Distribution Network Use-of-System Charges Under High Penetration of Distributed Energy Resources

by

Ashwini Bharatkumar

B.B.A., Operations Research & Information Systems
University of Wisconsin-Madison, 2012

Submitted to the Engineering Systems Division
and
Department of Electrical Engineering and Computer Science
in Partial Fulfillment of the Requirements for the Degrees

of

Master of Science in Technology and Policy
and
Master of Science in Electrical Engineering

at the

MASSACHUSETTS INSTITUTE OF TECHNOLOGY
February 2015

Signature of Author ....

Engineering Systems Division
Department of Electrical Engineering and Computer Science
January 30, 2015

Certified by ....

Jose Ignacio Pérez-Arriaga
Visiting Professor, Engineering Systems Division
Thesis Supervisor

Certified by ....

James L. Kirtley, Jr.
Professor of Electrical Engineering
Thesis Reader

Accepted by ....

Dava Newman
Professor of Aeronautics and Astronautics and Engineering Systems
Director, Technology and Policy Program

Accepted by ....

Leslie A. Kolodziejski
Professor of Electrical Engineering and Computer Science
Chair, Department Committee on Graduate Students

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Abstract

Growing integration of distributed energy resources (DER) presents the electric power sector with the potential for significant changes to technical operations, business models, and industry structure. New physical components, control and information architecture, markets, and policies are required as the power system transitions from one of centralized generation and passive load to a network of increasingly decentralized generation and diverse system users. Price signals will play a crucial role in shaping the interactions between the physical components and users of the electric power system. Distribution network use-of-system (DNUoS) charges signal to network users how their utilization of the distribution system impacts system costs and each user's share of those costs. Distribution utilities cover network operation and maintenance costs and recover infrastructure investments through DNUoS charges applied to network users. This thesis develops a framework for the design of DNUoS charges that addresses the challenge of distribution network cost allocation under growing penetration of DER. The proposed framework is comprised of 1) the use of a reference network model (RNM) to identify the key drivers of distribution system costs and their relative shares of total costs, and 2) the allocation of those costs according to network utilization profiles that capture each network user's contribution to and share of total system costs. The resulting DNUoS charges are highly differentiated for network users according to the impact that network use behaviors have on system costs. This is a substantial departure from existing methods of distribution network cost allocation and thus presents implementation challenges and implications that may be addressed in a range of ways to achieve varying regulatory objectives.

Thesis Supervisor: Jose Ignacio Pérez-Arriaga
Title: Visiting Professor, Engineering Systems Division

Thesis Reader: James L. Kirtley, Jr.
Title: Professor of Electrical Engineering and Computer Science

Acknowledgements

There are multiple people to whom I offer my sincerest gratitude for your intellectual generosity, encouragement, and support in the development of this thesis. MIT is a truly remarkable place of so many enrichment opportunities. I want to thank the people that have contributed to creating a mentally stimulating environment that has continually pushed me outside my comfort zone and unquestionably reshaped the way I think.

First and foremost, thank you so much to Ignacio, one of the most patient individuals I know, for your guidance, expertise, and ceaseless encouragement. It has been inspiring to work with you, and I hope that I will one day do justice to the knowledge and wisdom you have so generously imparted.

Thank you Professor Kirtley for your expertise and feedback, for pointing me towards helpful resources, for answering my questions along the way, and for fruitful conversations about my broader intellectual development.

Thanks to Claudio Vergara for your boundless generosity in sharing your expertise, help, and guidance. I am exceedingly grateful for the knowledge and time you have so readily offered.

Thanks to Carlos Mateo for so speedily answering my countless emails and for all of your advice and guidance on utilizing the reference network model.

Thanks to Jesse Jenkins for your highly valuable insight, suggestions, advice, and critical thinking, and for asking the right questions to guide my own thinking.

Many thanks also to Richard Tabors, Tomás Gomez, and Carlos Batlle for contributing to the intellectual foundations upon which I have only just started – and will continue – to build my understanding of the power sector.

Thanks to TPP for launching me into the continuing quest of grad school. Thank you Barb, Frank, and Ed for all of your help and support. Thanks to my friends and classmates for being the most wonderful sources of enriching conversation and constant exposure to new wonders of life.

And finally, thank you especially to my parents for your support and patience through the journey of grad school that is only just beginning. Thank you for being such incredible role models and friends, thank you for all of your honesty and encouragement. I would not be at this juncture in life without you.

My work is supported by a National Science Foundation Graduate Research Fellowship.

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1 Introduction

The power system is being reshaped by a host of changes rippling throughout the electric power sector and the utility industry. While all levels of the power system are facing new challenges driven by the potential for a range of new technologies and policies, the growing integration of distributed energy resources (DER) such as distributed generation and storage, electric vehicles, and demand response may significantly alter the planning and operation of the distribution system and the rest of the power system. A variety of reports — by organizations including Eurelectric [16], the International Energy Agency [29], the Edison Electric Institute [34], the Electric Power Research Institute [15], and many more — have described the power system-wide challenges and opportunities that DER may present or are already presenting in Europe and the United States. Corporations such as General Electric [45], ABB [1], and Siemens [57] have articulated visions and plans for a future power system and utility sector with increased integration of decentralized resources.

Distribution systems around the world are seeing growing integration of DER. As of October 2014, the installed capacity of solar photovoltaics (PV) in Germany was 38 GW. Approximately 60% of PV installations have a rated capacity of 100 kW or less and are connected to the distribution network. In areas such as Bavaria, the installed capacity of distributed generation (about 78% of which is solar PV) represents a large proportion of the region's peak load. In Galicia, Spain, the installed capacity of DG (which is primarily combined heat and power and medium voltage wind) is 1.2 times the distribution service area's peak demand. Of Italy's 17 GW of solar PV installed capacity, over 10 GW are connected to distribution networks [16]. Total solar PV installed capacity in the United States is approximately 17.5 GW, with California accounting for over 8 GW and Arizona accounting for nearly 2 GW [55]. Much of this installation is taking place at the level of the distribution system, with residential solar PV accounting for approximately 16% of total PV installed capacity [53].

The growth of DER has been shaped by a combination of forces, including decarbonization policy goals, infrastructure investment deferral opportunities, greater emphasis on reliability, resilience, and self-sufficient electricity supply, falling costs of distributed technologies such as solar PV, and opportunities for enhanced power quality and more customer-tailored electricity service offerings [38]. Managing the integration of DER in existing power systems presents the need for simultaneous updating of distribution network infrastructure, information and communication technologies (ICT), and technical standards; business models and industry structure; and regulatory and policy frameworks. The regulations that govern the planning and operation of the power system should ensure that a level playing field exists for the combination of technologies and business models that most efficiently meet the goals and objectives defined for the electricity sector. Creating such a level playing field requires designing regulations and markets that reflect the costs and benefits of the integration of a range of technologies and their operation in the power system.

Traditionally, system operators have far less visibility over and coordination of the distribution system relative to centralized generation and transmission. A "fit-and-forget" approach has been taken in the design and management of electricity distribution because the distribution network has largely consisted of predictable, passive loads [60]. Distribution utilities and system operators have typically built, operated, and maintained the lines, substations, and transformers necessary to serve end users, with limited control over and feedback from those users. However, the proliferation of new technologies — including distributed generation (DG), distributed storage (DS), and automated load control and demand response (DR) — requires greater interaction between distribution network operators and network users. Grid users are no longer “simple consumers” [46]. More prevalent DG and sale of electricity back to the grid, and increasing utilization of DR is obscuring the distinction between traditional producers and consumers. The integration of DER heralds the growth of distributed decision-making about the installation and operation of generation resources and other system components. These decisions that were once wholly under the purview of the distribution system operator or distribution utility impact the utility’s operational and capital expenditures. For example, at the heart of the ongoing controversy over net metering and volumetric electricity rates is the idea that owners of DG are not paying for their use of the distribution network and are instead subsidized by network users who do not own DG. Yet, the integration of DG presents benefits for network investment and operation that must be remunerated. Ensuring optimal system operation requires enhancing coordination between distributed decision-makers and system operators. In order to coordinate agents on a level playing field that reflects system conditions and the impacts of agents’ actions on those conditions, price signals will serve as crucial mechanisms by which to guide distributed decision making to achieve outcomes as close as possible to central optima. This key goal of electricity prices or rates was first summarized in the definition of “reasonable” public utility rates stated by James Bonbright in 1960: “Reasonable public utility rates, like reasonable prices in general, are rates designed to perform with reasonable effectiveness multiple functions as instruments of social control” [5]. While the regulation and operation of the power sector, and broader societal goals have certainly evolved since 1960, the fundamental purpose of price signals and rate setting to guide system users towards achieving those goals remain unchanged. As distribution system planning and operation transitions from a passive model to a model of active management of and interaction with network users selling services to the distribution network operator, the communication of accurate price signals derived from network planning and operational needs and the response of end users to those signals will be critical [19]. This thesis presents a framework for the design of one such price signal in a broader system of price signals: the distribution network use-of-system (DNUoS) charge.

DNUoS charges signal to network users how their utilization of the distribution system impacts system costs and each user’s share of those costs. Distribution utilities cover network operation and maintenance costs and recover infrastructure investments through DNUoS charges applied to network users. Well-designed DNUoS charges can enable more efficient use of the distribution system by, for example, incentivizing efficient location or siting of DER and optimal operation of DER in response to distribution system conditions. **Figure 1** below is an example residential rate schedule for Pacific Gas & Electric [48]. It illustrates that a typical end user’s electricity bill is comprised of charges for a variety of services, and it highlights the component of the final bill – the distribution network charge – upon which this thesis focuses. The rate schedule displayed here includes a distribution charge that is approximately 35% of the total residential rate. Generally, transmission and distribution use-of-system charges can range from approximately 15%-40% of customer electricity bills, depending upon the size and type of the customer (residential, commercial, or industrial) [14].

The terms “distribution utilities” and “distribution” are used here to refer to the provision of network connectivity and delivery of electricity between transmission substations and end users in the distribution network. Distribution services are provided by Distribution System Operators (DSOs) or distribution companies, which typically own, operate, and maintain the distribution network. Under varying regulatory conditions, DSOs may also perform retailing or other commercial activities, but those activities are ignored here. The distribution network costs that are considered are the capital expenditures (CAPEX) — namely, the annual depreciation expenses of capital costs depreciated over the lifetime of network assets and the regulated return on the DSO’s rate base, as

ELECTRIC SCHEDULE E-1
RESIDENTIAL SERVICES

Sheet 2

UNBUNDLING OF TOTAL RATES

Energy Rates by Component ($ per kWh)

Generation:	$0.09745 (I)
Distribution*:**	$0.07917 (I)
Conservation Incentive Adjustment:	
Baseline Usage	($0.05116) (I)
101% - 130% of Baseline	($0.02795) (I)
131% - 200% of Baseline	$0.07849 (R)
201% - 300% of Baseline	$0.13849 (R)
Over 300% of Baseline	$0.13849 (R)
Transmission* (all usage)	$0.01424
Transmission Rate Adjustments* (all usage)	$0.00385 (R)
Reliability Services* (all usage)	$0.00015 (R)
Public Purpose Programs (all usage)	$0.01312 (R)
Nuclear Decommissioning (all usage)	$0.00097 (I)
Competition Transition Charges (all usage)	$0.00067 (R)
Energy Cost Recovery Amount (all usage)	($0.00504) (R)
DWR Bond (all usage)	$0.00526 (I)
New System Generation Charge (all usage)***	$0.00302 (R)
Greenhouse Gas Volumetric Return (usage over 130% Baseline)***	($0.01813) (I)

Minimum Charge Rate by Component	**$ per meter per day**	**$ per kWh**
Distribution***	$0.11458 (R)	–
Transmission*	–	$0.01809 (R)
Reliability Services*	$0.00000	–
Public Purpose Programs	$0.00681 (I)	–
Nuclear Decommissioning	$0.00050 (I)	–
Competition Transition Charges	–	$0.00067 (R)
Energy Cost Recovery Amount	–	($0.00504) (R)
DWR Bond	–	$0.00526 (I)
New System Generation Charge***	–	$0.00302 (R)
Generation**	Determined Residually	

Figure 1: *The distribution network charge here accounts for approximately 35% of the final rate charged to a typical residential end user per kWh of electricity consumption. Image source: [48]*

well as annual operation and maintenance expenditures (OPEX) of the network, which are roughly proportional to the physical volume of assets. Before allocating distribution costs amongst network users, the utility commissioner determines the total revenue requirement that a distribution utility should collect from end user rates based upon CAPEX and OPEX deemed prudent[2]. The "costs" to be allocated to network users in DNUoS charges are thus more accurately identified as the DSO's total recoverable costs, or revenue requirement. The components of the DSO's recoverable costs are illustrated in **Figure 2**.

The topic of determining the distribution utility's revenue requirement is not addressed in this thesis. It is assumed that a suitable revenue requirement has been determined for a specified test period through the use of either cost-of-service or performance-based remuneration that will fully cover the distribution utility's costs (including a rate of return on capital investments) [5].[1] This

[1]For more on the topic of remunerating distribution utilities under high penetrations of DER see [31].

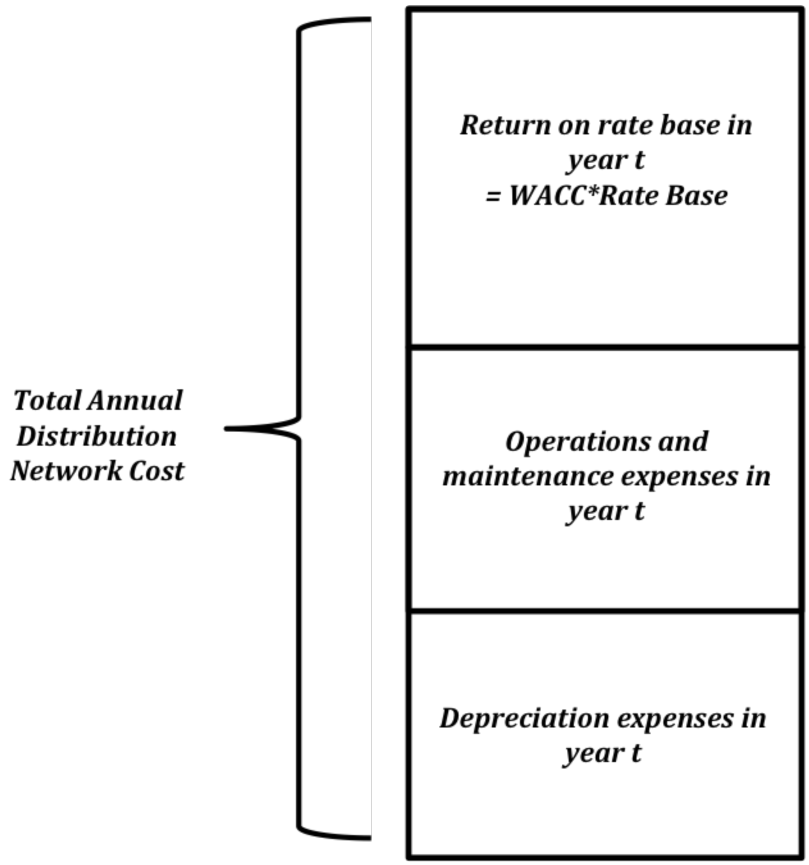

Figure 2: *The cost components to be collected through DNUoS charges*

thesis develops a framework for the step that follows the determination of the revenue requirement, that is, the allocation of the total collectable revenue for a specified year amongst distribution network users. The focus is not on the question of how much revenue is collected, but rather, on the question of who pays and how much does each distribution network user contribute to total DSO costs and revenue?

Growing integration of DER calls for the redesign of existing approaches to distribution network cost allocation because of the greater diversity of network utilization patterns that DER introduce. A new approach to DNUoS charge design should more accurately relate the network charge paid by users to their impacts on network costs. Such a granular approach to distribution network cost allocation is a departure from the current practice of charging network users average rates that are computed for customer classes, each class assumed to consist of customers with similar network utilization behaviors. As network use patterns diversify, so too do the impacts of network use on distribution system operations and investments. For example, it may no longer be the case that large swaths of residential electricity customers have similar profiles of network use behavior with similar impacts on the distribution network. Instead, through decisions to utilize distributed generation, electric vehicles, or other distributed resources, network users can have highly differentiated impacts on the distribution system.

This thesis proposes a method to allocate distribution network costs amongst network users based upon users' network ***profiles***. The concept of developing network use profiles for distribution network cost allocation was first proposed in [46]. The approach relies upon: 1) the use of a ***reference network model (RNM)*** to identify the key drivers of distribution system costs, and 2) the allocation of those costs according to network utilization profiles that capture each network user's contribution to and share of total system costs. This thesis further develops the proposed approach. Essential to the implementation of this cost allocation procedure is the availability of an RNM, or distribution network-planning tool, that accurately determines the impact of the connection and behavior of the network users on total distribution system costs. Such a tool allows a utility regulator to identify the key drivers of network costs and the portion of the total network cost corresponding to each cost driver. Additionally, the procedure relies upon the availability of complete information about the network utilization profile of each network user. Well–designed network tariffs compute the amount users pay for their utilization of the network through the use of data and measurements of parameters such as each user's location within a distribution system, contributions to peak power flows or contracted capacity, and profiles of power injection and withdrawal at the point of connection of that user, not upon an assumption that disparate network users follow generalized, identical profiles of consumption or generation. Each network user's profile reveals the contribution of that user to each network cost driver, to the cost associated with each cost driver, and as a result, to the total network cost. This thesis first approaches the design of DNUoS charges under the assumption of complete information about network use profiles through advanced metering or through the practice of contracting network capacity. When this information is not fully available, simplifications must be made to the proposed framework. Too many simplifications in the case of a significant lack of information on network utilization profiles can prevent meaningful redesign of network charges for increasing penetration of DERs; however, at the brisk pace of DER integration, of advanced metering technology improvements, and of regulatory and policy directives for advanced meter infrastructure rollout, it is not unreasonable to assume the availability of the metering and information collection capabilities required for adoption of the updated network charge design principles described here. In the absence of either or both of the above elements, simplifications must be made to the network cost allocation process. Those simplifications are briefly discussed in the final sections of this work.

The structure of this thesis is as follows: Section 2 describes the technical, economic, and regulatory principles of distribution network planning and operations that underpin the allocation of distribution network costs. Section 3 describes the proposed approach to calculating network costs and designing DNUoS charges. Section 4 describes how an RNM is utilized in the computation of DNUoS charges; Section 5 explains the simulation modeling process and results obtained. Section 6 discusses the policy and regulatory implications of implementing redesigned DNUoS charges. Section 7 concludes and summarizes future work.

2 Background

In most power systems, the costs of the distribution network are allocated to residential customers primarily on the basis of their volumetric energy consumption — that is, on the basis of the total kilowatt-hours consumed by each customer. Where utility services are unbundled and each service is charged a separate retail rate, an average volumetric rate (i.e. $/kWh) for the distribution component of residential customers' retail electricity bills is computed as part of the rate-setting process. Typically, the distribution rate is calculated by classifying the DSO's total costs according to cost-defining service characteristics — namely energy, demand, and customer costs.[2] (For residential users, most costs are classified as energy and customer costs.) The total costs associated with each service characteristic are allocated amongst customer classes — usually residential, commercial, and industrial customer classes — according to the magnitudes of the measurable service characteristics of each customer class. For example, the DSO's total energy-related costs are allocated to the residential rate class according to the share of total kWh consumed by residential customers. The residential energy charge for distribution is then simply the energy-related costs allocated to the residential rate class divided by the total kWh of electricity consumed by residential users over the course of the billing period [2].

This per–kWh distribution network rate is sometimes bundled together with the rates for energy consumption (or generation), transmission, and other regulated charges (such as programs for energy efficiency, promotion of renewables, industry restructuring, etc.) that are included in the electricity bill as shown in **Figure 1** to compute a total $/kWh rate for residential customers. In some cases, the rates paid by residential network users also include a fixed, per-customer component and perhaps a per-kW rate for the consumption capacity contracted for a billing period, though these are usually a small fraction of a residential end-user's electricity rate.

In this existing approach to distribution network cost allocation, costs are assigned to rate classes or groups of customers that are *a priori* identified as having similar service characteristics. The role of *profiles*, as developed in this thesis, is to obviate the need to group customers into classes. Rather, by applying the same cost allocation method to the profiles of all network users, differences in users' profiles will reveal differences in service characteristics, the commensurate differences in cost of service, and thereby result in different charges for users with different service characteristics. Allocating distribution network costs to each network user based on profiles is one step closer to allocating costs according to the cost causality of each user. The concept of rate classes will prove obsolete with growing integration of DER because of the difficulty of isolating the costs and benefits attributable to load and DG and grouping increasingly diverse network users into classes.

To determine the cost of serving customer classes, utilities conduct detailed cost of service studies. However, such cost of service studies are time and resource intensive, and may not be the most efficient manner in which to identify the drivers of distribution network costs and update the assignment of costs to cost drivers as network use and network design change. Using an RNM can enable the regulator and DSO to apportion system costs amongst drivers and allocate those costs amongst customers in an automated manner, allowing more frequent updating of cost allocation. Indeed, this requires accurate parametrization of the RNM used for rate design, but assuming that an upfront effort is undertaken to populate the RNM with an accurate catalog of available equipment and equipment costs, and the relationship between equipment characteristics and customer demand, then the RNM can be relied upon to accurately reflect changes in network design and costs, costs

[2] An adaptation of this list will later be referred to as ***cost drivers.***

related to each driver, and costs allocated to each network user.

Allocating network costs primarily on the basis of volumetric energy consumption presents inefficiencies in distribution systems evolving to incorporate a growing number of DER and a growing list of new stakeholders. These inefficiencies include: incomplete price signals to incentivize optimal network utilization; cross–subsidization among network users; and business model arbitrage of rate structures. For example, under existing policies of volumetric tariffs and net metering with conventional electricity meters, it is possible that network users without onsite generation subsidize utilization of the distribution network by users with DG. If a network user with DG produces enough energy to entirely offset his or her energy consumption requirements, then a net zero kilowatt–hours of energy are distributed to that network user. However, as is often the case with non–dispatchable DG, such as rooftop solar PV, periods of generation may not coincide with periods of peak consumption. For example, as data collected on a daily basis by the California Independent System Operator (CAISO) shows, peak solar PV output typically occurs between 11:00am and 3:00pm, while peak load at the wholesale level occurs between 6:00pm and 10:00pm. **Figure 3** shows CAISO load and solar output on a winter day, January 5, 2015 (top), and on a summer day, July 5, 2014 (bottom) [6]. Since peak load and peak generation are unlikely to occur at the same instant of time in this example, the kilowatts of power distributed to meet network user demand during peak load hours are not significantly reduced by solar PV generation. In any given hour, the power output of PV, at the wholesale level, does not exceed or even approach total system demand. But, in particular distribution circuits, power output during peak generation hours may well exceed load.

Over the course of one day, the net energy for a network user may be zero, but in each hourly or quarter–hourly time frame, the magnitude of the user's contribution to the kilowatts of power distributed through the network is nonzero. The particular characteristics of load and generation coincidence vary according to the load profile and generation resources in a distribution system. For example, in systems with summer consumption peaks resulting from midday air conditioning loads, solar PV generation coincides closely with load. The resulting reduction in distribution system capacity utilization can lead to a reduction of capacity–related distribution costs and future network reinforcement investments.[3] But in general, volumetric network rates charged entirely per kWh to the net energy distributed by the DSO to end users over the course of a billing period (such as a month) fail to fully take into consideration the drivers of distribution network costs, resulting in inefficient allocation of costs and cost–savings to network users.

[3]The value of coincidence between midday air conditioning load (which primarily occurs at workplaces, or commercial and industrial (C&I) network user sites) and distributed solar output still relies upon utilization of distribution system components to meet non-residential load in the MV or HV networks with residential generation in the LV network. This is one example of how, even during periods of coincidence between load and injection from DG, the network is utilized for balancing and transporting power from DG to load.

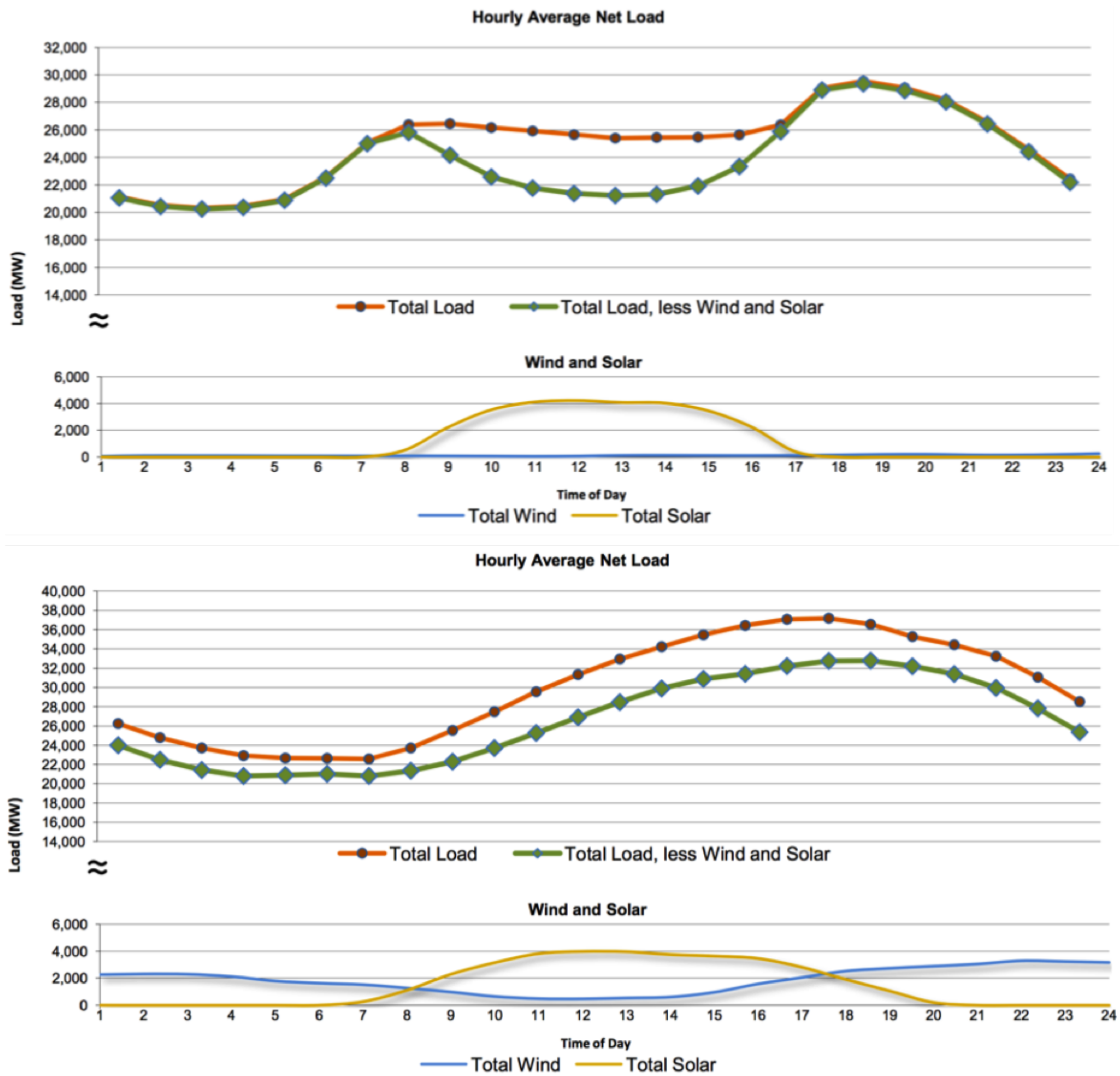

Figure 3: *CAISO load and solar output on January 5, 2015 (top) and July 5, 2014 (bottom)*

The issue of cross subsidization is one challenge that lies at the core of the debate over net metering of DG and volumetric tariffs (and more broadly, over the integration of DER that reduce volumetric energy sales). What has been termed the "utility death spiral" is the positive feedback cycle characterized by reduced energy distribution — or lower volumetric sales — alongside higher costs and higher rates. With volumetric tariffs, lower energy sales result in lower revenue for the distribution utility. This reduces utility revenue, and the ability to recover costs unless distribution network costs fall or rates on the remaining volumetric energy sales rise. Fixed distribution costs such as the size of the asset base and thus the allowed return on the rate base, as well as the depreciation of existing assets remain unchanged with changes in volumetric energy distribution. Additionally, the use of distribution network capacity by individuals with DG may not be significantly diminished, since the grid is used for balancing production and consumption, as described above, and for maintaining power quality to all system users. Depending upon the characteristics of a particular distribution system — including DG location and the extent of network upgrades necessary to integrate DG — network costs may rise over the long run with greater penetration of DG [11], [41], [58], [61]. The allocation on a per–kWh basis of costs that are not driven exclusively by volumetric energy consumption results in users without captive generation subsidizing use of the distribution network by those with captive generation.

While DG serves as the primary example in this discussion, it is worth noting that the drawbacks of purely volumetric network charges are apparent not only with distributed generation, but with demand response and energy efficiency as well.[4] In any of these cases, if volumetric energy consumption falls but network capacity utilization or peak power consumption are unchanged, then volumetric charges fail to consider the full impacts of user behavior on network costs, resulting in poor cost-reflectivity. More broadly, pricing mechanisms that result in lower network charges as a result of lower volumetric energy consumption give rise to the potential for cross subsidization. For example, measures to incentivize energy efficiency aim to reduce total energy consumption, but without temporal variation, they may not effectively reduce peak consumption [20]. This underscores the importance of designing price signals that reflect the drivers of system costs (including network charges, time–and–location varying energy prices, and prices for other electricity services), and that are consistent with one another.

The changes in distribution network utilization introduced by DER are not entirely new. Rather, they suggest that the nature of residential distribution network use is increasingly mirroring the patterns of use exhibited by commercial and industrial (C&I) customers. Large C&I customers are typically connected directly to the high voltage (HV) or medium voltage (MV) distribution network and often have captive generation. Thus, the distribution sector is facing problems that have, to some extent, been addressed with C&I rate structures and revenue models, and the idea of developing a new method of distribution network cost allocation may benefit from the approaches currently employed for C&I grid use, such as metering energy and demand for all network users. An important limitation of existing approaches to network cost allocation for C&I customers is that they have been developed within the context of the prevailing consumer–only mentality, and as a result, ad hoc, approximate methods have been used to account for local generation in rate design. This is primarily because no sound method to determine cost causality at the distribution level has yet been available to regulators. The difficulty of determining cost causality arises from the discrete nature of network investments and the sharing of joint and common costs amongst multiple network users. This limitation can be addressed with the development and use of the

[4] Again, note that energy prices may be time-varying to reflect how generation costs change according to the time of consumption and magnitude of peak power flows. However, this paper focuses exclusively on network charges.

aforementioned reference network models, as explained in greater detail in Section 4.

A distinguishing feature of C&I customers is the availability of detailed profiles of electricity consumption and production. Demand meters are installed to collect information in quarter–hourly intervals about peak demand within a billing period. Retail rates are typically structured to account for energy consumption, demand,[5] and grid connection and utilization, and vary by time of use. This rate structure enables better allocation of network costs according to network use, and therefore, according to cost causality. A new paradigm for distribution network charges for *all* network users — including both C&I and residential users — can compute network charges based on profiles of distribution network utilization and users' contributions to network costs.

[5]Again, here demand refers specifically to power *consumption*. For distribution networks with greater penetration of DER, network charge design requires an approach that more generally accounts for both consumption and production in the distribution network.

2.1 Technical Considerations of DNUoS Charge Design

End-user needs and expectations of the services that can be provided by the power system are changing significantly, from bidirectional power flows and increased risk of overvoltage, to changes in the inertia and frequency response requirements of power systems with a high penetration of solar PV or wind. As the demands on the power system change – as technologies evolve, as policy goals change, as the nature of users' needs change – the price signals sent to users of the system must capture those changes and communicate the impacts of those changes. DNUoS charges that allocate distribution costs according to network users' impacts on cost drivers are price signals that accurately reflect the physical impacts of network utilization behaviors on system planning and operations. This section provides an overview of the relevant technical features of distribution network design and cost drivers, and the impact of increasing penetration of DER on the planning and operation of distribution systems.

While the distribution activity refers universally to the final distribution of electricity from the transmission network to end users, the voltage levels that are considered distribution voltages vary around the world. **Table 1** lists the common ranges of distribution voltages in the U.S. and Europe [18], [23].[6]

	Nominal voltage		Other terms
	U.S.	Europe	
HV	69 kV – 138 kV	33 kV – 150 kV	Sub-transmission
MV	2.2 kV – 46 kV	3 kV – 36 kV	Primary distribution
LV	120 V – 480 V	< 1000 V: typically 230 V – 400 V	Secondary distribution

Table 1: *Nominal distribution voltages in the U.S. and Europe*

Each voltage level of the distribution network may be designed and operated in a meshed, loop, or radial fashion. HV distribution networks are designed and operated in a meshed manner (except in very sparse, rural areas). MV networks are designed in a meshed configuration in urban, high-load-density areas and a radial configuration in low-load-density areas. In both cases, they are operated in a radial manner. The LV network is nearly always designed and operated radially, though there may be flexibility for network reconfiguration [16], [21]. Particularly high-load-density areas such as downtown areas in cities may have meshed underground LV networks for enhanced reliability. **Figure 4** depicts the typical layout of a distribution network, from the primary transmission-to-distribution substation, along a three phase primary feeder main (which typically ranges in length from 1-30 miles) to the LV, single phase laterals and secondary feeders branching off the primary feeder [23].

[6] Extra-high voltage (EHV) is sometimes used to refer to voltages in the 220 kV-380 kV range, but in this voltage range, the delineation between distribution and transmission – and the vocabulary used – is blurred. For example, according to IEC definitions, the EHV network in Germany performs the function of connecting bulk power generation to distribution networks. This is labeled as transmission in the U.S., with U.S. transmission voltages ranging from

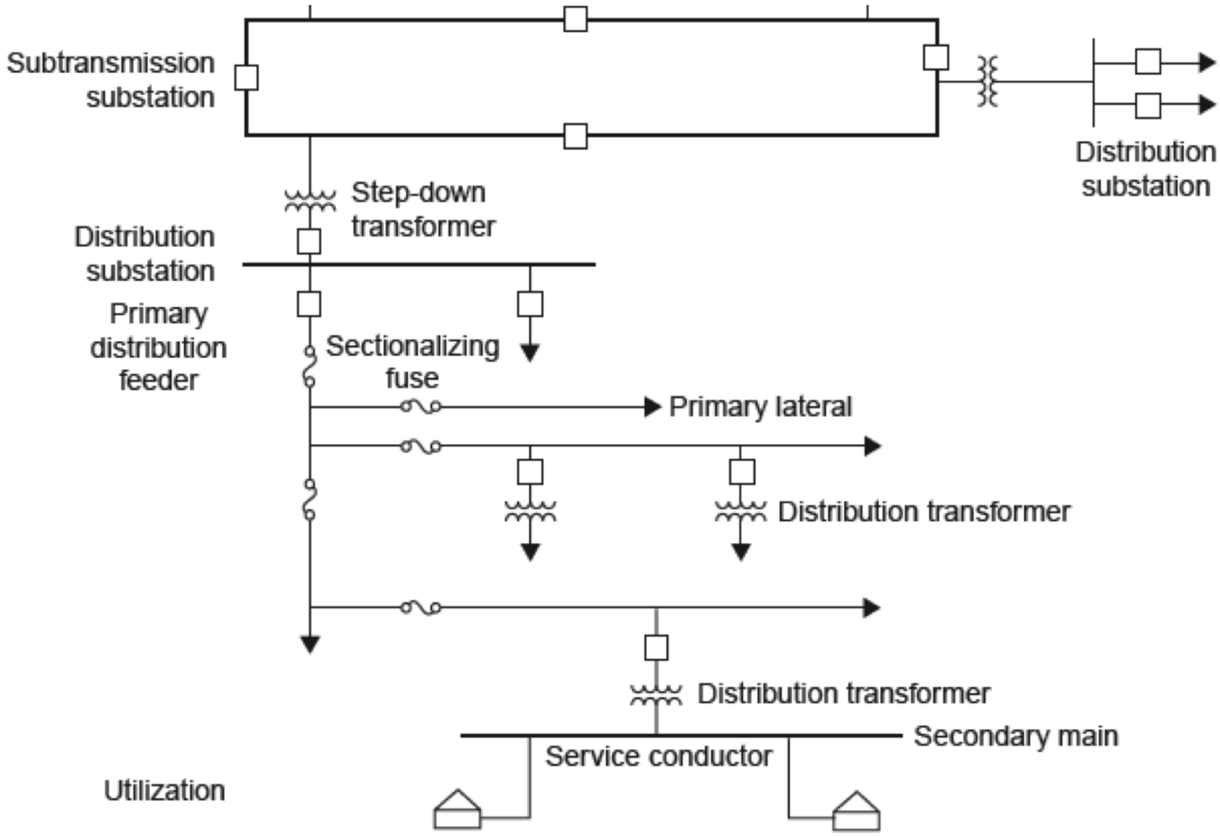

Figure 4: *Layout of a typical electricity distribution system. Image source: [23]*

The critical new feature that DER integration introduces to distribution networks is the possibility of bidirectional real and reactive power flows. These bidirectional power flows introduce a variety of challenges for the planning and operation of existing distribution networks. One of the key challenges of integrating DG is the impact of reverse real power flow on steady state voltage in distribution feeders. Adding DG to a distribution feeder introduces the possibility of overvoltage, or voltage rise at the site of embedded generation on the feeder beyond ANSI[7] limits, when local generation exceeds load [4], [40].

Under normal circumstances, the voltage for all end users along a distribution feeder should be maintained within $+/-5\%$ of the ANSI limits. The voltage drop along the line increases with increased distance and increased load, so ensuring compliance with voltage drop limits means ensuring that the voltage drop at the point of common coupling (downstream of the MV/LV transformer) of the end user farthest from the substation should be within the $+/-5\%$ threshold. During peak load, the last user's voltage should be above the lower ANSI limit, and during peak generation or minimum load, the last user's voltage should be below the upper ANSI limit. An example of the voltage profile of a radial feeder is shown in **Figure 5** [23].

When the output of embedded generation on a feeder is less than or equal to the load farther from the substation along the feeder, then any injection by the DG serves 'downstream' load. When

230 kV-765 kV [9].

[7]American National Standards Institute

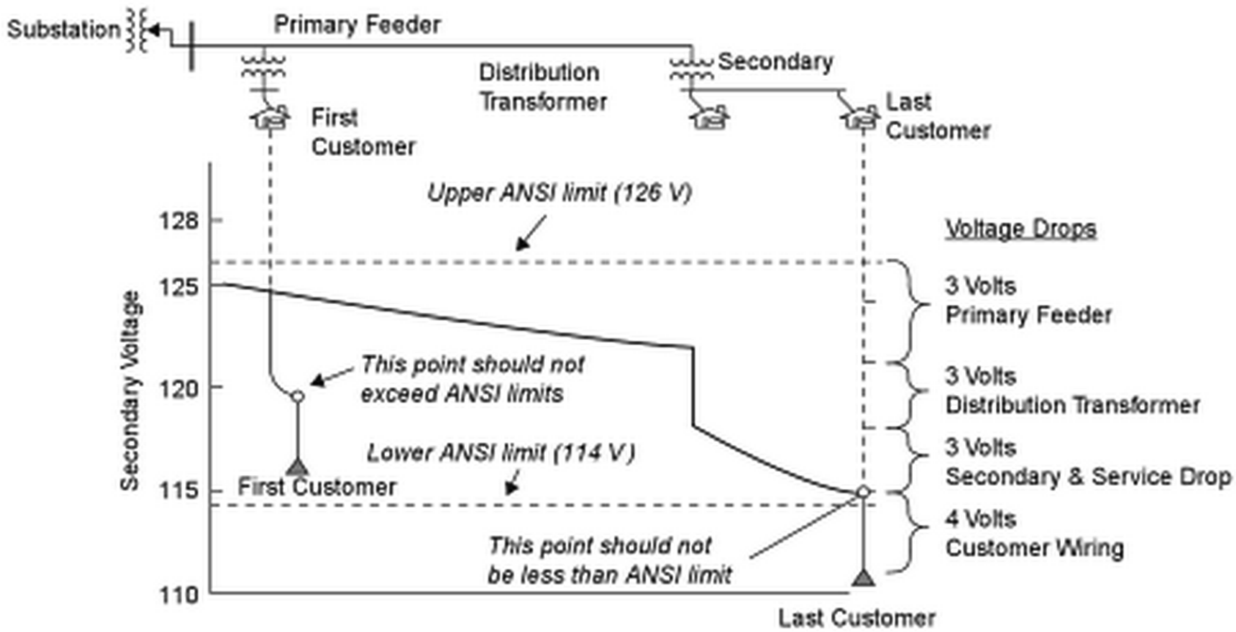

Figure 5: *The voltage profile typical of a radial feeder with residential distribution customers. Image source: [23]*

the DG output exceeds the load farther from the substation along the feeder, then the voltage at the DG connection point rises higher than the substation (and thus higher than elsewhere on the feeder). Some injected power serves downstream load, and some power flows towards the MV/LV substation serving the feeder. If there is no downstream load, then all injected power flows towards the substation, and the voltage rise at the DG connection point may be significant. **Figure 6** illustrates the magnitudes of overvoltage along a feeder with DG installed mid-feeder under varying conditions of load and generation [40].

In order to maintain the voltage at each user's connection point and point of common coupling (PCC) to the network, a variety of voltage regulation approaches are used. In light of standards that prohibit DER from actively regulating system voltage, voltage regulation is done by adjusting step voltage regulator (SVR) settings and on-load tap changers at distribution substation transformers, and by using switched and fixed capacitor banks [54]. Alternative overvoltage mitigation approaches include installing larger conductors or curtailing generation during periods of low demand [40]. Bilateral agreements between the DSO and DER operators may also permit the adjustment of inverter operating modes so that inverters can adjust their import and export of reactive power to regulate voltage at the PCC [61], [7]. Investments made by the DSO to reinforce the distribution network to address overvoltage problems are examples of costs that must be allocated amongst the DER that drive the costs [11]. Additional technical considerations of the integration of DER include impacts on feeder losses, power quality, and fault protection.[8]

Traditionally, distribution system planning has primarily needed to consider one worst case scenario of demands on the network – namely, power flows resulting from peak load. The integration of

[8]For example, additional voltage concerns arise under abnormal operating conditions, such as ground fault overvoltages and resonant overvoltages [4].

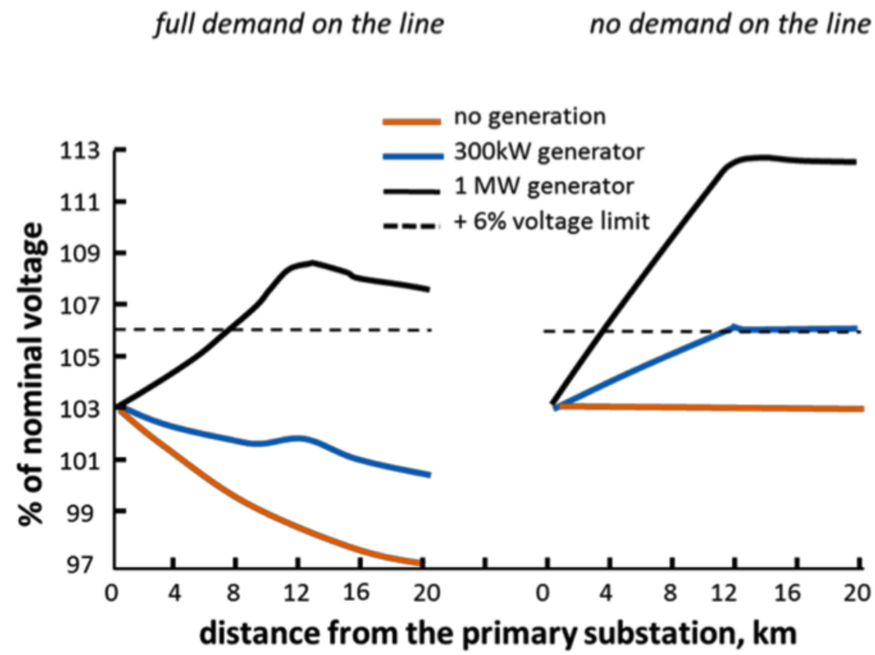

Figure 6: *The voltage profile typical of a radial feeder with residential distribution customers. Image source: [62], adapted from [40]*

DER, particularly distributed generation, creates the opportunity for *two* worst case scenarios: one is still the occurrence of maximum load, but the other results from net injection, or the occurrence of reverse power flows when generation exceeds consumption [36]. Thus, distribution capacity costs include costs associated with accommodating peak load and costs associated with accommodating injections when local generation exceeds load. Allocation of capacity costs to network users considers users' contributions to load and injection. Users' profiles indicate whether they are contributing to load or injection during any hour. When users inject power, their contribution to load is negative and their contribution to injection is positive. When users consume power, their contribution to load is positive and their contribution to injection is negative. The value of each of those activities to the network will vary according to the time of day and time of year: the net value that each agent presents to the network is determined by the sum of their contribution to consumption-related capacity costs and their contribution to injection-related capacity costs.

An estimation tool that will be used to determine the contribution of each network user to peak power flows in the absence of full information about users' hourly profiles is the simultaneity factor (SF). The SF of each network element indicates what portion of the peak power flow in those elements should be considered to determine the peak of the upstream element. For example, the SF of LV customers indicates what percent of the peak demand of each LV network user should be aggregated to determine the peak load on the MV/LV transformer immediately upstream of those LV users. Thus, the peak load on the MV/LV transformer is:

$$\sum_i SF * Peak\,Load_{Network\,User\,i} = SF * \sum_i Peak\,Load_{Network\,User\,i}$$

As described in greater detail in Section 5, SFs are utilized in the numerical analysis only to address the statistical limitations of the modeling technique applied. With real data for every network user's profile – as opposed to an artificial set of profiles generated from a sample of real profiles – SFs would not be required.

Reliability in distribution networks refers to continuity of supply, or the ability of the DSO to meet demand on a continuous basis. Continuity of supply is measured with reliability indices that quantify the frequency and duration of network service outages as an aggregate or per-customer average value. In much of the world, SAIDI (system average interruption duration index) indicates the average duration of interruptions per customer, and SAIFI (system average interruption frequency index) indicates the annual average number of interruptions per customer. In Spain, continuity of supply is measured with TIEPI (installed capacity equivalent interruption time) and NIEPI (installed capacity equivalent number of interruptions) [21]. In the numerical example, TIEPI and NIEPI targets are the mechanism used to evaluate the role of reliability in driving distribution costs.

2.2 Regulatory Economics of DNUoS Charge Design

There are multiple objectives for well-designed distribution network charges, as described in [5] for utility rates in general and in [46] for DNUoS charges in particular. They must provide sufficient revenue for network companies to recover efficiently–incurred network capital and operating costs; they should send economic signals to network users about how their behaviors impact network costs and allocate costs according to ***cost causality*** — or allocate costs to those who cause them to be incurred; they should be nondiscriminatory or equitable by applying the same method to determine charges for all network users;[9] they should be transparent in that the method used to compute the tariffs should be made publicly known; they should be stable in that they minimize regulatory uncertainty; and they should, to the extent possible, be simple and understood by network users and network service providers. Tariff design and practical implementation often requires tradeoffs between the aforementioned regulatory objectives [2].

In determining the allocation of distribution network costs amongst network users, key features of electricity distribution economics play a critical role. Distribution companies exhibit the defining characteristics of natural monopolies. They experience economies of scale, or a falling average cost of service over the relevant range of service provision[10]. As such, they experience diminishing marginal costs until the point at which marginal costs are equivalent to average costs. Because marginal costs (or the incremental cost per additional unit of output) are consistently less than average costs, marginal cost pricing does not ensure the full recovery of total distribution costs. Additionally, as with transmission networks, the reality of distribution investments is that investments cannot be made in a continuous manner; rather, there are discrete levels of feasible investment based on standard equipment capacities [51]. The approach to network charge design proposed here relies upon allocating the incremental costs associated with network cost drivers to network users based on a weighted average computed through users' contributions to cost drivers. This approach is a blend of an incremental and average cost approach to ensure cost recovery, rather than a short-run marginal cost approach.

While the cost-of-service standard, or the principle of cost causality, underlies the principles of sound rate structure, there have conventionally been limitations on the extent to which electricity rates are reflective of the cost of providing services to end users. These limitations arise from practical and theoretical considerations. The complexity of the relationship between total and component distribution system costs and the behaviors of system users has precluded the design of truly cost-reflective rates in the distribution sector. Capturing differences in which network users utilize which components of the distribution system, and capturing the costs of serving customers of different types at different locations and times would yield an impracticably large number of customer classes, subclasses, and rate schedules [5]. While the large number of users and components in the distribution system does indeed give rise to high-dimensionality and complexity that prevents

[9] Equity does not by itself imply that all users pay the same rate for network utilization, as it has traditionally meant in the computation of rates for utility customer classes deemed to have similar service characteristics. Rather, it means that the same *m*ethod is used to compute the rate charged for network utilization behaviors and therefore for the network charge associated with a particular agent's network utilization.

[10] The "relevant range of service provision" refers – somewhat circularly – to the spatial and demand-density range over which economies of scale exist. That is, within a given distribution service area, economies of scale exist in that it is lower cost for one DSO to serve end users than multiple DSOs. However, across a larger geographic scope, the cost of distribution increases roughly linearly with area and load. The boundaries of the geographic area over which economies of scale exist establish the sensible boundaries of the distribution territories within which to grant natural monopoly status to a DSO.

the exact translation of network cost allocation techniques utilized in the transmission system, for example, it does not prevent in improvement in the granularity with which network costs are attributed to network users. The utilization of ***profiles*** to characterize every user in the distribution system relies upon the profile itself revealing the cost causation of each customer. This obviates the need to group customers into classes, determine the cost causality of different classes and subclasses, and design separate rate schedules for each customer class. The complexity of network use profiles is bounded by their restriction to the primary cost drivers. It is assumed that the full cost of the distribution network can be accounted for through the costs of each of the primary cost drivers. Less significant cost drivers may indeed be overlooked, but the primary drivers reflect the largest, most stable cost relations.

The volatility of high cost-reflectivity is another key consideration in the design of sound electricity rates. In order for DNUoS charges to serve as effective price signals to network users, users must have some ability to predict how their network utilization will impact their DNUoS charges so that they may reshape their profiles to achieve some alteration in their charges [5]. While volatility is a characteristic of energy charges, which in some power systems are computed as often as every 5 minutes, the economic signals that inform consumers how changes in their profiles may change *future* network costs are far more stable, and do not raise concerns of DNUoS charges that are too volatile for customer acceptance or reaction.

All components of DSO costs – that is, O&M expenses, depreciation expense, and return on the rate base – change in response to changes in the rate base. If reinforcements are made to existing assets, or new assets are added to the rate base, all three components of the DSO costs and recoverable revenue will grow. If no new investments are made, the rate base may stay the same size or shrink as existing assets reach the end of their lives and are depreciated fully. **Figure 7** shows how the total distribution cost to be allocated amongst network users may change with changes in the network asset base.

Figure 7 reveals a critical feature of distribution network costs. Regardless of how network use changes from some year t_i to the next year t_{i+1}, since the existing asset base does not change unless assets are fully-depreciated, the costs that the distribution utility must recover are virtually fixed in the short run, or the time frame within which some inputs – such as capital investments – are taken as fixed. In contrast, in the long run, all costs can be varied [35].

Over the long run, as network use changes, the investment needed for network upgrades, repairs, or reinforcements also change. As such, the fixed sum to be allocated across network users in the long run will change. For example, if users lower their capacity requirements by reducing their contributions to system peak power flows, the network capacity does not dynamically shrink in the short run. What does change is the amount of reinforcements and network expansion that may be necessary in the long run. The overall size and costs of the network decline in the long run, which means that the DSO's rate base will shrink, and each network user will pay a lower network charge. Tension — in the form of "utility death spiral" adverse selection — may arise if the pace at which network users change their utilization profiles does not match the rate at which existing network assets are depreciated. The distribution utility may face the challenge of allocating the costs of stranded assets if network utilization declines faster than current network assets are fully depreciated.

The challenge of DNUoS charge design is determining how to allocate and recover costs that are static in the short-run (and dynamic in the long-run) in the face of dynamic network profiles, while simultaneously allocating costs as closely as possible according to cost causality. The aim of

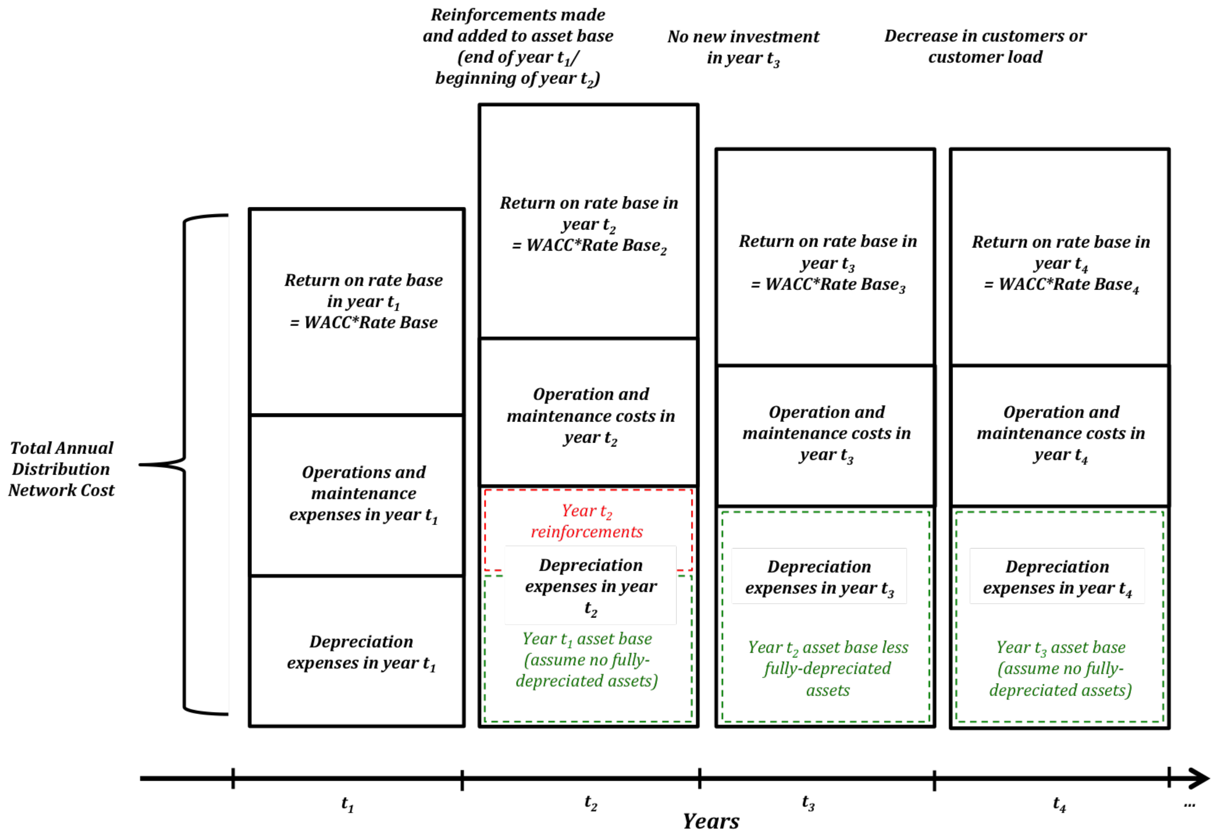

Figure 7: *How the cost components to be collected through DNUoS charges can evolve over time*

well-designed DNUoS charges is to send price signals to network users that a) encourage efficient utilization of the existing network, and b) reflect how changes in network utilization impact network costs so as to enable evolution towards a distribution system well-adapted to network user demands. For example, ideally, DNUoS charges can provide price signals to guide the optimal installation and operation of DER by appropriately rewarding and penalizing network users for the costs and benefits offered to the distribution network. However, the primary price signals upon which network users will make decisions to install DER or not will likely be the energy charges — i.e. generation-related charges — that they can avoid through the use of DER such as solar PV and/or storage. The rate at which network utilization patterns may lead to complete disconnection from the grid is unlikely to significantly impact the recovery of costs of existing network assets, but will certainly need to be considered in the long-term planning of distribution networks. Thus, the primary goal of the method described here is allocating and recovering the costs of the existing distribution network assets, with a keen awareness of the potential growth and impacts of DER integration in long-term distribution planning. The DNUoS charge can serve as a price signal to shape decisions about the operation of installed DER by *reapportioning* network users' shares of distribution costs according to changes in user profiles to indicate to customers how their impact on network cost drivers impacts their share of effectively-fixed total network costs.

Because of the discrete nature, or lumpiness, of network investments and the nonlinear relationship between network utilization and network costs, it is difficult to associate the marginal cost of future network reinforcements with individual network user behaviors. For example, the marginal cost of serving an additional unit of utilization of the distribution network along a particular feeder may be very small or even zero when the relevant distribution feeder and source substation and transformers have excess capacity. However, when the thermal capacity of the line is reached, for example, then the marginal cost of serving an additional unit of utilization amounts to the cost of reconductoring existing lines or installing an additional line.

In [27], the authors design a long run marginal cost (LRMC) approach to allocate the costs of network reinforcements and long run network developments by evaluating the impact of nodal injections on: circuit power flow, the length of time until a reinforcement is needed, and the present value of future reinforcements. This LRMC approach provides an accurate assessment of the impact that small changes in network injection can have on network costs, although it may result in revenue for the network company that differs significantly from the total network cost. Rather than taking a marginal cost approach, the framework proposed here relies upon identifying users' contributions to the cost drivers underlying distribution network development and thus their share of total distribution costs. The allocation of network costs to network zones and to users according to their profiles avoids the drawbacks of flat, average cost allocation and recognizes the varying impacts that additional units of a particular network cost driver can have on network costs. The use of zonal instead of nodal price differentiation aims to achieve cost causality while recognizing that differing incremental costs associated with network utilization may arise from planning decisions not made by individual network users. Additional measures of distribution network charge socialization may be employed by the regulator, as explained in subsequent sections. The central goal of the approach to network charge design proposed here is ensuring total network cost recovery in a manner that allocates costs according to cost causality. This approach relies upon allocating the incremental costs associated with network cost drivers to network users based on a weighted average computed through users' contributions to drivers. As mentioned previously, this approach is a blend of incremental and average cost approaches.

3 An updated framework for network use-of-system charge design

In Pérez-Arriaga et al. [46], the authors outline a new framework for DNUoS charge design. The framework proposes allocation of distribution network costs according to network users' profiles. A ***user***, defined at a point of connection or point of common coupling to the LV, MV, or HV distribution network, has a ***profile***, or a collection of values, of ***cost driver*** variables, the key factors that drive the total cost of the distribution network [50]. (See below for examples of cost drivers). A profile encapsulates all the information necessary to determine each grid user's contribution to network costs. The values of the variables defining each user's profile establish the amount that each user pays in network charges. For example, a single network user's profile may be comprised of that user's location in the distribution network; power injection and withdrawal during periods of peak power flow in the local network and upstream and downstream networks, or instead, if applicable, contracted capacity to consume or produce during peak periods; energy use pattern throughout the considered time period; and possibly other characteristics that may more completely define distribution network utilization and each user's contribution to, or cause of, network costs.

As grid users introduce DG, DR, load control and energy management systems, storage, and new loads such as electric vehicles (EVs), it is no longer possible or meaningful to continue using existing customer classifications. Moreover, network users' activities behind the electricity meter often are — and ought to remain as far as possible — a black box to distribution utilities (see **Figure 8** below). In order to ensure that tariffs are non-discriminatory, the method employed to compute DNUoS charges should be agnostic to the particular activities for which the network is used. Building user profiles based on cost drivers, and assigning charges for users according to those profiles avoids the challenges associated with having to identify network users' specific uses of electricity. Rather, profiles permit a distribution utility to quantify grid users' contributions to network costs without requiring detailed knowledge of which network users in a distribution utility's service area own and charge EVs, operate battery storage units, or utilize solar panels, micro-cogeneration units, or backup diesel generators.

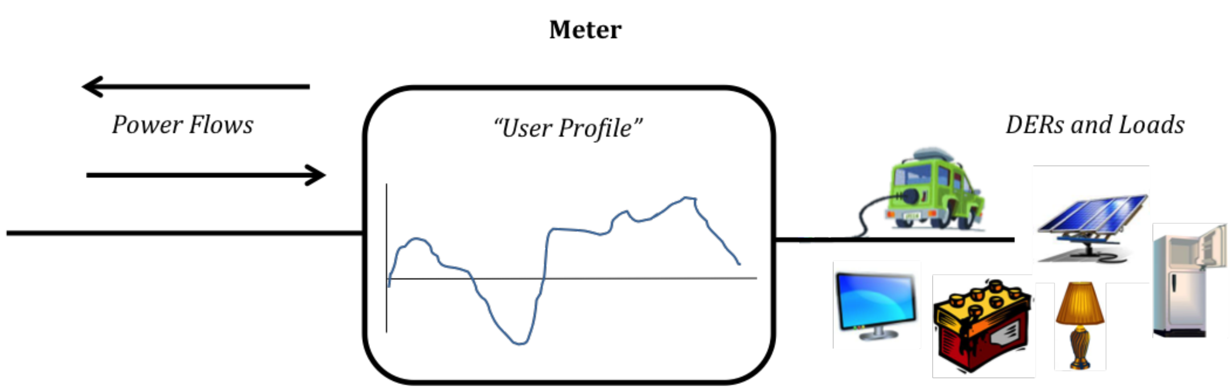

Figure 8: *All that the distribution utility sees of a network user's behind-the-meter activity is a user profile*

As indicated before, the fundamental principle underlying the framework for DNUoS charge design is the cost causality principle. In order to apply this principle to the computation of network charges in distribution networks with a high penetration of DER, there must be a clear understanding of the drivers of network costs, and the impacts on network costs of the presence and activity of network users — including traditional consumers and DER. Computing network users' DNUoS charges consists of the following four steps:

1. Identify the cost drivers, or primary variables that drive the total cost of the distribution system. Once the drivers have been identified and understood, network users' profiles can be defined.

   The cost drivers are a set of magnitudes of physical quantities $D = \{d_1, d_2, d_3, \ldots, d_N\}$ *such as capacity requirements, energy loss–reduction requirements at each voltage level, and quality of service requirements at the aggregated network level, as well as the locations of network user connection points* [52].

   Identification of the cost drivers is facilitated by the use of a network-planning tool — a reference network model as mentioned above. Such a tool enables trials of changes in the composition and/or behavior of networks users — such as adding rooftop solar PV generation — and observing any resultant changes in network costs.

2. Determine the contribution of each cost driver to the total distribution network cost. The analysis to allocate network costs to the cost drivers is conducted independently at each network voltage level. Thus, the sum of the costs at each voltage level allocated to a given cost driver should yield the total distribution system cost due to that driver. Costs that are joint and common to multiple voltage levels are considered in the next step, in which costs are allocated to network users.

   If appropriate, the total cost associated with each cost driver at each voltage level is allocated amongst homogeneous network zones (hereafter referred to simply as ***zones***). A zone is defined as a section of the distribution system such that every additional unit of each cost driver has the same impact on total network costs. A secondary distribution feeder may be the natural functional unit that qualifies as a zone, and is used as the definition of a zone throughout the remainder of this thesis, since different feeders experience different peaks (magnitude and timing) which are often measured and recorded by DSOs, they exhibit differences in the magnitude of losses, they differ by length and therefore outage frequency, but the location of users along a given feeder is often arbitrary. In current practice, distribution utilities separately estimate primary and secondary distribution costs [47], and they assess the hosting capacity of distributed generation at the secondary feeder level on the basis of what percent of total secondary distribution network load the distributed generation makes up [49]. Feeder circuits are often designed so that the load or utilization of each section of the feeder sums to a specified utilization of the total feeder capacity; as such, for very long feeders that extend multiple miles, it may make sense to further subdivide the feeder into sections and carry out cost allocation to those sections [63].[11] The motivation for defining network zones and allocating costs to zones — rather than computing individual shares of total network costs according to minute differences between all users' profiles — lies in the

[11] A zone may be defined as any unit of the distribution system other than a feeder, as there are multiple considerations in the characterization of a homogenous network zone. These may be technical, political, or economic characteristics. Zones may be defined more narrowly in order to communicate locational signals for the operation of DG along sections of a feeder. As previously indicated, network charges may have to be applied to new distributed generation located in non-favorable sites in the network. For example, generation along a branch of a feeder may require network reinforcements even without yielding a detectable injection peak in the feeder.

recognition that there are certain components of the total distribution network cost that are better allocated by grouping customers and then distributing the component cost amongst members of that group. Again, the key network user groupings are: allocating costs to drivers separately in the LV, MV, and HV networks, and allocating the costs at each voltage level to network zones such as feeders.

The total distribution network cost is the sum of the costs contributed by all cost drivers at all voltage levels. At the LV, MV, and HV levels, this step is comprised of two parts: a) dividing each voltage level's total network cost between the cost drivers, and b) dividing the total cost associated with each cost driver at each voltage level amongst network zones. A network–planning tool is central to identifying network zones and the share of network costs allocated to each zone.

3. Compute each network user's DNUoS charge. Determine each user's share of the total cost associated with each driver in the user's network zone. The user's share of the total cost associated with each driver is determined by the user's profile. The final DNUoS charge is the sum of the charges assigned for each driver.

   Each network user i will have a profile consisting of individual values of the N cost driver variables $D_i = \{d_{1i}, d_{2i}, d_{3i}, \ldots, d_{Ni}\} = \{d_{ni}\}$. *Each network user's share of* c_{zn}, *the total cost associated with driver* d_n *in network zone z, is* s_{izn}. *The value of* s_{izn} *is determined by the user's network utilization profile.*

   $$\textit{User i distribution network charge} = \sum_{\textit{Cost Drivers } d_n \in D} c_{zn} * s_{izn}$$

   where $s_{izn} = 0$ *for those cost drivers to which network user i has no contribution.*

4. Choose an adequate format for presenting the final distribution network charge on network users' electricity bills.

   Traditional formats such as \$/kW or \$/kWh rates would no longer provide efficient signals for network users since each user's charge is first based upon cost allocation to network zones and then to individual users. Presenting a large range of time- and zone-specific rates could lead to confusion amongst network users. Presentation of DNUoS charges as lump monthly charges, perhaps listed by cost driver, provides a transparent and understandable billing format.

Figure 9 graphically outlines the cost allocation process. Each step is explained in greater detail in the remainder of this section.

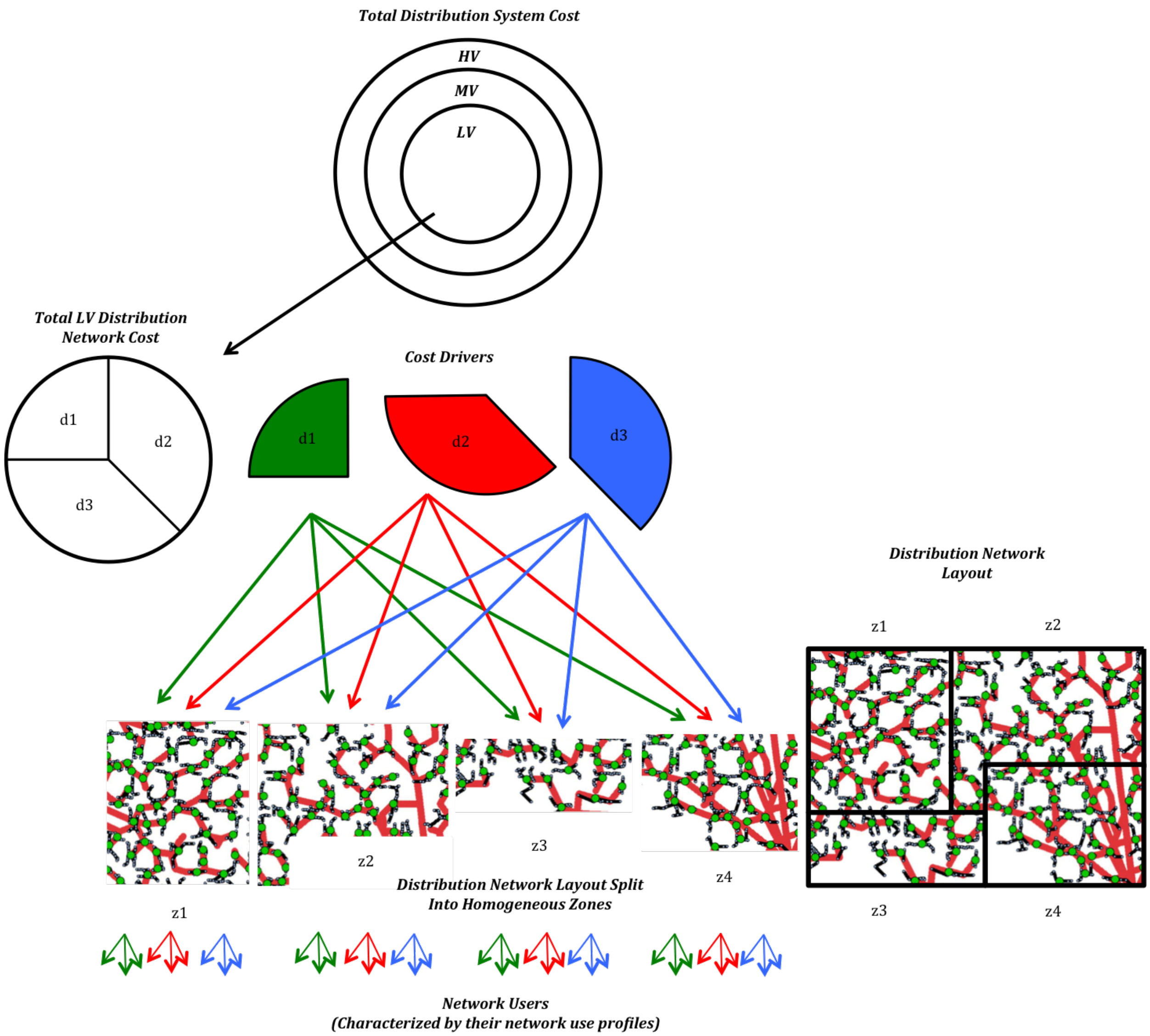

Figure 9: *Cost allocation involves first splitting the total network cost at each voltage level into the costs associated with each driver, then splitting the cost associated with each driver across network zones, and finally allocating the costs of each driver within each zone to network users based on their profiles*

3.1 Identifying the cost drivers

Cost drivers are the key factors that determine the cost of the distribution network. In the course of planning, operating, and controlling electricity distribution, the overwhelming majority of costs are linked in some manner to the amount and scale of network infrastructure assets, or the size of the DSO asset base (see **Figure 2**). More specifically, the distribution cost components described in Section 1 comprise investments in distribution infrastructure to replace, build new, reinforce, and expand network capacity, including lines, substations, control components, and monitoring devices; O&M costs such as costs of dispatch centers and maintenance personnel; and metering costs [21]. Cost drivers are the factors, or network user needs, that motivate the above investment and operational costs. The fundamental purposes of the distribution costs that are incurred are to connect all network users in a manner that meets utilization requirements under a range of operating conditions, while reducing network losses to an economically efficient level: these purposes underlie the definition of the cost drivers described below.[12]

Building upon prior work to identify distribution network cost drivers (such as [52] and [24]), the following are the cost drivers of focus in this work:

1. *Connection*

   The connection cost driver refers to the elements of distribution network design to provide users with connectivity to a distribution network that considers only the geographic locations and minimal load and/or generation of users and the impact of geography on network topology. The connection cost driver does not consider users' network utilization profiles. The magnitude of this cost driver depends on multiple factors, including feeder length and the density of the network to which the user is connected (urban, suburban, or rural), and reflects the costs incurred for digging trenches, installing poles, and laying lines to reach all users that must be served within the distribution service area.[13]

   The cost associated with connection should generally be the same for network users connected at the same voltage level and within the same zone; namely, the connection cost for each user along a feeder should be the average connection charge for the group of users along that feeder. This is because small differences in distance from a reference point — such as the distance from a substation to each home along a distribution feeder — are the result of design decisions about what network topology reaches the most individual users within a given area. Since the network layout is a result of decisions made without participation by the users, and multiple configurations are possible, socializing network connection costs along distribution feeders is justified. The integration of DER may present possible exceptions to this rule. For example, connection charges may be applied directly to new distributed generation that connects at sites where it is a priori known that substantial (higher–than–average) additional network connection costs will be incurred. In such a case, direct cost causality can be attributed to

[12] Losses are not a distribution cost in that the cost of losses is incurred at the generation stage and not the distribution stage. Transmission and distribution losses increase energy generation requirements, and the costs of increased generation are passed on to end users through energy charges. Losses are certainly influenced by physical properties of distribution infrastructure such as the cross-sectional area or length of lines or the type of conductor or transformers used. But, unless regulation provides incentives for distribution utilities to make network investments in a way that reduces estimated losses, the DSO does not incur any cost for higher-than-socially-optimal losses in the distribution network (and passes on any loss penalty to network users).

[13] The level of demand selected as the "minimum" to be served by the minimal connection network is somewhat arbitrary, but it is constrained by the need to obtain a feasible power flow for network users.

a particular network user. Similarly, in sparse, rural networks with isolated users located on long feeders, the full cost of the feeder can be attributed to that user and may be entirely allocated to that user. Or, costs of serving rural customers may be socialized amongst a broader swath of network users.

2. *Capacity*

   A key driver of distribution network costs is the need to design the network to accommodate peak power flows. Because of system planning requirements to ensure that distribution capacity can meet peak load under a variety of load conditions, the impact of network users' peak *demand* is a central consideration in distribution system design.[14] In addition to meeting peak demand requirements, networks with DER must be designed to accommodate bidirectional power flows. The integration of DER requires that contributions to reverse power flows (when local generation exceeds local demand and power is exported from a feeder circuit) be measured along with contributions to peak consumption as part of network users' profiles and used to compute network charges. As described in Section 2.1, critical voltage challenges can arise from reverse power flows that are significantly smaller than the magnitude of power flows associated with peak demand. Injection from DG impacts the voltage profile of the feeder on which DG is located, and voltage rise at the site of DG installations increases the risk of damage to distribution equipment [38]. Thus, capacity-related costs of the distribution system extend beyond planning for peak loads to considering the costs associated with maintaining voltage limits while accommodating bidirectional power flows.

   Additionally, benefits of DER such as alleviating peak demand can help defer network capacity expansion investments by reducing adverse impacts on the life of existing assets, and remuneration for such potential benefits should also be included in the DNUoS charge. Abiding by the principle of cost causality in using the coincidence of feeder-level power flows with relevant upstream power flows to compute network charges requires considering the economic value of the injection or withdrawal of power by a network user depending upon the timing and location of the injection or withdrawal. Since users must be charged or remunerated for their impacts on the power flows in the LV, MV, and HV networks, the occurrence of peak load or reverse power flows at the HV/MV and MV/LV substations, and along primary and secondary feeders must be considered. Capacity charges can be either positive or negative, depending upon whether network users' consumption or injection takes place during periods of system or local peak demand or production. For example, the benefits and associated remuneration of injection from DG during periods of peak consumption at the HV/MV substation (system level) may offset local injection-related costs in a feeder with a large amount of injection and lead to a negative capacity charge (typically in the form of a payment or credit on a user's bill). The sum of the credit and cost would reflect the net value of DG in serving load. On the other hand, power injection during periods of system or local peak injection (and even during off-peak periods) can lead to a positive capacity charge if the costs of the injection are not offset by the benefits of meeting load.

   Some of the investments made by the DSO to ensure that capacity requirements are met contribute to enhanced system reliability. However, a significant portion of reliability costs are – intentionally – neglected when determining capacity costs because the capacity costs of interest are the costs incurred to meet peaks under system-intact conditions with zero

[14] Nevertheless, most network charges in the U.S. and elsewhere are volumetric — i.e. they are applied as a $/kWh rate for energy sold to an end-user.

probability of equipment failures. Consideration of the actual, non-zero probabilities of failure of network equipment takes place in the realm of reliability cost determination, as described next.

3. *Reliability*

   In distribution network design, the system planner takes into account reliability criteria defined by network user needs and by reliability standards specified in federal law, national standards, or grid operation codes [18]. Unlike transmission reliability planning, distribution companies are often not mandated to abide by N-1 criterion. Internally, the DSO may carry out reliability planning using a range of deterministic adequacy or probabilistic risk assessment approaches or N-1 security criteria to ensure that distribution system load can be met even with the failure of any single component [63]. Regardless of the planning approach taken, what *is* mandated is the level of continuity and quality of service that must be achieved according to target reliability indices (SAIDI and SAIFI or TIEPI and NIEPI) described in Section 2 [30].

   In practice, planning the distribution network to "meet peak load" entails designing the network to ensure continuity and quality of supply during peak periods at well below 100% utilization of network components. The DSO incorporates a security margin of system capacity over the capacity required to meet expected peak load (and expected injections), to account for possible demand estimation errors, equipment failures, or faults and outages. This security margin incorporated by the DSO to meet peak capacity requirements during system-intact (N-0) and contingency (N-1) conditions may be considered the entirety of reliability spending. However, ensuring that the distribution system can accommodate the peak(s) at less than full network utilization during N-0 and N-1 conditions does not encapsulate the full magnitude of reliability costs. Reliability is not only needed during peak periods, and reliability costs are not only incurred with periods of peak network utilization in mind. Failures in network components can occur at any time, and investments in redundancy, extra transfer capacity, advanced automation, or network visibility, monitoring, and metering capabilities may only be justified when considering the probability and impact of a contingency over the course of an entire year, not only peak hours. This cost driver aims to isolate the costs of ensuring continuity and quality of network service for load and generation during every hour of the year, and is thus allocated amongst network users on the basis of their hourly energy profiles: see Section 3.3 for further detail.

4. *Losses*

   As stated above, losses directly impact generation costs, since higher losses require higher generator output in order to meet load. The large number of components in the distribution system can lead to significant aggregate losses in the network. Higher system losses lead to higher loads on upstream system components, which marginally impacts network asset lifetimes. Societally-optimal design of distribution networks should take into account the magnitude of losses that occur in the distribution system and the network investments to reduce them. The DSO — and thus the design of any regulatory mechanism to incentivize loss reduction in the distribution system — must consider the tradeoff between making the infrastructure investments to reduce losses in the distribution system, or operating with high losses and paying any regulated penalty for network losses.

   Losses at the distribution level are primarily transformer core losses and power line copper losses (or I^2R losses). The allocation of the costs associated with this driver to network users must reflect how a network user's profile impacts transformer and line losses and any investments made by the distribution utility to reduce those losses. Generally, transformer core losses are independent of transformer loading, so reduction of such losses is not driven by network user profiles to a significant degree [59]. Power line losses are driven by the magnitude of current within a line and the line resistance. Line resistance is a function of line length, cross sectional area, and material-dependent resistivity; line current varies with the power transmitted and the line operating current; and line losses vary quadratically with line current. As such, the most accurate allocation of the costs associated with recabling feeders, installing capacitors, or employing other strategies to reduce losses is as a quadratic function of network users' contributions to line current, and also as a function of their locations. This is revealed by their hourly profile of contributions to line real and reactive power loading – and their resulting impacts on line power factor [56]. In addition to allocation of costs for contributing to losses, users may also be remunerated for reducing losses. For example, by serving load locally and regulating reactive power flow, distributed generation can contribute to feeder loss mitigation. Demand response can reduce users' contributions to losses during periods of peak power flows. The hourly energy profiles and locations of the network users reveal these user contributions. See Section 3.3 for further detail.

The network cost drivers of connection (C), capacity (P), reliability (R), and losses (E) are the primary drivers of distribution network costs considered here because of their key role in driving investments in existing networks and networks with a growing penetration of DER. In order to quantify the relative significance of each individual driver in total network cost, a reference network model (RNM) can be used as described below. An RNM can reveal the temporal and geographic granularity of the measurement of each of the drivers and the allocation of their associated costs required for cost-reflective network charges. For example, the combination of the magnitude of energy use and the time of day at which it is distributed may impact component lifetimes, limiting the temporal simplifications made to the allocation of loss costs. That is, instead of allocating loss costs according to volumetric energy consumption and injection in a small number of time blocks, complete hourly network use profiles may be essential.

3.2 Allocating costs to drivers

The next step in computing DNUoS charges is determining the relative contribution of each of the cost drivers to the total distribution system cost. Identifying the proportion of the total cost contributed by each driver provides a set of cost driver *shares* that can be applied to the actual DSO costs to divide the DSO allowed revenue amongst the drivers.

Using the variables C, P, E, and R to denote the key cost drivers, the total cost of the distribution network is the sum of the total cost of network connections, the total cost of capacity to accommodate peak load and all reverse power flows – referred to as total capacity cost, the total cost associated with ensuring reliability, and the total cost associated with reducing distribution losses.

$$\begin{aligned}&\textit{Total Distribution System Cost} =\\ &\qquad \textit{Total Network Connection Cost} + \textit{Total Network Capacity Cost} +\\ &\qquad \textit{Total Network Reliability Cost} + \textit{Total Network Losses Cost}\end{aligned}$$

Decomposing the total distribution system cost into these cost drivers to compute network charges assumes that: 1) these cost drivers account for the full distribution system cost, 2) the impacts of these drivers on network costs can be isolated from one another, and 3) the impacts of these drivers on network costs can be determined sequentially (using an RNM).

The cost allocation process should be carried out sequentially for the LV, MV, and HV networks because the relative significances of the cost drivers may differ at each voltage level, and the network users connected at any given voltage level utilize the three voltage levels of the distribution system to varying extents. For example, serving LV load makes use of the LV, MV, and HV networks, but the same HV and MV network infrastructure is utilized by HV and MV network users. Demand and generation peaks are not necessarily coincident with one another nor are they coincident across the three network voltage levels. These differences should be reflected in the DNUoS charges computed for the users at each voltage level.

A reference network model (RNM) is the primary tool with which to determine the contribution of each cost driver to total distribution system costs. An RNM is a network-planning tool developed for regulatory purposes that designs a distribution network for a service area with specified network user characteristics[12]. Rather than designing the greenfield network or network expansions to be implemented by a DSO, the RNM provides a benchmark network design — or reference network — to help regulators and DSOs improve current methods of assessing distribution costs, determining revenue requirements, and allocating network costs. An RNM takes as input the characteristics of network users, including users' geographic locations and load and generation profiles, and yields as output the least-cost distribution network that meets user needs. Utility regulators in countries including Spain, Sweden, and Chile have used RNMs to evaluate the prudence of distribution utility investments and determine the suitable remuneration for distribution companies [10]. It is assumed here that the RNM utilized for DNUoS charge computation accurately embodies and reflects the relationship between perturbations in network use behavior and network cost.

An RNM can be utilized in stages for network cost allocation by isolating the incremental network cost attributable to each of the network cost drivers.The procedure is described in detail in Section 4. A brief outline of the method here will suffice to continue the present discussion of allocating network costs to cost drivers.

First, a greenfield network can be constructed to connect all network users within a sample distribution area. The total cost associated with this base network is the cost associated with the connection cost driver (C), or the *Total Network Connection Cost*. Total and component costs are separately reported for the LV, MV, and HV networks, as well as the HV/MV substations and MV/LV transformers. Thus, the total LV cost associated with the base network is the *Total LV Network Connection Cost*. Next, for the same sample distribution area, profiles can be specified for all of the network users; the distribution network designed in this second iteration of the RNM can accommodate the peak power flows and system voltage requirements associated with user profiles. The incremental cost associated with the now capacity-constrained network relative to the base network is the *Total Network Capacity Cost*. In a third iteration of the RNM, the cost associated with the reliability driver can be obtained by specifying realistic targets for the frequency and duration of outages (TIEPI and NIEPI) that were relaxed in all prior model iterations. The incremental cost of the network designed in this step relative to the previous step is the *Total Network Reliability Cost*. Finally, by specifying a cost for network losses, a network that finds the optimal trade-off between loss penalties and network reinforcements to reduce losses is designed. This yields the *Total Network Energy Loss Cost*, or the incremental cost associated with loss reduction. The share of the network cost at each voltage level attributable to each cost driver can then be computed. For example, the share of the LV cost attributable to network capacity is simply:

$$S_{LV,C} = \frac{TotalLVNetworkCapacityCost}{TotalLVNetworkCost}$$

Table 2 lists the values derived from the RNM to compute the cost driver shares.

	C	**P**	**R**	**E**	**TOTAL**
LV	LV_C	LV_P	LV_R	LV_E	$\mathbf{TOTAL_{LV}}$
MV	MV_C	MV_P	MV_L	MV_E	$\mathbf{TOTAL_{MV}}$
HV	HV_C	HV_P	HV_L	HV_E	$\mathbf{TOTAL_{HV}}$
	$\mathbf{TOTAL_C}$	$\mathbf{TOTAL_P}$	$\mathbf{TOTAL_R}$	$\mathbf{TOTAL_E}$	

Table 2: *The cost components derived from RNM output*

The share of each cost driver d at each voltage level is:

$S_{LV,d} = \frac{LV_d}{TOTAL_{LV}}$ $S_{MV,d} = \frac{MV_d}{TOTAL_{MV}}$ $S_{HV,d} = \frac{HV_d}{TOTAL_{HV}}$

Each share $S_{v,d}$ can be applied to the reported DSO costs at each voltage level to determine the total cost attributable to each cost driver. **Figure 10** illustrates the process of allocating DSO costs to cost drivers, using the LV network costs as an example.

3.3 Allocating costs to network users

After identifying the relative contributions of each of the cost drivers to total DSO costs — or the share of total system cost associated with each cost driver — at each voltage level, the costs of each driver should be attributed to feeders and individual network users. The DNUoS charge can be computed for each network user once the user's profile, or contribution to each cost driver, is known.

Recall that each network user i has a profile D_i consisting of individual values of the cost driver variables:

$$D_i = \{C_i, P_i, R_i, E_i\}$$

The total cost associated with cost driver d_n assigned to zone z is c_{zn}. Each network user's share of c_{zn}, is s_{izn}. The values of s_{izn} are determined according to users' network utilization profiles and the allocation method applicable to each particular cost driver.

Ideally, if all of the required information is available, the costs associated with connection are socialized within network zones (i.e. along feeders) on a per-connection basis. The costs associated with capacity requirements are assigned to network users based on their contributions to peak consumption and their contributions to reverse power flows through injection in the LV, MV, and HV networks. The reliability costs are allocated to users on the basis of their hourly energy consumption, and the costs associated with loss reduction are also allocated to users volumetrically according to hourly energy consumption or production. Note that only the energy losses and

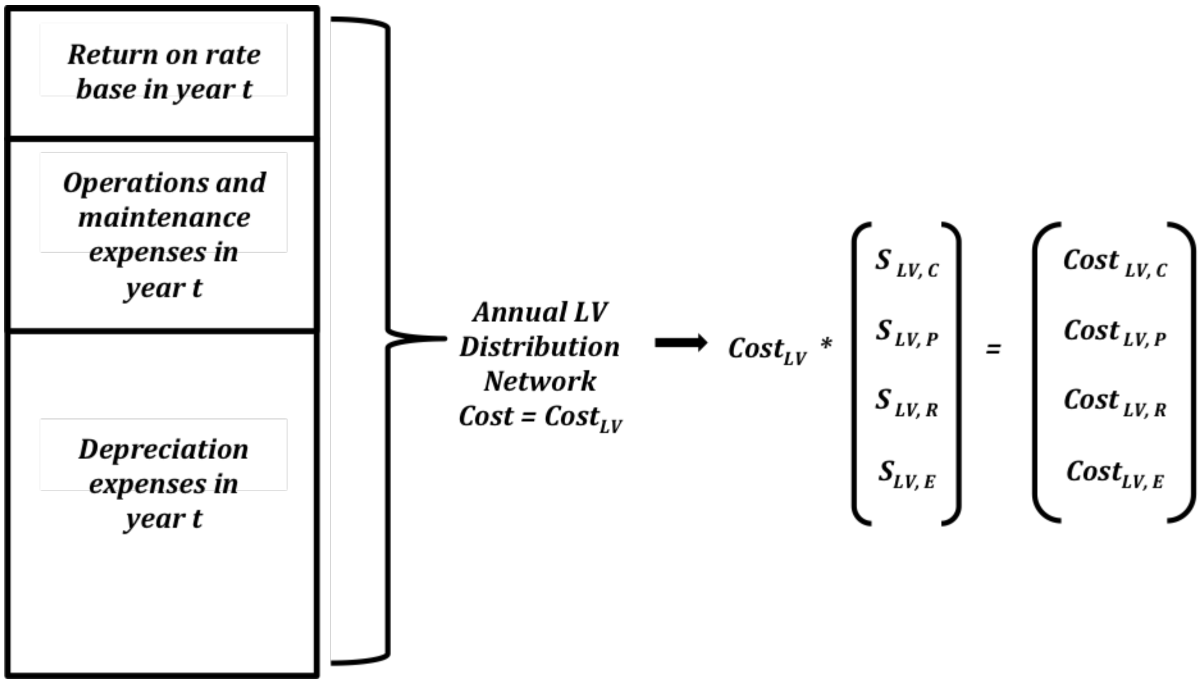

Figure 10: *The DSO's total recoverable costs at each voltage level are multiplied by the driver shares computed with RNM output to determine how much of the total DSO recoverable costs should be assigned to each driver.*

the reliability components of the DNUoS charge are based on volumetric energy use,[15] reflecting the subset of distribution costs that are driven by volumetric energy use. User i's DNUoS charge is:

$$User\ i\ DNUoS\ charge = \sum_{Cost\,Drivers\ d_n \in D} c_{zn} * s_{izn}$$

A user may have a null value, $s_{izn} = 0$, for those cost drivers to which the network user does not contribute: for example, a user may not contribute to load during a particular peak demand period.

Allocating the cost of connection

As previously mentioned, some differences in user profiles are the result of network design decisions and not network user behaviors. Such network costs should be socialized across all of the network users within a zone of the distribution network. For example, network users located at different points along a secondary feeder are located at varying distances from the MV/LV substation that serves their feeder circuit. As such, they have different values for the location component of their profiles, but their location on the feeder is not a result of their behavioral choices. Costs associated with the location of all users along a particular feeder should therefore be socialized amongst the users on the feeder. In general, clustering network user nodes into zones defines the boundaries of

[15] Allocating the reliability component according to the complete load profile is a simplified but effective representation of network users' impacts on reliability costs. An alternative approach is to measure network users' benefit from reliability investments as reflected by the reliability indices achieved within users' zones, and to allocate costs on the basis of average benefits. For more on a beneficiary-pays approach to the allocation of reliability costs, see [24]

portions of the network within which differences between network users' contribution to distribution costs are not directly attributable to differences in their network utilization profiles.

The use of network zones such as feeders accurately communicates to network users locational signals about local distribution system conditions. As a result, users with otherwise-identical network utilization patterns can have different final network charges if they are in different zones of the distribution system. This fact reflects temporal and spatial differences in the impacts of load and DER on network conditions and costs. Under some circumstances, DER can have a positive impact on the network and reduce long-term network costs; for example, greater penetration of DG along feeders heavily loaded with demand can serve local load, alleviate congestion, and enable network investment deferral. On the other hand, increasing penetration of DG in areas with more generation than consumption and significant reverse power flows can call for significant investment in network upgrades. The coincidence of network use by multiple users — whether for consumption or production of power — plays a central role in determining the value of DER to the grid. As such, users' profile values can be positive or negative depending on the impact of their activities on system conditions and on surrounding users' profiles.

In order to allocate connection costs to network feeders, total line costs at each voltage level should be assigned to feeders according to some weight of the lengths of the feeders, and then the cost of that feeder should be socialized amongst the network users connected to that feeder. This is not a straightforward procedure, as the DNUoS charge must be designed to both allocate connection costs in a way that does not charge network users for arbitrary differences in feeder length, yet that does charge different connection costs when the cost causality of a particular feeder is clearly identifiable and can fairly be assigned to a single user or small subset of users.[16]

Allocating the cost of capacity

Distribution networks are planned and designed to accommodate peak capacity requirements under a range of plausible operating scenarios and *anticipated* system peaks (accounting for variations in season, weather patterns, load growth, and other factors). The DSO's annual capacity-related costs can be assigned to spread over anticipated peak periods throughout the year or over the actual peak periods at the end of the year.

If historical data is used to provide an indication of when peak periods are likely to occur in future years,[17] the DSO can spread the annual capacity-related network costs based on the probability and magnitude of anticipated peak conditions. One approach taken by distribution utilities today is through the computation of peak capacity allocation factors (PCAFs). PCAFs assign a fraction of total annual capacity costs to each hour of a year according to the probable share of incremental load attributable to that hour. The incremental load in an hour h is the difference between the load in hour h and a peak threshold $P_{Threshold}$ which is typically defined as one standard deviation below the historical mean hourly peak [28].

$$PCAF_h = \frac{max[Load_h - P_{Threshold}, 0]}{\sum_{h=1}^{8760}(max[Load_h - P_{Threshold}, 0])}$$

The PCAF effectively weights the allocation of capacity-driven costs to each hour according to the

[16] For example, if the DSO is obligated to connect network users in rural areas, it may not be fair or desired by the regulator to allocate the full cost of that line to the small number of users for whom the line is built. Connection charges for DG present a similar challenge. See [3] for a more detailed exploration of designing DG connection charges.

[17] This may very well not be the case in distribution systems experiencing rapid changes in customer profiles and network utilization, but this approach provides a starting point.

probability of a system peak occurring within that hour on the basis of historical data. Periods other than hours may be used in capacity cost allocation, and capacity costs may be allocated to fewer time periods by setting the threshold higher to capture fewer likely peaks.

Note that the fixed sum that must be collected from users for network capacity investments in a given time period is established a priori and does not depend on the actual behavior of the network users during each period. However, the *allocation* of the capacity costs to be recovered from the network users does depend on each user's contribution to the actual peaks over the course of a year, creating the right incentive for network utilization in the short run. The magnitude of total recoverable capacity costs allocated to each hour is based on the anticipated peaks used in distribution network planning because the anticipated peaks guide network investments rather than the actual occurrence of peaks. With a record of the historical occurrence of system peaks and regulatory validation of projected peaks during the process of determining DSO revenue requirements, it is likely that the anticipated system peaks will match the actual system peaks reasonably well and thereby result in accurate allocation of total capacity-related network costs. Dividing the annual capacity-related costs across the hours of the year according to probable system peaks provides network users with rough signals to guide their network utilization behaviors and encourage them to shift network use away from peak periods.

Alternatively, rather than pre-assigning a fraction of capacity costs to be recovered during anticipated peak periods, every time period may be equally weighted with allocation to users based on the actual occurrence of peaks. For example, the TRIAD approach used in the UK to compute transmission network use of system (TNUoS) charges measures a network user's demand during the three half-hour intervals of the largest system peaks each year, with a required minimum time between the intervals. Users' TNUoS charges, or their shares of transmission network costs, are computed at the end of the year based on the average of their three peak-contribution measurements [13]. Allocating capacity charges to a wide sample of time periods throughout the year ensures that variability in network use patterns is accounted for and minimizes randomness in the computation of network charges.

Within each hour to which some non-zero fraction of total capacity-related costs is allocated, the capacity cost in that hour is allocated spatially according to the contribution of components at each voltage level of the network to the system peak. That is, the capacity cost of a given peak-flagged hour h_{p1} is assigned to each HV/MV substation according to the ratio of the load at the HV/MV substation during h_{p1} to the total system peak load (considering the load at the primary distribution substation to be the "system peak load"). Then, the cost attributed to each HV/MV substation is divided amongst the MV network users and MV/LV substations served by that HV/MV substation according to the load or injection of each MV user and MV/LV substation during h_{p1}. Note that the MV/LV substation may not necessarily be experiencing its peak load during the system peak load, and allocation of the HV/MV substation capacity cost to each of the MV/LV substations according to their hourly profiles captures that fact. The capacity cost assigned to each MV/LV substation is then divided amongst the LV feeders served by the MV/LV substation according to the ratio of each LV feeder's load or injection during h_{p1} to the total load or injection at the substation. Each feeder's capacity cost is allocated to users according to the ratio of the kW of consumption or injection by each user to the kW of load or injection in the feeder.

Allocating the cost of reliability

Reliability-related costs are allocated on the basis of hourly energy use because, as previously described, the reliability cost driver is associated with all hours of network use, not just peak hours. Ensuring reliable service during system peaks does not automatically ensure continuity of supply in all other hours of the year during which failures or contingencies may occur. The approach taken in [24] to include reliability-related costs in network charges achieves a high level of granularity, taking into account differences in reliability levels required by different network users and different levels of benefit derived by users from network protection equipment and reliability-related enhancements. In practice, the success with which reliability targets are met by the DSO may be tracked by regulators down to the feeder level, so it is feasible to allocate reliability costs to feeders on the basis of how well index targets are met [30]. While such granularity is important for designing cost-reflective charges, the framework proposed here incorporates a much less detailed approach as a starting point to sufficiently capture network users' contributions to reliability-driven costs. Further work can incorporate a more detailed method for reliability cost allocation.

It is worth noting that by assigning reliability-related costs to hourly energy use profiles, the risk of network failure to supply demand is much more heavily weighted than the risk of curtailment of local generation. This aligns with the fact that the economic impact is much larger in the former case than the latter.

Allocating the cost of losses

Line losses vary quadratically with line current, so ideally, the costs associated with upgrading equipment to reduce line losses ought to be allocated to network users as a quadratic function of their profile of energy consumption and production, and as a function of a user's location. To calculate the loss component of DNUoS charges, a simplified definition of a user's profile of power consumption and injection can be used: rather than considering the complete hourly profile for 8760 hours of a year, hours can be grouped into time blocks according to demand levels in each feeder. Users are charged for their contribution to losses during each block of time based on the ratio of the kWh of consumption or injection to the net consumption or injection of the feeder during the specified time block. Like capacity charges, the contribution of a user's profile to network losses can be positive or negative, depending upon whether the user is located in a mostly generation or consumption area and whether the user's profile is mostly that of a generator or a consumer.

Allocating costs across voltage levels

An important consideration in computing the DNUoS charges for any given user of the distribution network is how to allot common costs of the different voltage levels of the network to users. An incremental approach to constructing a distribution network with an RNM can not only be carried out for LV network users without MV or HV users, as demonstrated in this thesis, but can subsequently be carried out for MV network users without LV or HV users, and for HV network users without LV and MV users. This enables the identification of the costs that can be entirely allocated to each voltage level or shared amongst the users at multiple voltage levels.

Information requirements for cost allocation

In order to implement the proposed approach, it is critical to have the ability to measure the values of the cost driver variables in network use profiles. It may often be the case that detailed measures of cost driver variables are not available for all users of a distribution network (and it is in fact under such conditions that the numerical simulation is carried out). For example, since capacity is a primary driver of network costs, the availability of hourly meters, contracted capacity, or some accurate measure of contribution to peak power flows is essential. In the absence of such capacity measures, however, implementation of the above framework requires an estimate of network user contributions to peak capacity requirements. Poorly designed attempts to estimate network use profiles can create even greater inefficiencies. A variety of tariff formats have been proposed or utilized to improve the efficiency of network charges under differing constraints of information availability. Capacity charges are a favored approach to rectifying the shortcomings of volumetric network tariffs because of their potential to meet multiple regulatory criteria [17]. However, there are significant drawbacks to using entirely capacity-based charges. Movement from a volumetric tariff to a wholly capacity-based network charge ignores the contribution of energy use to network losses and reliability, and therefore to total network costs. In the absence of detailed information about network users' capacity requirements, all network users of a particular "type" — such as residential users — may be assumed to have a representative power profile or capacity requirement. Then, since all users' charges are computed with the same unit capacity rate, and no consideration is given to the total quantity of energy consumed by network users, users who consume less energy overall will have the same total kW-based network charge as users who contribute more to energy loss-related network costs. Utilization factors, or the ratio of total energy consumption in kWh to peak consumption or contracted capacity in kW, have also been used to approximate network users' peak coincident demand [50]. As profiles of network use become increasingly variable, diverse, and bi-directional, utilization factors are no longer effective estimates of network use and are not applicable in distribution systems increasingly departing from conventional networks of end consumers.

3.4 Choosing the DNUoS charge format

After using the method described above to determine the total distribution network cost to be allocated to and collected from each network user, the format to be employed for the collection of the DNUoS charge must be chosen. That is, the regulator and DSO must select *how* the charge information is presented to the network user. For example, the total amount to be charged to each network user can appear on each user's bill as a $/month sum, or it can be disaggregated into its components and presented on the bill as a connection charge, capacity charge, reliability charge, and loss charge. The format of the DNUoS charge defines how the network users will perceive the price signal they receive, since it communicates how their use profiles impact network costs. Choosing the format requires consideration of the regulatory goals and tradeoffs of DNUoS charge design, such as simplicity and transparency. For example, it should be clear to network users how the charge they see on their bill is derived from their network utilization if incentives for more efficient network utilization are to be preserved.

Traditionally, charge "format" refers to the rates seen by end users on their electricity bills such as $/kWh rates, $/kW rates, and/or $/customer or fixed charges. However, under the proposed approach to DNUoS charge computation, rates would not provide efficient signals for network users since each user's charge is based upon cost allocation to network zones first and then to individual users. Presenting network users with the capacity components of their DNUoS charges as $/kW rates can lead to widely differing values for different peak periods and for different feeders.

Computing cost-reflective DNUoS charges relies upon having an unbundled retail bill that separately lists a system user's charges for generation, transmission network use, distribution network use, and retail or marketing. The value of clearly identifying network cost drivers and allocating the costs of the network amongst users according to those drivers and according to network utilization profiles is only realized with an unbundled retail rate that clearly distinguishes between the costs (and thus the price signals) for generation and network utilization. For instance, a single flat volumetric rate effectively signals network users to reduce their total energy consumption. This is an inefficient signal of *network* costs, since analysis of the cost drivers reveals that the presence of a connection to the distribution network and contributions to peak power flows are the dominant drivers of distribution costs. Also, as explained in Section 6, the design of network charges should not interfere with energy price signals.

4 Using a Reference Network Model for DNUoS Charge Design

Distribution planning models such as RNMs have been utilized by utility regulators to aid in the assessment of prudent DSO investments and the remuneration process. As demonstrated in this thesis, RNMs can also be employed in the cost allocation process to isolate the effects of distribution network use on distribution costs. Using an RNM to carry out sensitivity analysis to identify how changes in network utilization impact network costs allows the regulator and DSO to link network costs to cost drivers and network users. Identifying this linkage is a notoriously difficult challenge because of the complications introduced by joint and common costs and the discrete nature of distribution network investments [5], [32]. The use of simulation environments such as RNMs offers an efficient method by which to estimate the effects on costs – or cost causality – of perturbations in network utilization – or network use profiles. What follows is a more detailed description of the procedure by which DNUoS charges can be computed with an RNM. A numerical example illustrates the calculation of LV network user DNUoS charges in a sample distribution service area.

4.1 Building a distribution network incrementally

The RNM used here is an adaptation of the PECO RNM originally developed and described in [25] and [26]. The PECO model has undergone a series of modifications and updates since its initial development, and the updated version used for this thesis is described in [12]. The greenfield RNM designs a network from scratch in a distribution area with no existing network. The brownfield RNM designs the reinforcement and expansion of an existing network required to accommodate growth in the number of network users, user load, and the integration of DG.

In order to first determine the contribution of each of the cost drivers to the total distribution system cost, the following sequence of greenfield RNM and brownfield, or incremental, RNM runs is carried out:

1. *Run00 – Initialization Run*: Run a full greenfield and brownfield RNM to build an optimal network for a set of network users, considering network users' full peak load and generation, 48-hour profiles of energy consumption and production, full reliability objectives, and a nonzero cost of losses.

   This run serves as a calibration run that populates the distribution service area with the locations of customers and samples and assigns profiles to those network users. By designing the optimal network in this run, a benchmark cost is provided for the completed distribution network against which the sum of the costs of all the incremental network build runs, *Run*01 through *Run*04, can be compared. Additionally, this run identifies the optimal locations of the HV/MV and MV/LV distribution substations. These locations are fixed for all subsequent runs to avoid building unrealistic networks in the incremental runs associated with each cost driver. This mitigates the potential of generating artificially low or high incremental costs between model runs.

2. *Run01 – Minimal Network Run/Connection Run*: Run a partial greenfield RNM. "Partial" refers to the fact that the locations of the substations are fixed in the positions identified in Run00. The key design input for this run is a minimum peak consumption and production value identified for each network user. The minimum demand identified for each load point is obtained as the minimum value of hourly energy consumption from each network user's

profile in Run00. Similarly, the minimum production is the minimum value of the hourly production profile for each distributed generation point (typically 0 kWh)[18]. Reliability indices are relaxed, and the cost of losses is set to a very small value (essentially a zero cost of losses). The objective of this run is to identify the cost of connecting all of the users to the distribution network assuming they consume or produce at their minimum demand and generation values each hour.

By raising or lowering the value of minimum demand set for each network user, the amount of the total distribution system cost associated with connection can be raised or lowered, thereby increasing or decreasing the share of total distribution costs socialized amongst network users.

Output: *Total Network Connection Cost (C) = Total Run01 Network Cost*

3. *Run02 – Capacity Run*: Run a partial greenfield with network users' real peak consumption and generation values followed by a brownfield run with full profiles for consumption and generation. Reliability indices are relaxed, and the cost of losses is set to a very small value (essentially a zero cost of losses). The goal of this run is to determine the cost of designing the network to meet the peak load for all network users and accommodate reverse power flows. Running the greenfield and brownfield models yields similar but slightly lower costs when compared to the results of carrying out only a brownfield run. This is because the initial greenfield network built to seed the brownfield RNM is constructed with knowledge of the full peak load and generation values, thus requiring fewer reinforcements in the brownfield model to correct the design shortcomings of the greenfield network. The smaller number of corrects reinforcements yields a more realistic incremental cost associated with accommodating peak power flows in the overall network design.

   The network design in this run accounts for both the connection and capacity requirements of network users, and the incremental cost relative to Run01 is the cost associated with capacity.

   Output: *Total Network Capacity Cost (P) = Total Run02 Network Cost - Total Run01 Network Cost = Total Run02 Network Cost - (Total Network Connection Cost (C))*

4. *Run03 – Reliability Run*: Run a brownfield with full network user profiles and realistic reliability objectives. For example, realistic TIEPI and NIEPI objectives for urban and concentrated rural networks are listed in **Table 3** below. The purpose of this run is to determine the cost of meeting reliability objectives for network users. As can be seen in **Table 3**, zonal indices and individual indices for LV and MV network users are defined. However, in the RNM version utilized in this thesis, continuity of supply is only taken into consideration for the MV network, and reliability investments are made only in response to MV reliability targets. The LV reliability targets are not taken into account in the model's network design. As such, the reliability component is not computed in the LV DNUoS charge numerical example provided.

   This step may be run for hours that experience system peaks and for all hours of the year in order to separately identify the reliability-related costs resulting from peak capacity requirements and those arising from all other operating conditions.

   Output: *Total Network Reliability Cost (R) = Total Run03 Network Cost - Total Run02*

[18] Even though the minimum hourly generation for each LV PV generator is 0 kW, the generators are still considered in the spatial layout of the greenfield network, with feeders extended to each network user that requires it. See **Appendix D** for an illustration of the network constructed during Run01 and Run00 in a portion of Network B with LV load and generation points.

Network Cost = Total Run03 Network Cost - (Total Network Connection Cost (C) - Total Network Capacity Cost (P))

	Individual Indices				Zonal Indices	
Zone	Low Voltage		Medium Voltage			
	TIEPI	NIEPI	TIEPI	NIEPI	TIEPI	NIEPI
Urban	6	12	4	8	2	4
Concentrated Rural	15	18	12	15	8	10

Table 3: *Sample reliability targets for an urban network and a concentrated rural network such as the network built in the case study*

5. *Run04 – Losses Run*: Run a brownfield with full network user profiles, realistic reliability objectives, and a nonzero cost of losses set to a value that captures a realistic cost to generators and a regulator-imposed penalty for distribution losses.[19] This full set of constraints on cost drivers reveals the cost of designing the distribution system to reduce network losses.

   Output: *Total Network Losses Cost (E) = Total Run04 Network Cost - Total Run03 Network Cost = Total Run04 Network Cost - (Total Network Connection Cost (C) + Total Network Capacity Cost (P) + Total Network Reliability Cost (R))*

Table **Table 4** summarizes the key features of the RNM runs, indicating the constraints that are relaxed and reintroduced in each run.

4.2 Defining the network characteristics

Two sample networks were built in this sequential manner. The method for populating the distribution service area with network users and assigning user characteristics and profiles is the method developed and described in [58]. The networks simulated for the sample DNUoS charge calculation represent realistic distribution networks in the concentrated rural area of Eaton, CO. A summary of the features of the simulated Eaton distribution service area is provided in **Table 5**.

Users and PV are placed randomly within the defined geographic area, and each network user is assigned a peak load and generation value according to a normal distribution with a mean and standard deviation specific to each voltage level. This peak value is used in the greenfield RNM design; the values are summarized in **Table 6**. Each network user is also assigned a 48-hour load or generation profile according to the proportion of residential, commercial, and industrial customers at each voltage level (see **Table 6**).

A network user of a particular type is assigned one of ten possible profiles of that type: a residential profile, commercial profile, industrial profile, or PV generation profile (see **Appendix A** for the profiles from which all network user profiles were sampled). The load profiles are drawn from

[19]The sample DNUoS charge utilized losses costs in the range of \$0.10-\$0.30/kWh.

	Run00	Run01	Run02	Run03	Run04
Model run type	Full GF + BF	Partial GF	Partial GF + BF	BF	BF
Number of network users	Calculated	Fixed	Fixed	Fixed	Fixed
Network user locations	Randomly assigned	Fixed	Fixed	Fixed	Fixed
Substation locations	Designed for optimum	Fixed	Fixed	Fixed	Fixed
Network user peak load or generation	Full peak	Minimum load or generation	Full peak	Full peak	Full peak
Network user 48-hour profile	Full profile	N/A	Full profile	Full profile	Full profile
Reliability indices	Realistic	Relaxed	Relaxed	Realistic	Realistic
Cost of losses	\$0.138/kWh	~0	~0	~0	\$0.138/kWh

Table 4: *The key parameters that are changed in each run to introduce cost driver constraints sequentially*

the EERE dataset of hourly load profiles for commercial buildings, and residential buildings [8].[20] The PV generation profiles were derived using the NREL PVWatts Calculator [43]. The 48 hours represented in the profiles correspond to a peak net load day and peak net injection day (load − generation). As input for the RNM, the profiles are a representative 48 hours of a year. Distribution equipment including conductors, transformers, and protective equipment such as sectionalizers and reclosers are selected from a catalog of equipment with the technical specifications and costs of equipment, and repair and maintenance time.

The first network (Network A) includes only LV load, omitting all MV and HV network users and excluding DG. The second network (Network B) includes LV load and LV distributed generation in the form of solar PV. **Table 6** below summarizes the key characteristics of Networks A and B pertinent to cost allocation. The spatial layout of the complete Network A is shown in **Figure 11**, and the spatial layout of the complete Network B is shown in **Figure 12**. Since the Eaton distribution service area represents a concentrated rural network, parts of the network are notably sparse. For example, in **Figure 11** and **Figure 12**, some of the LV user connection points – particularly those at the end of long MV feeders – are concealed by a MV/LV transformer in the same location. Each of these transformers is dedicated to serving a single LV network user, and the cost of the transformer and primary feeder section extending to the LV point may be allocated entirely to that user[21].

[20]The represented commercial buildings are from the Department of Energy commercial reference buildings, and residential profiles are based on the Building American House Simulation Protocols.

[21]Or it may be socialized in a manner selected by the regulator to share the cost burden of electrifying a single rural connection point.

Eaton, CO Simulated Network		
Distribution service area (km^2)	266.5	
Population density (people/km^2)	50	
Type of network	Concentrated rural	
Distributed PV penetration	30%	
Voltage (kV)	LV	0.24
	MV	12
	HV	33-66

Table 5: *Characteristics of the simulated concentrated rural network*

There are differences in the topologies of Networks A and B; however, the objective of the numerical example is to demonstrate the computation of DNUoS charges for the network users in each network separately, not to assess the impact of the presence of distributed PV on the charge for particular network users. The latter objective can be achieved in subsequent work with brownfield introduction of distributed PV to an existing network.

	LV
Number of load points	533
Load power density (kW/km^2)	10
Load point average power (kW/point)	5
Load point standard deviation power (pu)	0.20
Number of DG installations	24
PV power density (kW/km^2)	0.90
PV average power (kW/point)	10
PV standard deviation power (pu)	0.20
PV average capacity factor	0.25
PV standard deviation capacity factor	0.10

Table 6: *Network A and B load and generation parameters*

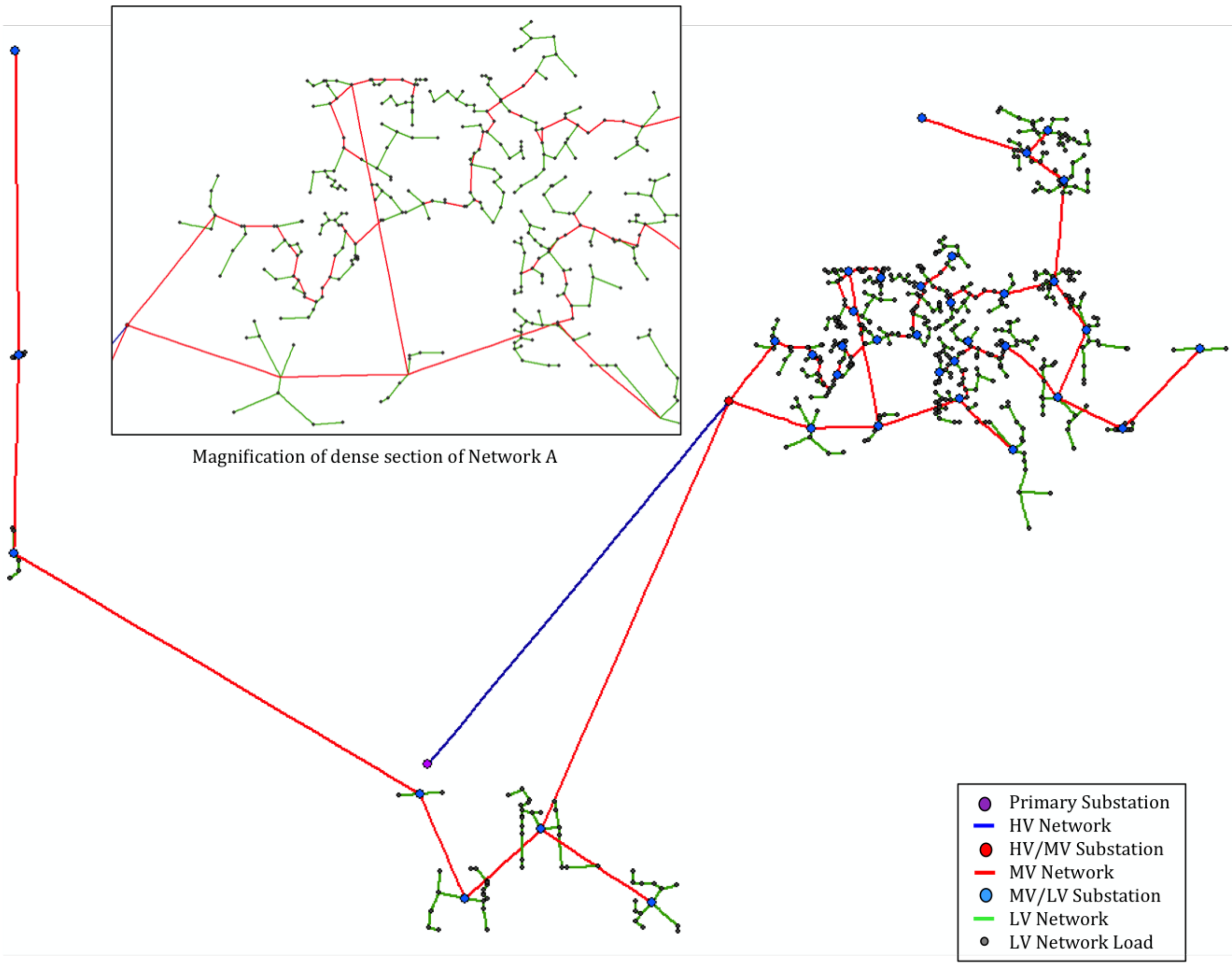

Figure 11: *The full Network A*

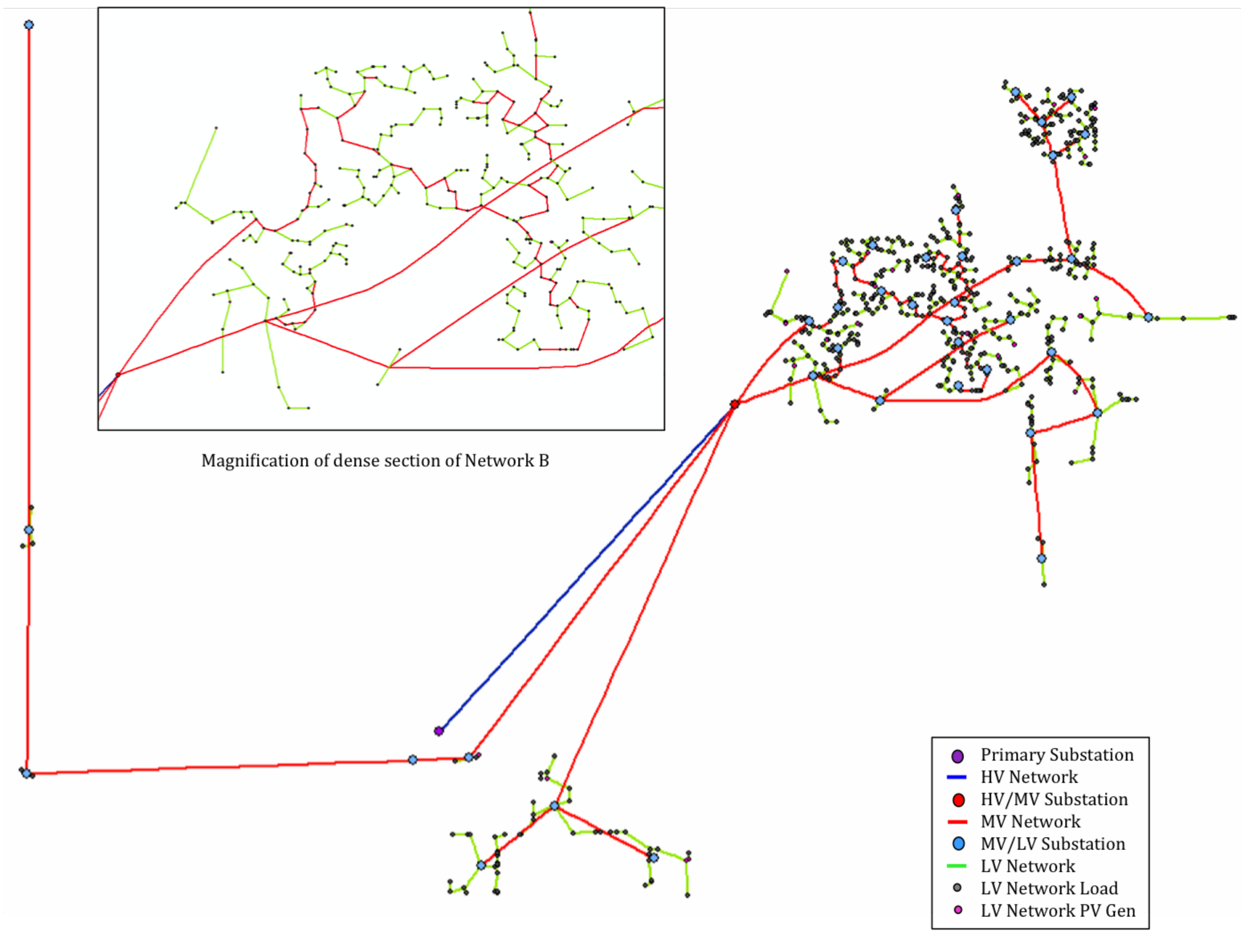

Figure 12: *The full Network B*

5 Simulation Results: Computing a LV DNUoS Charge

The total network cost expressed as an NPV of investment costs and annual O&M for a 40-year asset life are summarized for Networks A and B in **Table 7**, along with the cost driver shares obtained through the incremental model runs. The results reveal that the primary drivers of the network costs are connection and capacity. These results are highly dependent upon the parameters used to define each model run. For example, the minimum size of network components in the equipment catalog provide a lower bound for the total investments that can be made in Run01. Additionally, the high share of the connection driver arises from the fact that all of the HV, MV, and LV network costs are allocated amongst LV network users. With the addition of MV and HV network users, spare capacity on network components can be utilized and many of the connection costs shared by users at multiple voltage levels.

	Network A (LV Load)				
	Run00 (Benchmark)	Run01	Run02	Run03	Run04
Total network Cost	$11,320,497.42	$7,852,716.84	$10,610,251.44	$11,053,998.72	$11,246,345.88
Incremental Cost		$7,852,716.84	$2,757,534.60	$559,314.00	$76,780.44
Percent of Total Cost		69.82%	24.52%	4.97%	0.68%
Cost Driver		Connection	Capacity	Reliability	Losses

	Network B (LV Load and PV Generation)				
	Run00 (Benchmark)	Run01	Run02	Run03	Run04
Total network Cost	$11,421,364.38	$8,165,345.68	$10,927,887.42	$11,515,906.80	$11,484,645.66
Incremental Cost		$8,165,345.68	$2,762,541.74	$588,019.38	$-
Percent of Total Cost		70.83%	24.05%	5.12%	0.00%
Cost Driver		Connection	Capacity	Reliability	Losses

Table 7: *The NPV of the total and incremental costs associated with each RNM run for Network A and Network B, and the resulting cost driver shares*

The cost outputs of the RNM are identified as investment costs and O&M costs for each of five parts of the distribution network: the HV network, HV/MV substations, the MV network, MV/LV substations, and the LV network. The key outputs of the RNM for Network A and Network B are summarized in **Table 8** and **Table 9** respectively.

	Investment (overnight capital cost)	Annual O&M	
		Preventative Maintenance	Corrective Maintenance
Full network (DSO costs)			
LV network	$787,175.46	$22,062.06	$29,297.40
MV/LV substations	$399,510.00	$23,487.60	$1,072.26
MV network	$1,682,500.14	$23,562.12	$20,030.70
HV/MV substations	$3,091,200.00	$104,328.00	$24.84
HV network	$397,237.14	$7,639.68	$3,539.70
Total	$6,357,622.74	$181,079.46	$53,964.90

Table 8: *RNM cost outputs for Network A*

	Investment (overnight capital cost)	Annual O&M	
		Preventative Maintenance	Corrective Maintenance
Full network (DSO costs)			
LV network	$788,391.24	$22,434.66	$30,239.94
MV/LV substations	$410,136.00	$24,122.40	$1,101.24
MV network	$1,669,452.24	$27,088.02	$23,126.04
HV/MV substations	$3,091,200.00	$104,328.00	$24.84
HV network	$372,900.84	$7,171.86	$3,323.04
Total	$6,332,080.32	$185,144.94	$57,815.10

Table 9: *RNM cost outputs for Network B*

Before the investment and O&M costs output by the RNM can be allocated amongst feeders and network users, post-processing of the outputs must be carried out to more accurately reflect how total costs translate to the DSO's collectible revenue in a given time period (taken here to be a year).

To identify an annual recoverable cost for each year N of the asset base lifetime, an equivalent uniform annual cash flow (EUAC) of the deprecation expenses and return on the rate base is computed in current year dollars for each year N and added to the annual O&M costs (which are also expressed in current year dollars). For example, as shown in **Table 8**, the total investment cost of Network A is $6.36 million. Assuming a 40-year asset life, straight-line depreciation of the asset over its lifetime would yield an annual present value depreciation expense of $158,940 in constant dollars. When expressed in current year dollars (i.e. the future value of the annual payment in year N), depreciation expenses at the end of each year range from $170,066 to $2.3 million. This places a larger depreciation expense burden in the later years of the life of the asset relative to the earlier years. The EUAC is commonly used to equalize payments in constant net present value dollars over the life of an asset. It is best applied to annual cash flows that are either constant or normalized to a base year: in this case, the annual depreciation expenses and the annual return on the rate base are expressed as Year 0 present values [42].

To express the investment cost output by the RNM as a constant annual depreciation expense for every year N of the assets' lifetime, the RNM overnight capital cost of each simulated network is translated to current year N dollars using the EUAC formula:

$$EUAC = \frac{PV * r}{1 - \frac{1}{(1+r)^N}},$$

where $EUAC$ is the equivalent uniform annual cash flow of depreciation expense in year N (i.e. in current year N dollars); PV is the overnight capital cost, or present value of the total capital investment (this is the capital cost output by the RNM); N indicates the number of years over which the asset is depreciated; and r is the discount rate.

Similarly, an EUAC of the annual return on the rate base is computed using the overnight capital cost of the network as an estimate of the beginning value of the rate base. Estimating the value of the current asset base in any Year N requires knowing not only the starting asset base in Year 0, but also the vintages of all assets, keeping track of accumulated depreciation of existing assets, asset end-of-life and replacement, and additions to the asset base. In the sample DNUoS charge calculation, this process is carried out for the static, distribution network built "overnight" at the end of Year 0/beginning of Year 1 without consideration of changes to the asset base each year. Thus, the beginning rate base as estimated by the overnight cost output by the RNM is reduced each year by annual depreciation.

The rate base at the end of Year N is:

$$Rate\,Base\,Year\;N\;End = Rate\,Base\,Year\;N\;Beginning - Year\;N\;Depreciation Expense$$

The annual return on the rate base in Year N is:

$$Return\,on\,Rate\,Base\,Year\;N = Rate\,Base\,Year\;N\;Beginning * Weighted\,Average\,Cost\,of\,Capital$$

Annual preventative and corrective maintenance costs are used directly as expressed by the RNM as the O&M expenditures for each year N. The sum of the annual O&M costs, EUAC of the depreciation expense, and EUAC of the return on the rate base yields the total DSO cost to be recovered each year.

Again, annual additions and reinforcements to the starting network are not considered. **Figure 13** illustrates how the procedure demonstrated in the numerical example for the initial rate base can be repeated for additions to the asset base each year in order to compute the DSO cost to be allocated each year when considering network additions.[22]

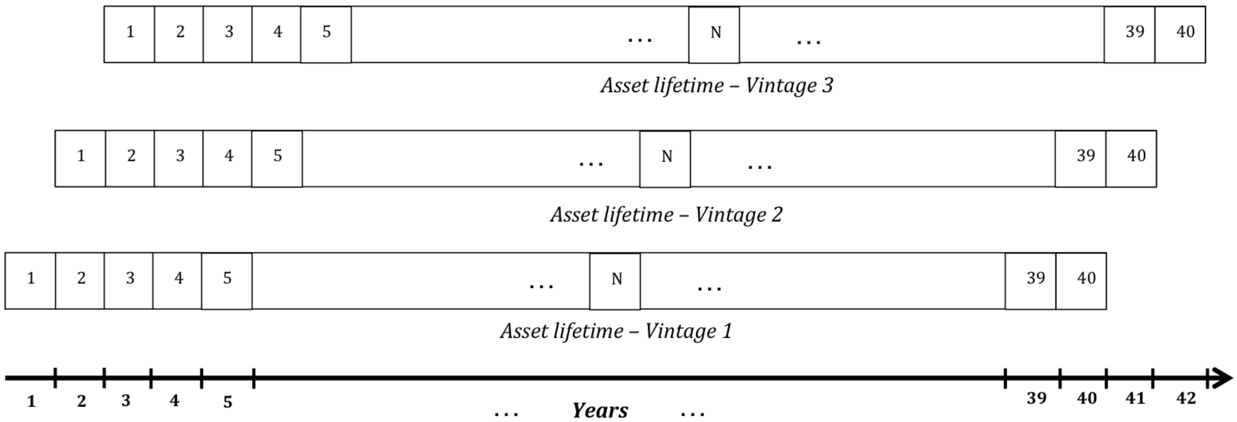

Figure 13: *The process demonstrated here for allocating the initial, Year 0 asset base should be repeated for each asset vintage. The sum of the annual DSO costs associated with each vintage yield the total DSO cost to be recovered each year.*

The total DSO cost to be recovered annually is then multiplied by the cost driver shares to determine the annual cost of each driver to be allocated to network users. **Table 10** summarizes the total cost and driver-specific costs for Network A and Network B. The driver costs obtained by applying the driver shares to the total annual DSO cost were verified by separately carrying out the above procedure of determining annual capital costs and adding them to O&M costs for each of the incremental networks constructed in *Run*01 through *Run*04.

Network A (LV Load)				
Total Year N cost to collect	**Connection**	**Capacity**	**Reliability**	**Losses**
$1,591,767.41	$1,111,445.34	$390,291.55	$79,163.30	$10,867.23
Network B (LV Load and PV Generation)				
Total Year N cost to collect	**Connection**	**Capacity**	**Reliability**	**Losses**
$1,594,232.31	$1,133,466.22	$383,480.12	$81,625.46	$-

Table 10: *Total DSO costs and allocation of DSO costs to drivers for Network A (only LV load) and Network B (LV load and PV generation)*

In order to calculate the LV network user DNUoS charges in the simulated Networks A and B with the available information, simplifications to the process described in Section 4 have been made. The reasons for and implications of these simplifying measures are described alongside the simulation

[22]The brownfield RNM is designed to estimate network expansion in response to vertical and horizontal load growth and increased penetration of DG, and subsequent work will explore the allocation of the costs of network expansion.

results.

As explained in Section 3.3, the connection cost of the network would first be allocated to feeders on the basis of the length of lines to reach clusters of network users. For example, in Network A, the costs of the MV network needed to meet the minimum load and injection requirements of LV network users could be allocated to the two distinct clusters of LV users labeled Cluster 1 and Cluster 2 in **Figure 14**. The length of the MV lines to reach each cluster can be used as a weighting factor with which to divide the total MV network cost. However, the regulator may choose to socialize the costs of reaching far-flung rural network users amongst all distribution system users. The challenge of determining how to cluster customers in distribution networks with more-concentrated and less-concentrated areas of the network parallels the discussion of the drawbacks of straight fixed/variable rates [37].

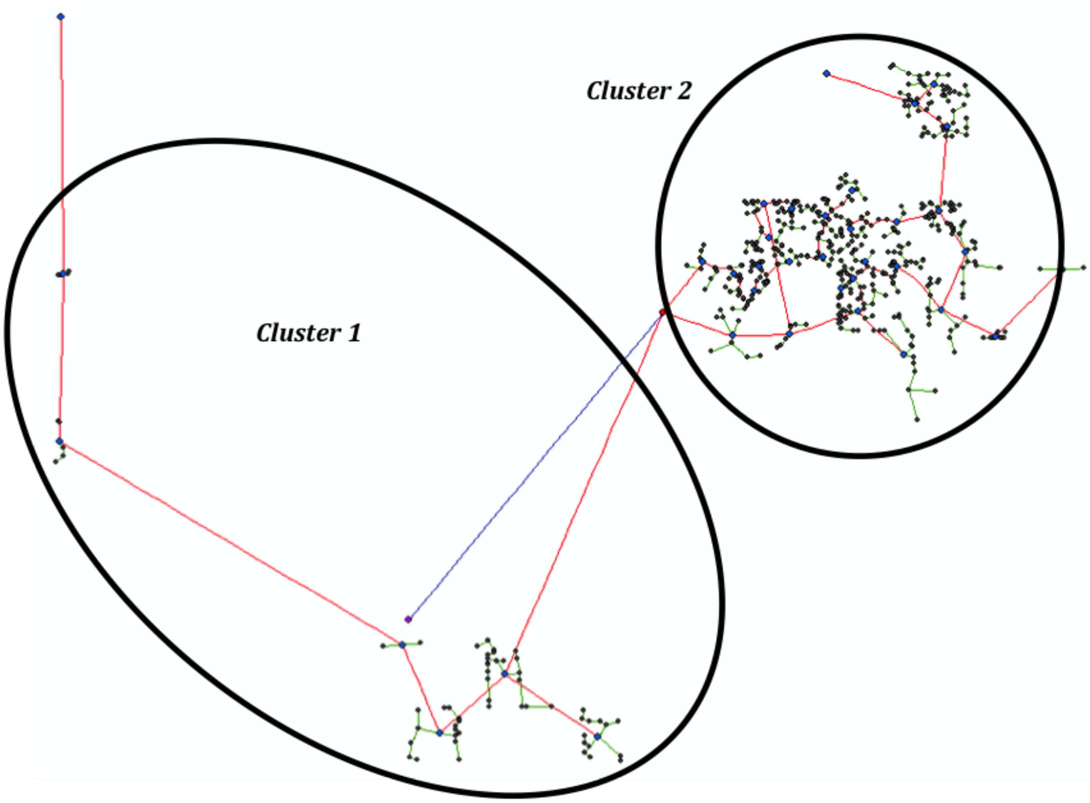

Figure 14: *Allocating connection costs to distinct clusters of network users in Network A.*

For the sample calculation, the connection cost is socialized amongst all LV network users by dividing the annual connection cost of \$1.11 million by 533, the number of LV connections. This yields an annual per-user connection charge of \$2085.26, or a monthly connection charge of \$173.77. As a point of comparison, this amount is much greater than the fixed charges that have been proposed by distribution utilities in multiple jurisdictions today. For example, in 2013 Georgia Power proposed a \$22 per month charge, and Idaho Power proposed a monthly charge of \$20.92 per residential customer to recover fixed distribution costs. (Both requests were denied by the state utility commissions) [33]. By simulating a third network, Network C, with both LV and MV load, one reason for this significant difference was revealed. In the sample Network A, the costs of the

HV and MV networks built in order to meet the needs of the LV customers have been allocated entirely to the LV customers. In reality, since the HV and MV networks are also utilized by the HV and MV network users, the costs of the HV and MV networks would be shared by HV, MV, and LV network users. Because of economies of scale and investment lumpiness, the minimal HV and MV networks built to serve only LV load have a significant amount of excess capacity that can be utilized by added MV and HV customers. The features of Network C are identical to Network A except for Network C's inclusion of MV customers as well. The annual connection cost to be allocated in the MV network for the same 533 LV customers as in network A plus 11 MV customers is nearly identical to the annual connection cost in Network C as seen in **Table 11**. The topology of Network C is illustrated in **Appendix B**.

Network C (LV and MV Load)				
Total Year N cost to collect	Connection	Capacity	Reliability	Losses
$1,614,090.22	$1,114,237.44	$408,521.12	$54,203.65	$37,128.00

Table 11: *Total DSO costs and allocation of DSO costs to drivers for Network C (LV and MV load)*

To allocate the total capacity cost of each network, simultaneity factors (SFs) were used to estimate the contribution of the peak load of components at each level of the distribution network to the system, or primary substation, peak load. With full profiles of hourly energy consumption and injection for every network user, SFs would not be necessary, since the actual load or injection of each network user and each network component would be known every hour. However, since the 48-hour profiles of all users in the simulated networks are drawn from a sample of 30 possible profiles, a realistic level of diversity of network user profiles is not captured. Thus, the profiles alone do not accurately reflect the time or magnitude of the peak hour. The simultaneity factors used in the brownfield RNM runs are listed in **Table 12**.

Simultaneity Factors		
	Greenfield	**Brownfield**
LV customers	0.30	0.32
MV customers	0.80	0.85
HV customers	0.90	0.96
LV feeders	0.80	0.80
MV feeders	0.85	0.85
MV/LV transformers	1.00	1.00
HV/MV transformers	1.00	1.00

Table 12: *The simultaneity factors used in the greenfield and brownfield RNM*

In the sample calculation, all of the capacity costs are allocated to a single peak. PCAFs can be used as described in Section 3.3 to divide the total capacity cost amongst multiple peak periods.

Since the SF = 1 for the contribution of each HV/MV substation to the total system load at the primary substation, the total capacity cost for the peak period is allocated to each HV/MV substation according to the ratio of each substation's peak power flow to the sum of the peak power flows at all HV/MV substations. In both Networks A and B, there is only have one HV/MV substation, so the entire capacity cost for the peak period goes to that single substation. Next, the MV/LV substations served by each HV/MV substation are identified, and, since the SF = 1 for the contribution of each MV/LV substation to the peak load at the HV/MV substation, the capacity cost attributed to the HV/MV substation is split amongst the downstream MV/LV substations according to the ratio of the peak at the MV/LV substation to the peak at the HV/MV substation. That is, capacity cost for each MV/LV substation is:

$$\begin{aligned}&\textit{Capacity cost at MV/LV substation } ML_i = \\ &\qquad\textit{Capacity cost at HV/MV substation } HM_i * \frac{PeakML_i}{PeakHM_i} * SF_{ML}\end{aligned}$$

The MV/LV substations served by the HV/MV substation in Network A and Network B are listed in **Appendix C**. In both cases, the peak loads at the MV/LV substations sum to the peak load at the HV/MV substation.

The capacity cost allocated to each MV/LV substation is then allocated to the feeders served by that substation and then to users along each feeder, as shown in **Figure 15**.

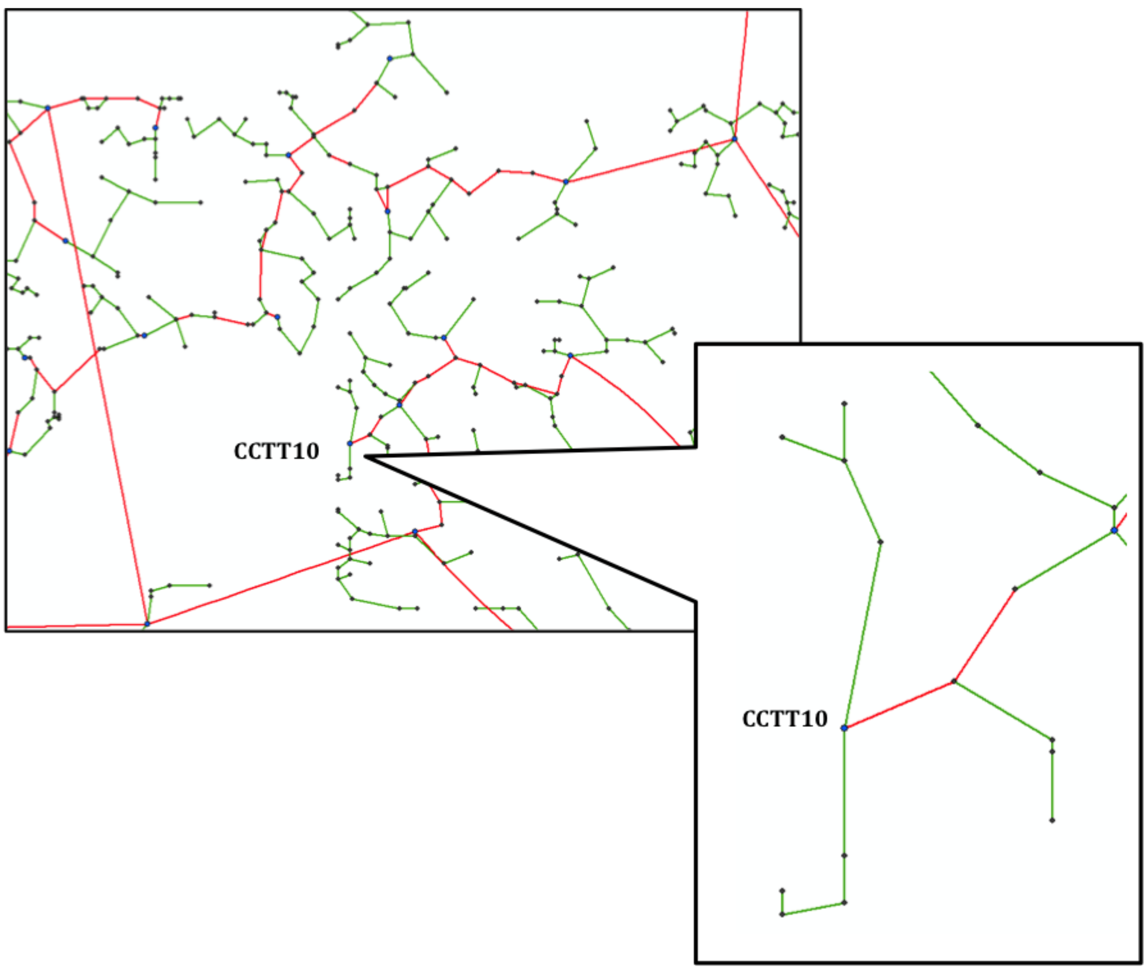

Figure 15: *The LV feeders and end users served by MV/LV substation CCTT10*

Allocating costs to feeders rather than directly to end users captures the possibility that all of the load along a particular feeder is served by generation along that feeder during the peak hour. In such a case, none of the capacity cost at the MV/LV substation level is allocated to that feeder. In the simulated Network A, since the hourly power flow in each feeder is unknown and all network users are strictly consumers, the contribution of each feeder to the peak load is computed as the sum of the peaks of each network user along that feeder adjusted by the SF for LV customers. With this approach, allocating to feeders amounts to directly allocating to end users based on the ratio of each users' peak to the MV/LV substation peak. A sample calculation of the capacity costs of all network users served by a particular MV/LV substation is summarized in **Table 13**.

MV/LV Substation ID	x coordinates	y coordinate	z coordinate	Peak Load (kVA)	Share of HV/MV substation peak	Share of capacity cost
CCTT10	11	6.595	0	18.5	0.022945736	$8,955.53

LV load points served by CCTT10						
Feeder 1						Feeder contribution to CCTT10 peak (kVA)
LV users along Feeder 1	LVC111	LVC331	LVC388	LVC500		
Contribution to feeder peak	1.149	2.028	1.399	1.062		5.638
Share of feeder capacity cost	0.204	0.360	0.248	0.188		
Capacity cost	$595.80	$1051.59	$725.27	$550.69		
Feeder 2						
LV users along Feeder 2	LVC283	LVC323	LVC447	LVC467		
Contribution to feeder peak	1.419	1.428	1.437	1.83		6.114
Share of feeder capacity cost	0.232	0.234	0.235	0.299		
Capacity cost	$735.80	$740.47	$745.14	$948.92		
Feeder 3						
LV users along Feeder 3	LVC29	LVC169	LVC378	LVC384	LVC67	
Contribution to feeder peak	1.133	1.122	1.656	1.611	1.149	6.670
Share of feeder capacity cost	0.170	0.168	0.248	0.242	0.172	
Capacity cost	$587.32	$581.80	$858.70	$334.92	$835.36	

Table 13: *The contribution of network users served by MV/LV substation CCTT10 to the peak load at HV/MV substation*

In Network B, one of the MV/LV substations experiences a negative power flow, or injection, during the peak load at the HV/MV substation (CCTT5 shown in **Figure 16**). Again, here it is assumed that this negative peak at the MV/LV substation is coincident with the peak load at the HV/MV substation.

The negative value of peak load contribution indicates that none of the users served by the injecting feeder are contributing to the peak load at the HV/MV substation because all of load in the injecting feeder is met by DG. Additionally, the injection at the MV/LV substation offsets load at the HV/MV substation and MV lines. The injecting DG is remunerated for this offset as a negative contribution to the peak. This amounts to a credit of $364.84 for the injecting MV/LV substation in Network B, as summarized in **Table 14**. By examining the profiles of all of the network users on the feeder circuit associated with the injecting substation, the distributed generators contributing to the injection can be remunerated for their negative contribution to the peak load. Credits

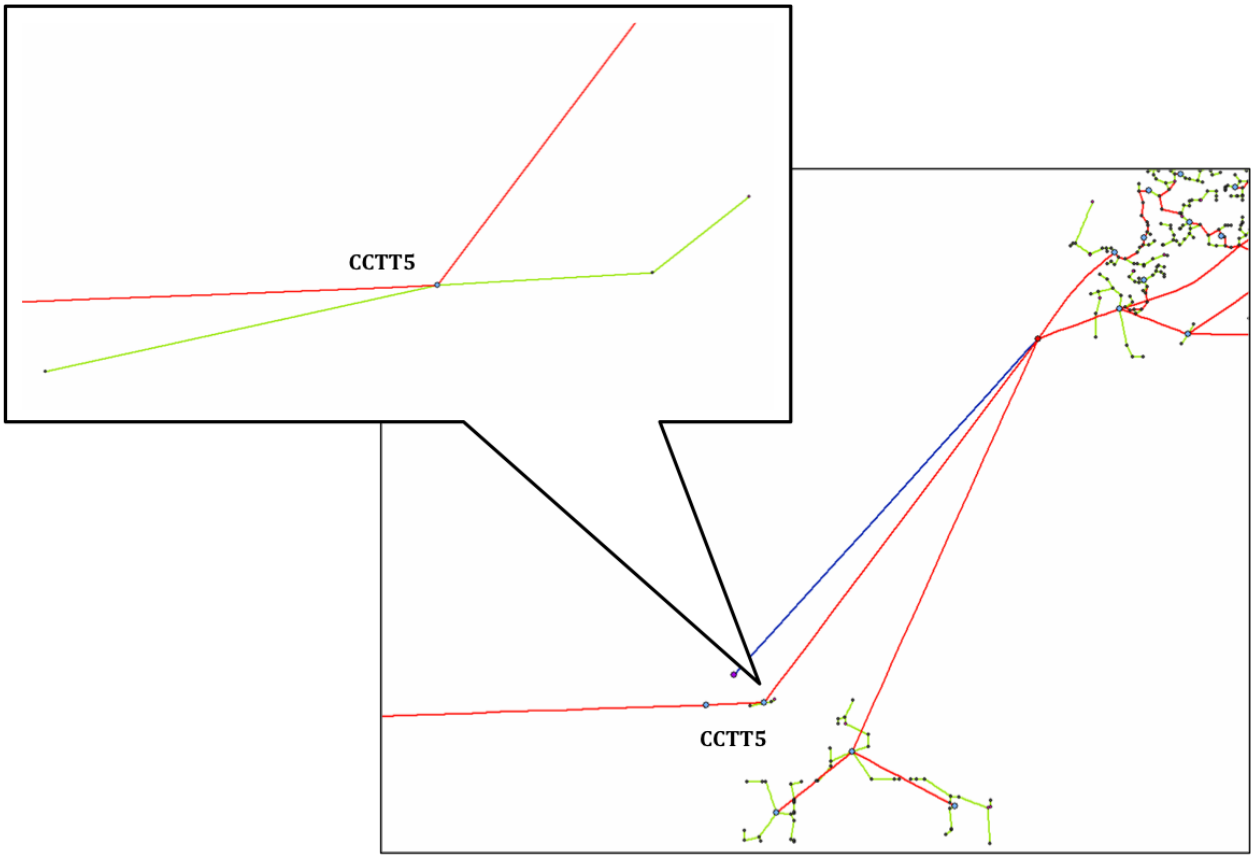

Figure 16: *The LV feeders and end users served by the injecting MV/LV substation CCTT5*

are distributed amongst the network users with negative contributions to the peak according the relative magnitudes of their negative contributions. It should be noted, that the remuneration for the DG through the DNUoS charge only reflects network users' contributions to distribution costs. DG installations also receives remuneration for energy provision in the energy-portion of their electricity bills. In addition to remuneration for negative contributions to peak load and load-related capacity costs, the capacity component of DNUoS charges should also reflect the contribution of DG to injection-related capacity costs. By carrying out the incremental RNM runs for load and generation separately, the costs associated with withdrawal and injection can be isolated. Then, injection-related capacity costs can be allocated to injection in the same manner that load-related capacity costs are allocated to load. The balance of a particular network user's load- and injection-related capacity costs determines the overall value of that DER to the distribution network. In the absence of the network users' actual profiles in the sample Network B, the known fact that LV network user LVC549 is a distributed PV installation indicates that all of the DNUoS capacity charge credits should be assigned to user LVC549. In practice, this information would be provided by the full profiles and would not require identifying which network users are generators and loads of any particular type.

Loss-related costs are assigned to users volumetrically based on their annual energy consumption or injection. The annual energy use of all network users is estimated from the users' 48-hour profiles, taken as representative of each 48-hour window for a year. The annual losses cost to allocate divided by the annual energy use yields a losses cost per-kWh. This is multiplied by each individual's energy

MV/LV Substation ID	x coordinates	y coordinate	z coordinate	Peak Load (kVA)	Share of HV/MV substation peak	Share of capacity cost
CCTT5	5.34193	1.67801	0	-0.83	-0.00114237	$(364.84)

LV load points served by CCTT5			
Feeder 1			Feeder contribution to CCTT10 peak (kVA)
LV users along Feeder 1	LVC214	LVC549	
Contribution to feeder peak	-	-0.83	1.579
Share of feeder capacity cost	-	-0.0011	
Capacity cost	-	$(364.84)	
Feeder 2			
LV users along Feeder 2	LVC123		
Contribution to feeder peak	-	-	6.114
Share of feeder capacity cost	-	-	
Capacity cost	-	-	

Table 14: *The contribution of network users served by injecting MV/LV substation CCTT5 to the peak load at HV/MV substation*

use to yield that individual's losses cost. Losses comprise a small fraction of the total network costs to allocate (only 0.68% of total DSO costs in Network A, and effectively 0% in Network B), though this value is heavily dependent upon the input losses cost and the number of profile hours used to extrapolate losses for the full year.

The allocation of reliability costs is omitted from the numerical example because the version of the RNM utilized for this thesis considers reliability targets only at the level of the MV network. Changes in LV reliability indices do not induce changes in distribution costs, and while LV customers may benefit from enhancements to reliability in the MV network, insufficient information is available to relate LV network user reliability directly to costs. Future analysis will consider in a more detailed manner the impact of LV reliability on distribution costs and the allocation of those costs amongst users.

The annual and monthly DNUoS charge components for a sample LV network user, user LVC388 served by MV/LV substation CCTT10 in Network A, are summarized in **Table 15**. The charge for LV network user LVC549, a PV generator served by the injecting MV/LV substation CCTT5 in Network B, is summarized in **Table 16**.

	Connection	Capacity	Reliability	Losses
Annual	$2,085.26	$725.27	-	$17.81
Monthly	$173.77	$60.44	-	$1.48

Table 15: *DNUoS charge for sample LV network user in Network A*

	Connection	Capacity	Reliability	Losses
Annual	$1,694.74	$(364.84)	-	
Monthly	$141.23	$(30.40)	-	

Table 16: *DNUoS charge for sample LV network user in Network B*

6 Implementation & policy considerations

6.1 Energy prices and network charges

Communicating time and location-based price signals to network users to encourage economically efficient network utilization should, ideally, take place with two instruments: nodal energy prices and network use-of-system charges.

Efficient operational signals should be sent via nodal energy prices such as distribution locational marginal prices (DLMPs). As described in Heydt et al. (2012), these would be energy prices analogous to transmission-level LMPs that reflect the marginal value of energy as well as the costs of losses and congestion in the distribution system. DLMPs would communicate to network users the economic value of injection or withdrawal of real or reactive power on a short time scale. More sophisticated DLMPs may indicate the value of provision of ancillary services to the distribution system operator. DLMPs would enable the recovery of some fraction of the distribution network costs. With no currently-known implementation of DLMPs, the most advanced pricing schemes communicate hourly or quarter-hourly wholesale energy prices to end consumers, but they do not have locational differentiation at the distribution level.

There are, however, key differences between LMPs and DLMPs. Transmission network use-of-system (TNUoS) charges provide locational signals for new generation and play a critical role in generation investment decisions, therefore they must be determined ex-ante and applied for a relatively long time period of time — for instance, 10 years [51]. Unlike the location of generation facilities in the transmission system, DER are typically installed at existing network user locations, and often, network users do not take network charges into account when making DER siting decisions. DNUoS charges may have some impact on the decision to install DER such as a rooftop PV panel, a micro turbine, or local storage at an existing residence, or a commercial or industrial facility, but once a DER installation decision has been, DNUoS charges should incentivize network users to maintain network utilization patterns that do not drive additional distribution network costs.

In power systems with LMPs, the complete short run economic signals are sent through the LMP, and TNUoS charges should not include any component that interferes with the LMP signal. In contrast, because of the absence of DLMPs in distribution, DNUoS charges should convey locational signals both in the short and long runs, reshaping DER network utilization patterns. This requires DNUoS charges to be more dynamic than TNUoS charges and to provide price signals that are closer to real time. They must be adjusted more frequently (every year for example) in response to changes in network users' profiles, incentivizing network users to adopt utilization profiles that do not create the need for additional network costs.

6.2 The "Utility Death Spiral" and DNUoS charge dynamics

The primary goal of the DNUoS charge is to collect, in the short-term, the fixed sum that the DSO must recover for its capital and operating expenditures in the billing period.

Figure 17 below illustrates the costs to be recovered through DNUoS charges, including recovery of costs for existing network infrastructure, costs for new reinforcements, and O&M costs. The reallocation of costs for existing network infrastructure in a given year signals to users how their network utilization can impact future reinforcement investments. **Figure 18** illustrates how the cost components to be collected through DNUoS charges and the resultant price signals sent to network users may evolve over time under several potential future development scenarios.

The costs that the distribution utility must recover for its network capital are fixed in the short run. Over the long run, however, as network use changes, the investment needed for network upgrades, repairs, or reinforcements also change. As such, the fixed sum to be allocated across network users in the long run will change. For example, if users lower their capacity requirements by reducing their contributions to system peak power flows, the network capacity does not dynamically shrink in the short run. What does change is the amount of reinforcements and network expansion that may be necessary in the long run. The overall costs of the network decline in the long run, which means that the distribution utility will have lower costs to recover, and each network user will pay a lower network charge. In the short run however, network costs are simply reallocated amongst network users according to the new set of network use profiles. Network users who have reduced their contributions to peak periods pay less towards the total system capacity costs, while network users who have not reduced their network utilization during peak periods face higher capacity charges, at least transitorily.

This form of cost reallocation differs from the issues of cross subsidization, adverse selection, and the "death spiral" arising from net energy metering and discussed in Section 2. Since the proposed network charge design method abides by the principle of cost causality, a decrease in an individual network user's DNUoS charge — or a decrease in their share of the total system cost — genuinely arises from diminished network utilization. If network users with captive generation produce excess electricity, their network charges will reflect their use of the network for selling electricity back to the distribution utility. However, if their DG production and consumption exactly coincide, wholly eliminating their use for the network, then they do in fact avoid any network charge. In this case, avoiding a network charge is a result of not using the distribution network; it is not the lucky consequence of equal volumetric energy production and consumption.

In distribution networks with growing load and network utilization, there is no tension between lower network utilization and lower charges for some network users, reallocation of costs to new network users, and cost recovery for the distribution utility. The DNUoS charge design developed throughout this thesis relies upon the assumption of some increased network utilization (resulting either from load growth or DER-related network expansion). However, in networks experiencing low or no load growth and falling network use, incentivizing lower network utilization while achieving complete cost recovery without accelerating adverse selection amongst network users may prove challenging. In this situation, cost allocation amongst network users will more closely approach socialization, or people who have been more responsible for network costs in the past will continue to contribute more in the future until utility investments are recovered. In such a scenario of surplus distribution capacity, the particular weight and relevance of cost drivers may change. For example, increasing the size of the minimum connection network and thereby increasing the importance assigned to the connection cost driver can increase the level of cost socialization.

While it is possible that widespread adoption of microgrids or islandable load, generation, and storage may eventually significantly reduce utilization of the distribution network, the time scale for such a transformation of distribution systems is much greater than the timescale over which the proposed tariff framework can be adopted. Implementation of more cost reflective DNUoS charges within the next decade can ensure that distribution utilities recover the costs of investments that they have already made in the very infrastructure essential to ensuring a successful transition to the power system of the future.

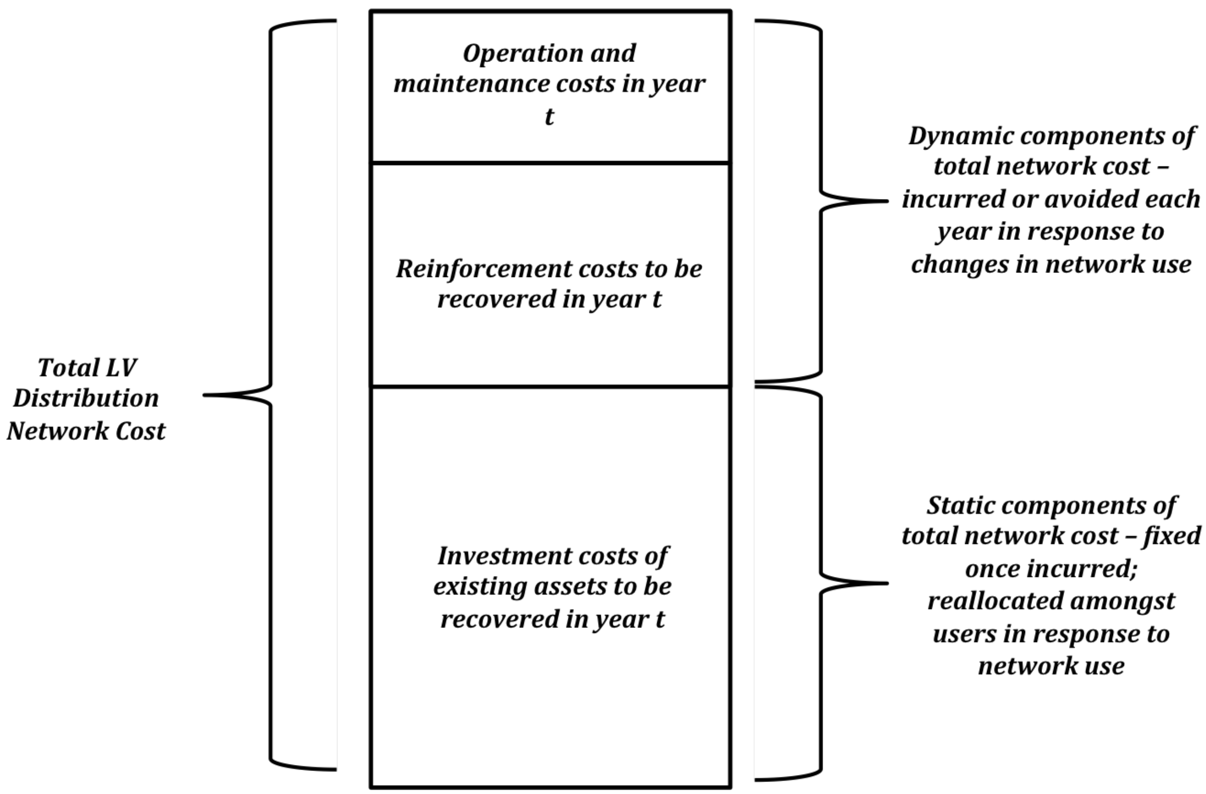

Figure 17: *The cost components to be collected through DNUoS charges (only the LV network cost is used as an example here; the same components make up the total MV and HV network costs)*

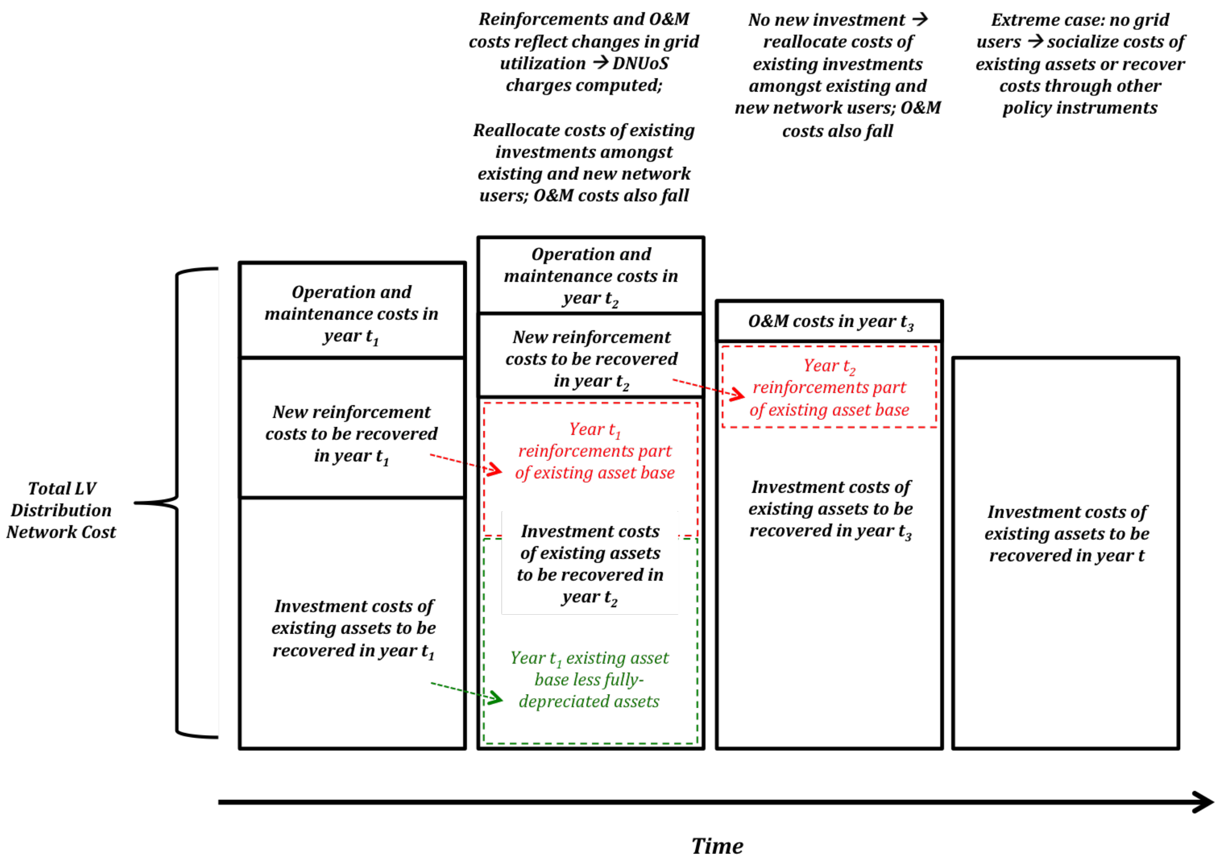

Figure 18: *How the cost components to be collected through DNUoS charges and the resultant price signals sent to network users may evolve over time*

6.3 Practical Limitations

The framework presented above is a "first-best" approach to efficient, cost reflective DNUoS charge design. However, the implementation of cost reflective DNUoS charges requires consideration of a range of practical limitations and potential "next-best" solutions.

- The level of differentiation between network users' DNUoS charges achieved with the proposed charge design may find opposition in the face of existing widespread policies of socialization of electricity costs or established guidelines for nondiscriminatory rate design.

  In most countries, retail rates are exactly the same for all consumers connected at the same voltage level, or retail rates are the same for all consumers within the same distribution service area, regardless of the location of the consumer's connection point. This practice has been extended to "prosumers" under different implementation schemes. While each network user pays a different total amount on the final retail bill, depending on the user's level of energy consumption and capacity contribution, the unit rates are the same for all: every kWh of energy consumption or production, or every kW of capacity utilization is valued equally (sometimes with differentiation based on the user's time of consumption). The tariff design proposed here uses a common method to compute the network charges for all network users, but values network utilization differently depending on the location and time of use. Although this is what efficiency requires, regulators will have to consider how to carry out DNUoS charge design in a way that aligns with their specific regulatory and policy goals. This may require either rethinking and re-articulating guidelines for nondiscriminatory rates and network socialization, or, as described next, utilizing the levers available in the proposed framework to better suit a particular jurisdiction's needs.

- The regulator retains the flexibility to alter the amount of cost socialization or differentiation achieved through the DNUoS charge by adjusting the proportion of network costs allocated to each of the cost drivers.

  It is currently a common regulatory practice to apply the same network rates to all consumers connected at the same voltage level, regardless of whether they are located in an urban or rural area and incur very different network costs. But with increasingly diversified distribution network utilization patterns, it is essential that DNUoS charges embody the differences in distribution costs caused by network users. In order to reconcile these two seemingly opposite views, one approach is to make the connection component (which most directly relates to the cost differences between urban and rural networks) more significant by strengthening the minimum connection grid and then socializing the cost to the entire system (effectively creating a single zone in the LV network for this cost component). The remaining cost components depend upon the specific utilization pattern of each network user and are best allocated according to profiles.

- Detailed measurements of cost driver variables may not be readily available if hourly metering is unavailable. Under such circumstances, estimates of driver values must be utilized to construct network-use profiles. Additionally, access to a reference network model and trained personnel must be available to carry out the computation of DNUoS charges proposed here.

- The context created by the specific objectives and tradeoffs most salient in varying jurisdictions may impose a range of additional regulatory and political constraints on the design of network charges.

7 Conclusions, Summary, & Future work

As the penetration of DER increases, balancing the needs of multiple stakeholders to ensure efficient and cost-effective operation of the distribution system, while enabling a transition to a low carbon power sector requires rethinking multiple aspects of distribution regulation. DNUoS charges must reflect the costs and benefits of DER integration to the distribution system and communicate those signals to network users. The structure of DNUoS charges developed in this thesis rests on two fundamental ideas: 1) allocating network costs according to network use profiles, and 2) utilizing a reference network model to isolate cost drivers and determine cost causality. This framework is neutral to the particular technologies employed behind a network user's meter and the level of aggregation of multiple DER at a point of network connection.

DNUoS charge design for the electricity sector of the future is a topic of considerable concern to numerous utility regulators throughout the U.S. and world today. For example, rate redesign is a central component of the New York PSC's vision for reforming the regulation of distribution utilities [44]. The Massachusetts DPU, while electing to exclude distribution rates from its anticipated framework for time-varying rates, recognizes the critical role of rate redesign in grid modernization efforts [39]. AB327 opens the door for more sophisticated residential rate design in California [22]. The design of network tariff structures has been a central regulatory question for the integration of renewable and distributed resources throughout the EU [17], [46]. This thesis has developed a framework for the design of cost reflective DNUoS charges under growing penetration of distributed energy resources and has provided an initial demonstration of the use of an RNM and customer profiles to allocate distribution costs.

Subsequent work will build upon the use of the RNM demonstrated here to compute DNUoS charges for network users at the MV and HV levels in order to allocate costs that are shared amongst users at multiple voltage levels. Additionally, an expanded range of network-use scenarios will be explored, considering the integration of a wider array of DER. Future work will explore the impacts of network utilization on the distribution cost drivers in more detail, including: identifying the contribution of LV reliability on LV DNUoS charges, developing a means by which to cluster network users to allocate connection charges, and demonstrating separate allocation of load-related and injection-related capacity costs. Additionally, feedback between network user reaction to DNUoS charges (i.e. changes in user profiles) and distribution costs can be captured by integrating the RNM with an operational model such as a power flow model to further inform DNUoS charge design.

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Appendices

A 48-hour load and PV generation profiles

The residential, commercial, and industrial load profiles, and PV injection profiles from which all network user profiles were sampled.

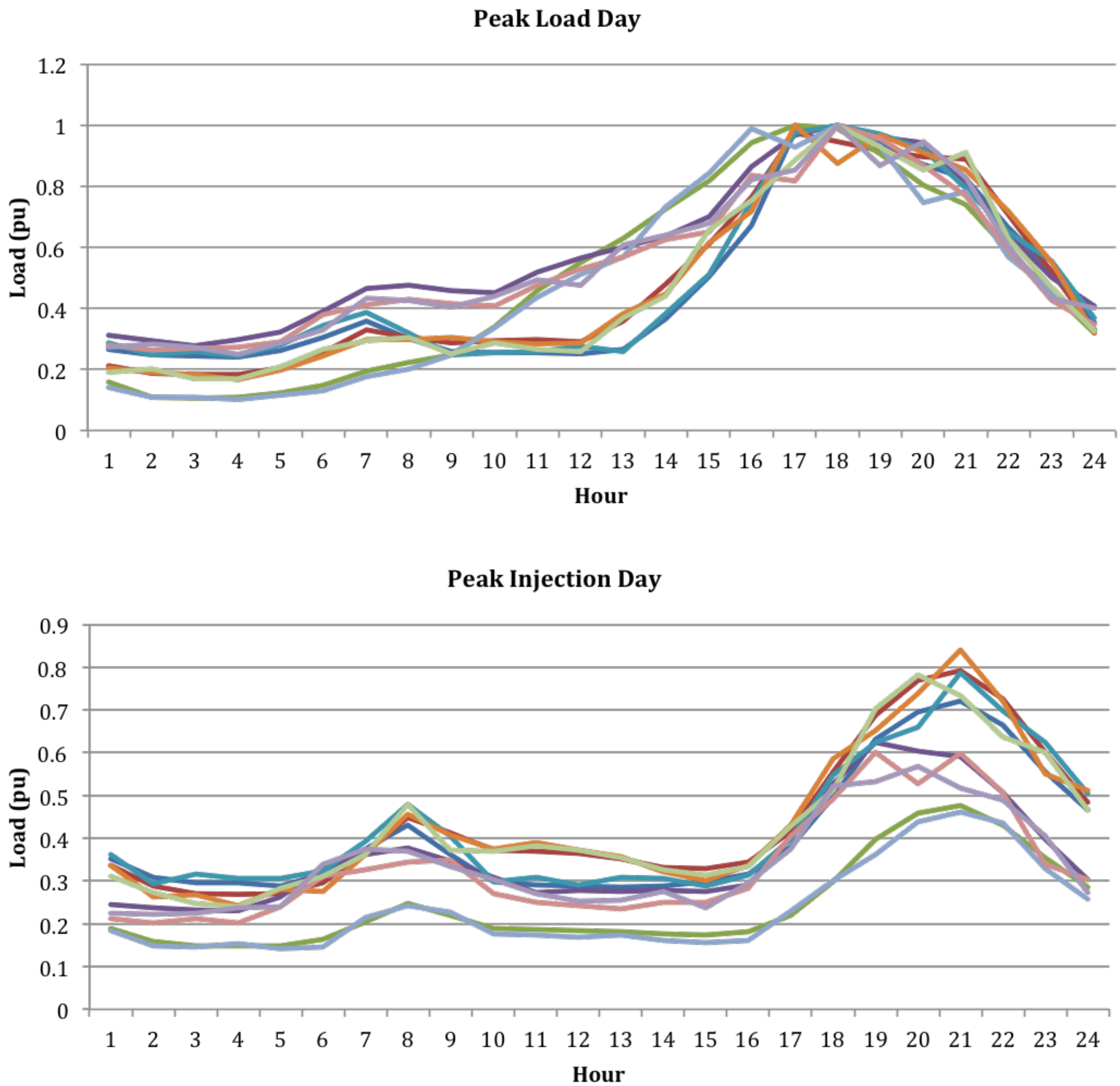
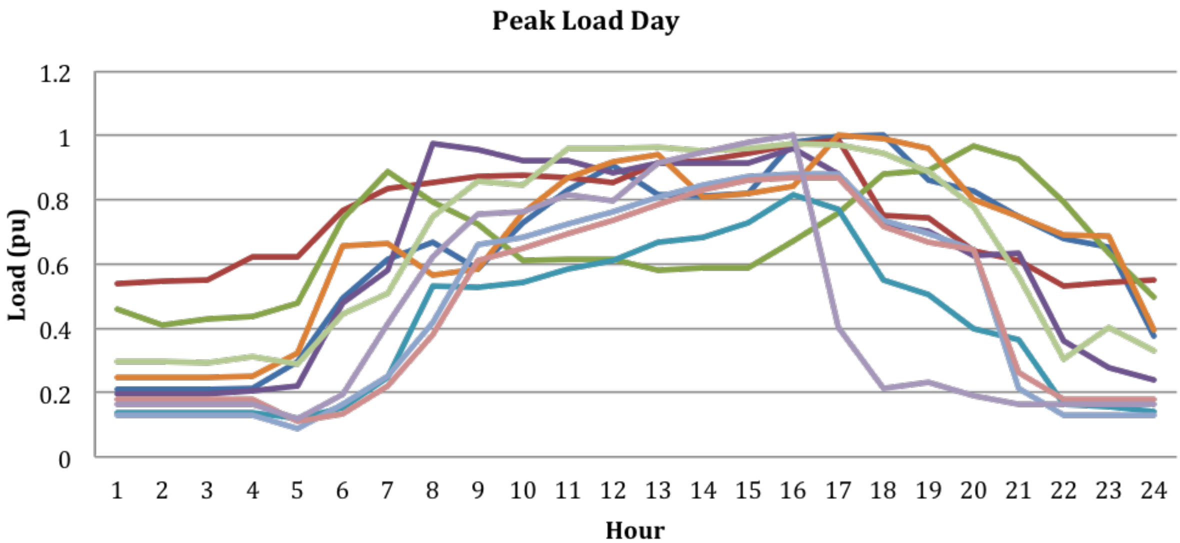


Figure 19: *Sample residential profiles*



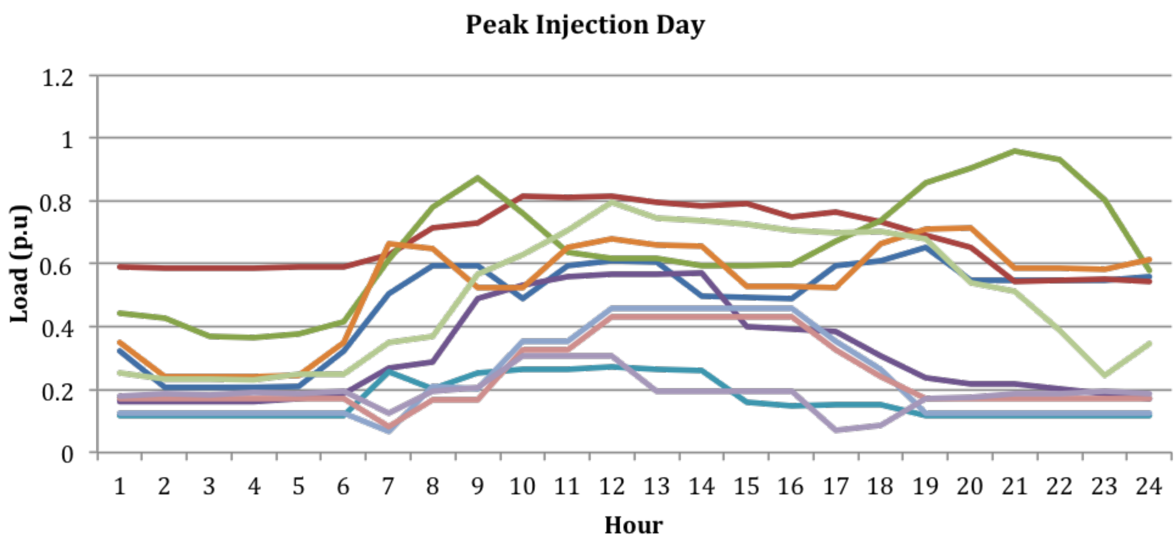


Figure 20: *Sample commercial profiles*

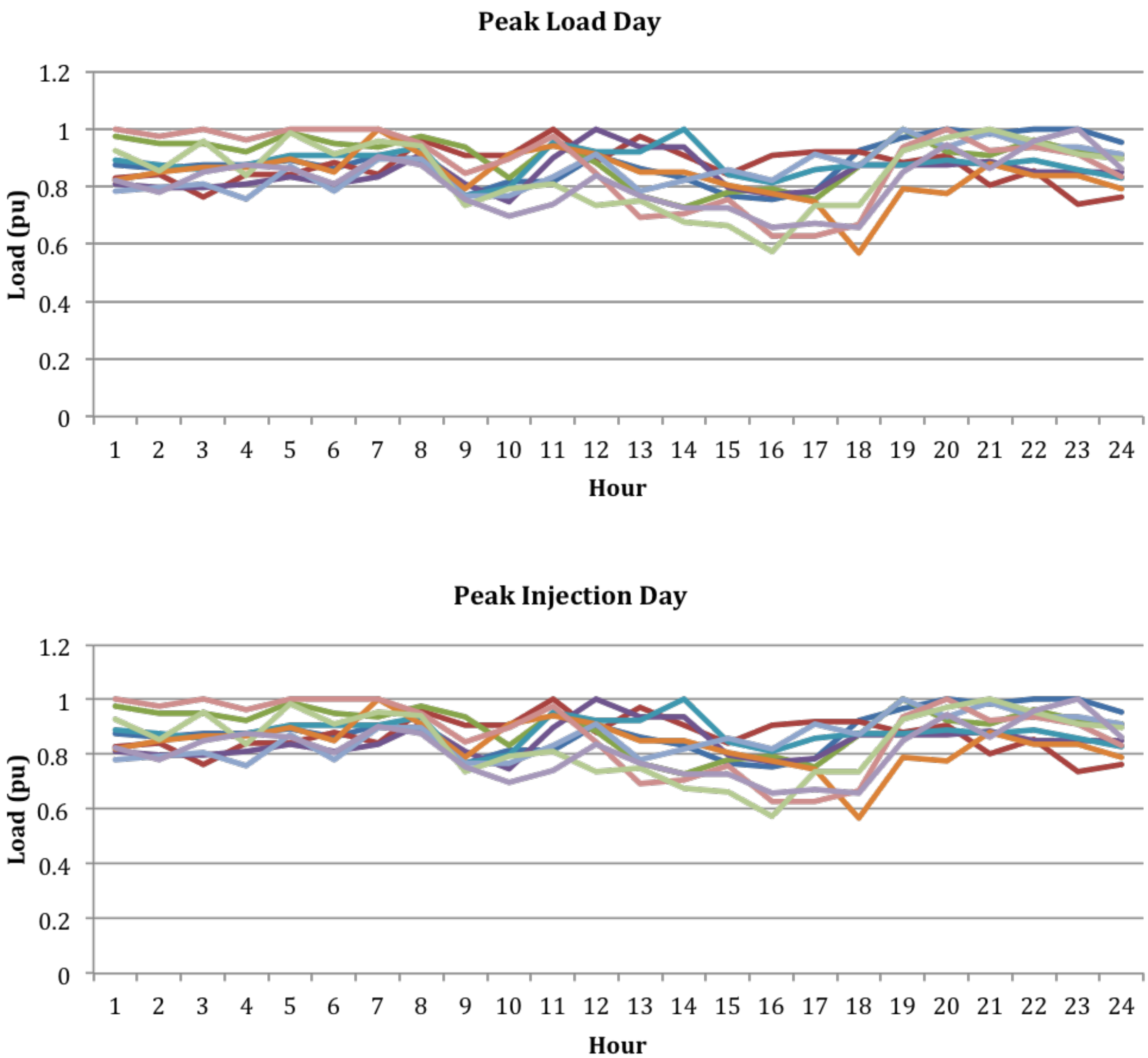


Figure 21: *Sample industrial profiles*

B Network C (LV and MV load)

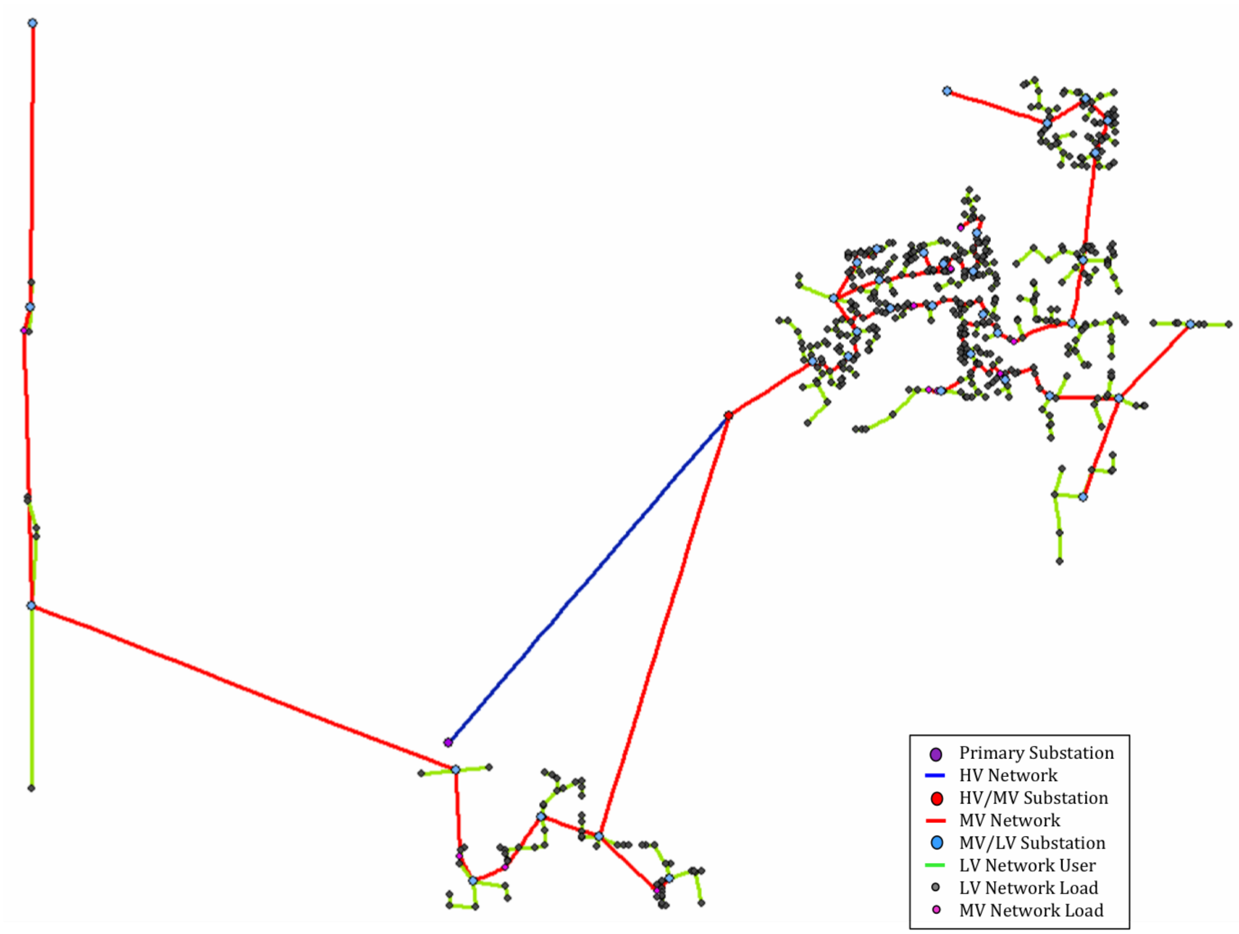


Figure 22: *The full Network C (LV and MV load)*

C MV/LV substations

MV/LV Substation ID	x coordinates	y coordinate	z coordinate	Peak Load (kVA)	Share of SSEE peak	Share of cost
CCTT0	7.6267	0.37552	0	19.19	0.02380155	3972.714816
CCTT1	5.42883	0.42866	0	25.56	0.031702326	5291.432553
CCTT2	6.32638	1.24011	0	32.76	0.040632558	6781.976935
CCTT3	4.90726	1.65486	0	3.57	0.004427907	739.061589
CCTT4	0.1379	4.48293	0	6.73	0.008347287	1393.244956
CCTT5	9.48999	5.94274	0	12.24	0.015181395	2533.925448
CCTT6	13.14843	5.93789	0	14.44	0.017910078	2989.369565
CCTT7	11.87223	5.68732	0	23.61	0.029283721	4887.74345
CCTT8	10.28899	5.96066	0	11.89	0.014747287	2461.46843
CCTT9	11.23	6.286	0	39.91	0.049500775	8262.170313
CCTT10	11	6.595	0	18.5	0.022945736	3829.87098
CCTT11	11.175	6.73	0	23.37	0.028986047	4838.058637
CCTT12	9.802	6.571	0	34.8	0.043162791	7204.297843
CCTT13	9.079	6.96	0	16.65	0.020651163	3446.883882
CCTT14	12.38557	6.30603	0	22.1	0.027410853	4575.14317
CCTT15	0.19413	6.79738	0	8.33	0.010331783	1724.477041
CCTT16	9.857	6.897	0	17.19	0.02132093	3558.67471
CCTT17	11.333	6.968	0	18.38	0.022796899	3805.028573
CCTT18	9.516	6.802	0	15.96	0.019795349	3304.040045
CCTT19	14.05656	6.8724	0	5.28	0.006548837	1093.06588
CCTT20	11.778	6.905	0	40.3	0.049984496	8342.908134
CCTT21	10.746	7.04	0	24.1	0.029891473	4989.183276
CCTT22	10.278	6.976	0	23.92	0.029668217	4951.919667
CCTT23	11.135	7.413	0	29.21	0.036229457	6047.055747
CCTT24	11.762	7.516	0	13.68	0.016967442	2832.034324
CCTT25	12.73024	7.09885	0	34.63	0.042951938	7169.104434
CCTT26	10	7.31	0	32.19	0.039925581	6663.975504
CCTT27	10.786	7.611	0	42.54	0.052762791	8806.633053
CCTT28	10.317	7.706	0	23.98	0.029742636	4964.34087
CCTT29	12.35507	7.66718	0	35.75	0.044341085	7400.966893
CCTT30	12.46782	8.84675	0	26.89	0.033351938	5566.769224
CCTT31	11.143	7.952	0	18.83	0.023355039	3898.187597
CCTT32	9.937	7.778	0	24.12	0.029916279	4993.323677
CCTT33	0.159	10.365	0	1.61	0.001996899	333.3022853
CCTT34	12.01999	9.16437	0	21.2	0.026294574	4388.825123
CCTT35	12.28167	9.43239	0	41.37	0.051311628	8564.419591
CCTT36	10.802	9.579	0	1.47	0.001823256	304.3194778
Total				**806.25**	**1**	**166909.9177**

Table 17: *The MV/LV substations in Network A*

MV/LV Substation ID	x coordinates	y coordinate	z coordinate	Peak Load (kVA)	Share of SSEE peak	Share of cost
CCTT0	7.53379	0.49423	0	10.64	0.014644351	2419.492389
CCTT1	5.48713	0.41218	0	30.24	0.041620788	6876.452053
CCTT2	6.35281	1.11784	0	18.24	0.025104603	4147.701238
CCTT3	0.12202	1.49653	0	2.94	0.004046466	668.5439496
CCTT4	4.679	1.65102	0	2.84	0.003908831	645.8043595
CCTT5	5.34193	1.67801	0	-0.83	-0.00114237	-188.738598
CCTT6	12.12129	4.02928	0	3.61	0.004968619	820.8992034
CCTT7	0.14954	4.37654	0	4.63	0.006372495	1052.843023
CCTT8	11.9885	5.51358	0	20.06	0.027609557	4561.561779
CCTT9	12.78519	5.75364	0	15.41	0.021209535	3504.170838
CCTT10	11.127	6.079	0	27.84	0.038317551	6330.70189
CCTT11	10.20677	5.90542	0	3.42	0.004707113	777.6939822
CCTT12	9.421	6.198	0	27.1	0.037299053	6162.428923
CCTT13	11.476	6.262	0	21.33	0.02935752	4850.354573
CCTT14	9.706	6.524	0	22.79	0.03136699	5182.352589
CCTT15	12.238	6.476	0	25.95	0.035716252	5900.923637
CCTT16	13.38095	6.87935	0	12.24	0.01684651	2783.325831
CCTT17	9.365	6.841	0	22.55	0.031036666	5127.777573
CCTT18	11.135	6.595	0	27.5	0.037849593	6253.387284
CCTT19	11	6.833	0	2.5	0.003440872	568.4897531
CCTT20	9.706	7.008	0	16.96	0.023342876	3856.634485
CCTT21	10.587	7.024	0	16.04	0.022076635	3647.430256
CCTT22	11.754	6.849	0	23.95	0.032963554	5446.131834
CCTT23	11.095	7.056	0	33.95	0.046727043	7720.090847
CCTT24	10.222	7.19	0	39.33	0.054131799	8943.480795
CCTT25	9.762	7.548	0	8.66	0.011919181	1969.248505
CCTT26	10.746	7.587	0	23.1	0.031793658	5252.845318
CCTT27	10.127	7.738	0	32.47	0.044690046	7383.544913
CCTT28	12.46509	7.56887	0	46.16	0.063532262	10496.5948
CCTT29	11.81791	7.54475	0	6.32	0.008698525	1437.142096
CCTT30	11.175	7.603	0	43.72	0.06017397	9941.748802
CCTT31	11.103	8.151	0	12.81	0.017631028	2912.941495
CCTT32	0.143	10.333	0	1.8	0.002477428	409.3126222
CCTT33	12.25158	8.78692	0	7.19	0.009895948	1634.97653
CCTT34	12.62653	9.04217	0	46.03	0.063353336	10467.03333
CCTT35	12.11186	9.19043	0	45.23	0.062252257	10285.11661
CCTT36	12.46468	9.47671	0	11.37	0.015649086	2585.491397
CCTT37	11.81451	9.53666	0	10.47	0.014410372	2380.835086
Total				**726.56**	**1**	**162835.9309**

Table 18: *The MV/LV substations in Network B*

D Network B Run 01 and Run 00

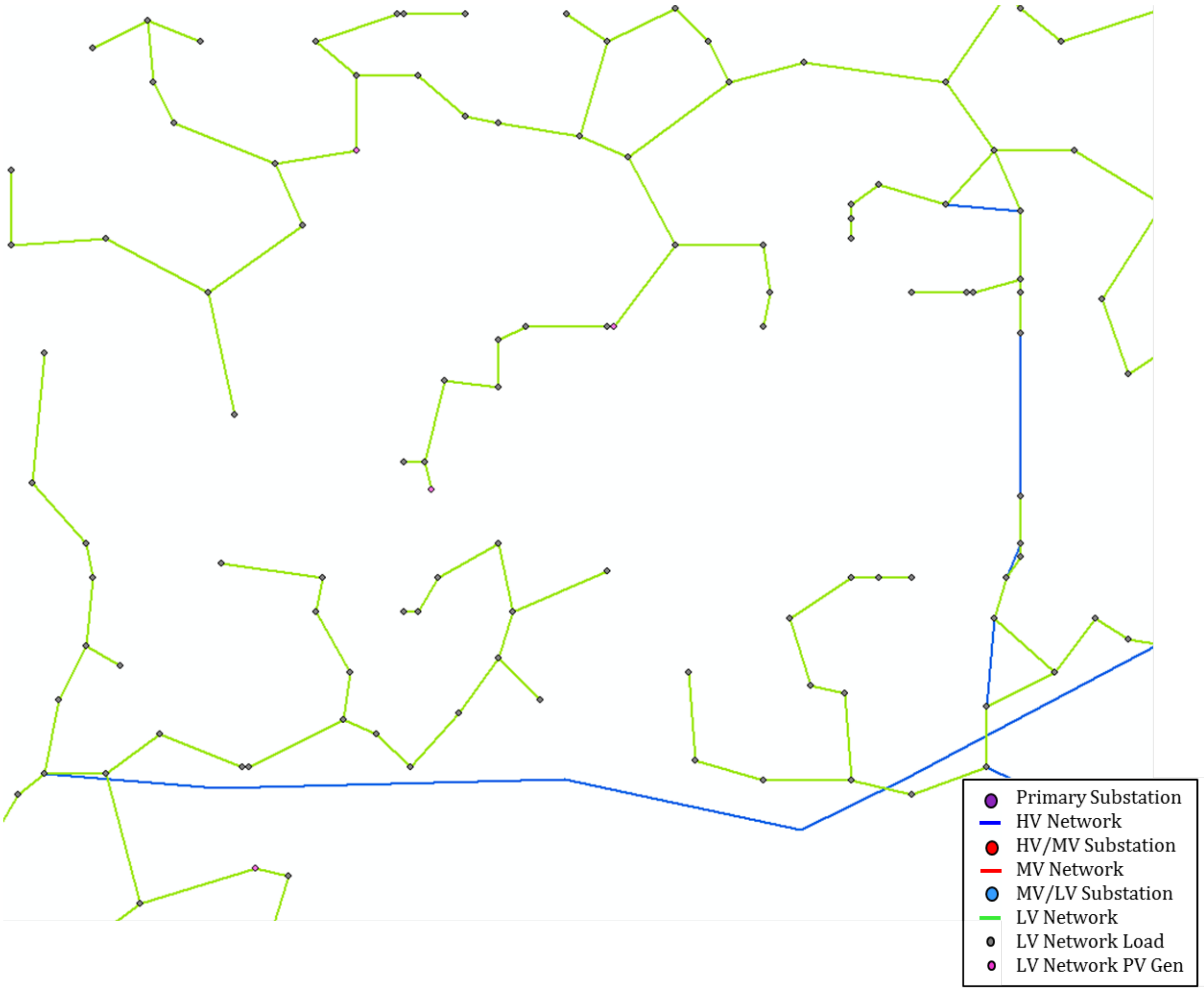


Figure 23: *A magnified section of Network B Run01 (connection network) with load and PV generation points*

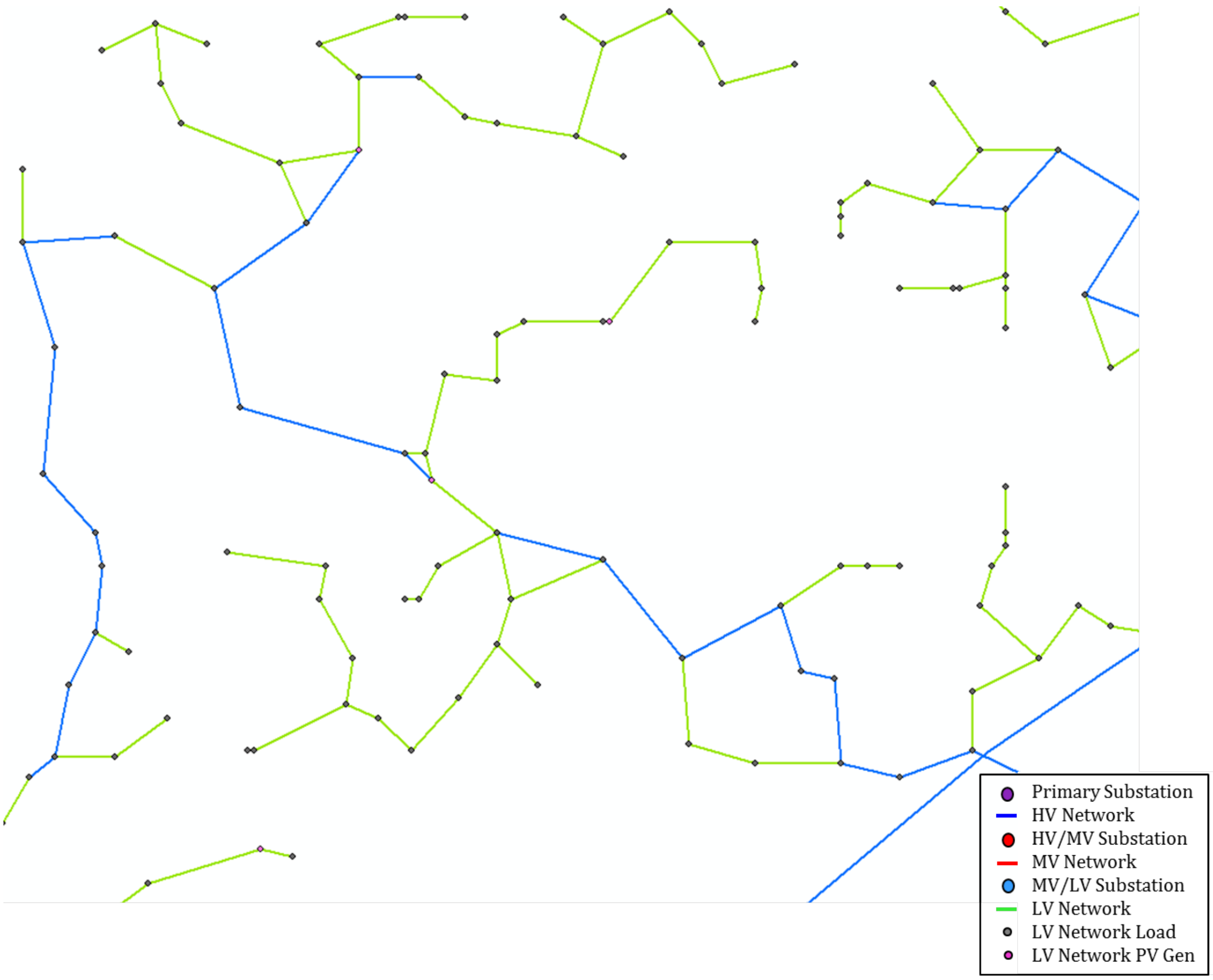


Figure 24: *A magnified section of Network B Run00 (full network) with load and PV generation points*