REPORT ON METERING REGULATION AND ACCOUNTING FRAMEWORK FOR GRID CONNECTED ROOFTOP SOLAR PV IN INDIA

April 2019

Forum of Regulators

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Acronyms

AMI	Advanced Metering Infrastructure
AMR	Automatic Meter Reading
APPC	Average Power Purchase Cost
BDEW	German Association of Energy and Water Industries
BESCOM	Bangalore Electricity Supply Company
CAPEX	Capital Expenditure
CEA	Central Electricity Authority
CFA	Central Finance Assistance
DISCOM	Distribution Company
DT	Distribution Transformer
EPC	Engineering, Procurement and Construction
EU	European Union
FIT	Feed in Tariff
FOR	Forum of Regulators
GoI	Government of India
GRPV	Grid Connected Rooftop Solar PV
JNNSM	Jawaharlal Nehru National Solar Mission
LVRT	Low-Voltage Ride-Through
MDMS	Meter Data Management System
MERC	Maharashtra Electricity Regulatory Commission
MNRE	Ministry of New and Renewable Energy
MRI	Meter Reading Instruments
NAPCC	National Action Plan on Climatic Change
NEG	Net Excess Generation
NEM	Net metering Regulation
OERC	Orissa Electricity Regulatory Commission
OPEX	Operating Expenditure
PG&E	Pacific Gas & Electric
PPA	Power Purchase Agreement
PSC	Public Service Commission
PUC	Public Utilities Commission
PV	Photovoltaic
RE	Renewable Energy
REC	Renewable Energy Certificate
RERC	Rajasthan Electricity Regulatory Commission
RESCO	Renewable Energy Service Company
RPO	Renewable Purchase Obligation
SERC	State Electricity Regulatory Commission
SNA	State Nodal Agency
UT	Union Territory
VAT	Value Added Tax
VDE	Verband der Elektrotechnik

THE REPORT WAS ENDORSED BY THE FORUM OF REGULATORS IN ITS 65TH MEETING HELD ON 13TH NOVEMBER 2018.

1. Executive Summary

1. Executive Summary

Since 2010, global success stories of rooftop solar photovoltaic (PV) in distributed grid management and power markets have attracted substantial interest from entrepreneurs, developers, financial institutions, development banks, end-users, as well as government entities in India. The gained momentum facilitated the development of a regulatory framework for Grid connected Rooftop Solar PV (GRPV) in India and the Forum of Regulators (FOR) formulated the draft Model Net Metering Regulation in 2013. In the early years, rooftop solar PV was not expected to become a focus technology that would gain momentum with large installation targets. Furthermore, considering pre-2014 energy mix in the country, business models for scaling rooftop solar PV were largely envisaged to be based on self-consumption. Hence, the Model Regulation formulated in 2013 contained directives to support this framework.

The report on **Metering Regulation and accounting framework for grid-connected rooftop solar PV in India** has been developed under the World Bank-State Bank of India Grid-Connected Rooftop Photovoltaic Technical Assistance program "SUPRABHA"**.** The objective of the report is to propose final recommendations for developing the new Model Regulation for Grid-Connected Rooftop Photovoltaic (GRPV) in India after analysing inputs gathered from stakeholder consultation, international review and As-Is assessment of the current regulatory framework.

In order to support the Government of India (GoI) target on widespread installation of rooftop solar PV, the World Bank is lending $625 million (under Perform for Results (P4R) lending instrument) to the State Bank of India (SBI) to debt-finance GRPV projects and capacitate the various stakeholders involved. As part of the loan, SBI has proposed a Technical Assistance (TA) program through a Project Management Consultant (PMC) under a Ministry of New & Renewable Energy (MNRE)-led Steering Committee to strengthen the market ecosystem with focus on areas of policy, Regulation, process alignments and demand creation.

Under this TA program, a study has been commissioned to support FOR to update Model Net Metering Regulation 2013 and to develop a 'Comprehensive Metering and Accounting Framework for Rooftop Solar Photovoltaic in India'. The study aims to identify gaps in the regulatory framework based on upcoming business models and international developments, available infrastructure for deployment and impact on various stakeholders; and thereafter propose necessary changes in the existing Model Regulation.

In 2014, Government of India (GoI) set an ambitious target to achieve 40 GW of cumulative installed capacity from GRPV systems by 2022. In order to achieve this ambitious target, a strategic combination of Top-Down impetus and Bottom-Up execution approach were initiated, in which Government of India (GoI) in partnership with the state governments and regulators adopted a number of measures to promote the rooftop solar sector. Provision of regulatory clarity and uprightness through policy and regulatory directives becomes imperative for market creation. Model Net Metering Regulation 2013 served as a precedent and a guiding regulatory document for the states to adopt. All the 29 States and 7 Union Territories have adopted Model Net Metering Regulation 2013, with few or no changes in their respective Regulations (draft or notified).

However, following the adoption of Model Net Metering Regulation 2013 by the states and despite the availability of several Government of India (GoI) support schemes, GRPV projects have not seen significant growth as compared to the ground-mounted solar projects. Key implementation challenges faced by the stakeholders have impeded the growth of GRPV in the country. The challenges are as follows.

- Limitations in existing Regulations in terms of system size, distribution transformer (DT) loading and benefit sharing
- Limited consumer awareness
- Operational challenges at DISCOM level
    a. Apprehension of loss of revenue by DISCOMs
- Absence of a strong ecosystem for low cost debt financing
- Limited knowledge of adequate safeguard requirements
- Integration challenges due to the variable nature of output and as the system was never planned considering reverse flow of power
- Limited options of business models; CAPEX and RESCO

In view of the above challenges, it is necessary to review the existing Regulation and identify challenges faced by the various stakeholders. This will require detailed consultation and studying of international experiences to suggest appropriate regulatory mitigation measures needed for the proliferation of GRPV in India.

While conducting the gap analysis for the present regulatory framework, different stakeholders such as the State Electricity Regulatory Commissions (SERCs), Distribution Companies (DISCOMs), developers and meter manufacturers were consulted to understand their views on the present regulatory framework and their expectations based on experience that will help to promote GRPV systems.

Following the introduction of Model Net Metering Regulation 2013, various states notified their Net Metering Regulations with modifications/additions to Regulations.

The cumulative capacity of GRPV systems on a particular DT was restricted at 15% of peak capacity to avoid any reverse power flow as the distribution system (below 33 KV) was designed for unidirectional power flow. While Model Net Metering Regulation 2013 has prescribed the maximum limit of 1 MW, the states have restricted consumers' individual capacity as some percentage of their sanctioned load or connected load. The range for individual GRPV system capacity is between 40% and 100% of the sanctioned load. The limits for GRPV systems that can be installed on a particular DT vary from state to state. Some states have adopted 15% limit in line with Model Net Metering Regulation 2013 whereas a few states have relaxed it further. The range for DT loading is between 15% and 75% (in Odisha). In Telangana, DT loading is allowed till 50% with additional condition that if the system study allows, more GRPV systems will be permitted on the same DT. The salient features of Model Net Metering Regulation 2013 and the state Regulations are provided in the table below:

Table 1: Major Provisions in Model Net Metering Regulation 2013 and State Regulations related to GRPV system

Sr. No.	Provisions	Model Net Metering Regulation 2013	State Regulations
1	Applicability	All consumers	All consumers
2	Business models	CAPEX and RESCO	CAPEX and RESCO
3	Metering principles	Net metering	Mostly net metering; gross metering in a few states
4	System capacity	Maximum capacity of 1 MW	40% to 100% of the sanctioned load
5	Limits on DT loading	15% (to be reviewed based on technical studies or standards subsequently defined by Central Electricity Authority (CEA)	15% to 75% of the peak capacity or rated capacity of DT
6	Exemption from other charges	Wheeling charges, cross-subsidy surcharge and banking charges	Wheeling charges, cross-subsidy surcharge and additional surcharge; banking charges and transmission charges; in some states, transmission loss and wheeling loss are also exempted
7	Communication capability	Meter Reading Instrument (MRI) compatible	MRI compatible; a few states have asked for Advanced Metering Infrastructure (AMI) compatible net meters
8	Rate applicable in case of export to the grid	No payment if electricity generated exceeds 90% of the electricity consumed	Feed in Tariff (FiT), Power Purchase Agreement (PPA) rate or Average Power Purchase Cost (APPC) (in most cases)
9	Settlement period	One year	Mostly one year; a few states like Andhra Pradesh and Telangana have half-yearly settlement period. In most cases, the settlement year is financial year (April to March) except Punjab and Sikkim where the settlement year starts from October.
10	Renewable Purchase Obligation (RPO) compliance	Units consumed by the consumer will qualify for the RPO compliance for the Distribution Licensee	Major states allow solar energy generated as part of RPO compliance; in case of Karnataka, if the GRPV is DISCOM-owned then total generation is considered under RPO compliance. otherwise total energy purchased is considered
11	Managing safety	Primarily responsibility of consumer, auto shutting of solar plant when grid supplier fails is also	Primarily responsibility of consumer, provisions for auto-shutting of solar plant when grid supply fails is also provided for

Sr. No.	Provisions	Model Net Metering Regulation 2013	State Regulations
		provided for	

As part of the assignment, the international experience of deployment of GRPV system in developed countries such as Germany, USA and Canada was also reviewed. The major provisions from USA, Germany & Canada are provided in the table below:

Table 2: Major Provisions of Net Metering in other countries

Sr. No.	Provisions	Descriptions
1.	Applicability	All consumers given multiple options to choose business models and financing
2.	Business models	CAPEX and RESCO (consumer centric and utility centric), community and virtual utility
3.	Metering principles	Net/gross/virtual (consumer given choice to select net or gross metering)
4.	System capacity	1. USA: California – 100% of the sanctioned load for NEM, Colorado – 120% of the customer's average demand and Virginia – not exceeding customers' annual load 2. Brazil – 100% of the sanctioned load or contract demand for NEM 3. Maximum System Capacity – California – 5 MW to 10 MW, Mississippi – 2 MW for non-residential consumer and 20 KW for residential, North Carolina – 1 MW
5.	Limits on system loading	Overall limit based on peak demand of utility such as 1.5% to 5% in USA
6.	Communication capability	1. Germany: DISCOMs are moving towards smart meters; though it is not compulsory 2. California: DISCOMs are moving towards smart meters; though it is not compulsory
7.	Rate applicable in case of export to the grid	1. Germany: Feed-in-Tariff 2. USA: California – 12 month average spot market price; Virginia, Nevada and Minnesota -- Avoided cost rate
8.	Settlement period	1. USA: In the states of Virginia, Minnesota and California, the settlement period is one year with option to roll over credit to next settlement period or settle at the end of 12 months

Based on the review of international experience, 48 countries worldwide had implemented net metering schemes, in most of the cases at a national level. Net metering became the incentive policy choice in 26 countries since 2012, when around 22 countries had adopted net metering schemes.[1]

The key learnings from the international experience suggest that the GRPV segment in India can also grow by removing the current restrictions. These include allowing higher system capacities or DT

[1] Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates

capacity, to the extent possible, with adequate measures from system operations points of view; increasing consumer reach by adopting different business models for different types of consumers; and providing suitable energy accounting and remunerative commercial settlement principles to attract consumers. The international experience is discussed in detail in a separate chapter in this report.

Unlike the global best practices, the present regulatory framework in India is focused on self-consumption and therefore the Model Net Metering Regulation 2013 and state Regulations have put certain restrictions in terms of permissible system capacity at the consumer-end and permissible system capacity on a single DT. These limits vary from state to state and require standardization. In a few cases, the excess generation is not compensated during the settlement period. The existing Regulations permit only two business models, CAPEX and RESCO, whereas other business models can also be incorporated in the Indian context to help in the proliferation of GRPV systems in India.

Following are some of the gaps identified based on the review of the Indian regulatory framework and international experience. These have been divided into three categories: technical, commercial and others, based on their nature. The identified gaps are listed below:

- Technical aspects
    - Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity
    - Different limits on GRPV capacities connected to DT
    - Limited provisions on real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems
- Commercial aspects
    - Limited business models options available to consumers and developers, limited scope for DISCOMs in the present scenario
    - Absence of additional clauses related to change in ownership and flexibility in existing PPA/connection agreement
    - No remuneration for excess generation in present energy accounting and commercial settlement principles
- Other aspects: general definition, metering and communication
    - Definition of premises and solar roof-top PV systems need review owing to future possibility of different scenarios
    - Metering and communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

A technical study was carried out to address technical gaps such as the identification of maximum individual capacity of a GRPV system that can be safely connected to the distribution grid without crossing the thermal limit and creating over-voltage at interconnection. Various parameters such as different types of feeders (rural/ urban, residential/ commercial), different types of DTs and different feeder lengths were considered for gauging the impact of GRPV on grid performance, reverse power flow and over voltage. The study concluded that the aggregate PV power plant capacity limit can be increased past the existing limit of 15% without compromising the grid safety. For detailed results, refer Chapter 5.

Based on the study of the present regulatory framework, review of international experience and technical study, the following provisions in the Model Regulation have been proposed:

- To address the gaps identified through the critical analysis of the present regulatory framework
- To enable regulatory framework for suggested business models
- To introduce governance structure, institutional framework and roles and responsibilities

The proposed changes in the Model Regulation to address the gaps identified are discussed below:

1. Proposed changes to remove restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity

In the proposed Model Regulation, two types of Distributed Renewable Energy (DRE[2]) systems have been proposed based on ownership: Prosumer Distributed Renewable Energy System (PDRES) and Independent Distributed Renewable Energy System (IDRES).

In case of PDRES, the permissible capacity is linked to the sanctioned load for prosumers. The capacity of PDRES shall not exceed the sanctioned load/contracted demand of the prosumer, while in the case of IDRES, the capacity is linked to the power system constraints. The maximum IDRES capacity to be installed by a person at a particular location shall be based on the capacity and configuration of the electricity system, and the power flows that distributed generation resource may cause.

In case of PDRES, a minimum of 1 KW and 10 KW capacity systems can be set under net metering and net billing, respectively. In case of IDRES, the minimum allowable capacity is 50 KW.

2. Proposed changes to address the issue of different limits on GRPV capacities that can be connected to DT

As per the technical study conducted, aggregate PV power plant capacity (AC nominal power of inverter) can be set up to 100% of DT capacity (even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor). In that case, the permitted distributed generation capacity should not exceed sanctioned load/ contract demand of the consumer.

However, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network can be decided on case-to-case basis. This would be based on the loading of the respective DT, considering over-voltage at Point of Common Coupling (PCC) as the deciding factor, in case the permitted distributed generation capacity is not based on sanctioned load/ contract demand.

Hence, based on the technical study carried out, the limit for connecting Distributed Renewable Energy (DRE) system to feeder or distribution transformer is proposed to be 100% of the respective feeder or distribution transformer.

[2] Distributed Renewable Energy"(DRE) means the electricity fed into the electric system at a voltage level of below 33 KV using rooftop solar PV [or such other forms of renewable sources as may be approved by the commission from time to time or as recognized by the Ministry of New and Renewable Energy, Government of India]

3. Proposed changes for required real-time monitoring of solar generation and participation in system operations

In view of the DRE system monitoring required in future for visibility on solar generation, provision of AMI facility with RS 485 (or higher) communication port has been proposed for all meters to connect future grid digitalization in the proposed Model Regulation.

4. Proposed business models and their accounting and commercial settlement mechanism

Apart from the present business models, CAPEX and RESCO models, new utility centric business models suitable for the Indian context have been proposed. The Model Regulation has been framed to support these business models in terms of provisions related to accounting and commercial settlement. It requires new definitions (RESCO, Prosumer) to allow participation from different stakeholders. The brief description of the new utility centric business models proposed is provided in the table below:

Table 3: A brief description of the proposed utility centric business models

S. No.	Business model	Description
1.	Utility aggregates demand	The utility acts as a facilitator for aggregating demand in the distribution circle. The utility identifies the least cost EPC/RESCO and takes one-time facilitation fee for the same. Other modalities are similar to business models 1 & 2.
2.	Utility aggregates demand and acts as an EPC	The utility acts as a facilitator for aggregating demand in the distribution circle. The utility identifies the least cost EPC and has a back-to-back EPC contract with it. The utility charges a one-time facilitation fee and EPC margin. Other modalities are similar to business models 1 & 2.
3.	Third party owned (Utility aggregates and acts as trader between the RESCO and consumer)	The utility acts as a facilitator for aggregating demand in the distribution circle and identifying the least cost RESCO. The DISCOM benefits by acting as a trader of generated power between the RESCO and the consumer. The utility charges a trading fee for facilitation.
4.	Utility aggregates and acts as RESCO	The utility aggregates demand and acts as a RESCO by being responsible for the complete capital and operational expenditure of the rooftop solar system. The utility signs a PPA with the consumer for the sale of the power generated from the rooftop solar system.

In case of PDRES, the settlement can be either through net metering or net billing. In case of IDRES, the settlement is similar to IPP where the electricity generated is sold directly to DISCOM through PPA.

Further, for assessing the commercial impact of GRPV penetration on a DISCOM, an analytical tool to capture the actual revenue loss due to GRPV and the benefits due to RPO, reduced procurement and reduced losses has been developed. Commercial impact of GRPV on two DISCOMs has been assessed – JBVNL (Jharkhand Bijli Vitran Nigam Limited) and BYPL (BSES Yamuna Power Limited, New Delhi).

For a GRPV penetration scenario wherein the state /DISCOM achieves the MNRE rooftop solar targets, the following are observed:

- For BYPL, the overall loss due to rooftop solar is limited to INR 9.93 Cr. **(0.25% of the approved ARR)** for 2019. In case of JBVNL, an overall benefit of INR 1.3 Cr. **(0.017% of the approved ARR)** for 2019 is observed. The overall benefit in case of JBVNL is due to the small difference between the APPC and the tariff charged. The overall benefit/loss has been computed by considering the revenue loss, RPO benefits, benefits due to reduced procurement and benefits due to reduced AT&C losses.
- The commercial impact of the above-mentioned business models was also assessed. Business Model 6, i.e., utility aggregates and acts as a RESCO, is commercially most feasible for the utility. Under Business Model 6, the PPA cost leads to no commercial impact on the utility assessed. For BYPL, the PPA cost lies between **5.8-5.9 INR/kWh**, while for JBVNL, it lies between **3.5-3.6 INR/kWh**.

The tool can enable the utility to assess the commercial impact of rooftop solar and to plan its investments in the most suitable consumer segments.

5. Proposed changes to address the new owners and flexibility in existing PPA/connection agreement

In the wake of newer arrangements, associations (such as RWAs, etc.) may also set up DRE systems. Therefore, the ownership of DRE system will not be limited to consumer or RESCO (or the third party). The DISCOM can also act as RESCO. Therefore, to accommodate possible different ownership models for setting up the DRE systems, certain changes have been proposed in the draft Model Regulation, viz., the definition of an Agreement ('Agreement' means an agreement entered into by the distribution licensee **with the person)**.

Also, in the proposed draft Model Regulation, the ownership DRE systems can be of two types: PDRES or IDRES. This reflects the dealing with different arrangements and their settlement mechanism.

6. Providing remuneration for excess generation in present energy accounting and commercial settlement principles

In the proposed Model Regulation, it is provisioned that the excess energy generated by PDRES will be settled at APPC for the year in which such excess energy is procured by the distribution licensee. It is also provisioned that the distribution licensee may undertake procurement of power from IDRES plants under Section 63 of the Act, provided the Ministry of Power, Government of India (GoI), has issued appropriate bidding guidelines for it.

7. Definition of premises and GRPV systems needs review owing to the possibility of different scenarios in the future

The definition of premises is different for Model Net Metering Regulation 2013 and a few state Regulations in the way they treat open land. In case of Rajasthan, open land is covered in the definition of "Rooftop PV Solar Power Plant". In some cases, elevated areas on the land or open areas on the land is also allowed as part of rooftop system in the definition of premises. The treatment of the definition of open land raised questions about the extent to which the ground-mounted DRE system can be allowed under rooftop arrangement. The provisions for limiting the DRE capacity either in terms of sanctioned load (in case of PDRES) or in terms of system constraints (in case of IDRES) ensure that capacity in sync with the consumer demand and within safe limit of grid operation is developed under the proposed Model Regulation. The premises have been defined as below:

"Premises" means rooftops [or/and elevated areas on the land, building or infrastructure or part or combination thereof][3] in respect of which a separate meter or metering arrangement has been made by the licensee for supply of electricity.

8. Metering and communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

Presently, different states have laid down varied specifications for metering, communication protocol and arrangements ranging from simple MRI to AMI-compatible (for systems above certain capacity). Moreover, for real time monitoring of GRPV systems, DISCOMs are required to have advanced metering and communication arrangements.

In view of real time monitoring of solar generation, meters with AMI facility with RS 485 (or higher) communication have been proposed to have compatibility with future grid digitalization. The AMI facility will also help in easy meter reading and billing of consumers opting for DRE systems.

The draft Model Regulation has also given detailed roles and responsibilities for DISCOMs so that any application for DRE system is processed in time. Provisions related to the online application process, a defined timeline for processing the application and the information regarding the grid network to be published for all consumers have been included in the proposed draft Model Regulation. This will help in addressing operational issues, and thus, enable proliferation of DRE systems in India.

Summary of deliberations on report on "Metering Regulation and accounting framework for grid connected rooftop solar PV in India" and proposed draft Model Regulations

The Model Regulations and the report were presented at the 64th FOR meeting held on 24th August 2018 at Ranchi. The Forum considered the Model Regulations and the report, and as directed, comments from SERCs/JERCs were sought and incorporated.

Subsequently, the Model Regulations and the report were discussed in the 21st and 22nd meetings of the Technical Committee for Implementation of Framework on Renewables at the State Level (*hereinafter referred to as "Standing Technical Committee")* held on 8th October 2018 and 1st November 2018, respectively. The Standing Technical Committee made the following recommendations:

a. Definition of Premises: Only residential consumers be allowed to interconnect ground-mounted solar systems under net-metering/net-billing, and that it should be limited to their maximum contracted demand.
b. Scope of demand aggregation: DISCOMs to aggregate demand, and such aggregation be restricted to residential consumers only.
c. Compensation for net billing: Each state may decide to choose appropriate option such as commission-determined reference price or price discovered from SECI/DISCOM RTS bids.

[3] [ ] to be incorporated if decided by the Commission, to cover RE sources other than Rooftop Solar PV and premises other than rooftop under DRE framework

The Forum of Regulators in its 65th meeting held on 14th November 2018 at Bhubaneshwar was apprised of the aforesaid recommendations made by the Standing Technical Committee.

After deliberations, the Forum endorsed the report along with Model Regulations with a focus on roof top installations and adoption of the net-billing concept.

2. Introduction

2. Introduction

2.1 Background

The global success stories of GRPV in distributed grid management and power markets have resulted in increased interest from entrepreneurs, developers, financial institutions, development banks, end-users and government entities in India since 2010. The gained momentum aided in the development of regulatory framework for grid connected rooftop solar in India. Accordingly, Forum of Regulators (FOR) formulated a draft Model Net Metering Regulation 2013, a concept adopted worldwide.

In 2014, the Government of India (GoI) set an ambitious target to achieve 40 GW of cumulative installed capacity of GRPV systems by 2022. In order to achieve this ambitious target, a strategic combination of Top-Down impetus and Bottom-Up execution approach was initiated, in which Government of India (GoI), in partnership with the state governments and regulators, adopted a number of measures to promote the rooftop solar sector. In this process, nearly 29 states adopted the Model Net Metering Regulation 2013 with few or no changes to the draft Regulation, keeping in mind the changing landscape since 2013.

However, the new changes in the market scenario pose limitations on the present Regulations, coupled with several implementation challenges. Thus, a modest uptake of GRPV has been achieved till date. For instance, the present regulatory framework is focused on self-consumption, and therefore, the provisions of Model Net Metering Regulation 2013 and state Regulations have put restrictions in terms of allowable rooftop solar capacity for individual consumers and on a single distribution transformer. In some cases, the excess generation is not compensated prudently, leaving consumers with no incentive to adopt GRPV systems. Therefore, higher installation levels of GRPV systems is limited mainly to the commercial and industrial consumers, with retail tariffs much higher than the cost of energy delivered by rooftop solar systems.

During the conceptualization phase of Model Regulation, Capital Expenditure (CAPEX) or self-owned models were the most dominant business models in the rooftop solar sector. The existing Regulation largely promotes self-consumption framework of the power generated by the rooftop solar system and sets the principles for the energy and financial settlement of the power fed to the grid. CAPEX and Renewable Energy Service Company (RESCO) models are largely the dominant business models. However, the stakeholders who have opted for these two business models are not equipped to resolve the issues to scale up the sector from the current level to 40 GW by FY 2021-22. These challenges have resulted in low volumes in the GRPV segment.

2.2 Need for review of present Model Net Metering Regulation 2013

Looking at the progress made so far, GRPV projects have not seen significant growth as compared to that of the ground mounted solar projects. The latter gained attention of policy makers and other stakeholders due to large-scale capacity addition, economies of scale and falling prices discovered through competitive bidding.

In India, cumulative rooftop solar installations stand at 1,861 MW (as of September 2017) vis-à-vis a cumulative installed solar capacity of 14,163 MW. Rooftop solar has maintained around 9-10% share in overall solar capacity addition. This is much lower than the market share in developed countries such as Germany, USA and China. Germany is the world leader in deployment of solar roof-top systems. Out of the total 40 GW of solar PV capacity installed in Germany in 2015, solar roof-top contributed around 74%[4].

In addition to the incentives provided by the central government in the last 3-4 years, many states have also come up with incentive polices such as capital subsidy, generation-based incentives, tax exemption and tax holidays particularly aimed at increasing GRPV penetration. Further, the prices of GRPV systems are showing decreasing trends whereas the retail tariff is expected to increase year-on-year. Therefore, at this stage, promotion of GRPV system in India should be encouraged due to its commercial attractiveness.

From the point of view of DISCOMs, increased GRPV penetration may result in loss of revenue derived from fixed costs and other consumers might have to bear the burden for compensating the DISCOMs. The variability of solar generation might put grid stability at risk and will pose challenges to the system operator when more and more GRPV projects are connected to the grid.

As explained earlier, the present regulatory framework is focused on self-consumption and therefore Model Net Metering Regulation 2013 and state Regulations provisions have set restrictions on allowable rooftop solar capacity for individual consumers and that on a single distribution transformer. These limits vary from state to state and require standardization. In some cases, the excess generation during the settlement period is not compensated at all. Apart from this, the existing Regulations allow only two business models, CAPEX and RESCO, whereas other business models can also be incorporated in the Indian context that may facilitate the proliferation of GRPV systems.

The key implementation-level challenges faced by all the stakeholders in the country include:

- Inadequacy in existing Regulations in terms of limits on system size, Distribution Transformer (DT) loading and benefit sharing
- Limited consumer awareness
- Operational challenges at DISCOM level
    a. Apprehension of loss of revenue by DISCOMs
- Absence of strong ecosystem for low cost debt financing
- Limited knowledge on adequate safeguard requirement
- Integration challenges due to the variable nature of output and as the system was never planned considering reverse flow of power

[4] *https://mnre.gov.in/file-manager/UserFiles/workshop-gcrt-0870616/german.pdf*

- Limited business models

In view of the above, it is necessary to review the existing regulatory framework, identify all such challenges faced by various stakeholders through detailed consultation and study international experiences to suggest appropriate regulatory mitigation measures required for proliferation of GRPV in India.

There is also a need to look beyond the prevalent business models. It is critical to promote and facilitate new and innovative models for installation of GRPV systems for eligible consumers, especially in the urban centres of India having inadequate rooftop area/inaccessible rooftops etc. However, the present Model Net Metering Regulation 2013 does not suitably address these challenges. With the SRISTI scheme that highlights distribution utility to be in the forefront, new utility centric business models will be devised in the near future. In this dynamic landscape, the existing metering/accounting mechanisms need revision to accommodate new and innovative business models and upcoming stakeholders, to suitably capture the needs by anticipating the sector transition.

2.3 Scope and focus of the report

In order to critically investigate the reasons behind the modest uptake, the existing policy gaps, operational challenges and market uptake trends need to be thoroughly examined. Thus, it is necessary to review existing regulatory framework (Model and State Regulations), carry out stakeholder consultation for getting insights from their experience and understand their expectations. Based on international desk research, business models that can be adopted in the Indian context need to be studied. The outcome of these exercises must be discussed with selected stakeholders to prepare a final report on comprehensive metering Regulations and settlement mechanisms proposed for GRPV in India and draft GRPV metering Regulations.

The report has nine chapters. A brief on each chapter is provided below:

- Chapter 1: Executive Summary
- Chapter 2: Introduction to the existing regulatory framework and the need for its review by understanding the existing implementation challenges faced by stakeholders across the value chain
- Chapter 3: Progress made so far in GRPV deployment in India and key drivers for its uptake. Key learnings from the international markets on regulatory provisions and their possible adoption in India.
- Chapter 4: Identified gaps and issues to be addressed in the Model Regulations based on the review of the existing Regulations and global best practices. All the identified gaps have been substantiated by global case studies and Indian case studies. Regulations of Ontario, California and Germany have been assessed and key learnings from these countries have been identified to highlight existing gaps in the Indian Regulation.

- Chapter 5: Findings from the technical study/load flow simulation analysis. The chapter covers the technical study methodology, key assumptions, main findings and recommendations for the upcoming Regulation.
- Chapter 6: The energy flow and the cash flow in each model is provided in the Annexure. Summaries on the proposed business models and a comparative analysis of the six developed business models highlighting the benefits for each stakeholder are also included.
- Chapter 7: Proposed provisions in the Model Regulation to address the technical, commercial and other issues. A governance and institutional structure for implementing the provisions has also been included in the chapter.
- Chapter 8: Annexures
- Chapter 9: Disclaimer

3. Development of solar roof-top in India and international experience

3. Development of solar roof-top in India and international experience

3.1 Solar capacity addition

GoI launched the National Action Plan on Climatic Change (NAPCC) in 2008 to outline a structure for the ecologically sustainable development of the country. Jawaharlal Nehru National Solar Mission (JNNSM), one of the several missions launched under this action plan, aims at achieving 20 GW of grid connected solar by 2022[5]. This target was further revised five folds to an ambitious target of 100 GW, to be achieved by 2022[6]. This 100 GW plan includes 40 GW capacity addition from the GRPV segment and the remaining 60 GW from large utility scale solar projects in the country.

The vigour in India's solar PV market resulted in tremendous growth of the installed capacity from 37 MW in FY 2010-11 to 21651 MW[7] by FY 2017-18. The year wise capacity addition is provided in the graph below:

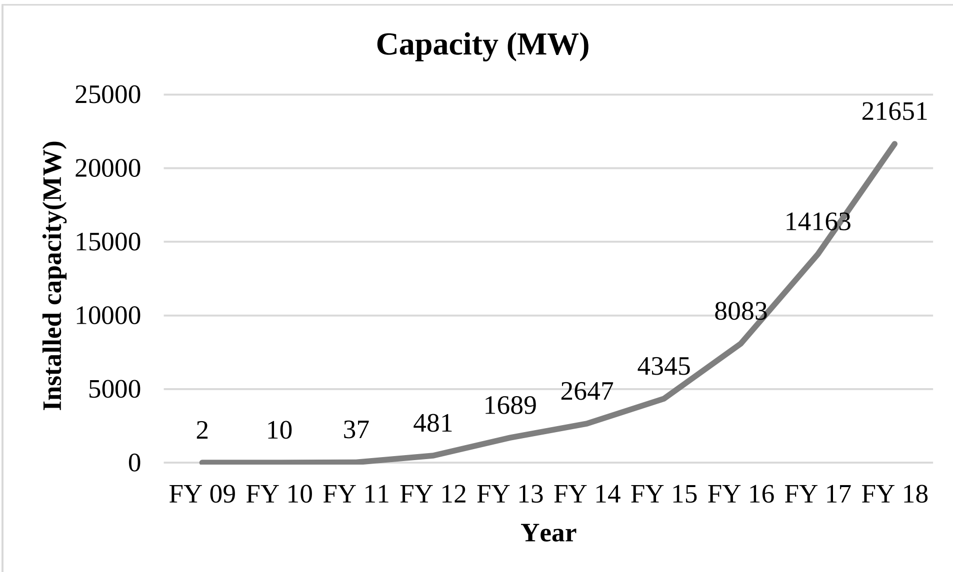


Figure 1: Capacity addition (Solar PV)[8]

The above figure clearly shows that the cumulative installed capacity has snowballed since JNNSM phase 1 i.e. 2008-09.

In India, only 1,861 MW GRPV systems were installed by the end of September 2017. The overall share of GRPV systems in total installed solar capacity has remained at about 10%. This is very less compared to the share in developed countries such as Germany, USA and China. Germany is the world leader in

5 http://www.seci.gov.in/content/innerinitiative/jnnsm.php
6 http://niti.gov.in/writereaddata/files/writereaddata/files/document_publication/report-175-GW-RE.pdf
7 http://www.cea.nic.in/reports/monthly/installedcapacity/2018/installed_capacity-03.pdf
8 http://shaktifoundation.in/wp-content/uploads/2014/02/Rooftop-Solar-Garnering-Support-from-Distribution-Utilities.pdf

the deployment of solar roof-top systems. Out of the total 40 GW of solar PV capacity installed in 2015, about 74%[9] was contributed by solar roof-top.

In USA, as on November 2017, out of the total 53 GW[10] of solar PV capacity installed, around 20 GW (38%) came from solar roof-top. In China, at the end of 2017, distributed solar PV capacity reached 19.44 GW[11] (including rooftop as well as ground mounted solar PV systems) which is about 15% of the total 130 GW of solar PV capacity installed. In residential roof-top segment, 2 GW and 10 GW of roof-top solar systems have been installed in China and USA, respectively, compared to 377 MW (as on September 2017) in India.

The graph below indicates the yearly capacity addition targets that the GoI has set to achieve by 2022:

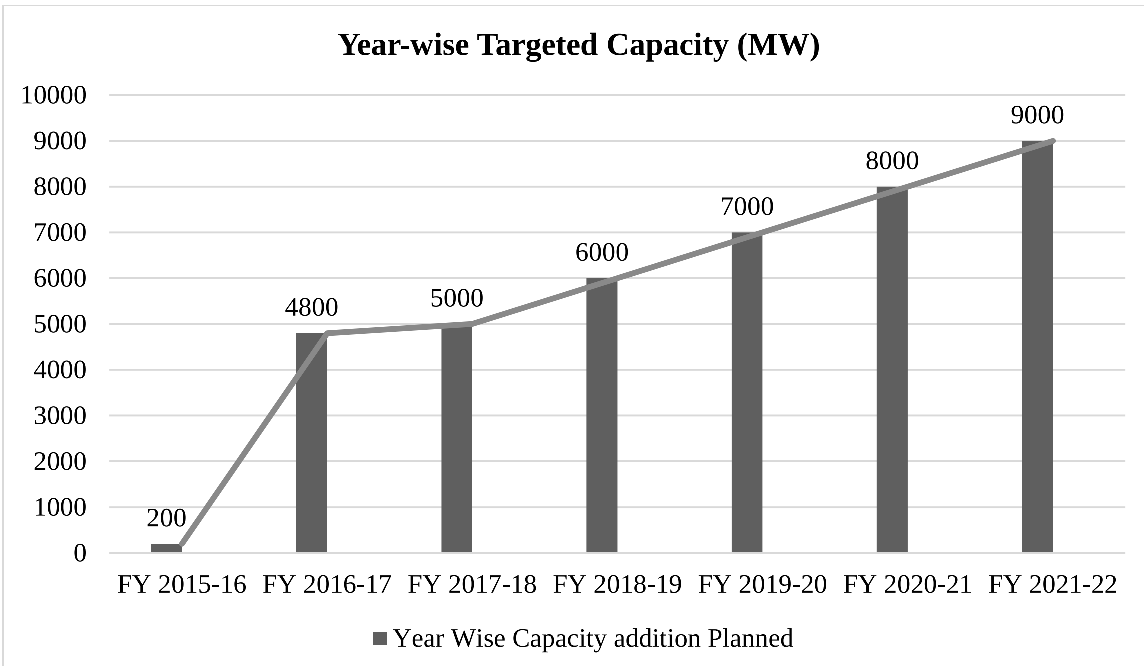


Figure 2 : Year wise capacity addition target[12]

The steep target of 4.8 GW in FY 2016-17 from 200 MW in FY 2015-16 sets a clear trend for the next five years till 2022. Effective execution thus requires a sustainable GRPV eco-system where all stakeholders co-exist with a clear win-win situation. Therefore, the policy landscape plays a pivotal role in creating the same.

Although the GRPV segment has seen a slow growth rate in the past, with decreasing cost of solar PV modules and government impetus, this sector has a promising future. Therefore, to achieve the

[9] https://mnre.gov.in/file-manager/UserFiles/workshop-gcrt-0870616/german.pdf
[10] https://www.seia.org/solar-industry-research-data
[11] https://mercomindia.com/china-2017-solar-report/
[12] https://mnre.gov.in/file-manager/UserFiles/OM-year-wise-cumulative-target-for-100000MW-grid-connected-SP-project.pdf

ambitious target of 40 MW, enabling policy and Regulation support along with key market development mechanisms will be required at both central as well as the state levels.

3.2 Key drivers for GRPV uptake

3.2.1 **Policy initiatives at central and state levels**

The central government has launched a capital subsidy funding at the central as well as state levels to boost the solar grid connected rooftop solar market in India. At the central level, the government provides financial incentives to the states for encouraging adoption of GRPV. The government also provides concessional loans to the investors of GRPV. An online portal called 'SPIN' has been launched that calculates the total GRPV area, the solar panel capacity one can install, and the associated budget constraints. Technical cooperation is also provided at the central level so that any layman can come forward and invest in GRPV.

Under the Central Financial Assistance (CFA) scheme, Ministry of New & Renewable Energy (MNRE) provides subsidy to the end users, which can be availed via State Nodal Agencies (SNAs).

The central government, on 30th December 2015, approved an increase in the CFA from Rs. 600 crore to Rs. 5,000 crore for implementation of 'Grid Connected Grid Connected Rooftop Solar and Small Solar Power Plants Programme' up to the financial year 2019- 20. The CFA being provided is up to 30% of benchmark cost/tender cost (whichever is lower) for general category states/UTs and up to 70% of benchmark cost/tender cost (whichever is lower) for special category states/UTs, i.e., north eastern states including Sikkim, Uttarakhand, Himachal Pradesh, Jammu & Kashmir, Lakshadweep, and Andaman & Nicobar Islands. Only residential, institutional and social sectors are eligible for CFA under the programme and no CFA can be availed for commercial & industrial establishments. For the government sector, an achievement-linked incentive scheme was made available under the programme as shown in the table below:

Table 4 : Achievement linked incentive scheme for the government sector

Achievement vs target	General category States (INR/KW)	Special category States (INR/KW)
Greater than 80%	16250	39000
Greater than 50% but less than 80%	9750	23400
Greater than 40% but less than 50%	6500	15600
Less than 40%	0	0

After Model Net Metering Regulation 2013, net metering Regulations for specific states have also been made by the respective regulators, Regulation and are being followed by the distribution licensees and consumers. The Renewable Purchase Obligation (RPO) targets are being set up by the state regulators for compulsory power purchase from renewable sources (solar and non-solar) and are to be met by each utility of the state. Further, it was proposed to increase the solar RPO target to 8% by 2022 in the National Tariff Policy amended in 2016.

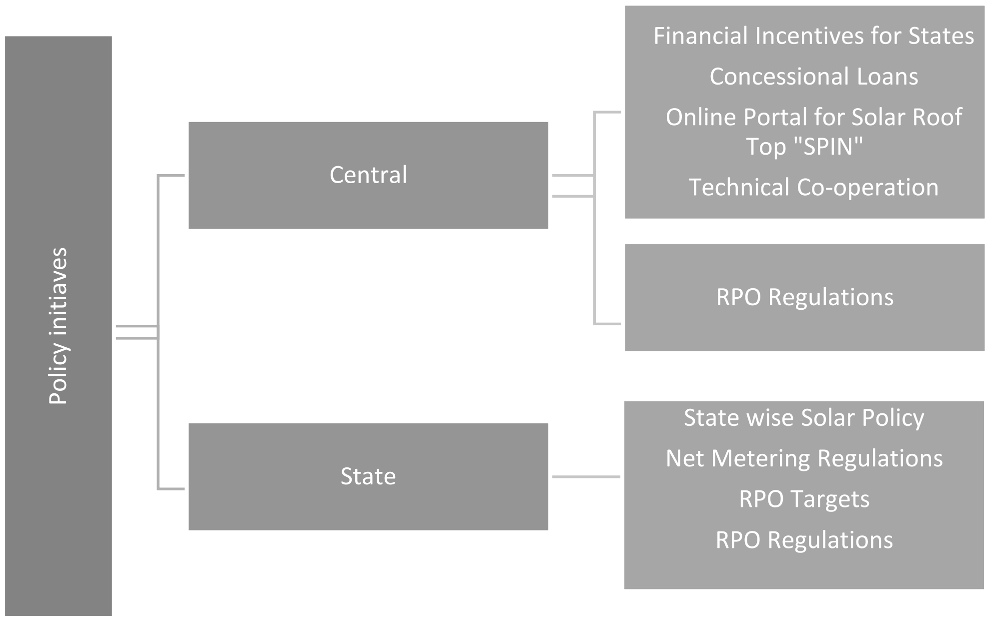


Figure 3 : Policy initiatives at central and state levels

At the policy level, in the last 3-4 years, in addition to the present incentives provided by the central government, many states have also come up with incentive polices such as capital subsidy, tax exemption and tax holidays, particularly aiming at increasing GRPV penetration.

3.2.2 **Decreasing trends in cost of solar system**

Following the global solar market trends, the Indian market has also seen a sharp decline in PV module prices, resulting in an overall reduction in the cost of solar projects. The module prices have fallen by 29% from 2015 to 2017 mainly due low-cost imports from Chinese/Korean markets, technological improvements in global arena and huge scalability of module manufacturing in China.

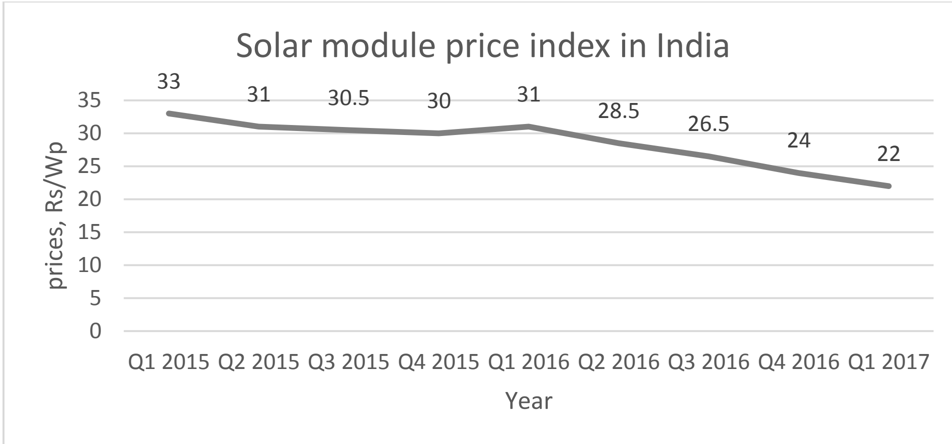


Figure 4 : Solar module prices in India[13]

The prices of solar module have fallen by 8% over the last quarter. The fall in prices indicates that the trend might continue, and the market is yet to reach price equilibrium. Based on the recent trends in module price fall, a system size pricing trend has been shown in the graph below:

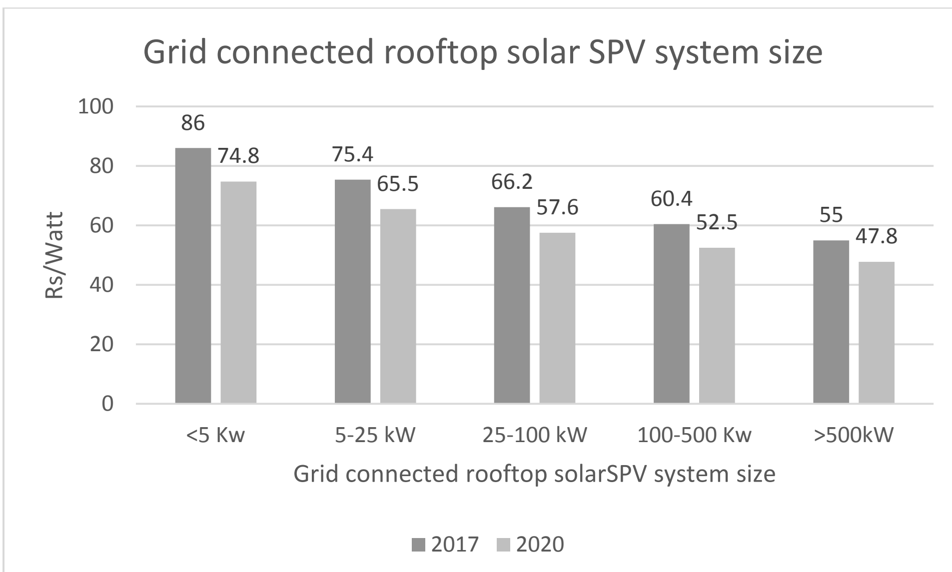


Figure 5 : System size pricing trend[14]

Due to economies of scale, larger sized systems result in less per Watt cost. It is anticipated that in 2020, the benchmark might reach below even 50 INR per Watt for project sizes greater than 600 kW capacity.

3.2.3 **Availability of compatible metering technology**

GRPV plants mainly are deployed in consumer premises and need neither net metering nor gross metering arrangements. In both metering arrangements, separate meters will be installed for recording

[13] http://www.bridgetoindia.com/wp-content/uploads/2017/05/BRIDGE-TO-INDIA_India-Solar-Handbook_2017-1.pdf
[14] http://www.bridgetoindia.com/wp-content/uploads/2017/05/BRIDGE-TO-INDIA_India-Solar-Handbook_2017-1.pdf

the energy exported to the grid. For a simple net metering arrangement, the present practice mandates installation of both solar meter and net meter.

The export and import meters with communication technologies will work as smart meters. The meter data can be managed at the developer side with a Meter Data Management System (MDMS). Metering infrastructure such as Advanced Metering Infrastructure (AMI) and Automatic Meter Reading (AMR) is utilized for optimization of benefits to developers as well as utilities and reduces manual interference.

With the advent of smart metering technologies in India, hurdles in effective net metering implementation get reduced. Users are slowly getting more confident in installing the systems as a result.

3.3 Existing regulatory framework

As mentioned earlier, the development of regulatory framework for GRPV started when FOR first came up with a draft Model Regulation for GRPV system in 2013 based on net metering. Various states introduced their net metering Regulations post modifications/additions to the existing rooftop solar Model Regulations.

Apprehensive about introducing distributed generation in distribution system (below 33 KV), which was designed for unidirectional power flow, the cumulative capacity of GRPV systems on a particular DT was restricted at 15% of peak capacity of the DT to avoid any reverse power flow. The salient features of Model Net Metering Regulation 2013 are provided in the table below:

Table 5: Salient features of Net Metering Regulation, 2013

Sr. No.	Provisions	Descriptions
1	Applicability	All consumers
2	Business models	CAPEX and RESCO
3	Metering principles	Net metering
4	System capacity	Maximum capacity of 1 MW
5	Limits on DT loading	15% (to be reviewed based on technical studies or standards subsequently defined by Central Electricity Authority (CEA))
6	Exemption from other charges	Wheeling charges, cross-subsidy surcharge and banking charges
7	Communication capability	Meter Reading Instrument (MRI) compatible
8	Rate applicable in case of export to the grid	No payment if electricity generated exceeds 90% of the electricity consumed
9	Settlement period	One year

Sr. No.	Provisions	Descriptions
10	Renewable Purchase Obligation (RPO) compliance	Units consumed by the consumer will qualify for the RPO compliance for the Distribution Licensee
11	Managing safety	Primarily responsibility of consumer, auto shutting of solar plant when grid supplier fails are also provided

In its report of August 2013, the Working Group of the FOR had also stated that the limit of 15% on DT could be reviewed based on technical studies conducted by the utility or standards subsequently defined by CEA. In the same report, FOR had set out the following reasoning for suggesting a capacity limit of 1 MW for GRPV net metering arrangements in its draft Model Regulations:

> *"The following provisions can be considered for developing the regulatory framework for net-metering based roof-top PV systems:*
>
> *The maximum rated capacity for a roof-top project for interconnection with the grid at a specific grid voltage level shall be as per the provisions of the respective state supply/distribution code, read for the purpose of deciding the interconnection voltage by replacing the contracted demand with maximum rated capacity of the solar roof-top system.*
>
> *The maximum capacity of roof-top solar system defined for grid connection in several states is 1 MW. The maximum permissible capacity under Rooftop and Other Small Solar Power Generation Plant (RPSSGP) is 2 MW, where most projects have been ground-mounted small-scale projects. Considering the above, the maximum capacity limit for roof-top solar system can be capped at 1 MW for a single metering point to qualify under net-metering."*

Model Net Metering Regulation 2013 also puts a maximum limit of 1 MW on the system size allowed for installation. The states have also put restrictions on consumers' individual installation capacity as some percentage of their sanctioned load or connected load. The range for individual GRPV system capacity is between 40% and 100% of the sanctioned load.

Following the Model Net Metering Regulation 2013, different states have notified their respective state Regulations, which were consistent with Model Net Metering Regulation 2013 in terms of the structure consisting of the following.

1. Metering schemes
2. System size, limit on DT capacity and maximum size allowed
3. Interconnection arrangement
4. Energy accounting and commercial settlement, and
5. Regulatory provisions related to RPO, Renewable Energy Certificate (REC) and open access

The states have also adopted principles based on the experience gained and metering and communication technology available at the time of framing Regulation. Most of the states have adopted net metering scheme, and in some cases, such as Andhra Pradesh and Telangana, both gross metering and net metering schemes have been permitted. The Net Metering Regulation stipulates that the maximum system size shall be 1 MW. This has been the same in almost all state Regulations except in Goa and Union Territories (UTs) under the jurisdiction of the Joint Electricity Regulatory Commission (JERC), where the limit is 500 KW.

The voltage-wise capacity that can be connected is also provided in state Regulations, though the capacity varies across states. The states have also put restrictions on consumers' individual capacity as a specified percentage of their sanctioned load or connected load. The range for individual GRPV system capacity is between 40% and 100% of the sanctioned load.

The DT loading limits are also different in different states. Some states have adopted 15% limit (in line with Model Net Metering Regulation 2013) whereas a few states have relaxed it further. The range for DT loading is between 15% and 75% (in Odisha). In the state of Telangana, the DT loading is allowed up to 50% with additional condition that if system study is allowed, more GRPV systems can be allowed on the same DT.

A brief summary of major provisions from state Regulations related to GRPV system are provided in the table below:

Table 6: Major Provisions in State Regulations related to GRPV System

Sr. No.	Provisions	Descriptions
1.	Applicability	All consumers
2.	Business models	CAPEX and RESCO
3.	Metering principles	Mostly net metering; gross metering in a few states
4.	System capacity	40% to 100% of the sanctioned load
5.	Limits on DT loading	15% to 75% of the peak capacity or rated capacity of DT
6.	Exemption from other charges	Wheeling charges, cross-subsidy surcharge and additional surcharge; banking charges and transmission charges; in some states, transmission loss and wheeling loss is also exempted
7.	Communication capability	MRI compatible; few states have asked for AMI compatible net meters
8.	Rate applicable in case of export to the grid	FiT, Power Purchase Agreement (PPA) rate or Average Power Purchase Cost (APPC) (in most cases)
9.	Settlement period	Mostly one year; a few states like Andhra Pradesh and Telangana have half-yearly settlement period. In most cases, the settlement year is financial year (April to March), except Punjab and Sikkim, where the settlement year starts from October

Sr. No.	Provisions	Descriptions
10.	RPO compliance	Major states allow solar energy generated as part of RPO compliance; in case of Karnataka, if the GRPV is DISCOM owned, then total generation is considered under RPO compliance otherwise total energy purchased is considered
11.	Managing safety	Primarily responsibility of consumer, provisions for auto-shutting of solar plant when grid supplier fails is also provided

3.4 Global experience

In the developed countries, the GRPV segment has seen tremendous growth. In the USA, as on November 2017, of the total 53 GW[15] of solar PV capacity installed, around 20 GW (38%) came from solar roof-top. In China, at the end of 2017, distributed solar PV capacity reached 19.44 GW16 (including roof-top and ground mounted solar PV systems), which was around 15% of the total 130 GW of solar PV capacity installed. In the residential roof-top segment, 2 GW and 10 GW of roof-top solar systems have been installed in China and USA, respectively, compared to 377 MW (as on September 2017) in India.

The key learnings from the international experience suggest that the GRPV segment in India can also grow by removing present restrictions in terms of system capacity or DT capacity (to the extent possible). This can be done by allowing higher system capacities (with adequate measures from system operations point of view), increasing consumer reach by adopting different business models for different types of consumers, and providing suitable energy accounting and remunerative commercial settlement principles to attract consumers.

The major provisions from international experience are provided in the table below:

Table 7: Major Provisions related to GRPV in other countries

Sr. No.	Provisions	Descriptions
1.	Applicability	All consumers with multiple options to choose: business models and financing
2.	Business models	CAPEX and RESCO (consumer centric and utility centric), community and virtual utility
3.	Metering principles	Net/Gross/Virtual (choice to consumer to select net or gross metering)
4.	System capacity	1. USA: California – 100% of the sanctioned load for NEM, Colorado – 120% of the customer's average demand and Virginia – not exceeding customers annual load 2. Brazil – 100% of the sanctioned load or contract

15 https://www.seia.org/solar-industry-research-data
16 https://mercomindia.com/china-2017-solar-report/

Sr. No.	Provisions	Descriptions
		demand for NEM 3. Maximum System Capacity – California – 5 MW to 10 MW, Mississippi – 2 MW for non-residential consumer and 20 KW for residential, North Carolina – 1 MW
5.	Limits on system loading	Overall limit based on peak demand of utility like 1.5% to 5% in USA
6.	Communication capability	Germany: DISCOMs are moving towards smart meters; though it is not compulsory California: DISCOMs are moving towards smart meters; though it is not compulsory
7.	Rate applicable in case of export to the grid	Germany: FiT USA: California – 12 month average spot market price; Virginia, Nevada and Minnesota -- Avoided cost rate
8.	Settlement period	USA: In the States of Virginia, Minnesota, California, the settlement period is one year with option to roll over credit to next settlement period or settle at the end of 12 months

As of May 2015, 48 countries worldwide had implemented net metering schemes, in most of the cases, at the national level. Net metering had become the incentive policy choice in 26 countries since 2012, when around 22 countries adopted net metering schemes.[17] EY has assessed the regulatory scenario of California, Germany, EU and Canada.

Key takeaways from the international experience are provided below:

California (USA):

- Higher system capacity (more than 1 MW) can be allowed depending upon the consumer category, their demand and technical feasibility of interconnection.
- Purpose of net metering Regulation is to promote self–consumption, which can be achieved when consumer demand is high and generation from higher GRPV capacity can be absorbed by the consumer himself at a single location.
- The issue of cost of upgrading infrastructure will also arise when higher capacity is allowed, which needs to be either recovered from the consumer or shared by the DISCOM and the consumer depending upon the upgradation required.
- Excess generation, if any, after settlement period should be compensated at a reasonable rate. In many cases, no payment is done for the excess generation.
- Different business models as per consumer needs can be permitted.

[17] *Regulatory Trends in Renewable Energy Self-Supply : A Summary of International Debates*

Germany:

- Visibility and control over solar generation beyond certain capacity is a must for the DISCOM or the system operator to meet the requirement of a stable grid operation. For low capacity systems, certain restrictions should be put so that a minimum level of feed-in is maintained.
- The GRPV invertor system must be able to respond to the system requirement and follow instruction of the area system operator. In addition, technical specifications need to be designed accordingly.
- Going forward, stringent interconnection standards will be required when a greater number of GRPV systems will get interconnected in the distribution network.

European Union (EU):

- Innovation in financing mechanisms and business models is possible only when the basic regulatory framework allows new entrants and ways of installing GRPV systems. If the regulatory framework is overly restrictive, new business models that can facilitate the upfront investment required cannot be accepted. It is critical that electricity market rules are opened-up across to allow for more decentralized electricity generation and supply.

Canada:

- Regulatory provisions related to eligibility and detailed definition in case of multiple business models will be required
- PPA related clauses - Cancellation and renewal of existing contracts need to be defined. It will be very useful if standard agreements are prepared for different business models with standardized terms and conditions for cancellation and renewal.
- Special cases for billing and commercial settlement – It will be useful for stakeholders if examples of accounting and billing settlements are provided for different business models

4. Gap Assessment and challenges in Model Net Metering Regulation 2013 and their mitigation measures

4. Gap assessment and challenges in Model Net Metering Regulation 2013 and their mitigation measures

4.1 Gap Assessment

As explained earlier, the present regulatory framework is focused on self-consumption and therefore the provisions of Model Net Metering Regulation 2013 and that of state Regulations have put restrictions on allowable rooftop solar capacity for individual consumers and single distribution transformer. These limits vary from state to state and require standardization. In some cases, the excess generation during the settlement period is not compensated at all. Also, the existing Regulations allow only two business models, CAPEX and RESCO, whereas other business models can also be incorporated in the Indian context, helping in proliferation of GRPV systems.

The following section deliberates on the changes required in the proposed GRPV Model Regulation based on international experience and case studies observed in India in recent times. The gaps have been divided into three categories: Technical, Commercial and Others, based on their nature. The identified gaps that require mitigation measures while framing proposed Model Regulation are listed below:

- Gaps related to technical aspects
    - Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity
    - Different limits on GRPV capacities connected to DT
    - Limited provisions on real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems
- Gaps related to commercial aspects
    - Limited business models options available to consumers and developers, limited scope to DISCOMs in the present scenario
    - Absence of additional clauses related to change in ownership and flexibility in existing PPA/connection agreement
    - No remuneration for excess generation in present energy accounting and commercial settlement principles
- Gaps relates to other aspects: general definition, metering and communication
    - Definition of premises and solar roof-top PV systems needs review owing to future possibility of different scenarios
    - Metering and communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

A detailed explanation of the identified gaps is provided in the subsequent sections.

4.1.1 **Gaps related to technical aspects**

4.1.1.1 Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity

The present Regulations (Model and state) have put restrictions on GRPV capacity that can be interconnected. Though Model Net Metering Regulation 2013 does not put any restriction on the installed capacity in terms of sanction load, a few state Regulations have put restrictions. The limit on GRPV system capacity in terms of sanctioned load differs from state to state; ranging from 40% to 100% in net metering. Further, the maximum capacity of 1 MW can be set up in India under the net metering arrangement.

There are instances where higher capacity is allowed under the net metering arrangement. Uttar Pradesh Electricity Regulatory Commission (UPERC) invoked the “Power to Relax” Clause of its Solar Rooftop Regulations and allowed setting up of GRPV systems (more than 1 MW) under net metering. The details are provided in the table below:

Table 8: Cases where UPERC has allowed GRPV systems above 1 MW

Sr. No.	Petitioner	Project Size Allowed (MW)	Sanctioned Load/ Contract demand of the facility (MW)	Date of order
1.	Ordnance Factory, Kanpur	5.00	22.00 MVA	01.06.2017
2.	Hindustan Aeronautics Ltd., Kanpur	2.90	2.90	18.12.2017
3.	Hindustan Aeronautics Ltd., Amethi	1.75	5.00 MVA	18.12.2017
4.	Jhanshi Workshop, North-Central Railway	1.20	2.945 MVA	18.12.2017
5.	L.B.S. International Airport, Varanasi	2.00	2.00 MVA	18.12.2017
6.	Sukhir Agro, Shahjahanpur	3.40	3.80	18.12.2017
7.	Hindustan Aeronautics Ltd., Lucknow	4.00	12.21	23.01.2018

From the above table it is clear that even though the project size is greater than 1 MW, it is less than or equal to their sanction loads/contract demand. The higher capacity systems were technically feasible and hence were granted interconnection. There have been cases wherein the commission has refused interconnection despite the system being technically feasible. The cases are as follows:

Case No. 133 of 2016 (Maharashtra Metro Rail Corporation Ltd. (MMRCL) vs Maharashtra State Electricity Distribution Company Limited & Maharashtra State Electricity Transmission Company Limited)

Maharashtra Metro Rail Corporation Ltd. (MMRCL) applied for net metering arrangement for 23 MWp at different locations such as metro stations, open land, boundary walls and viaducts in the city of Nagpur. However, the connectivity to the grid was available only at two of the abovementioned locations; one at 132 KV and another at 33 KV. The present regulatory framework in Maharashtra allows maximum 1 MW capacity at a single location. Further, GRPV systems only up to 40% of the DT capacity can be installed. Due to these limits, maximum 2 MW capacity was possible against a potential

23 MW under the present net metering Regulation. Maharashtra Electricity Regulatory Commission (MERC), in its order dated January 16, 2018, in case No. 133 of 2016 refused the demand of Nagpur Metro under present net metering Regulation and advised to explore other options such as gross metering and open access available for GRPV systems higher than 1 MW.

Case No. 163 of 2017 (Cleanmax Enviro Energy Solutions Pvt Ltd vs Maharashtra State Electricity Distribution Company Limited)

In another case, a consumer applied for availing benefits of two different Regulations -- net metering Regulation as well as open access Regulation -- simultaneously in Maharashtra. Cleanmax Enviro Energy Solutions Pvt Ltd. had installed a GRPV system of 991 KW (against the potential of 1027 KW, to meet the net metering criteria), for one of its client, Asahi India Glass Limited (contract demand of 7000 KVA) which was also availing open access for 3000 KVA from a conventional source under a group active arrangement.

As the GRPV capacity was below 1 MW, Asahi applied for net metering arrangement to Maharashtra State Electricity Distribution Company Limited (MSEDCL). Due to no response from MSEDCL, Cleanmax consulted with MERC to provide clarification that no such limitation is placed for granting permission to open access consumers for availing the net metering arrangement. MERC, in its order dated June 12, 2018, in case No. 163 of 2017 denied permission by saying that net metering and open access are two separate arrangements and cannot be availed simultaneously by the same consumer due to various potential issues related to grid security, accounting, billing and settlement etc.

Order dated October 09, 2017, on determination of benchmark capital cost for solar PV and solar thermal power projects applicable during FY 2017-18 and resultant generic levelled tariff, Rajasthan Electricity Regulatory Commission (RERC)

RERC, in its *suo motu* order dated October 09, 2017, while issuing generic tariff order for FY 2017-18, has determined a generic tariff for grid connected solar roof-top projects -- both ground mounted and GRPV -- for capacity less than 5 MW. This was done keeping in view the spirit of para 4.3.1 of the bidding guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects on long term basis issued by GoI on August 03, 2017. The guidelines suggest competitive route for long term procurement of electricity by procurers from grid-connected solar PV power projects having size of 5 MW and above.

<u>International Perspective</u>

Internationally, earlier restrictions on system capacity have been relaxed and higher capacity is permitted for GRPV system. Canada has removed the cap of 500 KW of system size. In North Carolina, USA, the system capacity limit was 20 KW for residential and 100 KW for commercial consumers. In 2007, the North Carolina legislature, through Session Law 2007-397, requested that the Public Utility Commission (PUC) consider raising the net metering generation cap to 1 MW, which the Commission agreed upon stating that the decision will assist in furthering renewable energy deployment.

In California, interconnection with the grid under net metering is permissible up to 10 MW. In California, higher system capacity (more than 1 MW) is permissible depending upon the consumer category, their demand and technical feasibility of interconnection. Further, under the bill credit transfer program authorized by Public Utilities Code 2830, GRPV systems of higher capacity, for e.g., 5-MW capacity, owned by, operated by, or on property under the control of a local Government or university are allowed in California.

In Mississippi, USA, net metering is limited to 20 KW for residential customers, and 2 MW for non-residential customers. Residential systems are limited to 20 KW and must be located on customer's premises. Non-residential customers can aggregate generation systems up to 2 MW within their premises.

While in India, the permissible system capacity based on sanctioned load varies from 40% to 100%, in countries such as Brazil and a few states in the USA such as California & Virginia, it is 100%. In case of other states such as Colorado, especially for shared renewables, the limit is 120% of the customer's average annual consumption.

In a nod to utility concerns that distributed energy resources to customer sites represent lost revenues, many states followed the practice of limiting the total aggregate capacity eligible for net metering based on peak demand. The most common program cap is based on a percentage of the utility or state's peak demand, capacity, or on-load in a given reference year. Typical range is from 1.5% to 5% in the USA. Many states in the USA have increased their caps over time as distributed PV penetrations have increased, or modifications have been made to net metering laws.

4.1.1.2 Different limits on GRPV capacities connected to DT require review

The present regulatory framework has put restrictions on the maximum capacity that can be connected to a DT. The main reason for introducing this restriction was apprehension about possible reverse power flow. Also, as the present distribution network is not designed for reverse power flow, it was envisaged that the limit can be reviewed after carrying out a technical study at a suitable point of time.

Practically, as learnt from the stakeholder consultations, the limit on DT loading has not been met so far. Therefore, the actual impact of putting more solar generation on a particular DT has not been evaluated. Neither have studies on the same been carried out by the DISCOM, nor have such studies been proposed by the regulator.

4.1.1.3 Limited provisions on real time monitoring of solar generation and participation in system operations; required in case of large penetration of GRPV systems

High penetration of GRPV systems may create technical issues such as reverse power flow, over frequency or under frequency, over voltage or under voltage and reactive power management depending on the length of the network and the supply-demand situation. Therefore, system operators must be aware of real time generation from GRPV systems, at least of large capacities. Germany has formulated stringent grid interconnection guidelines and laws to maintain grid stability and has standardized power quality from distributed generation resources.

Presently, the utilities in India lag behind European utilities in terms of real-time monitoring of their assets and distributed generation sources connected to their networks. This can be attributed to the lower GRPV penetration level. Although real time data monitoring requires extensive capital expenditure and technological advancements, regulatory directive might be helpful for utilities that are slowly moving towards grid digitization and enhancement of present communication protocols.

CEA technical standard for interconnection to grid states that, with regard to generating stations using inverters, measurement of harmonic content, DC injection and flicker shall be done at least once a year in the presence of the parties concerned. The indicative date for doing this shall be mentioned in the connection agreement.

IEEE Standard 1547 (2003), which is the primary document on interconnection of systems, also has reference to periodic tests among general requirements, responses to abnormal conditions, power quality, islanding and test specifications and requirements for design, production, installation evaluation, commissioning.

Provisions to refer such standards to address interconnection related issues are required.

International Perspective

In Germany, the Renewable Resources Act provides guidelines for interconnection, and mandates the connection of renewable systems on priority basis. Verband der Elektrotechnik (VDE) 4105 Code of Practice is mandatory from January 2012 for interconnection with the low-voltage grid.

Mainly, there are three major directives in Germany that mandate GRPV plants to meet technical standards for their interconnection with the grid:

- The BDEW medium voltage directive
- The VDE code of practice
- The Renewable Energy Sources Act (EEG) 2012

The BDEW medium voltage directive

Since January 1, 2009, the revised medium voltage directive has been in effect for all distributed power generation plants that feed at the medium voltage level into the power distribution grid – i.e., typically for plants with approximately 200 kW of power and more. Its requirements may be divided into four stages, which came into effect successively.

- Participation in feed-in arrangement - If a section of the relevant medium-voltage grid or higher level transmission grid is temporarily overloaded, the distribution grid operator sends a ripple control signal that must be implemented as limitation of the fed-in active power (typically 60, 30 or zero percent of the rated power). The required limitation must be implemented by the inverter within 60 seconds.
- Active power reduction in case of over frequency – Earlier, the PV inverters had to be disconnected from the grid immediately after the power frequency went beyond the permitted range of frequency. However, sudden disconnection of large PV power generation capacities can have a negative impact on grid stability. Therefore, the invertor now needs to reduce their

current power with a gradient of 40% per Hertz from 50.2 through 51.5 Hz and only disconnect from the grid above 51.5 Hz. The disconnection limit in case of under frequency remains unchanged at 47.5 Hz.

- Provision of reactive power - The grid operator may demand a displacement power factor between 0.95 and 1 with three variations for the definition of the target value being available to that end:
  - The grid operator specifies fixed target values that the plant operator is required to set.
  - Various reactive power values are set on the basis of an agreed upon time schedule or specified via supervisory control signal by a central control centre of the grid operator.
  - The reactive power percentage is regulated via a characteristic curve depending on the grid voltage measured at the connection point or the ratio of the currently supplied active power and the nominal power of the inverter.
- Dynamic grid support - The revised medium-voltage directive now requires PV inverters to support the grid in case of an incident by "riding through"[18] voltage drops of up to several seconds and then resuming normal feed-in immediately afterwards (so-called low-voltage ride-through, or LVRT). The inverter behaves passively throughout the course of the error in the limited version. The device also needs to feed reactive power into the power distribution grid during a voltage drop in the complete version of the LVRT, as it has been required since April 1, 2011. As a result, they contribute to the resolution of the incident and help to trigger the grid protection devices.

The VDE code of practice:

The VDE 4105 code of practice has been in place since August 1, 2011, and binding since January 1, 2012, and affects all GRPV plants that feed in to the low-voltage grid, which means the vast majority of them. The code requires the following requirements to comply:

- Active power reduction in case of over frequency - PV plants are not disconnected immediately when the power frequency is too high but is reduced gradually. The permissible frequency band will be then expanded to a range from 47.5 to 51.5 Hz. The current feed-in power must be reduced by 40%/Hz. The plant will be disconnected only if 51.5 Hz is attained.
- Connection criteria and permissible unbalanced load - A maximum plant power of 13.8 kVA results when using single-phase, uncoupled inverters (3 x 4.6 kVA) only. Therefore, at least the proportion of the power exceeding 13.8 kVA must be designed with three-phase or communicatively coupled single phase inverters in larger plants.
- Grid and GRPV plant protection - Set values for the G/P protection:
  - Deactivation limits: Voltage drop protection (U < 184 V)
  - Voltage increase protection (U >) > 253 V
  - Voltage increase protection (U >>) > 264.5 V Frequency drop protection (f < 47.5 Hz)
  - Frequency increase protection (f >) > 51.5 Hz Reconnection limits: Voltage greater than 195.5 V and less than 253 V. Frequency greater than 47.5 Hz and less than 50.05 Hz

[18] In electrical power engineering, fault ride through (FRT), sometimes under-voltage ride through (UVRT) or Low voltage ride through (LVRT) , is the capability of electric generators to stay connected in short periods of lower electric network voltage

The Renewable Energy Sources Act (EEG) 2012:

The Renewable Energy Sources Act (EEG), as amended by mid-2011 and valid from the beginning of 2012, included new requirements regarding the grid integration of PV plants.

- It stipulated that plants with more than 100 kW peak power must participate in feed-in management and, at the same time, extend this demand to smaller plants – of course, in a less stringent form
- Furthermore, operators of PV plants with less than 30 kWp of power were allowed to skip installing the device for remote power limitation if they agreed to accept limitation of feed-in power to 70 percent of the installed generator power.
- As for the obligation to retrofit, both power categories also differ: plants between 30 and 100 kWp were to be retrofitted by the end of 2013, if they were commissioned after December 31, 2008.

There was no obligation to retrofit plants with less than 30 kWp.

4.1.2 Gaps related to commercial aspects

4.1.2.1 Limited business models options available to consumers and developers, limited scope for DISCOMs in present scenario

The existing Regulations (Model and State) largely promote elf-consumption framework for the power generated by the GRPV system and set the principles for the energy accounting and commercial settlement for the net import/export of electricity received/fed in to the grid. Typical structures of the possible business models, prevalent in the USA, are provided in the table below:

Table 9: Structure of business models prevalent in the USA

Ownership structure	Metering structure	Revenue structure
▶ **Self-owned**	▶ Gross metering	▶ Solar lease
▶ **Third party**	▶ Net metering	▶ PPA
▶ **Utility owned**	▶ Virtual	▶ Self-use

Thus, there is a need to look beyond the prevalent business models to promote and facilitate new and innovative models for installation of GRPV systems, for eligible consumers, e.g., in the urban centres of India such as Delhi, which have inadequate rooftop area/inaccessible rooftops but are willing to participate in group GRPV installations and share the benefits.

Unlike the frameworks in developed countries, the present regulatory framework of India does not support multiple parties willing to install solar roof-top (like housing colony or apartment system) and participating in commercial settlement. The role of DISCOMs is also limited whereas they can be more proactive in the proliferation of the GRPV system. Multiple options of metering and business models, which shall balance interests of DISCOMs and consumers, will require certain amendments in the present provisions and addition of new provisions. This shall provide regulatory framework for the new business models including accounting and commercial settlement mechanisms for GRPV.

4.1.2.2 *Absence of additional clauses related to change in ownership and flexibility in existing PPA/connection agreement*

In the evolving scenario of GRPV segment in India, involvement of RESCOs has become more and more popular through Operational Expenditure (OPEX) models in which multiple beneficiaries take part in owning, maintaining GRPV systems and settling commercial agreements. Thus, DISCOMs and developers normally sign PPAs based on the mutually agreed terms and conditions for 25 years since useful life of solar panels is 25 years. In California, the agreement period is 20 years. However, there is no compulsion on the 20-year contract period.

Also, in India, the GRPV market is still in its nascent stages with limited consumer awareness. While looking at emerging business models, it is important to assist consumers in becoming more aware of different business modalities. Thus, taking cognizance of different versions of PPAs for different business models will assist consumers in validating agreement clauses with DISCOMs or developers. Therefore, guidelines for agreement signing, check list for different business models and also for different scenarios such as new agreement after existing PPA cancellation etc. need to be added in the upcoming Regulations.

In a few states like Tamil Nadu and Uttar Pradesh, the connection agreement can be cancelled after serving a notice for 90. In J&K, Punjab, Manipur and Mizoram, the notice period is of one month.

<u>International Perspective</u>

In Ontario NEM Regulations, existing PPAs/agreements/renewal is performed in the following manner. The PPA should insist on different possible scenarios on validity of the existing contracts, such as:

- Until the agreement expires
- Agreement expired but application for renewal has been submitted before final due date etc.
- Mention the cases against which agreements between a generator and distributor can be renewed. A few examples are:
    - Both the parties agreed to renew
    - In case of system modifications/additions, though both parties agreed, the formal procedure followed during the first time the system was commissioned needs to be followed
    - The type of new agreement is analogous to the old one and there are no significant policy changes in between. The tariff agreed must be different and must reflect the reduced cost of the solar plant
    - All features of agreements should conform to the Model Net Regulation, which should define the criteria (a template format may be given)

4.1.2.3 No remuneration for excess generation in present energy accounting and commercial settlement principles

Under the present Model Net Metering Regulation 2013, the consumer accrues no benefits for excess generation. Therefore, the existing energy accounting and commercial settlement mechanism also needs suitable revision to compensate all stakeholders in a reasonable manner. The mechanism should also suitably capture the stakeholders' needs and address their issues by anticipating the sector's transition.

A few concepts such as gross metering, community metering and virtual net metering are presently under discussion, which can further enable uptake if they can be a part of the regulatory mandate. A few State Electricity Regulatory Commissions (SERCs) have notified the provisions of gross metering as part of their GRPV regulatory framework. Other metering methods need to be suitably developed and adopted based on the new and emerging business models.

According to RERC (Connectivity and Net Metering for Rooftop and Small Solar Grid Interactive Systems) Regulations, 2015, the excess energy fed into the grid is compensated at variable feed-in-tariff to be determined by the Commission every year. The relevant excerpts are reproduced below:

> *"Provided that in the event the electricity injected exceeds the electricity consumed during the billing period, such excess injected electricity shall be paid by the Distribution Licensee at feed in tariff determined by the Commission from time to time for Solar Photo Voltaic generation in next billing period provided that such export is above 50 units……"*

The provision of variable rate for compensation will reflect the market trend and benefit DISCOM if the current trend of reducing prices continues. However, from a developer or consumer point of view, this can be treated as regulatory uncertainly as predicting future rate will become dynamic. Therefore, balancing of stakeholder's interest in a reasonable way is very critical for attracting consumers to opt for the GRPV systems.

<u>International Perspective</u>

In the USA, different states have followed different methods for energy accounting and commercial settlement. In Hawaii, Hawaii Public Utilities Commission eliminated the retail rate remuneration for new net metering customers. The new scheme replaces old net metering Regulation and leaves PV system owners to choose between a grid-supply option and a self-supply option.

- In case of grid-supply option, the customers receive a fixed credit for electricity injected into the grid and are billed at the retail electricity tariff for the energy they consume from the grid.
- The self-supply option is primarily aimed at creating solar owners who do not export generation to the grid, though the commission stressed no non-export design should prevent solar systems from providing grid.
- In Denmark, premium tariff system promotes the generation of electricity from renewable sources based on bonus payments. The operators of renewable energy plants usually receive a

variable bonus, which is paid on top of the market price. The sum of the market price and the bonus shall not exceed a statutory maximum per kWh, which depends on the source of energy used and the date of connection of a given plant. FiT for the excess electricity is guaranteed for 20 years, with a decreasing value after 10 years.

Commercial settlement period and rate for energy injection

A table on different provisions related to settlement period and rate in different states of the USA are provided below:

Table 10: Settlement period and rate for excess energy in different states of the USA

Sr. No.	Name of the State	Commercial settlement period and rate for energy injection
1.	Virginia	Credited to customer's next bill at retail rate. After 12-month cycle, customer may opt to roll over credit indefinitely or to receive payment at **avoided-cost rate**.
2.	Minnesota	Systems under 40 kW: Reconciled monthly; customer may opt to receive payment or credit on next bill at the **retail utility energy rate**. For systems 40 kW -1 MW, Net Excess Generation (NEG) is credited **at the avoided cost rate**, or customers may elect to be compensated in the form of a kWh credit. Excess credit will be reimbursed at the end of the calendar year at the avoided cost rate.
3.	California	Credited to customer's next bill at retail rate. After 12-month cycle, customer may opt to roll over credit indefinitely or to receive payment for credit at a rate equal to the 12-month average spot market price for the hours of 7 am to 5 pm for the year in which the surplus power was generated.
4.	Indiana	Credited to customer's next bill at **retail rate**; carries over indefinitely.
5.	New Mexico	Either credited to customer's next bill at avoided cost rate or excess kWh generated is credited to the account and rolled over indefinitely. If customer leaves the utility, unused credits are paid out at the **avoided cost rate**

In Canada, as per Ontario Regulation, a DISCOM shall calculate, for a billing period, the amount of the bill of an eligible generator who is billed on a net metering basis in the following manner:

In any billing period, when, $(D + E) \leq C$ the distributor shall use the following formula:

$A = B + C – (D + E)$. In any billing period when, $(D + E) > C$ the distributor shall use the following formula: $A = B$

For the purposes of this section,

"A" is the amount of the eligible generator's bill for the billing period,

"B" is the total amount of those charges for the billing period that are not calculated on the basis of the eligible generator's consumption of or demand for electricity, as calculated by the distributor in the manner applicable in billing a customer in the same rate class, "C" is the total amount of those charges for the electricity consumed from the distributor's distribution system by the eligible generator during the billing period that are calculated on the basis of the eligible generator's consumption of electricity or demand for electricity, including charges for the commodity of electricity, as calculated by the distributor in the manner applicable in billing a customer in the same rate class,

"D" is the total monetary value of the eligible electricity conveyed into the distributor's distribution system by the eligible generator during the billing period, calculated on the same basis as the eligible generator's consumption of electricity but not demand for electricity, including charges for the commodity of electricity, but without any adjustment for total losses as defined in the Retail Settlement Code, and

"E" is the amount of any accumulated electricity credits.

For the purposes of B, C and D in the subsection, an eligible generator's consumption of electricity is to be measured in kilowatt hours. In calculating the values of B and C in the manner applicable in billing a customer in the same rate class, the distributor shall have no regard for the eligible generator generating eligible electricity or being billed on a net metering basis.

Retail tariff and charges applicable to GRPV system user

In developed countries, with proliferated GRPV systems, tariff design has moved from volumetric tariff to fixed cost basis. This was in response to increased distributed generation to ensure DISCOM's recovery of fixed cost. For demonstrating the way retail tariff is redesigned in the context of high level of penetration of distributed generation (which might be the case in near future in India), a few examples have been provided in the table below:

Table 11: Tariff applicable for GRPV system users in the USA

Sr. No.	Name of the State	Charge for recovery of fixed charge	Details
1.	Massachusetts	Monthly minimum reliability contribution	This minimum contribution shall ensure that all DISCOM customers contribute to the fixed costs of ensuring reliability, proper maintenance and safety of the electric distribution system. This monthly minimum contribution is such that (i) It equitably allocates the fixed costs of the electric distribution system not caused by volumetric consumption; (ii) it does not excessively burden ratepayers; (iii) it does not unreasonably inhibit the development of GRPV
2.	California	Connection fee	Previously, Pacific Gas & Electric (PG&E) connected residential customers' solar systems to the company's grid for free. When the 5% penetration milestone was passed for adopting solar energy in California, the PG&E customers were imposed a fee of $75-145 if they wanted to connect their solar arrays to the PG&E electricity grid.

Sr. No.	Name of the State	Charge for recovery of fixed charge	Details
3.	Arizona	Residential Demand Charges	The Salt River Project (SRP), a utility in Arizona, is one of the few utilities in the country to impose residential demand charges, and they are mandatory only for customers with solar power systems. SRP levies a fixed charge of $32 per month for solar customers, plus a demand charge ranging from $8 to $33 per kilowatt in the summer, combined with an electric rate as low as only 3.9 cents per kWh off-peak.

Based on the above discussion, there is adequate scope for revision in the present Model Regulation.

As per Model Net Metering Regulation 2013, the excess generation during the settlement period is not compensated. The SERCs notifying their Net Metering Regulation afterwards tried to address the issue by allowing excess generation to be settled at a predefined rate such as FiT or APPC.

In India, the present tariff structure is volumetric, and the tariff determination is altogether a different procedure followed under different regulatory framework. In addition, a fixed cost is charged in a different way, such as per connection basis or per KW basis. Further, tariff determination is constrained by legacy issues such as cross-subsidy and inefficiencies.

4.1.3 Gaps related to other aspects: Generation definition, metering and communication

4.1.3.1 Definition of premises and solar roof-top PV systems needs review owning to future possibility of different scenarios

In a few state Regulations, the definitions of ‘premises’ and ‘roof-top solar system’ have been modified as compared to those provided in the Model Net Metering Regulation 2013 as explained below:

- In case of Gujarat, the definitions of ‘premises’ and ‘roof-top solar system’ have been modified by adding “open area” in the definition provided in the present Model Net Metering Regulation 2013.

- In case open land is allowed under net metering along with building infrastructure, in some cases, it might be possible to install high capacity GRPV system than the present restrictions – sanctioned load, DT capacity and maximum capacity allowed – which present framework does not allow.

In case of Nagpur metro, detailed previously, installation of 9 MWp capacity would have been possible on land available in their premises. If wall mounted GRPV systems were also taken into consideration, another 2.2 MWp of capacity would have been possible.

The Nagpur metro case also raises an important issue. If premises are at different locations within the same city and are under the jurisdiction of the same DISCOM, the Regulation may have provisions for allowing as well as disallowing such a connection. It may be a case that a customer has two connections under same consumer category at different locations, but only one location is technically feasible to cater to demand of both the locations. Presently, there is no restriction on ground mounted solar projects. But, capacity above 1 MW can connect with grid through either gross metering arrangement or reverse bidding. Therefore, in case present restrictions on GRPV systems are relaxed and ground mounted systems are allowed, there are chances that a number of ground mounted systems will apply under net metering arrangement.

4.1.3.2 Metering and communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

Under the current landscape, different states have specified varied specifications for metering, communication protocol and arrangements ranging from simple MRI to AMI compatible (for systems above certain capacity). Moreover, for real time monitoring of GRPV systems, it is required to have advanced metering and communication arrangement by DISCOMs, at least, for above a certain capacity, say, 20 KW. This can be decided post stakeholder consultations to monitor potential impact on grid stability and reactive power injections.

In view of real time monitoring of solar generation, smart meters or meters with AMI/AMR facility are required so that DISCOMs or the system operator can have visibility over solar generation when large scale deployment of GRPV system is envisaged.

Presently, consumers can purchase meter from DISCOM or can also buy meter directly from a third-party. In case of Karnataka, the list of vendors and prices is fixed by BESCOM. The information has been provided on BESCOM's website for convenience of the consumer. If DISCOM bulk purchases meters of the required specifications, the cost may reduce, ultimately benefiting the consumer. Further, the meter will be tested and kept ready for providing interconnection when consumer applies. There can be an option for a consumer to purchase meter from a third-party. However, like in Karnataka, DISCOMs should provide the list of vendors duly selected from competitive bidding meeting the technical specifications and regulatory requirement.

<u>International Perspective</u>

In California, the three big utilities moved to smart meters around 2012-13. Thus, any consumer of these utilities can install smart meters for solar roof-top (though this is not mandatory).

In case of Germany, utilities such as E.ON and Energiewende are transitioning towards 100% smart metering as there's been a progressive shift in the energy mix with the inclusion of more distributed generation (mainly GRPV).

California Distributed Generation Statistics (California DG Stats) currently includes data for all solar photovoltaic (PV) systems interconnected through the California Investor Owned Utilities (IOUs) net energy metering (NEM) tariffs regardless of capacity. The biggest balancing authority in the Western

Interconnection, the California Independent System Operator (CAISO), monitors nearly 10,000 MW of solar PV, mostly utility scale installations. SCADA systems help CAISO in grid balancing by enabling the operators in initiating or updating autonomous inverter functions at PV power plants. This includes connection with the PV plant at both high-voltage (38 kV–500 kV) transmission and medium-voltage (4 kV–38 kV) distribution levels. CAISO maintains that the power plants that do not meet the grid operator's SCADA requirements cannot interconnect.

4.2 Mitigation measures

To mitigate these gaps, the following measures have been proposed for consideration in the GRPV Model Regulation based on the recent cases arising in India and based on international experience.

4.2.1 Mitigation measures for gaps related to technical aspects

4.2.1.1 Relaxing or removing present limits based on sanctioned load and maximum GRPV capacity

As seen from the international scenario and present cases coming up in India, it is clear that:

- Higher capacity installations can be permitted as such provisions are present in other countries, and such higher capacities are also expected to increase in India in the near future.
- The dispensation for allowing higher capacity under net metering can be made based on consumer category or special cases. Large campuses of old government offices or other commercial establishments, institutes and industries etc. in order to harness GRPV potential as learnt from international cases mentioned above.
- There can be cases where the GRPV systems would be scattered within one premise or different premises within one city or within one utility area, accordingly, aggregation models for all such capacities would be required.
- In some cases, the consumer can avail the additional benefit of open access or other schemes available under different Regulation other than GRPV. Corresponding decision of allowing such connections needs to be taken.

However, allowing higher capacities will also raise certain issues. Addressing such issues would be critical for the deployment of GRPV systems in the Model Regulation. A few of such issues or challenges that need to be addressed and their mitigation measures are provided below:

- In case the consumer can consume most of the energy generated from such high capacity GRPV plants (in case no restrictions are put on GRPV capacity), then adequate accounting and commercial settlement needs to be designed.
- In cases where consumer demand is lower than the GRPV capacity, the DISCOM can be allowed to procure power from such GRPV systems on the basis of either gross metering or reverse bidding.
- It is also possible that GRPV capacity installed is lower than the sanctioned load/contract demand similar to the UP case mentioned in the earlier chapter. Such capacity should be allowed.
- The cost of upgrading existing infrastructure, if required to accommodate higher capacity, is a contentious issue as it raises the question of who will bear the cost – the consumer or the

DISCOM? The cost can be recovered based on “beneficiary-to-pay” principle. An option would be to allow recovery of such cost through Annual Revenue Requirement if the DISCOM benefits from serving more consumers or improving supply reliability by upgrading the existing infrastructure.

- If open access is allowed either partially or fully, adequate compensation would be required for DISCOMs such as cross subsidy surcharge and additional surcharge. Presently, these charges are exempted under net metering regulatory framework.
- From the system operator or DISCOM point of view, if GRPV systems of higher capacities are allowed, then regulatory provisions are required for real time visibility of their solar generation. Presently, for certain capacities, say 20 KW and above, to be decided after consultation, AMI arrangement can be installed. From future perspective, as technology is changing fast and also becoming affordable, smart meters can be made compulsory for each GRPV system.

4.2.1.2 *DT connection capacity for grid connected rooftop solar*

Considering the issue of reverse power flow and based on the technical study, following provisions can be considered for inclusion in the Model Regulation:

- It is obvious that load flow study can assist in understanding the impact of GRPV deployment on reverse power flow. Based on the load flow study, the limit can be reset to an acceptable level.
- An option can be to set a limit on GRPV systems than can be installed on a particular DT, but also make provisions for additional DT if applications for GRPV more than the limit have been received on a particular DT.
- Special monitoring of all such DTs will be required to collect real time data where GRPV systems are deployed which will assist in further analysis to review the limit.
- Further, suitable security measures are required at the consumer as well as the DT level so that the power flow can be monitored on real time basis.

4.2.1.3 *Inclusion of applicability clauses for grid interconnection and requirement for safe system operation*

Based on the German experience discussed above, especially in terms of safety of grid operations, the key observations are summarised below:

- Visibility and control over solar generation beyond certain capacity is a must for the DISCOM or system operator in view of requirement of stable grid operation. For low capacity systems, certain restrictions should be set so that a minimum level of feed-in is maintained
- The GRPV invertor system must be able to respond to the system requirement and follow instructions of the area system operator. Their technical specifications need to be designed accordingly
- Going forward, stringent interconnection standards and safety measures will be required when more and more GRPV systems will get added to the distribution network
- A monitoring framework for system parameters and reactive power control is required. Mentioning allowable cumulative GRPV capacity connected to a DT only from reactive power injection perspective might be helpful

It is also required to devise a short, medium and long term roadmap for actions required by DISCOMs at different levels of reactive power injection in the main grid based on the reporting/monitoring tool's data.

4.2.2 Mitigation measures for gaps related to commercial aspects

4.2.2.1 Adoption of new innovative and emerging business models

Among emerging business models, a few are DISCOM anchored/centric model, which will critically cover the following areas:

- Standardization of the mechanisms adopted by DISCOMs for real time monitoring of solar generation, capacity of interconnected systems and application status
- Procurement practices for net meters, metering specifications for procurement, maintenance procedures, testing procedures for the DISCOM
- Defining and standardizing the investment recovery framework for the procured net-meters or upgraded infrastructure
- Definition and standardization of parameters for quality of power such as harmonics, voltage, synchronization, flickers, DC injections and frequency etc.

Further, the Model Regulation requires changes to accommodate new business models, provide fair energy accounting and commercial settlement, relax restrictions on GRPV system capacities possible based on technical studies, adopt suitable safety and operational rules for stable grid operation and harmonize the regulatory framework across the country. This will help in the proliferation of GRPV systems in India.

As seen earlier, the current Regulation promotes only two business models: CAPEX & RESCO. Recent developments and market trends indicate that there is a need to include innovative business models in the current regulatory landscape to increase participation for DISCOMs, developers and end users. Thus, utility centric business models through which demand aggregation can be possible and other group/virtual net metering models may be considered in the upcoming Regulation.

As different business modalities are working well in Canada, USA and Germany, the business models suitable to the Indian context need to be adopted. Thus, it is suggested to:

- Incorporate innovative business models after stakeholder consultation to understand possible key challenges against proliferation of new business models proposed
- Devise risk mitigation strategies based on scenario analysis and incorporate those in the emerging business models proposed
- Design metering, accounting and commercial settlement principle for these business models

4.2.2.2 Clarity in PPAs/connection agreement clauses in certain conditions and include mechanism for renewal cancellation

Considering the international experience, following modifications are suggested that can be incorporated in the proposed Model Regulation.

- Clauses on sold out GRPV premises.
- Guidelines in case of change of ownership structures in the plant life.
- Future possibility of additional capacity installations due to change in regulatory restrictions or purchase of adjacent area by consumer.
- Expiration of the current PPAs (if the business model or arrangement is for short duration like in the case of modular plants where the contract period is till the payback period with clause of change in ownership)
- Provisions related to adequate notice period should be made if a consumer and developer want to discontinue the present agreement

4.2.2.3 Upgradation of present energy accounting and commercial settlement mechanisms

From the above discussion on energy accounting and commercial settlement, it is clear that:

- The consumer should be compensated reasonably when excess generation is fed into the grid to promote GRPV.
- Also, the DISCOMs should be allowed to recover their fixed cost in a way suitable to the Indian context.
- The emerging business model will also require innovative settlement principles as the number of parties will be more and the relative complexity will be higher for multi-stakeholder involvement that the Regulation must address through commercial settlement.

Once new business models will be considered, and sample cases provided to showcase how settlement will happen among the various stakeholders. A sample case is provided above as per the Ontario Regulation.

4.2.3 **Mitigation measures for other aspects: Generation definition, metering and communication**

4.2.3.1 Clarity in definition of premises, solar roof-top PV plant and inclusion of land

Based on the discussion made on gaps identified, and especially the Nagpur Metro case, the following issues need to be considered while defining premise:

- Adequate regulatory provisions will be required to bring clarity on the extent to which utilization of open land in the consumer premises can be considered and how the generation will be qualified under GRPV Regulations along with their metering principle, accounting and commercial settlement.
- If premises definition can be modified to accommodate more variations such as adjacent premises or premises at different locations but owned by the same person.
- If different premises of the same consumer are to be allowed, treating it as open access, which is not allowed for a consumer having sanctioned load/contract capacity of less than 1 MW. Therefore, in such cases, provisions of different Regulations also need to be considered. Or the premise where the GRPV system is installed can be allowed under gross metering and

commercial settlement can be done with its connection at different locations. However, this is possible only when both the premises are in the same DISCOM area.

4.2.3.2 Adoption of advanced metering, communication arrangements and also providing procurement guidelines for DISCOMs

Considering the need of real time monitoring from DISCOM and system operation points of view, and recent practice of procuring smart meters for single phase and three phase low tension consumers, the following changes can be adopted in the proposed Model Regulation:

- Smart meters/meters compatible with AMI should be made compulsory for real time monitoring purpose looking at large scale deployment in future
- The DISCOM shall also develop their IT infrastructure for monitoring solar generation
- The Regulation may develop a standardized meter procurement process/guideline for DISCOMs and devise testing measures for them

5. System study to assess GRPV deployment under different network conditions

5. System study to assess GRPV deployment under different network conditions

5.1 Objective of the technical study

The present regulatory framework for GRPV systems has put a limit of 1 MW on the maximum individual capacity that can be set up. Different limits have also been imposed on individual capacities in terms of sanction load and cumulative capacity. Though Model Net Metering Regulation 2013 has not prescribed any limit based on sanctioned load, the state Regulations have imposed additional restrictions based on sanctioned load, which varies from state to state. Overall, the range for limit is from 40% to 100% of the sanctioned load.

Looking at the different provisions for GRPV unit in terms of DT capacity or sanctioned load, it was necessary to review it based on a technical study. The objective of the technical study is to assess maximum aggregated capacity of solar PV rooftop plants that can be safely connected to the existing distribution grid without impacting the system operation and grid stability.

Discussion on large scale proliferation of distribution PV generation raises the major issue of reverse flow of power. In case the solar photovoltaic power generation goes beyond the minimum running load for a given consumer, at any voltage level, i.e., when the solar photovoltaic power generation will be more than a consumer's minimum demand, then such surplus photovoltaic electric power will be injected into the grid. In such a situation, as shown in the figure below, reverse active power 'Pkj' and reverse reactive power 'Qkj', will be fed from consumer's premises where the GRPV system is deployed to the LV feeder and the neighbouring consumers connected to the same LV feeder.

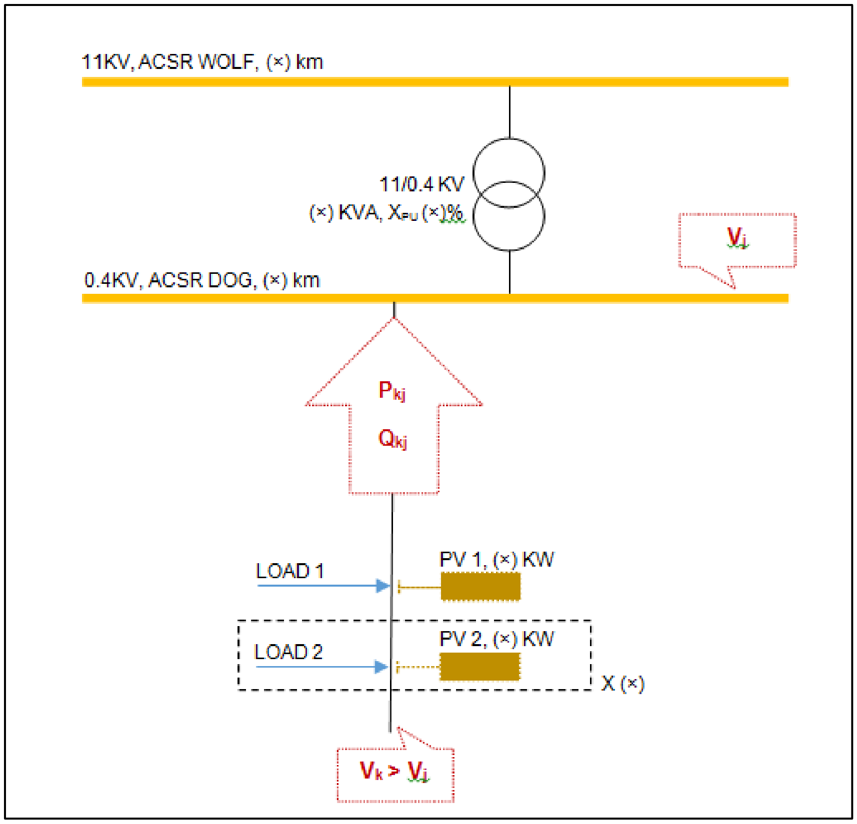


Figure 6: Basic structure of reverse power flow

Further, when cumulative photovoltaic generation is more than the cumulative demand connected to the DT, the excess power 'Pkj' and 'Qkj' will enter into the 11 KV distribution feeder (stepped up through the DT) and will flow through the neighbouring 11/0.4 KV transformers.

The maximum reverse power flow into the grid can be allowed based on two parameters:

- Feeder/grid asset thermal capacity
- Over-voltage at the point of interconnection

If the reverse power flow from distributed generation systems exceeds the thermal limit of the grid elements then it can cause excess heating, eventually leading to reduced life of grid elements such as transformer or cable, and in some cases, permanent failure of the grid elements. This may affect the transient and steady state grid stability, resulting in difficulties in system operation.

Similarly, if the voltage rise at interconnection point exceeds the limit prescribed by the CEA Regulations, it can cause damage to the insulation of grid assets such as transformers and power cables. The over voltage can also damage voltage sensitive equipment installed at the consumer's premises.

5.2 Approach & methodology of the study & simulation

The aggregated capacity of distributed generation that can be accommodated without impacting system operation adversely under the existing control and infrastructure configurations can be determined by the following two key limiting parameters:

- Feeder/grid asset thermal capacity
- Over-voltage at the point of interconnection

The following formula is used to calculate the maximum reverse power flow on a feeder:

$$P_{reversed\,(\max)} = P_{PV(\max)} - P_{load(\min)}$$

Where,

$P_{reversed\,(\max)} = Maximum\ reversed\ power\ flow\ in\ the\ network$

$P_{reversed\,(\max)} = Maximum\ power\ from\ PV\ pwer\ plant\ at\ noon\ time\ (peak\ irradiance)$

$P_{load\,(\min)} = Minimum\ load\ at\ noon\ time\ when\ PV\ power\ at\ peak$

The maximum phase current in a feeder has been calculated using the following formula:

$$I_{phase} = \frac{P_{reversed(\max)}}{\sqrt{3} x U_r}$$

Further, scenarios have been developed to calculate the phase current at different points on the LV/HV feeder, considering different loading conditions to determine the PV plant capacity between the points and end of the feeder. Maximum PV capacity is determined **when phase current exceeds the current carrying capacity (ampacity) of the feeder or the transformer.**

The second parameter, voltage rise in a radial feeder, has been calculated using the following formula:

$$U_k^2 = -\frac{a_4}{2a_3} = \pm\sqrt{(\frac{a_4}{2a_3})^2 - \frac{1}{a_3}(a_1^2 + a_2^2)}$$

$$a_1 = -RP_{kj} - XQ_{kj}$$

$$a_2 = -RX - XQ_{kj}$$

$$a_3 = (1 - XB)^2 - R^2B^2$$

$$a_4 = 2a_1(1 - XB) - U_j^2 + 2a_2RB$$

Where,

$U_j = Busbar\ voltage$

$U_k = Voltage\ at\ feeder\ end$

$R = Feeder\ resistance$
$X = Feeder\ Reactance$
$B = Feeder\ Susceptance$
$P = Active\ power\ flow$
$Q = Reactive\ power\ flow$

Based on the approach described above, Excel-based simulation tool was used to conduct power flow analysis on different voltage levels of the grid (0.4 KV, 11 KV & 33 KV) as per different scenarios (given below) to estimate the maximum aggregated distributed generation capacities keeping the "Feeder/grid asset thermal capacity" and "Over-voltage at the point of interconnection" in mind.

5.2.1 Different scenarios and input parameters

The different scenarios considered for the simulation study have been prepared for the different conditions of the following parameters:

1. Voltage level
2. Type of feeder
3. Transformer capacity
4. Feeder length

All three voltage levels (0.44 KV, 11 KV and 33 kV) have been considered where the GRPV systems are allowed to be connected based on their capacity. Typical DT capacity based on the type of feeder is chosen so as to correctly represent the consumer profile. The details of the different scenarios developed for conducting power flow analysis are provided in the table below:

Table 12: Different scenarios and input parameters considered for the carrying out simulation

Voltage Level	Type of Feeder	Transformer Capacity	Conditions/ Assumptions
0.4KV	Rural Residential	25 KVA	• Feeder Type ACSR DOG, length 0.65 km, 0.98 operating pf, 18 number of residential loads of 1.25 KVA capacity • Feeder Type ACSR DOG, length 0.72 km, 0.98 operating pf, 22 number of residential loads of 1.00 KVA capacity
0.4KV	Rural Residential	63 KVA	• Feeder Type ACSR DOG, length 0.65 km, 0.98 operating pf, 32 number of residential loads of 1.8 KVA capacity • Feeder Type ACSR DOG, length 0.65 km, 0.98 operating pf, 23 number of residential loads of 2.5 KVA capacity
0.4KV	Rural Residential	100KVA	• Feeder Type ACSR DOG, length 0.68 km, 0.98 operating pf, 38 number of residential loads of 2.35 KVA capacity • Feeder Type ACSR DOG, length 0.72 km, 0.98

Voltage Level	Type of Feeder	Transformer Capacity	Conditions/ Assumptions
			operating pf, 46 number of residential loads of 2.00 KVA capacity
0.4KV	Urban Residential	250KVA	• Feeder Type ACSR DOG, length 0.85 km, 0.98 operating pf,65 number of residential loads of 2.75 KVA capacity • Feeder Type ACSR DOG, length 0.82 km, 0.98 operating pf, 78 number of residential loads of 2.25 KVA capacity
0.4KV	Urban Residential	400KVA	• Feeder Type ACSR DOG, length 0.83 km, 0.98 operating pf, 68 number of residential loads of 4.15 KVA capacity • Feeder Type ACSR DOG, length 0.86 km, 0.98 operating pf, 76 number of residential loads of 3.65 KVA capacity
0.4KV	Urban Residential	630KVA	• Feeder Type ACSR DOG, length 0.92 km, 0.98 operating pf, 86 number of residential loads of 5.15 KVA capacity • Feeder Type ACSR DOG, length 0.72 km, 0.88 operating pf, 72 number of residential loads of 6.15 KVA capacity
0.4KV	Urban Commercial	1MVA	• Feeder Type ACSR DOG, length 0.46 km, 0.98 operating pf, 36 number of Commercial loads of 18.25 KVA capacity • Feeder Type ACSR DOG, length 0.42 km, 0.98 operating pf, 30 number of Commercial loads of 21.5 KVA capacity
0.4KV	Urban Commercial	1.25MVA	• Feeder Type ACSR DOG, length 0.52 km, 0.98 operating pf, 36 number of Commercial loads of 22.50 KVA capacity • Feeder Type ACSR DOG, length 0.56 km, 0.98 operating pf, 41 number of Commercial loads of 20.00 KVA capacity
11 KV		9.5MVA	• Feeder Type ACSR WOLF, length 4.5 km, 46 number of industrial loads of 18.00 KVA capacity • Feeder Type ACSR WOLF, length 4.8 km, 32 number of industrial loads of 15.00 KVA capacity
11KV		12.5MVA	• Feeder Type ACSR WOLF, length 4.7 km, 52 number of industrial loads of 32.50 KVA capacity • Feeder Type ACSR WOLF, length 4.75 km, 58 number of industrial loads of 21.50 KVA capacity
11KV		15MVA	• Feeder Type ACSR WOLF, length 5.25 km, 42 number of industrial loads of 52.50 KVA capacity • Feeder Type ACSR WOLF, length 5.5 km, 58 number of industrial loads of 22.50 KVA capacity
11KV		16.5MVA	• Feeder Type ACSR WOLF, length 5.75 km, 56

Voltage Level	Type of Feeder	Transformer Capacity	Conditions/ Assumptions
			number of industrial loads of 46.50 KVA capacity • Feeder Type ACSR WOLF, length 6.35 km, 38 number of industrial loads of 34.50 KVA capacity
33 KV		32.5MVA	• Feeder Type ACSR PANTHER, length 6.85 km, 38 number of industrial loads of 17.50 KVA capacity • Feeder Type ACSR PANTHER, length 7.50 km, 32 number of industrial loads of 20.50 KVA capacity
33KV		40MVA	• Feeder Type ACSR PANTHER, length 6.85 km, 32 number of industrial loads of 21.50 KVA capacity • Feeder Type ACSR PANTHER, length 6.85 km, 48 number of industrial loads of 21.50 KVA capacity
33KV		50MVA	• Feeder Type ACSR PANTHER, length 8.65 km, 48 number of industrial loads of 30.50 KVA capacity • Feeder Type ACSR PANTHER, length 8.65 km, 48 number of industrial loads of 35.50 KVA capacity

The simulations have been conducted considering feeder/station loading from 0% to 100%. The results of the simulation study are discussed below.

5.3 Results of the simulation study carried out

5.3.1 **0.4KV rural residential feeder**

Three rural residential LV feeders for different transformer capacities of 25KVA, 63KVA and 100KVA have been analysed. The following figure provides the schematic for the three different arrangements.

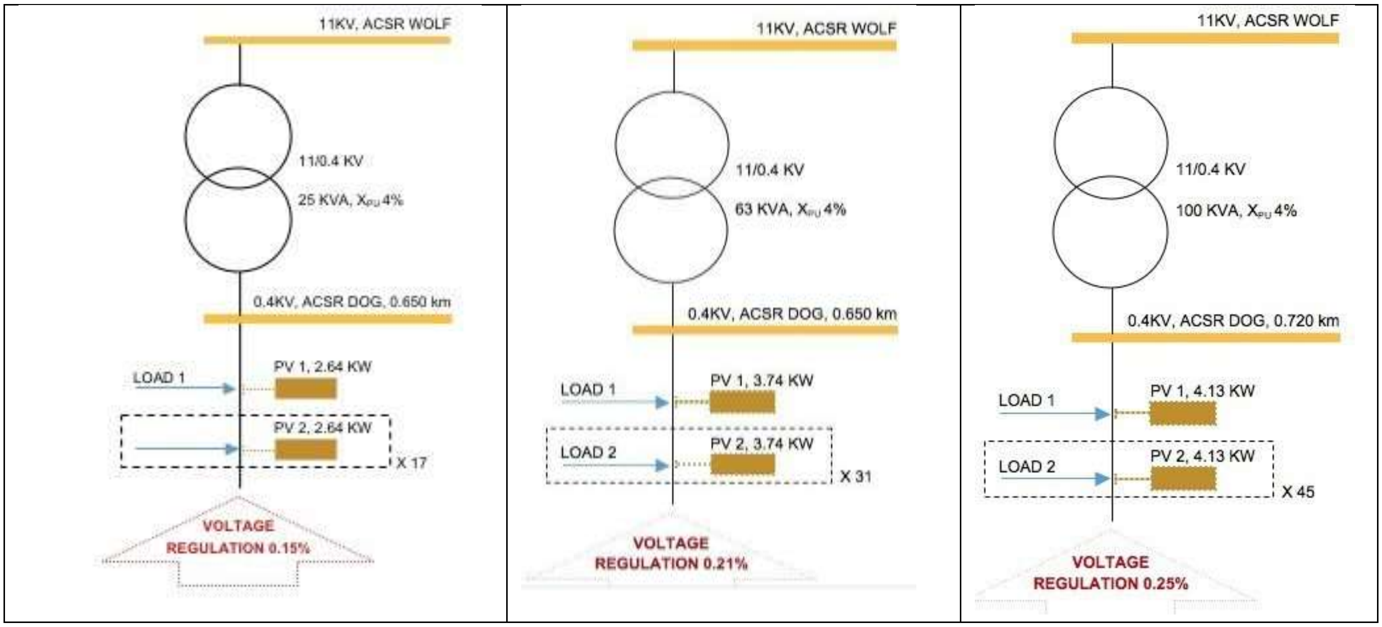


Figure 7: Schematic of 11/0.4KV feeder with 25KVA, 63KVA and 100KVA transformer

The simulation results for the rural residential feeder are discussed in the subsections below.

5.3.1.1 Summary of simulation result for rural residential feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not more than the sanctioned load/contract demand.

The simulation results when the permitted individual PV capacity is not more than the sanctioned load or contract demand for different DT ratings: 25 KVA, 63 KVA and 100 KVA, at different loading conditions are presented in the table below:

Table 13 : Simulation results for maximum PV capacity and voltage Regulation for rural DTs (25 KVA, 63 KVA and 100 KVA) for different loading conditions when the permitted individual GRPV system is not more than the sanctioned load

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	Photovoltaic capacity (KW)	Voltage Regulation (%)	Photovoltaic capacity (KW)	Voltage Regulation (%)	Photovoltaic capacity (KW)	Voltage Regulation (%)
100%	50.0	Up to 0.2	126.0	Up to 0.4	200.0	Up to 0.5
90%	47.5		119.7		190.0	
80%	45.0		113.4		180.0	
70%	42.5		107.1		170.0	
60%	40.0		100.8		160.0	
50%	37.5		94.5		150.0	
40%	35.0		88.2		140.0	
30%	32.5		81.9		130.0	

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	Photovoltaic capacity (KW)	Voltage Regulation (%)	Photovoltaic capacity (KW)	Voltage Regulation (%)	Photovoltaic capacity (KW)	Voltage Regulation (%)
20%	30.0		75.6		120.0	
10%	27.5		69.3		110.0	
0%	25.0		63.0		100.0	

From the above table, it is clear that when minimum running load on DT is 0%, the allowable maximum PV capacity without causing any over-voltage at the Point of Common Coupling (PCC) is 25 KW, 63 KW & 100 KW. When minimum running load on DT is 100%, it is 50 KW, 126 KW & 200 KW for the respective DT capacity considered.

A clear inference from the above simulation results table is that, when permitted distribution generation capacity is not more than the sanctioned load/contract demand, aggregate PV power plant capacity (AC nominal power of inverter) that can be connected to a network can be up to 100% of the DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor.

5.3.1.2 Summary of simulation result for rural residential feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand.

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different DT ratings in rural areas: 25 KVA, 63 KVA and 100 KVA at different loading conditions and feeder length of 850 meter are presented in the table below:

Table 14: Simulation results for maximum PV capacity and voltage Regulation for rural DTs (25 KVA, 63 KVA and 100 KVA) for different loading conditions when the permitted individual GRPV system is not restricted by the sanctioned load

Based on minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
100%	25.0	3.08	63.0	7.77	68.0	8.39
90%						
80%						
70%						
60%						
50%						
40%						
30%						

Based on minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
20%						
10%						
0%						

5.3.1.3 Summary of simulation result for rural residential feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand at different feeder lengths.

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different DT ratings in rural areas: 25 KVA, 63 KVA and 100 KVA at different feeder lengths are presented in the table below:

Table 15: Simulation results for maximum PV capacity and voltage Regulation for rural DTs (25 KVA, 63 KVA and 100 KVA) for different feeder lengths when the permitted individual GRPV system is not restricted by the sanctioned load

Based on feeder length (m) when photovoltaic power is at peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	25 KVA		63 KVA		100 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
850	25.0	3.08	63.0	7.77	68.0	8.39
800	25.0	2.90	63.0	7.32	73.0	8.42
750	25.0	2.72	63.0	6.86	77.0	8.38
700	25.0	2.54	63.0	6.40	83.0	8.38
650	25.0	2.36	63.0	5.94	89.0	8.40
600	25.0	2.18	63.0	5.49	97.0	8.41
550	25.0	2.03	63.0	5.03	100.0	7.98
500	25.0	1.84	63.0	4.57	100.0	7.26
450	25.0	1.66	63.0	4.12	100.0	6.53
400	25.0	1.47	63.0	3.66	100.0	5.81
350	25.0	1.28	63.0	3.20	100.0	5.08

From table numbers 11 and 12, it is clear that there will be over-voltage at the Point of Common Coupling (PCC), which is dependent on minimum running load on the DT and the feeder length. Hence, when permitted PV capacity (AC nominal power of inverter) is not controlled based on sanctioned load/ contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network has to be decided on a case to case basis; based on the loading of the respective DT and feeder length, considering over-voltage at PCC as the deciding factor.

5.3.2 **0.4KV urban residential feeder**

Three urban residential LV feeders for transformer capacities of 250KVA, 400KVA and 630KVA have been analysed. The following figure provides the schematic for the three different arrangements.

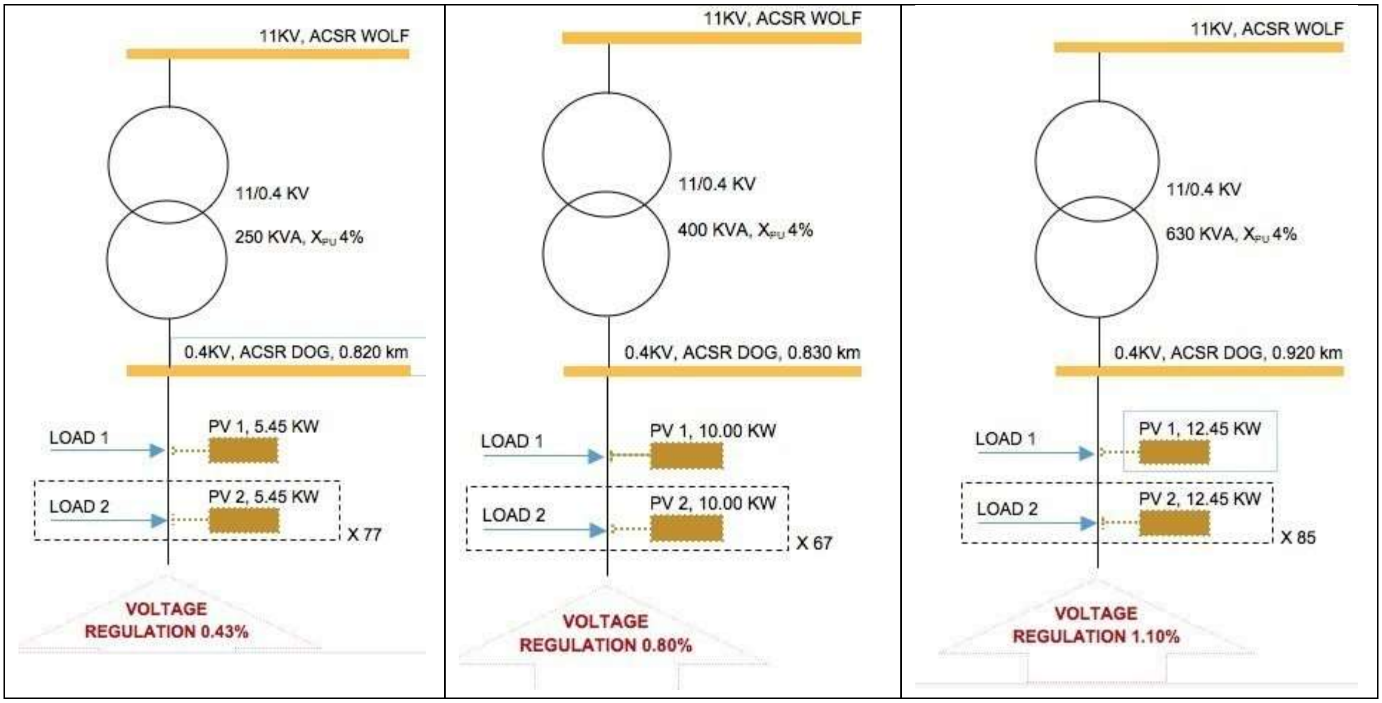


Figure 8: Schematic of 11/0.4KV feeder with 250KVA, 400KVA and 630KVA transformer

The simulation results for the urban residential feeder are discussed in the subsections below

5.3.2.1 Summary of simulation result for urban residential feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not more than the sanctioned load/contract demand.

The simulation results when the permitted capacity is not more than the sanctioned load or contract demand for different DT ratings: 250 KVA, 400 KVA and 630 KVA at different loading conditions are presented in the table below:

Table 16: Simulation results for maximum PV capacity and voltage Regulation for urban residential DTs (250 KVA, 400 KVA and 630 KVA) for different loading conditions when the permitted individual GRPV system is not more than the sanctioned load

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	250KVA		400KVA		630KVA	
	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)
100%	500.0	Up to 0.7	800.0	Up to 0.9	1260.0	Up to 1.5
90%	475.0		760.0		1197.0	
80%	450.0		720.0		1134.0	

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	250KVA		400KVA		630KVA	
	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)
70%	425.0		680.0		1071.0	
60%	400.0		640.0		1008.0	
50%	375.0		600.0		945.0	
40%	350.0		560.0		882.0	
30%	325.0		520.0		819.0	
20%	300.0		480.0		756.0	
10%	275.0		440.0		693.0	
0%	250.0		400.0		630.0	

From the above table, it is clear that allowable maximum PV capacity without causing any over-voltage at PCC varies from 250 KW, 400 KW & 630 KW when minimum running load on DT is 0% to 500 KW, 800 KW & 1260 KW when minimum running load on DT is 100%.

A clear inference from the above simulation results table is that, when permitted distribution generation capacity is not more than the sanctioned load/ contract demand, aggregate PV power plant capacity (AC nominal power of inverter) that can be connected to a network, can be up to 100% of DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor.

5.3.2.2 Summary of simulation result for urban residential feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand.

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different DT ratings in urban residential areas: 250 KVA, 400 KVA and 630 KVA at different loading conditions and feeder length of 850 m are presented in the table below:

Table 17: Simulation results for maximum PV capacity and voltage Regulation for urban residential DTs (250 KVA, 400 KVA and 630 KVA) for different loading conditions when the permitted individual GRPV system is not restricted by the sanctioned load

Based on minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	250 KVA		400 KVA		630 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
100%	68.0	8.33	68.0	8.39	66.0	8.16
90%						
80%						
70%						
60%						

50%						
40%						
30%						
20%						
10%						
0%						

5.3.2.3 *Summary of simulation result for urban residential feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand at different feeder lengths.*

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different DT ratings in urban residential areas: 250 KVA, 400 KVA and 630 KVA at different feeder lengths are presented in the table below:

Table 18: Simulation results for maximum PV capacity and voltage Regulation for urban residential DTs (250 KVA, 400 KVA and 630 KVA) for different feeder lengths when the permitted individual GRPV system is not more than the sanctioned load

Based on feeder length (m) when photovoltaic power is at peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (KVA)					
	250 KVA		400 KVA		630 KVA	
	PV (KW)	%VR	PV (KW)	%VR	PV (KW)	%VR
850	68.0	8.33	68.0	8.39	66.0	8.16
800	73.0	8.42	72.0	8.36	72.0	8.41
750	76.0	8.30	76.0	8.27	76.0	8.23
700	83.0	8.38	82.0	8.33	82.0	8.32
650	89.0	8.37	88.0	8.30	88.0	8.32
600	96.0	8.38	96.0	8.36	95.0	8.23
550	105.0	8.38	104.0	8.30	104.0	8.30
500	115.0	8.35	116.0	8.42	113.0	8.23
450	129.0	8.41	128.0	8.36	126.0	8.23
400	145.0	8.42	144.0	8.36	145.0	8.41
350	165.0	8.38	164.0	8.33	164.0	8.32

From table numbers 14 and 15, it is clear that there will be over-voltage at PCC, which is dependent on minimum running load on the DT and the feeder length. Hence, when permitted PV capacity (AC nominal power of inverter) is not controlled based on sanctioned load/contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network has to be decided on a case by case basis. This will be based on the loading of the respective DT and feeder length, considering over-voltage at PCC as the deciding factor.

5.3.3 **0.4KV urban commercial feeder**

Two urban commercial feeders for different transformer capacities of 1MVA and 1.25MVA have been analysed. The following figure provides the schematic for the two different arrangements.

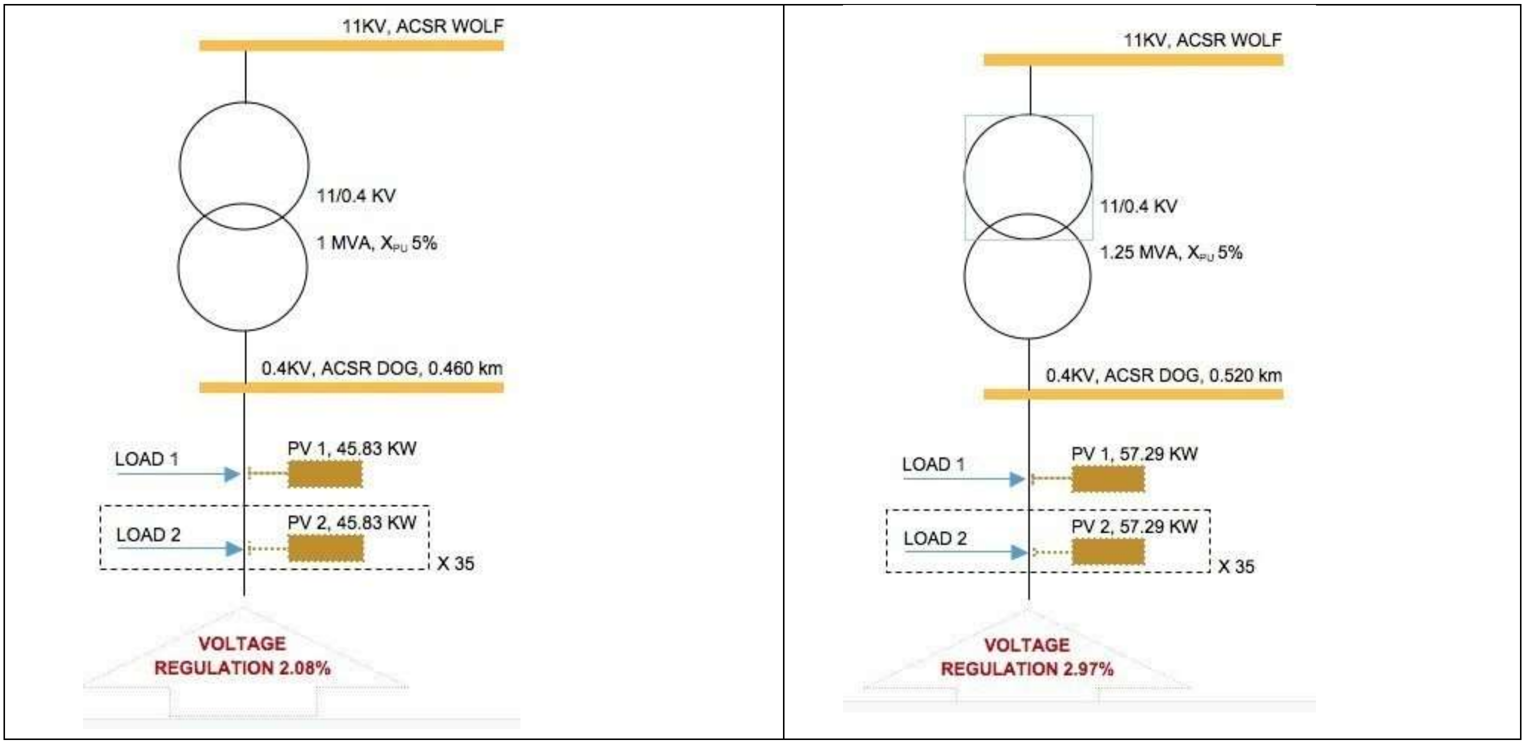


Figure 9: Schematic of 11/0.4KV feeder with 1MVA and 1.25MVA transformer

The simulation results for the urban commercial feeder are discussed in the subsections below:

5.3.3.1 Summary of simulation result for urban commercial feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not more than the sanctioned load/contract demand.

The simulation results when the permitted capacity is not more than the sanctioned load or contract demand for different DT ratings: 1 MVA and 1.25 MVA at different loading conditions are presented in the table below:

Table 19: Simulation results for maximum PV capacity and voltage Regulation for urban commercial DTs (1 MVA and 1.25 MVA) for different loading conditions when the permitted individual GRPV system is not more than the sanctioned load

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)
100%	2000.0	Up to 2.5	2500.0	Up to 3.0
90%	1900.0		2375.0	
80%	1800.0		2250.0	

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV Capacity (KW)	VR (%)	PV Capacity (KW)	VR (%)
70%	1700.0		2125.0	
60%	1600.0		2000.0	
50%	1500.0		1875.0	
40%	1400.0		1750.0	
30%	1300.0		1625.0	
20%	1200.0		1500.0	
10%	1100.0		1375.0	
0%	1000.0		1250.0	

From the above table, it is clear that allowable maximum PV capacity without causing any over-voltage at PCC varies from 1000 KW & 1250 KW when minimum running load on DT is 0% to 2000 KW & 2500 KW when minimum running load on DT is 100%. A clear inference from the above simulation results table can be taken that, when permitted distribution generation capacity is not more than the sanctioned load/contract demand, aggregate PV power plant capacity (AC nominal power of inverter) that can be connected to a network can be up to 100% of DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor.

5.3.3.2 Summary of simulation result for urban commercial feeder (0.4KV) with distributed PV Plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand.

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different DT ratings in urban commercial areas: 1 MVA and 1.25 MVA at different loading conditions and feeder length of 850 m are presented in the table below:

Table 20: Simulation results for maximum PV capacity and voltage Regulation for urban commercial DTs (1 MVA and 1.25 MVA) for different loading conditions when the permitted individual GRPV system is not restricted by the sanctioned load

Based on minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV (KW)	%VR	PV (KW)	%VR
100%	68.0	8.02	68.0	7.71
90%				
80%				
70%				
60%				
50%				
40%				

30%				
20%				
10%				
0%				

5.3.3.3 *Summary of simulation result for urban commercial feeder (0.4KV) with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand at different feeder lengths.*

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different DT ratings in urban commercial areas: 1 MVA and 1.25 MVA at different feeder lengths are presented in the table below:

Table 21: Simulation results for maximum PV capacity and voltage Regulation for urban commercial DTs (1 MVA and 1.25 MVA) for different feeder lengths when the permitted individual GRPV system is not restricted by the sanctioned load

Based on feeder length (m) when photovoltaic power is at peak (noon time)	Maximum PV Capacity (KW) against Distribution Transformer Rating (MVA)			
	1MVA		1.25MVA	
	PV (KW)	%VR	PV (KW)	%VR
850	65.0	8.02	63.0	7.71
800	70.0	8.13	69.0	7.98
750	75.0	8.17	75.0	8.17
700	80.0	8.13	81.0	8.26
650	85.0	8.02	88.0	8.26
600	95.0	8.27	94.0	8.17
550	105.0	8.38	100.0	7.98
500	115.0	8.35	113.0	8.17
450	125.0	8.17	125.0	8.17
400	145.0	8.42	144.0	8.35
350	165.0	8.38	163.0	8.26

From table numbers 17 and 18, it is clear that there will be over-voltage at PCC, which is dependent on minimum running load on the DT and the feeder length.

Hence, when permitted PV capacity (AC nominal power of inverter) is not controlled based on sanctioned load/contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network has to be decided on a case by case basis. This is based on the loading of the respective DT and feeder length, considering over-voltage at PCC as the deciding factor.

5.3.4 **11KV feeder**

Four HV feeders for different transformer capacities of *9.5MVA, 12.5MVA, 15MVA and 16.5MVA* have been analysed. Following figure provides the schematic for the four different arrangements.

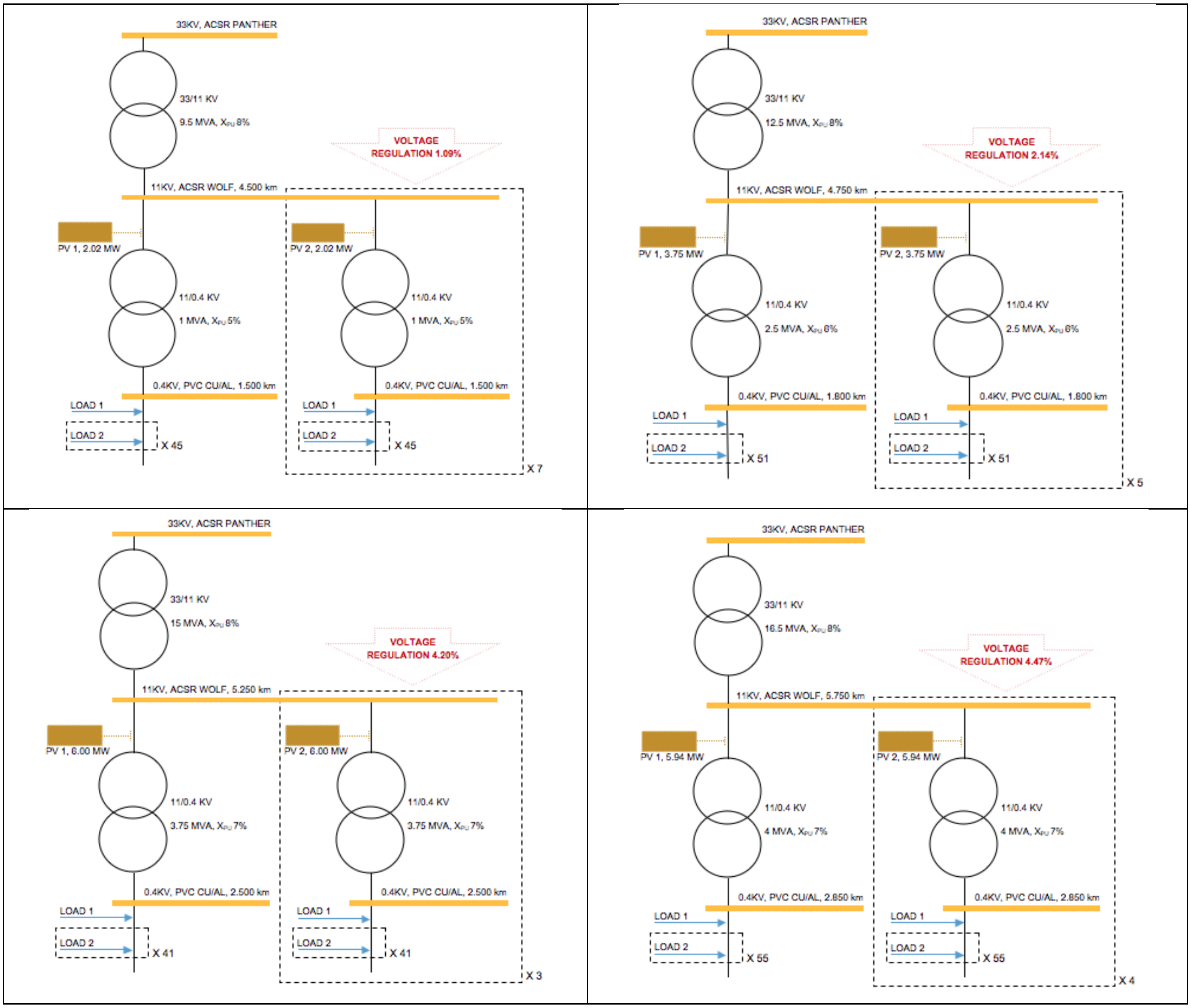


Figure 10: Schematic of 33/11KV feeder with 9.5MVA, 12.5MVA, 15MVA and 16.5MVA transformer

The simulation results for the 11 KV feeders are discussed in the subsections below.

5.3.4.1 Summary of simulation result for 11KV feeder with distributed PV plants when permitted individual PV capacity is not more than the sanctioned load/contract demand.

The simulation results when the permitted capacity is not more than the sanctioned load or contract demand for different DT ratings: 9.5 MVA, 12.5 MVA, 15 MVA and 16.5 MVA at different loading conditions are presented in the table below:

Table 22: Simulation results for maximum PV capacity and voltage Regulation for 11KV DTs (9.5 MVA, 12.5 MVA, 15 MVA and 16.5 MVA) for different loading conditions when the permitted individual GRPV system is not more than the sanctioned load

Minimum DT Loading when PV Power is at Peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)							
	9.5 MVA		12.5 MVA		15 MVA		16.5 MVA	
	PV capacity (MW)	VR (%)	PV capacity (MW)	VR (%)	PV capacity (MW)	VR (%)	PV capacity (MW)	VR (%)
100%	19.0	Up to 1.5	25.0	Up to 2.5	30.0	Up to 4.5	33.0	Up to 5.0
90%	18.1		23.8		28.5		31.4	
80%	17.1		22.5		27.0		29.7	
70%	16.2		21.3		25.5		28.1	
60%	15.2		20.0		24.0		26.4	
50%	14.3		18.8		22.5		24.8	
40%	13.3		17.5		21.0		23.1	
30%	12.4		16.3		19.5		21.5	
20%	11.4		15.0		18.0		19.8	
10%	10.5		13.8		16.5		18.2	
0%	9.5		12.5		15.0		16.5	

From the above table, it is clear that allowable maximum PV capacity without causing any over-voltage at PCC varies from 9.5 MW, 12.5 MW, 15 MW & 16.5 MW when minimum running load on DT is 0% to 19 MW, 25 MW, 30 MW & 33 MW when minimum running load on DT is 100%.

A clear inference from the above simulation results table is that, when permitted distribution generation capacity is not more than the sanctioned load/contract demand, aggregate PV power plant capacity (AC nominal power of inverter) that can be connected to a network can be up to 100% of DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor.

5.3.4.2 *Summary of simulation result for 11 KV feeders with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand at different feeder lengths.*

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different 11KV DT rating: 9.5 MVA, 12.5 MVA, 15 MVA and 16.5 MVA at different feeder lengths are presented in the table below:

Table 23: Simulation results for maximum PV capacity and voltage Regulation for 11KV DTs (9.5 MVA, 12.5 MVA, 15 MVA and 16.5 MVA) for different feeder lengths when the permitted individual GRPV system is not restricted by the sanctioned load

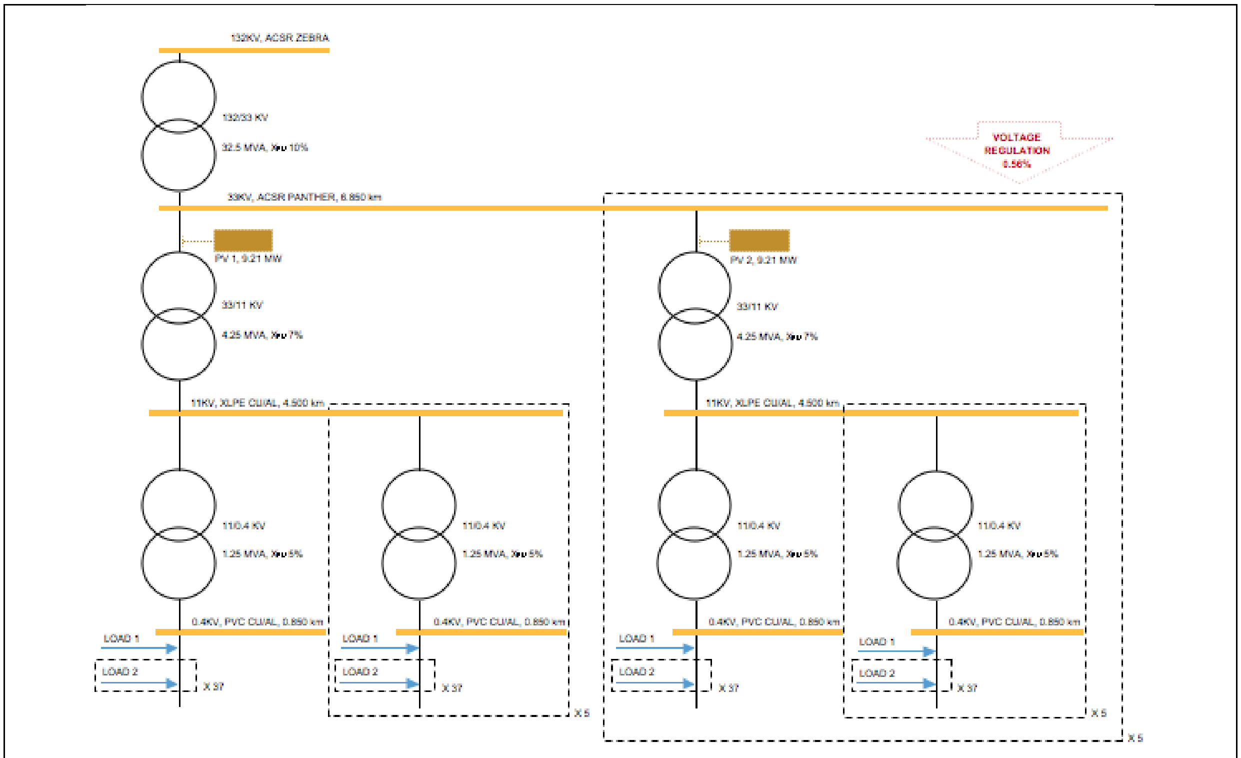
Feeder length (m) when	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)

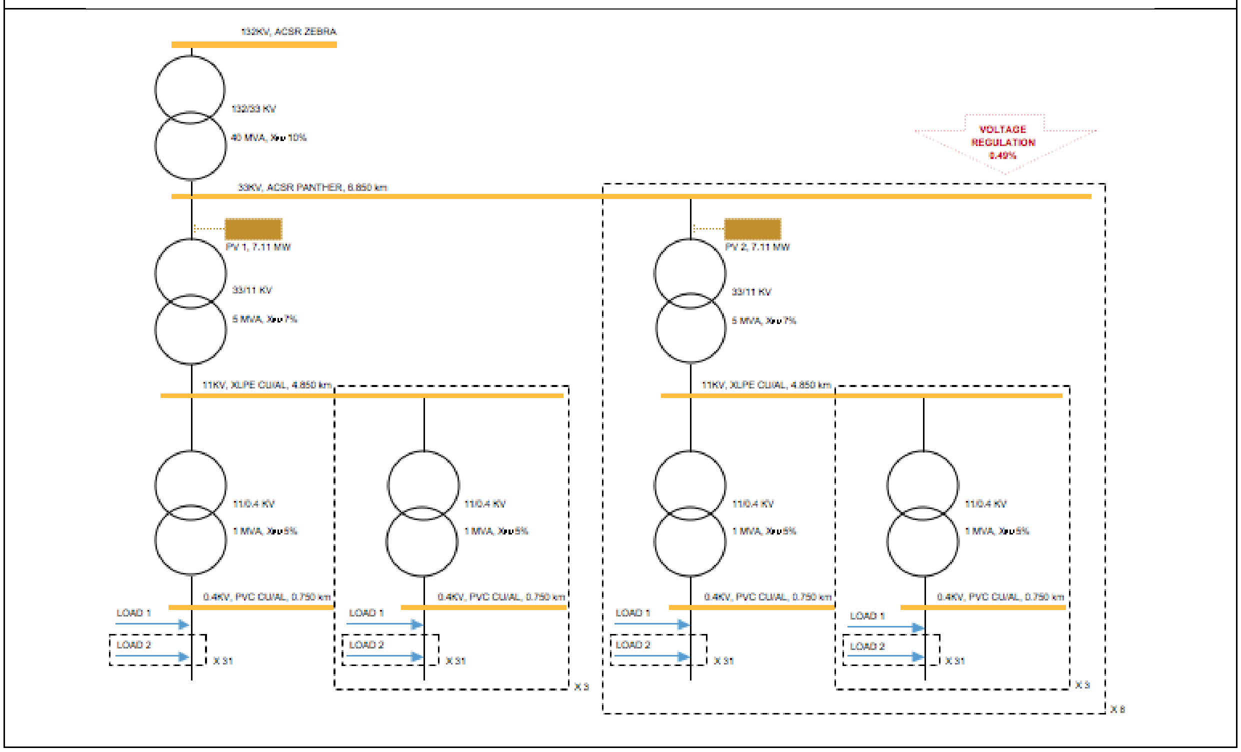
PV power is at peak (noon time)	9.5 MVA		12.5 MVA		15 MVA		16.5 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
6500	9.0	9.07	9.0	9.04	9.0	9.04	9.0	9.03
6000	9.5	8.81	9.8	9.04	9.8	9.04	9.7	9.03
5500	9.5	8.07	10.7	9.08	10.7	9.05	10.6	9.05
5000	9.5	7.34	11.8	9.08	11.7	9.04	11.7	9.05
4500	9.5	6.61	12.5	8.69	13.1	9.08	13.0	9.07
4000	9.5	5.87	12.5	7.73	14.7	9.08	14.7	9.08
3500	9.5	5.14	12.5	6.76	15.0	8.11	16.5	8.92
3000	9.5	4.40	12.5	5.80	15.0	6.95	16.5	7.65
2500	9.5	3.67	12.5	4.83	15.0	5.80	16.5	6.38
2000	9.5	2.94	12.5	3.86	15.0	4.64	16.5	5.10
1500	9.5	2.21	12.5	2.90	15.0	3.48	16.5	3.83

From table number 20, it is clear that there will be over-voltage at PCC, which dependent on minimum running load on the DT and the feeder length. Hence, when permitted PV capacity (AC nominal power of inverter) is not controlled based on the sanctioned load/contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network has to be decided on a case by case basis, based on the loading of the respective DT and feeder length, considering over-voltage at PCC as the deciding factor.

5.3.5 **33KV feeder**

Three 33 KV feeders for different transformer capacities of *32.5MVA, 40MVA and 50MVA* have been analysed. The following figure provides the schematic for three different arrangements.


132KV, ACSR ZEBRA
132/33 KV
32.5 MVA, Xpu 10%
VOLTAGE
REGULATION
0.56%
33KV, ACSR PANTHER, 6.850 km
PV 1, 9.21 MW
33/11 KV
4.25 MVA, Xpu 7%
PV 2, 9.21 MW
33/11 KV
4.25 MVA, Xpu 7%
11KV, XLPE CU/AL, 4.500 km
11KV, XLPE CU/AL, 4.500 km
11/0.4 KV
1.25 MVA, Xpu 5%
0.4KV, PVC CU/AL, 0.850 km
LOAD 1
LOAD 2
X 37
X 5
X 5


132KV, ACSR ZEBRA
132/33 KV
40 MVA, Xpu 10%
VOLTAGE
REGULATION
0.49%
33KV, ACSR PANTHER, 6.850 km
PV 1, 7.11 MW
33/11 KV
5 MVA, Xpu 7%
PV 2, 7.11 MW
33/11 KV
5 MVA, Xpu 7%
11KV, XLPE CU/AL, 4.850 km
11KV, XLPE CU/AL, 4.850 km
11/0.4 KV
1 MVA, Xpu 5%
0.4KV, PVC CU/AL, 0.750 km
LOAD 1
LOAD 2
X 31
X 3
X 8

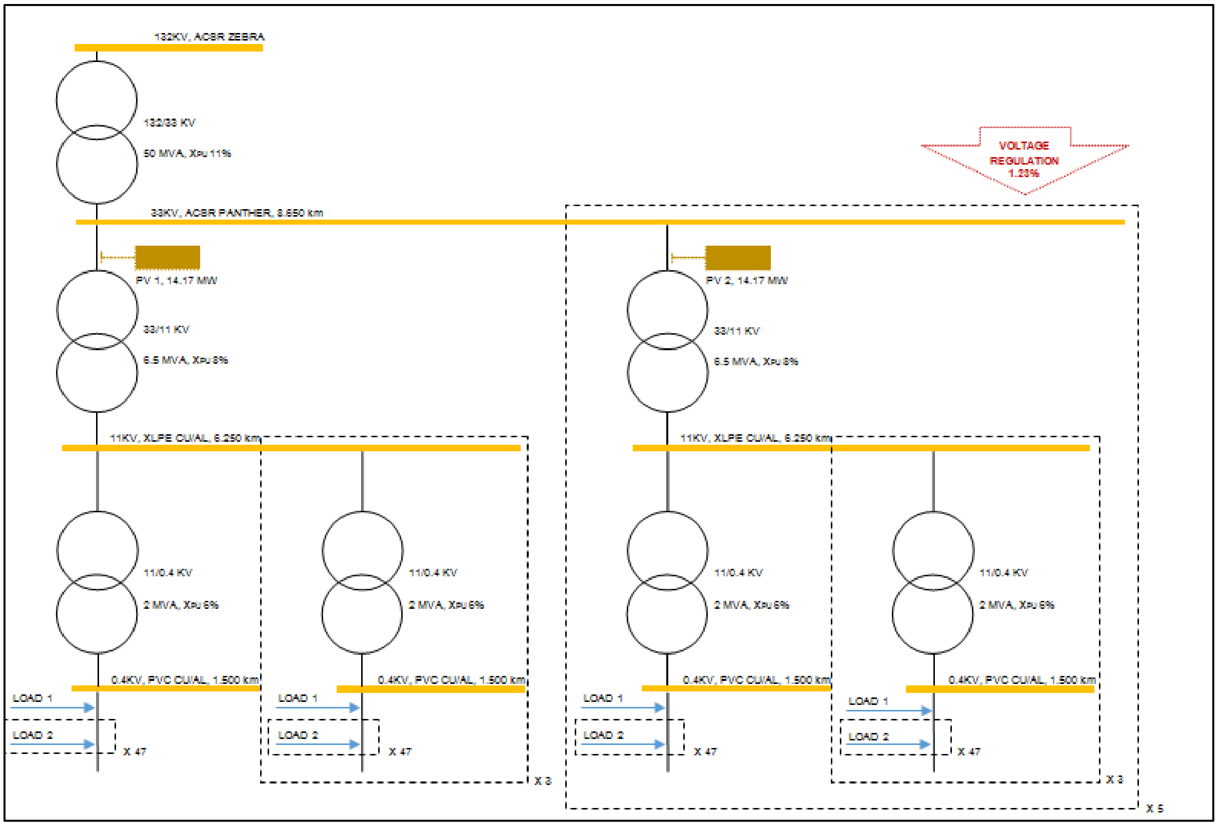


Figure 11: Schematic of 33/11KV feeder with 32.5MVA 40MVA and 50MVA transformer

The simulation results for the 33 KV feeders are discussed in the subsections below.

5.3.5.1 Summary of simulation result for 33KV feeder with distributed PV plants when permitted individual PV capacity is not more than the sanctioned load/contract demand.

The simulation results when the permitted capacity is not more than the sanctioned load or contract demand for different DT ratings: 32.5 MVA, 40 MVA and 50 MVA at different loading conditions are presented in the table below:

Table 24: Simulation results for maximum PV capacity and voltage Regulation for 33KV DTs (32.5 MVA, 40 MVA and 50 MVA) for different loading conditions when the permitted individual GRPV system is not more than the sanctioned load

Minimum station/feeder loading when photovoltaic power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)					
	32.5 MVA		40 MVA		50 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
100%	65.0	Up to 1.0	80.0	Up to 1.5	100.0	Up to 2.5
90%	61.8		76.0		95.0	
80%	58.5		72.0		90.0	
70%	55.3		68.0		85.0	

Minimum station/feeder loading when photovoltaic power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)					
	32.5 MVA		40 MVA		50 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
60%	52.0		64.0		80.0	
50%	48.8		60.0		75.0	
40%	45.5		56.0		70.0	
30%	42.3		52.0		65.0	
20%	39.0		48.0		60.0	
10%	35.8		44.0		55.0	
0%	32.5		40.0		50.0	

From the above table, it is clear that allowable maximum PV capacity without causing any over-voltage at PCC varies from 32.5 MW, 40 MW and 50 MW when minimum running load on DT is 0% to 65 MW, 80 MW & 100 MW when minimum running load on DT is 100%.

A clear inference from the above simulation results table is that, when permitted distribution generation capacity is not more than the sanctioned load/contract demand, aggregate PV power plant capacity (AC nominal power of inverter) that can be connected to a network can be up to 100% of DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor.

5.3.5.2 Summary of simulation result for 33 KV feeders with distributed PV plants when permitted individual PV capacity is not restricted by the sanctioned load/contract demand at different feeder lengths.

The simulation results when the permitted capacity is not restricted by the sanctioned load or contract demand for different 33 KV DT rating: 32.5 MVA, 40 MVA and 50 MVA at different feeder lengths are presented in the table below:

Table 25: Simulation results for maximum PV capacity and voltage Regulation for 33KV DTs (32.5 MVA, 40 MVA and 50 MVA) for different feeder lengths when the permitted individual GRPV system is not restricted by the sanctioned load

Feeder length (m) when PV power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)					
	32.5 MVA		40 MVA		50 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
19500	32.5	8.09	36.4	9.06	36.5	9.08
19000	32.5	7.88	37.4	9.07	37.25	9.03

Feeder length (m) when PV power is at peak (noon time)	Maximum PV Capacity (MW) against Distribution Transformer Rating (MVA)					
	32.5 MVA		40 MVA		50 MVA	
	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)	PV Capacity (MW)	VR (%)
18500	32.5	7.67	38.4	9.07	38.25	9.03
18000	32.5	7.47	39.4	9.05	39.5	9.08
17500	32.5	7.26	40.0	8.93	40.5	9.05
17000	32.5	7.05	40.0	8.68	41.75	9.06
16500	32.5	6.84	40.0	8.42	43.0	9.06
16000	32.5	6.64	40.0	8.17	44.25	9.04
15500	32.5	6.43	40.0	7.91	45.75	9.04
15000	32.5	6.22	40.0	7.66	47.25	9.04
14500	32.5	6.02	40.0	7.41	49.0	9.07

From table number 22, it is clear that there will be over-voltage at PCC, which is dependent on minimum running load on the DT and the feeder length. Hence, when permitted PV capacity (AC nominal power of inverter) is not controlled based on the sanctioned load/contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network, has to be decided on a case by case basis, based on the loading of the respective DT and feeder length, considering over-voltage at PCC as the deciding factor.

5.4 Key recommendations from the load flow simulation studies on DT interconnection capacity limits

- Decision making criteria for proposing a safe limit for network penetration by solar PV should be over-current (thermal capacity) for symmetrically distributed solar photovoltaic systems, when permitted PV capacity (AC nominal power of inverter) is not more than the sanctioned load/contract demand.

- When permitted PV capacity (AC nominal power of inverter) is not controlled based on the sanctioned load/contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network has to be decided on a case by case basis, based on the loading of the respective DT and the feeder length, considering over-voltage at PCC as the deciding factor.

- When permitted distribution generation capacity is not more than the sanctioned load/contract demand, aggregate PV power plant capacity (AC nominal power of inverter) that can be connected to a network can be up to 100% of DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder’s thermal capacity as the deciding factor.

6. Proposed Business Models

6. Proposed Business Models

6.1 Requirement of upcoming business models

The existing Model Net Metering Regulation 2013 largely promotes self-consumption of the power generated by the rooftop solar system by the consumer. Capital Expenditure (Capex) and Operational Expenditure (OPEX or RESCO) models are the dominant business models. Due to a few hurdles posed by the existing models, rooftop solar installations in the country have not scaled up.

The existing business models pose the following hurdles for the uptake of the rooftop solar sector:

- Limited capacity of outreach to large number of consumers
- Small unit size rooftop systems
- Lack of confidence among consumers and financial institutions in the technology and developers due to limited dissemination of knowledge
- Unavailability of a known and reliable agency to back up the installations to improve confidence
- Contractual and payment risks

The low installation volumes in the sector can be attributed to the abovementioned from the sector. Increased volumes in the rooftop solar sector will allow:

- Lowering of transaction costs and better operations
- Building of confidence amongst the stakeholders
- Streamlining the processes - customer acquisition, procurement, quality systems etc.
- Standardization of RTSPV systems and components
- Improving availability of funds from financial institutions
- Accelerating growth in the rooftop sector

Thus, there is a need to look beyond the prevalent business models. It is critical to promote and facilitate new and innovative models for installation of rooftop solar systems, for eligible consumers especially in the urban centres of India, with inadequate rooftop area/inaccessible rooftops etc. However, the present Model Net Metering Regulation 2013 does not suitably address these challenges. In this dynamic landscape, the existing metering /accounting mechanisms need revision as well to accommodate new and innovative business models.

6.2 Development of business model options

The primary consideration for development of business models was based on three parameters, namely, Ownership, Operation Expenditure Responsibility (Op-Ex) and Financial Settlement. The ownership is attributed to the party that incurs the entire capital expenditure for the asset. The next criterion – Operational Expenditure – is attributed to the party that pays for the operational expenditure. The settlement consists of only two options – settlement with utility or RESCO. In addition to these parameters, two additional conditions were considered -

- High Demand, Small Roof
- Multiple Beneficiaries

Possible combinations of business models for all the variable parameters were identified. Of the 72 identified combinations, four combinations have been identified as operationally possible. The identified business models are as follows -

- Consumer-owned (Capex Model)
- Third party-owned (RESCO Model)
- Third party-owned (utility aggregates and acts as trader between the RESCO and the consumer)
- Utility aggregates and acts as RESCO

Apart from these combinations, aggregation of demand by the utility has also been explored as an option. This has resulted into two additional business models, which are as follows -

- Consumer-owned (Utility only aggregates)
- Consumer-owned (Utility aggregates and acts as EPC)

6.3 Proposed business models

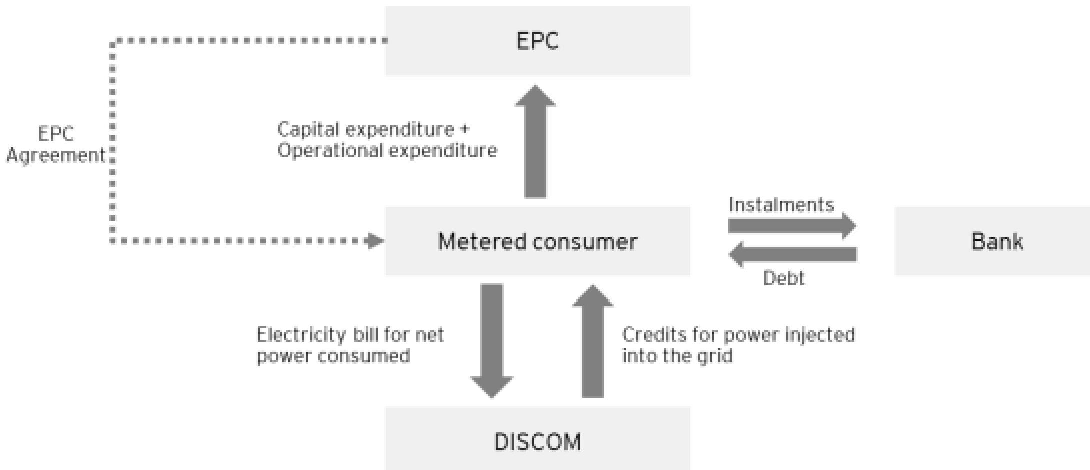
The following business models have been proposed

S. No.	Business model
A. Consumer-centric	
1.	Consumer-owned (Capex model)
2.	Third party-owned (RESCO Model)
B. Utility-centric	
3.	Consumer-owned (Utility only aggregates)
4.	Consumer-owned (Utility aggregates and acts as EPC)
5.	Third party-owned (Utility aggregates and acts as trader between the RESCO and Consumer)
6.	Utility aggregates and acts as RESCO

A. Consumer-centric models

1. Consumer-owned (Capex model)

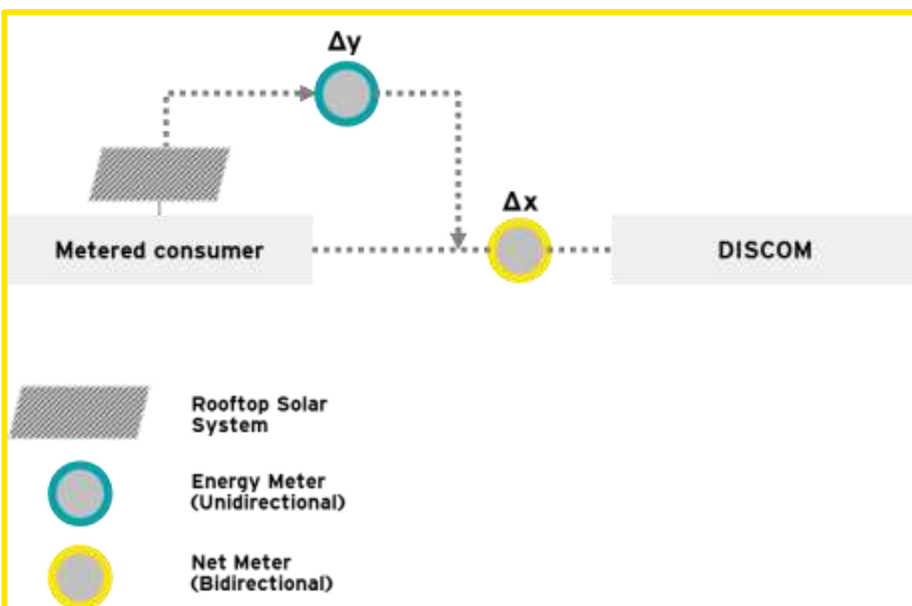
The consumer is responsible for the complete capital and operational expenditure for the rooftop solar plant. The consumer contracts an EPC firm to set up the plant at their premises. Based on the metering Regulation, the commercial and energy settlement can be facilitated through either net or gross-metering arrangements.



Under this model, the commercial and energy settlement can be performed through two modalities, namely net metering and net billing.

a. Net metering

The utility bills the consumer based on the net meter reading.



The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter.

Assuming that

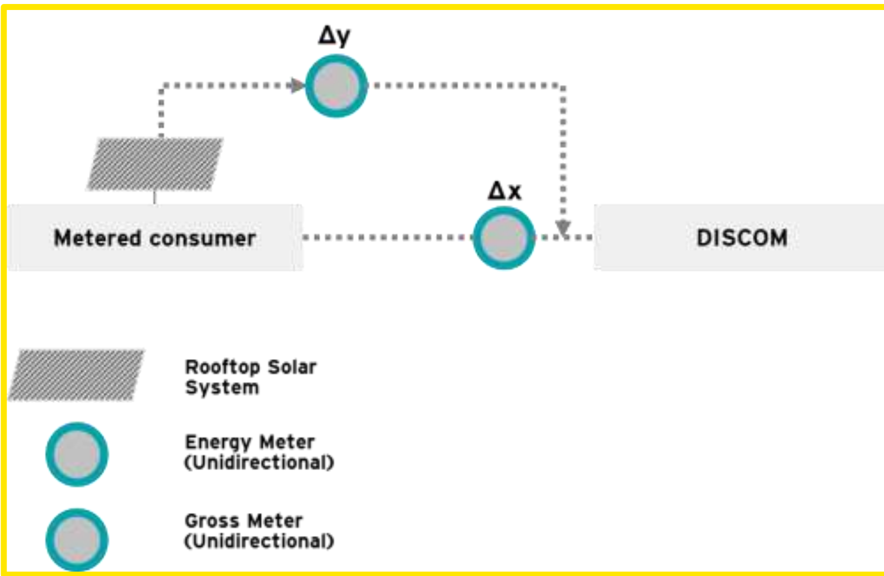
- x_n – Net meter reading for month “n”
- y_n – Energy meter reading for month “n”
- Δx – Number of units (kWh) consumed from the grid i.e. $x_n - x_{n-1}$
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T

b. Net billing

The utility bills the consumer based on the utility meter and the energy meter reading.



The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for total generated electricity against a pre-determined tariff.
Assuming that

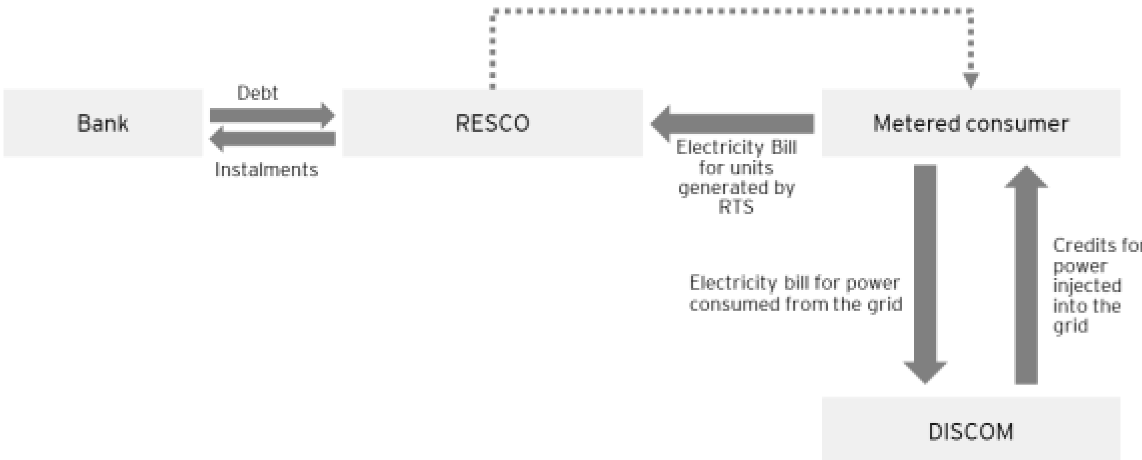
- x_n – Gross meter reading for month “n”
- y_n – Energy meter reading for month “n”
- Δx – Total number of units (kWh) consumed i.e. $x_n - x_n$-1
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T’ – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows:-
Electricity bill = Fixed charges + $\Delta x * T$ - $\Delta y * T'$

2. Third-party owned (RESCO) model

A Renewable Energy Service Company or RESCO sets-up the rooftop solar system on the rooftop of the customer for no or low-cost. The RESCO, for its investment, gets a share of the savings being earned by the consumer by signing a PPA with the consumer.



Under this model, the commercial and energy settlement can be performed through two modalities, namely net metering and net billing. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.

a. Net metering

The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter. The settlement between the consumer and the RESCO is performed internally.

Assuming that

- x_n – Net meter reading for month “n”
- y_n – Energy meter reading for month “n”
- Δx – Number of units (kWh) consumed from the grid i.e. $x_n - x_{n-1}$
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T’ – PPA tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows:
Electricity bill = Fixed charges + Δx*T

The consumer will pay the RESCO for the units generated by the rooftop solar system
Bill = Δy*T’, where T’<T

In case the net generation in the billing period is greater than the total consumption, Δx will hold a negative value. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of Δx will be credited to the consumer for the next month (subject to state Regulations). The consumer will pay the RESCO for all the units generated by the rooftop solar system.

b. Net billing

The settlement between the consumer and the RESCO is performed internally.

Assuming that

- x_n – Gross meter reading for month "n"
- y_n – Energy meter reading for month "n"
- Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n-1}$
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – Net billing tariff
- T'' – PPA tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

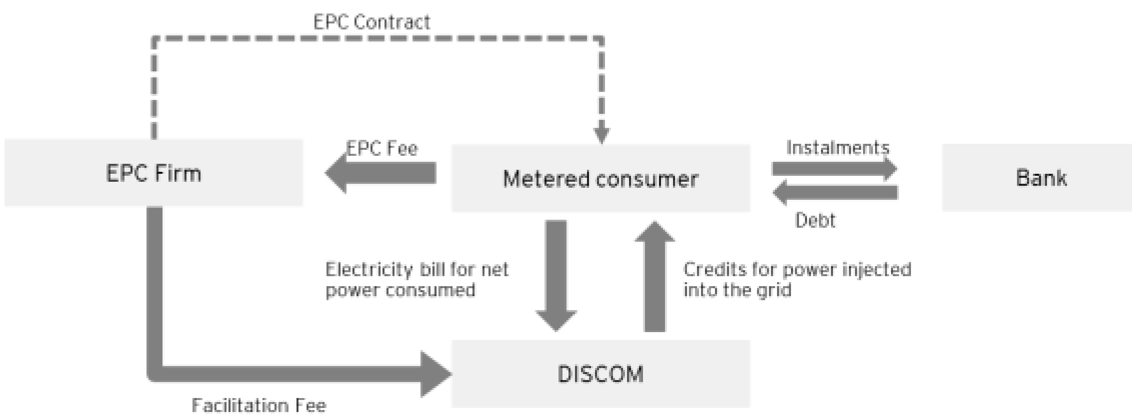
Under the net billing modality, the consumer will be billed as follows:
Electricity bill = Fixed charges + $\Delta x * T - \Delta y * T'$

The settlement between the consumer and the RESCO is performed through a PPA. However, in some cases, roof rent may also be collected by the consumer from the RESCO. No complications will arise in case the total generation in the billing period is greater than the total consumption.

B. Utility-centric models

3. Consumer-owned model (utility only aggregates)

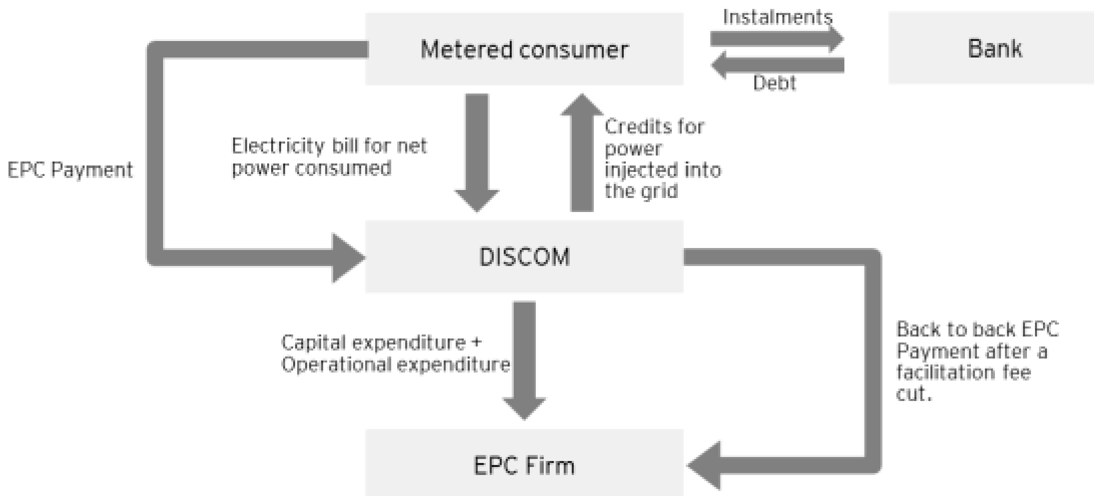
The utility acts as an aggregator by identifying the demand for rooftop solar in its distribution circle. The demand can be identified through a single-window portal on the utility website or through other methods. The consumers interested in installing rooftop solar will have to contact the utility for installation. Once the demand has been aggregated, the utility will initiate a reverse bidding to provide EPC services to the aggregated demand. Only EPC service providers empanelled by the utility will be permitted to participate in the reverse bidding. The successful EPC service provider will sign EPC contracts with the interested consumers. The utility will charge a facilitation fee from the successful bidder for aggregating the demand and thereby decreasing the transaction cost spent by EPC providers for lead generation. The utility will also sign a project management service agreement with the consumers for monitoring the project till interconnection with the grid. The consumer will be responsible for the complete capital expenditure.



The commercial and energy settlement remain similar to the consumer-owned model (Business model 1 – Consumer-owned model Cap-Ex).

4. **Consumer-owned model (utility only aggregates)**

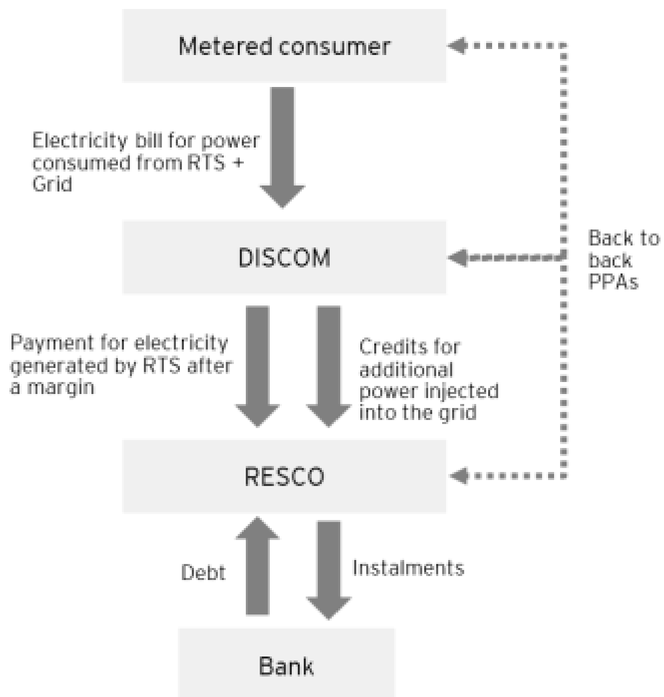
The model is similar to the previous model except that the EPC contract for the installation of the rooftop solar plants is signed between the consumer and the utility. The utility further signs back-to-back agreement with the successful EPC player identified through reverse bidding. The payment for the EPC services is paid to the utility, which further transfers the fee to the EPC services firm with a margin. The back-to-back agreements provide payment security to the service provider while ensuring better services to the consumer. The utility earns revenue in the form of a one-time facilitation fee and a margin on the back-to-back EPC agreements.



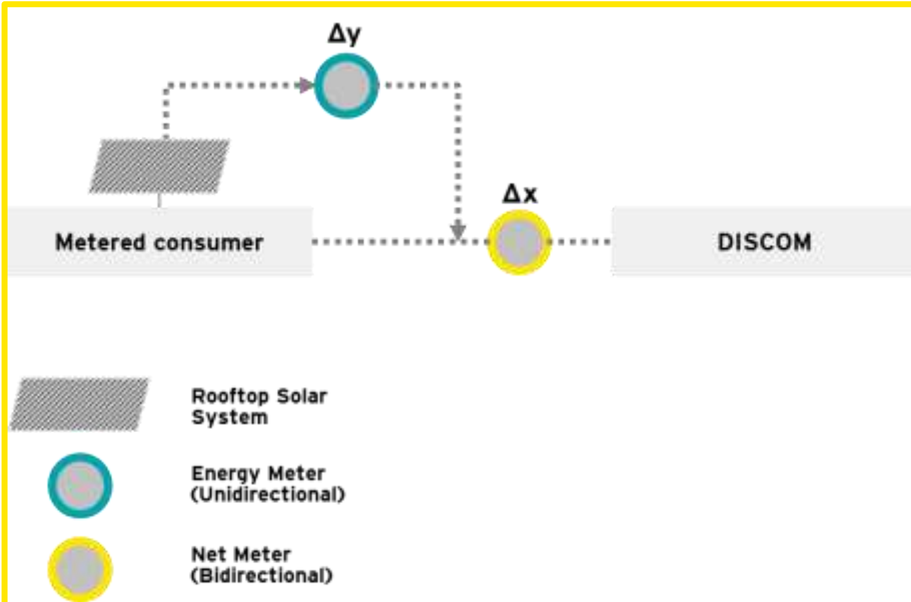
The commercial and energy settlement remain similar to the consumer-owned model (Business model 1 – Consumer-owned model Cap-Ex).

5. **Third-party owned model (utility aggregates and acts as trader between the RESCO and consumer)**

   Under this model, the utility does not set up, own or operate any rooftop solar plant but aggregates the demand in its distribution circle. However, instead of the utility, another RESCO, selected based on reverse bidding, invests. For securitising the payments to the RESCO from the consumer, the payment is routed through the utility, which signs back-to-back PPAs with the consumer and the RESCO. The RESCO will sign a PPA with the utility which will purchase all the energy generated by the solar plant. The utility will sign a PSA with the consumer for the energy generated by RESCO. The utility will charge a trading margin or a fixed fee for facilitating the trading operations.



a. Net metering



The settlement between the utility and the RESCO is performed based on the signed PPA. Assuming that

- x_n – Net meter reading for month "n"
- y_n – Energy meter reading for month "n"
- Δx – Number of units (kWh) consumed from the grid i.e. $x_n - x_{n-1}$
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – PPA tariff
- T'' – PSA tariff
- T'' – T' – Utility's trading margin

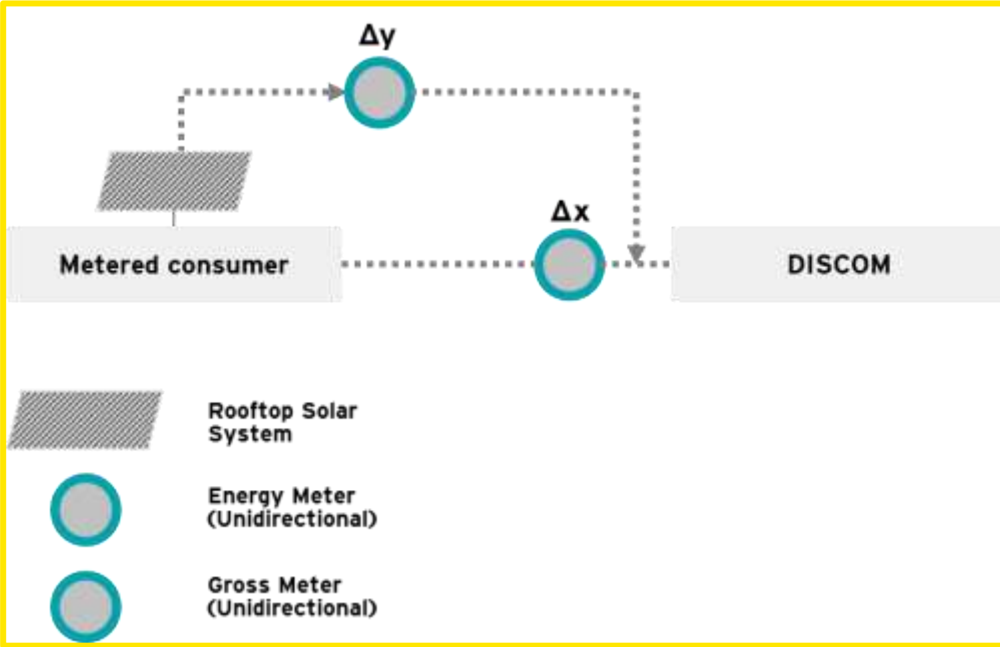
Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as the follows
Electricity bill = Fixed charges + Δx*T + Δy*T''

The utility will pay the RESCO for the units generated by the rooftop solar system
Bill = Δy*T', where T'<T

In case the net generation in the billing period is greater than the total consumption, the Δx will hold a negative value. In this case, the DISCOM will bill the consumer for the fixed charges and the energy generated by the rooftop solar plant, while the absolute value of Δx will be transferred as credit to the consumer for the next month (subject to state Regulations).

b. Net billing



The settlement between the utility and the RESCO is performed based on the signed PPA.
Assuming that
x_n – Gross meter reading for month "n"
y_n – Energy meter reading for month "n"
Δx – Number of units (kWh) consumed from the grid i.e. $x_n - x_{n-1}$
Δy – Number of units (kWh) generated by the rooftop solar plant
T – Grid tariff
T' – PPA tariff
T'' – PSA tariff
T'' – T' – Utility's trading margin

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

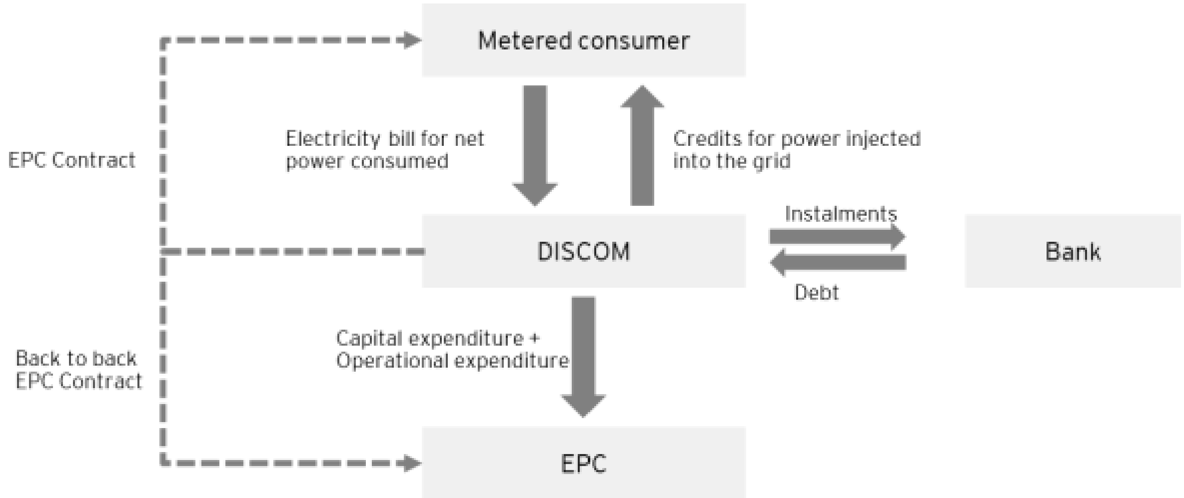
Under the net billing modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T - Δy*T''

The utility will pay the RESCO for the units generated by the rooftop solar system
Bill = Δy*T', where T'<T

No complications will arise in case the total generation in the billing period is greater than the total consumption.

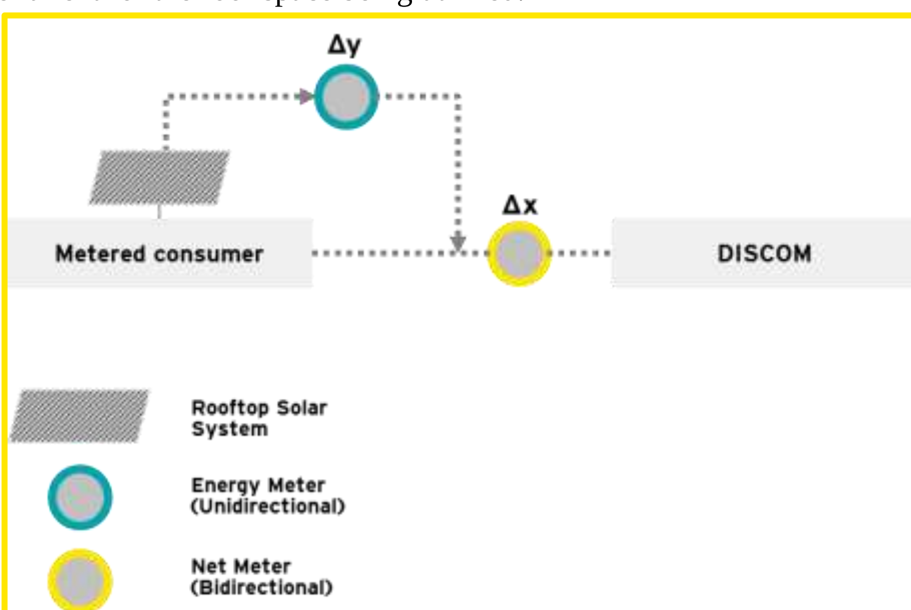
6. Third-party owned model (utility aggregates and acts as RESCO)

The utility acts as an aggregator, who acts as a RESCO for the aggregated demand by installing the rooftop solar systems at the premises of the consumers. The utility in this model sets up, owns and operates the rooftop solar plant. PPAs are signed between the utility and the consumers. It collects the charges for the electricity consumed from the grid and the rooftop solar plants through monthly billing.



a. Net metering

The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.



Assuming that

- x_n – Net meter reading for month "n"
- y_n – Energy meter reading for month "n"
- Δx – Number of units (kWh) consumed from the grid i.e. $x_n - x_{n-1}$
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – PPA tariff

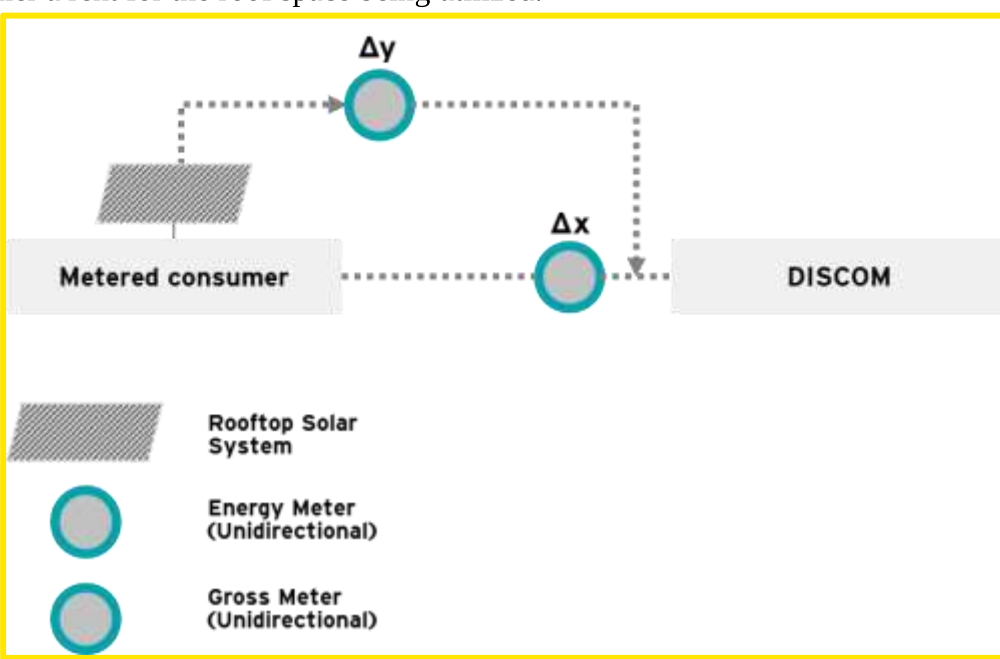
Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T + Δy*T'

In case the net generation in the billing period is greater than the total consumption, Δx will hold a negative value. In this case, the DISCOM will bill the consumer for the fixed charges and Δy*T', while the absolute value of Δx will be credited to the consumer for the next month (subject to state Regulations).

b. Net billing

The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.



Assuming that

- x_n – Gross meter reading for month "n"
- y_n – Energy meter reading for month "n"
- Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n-1}$

- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – PPA tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows
Electricity bill = Fixed charges + $\Delta x * T - \Delta y * T'$

6.4 Financial impact analysis of rooftop solar on a DISCOM

For assessing the commercial impact of rooftop solar penetration on a DISCOM, an analytical tool for capturing the actual revenue loss due to rooftop solar and the benefits due to RPO, reduced procurement and reduced losses has been developed. The commercial impact of rooftop solar on two DISCOMs has been assessed – JBVNL (Jharkhand Bijli Vitran Nigam Limited) and BYPL (BSES Yamuna Power Limited, New Delhi).

The methodology for developing the tools is as follows

- Identification of existing consumer categories and their respective tariffs
- Identification of the existing rooftop solar penetration for the respective consumer categories
- Development of future rooftop solar penetration scenarios such as MNRE target scenario (assuming that the state achieves the rooftop solar target stipulated by MNRE), 10% growth scenario (assuming the installations, in MW, increase by 10% annually), 20% growth etc.
- Development of assumptions for the utility such as
    - Tariff escalation
    - Energy sales annual escalation
    - Average cost of supply and annual escalation
    - Distribution loss escalation
    - APPC escalation
    - RPO targets and RPO deficit
    - Solar EPC costs and other financials
    - Grid injection percentage (% energy injected by the rooftop solar system back into the grid)

	0	1	2	3	4	5	6	7	8	9	
Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	
Energy requirement (MUs)	11,588	11,996	12354.85	12,725	13,107	13,500	13,905	14,323	14,752	15,195	15
APPC (INR/kWh)	4.07	3.75	3.86	3.98	4.10	4.22	4.35	4.48	4.61	4.75	
Distribution loss	20.40%	15%	15%	15%	15%	15%	15%	15%	15%	15%	
Average cost of supply (INR/kWh)		5.98	6.1594	6.34	6.53	6.73	6.93	7.14	7.35	7.58	
Energy sales (MUs)	9,223	11,996	12,356	12,725	13,107	13,500	13,905	14,323	14,752	15,195	15

Tariff scenarios	0	1	2	3	4	5	6	7	8	9
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Domestic LT	5.5	5.665	5.835	6.0	6.2	6.4	6.6	6.8	7.0	7.2
Domestic HT	5.3	5.4	5.6	5.7	5.9	6.1	6.3	6.5	6.7	6.9
Commercial LT	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
Commercial HT	6.0	6.2	6.4	6.6	6.8	7.0	7.2	7.4	7.6	7.8
Industrial LT	6.5	6.7	6.9	7.1	7.3	7.5	7.8	8.0	8.2	8.5
Industrial HT	5.8	5.9	6.1	6.3	6.5	6.7	6.9	7.1	7.3	7.5
Institutional	4.6	4.7	4.9	5.0	5.2	5.3	5.5	5.7	5.8	6.0
Unadjusted credits purchased back by	0.5	0.5	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.7

- Calculation of total MUs generated (year-wise in the next 25 years) by rooftop solar installations across the distribution circle for the selected generation scenario.
- Estimation of total revenues lost by the DISCOM due to rooftop solar penetration.
- Estimation of benefits due to rooftop solar to the DISCOM. The benefits to the utility due to rooftop solar have been assumed due to

- RPO benefits – DISCOMs are mandated to purchase RECs from the energy exchange to compensate for not meeting RPO targets. The generation from rooftop solar systems by non-obligated entities will benefit the DISCOMs.
- Reduced AT&C losses – Due to the decreased demand, lesser amount of energy will be procured from the generators. This will result in lower AT&C losses for the utility.
- Overall reduced procurement - Due to the decreased demand, less amount of energy will be procured from the generators thereby decreasing the overall expenses of the utility. The transmission losses for the reduced procurement are also taken into consideration.

► Calculation of the overall loss / benefit for the utility considering the revenue loss and other benefits.

Energy exported to the grid (MUs)	2.38	15.92	31.
Power purchase from consumers (INR Cr.)	0.12	0.82	1.
Impact on DISCOM	0	1	
Impact on DISCOM due to RTS	**2018**	**2019**	**20**
Total solar generation (MUs)	29.43	196.64	389.
Energy injected into the grid (MUs)	2.9	19.7	39
Net Consumption (MUs)	26.5	177.0	360
Loss due to reduced sales (INR Cr.)	-14.2	-97.0	-196
	0	1	
Impact on sales (INR)	**2018**	**2019**	**20**
Sales pre-RTS (MUs)	9222.7	11995	12354.
Sales post-RTS (MUs)	9,196.21	11,818.03	12,003.
Revenue loss due to RTS	-14.2	-97.0	-196
Additional cost due to power purchase from consumers (INR Cr.)	-0.12	-0.82	-1.
Total revenue loss due to RTS (INR Cr.)	-14.3	-97.8	-197
NPV	₹ -3,833.97		
INR loss per kWh	-0.02	-0.08	-0.
Additional benefits			
RPO benefits (INR Cr.)	1.47		
Benefits due to decreased procurement	₹ 3,203.35		
Benefits due to distribution loss (INR Cr.)	₹ 563.36		
Actual NPV of revenues lost	₹ -3,833.97		
Overall loss	₹ -17.98		
Additional scenarios			
1 **Utility aggregates**			
Assumptions	Aggregation fees (% of capital cost)	3%	

► Calculation of the overall loss / benefit for the utility considering the proposed business models. The assumptions for the proposed business models are input into the model and the benefits realized are analysed. The tool can be utilized to identify the feasible business model, target consumer categories and feasible PPA tariffs for DISCOM's participation in the rooftop solar space.

	5
	₹ -984.87
	₹ 248.34
	₹ -1,233.21

₹ 248.34	2.9	3	3.1	3.11	3.12	3.13	3.14	3.15	3.16	3.17	<PPA Tariff
5.000%	-28.2982	-18.3216	-8.34503	-7.34737	-8.34971	-5.35205	-4.35439	-3.35673	-2.3590712	-1.36141	
10.000%	-29.479	-18.4743	-7.46952	-6.36904	-5.26857	-4.16809	-3.06761	-1.96714	-0.8666622	0.233814	
15.000%	-30.8455	-18.7123	-6.57917	-5.36585	-4.15253	-2.93922	-1.7259	-0.51258	0.7007358	1.914053	
20.000%	-32.4073	-19.0386	-5.6698	-4.33293	-2.99605	-1.65917	-0.3223	1.01458	2.351457	3.688334	
25.000%	-34.1745	-19.4558	-4.73703	-3.26516	-1.79328	-0.32141	1.150465	2.622339	4.0942124	5.566086	
30.000%	-36.1572	-19.9867	-3.77622	-2.15717	-0.53811	1.080936	2.699988	4.319039	5.9380905	7.557142	
35.000%	-38.3661	-20.5743	-2.78251	-1.00333	0.775848	2.555025	4.334202	6.11338	7.8925567	9.671734	
40.000%	-40.8117	-21.2813	-1.75081	0.202234	2.155278	4.108322	6.061366	8.01441	9.9674538	11.9205	
45.000%	-43.5052	-22.0905	-0.67581	1.465656	3.607125	5.748594	7.890063	10.03153	12.173002	14.31447	
50.000%	-46.4579	-23.0049	0.44803	2.793325	5.138619	7.483914	9.829208	12.1745	14.519797	16.86509	

* RTS penetration rate

The two case studies are as follows

Case Study 1 – Jharkhand - Jharkhand Bijli Vitran Nigam Limited

For a rooftop solar penetration scenario wherein the state /DISCOM achieves the MNRE rooftop solar targets, the following are the observations:

- In case of JBVNL, an overall benefit of INR 1.3 Cr. (**0.017% of the approved ARR**) for 2019 is observed. The overall benefit in case of JBVNL is due to the small difference between the APPC and the tariff charged. The overall benefit/loss has been computed by considering the revenue loss, RPO benefits, benefits due to reduced procurement and benefits due to reduced AT&C losses.

- The commercial impact of the following business models was also assessed
  - Utility aggregation
  - Utility aggregation and acting as EPC
  - Utility as a trader
  - Utility as a RESCO

- Business Model 6, i.e., utility aggregates and acts as a RESCO, is the most commercially feasible model for the utility. Under Business Model 6, the PPA cost leads to no commercial impact on the utility assessed. For JBVNL, it lies between **3.5-3.6 INR/kWh**.

Case Study 2 – New Delhi - BSES Yamuna Power Limited

For a rooftop solar penetration scenario wherein the state/DISCOM achieves the MNRE rooftop solar targets, the following are the observations:

- For BYPL, the overall loss due to rooftop solar is limited to INR 9.93 Cr. (**0.25% of the approved ARR**) for 2019. The overall benefit/loss has been computed by considering the revenue loss, RPO benefits, benefits due to reduced procurement and benefits due to reduced AT&C losses.

- The commercial impact of the following business models was also assessed
  - Utility aggregation
  - Utility aggregation and acting as EPC
  - Utility as a trader
  - Utility as a RESCO
- The commercial impact of the abovementioned business models was also assessed. Business Model 6, i.e., utility aggregates and acts as a RESCO, is the most commercially feasible model for the utility. Under Business Model 6, the PPA cost leads to no commercial impact on the utility assessed. For BYPL, the PPA cost lies between **5.8-5.9 INR/kWh**.

The tool can be utilized by the utilities to identify the feasible business model, target consumer categories and feasible PPA tariffs for DISCOM's participation in the rooftop solar space. The tool can be utilized to plan future deployments of rooftop solar at a DISCOM level.

7. Proposed changes or new additions in the Model Regulation

7. Proposed changes or new additions in the Model Regulation

The objective of the proposed Model Regulation is to provide a guiding framework at the central level for the proliferation of GRPV in India after reviewing the existing regulatory framework, identifying all such challenges faced by various stakeholders through detailed consultation and studying international experience relevant to Indian context.

The proposed Model Regulation is provided in Annexure 1 of this report.

The Model Net Metering Regulation 2013 and the state Regulations, to that extent, cover the following aspects of the regulatory framework subject to variations in terms of treatment considered specific to the state:

- System size, limit on DT capacity and maximum size allowed
- Metering principles
- Energy accounting and commercial settlement, and
- Regulatory provisions related to RPO
- Other supporting provisions to the above aspects

Based on review of present regulatory framework and experience from other countries – discussed in earlier chapters – there is scope for revision in the present Model Net Metering Regulation 2013 to incorporate regulatory requirements for the changing landscape in the country. The findings and proposed Model draft Regulation were presented in the Standing Technical Committee meeting and FOR. After much deliberation, certain changes were suggested, according to which the draft Model Regulation was updated. The provisions made and the proposed changes in the Model Regulation post discussion with forum are discussed in this chapter.
The Model Regulations and the report were presented at the 64th FOR meeting held on 24th August 2018 at Ranchi. The Forum considered the Model Regulations and the report, and as directed, comments from SERCs/JERCs were sought and incorporated.

Subsequently the Model Regulations and the report were discussed in the 21st and 22nd meetings of the Technical Committee for Implementation of Framework on Renewables at the State Level (*hereinafter referred to as "Standing Technical Committee")* held on 8th October, 2018 and 1st November 2018 respectively. The Standing Technical Committee made the following recommendations:

a. Definition of Premises: Only residential consumers be allowed to interconnect ground-mounted solar systems under net-metering/net-billing, which should be limited to their maximum contracted demand.
b. Scope of Demand Aggregation: DISCOMs to do demand aggregation, which should be restricted to residential consumers only.
c. Compensation for Net Billing: Each state may decide to choose appropriate option such as commission-determined reference price or price discovered from SECI/DISCOM RTS bids.

The Forum of Regulators in its 65th meeting held on 14th November 2018 at Bhubaneswar were apprised of the aforesaid recommendations made by the Standing Technical Committee

After deliberations, the Forum approved the recommendations and endorsed the Model Regulations and report with a focus on rooftop installations and adoption of the net-billing concept.

In this chapter, the proposed changes/additions in the Model Net Metering Regulation 2013 vis-a-vis present provisions have been discussed at length. This will provide a robust model regulatory framework for the states to adopt and to further support the proliferation of solar and other forms of renewable sources, eligible in India.

The purpose of the proposed changes in the Model Regulation is to:

- Address the gaps identified through the critical analysis of the present regulatory framework
- Enable regulatory framework for suggested business models
- Introduce governance structure, institutional framework and roles and responsibilities

The proposed Model Regulation is focused on GRPV and also provisions its extension to all distributed renewable sources with adequate freedom to SERCs to decide on certain factors. Further, provisions to provide the necessary framework for different business models and to explore maximum potential along with their energy accounting and commercial settlement have also been proposed. The proposed changes to address the gaps identified and new provisions proposed are discussed in the subsequent sections.

7.1 Addressing the gaps identified through critical analysis of present regulatory framework

The following section deliberates on the changes required in the proposed GRPV Model Regulation based on international experience and case studies observed in India in recent times. The identified gaps that need review while framing proposed Model Regulation are listed below:

- Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity
- Different limits on GRPV capacities connected to DT requires review
- Limited business model options available to consumers and developers, limited scope to DISCOMs in the present scenario
- Definition of premises and GRPV systems needs review owing to future possibility of different scenarios
- Limited provisions regarding real time monitoring of solar generation and participation in system operations, required in case of large penetration of GRPV systems
- Present PPA or connection agreement needs additional aspects related to change in ownership and flexibility in existing PPA/connection agreement
- No remuneration for excess generation in present energy accounting and commercial settlement principles

- Metering and communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

To mitigate these gaps, required provisions have been proposed in the draft Model Regulation. The details of the provisions made are discussed below:

7.1.1 **Restrictions in terms of individual capacity based on sanctioned load and maximum GRPV capacity**

As discussed earlier, the present Regulations (Model and state) have put restrictions on GRPV capacity such as certain percentage of sanction load and individual maximum capacity that can be commissioned. Though, Model Net Metering Regulation, 2013 has not put any restriction in terms of sanction load, a few state Regulations have put certain restrictions. The limit on GRPV system capacity in terms of sanctioned load differs from state to state; ranging from 40% to 100% under net metering. Further, the maximum capacity of 1 MW can be set up in India under net metering arrangement.

In proposed Model Regulation, two types of DRE systems (the definition of Distributed Renewable Energy sources is also discussed in subsequent sections) have been proposed based on ownership:

1. Prosumer Distributed Renewable Energy System (PDRES) – A distributed renewable energy system set up by prosumer under net metering or net billing, connected on the prosumer side of the meter or on service line to the prosumer.

2. Independent Distributed Renewable Energy System (IDRES) -- A distributed renewable energy system set up by any person is connected to the distribution licensee network and sells electricity to the distribution licensee under PPA.

In case of PDRES, the allowable capacity is linked to the sanctioned load for prosumers. The capacity of PDRES shall not exceed the sanctioned load/contract demand of the prosumer. In case of IDRES, the capacity is linked to the power system constraints. The maximum IDRES capacity, to be installed by a person at a particular location, shall be based on the capacity and configuration of the electricity system, and in the power flows that the distributed generation resource may cause.

In case of PDRES, minimum 1 KW and 10 KW size systems can be set under net metering and net billing, respectively. In case of IDRES, the minimum size is 50 KW.

7.1.2 **Different limits on GRPV capacities connected to DT requires review**

In Model Net Metering Regulation 2013 and the state Regulations, there is a restriction on cumulative capacity that can be connected to single DT. As per Model Net Metering Regulation 2013 and some state Regulation, the limit was 15% of the DT capacity. The maximum limit on allowed capacity was 80% provisioned in GRPV Regulation in the states of Sikkim and Karnataka. The main reason for setting a limit on GRPV system in terms of DT capacity was the likely possibility of reverse power flow.

It was also envisaged that the limit can be reviewed after carrying out a technical study at a suitable point of time.

As per the technical study conducted, when permitted distribution generation capacity is not more than the sanctioned load/contract demand, aggregate PV power plant capacity (AC nominal power of inverter) can be up to 100% of DT capacity, even under worst case scenario(s), i.e. with 0% running load, considering feeder's thermal capacity as the deciding factor. When permitted distribution generation capacity is not controlled based on sanctioned load/contract demand, aggregate or single PV power plant capacity (AC nominal power of inverter) that can be connected to the network has to be decided on a case by case basis, based on the loading of the respective DT, considering over-voltage at Point of Common Coupling (PCC) as the deciding factor.

As per the latest communique of MNRE[19] with the SNAs, it is observed that the DT loading may be increased to 100% by MNRE in order to utilize the DT capacity. Relevant excerpts from the note published by MNRE are reproduced below:

> *"Annexure 1: Mandatory Reforms to be undertaken by the DISCOMs*
>
> *... 4. PV system capacity limitation due to distribution transformer (DT) capacity: Several DISCOMs already allow connecting RTS to 80% of the DT capacity. But the allowable PV capacity connected to a DT should be 100% of the DT's capacity. This is because the DT should be used to its fullest capacity, and also solar PV would typically not exceed 85% of its nameplate DC capacity. If the DT is unable to step-up power in the reverse direction, the DISCOM should make the necessary modifications/replacements to it"*

Based on the technical study carried out, the limit for connecting DRE system to a feeder or a distribution transformer is proposed to be 100% of the respective feeder or distribution transformer. The simulation results for different case studies have been provided in Annexure- 5.

7.1.3 Limited provisions on real time monitoring of solar generation and participation in system operations, required in case of large penetration of GRPV systems

As per Model Net Metering Regulation 2013, a meter equipped with the MRI facility was permitted to measure solar generation and the net import /export. Subsequently, due to availability of metering technology, state Regulations made provision for AMR/AMI compatibility of meter beyond certain capacity keeping in view the monitoring of DRE system required in future for visibility on solar generation (at least, beyond certain capacity) required in case of large penetration of GRPV systems.

Keeping this in view, the proposed Model Regulation provision of AMI facility with RS 485 (or higher) communication port has been proposed for all meters to connect future grid digitalization.

[19] http://solarrooftop.gov.in/notification/Notification-08112016901.pdf

7.1.4 Limited business models available to consumer and developers, limited scope to DISCOMs in the present scenario

As discussed earlier, the existing Regulations (Model and state) promote largely self-consumption framework for the power generated by the GRPV system and set the principles for the energy accounting and commercial settlement for the net import/export of electricity received/fed in to the grid. Presently, CAPEX and RESCO models are the dominant business models in India. Internationally, additional business models, depending upon capital investment, responsibility of operation and maintenance and the parties involved in the settlement, are very popular.

The proposed business models introduced new owners of the DRE system. Further, the distribution licensee may act as RESCO or Engineering, Procurement, and Construction (EPC) contractor to undertake deployment of DRE. The distribution licensee may undertake demand aggregation and other related activities to effectively deploy distributed renewable energy it its area of supply. The distribution licensee may charge facilitation fee to undertake demand aggregation provided that such fees are reasonable and announced upfront before the consumer decides to participate in such a demand aggregation program. In case the distribution licensee acts as a RESCO or EPC, such activity of the distribution licensee shall be considered as part of its other business as per the provisions of the Tariff Regulations.

The relevant provision enabling DISCOM a much wider scope is reproduced below:

"22.1. Role of the distribution Licensee

g) The distribution licensee may explore appropriate utility driven business models such as demand aggregation, distribution licensee as a RESCO or EPC, etc. to promote installations of distributed renewable energy in its area of supply."

The treatment of ownership in the proposed Model Regulation due to different models is discussed subsequently.

Energy accounting and settlement mechanism

The proposed Model Regulation aptly covers the required provisions for enabling the business models proposed: ownership and energy accounting and commercial settlement. The three different accounting and settlement mechanisms are proposed in the draft Model Regulation. In case of PDRES, the settlement can either be through net metering or net billing. In case of IDRES, the settlement is similar to IPP where the electricity generated is sold directly to the DISCOM through PPA.

7.1.5 **Present PPA or connection agreement need additional aspects related to change in ownership and flexibility in existing PPA/connection agreement**

As per Model Net Metering Regulation 2013, the agreement is entered into between the distribution licensee and the consumer. In the wake of newer arrangements, associations (such as RWAs, etc.) may also set up DRE systems. Therefore, the ownership of DRE system will not be limited to a consumer or a RESCO (or the third party). Even the DISCOM can also act as RESCO. Therefore, to accommodate possible different ownership models for setting up the DRE systems, certain changes have been proposed in the draft Model Regulation.

As per EA 2003, a "person" shall refer to the eligible consumer, group of eligible consumers or any company or body, corporate or association or body of individuals, whether incorporated or not, or artificial juridical person. Therefore, the definition of agreement has been changed to accommodate different ownership option possible due to different business models as given below:

2.1 Definitions and Interpretations

"Agreement" means an agreement entered into by the distribution licensee **with the person**;

Further, new definitions of RESCO, Prosumer and DRE that have been added in the proposed draft Model Regulation are reproduced below:

2.1 Definitions and Interpretations

1. *"Prosumer" is a person who consumes electricity from the grid and can also inject electricity into the grid using the same network from a renewable energy system set up on the consumer side of the meter.*
2. *"Renewable Energy Service Company (RESCO)" means an energy service company that owns a renewable energy system and provides renewable energy to the consumer, provided that the distribution licensee may act as a RESCO. However, this business shall be treated as other business of the distribution licensee.*
3. *"Distributed Renewable Energy"(DRE) means the electricity fed into the electric system at a voltage level of below 33 KV using rooftop solar PV system [or such other forms of renewable sources as may be approved by the Commission from time to time or as recognized by the Ministry of New and Renewable Energy, Government of India][20] ;*

Also in the proposed draft Model Regulation, the ownership DRE systems can be of two types, PDRES or IDRES, which reflects the dealing with different arrangements and their settlement mechanism. The definition of PDRES and IDRES is already provided in section 5.1.1 while explaining the proposed changes to address the issue of limits on individual system size and maximum capacity allowed.

[20] [ ] to be incorporated to cover RE sources other than Rooftop Solar PV under DRE framework

7.1.6 No remuneration for excess generation in present energy accounting and commercial settlement principles

As discussed earlier, as per Model Net Metering Regulation 2013, there is a limit on generation in terms of total consumption (90%). No payment is allowed when electricity generated exceeds 90% of the electricity consumed at the end of the settlement period. Further, no carry forward of energy credit in next settlement period is allowed. The SERCs who notified their net metering Regulation afterwards tried to address the issue by allowing excess generation to be settled at some predefined rate like FiT and APPC so that the consumer will also get due benefit.

The excess generation exported to the grid needs to be compensated at a fair price to promote the DRE system across consumer categories. Therefore, earlier, in the proposed Model Regulation, it was provisioned that the excess energy generated by PDRES will be settled at APPC for the year in which such excess energy is procured by the distribution licensee. It also provisioned that the distribution licensee may undertake procurement of power from IDRES plants under Section 63 of the Act provided that the Ministry of Power, Government of India, has issued appropriate bidding guidelines for the same.

The basis for settlement rate was deliberated in the Standing Technical Committee meeting and FOR meeting - what should be the appropriate rate for settlement. The Standing Technical Committee suggested that each state may decide the appropriate option such as Commission-determined reference price or price discovered from SECI/DISCOM RTS bids. After reaching a collective agreement, the following provision was made in the Model Regulation:

Net Metering arrangement

11. c) The distribution licensee shall procure any excess energy generated by PDRES at rooftop solar tariff discovered through competitive bidding undertaken by SECI or distribution licensee in the last financial year or such other reference rate as may be determined by Commission.

Net Billing arrangement

12. b) The distribution licensee shall procure energy generated by PDRES at the rate determined by the Commission from time-to-time for such systems.

17.2. vi. Rate of selling of power to the consumer shall be the same rate as determined by the Commission for procurement of power from DRE Plant.

7.1.7 Definition of premises and solar roof-top PV systems needs review owing to future possibility of different scenarios

The definition of premises is different in case of Model Net Metering Regulation 2013 and a few state Regulations in the way they treat open land in their definition. In case of Rajasthan, open land is covered in the definition of "Rooftop PV Solar Power Plant". An example of such different definitions and the treatment of open land is provided in the table below:

Table 26: Definition of Premises in different Regulations

Sr. No.	Regulation/ State	Definition
1	Model Net Metering Regulation 2013	"Premises" means rooftops **or/and elevated areas on the land**, building or infrastructure……..
2	Gujarat	"Premises" means rooftops **or/and open areas on the land**, building or infrastructure……..
3	Rajasthan	"Rooftop PV Solar Power Plant" means the solar photo voltaic power plant including small solar systems installed on the rooftops/ground mounted **or open land of consumer premises**……

The treatment of open land raised questions about the extent to which the ground mounted DRE system can be allowed under rooftop arrangement. However, the proposed Model Regulation has been framed with a broader view that aims to cover all eligible distributed renewable energy sources. Further, it provisions for limiting the DRE capacity either in terms of sanctioned load (in case of PDRES) or in terms system constraints (in case of IDRES).

Earlier, in the first draft Model Regulation presentation before the FOR, the definition for 'premises' provided in EA 2003 was proposed instead of the definition provided in Model Net Metering Regulation 2013. The Standing Technical Committee suggested that only residential consumers should be allowed to interconnect ground-mounted solar systems under net-metering/net-billing and that it should be limited to their maximum contracted demand. The FOR, in its 65th meeting, decided to focus on rooftop installation and their treatment. Accordingly, the following definition of 'premises' has been added in the proposed Model Regulation:

> *"Premises" means rooftops [or/and elevated areas on the land, building or infrastructure or part or combination thereof][21] in respect of which a separate meter or metering arrangements have been made by the licensee for supply of electricity.*

7.1.8 Metering and communication requirements need review to provide greater visibility on solar generation to DISCOMs and system operations

Presently, different states have specified varied specifications for metering, communication protocol and arrangements, from simple MRI to AMI compatible (for systems above certain capacity). Moreover, for real time monitoring of GRPV systems, it is required to have advanced metering and communication arrangement by DISCOMs.

In view of real time monitoring of solar generation, meters with AMI facility with RS 485 (or higher) communication have been proposed to have compatibility with future grid digitalization. The AMI facility will also help in easy meter reading and billing of such consumer opting for DRE systems.

[21] [ ] to be incorporated if decided by the Commission, to cover RE sources other than Rooftop Solar PV and premises other than rooftop under DRE framework

7.2 Roles and responsibilities of distribution Licensee, Governance Structure, and Institutional Framework

7.2.1 **Role of the distribution licensee**

The draft Model Regulation has proposed detailed roles and responsibilities of DISCOMS so that the application for DRE system is processed in time. The provisions related to online application process, defined timeline for processing the application and information of grid network to be published for all consumers has been included in the proposed draft Regulation. This will help in addressing operational issues, and thus the proliferation of DRE systems in India. The provisions proposed under the role of the distribution licensee are provided below:

- The distribution licensee shall provide information regarding feeder/distribution transformer hosting capacity available for connecting renewable energy system within three (3) months from the date of notification of these Regulations. The distribution licensee thereafter shall annually publish on its website cumulative installed capacity of the renewable energy systems and available hosting capacity
- The distribution licensee shall maintain a record of DRE systems set up under these Regulations with details including the type and capacity of renewable energy system and submit quarterly report within fifteen days of the previous quarter to the appropriate Commission with intimation to the state agency
- The distribution licensee shall adopt and notify the procedures and formats including standard "Agreement" form as specified under these Regulations and upload it on its website for information of stakeholders within one month of the notification of these Regulations.
- The distribution licensee shall undertake technical studies to assess the impact of penetration of DRE systems on the distribution system
- The distribution licensee shall undertake technical studies to assess the impact of different types of storage systems on the distribution system
- The distribution licensee shall set up a Distributed Renewable Energy Cell (DRE Cell) within three months of the notification of these Regulations
- The distribution licensee may explore appropriate utility-driven business models such as demand aggregation, distribution licensee as a RESCO or EPC, etc. to promote installations of distributed renewable energy in its area of supply.

7.2.2 **DRE Advisory Committee**

To facilitate DRE program, the draft Model Regulation has proposed the constitution of a DRE advisory committee to be notified by the respective commission. For timely resolution of issues, it is also provisioned that the advisory committee shall meet at least once in every quarter to take up the functions assigned to it and submit its proceedings to the Commission. The proposed members of the committee and their functions are provided below:

Members of the committee

- Director (Technical) of the Commission – Chairman
- Representative from the State Power Department;
- Representative of each distribution licensee in the State (In-Charge of DRE Cell);
- Representative from SNA;
- Representative from the Office of Electrical Inspector;
- Two independent external members from different Government departments;
- Three representatives from consumer or consumer associations representing interests of domestic, commercial, and industrial category consumers.
- Person in charge at SNA - Convener of the Advisory Committee;

Proposed functions of the DRE advisory committee

- Advise the distribution licensee(s) to develop consumer-friendly procedures, billing systems, etc.
- Develop technical standards for DRE impact assessment, load flow studies, etc.
- Develop reporting requirements for the distribution licensees
- Develop standards for data exchange between DRE System and the distribution licensee
- Promote cross-learning among the distribution licensees and other stakeholders
- Assist in developing common programs across the distribution licensees
- Develop common programs for training/capacity building
- Advise the distribution licensee(s) in developing common monitoring & reporting framework and maintenance of database
- Assist the Commission on issues that may be referred to it

7.2.3 Distributed Renewable Energy Cell

Further, the proposed draft Model Regulation also requires that each DISCOM shall constitute an in-house DRE Cell to promote DRE deployment in its area of supply, headed by an officer of rank not below that of superintending engineer or equivalent. However, for effectively discharging the duties, necessary authority and resource also need to be provided. This has been provided for in the proposed draft Model Regulation. The proposed functions of the DRE cell are provided below:

Proposed functions of DRE Cell

- Design interconnection processes and procedures
- Ensure and manage web-based application system for processing DRE applications

- Develop and monitor mechanism for online monitoring of DRE systems by the distribution licensee control centre
- Obtain regulatory approvals
- Guide persons desirous of setting up DRE systems in the state
- Facilitate training of field officers on DRE
- Appraise field officials about the changes in the processes and procedures
- Ensure modification to billing procedures/systems to account for provisions in these Regulations
- Undertake monitoring and reporting as envisaged under these Regulations
- Coordinate with DRE Advisory Committee and attend meetings of the same
- Prepare standard documents such as expression of interest, RFP, energy purchase and energy sale agreement, tripartite agreement, etc. if the distribution licensee decides to procure power under through competitive bidding
- Preparation of plan for procurement of energy from DRE sources
- Undertake analysis of data collected from DRE systems

Annexures

8. Annexures

Annexure 1: Draft Model Regulation for Grid Interactive Distributed Renewable Energy Sources

Draft Model Regulation for Grid Interactive Distributed
Renewable Energy Sources

Dated: DD.MM.2019

No. XX / XX /2019

In exercise of the powers conferred under sections 42, 61, 66, 86(1)(e) and 181 of the Electricity Act, 2003 (Act 36 of 2003) and all other powers enabling it in this behalf, and after previous publications, the …………………….(Name of State) Electricity Regulatory Commission hereby makes the following Regulations for the grid interactive distributed renewable energy sources:

Part — A
Preliminary

1. Short title, and commencement

i. These Regulations may be called the ……………… (Name of State) Electricity Regulatory Commission (Grid Interactive Distributed Renewable Energy Sources) Regulations, 20xx

ii. These Regulations may come into force from the date of their notification in the Official Gazette

iii. These Regulations shall extend to the whole of the State of……..

2. Definitions and interpretations

i. In these Regulations, unless the context otherwise requires,

a) "Act" means the Electricity Act, 2003 (36 of 2003) and subsequent amendments thereof;

b) "Agreement" means an agreement entered into by the distribution licensee with the person;

c) "Billing Cycle or Billing Period" means the period for which regular electricity bills are prepared for different categories of consumers by the distribution licensee, as specified by the Commission;

d) "Commission" means the ……..……….(Name of State) Electricity Regulatory Commission constituted under the Act;

e) “Contract Demand” or “Sanctioned Load” means the maximum demand in kW, kVA or BHP, agreed to be supplied by the licensee and indicated in the agreement executed between the licensee and the consumer;

f) “Distributed Renewable Energy”(DRE) means the electricity fed into the electric system at a voltage level of below 33 KV using rooftop solar PV system [or such other forms of renewable sources as may be approved by the Commission from time to time or as recognized by the Ministry of New and Renewable Energy, Government of India][22];

g) “Financial Year” or “Year” means the period beginning from first of April in an English calendar year and ending with the thirty first of the March of the next year;

h) “Generation Meter” means an energy meter installed at the point at which electricity generated by the renewable energy system is delivered to the eligible consumer;

i) “Hosting capacity” means capacity defined under Regulation 14 of these Regulations;

j) “Independent Distributed Renewable Energy System” or “IDRES” means a distributed renewable energy system set up by any person, connected to the distribution licensee network and selling electricity to the distribution licensee under a Power Purchase Agreement;

k) IDRES owner is a person who owns the IDRES plant.

l) “Interconnection point” means the interface of the renewable energy system with the outgoing terminals of the meter/distribution licensee’s cut-outs/switchgear fixed in the premises of the Eligible Consumer.

Provided that, in case of an Eligible Consumer connected at the High Tension (‘HT’) level, the ‘inter-connection point’ shall mean the interface of the renewable energy system with the outgoing terminals of the distribution licensee’s metering cubicle placed before such consumer’s apparatus;

m) “Invoice” means either a monthly bill/supplementary bill or a monthly invoice/ supplementary invoice raised by the distribution licensee

n) “kWp” means kilo Watt peak;

o) “Net billing” means an arrangement as defined under Regulation 17 of these Regulations;

p) “Net meter” or “bidirectional meter” means an energy meter which is capable of recording both import and export of electricity;

q) "Net metering" means an arrangement under which renewable energy system installed at eligible consumer premises delivers surplus electricity, if any, to the distribution licensee after offsetting the electricity supplied by distribution licensee during the applicable billing period.

r) “Obligated entity” means the entity mandated under clause (e) of subsection (1) of section 86 of the Act and identified under ……………..RPO Regulations;

s) “Premises” means rooftops [or/and elevated areas on the land, building or

[22] [ ] to be incorporated to cover RE sources other than Rooftop Solar PV under DRE framework

infrastructure or part or combination thereof][23] in respect of which a separate meter or metering arrangements have been made by the licensee for supply of electricity.

t) "Prosumer" is a person who consumes electricity from the grid and can also inject distributed renewable energy into the grid using the same network.

u) "Prosumer Distributed Renewable Energy System" or "PDRES" means a distributed renewable energy system set up by the prosumer under net metering or net billing.

v) "Renewable energy'' means the grid quality electricity generated from renewable energy sources, including a combination of such sources;

w) "Renewable Energy Certificate (REC)" means the certificate issued in accordance with the Central Electricity Regulatory Commission (Terms and Conditions for recognition and issuance of Renewable Energy Certificate for Renewable Energy Generation) Regulations, 2010;

x) "Renewable Energy Service Company (RESCO)" means an energy service company which owns a renewable energy system and provides renewable energy to the consumer.

Provided that the distribution licensee may act as a RESCO. However, this business shall be treated as other business of the distribution licensee.

y) "Renewable Energy System" means the generating station that generates electricity from renewable energy source(s) or combination thereof.

z) "Rooftop Solar PV System" means the solar photo voltaic power system installed on the rooftops of consumer premises that uses sunlight for direct conversion into electricity through photo voltaic technology.

aa) 'Settlement Period" means the period at the end of which net-metering/net billing settlement between the distribution licensee and the prosumer takes place, generally beginning from first of April in an English calendar year and ending with the thirty first of the March of the next year.

bb) "State Nodal Agency" or "SNA" means an entity in the State, designated by the State Government to act as the agency to deal with issues related to coordinated development of renewable energy; subsidy approval and disbursement to persons developing distributed energy projects, etc.

ii. All other words and expressions used in these Regulations, although not specifically defined herein above, but defined in the Act, shall have the meaning assigned to them in the Act. The other words and expressions used herein but not specifically defined in these Regulations or in the Act but defined under any law passed by the Parliament applicable to the electricity industry in the State shall have the meaning assigned to them in such law.

3. Scope and applicability

i. These Regulations would apply to:

[23] [ ] to be incorporated if decided by the Commission, to cover RE sources other than Rooftop Solar PV and premises other than rooftop under DRE framework

a) PDRES owned by prosumer or RESCO

b) IDRES installed in the area of supply of the distribution licensee

ii. These Regulations do not preclude the right of any person to undertake renewable energy projects through alternative mechanism.

iii. The consumer availing open access under Section 42(2) of the Act may establish renewable energy systems in its premises[24] only if it is under the IDRES.

4. Control period:

i. The Regulations shall come into force from the date of notification in the Official Gazette.

5. Web based application processing system

i. The distribution licensee shall implement a web-based application processing system for processing the applications for distributed renewable energy systems within three months from the date of notification of these Regulations.

ii. Matters related to subsidy application shall be dealt by the State Nodal Agency.

6. Monitoring and reporting framework

i. The distribution licensee shall annually publish on its website information related to DRE capacity added during the year and cumulative capacity on each element of the distribution system.

ii. The distribution licensee shall every year submit information related to the capacity added and energy procured from DRE systems within one month from the end of financial year.

[24] As defined under sub-clause (s) of clause (i) of Regulation 2

Part — B
Renewable Purchase Obligation

7. General principles

i. **Renewable Purchase Obligation**:

Distribution Licensee shall purchase 0.25%, 0.50% and 0.75% of its total energy requirement from distributed renewable energy sources in FY2020, FY 2021 and FY2022, respectively.

ii. **Renewable Purchase Obligation**

The quantum of distributed renewable energy generation as recorded by the generation meter shall be accounted by the distribution licensee towards compliance of its Renewable Purchase Obligation (RPO) as stipulated in these Regulations.

Provided that in case the renewable energy system is set up by an obligated entity, entire renewable energy generated by these renewable energy systems shall be accounted for RPO compliance by the obligated entity.

iii. **Eligibility to participate under Renewable Energy Certificate mechanism**

The issuance of Renewable Energy Certificate shall be as per the eligibility criteria specified under Central Electricity Regulatory Commission (Terms and Conditions for recognition and issuance of Renewable Energy Certificate for Renewable Energy Generation) Regulations, 2010 and subsequent amendments thereof.

Part — C
Technical Standards and Safety, Metering Infrastructure

8. Interconnection with the grid: technical standards and safety

i. The voltage level for interconnection with the grid shall be as specified in the …. Electricity Supply Code or the voltage level at which the prosumer has been given supply by the distribution licensee.

   Provided that the HT consumer executing the renewable energy project under net metering framework may connect the renewable energy system at its LT bus bar. The metering shall be done at HT level bus bar at the same voltage the consumer is presently connected with the distribution licensee.

ii. The interconnection of the renewable energy system with the network of the distribution licensee shall be as per the CEA (Technical Standards for Connectivity of the Distributed Generation Resources) Regulations, 2013 and subsequent amendments thereof.

iii. The interconnection of the renewable energy system with the distribution system of the licensee shall conform to the relevant provisions of the CEA (Measures Relating to Safety and Electric Supply), Regulations, 2010 and subsequent amendments thereof.

iv. The prosumer shall be responsible for safe operation, maintenance and rectification of any defect of the renewable energy system up to the point of net meter, beyond which the responsibility of safe operation, maintenance and rectification of any defect in the system, including the net meter, shall be that of the distribution licensee.

v. The distribution licensee shall have the right to disconnect the renewable energy system at any time in the event of threat/damage from such renewable energy system to its distribution system to prevent any accident or damage, without any notice. The distribution licensee may call upon the prosumer to rectify the defect within a reasonable time.

vi. The renewable energy system must be capable of detecting an unintended islanding condition. The system must have anti-islanding protection to prevent any feeding into the grid in case of failure of supply or grid. Applicable IEC/IEEE technical standards shall be followed to test islanding prevention measure for grid connected inverters.

vii. The prosumer may install grid interactive renewable energy system with or without battery backup.

   Provided that if the consumer prefers setting up renewable energy system with battery backup (full load backup/partial load backup), in all such cases the inverter shall have appropriate arrangement to prevent the battery power to flow into the grid in the absence of grid supply and manual isolation switch shall also be provided.

viii. Every renewable energy system shall be equipped with an automatic synchronization device.

Provided that the renewable energy system using inverter shall not be required to have separate synchronizing device if it is inherently built into the inverter.

ix. The inverter shall have the features of filtering out harmonics and other distortions before injecting the energy into the system of the distribution licensee. The Total Voltage Harmonic Distortion (THD) shall be within the limits specified in the Indian Electricity Grid Code (IEGC)/IEEE technical standards.

9. Metering infrastructure

i. All meters installed at the renewable energy system shall comply with the CEA (Installation and Operation of Meters) Regulations, 2006 and subsequent amendments thereof.

ii. All meters shall have Advanced Metering Infrastructure (AMI) facility with RS 485 (or higher) communication port.

iii. The generation and net meter(s) shall be procured, installed and maintained by the distribution licensee. However, if the prosumer wishes to procure the meter(s), he may procure and present them to the distribution licensee for testing and installation.

iv. In case of renewable energy system set up under net billing arrangement or DRE promotion arrangement, an additional check meter for generation meter of appropriate class shall be installed by the distribution licensee.

v. The distribution licensee shall undertake meter testing before installation to ensure accuracy of the meter.

vi. The meter shall be jointly inspected by both the prosumer or the third party owner, as the case may be, and the distribution licensee, and shall be sealed by the distribution licensee.

vii. The meter shall be tested or checked only in the presence of the representatives of the prosumer or the third party owner, as the case may be, and the distribution licensee and as per the procedure specified in the Electricity Supply Code.

viii. If the eligible consumer is under the ambit of time of day tariff, both generation and net meter shall be capable of recording time of day consumption/generation.

ix. The distribution licensee, within three months of the date of notification of these Regulations, shall modify its existing billing infrastructure to facilitate the metering arrangements as envisaged under these Regulations.

Part — D
Net Metering and Net Billing Arrangement

10. Prosumer and project capacity

i. Prosumer

a) Any consumer in the area of the distribution licensee shall be eligible to establish [distributed renewable energy][25] systems under net metering or net billing arrangement on a first-come-first-serve basis, subject to the technical limitations as outlined in these Regulations and shall be called Prosumer.

b) The prosumer may own the PDRES or may enter into a contract with the RESCO for the establishment of the PDRES.

c) The prosumer may avail either the net metering or the net billing mechanism to set up prosumer [distributed renewable energy][3] system under these Regulations.

Provided

, the prosumer shall not be eligible to establish two or more systems using both net-metering and net-billing mechanism.

ii. Individual project capacity

a) The capacity of PDRES shall not exceed the sanctioned load/contract demand of the prosumer.

Provided further that minimum size of renewable energy system that can be set up under net metering and net-billing arrangement would be 1 kW and 10kW respectively.

b) The prosumer is allowed to set up [distributed renewable energy][3] system with battery storage.

11. Net metering arrangement

a) The prosumer may set up [distributed renewable energy][3] system to offset the prosumer's electricity consumption from the distribution licensee.

b) The renewable energy system installed at the prosumer's premises[26] delivers excess electricity, if any, to the distribution licensee after offsetting the electricity supplied by the distribution licensee during the applicable billing period.

c) The distribution licensee shall procure any excess energy generated by PDRES at rooftop solar tariff discovered through competitive bidding undertaken by SECI or distribution licensee in the last financial year or such other reference rate as may be determined by the Commission.

[25] As defined under sub-clause (f) of clause (i) of Regulation 2
[26] As defined under sub-clause (s) of clause (i) of Regulation 2

d) The energy accounting and settlement under this arrangement shall be in accordance with Regulation 17.

12. Net billing arrangement

a) The prosumer may set up [distributed renewable energy][3] system to offset the prosumer's electricity purchase bill from the distribution licensee.

b) The distribution licensee shall procure energy generated by PDRES at the rate determined by the Commission from time-to-time for such systems.

c) The energy accounting and settlement under this arrangement shall be in accordance with Regulation 17.

13. Role of the distribution licensee

i. The distribution licensee may undertake demand aggregation and other related activities to effectively deploy [distributed renewable energy][27] in its area of supply.

ii. The distribution licensee may act as RESCO or Engineering, Procurement, and Construction (EPC) contractor to undertake the deployment of the DRE.

In case the distribution licensee acts as a RESCO or EPC, such activity of the distribution licensee shall be considered as part of its other business as per the provisions of the *Tariff Regulations*.

14. Hosting capacity:

The cumulative capacity of distribution renewable energy systems allowed to be interconnected with the distribution network (feeder/distribution transformer) shall not exceed 100% of the feeder and/or distribution transformer capacity, as applicable.

Provided that the feeder/transformer mentioned above, considered for the purpose of calculating the hosting capacity, shall mean the feeder/transformer owned by the distribution licensee.

15. Interconnection point

i. In case of net metering, the interface point shall be the appropriate meter as per CEA (Installation and Operation of Meters) Regulations, 2006, installed at consumer's premises i.e., prosumer side of the meter.

ii. In case of net billing, the interface point shall be on the licensee side of the meter.

16. Application process and procedure

i. **Filing of application**

[27] As defined under sub-clause (f) of clause (i) of Regulation 2

a) The prosumer (applicant) may either apply online on the distribution licensee website and/or <state nodal agency> website. <fee details>

b) An applicant that is Trust/Committee/Housing Society/Partnership Firm/Company etc. shall submit the Application Form along with an Authorization Certificate.

c) The applicant shall receive an acknowledgement email/short message service (SMS) on submission of the application. The acknowledgement email/SMS shall provide a unique registration number assigned to each applicant for future correspondence.

d) The distribution licensee shall maintain a separate Application Register (manual or online) for reference and records.

ii. **Application processing**

a) After submitting the application form, the distribution licensee shall undertake technical feasibility within 15 days of the date of acknowledgement issued to the applicant.

b) The distribution licensee shall undertake feasibility check and submit it to the Concerned Officer of the respective division.

c) If technical feasibility is found satisfactory, the distribution licensee shall approve the application and intimate the same to the applicant by providing a Letter of Approval (LoA) via email/SMS/post within 15 days from the issuance of acknowledgement of the application.

d) In case of any deficiencies found in the application, on account of renewable energy system capacity and available transformer loading as specified under these Regulations, during technical feasibility study, the same shall be intimated by the distribution licensee to the applicant through email/SMS notification within 22 days from the date of issuance of acknowledgement of the application.

e) The applicant shall remove all identified deficiencies within a period of 15 days from the receipt of intimation and intimate the distribution licensee about the resolution of deficiencies through email/post.

Provided that the distribution licensee shall assess the resolution of deficiencies and provide LoA to the applicant upon satisfaction. In case deficiencies are not removed in the said period, the application shall stand cancelled.

f) In case the technical feasibility is negative/non-satisfactory, it shall be intimated to the applicant within 22 days from the issuance of the acknowledgement of the application.

Provided that the technical feasibility is negative/unsatisfactory, the application shall not stand rejected and shall be put on a priority wait list. As and when the technical feasibility is re-established, the application which have been put on priority waiting list shall be considered first before processing any new application.

iii. **Approval for installation**

a) The applicant shall install the renewable energy system within 180 days of receiving the LoA, as per the Standards/Codes specified under these Regulations.

b) The aforesaid duration of 180 days is the maximum permissible time for the applicant to install the renewable energy system, until an extension is provided in writing by the distribution licensee. However, the applicant shall be at liberty to complete the installation process before this period and approach the distribution licensee to initiate subsequent steps.

c) In case the prosumer fails to install the system within 180 days, the application shall stand cancelled and the prosumer shall need to re-apply.

iv. **Signing of agreement**

a) The applicant shall submit a duly filled agreement to the distribution licensee within 30 days of the date of issuance of LoA.

b) The agreement shall be then signed by the distribution licensee within three days of receipt of duly filled net metering agreement from the applicant.

v. **Procurement of meters**

a) In case the applicant intends to procure meter from the distribution licensee, the applicant shall submit the Intimation Form along with an appropriate procurement fee to the distribution licensee. This shall be intimated to the distribution licensee at least 30 days prior to the expected date of submission of Work Completion Report.

b) In case the applicant intends to procure meter on its own, the applicant shall submit the procured meter along with a safety certificate and request form for testing of meter to the distribution licensee/test centres approved by the distribution licensee, at least 30 days prior to the expected date of submission of Work Completion Report.

Provided that the meter procured by the applicant should comply with the appropriate technical standards of the CEA and specifications of the distribution licensee.

Provided further, the distribution licensee shall notify meter specification(s) within one month from the date of notification of these Regulations.

c) The distribution licensee/test centres shall intimate the applicant regarding the completion of the meter testing.

vi. **Work completion and commissioning**

a) For system size greater than 500 kW:

i. The applicant shall submit the Work Completion Report to the <Office of Chief Electrical Inspector, name of State> with a copy to the distribution licensee. In case the consumer is availing subsidy, the copy of work completion report shall also be shared with the <State Nodal Agency>.

ii. The appropriate authority, as specified above, shall undertake system inspection and safety checks, as per the applicable practices, within seven days of submission of Work Completion Report and the issue safety certificate.

Provided that in case the Work Completion Report is not satisfactory, the applicant shall resolve the discrepancies within seven days of receiving the intimation from the appropriate authority, and resubmit the Work Completion Report.

iii. The applicant shall submit the safety certificate issued as above to the distribution licensee within three days from the date of receipt of the same.

iv. The distribution licensee, within seven days of receiving the safety certificate, shall synchronize the system with the distribution grid post verification of the Work Completion Report, install meters and issue letter of synchronization and Date of Commissioning (COD) to the applicant.

b) For system size less than 500kW:

i. The applicant shall submit the Work Completion Report to the distribution licensee. In case the consumer is availing subsidy, the copy of Work Completion Report is also to be shared with the <State Nodal Agency>.

ii. The distribution licensee shall undertake system inspection and safety checks, as per the applicable practices, within seven days of submission of the Work Completion Report and undertake system synchronization.

Provided that in case the Work Completion Report is not satisfactory, the applicant shall resolve the discrepancies within seven days of receiving the intimation from the appropriate authority, and resubmit the Work Completion Report.

iii. The distribution licensee shall synchronize the system with the distribution grid post verification of the Work Completion Report, install meters and issue letter of synchronization and Date of Commissioning (COD) to the applicant.

17. Energy accounting and settlement – Net metering/Net billing/Both[28]

[17.1 Net Metering – Energy Accounting and Settlement]

i. The distribution licensee shall undertake meter reading of all PDRES according to the regular metering cycle.

ii. The distribution licensee shall record readings of both generation meter and bidirectional consumer meter.

iii. For each billing period, the distribution licensee shall make the following information available on its bill to consumer:
   a) DRE generation recorded in the generation meter;
   b) Electricity injected by PDRES in the grid in the billing period, including opening and closing balance;
   c) Electricity supplied by the distribution licensee in the billing period, including opening and closing balance;
   d) Net billed electricity, for which a payment is to be made by the prosumer;
   e) DRE generation used by it for RPO compliance;
   f) Excess electricity carried forward from the last billing period;
   g) Excess electricity carried forward to the next billing period.

iv. In case the electricity injected by the renewable energy system exceeds the electricity consumed during the billing period, such excess injected electricity shall be carried forward to the next billing period as excess electricity and may be utilized in the following billing periods but within the same settlement period;

v. In case the electricity supplied by the distribution licensee during any billing period exceeds the electricity injected in the grid by the PDRES, the distribution licensee shall raise a bill for the net electricity consumption after taking into account any excess electricity carried forward from the previous billing period;

vi. In case the prosumer is under the ambit of time of day tariff, as determined by the Commission from time to time, the following process shall be followed:

   a) Electricity consumption in any time block (e.g., peak hours, off-peak hours, etc.) shall be first compensated with the electricity generation in the same time block.

   b) Any excess generation over consumption in any time block in a billing cycle shall be accounted as if the excess generation occurred during the immediately lower tariff time block.

   c) This process will continue till all consumption in lower tariff blocks is set off against PDRES generation.

[28] To be as per the model chosen by SERC

d) Any excess generation after setting off consumption in lower tariff time blocks would be carried forward to the next billing cycle.

e) Same process would be used to set off consumption in the subsequent billing cycle.

vii. The excess electricity at the end of settlement period shall be settled by the distribution licensee as per Regulation 11(c).

Provided further that at the beginning of each settlement period, i.e., April, carried forward electricity shall be zero.

viii. The injected electricity measured in kilowatt hour (kWh)/kVAh shall only be utilized to offset the consumption measured in kWh/kVAh and shall not be utilized to compensate any other fee and charges levied by the distribution licensee;

ix. In case, the consumer tariffs have been determined by the Commission on kVAh basis, the generation and consumer meter readings shall also be taken in kVAh and settlement of energy done accordingly.

x. Regardless of availability of excess electricity with the prosumer during any billing period, the consumer will continue to pay all other charges such as fixed/demand charges, Government levy, etc.

xi. The distribution licensee shall accept the power as per the useful life of the PDRES unless the prosumer ceases to be a consumer of the licensee or PDRES is abandoned earlier.

xii. In case the prosumer leaves the system, the excess electricity shall be considered as inadvertent injection and shall not be paid for by the distribution licensee.

xiii. The PDRES installed under these Regulations shall be exempted from all wheeling, cross subsidy, transmission and distribution and banking charges and surcharges.

[17.2 Net Billing – Energy Accounting and Settlement

i. Net billing is the arrangement where DRE plant is:
   a. Installed to serve a specific consumer,
   b. Connected on the utility side on the consumer meter,
   c. Selling power to a distribution licensee under Power Purchase Agreement, and
   d. Entire power is consumed by the consumer.

ii. The distribution licensee shall enter into Power Purchase Agreement at tariff to be determined by the Commission.

iii. Entire quantum of electricity generated by the DRE plant shall be procured by the distribution licensee.

iv. The distribution licensee shall enter into a Power Sale Agreement with the consumer for sale of entire quantum of power generated by the relevant DRE plant.

v. Power procured by the distribution licensee shall be sold to the consumer as per Power Sale Agreement to be approved by the Commission.

vi. Rate of sale of power to the consumer shall be the same rate as determined by the Commission for procurement of power from DRE plant.

vii. The distribution licensee shall raise bill on the consumer in accordance with the following equation:

viii. Energy Bill of consumer = Fixed charges + other applicable charges and levies + (EDL * TRST) - (ERE * TPSA) – Billing Credit

Where:

a) Fixed charges means the fixed/demand charges as applicable to the consumer category as per the applicable retail supply Tariff Order;
b) Other charges and levies means any other charges such as municipal tax, cess, etc.;
c) E_{RE} means the energy units recorded for the billing period by the DRE Plant's generation meter;
d) T_{PSA} means the energy charges as per the energy sale agreement signed between the consumer and distribution licensee;
e) E_{DL} means the energy units supplied (i.e. Gross Electricity Consumption) by the distribution licensee as recorded by the consumer meter for the billing period;
f) T_{RST} means the applicable retail supply tariff of the concerned consumer category as per the retail supply Tariff Order of the Commission;
g) Billing Credit is the amount by which the value of DRE generation in a particular month is more than the value of all other components of consumer bill

ix. In case the consumer is subjected to time of day tariffs, energy bill (E_{DL} * T_{RST}) shall be computed accordingly.

x. In case (E_{RE} * T_{PSA}) is more than (Fixed charges + other applicable charges and levies + (E_{DL} * T_{RST})), utility shall give credit of amount equal to difference (Billing Credit), which shall be carried forward to the next billing cycle.

xi. Such Billing Credit would be carried forward for the settlement period. At the end of the settlement period, if there is any outstanding Billing Credit, it shall not be paid by the distribution licensee.

xii. For each billing period, the distribution licensee will make the following information available on its bill to the consumer:

a) DRE generation recorded in generation meter;
b) Electricity injected by DER plant in the grid in the billing period, including opening and closing balance;
c) Electricity supplied by the distribution licensee in the billing period, including opening and closing balance;

d) DRE generation used by distribution licensee for RPO compliance;

e) Billing Credit carried forward from the last billing period;

f) Billing Credit carried forward to next billing period.]

18. Energy accounting during meter defect/failure/burnt

i. In case of defective/failure/burnt condition of any meter, the prosumer shall report the failure, to the distribution licensee in the specified format of distribution licensee.

ii. The distribution licensee shall replace the meter as specified in the Electricity Supply Code.

iii. The electricity generated by the renewable energy system during the period in which the meter is defective shall be computed on normative basis.

iv. In case of IDRES plant, energy recorded in check meter would be considered by IDRES owner for the purpose of billing the distribution licensee.

Part — E
Independent Distributed Renewable Energy Systems

19. Eligibility and project capacity

i. **Eligibility**

a) Any person shall be eligible to establish and interconnect IDRES with the network of distribution licensee on a first-come-first-serve basis.

Provided that the IDRES conforms to the provisions under the CEA (Technical Standards for Connectivity of the Distributed Generation Resources) Regulations, 2013.

ii. **Individual project capacity**

a) The maximum IDRES capacity, to be installed by a person at a particular location, shall be based on the capacity and configuration of the electricity system, and in the power flows that distributed generation resource may cause.

Provided further that minimum size of [distributed renewable energy][29] system that can be set up under this arrangement shall be 50 kW.

Provided further that any person may set up IDRES on the premises[30] of a prosumer and the individual project capacity limit as applicable as per IDRES guidelines.

b) The person is allowed to set up [distributed renewable energy][6] system with battery storage.

Provided that the flow of energy from IDRES to the grid is never more than the rated capacity of the IDRES.

20. Role of the Distribution Licensee

i. In order to facilitate procurement of power from IDRES plants, the Commission shall notify feed-in tariff under Section 62 of the Act.

a) The distribution licensee shall enter into an agreement for procurement of [distributed renewable energy][6] from IDRES plant on first-cum-first-serve basis.

b) The distribution licensee shall prepare technical guidelines for connecting IDRES plants to distribution network and seek approval of the Commission for the same.

c) The distribution licensee shall notify administrative procedures within three months of the date of notification of these Regulations.

d) The distribution licensee shall announce the quantum of renewable energy it can absorb at each distribution substation/feeder.

ii. The distribution licensee may undertake procurement of power from IDRES plants under

[29] As defined under sub-clause (f) of clause (i) of Regulation 2
[30] As defined under sub-clause (s) of clause (i) of Regulation 2

Section 63 of the Act.

Provided that the Ministry of Power, Government of India, has issued appropriate bidding guidelines for the same.

iii. The distribution licensee shall accept application from any person interested in setting up a distributed renewable energy system on case to case basis without any prejudice.

[Provided that the applicable feed in tariff for such systems shall be determined by the Commission either on case-by-case basis or during the annual feed in tariff determination for renewable energy, as applicable.]

iv. Energy procured by the distribution licensee under IDRES plants shall be considered as a part of procurement under Section 86(1)(b) of the Act.

21. Interconnection point

i. [In case a person sets up IDRES, the Interconnection Point shall mean a point on the network of the distribution licensee, including a sub-station or a switchyard, where the interconnection is established between the IDRES and the distribution system and where electricity injected into the distribution system can be measured unambiguously.]

Provided that, the interface point shall be as per CEA (Installation and Operation of Meters), Regulations, 2006 and subsequent amendments thereof.

Part — F
Governance Structure, Institutional Framework, Roles and Responsibilities

22. Role of Stakeholders

i. Role of the Distribution Licensee

a) The distribution licensee shall provide information regarding feeder/distribution transformer hosting capacity available for connecting renewable energy system within three (3) months from the date of notification of these Regulations. The distribution licensee thereafter shall annually publish on its website cumulative installed capacity of the renewable energy systems and available hosting capacity.

b) The distribution licensee shall maintain a record of DRE systems set up under these Regulations with details including the type and capacity of renewable energy system and submit quarterly report within fifteen days of the previous quarter to the Commission with intimation to the State Nodal Agency.

c) The distribution licensee shall adopt and notify the procedures and formats including standard “Agreement” form as specified under these Regulations and upload the same on its website for information of stakeholders within one month of the notification of these Regulations.

d) The distribution licensee shall undertake technical studies to assess the impact of penetration of DRE systems on the distribution system

e) The distribution licensee shall undertake technical studies to assess the impact of different types of storage systems on the distribution system.

f) The distribution licensee shall set up a Distribute Renewable Energy Cell (DRE Cell) within three months of the notification of these Regulations.

g) The distribution licensee may explore appropriate utility driven business models such as demand aggregation, RESCO, EPC, etc. to promote installations of distributed renewable energy in its area of supply.

23. DRE Advisory Committee

i. The Commission shall notify DRE Advisory Committee to facilitate DRE program implementation under these Regulations.

ii. The Advisory Committee shall meet at least once every quarter to take up the functions assigned to it and submit its proceedings to the Commission.

iii. The Committee shall consist of the following members:

a) Director (Technical) of the Commission – Chairman

b) Representative from the State Power Department;

c) Representative of each distribution licensee in the State (In-Charge of DRE cell);

d) Representative from SNA;

e) Representative from the Office of Electrical Inspector;

f) Two independent external members from different Government departments;

g) Three representatives from consumer or consumer associations representing interests of domestic, commercial, and industrial category consumers.

h) Person in charge at SNA - Convener of the Advisory Committee;

iv. Functions of DRE Advisory Committee

a) Advise the distribution licensee(s) to develop consumer friendly procedures, billing systems, etc.

b) Develop technical standards for DRE impact assessment, load flow studies, etc.

c) Develop reporting requirements for the distribution licensees

d) Develop standards for data exchange between DRE system and the distribution licensee

e) Promote cross-learning among the distribution licensees and other stakeholders

f) Assist in developing common programs across the distribution licensees

g) Develop common programs for training/capacity building

h) Advise the distribution licensee(s) in developing common monitoring & reporting framework and maintenance of database

i) Assist the Commission on issue that may be referred to it

24. Distributed Renewable Energy (DRE) Cell

i. Each distribution licensee shall constitute an in-house DRE Cell, to promote DRE deployment in its area of supply.

ii. DRE Cell shall be constituted within one month from the date of notification of these Regulations.

iii. DRE Cell shall be headed by an officer of rank not below that of Superintending Engineer or equivalent.

iv. DRE Cell shall be provided with necessary authority and resources so as to execute the functions assigned to the distribution licensee under these Regulations.

v. **Functions of DRE Cell**

a) Design interconnection processes and procedures

b) Ensure and manage web based application system for processing DRE applications

c) Develop and monitor mechanism for online monitoring of DRE systems by the distribution licensee control center

d) Obtain regulatory approvals

e) Guide persons desirous of setting up DRE systems in the State

f) Facilitate training of field officers on DRE

g) Appraise field officials about the changes in processes and procedures

h) Ensure modifications to the billing procedures/systems to account for provisions in these Regulations

i) Undertake monitoring and reporting as envisaged under these Regulations

j) Coordinate with DRE Advisory Committee and attend meetings of the same

k) Prepare standard documents, such as expression of interest, RFP, energy purchase and energy sale agreement, tripartite agreement, etc. if the distribution licensee decides to procure power through competitive bidding

l) Prepare plan for procurement of energy from DRE sources

m) Undertake analysis of data collected from DRE systems

Part — G
Miscellaneous

25. Penalty or compensation

i. In case of failure to meet timelines prescribed under these Regulations, penalty of Rs. 1000 per day for each day of delay shall be levied on the distribution licensee.

ii. The penalty accrued during the year under these Regulations will be deducted from the Return on Equity to the distribution licensee for that year.

26. Power to give directions

The Commission may from time to time issue such directions and orders as considered appropriate for implementation of these Regulations.

27. Power to relax

The Commission may by general or special order, for reasons to be recorded in writing, and after giving an opportunity of hearing to the parties likely to be affected, may relax any of the provisions of these Regulations on its own motion or on an application made before it by an interested person.

28. Power to amend

The Commission may from time to time add, vary, alter, suspend, modify, amend or repeal any provisions of these Regulations.

29. Power to remove difficulties

If any difficulty arises in giving effect to the provisions of these Regulations, the Commission may, by an order, make such provisions, not inconsistent to the provision of the Act and these Regulations, as may appear to be necessary for removing the difficulty.

30. Repeal and savings

Save as otherwise provided in these Regulations, the ……….. Regulations[31] are hereby repealed.

Provided that the renewable energy systems commissioned during the applicability of the ……Regulations[32], shall continue to be governed by the aforesaid Regulations and shall not be governed by these Regulations.

(Secretary)

[31] To be as per State Regulations
[32] To be as per State Regulations

Annexure 2: Provisions related to system capacity, limits on DT capacity and exemption of different charges applicable in different states

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
1.	Tamil Nadu	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size < 100% sanctioned load ▶ Cumulative capacity installed < 30% of DT capacity in the area	Wheeling and cross subsidy surcharge
2.	Maharashtra	▶ Capacity < 1MWp (with a variation of 5%) ▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 40 % of DT in the area	Banking, wheeling & cross subsidy charges
3.	Gujarat	▶ Capacity < 1 MWp ▶ Maximum plant size < 50% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 65% of DT capacity, in the area	Transmission charge, transmission loss, wheeling charge, wheeling loss, cross subsidy surcharge, electricity duty
4.	Uttar Pradesh	▶ Capacity: 1kWp - 1MWp ▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of solar systems in the area < 15% of DT capacity	Wheeling & cross subsidy surcharge if applicable
5.	Karnataka	▶ Maximum plant size < 150% of sanctioned load ▶ Limits of solar systems: Up to 1MWp for HT consumers, Up to 50 kWp for 3 phase LT consumers	Wheeling, banking, cross subsidy charges if applicable, Value Added Tax (VAT)
6.	Rajasthan	▶ Capacity: 1 kWp - 1MWp ▶ Maximum size< 80% of sanctioned load ▶ Cumulative capacity of solar systems installed in the area < 30% of DT capacity in the area	Banking, wheeling & cross subsidy charges
7.	Andhra Pradesh	▶ Capacity <= 1MW ▶ Cumulative capacity of all solar systems installed in the area < 60% of Local DT capacity at LT level and 100% at HT level	Distribution losses and charges
8.	Telangana	▶ Capacity< 1MWp ▶ Cumulative capacity of all solar systems installed in the area < 50% of Local DT capacity at LT level	Distribution losses and charges, electricity duty, cross subsidy surcharge, VAT
9.	Delhi	▶ Capacity 1kWP - 1MWp ▶ Maximum plant size <100% of sanctioned Load	Banking, wheeling & cross subsidy

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
		▶ Cumulative capacity of all solar systems installed in the area < 15% of DT capacity in the area	charges
10.	Haryana	▶ Capacity < 1MWp ▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 15% of DT capacity	Banking, wheeling & cross subsidy charges
11.	Andaman & Nicobar Islands	▶ System Size: Min 1 kW; > 500 kWp ▶ Cumulative capacity of all solar systems installed in your area < 30% of DT capacity	Banking, wheeling & cross subsidy charges
12.	Assam	▶ Capacity: 1 kWp - 1MWp ▶ Maximum plant size <40% of sanctioned load	Wheeling & cross subsidy charges
13.	Bihar	▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area ▶ < 15% of DT capacity ▶ Electricity generated by the grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period	Wheeling & cross subsidy charges
14.	Chhattisgarh	▶ Capacity: 50 kWp – 1 MWp ▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of all solar systems installed < 40% of DT capacity	N/A
15.	Goa	▶ System Size: 1 kW – 500 kW ▶ Cumulative capacity of all solar systems installed in the area < 30% of DT capacity	Banking, wheeling & cross subsidy charges
16.	Himachal Pradesh	▶ Size: 1 kWp – 1 MWp ▶ Voltage Level 1. 230 V (single phase): up to 5 kWp 2. 415 V (three phase): up to 15 kWp 3. <11kV: 1 MWp max ▶ Maximum plant size <80% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 30% of DT capacity	Banking, wheeling & cross subsidy charges
17.	Jammu & Kashmir	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <50% of sanctioned load ▶ Cumulative capacity of all solar systems installed < 20% of DT capacity	Various intra state open access charges
18.	Jharkhand	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of all solar systems installed < 15% of DT capacity	Wheeling & cross subsidy charges
19.	Kerala	▶ Capacity: 1 kWp – 1 MWp ▶ capacity of all solar systems installed < 30% of	Banking, wheeling, cross

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
		DT capacity	subsidy charges and electric duty
20.	Lakshadweep	▶ Capacity: Min 1 kW, > 500 kWp ▶ capacity of all solar systems installed < 30% of DT capacity	Banking, wheeling and cross subsidy charges
21.	Madhya Pradesh	▶ Maximum plant size <50% of Sanctioned Load ▶ Cumulative capacity of all solar systems installed in the area < 15% of DT capacity	banking, wheeling, cross-subsidy surcharges & electricity duty, no liability of property tax, exempted from VAT and entry tax
22.	Manipur	▶ Capacity: 1 kWp – 500 kWp ▶ Maximum plant size <80% of sanctioned load ▶ Cumulative capacity of all solar systems installed < 30% of DT capacity	Banking charge and cross subsidy surcharge
23.	Meghalaya	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <80% of sanctioned load ▶ Cumulative capacity of all solar systems installed < 30% of DT capacity ▶ Electricity generated by the grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period	N/A
24.	Odisha	▶ Capacity: 1 kWp – no cap on upper limit. ▶ Maximum plant size <80% of sanctioned load ▶ Cumulative capacity of all solar systems installed < 30% of DT capacity ▶ Electricity generated by the grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period	N/A
25.	Punjab	▶ Size: 1 kWp – 1 MWp ▶ Voltage Level 1. 230 V (single phase): up to 5 kWp 2. 415 V (three phase): up to 15 kWp 3. <11kV: 1 MWp max ▶ Maximum plant size <80% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 30% of DT capacity	Wheeling & cross subsidy charges
26.	Sikkim	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <80% of sanctioned load	Banking charge and cross subsidy surcharge
27.	Tripura	▶ Capacity: 1 kWp – 1 MWp ▶ Maximum plant size <100% of sanctioned load ▶ Cumulative capacity of all solar systems installed	Banking, wheeling, cross subsidy and other

Sr. No	States	Constraints on capacity of solar plants	Exemption on charges and taxes
		< 15% of DT capacity	charges
28.	Uttarakhand	▶ Size: 1. with battery backup: 300 Wp – 100 kWp 2. Without battery backup: up to 500 kWp ▶ Voltage Level 1. 230 V (single phase): up to 4 kWp 2. 415 V (three phase): 75 kWp 3. 11kV: 1.5 MWp max 4. >11 kV: 3 MWp max. ▶ Maximum plant size <80% of sanctioned load ▶ Cumulative capacity of all solar systems installed in the area < 30% of distribution	Wheeling & cross subsidy charges
29.	West Bengal	For institutional: ▶ Capacity > 5 kWp ▶ Mandatory for all existing and upcoming schools and colleges having a total contract demand of more than 500 kW will be required to install solar grid connected rooftop solar systems to meet at least 1.5% of their total electrical load ▶ Electricity generated by the grid connected rooftop solar system shall not be more than 90% of the electricity consumption at the end of the settlement period. For residential & commercial: ▶ Mandatory for all large housing societies having a total contract demand of more than 500 kW will be required to install solar grid connected rooftop solar systems to meet at least 1.5% of their total electrical load	Wheeling & cross subsidy charges

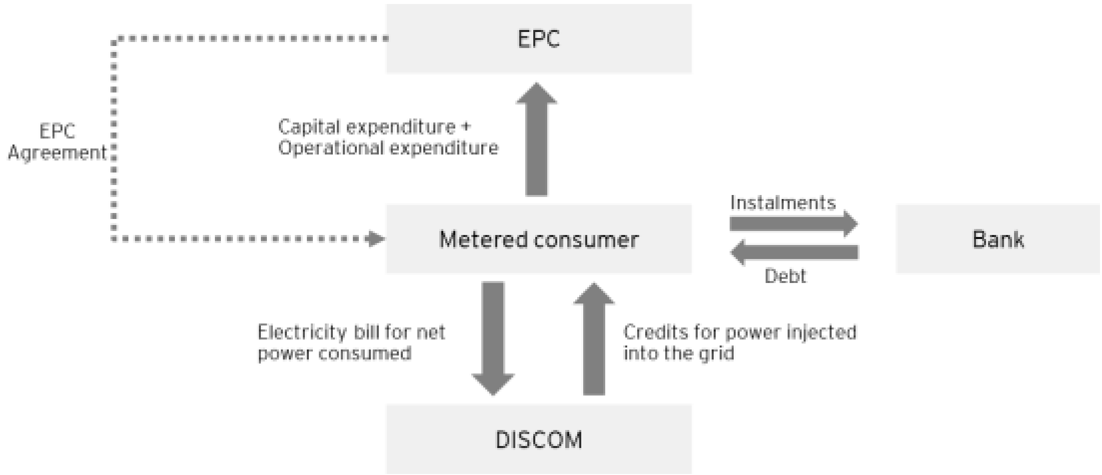
Annexure 3: Business models

1. Consumer-centric Models

1. Consumer-owned model (CAPEX)

The consumer is responsible for the complete capital and operational expenditure for the rooftop solar plant. The consumer contracts an EPC firm to set up the plant at their premises. Based on the metering Regulation, the commercial and energy settlement can be facilitated through either net or gross-metering arrangements.

Figure 12: Consumer-owned model (CAPEX) - Money flow and Energy flow



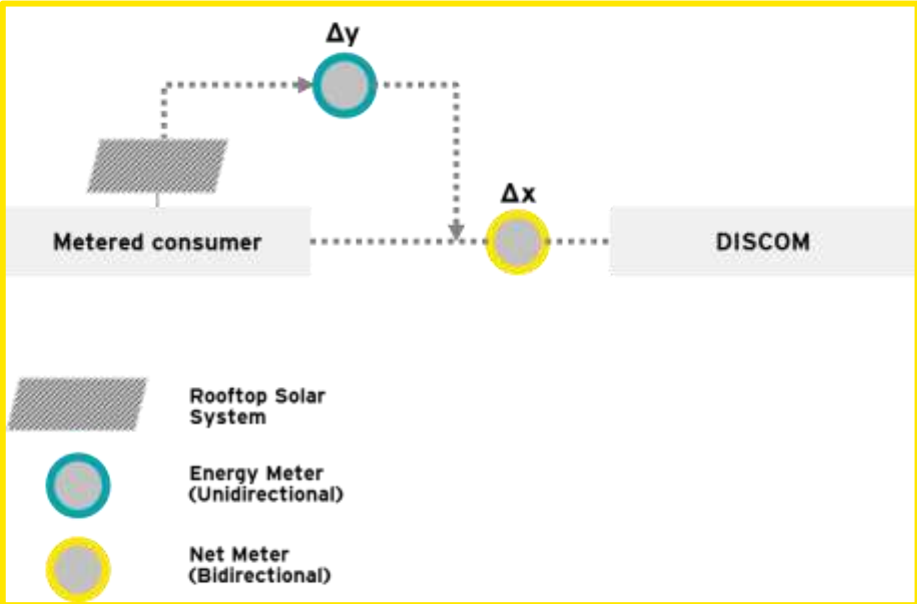
Commercial and energy settlement

Under this model, the commercial and energy settlement can be performed through two modalities, namely, net metering and net billing.

a. Net metering

A portion of the grid energy consumed by the site will be offset by the energy generated by the rooftop solar plant. Net metering mechanism promotes self-consumption by rooftop solar since all the power generated is first consumed by the site load and the excess (if any) is injected into the grid. The consumer procures additional power from the grid in case the power generated from the rooftop solar system is insufficient to meet the site load. Under this mechanism, the consumer pays only for the net energy (units) consumed i.e. Total energy consumption – Total energy produced. The net metering mechanism utilizes two meters, a bidirectional net meter and the energy meter. The rooftop solar generation is fed to the consumer-side of the net meter (refer to the illustration). **The utility bills the consumer based on the net meter reading**.

Figure 13: Energy flow under net metering - Consumer-owned model (CAPEX)



Settlement modality

The commercial settlement is performed between only two stakeholders in case of the consumer-owned model i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter.

Assuming that

xn – Net meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Number of units (kWh) consumed from the grid i.e. xn – (xn-1)

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows:

Electricity bill = Fixed charges + Δx*T

In case the net-generation in the billing period is greater than the total consumption, Δx will be negative. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of Δx will be credited the next month (subject to state Regulations).

The settlement and the cash flows have been described through the following cases:

1. **Business as usual (hereinafter referred to as BAU)**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh

For case 2, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 27: Monthly cash flow under net metering for consumer-owned model (CAPEX)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh X 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR	--
Consumer	--	200 kWh X 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR Operation & maintenance expenditure (*hereinafter referred to as OME*)

One-time expenditure/revenue

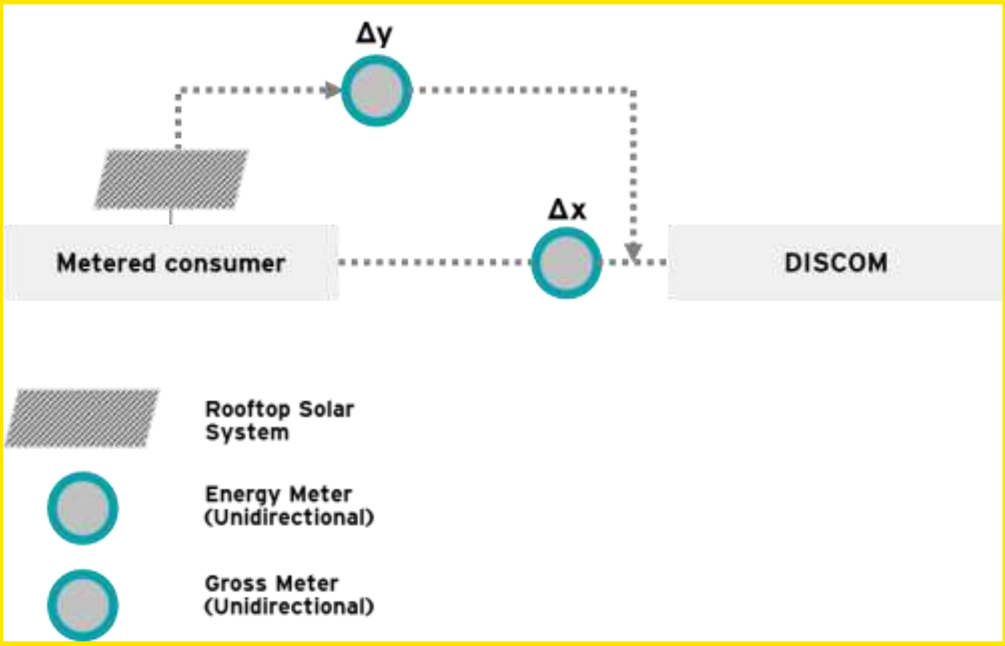
Table 28: One time expenditure/revenue under net metering for consumer-owned model (CAPEX)

	Revenue	Expenditure
Consumer	--	EPC fees
EPC	EPC fees	--

b. Net billing

Under the net billing mechanism, the generation from the rooftop solar is directly injected into the grid. The complete site load is met by the grid power, while the complete generation from the rooftop solar plant is injected into the grid. The net billing mechanism is facilitated through two unidirectional energy meters, one measuring the generation from the plant while the other measures the consumption from the grid. The utility bills the consumer based on the reading of the gross meter i.e. the total consumed electricity from the grid; and directly pays the consumer for all the electricity generated by the rooftop solar system on a pre-determined tariff. The rooftop solar generation is fed to the utility-side of the meter (refer to the illustration).

Figure 14: Energy flow under net billing – Consumer-owned model (CAPEX)



Settlement modality

The commercial settlement is performed between only two stakeholders i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for total generated electricity against a pre-determined tariff.

Assuming that

- x_n – Gross meter reading for month "n"
- y_n – Energy meter reading for month "n"
- Δx – Total number of units (kWh) consumed i.e. $x_n – x_n$-1
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows:
Electricity bill = Fixed charges + Δx*T - Δy*T'
No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case:

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh

   For case 2, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 29: Monthly cash flow under net billing for Consumer-owned model (CAPEX)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR	--	200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR
Consumer	--	200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	200 kWh x 10 INR / kWh = 2000 INR OME

One-time expenditure/revenue

Table 30: One time expenditure/ revenue under net billing for Consumer-owned model (CAPEX)

	Revenue	Expenditure
Consumer	--	EPC fees
EPC	EPC fees	--

The consumer recovers the investment through:
1. Savings made by offsetting the grid consumption with the power produced by the rooftop solar plant (net metering).
2. Credits earned by injecting the excess generation into the grid. The credits can be utilized to offset the grid consumption of the site in that month.

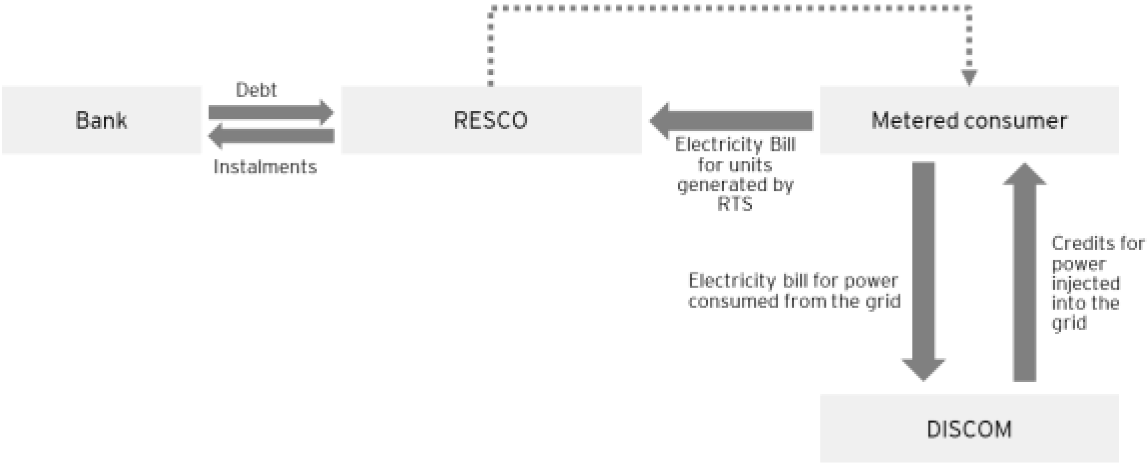
Benefits:
1. Consumer completely owns the asset (rooftop solar system)

Disadvantages:
1. Consumer faces an upfront capital expenditure
2. Operation and maintenance expenditure

2. Third-party owned model (RESCO)

A RESCO sets-up the rooftop solar system on the rooftop of the customer for no or low-cost. The RESCO, for its investment, gets a share of the savings being earned by the consumer by signing a PPA with the consumer.

Figure 15: Third party-owned model (RESCO) – Money flow and Energy flow



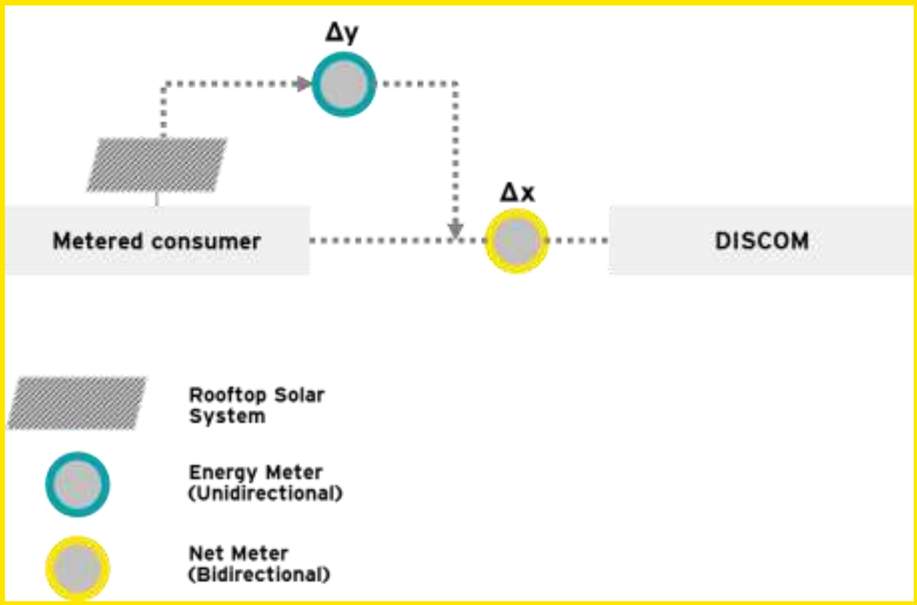
Commercial and energy settlement

Under this model, the financial and energy settlement can be performed through two modalities

a. Net metering

The commercial and the energy settlement between the consumer and the utility will be performed as in the consumer-owned model. The settlement between the consumer and the RESCO will be performed based on the signed PPA. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.

Figure 16: Energy flow under net metering - Third party-owned model (RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer only for the number of units indicated by the net meter. The settlement between the consumer and the RESCO is performed internally.

Assuming that

- xn – Net meter reading for month "n"
- yn – Energy meter reading for month "n"
- Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1
- Δy – Number of units (kWh) generated by the rooftop solar plant
- T – Grid tariff
- T' – PPA tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows

Electricity bill = Fixed charges + Δx*T

The consumer will pay the RESCO for the units generated by the rooftop solar system

Bill = Δy*T', where T'<T

In case the net generation in the billing period is greater than the total consumption, Δx will hold a negative value. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of Δx will be credited to the consumer for the next month (subject to state Regulations). The consumer will pay the RESCO for all the units generated by the rooftop solar system.

The settlement and the cash flows have been described through the following case

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PPA tariff – 8 INR / kWh

   For the above assumptions, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 31: Monthly cash flow under net metering for third party owned model (RESCO)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR	--
Consumer	--	200 kWh x 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR
RESCO	--	--	150 kWh x 8 INR / kWh = 1200 INR	OME

One-time expenditure / revenue

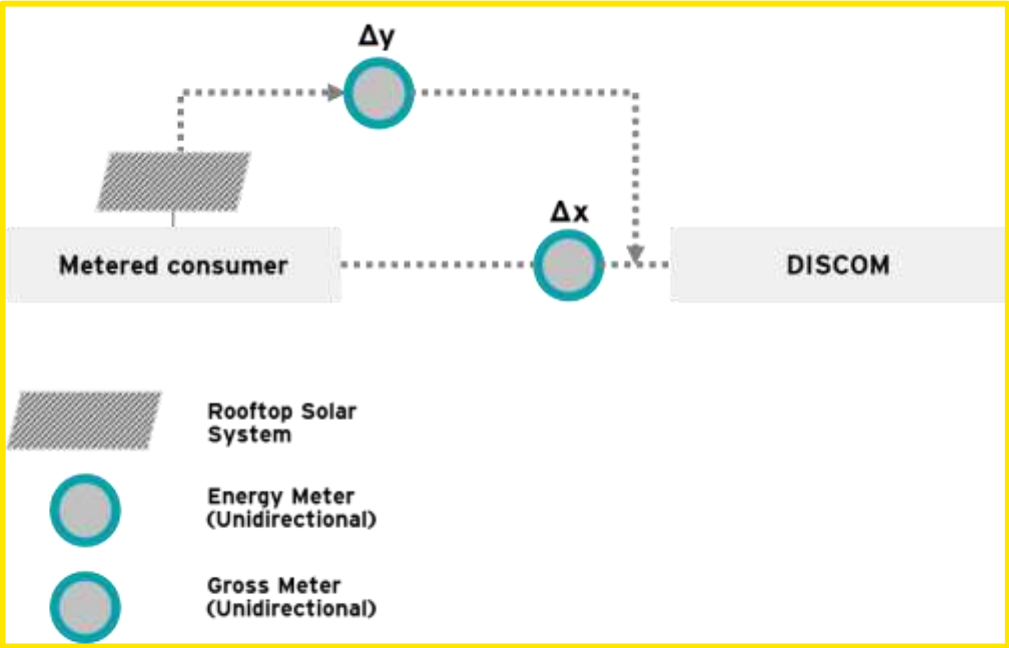
Table 32: One time expenditure/revenue under net metering for third party-owned model (RESCO)

	Revenue	Expenditure
Consumer	--	--
RESCO	--	EPC fees

b. **Net billing**

The energy and financial settlement between the consumer and the utility will be performed as in the consumer-owned model. The settlement between the consumer and the RESCO will be performed based on the signed PPA. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.

Figure 17: Energy flow under net billing - third party-owned model (RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer only for the number of units indicated by the net meter. The settlement between the consumer and the RESCO is performed internally.

Assuming that

x_n – Gross meter reading for month "n"

y_n – Energy meter reading for month "n"

Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n-1}$

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – Net billing tariff

T'' – PPA tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows
Electricity bill = Fixed charges + $\Delta x * T$ - $\Delta y * T'$

The settlement between the consumer and the RESCO is performed through a PPA. However, in some cases, roof rent may also be collected by the consumer from the RESCO. No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following cases

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh
   - PPA tariff – 7 INR / kWh

   For the above assumptions, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 33: Monthly cash flow under net billing for third party-owned model (RESCO)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR
Consumer		200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	200 kWh x 10 INR / kWh = 2000 INR 150 kWh x 7 INR/ kWh = 1050 INR
RESCO			150 kWh x 7 INR/ kWh = 1050 INR	OME

One-time expenditure / revenue

Table 34: One time expenditure/ revenue under net billing for third party-owned model (RESCO)

	Revenue	Expenditure
Consumer	--	--
RESCO	--	EPC fees

Benefits:

1. No upfront capital expenditure for the consumer
2. Operation and maintenance is performed by the RESCO

Disadvantages:

1. Payment default risk exists for the RESCO

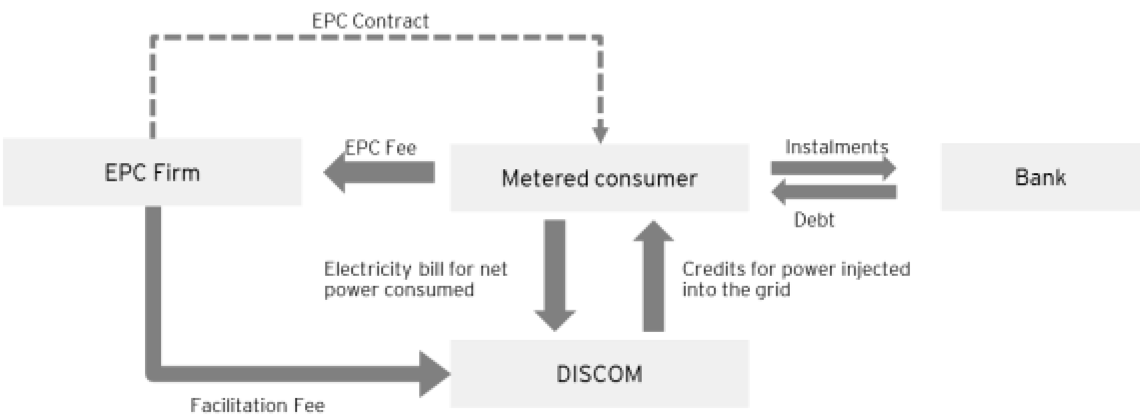
2. Utility-centric models

1. Consumer-owned model (utility only aggregates)

The utility acts as an aggregator by identifying the demand for rooftop solar in its distribution circle. The demand can be identified through a single-window portal on the utility website or through other sources. The consumers willing to install rooftop solar will have to contact just the utility for installation. Once the demand has been aggregated, the utility will initiate a reverse bidding to provide EPC services to the aggregated demand. Only EPC service providers empanelled by the utility will be permitted to participate in the reverse bidding. The successful EPC service provider will sign EPC contracts with the interested consumers. The utility will charge a facilitation fee from the successful bidder for aggregating the demand and thereby decreasing the transaction cost spent by EPC providers for lead generation. The utility will also sign a project management services agreement with the consumers for monitoring the project till interconnection with the grid. The consumer will be responsible for the complete capital expenditure.

The commercial and energy settlement remain similar to the consumer-owned model (business model 1).

Figure 18: Consumer-owned model (utility only aggregates) – Money flow and Energy flow



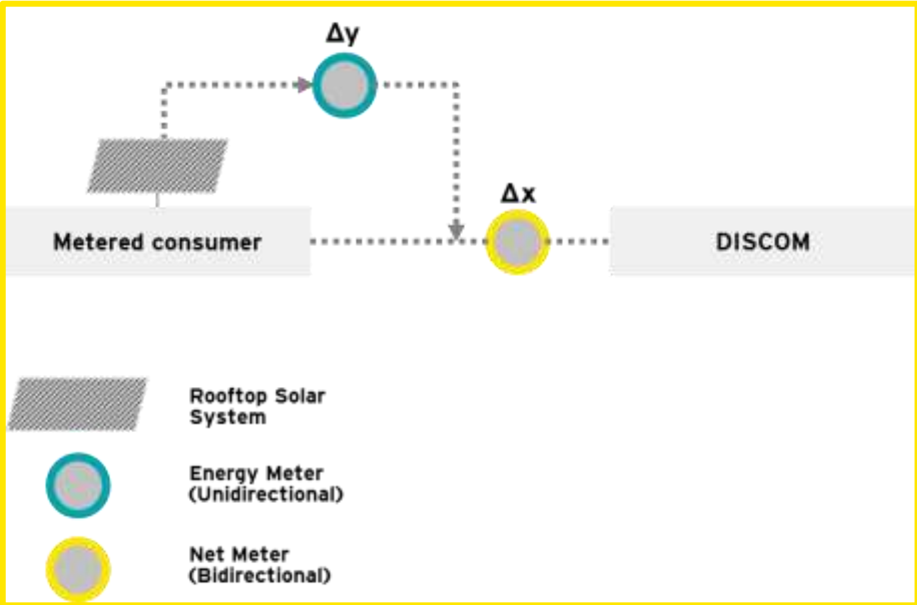
Commercial and energy settlement

Under this model, the commercial and energy settlement can be performed through two modalities, namely net metering and net billing.

a. Net metering

A portion of the grid energy consumed by the site will be offset by the energy generated by the rooftop solar plant. Net metering mechanism promotes self-consumption by rooftop solar since all the power generated is first consumed by the site load and the excess (if any) is injected into the grid. The consumer procures additional power from the grid in case the power generated from the rooftop solar system is insufficient to meet the site load. Under this mechanism, the consumer pays only for the net energy (units) consumed i.e. Total energy consumption – Total energy produced. The net metering mechanism utilizes two meters, a bidirectional net meter and the energy meter. The rooftop solar generation is fed to the consumer-side of the net meter (refer to the illustration). **The utility bills the consumer based on the net meter reading**.

Figure 19: Energy flow under net metering - consumer-owned model (utility only aggregates)



Settlement modality

The commercial settlement is performed between only two stakeholders in case of consumer-owned model i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer only for the number of units indicated by the net meter.

Assuming that

xn – Net meter reading for month “n”

yn – Energy meter reading for month “n”

Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows

Electricity bill = Fixed charges + Δx*T

In case the net-generation in the billing period is greater than the total consumption, Δx will be negative. In this case, the DISCOM will bill the consumer only for the fixed charges, while the absolute value of Δx will be credited to the next month (subject to State Regulations).

The settlement and the cash flows have been described through the following cases -

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh

   For case 2, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 35: Monthly Cash flow under net metering for consumer-owned model (utility only aggregates)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh X 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR	--
Consumer	--	200 kWh X 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR OME

One-time expenditure/revenue

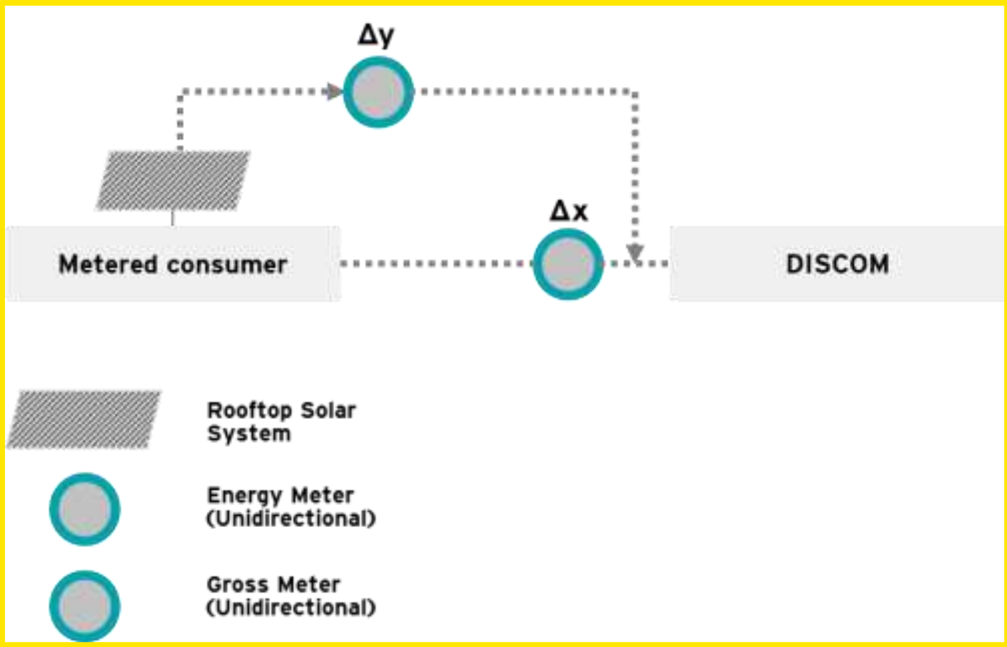
Table 36: One time expenditure/revenue under net metering for consumer-owned model (utility only aggregates)

	Revenue	Expenditure
Consumer	--	EPC fees
EPC	EPC fees	Facilitation fees
Utility	Facilitation fees	--

b. Net billing

Under the net billing mechanism, the generation from the rooftop solar is directly injected into the grid. The complete site load is met by the grid power, while the complete generation from the rooftop solar plant is injected into the grid. The net billing mechanism is facilitated through two unidirectional energy meters, one measuring the generation from the plant while the other measures the consumption from the grid. The utility bills the consumer based on the reading of the gross meter i.e. the total consumed electricity from the grid; and directly pays the consumer for all the electricity generated by the rooftop solar system on a pre-determined tariff. The rooftop solar generation is fed to the utility-side of the meter (refer to the illustration).

Figure 20: Energy flow under net billing - consumer-owned model (utility only aggregates)



Settlement modality

The commercial settlement is performed between only two stakeholders i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for total generated electricity against a pre-determined tariff

Assuming that

xn – Gross meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Total number of units (kWh) consumed i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T - Δy*T'

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case

1. **BAU**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh

   For case 2, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 37: Monthly cash flow under net billing for consumer-owned model (utility only aggregates)

	Case 1 (BAU)		Case 2	
	Cash inflow	Cash outflow	Cash inflow	Cash outflow
Utility	200 kWh x 10 INR / kWh = 2000 INR	--	200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR
Consumer	--	200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	200 kWh x 10 INR / kWh = 2000 INR OME

One-time expenditure/revenue

Table 38: One time expenditure/revenue under net billing for consumer-owned model (utility only aggregates)

	Revenue	Expenditure
Consumer	--	EPC fees
EPC	EPC fees	Facilitation fees
Utility	Facilitation fees	--

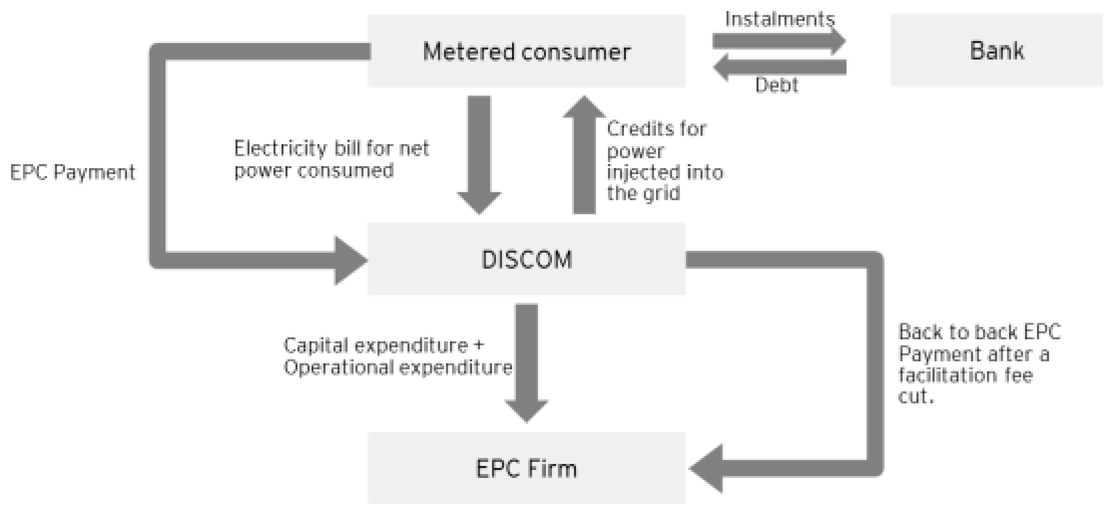
Benefits:
1. Single-window portal for the consumer for installation of rooftop solar
2. Reduced EPC costs due to economies of scale and competition amongst EPC providers
3. Streamlined interconnection process due to continued involvement of the utility through the installation stage
4. Verified quality of the installed systems due to setting up of procurement standards
5. Reduced financing costs due to lower risks

Disadvantages:
1. Upfront capital expenditure is required from the consumer
2. Payment default risk for the lender

2. Consumer-owned (utility aggregates and acts as EPC)

The model is similar to the previous model except that the EPC contract for the installation of the rooftop solar plants is signed between the consumer and the utility. The utility further signs back-to-back agreements with the successful EPC player identified through reverse bidding. The payment for the EPC services is paid to the utility, which further transfers the fee to the EPC services firm on a margin. The back-to-back agreements provide payment security to the service provider while ensuring better services to the consumer. The utility earns revenue in the form of a one-time facilitation fee and a margin on the back-to-back EPC agreements.

Figure 21: Consumer-owned (utility aggregates and acts as EPC) – Money flow and Energy Flow



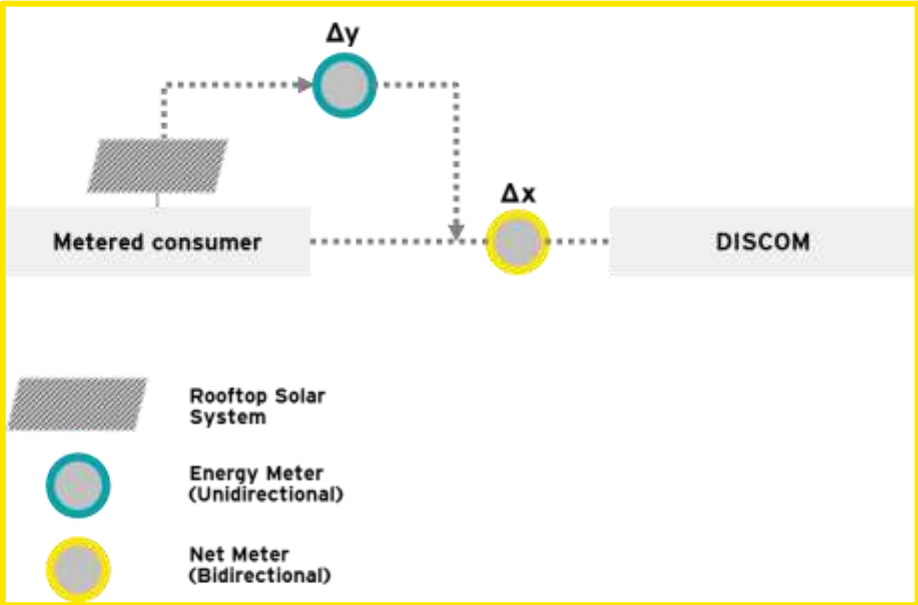
Commercial and energy settlement

Under this model, the commercial and energy settlement can be performed through two modalities, namely, net metering and net billing.

a. Net metering

A portion of the grid energy consumed by the site will be offset by the energy generated by the rooftop solar plant. Net-metering mechanism promotes self-consumption by rooftop solar since all the power generated is first consumed by the site load and the excess (if any) is injected into the grid. The consumer procures additional power from the grid in case the power generated from the rooftop solar system is insufficient to meet the site load. Under this mechanism, the consumer pays only for the net energy (units) consumed i.e. Total energy consumption – Total energy produced. The net metering mechanism utilizes two meters, a bidirectional net meter and the energy meter. The rooftop solar generation is fed to the consumer-side of the net meter (refer to the illustration). **The utility bills the consumer based on the net meter reading**.

Figure 22: Energy flow under net metering – Consumer-owned (utility aggregates and acts as EPC)



Settlement modality

The commercial settlement is performed between only two stakeholders in case of the consumer-owned model i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter.

Assuming that

xn – Net meter reading for month “n”

yn – Energy meter reading for month “n”

Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows

Electricity bill = Fixed charges + Δx*T

In case the net-generation in the billing period is greater than the total consumption, Δx will be negative. In this case, the DISCOM will bill the consumer for only the fixed charges, while the absolute value of Δx will be credited to the next month (subject to state Regulations).

The settlement and the cash flows have been described through the following cases -

1. **BAU**

   Assumptions

   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions

   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh

   For case 2, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 39: Monthly cash flow under net metering for Consumer-owned (utility aggregates and acts as EPC)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh X 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR	--
Consumer	--	200 kWh X 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR OME

One-time expenditure / revenue

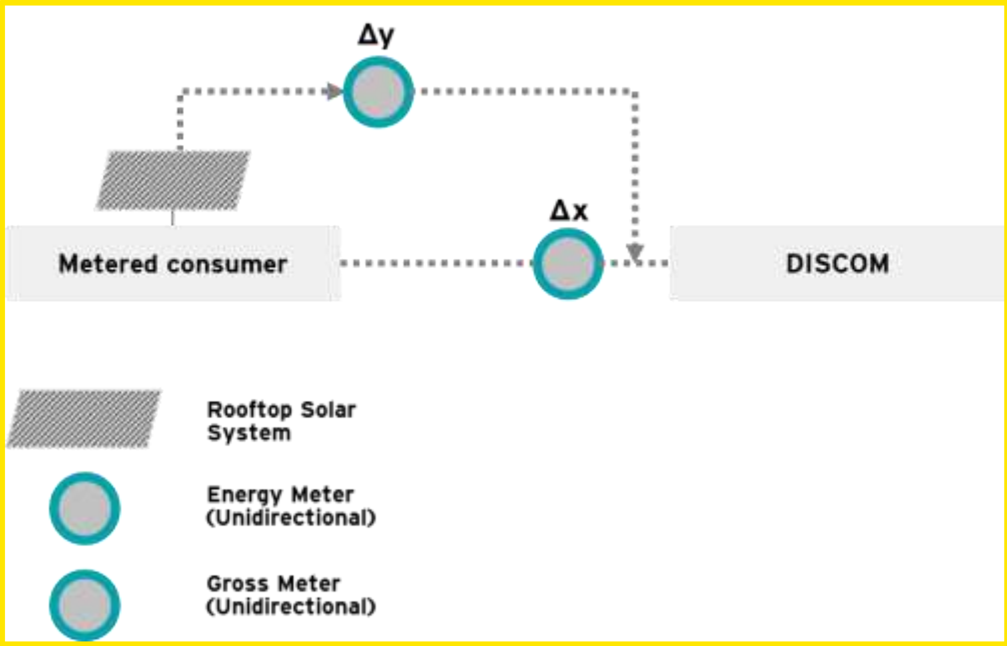
Table 40: One time expenditure/ revenue under net metering for Consumer-owned (utility aggregates and acts as EPC)

	Revenue	Expenditure
Consumer	--	EPC fees + EPC fees margin
EPC	EPC fees	Facilitation fees
Utility	Facilitation fees + EPC fees margin	--

b. Net billing

Under the net billing mechanism, the generation from the rooftop solar is directly injected into the grid. The complete site load is met by the grid power, while the complete generation from the rooftop solar plant is injected into the grid. The net billing mechanism is facilitated through two unidirectional energy meters, one measuring the generation from the plant while the other measures the consumption from the grid. The utility bills the consumer based on the reading of the gross meter i.e. the total consumed electricity from the grid; and directly pays the consumer for all the electricity generated by the rooftop solar system on a pre-determined tariff. The rooftop solar generation is fed to the utility-side of the meter (refer to the illustration).

Figure 23: Energy flow under net billing – Consumer-owned (utility aggregates and acts as EPC)



Settlement modality

The commercial settlement is performed between only two stakeholders i.e. the consumer and the DISCOM. The commercial settlement will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for the number of units indicated by the gross meter and will credit the consumer for the total generated electricity against a pre-determined tariff,

Assuming that

xn – Gross meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Total number of units (kWh) consumed i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – Net billing tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T - Δy*T'

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - Net billing tariff – 8 INR / kWh

For case 2, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 41: Monthly cash flow under net billing for Consumer-owned (utility aggregates and acts as EPC)

	Case 1 (BAU)		Case 2	
	Cash inflow	Cash outflow	Cash inflow	Cash outflow
Utility	200 kWh x 10 INR / kWh = 2000 INR	--	200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR
Consumer	--	200 kWh x 10 INR / kWh = 2000 INR	150 kWh x 8 INR / kWh = 1200 INR	200 kWh x 10 INR / kWh = 2000 INR OME

One-time expenditure/revenue

Table 42: One time expenditure/revenue under net billing Consumer-owned (utility aggregates and acts as EPC)

	Revenue	Expenditure
nConsumer	--	EPC fees + EPC fees margin
EPC	EPC fees	Facilitation fees
Utility	Facilitation fees + EPC fees margin	--

Benefits

1. Single-window portal for the consumer for installation of rooftop solar
2. Improved service experience for the consumer due to project management by the utility
3. Reduced EPC costs due to economies of scale and competition amongst EPC providers
4. Streamlined interconnection process due to continued involvement of the utility through the installation stage
5. Verified quality of the installed systems due to setting up of procurement standards
6. Securitized payments to the EPC providers
7. Reduced financing costs due to lower risks

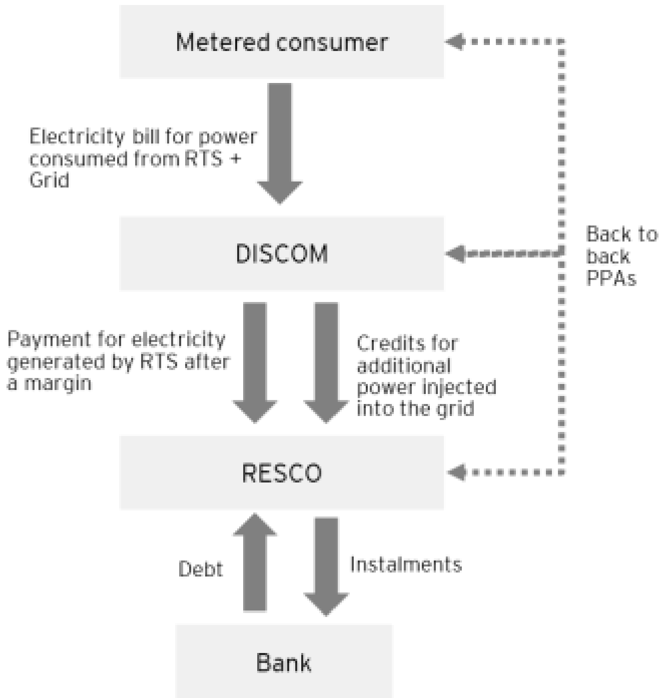
Disadvantages:

1. Upfront capital expenditure is required from the consumer.
2. Payment default risk for the lender

3. Third party-owned (utility aggregates and acts as trader)

Under this model, the utility does not set up, own or operate any rooftop solar plant. The utility aggregates the demand in its distribution circle. A RESCO, selected based on reverse bidding, invests in the asset. For securitizing the payments to the RESCO from the consumer, the payment is routed through the utility. The utility signs a PPA with the RESCO and purchases all the energy generated by the rooftop solar plant at a pre-determined tariff mentioned in the PPA. The utility further signs a PSA with the consumer for sale of all the generated power. The utility adds a trading fee or a facilitating fee for aggregating the demand and ensuring the payment security on the electricity purchased from the RESCO.

Figure 24: Third party-owned (utility aggregates and third party acts as RESCO) – Money flow and Energy flow



Benefits:

1. Single-window portal for the consumer for installation of rooftop solar (including finance)
2. Reduced finance costs due to economies of scale, lower risk profile due to utility involvement and lower transaction costs
3. Securitized payments to the financiers and the RESCO
4. Reduced financing costs due to lower risks

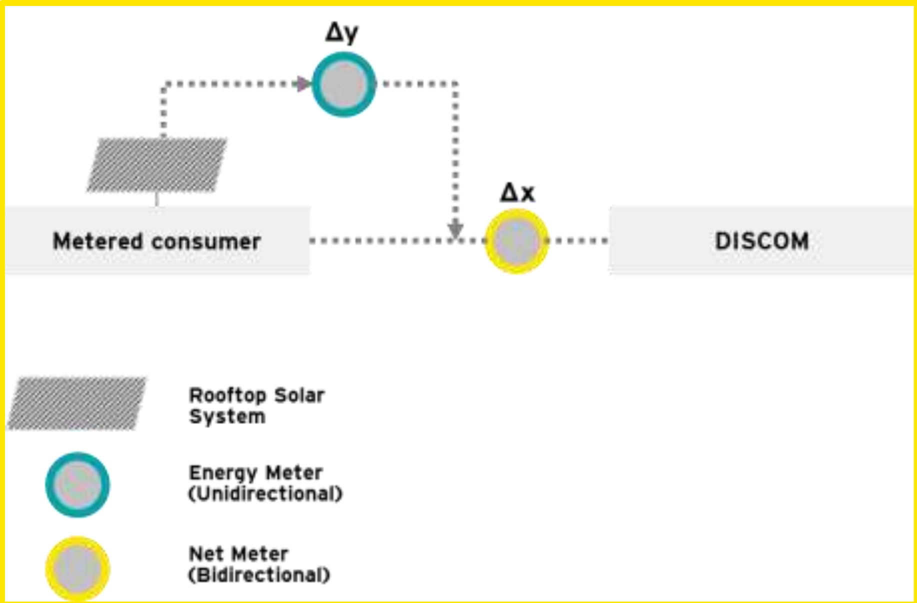
Commercial and energy settlement

Under this model, the commercial and the energy settlement can be performed through net and net billing.

a. Net metering

Settlement will be performed between RESCO and the utility, and the utility and the consumer. The settlement between the utility and the RESCO will be performed based on the signed PPA. The utility will pay the RESCO for all the energy generated by the rooftop solar system at a tariff mentioned in the PPA. The metering will be done similar to the conventional net metering as described below in the illustration.

Figure 25: Energy flow under net metering – Third party-owned (utility aggregates and third party acts as RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer for only the number of units indicated by the net meter. The settlement between the utility and the RESCO is performed based on the signed PPA.

Assuming that

xn – Net meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – PPA tariff

T'' – PSA tariff

T'' – T' – Utility's trading margin

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T + Δy*T''

The utility will pay the RESCO for the units generated by the rooftop solar system
Bill = Δy*T', where T'<T

In case the net generation in the billing period is greater than the total consumption, Δx will hold a negative value. In this case, the DISCOM will bill the consumer for the fixed charges and the energy generated by the rooftop solar plant, while the absolute value of Δx will be credited to the consumer for the next month (subject to state Regulations).

The settlement and the cash flows have been described through the following case

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PSA tariff – 8 INR / kWh
   - PPA tariff – 7 INR / kWh
   - Utility trading margin – 1 INR / kWh

   For the above assumptions, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Figure 26: Monthly cash flow under net metering for Third party-owned (utility aggregates and third party acts as RESCO)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	150 kWh x 7 INR / kWh = 1050 INR
Consumer		200 kWh x 10 INR / kWh = 2000 INR		50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR
RESCO			150 kWh x 7 INR / kWh = 1050 INR	OME

One-time expenditure/revenue

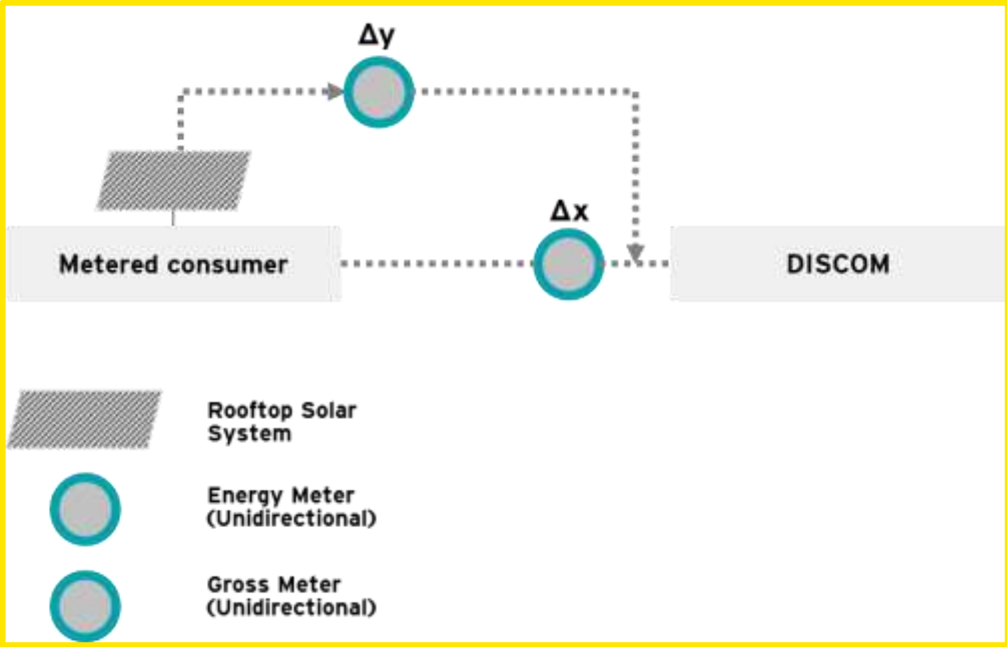
Table 43: One time expenditure/ revenue under net metering for Third party-owned (utility aggregates and third party acts as RESCO)

	Revenue	Expenditure
Utility	Facilitation Fee	--
Consumer	--	--
RESCO	--	EPC fees + Facilitation Fee

b. Net billing

Settlement will be performed between the RESCO and the utility, and the utility and the consumer. The settlement between the utility and the RESCO will be performed based on the signed PPA. The utility will pay the RESCO for all the energy generated by the rooftop solar system at a tariff mentioned in the PPA. The metering will be done similar to the conventional net billing as described below in the illustration.

Figure 27: Energy flow under net billing – Third party-owned (utility aggregates and third party acts as RESCO)



Settlement modality

The commercial settlement is performed between three stakeholders i.e. the consumer, the RESCO and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill, wherein the DISCOM will bill the consumer only for the number of units indicated by the net meter. The settlement between the utility and the RESCO is performed based on the signed PPA.

Assuming that

xn – Gross meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – PPA tariff

T'' – PSA tariff

T'' – T' – Utility's trading margin

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as follows
Electricity bill = Fixed charges + Δx*T - Δy*T''

The utility will pay the RESCO for the units generated by the rooftop solar system
Bill = Δy*T', where T'<T

No complications will arise in case the total generation in the billing period is greater than the total consumption.

The settlement and the cash flows have been described through the following case

1. **BAU**
   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**
   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PSA tariff – 8 INR / kWh
   - PPA tariff – 7 INR / kWh
   - Utility trading margin – 1 INR / kWh

   For the above assumptions, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 44: Monthly cash flow under net billing for Third party-owned (utility aggregates and third party acts as RESCO)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	150 kWh x 7 INR / kWh = 1050 INR
Consumer	--	200 kWh x 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR
RESCO	--	--	150 kWh x 7 INR / kWh = 1050 INR	OME

One-time expenditure/revenue

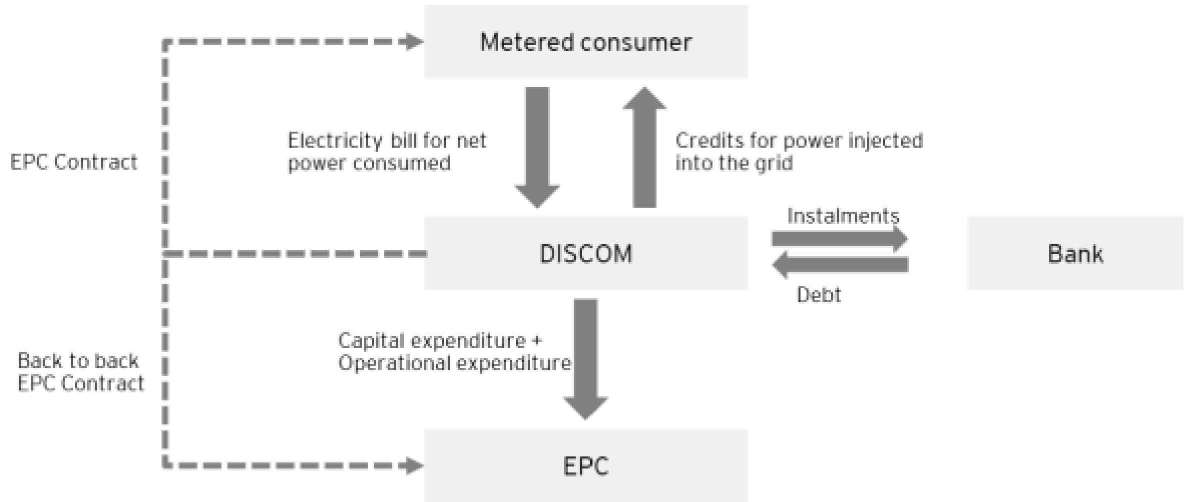
Table 45: One time expenditure/ revenue under net billing for Third party-owned (Utility aggregates and third party acts as RESCO)

	Revenue	Expenditure
Utility	Facilitation Fee	--
Consumer	--	--
RESCO	--	EPC fees + Facilitation Fee

4. Third party-owned (utility aggregates and acts as RESCO)

The utility acts as an aggregator and aggregates the demand as in the case of the aggregator model. It also raises debt for acting as a RESCO for the aggregated demand and installs the rooftop solar systems in the premises of the consumers. The utility in this model sets up, owns and operates the rooftop solar plant. PPAs are signed between the utility and the consumers. The utility may subcontract the EPC and the O&M components. It collects the charges for the electricity consumed from the grid and the rooftop solar plants through the monthly bill.

Figure 28: Third party-owned (utility aggregates and acts as RESCO) – Money flow and Energy flow



Benefits:

1. Single-window portal for the consumer for installation of rooftop solar (including finance)
2. Reduced finance costs due to economies of scale, lower risk profile due to utility involvement and lower transaction costs
3. Securitized payments to the financiers
4. Reduced financing costs due to lower risks

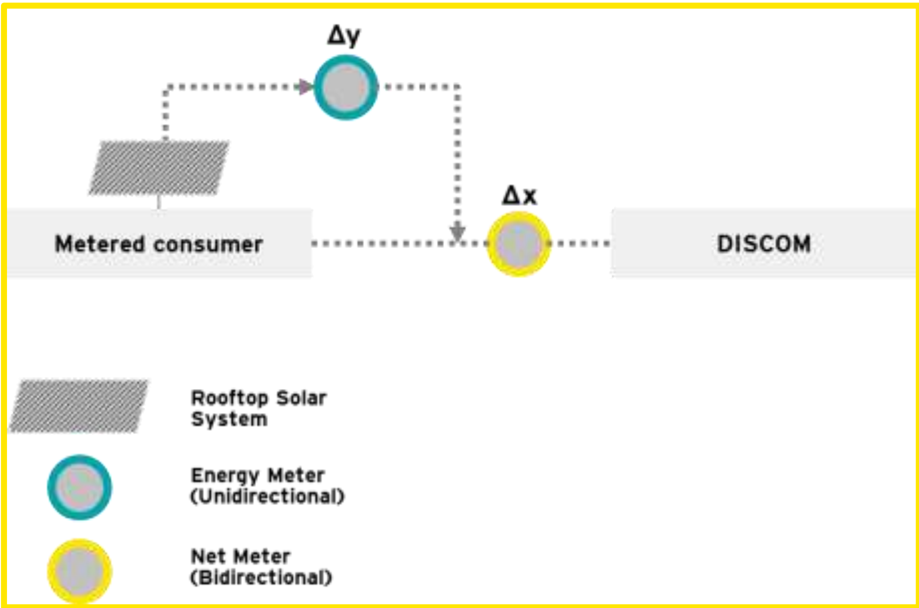
Commercial and energy settlement

Under this model, the financial and energy settlement can be performed through net metering and net billing.

a. Net metering

The commercial and the energy settlement between the consumer and the utility will be performed as in the consumer-owned model, except that the utility is the RESCO in this case. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.

Figure 29: Energy flow under net metering – Third party-owned (Utility aggregates and acts as RESCO)



Settlement modality

The commercial settlement is performed between two stakeholders i.e. the consumer and the DISCOM. The commercial settlement between the DISCOM and the consumer will be performed through the monthly electricity bill.

Assuming that

xn – Net meter reading for month "n"

yn – Energy meter reading for month "n"

Δx – Number of units (kWh) consumed from the grid i.e. xn – xn-1

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – PPA tariff

Δx is the value indicated by the net meter, while Δy is the value indicated by the energy meter.

Under the net metering modality, the consumer will be billed as the follows

Electricity bill = Fixed charges + Δx*T + Δy*T'

In case the net generation in the billing period is greater than the total consumption, Δx will hold a negative value. In this case, the DISCOM will bill the consumer for the fixed charges and Δy*T', while the absolute value of Δx will be credited to the consumer for the next month (subject to state Regulations).

The settlement and the cash flows have been described through the following case

1. **BAU**

   Assumptions
   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions
   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PPA tariff – 8 INR / kWh

   For the above assumptions, Δx (net meter reading) will be 200 – 150 kWh = 50 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 46: Monthly cash flow under net metering for Third party-owned (utility aggregates and acts as RESCO)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR	-	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	OME
Consumer	-	200 kWh x 10 INR / kWh = 2000 INR	-	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR

One-time expenditure/revenue

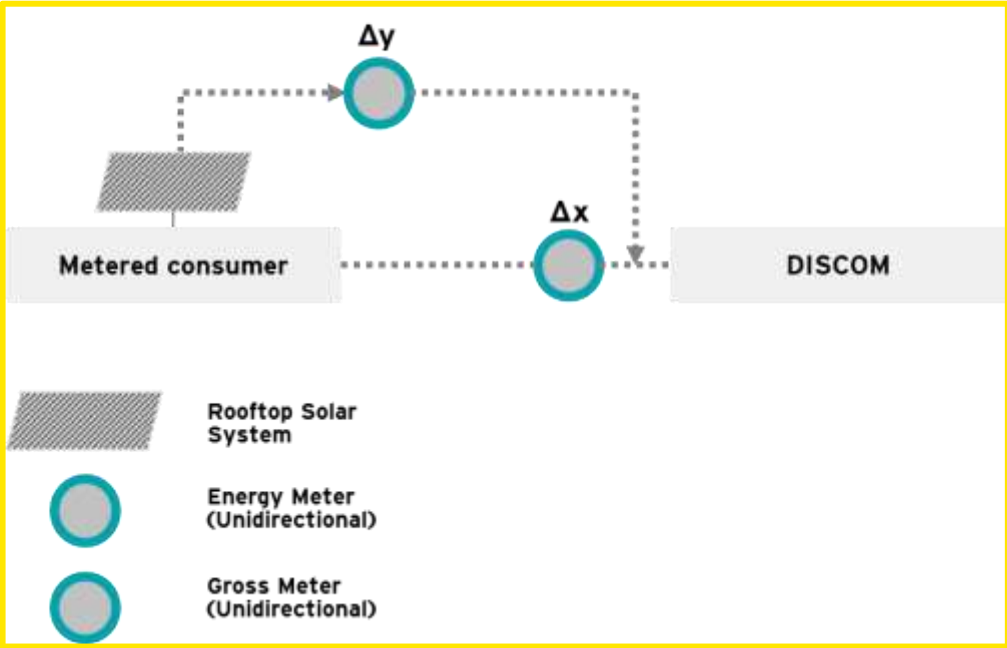
Table 47: One time expenditure/ revenue under net metering for Third party-owned (utility aggregates and acts as RESCO)

	Revenue	Expenditure
Consumer	--	--
Utility	--	EPC fees

b. Net billing

The energy and financial settlement between the consumer and the utility will be performed as in the consumer-owned model. The consumer will pay the RESCO for all the energy generated by the rooftop solar system at a tariff lower than the grid tariff (a portion of the savings generated). The RESCO may also pay the consumer a rent for the roof space being utilized.

Figure 30: Energy flow under net billing – Third party-owned (utility aggregates and acts as RESCO)



Settlement modality

The commercial settlement is performed between the consumer and the DISCOM, through the monthly electricity bill.

Assuming that

x_n – Gross meter reading for month "n"

y_n – Energy meter reading for month "n"

Δx – Total number of units (kWh) consumed i.e. $x_n - x_{n-1}$

Δy – Number of units (kWh) generated by the rooftop solar plant

T – Grid tariff

T' – PPA tariff

Δx is the value indicated by the gross meter, while Δy is the value indicated by the energy meter.

Under the net billing modality, the consumer will be billed as the follows

Electricity bill = Fixed charges + $\Delta x*T$ - $\Delta y*T'$

The settlement and the cash flows have been described through the following cases

1. **BAU**

   Assumptions

   - No rooftop solar installation
   - Total consumption in the billing period – 200 kWh
   - Monthly consumer electricity bill – 200 kWh x 10 INR / kWh = INR 2000

2. **Rooftop solar system installed**

   Assumptions

   - System Capacity – 1 kW
   - Number of units generated per day – 5 kWh
   - Settlement period – 30 days
   - Total consumption in the settlement period – 200 kWh
   - Total generation by the rooftop solar plant in the settlement period – 150 kWh (5X30)
   - Grid tariff – 10 INR / kWh
   - PPA tariff – 8 INR / kWh

   For the above assumptions, Δx (gross meter reading) will be 200 kWh while Δy (energy meter reading) will be 150 kWh.

Monthly cash flows

Table 48: Monthly cash flow under net billing for Third party-owned (utility aggregates and acts as RESCO)

	Case 1 (BAU)		Case 2	
	Cash inflow	**Cash outflow**	**Cash inflow**	**Cash outflow**
Utility	200 kWh x 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR	OME
Consumer	--	200 kWh x 10 INR / kWh = 2000 INR	--	50 kWh x 10 INR / kWh = 500 INR 150 kWh x 8 INR / kWh = 1200 INR

One-time expenditure/revenue

Table 49: One time expenditure/ revenue under net billing for Third party-owned (utility aggregates and acts as RESCO)

	Revenue	Expenditure
Consumer	--	--
Utility	--	EPC fees

3. Benefit analysis

Table 50: Legends for benefit analysis

Legend	
T	Grid tariff
T'	Discovered tariff
m	Total consumption (number of units)
n	Number of units of electricity consumed from the Rooftop Solar System

Table 51: Summary of benefits of proposed business models

S. No	Model	Utility	Consumer	Developer
1	Consumer-owned model (CAPEX)	Loss of energy sale due to influx of rooftop solar	EPC fees	Profit on EPC fee received
			n*T	
	Overall	Utility loses revenue due to loss of consumer	Saves on electricity bill. Gains the asset	Gains revenue as EPC fee
2	Third-party owned (RESCO) model	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC fees
				n*T'
	Overall	Utility loses revenue due to loss of consumer	Saves on electricity bill.	Gains the Asset
3	Consumer-owned model (utility only aggregates)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC fee received
		Loss of energy sale due to influx of rooftop solar	n*T	Facilitation fees (assuming 2-3% of the total investment)
	Overall	Utility loses consumer but makes revenue on facilitation fees	Lower cost of procurement due to economies of scale. CAPEX model overall beneficial under the current Regulations.	Gains revenue as EPC fee and saves on marketing cost.
4	Consumer-owned (Utility aggregates and acts as EPC)	Facilitation fees (assuming 2-3% of the total investment)	EPC fees	Profit on EPC Fee (after a margin cut)
		p% on back to back agreements	n*T	p% on back to back agreements
		Loss of energy sale due to influx of rooftop solar		Facilitation fees (assuming 2-3% of the total investment)
	Overall	Utility loses consumer but makes revenue on facilitation fee for aggregation and margin on back to back EPC contract.	Lower cost of procurement due to economies of scale. CAPEX model overall beneficial under the current Regulations.	Gains revenue on EPC. Although loses margin, saves on marketing cost and gains payment security.

S. No	Model	Utility	Consumer	Developer
5	Third party-owned (utility aggregates and third party acts as RESCO)	Loss of energy sale due to influx of rooftop solar	n(T-T')	EPC Fee
		Facilitation fees (assuming 2-3% of the total investment)		Facilitation fees (assuming 2-3% of the total investment)
		p% on all units of energy traded		p% on all units of energy traded
				Revenues from energy sale
	Overall	Utility makes revenues from energy trading and facilitation fees for aggregation	RESCO model beneficial due to no capital investment	Revenues due to energy sale and cheaper finance due to payment security. Low transaction costs and lower capital cost due to aggregated demand. Also, gains the asset.
6	Third party-owned (Utility aggregates and acts as RESCO)	EPC Fee	n(T-T')	
		Revenue from energy sale (y*n)		
	Overall	Utility makes revenue on energy sale to the consumers. Lower cost of procurement due to economies of scale.	RESCO beneficial due to no capital investment	Developer plays no role

Annexure 4: Comments from stakeholders

Comments from UERC

S. No.	Comment	Action
1.	Removing the cap on maximum capacity limit will help the industries grow, which in turn will be beneficial for the sector.	The cap on system capacity has been kept to 100% of the sanctioned load.
2.	Technical studies and international review need to be done for sanctioned load limit and DT interconnection capacity	Grid simulation analysis has been performed to assess the impact of rooftop solar on the grid.
3.	Vendor list should be given by MNRE for procurement of smart metering	Subject to further discussion by Forum of Regulators
4.	Real-time monitoring of rooftop solar plants is becoming increasingly important. Thus the Regulation should include some provisions for the same	Meter with AMI infrastructure proposed in the Regulation (smart meter is advocated by few SERCs)
5.	DISCOMs need to upgrade and closely monitor the DTs connected to rooftop solar plants	Subject to further discussion by Forum of Regulators
6.	Virtual metering business model might not be feasible on the basis of manual netting off of energy generated by GRPVs owned by consumer and the energy consumed by the consumer with the physical location of the GRPVs and the consumer premises being different.	Virtual net-metering not proposed in the Regulations
7.	Automatic meter reading transfer of both GRPVs and consumer meters at DISCOM's billing server followed by automatic energy adjustment by the billing software would be a feasible solution	DISCOMs to make such arrangements with the proposed AMI metering
8.	Definition needs to be properly defined for rooftop solar to include utilized space and wasteland of premises. These should preclude any possibilities where farmers under distress may handover fertile agriculture land to developers of plants. Agricultural land should not be compromised for setting up rooftop solar PV plants	Definition of premises as per the **2013 Draft Model Regulation for Rooftop Solar Grid Interactive systems based on net metering** has been retained. Further, the maximum capacity that can be set up is linked with sanctioned load.
9.	Inclusion of premises at diff location of the same owner will require virtual metering which will not be feasible at present with the existing IT infrastructure, the existing manpower and workload of DISCOMs.	Virtual net-metering not proposed under the Regulations
10.	All grid connections and system operation should comply with CEA Regulations under 53 and section 73 of Electricity Act, 2003	All grid connections to comply with CEA (Technical Standards for Connectivity of the Distributed Generation Resources) Regulations, 2013

S. No.	Comment	Action
11.	Long term PPAs over the useful life of the plant is economical considering the fact that levelled tariff is reasonable to DISCOMs/end-consumers. Otherwise year-on-year tariffs or short term PPAs would entail higher tariff burden on DISCOMs/Consumers in the initial years while the benefit of lower tariff after repayment of loan, spreading of depreciation in later years would not be extended to land availed by such DISCOMs/consumer	Subject to further discussion by Forum of Regulators
12.	In case new business models are introduced and existing developers are allowed to shift to any other model, the plants' original CoD, depreciated cost and tariff already recovered should be considered while undertaking renewal or cancellation of existing PPA in so far as tariff for balance life of the plant is considered.	Subject to further discussion by Forum of Regulators
13.	1 month cycle of settlement of injected and consumed energy should be done since developers have monthly liability towards the lenders	Annual cycle of settlement has been incorporated to safeguard the interest of DISCOMs and to make the process less complex
14.	Agencies or suppliers of smart meters compatible to AMI should be notified by MNRE. Price for a single smart meter and bulk purchase of the same should also be provided	Subject to further discussion by Forum of Regulators
15.	Instead of switching over to smart meters immediately, bidirectional (net) be installed at GRPV premises	Meter with AMI infrastructure proposed. Smart meters have been advocated by few SERCs.
16.	The extra fixed charge the DISCOMs have to bear (because of long term contracts) due to less requirement of power (demand) post proliferation of rooftop solar in the country needs to be compensated	Subject to further discussion by Forum of Regulators

Comments from KfW

S. No.	Comment	Action
1.	Transformer Loading: Loading should be allowed up to 100% (100% loading when there is 0 demand in the LT line) as most transformers have a factor of safety already built in – this will provide the necessary buffer in case of specific spikes	Incorporated
2.	Sizing of system capacity – the sizing of individual systems should be based on the inverter capacity and not DC panel capacity	Subject to further discussion by Forum of Regulators
3.	Gross Metering: Can be allowed till 100% of transformer loading on each transformer circuit; for each installation/consumer – this should be limited to technical limits of the last mile network on which the consumer is located. Allow gross metering capacity higher than connected load of consumer	Incorporated, permitted capacity under IDRES is not limited by the contracted load of the consumer
4.	Open Access: Generally Net Metering should not be allowed on Open Access (i.e. for consumers taking open access)	Incorporated. open access has been permitted only in the case of IDRES
5.	Individual capacity: Can be limited to the connected load of the consumer	Incorporated
6.	Maximum size of the installations: Should not be limited to 1 MW but should be restricted to the connected load/contract demand of the consumer	Incorporated
7.	Interconnection process: This is a bit of a challenge – if you put it as a part of the Regulation, then changing it for operational reasons will be a challenge – best would be to develop it and say that the utility may modify it for operational efficiencies. However the Regulation can lay down the key attributes and requirements that a process designed and administered by the DICOMs	Subject to further discussion by Forum of Regulators
8.	New business models like VNM and GNM – Please see and study the new proposed Haryana Regulations and please think of something innovative	Subject to further discussion by Forum of Regulators
9.	In case of utility acting as RESCO, how will you reconcile dual pricing of power – this will happen if the utility is to sell rooftop solar power at a cheaper price	Subject to further discussion by Forum of Regulators
10.	There is a need for looking at models for GRPV for affordable housing and powering of common loads which has still not be addressed	Subject to further discussion by Forum of Regulators

Comments from WBERC

S. No.	Comment	Action
1.	The MNRE subsidy needs to be channelized through DISCOM only	Out of scope of the net-metering Regulations
2.	Smart metering should be mandatory as there is hardly any price differential between AMI/AMR and smart metering	Incorporated; AMI has been incorporated in the existing Regulation
3.	Bringing DISCOMs at the forefront through DISCOM centric business models will not be sufficient	Subject to further discussion by Forum of Regulators
4.	Real time monitoring of distributed generation sources needs to be mandatory	Incorporated

Comments from Indus Towers

S. No.	Comment	Action
1.	Calculation of project size should consider demand aggregation model. Demand aggregation will encourage consumers with distributed loads to go for GRPV	Project size to be determined by the developer
2.	Indus supports model prescription of a standardized and consumer-friendly interconnection process for ease of adoption	Incorporated
3.	We fully support the idea of Virtual Group Net Metering concept where premises will be considered as a Virtual one, i.e. a demand aggregation model can work for utilities for single consumer with distributed load in multiple locations. We strongly prefer a tri-party Virtual Group Net metering model where the consumer can be part of Opex based model with support from a Third-party RESCO developer and the utility. Continuation of present practices like complete waiver of any kind of energy tax or wheeling, banking surcharges will enable this ecosystem further. Clarifications on ownership structure and in-premises generation and consumption are needed	VNM and GNM are not incorporated in the Regulations
4.	A standard guideline on PPA model should be available. It'll bring transparency and efficiency to the whole process	Incorporated
5.	Indus supports to promote large scale adoption of rooftop solar under net metering, compensation may be paid to the consumer for any excess energy credit at the end of settlement period	Incorporated
6.	Model Regulation should not discriminate among rooftop or ground-based consumers load. It should allow virtual group net metering model to accommodate demand aggregation at large scale.	VNM and GNM are not incorporated in the Regulations
7.	Definition of premises should accommodate virtual demand aggregation for consumers with distributed but large sized cumulative loads. Telecom Towers companies and similar organizations will be supported by such a move	VNM and GNM are not incorporated in the Regulations
8.	Virtual Net Metering model without physical geographical boundary should be allowed under the new model of business. This shall help create a win-win situation for all the stakeholders.	VNM and GNM are not incorporated in the Regulations
9.	We do not support the consideration of provisioning cost incurred for network augmentation on account of consumer application as it may work as a barrier initially to promote renewable power usage	Subject to further discussion by Forum of Regulators

S. No.	Comment	Action
10.	We support this recommendation that AMI infrastructure should be in place for real-time monitoring of generation to consumption	Incorporated

Comments from OERC

S. No.	Comment	Action
1.	To incorporate the voltage level in the definition of DRES **Proposed -** "Distributed Renewable Energy Sources" means the renewable sources or combination of such sources, such as Mini, Micro and Small Hydro, Wind, Solar, Biomass including bagasse, bio-fuel, urban or Municipal Solid Waste as recognized by the Ministry of New and Renewable Energy, Government of India, feeding electricity into the electricity system at a voltage level of below 33 KV.	Incorporated in the Regulations
2.	"Hosting capacity" means capacity defined under Regulation14 of these Regulations.	Incorporated in the Regulations
3.	Replace "distribution" from definition of SNA with "disbursement" **Proposed -** "State Nodal Agency" or "SNA" means an entity in the state designated by the state government to act as the agency to deal with issues related to coordinated development of renewable energy, subsidy approval and disbursement to persons developing distributed energy projects, etc. and for accreditation, recommending the renewable projects for registration etc. including such other functions as assigned in these Regulations.	Incorporated in the Regulations
4.	The capacity of PDRES shall not exceed the sanctioned load/ contract demand of the prosumer. Provided further that minimum size of renewable energy system that can be set up under~~ net metering and~~ net-billing arrangement would be 10kW respectively.	Capacity of PDRES has been restricted to the contract demand of the prosumer. The minimum size of the renewable energy system is subject to further discussion.
5.	Regulation 11(c) says that the excess energy generated by PDRES shall be procured by the distribution license at Average Power Purchase Cost for the year whereas Regulation 17.7 says that the excess electricity at the end of settlement period shall be settled by the distribution licensee at the rate of the lowest energy charge applicable to the consumer. Hence, Regulation11(c) contradicts Regulation 17.7. Therefore, suitable revision may be made to remove ambiguity. Further, various aspects of cost of power injected by DRES during off peak hours vis-à-vis Average Power Purchase Cost & cost of power available in power exchange may be taken into account while revising the Regulations.	Incorporated in the Regulations
6.	Hosting Capacity: The cumulative capacity of distribution renewable energy systems allowed to be interconnected with the distribution network (feeder/distribution transformer) shall not exceed ~~100%~~ 75% of the feeder and/or distribution transformer capacity, as applicable. Provided that the feeder/transformer mentioned above,	Subject to further discussion.

S. No.	Comment	Action
	considered for the purpose of calculating the hosting capacity, shall mean the feeder/ transformer connected to the particular RE system.	
7.	The distribution licensee shall supply the meter unless the consumer elects to supply the same. In case the applicant intends to procure meter from the distribution licensee, the applicant shall submit the intimation form to the distribution licensee at least 30 days prior to the expected date of submission of Work Completion Report. Meter rent shall rechargeable in case of meter supplied by the licensee but no meter rent in case of meters supplied by the consumer.	Incorporated in the Regulations
8.	Net Billing–Energy Accounting & Settlement: Energy Bill of consumer = Fixed charges + other applicable charges and levies + (EDL * TRST) - (ERE * TPSA) – Billing Credit Where: a) Fixed charges means the fixed/demand charges as applicable to the consumer category as per the applicable retail supply Tariff Order; b) Other charges and levies means any other charges such as municipal tax, cess, etc.; c) ERE means the energy units recorded for the billing period by the DRE Plant's generation meter; d) TPSA means the energy charges as per the energy sale agreement signed between the consumer and distribution licensee; e) EDL means the energy units supplied by the distribution licensee over and ~~above the ERE~~ for the billing period; f) TRST means the applicable retail supply tariff of the concerned consumer category as per the retail supply Tariff Order of the Commission; g) Billing credit is the amount by which value of DRE generation in a particular month is more than value of all other components of consumer bill.	Incorporated in the Regulations

Comments from TNERC

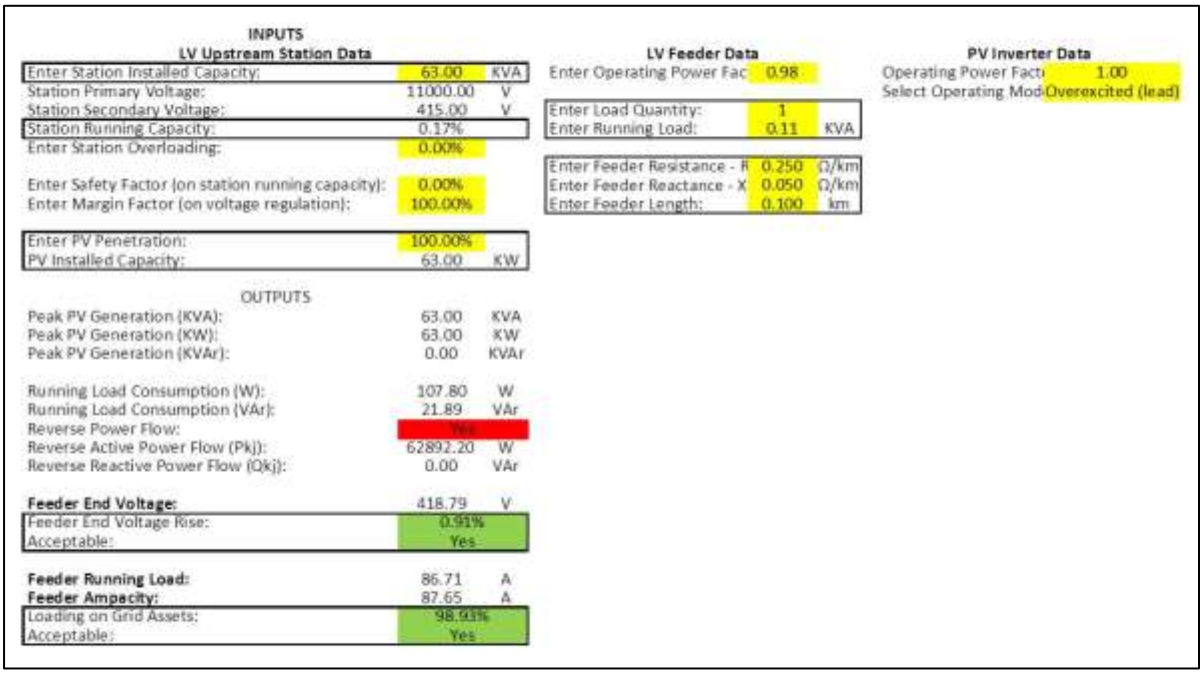
S. No.	Comment	Action
1.	• Draft Model Regulations should mention that installation of rooftop solar systems may be permitted only within consumer's premises. • It was contended that the interconnection of ground-mounted solar systems under net-metering/net-billing should be permissible only for residential consumers. Commercial and industrial consumers with ground-mounted solar systems in their premises should not be permitted interconnection under net-metering/net-billing beyond a specified system size. Commercial and industrial consumers may sell the power generated by such systems through open access/CPP route.	• It was suggested that only "residential" consumers be allowed to interconnect ground-mounted solar systems under net-metering/net-billing subject to further discussions at the Forum of Regulators
2.	• It was proposed by some members that the demand aggregation activities may be permitted only in the case of residential consumers. Aggregation of demand of commercial and industrial consumers should not be permitted to safeguard DISCOMs' revenues.	• The Model Regulations should provide demand aggregation by distribution utility only and such aggregation should be restricted to "residential" consumers only. Final view may be taken by Forum of Regulators
3.	• Net-billing tariff may be kept equal to the reference tariff as determined by the Regulator	• It was decided that Model Regulations will provide different options to decide rate of procurement from GRPV projects. It was proposed that each state may decide to choose appropriate option.

Annexure 5: Case Studies for 0.4KV, 11KV and 33KV feeders with simulation study results

Case Study 1: 0.4KV feeder and 63KVA DT at Ranchi

A 0.4KV feeder from 63KVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Ranchi has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of the study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 0.11 KVA i.e. 0.17% of the DT capacity.

Simulation has been performed at a feeder length of 0.100 km with resistance 0.250 Ω/km, reactance 0.050 Ω/km and operating power factor of 0.98. For simulation purposes, the operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.



INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	63.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.17%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	63.00	KW

LV Feeder Data

Enter Operating Power Fac	0.98	
Enter Load Quantity:	1	
Enter Running Load:	0.11	KVA
Enter Feeder Resistance - R	0.250	Ω/km
Enter Feeder Reactance - X	0.050	Ω/km
Enter Feeder Length:	0.100	km

PV Inverter Data

Operating Power Fact	1.00
Select Operating Mod	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	63.00	KVA
Peak PV Generation (KW):	63.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	107.80	W
Running Load Consumption (VAr):	21.89	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	62892.20	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	418.79	V
Feeder End Voltage Rise:	0.91%	
Acceptable:	Yes	
Feeder Running Load:	86.71	A
Feeder Ampacity:	87.65	A
Loading on Grid Assets:	98.93%	
Acceptable:	Yes	

The result of the load flow study shows that at 0.11KVA of DT loading i.e. 0.17% of the DT capacity (minimum loading of the year at noon time), solar power plants of 63KW (inverter nominal capacity) i.e. 100% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 0.91% voltage rise at interconnection point and 98.93% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of the DT vs. he solar power generation have been generated and presented in the figures below:

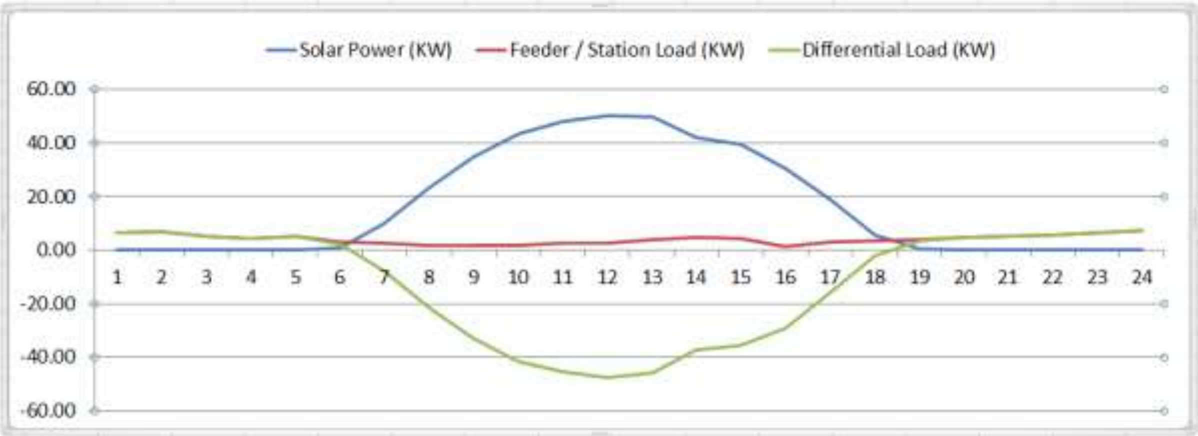


Figure 31: Typical daily load profile of 63KVA DT vs. power generation from 63kW solar power plant

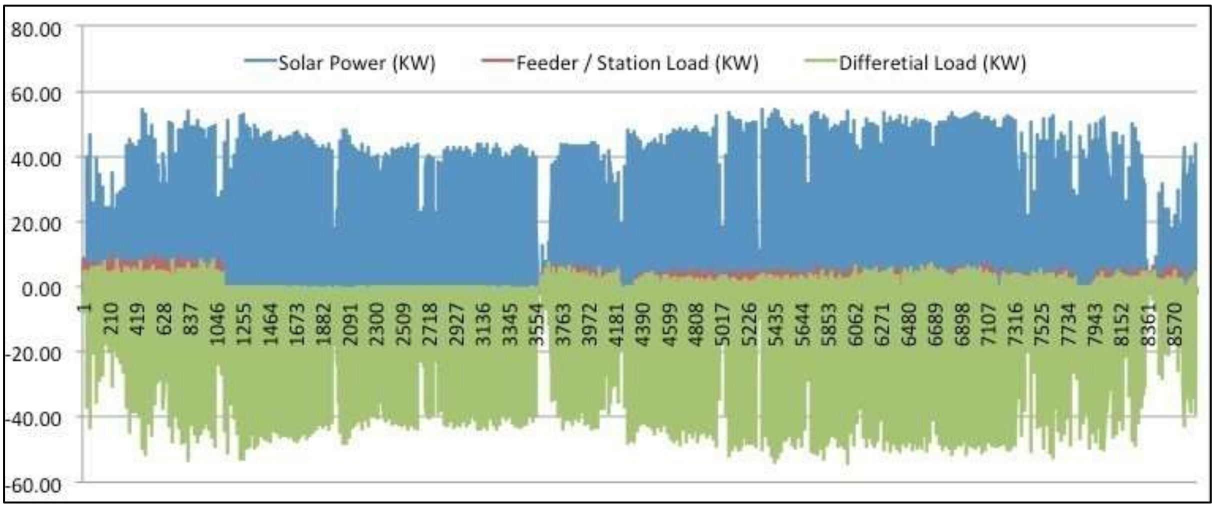


Figure 32: Typical annual load profile of 63KVA DT vs. power generation from 63kW solar power plant

Case Study 2: 0.4KV feeder and 100KVA DT at Ranchi

A 0.4KV feeder from 100KVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Ranchi has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of the study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 0.02KVA i.e. 0.02% of the DT capacity.

Simulation has been performed at a feeder length of 0.350km with resistance 0.150 Ω/km, reactance 0.075 Ω/km and operating power factor of 0.98. For simulation purposes, operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

LV Upstream Station Data

Enter Station Installed Capacity:	100.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.02%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	100.00	KW

LV Feeder Data

Enter Operating Power Factor	0.98	
Enter Load Quantity:	1	
Enter Running Load:	0.02	KVA
Enter Feeder Resistance R:	0.150	Ω/km
Enter Feeder Reactance X_L:	0.075	Ω/km
Enter Feeder Length:	0.350	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	100.00	KVA
Peak PV Generation (KW):	100.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	23.52	W
Running Load Consumption (VAr):	4.78	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	99976.48	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	427.65	V
Feeder End Voltage Rise:	3.05%	
Acceptable:	Yes	
Feeder Running Load:	134.98	A
Feeder Ampacity:	139.12	A
Loading on Grid Assets:	97.02%	
Acceptable:	Yes	

The result of the load flow study shows that at 0.02KVA of DT loading, i.e. 0.02% of the DT capacity (minimum loading of the year at noon time), solar power plants of 100KW (inverter nominal capacity) i.e. 100% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 3.05% voltage rise at interconnection point and 97.02% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation have been generated and presented in the figures below:

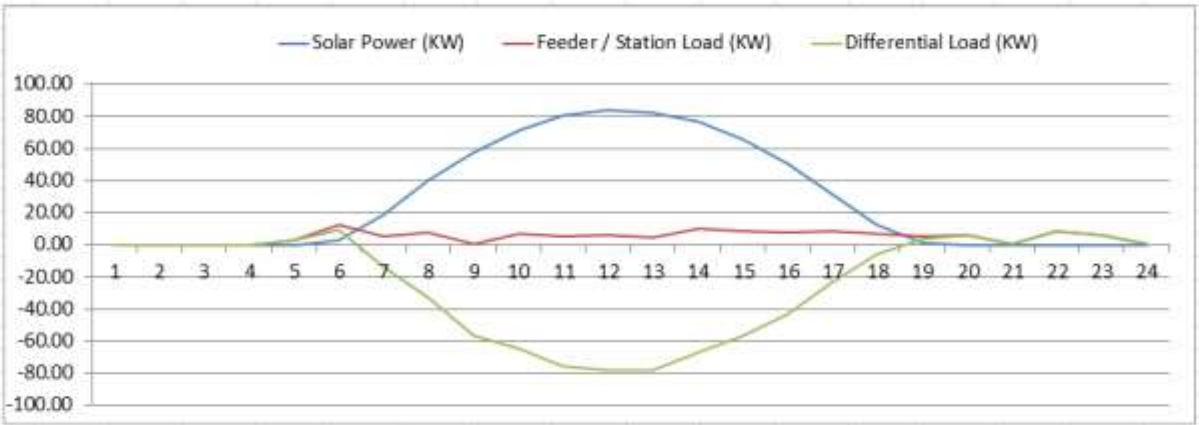


Figure 33: Typical daily load profile of 100KVA DT vs. power generation from 100kW solar power plant

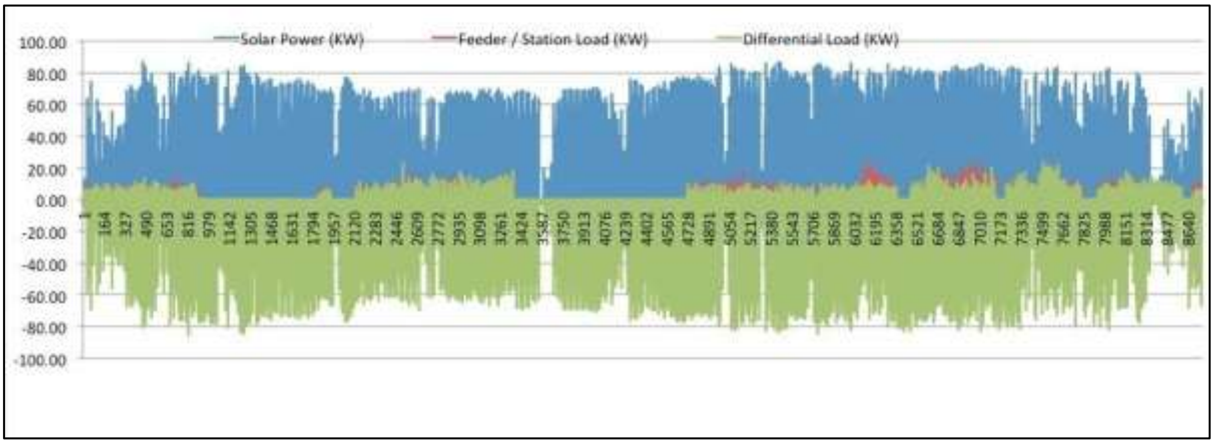


Figure 34: Typical annual load profile of 100KVA DT vs. power generation from 100kW solar power plant

Case Study 3: 0.4KV feeder and 100KVA DT at Ranchi

A 0.4KV feeder from 100KVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Ranchi has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of the study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 1.56KVA i.e. 1.56% of the DT capacity.

Simulation has been performed at a feeder length of 0.450km with resistance 0.279 Ω/km, reactance 0.00 Ω/km and operating power factor of 0.98 considering 26 consumers connected to the network. For simulation purposes, the operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

LV Upstream Station Data		
Enter Station Installed Capacity:	100.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	1.56%	
Enter Station Overloading:	0.00%	
Enter Safety Factor (on Station running capacity):	0.00%	
Enter Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	101.00%	
PV Installed Capacity:	101.00	KW

LV Feeder Data		
Enter Operating Power Factor	0.98	
Enter Load Quantity:	26	
Enter Running Load:	0.06	KVA
Enter Feeder Resistance R:	0.279	Ω/km
Enter Feeder Reactance X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data	
Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	3.88	KVA
Peak PV Generation (KW):	3.88	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	58.80	W
Running Load Consumption (VAr):	11.94	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	3825.82	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	416.16	V
Feeder End Voltage Rise:	0.28%	
Acceptable:	Yes	
Feeder Running Load:	138.00	A
Feeder Ampacity:	139.12	A
Loading on Grid Assets:	99.20%	
Acceptable:	Yes	

The result of the load flow study shows that at 1.56KVA of DT loading, i.e., 1.56% of the DT capacity (minimum loading of the year at noon time), solar power plants of 101KW (inverter nominal capacity) i.e. 100% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 0.28% voltage rise at interconnection point and 99.20% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation have been generated and presented in the figures below:

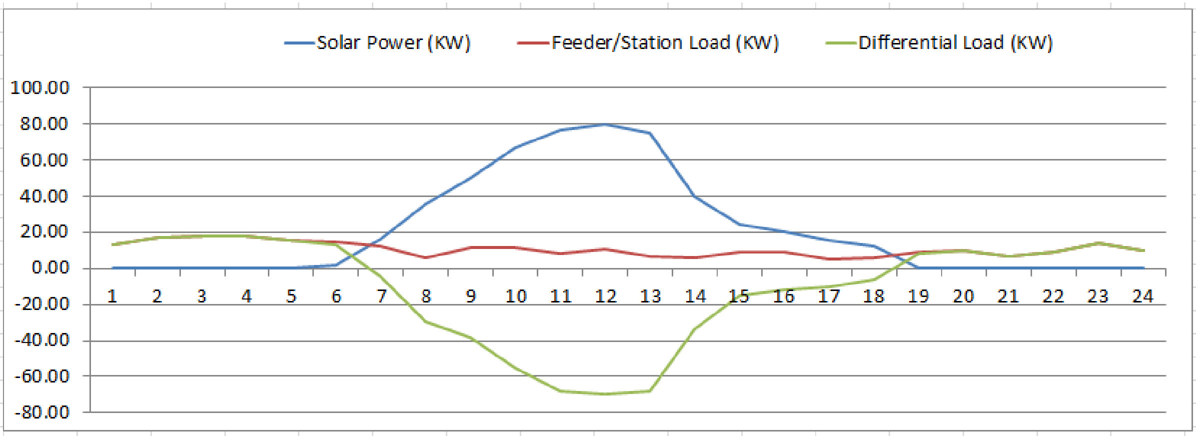


Figure 35: Typical daily load profile of 100KVA DT vs. power generation from 101kW solar power plant

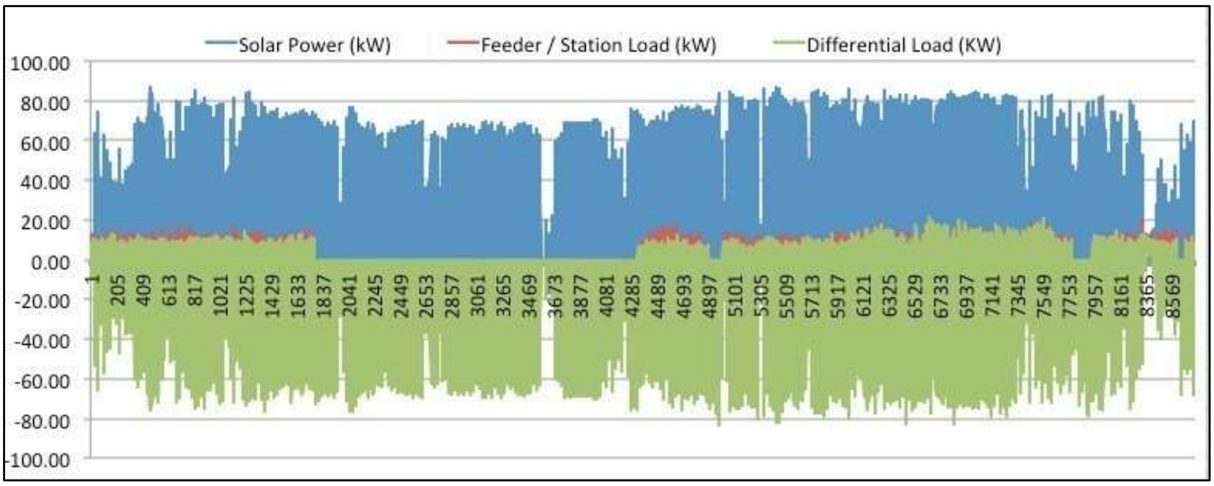


Figure 36: Typical annual load profile of 100KVA DT vs. power generation from 101kW solar power plant

Case Study 4: 11KV feeder and 115KVA DT at Ranchi

An 11KV feeder from 115KVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Ranchi has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of the study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 0KVA i.e. 0% of the DT capacity.

Simulation has been performed at a LV feeder length of 0.650km with resistance 0.350 Ω/km, reactance 0.015Ω/km and operating power factor of 0.86 considering 16 consumers connected to the network. Similarly, study point at MV feeder was considered at a length 0.450 km with resistance 0.187 Ω/km, reactance 0.00 Ω/km and operating power factor of 0.82. For simulation purposes, the operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	115.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.00%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	115.00	KW

LV Feeder Data

Enter Operating Power Factor:	0.86	
Enter Load Quantity:	16	
Enter Running Load:	0.00	KVA
Enter Feeder Resistance R:	0.350	Ω/km
Enter Feeder Reactance X_L:	0.015	Ω/km
Enter Feeder Length:	0.650	km

LV Upstream Station Data

Enter Station Quantity:	1	
Station Installed Capacity:	115.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.00%	
Station Running Capacity:	0.00	KVA
Station Per Unit Reactance X_{PU}:	7.00%	
Station Base Reactance X_{BASE}:	75625000	Ω
Station Actual Reactance X_{Ω}:	5293750	Ω

MV Feeder Data

Operating Power Factor:	0.82	
Enter Adjusted Power Factor:	0.82	
Enter Feeder Resistance R:	0.187	Ω/km
Enter Feeder Reactance X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	verexcited (lea

OUTPUTS

Peak PV Generation (KVA):	115.00	KVA
Peak PV Generation (KW):	115.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	1.31	W
Running Load Consumption (VAr):	0.92	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	114998.69	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11000.88	V
Feeder End Voltage Rise:	0.01%	
Acceptable:	Yes	
Feeder Running Load:	6.04	A
Feeder Ampacity:	6.04	A
Loading of Grid Assets:	99.99%	
Acceptable:	Yes	

The result of the load flow study shows that at 0KVA of DT loading i.e. 0% of the DT capacity (minimum loading of the year at noon time), solar power plants of 115KW (inverter nominal capacity) i.e. 100% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study at 100% loading indicates 0.01% voltage rise at interconnection point and 99.99% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation have been generated and presented in the figures below:

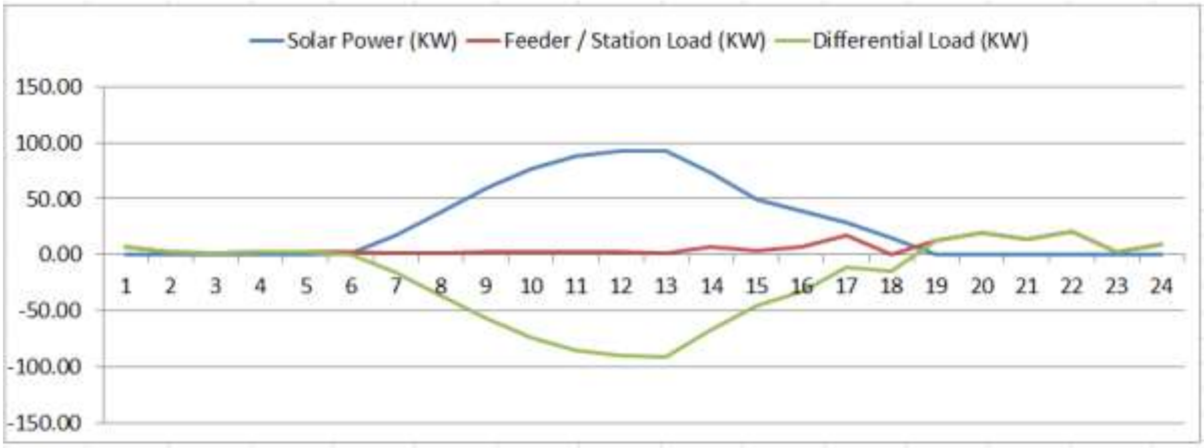


Figure 37: Typical daily load profile of 115KVA DT vs. power generation from 100kW solar power plant

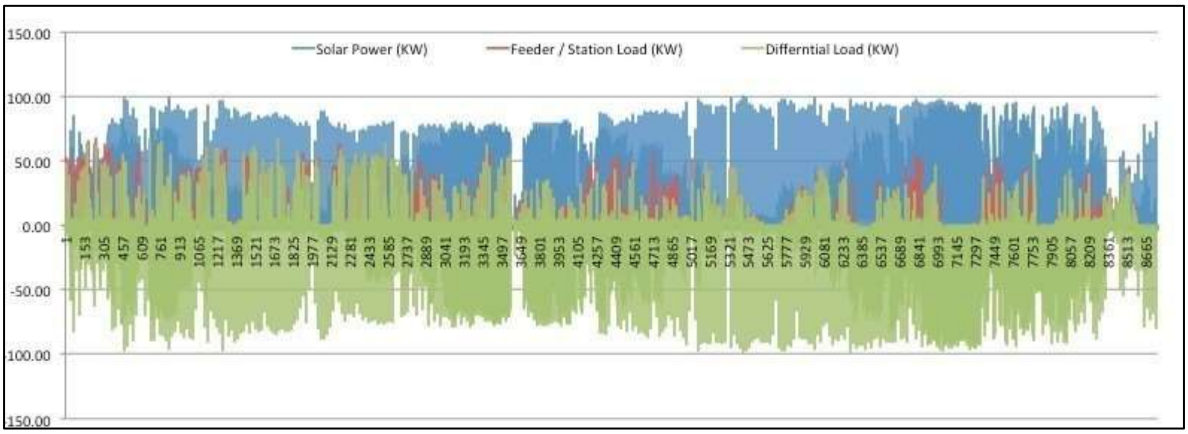


Figure 38: Typical annual load profile of 100KVA DT vs. power generation from 100kW solar power plant

Case Study 5: 11KV feeder and 140KVA DT at Ranchi

An 11KV feeder from 140KVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Ranchi has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 0KVA i.e. 0% of the DT capacity.

Simulation has been performed at a LV feeder length of 0.750km with resistance 0.350 Ω/km, reactance 0.015Ω/km and operating power factor of 0.86 considering 18 consumers connected to the network. Similarly, study point at MV feeder was considered at a length 0.450 km with resistance 0.187 Ω/km, reactance 0.00 Ω/km and operating power factor of 0.82. For simulation purpose operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	140.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.00%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	140.00	KW

LV Feeder Data

Enter Operating Power Factor:	0.86	
Enter Load Quantity:	18	
Enter Running Load:	0.00	KVA
Enter Feeder Resistance R:	0.350	Ω/km
Enter Feeder Reactance X_L:	0.015	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	140.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	0.00%	
Station Running Capacity:	0.00	KVA
Enter Station Per Unit Reactance X_{PU}:	7.00%	
Station Base Reactance X_{BASE}:	67222222	Ω
Station Actual Reactance X_{Ω}:	4705556	Ω

MV Feeder Data

Operating Power Factor:	0.82	
Enter Adjusted Power Factor:	0.98	
Enter Feeder Resistance R:	0.187	Ω/km
Enter Feeder Reactance X_L:	0.000	Ω/km
Enter Feeder Length:	0.450	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

OUTPUTS

Peak PV Generation (KVA):	140.00	KVA
Peak PV Generation (KW):	140.00	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	1.76	W
Running Load Consumption (VAr):	0.36	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	139998	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11001.07	V
Feeder End Voltage Rise:	0.01%	
Acceptable:	Yes	
Feeder Running Load:	7.35	A
Feeder Ampacity:	7.35	A
Loading of Grid Assets:	99.99%	
Acceptable:	Yes	

The result of load flow study shows that at 0KVA of DT loading i.e. 0% of the DT capacity (minimum loading of the year at noon time), solar power plants of 140KW (inverter nominal capacity) i.e. 100% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 0.01% voltage rise at interconnection point and 99.99% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation has been generated and presented in the figures below:

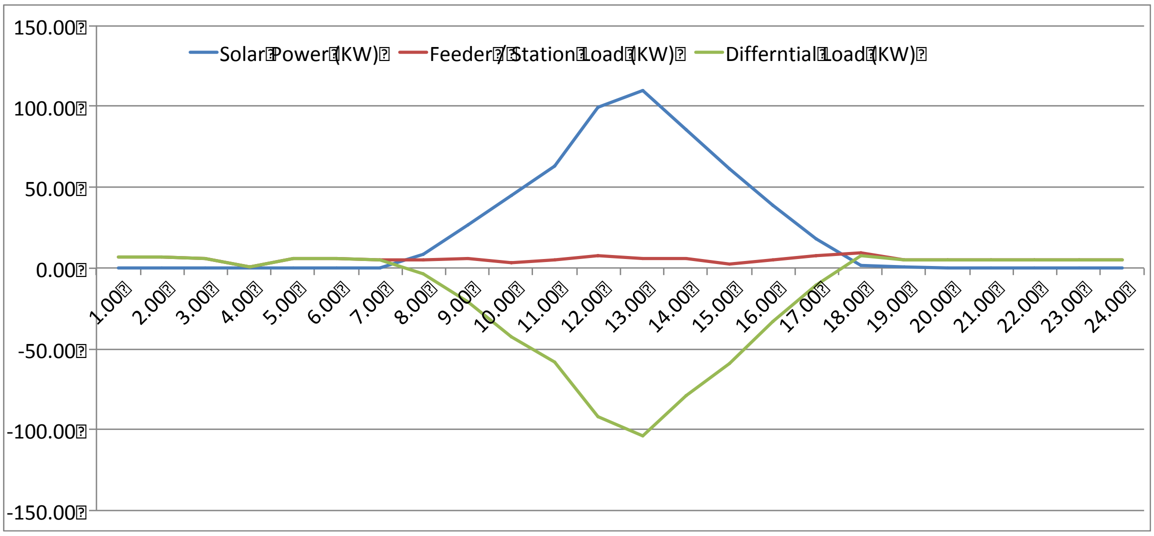


Figure 39: Typical daily load profile of 140KVA DT vs. power generation from 140kW solar power plant

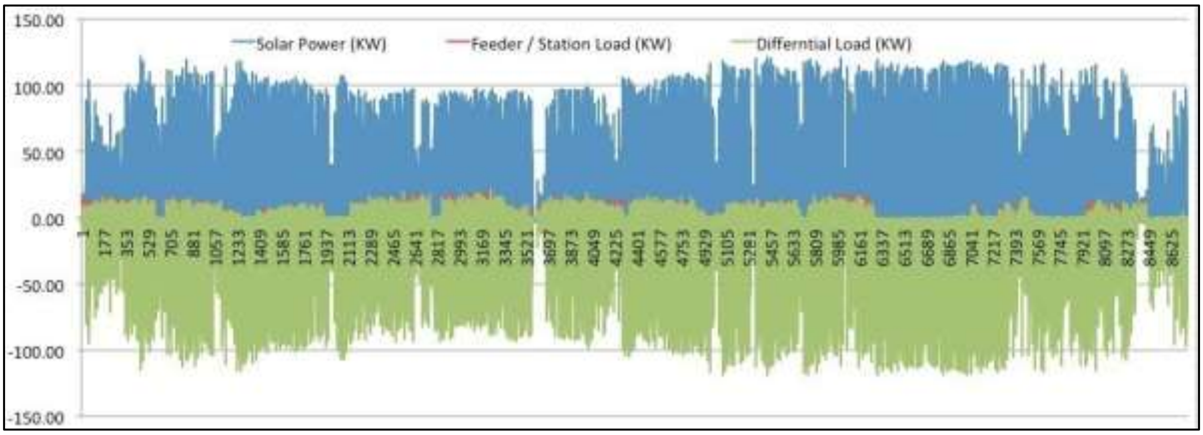


Figure 40: Typical annual load profile of 140KVA DT vs. power generation from 140kW solar power plant

Case Study 6: 11KV feeder and 630KVA DT at Delhi

An 11KV feeder from 630KVA distribution transformer of BSES Rajdhani, Delhi, has been studied. BSES provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 78.12KVA i.e. 12.41% of the DT capacity.

Simulation has been performed at a LV feeder length of 0.750km with resistance 0.350 Ω/km, reactance 0.015Ω/km and operating power factor of 0.96 considering 62 consumers connected to the network. Similarly, study point at MV feeder was considered at a length 0.750 km with resistance 0.150Ω/km, reactance 0.10Ω/km and operating power factor of 0.94. For simulation purpose operating power factor of PV Inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

MV Upstream Station Data

Enter Station Installed Capacity:	630.00	KVA
Station Primary Voltage:	33000	V
Station Secondary Voltage:	11000	V
Station Running Capacity:	12.41%	
Enter Station Overloading:	0.00%	
Safety Factor (on Station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100%	
Enter PV Penetration:	112%	
PV Installed Capacity:	705.60	KW

LV Feeder Data

Enter Operating Power Factor:	0.96	
Enter Load Quantity:	62	
Enter Running Load:	1.26	KVA
Enter Feeder Resistance (R):	0.350	Ω/km
Enter Feeder Reactance (X_L):	0.015	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	1	
Station Installed Capacity:	630	KVA
Station Primary Voltage:	11000	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	12.41%	
Station Running Capacity:	78.18	KVA
Station Per Unit Reactance (X_{PU}):	6.00%	
Station Base Reactance (X_{BASE}):	1548	Ω
Station Actual Reactance ($X_{Ω}$):	92.86	Ω

MV Feeder Data

Operating Power Factor:	0.94	
Enter Adjusted Power Factor	0.98	
Enter Feeder Resistance (R):	0.150	Ω/km
Enter Feeder Reactance (X_L):	0.100	Ω/km
Enter Feeder Length:	0.750	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead

OUTPUTS

Peak PV Generation (KVA):	706	KVA
Peak PV Generation (KW):	706	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	76618	W
Running Load Consumption (VAr):	15558	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	628982	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	11008	V
Feeder End Voltage Rise:	0.08%	
Acceptable:	Yes	
Feeder Running Load:	33.00	A
Feeder Ampacity:	33.07	A
Loading of Grid Assets:	99.79%	
Acceptable:	Yes	

The result of the load flow study shows that at 78.12KVA of DT loading i.e. 12.41% of the DT capacity (minimum loading of the year at noon time), solar power plants of 705KW (inverter nominal capacity) i.e. 112% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 0.08% voltage rise at interconnection point and 99.79% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation have been generated and presented in the figures below:

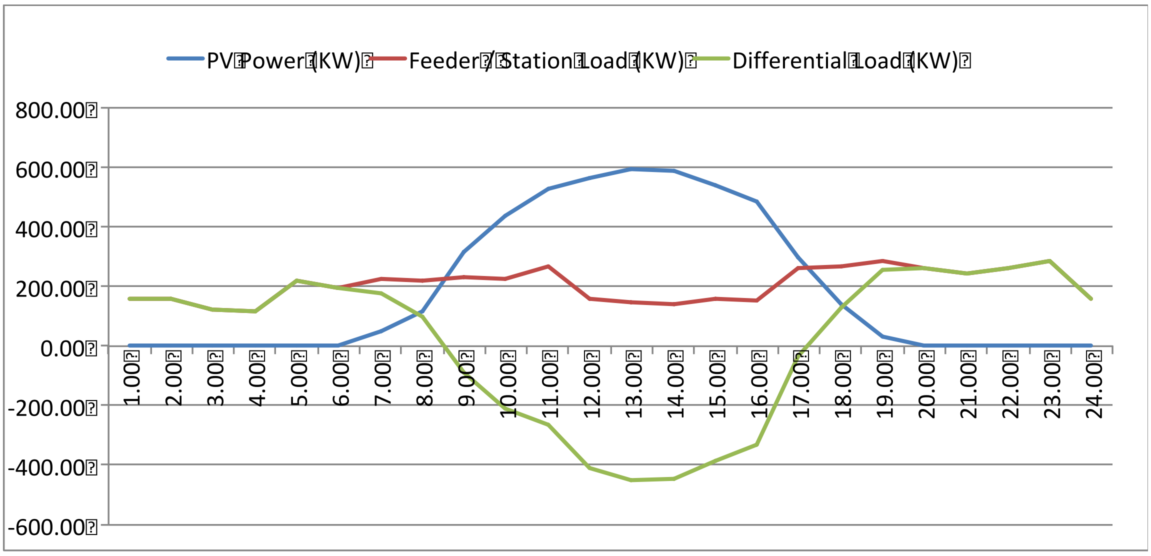


Figure 41: Typical daily load profile of 630KVA DT vs. power generation from 705kW solar power plant

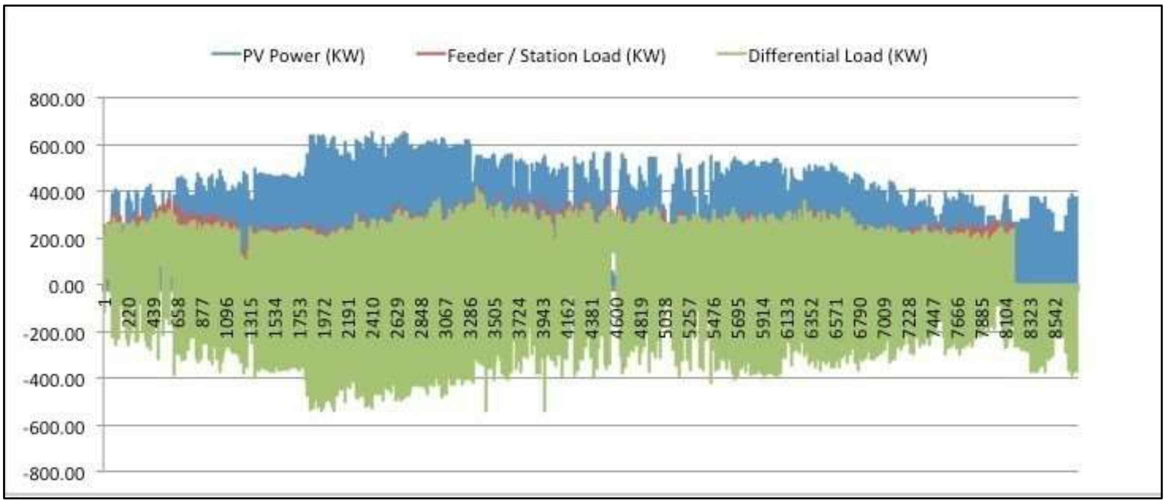


Figure 42: Typical annual load profile of 630KVA DT vs. power generation from 705kW solar power plant

Case Study 7: 33KV feeder and 1.1MVA DT at Jamshedpur

A 33KV feeder from 1.1MVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Jamshedpur has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 1296KVA i.e. 11.78% of the DT capacity.

Simulation has been performed at a LV feeder length of 0.750km with resistance 0.450 Ω/km, reactance 0.025Ω/km and operating power factor of 0.87. Study point at 11KV feeder was considered at a length 4.85km with resistance 0.35Ω/km, reactance 0.015Ω/km and operating power factor of 0.84. HV feeder of length 9.5 km with resistance 0.139 Ω/km, reactance 0.00 Ω/km and operating power factor of 0.80 was considered.

For simulation purposes, the operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

HV Upstream Station Data

Enter Station Installed Capacity:	11000	KVA
Station Primary Voltage:	132000	V
Station Secondary Voltage:	33000	V
Station Running Capacity:	11.78%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	111.00%	
PV Installed Capacity:	12210	KW

OUTPUTS

Peak PV Generation (KVA):	12210	KVA
Peak PV Generation (KW):	12210	KW
Peak PV Generation (KVAr):	0	KVAr
Running Load Consumption (W):	1231200	W
Running Load Consumption (VAr):	404676	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	10978800	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	33458	V
Feeder End Voltage Rise:	1.39%	
Acceptable:	Yes	
Feeder Running Load:	189.58	A
Feeder Ampacity:	192.46	A
Loading of Grid Assets:	98.51%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.87	
Enter Load Quantity:	30	
Enter Running Load:	10.80	KVA
Enter Feeder Resistance R:	0.450	Ω/km
Enter Feeder Reactance X_L:	0.025	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	4	
Enter Station Installed Capacity:	2750.00	KVA
Station Primary Voltage:	11000.00	V
Station Secondary Voltage:	415.00	V
Station Running Capacity:	11.78%	
Station Running Capacity:	324.00	KVA
Station Per Unit Reactance X_{PU}:	6.00%	
Station Base Reactance X_{BASE}:	373.46	Ω
Station Actual Reactance X_{Ω}:	22.41	Ω

MV Feeder Data

Operating Power Factor:	0.84	
Enter Feeder Resistance R:	0.350	Ω/km
Enter Feeder Reactance X_L:	0.015	Ω/km
Enter Feeder Length:	4.850	km

MV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	11000.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	11.78%	
Station Running Capacity:	1296.00	KVA
Station Per Unit Reactance X_{PU}:	7.00%	
Station Base Reactance X_{BASE}:	840.28	Ω
Station Actual Reactance X_{Ω}:	58.82	Ω

HV Feeder Data

Operating Power Factor:	0.80	
Enter Adjusted Power Factor:	0.95	
Enter Feeder Resistance R:	0.139	Ω/km
Enter Feeder Reactance X_L:	0.000	Ω/km
Enter Feeder Length:	9.500	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead)

The result of the load flow study shows that at 1296KVA of DT loading i.e. 11.78% of the DT capacity (minimum loading of the year at noon time), solar power plants of 1.22MW (inverter nominal capacity) i.e. 111% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 1.39% voltage rise at interconnection point and 99.51% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation have been generated and presented in the figures below:

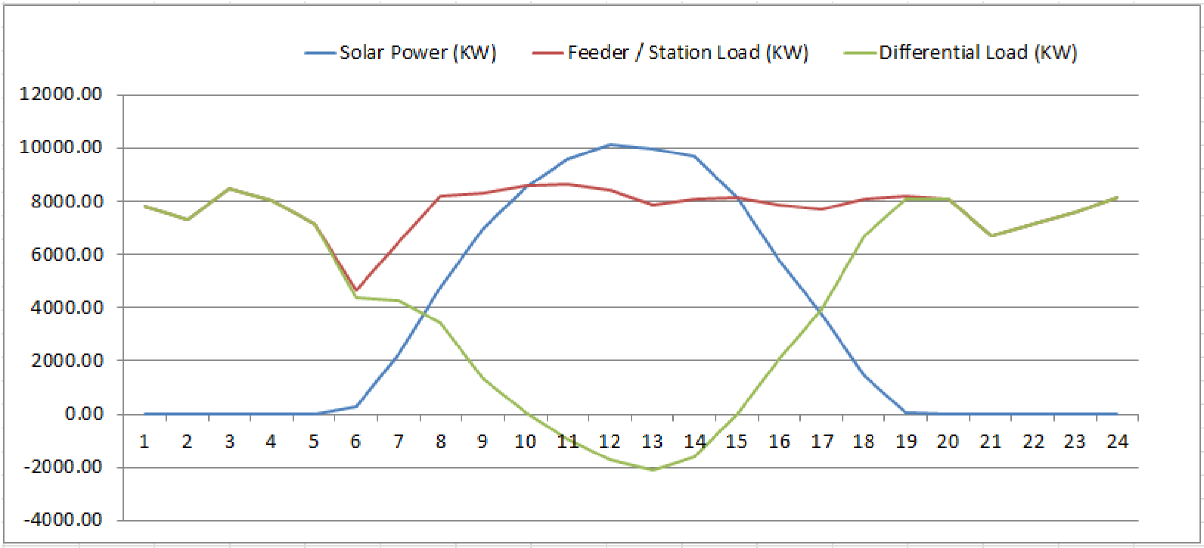


Figure 43: Typical daily load profile of 1.1MVA DT vs. power generation from 1.22MW solar power plant

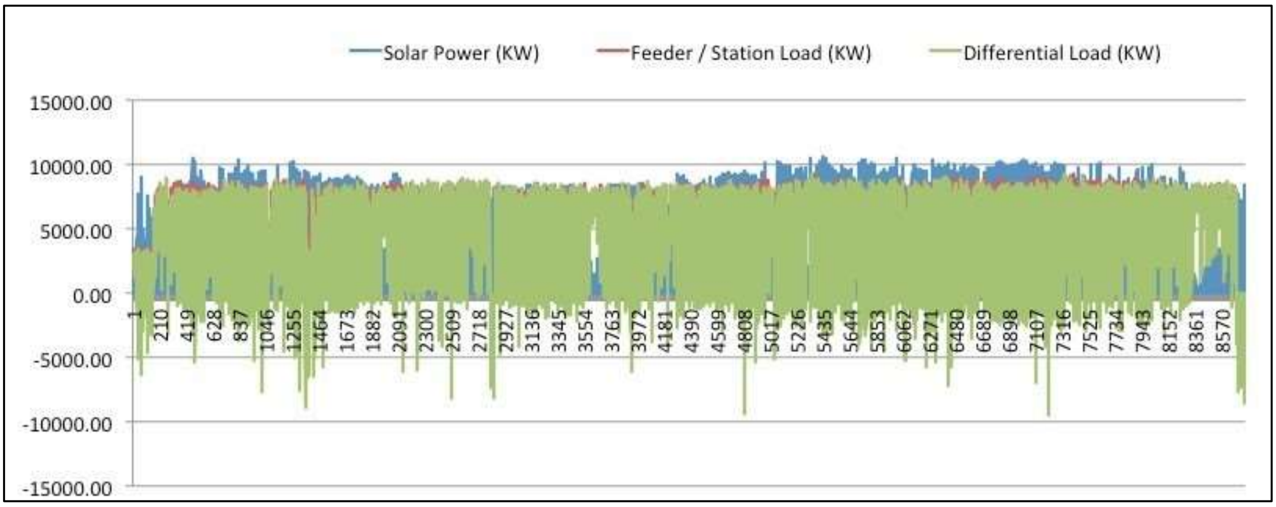


Figure 44: Typical annual load profile of 1.1MVA DT vs. power generation from 1.22MW solar power plant

Case Study 8: 33KV feeder and 1.75MVA DT at Jamshedpur

A 33KV feeder from 1.75MVA distribution transformer of Jharkhand Bijli Vitran Nigam Limited (JBVNL) at Jamshedpur has been studied. JBVNL provided feeder data, namely, hourly demand, rating of DT, length of feeder, operating power factor and feeder parameters (R & X) for the purpose of study. Hourly load demand on the DT for one year has been analysed and minimum demand at noon time (when solar PV is at peak) was found to be 7.2KVA i.e. 0.41% of the DT capacity.

Simulation has been performed at a LV feeder length of 0.750km with resistance 0.450 Ω/km, reactance 0.025Ω/km and operating power factor of 0.87. Study point at 11KV feeder was considered at a length 4.85km with resistance 0.35Ω/km, reactance 0.015Ω/km and operating power factor of 0.84. HV feeder of length 9.5 km with resistance 0.139 Ω/km, reactance 0.00 Ω/km and operating power factor of 0.80 was considered.

For simulation purposes, the operating power factor of PV inverter was considered as unity. Below is the snapshot of the simulation results.

INPUTS

HV Upstream Station Data

Enter Station Installed Capacity:	1750	KVA
Station Primary Voltage:	132000	V
Station Secondary Voltage:	33000	V
Station Running Capacity:	0.41%	
Enter Station Overloading:	0.00%	
Safety Factor (on station running capacity):	0.00%	
Margin Factor (on voltage regulation):	100.00%	
Enter PV Penetration:	100.00%	
PV Installed Capacity:	1750	KW

OUTPUTS

Peak PV Generation (KVA):	1750	KVA
Peak PV Generation (KW):	1750	KW
Peak PV Generation (KVAr):	0.00	KVAr
Running Load Consumption (W):	6624	W
Running Load Consumption (VAr):	2822	VAr
Reverse Power Flow:	Yes	
Reverse Active Power Flow (Pkj):	1743376	W
Reverse Reactive Power Flow (Qkj):	0.00	VAr
Feeder End Voltage:	33070	V
Feeder End Voltage Rise:	0.21%	
Acceptable:	Yes	
Feeder Running Load:	30.44	A
Feeder Ampacity:	30.62	A
Loading of Grid Assets:	99.41%	
Acceptable:	Yes	

LV Feeder Data

Enter Operating Power Factor:	0.87	
Enter Load Quantity:	16	
Enter Running Load:	0.23	KVA
Enter Feeder Resistance - R:	0.450	Ω/km
Enter Feeder Reactance - X_L:	0.025	Ω/km
Enter Feeder Length:	0.750	km

LV Upstream Station Data

Enter Station Quantity:	2	
Enter Station Installed Capacity:	875.00	KVA
Station Primary Voltage:	11000	V
Station Secondary Voltage:	415	V
Station Running Capacity:	0.41%	
Station Running Capacity:	3.60	KVA
Station Per Unit Reactance - X_{PU}:	6.00%	
Station Base Reactance - X_{BASE}:	33611	Ω
Station Actual Reactance - X_{Ω}:	2017	Ω

MV Feeder Data

Operating Power Factor:	0.84	
Enter Feeder Resistance - R:	0.350	Ω/km
Enter Feeder Reactance - X_L:	0.015	Ω/km
Enter Feeder Length:	4.850	km

MV Upstream Station Data

Enter Station Quantity:	1	
Enter Station Installed Capacity:	1750.00	KVA
Station Primary Voltage:	33000.00	V
Station Secondary Voltage:	11000.00	V
Station Running Capacity:	0.41%	
Station Running Capacity:	7.20	KVA
Station Per Unit Reactance - X_{PU}:	7.00%	
Station Base Reactance - X_{BASE}:	151250	Ω
Station Actual Reactance - X_{Ω}:	10588	Ω

HV Feeder Data

Operating Power Factor:	0.80	
Enter Adjusted Power Factor:	0.92	
Enter Feeder Resistance - R:	0.139	Ω/km
Enter Feeder Reactance - X_L:	0.000	Ω/km
Enter Feeder Length:	9.500	km

PV Inverter Data

Operating Power Factor:	1.00
Select Operating Mode:	Overexcited (lead

The result of the load flow study shows that at 7.2KVA of DT loading i.e. 0.41% of the DT capacity (minimum loading of the year at noon time), solar power plants of 1.75MW (inverter nominal capacity) i.e. 100% of the DT capacity can be easily integrated to the network without affecting the existing grid infrastructure. The load flow study indicates 0.21% voltage rise at interconnection point and 99.41% loading in terms of current carrying capacity of the conductor and DT, which are acceptable.

Typical daily and annual load profiles of DT vs. solar power generation have been generated and presented in the figures below:

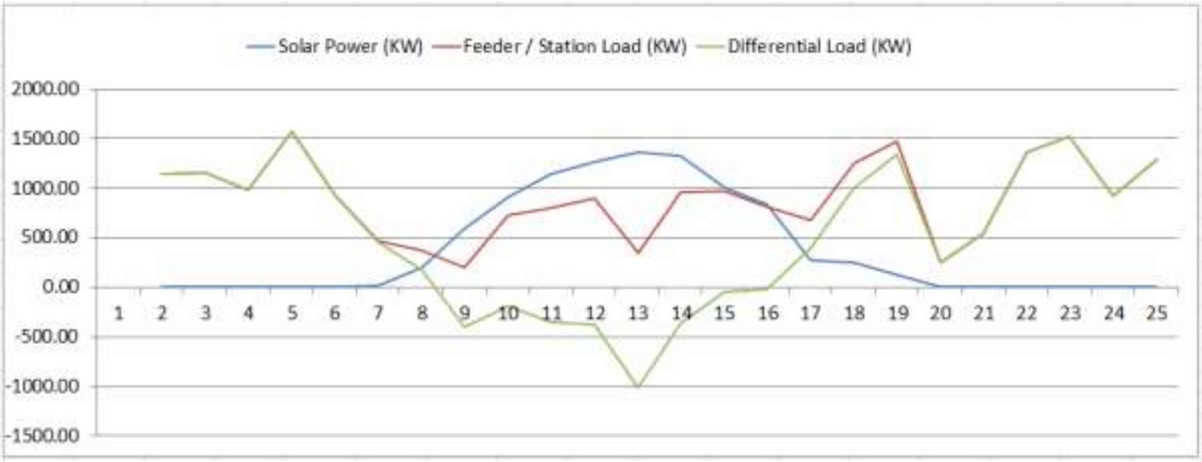


Figure 45: Typical daily load profile of 1.75MVA DT vs. power generation from 1.75MW solar power plant

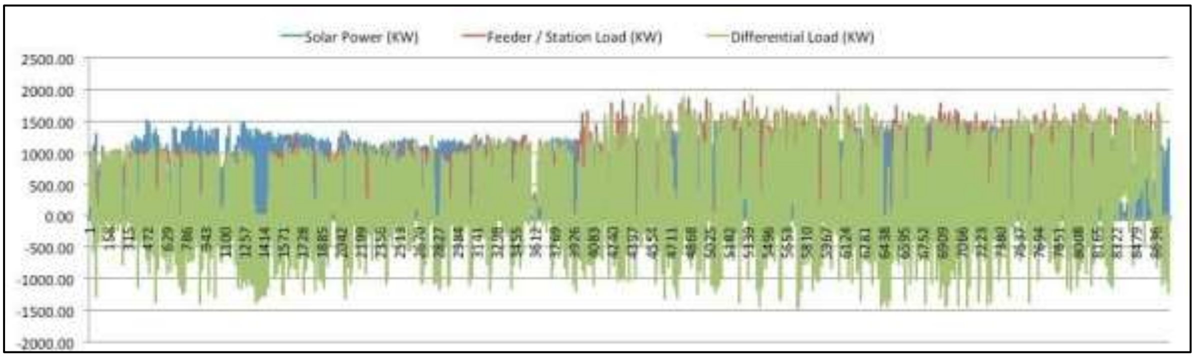


Figure 46: Typical annual load profile of 1.75MVA DT vs. power generation from 1.75MW solar power plant

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