MIT CEEPR

MIT Center for Energy and Environmental Policy Research

A Framework for Redesigning Distribution Network Use of System Charges Under High Penetration of Distributed Energy Resources: New Principles for New Problems

Ignacio Pérez-Arriaga and Ashwini Bharatkumar

October 2014

CEEPR WP 2014-006

A Framework for Redesigning Distribution Network Use-of-System Charges Under High Penetration of Distributed Energy Resources

New principles for new problems

Ignacio Pérez-Arriaga* & Ashwini Bharatkumar†

October 2014

Abstract

The growing potential for widespread integration of distributed energy resources (DER) presents the electric power sector with significant changes to technical operations, business models, and industry structure. Management of such changes to ensure the development and maintenance of well-adapted, reliable power systems requires updated regulations that keep pace with the evolution of technologies and end-user needs. Regulators are faced with the challenge of ensuring that a level playing field exists for electricity service business models that align with a range of policy goals including the assurance of reliability and quality of electricity supply, affordability of electricity services, encouragement of innovation and economic growth, and the development of clean energy technologies for decarbonization. As the distribution system transitions from a passive network of consumers to a more actively managed system of network users with diverse consumption and production behaviors, price signals will play a crucial role in shaping the interactions between the physical components of the distribution system and network users. Distribution network use of system (DNUoS) charges, are the method by which distribution utilities cover network operation and maintenance costs and recover their infrastructure investments, and they signal to network users how their utilization of the distribution network impacts system costs and each user?s share of those costs. This paper proposes a new framework for the design of DNUoS charges, calling for an overhaul of how distribution network cost allocation has been carried out thus far. The authors present a method for: 1) utilizing a reference network model (RNM) to identify the key drivers of distribution system costs and 2) allocating those costs to network users according to network utilization profiles that capture each user's contribution to 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 the convention of allocating distribution system costs across multiple users assumed to have similar network utilization behaviors and identical impacts on network cost drivers. Thus, regulators may choose to adjust the allocation of network costs to cost drivers in order to achieve varying regulatory objectives such as increased socialization and equity.

*MIT Energy Initiative, Massachusetts Institute of Technology; Institute of Research in Technology, Comillas Pontifical University; Center for Energy and Environmental Policy Research, Massachusetts Institute of Technology. Email address: ipa@mit.edu

†MIT Energy Initiative, Massachusetts Institute of Technology; Engineering Systems Division, Massachusetts Institute of Technology. Email address: abharat@mit.edu

I Introduction

The existing power system paradigm 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 distribution system and its interaction with the rest of the power system.A variety of reports — by organizations including Eurelectric [10], the International Energy Agency [19], the Edison Electric Institute [23], the Electric Power Research Institute [9], 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.

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 [24]. 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. As the nature of network use is transformed, regulators must entirely rethink the design of network charges.

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.

Throughout this paper, "distribution utilities" and "distribution" refer solely to the network activity of connecting transmission substations to the end users in the distribution network, whatever the nature of those users. This activity is performed by Distribution System Operators (DSOs) or distribution companies, which typically own, operate, and maintain the distribution network. Depending on the specific regulation, 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 well as annual operation and maintenance expenditures (OPEX) of the network, which are roughly proportional to the physical volume of assets.[1] 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[1]. 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

[1]Network losses occur in distribution networks, but they are not a distribution cost, as the cost of losses is incurred when the corresponding energy is generated. See below for further discussion of the role of losses in distribution network pricing.

requirement. The components of the DSO's recoverable costs are illustrated in **Figure 1**.

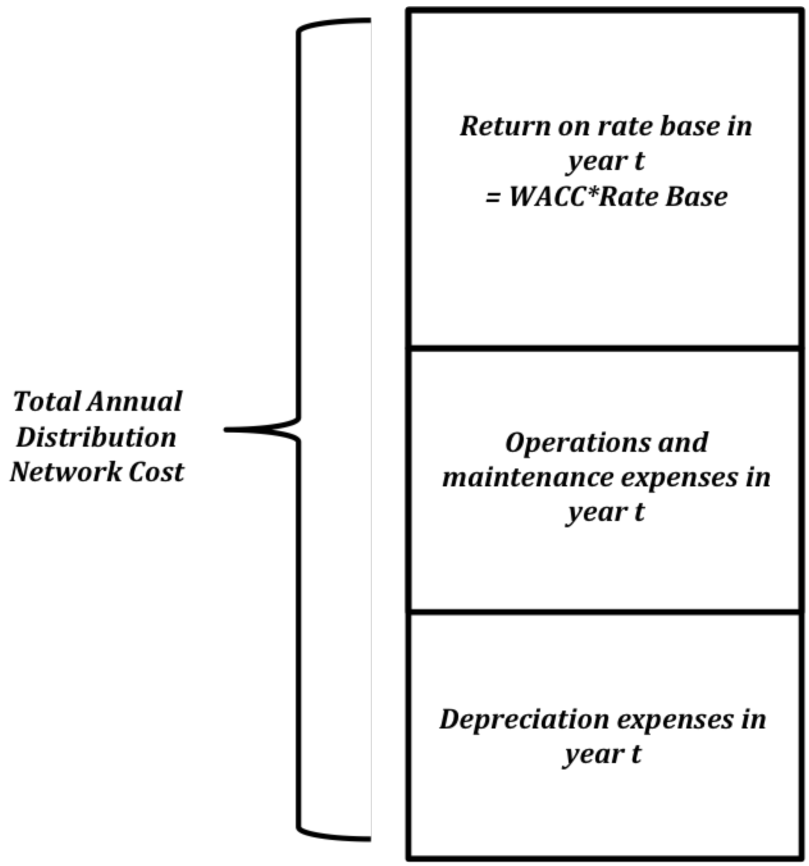

Figure 1: *The cost components to be collected through DNUoS charges*

The topic of determining the distribution utility's revenue requirement is not addressed in this paper. We develop a framework for more efficient distribution network cost allocation assuming that a well-designed regulatory framework for performance-based remuneration of the distribution utility exists, and assuming that the determined revenue will then be collected in full from network users. [2] This paper focuses exclusively on the allocation of total collectable revenue amongst network users, focusing not on the question of how much revenue is collected, but rather, on the question of who pays and how much does each user contribute to total utility costs and revenue? Our proposed approach is based on the principle of cost causality: *Allocate network costs to users according to how each network user's activity contributes to the recoverable costs incurred by the distribution utility.*

In order to carry out cost allocation, we assume that we have available to us two key elements. The first of these is a 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, called a "reference network model" (RNM) is the "magic box" that allows us to identify the key drivers of network costs and the portion of the total network cost corresponding to each cost driver. The second key element is complete information about the network utilization profile of each network user – i.e. the hourly pattern of energy injections to or withdrawals from the network. Collecting this profile

[2] For more on the topic of remunerating distribution utilities under high penetrations of DER see [22].

information relies upon the availability of advanced metering infrastructure (AMI). With user profiles we can determine the contribution of each network user to each cost driver, each user?s contribution to the cost associated with each cost driver and, as a result, each user?s contribution to the total network cost.

This approach to cost allocation is a significant departure from the convention of charging network users average volumetric ($/kWh) or capacity ($/kW) rates that are computed for broad classes of customers assumed to consist of network users with similar behavior. But, 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 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 calls for a method of allocating distribution system costs in a differentiated manner: a manner that more directly relates individual network use behavior to network cost contribution.

This paper proceeds as follows: Section II summarizes how greater penetration of DER is altering the electricity distribution system, and Section III elaborates on the challenges presented by conventional network charges in the face of those changes. Section IV explains the proposed framework for DNUoS charge design; Section V describes the interaction between network charges and energy price signals; and Section VI discusses the dynamics of DNUoS charges — or how they evolve over time. Section VII explores practical implementation considerations, and Section VIII concludes and summarizes future work.

II How use of the distribution network is changing

The conventional distribution network paradigm has been one of "fit-and-forget." Distribution utilities and system operators have typically built, operated, and maintained the lines, substations, and transformers necessary to serve end users, with limited visibility of, control over, and feedback from those users. However, the proliferation of new technologies — including 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" (Pérez-Arriaga et al., 2013). 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." While this alters the existing distribution paradigm, it presents an opportunity for pricing methods to communicate signals that enable more efficient use of the distribution network. This includes incentives for efficient location or siting of DER and optimal operation of DER in response to distribution system conditions. 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 [12].

However, the changes discussed thus far are not entirely new. The nature of residential distribution network use is increasingly mirroring the profiles 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. An important limitation of these approaches 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 tariff design. This is primarily because no sound method to determine cost causality at the distribution level has yet been available to regulators. This limitation can be addressed with the development and use of *Reference Network Models* as explained in Section III below.

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,[3] 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 – should compute network charges based on profiles of distribution network utilization and users' contributions to network costs.

Now more than ever before, as the lines between electricity consumers and producers are increasingly blurred, a generalizable approach to network charge design must be developed in order to fairly and efficiently allocate network costs. Well–designed network charges compute the amount users pay for their utilization of the network with 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.

In this paper, we first approach the design of efficient distribution network tariffs under the assumption that we either have access to complete information about network use profiles through advanced metering or that network users contract for network capacity. When detailed profile information is not fully available, simplifications must be made to the proposed framework. Too many simplifications 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 metering infrastructure rollout, it is not unreasonable to assume the availability of the metering and information collection capabilities required for adoption of the network charge design principles described here.

III The network use-of-system charge challenge

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.[4] (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

[3] 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.

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

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 [1].

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 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 paper, 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. Additionally, 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 related to each driver, and costs allocated to each network user [2].

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: few 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 distributed generation (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 [4]. 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 and the excess power output during peak generation hours do not cancel one another out. 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.[5] But in general, volumetric network tariffs, charged entirely per kilowatt–hour of net energy sold by the retail service provider or distribution utility fail to fully take into consideration the drivers of distribution network costs, resulting in inefficient allocation of costs and cost–savings to network users.

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 cost recovery and profits unless distribution network costs fall or rates on the remaining volumetric energy sales rise. Fixed distribution costs remain unchanged with changes in volumetric energy distribution, and 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. 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 [6], [25], [33], [34]. 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.[6] 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 [13]. 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. As the nature of network use evolves beyond simple consumption, costs that could once be allocated through the use of average rates for consumers with largely similar network utilization patterns can no longer be assigned to an increasingly diverse set of network users.

Well-designed distribution network charges must abide by a set of regulatory principles as described in [3] for utility rates in general and in [26] for DNUoS charges in particular. They must provide

[5] 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.

[6] 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.

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 according to users' contributions to network costs; they must be nondiscriminatory or equitable by applying the same method to determine charges for all network users;[7] they must be transparent in that the method used to compute the tariffs should be made publicly known; they must be stable in that they minimize regulatory uncertainty; and they must be, to the extent possible, simple and understood by network users and network service providers. Tariff design and practical implementation often requires tradeoffs between the aforementioned regulatory criteria.

This paper proposes DNUoS charges that adhere to the cost causality principle.[8] According to the cost causality principle, network users pay the costs that they cause in the network and cause the distribution utility to incur.[9] Efficient charges send network users clear economic signals about how their network use patterns at a given location cause or impact network costs incurred by the distribution utility. Without distorting other price signals to which power system users may respond, efficient network charges influence the location and nature of network utilization.[10] A key goal of efficient charges is to ensure a level playing field for the integration of DER and new business models that use the distribution network. For example, while the aggregation of distributed devices may provide a variety of benefits to end–users, aggregators, and system operators, the reduction of distribution network charges should not be one of those benefits under a well–designed network charge. Aggregating distributed resources that, when operated alone may not yield significant benefits for users but in coordination allow DER to participate in markets or derive other benefits, does not alter the network utilization patterns of those devices. As such, the total network charge for an aggregation of devices should equal the sum of the individual network charges of each device.[11]

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

In Pérez-Arriaga et al. [26], the authors outline a new framework for distribution network charge design. The framework proposes allocation of fixed network costs according to network users' profiles. A ***user***, defined as a point of connection 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. (See below for examples of cost drivers). A profile encapsulates all the information necessary

[7]Equity does not by itself imply that all users pay the same *r*ate for network utilization. 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.

[8]The regulator must often choose between which of many policy objectives to achieve through the DNUoS charge and to adjust the specifics of computing charges in order to more heavily favor objectives such as fairness or responsiveness to end-user behavior.

[9]We refer here only to the cost causality principle and not to beneficiary pays because we consider the two principles equivalent for network cost allocation, and cost causality is more easily applied than beneficiary pays at the distribution level. Network users cause or contribute to those costs of the distribution network that have been deployed for their benefit, in order to enable them to utilize the network to meet their needs. This includes using the network for consumption, production, storage of electricity, or any combination thereof.

[10]Here we focus exclusively on the price signal communicated to network users by the distribution network charge; however, the network cost signal must not distort other price signals such as the short–term energy price that may, for example, be provided by distribution–level locational marginal prices (DLMPs).

[11]Application of this principle requires symmetry in network charges for injections and withdrawals at the same connection point and time, and therefore the existence of negative charges (i.e., credits) for some patterns of utilization of the grid.

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 network costs.

As grid users become more sophisticated by introducing 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 2** below). In order to ensure that tariffs are non-discriminatory, the method employed to compute distribution use-of-system 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.

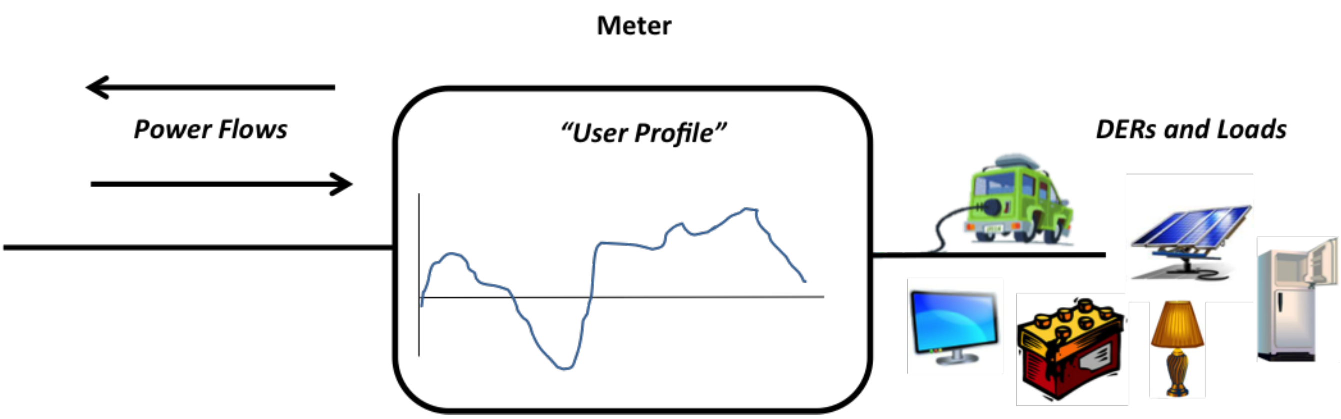

Figure 2: *All that the distribution utility sees of a network user's behind-the-meter activity is a user profile*

As indicated before, the fundamental principle underlying a new distribution network charge framework is the *cost causality* principle. In order to apply this principle to computing network charges in distribution networks with a high penetration of DER, there must be a clear understanding of the impacts on network costs of the presence and activity of network users — including traditional consumers and DERs.

In order to allocate network costs amongst users, the total cost of the distribution network — which should coincide with the revenue the distribution utility should collect — must first be determined. The network planning process is the basis of determining the total network cost and remuneration of the network company. This paper proceeds with the steps that follow the determination of the distribution utility's revenue requirement. The cost drivers used in the computation of network charges are a byproduct of network planning, and we begin the cost allocation process with the identification of network cost drivers. The method 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* [31].

   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 paper, 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 [27], 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 [28]. 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 [35].[12] 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 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

[12] 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. As previously indicated, zones may be defined more narrowly than feeders in order to communicate locational signals for the operation of DG along sections of a feeder, and network charges may have to be applied to new DG 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.

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 3 graphically outlines the cost allocation process. Each step is explained in greater detail in the remainder of this paper.

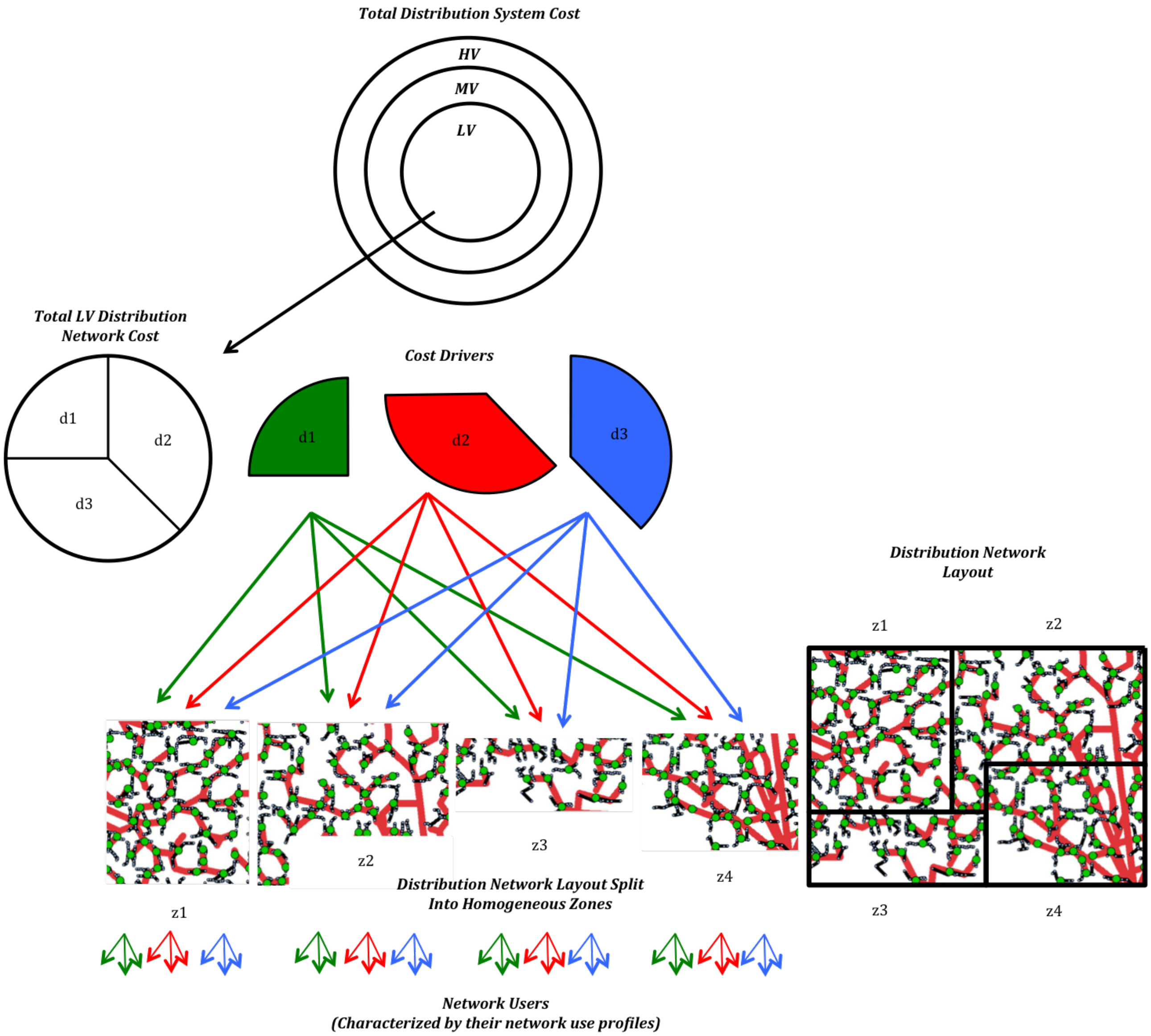

Figure 3: *Cost allocation involves first splitting the total network cost at each voltage level into the costs associated with each driver, then splitting the cost associated with each driver across network zones, and finally allocating the costs of each driver to network users within each zone based on their profiles*

Step 1: Identify the cost drivers

Cost drivers are the key factors determining the cost of the distribution network. In the course of planning, operating, and controlling electricity distribution, the overwhelming majority of costs are linked to the amount and scale of network infrastructure assets. Distribution costs consist of investment in distribution infrastructure to reinforce and expand network capacity — including lines, substations, control components, and monitoring devices; operation and maintenance (O&M) costs such as costs of dispatch centers and maintenance personnel; and metering costs (Gómez, 2013). Cost drivers are the factors, or network user needs, that motivate the above investment and operational costs. From a welfare-maximizing perspective, network costs are guided by the need to connect all network users in a manner that meets network user requirements under a variety of plausible operating conditions, while reducing network losses to an economically efficient level.[13]

Building upon prior work to identify distribution network cost drivers (such as [31] and [14]), the following are the cost drivers of focus in this work:

1. Connection (represented here as variable C)

   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.[14]

   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 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.

[13]As previously indicated, losses are, strictly speaking, a generation cost and not a distribution cost, since the generator incurs the cost of energy losses, not the distributor. 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 plan network investments in a way that reduces estimated losses, the network owner/operator does not incur any cost for losses. Instead, transmission and distribution losses increase energy generation requirements, and the costs of increased generation are passed on to end–use electricity consumers.

[14]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.

2. Capacity (represented here as variable P)

   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.[15] 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. 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 [24]. 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.

   Ideally, real-time operational price signals should be provided by nodal energy prices such as locational marginal prices (LMPs) (or potentially, distribution locational marginal prices (DLMPs)), or from other time-of-use energy pricing, but not by network charges. See the section on "Energy prices and network charges" for more discussion about the interaction between DNUoS charges and energy prices.

3. Reliability (represented here as variable R)

   In designing a distribution network, the system planner also takes into account reliability criteria defined by network user needs or by regulatory requirements. The investments made by the distribution utility to ensure system reliability, such as component redundancies and security margins or "buffers," are intended to ensure continuity and quality of supply. In practice,

[15] 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.

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. One could argue that reliability concerns can be implicitly addressed by any security margin incorporated in distribution system design. Then, the cost incurred for reliability-related network investments could be associated to the capacity cost driver.

However, reliability is not only needed at peak load times. 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 the entire year — not only the few peak hours — are considered. Thus, the reliability cost driver is associated with users' entire network utilization profiles not just capacity requirements, and reliability-related costs are allocated on the basis of hourly energy use. For a more detailed approach to allocating reliability costs to network users in the medium voltage distribution network according to the frequency and duration of service interruptions experienced by users, see [14]. This approach achieves a high level of granularity of cost allocation that takes into account differences in reliability levels requested by network users and different levels of benefit derived by users from network improvements. While such granularity is important for accurate cost allocation, the network charge framework proposed here incorporates a much less detailed approach to allocating reliability costs. Since reliability is one of multiple cost drivers, assigning costs according to kilowatts-hour of energy-use by distribution network users sufficiently captures network users' contributions to reliability-driven costs.

4. Energy losses (represented here as variable E)

   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 losses. As such, this cost driver reflects how a network user's profile impacts transformer and line losses, and therefore, 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. 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 voltage; 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 [32]. 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.

The network cost drivers C, P, R, and E are — in principle — likely to remain the primary drivers of distribution network costs in networks with growing penetrations of DER; however, further work is necessary to confirm their relative significances as cost drivers. A reference network model (RNM) can be used for this purpose as described in Step 2 below. An RNM can reveal the temporal and geographic granularity of C, P, R, and E required to compute accurate and efficient network charges. For example, the combination of energy use and the time of day at which it is distributed may impact component lifetimes, and thus is an important network cost driver. This limits the temporal simplifications of cost driver E that can be made, requiring complete hourly network use profiles rather than a small number of time-of-use blocks.

Step 2: Determine the cost contribution of each cost driver to the total distribution network cost at the LV, MV, and HV levels.

Once the primary cost drivers have been identified and understood, their contributions to the total distribution system cost must be determined. Focusing on the variables C, P, R, and E as 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 contributions to peak power flows — referred to as total capacity cost, the total cost associated with reliability, and the total cost associated with losses.

Total Distribution System Cost =

$$\textit{Total Network Connection Cost} + \textit{Total Network Capacity Cost} + \\ \textit{Total Network Reliability Cost} + \textit{Total Network Losses Cost}$$

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 are independent of one another, and 3) the impacts of these drivers on network costs can be determined sequentially (using a reference network model as described below).

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. Determining this network utilization for cost allocation was simpler when network users were just consumers, but it is a more complex task in networks with a high penetration of DG, bidirectional power flows, and system peak power flows from both generation and consumption.

A reference network model (RNM) is the primary tool by which to compute the contribution of each cost driver to total distribution system cost. A reference network model is a network-planning tool developed for regulatory purposes which designs an optimal distribution network — or reference network — for a specified distribution service area [7]. Rather than designing a greenfield network or network expansions to be implemented, the RNM helps regulators and companies improve current methods of distribution remuneration and cost allocation. An RNM takes as input the characteristics of network users — such as load and generation profiles and their geographic locations — and yields as output the least-cost distribution network that meets specified network requirements such as voltage limits, loss percentages, or reliability levels. An RNM provides the regulator with a benchmark for distribution costs, and 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 [5]. We assume here that a reference network model serves as a "magic box" — a planning tool that accurately

An RNM can be utilized in stages for DNUoS design to determine the relative significance of multiple cost drivers and to compute the cost associated with the design of a sample distribution network.[16] 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:

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

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.

Step 3: Compute network users' distribution charges based on their measured profiles of cost drivers

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 (zones) 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 social-

[16] See Appendix A for an outline of the procedure to follow to utilize an RNM for DNUoS charge computation.

ized 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 the reliability components of the DNUoS charge are based on volumetric energy use,[17] 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 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.

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 spread over anticipated peak periods throughout the year or over the actual peak periods at

[17] 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 [14]

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,[18] 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 [18]. The PCAF effectively weights the allocation of capacity-driven costs to each hour according to the 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 month is established a priori and does not depend on the actual behavior of the network users during that period. However, the *allocation* of the monthly charge among the network users does depend on each user's contribution to the actual peaks during that month, creating the right incentive for network utilization in the short run. The magnitude of total recoverable capacity costs allocated to each month is based on the anticipated peaks used in distribution network planning because the anticipated peaks guide network investments rather than actual peaks. With a record of the historical occurrence of system peaks and regulatory validation of projected peaks during the course of determining distribution utility remuneration, 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 to several forecasted peak periods. Operations and maintenance costs that vary according to capacity requirements (i.e. on a per–kW basis) can be added to each user's share of capacity–related investment costs on a per–kW basis. 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 actual 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 [8]. 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.

Dividing the total recoverable capacity-related costs across time periods according to anticipated system peaks also provides network users with rough signals to guide their network utilization behaviors and encourage them to shift network use away from peak periods. 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

[18] 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.

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 [14] 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 [20]. 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.

In 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, since the economic impact is much larger in the former case.

Allocating the cost of losses

The contribution of an individual network user to network losses is determined by the user's location and complete hourly profile of power injection and withdrawals at the connection point. 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.

Conventionally, uniform volumetric rates (and capacity charges in some power systems) have been used in the network tariffs charged to all network users of a particular type. That is, roughly all users that are connected at the same voltage level of an urban, suburban, or rural distribution network pay the same $/kWh (and $/kW) rate. The framework proposed here uses the same *method* to compute tariffs for all network users, but the traditional concept of unit prices for network utilization that are based on energy consumed or some capacity measure has to be abandoned. In the proposed method, the DNUoS charge is a blend of connection, capacity, loss, and reliability charges, but unit energy or capacity charges do not exist. Two network users with identical profiles who are located in different distribution network zones may have different impacts on distribution network costs and therefore different network charges. Two network users located close to one another in the same network zone and consuming the same amount of energy, but at different times, may have very dissimilar network charges. This temporal and locational differentiation ensures efficient allocation of network costs. Adoption of the proposed approach will enable the elimination of undesirable cross-subsidies between network users, creating a level playing field for a variety of new business models at the distribution level.

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 [17], 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.

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 [11]. 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 [29]. 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.

Step 4: Choose an adequate format for the final distribution network charge billed to network users

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 **??**, the design of network charges should not interfere with energy price signals.

V 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 via two channels: 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 [21], 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. However, as far as the authors know, DLMPs have not yet been implemented. For the time being, the most advanced pricing schemes communicate hourly or sub-hourly wholesale energy prices for end consumers, but they do not have locational differentiation at the distribution level.

The recovery of the total distribution network costs takes place via DNUoS charges. By taking into account network users' contributions to the drivers of distribution system costs, DNUoS charges should send network users efficient price signals to shape their pattern of network utilization behavior and, if possible, to optimally site their new facilities. DNUoS charges should reinforce and not interfere with the economic signals sent by any kind of adopted DLMPs. This paper only addresses the design of DNUoS charges.

There are, however, key differences between LMPs and DLMPs. Transmission UoS 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 [30]. 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 has been installed, 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 transmission network use of system (TNUoS) charges should not distort them. Therefore 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. Thus, in the absence of DLMPs, DNUoS charges must be more dynamic than TNUoS charges. 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. Since the use of DLMPs is unheard of in existing power systems, it is justifiable to employ distribution network charges to provide price signals that are closer to real time. This is precisely what has been proposed through the design of the capacity, loss, and reliability components of the DNUoS charge explained above.

VI 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 distribution utility must recover in the current billing period for its capital and operating expenditures.

Figure 4 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 5** 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 changes in users' profiles. Network users who have reduced their contributions to peak power flows reduce their *shares* of each peak and thus of peak-related costs, and they pay less towards the total system capacity costs. On the other hand, network users who have not reduced their network utilization during peak periods pay a higher proportion of total capacity costs, and thus face higher capacity charges. If all network users were to reduce their peak load by an equal proportion of their original contribution to peak load, then the magnitude of the peak would fall, but each user's *share* of the now-smaller peak would be identical to their share prior to the total peak reduction, and therefore, each user's share of the total capacity cost would remain the same. Thus, each network user is incentivized to reduce his or her contribution to the peak by *more* than the average reduction in peak contribution.

This form of cost reallocation differs from the issues of cross subsidization, adverse selection, and the "death spiral" discussed in Section III. 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. However, in networks experiencing low or no load growth, 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.

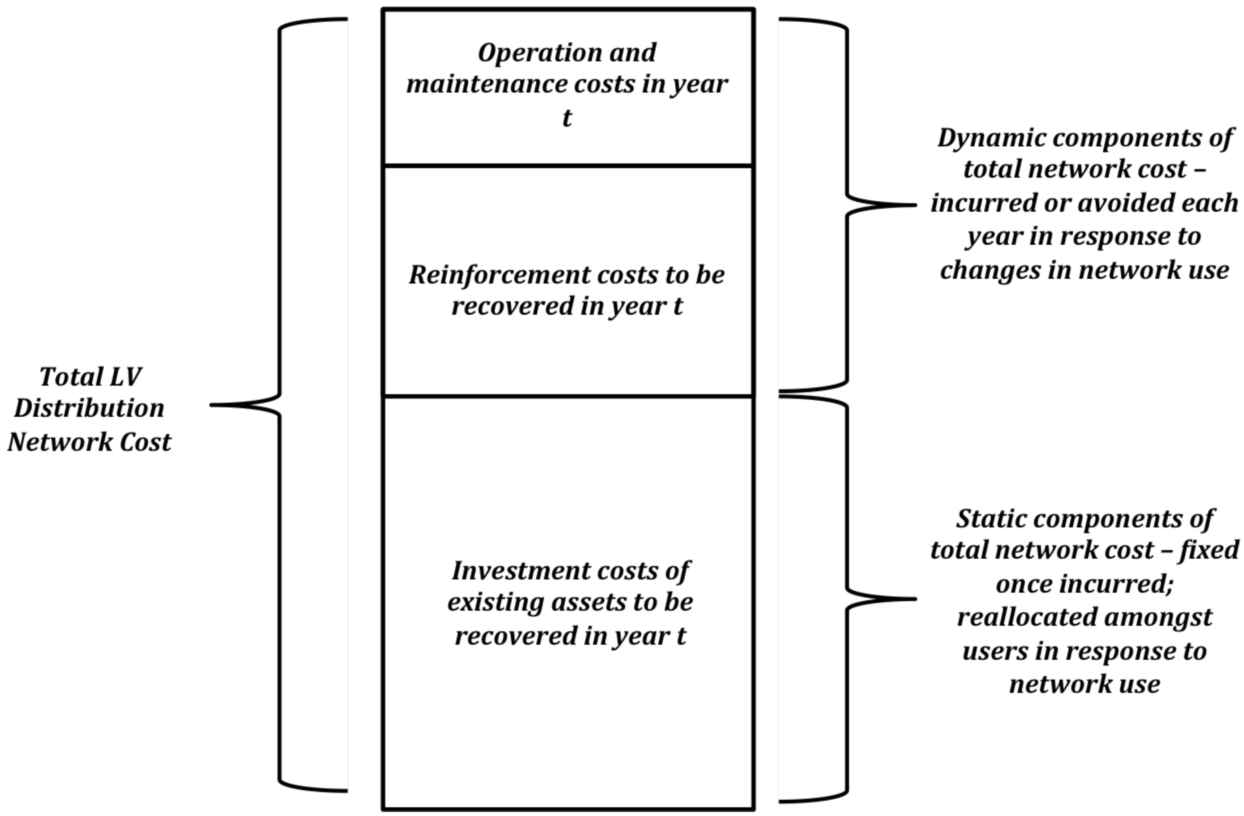

Figure 4: *The cost components to be collected through DNUoS charges (only the LV network cost is used as an example here; the same components make up the total MV and HV network costs)*

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 DNUoS charge 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.

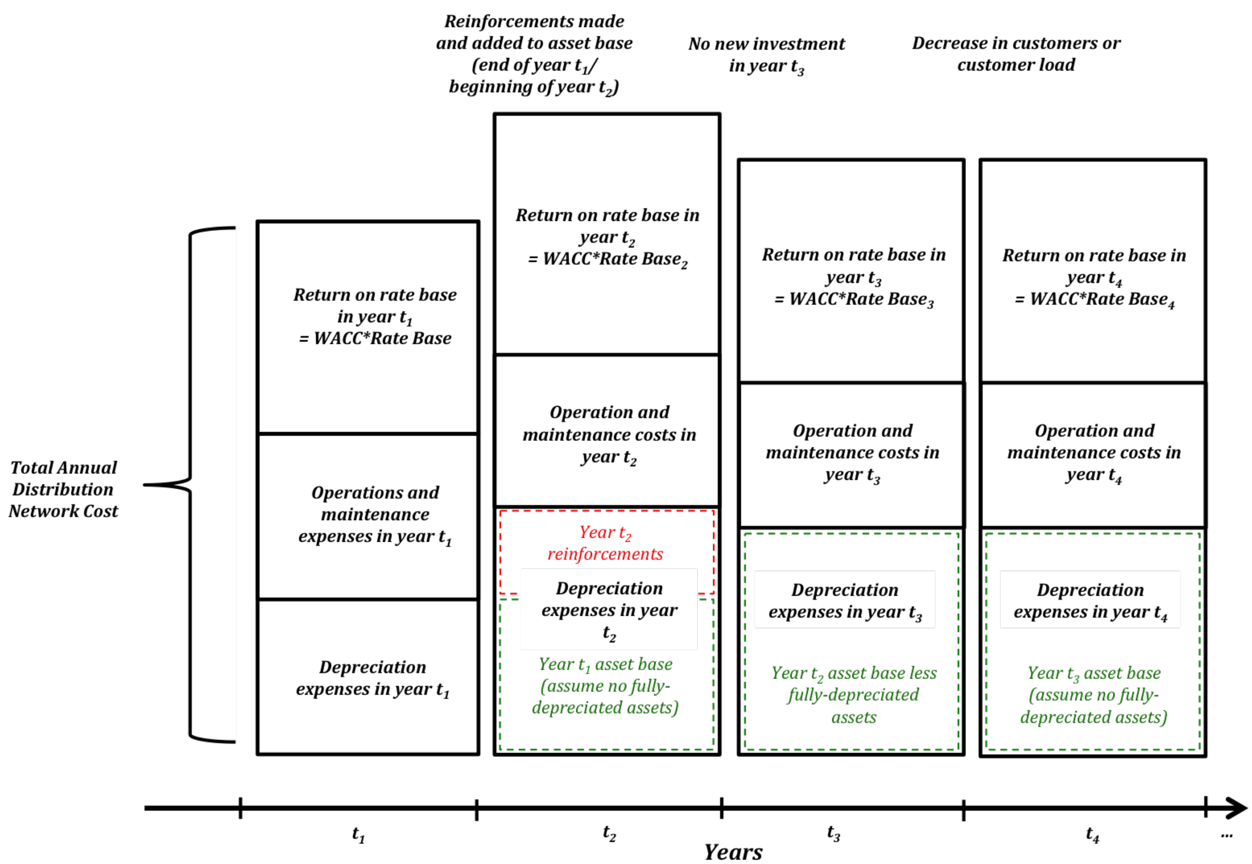

Figure 5: *How the cost components to be collected through DNUoS charges can evolve over time*

VII 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.

VIII Summary & Future work

As the penetration of DER increases, a new approach is required for the design of distribution network charges. We have proposed here the conceptual framework upon which a new design should be based. The proposed structure of DNUoS charges allocates network costs according to network use profiles. 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, and it is suitable for the distribution network component of the regulated electricity access charge under any regulatory framework.

Subsequent work will utilize a reference network model to demonstrate the proposed approach to network cost allocation in high DER-penetration scenarios. An RNM will be employed to identify the key drivers of distribution costs as the penetration of distributed resources within a network increases, and costs will be allocated across network users according to the above framework.

IX References

[1] Lowell E. Alt. *Energy Utility Rate Setting.* 2006.

[2] Ashwini Bharatkumar. *Distribution Network Use-of-System Charges Under High Penetration of Distributed Energy Resources.* Master's thesis, Massachusetts Institute of Technology, 2015.

[3] James Bonbright. *Principles of Public Utility Rates.* 1961.

[4] California ISO. Daily renewables watch [Data file], 2014.

[5] Rafael Cossent. *Economic Regulation of Distribution System Operators and its Adaptation to the Penetration of Distributed Energy Resources and Smart Grid Technologies.* Phd thesis, Comillas Universidad Pontificia, 2013.

[6] Rafael Cossent, Luís Olmos, Tomás Gómez, Carlos Mateo, and Pablo Frías. Distribution network costs under different penetration levels of distributed generation. *European Transactions on Electrical Power*, (21):1869–1888, 2011.

[7] Carlos Mateo Domingo, Tomás Gómez, San Román, Senior Member, Álvaro Sánchez-Miralles, Jesús Pascual, Peco González, and Antonio Candela Martínez. A Reference Network Model for Large-Scale Street Map Generation. 26(1):190–197, 2011.

[8] EDF Energy. TRIAD Charge Reconciliation: For Large Business Customers, 2013.

[9] EPRI. The Integrated Grid: Realizing the Full Value of Central and Distributed Energy Resources. Technical report, Electric Power Research Institute, 2014.

[10] Eurelectric. Active Distribution System Management: A Key Tool for the Smooth Integration of Distributed Generation. Technical Report February, 2013.

[11] Eurelectric. Network tariff structure for a smart energy system. Technical Report May, 2013.

[12] Eurelectric. Utilities : Powerhouses of Innovation. Technical Report May, 2013.

[13] Ahmad Faruqui and Neil Lessem. Comments on Massachusetts Department of Utilities Notice DPU 14-04 Investigation by the Department of Public Utilities into its own motion on Time Vary Rates. Technical report, The Brattle Group, 2014.

[14] Alezeia Garcia González. *Implicaciones de la continuidad de suministro en el diseno de la tarifa de red de distribucion.* Doctoral dissertation, Universidad Pontificia Comillas, Madrid (Spain)., 2014.

[15] Jesús Pascual Peco González. *Modelo de cobertura geografica de una red de distribucion de energia electrica.* Doctoral dissertation, Universidad Pontificia Comillas de Madrid, 2001.

[16] Jesús Pascual Peco González. A Reference Network Model: the PECO model. 2004.

[17] Chenghong Gu and Furong Li. Long-run marginal cost pricing based on analytical method for revenue reconciliation. *IEEE Transactions on Power Systems*, 26(1):103 – 110, 2011.

[18] Grayson Heffner, C K Woo, Brian Horii, and Debra Lloyd-Zannetti. Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution. *IEEE Transactions on Power Systems*, 13(2):560–567, 1998.

[19] Steve Heinen, David Elzinga, Seul-Ki Kim, and Yuichi Ikeda. Impact of Smart Grid Technologies on Peak Load to 2050. 2011.

[20] Serena Hesmondhalgh, William Zarakas, and Toby Brown. Approaches to setting electric distribution reliability standards and outcomes. Technical Report January, The Brattle Group, 2012.

[21] G.T. Heydt, B.H. Chowdhury, M.L. Crow, D. Haughton, B.D. Kiefer, Meng Fanjun, and B.R. Sathyanarayana. Pricing and control in the next generation power distribution system. *IEEE Transactions on Smart Grid*, 3(2):907 – 914, 2012.

[22] Jesse D Jenkins and Ignacio Pérez-Arriaga. The Remuneration Challenge: New Solutions for the Regulation of Electricity Distribution Utilities Under High Penetrations of Distributed Energy Resources and Smart Grid Technologies. 2014.

[23] Peter Kind. Disruptive Challenges: Financial Implications and Strategic Responses to a Changing Retail Electric Business. Technical Report January, Edison Electric Institute, Washington, DC, 2013.

[24] J.A.P. Lopes, N. Hatziargyriou, J. Mutale, P. Djapic, and N. Jenkins. Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities. *Electric Power Systems Research*, 77(9):1189 – 1203, 2007.

[25] P. Mitra, G.T. Heydt, and V. Vittal. The impact of distributed photovoltaic generation on residential distribution systems. Arizona State University, Department of Electrical, Computer and Energy Engineering, Tempe, AZ, 85287, USA, 7864, 2012.

[26] Ignacio Pérez-Arriaga, Sophia Ruester, Sebastian Schwenen, Carlos Batlle, and Jean-Michel Glachant. From Distribution Networks to Smart Distribution Systems: Rethinking the Regulation of European Electricity DSOs. Technical report, European University Institute, Florence, 2013.

[27] PG&E. PG&E 2014 General Rate Case Phase II Prepared Testimony: Marginal Costs, 2013.

[28] Public Utility Commission of Texas. Substantive Rules Applicable To Electric Service Providers, 2014.

[29] Javier Reneses, Maria Pia Rodriguez, and Ignacio Perez-Arriaga. Electricity Tariffs. In *Regulation of the Power Sector*, pages 397–441. Springer, London; New York, 2013.

[30] Michel Rivier, Ignacio Perez-Arriaga, and Luis Olmos. Transmission Cost Allocation. In *Regulation of the Power Sector*, chapter Electricity Transmission, pages 251–341. 2013.

[31] María Pía Rodríguez Ortega, J. Ignacio Pérez-Arriaga, Juan Rivier Abbad, and Jesús Peco González. Distribution network tariffs: A closed question?. *Energy Policy*, 36(5):1712 – 1725, 2008.

[32] D I H Sun, S Abe, R R Shoults, M S Chen, P Eichenberger, and D Farris. Calculation of Energy Losses in a Distribution System. *IEEE Transactions on Power Apparatus and Systems*, 52(4):1347–1356, 1980.

[33] Claudio Vergara, Ignacio Pérez-Arriaga, Carlos Mateo, and Pablo Frías. Estimating the Aggregate Impact of Distributed Photovoltaic Generation over Distribution Networks. 2014.

[34] R. A. Walling, Robert Saint, Roger C. Dugan, Jim Burke, and Ljubomir A. Kojovic. Summary of distributed resources impact on power delivery systems. *IEEE Transactions on Power Delivery*, 23(3):1636 – 1644, 2008.

[35] Scott Zima. South Minneapolis Electric Distribution Delivery System Long-Term Study. Technical report, 2009.

Appendices

A Building a distribution network incrementally

What follows is an outline of the procedure by which DNUoS charges can be computed with a reference network model. The RNM used here is an adaptation of the PECO RNM originally developed and described in [15] and [16]. 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 [7]. 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, $Run01$ through $Run04$, 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). 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 (i.e. TIEPI and NIEPI objectives). The purpose of this run is to determine the cost of meeting reliability objectives for network users.

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

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. 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))*