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RESEARCH ARTICLE

Synergies Between Low Carbon Technologies in a Large-Scale MV/LV Distribution System

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ABSTRACT Power distribution systems are experiencing large deployment of behind-the-meter distributed generation and storage along with electrified transport and heat, requiring fundamental changes in planning and operation. There are increasing efforts to directly model real large-scale networks and conduct detailed analysis beyond conventional practices. Utilizing optimization methods to leverage distributed generation to the benefit of the distribution system and all customers is the ideal. However, progress towards adoption of such controls by system operators are impeded by concerns over privacy, regulatory and market issues in many jurisdictions. While these issues are being addressed, there may be opportunity to exploit the synergistic effect of mixing low carbon technologies (LCT). This paper presents a large-scale medium voltage (MV)-low voltage (LV) integrated system model building, scenario determination and analysis approach for distribution systems. Data with different formats from several databases are used in model building. In collaboration with the national distribution system operator (DSO) in Ireland (ESB Networks), a pilot study is conducted for a rural system in the Southwest of Ireland, highlighting the challenges of directly modelling real distribution systems and investigating the potential synergies between multiple low carbon technologies.

INDEX TERMS Distribution control, distribution lines, distribution planning, power distribution, power system simulation.

I. INTRODUCTION

Distribution systems are on the frontline of bottom-up transformation of power systems [1]. Efforts towards decarbonization, decentralization, integration and digitalization are shaping the necessities for distribution system planning and operation [2]. In 2021 even with arising supply challenges in the industry, annual electric vehicle (EV) sales more than doubled from 2020 sales figures to 6.6 million, reaching

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around 9% of the global car market and more than tripling market share compared to 2019 [3]. From 2019 to 2024, residential, commercial and off-grid distributed photovoltaic (PV) installations are expected to more than double, constituting nearly half (more than 300 GW) of the overall solar PV capacity growth [4]. The proliferation of heat pumps (HP) is also expected to increase with some net zero energy scenarios indicating a 600 million HPs by 2030, and increasing from nearly 180 million globally in 2020 [5]. At low penetration levels of low carbon technologies (LCT), while transmission system operators (TSO) do not face considerable

problems, distribution system operators (DSO) observe bus voltage and line loading limit violations which become more significant at large penetration rates, especially in rural grids [6].

There are significantly more assets in distribution grids compared to transmission grids. In Ireland, there are over 20 times more lines, 500 times more substations and 3700 times more transformers at the distribution level compared to the transmission level [7]. This structural complexity meant that distribution systems were conventionally modelled and analyzed considering mainly the primary or medium voltage (MV) systems, while the secondary or low voltage (LV) sides of the systems have limited details or are not even included [8]. The preliminary approach to handle the initial integration of EV chargers, batteries, PVs, HPs and other new assets is to have a reinforceable system and follow a wait-and-see approach. There is an initial application procedure and a lead planning time to respond to such major changes in the operated system for large facilities but not for residential. Locally concentrated behind-the-meter integration of new assets (such as installing electric heaters in large residential complexes, special offers in setting up domestic EV chargers and other) may accelerate the escalation of highly localized network issues at the LV level. It may be more challenging for the system operator to deal with such problems, as reinforcements on the main feeder and transformer may not satisfactorily address highly localized network issues.

An impact assessment of HPs on LV networks showed that more feeders suffered voltage and congestion issues with higher penetration levels [9]. Importantly for operators of rural grids, generally the further the PV source from the feeder head the lower the potential for penetration without network issues [10]. Assessment of the impact of a range of LCTs on LV feeders was considered in a study [11] but there is a deficit of such integrated MV/LV distribution system studies considering LCTs of EVs, HPs and PV as this study does.

This paper presents a framework for MV-LV distribution system modelling and automated scenario determination, and a combined integration analysis of different LCTs for distribution grids. The vast majority of the past works have dominantly considered individual integration scenarios of PV, EV or HPs into distribution systems. There have been some efforts to investigate dual combinations. This is one of the first studies to investigate the integration of all the three technologies together, in a large-scale network, using high-fidelity scenarios for PV, EV, HP, residential and commercial demand, highlighting the synergies between different technologies in daily operation comparatively with the individual and dual integration options.

The main contributions of this study are threefold:

- 1) To the best knowledge of the authors, this is one of the first studies that provides integrated penetration analysis of PV, EV and HPs, highlighting the synergies between these technologies.

- 2) The challenges of developing large-scale MV/LV distribution system models and the benefits of conducting integrated penetration of LCTs are addressed from the DSO point of view.
- 3) A real large-scale integrated MV/LV distribution system in Ireland is modelled in detail considering all distribution system constraints.

Section II of the paper provides an overview of the latest state-of-the-art and identifies the gaps that should be addressed. Section III presents the methodologies developed throughout the course of this work. Section IV is devoted to the pilot study details and its results. Section V concludes the paper by discussing the findings and providing directions for future research.

II. STATE OF THE ART

In terms of power system model development, a study identifies four approaches that best generalizes the prominent works in the literature: manual design, clustering and combining, use of real data through feeder anonymization and automated planning tools [12]. Manual design and clustering are used for synthetic system modelling, while feeder anonymization is for modelling systems based on real data and automated planning can serve both purposes. Some systems comprise a substation with several different feeders such as residential, commercial and industrial feeders as in [13] or local generation and storage assets to represent a microgrid case as in [14]. These studies aim to provide a system available for use to researchers, rather than presenting a replicable model building approach, as they develop the models in a straightforward and deterministic way.

There are also some replicable approaches such as Reference Network Model greenfield approach using the general statistics provided by DSO [15] or clustering several networks based on k-means together with Euclidean distance [16], fuzzy k-medoids [17] or a combination of several methods (k-meoids++, k-means++, Gaussian Mixture Model together) [18]. The resulting networks can represent diverse topologies and characteristics up to an extent, with tolerable differences in analysis results of the representative ones and the rest of the networks in the identified clusters. Production of synthetic models may require some assumptions for simplification, such as equal distribution of branches on a main feeder, consecutive distribution of load points and other. Statistical, operational and expert validation approaches are suggested to evaluate the realism of synthetic networks [19].

A study that reviewed the distribution test feeders, identified the main limitations as,

- small size,
- lack of time series data,
- lack of representativeness,
- missing geographical coordinates,
- design and data availability for a single purpose and isolated feeders,

specifically emphasizing the need for building larger-scale systems [20]. A recent alternative and hybrid approach is to

use a mixture of real network data from different parts of the network to develop large scale integrated MV-LV models [21]. Although the considered networks are not directly connected to each other in reality, the developed integrated model can serve as a highly realistic model for researchers. In a similar manner, direct modeling of large scale real MV-LV systems is a recent approach that gains particular interest [22]. There are efforts to automate the determination and exploration of the desired planning and operational scenarios. Load allocation to customer nodes can be organized to match feeder level real measurements as in [23]. Smart meter data can be automatically allocated to customer nodes using Euclidean distance as in [24]. A recent study proposes the use of advanced metering infrastructure (AMI) data from customer nodes, together with data acquisition system (DAS) measurements at MV-to-LV transformers to determine time-series load profiles, comprising the unmetered loads [25].

Building large scale systems models by direct integration of real data from the field can also enable real-time analysis and digital twin applications. A conceptual explanation of real-time distribution system analysis is available and a pilot application examining its applicability in the field is presented in [26]. In terms of analysis, the approach taken depends on the purpose of the study. Quasi-Static Time Series (QSTS) analysis is among the four main approaches mentioned in the draft IEEE guide on conducting DER impact studies investigating equipment control, operation and voltage regulation. The other approaches are dynamic simulation for stability and voltage frequency ride-through studies, electromagnetic transient simulation for protection design and fault analysis and harmonic and flicker study for power quality of feeders [27]. Unlike snapshot simulation, QSTS allows accurate analysis of DER impacts on voltage variations, energy and loss calculations closer to daily operational cases, preventing overestimation of impacts due to sole consideration of extreme peaks. It can provide accurate quantification of magnitude, occurrence and duration of impact.

Recent literature has proposed optimization and control strategies for managing congestion and voltage in integrated MV/LV distribution systems [28], [29]. In principle, such concepts present the ideal solution for the DSO but there are significant challenges to their implementation. One study which considers a MV/LV distribution system with PV avoids many of the modelling challenges detailed in Section IV.B of this paper by avoiding the direct modelling of the system. The scheme determines the appropriate setpoints for the onload tap changers (OLTC) to manage voltage and PV to manage congestion. To successfully operate, irradiance data and smart meter data as well as power measurements from the MV feeder are required. If smart metering is not present or not interrogatable, it requires measurement devices at every distribution transformer, at the head of each LV feeder and at the remote end of at least the longest LV feeders for the furthest distribution transformers from the MV feeder [28].

Additionally, it requires communication and operating permissions for the PV system, essentially requiring the owner of the PV system to relinquish some control to the DSO. As reducing costs is a key driver for homeowners who install PV systems, suitable market mechanisms would have to be in place to incentivize prosumers to participate in such schemes. Smart meter data is personal data under data protection laws in some jurisdictions such as Ireland. In this case the DSO is currently restricted from using smart meter data for uses outside of those explicitly permitted under its operating license or by law and only relevant to the tariff type selected by the consumer [30]. While this may change in the future, in the interim studies that look at the synergies of deployment of multiple LCTs, such as the one presented in this paper are particularly important. The synergies can pave the way for the development of more effective DER coordination approaches and mechanisms too.

III. METHODOLOGY

As seen in Fig. 1, an MV model used for DSO system planning purposes of a particular area is converted from commercial planning software format to the open source power system analysis tool OpenDSS format. The OpenDSS MV model is validated against the original DSO system planning model to confirm that the voltage profile obtained with the OpenDSS MV model is reasonable. In parallel, data is extracted from the DSO geographic information system (GIS), asset management and operational databases for the individual LV areas, located within a subset of the geographical area covered by the MV model. The extracted data is formatted into generic data format and missing/incorrect data is detected and corrected using python scripts and assumptions. Subsequently, OpenDSS models for the individual LV areas are created. Each LV model is validated using historical information, where available. Integration of the MV and LV models then takes place, ensuring alignment of the respective model geometries. Validation of the integrated MV-LV model is performed using historical measurements and through assessment made in consultation with the DSO for the modelled area. Scenarios are determined for PV, EV, and HP penetrations and comparative analyses performed to determine potential synergies of the deployment of multiple LCTs as indicated in Fig. 1.

IV. CASE STUDY

A. THE MODELLED DISTRIBUTION SYSTEM

A real 10 kV MV feeder owned and operated by the Irish DSO ESB Networks, with 2,188 customers is used for this work. The network comprises a mixture of underground and overhead conductors. The customers are predominantly residential with a significantly smaller number of industrial/commercial customers. In addition to the MV feeder, a total of 51 individual real LV networks are modelled connecting 317 customers, inclusive of 12 3-phase customers. The remaining 1,871 customers are represented by loads connected directly to the MV network. The number of customers

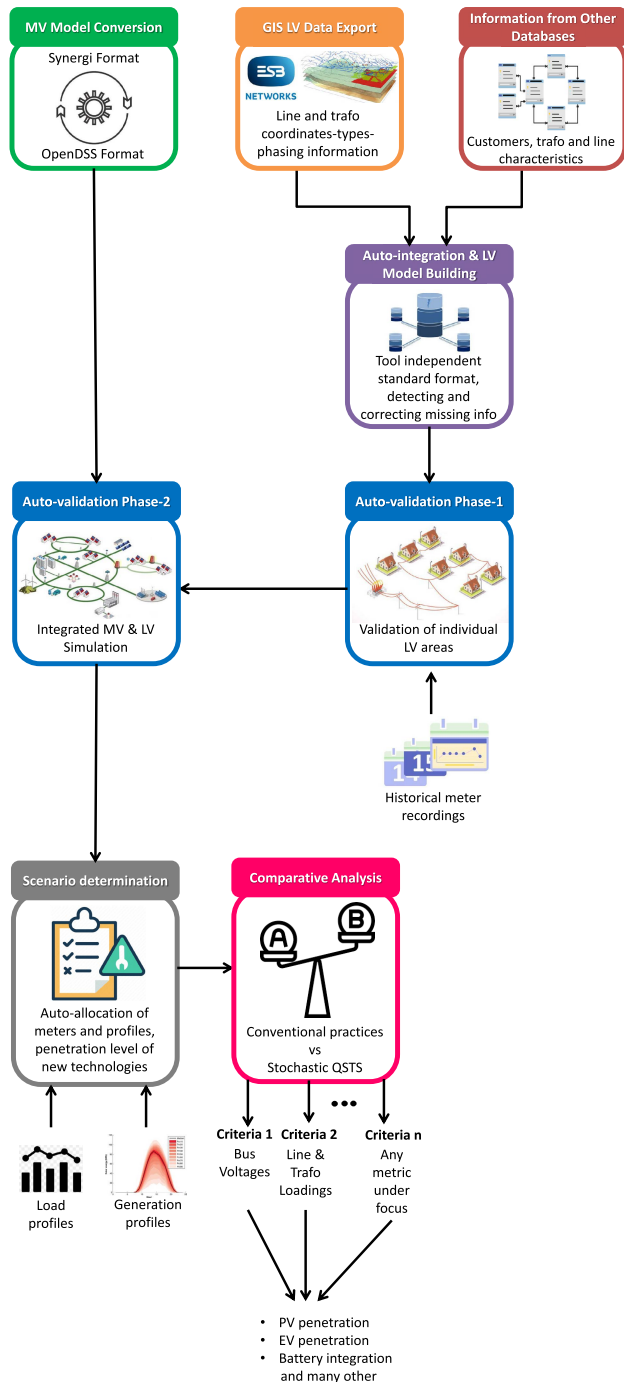


FIGURE 1. Overview of modelling process.

per LV network varies from 1 to 56 reflecting the reality of the mixture of one-off housing and holiday home estates in many coastal areas in Ireland. The distance of customers to the MV/LV transformer in the LV networks also varies significantly, the nearest is ~18 m, the furthest ~370 m and the average distance of customers within all 51 LV networks is ~149 m. The 51 MV/LV transformers range in size from 5 to 200 kVA. The 38 kV substation at the

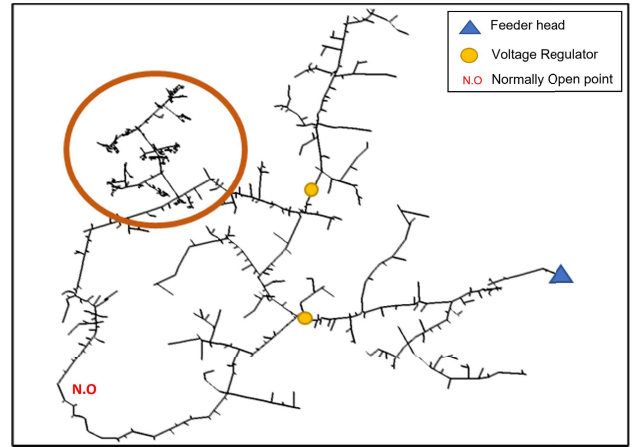


FIGURE 2. Integrated MV-LV modelled area (circled area is the detailed LV section).

head of the feeder supplies the 10 kV feeder (and other 20 kV feeders not included in this model) via a mix of both 38/10 kV and 38/20 kV transformers. The 10 kV side of this feeding substation is represented by the blue triangle in Fig. 2, i.e., the feeder head for the purpose of this model. The feeder voltage is set to 1.05 pu in line with typical network operation by the DSO for this substation.

B. LOAD ALLOCATION AND DETERMINATION OF PV, EV, AND HP PROFILES

Load allocation was carried out separately for the LV and MV parts of the network. Within the modelled LV network, load allocation was confined to line end points starting with the furthest point from the MV-LV transformer and divided equally among the endpoints. Loughborough University’s CREST Demand Model [31] was used to generate stochastic individual daily load profiles for each residential customer in a manner that ensured the measured transformer peak demand at each of the 51 MV/LV substations did not exceed operational tolerances allowed under the DSO security and planning standards [32]. CREST Demand Model is an open-source tool that has already been cited and used in over a thousand studies. It is based on household usage statistics of the United Kingdom, meteorological data and appliance parameters. It provides the specification of the number of people, the day of the year and assignment of appliances in a dwelling.

Following a bottom-up approach and using stochastic programming methods, it aggregates the consumption behavior of each appliance and produces residential load profile for a day with 1 min resolution. The details of the tool together with its performance verification can be found in [31]. Synthetic load profiles using the annual total energy consumption data were generated for each commercial customer using the commercial load hourly average per unit values presented in previous literature [33]. For the remainder of the MV network modelled, where LV is not specifically modelled,

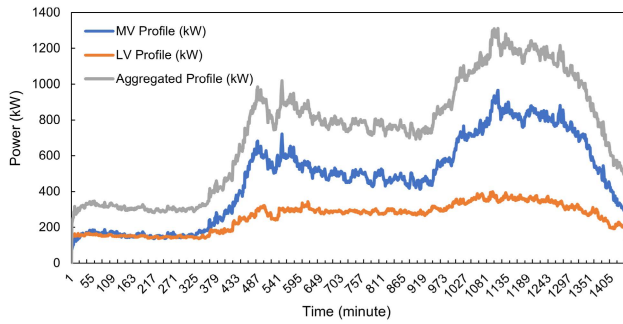


FIGURE 3. 24 hour base load profile for MV, LV and combined MV and LV demand.

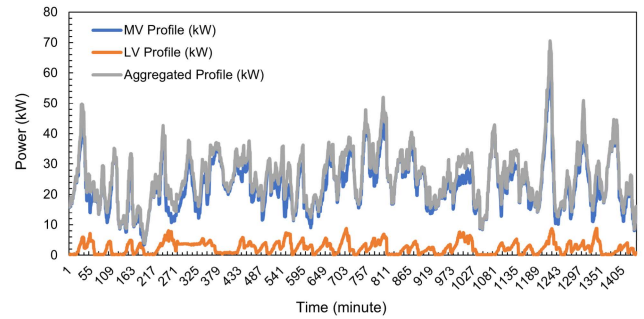


FIGURE 6. Daily aggregated HP demand profile for MV, LV and combined MV and LV with 15% penetration level.

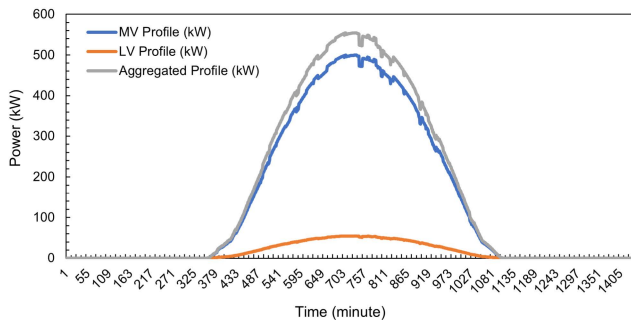


FIGURE 4. Daily aggregated PV production profile for MV, LV and combined MV and LV with 15% penetration level.

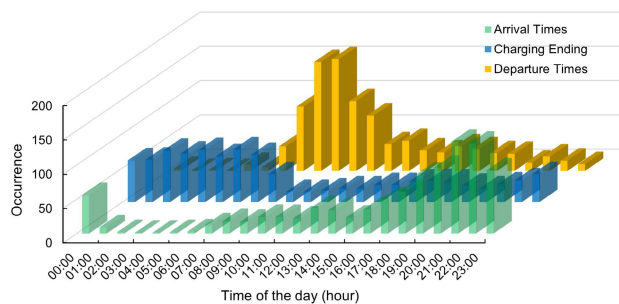


FIGURE 5. EV arrival, departure and charging starting times recorded during the field pilot.

bulk MV loads to represent the remaining 1,871 customers were created using synthetic load profiles based on the peak load and number of customers connected to each MV point. The generated load profiles for MV, LV, together with combination of MV and LV are depicted in Fig. 3.

For PV, a standard installation size of 2.1 kWp was considered. This reflects the size adopted in a recent pilot project by the DSO in the area modelled [34]. The percentage penetration of PV is attributed to the percentage of the number of customers in each substation and it is rounded up to the nearest integer. In addition, it is assumed that each customer is able to have a 2.1 kWp standard PV size. For example, in the case of 10% PV penetration, a substation with 48 customers, the 5 furthest away customers are going to have 2.1 kWp

PV installed (i.e., 10% X 48 equates to $4.8 \approx 5$ customers). PV profiles were derived using another version of the CREST model, which can generate stochastic solar irradiance profiles with 1-min resolution, based on meteorological statistics, including cloudiness [35]. Figure 4 depicts the aggregated PV production profiles for only LV customers, only MV customers, and a combination of them in case of 15% penetration level.

The data from the DSO project [34] into EV use and smart charging in the area modelled was used to generate statistics for EV arrival/charging start time, charging end time, and EV departure time as demonstrated in Fig. 5. This enabled the generation of 951 EV charging profiles with 1 min resolution. In line with the field pilot, charging power is considered as 7.4 kW. Similar to the findings of the pilot study, EV charging typically takes place between 11 pm and 8 am taking advantage of the reduced night-time tariff rate. Combinations of the EV profiles are randomly selected and assigned within the network to reflect the relevant percentage of EV penetration under assessment. Similarly, HP profiles were modelled based on measurements taken from energy meters installed on the 5 HPs installed as part of the DSO project. Figure 6 demonstrates the aggregated HP power demand profiles for only LV customers, only MV customers, and a combination of them in case of 15% penetration level.

Scenarios involving PV, EV, and HP separately were investigated, as well as every technology combination. Increases of 1% penetration were simulated until the model ceased to converge. This non-convergence is explained by the fact that for every technology case, the maximum penetration level achieved is considerably larger than the peak loading conditions of the feeder, i.e., the feeder is not designed to handle larger currents, power flows, voltage drops and rises, etc.

C. CHALLENGES OF LARGE SCALE INTEGRATED MV-LV MODEL DEVELOPMENT

A number of challenges were encountered during the model development process. These challenges can be grouped into several broad categories:

1) LEGACY ASSET DATA ISSUES

Within power utilities there is often a diverse range of data sources and databases relating to network assets such as GIS, Asset Management Systems (AMS) and Energy Management Systems (EMS) [36]. While 45 years is considered the typical length for distribution network asset life from a business perspective in Ireland [37], the technical reality is that many assets remain fully functional and operational on the network beyond this timeframe, particularly at lower voltage levels. Records for such older network assets, commissioned at a time when paper records were standard, were often stored in local area offices rather than a central repository with cataloguing and archiving approaches varying from area to area. A backup of digital records is commonplace nowadays, however backups of paper records were not standard in the past. Thus, even though digital records of every asset typically exist today, the level of detail contained in these records for older assets is dependent on the existence and condition of the paper record at the time the digital records of the asset were created. This issue is often the cause of missing asset data which can make it difficult to create models of real networks.

2) DIFFERENCE IN GEOMETRIES BETWEEN MV AND LV NETWORK

The geometry of an asset is used to locate it on a map and this works very well for significant lengths of line and cable assets. Other assets, although essential to the network and documented in the asset registry for the distribution network, may not need to be mapped due to their small lengths. Thus, they may not be specified in a GIS system. These include assets such as jumpers and lead-ins. This can lead to a misalignment in geometries when developing MV and LV network models. Additionally, if the origin of geospatial information is not the same for the MV network and the LV network this can introduce further differences in the alignment of the model geometries. This is particularly a problem when it comes to integration of MV and LV models.

3) TIMING OF MV AND LV DATA EXTRACTION

By their nature distribution networks are constantly evolving, with network upgrades and reinforcements, phasing changes to address unbalance issues, and new connections. By availing of already existing MV models, as was adopted in the methodology in this paper, there can be a difference in the date at which data was extracted to build the MV and LV models, leading to higher chance that the MV model does not fully reflect the real MV network at the time the LV models were built. Updating the MV network can be a labour intensive process and if it is not completed, it can cause problems at model integration stage, particularly if phasing is not correct.

4) AVAILABILITY OF HISTORICAL DATA

To validate an integrated MV-LV model, ideally a full set of historical network and customer meter data would be

available. In reality, this is challenging. For this work, real historical metering data for individual customers was available from the DSO project, where permission was sought and obtained from each individual customer to allow recording of meter data for a specific period only. Typically, individual customer metering data is not available due to privacy and regulatory issues. Aggregated customer data can be used but would typically be located at the MV-LV transformer point. Due to the radial nature of the distribution network and its historical unidirectional power flow paradigm, real time network monitoring of MV/LV is not widespread. Although, it may be warranted with the increase in distributed and behind-the-meter generation, there can be challenges in acquiring this data remotely, particularly in rural areas with poor telecommunications coverage. This makes model validation particularly challenging and in the future may present difficulties implementing control strategies to manage congestion and voltage issues. The approach used to overcome each type of challenge is presented in Table 1.

D. BENEFITS OF INTEGRATED MV-LV MODELLING

The fundamental role of a DSO is to operate a safe secure and reliable network in as economic a manner as possible. The traditional approach using design rules of thumb had significant merit. However, the increasing volume of DER at MV and LV is changing the traditional unidirectional power flow of radial distribution networks. Integrated modelling of MV-LV networks provides an opportunity for DSO to ascertain whether the enduring use of these design principles sufficiently meet the requirements of the fundamental role of a DSO. Integrated MV-LV models offer several additional benefits for DSO and the research community including the ability to:

- 1) Identify strain on the LV circuits due to local energy balancing
- 2) Evaluate suitable network reinforcements to harness the benefit of combinations of DER technologies and minimize cost
- 3) Quantify the impact of network investment on network losses
- 4) Estimate hosting capacity across the network
- 5) Assess the impact and efficacy of proposed operational strategies to address network issues such as active voltage regulation, phase changes, curtailment or other.
- 6) Provide a base model for developing detailed models required for dynamic stability or harmonics studies.

While there are challenges to developing these models in the first instance, once developed the overhead in updating and modifying existing elements of the models is relatively small, particularly if a suitable naming convention has been employed. Furthermore, the range of scenarios and technology types that can be explored is extensive, particularly when using an open source modelling tool such as EPRI OpenDSS. Such models, complemented by suitably located monitoring devices could also be used in the development of state estimation tools for real time network monitoring by DSO.

TABLE 1. Challenges and mitigation measures.

Legacy asset data issues	Utilise assumptions for missing asset data. For incorrect data - appoint a single source of truth for each data item
Difference in Geometries	Add low impedance connectors to address the misalignment of geometries
Timing of data extraction	Develop MV and LV models at the same time If not possible, using a standardised nomenclature in both models will assist in speeding up the correction process.
Availability of historical data	Utilising demand modelling tools such as the CREST model for each customer and ensuring alignment with the peak of the aggregate profiles if available will mitigate this. Availing of DSO in-house expertise to validate the model the integrated model like the approach adopted in [37]

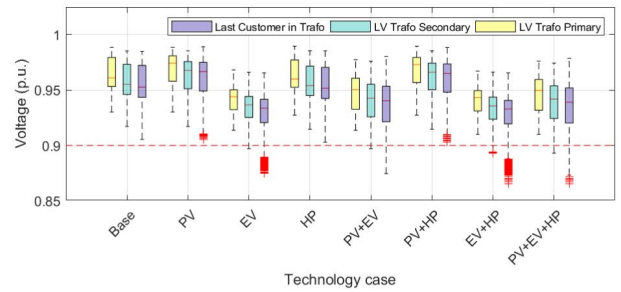


FIGURE 8. Voltage measured at different points for all transformers and each case.

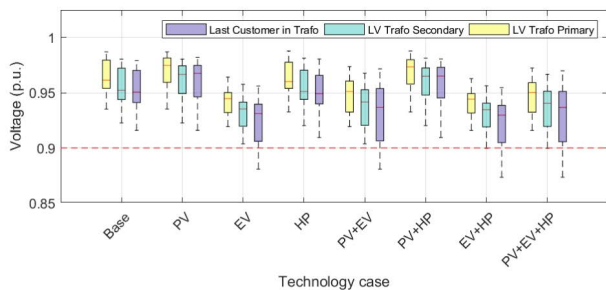


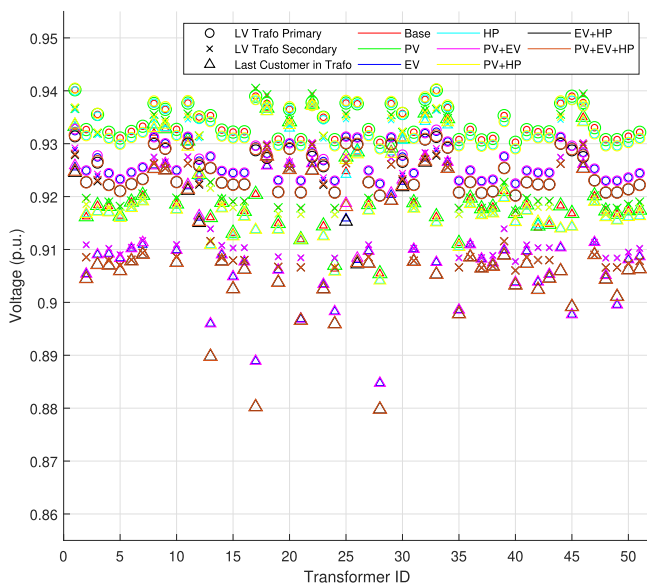
FIGURE 7. Voltage measured at different points for a selected transformer (ID 13) for each case.

V. RESULTS

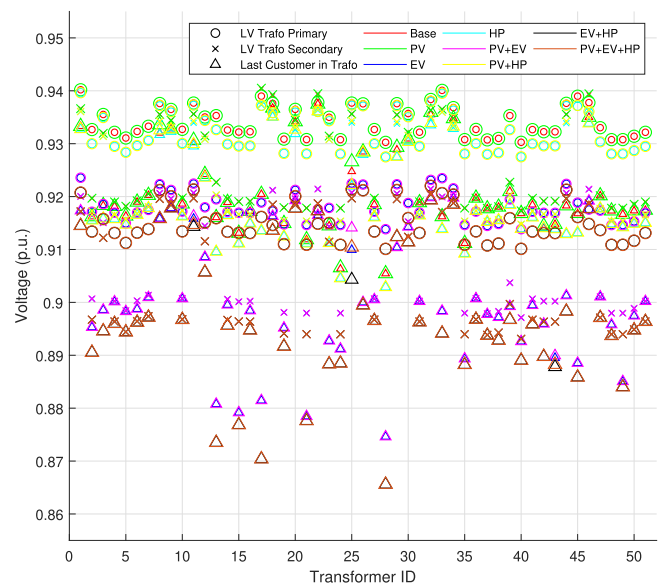
Numerous simulations have been conducted to investigate the impacts of integrating combinations of LCTs on the MV/LV distribution system in the Dingle peninsula. For clarity and due to page limitations all obtained results could not be

presented within the paper. All measurements are monitored at three different points in the model that are, in turn, primary sides of LV transformers, secondary sides of transformers, and furthest customers in the related substation. A boxplot for voltage levels measured at different points for a transformer (ID 13) is demonstrated in Fig. 7 in case of both individual penetrations and combinations of the evaluated technologies. It is worth underlining that the penetration level is 15% here for each technology and the transformer ID 13 has been given as an example here due to remarkable changes in voltage levels. As can be concluded from the mentioned figure, while only PV penetration causes voltage rise, it is still within the limits, EV penetration for both individual penetration and its combinations with other technologies (dual and triple combinations) results in relatively lower voltages. In addition, voltage exceeding the lower bound limits can be seen in each case which is including EV integration.

Comparative analysis results of LV transformer primary, secondary and the furthest LV customer for all transformers and each technology integration scenarios is shown in the

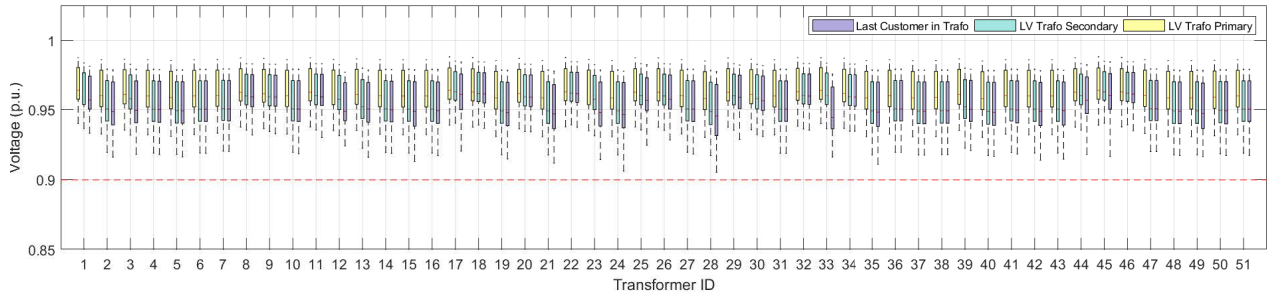


(a)

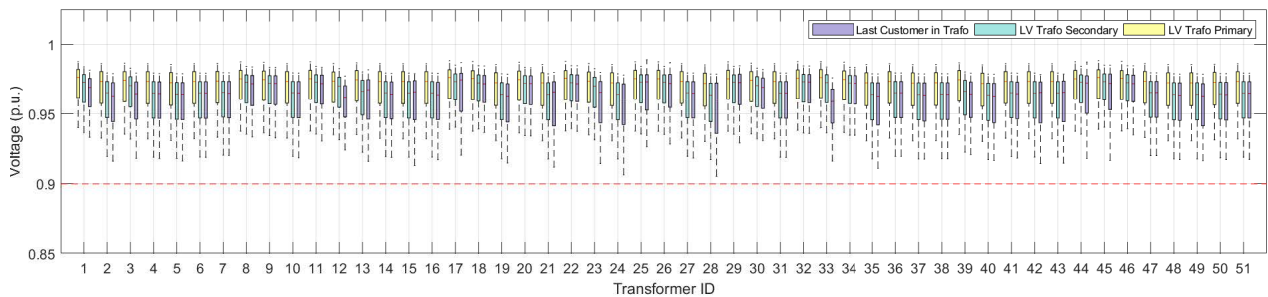


(b)

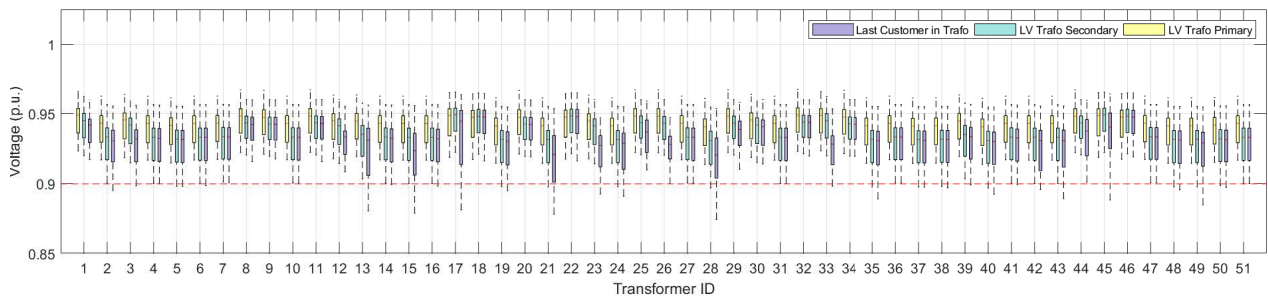
FIGURE 9. Scatter plot containing the critical voltage of the day for each transformer, technology and measuring point (a) 10% penetration (b) 15% penetration.



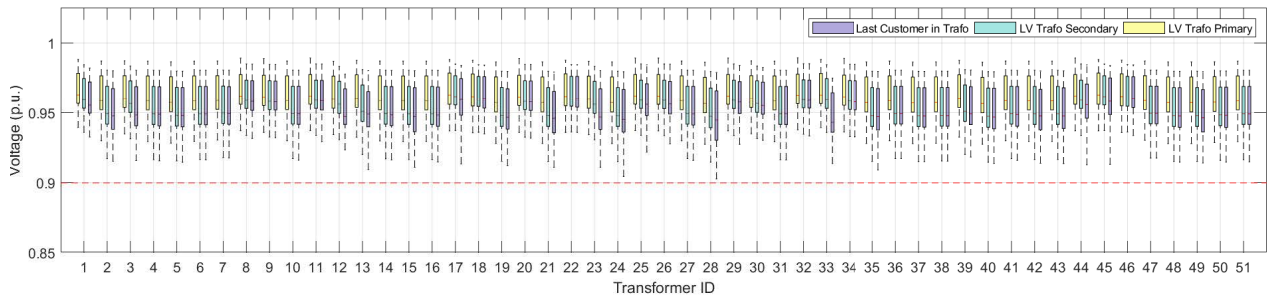
(a)



(b)



(c)

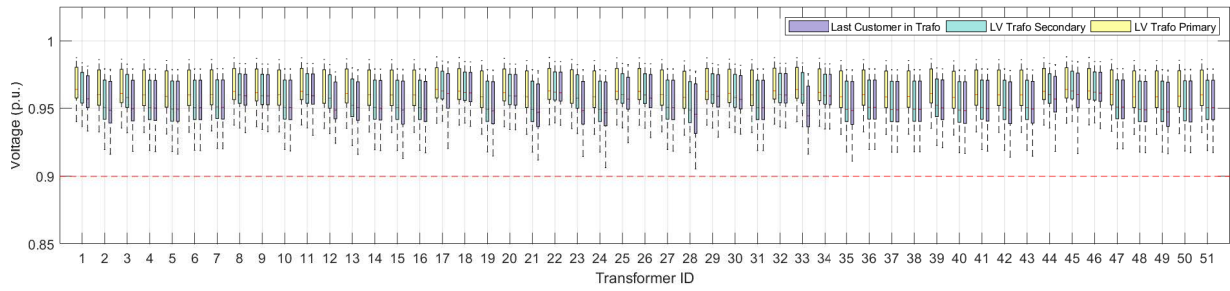


(d)

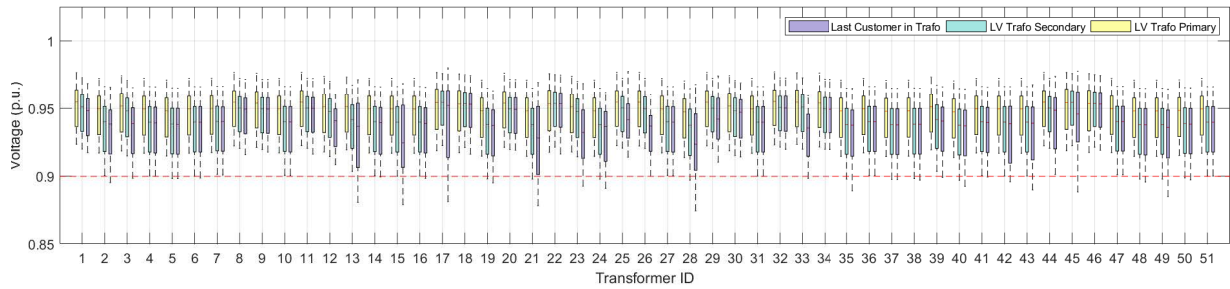
FIGURE 10. Voltage measured at different points in the base case and the individual cases with 15% penetration level (a) Base Case (b) PV only (c) EV only (d) HP only.

Fig. 8 and 9. Results for each LV area are provided in the Appendix. PV integration results in increased average and highest voltage values, with no considerable improvement in the lowest voltages observed in daily operation (see Fig. 10b). This is mainly due to occurrence of daily peak demand in

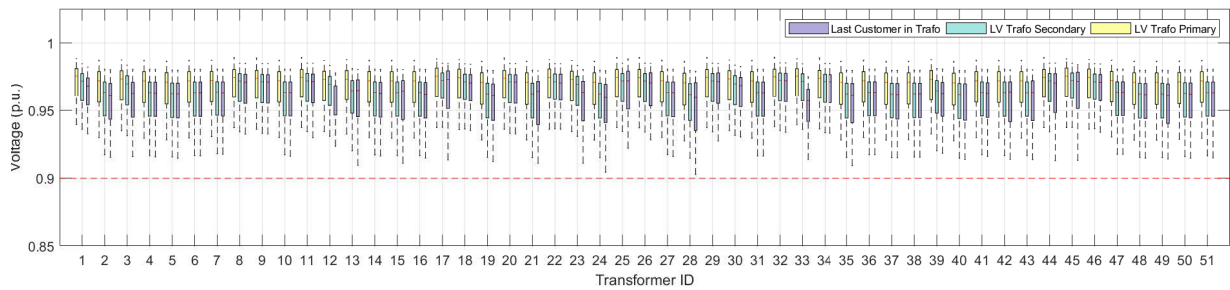
the evening, when there is no output from PVs. Integration of HPs has minor impacts on the highest, average, and lowest observed voltages, since they usually simultaneously operate early in the morning, during low demand times (see Fig. 10c). Integration of EVs, considerably reduces the highest,



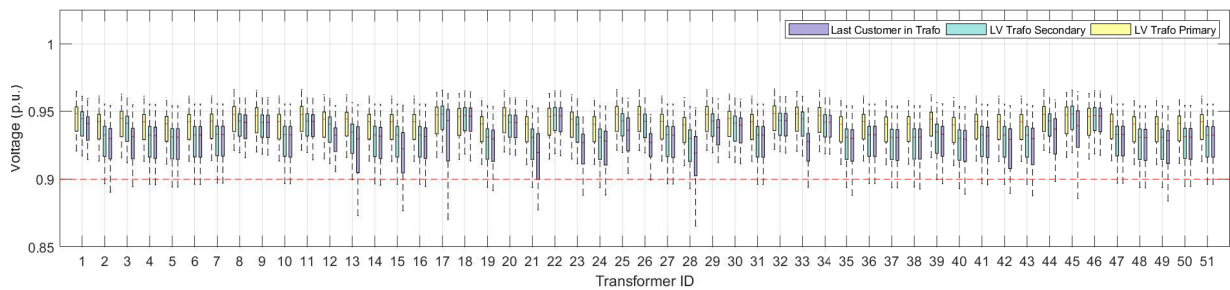
(a)



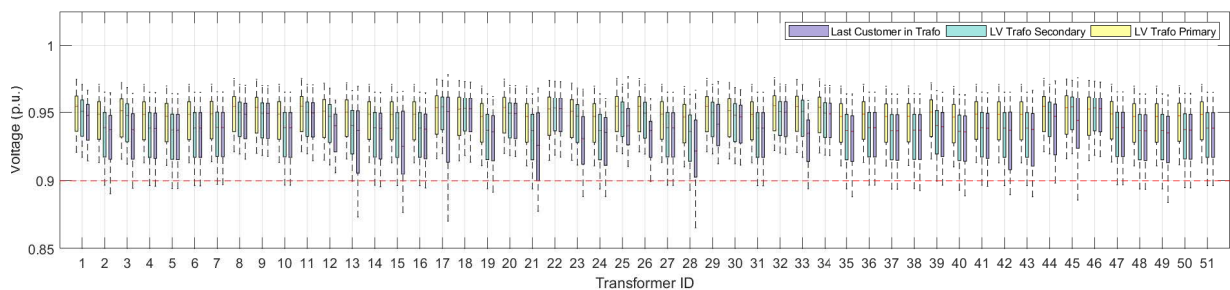
(b)



(c)



(d)



(e)

FIGURE 11. Voltage measured at different points in the base case and the combined cases with 15% penetration level (a) Base Case (b) PV and EV Case (c) PV and HP Case (d) EV and HP Case (e) PV, EV and HP Case.

average, and lowest observed voltage values, triggering undervoltage issues at customer nodes at the same penetration level (see Fig. 10d). This is due to high charging rates of chargers and the coincidence of simultaneous EV charging with high residential demand times.

Combined integration of PV with EV increases the average and the highest observed voltages (see Fig. 11b), compared to the sole EV integration case. On the other hand, it does not improve the lowest observed voltages since these voltages occur in the evening when there is no generation from PV. Combined integration of PV and HP helps increase the average voltages considerably compared to the sole HP integration case, while the highest and lowest observed voltages remain almost the same (see Fig. 11c). Combined integration of EV and HP results in slightly further decrease in the average and lowest observed voltages since their high demand times mostly do not coincide with each other (see Fig. 11d). The impacts for this case are particularly evident at the LV customer nodes. Addition of PV to EV and HP integration increases the average and the highest observed voltages, without considerable improvement in the lowest observed voltages and undervoltage risk as seen in Fig. 11e.

The analysis provided valuable findings for PV, EV and HP integration options into distribution systems. Due to higher per customer installed power and coincidence of EV and HP demand with residential peaks compared to lower coincidence of PV peaks with low demand times, undervoltage problems is primarily observed rather than overvoltage issues for the same penetration rates of technologies. Furthermore, it is possible to integrate EV and HP together with no considerable escalation of unintended impacts compared to sole EV integration, due to low coincidence of their daily peaks. Moreover, PV can be integrated together with EV, HP or both to help improving the overall voltage profiles; but not reducing the undervoltage risks considerably. Combined integration of PV with EV, HP or both is also helpful at reducing the risk of overvoltages that may be faced in uneven penetration rates (with high penetration of PV and relatively lower penetration of EV, HP or both) of technologies. The analysis highlighted the need to implement active mitigation methods especially to prevent undervoltage problems and increase hosting capacity of EV and HP.

VI. CONCLUSION

This study presented a large scale MV/LV integrated distribution system modelling approach and comparative PV, EV, and HP integration analysis, considering combined integration scenarios. Different types of data from diverse databases were used to develop models of LV feeders in detail and conduct MV/LV integrated quasi-static time series analysis at large scale, in collaboration with the DSO ESB Networks, in a pilot area in Ireland.

The modelling study highlighted the challenges that DSO may face in further extended LV modelling efforts. The comparative analysis highlighted the suitable integration combinations of new technologies into existing

networks. In combined integration with similar penetration levels, undervoltage problems are more likely to be faced rather than overvoltage issues. PV is useful to increase average voltage and the highest observed voltages in combined integration, while it does not prevent undervoltage events that occur in the evening or early in the morning, at times when supply from PV is not available. HP peak demand does not coincide with the daily residential peak, causing slight negative impacts compared to the base case. EV integration has considerable impacts on the average, highest and the lowest voltages, leading to undervoltage issues.

Combined integration of EV and HP provided results similar to sole EV integration case, since their daily peak times (early morning for HP and late night for EV) do not coincide with each other. Addition of PV to EV and HP integration is useful to improve voltage profiles. However, active voltage mitigation techniques need to be implemented to prevent undervoltage and enable higher penetration rates of electrified transport and heat. The MV-LV area modelled has known challenges and significant projects are in the pipeline to upgrade the existing MV network voltage level from 10kV to 20kV. Yet, the insights gained during the model development can assist in facilitating country-scale implementation.

The future work will address active management methods to mitigate the operational problems faced in integration of PV, EV and HP and analysis of the additional hosting capacities that may become available in LV networks.

APPENDIX A DETAILED COMPARISONS OF CASE STUDIES

Voltage measured at different points in the base case and the cases and its combinations with 15% penetration level are shown in Fig. 10 and Fig. 11.

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