP positions renewable energy as the central pillar of India's electricity planning. It emphasizes the need for a diversified energy mix that increasingly relies on renewables to meet the growing electricity demand sustainably.One of the challenges associated with renewable energy is its intermittent nature. The NEP addresses this by focusing on the need for grid flexibility and the integration of advanced technologies. It promotes the development of smart grids, energy storage solutions, and flexible power generation resources to manage the variability of renewable energy. The plan aims to transition away from fossil fuel-based power generation, thus contributing to global efforts to combat climate change. The NEP underscores the importance of investment in renewable energy infrastructure, including the development of transmission lines, substations, and grid connections specifically designed to handle the integration of renewable energy sources. NEP identifies the potential of emerging renewable energy technologies such as offshore wind, floating solar, and bioenergy. It recommends the exploration and pilot testing of these technologies to assess their viability and scalability.

Based on the generation planning studies, the likely Installed Capacity for the year 2026-27 is 609,591 MW comprising of; 273,038 MW of conventional capacity (Coal-235,133 MW, Gas–24,824 MW, Nuclear-13,080 MW) and 336,553 MW of Renewable based Capacity (Large Hydro-52,446 MW, Solar-185,566 MW, Wind-72,895 MW, Small Hydro-5,200 MW, Biomass-13,000 MW, Pumped Storage Plants (PSP projects) -7,446 MW, along with BESS capacity of 8,680 MW/ 34,720 MWh.

The likely Installed Capacity for the year 2031-32 is estimated to be 900,422 MW comprising of 304,147 MW of Conventional capacity (Coal-259,643 MW, Gas–24,824 MW, Nuclear-19,680 MW) and 596,275 MW of Renewable based Capacity (Large Hydro-62,178 MW, Solar-364,566 MW, Wind-121,895 MW, Small Hydro-5450 MW, Biomass-15,500 MW, PSP-26,686 MW (excluding 5856 MW of likely Hydro based Imports), along with BESS capacity of 47,244 MW/ 236,220 MWh. The projection of total capacity addition is in line with the target of the country to achieve a non-fossil based installed capacity of around 500 GW by the year 2029-30.

NEP envisages that the share of non-fossil-based capacity is likely to increase to 57.4% by the end of 2026-27 and may likely to further increase to 68.4% by the end of 2031-32 from around 42.5% in April, 2023. Further, as per the National Electricity Plan projections, the energy storage capacity of 16.13 GW/ 82.37 GWh, with PSP based storage of 7.45 GW capacity and 47.65 GWh storage and BESS based storage of 8.68 GW/ 34.72 GWh, is required by the year 2026-27. The storage capacity requirement increases to 73.93 GW (26.69 GW- PSP and 47.24 GW- BESS) with storage of 411.4 GWh (175.18 GWh from PSP and 236.22 GWh from BESS) by the year 2031-32.

To facilitate faster integration of intermittent RE, CEA has notified regulations on 25-01-2023 mandating flexible operation of coal based plants specifying a minimum power level of 40% and higher ramp rates. Those plants not capable of achieving these flexibility standards are mandated to achieve the same as per the phasing plan of CEA. The investments for better flexible operation of coal plants are expected to increase the tariff of power from all coal based plants[8].

2.4 Renewable Energy regulations by the Central Commission

The Central Electricity Regulatory Commission (CERC) adopts tariffs of interstate renewable energy projects selected through tariff based competitive bidding guidelines notified by the Central Government under Section 63 of the Act. Further, the CERC has to determine tariff of interstate renewable energy projects under Section 62 of the Act, for which the Commission has issued regulations for the determination of tariff from renewable energy sources for the period 2024-2027. The regulations are designed to promote growth in the sector, ensure fair tariff structures, and simplify regulatory requirements. These changes are expected to encourage investment in renewable energy projects, particularly those based on MSW, RDF, and hybrid technologies.[9]

For projects utilizing storage, the regulations specify different efficiency standards. Solid-state battery storage projects are expected to achieve an efficiency of 80%, while Pumped storage projects have a benchmark of 75%. These efficiency metrics are crucial for determining the overall viability and tariff structure for storage-based renewable energy projects.

In accordance with the Tariff policy published by the Central Government CERC has notified the regulations for regulating the renewable energy certificate (REC) mechanism. The present regulations were notified on 9th May, 2022, which replaced the earlier regulations on the matter. The REC mechanism is a market-based instrument, to promote renewable sources of energy and development of markets in electricity. The REC mechanism provides an alternative voluntary route to a generator to sell his electricity from renewable sources just like conventional electricity and sell the green attribute separately to obligated entities to fulfil their Renewable Purchase Obligation (RPO). These regulations establish a framework for issuing Renewable Energy Certificates (RECs) to renewable energy generators and enable the trade of REC's. This trading mechanism allows entities obligated by Renewable Purchase Obligations (RPOs) to buy RECs to meet their mandates, supporting India's shift towards green energy[10].

Key changes in the 2022 regulations include a revised validity period for RECs, which now remains perpetual, eliminating the expiration dates that previously limited the trade flexibility. The framework also introduces differential pricing for solar, non-solar, and hydro RECs to reflect the cost variations and market demand across technologies.

CERC has introduced enabling provisions in the Grid code in accordance with CEA regulations for flexible operation of coal based thermal

plants to facilitate integration of intermittent renewable resources into the grid. Technical Minimum load for operation of coal-based thermal power plants is reduced to 40%. The IEGC, 2023 emphasizes “flexible operation” of thermal plants, directing them to support the grid by ramping up or down based on real-time demand and renewable energy availability. The concept of two-shift operation in thermal power plants is being contemplated to enhance flexibility of operation. Two-shift operation of thermal plants seeks to adjust its operation to the grid’s needs by running during peak demand periods (e.g., morning and evening) and shutting down or reducing load significantly during periods of low demand, such as midday or late at night, when renewable energy generation is typically higher. Two-shift operation has notable technical and economic implications. Technically, the cycling process of starting up and shutting down the plant introduces challenges, including thermal stress on boilers, turbines, and auxiliary systems. Each cycle can affect the plant’s components, leading to potential maintenance needs and a reduction in the overall lifespan of equipment. Plants need to undergo retrofitting or upgrades to handle this more flexible operation safely, which might include installing advanced control systems, implementing predictive maintenance practices, and adopting technologies that minimize the impact of thermal stress[11].

2.5 Evolution of the State Regulations on Renewable Energy

In 2006, the Kerala State Electricity Regulatory Commission published the KSERC (Power Procurement from renewable sources by Distribution Licensee) Regulations, 2006, wherein the RPO was stipulated as 5% (2% each from small hydro and wind and 1% from others). It also specified the tariff norms for small hydro and wind projects. Subsequently, in 2008, the Commission published the regulations applicable to bagasse based cogeneration plants. On 1st January 2009 the Commission published the KSERC (Power Procurement from Solar Plants by Distribution Licensee) Regulations, 2008, wherein a generic tariff of Rs 15.18 per unit and the tariff norms were adopted. The Commission further issued the KSERC (Renewable Purchase Obligation and its compliance) Regulations, 2010, wherein the solar energy purchase obligation has been fixed at 0.25% of the total consumption of energy. In 2013, the Commission issued the KSERC (Power Procurement from renewable sources by Distribution Licensee) Regulations, 2013 whereby the 2006 Regulations were repealed and new norms were introduced along with RPO of 3% with an annual increase at

10%. Thereafter, the Commission published the KSERC (Grid Interactive Distributed Solar Energy Systems) Regulation, 2014, on 30.06.2014, governing the grid connected rooftop and other solar energy systems in consumer premises and introduced concepts like net metering, banking etc. The Commission in 2015 decided to issue a comprehensive regulation on RE in supersession of the existing regulations on RE, integrating provisions related to tariff norms for different renewable sources, renewable purchase obligation and decentralised renewable energy. It introduced concepts like prosumer, time zone wise differential adjustment of banked energy by prosumers and adopted generic levelized tariff for the FYs 2014 -2016.

On 07.02.2020, the Commission issued the prevailing regulation, repealing all the previous regulations, namely KSERC (Renewable Energy and Net Metering) Regulations, 2020. It introduced differential treatment of prosumers below 1 MW and those exceeding 1 MW. The prevailing provisions regarding energy banking available to prosumers were extended to captive consumers and IPPs availing open access. Newer concepts like grid support charges and banking charges for availing banking beyond the billing period were introduced. It was amended on 15.07.2022 to notify the RPO targets up to FY 2023-24 and to introduce Hydro Power Obligation for the first time. It was further amended on 07.08.2024 incorporating the provisions of the Electricity (Rights of Consumers) Rules, 2020, specified RPO targets till 2029-30, introduced energy storage obligation (ESO) for the first time and extended the validity of the regulations till financial year 2024-25. Full fungibility was introduced among different baskets of renewable energy sources for the purpose of RPO.

Meanwhile, in compliance of the provisions under the Electricity Rules, 2022 and taking into account requests from different consumers, the Commission vide the tariff order dated 31.10.2023 in OP 18/2023, has approved the green tariff applicable to those consumers requiring their distribution licensee to supply renewable energy either to meet their entire requirements or a part thereof.

Chapter 3

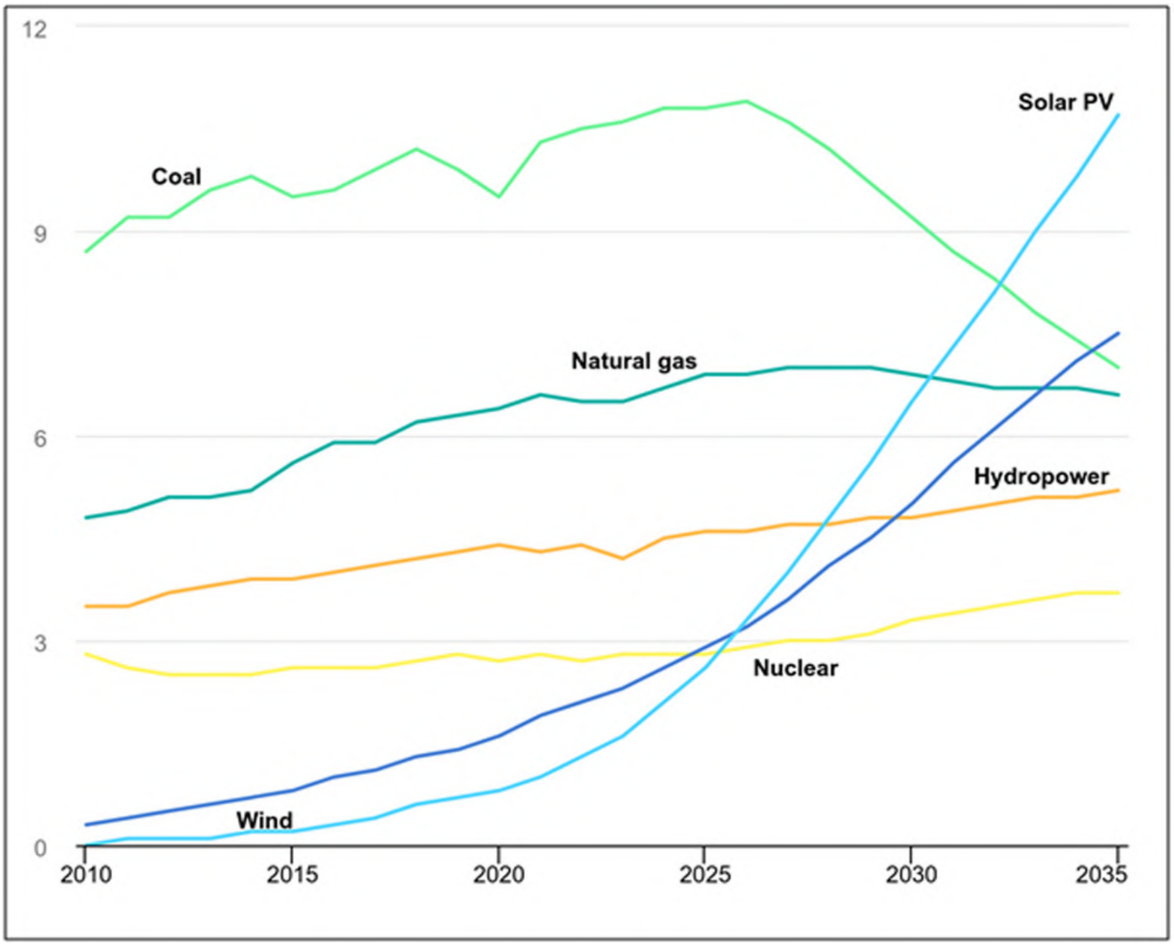
Key trends in energy transition and its regulation

3.1 Solar emerges as the leading RE source

Globally, wind and solar power has contributed significantly towards the greening of the electricity grid. Until the first half of the last decade wind power was the bulwark of renewable energy and subsequently the growth rate of solar power picked up along with dramatic fall in prices. On April 14, 2022, Forbes [16] reported by quoting an International energy agency report that the cumulative solar power capacity has surpassed the cumulative wind power capacity. It reported that 28% of global renewable generation capacity of 3,064 GW (in 2021) accounts for solar capacity, while contribution from wind capacity is 27%. More recently, a 7th November, 2024 report by Economic Times[17] suggests that the global solar capacity has crossed 2,000 GW, doubling the capacity in two years. Most strikingly, the rooftop solar capacity forms 40% of the total solar installed capacity, signalling significant consumer participation towards greening the grid.

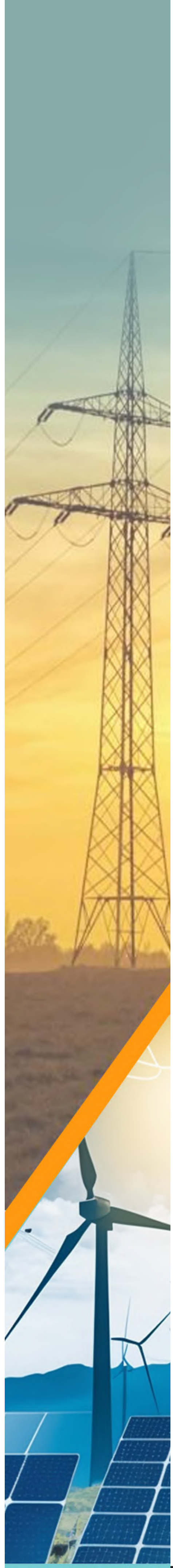
The following chart (Chart 1) from the World Energy Outlook, 2024 by IEA provides the anticipated transition in energy generation until 2035 under the Stated Policies Scenario (STEPS) is designed to provide a sense of the prevailing direction of energy system progression, based on a detailed review of the current policy landscape. It may be noted that the value in the Y-axis is electricity generation in TWh. The most dramatic features are the steep rise in solar power generation and the anticipated steep fall is coal power generation. The generation from nuclear, wind and hydro are also projected to grow, while that from natural gas is to fall.

Chart 1: Changing Energy mix under STEPS[18]



3.2 Overproduction push solar prices down

The Economist in its June 2024 special issue titled "Dawn of the solar age" interalia provided indications of overproduction of solar modules, especially in China that is driving the prices down further. The Chinese solar module production capacity has tripled since 2021 and has reached an annual production capacity of 1,000 GW. This is almost five times the rest of the world's combined capacity. The production capacity of China alone is twice the global annual module demand. As a result, the global price has fallen to a record 10 cents per watt, according to PV Insights, a data provider. At the same time, China is adding on its production capacity and Wood Mackenzie forecasts that China's solar industry will expand capacity to nearly 1,700 GW by 2026.



3.3 Global trends in regulating renewable energy development

An analysis of the evolution of regulatory framework in major jurisdictions that has achieved significant growth in renewable energy generation was undertaken. The same is included as **Annexure A.** The salient features are listed below:

3.3.1 California

California's Net Energy Metering (NEM) program, launched in 1996 with NEM 1.0, was designed to incentivize rooftop solar adoption by allowing residential and small commercial customers to offset their energy usage and receive bill credits for excess electricity exported to the grid. Under NEM 1.0, customers received credits at full retail rates, which helped make solar investments financially attractive. However, the program faced criticism for creating a significant cost shift onto non-solar customers who indirectly subsidized NEM participants, as solar customers avoided many charges tied to grid maintenance and public service programs. This inequity primarily impacted lower-income customers, who were less likely to afford solar installations, while higher-income households benefited disproportionately.

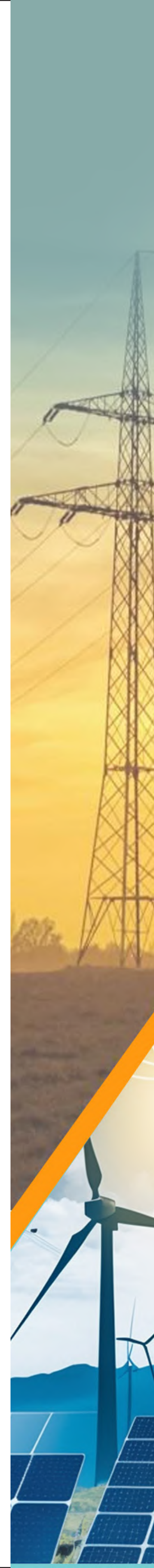
To address these issues, California introduced NEM 2.0 in 2016, requiring new solar customers to use time-of-use (TOU) rates and pay non-bypassable charges on imported electricity to contribute toward grid upkeep. An interconnection fee and adjustments to the billing structure further aimed to balance solar incentives with grid costs. Despite these reforms, NEM 2.0 still led to cost shifts, prompting the adoption of NEM 3.0 in 2023. NEM 3.0 restructured compensation rates based on the Avoided Cost Calculator (ACC), moving away from retail rate credits to better reflect the value of solar exports to the grid. The program also implemented highly differentiated TOU rates and non-by passable charges, while allowing systems to be oversized by up to 50% for future use needs, with a nine-year legacy period. These adjustments aim to ensure sustainable solar growth while reducing financial impacts on non-solar customers and making the benefits of solar energy more equitable across the State[19].

3.3.2 United Kingdom

Britain introduced Feed-in-tariff (FiT) in 2010 to promote small scale renewable energy producers as part of decarbonising its grid. The scheme involved payment at FiT for the entire generation and for export at an export tariff. The initial high rates offered under the FiT scheme led to rapid uptake, which put immense financial pressure on the government. Smart Export Guarantee (SEG) replaced FiT in 2019, introducing a market-driven approach where suppliers (similar to DISCOMs in Indian context) set competitive rates for exported electricity, encouraging consumers to choose among suppliers (DISCOMs) for better returns. Unlike FiT, SEG only compensates for exported energy, thus incentivizing efficient usage and export during peak times. This shift is intended to support the evolving energy market while reducing government intervention, aligning with broader goals for renewable energy adoption in a competitive market framework[20].

3.3.3 Germany

Germany's Electricity Feed-in Act of 1991 marked a pivotal moment in renewable energy policy, mandating grid access for renewable producers and establishing fixed compensation rates. Renewable energy sources received payments at percentages of the average retail electricity price (90% for wind/solar, 65-80% for others). However, this initial policy provided limited financial security for investors. The Renewable Energy Sources Act (EEG) in 2000 further advanced renewable adoption with feed-in tariffs (FiTs) guaranteed for 20 years and prioritized grid access, allowing producers to benefit from higher, fixed compensation rates. Producers were paid for all the electricity they exported to the grid rather than offsetting it against their own consumption. The specific tariff levels varied by system type and capacity. Initially, the EEG 2000 successfully accelerated renewable energy adoption by offering high fixed feed-in tariffs, resulting in rapid growth in solar, wind, and other renewable capacities. However, this success also led to higher costs, passed on to consumers through increased EEG surcharges on electricity bills, sparking a need to control expenses and reduce the financial burden on households and businesses. The EEG 2014 and 2017 updated the framework to control the rising consumer costs and integrate renewables into the market, shifting to competitive auctions for large installations and adjusting FiTs as renewable costs fell.



Key features of EEG 2014 included Self-Consumption Levy, Degression Mechanism by which FiT rate automatically decreased over time, Grid Access Fees, VAT on Solar PV Installations and Electricity Sales. Consumers were charged with an EEG surcharge to fund the green transition. With lower feed-in tariffs and the introduction of the self-consumption levy, EEG 2014 indirectly encouraged solar consumers to use their own electricity rather than export it. This made battery storage systems and energy management tools more appealing, as they helped maximize self-consumption and reduce reliance on the grid. EEG 2017 encouraged more market access to larger RE installations.

Through EEG 2023, Germany aims to generate 80% of its electricity from renewables by 2030, adjusting the EEG to address carbon neutrality and energy independence needs. By reducing financial burdens like the EEG surcharge on self-consumption and increasing the incentives for battery storage, Germany sought to balance the requirement for making renewable energy generation attractive for both residential and commercial sectors with the requirement for resilience and flexibility in its energy grid. It mandates smart energy meters for even small renewable energy generators. There is an expanded focus on energy storage systems (including home batteries and large-scale storage projects) as a means to smooth out the fluctuations of renewable energy and enhance overall grid stability. Prosumers and businesses are incentivized to install storage systems that can provide flexibility and stability to the grid by participating in Demand Response programs. EEG 2023 offered expanded support for community projects, incentivized integrated storage solutions, reducing the financial burden on consumers through capped EEG surcharges. Provisions are made to encourage peer-to-peer energy sharing, allowing energy producers to share excess energy directly with neighbours or local businesses. A gradual transition to a fully market-based renewable energy system is a key goal of EEG 2023. Over time, feed-in tariffs (FiTs) will be phased out for new projects, and market premiums will become the dominant compensation mechanism [21].

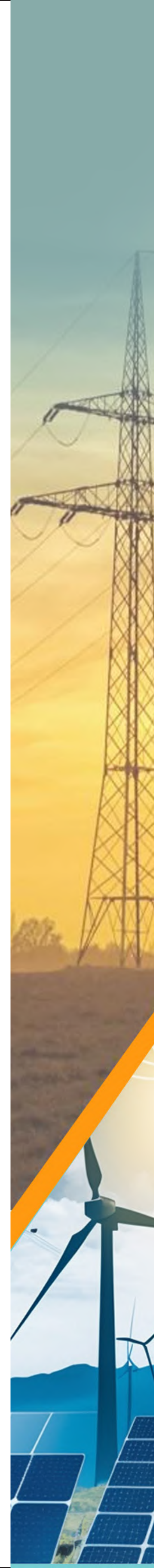
3.3.4 Australia

Australia, in 2000, began with the gross metering system to promote solar energy under the Renewable Energy (Electricity) Act, 2000 that introduced the Mandatory Renewable Energy Target (MRET). The Feed-in-Tariff (FiT) was initially based on the wholesale market price of electricity which transitioned to a more attractive state specific FiT like the Solar Bonus Scheme by NSW during 2005 - 2010. Between 2010 - 2015 most States transitioned to net metering and net billing systems. Between 2015 - 20 as solar technology became more affordable, many States phased out or reduced premium FiT schemes. In recent years, settlement mechanisms have become more sophisticated. Time-of-Use Billing has been introduced in many States, including Victoria and Western Australia, offering higher rates during peak evening hours. In addition, battery integration incentives have been introduced, such as South Australia's Home Battery Scheme, enabling prosumers to maximize self-consumption and export during high-demand periods.

In August 2021, the Australian Energy Market Commission (AEMC) introduced new rules to regulate export of electricity to the grid by prosumers which are initially optional and to become mandatory by 2025. The electricity companies will have to offer a "basic export service" – that allows solar owners to export excess solar up to a particular threshold without having to pay additional charges. For prosumers wanting to export above the threshold, the electricity companies are to offer two different payment plans, where households pay an additional charge to export their excess power into the grid, but in return could benefit from higher feed-in-tariffs and other incentives to export power at times beneficial to the wider grid. In 2024, the electricity companies started implementing the new rules on an optional basis which will become mandatory from July 2025. The transition intends to carve a path for smart solar, batteries and electric vehicles, whereby more solar can be used and keep costs down for all consumers and protect the value of household solar investments already made[22].

3.4 Focus on Energy Storage Systems (ESS)

Internationally, countries such as Germany, the United States, and Australia have incentivized the deployment of Battery ESS (BESS) through various funding programs, tax credits, and subsidies. For example, the United States offers Investment Tax Credits (ITC) for BESS, making them more affordable for commercial and residential users. In Australia, the government has introduced rebates for battery systems, often in conjunction with solar PV installations, to encourage the use of energy storage. Additionally, in countries like South Korea, BESS has been integrated into national grid management systems, where operators can call upon stored energy during periods of high demand. These international initiatives aim



to enhance grid resilience, support the integration of renewable energy, and reduce the need for additional fossil-fuel-based peaking power plants. Few international experiences and best practices are summarised below.

3.4.1 Experience in USA

In United States, particularly in California, Vehicle-to-Grid (V2G) systems are actively encouraged through participation in the California Independent System Operator (CAISO)'s ancillary services market. This market provides an opportunity for vehicle owners with V2G-capable electric vehicles (EVs) to earn compensation by offering valuable grid services such as frequency regulation and spinning reserves. By providing these services during periods of high demand or low renewable generation, V2G systems help to stabilize the grid and enhance its reliability. In exchange for this support, vehicle owners are financially compensated, creating a win-win scenario where EV owners can offset the cost of owning and charging their vehicles, while simultaneously contributing to the stability of the State's energy infrastructure. This model is part of California's broader strategy to encourage clean energy technologies and smart grid innovations[19].

3.4.2 Experience in Australia

In Australia, the Government offers various grants and subsidies to support the deployment and scaling of energy storage solutions, including Battery Energy Storage Systems (BESS), through programs such as the Australian Renewable Energy Agency (ARENA). These initiatives are aimed at accelerating the adoption of large-scale storage technologies that can enhance the reliability and efficiency of the country's renewable energy infrastructure. BESS are increasingly integrated into the country's Frequency Control Ancillary Services (FCAS), where storage operators are compensated for providing critical grid stabilization services. In return, storage operators are paid for their contribution to grid reliability, making it a financially attractive proposition for investors and further incentivizing the expansion of battery storage systems as a key part of Australia's energy transition towards a more sustainable, low-carbon future[22].

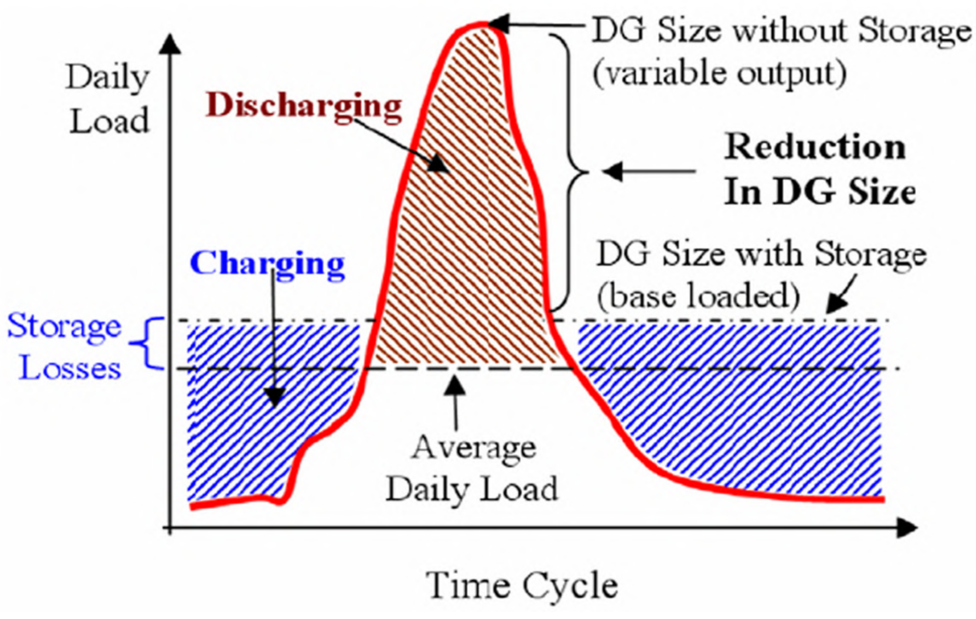
3.4.3 Experience United Kingdom

In the UK, the National Grid ESO has collaborated with electric vehicle (EV) charging companies to integrate Vehicle-to-Grid (V2G) technology into the Balancing Mechanism (BM), the tool used to stabilize the electricity grid in real-time. The initiative allows EV owners to provide ancillary services by exporting electricity back to the grid during times of imbalance, such as during peak demand periods. Participants are compensated for this service, and the trial has shown that, if scaled up, V2G could generate significant benefits, potentially saving the consumers millions in balancing costs and even reducing their electricity bills. This integration marks a significant step toward using EVs as an active part of the grid management system, contributing to a greener and more stable energy infrastructure[20].

3.5 Roles of Grid scale ESS and Decentralised ESS

A Distributed Energy Storage System (DESS) optimally located on the utility grid can mitigate many of the issues of heavy penetration of decentralised generation through rooftop solar etc.

Figure 1: Impact of energy storage on DG rating[23]



Energy storage systems in combination with advanced power electronics (power electronics are often the interface between energy storage systems and the electrical grid) have a great technical role and lead to many financial benefits.

Grid Frequency Support and Angular Stability Support are required to reduce any sudden, large load generation imbalance in order to keep the grid frequency and tie line flows within the permissible tolerance for periods up to 30 minutes. Storage systems shall have sufficient capacity to provide such support to the grid on call. This is a paid service in most of the countries and is on the anvil for implementation in India.

Load Levelling Support is required to meet the load during no-solar, no-wind period as well as, when the generation is not sufficient to balance the load in real time. This aspect requires the ESS to be schedulable as per system requirements. The cost of energy delivered is the sum of the cost of the energy used for charging/ pumping and the cost of maintaining the ESS. As this is the major purpose of the Energy Storage Scheme, this is to be fixed as the tariff of the ESS. It also follows that the grid requires a sufficient number of storage systems of suitable unit capacity so as to schedule and operate them. In other words, the distributed storage systems need to be limited to local compensation, including local power quality improvement.

Storage could be used to time-shift electric energy generated by renewables. Energy is stored when demand and price for power are low, so the energy can be used when demand and price for power is high and output from the intermittent renewable generation is low. Thus, it can enhance the profitability of the renewable sources from a generators' perspective and reduce the tariff from the Regulators' and DISCOM's perspective.

ESSs can provide black start capability, which helps a system startup from a total shutdown.

Energy Storage Schemes can be compared in terms of power density, energy density, power capacity, discharge time, cycling times, efficiency etc. as depicted below:

Figure 2: Power and energy density comparison of ESS[24]

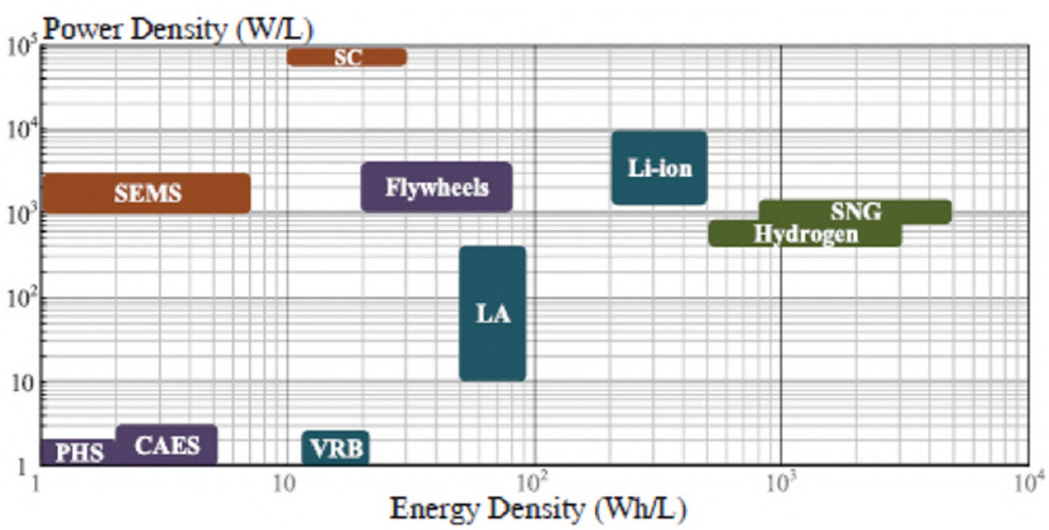
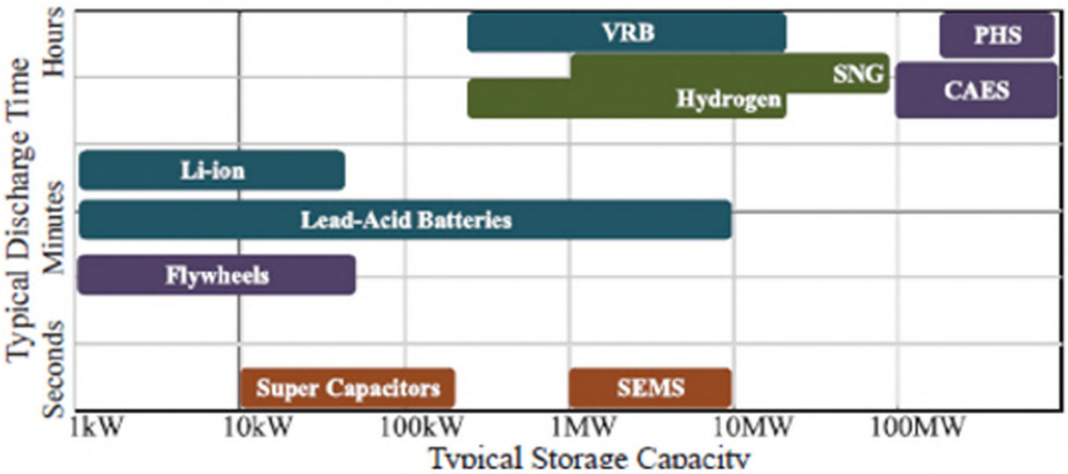
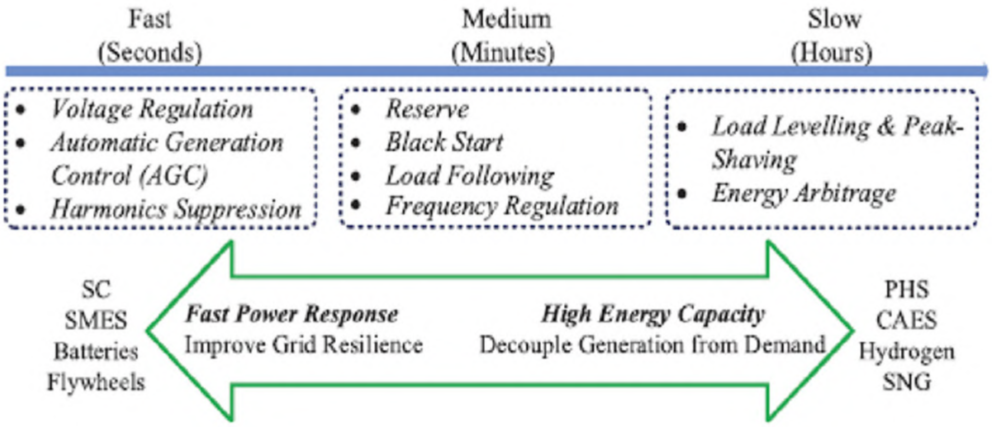


Figure 3: Typical power capacity and discharge time for ESS[24]



The selection of the ESS depends on the purpose as depicted in the picture below.

Figure 4: Grid support function diagram[24]



Energy arbitrage (leveraging price difference in different time periods) is another role of ESS by attempting to earn a profit by charging the ESS at a lower electricity rate and selling the stored energy at a higher price. Traditionally, this function is implemented by pumped hydro storage (PHS) systems. In general, the ESSs are charged in the daytime, when PVs generate power, and are discharged at night when PV power is unavailable. As a result, the system power is balanced and the reliability is enhanced. With the wide application of EVs, numerous charging scheduling are possible for energy arbitrage.

While short duration energy storage devices are low-hanging fruits, long duration energy storage (LDES) is essential for reducing the carbon foot-print. The battery energy storage for LDES is still in the developmental stage for cost optimization. As on date, the best LDES is pumped storage schemes with sufficient storage capacity of reservoirs.

3.6 Decentralised RE regulations across various States in India

A compilation of major features of RE regulations in different States in India is available at **Annexure B**. It gives the details of various billing systems (net metering, net billing, gross metering, behind the meter, group net metering, virtual net metering etc.) in place in each State, energy banking available, settlement rate for renewable energy fed into the system, settlement period, Time of day (ToD/ToU) settlement of surplus energy fed into the system etc. It can be seen that regulations in various States are still evolving and there are significant differences between the State Regulations, resulting in varied compensation mechanisms. A comparison of settlement rate for net metering, net billing and grosmetering in different States is provided in Table 1.

Table 1: Settlement rate for renewable energy fed into the system

State	Net Metering	Net Billing	Gross Metering
Kerala	At Average Pooled Power Purchase Cost Rate (Rs 3.15/ unit for FY 2023-24)	NA	NA
Tamil Nadu	No payment for any excess unadjusted electricity at the end of settlement period	Feed in tariff Rs.3.61 (0-10kW) Feed in tariff Rs.3.37 (11-150kW) Feed in tariff Rs.3.10 (>150 kW)	Feed in tariff Rs.3.61 (0-10 kW) Feed in tariff Rs.3.37 (11-150kW) Feed in tariff Rs.3.10 (>150 kW)
Maharashtra	Generic Tariff - latest tariff rate discovered for Grid Scale Solar project as generic tariff of surplus energy from Rooftop PV projects and is Rs. 2.90/kWh for FY 2024-25	Generic Tariff - latest tariff rate discovered for Grid Scale Solar project as generic tariff procurement of surplus energy from Rooftop PV projects and is Rs. 2.90/kWh for FY 2024-25	APPC Rate @ 4.88/kWh for FY 2024-25

Gujarat	RESIDENTIAL, GOVERNMENT and MSME enterprises: Self-owned and third party sale : - 2.25 Rs/unit for the first 5 years. 75% of simple average tariff discovered for non-park based solar projects in preceding 6months period (April - Sep, or oct - march) from CoD in competitive bidding. For other consumers :- At 75% of the simple average of tariff discovered and contracted through competitive bidding process conducted by GUVNL for non-park based solar projects in the preceding six months period.		At the rate determined by the Commission as per decision of the Commission in Petition No. 1802/2019. (Rs 2.62/ kWh to 2.66 kWh + Rs 0.20)
Rajasthan	weighted average tariff of large-scale solar projects of 5 MW and more, discovered through Competitive Bidding in last Financial Year, for entire duration of the project (₹2.87–₹3.00/kWh for the year 2024)	weighted average tariff discovered through Competitive Bidding for respective technology in previous Financial Year and adopted by the Commission, plus an incentive of 25%, for entire duration of the project (₹2.87–₹3.00/kWh for the year 2024)	
Uttar Pradesh	at Rs 2/ kWh for the unadjusted electricity credits at the end of settlement period	weighted average tariff of large-scale solar projects of 5 MW and more, discovered through Competitive Bidding in last Financial Year, for entire duration of the	weighted average tariff of large-scale solar projects of 5 MW and more, discovered through Competitive Bidding in last Financial Year, for entire duration of the project plus 25% incentive (Rs 2.98 per

		project plus 25% incentive (Rs 2.98 per unit +25% incentive - March, 2024 rate)	unit +25% incentive - March, 2024 rate)
Haryana	Unadjusted units shall lapse at the end of the settlement period and shall not be paid for by the distribution licensee		the tariff be Rs. 3.11/- per unit for five year without any escalation despite market asymmetry
Bihar	Excess energy lapse at end of settlement period		Feed-in Tariff at Rs 3.11 per unit (Rate discovered in 2022 and is still continuing)
Delhi	Rate for FY 2020-21 at Rs 2.79/ unit for BSES (from true up order- latest published)		
Madhya Pradesh	Any energy excess unadjusted net credited units of electricity shall be payable by the discom at the lowest tariff rate discovered by solar/wind bidding in MP in the preceding FY. (Rs 2.14 per kWh		at the lowest tariff rate discovered by solar/wind bidding in MP in the preceding FY, for the energy injected by the prosumer. (Rs 2.14 per kWh
Assam	APPC rate (Rs 5.33 kWh. For FY 2024-25)		APPC rate (Rs 5.33 kWh. For FY 2024-25)
`West Bengal	Rs . 2.09/unit	Rs . 2.09/unit	"Feed in Tariff Rs. 3.13/unit (LT), Rs. 2.92/unit (HT of max 1.5MW plant capacity), Rs. 2.71/unit during off peak hours and Rs. 4.17/unit during peak hours (HT/EHT of max 5MW"

Tripura	1) If energy export exceeds consumption, the DISCOM will pay for the excess monthly at the Feed-in Tariff. 2)For domestic consumers, if injected electricity exceeds consumption by more than 100 units, the DISCOM will pay quarterly, capped at 3.8 units per kW of installed capacity per day. 3) Net energy credits under 100 units will carry over to the next billing period. 4) For non-domestic consumers, the 3.8 units per kW cap per day also applies, and any surplus at the end of the billing period will lapse without payment. 5) The feed-in tariff will be 35% of the average cost of supply of the financial year as determined by the commission for SRTPVS commissioned under net metering.		1) For gross metering in LT supply, the feed-in tariff will be 35% of the average cost of supply for SRTPVS systems. 2) For gross metering in HT supply (up to 1500 kWp capacity), the feed-in tariff will be 50% of the average cost of supply for SRTPVS systems. 3) For gross metering in HT/EHT supply (1501 kWp to 5000 kWp), the feed-in tariff will be 50% of the average cost of supply for SRTPVS systems. 4) For gross metering in HT/EHT supply with battery storage, the feed-in tariff will be 80% of the average cost of supply if power is supplied during the evening peak (18:00 to 22:00) as per DISCOM requirements.
Himachal Pradesh	1. For consumers approved or who opt for solar metering arrangements on or after 01-09-2022 for both net-metering and net-billing: a) If subsidy/grant/incentive is less than 50% of capital cost: 40% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.402/kWh b) If subsidy/grant/incentive is 50% or more but less than 70% of capital cost: 30% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.051/kWh c) If subsidy/grant/incentive is 70% or more but less than 90% of capital cost: 25% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.876/kWh d) If subsidy/grant/incentive is 90% or more of capital cost: 15% of weighted average rate (₹3.504/kWh) for settlement		. For consumers approved or who opt for solar metering arrangements on or after 01-09-2022 for gross metering: a) If subsidy/grant/incentive is less than 50% of capital cost: 40% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.402/kWh b) If subsidy/grant/incentive is 50% or more but less than 70% of capital cost: 30% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.051/kWh c) If subsidy/grant/incentive

	Applicable rate: ₹0.526/kWh		is 70% or more but less than 90% of capital cost: 25% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.876/kWh d) If subsidy/grant/incentive is 90% or more of capital cost: 15% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.526/kWh
Punjab	1) The electricity generated from a rooftop solar system shall not exceed 90% of the consumer's total electricity consumption during a settlement period. If generation exceeds 90%, the excess will not be paid for by the distribution licensee, cannot be carried forward to the next settlement period, and will be treated as inadvertent injection.	"1) Feed-in-tariff of Rs.2.65/kWh for FY 2023-24 2) In case (ERE x TRE) is more than {Fixed charges + other applicable charges and levies + (EDL x TRST)}, utility shall give credit of amount equal to difference (Billing Credit), which shall be carried forward to the next billing cycle. 3) Billing credits will be carried forward to the next billing cycle throughout the settlement period. However, any remaining billing credits at the end of the settlement period will not be paid by the distribution licensee."	Feed-in-tariff of Rs.2.65/kWh for FY 2023-24
Karnataka	feed in tariff (generic tariff) of ₹3.82/kWh for residential systems between 1 kW and 10 kW, and ₹2.84/kWh for		HT: PPA or Optional ToD tariff. Real-time Settlement for Captive RE producers based on production and

	projects between 1 kW and 2 MW (large-scale).		consumption Megawatt-scale Solar Projects: Rs. 3.04 per unit. Megawatt-scale Solar with BESS: Rs. 5.66 per unit. Solar Rooftop (1 kW up to sanctioned load, excluding domestic 1 kW - 10 kW): Rs. 3.20 per unit, without subsidy.
Andhra Pradesh	Rs . 2.09/unit	Rs . 2.09/unit	Feed in Tariff Rs. 3.13/unit (LT), Rs. 2.92/unit (HT of max 1.5MW plant capacity), Rs. 2.71/unit during off peak hours and Rs. 4.17/unit during peak hours (HT/EHT of max 5MW
Telangana	APPC rate and shall be either adjusted in next month electricity bill or deposited in the bank account of the Eligible Consumer. When an Eligible Consumer cancels the Net metering Agreement entered into with the DISCOM after giving a month's notice, then, unused electricity credits shall be paid at a rate of Rs 0.50/kWh by the DISCOM or at a rate as notified by the Commission from time to time and ceases to be an Eligible Consumer thereafter. The gross net metering at 11 kV and above at an average rate or price from the latest Solar Purchase Agreements into by the Distribution Licensee.		

3.7 Initiative by Forum of Regulators

The Forum of Regulators (FOR) constituted under Section 166 (2) of the Electricity Act, 2003, comprising of the Central Commission, Joint Commissions and all the State Commissions has constituted a Working Group (WG) for conducting a detailed examination of all the RE related policy and regulatory issues. The WG is yet to finalise its report. Meanwhile the WG has put forth certain suggestions, which reflect the present thinking of the WG. These include:

(1) Net Metering can be defined as mechanism whereby energy exported to the Grid from distributed renewable energy sources (DRES) of a Prosumer is deducted from energy imported from the Grid in units (kWh) to arrive at the net imported or exported energy and the net energy import or export is billed or credited or carried-over by the distribution licensee on the basis of the applicable retail tariff by using a single bidirectional energy meter for net-metering at the point of supply.

(2) Gross Metering means "a mechanism whereby the total energy generated from DRES of a Prosumer and the total energy consumed by the Prosumer are accounted separately through appropriate metering arrangements and for the billing purpose, the total energy consumed by the Prosumer is accounted at the applicable retail tariff and total solar power generated is accounted for at the feed-in tariff determined by the Commission."

(3) Net Billing can be defined as a single bidirectional energy meter used for net-billing at the point of supply wherein the energy imported from the Grid and energy exported from DRES of a Prosumer are valued at two different tariffs, where;

- the monetary value of the imported energy is based on the applicable retail tariff;
- the monetary value of the exported renewable energy is based on the feed-in tariff determined by the Commission;
- the monetary value of the exported energy is deducted from the monetary value of the imported energy to arrive at the net amount to be billed (or credited / carried- over)".

(4) Behind the Meter (BTM) means an arrangement in which the DRES is connected behind the Consumer's meter, operating in parallel with the distribution licensee's grid, and not opting for any other metering or billing arrangement options and subject to other conditions under the regulations.

(5) Virtual Net Metering (VNM) means an arrangement whereby the entire energy generated from a DRES is exported to the grid and the energy exported is adjusted in more than one electricity service connection(s) of the participating consumers located within the area of supply of the licensee as specified by the Commission.

(6) Group Net Metering (GNM) means an arrangement whereby surplus energy from a DRES is exported to the grid and the exported energy is adjusted in more than one electricity service connection(s) of the same name consumer located within the area of supply of the licensee as specified by the Commission.

(7) WG also highlighted that States such as UP, Delhi and Karnataka have notified the guidelines for Peer to Peer transactions. They recommend introducing separate chapter/enabling provisions regarding P2P trading using block chain technology in regulations for only domestic consumer category and also subject to review until cumulative installations under this P2P mode reach a certain threshold capacity (say, 200 MW or 500 MW), as may be decided by the Appropriate Commission.

(8) The WG has also made observations on the category of consumers for which different metering/billing is to be made applicable taking into account the prevailing level of cross subsidy in the retail electricity tariff. In view of the significant difference in retail tariff of different categories of consumers, following a single metering/billing system for all DRES will result in widely varying compensation systems among different groups. Thus, different metering/billing systems can be made applicable among different categories of consumers [25].

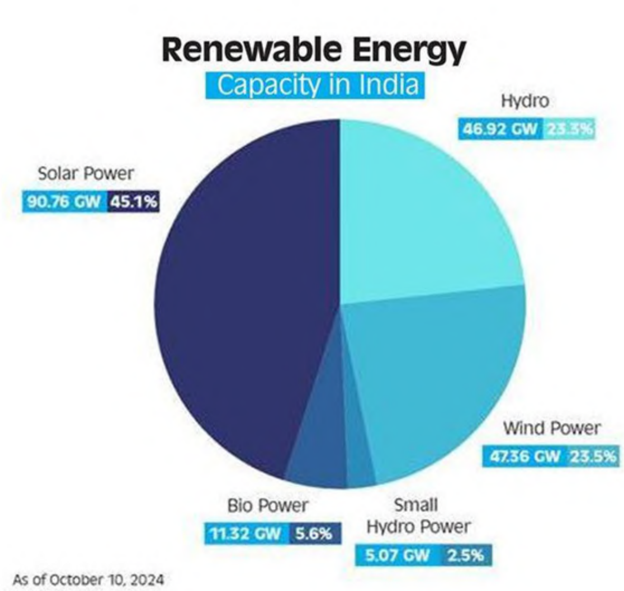
Chapter 4

Renewable Energy in India

4.1 Energy mix in India

India has reached a significant milestone in its renewable energy journey, with the country's total renewable energy capacity crossing the 200 GW (Gigawatt) mark as of October 10, 2024. According to the Central Electricity Authority, the total renewable energy-based electricity generation capacity now stands at 201.45 GW. India's total electricity generation capacity has reached 452.69 GW, with renewable energy contributing a significant portion of the overall power mix. As of October 2024, renewable energy-based electricity generation accounts for 46.3 percent of the country's total installed capacity. This marks a major shift in India's energy landscape, reflecting the country's growing reliance on cleaner, non-fossil fuel-based energy sources.

Chart 2: Renewable energy capacity in India[26]



A variety of renewable energy resources contribute to this impressive figure. Solar power leads the way with 90.76 GW, playing a crucial role in India’s efforts to harness its abundant sunlight. Wind power follows with 47.36 GW, driven by the vast potential of the coastal and inland wind corridors across the country. Hydroelectric power is another key contributor, with large hydro projects generating 46.92 GW and small hydro power adding 5.07 GW, offering a reliable and sustainable source of energy from India’s rivers and water systems. Bio power, including biomass and biogas energy, adds another 11.32 GW to the renewable energy mix. These bioenergy projects are vital for utilizing agricultural waste and other organic materials to generate power, further diversifying India’s clean energy sources. Together, these renewable resources are helping the country reduce its dependence on traditional fossil fuels, while driving progress towards a more sustainable and resilient energy future.

However, contrary to the global scenario, the share of rooftop solar PV in the total solar capacity in the country is only 16% as against the global share of around 40%. The state wise rooftop solar (RTS) capacity and its share in the total solar capacity are depicted in Charts 3 and 4 below. While Kerala stands in 4th position in respect of total RTS capacity, the share of RTS in total solar capacity in Kerala is the highest in the country at 72% and is much higher than even the global average.

Chart 3: Rooftop solar capacity across the States in India

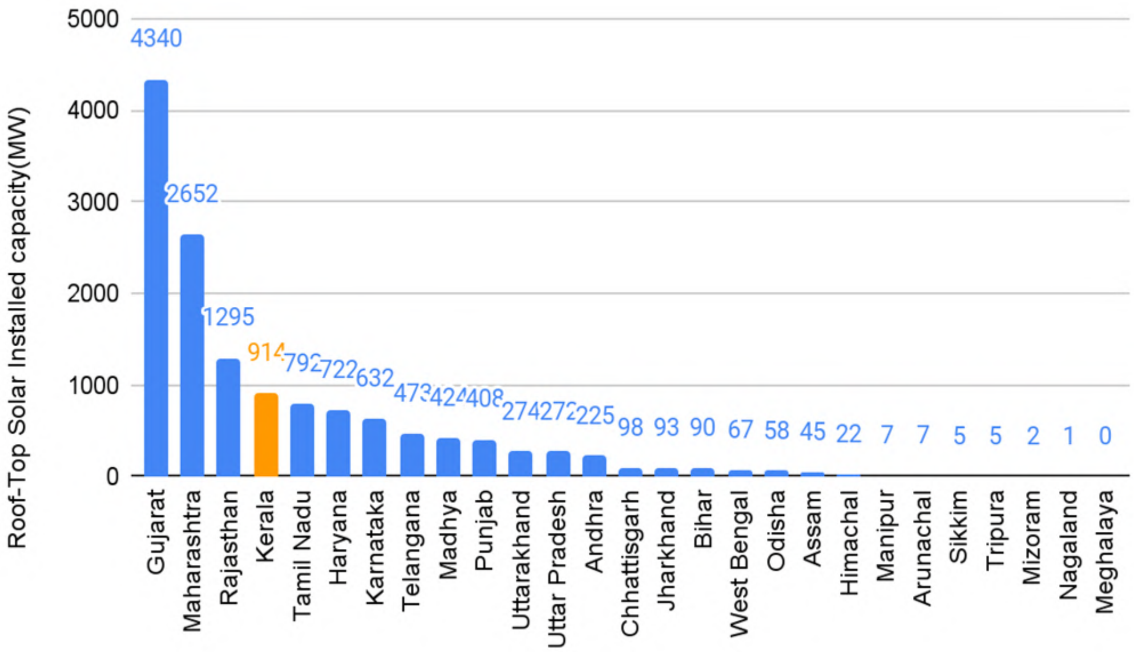
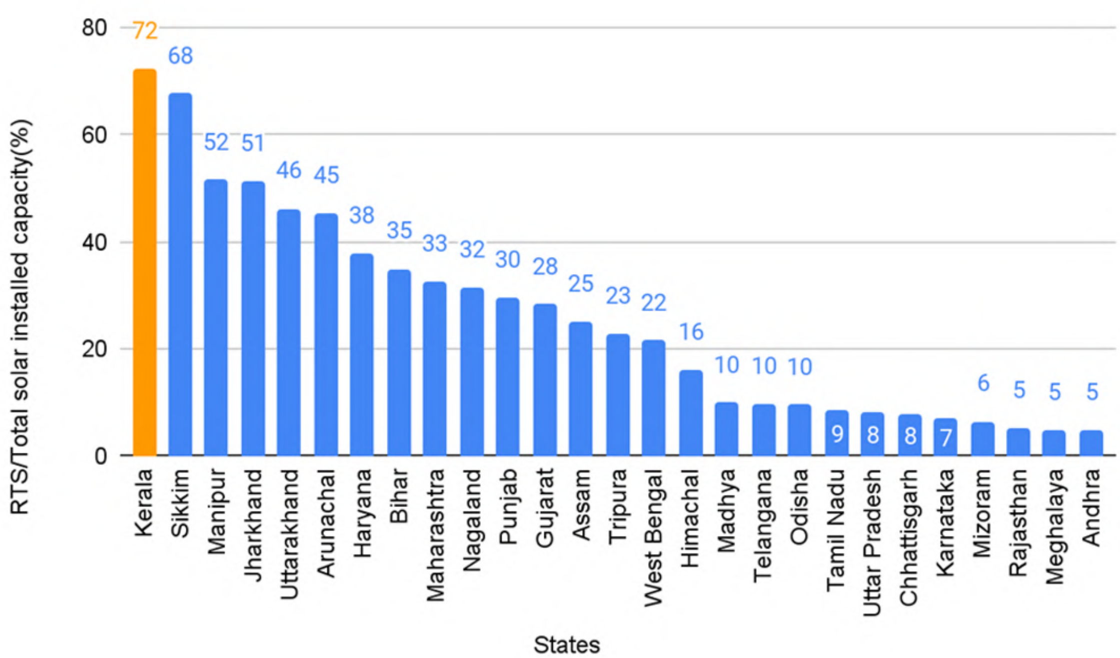


Chart 4: Share (%) of RTS in total solar capacity in each State



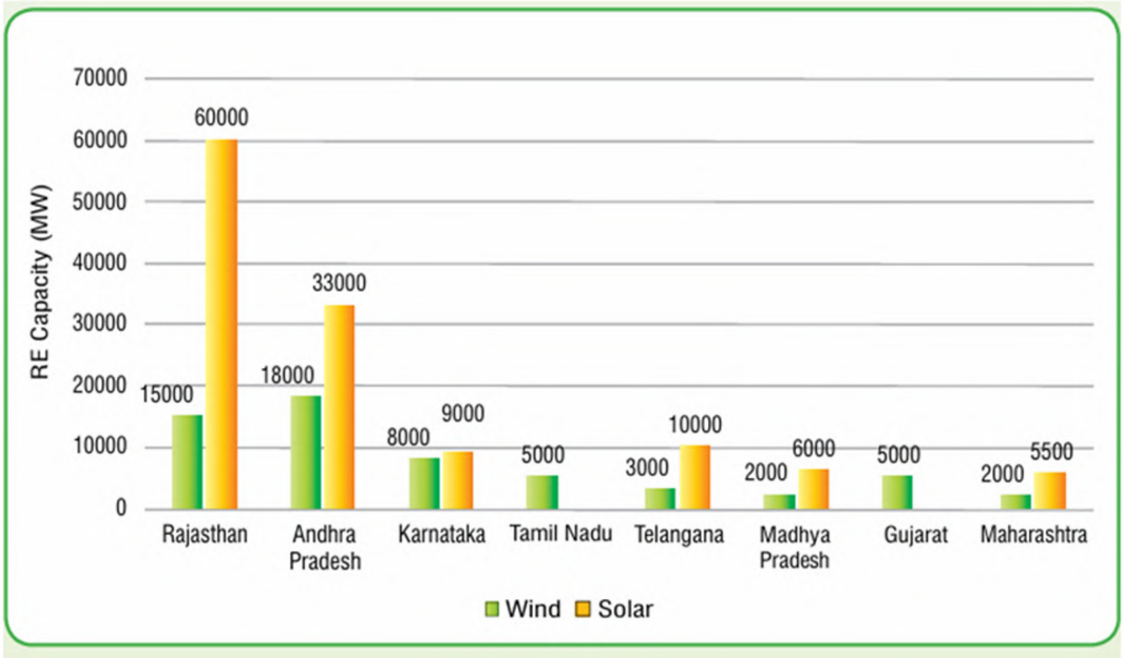
4.2 Leading States in Renewable Energy Capacity

Several states in India have emerged as leaders in renewable energy capacity addition. Rajasthan tops the list with an impressive 29.98 GW of installed renewable energy capacity, benefiting from its vast land and abundant sunlight. Following closely is Gujarat, which boasts a capacity of 29.52 GW, driven by its strong focus on solar and wind energy projects. Tamil Nadu ranks third with 23.70 GW, leveraging its favourable wind patterns to generate substantial energy. Karnataka is in the fourth position with a capacity of 22.37 GW, supported by a mix of solar and wind initiatives. Together, these states play a crucial role in advancing India's renewable energy goals and establishing a more sustainable energy future.

4.3 Additional RE potential Zones

As part of achieving the 500 GW RE target by 2030, MNRE/SECI have identified Renewable Energy Zones (REZs) totaling to 181.5 GW for likely benefits by the year 2030, in addition to the existing and ongoing schemes. These REZ's are located in eight States as depicted in the Chart 5 below.

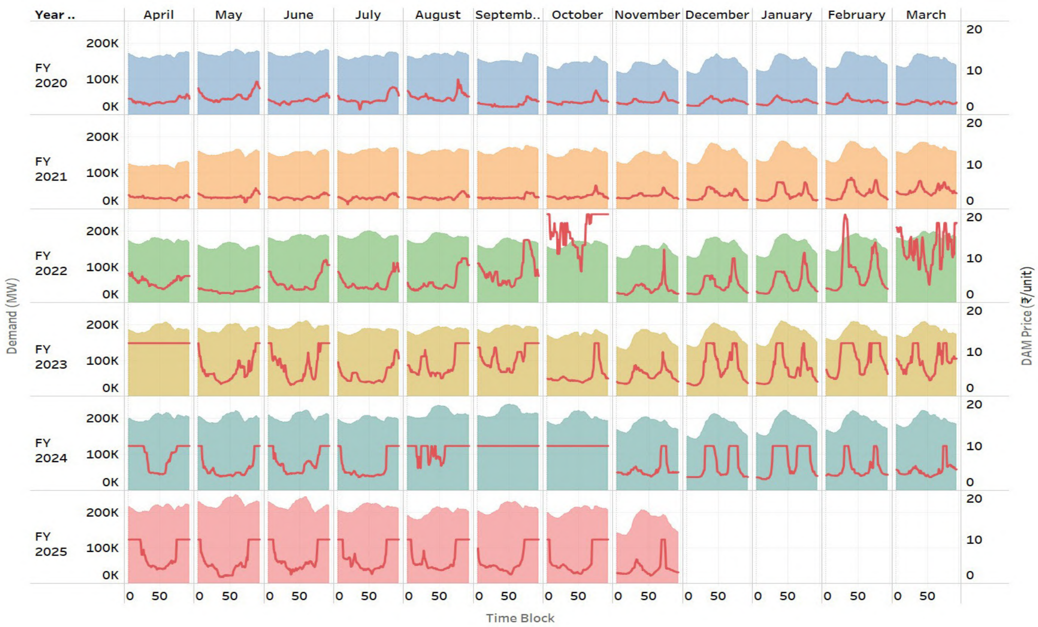
Chart 5: Additional RE potential zones in India[27]



4.4 Significant change in day power price in DAM

With significant growth in solar power generation, which is available only during day time, the price trends in the Day Ahead power Market (DAM) are witnessing a significant shift in recent times, with very low prices during day time and high prices, which often touches the ceiling rate of Rs 10 per unit, during non solar hours. Trend of intra day prices in the power market over a five year period on the maximum demand days of each month is depicted in Chart 6. The line chart provides the price discovered in each of the 15 minute time blocks (96) in the day and the area curve provides the 15 minute wise load on that day. Interestingly, even as day demand is growing rapidly, the price of day power is falling sharply, which possibly can be explained only as an outcome of rapid scaling up of solar power generation.

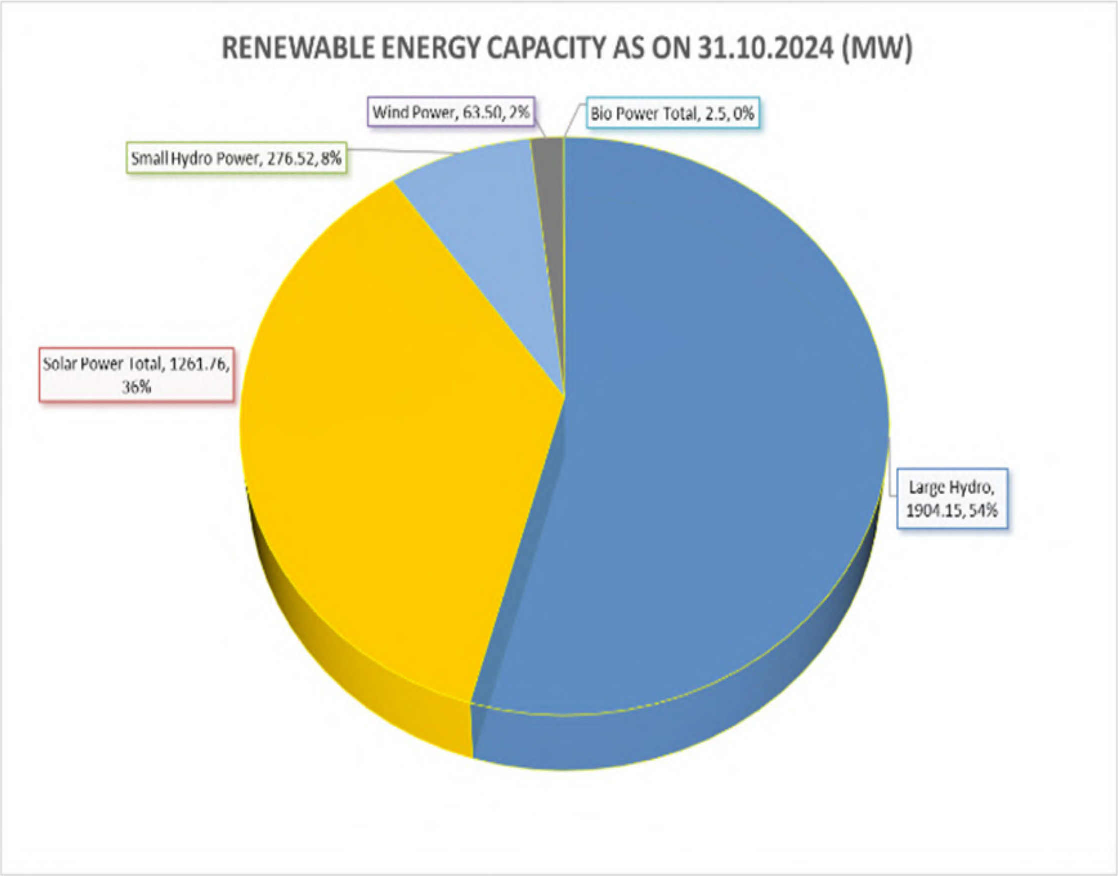
Chart 6: Intra- day demand pattern and price trend of electricity in Power Exchanges



4.5 Kerala scenario

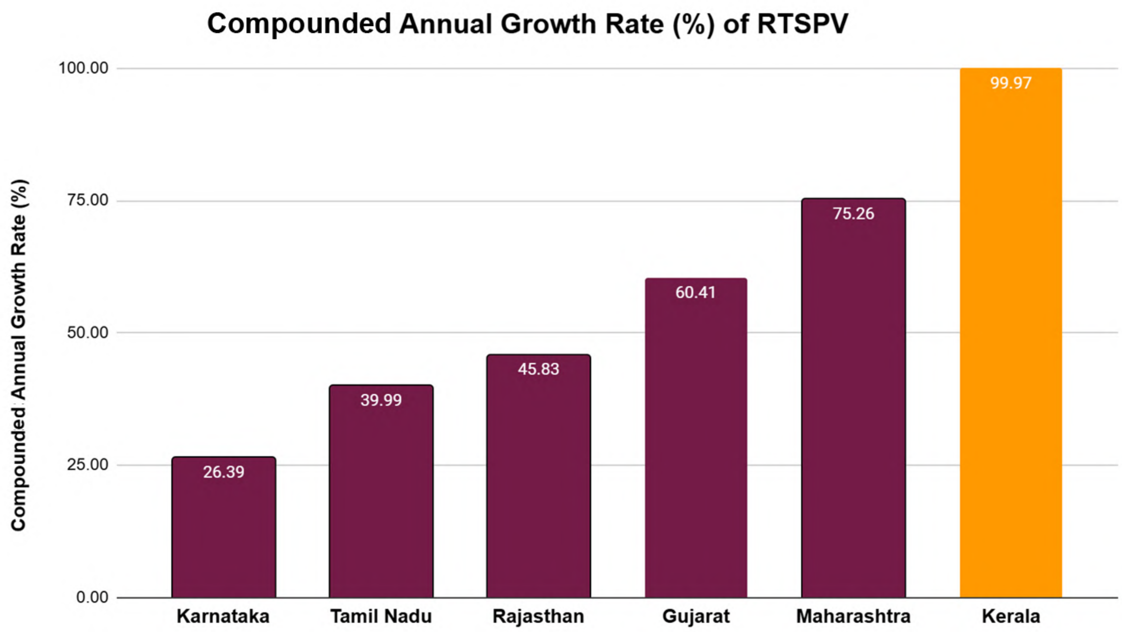
Kerala has a unique characteristic with its entire operational power generation capacity being from renewable energy sources. Even though few fossil fuel based power plants were established in the State in the late 90's, they are seldom operated. The renewable energy capacity of the state is depicted in Chart 7.

Chart 7: Renewable energy capacity of Kerala



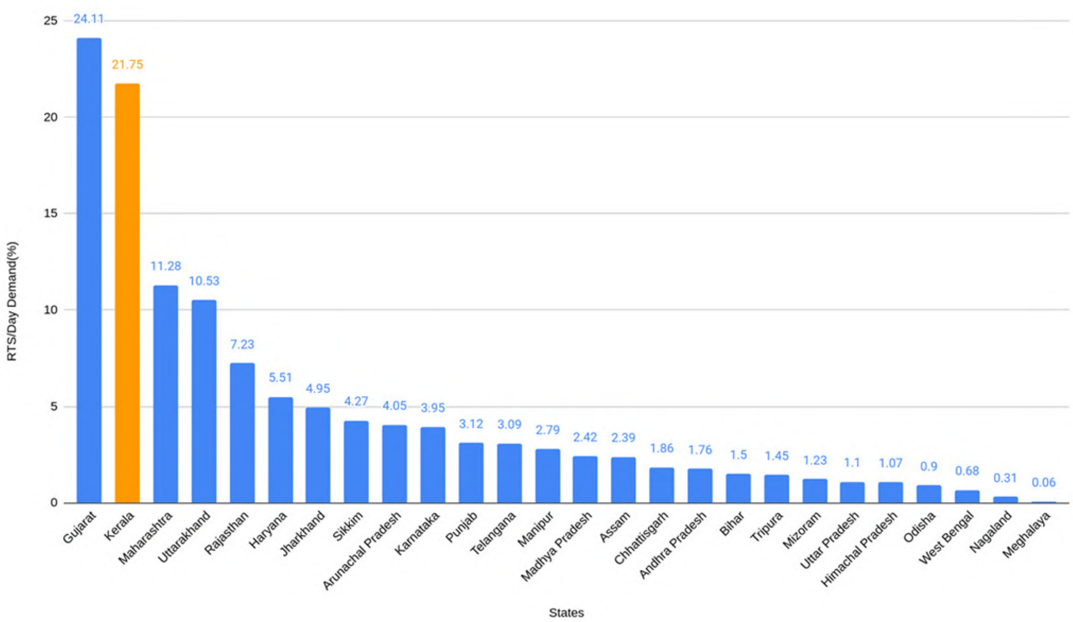
The most striking feature of the State is the share of rooftop solar PV capacity in the total solar power capacity of the State as depicted in Chart 4 above. In Kerala, the total installed capacity of Rooftop Solar plants as on 31.10.2024 is 946.9 MW and the number of RTS plants is 1,51,922. The rate of growth in rooftop solar installations in the state is the highest in the country. Chart 8 indicates the compounded annual growth rate (CAGR) of rooftop solar capacity in the states which have the largest share of rooftop solar installations in the country, from 2020. Kerala has the highest CAGR among the Indian States.

Chart 8: CAGR of rooftops solar PV capacity addition in leading States



The rooftop solar contribution towards the day demand of the State is another noteworthy feature. Chart 9 depicts the rooftop solar capacity as a percentage of each State's day demand.

Chart 9 - RTS capacity as a % of day demand of States



As can be seen, only Gujarat and Kerala have a predominant share of rooftop solar capacity as compared to their day demand. Here, one distinguishable feature of Kerala is its daily load curve as against the load curve of Gujarat. The daily load curves of these states over a fourteen year period as provided in the Electricity Demand Pattern Analysis report 2023 of Grid India[28] is furnished in Charts 10 and 11 below. It provides the daily demand met curve for each month of the year over a period from 2009 to 2022. While the solar generation during the day supports the peak demand of Gujarat (which is during daytime), there is little support from solar generation for meeting Kerala's peak demand (which is during night).

Chart 10: Daily demand curve of Gujarat in each month[28]

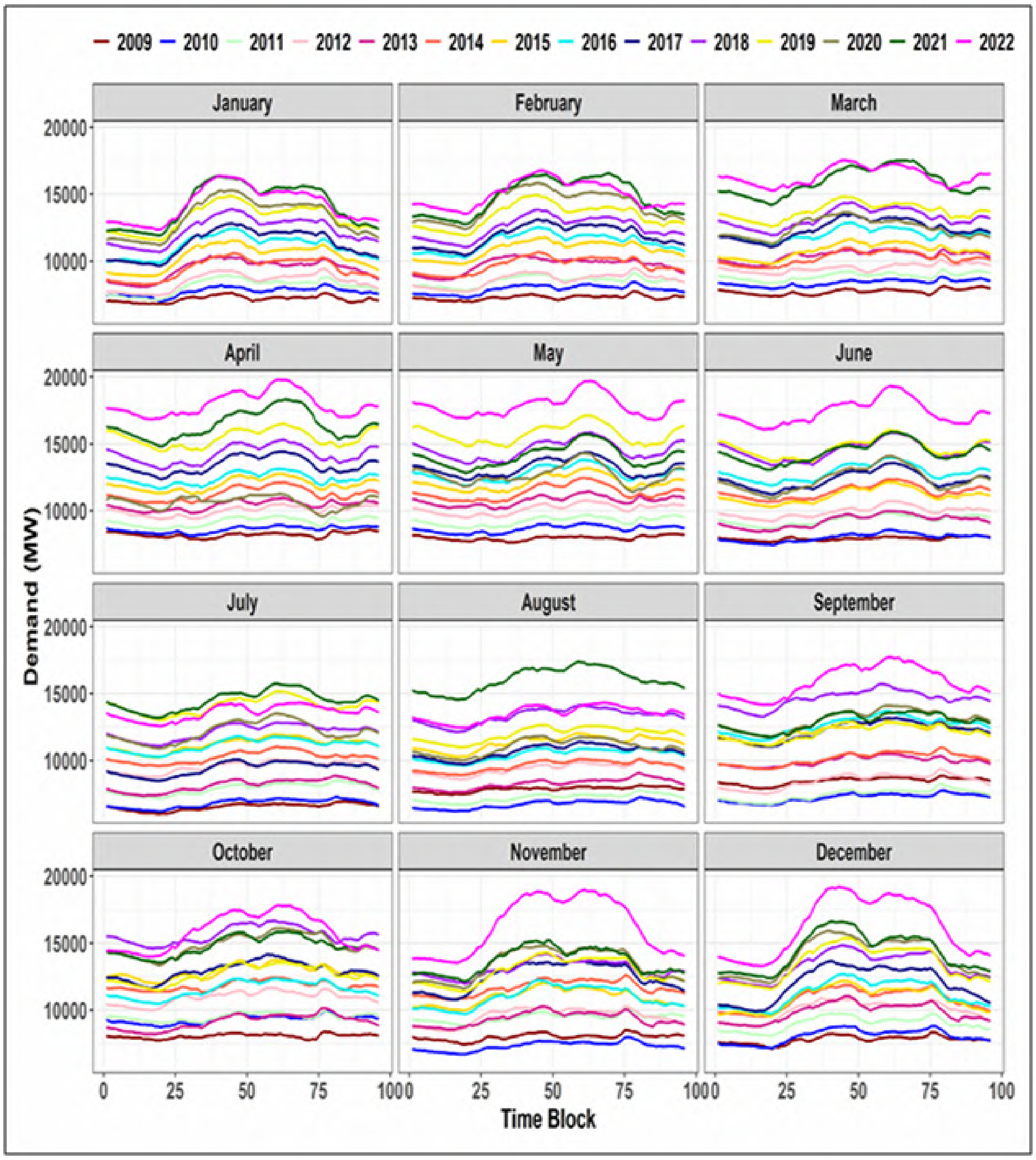
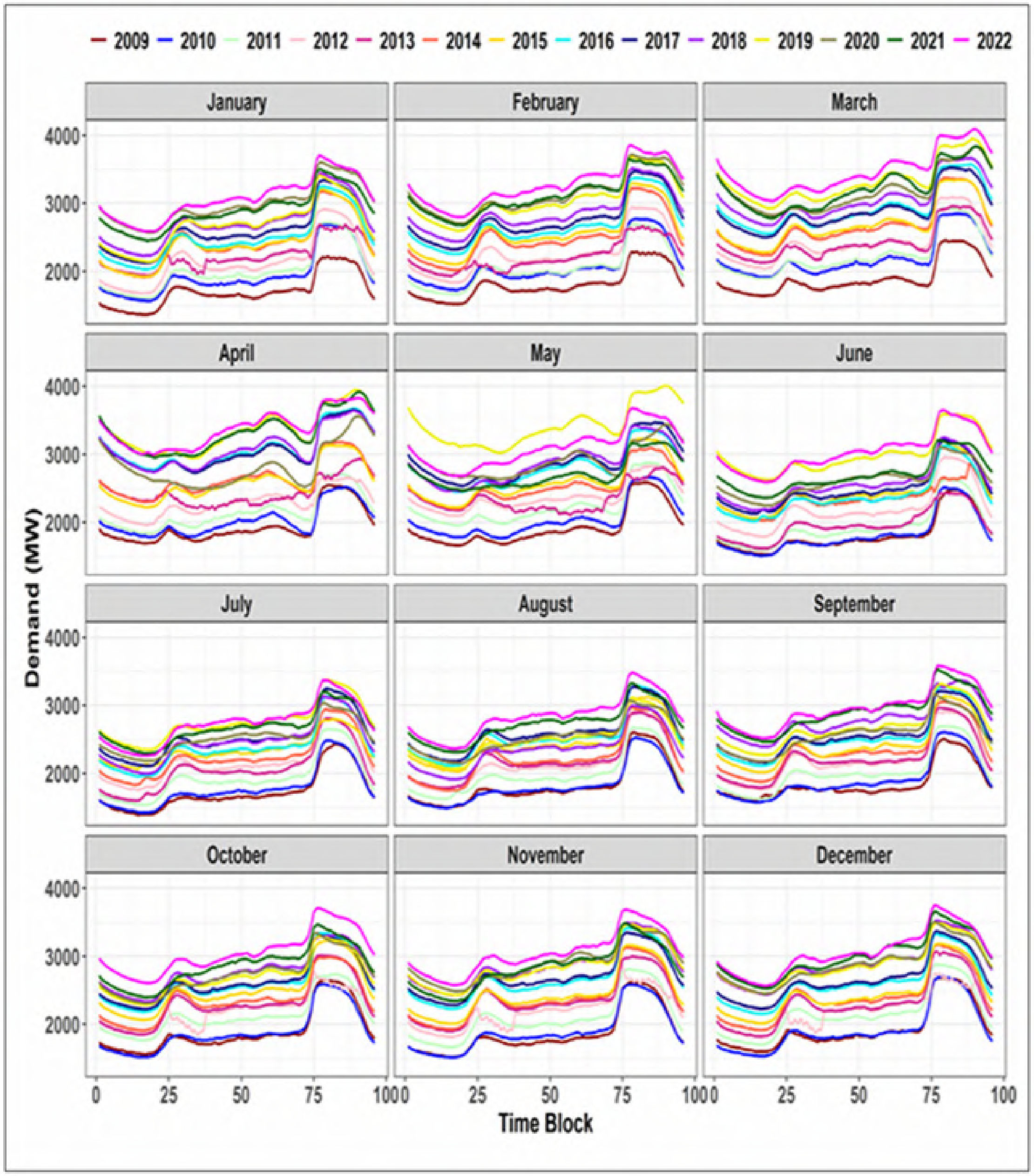


Chart 11: Daily demand curve of Kerala for each month[28]



Chapter
5

Recent Developments in India's RE Ecosystem

5.1 Renewable energy market

As part of creating an efficient market for renewable energy, Central Government has notified central PSUs viz Solar Energy Corporation of India Ltd (SECI), NTPC Ltd, NHPC Ltd and Satluj Jal Vidyut Nigam Ltd (SJVN) as intermediary procurers to initiate aggregate bidding on behalf of the distribution companies (DISCOM) in the country. The Government has also notified the guidelines for tariff based competitive bidding (TBCB) for procurement of renewable energy under Section 63 of Electricity Act, 2003 along with standard bidding documents (SBDs). The DISCOMs can independently invite bids for procurement of RE or can entrust any of the intermediary procurers to initiate bidding on their behalf. Subsequently, as part of meeting the 500 GW RE target by 2030, Central Government has set an annual target of 50 GW bidding quantum for the intermediary procurers and accordingly the intermediary procurers has started inviting bids even before obtaining authorisation from DISCOMs. Furthermore, intermediary procurers act as a financial buffer between developers and DISCOMs, mitigating risks associated with payment delays or default. The aggregation of demand by the intermediary procurers has resulted in bids having large volumes thereby creating sufficient interest among investors and has helped in creating an efficient market for RE. This strategy has helped in faster fall in price of renewable energy products.

5.2 New products in RE market

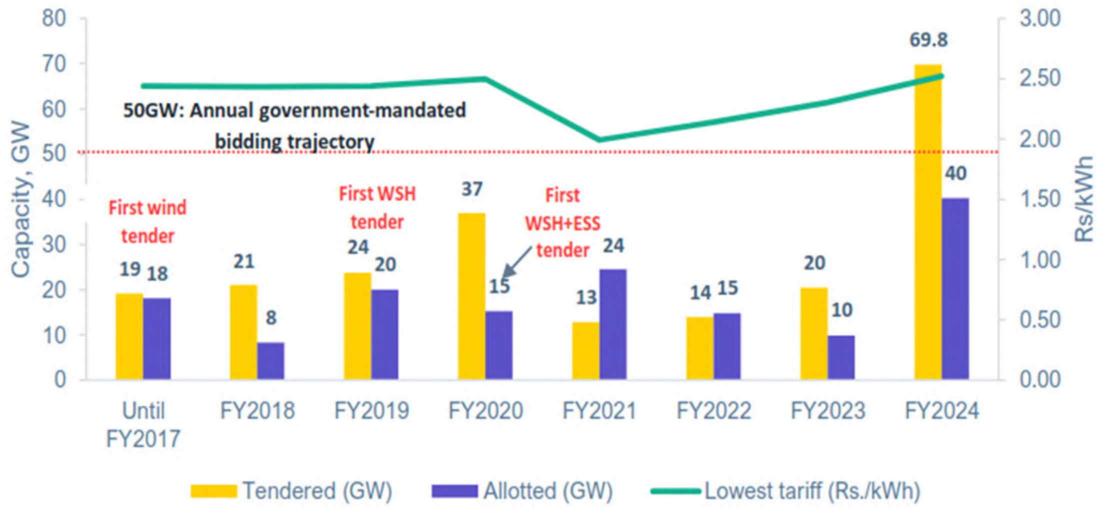
Apart from conventional bids for solar and wind power procurement, newer products to address the diurnal and seasonal variations of RE power are being introduced in the market. These include products like hybrid RE, RE alongwith storage, Round the clock (RTC) RE, Firm and Dispatchable RE (FDRE), standalone storage etc. Hybrid RE ensures round the clock availability of power as solar is available in the day and wind is available mostly in non solar hours. Hybrid products have flexibility of combining different sources including hydro. RE along with storage tries to cater the peak hour requirement of DISCOMS along with cheaper RE power. The storage component ensures assured supply for a few hours in the peak demand period of each day. Depending on the daily demand profile of DISCOMs the bid can be structured suitably. FDRE is a renewable energy product that provides a consistent supply of power to the DISCOMs round the clock. FDRE is achieved by integrating different renewable energy sources with energy storage systems (ESSs). The quantum of each renewable source and the storage requirement can be custom designed based on the daily and seasonal demand requirement of the respective DISCOM. Accordingly, FDRE tenders can be modelled according to the off-taker demand profile. The FDRE tender by SJVN for 1,500 megawatts (MW) in November 2023 has a discovered rate of Rs. 4.38. Already four Tranche FDRE tenders are floated by SECI. The SECI Tranche IV tender was floated in August 2024, with assured 4 hours peak power at 80-90 % probability and following the demand curve of the buyer. The rate discovered is Rs. 4.98 for 630 MW.

5.3 Recent price trend in RE market

The record low price for Solar RE was discovered in the bid during December 2020 at Rs 1.99 per unit of solar power. The supply chain disruptions post Covid has resulted in higher prices for solar modules and components and solar power prices have also gone up. After restoration of supply chains and especially since August 2022 the solar module price has fallen by 57%. However, contrary to expectations, the subsequent bids have actually seen a slight increase in RE prices.

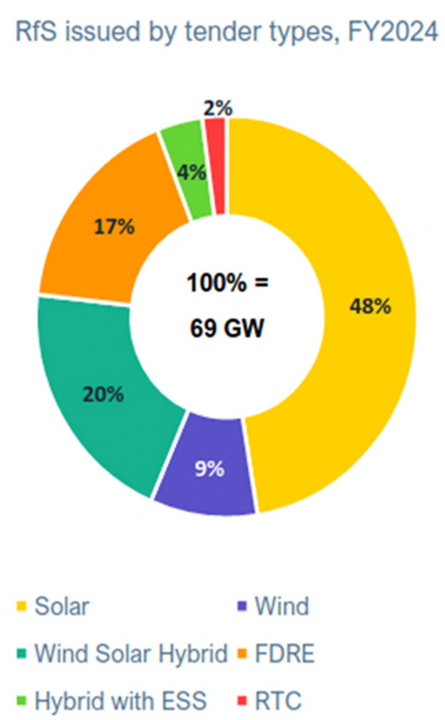
In May 2024, IEEFA and JMK Research & Analytics brought a report on Utility scale renewable energy tendering trends in India. It notes that against a target of 50 GW RE tendering, bids for 69 GW were initiated in 2023-24, even though allotted capacity remains 40 GW. The utility scale RE tendering trajectory in India is depicted in Chart 12. Only around 63% of the bid quantum in 2023-24 was initiated by the intermediary procurers and balance was initiated by individual DISCOMs.

Chart 12: RE tendering trajectory[29]



The bids in 2023-24 has widened the product mix with having solar, wind, solar-wind hybrid, hybrid with BESS, RTC and FDRE forming part of this product mix. The contribution of each product is depicted in Chart 13. The product mix has significantly diversified compared to earlier years when the majority of bids were for solar power.

Chart 13: RFS issued for different RE products in FY 2024[29]



Apart from the above, standalone tenders for energy storage for 22 GW including around 20 GW for pumped hydro storage were invited during the period.

The prices discovered in solar tenders in 2022-23 and 2023-24 are plotted in Chart 14. Generally, the tariff for floating solar plants is higher than the ground mounted solar plants. As already discussed, the price is showing a slight upward trend despite huge fall in solar module prices, the reasons attributed being steep imposition of basic customs duty (BCD) and uncertainties regarding applicability of approved list of models and manufacturers (ALMM) by Central Government.

Chart 14: Solar bid outcomes[29]

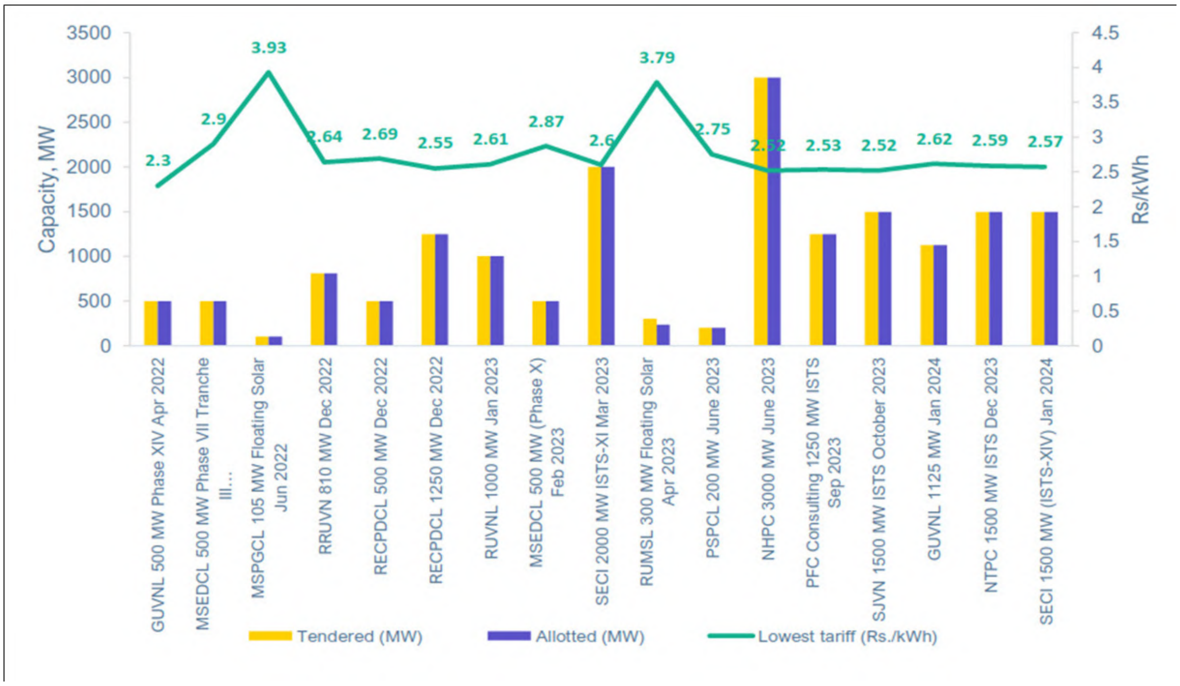
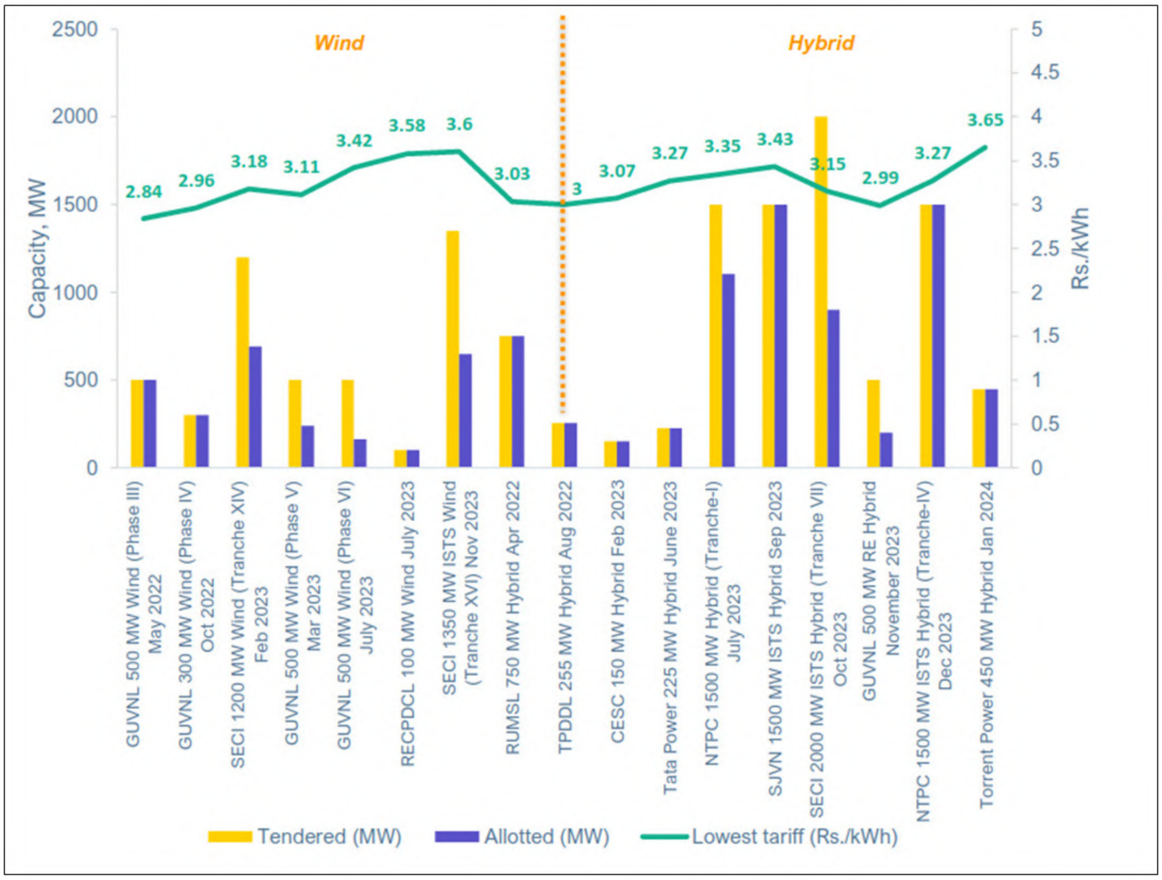


Chart 15 plots the price discovered in wind bids during the period. Wind power tariffs have shown a rise of about 20% during the period. The main factor attributed for this rise is removal of reverse auction in the wind bidding guidelines by the central government. The price trends in wind-solar hybrid bids are also plotted in Chart 15.

Chart 15: Wind and Wind-Solar hybrid bid outcomes[29]



5.4 Initiatives by the Central government

5.4.1 VGF for development of Battery Energy Storage Systems (BESS)

The Ministry of Power vide Order dated 15th March, 2024 has approved the Scheme for Viability Gap Funding (VGF) for development of Battery Energy Storage Systems (BESS). The approved scheme envisages development of 4,000 MWh of BESS projects by 2030-31, with a financial support of up to 40% of the capital cost as budgetary support in the form of Viability Gap Funding (VGF). The VGF has an initial outlay of Rs.9,400 crore, including a budgetary support of Rs.3,760 crore. By offering VGF support, the scheme targets achieving a Levelized Cost of Storage (LCoS) ranging from Rs. 5.50-6.60 per kilowatt-hour (kWh), making stored renewable energy a viable option for managing peak power demand across the country. The VGF shall be disbursed in five tranches linked with the various stages of implementation of BESS projects.

To ensure that the benefits of the scheme reach the consumers, a minimum of 85% of the BESS project capacity will be made available to Distribution Companies (DISCOMs). The scheme period shall be three years from 2023-24 to 2025-26. VGF of up to 40% of capital cost for BESS shall be provided by the Central Government. The recent bid under VGF for 500 MW/1000 MWH BESS has discovered a very competitive rate of Rs 2,38,000 per MW per month[30].

5.4.2 VGF scheme for implementation of Offshore Wind Energy Projects

The present level of capital cost required for development of offshore wind projects does not make them competitive with other forms of power generation. Considering this, Ministry of Power vide Order dated 11th September, 2024 has approved the Viability Gap Funding (VGF) scheme for offshore wind energy projects at a total outlay of Rs.7,453 crore, including an outlay of Rs.6,853 crore for installation and commissioning of 1 GW of offshore wind energy projects (500 MW each off the coast of Gujarat and Tamil Nadu), and grant of Rs.600 crore for upgradation of two ports to meet logistics requirements for offshore wind energy projects.

Offshore wind is a source of renewable energy which offers several advantages over onshore wind and solar projects, such as higher adequacy & reliability, lower storage requirement and higher employment potential. The 1 GW offshore wind projects is expected to produce renewable electricity of about 3.72 billion units annually, which translates to a better CUF of 42.5%. India has planned the development of an initial 37 GW of offshore wind energy at an investment of about Rs.4,50,000 crore[31].

5.4.3 Budgetary Support for creating Enabling Infrastructure for Hydro projects having capacity above 25 MW

The Ministry of Power vide Order dated 8th March, 2019 has introduced budgetary support aimed at offsetting the cost of enabling infrastructure, specifically for the construction of roads and bridges necessary for hydro power projects. Vide order dated 30th September 2024, the scheme was amended to include budgetary support for associated works like transmission line for power evacuation, ropeways, railway sidings and communication infrastructure[32]. According to the guidelines, this support is available for projects that commence construction after the official notification of the policy. The funding is available to pumped storage hydro projects also. The funding cap for this infrastructure support is structured based on the project's capacity:

(1) For projects up to 200 MW, a budgetary grant of up to ₹1.5 crore per MW is available.

(2) For projects exceeding 200 MW, the support is capped at ₹1.0 crore per MW.

5.4.4 National Green Hydrogen Mission (NGHM)

Green hydrogen production and storage is critical for the widespread adoption of hydrogen as a clean energy carrier. It can also act as an energy storage service in an increasingly greener grid relying more on intermittent RE power. Hydrogen can be used in various applications, including fuel cells for transportation, power generation, and as a feedstock in industrial processes. However, hydrogen storage presents challenges due to its low density and need for safe, efficient, and cost-effective storage solutions. On January 4th, 2023, the Union Cabinet approved the National Green Hydrogen Mission with an outlay of ₹19,744 crore. The mission's main objective is to make India a global hub for the production, usage, and export of green hydrogen and its derivatives, with a target of producing 5 million metric tons annually by 2030. Key components of the mission include creating demand through exports and domestic utilization, the Strategic Interventions for Green Hydrogen Transition (SIGHT) programme, which provides incentives for manufacturing electrolysers and green hydrogen production, and pilot projects in sectors like steel, mobility, and decentralized energy. The mission also aims to develop green hydrogen hubs, support infrastructure development, and establish a robust regulatory framework. Additionally, it includes a Research & Development programme in collaboration with public-private partnerships, skill development initiatives, and public awareness efforts. With an allocation of ₹600 crore for FY 2024–25, the mission envisions generating over ₹8 lakh crore in investments, creating approximately 600,000 jobs by 2030, and reducing fossil fuel imports by ₹1 lakh crore. Green hydrogen is expected to replace imported fossil fuels across sectors such as fertilizer production, petroleum refining, steel, and shipping[33].

5.4.5 PM Surya Ghar

Based on the National Action Plan on Climate Change (NAPCC), and in the wake of underachievement of only 7.5 GW as against the target of 40 GW rooftop solar capacity by 2022 under the National Solar mission, the Central Government has launched PM Surya Ghar, in 2023, a landmark initiative targeting 1 crore households. As of 2024, the PM Surya Ghar initiative has received over 1.2 million applications across India. The program has achieved significant traction owing to larger subsidies to smaller rooftop solar plants and streamlining and digitalisation of the entire application process including release of subsidy[33].

5.4.6 Pradhan Mantri Kisan Urja Suraksha Evam Utthaan Mahabhiyan (PM-KUSUM)

The PM-KUSUM Scheme was launched by the Central Government in 2019; to provide energy and water security, de-dieselise the farm sector and generate additional income for farmers by producing solar power. The scheme aims to add 30.8 GW of solar capacity with central financial support of over Rs. 34,000 Crores. It has three components:

(1) Installation of 10,000 MW of decentralized grid connected solar power plants each of capacity up to 2 MW,

(2) Setting up of 20 lakh standalone solar powered agriculture pumps, and

(3) Solarisation of 15 Lakh existing grid-connected agriculture pumps.

As on 31st December, 2021 over 77000 stand- alone solar pumps, 25.25 MW capacity solar power plants and over 1026 pumps were solarised under individual pump solarisation[33].

5.5 Developments related to Energy Storage systems

In the discussion paper published by TERI, titled “Roadmap to India’s 2030 Decarbonisation Targets”, the creation of 500 GW non-fossil fuel capacity by 2030 was found to be feasible though challenging. For this creation of large-scale energy storage capacity would be essential for the optimal utilization of the rapid increase in solar capacity that would need to be created. Storage would also be necessary for reliable supply and grid stability as the share of variable renewable energy (VRE) would go up sharply from the existing level. Amongst the storage options, Battery Energy Storage Systems (BESS) and Pump Storage Projects (PSPs) were the most attractive, viable and technologically proven storage systems and should, therefore, be given the highest priority[34].

5.5.1 Battery Energy Storage Systems

The development and economics of Battery Energy Storage Systems (BESS) are crucial to the ongoing energy transition, particularly as renewable energy sources become more prevalent. BESS technologies have evolved significantly in recent years, driven by advances in battery chemistry, manufacturing, and energy management systems. Battery costs have fallen sharply in recent years and based on developments across the globe it is reasonably anticipated that the cost will come down further to achieve sufficient competitiveness for large scale reduction in dependence on round the clock (RTC) power from fossil fuels. Below is a giston various applications of BESS in the transition towards a greener grid:

(1) Renewable integration: BESS are essential for balancing supply and demand in grids with high penetration of renewable energy sources like solar and wind.

(2) Frequency regulation: Batteries provide fast-response energy to stabilize grid frequency and voltage, enhancing over all grid reliability.

(3) Peak demand management: BESS can reduce energy costs for businesses by storing energy during low-cost periods and discharging during peak demand.

(4) Backup power: Providing reliable backup power during grid outages.

(5) Residential storage: Batteries can serve domestic storage purposes

(6) Solar integration: Home battery systems, often paired with rooftop solar, allow home- owners to store excess solar energy for use at night or during outages.

(7) Energy independence: Depending on the system size and energy needs, BESS can enable partial or complete energy independence from the grid.

(8) Energy arbitrage: BESS can buy electricity from the grid during low-price periods and sell it back during peak price periods, capitalizing on price differentials.

5.5.2 Pumped storage hydro Power (PSP)

PSP is a mature and proven technology and operational experience is also available in the country. The operation of pumped storage power plants requires two reservoirs viz. upper and lower reservoir. The water in the upper reservoir is used for generating power during peak demand hours. The water in the lower reservoir is pumped back to the upper reservoir during the off-peak hours and the cycle continues. The pumped storage plants are of two types: ‘open loop’, which has an associated natural-water source (like a river) for one or both the reservoirs; and ‘closed loop’ (or off-river PSH), which does not have a connected natural-water source and the same water is cycled between the two reservoirs for pumping and generation. The energy storage capacity of a pumped hydro facility depends on the size of its two reservoirs and the head between the reservoirs, while the amount of power generated is linked to the size of the turbine. As per the CEA data, the current potential of ‘on-river pumped storage’ in India is 103 GW.

Pumped storage plants can generate power continuously for a long duration, depending on the storage capacity of the reservoir. These plants have a lifetime of over 40 years, and they operate with an efficiency of 70- 80 percent. Further, as compared to the conventional thermal generator, PSP has the ability of quick start-stop as well as higher ramping capability. These features enable PSP to provide multiple services to the power grid. The high ramping capability helps it deal with the sudden increase of load in the power system. Furthermore, it can smoothen the sudden fluctuations in RE generation, and can also provide frequency and voltage support ancillary services. In addition to these short-term grid services, suitably designed PSP can cater to the seasonal mismatches in RE and load due to its bulk storage capability.CEA has estimated a storage capacity of 74 GW by 2032.

5.5.3 Other new energy storage systems:

A brief overview of other energy storage systems that can emerge into prominence is given below:

(1) **Thermal storage:** Thermal energy storage (TES) is a technology that stores thermal energy for later use, helping to balance energy demand and supply, improve energy efficiency, and integrate renewable energy sources. TES is especially useful in heating, ventilation, and air conditioning (HVAC) systems, industrial processes, and storing energy from solar thermal power plants. It stores heat (or cold) during off-peak periods and releases it when

energy demand is high or renewable energy generation is low.

(2) **Supercapacitors:** Supercapacitors, also known as ultra capacitors or electric double- layer capacitors (EDLCs), are high-capacity capacitors with a much higher energy density than traditional capacitors, but lower than batteries. They store and release electrical energy through electrostatic rather than chemical reactions, allowing rapid charge and discharge cycles.

(3) **Flywheels:** Flywheel energy storage is a mechanical technology that' stores energy through rotational kinetic energy. A flywheel consists of a rotating disc or wheel that spins at high speeds, and the energy is stored in the wheel's rotational motion. This technology is used for various applications, including grid stabilization, uninterruptible power supplies(UPS), and supporting renewable energy integration.

(4) **Compressed air energy storage:** Compressed Air Energy Storage (CAES) is a method of storing energy by using excess electricity to compress air and store it in underground caverns or pressurized vessels. The stored compressed air can later be released to generate electricity when needed. CAES is particularly useful for balancing supply and demand in electrical grids and integrating intermittent renewable energy sources.

Chapter

6

Renewable Purchase Obligation: Trajectory, compliance, Information dissemination and Monitoring

6.1 National RPO Trajectory

Renewable Purchase Obligation (RPO) is an obligation of DISCOMs under Section 86 (1)(e) of the Act to procure from renewable energy sources a certain percentage of electricity consumption in its area of license. As per tariff policy and subsequent notifications of the Central Government this obligation has been extended to open access consumers also. Subsequently, under the Energy Conservation Act, 2001, as amended in 2022, Central Government has included the obligated entities under the said Act also in the ambit of RPO. The Ministry of Power (MoP), GoI vide Order dated 22nd July, 2022 has issued the RPO trajectory for the FY 2022-23 to FY 2029-30. In the said order, MoP has introduced Wind RPO and also specified that the Wind RPO shall be met only by energy produced from Wind Power Projects commissioned after 31st March, 2022. The Solar RPO has been merged with 'Other RPO' in the aforesaid Order of MoP. The RPO targets notified by MoP vide Order dated 22nd July, 2022 is shown in Table 2.

Table 2: RPO trajectory notified by MoP[6]

Financial Year	Wind RPO (%)	HPO (%)	Other RPO (%)	Total RPO (%)
2022-23	0.81	0.35	23.44	24.61
2023-24	1.60	0.66	24.81	27.08
2024-25	2.46	1.08	26.37	29.91
2025-26	3.36	1.48	28.17	33.01
2026-27	4.29	1.80	29.86	35.95
2027-28	5.23	2.15	31.43	38.81
2028-29	6.16	2.51	32.69	41.36
2029-30	6.94	2.82	33.57	43.33

Further, Energy Storage Obligation has also been specified by MoP in the Order dated 22^{nd} July, 2022. It is also mentioned that the Energy Storage Obligation shall be calculated in energy terms as a percentage of total consumption of electricity and shall be treated as fulfilled only when at least 85% of the total energy stored in the Energy Storage System (ESS) on an annual basis, is procured from renewable energy sources. The Energy Storage Obligation notified by MoP in the Order dated 22^{nd} July, 2022 is shown in Table 3.

Table 3: Energy Storage Obligation

Financial Year	Storage (on Energy basis) (in %)
2023-24	1.00
2024-25	1.50
2025-26	2.00
2026-27	2.50
2027-28	3.00
2028-29	3.50
2029-30	4.00

The Ministry of Power (MoP) also notified RPO targets under the Energy Conservation (Amendment)Act, 2022 for the years 2024–2030 on October 20, 2023 applicable to all obligated entities. These targets include targets for procuring from Distributed RE sources also. Distributed renewable energy (DRE) refers to small-scale, decentralized energy systems that generate power close to where it will be used, rather than relying on large, centralized power plants. This approach includes technologies like rooftop solar panels, small wind turbines, and local biomass or hydro systems. The RPO targets as per the MoP order dated 20th October, 2023 is shown in Table 4.

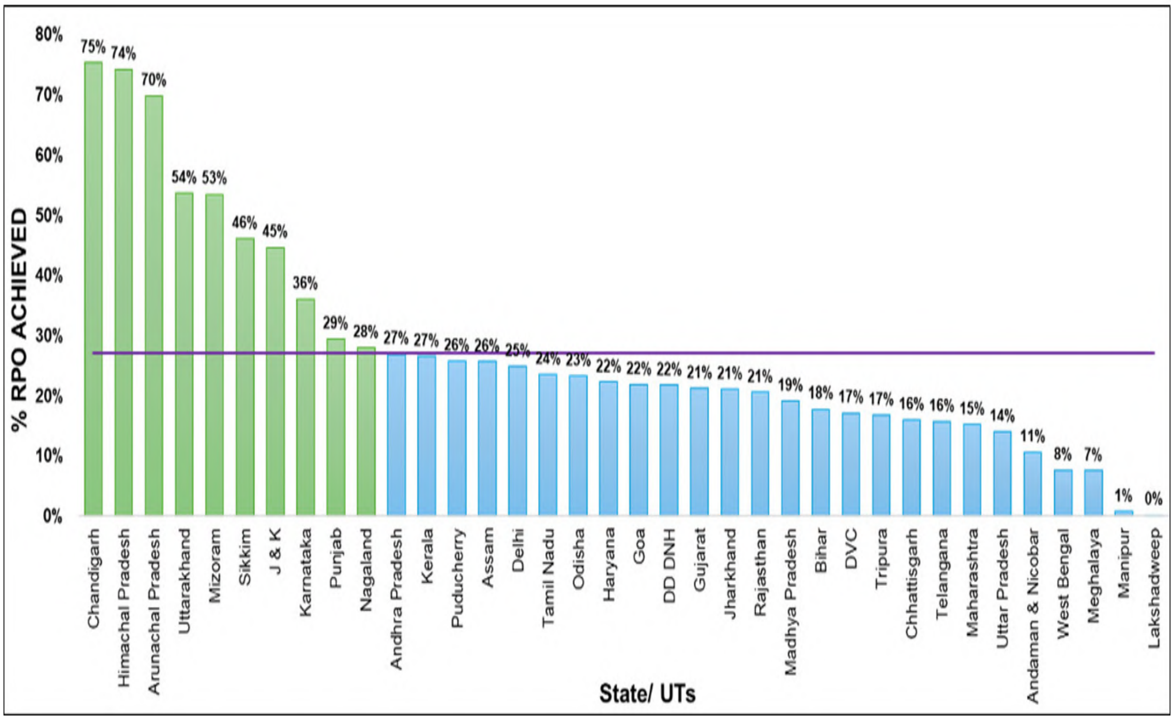
Table 4: RPO trajectory notified by MoP for FYs 2024 to 2030

Financial Year	Wind RPO (%)	HPO (%)	Distributed RE (%)	Other RPO (%)	Total RPO (%)
2024-25	0.67	0.38	1.5	27.35	29.91
2025-26	1.45	1.22	2.10	28.24	33.01
2026-27	1.97	1.34	2.70	29.94	35.95
2027-28	2.45	1.42	3.30	31.64	38.81
2028-29	2.95	1.42	3.90	33.10	41.36
2029-30	3.48	1.33	4.50	34.02	43.33

6.2 RPO Compliance

The status of compliance of RPO for FY 2023-24 by different States was analysed by the Central Government and was presented in the Special FOR meeting held in October, 2023. The details are provided in Chart 16. The horizontal blue line in the chart indicates the RPO target fixed by the Central Government for 2023-24.

Chart 16: RPO Compliance for 2023-24 by Indian States[33]



6.3 Kerala State RPO Targets

Considering the Government of India's ambitious target of 500 GW of non- fossil fuel-based energy capacity by 2030 and for achieving the target laid down for Renewable Energy (RE) sector, and the State Climate Change Action Plan 2.0, the Commission has notified the RPO targets for the financial years upto 2029-30 on 7th August, 2024. To achieve the target fixed by the Government of Kerala (GoK), a higher RPO trajectory than that specified by MoP is to be followed in the State. In order to accomplish these goals, the total RPO proposed in the State is higher than that provided by MoP. But necessary changes have been made in WPO and HPO trajectory considering the potential within the State and the sluggish market conditions. In view of the uncertainties prevailing in many fronts, fungibility among different sources in achieving the targets is also provided. The RPO (%) trajectory for the period from FY 2024-25 to 2029-30 notified by the Commission is indicated in Table 5.

Table 5: RPO trajectory for Kerala[15]

Financial Year	Quantum of generation and/or purchase from Renewable Energy Sources and the quantum of energy to be stored in ESS, as a (%) of the total consumption (in terms of energy in kWh)				
	HPO	WPO	Other RPO	Total RPO	ESO
2024-25	2.20	1.20	33.60	37.0	0
2025-26	2.40	1.75	37.85	42.0	0.15
2026-27	2.80	1.80	41.40	46.0	0.50
2027-28	3.50	1.90	42.60	48.0	0.75
2028-29	3.90	2.00	43.10	49.0	1.00
2029-30	4.20	2.20	43.60	50.0	2.00

6.4 RPO monitoring, information dissemination

The current regulations lack a mandate for proper and orderly dissemination of relevant information on RE development and RPO achievements in the State. It also lacks an appropriate and transparent monitoring mechanism on RPO. Proper definitions on crucial parameters like “total consumption” to ensure consistent interpretation, transparent treatment of Short-Term Open Access (STOA) and Power Exchange (PX) procurement, clear treatment of transmission losses etc. need to be included in the regulations for the new control period to avoid multiple interpretations and disputes.

KSERC Renewable Energy Regulations, 2020 currently lack a dedicated process to verify RPO compliance, meaning obligated entities are not formally assessed for meeting their renewable targets. Additionally, the Commission’s True-Up Orders do not include RPO compliance verification, which reduces accountability and transparency in tracking progress toward renewable energy goals. Adding specific RPO compliance proceedings and including them in True-Up Orders could improve monitoring and ensure that RPO targets are met in line with Kerala’s Renewable Energy objectives. To ensure a robust and transparent Renewable Purchase Obligation (RPO)

compliance framework, there is a pressing need to mandate separate RPO compliance proceedings that present the data in a clear, standardized format, accessible in the public domain. This structured approach would improve transparency and enable all stakeholders, including the public, to monitor compliance effectively. Future regulations should also address any RPO compliance shortfall or surplus by stipulating penalties or incentives to maintain adherence to targets. For Energy Storage Obligation (ESO), detailed accounting guidelines are necessary to clarify how storage contributions are measured and counted toward obligations, fostering consistency and clarity across the entities.

Furthermore, the new regulations should incorporate a requirement for licensees to establish an annual renewable energy procurement strategy that includes a yearly tender calendar. This strategy would align with a Resource Adequacy plan focused on achieving the 50% RPO target by the year 2030. This planned approach could streamline procurement efforts, prevent potential shortfalls, and ensure that the obligated entities meet their RPO and ESO commitments. Without a stringent compliance framework, including clear timelines, data transparency, and accountability measures, achieving the additional procurement of 10,000 MU of renewable energy by 2030 to meet the mandated RPO will be challenging.

Thus, the new regulations shall include clear data formats for reporting of compliance of RPO by obligated entities on a quarterly basis. This shall also include the RE tendering calendar for the DISCOMs and adherence to the same. Since ESO is a relatively new concept, clear modalities/ energy accounting guidelines for ESS shall also be made part of the regulations. The regulations shall also specify the penalties/incentives in case there is underachievement/excess over target cases by obligated entities. The examination of compliance by the regulatory commission can be on an annual basis, as a separate proceedings, in the first quarter of every financial year based on mandated annual filings by all the obligated entities including the DISCOMs. The State nodal agency under the Energy Conservation Act, 2001 or KSEB Ltd shall be mandated to file the RPO compliance data in respect of obligated entities other than the DISCOMs.

Chapter

7

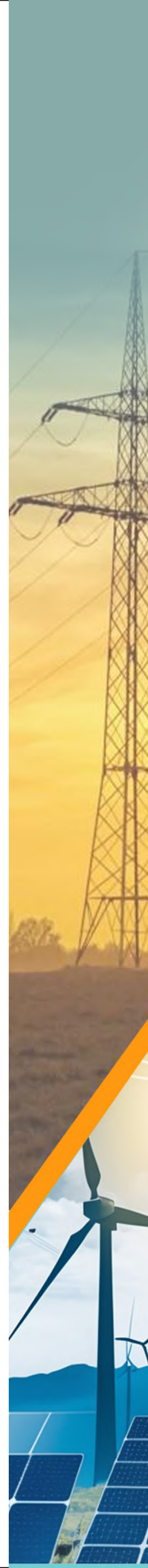
Challenges in meeting the RPO Trajectory

7.1 Additional RE requirement until 2030

As per the KSERC (Renewable Energy and Net Metering) (Second Amendment) Regulations, 2024, Renewable Energy procurement target by 2029-30 is 50%. By 2029-30, demand is anticipated to grow to about 40,000 MU as per CEA projections. To achieve the RPO specified, Kerala has to source about 20,000 MU of RE power. Presently, the renewable component in Kerala’s procurement is about 10,000 MU, out of which about 7,500 MU is from hydro sources. The balance is mainly from solar and wind sources. Thus, renewable energy sourcing needs to be doubled by 2029-30.To reach the projected renewable energy requirement of over 20,000 MU by FY 30, an additional 10,000 MU of renewable capacity must be added within the next 5–6 years. This target will require significant investment in new renewable energy projects, as well as technological advancements and policy incentives to facilitate rapid scaling, particularly in solar, wind, BESS and emerging renewable technologies.

Currently, about 75% of the renewable energy supply is generated from existing hydro plants, indicating that much of the infrastructure supporting renewable energy is aging. This reliance on older plants could pose operational and efficiency challenges as demand grows. Given this context, there may be a need for substantial upgrades or replacements in these plants to maintain reliability. Furthermore, to diversify and modernize the energy mix, expanding other renewable sources like solar and wind along with adequate storage will be crucial for enhancing system resilience and meeting future demand sustainably. In view of increasing energy storage requirements, developing hydro projects having adequate storage reservoirs can be a policy priority for the long term.

The challenges in doubling the current renewable energy portfolio in



the next 5 - 6 years need to be looked into in detail to put in place policy and regulatory frameworks to address those challenges.

7.2 Development of Hydro Projects

Contrary to popular perception, the tariff for hydro projects is higher than most of the other RE sources of electricity. The tariff approved by the commission recently for different small hydro projects is furnished in Table 6.

Table 6: Tariff for small Hydro projects approved by the commission

Project Name	Year of approval of tariff	Capacity (in MW)	Tariff approved (in Rs/ unit)	
			Without benefit of accelerated depreciation	with benefit of accelerated depreciation
Anakampoil Power Pvt Ltd	2023	8	4.43	4.15
Pathamkayam SHEP (Minar)	2019	8	4.22	4.08
Arippara SHP	2023	4.5	4.63	4.3

The tariff is high mainly on account of two aspects. Higher capital cost and lower capacity utilisation factor (CUF). Both these issues need resolution to some extent. The capital cost of almost all hydro projects commissioned recently and those under construction as well as those under planning is much above the normative capital cost adopted by the Central Commission. The capital cost proposed for various hydro projects in the capital investment plan of KSEBL is given in Table 7 along with the normative cost as per the regulations of the Central Commission. The second issue of low CUF is a design issue purposefully created to lower the submergence area of respective reservoirs. This under-sizing of reservoir capacity also leads to an undesirable effect whereby hydro power from newer plants is not available during peak demand period of summer. This further reduces the economic viability of new hydro projects. Apart from these two issues another dilemma confronting the State power sector is also contributing to the higher costs. This involves purposeful downsizing the capacity of hydro power projects to pose it as small hydro projects which essentially results in the loss of economies of scale.

Table 7 - Capital cost of hydro projects vs. normative costs

Project Name	Capacity (in MW)	Estimated project cost (in Rs Cr)	Cost per MW (in Rs Lakh/ MW)	Cost per MW as per CERC Norms (in Rs Lakh/ MW)
Upper Shengulam HEP	24	316	13.17	10.27
Peechad SHEP	3	27.64	9.21	8.9
Western Kallar SHEP	5	51.24	10.25	10.27
Ladrun	3.5	48.81	13.95	8.9
Marmala	7	74.28	10.61	10.27
Pasukkadavu	4	51	12.75	8.9
Valanthode	7.5	69.11	9.21	10.27
Maripuzha	6	71.95	11.99	10.27
Chembukadavu- III SHEP	7.5	64.11	8.55	10.27
Chathankottunada SHEP Stage -1	5	71.59	14.32	10.27
Olikkal SHEP	5	46	9.20	10.27
Poovaramthodu SHEP	3	46	15.33	8.9
Mankulam HE	40	750	18.75	10.27
Poringalkuthu SHEP StageII	24	80.7	3.36	10.27
Keerithode SHEP	3.5	141.92	40.55	8.9

As discussed earlier, the Central Government is providing budgetary support for the cost of Enabling Infrastructure for Hydro Electric Projects (HEP) with a total outlay of Rs.12,461 crore to improve its economic viability.

While, availing this financial support would be helpful, that alone would not make hydro projects in Kerala feasible. To that end, the issues with respect to; (1) higher capital cost above normative/benchmark levels, (2) Limited or no Generation in Dry Seasons, (3) Inadequate Reservoir Capacity, (4) non optimal sizing of power plant, (5) Sedimentation and Reduction in Storage Capacity during project lifecycle etc. needs to be addressed.

Some of the above issues can be addressed through technological solutions. It is understood that KSEBL has already undertaken an exercise in collaboration with IIT, Roorkee for optimising the civil structure designs to bring down the cost. However, the majority of the issues discussed above require building of social consensus on how to utilise hydro potential of the State to effectively address the climate change concerns.

It is well understood that Hydroelectric projects can alter local ecosystems and disrupt communities. Hydroelectric projects in India face significant

environmental and forest clearance challenges due to their large-scale infrastructure and impact on natural ecosystems. The construction of dams and reservoirs often requires extensive deforestation, which results in the loss of biodiversity and disrupts wildlife habitats. This can also lead to soil erosion, landslides, and alterations in river ecosystems, affecting aquatic species and the availability of water downstream. Additionally, the flooding of forested areas and displacement of indigenous communities further complicates the approval process. Securing forest clearance is a complex and time-consuming process, especially for projects in protected areas, and the creation of reservoirs often leads to long-term environmental consequences, including water quality degradation and changes in sediment flow. The challenges include ensuring the sustainability of fish migration, maintaining water quality, and addressing the cumulative impacts of multiple projects on river ecosystems.

To mitigate these impacts, hydro projects are subject to stringent environmental impact assessments (EIA) and forest clearance processes, which include mandatory public consultation processes. The meticulous processes are also under close scrutiny and judicial oversight in the form of Green Tribunal etc.

In spite of these safeguards and counterchecks by multiple agencies, taking up projects that were even cleared through these stringent processes has become an almost impossibility in the State due to lack of social consensus. Further, even investigation of new projects to secure necessary clearances are being stoutly objected to. In this context, building a social contract on ways of utilising the available hydro potential in the State to meet its net zero targets, through effective communication and leadership, is a necessary major step towards energy transition in the State.

Apart from the above, the regulatory framework may consider measures to bring down cost through improved competition. At present the State Government allot small hydro projects based on a bidding whose bid criteria is upfront premium payable by developers. This is a revenue maximisation criteria and does not create any competition to bring down costs and tariffs. To bring in effective competition and bring down tariffs, it may be considered to approve PPAs for hydro projects awarded through a transparent tariff based competitive bidding process only. Similarly, the participation in bids invited by KSEB for execution of its hydro projects are inadequate to create competitive pressure on bidders. It may be necessary to have a review of the bid process and contract conditions and develop a bidding framework that can attract adequate competition. As a regulatory measure, it may be desirable to approve capital cost only within predetermined normative/benchmark costs to provide necessary signals to the market. At the same time, the need or otherwise of having a higher normative/benchmark cost than that specified by Central commission may be looked into.

Equally important is the need for addressing interdependent issues relating to inadequate storage, lower CUF and non-availability during summer period. The regulatory measures to provide signals to the market could be; incentivised tariff for summer period, specifying minimum threshold value for CUF for project approvals etc.

In cases where increasing the reservoir storage to adequate levels is not possible, developers can opt for open loop pumped hydro storage projects, which can effectively put to use available storage capacity, by having a lower sump also. In this mode of operation the project can operate in conventional hydro generation mode during monsoon period and in pumped storage hydro mode in lean seasons. This will provide availability during peak hours in summer period and improve CUF significantly. To promote such projects, the regulations may consider higher tariffs in peak summer periods or higher benchmark costs.

The Center for Study of Science, Technology and Policy (CSTEP) study[35] titled Kerala Energy Transition Roadmap 2040 suggests an additional hydro capacity to the tune of 693 MW and 1913 MW by 2030 and 2040 respectively.

7.3 Developing Pumped Storage Hydro Projects (PSPs)

The CSTEP study recommended a storage capacity of 2,100 MW and 4,100 MW storage capacity by 2030 and 2040 respectively.

Pumped hydro storage projects, broadly classified as open loop or closed loop are integral to managing the intermittency of renewable energy sources like solar and wind. Pumped storage hydropower facilities can store energy generated during peak rainfall season for use in dry months. These systems pump water to an elevated reservoir during periods of low demand, which can be released to generate electricity during high-demand periods. Most PSPs operate at an efficiency range of 70% to 80%, meaning that the energy output during generation is 20-30% less than the energy consumed during pumping. The net efficiency depends on factors like pump and turbine design, water management, and operational practices.

The cost-effectiveness of a pumped storage plant is heavily influenced by its location. Suitable topography for the construction of reservoirs is limited, and projects in areas with difficult terrain or higher environmental impact assessments tend to be more expensive. However, technological

advancements in underground and off-river pumped storage can reduce the geographical limitations and associated costs.

Reportedly, KSEBL has identified many pumped storage projects, wherein three major ones are in Kakkayam, Idukki, and Pallivasal with capacities of 800 MW, 700 MW, and 600 MW. Kakkayam (800 MW) site requires a total of 15 hectares of land, with 6 hectares being forest land. Idukki (700 MW) project will require 67 hectares, out of which 17 hectares are forest land. Pallivasal (600 MW) will require 83 hectares for the proposed development, no forest land is required.

One issue noted with the PSPs being considered by KSEBL is its limited storage ability. Most of the proposed PSPs have a low generation period of around 6 hours. That is, the entire upstream storage will get depleted in 6 hours of operation. For further generation, the water stored in the lower reservoir after generation has to be pumped back, which takes more time. This daily cycle of pumping and generation is identical to the charging and discharging cycle of Battery Energy Storage Systems (BESS). Thus, it appears, these PSPs are designed as a competitor to BESS, which they are unlikely to succeed in view of the fast fall in battery prices and significantly lower gestation periods for BESS. In the longer term, the cost of establishing PSPs is expected to increase due to inflationary trends for materials like cement, steel etc., whereas the cost of establishing BESS is already comparable with PSPs and is likely to come down steeply.

Apart from addressing the intermittency of solar and wind power, the energy storage requirement of Kerala system is on account of its two significant features. One is the significant difference in daily peak and off-peak hours. Second is the significant difference between summer demand and non-summer demand.

Chart 17 shows the day demand curve of the summer peak demand day of 2024 and the day demand curve of a typical day in the monsoon month of July 2024. It can be easily noted that even the monsoon peak demand is less than the summer base demand.

Chart 17:
Seasonal Daily demand curves of 2024

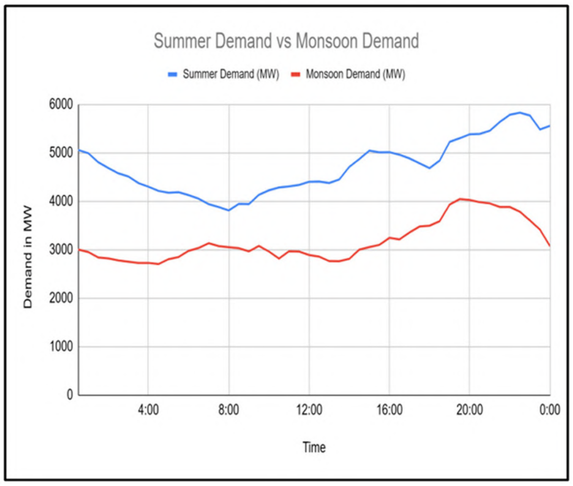
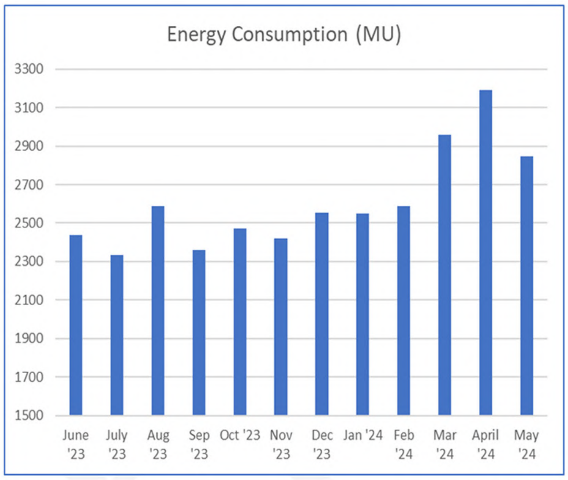


Chart 18:
Monthly energy demand 2023-24 Water year



This would mean that generation capacity available/contracted to meet even the summer base load will be more or less sufficient to fully meet the peak demand in non-summer months. The daily variability in monsoon and winter months can be mostly managed with flexible operation of hydro as well as the flexible operation introduced for thermal plants if annual base load capacity is available/contracted. Thus, storage requirements to meet daily peak demands in monsoon and winter will be limited for the time being. If there is a case for substantial daily energy storage requirement in non summer months, the same is to be established through a detailed resource adequacy planning exercise. Further, since even the day's minimum demand in summer is significantly higher, availability of surplus power to charge/pump for energy storage on a daily basis will also be very limited in summer months.

Chart 18 assumes relevance in this context. It shows that the monthly energy demand for three months in summer is about 400 - 600 MUs higher than the average monthly energy requirements in the other nine months of the year. The total additional energy to meet the higher demand of summer months over the average monthly energy requirement for the balance period is about 1200 - 1400 MUs. BESS cannot economically offer such a large storage solution covering different seasons. However, a properly designed pumped storage hydro plant can effectively provide such seasonal storage. For example, if the existing storage reservoirs of major hydel projects in Kerala can be operated in such a manner to have near to full capacity storage at the beginning of summer, it can easily result in an additional energy availability of 1500 MU. Thus, if the PSPs are designed to augment the existing reservoirs in such a manner to operate mostly in pump mode in the post monsoon months till onset of summer, it can economically meet the inter seasonal storage requirement. During the entire summer, the PSPs can operate fully in generator mode to augment energy and peaking capacity availability. During monsoon also it can operate mostly in generation mode. It will operate mostly in pump mode in post monsoon months till the onset of summer. Such a modification in the operational pattern needs to take care of lower riparian rights also. Most importantly, various techno economic analysis are required for each of the river basins and existing projects to evaluate this mode of developing PSPs.

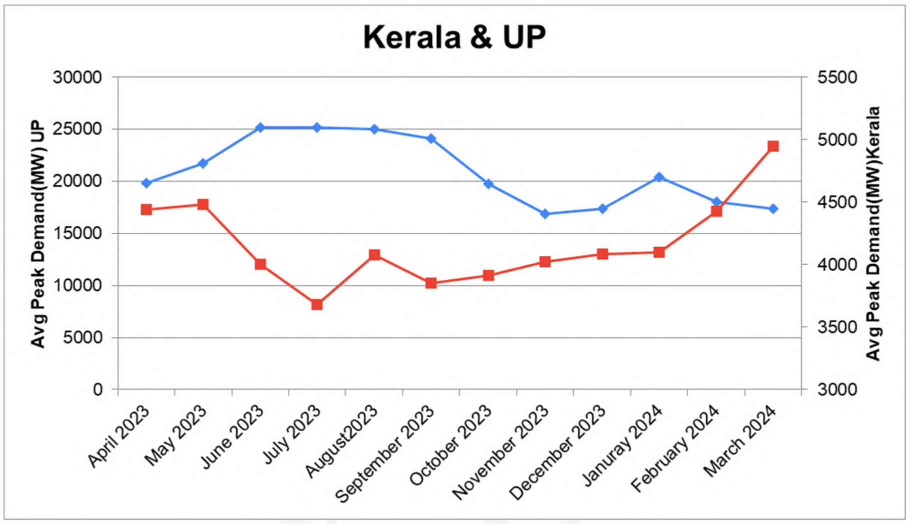
In the alternative, if PSPs with lower storage capacity (mostly in closed loop operation for a few hours daily) or BESS is preferred over seasonal PSPs, the flip side will be lower utilisation of such investments during non summer months, adversely impacting their economic viability. In such a scenario, it might be advisable to share the storage facilities with States/ DISCOMs having complementary demand patterns.

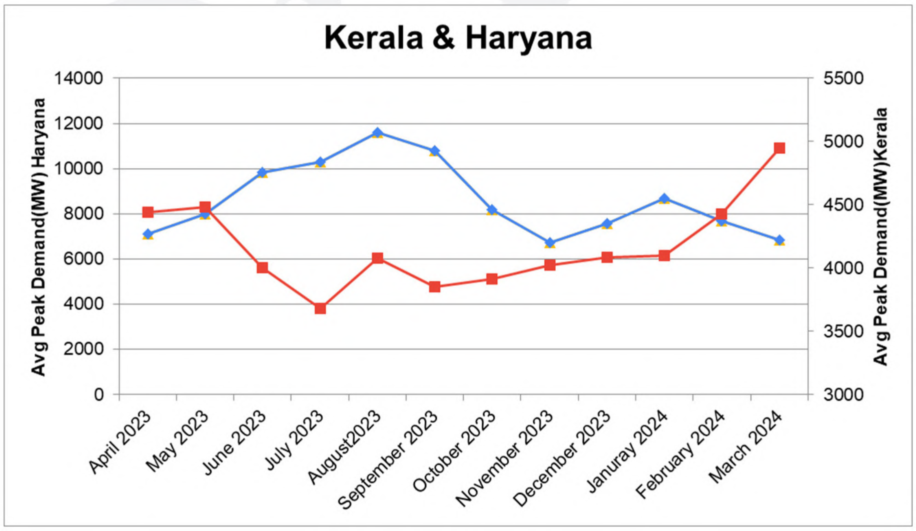
7.4 Joint development of Energy storage systems by States having complementary demand pattern

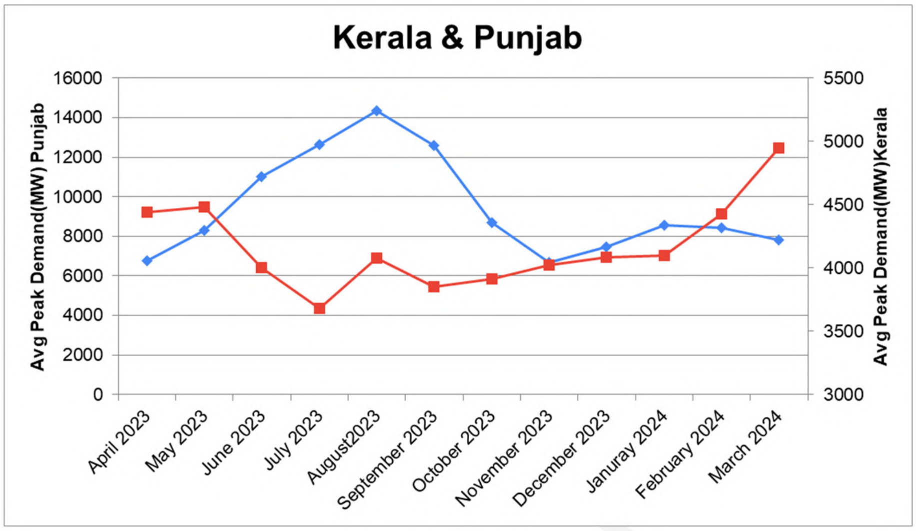
Recently, Madhya Pradesh (MP) and Uttar Pradesh (UP) have joined together to develop energy storage facilities for mutual benefit. The low demand season of MP (Q1 and Q2) matched with the high demand season of UP and vice versa. This complementarity in demand pattern was leveraged to develop a joint energy storage project to be used by respective parties in different periods of the year thereby achieving optimization in investment as well as higher CUF for the storage project.

The Chart 19 depicts the demand pattern of a few States having complementary demand patterns with Kerala (red line depicts Kerala demand) which indicates strong possibility for similar approaches by Kerala along with other States.

Chart 19: States having complementary demand patterns







Thus, for development of energy storage facilities with few hours of storage meant for daily storage-discharge or pump-generator mode of operation, there exists significant potential to identify partners with complementary demand patterns to optimise investment and ensure better capacity utilisation.

7.5 Wind

The CSTEP study recommends an additional wind capacity of 998 MW and 2,754 MW by 2030 and 2040 respectively.

Wind energy sector is more than two decades old with manufacturing more than 80% of the components under 'Make in India'. Wind Turbine technology has evolved significantly over the last decade with emphasis on greater energy capture and improved capacity utilization factor. Modern turbines have larger rotor diameter and higher hub heights. Hence, it became necessary to identify areas which have wind potential at higher heights. Considering this and using advancements of mapping techniques, wind potential assessment of the country at 150m hub height was undertaken. Based on the study conducted by National Institute of Wind Energy, high CUF potential regions are distributed in the States of Andhra Pradesh, Gujarat, Karnataka, Maharashtra and Tamil Nadu with scattered potential in Kerala, Madhya Pradesh, Telangana and Rajasthan. Pockets of medium wind potential are located in States of Himachal Pradesh, Uttarakhand, Bihar, West Bengal and Odisha. The wind power generation potential in the State is reported differently in various reports; also it is mostly located in challenging terrains. As discussed, the tariff for wind power in the country is showing an upward trend creating another barrier.

Further, the tariff of wind power projects recently developed in Kerala is on the higher side and varies between Rs 3.93 to Rs 5.23 per unit, much above the tariff discovered for interstate wind projects. In the recent tariff based competitive bidding by KSEBL in 2022 for procurement of wind power from projects to be developed in Kerala, the discovered price was Rs 3.96 per unit. Moreover, none of the bidders showed interest in developing the projects based on the tariffs so discovered.

7.5.1 Offshore wind

India has significant potential for offshore wind energy, particularly along its vast coastline, which stretches over 7,500 kilometers. The country has identified potential for offshore wind energy as approximately 70 GW along the coasts of states like Gujarat, Tamil Nadu, and Maharashtra. Gujarat, in particular, has been identified as a key region for offshore wind development due to its favourable wind speeds and shallow seabed conditions, which make it suitable for turbine installation.The first offshore wind energy project in India is under development off the coast of Gujarat, where a pilot project of 1 GW capacity is planned. This pilot project is expected to serve as a blueprint for future developments in offshore wind energy in the country.

At present Offshore wind projects are capital-intensive, with costs primarily driven by turbine installation, offshore infrastructure, and maintenance. The initial cost for setting up offshore wind projects is significantly higher compared to onshore wind projects. Further the coastal regions where offshore wind potential exists are often not well-connected to the national grid. Establishing robust transmission infrastructure is necessary to transmit the electricity generated offshore to the mainland, which presents both technical and financial challenges. Offshore wind projects require comprehensive environmental assessments to ensure minimal disruption to marine ecosystems, fishing activities, and local biodiversity. Navigating the regulatory and environmental clearance processes can be complex and time-consuming.

7.5.2 Vertical Axis Wind Turbines (VAWT)

Globally interest on VAWT is growing on account of its potential for evolving as a potential decentralised RE source with complementary power generation along with solar plants. Typically wind power generation peaks as daylight diminishes and thus it can work in tandem to provide a consistent power supply round the clock. R&D and Local entrepreneurship is the key for accelerating its development.

7.6 Solar

The CSTEP study recommended an additional solar capacity of 3,825 MW and 10,558 MW by 2030 and 2040 from 2022 level.

The possibilities for development of solar PV is mainly through Ground mounted, floating and rooftop solar projects, each of which are examined below.

7.6.1 Ground mounted Solar

Kerala is a densely populated State with limited availability of land for large-scale solar installations. Much of the land is either under cultivation, covered by forest, or in areas unsuitable for solar farms due to the State's unique geography, which includes hills, water bodies, and highly fragmented land holdings. This makes it challenging to secure contiguous plots of land necessary for economically viable ground-mounted solar projects. Additionally, high land costs further complicate the development of solar infrastructure. Land in Kerala is expensive, particularly compared to other states with vast open spaces, making ground-mounted solar projectsuncompetitive. Possibilities for pooling of land having little alternative economic prospects and sharing a fixed percentage of the revenue from solar power generated with the land owners in lieu of land use rights can be explored to overcome the present challenges.

7.6.2 Floating Solar

Floating solar power installations offer several benefits, particularly in areas with limited land availability, such as Kerala. They use water bodies instead of land, freeing up valuable terrestrial space for other purposes like agriculture. Floating solar panels also have a natural cooling effect from the water, which can improve efficiency and reduce panel degradation compared to ground-mounted systems. Additionally, these systems can help reduce water evaporation in reservoirs and improve water quality by limiting algae growth, making them an effective choice for water-stressed regions. KSEB Ltd has installed a floating solar project at the Banasura Sagar Dam, one of the first in the country. Subsequently, NTPC has set up a floating solar plant of 92 MW at Kayamkulam, which is one the largest in the country. Major reservoirs in the State offer immense potential for development of floating solar plants. However, issues related to the forest department are to be resolved on a fast track for leveraging its vast potential.

The West Kallada Floating Solar Project is a unique but replicable model for Kerala. The project initiated by local MLA Sri. Kovoor Kunjumon for development of large swamp area in his constituency for power generation, fishing and tourism, later got attention of KSEB Ltd and NHPC. The project envisages installing solar power plant on uncultivable swamp land with farmer participation. Landowners will receive three percent of the electricity income from this venture and it comes around Rs. 15,000/Acre/Year. The project spans approximately 300 acres of privately owned land in Mudakapadam, West Kallada village, Kunnathur taluk, which has become unfit for cultivation due to silt and sand mining, and remains flooded round the year. The West Kallada project ensures a steady income for landowners by establishing West Kallada Non-Conventional Energy Promoters Private Limited (WKNCEPPL) by the landowners itself, which holds the land use rights for the project. The panchayat owns around 50 acres of land, the rest belongs to farmers that include 400 property owners. The National Hydroelectric Power Corporation (NHPC), the nodal agency for the project, will bear all expenses for the ₹300-crore project. In order to lease the land to the NHPC for a period of 25 years, West Kallada Non-Conventional Energy Promoters Pvt Ltd., that includes all land owners and government officials, was formed. Many such otherwise unusable land can be identified across various districts for development of renewable energy with benefits to the local community and the environment.

7.6.3 Roof Top Solar

As already discussed in Chapter 4 of this paper, Rooftop solar (RTS) is the bulwark of recent renewable energy development in the State. It grows at an astonishing CAGR of 100%; (i.e.) doubling capacity each year. It already forms around 22% of the peak day demand of the State. In view of constraints noted in developing other sources, it is eminently clear that RTS remains the most prominent mode for development of RE within the State. At the same time, given the technological challenges it brings forth, as discussed in the subsequent chapter of this paper, there is a need for a more balanced and equitable development framework for the sector. Emerging technologies and proper regulatory framework has to work in synergy to unleash the potential of RTS for optimum benefits to Kerala society and to achieve the ambitious goals of energy transition. These include promoting decentralised energy storage, enabling reactive power support along with active power from RTS, ensuring power quality etc, as explained in more detail in the following chapter.

7.7 Other renewable energy sources

7.7.1 Municipal Waste to energy

Even though electricity from Municipal Waste-to-Energy (WtE) plants cannot be a major source to meet our energy requirements, it is emerging as a practical solution for managing urban waste. These plants convert non-recyclable solid waste into energy using technologies such as incineration and gasification, helping reduce the burden on landfills while contributing to renewable energy production. With India's urban population generating millions of tons of solid waste annually, WtE plants offer a dual benefit of waste reduction and energy generation. By processing waste at high temperatures, these plants significantly reduce waste volumeand minimize harmful emissions associated with landfill decomposition, such as methane. Notable projects include the Timarpur-Okhla Waste Management Plant in Delhi, which processes around 1,950 tons of waste daily, and the Jawaharnagar WtE plant in Hyderabad, which generates 19.8 MW of electricity. Other major WtE projects are also operational in cities like Pune, Bengaluru, and Lucknow.

7.7.2 Tidal Energy

Tidal energy, a renewable energy source harnessed from the natural rise and fall of ocean tides, presents significant potential for clean power generation in India due to the country's extensive coastline. India's key tidal energy resources are primarily located in regions like the Gulf of Kutch, Gulf of Khambhat (in Gujarat), and the Sundarbans (in West Bengal), where strong tidal currents make energy generation feasible. Estimates suggest that India has a potential of around 8,000 MW for tidal energy, particularly concentrated in these regions. Despite this potential, tidal energy remains largely underdeveloped in India due to high initial investment costs, technical challenges, and limited experience in managing tidal power infrastructure.

7.8 Unprecedented increase in interstate transmission charges

In recent years, with exponential growth in interstate transmission systems aimed at faster integration of renewable energy, especially to utilise generation from RE rich zones in the country, has resulted in an unprecedented increase in Interstate transmission system (ISTS) charges. This is mainly on account of three factors: (1) Huge lump sum investment in new transmission assets to accommodate Gigawatt scale RE expansion (which is having relatively low gestation periods) in renewable energy parks etc., (2) serious levels of underutilisation of these new assets owing to very low capacity utilisation factors (CUF) of RE plants as well as lower than estimated growth in generation capacity in major RE zones and (3) waiver of interstate transmission charges for RE projects including storage and green hydrogen projects etc is getting loaded to DISCOMs as higher charges for drawal of conventional power. The costs associated with the first two factors are also uniformly distributed to all States irrespective of whether or not they are beneficiaries of these RE projects. Thus, under the present regime of sharing of ISTS charges it is foolhardy to rely entirely on State projects to meet RPO discarding cheaper RE sources from RE rich zones in the country.

It is also noteworthy that, despite these hikes in charges, importing RE power is still economical and competitive when compared to many RE projects that can be developed within the State. This economic benefit becomes more evident in the case of interstate RE projects having full/ partial waiver of ISTS charges. Also, many interstate RE projects benefit from higher CUF (owing to higher resource potential in RE rich zones in the country), which enable them to keep the electricity prices down.

Thus, in order to keep electricity tariffs in the State under reasonable control and to meet the RPO in line with the States objectives on energy transition, significant quantities of affordable RE power has to be sourced from RE rich zones as indicated in the paragraph 4.3 of this paper. A right balance is to be achieved in sourcing the additionally required RE power from within the State and from other economically beneficial regions of the country.

Chapter

8

Challenges in faster adoption of Decentralized RE (DRE)

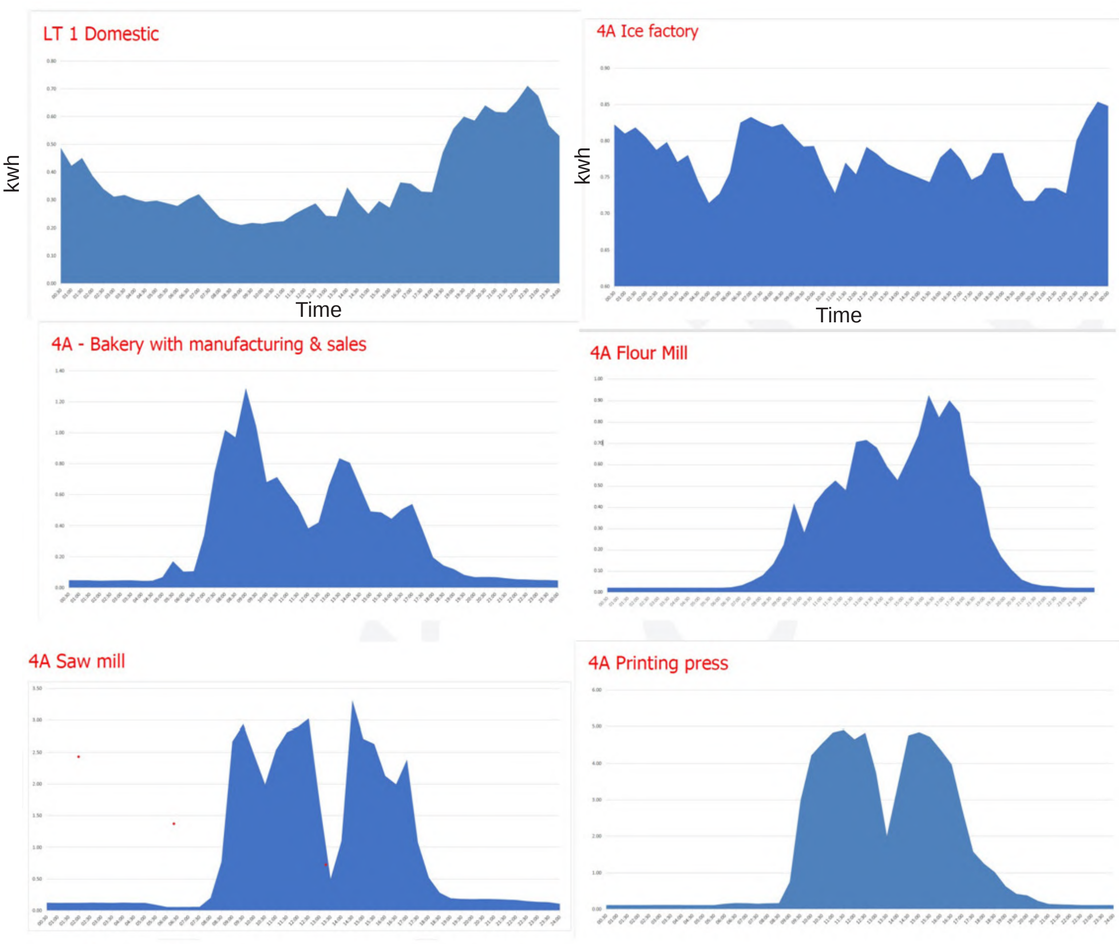
8.1 Grid related issues with higher penetration of DRE

The difficulty in managing non-firm DRE resources, especially when the generation from the DRE exceeds the in-situ demand during the high generation periods, is recognised as a major challenge with many dimensions. Technical issues on the stability of the grid primarily due to reduction in inertia and fault level are also valid concerns. The technology to mitigate the issues and to optimise the cost of generation have been developed and practised in high RE penetration jurisdictions, which include demand side management, storage, micro grids, optimum location of renewable assets to provide grid support, compensatory mechanisms to improve grid stability and reliability etc. Mitigation of the technical challenges involves additional expenditure. The basic question is how to share this additional cost on grid management, which is induced now on account of faster adoption of DRE resources. In other words, the cost of RE, especially non-firm RE needs to factor the expenses on account of mitigation of the technical challenges to ensure reliability of power supply. It is to be understood that the term “reliability of power supply” is meant at consumer premises and the grid-stability, balancing power requirement, reactive power compensation, controllability of the grid etc. are all encompassed in this term. This chapter tries to look into each of the related issues and find ways and means to address them which is assisted by some field studies as well.

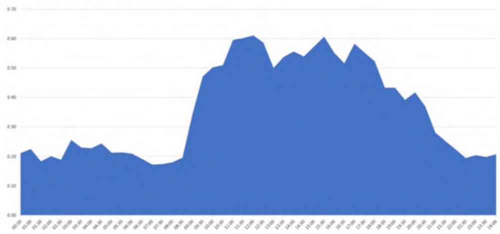
8.2 Load profile of different consumer segments

The load profile of typical consumer groups connected to LT network and a few prosumers were collected to understand the diurnal variation in demand, as against the DRE availability which is limited to the solar hours, and are plotted in Chart 20. While some consumer segments like industries, hospitals, offices, IT industries, Banks, educational institutions etc., as most of their power consumption is during the day time, where as the situation is different in respect of domestic consumers. Thus, among different consumer segments, the impact of solarisation of each segment of consumers on the distribution network varies significantly depending on their load profiles. This is an aspect requiring consideration while designing the appropriate compensation mechanism for each consumer segment.

Chart 20: Daily load profile of different LT consumer segments

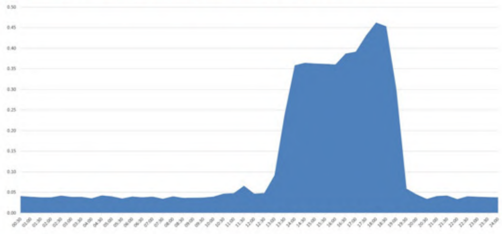


4B Software Industry

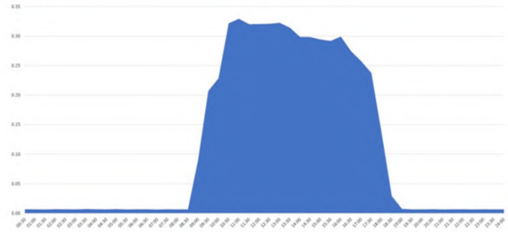


6A Educational Institution

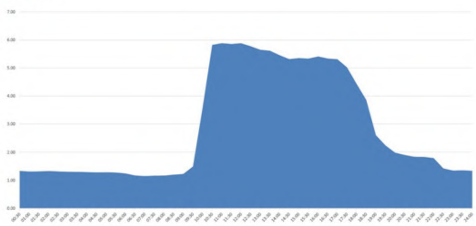
6A Government/LSG Hospital/PHC/Dispensaries



6B Govt Office



6C Bank

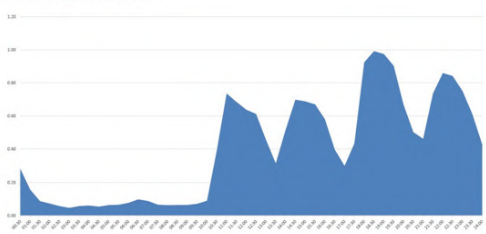


6D Orphanage

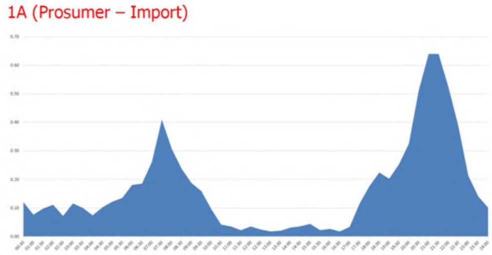
7A Bakery without manufacturing

7A Hotel & Restaurant

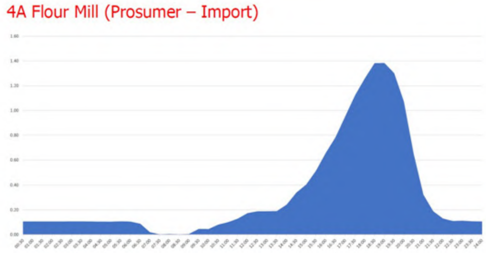
7C Cinema Theatre



1A (Prosumer – Import)



4A Flour Mill (Prosumer – Import)



8.3 Network Issues reported by KSEB Ltd

KSEB Ltd made a presentation before the Committee, based on astudy on the impact of solar generation in the low voltage distribution network[36]. The scope of the study included the following:

(i) Impact of RE generation in power quality in LT system due to the installation of solar;

(ii) Neutral shifting phenomenon in distribution transformer due to the installation of solar;

(iii) Impact of increasing the cumulative capacity of distributed energy systems from 75% to 90%;

(iv) Commercial impact due to banking;

(v) Proposals for mitigating the technical and commercial issues; and

(vi) Capacity of solar plants connected to each phase of the transformer.

The issues due to the RE penetration as identified in the report of KSEBLtd are detailed in subsequent paragraphs:

(1) Observations in network voltage

During solar power delivery hours, significant voltage rise and voltage unbalances have occurred at Distribution Transformer (DT) points. Alos, it is noted from the PQ reports and load survey reports, carried out in the distribution transformers during phasing out of the solar plants in the evening, that significant voltage dips are felt even at DT points.

From the PQ analysis, flicker and dips are observed during peak solar delivery periods. During solar peak hours, with the capacity of the connected solar system of 65% capacity of the DT, the terminal voltage at consumer premises was observed to be 257.5 V with an I- THD of 299.67%. Power quality analysis at intermediary points in the LT network revealed that there is a considerable voltage rise at the branches connected to solar prosumers far from the transformer point during solar peak hours. Voltage rise of more than 10 V and above at the DT points are observed at intermediary distributor levels of DTs having moderate load during solar peak hours. At DT points voltages above 264 V, the prescribed upper limit as per supply code, has been observed.

As per Regulation 11 (6) (a) of Central Electricity Authority (Technical Standards for Connectivity of the Distributed Generation Resources) Regulations, 2013, distributed generation sources operating in parallel with electricity system shall be equipped with “over and under voltage trip functions if voltage reaches above 110% or below 80% respectively with a clearing time up to two seconds; however, appropriate licensee may prescribe a narrower range of voltage for the purpose". However, it appears that these trip settings are not effective or are not adhered to by the developers.

(2) Observation in phase unbalance

During the PQ survey and load survey, significant unbalancing and subsequent neutral currents are observed during the solar hours. Due to the day wise inherent uncertainty in firm solar power delivery, the limitation in optimum load balancing in respect of both day peak and night peak has increased. Even at intermediary levels at the LT distributor, the effect of neutral shifting is evident from the unbalance in the voltage values.

(3) Observation in network harmonics

The current harmonics seems (I-THD) to be significantly high during solar hours. Though the proportionate effect on voltage harmonics (V-THD) is not evident at DT points, significant effect is seen at consumer/prosumer points during solar peak hours.

(4) Observation in Power factor and reactive over drawal

During the solar hours, the reactive power requirement of the loads connected to the distribution system is being entirely met from the DT source. Due to the increased reactive drawal during the solar hours, the operating power factor (pf) gets lowered; consequently the losses are increasing and the transformer efficiency is reduced. PV inverters normally operate at unity power because the owners of small residential PV systems in the incentive-programs are getting revenue only for their kilowatt-hour yield, and not for their kilovolt-ampere hour production. There is no benchmarking for the power factor during the time of active power delivery from PV plants. Thus, they prefer to operate their inverters at unity power factor to maximize the active power delivery, resulting in voltage excursions and poor power quality.

(5) Commercial impact due to banking

During 2024 summer, the increase in peak demand during late night hours was more than 600 MW than the evening peak demand level. Behaviour of the solar prosumers was partly contributing to this huge increase. Apart from the financial impact it imposes on the DISCOM, the unprecedented demand hike, especially during late night hours, has upset the load generation balance of the DISCOM.

The solar generation and the import – export scenario of the prosumers during the period from January 2024 to March 2024 is detailed in Table 8.

Table 8: Solar generation and the import – export scenario of the prosumers

LT			
Month	**Generation -kWh**	**Import -kWh**	**Export -kWh**
Jan-24	63953943	46678921	50052840
Feb-24	72303788	52316686	56808735
Mar-24	76552687	66558573	57423225

It is seen that the import by the prosumer, which is happening mainly during non solar hours, has increased by around 43% (19.9 MU) in March 2024 compared to January 2024 level, when the DISCOM is procuring at higher rates to ensure resource adequacy. The export by the prosumer is happening mainly during solar hours, when the market rates are low. The operational burden due to this was Rs.11.7crores.

8.3.1 Proposal by KSEBL to mitigate the technical issues

(1) Applying LGB techniques at DT distributor level:

a. PV plants above 2 kWp capacity shall be restricted with three phase inverters and three phase connectivity;

b. Balance the solar generation in the LT network, same as load balancing. LT phase wise distribution database is to be prepared to identify and record the phases to which the existing solar plants are connected;

c. Phase wise database of category wise consumer's connected loads in relation to load profile is to be prepared and maintained.

(2) Reactive Power Compensation:

Inverters provide dynamic voltage support and inject active and reactive power to prevent short-term voltage stability.

(3) Voltage/ Frequency Stability by promoting distributed storage systems:

The use of battery energy storage (BES) alongside the PV

systems can negate the intermittency associated with the PV generation and will enhance voltage stability margin (VSM) of the system. BESS emulates synthetic inertia to negate the frequency stability issues due to the high penetration of PV systems into the power grid.

(4) Harmonics Component:

Control strategies such as; passive and active filters, additional compensators for inverters are to be insisted to compensate for theharmonics distortions. Monthly THD values are to be logged and analysed, with respect to the limits under IEEE 519 and refinement strategies are to be imposed.

(5) Proposals for mitigating the commercial issues:

a. Transform the billing methodology of prosumers from net metering to net billing;

b. ToD billing may be made mandatory for all the prosumers. Reduced tariff may be made applicable for consumption during solar hours and higher tariff during non-solar hours;

c. Monthly settlement with appropriate feed in tariff is to be considered

8.4 Technical issues of Variable Distributed Generation

(1) The technical issues associated with VRE injection are becoming evident as the rooftop solar penetration is reaching the threshold levels under different distribution transformers. The developers/prosumers would consider only the cost of the solar panel and inverter and are not aware of the grid integration cost that could happen when the PV penetration increases. The additional coststo address the technical issues like the enhanced investment in distribution network, degradation of heat rates on account of partial use of thermal generation, additional investment in transmission system like STATCOM even at 400 kV level and lower voltages, additional compensatory devices in distribution network, difference in the cost of generation during peak (non-solar period in particular) and solar period, effect of power system pollution by harmonics and sudden voltage changes and its impact on the equipment in the prosumer's premises itself etc. are not available upfront, which gets loaded to tariff to be paid by all the consumers.

(2) The common issues with high penetration of DRE can be classified as voltage increase, voltage fluctuation, reverse power flow, harmonics, frequency distortions, system stability, system faults and protection problems etc. and these could influence the voltage and power quality of the power system.

(3) Voltage increase is the most common challenge caused when electricity generated from solar PV exceeds the consumer load, the voltage at the Point of Common Coupling (PCC) of the inverter and the grid increases. This is observed in the case of single -phase consumers having rooftop solar. As per the present regulations, single phase consumers can install upto 5 kW on their roof tops. The issue is amplified if there are more than one consumer connected to the single -phase line and the consumers install RTPV to compensate for their entire consumption through banking.

(4) The variation in the voltage and solar generation leads to changes in the line flows. Some of the studies have shown that the majority of the voltage fluctuations and flickers are contributed by connection problems and bad weather conditions, which are not attended to in the case of a behind the meter distributed PV system. Voltage fluctuation is also found manifested on the single-phase connections in Kerala cases. In the case of three phase consumers also, the solar plant is often connected on single phase exacerbating network issues. The load in the consumers' premises itself may not be balanced. The distribution utility may not be able to match the phase load as the phase balancing itself becomes dynamic. If the solar generation is more on a lightly loaded phase, the unbalance in current could further increase the voltage unbalance. Hence, there is a requirement of dynamic compensation such as DSTATCOM in the distribution grid.

(5) On physical survey of some of the sites, it is observed that the inverters are provided settings to optimise on the power injection at the PCC. This is achieved by maintaining unity power factor at the AC side of the inverter. The present metering methodology does not account the reactive power flow for most of the domestic prosumers and hence even the inverters having capability for "constant voltage mode" are set at "high power mode".

(6) Another power quality issue is the voltage sag affecting the grid-connected solar generation. In the case of transient voltage sags or swells, caused

by switching, lightning, starting of heavy loads etc., the PV solar plant is likely to get disconnected. The general conditions of connectivity regulations of CEA have specified the low voltage and high voltage ride through requirements. This requirement is scrupulously checked in the case of connectivity at transmission level. When a connected solar PV source also trips along with a voltage sag, say created by a large motor starting, the distribution system is overstressed and may mis-behave or more margin to be provided in the design and construction stage.

(7) Power system protection aims at disconnection of a faulty element at the earliest possible so that the remaining grid is not affected. With the influx of solar and wind generation, with practically no contribution to the fault level, the performance of the protection schemes is also put to acid test. Though this is not visible at present at 110 kV and 11 kV systems, the issue could surface when the distribution network is meshed with the introduction of SCADA control and development of sub-transmission network. The earth fault current reflected at some of the nodes could be affected on account of high solar injection in the neighbourhood.

(8) Kerala's Distribution Network has started facing the growing impacts of the above problems especially on lightly loaded networks with larger solar PV penetration leading to stand-offs between Distribution Officials and Prosumers. Overvoltage window being set at 240+10% = 264 V and 240-20% = 192 V (as per CEA Technical Standards for Connectivity of the Distributed Generation Resources, 2013 and its amendments), prosumers are facing power curtailment due to Overvoltage Cut-off during peak solar hours, say from 11 am to 2 pm. Solar EPC Contractors are reportedly resorting to unfair practices of raising the Overvoltage cut-off to 270 V, thereby leading to: overvoltage issues at adjacent consumer premises, phase unbalancing and neutral shifting.

(9) The injection of solar power without sufficient storage and/ or load management services is bound to increase the cost of power delivered in the control area.

8.5 Study under World Bank Transaction Advisory support by Madhya Pradesh

The Committee invited Dr. Priyanka Paliwal, Associate Professor, Department of Electrical Engineering, Maulana Azad National Institute of Technology, Bhopal to present the outcome of the World Bank assisted study on ‘Solar Generators in Distribution network voltage support’, conducted in a solansed distribution feeder in the state of Madhya Pradesh.

The study was based on the data from an existing solarised feeder (Raipura feeder) having low voltage issues and frequent tripping of solar plants connected to the feeder during low voltage conditions. Study simulated operation of the solar inverter in ‘Active as well as Reactive power injection mode’ and compared it with simulated models with centralised capacitor banks to address the voltage related issues. The study notes that the solar inverters are inherently capable of absorbing/ injecting reactive power based on system requirements. But, usually developers set the inverters in active power injection mode to maximise power generation. But, the study indicates that, in effect, this setting results in frequent inverter trippings due to voltage issues and result in very low CUF and power generation. This issue can be addressed by installing centralised capacitor banks, but will result in additional costs which will eventually get transferred to all consumers.

As part of the study, the team simulated the voltage profile and power generation from the solar plant in case the inverter is operated in Active-Reactive power injection mode. The results indicate that the voltage profile improves and the power generation from the solar plant also gets augmented, providing additional revenue to the project. Interestingly, the voltage profile was found to be better than the case with capacitor banks, probably because the reactive power compensation is made at the load point itself with the decentralised solar inverters. Thus, if the inverters are allowed to dynamically absorb/inject reactive power based on system requirements, it will be a win-win proposition for the solar PV generators and the grid. It enhances the duration of power generation from solar PV plants and improves the voltage profile of the distribution network without any additional investment in the network. The study also recommends incentivising solar producers for the reactive power support they provide to the grid by changing the operating mode of the inverters.

8.6 Differentiated incentives/compensation for different categories of prosumers

At present, prosumers are mostly treated at par irrespective of their category of tariff and without considering their load profiles. This creates a differentiated incentive structure among prosumers, with some receiving greater benefits. It emerges that while designing a compensation structure for prosumers, the tariff category of each consumer group also has to be looked into. This is necessitated due to the cross subsidy element built into the tariff structure whereby certain consumer groups have a tariff higher than the average tariff while others have a tariff on the lower side. Further, in the present net metering regime, the compensation structure solely depends on the tariff of the category the consumer belongs to.

To understand this disparity, the reasonable tariff for a rooftop solar plant to ensure the recovery of investment within a reasonable period and earn a reasonable return/profit can be looked into as per the provisions of the existing regulations. This tariff will be similar to all consumers for plants having similar capacity irrespective of the category they belong to. As the plant capacity becomes larger the tariff comes down slightly due to economies of scale. If a prosumer is guaranteed compensation based on such a reasonable tariff it will ensure recovery of all reasonable costs along with a reasonable return. The Table 9 provides the reasonable tariff (based on benchmark costs) for different plant capacities and the actual tariff a prosumer realises based on his present retail tariff and his consumer category under the net metering regime. For ease of estimation, it is assumed that the entire solar generation is used by the prosumers through banking within the settlement period.

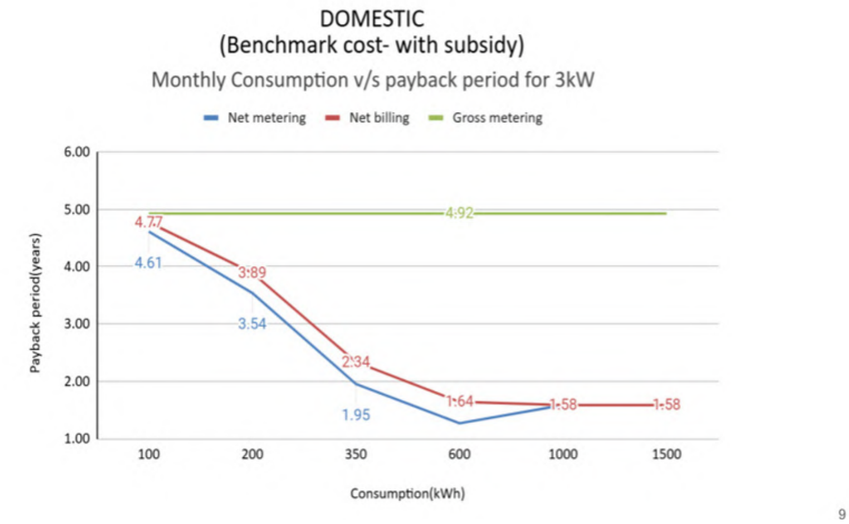
Table 9: Reasonable tariff for RTSPV vs Realised tariff under net metering

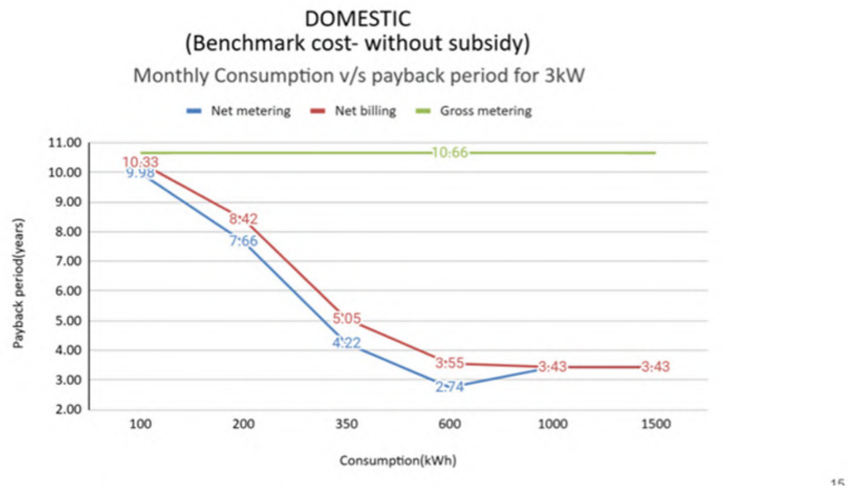
Capacity (in kWp)	Rate as per RE Norms (Rs/unit)		Industrial	Commercial	Educational Institutions	Domestic	
	with subsidy	without subsidy	Rate of realisation for consumer (Rs/unit)			Consumption	Realisation in Rs/unit
2	1.76	3.92	5.85-5.95	6.05-9.40	5.90-6.75	100	3.73
3	1.82	3.69				200	4.95
5	2.24	3.37				250	5.63
10	2.38	2.94				Above250	6.25 -9.20

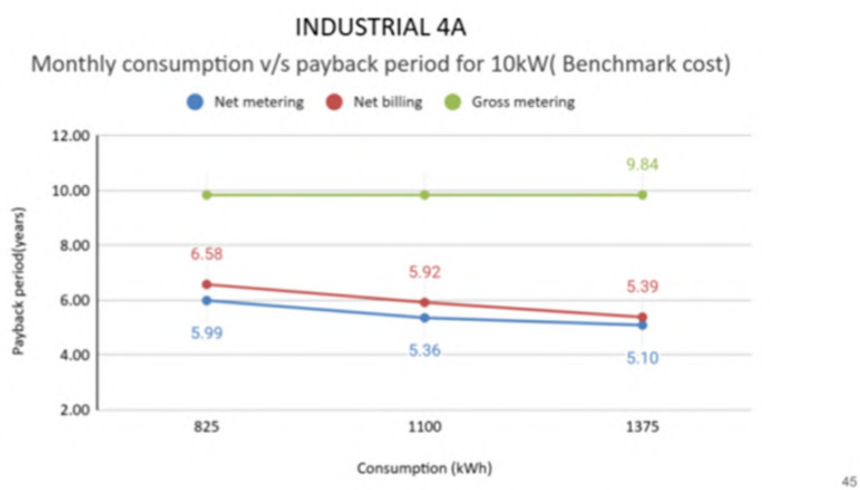
While deciding the compensation structure for rooftop solar it has to be ensured that the same is fair and reasonable. If the structure overcompensates the prosumer it will lead to inefficiencies, gold plated investments and distorts the market. On the other hand, undercompensation will result in inadequate investments and poor growth of the sector. So a right balancing of the compensation mechanisms is to be achieved.

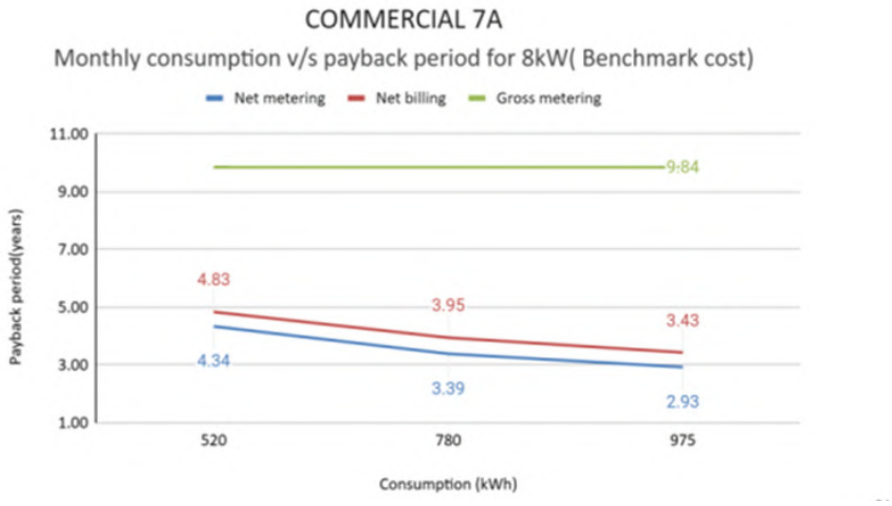
In this regard, three compensation systems are generally followed across the globe, with certain fine tuning within each of the three structures. These are broadly, net metering, net billing and gross metering. The feed-in-tariff applicable also plays a crucial role in the compensation mechanism. To understand the prevailing compensation regime, the existing APPC rate of Rs 3.15 per unit is considered for all the three compensation systems. The payback period for prosumers having various consumption levels under different categories of tariff are plotted for each of these three compensation systems and is provided as **Annexure C**. Few typical cases are provided under Chart 21.

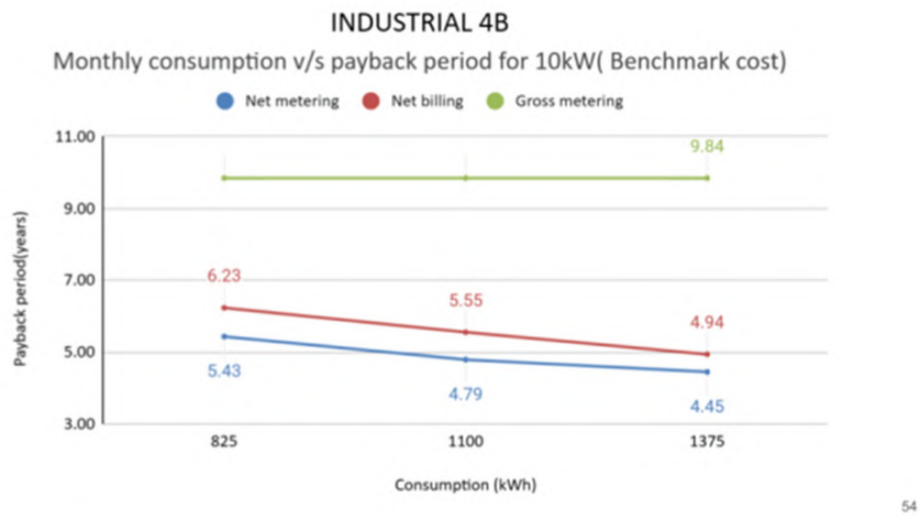
Chart 21: Pay back periods for different consumers under different mechanisms

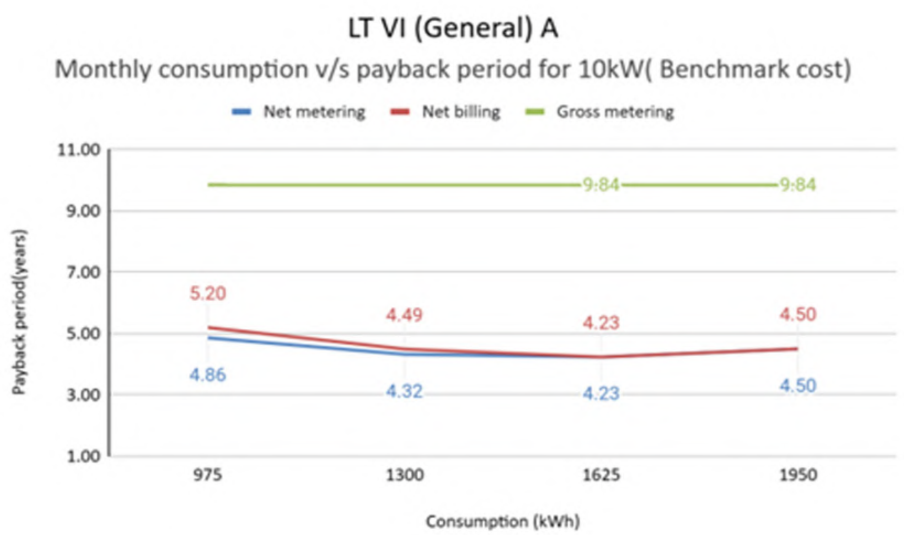







COMMERCIAL 7A
Monthly consumption v/s payback period for 8kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9:84
4.83
3.95
3.43
4.34
3.39
2.93
520
780
975
Consumption (kWh)


INDUSTRIAL 4B
Monthly consumption v/s payback period for 10kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
Payback period(years)
9.84
6.23
5.55
4.94
5.43
4.79
4.45
825
1100
1375
Consumption (kWh)
54


LT VI (General) A
Monthly consumption v/s payback period for 10kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9:84
9:84
5.20
4.49
4.23
4.50
4.86
4.32
4.23
4.50
975
1300
1625
1950
Consumption (kWh)

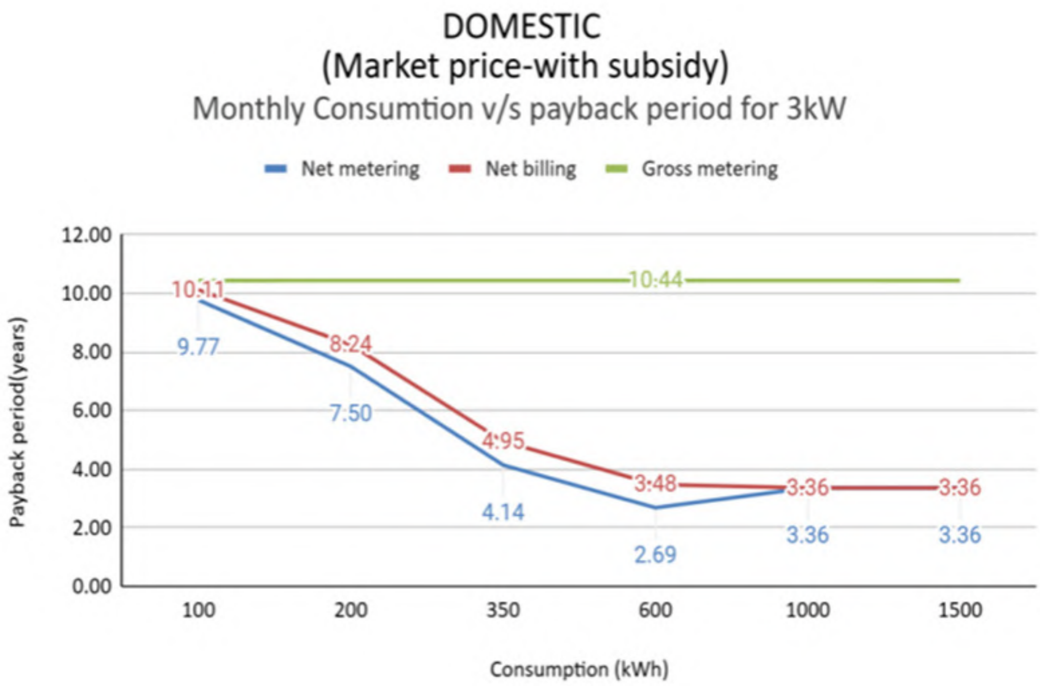
For domestic consumers availing subsidy for installing the rooftop solar plant (RTSP), the payback periods are reasonable in all the three systems of billing. While gross metering has a longer payback period than that for net billing and net metering are very attractive and are not much different. For domestic consumers having monthly consumption above 350 units, there is overcompensation as evident from the very low payback periods. For these consumers, even if the subsidy for RTSP is not available the payback periods are very attractive. However, for domestic consumers having lower monthly consumption, payback periods are not attractive without the subsidy for plant installation.

For industrial consumers the payback periods are very reasonable under net metering and net billing. For commercial and non-domestic consumers the payback periods are very attractive under net metering and net billing.

In case the feed-in-tariff for gross metering is properly designed to compensate for the investment, the payback periods can be made more reasonable for all the categories of consumers.

It is also noted that the cost for solar systems charged by developers/vendors are significantly higher than the benchmark costs notified earlier despite the sharp fall in solar module prices in the market. It appears that developers/vendors are not inclined to pass on the benefits of lowering prices or are not bringing in efficiencies and benefits of enhanced productivity, in view of the prevailing overcompensation under the existing net metering regulations. Tightening of the regulations is expected to result in adequate market responses and prices aligning better with the reasonable cost of RTSPs, ensuring an orderly development of the sector. The payback periods considering the price presently charged by the developers are provided in **Annexure C** and for a typical domestic consumer is provided in Chart 22.

Chart 22 - Payback periods considering higher market prices



8.7 Cost of energy storage

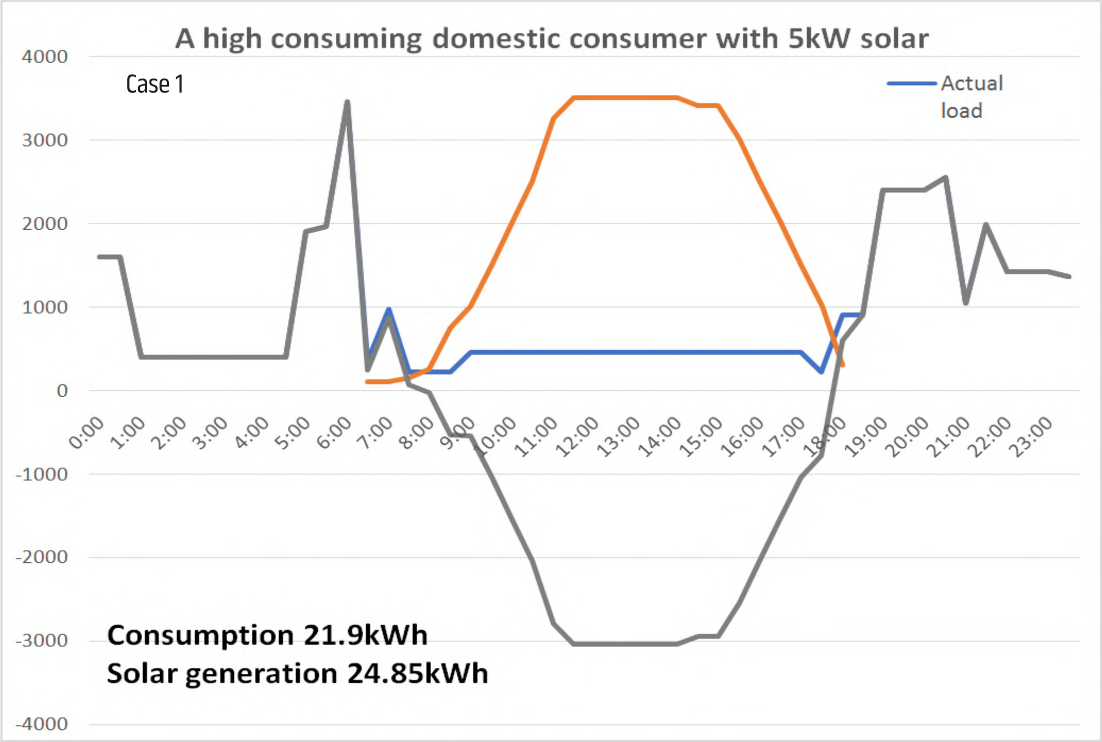
The injection of solar power without sufficient storage and/ or load management services is bound to increase the cost of power delivered in the control area/State. These stem mainly on account of the higher consumption during non-solar hours and the apparent reduction in demand during solar hours from behind the meter solar generation.

Some typical case studies are presented here:

1. The solar generation from the monitored sources were studied and following conclusion were drawn:
   a. Maximum generation observed is almost 68% of the installed capacity. It is presumed that the installed capacity referred is at AC level.
   b. As per the 15 minutes data reviewed, the dip in generation in certain time blocks in solar hours is as much as 33% of the installed capacity/ 47% of the actual generation.
2. For a higher end domestic consumer with 2 air conditioners and using electricity for cooking is modelled. As per the model, the consumption is

21.9 units per day (650 units/month). Assuming that he installs a 5 kW solar system without any storage, as per the model, surplus created is around 2.9 units after setting off his entire consumption. The total solar generation as per the model is 24.85 units.

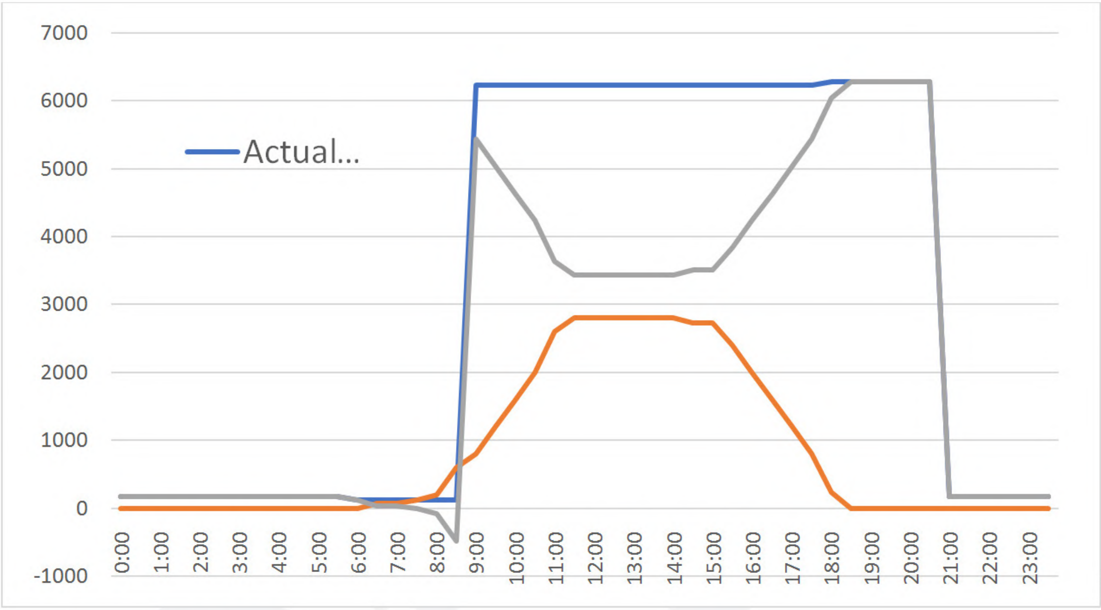
Chart 23 - Case study modeling - A high consuming domestic consumer with 5kW solar[37]



The total solar generation in the model was derived in line with the real time solar generation details available in Kerala. This corresponds to 4.97 units per kW panel. Even if it is assumed on a higher side on average conditions, and generation of 4 units/ kW panel is assumed, the total solar generation becomes 19.9 kWh/day, resulting in drawing around 2 kWh from the distribution licensee.

3. Another modelling of a commercial/ office consumer with hypothetical load is given in Case 2. The same solar capacity is assumed, as the area for solar installation could be the same or even less. Here also, the solar generation assumed is in line with the assumption of 4 units/ kW panel. It can be seen that the peak load requirement remains the same as per the load, whereas the day time load is not fully compensated by the solar injection.

Chart 24:Case study modelling- A typical commercial/ Office Consumer with 5kW solar[37]



This pattern of generation and in-situ consumption causes an additional cost as part of integration of DRE, which is not properly accounted for or factored at present. When one unit of energy is injected to the grid and used at another instant through a mechanism called banking, the hidden cost can be appreciated by the prosumers easily. The evolving price pattern in power exchanges where day tariffs are very low and non solar hour tariffs consistently reaching ceiling rates is depicted in Chart 6. But, the cost of energy not taken from the grid on account of solar generation is also having a cost impact that is not easily conveyed. These relate to the cost of backing down of conventional plants like, higher heat rates and fuel costs, higher O&M costs, higher capital costs to make flexible operation possible etc. These factors lead to the requirement of energy storage systems that can absorb the excess generation during solar hours and provide support during non solar hours.

4. In view of the fast transition towards non-firm renewable energy, the Commission has mandated storage obligation on the licensees and KSEB Ltd has already entered into a 500 MWh storage contract with SECI. Also plans to set up around 500 MW battery storage and pumped storage plants are being pursued in Kerala. The recurring cost on BESS as per latest market trends is over Rs 3 Lakhs/MW/month, which is

coming down significantly. Investment required for pumped storage plants is around Rs 5 crores/MW.

5. It is not fair and reasonable to load all these costs into the tariff and then realise it from consumers who have not installed solar plants or have plants meeting only part of his energy requirement. Ideally a reasonable portion of the cost of storage is to be borne by the prosumers. Similar is the case of cycle efficiency of energy storage systems. While BESS has around 80% cycle efficiency, pumped storage plants have a cycle efficiency of around 70 - 80%. Thus, only 70% - 80% of the energy used for charging/pumping is available for use at a different period. Thus, the present regime that allows drawing back of the entire units pumped into the grid during solar hours, during other periods of the day, may require a review for fair cost sharing.

8.8 Cost of Balancing

Integration of variable renewable energy (VRE) sources requires additional investment to enable the secure power system operation where the generation has to necessarily follow the demand. The additional investment is required to manage both real power and reactive power. The conventional method of LCOE (Levelized Cost of Energy) method does not capture the additional costs introduced on account of VRE and hence the tariff could increase beyond expectations.

Integration costs are categorized into three components – balancing costs, grid costs, and profile costs.

a) Balancing costs refer to the costs imposed by the unpredictable nature of VRE generation which necessitate operating reserves and/or storage to balance supply and demand.

b) Grid costs result from the additional transmission infrastructure to deliver the energy.

c) Profile costs can be further classified as;

    i) Overproduction costs – the cost arising from the curtailment required for over-generated power from VRE;

    ii) Backup costs – the costs of backup capacity needed to balance supply and demand during variation in VRE;

    iii) Full-load hour (FLH) reduction costs – VREs reduce the FLH of dispatchable plants, resulting in lower generation per capacity for these plants.

8.8.1 Estimation of Integration Costs

1) Several methods can be used. One of the simplest is the load duration curves method, where the costs are analysed based on the change in the load duration curve due to the introduction of VRE. According to a study, for wind energy integration with less than 30% penetration level, the balancing cost is about 2.5€/MWh, the grid cost isaround 13 €/MWh and the profile cost is 30€/MWh which will be a changing to 60€/MWh at 40% wind penetration.
2) Another method to estimate the integration cost is the cost production model, which can be implemented using PLEXOS or similar software. The cost is computed for scenarios corresponding to zero VRE and various levels of VRE with compensatory mechanisms like storage, gas fired plants etc. PLEXOS optimizes the unit commitment and economic dispatch and hence gives realistic figures.
3) As per European models, integration costs increased linearly up to 40% penetration reaching approximately 30 €/MWh and showing exponential growth after the 40% mark. In a coal predominant study in China, integration costs for wind and solar PV ranged from 2.18 €/MWh to 11.47 €/MWh and 5.21 €/MWh to 6.73 €/MWh, respectively, for penetration levels up to 30%.
4) According to various literature, balancing costs are generally low compared to other components, typically from 2 €/MWh to 4 €/MWh for wind penetration from 0% to 40%. The grid costs are also small, estimated to be in the order of 5 €/MWh. Wind profile costs are estimated to be negative or close to zero at low penetration rates going to 15 to 25 €/MWh at penetration between 30% and 40%. Comparing the literature, it can be seen that the integration cost is close to zero or even negative at low VRE penetration levels and increases rapidly as the penetration level increases.
5) The Lawrence Berkeley National Laboratory has estimated that solar PV with Li-ion battery storage in India can deliver electricity at a tariff of ₹3.32 by 2025 and ₹2.83 by 2030.

8.9 Cost of Network modernization

The distribution network needs upgradation to accommodate the increasing penetration of RE generation. But these costs are not charged exclusively to the prosumers, but are included in the tariff of other

consumers in the system through ARR and consequent tariff. i.e. in the net-metering scenario, the cost of network modernization for RE integration is solely borne by the consumers availing power by paying the appropriate tariff charges. This cross subsidizing needs to be addressed and this subsidising is to be restricted to the prosumers under the subsidized group of consumers.

In view of the substantial costs being incurred, which are likely to increase manifold during the transition period, there is a need for proper estimation of costs related to; energy storage, balancing and network modernisation and for creating a regulatory framework for equitable sharing of all the costs associated with RE integration among all the network users; like consumers, prosumers, open access customers etc. A separate study may be undertaken for the same which shall take into account, evolving technologies, cost trends, adoption trends etc. in the Kerala context.

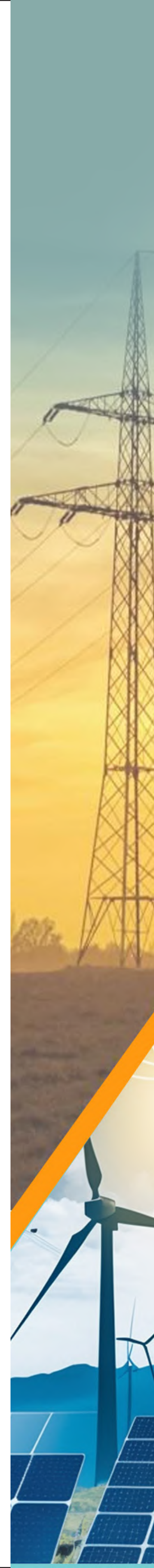
8.10 Need for monitoring decentralised generation

To manage rooftop solar integration, DISCOMs need detailed data on solar capacity per feeder and block-wise load analysis to understand solar penetration and grid impact. Tracking monthly application data, including approvals, rejections, and processing times, will improve transparency and efficiency. Monitoring reverse power flow on feeders and requiring mandatory registration of behind-the-meter RE capacity will help manage grid stability. Identifying transformers experiencing voltage fluctuations beyond the standards, along with determining retrofits or upgrades (such as OLTC installation), will further enhance reliability. A robust process for monitoring and enforcing RE regulations is essential to ensure smooth solar integration and grid management. The new regulation may mandate the prosumers and RE generators to share all necessary data with the DISCOMs and the DISCOMs shall conduct a detailed study and present the findings before the Commission within a period of one year. Any course correction on mandates for hosting capacity, reverse power flows, network modernisation etc, found required by the Commission can be undertaken thereafter.

Chapter
9

Policy Options

“The secret of change is to focus all of our energy not on fighting the old, but on building the new.” – Socrates



9.1 Promoting Hydro and large ESS

The measures being taken by the Central Government to promote hydro power projects including large hydro and pumped hydro storage projects (PSPs) were enumerated in Chapters 2 and 5. The challenges being faced by these prosumers were captured in Chapter 7. In this backdrop the new regulatory framework can consider the following options:-

(1) Remove fungibility in RPO with respect to Hydro Power Obligation (HPO) and strictly enforce the same. However, considering the higher gestation periods for hydro projects, the removal of fungibility may be considered after a period of 5 years;

(2) Allow a higher capital cost over CERC benchmarks for hydro projects having summer benefits (i.e., higher storage, higher CUF above a threshold, PSP mode of operation etc.);

(3) New projects be implemented with private participation through tariff based competitive bidding (TBCB) alone, to alleviate tariff related risks and difficulties in financial closure;

(4) Under TBCB, allow a prespecified premium tariff over the quoted tariff for power generation in summer months;

(5) Allow a longer tariff period/BOOT period of 40 years or more considering the longer useful life of hydro projects;

(6) Promotion of PSPs leveraging the existing reservoirs for inter seasonal storage benefits through differential tariff for summer and non-summer months. For DISCOM owned PSPs with interseasonal

benefits, the regulations may allow higher capital costs (on a per MW basis), accelerated depreciation to allow early recovery of capital or other suitable promotional measures than provided for PSPs having diurnal benefits only;

(7) Enabling framework for multi beneficiary/State PSPs having few hours storage only; similar approach can be followed for utility scale BESS also;

(8) Enhance the Energy Storage Obligation (ESO) from 2029-30 onwards to enable focus on faster development of PSP.

9.2 Promoting decentralised energy storage

As discussed earlier, decentralised energy storage helps to mitigate many of the adverse impacts of faster adoption of decentralised renewable energy in particular as well as those related to energy transition in general.

1) At present the majority of consumers own decentralised storage capacities in the form of backup inverters with battery. But these are seldom put to use for grid support and act as a backup source only when grid supply is not available. As reliability of the distribution network has improved significantly over the years, these systems mostly remain idle and the investment does not provide any returns. This is a low hanging fruit and the system as well as the consumers can be benefited through appropriate technical and commercial measures that ensure its proper use. Through Time of Use (ToU) tariffs, the consumers can be incentivised to charge the batteries during the day time and discharge it during the peak times. Minor modifications in the inverter circuit can even automate this procedure. In case the stored energy is to be exported to the grid, modifications in the existing inverter circuit would be required and the market for the same can be developed, if adequate incentives are provided through tariff.

2) Another latent opportunity is the large batteries coming along with electric vehicles. The integration of Vehicle-to-Grid (V2G) technology has gained significant traction worldwide as a potential solution for grid stability, particularly during periods of peak electricity demand. International experience has shown that offering financial incentives to vehicle owners, can encourage their participation in V2G programs. These incentives typically can come in the form of direct payments, tax rebates, or preferential electricity rates for the both the vehicle owners and the energy suppliers, who participate in the grid balancing process.

For instance, in countries like the United Kingdom and Netherlands, Governments have introduced programs where EV owners are compensated for supplying excess energy from their vehicle batteries back to the grid, particularly during peak hours. In addition, utilities may offer “demand response” programs, where EV owners receive payment for agreeing to discharge their vehicle batteries during periods of high demand. These incentives help not only in stabilizing the grid but also in providing cost-effective energy storage solutions, reducing reliance on traditional peaking power plants, which are often fossil fuel-dependent.

Offices and Residential complexes can beneficially utilise V2G systems by establishing solar powered EV charging stations which allow EV charging during solar hours and encourage EV owners to use the charging system to inject stored energy to the grid at a premium tariff during peak demand periods.

3) Another option that appears immediately feasible is promoting hybrid inverters for rooftop solar systems where batteries are an inherent part of the system. This has multiple benefits like enabling solar generation even while the grid is not available, more reliable supply for prosumers, enhancing local demand and stabilising the grid.

As per the new operational guidelines for the implementation of PM Suryaghar, issued by MNRE on 07.06.2024, systems connected to the grid but not feeding power into it (such as Behind-the-Meter systems and battery hybrid systems) will also be eligible for Central Financial Assistance (CFA) under the scheme, subject to approval by the respective Electricity Regulatory Commissions. In these cases, the DISCOM will inspect the installation, verify the functioning of the reverse power relay protection, and provide appropriate remarks in their report.

Prosumers are also benefited through the use of hybrid inverters as grid unavailability does not curb generation during solar hours and the supply reliability gets enhanced. Consumers may also be encouraged to utilize grid-connected hybrid systems and support the grid by injecting power during non-solar hours. Such injections may be compensated through applicable incentives. These incentives will encourage more individuals and businesses to invest in energy storage solutions, helping to alleviate strain on the grid during high-demand periods. The rate for these incentives shall be determined in such a manner to ensure a reasonable return on investment for the prosumers, making it financially attractive for them to participate in the program.

4) While Time of Use (ToU) tariff is a common tool to incentivise consumers to shift load from high demand periods to low demand periods, the same is also a suitable measure to use batteries to reduce drawal from the grid during high demand periods through adequate education of the consumers on the financial benefits accruing from such use.

At the same time, in view of the emerging importance to tap decentralised energy storage capacities and to promote establishment of more such capacities it would be appropriate to offer a premium feed-in-tariff during high demand periods. Through this the consumer/prosumer can monetise his investments in energy storage systems. Along with this, charging of batteries during solar hours can also be promoted by specifying a relatively low feed-in-tariff during solar hours.

5) In this background, the policy options that can form part of the regulatory framework include:-

(1) Extending present ToU/ToD tariff to more consumers/prosumers and increase the price differential between solar and non-solar hours to help monetisation of existing inverters;

(2) Introduce differential feed-in-tariff for energy fed into the grid, with premium tariff during high demand periods and lower tariff for solar hours;

(3) The consumers not having rooftop solar plants may also be allowed to participate in this program. By this, V2G participation and monetisation of existing backup inverters of consumers can be facilitated;

(4) Preferential grant of connectivity to rooftop solar plants having hybrid inverters above a threshold storage capacity, say, 30% of solar plant generation. Hybrid inverters may be suggested for the consumers having monthly consumption above 300 units.

(5) Incentives in the form of premium feed-in tariffs should be offered to prosumers/ consumers/ EV chargers who install Battery Energy Storage Systems (BESS)/ use EV batteries and contribute energy to the grid during peak hours.

9.3 Tariff for utility scale RE projects

The basic principles on which tariff is to be determined as laid down in Section 61 of the Act are that generation, transmission and distribution and supply of electricity should be conducted on commercial principles; keeping in mind factors which would encourage competition, efficiency, economic use of resources, good performance and optimum investments. Section 62 provides the principles for determination of tariff and Section 63 provides the principles for determination of tariff by bidding process. Accordingly, the regulated tariff is determined as per Section 62 and tariffs discovered through Tariff based Competitive Bidding (TBCB) are adopted as per Section 63 of the Act.

The regulated tariff can be; generic tariff determined and published in advance by the Commission or project specific tariff determined by the Commission based on the prudent project completion cost. In case generic tariff is available, the developer has a clear view of the revenue stream and possible returns on the investment in advance and can take appropriate decisions before investment. The financial closure of viable projects for which generic tariff is available is easier. However, risks related to project development are to be fully borne by the developer. On the other hand, under project specific tariff the norms for tariff determination including benchmark project costs are available in advance and developers can select viable projects. All prudent costs incurred by the developer including regulated return is allowed to be recovered through tariff. Any cost incurred on the basis of factors beyond the control of the developer is allowed as a pass through in tariff. However, as tariff is not known upfront the projects face delays in financial closure. In both the routes, in case the DISCOMs find the tariff to be higher than the market rates, the development of the project becomes uncertain.

Whereas in TBCB, the tariff is arrived at through a competitive bidding process and will be reflecting the market conditions. The State, in consultation with KSEB Ltd, may also arrive at an upper tariff at which KSEB Ltd is mandated to procure energy from projects identified through the TBCB route under a reverse bidding framework. In this route, the project will be allotted only if the tariff is found to be market aligned and the uncertainty as to whether the DISCOM is interested in the project is alleviated. Also, as the tariff is known upfront, financial closure can be expedited. GoI insists on a TBCB route for procurement of power by DISCOMs.

In view of the current state of the market development in the country, it is better to follow the TBCB route for all the power procurement including that for RE and ESS. At the same time, when DISCOMs themselves develop projects the same need to be regulated based on benchmark cost and tariff related norms. For this purpose the benchmark costs and tariff norms of the Central Commission can be followed in general. In this regard the points discussed under the heading “Promoting Hydro and large ESS” (9.1) also need to be put in place to provide clear signals for investment by DISCOMs.

9.4 Preference to projects within the State: promotion of entrepreneurship

While it is preferable to procure from the least cost sources, it is generally noted that the tariff for projects developed within the State are higher than those developed in other parts of the country due to a variety of reasons, some of which are genuine. Completely ignoring the project development within the State solely on the basis of tariff comparison, could be counterproductive on many counts. The Commission has to create enabling market conditions for optimum development of energy resources within the State without unduly burdening the electricity consumers.

In this regard, it is noted that the waiver of interstate transmission charges available for RE and ESS are being gradually phased out and consequently the projects within Kerala can become more competitive on a delivered price basis. Thus, the projects within Kerala can be given preference as long as their tariffs are reasonably around the delivered price of competing interstate projects within the same technology brackets.

9.5 Measures to ensure adequate RE capacity to meet RPO

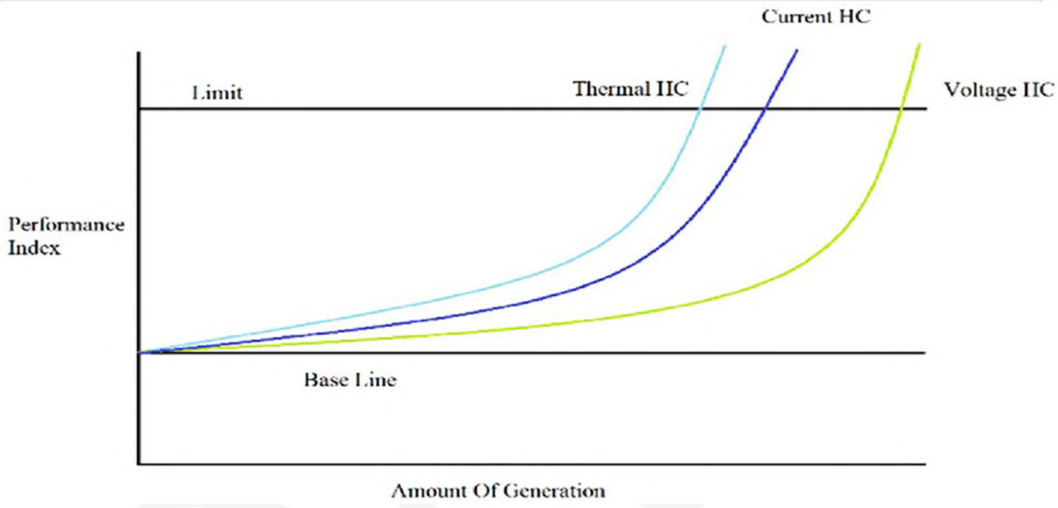
Under Rule 16 of the Green Energy Open Access Rules, 2022, the Central Electricity Authority (CEA) has published the guidelines for resource adequacy planning (RA), a critical framework for ensuring sufficient power generation capacity to meet the State's future energy demand. As a first step, the resource adequacy plan taking into account the RPO trajectory has to be developed and is to be updated on an annual basis. On the basis of the resource mix and the quantum identified for each resource as per the approved RA plan, there has to be an approved RE/ESS procurement/ development plan in place in advance. For the identified RE/ESS procurement there has to be advance bidding to procure the required quantum. In respect of RE/ESS development by DISCOM the development milestones should be approved in advance. The progress on both these accounts need to be regularly reported and published and necessary corrective actions, as may become necessary, have to be ensured. The regulations may provide for an appropriate framework encompassing all these features.

To ensure a streamlined process, the regulations may provide data formats for reporting; (1) RPO for the control period, (2) Projects under pipeline for benefits during control period, (3) Timelines for entering into procurement arrangements to meet RPO in each year of the control period etc. Separate proceedings may be mandated in the regulations for finalising the procurement arrangements for meeting the RPO for the entire control period along with annual review for corrective actions, including for penalties and incentives based on achieving the RPOs.

9.6 RE Hosting capacity

1) For a distribution network, a safe limit for solar integration can be worked out on technical considerations alone. Hosting Capacity (HC) is defined as "the total Distributed Generation (DG) capacity that can be accommodated on a given feeder without adversely impacting voltage, protection, and power quality and with no feeder upgrades or modifications.

Figure **5:** Hosting capacity with respect to different performance indices



2) PV rooftop applications with ESSs can efficiently manage the energy, improve grid stability, mitigate the effects of voltage fluctuations, and solve power quality problems led by high PV penetration. The time interval of voltage fluctuations in the power output being less than one -minute, short-term storage systems such as lead-acid batteries, super capacitors and Li-ion batteries help to improve system stability. The effectiveness of the method is reported to have been tested using real time data for a building in Austria, where the results revealed that a storage size of 5 kWh per household was reasonable, but currently available storage technology prices are still too high. From the commercial point of view, where the dependency on the grid for peak power consumption can be reduced, storage systems capable of meeting diurnal variation could be promoted by appropriate price signals in Time-of-Day tariff.

3) The limits of distributed RE Generation without sufficient storage is well studied and deliberated. Various control areasadopt different yardsticks. The maximum capacity of VRE that can be integrated can be determined in several ways. One of the practical methods is to determine the hosting capacity. The Hosting Capacity (HC) is locational- sensitive and depends upon; the topography of the grid, connectivity of the distribution grid to the transmission system, fault level, number of consumers and their load profile etc. Therefore, a single generic approach for defining the HC cannot be implemented on all the grid systems. In general, HC can be enhanced through;

   i. OLTC Transformer Employment;
   ii. Curtailment of DG Resources at Time of Need;
   iii. Optimized PV Deployment (Space Optimized);
   iv. Active and Reactive Power Control;
   v. Static and Dynamic Network Reconfiguration;
   vi. Battery Energy Storage Systems; and
   vii. Mitigation of Harmonics.

At international level, the following observations are made:

Figure 6: Different DSO's rule of thumb for DG Integration[38]

Limiting constraint	Country	DSO rules for DG ratings
Transformer rating	Portugal	<25% of the MV/LV transformer rating
	Italy	<65% of the MV/LV transformer rating
	Belgium	<MV/LV transformer rating
	Spain	<50% of the MV/LV transformer rating
	South Africa	<50% of the MV/LV transformer rating
CB rating	South Africa	<25% of the feeding CB for shared feeder <75% of the feeding CB for dedicated feeder for DGs
SCC	USA	DG rating should be <10% of the SCC at the PCC
	China	
Feeder load	Canada	<50%–100% of the feeder capacity
	USA	<15% of the annual feeder load
	South Africa	

Abbreviations: CB, circuit breaker; LV, low-voltage; MV, medium voltage; PCC, point of common connection; SCC, short circuit capacity.

Figure 7: Summary of HC limiting constraints, defining criteria, enhancement technique and enhanced values[38]

Defining criteria	Limiting constraints	Enhancement technique	HC value	Enhanced HC value
_	Over voltages, under voltages	C-type filter design	30%	75%
Number of customers having PV	_	Optimal PV placement	_	30%
Transformer, cable, and line ampacity	Rise in voltage levels	Curtailment of DGs	130 MW	170 MW
Current carrying capability of supply lines	Harmonic distortion voltage changes	Passive filters	38.53%	55.34%
Transformer overloading	Voltage quality	_	37.40%	80.10%
_	Over voltages	OLTC transformers	89.81%	113.48%
_	Over voltages	Reactive power absorption	_	_
Transformer and cable rating	Over voltages	Cos(θ) control and PV storage control	_	101% and 116%
Transformer rating	Voltage unbalance	Using active MV/LV transformers	38%	45%
_	Over voltages	Electric energy storage system (EESS)	_	_
Equipment ampacity	Steady state bus voltage	_	_	_
Thermal violation of equipment	Transient and steady state voltage violations	Volt-VAR droop control	–	Increased by 533 kVA
Short circuit capacity, minimum load, and transformer rating	Voltage level violations	Reactive power support	7.9 MW	18.7 MW
_	Dynamic voltage regulation	Using STATCOMS	_	_
Transformer rating	Over voltages	Using active transformers	45%	87%
Transformer rating	Rise in voltage	PF droop control and grid reinforcement	_	_
_	Harmonics	Passive filter	44%	73.30%
Grids equipment ampacity	_	Grid reconfiguration	17.20%	73.46%
_	Primary Impedance	Grid reinforcement and restricting PV locations	30%	50%
_	Thermal and voltage constraints	Static and dynamic reconfiguration and active network management	–	51.8% and 50.2%
Thermal limit of power lines	Reverse active Power	Quadratic power control and optimal battery and converter size	–	50
_	Voltage Rise	Using BESS	25%	60%
_	Power Quality and voltage unbalance	Optimal location of BESS	–	111%
Current carrying capability	Harmonic Distortion	Implementing a C type Filter	38.50%	55.34%
_	Voltage Magnitude and voltage unbalance	Volt-Var control	30%	60%
Ampacity limit of lines and cables	Rapid voltage changes	Network reconfiguration	_	18%
Transformer rating and number of customers having PV	Over Voltages	Efficiently controlling active transformers	38%	45% with maximum of 3% of voltage rise
Number of customers with PV	Transient and steady state Voltage violations	Reactive power control	–	84.40%
Equipment overloading	Over voltages	Using residential PV storages and reactive power control	_	80% by Cos(θ) control 120% by Q(V) control 70% by forecasting

4) At present the renewable power hosting capacity of the distribution transformers in Kerala is specified as 90%. However, Kerala State Electricity Board (KSEB Ltd) raised concerns about the impact of increased RE penetration, particularly due to voltage fluctuations observed in certain areas. Considering these, it may be required to put in place additional safeguards including:-

(1) Rooftop solar PV capacity connected on each individual phase should not exceed 30% of distribution transformer capacity to ensure balanced loading across phases and prevent potential damage to the transformers;

(2) The reverse power flow through distribution transformers may be restricted as a percentage of their total capacity, after conducting a detailed study on its impact on asset life etc;

(3) To maintain the stability and reliability of the power distribution network, neutral earthing must be provided at the distribution transformer point, as well as at intervals of every five electricity distribution poles and at the consumer connection point. These measures are designed to enhance system safety, improve grounding, and reduce the risk of electrical faults or imbalances;

(4) To check cornering of the hosting capacity by few prosumers, the rooftop solar plant that can be installed in a consumer premises may be limited to the connected load/contract demand of the consumer;

(5) For rooftop solar plants exceeding a threshold capacity, say 3 kW, hybrid/smart inverters with BESS may be promoted to enhance daytime loading and to limit voltage fluctuations;

(6) Under the distribution transformers/feeders where the hosting capacity is exhausted, additional solar plants may be allowed only in any of the following manners:-

i. Behind the Meter (BTM) RTSPV systems without net meter facility, ensuring necessary safety protocols;

ii. RTSPV systems with hybrid smart inverters with BESS for at least 30% generation and dynamic reactive power support;

iii. Prosumers opting for smart inverters along with smart meters and agreeing to real time curtailment of generation in the event of clearly specified system conditions.

(7) For RTSPV systems exceeding 3 kW, use of three phase inverters may be mandated. With the introduction of per kVA/kW rates (based on recently notified amendments in the state

supply code) for availing new connections and modifications in existing connections, it is expected that the process of conversion of existing single phase connections to three phase becomes smoother.

9.7 Incentivising Reactive Energy Support

Inverters with reactive power injection capability can be incentivized for their role in supporting grid voltage stability and reducing reliance on central compensators. This dual capability of solar inverters to manage both active and reactive power can significantly improve grid performance, particularly in decentralized solar generation systems. By incentivizing such inverters, solar producers can benefit from additional revenue streams, such as compensation for providing grid services like voltage regulation. This would also create entrepreneurial opportunities in the renewable energy sector, with businesses potentially emerging to manufacture and deploy these advanced inverters or retrofit existing systems. The resulting market would foster innovation, enhance grid stability, and promote further integration of renewable energy into the power grid. Thus, the new regulatory framework may consider fixing an appropriate tariff regime for reactive power support for both low voltage and high voltage grid conditions. There can be a graded tariff structure linked to voltage conditions.

9.8 Promoting smart appliances and automation

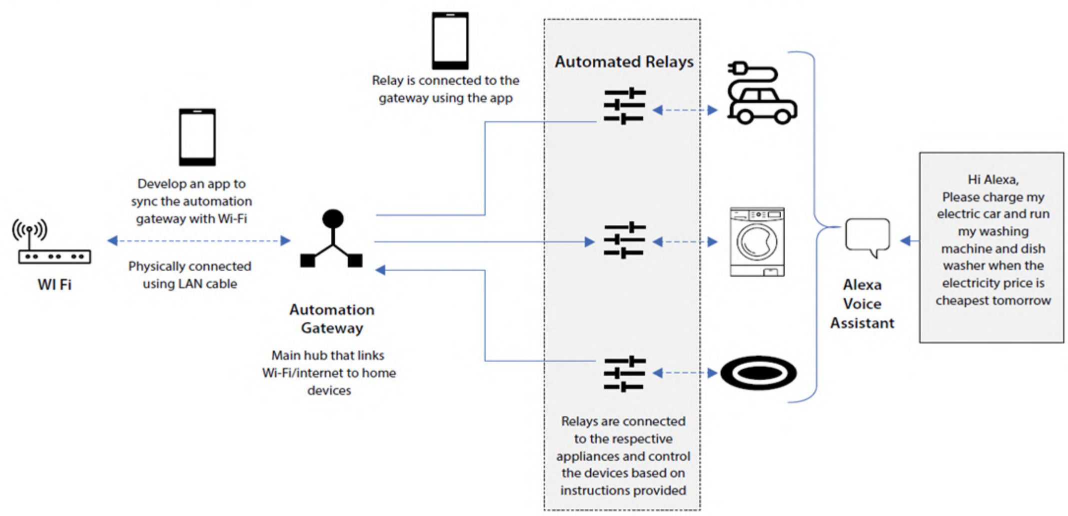
Time of Use/Day (ToU/ToD) tariffs are designed to infuse behavioural changes of consumers, so that electricity usage is minimised during stress (high demand) periods and promote usage during low demand or high supply periods. However, behavioural changes are hard to achieve solely based on tariff signals and since the electrical appliances are mostly operated manually the desired changes are found to be hard to achieve. This brings to focus smart devices that automate the process of load shifting based on tariff signals. Smart devices can automate the process of actively monitoring the change in tariffs and responding to it, thereby sparing consumers from performing this activity manually. A few start-ups and other companies are already exploring the possibility of developing smart devices that can react to changes in price signals in real time. Automating existing appliances or purchasing smart devices requires consumers to spend more money, leading to a reluctance to buy these devices. However, consumers must understand that in the long term, the money saved on

electricity bills will outweigh the initial spending. The smart appliances market is growing at an unprecedented rate because there is a rise in interest in smart appliances and gadgets, especially among Millennials and Gen Z.

As a first step towards promoting use of smart devices and automation, solar grid connectivity requirements may be relaxed for consumers opting to switch to such devices for specified minimum load.

Figure 8: Alexa based smart appliances

Figure demonstrates the development of an Alexa-based application that can make any home appliance smart. The user just needs to provide a command such as "Hey Alexa, turn on my washing machine when the power tariff is cheapest."



9.9 Energy metering and accounting of prosumers

From 2020, the rooftop solar PV (RTSPV) capacity in the State is growing at a CAGR of about 100% and its growth rate is the highest in the country. This means the RTSPV capacity in the State is doubling every year. Already, the share of RTSPV capacity in the day demand has reached 21.75%. While day-time demand won't rise as quickly, rooftop solar capacity could reach almost half of the State's day demand in a few years, with even higher contributions in areas with high solar penetration. This rapid growth will require adjustments in grid management to handle variability and maintain stability, especially during peak solar generation periods.

A detailed Time-of-Day (ToD) and tariff design study for FYs 2025-2030 is crucial to adapt to shifting the load and generation patterns. This study should address consumer categories, seasonal ToD variations, and advanced metering needs, along with incentives and penalties to encourage efficient energy use. An optimal balance of Fixed and Variable Costs in the tariff structure would support rooftop solar and Battery Energy Storage System (BESS) adoption by signalling cost-effective consumption times. With domestic consumers driving demand, especially at night, energy efficiency for Air conditioners and appropriate ToD rates for EV charging are essential. KSEB Ltd reported ₹310 crore burden from energy banking, highlights the need for strategic ToD tariffs to support grid stability and renewable integration.

Banking charges shall be introduced for prosumers operating under the net metering framework. These charges will account for the grid infrastructure's use to store surplus energy exported by prosumers and retrieve it during periods of deficit. Additionally, differential banking charges may be considered based on time-of-use patterns, such as peak and off-peak hours, to incentivize better load management.

To address various issues as discussed in this paper, the following framework can be considered:-

(1) Given the rapid growth of rooftop solar adoption in Kerala, a rationalization of Net Metering policies is essential to balance the grid stability with consumer benefits. Current discussions suggest restricting Net Metering with monthly banking to smaller systems—specifically, those up to 3 kW.

(2) For systems between 3 kW and 100 kW, net billing rather than traditional net metering can be considered, where energy fed into the grid is credited at a separate rate from the consumption rate. This method allows the utility to control costs to be passed on to other consumers and provides a financial return to prosumers based on actual grid value.

(3) The present system of treating APPC rate as the feed-in-tariff may be done away with as it creates uncertainties among all the stakeholders. Instead, feed-in-tariff that ensures fair compensation may be fixed for the entire control period of the regulation. This can also facilitate immediate settlement of surplus energy instead of waiting for more than a year to monetise the value of energy fed into the system. This can also facilitate 'zero billing' of prosumers as the value of surplus electricity is netted off against payment of fixed charges, meter rent etc. Unsettled amount, if any, shall be paid by the DISCOM in that month itself or carried over to subsequent months at the option of the prosumers.

For installations above 100 kW, with no upper limit, banking could be removed entirely, and accounting would shift to 15-minute intervals.

This fine-grained accounting incentivizes large consumers to closely match their generation with their demand or risk financial loss from overproduction. By removing banking from larger systems, the grid can more reliably predict supply, reducing potential strain from excess generation during low-demand periods.

(4) A Gross Metering option, which measures all the energy generated separately from the energy consumed, may be made available to any prosumer, allowing them to sell all the generated energy to the grid at a predetermined tariff without offsetting their consumption.

(5) For prosumers with net metering facility a new energy banking framework may be considered where only 90% of exported energy is allowed to be drawn back and 10% of exported energy be treated as banking/storage charge, initially. This may be gradually enhanced to 20% in steps of 5% to align it with the cycle efficiency of BESS. This provides a signal to prosumers on the energy lost in banking/storage transactions due to use of grid level storage technologies and would encourage more self-consumption during solar hours and use of home battery storage systems.

(6) To expand renewable energy access, Virtual Net Metering (VNM) can be introduced for public bodies, allowing shared solar credits across institutions like schools and hospitals. The VNM framework can be extended to housing colonies and other community projects, in case BESS forms part of the project for at least 30% of the RE generation.

(7) Group Net Metering (GNM) facility may be allowed for those consumers eligible for net metering with the modified banking facilities.

(8) Banking/storage charges shall be levied from the prosumers under Net metering arrangement. As an introductory measure, it may be specified as Rs 1.00 per unit for energy drawn back after banking/storage, for the first two years. Thereafter, the exact cost of banking/storage based on the discovered price of utility scale energy storage systems shall be fixed as the banking/storage charge.

An alternate framework can also be looked into for the metering and energy accounting of prosumers so that the prosumers can align the system in accordance with their energy consumption patterns.

Alternate framework

Under the alternate framework also, the suggestions under paragraphs (3), (4), (5), (6), (7) and (8) above remain the same. The alternative to suggestions under paragraphs (1) and (2) is provided below:

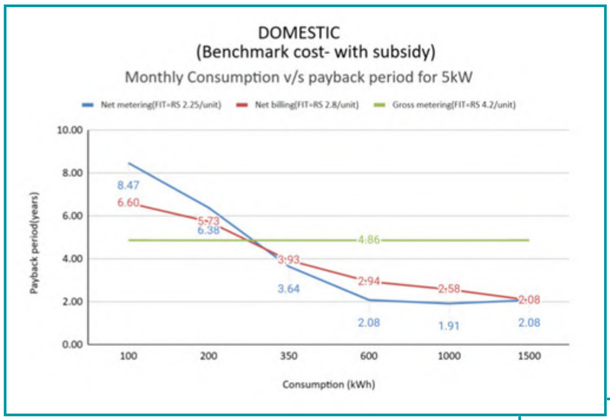
(1) Net metering with monthly energy banking may be made applicable to all the domestic prosumers with plant capacity up to 3 kW.

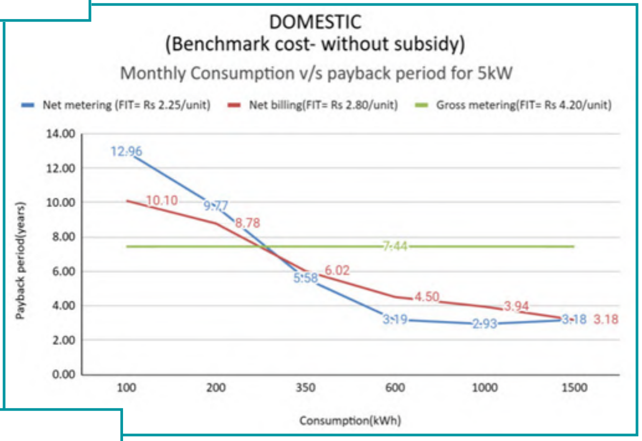
(2) For domestic prosumers with plant capacity above 3 kW but not exceeding 5 kW, the net metering facility with ToD energy adjustment can be provided. These prosumers may be incentivised for installing BESS of adequate capacity. Thus, prosumers under this group need to use their own energy during peak hours and they can also inject to grid surplus energy during peak hours for which 150% of normal feed-in-tariff can be the settlement rate. In case they draw power from the grid during peak hours, it can be charged as per applicable retail tariff. Since battery storage will be available only for limited hours, these prosumers can be allowed to draw back the surplus energy injected during solar hours in any time of the day except during peak hours, by incurring banking/storage charges.

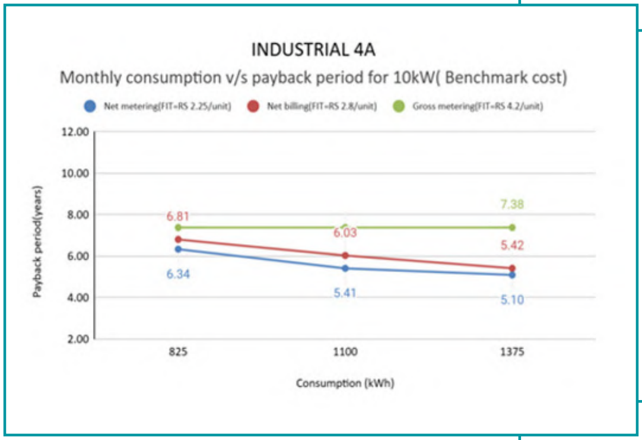
(3) For all other consumers there shall be an option to choose between the three systems, viz, net metering as provided under (2) above, net billing and gross metering. In case no option is provided by these consumers/ prosumers, net billing will be the default system.

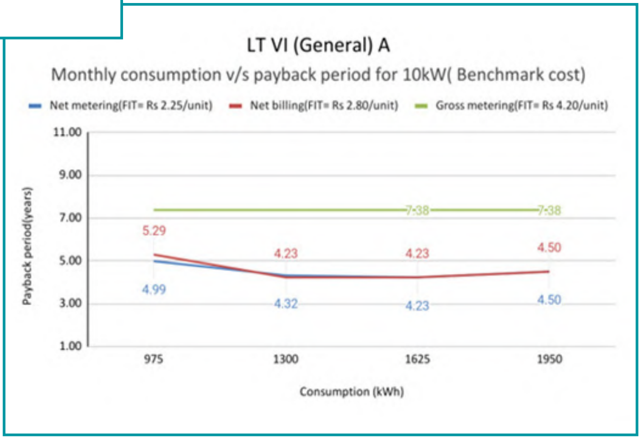
(4) The feed-in-tariff under these three systems can be different so as to balance the compensation mechanisms. Thus, the feed-in-tariff can be 75%, 100% and 150% of the latest price discovered in tariff based competitive bids and as specified in the regulations, for net metering, net billing and gross metering respectively. The payback periods for different categories of prosumers under this arrangement is depicted in Chart 25. It can be seen that the payback periods are reasonable for gross metering also and the compensation among different billing systems are getting more aligned. Further fine tuning can be done as may be found necessary based on stakeholder feedback.

Chart 25: Payback periods in optional systems









The freedom given to prosumers to select the best billing system suitable to their demand pattern is also expected to result in more optimal development of rooftop solar systems. For example, an industrial consumer having operation mostly in day time can choose net billing by designing the plant capacity matching his daily demand. Any occasional export to the grid will be compensated at a rate aligned to the generation cost of the plant. An agriculture consumer can opt for gross metering and earn more revenue as his retail tariff is lower than the applicable feed-in-tariff. A domestic consumer billed under lower slabs of up to 150 units may opt for gross metering to get better compensation than the net metering system depending on the net-feed-in tariff applicable. Thus, the optional billing system can foster a wider adoption towards greener energy. Also, an examination of Chart- 20 indicates that predominant consumption of many consumer groups are in day time coinciding mostly with solar generation. For such consumers the compensation under net billing could be more beneficial than under net metering in case differentiated feed-in-tariffs are applied.

(6) The differentiated feed-in-tariff has strong economic rationale on two fronts. Firstly, it balances out the compensation structure and ensures that all the prosumers get a reasonable return on their investments. Secondly, the economic value of the energy fed into the grid is factored for the compensation. Under net metering the feed-in-tariff is applicable to the left over energy after own use after availing the benefit of banking. The economic value for such energy for the buyer (DISCOM) is insignificant, as he has no control in effectively utilising it. Under net billing the energy fed into the system can be put to use by the buyer (DISCOM) as it is not bound to return it. At the same time, DISCOM has no control on how much energy is procured at any time as it depends both on sunshine and simultaneous use by prosumers. Further, the surplus is mostly incidental as the prosumer has put the plant mostly for his own use. Under gross metering, the entire generated energy is available to the buyer (DISCOM) and thus the prosumer has to be fully compensated for his entire investment.

(7) The realignment of compensation systems have many things in common with the systems where rooftop systems have grown significantly. Such a realignment is necessary for balancing solar hour generation with in-situ electricity consumption and equitable sharing of costs related to

integration of non-firm distributed renewable energy into the grid. It also ensures a more efficient and optimum development of the renewable energy resources. It would also develop entrepreneurship in areas like BESS, hybrid inverters, smart inverters, home automation with smart devices, retrofitting of existing inverters etc.

At present consumers having loads above 100 kW are allowed green energy open access and energy accounting shall be similar to prosumers having capacity above 100 kW. Mandatory Forecasting and Scheduling (F&S) for OA and CPP projects is essential, as well as extending these regulations to all the utility-scale RE projects to enhance grid stability.

9.10 Transition to new billing and metering systems

Existing prosumers may be provided adequate time for transition to new mechanisms. Consumers availing grid connectivity from the date of effect of new regulations will be governed by the provisions in the regulations.

Existing prosumers having plant capacity upto 1 MW may be allowed to continue under net metering arrangement with energy banking facilities as under 9.9 above. The proposed banking charges of Rs 1.00 per unit may be exempted for the existing prosumers, as energy storage systems are being implemented mostly to meet the requirement of upcoming prosumers. Also, instead of differentiated feed-in tariffs, the existing prosumers may be allowed a compensation based on APPC of solar power for KSEB Ltd and decided upfront for the control period based on the approved ARR of KSEB Ltd. At the same time, the existing prosumers can be given an option to transition to the new arrangements within a period of one year based on their usage patterns, establishment of BESS etc along with the existing RTSPV system and align with the new compensation structure. Existing prosumers having plant capacity above 1 MW may be granted a transition period of up to one year to make modifications, if any, including may be setting up of battery energy storage or for making arrangements for sale of surplus energy etc, to move on to the new arrangement.

9.11 Providing new options to prosumers

It is felt that prosumers can be given more options to utilise the electricity generated from their rooftop systems than that discussed above:

(1) Peer to Peer: P2P energy trading allows consumers to sell surplus electricity generated from renewable sources like solar panels to other consumers in their local community or network, often at competitive prices. It offers numerous benefits, including cost savings, increased energy independence, and the promotion of renewable energy use. Additionally, P2P trading has the potential to enhance grid stability by allowing for more localized energy exchange and reducing transmission losses. This system typically utilizes blockchain or smart contract technology to securely facilitate and track transactions, ensuring transparency and efficiency.

(2) Vehicle to Grid: To incentivize the adoption of V2G, vide notification dated 14th January 2022, the Ministry of Power (MoP) issued guidelines for the integration of Vehicle-to-Grid (V2G) technology, a critical step towards enhancing India's energy grid stability and promoting sustainable mobility. V2G enables electric vehicles (EVs) to not only draw electricity for charging but also supply excess stored energy back to the grid when needed, helping to manage grid demand fluctuations. The guidelines establish a regulatory framework that outlines the technical, financial, and operational parameters for V2G systems. Key components of the guidelines include the standardization of technical specifications for V2G infrastructure to ensure seamless integration across various EV models, charging stations, and grid operators. Additionally, the guidelines highlight the need for upgraded grid infrastructure to handle bidirectional power flow, promoting the use of smart grids and advanced metering systems. To incentivize the adoption of V2G, the MoP recommends financial incentives, pilot projects, and public-private partnerships to test the technology's viability and scalability. These efforts are intended to allow EVs to act as decentralized energy storage systems, contributing to better load balancing, reducing grid congestion, and enabling cost-effective energy management. The guidelines are part of India's broader push towards a greener, more resilient energy infrastructure while supporting the country's transition to electric mobility.

(3) Demand Response (DR) programs: The concept involves the Utility offering electricity price to consumers on a real time basis considering the load-generation balance at respective time blocks. The price will be high during high demand periods and low or negative during high generation periods. The consumer can schedule load/generation on its own depending on the received price signal. Decentralised renewable energy systems with

storage can provide a more dependable energy supply by combining storage technologies with various renewable energy sources.

(4) Virtual Power Plants: Small rooftop solar plant owners, storage service providers and other RE generators can aggregate their capacities through an aggregator and can be allowed to participate in trading in the power market or through green open access to get better value for the electricity generated.

These mechanisms are presently in nascent stage and it is expected that the same will gain traction during the control period of the new regulations itself. Thus, enough enabling provisions with needed flexibility can be incorporated in the regulations to tap the emerging opportunities fully.

9.12 Inter licensee RE accounting

More and more consumers in small licensee areas are opting for decentralised RE plants. At the same time the demand in the small licensee areas are not showing any appreciable increase. It is anticipated that in the near future there can be export from small licensee areas to the KSEBL grid. As per existing regulations KSEBL is not responsible to compensate the licensee for this exported energy and the prosumer/small licensee will not get compensated for the export energy. Since the right of consumers in small licensee areas to set up RE plants cannot be denied, appropriate mechanisms for treating such transactions has to be evolved and made part of the regulations.

9.13 Green Tariff

Rule 4(2) (c) of the Green Energy Open Access Rules, 2022 specifies that the Appropriate Commission shall determine the tariff for green energy. The Commission has notified the Green tariff, in the Tariff Order dated 31.10.2023 issued by the Commission in OP No.18/2023. The Green Tariff as determined by the Commission in the Tariff Order dated 31.10.2023 is as below:

"7. Green tariff. – Rs 0.77/unit over and above the normal tariff.

The consumers voluntarily opting for the purchase of RE power from distribution licensees shall pay green tariff over and above the normal demand charge/fixed charge and energy charge of the respective tariff *category in which the consumer belongs to."*

It is appropriate to incorporate suitable provisions on green tariff determination in the upcoming regulations.

9.14 Providing data of behind the meter generation

The distribution companies are obligated to maintain the power supply at the rated parameters in the area of supply. In the case of Kerala, in addition to the variability from the solar and wind sources, the seasonal variation in the availability from small hydro generating stations is also a matter of concern

Maintaining availability of power round the clock requires planning and arranging resources to;

(i) meet the sudden changes in the availability of power from VRE sources;

(ii) meet the demand during the non-solar and off- wind period;

(iii) meet the seasonal demand variations.

It is therefore imperative that real time data from the generation sources is made available to grid operators. At present solar plants above 1 MW capacity are mandated to provide real time data to SLDC. The solar inverters of less than 1MW capacity but above a threshold capacity of above 100 kW also may be mandated to provide the real time data to the SLDC or the RE Control center of the DISCOM. The possibility for utilising the real time data available from inverters may be examined. This can be mandated now with provision to provide such facilities in a time frame of, say one year.

Chapter

10

Suggestions and Recommendations of the Committee

In view of the various RE related issues, developments and mitigation measures discussed above in this paper, the Committee makes the following suggestions and recommendations to be adopted in the State, to enable a conducive environment for the rapid integrated development of RE in the State.

10.1 Recommendation on the RE regulation

The Committee recommends that the suggestions under the Chapter 9 ‘Policy options’ may be appropriately incorporated in the RE regulations for the new control period.

10.2 General recommendations

(1) Kerala grid is having acute stability issues due to the unprecedented increase in Rooftop solar injection by the prosumers during day time. To mitigate the adverse effect of this injection, cost effective Energy storage systems with appropriate technology and time frame need to be established at appropriate locations in the State Grid, as suggested in the following paras:

(2) To enhance the energy storage capability for the immediate future and to improve grid stability, implement Battery Energy Storage System (BESS) with appropriate sizing at key grid stations and major substations

located in areas having significant RE penetration, based on RA studies, This initiative will help to store the excess RE energy during the solar hours with low demand and supply it back to the grid during peak hours, ensuring more efficient load management. Furthermore, BESS can act as a backup power source in case of outages, enhancing the reliability and resilience of the grid. These units can be developed through TBCB or PPP mode.

(3) As a medium-term measure to resolve the demand management issues and energy needs, implement Pumped Storage plant (PSP) projects (both open and closed cycle type) based on a detailed resource adequacy planning for benefits by year 2030 /2035.

(4) While developing energy storage projects, the planners may duly take into account the views of the Committee presented in Chapter 7.

(5) KSEB Ltd shall further study the demand complementarity among different States, including those depicted in Clause 7.4 in Chapter 7, to evolve proposals for joint development of ESS. The study shall include analysis of more granular data on daily demand patterns as available in the weekly reports of GRID India and Resource Adequacy Plan reports of each State by CEA. Future proposals for capital investment for ESS or procurement of storage services shall leverage joint development potential.

(6) Explore the possibility of increasing the pondage capacity of the existing run-of-river hydropower projects to a minimum of two/ three days (48/ 72 hours). This storage will allow for better regulation of water flow, ensuring consistent power generation during periods of high demand. Studies should be conducted to assess the potential for increasing the pondage capacities of the existing projects. The research and studies should help to determine the most effective methods for optimizing the energy output, enabling to improve grid reliability, and ensuring that the water resources are managed effectively and efficiently to meet the future energy needs. Further, SHEPs that are to be developed in future shall be designed as open loop PHPs and the DPRs should be revised accordingly.

(7) The potential for new hydroelectric power projects needs to be thoroughly studied to assess their viability and contribution to the energy landscape. The design and safety margins shall be suitably optimised and the project costs need to be reduced by 20 to 30% below the existing rates.

(8) The wind energy potential at Kanjikode, Attapady and Ramakkalmedu shall be thoroughly explored, to assess its feasibility for large-scale wind

power generation. Wind power plants with a hub height greater than 100 meters may be developed in these regions using public-private partnership (PPP) mode, which will encourage investment and technical expertise from both the sectors. Additionally, the State Transmission Utility (STU) must provide the necessary infrastructure ensuring efficient evacuation of energy generated from these projects. By integrating these initiatives, the State shall harness the region's wind resources to boost; the renewable energy capacity, achieve the RPO targets and enhance energy security.

(9) The Offshore wind energy potential of the western coast of the State may be studied, to identify suitable locations for cost effective development, utilizing the funds being allocated by the Ministry of Power under the Viability Gap Funding (VGF) scheme for offshore wind energy projects. The VGF will help to bridge the financial gaps and make these projects more attractive to investors by covering the initial infrastructure costs. This strategic approach will not only accelerate the development of offshore wind farms but also contribute to; diversify the State's renewable energy mix and meet long-term sustainability goals. The development of the Offshore wind needs to be done through TBCB mode only.

(10) All the Municipalities and Corporations shall be encouraged to establish municipal waste-to-energy (WTE) plants with capacities ranging from 2 to 6 MW, utilizing the public-private partnership (PPP) model, encouraging private sector involvement in project financing and management. This will help to harness the potential of municipal waste as a renewable energy source, while to a great extent obliviate the associated; social, environmental, health hazards and to create a neat and tidy city. The Ministry of New and Renewable Energy (MNRE) is actively implementing the Waste to Energy (WTE) Programme under the National Bioenergy Programme, with a budget allocation of ₹600 crore for the fiscal years 2021-22 to 2025-26. Leveraging this program will provide the necessary financial support and guidance to develop WTE projects, contributing to sustainable waste management, reducing landfill dependency, and generating clean energy for urban areas. Experience shows that WTE plants focussing on electricity generation alone is making the projects unviable. Thus, possibilities for conversion to other energy forms also need to be explored.

(11) To ensure orderly and timely information dissemination on renewable development in the State and for adherence to the ambitious RPO

targets, the new regulations shall include clear data formats for reporting of compliance of RPO by obligated entities on a quarterly basis. This shall also include the RE tendering calendar for the DISCOMs and adherence to the same. The regulations shall also specify the penalties/incentives in case there is underachievement/excess over target cases by obligated entities. The examination of compliance by the regulatory commission can be on an annual basis, as a separate proceedings, in the first quarter of every financial year based on mandated annual filings by all the obligated entities including the DISCOMs. The State nodal agency under the Energy Conservation Act, 2001 or KSEB Ltd shall be mandated to file the RPO compliance data in respect of obligated entities other than the DISCOMs.

(12) The promotion of green ammonia, produced using renewable energy sources, holds significant potential for decarbonizing the industries, enhancing energy storage capabilities, and supporting the transition to cleaner, more sustainable fuel alternatives in sectors such as; agriculture, shipping, and heavy industry. Kerala shall evolve a conducive echo system for development of such projects through private participation.

(13) Nuclear energy has an important role in the energy transition as a clean energy source that caters the base load of the power system. With gradual phasing out of coal plants, nuclear power is considered as a requirement for ensuring energy security of the country. The CSTEP study highlights the need for an additional nuclear capacity of; 382 MW and 1056 MW by 2030 and 2040 respectively to meet energy transition goals. Along with various technological options that are emerging, the State may explore the possibility of tapping the potential of the emerging small modular nuclear power plant models also, to secure the long term energy security of the State.

(14) With several techno-economic and policy-regulatory changes underway in the sector, there is a need to study several issues in detail which can help the Commission in formulating appropriate regulations over time. These studies include:

(a) Analysis for a new customer/tariff category for whom KSEB Ltd will supply actual 100% RE with 15-min verification of RE energy. KSEB Ltd is much better placed (given its demand diversity and scale) to provide such solutions to customers than customers individually contracting for such power under OA/CPP. This is important since several C&I consumers are beginning to demand 100% RE due to a variety of reasons including;

i. future carbon taxes like CBAM which is critical for exporting industries;

ii. customers demanding 100% RE powered data centres;

iii. customers signing up for RE 100 like pledges etc.

(b) Assess impact of solar rooftop projects on its distribution network (including grid operation, technical standards, reverse power flow and financial implications), for consideration on future changes required, if any, especially related to technical criteria for reliable grid operation and maintaining the power quality and safety in the distribution network, especially in pockets where rooftop solar penetration is high and rising.

(15) Kerala already has a strong ToD framework in place, however given the high share of residential consumption in Kerala, the 50% RPO target by 2030, it is crucial that ToD tariffs are reflective of changes in cost due to changes in net-peak demand on a seasonal and diurnal basis. There may be a strong case for day-time rebates, discontinuation of night-time penalties and extension of evening peak hours. Further, ToD tariffs should be levied on a wide base of consumers, especially domestic which contribute to the bulk of the load in the State.

(16) The regulation may detail the guidelines for accounting energy storage systems under the RPO framework.

(17) With exponential growth of decentralised solar systems there is an urgent need to ensure compliance with various standards and protocols for inverters including those on LVRT, reference voltage, harmonics etc. The Commission may, in consultation with the enforcing agencies like Electrical Inspectorate, EMC and DISCOMs, coordinate for the effective enforcement of standards under various rules and regulations. The capabilities of technical education institutions in the state may be leveraged for monitoring and reporting purposes.

(18) For faster adoption of energy storage systems, including systems owned by consumers/ prosumers, the State Government may consider providing appropriate financial support in the form of grant/ VGF/ subsidy.

(19) To enable faster electrification of transport sector, State Government may issue guidelines for conversion of ICE vehicles to Electric Vehicles as per

the approved schemes of ARAI.

(20) Guiding the prosumers/consumers in making prudent investments:

Huge investment is taking place in a decentralized manner in Kerala in RE sector. With the advancements in BESS, this investment is likely to increase manifold. In the absence of proper guidance on technology, optimisation of plant/ storage capacity, prudent costing etc., there is likelihood for wasteful expenditure, redundant investment, non optimal returns, unintented network disruptions etc., which are harmful for the development of the sector. To address this, the Government through agencies like KSEB Ltd, EMC and ANERT may put in place appropriate and effective arrangements to guide the prosumers/ investors in various aspects of RE investment.

(21) In view of the rapid development in technology related to RE, there is an imperative to create technology partnerships to promote/commission Research and Development (R& D) in critical areas. To begin with, the State Government and KSEB Ltd shall associate with Kerala Technical University (KTU), Cochin University of Science and Technology (CUSAT) and IIT Palakkkad, and commission R & D projects on cutting edge technology areas. It is encouraging to note that faculties in institutions like IIT, Mumbai has done pioneering research in advanced research areas on Sodium- ion batteries. The State shall endeavour to create an enabling environment that promotes excellence in R & D related to RE sector.

(22) The west kallada model of community participation to make use swamp land parcels for setting up floating solar plants has the potential for beneficial replication in various parts of the state. In view of rapid price fall in BESS, future solar projects can also be integrated with adequate storage solutions at competitive prices. The government may entrust district administration to identify atleast one location in each district in coordination with KSEB Ltd for development of around 500 MW floating solar capacity along with 1,000 MWh BESS in the next couple of years through tariff based competitive bidding route. Based on the experience gathered, the model can further fine-tuned and spread out to more areas.

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Annexure A

Evolution of Regulation in Renewable Energy sector in the major jurisdictions

Renewable Energy Regulations in California- An overview

A. Net Energy Metering (NEM) 1.0

California's Net Energy Metering (NEM) 1.0 program, implemented by the California Public Utilities Commission (CPUC) in 1996, was designed to encourage the adoption of renewable energy, particularly rooftop solar, among residential and small commercial customers. The core purpose of NEM 1.0 was to support California's renewable energy goals by providing an incentive structure where solar customers could offset their electricity usage and receive bill credits for excess energy sent back to the grid at full retail rates. NEM 1.0 operated under a "one-for-one" credit mechanism, meaning that customers received credits on their electric bills equal to the retail rate of the electricity they exported. This setup was intended to reduce the payback period for solar investments, making solar more financially viable and attractive. However, as solar adoption grew, this model presented challenges, including cost shifts to non-solar customers and financial impacts on utilities due to the reduced contributions to grid maintenance and public service costs

When first introduced, the NEM 1.0 programme had a cap on total participation by customers, which was defined by legislation as "0.1 percent of the utility's peak electricity demand forecast for 1996." Further, the Legislature also set the capacity limit for each NEM-eligible facility at 10 kW (kilowatts). However, with the enactment of AB X1 29 (Kehoe), Stats in 2001, has increased the eligible system size from 10 kilowatts to 1 megawatt (MW). The Legislature has amended the statute several times since 1995, often to raise the cap on NEM participation to 5% of the total customer peak demand for each utility.

Under NEM 1.0, the billing process for prosumers involved netting the amount of electricity they consumed against the amount they produced within each billing cycle. Customers with excess generation could carry forward credits month-to-month, with a “true-up” at the end of a 12-month period to balance any remaining credits or charges. This model helped encourage early solar adoption but led to some financial strain on utilities as the costs for grid maintenance and public service programs, typically funded through utility rates, were not fully covered by NEM 1.0 participants. The billing methods under NEM 1.0 were

(a) Net Metering

(b) Virtual Net Metering – applicable to multifamily housings

The California Public Utilities Commission’s (CPUC) conducted “Look back Study” on Net Energy Metering (NEM) 1.0 aimed to evaluate the program’s cost-effectiveness, fairness, and impacts on the energy grid and ratepayers. Key findings from the study highlighted the following:

1. Cost Shift to Non-Participants: NEM 1.0 led to a substantial cost shift, with non-solar customers indirectly subsidizing NEM participants. This shift stemmed from the full retail rate compensation that solar customers received for exporting energy back to the grid, costing non-solar customers about $3.37 billion annually by 2021
2. Equity Concerns: The program disproportionately benefited higher-income households, who could afford the upfront costs of solar installation. Lower-income customers, in contrast, saw little benefit, as they were less likely to install solar but still faced higher utility rates due to the cross-subsidization created by NEM 1.0
3. Grid and Ratepayer Impacts: While NEM 1.0 supported solar adoption, it also added operational costs for utilities managing a higher proportion of distributed solar energy. The study recommended reforms to NEM compensation structures to better align solar export rates with actual grid costs.

The report suggested CPUC to move toward time-of-use rates, implementing a “Grid Participation Charge” for NEM users, and creating an “equity fee” to support low-income solar initiatives. These reforms aim to reduce cost shifts and promote more equitable access to solar energy benefits.

B. Net Energy Metering (NEM) 2.0

NEM 2.0 was introduced in California in 2016 by the California Public Utilities Commission (CPUC) to address the financial and grid challenges posed by the original NEM 1.0 program. It became mandatory in mid-2017 for new solar customers, effectively replacing NEM 1.0. It continued the basic features of the NEM 1.0. NEM 2.0 is available for 20 years to new solar customers through April 13th, 2023. The major highlights in the new regime are as follows:

(1) Time-of-Use (TOU) Rates: NEM 2.0 required customers to adopt TOU rate schedules, meaning their solar production and energy usage were billed differently based on the time of day. TOU rates were designed to encourage solar customers to use energy when grid demand was lower, improving grid stability.

(2) Non-Bypassable Charges: NEM 2.0 introduced non-bypassable charges, which are small charges per kilowatt-hour (kWh) for all energy consumed from the grid, including the energy offset by solar. These charges cover public programs, Nuclear Decommissioning Charge, Competition Transition Charge and Department of Water Resources bond charges. Such charges cannot be offset by solar generation credits.

(3) Monthly Billing with Annual True-Up: While customers were billed monthly under NEM 2.0, an annual "true-up" process adjusted for any remaining balance. This true-up reconciled the total energy consumed and produced throughout the year, determining if customers owed any additional charges or retained credits.

(4) Interconnection Fees: Unlike NEM 1.0, NEM 2.0 customers were required to pay a one-time interconnection fee to connect their solar systems to the grid.

Fees -$100 for system under 30 kW

- $1600 for systems above 30 kW and upto 500 kW

- Interconnection fees plus distribution upgrade costs triggered for their system.

(5) Capacity limit – upto 1 MW

Allow projects greater than one megawatt that do not have significant impact on the distribution grid to be built to the size of the onsite load if the projects with a capacity of more than one megawatt are subject to reasonable interconnection charges established pursuant to the commission's Electric Rule 21 and applicable state and federal requirements.

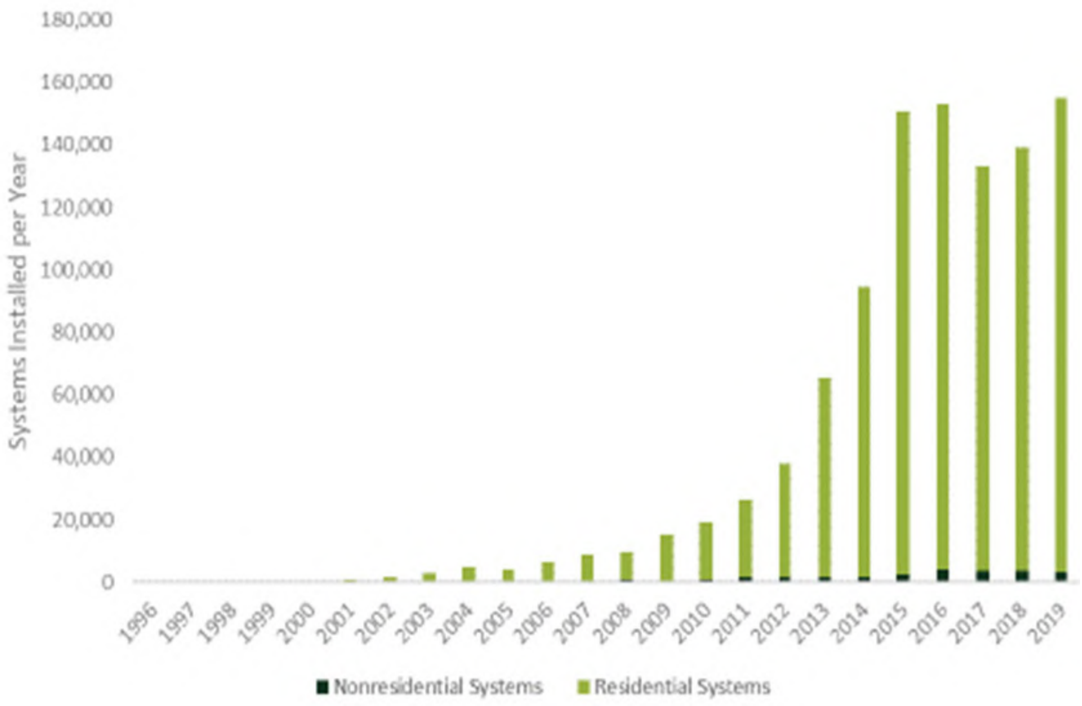
(6) Provision for connecting Battery Energy Storage systems

The billing methods under NEM 2.0 were:

(a) Net Energy Metering Aggregation- eligible customer-generator with multiple meters to elect to aggregate the electrical load of the meters located on the property where the renewable electrical generation facility is located and on all property adjacent or contiguous to the property on which the renewable electrical generation facility is located, if those properties are solely owned, leased, or rented by the eligible customer-generator.

(b) Virtual net metering - expanded VNM to include multiple service delivery points, but only for properties in the multifamily affordable housing properties.

Chart: Status of RTS under NEM 2.0



C. Net Energy Metering (NEM) 3.0

The California Public Utilities Commission examined the impacts of the Net Energy Metering 2.0 (NEM 2.0) program, analysing both its successes and challenges. The decision's lookback study conducted by CPUC revealed that while NEM 2.0 contributed significantly to California's solar adoption rates, it also had unintended financial impacts on non-solar customers and utility infrastructure. Under NEM 2.0, solar customers were compensated at retail electricity rates for excess power sent back to the grid. This arrangement helped grow the residential solar market but created a cost shift, leading to increased rates for customers without solar systems, who still bore the infrastructure maintenance costs. The findings in the Lookback Study shows that NEM 2.0, and thus NEM 1.0, disproportionately benefited non-CARE residential net energy metering customers while all customers, including those with lower incomes, must bear the addition of the 82 to 91 percent of the cost of service bypassed by net energy metering customers. The Study indicates that NEM 2.0 disproportionately harms low-income customers not participating in the net energy metering tariff.

The findings highlighted a need to balance incentives for solar adoption with equitable distribution of grid costs. This analysis informed the shift to NEM 3.0, where compensation is based on the avoided cost rate, incentivizing solar usage with less impact on non-solar customers. In NEM 3.0 Net billing is introduced and Virtual net Metering is allowed to continue. The NEM 3.0 program under CPUC Decision 22-12-056 officially took effect on April 15, 2023.

Net Billing :- Imports and exports will be calculated based on no netting of consumption and production and will be trued-up on an annual basis. Bill credits will be applicable toward import charges from any time of use time period. The net billing tariff shall contain the following adopted elements:

(1) Retail Export Compensation: Under the net billing tariff, export compensation rates for solar energy sent back to the grid are based on hourly Avoided Cost Calculator (ACC) values, averaged by day type (weekdays versus weekends/holidays). This rate structure is part of a five-year "glide path" during which customers receive a stable, predictable rate schedule based on the ACC at the time of their interconnection.

Following this period, customers will not have a locked-in ACC rate, and compensation will adjust with changing ACC values.

(2) Avoided Cost Calculator (ACC) Plus Adder: In NEM 3.0, an ACC Plus adder (a cents per kWh boost to the ACC-based compensation rate) is available as an added incentive. This adder remains constant for a customer for nine years after interconnection but does not apply to customers transferring from NEM 1.0 or NEM 2.0.

**The ACC Plus is not available to: (i) customers transitioning from the NEM 1.0 tariff or the NEM 2.0 tariff at the end of their legacy period; and (ii) customers who have purchased a building with an existing system.

(3) Highly Differentiated Time-of-Use (TOU) Rates: All net billing customers must enrol in TOU rates, which charge different prices based on the time of day to reflect peak demand periods. Critical peak pricing options are available for eligible customers. However, discounts under CARE (California Alternate Rates for Energy) and FERA (Family Electric Rates Assistance) programs are not applied to export compensation rates.

(4) System Sizing: New solar systems can be oversized by up to 50% based on a customer's prior 12-month energy usage. This allows customers to account for anticipated increases in usage, such as for electric vehicles or additional family members, but they must justify expected usage within 12 months.

(5) Non-Bypassable Charges (NBCs): The four charges are the public purpose program charge, nuclear decommissioning charge, competition transition charge, and the Wildfire Fund Non-Bypassable Charge.

(6) Fixed and Minimum Bills: Net billing tariff customers are subject to any minimum bill or fixed charge that is contained in a customer's applicable rate

(7) True-Up Dates: Customers are allowed a one-time adjustment to select a new true-up date, simplifying annual billing and making it consistent with customer billing cycles. Annual True-Up will remain the same as

the Net Energy Metering. Credits and debits will be provided in dollars rather than in kilowatt-hours, in monthly basis.

(8) Legacy Period: The tariff includes a nine-year legacy period, during which compensation rates and provisions are maintained for the original customer. If the system's ownership is transferred, the legacy period remains in effect only for customers meeting specific criteria (e.g., legal partner or same entity ownership).

(9) Capacity limit – upto 1 MW

Only customer-generators with systems over one MW in capacity must pay for any transmission or distribution system upgrades and also pay an $800 interconnection fee.

Table: Comparison between NEM 1.0, NEM 2.0 and NEM 3.0

Particulars	NEM 1.0	NEM 2.0	NBT
Eligible import rate schedule	Any	TOU rates	Specific "electrification" TOU rates
Onsite use of generated energy avoids energy imports	Yes	Yes	Yes
Basis of credits for retail energy exports before true-up	Import rates	Import rates	CPUC Avoided Cost Calculator values (usually lower than import rates)
Basis of credits for net surplus energy at true-up	Wholesale price of energy	Wholesale price of energy	Wholesale price of energy
Basis of non-bypassable charges calculation	Net energy consumed (imports	Net energy consumed in a metered	

	minus exports) in a year	interval (1 hour for residential and 15 minutes for nonresidential customers)	All energy imports
Interconnection fee	None	$94-145	$94-145
Billing and true-up period	Annual billing, annual true-up (both charges and credits roll over for 12 months)	Annual billing, annual true-up (both charges and credits roll over for 12 months)	Monthly billing (pay monthly); annual true-up (credits roll over for 12 months)
Installation size limit	Customer's annual electric load with limited exceptions; capped at 1 MW	Customer's annual electric load with limited exceptions	Customer's annual electric load plus up to 50% if customer attests to need

Virtual Net Metering In NEM 3.0- changes

(a) VNEM subtariff is revised to allow multiple solar arrays on one property to be treated as one generator, with credits allocated across the property; and

(b) for customers applying to interconnect to VNEM after the NEM 2.0 tariff Sunset Date, this decision reduces the legacy period to nine years to align with customers of the net billing tariff.

Other suggestions in NEM 3.0

The policy recommends the consumers to pair a battery with the solar system allows to store your excess solar energy from sunlit hours and then use the stored energy at home, instead of importing electricity from the electric grid, during part of the evening.

D. Introduction of New Regimes vide decision dated November 16, 2023.

Virtual Net Billing Tariff- The virtual net bill tariff shall contain the following elements:

(a) Retail Export Compensation Rates based on hourly Avoided Cost Calculator values averaged across days in a month, differentiated by weekdays and weekends/holidays as adopted for the net billing tariff in NEM 3.0. For the first five years of the successor tariff, i.e., the glide path transition time, retail export compensation rates for residential and non residential virtual net billing tariff customers will be based on a nine-year schedule of values for each hour from the most recent Avoided Cost Calculator, adopted as of January 1 of the calendar year of the renewable electrical generation facility initial interconnection date. Following the locked in period, retail export compensation rates will be based on averaged hourly avoided cost values from the most recent Avoided Cost Calculator, adopted as of January 1. Tariff customers enrolling after the five-year glide path will not receive a lock-in period for Avoided Cost Calculator values

(b) An Avoided Cost Calculator Plus (ACC Plus) adder, based on a cents per kilowatt-hour exported rate. The ACC Plus will be available to virtual net billing tariff residential benefiting account customers during the first five years of the successor tariff, as a glide path.

(c) Energy Consumption/Retail Import Rates will be different for residential and non residential customers. Residential virtual net billing customers shall take service on any eligible time-of-use rates. Non residential virtual net billing customers may take service on any currently available rate schedule.

(d) Non-bypassable charges. The four charges are the public purpose program charge, nuclear decommissioning charge, competition transition charge, and the Wildfire Fund Non bypassable Charge.

(e) Minimum bill or fixed charges. Virtual net billing tariff customers are subject to any minimum bill or fixed charge that is contained in a customer's applicable rate.

(f) True-up Dates. Each generating account customer or renewable electrical generation facility owner taking service under the virtual net billing tariff may make a one-time request that their annual true-up date be changed going forward.

(g) Legacy Period. The terms of the virtual net billing tariff will be available to virtual net billing tariff customers for a period of nine years.

(h) Storage Devices. If a current virtual net billing renewable electrical generation facility (Generation Facility) owner adds a storage device, there is no impact to the Generation Facility's current tariff status, including the legacy period.

(i) Planned or Emergency Outages. Operation of the renewable electrical generation facility, including storage, in isolation, is permitted to serve onsite loads during planned or emergency outages. Pending advice letter approval, storage may charge from the grid in advance of a planned or emergency outage.

(j) Participation in Demand Response Programs. All virtual net billing customers, including the generation account holder, are permitted to participate in demand response or emergency reliability programs for which the customer is otherwise eligible.

References

1. www.epcube.com

2. California Public Utilities Commission website (www.cpuc.ca.gov)

Renewable System in Britain- An Overview

A. The Feed-in Tariffs (FIT) scheme

The scheme was designed by government to promote the uptake of renewable and low-carbon electricity generation.Introduced on 1 April 2010, the scheme requires participating licensed electricity suppliers to make payments on electricity generated and exported by accredited installations

Eligibility: Anyone who had installed an eligible installation that uses one of the following technology types could apply for accreditation:

(a) Solar photovoltaic (solar PV)

(b) Wind

(c) Micro combined heat and power (Micro CHP)

(d) Hydro

(e) Anaerobic digestion (AD)

Capacity: Installations could have a capacity of up to 5 megawatt, or 2 kilowatt for Micro CHP.

Other details:

There are two types of participant on the FIT scheme:

(a) FIT generators – the owners of accredited installations

(b) FIT licensees – licensed electricity suppliers who registered applications and make FIT payments for the electricity produced by accredited installations.

The scheme was administered through two main roles: FIT generators, who owned and operated the accredited installations, and FIT licensees, which were the suppliers who handled the registration, payments, and meter readings. The payments for electricity generation were based on the fixed generation tariff, while payments for exported electricity were based on the export tariff. These tariffs were guaranteed for up to 25 years depending on the technology used, the installation's capacity, and when it was commissioned. The government, through the Department for Business, Energy & Industrial Strategy (BEIS), periodically reviewed and set the tariffs, and the costs were spread across all licensed electricity suppliers through a levelisation process.

Reason for moving out of FiT scheme

The initial high rates offered under the FIT scheme led to rapid uptake, which put immense financial pressure on the government. Critics argued that the scheme was overly generous and unsustainable in the long term.

B. Smart Export Guarantee (SEG)

SEG replaced FIT in 2019, introducing a market-driven approach where suppliers set competitive rates for exported electricity, encouraging consumers to choose among suppliers for better returns. Unlike FIT, SEG only compensates for exported energy, thus incentivizing efficient usage and export during peak times. This shift is intended to support the evolving energy market while reducing government intervention, aligning with broader goals for renewable energy adoption in a competitive market framework.

The procedure for participating in the Smart Export Guarantee (SEG) scheme in Britain involves several key steps for renewable energy generators and electricity suppliers.

1) Accreditation: Unlike the Feed-in Tariff (FiT) scheme, where installations needed to be registered with Ofgem, SEG participants must first ensure their system is eligible under the scheme. This typically applies to small-scale generators (e.g., solar PV, wind) that export energy to the grid. Ofgem does not directly manage SEG accreditation, but it provides guidance and oversight for compliance. Generators can apply for SEG accreditation with their energy supplier, which then determines eligibility.
2) Eligibility and capacity; The Smart Export Guarantee (SEG) makes sure that small-scale low-carbon generators receive payment for any electricity

they export to the grid. It requires licensed electricity suppliers to offer export tariffs to anaerobic digestion (AD), hydro, onshore wind, and solar photovoltaic (PV) generators with a total installed capacity up to 5MW, and micro-combined heat and power (micro-CHP) up to 50kW.

3) Registration with an Energy Supplier: Generators must register with an electricity supplier offering SEG tariffs. The supplier sets the export tariff, which can vary, allowing generators to choose based on the best available rates. Unlike FIT, SEG only compensates for exported energy, and the payments are determined by the market, not fixed by the government. Payments are based on the volume of energy exported, and they may be fixed or fluctuate depending on the supplier's tariff structure.

4) Metering: A smart meter or appropriate metering system is typically required to ensure accurate tracking of exported electricity. This allows suppliers to make quarterly or monthly payments to the generator for the energy exported to the grid.

5) Payment Structure: The payments under SEG are based on the amount of electricity exported to the grid. Suppliers must offer at least one export tariff, with a minimum payment of 0.5p per kWh. However, they are free to offer more competitive rates depending on market conditions. SEG does not include a fixed contract length, so generators can switch suppliers if better tariffs become available.

6) Monitoring and Reporting: Suppliers are responsible for monitoring and verifying the amount of electricity exported by each generator. The generator submits regular meter readings to the supplier, who then processes payments accordingly.

Table: Comparison between the FiT and SEG Schemes

Feature	Feed-in Tariff (FiT)	Smart Export Guarantee (SEG)
Launch Date	April 1, 2010 (closed to new applicants on March 31, 2019)	January 1, 2020
Eligibility	Open to small-scale renewable generators (up to 5 MW) for applicants before scheme closure	Open to small-scale renewable generators (up to 5 MW)
Type of Payment	Paid for both generated electricity and exported surplus	Payment for surplus electricity exported to the grid only

Tariff Rate Structure	Fixed tariffs set by Ofgem and adjusted annually according to inflation	Rates set by energy suppliers and can be variable or fixed
Typical Rates (2024)	Higher, with generation tariffs previously starting from 4-12 pence per kWh for generation, plus export tariffs	Variable; typically ranges from 1-15 pence per kWh depending on the supplier
Administration	Managed by Ofgem with payments from government-backed funds	Managed directly by licensed electricity suppliers
Duration of Payments	20–25 years for solar installations	Determined by supplier; typically 1–3 years or as per contract
Metering Requirements	Generation and export meters required	Smart meter or export meter required to measure actual exports
Application Process	Application through accredited FIT licensees	Apply directly to participating electricity suppliers
Government Support	Heavily government-subsidized to promote early adoption of renewables	Market-driven, designed to encourage competitive rates for exported electricity
Scheme Status	Closed to new applicants since March 31, 2019	Active
Incentive Focus	Provided significant upfront incentive to drive solar adoption and subsidized generation, regardless of export level	Encourages efficient use of solar power and fair compensation for excess energy exported to the grid

Reference

www.ofgem.gov.uk

Renewable Energy Regulations in Germany- An overview

A. The Electricity Feed-in Act (Stromeinspeisungsgesetz) of 1991

Germany's first major policy to support renewable energy development, which laid the groundwork for renewable energy adoption. The Key features of the policy were:

(1) The scheme was applicable to all consumers.

(2) The Act established fixed rates for renewable energy, ensuring that producers would receive compensation for every kilowatt-hour (kWh) they fed into the grid.

(3) Compensation rates were set at a percentage of the average retail electricity price: wind and solar received around 90% of the retail price, while other renewables like hydropower and biomass received 65-80%.

(4) While grid access and fixed rates were guaranteed, the Act did not provide a guaranteed rate, limiting financial security for some investors.

B. Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz EEG) 2000

The Renewable Energy Sources Act (Erneuerbare-Energien-Gesetz, EEG), introduced in Germany in 2000, to reduce greenhouse gas emissions, promote energy independence, and set Germany on a path toward sustainable energy. The German solar industry, for example, saw significant growth due to the steady demand created by the feed-in tariffs. The Key features of EEG 2000 were:

(1) Feed-In Tariff (FiT) System: Under the EEG 2000, solar producers received a fixed tariff for every kilowatt-hour (kWh) of electricity they fed into the grid. This FiT was set at a guaranteed rate above market prices to incentivize renewable energy production. Producers were paid for all electricity they exported to the grid rather than offsetting it against their own consumption. The specific tariff levels varied by system type and capacity.

(2) Fixed Rates for 20 Years: Compensation rates were guaranteed for a 20-year period from the installation date, providing long-term financial security for producers.

(3) Priority Grid Access: The renewable energy producers got priority access to the electricity grid, meaning grid operators had to purchase all the electricity generated from renewable sources before procuring energy from conventional sources. This eliminated the risk of renewable energy being "shut out" of the market due to grid capacity issues, ensuring that renewable energy had a place in the country's energy mix.

(4) System Size Cap: There was no strict system size cap limiting residential or commercial consumers from installing large solar systems.

(5) Solar producers received payments based on the total kilowatt-hours (kWh) generated and fed into the grid within a monthly basis.

C. Renewable Energy Sources Act (EEG) 2014

The policy was officially implemented on August 1, 2014. This version of the law introduced significant changes to Germany's renewable energy policy, including the shift from fixed feed-in tariffs to competitive auctions for renewable energy projects, cost-control mechanisms, and further integration of renewable energy into the national grid.

Germany's shift from EEG 2000 to EEG 2014 was driven by the need for a more sustainable, market-integrated, and cost-effective approach to renewable energy. Initially, the EEG 2000 successfully accelerated renewable energy adoption by offering high fixed feed-in tariffs, resulting in rapid growth in solar, wind, and other renewable capacities. However, this success also led to higher costs, passed on to consumers through increased EEG surcharges on electricity bills, sparking a need to control expenses and reduce the financial burden on households and businesses. By 2014, the costs of renewable technologies—especially solar PV—had significantly decreased, so the EEG 2014 reduced feed-in tariffs accordingly to avoid over-subsidizing renewables. In addition to cost concerns, Germany sought to improve the grid's stability and resilience. The rapid growth of renewables, with their intermittent nature, presented challenges for balancing supply and demand across the electricity grid.

The key features in EEG 2014 were as follows:

(1) Self-Consumption Levy: For the first time, a partial EEG surcharge (EEG-Umlage) was applied to self-consumed electricity for solar installations larger than 10 kW. This meant that consumers having solar capacity larger than 10 kW that self-consumed their generated electricity were subject to a partial EEG surcharge, amounting to 40% of the full EEG surcharge rate. This fee was introduced to ensure that self-consumers contributed to the costs of the renewable energy transition, as they benefit from the grid infrastructure even if they reduce their grid dependency.

(2) Encouragement of Self-Consumption: With lower feed-in tariffs and the introduction of the self-consumption levy, EEG 2014 indirectly encouraged solar consumers to use their own electricity rather than export it. This made battery storage systems and energy management tools more appealing, as they helped maximize self-consumption and reduce reliance on the grid.

(3) Degression Mechanism: EG 2014 implemented a degression mechanism, meaning that the FiT rate automatically decreased over time. The purpose was to align with the steadily declining costs of solar PV technology, gradually reducing the tariff for new installations to ensure cost-effectiveness and discourage excessive dependency on subsidies

(4) Market Premium Model for Larger Installations: Solar installations over 100 kW were required to participate in the electricity market via the market premium model instead of receiving a fixed FiT. In this model, consumers received a variable market premium in addition to the market price, incentivizing them to adapt production to market demand and fostering market integration of renewables.

(5) Feed in Tariff:

(a) Small Systems (<10 kW)

For small residential and rooftop solar systems under 10 kW, FiTs were generally higher to encourage small-scale, decentralized solar adoption. The rate for these small systems was typically around 12–13 euro cents per kWh at the beginning of the EEG 2014 implementation. These systems also benefited from exemptions or lower contributions to the EEG surcharge when consuming their own electricity.

(b) Medium Systems (10 kW to 1 MW)

For medium-sized systems between 10 kW and 1 MW, such as those on larger buildings or commercial properties, the FiT was slightly lower, reflecting economies of scale. The rates for these installations generally ranged around 9–11 euro cents per kWh. The FiT rate within this range depended on the specific size of the system and the quarterly adjustments made by the deployment corridor mechanism to control the growth rate.

(c) Large Systems (>1 MW)

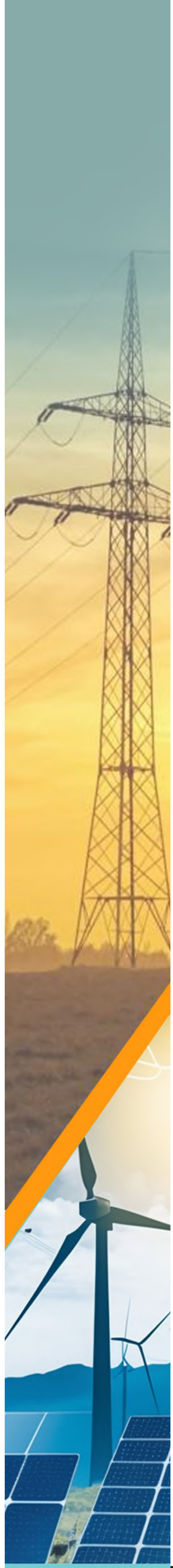
Large installations, particularly those over 1 MW, were either given much lower FiTs or required to sell their electricity directly to the market under the market premium model. In this model, they received the market price for electricity plus a variable premium to ensure profitability.

(6) Priority Grid Access: EEG 2014 maintained priority grid access for renewable energy, ensuring that electricity from solar PV would still be fed into the grid when available, ahead of conventional energy sources.

(7) Grid Access Fees (Netzentgelte):

For solar producers, especially those who also used electricity from the grid when their generation was insufficient, grid access fees applied. These fees, paid to grid operators, covered the costs of maintaining and upgrading grid infrastructure. Residential and small commercial solar users were usually subject to these fees based on the electricity they drew from the grid. Some regional variations in grid fees existed, as the charges depended on the specific grid operator and regional grid requirements.

(8) VAT on Solar PV Installations and Electricity Sales: Solar installations, even for self-consumption, were subject to VAT. Additionally, any electricity sold to the grid was considered income, and the operator was required to pay VAT and income tax on that revenue unless they qualified for small business exemptions.



(9) Trade Tax for Larger Producers: Larger solar projects (typically 10 kW) could be subject to trade tax, depending on their business status and annual income. This tax was generally applicable to commercial operators.

(10) Administrative Fees and Permit Costs:

For larger or ground-mounted solar projects, administrative fees might be incurred for permitting, environmental assessments, or other regulatory requirements. Although these fees were typically minimal for rooftop solar systems, larger installations faced stricter requirements.

D. Renewable Energy Sources Act (EEG) 2017

Germany transitioned from EEG 2014 to EEG 2017 to enhance cost-efficiency, encourage market-driven competition, and improve grid stability amid rapidly growing renewable energy capacity. By 2017, Germany's renewable sector had grown significantly, increasing financial pressure on the EEG surcharge paid by consumers. The competitive auction system introduced in EEG 2017 replaced fixed feed-in tariffs for larger installations, ensuring that only the most cost-effective projects received funding. This shift allowed Germany to control subsidy spending while maintaining renewable energy growth. Additionally, EEG 2017 aimed to address grid congestion issues by managing the geographical distribution of new renewable installations, particularly wind, and setting annual capacity limits for each technology to stabilize expansion. These adjustments aligned with Germany's long-term Energiewende (energy transition) goals, seeking a sustainable balance between renewable growth, economic efficiency, and energy security.

The key features of the policy were the following:

(1) Capacity-

(a) Small-scale solar installations (typically up to 100 kW) that don't engage in direct marketing receive a fixed feed-in tariff for their electricity.

(b) For installations above a certain size >750 kW, capacity is awarded through a competitive bidding process. This ensures that only the most economically viable projects proceed, keeping costs manageable for the overall energy system.

(c) Smaller installations <750 kW receive a guaranteed fixed rate per kilowatt-hour (kWh) for the electricity they feed into the grid.

(2) Degression Mechanism: The feed in tariff applicable to each category decreases gradually over time through a degression mechanism. This reduction is typically adjusted quarterly and is based on the growth rate of solar installations nationwide.

(3) The FiT model applies to residential and small commercial consumers <750 kW who generate power for both self-consumption and grid export. The specific rate has varied but generally ranged from approximately 8 to 12 Euro cents per kWh for solar PV installations under 750 kW in EEG 2017.

(4) Market Premium Model and Competitive Auctions for Large Installations

In EEG 2014 Large solar installations above 500 kW could opt for direct marketing through the market premium model but were not required to participate in auctions. Instead, they could still access feed-in tariffs.

The EEG 2017 increased the threshold for mandatory auctions to 750 kW, requiring installations above this capacity to participate in competitive bidding to secure market premiums. This shift emphasized a more market-oriented approach for larger projects, reducing reliance on fixed feed-in tariffs and introducing competition to control costs. Installations under 750 kW could still access fixed tariffs, simplifying the process for small and medium-sized producers.

(6) Reduced Incentives for Ground-Mounted Solar on Agricultural Land

Restricted eligibility for feed-in tariffs on ground-mounted systems located on agricultural land to prioritize land use for agriculture and discourage large-scale solar farms from occupying valuable farmland. These restrictions reduced the potential revenue for new installations on such land and encouraged rooftop and non-arable land installations instead.

(7) EEG Surcharge (EEG-Umlage) on Self-Consumption

Continued the EEG umlage as same as that of EEG 2014.

Table: Comparison between the FiT and SEG Schemes

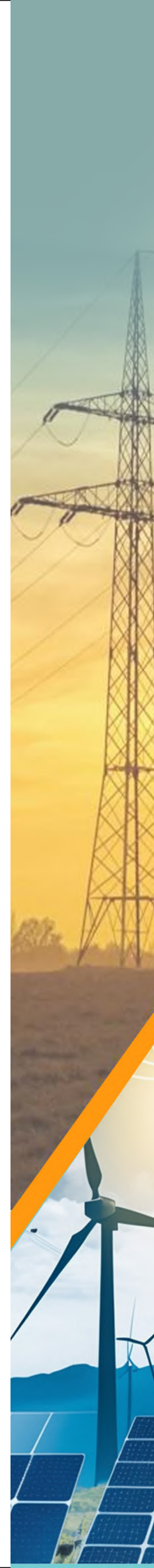
• Particular	• EEG 2014	• EEG 2017
• Billing Methods	• Fixed Feed-in Tariffs (FiT): For installations below 500 kW. • Market Premium Model: Optional for installations above 500 kW to directly market energy and receive a market premium. • Self-Consumption Model: Allowed with partial surcharge for larger installations (above 10 kW).	• Competitive Auctions for Installations >750 kW: Mandatory for installations above 750 kW to bid for tariffs in auctions. • Fixed Feed-in Tariffs (FiT): Remain available for installations below 750 kW. • Market Premium Model: Required for larger installations participating in auctions.
• Settlement Period	• Monthly settlement of market premiums for installations choosing direct marketing. • • Feed-in tariffs settled monthly for smaller installations.	• Settlement periods unchanged; monthly settlements continued for both FiTs and market premiums.
• Applicable Consumers	• **Households/Small Producers:** Feed-in tariff or self-consumption model, typically below 10 kW. • **Medium-sized Producers (10-500 kW):** Can choose FiT or market premium. • **Large Producers (>500 kW):** Encouraged to use market premium but not mandatory.	• **Small Installations (<750 kW):** Can use FiT or self-consumption without participating in auctions. **Large Installations (>750 kW):** Must bid in competitive auctions and use market premium. - Clarified exemptions and stricter requirements for different producer categories.
• Tariffs for Each Category	• **Small Installations (<10 kW):** FiT with no EEG surcharge on self-consumption. • **Medium Installations (10-500 kW):** FiT with partial EEG surcharge on self-consumption. • **Large Installations (>500 kW):** Market premium optional. - FiT degression quarterly based on national solar growth targets.	• **Small Installations (<10 kW):** FiT available with no EEG surcharge on self-consumption. **Medium Installations (10-750 kW):** FiT with partial surcharge for self-consumption above 10 kW. **Large Installations (>750 kW):** Only eligible for market premiums through competitive bidding. - Tariffs adjusted more frequently and rates reduced more responsively to actual capacity growth.

• Provisions for Battery Storage	• Battery use encouraged but not incentivized through separate tariffs or subsidies.	• Additional incentives for battery storage through separate programs outside EEG (e.g., grants, low-interest loans). Support for battery storage to increase self-consumption and reduce grid dependency.
• Other Charges Applicable	• **EEG Surcharge on Self-Consumption:** 40% of EEG surcharge rate applied to installations above 10 kW that self-consume. - **Grid Access Fees:** Standard grid access fees applied for grid-drawn electricity. - **Metering Costs:** Required certified meters for installations above 10 kW. - **Trade Tax/VAT:** Applied to income from excess electricity sold to the grid for larger producers.	• **EG Surcharge on Self-Consumption:** 40% surcharge rate on self-consumption for installations above 10 kW; exemptions maintained for small installations. **Grid Stability Requirements:** Larger producers had stricter obligations to coordinate with grid operators during peak solar production. **Mandatory Smart Meters:** Required for installations above 100 kW to improve grid integration. • **Administrative Costs for Auction Participation:** New costs for large installations participating in competitive bidding.

E. Renewable Energy Sources Act (EEG) 2023

The German government set itself the targets of generating 80 percent of electricity from renewable sources of energy and reaching a photovoltaic capacity of 215 GW by 2030. The 2023 EEG, which came into force on July 30, 2022.

Germany transitioned from EEG 2017 to EEG 2023 to address evolving energy needs and accelerate its path toward carbon neutrality and energy independence. The EEG 2023 was designed in response to increasing urgency around climate goals, amplified by the need to reduce reliance on fossil fuels amid geopolitical tensions affecting energy security, especially after the 2022 energy crisis. This updated legislation introduced higher feed-in tariffs (FiTs) for small and medium-sized installations, expanded support for community



and cooperative energy projects, and strengthened provisions for battery storage to encourage decentralized energy systems. Additionally, EEG 2023 aimed to better integrate renewable sources into the grid by incentivizing self-consumption and expanding competitive auctions for larger installations, including hybrid systems with storage. By reducing financial burdens like the EEG surcharge on self-consumption and increasing incentives for battery storage, Germany sought to make renewable energy generation more attractive for both residential and commercial sectors, promoting resilience and flexibility in its energy grid. Overall, EEG 2023 reflects Germany's strategic shift to bolster renewable energy deployment, reduce carbon emissions, and enhance energy independence.

(1) EG Surcharge (EEG-Umlage) on Self-Consumption

Reduced or Capped Surcharge: Unlike previous versions, EEG 2023 has significantly reduced or capped the EEG surcharge on self-consumed electricity for smaller installations (generally below 30 kW), making it easier and more cost-effective for households and small businesses to invest in solar without additional financial burden. Exemptions for Small Installations: Installations under 10 kW are fully exempt from the EEG surcharge, while larger installations up to 30 kW face either capped or reduced surcharge rates, depending on the amount of self-consumption.

2. Grid Stability and Access Charges

Grid Stabilization Fees for Larger Installations: Larger installations (typically above 1 MW) must comply with grid management measures, which can include fees for services like grid reinforcement or technical modifications. These fees ensure that large-scale solar systems operate smoothly with the grid, especially during peak generation times.

Standard Grid Access Fees: Solar consumers drawing power from the grid still pay standard access fees, which help maintain and upgrade grid infrastructure. However, incentives are in place to encourage local energy use and limit strain on the grid.

3. Smart Metering Costs

Mandatory Smart Meters for Smaller Installations: EEG 2023 broadens the requirement for smart meters to include installations as small as 7 kW, aiming to improve grid interaction and real-time data collection. This can add a small ongoing metering cost for households and businesses.

Smart Meter Expansion Costs: Larger installations may incur additional costs for advanced metering infrastructure, especially if they participate in direct marketing or require more sophisticated grid coordination.

4. Administrative and Auction Participation Costs

Auction Participation for Large Installations (>1 MW): Solar installations above 1 MW must participate in competitive auctions to receive a market premium. These projects incur administrative costs for bid preparation, permitting, and regulatory compliance. While necessary, these costs are intended to ensure only viable and competitive projects receive support.

Permit Fees for Battery Storage: New in EEG 2023, installations with integrated battery storage systems may face small additional fees for permitting and regulatory compliance, especially for larger-scale storage solutions.

5. Taxes (VAT and Trade Tax)

VAT Exemptions for Smaller Installations: Residential systems with lower power output may be partially exempt from VAT on self-consumed electricity, making small-scale solar more affordable for individual households.

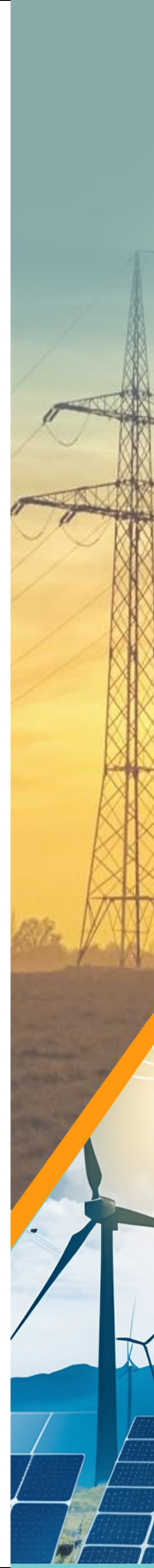
Trade Tax for Commercial Solar Installations: Larger, commercially operated installations are liable for trade tax if their revenue exceeds certain thresholds, primarily affecting large-scale or commercial solar farms rather than private users.

6. Optional Grid-Coordination Incentives

Incentives for Grid-Supportive: EEG 2023 provides optional incentives for consumers with battery storage to manage energy usage and discharge during peak grid demand times, reducing charges. This incentivizes solar consumers to help stabilize the grid, reducing peak stress and avoiding grid coordination fees

Other key features of EEG 2023

(1) Expanded Renewable Energy Targets



Ambitious Renewable Energy Expansion: EEG 2023 sets more aggressive targets for renewable energy, aiming to meet 80% of electricity consumption from renewable sources by 2030. This is part of Germany's broader strategy to reduce greenhouse gas emissions and transition to a sustainable energy system.

Acceleration of Solar and Wind Energy Deployment: Solar energy capacity targets are set to grow significantly, with an emphasis on community-based solar projects and offshore wind expansion.

(2) Increased Support for Community and Cooperative Projects

- Local Energy Production and Consumption: EEG 2023 places a stronger emphasis on community solar and cooperative energy projects, aiming to involve local stakeholders in energy generation. These projects benefit from higher FiTs and fewer administrative barriers, empowering local communities to generate and consume their own renewable energy.
- Priority Grid Access: Such community projects receive priority grid access, allowing local producers to easily connect to the grid and consume or sell their energy without long waiting periods.

(3) Enhanced Flexibility and Grid Integration

- Grid Support for Flexibility: EEG 2023 introduces measures to increase grid flexibility through the integration of renewable energy storage systems, demand-side management, and flexible energy tariffs. These changes aim to balance the grid during times of variable renewable energy production, such as solar during the day and wind at night.
- Incentives for Energy Storage and Demand Response: There is an expanded focus on energy storage systems (including home batteries and large-scale storage projects) as a means to smooth out the fluctuations of renewable energy and enhance overall grid stability. Prosumers and businesses are incentivized to install storage systems that can provide flexibility and stability to the grid.

(4) Simplified Administrative Processes

- Streamlined Permitting for Small Projects: EEG 2023 aims to reduce bureaucracy and simplify the permitting process for renewable energy installations, particularly for smaller projects and residential systems. This is intended to make it easier for citizens and businesses to install solar and other renewable energy systems without facing lengthy approval processes.

- Easier Grid Connection: The new law seeks to make it quicker and easier for renewable energy producers to connect to the grid by offering faster approval and clearer processes for grid operators.

(5) Decentralized Energy Systems

- Promotion of Decentralized Energy Production: EEG 2023 encourages the development of more decentralized energy systems, where energy is produced closer to where it is consumed. This includes promoting rooftop solar installations, local wind farms, and small-scale hydroelectric projects. These systems reduce transmission losses and improve energy security by diversifying energy sources.
- Energy Sharing Models: Provisions are made to encourage peer-to-peer energy sharing, allowing energy producers to share excess energy directly with neighbors or local businesses, thus fostering local energy markets.

(6) Carbon Pricing and Emission Reduction

- Link to EU Emissions Trading System (ETS): EEG 2023 aligns with the EU Emissions Trading System (ETS) by implementing a carbon pricing mechanism for emissions from energy producers. This aims to internalize the cost of carbon emissions and further incentivize the shift towards clean energy sources.
- Integration with Climate Protection Goals: The EEG 2023 is also closely linked to Germany's Climate Protection Act, reinforcing the country's goal to become carbon neutral by 2045. The EEG serves as a core instrument in reducing the country's emissions and fostering a green economy.

(7) Financial Support and Incentives for Innovation

- Green Finance Instruments: EEG 2023 includes provisions to support green financing for renewable energy projects, such as low-interest loans, subsidies, and investment incentives aimed at making renewable energy projects more attractive to investors.
- Innovative Technologies: The law supports research and development of innovative renewable energy technologies, including hydrogen, marine energy, and smart grids, ensuring that Germany remains at the forefront of renewable energy advancements.

(8) Flexibility for Hybrid Systems (Solar + Storage, Wind + Solar)

- Hybrid Energy Systems: EEG 2023 promotes hybrid systems that combine solar, wind, and energy storage. These systems are seen as a way to ensure continuous energy supply, balancing the intermittent nature of wind and solar energy by pairing them with storage technologies or other forms of flexible generation.

(9) Phased Transition to Full Market-Based System

- Market-Driven Energy Transition: A gradual transition to a fully market-based renewable energy system is a key goal of EEG 2023. Over time, feed-in tariffs (FiTs) will be phased out for new projects, and market premiums will become the dominant compensation mechanism. Competitive auctions will determine the price paid for renewable energy, making the system more market-oriented and cost-efficient.
- Long-Term Contracts for Large Projects: Large-scale projects will be encouraged to enter into long-term power purchase agreements (PPAs) with industrial consumers or utilities, offering more price certainty and stability.

(10) Focus on Energy Efficiency

- Energy Efficiency in Renewable Energy Projects: EEG 2023 includes measures to improve energy efficiency across all renewable energy projects, ensuring that systems are not only renewable but also optimized for performance and cost-effectiveness.

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Renewable Energy Regulations in Australia- An overview

A. Renewable Energy (Electricity) Act 2000

The Renewable Energy (Electricity) Act 2000 is a key piece of legislation in Australia that underpins the country's commitment to renewable energy development and reducing greenhouse gas emissions. Enacted by the Australian Government, the Act provides the legislative framework for the Renewable Energy Target (RET), a policy designed to increase the production of electricity from renewable sources.

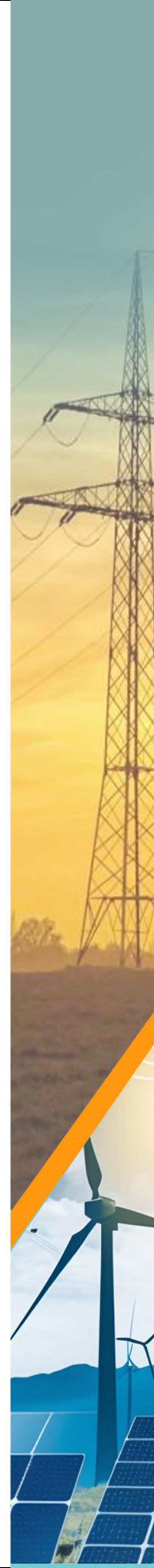
In the introduction period, the consumer categories installing solar plants in Australia were largely restricted to affluent residential users, off-grid communities, environmentally conscious businesses, and government institutions. The Renewable Energy (Electricity) Act 2000 introduced the Mandatory Renewable Energy Target (MRET), which set the stage for supporting renewable energy. However, incentives for small-scale solar systems were sparse, and adoption was limited to affluent households and off-grid communities.

Billing System – Gross metering

Most solar systems operated under a gross metering model, where all electricity generated by the system was exported to the grid. Prosumers were paid for the total electricity exported at the wholesale price, while their consumption from the grid was billed at the standard retail rate.

Settlement Rate – Feed in Tariff (FiT)

FiT were based on the wholesale market price of electricity, which represented the cost at which electricity was traded in the National Electricity Market (NEM). These prices were significantly lower than the retail electricity price paid by consumers, typically ranging from 3 to 6 cents per kWh.



B. Emergence of Feed-in Tariffs (2005–2010)

During the mid-to-late 2000s, there was a significant shift in policy with the introduction of state-specific feed-in tariff (FiT) programs that incentivized prosumers to export excess solar electricity. Victoria introduced net metering and a FiT program in 2008, offering 60 cents/kWh for exported electricity under a premium FiT scheme. South Australia introduced a FiT of 44 cents/kWh in 2008, which sparked a high rate of solar adoption.

New South Wales followed in 2009 with the Solar Bonus Scheme, initially offering 60 cents/kWh for exported electricity, later transitioning to net billing.

The Solar Bonus Scheme was part of the NSW Government's broader initiative to meet renewable energy targets and reduce reliance on fossil fuels. It incentivized the installation of solar photovoltaic (PV) systems by offering a premium feed-in tariff.

Premium Feed-in Tariff:

- The scheme initially offered a 60 cents per kWh tariff for solar electricity exported to the grid.
- This premium FiT rate was significantly higher than the retail price of electricity, making solar energy installations attractive for consumers.
- Households or businesses with systems installed under this scheme received payments for every kilowatt-hour (kWh) of solar energy they fed into the grid.

Eligibility:

- The Solar Bonus Scheme applied to solar systems installed on residential and small business properties.
- To qualify, the solar PV system had to meet specific technical and regulatory standards, and the consumer had to sign up with an approved retailer.

Duration:

- The premium tariff of 60 cents/kWh was guaranteed for 7 years for all systems installed before 1 January 2011. After this period, the tariff would drop, and participants would receive the market-based FiT rate for their exported energy.
- The scheme closed to new participants in 2011 but continued to pay the premium tariff to those already enrolled.

Impact:

- The scheme significantly boosted the uptake of solar PV systems in NSW during its active years, leading to an increase in solar capacity across the state.

- By the end of the program, thousands of households had installed solar panels to take advantage of the generous FiT.

C. Net Metering and Net Billing Adoption (2010–2015)

Between 2010 and 2015, most States transitioned from gross metering to net metering or net billing systems. Under net metering, consumers could offset their electricity bills using energy generated and consumed on-site, with credits provided for surplus exports. In net billing, surplus electricity was compensated at FiT rates, which were lower than retail electricity prices and reflected wholesale market dynamics. The introduction of the Small-scale Renewable Energy Scheme (SRES) in 2011 further supported prosumers by providing Small-scale Technology Certificates (STCs), reducing upfront costs for solar installations.

D. Decline of Premium Feed-in Tariffs (2015–2020)

As solar technology became more affordable, many States phased out or reduced premium FiT schemes. Victoria replaced its premium FiTs with a time-varying FiT model in 2017, with rates ranging from 6.5 to 29 cents/kWh to encourage exports during peak demand. New South Wales ended the Solar Bonus Scheme in 2016, transitioning to market-driven FiTs between 5 to 15 cents/kWh. Queensland shifted from premium FiTs of 44 cents/kWh to regulated FiTs for regional areas (e.g., 8.6 cents/kWh) and competitive rates in South East Queensland.

E. Modern Settlement Mechanisms (2020–Present)

In recent years, settlement mechanisms have become more sophisticated. Time-of-Use Billing has been introduced in many states, including Victoria and Western Australia, offering higher rates during peak evening hours. In addition, battery integration incentives have been introduced, such as South Australia's Home Battery Scheme, enabling prosumers to maximize self-consumption and export during high-demand periods.

Market-driven FiTs: Retailers in deregulated markets, such as New South Wales and South East Queensland, set FiTs based on wholesale electricity prices, typically ranging from 5 to 15 cents/kWh.

In deregulated markets like New South Wales and South East Queensland, market-driven feed-in tariffs (FiTs) are offered by electricity retailers to prosumers who generate their own electricity, typically through rooftop solar systems. Unlike the fixed or government-mandated FiTs, market-driven FiTs are determined by the electricity retailers based on factors like wholesale electricity prices, competition among retailers, and time-of-use pricing. These rates typically range from 5 to 15 cents per kWh for solar energy exported to the grid, and the exact amount varies depending on the retailer and the market conditions. Retailers may offer different pricing models, such as higher FiTs during peak demand periods (e.g., evening hours when electricity demand is highest), incentivizing prosumers to export their surplus energy during those times. The rates are more flexible and can change over time in response to shifts in energy prices and demand, which provides prosumers with opportunities to optimize their financial returns. While these market-driven FiTs are generally lower than the premium FiTs from earlier feed-in tariff schemes, they still provide an important financial incentive for solar adopters in these regions, contributing to the growth of renewable energy and supporting grid stability.

F. New Rules on solar export to be mandatory from July 2025

The Australian Energy Market Commission (AEMC) introduced new rules in August 2021 to regulate export of electricity to the grid by prosumers. As per the new rules, electricity companies will have to offer a “basic export service” – that allows solar owners to export excess solar up to a particular threshold without having to pay additional charges. For prosumers wanting to export above the threshold, the electricity companies are to offer two different payment plans, where households pay an additional charge to export their excess power into the grid, but in return could benefit from higher feed-in-tariffs and other incentives to export power at times beneficial to the wider grid. AEMC expects that by carving a path for smart solar, batteries and electric vehicles, more solar can be used and keep costs down for all consumers and protect the value of household solar investments already made. AEMC anticipates that electricity costs for most electricity customers would fall, as “they would no longer pay for solar export services they aren’t using”, while households with rooftop solar would still receive at least 90 per cent of the existing financial benefits. In 2024, the electricity companies started implementing the rew rules on an optional basis for prosumers which will become mandatory from July 2025.

Challenges in the Grid

Despite successes, challenges persist. Equitable cost distribution remains a concern, as prosumers exporting excess electricity at higher FiT rates raise cross-subsidy issues for non-solar consumers. Grid stability is also a challenge, as high solar penetration can cause voltage fluctuations, prompting measures like export limits or dynamic export pricing. Future policies are likely to emphasize self-consumption, battery storage, and the integration of virtual power plants (VPPs), where prosumers collectively contribute to grid stability.

Table: Evolution of Renewable Energy Regulations in Australia

• Time Period	• Key Developments
• Early Stages (2000–2005)	• In the early 2000s, prosumer-related schemes were minimal, and settlement mechanisms were underdeveloped. Most states relied on gross metering, where all electricity generated by solar systems was exported to the grid, with compensation based on wholesale electricity prices. The Renewable Energy (Electricity) Act 2000 introduced the Mandatory Renewable Energy Target (MRET), which set the stage for supporting renewable energy. However, incentives for small-scale solar systems were sparse, and adoption was limited to affluent households and off-grid communities.
• Emergence of Feed-in Tariffs (2005–2010)	• The mid-to-late 2000s saw a significant shift with the introduction of state-specific feed-in tariff (FiT) programs, incentivizing prosumers to export excess solar electricity. Key milestones include: - Victoria (2008): Implemented one of the first net metering and FiT programs, offering 60 cents/kWh for exported electricity under a premium FiT scheme. - South Australia (2008): Introduced a FiT of 44 cents/kWh, sparking high solar adoption rates. - New South Wales (2009): Launched the Solar Bonus Scheme, initially offering generous gross FiTs of 60 cents/kWh, later

	transitioning to net billing. These policies led to rapid growth in rooftop solar installations, though their sustainability came under scrutiny due to the financial burden on electricity retailers and non-solar consumers.
• Net Metering and Net Billing Adoption (2010–2015)	• During this period, most states transitioned from gross metering to net metering or net billing systems: - Net Metering: Consumers could offset their electricity bills using energy generated and consumed on-site, with credits provided for surplus exports. - Net Billing: Surplus electricity was compensated at FiT rates lower than retail electricity prices, reflecting wholesale market dynamics. The Small-scale Renewable Energy Scheme (SRES), introduced in 2011, further supported prosumers by providing Small-scale Technology Certificates (STCs), reducing upfront costs for solar installations. Settlement rates under FiT schemes varied significantly, ranging from 5 to 60 cents/kWh, depending on the state and policy.
• Decline of Premium Feed-in Tariffs (2015–2020)	• As solar technology became more affordable, many states reduced or phased out premium FiT schemes: - Victoria: Replaced premium FiTs with a time-varying FiT model in 2017, with rates ranging from 6.5 to 29 cents/kWh, encouraging exports during peak demand. - New South Wales: Ended the Solar Bonus Scheme in 2016, transitioning to market-driven FiTs of 5 to 15 cents/kWh. - Queensland: Shifted from premium FiTs of 44 cents/kWh to regulated FiTs for regional areas (e.g., 8.6 cents/kWh) and competitive rates in South East Queensland. States also emphasized self-consumption and energy efficiency, reducing reliance on high FiTs. The focus shifted to ensuring grid stability as solar penetration increased.
• Modern Settlement Mechanisms (2020–Present)	• Settlement mechanisms in recent years have become more sophisticated, reflecting evolving energy market dynamics: - Time-of-Use Billing: Many states, including Victoria and Western Australia, introduced time-of-export FiTs, offering higher rates during peak evening hours (e.g., Western

	Australia's DEBS scheme with rates of up to 10 cents/kWh). - Market-driven FiTs: Retailers in deregulated markets, such as New South Wales and South East Queensland, set FiTs based on wholesale electricity prices, typically ranging from 5 to 15 cents/kWh. - Battery Integration Incentives: South Australia's Home Battery Scheme and other programs incentivize energy storage, enabling prosumers to maximize self-consumption and export during high-demand periods.
• Challenges and Future Directions	• Despite successes, challenges persist: - Equitable Cost Distribution: Prosumers exporting excess electricity at higher FiT rates raise cross-subsidy concerns for non-solar consumers. - Grid Stability: High solar penetration can cause voltage fluctuations, prompting measures like export limits or dynamic export pricing. Future policies are likely to emphasize self-consumption, battery storage, and virtual power plants (VPPs), where prosumers collectively contribute to grid stability.

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(3) Australian Energy Regulator (AER)

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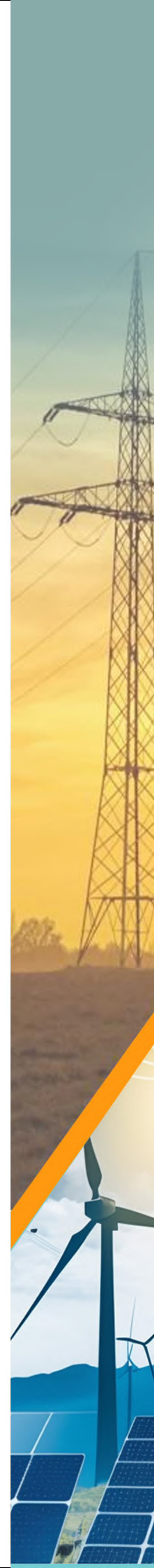


Annexure B

Decentralised RE Regulations across various States in India

Sl No.	State	Billing Method		Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
1	Kerala	Applicability (Eligibility)	Consumer Category	Available for all categories, including residential, commercial, and industrial consumers	NA	NA	Available for all categories, including residential, commercial, and industrial consumers	PM KUSUM - C component	NA	NA
			Load/ Capacity limit	(1) the domestic consumers with connected load up to 20 kW is permitted to install 'Renewable Energy System' of capacity up to 20 kW, irrespective of their connected load. (2)above 1 kW and upto sanctioned load/contract demand or 1000kW whichever is lower, for all other category of consumers. (3) rosumers above 1 MW			(1) the domestic consumers with connected load up to 20 kW is permitted to install 'Renewable Energy System' of capacity up to 20 kW, irrespective of their connected load. (2)above 1 kW and upto sanctioned load/contract demand or 1000kW whichever is lower, for all other category of consumers.			
		Applicable charges		for the prosumer above 1 MW capacity Banking charges - 5% of the injected energy. Grid support charges - 5% of the injected energy.			Wheeling Charges at Rs 0.62/unit and distribution loss			
		Banking		allowed for All the prosumers upto the end of a financial year Provisions: Other than peak: 80% against peak time, 100% during the time period other than peak hours. Peak hours: 100% against peak time; balance to be adjusted at 120% during other time blocks						
		Settlement Period		FY basis			FY basis	FY basis		
		Settlement Rate		At Average Pooled Power Purchase Cost Rate (Rs 3.15/ unit for FY 2023-24)			At Average Pooled Power Purchase Cost Rate (Rs 3.15/ unit for FY 2023-24)	At Average Pooled Power Purchase Cost Rate (Rs 3.15/ unit for FY 2023-24)		
		Billing of imported units		Imported energy is billed as per the prevailing Retail tariff			Imported energy is billed as per the prevailing Retail tariff	Imported energy is billed as per the prevailing Retail tariff		
		Ownership Models		Primarily Consumer Owned; third-party ownership models allowed under specific conditions						
		Remarks								

Sl No.	State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
2	Tamil Nadu	Applicability (Eligibility)	Consumer Category	Applicable to all domestic consumers	All categories of consumers (except Hut & Agriculture) irrespective of load, tariff and voltage level	The existing and new consumers of all categories except Low Tension category up to 150 kW and generators are eligible for gross metering mechanism irrespective of tariff				
			Load/ Capacity limit	upto the level of sanctioned load/contracted demand	up to the level of sanctioned load / contracted demand of their service connection or 999kW whichever is lower	The minimum size of the Solar System shall be 151 kW to a maximum capacity of 999 kW				
		Applicable charges		Upto 10 kW - Network charges at 20% of (LT- Rs 1.59/ kWh) Above 10 kW- Network charges at 20% of (LT- Rs 1.59/ kWh)	Network charges are determined by the Commission from time to time: For FY 204-25 HT- Rs 1.04/ kWh LT- Rs 1.59/ kWh	Nil				
		Banking		the net units of surplus generation al get lapsed at end of settlement period	At the end of a 12-month settlement period, the consumer has the option to receive payment of the net credit amount balance (if any) or have such credit amount balance carried-over to the next settlement period	Nil				
		Settlement Period		Financial Year basis	Financial Year basis	Biling cycle				
		Settlement Rate		No payment for any excess unadjusted electricity at the end of settlement period	Feed in tariff Rs.3.61 (0-10 kW) Feed in tariff Rs.3.37 (11-150 kW)	Feed in tariff Rs.3.10 (>150 kW)				
		Billing of imported units		At the retail tariff approved by the Commission	Imported energy based on retail tariff	Imported energy based on retail tariff				
		Ownership Models		Self ownership and RESCO model	Self ownership and RESCO model	Self ownership and RESCO model				
		Remarks								

Sl No.	State / Billing Method			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
3	Maharas htra	Applicability(Eligibility)	Consumer Category	All consumers	All consumers	All consumers	for multiple premises owned by the same or different consumers under a single licensee.	housing society or apartment owners association including their common connection within the same Distribution Licensee's	All consumers	
			Load/ Capacity limit	limited to 5 MW or Contract Demand/Sanction Load of consumer, whichever is lower.	Minimum size of RE system of 1kW and maximum size of sanctioned load/contract demand of consumer.	Upto Contract Demand/Sanctioned Load of consumer	to Contract Demand/Sanctioned Load of consumer	shall not exceed summation of capacity eligible to each participating consumer	Minimum size of RE system of 1kW and maximum size of sanctioned load/ contract	
		Applicable charges		Grid Support Charges shall not be levied till installations under rooftop arrangement in the State reach 5000 MW			Wheeling Charges and Wheeling losses exempted till installed capacity of rooftop solar in Maharashtra reaches 5000 MW	Open Access Charges and losses for sourcing electricity exempted till installed capacity of rooftop solar in Maharashtra reaches	Not specified any charges	
		Banking		allowed			allowed	allowed		
		Settlement Period		FY basis	Monthly	Monthly	FY basis	FY basis		
		Settlement Rate		Generic Tariff - latest tariff rate discovered for Grid Scale Solar project as a for generic tariff procurement of surplus energy from Rooftop PV projects and is Rs. 2.90/kWh for FY 2024-25		APPC Rate @ 4.88/kWh for FY 2024-25	Generic Tariff - latest tariff rate discovered for Grid Scale Solar project as a for generic tariff procurement of surplus energy from Rooftop PV			
		Billing of imported units		billed according to the prevailing tariff rates applicable to the consumer category	Energy Bill of consumer = Fixed Charges + other applicable charges and levies + (Edl × Trst) - (Ere × Tgc) – Billing Credit; Edl means the energy drawn from the Grid by the Prosumer ; Trst means the applicable retail supply tariff of the concerned consumer category as per the applicable retail supply Tariff Order of the Commission; Ere means the energy injected into the Grid by the Prosumer; Tgc means the Generic Tariff approved by the Commission for that year	Energy Bill of consumer = Fixed Charges + other applicable charges and levies + (EDL x TRST) - (ERE * TPPA) – Billing Credit; ERE means the energy units recorded for the billing period by the Renewable Energy Generation Meter; TPPA means the energy charges as per the Power Purchase Agreement signed between the Consumer and Distribution Licensee, EDL means the energy units supplied by the Distribution Licensee f) TRST means the applicable retail supply tariff of the concerned consumer category	as per ratio of procurement indicated under Net Metering Agreement	as per ratio of procurement indicated under Net Metering Agreement	As per retail tariff of the consumer	
		Ownership Models		self owned or third party leasing such System						
		Remarks								

Sl No.	State	Billing Method →	Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
4	Gujarat	Applicability(Eligibility) – Consumer Category	All consumers		All consumers				
		Applicability(Eligibility) – Load/ Capacity limit	for projects having capacity of 1 kW and above and upto 1000kW For Residential consumers: irrespective of their sanctioned load No capacity restrictions upto sanctioned load/ contracted demand shall be applicablefor the captive consumers and project set up under Third Party Sale within the permissible limit.		for projects having capacity of above 10 kW and upto 1000 kW For Residential consumers: irrespective of their sanctioned load No capacity restrictions upto sanctioned load/ contracted demand shall be applicablefor the captive consumers and project set up under Third Party Sale within the permissible limit.				
		Applicable charges	Banking charges of Rs 1.50 / unit shall be applicable on solar energy consumed in case of Demand based Consumers shall be applicable. In case of MSME units and other than LT Demand based Consumers, Banking Charge of Rs.1.10 per unit shall be applicable on Solar Energy consumed shall be applicable. Banking Charges shall not be applicable to government buildings. Further transmission charges, wheeling charges, distribution losses cross subsidy surcharge and addition surcharge as determined by the Commission shall be levied		Banking charges of Rs 1.50 / unit shall be applicable on solar energy consumed in case of Demand based Consumers shall be applicable. In case of MSME units and other than LT Demand based Consumers, Banking Charge of Rs.1.10 per unit shall be applicable on Solar Energy consumed shall be applicable. Banking Charges shall not be applicable to government buildings. Further transmission charges, wheeling charges, distribution losses cross subsidy surcharge and addition surcharge as determined by the Commission shall be levied				
		Banking	allowed within one billing cycle						
		Settlement Period	Billing cycle		Billing cycle				
		Settlement Rate	RESIDENTIAL, GOVERNMENT and MSME enterprises: Self-owned and third party sale : - 2.25 Rs/unit for the first 5 years. 75% of simple average tariff discovered for non-park based solar projects in preceding 6months period (April - Sep, or oct - march) from CoD in competitive bidding. For other consumers :- At 75% of the simple average of tariff discovered and contracted through competitive bidding process conducted by GUVNL for non-park based solar projects in the preceding six months period.		at the rate determined by the Commission as per decision of the Commission in Petition No. 1802/2019. (Rs 2.62/ kWh to 2.66 kWh + Rs 0.20)				
		Billing of imported units	For Industrial, Commercial and Other Consumers peak charges shall be applicable for consumption during peak hours. For demand based consumers Time of Use charges appllicable For energy consumption during the two peak periods, Viz., 0700 Hrs. to 1100 Hrs. and 1800 Hrs. to 22: 00 Hrs For Billing Demand up to 500 kVA: 65 Paise per Unit For Billing Demand above 500 KVA: 100 Paise per Unit						
		Ownership Models	self owned or third party leasing such System						
		Remarks	In case of solar projects set up by HT / EHV consumers, the energy set-off shall be allowed between 07.00 hours to 18.00 hours of the same day meaning thereby, the generated solar energy during a day shall be consumed by HT or EHV consumer during 07.00 hours to 18.00 hours on the same day. In case of solar projects set up by LT demand-based consumers, the energy setoff shall be allowed between 07.00 hours to 18.00 hours basis of the same billing cycle meaning thereby, the generated solar energy during 7:00 hours to 18:00 hours of a billing cycle shall be consumed by the consumer during the specified period of 7:00 hours to 18:00 hours in the same billing cycle						

Sl No.	State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
5	Rajasthan	Applicability(Eligibility)	Consumer Category	All consumers	All consumers				All consumers	
			Load/ Capacity limit	for loads up to 500 Kilowatt or upto the sanctioned load, whichever is lower	Minimum capacity shall not be less than 1 kW and upto sanctioned load/contract demand or 1000kW whichever is lower				limited to 100% of Contract Demand	
		Applicable charges		cross subsidy surcharge and additional surcharge shall be applicable for RESCO-owned					Fixed Charges or Demand Charges as per retail traiff order	
		Banking		allowed						
		Settlement Period		FY basis	value of Renewable Energy generation (net amount in Rs after adjustment in billing cycle) shall be carried forward to next month and shall be adjusted upto end of settlement period				Billing cycle	
		Settlement Rate		weighted average tariff of large-scale solar projects of 5 MW and more, discovered through Competitive Bidding in last Financial Year, for entire duration of the project (₹2.87–₹3.00/kWh for the year 2024)	weighted average tariff discovered through Competitive Bidding for respective technology in previous Financial Year and adopted by the Commission, plus an incentive of 25%, for entire duration of the project (₹2.87–₹3.00/kWh for the year 2024)				No payment for injection	
		Billing of imported units		billed according to the applicable slab corresponding to the Net imported energy (Total Consumption from all sources – Allowable Solar Generation) from the grid.	Energy Bill of consumer = Fixed Charges + other applicable charges and levies + (EDL x TRST) - (ERE * TPPA) – Billing Credit; EDL means the energy units supplied (i.e., Gross Electricity Consumption by the Consumer) by the Distribution Licensee as recorded by the consumer meter for the billing period; TRST means the applicable retail supply tariff of the concerned consumer category as per the applicable retail supply Tariff Order of the Commission; ERE means the energy units recorded for the billing period by the RE Generation Meter; TPPA means the Tariff as per the Connection Agreement signed between the Consumer and Distribution Licensee				As per retail tariff order	
		Ownership Models		self owned or RESCO models	self owned or RESCO models				RESCO	
		Remarks		The net remaining energyavailable at the end of billing period of the respective category shall lapse and no payment shall be made for consumers other than domestic for the same					Consumer shall ensure that no energy is injected into the grid from such Renewable Energy generating system installed behind the Consumer's meter	

Sl No.	State / Billing Method			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
6	Uttar Pradesh	Applicability(Eligibility)	Consumer Category	LMV-5 (Agriculture), or residential/ domestic consumers under LMV-1	all consumers	all consumers	LMV-5 (Agriculture), or residential/ domestic consumers under LMV-1			Provision for peer to peer transaction in a secured manner. Only be implemented once the UPPCL and UPNEDA jointly put forth a proposal regarding the accouting and billing mechanism for such transactions
			Load/ Capacity limit	Shall not be less than 1 kWp and not more than 2 MWp upto sanctioned connected load/ contract demand	Shall not be less than 1 kWp and not more than 2 MWp upto sanctioned connected load/ contract demand	Shall not be less than 1 kWp and not more than 2 MWp upto sanctioned connected load/ contract demand	Shall not be less than 1 kWp and not more than 2 MWp upto sanctioned connected load/ contract demand			
		Applicable charges		Fixed/ demand charges, Government levy			Fixed/ demand charges, Government levy			
		Banking		allowed	allowed		allowed			
		Settlement Period		excess energy injected by the prosumer iscaary forward as ellectricity credits till the end of settlement period (based on FY basis)	FY basis	billing cycle	excess energy injected by the prosumer iscaary forward as ellectricity credits till the end of settlement period (based on FY basis)			
		Settlement Rate		at Rs 2/ kWh for the unadjusted electricity credits at the end of settlement period	weighted average tariff of large-scale solar projects of 5 MW and more, discovered through Competitive Bidding in last Financial Year, for entire duration of the project plus 25% incentive (Rs 2.98 per unit +25% incentive - March, 2024 rate)	weighted average tariff of large-scale solar projects of 5 MW and more, discovered through Competitive Bidding in last Financial Year, for entire duration of the project plus 25% incentive (Rs 2.98 per unit +25% incentive - March, 2024 rate)	at Rs 2/ kWh for the unadjusted electricity credits at the end of settlement period			
		Billing of imported units		Net Consumption (in kWh) = kWh (Import) - kWh (Export)	The net bill payable/ receivable shall be determined as the difference between electricity bill of the electricity supplied by the Distribution licensee (including government levy etc.) and the sum of monetary value of the exported energy & receivables, if any, carried over from last month	Licensee issue net off bill based on the amount payable by the DISCOM as per settlement rate and amount payable by the prosumer as per RST .	Billed based on the ratio of procurement indicated under Net Metering Agreement			
		Ownership Models		self owned or third party	self-owned or third party owned	self owned or third party				
		Remarks			* Group Net billing is allowed as per the same conditions as of net billing. The settlement between the individual consumer in the group and the third party (if involved) will be the responsibility of the group or third party itself and shall be governed by the agreement between them. The third party aggregator is not be charged by DISCOM any fixed charges on this account but shall be charged for energy imported as per prevailing Rules and Regulations					

Sl No.	State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
7	Haryana	Applicability(Eligibility)	Consumer Category	All consumers of electricity, except AP Consumers		All consumers of electricity, except AP Consumers				
			Load/ Capacity limit	for the loads up to 500 kW or up to sanctioned load/contracted demand, whichever is lower		for the loads up to sanctioned load/contracted demand				
		Applicable charges								
		Banking		carry forward upto end of settlement period						
		Settlement Period		FY basis		Billing period				
		Settlement Rate		Unadjusted units shall lapse at the end of the settlement period and shall not be paid for by the distribution licensee		the tariff be Rs. 3.11/- per unit for five year without any escalation despite market asymmetry				
		Billing of imported units		Net Consumption (in kWh) = kWh (Import) - kWh (Export) ii. Net Consumption (in kVAh) = Net Consumption (in kWh) divided by the power factor maintained by the consumer during corresponding billing period. **Regardless of availability of electricity credits with the eligible consumer during any billing period, the consumer will continue to pay applicable charges such as fixed/demand charges, Government levy, etc						
		Ownership Models		self owned or Third Party Owned Rooftop Solar PV		self owned or Third Party Owned Rooftop Solar PV				
		Remarks		for third party owned solar PV system, the electricity generated from such plants/system shall be used to meet the eligible consumer's internal electricity needs up to the capacity allowed						

Sl No.	State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
8	Bihar	Applicability(Eligibility)	Consumer Category	All consumers		All consumers				
			Load/ Capacity limit	shall not be less than one kWp and shall not exceed sanctioned/contracted load		shall not be less than one KWp and shall not exceed sanctioned/contracted load				
		Applicable charges								
		Banking		excess injected electricity shall be carried forward to next billing period as electricity credit and may be utilized to net electricity injected or consumed in future billing periods upto end of settlement period		No banking				
		Settlement Period		FY basis		Billing cycle				
		Settlement Rate		Excess energy lapse at end of settlement period		Feed-in Tariff at Rs 3.11 per unit (Rate discovered in 2022 and is still continuing)				
		Billing of imported units		As per tariff in force applicable to that category of eligible consumers.						
		Ownership Models		self owned or third party owners		self owned or third party owners				
		Remarks								

Sl No.	State ↓ / Billing Method →		Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
9	Delhi	Applicability(Eligibility) – Consumer Category	all consumers			all consumers	for residential consumers, Group housing societies, offices of Government /Local Authorities and Renewable Energy Generators registered under Mukhya Mantri Kisaan Aay Badhotari Yojna.		Prosumers, except Ground Mounted Projects
		Applicability(Eligibility) – Load/ Capacity limit	upto the sanctioned load of the Consumer			shall be upto 5 times of Sanctioned Load of participating consumer who have opted for VNM/GNM with maximum of 10 MW			shall be less than or equal to 200 kW or equivalent kVA, capacity of RE plant capped at 500% of its Sanctioned Load
		Applicable charges							Energy Charge, Fixed charge, PPAC, RA Surcharge, Pension Trust Surcharge and Electricity Tax, Transaction Charge (inclusive of GST) per kWh or per Transaction to be paid by Consumer & Prosumer
		Banking							
		Settlement Period	FY basis			surplus units injected by the consumer shall be carried forward to the next billing period as energy credit and shown as energy exported by the consumer for adjustment against the energy consumed in subsequent billing periods within the settlement	surplus credited units shall be carried forward in the next billing period as energy credits for adjustment against the energy consumed in subsequent billing periods within the settlement period of each participating consumer		Billing cycle
		Settlement Rate	Rate for FY 2020-21 at Rs 2.79/ unit for BSES (from true up order- lates published)						Settlement shall be done first towards the energy transacted on P2P Platform and then towards the energy supplied by Distribution Licensee. Rates not yet determined
		Billing of imported units	as per applicable tariff, only after adjusting / netting off of the unadjusted energy credits of the previous billing cycle						Distribution Licensee or Service Provider employed by DISCOM shall generate the bills of P2P participants. Payments made by P2P consumers shall be settled in the following order of priority: a) energy transacted by them on the P2P platform. b) transaction charges. c) the energy supplied by the distribution licensee. (1) Under injection of energy by P2P Prosumer- Payment by Prosumer to Consumer arrived as product of Energy imported by Consumer from DISCOM due to NonSupply by Prosumer with rate equivalent to absolute difference of Energy Charges of Consumer, as per Tariff Schedule, and mutually agreed price on P2P Platform. (2) Over injection of energy by the Prosumer- Settlement at th e rates of Net Metering (3)Under-drawl of energy by P2P Consumer -Full payment of quantum of energy pledged by it on P2P platform to the Prosumer(s) (4) Over-drawl of energy by P2P Consumer- Settlement shall be done first towards the energy transacted on P2P Platform and then towards the energy supplied by Distribution Licensee. In the event of Total Demand (P2P Transaction + Purchase from Distribution Licensee) exceeds the contracted demand
		Ownership Models							
		Remarks							

Sl No.	State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
10	Madhya Pradesh	Applicability(Eligibility)	Consumer Category	All consumers		All consumers	All consumers	All consumers		
			Load/ Capacity limit	upto 500 kW capacity, subject to connected load/ contract demand		upto 1 MW capacity	upto 100 kW capacity, subject to the total contract demand/ connected demand of the parent consumer and participating consumer	upto 100 kW capacity, subject to the total contract demand/ connected demand of the parent consumer and participating consumer		
		Applicable charges		Fixed charges based on the energy imported from the grid. Minimum charges for the category of consuemr as per the RST will be applicable. Further duty/tax/cess imposed by the Government if any shall be applicable.			voltage wise losses, Wheeling charge, cross subsidy surcharge, additional surcharge as per RST on the wheeled energy prior to crediting of the participating consumers			
		Banking		allowed						
		Settlement Period		1st day of October to the 31st September of the next year		1st day of October to the 31st September of the next year	1st day of October to the 31st September of the next year	1st day of October to the 31st September of the next year		
		Settlement Rate		Any energy excess unadjusted net credited units of electricity shall be payable by the discom at the lowest tariff rate discovered by solar/wind bidding in MP in the preceding FY. (Rs 2.14 per kWh		at the lowest tariff rate discovered by solar/wind bidding in MP in the preceding FY, for the energy injected by the prosumer. (Rs 2.14 per kWh	Any excess unadjusted net credited units of electricity shall be payable by the discom at the lowest tariff rate discovered by solar/wind bidding in MP in the preceding FY			
		Billing of imported units		as per applicable retail tariff, only after adjusting / netting off of the unadjusted energy credits of the previous billing cycle		Licensee issue net off bill based on the amount payable by the DISCOM as per settlement rate and amount payable by the prosumer as per RST . If the net bill is to payable by the distribution licensee then such amount shall be carry forward by the DISCOM till the end of				
		Ownership Models		self owned or RESCO models		self owned or RESCO models				
		Remarks								

Sl No.	State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
11	Assam	Applicability(Eligibility)	Consumer Category	All consumers		All consumers				
			Load/ Capacity limit	1 kWp to 1000 kWp , Limited to 100% of contract demand / connected load for LT consumers		1 kWp to 1000 kWp , Limited to 100% of contract demand / connected load for LT consumers				
		Applicable charges		Fixed charges applicable for the respective category as per RST		Fixed charges applicable for the respective category as per RST				
		Banking		allowed						
		Settlement Period		FY basis		monthly				
		Settlement Rate		at APPC rate (Rs 5.33 kWh. For FY 2024-25)		at APPC rate (Rs 5.33 kWh. For FY 2024-25)				
		Billing of imported units				Licensee issue net off bill based on the amount payable by the DISCOM as per APPC rate and amount payable by the prosumer as per RST .				
		Ownership Models		self owned or third party		self owned or third party				
		Remarks				mentioned as Exim Metering Arrangement in AERC Regulations				

Sl No.	State	Billing Method →		Net Metering	Net Billing	Gross metering		Group Net Metering	Virtual Net Metering	Behind The meter
12	West Bengal	Applicability	Consumer Category	i) A consumer within the supply area of the distribution licensee who has installed or plans to install a solar PV system. ii) All Eligible Agriculture Consumers	NA	i)Consumers (Except Agriculture)			NA	
			Load/Capacity limit	i)**1 kW or more** on a rooftop or any mounting structure on their premises. ii) Consumers with Sanctioned Load/Contract Demand up to 5 kW (Except agriculture consumers) iii)The installed capacity of the Solar PV generating system shall not exceed the consumer's contract demand (in kVA) or sanctioned load (in kW), except for government-funded projects or projects under specific schemes.		ii) Sanctioned Load/Contract Demand Above 5 kW.				
		Applicable Charges		1)Regardless of availability of excess electricity with the eligible consumer during any billing period, the consumer will continue to pay all other charges such as fixed/demand charges,Government levy, etc.		NA				
		Banking		1) For consumers under a time-of-day tariff set by the Commission,electricity consumption in each time block (peak or off-peak) will first be offset by the electricity generated in the same block. Any excess generation beyond consumption in a time block will be accounted for as if it occurred in the next lower tariff block. This process will continue until all consumption in the lower tariff blocks is offset by the solar PV generation. 2) Offsetting in higher tariff zone not allowed.						
		Settlement Period		i)Settlement period – Financial year basis.		i)Settlement period – Financial year basis.				
		Settlement Rate		1) Any excess energy generated from rooftop solar PV systems exceeding 90% of the consumer's energy usage from the licensee's supply per billing period will be carried over to the next billing period within the same year. 2) If, at the end of the year, the energy supplied by the licensee is less than the energy injected by the consumer's rooftop solar system, the licensee will not pay for any excess energy beyond 90% of the consumer's yearly consumption, treating it as unwanted inadvertent injection.		1) The distribution licensee shall enter into a Power Purchase Agreement at a generic tariff set by the Commission, fixed for the project's entire useful life, with specific tariffs for solar PV installations as follows: **378.82 Paise/kWh for 2023-24, 379.86 Paise/kWh for 2024-25, and 373.10 Paise/kWh for 2025-26.** 2) Billing Credit, which is the amount by which the renewable energy generation in a month exceeds all other components of the consumer's bill. Any surplus billing credits at the end of settlement period will lapse and will not be paid by the distribution licensee. While, entire quantity of electricity generated by the solar PV system will be procured by the distribution licensee.				
		Billing of imported units		1) A slab tariff, as per the applicable tariff order under the Tariff		1)The distribution licensee shall raise the consumer's bill according to the following equation:				
		Ownership model								
		Remarks					It is recognised as net-billing in regulation.			

Sl No.	State	Billing Method →		Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
13	Punjab	Applicability	Consumer Category	1)Eligible consumer can opt for only one arrangement i.e. either net metering or net-billing or gross metering. 2)A consumer of electricity in the area of supply of distribution licensee, who uses or intends to use a rooftop SPV system installed in his premises.	1) Eligible consumer can opt for only one arrangement i.e. either net metering or net-billing or gross metering.	1) Eligible consumer can opt for only one arrangement i.e. either net metering or net-billing or gross metering.				
			Load/Capacity limit	1) The minimum capacity of Rooftop SPV system under net metering arrangements shall be 1 kWp for a single eligible consumer. 2) The maximum capacity of Rooftop SPV systems under Net-Metering shall not exceed 500 kWp. 3) The maximum capacity of the Rooftop SPV system is subject to the sanctioned load/contract demand. i)**Non-Domestic Consumers**:The maximum capacity of the Rooftop SPV system (inverter capacity on the AC side) cannot exceed 70% of the sanctioned load (in kW) or contract demand (in kVA converted to kW using a power factor of 0.9). ii)**Domestic Consumers**:The maximum capacity of the Rooftop SPV system cannot exceed the sanctioned load (in kW) or contract demand (in kVA converted to kW using a power factor of 0.9).	1) The minimum capacity of Rooftop SPV system under net billing arrangements shall be 1 kWp for a single eligible consumer. 2) The maximum capacity of the Rooftop SPV system is subject to the sanctioned load/contract demand. i)Non-Domestic Consumers:The maximum capacity of the Rooftop SPV system (inverter capacity on the AC side) cannot exceed 70% of the sanctioned load (in kW) or contract demand (in kVA converted to kW using a power factor of 0.9). ii)Domestic Consumers:The maximum capacity of the Rooftop SPV system cannot exceed the sanctioned load (in kW) or contract demand (in kVA converted to kW using a power factor of 0.9).	1) Under gross metering arrangements, the minimum capacity shall be 50 kWp for a single eligible consumer 2)The maximum capacity of the Rooftop SPV system is subject to the sanctioned load/contract demand. i)**Non-Domestic Consumers:** The maximum capacity of the Rooftop SPV system (inverter capacity on the AC side) cannot exceed 70% of the sanctioned load (in kW) or contract demand (in kVA converted to kW using a power factor of 0.9). ii)**Domestic Consumers:** The maximum capacity of the Rooftop SPV system cannot exceed the sanctioned load (in kW) or contract demand (in kVA converted to kW using a power factor of 0.9).				
		Applicable Charges		i) Regardless of availability of excess electricity with the prosumer during any billing period, the prosumer will continue to pay all other charges such as fixed/demand charges, Government levy, etc						
		Banking		Under the time-of-day tariff system: i)Electricity consumption during any time block (e.g., peak or off-peak hours) is first offset by electricity generation during that same block. ii)If generation exceeds consumption in any block, the excess is credited to the next lower tariff block. iii)This process continues until all lower tariff block consumption is set off. iii) Any remaining excess generation after setting off all consumption is carried forward to the next billing cycle. iv) Offsetting in higher tariff zone not allowed. The same procedure is followed in subsequent billing cycles.						
		Settlement Period		1) The standard settlement period runs from **October 1st to September 30th** of the following year. 2) For seasonal industries—excluding cotton ginning, pressing and baling plants, rice shellers, rice bran stabilization units (without T.G. sets), and kinnow grading & waxing centres—the settlement period begins on **April 1st and ends on March 31st**, as defined under the General Conditions of Tariff.	1) The standard settlement period runs from **October 1st to September 30th** of the following year. 2) For seasonal industries—excluding cotton ginning, pressing and baling plants, rice shellers, rice bran stabilization units (without T.G. sets), and kinnow grading & waxing centres—the settlement period begins on **April 1st and ends on March 31st**, as defined under the General Conditions of Tariff.	1) Settlement period same as billing period. Billing period is monthly.	NA			
		Settlement Rate		1) The electricity generated from a rooftop solar system shall not exceed 90% of the consumer's total electricity consumption during a settlement period. If generation exceeds 90%, the excess will not be paid for by the distribution licensee, cannot be carried forward to the next settlement period, and will be treated as inadvertent injection.	1) Feed-in-tariff of Rs.2.65/kWh for FY 2023-24 2) In case (ERE x TRE) is more than {Fixed charges + other applicable charges and levies + (EDL x TRST)}, utility shall give credit of amount equal to difference (Billing Credit), which shall be carried forward to the next billing cycle. 3) Billing credits will be carried forward to the next billing cycle throughout the settlement period. However, any remaining billing credits at the end of the settlement period will not be paid by the distribution licensee.	Feed-in-tariff of Rs.2.65/kWh for FY 2023-24				
		Billing of imported units		1) In case the electricity supplied by the distribution licensee during any billing period exceeds the electricity injected in the grid by the prosumer, the distribution licensee shall raise a bill for the net electricity consumption as per applicable tariff of that category after taking into account any excess electricity carried forward from the previous billing period	Energy Bill Calculation Formula: Energy Bill = Fixed Charges + Other Charges/Levies + (Energy Imported x Retail Supply Tariff) - (Energy Exported x Feed-in Tariff) - Billing Credit (from the last billing cycle). Definitions: Fixed Charges: Fixed or demand charges applicable as per the retail tariff order. Other Charges: Includes taxes like electricity duty, municipal tax, cess, etc. Energy Imported (EDL): Energy imported by the consumer from the grid. Retail Supply Tariff (TRST): Tariff rate for the consumer category as per the retail supply order. Energy Exported (ERE): Energy exported to the grid by the consumer. Feed-in Tariff (TRE): Approved tariff for energy exported to the grid. Billing Credit: The surplus amount when the value of exported solar energy exceeds the total consumer bill.	1) Import units billed at appliacable retail. 2) Export units billed at feed-in-tariff.				
		Ownership model		'Self owned' or 'Third party' owned.	'Self owned' or 'Third party' owned.	'Self owned' or 'Third party' owned.				
		Remarks								

Sl No.	State	Billing Method →		Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
14	Himachal Pradesh	Applicability	Consumer Category	1) Any consumer getting supply of electricity from distribution licensee in its area of supply, who uses or intends to use a rooftop Solar PV system installed in his premises to offset part or all of the consumer's own electrical requirements.	1) Any consumer getting supply of electricity from distribution licensee in its area of supply, who uses or intends to use a rooftop Solar PV system installed in his premises to offset part or all of the consumer's own electrical requirements.	NA	1) Any consumer getting supply of electricity from distribution licensee in its area of supply, who uses or intends to use a rooftop Solar PV system installed in his premises to offset part or all of the consumer's own electrical requirements.		NA	
			Load/Capacity limit	1) For consumers with a sanctioned load of 10 kW or less, the maximum capacity for rooftop solar systems is 10 kW as per regulations. 2) For consumers with a sanctioned load exceeding 10 kW, the maximum rooftop solar capacity is 50% of the sanctioned load or 10 kW, whichever is higher. 3)Rooftop solar systems with a capacity of up to 50 kWp may be installed under this arrangement. 4)Maximum Peak Capacity Based on Supply Voltage i) LT (1Ø) (Single-phase supply): Maximum solar PV system capacity: 10 kWp. ii) LT (3 Ø) (Three-phase supply): Maximum solar PV system capacity: 20 kWp. iii) 11 kV or higher voltage level: Maximum solar PV system capacity: 1 MWp.	1) The rooftop solar system with capacity of more than 50 kWp, but not exceeding 1.00 MWp, may be installed under this arrangement.		1) The maximum capacity of the rooftop solar system under this arrangement will be the sum of the eligibility of each participating consumer. 2) The total installed capacity must not exceed the maximum limit allowed for the relevant voltage level. 3) Rooftop solar systems with capacities between 20 kWp and 1 MWp can be installed under this arrangement.			
		Applicable Charges								
		Banking		Eligible Consumer with Time of Day (ToD) Tariff: i) Electricity flows are recorded separately for each time period of the day over the billing period. ii) Energy accounting is done separately for each time period. iii) Net flows or electricity credits for one time period cannot be adjusted against another time period, even when settling unadjusted credits.			1) The energy allocated to the accounts of the participating consumers will be calculated after deducting 9% from the total energy received during the billing period. 2) The remaining energy will be credited to the participating consumers' accounts based on the respective percentages outlined in their agreement.			
		Settlement Period		Maximum 12 consecutive billing months starting from **16th March** of the financial year, for the operational rooftop solar system under the applicable arrangement.	Maximum 12 consecutive billing months starting from **16th March** of the financial year, for the operational rooftop solar system under the applicable arrangement.		Maximum 12 consecutive billing months starting from **16th March** of the financial year, for the operational rooftop solar system under the applicable arrangement.			
		Settlement Rate		1. For consumers approved or who opt for solar metering arrangements on or after 01-09-2022 for both net-metering and net-billing: a) If subsidy/grant/incentive is less than 50% of capital cost: 40% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.402/kWh b) If subsidy/grant/incentive is 50% or more but less than 70% of capital cost: 30% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.051/kWh c) If subsidy/grant/incentive is 70% or more but less than 90% of capital cost: 25% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.876/kWh d) If subsidy/grant/incentive is 90% or more of capital cost: 15% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.526/kWh			1. For consumers approved or who opt for solar metering arrangements on or after 01-09-2022 for gross metering: a) If subsidy/grant/incentive is less than 50% of capital cost: 40% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.402/kWh b) If subsidy/grant/incentive is 50% or more but less than 70% of capital cost: 30% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹1.051/kWh c) If subsidy/grant/incentive is 70% or more but less than 90% of capital cost: 25% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.876/kWh d) If subsidy/grant/incentive is 90% or more of capital cost: 15% of weighted average rate (₹3.504/kWh) for settlement Applicable rate: ₹0.526/kWh			
		Billing of imported units		1)The energy credited to a participating consumer's account will be offset against their consumption for the billing period, and the consumer will be billed at the applicable retail tariff based on their net consumption after the offset.			1)The energy credited to a participating consumer's account will be offset against their consumption for the billing period, and the consumer will be billed at the applicable retail tariff based on their net consumption after the offset.			
		Ownership model								
		Remarks								

Sl No.	State ↓ / Billing Method →		Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
15	Tripura	Applicability – Consumer Category	1)consumers intending to install grid-interactive SRTPVS within its supply area on a non-discriminatory, first-come, first-served basis. 2)All registered companies, government entities, semi-government bodies, educational institutes, partnerships, firms, and individuals who are consumers of Tripura Discom(s)	NA	1)consumers intending to install grid-interactive SRTPVS within its supply area on a non-discriminatory, first-come, first-served basis. 2)All registered companies, government entities, semi-government bodies, educational institutes, partnerships, firms, and individuals who are consumers of Tripura Discom(s)	1)consumers intending to install grid-interactive SRTPVS within its supply area on a non-discriminatory, first-come, first-served basis. 2)All registered companies, government entities, semi-government bodies, educational institutes, partnerships, firms, and individuals who are consumers of Tripura Discom(s)		NA	
		Applicability – Load/Capacity limit	**Individual Net Metering:** •Minimum capacity: 1 kWp •Maximum capacity: 10 kWp or the contracted load/contract demand of the consumer, whichever is lower.		• Minimum capacity: 10 kWp • Maximum capacity: 500 kWp or the contracted load/contract demand of the consumer, whichever is higher.	• Minimum capacity: 5 kWp • Maximum capacity: 500 kWp or or the contracted load/contract demand of the consumer, whichever is lower. **Net Metering of Multiple Points of an Individual:** • Minimum capacity: 5 kWp • Maximum capacity: 500 kWp or or the contracted load/contract demand of the consumer, whichever is lower.			
		Applicable Charges							
		Banking	Banking applicable						
		Settlement Period	1) For the case of domestic consumers, settlement happens quarterly only when injected electricity exceeds consumption by more than 100 units. If net energy credits is under 100 units, it will be carried over to next billing period. 2) For non-domestic consumers, settlement period is monthly basis.		Monthly basis	Monthly basis			
		Settlement Rate	1) If energy export exceeds consumption, the DISCOM will pay for the excess monthly at the Feed-in Tariff. 2)For domestic consumers, if injected electricity exceeds consumption by more than 100 units, the DISCOM will pay quarterly, capped at 3.8 units per kW of installed capacity per day. 3) Net energy credits under 100 units will carry over to the next billing period. 4) For non-domestic consumers, the 3.8 units per kW cap per day also applies, and any surplus at the end of the billing period will lapse without payment. 5) The feed-in tariff will be 35% of the average cost of supply of the financial year as determined by the commission for SRTPVS commissioned under net metering.		1) For gross metering in LT supply, the feed-in tariff will be 35% of the average cost of supply for SRTPVS systems. 2) For gross metering in HT supply (up to 1500 kWp capacity), the feed-in tariff will be 50% of the average cost of supply for SRTPVS systems. 3) For gross metering in HT/EHT supply (1501 kWp to 5000 kWp), the feed-in tariff will be 50% of the average cost of supply for SRTPVS systems. 4) For gross metering in HT/EHT supply with battery storage, the feed-in tariff will be 80% of the average cost of supply if power is supplied during the evening peak (18:00 to 22:00) as				
		Billing of imported units	1) If energy consumption exceeds export in a billing month, prosumers will pay for the net energy at the applicable tariff.		1) units of consumption will be computed at applicable retail tariff and units of generation will be computed at feed-in tariff.				
		Ownership model							
		Remarks							

Sl No.	State ↓ / Billing Method →		Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
16	Karnataka	Applicability (Eligibility): Consumer Category	Residential, Agricultural & small scale Industrial and Commercial	NIL	Large Scale Industrial and Commercial, Captive RE Producers or Open Access consumers	NIL	NIL	NIL	**Participant**:A prosumer(sell) or consumer(buy) registered with the Distribution Licensee and Service Provider to trade rooftop solar energy on a P2P platform.
		Applicability (Eligibility): Load or Capacity limit	Upto 5 kW (230 V- 1 phase),Above 5 kW and upto 150 KW (LT level, 400 V- 3 phase),Above 150 kW and upto 2000kW (11kV HT). **Plant capacity**:1 kW to 500kW or upto Sanctioned load (whichever is lower)		Above 500kW or upto santioned load whichever is lower				Participants with net or gross metering provided a ToD-compliant energy meter or smart meter is installed at their premises who choose to trade energy with each other via an online P2P platform through blockchain mechanism.
		Applicable Charges	minimal utility charges for agricultural prosumers Fixed or demand charges based on consumer's tariff category		Fixed or demand charges based on consumer's tariff category				Green Energy Open Access charges if participants are not under same substation and DT, Transaction charges through p2p platform
		Banking	monthly		NIL				Cumulative P2P capacity ≥ 100 MW, the distribution licensee will require prosumers/consumers to submit schedules: **Day-Ahead**:Submit the next day's P2P energy schedule by 17:00 on the previous day, with no changes allowed afterward. **Intraday**:Submit the P2P energy schedule at least four-time blocks before it starts, with no changes allowed after submission.
		Settlement Period	Annual Settlement at PPA rate at the end of FY		Monthly				
		Settlement Rate	feed in tariff (generic tariff) of ₹3.82/kWh for residential systems between 1 kW and 10 kW, and ₹2.84/kWh for projects between 1 kW and 2 MW (large-scale).		HT: PPA or Optional ToD tariff. Real-time Settlement for Captive RE producers based on production and consumption Megawatt-scale Solar Projects: Rs. 3.04 per unit. Megawatt-scale Solar with BESS: Rs. 5.66 per unit. Solar Rooftop (1 kW up to sanctioned load, excluding domestic 1 kW - 10 kW): Rs. 3.20 per unit, without subsidy.				
		Billing of imported units	Retail Tariff		Tariff agreed to in the PPA,or Prevailing retail supply tariff whichever is higher deducted from export payments.				
		Ownership model	self-owned systems or third-party models		self-owned systems				
		Remarks	APPC rate : Rs.4.93 per unit the ESCOMs shall bill the RE generators selling to them under REC mechanism at lower of Rs.4.93/unit or 75% of the Generic tariff determined for FY25 by the Commission, for the respective RE source, which is subject to truing up of APPC for FY25. APPC of Rs.4.25 per unit for the financial year 2023-24		SRTPV consumers with a captive plant or wheeling agreement will lose Net Metering PPA. ESCOM pays interest if payment is delayed beyond 30 days.				If no excess energy is available in the P2P network, the consumer's needs are met by the distribution licensee. If no buyer is found, the energy is sold back to the licensee at the fixed PPA price.

State ↓ / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
Andhra Pradesh	Applicability (Eligibility)	Consumer Category	Domestic, institutional, commercial, agricultural consumers with RTS	Domestic & commercial consumers with larger capacities.	Large-scale solar projects and institutional installations EHT consumers	Multiple domestic, commercial, and institutional consumers sharing a single solar installation.	Participants in community solar projects or shared solar initiatives receiving virtual credits.	NIL	NIL
		Load/ Capacity limit	1kW - 500kW Single Phase :LT, 240V (upto to 3kWp plant capacity) Three Phase: LT, 415V (3kWp to 75kWp),HT, 11kV (76kWp to 1500kWp), HT, 33kV (1501kWp to 5000kWp), EHT, 132 kV and Above (5000kWp)	1kW - 1 MW(or Contract demand whichever is lesser) Single Phase :LT, 240V (upto to 3kWp plant capacity) Three Phase: LT, 415V (3kWp to 75kWp),HT, 11kV (76kWp to 1500kWp), HT, 33kV (1501kWp to 5000kWp), EHT, 132 kV and Above (5000kWp)	1kW - 5MW (or Contract demand whichever is lesser) Single Phase :LT, 240V (upto to 3kWp plant capacity) Three Phase: LT, 415V (3kWp to 75kWp),HT, 11kV (76kWp to 1500kWp), HT, 33kV (1501kWp to 5000kWp), EHT, 132 kV and Above (5000kWp)	5kW - 500kW Single Phase :LT, 240V (upto to 3kWp plant capacity) Three Phase: LT, 415V (3kWp to 75kWp),HT, 11kV (76kWp to 1500kWp), HT, 33kV (1501kWp to 5000kWp), EHT, 132 kV and Above (5000kWp)	5kW - 500kW Single Phase :LT, 240V (upto to 3kWp plant capacity) Three Phase: LT, 415V (3kWp to 75kWp),HT, 11kV (76kWp to 1500kWp), HT, 33kV (1501kWp to 5000kWp), EHT, 132 kV and Above (5000kWp)		
	Applicable Charges		min energy charge (net consumption < threshold), Grid support charges and T&D losses & charges as per MYT orders from injection to drawal point.	Grid support charges	Grid support charges and T&D losses & charges as per MYT orders from injection to drawal point.	Grid support charges and T&D losses & charges as per MYT orders from injection to drawal point are deducted after adjusting generation against consumption	Grid support charges and T&D losses & charges as per MYT orders from injection to drawal point are deducted after adjusting generation against consumption		
	Banking		Monthly banking to offset future consumption during billing cycle but limits on the duration and amount of banked energy that can be carried forward, often on an annual basis.	NIL	NIL	Monthly banking to offset future consumption during billing cycle but limits on the duration and amount of banked energy that can be carried forward, often on an annual basis.	Monthly banking to offset future consumption during billing cycle but limits on the duration and amount of banked energy that can be carried forward, often on an annual basis.		
	Settlement Period		Annual	Monthly		Annual			
	Settlement Rate		Rs . 2.09/unit	Rs . 2.09/unit	Feed in Tariff Rs. 3.13/unit (LT), Rs. 2.92/unit (HT of max 1.5MW plant capacity), Rs. 2.71/unit during off peak hours and Rs. 4.17/unit during peak hours (HT/EHT of max 5MW				
	Billing of imported units		Retail tariff (Rs. 6.7) as per PPA (net energy* 6.7)	Retail tariff as per PPA					
	Ownership model		Self-owned or third-party-owned, with on-site consumption offset.	self owned,3rd party or RESCO	Self-owned or RESCO model	Self owned	Community-owned or 3rd party owned		
	Remarks		ToD tariff :off-peak consumption is netted against total export divided by off-peak time blocks in a billing month. Consumer are free to choose billing method for selling power to DISCOM						

Sl No.	State / Billing Method →			Net Metering	Net Billing	Gross Metering	Group Net Metering	Virtual Net Metering	Behind The Meter	Peer to Peer
18	Telangana	Applicability (Eligibility)	Consumer Category	Residential,Industrial, Commercial	NIL	NIL	NIL	NIL	NIL	NIL
			Load/ Capacity limit	Upto 5kW (240V,1 phase), Above 5 kW and upto 75 kW (415 V,3 Phase), Above 75 kW /kVh and upto 1MW (HT- 11kV or 33 kV feeder). **Plant capacity**: Domestic(100% of santioned load) ,industrial & Commercial (80% of santioned load)						
		Applicable Charges		Grid Support Charges = Total Installed Capacity x Rate of GSC (Rs./kW/month) and shall pay Rs.15/kW/month. exempted from Transmission charge,Transmission loss,Wheeling charge,cross subsidy surcharge and additional surcharge						
		Banking		Normal Eligible Consumer is within the ambit of ToD tariff, consumption in any time block, i.e. peak or off- peak hours, etc., shall be first compensated with the quantum of electricity injected in the same time block. Any excess injection over and above the consumption in any other time block in a Billing Cycle shall be accounted as if the excess injection had occurred during off-peak hours.						
		Settlement Period		Twice in a year(June and December)						
		Settlement Rate		APPC rate and shall be either adjusted in next month electricity bill or deposited in the bank account of the Eligible Consumer.						
		Billing of imported units		Retail tariff						
		Ownership model		Self owned or third party						
		Remarks		When an Eligible Consumer cancels the Net metering Agreement entered into with the DISCOM after giving a month's notice, then, unused electricity credits shall be paid at a rate of Rs 0.50/kWh by the DISCOM or at a rate as notified by the Commission from time to time and ceases to be an Eligible Consumer thereafter. The gross net metering at 11 kV and above at an average rate or price from the latest Solar Purchase Agreements into by the Distribution Licensee.						

Annexure C

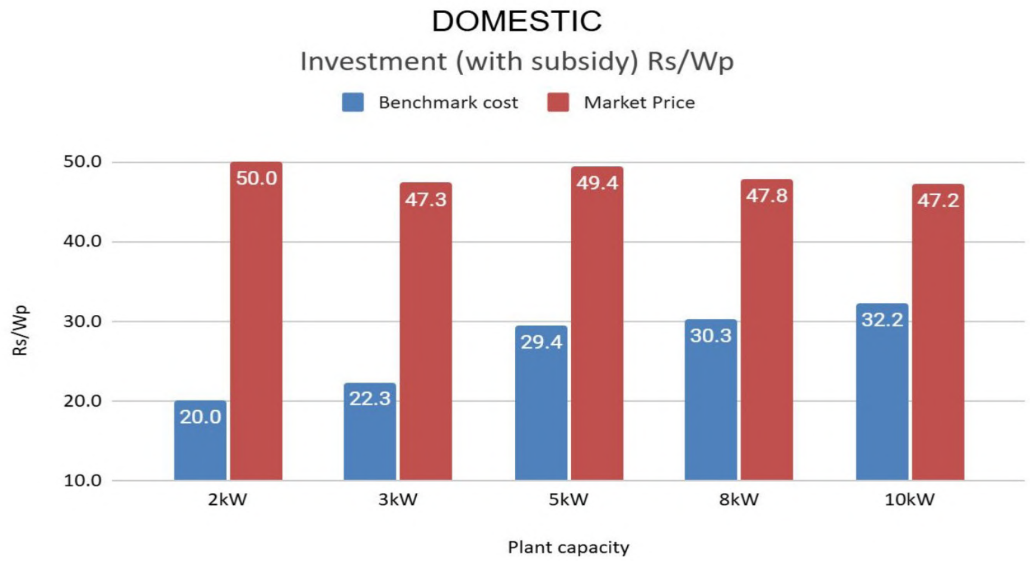
PAYBACK PERIOD ANALYSIS

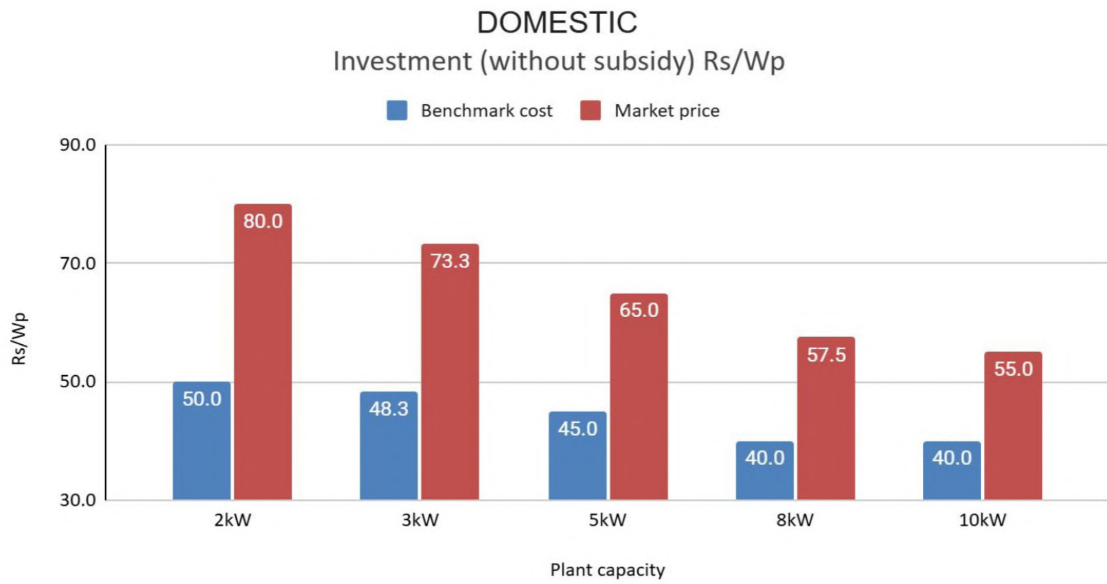
COMPARISON WITH DIFFERENT BILLING SYSTEM FOR DIFFERENT CATEGORIES

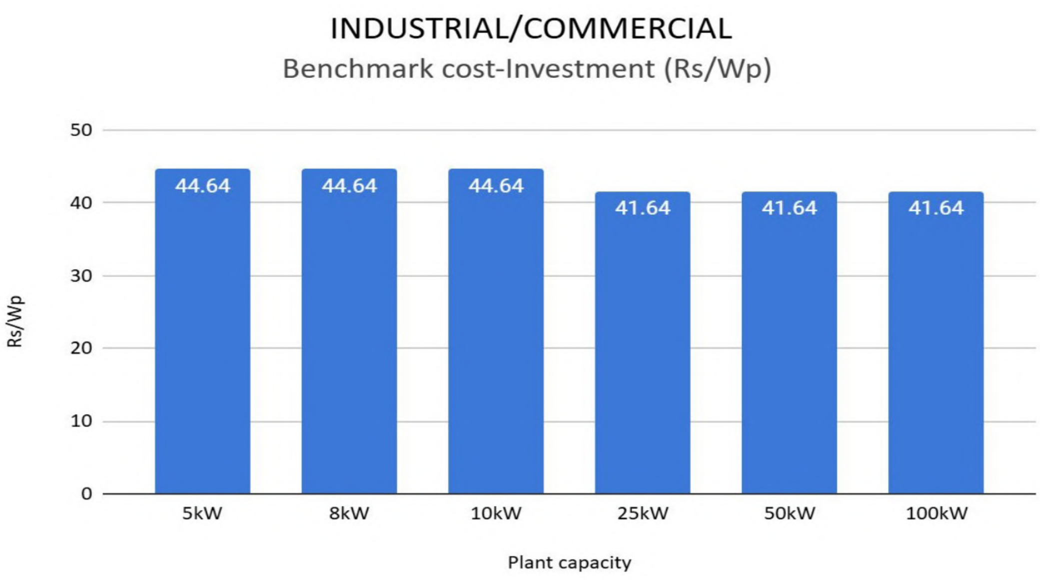
ASSUMPTIONS :

1. Investment - based on benchmark cost and market price
2. Consumption pattern -
   based on Power System Statistics and Tariff order
3. Generation assumed as 4 unit/kW/day

2

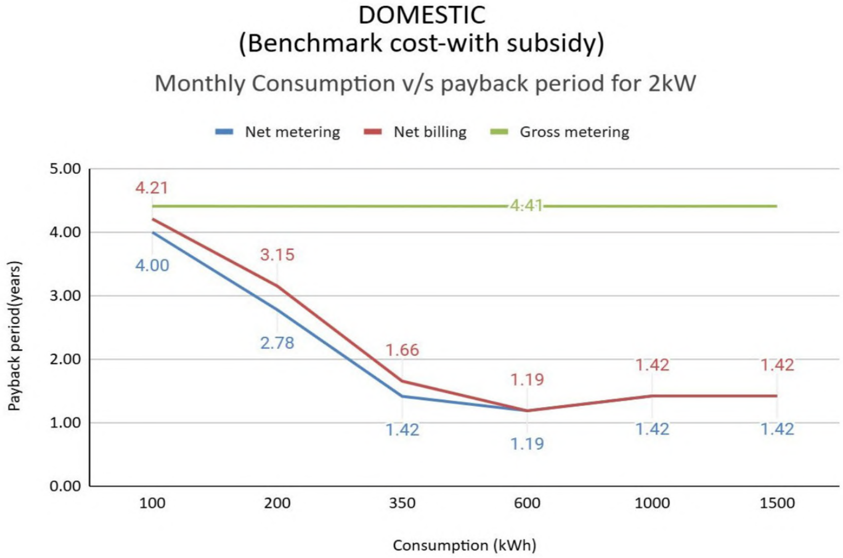

DOMESTIC
Investment (with subsidy) Rs/Wp
Benchmark cost
Market Price
50.0
40.0
30.0
20.0
10.0
Rs/Wp
20.0
50.0
22.3
47.3
29.4
49.4
30.3
47.8
32.2
47.2
2kW
3kW
5kW
8kW
10kW
Plant capacity

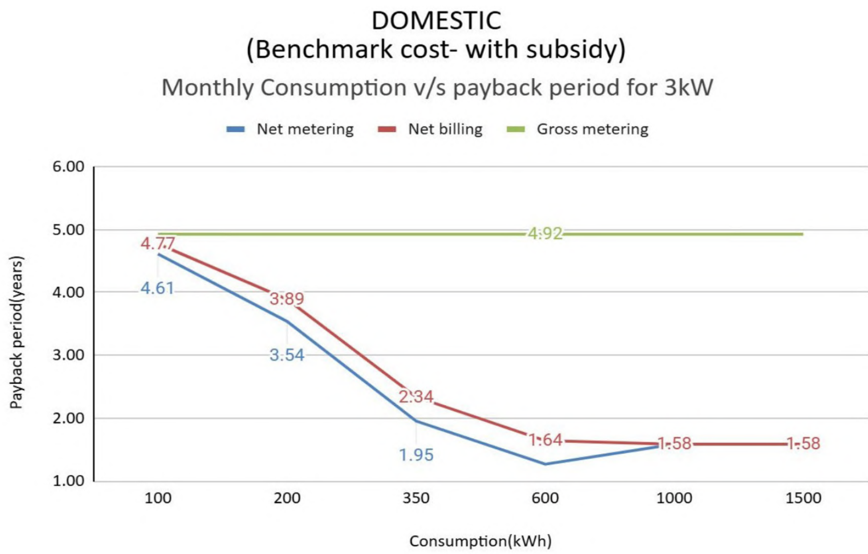

DOMESTIC
Investment (without subsidy) Rs/Wp
Benchmark cost
Market price
90.0
70.0
50.0
30.0
Rs/Wp
50.0
80.0
48.3
73.3
45.0
65.0
40.0
57.5
40.0
55.0
2kW
3kW
5kW
8kW
10kW
Plant capacity

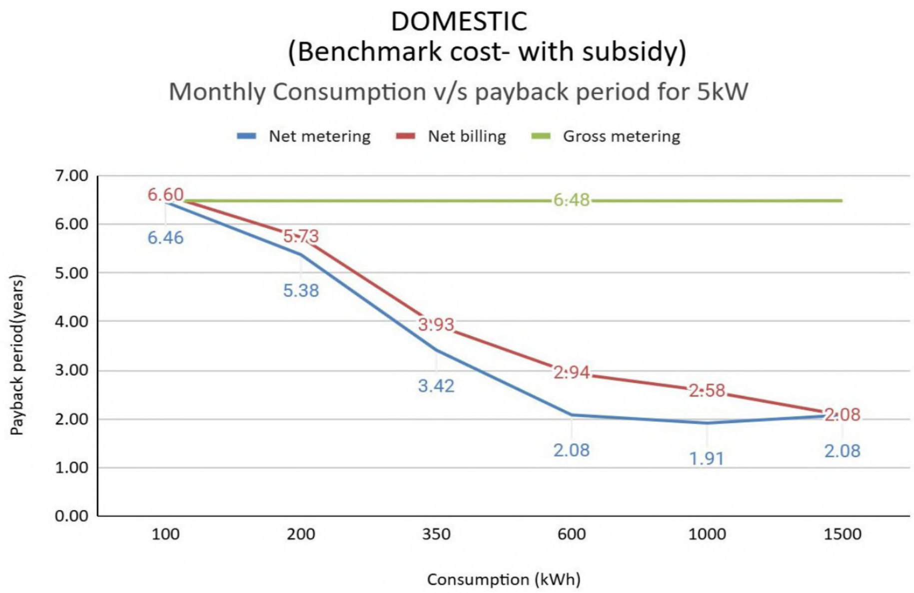

INDUSTRIAL/COMMERCIAL
Benchmark cost-Investment (Rs/Wp)
50
40
30
20
10
0
Rs/Wp
44.64
44.64
44.64
41.64
41.64
41.64
5kW
8kW
10kW
25kW
50kW
100kW
Plant capacity

CONSUMPTION VS PAYBACK PERIOD

NB: Feed in Tariff for Net Metering,Net Billing & Gross Metering is considered as Rs.3.15/unit

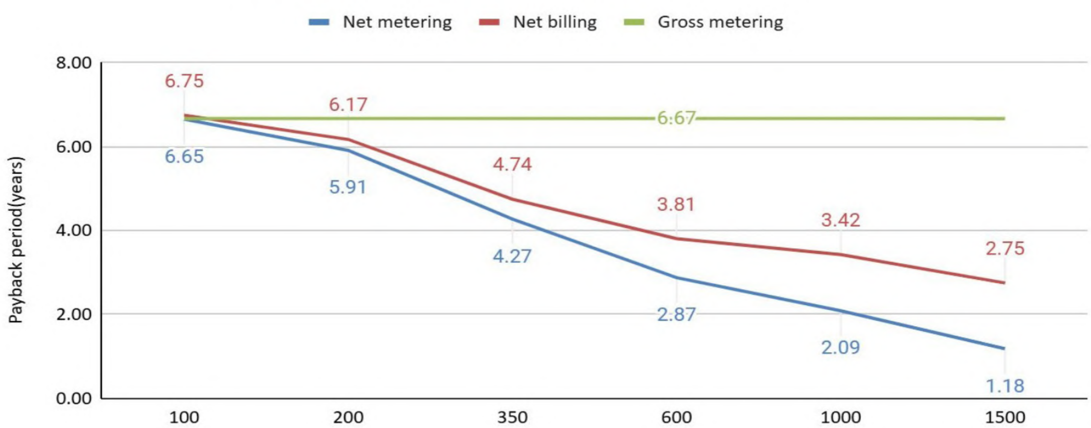

DOMESTIC
(Benchmark cost-with subsidy)
Monthly Consumption v/s payback period for 2kW
Net metering
Net billing
Gross metering
Payback period(years)
5.00
4.00
3.00
2.00
1.00
0.00
4.21
4.41
4.00
3.15
2.78
1.66
1.42
1.19
1.19
1.42
1.42
1.42
1.42
100
200
350
600
1000
1500
Consumption (kWh)


DOMESTIC
(Benchmark cost- with subsidy)
Monthly Consumption v/s payback period for 3kW
Net metering
Net billing
Gross metering
Payback period(years)
6.00
5.00
4.00
3.00
2.00
1.00
4.77
4.92
4.61
3.89
3.54
2.34
1.95
1.64
1.58
1.58
100
200
350
600
1000
1500
Consumption(kWh)


DOMESTIC
(Benchmark cost- with subsidy)
Monthly Consumption v/s payback period for 5kW
Net metering
Net billing
Gross metering
Payback period(years)
7.00
6.00
5.00
4.00
3.00
2.00
1.00
0.00
6.60
6.48
6.46
5.73
5.38
3.93
3.42
2.94
2.58
2.08
2.08
1.91
2.08
100
200
350
600
1000
1500
Consumption (kWh)

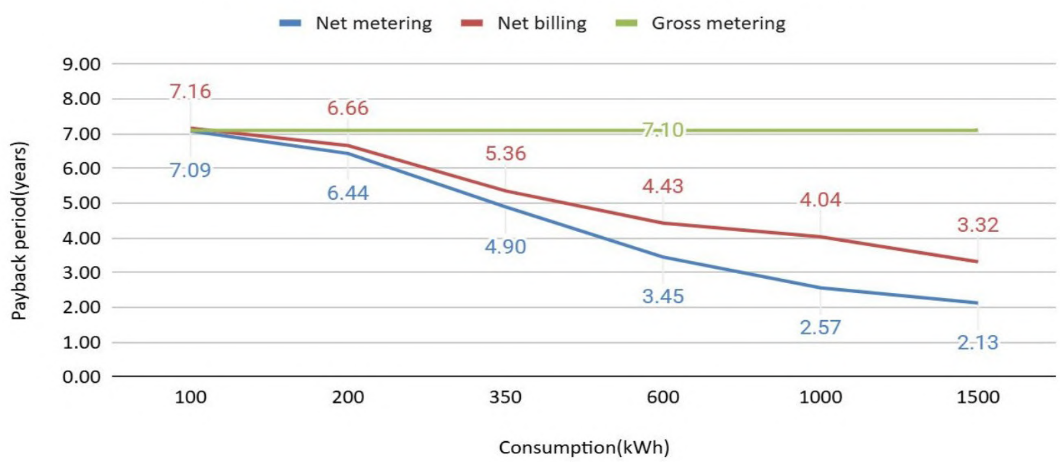
DOMESTIC
(Benchmark cost- with subsidy)

Monthly Consumption v/s payback period for 8kW



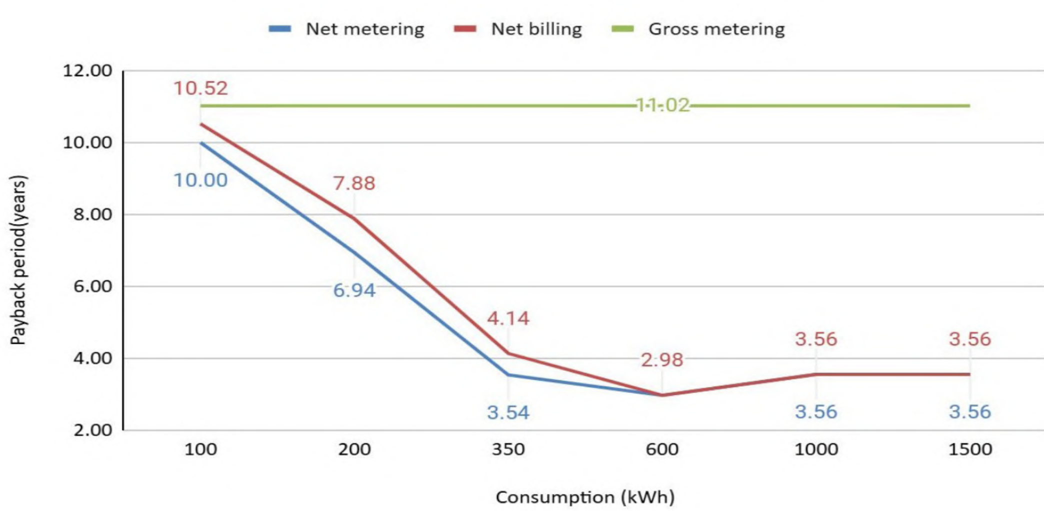
DOMESTIC
(Benchmark cost- with subsidy)

Monthly Consumption v/s payback period for 10kW

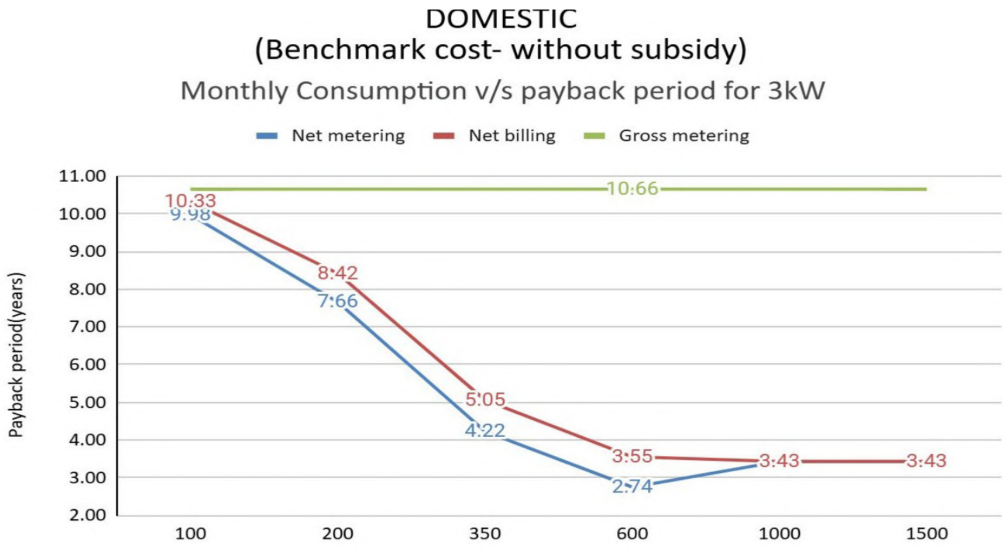


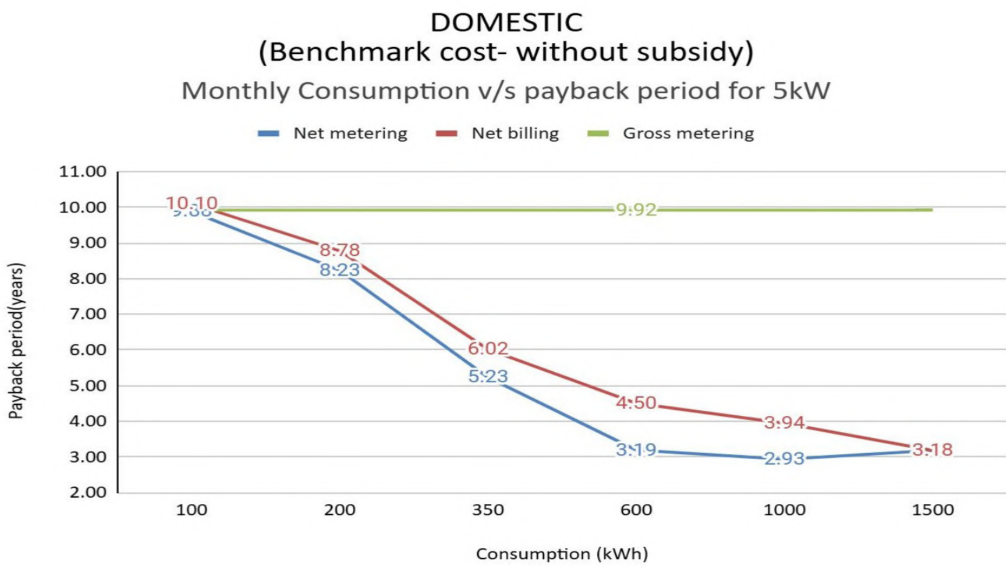
DOMESTIC
(Benchmark cost-without subsidy)

Monthly Consumption v/s payback period for 2kW

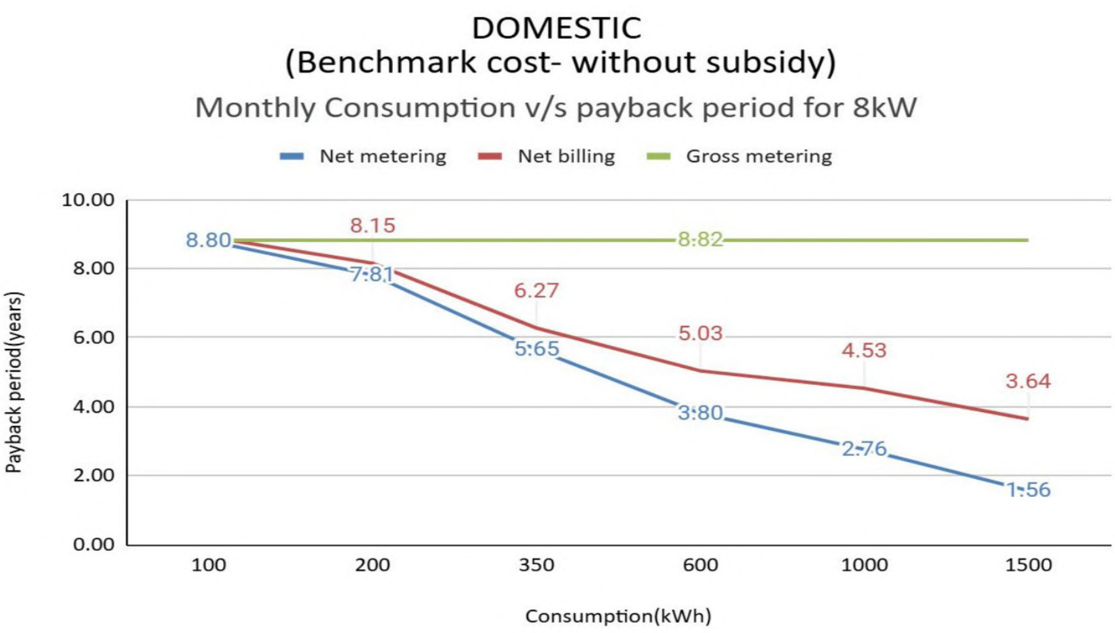


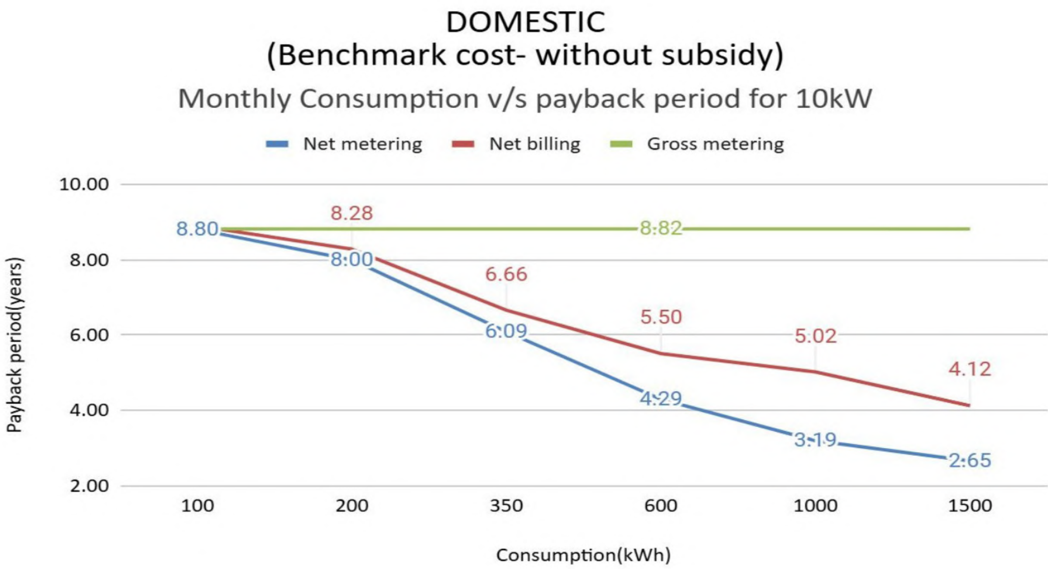
12

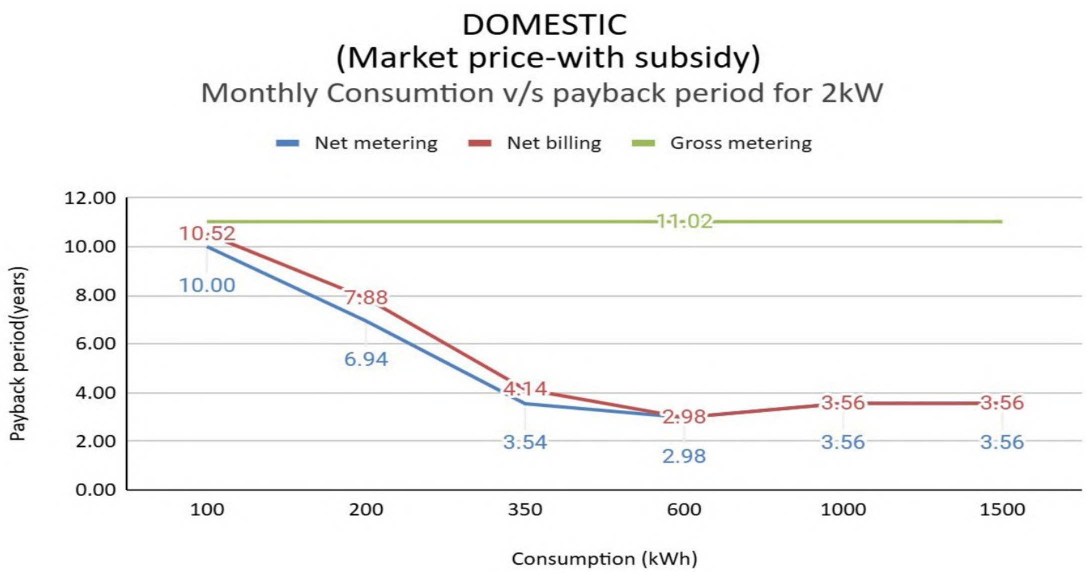

DOMESTIC
(Benchmark cost- without subsidy)
Monthly Consumption v/s payback period for 3kW
Net metering
Net billing
Gross metering
Payback period(years)
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
10.66
10.33
9.98
8.42
7.66
5.05
4.22
3.55
2.74
3.43
3.43
100
200
350
600
1000
1500

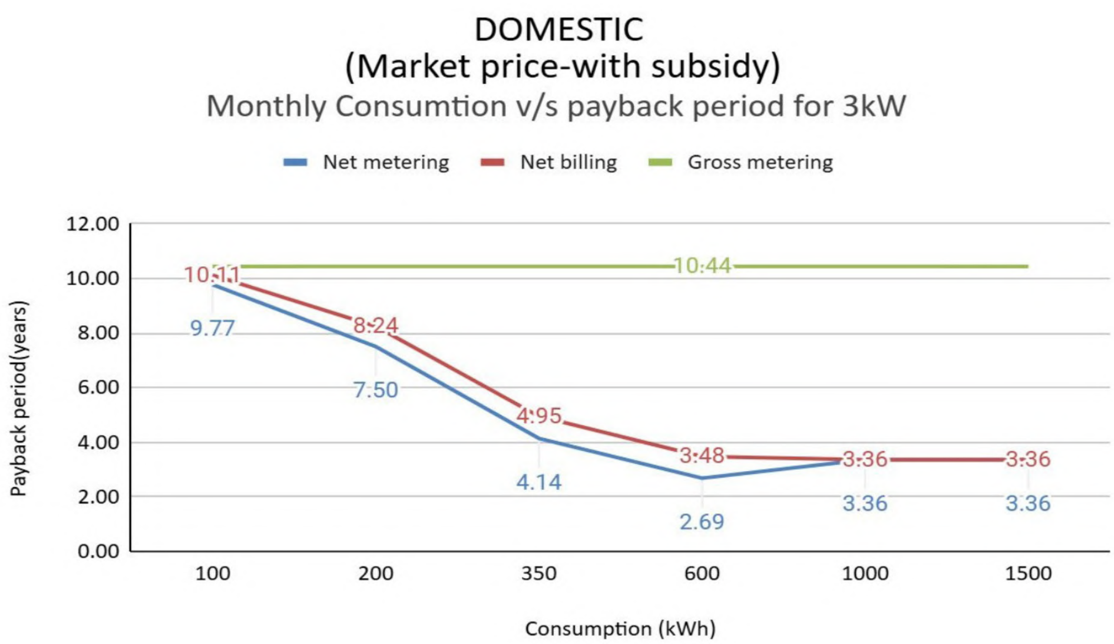

DOMESTIC
(Benchmark cost- without subsidy)
Monthly Consumption v/s payback period for 5kW
Net metering
Net billing
Gross metering
Payback period(years)
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
2.00
10.10
9.92
8.78
8.23
6.02
5.23
4.50
3.94
3.19
2.93
3.18
100
200
350
600
1000
1500
Consumption (kWh)

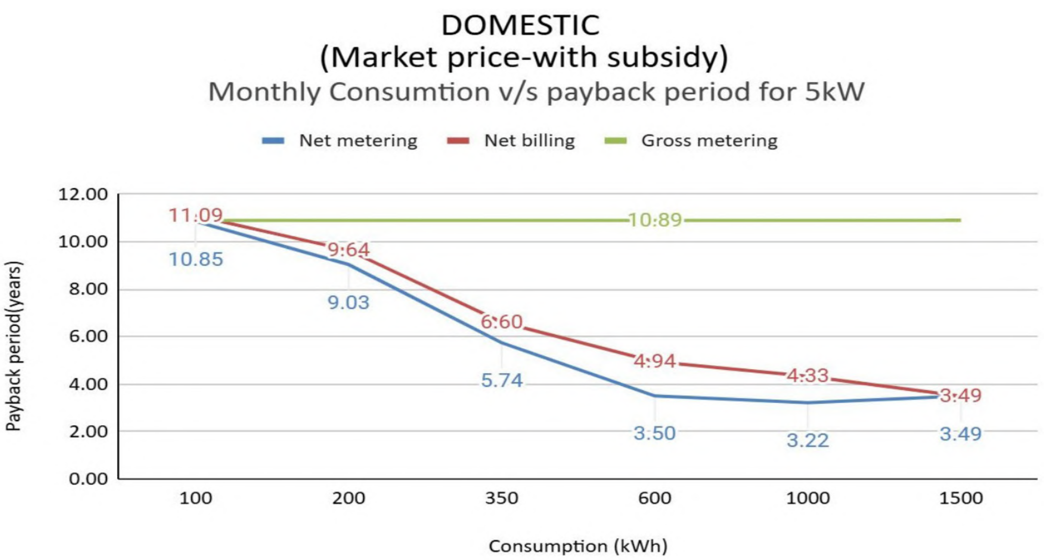
14

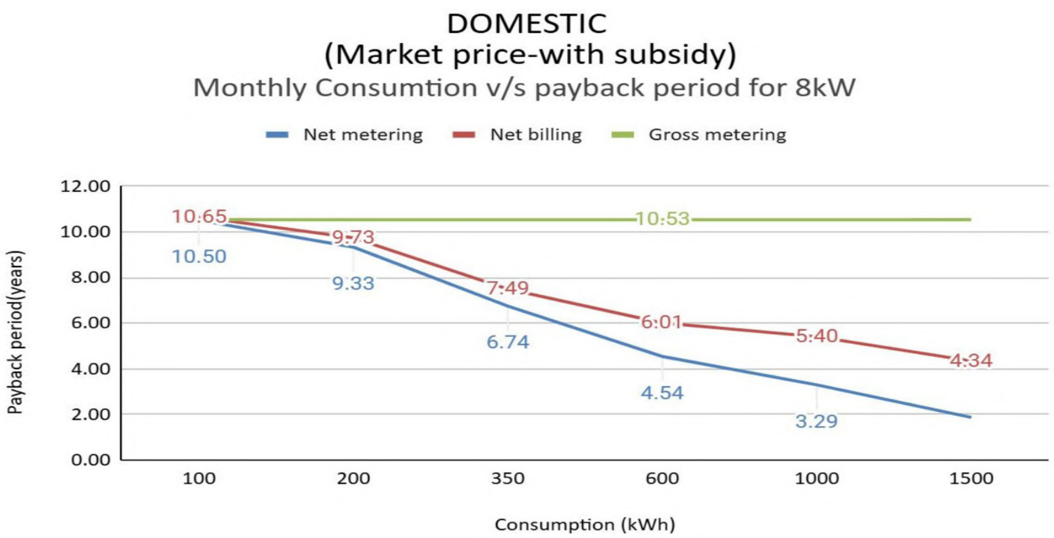

DOMESTIC
(Benchmark cost- without subsidy)
Monthly Consumption v/s payback period for 8kW
Net metering
Net billing
Gross metering
Payback period(years)
10.00
8.00
6.00
4.00
2.00
0.00
8.80
8.15
8.82
7.81
6.27
5.65
5.03
4.53
3.64
3.80
2.76
1.56
100
200
350
600
1000
1500
Consumption(kWh)

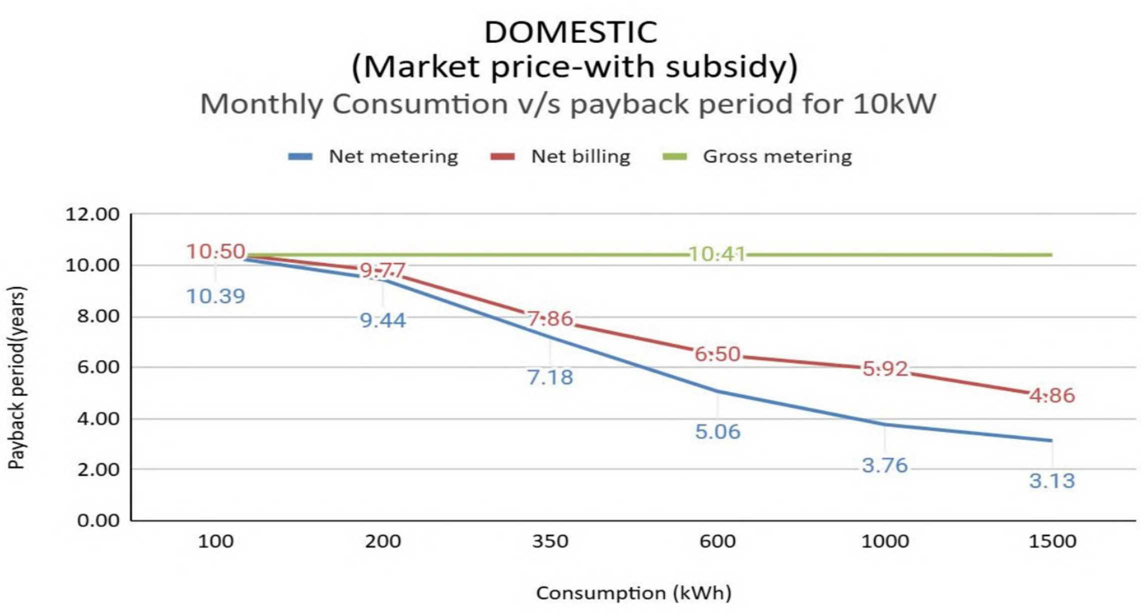

DOMESTIC
(Benchmark cost- without subsidy)
Monthly Consumption v/s payback period for 10kW
Net metering
Net billing
Gross metering
10.00
8.00
6.00
4.00
2.00
Payback period(years)
8.80
8.28
8.82
8.00
6.66
6.09
5.50
5.02
4.12
4.29
3.19
2.65
100
200
350
600
1000
1500
Consumption(kWh)

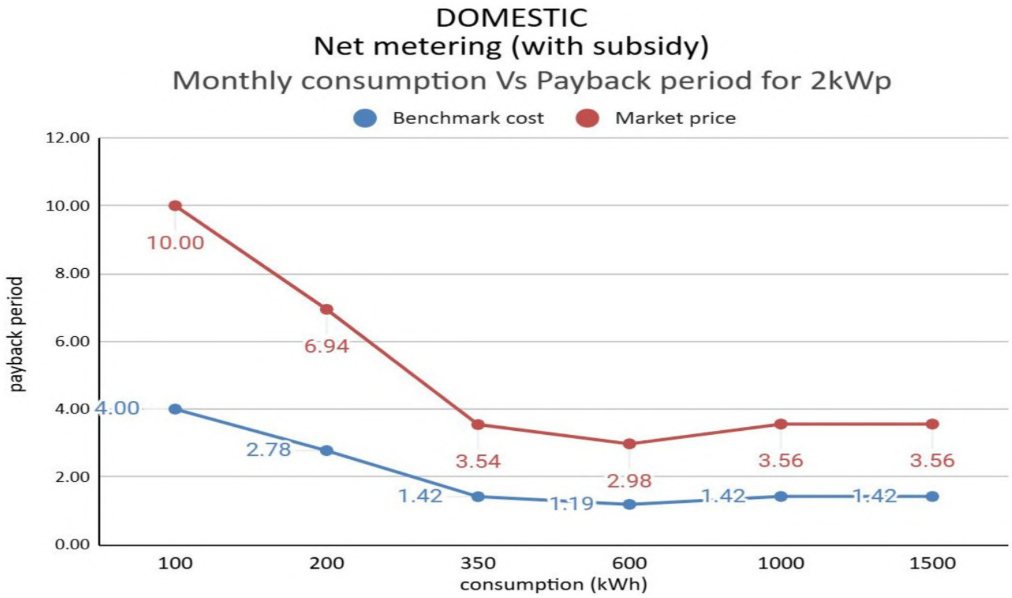

DOMESTIC
(Market price-with subsidy)
Monthly Consumtion v/s payback period for 2kW
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Payback period(years)
11.02
10.52
10.00
7.88
6.94
4.14
2.98
3.56
3.56
3.54
2.98
3.56
3.56
100
200
350
600
1000
1500
Consumption (kWh)


DOMESTIC
(Market price-with subsidy)
Monthly Consumtion v/s payback period for 3kW
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Payback period(years)
10.44
10.11
9.77
8.24
7.50
4.95
4.14
3.48
3.36
3.36
2.69
3.36
3.36
100
200
350
600
1000
1500
Consumption (kWh)

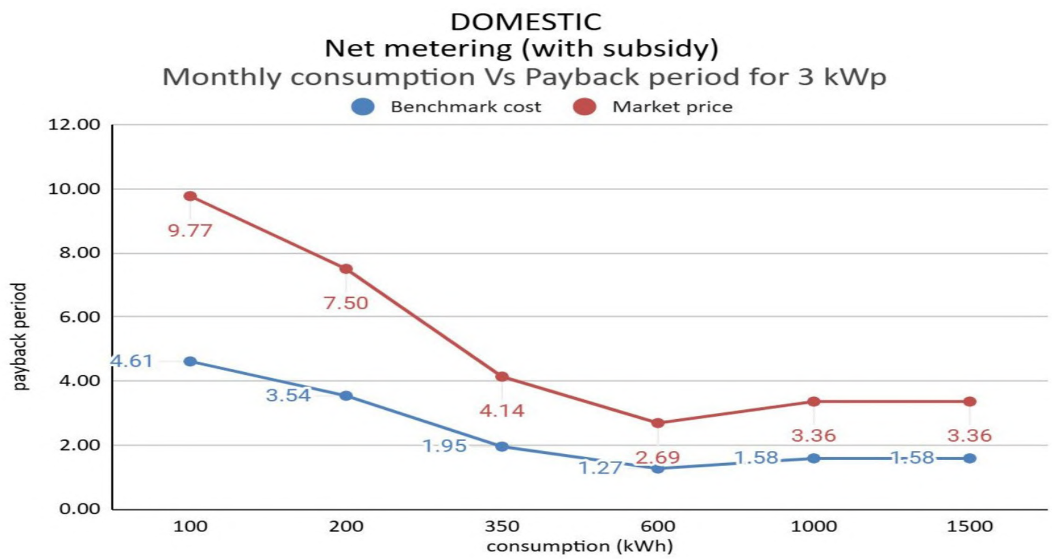

DOMESTIC
(Market price-with subsidy)
Monthly Consumtion v/s payback period for 5kW
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Payback period(years)
11:09
10.85
9:64
9.03
6:60
5.74
4:94
3.50
4:33
3.22
3:49
3.49
10:89
100
200
350
600
1000
1500
Consumption (kWh)


DOMESTIC
(Market price-with subsidy)
Monthly Consumtion v/s payback period for 8kW
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Payback period(years)
10:65
10.50
9:73
9.33
7:49
6.74
6:01
4.54
5:40
3.29
4:34
10:53
100
200
350
600
1000
1500
Consumption (kWh)

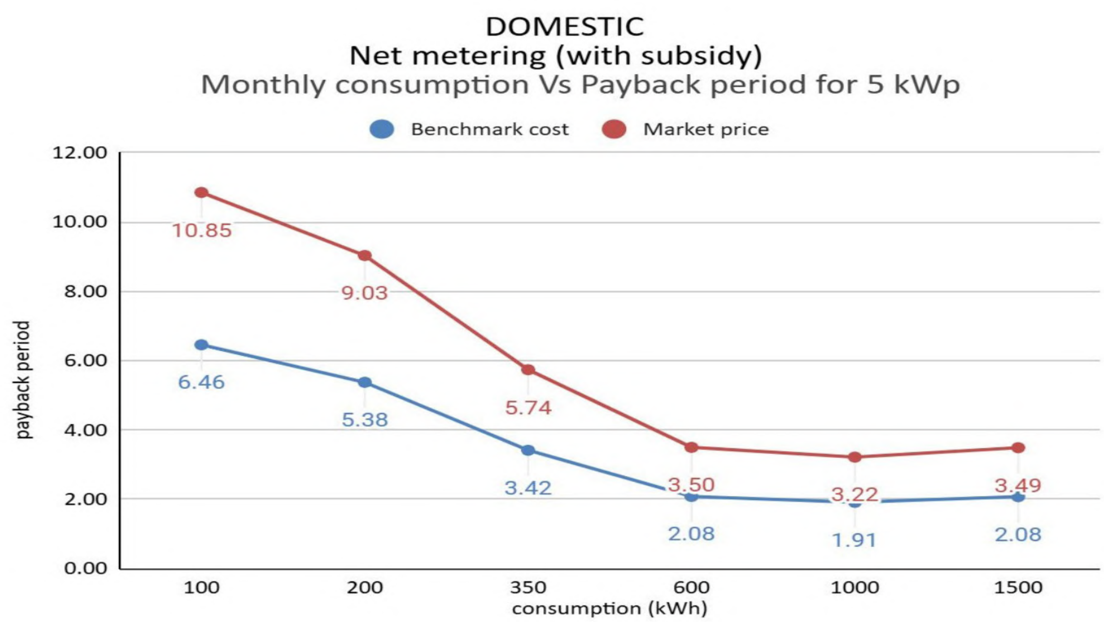

DOMESTIC
(Market price-with subsidy)
Monthly Consumtion v/s payback period for 10kW
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
0.00
Payback period(years)
10:50
10.39
9:77
9.44
7:86
7.18
6:50
5.06
5:92
3.76
4:86
3.13
10:41
100
200
350
600
1000
1500
Consumption (kWh)

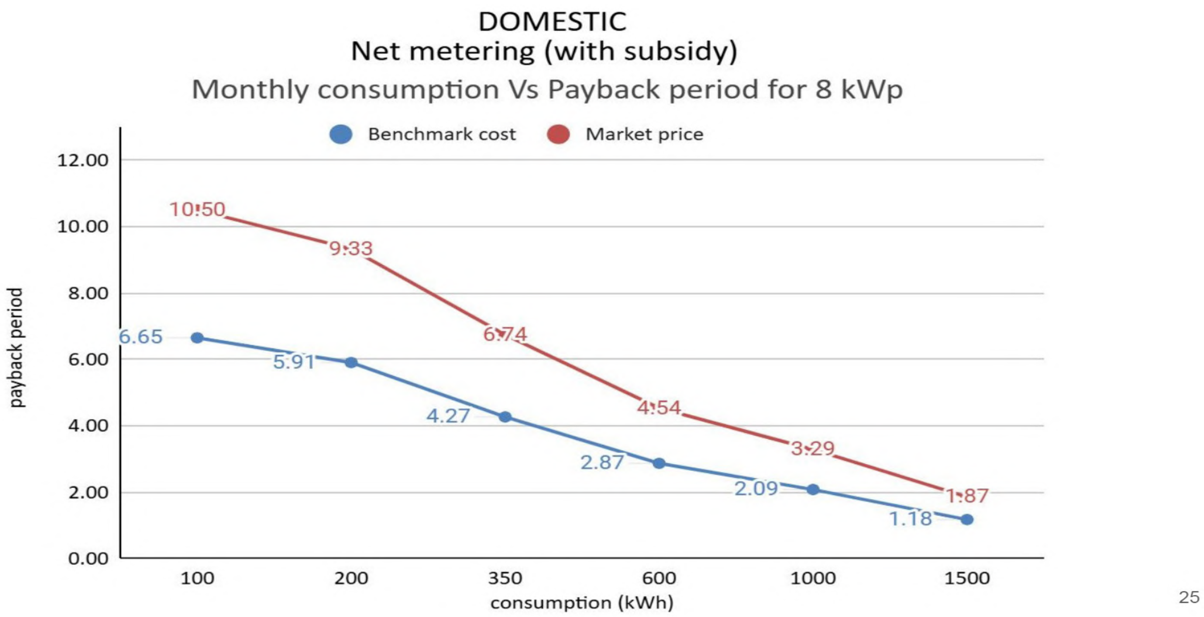

DOMESTIC
Net metering (with subsidy)
Monthly consumption Vs Payback period for 2kWp
Benchmark cost
Market price
payback period
consumption (kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
100
200
350
600
1000
1500
10.00
6.94
3.54
2.98
3.56
3.56
4.00
2.78
1.42
1.19
1.42
1.42

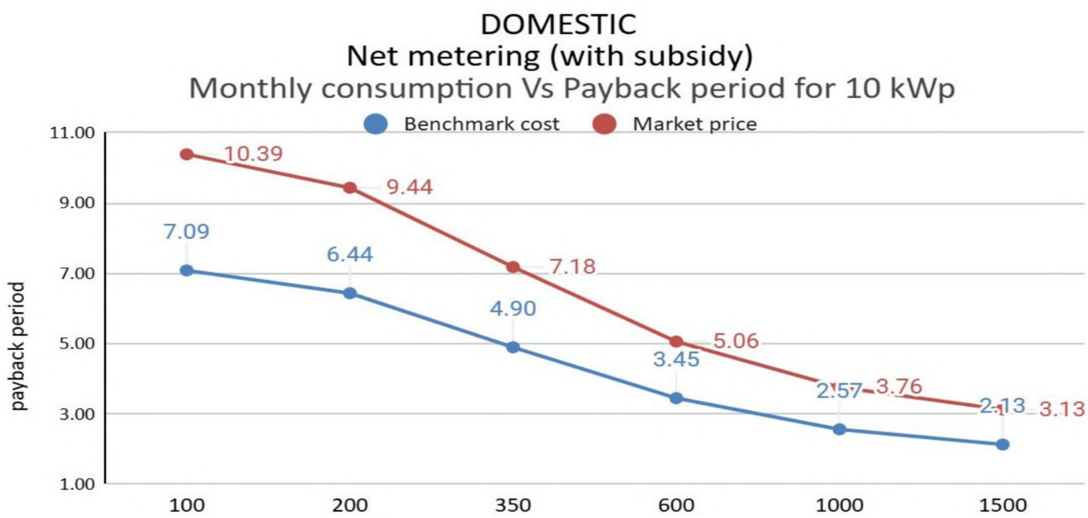
22

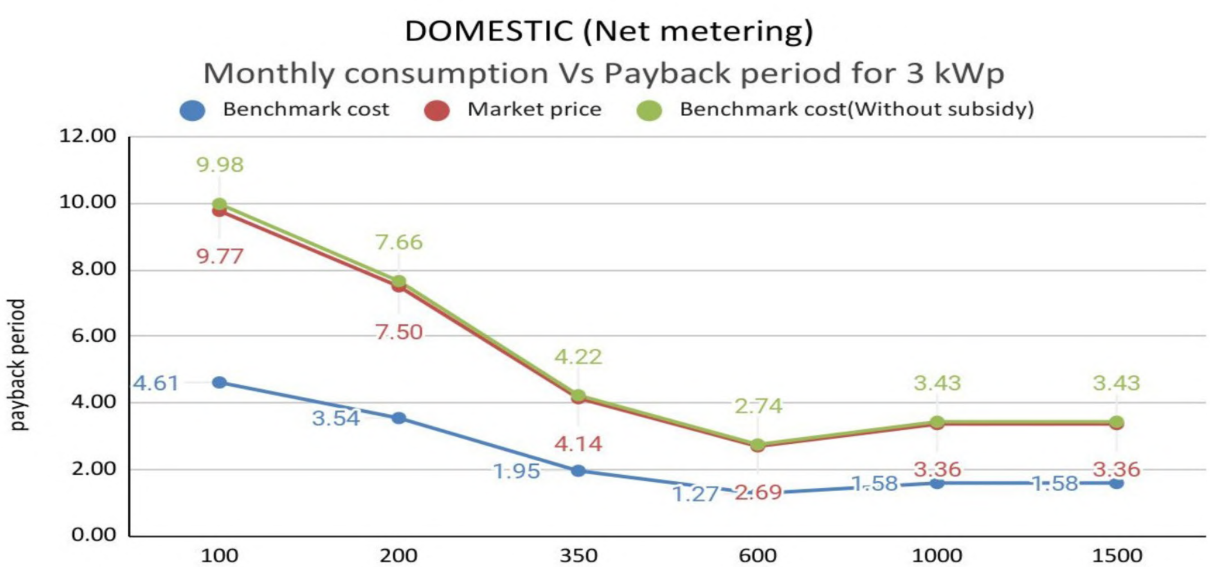

DOMESTIC
Net metering (with subsidy)
Monthly consumption Vs Payback period for 3 kWp
Benchmark cost
Market price
payback period
consumption (kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
100
200
350
600
1000
1500
9.77
7.50
4.14
2.69
3.36
3.36
4.61
3.54
1.95
1.27
1.58
1.58

23


DOMESTIC
Net metering (with subsidy)
Monthly consumption Vs Payback period for 5 kWp
Benchmark cost
Market price
payback period
consumption (kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
100
200
350
600
1000
1500
10.85
9.03
5.74
3.50
3.22
3.49
6.46
5.38
3.42
2.08
1.91
2.08


DOMESTIC
Net metering (with subsidy)
Monthly consumption Vs Payback period for 8 kWp
Benchmark cost
Market price
payback period
consumption (kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
100
200
350
600
1000
1500
10.50
9.33
6.74
4.54
3.29
1.87
6.65
5.91
4.27
2.87
2.09
1.18
25


DOMESTIC
Net metering (with subsidy)
Monthly consumption Vs Payback period for 10 kWp
Benchmark cost
Market price
payback period
11.00
9.00
7.00
5.00
3.00
1.00
100
200
350
600
1000
1500
10.39
9.44
7.18
5.06
3.76
3.13
7.09
6.44
4.90
3.45
2.57
2.13


DOMESTIC (Net metering)
Monthly consumption Vs Payback period for 3 kWp
Benchmark cost
Market price
Benchmark cost(Without subsidy)
payback period
12.00
10.00
8.00
6.00
4.00
2.00
0.00
100
200
350
600
1000
1500
9.98
7.66
4.22
2.74
3.43
3.43
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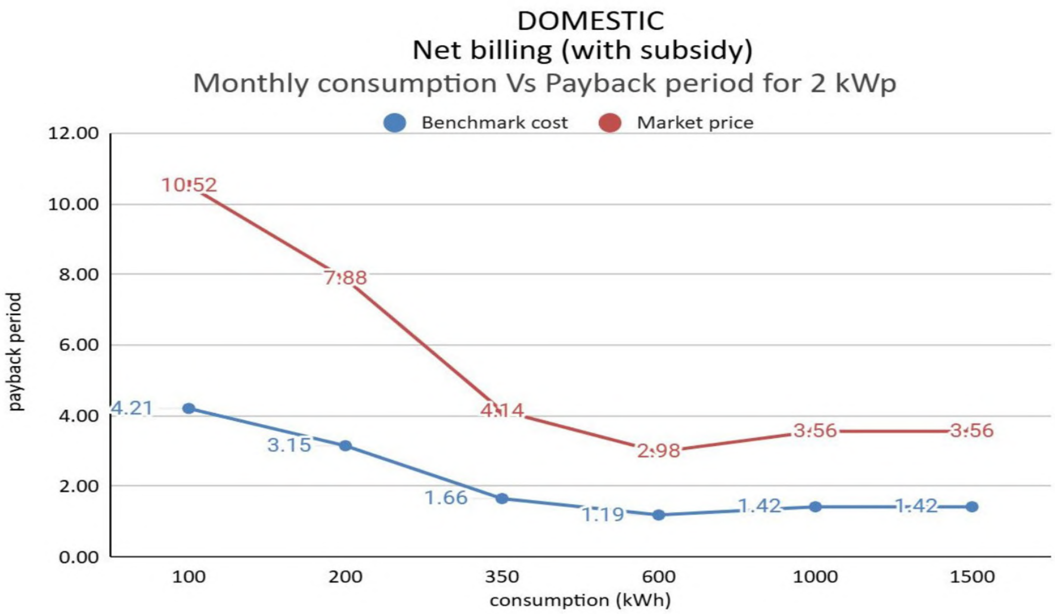
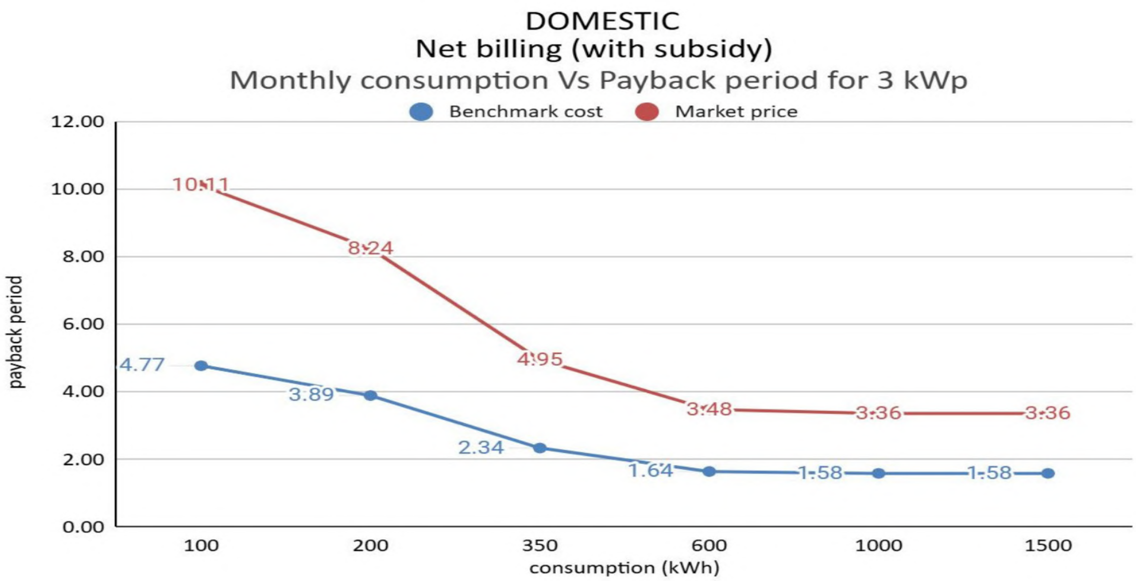
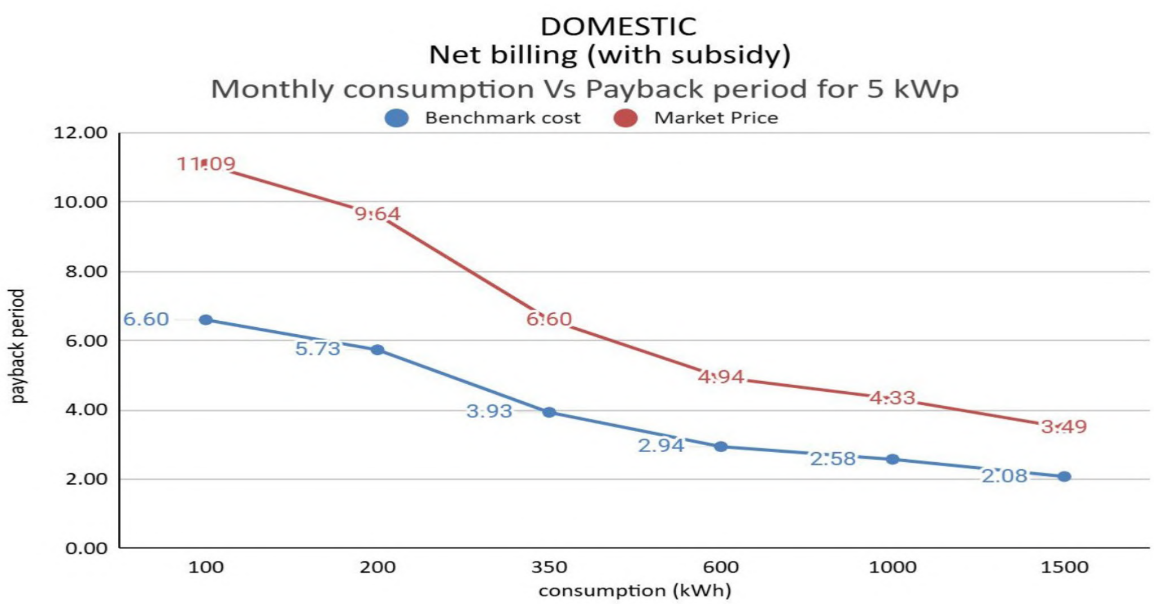
1.27
1.58
1.58

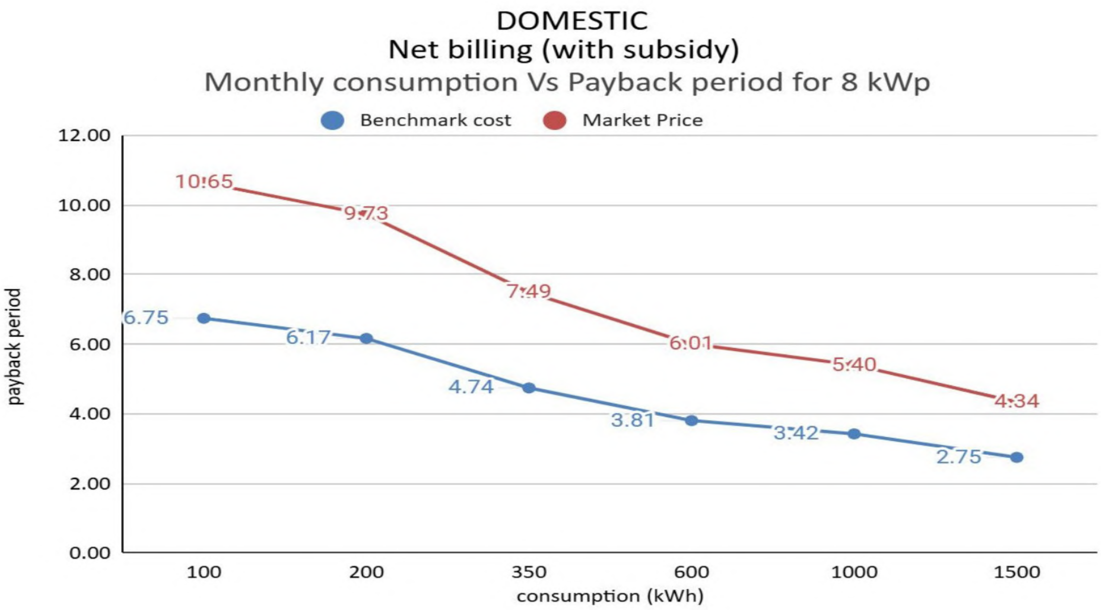

DOMESTIC
Net billing (with subsidy)
Monthly consumption Vs Payback period for 2 kWp
Benchmark cost
Market price
payback period
12.00
10.00
8.00
6.00
4.00
2.00
0.00
10.52
7.88
4.14
2.98
3.56
3.56
4.21
3.15
1.66
1.19
1.42
1.42
100
200
350
600
1000
1500
consumption (kWh)

28

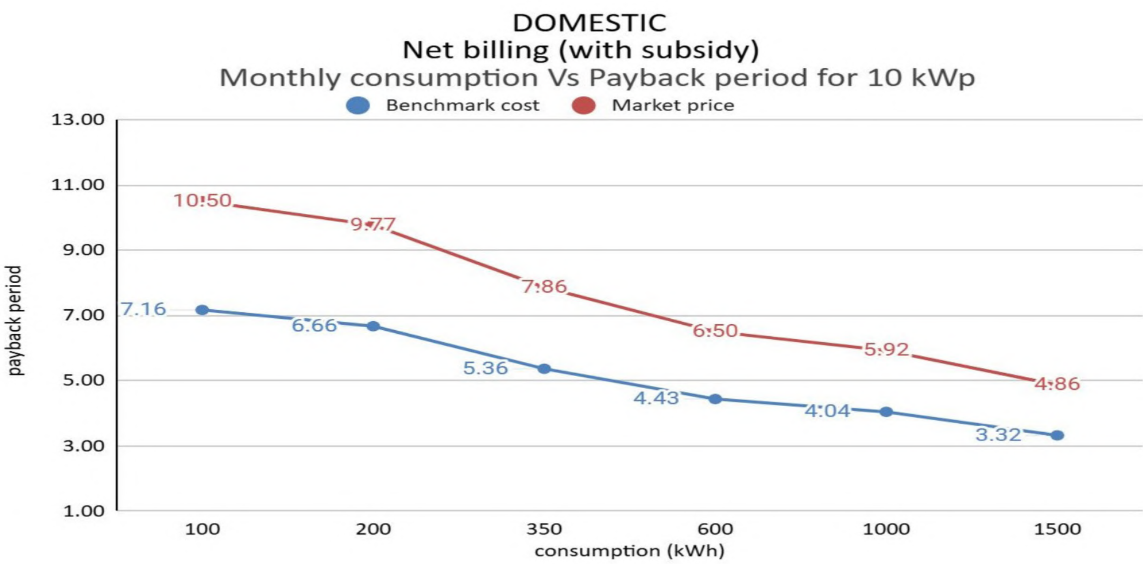

DOMESTIC
Net billing (with subsidy)
Monthly consumption Vs Payback period for 3 kWp
Benchmark cost
Market price
payback period
12.00
10.00
8.00
6.00
4.00
2.00
0.00
10.11
8.24
4.95
3.48
3.36
3.36
4.77
3.89
2.34
1.64
1.58
1.58
100
200
350
600
1000
1500
consumption (kWh)

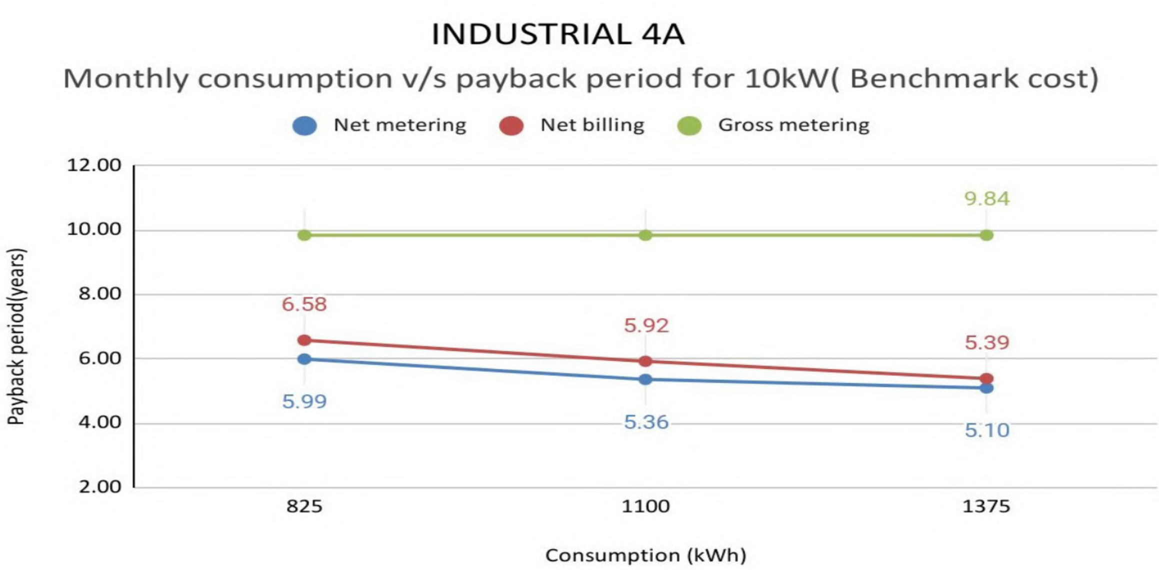
29

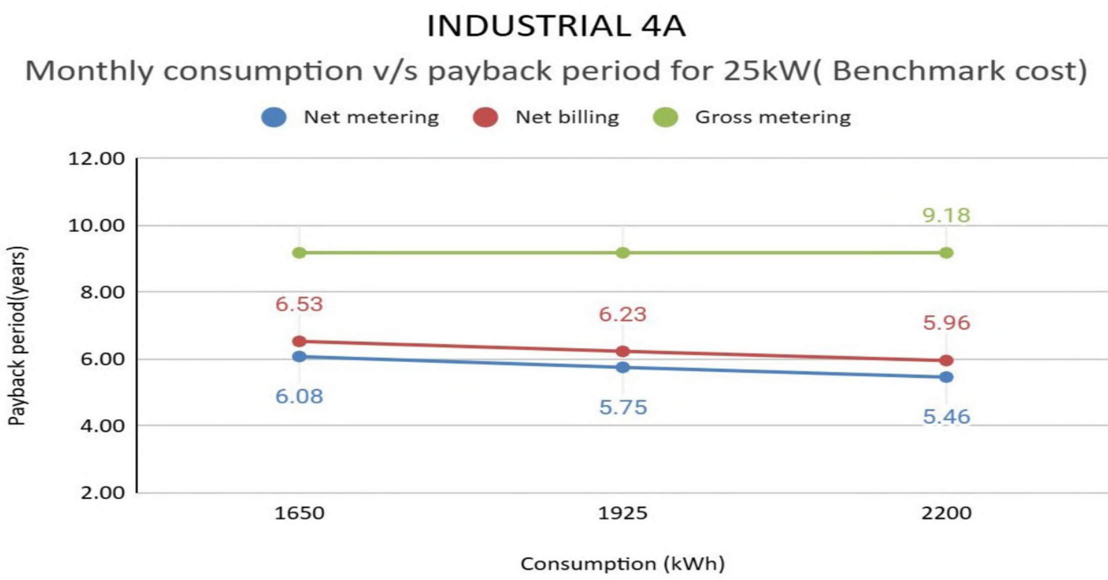

DOMESTIC
Net billing (with subsidy)
Monthly consumption Vs Payback period for 5 kWp
Benchmark cost
Market Price
payback period
12.00
10.00
8.00
6.00
4.00
2.00
0.00
11.09
9.64
6.60
4.94
4.33
3.49
6.60
5.73
3.93
2.94
2.58
2.08
100
200
350
600
1000
1500
consumption (kWh)

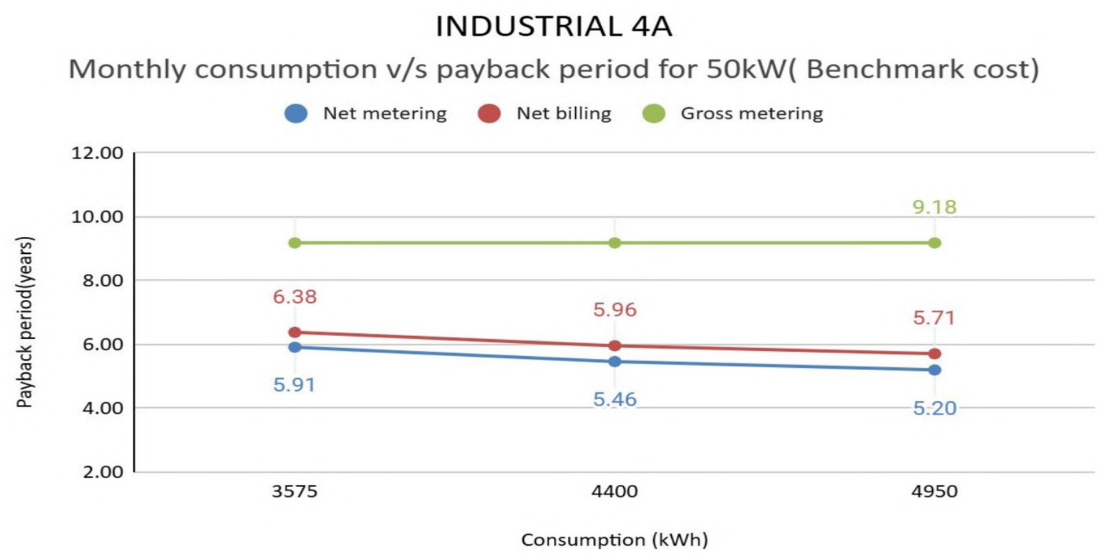

DOMESTIC
Net billing (with subsidy)
Monthly consumption Vs Payback period for 8 kWp
Benchmark cost
Market Price
payback period
consumption (kWh)
12.00
10.00
8.00
6.00
4.00
2.00
0.00
100
200
350
600
1000
1500
10.65
9.73
7.49
6.01
5.40
4.34
6.75
6.17
4.74
3.81
3.42
2.75

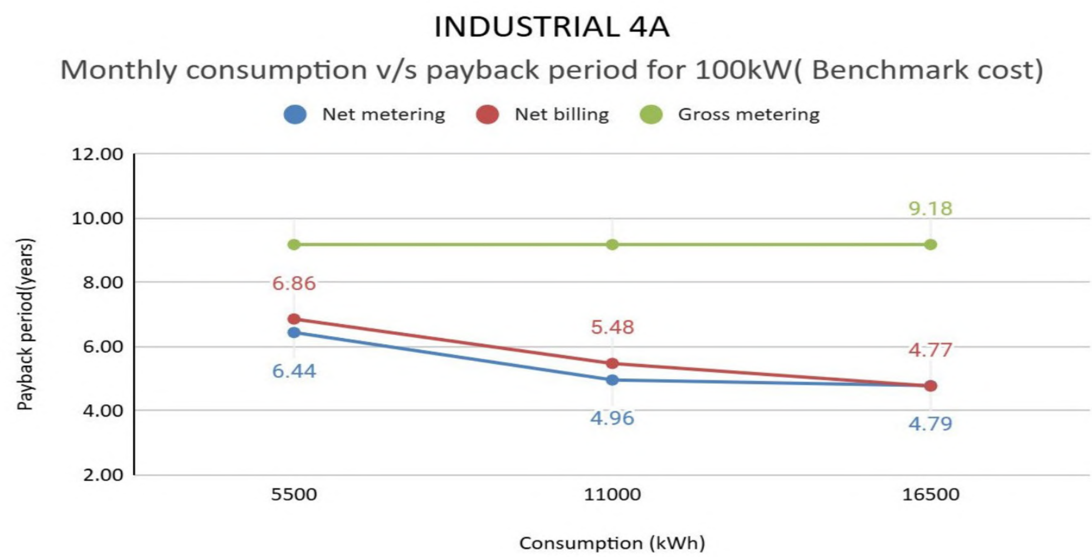
31

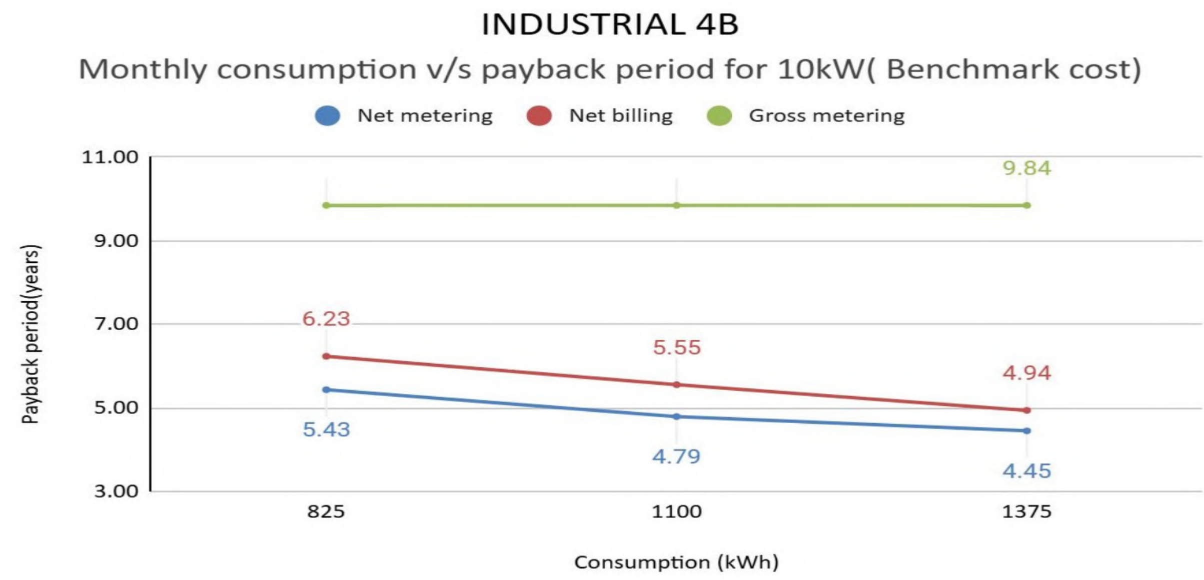

DOMESTIC
Net billing (with subsidy)
Monthly consumption Vs Payback period for 10 kWp
Benchmark cost
Market price
payback period
consumption (kWh)
13.00
11.00
9.00
7.00
5.00
3.00
1.00
100
200
350
600
1000
1500
10.50
9.77
7.86
6.50
5.92
4.86
7.16
6.66
5.36
4.43
4.04
3.32

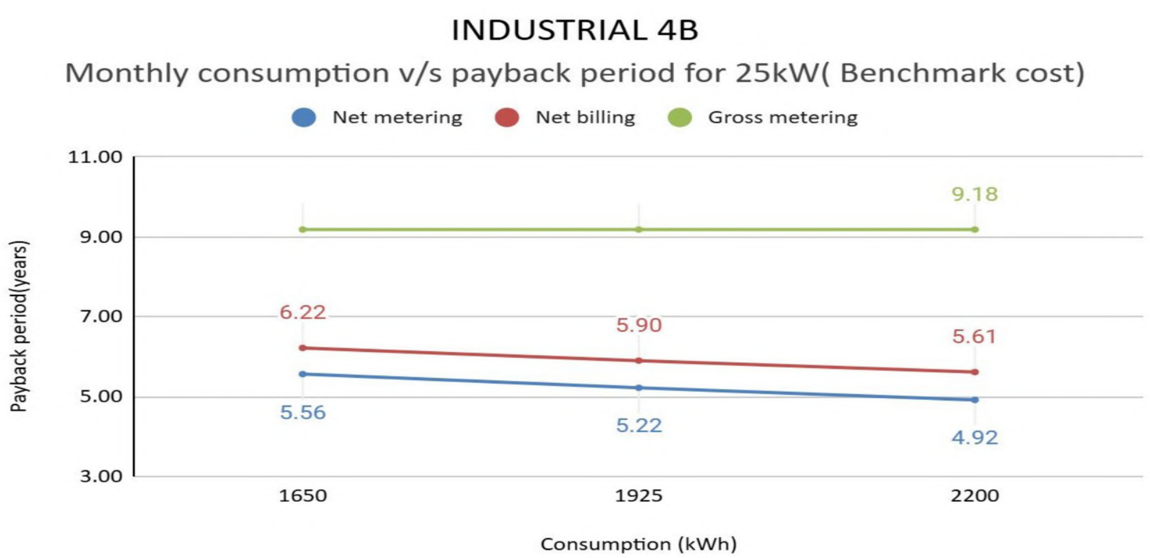

INDUSTRIAL 4A
Monthly consumption v/s payback period for 10kW(Benchmark cost)
Net metering
Net billing
Gross metering
Payback period(years)
Consumption (kWh)
12.00
10.00
8.00
6.00
4.00
2.00
825
1100
1375
9.84
6.58
5.92
5.39
5.99
5.36
5.10

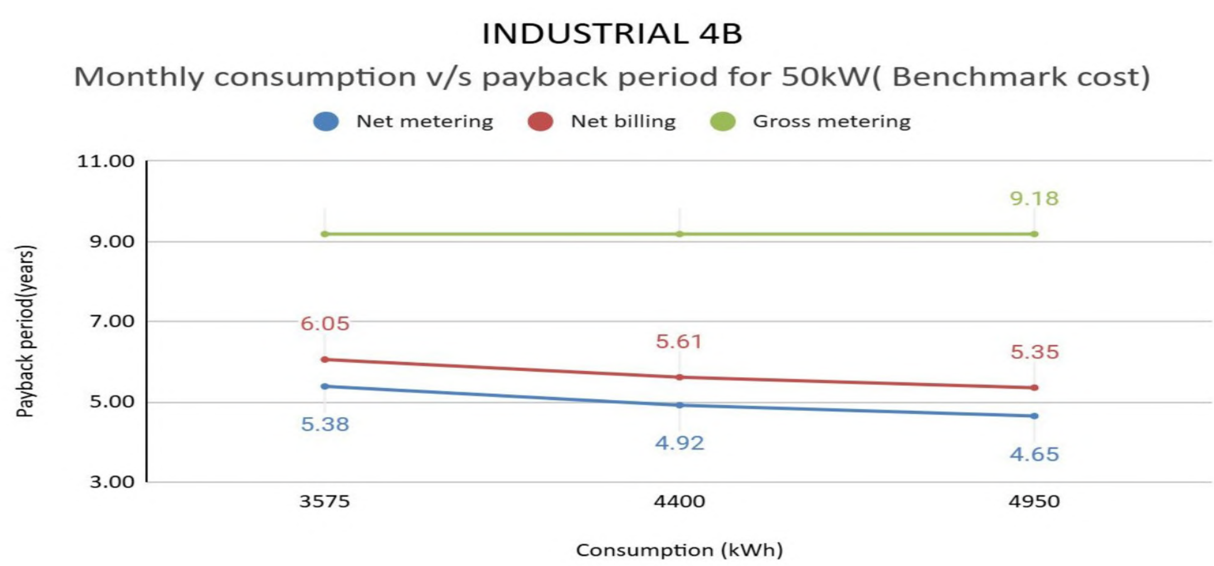

INDUSTRIAL 4A
Monthly consumption v/s payback period for 25kW(Benchmark cost)
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
Payback period(years)
9.18
6.53
6.23
5.96
6.08
5.75
5.46
1650
1925
2200
Consumption (kWh)

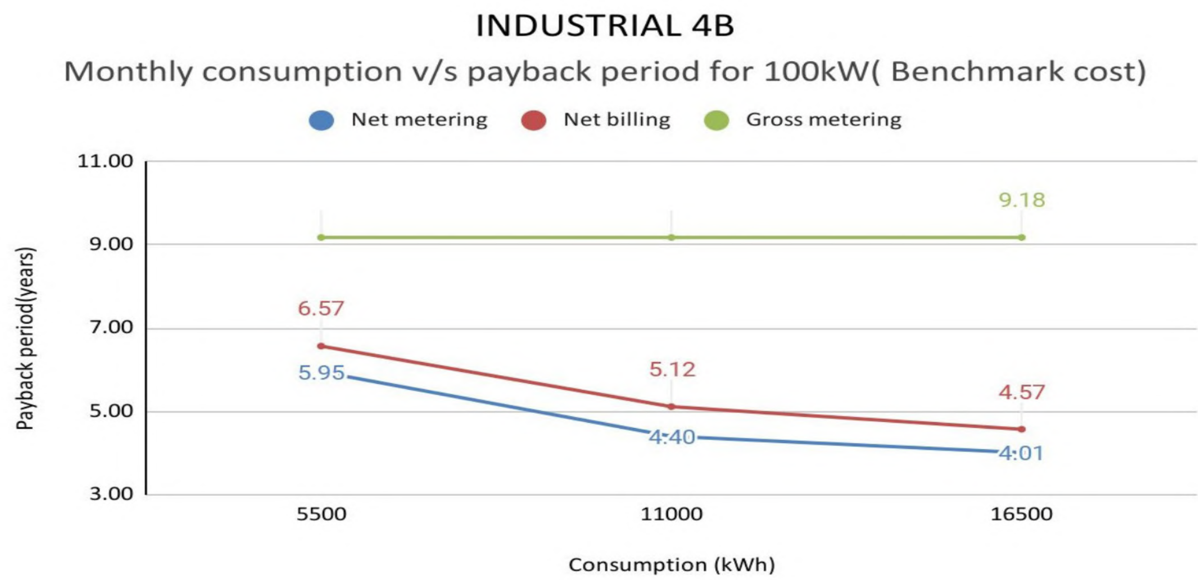

INDUSTRIAL 4A
Monthly consumption v/s payback period for 50kW(Benchmark cost)
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
Payback period(years)
9.18
6.38
5.96
5.71
5.91
5.46
5.20
3575
4400
4950
Consumption (kWh)

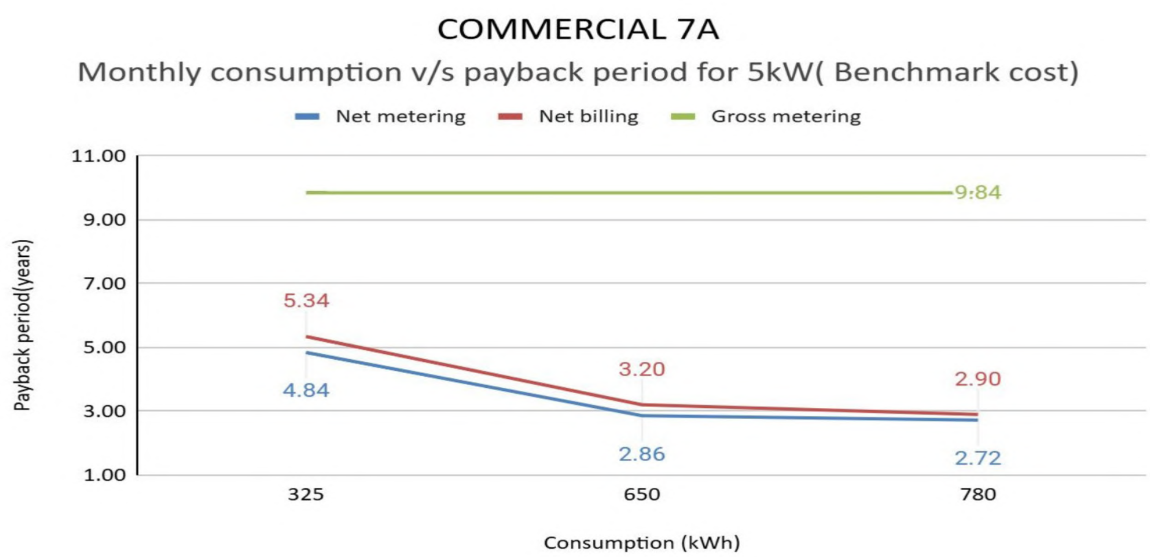

INDUSTRIAL 4A
Monthly consumption v/s payback period for 100kW(Benchmark cost)
Net metering
Net billing
Gross metering
12.00
10.00
8.00
6.00
4.00
2.00
Payback period(years)
9.18
6.86
5.48
4.77
6.44
4.96
4.79
5500
11000
16500
Consumption (kWh)

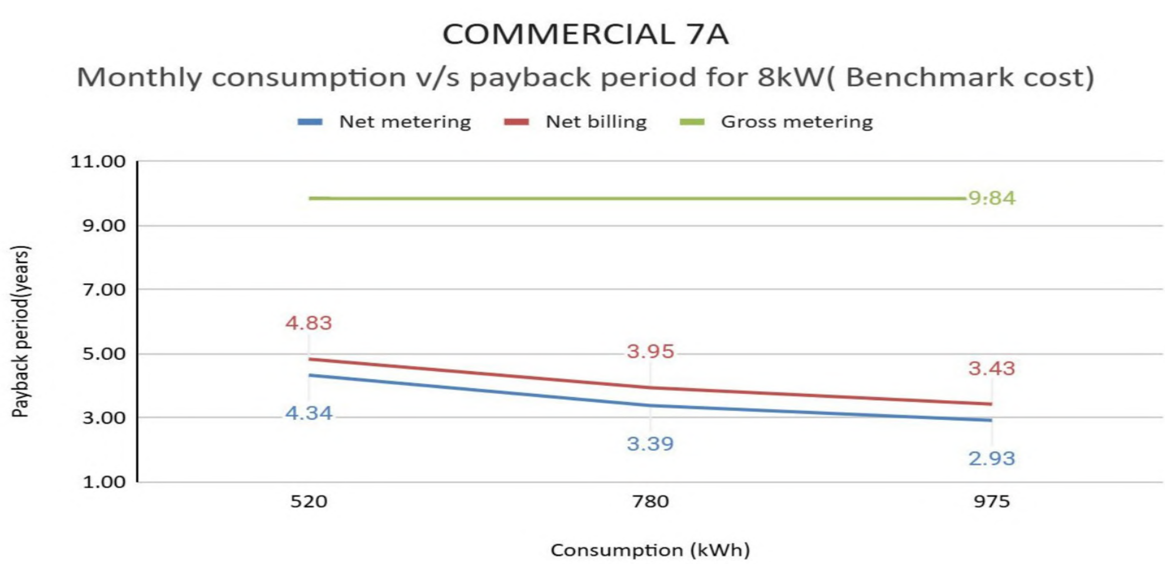

INDUSTRIAL 4B
Monthly consumption v/s payback period for 10kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
Payback period(years)
9.84
6.23
5.55
4.94
5.43
4.79
4.45
825
1100
1375
Consumption (kWh)

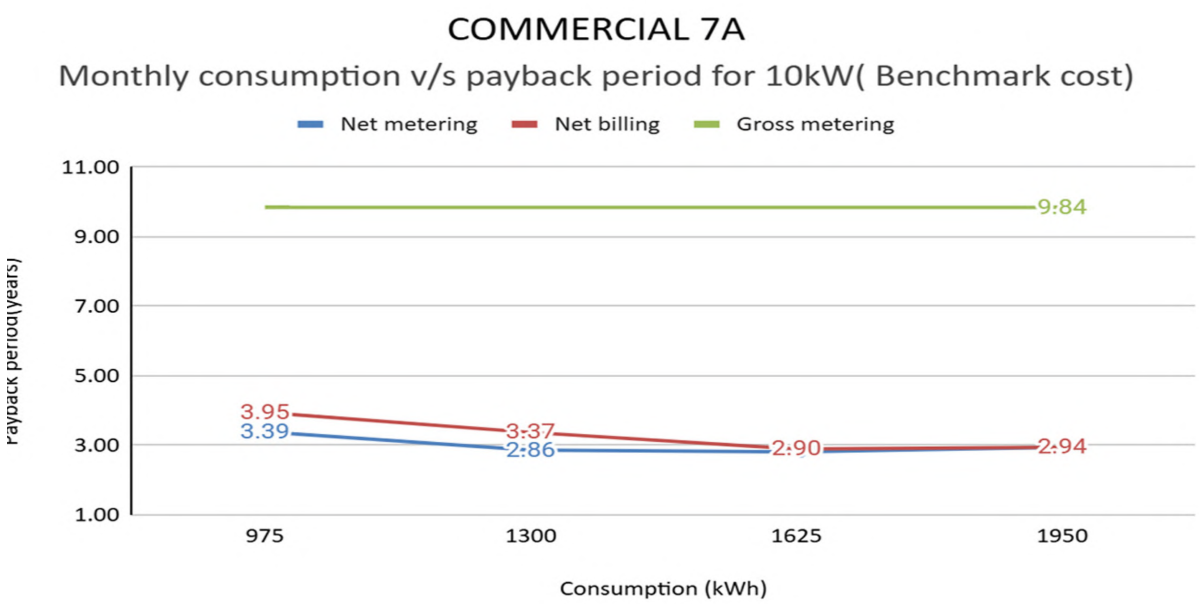

INDUSTRIAL 4B
Monthly consumption v/s payback period for 25kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
Payback period(years)
9.18
6.22
5.90
5.61
5.56
5.22
4.92
1650
1925
2200
Consumption (kWh)


INDUSTRIAL 4B
Monthly consumption v/s payback period for 50kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
Payback period(years)
9.18
6.05
5.61
5.35
5.38
4.92
4.65
3575
4400
4950
Consumption (kWh)

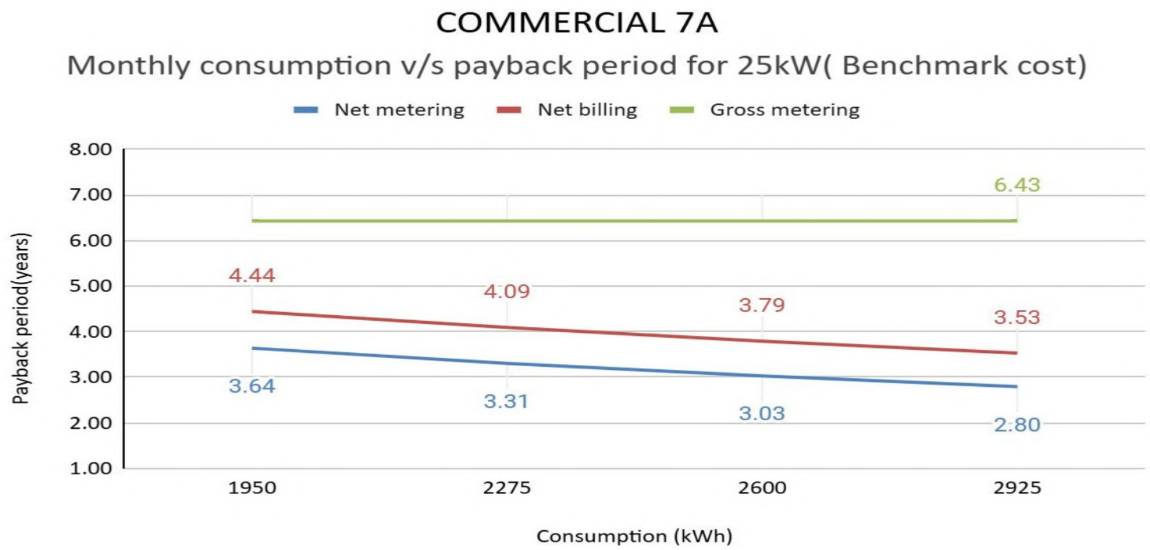

INDUSTRIAL 4B
Monthly consumption v/s payback period for 100kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
Payback period(years)
9.18
6.57
5.95
5.12
4.57
4:40
4:01
5500
11000
16500
Consumption (kWh)


COMMERCIAL 7A
Monthly consumption v/s payback period for 5kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9:84
5.34
4.84
3.20
2.90
2.86
2.72
325
650
780
Consumption (kWh)

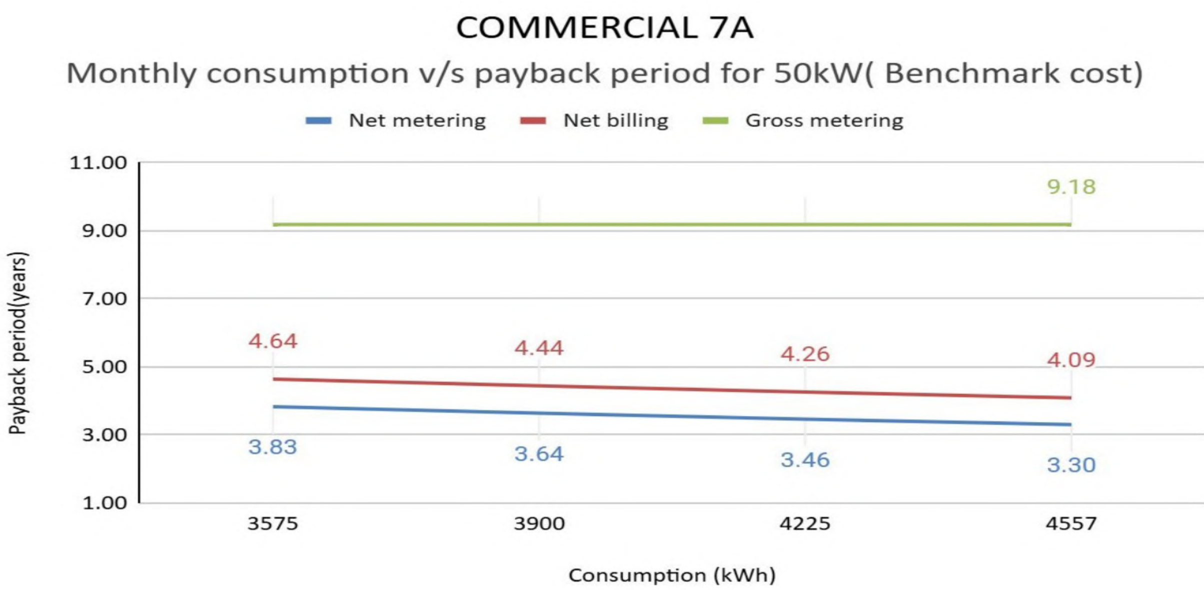

COMMERCIAL 7A
Monthly consumption v/s payback period for 8kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9:84
4.83
3.95
3.43
4.34
3.39
2.93
520
780
975
Consumption (kWh)



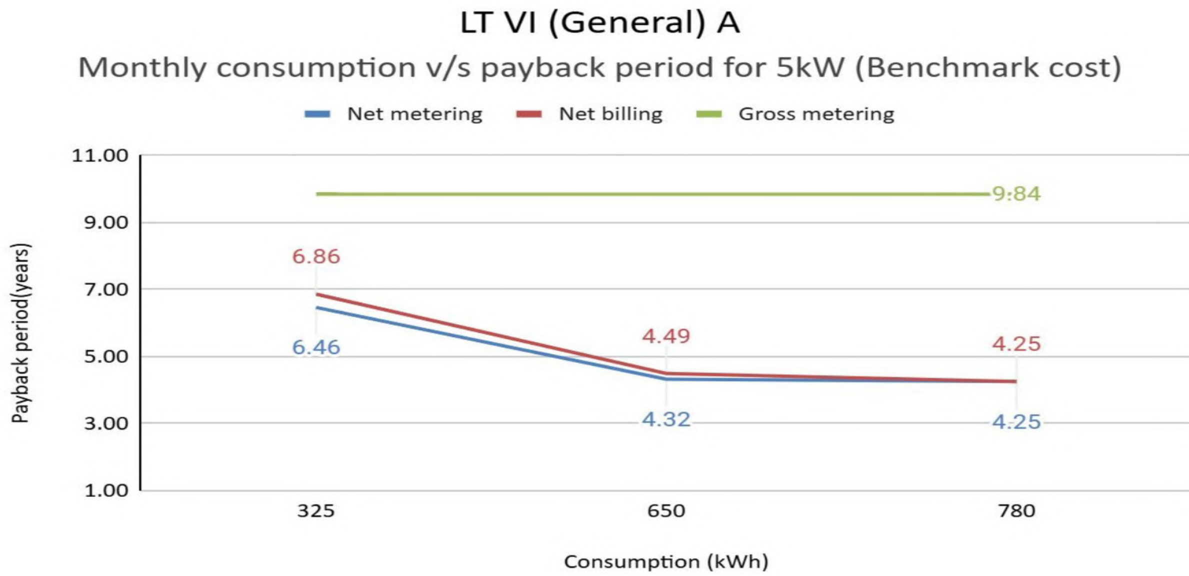
COMMERCIAL 7A
Monthly consumption v/s payback period for 10kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9.84
3.95
3.39
3.37
2.86
2.90
2.94
975
1300
1625
1950
Consumption (kWh)

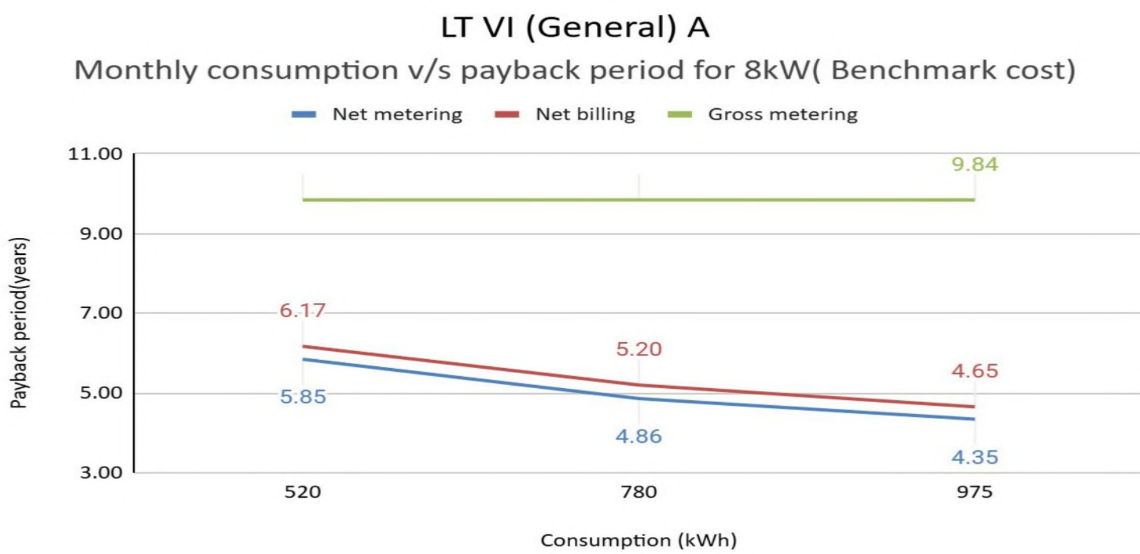


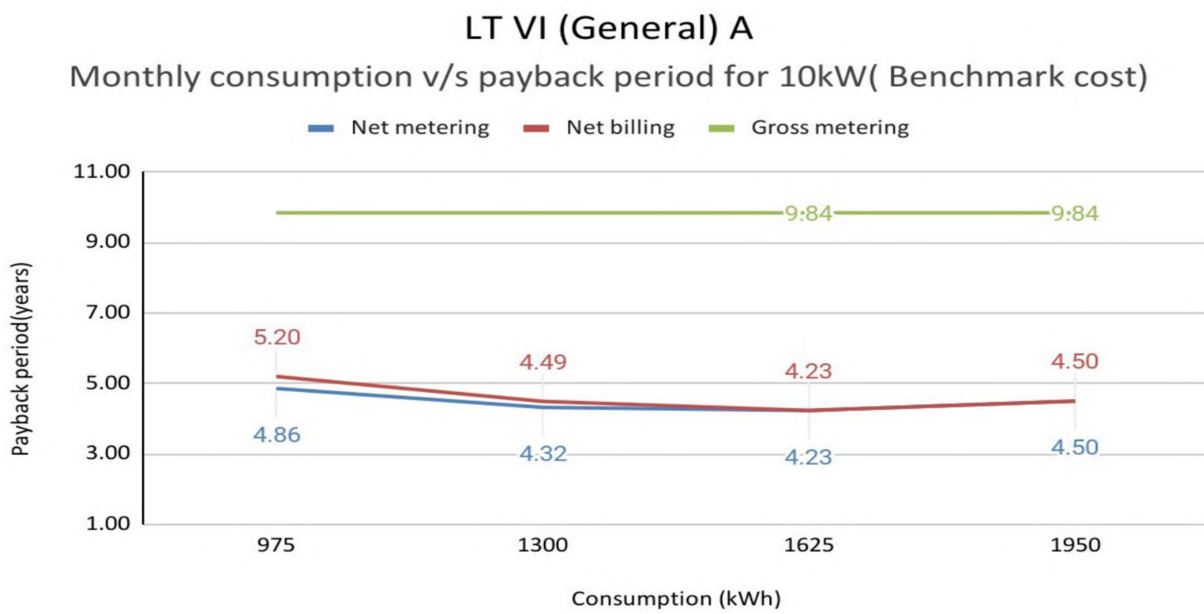
COMMERCIAL 7A
Monthly consumption v/s payback period for 25kW(Benchmark cost)
Net metering
Net billing
Gross metering
8.00
7.00
6.00
5.00
4.00
3.00
2.00
1.00
Payback period(years)
6.43
4.44
4.09
3.79
3.53
3.64
3.31
3.03
2.80
1950
2275
2600
2925
Consumption (kWh)

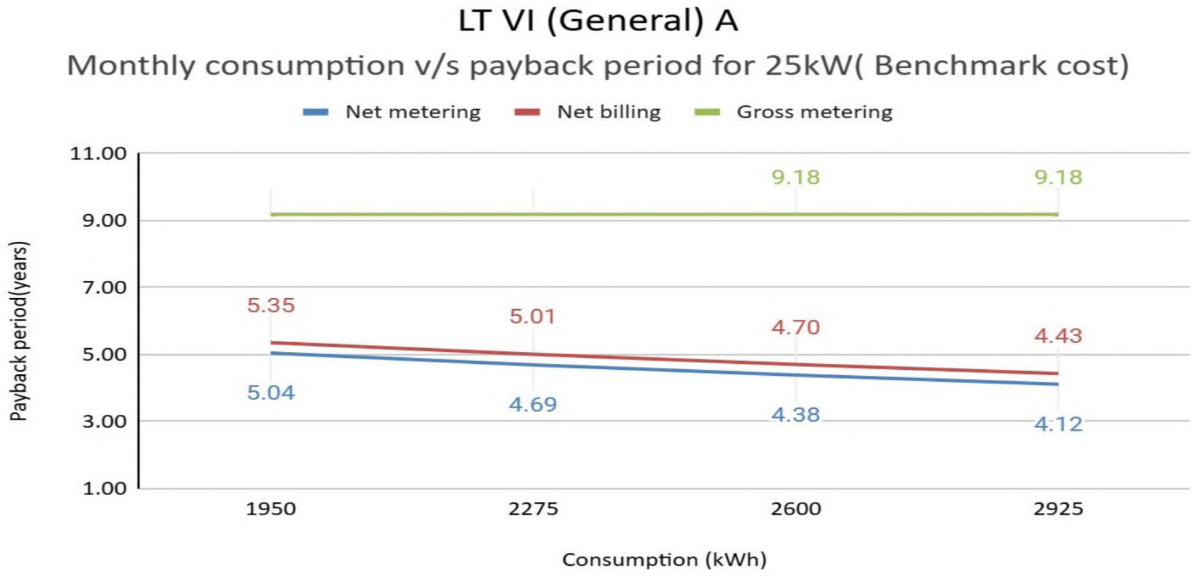


COMMERCIAL 7A
Monthly consumption v/s payback period for 50kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9.18
4.64
4.44
4.26
4.09
3.83
3.64
3.46
3.30
3575
3900
4225
4557
Consumption (kWh)

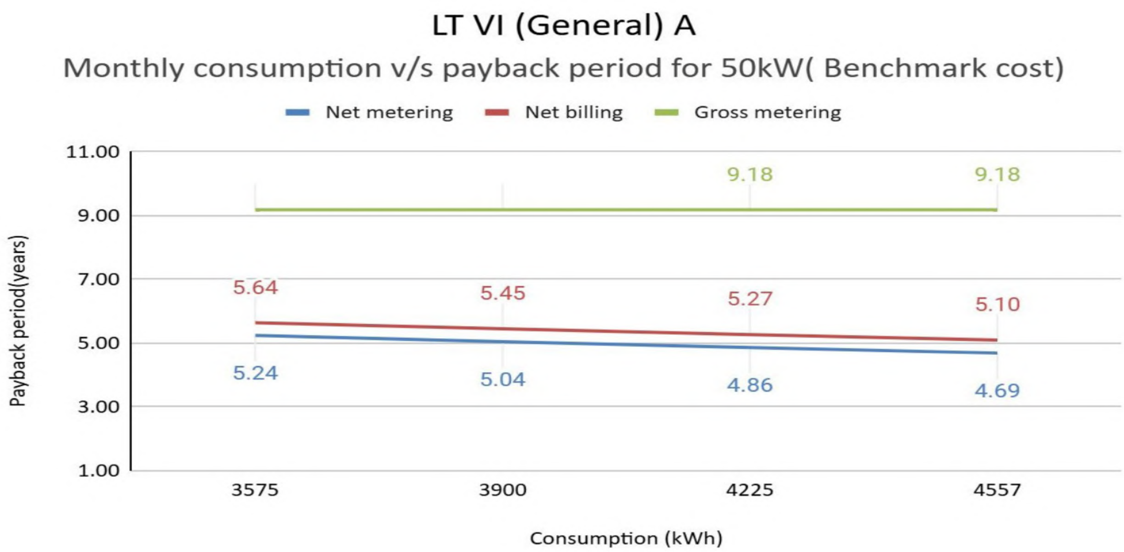

LT VI (General) A
Monthly consumption v/s payback period for 5kW (Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9:84
6.86
6.46
4.49
4.32
4.25
4.25
325
650
780
Consumption (kWh)


LT VI (General) A
Monthly consumption v/s payback period for 8kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
Payback period(years)
9.84
6.17
5.85
5.20
4.86
4.65
4.35
520
780
975
Consumption (kWh)


LT VI (General) A
Monthly consumption v/s payback period for 10kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9:84
9:84
5.20
4.86
4.49
4.32
4.23
4.23
4.50
4.50
975
1300
1625
1950
Consumption (kWh)

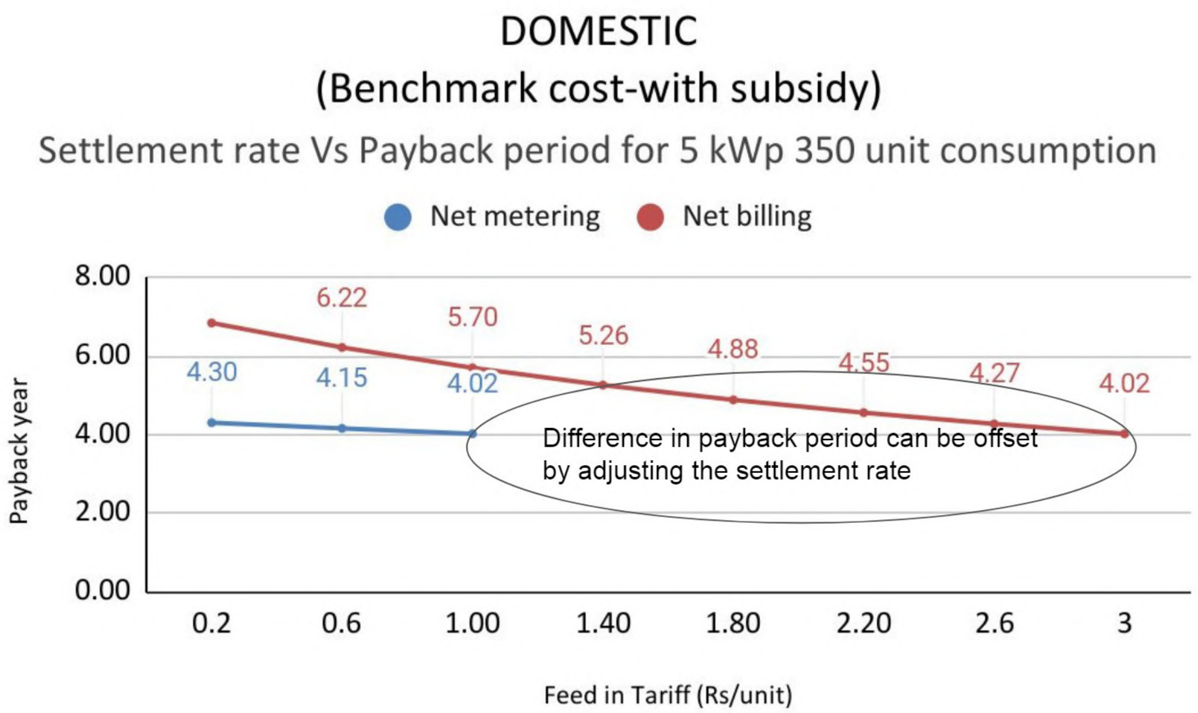


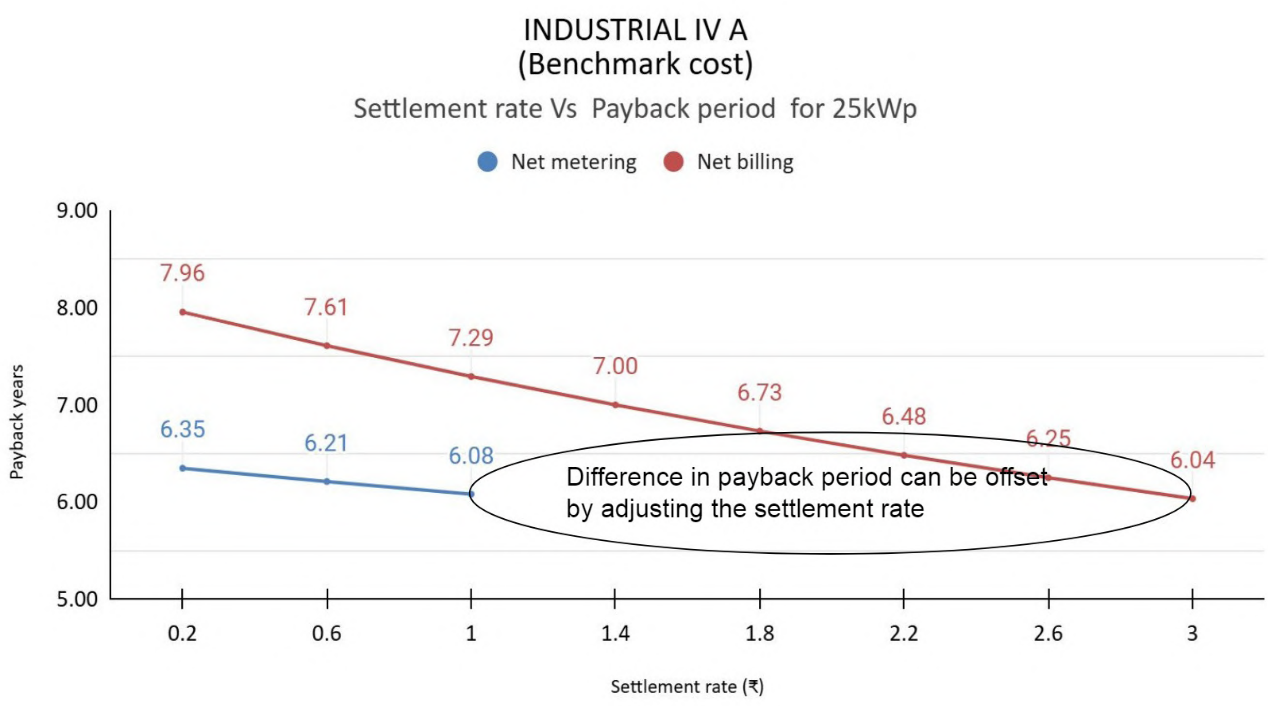
LT VI (General) A
Monthly consumption v/s payback period for 25kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9.18
9.18
5.35
5.01
4.70
4.43
5.04
4.69
4.38
4.12
1950
2275
2600
2925
Consumption (kWh)

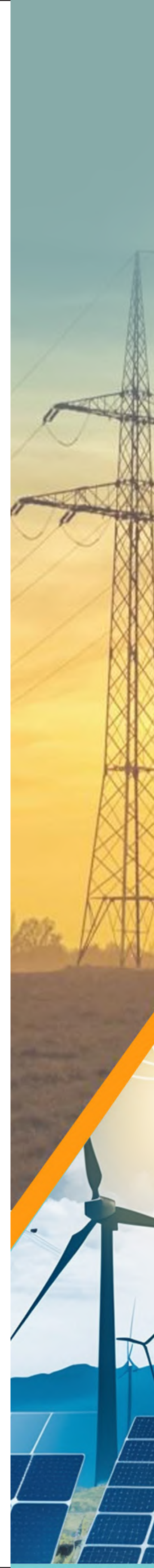


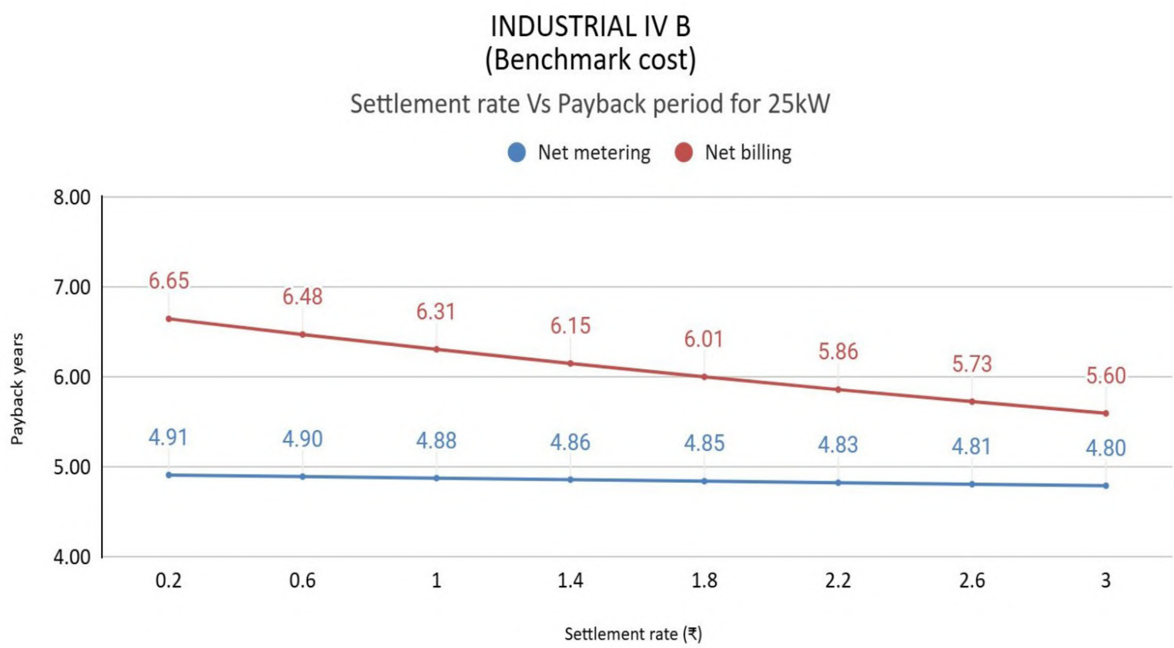
LT VI (General) A
Monthly consumption v/s payback period for 50kW(Benchmark cost)
Net metering
Net billing
Gross metering
11.00
9.00
7.00
5.00
3.00
1.00
Payback period(years)
9.18
9.18
5.64
5.45
5.27
5.10
5.24
5.04
4.86
4.69
3575
3900
4225
4557
Consumption (kWh)

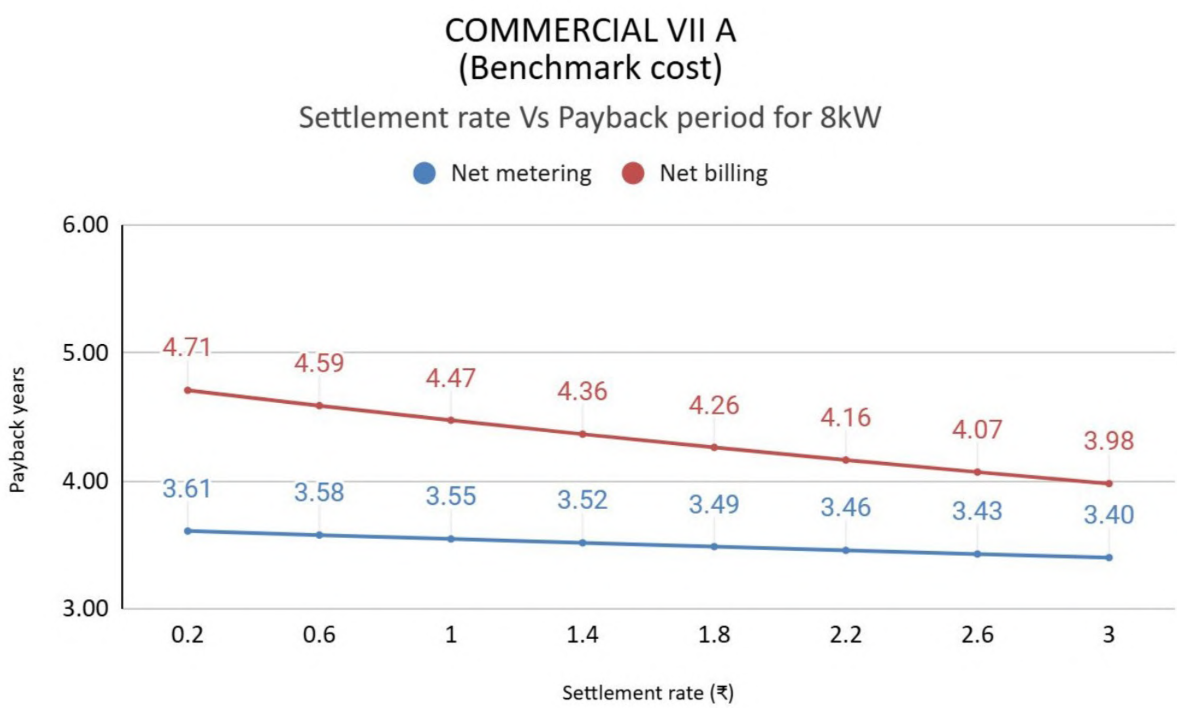
SETTLEMENT RATE
VS
PAYBACK PERIOD

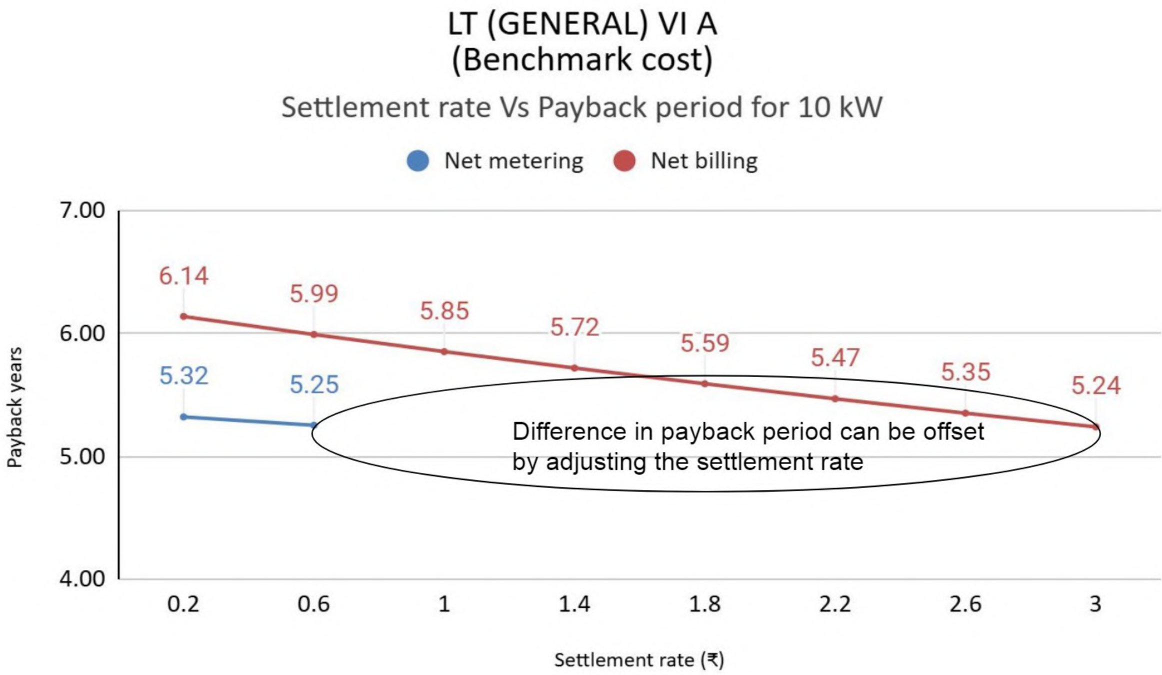

DOMESTIC
(Benchmark cost-with subsidy)
Settlement rate Vs Payback period for 5 kWp 350 unit consumption
Net metering
Net billing
Payback year
8.00
6.00
4.00
2.00
0.00
6.22
5.70
5.26
4.88
4.55
4.27
4.02
4.30
4.15
4.02
Difference in payback period can be offset by adjusting the settlement rate
0.2
0.6
1.00
1.40
1.80
2.20
2.6
3
Feed in Tariff (Rs/unit)

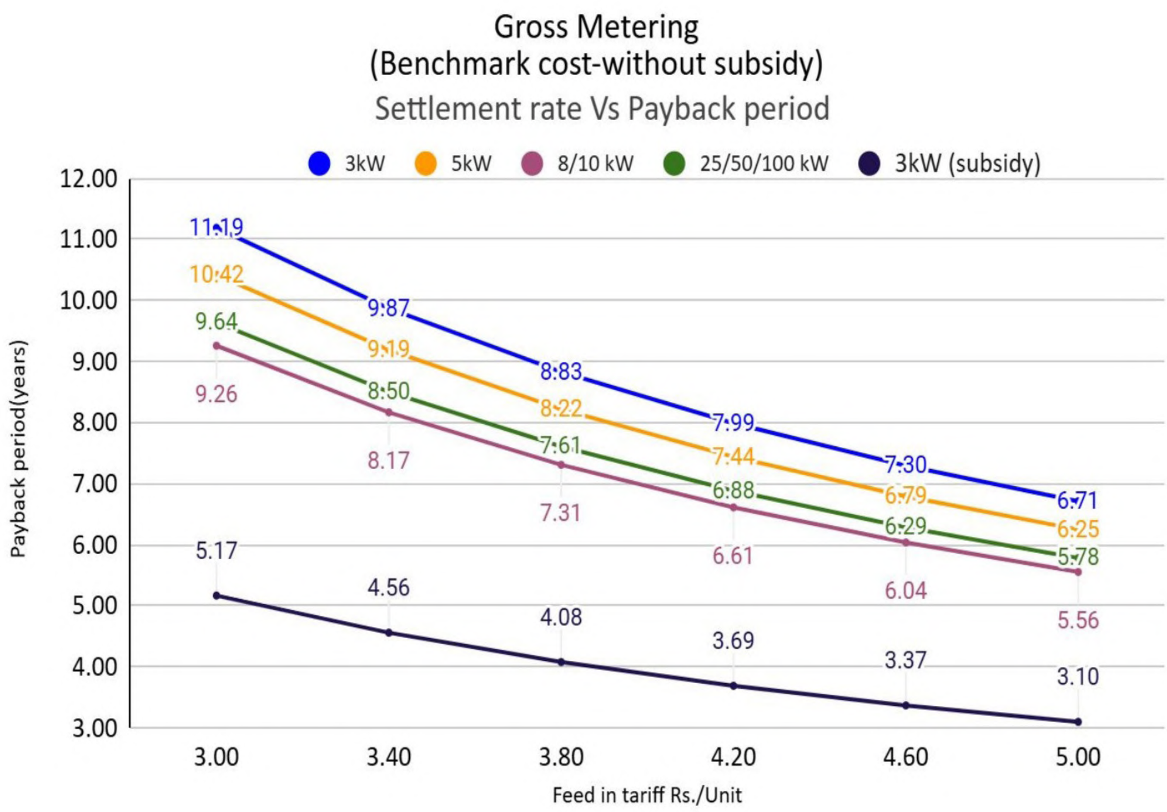

INDUSTRIAL IV A
(Benchmark cost)
Settlement rate Vs Payback period for 25kWp
Net metering
Net billing
Payback years
9.00
8.00
7.00
6.00
5.00
7.96
7.61
7.29
7.00
6.73
6.48
6.25
6.04
6.35
6.21
6.08
Difference in payback period can be offset by adjusting the settlement rate
0.2
0.6
1
1.4
1.8
2.2
2.6
3
Settlement rate (₹)




INDUSTRIAL IV B
(Benchmark cost)
Settlement rate Vs Payback period for 25kW
Net metering
Net billing
8.00
7.00
6.00
5.00
4.00
Payback years
6.65
6.48
6.31
6.15
6.01
5.86
5.73
5.60
4.91
4.90
4.88
4.86
4.85
4.83
4.81
4.80
0.2
0.6
1
1.4
1.8
2.2
2.6
3
Settlement rate (₹)


COMMERCIAL VII A
(Benchmark cost)
Settlement rate Vs Payback period for 8kW
Net metering
Net billing
6.00
5.00
4.00
3.00
Payback years
4.71
4.59
4.47
4.36
4.26
4.16
4.07
3.98
3.61
3.58
3.55
3.52
3.49
3.46
3.43
3.40
0.2
0.6
1
1.4
1.8
2.2
2.6
3
Settlement rate (₹)


LT (GENERAL) VI A
(Benchmark cost)
Settlement rate Vs Payback period for 10 kW
Net metering
Net billing
Payback years
7.00
6.00
5.00
4.00
6.14
5.99
5.85
5.72
5.59
5.47
5.35
5.24
5.32
5.25
Difference in payback period can be offset
by adjusting the settlement rate
0.2
0.6
1
1.4
1.8
2.2
2.6
3
Settlement rate (₹)


Gross Metering
(Benchmark cost-without subsidy)
Settlement rate Vs Payback period
3kW
5kW
8/10 kW
25/50/100 kW
3kW (subsidy)
Payback period(years)
12.00
11.00
10.00
9.00
8.00
7.00
6.00
5.00
4.00
3.00
11.19
10.42
9.64
9.26
5.17
9.87
9.19
8.50
8.17
4.56
8.83
8.22
7.61
7.31
4.08
7.99
7.44
6.88
6.61
3.69
7.30
6.79
6.29
6.04
3.37
6.71
6.25
5.78
5.56
3.10
3.00
3.40
3.80
4.20
4.60
5.00
Feed in tariff Rs./Unit

KERALA STATE ELECTRICITY REGULATORY COMMISSION

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