FLEXIBLE NETWORK ACCESS, LOCAL FLEXIBILITY MARKET MECHANISMS, AND COST-REFLECTIVE TARIFFS: THREE REGULATORY TOOLS TO FOSTER DECARBONIZED ELECTRICITY NETWORKS

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A carbon-neutral power system based on renewable generation will require tremendous investment in electricity networks if demand flexibility and storage are not efficiently developed to compensate renewable variability locally. The decarbonization of the energy system with the electrification of transport through electric vehicles, and the heating and cooling of buildings with heat pumps, and the reduction of stationary battery costs offer new distributed flexibility opportunities. Network regulation should be adapted to promote the adoption of those flexible resources by end users and their use by network operators, mainly at distribution level, in day-by-day operations and when planning network reinforcement and expansion. This article discusses three regulatory tools that can be used for this purpose: flexible network access, local flexibility market mechanisms, and cost-reflective tariffs.

Flexible network access

Conventionally, grid operators have granted network access on a firm basis to both consumers and generators. Thus, network users were entitled to inject or withdraw as much energy to and from the grid as they wanted, provided that they did not surpass the maximum capacity allocated. This capacity, in some cases, presents a time-of-use differentiation in order to account for the varying loading conditions of the grid. For instance, consumers in Spain, as of January 2021, will all be entitled to contract a different capacity in each tariff time period. The number of periods will be two for smaller low-voltage consumers (below 15 kW), and up to six for larger low-voltage consumers and all consumers connected to higher voltage levels.

The main benefit of firm access is its simplicity, as it eliminates the need for real-time management of injections and withdrawals. However, firm access may result in an inefficient capacity allocation and/or inefficient grid expansion, as grid operators tend to follow excessively conservative criteria. As a result, some network components are only used at their rated values for a few hours of the year, if ever. Additionally, the need to provide new users with firm network access often results in denial of the right to connect to the network due to lack of firm hosting capacity.

With the growing penetration of intermittent generation, ensuring a swift and efficient grid-access process is becoming central. In this context, non-firm or flexible network access is gaining interest as a means to attain an expeditious grid connection of large shares of renewables.

Under these flexible grid-connection agreements, grid operators would relax some of the previous access criteria on condition that they are granted the ability to manage the end user's feed-in and consumption during grid operation. In exchange, these users may be offered an agreed remuneration, reduced connection charges, a faster grid connection, or simply the right to connect instead of a rejection.

The compensation mechanism would depend on existing regulation, particularly regarding connection charges – that is, the one-off payments new users make at the time of connection. Two main approaches exist: deep charges include the direct cost of connection as well as the cost of reinforcing the network to accommodate the new capacity, whilst shallow charges only include the direct connection costs. Under deep connection charges, flexible network access would directly benefit new users by reducing the need for network reinforcements. Nonetheless, flexible access, when it is the most efficient alternative, would always yield benefits to the system as a whole; hence, appropriate compensation mechanisms need to be defined in each case.

For example, the British regulator Ofgem (the Office of Gas and Electricity Markets), as part of the so-called Significant Code Review, has proposed several amendments to the regulation of network access where flexible access plays a central role. Therein, three different flexible access types are defined:

- Shared access – different users can share access rights (capacity) on condition that they coordinate to ensure that the limits set out in their shared access rights are not exceeded.
- Static time-profiled non-firm access – access rights vary over fixed time intervals (half-hourly, daily, weekly, monthly, seasonally), potentially following an 'on-peak and off-peak' access right.
- Dynamic time-profiled non-firm access – access limits vary over time depending on network conditions or specific events, for example when wind generation exceeds a certain threshold.

The options considered by Ofgem include the possibility that new grid users may have some freedom to choose the level of firmness and the risk of generation or load curtailment, benefiting themselves and, in the long term, increasing system efficiency.

Local flexibility market mechanisms

Traditionally, DSOs (distribution system operators) do not consider flexibility services provided by third parties – for example, generators, consumers, or storage operators – when planning new network reinforcements to reduce network incremental costs. In the future, these services would be procured through so-called local flexibility market mechanisms, such as long-term auctions, short-term markets, bilateral contracts, and regulated payments. This change in paradigm is particularly promoted by the Clean Energy Package for all Europeans in Article 32 of the Directive for the Internal Market in Electricity (Recast), which states that DSOs shall procure services in a market-based manner from resources such as distributed generation, demand response, or storage, as an alternative to system grid expansion.

Local flexibility market mechanisms are already being implemented in different European countries, such as the United Kingdom, Germany, the Netherlands, Sweden, and Norway. Moreover, several Horizon 2020 European research projects – InteGrid, EUniversal, CoordiNet, and INTERRFACE, among others – are also exploring different design alternatives. Some local market platforms in operation – Piclo Flex, Enera, GOPACS, and NODES – are demonstrating the possibilities of new business models in this area. While Piclo Flex is a market platform which enables DSOs to procure long-term flexibility commitments, the latter three platforms are focused on daily flexibility products to solve network congestions.

Some key challenges related to the design and implementation of local flexibility market mechanisms discussed below are (1) whether regulation enables DSOs to procure flexibility services when and where this is more efficient, (2) standardization of flexibility products, (3) feasibility of aggregation, (4) network topologies and potential competition, and (5) the level of coordination needed between TSOs (transmission system operators) and DSOs.

A first challenge for flexibility markets is knowing when and where flexibility might be needed. Distribution networks generally operate well below their rated capacity most of the year. However, the situation can be very different locally – for example, due to a large concentration of renewable projects. Moreover, grid expansion can be very difficult in some places, such as protected areas, due to environmental restrictions, or in city centres. In these situations, long-term flexibility contracts can be very helpful. These would be activated in day-by-day operation as needed. However, when and where this may happen is not easy to generalize. Therefore, DSO revenue regulation should be flexible and enable DSOs to engage in such contracts under similar conditions as traditional network investment when it is more economically efficient to do so. Moreover, regulation should consider that managing local flexibilities comes at a cost, as DSOs need to invest in order to increase monitoring and control capabilities and acquire forecasting tools, and they rely on third-party providers that should be reliable and available to provide the service when required. Finally, the contracting, administration, and settlement of those services require new capacity building.

The recent European regulation mandates standardization of flexibility products to be used under market-based rules by DSOs on a daily basis as TSOs do today. This is a challenge under the current European electricity market design, which is organized in bidding zones, generally one per country. Local congestions within a zone, be it in transmission or in distribution, are thus not captured by market prices. TSOs use a wide range of flexibility mechanisms to manage network constraints within each zone, including market-based or cost-based regulated redispatch of flexible resources. However, DSOs solve congestions only occasionally, when detected, mostly based on emergency procedures to disconnect loads or by curtailing generation.

At distribution level there are many, but generally small, flexible units. Individually, they have a limited impact on the network. Thus, aggregation is key to enable efficient management of those resources. However, this is a new business model that still has to prove its feasibility. In addition, a level playing field for competition between independent aggregators and conventional retailers is yet to be developed in many European countries, as required by the new European regulation.

Conventional retailers can also perform aggregation in competition with independent aggregators. The latter may focus solely on the provision of flexibility services and may not perform other functions that retailers do, such as energy trading in the wholesale market. Transparent methodologies should be established to avoid retailers creating barriers for independent aggregators, such as disproportionate compensation for energy imbalances when aggregators activate flexibility from retailers' customers.

The radial network topology and scarcity of flexibility resources in some distribution networks may limit competition and the potential application of market-based mechanisms to solve congestions. In this case, the dispatch of flexibility resources previously auctioned or contracted at regulated prices can be the only feasible solution.

Another key aspect to unlock the potential contribution of flexibility resources connected at distribution is to establish coherent market mechanisms properly coordinated between TSOs and DSOs. Those resources, especially those connected to the medium- and high-voltage distribution grids, may provide flexibility not only to solve congestion at distribution but also to help keep the system balance or solve congestion at transmission, services that are the responsibility of TSOs. That would require coordination on how the sequence of markets is organized, and how both operators transmit information and take decisions on specifically designed platforms.

Cost-reflective network tariffs

Network tariffs should not only recover the allowed network costs determined by the regulator, but also promote efficient use of the grid in the short and long term. In decarbonized and decentralized power systems, properly designed network tariffs become essential to promote efficient behaviour by network users. However, current network tariffs generally focus mostly on cost recovery. Thus, tariff design ought to be revised to enhance cost-reflectivity.

In the short term, energy locational marginal prices that reflect grid losses and congestion marginal costs are deemed the first-best tool. In the long term, the main goal is to reduce incremental network costs through cost-reflective tariffs that allocate incremental costs to the users that stress the network in the periods of maximum utilization. The Massachusetts Institute of Technology study *Utility of the Future* proposed a forward-looking peak coincident network charge as a first approach to allocate the long-run incremental network costs. Under this scheme, every network user is charged based on its contribution to the peak of the network elements that are close to their rated capacity. This method would result in differentiated tariffs for each node of the system and time period.

The remaining network costs that do not depend on the peak conditions, known as residual costs, would be met through fixed charges (€/customer) in order not to distort efficient energy prices or cost-reflective peak coincident charges. Fixed charges also make it possible to address equity issues by differentiating between customer categories. Despite other alternatives, for instance, Great Britain's Ofgem has proposed to recover residual network costs through a fixed charge for domestic customers depending on the aggregated net consumption of each customer category.

Today network tariffs are quite far from this ideal first-best efficiency benchmark. Many countries in Europe still apply constant volumetric charges for network cost recovery, assuming tariffs essentially as an instrument to collect costs from passive consumers. Other countries, like Spain, Italy, and the Netherlands, moving towards a more cost-reflective design, already charge a high percentage of the total network costs depending on the consumer contracted capacity or the maximum metered demand.

Digitalization provides opportunities to continue moving in the right direction by designing more granular and cost-reflective tariffs. For instance, smart meters allow the introduction of dynamic tariffs indexed to the periods of maximum network utilization. Those flexible consumers capable of reacting to these tariffs could manage their loads intelligently, on their own or through contracts with aggregators, for the benefit of themselves and the system. On the other hand, passive consumers could opt for a simple and easy-to-understand tariff alternative, hedging them from the tariff variability that would be financially managed by their retailers.

Discussion

Promoting efficient use of the electricity network and minimizing incremental costs are becoming increasingly relevant in the transition towards decarbonized and decentralized power systems. The three regulatory mechanisms discussed in this article show substantial promise. Nonetheless, their practical implementation faces some trade-offs and synergies that ought to be considered.

Non-firm network access can reduce overall system costs by reducing the need for reinforcements driven by individual new users. The benefit perceived by these users depends on the design of the connection charges; under deep connection charges, they can directly reduce their one-off payments, whereas under shallow connection charges, they could mainly benefit from a faster connection or direct compensation.

The management of flexibility provided by users under non-firm access contracts should be coordinated with other mechanisms. A non-firm access agreement would in principle only apply to new network users. Forcing it on existing users (who currently have firm grid access) would be possible, but could have legal implications. It could be offered to existing users as an option; but whenever possible, this should be accomplished through market mechanisms.

For these reasons, non-firm access agreements may not be enough to prevent network congestion or costly reinforcements in some areas. Therefore, a natural complementarity arises between non-firm access agreements and flexibility markets. What is more, in areas with a high number of grid connection applications, non-firm access contracts may be awarded through local market mechanisms.

Likewise, implementing cost-reflective dynamic network tariffs presents trade-offs related to time granularity and tariff predictability. Truly dynamic network tariffs based on peak coincident charges can change from one day to the next in order to reflect the stress level and changing periods of maximum grid utilization. On the other hand, if time-block durations and charges are known in advance and remain stable, for instance for the next year, that would facilitate flexible consumer reactions and sound decisions about investment in flexibility resources. Therefore, in practice, implementing dynamic network tariffs could require a combination of both approaches, pre-defining some periods of maximum utilization throughout the year together with day-ahead short notice for those events that are not easily anticipated.

Traditionally, network tariffs have presented limited geographical granularity, too. In some countries (like Italy, France, and Spain), national tariffs are exclusively differentiated by voltage levels, whereas others (like the UK, the Netherlands, and Sweden) impose distinct network tariffs by region or DSO area. Nonetheless, like with time granularity, the level of utilization of network assets and the contribution of consumers to that use may also change per location, as well as whether they inject or consume power to/from the grid.

Fully reflecting grid utilization would eventually lead to individualized network tariffs, which are naturally impractical. Thus, a trade-off must be reached by selecting network areas that are large enough that the level of utilization may be consistent in time and calculating the tariffs for those areas with an adequate level of time segmentation. These would be charged to the consumers connected to them. Again, this practical criterion for designing network tariffs in large areas of the system may be complemented with local flexibility mechanisms designed ad-hoc for dealing with congestion problems that mainly affect specific network components located within those larger areas. Likewise, flexibility mechanisms can be implemented to introduce geographical discrimination in countries where legislation hampers doing so in the network tariffs.

Local flexibility market mechanisms can be another option to deal with potential grid congestions that are difficult to manage under cost-reflective dynamic tariffs. Here the suitability of one option or the other may depend on how extended the required customer reaction should be. For instance, system-wide reactions, caused for example by a heat wave, are better achieved by broadcasting high network tariffs for the following day during peak-use hours, while more local resources to solve specific network congestions, which occur at different times and locations, can be better mobilized under local flexibility markets.

Finally, a key difference between dynamic tariffs and flexibility market mechanisms (or flexible access contracts), is that the former rely on the uncertain reaction of potentially responsive network users, whereas the latter force flexibility providers to commit to providing the service in response to the grid operator’s command. In fact, in some cases, this response may be automatic. Hence, the last type of mechanism enables network operators to rely on flexibility for actively managing the network in daily grid operations, and to avoid grid reinforcements when planning the expansion of the grid.

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