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Modernization of the Peruvian electricity system

Pillar 3: Innovation in distribution and retail

Final deliverable
Best practices and Recommendations

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This document is the final deliverable corresponding to the "Pillar 3: Innovation in distribution and retail", within the context of the "Modernization of the Peruvian electricity system" project.

This report is part of a White Paper commissioned by the CRSE of Peru describing the details of the proposals and the necessary actions for transitioning to the new electricity sector regulatory and institutional framework.

The White Paper develops the conceptual models/frameworks of the four thematic lines that will serve as (recommended) inputs to the consulting group/firm that will be in charge of the full white book report, to be engaged later.

The third pillar is focussed on "Innovation in distribution and retail": The challenges posed by the incorporation of renewable energies and other distributed resources, the improvement of service quality and the expansion of coverage make it necessary to identify and develop a new model of economic regulation for electricity distribution, as well as the redesign of the Peruvian retail market, the independent development of the retail (supply) activity, and the potential active role of customers/consumers as prosumers.

This final report herein analyses the Peruvian context and taking as background the best practices stemming from the revised international experiences in the first report (which can be found below this final report), recommends the conceptual models and regulatory proposals to be developed in detail and further implemented under this reform.

This document has been elaborated by the authors from the Institute for Research in Technology of Universidad Pontificia Comillas for The World Bank Group.

Executive summary

The objective of this final deliverable is to provide the conceptual models and regulatory proposals related to innovation in distribution and retail for the Peruvian reform.

These recommendations are based on the best practices identified from the revision of international experiences in the first deliverable (which can be found below this final report), and starting from the current context in Peru propose gradual changes, some of them to be implemented in the short-term, while others in future stages, after gaining experience with the new models.

Restructuring distribution activities

The decentralization of the power sector is a central element of the energy transition and it entails both challenges and opportunities for the distribution sector and distributed energy resources (DERs). There is a total consensus about the necessity to reform the regulation according to this new reality, redefining the role of distribution companies in this new paradigm. These latter must become active Distribution System Operators (DSOs), they will have to actively manage the grid and interact with DERs, serving also as a neutral facilitator of market-based solutions provided by DERs.

This new role must be achieved by distributors in Peru, starting from a regulatory condition where distribution companies also act as retailers (mostly for regulated consumers). In order to ease this change of paradigm at the distribution level, there are several overarching regulatory recommendations as regards distribution activities regulation, in particular recommended for those distributors with more than 50,000 consumers.

Unbundling of distribution and retail

The first recommendation is centered on the need to restructure and supervise distribution activities, particularly the convenience to unbundle the network operation and retail activities. The textbook ideal restructuring consisting of ownership unbundling between distribution and retail is not a feasible option in many jurisdictions around the world, neither in Peru. Therefore, legal and functional separation with strict supervisory rules is recommended to be implemented gradually in stages, according to the proposed reform of the wholesale market, and the recommendations provided below.

Unbundling of distribution and distributed energy resources/storage /electric vehicle charging installations

The second recommendation is about the incompatibility of the new DSO functions with the ownership of distributed resources, such as distributed generation or storage. Based on best practices of vertical separation, it is recommended that ownership, development, management or operation of energy distributed resources, storage or electric vehicle charging installations by distribution companies should be forbidden.

Some exemptions subject to strict regulatory approval could be considered. For instance, if facilities are integrated within the network components, or the case where there is a study clearly showing the convenience of relying on distributed resources to fulfill the distributor's obligations and after a tendering procedure no other parties have been awarded.

Another potential exemption, to be assessed by OSINERGMIN could apply to those distributed generation resources that are owned by the distribution company before the implementation of the reform. Although solutions based on the requirements established in Europe for legal and functional unbundling of DSOs are the first-best alternative, depending on the relative importance of those generation assets it could be considered exempting them from these unbundling requirements.

In the context of integration of distributed resources, the pre-published Peruvian regulation on distributed generators needs deeper analysis and reconsideration of some issues. First, the definition of network incremental costs needs to be clarified distinguishing between shallow and deep costs. Second, the economic compensation for surpluses from micro distributed generation should be reconsidered avoiding net-metering practices. Third, information disclosed by the distributor about available capacity in the network should be recommended. Finally, an explicit prohibition to granting any discriminatory treatment to any distributed generation should be more clearly mandated.

Data management

Within the new roles and responsibilities that need to be carried out by the distribution companies, the management of consumption data that would be produced by smart metering systems is a key element that should be conveniently regulated. In this regard, it is proposed to implement a decentralized model for data management under the responsibility of the distribution companies with standardized data formats and information exchange procedures approved by OSINERGMIN. In a second stage, it could be considered moving to a fully centralized model, where all key aspects of data management would be centralized through the use of a data hub. This change would depend on a cost-benefit analysis and also on the gained experience.

Transparency and information to stakeholders

Another function of DSOs to be adequately regulated is the need to increase transparency and publish, among others, information about hosting capacity. It is recommended to impose the obligation for distribution companies to publish the hosting capacity maps in their networks together with submitting to public consultation their network investment plans.

Flexibility services

With the increasing penetration of distributed resources, distribution companies may acquire flexibility from these resources to manage and plan their networks more efficiently. An initial stage of experimentation guided by OSINERGMIN is recommended to implement some local flexibility platforms based on long-term auctions to acquire flexibility services by distribution companies.

Finally, in this context of distributed resources providing network and system services, the coordination between COES and distribution companies, as network operators, should be reinforced and ensured by appropriate detailed regulation. In this sense, the draft regulation on distributed generators goes in the right direction.

Advanced metering infrastructure

Distribution companies in Peru are at an incipient stage of advanced meter infrastructure deployment. The Supreme Decree 018 2016 EM established the obligation for distribution companies to present an AMI 8-year rollout plan to OSINERGMIN. Under this regulation, meters are owned by the distribution companies and their cost is included in the distribution tariff (VAD).

Cost-benefit analysis as a key decision-making tool for the implementation plan

Best international practices recommend that a cost-benefit analysis should be carried out not in a go/no-go format for a 100% rollout of smart meters, but rather via a customer categorization that allows presenting some sort of menu of investments, each one with its net present value.

The first category of AMI benefits includes, among others, improved quality of service, through an enhanced outage detection and management; reduction of non-technical losses, through a more efficient detection of meter tampering and energy theft, and better customer services, since the remote meter reading and the automated billing reduces the number of errors. As regards these operational savings, the best customer categorization may be based on the classical division according to voltage levels, distribution urban/rural areas and load consumption levels.

As regards the second category of AMI benefits related to demand activation, the categorization of customers should be based on their potential for activation of flexibility, screening for final energy uses which can provide the largest benefits.

Cost-benefit analyses must be repeated over a certain number of years, in order to take a picture of the new reality and the new forecasts and to widen the rollout to new consumer categories.

In Peru, a nationwide AMI cost-benefit analysis should be elaborated to identify those customers who should have an advanced meter installed; this would be used to define targets for each distribution company, which could then present the rollout plan to OSINERGMIN.

AMI functionalities

The already specified list of AMI functionalities by OSINERGMIN is well aligned with international standards; these functionalities must be fulfilled for all customer categories in order to guarantee interoperability. Interoperability encompasses, among other issues, the standardization of the equipment, the communication protocol, and the data format and management. Interoperability guarantees smoother communication among all the actors involved in the process, higher competition among technology manufacturers and lower prices, and it ensures the same conditions to all final customers.

AMI ownership and cost recovery

The Peruvian regulation assigns the ownership of the smart meter to the distribution company in charge of installing it; this approach is supported by international experiences. As in the previous framework, the meter was owned by the customer, specific solutions may be required to compensate for recently replaced meters or low-income customers.

Encompassing the expenditures on AMI in the remuneration of the distribution activity is the recommended alternative for Peru; however, the distribution remuneration methodology must be reformed, as it is proposed below.

Distributional impacts

Finally, AMI deployment and the integration of demand response in the market may have distributional impacts. Some specific customer segments, as low-income consumers, may not be able to tap all the benefits stemming from the new data, although they are asked to cover part of the costs. These distributional impacts must be forecasted and addressed in the rollout program (e.g., through specific engagement strategies that consider some sort of economic aid); otherwise, they may provoke the rejection of AMI from these customer segments.

Distribution activity revenue setting

Diagnosis of the current framework

The current VAD scheme used in Peru to remunerate distribution activities is not able to provide network companies with adequate incentives to support decarbonization, deliver adequate grid investments, use new distributed resources efficiently, foster innovation, and provide value to current and future consumers.

The computation of the VAD involves the calculation of the annuity of the VNR[1] that implicitly entails that the Regulatory Asset Base (RAB) is reopened and reassessed at the end of each regulatory period by means of a greenfield type model and considering efficient costs. This approach has provided reasonable results up to date, but it is not well-suited for the new changing and more uncertain context. That would extremely increase risk exposure to DSOs.

In addition, the low quality of electricity service provided by state-owned distribution companies, facing institutional and governance problems as it is analyzed in Pillar1, mainly in rural areas, became a major concern as their assets run down, and improving the quality of service of these companies is a priority today for the electricity sector.

It is assumed the pre-condition that a framework is in place for state-owned companies that: (i) permits them to access resources to finance new investments, and (ii) allows them to perceive and respond to incentives in a similar fashion as private companies would do. Therefore, the proposed framework would be the same for state-owned and private companies.

The proposed conceptual framework: building-blocks (CAPEX + OPEX)

The recommended remuneration framework for distribution activities is based on a building-block approach (CAPEX+OPEX) with a revenue cap mechanism. CAPEX remuneration is based on ex-ante allowances based on investment plans submitted by distribution companies at the beginning of each regulatory period, and the calculation of the consolidated Regulatory Asset Base (RAB) at the end of each regulatory period. In this way, distribution companies have certainty on the recovery of acknowledged investments.

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[1] Valor Nuevo de Remplazo (New replacement value)

CAPEX remuneration

In particular, the remuneration formula for CAPEX starts with an ex-ante estimation of allowances based on the investment plan submitted by the company and the efficiency scrutiny issued by the regulator. The ex-ante CAPEX revenue allowances are computed as a weighted average of both, the distribution and the regulator investment estimates. At the end of the regulatory period, an ex-post CAPEX revenue correction takes place according to a profit-sharing menu of contracts that incentivizes both the efficiency in the execution of the plan and also to submit accurate investment forecasts. The ex-post correction is computed according to the actual CAPEX expenditures and the ratio of the distribution company/regulator estimates calculated at the beginning of the regulatory period following the outcome of the "menu of contracts matrix".

To change the remuneration framework from VNR to RAB, the calculation of the opening RAB at the outset of the reform is required. This is known as "the legacy RAB". It is recommended to use the so-called "implicit RAB" method for the calculation of the legacy RAB. The implicit RAB is a very simple alternative that prioritizes revenue stability. The methodology computes the RAB that ends up providing a similar CAPEX-based remuneration to the one the company perceived in the previous scheme, i.e. the one "implicit" in the remuneration received in previous years. This approach mitigates sudden changes in the tariffs and its calculation does not require extensive input data or modeling studies. This approach has been also compared to other that computes the legacy RAB as the annuity of the VNR corresponding to the existing assets, this value would be frozen as the CAPEX remuneration paid to distribution companies for pre-existing assets throughout the whole operating life of these assets. Despite its simplicity, this latter approach is not recommended for several drawbacks, as it would result in an ever increasing RAB in the detriment of rate payers, and it could create a perverse incentive to keep obsolete and inefficient network components under operation.

OPEX remuneration

On the other hand, the OPEX remuneration formula consists basically of a standard RPI-X scheme with no ex-post corrections. The efficiency requirements for controllable OPEX associated with the RPI-X, would be determined through benchmarking studies at the beginning of each regulatory period that would seek long-term efficiency gains.

Incentives for improving quality of supply and energy losses and implementing innovation projects

Incentives to improve quality of supply indicators (SAIDI and SAIFI) and energy losses are also recommended within the remuneration formula. A bonus-malus scheme is recommended. The incentive rate for quality of supply should be adequately set by reflecting both the true value for network users and the incremental distribution costs of improving network reliability.

The proposal of reform also includes the acknowledgement of specific innovation projects submitted by distribution companies with previous regulatory approval. They would be added to the RAB with no further efficiency requirements and awarded with a higher return. It is recommended also that the allocation of these incentives be done by the regulator under competitive calls.

A TOTEX approach for further implementation

Thinking in the long-term, and for instance, after having at least two regulatory periods of experimentation with the recommended building-block approach (CAPEX+OPEX), it is advisable to consider the possibility of migrating to a more advanced approach based on TOTEX. This approach would provide more equalized incentives to innovation by distribution companies, exploiting the potential trade-offs between both types of expenditures, for instance, by introducing flexibility markets to defer or avoid grid investments or signing non-firm connection agreements to mitigate the impact of connecting large volumes of DER to the grid.

A future-proof tariff design

Diagnosis of the current situation

Peru's electricity tariff regime is designed to recover the full costs of each of the three segments: generation, transmission, and distribution. The formation of electricity prices for the end-user is made up of the addition of these three components, each of which presenting a different methodology to allocate its costs. On top of these components, there are also cross-subsidies among consumers.

In subsection 4.1 it is reviewed how there are currently some features within the cost allocation methodologies in the tariff in Peru that do not allow sending efficient signals to consumers. In particular, we can highlight the situation with transmission tariffs and with cross-subsidies.

Transmission tariffs, which are regulated and determined by OSINERGMIN, charge their costs to the peak coincident component. In the last decade, these tariffs have been used to allocate the costs corresponding to several policy-driven mechanisms, therefore currently overincentivizing the reduction of peak coincident consumption (in those tariffs options including a capacity charge).

The FOSE is a cross-subsidy playing a central role in Peru. It subsidizes residential consumptions below 100kWh/month, being the reduction even higher for consumptions below 30kWh/month. This is financed through a surcharge in the billing that is applied to the energy, fixed and capacity charges of users with consumptions above 100kWh-month. In a context with increasing penetration levels of distributed generation and more active users, the current design of this subsidy, based on volumetric and capacity-based discounts/surcharges may trigger inefficient responses from consumers.

Proposal: a potential roadmap for tariff design transition

The list of recommendations, ordered according to some sort of rate between their expected benefits and their expected implementation costs in Peru would be the following:

- Remove residual costs from both the volumetric and the capacity components of the tariff and charge these costs through an "uneven" fixed charge, while also accounting for the risk of inefficient grid defection. This would entail, for example, taking out some of the charges of the transmission tariff and allocate them to the fixed charge.
- Redesign the subsidies. Electricity subsidies will definitely continue to be a central element of the Peruvian power system; however, their design mustn't distort the economic signals conveyed by electricity tariffs. In order to avoid that subsidies distort the economic signals conveyed by an efficient electricity tariff, the recommended approach would be to allocate the

subsidy by means of a fixed component in the tariff. Therefore, the resulting fixed charge in the tariff would be additive and would involve two components: a positive residual cost component and a negative (for the subsidized consumers) subsidy component.

- Avoid net metering policies for MCG (micro distributed generation). The combination of simple volumetric tariffs and net metering policies represents a dangerous and difficult-to-control cross-subsidy between consumers that should be avoided.
- Make prices and charges for electricity services non-discriminatory and technology-neutral.
- Introduce flexible access options to the network and consider shallow charges for small distributed generation.

Once smart meters are installed, further refinements are possible. With smart meters, tariff signals should try to capture and reflect the marginal or incremental costs of the production and utilization of electricity services. This involves increasing the time and locational granularity of signals:

- Expose regulated customers to time-varying energy prices. In this respect, two periods do not seem to be enough to unfold the potential response of some distributed energy resources (such as storage). At least three or four periods would be advisable, with the long-term objective of providing hourly signals.
- Apply coincidental peak capacity charges for network investments to residential consumers. The coincidental peak capacity also calls for the right time granularity in the definition of the capacity charge periods.
- Consider the application of nodal prices to price-responsive demand and DERs in general.

Retail market

The creation of a retail market is seen as the final step of the Peruvian power sector liberalization. In theory, an efficient retail market may result in lower tariffs for consumers and increase the competition in the wholesale market. Nevertheless, in the light of international experience, we recommend putting into question the liberalization for some demand segments in Peru (particularly residential ones).

Default tariff design

In any case, it is recommended to keep a sort of default protection for domestic customers, as it has been done in more mature retail markets (as, for instance, the UK or Spain). Default tariffs may hamper the development of the retail market if not properly designed; this is why it is so important that default tariffs are cost-reflective and introduce the least-possible regulatory intervention. A tariff that is subsidized and below market prices represents unfair competition and eventually would end with the retail market.

As regards the energy price signals in the default tariff, it is recommended to contract in advance certain percentages in different timeframes (in the energy auctions), while trying at the same time to convey the short-term market signal as much as possible.

Legacy costs

Legacy costs represent a challenge in the Peruvian context. Long-run marginal costs are decreasing below current market price levels, and more importantly, below prices signed in long-term contracts.

The allocation of legacy costs has to be designed in a way that there is no room for inefficient opportunistic switching to the free market. These new stranded costs should receive the category of residual costs, and should be allocated among all end-users via a consumer-dependent fixed charge based on historical cost causality.

Gradual process

The unbundling of retail activity is not a change that happens overnight. It is indeed a gradual process where different measures would be implemented in different steps:

- The first two measures, calling for an urgent reform are the following:
    a. Unbundling the "free market retail" activity from that of distribution and generation activities.
    b. To fine-tune long-term auctions and their associated cost allocation (the allocation of generation costs in the regulated tariff). This will help to pave the way for the design of a future cost-reflective default tariff, which as commented, would be necessary as a safety net.
- Unbundle the regulated retailer from distribution companies.
- Remove the barriers pointed out in section 5, among which dealing with legacy costs play a major role.
- Progressively liberalize the different demand segments:
    a. First introduce the optionality to choose between the regulated tariff and the free market. Progressively reducing the threshold to be eligible for such choice.
    b. Keeping the default tariff, at least for some years, and remove it for larger users.

Roadmap

Finally, as a way to conclude this study, the most relevant recommendations are briefly listed and classified according to their priority into three groups: short, medium and long-term reforms.

Short-term reforms (<4 years)

Short-term reforms represent the changes that lay the necessary foundations for completing the rest of the reforms afterward. It is noteworthy that these short-term reforms can be implemented before the roll-out of smart meters is carried out.

Medium-term reforms

Medium-term reforms represent measures that have been tested in the international experience, but which at the same time, in order to be implemented, require a series of prior reforms (those mentioned in the previous section)

Long-term reforms

Long-term reforms consist of measures that represent the international best practice to date, but some of them are still in a rather embryonic state.

Within each group, they are sorted within the five topics over which this consultancy has revolved around. The next table summarizes the priority of the different proposals according to this classification.

<table>
<tr><th></th><th>Restructuring distribution</th><th>Advanced metering infrastructure</th><th>Distribution revenue setting</th><th>Tariff redesign</th><th>Retail markets</th></tr>
<tr><td rowspan="4">Short-term (< 4 years)</td><td>Functional & legal unbundling of distribution and retail (>50.000 customers)</td><td>Cost/Benefit analysis by customer categories</td><td rowspan="4">From VAD to building blocks (CAPEX + OPEX)
Key elements:
- Legacy RAB
- Investment plans
- Menu of contracts
- Quality of service</td><td>Redesign residual cost charges</td><td>Well-designed default tariff</td></tr>
<tr><td>Functional & legal unbundling of distribution and DER (DG, Storage, EV charging)</td><td>Deployment plan (functionalities/ interoperability; ownership & cost recovery)</td><td>Redesign subsidies</td><td>Allocate legacy costs based on historical cost causality</td></tr>
<tr><td rowspan="2">Publishing basic hosting capacity maps</td><td rowspan="2">Data management legislation</td><td rowspan="2">Avoid net-metering</td><td>Unbundling of the retail activity to free consumers</td></tr>
<tr><td>Regulate switching procedures</td></tr>
<tr><td rowspan="2">Medium-term (4-8 years)</td><td>Long-term auctions for procuring local flexibility services from DER</td><td rowspan="2">Continue with deployment</td><td rowspan="2"></td><td rowspan="2">More time granular tariffs and market prices</td><td>Expand the retail free market eligibility to other consumer segments</td></tr>
<tr><td>Develop the role of distributor as a market facilitator</td><td>Complete the unbundling of distribution and retail in all segments (both for free and regulated customers)</td></tr>
<tr><td rowspan="3">Long-term (> 8 years)</td><td>Advanced hosting capacity maps</td><td rowspan="3">Evaluate implementation of a data hub</td><td rowspan="3">Moving to a TOTEX approach with gradual capitalization rates</td><td rowspan="3"></td><td rowspan="3">Maintain the default tariff for domestic customers & eliminate it for the rest of customer categories</td></tr>
<tr><td>Short-term local flexibility markets</td></tr>
<tr><td>Real-time coordination between TSO & DSOs</td></tr>
</table>

Figure 1.- Implementation Roadmap

1. Restructuring distribution activities

1.1 Introduction

As it has been discussed in the first report, the decentralization of the power sector is a central element of the energy transition and it entails both challenges and opportunities for the distribution sector and distributed energy resources (DERs). There is a total consensus about the necessity to reform the regulation according to this new reality, redefining the role of distribution companies in this new paradigm. These latter must become active Distribution System Operators (DSOs), to use a concept widely used in the European context. This means that they will have to actively manage the grid and interact with DERs, serving also as a neutral facilitator of market-based solutions provided by DERs.

This new role must be achieved by distributors in Peru, starting from a regulatory condition where distribution companies also act as retailers (mostly for regulated consumers). In order to ease this change of paradigm at the distribution level, there are several overarching regulatory recommendations that need to be addressed as regards distribution activities regulation, in particular for those distributors with more than 50,000 consumers, namely:

- The need to restructure and supervise distribution activities, particularly the convenience to unbundle the network operation and retail activities (subsection 1.3);
- The incompatibility of the new DSO functions with the ownership of distributed resources, such as distributed generation or storage (subsection 1.4);
- The new roles and responsibilities that need to be carried out by the distribution companies, including:
    a. the management of consumption data that may be produced by smart metering systems (subsection 1.5).
    b. the need to increase transparency and publish, among others, information about hosting capacity (subsection 1.6);
    c. the role of the distributor as a market facilitator in local flexibility markets (subsection 1.7);
    d. the need to significantly reinforce the coordination between the operator of the distribution grid and the system operator (subsection 1.8);

Before tackling the proposals as regards these discussions, we first present in the following section the Peruvian background with respect to these topics. In particular, we focus on distribution companies' structure in Peru, unbundling provisions and finally we review the regulatory framework for distributed generation.

1.2 The Peruvian context

Distribution companies in Peru

In Peru, distribution companies carry out the medium and low-voltage network activities and also act as regulated retailers for certain categories of consumers connected to their network. Distributors can also act as retailers for the free market segment, where they compete with generators (which clearly dominate the energy sold in the free market).

In the following figure, it is shown the energy sales (both for the free market and regulated market) of Peruvian distribution companies (see Figure 2).

Empresa	Total	Libre	Regulado	Participación (%)
TOTAL	**47 286 338**	**28 132 783**	**19 153 554**	**100,0**
Generadoras	24 915 445	24 915 445		52,7
Distribuidoras	22 370 893	3 217 338	19 153 554	47,3
Enel Distribución	6 840 147	1 730 265	5 109 882	14,5
Luz del Sur	6 176 809	126 128	6 050 681	13,1
Hidrandina	1 807 730	358 585	1 449 145	3,8
Electronoroeste	1 305 483	361 134	944 349	2,8
Seal	1 045 069	143 969	901 100	2,2
Electrocentro	839 395	5 020	834 374	1,8
Electro Oriente	835 666	84 400	751 266	1,8
Electronorte	748 252	101 594	646 659	1,6
Electro Dunas	720 756	89 642	631 114	1,5
Electro Sur Este	664 629	30 626	634 004	1,4
Electrosur	392 904	38 877	354 027	0,8
Electro Puno	346 981	21 670	325 311	0,7
Electro Ucayali	292 141	3 805	288 336	0,6
Coelvisac	231 286	121 623	109 663	0,5
Electro Tocache	29 146		29 146	0,1
Adinelsa	25 673		25 673	0,1
Chavimochic	24 550		24 550	0,1
Emseusa	16 246		16 246	0,0
Emsemsa	12 602		12 602	0,0
Sersa	10 636		10 636	0,0
Electro Pangoa	3 308		3 308	0,0
Edelsa	1 483		1 483	0,0

Figure 2.- Distribution companies' energy sales (MWh) (both for the regulated and the free market). Source: (OSINERGMIN, 2020)

As shown in the previous figure, the free market moves around 60% of the energy in the country. This 60% represents, however, less than 1% of users (2000 from a total which is around 7.6 million country-wide). Enel Distribución y Luz del Sur own 31% and 28% of total electricity sales, respectively. This is related to the fact that both companies have the concession in Lima[2].

[2] Lima has the largest number of clients, both free and regulated, representing 32% of the national total. As for free users, approximately 50% are located in Lima.

It is also shown below, for future reference, the areas of influence of the different distribution companies (Figure 3)

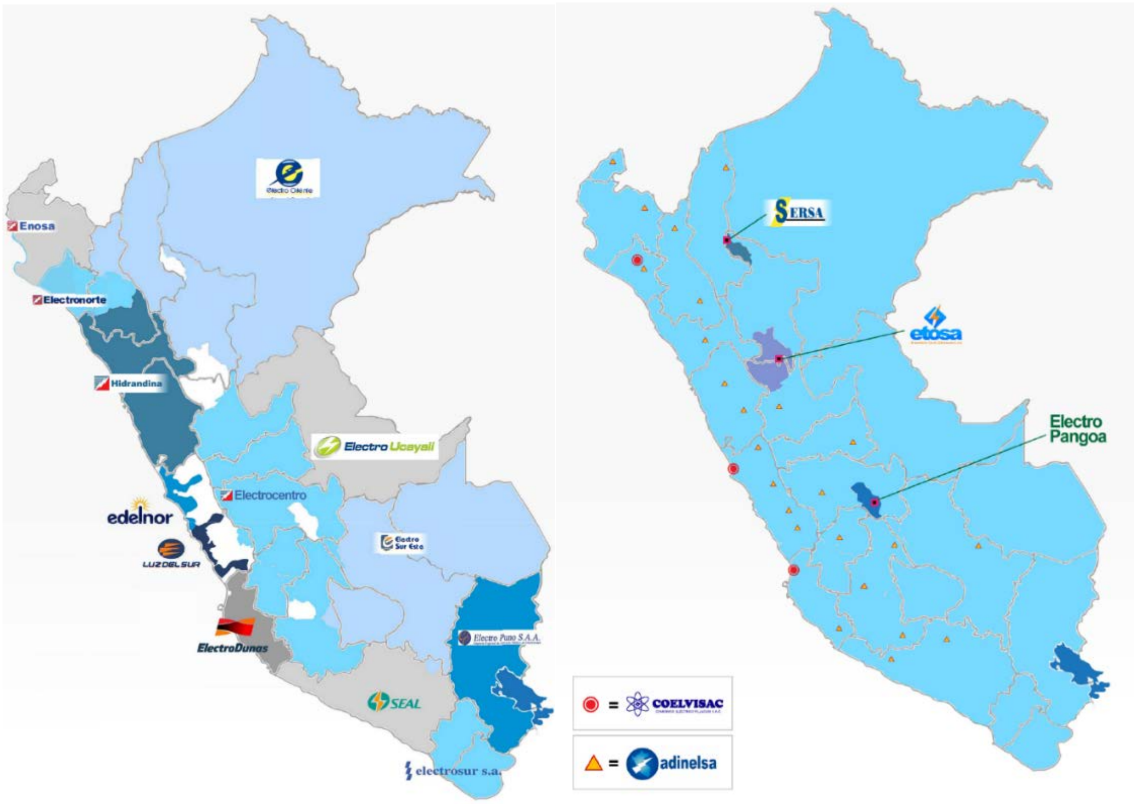

Figure 3.- Distribution companies and their areas of influence (OSINERGMIN, 2016)

Unbundling

The Peruvian regulatory framework establishes the vertical unbundling of electricity generation, transmission and distribution activities. This separation dates back to 1992, in the context of the Electricity Concession Law (LCE). In particular, it is in article 122, where it was stipulated that generation and/or transmission activities in the main electrical system and/or distribution of electric energy, may not be carried out by a single company, holding company or company group, or by any person or company who directly or indirectly exercises control of the former, except as provided in the Law. The unbundling of retail from other activities was not established, however.

Despite this unbundling regulation, reality has shown that these provisions are not free from exceptions. As of today, there are some cases where generation and distribution companies belong to the same group[3]. Likewise, we also find a relevant case where the same company vertically integrates transmission and distribution, this is the situation with Electro Dunas and the ISA group[4].

[3] This is the case with Enel Generation and Enel Distribution, and it is also the case with Luz del Sur and Inland Energy. The market share of all these companies is significant.

[4] Electro Dunas S.A.A. was acquired by ISA group, which is the parent company of Red de Energía del Perú, one of the major transmission owners in Peru.

In Peru, the 1992 Law established the vertical unbundling of electricity generation, transmission and distribution activities. However, the unbundling of retail was not. In practice, there are today some exceptions integrating generation and distribution or transmission and distribution.

The unbundling of distribution from retail is the last step of the unbundling process still to be taken. The intention of stakeholders today is that of following the steps of the Colombian or the Chilean experience. This will be further addressed in section 5.

Distributed generation regulation

In Peru, there is a legal basis for the development of distributed generation. Next, we summarize the most relevant aspects.

The LCE does not explicitly mention distributed generation. It is within the framework of Law No. 28832, the Law to ensure the efficient development of electricity generation, approved in 2006, where distributed generation is first defined as a "generation facility with a capacity no greater than that of indicated in the Regulations, and that is directly connected to the networks of an electricity distribution concessionaire". The Law also establishes that the Regulation will provide conditions for the promotion of efficient distributed generation and cogeneration, and among others, they will consider the following two provisions:

- The sale of its uncontracted surpluses of energy to the short-term market
- The right to use the distribution networks paying only the incremental cost incurred

In Legislative Decree No. 1221, the "Law that improves distribution regulation to promote access to the electricity service in Peru", approved in 2015, it is established the following:

- Users of the public electricity service who have non-conventional renewable electricity generation equipment or cogeneration, up to the maximum power established for each technology, have the right to self-consume or inject their surplus into the distribution system (always subject to not affect the security of the distribution system).
- The maximum capacity, the technical and the regulatory conditions and the definition of the non-conventional renewable technologies that can be considered as distributed generation, among other necessary aspects, are to be established in the specific regulation on distributed generation.

Finally, in 2018, through the Ministry of Energy and Mines (MINEM), the draft for the regulation of distributed generation was pre-published. This is an aspect that has been pending for around a decade.

This Draft Regulation basically defines two types of distributed generation:

- Medium Distributed Generation (MGD), defined as the "facilities with a capacity greater than 200 kW and below 10 MW, which are connected to the medium voltage distribution network"

- Distributed Microgeneration (MCD), defined as the "facilities owned by a user of the public electricity service, which are connected to the distribution network in low or medium voltage. The maximum capacity will correspond to the user's contracted capacity and under no circumstances will this maximum capacity exceed 200 kW".

For the MGD, the regulation defines aspects related to (i) the request for information, (ii) the connection study and the request for approval of the connection study, (iii) the connection and operation agreement, (iv) the network costs and the required tests, (v) the operating conditions, (vi) the commercial and tariff regime and (vii) the energy and firm capacity of the MGD (it should be noted that these requirements are similar to those required for conventional generation).

For the MCD, the regulation is simpler, and only defines aspects related to (i) the request for feasibility and connection study, (ii) the connection and operation agreement and the required tests and (iii) the commercial and tariff operation regime.

The following table summarizes the main features of the current scheme for the two types of distributed generation.

Table 1.- The regulation applying to the two types of distributed generation.

Feature	**MGD** **Medium Distributed Generation**	**MCD** **Micro Distributed Generation**
Capacity	Between 200kW and 10 MW	Below 200kW
Connection to the distribution system	Medium voltage	Low voltage
Connection study	To be carried out by the interested party or by the distributor.	To be carried out by the interested party.
Costs associated with adapting the grid	Incremental. Financed by the interested party.	Incremental. Financed by the interested party.
Selling surpluses in the short-term market	Yes.	No. Surpluses are net-metered with consumption along a year and are compensated as discounts on electricity bills.
Selling surpluses to the regulated market	Yes. They can sell energy contracts to distribution companies. Subject to firm capacity requirements (as other generators).	
Selling surpluses in the free market	Yes. They can sell energy contracts in the free market. Subject to firm capacity requirements (as other generators).	

The current pre-published regulation goes in the right direction in the sense that represents progress in defining the regulatory framework for distributed generation. Nevertheless, there are some key aspects that are not yet addressed in sufficient depth, being the most relevant ones:

- In the matter of the cost associated with adapting the network, it would be advisable to properly define how incremental network costs will be calculated. In this respect, it would be probably worth differentiating between connection costs and upstream reinforcement costs, since the latter would probably need to be allocated among other users of the network too (including, for example, future potential connections requested by other distributed generators).
- It is necessary to precise the way the discounts on the energy bills will be implemented for MCD generation based on their surpluses. In general net-metering compensation schemes are not recommended by regulators and are being removed in Europe. In this way, it is key that the distributed generation regulation is accompanied by a tariff redesign. Self-consumption development can actually become a serious problem for the system if it is not accompanied by a design that is in line with that off presented in section 4.
- The information the DSO would need to disclose. This is further discussed below, in section 1.6.
- The provisions to avoid conflicts of interest (derived from the possibility of distributed generation selling contracts to distributors for their regulated consumption). This is discussed in sections 1.3 and 1.4. The regulation would need to clearly state an express prohibition of the electricity distribution company, granting a differentiated or discriminatory treatment to any distributed generator.
- Finally, the regulation does not solve a major problem today with distributed generation. Generation embedded in distribution networks is an activity that currently exists in Peru. These generators often sell their electricity to the distribution company via contracts (often these generators are owned by the same distribution company). The problem is that while the distribution company collects all the charges from its users and transfers them to the generators with whom they have contracts, these generators may not always transfer the full amount collected through these charges to the transmission owners[5].

[5] According to the knowledge of the authors, this was like that because these transfers occur only with members of the COES, and not all the distributed generators were part of the COES (only those above 10 MWs, which is precisely the upper bound to be considered MGD)

In Peru, the pre-published regulation of distributed generation needs deeper analysis and reconsideration of some issues related to: definition of network incremental costs, definition of the economic compensation for surpluses from micro distributed generation, the information not disclosed by the distributor about available capacity in the network, and explicit prohibition to granting any discriminatory treatment to any distributed generation.

After this brief background, we next present the proposals as regards the restructuring and regulation of the new roles of the DSO (and its interaction with the distributed energy resources).

1.3 Restructuring models for the distribution and the retail activity

To avoid new conflicts of interest that may affect the efficiency of the system as a whole it is recommended to restructure the roles and responsibilities of distributors.

In particular, the suggested approach would be to combine the highest degree of unbundling workable between distribution and retail (for distributors larger than 50,000 customers) and complement it with regulatory supervision. As discussed in the first report, legal and functional unbundling are often ineffective and need to be complemented with some level of supervision. Only ownership unbundling between distribution and retail would guarantee a higher efficient framework, however, this last type of unbundling is not a feasible option in most contexts[6], and most likely this is the situation in Peru.

In case it was only workable a legal and functional unbundling in Peru, then, it would be necessary that the activities of distribution system operators were subject to certain measures and monitoring, so that they are prevented from taking advantage of their vertical integration as regards their competitive position on the market, which is particularly relevant concerning household and small non-household customer. These measures include, among others:

- Measures for ensuring that the entire network activities, as well as individual employees and the management of the DSO, comply with the principle of non-discrimination.
- In line with the previous point, measures should be taken to ensure that staff responsible for the management of the distribution system operator does not participate in the company structures of the integrated electricity undertaking which is responsible for the day-to-day operation of the network.

[6] This has been the case in the US and in most EU countries.

- Measures taken to ensure vertically integrated distribution system operators shall not, in their communication and branding, create confusion in respect of the separate identity of the supply branch of the vertically integrated undertaking
- Companies would submit reports on the unbundling measures to the regulator. These reports should contain elaboration of the taken measures and their effectiveness as well as any risk for non-compliance.
- It is also necessary the appoint an independent monitoring unit. To fulfill his task, the monitoring unit must be fully independent and must have access to all the necessary information, not only of the DSO but of any affiliated undertaking
- Grid operators must publish their tariffs on the website of the national regulator.
- Others like monitoring the time taken to connect or to repair.

On top of the previous measures, transparency rules and monitoring would also be needed on the retail business (including a switching framework, a switching office, an obligation for the suppliers to communicate to the regulator all public offers of electricity, etc.).

It is also considered that the unbundling of the retail activity should be carried out in stages, starting with the unbundling of the retail activity for the free consumers, also following a strategy consistent with the proposals in Pillar 2. This is further explored in section 5.

Ownership unbundling between distribution and retail is most likely not a feasible option in Peru. Legal and functional separation with strict supervisory rules is recommended. Moreover, unbundling should be carried out gradually in stages, according to the proposed reform of the wholesale market.

1.4 Ownership of distributed energy resources and/or storage and/or electric vehicle recharging facilities

The ownership, development, management or operation of distributed assets, in particular distributed generation, storage or electric vehicle charging installations, by distribution companies should be forbidden as a general rule, therefore leaving the deployment of distributed energy resources and storage to market-based solutions. There is a clear incompatibility between the operation of networks and the ownership and management of energy resources.

Exemptions for new distributed resources or vehicle charging installations

The recommended exemptions in Peru to this general prohibition would be in line with those applied in the European context (EC, 2019). The first exemption would take place when the facilities are integrated within the network components and OSINERGMIN grants its approval.

The second exemption would be the case where there is a study clearly showing the convenience of relying on distributed resources to fulfill the distributor's obligations. In this case, the following additional conditions would need to be also fulfilled:

- The distributed resources are not used to buy or sell electricity to the market,
- a fair and non-discriminatory tendering procedure has been called and no other parties have been awarded a right to own, develop, manage or operate such facilities.
- OSINERGMIN has assessed the necessity of such an exemption and has carried out an assessment of the tendering procedure, including the conditions, and has granted its approval.

Another potential exemption, to be assessed by OSINERGMIN could apply to those distributed generation resources that are owned by the distribution company before the implementation of the reform. Although solutions based on the requirements established in Europe for legal and functional unbundling of DSOs are the first-best alternative, depending on the relative importance of those generation assets it could be considered exempting them from these unbundling requirements.

It is recommended that ownership, development, management or operation of energy distributed resources and/or storage and/or electric vehicle charging facilities by distribution companies should be forbidden. Some exemptions subject to strict regulatory approval could be considered.

1.5 Data services

Data produced by smart meters can foster innovative services, especially in the retailing business, but in order to harvest this potential, a sound regulatory framework for data management is to be established.

For data services to be useful, regulators have to address several crucial barriers. The first obstacle is the lack of widespread deployment of smart meters, which are essential as a data-gathering tool (this issue is reviewed in section 2). The management of the data gathered by these smart meters can be the second impediment to the introduction of data services, as different data-management models can act as a third-party access barrier.

Data management

A proper data management model should enable an efficient, safe and secure exchange of customer and metering data, facilitating retail market competition and adequate customer protection. Data should be provided to competitive market actors in a standardized format and ensure that customers maintain full ownership and control over their data.

The principles to be applied would be in line of those presented in (CEER, 2015):

- Privacy and security: customer meter data should be protected by the application of appropriate security and privacy measures. Customers should control access to their customer meter data, with the exception of data required to fulfill regulated duties and within the national market model.

- Transparency: OSINERGMIN shall make the following general guidelines on meter data management publicly available:

  a. the customer's rights with regard to customer data management;

  b. what type of customer meter data exists and what it is used for;

  c. how customer data is stored and for how long;

  d. how the customer and market participants authorized by the customer get access to that data; and

  e. within what time period the customer and market participants authorized by the customer have to wait to get disaggregated data."

- Accuracy: The distribution company has to communicate to the customer any inaccuracies that might have taken place in relation to customer meter data and how these inaccuracies have been addressed.

- Accessibility: the user should have easy access to customer meter data. This principle is connected to both the minimum smart meters functionalities and also as an obligation to distributors to provide access through the web and/or apps (section 2).

- Non-discrimination: to support an effective and competitive market, the data management model should not give undue preference to one stakeholder over another. This is especially important in relation to DSO-led smart meters roll-outs. Here it is very relevant to standardize the information exchange process between retailers so as to streamline and automate supplier switching, in less than a maximum established time to be defined by OSINERGMIN.

As regards the level of data centralization in Peru, the proposal is to first start by implementing a fully decentralized model. All key aspects of data management are therefore decentralized and under the responsibility of the DSO. DSOs store and manage the smart meter information, which can then be requested by consumers and other agents (if they fulfill the necessary requirements). For this scheme to work, it is of the utmost importance the role of OSINERGMIN, standardizing data formats and data exchange processes between suppliers (to ease supplier switching) (see section 2 for more details). In a second stage, it could be considered moving to a fully centralized model, where all key aspects of data management would be centralized through the use of a data hub. This change would depend on a cost-benefit analysis and also on the experience observed in those systems that have opted for this framework (in the first report, we mentioned for example Sweden).

It is proposed to implement a decentralized model for data management under the responsibility of the DSO with standardized data formats and information exchange procedures approved by OSINERGMIN.

1.6 Increasing DSO transparency and publishing hosting capacity maps

Peru needs to increase the information disclosed about the status of the distribution networks: including aspects associated with the operation of the short term and with the planning of the distribution systems in the long term.

The disclosure of information by DSOs is necessary to facilitate the connection of new grid users by enhancing the transparency related to the calculation of connection charges and also the available network hosting capacity.

Today the information disclosed is very limited, and the project of Regulation for distributed generation does not solve this problem. In this Regulation it is stablished that:

> *"For the development of the connection study, the interested party must complete and submit a request to the distribution company, presenting the main characteristics of the project and requesting the necessary information for the process. The distributor will deliver the requested information within a maximum period of twenty (20) business days after the request is submitted."*

The available capacity in the grid should be represented graphically in every (relevant) node in the grid, in what is commonly known as hosting capacity maps[7]. This information should be easily available, not needing to be requested on a node by node basis. These maps transparently indicate the connection possibilities of new distributed resources (which is the information delivered upon request today). Making public this basic piece of information will help to identify the locations where DER investments make more sense. These basic hosting capacity maps represent the minimum information that should be available to grid users initially, but could be further complemented and refined afterward in line with the best international experiences reviewed in the first report.

To determine this hosting capacity, it is necessary to take into account how the integration of distributed resources affects the reliability and quality of supply of the distribution network. OSINERGMIN would be in charge of defining the guidelines to carry out this task.

On the other hand, hosting capacity maps should not share information that would permit to identify the load of individual customers. This could be achieved by redacting load profiles if they contain data on fewer than a small threshold (e.g. 10 customers), or if a single customer constitutes a certain percent of the load or more (e.g. 10%).

Finally, and also for the sake of transparency, DSOs should produce network investment plans that go through public consultation. This is essential so that grid users have the necessary information to decide on new grid connections. This is further discussed in section 3.

[7] Hosting Capacity is the amount of DER that can be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades (EPRI, 2016).

It is recommended to impose the obligation for distribution companies to publish the hosting capacity in their networks together with submitting to public consultation their network investment plans.

1.7 The role of distributors in local flexibility markets

The efficient integration of distributed energy resources can provide solutions to local problems in distribution networks (mostly related to the relief of local congestion and voltage control). This way, DSOs can take advantage of DER capabilities to enhance the system's short- and long-term efficiency by means respectively of short- and long-term flexibility mechanisms.

Of the above two mechanisms, long-term flexibility ones, that is, those aimed at decreasing network investments, are those with higher potential in Peru. As discussed in the first report, they represent the perfect long-term complement to electricity tariffs at the distribution level. These long-term mechanisms allow procuring flexibility in a framework where wires and different non-wires alternatives can compete on an equal footing. The creation of this leveled playing field for all types of DERs, regardless of the structure of ownership and control, is of the utmost importance. This ideally requires a neutral market facilitator for all these commercial transactions. This ideal solution is, however, difficult to be implemented in practice. This is the reason why, for the sake of simplicity, we propose that these platforms are controlled by DSOs. Nevertheless, it is important to bear in mind that its role needs to be neutral, and therefore, some supervision will be needed to avoid entry barriers as much as possible. In Peru, it is recommended an initial stage of experimentation with these new long-term solutions with close involvement and supervision of OSINERGMIN.

Local flexibility platforms based on long-term auctions to acquire flexibility services by DSOs can be implemented in Peru. An initial stage of experimentation guided by the regulator is recommended.

The product

In these auctions, called and coordinated by the distribution system operator (DSO), the product has to be technology-neutral. To define this product, it is needed to outline a series of operational parameters and also a baseline. Figure 4, shows the operational parameters associated with UK Power Networks flexibility tender through the Piclo market platform. In general, these operational parameters would be defined by the DSO, depending on the particular flexibility requirements in its network.

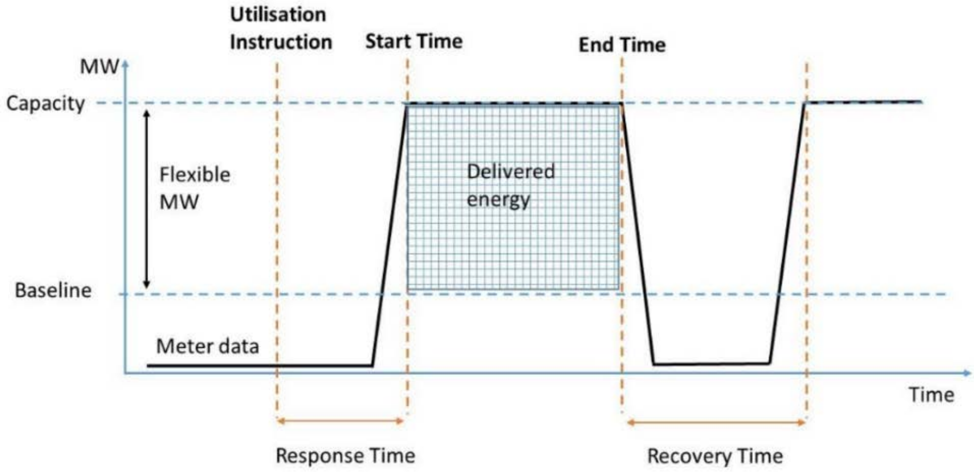

Figure 4: Operational parameters presented by UK Power Networks in a flexibility tender (UK Power Networks, 2018)

The baseline represents the capacity that the contracted DER is expected to be demanding or producing during the time of the event (the instance when the DER resource is going to be required to deliver its contracted capacity) if the event had not taken place. Therefore, the baseline represents the normal expected operation of the DER at that time of day, but not the capacity being demanded or produced in that particular event. This value is again to be determined by the DSO, although it would be recommended that OSINERGMIN would publish some guidelines to avoid a great divergence in the criteria used by the different DSOs.

Wires vs non-wires alternatives

Finally, a cost-benefit methodology needs to be developed so as to define the maximum price the DSOs are willing to pay for long-term flexibility in the mechanism. We cannot forget that these auctions are nothing but a scheme that allows wires and non-wires alternatives to compete on a level playing field. Again, homogenizing criteria would be advisable.

1.8 Coordination with the system operator

Since distributed resources will be able to provide services to the distributor and the system operator, there will be a need for some sort of coordination between both network operators.

The enhancement of TSO-DSO coordination is necessary and should take place at three different levels, namely the network planning, operational planning and real-time management of the grid.

In this respect, the regulation of distributed generation goes already in this direction. The draft already considers this coordination, mostly focused on the short term:

- "The COES may temporarily delegate part of its functions to one or more members of the System, in order to make the coordination of the operation more efficient in real-time".
- "It is necessary to enable the coordination of the Distributed Generation by the Distribution Companies. This will allow strengthening the functionalities of the Distributors' control centers".

- "It is needed to define the limits of coordination in charge of the COES".

With high penetration of distributed resources providing network and system services, the coordination between COES and distribution companies, as network operators, should be ensured. The DG regulation draft goes in the right direction.

1.9 References

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2 Advanced metering infrastructure

2.1 The Peruvian context

The deployment of advanced metering infrastructure (AMI) is regulated in Peru through the Supreme Decree 018-2016-EM. The latter establishes the obligation for distribution companies to present an AMI rollout plan to the regulator, considering an eight-year time horizon for such deployment. The Decree also defines two relevant features regarding property and cost recovery. In contrast with the current regulation regarding conventional metering devices, smart meters will be owned by the distribution firm, which is responsible for the installation. The investment and operation costs relative to the new smart meters will be included in the distribution added value (VAD, or *Valor Agregado de Distribución*, in Spanish); therefore, their costs will be recognized and recovered through distribution tariffs.

Supreme Decree 018-2016-EM establishes the obligation for distribution companies to present an AMI rollout plan to the regulator; meters will be owned by the distributor and their cost will be included in the VAD

After the publication of the Decree, the regulator also proposed a tentative list of minimum functionalities that the smart meters should have (OSINERGMIN, 2017):

i. Energy and capacity measures for time intervals no longer than 15 minutes.
ii. Bidirectional metering, both withdrawals and injections, including reactive power.
iii. Remote reading and two-way communication.
iv. Information system for end-users to know their consumption in real time.
v. Remote disconnection and reconnection.
vi. Potential for limiting power demand for demand response programs.
vii. Potential for applying multi-tariff options.
viii. Alerts of lack-of-voltage and fault detection to the control center.

In the last rate case, the regulator allowed some AMI pilot projects. According to GAPEL (2020), almost 80 000 smart meters have been installed in the framework of these pilots, accounting for 1% of electricity consumers in Peru. The same document also provides relevant figures on customer characterization, specifying that low-voltage customers represent 99.7% of total end-users and that only 0.35% of them are currently exposed to binomial tariffs. These low-voltage customers are distributed among urban (74%), rural (19%), and urban-rural (7%) areas.

2.2 Best practices and recommendations

As mentioned in the first report, the deployment of smart meters must be framed in a larger set of reforms that create the proper conditions to tap the full potential benefits of smart meters. These reforms involve tariff design, retail market competition, but also the regulation of the distribution activity. The cost-benefit analysis, the essential element for efficient deployment of advanced meters, should consider the existing or the planned regulatory framework as an input to try to accurately estimate the equilibrium between expenses and savings, instead of reckoning an abstract list of potential benefits that may not materialize in the jurisdiction under study.

The goal of this section is not to define a prescriptive plan for AMI deployment in Peru, nor to identify the technical specifications that should guide this process, but rather to provide a high-level roadmap with clear recommendations on a number of features that the regulator should consider when designing the rollout program. It first focuses on the cost-benefit analysis and then on other relevant implementation elements, such as how to devise the implementation plan, functionalities and interoperability, the ownership of the equipment, the cost-recovery strategy, data management organization, and how to ensure customer engagement and acceptance of this new technology.

2.2.1 Cost-benefit analysis

As already mentioned in the first report, the deployment of smart metering systems should be based on a sound cost-benefit analysis (CBA) that estimates the net present value of the rollout[8]. It must be remarked that smart meters may bring very different benefits to different categories of consumers. Therefore, a modern CBA should not be elaborated in a go/no-go format for a 100% rollout of smart meters, but rather via a previous categorization of end-users that allows to estimate costs and benefits for each customer segment and to present some sort of menu of investments, each one with its net present value. The latter would then allow the regulator to define a consistent and cost-effective rollout plan. As discussed in subsection 2.2.7, this is also relevant to avoid the rejection of AMIs from all or part of consumers (as it was the case in Chile[9]; see GAPEL, 2020; Plaza Reveco, 2020).

A modern CBA should not be elaborated in a go/no-go format for a 100% rollout of smart meters, but rather via a customer categorization that allows presenting some sort of menu of investments, each one with its net present value

Broadly speaking, smart meters improve the efficiency in the operation of both the distribution grid and the system; since all the costs of the electricity supply chain are eventually borne by consumers, the savings resulting from the efficiency gain, if the regulation is designed correctly,

[8] Regarding the methodology to elaborate the CBA, relevant authorities and institutions have published guidelines (EPRI, 2012; IRENA, 2015) and there are also reviews of international experiences specific for this topic (DG ENER, 2015). However, it must be remarked once again that the CBA methodology must be tailored to the jurisdiction under study.

[9] In Chile, the regulation on the deployment of smart meters suffered dramatic modifications due to customer rejection. The initial plan considered a change in the ownership of the metering equipment from the user to the distribution company, who receives the consequent remuneration through the distribution tariffs (BCN, 2019). However, the rollout had to be halted and the Ministry announced that the installation of the smart meter was going to be voluntary and that distribution companies had to return the fees already charged (CNE, 2019a, 2019b). This regulatory change was declared illegal by the Chilean Supreme Court and the issue is still to be solved.

should reach end-users. However, these benefits should be allocated to the different categories of customers because the amount of expected benefits would differ from one to another. In CBAs, the benefits of AMI are usually divided in two groups: i) savings due to improved efficiency in the operation of the network, and ii) savings stemming from the activation of electricity demand.

The first category of benefits includes improved quality of service at the distribution level, through an enhanced outage detection and management, which decreases the frequency and duration of supply interruptions; reduction of non-technical losses, through a more efficient detection of meter tampering and energy theft, with the resulting benefits in terms of revenue collection; better customer service, since the remote meter reading and the automated billing reduces the number of errors. All these improvements are very relevant in the Latin American context in general and in Peru in particular (BID, 2020). These benefits may be more homogenous within electricity customers (although relevant differences can still be found); the best customer categorization for these benefits may be based on the classical division according to voltage level (medium- and low-voltage) and distribution area (urban, rural, and urban-rural) at which they are connected and also their load consumption levels. For instance, larger potential benefits could be expected by customers connected in rural and urban-rural areas, where the supply is usually subject to more frequent interruptions, while detection of fraud and reduction of commercial energy losses benefits may be more relevant in urban areas with high load consumptions.

As regards operational savings in the distribution network, the best categorization may be based on the classical division according to voltage levels, distribution areas and load consumption levels

On the other hand, the potential for demand activation may vary broadly among customer categories, since not all end-users have the same engagement capability. Actually, recent research highlighted that demand response is usually characterised by a diminishing marginal utility, i.e., the marginal benefits it provides decrease as the participation of demand resources increases (NREL, 2020). This means that, once the largest margins have been exploited, the potential saving becomes smaller, resulting in the need for tapping the largest potential first, targeting those end-uses that can provide a certain service at the least cost. Furthermore, the benefits from demand response, especially in a power system like the Peruvian one, characterized by a large share of hydropower, depend on the penetration of intermittent renewables and the resulting need for flexibility services. Therefore, the strategy for the exploitation of demand response should be also aligned with the expected deployment of wind and solar power. For all these reasons, the customer segments to be used to analyse the benefits of demand response should be defined based on the potential for demand activation, identifying those final uses of electricity that may be flexible and provide the largest contribution to the system. Within the customer segments defined by GAPEL (2020), the largest potential for demand response may be expressed by medium-voltage customers and by low-voltage customers with binomial tariffs; this notwithstanding, a screening on final uses may found other sources of demand response.

As regards the benefits related to demand activation, the categorization of customers should be based on their potential for activation of flexibility, screening for final energy uses which can provide the largest benefits

Considering all costs and benefits for these different categories should allow the regulator to define which end-users are to be included in the rollout at a given time. However, the regulation should allow consumers not included in the rollout plan to require the installation of a smart meter, if they believe that this is beneficial for their consumption, and should consider a methodology to efficiently assign the cost of the equipment. On the other hand, the regulation may also consider the possibility for consumers encompassed in the rollout plan to opt-out, as it happens in some jurisdictions in the United States, although, most of the times, this implies a fee to be paid by the customer (NCLS, 2019). The possibility of opting out is not commonly found in Europe. In Spain, for instance, the rollout plan was legally enforced (BOE, 2007) and the regulator proposed to include an extra charge in the bill of those customers who impede the access to their conventional meter for the replacement with a smart meter (CNMC, 2020a). The proposal for the Colombian rollout plan (CREG, 2020) is even more categorical, foreseeing the possibility of disconnection for those users who hinder the replacement.

2.2.1.1 *Gradualism and forward-looking approach*

Another key element of an efficient AMI deployment is gradualism. Benefits that cannot be exploited today may materialize in a few years, due, among other factors, to the penetration of renewables and the resulting higher needs for flexibility, a change in the regulatory framework (e.g., in tariff design for certain customer categories), or the development of certain business models or technological innovations that permit to engage more customers. Cost-benefit analyses must be repeated over a certain number of years, in order to take a picture of the new reality and the new forecasts and to widen the rollout to new consumer categories, if the net present value of these investments is expected to be positive.

Cost-benefit analyses must be repeated over a certain number of years, in order to take a picture of the new reality and the new forecasts and to widen the rollout to new consumer categories

It must also be remarked that the useful life of smart meters may span from 15 to 20 years. As mentioned in the first report, it is essential to avoid the early obsolescence of the equipment. Therefore, the cost-benefit analysis must have a forward-looking approach, identifying also those benefits that will be available in the near future and helping the regulator design a future-proof deployment of smart meters.

2.2.2 Deployment plan

In international experiences, the CBA is commonly carried out for the entire power system, regardless of the entity finally in charge of the installation of the advanced metering infrastructure. As regards the latter activity, the most common approach is to leave this task to the incumbent utility (the distribution company, in case of a restructured power sector).

This was the case, for instance, in Spain[10], where the regulation defined a rollout process (BOE, 2007) with intermediate milestones for distribution companies in charge of the installation (30% in 2008/2010; 20% in 2011/2012; 20% 2013/2015; and 30% in 2016/2018). Distribution companies had to present intermediate plans to local governments, but they could develop the rollout with certain autonomy; the regulator regularly published tracking reports to monitor the achievement of milestones (e.g., CNMC, 2020b). The plan suffered delays, especially in the initial phases, mainly due to a lack of availability of the equipment, but in 2020, more than 99% of connection points had a smart meter installed.

> *In the Peruvian case, a nation-wide cost-benefit analysis should be elaborated to identify those customers who should have an advanced meter installed; this may be used to define targets for each distribution company, which could then present a rollout plan to the regulator*

In the Peruvian case, the recommendation is to elaborate a nationwide cost-benefit analysis that allows identifying those customers who should have an advanced meter installed. This information may be used to define targets for each distribution company, which could then present a rollout plan to the regulator, as foreseen by the DS 018-2016-EM, with intermediate milestones. The regulator periodically would supervise the deployment plan according to the achievements made by the distribution companies.

The choice of commissioning AMI deployment to distribution companies is the recommended approach in the current Peruvian regulation. This is the most widespread method and has been used also in jurisdictions that do not rely on a retail market (e.g., as in some power systems in the United States or in Chile). Other approaches can be found in international experiences (as in the United Kingdom or Germany), but they usually require opening metering services to competition, a reform that would require significant changes to the current Peruvian regulatory framework.

2.2.3 Functionalities and interoperability

International experiences underline the importance of setting a list of minimum functionalities for the smart meters to be installed during the AMI rollout. The list proposed by the Peruvian regulator (OSINERGMIN, 2017) presents several overlaps with the one defined by the European Recommendation 2012/148/EU and analyzed in the first report, as highlighted in Table ii. Although some minor difference exists, the two sets of functionalities are almost equivalent. The Peruvian one, which has been developed more recently, directly refers to 15-minute time periods; it also has a stronger focus on fault detection, while the European one centers the attention on

[10] As mentioned in the first report, the Spanish experience was controversial, since the rollout did not rely on a proper cost-benefit analysis.

fraud. The European set of functionalities includes secure data communications, which is not part of the Peruvian one. It is recommended to include this aspect in the Peruvian functionalities.

Table ii. Comparison between European functionalities and those proposed for Peru

European Recommendation 2012/148/EU	OSINGERMIN (2017)
Update readings frequently enough to allow the data to be used for energy savings	Energy and capacity measures for time intervals no longer than 15 minutes
Allow frequent enough readings for the data to be used for network planning	
Allow remote meter reading by the operator	Remote reading and two-way communication
Provide two-way communication for maintenance and control	
Provide readings directly to consumer and any third party designated by the consumer	Information system for end-users to know their consumption in real time
Provide import/export and reactive metering	Bidirectional metering, both withdrawals and injections, including reactive power
Allow remote on/off control of the supply and/or flow or power limitation	Remote disconnection and reconnection
	Potential for limiting power demand for demand response programs
Support advanced tariff systems	Potential for applying multi-tariff options
Fraud prevention and detection	Alerts of lack-of-voltage and fault detection to the control center
Provide secure data communications	

The Peruvian list of functionalities is well aligned with international standards; these functionalities must be fulfilled for all customer categories in order to guarantee interoperability

As mentioned in the first report, global AMI functionalities should be standardized in order to guarantee the so-called interoperability[11]. Exceptions to this rule may apply only in case there are customers with specific needs. For instance, electricity consumers with very large loads and higher capability to respond to price signals may need specific meter equipment that typically is

[11] As already mentioned in the first report, interoperability is defined as the ability of two or more energy or communication networks, systems, devices, applications or components to interwork to exchange and use information in order to perform required functions (EC, 2019).

considered already for market participation. As mentioned, the CBA is used to define a global set of functionalities, just in case, it may include particular subsets applying to specific consumer categories.

On the other hand, consumers in the same segments should always rely on the same functionalities. This is essential especially when the deployment is carried out by several entities, as it is the case when the task is commissioned to distribution companies. Interoperability encompasses, among other issues, the standardization of the equipment, the communication protocol, and the data format and management. Interoperability guarantees a smoother communication among all the actors involved in the process, higher competition among technology manufacturers and lower prices, and it ensures the same conditions to all final customers. Achieving interoperability is not an easy task: despite the standardisation efforts, some studies identified, for instance, 17 different communication standards co-existing at a certain time only in the European Union (Erlinghagen et al., 2015).

2.2.4 Ownership

The Peruvian regulation assigns the ownership of the smart meter to the distribution company in charge of installing it. This approach is supported by international experiences, where the predominant approach is to leave the ownership to the entity in charge of metering services, commonly, the distribution company (WB, 2018; EC, 2014). If metering services are liberalized, other approaches are possible (e.g., the meter could be owned by a retailer), but these solutions do not seem to fit well with the current Peruvian regulation. Some intermediate solutions have been implemented or proposed in Spain (BOE, 2007) and Colombia (CREG, 2020), where consumers may decide whether to buy or lease the equipment.

The Peruvian regulation assigns the ownership of the smart meter to the distribution company in charge of installing it; this approach seems supported by international experiences. As previously the meter was owned by the customer, specific solutions may be required to compensate for recently replaced meters or low-income customers.

The peculiarity of the Peruvian situation is that the conventional meters currently installed are usually owned by the end-users. Therefore, the installation of smart meters would imply a change in the ownership model.

The sunk cost of conventional meters (potentially including recycling costs) has to be considered in the cost-benefit analysis, but, in general, it cannot be recognized to the end-user[12].

Specific solutions may be found for users who recently had their conventional meter replaced or for low-income customers. In Chile, it was proposed to require the distribution company to purchase the old equipment (CNE, 2019a). In Spain, an initial exemption to the increment of the lease of the new equipment was considered for those meters that were replaced before the 15-year

[12] It must be highlighted that, according to GAPEL (2020), the residual value of old meters is usually zero.

useful life (e.g., if the conventional meter was replaced after 10 years of operation, the lease of the equipment could not be increased as a consequence of the installation of the new smart meter during the first 5 years; BOE, 2007). For low-income customers, specific grants on installation costs or subsidies on the lease of the equipment could be considered and included in the wider framework of the national policy on energy poverty.

2.2.5 Cost recovery

AMI rollout entails large investments, which generate savings in the long term that are spread across different categories of beneficiaries (distribution companies, end-users, retailers or other business models taking advantage of the new data availability). An efficient cost-recovery strategy must be identified and this is also relevant for obtaining the acceptance from consumers. Although different approaches can be found, both in literature and in international experiences, the two most common strategies are i) to include the investment costs of AMI in the regulatory asset base of the regulated company in charge of the deployment (the benefits are then passed through to consumers as efficiency gains to be encompassed in tariff reviews; WB, 2018) or to recover the smart-metering costs through a specific surcharge, which allows keeping a better track of the economic outcome of the rollout (DOE, 2020). In some cases, cost recovery is directly related to the CBA, as in the United Kingdom, where the operating cost allowance recognized to the distributor and included in the electricity bill is calculated by considering some of the costs and benefits (those relative to the network operation) presented in the initial assessment (Ofgem, 2020).

Encompassing the expenditures on AMI in the remuneration of the distribution activity is the recommended alternative for Peru; however, the distribution remuneration methodology must be reformed, as addressed in the section 3 of this report on this specific topic

In Peru, if distribution companies will be in charge of the rollout and will own the equipment, the most efficient alternative is to include investment costs[13] in the rate base used to calculate the distribution tariff. Nonetheless, the current methodology to calculate the remuneration of the distribution activity in Peru, based on the new replacement value, may not be able to foster innovation. This methodology is meant to incentivize efficiency gains on conventional cost elements, but it is not the most suitable approach for the rollout of smart meters, whose future costs and benefits are subject to uncertainty, creating a significant risk for the firms (GAPEL, 2020). A new revenue setting mechanism is defined, for the entire distribution activity, as further discussed in section 3.2.

[13] These costs are not only relative to the capital expenditures for the acquisition of the smart meters themselves, but also to other cost items of the rollout process, as the creation of a data management system or the elaboration of a cyber-security strategy.

2.2.6 Data management

The data produced by smart meters regarding consumption are one of the most valuable outcomes of the rollout. Different strategies for data management have been presented in the first report. Colombia recently proposed the creation of a centralized agent for the management of the data produced by smart meters (CREG, 2020). In most of the jurisdictions where distribution companies carry out the rollout and own the smart meters, however, a decentralized approach to data management was selected. This is also, initially, the recommended alternative for Peru, although, as already mentioned above, the interoperability must be guaranteed also at the data level. The information access and exchange are critical to ensure a well-functioning retail market with quick and safe supplier switching procedures. Moreover, it is also essential to define a simple and transparent protocol for end-users with a smart meter installed to be able to access the data it produces, keeping in mind the need to protect data through specific cyber-security strategies.

2.2.7 Customer engagement and acceptance

The costs of AMI deployment will be paid, at some stage, by final customers. Therefore, it is essential to include in the rollout a proper communication campaign that explains to the general public the benefits of smart metering. Rollouts focusing on operational benefits on the distribution side risk having a very low acceptance from customers. If most of the benefits are to be obtained in the distribution activity, the cost-recovery strategy must be communicated clearly, explaining when and how the expected savings will be passed through to consumers.

However, the best approach to improve the acceptance is customer engagement through data. The possibility to access data that make energy usage visible was one of the success factors, for instance, of the British rollout (BEIS, 2017). If demand response is to be pursued through the rollout, customers should be delivered clear and actionable insights on how to fully exploit the new data and to obtain energy and economic savings[14]. The development of web platforms with protected customer data and specialized apps is key. In addition, dynamic prices and tariffs are required to provide the economic rationale for such demand response. Moreover, effective communication campaigns can have a dramatic impact on the effectiveness of behavioral demand programs, as it was the case with programs launched by OPower and BGE (UtilityDive, 2014).

If demand response is to be pursued through the rollout, customers should be delivered clear and actionable insights on how to fully exploit the new data and to obtain energy and economic savings

Finally, it must be remarked that AMI deployment and the integration of demand response in the market may have distributional impacts. Some specific customer segments, as low-income consumers, may not be able to tap all the benefits stemming from the new data, e.g., because they may not be able to face the upfront costs that may be required to achieve savings (as the purchase

[14] In Spain, for instance, the access to the data produced by smart meters allowed customers, directly or advised by their suppliers, to optimize their contracted power and reduce their bill accordingly.

of an energy-efficient or an intelligent appliance), although they are asked to cover part of the costs. These distributional impacts must be forecasted and addressed in the rollout program (e.g., through specific engagement strategies that consider some sort of economic aid); otherwise, they may provoke the rejection of AMI from these customer segments.

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3 Distribution activity revenue setting

3.1 The Peruvian context[15]

Peru represents a particularly complex context as regards how to regulate the distribution activity. The main reason for this complexity is the great diversity in terms of the casuistry of the types of distribution companies and also the challenges they have to face. Schematically we can highlight:

- There are 23 distribution companies in Peru that build, operate and manage medium and low voltage networks. There is a great diversity of geographical contexts in which distribution companies can operate. These contexts involve both urban and rural areas, and cover geographical locations as diverse as the coast, the mountains or the jungle. In many cases, distributors have to serve widely dispersed consumers in remote areas. To consider this diversity to some extent, OSINERGMIN defines the types of distribution sectors according to some physical characteristics (from urban to rural including different load densities).

- There are both private and state-owned distribution companies. Due to various factors, state-owned companies (with some exceptions) have historically performed well below expectations (in terms of losses, quality of service, etc.). As a consequence of this situation, a particular regulation has been developed for state-owned companies' new investments.

- The main regulatory scheme that applies to distribution companies is based on the calculation of the VAD, complemented now with the PIDE for state-owned companies:

    a. The VAD (Valor Agregado de Distribución) regulation, which is the sole regulation that applies to private companies, and the scheme that applies for existing assets to state-owned companies. This regulation consists of a price cap scheme based on the model company.

    b. The new PIDE[16] regulation, which exclusively affects new investments of state-owned companies. This PIDE framework introduces the requirement to carry out long-term investment plans and considers a pass-through of the associated (and approved) costs.

- There is a great diversity of sizes in terms of the number of clients. In Peru, it is considered that 50,000 clients represent the threshold for a distribution company to be considered large. As we shall see, this threshold also affects how the VAD regulation is applied to them.

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[15] This section draws on a series of documents provided by the World Bank Group to the consultant team of this pillar.

[16] Electricity Distribution Investment Plan or Plan de Inversión en Distribución Eléctrica in Spanish.

- There are also differences in terms of the characteristics of the consumers they serve, which can be industrial, commercial or residential.

In this background section, we first review the role of the "sectors" considered in the regulation of the distribution activities (section 3.1.1). Second, we present the situation as regards state-owned companies (section 3.1.2), a major concern today. Third, we briefly describe the major characteristics of the different remuneration mechanisms that apply to private companies and state-owned companies, including the incentives oriented to the quality of service and innovation (section 3.1.3). Finally, the situation of access and the regulation of the rural system is presented (section 3.1.4).

3.1.1 Distribution sectors

In order to be able to more easily supervise and regulate distribution companies in Peru, a series of typical sectors are defined. OSINERGMIN must determine, through technical and economic studies, the methodology by which the characteristics and number of typical distribution sectors are set, and then propose their approval to the General Directorate of Electricity (DGE) of the Ministry of Energy and Mines (MINEM).

Typical distribution sectors are defined based on demand density and physical parameters of distribution electrical system. For the 2019-2022 regulation, MINEM approved 5 typical sectors as follows[17]:

- Sector 1: urban high load density
- Sector 2: urban medium and low load density
- Sector 3: urban-rural low load density
- Sector 4: rural low load density and
- Sector 5: rural electrical systems (the so-called SER systems). SERs are considered separate rural systems with tariffs that are calculated individually for each SER.

As we shall see, for large distribution companies, the studies for determining the VAD entail each distribution company carrying out a detailed study. In these studies, it is a requisite to gather part of the information differentiated by sector. This allows OSINERGMIN better supervising the information provided and also to account for the different reference infrastructure costs in each context. For small distribution companies (below 50,000 consumers), only one representative system and VAD calculations are performed for all of them together (as it was done before the last reform that implemented individual VAD calculations for large companies).

[17] Three indicators define the typical sectors, where I1 is related to the "rurality" of the system:

I1 = (kilometers of MV circuits / peak demand);

I2 = (kilometers of LV circuits / number of clients in LV); and

I3 = (total clients in MV and LV / total MV and LV energy consumption).

Several analyses have pointed out that more sectors need to be defined to better account for the existing differences in the associated costs (both investment and operation and maintenance). The White Paper (ME-COMILLAS, 2019) discussed the need to consider the climate, geography, dispersion, population density, demand, etc., when determining the sectors and the associated efficient costs of providing the service.

3.1.2 State-owned distribution companies

Structure of the state-owned distribution companies' sector

State-owned electricity distribution companies serve over 60 percent of customers. Distriluz[18], the largest state-owned distribution company, serves seven departments involving both rural areas with low demand levels and cities of medium size. Distriluz has over 2 million customers (above 10 million people); and the activity is considered to be profitable enough to sustain the business.

Other smaller public distribution companies struggle to be economically viable, but are not far from it. This is the case of two smaller state-owned companies that present similar characteristics to Distriluz: Seal (in Arequipa), with about 400 thousand customers, and Electro Sur Este (in Cuzco), with about 470 thousand customers.

The other state-owned distribution companies typically serve a few small cities and rural areas with dispersed communities and very low demand. The three largest in this group are Electro Oriente (in Iquitos, with around 400 thousand clients); Electro Puno (in Puno, with around 270 thousand customers); and Electro Sur (in Tacna, with around 150 thousand customers).

Finally, around 175 thousand customers are served by another eight distribution companies that are mostly unprofitable, in some cases barely covering their operating expenses.

It is also noteworthy the role of Adinelsa. Adinelsa is a public distribution company whose main activity is oriented to the distribution of electrical energy for rural, remote and difficult access areas, where no other state-owned distribution company has a concession, or it is not within its area of technical responsibility. Adinelsa administers these assets and operates several rural electrification systems and household PV system projects implemented by MINEM. In Fig.3, it is represented the coverage of isolated systems in Peru.

[18] Distriluz is made up of Electro Centro, Electro Noroeste, Hidrandina, and Electro Norte.

Sistema	Total	Libre	Regulado	Participación (%)
TOTAL	47 286 338	28 132 783	19 153 554	100,0
Sistema Eléctrico Interconectado Nacional	46 927 640	28 132 783	18 794 857	99,2
Sistemas Aislados	358 697		358 697	0,8

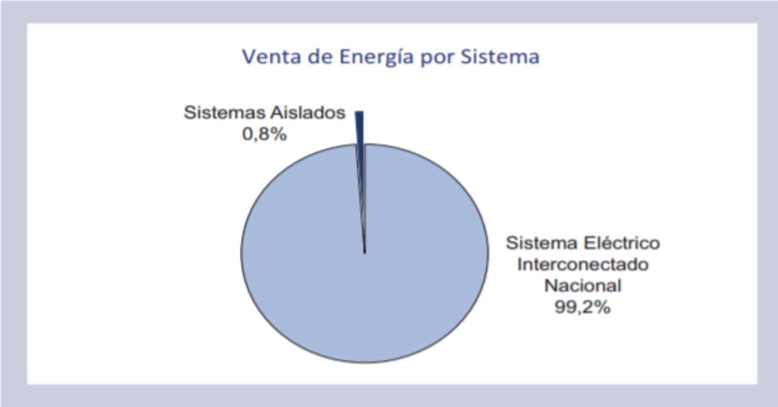

Figure 5.- Isolated systems. Source: (OSINERGMIN, 2019)

The institutional framework of state-owned companies

FONAFE[19] is the entity that manages all state-owned electricity distribution companies (including Adinelsa). In the past, FONAFE's policy was to restrict to a large extent investment and retain earnings (which were transferred to the Treasury). There was a wide consensus that this did not represent good practice for long-term asset sustainability, and this led to a new framework that is reviewed later on.

The problems

The state-owned distribution companies have well-known problems. They include:

- management and operational limitations imposed by government administration, including political appointments to the board of directors and upper management;
- restrictions to budget, procurement, and financing, also imposed by government administration;
- the need to service low-demand and low-income markets and dispersed populations in rural areas;
- inadequate incentives:
    a. the personnel of the state-owned distribution companies is not aligned with the proper management of the company, including planning and ensuring quality of supply.

[19] Fondo Nacional de Financiamiento de la Actividad Empresarial del Estado.

b. The penalties imposed by the regulator do not generate incentives for distribution companies to improve the quality of supply, since they are often below the cost of increasing the quality of supply (CEPA, 2016);

All these limitations and problems took place in a context where rural electrification has been increasing rapidly in the last years, and therefore these companies have not been able to keep this pace and ensure service quality. This way, while electricity quality in urban areas is to a large extent satisfactory, more frequent and longer power outages are an issue outside urban areas.

The low quality of electricity service provided by state-owned distribution companies became a major concern as their assets run down, and improving the quality of service of these companies is a priority today for the electricity sector.

The reform of the state-owned regulatory framework

This situation has led FONAFE and sector authorities to try to improve the situation of state-owned distribution companies by, for example, updating the remuneration scheme or by enacting legislation to allow the financing of investments by public distribution companies (this is analyzed below).

Nevertheless, there may be still intrinsic difficulties in the legal and administrative framework of these public sector companies that prevent their efficient operation.

3.1.3 Remuneration scheme

The common framework for both, private and state-owned companies: the VAD

The basic legal framework for distribution in the Peruvian electricity sector is the Electricity Concessions Law DL 25844 of 1992 (LCE), supplemented by Law 28832 of 2006, and its most important regulations.

The distribution remuneration scheme[20] is the so-called Distribution Value Added (VAD, *Valor Agregado de Distribución* in Spanish). In its initial design, the remuneration was based on due investments for a model company (a well-known concept in the Latin American context) where the studies for determining the VAD were made for typical distribution systems per sector (therefore, it was based on benchmarking). The scheme also checked that the remuneration achieved, on average, a minimum target in terms of the internal rate of return (IRR) of the distribution companies.

The computation of the VAD involves the calculation of the annuity of the VNR[21] that implicitly entails that the RAB is reopened and reassessed at the end of the regulatory period by means of a greenfield type model and considering efficient costs (VNR). This approach has provided reasonable results up to date, but it is not well-suited for the new changing and more uncertain context, for it could extremely increase risk exposure to DSOs.

[20] Also known in Peru as distribution tariffs.

[21] Valor Nuevo de Remplazo (New replacement value)

Tariff studies are approved by the OSINERGMIN every 4 years. Since 1994, five tariff processes have been carried out, being the last tariff setting in 2018 (for the period starting in 2019).

In 2016, MINEM approved a new calculation scheme of the VAD, which has been applied for the first time in the tariff resetting corresponding to the current four-year period 2019-2022. The new regulatory scheme has retained several of the main characteristics of the previous procedure, but has also introduced some relevant additions:

- In the previous scheme the model company was applied, per sector, to just one representative system that was latter used as benchmark of all the systems of all the companies within that very same sector. One unique system per sector was identified as not being enough to represent the casuistry we may find in Peru, and this motivated the more granular analysis implemented today. The model company study is now carried out based on one system per sector and per company. This way, the analysis is based on one representative typical system owned by the company whose remuneration is to be determined. Verification analyses of the internal rate of return (IRR) are also carried out on a company-by-company basis.
- MINEM defines for each distributor its geographical responsibility zone (*Zona de Responsabilidad Técnica* or ZRT in Spanish). The objective is to assign distribution companies the responsibility of carrying out indicative planning for expansion within the zone. ZRT includes the limits of the regions where the distributor operates.
- Readjustment factors for innovation and quality of service[22] are introduced.
    a. As regards the quality of service, the distribution company will propose to the regulator annual goals, for the regulatory period (4 years), of improvement of its SAIFI and SAIDI indexes. The investment and operational expenses dedicated to quality improvement can reach a maximum of 5% of the VAD and will be given at the beginning of the tariff period. If the company does not comply with the committed goals, it must return the corresponding amounts in the next tariff period.
    b. As regards technological innovation, companies can propose technological innovation or energy efficiency projects. This additional incentive on VAD will be recognized up to 1% of revenues, for companies that implement efficient technologies. Investments projects must be previously approved by the Regulator.

[22] The System Average Interruption Frequency Index (SAIFI) and the System Average Interruption Duration Index (SAIDI) are used as reliability/quality indicators by electric utilities. SAIFI is the average number of interruptions that a customer might experience over a year. SAIDI is the average outage duration for each customer served, measured over a year.

Quality standards

Regarding the quality standards, in October 1997, MINEM approved them through the Technical Standard for Quality of Electric Services – NTCSE. The NTCSE regulates the aspects of quality in the electric service that electric service companies must comply with, establishing:

- minimum levels of quality and obligations of electricity companies to their customers.
- the characteristics, parameters and indicators under which the quality of the electricity service is evaluated
- the minimum number of measurement points and conditions,
- the tolerances and the respective compensations and fines for non-compliance[23].

In 2008, MINEM approved the Technical Standard for Quality of Rural Electricity Services (NTCSER), establishing the minimum levels of quality of Rural Electrical Systems (SER) developed within the framework of The General Law of Rural Electrification N° 28749 and its regulations.

The control of the quality of the electricity services is focused on the following aspects:

- Product Quality: voltage level, disturbances and frequency;
- Quality of Supply: supply interruptions;
- Quality of Commercial Service; and
- Quality of Public Lighting.

In order to systematically monitor the quality of service, OSINERGMIN approved several Procedures[24] in 2004, 2008 and 2009.

In relation to the quality of service, the electricity companies report to OSINERGMIN: (i) monthly, the list of all interruptions registered in the previous month; (ii) quarterly, the number of interruptions associated with affected customers; and (iii) each semester, the calculation of quality indicators and the amount of compensation for customers that exceeded the tolerances. OSINERGMIN monitors monthly the compliance of the electricity companies with the quality of service standards.

In the following figures it can be seen how the indexes have been improving in the last decade, but at the same time, the problem of the diversity among regions.

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[23] If a minimum level of quality of service is not provided, electricity companies are subject to fines and penalties imposed by OSINERGMIN, as well as to monetary compensatory mechanisms for customers who received sub-standard service.

[24] In 2004, the Procedure for the Supervision of the Operations of Electrical System; in 2008 the Procedure for the Supervision of the Technical Standard of Quality of the Electric Services and its Methodological Base; and in 2009 the Methodological Basis for the application of the Technical Standard of Quality of Rural Electricity Services (in 2014 OSINERGMIN made slight modifications to these procedures).

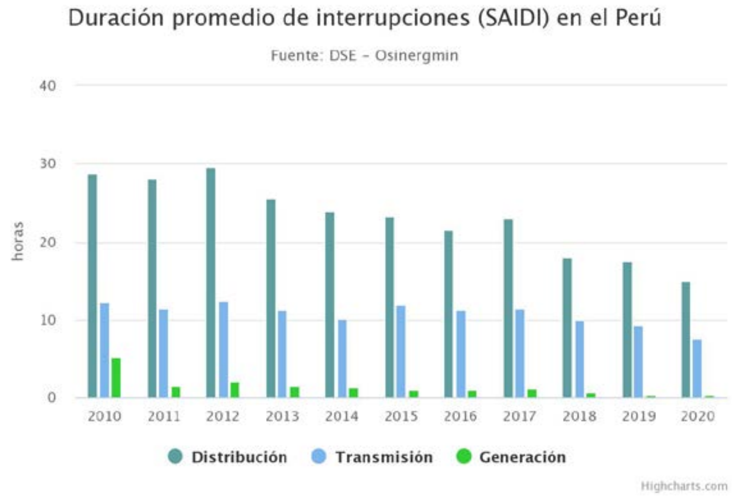

Figure 6.- Evolution of the SAIDI index (2010-2020). Source: OSINERGMIN

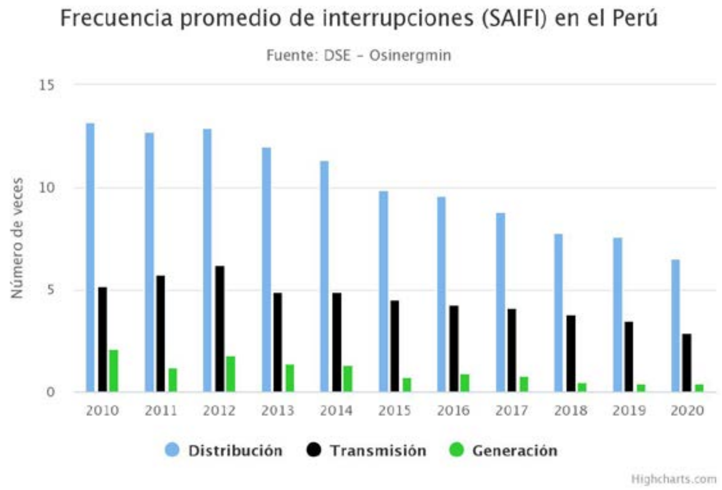

Figure 7.- Evolution of the SAIFI index (2010-2020). Source: OSINERGMIN

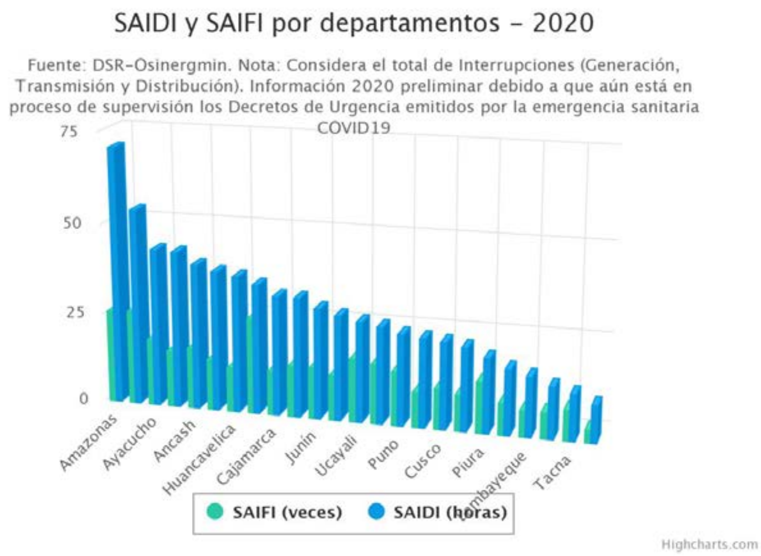

Figure 8.- SAIDI and SAIFI in the different regions. Source: OSINERGMIN.

The quality of electricity service in rural areas, and particularly the quality of supply, is a crucial problem that requires special attention and is briefly described in the next subsection.

The specific investment framework for state-owned companies

Recent sector legislation provides an opportunity to solve state-owned distribution companies' investment problems and improve quality of service. The law requires each state-owned distribution company to submit to OSINERGMIN a long-term planning study and four-year investment program (the PIDE) to be used for setting the tariff. These programs should consider investments to strengthen, expand, and update the system; save energy; improve service quality, safety, security of supply, and technological innovation; and other measures to improve the efficiency and effectiveness of distribution networks.

A Trust Fund is to be created under FONAFE to finance the four-year investment programs. Revenues from the annuities for replacement of the system that come from the tariff, and distribution company profits, may be transferred to the Trust Fund to finance investment programs. The Trust Fund should not demand additional resources from the Treasury.

Smart meter rollout

Additionally, as reviewed in section 2, a replacement plan for measuring equipment has been proposed. The distribution companies must present a plan for adapting or replacing the current measuring equipment with smart meters or measuring systems. The plan must contemplate all the tariff options and establish a full substitution plan in a period of two tariff regulations (8 years). The plan presented by the companies must be approved by OSINERGMIN.

3.1.4 Access and rural electrification

In addition to the basic legal framework provided by Law DL 25844 of 1992 (LCE), it is also relevant the General Law on Rural Electrification (2006 and its regulations in 2007). This new law clearly defined the Rural Electrification Systems, the sources of financing and organize rural electrification through the National Rural Electrification Plan.

Most rural systems have poor electricity service quality, as measured by key indicators. As a way of example, the worst-performing rural systems exceed more than three times the national key indicators average. In general terms, it could be said that the quality of service of a company is inversely related to the number of rural circuits (SERs). As mentioned above, SERs are considered separate rural systems with tariffs that are calculated individually for each SER.

Although great progress has been made in recent years, Peru's level of rural electricity access, which was 82% in 2018, is one of the lowest in Latin America.

Extending the network vs isolated systems

Although extending rural networks has been the traditional form of rural electrification in Peru, household and community-based solar photovoltaic (PV) systems have also been used increasingly, particularly since being included as an important component of two World Bank-supported electrification projects in Peru. These projects have been implemented by MINEM through the regional electricity distribution companies, which are responsible for the extension of their electricity grid or installation and operation of household PV systems.

In any case, it is also believed that traditional network extensions and household PV systems reflect a narrow vision of requirements based solely on lighting, communications, and battery and small appliance charging. This approach needs to change to support productive uses, given their significant potential for economic and social development (Jacquot, Perez-Arriaga, Nagpal, Stoner, 2020).

3.1.5 DERs and smart grids

Distributed generation and smart grids are transforming power grids and challenging traditional business models in power markets worldwide, but the adoption of these technologies remains limited to pilot initiatives in Peru.

OSINERGMIN commissioned a strategic smart grid study in 2012 that identified the main lines of action, including smart metering equipment, integration of distributed generation, demand management, distribution automation, and electric vehicles. As it is explained below, this type of investment in innovation is a key aspect included in the new regulatory proposal. In section 1 of this report, the actual proposal of regulation for the connection of distributed generation was also commented. However, it is widely acknowledged that these resources are far from receiving today a comprehensive and efficient system of charges and prices (this is tackled in section 4).

3.2 Proposal for revenue setting

This section presents the proposal for distribution activity revenue setting in Peru. Previous analyses have identified the current scheme (the VAD) based on the "model company" as not being able to provide network companies with adequate incentives to support decarbonization, deliver adequate grid investments, use new distributed resources efficiently, foster innovation, and provide value to current and future consumers (see for example CEPA & NEGLI, 2016).

> *The current VAD scheme has not been able to provide network companies with adequate incentives to support decarbonization, deliver adequate grid investments, use new distributed resources efficiently, foster innovation, and provide value to current and future consumers*

Although the scheme has been updated (see section 3.1.3), the fact is that in the current context the regulation of distribution in Peru requires a far-reaching regulatory reform to better deal with the aforementioned challenges.

A necessary precondition: the need to revert the situation of state-owned companies

In line with the background section, a major pre-condition to successfully reform the remuneration of the distribution sector is to revert the situation of state-owned companies. Today, there are barriers in the framework of state-owned companies that prevent their efficient investment planning, operation and management.

Removing these barriers is one of the major objectives of pillar 1 of the present project. As indicated in the first report of this pillar (Rudnick and Navarro, 2021), the consultants are at the time of this writing evaluating different alternatives. Among these alternatives, we find the privatization of remaining public companies, the creation of an independent entity that controls state-owned companies, grouping several companies into corporations (the 2009 White Paper recommendation, see ME-COMILLAS, 2009), and allowing independent private investors to participate in distribution concessions.

Henceforth, we will assume that a framework is in place for state-owned companies that: (i) permits them to access resources to finance new investments, and (ii) allows them to perceive and respond to incentives in a similar fashion as private companies would do. This is a fundamental precondition.

Introducing a common revenue scheme for both private and state-owned companies

The proposed framework would be the same for state-owned and private companies, although logically it would be necessary to bear in mind in this common framework the different characteristics of each sector of each distribution company. Based on this, it makes sense to consider differences in the costs of technological solutions, differences in the quality of service required to each system, etc.

As regards the scheme, only those systems corresponding to the so-called SER sector would be outside this framework, which due to its particular conditions does merit a differentiated treatment. We will not deal with these systems in this document.

3.2.1 The proposal in a nutshell

The proposal presented here looks for a future-proof design. It is based on three main features:

- First, a revenue cap scheme would substitute the current VAD scheme which is closer to a price cap due to the absence of an ex-post revenue reconciliation mechanism. As discussed in the first report, today, there is a total consensus on the need to decouple the remuneration of the distribution activity from the distributed energy volume[25], which may be reduced by DER investments without a corresponding reduction in costs (MITEI, 2016; IRENA, 2017).
- The remuneration of CAPEX based on the annuity of the VNR, computed on the basis of an adapted system, is replaced with a mechanism that explicitly accounts for the Regulatory Asset Base (RAB) of the distribution company, which is consolidated at the end of each regulatory period[26]. The RAB model is proposed to incentivize new investments in the present context since it provides a secure payback and returns on investment for developers.

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[25] That said, it is worth mentioning that price cap regulation with an ex-post revenue correction can resemble to a large extent to a revenue cap regulation.

[26] As it is explained below, this requires a transition between the two CAPEX remuneration approaches to set the opening RAB for the first period after the reform.

- Before the beginning of the regulatory period, when the tariff review is initiated, the distributors have to submit their year-by-year investment plans appropriately justified following pre-defined criteria.

The recommended regulation is based on a building-block approach with a revenue cap mechanism. CAPEX remuneration is based on the calculation of a consolidated Regulatory Asset Base (RAB) at the end of each regulatory period and ex-ante allowances based on investment plans submitted by distribution companies at the beginning of each regulatory period.

We next briefly outline some other major features, and then describe the whole scheme in more detail in the following sections.

First CAPEX and OPEX, then TOTEX

As regards the consideration of CAPEX and OPEX, we have seen in the first report how, in a context with increasing penetration level of DERs and smarter distribution grids, the best textbook practices lie on the side of equalizing the incentives for reducing both of them (being the TOTEX approach the one that best achieves this aim).

However, and for the sake of limiting the magnitude of the reform, we propose to have a first implementation stage (that could last two regulatory periods) with a scheme that separates the incentives for CAPEX and OPEX. This method is the usual approach in Europe (with some exceptions) (CEER, 2021) and also characterizes the so-called "building block model" that is used in Australia (AER, 2017).

During this first implementation stage, this classic "building block" approach would be combined with some state-of-the-art tools. Once the scheme has been settled and consolidated, and agents have become familiar with the new features of the scheme[27], the remuneration mechanism could eventually evolve to a TOTEX approach. In order to support this transition process, section 3.4 discusses how this transition could be progressively implemented.

In any case, as we shall see, some provisions can be introduced also in the first stage so that distribution companies have incentives to opt for OPEX-based solutions over grid reinforcements when this is the most efficient alternative.

Ex-ante remuneration with an ex-post correction

The remuneration formula would be based on an ex-ante regulation subject to ex-post adjustment mechanism, so as to adequately share the risk between DSOs and consumers. In this regard, CAPEX remuneration would be subject to a menu of contracts regulation, whereas controllable

[27] As for instance the aforementioned explicit consideration of the RAB, the need to present an investment plant, the use of a forward-looking reference model or the menu of contracts.

OPEX would be subject to a standard RPI-X (those OPEX deemed as non-controllable would be passed-through).

The remuneration formula is based on an ex-ante regulation subject to ex-post adjustment mechanism for CAPEX. CAPEX remuneration is subject to a profit-sharing menu of contracts. Controllable OPEX remuneration is subject to a standard RPI-X regulation.

We next describe the proposal, starting with the first phase, where a CAPEX and OPEX approach would be implemented. Then we review the second phase, where a shift towards the TOTEX-oriented approach (eliminating the separate treatment between CAPEX and OPEX) would take place.

The regulatory period

As discussed in the first report, short regulatory periods reduce the uncertainties faced by regulators and prevent large deviations between DSO costs and revenues, but at the same time dilute the incentives to increase efficiency through actions that yield benefits in the long-term (asset replacement, staff training, R&D expenditure) and also increase the regulatory burden both on regulators and DSOs. This is why, following the best practices, we would advise to use a 5-year period.

3.3 The shorter-term reform (first stage): separate treatment of CAPEX and OPEX with some state-of-the-art tools

In the first stage, it would be separately assessed and set targets for operating costs (OPEX) and long-term capital investment costs (CAPEX). This way, the general framework (that is further refined below) would be the classic "building block" approach, focused on unevenly placing cost-reduction incentives on CAPEX and OPEX.

To reduce the disincentive for reducing grid reinforcements through alternative shorter-term measures[28], OSINERGMIN could evaluate the possibility of considering some OPEX-based solutions (such as using demand-side services to avoid network investments) as CAPEX valued at a percentage of the avoided investment. This analysis would be carried out on a case-by-case basis by OSINERGMIN, and the project candidates to receive such treatment would be proposed by the distributors before carrying out the project.

As shown in Figure 9, the remuneration formula would be based on an ex-ante allowance (one for CAPEX and one for OPEX) subject to an ex-post adjustment mechanism for CAPEX according to the profit-sharing mechanism based on the menu of contracts.

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[28] Such as by implementing preventive maintenance, extending the life of assets when workable or procuring flexibility services to distributed energy resources (and storage).

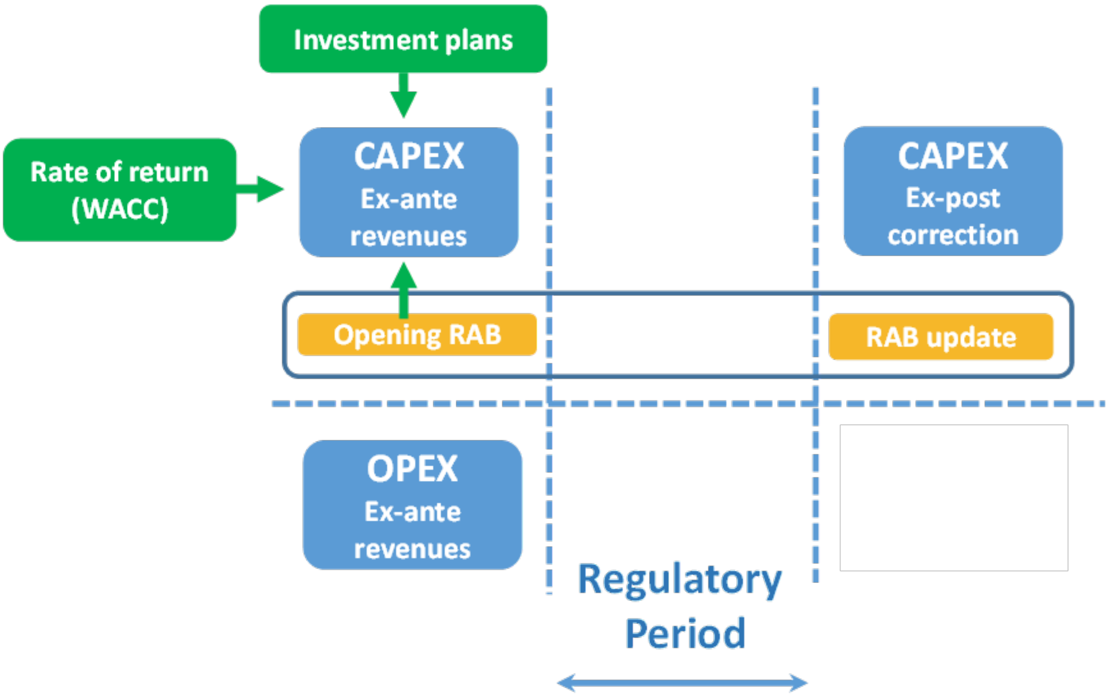


Figure 9.- Ex-ante revenue allowances for CAPEX and OPEX and ex-post correction for CAPEX.

3.3.1 Ex-ante allowed revenues: CAPEX

Establishing the allowed revenues of each DSO probably represents the most important task concerning electricity distribution regulation. Generally speaking, CAPEX-related allowances aims to compensate network companies for two main concepts, namely the return of the capital (or depreciation), and the return on capital.

The calculation of the CAPEX remuneration eventually granted to the distribution company can be broken down into three key elements, as shown in Figure 9[29]. These three major elements are:

- The opening RAB,
- the reference investment plan,
- and the rate of return (which we will assume to be the WACC in the following).

We next present the proposal as regards each of these three design elements in subsections 3.3.1.1 (opening RAB), 3.3.1.3 (the reference investment plan) and 3.3.1.2 (the rate of return).

3.3.1.1 *The opening RAB*

As regards the determination of the opening RAB, we can differentiate between the opening asset value at the beginning of establishing the RAB-based framework, i.e. the first regulatory period

[29] The previous three are the most relevant ones, but there are some others, such as choosing the depreciation method or the regulatory life of assets.

after the reform, and the opening RAB in the forthcoming regulatory periods (e.g. how to update the opening RAB from the second regulatory period onwards, that is, once the reform is fully implemented).

The value at the beginning of implementing the RAB framework is often known as the legacy RAB (this is the terminology we shall use hereafter). We first discuss the proposal as regards the legacy RAB and then the more general problem of subsequently updating the RAB value.

Legacy RAB

The recommended approach to compute the opening RAB at the outset of the reform would be to base the calculation on the so-called "implicit RAB". The implicit RAB is a very simple alternative that prioritizes revenue stability. The methodology computes the RAB that ends up providing a similar CAPEX-based remuneration to the one the company perceived in the previous scheme, i.e. the one "implicit" in the remuneration received in previous years.

The legacy RAB calculation is needed to change the remuneration from VNR to a RAB framework. The implicit RAB calculation provides revenue stability for the transition to the new regulatory framework.

This approach presents the important advantages that it mitigates sudden changes in the tariffs and its calculation does not require extensive input data or modelling studies. More specifically, the only input data that are required are the distribution revenues in the previous scheme, the share of CAPEX over total distribution revenues, the average age of assets (possibly with some form of smoothing[30]), the regulatory asset life and the WACC.

The multiplication of the two first parameters, i.e. previous revenues times share of CAPEX over total revenues, would provide the total initial *CAPEX* remuneration for each distribution company. Them the implicit RAB would be calculated using the formulas below, based on the concept that CAPEX remuneration is the sum of the return of the investment (depreciation) plus the return on the investment (RAB times the rate of return), where the only unknown is the RAB.

$$CAPEX = D + RAB \cdot WACC = \frac{GrossAssets}{Life} + WACC \cdot \frac{Life - Age}{Life} \cdot GrossAssets \qquad \text{Eq. (1)}$$

$$CAPEX = \frac{GrossAssets}{Life} \cdot \big(1 + WACC \cdot (Life - Age)\big) = D \cdot (1 + WACC \cdot (Life - Age)) \qquad \text{Eq. (2)}$$

[30] Assuming the same average life, and consequently the same remaining regulatory life, for all existing assets can introduce a relevant discontinuity in the future cash flow remuneration, since all legacy investments would be written off at the same point in time. Thus, some form of smoothing is recommended to prevent this depreciation "cliff-edge", e.g. by setting a progressive variation in the remaining regulatory life of legacy assets over time. A similar effect can be attained by dividing the legacy RAB into several blocks with different asset ages; in this case, a step-wise legacy RAB evolution would be obtained as the different blocks become fully depreciated.

$$D = \frac{CAPEX}{1+WACC\cdot(Life-Age)} \qquad \text{Eq. (3)}$$

$$RAB = \frac{CAPEX-D}{WACC} \qquad \text{Eq. (4)}$$

Where:

CAPEX	Annual CAPEX allowance
D	Annual depreciation remuneration
GrossAssets	Gross assets implicit in the CAPEX remuneration
Life	Regulatory life of assets
Age	Average age of assets

In order to illustrate the approach, let us imagine a distribution company that last year received 1,000 monetary units, its share of CAPEX over the total remuneration is 40%, and its assets have an average age of 25 years. The regulator wants to calculate its implicit RAB using a regulatory life of assets of 40 years and a rate of return of 10%. Using the formulas above:

- The CAPEX remuneration, both depreciation and return on investment, would be 400 monetary units (40% of 1000).
- Following Eq. (3), the annual depreciation term would be equal to 160 monetary units (to be perceived over the next 15 years, which is the average remaining life of the legacy assets).
- Finally, following Eq (4), the resulting implicit RAB would be equal to 2,400 monetary units.

It is relevant to note that most of the parameters required to compute the implicit RAB can be easily obtained and, in fact, already available nowadays in the regulatory price reviews in Peru. The regulatory rate of return (WACC) and the life of assets are used to compute the annuity of the VNR, whereas the weight of CAPEX over total distribution revenues is obtained in each price review as a result of the VAD studies. Therefore, the only additional parameter the regulator would need to define is the average age or remaining life of existing assets. This parameter can be estimated from historical information from distribution companies (investment plans, VAD studies, audits, etc.) and, if deemed necessary, be tailored to each one of them.

An alternative method for computing the legacy RAB based on calculating the VNR of existing assets and consolidating this value for subsequent regulatory periods was also considered by the consultants. However, after analysis of pros and cons, it was not recommended, as, in practice, it can lead to an unreasonable increase in CAPEX remuneration. This topic is discussed in more detail in annex 3B.

Opening RAB: general approach

We propose that, as regards the RAB updating from the second regulatory period onwards, it would be calculated by consolidating the non-depreciated investments already allowed in previous regulatory periods (thus, not reassessing that part). This is known as consolidating the RAB, as opposed to reopening the RAB. Consolidating the RAB has the desirable properties of mitigating regulatory instability and reducing the regulatory burden.

In the particular case of Peru, as it has been commented, the computation of the annuity of the VNR implicitly entails that the RAB is reopened and reassessed at the end of the regulatory period by means of a greenfield type model and considering efficient costs (*the model company*). This approach has provided reasonable results up to date, but it is not well-suited for the new changing and more uncertain context, for it could extremely increase risk exposure to DSOs. In the present context, it makes sense to turn into a consolidated approach. We next briefly review the design of this relevant element.

Introducing RAB additions under the consolidated RAB approach

When consolidating the RAB, regulators just have to update the RAB based on the results provided by the application of the profit-sharing mechanism depending on the actual investment and the ratio between DSO/regulator ex-ante projections.

As regards the frequency for updating the RAB, we propose as a general rule to update it ex-ante based on the reference investment plans (section 3.3.1.3), and then correct it ex-post at the end of the regulatory period[31]. Both the allowed ex-ante RAB value and the ex-post RAB correction are determined by the matrix defined by the menu of contracts (this is reviewed in section 3.3.1.4 and, in much more detail, in annex 3A). Additionally, as we shall see, some events can trigger a major reopening process (and introduce major corrections) before the end of the regulatory period.

3.3.1.2 *The rate of return*

The rate of return that is used for the allowed CAPEX would be calculated as the weighted average cost of capital (WACC). This means that the final rate of return is obtained as the weighted sum of the cost of the different sources of financing used by DSOs, mainly debt and equity. The method proposed to compute the cost of equity would be to resort to the capital asset pricing model (CAPM), which determines the cost of capital as the sum of a risk-free rate plus a market risk premium. A similar approach has been recently implemented in Chile, where the risk-free rate is computed as the average returns provided by the Central bank or the National Treasury for five-year products (MINISTERIO DE ENERGÍA, 2019).

3.3.1.3 *The reference investment plans*

In the scheme proposed, distribution investment plans would play a central role. Firstly, before the beginning of the regulatory period, OSINERGMIN would ask the DSOs to submit their year-by-year investment plans appropriately justified following some pre-defined criteria[32]. These

[31] The ex-post correction would be based on the discounted value of the resulting annual corrections resulting from the application of the matrix of the menu of contracts.

[32] OSINERGMIN would need to develop the criteria and planning methodology that must be used by the distribution companies to prepare the distribution investment plan. The criteria must consider the fulfillment of the electrical service quality standards, the level of performance, the planning horizons and the models to be used. The MEM would have to approve the planning criteria and methodology.

criteria should not focus exclusively on the technologies or types of investments, but also (and mainly) on the outputs that DSOs are expected to deliver. DSOs should also detail how the uncertainties over demand and distributed generation could affect their investment plans. This can be an iterative process where stakeholders could be involved.

Note that, in a traditional revenue setting there would be only one investment plan or expenditure forecast per distribution company. This plan is usually approved by the regulator eventually, and it is typically used as a reference against which actual investments are compared and deviations between both, limited or scrutinized in some way. However, the use of a menu of contracts approach requires two expenditures forecasts delivered by the regulator and the distributor respectively. The ex-ante revenue allowances would be computed as a weighted average of both, but an ex-post correction will be performed in order to remove the incentives to inflate expenditure forecasts submitted by the companies[33].

Therefore, in order to both assess the DSOs plan and use the menu mechanism, a parallel regulator's estimate is deemed necessary[34]. This estimate should be forward-looking (it has to try to anticipate future conditions that may have not been observed in the past). For this forward-looking approach, engineering-based reference network models (RNMs) are tools that can represent future potential scenarios.

The ex-ante CAPEX revenue allowances are computed as a weighted average of both, the distribution and the regulator investment estimates. Those estimates set the revenue framework based on the menu of contracts.

The regulator is responsible for establishing the base planning (or regulator's estimate), and based on this, also the revenue framework based on the menu of contracts.

3.3.1.4 *The ex-ante menu of contracts with ex-post correction*

The framework would establish an ex-ante remuneration subject to an ex-post adjustment mechanism (where the uncertainties anticipated in the plans are accounted for). This would be achieved through a menu of contracts. Ex-post corrections, based on the actually incurred CAPEX and the DSO/regulator ratio, are important to reduce the risk of the distributor, which is likely to increase in the forthcoming years (since distributed resources introduce more uncertainty, along with new potential technologies, digitalization, smart grids, etc.).

[33] This could be somehow similar to the 1/3 and 2/3 rule formerly used in Chile to determine the allowed revenues of distribution companies. However, an essential difference of the mechanism proposed in this report is that the use of the menu of contracts encourages companies to send accurate expenditure forecasts, thus preventing the large deviations between the companies and the regulator's estimates observed in the Chilean context.

[34] As discussed below, the menu of profit-sharing contracts functions around the ratio of the DSO/regulator projections.

The main idea behind the menu of contracts approach is that the regulator defines different profit-sharing contracts with different combinations of ex-ante allowed revenues and sharing factors for CAPEX. A profit-sharing contract may be seen as a hybrid between a pure (ex-ante) revenue cap and an (ex-post) cost of service regulation, as explained in the box below.

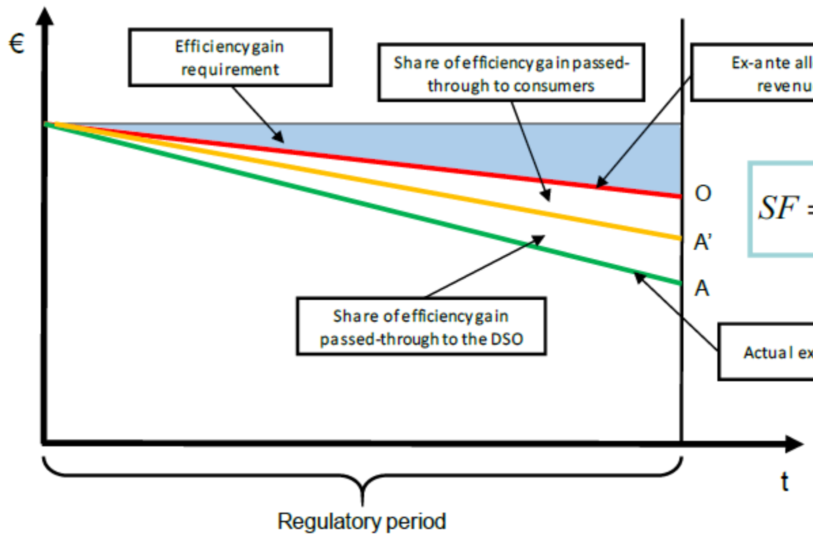
Illustration of one profit-sharing contract

The next figure illustrates the functioning of one profit-sharing contract (remember that the menu of contracts is made up of several of these contracts).

The contract illustrated in the figure below assumes a symmetric sharing factor. The ex-post allowed revenues are computed as the sum of the conventional ex-ante remuneration (*Rn-1*) times the sharing factor (*SF*) plus a second term that is obtained as the product of the actual expenditures declared by the distributor (*En*, declared ex-post) times the complementary of the sharing factor. This remuneration formula has the following characteristics:

- If the sharing factor is equal to 1, the formula is a pure revenue cap.
- If the sharing factor is zero, the formula corresponds to a pure cost of service regulation.
- For values of the sharing factor between 0 and 1, the formula is a hybrid approach. The higher the value of SF, the closest the regulation would be to a revenue cap and vice versa.

$$R_n = R_{n-1} \cdot SF + E_n \cdot (1 - SF)$$



$$SF = 1 - \frac{OA'}{OA}$$

Figure 10.- Illustration of a profit-sharing mechanism combined with a revenue cap. Source; (INTEGRID, 2020a).

As it is reviewed in annex 3A, the profit-sharing contract that applies to each specific distribution company would depend on the ratio computed as the distributor's cost estimate, based on its investment plan, as the regulator's cost estimate based on efficiency analyses and cost studies (see the discussion in section 3.3.1.3). This ratio measures how much the company foresees it is necessary to spend as compared to the regulator's view. Each profit-sharing contract is constructed with different combinations of ex-ante allowed revenues and sharing factors. Provided these contracts are correctly designed, distribution companies can be incentivized to both be efficient and also to submit accurate investment forecasts[35]. One of the annexes to this chapter (annex 3A) provides additional details on the appropriate design and the incentive properties of this regulatory mechanism.

The strength of both incentives can be calibrated. As regards the incentive associated with the ex-post profit-sharing review, the recommendation would be to bring the ex-post correction closer to a cost of service regulation in the first regulatory period. The strength of the incentive scheme could later be increased over time as both regulators and distribution companies become familiar with the scheme.

Summing up, the main steps followed for the application of this menu regulation would be the following:

- At the beginning of the regulatory period, the distribution companies have to submit their investment plans to the regulator, following certain formats and guidelines. These investments plans are subject to a consultation process with stakeholders. The regulator may also require additional explanations or justifications.
- After this consultation period, the companies have to submit the final investment plans. It is relevant to note that they may introduce the modifications they deem necessary at this point, but the amount of expenditures should reflect their own expectation on investment requirements. The regulator would publish the cost baseline for each distribution company, usually differing from the companies' estimates (based on in-house analyses and/or consultancy studies) and would publish the menu of contracts (see the format in annex 3A).
- Depending on the ratio of the costs estimated by the distributor over the forecast by the regulator, the specific profit-sharing contract to be applied to each company is fixed.
- At the end of the regulatory period, an ex-post adjustment to the ex-ante CAPEX remuneration is carried out once the actual CAPEX expenditures incurred by each company are communicated to the regulator. This correction is computed applying the parameters of the profit-sharing contract previously determined as the discounted value of the annual differences throughout the period. This ex-post correction can be positive or negative depending on whether under or over investments have taken place. This amount should be conveyed to the corresponding distribution company as a revenue adjustment for the next regulatory period. In addition, the RAB is updated with the values finally acknowledged after the ex-post adjustment.

[35] Encouraging the distributors to submit accurate investment forecast can become a complex matter if we consider how the companies own forecasts conditions eventually the regulator's one. This issue is analyzed in detail in (OFGEM, 2018).

At the end of the regulatory period, the ex-post CAPEX revenue correction is computed according to the actual CAPEX expenditures and the ratio of the distribution company/regulator estimates calculated at the beginning of the regulatory period applying the menu of contracts matrix.

3.3.2 OPEX

OPEX comprises a myriad of factors, some of which are related to the network activities such as asset maintenance (preventive or corrective) and repair, and some others are related to non-network activities (including personnel costs, building rentals, expenditures in innovation, business support costs, outsourcing, etc.).

3.3.2.1 *Ex-ante allowed revenues*

First, OPEX should be divided into controllable and non-controllable cost. The costs subject to efficiency targets should be those considered as under the control of distribution companies. Whereas for non-controllable costs it would be implemented a direct pass-through[36].

Controllable OPEX costs

The path of allowed controllable OPEX would be based on a standard RPI-X, and would be set for every regulatory period. In this way, different from CAPEX, no ex-post corrections are considered for OPEX subject to a RPI-X revenue cap. The efficiency requirements associated with the RPI-X, would be determined through benchmarking (the costs that could not be subject to benchmarking would be assessed by independent consultants). This way, an efficiency target, computed through a benchmarking study, would reduce the controllable allowed cost year by year.

In the next regulatory period, a new benchmarking study would be performed, including in this update the information about actual OPEX within the previous regulatory period.

OPEX revenue allowances at the beginning of each regulatory period are set subject to a RPI-X revenue cap formula. Efficiency targets are determined through benchmarking.

This requirement on higher productivity would not be applied for the non-controllable cost, which as has been mentioned would be subject to a direct pass-through.

[36] Non-controllable OPEX are those which may not be reduced through efficiency efforts by the distributors. These may include mandatory fees, taxes or insurances (e.g. land use, pension fund contributions).

3.3.3 Other design elements

3.3.3.1 *Quality of service*

The proposed framework would be based on a bonus-malus scheme. A bonus-malus scheme is more effective than the new scheme currently in place, where the incentive is given at the beginning of the tariff period, and if the company does not comply with the objective, it must return the corresponding amounts in the next tariff period. A bonus-malus scheme, if well calibrated provides a more continuous signal.

The reference value (see the figure below) would have to be calibrated for each distribution company and sector. These reference values would have to be based on the initial quality level offered by the company and also on the expected investment plans.

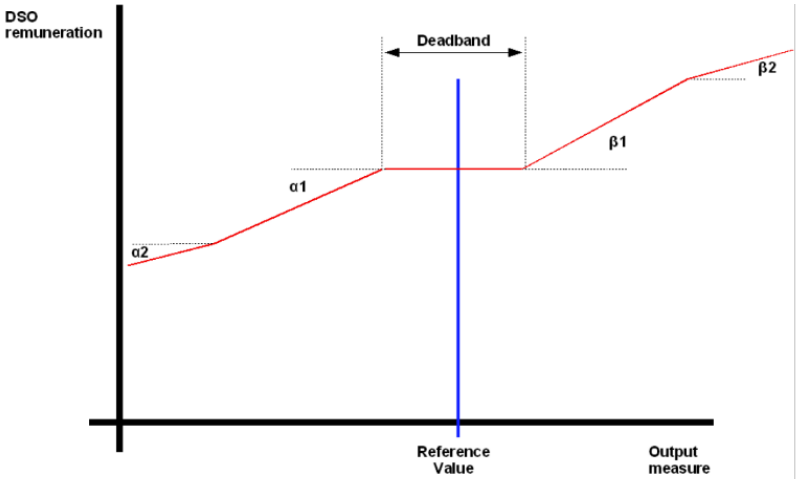


Figure 11.- Relevant parameters in a bonus-malus scheme. Source: (Cossent, 2013)

The output measure of the incentive scheme should be tied to both the duration and the number of interruptions. This is typically done by setting two bonus-malus terms, one accounting for the number of interruptions (e.g. SAIFI-related) and another accounting for the duration of the interruptions (e.g. SAIDI-related). The interruptions would be weighted differently depending on whether they correspond to planned or unplanned interruptions (for the latter cause a lower impact on grid users). This would require a framework that allows to qualify (and supervise) an incident as planned interruption.

Lastly, the marginal incentive needs to appropriately reflect the true value of quality of service for network users as well as the new opportunities distributors have to improve reliability. In particular, this incentive rate should ideally be equal to the marginal cost of improving reliability when optimal quality levels would be achieved.

Other well-known parameters that need to be calibrated are the dead-band and the marginal incentive for extreme values of the output measure (which can be flat, representing a maximum bonus and a minimum malus).

A bonus-malus scheme is recommended to improve quality of supply indicators (SAIDI and SAIFI). The incentive rate should reflect the true value for network users and the incremental distribution cost of improving reliability.

3.3.3.2 *Losses*

As regards the losses, the proposed framework would be based on two major changes:

- To base the acknowledged associated losses-related costs on the real network. These costs could be subject to an upper limit determined through benchmarks.
- Implement a bonus-malus scheme, similar to the one that has been just described for the quality of service.

3.3.3.3 *Incentives to extend the useful life of assets*

Under the “CAPEX and OPEX” RAB-oriented regulation, distributors may have an incentive to replace assets when they are written off. A revenue driver could be introduced so as to extend the useful life of assets (when economical). This way, an end-of-life incentive is recommended to provide remuneration for assets for an additional number of years. This incremental remuneration may be defined as a unit operation and maintenance allowance that increases over time for fully depreciated assets.

3.3.3.4 *Incentives to innovation*

The adoption of new grid operation solutions and technologies requires distributors to test them at a limited scale before deploying them at a larger scale. Pilot projects allow them to test and compare alternative technology solutions, work together with developers and manufacturers, and prevent mistakes and dead-ends when performing the deployment. Since distributors face some technology risks in this process, the existence of mechanisms that allow them to mitigate these risks are essential to facilitate the adoption of innovative solutions. This would be achieved through ad-hoc economic incentives that allow distribution companies to recover, at least partly, the corresponding costs outside the regulator allowed revenues.

This would take the form of direct payment to distribution companies in order to undertake specific pilot projects, through a partial or total pass-through of certain costs (these costs would be added to the RAB without subjecting them to efficiency analysis) and by awarding distribution companies a higher return on these investments. The allocation of these funds may be done under competitive mechanisms whereby ad-hoc calls would be organized in which distribution companies may submit proposals for pilot projects justifying their relevance and potential benefits. Information disclosure obligations may be set.

Innovation projects with previous regulatory approval can be added to the RAB with no further efficiency and even awarded with a higher return. It is recommended that the allocation of these incentives be done under competitive calls.

In any case, regulatory supervision both as an ex–ante approval and ex-post evaluation is needed. Such evaluation should be made based on a set of indexes and/or cost benefit analyses where the benefits for network users are clearly shown.

3.3.3.5 *Incentives to increase the penetration level of distributed energy resources*

Distributed energy resources can be incentivized by adding DER-related revenue drivers to the revenue cap formula in order to compensate DSOs for the associated incremental costs[37].

3.3.3.6 *Reopeners*

To reduce risk exposure, it should be possible to reopen the revenue determination when a large deviation with respect to the conditions expected at the price review happens. The type of events that can trigger a reopening would include large demand forecast errors, a high increase in DG connection, or sudden technology changes. This reopening may take place at the request of the distribution company either at any moment or in pre-defined windows throughout the regulatory period.

3.4 Long-term reform: TOTEX-oriented approach

After two regulatory periods, when distribution companies and stakeholders have become familiar with the new elements of the scheme, the remuneration mechanism could eventually evolve to a TOTEX approach. This is the scheme at which Peru should aim in the long term.

The TOTEX-oriented mechanism is similar in many ways to the "CAPEX and OPEX". The following aspects represent the most relevant changes with respect to the previous scheme:

- Under the TOTEX framework, distribution networks are given a single expenditure allowance and therefore there is no differential treatment for CAPEX (see the figure below). If efficiency incentives are neutral to CAPEX and OPEX reductions, distribution companies are provided with the incentive to exploit the potential trade-offs between both types of expenditures.

  As described in section 1, local flexibility markets can allow distribution companies to defer or avoid grid investments, thus exploiting tradeoffs between CAPEX and OPEX. However, it is relevant to stress that this is not the only possible CAPEX/OPEX tradeoff. In other words, TOTEX regulation can be beneficial even if local flexibility markets are not fully developed yet. In fact, since the use of these mechanisms is not yet mature, distribution companies will probably explore other alternatives first.

  For instance, non-firm connection agreements can be used instead of local flexibility markets to mitigate the impact of connecting large volumes of DER to the grid. These are bilateral agreements between the grid operator and new network users under which the distribution companies are granted the right to modify/curtail the energy

[37] Another way to introduce these incentives is by modifying efficiency requirements (X factor) according to DER penetration rates.

injected or withdrawn from the network in case of grid constraints. In exchange, the new users could benefit from lower connection costs or network charges, or a faster grid connection. Likewise, the progressive digitalization of the distribution grid, can enable the implementation of advanced grid operation functionalities that would reduce CAPEX needs. For example, predictive maintenance strategies, supported by extensive data collection and analytics, is expected to lengthen the operating lives of assets and optimize asset replacement decisions.

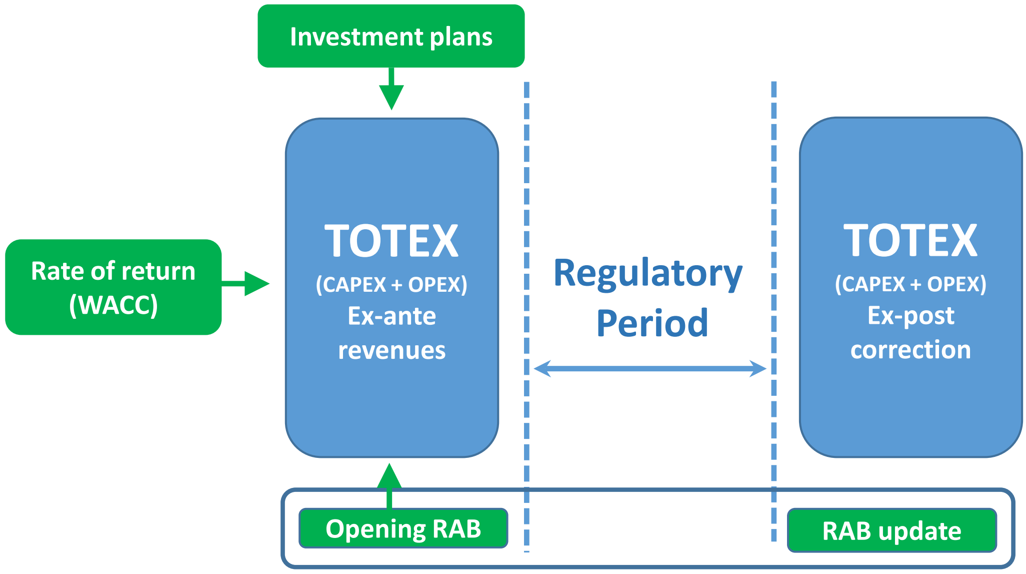


Figure 12.- Ex-ante revenue allowances and ex-post correction for TOTEX.

It is worth mentioning that setting a TOTEX allowance does not mean that the underlying ex-ante allowance cost assessment cannot be based on the separate estimated/updated CAPEX and OPEX values. Indeed, the investment plans would still play a central role in this framework, and revenue allowances would still be calculated considering the building blocks of distribution companies' expected costs. The key is that regulation ensures that allowed revenues are independent of the actual cost structure of distribution companies.

- The menu of contracts and the ex-post correction would apply in this framework to total costs (except pass-through costs). Therefore, the mechanism would be myopic as regards how these costs are allocated between CAPEX and OPEX when computing the ex-post compensations.

- In TOTEX-based regulation, to keep the CAPEX-OPEX incentive-neutrality it is necessary to decouple, at least to some extent[38], the new RAB additions from actual CAPEX investments. The larger the decoupling the larger neutrality between

[38] A partial decoupling could be implemented by exempting certain types of assets from the menu regulation or by partly adapting the capitalization rates to the actual cost structure of each distribution company. Individual capitalization rates could be set in the beginning and, progressively, evolve towards a more homogeneous value of the capitalization rate for all companies.

CAPEX and OPEX cost reductions (but the larger the potential risk for the distributor).

The recommended approach would be to end up applying a fixed capitalization rate. That is to say, a fixed proportion of the allowed TOTEX is capitalized and added to the RAB. However, this does not mean that the shift from the separate treatment of CAPEX and OPEX towards a TOTEX-oriented regulation needs to happen overnight. A gradual process should need to be implemented to smooth out possible changes in network tariffs. In order to achieve this, the regulator may resort to modulating several parameters.

Firstly, the capitalization rate can be adapted over time, in such a way that it is started at values that are close to the actual CAPEX/TOTEX ratio and little by little it converges to the value the regulator may deem representative for the optimally managed and planned company. In this process, the regulator may set a distinct capitalization rate for each company. Moreover, capitalization rates throughout the regulatory periods can be reassessed or, if these are very long, in a mid-term review. However, this should be made only for future investments, not the ones already incurred[39].

Another complementary strategy for a gradual implementation of TOTEX-oriented regulation consists in including different OPEX categories progressively into the menu of contracts framework. The first type of OPEX to be included under the TOTEX framework would be those where CAPEX/OPEX tradeoffs are most relevant (e.g. asset maintenance). The rest of OPEX categories may remain under a separate treatment. The process would progressively converge along several regulatory periods to a full TOTEX approach.

After at least two regulatory periods by experiencing the recommended building-block approach (CAPEX+OPEX), it is recommended to migrate to a more advanced approach based on TOTEX. This approach would provide more equalized incentives to innovation by distribution companies. The capitalization rate, a key regulatory parameter under this approach, can be gradually updated to target optimally managed companies.

3.5 Annex 3A: The incentive-compatible menu of contracts

A key element in the proposal for amending distribution revenue setting in Peru presented above is the use of a menu of profit-sharing contracts to regulate network investments and, at a later stage, TOTEX. The functioning of profit-sharing contracts was already discussed above and illustrated in Figure 10.

[39] Changing the capitalization rates for existing assets would imply re-opening the RAB, which goes against the approach proposed in this report based on consolidateing the RAB from previous regulatory periods.

The proposed mechanism combines this type of regulatory contract with a menu regulation based on the work of (Laffont and Tirole, 1993), which showed that offering regulated companies a well-designed menu of options instead of a single regulatory contract, e.g. a conventional revenue cap, can encourage companies to reveal private information about cost reduction opportunities. The advantage of this approach, as compared to a pure revenue cap regulation, is that it accounts for the fact that the regulator's expenditure estimates may be flawed due to uncertainties and information asymmetries[40].

In order to illustrate this property, a very simple example is presented below. Let us imagine a country with three distribution companies, namely company 1 to 3, where the regulator offers them three different profit-sharing contracts following the formula in Eq. (5) (a one-year regulatory period is assumed for the sake of simplicity).

$$R_1 = R_0 \cdot SF + E_1 \cdot (1 - SF) \qquad \text{Eq. (5)}$$

These three contracts consist in distinct pairs of values for the sharing factor (*SF*), i.e. 0, 1 or 0.5, and initial allowed revenues (R_0), i.e. 120, 100 or 110 respectively[41] (see the table on the left-hand side of Figure 13).

Company 1			
SF	R0	E1	R1
0	120	115	115
1	100	115	100
0.5	110	115	112.5
Company 2			
SF	R0	E1	R1
0	120	98	98
1	100	98	100
0.5	110	98	104
Company 3			
SF	R0	E1	R1
0	120	80	80
1	100	80	100
0.5	110	80	95

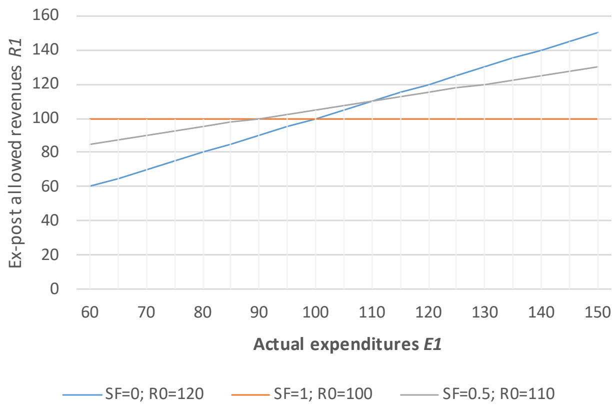


Figure 13: Illustrative example of the menu of profit-sharing contracts

The three distribution companies are offered the same set of profit-sharing contracts. Nonetheless, each distributor has different capabilities to reduce their costs below the regulator's estimate (provided adequate efforts are made). In the example, this is shown with the parameter E_1, i.e. it is assumed that the actual expenditures of each company in year 1 are the lowest possible expenditure they could achieve with a reasonable managerial effort[42].

[40] Note that cost of service regulation would also remove the problems related to regulatory errors; however, it would also eliminate any cost-reduction incentive as desirable by the regulator.

[41] The values of R_0 can be interpreted as a percentage of the efficient expenditure level estimated by the regulator for each company, i.e. the allowed revenues under a pure revenue cap regulation.

[42] Under a conventional revenue cap regulation (which in fact corresponds to the contract {SF=1; R0=100}) this information is only known to the regulator once the regulatory period is elapsed.

By calculating the final ex-post revenues that each company would obtain should they choose each of the contracts (column R_i), we can determine what contract each company would optimally choose (highlighted in green). It can be easily seen that each distributor would choose a different profit-sharing contract, thus revealing the cost reduction they estimate to achieve as compared to the regulator's forecast:

- Company 1 would actually need to spend more than the amount computed by the regulator, hence choosing a low-powered contract {SF=0; R0=120} (closer to cost of service regulation)
- Company 2 foresees actual expenditures close to those set by the regulator and the optimal choice for her is to pick the contract {SF=0.5; R0=110}
- Company 3 can attain significant reduction in costs below the regulator's baseline, thus selecting a high-powered contract {SF=1; R0=100}

The companies that have a stronger potential to reduce costs would opt for a higher-powered regulatory contract (higher SF) and vice versa. Hence, this shows that, if the menu of contracts of correctly designed, it promotes distribution companies to reveal private information and reduce information asymmetries.

The graph on the right-hand side of Figure 13 generalizes this conclusion by showing the ex-post allowed revenues that a distribution company would obtain under the three contracts for different expenditure levels. Naturally, the optimal contract would that which provides the highest level of allowed revenues for the same expenditures. Therefore, from the distributor's point of view, the optimal contract would be {SF=1; R0=100} for expenditures below 90, {SF=0.5; R0=110} for expenditures between 90 and 110, and {SF=0; R0=120} for expenditures above 110.

Of course, this is a simplified example of menu regulation. In practice, it is common to offer regulated companies a continuum of contracts instead of a discrete set of profit-sharing options as presented in Figure 14. The matrix in the upper part of the figure presents different profit-sharing contracts which, as in the simple example above, present different combinations of ex-ante allowed revenues and sharing factors. In this case, a third parameter, named additional income, is added. This is a lump sum added to the ex-ante allowed revenues and it aims at encouraging distribution companies to provide their best expenditure forecast in their investment plans.

The elements of the matrix represent the amount of money, again expressed as a percentage of the regulator's expenditure baseline, that each distribution company would obtain on top of their actual realized expenditures, i.e. the profit or loss attained, for each combination of regulatory contract (columns) and actual expenditures (rows). It can be seen that the maximum value for each row (expenditure level), the maximum profit (or lowest loss) is obtained when the ex-post expenditures match the ex-ante forecast submitted by the distribution company.

Ratio DSO/Regulator	95	100	105	110	115	120	125	130	135	140
Allowed revenues	98.75	100	101.25	102.5	103.75	105	106.25	107.5	108.75	110
Sharing factor	63.8%	60.0%	56.3%	52.5%	48.8%	45.0%	41.3%	37.5%	33.8%	30.0%
Additional income	3.7	3.0	2.2	1.3	0.3	-0.8	-1.9	-3.2	-4.5	-6.0
85	12.5	12.0	11.3	10.5	9.5	8.3	6.8	5.3	3.5	1.5
90	9.3	9.0	8.5	7.9	7.0	6.0	4.8	3.4	1.8	0.0
95	6.1	6.0	5.7	5.3	4.6	3.8	2.7	1.5	0.1	-1.5
100	2.9	3.0	2.9	2.6	2.2	1.5	0.7	-0.4	-1.6	-3.0
105	-0.3	0.0	0.1	0.0	-0.3	-0.8	-1.4	-2.3	-3.3	-4.5
110	-3.5	-3.0	-2.7	-2.6	-2.7	-3.0	-3.5	-4.1	-5.0	-6.0
115	-6.7	-6.0	-5.5	-5.3	-5.2	-5.3	-5.5	-6.0	-6.7	-7.5
120	-9.8	-9.0	-8.3	-7.9	-7.6	-7.5	-7.6	-7.9	-8.3	-9.0
125	-13.0	-12.0	-11.2	-10.5	-10.0	-9.8	-9.7	-9.8	-10.0	-10.5
130	-16.2	-15.0	-14.0	-13.1	-12.5	-12.0	-11.7	-11.6	-11.7	-12.0
135	-19.4	-18.0	-16.8	-15.8	-14.9	-14.3	-13.8	-13.5	-13.4	-13.5
140	-22.6	-21.0	-19.6	-18.4	-17.3	-16.5	-15.8	-15.4	-15.1	-15.0

	Inflated DSO estimation	Reference	Cost reduction
Regulator's estimate [M€]	250	250	250
DSO's estimate [M€]	300	275	275
Ratio DSO/Regulator	120	110	110
Sharing factor [%]	45	52.5	52.5
Additional income [%]	−0.8	1.3	1.3
Allowed expenditure [M€]	$105\% \cdot 250 = 262.5$	$102.5\% \cdot 250 = 256.25$	$102.5\% \cdot 250 = 256.25$
Actual expenditure [M€]	275	275	250
Actual efficiency incentive [M€]	$45\% \cdot (262.5 - 275) = -5.625$	$52.5\% \cdot (256.25 - 275) = -9.844$	$52.5\% \cdot (256.25 - 250) = 3.281$
Additional income [M€]	$-0.8\% \cdot 250 = -2$	$1.3\% \cdot 250 = 3.25$	$1.3\% \cdot 250 = 3.25$
Final remuneration [M€]	$275 - 5.625 - 2 = 267.375$	$275 - 9.844 + 3.25 = 268.41$	$250 + 3.281 + 3.25 = 256.531$

Figure 14: Source (Cossent and Gómez, 2013)

The incentive properties are better shown by the calculations in the bottom part of Figure 14. The figures in the first two columns (excluding the text column) show the final revenue of a distribution company under two different ex-ante estimations with the same actual expenditure. Let us assume that the distributor tried to inflate its forecast from 275 M€ (2nd column) to 300 M€ (1st column) expecting a higher remuneration. It can be seen that for the same level of actual expenditure, the firm receives a higher remuneration when the forecast turned out to be more accurate.

On the other hand, the third column represents the same distributor with a forecast of 275 M€ in expenditure, which in this case it has been able to reduce its expenditures down to 250 M€. Comparing the second and third columns, it can be seen that, under the latter circumstances, the distribution company would receive a higher differential between actual costs and revenue allowances. Hence, efficiency incentives remain in place. Note that if this company had forecasted this potential cost reduction ex-ante, its revenues would have been higher.

These properties are kept as long as the distribution company has a reasonable expectation that their cost estimates will not affect the regulator's estimate (OXERA, 2007).

3.6 Annex 3B: An alternative approach for determining the legacy RAB

In order to determine the legacy RAB, as discussed in section 3.3.1.1, an alternative to the implicit RAB proposed therein was also considered by the consultants. Under this alternative approach, the opening RAB for the first regulatory period would be computed as the annuity of the VNR corresponding to the existing assets, similarly to current practices. However, instead of reassessing the VNR at each price control as is the case nowadays, this value would be frozen as the CAPEX remuneration paid to distribution companies for pre-existing assets throughout the whole operating life of these assets. If deemed necessary, this value may be updated periodically according to inflation or other macroeconomic indicators. Additionally, new investments, including asset replacement, would be included in the RAB and be subject to depreciation along their regulatory economic life as described in the main body of this chapter.

A characteristic of this approach is that it requires detailed inventory of existing assets and specific efficient standard costs depending on the type of network installations, The availability of these data, in the Peruvian context, is ensured because of the current regulatory practices and, therefore, this method could be more easily accepted by stakeholders. An added advantage of this approach is that it does not require to explicitly define a remaining life of pre-existing assets as the implicit RAB method does, which, may mitigate possible opposition from or litigation with stakeholders.

However, whilst both previous characteristics could facilitate acceptance and result in an easier implementation, this alternative approach for calculating the legacy RAB presents important drawbacks that, in our opinion, make the implicit RAB preferable. The main challenges of this alternative are the following:

- Under the current approach in Peru, the VNR is reassessed and updated at each price review considering an adapted network; thus, only useful assets are remunerated. However, should this legacy RAB method be implemented, CAPEX remuneration for pre-existing assets would be frozen and passed-through to the tariffs indefinitely, whilst new investments carried out by the distribution companies would be added to the RAB. This can result in an ever increasing RAB in the detriment of rate payers.
- Indeed, this can be solved by retiring obsolete assets and writing them off the legacy RAB. However, determining what assets should be written-off is not straightforward. Distribution companies would have little incentive to do so since, if they did, their CAPEX remuneration would decrease (especially if the initial value is indexed to inflation). Hence, they could see a perverse incentive to keep obsolete and inefficient network components under operation.
- Avoiding this would thus require increased regulatory oversight, e.g. monitoring asset commissioning dates and remaining lives (which is what we wanted to avoid in the beginning with this method).
- Moreover, especially if distribution companies perceive an asymmetric treatment between legacy assets and new investments (e.g. very strict approval processes for investment plans), distribution companies could prioritize partial interventions on legacy assets over complete asset replacements, even if the latter may make more sense from a system economic perspective. These partial interventions could comprise, among other, replacing the conductor of an existing line or increasing the height of overhead line towers.
- Finally, reviewed international experience in Europe and US is aligned with the practice of consolidating RAB assets (legacy plus new investment) under a consistent method, where the effect of the legacy asset treatment would be completely vanished in the medium to long-term..

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4 Tariff design

4.1 The Peruvian context

Peru's electricity tariff regime is designed to recover full costs for the provision of the electricity service in each of three segments: generation, transmission (bulk transmission and subtransmission systems), and distribution (primary and secondary[43] distribution systems.). The formation of electricity prices for the end-user is made up of the addition of these three components, each of which presenting a different methodology to allocate its costs. On top of these components, there are also cross-subsidies among consumers, like the social compensation power fund (FOSE).

As regards the generation tariff component, free users can contract directly with a generator or a distributor the price of their electricity generation tariff supply, while the rate of electricity generation for regulated users is established by OSINERGMIN[44].

The sector's legislation classifies free users and regulated users according to the user's maximum annual electricity demand level:

- Users with demands up to 200 kW are considered regulated users.
- Users with demands over 200 kW and up to 2,500 kW can choose to be a regulated user or a free user.
- Finally, consumers with demands over 2,500 kW are considered free users[45].

Transmission and distribution charges are regulated and also determined by OSINERGMIN (free users cannot negotiate these regulated charges freely). It is also noteworthy that, for free users, both their contracts and their corresponding invoices have to clearly disaggregate the prices and charges for each of the segments[46].

Depending on the tariff (reviewed below), each of the aforementioned cost components is allocated through the fixed, capacity and energy charges, with the capacity and energy charges offering some time discrimination in some tariffs.

We next briefly review some further details of the three cost components (section 4.1.1), the tariffs available and the corresponding formats as regards how they allocate costs to the fixed, capacity

[43] Medium- and low- voltage.

[44] In particular, this responsibility corresponds to OSINERGMIN's Adjunct Office for Tariff Regulation (GART).

[45] Users with demand equal or greater than 10,000 kW are considered large users. Large users form part can directly participate in the wholesale spot market.

[46] The contract also needs to describe the quality of service in which the service will be provided, which may not be lower than those established in the NTCSE (see section 3), unless the free user expressly states otherwise in exchange for some other special condition that favors her.

and energy charge (section 4.1.2) and finally the existing electricity subsidies and cross-subsidies (section 4.1.3).

Peru's electricity tariff regime is designed to recover full costs of each of the three segments: generation, transmission, and distribution. The formation of electricity prices for the end-user is made up of the addition of these three components, each of which presenting a different methodology to allocate its costs.

On top of these components, there are also cross-subsidies among consumers.

4.1.1 Cost components of the tariff

Generation

As commented above, the rate of electricity generation for regulated users is established by OSINERGMIN, while free users can contract directly with a generator or a distributor the price of their electricity generation supply. Particularly, the price at the generation level is the weighted average of the bar prices (*precio en barra*, in Spanish), the prices of bilaterally agreed contracts, and the prices of contracts resulting from auctions (plus an incentive for early bidding).

A major drawback of the allocation approach is that the final consumer is almost completely isolated from spot market signals. The scheme is therefore losing the opportunity of triggering a response from consumers that could be beneficial to the system.

Free users can contract directly with a generator or a distributor the price of their electricity generation tariff supply, while the rate of electricity generation for regulated users is established by OSINERGMIN, as the weighted average of bilateral contracts and long-term auctions contracts

Transmission

Transmission and subtransmission charges/tariffs are established and updated annually by OSINERGMIN. If the format of the tariffs allows it, these transmission charges are allocated in terms of the consumer's peak coincident demand[47].

[47] Measured during the so-called peak hours (defined by the MEM, today from 5:00 p.m. to 11:00 p.m.).

A major concern in the last decade has been the progressive addition of some other charges to the transmission tariff. Since the transmission tariff is paid by all users, it has been seen as the channel to allocate some other costs[48] that are to be borne by all the system. This is reviewed next.

Additional charges in the transmission tariff

The nature of each of the additional charges included in the transmission tariff is quite diverse. There is a total of six main additional charges that are currently embedded in the transmission tariff, as detailed next:

- The charge for emergencies: this charge is oriented to recover the costs related to emergencies. These situations have mostly involved distribution companies renting emergency generators (oil) to avoid non-served energy.
- The charge for *Nodo Energético del Sur:* Law No. 29970 created a charge to compensate generators helping to ensure security of supply in *Nodo Energético del Sur*.
- The charge for security of supply and cold reserve: this charge is intended to compensate the plants classified as dual-fuel plants[49] and also the cold reserve plants awarded by PROINVERSION.
- The charge associated with the FISE compensation: this charge was created to compensate electricity generators that use natural gas as fuel, for the payment they have to make to the Social Energy Inclusion Fund (FISE). In particular, the compensation amount corresponds to the surcharge paid by natural gas generators, which is equivalent to USD 0.055 per thousand cubic feet.
- The charge associated with the renewable support mechanism: this charge is aimed at recovering the cost associated with the premium that is to be paid to generators that operate within the Renewable Energy Resources (RER) support scheme. The premium represents the price that has to be paid on top of the spot market price, in order to guarantee the annual income that RER was ensured in the auctions[50].
- The charge associated with the transfer of property of natural gas pipelines: the objective of this charge is to compensate generators that had natural gas pipelines for their own use and that, by regulatory mandate, had to transfer them to the natural

[48] Many of these sources of costs are associated with special regulations enacted to promote some specific projects and technologies.

[49] That is, generators that operate with natural gas and that have facilities that allow alternative operation with another fuel. This position was created through Legislative Decree No. 1041, approved in 2008, with the purpose of remunerating the additional cost of those units that offer duality service, that is, operating with two types of fuel (for example, natural gas or oil), so that they contribute to provide greater security of supply in cases of emergency, such as problems with the supply of natural gas.

[50] The purpose of these auctions is to promote the use of RER generators, such as wind, solar, biomass and hydraulic energy, the latter with an installed capacity of less than 20 MW. For which, the companies awarded in the RER Auctions have a guaranteed income for 20 years.

gas concessionaire. Thus, this charge compensates for the new payment (the distribution gas tariff) that generators previously did not have to bear. This is intended to be a transitory charge and will disappear in the future.

The problem of overcharging the transmission tariff

As mentioned above, the transmission tariff allocates the costs to the peak coincident capacity charge (at least in those tariffs options where there is a capacity charge, such as tariffs for industrial consumers). This has led to over-incentivizing the reduction of the peak coincident demand consumption to industrial consumers. Through the installation of small generators oriented to self-consume at peak hours, these industrial consumers are able to avoid these system charges. This is clearly a source of inefficiencies.

Transmission tariffs are regulated and also determined by OSINERGMIN, and they charge costs over the peak coincident component.

These tariffs are being used to allocate the costs corresponding to several policy-driven mechanisms, therefore overincentivizing the reduction of peak coincident consumption (in those tariffs options with capacity charge).

Distribution

The distribution network electricity charges to be paid depend on the location within the network of the final user. A cascading approach is applied to the final allocation of network costs, considering a cascade that starts upstream with generation, then goes through transmission and subtransmission, and terminating with distribution (medium and low voltages). This way, a large user connected to the high-voltage transmission system will pay only generation and transmission costs. A small residential user will pay the chain of all charges up to the low- voltage supply point.

Distribution charges are made up of the added value for medium voltage and the distribution added value for low voltage. Distribution charges/tariffs are recalculated every four years, following evaluation studies carried out by the distribution companies and reviewed by OSINERGMIN (see section 3).

Similarly, to the transmission tariff, distribution charges are allocated in terms of the capacity charge (again, conditioned to the fact that the particular tariff presents a capacity charge, see next subsection).

Distribution tariffs are regulated and determined by OSINERGMIN every four years based on the so-called VAD. The allocation of the cost is based on a cascading *approach and on the a peak coincident charge (in those tariffs options with capacity charge).*

4.1.2 Tariff structure and cost allocation for regulated users

The main classification applied to regulated customers in Peru is related to the connection voltage. Low-voltage users are connected below 1 kV, while medium-voltage users have connections to the grid between 1 and 30 kV (high-voltage users are considered to be free customers and they are not considered in this classification). Each group is then divided into subgroups, according to the tariff components and the level of time differentiation. The main tariff options currently available in Peru are presented in the following table.

Table 3- Tariff structure applied in Peru. Classification from OSINERGMIN

Group MT Medium voltage 1 < V < 30 kV	MT2	Peak and off-peak energy + peak and off-peak capacity
	MT3	Peak and off-peak energy + maximum capacity
	MT4	Total energy + maximum capacity
Group BT Low voltage V < 1 kV	BT2	Peak and off-peak energy + peak and off-peak capacity
	BT3	Peak and off-peak energy + maximum capacity
	BT4	Total energy + maximum capacity
	BT5A	Peak and off-peak energy
	BT5B	Total energy
	BT5C-AP	Total energy (public lighting)
	BT6	Maximum capacity
	BT7	Total energy (prepaid)
	BT8	Total energy (rural supply with PV)

The evolution of the average tariff by rate option (nationwide) during 2019 is shown in the following figures.

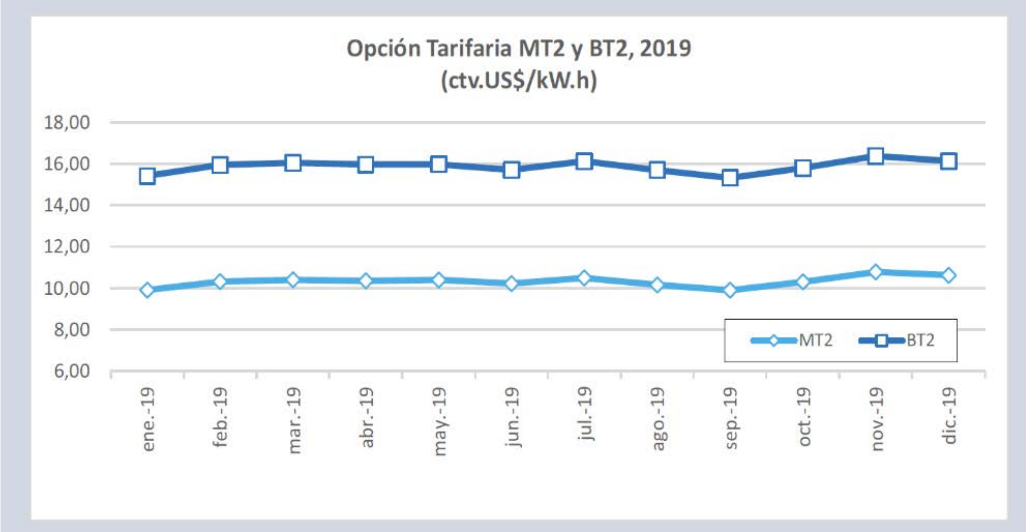

Figure 15.- Medium and low voltage tariffs options (MT2-Industrial y BT2-Comercial) Source: (OSINERGMIN, 2020)

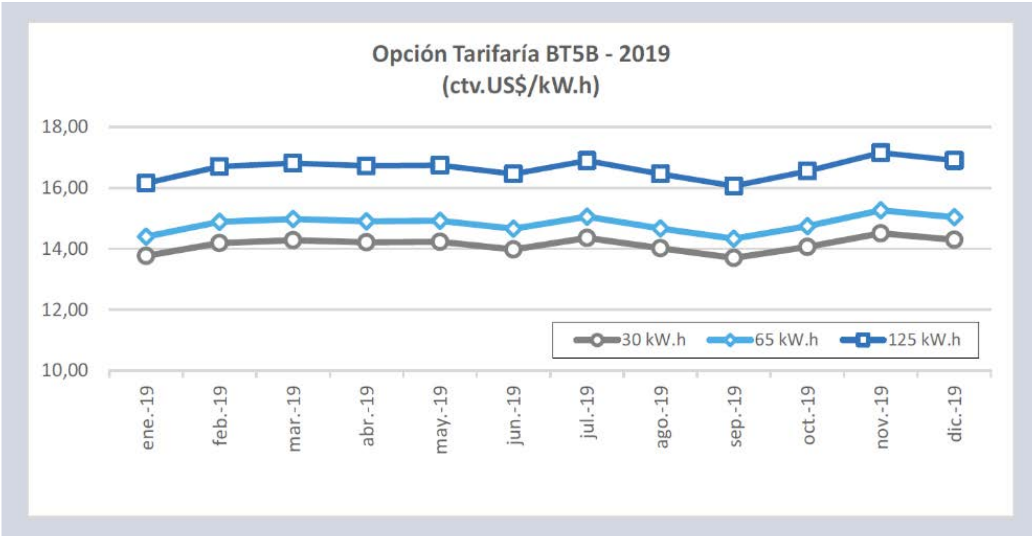

Figure 16.- Low Voltage residential tariffs options (monthly consumption of 30 kW.h, 65 kW.h and 125 kW.h, accounting for the FOSE). Source: (OSINERGMIN, 2020)

Very different levels of complexity can be observed in the tariff structure. This is even more evident when analysing the charges included in these tariff options, which vary from seven different charges to only two charges for low-consumption residential users (BT5B, one of the most applied tariff options). These charges are summarised in the table below (where peak hours are defined every day from 18:00 to 23:00).

Table 4.- Charges applied to the Peruvian tariff structure.

Tariff option	Fixed charge [$/month]	Reactive energy charge [$/kVARh]	Energy charge [$/kWh]		Capacity charge [$/kW-month]	Distribution charge [$/kW-month]	
MT2	Fixed charge	RE charge	Peak	Off-p.	Peak	Peak	Off-p.
MT3	Fixed charge	RE charge	Peak	Off-p.	Capacity charge	Dist. charge	
MT4	Fixed charge	RE charge	Energy charge		Capacity charge	Dist. charge	
BT2	Fixed charge	RE charge	Peak	Off-p.	Peak	Peak	Off-p.
BT3	Fixed charge	RE charge	Peak	Off-p.	Capacity charge	Dist. charge	
BT4	Fixed charge	RE charge	Energy charge		Capacity charge	Dist. charge	
BT5A	Fixed charge	-	Peak	Off-p.	-	-	
BT5B	Fixed charge	-	Energy charge		-	-	
BT5C	Fixed charge	-	Energy charge		-	-	
BT6	Fixed charge	-	-		Capacity charge	-	
BT7	Fixed charge	-	Energy charge		-	-	
BT8	Fixed charge	-	Energy charge		-	-	

Once the costs to be recovered are defined, they are allocated to each tariff option depending on the charges considered. The fact that, for example, only certain tariff options have an explicit distribution charge does not mean that only those users pay for distribution costs. The other tariff options have distribution costs included in other charges, either energy or capacity charge.

Moreover, it must be observed that, also when no time differentiation is in place for the energy or the capacity charge, the latter may vary depending on whether the user has his peak consumption during peak or off-peak hours. Another relevant feature of the tariff structure is that certain residential tariff options are restricted to some users depending on their power demand. For example, only consumers with a demand lower than 20 kW can be included in the BT5B tariff option.

Simplicity over efficiency

As in many other systems worldwide, residential consumers in Peru pay an additive volumetric charge ($/kWh) and a small fixed charge. The fixed charge collects the costs associated with power supply restoration and maintenance, street lighting, GST and the contribution established by the Act No. 28749 (and also the costs associated with reading, processing and issuing invoices). This design prioritizes simplicity over efficiency in the cost allocation process, an approach that is not so well-suited for some users in the new context.

The charges included in the tariff options vary from seven different charges to only two charges for low-consumption residential users (BT5B, one of the most applied tariff options, which presents and additive volumetric charge ($/kWh) and a small fixed charge). This design prioritizes simplicity over efficiency in the cost allocation process, an approach that is not so well-suited for some users in the new context.

Tariffs present spatial and time granularity. As regards time granularity, there two periods in some tariff options, with peak hours are defined every day from 18:00 to 23:00.

4.1.3 Electricity tariff subsidies and cross-subsidies[51]

The Peruvian state imposes three major contributions that are aimed at subsidizing the energy bills: a mechanism to subsidize all residential energy bills (MCTER) and two cross-subsidies (FOSE and FISE).

First, we find the MCTER (mechanism of electricity tariff compensation). This is a subsidy introduced with Law 30468 and is applicable to residential users of the public electricity service regardless of their geographic location and the electrical system to which they belong. The compensation mechanism for the residential electricity rate is aimed at reducing the energy charge and the fixed charge of the residential users (mostly BT5B tariff option).

On top of the previous subsidy, two cross-subsidies aimed at protecting vulnerable consumers: the FOSE and the FISE. These two are briefly reviewed next.

FOSE (Fondo de Compensación Social Eléctrica)

It operates as the most relevant cross-subsidy for electricity, in which the consumer only pays a % of the energy charge (as low as 22.5% of the actual tariff for low-consumption rural clients in isolated systems). The reduction is aimed at consumptions below 100kWh/month, being the reduction even higher for consumptions below 30kWh/month.

It should be noted that, as of October 2019, the users who benefit from the FOSE are around 4.8 million and represent 62% of the total number of users that have electricity service.

[51] In addition to the subsidies reviewed in this section, it is worth highlighting the existence of an additional compensation mechanism. Article 29 of Law No. 28832, defined the price of generation (the so-called Precio a Nivel de Generación in Spanish, or PNG). This law also provides for the establishment of a compensation mechanism between regulated users of the SEIN, with the aim that the PNG is unique to all these regulated users, except for losses and congestion of the transmission systems. This mechanism was regulated by Supreme Decree N° 019-2007-EM. This measure is in principle compatible with the recommendations provided in section 4. Even though contracts are socialized among all regulated consumers, it is still possible for example to increase the energy generation component time granularity to account for the different cost of electricity with time.

The following tables shows the reduction over the energy charge that applies to the different types of low-consumption clients, as a function of their monthly consumption and sector.

Usuarios	Sector (*)	Reducción tarifaria para consumos menores o iguales a 30 kW.h/mes	Reducción tarifaria para consumos mayores a 30 kW.h/mes hasta 100 kW.h/mes
Sistemas Interconectados	Urbano	25% del cargo de energía	7,5 kW.h/mes por cargo de energía
	Urbano-rural y Rural	50% del cargo de energía	15 kW.h/mes por cargo de energía
Sistemas Aislados	Urbano	50% del cargo de energía	15 kW.h/mes por cargo de energía
	Urbano-rural y Rural	77,5% del cargo de energía	23,25 kW.h/mes por cargo de energía

(*) El sector será considerado urbano, urbano-rural o rural, de acuerdo con la clasificación de los Sectores de Distribución Típicos que establece la R.D. N° 154-2012-EM/DGE.

Figure 17.- Reduction factors for low-consumption residential users per sector. Source: (OSINERGMIN, 2020)

The FOSE mechanism is financed through a surcharge in the billing that is applied to the energy charge, the capacity charge and also to the fixed charge of users with consumptions above 100kWh-month. The surcharge factor (*Factor de Recargo del FOSE*) has been stablished to 1.042 in the last revision[52]. The annual subsidy for 2020 was around 348 million Soles (104 million USD). Year 2019 ended with 298.8 million Soles (89.4 million USD).

FISE (Fondo de Inclusión Social Energético)

The Social Energy Inclusion Fund (FISE) is intended to bring clean energy to the country's most vulnerable populations. Those eligible[53] and who apply for this discount benefit for the purchase of domestic gas cylinders. This discount is usually given in the form of a coupon attached to the electricity bill and has a validity of two months.

The FISE is partially financed through a surcharge in monthly billing of free users of the interconnected systems.

3 subsidies give final shape to the tariff: a mechanism to subsidize all residential energy bills (MCTER) and two cross-subsidies (FOSE and FISE).

The FOSE, subsidizes residential consumptions below 100kWh/month, being the reduction even higher for consumptions below 30kWh/month.

It is financed through a surcharge in the billing that is applied to the energy, fixed and capacity charges of users with consumptions above 100kWh-month

[52] Programa Trimestral de Transferencias Externas correspondiente al periodo del 01 de noviembre de 2020 y el 03 de febrero de 2021.

[53] Residential electricity users with average annual consumption less than 30 kWh and who have an LPG stove. These people must also be included in strata 1 to 5 of the SISFOH.

Is there a problem with the current design of subsidies?

Consumption subsidies have been a central element of the Peruvian tariff; however, their current design can distort the economic signals conveyed by the electricity tariffs. As consumers become more responsive, subsidizing/surcharging by reducing/increasing the energy and/or the capacity charge can lead to inefficiencies. This is further discussed in subsection 4.2.2.

Subsidies are volumetric and capacity-based, what distorts tariff signals.

4.2 Proposal: a potential roadmap for tariff design transition

In the first report, some recommendations were outlined as regards how to reform tariff design. These recommendations were ordered according to some sort of rate between their expected benefits and their expected implementation costs in Peru. The final list (slightly changed from the first report, after taking into consideration the comments received by stakeholders) would be the following:

- Remove residual costs from both the volumetric and capacity components of the tariff and charge these costs through a fixed charge, while also accounting for the risk of inefficient grid defection.
- Redesign the subsidies. Electricity subsidies will definitely continue to be a central element of the Peruvian power system; however, their design mustn't distort the economic signals conveyed by electricity tariffs.
- Avoid net metering policies for MCG.
- Make prices and charges for electricity services non-discriminatory and technology-neutral.
- Introduce flexible access to the network.

Once smart meters are installed, further refinements are possible. With smart meters, tariffs signals should try to capture and reflect the marginal or incremental costs of the production and utilization of electricity services. This involves increasing the time and locational granularity of signals[54]:

- Expose regulated customers to time-varying energy prices.
- Apply coincidental peak capacity charges for network investments to residential consumers.
- Consider the application of nodal prices to price-responsive demand and DERs in general.

4.2.1 Remove residual costs from both the volumetric and capacity components

As reviewed in the first report, not all costs can be allocated efficiently, or at least not entirely, for they do not increase/decrease due to changes in consumption patterns. All these expenses are

[54] As it has been shown in section 4.1.2, today some tariffs already consider some degree of granularity.

commonly grouped in the broad category of residual costs. Since these costs cannot be assigned efficiently, they should be recovered in the least distortive manner.

Figure 18 depicts graphically the different cost elements reviewed in the first report and presents a qualitative identification of the weight residual costs usually represent.

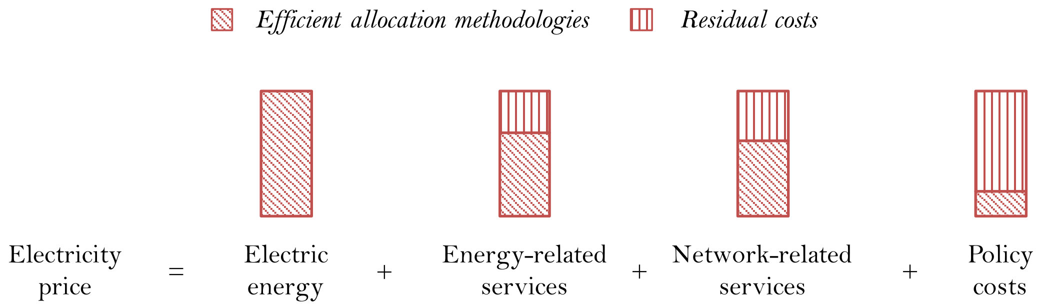

Figure 18. Cost elements of electricity supply and allocation methodologies

Residual costs can be defined as the difference between the recognised costs of a certain activity and the revenues collected through the application of an efficient allocation methodology. There are many cost items that can be encompassed, entirely or partially, in this category: residual network costs, residual renewable support costs, economic support to certain geographical locations (including rural areas) with higher costs of service, institutional costs (system and market operators), etc.

A growing concern today in Peru

The weight of residual costs in the electricity bill has experienced a significant increase in the last decade in Peru. Two main drivers for this growth can be identified: the allocation of sunk network costs and the growing weight of other charges (mostly policy costs).

As a general rule in every system, a non-negligible percentage of network costs are residual. Apart from this, there is a major problem today in Perú as regards how some residual costs are embedded in the transmission tariff and charged based on the peak coincident consumption (capacity charge). These charges include (see section 4.1.1): the charge for emergencies, the charge for Nodo Energético del Sur, the charge for security of supply and cold reserve, the charge associated with the FISE compensation, the charge associated with the renewable support mechanism and the charge associated with the transfer of property of natural gas pipelines.

Residual cost should be recovered through a fixed charge

The residual component of costs must be recovered through complementary charges on top of the system of prices and charges defined through the application of efficient allocation methodologies. Since the latter are supposed to convey the most efficient signal for the operation and expansion of the power sector, the basic recommendation for the allocation of these residual costs is to minimise distortions. This is why residual costs would be better recovered through a fixed charge, expressed as a lump sum that could be computed on a yearly basis and billed in monthly instalments. However, this charge cannot be the same for all consumers, for introducing the same fixed charge to all has two negative implications:

- It may raise equity issues (this is reviewed later).
- If the fixed charge does not consider the long-term elasticity, it may result in inefficient grid defections, as analyzed next.

In order to compute the "uneven" fixed cost, two major objectives can be pursued by policymakers: 1) to allocate residual costs based on historical cost-causality and 2) to allocate costs encouraging equity.

In (Batlle et al, 2020) it is presented the major guidelines to implement a fixed charge based on the first objective: moving residual costs to an "uneven" fixed charge which is calculated following a principle that can be defined as backward cost causation. Historical consumption behaviour is used to define the responsibility of each customer in the incurrence of each residual cost item.

In case the objective would be exclusively the second, allocating residual costs in proportion to property value would be the first-best alternative. Expensive homes (or high-rent) properties pay proportionally more, so it is more equitable. In Peru, if this would be the selected approach, the government could contract with private parties to provide an unbiased estimate of home value

In any case, uneven fixed charges can be introduced gradually, avoiding abrupt changes in electricity bills. This is further explored at the end of the section.

The allocation of residual costs by means of a fixed charge and the limit imposed by grid defection

Distributed energy resources increase the long-term elasticity of end-users, who can make an investment decision in response to electricity prices. An extreme instance of this long-term elasticity is represented by grid defection. The combined effect of decreasing costs of both domestic distributed generation (rooftop photovoltaic above all) and small-scale batteries (and/or an onsite gen-set) is reducing the cost of supplying a kWh through a stand-alone system. When this cost gets closer to the cost of supplying the same kWh through the grid[55], grid defection may become a problem. A grid defection, if it is triggered by the allocation of residual costs (even if this is allocated through a fixed charge), would be beneficial for the end-user, but would be inefficient from a system-wide perspective.

In order to avoid inefficient grid defections, (MITEI, 2016) proposes the application of thresholds to residual cost allocation. Figure 19 compares the tariff for grid supply, represented as the summation of generation costs (and other costs related to competitive activities), non-residual network and renewables costs[56], and finally the residual costs, with the cost of two stand-alone systems.

[55] This is not completely true. A proper economic assessment should consider also the cost of non-served energy. A stand-alone system (a properly-sized rooftop PV panel and a battery) has a loss-of-load probability much higher than a modern interconnected power system. Depending on the value assigned to non-served energy, this lower reliability would affect the economic comparison, reducing the competitiveness of stand-alone systems.

[56] As reviewed in the first report, this corresponds to the long-run marginal costs (LRMC) of both network and renewables.

Stand-alone system 1 is a theoretical and extremely cheap system that supplies electricity at a cost lower than the summation of efficient generation, network, and RES-E support costs. Apart from some exceptional cases (isolated or very unreliable interconnected systems), such a scenario cannot be found in practice with the current prices of photovoltaic panels and batteries and it is also quite unlikely for the near future. However, if a stand-alone system with these characteristics existed, it would produce at a cost lower than the overall marginal cost of producing electricity from the grid. In this case, grid defection would not be detrimental to the power system, since it would be fully cost-efficient. No tariff threshold is to be applied in this case.

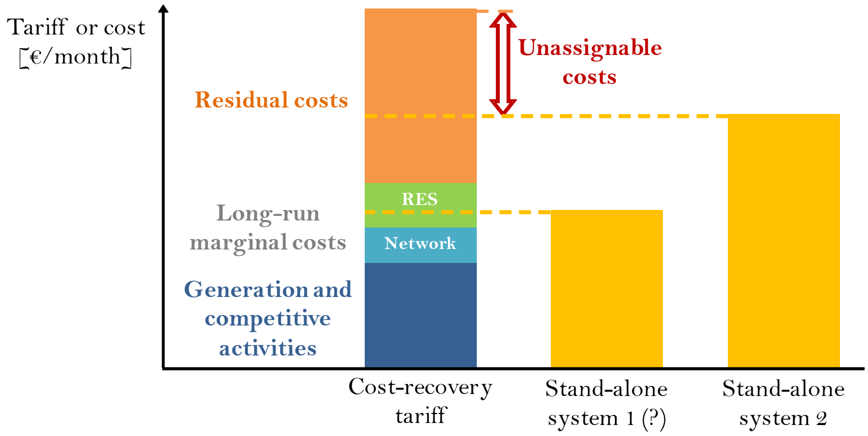

Figure 19. Stand-alone systems cost compared to tariff for grid supply. Source: (MITEI, 2016)

A completely different situation is depicted in Figure 19 for stand-alone system 2. This system is producing at a cost higher than the overall long-run marginal supply cost from the grid. Therefore, a grid defection from this user would be inefficient from the economic point of view, since the electricity produced by this stand-alone system would be more expensive than the one withdrawn from the grid. Inefficient grid defection is caused, in this case, by an improper allocation of residual costs. In this context, it must be also remarked that, as soon as grid defections start taking place, tariffs must be readjusted in order to fully recover residual costs, causing an increase in electricity bills for remaining customers and worsening the problem, an extreme version of the so-called "death spiral" for electric utilities.

The cost of stand-alone system 2 then must become a threshold[57] that is not to be exceeded by the inappropriate allocation of residual costs. The share of residual costs beyond such a threshold should be treated as unassignable costs.

How to recover unassignable residual costs

Such unassignable costs must be recovered, in order to guarantee the financial stability of the power sector and adequate funding for public policy objectives, but these revenues cannot be recovered through conventional components of electricity tariffs. Different alternative options

[57] Batlle et al. (2016) propose the application of the "marginal threshold". In fact, the cost of a stand-alone system varies depending on many factors, but the threshold should be unique and the lower stand-alone cost should be considered. Moreover, these authors remark how the threshold should be subject to frequent revisions, since the cost of a stand-alone system may evolve rapidly in the next decade.

have been proposed in the literature for the collection of these costs, but if these costs are not to be taken out of the electricity system (the case in Peru as in most electricity systems worldwide), the only alternative left is 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[58].

The weight of residual costs in the electricity bill has experienced a significant increase in the last decade in Peru. There is a major problem today as regards how some residual costs are embedded in the transmission tariff and charged based on the peak coincident consumption (capacity charge).

Residual costs would be better be removed from the volumetric and capacity component, and then be recovered through a fixed charge, expressed as a lump sum that could be computed yearly and billed in monthly installments; this fixed charge can be consumer-dependent.

The fixed charge should not convey any price signal (that could trigger an inefficient response) to the consumer

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4.2.2 Subsidies

Subsidies have to avoid distorting tariff signals

Consumption subsidies, if not properly designed, can become a hurdle for the efficient development of distributed resources. The removal of this hurdle, however, does not entail removing the subsidies themselves. The latter, has been in the past and will be in the future a fundamental pillar of the social policy of Peru.

What is important is that the design of subsidies does not distort the economic signals conveyed by electricity tariffs, which as discussed in the first report, are called to define the equilibrium between centralized and distributed services in the future.

Tariff reforms may have an impact on how electricity costs are distributed among different classes of consumers, this is the reason why subsidies should be designed as the last variable of the tariff design. This also means that after any tariff reform subsidies need to be re-calculated to re-establish the balance sought among consumers' bills.

[58] The other alternatives would be to move part of the residual costs to the state budget and collect them through conventional taxes, or to embed them in real-estate taxes, proportionally to the property tax currently paid.

The subsidy will target specific categories according to the national social policy, which so-far in Peru has been focused on low-income or vulnerable customers, identifying these as those with low electricity consumption (especially those consuming less than 30kWh-month).

In order to avoid the problem of distorting tariff price signals, the textbook solution for subsidies design is the so-called transfer-in-cash. With the transfer-in-cash approach, a certain amount of consumption is defined according to the objective pursued by the regulator through the subsidy and a cash transfer is carried out in order to cover the expected expense for such consumption. End users periodically receive a cheque or are entitled a credit for the predefined consumption, but then the standard tariff is applied on the entire consumption and end-users are exposed to the efficient market signals.

Modifying the fixed charge as an alternative to the transfer-in-cash

A second-best approach that would represent the recommendation for Peru, would be to allocate the subsidy by means of a fixed component in the tariff. Since in Peru there is a cross-subsidy between consumers, this fixed component would be negative for consumers subsidized, while it would be positive for those consumers subsidizing. Therefore, the resulting total fixed charge in the tariff would be additive and would involve two components: a positive residual cost component (analyzed in the previous subsection) and a (either positive or negative) cross-subsidy component.

The cross-subsidy component would seek to reduce the expenditure of low income (or low consumption) consumers, while not affecting the efficiency principle we want to accomplish. That is, the efficient signals (including those described in the following sections) would be implemented for all consumers (as long as the technology allows it), but the fixed subsidy component charge would play the role of reducing the total expenditure to subsidized consumers.

Note that the additive fixed charge could be positive or negative (a lump sum the consumer receives to compensate the bill). This will depend on the size of the residual cost charge component and the cross-subsidy component."

In order to avoid that subsidies distort the economic signals conveyed by an efficient electricity tariff, the recommended approach would be to allocate the subsidy by means of a fixed component in the tariff. Therefore, the resulting fixed charge in the tariff would be additive and would involve two components: a positive residual cost component and a negative (for the subsidized consumers) subsidy component.

Notwithstanding the foregoing, it is worth mentioning that in the allocation of each of the electricity costs there are inevitably decisions that can be seen as subsidies or cross-subsidies. This is the case of the residual cost allocation based on equity principles.

4.2.2.1 *MCD (micro distributed generation) and tariff design*

The current regulatory framework for micro distributed generation (MCD) has been introduced in section 1.2. As it was pointed out back then, the installation of MCD should not allow prosumers to avoid paying tariff charges associated with the use of the network. For this to be carried out efficiently, it is urgent to address the tariff redesign presented so far.

A tariff design based exclusively (or mostly) on a volumetric charge can lead, in the presence of prosumers, to an economically unsustainable system. The application of mechanisms such as the one proposed in the distributed generation regulation, known as "net metering", may imply that those users who do not have the possibility of installing MCD, end up bearing most part of network costs (although MCD users keep on using the network).

A BT5 user who has MGD would only pay the rate for the annual net energy that is measured. In the long run, this generates two effects: i) that the distribution and the transmission owners do not receive the full annual remuneration for their networks, and ii) that users who do not have MGD eventually see their rates increased in order to recover these costs.

Therefore, it represents a dangerous and difficult to control cross-subsidy between consumers. At the same time, the fact that energy can be accounted for in a period other than the one in which it is generated adds an inefficient signal for investment, since it eliminates any marginal signal embedded in the market price. In this way, for example, those facilities that could produce in those hours or seasons in which the cost of energy in the country is higher are discouraged.

In any case, if an incentive mechanism is to be used, it should be oriented towards a net billing mechanism and only for that part corresponding to the component of the tariff linked to electricity generation. A reference case that has adopted this model is the Chilean one.

If it is desired to subsidize the development of DG, something perfectly admissible, it must be done through direct, transparent and controllable mechanisms that avoid discriminatory treatment between network users.

The combination of simple volumetric tariffs and net metering policies represents a dangerous and difficult to control cross-subsidy between consumers.

4.2.3 Connection and Access

Connection

As regards the one-off payments that new network users have to make to cover for the costs of connection, there are two main approaches:

- Deep charges, which include the direct cost of connection as well as the cost of reinforcing the upstream network to accommodate the new capacity.
- Shallow charges, which only comprise the direct connection costs. In the latter case, any additional cost of connecting the new users would be socialized and recovered through the network charges paid by all users.

The recommendation would be to apply shallow charging approaches for small DER units at least during some years, to avoid excessive barriers to the connection of small units to the grid. Regulation may establish differences by requested capacity and/or by voltage levels.

Large DER may be subject to deep connection charges in order to provide them with efficient locational signals. However, this should be implemented together with flexible network access and information disclosure about available grid capacity.

Firm vs. flexible network access

Access rights are generally granted on a firm basis, i.e. grid users are free to inject or withdraw as much energy to and from the grid as they want as long as they do not surpass the capacity allocated.

This approach of firm access is simple to implement as does not require an active grid operation. However, it requires adopting conservative technical criteria to ensure no problems arise during real-time operation under no circumstance. Therefore, some network components may only be used at their rated values on rare occasions if ever. Additionally, the need to provide new users with firm network access can result in long connection delays or the rejection of the request. This can be an important barrier to the connection of new DER.

Non-firm or flexible network access could be used to facilitate network access and avoid unnecessary grid reinforcements. Flexible grid connection schemes would allow DSOs to curtail the consumption or generation of network users to prevent grid constraints under the conditions agreed. Thus, DSOs could relax some of the aforementioned technical criteria as they now have the possibility to manage the end user's feed-in/consumption during grid operation. In turn, network users could be offered a remuneration as a service, lower connection charges (especially if deep connection charges apply), or a faster grid connection. The activation of non-firm access agreements may be coordinated together with other flexibilities procured by DSOs through any local flexibility mechanism/market.

Due to its potential to reduce reinforcement costs, increase the number of flexibility sources available to DSOs and allow new DER to avoid the payment of costly deep connection charges, it is recommended to implement gradually flexible network access in Peru as an alternative to firm access.

It is recommended to apply shallow charging approaches for small DER units at least during some years, to avoid excessive barriers to the connection of small units to the grid.

It is also recommended to implement gradually flexible network access in Peru as an alternative to firm access.

4.2.4 Technology-neutrality

As a general principle, prices and charges for electricity services should be non-discriminatory and technology-neutral. Any component of prices and regulated charges should be based exclusively on the individual injections and withdrawals at the network connection point, regardless of the specific technology producing those injections or withdrawals[59]. In fact, for the power system, it does not make any difference whether a change in the power withdrawn or injected at a specific time and place has been caused by reducing demand, discharging a battery (or reducing the battery charging), or injecting power from a distributed energy source. The impact on the system is not dependent on the technology involved, thus prices and charges should not depend on technology either.

Prices and charges for electricity services should be non-discriminatory and technology-neutral

4.2.5 Increased granularity (time and space)

The previous measures have been considered more urgent, since they could be implemented even before the smart meters are rolled out. In the following, we will review the proposals that assume a deployment of advanced metering infrastructure in Perú. If this is not the case, because, for example, the cost-benefit analysis is not positive for a cluster of consumers (and its implementation is left for the end of the 8-year period), then the idea would be to move, the closest the technology allows, in the direction of the general recommendations.

First and foremost, as discussed in the first report, distributed energy resources may have their economic value revealed only in the case where price signals convey an adequate level of granularity to capture the important variations in the cost of supplying electricity across time and space.

A preliminary comment about the right level of granularity

This being said, it must be noted that although increased granularities have clear benefits in terms of efficiency, these gains come at a cost, in terms of, among others, increased computational efforts and acceptance reluctance from the point of view of consumers. A trade-off between benefits and costs of increased granularities must be found. This "overall efficient" granularity is also prone to change with time, as the penetration level or distributed energy resources increase. Higher penetration levels of distributed energy resources will call for increasing levels of granularity in price signals.

Granularity comes at a cost and a trade-off must be pursued; distributed locational energy prices do not seem to be a workable and desirable solution.

[59] This does not mean that there cannot be in place support mechanisms in parallel for certain technologies.

4.2.5.1 *Time-varying energy prices*

The marginal cost of electricity varies depending on the time it is consumed, due to load patterns and generation costs, and this variation could be significant. To provide consumers with accurate signals, the price of electricity must be calculated and charged for short-time intervals, ideally hourly if the technology allows it. This would help to disclose the value of some resources, like distributed storage, and allow consumers to shift demand over a certain time horizon, within which different prices arise. Two periods for the energy charge (the granularity offered today) do not seem enough to capture the value of some resources, such as storage. A minimum of three or four periods (subject to a deeper analysis by OSINERGMIN) would be recommended.

It is also worth noting that, as further analysed in section 5, sending short-term energy signals to consumers is compatible with the long-term contracts that are signed under the SFPFC mechanism (Wolak, 2021).

Communication of prices to consumers

Beyond time granularity, another element in the temporal dimension of electricity rate design is the existing time interval in which communication of forthcoming prices to consumers occurs. For the same time granularity, the reaction to price signals may be completely different depending on when prices and charges are communicated (one day ahead, few hours ahead, or even *ex-post*).

Defining ex-ante the energy prices seems to be the most reasonable way to allow effective participation of consumers. The communication of energy prices could be annually or monthly in a first stage, but this communication could (and should) move closer to the day ahead. This would be beneficial for short-term efficiency, since this way price signals are more likely to reflect the real conditions that will be registered during the operation of the system.

The price of electricity should be calculated for shorter time intervals to disclose the real value of distributed resources; this requires having previously deployed advanced meters among the clients that can respond to such signals.

Two periods for the energy charge do not seem enough to capture the value of storage. A minimum of three or four periods (subject to a deeper analysis) would be recommended

If consumers are supposed to react to price signals, these must be communicated with a sufficient anticipation. The communication of energy prices could be annually or monthly in a first stage, but this communication could (and should) move closer to the day ahead.

Allocation the of adequacy support mechanism costs

The cost related to the mechanism that pursues system adequacy has to be assigned efficiently, following the cost-causality principle.

The SFPFC mechanism (Wolak, 2021) revolves around fixed-price fixed-quantity requirements forward energy contracts. SFPFC energy would be shaped to the hourly system demand within the compliance period of the contract and the obligations would be allocated to retailers based on their share of system demand during the compliance period. To provide more granular signals associated with these contracts, a similar approach as the one used today to determine the so-called *precio de barra*, implying the execution of a simulation model, would be needed.

In case the contracts would present hourly granularity, and capacity and energy would be decoupled, a more effective cost allocation would be possible in the tariff.

In case there is a capacity-based remuneration (which seems not to be the case according to Wolak, 2021), the associated cost would need to be allocated to the expected consumption during scarcity periods.

Firm capacity charge should be proportional to the expected consumption during the scarcity periods

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4.2.5.2 ***Peak coincident network charges***

The long-run marginal cost

A portion of the network cost not covered through network rents can still be assigned among power system agents through an efficient allocation methodology. The recommended approach, in line with the best practices described in the first report, implies calculating the Long-Run Marginal Cost (LRMC[60]). 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.

Peak coincident charges

Once long-run marginal costs have been calculated (or approximated) for each group of grid users, they must be applied to specific cost drivers. It is evident that network costs are driven by the demand of capacity, so the most efficient format is $/kW, based on the peak-coincident capacity. That is, consumers pay for grid costs according to their contribution to aggregate peak network utilization. In this respect, Peru already charges based on peak-coincident capacity, but the period to measure it is probably rather long to send an accurate and efficient signal (from 17h to 23h).

Identifying the peak coincident periods

The proposal would be to identify peak coincident periods both ex-ante and ex-post for industrial consumers. A percentage of the charge (for example, 85%, but to be determined by OSINERGMIN) would correspond to the consumption during some pre-defined ex-ante hourly

[60] In this context, 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, thus considering the possibility of new investments in the grid.

periods. These periods are the periods in which the network system operator expects the highest infrastructure usage (implying close to an overloading regime). A small percentage (for example, 15%) would correspond to ex-post (or real-time) defined peak coincident periods.

For residential consumers, peak coincident periods would be fully determined ex-ante.

The locational granularity of network charges

Similarly, to what was described for energy, there is also a need for locational granularity in network charges, since the network costs reflected by these charges vary significantly depending on where the electricity is consumed (at the end of a feeder in a rural area or from a highly-meshed network in an urban area) and on the load profile (consumption during peak demand in the network). Transmission and distribution charges should encompass some level of granularity.

Peak coincident network charges should be used to recover network costs

4.2.5.3 *Symmetrical signals*

Once a certain level of granularity has been implemented, a relevant principle (derived from cost-causality) is that prices and charges should be symmetrical. A marginal injection at a specific place and time should be compensated at the same rate that is charged for a marginal withdrawal at the same place and time. Non-symmetrical prices and charges would incentivize inefficient strategic decisions regarding the location of distributed energy resources behind or in front of the meter, and also can create artificial opportunities for batteries (such as it was reviewed in the first report).

Once a certain level of granularity has been implemented, a relevant principle (derived from cost-causality) is that prices and charges should be symmetrical.

4.2.6 Distributional impacts

Tariff reforms may have an impact on how electricity costs are distributed among different classes of consumers. The aforementioned measures, such as increasing the granularity of electricity prices, introducing demand charges for network costs, or introducing fixed charges for residual costs recovery have been identified by experts as possible enhancements in tariff design, however, they may increase the bill of some customers and, among them, potentially vulnerable customers. Measures should be taken to prevent this from happening.

The new system of prices and charges may be complemented with "equity" measures, which can be applied during a transitional period or permanently.

The first alternative would be to design the "uneven" fixed charges linked to residual costs in such a way that certain gradualism is achieved in the total tariff change.

However, the best way to deal with this is directly through subsidy mechanisms. For example, MITEI (2016), proposes to complement the new tariffs with means-tested rebates for low-income consumers; such rebates could be provided as a lump sum, thus not distorting the efficient economic signals. As mentioned above, this can be achieved in Peru by means of a proper redesign of the Peruvian subsidies mechanisms. These subsidies would need to be based on a fixed component (lump sum) that would need to also deal with this distributional issue. This redesign would allow sending efficient signals, while final bills would be similar to those paid before the reform.

4.3 References

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5 Retail

5.1 The Peruvian context

5.1.1 Retail activity in Peru: unbundling and types of consumers

As reviewed in section 1, the Peruvian regulatory framework establishes the vertical unbundling of electricity generation, transmission and distribution activities. These activities cannot be carried out by the same company or company group. The unbundling of retail from other activities has not been established yet, however. This unbundling, particularly between distribution and retail, and the subsequent full liberalization of retail, are the last steps still to be taken and being discussed today.

Although the LCE, and other regulations that regulate the electricity subsector, are based on the understanding that both the activities of electricity generation and retail can be provided in conditions of competition, not all electricity consumers have been enabled to purchase their electricity by choosing their retailer (only the so-called "free users"). There is a segment of consumers known as regulated users who are obliged to acquire the electricity supply from the electricity distribution company to which they are connected, while the distribution companies are obliged to supply them.

Users with demands up to 200 kW are considered regulated users, users with demands over 200 kW and up to 2,500 kW can choose to be a regulated user or a free user (since 2009) and users with demands over 2,500 kW are considered free users. The regulated market is made up mainly of low voltage customers, but as seen in the next figure, there are also medium, high and very high voltage users in this segment (often representing small industrial and commercial users).

Nivel de Tensión	Total	Libre	Regulado	Participación (%)
Total	47 286 338	28 132 783	19 153 554	100,0%
Muy Alta Tensión	15 769 448	15 767 549	1 899	33,3%
Alta Tensión	2 877 253	2 853 622	23 631	6,1%
Media Tensión	13 928 418	9 511 612	4 416 806	29,5%
Baja Tensión	14 711 218		14 711 218	31,1%

Figure 20.- Type of user by voltage level. Source: (OSINERGMIN, 2020)

Free users can contract directly with a generator or a distributor the price of their electricity generation supply, while the rate of electricity generation for regulated users is established by OSINERGMIN, this is analyzed next.

The creation of a full liberalized retail market is seen as the final step of the Peruvian power sector liberalization.

The price of generation for regulated users in Perú

The generation-activity price for regulated consumers is the weighted average of the prices of bilaterally agreed contracts (limited by the so-called regulated bar prices or *precio en barra*, in Spanish), and the prices of contracts resulting from long-term auctions (plus an incentive for early procurement in these long-term auctions). This weighted average price is kwon as PNG (Precio a Nivel de Generation) and is mainly driven by the mentioned long-term auctions, which represent above 85% of the generation cost for regulated users.

The regulation as regards these long-term auctions is established in Law Nº 28832, and its target objective is precisely to meet the demand of the regulated market. In these auctions, the supply contracts between generation and distribution companies (in their role of regulated retailers) are awarded under competitive bidding procedures. Generation prices resulting from the auctions are incorporated in the methodology for setting regulated generation tariffs. The Law establishes three types of auctions with different types of requirements for the distributor:

- Auctions called at least three years in advance, and offering contracts for at least 5 years. It is not specified the maximum percentage that may be procured by the distributor in this type of auctions, although it has been understood that it is 100%.
- Auctions called at least three years in advance, and offering contracts up to 5 years. The energy procured in these auctions may cover up to 25% of the regulated demand.
- Auctions called less than three years in advance, and offering contracts whose durations are to be specified by OSINERGMIN. The energy procured in these auctions might cover up to 10% of the regulated demand.

The Law also introduced an incentive to encourage the distributor to make purchases in the long term, that is, more than three years in advance.

The contracts in the auction are "full requirement", meaning that are both for capacity and energy, and where the generating resources can only sell the energy backed up by their firm capacity[61]. Indeed, the firm capacity is the feature that conditions and determines the energy that is allocated to each generating resource in the auction. It is also worth mentioning that while the energy price results from the competitive process, the capacity price is regulated and determined by OSINERGMIN.

The scheme has not been able to provide a balanced mix of long and short-term signals to the tariff

In principle, the different type of auctions would allow sending two types of price signals:

- A longer-term one: oriented to send the price signal that is required in the medium and long term to bring new generation investments. This would be achieved through long-term contracts (durations of up to 20 years) and long lag periods (the aforementioned 3 years in advance period);

[61] What limits the integration of resources with low or zero firm capacity.

- A shorter-term one, aimed at internalizing the prices linked to short-term conditions. This type of auctions, offering shorter-term contract durations and lag periods, would be in principle focused on the existing generation.

Despite the fact that a balanced mix of these two type of auctions would be preferable, due on the one hand to the mentioned incentives to distributors for long-term procurement, and on the other hand due to the fact that it is not clearly defined in the regulation the different objectives[62] each type of auction would need to pursue, the situation is that short-term auctions have not been used yet, which has caused a loss of the short-term signal in the regulated market. In any case, the limitation of 10% can be quite restrictive in the face of the problems we are going to review later on.

There has been indeed an attempt to introduce a sort-term signal today associated mostly with congestions: the so-called FTE[63] factor. The problem with this factor is that it is determined ex-post, and with a significant lag (above 3 months). Therefore, it fails to provide in practice any efficient short-term signal. This FTE value only affects the auction contracts, and not the bilateral contracts.

There is room for improvement today as regards energy auction design and the price signals they convey to the tariff.

The migration (switching) from the regulated to the free market

As mentioned above, the segment that can choose to be either regulated or in the free market is defined in the "Free User Regulations" as one that comprises consumers whose maximum annual demand is greater than 200 kW and up to 2500 kW. The migration decision from the regulated segment should be communicated at least 1 year in advance and the free market category needs to be maintained for at least 3 years.

The fact is that the existence of low prices in the spot market in the last years (Figure 21) has encouraged a significant migration from the regulated market to the free electricity market (Figure 22).

[62] And the different features the auction should present to pursue these objectives (long-term and short-term ones).

[63] Electricity Transmission Factor (Factor de Transmisión Eléctrica, in Spanish).

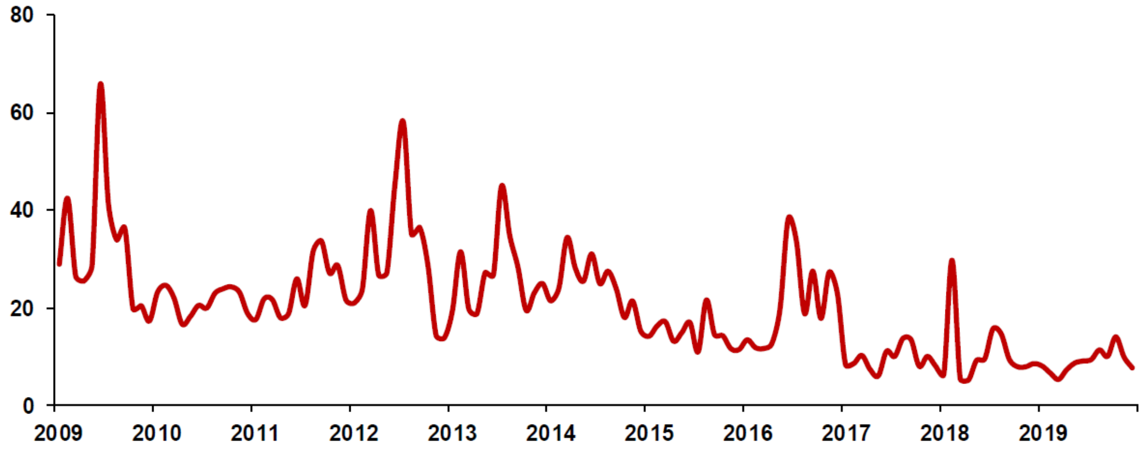

Figure 21.- Electricity marginal cost evolution ($/MWh). Source: (MINEM, 2020)

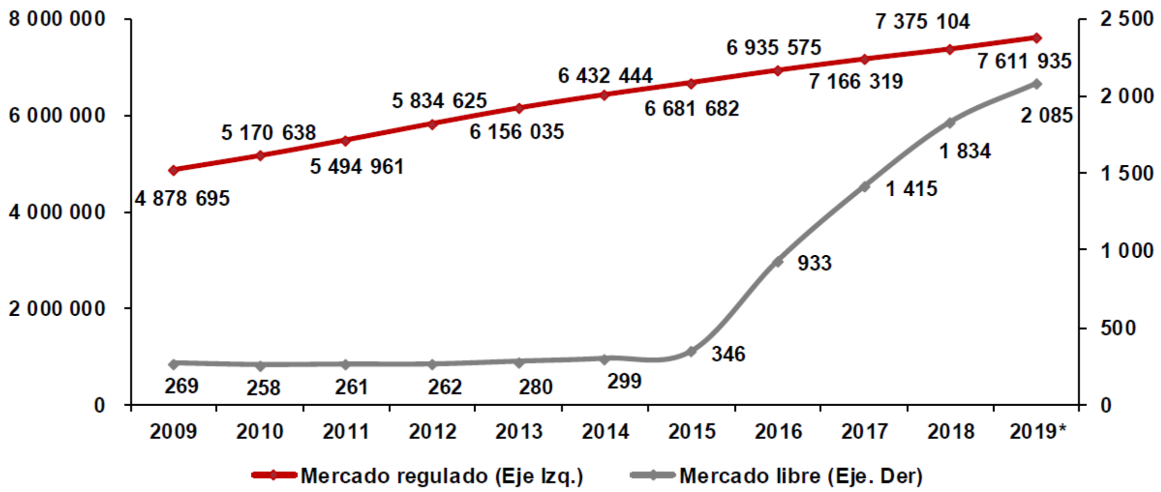

Figure 22.- Evolution of the number of users per type of market segment. Source: (MINEM, 2020)

The main motives behind the low short-term prices trend are: (i) the reserve margin and (ii) the declaration of prices from natural gas plants. We briefly review them next.

The reserve margin has shown a growing trend in the 2009-2019 period reaching up to 72%, and being around 64% in 2019, which is well above the margin recommended for Peru (33%). The reduction in the annual growth of GDP, the decreasing demand from the mining sector, and the entry into operation of new generation in recent years have caused this excess of supply, which has contributed to a significant increase in the reserve margin, and to a reduction in the spot price. In the following figure, it is shown the evolution of the reserve margin.

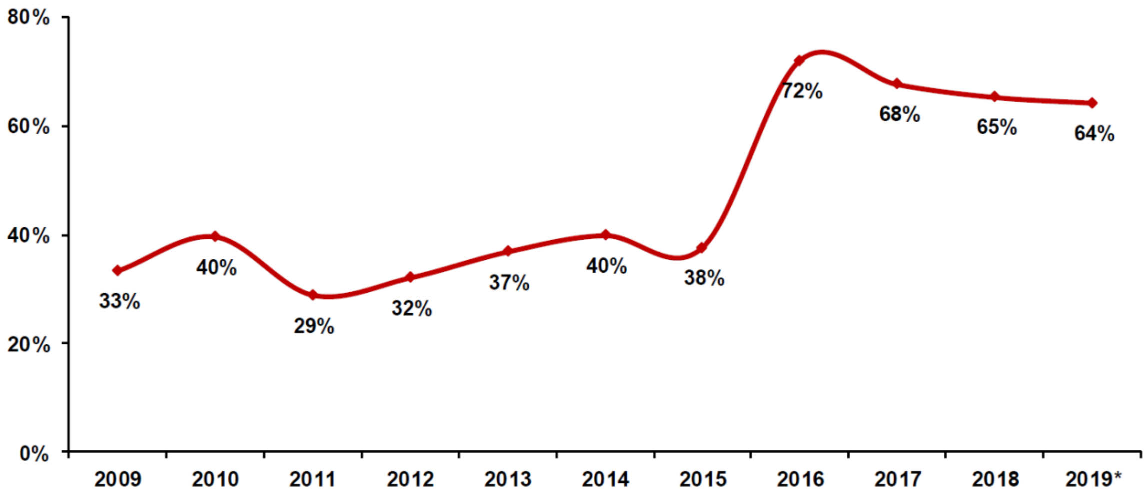

Figure 23.- Evolution of the reserve margin in the Peruvian electricity system. Source: (MINEM, 2020)

As a consequence of this situation, there is strong competition to enter the dispatch. This situation, coupled with the take or pay contracts and the destination clauses that natural gas plants signed in the past, have led to very low declaration prices from these natural gas plants. And since these natural gas plants represent 50% capacity, they are the ones that normally set the marginal price in the short-term market.

In the last 5 years, there has been a significant migration of regulated consumers to the free market. The main reason being the abnormally low short-term prices, which are the consequence of a high reserve margin and the declaration of prices from natural gas plants.

The problem of migration: sunk costs and a death spiral

The long-term auctions regime is not flexible enough, particularly as regards the (firm) capacity quantity contracted by distributors, which is to all intends and purposes a take or pay component of the full requirement contract. This is an issue that reduces the ability of the distributor to reduce its regulated contracted quantity and therefore to better adapt to its changing regulated demand. As a consequence of this inflexibility, the overcontracted capacity becomes a sunk stranded cost. The consequences of this lack of flexibility is borne by both regulated consumers and the distribution company:

- Since the fixed cost of capacity has to be recovered through the PNG, this implies that the costs of electricity in the regulated market increase, while in the free market prices continue to decline. This is shown in Figure 24.
- Since the distribution company does not make a direct pass-through of all the auction-related costs to the PNG, they are forced to bear part of the risk associated with this overcontracting.

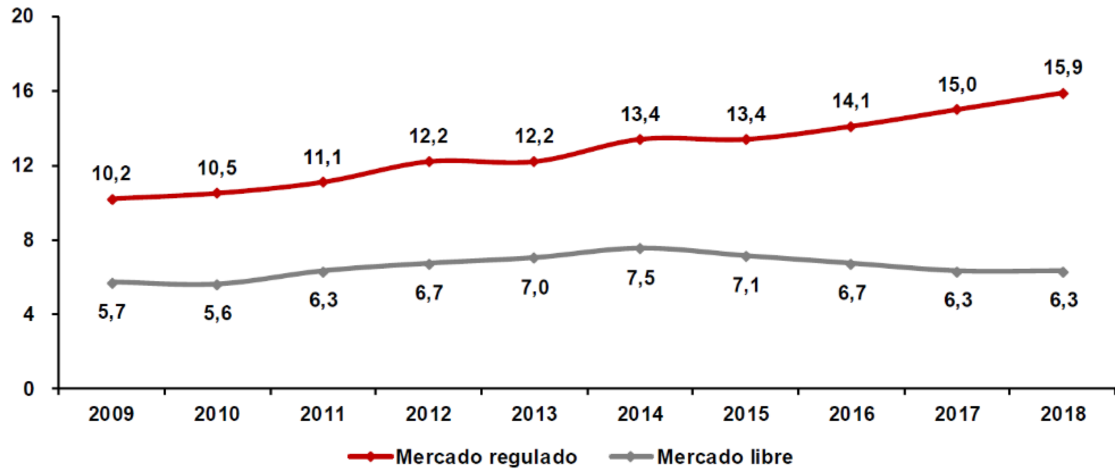

Figure 24.- Evolution of the average free-market and regulated market generation prices ($/MWh). Source: (MINEM, 2020)

Part of these stranded costs are a consequence of some inconsistencies

There is a clear inconsistency today in the regulation among the following requirements:

- The incentive for the distributor to call three years in advance long-term auctions to meet its regulated demand.
- The twenty-four months of supply guarantee that the distributor must meet for its regulated demand.
- The twelve months' notice for users to change their status from regulated user to free user and the non-existence of a notice period when they want to return to their status as regulated user.
- The inflexible contractual commitments cannot be reduced (without the prior approval of OSINERGMIN).

This inconsistency complicates the task of supplying the regulated demand while minimizing the potential stranded costs associated with the contracts.

The migration from the regulated to the free market gives rise to stranded costs, which are aggravated by (i) the rigidity of long-term auction contracts and (ii) some inconsistencies between the requirements for distributors and consumers.

5.2 Proposals for retail

The section is structured as follows:

- First, we discuss how the gains that can be achieved in Peru through the full liberalization of the retail activity can be limited by some factors still to be defined. Because of this, these authors believe that this relevant step should still be subject to further analysis, since it is not clear a priori that all segments of consumers would benefit from such a reform (subsection 5.2.1).

- Second, in case it is decided to proceed with the liberalization (at least for some segments), the regulated tariffs would need to coexist for a number of years with the liberalized market. The design of the default tariff is particularly a key issue, and it should be cost-reflective and convey, at least partially, a short-term signal to consumers so as to get some response to short-term price conditions (subsection 5.2.2). As we discuss, and in line with the proposal carried out in Pillar 2 (Wolak, 2021), this is compatible with hedging consumers' risk.
- Third, we present the proposed alternative to deal with the stranded costs associated with long-term contracts, (we will refer to these costs as legacy costs), a major issue today in Peru that is distorting the decisions of consumers able to be subject to regulated tariffs or to participate in the free market (subsection 5.2.3).
- Forth, we propose the measures to be implemented to remove the most relevant barriers that can impede an efficient development of the retail business (subsection 5.2.4),
- Finally, to proceed with the liberalization, we propose a gradual liberalization process (subsection 5.2.5).

5.2.1 First thing first: is it worth liberalizing retail in all segments in Perú?

In the first deliverable, we discussed how liberalizing the retail activity is supposed to attain three main objectives:

- introduce competitive pressure on the operating costs of retail (billing, customer services and others),
- introduce competitive pressure on the upstream costs of electricity as a consequence of further downstream participation,
- widen the range of available tariffs to final consumers.

Nevertheless, we also reviewed how many worldwide experiences have raised questions on these results, showing that the efforts needed to liberalized certain segments of retail are high and the results are more often than not far from those initially expected. Particularly, the possibilities of reducing costs are highly questionable in most cases.

Additional conditioning factors in Peru

The possibilities to widen the range of available tariffs to final consumers are conditioned by the retailers' ability to innovate with new products and differentiate themselves from competitors. In Peru, there are three factors that will heavily condition this possibility of designing new products for consumers:

- On the one hand, as widely acknowledged in the international experience, smart metering deployment is key in allowing future innovation in the retail energy market. As discussed back in section 2, the most reasonable way to plan the future deployment of smart meters in Perú involves identifying segments of consumers and carrying out a segment-oriented cost-benefit analysis. These analyses would be the tool to set the priority for the physical deployment. However, note that those segments being the latest in the roll-out process will also have to wait to be offered innovative products until the smart meters are fully operational.

- On the other hand, the energy component, which is the component of the final price over which the retailer builds its business, is shrinking in relative terms in Peru (and worldwide) as a consequence of the increasing weight of policy costs in the final price of electricity. This leaves less room for retailers (in relative terms) to differentiate their offers with respect to competitors. As it has been discussed in section 4, it is particularly relevant to assign these policy costs efficiently so as to "clean" the energy component as much as possible from non-cost-efficient signals.

- Finally, it has to be noted that long-term supply mechanisms can also limit the role of retailers, since some decisions that ideally could also be taken by retailers, are often taken by the regulator. We next discuss this final issue, analyzing the interaction between the mechanism proposed in Pillar 2 and the retail activity.

The SFPFC approach (Pillar 2) and the retail activity

SFPFC mechanisms (Wolak, 2021)

The SFPFC mechanism revolves around fixed-price fixed-quantity requirements forward energy contracts. As regards its interaction with the retail activity, it is worth pointing out the following main characteristics:

- The mechanism would require all free consumers and distributors (regulated consumers) to hold standardized long-term fixed-price fixed-quantity forward contracts equal to fractions of their realized demand at various horizons to delivery.

    a. 100 percent of realized system demand purchased three years in advance

    b. 95 percent of realized system demand purchase four years in advance of delivery,

    c. 90 percent of realized system demand five years in advance of delivery,

    d. and 85 percent of realized demand six years in advance of delivery

- SFPFC energy would be shaped to the hourly system demand within the compliance period of the contract. This compliance period could be in principle based on quarterly periods to properly account for seasonality (although it would correspond to OSINERGMIN determining it).

- The total standardized fixed-price forward contracts obligations are allocated to retailers based on their share of system demand during the compliance period. Total demand requirement would be defined by COES.

- These contracts would be procured through multi-round descending clock auctions.

- Ex post true-up auction would be used to match contracts with physical requirements.

As it is well known, fixed-quantity fixed-price contracts offer a hedging tool that does not affect short-term efficiency. Under these contracts, all suppliers have an incentive to minimize the cost of meeting their SFPFC obligations by offering to supply this energy at their marginal cost of production in the short-term market (Wolak, 2021), while retailers, on behalf of consumers, are incentivized to buy electricity according to consumers short-term willingness to pay for energy (the so-called marginal utility).

Therefore, with the proposed scheme, retailers will have incentives to define the tariffs in such a way that they get some response from consumers based on short-term signals. It is worth noting that fully exposing at the margin[64] consumers is compatible with hedging their risk. Being fully exposed to the real-time price does not entail excessive risk if retailers buy forward consumers' expected consumption in the auctions. This would allow consumers facing the short-term price on the margin, but most of their electricity would be purchased at much less volatile forward prices. In any case, designing these or other tariffs will be one of the innovative characteristics of the tariffs, if retail is opened to competition.

The scheme presents some good properties, but it is worth mentioning that the hedging strategy is mostly defined by the regulator. We do not mean to say that further degrees of freedom should be provided to retailers, but it is important to bear in mind that this limits the possibilities of retailers to differentiate their products from competitors.

It is true, as stated in (Wolak, 2021), the mechanism would start with 100 percent coverage of system demand, but retailers could subsequently unwind at their own risk. However, for all this to be possible, it is needed the development of a liquid secondary market. Although the scheme could be regarded as the driver for this secondary market to develop (theoretically it is), it is not obvious how to ensure in practice that this secondary market would work well without further intervention (such as forcing larger agents to act as market makers).

Without a well-functioning secondary market, the result would be that of having the regulator establishing the hedging strategies of retailers, and therefore conditioning (and limiting) the tariffs they can offer.

One product that would give more room to retailers to define long-term strategies would be call options (the so-called cap contracts in Pillar 2 document). As pointed out in the document, these contracts are also very effective instruments for guarding against price spikes in the short-term market and for funding generation capacity. The starting point would be less interventionist, although again, to guarantee that retailers can achieve their desired long-term hedging strategy, it would be needed a liquid secondary market.

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[64] By exposing at the margin, we mean that each additional kWh consumed is charged at the short-term price.

5.2.1.1 *Conclusion: is it worth liberalizing retail?*

International experience shows that despite all efforts to monitor and increase market competitiveness and consumer engagement, overall welfare improvement seems to be very small (if any) for some consumer segments. Problems like high mark-ups, a not always competitive sector, and above all, the low participation of consumers in retail markets have affected the ability of retail liberalization to bring benefits to consumers. If on top of all this, we add that product differentiation is going to be quite restricted in Peru, then all together seems to call for deeper analyses before deciding to liberalize some segments of the demand.

Liberalizing retail is sometimes presented as a way to avoid the problem of determining the generation tariff to regulated consumers, hoping that if competition was ensured, and the resulting prices were acceptable to consumers, it could be left to the market the task of determining the generation prices to be applicable to consumers (all would then be free users).

However, as we discuss below, we believe that a regulated tariff would still be needed in a liberalized context, at least for a good number of years. Indeed, the current problem in Perú with the regulated tariff can be to a large extent tackled by fine-tuning the long-term auction-based scheme. It is not necessary to liberalize the market to solve that problem, for the market is not likely to solve it either, since the major decisions in system planning are still in the hands of the regulator.

In the light of international experience, we recommend putting into question the liberalization for some demand segments in Peru.

In any case, a regulated tariff would still be needed in a liberalized context, at least for a good number of years.

5.2.2 Regulated tariffs

The liberalized electricity retail business can co-exist with some form of regulated tariffs. These regulated tariffs usually pursue two objectives:

- Ensure the supply for a short period of time to consumers who do not have a contract with a retail company (e. g., because the previous contract has ended and there is no new contract, due to bankruptcy of the retail company, etc.),
- Determining a tariff that competes with the liberalized market, and that usually only applies to certain consumers segments (e.g., residential customers) that the regulator wants to protect from market risk.

The first type of tariffs is often known as "last resort" or "back-up", while the second is known as "default tariff". It is worth mentioning that the previous two objectives can be achieved with the same regulated tariff, and also that the regulator might decide not to determine the tariff itself, but to impose guidelines to retailers on how to set the previous tariffs. As mentioned above, we believe that implementing a regulated tariff that fulfils these objectives is advisable. We next discuss its proposed design.

5.2.2.1 *Default tariff design*

As it has just been mentioned, default tariffs' objective is to offer certain consumer segments a safety net in the market, but we cannot ignore that this is a tariff alternative designed by the regulator that would compete in the retail market. Since the concept in itself is clearly controversial, the only default tariff that can make sense is the one that is as much as possible cost-reflective[65] and that includes the least-possible regulatory intervention. A tariff that is subsidized and below market prices represents unfair competition and eventually would kill the retail market. Default tariffs need also to avoid, as much as possible, being the sole regulator's tool to allocate some system costs (like legacy costs, more on this in subsection 5.2.3).

Provided the previous principles, there is still one major decision to be taken by the regulator in the design of the default tariff: whether or not to use hedging strategies so as to reduce consumers' exposure to energy market risk.

In this respect, the Peruvian framework will certainly continue to be based on organizing different types of auctions, or at least sign two different types of contracts with generators. On the one hand, long-term contracts (often in auctions where new capacity plays the central role), whose objective is to provide stable conditions so as to ensure building the new plants. On the other hand, the existing generation will be offered shorter-term contracts (around one year, often in auctions for existing capacity).

The quantities to be procured with each type of contract will determine the size of the hedge. This decision should be taken by MINEM. Again, let us insist on the fact that this hedge is compatible with trying to convey the short-term market signal.

Finally, it is also necessary to define certain commitments to consumers under the regulated tariff, as well as conditions to move from the market to the regulated tariff, so as to avoid short-term opportunistic behaviors.

It is highly recommended to keep a sort of default protection tariff for domestic customers.

This default tariff needs to be cost-reflective.

Finally, it is worth mentioning that a well-designed default tariff is compatible with the compensation mechanism implemented today between regulated users of the SEIN. Having a unique price, except for losses and congestion of the transmission systems is compatible with the aforementioned well-design default tariff design.

[65] See section 4.

5.2.3 Legacy costs and exit fees

We present the proposed alternative to deal with legacy costs due to long-term contracts, a major issue today in Peru that is distorting the decisions of consumers able to be subject to regulated tariffs to participating in the free market. The allocation of legacy costs has to be designed in a way that there is no room for inefficient opportunistic switching to the free market.

We have seen how the migration of end-users who can choose to remain under the regulated tariffs or contract with a retailer in the free market exposes the distributor (the regulated retailer in the Peruvian context) to a volume risk. This is something that is not reasonable, as discussed in the background section. But it is also not reasonable either that users who cannot or simply do not switch should bear an incremental cost burden as a consequence of this migration, otherwise this opportunistic migration would certainly lead to significant inequities.

The recommended alternative to deal with this problem without taking legacy costs out of the electricity sector[66] would be to consider the stranded costs associated with past energy contracts as residual costs. Therefore, these costs would be allocated via the regulated access-to-the-network component in the tariff through a fixed charge, as discussed in section 4 (being this fixed-charge consumer-dependent).

The mechanism would be based on the PCIA fee implemented in California[67]. The mechanism intends to ensure that regulated customers are not burdened with costs associated with energy contracts that were procured on behalf of regulated customers now departing to the free market. The objective would be to ensure that customers pay their fair share for legacy costs associated with the energy contracts that the distributor, in its role of regulated retailer, procured on their behalf. This way, the methodology would imply assigning to each customer departing a certain number of contracts. These contracts would expire over time. Therefore the recommended allocation would be based on a consumer by consumer basis and looking for a historical cost-causality allocation.

Stranded costs associated with past energy contracts should be treated as residual costs, and therefore be allocated through a consumer-dependent fixed charge.

The fixed charge would be dimensioned based on historical cost-causality.

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[66] The other alternative consists of taking these potentially stranded costs out of the electricity rates paid by all electricity consumers, including them as an extra item in the national budget, ultimately defrayed by taxpayers.

[67] https://californiachoiceenergyauthority.com/pcia-fee/

5.2.4 Proposal to remove barriers to the development of the retail market

If the objective is to liberalize, it is essential to guarantee a market with low entry barriers for suppliers and low switching barriers for end-users. This is the only way to ensure competition is maximized and prices are efficient.

In 2016, CEER published a report that identified barriers to entry for energy suppliers into retail gas and electricity markets across the EU (CEER, 2016). The study also presented the actions National Regulatory Authorities had taken (or were going to take) to remove them. Most of the major recommendations from the EU experience can be applied to Peru. We gather in the next box these basic principles to be applied (some of which have already been described previously).

Barriers to retail and actions to be taken

Access to data and data standardization

A major challenge for new entrants is related to accessing customer and market information. Also associated with data, it was identified the burden created by data management processes. Standardizing the data format and processes would be a first necessary step to be carried out by OSINERGMIN (this has been discussed in section 1).

Avoid non-cost reflective regulated end-user prices

Aligning prices of regulated tariffs with costs is fundamental to avoid unfair competition to the retail business. Also, conditions need to be defined so as to avoid opportunistic switching between the regulated and the free market tariff.

Smart meters

As it has been commented before, there was a total consensus regarding the role of smart metering deployment to allow future innovation in the retail energy market.

Inefficient unbundling

Inefficient unbundling is a major reason behind the potential failure of liberalizing retail activity. One example relates to the advantage of the incumbent supplier to share an identical or similar branding with the DSO. Measures need to be taken in this respect to avoid this advantage.

Obligations on suppliers

Licensing and contracting processes, involving obligations and guarantees are a relevant barrier to entry. While it is acknowledged that these processes are essential to ensure a safe business environment, several regulators reported efforts to reduce the impact of obligations on suppliers.

Switching process

Complicated switching processes represents also a major entry barrier. A clear objective to improve gradually timeframes for switching would need to be established by OSINERGMIN.

However, this relies on improvements in some of the previous points, such as smart-meters deployment.

In order to ease the switching process, alternative recommended measures include: ensure price comparison tools, try to increase consumers' engagement.

5.2.5 Gradual process

The unbundling of retail activity is not a change that usually happens overnight. It is indeed a gradual process where the different measures commented so far would be implemented in different steps:

- The first two measures, calling for an urgent reform are the following:
    a. Unbundling the "free market retail" activity from that of distribution and generation activities.
    b. To fine-tune long-term auctions and their associated cost allocation (the allocation of generation costs in the regulated tariff). This will help to pave the way for the design of a future cost-reflective default tariff, which as commented, would be necessary as a safety net.
- Unbundle the regulated retailer from distribution companies.
- Remove the barriers pointed out in this section, among which dealing with legacy costs play a major role.
- Progressively liberalize the different demand segments:
    a. First, introduce the optionality to choose between the regulated tariff and the free market. Progressively reducing the threshold to be eligible to such a choice.
    b. keeping the default tariff, at least for a number of years, and remove it for larger users, while keeping it (at least for a good number of years) for residential consumers.

5.3 References

CEER, Council of European Energy Regulators, 2016a. CEER Benchmarking report on removing barriers to entry for energy suppliers in EU retail energy markets.

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OSINERGMING, 2020, "Anuario estadístico 2019", Gerencia de Regulación de Tarifas (GRT), División de distribución eléctrica, OSINERGMIN.

Wolak F. A., 2021, Preliminary Report on Thematic Line 2: Transformation of the Peruvian Wholesale Electricity Market, February, 2021.

6 Roadmap

In this final report, some recommendations have been outlined as regards how to reform the distribution and retail sector in Peru. In this final section, as a way to conclude this study, the most relevant recommendations are briefly listed and classified according to their priority.

That is, we classify the proposed reforms into those which are more urgent and preferably to be implemented in the short-term (less than 4 years), and then continue with those to be implemented in the medium- (between 4 and 8 years), and long-term (more than 8 years).

6.1 Short-term reforms (less than 4 years)

Short-term reforms represent the changes that lay the necessary foundations for completing the rest of the reforms afterward. It is noteworthy that these short-term reforms can be implemented before the full roll-out of smart meters would be carried out.

- Restructuring distribution activities
  a. Functional and legal unbundling of distribution and retail (distributors with more than 50.000 customers).
  b. Functional & legal unbundling of distribution and DER (DG, Storage, EV charging).
  c. Increasing DSO transparency and publishing basic hosting capacity maps.
- Advanced metering infrastructure
  a. Carry out cost/benefit analysis differentiated by customer category.
  b. Develop a detailed deployment plan, including the functionalities and interoperability requirements; the ownership and the cost recovery mechanism.
- Distribution activity revenue setting
  a. Reform the distribution activity revenue setting: from VAD to building blocks (CAPEX + OPEX). This is one of the major changes proposed in this document, involving a series of key elements, such as the determination of the Legacy RAB, the role of distributor's investment plans, the introduction of menu of contracts and the mechanism to ensure the quality of service.
- Tariff redesign
  a. Redesign residual cost charges
  b. Redesign subsidies in a non-distortive way
  c. Avoid net metering support mechanisms for DER
- Retail markets

a. Implement a well-designed default tariff.

b. Implement a methodology to allocate legacy costs: allocate legacy costs based on historical cost causality

6.2 Medium-term reforms

Medium-term reforms represent for the most part measures that have been tested in the international experience, but which at the same time, in order to be implemented, require a series of prior reforms (those mentioned in the previous section)

- Restructuring distribution activities
  a. Develop the role of the distributor as a market facilitator
  b. Implement long-term auctions for procuring local flexibility services from DER
- Advanced metering infrastructure
  a. Continue with the roll-out of smart meters.
- Tariff redesign
  a. More time granular tariff signals and market prices (conditioned by the deployment of smart meters).
- Retail
  a. Expand the retail free market eligibility to other consumer segments
  b. Complete the unbundling of distribution and retail in all segments (both for free and regulated customers)

6.3 Long-term reforms

Long-term reforms consist of measures that represent the international best practice to date, but some of them are still in a rather embryonic state.

- Restructuring distribution activities
  a. Increase the information disclosed within hosting capacity maps
  b. Implement short-term flexibility markets
  c. Real-time coordination between TSO & DSOs
- Advanced metering infrastructure
  a. Data management regulation (evaluate the implementation of a centralized hub-based approach).
- Distribution activity revenue setting

a. Moving to a TOTEX approach with gradual capitalization rates

- Retail

    a. Maintain the default tariff for domestic customers & eliminate it for the rest of customer categories

Next figure summarizes the priority of the different proposals.

	Restructuring distribution	Advanced metering infrastructure	Distribution revenue setting	Tariff redesign	Retail markets
Short-term (< 4 years)	Functional & legal unbundling of distribution and retail (>50.000 customers)	Cost/Benefit analysis by customer categories	From VAD to building blocks (CAPEX + OPEX) Key elements: - Legacy RAB - Investment plans - Menu of contracts - Quality of service	Redesign residual cost charges	Well-designed default tariff
	Functional & legal unbundling of distribution and DER (DG, Storage, EV charging)	Deployment plan (functionalities/ interoperability; ownership & cost recovery)		Redesign subsidies	Allocate legacy costs based on historical cost causality
	Publishing basic hosting capacity maps	Data management legislation		Avoid net-metering	Unbundling of the retail activity to free consumers
					Regulate switching procedures
Medium-term (4-8 years)	Long-term auctions for procuring local flexibility services from DER	Continue with deployment		More time granular tariffs and market prices	Expand the retail free market eligibility to other consumer segments
	Develop the role of distributor as a market facilitator				Complete the unbundling of distribution and retail in all segments (both for free and regulated customers)
Long-term (> 8 years)	Advanced hosting capacity maps	Evaluate implementation of a data hub	Moving to a TOTEX approach with gradual capitalization rates		Maintain the default tariff for domestic customers & eliminate it for the rest of customer categories
	Short-term local flexibility markets				
	Real-time coordination between TSO & DSOs				

Figure 25.- Implementation Roadmap

Modernization of the Peruvian electricity system

Pillar 3:
Innovation in distribution and retail

First deliverable
Preliminary analysis of best practices based on the international experiences

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This document is the first deliverable corresponding to the "Pillar 3: Innovation in distribution and retail marketing", within the context of the "Modernization of the Peruvian electricity system" project.

The report herein analyses the chief discussions and best practices stemming from the international experience. This sets the background for the detailed alternatives to be presented for the Peruvian context in the final report.

The document has been elaborated by the authors from the Institute for Research in Technology of Universidad Pontificia Comillas for The World Bank Group.

Executive summary

The objective of this first deliverable is not to provide specific and detailed recommendations for the Peruvian reform, which will be the aim of the next and final report, but to summarize both the main regulatory discussions and best practices that delve around the new role of and innovations in distribution and retail companies, all based on recent international experiences.

Restructuring distribution activities

The decentralization of the power sector is a central element of the energy transition and it entails both challenges and opportunities for the distribution sector. The regulation of the distribution activity must be reformed to adapt to this new reality and to allow and efficient development of new business models arising at the end of the grid.

Among all the differences that can be found in the regulation of the distribution activity, the most relevant is probably the relationship with the retailing business. While, in the European Union and some jurisdiction in the United States, distribution and retailing are unbundled and the regulated network activity has been somehow separated by the competitive activity to be carried out in the retail market, in other regions, as in most of Latin America, distribution companies also act as regulated retailers for certain categories of consumers connected to their network. This is the situation also in Peru, although this aspect may be reformed in the future.

In this context, distribution companies must become active operators that coordinate distributed energy resources (DERs) and facilitate market-based solutions for the services that they can offer.

The new paradigm gives rise to new potential conflicts of interest between the distribution and other activities. A new discussion on the unbundling of regulated and competitive businesses is required. According to some experts, only ownership unbundling between distribution and generation/retailing activities would guarantee an efficient framework for the integration of DERs. If ownership unbundling cannot be implemented, the distributor should be subject to strict regulation (including transparency rules) and monitoring. Several regulators directly prohibited the ownership of DERs by distribution companies, for instance in the European Union, storage or electric vehicle recharging facilities. However, several exemptions to this rule are usually applied.

DERs will be able to provide local services to the distribution network, but they can also sell flexibility services to the system operator. This will require a stronger coordination between network operators. Such trade may take place in specific local flexibility markets, which may foster a more efficient distribution network congestion management and long-term planning. If these local markets are implemented by distribution companies without a strong ownership unbundling, some supervision is advisable to avoid the creation of entry barriers.

Beyond the signals provided by local markets, it is also relevant to establish methodologies for the disclosure of information, by distribution companies, associated with the status of the grid. Hosting capacity maps, a tool which is widespread in the United States, represent the minimum information that should be available to agents so that they can make informed investment decisions at the distribution level.

Data produced by smart meters can foster innovative services, especially in the retailing business, but in order to harvest this potential, a sound regulatory framework for data management need to be established. Regardless of the management strategy (centralized vs. decentralized), data should be provided to competitive market actors in a standardized format and ensure that customers maintain full ownership and control over their data.

Advanced metering infrastructure

Distribution companies in Peru are at an incipient stage of smart meter deployment. The European Union and United States experiences present a rich and diversified set of solutions to extract lesson for developing further policies on this issue.

In 2018, smart meters accounted respectively for 34% and 56% of metering points in the European Union and the United States. Several jurisdictions have elaborated or are developing rollout plans for advanced metering infrastructures. The most widespread drivers for the deployment of smart meters are the digitalization of the distribution grid, the possibility to apply dynamic tariffs, the enhancement of the retail market and a more efficient integration of distributed energy resources. However, a large part of the potential benefits of advanced metering infrastructure (AMIs) can only be gathered if market and tariff designs are modified accordingly. Therefore, the rollout of smart meters should be part of a larger set of reforms that go in this direction. Furthermore, regulators should guide the rollout of smart meters, anticipating private initiatives and making sure that the deployment of smart meters is always aligned with the objectives of the system.

As mentioned, AMIs may result in large efficiency gains and the rise of new business models, but they also entail significant costs, which are ultimately held by consumers. It is essential that the equilibrium between costs and benefits is properly assessed in a specific analysis prior to any implementation phase, possibly for different consumer categories. In the European Union, for instance, Member States are legally required to carry out cost-benefit analyses (CBAs) on smart metering systems on a periodic basis and to proceed with the rollout if the outcome is positive. CBAs are also used in other regional contexts, as in the United States or Australia.

Several smart meter models can be found in the market and each of them may offer different services. It is important that the regulator defines a minimum set of functionalities required before the rollout begins, in order to avoid early obsolescence of the equipment. Other implementation details of the rollout plan are the level of centralization of the installation process, the management of the data produced by the smart meters and the resilience of the metering system to cyber-attacks.

Distribution activity revenue setting

The current revenue setting of distribution companies in Peru is based on some design elements that do not promote innovation and new investment on technologies for DER integration and quality of service improvement. More specifically, the most important elements of distribution revenue setting that should be revisited are related to the calculation and treatment of the asset base and capital expenditures, as well as output-based incentives (such as quality of service).

Revenue cap methodologies, which represent the starting point of the analysis[1], can be subject to many different forms of implementation. The most relevant design elements and the recommended design decisions in the present context of increasing penetration of DERs are analyzed. These best practices are as follows.

TOTEX-oriented remuneration

As regards the remuneration, it is recommended to move in the direction of equalizing the incentives perceived by distribution system operators (DSOs) to reduce costs regardless of their nature (CAPEX or OPEX). This is achieved by introducing some sort of TOTEX-oriented revenue cap regulation. It is worth emphasizing that there is a whole range of approaches between completely separating CAPEX and TOTEX and evaluating both as a whole. A solution in between seems to be the most reasonable alternative.

Any building block methodology involves calculating and updating the regulated asset base (RAB)

Any remuneration methodology should be based on calculating (or estimating) the so-called "building blocks" of the distribution business, and this involves determining the (actual, efficient or estimated.) RAB. The RAB value is a fundamental part to the determination of allowed revenues because both depreciation and return on capital are calculated from it.

When implementing the methodology, the most suitable approach for determining the initial (or legacy) RAB is in general very case dependent, but a combination of considering actual investments (whenever possible) and norm costs seems to present a reasonable trade-off.

Afterwards, at the beginning of every subsequent regulatory period, the regulator should include in the RAB the non-depreciated investments already allowed in previous regulatory periods (thus, not reassessing that part). This is known as consolidating the RAB. Consolidating the RAB is recommended to mitigate regulatory instability and reduce the regulatory burden. Reopening the RAB, such as the VNR methodology does today, does not represent a future-proved mechanism.

As regards the RAB, it is also needed to point out that in TOTEX-oriented regulation, it is necessary to decouple, at least to some extent, the new RAB additions from actual investments. This decupling can be partial, and therefore the RAB can in part account for actual investments.

Incorporating new investments into revenue allowances

DSO ex-ante remuneration formulas should incorporate profit-sharing mechanisms to mitigate the impact of regulatory forecasting errors in a context with growing uncertainties. The menu of contracts is a sophisticated tool that presents desirable properties. The ex-post review associated with the menu of contracts can be calibrated to situate the incentive and risks in between pure incentive-based and pure cost-of-service-based regulation.

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[1] Today, there is a total consensus on the need to decouple the remuneration of the distribution activity from the distributed energy volume, which may be reduced by DER investments without a corresponding reduction in costs (MITEI, 2016; IRENA, 2017). This is why price cap regulation is not even considered in this analysis. That said, it is worth mentioning that price cap regulation with an ex-post revenue correction can resemble to a large extent to a revenue cap regulation.

In order to obtain the ex-ante remuneration, an engineering-based forward-looking reference network model (RNM) represents a suitable approach.

Regutatory period

Long regulatory periods (5 years or above) and allowing for reopeners represent recommended practices today. These are compatible with in between revisions for some specific elements (e.g. investment plans).

Other incentives

Output-based incentive/penalty mechanisms coupled with a TOTEX-oriented remuneration, are the best tools to improve network reliability today. The outputs to be monitored need to incorporate both the number and the duration of interruptions.

Finally, it is relevant to note that despite the fact that output regulation is generally preferable than the regulation of inputs, innovation can be difficult to attain through output-only regulation.

Tariff design

Tariffs will play a crucial role during the energy transition, since they will be called to define the equilibrium between centralised and distributed energy resources and services. Beyond fulfilling the classical ratemaking principles of allocative efficiency and cost sufficiency, prices and charges for electricity services will have to be non-discriminatory (and symmetrical for generation and consumption) and technology-neutral.

The granularity of the energy prices must be enhanced. Electricity prices should be calculated for shorter time intervals to disclose the real value of distributed resources. However, this requires a previous deployment of AMIs among the customers that can respond to such signals. Spatial granularity, on the other hand, comes at a cost (in terms of computation and increased complexity) and a trade-off must be pursued. Distributed locational energy prices does not seem to be a workable solution for the time being. When adequacy mechanisms are in place, the charges to recover the costs of these schemes should be proportional to the expected consumption during scarcity conditions.

Network costs, on the other hand, should be recovered through peak coincident charges. Residual costs, both residual network costs that cannot be allocated efficiently and most of policy costs, would be better recovered through a fixed charge, expressed as a lump sum that could be computed yearly and billed in monthly instalments. This fixed charge is supposed not to convey any signal that could trigger an inefficient response by the consumer.

Net-metering policies for the deployment of distributed generation should be avoided. DERs should receive a compensation reflecting the market value of that electricity and pay for charges that reflect the costs associated with using the network. It is also important to note that DER deployment, and the redesign of electricity tariffs required to guarantee its efficient integration, may create a distributional impact that will increase the burden for low-income consumers. This effect may be corrected within the tariff design or through specific protection measures.

Despite this theoretical framework, it must be remarked that many jurisdictions still apply a simplistic tariff design. For instance, in both Europe and the United States, most of the systems continue to allocate the majority of network costs (and other regulated costs) through volumetric charges and only some of them apply some level of hourly discrimination.

Local flexibility markets

As already mentioned, DERs may improve the efficiency in both the operation and the long-term planning of the distribution network. However, specific local markets are required to fully exploit these potential benefits.

Even efficiently-designed tariffs cannot provide the long-term signal and commitments that end-users may require in order to invest in DER and DSOs to plan the network. This inefficient situation may be solved through auctions for long-term local flexibility contracts.

These new distributed auctions must be carefully designed, especially in terms of the kind of availability required to DER, the notification time for delivery, penalties for underperformance, the possibility of embedding a financial contract and potential constraints on the amount of product that each resource can offer (as it happens in capacity markets). If the product is not univocally defined, very different resources, providing different services, may have to be compared in the auction (case in some systems in the US). This is a very complex task with no obvious solution.

Although this topic has been broadly addressed in literature, very few examples of market platforms for the trade of distributed services can be found in international experiences, some of them only as pilot projects. The most relevant local markets for distribution services in Europe are NODES, Cornwall LEM, Piclo Flex, GOPACS and Enera. The main difference among these experiences lies in the product they permit to trade.

Retail sector

In Peru, residential consumers below 20 kW and commercial or industrial consumers below 20-200 kW are still supplied by distribution companies under a regulated tariff.

The creation of a retail market is the final step of power sector liberalization, which has been taken only in some jurisdictions that restructured their electricity system. In theory, an efficient retail market may result in lower tariffs for consumers and increase the competition in the wholesale market. In order to achieve these benefits, the regulation of retailing should pursue low entry barriers for suppliers and low switching barriers for end-users. However, the debate on the actual realization of these benefits is still ongoing. The most commonly mentioned barriers to efficient retailing are the presence of default tariffs, inefficient unbundling (with generation or distribution), complex supplier switching processes and the lack of proper price comparison tools.

The more advanced experience with retail liberalization is probably the European one, where the creation of a retail market was included in the target model for power sector regulation. Also, in this region, however, the retail market has not yet been able to fulfil its promises in terms of expected benefits. The difference between wholesale and retail market prices is high in several jurisdictions, while many markets still present an undesirable level of concentration.

Even in some of the more mature markets (as, for instance, the UK or Spain), regulators have decided to keep a sort of default protection for domestic customers. Default tariffs may hamper the development of the retail market; they should be cost-reflective and introduce the least-possible regulatory intervention. A tariff that is subsidized and below market prices represents unfair competition and eventually would end with the retail market. As regards the energy costs in the default tariff design, contracting a certain percentage in advance, and trying at the same time to convey the short-term market signal as much as possible seems to be the most efficient approach.

On the other hand, legacy costs represent a challenge in certain contexts. Long-run marginal costs are decreasing below current market price levels, and more importantly, below prices signed in long-term contracts. On top of that, end-users have to bear the costs of different sorts of the so-called policy costs. The immediate consequence is that, if tariffs and charges are not properly designed, there is a certain risk that those end-users who have been under the protection of regulated tariffs could opt out from them to benefit from a free arbitrage that would leave the burden of legacy costs on those other end users that for whatever reason could not do it

The allocation of legacy costs has to be designed in a way that there is no room for inefficient opportunistic switching to the free market. There are several possible alternatives. One of them consists of take these potentially stranded costs out of the electricity rates paid by all electricity consumers, including them as an extra item in the national budget, ultimately defrayed by taxpayers. Alternatively, these new stranded costs could receive the category of residual costs, and could be allocated among all end-users via the regulated access-to-the-network component in the tariff. Finally, an increasingly considered alternative is to design an exit fee to be charged on those end-users that would decide to migrate from the regulated rates to the free market.

1. Restructuring distribution activities

One of the main trends that characterizes the energy transition is the decentralization of the power sector. This decentralization process consists in the appearance of new actors and business models in the distribution grid, triggered by the installation of distributed generation and storage, the deployment of an advanced metering infrastructure, and the large amount of data that the latter produces. This decentralization entails both challenges and opportunities for the distribution sector. On the one hand, the operation of the distribution network becomes more complex and requires innovative technologies and strategies that allow a smart operation of the grid. On the other hand, the distributed energy services offered by new actors and business models can be highly beneficial for an efficient operation of the network in the short term, but also for its more efficient planning in the long-term. This change of paradigm requires to redefine the role of distribution companies, which must become active Distribution System Operators (or DSOs, to use a concept widely used in the European context), which actively manage the grid and the interaction with distributed energy resources (DERs) and serve as a neutral facilitator of market-based solutions.

The decentralization of the power sector is a central element of the energy transition and it entails both challenges and opportunities for the distribution sector; the regulation of the distribution activity must be reformed according to this new reality

This new role must be achieved starting from a regulatory condition which is far from being uniform among liberalized power sectors. Among all the differences that can be found in the regulation of the distribution activity, the most relevant for this discussion is probably the relationship with the retailing business. While, in the European Union and some jurisdiction in the United States, distribution and retailing are unbundled and the regulated network activity has been somehow separated by the competitive activity to be carried out in the retail market, in other regions, as in most of Latin America, distribution companies also act as regulated retailers for certain categories of consumers connected to their network. This is the situation also in Peru, although this aspect may be reformed in the future. The objective of this deliverable is not to provide specific and detailed recommendations for the Peruvian context, which is the objective of the next phases of this project, but to summarize both the main regulatory discussions and best practices that delve around the new role of distribution and retail companies, all based on recent international experiences. Pursuing this objective, this introductory section presents six overarching regulatory discussions that provide the background for the topics covered in the rest of the deliverable:

- the need to restructure or closely supervise distribution activities (subsection 1.1);
- the compatibility or incompatibility of DSO functions with the ownership of distributed resources, such as generation or storage (subsection 1.2);
- the need to significantly reinforce the coordination between the operator of the distribution grid and the system operator (subsection 1.3);

- the role of the distributor as a market facilitator in local flexibility markets (subsection 1.4);
- the need to increase transparency and publish, among others, information about hosting capacity (subsection 1.5);
- the management of consumption data that may be produced by smart metering systems (subsection 1.6).

Although the international experiences covered in this section come from jurisdictions with vertical unbundling between distribution and retailing, most of these discussions are relevant also for distribution companies that act as regulated retailers, as in the case of the ownership of distributed resources, the publication of hosting capacity maps, or the management of data produced by smart meters. The rest of discussions will be refined and tailored to the Peruvian context in the next deliverable.

1.1 Restructuring models for the distribution activity

Burger et al. (2019) discuss the role and functions of the distributor in the new context, with special attention to new conflicts of interest that may affect the efficiency of the system as a whole. Three options are proposed to (re)structure the roles and responsibilities of distributors to a greater or lesser extent:

(i) The first model is an ideal text-book model with very few real-world implementations, still at an initial stage (as in Slovenia, EURELECTRIC, 2020), which would entail the separation between the owner and the operator of the distribution network, both being also vertically unbundled from the generation and retail activities. This model would seek to replicate the ISO (Independent System Operator) model that is applied in liberalized systems (at the high voltage level) in the US. The operator of the distribution network would be in charge of managing the purchase of local services for an efficient operation and expansion of the distribution grid.

(ii) The DSO (Distribution System Operator) model, where the DSO combines the ownership of the distribution network and its operation and planning (and therefore also the management of the potential purchasing mechanisms). This DSO would have to be vertically unbundled from generation and retail activities.

(iii) The model in which the distributor is vertically integrated with either generation, retail or with both activities. In this case, the distributor owns the network, is responsible for operating and planning it, and is part of the same company (or holding company) that has generation and/or retail activity.

When in the previous classification we talk about unbundling, we are referring to an effective vertical unbundling. In MITEI (2016), it is argued how legal or functional unbundling is completely ineffective, and how the lessons learned in the US and the EU in generation and transmission activities lead to the conclusion that structural (ownership) unbundling is the only real effective unbundling. The same report suggests that any other type of vertical unbundling must be treated to all intents and purposes as the third model (absence of restructuring).

Nonetheless, it must be remarked that, for instance, functional unbundling is the model adopted by the vast majority of European countries.

The new paradigm gives rise to new potentials conflicts of interest between the distribution and other activities. According to some experts, only ownership unbundling between distribution and generation/retailing activities would guarantee an efficient framework for the integration of DERs

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In general, the first two models can achieve an efficient integration of distributed energy resources, with no conflicts of interest and moderate regulatory oversight. The focus in both cases is ensuring the unbundling between the DSO and activities, such as generation and retail, which are open to competition. However, in the case of the third model, only close monitoring can achieve the same effect, as this unbundling is not inherently present.

If ownership unbundling cannot be implemented, the distributor should be subject to strict regulation (including many transparency rules) and monitoring

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The challenge of the third model is to regulate the distribution activity so that the operator's incentives are as aligned as possible with the efficient (and competitive) integration of DERs. In fully-liberalized power sectors, a distribution operator that is not effectively unbundled from retailing should be subject to strict regulation including specific rules on transparency (see the following subsections), in order to minimize opportunities to introduce entry barriers to third parties (in terms of connection or provision of services. On the other hand, in power sectors where distribution companies also act as regulated retailers, a clear framework on which agents are entitled to provide distributed services must be developed and, according to this framework, the boundaries of distribution activities should be defined, together with a monitoring strategy.

Unbundling regulation in Europe

European directives regarding electricity markets emphasize the importance of vertical unbundling (although not necessarily ownership unbundling) of DSOs or, if this is not possible, heavy monitoring to prevent a negative effect in competition. Article 35 of Directive 2019/944 states (European Commission, 2019):

"1. Where the distribution system operator is part of a vertically integrated undertaking, it shall be independent at least in terms of its legal form, organization and decision-making from other activities not relating to distribution. Those rules shall not create an obligation to separate the ownership of assets of the distribution system operator from the vertically integrated undertaking.

2. In addition to the requirements under paragraph 1, where the distribution system operator is part of a vertically integrated undertaking, it shall be independent in terms of its organization and decision-making from the other activities not related to distribution." [...]

[...] "3. Where the distribution system operator is part of a vertically integrated undertaking, the Member States shall ensure that the activities of the distribution system operator are monitored by regulatory authorities or other competent bodies so that it cannot take advantage of its vertical integration to distort competition. In particular, vertically integrated distribution system operators shall not, in their communication and branding, create confusion with respect to the separate identity of the supply branch of the vertically integrated undertaking."

1.2 Ownership of distributed energy resources and/or storage

A new role for DSOs is the efficient integration of innovative technologies such as distributed generation, distributed storage or EV recharging infrastructure. The main question that arises in this respect is whether these technologies could be considered as the distribution operator's assets (and thus be regulated) or treated as assets to be delivered competitively and owned by third parties.

In the US and EU, the best practice lies on the side of prohibiting the ownership, development, management or operation of these assets by distribution companies. There is a clear incompatibility between the operation of networks and the ownership and management of energy resources (only the ideal text-book model introduced in the previous sections would be compatible).

Distribution system operators should not be allowed to own, develop, manage or operate energy distributed generation, storage facilities or EV charging stations

Although not allowing the ownership represents the best practice, in the US it is not the only approach. For example, in California (MITEI, 2016), the regulatory commission mandated that large investor-owned utilities deployed a certain target quantity of storage capacity by 2020. The network utilities themselves were able to own up to 50 percent of this storage capacity; the remainder could be owned by independent companies.

Exceptions

In the framework of the Clean Energy Package, the European Commission Directive (European Commission, 2019) explicitly prohibits the distributor the ownership of these resources, leaving the deployment of distributed energy resources and storage to market-based solutions.

The only exceptions to this general prohibition are described in article 36 of Directive 2019/944. Similar exceptions apply to the ownership of EV charging stations.

Exceptions to the ownership of energy storage in Europe

"Member States may allow distribution system operators to own, develop, manage or operate energy storage facilities which are fully integrated network components and the regulatory authority has granted its approval OR if all of the following conditions are fulfilled:

a) such facilities are necessary for the distribution system operators to fulfil their obligations under this Directive for the efficient, reliable and secure operation of the distribution system and they are not used to buy or sell electricity to the wholesale market, including balancing markets;

b) other parties, following an open, transparent and non-discriminatory tendering procedure, subject to review and approval by the regulatory authority have not been awarded with a right to own, develop, manage or operate such facilities. Regulatory authorities may draw up guidelines or procurement clauses to help distribution system operators ensure a fair tendering procedure; and

c) the regulatory authority has assessed the necessity of such derogation and has carried out an assessment of the tendering procedure, including the conditions, and has granted its approval."

In NY, REVs Order[2] only allows distributed energy resources and storage to be owned by the utility in exceptional cases.

Regulation in the State of New York

NY REV (Reforming the Energy Vision)

In general, the New York Public Service Commission (PSC) has established through a number of REV orders and proceedings that utility ownership of Distributed Energy Resources (DER) is generally to be prohibited (with some specific exceptions). Exceptions include the following circumstances:

- when procurement of DER has been solicited to meet a system need, and a utility has demonstrated that competitive alternatives proposed by non-utility parties are clearly inadequate or costlier than a traditional utility infrastructure alternative;
- when a project consists of energy storage integrated into distribution system architecture;
- when a project will enable low- or moderate-income residential customers to benefit from DER where markets are not likely to satisfy the need;
- when a project is being sponsored for demonstration purposes.

New York Order on storage (2018)

[2] which include several measures to ensure rapid distributed renewable energy generation, reduced greenhouse gas emissions and increase energy efficiency in NY,

In 2018, the New York Public Service Commission (PSC) issued an order establishing a 3 000 MW energy storage goal by 2030, following a statement earlier in the year by governor Cuomo which established an objective of 1 500 MW of energy storage deployment by 2025. These targets would be met, in part, through competitive procurements made by investor-owned utilities (NYSERDA, 2021).

Although many regulators prohibit the ownership of DERs by distribution companies, several exemptions to this rule can be found

The regulator for gas and electricity markets in Great Britain is aligned with these approaches (Ofgem, 2017), although recognizing that "*there are certain small-scale applications of DNO-operated generation (including storage)*" considered "*to be within the normal business activities of the DNO*", namely uninterruptible power supplies emergency response and maintenance fleets for ensuring continuity of supply in outage situations. Ofgem acknowledges that there may be a very limited number of exceptional circumstances where it might be acceptable for DNOs to operate storage directly. Among other requirements, "*DNOs would need to demonstrate that every possible effort had been made to seek a market-based solution (…) and that storage is identified as the most economic and efficient solution*".

1.3 Coordination with the system operator

Ancillary services, including those used to maintain the frequency of the system and those used to solve network congestions, are expected to take on greater relevance in a context of high penetration of intermittent renewable and distributed resources. In the case of network congestions, its weight will increase both in the transmission and in the distribution network.

Furthermore, distributed resources will be able to provide services to both the system operator (SO) and the distributor (DSO); thus there is a need for some sort of coordination between the two network operators (in Europe, this concept is known as TSO-DSO coordination). This new scenario significantly increases the complexity of the system operation.

In addition to the above-mentioned short-term coordination, there is also a clear need to coordinate the planning and operation functions of the network more closely in the long term. This is reflected in the European context in Article 53 of the European Commission's proposal on the Regulation of the Internal Electricity Market (European Commission, 2016).

All of this will lead to greater efficiency both in the use of the networks and in the use of electricity generation and consumption facilities.

Since distributed resources will be able to provide services to the distributor and the system operator, there will be a need for some sort of coordination between both network operators

1.4 The role of distributors in local flexibility markets

The efficient integration of distributed energy resources can provide solutions to local problems in distribution networks: relief of local congestion (in the short and long term), reduction in the overload of some elements, voltage control, etc. To materialize these solutions, it is necessary to develop new local mechanisms for the acquisition of services.

Local flexibility markets are called to play an important role in distribution network congestion management and long-term planning

Local flexibility markets are called to play an important role in distribution network congestion management and long-term planning. In the platforms for the trade of these services, maximum efficiency would be achieved if a level playing field existed for all types of DERs, regardless of the structure of ownership and control. This requires a neutral market facilitator for all these commercial transactions. Ideally, these market platforms should be managed by independent third parties, but in several cases, they are controlled by TSOs or DSOs. For example, in the context of NY REV, regulators identified distribution utilities as the distributed system platform providers, despite the absence of unbundling rules (NYDPS 2014). When this is the case, some supervision is advisable to avoid entry barriers as much as possible. Local flexibility markets are reviewed in section 5.

If local flexibility markets are to be implemented by DSOs not subject to ownership unbundling, some supervision is advisable to avoid the creation of entry barriers

1.5 Increasing DSO transparency and publishing hosting capacity maps

Prior to the implementation of the aforementioned local mechanisms, it is fundamental to establish methodologies for the management and disclosure of information associated with the status of the distribution networks: aspects associated with the operation of the short term and with the planning of the distribution systems in the long term.

Allowing investors to identify investment opportunities in distributed resources that are beneficial to the system is of utmost relevance. To achieve this end, it is essential to regulate the adequate provision of information on distribution systems. This provision of information has to achieve an adequate balance between transparency and confidentiality:

- Transparency: this involves publishing the information to ensure the connection of new distributed resources to the network can be achieved in an agile way, prioritizing the removal of inefficient barriers and information asymmetry. The disclosure of information by DSOs can facilitate the connection of new grid users by enhancing the transparency related to the calculation of connection charges and the available network hosting capacity. The available capacity in the grid can be represented graphically in every node in the grid, in what is commonly known as hosting capacity maps, which transparently indicate the connection possibilities of new distributed resources and represent the minimum information that should be available to grid users. Although, as we will see, it is advisable to provide more information on network planning. Additionally, transparency helps reduce complaints and litigations in access conflicts that may arise as large volumes of DER request a grid connection (INTEGRID, 2020a).

- Confidentiality: on the other hand, minimum levels of confidentiality and security of distribution systems must be guaranteed. Hosting capacity maps should not share information that would permit to identify the load of individual customers. This could be achieved by redacting load profiles if they contain data on fewer than 15 customers, or if a single customer constitutes 15 percent of the load or more, through the so-called 15/15 rule (IREC, 2019). However, the strategies for guaranteeing confidentiality should be balanced with the transparency objective and should avoid unnecessary exacerbation, so as not to build artificial barriers for new entrants.

The paradigmatic experiences in this field are found in the United States, where there are several states in which distributors have to offer transparent information to facilitate the integration of new distributed generation within their networks. This experience is analyzed next.

It is fundamental to establish methodologies for the disclosure of relevant DSO information associated with the status of the distribution networks; hosting capacity maps represent the minimum information that should be available to agents so that they can make informed investment decisions at the distribution level.

1.5.1 International experience

Due to the relatively recent development of this regulatory discussion, the international experience around providing this transparency in distribution networks is limited and still developing (although this is rapidly changing). Several states include the obligation to present maps of available capacity (hosting capacity).

Hosting Capacity is the amount of DER that can be accommodated without adversely impacting power quality or reliability under current configurations and without requiring infrastructure upgrades (EPRI, 2016).

Figure 1 below (Cooke, 2018) shows the different practices in terms of hosting capacity by states. The states of California, Minnesota, and New York are among the most advanced in these desirable practices in DSO planning, as all three have introduced the concept of hosting capacity.

Planning Approaches	States With Advanced Practices					Other States' Approaches											
	California	Hawaii	Massachusetts	Minnesota	New York	D.C.	Florida	Illinois	Indiana	Maryland	Michigan	Ohio	Oregon	Pennsylvania	Rhode Island	Washington
Distribution system plan requirement[1]	√	√	√	*	√					√	√					
Grid modernization plan requirement	√	√	√	√	√											
Incentives reflecting locational value	√				√											
Hosting capacity analysis requirement	√	√		√	√			√								
Non-wires alternatives requirements	√				√										√	
Standardized calculations / processes	√				√											
Storm hardening requirements							√			√						
No planning requirement but proceeding underway[2]						√		√				√	√		√	√
Requirement to summarize current practice				√	√					√						
Voluntary distribution or grid modernization plans supporting surcharge/rider cost recovery								√	√			√		√		
Improved alignment / linking processes	√			*											*	*
Required reporting on poor-performing circuits and improvement plans							√	√				√		√	√	

√ is used to indicate the planning approach is applicable under the present regulatory or statutory requirements.
* is used to indicate that the planning approach would apply under pending proposals or proposed decisions.
[1] Requirements for one or more utilities.
[2] States noted in this row have processes underway which may result in adoption of one or multiple planning approaches listed in this table.

Figure 1: Advanced practices in distribution network planning in the USA Source: (Cooke, 2018)

California

Since 2013, California has required distribution companies to consider the costs and benefits of incorporating distributed resources into their networks. This cost-benefit analysis is part of a comprehensive study (Distribution Resources Plan, DRP) that is broken down into the following sections (GEC, 2013):

- Evaluate the local benefits and costs of the resources distributed in the distribution network
- Propose mechanisms to incorporate distributed resources that are economically efficient
- Identify the additional cost to be incurred by the DSOs to include the resources distributed in the network
- Identify barriers to the implementation of the distributed resources in the network

After the implementation of this order, hosting capacity began to be calculated through a process called Integration Capacity Analysis (CPUC, 2014). The process takes into account how the integration of distributed resources affects the reliability and quality of supply of the distribution network, and is represented in maps that reflect the entire network (hosting capacity maps).

Figure 2 shows the hosting capacity in a part of Los Angeles operated by Southern California Edison[3].

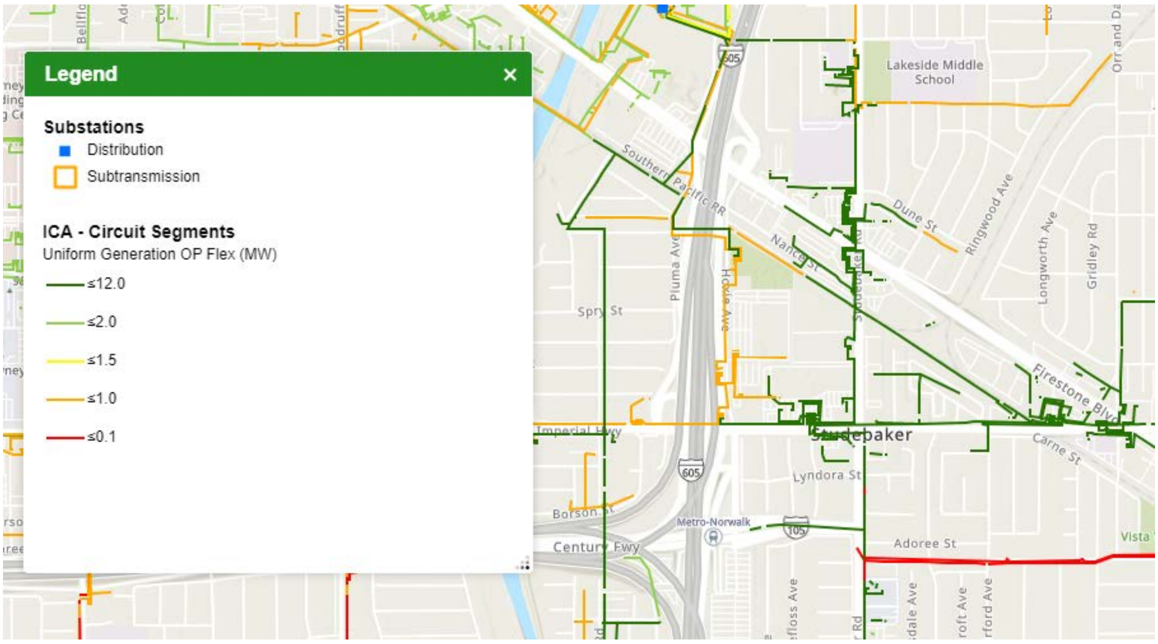

Figure 2: Hosting capacity map from Los Ángeles. Source: Southern California Edison DRPEP

The information that distributors publish nowadays goes beyond these hosting capacity maps, which in CAISO also includes demand profiles per node (figure below), DSOs future investments and even the opportunities for distributed generation to provide network services (that can serve to delay infrastructure investments).

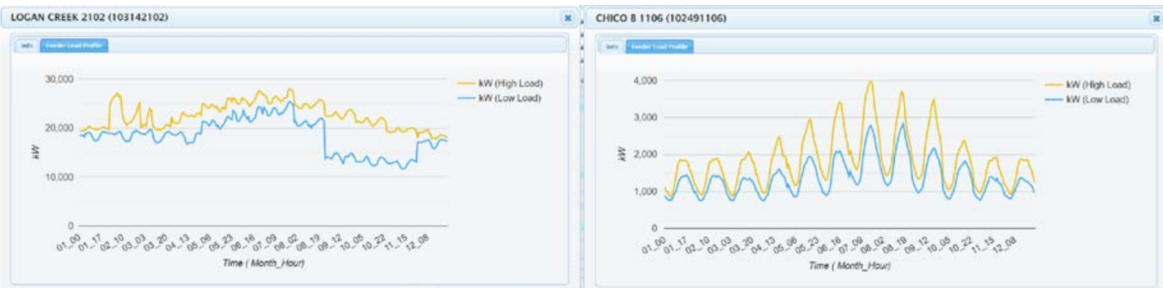

Figure 3: Demand profiles in a 21 kV node (left figure) and 1 kV (right figure). In the case of 1 kV, the information is indicative (it is not allowed to be exact due to confidentiality issues). Source: https://www.pge.com/

Other examples of maps published by the DSOs in the state of California:

Pacific map: https://www.pge.com/en_US/for-our-business-partners/distribution-resource-planning/distribution-resource-planning-data-portal.page

Southern California Edisonmap: https://www.sce.com/sites/default/files/inline-files/DERiM_User_Guide_Final_AA_1.pdf

San Diego Gas & Electricmap: https://www.sdge.com/more-information/customer-generation/enhanced-integration-capacity-analysis-ica

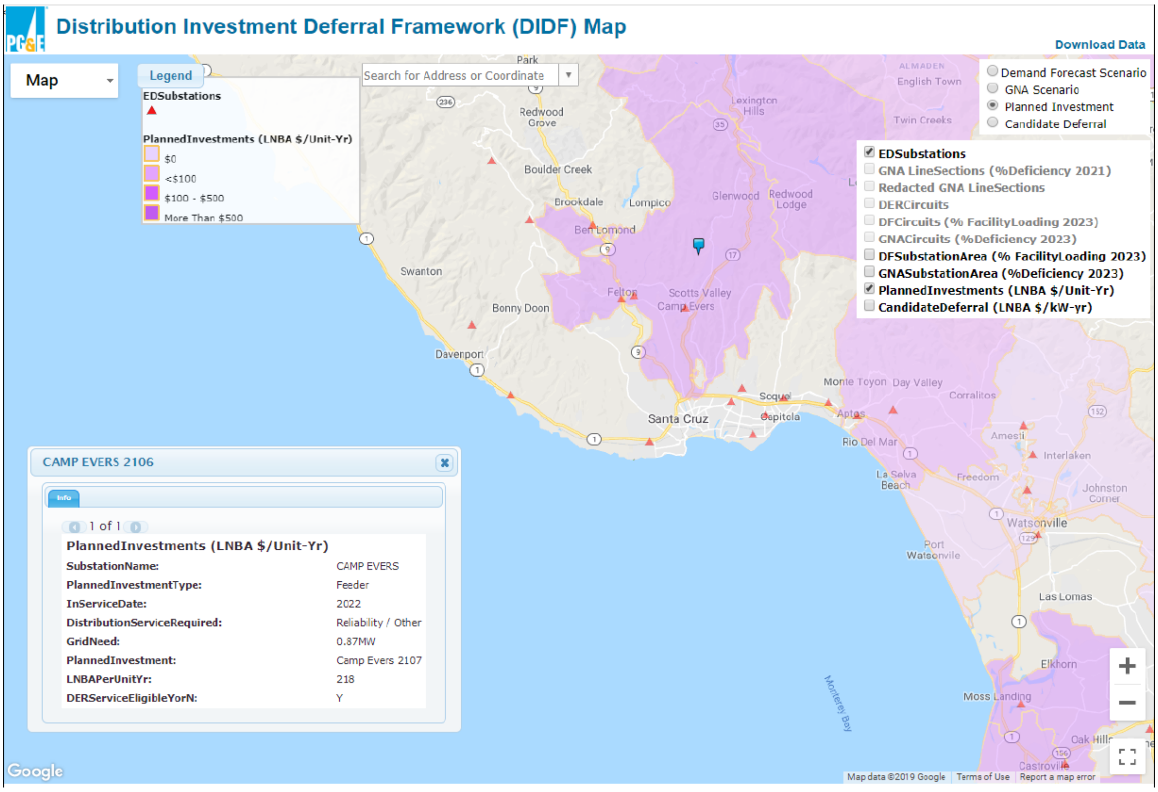

Figure 4: Map that represents distribution network investments that can be deferred through the acquisitions of distributed generation services. Source: https://www.pge.com/

New York

The state of New York has implemented several measures oriented to improve the integration of distributed resources (SNYPSC, 2015), including differentiated rates for distributed resources and increased transparency by the DSOs. Regarding the latter, the DSOs agreed to follow a four-stage approach to give information about the hosting capacity in their networks. This approach is based on a report from the Electric Power Research Institute (EPRI) (Joint Utilities, 2016 and EPRI, 2016), and consists of four stages:

- First, the nodes where installing additional distributed energy resources involve higher costs are identified. At this stage, substations/feeders that may have high costs associated with interconnecting distributed energy resources are indicated.
- A preliminary hosting capacity is calculated on each feeder node. The evaluations, carried out using the Distribution Resource Integration and Value Estimation (DRIVE) tool, developed by EPRI, consider local and also upstream constraints.
- Advanced hosting capacity analysis: temporal and spatial granularity is improved to provide more accurate information.
- Comprehensive analysis: this stage consists of an in-depth study of the costs and benefits offered by the distributed resources, depending on the particular technology and the precise situation of the resource.

Currently, the hosting capacity is represented by maps similar to those seen in California, as shown in Figure 5.

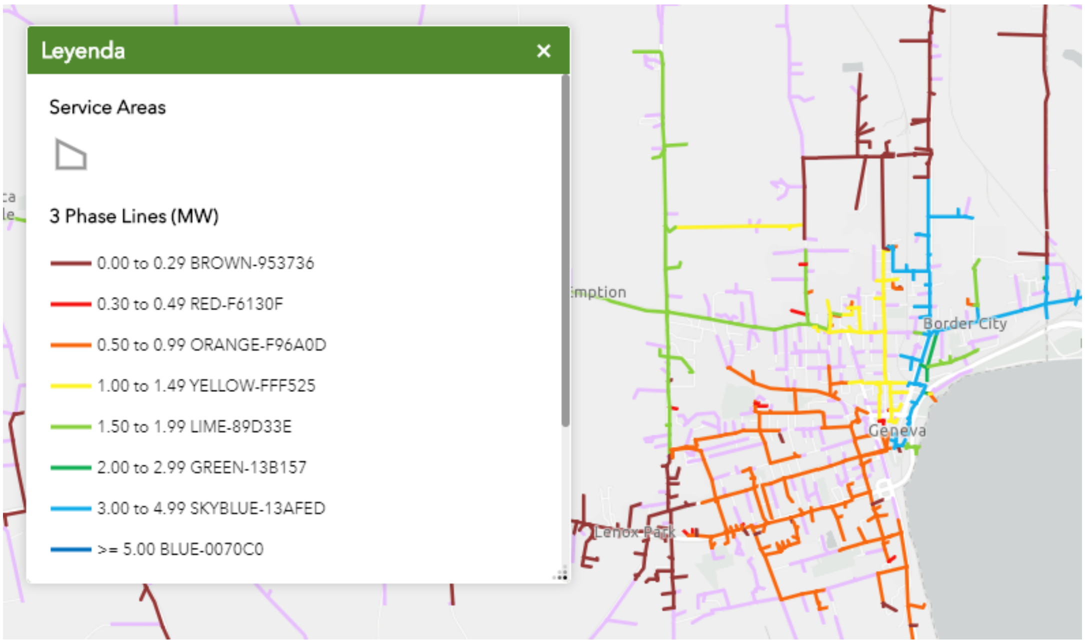

Figure 5: Hosting capacity map (NYSEG). Source: NYSEG/REG Hosting Capacity Map

Minnesota

Since 2015, Minnesota, as well as California and New York, requires DSOs to study the impact of introducing distributed resources in their networks. DSOs must analyze the cost and the impact of implementing these resources in an analogous manner to any other network project and they must also study the cost of adapting the grid to facilitate the inclusion of these resources.

The result of these measures is very similar to that of California, as it has resulted in the development of maps that allow agents to know the hosting capacity of the distribution network in Minnesota, as shown in Figure 6.

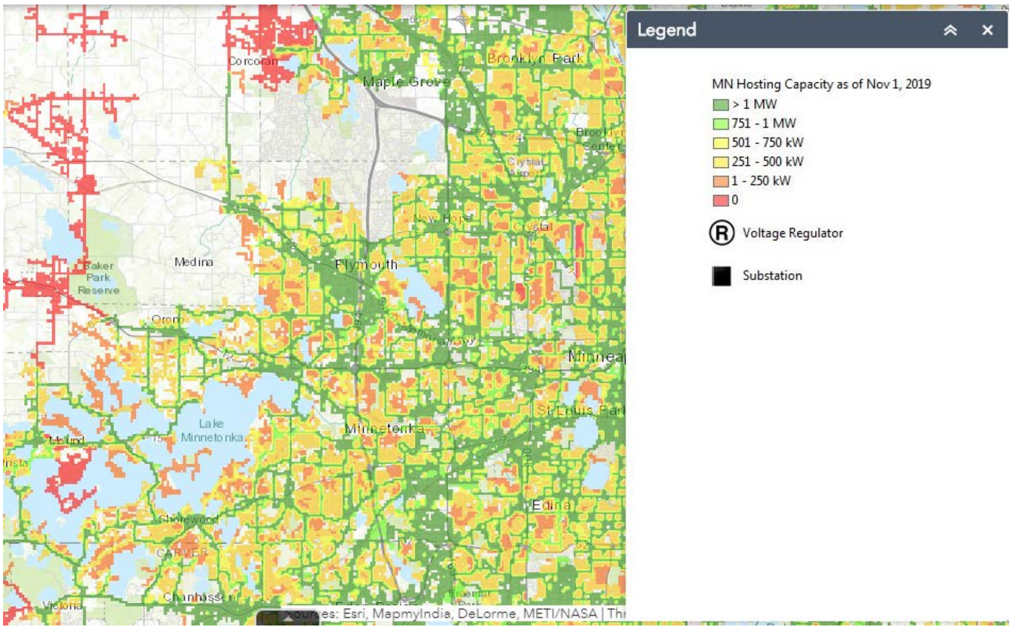

Figure 6: Map showing the hosting capacity of the distribution grid in Minnesota. Source: Arcgis Hosting Capacity Map Overview

1.6 Data services

The shift from traditional distribution grids to smart grids can create opportunities for new business models, especially regarding the use of time-differentiated electricity consumption data from consumers. Modern smart meters can permit agents to access this kind of data, allowing customers to adapt their consumption patterns or enabling companies to provide services for consumers or other third parties. The latter is usually referred to as data services and is one of the main issues in distribution grid regulation.

> *Data produced by smart meters can foster innovative services, especially in the retailing business, but in order to harvest this potential, a sound regulatory framework for data management is to be established*

For data services to be useful, governments and regulators have to address several crucial barriers. The first obstacle is the lack of widespread deployment of smart meters, which are essential as a data-gathering tool (this issue is reviewed in section 2). The management of the data gathered by these smart meters can be the second impediment to the introduction of data services, as different data-management models can act as a third-party access barrier.

1.6.1 Data management

Data management, according to the European Commission (EC, 2016) and CEER (CEER, 2016a), "*compromises the processes by which data is sourced, validated, stored, protected and processed and by which it can be accessed by suppliers or customers*". Both entities outline that smart meter data management can become an entry barrier for agents trying to provide data services.

CEER (2016b) argues that a proper data management model should enable an efficient, safe and secure exchange of customer and metering data, facilitating retail market competition and adequate customer protection. Data should be provided to competitive market actors in a standardized format and ensure that customers maintain full ownership and control over their data. Following these general outlines, CEER presented a set of guiding principles for data management models (CEER, 2015):

- Privacy and security: "Customer meter data should be protected by the application of appropriate security and privacy measures. Customers should control access to their customer meter data, with the exception of data required to fulfil regulated duties and within the national market model."

- Transparency: "The relevant body in each MS… shall make the following general information on meter data management publicly available… (a) the customer's rights with regard to customer data management; (b) what type of customer meter data exists and what it is used for; (c) how customer data is stored and for how long; (d) how the customer and market participants authorized by the customer get access to that data; and (e) within what time period the customer and market participants authorized by the customer have to wait to get disaggregated data."

- Accuracy: “The relevant body… should communicate to the customer any inaccuracies that might have taken place in relation with customer meter data and how these inaccuracies have been addressed.”
- Accessibility: “The customer… should have easy access to customer meter data”
- Non-discrimination: “To support an effective and competitive market, the data management model should not give undue preference to one stakeholder over another. This is especially important in relation to DSO-led smart meters roll-outs”.

Regardless of the management strategy (centralized vs. decentralized) data should be provided to competitive market actors in a standardized format and ensure that customers maintain full ownership and control over their data

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1.6.2 International experiences

International experiences can be classified according to the centralization levels of their data management models. In this context, centralization does not refer solely to how the data is stored but also to how it is sourced, validated, protected, processed and distributed. Therefore, we can distinguish three main centralization levels (CEER 2016b):

- Fully centralized model: all key aspects of data management are centralized, for example, through the use of a data hub. Sweden is a prime example of this type of model, as it is developing a centralized data hub where data will be stored, accessed, processed, etc (INTEGRID, 2020).
- Partially centralized model: some key aspects, usually distribution and access to data, are centralized, whilst the other key elements are decentralized.
- Fully decentralized model: all key aspects of data management are decentralized and are the responsibility of the DSO. Portugal, Slovenia, Austria and Spain are examples of this kind of model. In all of these countries, DSOs store and manage the smart meter information, which can then be requested by consumers and other agents (if they fulfil the necessary requirements). Nevertheless, Austria has a slight difference compared to the other three countries, as it has set up a decentralized infrastructure for data exchange which will be common for all DSOs (INTEGRID, 2020).

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2. Advanced metering infrastructure

According to the Clean Energy Package of the European Commission (EC, 2019), smart meters "*empower consumers because they allow them to receive accurate and near real-time feedback on their energy consumption or generation, and to manage their consumption better, to participate in and reap benefits from demand response programmes and other services, and to lower their electricity bills. Smart metering systems also enable distribution system operators to have better visibility of their networks, and as a consequence, to reduce their operation and maintenance costs and to pass those savings on to the consumers in the form of lower distribution tariffs*". This statement not only reflects the point of view of the European legislator, but it also perfectly resumes the advantages that, according to some experts, an Advanced Metering Infrastructure (AMI) may bring to the power sector. Pursuing these potential benefits, several regulators and private companies have been rolling out smart meters, and developing all the surrounding technological innovation, in the last two decades.

In 2018, smart meters accounted respectively for 34% and 56% of metering points in the European Union and the United States

In 2018, smart meters accounted for 34% of metering points in the European Union (99 million units installed; EC, 2020) and for 56% of metering points in the United States (87 million unites installed, Figure 7; FERC, 2020). These penetrations are expected to grow swiftly in the next decade (the European Union expects to reach 92% by 2030, although no formal commitment is in place).

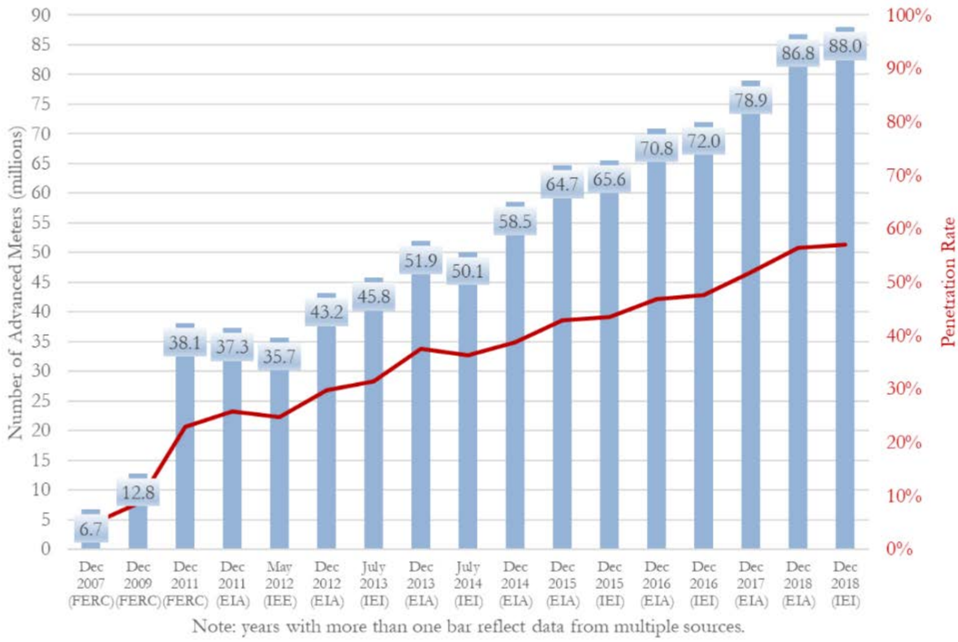

Figure 7. Advanced meters rollout in the United States (FERC, 2020)

However, the deployment of smart meters has also been subject to controversies and AMIs have not always delivered their expected benefits. The experiences developed so far evidenced the central role of the regulator and the legislator, who are called to guide the implementation of these technologies and to align it with the interests of the society as a whole. Regulators must ensure that: i) the deployment of smart maters is carried out only after a positive assessment of a cost-benefit analysis, which identifies when and for which categories the rollout is beneficial, and ii) this deployment is coordinated with the necessary reforms, in terms of market and tariff design, that allow to fully exploit the potential of the AMI technologies. This section advances some recommendations based on international experiences.

2.1 Drivers for AMI deployment

Some of the benefits that AMIs can create have already been cited. The market drivers for smart meters that are more commonly mentioned in literature are as follows.

- Digitalisation of the distribution grid; smart meters not only allow remote reading, but they also provide operators with a better knowledge on the status of their grid, which may result in an enhanced management of the network, with positive effects both in the short term (outage management, technical of non-technical losses, etc.) and in the long term (capacity deferral).
- Application of dynamic tariffs that convey efficient signals; although tariff design has been decoupled, in some cases, by the deployment of smart meters, the latter are a prerequisite to introduce time-of-use prices and charges that are capable of driving a more efficient demand behaviour.
- Enhancement of the retail market services; smart meters, and the big data they produce, may foster the appearance of innovative services in the retail market, as those offered by aggregators, increasing the potential for demand response.
- Integration of distributed energy resources; bidirectional smart meters may also register data on the operation of distributed generation and storage installed behind the meter, allowing a better monitoring of the impact of these resources on the grid and the application of a system of prices and charges that foster their efficient integration in the power sector.

The most widely mentioned drivers for the deployment of smart meters are the digitalisation of the distribution grid, the possibility to apply dynamic tariffs, the enhancement of the retail market and a more efficient integration of distributed energy resources

A recent review from the European Commission (EC, 2020) analysed the regulatory framework regarding smart meters in all member states and measured the weight of different drivers. The outcome of this analysis can be observed in Figure 8.

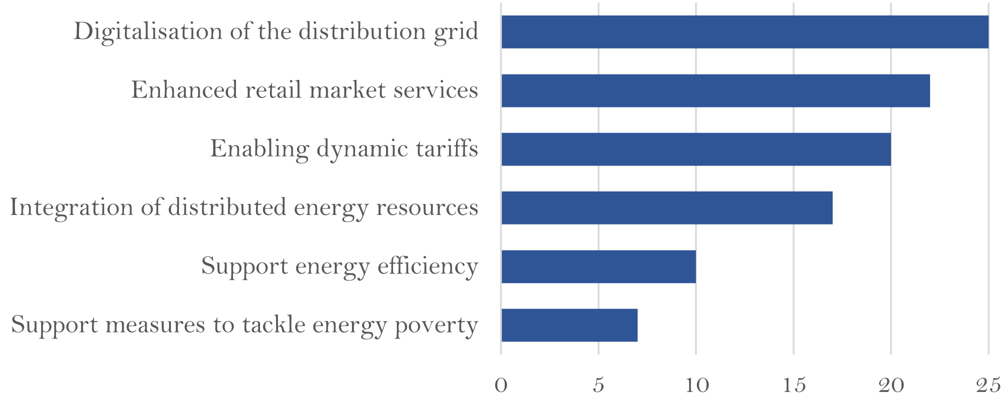

Figure 8. Market drivers mentioned by European Member States for the rollout of AMI (data from EC, 2020)

It must be remarked that the deployment of AMIs does not automatically result in the achievement of these targets. International experiences show that, excluding the remote management of the smart meter, all other objectives must be pursued with a combination of strategies of which AMIs are just one of the components.

2.2 Cost-benefit analysis

Another important finding form international experiences is the need to base the deployment of smart meters on a sound cost-benefit analysis (CBA). AMIs may result in large economic savings for different agents active in the power sector, but they also entail significant expenses, not only related to the intelligent meters themselves, but to the entire architecture that supports them. The equilibrium between costs and benefits may vary over time and, especially, among different consumer categories (for instance, the CBA could be positive for small and medium enterprises, but negative for households).

AMIs may result in large efficiency gains, but they also entail significant costs; the equilibrium between the two must be assessed in a cost/benefit analysis prior to any implementation phase

Some jurisdictions formally introduced a requirement for the rollout of smart meters to be backed by a cost-benefit analysis. The European Commission introduced this requirement already in the Third Energy Package (EC, 2009) and ratified it in the Clean Energy Package (EC, 2019); furthermore, it also defined a standardized methodology for European CBAs, through Recommendation 2012/148/EU (EC, 2012). The current legislation requires Member States to carry out a CBA on smart meters. If the outcome is positive, at least an 80% penetration must be achieved by 2024; if the outcome is negative, the analysis must be repeated after four years. The current status of CBAs in Europe is shown in Figure 9.

In the European Union, Member States are legally required to carry out these cost-benefit analyses on a periodic basis and to proceed with the rollout if the outcome is positive

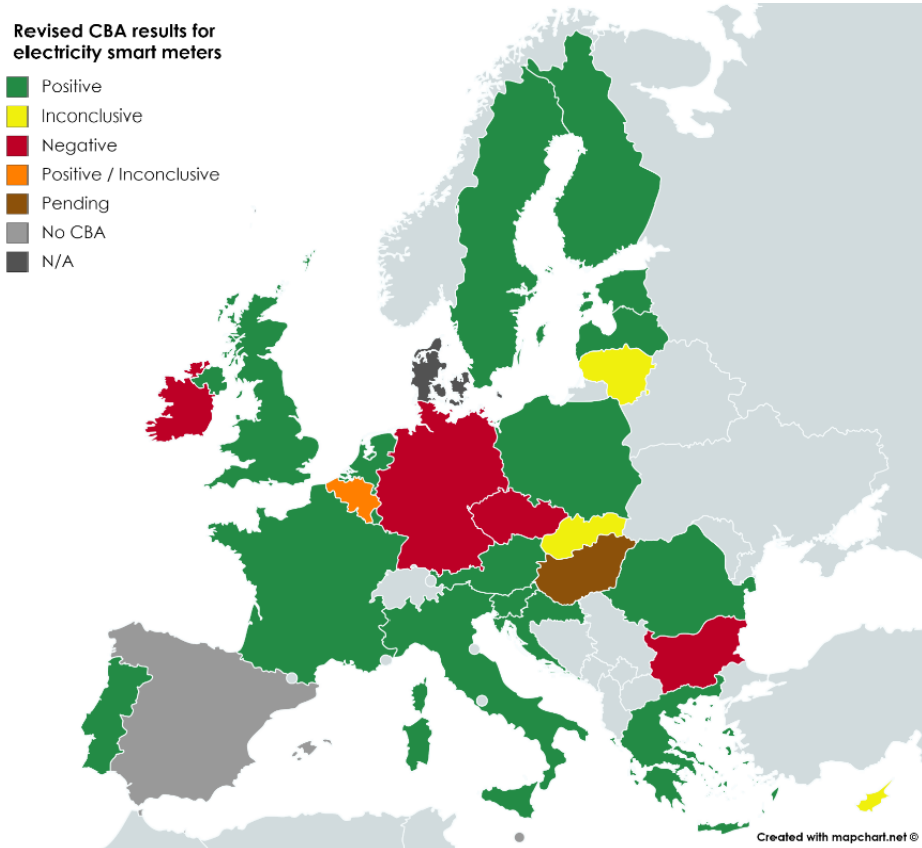

Figure 9. Outcomes of smart meters cost-benefit analyses in Europe (EC, 2020)

It is interesting to note how not all CBAs have a positive outcome. The most famous example is probably Germany, where the cost-benefit analysis conducted in 2013 had a negative result and the regulator decided not to foster the rollout of smart meters (according to the Clean Energy Package, a new CBA will have to be carried out in the next years). On average, the expected costs and benefits of smart meters in European Member States were respectively 223 € and 309 € per metering point in 2014 (EC, 2014) and 172 € and 253 € per metering point in 2020 (EC, 2020).

Cost-benefit analyses are also common outside of the European Union and have been used in the United Kingdom (BEIS, 2019), in the United States, (for instance, in California or Illinois; CPUC, 2005; Ameren, 2012) or in Australia (for instance, in Victoria; Deloitte, 2011). Examples of the outcomes of these analyses are provided in section 2.6.

Cost-benefit analyses are also used in other regional contexts, as in the United States or Australia

Cost-benefit analyses usually includes both capital and operational expenditures (EC, 2020). The costs more commonly considered in these studies are listed hereunder.

- Investments in smart meters.
- Investment in the supporting information and telecommunication technologies.
- IT maintenance and meter reading.
- Sunk costs of conventional meters.
- Unplanned renewal of smart meters.
- Consumer engagement plans.

On the other hand, the benefits that are more commonly found in cost-benefits analyses are summarised below.

- Operational savings from remote meter reading.
- Reduction of non-technical losses, including fraud.
- Reduction in energy demand due to energy efficiency.
- Enhanced demand behaviour through dynamic pricing.
- Reduction in CO_2 emissions.
- Reduction in O&M costs for the distribution grid.
- Distribution capacity deferral.
- Increased competition in the retail market.

2.3 Functionalities

Most of the high-level literature regarding AMI refers to smart meters without specifying what this term means, as if the definition were univocal. However, there are several brands, several models, and a very wide range of services that these instruments can provide. International experiences show that it is essential for the regulator to specify at least a minimum set of functionalities that smart meters to be installed in the system must have. Probably, the most cited set of functionalities is the one specified in the already-mentioned European Recommendation 2012/148/EU, which is summarised hereunder.

a) Provide readings directly to consumer and any third party designated by the consumer.
b) Update readings frequently enough to allow the data to be used for energy savings.
c) Allow remote meter reading by the operator.
d) Provide two-way communication for maintenance and control.
e) Allow frequent enough readings for the data to be used for network planning.
f) Support advanced tariff systems.
g) Allow remote on/off control of the supply and/or flow or power limitation.
h) Provide secure data communications.

i) Fraud prevention and detection.
j) Provide import/export and reactive metering.

Different models of smart meters may offer different services; the regulator should set a minimum set of functionalities required before the rollout begins, in order to avoid early obsolescence of the equipment

Once again, it must be remarked that these functionalities must be aligned with the objectives that the smart metering campaign is pursuing. Furthermore, these specifications should be forward-looking and aim to foresee the services that will be needed in the future; otherwise, there is a large risk of early obsolescence of the selected metering equipment (DG ENER, 2015).

2.4 Recommendations

The international experiences and theoretical principles analysed in this section allow to advance some recommendations. The deployment of smart metering systems should be based on a sound cost-benefit analysis that estimates the net present value of the rollout; if possible, the assessment should be subdivided into different consumer categories. The deployment should be carried out following a minimum set of functionalities defined by the regulator. Both the CBA and the functionalities should not be developed based on ideal conditions, but rather it should be tailored to each power system and to the regulatory objectives that are being pursued, in coordination with other reforms to engage customers in the electricity market. A large part of AMI benefits stems from this engagement, but smart meters are only one of the several conditions required to foster this participation, others being the existence of tariffs that convey efficient signals and a market environment that fosters innovation, especially in retailing services and demand response.

A large part of the potential benefits of AMIs can only be gathered if market and tariff design is modified accordingly; the rollout of smart meters should be part of a larger set of reforms

The above-mentioned considerations highlight the central role that the regulator should have in this process. The European experience provides relevant lessons learned in this sense. Although the regulation requires the deployment of smart meters to be preceded by a cost-benefit analysis, there are countries, like Spain, which rolled out AMIs without any CBA; in other cases, private initiatives resulted in a fast-paced deployment even before the definition of a proper regulatory framework regarding smart metering (as in Flanders or Croatia; EC, 2020). This lack of guidance risks to result in roll-out plans that are far from being optimal from a system-wide perspective and in an advanced metering infrastructure that is not able to satisfy the real needs of the customers.

Regulators should guide the rollout of smart meters, anticipating private initiatives and making sure that the deployment of smart meters is always aligned with the objectives of the system

In terms of detailed design of the rollout plan, there are several decisions that are to be taken by the regulator. The deployment may be carried out by a single entity, to take advantage of the economies of scale, or by the entities in charge of metering, commonly, distribution companies. In case more entities are involved, it may be important to ensure the so-called interoperability[4] of the equipment. Another controversial issue that must be regulated is the management of the data produced by smart meters and the modality for consumers to have access to their own data. Different approaches can be found in international experiences, with some jurisdictions opting for a centralised data hub and others on a decentralised system. According to EC (2020), beyond this dichotomy, important elements of the data management system are the resilience of the system to cyber-attack, black-out recovery capability as well as the feasibility of a system replacement if better options can be considered.

Other implementation details of the rollout plan concern the entity/entities in charge of installation, the management of the data produced by the smart meters and the resilience of the metering system to cyber-attacks

2.5 References

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[4] Interoperability is a key principle, for instance, of the European smart metering strategy (EC, 2019) and is defined as the ability of two or more energy or communication networks, systems, devices, applications or components to interwork to exchange and use information in order to perform required functions.

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2.6 Annex 1: cost-benefits analyses in Germany, the United Kingdom, and Victoria (Australia)

In this annex, three real-world cost-benefit analyses for AMI deployment are presented, the German CBA from 2013 (negative outcome), the British CBA from 2016 (positive outcome), and the update of the Victorian CBA from 2011 (negative outcome).

The German cost-benefit analysis was carried out by the consulting company Ernst & Young (2013). The main outcomes of the CBA are summarised in Figure 10.

Item	Value (€/metering point)
Costs	
Average cost of smart meters	190.34
Average cost of IT	86.34
Average cost of communications	171.15
Average cost of in-home displays	33.36
Training	10.93
TOTAL COSTS	**492.12**
Benefits	
Reduction in meter reading and operations	50.32
Avoided distribution capacity investment	31.53
Avoided transmission capacity investment	9.22
Electricity cost savings	239.69
Reduction in commercial losses	1.52
Reduction in outage time	0.43
Avoided investment in standard meters	77.04
TOTAL BENEFITS	**484.90**
NET BENEFIT	**-7.22**

Figure 10. German cost-benefit analysis from 2013 (DG ENER, 2015)

Since the net present value per metering point was negative, the German regulator decided not to introduce any requirement for the rollout of AMIs. However, as mentioned in DG ENER (2015), this CBA showed a significant volatility in the results depending on the impact of smart meters on consumption (a challenge for all CBAs on this topic).

In the United Kingdom, the cost-benefit analysis was conducted by a public authority (BEIS, 2016). The subdivision of costs and benefits are represented in Figure 11 and Figure 12 respectively.

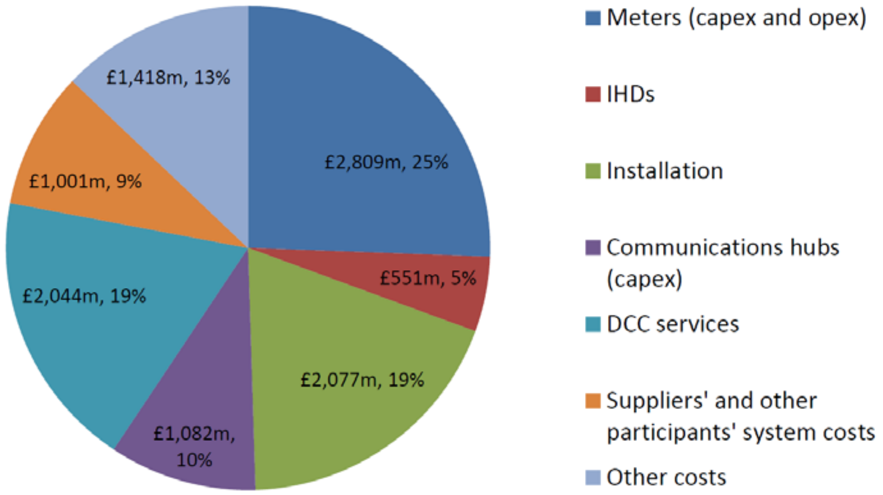

Figure 11. Expected costs considered in the British smart metering CBA (BEIS, 2016)

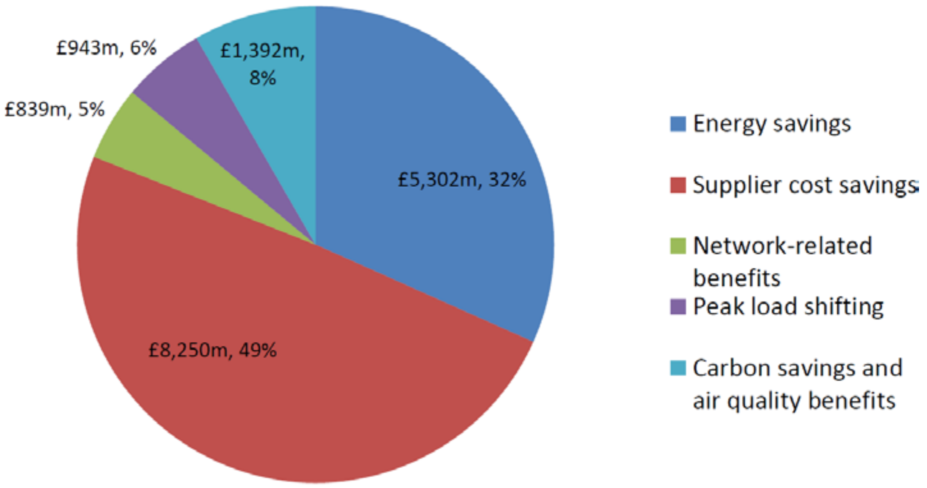

Figure 12. Expected benefits considered in the British smart metering CBA (BEIS, 2016)

The final outcome of the 2016 British CBA was a total cost equal to 10 980 million £, a total benefit of 16 720 million £, and a net present value equal to 5 750 million £.

In 2011, the Victorian Government commissioned an update of the smart metering CBA to define the pace of deployment after the initial phase of the rollout. The study focuses on the period 2008-2028 and its outcomes are interesting since they show the evolution of costs (Figure 13) and benefits (Figure 14) over time.

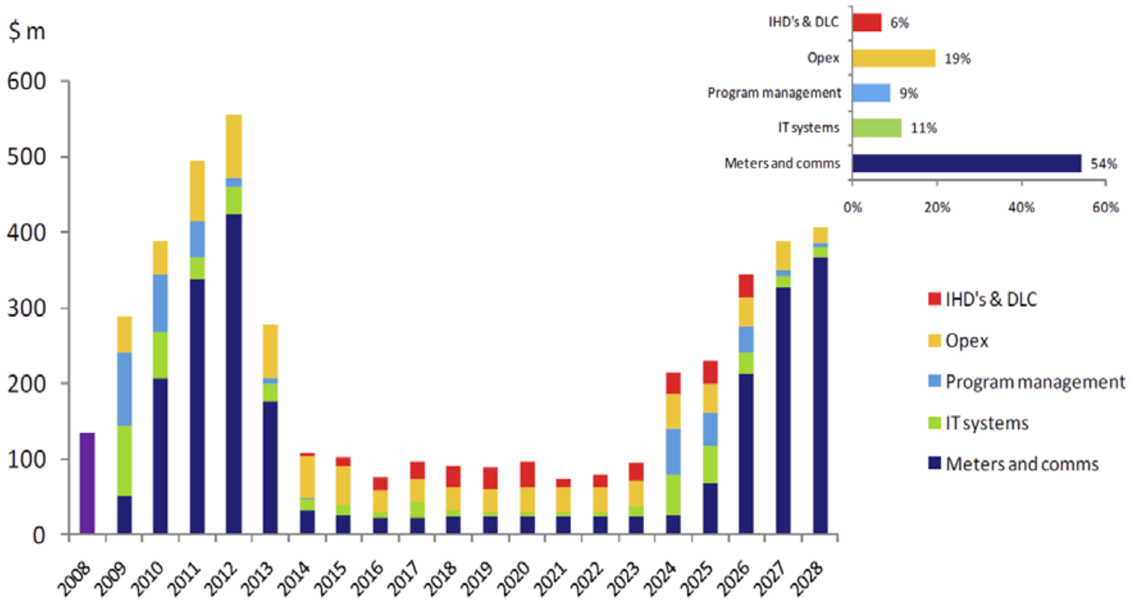

Figure 13. Evolution of AMI deployment expected costs from 2008 to 2028 (Deloitte, 2011)

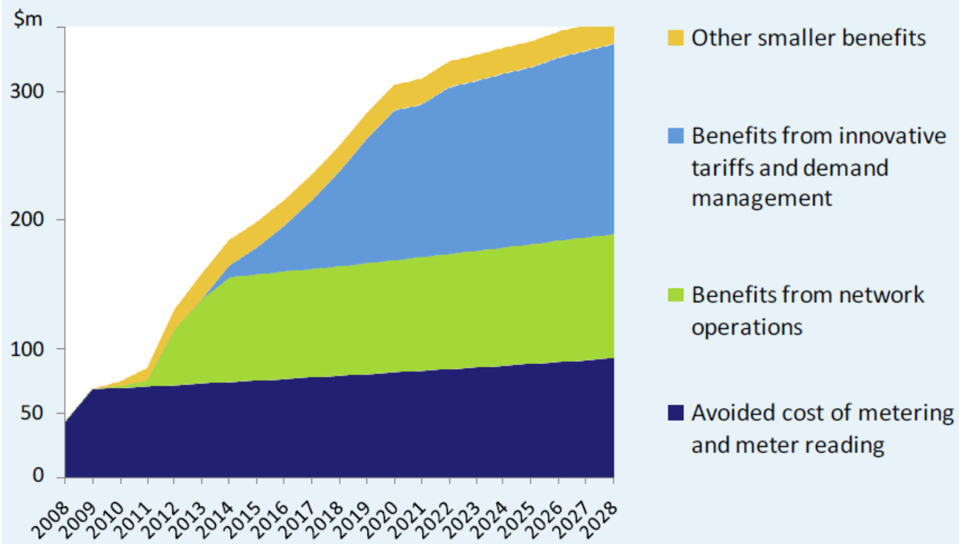

Figure 14. Evolution of AMI deployment expected benefits from 2008 to 2028 (Deloitte, 2011)

According to the cost-benefit analysis, following with the AMI rollout strategy would have generated a net cost for Victorian customers of 319 million $ (Figure 15).

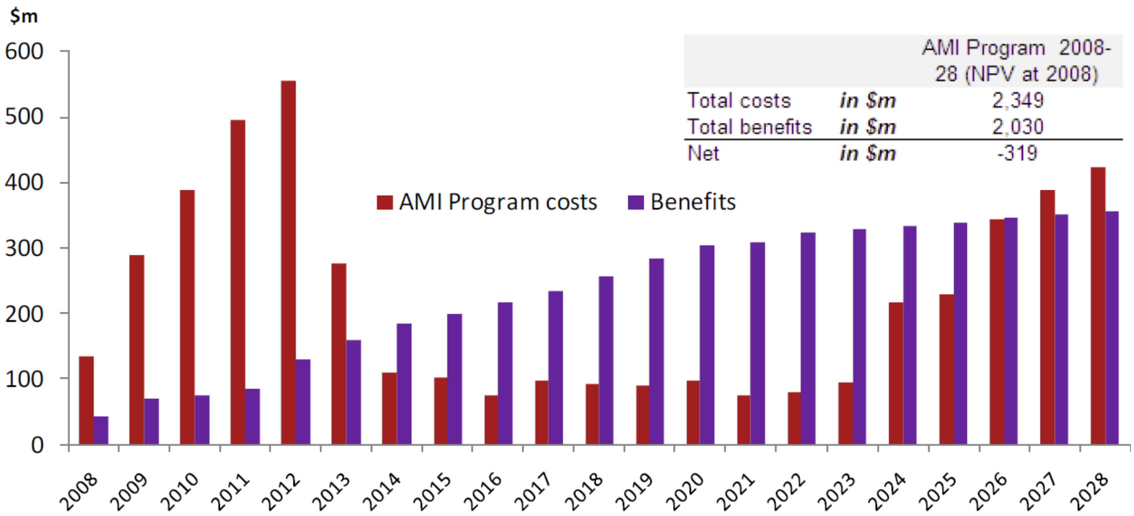

Figure 15. Evolution of expected costs and benefits and final outcome (Deloitte, 2011)

3. Distribution activity revenue setting[5]

This section analyses best practices in distribution remuneration regulation. The objective is to identify the most relevant design elements and implementation alternatives, particularly focusing on those aspects that have been previously identified to be key for the Peruvian case. More specifically, the most important elements in previous studies (CEPA, 2016) have revolved around the calculation and treatment of the asset base and capital expenditures, as well as output-based incentives (such as quality of service).

Design elements

Power distribution, being considered a natural monopoly for well-known reasons, is a regulated activity whose revenue methodology is to be determined by the corresponding regulatory authority. Today, the vast majority of systems have implemented some form of incentive regulation. In the particular case of Europe and Australia, this incentive regulation is most commonly based on the revenue cap approach (CEER, 2020a), (AER, 2017).

Revenue cap methodologies, which will be the starting point of the analysis[6], can be subject to many different forms of implementation:

- First and foremost, the regulator can unevenly place efficiency incentives on CAPEX and OPEX (the conventional approach in Europe or Australia) or put these incentives on equal terms on both (TOTEX approach).
- Then, the regulator needs to define a remuneration formula (conditioned by the first decision), which in any case has to somehow account for the different return requirements of capital costs and operational costs. This leads to the second fundamental design element: the annual DSO allowances and within it, the treatment of the rate asset base (RAB in the following), and the new capital and operation expenditures.
- The third element would be related to the end of one regulatory period and the beginning of the next one, where RAB updating takes place.
- Finally, distribution network operators can also be evaluated and incentivized based on their performance, measured through a set of representative indicators (output-based regulation).

We next analyze the practical tradeoffs to be addressed and the different solutions that can be found for each of these design elements.

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[5] This section draws heavily on (INTEGRID, 2020a) and (Cossent, 2013).

[6] Today, there is a total consensus on the need to decouple the remuneration of the distribution activity from the distributed energy volume, which may be reduced by DER investments without a corresponding reduction in costs (MITEI, 2016; IRENA, 2017). This is why price cap regulation is not even considered in this analysis. That said, it is worth mentioning that price cap regulation with an ex-post revenue correction can resemble to a large extent to a revenue cap regulation.

3.1 Separate treatment of CAPEX and OPEX or TOTEX

CAPEX and OPEX cost regulation

Conventionally, the regulator separately assesses and set targets for operating costs (OPEX) and long-term capital investment costs (CAPEX). The usual approach in incentive regulation is to unevenly place cost-reduction incentives on CAPEX and OPEX. Efficiency incentives are generally imposed on OPEX (via an RPI[7]-X incentive), while capital investments are included in the RAB[8] and ensured a rate of return. This method is the usual approach in Europe (with some exceptions) and also characterizes the so-called "building block model" that is used in Australia (AER, 2017).

The rationale behind this approach has been to reduce to DSOs the risk associated with CAPEX investments. By reducing this risk, it has been claimed that new investments are carried out when needed.

Reducing the risk of the distributor has always been relevant and will be even more essential in the forthcoming years since distributed resources introduce more uncertainty. Nevertheless, as we shall see, there are other most convenient ways to reduce this risk in the present context (ex-post remuneration corrections at the end of the regulatory period).

The relevant downside of the separate treatment of CAPEX and OPEX is that it represents a clear barrier for reducing grid reinforcements through alternative shorter-term measures, such as by implementing preventive maintenance, extending the life of assets when workable or procuring flexibility services[9] to distributed energy resources (and storage). Any of these aforementioned short-term measures imply a reduction in CAPEX at the expense of increasing OPEX, and the conventional regulation is myopic to CAPEX reductions (reducing the CAPEX only represents a lost opportunity to increase the RAB), whereas the increase in OPEX is seen as

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[7] Inflation is generally accounted for through publicly determined inflation indexes, being the most common approach to use a single consumer or retail price. Nonetheless, regulators may opt to use several price indices in order to account more accurately for the price variations faced by DSOs.

[8] As we shall see, depending on the particular design the investments can be included in the RAB as declared, they can be subject to some form of ex-post auditing that may *clawback* some investments, they can be included based on benchmark analyses (thus only acknowledging efficient investments), etc.

[9] Within this category we find the so-called "Non-Wires Alternatives" (or NWAs). According to Navigant (2017), NWAs can be defined as "an electricity grid investment or project that uses non-traditional 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 lines or transformers, by reducing load at a substation or circuit level".

NWAs are known to present a huge potential in the distribution sector. Their main advantage, with respect to conventional "wire" alternatives, reside in the treatment of uncertainty. As properly explained by Chew et al. (2018), uncertainty of load growth is a challenge for distributors, but a strength for NWAs. In fact, the latter usually have lower upfront costs and are based on technologies that may serve multiple purposes beyond deferring network investments. Therefore, if demand does not grow as expected, the economic loss would be lower if the growth has been covered through NWAs than through lines and transformers.

inefficient and penalized. As a result, the DSO is penalized for shorter-term solutions even when they are less costly overall.

Regulators are becoming more and more aware of this problem. In Europe, in the context of the H2020 INTEGRID[10] project, the so-called "CAPEX bias" in existing revenue regulation was highlighted by all the regulators interviewed during the stakeholder consultation (INTEGRID, 2020a). Several of them pointed out that the solution could be to shift towards changing this separate treatment between CAPEX and OPEX. Likewise, the same problem was anticipated in Australia back in 2018. As a result, it was entrusted to Frontier Economics an analysis about key drivers and trade-offs involved in shifting to a TOTEX-oriented approach for Australian energy network businesses (Frontier, 2018). During 2019 some final decisions on the distribution determination for the period 2019-24 were published (see for example AER, 2019) and none include a TOTEX approach. But they did include some incentives to increase OPEX-based solutions.

TOTEX

The mentioned existence of tradeoffs between OPEX and CAPEX suggests that it would be necessary to evaluate total distribution costs as a whole to prevent inefficient outcomes. This is known as the TOTEX approach.

Under the textbook TOTEX-oriented approach, distribution networks are given a single expenditure allowance and therefore there is no special treatment for CAPEX. If efficiency incentives are neutral to CAPEX and OPEX reductions, it is provided the incentive to DSOs to exploit the potential trade-offs between both types of expenditures.

It is worth mentioning that setting a TOTEX allowance does not mean that the underlying cost assessment cannot be based on the separate estimated/updated CAPEX and OPEX values. In other words, under a TOTEX approach, revenue allowances may still be calculated considering the building blocks of DSOs costs, as long as regulation ensures that finally allowed revenues are independent of the actual cost structure of distribution companies.

There is a greyscale of methods between completely separating CAPEX and TOTEX and evaluating both as a whole. Some intermediate approaches can be achieved depending on:

(i) whether the TOTEX regulation includes all costs or leave some aside,
(ii) how ex-post corrections are carried out and
(iii) how the RAB is updated[11]

Experience with TOTEX-oriented regulation

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[10] INTEGRID: Demonstration of Intelligent grid technologies for renewables Integration and Interactive consumer participation enabling Interoperable market solutions and Interconnected stakeholders. For more information: https://integrid-h2020.eu/

[11] With respect to this latter, as we shall see in section 1.2.3, to avoid uneven incentives over CAPEX and OPEX reductions, it is also necessary that new RAB additions are (at least partially) decoupled from the investments actually carried out by the DSO.

Experience with TOTEX-oriented regulation is limited. The pioneering and most paradigmatic example, is the UK case (OFGEM; 2009a). Because of the particular interest of this experience, we have included a more detailed analysis of the UK methodology in section 3.5. Other examples including TOTEX at least partially in the remuneration scheme are Portugal and Austria.

In Portugal, a TOTEX approach is followed for the LV grid, by which all costs (except concession rents and workforce restructuring plans) are subject to an efficiency target.

In Austria CAPEX investments within a regulatory period are added to the RAB with a two-year delay, without any assessments about cost efficiency or usefulness. However, a backward-looking TOTEX benchmarking is applied. This benchmark determines the productivity factor, which alters ultimately the RAB of the next regulatory period. Thus, this may be considered a hybrid approach.

In the present context, it becomes necessary to move in the direction of equalizing the incentives perceived by DSOs to reduce costs regardless of their nature (CAPEX or OPEX). This is achieved by introducing TOTEX-oriented revenue cap regulation.

There is a whole range of approaches between completely separating CAPEX and TOTEX and evaluating both as a whole. A solution in between seems to be the most recommended alternative.

3.2 The remuneration formula and annual DSO allowed revenues

Establishing the allowed revenues of each DSO represents one of the most important tasks of regulators concerning electricity distribution. Irrespective of whether a TOTEX-based or a separate CAPEX and OPEX regulation is applied, the regulator needs to define a methodology for estimating and updating the CAPEX and the OPEX.

Generally speaking, actual (or estimated) CAPEX involves a remuneration that aims to compensate network companies for two main concepts, namely the return of the capital (or depreciation), and the return on capital.

The calculation of the CAPEX remuneration eventually granted to the distribution company can be broken down into a set of steps shown in Figure 16.

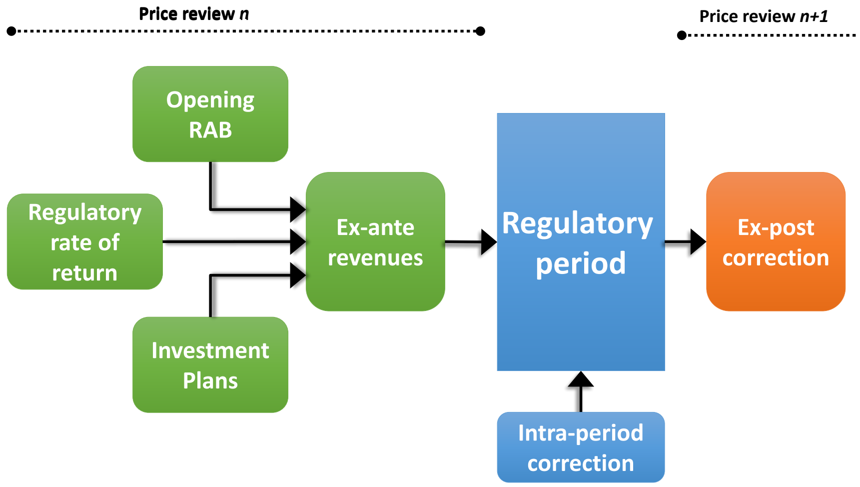

Figure 16: General steps to determine the remuneration associated with CAPEX

Before the start of a regulatory period, the regulator has to determine the ex-ante revenue allowances, and this schematically involves three major decisions, each, as usual, presenting tradeoffs in its design:

- Determining the opening RAB,
- how to incorporate new investments into the revenue allowances, either ex-ante and/or ex-post,
- determining other parameters, such as the regulatory rate of return or the depreciation method (since the remuneration associated to the CAPEX will be the depreciation plus the RAB times the rate of return).

We next analyze the practical tradeoffs that can be found for each of these design elements.

3.2.1 Determining the opening RAB

As regards the determination of the opening RAB, we can differentiate between the opening asset value at the beginning of establishing the RAB-based framework, i.e. the first regulatory period after the possible reform, and then how the opening RAB in the forthcoming regulatory periods is updated (e.g. how to determine the opening RAB once the reform is fully implemented). The value at the beginning of implementing the RAB framework will be referred to as the legacy RAB hereafter. We first analyze this legacy RAB and then the more general problem of subsequently updating the RAB value.

Legacy RAB

Regulators can use several methods to value legacy distribution network gross assets in order to determine the (legacy) opening RAB at the beginning of establishing new implemented framework. Most methods[12] depend on two major choices:

[12] Implicit RAB, not covered here, follows a slightly different approach.

- What network infrastructure is considered for the legacy opening RAB: either the actual network or an efficient one (calculated employing benchmarking techniques).
- What costs are considered for the legacy opening RAB network: either the actual costs, the efficient historic costs, or the replacement costs.

The selection of one or another alternative for the previous two decisions essentially depends on the particular circumstances of each country. Theoretically, two extreme opposing approaches can be found when combining the previous alternatives, namely book values (also known as purchase costs) and replacement network and costs (new replacement cost).

- The book value approach considers the actual cost of purchasing or installing a specific asset according to the regulatory accounting books. The main advantages of using historical costs are that they ensure cost recovery preventing regulators from "clawing back" part of the cost of the assets and that it is based on objective information. However, the use of book values does not penalize past inefficient investments[13].
- The new replacement cost can be defined as the cost of building an asset that would provide equivalent service at present with current technologies. The main advantage of using replacement costs is that it penalizes inefficient investments as it introduces a kind of yardstick competition. However, regulated firms are exposed to risks associated with technological changes causing large deviations between past and future costs. This method is preferable when information from the actual assets is scarce or untrustworthy, or severe inefficiencies are likely to have taken place in the past.
- In between the previous two approaches, an alternative that provides a suitable trade-off between the advantages and disadvantages of the aforementioned methods consists in accounting for the assets registered in the accounting books, but valuing them at some norm costs. This approach is usually known as reproduction cost.

Since in many cases the gross value of assets is computed, it is also necessary to assume the remaining regulatory lives of assets to compute the legacy RAB (net assets), either by estimating the average life of assets or assuming new assets (replacement). Estimating the average life of assets can introduce a relevant discontinuity in the future cash flow remuneration, since all legacy investments would be written off at the same point in time. Thus, some form of smoothing may be evaluated to prevent this depreciation "cliff-edge", e.g. by setting a progressive variation in the remaining regulatory life of legacy assets over time.

The most suitable methodology for determining the legacy RAB is very case dependent, but a combination of considering actual investments and norm costs seems to present a reasonable trade-off.

[13] It can also happen that if the grid is very old and depreciated, book costs are too low to allow for the sustainable financing of the network company.

Opening RAB: general approach

Evaluating the asset base requires significant efforts from both the regulator and DSOs and may lead to litigations. Therefore, instead of reassessing the RAB at the beginning of every regulatory period, the regulator often decides to include in the RAB the non-depreciated investments already allowed in previous regulatory periods (thus, not reassessing that part). This is known as consolidating the RAB, as opposed to reopening RAB. Consolidating the RAB has also the desirable property of mitigating regulatory instability and reducing the regulatory burden.

In the particular case of Peru, the model company entails that the RAB is reopened and reassessed at the end of the regulatory period by means of a greenfield type model and considering efficient costs (VNR[14]). This approach has provided reasonable results up to date, but it is not well-suited for the new changing and more uncertain context, for it could extremely increase risk exposure to DSOs. In the present context, it makes sense to turn into a consolidated approach. We next briefly review the design of this relevant element.

Consolidating the RAB is recommended in the present context to mitigate regulatory instability and reduce the regulatory burden.

Introducing RAB additions under the consolidated RAB approach

When consolidating the RAB, regulators just have to update the RAB based on the actual/efficient new CAPEX investments. The two main differences in the alternative ways this update can be carried out are concerning:

- when to update (annually, annually with a lag of some years or at the end of the regulatory period)
- how the RAB is updated, as always this can be carried out more closely following the actual investments and actual costs or based on the efficient investments and/or efficient costs. The pros and cons of the different approaches are those reviewed in the previous analysis on how to determine the legacy RAB.

Depending on the previous decisions regarding the RAB updating, the regulator can introduce powerful efficiency incentives to DSOs, but at the cost of increasing the risk of no recovering investment costs. It is worth highlighting that in case it is implemented a TOTEX regulation, the RAB updating has to be (at least partially) decoupled from actual investments, this is explained next.

Updating the RAB in a TOTEX-oriented revenue cap regulation

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[14] Valor Nuevo de Remplazo (New replacement value)

We have seen how under a TOTEX approach, distributors are given a single expenditure allowance over which any savings are settled. Not making a distinction between capital savings and operating saving avoids the aforementioned bias for increasing CAPEX.

In TOTEX-based regulation, to hold this incentive it is necessary to decouple, at least to some extent, the new RAB additions from actual investments. The larger the decoupling the larger neutrality between CAPEX and OPEX cost reductions (but the larger the risk for the distributor).

Some options that can be explored include applying a fixed capitalization rate like in the UK (that is to say, a fixed proportion of the allowed TOTEX is capitalized and added to the RAB), applying this fixed capitalization only to certain asset categories (those that will be subject to efficiency criteria), or adapt over time the capitalization rate, in such a way that it is started at values that are close to the actual CAPEX/TOTEX ratio and little by little it converges to the value the regulator may deem desirable[15].

In TOTEX-oriented regulation, it is necessary to decouple, at least to some extent, the new RAB additions from actual investments. Total decoupling is achieved with the application of the fixed capitalization rate. This attains total neutrality between CAPEX and OPEX cost reductions but at the cost of increasing the risk for the distributor. Updating the RAB accounting partially for actual investments is recommended to achieve a suitable balance.

3.2.2 Incorporating new investments into revenue allowances

Once we have covered the determination (and updating) of the RAB, we can focus on the revenues that are to be perceived by the distributor. Here the discussion revolves around whether this is established ex-ante, ex-post or with a combination of both. This formula will take into account the different remuneration needed by CAPEX and OPEX (irrespective of the method used to calculate these values).

Ex-ante vs ex-post

As well known, ex-ante incentive regulation offers the strongest cost-saving incentive to DSOs, but also fully exposes them to any deviation between actual costs and allowed revenues. To mitigate this undesirable characteristic of purely ex-ante regulation, several ex-post mechanisms, such as profit-sharing methods, can be found to share the risk between DSOs and consumers.

A profit-sharing regulatory contract can be seen as a hybrid between a cost-of-service and a revenue cap approach (Joskow, 2008). Whereas under a pure revenue cap regulation DSOs are exposed to 100% of the deviations between the ex-ante allowances and the actual expenditures (E), under a profit-sharing regulation, DSOs would only be exposed to a pre-defined share of these deviations, known as the sharing factor (SF).

[15] Capitalization rates throughout the regulatory periods can be reassessed or, if these are very long, in a mid-term review. However, this should be made only for future investments, not the ones already incurred.

The next figure illustrates the functioning of this mechanism (assuming a symmetric sharing factor). The formula at the top of the figure represents the DSO remuneration formula. The annual ex-post allowed revenues (Rn) are computed as the sum of the conventional revenue cap formula (in this case represented through the conventional RPI-X approach) times the sharing factor (SF) plus a second term that is obtained as the product of the actual expenditures declared by the DSO (ex-post) times the complementary of the sharing factor. This remuneration formula has the following characteristics:

- If the sharing factor is equal to 1, the formula is a pure revenue cap.
- If the sharing factor is zero, the formula corresponds to a pure cost of service regulation.
- For values of the sharing factor between 0 and 1, the formula is a hybrid approach. The higher the value of SF, the closest the regulation would be to a revenue cap and vice versa.

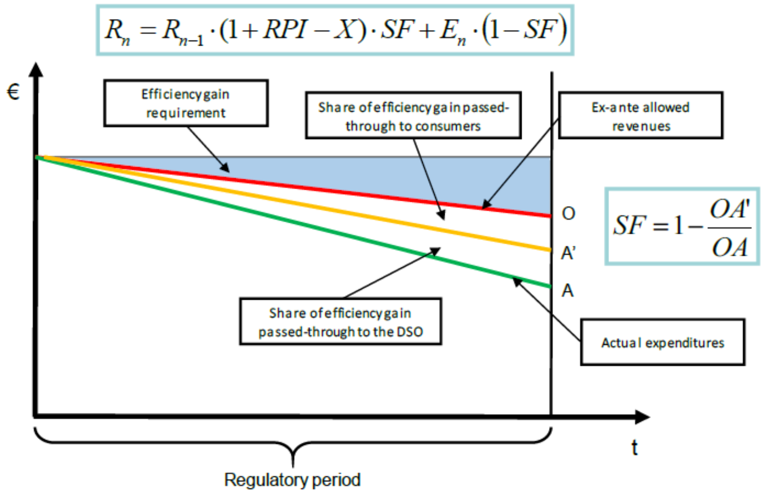

Figure 17.- Illustration of a profit-sharing mechanism combined with a revenue cap. Source; (INTEGRID, 2020a).

DSO ex-ante remuneration formulas should incorporate profit-sharing mechanisms to mitigate the impact of regulatory forecasting errors in a context with growing uncertainties.

Further refining the profit-sharing approach: the menu of contracts

The main idea of the menu of contracts approach is that the regulator offers DSOs the possibility to choose between different profit-sharing contracts with different combinations of ex-ante allowed revenues and sharing factors. By doing so, regulators can also encourage DSOs to submit accurate investment forecasts[16].

[16] Encouraging the DSO to submit accurate investment forecast can become a complex matter if we consider how the DSO own forecasts conditions eventually the regulator's one. This issue is analyzed in detail in (OFGEM, 2018).

The approach is based on a two-step process. At the beginning of each regulatory period, DSOs' cost estimation is compared against a baseline determined by the regulator. At the end of the period, the actual costs of each DSO are compared against the ex-ante revenue allowances and final revenues are computed following an ex-ante defined matrix (for more details, see section 3.5.2). Additional details on the design and implementation of profit-sharing contracts with menu regulation to regulate electricity DSOs can be found in (Crouch, 2006) and (Cossent and Gómez, 2013).

Even though menus of contracts seem to present important advantages, the fact is that they have been barely applied. In Europe, only in the UK and Italy[17], we find this approach implemented. In these systems, regulatory authorities have applied a combination of profit-sharing contracts with menu regulation (OFGEM, 2013a) (ARERA, 2016) to regulate DSOs' remuneration.

The menu of contracts has several degrees of freedom to adapt to different circumstances

The strength of the incentive associated with the ex-post review of the menu of contracts can be adapted to the conditions of the system. When the regulator and the DSOs face high uncertainties over the future costs of the companies it makes sense to bring the ex-post correction closer to a cost of service regulation. The strength of incentive schemes can later be increased over time as both regulators and DSOs become familiar with the situation.

The costs subject to efficiency targets should be those considered as under the control of DSOs. Controllable OPEX should be subject to benchmarking and could be added to CAPEX in the mechanisms. Including both OPEX and CAPEX in the scheme requires defining some rules to calculate the annual revenue allowances and perform the ex-post corrections on TOTEX.

The regulator could implement this scheme either only for new investments, which is the main application proposed herein, or to a broader range of cost components, e.g. including network-related OPEX.

The menu of contracts is a sophisticated tool that presents desirable properties. The ex-post review associated with the menu of contracts can be calibrated to situate the incentive and risk in between pure incentive-based and pure cost-of-service-based regulation.

The regulator's estimates have to be forward-looking

The ex-ante allowed investments can either be determined based on the regulator's estimate of efficient expenditures, based on the DSO's prognoses or based on a combination of both. If the regulator's estimate is deemed necessary, this will be based on benchmarks, which can be backward-looking (extrapolates from the past) or forward-looking (tries to anticipate future conditions that may have not been observed in the past).

[17] In the case of Italy, the approach has only been implemented to regulate the implementation of the 2nd generation smart meters.

Today there is a total consensus that estimates should be forward-looking to account for the most likely changes that are to take place (MITEI, 2016). For the forward-looking approach, engineering-based reference network models (RNMs) are tools that can represents future potential scenarios. RNMs have been applied to regulate electricity distribution companies in several countries. The use of these models is familiar in several South American systems (including Peru) as a tool to implement the model company scheme, but again, the key is that the methodology includes the forward-looking capability (Jenkins, 2018), which is not the situation in the Peruvian case.

An engineering-based forward-looking reference network model (RNM) can better prepare regulators for the task of estimating ex-ante revenues in the highly uncertain electricity landscape we have today.

3.2.3 Other design elements affecting allowed revenues

Reopeners

A potential regulatory instrument to reduce risk exposure consists in reopening the revenue determination when a large deviation with respect to the conditions expected at the price review happens. The type of events that can trigger a reopening may include large demand forecast errors, high increase in DG connection, or sudden technology changes. This reopening may take place at the request of the DSO at any moment during the regulatory period, or at pre-defined time windows (OFGEM, 2013a).

Giving shape to the DSOs cash flow

It is worth remarking that ex-ante allowed revenues correspond to the amount that DSOs should receive during the entire regulatory period. Therefore, this amount has to be distributed along all the years of the regulatory period. In principle, there could be many different ways to do this, being the simplest and preferred one to use the X factor (of the RPI-X formula) to smooth DSO's revenues along the regulatory period. Indeed, in case the incentives are provided by means of the previously introduced menu of contracts scheme, smoothing revenues will be the sole objective of the X factor (since incentives are dealt with via the menu of contracts).

Lifetime of assets and depreciation method

Although relevant for the determination of the allowed revenues, the regulatory lifetime of assets or the depreciation method will not be addressed in analysis. There are well-known and accepted standard practices for both of them.

The regulatory rate of return

The rate of return that is used for the allowed (either actual or estimated) CAPEX is frequently calculated as the weighted average cost of capital (WACC). This means that the final rate of return is obtained as the weighted sum of the cost of the different sources of financing used by DSOs, mainly debt and equity.

The WACC is a critical parameter in regulation, especially to determine the investment conditions faced by DSOs. The most controversial issue is generally how to compute the cost of equity. The most widely used method is the capital asset pricing model (CAPM), which determines the cost of capital as the sum of a risk-free rate plus a market risk premium.

Establishing the regulatory period

Under incentive regulation, price reviews or price ratchets are carried out at the beginning of each regulatory period; typically, between 3 to 5 years. Short regulatory periods reduce the uncertainties faced by regulators and prevent large deviations between DSO costs and revenues, but at the same time dilute the incentives to increase efficiency through actions that yield benefits in the long-term (asset replacement, staff training, R&D expenditure) and also increase the regulatory burden both on regulators and DSOs. Long periods (a minimum of 5 years) is advisable in the present DER-driven context. In this line, OFGEM proposed to increase the length of regulatory periods in the UK up to 8 years in its RIIO-1[18], introducing also additional mechanisms to control for uncertainties or reviewing this length in the future (the aforementioned menu of contracts or reopeners). Nevertheless, this regulatory period has been decreased to 5 years in the last review (RIIO-2).

Gradualism

It is worth noting that any change in the remuneration regulation can lead to relevant variations, such as deviations between the asset structure of DSOs and the RAB. To avoid abrupt changes in the remuneration, a progressive implementation over several regulatory periods is always considered advisable.

Long regulatory periods (5 years or above) and allowing for reopeners represent recommended practices today. These are compatible with in between revisions for some specific elements (e.g. investment plans).

3.3 Additional incentives

3.3.1 Bonus-malus schemes for quality of service

A common way to implement regulatory output-based incentives is through bonus-malus schemes, which consist in setting a reference value (see the figure below) for a particular quality-related output measure. DSOs are penalized in case they fail to attain this reference value and rewarded otherwise.

[18] Italy also introduced an 8-year regulatory period, with partial revisions after 4 years.

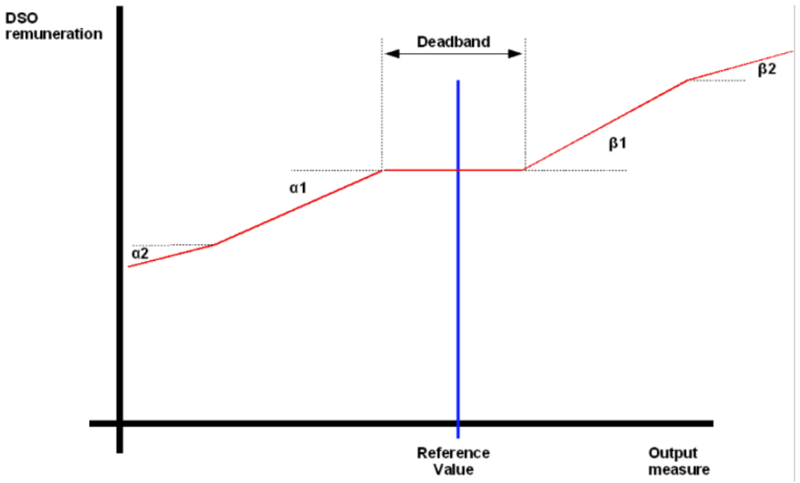

Figure 18.- Relevant parameters in a bonus-malus scheme. Source: (Cossent, 2013)

These schemes are nowadays widely used to promote DSOs to improve continuity of supply across European countries (CEER, 2016b).

The incentive schemes must be tied to both the duration and the number of interruptions. Exclusively focusing on indices measuring the duration of interruptions, can dilute the incentives seen by DSOs to implement advanced fault detection. Advanced fault location, if combined with tele-controlled grid reconfiguration in meshed networks, can reduce both the measured duration and the number of interruptions if consumers can be reconnected in less than a few minutes after an interruption. This is because long interruptions are considered to be those that last more than a pre-defined number of minutes, typically 3 min in Europe (CEER, 2016b).

Implement incentive/penalty mechanisms for the DSOs to improve network reliability.

These mechanisms should incorporate reliability indicators measuring both the number and the duration of interruptions.

Another aspect to consider is how planned and unplanned interruptions are treated in the regulation, i.e. whether the incentive strength is different for both types of interruptions, and how easy it is for DSOs to qualify an incident as a planned interruption. This is particularly relevant concerning the implementation of predictive maintenance strategies. By monitoring the condition of transformers, a potential unplanned interruption caused by an equipment failure can be prevented by a maintenance action that may also require taking the transformer out of service, thus causing a scheduled interruption. Although in both cases consumers would be interrupted, this allows the DSO both to notify grid users in advance and schedule the maintenance works at a time that disturbs grid users the least. Therefore, this should be encouraged.

Nonetheless, the current regulation in many countries does not seem to promote this in most cases.

Incentive schemes should encourage DSOs to replace unplanned interruptions with scheduled interruptions, as the latter have less impact on grid users.

Lastly, even if incentive mechanisms are in place, and these appropriately discriminate between planned and unplanned interruptions, DSOs may still not implement the advanced O&M approaches if the gain they perceive from improving reliability is very low. There are two key parameters that determine this: the reference reliability levels and the marginal incentive rate. Moreover, as shown in the figure above, discontinuities in the incentive mechanisms may be introduced in the form of dead-bands around the reference values or upper/lower bounds on the value of the incentive/penalty, i.e. caps and floors.

Such discontinuities are used to mitigate the risk of excessively high rewards or penalties due to errors in the regulator's estimates when designing the incentive or to unforeseen events. However, if they are not correctly set and periodically revised, they can significantly weaken the power of the incentive. For instance, if a DSO presents reliability levels that are within the dead-band or above/below the cap/floor, the incentives obtained from improving reliability may be negligible. This "incentive trap" can be avoided updating the reference values. However, since these are oftentimes defined based on historical information, this may result in a permanent stagnation of reliability levels. Basing reference values on the results of a benchmarking analysis among DSOs seems to be a more suitable approach.

Lastly, the marginal incentive rate is usually determined based on consumer surveys that estimate the cost of interruptions for consumers (CEER, 2016b). It is important that this parameter appropriately reflects the true value of quality of service for network users as well as the new opportunities DSOs have to improve reliability. Therefore, regulatory practices should be reviewed to account for these.

Regulators should ensure that the incentive mechanisms parameters send adequate incentives for DSOs to improve quality of service by avoiding wide dead-bands, tight cap and floors.

Moreover, reference values and marginal incentive rates should be assessed, and not be based exclusively on historical values, in order to reflect appropriately both the marginal cost of improving reliability (including smart grid solutions) and the cost of interruptions for consumers.

Revenue drivers

Revenue drivers incentivize directly a certain factor (usually linearly) in the remuneration formula. This mechanism could be considered a particular case of the bonus-malus general function.

Two revenue drivers that are of particular interest are those that seek to increase DERs in the network or those looking for extending the useful life of assets (when economical):

- Distributed energy resources can be incentivized by adding DER related revenue drivers to the revenue cap formula in order to compensate DSOs for the associated incremental costs[19]. The UK pioneered the application of these schemes to electricity distribution regulation with a temporal mechanism that combined a DG revenue-driver with a partial pass-through (OFGEM, 2009). Similar mechanisms could be devised for costs driven by EVs or demand response.
- Under the conventional regulation, DSOs may have an incentive to replace assets when they are written off (this is the case in the separate CAPEX and OPEX approach). An end-of-life incentive could provide remuneration for assets for an additional number of years.

3.3.2 Financeability assessment

The regulatory agency can monitor and control equity and credit metrics as well as several qualitative factors in order to monitor the financial health of distribution companies. This is the case of the UK, as we shall see in section 3.5.2 (OFGEM, 2013). Spain has also introduced a penalty associated to this financial health[20], which is proportional to the remuneration of the distributor and also to the deviation of a reference index (that accounts for the gearing ratio and the economic-financial capacity) with respect to a reference value.

3.3.3 Input incentives for innovation

The adoption of new grid operation solutions and technologies will presumably require DSOs to test them at a limited scale before deploying them at a larger scale. This will allow them to test and compare alternative technology solutions, work together with developers and manufacturers, and prevent mistakes and dead-ends when performing the deployment. Since DSOs face some technology risks in this process, the existence of mechanisms that allow DSOs to mitigate these risks would facilitate the adoption of innovative solutions. This can be achieved through ad-hoc economic incentives that allow DSOs to recover, at least partly, the corresponding costs outside the regulator allowed revenues.

Therefore, despite the fact that output regulation is generally preferable than the regulation of inputs, innovation can be difficult to attain through output-only regulation (Eurelectric, 2011).

Input incentives can be designed as direct payment to DSOs in order to undertake specific projects, through a partial or total pass-through of certain costs (these costs would be added to the RAB without subjecting them to efficiency analysis) or by awarding DSOs a higher return on certain investments. Existing incentive mechanisms include the Finish remuneration mechanism (pass-through), the Italian (differentiated rate of return) and the British (reviewed in 3.5) cases (Cossent, 2013).

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[19] Another way to introduce these incentives is by modifying efficiency requirements (X factor) according to DER penetration rates.

[20] Circular 6/2019, de 5 de diciembre, de la Comisión Nacional de los Mercados y la Competencia, por la que se establece la metodología para el cálculo de la retribución de la actividad de distribución de energía eléctrica.

In any case, regulatory supervision either as an ex–ante approval, an ex-post evaluation, or both is needed. Such evaluation should be made based on a set of indexes and/or cost benefit analyses where the benefits for network users are clearly shown.

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3.5 Annex 1- Distribution network regulation in Great Britain

3.5.1 Background

OFGEM is the regulatory authority supervising electricity network operators in Great Britain (GB) since the liberalization and privatization of the power sector. GB pioneered the use of RPI-X regulation in electricity networks, applying it to distribution network operators (DNOs) from 1990 to 2015. As shown in Figure 19, this regulatory approach led to significant reductions in revenue allowances after privatization. However, this downwards trend stalled or even reverted after almost 20 years; in fact, in the case of the TO, increases in revenue allowances were even admitted.

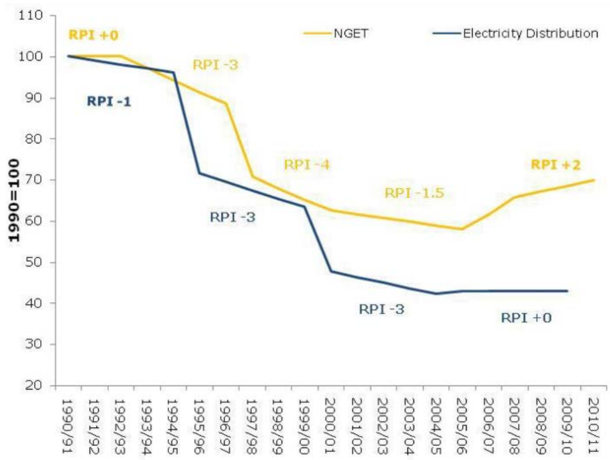

Figure 19: Adjustments in revenue allowances of network operators over successive price controls in Great Britain. Source: (OFGEM, 2009a)[21]

Besides the fact that efficiency gains were presumably easier to attain due to highly inefficient pre-privatization companies, the main reason for this effect is the need for network investments (OFGEM, 2009). As a result, OFGEM undertook a deep revision of energy network regulation in GB which resulted in the implementation of the so-called RIIO regulation, which stands for Revenues = Incentives + Innovation + Outputs. This new regulatory approach aimed at providing network companies with adequate incentives to support decarbonization, deliver adequate grid investments, foster efficiency and innovation, and provide value to current and future consumers (OFGEM, 2009b). The first period where RIIO has been applied to electricity distribution comprises the period from 1 April 2015 to 31 March 2023.

It is relevant to note that previous analyses of the Peruvian context (CEPA & NEGLI, 2016) showed that many of the drivers behind this regulatory overhaul in GB are relevant to Peru as

[21] NGET stands for National Grid Electricity Transmission, the licensed transmission owner in England and Wales.

well. Therefore, the case of GB has been selected as a relevant experience for this report due to the following:

- RIIO regulation is broadly considered an example of innovation and best practices in distribution network regulation
- RIIO was designed to tackle challenges somehow similar to those the Peruvian sector is facing nowadays: need to promote sufficient network investments, innovation and quality of service improvements, whilst ensuring economic efficiency.

3.5.2 DISCO revenue setting workflow and key decisions

This section presents a detailed description and analysis of GB's distribution regulation, with an emphasis on those aspects that have been previously identified to be key for the Peruvian case. More specifically, the focus is placed on the treatment of the asset base and capital expenditures, as well as out-based incentives, particularly those related to quality of service, innovation and financial health.

CAPEX regulation

Before the start of a regulatory period, the regulator has to determine the ex-ante revenue allowances. This involves determining the i) opening value of the asset base, ii) the regulatory rate of return, and iii) whether/how to incorporate expected future investments into ex-ante allowances. Then, either during the regulatory period or after it is finished as part of the next price review, ex-post revenue adjustments may be made based on actual capital expenditures reported by distribution companies.

For each one of these steps, the British approach is described hereafter. It must be noted that the British approach to price reviews is time-consuming, taking around 3 years from the moment the process kicks-off to the beginning of the regulatory period. For example, the last price review started in February 2012, when the first proposals were published by the regulator, and the regulatory period started in April 2015.

The opening RAB

OFGEM follows an accounting method to determine the opening RAB and the corresponding CAPEX remuneration (i.e. the so-called RAB x WACC method). Hence, as opposed to the model company approach used in Peru, the asset base is not reopened in every price review, but consolidated based on investments and depreciation allowances from past regulatory periods.

The most relevant discussion during price reviews are, therefore, related to how ex-ante revenue allowances are calculated and how the RAB is updated during and after the end of the subsequent regulatory period. In other words, discussions do not revolve around the value of existing assets (or their replacement), but on how much investments are needed in the coming years and how these are remunerated. These topics will be discussed later in this section.

The regulatory rate of return

The allowed return on investments is determined following the vanilla WACC[22] approach, with different values per company, where:

- The cost of debt is based on a long-term trailing average (between 10- and 20-year average) of stock market indicators, which is adjusted annually in an automatic manner.
- The cost of equity is computed following the capital asset pricing model (CAPM). A value of 6% (post-tax) was considered for all companies in the last regulatory period (only one company was granted a higher return of 6.4% as a result of it being fast tracked thanks to the submission of a convincing business plan).
- The gearing ratio was estimated based on the business plans submitted by the distribution companies. A value of 65% was finally considered for all companies.

Further details can be found in (OFGEM, 2013a, 2013b, 2014a, 2014b).

Ex-ante revenue allowances and ex-post updates

This subsection describes the regulatory process through which the British regulator collects forward-looking investment needs from distribution companies, performs an efficiency assessment of these costs, sets ex-ante revenue allowances per company, and performs any necessary ex-post adjustments based on actual costs reported. Its contents rely mostly on (OFGEM, 2013a, 2013b, 2013c, 2013d, 2014a, 2014b).

The ex-ante revenue allowances are mostly determined on the basis of two key elements: i) the business plans submitted by the grid operators, and ii) the cost assessment performed by the regulator.

Business plans:

Distribution companies must prepare and submit to the regulatory authority their business plans for the next regulatory period well before it starts. These plans play a central role in the price review and they must be forward-looking and output oriented, i.e. setting clear links between the expenditures proposed for the upcoming years and the expected outputs and benefits for grid users and the society as a whole.

In order to facilitate comparability across companies and make them accessible to other stakeholders (the business plans are made publicly available[23].), the regulator set a mandatory common structure for these plans. This structure is depicted in Figure 20.

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[22] The vanilla WACC is a version of this indicator calculated with the cost of debt pre-tax and the cost of equity post-tax.

[23] These plans can be found in the web pages on the different distribution companies, for example:

UK Power Networks: https://www.ukpowernetworks.co.uk/internet/en/about-us/business-plan/

SP Energy Networks: https://www.spenergynetworks.co.uk/pages/distribution_business_plan.aspx

Western Power Distribution: https://www.westernpower.co.uk/our-riioed1-business-plan

Expenditures must be justified following on a common CBA methodology and supported by modelling tools. The regulator additionally sets some common guidelines to perform the CBA with which to justify the investment decisions proposed, including homogeneous approaches for discount rates, modelling tools, financial metrics, etc.

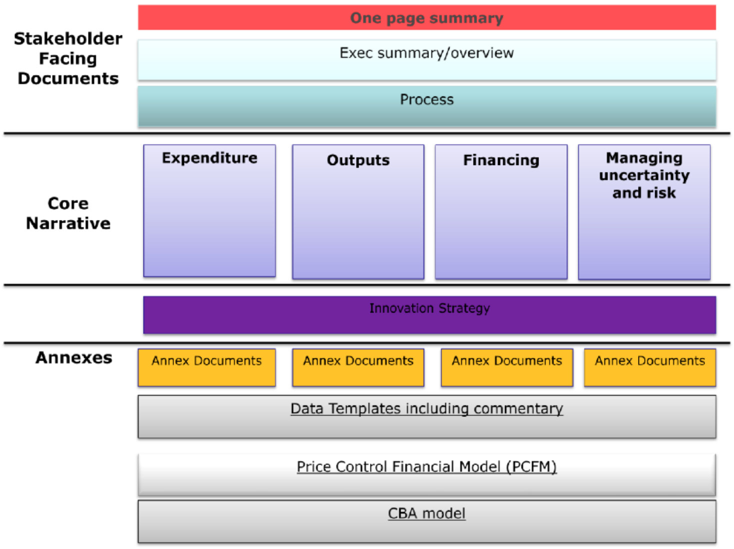

Figure 20: Structure of distribution business plans in GB. Source: (OFGEM, 2013c)

The regulator assessed the quality of the business plans is assessed separately for five different criteria:

- **Process:** this criterion accounts for the clarity, level of detail, stakeholder engagement process and data completeness of the plan.
- **Outputs:** evaluates whether the plans clearly and convincingly explain how they plan to achieve the expected outputs, and how expenditures and linked to these outputs.
- **Resources-efficient costs**: assesses whether the projected expenditures are efficiently incurred and provides sufficient evidence for this.
- **Resources-efficient finance**: checks whether companies plan to follow in line with good practices in terms of cost of debt, gearing ratio, cost of equity, financial risk, etc.
- **Uncertainty and risk**: determines whether distribution companies have clearly identified the main uncertainties and risks they face, evaluated their impact on their business plan, and proposed means to address them.

Distribution companies that are positively evaluated on all criteria can be fast-tracked. This means that they will know their allowed revenues in a shorter period of time, at least one year before the beginning of the regulatory period, and are offered a more lenient cost assessment and advantageous conditions (in the period 2015-2018, OFGEM offered fast-tracked firms an additional upfront revenue of 2.5% of TOTEX instead of the IQI (Information Quality Incentive) mechanism explained below. The company may refuse the revenue proposal made by the regulator at this stage; in this case, it would follow the same cost assessment as slow-tracked companies.

As shown in Figure 21, only one business group, which controls four distribution companies, was assessed positively on all five criteria and consequently fast-tracked by the regulator in the last price control.

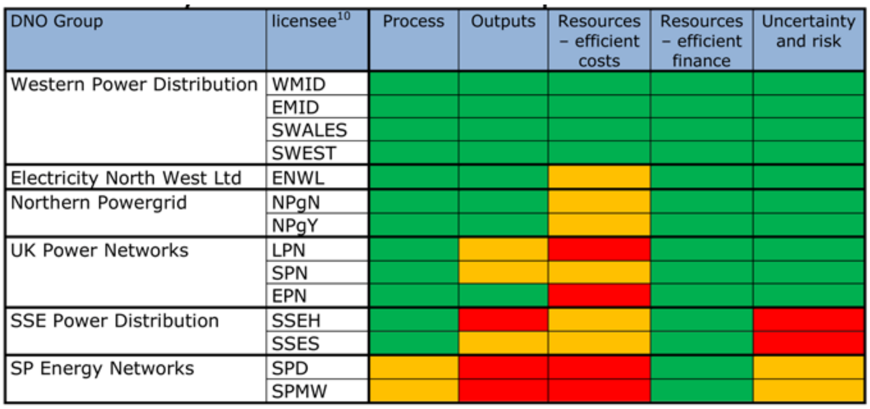

Figure 21: Summary of OFGEM's assessment of the business plans submitted for the period 2015-2023. Source: (OFGEM, 2013e)

Cost assessment:

It can be seen that the criterion where distribution companies were generally evaluated more harshly in the last price review is cost efficiency. The key elements of the approach followed by OFGEM to perform such costs assessment is summarized below (OFGEM, 2013d, 2014b).

Following the practices from previous price controls, for the 2015-2023 regulatory period, OFGEM used a toolkit of several different costs assessment and benchmarking models relying not only on historical information, but also on forecast data. Such toolkit comprises both total expenditure (TOTEX) analysis, capturing the key trade-offs between different costs elements, and the use of disaggregated approaches that follow a building-blocks approach to assess efficiency separately for specific cost categories (load-related network investments, non-load-related investments, network operating costs, business support costs, etc.).

OFGEM emphasizes that the results of these analyses should be used to inform their assessment and decisions rather than using them in a "mechanistic" way to compute allowed revenues. The use of such a set of models aims at allowing for cross comparisons across models as well as to apply some tools for specific types of costs, e.g. econometric models for TOTEX or general corporate costs, and engineering models specifically for load-driven network investments.

Ex-ante revenue allowances:

After the two steps previously described, the regulator determines the ex-ante revenue allowances expressed as an annual TOTEX allowance, i.e. no differentiation between CAPEX and OPEX allowance, computed as follows:

- Fast-tracked firms: ex-ante allowances are based on the submitted business plan, subject to possible modifications proposed by the regulator, plus an additional upfront revenue of 2.5% of TOTEX.

- Slow-tracked firms: ex-ante revenue allowances are calculated as the weighted average of OFGEM's cost estimation (75%) and the cost estimation resulting from the business plans of the distribution companies (25%). The regulator's estimate is calculated as a weighted average of three benchmarking models; 25% for each of two TOTEX models, and 50% for the disaggregated or building blocks model (OFGEM, 2014c)[24]. Additional adjustments are made to account for inflation, smart grid investments, and the application of the IQI explained below.

- As shown in Figure 22, in the last price control, the regulator's cost assessment models, although below the companies' estimates on average, show a large dispersion when compared to the TOTEX estimates provided by each distribution company.

Figure 22: Difference between TOTEX estimations by distribution companies and the regulator for RIIO-ED1 (before adjustments). Source: (OFGEM, 2014c)

The aforementioned process results in individual revenue allowances are made for each year of the regulatory period. However, these initial annual revenue allowance can present large variations across years. Thus, a reprofiling or smoothing of allowed revenues is done to ensure an even profile of revenues throughout the regulatory period. This means that annual allowed revenues are adjusted to follow a smooth downwards or upwards trajectory in such a way that the net present value throughout the regulatory period remains the same. The vanilla WACC is used as discount rate. Nonetheless, distribution companies can ask for adjustments if justified for financeability issues.

[24] This disaggregated modelling can be considered similar to the process followed in Peru to determine the model company costs.

Throughout the regulatory period, ex-ante revenue allowances are automatically adjustment annually to account for changes in the Retail Prices Index (RPI).

Ex-post adjustment and final allowed revenues

Probably, the most unique feature of the British regulation in RIIO can be found in the approach followed to update ex-ante revenue allowances once the actual expenditures of grid operators are known. This consists in two main mechanisms: i) a menu of profit-sharing contracts to update allowed revenues ex-post, and ii) the used of a fixed capitalization rate applied on TOTEX to update the RAB.

Ex-post adjustments to the overall revenues: efficiency incentives and IQI

The ex-post allowed revenues are calculated through the so-called IQI matrix shown in Figure 23.The key elements of this mechanism are briefly described below[25].

DNO:Ofgem Ratio	90	95	100	105	110	115	120	125	130
Efficiency Incentive	65%	63%	60%	58%	55%	53%	50%	48%	45%
Additional income (£/100m)	3.1	2.4	1.7	0.9	0.1	-0.8	-1.8	-2.8	-3.9
Rewards & Penalties									
Allowed expenditure	97.50	98.75	100.00	101.25	102.50	103.75	105.00	106.25	107.50
Actual Exp									
90	7.95	7.9	7.7	7.4	7.0	6.4	5.7	4.9	4.0
95	4.7	4.76	4.7	4.5	4.2	3.8	3.2	2.5	1.7
100	1.5	1.6	1.7	1.6	1.5	1.1	0.7	0.1	-0.6
105	-1.8	-1.5	-1.3	-1.2	-1.3	-1.5	-1.8	-2.2	-2.8
110	-5.1	-4.6	-4.3	-4.1	-4.1	-4.1	-4.3	-4.6	-5.1
115	-8.3	-7.7	-7.3	-7.0	-6.8	-6.7	-6.8	-7.0	-7.3
120	-11.6	-10.9	-10.3	-9.9	-9.6	-9.4	-9.3	-9.4	-9.6
125	-14.8	-14.0	-13.3	-12.7	-12.3	-12.0	-11.8	-11.7	-11.8
130	-18.1	-17.1	-16.3	-15.6	-15.1	-14.6	-14.3	-14.1	-14.1
135	-21.3	-20.2	-19.3	-18.5	-17.8	-17.2	-16.8	-16.5	-16.3
140	-24.6	-23.4	-22.3	-21.4	-20.6	-19.9	-19.3	-18.9	-18.6
145	-27.8	-26.5	-25.3	-24.2	-23.3	-22.5	-21.8	-21.2	-20.8
150	-31.1	-29.6	-28.3	-27.1	-26.1	-25.1	-24.3	-23.6	-23.1

Figure 23: IQI matrix for RIIO-ED1

At the beginning of the regulatory period, the ex-ante allowed revenues are determined as a weighted average of the regulator's cost estimate and the distribution company projections, as already mentioned before. At the same time, the ratio between both TOTEX projections determines the column of the matrix each company is positioned at. Each column corresponds to a certain value of the efficiency incentive and additional income. The additional income, either positive or negative, is a lump sum which is added on top of the allowed expenditures and its purpose is to incentivize network companies to provide their true best cost estimate in their business plans, thus mitigating information asymmetries[26].

On the other hand, the efficiency incentive is used to calculate ex-post allowed expenditures as follows. Annually[27], ex-post allowed expenditures allowances are calculated as the product of the

[25] For further information on how such a mechanism is built and its functioning, the reader is referred to (Cossent and Gómez, 2013).

[26] For a deeper discussion on the implicit assumptions and how these hold in practice, the reader is referred to section 4.4 of (CEPA, 2014).

[27] The ex-post correction could also be made at the end of the regulatory period or on a rolling time window.

difference between ex-ante allowed costs and actual costs times an efficiency rate plus the additional income[28].

The efficiency rate is a symmetric sharing factor between rate payers and grid companies for over or under performance with respect to ex-ante allowances. Note that in a pure revenue cap regulation the value of this efficiency rate would be 100%, whereas in a cost-plus or rate-of-return regulation it would be zero. In the case of RIIO-ED1, fast-tracked distribution companies received an efficiency incentive rate of 70 per cent, whereas non-fast-tracked companies received an efficiency sharing rate between 50 and 65 per cent, depending on the efficiency of their business plans

Updating the RAB: the capitalization rate

Once the final allowed TOTEX are known, the regulator needs to determine the RAB additions. Instead of updating it based on the actual investments made by distribution companies, as it is done in most countries, RAB additions are calculated as a pre-defined share of allowed revenues. This percentage is known as the capitalization rate and works as follows:

- X% of expenditures (with a few exceptions for pass-through costs) are considered as **slow money** to be **included in the RAB** and recovered over a period of 45 years, being X the capitalization rate.
- (100-X) % of costs are considered as OPEX or **fast money** to be recovered in the same year they are incurred/allowed.

The objective of considering a fixed rate is to encourage network operators to use the most efficient combination of cost categories, i.e. CAPEX-OPEX, avoiding the conventional problems of a CAPEX-oriented regulation. The values of the capitalization rates considered in RII-ED1 were in the range 68%-80%, and were estimated based on the real accounting of network companies and their business plans.

Output indicators, innovation and financeability

The regulatory framework for distribution companies in GB includes several incentive schemes based on output indicators into 6 categories, namely safety (e.g. asset and personnel health), environmental impact (e.g. energy losses, carbon footprint), customer satisfaction, social obligations (e.g. vulnerable consumers, stakeholder engagement), connections, and reliability and availability.

It is relevant to note that the regulatory treatment of these output indicators in some cases comprises economic incentives/penalties for distribution companies, whereas in other cases the regulator simply set discretionary rewards for outstanding performance or simply reputational incentives. Incentives and penalties are incorporated to the remuneration of distribution companies with a two-year lag, i.e in year n, DNOs report what happened in year n-1 and the associated economic rewards or penalties are included in the remuneration of year n+1.

[28] The elements of the IQI matrix reproduce this calculation for each combination of ex-ante allowed costs (in the column) and ex-post expenditures (in the rows).

In this section, a key type of output indicator will be analyzed in further detail due to its relevance to the Peruvian context, i.e. reliability or continuity of supply.

In addition to this extensive list of output indicators, the RIIO-ED1 framework included different forms of mechanisms to promote innovative projects and grid modernization, as well as a scheme to continuously monitor and assess the financial health or financeability of distribution companies. These are discussed in subsections 0 and 3.3.2 respectively.

Continuity of supply incentives

Distribution companies are exposed to three complementary economic incentive schemes to encourage them to improve the levels of grid reliability.

The first one is the so-called **Interruptions Incentive Scheme (IIS)**, which aims to encourage distribution companies to improve average levels of continuity of supply. More specifically, two indicators, i.e. the number of interruptions per 100 customers (similar to SAIFI) and the customer minutes lost (similar to SAIDI), are measured and compared against a target derived from benchmark performance across all companies. Over or under performance is rewarded or penalized respectively. Revenue exposure to the IIS is capped, both upwards and downwards, to 250 RORE basis points per annum.

Both unplanned and planned interruptions, the latter with a weight of 50% of that of unplanned ones, are considered. As shown in Figure 24, most distribution companies managed to beat their targets in the period 2018-2019. This also led to significant financial rewards for distribution companies. Nonetheless, an ex-post analysis argues that these returns may have been excessive as a result of target levels being based on outdated data which did not take into account recent improvements in reliability levels achieved by distribution companies, and therefore easily outperformed (CEPA, 2018).

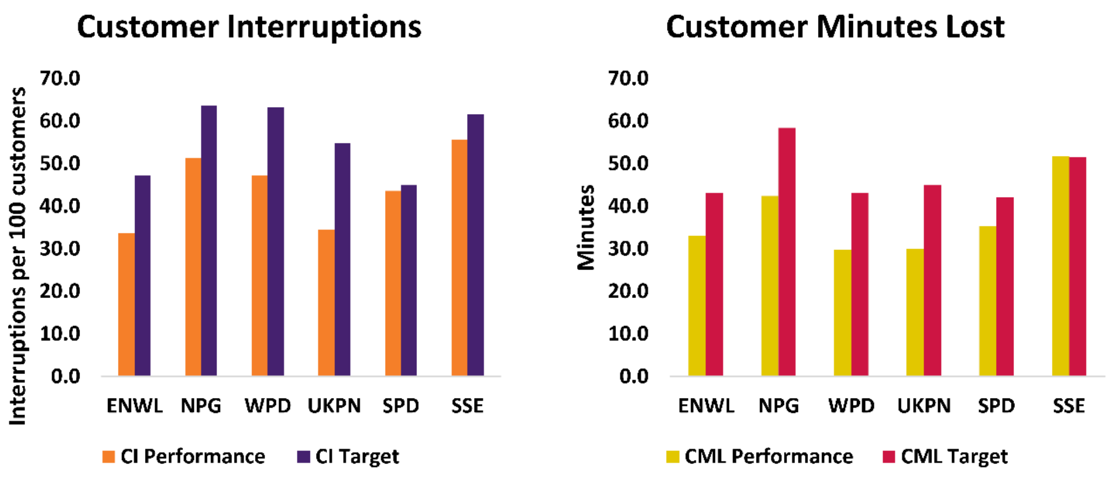

Figure 24: Reliability performance of GB's distribution companies in the period 2018-2019 as compared to regulatory targets. Source: (OFGEM, 2020)

The second incentive scheme corresponds to the **guaranteed standards of performance (GSoP)**, which grants customers the right to receive a direct payment from the grid company where the specified minimum levels of performance are not met. Ths scheme aims to promote a fast recovery of very long interruptions usually caused by extreme weather events (interruptions longer than

12 hours). In 2018/2019, distribution companies compensated their users with just under £2.5m under the GSoP.

Lastly, distribution companies are given access to ad-hoc funding to improve the reliability performance experienced by **worst-served customers**. This funding is given on the condition that the specific customers experience a specified improvement in service. In 2018-19, distribution companies spent £1.2m improving quality of service for worst-served customers.

Innovation incentives

In addition to the revenue allowances discussed above, distribution companies are exposed to a package of incentives for innovation that comprise three main components. Each one of these is targeting different types of projects in terms of scope and technological maturity.

- **Annual Network Innovation Competition (NIC):** this is an annual competitive call where grid operators, both transmission and distribution, can request to recover up to 90% of the cost of large-scale innovative projects with environmental benefits. In 2018-19 two distribution projects received £23.3m funding from this mechanism.
- **Network Innovation Allowance (NIA)** allows distribution companies to spend (use-it-or-lose-it) between 0.5% and 1% of their base allowance on small-scale innovation projects (90% of the costs may be passed-through). The amount granted to each company depends on how well the innovation strategy is demonstrated. In 2018-19 distribution companies spent £22.1m (77% of that year's allowances); an increase on the £22.0m spent in 2017-18 (83% of that year's annual allowances)
- **Innovation Roll-out Mechanism (IRM)** gives grid operators the possibility to request a revenue adjustment to fund the roll-out of proven innovative solutions after the regulatory period has started in two pre-defined time windows

Financeability assessment

The regulatory agency monitors two equity metrics and six credit metrics as well as several qualitative factors in order to monitor the financial health of distribution companies (OFGEM, 2013). These indicators are similar to those commonly used by credit rating agencies and include:

- Equity metrics[29]: Regulated Equity / EBITDA, Regulated Equity / Regulated Earnings
- Credit metrics[30]: Net debt / RAV, FFO / Interest, FFO / Net debt, RCF / Capex, RCF / Net debt, PMICR (also known as "adjusted interest cover ratio")

In principle, OFGEM has not established any explicit economic incentives or penalties related to these indicators. Nonetheless, some of the actions that OFGEM has listed as potential solutions for addressing these problems by increasing the available cash for companies or reducing their

[29] EBITDA (Earnings Before Interests, Tax, Depreciation and Amortization)

[30] RAV (Regulatory Asset Value), FFO (Funds From Operations), RCF (Retained Cash Flow), PMICR (Post-Maintenance Interest Coverage Ratio).

cost of debt. These include restriction of dividends, equity injection, refinancing of expensive debt, adjust capitalisation or depreciation rates, or adjust the notional gearing (OFGEM, 2019).

4. Tariff design

The vast majority of power systems lack a comprehensive system of efficient prices and regulated charges for electricity services. Progress has been made in the last years, but there is still a long way to go in most jurisdictions if we want tariffs to unlock the value of demand response and distributed energy resources. The general landscape today is that only minor adjustments have been carried out in tariff design, and in most cases, residential consumers still pay an additive volumetric charge ($/kWh) which prioritizes simplicity over efficiency in the cost allocation process.

These tariffs are not able to “guide” an efficient development of distributed energy services. The only way for centralized and distributed resources to jointly and efficiently operate and compete is to establish a comprehensive system of economic signals. This system of signals is supposed to drive not only the operation but also the planning of new resources and it will probably define the equilibrium between centralised and distributed services in the future. This section is dedicated to present and analyse electricity pricing methods for an efficient assimilation of distributed energy resources (DERs).

In the present context, tariffs are supposed to define the equilibrium between centralised and distributed services

4.1 Principles of tariff design

MITEI (2016) identifies two “dominant” principles in tariff design and that should be given priority over other principles[31]:

- Allocative efficiency. Efficient economic signals should try to capture and reflect the marginal or incremental costs of the production and utilization of electricity services. Such signals serve as the key tools with which to coordinate all the planning and operational decisions made by the diverse range of power sector agents to achieve efficient outcomes. For services provided competitively, the corresponding markets generally provide the required prices. For other services, regulated charges must be designed to send efficient signals reflecting each user’s marginal or incremental contribution to regulated costs (such as network capacity).
- Sufficiency to recover the regulated costs. Prices and charges should enable the economic sustainability of regulated services via recovery of regulated costs (such as distribution network costs and policy costs). While prices and charges that provide economic signals by reflecting marginal or incremental costs contribute to recovery of regulated network costs, such prices and charges alone are unlikely to be sufficient for full cost recovery. Regulated costs not

[31] Many authors have defined the complete list of basic principles that electricity tariff design should follow. Reneses et al. (2013) listed the following: cost recovery or economic sustainability, economic efficiency, equity in cost allocation, transparency, additivity, simplicity, stability and consistency with liberalization.

recovered via cost-reflective prices and charges, the so-called "residual costs", should be recovered in a minimally distortive manner.

The same report remarks how only the second principle is routinely met in practice, while much effort must be spent to enhance the efficiency of future electricity tariffs. (MITEI, 2016) also identifies two tariff principles that specifically apply to distributed energy services. According to the authors, prices and charges for electricity services should be non-discriminatory and technology-neutral. Any cost-reflective component of prices and regulated charges should be based exclusively on the individual injections and withdrawals at the network connection point, regardless of the specific technology producing those injections or withdrawals. In fact, for the power system, it does not make any difference whether a change in the power withdrawn or injected at a specific time and place has been caused by reducing demand, discharging a battery (or reducing the battery charging), or injecting power from a distributed energy source. The impact on the system is not dependent on the technology involved, thus prices and charges should not depend on technology either.

Another principle that should guide the development of DES is that cost-reflective prices and charges should be symmetrical. A marginal injection at a specific place and time should be compensated at the same rate that is charged for a marginal withdrawal at the same place and time. Non-symmetrical prices and charges would incentivise strategic decisions regarding the location of distributed energy resource behind or in front of the meter.

Prices and charges for electricity services should be non-discriminatory (and symmetrical for generation and consumption) and technology-neutral

4.2 The elements of electricity price

An electricity tariff is composed by a combination of prices and charges that have to recover the different cost elements incurred in the power supply chain. Such cost elements can be divided among (MITEI, 2016):

- Electric energy
- Energy-related services, as operating reserves or firm capacity
- Network-related services
- Policy costs, as taxes or costs related to renewable and energy efficiency support

As already mentioned, for cost elements related to services provided competitively, the efficient signal should be conveyed by a price defined in the corresponding market; on the other hand, cost elements related to regulated activities should rely on allocation methodologies based on cost-causality (beneficiary-pays, causer-pays principles). In both cases, efficient economic signals should reflect, whenever possible, the marginal or incremental cost of electricity services.

Each of the cost items listed above will therefore have a different efficient allocation methodology (or a combination of these). Nonetheless, not all costs can be allocated efficiently, or at least not entirely. For some cost elements (as, for example, network-related costs), prices and charges that reflect the marginal or incremental cost of a service are not sufficient to achieve full cost recovery. For other cost elements (as taxes or institutional costs), there may be no obvious application of the cost-causality principle. All these expenses are commonly grouped in the broad category of residual costs. The latter, which, as mentioned, cannot be assigned efficiently, should be recovered in the least distortive manner. Figure 25 depicts graphically the different cost elements and the identification of residual costs.

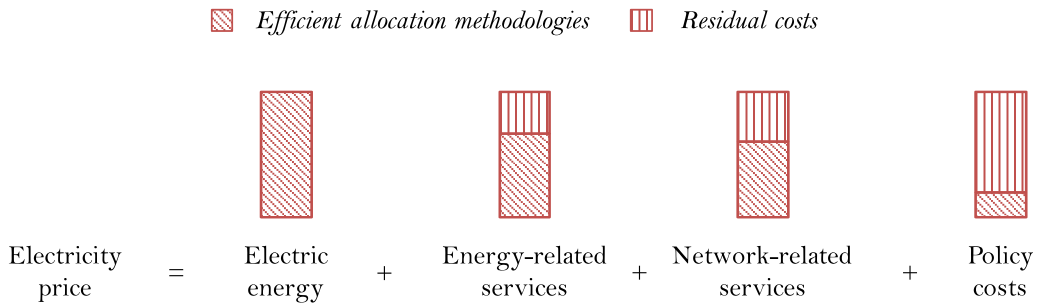

Figure 25. Cost elements of electricity supply and allocation methodologies

Beyond this initial classification, it is important to remark that each cost element should be associated to the relevant cost driver (energy demand, power demand, time of demand, location of demand, connection point, etc.) and charged accordingly in the proper format ($/kWh, $\$/kW_{contracted}$, $\$/kW_{peak}$, $/year, etc.). If, through an efficient allocation methodology, a power supply cost is efficiently assigned to each consumer according to her responsibility in the occurrence of the cost, but then it is charged in the wrong tariff format, then it will still convey an inefficient signal.

It must be remarked that the choice of the proper charging format is important not only for those cost elements that can be assigned through an efficient methodology, but also for the allocation of residual costs.

4.3 Efficient allocation methodologies

As already mentioned in the previous sections, the most efficient cost-allocation methodology may be different for different cost elements and this is why electricity tariff should be additive. Following this line of thinking, this section analyses efficient methodologies for each cost item.

In the following, we will assume a deployment of advanced metering infrastructure. If this is not the case, because, for example, the cost-benefit analysis is not positive for a cluster of consumers, then the idea would be to move in the direction of the principles that are reviewed hereunder the closest the technology allows.

4.3.1 The price of electric energy

Marginalism is known to be the most efficient way to price electric energy. The cost of supplying a marginal increment in electricity demand represents an efficient signal for both operation and expansion of the system. Marginal prices, however, can be calculated with very different granularities, both in space and time, and the efficiency of the economic signal will be highly affected by this granularity.

Distributed energy resources may have their economic value revealed only in the case where price signals convey an adequate level of granularity to capture the important variations in the cost of supplying electricity across time and space. Although the focus in this subsection is on pricing energy, the insights are equally applicable to other economic signals such as network costs (that are covered a few lines below).

Time granularity

The marginal cost of electricity varies depending on the time it is consumed, due to load patterns and generation costs, and this variation could be significant. To provide consumers with accurate signals, the price of electricity must be calculated and charged for short-time intervals. This would help to disclose the value of some resources, like distributed storage, and allow consumers to shift demand over a certain time horizon, within which different prices arise.

The price of electricity should be calculated for shorter time intervals to disclose the real value of distributed resources; this requires having previously deployed advanced meters among the clients that can respond to such signals

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Spatial granularity

The marginal cost of electrical energy also differs significantly by location within the network. These differences are due to the presence of losses within transmission (and distribution) lines, and the occurrence of congestions in the grid. In theory, the best option is to replicate the methodology implemented at the wholesale level by ISOs, calculating a price for each node of the transmission network and applying this nodal price to both generation and consumption located in that node (Caramanis et al., 2016).

The right level of granularity

This being said, it must be noted that although increased granularities have clear benefits in terms of efficiency, these gains come at a cost, in terms of, among others, increased computational efforts. A trade-off between benefits and costs of increased granularities must be found and this equilibrium point will depend on the characteristics of each power system, including its generation mix, the development of its transmission and distribution networks, and the state of deployment of distributed energy resources, among other factors. This "overall efficient" granularity is undoubtedly one of the key topics still to be explored today.

Thus, replicating the transmission nodal prices calculation to the distribution network nodes (which is at least one order of magnitude larger) appears to be an unnecessary (and very likely unfeasible) effort. In those segments of the network that will experience congestion, distributional locational prices may be very volatile and the focus should be on ad-hoc mechanisms through auctions for distributed energy services periodically launched by the DSO only in those locations where actual needs are detected). This is covered in section 5.

Granularity comes at a cost and a trade-off must be pursued; distributed locational energy prices does not seem to be a workable and desirable solution

Communication of prices and charges to consumers

Beyond time granularity, another element in the temporal dimension of electricity rate design is the existing time interval in which communication of forthcoming prices to consumers occurs. For the same time granularity, the reaction to price signals may be completely different depending on when prices and charges are communicated (one day ahead, few hours ahead, or even *ex-post*).

If prices and charges are known only *ex-post*, consumers cannot effectively react to such signals; alternatively, they will react according to their expectations of those signals. This approach has advantages but also clear disadvantages.

When prices and charges are communicated *ex-ante*, moving this communication close to real time may be beneficial for the efficiency of the signals (since they are more likely to reflect the real conditions that will be registered during the operation of the system), but, at the same time, it may hamper the participation of some agents who may not be able to react in such a short time interval.

If consumers are supposed to react to price signals, these must be communicated with a sufficient anticipation

4.3.2 The price of energy-related services

Among energy-related services, those that are most commonly found in power systems are operating reserves and firm capacity, which are analysed hereunder.

Operating reserves

The cost of operating reserves usually accounts for a small percentage of the final cost of electricity. However, this percentage could grow in the next decades, due to the penetration of intermittent resources. Moreover, despite the comparatively small size of the ancillary services market, this may represent a significant economic opportunity for demand-response and distributed energy resources.

An efficient pricing of operating reserves should be based on economic signals that convey the costs of reserve provision and through which the occurrence of reserves scarcity reaches all power system agents. This can be achieved either by facilitating the participation of DERs in the reserve market (eliminating unnecessary limitations and moving these markets closer to real time) or by improving the allocation methodology of the cost of reserves, establishing a system of charges that reflects the cost-causality for both the capacity reservation and its activation in real time and signals the scarcity of operating reserves.

Firm capacity

The cost related to capacity mechanisms, or, more in general, to mechanisms that pursue system adequacy and reliability, is another item of the final electricity cost that is expected to grow in the future (ISO New England, 2015). Also in this case, it is essential that future regulation allows for the participation of DERs in capacity and reliability markets and that the cost of these mechanisms is assigned efficiently, following the cost-causality principle. This efficient methodology varies depending on the characteristic of the system and its scarcity conditions. A capacity-constrained system dominated by thermal power plants has stress events related to the supply of peak demand during certain hours and its capacity mechanism is likely to remunerate the ability of resources to deliver during those hours. In this case, an efficient charge should be proportional to the capacity demand in those same hours. On the other hand, a hydro-dominated system has stress events related to dry seasons that may last for months and an efficient charge should be proportional to the energy consumption rather than to capacity.

Firm capacity/energy charges should be proportional to the expected consumption during the scarcity periods

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4.3.3 Network charges

The most efficient way to (partially) recover network cost is through the aforementioned locational prices. Due to losses and congestions, locational prices generate the so-called "network rents"[32]. In the absence of economies of scale in network investment (and if other theoretical hypotheses are fulfilled), it has been proved that locational prices completely recover the network costs (Rubio-Odériz, 1999). However, in practice, network rents can cover only a small percentage of total network cost, due to, among other factors, the lumpiness of transmission investments and risk aversion to power system failures.

The long run marginal cost

The remainder of the total network cost not covered through network rents can still be assigned among power system agents through an efficient allocation methodology. A method commonly applied to electricity networks is the Long-Run Marginal Cost (LRMC). In this context, 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, 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.

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[32] Network rents is a more general expression than congestion rents, since it encompasses also the effect of losses. It must be remarked that network rents result from the application of locational prices and that this applies not only to the price of energy, but also to the price of energy-related services, as operating reserves and firm capacity.

However, the application of the LRMC to network costs present many challenges, as studied in literature (Batlle et al.,2016). The first problem arises at the moment of setting the marginal increment. Mathematically speaking, the expression "marginal" could be interpreted as very small if compared with the actual withdrawals/injections. However, such marginal increment is likely to result in no cost at all, since it could be supplied, most of the times, through the existing network (especially considering the significant lumpiness of investment that characterizes network industries). No consensus can be found around the size of the increment. Some authors, as for instance (Williams and Strbac, 2001), proposed 500 MW; some other reports, as (FSR, 2005), preferred the concept of long-run average incremental cost, which is the cost of meeting large increases in demand, averaged over the size of the increment.

Once long-run marginal costs have been calculated (or approximated) for each group of grid users, they must be applied to specific cost drivers. It is evident that most network costs are driven by the demand of capacity, so the most efficient format is $/kW. However, which capacity should be used for this charge? The methodology with more support in literature is the peak-coincident network charge, through which consumers pay for grid costs according to their contribution to aggregate peak network utilization. Also in this case, several challenges arise when applying this methodology to real-world tariffs. Which is the peak demand? Is the network-wide peak demand or it is assessed at node or voltage level? Is the yearly peak demand or a set of peaks is to be defined? Are these peaks identified *ex-ante* or *ex-post*? This latter discussion is briefly tackled next.

Identifying the peak coincident periods: ex-ante vs. ex-post approaches

Identifying the peak coincident periods to charge the network LRMC in the tariff is a complex issue in itself.

- One alternative is to assign the peak coincident periods to some pre-defined ex-ante hourly periods. These periods are the periods in which the distributor expects the highest infrastructure usage (implying close to overloading regime).

  While this approach may be advantageous because it is predictable for the consumer, the definition of the periods can be subject to continuous (annual) changes. This would be the case when too many consumers respond to these ex-ante price signals, for example by investing in storage or other solutions to move consumption from the predefined ex-ante periods to other periods where the tariff charges are lower. This leads to the necessity to recalculate again the peak coincident periods, trying to "chase" and anticipate the new peak coincident periods.

- In those systems where the consumer has to contract in advance its maximum consumption capacity, the LRMC charge would be assocated with the ex-ante contracted capacity in the peack coincident period. The second alternative is to defined ex-post these peak periods. Here we find two main alternatives:

  - Charge the long-term network costs during the "n" most demanding network periods. This does not necessarily imply that the network is even close to congestion (which would result in an inefficient signal).

Charge long-term network costs during all ex-post periods that present network congestion (meaning that if there were no congestion, then there are no peak periods).

The granularity of network charges

Similarly, to what was described for energy, there is also a need for granularity in network charges, since the network costs reflected by these charges vary significantly depending on where the electricity is consumed (at the end of a feeder in a rural area or from a highly-meshed network in an urban area) and on the load profile (consumption during peak demand in the network). Transmission and distribution charges should encompass some level of granularity.

Peak coincident network charges should be used to recover network costs

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Residual network costs

Regardless of the design of the LRMC methodology, not all network costs will be recovered through these efficient charges. The part of network costs not covered through network rents nor through LRMC charges is referred to as residual network costs. It must be remarked that the recent evolution of power sectors may further affect the ability of the LRMC approach to recover network costs. After several decades of fast-paced growth, many countries are now experiencing decline in electricity demand. Sometimes these decreases were expected by regulators, but sometimes they caught system planners unprepared. Beyond demand declines, the sudden entrance of distributed generation and, more significantly, of electricity storage and demand response may reduce peak power consumption, thus leaving part of the network capacity unused. For these reasons, in the near future, many networks may become oversized and present a significant surplus capacity. In such condition, long-run marginal costs would reflect such surplus (even large increments would not result in the need for new investments) and LRMC charges may decrease sharply (the same applies to network rents), reducing the quota of network costs that cannot be assigned efficiently and that must be treated as residual network costs.

4.3.4 Policy costs

Policy costs are the element of electricity tariffs that more rapidly is growing in many jurisdictions. Policy costs are also the cost item that has been more frequently considered as a residual cost that could not be allocated through an efficient methodology. In some cases, this may be true, since there are cost elements that has no direct cost driver within the electricity supply chain and for which it is impossible to identify beneficiaries (as the institutional costs of system and market operators).

Nonetheless, there are some policy costs, as those related with the support of renewable energy technologies (which, in many cases, account for the largest share of this cost category), that could be assigned efficiently, once again through the methodology of the long-run marginal cost. As explained in MITEI (2016), many jurisdictions have established renewable energy obligations or renewable portfolio standards policies, which require utilities or retailers to produce or procure a percentage of their electricity from renewable sources, or have defined national renewable energy targets expressed as a percentage of electric energy consumption. In these cases, an increase (or a decrease) in electricity demand directly increases (or decreases) the marginal cost of compliance with such policies. For example, with a 20% renewable electricity obligation, increasing total electricity demand by 10 kWh would require an increase of 2 kWh of electricity supplied by renewable electricity sources. A cost-reflective allocation of the cost of renewable support policies, therefore, would entail a volumetric charge calculated as the product of the percentage renewable target and the extra cost of generation from renewable sources.

(Batlle et al., 2016) go further in this analysis and shows how both these parameters (the renewable target and the renewable extra cost) can change over time. On the one hand, renewable penetration targets are usually defined as a penetration path, with increasing targets to be achieved each year. Since the renewable LRMC is supposed to be a long-term signal, (Batlle et al., 2016) suggest to use the final penetration target. On the other hand, the extra cost of renewable generation varies depending on market price fluctuations and, more importantly, on the learning curve of these technologies. Particularly due to the latter, the renewable extra cost is supposed to decrease over time, until it becomes null when the renewable generation cost achieves the market price (probably in the near future). This trend automatically defines the renewable LRMC and the renewable residual cost, as presented graphically in Figure 26.

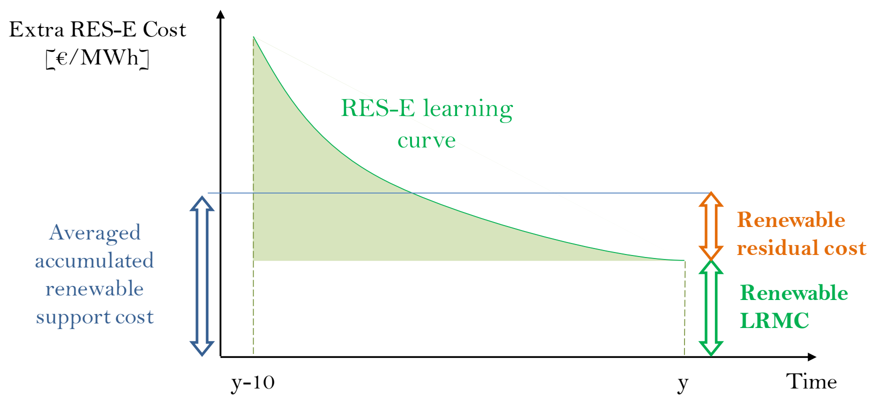

Figure 26. Renewable LRMC evolution and impact on the renewable residual cost; chart from Batlle et al. (2016)

Batlle et al. (2016) also highlight the importance of adequately allocate renewable support costs among energy users. In many countries, the power sector has historically born 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, these authors recommend the renewable support burden to be borne by all energy consumers, according to their final energy consumption, or to the total carbon emissions provoked by each energy sector.

4.4 Residual costs and grid defection

Residual costs can be defined as the difference between the recognised costs of a certain activity and the revenues collected through the application of an efficient allocation methodology. 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 (system and market operators), and interests on tariff deficits.

These costs must be recovered through complementary charges on the top of the system of prices and charges defined through the application of efficient allocation methodologies. However, the latter are supposed to convey the most efficient signal for the operation and expansion of the power sector. Therefore, the basic recommendation for the allocation of residual costs is to minimise distortions of the already defined economically efficient signals.

Residual costs would be better recovered through a fixed charge, expressed as a lump sum that could be computed on a yearly basis and billed in monthly instalments. However, this solution has two negative implications:

- Consumers would pay the same charge, irrespective of their energy and capacity demand, and this may raise equity issues (this is reviewed later).
- If the fixed charge does not consider the long-term elasticity, it may result in inefficient grid defections, as analysed next (see next section).

4.4.1 Long-term elasticity and grid defection

Distributed energy resources increase the long-term elasticity of end-users, who can make investment decision in response to electricity prices. An extreme instance of this long-term elasticity is represented by grid defection. The combined effect of decreasing costs of both domestic distributed generation (rooftop photovoltaic above all) and small-scale batteries (and/or an onsite gen-set) is reducing the cost of supplying a kWh through a stand-alone system, and this cost is getting closer (at least in the same order of magnitude) to the cost of supplying the same kWh through the grid, when the classic tariff design is taken into consideration[33]. However, this apparent competitiveness stems, most of the times, from an improper allocation of residual costs. A grid defection, in this context, would be beneficial for the end-user, but would be inefficient from a system-wide perspective.

In order to avoid inefficient grid defections, (Batlle et al., 2016) propose the application of thresholds to residual cost allocation. Figure 27 compares the tariff for grid supply, represented as the summation of generation costs (and other costs related to competitive activities), long-run marginal costs (including network and renewable LRMCs), and residual costs, with the cost of two stand-alone systems. Stand-alone system 1 is a theoretical and extremely cheap system that supplies electricity at a cost lower than the summation of efficient generation, network, and RES-E support costs. Apart from some exceptional cases (isolated or very unreliable interconnected systems), such a scenario cannot be found in practice with the current prices of photovoltaic panels and batteries and it is also quite unlikely for the near future. However, if a stand-alone system with these characteristics existed, it would produce at a cost lower than the overall marginal cost

[33] This is not completely true. A proper economic assessment should consider also the cost of non-served energy. A stand-alone system (a properly-sized rooftop PV panel and a battery) has a loss-of-load probability much higher than a modern interconnected power system. Depending on the value assigned to non-served energy, this lower reliability would affect the economic comparison, reducing the competitiveness of stand-alone systems.

of producing electricity from the grid. In this case, grid defection would not be detrimental for the power system, since it would be fully cost-efficient. No tariff threshold is to be applied in this case.

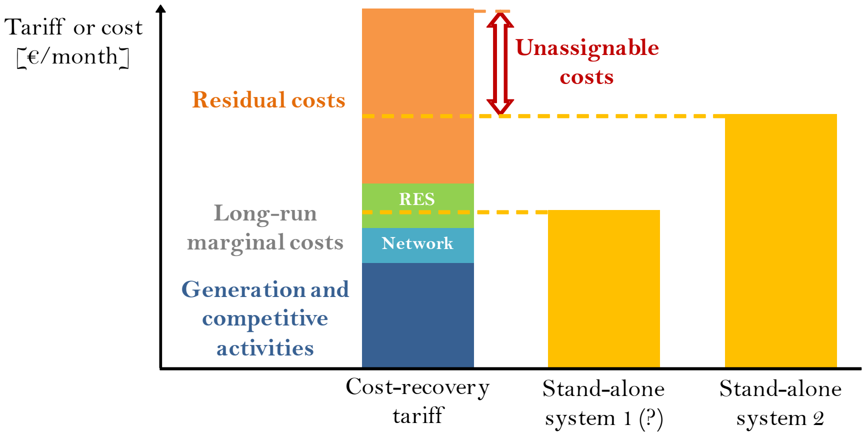

Figure 27. Stand-alone systems cost compared to tariff for grid supply

A completely different situation is depicted in Figure 27 for stand-alone system 2. This system is producing at a cost higher than the overall long-run marginal supply cost from the grid. Therefore, a grid defection from this user would be inefficient from the economic point of view, since the electricity produced by this stand-alone system would be more expensive than the one withdrawn from the grid. Inefficient grid defection is caused, in this case, by an improper allocation of residual costs. In this context, it must be also remarked that, as soon as grid defections start taking place, tariffs must be readjusted in order to fully recover residual costs, causing an increase in electricity bills for remaining customers and worsening the problem, an extreme version of the so-called "death spiral" for electric utilities.

The cost of stand-alone system 2 then must become a threshold[34] that is not to be exceeded by the inappropriate allocation of residual costs. The share of residual costs beyond such a threshold should be treated as unassignable costs.

4.4.2 How to recover unassignable residual costs

Such unassignable costs must be recovered, in order to guarantee the financial stability of the power sector and adequate funding for public policy objectives, but these revenues cannot be recovered through conventional components of electricity tariffs. Different alternative options have been proposed in literature for the collection of these costs:

- 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

[34] Batlle et al. (2016) propose the application of the "marginal threshold". In fact, the cost of a stand-alone system varies depending on many factors, but the threshold should be unique and the lower stand-alone cost should be considered. Moreover, these authors remark how the threshold should be subject to frequent revisions, since the cost of a stand-alone system may evolve rapidly in the next decade.

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.

- Embed unassignable residual costs 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 and of its electricity consumption. Therefore, this solution would allow to charge more residual costs to end-users with higher consumption, but without affecting the efficient economic signals and without the risk of grid defection.

- 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.

Each of these alternatives has pros and cons and each system needs a tailored solution. The selection of the methodology for the allocation of residual costs will dramatically affect the potential for electrification of the energy sector. The latter is claimed by many experts as the main strategy to reduce greenhouse gas emissions (NREL, 2017), but an inefficient electricity tariff design would definitely hamper this transition.

Residual costs would be better recovered through a fixed charge, expressed as a lump sum that could be computed yearly and billed in monthly instalments; this fixed charge can be consumer-dependent, but it should not convey any price signal (that could trigger an inefficient response) to the consumer

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4.5 Remuneration of behind the meter DER production

Net metering combined with volumetric rates has been proved to be one of the most harmful support schemes to incentivize distributed generation. When the negative impact of this mechanism began to be evident, many jurisdictions in the United States and Europe started altering or dismantling their net metering policies.

Particularly, in 2017 New York started to transition towards a new scheme for more efficiently incentivizing distributed energy generation, known as the Value of Distributed Energy Resources (VDER). This VDER seeks to more accurately compensate distributed renewable energy generation injections, based on its actual benefits with respect to both the electrical grid and the environment. VDER remunerates based on the so-called Value Stack Tariff, which consists of the following concepts: (i) locational-based marginal pricing, (ii) capacity, (iii) environmental value (E-value), (iv) demand reduction value and (v) other locational values.

While this VDER scheme it is clearly a needed step forward, it is still not the most complete and efficient alternative overall, for it does not provide the consumer with a symmetrical price signal. As stated in MITEI (2016), "cost-reflective prices and regulated charges should be symmetrical, with injection at a given time and place compensated at the same rate that is charged for withdrawal at the same time and place."

Applying different prices and charges to injections and withdrawals introduces distorted signals and incentives as well as arbitrage opportunities. Therefore, it would be worth exploring different ways to provide symmetrical price signals to the consumer.

Net-metering policies should be avoided; DERs should receive a compensation reflecting the market value of that electricity and pay for charges reflecting he costs associated with using the network infrastructure

4.6 Distributional impacts

Tariff reforms aimed at guiding an efficient deployment of storage and other DER may have an impact on how electricity costs are distributed among different classes of consumers. The aforementioned measures, increasing the granularity of electricity prices, introducing demand charges for network costs, introducing fixed charges for residual costs have been identified by experts as possible enhancements in tariff design, however they may increase the bill of some customers and, among them, potentially vulnerable customers.

In order to avoid this effect, without sacrificing the efficiency of the tariff, the new system of prices and charges may be complemented with "equity" measures, which can be applied during a transitional period or permanently. For example, MITEI (2016), proposes to complement the new tariffs with means-tested rebates for low-income consumers; such rebates could be provided as a lump sum, thus not distorting the efficient economic signals. Another alternative would be to introduce "uneven" fixed charges linked to historical bills, designed to guarantee a certain gradualism in the tariff change. This way, efficient signals could be conveyed, but final bills would be similar to those paid before the reform.

DER deployment and the redesign of electricity tariffs that may be required to correct its outcomes may create a distributional impact that hampers low-income consumers; measures should be taken to avoid this effect

4.7 A potential roadmap for transition

The guidelines presented in the previous sections represent a dramatic change of paradigm in tariff design. Furthermore, each power system has its own characteristics and its own regulation and some of the recommendations expressed here may not be applicable or may result in very reduced benefits. In this sense, MITEI (2016) proposes a list of recommendations ordered according to some sort of rate between their expected benefits and their expected implementation costs. Such list is resumed hereunder:

- Remove residual costs from the volumetric component of the tariff and charge these costs through a fixed charge determined through some proxy of the end-user wealth, always keeping in mind the need to avoid inefficient grid defections.
- Smart meters, whose rollout is almost completed in many power systems, allow to easily expose customers to hourly or sub-hourly energy prices and this exposure could be highly beneficial, especially in capacity-constrained systems.
- Extend wholesale energy prices to all voltage levels of the distribution network through loss factors (this can be done even if a uniform price is computed in the wholesale market). Loss factors would be time-dependent and, at time of scarcity, they may significantly increase the energy price at the end of a feeder, signalling the comparative benefits of DER installation.
- Smart meters also allow for an easy application of coincidental peak capacity charges for firm capacity and for responsibility in network investment.
- Calculate nodal prices at the transmission level and consider their application not only to generation but also to price-responsive demand and DERs in general.
- Introduce detailed locational signals at the distribution level, capable of guiding DER installation towards those zones of the distribution network where they would be beneficial.

4.8 International experiences

In this section, a brief review of international experiences on the design of access rates is presented. Regarding network cost allocation, many jurisdictions continue to recover transmission and distribution costs through volumetric charges.

The next table shows the percentage of total network costs that are allocated through a demand (or fixed) charge (the main driver of network investments). It evidences that only a small number of countries allocate most of the network costs to these charges.

Table i. Percentage of network costs recovered using a demand charge in different European countries; Data of EURELECTRIC (2016)

	Demand charge (or fixed charge)				
	0-25%	25-50%	50-75%	75-100%	100%
Residential	AT, CY, CZ, FR, DE, GB, GR, HU, LU, RO	IE, IT, PL, PT, SK, SI	NO	ES, SE	NL
Industrial	CY, DE, GB, GR, RO, SK	CZ, FI, FR, HU, SE	AT, PL, SI	IT, LU, ES	NL

The time granularity of network charges, another element that can increase the efficiency of price signals, is applied only in some countries, mainly at the energy level, as shown in the following table.

Table ii. Time of use network charges in Europe; Source: EURELECTRIC (2016)

	Time of use charges	
	Energy	Capacity
Residential	AT, ES, FR, GR, LV, PL, PT	GR
Industrial	AT, ES, FR, LV, PL, PT	ES, FR, PT

Although many regulators have started a tariff reform process, the data presented in these tables continues to reflect the European reality, as shown by (Schittekatte, 2019). Also in the United States, the most common tariff design uses volumetric charges for network costs (Brown and Faruqui, 2014), with some exceptions, such as Massachusetts.

In both Europe and the United States, many systems continue to allocate the majority of network costs (and other regulated costs) through volumetric charges; only some apply some level of hourly discrimination

Regulated costs are also usually recovered through volumetric charges in the electricity tariff. However, in countries that have more generously incentivized renewables, this approach is leading to a significant increase in electricity rates. For this reason, some governments have decided to shift the costs of the support mechanisms to the general state budget. That is what they do, in Europe, Finland, Malta and Latvia (CEER, 2017). More recently, Denmark, one of the countries with the highest renewable penetration in the world, has also decided to follow this path (Danish Government, 2018).

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5. Local flexibility markets

DERs connected to distribution networks may become an important source of flexibility for the distribution network and they may support an efficient short-term operation and long-term planning:

- In the short term, for example, using DERs flexibility would allow to allocate electricity energy efficiently in real time if there is scarce supply in a distribution area.
- In the long term, DERs response could be used to substitute distribution network investments (obviously, when these investments are more expensive than the solution provided by DER). These are the so-called Non-Wires Alternatives (in the US) or Reinforcement Deferral services (in EU).

Therefore, DSOs can take advantage of DER capabilities to enhance the system short- and long-term efficiency. This entails integrating this flexibility in their planning and operation tools and also implementing local (flexibility) market mechanisms so as to select the most cost-efficient alternatives.

DERs may improve the efficiency in both the operation and the long-term planning of the distribution network; specific local markets are required to fully exploit these potential benefits

In this section, we mainly focus on the second type of services, that is, those aimed at decreasing network investments, since they are probably those with higher potential for development, at least in the initial implementation stage of these markets. Section 5.1 introduces the need to complement electricity tariffs with some sort of long-term mechanisms, and how these local flexibility markets can fill that gap. Section 5.2 reviews the major challenges associated with the design of these local flexibility markets, many of which are still to be solved or refined. Finally, section 5.3 presents some pioneering international experiences as regards local flexibility markets.

5.1 The need for long-term signals at the distribution level

One of the relevant problems at the distribution level is the lack of long-term network signals. This situation creates a double (and specular) source of uncertainty that does not allow to take advantage of all potential benefits from DER in the long term. On the one hand, the distribution system operator cannot predict accurately the potential response of DER and, therefore, cannot plan the grid expansion efficiently; on the other hand, end-users cannot hedge the risk associated to their investment decisions. Tariffs alone do not provide these long-term signals to both consumers' and distributors due to two reasons: (i) they do not usually represent a long-term stable signal for the potential investor and (ii) they do not imply any reliable commitment from the DER side to the distributor[35].

Even efficiently-designed tariffs do not provide the long-term signal that end-users may require in order to invest in DER; long-term contracts traded in local markets allow consumers and third parties to hedge their risk and define a commitment on which the DSO can rely

The DSO's point of view

A major problem from the point of view of the DSO when planning the distribution system is information incompleteness about consumers. Network utilities have little knowledge of network users' actual preferences (MIT, 2016). The past response to prices and network capacity charges (where implemented) may provide some information, but it does not capture properly the consumers' 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 by 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 in a context characterized by a lack of long-term signals. This exposes them to significant risks. 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. The risk does not only come from the possibility that the tariff design is changed by the regulator, but also from the uncertainty regarding the investment strategy of other end-users.

Local flexibility markets auctions as a means to provide long-term signals at the distribution level

The alternative to deal with this problem would be to enter into any type of long-term commitment between potential flexibility providers and distributors. The long-term contract can ensure a stable framework for the potential providers thinking about investing in DERs or storage. If the acquisition of these long-term contracts is carried out in a coordinated market context, such as an auction, it allows disclosing the consumers' preferences. The distributor could procure from DER, a product that could substitute network investments when these are more

[35] As analyzed in (Gómez et al, 2020), non-firm or flexible access tariffs could partially deal with this second problem. Under flexible access tariffs, grid operators would relax the traditional firm connection scheme and would have some pre-agreed flexibility over the end user's feed-in and consumption. In exchange, these users may for example benefit from lower rates or a faster grid connection.

expensive than the solution provided by DER. Auctions solve the coordination 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 having the option to use network capacity.

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

A text-book design and product

In these auctions, called and coordinated by the distribution system operator (DSO), wires and non-wires alternatives 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 third-parties (who, as mentioned above, will be the owners of these distributed resources).

As discussed in (MITEI, 2016), a product that could actually provide a similar benefit to network infrastructure would be a forward network capacity option, entailing physical supply and the option to get that energy at a maximum guaranteed price.

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-year) 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 that network utilities can exercise at periods of network congestion, up to the contracted firm capacity quantity.

5.2 The challenge of designing the distributed auctions

The design of these tendering mechanisms that provide access to long-term commitments associated with long-term distribution planning is still in a developing phase, with some pioneering experiences both in the US and EU (this topic will be further addressed in the next section).

There are two aspects of this type of mechanism that are particularly challenging:

- First, and foremost, the definition of the product to be procured by the distributor.
- Second, the definition of a methodology to compare the value and reliability (or firmness) provided by the different resources in these auctions.

Definition of the products

The definition of the products to be procured from third-party providers as an alternative to traditional network investment is one of the keys of the mechanism. 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. For instance, today, in the context of demand response programs, DR is typically available only for limited hours in a year (e.g., less than 100 hours).
- 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[36]: which represents the amount of the product each unit is "reasonably" capable to provide. This firm supply limit is used in order to reduce the risk of non-compliance. The concept is analogous to that of firm supply in capacity markets.

These new distributed auctions must be carefully designed, especially in terms of the kind of availability required to DER, notification time, penalties for

[36] 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) 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 the expected contribution depends 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 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).

underperformance, the possibility of embedding a financial contract and potential constraints on the amount of product that each resource can offer

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.

Comparing different resources (wires vs non-wires alternatives)

One alternative to integrate DERs is to clearly define a product and procure the one offering the lowest price. However, particularly in the US, regulators use to require carrying out a cost-benefit analysis in which the different alternatives have to be compared from the point of view of the social welfare. This is a complex task: 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.

If the product is not univocally defined, very different resources, providing different services, may have to be compared in the auction, a very complex task with no obvious solution

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 worth 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 wire technology, the need to ensure 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 for example 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."

5.3 International experiences

One of the barriers for DER owners to provide flexibility network services is the lack of markets in which to offer them to DSOs or TSOs. At the time of this writing, in Europe, there are only 5 market platforms that allow DSOs and distributed generation owners, or other flexibility providers, to purchase or sell, respectively, flexibility services in the distribution grid. These platforms are NODES, Cornwall LEM, Piclo Flex, GOPACS and Enera. For details on these projects, see the review carried out by Schittekatte & Meeus (2020).

NODES

NODES was established in 2018 as a joint venture between Adger Energie a Norwegian utility and the market operator Nord Pool. The pilot project used by NODES, the Engene pilot, was run by Adger Energie to demonstrate its usefulness as grid investment deferral. Currently, NODES allows users to trade in a short-term market, ShortFlex, which focuses on solving immediate flexibility needs, and LongFlex, which allows DSOs to acquire flexibility resources in advance for longer time periods (NODES, 2020).

Cornwall LEM

Cornwall Local Electricity Market (Cornwall LEM) was established as a pilot project in Cornwall, UK, in 2019. The objective was to set up a trading platform in which flexible demand, storage and generation could trade with local DSOs to provide benefits for all parties involved. Residential customers were grouped into a Virtual Power Plant (VPP) and participated in a fast frequency response pilot program (DFFR), while local businesses could offer their flexibility directly by bidding in the Cornwall LEM platform matching the different requests presented by the DSOs (Centrica, 2020).

GOPACS

GOPACS (Grid Operator Platform for Congestion Solutions) was launched in 2019 as a joint initiative between the Dutch TSO Tennet and several Dutch DSOs. GOPACS is not an independent market platform but rather a complementary platform connected to an existent wholesale market platform, such as the Energy Trading Platform of Amsterdam (ETPA). The difference between GOPACS and Cornwall LEM is that any flexibility trade organized through the platform is then readjusted in a short-term wholesale market, in this case, the intra-day market of ETPA. The main focus of GOPACS is to solve congestion problems that may arise in the distribution network by allowing DSOs to reflect their necessities in GOPACS and DER to bid to provide their services (GOPACS, 2020).

ENERA

Similar to GOPACS, Enera was created in 2018 to solve distribution grid congestions by a consortium of businesses alongside EPEX-SPOT (market operator), and EWE (German electric utility; EWE, 2018). The market platform was designed as an extension of wholesale market platforms operated by EPEX, another similarity to GOPACS (EPEX SPOT, 2019).

PICLO FLEX

Piclo (previously known as Open Utility) is an independent software company that has been active in the energy industry since 2013. In October 2016, Piclo launched its first energy application, Piclo Match, a peer-to-peer energy matching service.

Piclo's second application, Piclo Flex, which was piloted in June 2018 with funding from the UK Government Department of Business, Energy & Industrial Strategy (BEIS) and subsequently launched as a commercial offering from March 2019, when the first flexibility tenders to deliver flexibility needs for 2019/20 and 2020/21 were organized by UKPN on Piclo Flex (Piclo, 2019).

Very few examples of market platforms for the trade of distributed services can be found in international experiences, some of them as pilot projects; the most relevant are NODES, Cornwall LEM, Piclo Flex, GOPACS and Enera; the main difference among these experiences lies in the product they permit to trade

5.3.1 Contracts in these pioneering experiences

Contracts for voltage control or frequency regulation

Voltage control or frequency regulation are short-term issues that may appear sporadically in distribution networks and that require fast and momentaneous responses by DSOs. These issues can be tackled with medium-term (or long-term) contracts for highly flexible resources.

All existing flexibility platforms allow for the trade of these services. Several flexibility platforms were created with the sole objective of solving these issues, this is the case with Cornwall LEM, GOPACS and Enera:

Contracts for investment deferral

Most existing market platforms concentrate on solving short-term problems in the distribution grids, such as transitory congestions, voltage control or frequency regulation.

Nevertheless, Piclo Flex provides DSOs with the opportunity of contracting flexibility services to defer reinforcement in their distribution networks. In a trial performed throughout 2018 and 2019, Piclo allowed the different UK DSOs to publish their flexibility needs in their platform and to describe their motivation for these needs. The results, presented in Figure 28, reflected that the largest need was reinforcement deferral, with almost half of the requested flexibility capacity (45.2%) (Piclo, 2019).

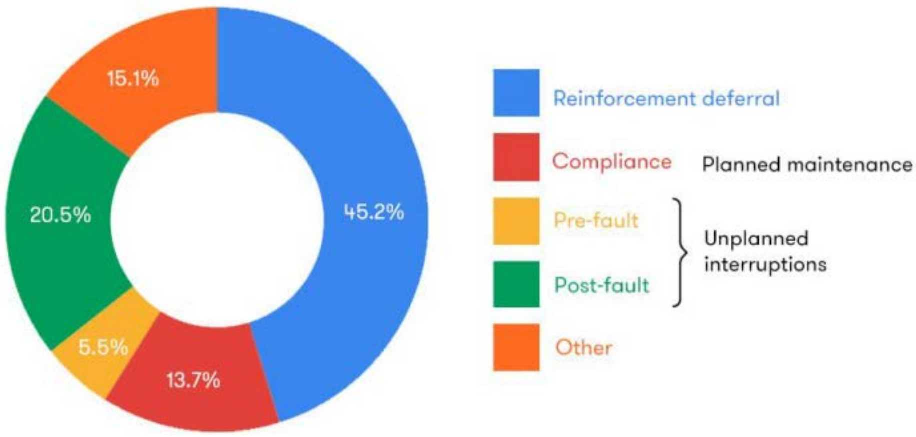

Figure 28: Different flexibility requirements during 2018-2019 Piclo Flex trial (Piclo, 2019)

A technical report prepared for Piclo (Piclo, 2020), estimated that the implementation of different flexibility services could reduce the total electricity system cost (originally 47,000 M/year) by 4,550 M/year. The majority of these savings (2,700 M/year) would arise precisely due to network investment deferral, which is coherent with the data presented in Figure 28.

Some characteristics of the flexibility products

Even though flexibility markets present some differences, any flexibility product is defined by some common operational parameters. In Figure 29, it is shown the operational parameters associated with UK Power Networks flexibility tender through the Piclo market platform in 2019.

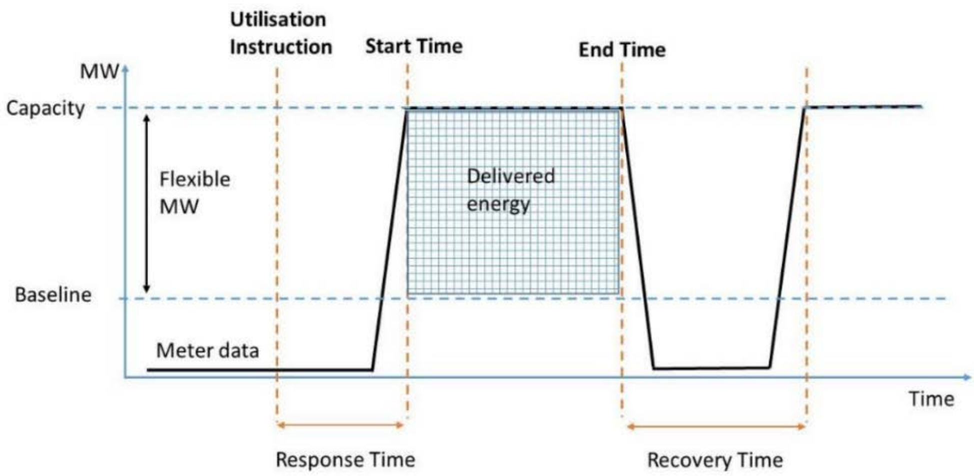

Figure 29: Operational parameters presented by UK Power Networks in a flexibility tender (UK Power Networks, 2018)

Two of the most important characteristics of a flexibility service contract is the baseline and the contracted capacity:

- The baseline represents the capacity that the contracted DER is expected to be demanding or producing during the time of the event (the instance when the DER resource is going to be required to deliver its contracted capacity) if the event had not taken place. Therefore, the baseline represents the normal expected operation of the DER at that time of day, but not the capacity being demanded or produced in that particular event.

- On the other hand, the contracted capacity represents the maximum power above/below the baseline defined previously. Therefore, the delivered energy will be the "area" between the delivered capacity minus the baseline.

We also find some relevant time-related parameters, among others:

- The Response Time, i.e. the time between the Utilization Instruction (the command issued by the DSO to deliver the contracted capacity) and the Start Time, represents the time a DER has to reach the contracted capacity after the Utilization Instruction is issued. This parameter is very important for DER that have a slow ramp rate, i.e. need a long time to increase or decrease their capacity, as a slow response time might mean they are not able to reach the contracted capacity at the Start Time of the event and possibly incur in penalties.

- The Recovery Time represents the minimum time between the End Time of an event and the Start Time of the next event. This specification is especially important for DER that are energy-constrained, such as electricity storage, as they might need to increase their stored electricity between consecutive events to fulfil their contracted capacity in following events.

Apart from these technical characteristics, any flexibility service contract must detail the contract duration and a service window, i.e., the specific days and hours in which the DER can be demanded to deliver.

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6. Efficiency of retail processes

The liberalisation of the power sector began with the wholesale market reform, and the creation of a retail market was frequently deferred to the later stages of the deregulation process (Batlle, 2013), with many systems not even considering taking this last step.

In a recent report (IEA, 2020), the IEA points out that:

"Retail markets are liberalised to a lesser extent than wholesale markets, with fully competitive markets accounting for 22% of global demand, partially competitive accounting for 45%, and fully regulated monopolies the remaining 33%.

Europe is the region in which markets operate under the greatest degree of liberalisation: 93% of demand in Europe operates under full wholesale market competition, with 85% under full retail competition. In North America 48% of demand is in fully competitive wholesale markets, with 29% under full retail competition"

In the figure below (IEA, 2016), it is illustrated this reality.

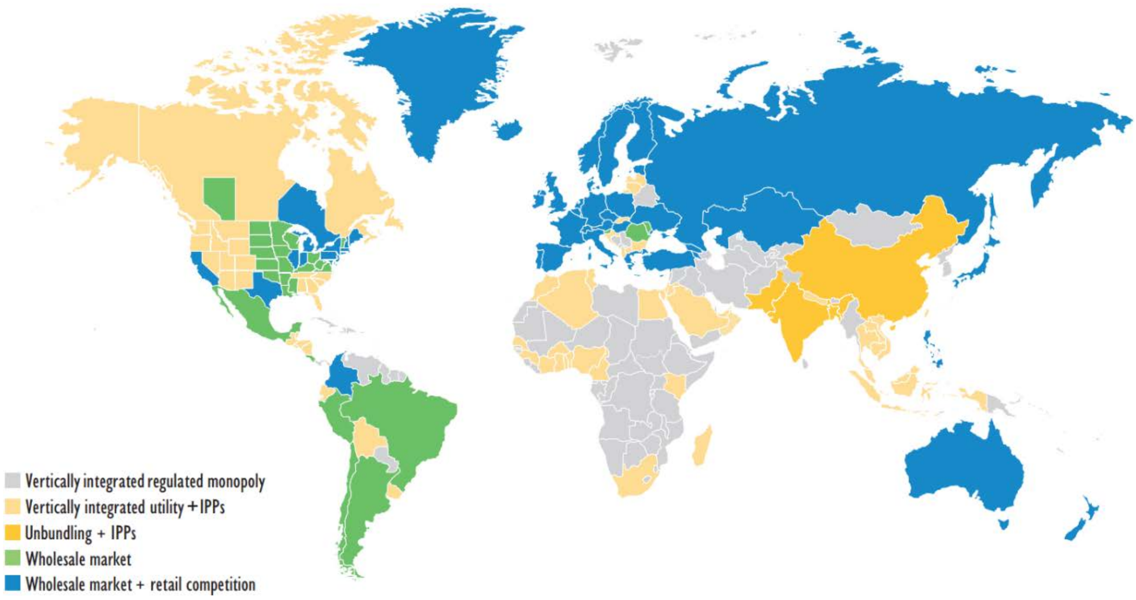

Figure 30.-

Even in those jurisdictions where the liberalization of the retailing activity was part of the original plan for restructuring, several delays in the agreed processes can be found. Among other factors, the existence of vertical integration, hard-to-fit mechanisms, inefficient allocation of legacy costs and subsidies put into question the theoretical benefits that retail competition could imply, particularly for certain customer segments.

The creation of a retail market is the final step of power sector liberalization that has been taken only in some jurisdictions

Herein we analyze why liberalizing retail markets is such a complex task and what are the recommended approaches to do so. The remainder of the section is structured as follows:

- First, in light of the international experiences, we review the most relevant barriers that impede an efficient development of the retail business, and highlight the best practices (subsection 6.1),
- then, we review the current state of the retail market in the paradigmatic experience of the EU, to extract the lessons that can be learnt from the context in which retail liberalization has been taking to its largest level (section 6.2), and
- finally, we tackle two of the most controversial topics: the need and design of regulated tariffs (subsection 6.3) and the role and potential interference in the retail market of legacy costs (subsection 6.4).

6.1 Removing barriers: best practices

Ideally, liberalizing the retail level is supposed to introduce competitive pressure on both the upstream costs of electricity and also on the operating costs of retail (billing, customer services and others), while at the same time widening the range of available tariffs to final consumers.

If an active participation of consumers is achieved (which involves the absence of consumers' supplier switching costs) and it is also ensured low costs of entry and exit in the business, retail competition should result in better tariffs for consumers, what in the end is supposed to increase the overall efficiency of the system. Under such a paradigm, the key objectives of retail electricity policy should be to create a market with low entry barriers for suppliers and low switching barriers for end-users. This would be the way we can ensure competition is maximized and prices are efficient.

The regulation of retailing should pursue low entry barriers for suppliers and low switching barriers for end-users

In 2016, CEER published a report that identified barriers to entry for energy suppliers into retail gas and electricity markets across the EU (CEER, 2016). The study also presented the actions National Regulatory Authorities had taken (or were going to take) to remove them. The major conclusions are gathered in the next box.

Barriers to retail and actions taken by regulatory authorities in Europe (CEER, 2016)

Access to data and data standardization

A major challenge identified for new entrants was related to accessing customer and market information. Also associated with data, it was identified the burden created by data management processes. Standardizing the data format and processes would be a first necessary step. Then, the most promising identified solution is to set up a data hub, taking always into account the fundamental role of data privacy when giving access to third parties.

Regulated end-user prices

Regulated prices are in the process of being phased out in Europe at least for non-household customers. Yet, as outlined in the 2016 ACER-CEER Market Monitoring Report, regulated end-user prices for households remained widespread and the process of moving away from regulated retail prices is usually very slow. The phasing out of regulated prices relies on aligning prices with supply costs and closely monitoring the development of competition. However, in Europe many systems consider the need to retain appropriate protections for some customers, even when phasing out regulated end-user prices.

Smart meters

There was a total consensus regarding the role of smart metering deployment to allow future innovation in the retail energy market.

Inefficient unbundling

The majority of National Regulatory Authorities considered that some entry barriers remained due to inefficient unbundling. One example pointed out relates to the advantage of the incumbent supplier to share an identical or similar branding with the DSO. Measures have been recently taken in this respect to avoid this advantage.

Obligations on suppliers

Licensing and contracting processes, involving obligations and guarantees are seen as a relevant barrier to entry (this was the point of view of half of the National Regulatory Authorities). While it is acknowledged that these processes are essential to ensure a safe business environment, several regulators reported efforts to reduce the impact of obligations on suppliers.

Switching process

Complicated switching processes were also identified as a relevant entry barrier. In Europe, there is a clear objective to improve gradually timeframes, up to next-day switching. However, this relies on improvements in some of the previous points, such as smart-meters deployment.

In an update of the previous analysis (CEER, 2018), some additional measures are added, such as the importance of having comparison tools to increase consumers' engagement or ensure appropriate protection for vulnerable customers.

The most commonly mentioned barriers to efficient retailing are the presence of default tariffs, inefficient unbundling (with generation or distribution), complex switching processes and the lack of proper comparison tools

The discussion on the barriers for a healthy functioning of retail markets are still at the center of the regulatory debate in the UK, the power system that first and more aggressively moved towards retail liberalization.

Prof. Littlechild (2004), Director General of Electricity Supply and Head of the Regulatory Authority at the time the liberalization was implemented, wrote about some barriers that need to be removed prior to ever consider it.

> *"In the light of UK experience, five principles seem to be fundamental to securing effective competition.*
>
> *First, effective competition needs more than simply removing the statutory barriers to entry.*
>
> *Second, there need to be enough sellers at the outset, to ensure that prices are competitive and to provide buyers with a choice of sellers. (No doubt it is also necessary to have enough buyers to provide sellers with adequate choice, but that was never an issue in the UK at the time, with twelve major supply businesses and a significant number of large users able to buy direct.)*
>
> *Third, there needs to be adequate separation and unbundling of business activities, distinguishing especially between monopoly and competitive sectors. Putting the transmission network into separate ownership was particularly important.*
>
> *Fourth, different activities within a company - such as generation, retail supply, and distribution - need to be run as separate businesses, with separate accounts. Later, this needed to be reinforced by requirements of separate staff, premises, IT facilities, and separate legal ownership.*
>
> *Fifth, operators of transmission and distribution networks need to publish charges for access. These charges must be non-discriminatory, transparent and subject to regulatory review."*

6.2 The European experience: the state of the retail market today

In the European Union, the liberalization of the retail activity has been a core part of the target model for the internal electricity market. As a consequence, there has been EU legislative packages aimed at ensuring the proper conditions for this liberalization to happen successfully. After more than 10 years since the third energy package was published (which put the focus on unbundling, among other topics), and despite all efforts to monitor and increase market competitiveness and consumer engagement, evidence shows that the overall welfare improvement seem to be very small (if any). In its last report published on Market Monitoring of the retail electricity sector, ACER (2020) does not appear to detect a positive evolution of the functioning of retail markets for electricity:

"The difference between wholesale energy prices and retail energy prices (mark-up) widened in 2019. A strong correlation between retail and wholesale energy prices is observed when wholesale energy prices increase. However, a weaker correlation is observed with regard to the rate of reduction of retail prices following a fall in wholesale energy prices (a phenomenon known as downward sticky prices). Such "sticky prices" can result in energy consumers paying higher than needed prices for their energy consumption."

We can also find some interesting figures that are quite eloquent as regards the situation today in Europe.

A shrinking business?

First of all, it is worth mentioning that the energy component has been shrinking in the last decade and this may negatively affect the retail market. Policy cost charges, network costs and taxes are gaining relevance in the tariffs as shown next. This leaves less room to retailers (in relative terms) to differentiate their offer with respect to competitors.

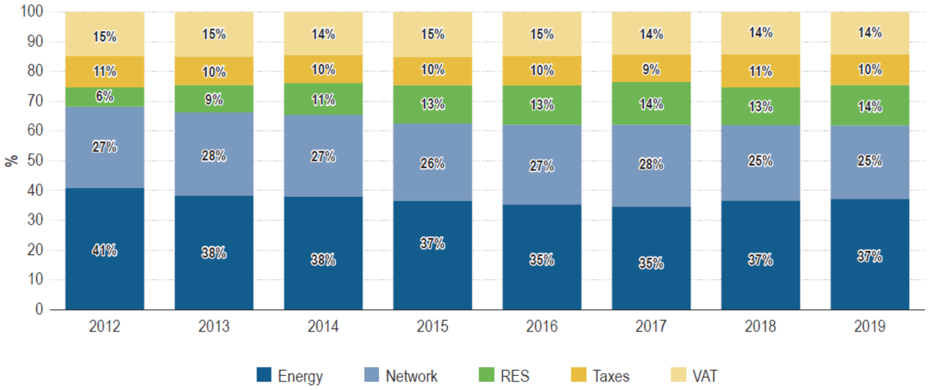

Figure 31.- Components of the electricity tariff in the UE. Source: (ACER, 2020)

Related with the gross profitability of retail activity in the different systems, we show the mark-up below. The gross 'profitability' level is the difference between prices charged to consumers and the estimated costs to supply them with energy (note that mark-ups are not the same as profits, this is because suppliers have additional operating costs not considered here). The analysis is also based on a number of assumptions, such as a rational and optimal procurement strategy.

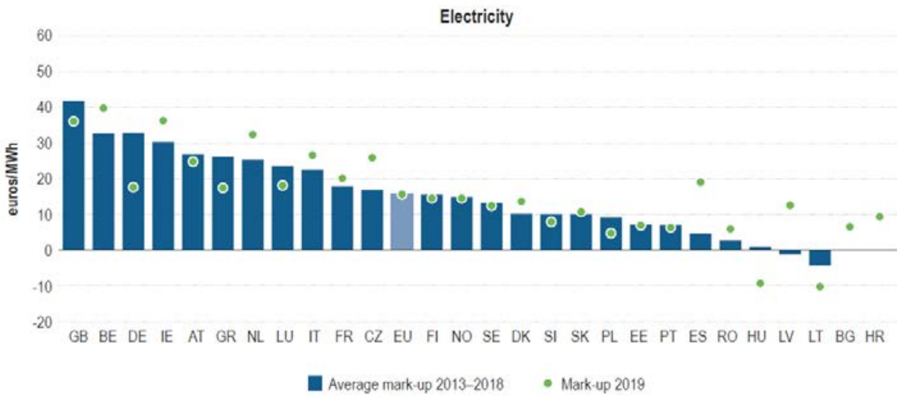

Figure 32.- Mark-up in the retail sector. Source: (ACER, 2020)

A not always competitive sector

As shown in the figures below, there are large differences regarding the number of suppliers, and what is more important: a large number of suppliers is not always synonymous of competition. We can see how 17 out of the 24 systems reviewed present HHI indexes above the threshold recommended to ensure competition.

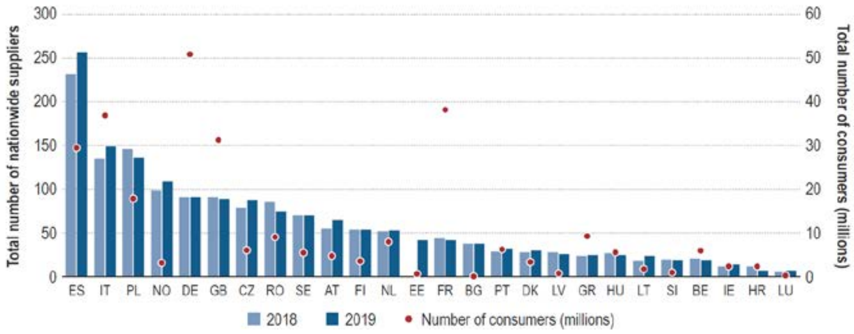

Figure 33.- Total number of nationwide suppliers. (ACER, 2020)

Market concentration (measured through the HHI) is still high in several retail markets

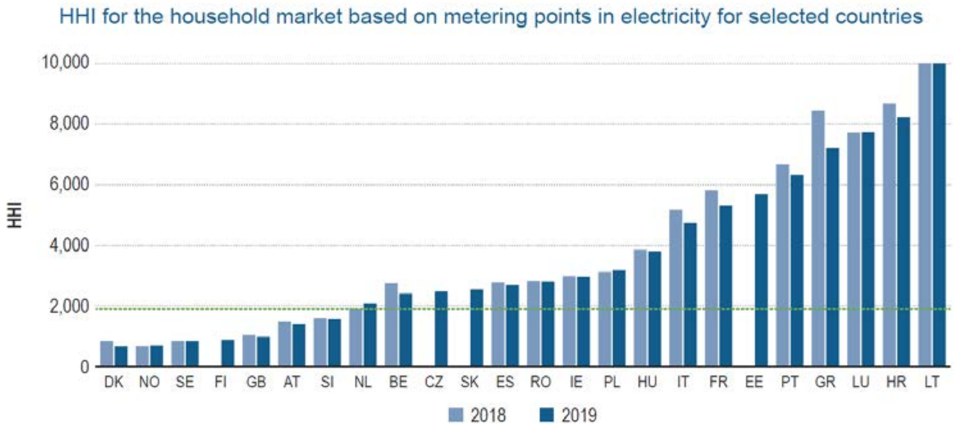

Figure 34.- HHI index in retail markets. Source: (ACER, 2020)

And finally, the major concern: the low participation of consumers in retail markets

There are 16 systems with some sort of price intervention in electricity. In 8 out of these 16, the form of intervention in the price setting is end-user price regulation, of which three countries, Cyprus, Great Britain and Spain, have a coexistence of price regulation and price intervention for vulnerable consumers.

The figure below shows the number of household consumers with price intervention when compared to the total number of households in each system. We find one extreme in Poland, where 100% of households are subjected to price regulation (due to the Price Freezing Act in 2019). In Great Britain, one of the paradigmatic retail experiences worldwide, 53% of households are still subjected to a price regulation. In France, 72% of the households. In Spain, whose regulated tariff is review in the next section, still above 40% have not moved to the free market.

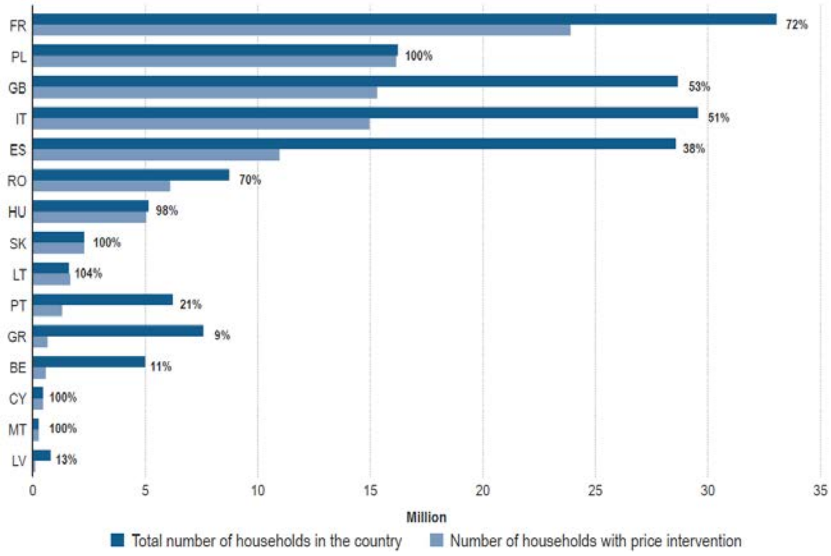

Figure 35.- Electricity household consumers with price intervention compared to the total number of households in the country in 2019. Source: (ACER, 2020)

The retail market experience in Great Britain

UK government policy was to open the retail supply market in three phases. Customers with a maximum demand greater than 1 MW a year would be free to choose their electricity supplier from 1990. In 1994 market opening would be extended to customers with a maximum demand of 100 kW, and in 1998 to all customers.

Following concern that the energy market was not working for all customers, the regulator Ofgem referred the energy market to the Competition and Markets Authority (CMA) in June 2014. The CMA report found that customers are overpaying around £1.4bn a year for energy.

Despite not being a CMA recommendation, a wider tariff cap was a key political issue and price capping appeared in both the Labor and Conservative manifestos in the 2017 election. In October 2017, the Prime Minister Theresa May announced that the Government would publish a Bill to put a temporary price cap on energy bills. On 19 July 2018, the Bill received Royal Assent and became the Domestic Gas and Electricity (Tariff Cap) Act 2018.

The cap is on the unit cost of energy, so prices can still rise if customers consume more. The cap is reviewed twice a year; in February 2019, shortly after the cap came into force, Ofgem announced increases in the levels of the caps, citing an increase in the underlying cost of supplying energy. Then in August 2019, February 2020 and August 2020, Ofgem announced reductions in the levels of the cap mainly due to falling wholesale costs. Originally intended to end in 2020, the Government has extended the cap to December 2021. The Act allows the cap to continue until 2023 if needed.

Poudineh (2019) argues that "the reference design of the retail electricity market in the post liberalization era has not only failed to achieve its original objectives but has also proved to be unfit to keep pace with technological change, consumer preference, and the energy transition." He considers that a number of reasons are behind this failure: among many others, the lack of consumer engagement (currently more than 50 per cent of consumers have never switched), the fact that electricity is considered as an essential service by sector regulators and the growth of government wedge and policy costs. Other authors add many other reasons: lack of efficient unbundling, vertical integration, narrow room for creation of added value, etc.

After more than a decade of full retail liberalization in Europe, the retail market has not yet been able to evidence its expected benefits; in some of the more mature markets (as, for instance, the UK or Spain), regulators have decided to keep a sort of default protection for domestic customers

6.3 Regulated tariffs

The liberalized electricity retail business can co-exist with some form of regulated tariffs. These regulated tariffs usually pursue two objectives:

- Ensure the supply for a short period of time to consumers who do not have a contract with a retail company (e. g., because the previous contract has ended and there is no new contract, due to bankruptcy of the retail company, etc.),
- Determining a tariff that competes with the liberalized market, and that usually only applies to certain consumers segments (e.g., residential customers) that the regulator wants to protect from market risk.

The first type of tariffs is often known as "last resort" or "back-up", while the second is known as "default tariff". It is worth mentioning that the previous two objectives can be achieved with the same regulated tariff, and also that the regulator might decide not to determine the tariff itself, but to impose guidelines to retailers on how to set the previous tariffs.

Next, we focus on default tariffs design.

6.3.1 Default tariff design

As it has just been mentioned, default tariffs' objective is to offer certain consumer segments a safety net in the market, but we cannot ignore that this is a tariff alternative designed by the regulator that would compete in the retail market. Since the concept in itself is clearly controversial, the only default tariff that can make sense is the one that is as much as possible cost-reflective[37] and that include the least-possible regulatory intervention. A tariff that is subsidized and below market prices represents an unfair competition and eventually would kill the retail market. Default tariffs need also to avoid, as much as possible, being the sole regulator's tool to allocate some system costs (like legacy costs, more on this in subsection 6.4).

Provided the previous principles, there is still one major decision to be taken by the regulator in the design of the default tariff: whether or not to use hedging strategies so as to reduce consumers' exposure to energy market risk.

In this respect, we find two extremes, each one presenting advantages and disadvantages:

- Make a pass-through of the short-term market price with no hedge for the consumer. The accuracy of the signal depends on the regulator's willingness to do so and of course on the deployment of the proper technology, such as smart meters. The case of the regulated tariff in Spain, briefly analysed below, is a paradigmatic example of this approach.
- Contract the energy in advance in the so-called default energy auctions. Although there are experiences worldwide, the paradigmatic example is found in South America, where regulated tariffs have been historically determined with this approach (this is also briefly reviewed below).

[37] See section 4.

Default tariffs must be cost-reflective and introduce the least-possible regulatory intervention. A tariff that is subsidized and below market prices represents unfair competition and eventually would end with the retail market. Default tariffs need also to avoid, as much as possible, being the sole regulator's tool to allocate some system costs

6.3.2 A cost reflective default tariff: the default tariff in Spain

The Voluntary Price for Small Consumers (*Precio Voluntario al Pequeño Consumidor*, or PVPC, in Spanish[38]) is the electricity price-setting system that was introduced by the Spanish Government pursuant to Royal Decree 216/2014. It is applied to the electricity bill of those consumers whose contracted capacity does not exceed 10 kW. The electricity bill has two main components associated with the energy consumed (there is also a capacity charge, that is indeed quite relevant as seen back in section 4.8):

i) A dynamic hourly price resulting from the direct pass-through of the day-ahead and intraday market prices plus the cost of ancillary services for the day after;

ii) The access tariff, fixed by the Government to cover all the regulated costs (namely network and policy costs); consumers can opt for three different formats for this access tariff:

a) 2.0 A, a flat rate for the 24 hours of the day;

b) 2.0 DHA, a two-period tariff (night and day, the first at an extremely low price and the latter at a price around 20% higher than the flat one in 2.0 A),

c) 2.0 DHS, which includes a third period, the so-called super valley (from 1:00 to 7:00) at a close to zero price, aimed at incentivising the night charging of electric vehicles.

Red Eléctrica de España, the System Operator, publishes each day the electricity pricing schedule that will be applied in each of the 24 hours of the following day (Figure 36).

This scheme conveys a price signal connected to the short-term market, that allows consumers to decide in advance whether and how to manage the electricity consumption.

During January 2021, two extreme situations were observed, that help understanding the capability of this design to convey wholesale market signals:

- During the first weeks of January 2021, the cold weather across Spain together with the partial confinements due to Covid-19 pushed up the demand for gas and electricity. On to of this, gas supply was also affected by tube supply problem and the CO_2 price was around 45% above last year January price. All this created the perfect storm in the electricity market, leading to energy prices above 120€/MWh in the spot market. This was the case for example on January the 9th. These prices were passed through to the regulated demand as shown in the figure below. The figure (taken from the Spanish System Operation

[38] www.ree.es/en/activities/operation-of-the-electricity-systemvoluntary-price-small-consumer-pvpc

webpage), shows the hourly prices that were charged to the three aforementioned tariffs: 2.0 A (the profile in red), 2.0 DHA (the profile in blue) and 2.0 DHS (the profile in green). The different shade of colors corresponds to the additive charges that make up the energy tariff at 20 hours (where the maximum price was achieved that day). The four more relevant charges are the price of energy in the day-ahead and intraday market ("Mercado diario e intradiario"), the ancillary services costs ("Servicios de ajuste"), the access tariff ("Peaje de acceso") and the capacity mechanism charges ("pago por capacidad"). As it can be observed, the energy price was 145.87 €/MWh at 20 hours.

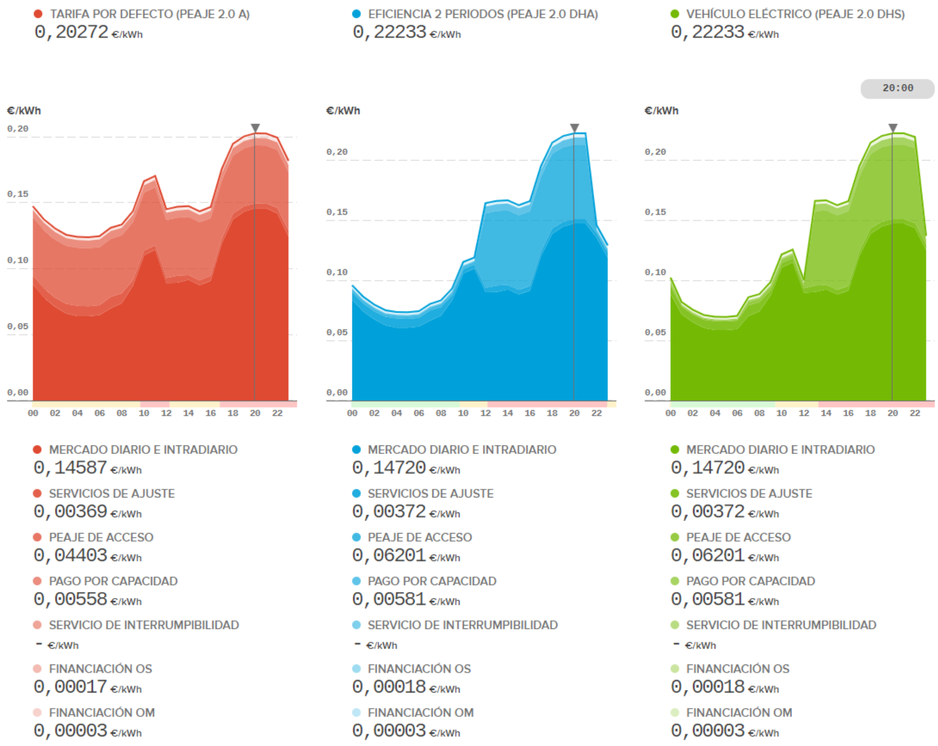

Figure 36. Voluntary Price for the Small Consumer for January 9th, 2021 (www.ree.es)

- Just a couple of days after the previous event, temperature stabilized and intermittent production (mainly wind) experienced a relevant increment in production. As a consequence, Spain experienced the lowest prices in the market in the last two years. As a way of example, it is shown below the PVPC prices during January the 30th. In this case, the "wholesale market signal" is equal to 1,6 €/MWh during the peak demand hour.

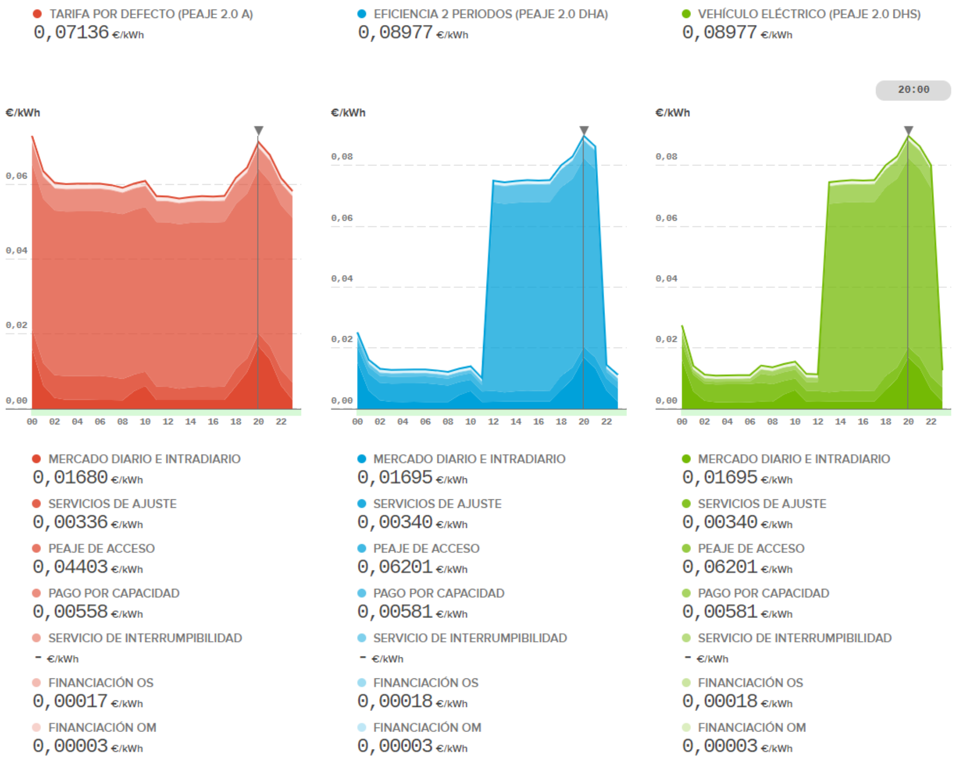

Figure 37.- Voluntary Price for the Small Consumer for January 30th, 2021 (www.ree.es)

6.3.3 Default tariffs based on medium to long-term energy auctions: the case of South America

In South America, it is usual to organize two different types of auctions, or at least sign two different types of contracts with generators. On the one hand, new investments are offered long-term contracts (often in auctions for new capacity), whose objective is to provide stable conditions so as to ensure building the new plants. On the other hand, existing generation are offered shorter term contracts (around one year, often in auctions for existing capacity). The objective of these latter contracts is to set the default tariffs in a competitive way. This way the price is established ex-ante.

Brazil

One of the paradigmatic examples of this approach is Brazil. In Brazil separate auctions are organised for new and existing power plants. The so-called A1 auctions are designed as a sort of default service auctions -i.e. to set the default tariff prices, and thus they are just targeted to existing power plants. The auction implementation details are similar to the A3 and A5 ones, except for the fact that, since the objective is different (set tariffs in the short- to medium-term versus bringing in new generation facilities), the contract due dates are much shorter (1-year lag period, 1 to 15 years contract duration, decided by the government). In the case of the A1 auctions, adjustment auctions are available four times per year, with a lag period of 4 months and contract duration of 1 to 2 years. However, distribution companies can procure in these auctions only 1% of their demand.

The problem of using one single contract to achieve both objectives

In Peru, the scheme introduced in 2006 (Law 28832) was based long-term electricity auctions, which were supposed to achieve the double aim: to define the energy tariff in a competitive way and at the same time serve as a tool to enhance the entry of new and efficient generation in the system. The reform introduced the obligation for distribution companies to contract the expected demand of their captive consumers three years in advance (i.e. the lag period), signing contracts (with existing and new plants) that must have durations larger than five years for 75% of the demand. Even if the scheme is completely decentralised, a strong regulatory control on the auctions was applied. The auction format and indexation formulas must be approved by the Regulator, who also sets a price cap for each auction. At the moment of setting the lag period and the contract duration for the auctions, the two abovementioned goals resulted in the choice of a compromise solution.

If energy auctions are to be used for the determination of the default tariff, it is important to decouple them from those used to bring new power plants to the system (if they are to be used).

6.3.4 What is the recommended level of hedging in default tariff setting?

There is no one-solution fits all as to which is the optimal hedging strategy for the default tariff. This obviously depends on many factors, among others:

- Whether there is a mechanism that ensures adequacy,
- what type of scarcity conditions the system is prone to suffer, and
- what is the maturity of the market both at the wholesale and retail levels.

In the case of Spain, for example, there is overcapacity and scarcities seldom arise. This situation is clearly different from the one a hydro-dominated system has to face. Nevertheless, it is worth noting that there is whole greyscale of alternatives in between making a pass-through of the short-term maginal price and contracting in advance 100% of the consumption. Contracting a certain percentage, and trying to convey the short-term market signal as much as possible seems to be most efficient approach no matter the context. Note that hedging consumers does not mean that they cannot perceive the short-term market signal.

In what respects to default tariff design, contracting a certain percentage in advance, and trying at the same time to convey the short-term market signal as much as possible seems to be the most efficient approach

6.4 Legacy costs, inefficient and inequitable arbitrage and exit fees

As it was the case back in the early nineties when the liberalization of the electricity generation side was implemented in a large number of electricity systems, the current context exposes regulatory design to a major dilemma. The fast-learning curves of renewable and distributed resources are significantly reducing long-run marginal costs on one side, and on the other, might also be reducing the utilization of transmission and distribution networks. These factors can lead to turn those generation and network investments into sunk costs. If regulatory design is not properly developed, particularly the retail and end-user tariff sides, there is a high risk to lead the system to an unbalanced, inequitable and thus unsustainable situation, which would quickly turn to be economically and socially unbearable.

This is not at all an unprecedented problem in the electricity sector. Prior to delve in the matter in the current context, it is worth introducing the previous experience.

The precedent: stranded costs at the wholesale market liberalization

In the majority of jurisdictions, the electric energy markets started operation in a context in which long-run marginal energy prices were expected to be lower than average energy prices at the time. Indeed, combined cycle generation plants were assumed to be able to gradually set market marginal prices at levels that would not allow to recover the investment costs of a good part of the generation investments made until that moment. The fact that those investment had been made in a regulated environment led to the conclusion that the costs that were assumed not to be recoverable in the market scheme, the so-called stranded costs, needed to be compensated in any way.

For instance, the Public Utility Commission of Texas[39] defined two concepts, "stranded investments" and "potentially strandable investments." The first ones were defined as the historic financial obligations of utilities incurred in the regulated market that become unrecoverable in a competitive market. Those generation investments (or contracts signed with independent power producers) were expected to become "unrecoverable in a competitive market" because upcoming energy market prices were supposed to be below regulated prices. Since generators could not charge as much in a competitive market as it was charged in the rates in the regulated context, a portion of the assets became "stranded". The term "potentially strandable investment" reflected the fact that the portion of potentially strandable investments was unknown. Costs may become stranded because the customer leaves a regulated utility for a market-based source of supply or simply due to the difference between the previous regulated price and the new market price.

Stranded costs recovery

A methodology of stranded cost recovery must be determined. A key first step is identifying who is responsible for the cost being stranded.

[39] http://www.psc.state.ga.us/electricindust/5d.htm

Some claim that the formation of a regulated monopoly was intended to provide the utility a return on capital, for the exchange of a fair price structure, but that it was never the intent of the regulatory compact to guarantee the full amortization of all investments in all future situations.

Others hold the "regulatory compact" argument: the obligation to provide electric service invoked by regulators in exchange for monopoly status led electric utilities to invest to ensure safe and reliable service. In exchange they were guaranteed recovery of these investments plus a fair rate of return. As the regulator contemplated moving from a regulated market to a competitive market, utilities could not be penalized due to change in the rules of the game, so stranded costs could not be borne by their shareholders.

The solution adopted in most jurisdictions entitled retail providers to full recovery of the stranded costs over a reasonable period of time, through a non-bypassable Stranded Cost Recovery Charge imposed on end-users. A key condition was that no class of customers could be assessed a stranded cost recovery charge in excess of the class's proportional responsibility.

Two main factors had to be decided when it came to design the methodology to recover the stranded costs: how much should be compensated, who had to pay for it?

Regarding the first question, the key factor had to do with the previously mentioned fact that often a portion of the potentially strandable investments was unknown. Therefore, the solution had to be between two extremes: i) to make the best forecast possible of these future costs (estimating market prices, demand evolution, generation production, etc.), and stick to that estimate, or ii) keep track as time passes of the actual stranded costs as those unknown variables are revealed. The first option is clearly subject to the risk of over or underestimating the actual amount of stranded costs, but on the other hand it has the advantage of exposing the utilities to the marginal prices in the future (keeping the incentive to make maximize efficiency and profits in the market, as the amount of stranded costs to be recover would not be affected).

When it came to decide who should pay roughly speaking, three alternatives were considered to allocate the burden: i) tax-payers, i.e. allocate the costs to the National or State budget; ii) end-users, i.e. allocate the costs among all energy consumers; iii) residential end-users, i.e. allocate the costs only among residential customers, exempting industrial customers.

In those cases, in which the utility subject to stranded losses was a publicly-owned company, the decision not to compensate the company corresponded to the first alternative, as it were the taxpayers the ones who implicitly were bearing the burden. This was for instance the case in the UK, in which the state-owned company CEGB was split in smaller companies and later sold in the market: taxpayers borne the cost of the write off[40]. In other situations, the decision of the

[40] Steve Thomas, 2004. The British Model in Britain: Failing slowly. March 2004. https://core.ac.uk/download/pdf/67061.pdf

regulator was to evaluate annually the actual unrecovered costs to compensate the generators accordingly[41].

The current context: the new stranded costs and their impact on retail prices

Essentially, from the stranded cost perspective, the current situation does not differ much from the one described above. Long-run marginal costs are decreasing below current market price levels, and more importantly, below prices signed in long-term contracts. On top of that, end-users have to bear the costs of different sorts of the so-called policy costs. The immediate consequence is that, if tariffs and charges are not properly designed, there is a certain risk that those end-users who have been under the protection of regulated tariffs could opt out from them to benefit from a free arbitrage that would leave the burden on those other end users that for whatever reason could not do it.

The migration of end-users who can choose to remain under the regulated tariffs or contract with a retailer in the market exposes the distributor (the regulated retailer in the Peruvian context) to scenarios of low marginal costs, such as the currently existing one. On one side, regulated retailers should not be exposed to such volume risk, and on the other, the users who cannot or simply do not switch should not bear with this cost burden either.

In those systems in which regulated rates are based on short-term agreements (i.e. in which the medium- to long-term price volatility risk remains on the side of end-users, e.g. the dynamic rates implemented in Spain previously introduced), there is no risk of overcontracting. But in those other systems in which regulated retailers (distributors) are entitled to hedge regulated customers against the long-term energy (and/or capacity) price risk, this opportunistic migration would certainly lead to significant inequities.

Fixed charges or exit fees to avoid inefficient opportunistic switching to the free market

There are three main alternatives to deal with this problem. One of them consists of take these potentially stranded costs out of the electricity rates paid by all electricity consumers, including them as an extra item in the national budget, ultimately defrayed by taxpayers. This is for instance the solution that Dieter Helm, the energy and climate advisor of the UK Government defends[42]:

"*In the Cost of Energy Review, I suggested that these legacy costs should be put in a legacy bank, so as not to distort the market, to allow prices to fall and hence customers to benefit from the falling costs of renewables and probably gas too. (…) these legacy costs should be socialised. (…) Government acts ultimately on behalf of the citizens, and pays its bills from taxation and borrowing. Ultimately the unfortunate taxpayer is in the firing line if – and it is an important if – the government wants well-functioning competitive energy markets.*

[41] Amorim, F., Vasconcelos, J., Abreu, I., Silva, P., Martins, V., 2012. Assessment of legacy generation contracts' costs in the future Portuguese electricity system. 9th International Conference on the European Energy Market.

[42] Helm, D., 2019. Why aren't electricity prices falling? 1st February 2019. http://www.dieterhelm.co.uk/energy/energy/why-arent-electricity-prices-falling/

The task would be made easier by the very low cost of debt. Taking the legacy costs into a legacy bank could be facilitated by borrowing the offsetting amount. The legacy costs are in effect a giant Regulated Asset Base (RAB), and since real interest rates are still negative, the costs could be gradually written off. Indeed, with negative real interest rates, from the point of view of UK plc, there are no extra costs, but rather a financing problem. At say a cost of minus 2% real interest, very gradually the costs could be written off over the next decade. This would be made easier because many of the legacy costs are for time-limited contracts, which expire in the middle of the next decade."

Alternatively, these new stranded costs could receive the category of residual costs, and could be allocated among all end-users via the regulated access-to-the-network component in the tariff, as discussed in section 4.4.

Finally, an increasingly considered alternative is to design an exit fee to be charged on those end-users that would decide to migrate from the regulated rates[43]. Regulatory Authorities can calculate a customer's pro rata share of the utility's book costs, and then require the customer to pay that cost on departure—either in a lump sum, or as an adder to the customer's continuing purchases of whatever monopoly service the customer still needs.

Next, two practical examples illustrating this alternative are introduced.

The PCIA in California

In the US, Community Choice Aggregation (CCA) is becoming a prevalent method for local communities to source electricity. Under these programs, groups of end-users, cities and local governments generate or buy electricity, usually from renewable energy sources.

CCAs, which are in the majority of cases administered by the local government, purchase the power, while the incumbent utility maintains the grid and provides customer service. As of 2017, seven states (Massachusetts, Ohio, California, New Jersey, Illinois, New York, and Rhode Island) have passed legislation enabling communities to form CCA programs and another six are exploring CCA options.

The problem we are referring to is clearly discussed by the California Public Utilities Commission:

"In California the law explicitly clarifies the problem we discuss in this section: "The implementation of a community choice aggregation program shall not result in a shifting of costs between the customers of the community choice aggregator and the bundled service customers of an electrical corporation." This prohibition against cost shifting between customers is known as the "indifference requirement." The indifference requirement is necessary due to the mandate of the Commission and the Legislature directing the Joint Utilities to procure extensive generation resource portfolios on behalf of their then-bundled service customers (and anticipated load growth). Those generation portfolios include many long-term renewable energy contracts, several of which were required by (and all of which were explicitly approved by) the California Public Utilities Commission. As the Commission recently explained, over time market prices have dropped to levels significantly below those underlying the Joint Utilities' generation portfolios. These

[43] Hempling, S., 2015. From Streetcars to Solar Panels: Stranded Cost Policy in the United States. Energy Regulation Quarterly. Volume 3, issue 3, 2015.

portfolios were procured for all of the then-bundled service customers (plus anticipated load growth). If CCA service does not carry with it the obligation for customers to pay for their pro rata share of those portfolios' costs, the costs of those portfolios will be unfairly shifted to the remaining, shrinking pool of utility bundled service customers.

The Power Charge Indifference Amount (PCIA) is the Commission's ratemaking mechanism designed to recover the pro rata above-market costs of the Joint Utilities' generation portfolios from departing load customers."

The Power Charge Indifference Adjustment (PCIA) ensures that the customers who remain with the utility do not end up taking on the long-term financial obligations the utility incurred on behalf of now-departed customers. Examples of such financial obligations include utility expenditures to build power plants and, more commonly, long-term power purchase contracts with independent power producers. The PCIA is billed as a monthly charge by the utility that appears on the CCA customers' bills. The intent of the PCIA is to ensure that all customers (utilities and CCA) pay a fair share of the utility's power cost obligations, and avoid inequitable cost shifting when CCAs begin providing power to local residents.

Legacy costs in the Brazilian electricity market

The Brazilian electricity system regulation is a good and illustrative example of increasingly good practices to deal with the legacy costs allocation imbalance.

The Senate Bill (PLS) No. 232/2016, still under discussion in the Senate, contains two provisions aimed at designing charges for consumers who migrate from the regulated market. The first deals with the costs of financial operations that, in general, have contributed to the low tariff (for instance the case of the Covid Account, introduced right below). The second deals with the costs related to over-contracting generated by the migration of consumers to the free market.

The Provisional Measure (MP) No. 998/2020 recently passed is the first legal instrument that determines that a consumer, when migrating to the free market, will carry with it some legacy cost from the time when he participated in the regulated market. The cost in question is the so-called "Covid Account", through which loans were made to distributors during the year 2020 so that they could cope with the impacts on the load and default, resulting from the Covid-19 pandemic and the social distancing.

The allocation of legacy costs has to be designed in a way that there is no room for inefficient opportunistic switching to the free market

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