# Electricity tariffs for a distributed future (II): Advanced topics

## Allocation of residual costs

## Long-term signals at the distribution level

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*Developed for*

ABRADEE
ASSOCIAÇÃO BRASILEIRA DE DISTRIBUIDORES DE ENERGIA ELÉTRICA

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# 1. Introduction

In the first paper[1], it was reviewed how a transition to a more distributed model is taking place in electricity systems worldwide, and how this transition calls for urgent changes in the tariff design before it is too late.

The core of the problem lies in the fact that today the vast majority of power systems lack a comprehensive system of efficient prices and regulated charges for electricity services (MITEI, 2016). Indeed, electricity-related costs are in most cases recovered through simple volumetric charges. As a result of this inefficient allocation of costs, some customers are making inefficient investments and are overcompensated for the services that they provide to the power system. At the same time, many more opportunities that could deliver greater value are being left untapped because of inadequate short and long-term signals.

Well-designed tariffs, as well as some complementary mechanisms (analysed below), will need to introduce these missing short to long-term pricing signals. Generally speaking, the well-known first-best methodology reviewed in the first deliverable to allocate costs is to, whenever possible, resort to the cost causation principle. Nevertheless, it was also highlighted that there is a (growing) portion of those costs, known as residual costs, that cannot be allocated based on this cost causation principle.

In this current ill-designed context, this second deliverable deepens on two topics that were identified as advanced regulatory issues in the first deliverable. These two topics represents two of the major discussions that are attracting growing attention, for its relevance is also increasing in the new “more distributed” paradigm. These are one the one hand the residual cost allocation methodologies and the implications from the point of view of distributional effects, and on the other hand the need for additional mechanisms to provide long-term network signals at the distribution level. This paper is structured as follows:

- In section 2, this document analyses the different allocation methodologies considered to date for residual costs, and also proposes a solution, based on uneven fixed charges for each customer (or group of customers), that allows to achieve efficiency, more equity than the fixed charge, while not endangering cost recovery. In section 3, it is briefly discussed the role for gradualism in any tariff reform and the role of the allocation of residual costs to achieve this gradualism.
- Section 4 focuses on the need of long-term signals at the distribution level. Introducing long-term signals to (and clear commitments from) DERs are fundamental both for the network user and for the distributor. They are needed on the one hand to drive efficient consumers’ investment decisions, and on the other hand to properly integrate distributed resources in the

[1] Mastropietro, P., Rodilla, P., Batlle, C., 2018. “Electricity tariffs for a distributed future”. Deliverable for the project “Projeto Cooperado de P&D sobre Modernização das Tarifas de Distribuição de Energia Elétrica”. Developed for Abradee.

long-term network planning. Tariffs can partially give these long-term signals, but some complementary mechanisms in the form of auctions would be more suitable to this end.

- Finally, section 5 concludes.

## 2. Residual costs allocation and the distributional effects

*What are residual costs?*

Residual costs can be defined as the difference between the recognised costs of a certain activity and the revenues collected through the application of allocation methodologies based on cost-causality[2]. Also the costs for which no evident cost-causation principle can be applied are commonly considered as residual costs.

In the electricity sector, there are many cost items that can be encompassed, entirely or partially, in this category: residual network costs, residual renewable support costs, subsidies for vulnerable customers, economic support to islands or rural areas with high costs of service, institutional costs (such as regulatory authorities or system and market operators), and interests on tariff deficits, just to cite some of the most widespread.

In most power systems, residual costs are allocated through volumetric charges. This design, whose inefficiency has been latent in the last decades, is being challenged by the development of distributed energy resources and ill-designed end-user rates, through which high-consumption customers may dramatically reduce the share of residual costs they pay by resorting to self-consumption, leaving a deficit to be paid by other customers. In the face of this problem, in principle, the most efficient alternative appears to be to allocate residual costs through fixed charges. These fixed charges are usually considered to be flat for all consumers, but then tariff equity is endangered.

*A growing concern today*

The weight of residual costs in the electricity bill has experienced a significant increase in the last decade in many systems worldwide. Two main drivers for this growth can be identified: the allocation of network costs in a decreasing and more elastic consumption, and the growing weight of policy costs.

As regards networks, in pursuit of economic efficiency, part of their cost are being increasingly assigned through methodologies inspired by the long-run marginal cost (LRMC)[3]. However,

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[2] It must be remarked that some electricity costs are improperly considered as residual costs, while it would be possible to assign them, at least in part, through cost-causation methodologies. As it will be analyzed later, this is the case of renewable support costs.

[3] In the context of electricity networks, the LRMC represents the increment in network costs that is caused by a marginal increment of withdrawals or injections in a certain point of the grid in the long run,

after several decades of fast-paced growth, many countries are now experiencing a decline in electricity demand. For this, among other reasons, many networks might increasingly present a significant surplus capacity. In such conditions, long-run marginal costs methodologies reflect such surplus (even large increments in withdrawals or injections would not result in the need for new investments) and LRMC charges may decrease sharply, augmenting the quota of network costs that cannot be assigned efficiently and that must be treated as residual network costs.

## 2.1 Allocation of renewable support mechanisms costs

*Res support costs should be allocated to all polluting energy vectors*

It must be remarked that considering the entire renewable support budget as residual costs to be recovered through electricity tariffs is, most of the times, a political choice. In many countries, the power sector has historically borne most of the national emission-reduction burden. If the renewable support cost is fully recovered through electricity tariffs, electricity consumers are clearly subsidising the consumption of other energy sources, which are not required to achieve any reduction target. This may lead to inefficient decisions, for example, favouring standard internal-combustion-engine cars over plug-in electric vehicles. In order to avoid such undesired effect, Batlle (2011) argues that the renewable support burden would be more efficiently allocated among all energy consumers (not only electricity, but also gas, oil, coal, etc.), according to their final energy consumption, or to the total carbon emissions provoked by each energy sector.

*Not all RES support costs are residual costs*

Once renewable costs are properly assigned among all energy sectors, the quota assigned to the electricity sector may still be allocated among end-users, at least in part, through an efficient methodology. As discussed in the first deliverable, Batlle (2011) proposes that a cost-reflective allocation of the cost of renewable support policies would entail a volumetric charge calculated as the product of the percentage renewable target and the extra cost of generation from renewable sources.

## 2.2 Conventional residual cost allocation and the impact of DER

The basic recommendation for the allocation of residual costs is to minimise distortions to the already defined economically efficient signals (MITEI, 2016). Historically, this has been achieved through the application of the so-called Ramsey-pricing theory, or inverse-elasticity

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thus considering the possibility of new investments in the grid. Obviously, the LRMC of the network depends on the time and location of the marginal increment; therefore, the resulting charges are supposed to consider a certain temporal and spatial granularity and to be applied to both generation and demand. It must be remarked, however, that, in most power systems, also network costs are collected from domestic consumers through simple volumetric charges.

rule. Higher complementary charges should be therefore applied to those agents who change their behaviour the least in response to price changes, i.e., who are less elastic.

Domestic consumers have often been considered as almost completely inelastic in the short term and not very reactive to price increases in the long term, so they have been charged a significantly higher share of residual costs. The format chosen, in many power sectors, to recover residual costs from domestic consumers was a volumetric charge (€/kWh), which is a format that contradicts the principle expressed above, according to which the complementary charge should not distort the efficient signal conveyed by the energy price.

A volumetric charge may result in significant inefficiencies if the elasticity estimated reveals to be wrong or it is expected to change, as in the present scenario. Today, distributed generation, storage devices, plug-in vehicles, smart meters, domotics, and other innovations can significantly alter the role and elasticity of consumers and the whole functioning of power systems and markets.

The elasticity of electric demand can actually grow not only in the short term, but also, and more dramatically, in the long term, as end-users can react to prices and charges by installing DERs. The enhanced elasticity of demand is certainly a positive element in liberalised power sectors, where the ability of demand of responding to price signals is essential to improve the efficiency of market outcomes. However, problems arise when DERs and the enhanced elasticity they bring are introduced in a system where tariff design still reflects the old regime.

Regulation should try to guide this transition and a central element of this process is represented by electricity tariffs, which, in the future, will most likely define the equilibrium between centralised and decentralised resources (MITEI, 2016).

Many experts have recently addressed this complex problem and proposed alternative solutions to recover residual costs in future electricity tariffs that will have to be applied not only to consumers, but also to prosumers. The next section presents a short review of these studies.

## 2.3 Options for residual cost allocation with DER

Most of recent literature on this topic focused on the allocation of fixed costs (Pollitt, 2017) or, more specifically, of residual network costs. The articles and reports analysed in this section are Brown et al. (2015), Borenstein (2016), and Ofgem (2017), which present alternative approaches to recover residual or fixed costs. These alternatives can be summarised as follows:

i. Postage-stamp pricing (Brown et al., 2015), average-cost pricing (Borenstein, 2016), or charges based on net consumption (Ofgem, 2017): this basically means to recover residual network costs by an increased volumetric charge; this approach is perceived as fair but it could be inefficient, since it distorts the signal computed through efficient allocation methodologies; this methodology would also allow prosumers to avoid paying part of their share of residual costs.

ii. Ramsey-pricing (Brown et al., 2015; Borenstein, 2016): the volumetric charge is increased disproportionately across customers according to their elasticity. According to Brown et al. (2015), this approach yields a declining block tariff, which can be considered unfair and whose efficiency depends on the accurateness of the elasticity estimates.

iii. Fixed charges (all documents): residual costs are gradually moved from volumetric to flat fixed charges. The fixed charge does not distort efficient signals, but, since in principle all end-users are supposed to pay the same, regardless of their consumption or income, this alternative may be perceived as unfair and its impact on low-energy and vulnerable consumers would need careful consideration.

iv. Fixed charges plus exemptions for low-income consumers (Brown et al., 2015): the latter do not receive an explicit subsidy, but they are simply not considered in the fixed charge calculation process and are exempted from this payment.

v. A fixed charge set by connected capacity (Ofgem, 2017; Borenstein, 2016): this option considers a "fixed" charge based on either contracted or peak demand, and it does not avoid completely inefficient incentives to prosumers.

vi. Tiered pricing (Borenstein, 2016), either increasing- or decreasing-block volumetric charges.

vii. Minimum bills (Borenstein, 2016) that charges a minimum amount to all consumers regardless of their consumption, if this is below a certain threshold.

viii. Move part of the residual costs to the state budget and collect them through conventional taxes. As already mentioned, renewable support costs permit to achieve objectives that go beyond the electricity sector and could be included in the state budget. MITEI (2016) states that also the residual costs of electricity networks may be paid by taxpayers. Residual costs could be embedded in real-estate taxes, proportionally to the property tax currently paid. The real-estate tax is used in this proposal because it is considered as a good proxy of the wealth of the household (but not necessarily to its electricity consumption, which might be arguable). Therefore, this solution would allow to charge more residual costs to end-users with higher wealth, but without affecting the efficient economic signals and without the risk of grid defection.

In any case, a complementary tool to some of the previous approaches would be to introduce a specific exit fee for grid defection, by which grid defectors pay their share of unassignable costs. If the fee is conceived as a lump sum, it should be calculated as the summation of the expected shares of unassignable costs along a predefined period of time. This alternative is difficult to be applied in practice (especially as regards the calculation of the exit fee) and its implementation may be more than contentious for legal reasons.

These documents assess the alternatives based on a set of principles that always include efficiency and fairness, but none of them identifies an option that could be considered as a first best. This is due to the fact that none of the alternatives mentioned above is able to achieve efficiency and equity at the same time.

*A classic controversial solution: allocating residual costs through flat fixed charges*

Two main arguments, can be found in the literature against flat fixed charges Synapse (2016):

i. The shift of residual costs to fixed charges decreases volumetric charges and this reduces incentives for energy efficiency and distributed generation and lead to an inefficient increase in consumptions.
ii. Low-usage and low-income customers may face significantly higher electricity bills if fixed charges are increased and this may infringe the equity principle.

The first argument clearly violates basic economic theory. The volumetric charge should reflect the short-run marginal cost of providing electricity (Borenstein, 2016), and any deviation from this price distorts the efficient signal it conveys. Residual charges are needed to ensure cost recovery, but they are not meant to incentivise specific actions by end-users (Ofgem, 2017) and should not give any price signal. The marginal cost of electricity (incremented by any other efficient volumetric charge meant to recover costs that are actually driven by energy consumption) is the optimal signal for the development of energy efficiency and distributed generation. An increase of the volumetric charge above the marginal cost may indeed cause larger investments in distributed energy resources, but these installations would be inefficient and cause additional costs to the system. If the problem stems from the fact that current electricity price is not properly internalising certain externalities, as the environmental ones, the solution is not to improperly assign residual costs, but rather to introduce a specific mechanism targeting this market failure (e.g., a carbon tax).

On the other hand, the second argument does represent an actual drawback of fixed charges. Also Bird et al. (2015), Brown et al. (2015) or Ofgem (2017) highlight the potential impact of fixed charges on the equity of electricity tariffs. Changing the format of the residual-costs charge, from a volumetric (as currently implemented in many jurisdictions) to a fixed one, is expected to alter the distribution of these costs among different consumer categories. In particular, low-income consumers are likely to pay higher electricity bills. In fact, low-income households are supposed to have lower electricity demands than wealthier households; if this hypothesis is correct, the volumetric charge allow low-income consumers to pay a lower share of residual costs. When residual costs are assigned through a simple fixed charge, all end-users included in the same tariff category or segment pay the same amount. Since in many cases end-users are assigned to these categories irrespective of their incomes (e.g. the voltage level at which they are connected), this may cause a sharp increase in the bill of low-income households[4].

[4] It must be remarked that this section covers only the equity issues that arise when residual costs start being covered through a fixed charge. Other changes in the tariff design (increasing the temporal and

Some recent proposals try to tackle this problem by introducing a more detailed customer grouping. The fixed charge of a customer group is set proportional to the electricity consumption of the entire group. Therefore, this approach does not allow prosumers to reduce their contribution to the coverage of residual costs, since the reduction in consumptions that can be obtained through DER installation would be diluted in the consumption of the entire group. On the other hand, depending on the grouping strategy, it may be possible to put together consumers with similar living conditions, thus reducing the impact of the fixed charge on equity (a group of low-income customers has lower electricity consumptions and would pay lower fixed charge than a group of high-income customers). However, this approach requires a trade-off between efficiency and equity that depends on the granularity of the grouping. A low granularity (large groups) may endanger equity, since low-income and high-income consumers may be encompassed in the same group. A high granularity (small groups) may endanger efficiency, since a group could be formed by a few households who can agree to all install DER and avoid the payment of part of residual costs. An equilibrium point may be hard to find.

The goal of the next section is to present a proposal to overcome these disadvantages and to design equitable fixed charges for the recovery of residual costs. The objective is not to find a trade-off between efficiency and equity, but rather to fulfil both principles at the same time in the best way possible.

## 2.4 An additional proposal to allocate residual costs

The methodology proposed in this section is guided by three principles: economic efficiency, equity, and cost recovery. The application of the efficiency principle to residual cost allocation must be intended as not distorting the efficient economic signals. As discussed in the first deliverable, the equity principle is open to many possible interpretations. In this document, equity means that any change in the tariff design should consider the distributional impacts it may have on end-users, particularly avoiding that certain consumer categories, such as (but not limited to) vulnerable or low-income households, are left worse off by the reform[5].

The first element that needs to be fixed is the tariff format used to recover residual costs. As already mentioned, the energy consumption is not a direct driver of residual costs. This means that a reduction in electricity consumption does not lead to any reduction in residual costs. If the latter are recovered through a complementary volumetric charge, first, the signal conveyed by efficient charges (as the marginal energy price) is distorted, and second, a wrong incentive is provided to network users. For exactly the same reasons, a complementary capacity charge (proportional to contracted capacity or peak demand) is not suitable either, since capacity is not

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spatial granularity of the energy price, introducing locational distribution tariffs, etc.) may raise other equity issues that are not being considered in this subsection.

[5] In other documents, this principle is sometimes referred to as fairness (Brown et al., 2015). Other articles also consider a definition of equity different from the one used here. Borenstein (2016) defines equity as a notion of fairness across customers with different consumption levels and patterns, while he talks about distributional effects when this fairness is across customers of different levels of income or wealth.

a residual cost driver and the same detrimental distributional effects due to DER installation could take place, as discussed in Azarova et al. (2018).

The only way not to distort efficient prices and charges, either for energy or capacity, and to avoid incentives to inefficient DER installations is to recover residual costs through a fixed charge. This fixed charge needs to be independent for future consumer decisions and could be expressed as a lump sum that could be computed on a yearly basis and billed in monthly instalments. As discussed in the previous section, many experts coincide that a fixed charge is the best option to fulfil the efficiency principle that should guide tariff design. However, most of them express concerns about the equity of this solution.

This line of thinking is based on the assumption that the fixed charge is flat and uniform for all consumers in the same tariff segment, but this is not the only possible design. An "uneven" fixed charge, based on historical consumption behaviours, may significantly reduce equity issues and overcome public opposition to the tariff change. Residual costs would still be recovered through a fixed charge, thus eliminating the incentive to inefficient DER installations, but the lump sum would not be the same for all end-users. Borenstein (2016) seems to contemplate this design option, but he states that a fixed charge based on past (or current) usage is effectively volumetric and creates the same efficiency losses as a volumetric charge. However, this is true only if the allocation coefficients used to set the fixed charge for each customer are recalculated periodically and the consumption considered in the calculation could be modified, for example, through DER installation. In this case, the inefficient incentive remains and it is only "diluted" over time. Nonetheless, this detrimental effect could be avoided by calculating these allocation coefficients only once, at the moment of reforming the tariff design and considering a sufficiently large number of years for such coefficients to be representative.

The approach can be further developed: if detailed historic hourly consumption data is available (or easily estimated based on historic metering), the allocation methodology can seek to use the implicit cost drivers of residual costs. As already mentioned, residual costs do not have any direct future cost driver, since their amount does not vary in response to a change in electricity consumption or peak demand. Nevertheless, when some of these costs were incurred, they had a cost driver. For example, most of residual network costs were certainly driven by the contracted capacity of grid users (or their consumption at the peak) and, in those jurisdictions that set renewable targets as a percentage of electricity consumption, residual renewable support costs were driven by this latter parameter. These residual costs can be assigned according to the historical contracted capacity and electricity consumption. The allocation coefficients, in this case, would be the share of contracted capacity (or demand at the peak) or electricity consumption of a customer within her customer group. On the other hand, for some residual costs (for example the cost of the system operator or the regulatory authority), it may be impossible to identify an implicit cost driver; these costs should then be assigned through a flat fixed charge uniform within a customer group. However, these costs use to cover a minor share of residual costs, so the impact of this uniform part of the fixed charge on equity is supposed to be small.

With this approach, the uneven fixed charge reflects past consumption behaviours; thus, the share of residual costs borne by each customer should be similar to the one in place with the previous tariff design, even if some discrepancy may still be produced. If the regulator considers that also these minor changes in the electricity bills might be considered politically or socially unacceptable, she might want to introduce some sort of gradualism in the tariff reform. In this case, the fixed charge could be used as a free variable to gradually move from the original distribution of charges to the definitive state.

## 2.5 Implementation issues: household switching and new constructions

The uneven fixed charge as proposed in this article would be calculated for specific metering points; e.g., at the residential level, it would be applied on dwellings, not on homeowners. Therefore, before entering into the numerical analysis, this subsection discusses the application of charges based on historical consumption behaviours in the cases of household switching and new constructions.

Household switching may be frequent in the real-estate market. A consumer may enter in a new house that she purchased or rented and find a fixed charge in the electricity tariff that is related to the past consumption behaviour registered in that dwelling. This may sound unfair, but it is not unusual in the real-estate sector. There are many charges and fees applied at the household level on which a new homeowner or a tenant has no control. Examples are service charges in a building or neighbourhood or a specific fee raised, for instance, to recover the cost of installation of an elevator, or even decisions made by the previous owner affecting for instance the energy efficiency of the house that might not be always reversible at a low cost. The uneven fixed charge may be just one of these cost elements, which will affect the value of the household in the real-estate market and will be considered by agents active in this market accordingly.

As regards new constructions for which no historical consumption can be considered, the calculation of the uneven fixed charge may have to rely on some sort of benchmark; for example, it may be obtained considering the fixed charges applied in the same neighbourhood to dwellings of similar size.

## 1.1 Residual costs and grid defection

As mentioned in this section, the main objective of introducing a fixed charge, either flat or uneven, for the recovery of residual costs is to eliminate the inefficient incentives to DER investment that arise when the wrong cost drivers are selected. Nonetheless, a fixed charge does not eliminate completely the possibility of distributed investment decisions that can be beneficial for the individual end-user, but inefficient from a system-wide perspective. DERs increase the long-term elasticity of consumers. An extreme instance of this long-term elasticity is represented by grid defection, a possibility favoured by the decreasing cost of stand-alone systems based on distributed generation plus battery storage. A fixed charge can avoid strategic reductions in electricity consumption and contracted capacity, but it cannot avoid grid defection.

Grid defection is a topic broadly studied in literature and several proposals to avoid inefficient disconnections from the grid have been recently advanced. Batlle et al. (2016) support the definition of thresholds based on the cost of stand-along systems. These threshold limit the amount of residual costs that can be recovered through electricity tariffs and their application results in the creation of some unassignable costs. The latter can be either included in the state budget (thus, they would be collected via conventional taxes), or embedded in real-estate taxes (MITEI, 2016), proportionally to the property tax currently paid, which is considered as a good proxy of wealth.

# 3. Achieving gradualism in a context of a major tariff design overhaul

The final complementary idea is that abrupt changes in tariff design need to be progressively implemented in time. Sudden changes in the electricity bills are to be avoided, for they are politically and socially difficult to accept. This gradualism is also fundamental to provide a stable regulatory framework that will not endanger the recovery of some consumers' investments.

In this respect, there are two different ways to introduce gradualism in the context of a major tariff redesign involving departing from the volumetric tariff to a more complex one (with two or more components such as fixed charges, demand charges, etc.).

- The first approach is that, bearing in mind which is the format and the values of the optimal signals we want to move to, we gradually decrease the volumetric component and increase the other new components. Obviously, such calibration needs to ensure revenue sufficiency.
- The second approach is to use the fixed charge as the perfect tool to achieve some gradualism in the bill expenditure while not affecting the efficiency principle we want to accomplish. That is, the efficient signals (including demand charges) would be implemented since day one of the reform. But the fixed charge would play a major role as a tool to achieve gradualism. The fixed charge could be used as a variable to gradually move from the original bill expenditures to the definitive state. The evolution of the allocation of the fixed charge can then be implemented including a transitory period. At the beginning of this transitory period, a corrective component is included in the fixed charge to guarantee that each customer pays exactly the same access fee that she was paying before the redesign. During the transitory period, this corrective component can be gradually removed (e.g. -20% each year during five years period) and, after the transitory period, each customer would be finally exposed to her final access fee including its final fixed component computed following whichever of the methodologies presented in this document.

# 4. Complementary mechanisms to provide long-term signals: auctions for long-term distribution planning

One of the relevant problems at the low voltage level is the lack of long-term network signals. This situation creates a double source of uncertainty that does not allow taking advantage of all potential benefits from DER. On the one hand, the distribution system operator cannot predict accurately the installation and response of DER and, therefore, cannot plan the grid expansion efficiently; on the other hand, end-users cannot hedge the risk associated to their investments decisions. Tariffs alone do not provide these long-term signals to both consumers' and distributors because of two reasons: (i) they do not usually represent a long-term stable signal and (ii) they do not imply any reliable commitment from the DER's side to the distributor.

In this section we analyze this problem, as well as the most promising mechanisms to overcome this hurdle: auctions for long-term distribution planning.

## 4.1 The need to hedge risk at the distribution level

***The distributor's long-term planning problem***

An economically efficient network planner seeking to maximize (social) welfare would make investments in network capacity only up to the point where the cost of network expansion equals the benefit derived by network users from the expanded capacity over the economic life of the asset.

In this context, it is important to ensure that DERs (including storage) are accounted for and are optimized so that welfare is maximized. This includes appropriate provision and remuneration of services from DERs to the distribution company, which may save or defer some network investments thanks to the timely provision of services by DERs. These are the so-called non-wires alternatives (NWA)[6].

Although the theory is well-known, the real life ideal application of the previous criteria has always been difficult, and it is even becoming more difficult today for two major reasons: (i) there is a lack of information about consumers' preferences, and (ii) there is also a lack of reliable commitments from the DER's side to the distributor.

Information incompleteness about consumers is indeed a major problem when planning the distribution system. Network utilities have little knowledge of network users' actual preferences. The past response to prices and network capacity charges (where implemented) may provide some information, but it only represents an incomplete picture of network user's

[6] According to Navigant (2017), NWAs can be defined as "an electricity grid investment or project that uses non-traditional transmission and distribution solutions, such as distributed generation, energy storage, energy efficiency, demand response, and grid software and controls, to defer or replace the need for specific equipment upgrades, such as T&D lines or transformers, by reducing load at a substation or circuit level".

long-term preferences. This fact complicates the necessary coordination between tariff design and optimal planning. Sometimes the DSO can estimate that it is better to reduce the consumption in a certain amount rather than investing in new network capacity. However, because of the lack of precise information about the consumer, a tariff is not likely to obtain the targeted "amount" of response from consumers (particularly if at the same time we also look for a predictable and stable tariff signal).

***The consumer (or prosumer) problem***

On the other hand, network users (and potential third-party providers) must make investments given a lack of long-term signals that exposes them to significant risks. As pointed out in the first deliverable, distributed energy resources require investments that, from a household perspective, may be considered as capital-intensive. In the absence of long-term signals, if end-users are risk averse, they may decide not to invest even if the expected value of such investment is positive

In this section we take for granted that DER can only be owned by consumers or other third party providers. On both sides of the Atlantic, there is a growing consensus on prohibiting the ownership of DER by regulated entities like distribution companies. In the framework of the Clean Energy Package, the European Commission proposed a Directive (EC, 2017) that explicitly prohibits this kind of ownership, leaving the deployment of storage to market-based solutions. NYs REVs Order only allows storage to be owned by the utility in exceptional cases. However, these exceptions should be as limited as possible and always be considered as the last resort alternative7.

## 4.2 Auctions at the distribution level as a means to provide long-term signals

The alternative to deal with this problem would be to enter into any type of long-term commitment with distributors.

The long-term contract can ensure the recovering of all network costs to the DSO and provide a stable framework to the potential providers thinking about investing in DERs or storage. If the acquisition of these long-term contract are carried out in a coordinated market context, such as an auction, it allows disclosing the consumers' preferences.

Therefore, the solution are regular auctions where the distributor could procure from DER, a product that could substitute network investments when these are more expensive than the solution provided by DER. As discussed in (MITEI, 2016), forward network capacity options could be the product procured by the distributor and remunerated to DERs. These auctions would solve both the coordination challenge helping overcoming incomplete information and would provide the necessary long-term signals to network users.

[7] See Burger et al., 2018.

Auctions solve the problem by communicating to network users the marginal cost of forthcoming network expansion (or approximation of the marginal cost for discrete investments) and creating incentives for network users to reveal their willingness to pay for forward options to use network capacity. With sufficient lead-time to make investments based on auction results, the network utility would request demand bids for forward network capacity options contracts for each area of the network that is experiencing congestion or expected to experience congestion in the near-future — i.e., if the network capacity margin has become small. Each bid would reflect a quantity of network capacity (in kW) and a price (in $/kW-yr) reflecting the network user's willingness to pay for the option to use that quantity of capacity during periods of congestion. DERs would commit to a firm call option which network utilities can exercise at periods of network congestion, up to the contracted firm capacity quantity.

By opening up such opportunities and allowing third party providers to provide services to a DNO through contractual arrangements, potentially spanning multiple years, benefits can be realized by project developers, the relevant DNO and the system as a whole.

*Another relevant driver for these distributed auctions*

Economies of scale still matter for distributed resources. Distributed resources (such as solar PV or batteries) can be deployed at multiple scales (e.g. IFM or BTM), incremental costs associated with failing to exhaust economies of unit scale can outweigh the specific locational value of BTM. This can result in an opportunity cost, making BTM deployment of these resources inefficient. Mechanisms coordinated by the DSO that anticipate these potential situations would offer consumer deals that maximize their benefit.

## 4.3 The challenge of designing the distributed auctions

Designing these tendering mechanisms that would provide access to longer-term commitments associated to long-term distribution planning and that would send long-term is a not so explored topic today.

In these auctions, called and coordinated by the distribution system operator (DSO), wires and non-wires alternatives (NWA) would participate playing an active role in the long-term distribution planning. These auctions would have to promote competitive procurement of well-designed products to be provided by network users or other 3rd-parties (who, as mentioned above, will be the owners of these distributed resources).

There are two aspects of this type of mechanism that are particularly challenging and are further analyzed within the section:

- First, and foremost, the definition of the product to be procured by the distributor. It is necessary to first identify the design elements of such product and then explore how the different alternatives can affect results and welfare.
- Second, the definition of a methodology to compare the value and reliability (or firmness) provided by the different resources in these auctions. Think for example in how to compare

resources as different as a wire, a base-load demand that offers to be curtailed, a PV panel and a storage facility that is going to be also selling/buying energy in the wholesale market.

***Definition of the products***

The definition of the products to be procured from third party providers as an alternative to traditional wire alternatives seems to be one of the cornerstones of the mechanism and a fundamental line of research. Some of the more relevant design elements of these NWA products to be considered include:

- Availability required to potential non-wires alternatives (NWA): whether resources providing NWA services should be available at all times or only during predefined periods or specific time windows. This also raises the complexity of comparing different resources with different availabilities (where no resource is going to be able to be as available as a wire alternative).
- Limits on the amount of energy that can be requested: the energy to be delivered by the NWA resource could be limited. These limits could come in the form of a maximum continuous delivery (e.g. a limit of 4 hours of continued production), or/and a maximum number of hours during the year (as a way of example, today, in the context of DR programs, DR is typically available only for limited hours in a year (e.g., <100 hrs)).
- The possibility of embedding a financial contract commitment: if the objective is to offer the same "product" as a wire alternative, the NWA will also need to put forward a financial contract commitment, for the wire alternative allows importing (or exporting) a certain amount of energy at the price of the connected node.
- Notification time: the lead time to provide the service (one day, some hours or real time). Linked to this design element, it is also relevant to establish whether the activation should be automatic or manual.
- Penalties: which the penalty for non-delivery would be.
- The firm supply of the resource: which represent an upper limit on the amount of the product each unit is "reasonably" capable to provide. This firm supply limit is use in order reduce the risk of non-compliance. The concept is analogous to that of firm supply in capacity markets.

Also associated to the product defined, the DSO will have to decide the quantity of the product to be procured. This quantity is obviously going to depend on the characteristics of the product.

In addition, another open question is how to account for the possibility of procuring different products with different commitments. This would entail the distributor defining requirements for each type of product, and the relative (substitution) value of one type of product with respect to others.

***Defining the firm supply of the potential providers of the product***

When the objective is to avoid network investment, defining the firm supply (the expected contribution) of any resource is a complex undertaking. The reason why is because it depends on to what extent the resource is first available and second coincident with the distribution equipment peak. The firm supply are project specific inputs. Three major DER categories can be considered: i) baseload, ii) variable (or intermittent) and iii) dispatchable (generation or load).

From the categories above, the real challenge is to determine the parameters for the dispatchable type. In particular, the highest complexity stems from the fact that both the derating factor and the coincident factor will depend on how we define the product. For example, if the penalty for not reducing the peak is high, then the likelihood of the resource being available when needed will clearly increase, since the owner will manage the resource to avoid the penalty. But at the same time, obtaining this enhanced response will reduce the value that the resource will be able to capture in the wholesale markets (what in the end will increase the bid and the associated cost).

*Introducing the value of optionality*

Risk is an additional dimension that complicates the task of comparing different alternatives, and in particular of setting the price the distributor would be willing to pay for non-wires alternatives.

It is work mentioning that most network investments are long-lived, capital intensive assets. Once a network investment is made, its costs are almost entirely sunk. This increases the risks of taking action amidst uncertainty and incomplete information with only network users' historical patterns of behavior to inform network investment decisions.

The key driver of network upgrades is the stochastic evolution of load throughout the network. While network upgrades are bulky and irreversible investments, DER (such as batteries) are scalable and reversible investments. Absent a scalable and reversible technology, the need to assure access forces investments to be made which are often oversized and sometimes ex post regrettable. Availability of DER as NWA enables investments to be better scaled and more successfully targeted to where they are needed.

This flexibility is known in capital planning as *optionality*. Quantifying optionality value has been identified in the NY Storage Roadmap (NYSERDA, 2018) as a major objective, particularly in the context of the NWA projects. However, as pointed out in the Roadmap:

> *"currently, New York's regulatory benefit-cost analysis (BCA) framework relies upon deterministic net present value (NPV) calculations that ignore optionality and forecast uncertainty. Projects that appear to be higher cost on a deterministic basis may be the lower-cost option when risk and uncertainty of future conditions are accounted for. As a result, many projects that could benefit both utilities and ratepayers may not be selected because they cannot pass existing deterministic BCA tests. By contrast, real option analysis incorporates uncertainty by calculating the value of optionality under a variety of circumstances and considers the additional information available after an investment has been made. Real option analysis does not replace NPV, but rather augments NPV in situations where 1) the NPV is close to zero; 2) an investment is flexible (i.e., multi-use, modular, and/or mobile); or 3) information about the future is uncertain."*

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