

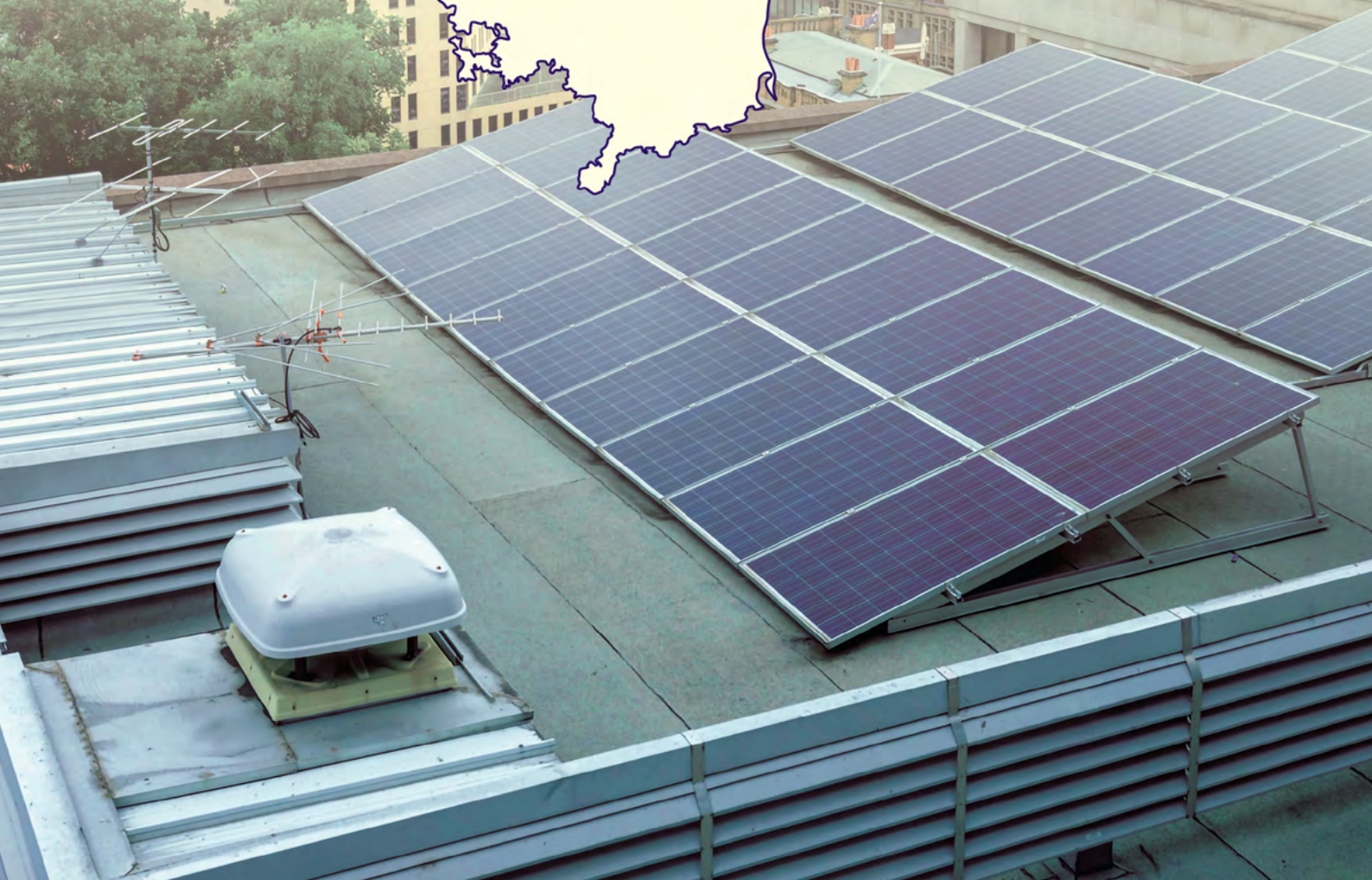
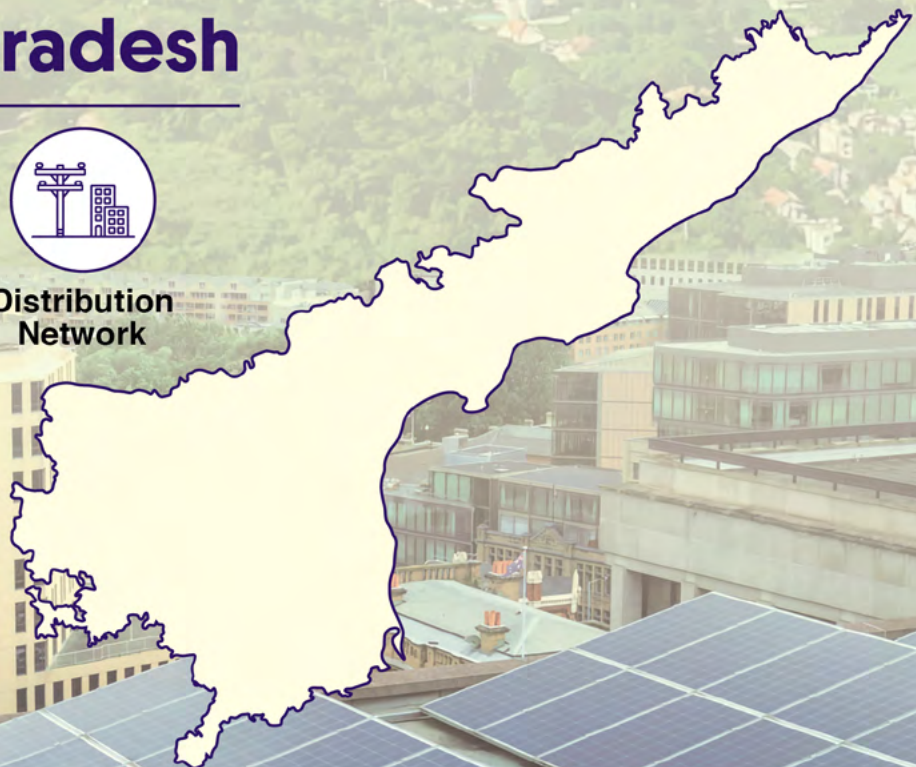
Assessing the Impact of Distributed Renewable Energy (DRE) on the Distribution Network in Andhra Pradesh



Rooftop
Solar



Distribution
Network



Assessing the Impact of Distributed Renewable Energy (DRE) on the Distribution Network in Andhra Pradesh

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Executive Summary

Andhra Pradesh is entering a period of significant transformation in its electricity sector, driven by expanding industrial activity, urbanisation, and the growing adoption of renewable energy. Emerging electricity-intensive developments, including data centres and green hydrogen, are expected to further reshape the state's demand profile. In contrast, the state's ambitious renewable energy targets will accelerate the deployment of both utility-scale and distributed renewable energy. This evolving generation–demand landscape will place new requirements on the state's distribution infrastructure and its ability to accommodate increasing levels of rooftop solar (RTPV) and other distributed energy resources (DRE).

The state's future distribution grid will therefore need to integrate both centralised and decentralised generation capacity. With increasing RTPV penetration, distribution networks are expected to face operational challenges such as transformer overloading, voltage fluctuations, reverse power flow, and evening peak-demand stress. Strengthening and modernising distribution networks will therefore be important for enabling the state's energy transition.

In this context, the Center for Study of Science, Technology and Policy (CSTEP), in collaboration with Andhra Pradesh Eastern Power Distribution Company Limited (APEPDCL), conducted a technical and financial assessment of DRE integration at the 11 kV feeder level. The study evaluated the impacts of RTPV and battery energy storage system (BESS) on network performance, transformer loading, voltage conditions, technical losses, and financial viability for distribution companies (DISCOMs) under current and future demand conditions.

The assessment focused on two representative 11 kV feeders in Visakhapatnam city: the Hobel Belows (HBL) industrial feeder and the Kurmannapalem (KRPM) residential feeder. Detailed field surveys were conducted to map the feeder networks and collect the required data. Quasi-dynamic time-series load flow simulations were carried out using hourly loading data. The study assessed four scenarios: business-as-usual (BAU) 2025, BAU 2030, BAU 2030 with RTPV, and BAU 2030 with RTPV and BESS.

The analysis showed that under the BAU scenario, future demand growth would increase stress on distribution transformers (DTs), resulting in higher DT overloading and deterioration in the voltage profile of the downstream network.

However, RTPV integration in financial year (FY) 2030 demonstrated significant technical benefits for the HBL industrial feeder. As industrial demand coincides with daytime solar generation, RTPV helped reduce transformer loading from 104% to 78%, improve voltage profiles, and lower both active and reactive power losses. Under the BAU 2030 with RTPV scenario, no DT was overloaded across the feeder, and the study also observed improvements in feeder loading margins.

The KRPM residential feeder presented a different operational challenge. Since residential peak demand occurs mainly during evening hours when solar generation is unavailable, RTPV provided limited relief during peak demand despite significantly reducing daytime loading. RTPV integration also introduced reverse power flow conditions during periods of high solar generation, creating additional operational complexities and localised DT stress.

Integration of RTPV and BESS in FY 2030, however, emerged as the most effective solution for the residential feeder. By storing surplus daytime solar generation and discharging it during evening peak hours, BESS significantly reduced DT loading (from 160% to 131%) during peak hours, improved voltage conditions, reduced system losses, and mitigated reverse power flow impacts. Under the BAU 2030 with RTPV and BESS scenario, all overloaded DTs in the KRPM residential feeder were brought within permissible operating limits. The analysis also highlighted the financial benefits of localised BESS deployment through the deferment of conventional infrastructure upgrades and enhancement of network reliability.

In addition to the technical analysis, the study assessed the financial implications of RTPV and BESS integration for DISCOM revenues and consumer electricity costs. The results indicated that:

- RTPV adoption reduces consumer electricity bills primarily through lower energy charges.
- DISCOM revenue reduction due to lower energy sales is largely offset by avoided power purchase costs.
- RTPV integration can remain financially neutral or marginally positive for the DISCOM when appropriately planned.
- BESS integration further improves operational and economic outcomes by reducing dependence on costly short-term market power procurement during peak periods.

Among the evaluated BESS business models, the Build–Own–Operate (BOO) model emerged as the most financially viable under the current assumptions.

Based on the analysis and results, the study recommends the following measures for smooth RTPV integration and deployment in the state:

- **Make RTPV deployment planning technically informed:** DISCOMs should transition from conventional planning to hosting-capacity-based RTPV approvals at the feeder and DT levels. RTPV penetration should be guided by detailed technical assessments of transformer loading, voltage conditions, reverse power flow limits, and local demand characteristics to ensure grid reliability under high DRE penetration scenarios.
- **Develop dedicated RTPV-ready distribution corridors:** DISCOMs should identify potential urban, industrial, and commercial zones with favourable daytime demand profiles and develop them as dedicated RTPV corridors. These corridors should be targeted to support higher RTPV penetration while minimising operational challenges.
- **Strengthen digital distribution planning and flexibility infrastructure:** DISCOMs should establish comprehensive feeder- and DT-level digital datasets supported by smart monitoring systems, integrated technical-financial planning dashboards, and real-time network visibility tools. Such systems will enable proactive planning of RTPV deployment, identification of network stress points, optimised BESS integration, and data-driven decision-making for future distribution grid modernisation.

Overall, the study concludes that grid readiness is important for smooth, high DRE penetration and must be supported by digital monitoring and data-driven planning. The study provides an important roadmap for DISCOMs and policymakers to accelerate the clean energy transition while maintaining a stable and future-ready power distribution system.

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1. Introduction

India is the third-largest emitter of greenhouse gases in the world. In alignment with its commitment at the 26th Conference of the Parties to the UNFCCC (COP26) to achieve net-zero emissions by 2070, the country has set an ambitious target of achieving 500 GW of renewable energy (RE) capacity by 2030 (Ministry of Environment, Forest and Climate Change, 2022). As of April 2026, India has achieved 288 GW of RE capacity, of which solar energy accounts for 154 GW. Strengthened renewable consumption obligation (RCO) frameworks have further accelerated RE deployment across the country. The RCO framework, along with the need for a reliable round-the-clock power supply, has contributed to the increasing adoption of distributed renewable energy (DRE), particularly rooftop solar photovoltaic (RTPV) systems, at the distribution level. RTPV systems account for approximately 17% of the total installed solar capacity (Ministry of New and Renewable Energy, 2026).

This transition is fundamentally reshaping distribution networks, from unidirectional power flow (grid to load) towards bidirectional power flow, with consumers increasingly acting as prosumers by generating and consuming electricity locally.

Distribution companies (DISCOMs) must therefore proactively strengthen and adapt their networks to accommodate increasing levels of decentralised generation, transitioning from conventional centralised procurement models to a more distributed and dynamic supply paradigm. Consequently, DISCOMs are undergoing significant structural and operational transformation.

However, the large-scale integration of RTPV into existing distribution systems introduces several technical challenges, including generation intermittency, voltage regulation issues, reverse power flow, and peak load management constraints. Addressing these challenges requires detailed network-level analysis and forward-looking planning.

In this context, the Center for Study of Science, Technology and Policy (CSTEP) undertook this study to understand the impact of DRE integration at the 11 kV feeder level in the distribution grid. The study addresses the following research questions:

-
- *What operational stress points may emerge on the 11 kV feeder due to growing demand and evolving load profiles?*
 - *How effectively can DT-level RTPV integration mitigate feeder-level stress?*
 - *What is the optimal RTPV penetration level required to maintain reliable operations?*
 - *What grid interventions or control strategies are needed to support higher DRE penetration while ensuring safe, efficient, and reliable feeder operations?*
 - *What are the financial implications of RTPV and RTPV+BESS integration for DISCOM revenue structures and consumer electricity costs?*
-

The assessment focuses on the distribution voltage level (11 kV and below), which forms the backbone of India's retail electricity system. It proposes practical and implementable measures to enhance grid performance, improve reliability, and enable higher penetration of distributed resources.

Andhra Pradesh possesses significant RE potential and has successfully harnessed large-scale RE resources over the years. The state is also actively promoting distributed RE solutions, particularly RTPV systems, with a focus on increasing adoption among low-consumption and subsidised consumer categories. In this context, the Andhra Pradesh Eastern Power Distribution Company Limited (APEPDCL) has been facilitating RTPV integration across its distribution network. Accordingly, this study was undertaken in collaboration with APEPDCL, which provided access to detailed technical datasets and field-level support. This enabled a comprehensive, realistic, and operationally grounded evaluation of the distribution network. The findings offer actionable insights for DISCOMs, highlighting both the benefits of DRE integration and the critical inflection points where timely grid investments are required to support a reliable, resilient, and sustainable energy transition.

The report is organised into five sections. Following this introduction, the next section provides a brief overview of the DRE policy landscape in Andhra Pradesh, with a focus on the various policies relevant to DRE. The subsequent section describes the study methodology, followed by an assessment of the feeder profiles and RTPV potential. The following section presents the scenario analysis, detailing the technical and financial impact of RTPV and BESS integration on the network. The final section presents recommendations based on the study analysis and findings.



2. DRE Policy Landscape in Andhra Pradesh

The DRE regulatory landscape in Andhra Pradesh has evolved gradually since the introduction of its first rooftop solar and net-metering policy in 2013. The 2015 and 2019 solar policies built on this foundation by simplifying approvals, expanding project limits, and providing greater flexibility in metering options as rooftop solar adoption increased. More recently, the 2024 Andhra Pradesh Electricity Regulatory Commission (APERC) Grid Interactive Solar Rooftop Photovoltaic Systems (SRTPV) Regulations, the 2024 Integrated Clean Energy (ICE) Policy, and the 2025 APERC regulations for BESS and PM Surya Ghar fee waivers have further strengthened the framework for DRE deployment in the state. By 2024–2025, this framework had expanded to cover rooftop solar, battery storage, and distributed energy resources. The key policies and regulations supporting DRE integration in the state are listed in Table 1.

A clear regulatory framework is important for scaling DRE adoption because it provides certainty for investors and consumers, supports grid integration, and enables long-term planning for the state's clean energy transition.

Table 1: Policy and regulatory framework for DRE integration in Andhra Pradesh

Policy	Description	Status
Rooftop Solar/Net Metering Policy, Energy Department, Andhra Pradesh (Government of Andhra Pradesh, 2013)	First net-metering policy in the state – provided a 20% subsidy of capital cost up to 3 kW capacity for domestic consumers	Repealed
Andhra Pradesh Solar Power Policy (Government of Andhra Pradesh, 2015)	Revised policy reflecting falling tariffs. Projects up to 1,000 kWp permitted; 14-day clearance window for DISCOMs; consumers free to choose net or gross metering	Superseded
Modalities (Guidelines) for implementing the Solar Roof Top (SRT) Policy, 2018	APERC-approved guidelines for implementing the 2018 SRT Policy, addressing key issues including capacity limits (aggregated RTPV capacity up to 80% of DT rating), metering standards, approval timelines, safety inspections, and jurisdictional clarifications	In-force
Andhra Pradesh Solar Power Policy (Government of Andhra Pradesh, 2018)	Revised policy reflecting falling tariffs. Tariff at average pooled purchase cost for 25 years; DISCOMs eligible to adjust power generation from rooftop projects towards RPO	Superseded

Policy	Description	Status
APERC (The Grid Interactive SRTPV under Gross/Net Metering) Regulation (Andhra Pradesh Electricity Regulatory Commission, 2023)	Comprehensive regulation replacing all prior guidelines on rooftop systems	In-force
Andhra Pradesh Integrated Clean Energy Policy (Government of Andhra Pradesh, 2024)	State-level clean energy master policy. Targets 50% non-fossil power capacity by 2030 and net-zero by 2047. Promotes RTPV via PM-Surya Ghar Yojana and PM-KUSUM. Directed APERC to amend Regulation 4 of 2023. Allows distributed energy resource (DER) aggregators	In-force
APERC PM-Surya Ghar: Muft Bijli Yojana Fee Waiver Order (under Grid Interactive Regulations; Andhra Pradesh Electricity Regulatory Commission, 2025a)	Waived application fees and net-metering charges for domestic consumers installing rooftop systems up to 10 kW under PM-Surya Ghar scheme	In-force
APERC [Planning, Procurement, Deployment, and Utilisation of BESS] Regulations (Andhra Pradesh Electricity Regulatory Commission, 2025b)	Establishes a comprehensive regulatory framework for the deployment of BESS. Enables aggregation of BESS resources, including DRE sources integrated with BESS, to provide services to state utilities	In-force

3. Methodology

The study methodology was developed in close consultation with APEPDCL, which provided details of six feeders—two each from the residential, commercial, and industrial categories. From these, two representative 11 kV feeders in Visakhapatnam city (Zone 2) were selected: Hobel Belows (HBL), an industrial feeder, and Kurmannapalem (KRPM), a residential feeder. The feeders were selected based on the number of distribution transformers (DTs) connected and feeder length.

Following feeder selection, the study methodology involved the following steps:

- **Physical survey and data collection:** The project team conducted a detailed field visit for each feeder, traversing the network from the supply substation to every connected DT and capturing the geocoordinates of the substation and DTs. This was done to validate the feeder details shared by the corporate office and capture missing data. At the substation, parameters including voltage levels, transformer capacity, peak demand periods, and conductor ampacities were recorded. The conductor type and approximate span for both 11 kV feeders were recorded, along with the make and rated capacity of each connected DT. DT-wise consumer monthly consumption data (kWh) and hourly feeder loading data for financial year (FY) 2025 were collected from the corporate and section offices.
- **Network modelling:** Following the field survey and data collection, the selected distribution feeders were modelled in DIgSILENT PowerFactory power simulation software to develop a digital representation of the network under consideration. The network model comprised the distribution substation (33/11 kV), power transformers, selected 11 kV feeders, associated DTs, and interconnecting line conductor elements up to the DT level. The electrical ratings and technical specifications of the power transformers, DTs, and conductors were incorporated into the model based on field and utility data. The aggregated consumer demand at each DT was represented as a lumped load connected to the corresponding DT busbar. A detailed quasi-dynamic load-flow analysis was then performed.
- **Estimation of DT-level loads:** The hourly load profiles at each DT-level served as an important input to the load-flow analysis. However, as this data was not available from the utility because the DTs were unmetered, each DT was assumed to follow the same hourly load pattern as its respective feeder. The hourly load profile for each DT was therefore derived by apportioning the feeder's annual energy consumption in proportion to its monthly energy share. Thus, the feeder's hourly load was proportionally allocated to each DT based on its energy consumption share to generate the DT-wise 8,760-hour load profile.
- **RTPV potential assessment:** To assess the impact of RTPV, it was essential to calculate the overall RTPV potential of the residential buildings served by the selected feeders. For this, high-resolution aerial imagery covering the entire feeder service area was utilised. Using solar geometry algorithms and a multi-criteria assessment approach, the RTPV potential of individual buildings was estimated after accounting for shading effects from adjacent buildings, trees, utility poles, and other surrounding obstructions. The estimated building-level RTPV potential was subsequently aggregated and spatially mapped to the corresponding DT service areas based on geographic boundaries, enabling DT-wise and feeder-wise assessment of the available RTPV potential.
- **Scenario analysis:** The following scenarios were analysed to assess the technical impact on the grid:
 - » Business-As-Usual (BAU) 2025: The existing system performance was analysed,
 - » BAU-2030: System performance was analysed with anticipated load growth for the feeders under the existing grid infrastructure, thereby capturing the system

reinforcement requirements. Load growth was estimated using historical data, applying a compound annual growth rate (CAGR) of 3.3% and 2.1% for the industrial and residential feeders, respectively, for FY 2030.

- » BAU-2030 with RTPV: RTPV was modelled at each DT to analyse system performance and assess its impact.
- » BAU-2030 with RTPV+BESS: RTPV was coupled with BESS to analyse system performance.
- **Financial impact assessment:** The financial implications of RTPV adoption were computed for both DISCOMs and end consumers.



4. Feeder Profile and RTPV Potential Assessment

During the survey, it was observed that most DTs in the two selected feeders were not metered. As actual loading (in kW) and energy consumption (in kWh) data for the DTs are vital for load flow analysis, the team computed the required details using DT-wise consumer tagging and month-wise consumption data from the DISCOM's master billing database. Additionally, the team manually recorded hourly feeder demand readings from the utility's logbooks. These data captured the seasonal and diurnal variability of demand on each feeder and were used to identify the peak demand period. Representative field survey photographs involving the CSTEP team and DISCOM officials are presented in Figure 1. The feeder profiles of the selected feeders are provided in Table 2.

Figure 1: Sample photographs captured during the field survey



Table 2: Characteristics of the selected feeders

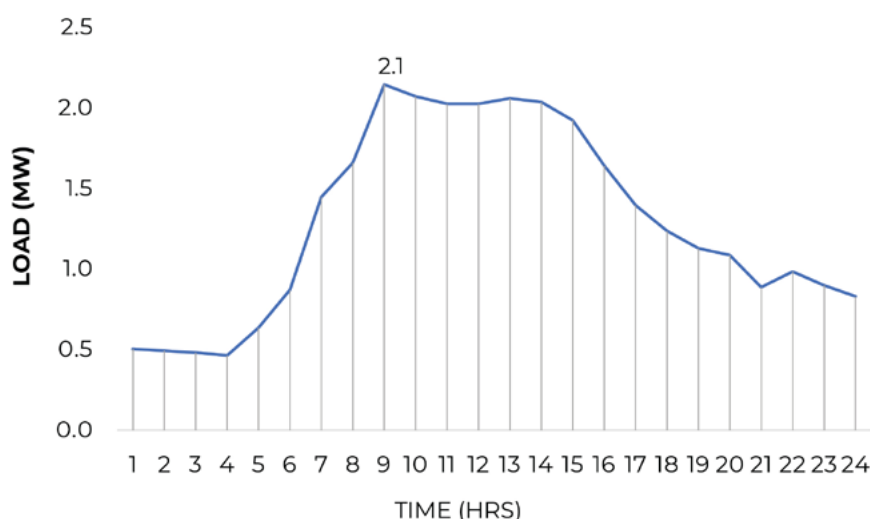
Particulars	Feeder details	
Substation (33/11 kV)	Visakhapatnam Special Economic Zone (VSEZ)	Vadlapudi
Feeder name	HBL	KRPM
Feeder load type	Industrial	Residential
Feeder make	All-Aluminium Alloy Conductor (AAAC)	Aluminium Conductor Steel Reinforced (ACSR)
Rated current and capacity	175 A, 3.2 MW	175 A, 3.3 MW
Feeder length	9.6 km	8.3 km
Feeder load	2.9 MW	9.6 MW
Feeder annual consumption	6.5 MUs	11 MUs
No. of DTs	23	55
Summation of the DT transformation capacity	3.05 MVA	5.7 MVA
Peak-demand / Hour	2.1 MW / (29 April 2024, 9.00 a.m. IST)	3.3 MW / (29 May 2024, 9.00 p.m. IST)

The DT-wise load profile assessment of the selected feeders is presented in detail in Appendix 8.1.

4.1. HBL industrial 11 kV feeder

The HBL feeder emanates from the VSEZ 33/11 kV substation, comprising (8 × 1) MVA and (5 × 1) MVA power transformers operating in parallel mode. The feeder has a total of 23 DTs connected to it. Of these, 16 DTs supply small-scale industries, while seven are dedicated to heavy industries based on their sanctioned capacity. The feeder's hourly load profile for the peak day is shown in Figure 2. The 8,760 hourly load profile of the feeder recorded in FY 2025 is provided in Appendix 8.3.

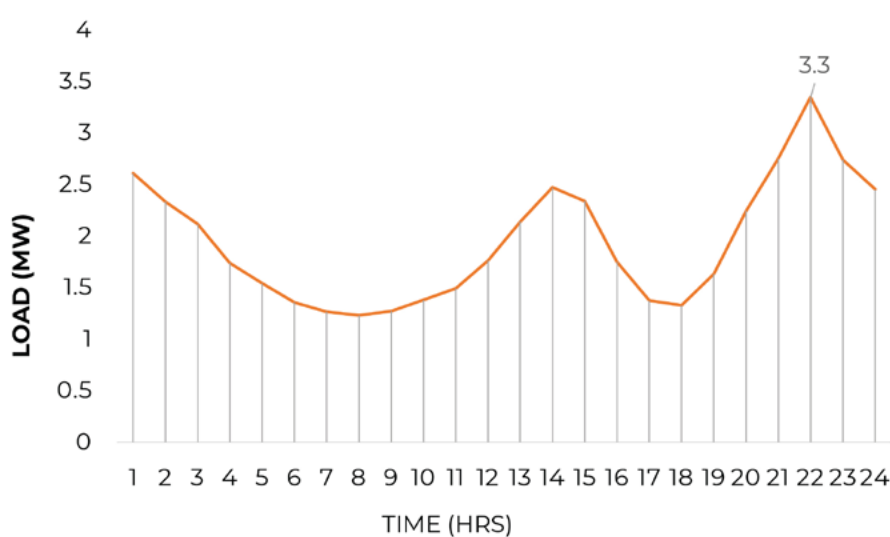
Figure 2: Peak-day hourly load profile of the HBL industrial feeder



4.2. KRPM residential 11 kV feeder

The KRPM feeder emanates from the 33/11 kV Vadlapudi substation, comprising (8 × 1) MVA and (5 × 1) MVA power transformers. The feeder predominantly supplies residential consumer bases through its 55 DTs. Its hourly load profile for the peak day is shown in Figure 3. The 8,760 hourly load profile of the feeder recorded in FY 2025 is provided in Appendix 8.5.

Figure 3: Peak-day hourly load profile of the KRPM residential feeder



4.3. RTPV potential assessment

When assessing the impact of large-scale RTPV integration on a distribution feeder, the DISCOM should evaluate not only the feeder's capacity to accommodate RTPV systems but also the available rooftop potential, including the feasible RTPV capacity and its spatial distribution across the feeder. Effective RTPV planning therefore lies at the intersection of two complementary assessments:

- Technical hosting capacity of each DT, determined through network modelling, and
- RTPV potential available within the corresponding DT service area.

These two factors do not necessarily align. For example, a DT may possess sufficient hosting capacity but have limited rooftop area suitable for deployment, while another DT may have abundant rooftop potential but insufficient network capacity to accommodate RTPV. Without quantifying RTPV potential at the DT and feeder levels, network planning risks either underutilising available infrastructure or investing in upgrades where deployable potential is limited.

Accordingly, the RTPV potential assessment was designed to support DISCOM decision-making across three phases:

- **Phase 1 (Immediate)** – Align DT-level hosting capacity with available RTPV potential to identify technically feasible deployment opportunities.
- **Phase 2 (Prioritisation)** – Rank rooftops within each DT service area based on technical feasibility and potential, enabling targeted consumer outreach and programme implementation.
- **Phase 3 (Long-term)** – Identify clusters of high rooftop solar potential to support the development of dedicated RTPV corridors, allowing future distribution networks to be planned around concentrated deployment zones rather than accommodating rooftop systems incrementally across the existing grid.

To estimate the RTPV potential in this study, high-resolution satellite imagery covering the entire service area of each selected feeder was analysed. Solar geometry algorithms were applied at the individual building level, together with a multi-criteria assessment that accounted for real-world constraints such as shading from buildings, trees, utility poles, and other obstructions.

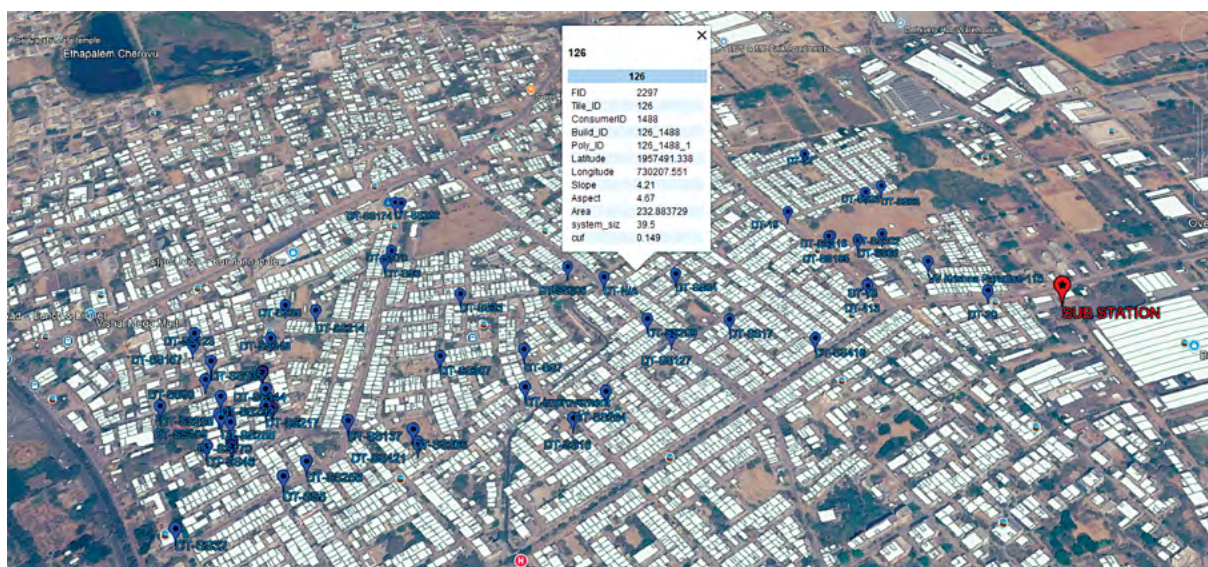
Building-level assessment is essential because feeder- or DT-level averages can mask significant variations in the usable solar potential of individual rooftops. Capturing this spatial variability enabled the identification and prioritisation of the most suitable rooftops for deployment. The estimated building-level potential was subsequently aggregated and spatially mapped to the corresponding DT service areas based on geographic boundaries, generating DT-wise and feeder-wise RTPV potential datasets aligned with the operational scale at which DISCOMs plan, operate, and strengthen their distribution networks.

An estimated total deployable RTPV potential of approximately 56 MW was identified across the HBL feeder and 112 MW across the KRPM feeder. The spatial distribution of this potential is illustrated in Figures 4 and 5, respectively. The RTPV and BESS configurations considered and modelled in the simulation software are described in detail in Appendix 8.2.

Figure 4: RTPV potential mapping – HBL industrial feeder



Figure 5: RTPV potential mapping – KRPM residential feeder





₹

₹
₹
₹

+ 11.38

+ 7.12

+ 7.00

+ 6.01

+ 6.92

+ 5.56

+ 1.75

+ 1.54

+ 2.43

₹ ₹

5. Scenario Analysis and Results: Technical and Financial Impacts

5.1. Technical performance

5.1.1. HBL industrial feeder: Network performance assessment

Load-flow analysis was performed for the HBL industrial feeder under three scenarios to assess current network adequacy, future stress under load growth, and the mitigating effect of distributed solar integration:

- 1. BAU-2025 (Baseline):** Existing system performance was evaluated under present demand conditions.
- 2. BAU-2030 (Load growth, no RTPV):** Projected DT-wise demand with 3.3 % CAGR, based on historical demand. Feeder network performance was assessed under projected load growth to identify reinforcement requirements.
- 3. BAU-2030 with RTPV (Mitigation scenario):** RTPV was modelled at DTs using peak-hour generation profiles (29 April 2029, 9:00 a.m. IST) to evaluate the extent to which solar integration offsets the reinforcement needs identified under the BAU-2030 scenario.

All simulations were benchmarked against the reference peak-demand hour, with DT thermal loading limits of $\leq 90\%$ and statutory voltage limits applied as performance thresholds.

5.1.1.1. Results

BAU-2025: In this scenario, the DTs of the HBL industrial feeder show early signs of voltage stress during the peak hour. Out of the seven DTs serving dedicated loads (high-tension [HT] services), one DT operates at the highest loading of 87%. The 14 DTs serving small-scale industries are loaded in the range of 80%–82%, indicating that they are operating at elevated utilisation and approaching the 90% threshold. Feeder loading, however, remains moderate at around 62% of rated capacity. Voltage drop along the radial feeder is nevertheless evident: 10 of 49 buses, concentrated at the tail end of the feeder, operate in the 0.93–0.94 per unit (p.u.) range, which is typical of radial voltage-drop behaviour. The single line diagram (SLD) and network performance during the peak-demand hour are illustrated in Figure 6.

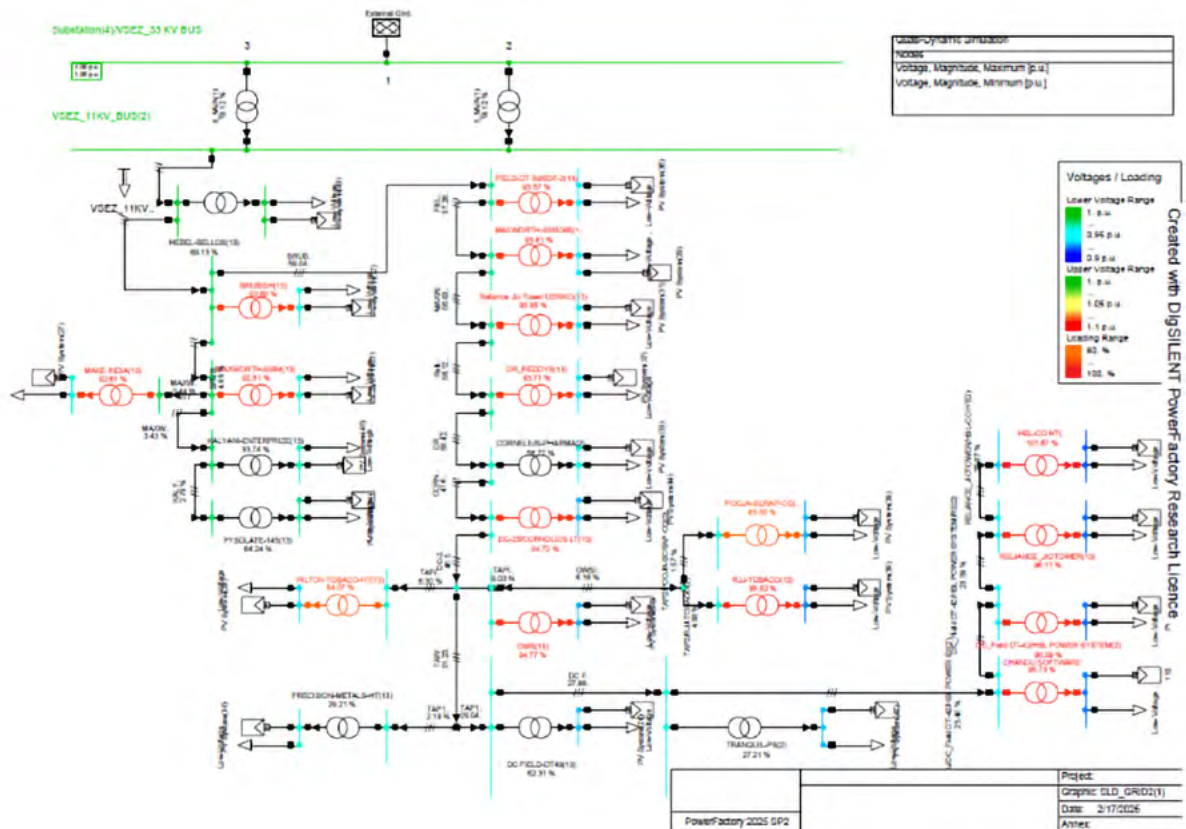
BAU-2030: This scenario indicates that load growth places additional strain on the network elements. Feeder loading increases to 74%, although it remains within the permissible thermal limits. The feeder experiences undervoltage conditions, with the number of undervoltage buses (0.92–0.94 p.u.) increasing from 10 to 16. The dedicated DT serving the HT consumer (750 kW contract demand) reaches 104% loading, requiring revisions to its contract capacity and transformer augmentation. The DTs catering to small-scale industrial demand show signs of overloading risk: 14 DTs record loading $\geq 90\%$, while three DTs fall in the 80%–90% range.

BAU-2030 with RTPV: In this scenario, integrating RTPV at the DT level substantially reduces the network stress identified under the BAU-2030 scenario. The HT service DT loading reduces from 104% to 78%, falling within permissible limits, while the remaining DT loading is in the 21%–74% range. Feeder loading reduces to 55%—the lowest across all three scenarios—confirming that localised generation reduces network stress. Voltage performance also improves, with the number of undervoltage buses reducing from 16 to five. Network losses (active/reactive), which increased from 2%/5% in 2025 to 3%/11% in the 2030 base case, reduced to 2%/6% with RTPV, demonstrating that distributed generation

can both defer capacity augmentation and restore network efficiency to near-baseline levels.

The consolidated network performance assessment under the three scenarios is summarised in Table 3.

Figure 6: HBL industrial feeder – SLD and system performance, BAU-2025 (peak-demand hour)



Corresponding SLDs for the BAU-2030 and BAU-2030 with RTPV scenarios are provided in Appendix section 8.6.

Table 3: Consolidated network performance – HBL industrial feeder

Parameter	BAU-2025	BAU-2030	BAU-2030 with RTPV
Maximum DT loading (HBL HT service)	87%	104%	78%
DT loading range	15%–87%	15%–104%	21%–74%
No. of DTs >90% loading	0	14	0
No. of DTs within safe limits ($\leq 90\%$)	23	9	23
Maximum feeder loading (11 kV)	62%	74%	55%

Parameter	BAU-2025	BAU-2030	BAU-2030 with RTPV
Critical feeder section	Substation – HBL HT service		
Voltage range (p.u.)	0.93–0.99	0.92–0.99	0.93–0.99
No. of undervoltage buses (≤ 0.94 p.u.)	10	16	5
Active power losses	2%	3%	2%
Reactive power losses	5%	11%	6%
Overall network condition	Thermally adequate; mild voltage stress	Transformer overloaded; widening voltage-drop range	Overloading eliminated; losses and voltage restored near baseline

5.1.1.2. Key insights

- Load growth results in increased DT overloading, while feeder loading remains within the thermal limits of the conductor. This indicates that DT capacity is the binding constraint on network performance.
- RTPV integration is a technically effective alternative to conventional network reinforcement, deferring or avoiding transformer augmentation while improving voltage stability and system efficiency.

5.1.2. KRPM residential feeder: Network performance assessment

A quasi-dynamic time-series load-flow simulation was performed for the residential 11 kV KRPM feeder across all 8,760 hours, capturing both demand variability and RTPV-BESS intermittency. The following four scenarios were evaluated:

1. BAU-2025 (Baseline): Existing system performance was evaluated under present demand conditions.

2. BAU-2030 (Load growth without RTPV): Projected DT-wise demand with 2.4 % CAGR, based on historical demand. Feeder network performance was assessed under projected load growth to identify reinforcement requirements.

3. BAU-2030 with RTPV: RTPV was modelled at DTs using hourly generation profiles to evaluate the extent to which solar integration offsets the reinforcement needs identified under the BAU-2030 scenario.

4. BAU-2030 with RTPV+BESS: An instantaneous load-flow analysis was performed in which battery storage (RTPV: 4.4 MW; BESS: 1.11 MWh, 4-hour discharge) was sited at the overloaded DTs identified in the BAU-2030 with RTPV scenario, for the peak-hour (29 May 2029, 9:00 p.m. IST) to assess the effectiveness of BESS in addressing evening-peak constraints that remain unresolved by RTPV alone.

5.1.2.1. Results

BAU-2025: In this scenario, the DTs of the KRPM residential feeder show early signs of voltage stress during the peak hour. Nineteen DTs are loaded beyond the threshold limits (>90%), and feeder loading exceeded the thermal limits (>107% loading). Voltage drops (0.91–0.94 p.u.) are identified at 23 of 137 buses, concentrated at the tail end of the feeder, which is typical of radial voltage-drop behaviour. The SLD and network performance during the peak-demand hour are shown in Figure 7.

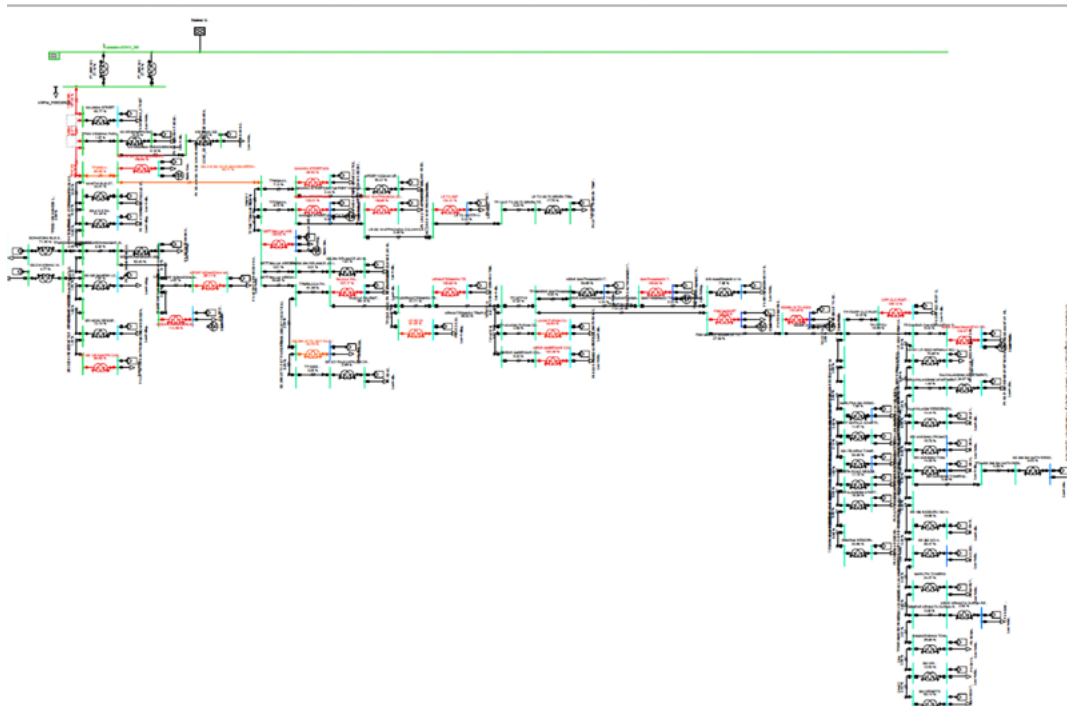
BAU-2030: This scenario indicates that the feeder is stressed under demand growth. Feeder loading increases significantly to 121%. The feeder experiences deteriorating voltage conditions, with a widening voltage-drop range (0.908–0.94 p.u.), and 27 elements experience undervoltage conditions. Twenty DTs are overloaded beyond threshold limits (>90%), while 2 DTs fall in the 80%–90% range. Thus, the network is clearly transitioning towards a combined feeder-loading and DT-overloading constraint.

BAU-2030 with RTPV: In this scenario, RTPV substantially offsets DT loading during daylight hours but offers no relief during the evening peak-demand period, when solar generation is unavailable. In addition, reverse power flow conditions (maximum export of ~2.7 MW vs maximum evening import of ~3.7 MW; reactive exchange of ~0.82 MVar) are observed in some cases, leading to an increase in current magnitudes and losses in certain sections, which can place stress on DTs not designed for reverse loading.

BAU-2030 with RTPV+BESS: This scenario demonstrates that BESS, sited at the 20 overloaded DTs, significantly reduces loading during the evening peak hours (7:00 p.m. to 10:00 p.m.), which RTPV alone was unable to mitigate. As a result, 14 of the 20 DTs are brought within the permissible operating limit (<90%), while six DTs remain overloaded. The voltage profile improves at the six undervoltage buses, reaching ≥ 0.94 p.u. System losses fall below BAU-2025 levels (active power loss: 1.9% in FY 2030 with BESS vs 2.9% in FY 2030 vs 2.3% in FY 2025; reactive power loss: 10.1% in FY 2030 with BESS vs 15.1% in FY 2030 vs 12.9% in FY 2025), reflecting better load balancing and reduced peak-hour losses. This confirms that RTPV+BESS is an effective intervention for managing evening peaks in residential feeders.

The consolidated network performance assessment under the four scenarios is summarised in Table 4.

Figure 7: KRPM residential feeder – SLD and system performance, BAU-2025 (peak-demand hour)



SLDs for the BAU-2030, BAU-2030+RTPV, and BAU-2030+RTPV+BESS scenarios, and the DT-wise BESS sizing/siting table, are provided in Appendix section 8.4.

Table 4: Consolidated network performance – KRPM residential feeder

Parameter	BAU-2025	BAU-2030	BAU-2030+RTPV	BAU-2030+RTPV+BESS
Maximum DT loading	160%	180%	~134% (peak hour; unchanged)	131%
No. of DTs >100% (critically overloaded)	14	19	19 (peak hour; unchanged)	3
No. of DTs loaded to threshold limit (91%–99%)	5	1	1	3
Maximum feeder loading	107%	121%	Reduced (daytime only)	83%, optimised
Voltage range (p.u.)	0.91–1.00	0.90–1.00	0.90–1.00 (evening peak); improved daytime	≥0.93 (all buses)
No. of undervoltage buses	23 (0.91–0.94 p.u.)	27 (0.90–0.94 p.u.)	27 (peak, unchanged)	21 (0.92–0.94 p.u.)
Daytime DT loading offset by solar	—	—	Up to ~80%	Up to ~80% (stored for peak use)
Maximum reverse power export / import	—	—	2.7 MW / 3.74 MW	Managed via BESS discharge
Active power loss	2.3%	2.9%	2.9% (peak, unchanged)	1.9%
Reactive power loss	12.9%	15.1%	15.1% (peak, unchanged)	10.1%
Power flow nature	Unidirectional	Unidirectional	Bidirectional (daytime)	Controlled bidirectional
Overall network condition	DT-overloaded; minor voltage stress	DT-overloaded; widening voltage drop	Daytime relief only; peak unresolved	Overloading eliminated; reduced losses, peak resolved

5.1.2.2. Key insights

- KRPM is a feeder- and DT-constrained, evening-peaking residential feeder. Its conductors are stressed at peak, and DT overloading acts as an additional binding constraint. Accordingly, both conductor reinforcement and DT augmentation are required.
- RTPV alone reduces daytime loading but is insufficient to address peak demand and introduces bidirectional power flow challenges. Integrating RTPV with BESS effectively mitigates these challenges while significantly improving the voltage profile, reducing system losses, and enhancing overall network performance. Thus, decentralised BESS at overloaded DTs need to be considered.

The findings reinforce a broader pattern where feeder-level RTPV integration must be evaluated alongside load-timing characteristics — RTPV is highly effective for daytime-peaking feeders, but evening-peaking feeders require storage to realise substantial benefits. Thus, RTPV reduces energy demand, while RTPV+BESS manages power—making the network reliable, efficient, and future-ready.

5.2. Financial impact assessment of RTPV integration on DISCOMs and consumers

One of the common concerns associated with RTPV adoption is revenue loss for DISCOMs, as high-paying consumers shift towards RTPV, leading to reduced sales. This assessment quantifies the impact for both consumers and DISCOMs under two scenarios: RTPV-only integration and RTPV combined with BESS. The objective is to equip DISCOMs with an evidence-based analysis for strategically targeting RTPV rollout across consumer segments.

5.2.1. Data collection and considerations

To carry out this assessment, consumer-level billing data, including connected load, DT-feeder mapping, monthly consumption, and billing components, were sourced from the management information system (MIS)-based billing reports for all 12 months of FY 2025. Two cases were analysed using two representative DTs of the KRPM residential feeder:

- **Case 1 (RTPV-only):** A 160 kVA DT serving 314 consumers (Categories I, II, and IV).
- **Case 2 (RTPV+BESS):** A 160 kVA DT identified as overloaded under the BAU-2030 with RTPV scenario, serving 184 consumers.

For both cases, consumers were segmented by monthly consumption into three slabs, with differentiated RTPV penetration assumptions reflecting realistic adoption patterns and technical hosting-capacity limits. The hosting capacity limit for the representative DTs is 122 kW ($160 \text{ kVA} \times 0.95 \text{ PF} \times 80\% \text{ loading constraint}$).

5.2.2. Financial impact assessment

Case 1: RTPV-only impact

The 314-consumer DT had an aggregated connected load of 855 kW and energy consumption of 56,179 units in April 2024, with gross billing of INR 4,12,950 based on APERC FY 2025 tariffs.

RTPV penetration was modelled as a percentage of energy consumed by consumers in their respective slabs:

- Slab 1 (0–225 units) at 65%
- Slab 2 (226–400 units) at 10%
- Slab 3 (>400 units) at 5%

This yielded an aggregate RTPV capacity of 121 kW, within the 122-kW hosting limit, generating ~17,370 units/month that are fully consumed locally, with no surplus export.

Because RTPV generation is fully consumed locally, with no export, the DISCOM incurs no Feed-in-Tariff (FiT) liability. The revenue lost through lower energy billing is almost entirely offset by avoided power purchase costs, making this a financially neutral outcome for the DISCOM, while consumers benefit from a ~24% reduction in their bills. The financial impact summary for Case 1 is presented in Table 5.

Table 5: Financial impact summary – Case 1

Parameter	Value
Gross billing, pre-RTPV	INR 4,12,950
Revised billing, post-RTPV	INR 3,14,227
DISCOM revenue reduction	INR 98,722/month
Avoided power purchase cost including transmission and distribution (T&D) loss (17,370 units × Average power purchase cost [APPC] INR 5.174)	INR 97,959/month
Net impact to DISCOM	+INR 764/month (near neutral)

Case 2: RTPV+BESS impact

This 184-consumer DT had a connected load of 297 kW, monthly consumption of 29,081 units, and gross billing of INR 1,71,450. Here, Slab 1 consumers were modelled at a higher 115% RTPV penetration (net-export capable), with Slabs 2 and 3 at 10% each, reflecting the DT's overloaded status and corresponding need for more aggressive solar offtake. The aggregate RTPV capacity was 122 kW, generating ~17,572 units/month, of which 2,095 units were exported as surplus.

This DT shows a stronger positive outcome than Case 1, as higher RTPV penetration generates proportionally greater avoided power purchase savings relative to the billing reduction. The financial impact summary for Case 2 with RTPV only is presented in Table 6.

Table 6: Financial impact summary – Case 2

Parameter	Value
Gross billing, pre-RTPV	INR 1,71,450
Revised consumer billing, post-RTPV	INR 1,08,074
Surplus energy exported	2,095 units
DISCOM FIT pay-out (INR 2.09/unit)	INR 4,378
DISCOM revenue reduction (net of FIT)	INR 58,997/month
Avoided power purchase cost	INR 94,724/month
Net impact to DISCOM (RTPV-only)	+INR 35,727/month

Adding BESS: The 2,095 units of surplus solar energy can be stored via an 83 kW/4-hour BESS instead of being exported to the grid. The stored energy can then be discharged during peak hours, avoiding the need to purchase power from the market at INR 7.5/unit (a cost of INR 15,712 if procured conventionally). Three ownership models were evaluated (Business Models of BESS, 2025) during the study. The details of the assumptions considered for various business models for BESS has been provided in Appendix 8.7.

Of the three models, only the Build-Own-Operate (BOO) model is marginally cost-positive; the Engineering-Procurement-Construction (EPC) and Build-Own-Operate-Transfer (BOOT) models result in net costs under the current levelised cost of supply assumptions. However, EPC may still be preferred where the DISCOM values direct operational control over marginal cost savings. The financial impact summary for Case 2 after BESS integration is presented in Table 7.

Table 7: Summary of financial implications of BESS integration

BESS model	Service cost (INR)	Charging cost (INR)	Net benefit vs Market purchase (INR)
BOO (Provider-owned)	11,103	4,378	+230
EPC (DISCOM-owned)	15,481	4,378	–4,148
BOOT (By provider to DISCOM)	39,840	4,378	–28,507

5.2.3. Strategic implications for RTPV targeting

Consumer energy intensity is the key variable governing both technical feasibility (hosting capacity) and financial outcomes (revenue impact) of RTPV adoption. This suggests a differentiated, slab-based targeting strategy rather than a uniform rollout:

Low-consumption (Slab 1) consumers: Encourages higher RTPV penetration. This maximises equitable access and, as shown in Case 2, can improve net DISCOM outcomes when paired with appropriate storage arrangements.

High-consumption (Slab 2-3) consumers: Considers moderated penetration limits to protect revenue and avoid reverse power flow issues at the DT level.

Overloaded or storage-equipped DTs: Where BESS is deployed, as in Case 2, higher Slab 1 penetration, including net export, becomes viable because surplus energy can be captured productively rather than placing strain on the network.

The financial implications across both cases are summarised in Table 8.

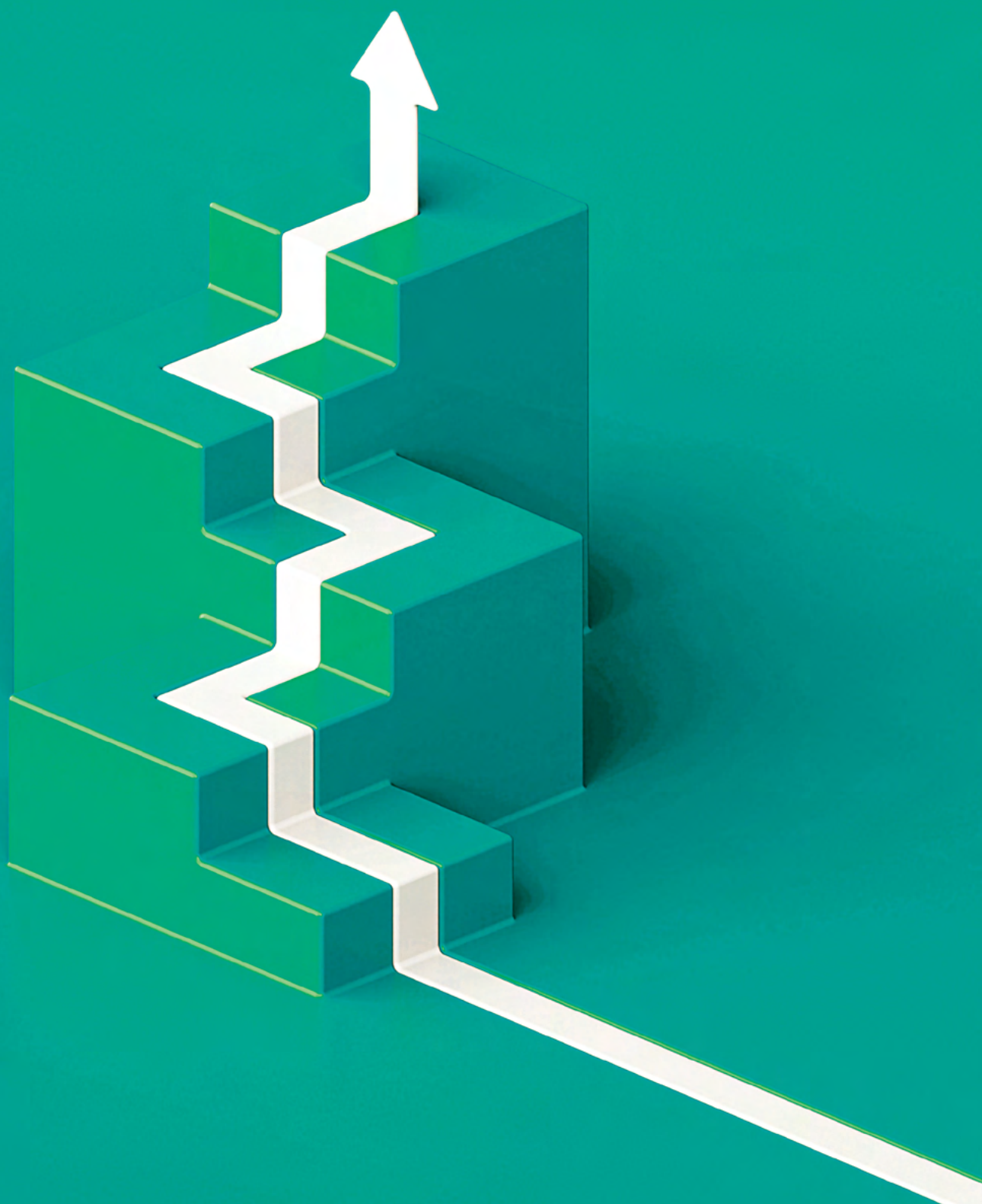
Table 8: Comparison of financial implications across all cases for RTPV deployment

Dimension	RTPV-only (Case 1)	RTPV-only (Case 2)	RTPV+BESS (Case 2)
Net DISCOM financial impact	+INR 764/month	+INR 35,727/month	+INR 230/month (BOO model, incremental)
Consumer bill reduction	~24%	~37%	~37% (unchanged by BESS)
Export/Fit exposure	None	INR 4,378/month	Internalised via storage
Overall verdict	Financially neutral	Net positive	Marginally positive only under BOO

5.2.4. Key takeaways

Across both cases, RTPV adoption does not erode DISCOM finances when modelled realistically. Avoided power purchase costs largely offset reduced billing revenue, and in higher-penetration scenarios, the DISCOM can see a clear net gain. BESS adds an additional layer of efficiency by monetising surplus generation, but its financial case is sensitive to the chosen ownership/business model, with BOO emerging as the only viable structure under the current cost assumptions.

These findings support the central conclusion that strategically targeted, slab-differentiated RTPV and, where applicable, RTPV+BESS deployment can be a financially sustainable pathway for the DISCOM and need not come at the cost of revenue stability, provided rollout is planned with consumer-level granularity rather than applied uniformly.



6. Recommendations and Way Forward

The assessment indicates that localised RTPV deployment integrated with BESS is the most effective solution for managing future challenges in Andhra Pradesh's distribution network. The integrated solution significantly reduces DT overloading, improves voltage profiles at downstream nodes, reduces active and reactive power losses, and mitigates the impacts of reverse power flow. By storing surplus solar energy during the daytime and discharging it during evening peak hours, BESS enables effective load shifting, thereby enhancing network reliability and operational flexibility while deferring conventional grid reinforcement requirements.

Further, the analysis shows that DISCOMs can minimise potential revenue impacts from increasing consumer participation through targeted RTPV adoption strategies based on consumer energy intensity, combined with suitable BESS business models. Such approaches can also reduce dependence on high-cost, short-term power procurement during peak periods.

Based on the findings of the study, the following strategic recommendations are proposed to enable reliable and large-scale integration of RTPV and BESS into Andhra Pradesh's distribution network. An implementation checklist for the proposed recommendations is provided in Appendix 8.8.

1. Establish digital distribution planning and decision-support systems

DISCOMs should develop a comprehensive digital data management framework comprising feeder- and DT-level operational datasets, including hourly feeder loading and DT demand profiles, to support load-flow studies, hosting-capacity assessments, and optimal RTPV-BESS planning. This should be complemented by DT-level smart metering, integrated technical-financial decision-support dashboards, and real-time network monitoring systems to enable data-driven planning, automated energy auditing, identification of network stress points, and informed asset planning for future grid modernisation.

2. Adopt technically informed RTPV planning and targeted deployment strategies

DISCOMs should transition from the existing first-come, first-served approach to hosting-capacity-based RTPV planning at feeder and DT levels. RTPV approvals should be guided by transformer hosting capacity, local demand characteristics, and cumulative penetration levels to prevent network saturation and reactive infrastructure augmentation. Further, targeted RTPV deployment should be promoted by encouraging higher penetration among low-consumption consumers while moderating adoption among high-consumption consumers. Industrial consumers should also be prioritised for RTPV deployment owing to their daytime load profile, which closely aligns with solar generation and minimises reverse power flow concerns.

3. Strengthen distribution network flexibility for higher DRE integration

To enhance grid reliability under increasing RTPV penetration, DISCOMs should integrate decentralised BESS at DT levels, particularly in residential networks where evening peak demand does not coincide with solar generation. Deployment of smart inverters with reactive power support should also be promoted to improve voltage regulation and reduce reactive power losses. These flexibility measures will help mitigate DT overloading, minimise network losses, and improve voltage support during peak operating conditions.

4. Develop dedicated RTPV-ready distribution corridors

DISCOMs should identify potential urban, industrial, and commercial zones with favourable daytime demand profiles for development as dedicated RTPV corridors. These corridors should be targeted to support higher RTPV penetration and minimise operational challenges.

5. Adopt a financially viable RTPV and BESS deployment strategy

DISCOMs should adopt strategically targeted RTPV deployment based on consumer energy intensity, complemented by decentralised BESS under viable business models such as BOO. This approach enables DISCOMs to maximise avoided power purchase benefits, maintain revenue neutrality, and support financially sustainable DRE integration.

6. Develop a regulatory framework for decentralised BESS deployment at DT level

DISCOMs should develop regulatory provisions to promote decentralised DT-level BESS deployment under financially viable business models, enabling effective utilisation of surplus RTPV generation, enhanced grid flexibility, and economically sustainable DRE integration.

Overall, the study demonstrates that a coordinated RTPV+BESS deployment strategy, supported by digital monitoring and targeted planning interventions, can significantly improve grid readiness for higher DRE penetration while ensuring operational reliability, financial sustainability, and long-term network resilience.



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8. Appendix

8.1. Load estimation and assumptions

After collecting the feeder profile details, hourly feeder and DT loading profiles are required to run the load-flow simulation for the selected feeders. The utility provided DT-wise monthly energy consumption (kWh), aggregated across all industrial consumers connected to each transformer, for the HBL industrial feeder.

Historical monthly DT-wise energy consumption data were used to develop demand projections based on the CAGR for each DT. Based on this analysis, the demand for the HBL industrial feeder and KRPM residential feeder is projected to grow at a CAGR of 3.3% and 2.4%, respectively, through FY 2030.

The feeders are metered, and data are recorded at the substations. However, the DTs were not metered, except for seven HT services equipped with DT meters in the HBL industrial feeder. Therefore, their peak-hour loading profiles (MW), which contributed to the cumulative feeder peak load, had to be estimated. For this purpose, the annual energy share of each DT was used as a weighting factor and applied to the feeder's peak-hour loading for the recorded peak day.

In the case of the HBL industrial feeder, two DTs, when allocated peak load based on energy share, exceeded their safe loading limits (e.g., >100% of kVA at power factor [PF] 0.95), which is not operationally realistic. Therefore, the peak loading of the seven HT services (1.48 MW) for April 2024 was subtracted from the feeder peak demand of 2.15 MW. The residual peak load was then allocated across the remaining 16 DTs in proportion to their annual energy consumption, followed by capping each DT at its safe loading limit through an algorithm-based iteration method. Any excess load was redistributed to uncapped DTs, with priority assigned to DTs with higher energy consumption, so that the total allocation matched the feeder peak load.

In the case of the KRPM residential feeder, the annual energy consumption share of each DT was used as a weighting factor and applied to the feeder's peak-hour load observed on the recorded peak day.

This approach enabled the assignment of connected loads to each DT in the simulation model and supported a realistic assessment of distribution network performance under peak conditions. This finding highlights the need for DT-level smart meters for real-time power flow assessment.

8.2. RTPV systems and BESS modelling

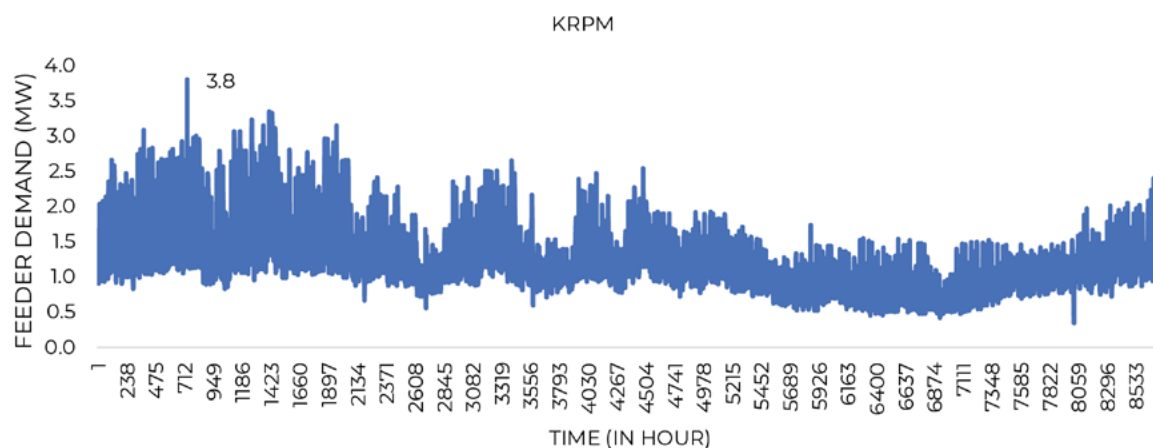
APERC has approved the APEPDCL's 'Modalities (Guidelines) for Implementing the Solar Rooftop (SRT) Policy, 2018', which imposes a technical constraint limiting the aggregate RTPV capacity connected at a DT to 80% of its rated capacity. In accordance with this provision, RTPV systems were modelled at the DT level by aggregating the installed capacities at each DT node, while ensuring that cumulative RTPV penetration did not exceed 0.8 p.u. of the respective DT rating.

Further, decentralised BESS were modelled at the DT level to mitigate anticipated overloading and reverse power flow conditions under future demand scenarios. The siting of BESS was determined based on time-series load-flow simulations, through which DTs exhibiting thermal overloading in projected scenarios were identified. For each such DT, an hourly co-analysis of RTPV generation and demand profiles was carried out using a nodal demand-supply balance framework, assuming a unity power factor. This approach enabled the quantification of surplus generation (i.e., reverse power flow) during peak solar injection periods, particularly under worst-case operating conditions.

The BESS sizing was subsequently derived by estimating the maximum surplus energy available for storage, assuming a fixed 4-hour discharge duration (i.e., an energy-to-power ratio of 4:1). The corresponding BESS power and energy ratings were back-calculated to ensure effective absorption of excess RTPV generation and mitigation of DT overloading.

8.3. KRPM residential feeder's 8,760 hourly load profile

Figure A1: KRPM residential feeder's 8,760 hourly load profile: FY 2025



8.4. SLDs of KRPM residential feeder under various scenarios

Figure A2: KRPM residential feeder: SLD and system performance of the network in BAU-2030 with RTPV scenario

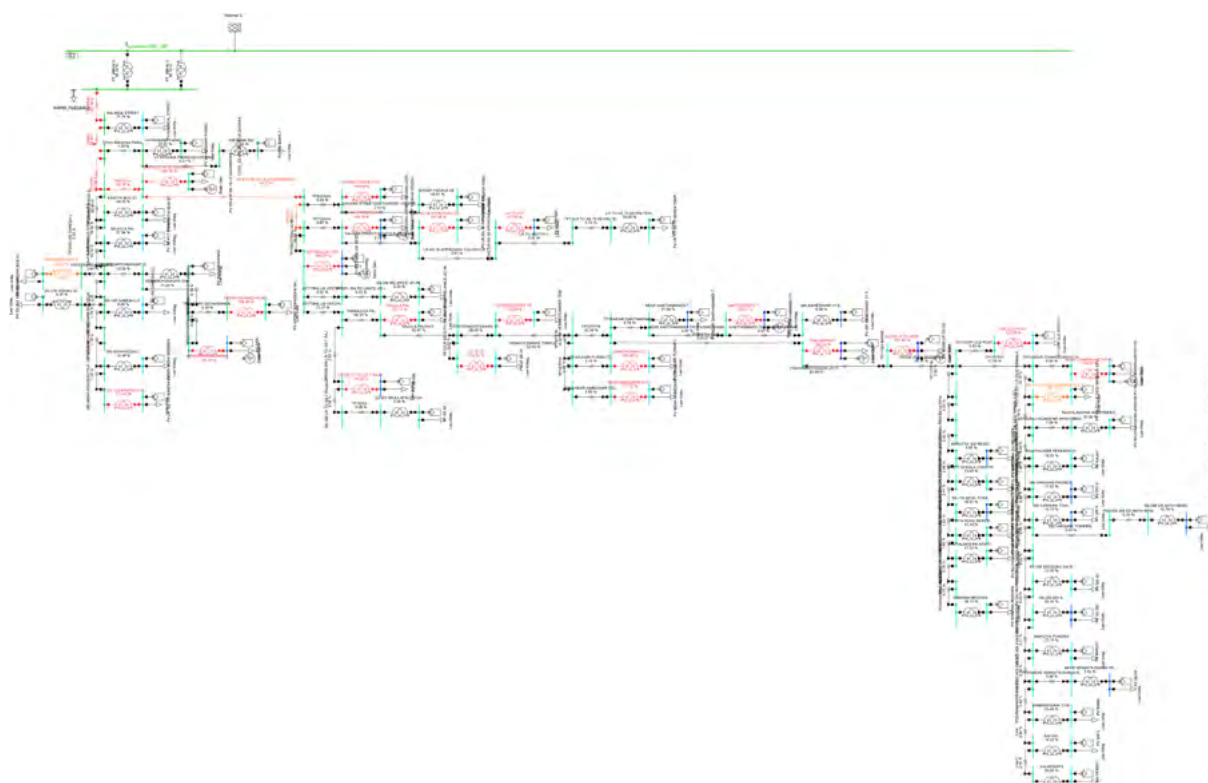


Figure A3: KRPM residential feeder: SLD and system performance of the network in BAU-2030 scenario

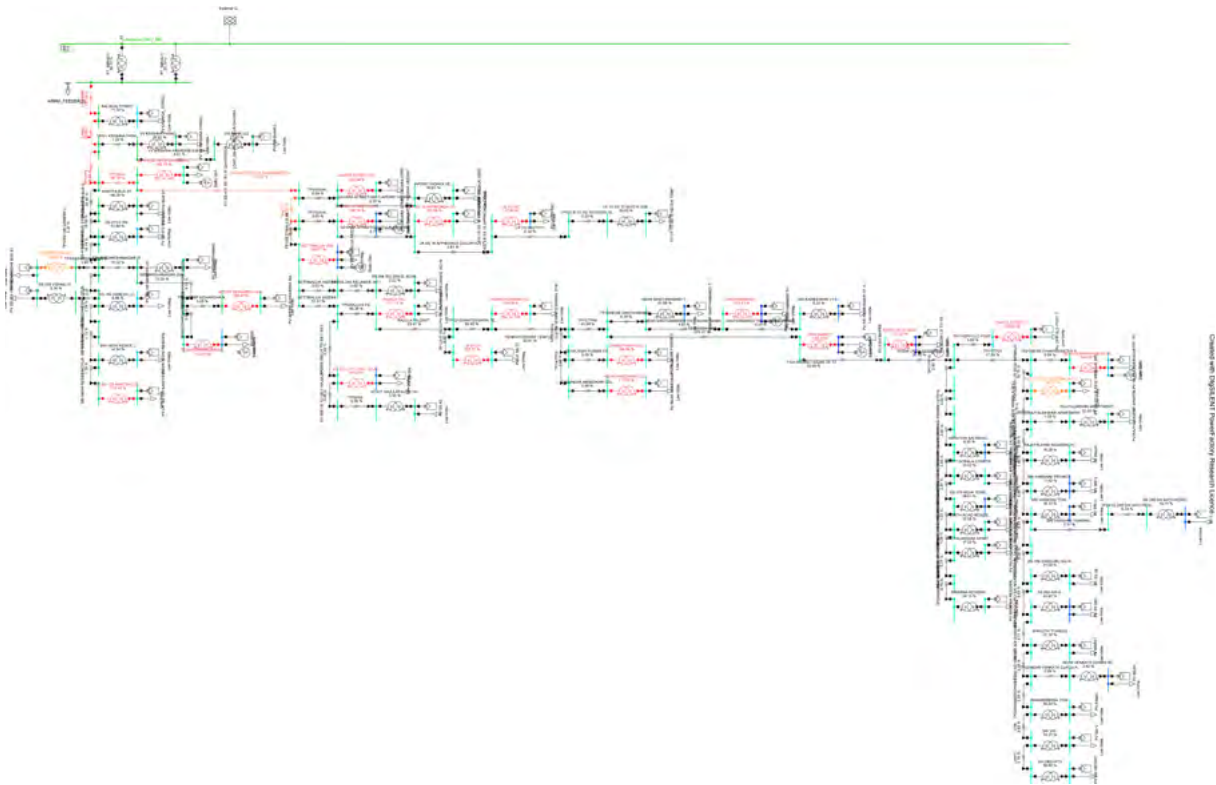
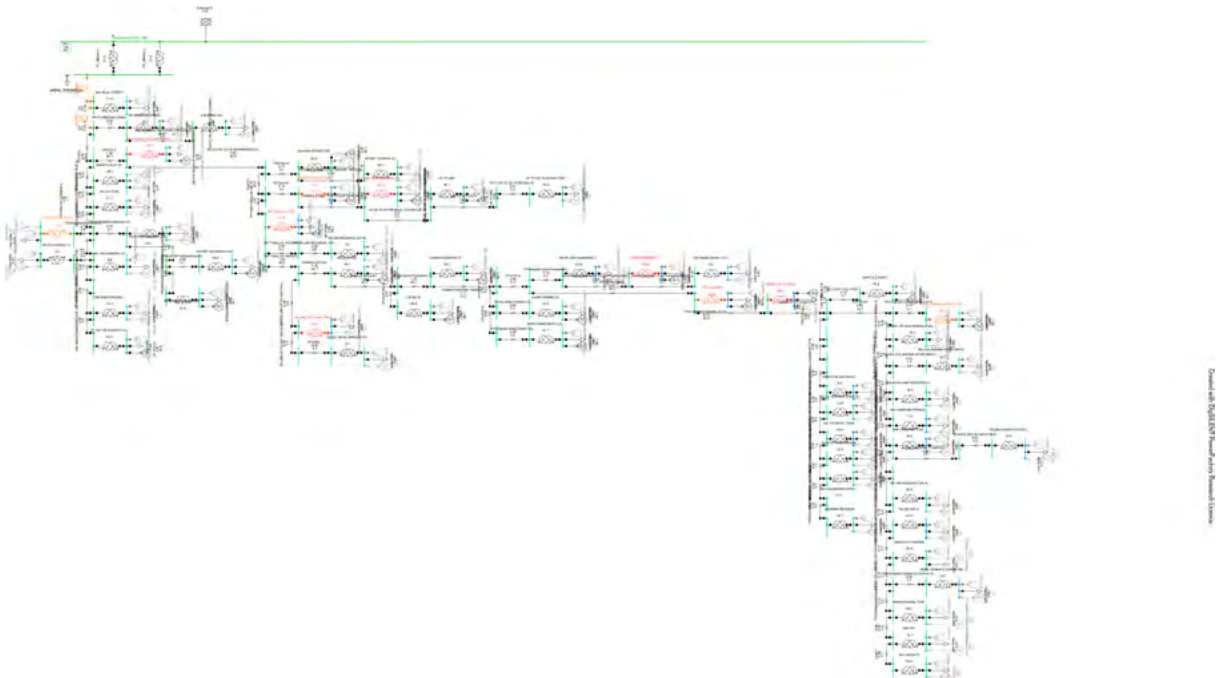
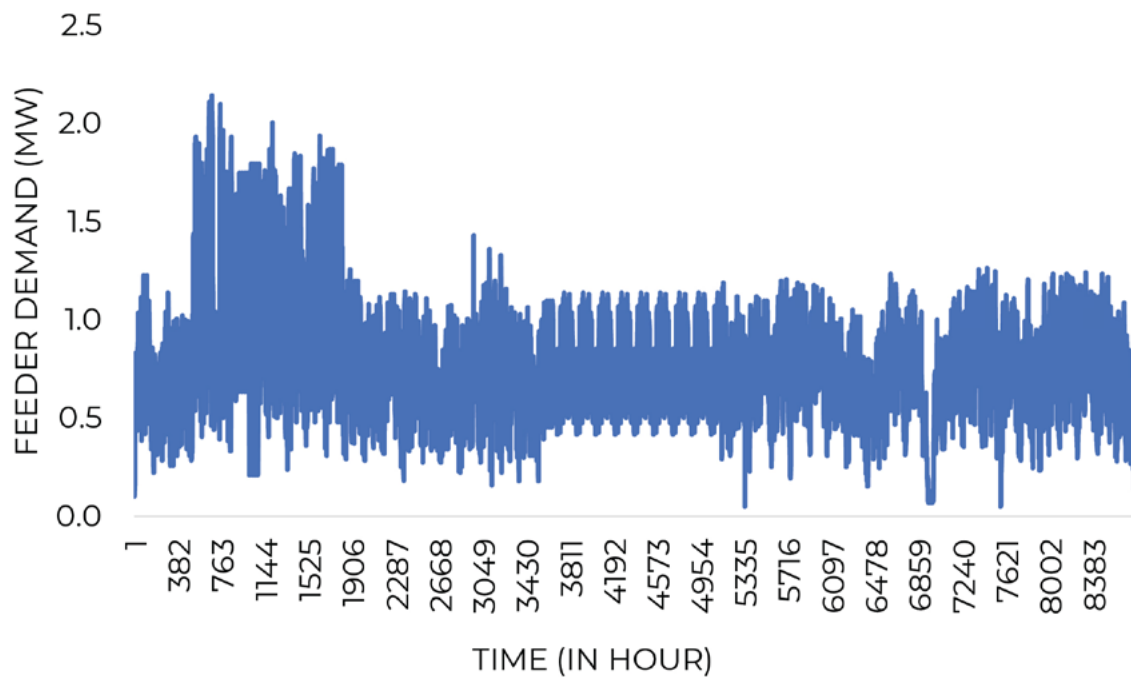


Figure A4: KRPM residential feeder: SLD and system performance of the network in BAU-2030 with RTPV+BESS scenario



8.5. HBL industrial feeder's 8,760 hourly load profile

Figure A5: HBL industrial feeder's 8,760 hourly load profile (MW)



8.6. SLDs of HBL industrial feeder under various scenarios

Figure A6: HBL industrial feeder: SLD and system performance of the network during peak hour in BAU-2030 scenario

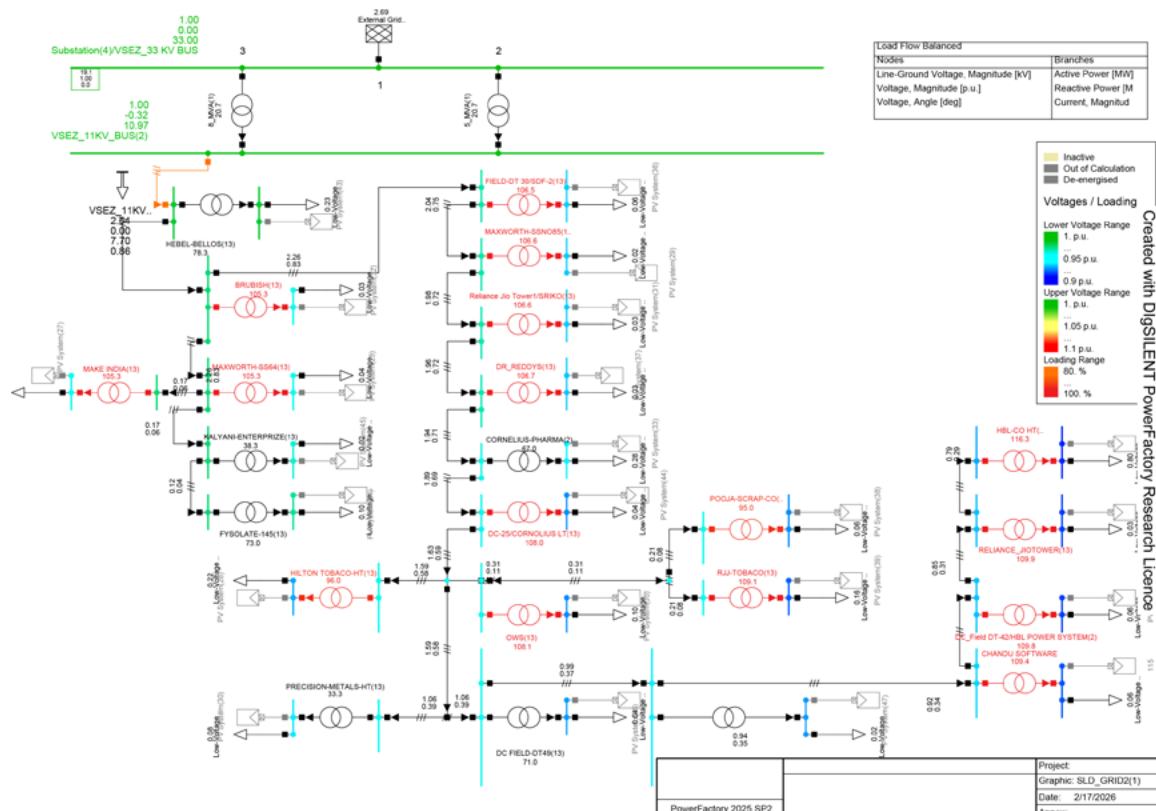
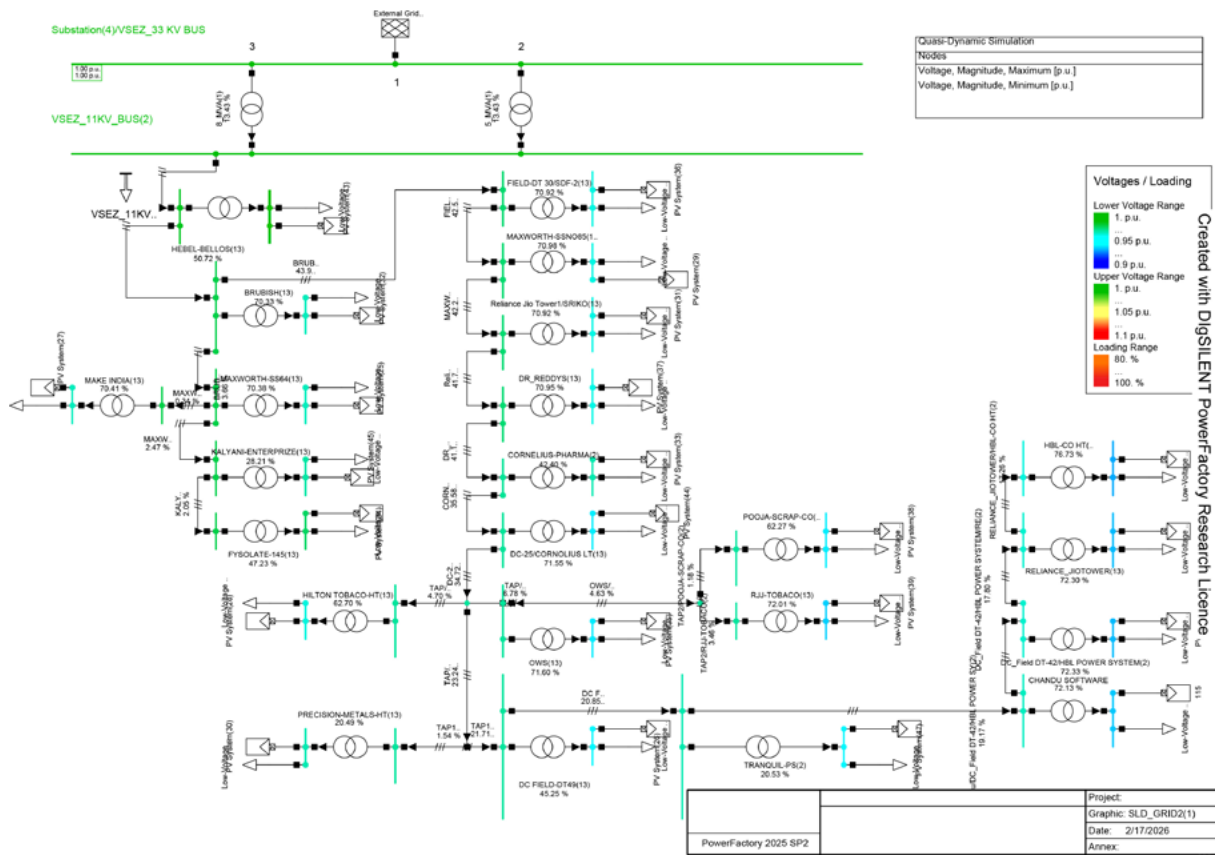


Figure A7: HBL industrial feeder: SLD and system performance of the network in BAU-2030 with RTPV scenario



8.7. Assumptions considered for various business models for BESS

Table B1: Data assumptions for financial assessment of BESS

Business model	Levelised cost of electricity	Remarks
BOO	5.3 INR/unit	5.1 to 5.6 INR/unit
EPC	7.8 INR/unit	7.5 to 8.1 INR/unit, with charging cost of 2.5 INR/unit
	7.4 INR/unit	7.5 to 8.1 INR/unit, with charging cost of 2.09 INR/unit
BOOT	4,80,000 INR/MW/month	57,60,000 INR/MW/year
Charging cost~ FiT	2.09 INR/unit	As per APERC orders, FY 2025
Market purchase cost	7.5 INR/unit	As per APERC orders, FY 2024

8.8. Implementation checklist for the proposed recommendations

Recommendations	Key action	Checklist item / Verification criterion	Responsible department / Officer
Establish digital distribution planning and decision-support systems	Build feeder/DT-level digital datasets and monitoring systems	- Feeder-DT data validation - Hourly feeder loading and DT demand profiles available - DT smart metering enabled - RTPV installations mapped to DTs - Digital planning/decision-support dashboard available - Network stress points identified through load-flow assessment	- Respective assistant engineer (AE) of each 33/11 kV substation - Commercial, Planning, and IT departments
Adopt technically informed RTPV planning and targeted deployment	Shift from first-come-first-served to hosting-capacity-based approvals. Encourage higher penetration among low-consumption consumers while promoting moderate adoption among high-consumption consumers	- Feeder- and DT-level hosting-capacity assessment - Cumulative RTPV penetration check - Voltage/loading/reverse-flow limits assessment - Consumer-category-wise deployment targets	- Solar cell - Commercial and Planning department - Operations and Customer Service department - Substation AE
Strengthen distribution network flexibility for higher DRE integration	Integrate DT-level BESS and smart inverter functions	- Identification of DTs with evening peak stress - BESS sizing and siting assessment, including charging/discharging profile optimisation - Smart inverter Volt-VAR capability assessment - Reactive power requirements evaluation - Verification of impacts on voltage, loading, and losses	- Planning department - Substation AE - Commercial department

Recommendations	Key action	Checklist item / Verification criterion	Responsible department / Officer
Develop dedicated RTPV-ready distribution corridors	Identify areas suitable for higher RTPV penetration	• Residential/industrial/commercial zones screening • Daytime demand profile assessment • Network hosting capacity verification • Identification of RTPV-ready corridors • Priority areas shortlisted for targeted deployment	• Commercial and Planning department • Substation AE
Adopt financially viable RTPV and BESS deployment strategy	Align DRE deployment with consumer economics and DISCOM benefits	• Consumer energy intensity assessment • Avoided power purchase benefits quantification • DISCOM revenue impact and neutrality assessment • RTPV-BESS combinations evaluation • BOO/other business models assessment • Financial viability assessment	• Operations and Customer Service department • Revenue Wing of DISCOM
Develop regulatory framework for DT-level BESS	Establish provisions for decentralised BESS deployment	• Define DT-level BESS eligibility criteria • Define financially viable ownership/business models • Establish BESS operation and dispatch framework • Define surplus RTPV utilisation mechanism • Assess tariff/settlement provisions • Identify regulatory approval requirements	• Regulatory Commission • Director of Operations and Projects

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