Smart ReStart

Simulation Roadmap

Prepared for SP ENW

Final report

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Executive summary

In this report, we present the findings from our time-series power flow analysis which was carried out to investigate the effectiveness of smart meter functionalities in supporting network operation during power system restoration following an outage, with a particular focus on mitigating Cold Load Pick Up (CLPU).

Three key smart functionalities were recommended in WP2 and assessed in this study:

1. Pre-set randomised offset: Randomised delays, which stagger customer reconnection following restoration;
2. Household load limitation: Temporary power limitation per household, which caps the maximum demand that can be drawn at any given time; and
3. Proportional load management via Auxiliary Proportional Control (APC): Gradual demand recovery following restoration rather than being fully restored instantaneously.

The analysis was performed on three different distribution network topologies representing urban, semi-urban, and rural areas, incorporating both ground-mounted and pole-mounted transformers. A set of restoration scenarios was defined for each topology based on three key factors: the timing of the cold start (peak or off-peak hours), the duration of the preceding outage, and the level of LCT uptake. These scenarios were consistently tested across all network models to enable comparison.

The key findings from our analysis are:

- Before evaluating smart meter functionalities, baseline power flow studies were conducted under normal operating conditions (i.e. without outages) for both partial and full deployment of LCTs. The results indicate that, in some cases, the existing network infrastructure may experience constraints at high levels of LCT uptake even under normal operating conditions. In such situations, network reinforcement (e.g., transformer uprating) may ultimately be required. However, decisions regarding the timing and extent of reinforcement would be determined by SP ENW in line with their established planning criteria, investment strategies, and DFES-aligned uptake scenarios. It should therefore be noted that smart meter-based mitigation measures during CLPU conditions are not intended to replace strategic network reinforcement, but rather to complement broader network planning approaches where appropriate.
- For scenarios in which restoration occurs during off-peak hours, particularly at night, the network is often able to tolerate the temporary increase in demand caused by CLPU without the need for smart meter intervention. While smart meter functionalities can still reduce overall system stress in these cases, they are not strictly necessary to maintain secure operation.
- Pre-set randomised reconnection delays were found to reduce peak loading and voltage stress by spreading demand recovery over time. However, in most stressed scenarios, especially those involving peak-time restoration or prolonged outages. This approach alone was insufficient to fully resolve network constraint violations.
- In contrast, the application of total load limits per household proved to be highly effective across almost all scenarios. By directly capping customer demand during the restoration

period, this functionality significantly reduced loading on lines and transformers, improved voltage performance, and, in many cases, prevented secondary outages caused by excessive demand.

- The APC-based approach also demonstrated benefits in most scenarios by smoothing the recovery of LCT related demand. However, its overall effectiveness was generally lower than that of a fixed total power limit per household, particularly in scenarios with severe loading conditions.
- The results indicate that Smart ReStart project can play a valuable role in managing CLPU. However, the effectiveness of different smart meter functionalities depends strongly on network topology, restoration timing, and the level of LCT uptake. Among the functionalities assessed, total load limitation per household emerges as the most robust and consistently effective strategy for reducing network stress and enhancing resilience during restoration.
- Nevertheless, to fully evaluate the potential, benefits, and economic implications of these solutions, from both the customer and network operator perspectives, further investigation is required. Two evidence gaps are presented below which have been recommended for the next phase of work;
    - Additional analysis focussed on identifying LCT penetration thresholds at which network reinforcement becomes necessary, as well as examining customer behaviour before and after outages. Such assessments would enable a more comprehensive understanding of the operational, economic, and societal impacts of these control strategies.
    - An assessment of customer impact, including implications for comfort, behavioural response, and acceptance of control strategies especially in the context of household load limitation and proportional load management (via APC)

Contents

1. Introduction

This section introduces the objectives and scope of the work package, outlining the purpose of the power-flow analysis and the modelling approach adopted.

1.1. Purpose of the work package

This work package focuses on assessing the impact of CLPU and demand recovery following outages in low-voltage (LV) distribution networks, with particular emphasis on the role of smart meter functionalities in mitigating network stress. To achieve this, a detailed power-flow analysis has been carried out using representative LV network topologies provided by SP Electricity North West (SP ENW). These network models are intended to reflect realistic operational conditions and asset configurations within GB distribution systems.

The primary objective is to evaluate how different smart meter functionalities identified in the Smart ReStart project can support network resilience during cold start events. The analysis considers multiple LV network topologies with varying characteristics, including configurations supplied by pole-mounted transformers and ground-mounted transformers, to capture a range of practical deployment scenarios.

A comprehensive set of operating scenarios has been developed and used as inputs to the power-flow model. These scenarios account for variations in outage duration, the time of day at which the cold start occurs, and different levels of uptake of Low Carbon Technologies (LCTs), such as electric vehicles (EVs) and heat pumps (HPs). The focus on these parameters is deliberate, as they are expected to have the most significant influence on the magnitude and temporal characteristics of CLPU events. By combining these factors, the work package aims to provide insights into the conditions under which different smart meter functionalities are most effective, as well as identifying potential network constraints and risks under worst-case demand recovery conditions.

Below is a description of the methodological approach:

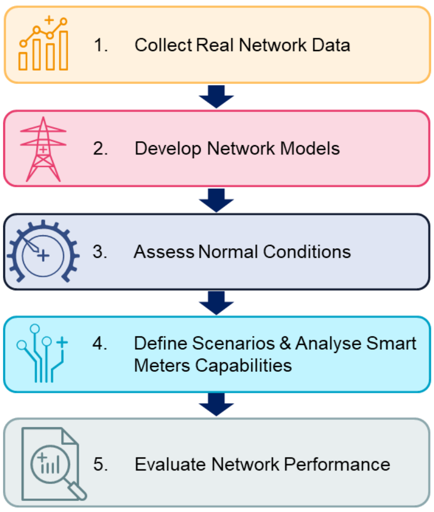


Figure 1 Methodological workflow illustrating the sequential steps of the analysis

Step 1: Collection of Real Network Data

To ensure that the analysis reflects real-world conditions, network data was provided by SP Energy Networks (SP ENW). The data represent different categories of low-voltage networks and include key characteristics such as network layout, asset types, and customer connections. Using real network information this ensure the study to be grounded in practical operating conditions rather than relying on purely theoretical models.

Step 2: Development of Network Models

Based on the information received from SP ENW, representative low-voltage network models were created. The modelling process accounted for the main physical characteristics of each network, including the type of transformer, feeder length, and connection arrangement. This step ensured that the simulated networks closely resemble those operated in practice.

Step 3: Assessment of Normal Operating Conditions

Before studying outage and recovery events, power-flow simulations were first carried out under normal operating conditions. These simulations establish a baseline understanding of how the network performs during typical operation, including voltage levels and asset loading. This assessment was repeated for different levels of LCT uptake, such as EVs and heat pumps, to understand their impact under normal conditions.

Step 4: Scenario Definition and Smart Meter Analysis

A range of outage and recovery scenarios was then defined, considering factors such as the duration of the outage, the time of day at which supply is restored, and different uptake levels of LCT's. For each scenario, power-flow simulations were carried out while applying different smart meter functionalities, to assess their influence on demand recovery and network performance.

Step 5: Evaluation of Network Performance

Finally, the results of the power-flow simulations were analysed using a set of predefined performance criteria. These criteria include voltage levels experienced by customers, loading of lines and cables, and loading of transformers. This step allows the identification of network constraints and enables comparison of the effectiveness of different smart meter strategies under a wide range of scenarios.

1.2. Modelling scope and assumptions

The scope of this work package is defined to ensure a clear and controlled assessment of cold start impacts while maintaining a manageable modelling complexity. Several assumptions and limitations have therefore been applied, as outlined below.

- All network topologies considered in this study are radial. Meshed LV configurations have not been included, as radial networks represent the most common structure in LV distribution systems and are generally more vulnerable to overloads and voltage issues during cold start events. Focusing on radial topologies also allows clearer interpretation of the impact of demand recovery and smart meter actions on individual feeders and transformers.
- The power-flow analysis in this work package was conducted under the assumption of a balanced system. This assumption was adopted to reduce modelling complexity and computational burden, while remaining appropriate for the scope of this study. As the primary objective was to assess overall network loading, voltage profiles, and transformer utilisation under varying LCT penetration and restoration scenarios, a balanced representation provides sufficient accuracy at the feeder level.

- In the network modelling, all residential customers supplied along a cable or overhead line are aggregated and modelled at the downstream end of the line. This represents a conservative, worst-case assumption, as it maximises power flows, voltage drops, and losses along the feeder. While this approach may overestimate localised impacts compared to a more spatially distributed load model, it ensures that the results provide an upper bound on network stress during cold start conditions.
- All houses connected to the same bus are assumed to follow identical demand profiles within each scenario. This simplification reduces model complexity and ensures consistency across simulations. Although real-world customer behaviour would exhibit some degree of diversity, this assumption again represents a conservative case by allowing simultaneous demand recovery at each bus. More heterogeneous demand profiles could be incorporated to better capture behavioural diversity and stochastic recovery patterns. Such an approach would enable a more detailed and realistic representation of customer behaviour, however, it will increase modelling complexity and computational requirements.
- The model assumes that all thermostatically controlled loads (heating systems, water heaters, refrigerators, etc.) and EV chargers restart simultaneously once power is restored. In other words, it is assumed that customers are not pre-prepared for outages. In particular, EVs and HPs are assumed not to be pre-charged or pre-heated prior to restoration of supply. As a result, their demand contributes fully to the post-outage recovery period. This assumption reflects a worst-case operational scenario, in which customer behaviour exacerbates CLPU effects and places maximum stress on LV network assets.
- The analysis does not explicitly account for the inherent randomised delays that may already be embedded within certain customer assets (e.g., heat pumps or EV chargers). These built-in diversity mechanisms, which can naturally stagger reconnection or restart behaviour, were not modelled in this study. As a result, the simulations represent a more conservative condition with higher demand coincidence during restoration. Incorporating asset-level randomisation in future work could provide a more realistic assessment of post-outage demand recovery characteristics.
- In this analysis, it is assumed that no on-site distributed generation or energy storage systems are present at the residential level. Specifically, rooftop photovoltaic (PV) systems and domestic battery storage are not considered in the modelling. This assumption allows the analysis to focus exclusively on the impact of load-driven demand, particularly under varying levels of LCT uptake and during post-outage recovery conditions. The exclusion of local generation and storage avoid additional operational complexity and ensures that observed network constraints are attributable solely to demand-side effects.
- Future studies could incorporate distributed generation and storage to assess their impact and sensitivity on post-outage network performance. However, the present scope deliberately focused on a conservative, demand-driven worst-case scenario. In practice, real distribution networks are likely to comprise a more heterogeneous mix of load profiles, distributed energy resources, and control behaviours, which would require a more advanced and detailed modelling framework. Such complexity was considered beyond the requirements of this stage of assessment.
- The sensitivity of the results to customer behaviour during and after the outage has not been analysed within the scope of this work package. All demand recovery was modelled based on a worst-case assumption, in which latent demand returns

immediately upon restoration without any customer intervention or behavioural diversity. Future work could explicitly investigate behavioural variability, including staggered manual reconnection, pre-heating or pre-charging strategies, and adaptive consumption patterns. Incorporating such factors would enable a more comprehensive assessment of post-outage demand dynamics and their influence on network performance.

- The simulations performed in this work package are based on a combination of network and demand data from established sources. The distribution network topologies are derived from representative low-voltage feeder models provided by SP ENW. Baseline residential electricity demand profiles are obtained from Elexon settlement data[1]. Heat pump demand profiles are based on outputs from the Peak Heat project[2], reflecting electrified heating behaviour under cold weather conditions. Electric vehicle charging profiles are informed by findings from the Electric Nation[3] and Cold Start[4] projects, providing insight into charging demand magnitude and temporal characteristics. The parameters used to model CLPU behaviour are adapted from the Cold Start project and applied consistently across all scenarios.

Overall, the scope and assumptions adopted in this work package are intentionally conservative. They are designed to stress-test the LV network under challenging conditions and to robustly evaluate the potential benefits and limitations of smart meter-based interventions during cold start events.

[1] Load Profiles and their use in Electricity Settlement - Elexon Digital BSC
[2] Peak Heat | ENA Innovation Portal
[3] Electric Nation - PoweredUp | ENA Innovation Portal
[4] Cold Start - UKPN Innovation

2. Modelling and Assessment Criteria

This section describes the modelling approach adopted in this work package, including the definition of cold start scenarios and the consumer demand profiles used as inputs to the analysis. It also outlines the assessment criteria applied to evaluate network performance under these scenarios.

2.1. Scenario Definition

The behaviour of distribution networks during a cold start event is highly dependent on a combination of demand conditions, outage characteristics, and the level of electrification across connected customers. For this reason, a structured set of scenarios is required to robustly assess network performance under both normal operating conditions and post-outage restoration. Scenario definition is particularly important in this project, as it focuses on the increasing uptake of LCTs, which are expected to significantly alter demand magnitude and temporal profiles at the LV level.

Before assessing CLPU impacts, it is essential to establish whether the existing grid topology can tolerate high penetrations of LCTs under normal (non-outage) operating conditions. In particular, the project examines whether the current network configuration can accommodate a scenario in which LCTs are deployed at all buses, representing a future state with widespread electrification. This provides an important baseline assessment, allowing any additional stresses observed during cold start conditions to be clearly attributed to CLPU effects rather than pre-existing network inadequacy.

To comprehensively capture the range of plausible operating conditions, scenarios are defined across three key dimensions: re-energizing timing, outage duration, and level of LCT deployment.

Re-energising Timing Scenarios

Two cold start timing scenarios are analysed, recognising that the impact of restoration depends strongly on the underlying demand level at the time of re-energisation.

- Off-Peak (Night-Time) Restoration: This scenario represents restoration during periods of typically low baseline demand, such as overnight hours. While general household demand is reduced, heating demand, particularly from heat pumps, may be elevated due to lower ambient temperatures.
- Peak-Time Restoration: In this scenario, restoration occurs during periods of high background demand, such as early evening, increasing the risk of thermal overloads and voltage limit violations.

Outage Duration Scenarios

The magnitude of the demand in the first few hours after re-energisation is strongly dependent on the duration of the preceding outage as shown in Figure 2. Longer outage durations result in significantly higher initial demand peaks, with the 24-hour outage scenario exhibiting the highest post-restoration load. As the outage duration decreases (from 24 h to 16 h and 8 h), both the peak magnitude and the rate of demand decay are reduced, indicating a lower level of accumulated deferred demand. In all outage scenarios, the demand gradually converges towards the baseline profile after several hours, suggesting that the cold load pick-up effect is transient. Two outage durations are examined to capture the effect of load recovery dynamics.

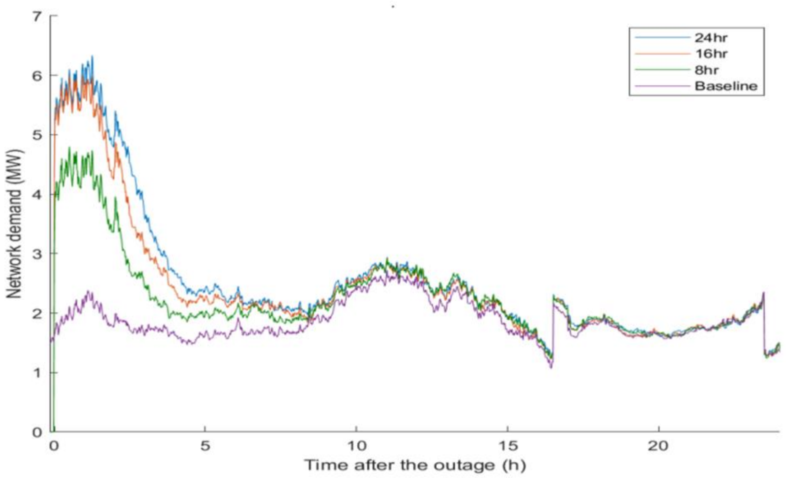


Figure 2 ***Graph showing how the outage duration can affect the network demand during a cold weather event [From Cold Start project[5]]***

- Short-to-Medium Duration Outage (8 Hours): This scenario represents a relatively short interruption where only limited deferred demand accumulates.
- Prolonged Duration Outage (24 Hours): This scenario represents an extended interruption that leads to significant cold load pick-up, particularly from heat pumps, posing a greater challenge during system restoration.

LCT Deployment Level Scenarios

Different levels of LCT deployment are considered to reflect varying stages of electrification across the network.

- Partial Deployment: 50% of the houses connected to each bus are equipped with LCTs, representing near-term or transitional adoption levels.
- Full Deployment: All houses (100%) connected to each bus have LCTs installed, representing a future high-electrification scenario and providing a worst-case assessment for network loading.

Based on these categories (shown in Figure 3), eight different scenarios are defined as below:

[5] Cold Start - UKPN Innovation

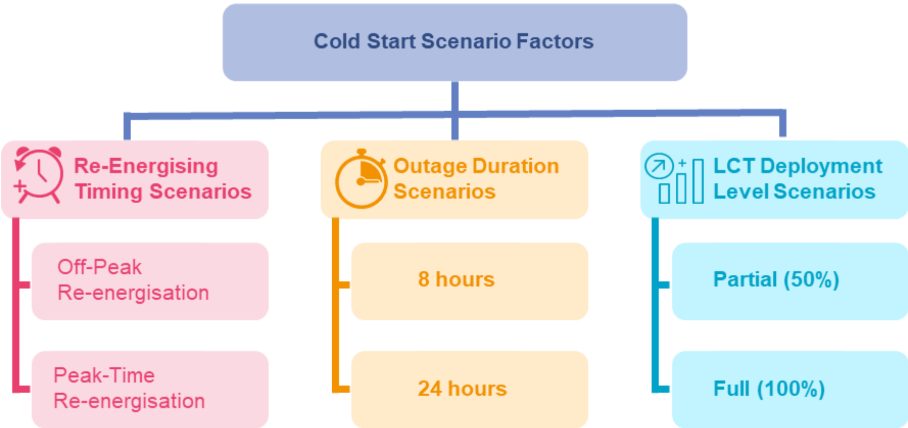


Figure 3 Cold start scenario structure

Table 1 Cold start's scenarios based on the timing, outage duration and the deployment of LCTs

Scenario ID	Restoration Timing	Outage Duration	LCT Deployment Level	Scenario Description
S1	Off-peak (night-time)	Short-to-medium (8 h)	Partial (50%)	Power is restored during off-peak hours following an 8-hour outage, with half of customers owning LCTs. CLPU is present but moderated by lower background demand and partial electrification.
S2	Off-peak (night-time)	Short-to-medium (8 h)	Full (100%)	Night-time restoration after an 8-hour outage with full LCT deployment. Although background demand is low, simultaneous recovery of heat pumps and EVs creates a noticeable CLPU impact.
S3	Off-peak (night-time)	Prolonged (24 h)	Partial (50%)	Restoration occurs overnight after a prolonged outage. Thermal inertia is lost, increasing heat pump demand, but impacts are limited by partial LCT penetration and off-peak timing.
S4	Off-peak (night-time)	Prolonged (24 h)	Full (100%)	Worst-case night-time CLPU driven by long outage duration and full LCT deployment. Significant rebound demand is expected despite lower base load conditions.
S5	Peak-time	Short-to-medium (8 h)	Partial (50%)	Peak-time restoration coinciding with normal high residential demand. Partial LCT uptake results in elevated loading and voltage stress during the recovery period.
S6	Peak-time	Short-to-medium (8 h)	Full (100%)	Peak-time reconnection with full LCT penetration following an 8-hour outage. High coincidence of base load and LCT

				recovery creates a severe CLPU scenario.
S7	Peak-time	Prolonged (24 h)	Partial (50%)	Restoration during peak hours after a prolonged outage. Heat demand dominates recovery, and even partial LCT deployment can lead to network constraint violations.
S8	Peak-time	Prolonged (24 h)	Full (100%)	Extreme worst-case scenario. Peak-time restoration after a 24-hour outage with full LCT deployment leads to maximum CLPU severity, representing the highest risk to LV network operation.

2.2. Load Definition

The total demand at each bus in the network is constructed by considering three distinct load components: baseline (background) residential demand (e.g. general appliances), EV charging demand, and HP demand. These load components are modelled separately and combined in different scenarios to reflect varying levels of electrification and operating conditions. This modular approach allows the individual and combined impacts of each load type to be clearly identified, particularly under normal operation and cold start conditions.

Under normal operating conditions, both the baseline residential load and the EV load exhibit a clear diurnal pattern characterised by two main peaks during the day. This behaviour is consistent with typical domestic demand profiles reported by Elexon[6]. As illustrated in the corresponding figure, the EV demand closely follows the baseline load profile, indicating that EV charging does not significantly alter the overall shape of the daily demand curve, but instead adds to the existing demand pattern.

In contrast, the heating load demonstrates markedly different behaviour. The heat pump demand profile exhibits multiple peaks throughout the day, reflecting the cyclic operation of heating systems and their strong dependence on external temperature conditions rather than occupant-driven daily routines. Consequently, the heating demand pattern is less aligned with the baseline and EV profiles and plays a dominant role in driving peak loads, particularly during cold weather and post-outage restoration.

2.2.1. Baseline Residential Load

For the baseline operating scenario, residential electricity demand profiles are derived from the Elexon load profile dataset. Elexon provides standardised half-hourly demand profiles representing the average usage patterns of different domestic customer classes. In this study, the profile corresponding to semi-detached houses with unrestricted tariffs is selected, as it is considered representative of typical residential customers connected to LV networks.

As defined by Elexon, a load profile represents the proportional distribution of electricity demand across each half-hour settlement period within a day and over the course of a year. The absolute magnitude of demand is determined separately. Based on information provided by SP ENW, the After Diversity Maximum Demand (ADMD) for domestic customers typically lies in the

[6] Load Profiles and their use in Electricity Settlement - Elexon Digital BSC

range of 1.0–1.4 kW. In this study, a conservative value of ADMD = 1 kW is adopted. The selected Elexon load profile is therefore scaled such that the peak household demand equals 1 kW, ensuring consistency with network planning assumptions while preserving the realistic temporal shape of demand.

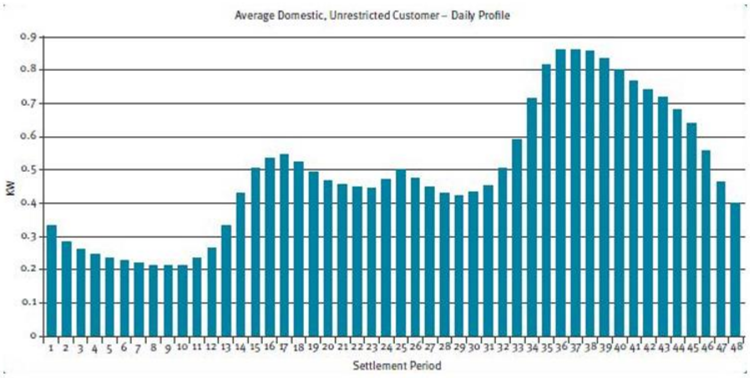


Figure 4 Baseload from Elexon for detached houses[7]

2.2.2. Electric Vehicle Load

The EV demand profile assumptions adopted in this study are informed by findings from the Electric Nation Project. Although the Electric Nation trials were conducted primarily at the feeder level, they provide valuable insight into the impact of increasing EV uptake on electricity demand, particularly with respect to demand magnitude and temporal characteristics.

Analysis in Report 1 of the Electric Nation Project indicates that the addition of EV charging load does not significantly alter the underlying daily demand shape[8] as shown in Figure 5. Instead, EV charging results in a relatively uniform uplift in demand across the day, corresponding to an approximate 20% increase compared to baseline domestic loads. This observation is consistent with findings from the Cold Start Project, which also reported that EV uptake tends to increase demand levels without fundamentally changing the diurnal demand pattern.

Based on these findings, EV uptake in this study is modelled as a proportional increase in household electricity demand. Specifically, the presence of EVs is represented by a 20% increase in per-house demand at each half-hourly time step. This approach preserves the original baseline load profile shape while capturing the additional loading imposed by EV charging, providing a realistic yet tractable representation of EV impacts for distribution network and cold start analysis.

[7] Load Profiles and their use in Electricity Settlement - Elexon Digital BSC
[8] Electric Nation - PoweredUp | ENA Innovation Portal

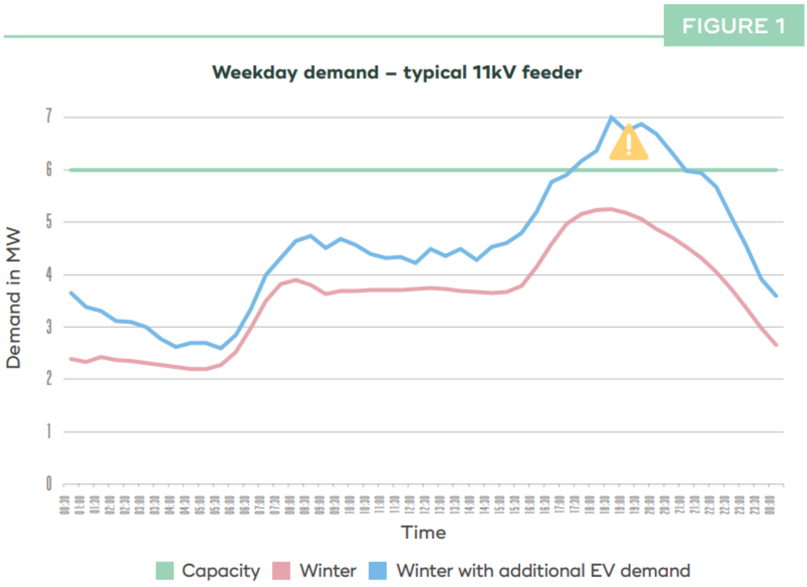


Figure 5 EV load profile from Electric Nation project[9]

2.2.3. Heat Pump Load

The heat pump demand profile is defined based on insights from the Peak Heat Project[10], which examined the impacts of domestic heat electrification on electricity distribution networks. The project demonstrates that widespread deployment of heat pumps can lead to substantial increases in both LV and MV peak loads, driven by the replacement of conventional heating technologies and changes in end-user demand behaviour.

A key conclusion of the Peak Heat Project is that heat pump demand profiles differ significantly from traditional domestic electricity loads, with peaks strongly influenced by different features including ambient temperature, building thermal characteristics, and heating system control strategies. The interaction between heat pumps, thermal storage, and diversity across customers plays a critical role in determining network impacts and may either exacerbate or mitigate peak loading.

Figure 6 illustrates the range of HP demand profiles considered in Peak Heat Project. The profiles are differentiated according to type of the building (in this case semi-detached), prevailing weather conditions (e.g., average and cold days), and occupancy status (occupied versus unoccupied). The figure highlights the variability in both the magnitude and temporal distribution of heat demand. Under colder weather conditions, peak demand levels are significantly higher and more sustained, reflecting increased space heating requirements. Similarly, occupied dwellings exhibit more pronounced and dynamic demand patterns compared to unoccupied properties, where heating demand is generally lower and more stable. For this study, the *occupied dwelling – cold weather* HP demand profile has been selected, as it exhibits

[9] Electric Nation - PoweredUp | ENA Innovation Portal
[10] Peak Heat | ENA Innovation Portal

the highest peak demand and therefore represents a conservative, worst-case scenario for network assessment.

Emphasis is placed on off-gas grid areas and new-build developments, which are expected to transition to electric heating earlier than other customer groups and therefore represent near-term challenges for network planning. The findings of the Peak Heat Project provide a robust evidence base for defining representative heat pump load profiles and support their inclusion in this study, particularly in the context of ED2 business planning and least-regrets investment decisions.

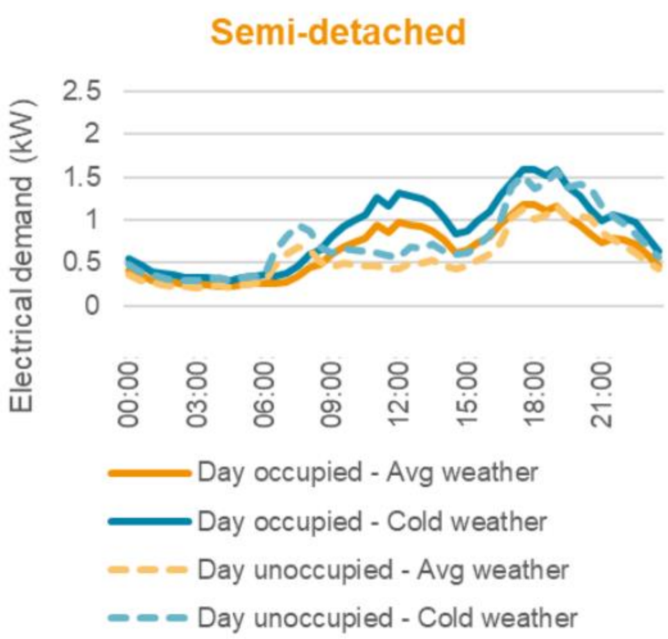


Figure 6 HP load profile from Peak Heat project[11]

Figure 7 presents the half-hourly residential demand composition under normal operating conditions, disaggregated into baseline (background) load from Elexon, EV charging demand, and heating demand. The stacked representation has been constructed using the data source mentioned previously (Elexon, EV Nation and Peak Heat) and highlights the relative contribution of each load component to the total demand over a 24-hour period. This figure illustrates how different load types contribute to overall network loading and motivates the need to consider load composition, rather than total demand alone, when assessing network performance and cold start behaviour.

[11] Peak Heat | ENA Innovation Portal

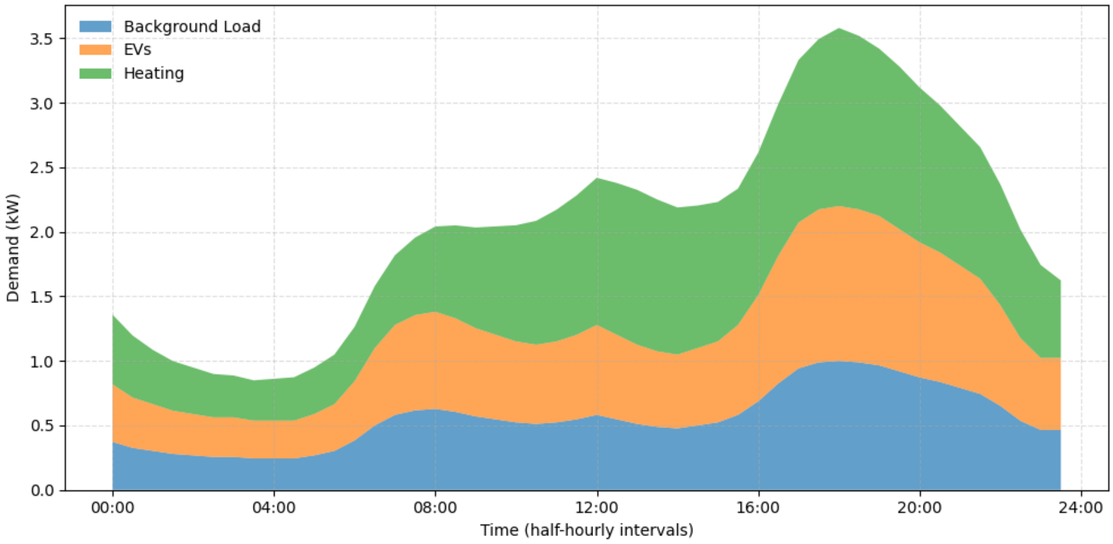


Figure 7 Power profiles per day derived from multiple data sources.

2.3. CLPU Modelling Approach

Following a prolonged outage, electricity demand during network restoration can exceed normal operating levels due to the coincident reconnection of thermostatically controlled loads and the recovery of deferred demand. This phenomenon, commonly referred to as CLPU, is particularly pronounced in networks with a high penetration of electric heating technologies, such as heat pumps. Accurately representing CLPU behaviour is therefore essential for assessing network performance, thermal loading, and voltage conditions during post-outage restoration.

In this study, the increase in demand observed during a cold restart is represented by applying a CLPU multiplier to the baseline residential demand profile following network re-energization. A widely adopted engineering approach is to model CLPU behaviour using a decaying exponential function, which captures both the initial surge in demand immediately after restoration and its gradual return to normal operating levels as loads recover and diversity is re-established.

The resulting post-restoration demand is expressed as:

$$P_{CLPU}(t) = P_{base}(t)\left(1 + k\,e^{-\frac{(t-t_0)}{\tau}}\right),\ for\ t \geq t_0$$

where:

$\boldsymbol{P_{base}(t)}$ is the baseline residential demand profile,

$\boldsymbol{t_0}$ is the time at which network re-energization occurs,

$\boldsymbol{k}$ represents the magnitude of the demand surge immediately following restoration,

$\boldsymbol{\tau}$ is the decay time constant governing the rate at which demand returns to normal operating levels.

The parameter k reflects the severity of the cold restart event and is influenced by several factors, including outage duration, ambient temperature, building thermal characteristics, and the composition of connected loads. Longer outages and colder weather conditions generally result in higher values of k, as a greater proportion of thermostatically controlled loads operate simultaneously upon restoration.

The decay constant τ represents the recovery dynamics of the system and determines how quickly demand returns to baseline levels. Typical recovery periods range from tens of minutes to several hours, depending on heating system controls, thermal inertia, and customer diversity. This formulation provides a flexible and transparent means of capturing CLPU behaviour across a range of outage scenarios while remaining computationally efficient for time-series power flow analysis.

To illustrate the influence of key modelling parameters on CLPU behaviour, a series of sensitivity analyses was conducted by varying the parameters of the exponential CLPU formulation and comparing the resulting demand profiles. Specifically, the effects of the restoration time (t_0) (figure (b)), the surge magnitude parameter (k) (figure (c)), and the decay time constant (τ) (figure (d)) were examined while keeping the baseline residential load profile unchanged.

Figure (a): Baseline CLPU (t_0 = 9, k = 2, τ = 5)

This figure illustrates the impact of network re-energisation occurring in the morning period. When restoration takes place at t_0 = 9, the CLPU demand surge coincides with the natural morning increase in residential demand. As a result, the post-restoration load peak is amplified compared to the baseline profile, highlighting the sensitivity of CLPU severity to the time of reconnection relative to daily demand patterns.

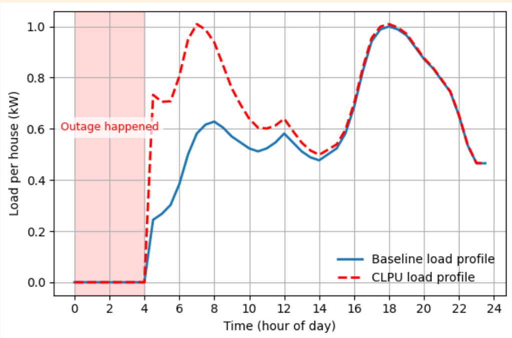


Figure (b): Effect of Later Re-Energisation Time, t_0 (t_0 = 20, k = 2, τ = 5)

This figure shows the same CLPU parameters applied to a later re-energisation time. When restoration occurs in the evening (t_0 = 20), the CLPU surge overlaps with an already elevated baseline demand. This leads to a higher absolute peak compared to earlier restoration, demonstrating that outages restored during peak demand periods pose a greater risk to network loading.

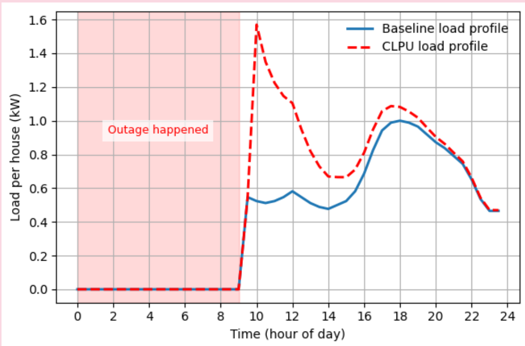
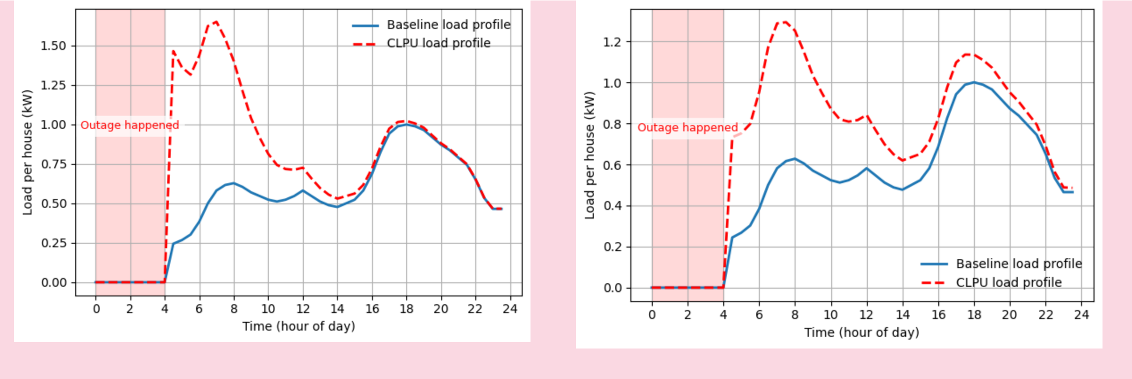


Figure (c): Effect of Increased Surge Magnitude, *k* (t_0 = 9, k = 5, τ = 5)

This figure highlights the influence of the surge magnitude parameter *k*. Increasing *k* results in a substantially higher immediate post-restoration demand peak, while the overall recovery duration remains similar. This indicates that *k* primarily controls the severity of the initial CLPU spike, directly affecting peak loading on network assets.

Figure (d): Effect of Recovery Time Constant, τ (t_0 = 9, k = 2, τ = 10)

This figure demonstrates the impact of a longer recovery time constant. Increasing *τ* smooths the CLPU response by extending the duration over which demand returns to baseline levels. While the peak magnitude is similar to the base case, the elevated demand persists for longer, illustrating how *τ* governs the rate of demand recovery rather than the peak size.



By applying this CLPU formulation consistently across different restoration timings, outage durations, and levels of LCT deployment, the model enables systematic assessment of worst-case loading conditions and supports robust evaluation of network resilience during cold start events.

2.4. Smart Meter–Enabled Cold Start Mitigation Strategies

Functionality 1: Pre-set randomised offset: Randomised delays which stagger customer reconnection following restoration

For a selected CLPU scenario, the difference between the CLPU demand profile and the baseline residential load profile was time-shifted and applied differently across the low-voltage buses. This approach represents a staggered reconnection of demand following network re-energisation. The purpose of this modelling approach is to reflect the capability of smart meters to introduce controlled delays in customer reconnection times. By distributing the recovery of additional demand across successive time steps, the model captures the effect of delayed reconnection in reducing the simultaneity of load restoration and mitigating peak demand during a cold restart.

Functionality 2: Household load limitation: Temporary power limitation per household following restoration

For a selected CLPU scenario, a temporary limit on the allowable demand per household was applied following network re-energisation. Under this approach, the additional demand associated with CLPU is constrained at each time step, and any excess demand is deferred to subsequent periods. This represents a controlled recovery of load rather than an immediate return to full demand. The purpose of this modelling approach is to reflect the capability of smart meters to enforce temporary power limits on connected devices after supply restoration. By limiting the maximum demand that can be drawn by each household during the recovery period, (which is defined as the time interval immediately following network restoration) the model reduces the instantaneous demand surge and spreads load recovery over time. This helps to mitigate peak loading on network assets and supports a more stable and resilient cold restart process.

Functionality 3: Proportional load management (via APC): gradual demand recovery following restoration

For a selected CLPU scenario, a gradual recovery of customer demand was modelled using an APC. Under this approach, following network re-energisation, the difference between the CLPU demand profile and the baseline residential load is not restored instantaneously. Instead, the additional demand is incrementally released over time in proportion to the remaining unmet demand. This modelling approach represents the functionality of smart meters to support controlled ramp-up of customer load after reconnection. By smoothing the recovery trajectory, the APC-based method reduces sudden changes in demand, helping to improve voltage stability and limit thermal stress on network assets. Compared to immediate restoration, this gradual recovery strategy spreads demand over successive time steps, supporting a more stable and coordinated cold restart process.

2.5. Assessment Criteria

To evaluate the impact of cold start events and the effectiveness of smart meter interventions on LV distribution networks, a set of technical performance criteria has been defined. These criteria are selected to capture the most critical operational limits and asset constraints that may be violated during periods of rapid demand recovery. The assessment focuses on voltage performance, thermal loading of network components, and transformer utilisation, as described below.

2.5.1. Voltage Drop

Voltage drop is used as a key performance indicator to assess the quality of supply experienced by customers during and following cold start events. In LV networks, high simultaneous demand can lead to significant voltage reductions along feeders, particularly at electrically remote customers. Excessive voltage drop may result in voltages falling outside statutory limits, leading to poor power quality, malfunction of customer equipment, or customer complaints.

During cold start conditions, the coincidence of loads, especially from electric heating and electric vehicle charging, can substantially increase feeder currents and exacerbate voltage drops. Monitoring voltage levels therefore provides a direct measure of the network's ability to maintain acceptable service quality under different outage scenarios and levels of LCT uptake. In the UK, low-voltage supply limits are defined by ESQCR (Electricity Safety, Quality and Continuity Regulations). For LV networks (nominal 230 V single-phase), the allowable steady-state voltage range at customer terminals is: −6% to +10% of nominal voltage (expressed in per unit (p.u.), this corresponds to: Minimum voltage = 0.94 p.u. and Maximum voltage = 1.10 p.u.

2.5.2. Line and Cable Loading

Line and cable loading is assessed to determine whether conductors are operating within their thermal limits during demand recovery. High post-outage demand can result in currents that exceed the rated capacity of overhead lines or underground cables, increasing the risk of overheating, accelerated asset ageing, or protection operation.

Evaluating line and cable loading is particularly important in LV networks, where conductor ratings can be relatively low and diversity assumptions do not hold during cold start events. This criterion helps identify feeders that are at risk of overload and provides insight into whether smart meter-based demand control strategies can effectively reduce peak currents.

2.5.3. Transformer Loading

Transformer loading is considered to assess the utilisation and thermal stress of LV distribution transformers during cold start conditions. Transformers are critical assets within the network, and sustained operation above rated capacity can lead to excessive heating, insulation degradation, and reduced asset lifetime.

CLPU events can cause transformer loading to increase rapidly and, in some cases, exceed acceptable operating limits due to the simultaneous reconnection of downstream loads. Assessing transformer loading allows the identification of scenarios in which transformers are most vulnerable and supports the evaluation of smart meter interventions aimed at smoothing demand recovery and reducing peak loading.

Table 2 Acceptable ranges for the line loading and transformer loading

Asset	Operating condition	Loading range (% of rating)	Interpretation
LV feeders / mains cables	Normal operation	≤ 70–80%	Healthy operation with sufficient thermal headroom
	High utilisation (peak)	80–100%	Acceptable during infrequent peak periods; indicates emerging constraint
	Overload (short-term)	100–120%	Tolerable only for limited durations (e.g. winter peak, post-fault); not acceptable continuously
LV distribution transformers	Normal operation	60–75%	Preferred planning range balancing losses, ageing, and resilience
	High utilisation (peak)	75–90%	Common at winter peak; acceptable but monitored
	Cyclic / short-term overload	90–110%	Allowed due to thermal inertia; duration-dependent
	Emergency operation	110–130%	Emergency or post-fault only; hours to days, depending on oil temperature

2.5.4. Feeder Fuse Thresholds at the LV Board

In addition to thermal and voltage performance criteria, it is important to consider the protection limits imposed by feeder fuses located at the low-voltage (LV) board. These fuses are typically rated at 100 A per phase, although higher ratings (e.g., 200 A) may be used depending on feeder capacity and design. While the power-flow analysis does not explicitly model fuse disconnection, any scenario in which simulated feeder currents exceed these thresholds, particularly for sustained periods, should be interpreted as posing a risk of protection operation. Such events could result in automatic disconnection of the feeder, interrupting supply to customers and complicating post-outage restoration. Therefore, feeder fuse ratings serve as a practical constraint in assessing the operability of the LV network during cold start events.

3. System topology and results

This section presents the characteristics of three representative network topologies, reflecting configurations with both pole-mounted and ground-mounted transformers. It then provides the results of the power flow analysis undertaken to assess network performance. Emphasis is placed on evaluating the effectiveness of selected smart meter functionalities in mitigating network constraints during cold start conditions.

To investigate the impact of CLPU and increasing penetration of LCTs under different physical network configurations, three representative low-voltage distribution network topologies provided by SP ENW are considered. The selected networks reflect common GB distribution arrangements based on both pole-mounted and ground-mounted distribution. Using multiple topologies enables assessment of how network layout, asset configuration, and transformer installation type influence thermal loading, voltage performance, and system resilience during normal operation and cold start conditions.

All three topologies are real-world inspired case studies and are modelled using consistent assumptions for load definition, transformer representation, and cable parameters to allow meaningful comparison between scenarios.

To carry out this analysis, the following structured approach was adopted:

1. **Network Modelling**
   Each selected topology was modelled in detail, including the transformer, feeders, buses, and allocated residential loads. The models were developed to accurately represent the electrical characteristics of the network under study.
2. **Baseline and Full LCT Deployment Assessment**
   For each topology, power flow analysis was first conducted under normal operating conditions (i.e., without LCTs). Subsequently, the analysis was repeated assuming 100% LCT deployment. This step was essential to determine whether the network could withstand full electrification under steady-state conditions before assessing CLPU impacts.
3. **Scenario Definition and Functionality Assessment**
   Multiple scenarios were defined based on outage timing, duration, and LCT uptake levels.

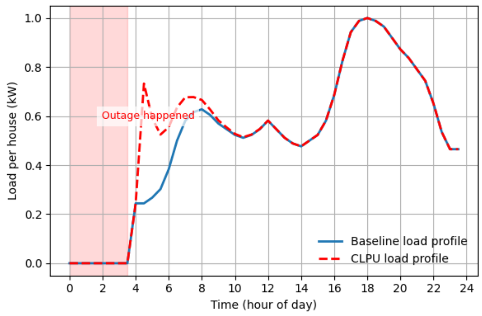
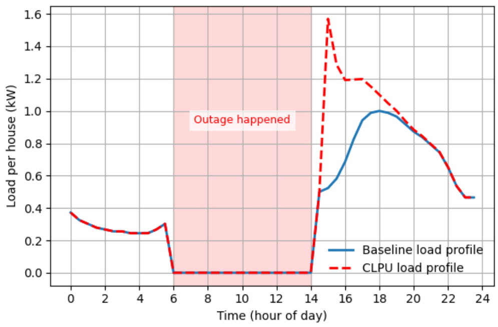
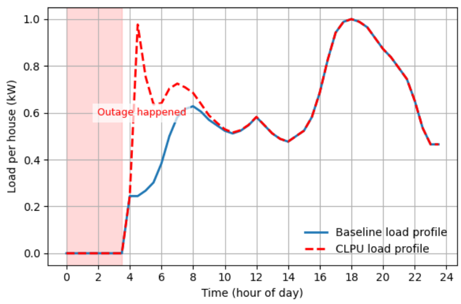
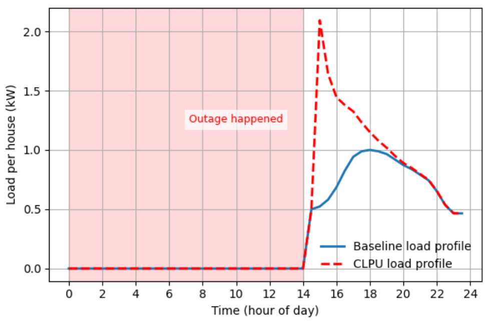
able 3 presents the different CLPU patterns considered across the defined scenarios. It should be noted that the deployment level of LCTs primarily affects the magnitude of demand at each bus, depending on the number of houses exhibiting LCT-related demand patterns. For each scenario, the effectiveness of the smart meter functionalities, such as staggered reconnection, total power limiting, and gradual demand recovery, was evaluated in terms of voltage limits, transformer loading, and overall network performance.

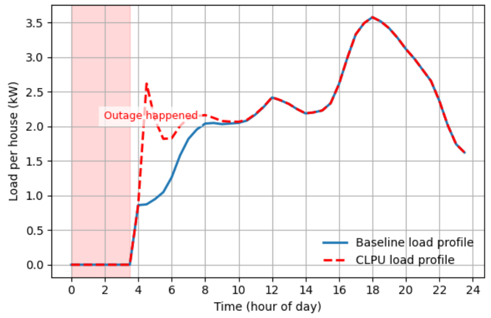
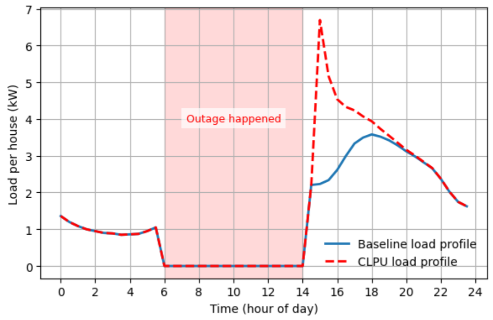
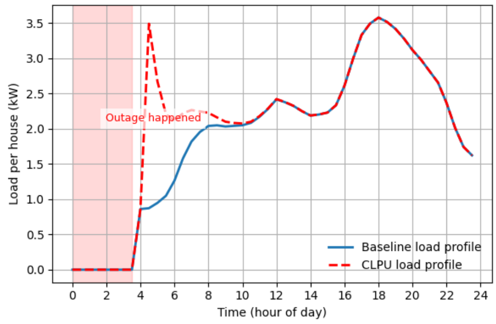
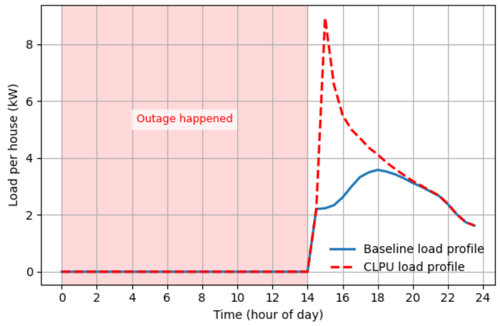
To present the results in a clear and conservative manner, for each topology the bus exhibiting the largest voltage deviation and the line experiencing the highest loading were selected, as these elements represent the most critical points within the network as:

- Critical buses were identified as those located electrically furthest from the feeder head (i.e., at the end of radial sections), where the cumulative series impedance of the upstream lines results in the largest voltage drop. Due to the aggregated power flow and associated I^2R losses along the feeder, these buses experience the lowest voltage magnitudes and are therefore most susceptible to statutory voltage limit violations.

- Critical lines were defined as those exhibiting the highest loading relative to their thermal rating. In radial LV networks, such lines are typically located either close to the feeder head, where downstream loads are electrically aggregated and current levels are highest, or along sections supplying buses with significant demand concentrations. These lines are most prone to thermal overloading and therefore represent the primary constraint from an asset capacity perspective.

Table 3 Different CLPU patterns in different scenarios illustrated for a day (for different outage durations and different timings of cold start)

	Off-peak cold start	Peak cold start
8 hours		
24 hours		

8 hours		
24 hours		

3.1. Topology 1

Topology 1 represents a typical radial low-voltage network supplied by a pole-mounted distribution transformer shown in Figure 8. The network consists of six buses in total. One bus operates as the slack (source) bus at 11 kV, representing the upstream medium-voltage (MV) grid. The remaining five buses are low-voltage (LV) load buses operating at 0.4 kV, supplying residential customers.

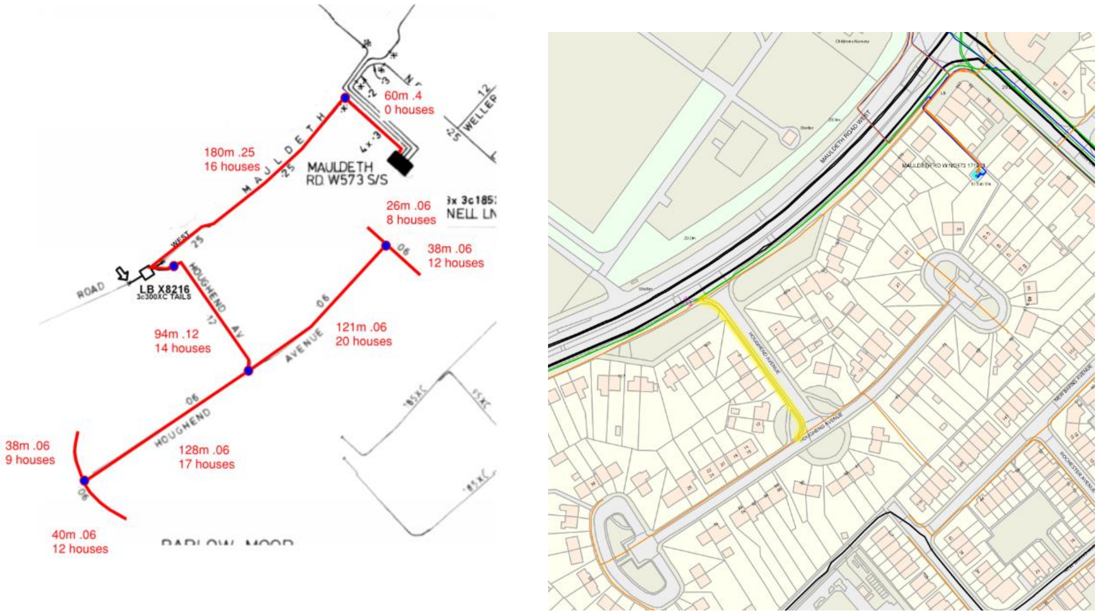


Figure 8 The diagram of Topology 1 from SP ENW

A total of 108 residential properties are connected to the network and distributed across the LV buses. The interface between the MV and LV networks is provided by a 750 kVA distribution transformer. The transformer is modelled using representative technical parameters ensuring realistic representation of typical pole-mounted LV substations.

The LV feeders are modelled using standard underground or overhead cable characteristics derived from the CP204 report. Electrical parameters, including resistance and reactance, are selected based on the relevant reference tables to ensure the model reflects typical GB LV distribution assets.

For this study, an ADMD of 1 kW per household is assumed, representing a typical diversified residential peak demand consistent with ENWL planning guidance. Individual households are not modelled as separate load buses. Instead, the aggregate demand of all properties connected to a feeder section is applied at the corresponding downstream LV bus.

This aggregation approach is widely adopted in LV network studies, as it captures the overall electrical behaviour of the feeder while maintaining computational efficiency and avoiding unnecessary modelling complexity.

Table 4 Characteristics of the transformer

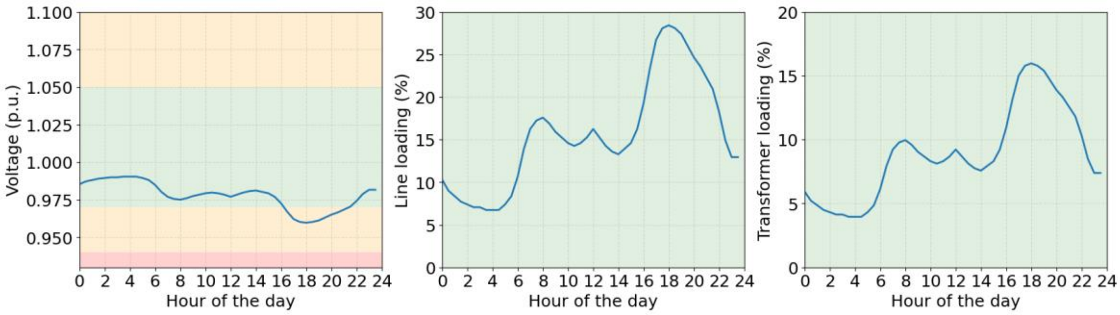
SIZE (kVA)	R (Ω)	JX (Ω)	R%	JX%
750	0.00288	0.01060	166.9	613

 Internal Use

Table 5 Characteristics of the Line

LV Mains 4-core Cables - Modern Types			
4 –core Polymeric insulated cables with solid Aluminium phase conductors and concentric Copper wire Waveform neutral/earth conductor to BS 7870-3.40 Assumes earth return via the sheath only	size	R1	X1
	300mm2	0.102	0.072

In the first stage of the assessment, the network was evaluated under normal operating conditions considering only the baseline (non-LCT) demand. The results indicate that all assessment criteria were satisfied in this case. Specifically, voltage levels remained within acceptable limits, and both line loading and transformer loading were within their thermal capacity constraints.



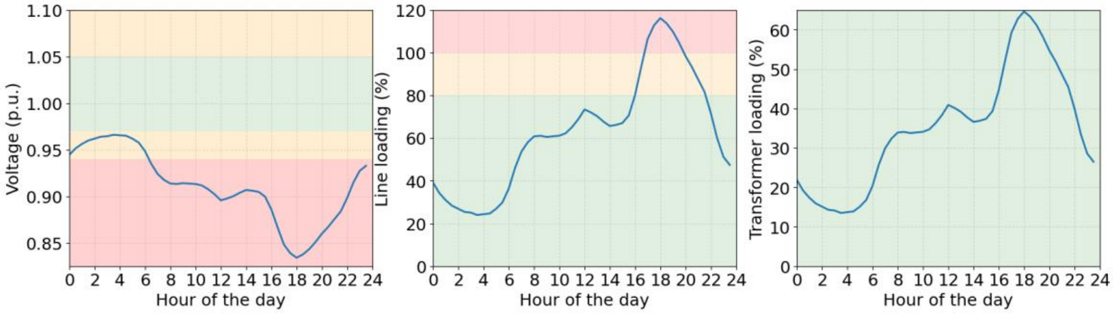
(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Figure 9 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

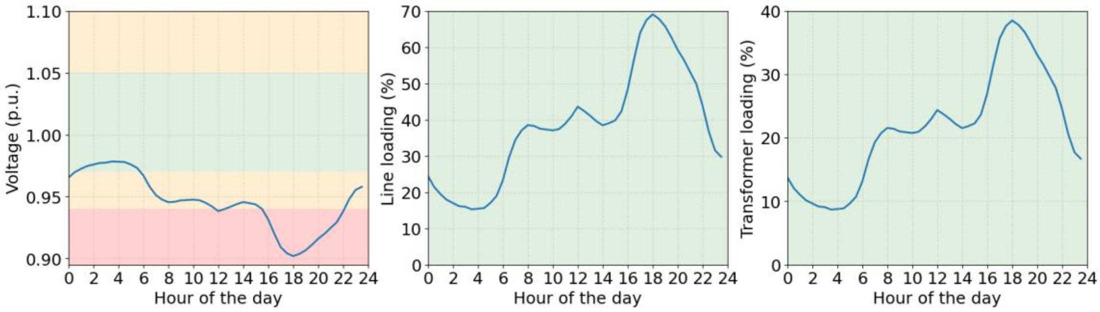
Subsequently, a scenario with 100% deployment of LCTs was analysed under normal operating conditions. The results demonstrate that voltage drop exceeds the acceptable range, particularly at remote buses, and line loading surpasses allowable limits during peak demand periods. These findings indicate that, even without considering post-outage CLPU effects, the network is unable to accommodate full LCT deployment under steady-state conditions. Therefore, further analysis of post-outage behaviour would not provide meaningful insights unless network reinforcement measures are implemented, as per SP ENW network planning reinforcement plans.



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Figure 10 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

In addition, a partial deployment scenario was considered, where 50% of the houses connected to each bus were assumed to have LCTs. The results show a noticeable increase in voltage drop compared to the baseline case. This indicates that even moderate levels of LCT penetration can lead to technical limit violations, suggesting that reinforcement measures may also be required under partial deployment scenarios.



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Figure 11 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

3.2. Topology 2

The second network topology represents an urban low-voltage distribution area. It consists of one 11 kV bus supplying ten 400 V buses, to which a total of 120 residential consumers is connected. The allocation of consumers across the low-voltage buses is non-uniform, with some buses serving a higher number of households than others, reflecting realistic urban feeder conditions.

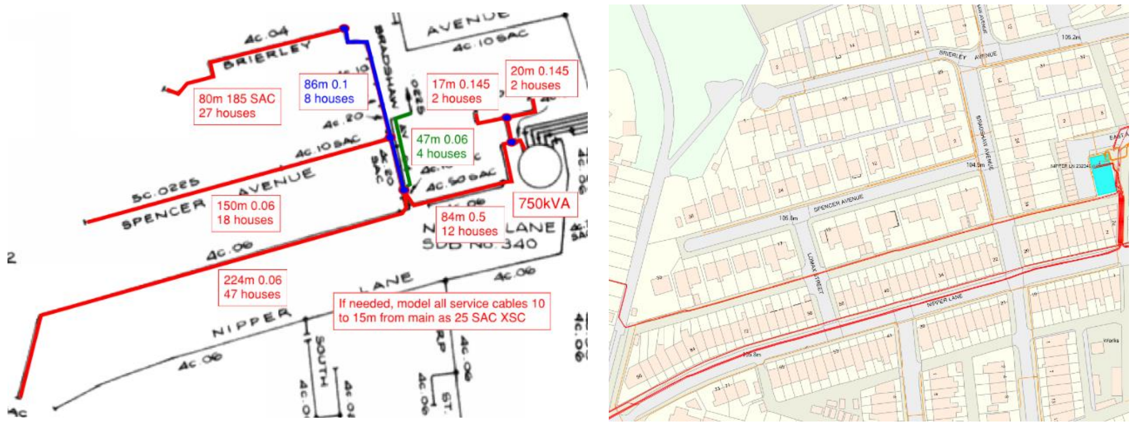


Figure 12 The diagram of Topology 2 from SP ENW

An ADMD of 1 kW per household is assumed for all residential consumers. To reduce modelling complexity while preserving feeder loading characteristics, households connected along each feeder are aggregated and modelled as a lumped load at the end of the line, rather than being represented as individual buses for each consumer.

The electrical characteristics of the distribution transformer and low-voltage lines used in this topology are summarised in Table 6 and 7.

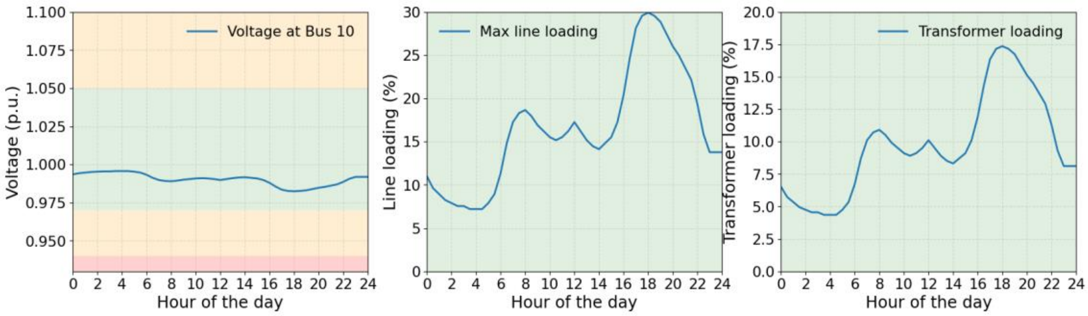
Table 6 Characteristics of the line

LV Mains 4-core Cables - Modern Types			
4 –core Polymeric insulated cables with solid Aluminium phase conductors and concentric Copper wire Waveform neutral/earth conductor to BS 7870-3.40 Assumes earth return via the sheath only	size	R1	X1
	300mm2	0.102	0.072

Table 7 Characteristics of the transformer

Size (kVA)	R(Ω)	JX(Ω)	R(%)	JX(%)
750	0.00288	0.01060	166.9	613

For the second topology, the assessment again began with a simulation of normal operating conditions without any LCT deployment. The results confirm that all technical criteria were satisfied in this case, with voltage levels remaining within acceptable limits and both line loading and transformer loading operating within their respective thermal capacities.



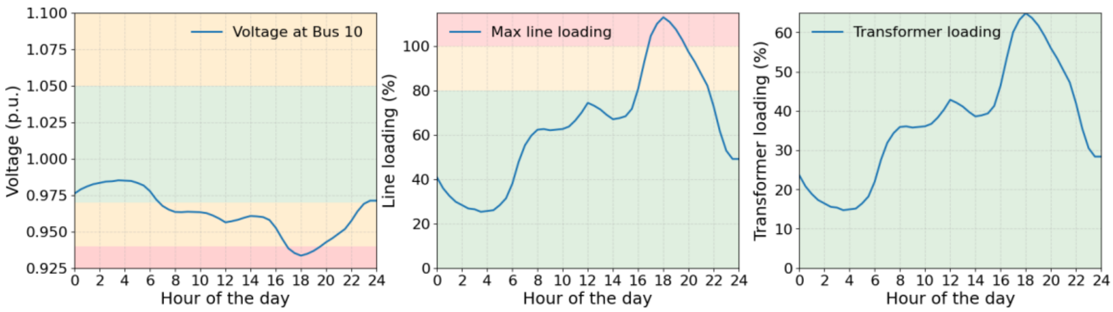
(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Figure 13 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

Following this baseline assessment, a scenario with 100% LCT deployment was modelled and analysed under normal operating conditions. This step was undertaken to evaluate whether the network could accommodate full electrification demand in steady-state conditions before proceeding to any post-outage or CLPU-related analysis. Under normal operating conditions (i.e., without outage or CLPU), the scenario with 100% deployment of LCTs across all houses already results in violations of the voltage drop and line loading assessment criteria. This indicates that the existing network topology is unable to accommodate full LCT uptake without reinforcement. Consequently, further analysis of smart meter functionalities during cold start conditions is not meaningful for this topology, as the network fails to operate within acceptable limits even in the absence of restoration-related stress. Therefore, the subsequent analysis is limited to scenarios S1, S3, S5, and S7, which correspond to partial deployment of low-carbon technologies.



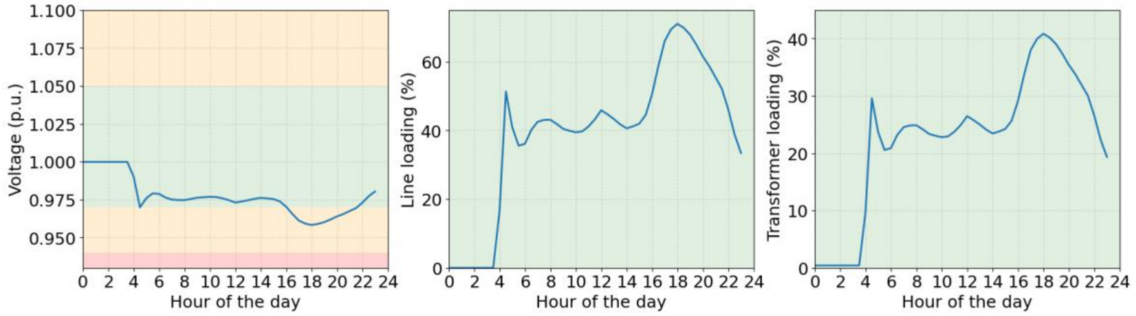
(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Figure 14 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

Scenario 1 (defined in Table 1): CLPU after 8 hours during off-peak hours with partial LCT deployment



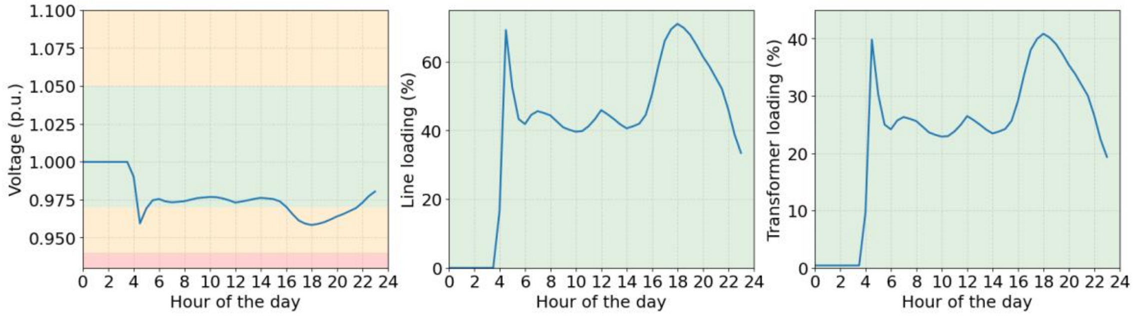
(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

For Scenario 1, the results indicate that, in the absence of any smart meter–based control, all assessment criteria are satisfied. Consequently, the use of smart meter functionalities to manage cold start is not required for this scenario.

Scenario 3 (defined in Table 1): CLPU after 24 hours during off-peak hours with partial LCT deployment



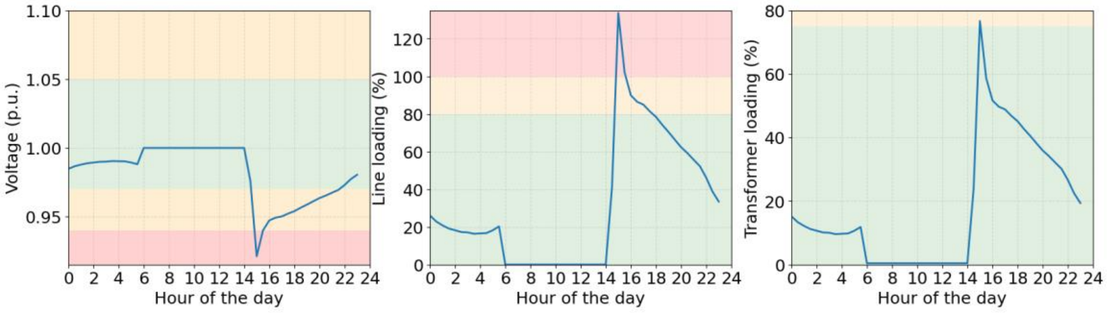
(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

For Scenario 3, the results show that any CLPU, related demand spike occurs during off-peak hours. As a result, the network is able to accommodate the temporary increase in load without violating voltage or thermal limits, even in the absence of smart meter-based control. Therefore, the application of smart meter functionalities is not required to manage cold start under this scenario.

Scenario 5 (defined in Table 1): CLPU after 8 hours during peak hours with partial LCT deployment



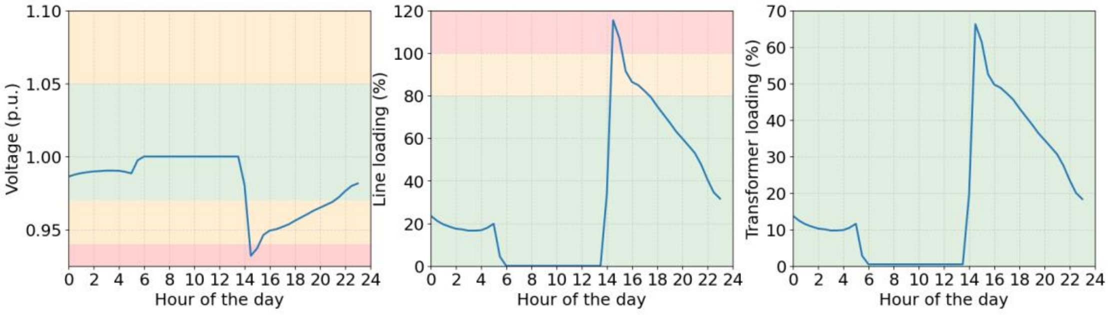
(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

For Scenario 5, CLPU coincides with peak demand hours, resulting in voltage drops beyond the acceptable range and line loadings exceeding allowable limits. Under these conditions, the network is unable to operate within the defined assessment criteria without intervention. Therefore, the application of smart meter functionalities can be effective in mitigating the resulting stress on the grid.

Pre-set randomised offset: The maximum delay that smart meters can introduce to the reconnection of houses equipped with LCTs is assumed to be 30 minutes. In this scenario, the full 30-minute delay was applied to all households with LCTs following network re-energisation. The results indicate that applying the 30-minute reconnection delay reduces the immediate pressure on the network by lowering the coincidence of demand following re-energisation. However, despite this improvement, instances of line overloading and voltage drop beyond acceptable limits are still observed. This suggests that while staggered reconnection mitigates the severity of the demand surge, it is not sufficient on its own to fully maintain network operation within technical constraints.

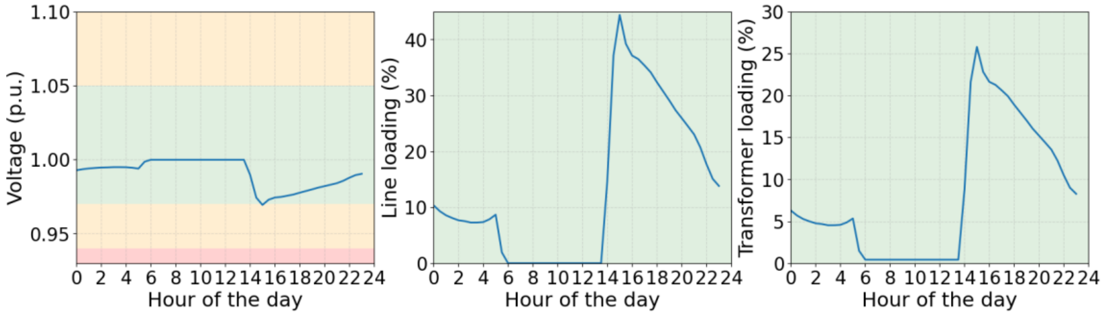


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Household load limitation - Power limit on the TOTAL consumption of each consumer (5kW per house for 5 hours): Imposing a limitation on the total demand per household proves to be a more effective mitigation strategy. The results show that this approach significantly reduces network stress and enables voltage levels, line loading, and transformer loading to remain within acceptable ranges. It should be noted, however, that the effectiveness of this method strongly depends on the specific power limit defined for each household. Stricter limits provide greater network protection but may also impose higher levels of demand restriction on customers and reduce their comfort.

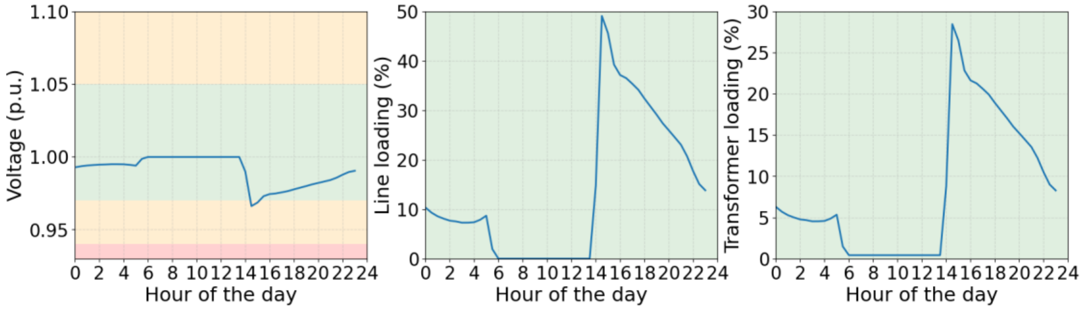


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Proportional load management - Power limit only on LCTs for 5 hours: The APC approach is also shown to be effective in reducing network stress by enabling gradual demand recovery. However, its impact is generally less pronounced compared to the fixed power limitation strategy. Similar to the total demand limit method, the effectiveness of APC is highly dependent on the selected ramp-up rate. Slower recovery rates lead to improved network performance, whereas faster recovery reduces its mitigation benefits.

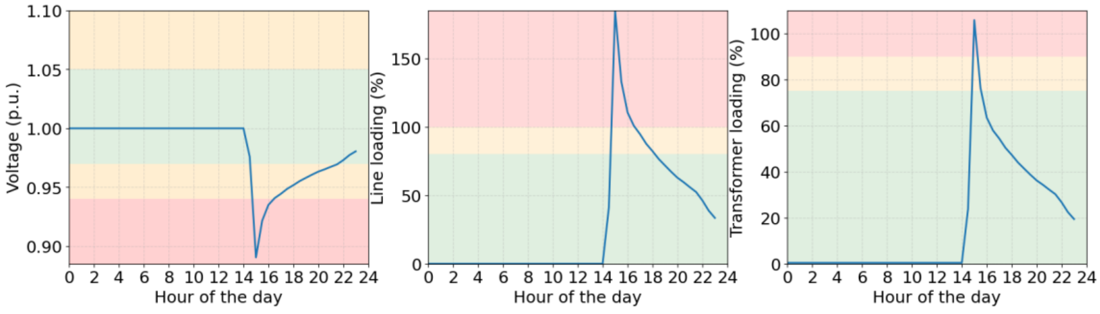


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

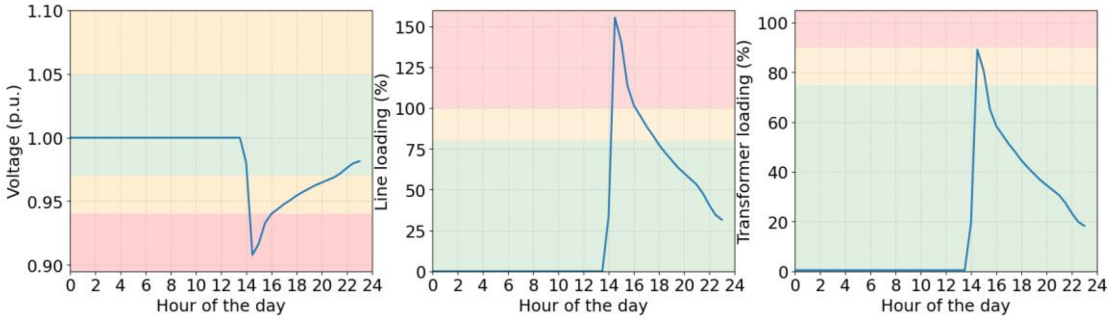
Scenario 7 (defined in Table 1): CLPU after 24 hours during peak hours with partial LCT deployment



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (C) Transformer Loading

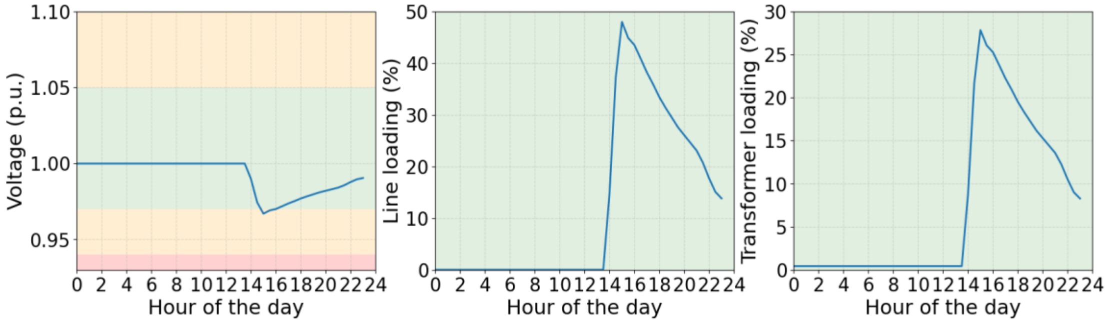
For Scenario 7, CLPU occurs during peak demand hours following a prolonged outage, leading to voltage drops and line loadings that exceed acceptable limits. In addition, transformer loading enters the amber operating region, indicating an increased risk of thermal stress. Under these conditions, the network performance deteriorates across multiple criteria, and the application of smart meter functionalities can be beneficial in mitigating the pressure on the grid.

Pre-set randomised offset: For Scenario 7, the implementation of the maximum permissible reconnection offset results in a noticeable moderation of the initial demand surge following supply restoration. The temporal dispersion of load reconnection reduces peak coincidence and alleviates part of the immediate stress on the network. Nevertheless, the results indicate that thermal overloads and voltage deviations beyond statutory limits still occur.



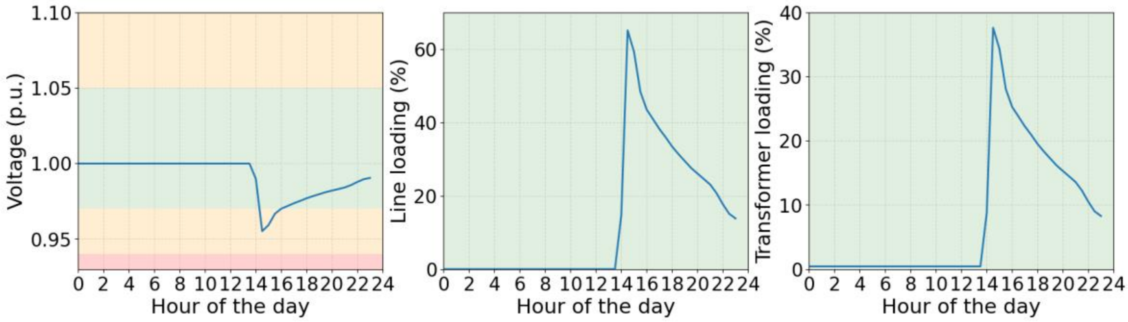
(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c)Transformer Loading

Household load limitation - Power limit on the TOTAL consumption of each consumer (5kW per house for 5 hours): Introducing a cap on the allowable household demand demonstrates a more robust mitigation effect. By constraining the aggregate load contribution from each dwelling, the network operates within acceptable voltage boundaries and thermal loading thresholds. Similar to the previous scenario, the degree of improvement is directly linked to the selected demand cap. Lower thresholds provide stronger protection to network assets but may result in greater restriction of end-user consumption.



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Proportional load management - APC for 5 hours: The gradual restoration strategy based on proportional load ramping also contributes to reducing system stress by smoothing the recovery profile. As with the previous scenario, the overall effectiveness is strongly influenced by the chosen ramping gradient. Slower increments in demand recovery yield better compliance with network limits, whereas steeper recovery rates diminish its mitigating capability.



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

3.3. Topology 3

Topology 3 represents an alternative LV network configuration supplied by a pole-mounted distribution transformer, reflecting a more rural installation. The network consists of 12 buses in total, comprising one MV slack bus at 11 kV and 11 LV load buses operating at 0.4 kV. The network serves the same overall number of residential consumers, with 24 dwellings allocated across the low-voltage (LV) buses. The medium-voltage (MV) and LV systems are interconnected through a 100 kVA distribution transformer. This transformer is modelled based on representative technical specifications provided by SP ENW (see Table 8), capturing typical impedance and thermal characteristics associated with ground-mounted substations.

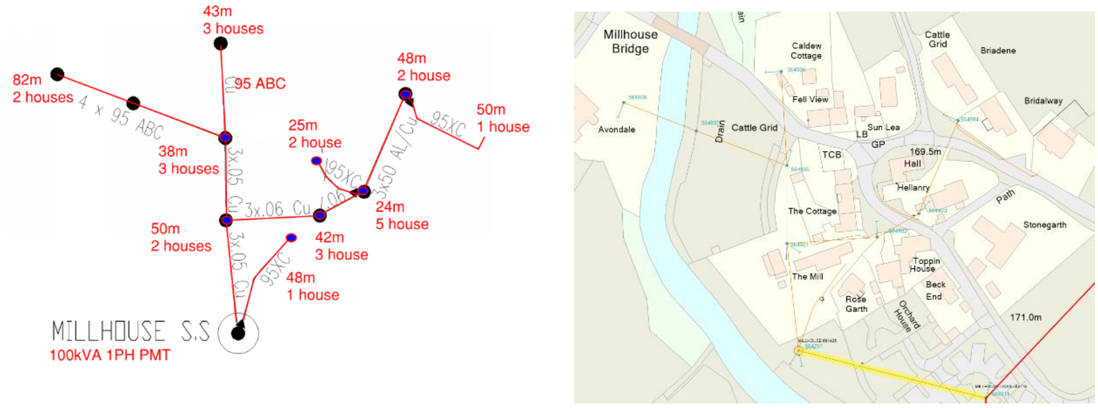


Figure 15 The diagram of Topology 2 from SP ENW

The LV feeders are modelled using standardised cable data derived from the CP204 report[12]. Maintaining consistent conductor parameters across all examined topologies ensures that observed performance variations can be attributed predominantly to structural configuration and transformer characteristics, rather than differences in modelling inputs.

An ADMD of 1 kW per dwelling is assumed for all residential customers. Consistent with the approach adopted in other topologies, individual household loads are not represented explicitly. Instead, aggregated demand is assigned at the feeder bus level. This modelling approach achieves a practical compromise between network representation accuracy and computational efficiency, particularly for time-series power flow simulations and CLPU assessments.

Table 8 Characteristics of the transformer

SIZE (kVA)	R (Ω)	JX (Ω)	R%	JX%
100	0.00288	0.01060	166.9	613

For this topology, power flow analysis was first performed under normal operating conditions for two cases: 0% LCT deployment and 100% LCT deployment. The simulation results indicate that, under normal operating conditions and in the absence of any LCT deployment, all technical performance criteria are satisfied. Voltage levels remain within permissible limits, and both line loading and transformer loading operate within their respective thermal capacity constraints.

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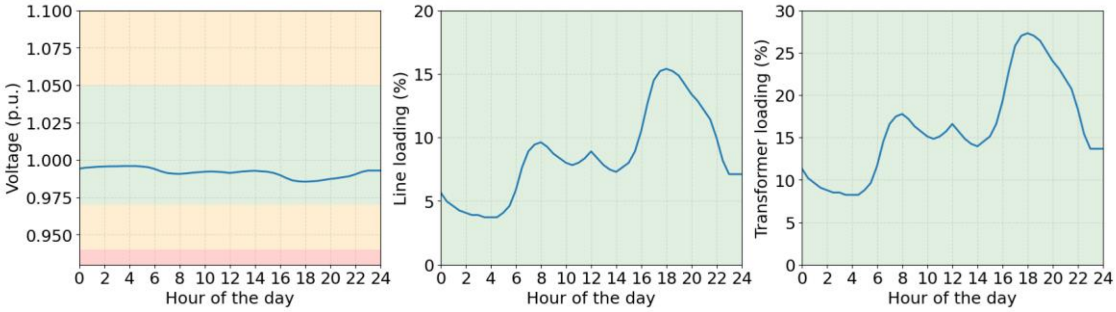
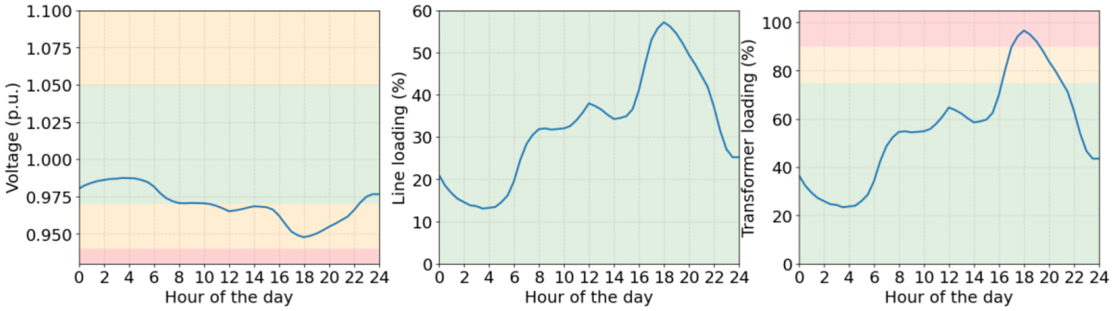
[12] SP Electricity North West



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Figure 16 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

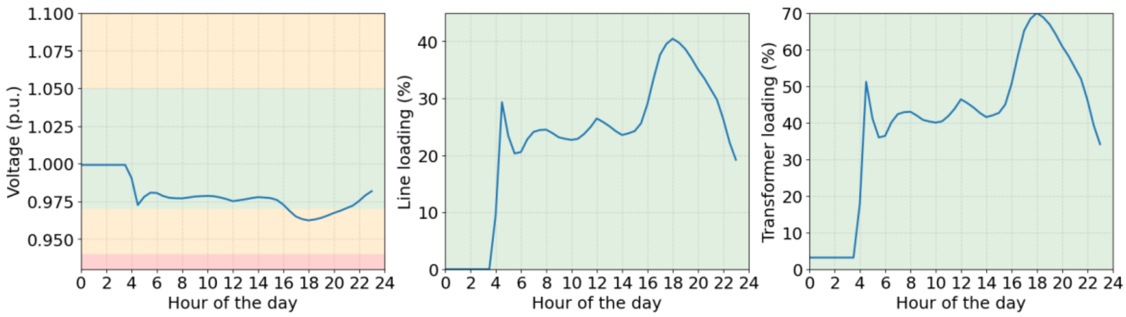
However, under normal operation with 100% LCT deployment, the transformer becomes overloaded, indicating that the existing network capacity is insufficient and that reinforcement, specifically, the installation of a larger transformer, is required. As a result, analysing cold start scenarios with full LCT deployment is not meaningful for this topology. Consequently, only scenarios S1, S3, S5, and S7, which correspond to partial LCT deployment, are considered in the subsequent analysis.



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Figure 17 Daily profiles of voltage at the critical bus, maximum line loading, and transformer loading

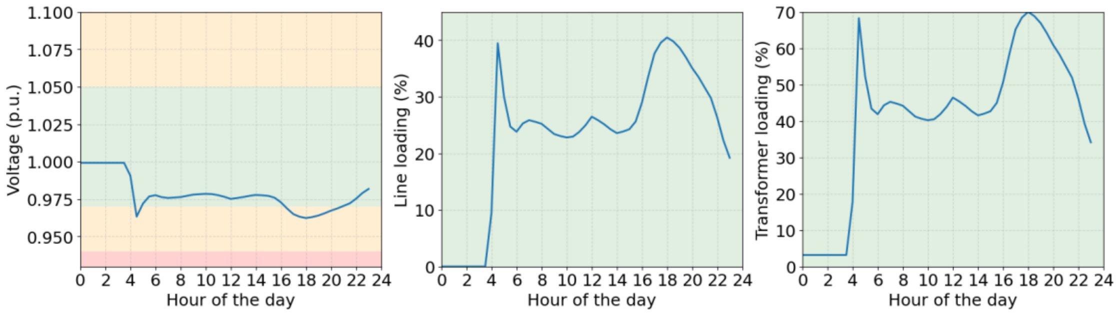
Scenario 1 (defined in Table 1): CLPU after 8 hours during off-peak hours with partial LCT deployment



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

For Scenario 1, the results indicate that, in the absence of any smart meter–based control, all assessment criteria are satisfied. Consequently, the use of smart meter functionalities to manage cold start is not required for this scenario.

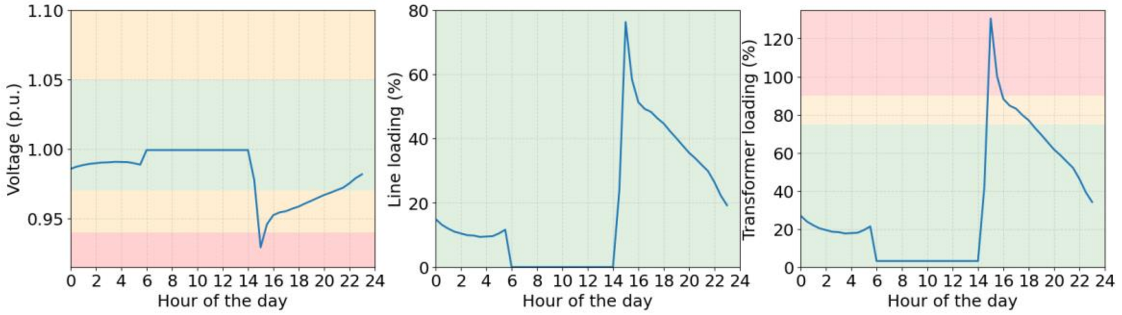
Scenario 3 (defined in Table 1): CLPU after 24 hours during off-peak hours with partial LCT deployment



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

For Scenario 3, the results show that any CLPU–related demand spike occurs during off-peak hours. As a result, the network is able to accommodate the temporary increase in load without violating voltage or thermal limits, even in the absence of smart meter–based control. Therefore, the application of smart meter functionalities is not required to manage cold start under this scenario.

Scenario 5 (defined in Table 1): CLPU after 8 hours during peak hours with partial LCT deployment

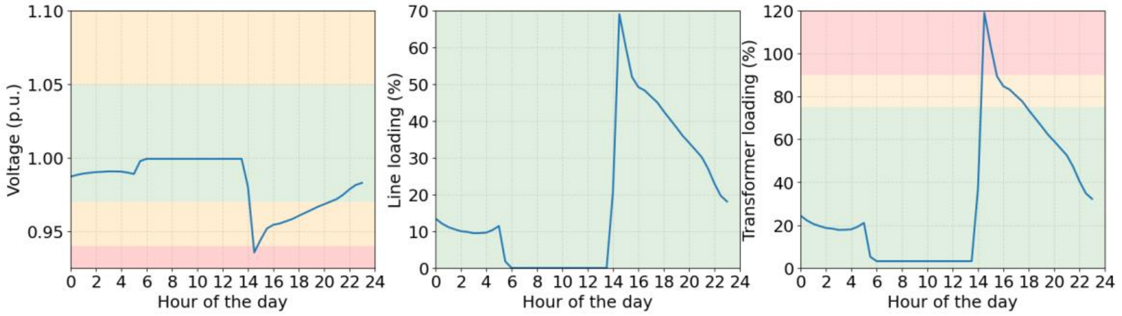


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Pre-set randomised offset: In this scenario, applying the maximum allowable reconnection delay of 30 minutes mitigates the initial demand coincidence after supply restoration and consequently eases network stress. However, the results indicate that voltage deviations and transformer utilisation still exceed permissible thresholds. Therefore, while delayed reconnection provides partial relief, it does not fully resolve the constraint violations.

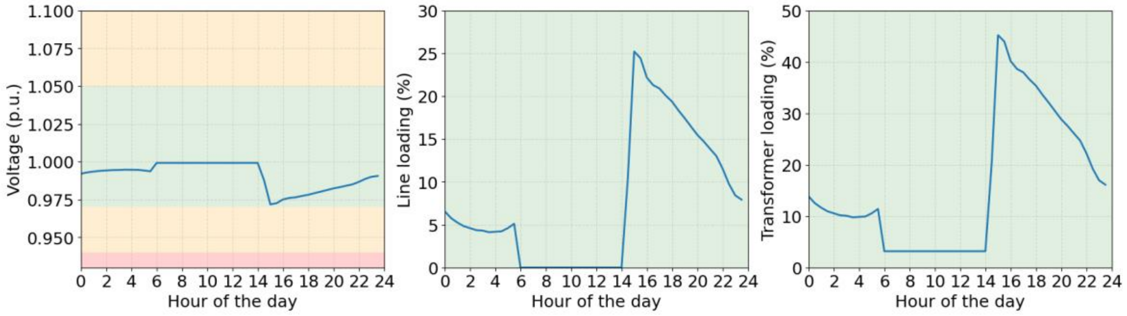


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

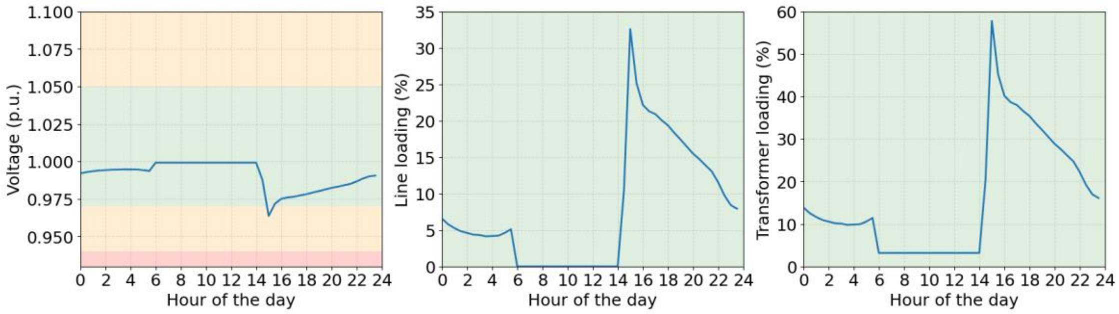
(c) Transformer Loading

Household load limitation - Power limit on the TOTAL consumption of each consumer (5kW per house for 5 hours): Enforcing a cap on household demand is shown to be a particularly robust mitigation measure. With an appropriately selected limit, all assessment criteria remain within acceptable boundaries. However, it should be emphasised, the success of this approach is highly sensitive to the specified demand cap. The level of restriction directly determines the degree of network protection achieved.



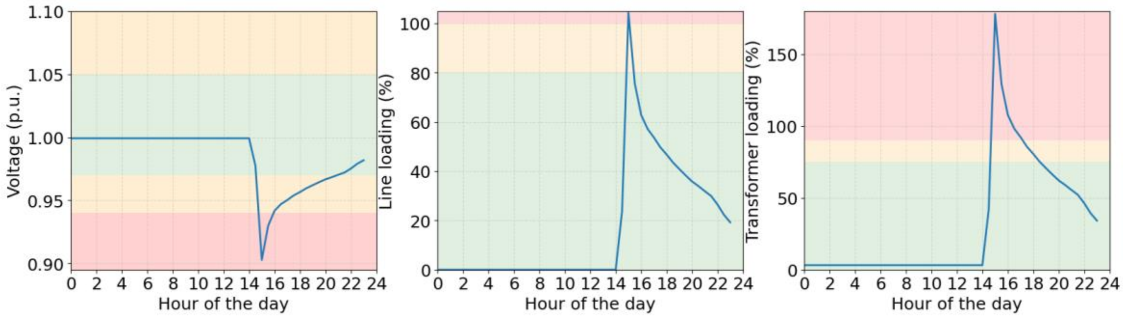
(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Proportional load management - APC for 5 hours: The gradual demand recovery strategy implemented through the APC mechanism also contributes significantly to reducing system stress. By smoothing the load restoration trajectory, it limits abrupt loading peaks. Nonetheless, its effectiveness is governed by the selected ramping gradient. A slower, more controlled increase in demand improves compliance with operational limits, whereas a steeper recovery rate diminishes its mitigating impact.



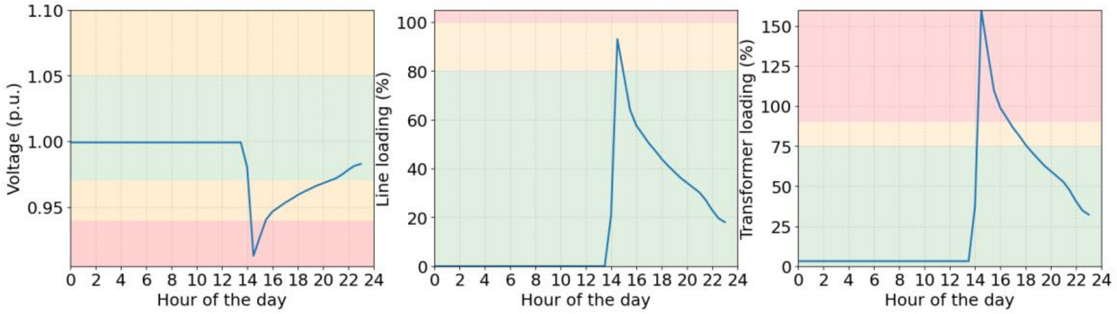
(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Scenario 7 (defined in Table 1): CLPU after 24 hours during peak hours with partial LCT deployment



(a) Voltage Drop on the Critical Bus (b) Line Loading on the Critical Line (c) Transformer Loading

Pre-set randomised offset: For this scenario, implementing the maximum reconnection delay of 30 minutes reduces the immediate stress on the network by lowering the simultaneity of demand following restoration. However, despite this improvement, both voltage drop and transformer loading still exceed acceptable limits. This indicates that staggered reconnection alone is insufficient to fully mitigate network constraint violations under the given conditions.

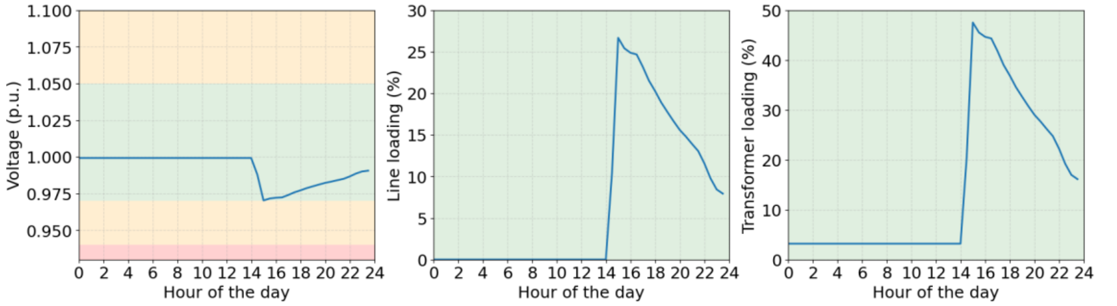


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Household load limitation - Power limit on the TOTAL consumption of each consumer (5kW per house for 5 hours): Introducing a demand limitation per household proves to be a highly effective mitigation strategy. The results show that this approach successfully maintains voltage levels, line loading, and transformer loading within permissible ranges. Nevertheless, its effectiveness is strongly dependent on the selected demand threshold. More restrictive limits provide greater network protection, whereas higher limits may reduce its overall impact.

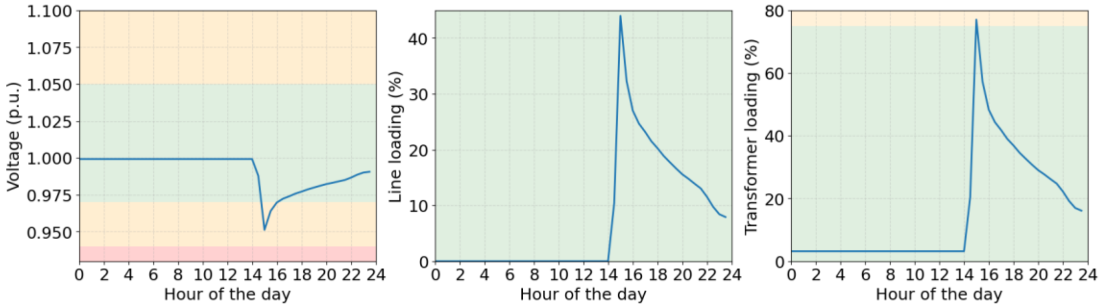


(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

Proportional load management - APC for 5 hours: This approach is also demonstrated to be an effective method for alleviating network stress by enabling gradual demand recovery. However, similar to the demand limitation strategy, its performance is closely linked to the chosen ramp-up rate. Slower recovery rates enhance its effectiveness, while faster increases in demand reduce its ability to maintain network parameters within acceptable limits.



(a) Voltage Drop on the Critical Bus

(b) Line Loading on the Critical Line

(c) Transformer Loading

4. Insights and Conclusion

This section presents the conclusions of the study and outlines the proposed next steps for the project.

The results demonstrate that smart meter enabled control functionalities are beneficial in supporting network performance during CLPU events. The effectiveness of these functionalities, however, is highly scenario dependent. Factors such as the underlying network topology, the level of LCTs uptake, particularly EVs and HPs and the timing of the cold start relative to daily demand patterns, all have a significant influence on the extent to which smart meter interventions can mitigate adverse impacts.

In some scenarios, strategies such as staggered reconnection, temporary demand limiting, and gradual demand recovery were effective in reducing peak demand, alleviating thermal loading, and improving voltage stability.

In other cases, particularly under high LCT penetration or during restoration at peak demand periods, the benefits were more limited and required tighter control or combined measures to achieve meaningful improvements. Smart meter functionalities should not be considered as a one-size-fits-all solution, but rather as flexible tools whose value depends on careful coordination with network characteristics and operating conditions.

Overall, the results positive outcomes for each solution and targeted and context aware deployment of smart meter-based controls could enhance the resilience of distribution networks during cold restart events.

Next Steps

The current assessment demonstrates positive benefits of Smart ReStart, and further analysis would enhance our understanding and robustness of Smart Restart and network benefits.

The following next steps have been identified:

1. **Model validation using real outage events:** Future work should incorporate data from an actual cold start event within a representative low-voltage network. Simulating the model against a real-world case will allow for validation of the modelling assumptions and provide a stronger basis for operational planning and decision-making.
2. **Expanded scenario framework:** The scenario framework can be enhanced by introducing greater variation in LCT deployment. This includes modelling feeders where customers have differing combinations and quantities of electric vehicles, heat pumps, and other technologies.

   A key extension of the scenario set would therefore be the inclusion of behind-the-meter (BTM) assets such as rooftop solar PV and domestic battery storage systems. For example, a scenario could consider batteries that are fully charged prior to restoration and are capable of supplying part of the household demand during the initial pick-up period, thereby reducing net demand seen by the network. Similarly, during daylight hours, local solar generation and increased self-consumption could reduce feeder loading and mitigate voltage drop, particularly in spring and summer months.

Seasonal variation should also be considered more explicitly. While severe cold-start impacts are most critical in winter due to high heating demand, scenarios in shoulder months (e.g., autumn and spring) may present different dynamics due to moderate heating demand combined with solar generation. Although summer conditions are less likely to present heating-driven peaks, increasing adoption of air conditioning could introduce new seasonal demand patterns that warrant assessment.

Additionally, the modelling framework coild be enhanced by testing the impact of different customer behaviour. The current analysis assumes a worst-case scenario in which customers are not pre-prepared for outages. In future stages, it is recommended to incorporate behavioural diversity by accounting for customer actions such as pre-charging electric vehicles, pre-heating homes, or manually managing appliance loads. Including these factors would provide a more realistic representation of post-outage demand recovery and allow for a more nuanced understanding of CLPU effects.

Incorporating these additional dimensions would provide a more comprehensive understanding of network performance under realistic future energy mixes and improve the robustness of conclusions regarding smart meter-enabled mitigation strategies. Such an approach would enable exploration of how long smart meter-based mitigation strategies remain effective as electrification progresses, and under what conditions their impact diminishes.

3. **Estimation of secondary outage risk**: Another next step is to estimate the probability of a secondary outage occurring as a result of CLPU. This can be achieved by analysing the simulated feeder current at the transformer level and comparing it against typical fuse thresholds. By incorporating fuse time-current characteristics and considering the duration and magnitude of post-restoration loading, it is possible to assess the likelihood of protection device operation, which may lead to subsequent disconnections.

   In addition, the methodology can be extended to identify critical network areas that are inherently more vulnerable to secondary outages. These may include:

   - Radial feeders with long electrical distances, where high impedance contributes to both elevated voltage drop and increased current during demand recovery.
   - Topologies with high load concentration near the transformer, where aggregated downstream demand leads to large feeder-head currents and increased stress on LV board fuses.
   - Networks with high LCT penetration in clustered configurations, where simultaneous heat pump and EV recovery amplifies peak loading.
   - Rural or weak networks with smaller transformer ratings, where limited thermal headroom increases sensitivity to transient demand surges.

   By mapping protection stress against topology characteristics (e.g., feeder length, transformer capacity, load diversity, and LCT clustering), it becomes possible to identify areas at greater risk of cascading or secondary outages. This analysis would provide valuable insight into the reliability risks associated with cold start events and help quantify the resilience of the LV network under different restoration scenarios.

Power Factory Modelling

Validation of Network Performance Under Full LCT Deployment

All three representative network topologies were additionally modelled in DIgSILENT PowerFactory and analysed under steady-state (normal operating) conditions assuming 100% deployment of LCTs.

The results obtained in PowerFactory are closely aligned with those derived from the Python simulations, providing confidence in the modelling assumptions, parameter conversion, and network representation adopted in this work package.

Under the assumption of full LCT uptake, network constraint violations were observed in each topology, although the limiting factors differed:

- **Topology 1:** Voltage drop violations at the LV level in addition to thermal overloading of distribution lines.
- **Topology 2:** Thermal overloading of one line, without significant voltage drop violation.
- **Topology 3:** Overloading of the distribution transformer, while feeder voltages and line currents remained within acceptable limits.

These findings demonstrate that, even under normal (non–cold start) operating conditions, full LCT penetration is not technically feasible in the studied configurations without reinforcement or active management. More importantly, the results indicate the existence of a critical LCT penetration threshold for each topology. Below this threshold, the network operates within statutory voltage limits and thermal ratings; beyond it, one or more operational constraints are violated.

Identifying this critical deployment level is essential, as it defines the operational envelope within which the network can accommodate LCTs without infrastructure upgrades. Up to this penetration rate, selected smart meter functionalities, such as demand limiting, controlled load ramping, or staggered reconnection strategies (as discussed in Chapter 4), can provide effective mitigation measures to maintain network compliance. Beyond this point, however, smart control alone may not be sufficient, and reinforcement or more advanced active network management solutions would be required.

Overall, the cross-validation between Python and PowerFactory strengthens the robustness of the analysis and confirms the topology-dependent nature of LCT hosting capacity under steady-state conditions.

The corresponding simulation snapshots for each topology in PowerFactory are presented in Figures 18 to 19.

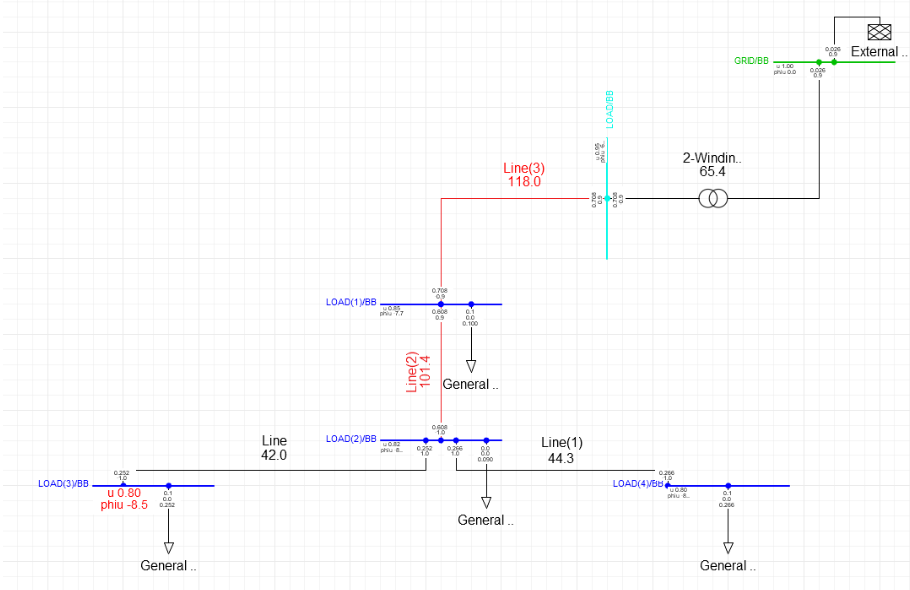


Figure 18 PowerFactory load flow results for Topology 1 under 100% LCT deployment, showing voltage drop and thermal overloading in LV feeders.

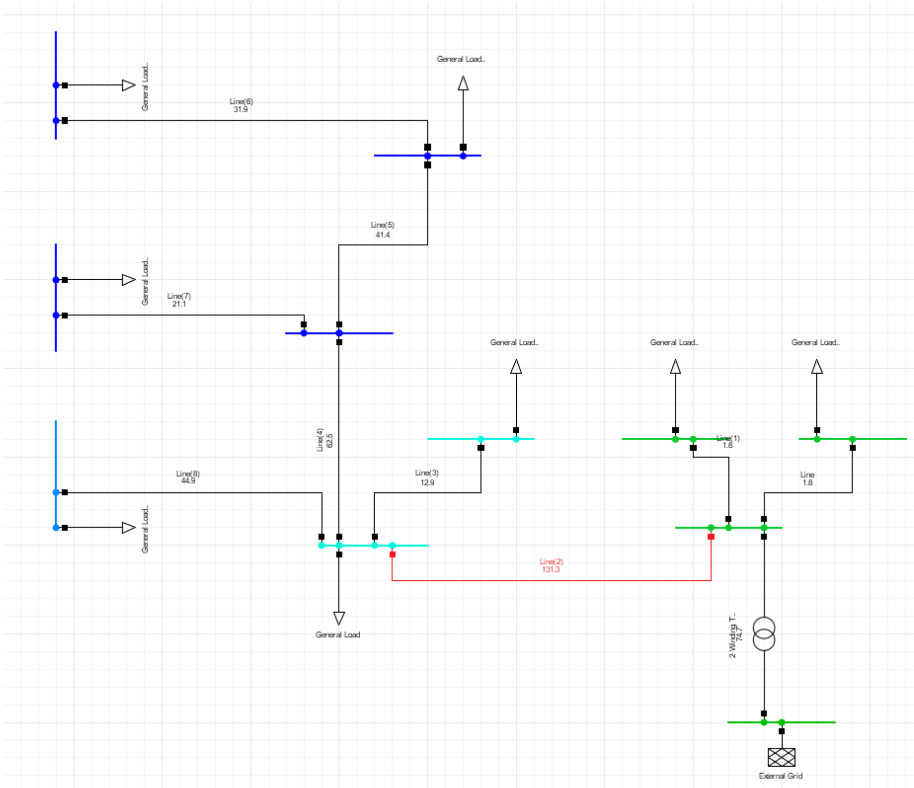


Figure 19 PowerFactory load flow results for Topology 2 under 100% LCT deployment, thermal overloading of a line.

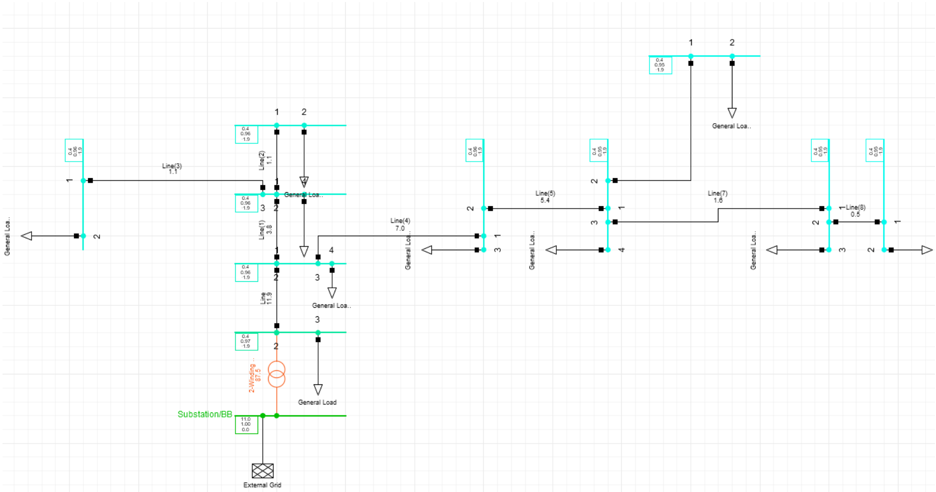


Figure 20 PowerFactory load flow results for Topology 3 under 100% LCT deployment, showing transformer overloading