Regulation of Public Utilities of the Future in Latin America and the Caribbean:

The Argentine Electricity Sector

Santiago Urbiztondo
Fernando Navajas
Diego Barril

Department of Research and Chief Economist

TECHNICAL NOTE Nº IDB-TN-1804

June 2020

Regulation of Public Utilities of the Future in Latin America and the Caribbean:

The Argentine Electricity Sector

Santiago Urbiztondo*
Fernando Navajas*
Diego Barril**

* Fundación de Investigaciones Económicas Latinoamericanas (FIEL)
** Development Bank of Latin America (CAF)

June 2020

Inter-American Development Bank

Cataloging-in-Publication data provided by the
Inter-American Development Bank
Felipe Herrera Library

Urbiztondo, Santiago.
Regulation of public utilities of the future in Latin America & the Caribbean: the Argentine electricity sector / Santiago Urbiztondo, Fernando Navajas, Diego Barril.
p. cm. — (IDB Technical Note ; 1804)
Includes bibliographic references.
1. Electric utilities-Law and legislation-Argentina. 2. Public utilities-Law and legislation-Argentina. I. Navajas, Fernando. II. Barril, Diego. III. Inter-American Development Bank. Department of Research and Chief Economist. IV. Title. V. Series.
IDB-TN-1804

http://www.iadb.org

Contents

Abstract[*]

This paper presents an analysis of the main challenges faced by Argentina, regarding both institutional and tariff + taxes + subsidies accommodations, to properly handle the new opportunities behind Distributed Energy Resources (DER). Regarding electricity prices and tariffs, examining fixed and variable distribution margins in particular, the paper computes the rebalancing pre-tax tariff corrections—keeping constant net distribution incomes—in various jurisdictions, requiring in all cases much higher fixed charges and lower variable charges than today in order to better reflect fixed and variable distribution costs, a pre-requisite to efficient DER development. While efficient in the longer run, such tariff adjustment is shown to have distributional impacts, which can be dealt with by compensating fixed transfers to the poorest 30 percent of users at a relatively low cost. Taxes and subsidies pursuing social and environmental goals also need major restructuring to be efficient and consistent with price signals leading to socially efficient decentralized decision. While these corrections are neither minor nor politically insignificant, a failure to accommodate institutional + pricing + subsidy + tax rules and criteria will eventually lead to unsustainable distribution networks or inefficient duplication of costs.

JEL classifications: L51, L94
Keywords: DER, Network sustainability, Tariff rebalancing, Welfare impact

[*] This technical note was undertaken in preparation with the Inter-American Development Bank 2020 Development in the Americas report *Improving Infrastructure Services in Latin America and the Caribbean*.

1. Introduction

Public utilities are currently subject to structural changes due to three main elements—new climate change policy objectives, stronger distributional concerns, and potentially decentralized new sources of supply—which in turn affect the "regulatory compact" (institutions, policies and instruments) best fitted to deal with them. The new regulatory compact best fitted for this task can be called "(optimal) regulation of the utilities of the future," where the meaning of "optimal" is of course constrained to each particular environment.

This paper examines the electricity sector in Argentina in order to provide answers to the following questions:

- What are the main challenges posed by structural changes in this industry, and what is the cost of not adapting regulation to properly respond to them?
- How distant are current regulatory policies and instruments regarding those needed to properly regulate the "electricity sector of the future"?
- What are the fundamental corrections that should be pursued now, both in terms of institutional, policy and instrumental dimensions?
- What are some of the challenges emerging after those corrections?

The next section deals with the identification of the key elements that characterize structural changes in the electricity markets—namely, current and potential developments regarding universal access / distributive concerns (social tariffs), environmental demands (on the structure of the generation matrix) and the emergence of Distributed Energy Resources (DER)—and the corresponding regulatory adaptations necessary to efficiently regulate the electricity sector. One fundamental question is why should the implied reforms be urgently carried on this time? The answer to this question starts with recognizing the costs emerging from the status quo, i.e., the costs of not reforming the current regulatory compact (institutions, policies and instruments) in the face of the new anticipated environment. In particular, if regulation does not respond properly to those new demands, the outcome (in terms of overall prices, tariffs, costs, quality, coverage, etc.) will sacrifice competition and decentralized information, as well as reduce and misplace efforts and investments that would have helped to transform the sector by allowing diversification of quality / security / regularity according to individual preferences. Not adapting the regulatory compact makes users of the electricity service likely to remain trapped in an increasingly obsolete and artificial monopoly situation.

As Section 2 further discusses, the initial uncertainty and dispersed information which are natural in such a dynamic technological and preferences' environment suggest that regulatory features must include a setting where the regulator of the electricity sector can act as a sort of judge once all involved parties have had a real chance to participate, settling agreements accommodating their interests, as the regulator's anticipated intervention represent the main mechanism inducing agreements in the first place (see Glachant, 2012, and Littlechild, 2011). This means that the regulator will have to be sufficiently autonomous and technically sophisticated, subject to open discussion and public hearing practices, administering a policy for the electricity sector that limits regulation to those markets / activities / assets where competition is too weak or unfeasible, and committed to the promotion of (non-opportunistic) competition whenever that is possible, with a clear sense of the need to attend universal service / distributive demands in the least distortive way (not averting competition nor promoting consumption inefficiencies or miss-focalized assistance). He will also have to be engaged in inter-jurisdictional contacts and interaction to coherently revise externalities and needs to adopt specific solutions or generally applicable average requirements, leading downstream regulation of transmission and distribution (T&D) to reflect true network costs (fixed and variable, seasonal, locational, etc.).

Indeed, we believe that such new regulatory setting and global rules applying to the regulatory decision-making process constitute necessary conditions to adopt the pricing reforms required to correctly represent incurred and avoided costs in the electricity sector, particularly considering the complex pricing devices characterizing multi-sided markets (i.e., markets where buyers and sellers meet because of the facilitating services of a mediator whose role is the reduction of transaction costs to increase participation of agents in both sides, exploiting the positive cross-externalities between them) that might develop within the digital platforms placed inside the existing distribution networks (see Peterson and Ros, 2018, also Costa et al., 2018).

The third section briefly explores the current argentine regulatory compact in the electricity sector, particularly regarding its main institutions, to assess the viability and difficulty of implementing the reforms previously identified. We conclude that various improvements are required in order to implement better regulations that address the new and prospective technological, environmental and social context.

Section 4 subsequently discusses specific corrections regarding retail pricing, social tariffs and taxes, which should be advanced immediately in order to set the correct stage for more detailed adaptations to be adopted later on based on technological developments and decentralized information effectively observed and collected in each provincial regulatory setting, preparing the electricity sector to be receptive to the foreseen structural changes (i.e., allowing them to emerge if it is efficient for them to do so). In particular, we compute the tariff changes that would seemingly be most efficient in terms of cost-reflection, in what we call a "tariff-rebalancing exercise," and examine the consequences in various areas.

The tariff-rebalancing exercise looks into the change of the tariff structure of residential users in the *Area Metropolitana de Buenos Aires* (AMBA) that leaves unchanged the total net (distribution) income received by one of the two local distribution companies (Edenor, which covers close to 50 percent of the total area in AMBA, while Edesur covers the rest), imposing first that all residential users face the same fixed and variable distribution charges, and that fixed charges jointly allow coverage of 70 percent of total distribution costs (so that fixed and variable residential distribution charges better reflect the annual averages of fixed and variable distribution costs). This exercise allows us to compute the impact of such rebalancing of distribution tariffs on allocative efficiency (the sum of gains by various residential users, regardless their type) and various measures of total welfare, as well as to compute the fiscal cost of implementing a compensating transfer to various deciles of poorest users (which would then become a social tariff where targeted users receive rebates but face the same marginal price and tariff signals as everyone else). We further inform about the ongoing distortions caused by current (sizable) taxes applied on the electricity supplied through distribution companies but exempted for self-generated DER (calling for a revision of current discrimination), and show that such tariff rebalancing in AMBA is qualitatively similar to those that will be required in the rest of the country.

The final section of the paper concludes with a brief discussion of some of the more specific regulatory issues ahead.

2. Efficient Regulation of Electricity in the Face of Structural Changes

The electricity sector is facing a new wave of technological changes with profound consequences for the structure of demand, supply and the infrastructure supporting the electricity service, including the following main features:

- distributed energy resources (DER), which chiefly include intelligent meters, distributed small-scale solar (PV) and wind generation, low-cost battery storage, consumption programming devices and electric vehicles;
- uncertainty about costs of new distributed generation alternatives;
- insufficient knowledge about the necessary investments to adapt the existing distribution network to a multidirectional use, where *prosumers* inject their own excess self-consumption generation to the network;
- the possibility to differentiate quality / reliability / firmness for each individual user, according to the different time-patterns and seasonality of their withdrawals for own consumption and injection of excess self-consumption generation; and
- growing opportunities for multiple transactions among different agents in the sector, facilitated by new computing and information technology available, in which the roles played by consumers and producers change in different circumstances (buying and selling energy or associated services), requiring the development of platforms at the distribution and perhaps also at the transportation network.[1]

A great deal of these technological developments has been driven by decarbonization policy constraints put on energy systems (see, for example, Hansen and Percebois, 2017, and Natale et al., 2018, on Argentina). Besides, social and distributional concerns where access and affordability are main issues also shape policies.

Thus, in order for these new technological alternatives—which would redefine the electric service of the future—to materialize if it is efficient that they do (which is impossible to know for sure based on current information, taking into account not only the different costs and

[1] Villar et al. (2018) point out the path towards decarbonized, clean and more efficient energy generation and consumption mechanisms, giving place to a new environment characterized by increasing investments in renewable generation, renewable generation uncertainty, low variable costs of renewable generation, increasing Distributed Generation (DG), Energy Storage Systems (ESS), Electric Vehicles (EV), and a more active role played by consumers.

possibilities presented by the new technologies in different parts of the country but also the unknown availability in quantity and costs of alternative generation sources–i.e., natural gas nonconventional resources in Argentina), the incentives faced by all players need to be conducive to an efficient outcome. In that regard, *economic regulation has to maximize the probability that efficient transactions among the various actors in the energy sector take place*, assuring that each player who is interested in participating of decentralized investments and exchanges could do so facing the real (social) costs of her/his decisions. This in turn demands that technical and tariff issues applicable to a changing environment will have to be resolved subject to highly asymmetric and decentralized information, meaning that the current centralized and unilateral mechanism of regulatory intervention must be deeply revised. Indeed, its reform must include provisions for maximizing the participation not only of final users ("*consumer engagement*") but also that of all economic, social and environmental agents and representatives with various interests in the electricity sector, assigning the regulator the (most complex) task of allowing and promoting that such decentralized information, actions and incentives jointly show which is the right way to follow, including flexible correction mechanisms to adjust the initial steps if they were wrong or became obsolete.

Indeed, the main elements stressed by various authors are highly coincident and consistent with each other: although there is a significant degree of uncertainty regarding the exact technological changes ahead, there are coincident views that the institutional, policy and instrumental settings should be designed and prepared to let the best technology succeed according to dispersed preferences on a level playing field, while not forgetting that the current electricity network and its reformed version, whatever it might be, will still be necessary to assure regular, continuous and universal electricity service for at least some decades ahead.

2.1 Institutional and Procedural Practices

The consequences of more complex regulatory issues and increased asymmetry of information, combined with easier informational mechanisms to allow active participation of interested parties in the regulatory process and the overall requirement of transparency to reach political acceptance of sometimes unpopular decisions, have been discussed in the literature regarding both current regulatory practices and recommended adoption of institutional and procedural innovations in somewhat old-fashioned settings. Littlechild (2011) and Glachant (2012), in particular, are in favor of more consumer engagement, for various reasons. Glachant (2012), for instance, argues that if the regulator gives priority to its independence or neutrality, it should set open spaces of rivalry and cooperation between the various stakeholders in arenas, allowing a reduction of the asymmetry of information and its manipulation by interest groups, perhaps through public “posting,” which would serve as a public display allowing recurring alterations to be immediately visible to all in the manner of a collective “post-it” or a blog of regulation-making. Glachant (2012) also notes that regulation through open arenas provides an incentive for smaller interest groups to participate, allowing better reciprocal control of strategic manipulation of biased representations by one side or the other.[2]

In any case, Glachant argues that regulation by an “open arena” leads to focal points in which expectations converge to create a space of common beliefs and consistent behavior, and that in order for these arenas to work properly regulators must nurture their dynamics by accounting for the interests of the various stakeholders, in the same way that a platform administrator would do. The regulator thus would assume a central role in recognizing the “constraints on participation” facing the various interests in the regulatory interplay and would run the regulatory arena as a “***regulation-making platform***” in the sense of the economic theory of two-sided markets. Notably, the regulator can induce cross-subsidization between the various stakeholders as a function of their propensity to pay and participate, and thus maximize total participation (particularly facilitating the participation of groups less inclined to do so).

In our view, this two-sided market perspective on the best regulatory process under strong asymmetric, dispersed and evolving information—which gives place to the development of various levels of platforms (in the business model, to allow flexibility of peer-to-peer exchanges; and in the regulatory process, to allow balanced participation of different interest groups)—is an excellent idea. There are complementary benefits emerging from the partial and biased perspectives and information of various stakeholders (final users, generators, retailers, aggregators, distribution companies, technology developers, etc.), which need to be collected and processed by the regulator, recognizing the innate inclinations and difficulties of these various stakeholders to spontaneously participate in the regulatory process; once sufficiently complete participation is reached, the actions finally adopted by the regulator will be closely scrutinized

[2] For a formal treatment of the idea of social benefits from open standing in administrative and regulatory processes, see de Figueiredo et al. (1999).

considering its correspondence with the arguments and information disclosed at the regulatory arena, so regulatory decisions will tend to be better grounded and more accepted by all parties affected by it, providing more efficiency and substantial stability to that process (until new information or arguments come along). This reduces regulatory risk and the cost of capital, optimizing decentralized investment, production and consumption decision-making.

2.2 Disruptions Introduced by Decentralized Energy Resources (DER)

Corneli and Kihm (2015) note that the emergence of DER transforms the electricity sector through three major changes:

1. The new competitive alternatives to energy and capacity supplied by the bulk electricity system—the "grid"—will dramatically increase customers' elasticity of demand for electricity, leading to downward pressure on both utility profitability and cost structures.
2. The natural monopoly of the distribution utility will be eroded: DER will improve customers' energy costs, resilience and quality of service, but they can also help utilities to avoid risky capital expenditures and operate their systems more efficiently.
3. Utilities could have a fundamental role in supporting this lower cost, higher value service provided when *prosumers* are coordinated not only to provide customer services but to also to create value for the distribution utility and the grid as well.

MIT (2016) contains an in-depth study directly oriented to characterize the technological changes within the electricity sector and the regulatory requirements to properly deal with them. This study basically proposes a framework designed to establish a level playing field for the provision and consumption of electricity services, which would select the combination of centralized and distributed resources based on their relative efficiencies, taking into account that such a regulatory environment requires the removal of inefficient barriers to the integration of cost-effective new sources of electricity services, rethinking ill-designed incentives, and setting a system of prices and charges that promotes efficient decisions based on the economic value of services and diverse personal preferences. Along the same lines, Wolak (2017) stresses the distortions that deficient pricing signals imply in the face of the renewed competitive forces emerging with DER and other technological advances in the electricity sector.

Considering both MIT (2016) and Wolak (2017) together, their main recommendations regarding pricing are the following:

1. Significantly improve prices and tariffs for electricity services to put all resources on a level-playing-field and to achieve efficient operation and planning in the power system, through:
    - cost-reflective electricity prices and regulated charges, based on the profile of injections and withdrawals of electric power at a given time and place, assuring *symmetric cost-reflective prices and regulated charges (i.e., equating compensation for injections and the rate charged for withdrawals at a given time and place)*;[3]
    - widespread use of information and communications' technologies *(advanced meters or interval meters*) enabling detailed monitoring of electricity withdrawals and injections;
    - peak-capacity and scarcity charges, reflecting users' contributions to incremental network costs incurred to meet peak demand and injection, which help unlock flexible demand and distributed resources;
    - sufficient granularity, i.e., recognizing that the value or cost of electricity services can vary significantly at different times and locations; and
    - *minimizing distortions from charges to collect taxes, recover the costs of public policies* (such as efficiency programs, heating assistance, subsidies for renewable energy, cross-subsidies between different categories of users, etc.) and/or pay common network costs, preventing possible *socially inefficient "grid defection"* if these charges are too high.

[3] Wolak (2017) notes that the conventional approach to distribution network pricing (charging a fix per-unit charge for all withdrawals of the distribution grid to cover the main part or all of its costs, despite the significance of fixed network costs) is increasingly costly in regions with opportunities to deploy DER, as the distorted price signal (because the variable charge is much higher than the marginal cost of using the distribution network) over-incentivizes by-pass of grid-supplied electricity through DER (which in turn provokes an additional increase in the per-unit distribution price in order to cover fixed sunk distribution costs, feeding back the initial distortion). Avoiding this bias requires thus that the fixed and variable charges applied to recover distribution costs correctly reflect the cost structure of the distribution service. Also, as the share of intermittent renewable generation increases, more efficient wholesale and retail pricing implies significantly greater price volatility, requiring some competition and regulatory safeguards to protect consumers while preserving correct price signals.

2. Improving the wholesale market design by integrating distributed resources, rewarding greater flexibility, and creating a level-playing-field for all technologies, by:
   - enabling transactions to be made closer to real time, thus rewarding flexible resources and allowing better forecasting and control of variable renewable resources and electricity demand;
   - updated market rules, such as bidding formats, to reflect the operational constraints of new resources such as demand response and energy storage, as well as new patterns of operation of conventional power plants; and
   - better price signals for energy and operating reserves, strengthening the link between these two services.[4]

Wolak (2017) also stresses the importance of pricing across all segments and dimensions of the electricity service. He notes that innovative technologies and business models will only be adopted if wholesale and retail prices are cost-reflective enough to provide compensation as requested by those deciding on them, and he thus concentrates his analysis on the development of different recommendations on the design of the structure and pricing of electricity, including the following:

- Multi-settlement locational marginal pricing (LMP) markets, with spot and day-ahead markets, set efficient short-term wholesale electricity prices, avoid transmission and other operational constraints (such as varying reliability and intermittency of renewable generation, which is increasingly important) and minimize market power risks.[5]
- If, for political or equity issues, it is not possible to implement different prices of energy paid by various users in the same region (e.g., urban vs. rural,

[4] MIT (2016) includes other regulatory recommendations outside retail and wholesale pricing. These include the following: i) allowing development of more efficient distribution business models, ii) minimizing potential conflicts of interest within the electricity industry, iii) recognizing the increased importance of cybersecurity and privacy concerns in the face of widespread connection of distributed energy resources and smart appliances, and iv) taking into account that economies of scale are still important and that the distributed deployment of solar photovoltaic (PV) or energy storage is not cost-effective in all contexts and locations.
[5] In Argentina, bids presented by generators in the wholesale market (*Mercado Eléctrico Mayorista*, MEM) are cost-based, with a one-day-ahead declaration of availability, so such type of variable wholesale energy pricing would require a major reform in the functioning of the MEM, as cost-based systems cannot fully account real-time full economic cost differences signaled by price-bids.

because of different transmission constraints), a possible solution is to average prices faced by users, which still allows efficiency in generation as long as the price-signal received by generators remains the LMP.

- Since a larger share of intermittent renewable resources imposes more reliability constraints on the LMP, there is more space to exercise local market power and allow for (or even request) fixed-price forward contract obligations (which limit the incentive of suppliers to exercise system-wide unilateral market power in the short-term market).
- Assuming that all residential users have smart meters, the pricing of the distribution network should include per-use charges reflecting the marginal cost of withdrawing energy from the distribution grid at the customer's location during each hour of the day, while fixed charges (a sunk-cost recovery problem) should be set according to each customers' willingness to pay in order to avoid disconnection from the grid.
- Adopt retail pricing reflecting changing real-time conditions in the T&D grid during each hour of the day at each location, capturing marginal cost volatility, as this provides economically efficient signals for decentralized investment in storage devices, automated response technologies, sensors and control systems that can reduce the cost of serving demands.[6]
- Finally, assure symmetric treatment of load and generation, so that (apart from fixed-price contracts signed between users, retailers and generators) both users and generators pay and receive the hourly price for the energy consumed and supplied to the system (and can sell and buy energy exceeding or falling short of the amount contracted at fixed prices in the day-ahead market).

A relevant but not exhaustive list of recent contributions includes several other recent studies addressing pricing and other dimensions where regulation of the electricity sector will need to be adapted. They include Villar et al. (2018), who stress the increased need for flexibility

[6] As Wolak (2017) notes, dynamic retail pricing does not necessarily involve too much price-risk in the monthly bill, as users can contract smoothing their bills with retailers, but it does require active involvement of final users, who need to have smart metering to record consumption on an hourly basis, receive timely information to be able to react to it, and face the correct price signal reflecting the system's marginal cost; thus, monthly bill smoothing can reduce price volatility in the short-run but should not provide full insurance to final users, allowing their average price paid over a given period to adjust to the average cost of their actual purchases and use of energy.

due to increasing renewable generation, which produces a net load with larger variability and uncertainty and thus implies larger ramping needs. This in turn leads to the emergence of ***flexibility markets***[7] and the increased complexity that distributed generation and electric vehicles development imply for the operation of the distribution grid, with reverse power flows, congestions, voltages drops and losses. Peterson and Ross (2018) additionally note the historical dependence of regulation on adapting to technological changes in the electricity sector, and that current innovative technologies and applications seem to hold the potential to transform the energy delivery system into a *services-centered platform* that fits with the modern evolution of other industries such as retailing, telecommunications, lodging, livery vehicles and logistics, among others. Glachant (2012) likewise stresses the implications of the economics of platforms for both the design of an updated business model and new regulatory procedures developed side by side in order to best combine with possible futures for the electric grid, discussing various likely structural adaptations ahead.[8]

Summing up, there are many debates ahead requiring first-class regulatory institutions and discovery processes. Yet, while many of the developments required to allow full space for the efficient development of a possibly unrecognizable electricity system in the future do require such institutional innovation, there are some basic pricing corrections that could be implemented immediately, setting a better stage for that possible revolution (and to avoid its artificial and ruinous emergence). In Argentina, these corrections include both institutional reform in a federal setting and a fundamental change in the retail tariff structure to recover distribution costs (with associated changes in the design of social tariffs and taxes to account for social/political and environmental aspirations). We address these two issues in Sections 3 and 4.

---

[7] They notice that if enough power and ramping capacity is available in the system, and the net load could be ramping rapidly, energy-only market prices would appropriately reward generators for their flexibility to supply a variable but perfectly forecasted demand, meaning that uncertainty—and not variability—of demand is the main cause of flexibility needs.

[8] As these authors explain, what matters for platforms is that they facilitate exchange, providing what economists call intermediation or a "matching function." Economists have used the term two-sided markets, applicable to platforms, to describe market organizations where the volume of transactions is influenced by the pricing structure. The value of the platform increases with increased usage, providing a strong incentive for the platform provider to price access and use of the platform in a manner that induces the largest number of transactions, exploiting two-sided network effects (e.g., more customers drive the growth in suppliers and more sellers drive the growth in the number of buyers) while the size of those cross-effects are typically different.

3. The Argentine Electricity Sector and Recent DER Developments

3.1 Salient Structural Features and Rules

After its reform in 1992, the argentine electricity sector has gone through some significant changes regarding specific governmental interventions, which since the early 2000s distorted prices and institutions at various levels. Yet, its structure has remained mostly intact, with the following salient characteristics.

- Regulatory federalism: a variety of regulatory-related institutions at the federal, provincial and local levels of government.
- Vertical segmentation between generation, transmission and distribution (G-T-D), where G is "competitive" and T&D include various regional monopolies subject to tariff regulation.
- G includes generators with different technologies (public nuclear, hydro, thermal, wind, solar, etc.), using various primary sources and with varying construction designs and thus costs, normally located far away from highest-demand concentrations.
- Dispatch at the wholesale market (MEM) is based on declared costs (with fuel inputs provided by the dispatch authority CAMMESA) and declared availability one-day ahead, not truly competitive nor capturing full (direct and opportunity) "marginal costs" that reflect the true scarcity. Moreover, since 2002 there have been growing distortions (partially alleviated since 2016), by which reference wholesale electricity prices for residential users cover only 50 percent of average generation costs, whereas MEM prices do not reflect cost variations at all (not even average cost variations across seasons, as there are only 2 seasonal wholesale prices per year, basically adjusted because of inflation or previous devaluations).
- Distribution companies have territorial legal monopolies for supplying a quality-homogenous service to their (captive) users, and only large (not residential) users are allowed to procure their own energy through commercial *by-pass*.

- Environmental goals are promoted by imposing increasing obligations to contract renewable generation in the years ahead.
- Tariff structures, and provincial / local taxes on end-users, vary across regions. In general, they are characterized by high variable charges and taxes containing implicit cross-subsidies that favor residential users with low consumption.
- New explicit federal social tariffs since 2016, delegated to provinces since 2019 (some of which might discontinue them), reach 30 percent of the lowest-income users and include a 100 percent discount on the wholesale price of energy for the first 150 kwh/month consumed and a 50 percent discount on up to an additional 150 kwh/month consumed by the target poorest users.

Overall, final residential users face tariffs which do not reflect their individual impact on total fixed (distribution) costs and, most importantly, are unrelated with the variable costs (for generation, transmission and distribution) involved, not to mention that they also neglect hourly, daily and seasonal variations.

3.2 The Institutional Setting

The Argentine electricity sector is characterized by a very complex web of institutions working at various segments and jurisdictional levels. The Secretary of State of Energy (ex–MINEM until August 2018) has responsibilities covering all energy services across the country in terms of implementing national energy policy. These include planning and second-level general legislation, as well as setting the rules under which the various energy wholesale markets (e.g., the wholesale electricity market -MEM-, and natural gas -NG-, fuel liquids) work.

Yet, regulation of T&D (infrastructure, downstream) firms in the various energy sub-sectors or services is decentralized in many dimensions. First, electricity and natural gas are separated into two different regulated services, with ENARGAS (*Ente Nacional Regulador del Gas*) overseeing and regulating T&D in the NG sector and ENRE (*Ente Nacional Regulador de la Electricidad*) doing the same in the electricity sector. Second, ENARGAS's and ENRE's roles and reaches are very different: while T&D in NG have a single and centralized regulator (i.e., ENARGAS) across all provinces, the regulation of electricity service is fragmented: ENRE regulates both national high-tension transmission and distribution (including supply to captive users and open access to large free users) within the AMBA, provided by firms concessionaires of assets previously belonging to *Servicios Eléctricos del Gran Buenos Aires* (SEGBA), a former national SOE privatized in 1992, while every province retains regulatory powers regarding local transmission and distribution services (including access and final supply—retail—to captive users). Third, similarly to what happens in the United States, regulation at the provincial level is alternatively conducted by specialized energy regulators or (slightly less frequently) by multi-service regulators, whereas public utilities are also of varied form, including private concessionaires, SOEs and Cooperatives (particularly active in smaller cities). Fourth, while municipalities lack formal regulatory powers, they do have power regarding the use of public space (relevant for various activities as repairs, deployment of electricity or telephone lines, etc., according to their local environment protection responsibilities) and, as in the case of the national and provincial governments, act as large users of electricity services (for government offices and public lighting) and taxing authorities. Finally, while social authorities and agencies at the national, provincial and local levels of government (including the ombudsman, for instance) do not have any regulatory or tariff authority, they do intervene in various stages of the regulatory process depending on their capacities to press their agendas in each relevant decision-making political economy setting.

Another dimension of this fragmentation is the varying nature of provincial regulatory institutions and local participation of interest groups (including official social entities in charge of representing captive final users). Indeed, provincial governments (and the national government's intervention in distribution of electricity) differ among themselves regarding the quality of their policy intervention in general and regarding the quality of their regulatory involvement: in some cases (as with ENRE), regulatory institutions are relatively well staffed and undertake autonomous interventions based on relatively open and transparent processes, but the normal case is one of general insufficiency regarding specialized well-paid staff able to act with political independence, technical orientation and real power. In many cases, regulated firms (because of the interests they represent, e.g., strong labor unions and/or input providers as in Córdoba) can influence provincial authorities much more than their regulators, which therefore cannot truly impose rules (or application of regulations already defined in contractual clauses) aiming at improved electricity service.

The institutional design of electricity regulation varies by province, and most likely this has some effect (together with other elements present in each case[9]) on the quality of regulatory practice, something which is beyond the scope of this paper. Nonetheless, two common observations rapidly emerge. First, such quality differences are not made evident by looking at each tariff design (discussed in Section 4), as in all cases residential tariffs show various degrees of distortions: leaving aside seemingly high levels in various cases, they include, except in Santa Fe and Entre Rios, multiple fixed monthly charges that increase with average annual consumption and yet are substantially below any approximation to the impact of each user on the fixed costs of the distribution company, as well as multiple variable distribution charges which are generally above variable distribution costs and also increase with average annual consumption. Second, the procedural requirement of having public hearings before tariff and other relevant regulatory decisions is both generalized and superficially implemented (see the discussion in the following sub-section for a sample of cases), thus pointing to a major change required if these provincial regulators will play a role such as called for efficient regulation in the future—i.e., as the organizers of a platform where meaningful decentralized information is collected in order to decide on multiples issues that have to do with prices, investment and competition, among other concerns.

Considering Mendoza, for instance, the president and a director of EPRE (*Ente Provincial Regulador Eléctrico*) are nominated to their positions by the provincial executive power and confirmed by the provincial Senate after a public hearing, and yet its residential tariff structure is very similar to those applied in Córdoba and Tucumán, where provincial regulators do not have much autonomy or prevalence in guiding regulation. Entre Rios also has public hearings, with accessible information on its *Ente Provincial Regulador de Energía* (EPRE)'s web page (see http://epre.gov.ar/web/) but apparently the same procedures (i.e., to discuss proposals presented by the regulated firm, not questions or proposals based on those requests and others presented by the regulator).

[9] For instance, pro-consumer interest groups are very active in AMBA: these include both official entities (as the Ministry of Health and Social Development at the national level, the Ministry of Social Development in the Province of Buenos Aires and the Ministry of Human Development and Habitat in the city of Buenos Aires – CABA) and traditional pro-consumer non-profit private entities (Adelco, Unión de Usuarios y Consumidores, Adecua, etc.: out of about 40 associations included in the National Registry, 70 percent are based in AMBA. The remaining ones are mostly based in Santa Fe (5) and the interior of the province of Buenos Aires (3), with only one each in Salta, Mendoza and Corrientes).

In **Appendix 1** we briefly depict salient institutional and public hearing experience in three provincial cases: AMBA, Córdoba and Tucuman. These cases show some specific particularities and leave out many provinces where the quality of regulation could show varying features, but they nonetheless confirm a common pattern pointing to the need for institutional improvements in order to tackle the new, modified, regulatory roles foreseen in the future based on the discussion in Section 2.

3.3 Law 27.424 (Promotion of Distributed Generation)

Argentina has recently passed new legislation promoting generation of renewable electricity by users connected to the distribution network, considering for self-consumption and eventual injection of exceeding volumes to the network. This legislation—Law 27.424 (Promotion of Distributed Generation, 17-12-2017) and its regulatory Decree 986/18 (11-01-2018)—aims to have national reach, but its application in the interior of the country rests on adhering decisions by each province

The salient features of this legislation are the following:

1. It creates a fund (named FODIS, *Fondo para la Generación Distribuida de Energías Renovables*) to subsidize acquisition of equipment by interested users (who become *prosumers*);
2. It sets the steps to be followed in order for users and distribution companies to sign distributed energy contracts once the former's new equipment and its connection to the network are declared fit according to regulated technical and safety revisions, without limiting the capacity of the new installations (unless the equipment installed by the *prosumer* allows for generation beyond the maximum capacity contracted with the distribution company, such contracted capacity will have to be increased up to that of the installed equipment—see Article 4 of the law and its regulatory decree); and
3. It sets the terms of payment of (surplus) energy injected by *prosumers* into the network.

While the first two elements are reasonable (i.e., given the positive externalities brought by renewable generation, and the difficult access to low-price financing for Argentine consumers, subsidizing part of their investment seems natural, and so is the requirement for technical and safety review of new equipment connected to the network, avoiding strategic denials by the distributor through regulatory supervision of regulated steps and without imposing artificial restrictions on the size of the DER equipment to be installed), the terms of payment of excess (*vis-à-vis* own consumption) of distributed generation injected into the network by consumers is more problematic in the current tariff context characterizing the Argentine electricity sector.

Indeed, Article 12 of Law 27.424 (and more precisely its recent regulatory decree 986/18) determine that such injections will be paid a price equal to the price paid by the distribution company for energy (including transmission) bought at the wholesale market (MEM), whereas only those *prosumers* whose distribution service discriminates the hourly price of energy will be paid such hourly prices for their injections. So, this means that residential *prosumers,* who will have to invest in their (mostly solar PV) generation equipment and bidirectional intelligent meters (to measure both their consumption and reverse injections), but whose current tariffs only contain non-discriminated peak and off-peak wholesale energy prices (with minimal differences between them), will be rewarded with the average price of energy paid by distribution companies, which is a mix of various sources of energy bought at different times of the day and will normally be lower than the wholesale price at peak demand periods when the marginal generation dispatched at the MEM is of highest cost. Worse than that, even users who do have hourly prices defined in their distribution contacts (not residential users at this point), will also fail to receive signals of the true marginal cost of the electricity generated at the MEM, which their injections will help to save, as current hourly prices in Argentina have limited variation due to the cost-based nature of the system.[10] So, as long as the current general tariff system does not reflect the marginal prices paid for the wholesale energy generated at the MEM in all bills received by final users (including residential ones), and those marginal prices paid at the MEM do not reflect the marginal cost of generation at each hour of the day, payments to *prosumers* for their injections will not surely help reduce the general cost of generating energy in Argentina, failing to induce correct investments in storage, demand-shifting equipment, intelligent appliances, etc.

[10] Residential users of various sub-categories now pay the same energy prices regardless of their level of consumption, something that was not so between 2008 and 2016.

Furthermore, if it also happens that the tariff structure of distribution margins is far away from reflecting fixed and variable distribution costs (as considered in our rebalancing exercise, where we see variable distribution charges far larger than variable distribution costs), decisions to invest in DER will be additionally inefficient, inducing overdevelopment of DER that imposes negative externalities on other users who will have to pay more (variables distribution charges) to maintain the fixed cost of the distribution network.

Two final comments about this new legislation are relevant here. First, it does not recognize—in fact, it is silent about—the cost-incidence of *prosumers* on the electric system, as there might be higher costs to manage a bidirectional network depending on the changed time pattern of net consumption and injections to the network, while distribution companies are forbidden to apply specific charges to *prosumers* (see the last paragraph of Article 12 of the law, stating that "there cannot be additional charges for maintenance of the network, access fee, electric backup or any other concept associated with installing distributed generation equipment" not regulated in the recent decree).

Second, Article 12 of the law indicates that energy injected to the system by a *prosumer* will be exempted from paying any taxes, whereas Article 12 Bis of Decree 986/18 specifically refers to the exemptions of taxes on income (earning tax) and value added (VAT) for injections into the distribution network by *prosumers*. So, since generation for self-consumption is also exempted from earnings and VAT taxes, investment in DER is additionally promoted against conventional centralized generation / distribution of electricity, inducing private decisions which might not be economically efficient (and instead motivated to elude taxes applicable to regular electricity services supplied through distribution networks).

4. Retail Tariff Rebalancing, Social Tariffs and Taxes: Three Fundamental Corrections

One key element of the regulation of the electric utilities of the future, in a new context in which the contestability of distribution services is significantly enhanced through the development of DER alternatives, is that (retail) tariffs reflect distribution costs, addressing social and environmental goals in an integrated and coherent way. While smart-metering brings the discussion of cost-reflection to a higher level than in the past, admitting multiple dimensions and frequency definitions (by the hour, day, week, season or year, both regarding fixed and variable costs), a basic prerequisite is that average annual tariffs reflect average fixed and (fundamentally) variable costs. Otherwise, pretended cross-subsidies under the prevailing tariff structure will be eroded through defection of the grid by *prosumers* developing DER, or DER development will have to be artificially truncated and distorted, in both cases leading to inefficient (i.e., not cost-minimizing and quality enhancing) investment and long-run shaping of the electricity sector.

We devote this section of the paper to exploring the key (retail) tariff and tax distortions and corresponding corrections that need to be implemented as the first main step to properly regulate electric utilities in the new technological, social and environmental scenario of this industry.

4.1 Retail Price Corrections: Tariff-Rebalancing Exercise

The correction of the structure of distribution tariffs of electricity entails changing the fixed and variable distribution charges so that they correctly reflect the fixed and variable nature of distribution costs, so that those final (retail) tariffs are part of correct signals to decide on investments of DER or not, building on them economically efficient social tariffs and environmentally appropriate and consistent taxes.

We develop an exercise centered in the *Buenos Aires Metropolitan Region*, AMBA, computing the changes required in the residential tariff structure of the distribution service so that the new residential tariffs closely reflect its cost structure. This will minimize incentives for residential users to invest in DER as a way to escape paying a cross-subsidy to other users served by the distribution company and, also, minimize the cost faced by the distribution company regarding lower sales of electricity to those users developing DER. We assume that these users remain connected to the network, i.e., do not disconnect themselves from the network and retain it either to supplement their consumption, to deliver their excess self-consumption generation or just to serve as a back-up (we discuss potential disconnection in Section 5). Once DER is a real technical and economic possibility, if current residential tariffs recover distribution costs without matching fixed charges vs. fixed costs and variable charges vs. variable costs, then signals to invest in DER are distorted. For example, if the variable charge is higher than the variable distribution cost then a residential user might decide to develop DER in order to reduce her total electricity expenditure over time, but this decision could entail higher aggregated (social) energy costs as savings by the residential user are lower than the net income (i.e., income from variable charges minus variable distribution cost) lost by the distribution company, making the investment decision socially inefficient. Viewed from a different perspective, if fixed (distribution) charges are lower than fixed distribution costs, then the residential user who invests in DER but continues connected to the distribution network pays a lower price for the distribution service it continues to enjoy.[11,12]

In so doing, we leave aside some key and complementary reforms regarding real-time pricing which are particularly relevant in regard to energy and less so in regard to distribution.[13]

4.1.1 Tariff Structures, Revenues and Rebalancing

We examine the residential tariff structure (in US$, with an exchange rate of 38.5)[14] for Edenor's so called "full payers residential users," i.e., disregarding currently existing social tariffs and discount schemes for reduced consumption vis-à-vis 2015. As this multi-block tariff structure divides fixed and variable charges for nine residential sub-categories according to their monthly consumption, this tariff structure generates aggregate income and cost according to the distribution of various types or categories of residential users that could either be arranged by the share of users or by each category's share of consumption. To compute that distribution in a way that is compatible with our welfare exercise below, we use the 2012 National Household Expenditure Survey (NHES, the last one available in Argentina), which informs total electricity

---

[11] Assume customers pay a tariff characterized by $G=(A+p.x)*(1+t)$ where G is expenditure, A is a fixed charge, p is the unit (marginal) price, x is consumption and t is the tax rate. Then a distortion occurs for example if $p>C_{VDER}>C_V$ and $C_{FDER}<A<C_F$, where C_{VDER} and C_V are variable unit costs of DER and of Utility's provision (which includes the variable cost of distribution plus the marginal cost of MEM-generated electricity), and C_{FDER} and C_F are the corresponding fixed costs. Indeed, in this case (leaving taxes aside), there is an incentive to develop DER even though it is more costly than MEM-generated and distributed electricity. Notice that the cost of DER is variable ex-ante (i.e., before investing in it), and so we consider the decision to invest in DER—not the use of DER-generated energy once the household already invested in it.

[12] The case where the residential user decides to disconnect from the distribution network (exit) after investing in DER poses a different problem, since this exit leaves a fixed cost of distribution unpaid, causing an economic loss to the distribution company as part of its network becomes a stranded asset. Should disconnection then be avoided, or minimized, through regulatory intervention? One solution would be to allow the distribution company to negotiate a lower fixed charge with residential *prosumers* claiming their disconnection from the distribution network. Another solution would be to ban disconnection, or to impose taxes (otherwise not applied) to residential users who invest in DER and disconnect themselves from the distribution network.

[13] For example, the marginal cost of distribution is different at different hours of the day and months of the year depending on whether aggregate demand is at peak or not, but this is of a second order of importance vis-à-vis the cost variation of generation of energy in the MEM and the need to signal this cost variation in order to induce the correct investment decision regarding DER—including storage, consumption-shifting programming devices, etc.). Yet, as we show below, the rebalancing of annual average distribution charges poses a first-degree regulatory challenge and allows a clear understanding of the joint determination of efficient tariffs, social tariffs and taxes on electricity.

[14] In December 2018, the wholesale official exchange rate ranged between 36.5 and 38.6 AR$/US$.

spending by households and thus allows us to recover the quantities of electricity consumed per month by each household included in the survey after applying the tariff (plus taxes) structure of year 2012. Since in 2012 there were no social tariffs, the emerging distribution (share of sub-categories in number of users and their average monthly consumption) includes all residential users, including those currently receiving social tariffs. With that information, and the 2017 information published by Edenor regarding the number of residential users and tariff income obtained from them, we computed the theoretical monthly tariff income received from residential users since August 2018 (when the current tariff structure was set) and check reasonable (rough) consistency with actual income from residential users reported by the company. Table 1 below presents the corresponding values in current AR$.

Table 1. Edenor: Basic Information Used for the Rebalancing Exercise, December 2018

Consumption, KWh/month	Sub-category	Fixed Charge ($/month)	Variable Charge ($/kWh)	Monthly Bill ($/month)	Average consumption assumed (kWh/month)	Number of users in 2017	Total R consumption in 2017 (GWh/year)	MEM wholesale price ($/kWh)	Variable D Margin ($/kWh)
up to 150	R1	31	1,96	182	77	410.700	379	1,46	0,50
from 151 to 325	R2	55	1,96	503	229	768.220	2.111	1,46	0,50
from 326 to 400	R3	91	2,01	818	361	379.031	1.642	1,46	0,55
from 401 to 450	R4	107	2,09	995	424	354.366	1.803	1,46	0,63
from 451 to 500	R5	163	2,17	1.193	474	90.739	516	1,46	0,71
from 501 to 600	R6	322	2,23	1.538	546	168.723	1.105	1,46	0,76
from 601 to 700	R7	839	2,37	2.370	646	137.734	1.068	1,46	0,91
from 701 to 1400	R8	1.204	2,48	3.427	897	228.166	2.456	1,46	1,01
from 1401 up	R9	1.450	2,50	6.383	1.970	42.025	993	1,46	1,04

Source: Authors' compilation based on Edenor data.

Then, after detracting the wholesale energy price paid by residential users from the variable tariff component, we end up with a set of current fixed and variable distribution charges that result in aggregated income and costs presumably equal to each other (as costs include a reasonable rate of return), and pose the following rebalancing exercise: set fixed and variable distribution charges so that total distribution income with observed consumption would remain unchanged, provided that all residential users pay the same fixed and variable distribution charges and that fixed and variable charges reflect sufficiently well fixed and variable distribution costs. For this last requirement we assume that fixed costs represent 70 percent of total distribution costs incurred prior to the rebalancing exercise.[15]

Our exercise makes a number of simplifying assumptions, such as:

- fixed and variable charges are averages of annual cost figures (so that rebalanced tariffs do not reflect energy losses varying with daily or seasonal demand and use of the system);
- fixed charges do not account for different consumption loads that introduce heterogeneous impacts of users on fixed distribution costs;[16]
- the energy price is assumed constant throughout the day and the entire year; and
- the fixed distribution costs are assumed to be proportionally attributable to individual users (i.e., fixed distribution costs are not joint or common costs).

While these are indeed assumptions that leave out of the analysis many of the emerging questions about the structure of electric tariffs and prices of the future, they are adopted in order to present the main lines of a significant tariff correction exercise. Some of these assumptions are partly reconsidered in Section 5, as is the existence of joint fixed costs, but most of them—such as the application of time-of-use tariffs and prices, or fixed charges based on each user's load

[15] We adopt this 70 percent share based on a recent study in Australia (including different distribution companies) which estimated that ratio to range between 60 percent and 70 percent; see https://www.erawa.com.au/cproot/2659/2/Appendix%202%20-%20Benchmark%20Economics%20report%20Vol%201.pdf and https://www.erawa.com.au/cproot/2660/2/Appendix%202%20-%20Benchmark%20Economics%20report%20Vol%202.pdf. Given the incidence of higher capital costs in Argentina, we assume a share around the upper bound of that range for Edenor (and perhaps somewhat higher for distribution companies in the interior of the country, as different jurisdictions surely would present differences due to varying sizes, densities and consumption levels). Notice that the rebalancing exercise will change the final prices of electricity observed by various users in different ways depending on which tariff sub-category they belong to, so that the amount of electricity (and use of the distribution network) will change with the new tariffs, probably increasing (as variable charges decrease) overall consumption (and thus affecting the share of total distribution costs that the new fixed charges represent). Yet, since our 70 percent is a rough estimate, there is no need to compute fixed charges that represent 70 percent of total distribution costs after rebalancing (which would imply some technical complications to the simple rebalancing exercise presented there). Of course, as briefly discussed in Section 5, determining the cost structure of the distribution service is one central regulatory task ahead, as erring such estimation might provoke higher or lower profits of distribution companies out of the rebalancing exercise.

[16] Accounting for these different individual impacts on fixed distribution costs will no doubt be a salient issue in the future. Yet, this will require advanced smart metering, since imposing load-demand pricing without metering will be arbitrary and inefficient (see Borenstein, 2016). One way of introducing load-demand pricing with smart metering into fixed charges that also reflect willingness to pay for network infrastructure is proposed by Wolak (2018).

curve—will have to be implemented not only once smart metering is available but also after the annual average structure of fixed and variable distribution charges is sufficiently well computed.

The result for Edenor in AMBA is shown in the next two tables. We can see that current distortions are significant, with fixed charges for the largest residential users being 46.3 times those of the smallest residential ones, and variable margins also being 109 percent higher for the former than the latter. Furthermore, since current income obtained from fixed charges represents about 23 percent of net income from residential users of Edenor, the required rebalancing exercise to reach uniform fixed charges that cover 70 percent of total distribution costs is very significant, having to almost triple the monthly bill for the smallest residential users and to reduce it by more than 35 percent for the largest residential users.[17]

Table 2. Edenor's Electricity Tariffs, before Taxes, without Social Tariffs or Saving Discounts, in December 2018 (exchange rate: 38.5 AR$/US$)

Monthly consumption in KWh	Category of User	Fixed Charge (US$)	Variable Charge (US$/kWh)	D Variable Margin (US$/kWh)	Monthly Bill (US$)
up to 150	R1	0,8	0,051	0,013	4,7
from 151 to 325	R2	1,4	0,051	0,013	13,1
from 326 to 400	R3	2,4	0,052	0,014	21,2
from 401 to 450	R4	2,8	0,054	0,016	25,8
from 451 to 500	R5	4,2	0,056	0,018	31,0
from 501 to 600	R6	8,4	0,058	0,020	39,9
from 601 to 700	R7	21,8	0,062	0,024	61,6
from 701 to 1400	R8	31,3	0,064	0,026	89,0
from 1401 up	R9	37,7	0,065	0,027	165,8
Average R (w by # of users)		**6,5**	**0,054**	**0,016**	**28,9**
25,6	**R9/R1**	**47,3**	**1,28**	**2,09**	**35,1**

Source: Authors' compilation based on Edenor data.

[17] As a matter of fact, current residential tariffs include a wholesale price of electricity that is subsidized. This price is slowly catching-up to the average cost of wholesale electricity supplied through the MEM (represented by the "monomic price," which includes both energy and capacity costs of all the electricity supplied through the MEM), and currently represents a little more than 50 percent of that average cost (starting from 14 percent in Dec-2018, the epilogue of the market-intervention seen after the Convertibility Plan collapsed in the early 2000s). Therefore, current and future tariffs would both be higher if they fully reflected the current costs of the system. Indeed, current tariffs for low-consumption R users (R1-R3) would need to be 53 percent higher than today, and those for high-consumption R users (R7-R9) should be 34 percent higher than today. Consequently, as both current and future rebalanced tariffs would include a higher wholesale price, the percentage changes in the monthly bills would be lower than those presented in the paper (for instance, the 188 percent monthly bill increase for R1 users reported in the Table 3 would be a 124 percent increase, whereas the 36 percent decrease for R9 users would be a 26 percent decrease).

Table 3. Rebalancing Exercise: Edenor's Cost-Reflective Tariffs (if 70% of its costs are fixed)

Monthly consumption in KWh	Category of User	Fixed Charge of the Future (US$)	Variable Charge of the Future (US$/kWh)	D Variable Margin of the Future (US$/kWh)	Monthly Bill of the Future (US$)	Change in Fixed Charge	Change in Variable Charge	Change in D Variable Margin	Change in Monthly Bill
up to 150	R1	9,8	0,049	0,011	13,6	1134%	-4%	-16%	188%
from 151 to 325	R2	9,8	0,049	0,011	21,0	593%	-4%	-16%	61%
from 326 to 400	R3	9,8	0,049	0,011	27,5	315%	-7%	-24%	29%
from 401 to 450	R4	9,8	0,049	0,011	30,5	252%	-10%	-34%	18%
from 451 to 500	R5	9,8	0,049	0,011	33,0	132%	-13%	-41%	6%
from 501 to 600	R6	9,8	0,049	0,011	36,5	18%	-16%	-45%	-9%
from 601 to 700	R7	9,8	0,049	0,011	41,4	-55%	-21%	-54%	-33%
from 701 to 1400	R8	9,8	0,049	0,011	53,6	-69%	-24%	-59%	-40%
from 1401 up	R9	9,8	0,049	0,011	106,0	-74%	-25%	-60%	-36%
Average R (w by # of users)		**9,8**	**0,049**	**0,011**	**28,9**	**51%**	**-10%**	**-33%**	**0%**
25,6	**R9/R1**	**1,0**	**1,0**	**1,0**	**7,8**				

Source: Authors' compilation based on Edenor data.

4.2 Incidence Impact Calculation

The rebalancing exercise shown above is strictly a change in end-user residential tariffs in both (fixed and variable charges) dimensions, with the corresponding changes in outlays for consumers. Such changes in prices induce changes in consumption decisions. So, to capture these changes in the following sensitivity analysis, we assume a given price elasticity[18] and perform two different exercises. Here we make an incidence impact analysis (of tariff changes) across sub-categories of residential users and income deciles, and below we address a welfare impact analysis across households. In both cases we use micro-data from the 2012 NHES which reports information including aggregate expenses (a good proxy for total income) and expenditure in the electricity service.

From NHES 2012 information for the AMBA region, we are able (through Edenor's tariff schedule in 2012) to compute the number of users (and their consumption) belonging to each tariff sub-category (R1 to R9) and sort them by the income decile to which they belong, then computing the distribution of users of different sub-categories and the electricity consumed by them within each income decile. The results are shown in Tables 4 and 5 below.[19] As we can

[18] We adopt a very low estimate of -0.055, corresponding to estimates observed for natural gas in AMBA, including the large real price monthly variations observed between January 1993 and June 2017, but additionally consider higher values to explore its sensitivity. See Urbiztondo (2017).

[19] The first table includes both the average monthly bill increase out of the rebalancing exercise (called price change) and, for each income decile of households in AMBA, the percentage of the electricity consumed by different sub-categories of users within that decile. With these two elements, we compute the overall (short-term) impact of the

see in the next table, the increases in tariffs due to the rebalancing exercise (for users in sub-categories R1 to R5) affect users of all income deciles. Furthermore, while if we consider in the last row the average user of all except the last income decile end up paying a higher electricity bill after rebalancing, previous rows show that every decile includes users who pay more and users who pay less after the rebalancing exercise.

Table 4. Impact of Rebalancing on Monthly Bills Paid by Users of Various Levels of Income

Residential sub-category	Price change	Distribution across residential sub-categories of electricity consumed within each income decile									
		1	2	3	4	5	6	7	8	9	10
R1	188%	7%	4%	4%	5%	4%	5%	5%	3%	4%	2%
R2	61%	21%	27%	23%	27%	14%	14%	18%	19%	17%	6%
R3	29%	21%	17%	15%	20%	14%	8%	18%	14%	12%	5%
R4	18%	11%	18%	20%	14%	18%	30%	10%	11%	10%	8%
R5	6%	5%	4%	7%	1%	5%	2%	8%	1%	5%	3%
R6	-9%	3%	12%	10%	8%	10%	7%	11%	4%	10%	14%
R7	-33%	9%	6%	11%	12%	6%	10%	9%	7%	9%	8%
R8	-40%	23%	11%	9%	14%	28%	21%	20%	32%	22%	31%
R9	-36%	0%	1%	0%	0%	1%	5%	1%	9%	12%	24%
Impact (weighted average)		**20,8%**	**25,3%**	**22,0%**	**24,2%**	**8,9%**	**11,9%**	**16,7%**	**4,1%**	**5,5%**	**-14,7%**

Source: Authors' compilation based on Edenor data.

The following table, informing the share of residential users of various sub-categories within each decile, shows the percentage of users who end-up paying more and less after rebalancing. So, for instance, while 86% of users who belong to the poorest 10% of the population in AMBA would pay a higher monthly bill after tariff rebalancing, 14% of them would pay less; and regarding the richest 10% users, 49% would pay more and 51% would pay less.

rebalancing exercise on the average household of each decile, shown in the last row of the table. There, the price changes faced by each type of user belonging to the same decile are weighted by the participation of that type of user in the total volume of electricity consumed by households in that decile.

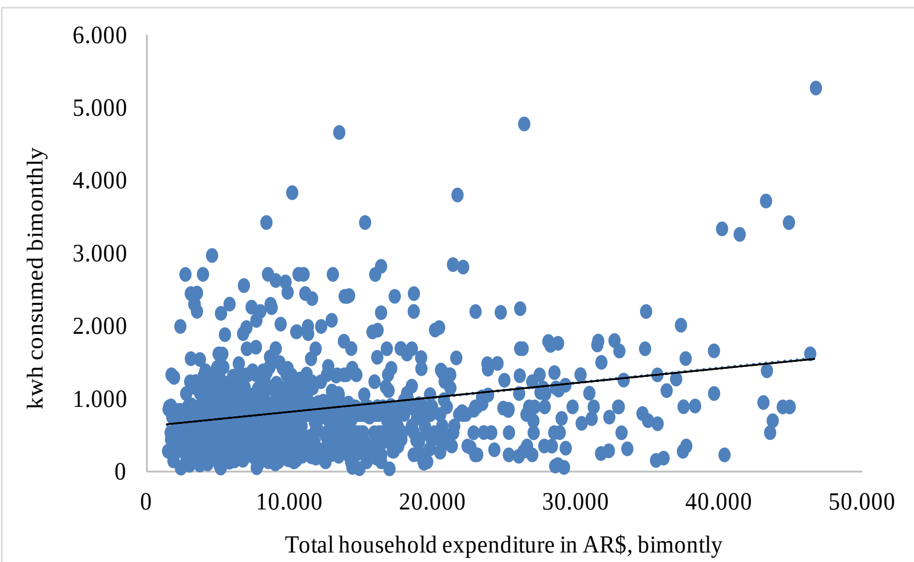
Table 5. Percentage of Users Paying More and Less for Electricity after Rebalancing

Residential sub-category	Price change	Distribution across residential sub-categories of number of users within each income decile									
		1	2	3	4	5	6	7	8	9	10
R1	188%	22%	13%	15%	15%	16%	17%	17%	14%	15%	10%
R2	61%	31%	38%	32%	39%	24%	24%	28%	34%	31%	16%
R3	29%	19%	16%	14%	19%	15%	9%	18%	15%	13%	8%
R4	18%	9%	14%	17%	11%	17%	28%	9%	11%	10%	12%
R5	6%	4%	3%	5%	0%	5%	2%	7%	1%	4%	4%
R6	-9%	2%	8%	7%	5%	8%	5%	8%	3%	8%	15%
R7	-33%	5%	3%	6%	6%	4%	6%	5%	5%	6%	7%
R8	-40%	7%	4%	4%	5%	12%	8%	7%	14%	11%	21%
R9	-36%	0%	0%	0%	0%	0%	1%	0%	3%	3%	7%
% of users paying more		86%	85%	83%	84%	77%	80%	80%	75%	73%	49%
% of users paying less		14%	15%	17%	16%	23%	20%	20%	25%	27%	51%

Source: Authors' compilation based on Edenor data.

Indeed, as shown in Figure 1 below, there is a positive but imprecise relationship (only 21 percent correlation) between the income level of each household (according to their total level of aggregate expenditure) and the amount of electricity they consume (which determines the type of user or residential sub-category to which he/she belongs).

Figure 1. Household Consumption of Electricity and Total Household Income (Expenditure), AMBA 2012



Source: Authors' compilation based on Edenor data.

Although the distributional incidence of rebalancing initially seems regressive, a first efficiency exercise (without distributive weights of the gains and losses of different users according to income) shows a positive impact of the short-term measure, and obviously a positive impact (not quantified) in the longer term, as the rebalancing of distribution tariffs is intended to induce the right decisions about DER investment and to allow distribution companies to avoid inefficient stranded costs (whose anticipation will probably cause higher capital costs and higher tariffs to all users of the electric network service).[20] This efficiency result (by which the higher surplus obtained by fewer users receiving a lower electricity bill after rebalancing outweigh the lower surplus of the more numerous users who face a higher electricity bill) is due to the fact that the consumption of favored households is much higher than the consumption of households negatively affected by the measure.

4.3 Welfare Impacts

The tariff rebalancing can be evaluated according to a household welfare exercise adapting the algebra of relative price changes (based on Newberry, 1995; see also Navajas, 2004, for an application to Argentina) to the case of a rebalancing of (different) two-part tariffs for each (heterogeneous) household, assuming inelastic demand. The analysis is static, at a point in time, without computing the long-term welfare gains attached to better investment decisions induced by the tariff-rebalancing correction, so it is important to keep this limitation in mind. In **Appendix 2** we show our analytic framework, while here we describe data inputs, computational efforts and results.

Changes in tariffs for various types of users were those illustrated in previous tables, and they come from two different sources, namely price (or variable unit charges) changes and fixed charges changes. As we did before for the incidence exercise, we follow Navajas (2009) and use the tariff structure (including taxes) in effect during the period of the survey (2012-2013) and retrieve the quantities of electricity consumed by each household. We also use the distribution of aggregate expenditure across households, which allow us to compute a measure of the social marginal utility of income of each household, in order to implement the welfare weights of the form $\beta_h = g_h^{-v}$, where h is household, g is aggregate expenditure and v is an inequality-aversion parameter (with $v=0$ representing absence of distributional concerns, i.e., $\beta_i = 1\ \forall i$, and values

[20] The aggregated short-term efficiency gain estimated is of only 0.54 million US$/year, which represents 0.06 percent of the total expenditure on electricity by Edenor's residential users. This is consistent with the very small price-elasticity assumed in this exercise (-0.055). But in any case, if the price-elasticity is assumed to be -0.3, the estimated annual efficiency gain is 3.0 million US$ (and 0.33 percent of total R's expenditure on electricity), still very low.

of *v=0.5*, *v=1* and *v=2* representing low, medium and high distributional concerns). See **Appendix 2**.

Computing the change in welfare for each household and then aggregating by income (aggregate expenditure) decile is straightforward following the algebra of **Appendix 2** (see expression (4)). The results in the following table show that aggregate welfare changes are negative for all values of *v* reflecting low, medium and high inequality aversion) in our analysis, namely -1.1 percent for *v=0.5*, -2.4 percent for *v=1* and -5.7 for *v=2*.[21] Of course, as seen before, this is not uniform across households. The table also shows that losses are pervasive except for the top 30 percent of households according to income (aggregate expenditure). This welfare gain also happens, strangely enough, for decile 5. Thus, the tariff rebalancing exercise is overall regressive and pro-rich. Nevertheless, monotonicity of welfare changes across income deciles does not apply due to the non-monotonicity observed in consumption patterns, and the same happens, to a lesser extent, for *v*-sensitivity of welfare changes for a given income decile.

Table 6. Welfare Changes After Rebalancing in AMBA, by Deciles, According to Inequality-Aversion

Decile AMBA	ΔW/W (υ=0)	ΔW/W (υ=0.5)	ΔW/W (υ=1)	ΔW/W (υ=2)
1	-8,2%	-9,0%	-9,8%	-11,2%
2	-8,1%	-8,2%	-8,2%	-8,4%
3	-4,8%	-4,6%	-4,5%	-4,1%
4	-4,1%	-4,0%	-4,0%	-4,0%
5	0,4%	0,4%	0,4%	0,3%
6	-0,3%	-0,3%	-0,3%	-0,4%
7	-1,0%	-1,0%	-1,1%	-1,2%
8	1,4%	1,4%	1,3%	1,2%
9	0,9%	0,8%	0,8%	0,8%
10	3,2%	3,1%	3,0%	2,9%
Total	**0,0%**	**-1,1%**	**-2,4%**	**-5,7%**

Source: Authors' calculations.

This non-monotonic result does not appear if computations are reported by income (aggregate expenditure) quintiles: as the quintile is higher (income or aggregate expenditure,

[21] Naturally, when there is no aversion to inequality (υ=0, in the first column of Table 6), the rebalancing exercise leaves total expenditure on electricity by residential users constant, and as the demands are assumed to be inelastic it becomes a zero-sum game where (short-term) welfare remains constant as well.

vertically), the welfare impact is larger for all inequality-aversion measures, whereas for each quintile (horizontally), the welfare impact decreases as the inequality-aversion measure grows.

Table 7. Welfare Changes After Rebalancing in AMBA, by Quintiles, According to Inequality-Aversion

Quintile AMBA	ΔW/W (υ=0)	ΔW/W (υ=0.5)	ΔW/W (υ=1)	ΔW/W (υ=2)
1	-8,1%	-8,6%	-9,1%	-10,2%
2	-4,4%	-4,3%	-4,2%	-4,1%
3	0,0%	0,0%	0,0%	0,0%
4	0,3%	0,2%	0,1%	-0,2%
5	2,3%	2,1%	1,9%	1,6%
Total	**0,0%**	**-1,1%**	**-2,4%**	**-5,7%**

Source: Authors' calculations.

Finally, results across residential tariff sub-categories show somehow more monotonicity.

Table 8. Welfare Changes After Rebalancing in AMBA, by Residential Tariff Sub-Categories, According to Inequality-Aversion

Tariff sub-category AMBA	ΔW/W (υ=0)	ΔW/W (υ=0.5)	ΔW/W (υ=1)	ΔW/W (υ=2)
1	-8,1%	-10,2%	-13,0%	-20,3%
2	-7,6%	-9,5%	-12,0%	-18,6%
3	-5,9%	-7,5%	-9,8%	-15,8%
4	-4,2%	-5,1%	-6,2%	-9,6%
5	-1,7%	-2,3%	-3,3%	-6,3%
6	2,4%	3,0%	3,8%	5,5%
7	15,7%	21,1%	29,5%	56,1%
8	23,5%	29,5%	38,1%	63,4%
9	19,3%	22,0%	25,7%	36,5%
Total	**0,0%**	**-1,1%**	**-2,4%**	**-5,7%**

Source: Authors' calculations.

4.4 Rebalancing outside AMBA

The distortions observed in Edenor's tariffs in AMBA are extreme in one sense (nowhere in Argentina—except for Edesur, also in AMBA—are fixed charges for residential users as heterogeneous as in AMBA), and yet all residential tariff structures in the country share two main features in common: varying fixed and variable charges for different sub-categories of consumption, and a marked tendency to have fixed charges well below the level that would allow recovering 70 percent of total distribution costs. So, as we show below, the rebalancing exercise shown in AMBA has to be carried out countrywide, with different magnitudes and details to be worked out by each provincial regulator.

Indeed, we include below a table with a summary of various residential tariff structures observed in 9 different jurisdictions in the interior of the country, involving both private and public firms. In each case, the current tariff structures applicable to the electricity service are expressed with reference to 9 sub-categories of residential users (as occurs in AMBA) even though, in reality, the number of sub-categories outside AMBA varies between a minimum of 3 (Mendoza) and a maximum of 9 (Edelap in La Plata, Province of Buenos Aires), whereas the new fixed and variable charges corresponding to the provincial rebalancing exercises are computed assuming that the distribution of users in those 9 sub-categories coincides with that of AMBA emerging from the NHES 2012. This is an admittedly strong assumption, but we consider it of little relevance in order to present a qualitatively similar result to that obtained in AMBA: fixed charges would have to increase and variable charges would have to decrease in order to have homogeneous fixed and variable charges where the former represent 70 percent of total distribution costs, so that low-consumption residential users would face higher electricity bills and high-consumption residential users would reduce theirs.[22]

Considering Table 9 below, the data include—for 9 jurisdictions, plus AMBA—the current fixed and variable charges for each category (which in the interior of the country are applicable to sub-category boundaries somewhat different than those in AMBA, resulting in average assumed consumption at slightly varying levels in different jurisdictions despite the assumed common distribution of residential users across sub-categories), as well as the current final monthly bill (before taxes), all expressed in US$ (with a 38.5 AR$/US$ exchange rate), and then the new fixed charges, variable charges and monthly bills after the same rebalancing exercise which maintain invariant the profits of the distribution firms (and thus also the total

[22] Imposing AMBA's distribution of residential users over 9 sub-categories on the rest of the country, even though the precise boundaries and assumed average consumption within each category vary in each case, results in an overestimation of the average residential consumption in each jurisdiction of the interior of the country (particularly in the case of EDEA covering Mar del Plata and other municipalities with strong presence of touristic seasonality, highly influenced by the lower annual average consumption in vacationing houses barely used outside the summer. This means that tariff rebalancing outside AMBA will surely involve different magnitudes than those computed here.

expenditure in electricity of all residential users taken together, since the rebalancing exercises assume zero price-elasticity everywhere).

As we can see in the previous to last row for each jurisdiction, where figures for the average residential user are reported, average fixed charges are highest in EDELAP (the city of La Plata, capital of the Province of Buenos Aires) and EDESE (Santiago del Estero), similar to Edenor's, and lowest in Santa Fe, Mendoza and Córdoba, whereas the average monthly bill is highest in EPEC (Córdoba), EDEA (interior of Province of Buenos Aires), ENERSA (Entre Rios), EDELAP, EDESA (Salta) and EPESF (Santa Fe), with intermediate values in EDESE (Santiago del Estero) and the lowest values in EDEMSA (Mendoza), EDET (Tucumán) and (as in previous tables) Edenor (AMBA). EPESF in Santa Fe and ENERSA in Entre Rios appear as the only cases where fixed charges are homogenous across residential users, but in both cases they are particularly low with respect to the fixed cost assumed in the rebalancing exercise.

Table 9. Residential Tariff Structures of Electricity Service and (rough) Rebalancing Exercises in the Interior of the Country, December 2018

Córdoba (EPEC)								
User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	70	1.2	0.087	7.3	16.6	0.058	20.6	183%
R2	160	1.7	0.091	16.2	16.6	0.058	25.8	59%
R3	270	1.7	0.096	27.7	16.6	0.058	32.2	16%
R4	380	1.7	0.099	39.1	16.6	0.058	38.5	-2%
R5	540	2.4	0.114	63.9	16.6	0.058	47.7	-25%
R6	640	2.4	0.115	76.1	16.6	0.058	53.5	-30%
R7	730	2.4	0.128	95.6	16.6	0.058	58.7	-39%
R8	1,000	2.4	0.130	132.2	16.6	0.058	74.2	-44%
R9	1,500	2.4	0.132	200.1	16.6	0.058	103.0	-49%
Avg	363	1.8	0.101	42.7	16.6	0.058	37.5	
R9/R1	21.4	2.0	1.5	27.5	**1.7**	**1.2**	5.0	

Tucumán (EDET)								
User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	60	0.8	0.057	4.2	8.7	0.049	11.6	175%
R2	120	1.5	0.058	8.4	8.7	0.049	14.5	72%
R3	200	1.9	0.061	14.1	8.7	0.049	18.4	31%
R4	330	2.5	0.065	23.8	8.7	0.049	24.8	4%
R5	480	3.2	0.067	35.5	8.7	0.049	32.1	-10%
R6	630	3.2	0.069	46.9	8.7	0.049	39.4	-16%
R7	830	3.2	0.071	62.2	8.7	0.049	49.1	-21%
R8	1,150	3.2	0.073	86.7	8.7	0.049	64.7	-25%
R9	1,500	3.2	0.073	113.4	8.7	0.049	81.8	-28%
Avg	349	2.0	0.063	25.7	8.7	0.049	25.7	
R9/R1	25.0	4.1	1.3	26.9	**0.9**	**1.0**	7.0	

La Plata, Prov Buenos Aires (EDELAP)								
User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	80	1.6	0.066	6.9	14.1	0.054	18.4	167%
R2	200	4.0	0.061	16.3	14.1	0.054	24.9	53%
R3	350	5.1	0.062	26.9	14.1	0.054	33.1	23%
R4	420	7.1	0.064	34.2	14.1	0.054	36.9	8%
R5	470	8.5	0.066	39.4	14.1	0.054	39.6	0%
R6	530	14.5	0.071	52.1	14.1	0.054	42.8	-18%
R7	630	20.1	0.075	67.2	14.1	0.054	48.3	-28%
R8	900	29.1	0.077	98.6	14.1	0.054	62.9	-36%
R9	1,500	35.0	0.078	151.6	14.1	0.054	95.5	-37%
Avg	370	8.6	0.066	34.2	14.1	0.054	34.2	
R9/R1	18.8	22.0	1.2	22.0	**1.4**	**1.1**	5.2	

Interior of Prov Buenos Aires (EDEA)								
User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	60	1.9	0.069	6.0	16.4	0.057	19.8	229%
R2	130	2.8	0.075	12.6	16.4	0.057	23.8	90%
R3	250	3.9	0.079	23.6	16.4	0.057	30.7	30%
R4	425	4.8	0.082	39.7	16.4	0.057	40.7	3%
R5	530	7.7	0.087	53.6	16.4	0.057	46.7	-13%
R6	730	12.5	0.092	79.3	16.4	0.057	58.1	-27%
R7	870	12.5	0.092	92.1	16.4	0.057	66.1	-28%
R8	1,000	12.5	0.092	104.0	16.4	0.057	73.5	-29%
R9	1,500	15.2	0.100	164.5	16.4	0.057	102.0	-38%
Avg	369	5.5	0.080	37.5	16.4	0.057	37.5	
R9/R1	25.0	8.2	1.4	27.3	**1.7**	**1.2**	5.1	

Table 9., continued

Salta (EDESA)

User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	60	1.4	0.083	6.3	14.5	0.054	17.8	181%
R2	130	1.4	0.083	12.1	14.5	0.054	21.6	78%
R3	250	2.8	0.082	23.3	14.5	0.054	28.1	21%
R4	430	2.8	0.082	38.0	14.5	0.054	37.9	0%
R5	550	3.8	0.085	50.8	14.5	0.054	44.4	-12%
R6	730	6.8	0.085	68.8	14.5	0.054	54.2	-21%
R7	870	6.8	0.085	80.7	14.5	0.054	61.8	-23%
R8	1,100	6.8	0.085	100.2	14.5	0.054	74.4	-26%
R9	1,500	12.5	0.091	149.0	14.5	0.054	96.1	-35%
Avg	379	3.2	0.083	35.1	14.5	0.054	35.1	
R9/R1	25.0	9.3	1.1	23.6	**1.5**	**1.1**	5.4	

Santiago del Estero (EDESE)

User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	80	0.7	0.071	6.3	10.6	0.050	14.7	132%
R2	200	2.4	0.057	13.9	10.6	0.050	20.7	49%
R3	350	4.3	0.058	24.6	10.6	0.050	28.2	15%
R4	425	5.8	0.059	31.0	10.6	0.050	32.0	3%
R5	470	9.0	0.061	37.5	10.6	0.050	34.3	-9%
R6	530	9.4	0.061	42.0	10.6	0.050	37.3	-11%
R7	630	20.0	0.062	59.0	10.6	0.050	42.3	-28%
R8	900	21.4	0.063	77.8	10.6	0.050	55.9	-28%
R9	1,500	39.0	0.063	134.1	10.6	0.050	86.1	-36%
Avg	371	6.8	0.061	29.3	10.6	0.050	29.3	
R9/R1	18.8	59.1	0.9	21.2	**1.1**	**1.0**	5.9	

Santa Fe (EPESF)

User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	50	1.3	0.067	4.6	11.7	0.054	14.4	211%
R2	100	1.3	0.069	8.2	11.7	0.054	17.1	109%
R3	220	1.3	0.083	19.5	11.7	0.054	23.6	21%
R4	350	1.3	0.095	34.7	11.7	0.054	30.6	-12%
R5	465	1.3	0.105	49.9	11.7	0.054	36.8	-26%
R6	530	1.3	0.108	58.5	11.7	0.054	40.3	-31%
R7	630	1.3	0.112	71.7	11.7	0.054	45.7	-36%
R8	1,000	1.3	0.119	120.6	11.7	0.054	65.7	-46%
R9	1,500	1.3	0.124	186.7	11.7	0.054	92.6	-50%
Avg	316	1.3	0.086	33.9	11.7	0.054	28.8	
R9/R1	30.0	1.0	1.8	40.2	**1.2**	**1.1**	6.4	

Mendoza (EDEMSA)

User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	80	0.3	0.055	4.7	7.1	0.047	10.9	134%
R2	170	0.5	0.064	11.4	7.1	0.047	15.1	33%
R3	230	0.5	0.064	15.2	7.1	0.047	18.0	18%
R4	350	3.2	0.064	25.7	7.1	0.047	23.6	-8%
R5	470	3.2	0.064	33.4	7.1	0.047	29.3	-12%
R6	530	3.2	0.064	37.3	7.1	0.047	32.1	-14%
R7	630	3.2	0.064	43.7	7.1	0.047	36.8	-16%
R8	900	3.2	0.064	61.1	7.1	0.047	49.5	-19%
R9	1,500	3.2	0.064	99.7	7.1	0.047	77.8	-22%
Avg	334	1.5	0.063	22.9	7.1	0.047	22.9	
R9/R1	18.8	12.6	1.2	21.4	**0.7**	**1.0**	7.2	

Entre Rios (ENERSA)

User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	70	1.6	0.072	6.7	12.2	0.054	16.0	139%
R2	150	1.6	0.076	13.1	12.2	0.054	20.3	55%
R3	250	1.6	0.087	23.3	12.2	0.054	25.7	10%
R4	370	1.6	0.101	38.9	12.2	0.054	32.2	-17%
R5	430	1.6	0.106	47.2	12.2	0.054	35.4	-25%
R6	530	1.6	0.112	61.0	12.2	0.054	40.8	-33%
R7	630	1.6	0.116	74.8	12.2	0.054	46.2	-38%
R8	900	1.6	0.123	112.0	12.2	0.054	60.7	-46%
R9	1,500	1.6	0.129	194.7	12.2	0.054	93.1	-52%
Avg	331	1.6	0.091	36.4	12.2	0.054	30.1	
R9/R1	21.4	1.0	1.8	29.1	**1.2**	**1.1**	5.8	

AMBA / GBA (EDENOR)

User	Avg use (kWh/mo)	Fixed Charge 2018	Var Charge 2018	Bill 2018 (month)	New Fixed Charge	New Var Charge	New monthly bill	Change in Monthly Bill
R1	77	0.8	0.051	4.7	9.8	0.049	13.6	188%
R2	229	1.4	0.051	13.1	9.8	0.049	21.0	61%
R3	361	2.4	0.052	21.2	9.8	0.049	27.5	29%
R4	424	2.8	0.054	25.8	9.8	0.049	30.5	18%
R5	474	4.2	0.056	31.0	9.8	0.049	33.0	6%
R6	546	8.4	0.058	39.9	9.8	0.049	36.5	-9%
R7	646	21.8	0.062	61.6	9.8	0.049	41.4	-33%
R8	897	31.3	0.064	89.0	9.8	0.049	53.6	-40%
R9	1,970	37.7	0.065	165.8	9.8	0.049	106.0	-36%
Avg	390	6.5	0.054	28.9	9.8	0.049	28.9	
R9/R1	25.6	47.3	1.3	35.1	**1.0**	**1.0**	7.8	

Source: Authors' calculations.

In all cases, the tariff rebalancing (magnitude of changes of new tariffs and impact on various types of residential users, shown in the last column of each provincial summary) is significant. Indeed, the last row in each case shows two synthetic indicators of current tariff distortions. The first distortion is shown by various ratios observed in 2018 regarding R9 vs. R1 users, i.e., i) their relative consumption based on their current R sub-categories (24.6 times higher for R9 than R1 in AMBA); ii) the ratio of fixed charges and variable charges (46.3 and 0.3 times higher fixed and variable charges for R9 than R1 also in AMBA); and iii) the ratio of their monthly bills (34.1 times higher for R9 than R1 in AMBA). Notice that if the relative monthly bill is higher than the relative consumption ratio (as occurs in every jurisdiction before rebalancing), that is an obvious sign of tariff distortion since efficient average tariffs should decrease with consumption as fixed charges become less important in the overall bill. Indeed, we can see that after rebalancing, the new ratios of monthly bills (the R9/R1 monthly bill ratios after rebalancing) would be much lower than the ratios of monthly consumption between these two categories (for instance, 6.0 vs. 25.6 in AMBA).

The second distortion is shown in the **bold** figures, also in the last row of each provincial summary. These indicate the ratios of future fixed and variable charges in each province vis-à-vis those of Edenor in AMBA (assuming that the level of distribution costs is different across jurisdictions as signaled by the current total income received by each regulated firm). In Córdoba, for instance, rebalanced fixed charges are on average 70 percent higher than in AMBA, while variable charges are 20 percent higher. This demonstrates the magnitude of absolute cost differences which make DER generally more attractive in the interior of the country, resulting in variable charges after rebalancing that should be equal or slightly above those of Edenor. They are 10 percent higher in Santa Fe and 20 percent in the interior of Buenos Aires for EDEA. Fixed charges are generally much higher—70 percent higher in Córdoba, 40 percent higher in the city of La Plata with EDELAP, 70 percent higher in the interior of Province of Buenos Aires with EDEA and 50 percent higher in Salta; only in Mendoza do fixed charges appear to be (30 percent) lower than in AMBA. Of course, to the extent that these differences in fixed and variable distribution costs are due to inefficiencies or excessive profits, future variable charges would present some differences (downward in general).

4.5 Social Tariffs: Main Elements of Their Design and Quantification

If social tariffs are computed as a fraction of full-paying tariffs (so that discounts are proportional to consumption, reducing both fixed and variable charges proportionally), the previous results obtained in the rebalancing exercise extend to social tariffs: such rebalancing implies changes in social tariffs in the same proportions, increasing social tariffs for low-income users with low consumption of energy and reducing social tariffs for low-income users with high consumption of energy (indeed, this might end up reducing the total amount paid as subsidies for social tariffs).

In any case, a well-designed social tariff is one where the target group is selected based on objective information about its low-income condition, and then the public assistance is provided in the form of lump-sum transfers which leave untouched the price signals so that consumption decisions are efficient. We can thus estimate, based on the available data on income distribution in AMBA used in this section, the total fiscal cost of the existing social tariff applicable to Edenor's poor users (assumed to be those in the 3 lowest deciles), and compare this estimate with an estimation of a compensatory transfer that would leave all poor users (i.e., those in the lowest 3 deciles) paying the same monthly amounts after rebalancing. So, those two estimations would indicate that, while the tariff rebalancing would eliminate all hidden cross-subsidies among residential users, a compensatory transfer from the government could still protect low-income users so as to keep (now explicitly through the compensation) the current cross-subsidies benefiting them (but not the explicit social tariff in place).

The existing social tariff effectively reduces the wholesale price paid for electricity to about 30 percent of lower-income users: the wholesale cost of energy for target-users is 100 percent subsidized for the first 150 kwh/month consumed, and 50 percent for up to an additional 150 kwh/month consumed.[23] Such a design is very incorrect, not regarding its targeting[24] but because it subsidizes wholesale energy instead of distribution charges (which include joint costs and are then more prone to price differentiations short of being cross-subsidies), and because it distorts variable instead of fixed payments (inducing incorrect consumption decisions).

In any case, since we have an estimation of the number of users in the lowest 3 income deciles, including whether they consume less or more than 150 kwh/month, and the subsidy is paid on the MEM price (the same value no matter the sub-category of user who receives it), we can produce the estimated fiscal cost of such subsidy (constructed as in Table 10 below). Indeed, this amount is 69.1 MM US$/year (or 97 US$/year per social tariff beneficiary), and represents

[23] As of December 2018, the subsidy contained in the social tariff for the electricity service covers 100 percent of the wholesale price of electricity for consumption up to 150 kwh/month, and 50 percent of it for exceeding consumption up to the same amount, regardless of the annual consumption level of the user receiving the social tariff (which means that discounts decrease with their consumption). This implies a discount on monthly bills that decreases as consumption increases: a 62 percent discount for R1 users with a social tariff, a 44 percent discount to R2 users, 35 percent to R3, 29 percent to R4, and finally 8 percent to R8 and 5 percent to R9. Since 2019, this subsidy was delegated to the provinces (some of which, such as Buenos Aires, have delegated it to municipalities).

[24] Beneficiaries of social tariffs (both in natural gas and electricity) have to fulfill the following conditions: be retired or pensioners with benefits not higher than 2 minimum wages (around US$ 280 per month), self-employed workers with income also not higher than 2 minimum wages (called "*monotributistas*"), beneficiaries of social programs, domestic workers (maids), unemployed workers who receive unemployment insurance, Malvinas war veterans, persons with disabilities or families including electricity-dependent or handicapped members. On the other hand, beneficiaries cannot have more than one house or property, a vehicle less than 10 years old (unless handicapped), airplanes or luxury boats.

15.1% of the total cost of wholesale energy consumed by residential users served by Edenor (estimated at current prices).[25]

Table 10. Estimated Fiscal Cost of Current Social Tariffs Reaching Edenor's Users in the Lowest 3-Deciles of Income

Decile	1	2	3	Total
# of R users consuming less than 150 kwh/month	55.328	29.019	34.886	119.233
# of R users consuming more than 150 kwh/month	193.709	194.954	205.024	593.687
Fiscal subsidy to those consuming 150 kwh/month -100% of MEM prices- (MM AR$/year)	146	76	92	314
Fiscal subsidy to those consuming beyond 150 kwh/month -100% on 150 kwh/month + 50% on 150 kwh/month- (MM AR$/year)	766	771	810	2.347
Total fiscal subsidy to Social Tariff (MM AR$/year)				2.661
Total fiscal subsidy to Social Tariff (MM US$/year)				69,1

Source: Authors' calculations.

Our proposal is to eliminate the current social tariff and replace it with a fixed sum transferred to the target population; low-income residential users would receive a rebate or global discount on their monthly bills regardless of their consumption level. If, in particular, such compensation could be designed so as to leave all users belonging to the 3 lowest deciles paying the same monthly bill that they pay now (without the explicit current social tariff, but with an implicit social tariff emerging from artificially low fixed charges net of the compensating transference), and we include all users in those deciles (i.e., those belonging to low R sub-categories facing higher bills after rebalancing and those who belong to higher R sub-categories who face lower monthly bills after rebalancing), the estimated fiscal cost would be US$ 25.0 MM/year; if the latter (users R6 to R9, whose compensation for the rebalancing would in fact mean that they would have to receive a negative subsidy—i.e., face a tax—to undo the reduction of their electricity bills) are left aside, the estimated total cost of the scheme is US$ 50.6 MM/year or 5.7 percent of total residential expenditure in electricity (see Table 11 below).[26]

[25] This estimated fiscal cost of social tariffs represents 8 percent of total electricity expenditures by residential users of Edenor. Also, a linear extrapolation to Argentina results in an annual estimated cost of US$ 375 million.

[26] Notice that delivering such global amount of compensating variations to each low-income user might in fact be impossible and instead it would require a common (equal) transference to all of them. Indeed, it might be very difficult to give compensations depending on the decile or current R sub-category to which the user belongs, and thus only the average beneficiary would end-up receiving the same social assistance before and after tariff rebalancing. In any case, this becomes an issue of implementation / focalization of the social tariff outside the scope of this paper.

Table 11. Fixed-Sum Transfers to Replace Current Social Tariffs – Low-Income Users of Edenor

	Current Spending on electricity (MM US$/year)				Post-rebalancing spending on electricity (MM US$/year)				Compensatory variation (MM US$/year)			
Decile	1	2	3	Total	1	2	3	Total	1	2	3	Total
R1	3,1	1,6	2,0	6,8	9,0	4,7	5,7	19,5	5,9	3,1	3,7	12,7
R2	12,2	13,5	12,1	37,8	19,6	21,7	19,5	60,8	7,4	8,2	7,4	23,0
R3	12,3	9,3	8,8	30,3	15,9	12,0	11,4	39,2	3,6	2,7	2,6	8,9
R4	6,9	10,0	12,5	29,5	8,2	11,8	14,8	34,8	1,3	1,8	2,3	5,4
R5	3,6	2,5	4,5	10,6	3,8	2,7	4,7	11,2	0,2	0,2	0,3	0,7
R6	2,5	8,2	7,7	18,4	2,3	7,5	7,1	16,8	-0,2	-0,7	-0,7	-1,6
R7	9,2	5,6	11,5	26,2	6,2	3,7	7,7	17,6	-3,0	-1,8	-3,8	-8,6
R8	19,3	9,2	9,7	38,2	11,6	5,5	5,8	23,0	-7,7	-3,7	-3,8	-15,2
R9	0,0	0,6	0,0	0,6	0,0	0,4	0,0	0,4	0,0	-0,2	0,0	-0,2
Total	69,2	60,4	68,8	198,4	76,7	70,0	76,7	223,4	7,5	9,6	8,0	25,0
Losers (R1 to R5)	38,1	36,9	39,9	115,0	56,5	52,9	56,1	165,6	18,4	16,0	16,2	50,6

Source: Authors' calculations.

So, by defining the amount of a fixed compensation to low income electricity users, the current social tariff could be replaced with a new one in which the global amount of assistance is less expensive. Under such rebalancing-plus-compensating transfers for the poorest 30 percent, current social tariff beneficiaries would face higher tariffs: they lose their actual formal benefits and retain only the implicit cross-subsidy currently received by full-payers.

Another dimension to take into account has to do with affordability beyond poverty, normally referred to as "energy poverty." The next table shows the share of electricity service in households' total expenditures in AMBA, in 2012 and in 2018 pre and post-rebalancing, considering both their deciles and tariff sub-categories. We can see that, without social tariffs, the burden of the electricity service would be above 10 percent of households' total spending both before and after rebalancing, well above the percentage in 2012 when tariffs were artificially depressed. Nonetheless, the percentage for those deciles would not increase very much post-rebalancing, as many low-income users belong to sub-categories R6 to R9 which face a tariff reduction, partially compensating the negative effect on poor users who belong to sub-categories R1 to R5. Indeed, once we observe the percentage of rebalancing according to users' tariff sub-categories (on the right-hand side of Table 12 below), it increases noticeably for low-consumption users and also decreases sharply for high-consumption users, with an incidence range across sub-categories that is well below the range observed for the 3 lowest deciles of the household income distribution.

Table 12. Share of Electricity Bill on Total Household Spending, AMBA, 2012 and 2018, Pre- and Post-Rebalancing

Decile	2012	2018	2018 post-rebalancing
1	1,8%	18,2%	20,2%
2	1,1%	11,2%	12,9%
3	0,9%	9,0%	10,0%
4	0,7%	6,7%	7,6%
5	0,7%	7,0%	7,0%
6	0,6%	5,6%	5,7%
7	0,4%	4,3%	4,5%
8	0,5%	4,4%	4,1%
9	0,4%	3,4%	3,2%
10	0,3%	3,2%	2,6%

R Sub-Category	2012	2018	2018 post-rebalancing
1	0,1%	0,9%	2,7%
2	0,3%	2,7%	4,3%
3	0,4%	4,3%	5,6%
4	0,5%	4,9%	5,8%
5	0,5%	5,4%	5,8%
6	0,6%	5,8%	5,3%
7	0,9%	10,3%	6,9%
8	1,1%	12,4%	7,4%
9	1,7%	11,9%	7,6%

Source: Authors' calculations.
Note: Calculations include taxes and exclude social tariffs.

In light of this result, we could wonder about the need to introduce a more general social tariff than previously discussed, also including users in deciles 4 and 5 of households' income distribution (i.e., granting them a compensating transfer in order to leave them indifferent after the tariff-rebalancing exercise). In Table 13 below, we compute the cost such compensation to users of deciles 4 and 5, which (considering the compensation only of those users that would be worse-off after the rebalancing exercise) would add 30 million US$/year to the previously estimated 50.6 million US$/year (see Table 11) to compensate Edenor's residential users in the 3 lowest deciles who would lose the implicit subsidies they currently receive from the distorted tariff structure.

Table 13. Fixed-Sum Transfers to Replace Current Social Tariffs – Middle-Low Income Users of Edenor

	Current Spending on electricity (MM US$/year)			Post-rebalancing spending on electricity (MM US$/year)			Compensatory variation (MM US$/year)		
Decile	4	5	Total	4	5	Total	4	5	Total
R1	2,1	1,8	3,9	6,0	5,2	11,2	3,9	3,4	7,3
R2	14,7	7,7	22,4	23,6	12,3	35,9	8,9	4,7	13,6
R3	11,5	7,8	19,3	14,8	10,1	24,9	3,4	2,3	5,6
R4	8,1	10,9	19,0	9,5	12,9	22,4	1,5	2,0	3,5
R5	0,4	3,5	3,9	0,5	3,7	4,2	0,0	0,2	0,2
R6	5,8	7,4	13,2	5,3	6,8	12,0	-0,5	-0,6	-1,1
R7	10,5	5,8	16,3	7,1	3,9	11,0	-3,5	-1,9	-5,4
R8	12,7	25,0	37,7	7,6	15,1	22,7	-5,0	-9,9	-15,0
R9	0,0	1,4	1,4	0,0	0,9	0,9	0,0	-0,5	-0,5
Total	65,7	71,3	137,0	74,4	70,9	145,3	8,7	-0,4	8,3
Losers (R1 to R5)	36,7	31,7	68,4	54,5	44,3	98,7	17,7	12,5	30,3

Source: Authors' calculations.

4.6 Current Taxes on the Electricity Service and Environmental Demands

Price signals are also affected by taxes, which in Argentina show problems both in levels and structures across jurisdictions (see Navajas, 2018).

Table 14 below shows a summary of national, provincial and local taxes applicable on monthly bills of the electricity service, regardless of the technology with which the consumed energy was generated. National taxes include basically the Value Added Tax (VAT), whereas provincial taxes include *Ingresos Brutos* (IIBB) and some other charges and municipal taxes are basically sales taxes.[27] While most of these taxes and charges are ad-valorem, there are many cases where taxes have a specific (fixed) form. Some cases also include increasing-block charges. Overall, the joint magnitude of taxes across provinces range from 21 percent to more than 50 percent of the net-of-tax spending on electricity by each final user, a very high rate indeed.

This inefficient configuration of taxes would require a direction of reform with three main ingredients: first, the level of taxes should be reduced; second, the jurisdictional structure should converge to a single format; and third, the tax design should not induce a bias in favor of or against decentralization of electricity provision.

The first two points require coordination across provinces, which we see as part of a required regulatory convergence. The third point, which depends on the central government, has not been properly dealt with in the recent DER legislation, as DER generation is exempted from national taxes (both VAT and earnings tax), while centrally provided energy (from any technological source) is obviously not. In light of such distortion, we suggest the concentration of taxes at the generation level, according to the generation technology (so that negative externalities of fossil generation are penalized, as with a carbon tax), and the unification of taxes for MEM and DER generation.

Alternatively, it should be noted that (except for the few increasing-block cases) almost all national, provincial and local taxes apply linearly to the final electricity bill paid to the distribution company, and the amount of taxes to be collected will remain invariant after a tariff rebalancing that maintains constant profits and assumes no change in consumption (and then, in consumer spending on electricity). Nonetheless, tax collection will be partly reduced because of

[27] Since 2016 there have been some minor changes in these rates, particularly a 6 percent reduction in the Province of Buenos Aires in 2018 (which eliminated by law all municipal charges on electric tariffs since 2019), not reflected in the table.

higher penetration of DER, which is exempted from VAT and earnings taxes at the national level, both regarding generation for self-consumption and injections of excess generation into the network. So, this asymmetric treatment of taxes to distribution services and DER might both encourage excessive investment in DER and lower tax collection unless it is centralized at the generation level and linked to technology and emissions.

Table 14. Argentina: Taxes Applicable to the Electricity Service, as Percentage of the Amounts Paid to Distribution Companies, 2016

	National (VAT)	Provincial (IIBB)	Municipal	Total
Misiones*	21.0%	0.0%	0.0%	21.0%
Corrientes	21.0%	0.0%	0.0%	21.0%
Salta*	21.0%	0.0%	0.0%	21.0%
Formosa	21.0%	0.0%	0.0%	21.0%
Neuquén*	21.0%	0.0%	4.5%	25.5%
Río Negro	21.0%	0.0%	6.0%	27.0%
CABA*	21.0%	0.0%	6.4%	27.4%
San Luis	21.0%	0.0%	6.4%	27.4%
Jujuy	21.0%	1.5%	6.0%	28.5%
Mendoza	21.0%	8.5%	0.0%	29.5%
Santa Fe	21.0%	1.5%	8.4%	30.9%
Chaco*	21.0%	10.7%	0.0%	31.7%
Córdoba*	21.0%	1.9%	10.0%	32.9%
Tucumán*	21.0%	0.0%	15.0%	36.0%
San Juan*	21.0%	3.7%	13.5%	38.2%
Santiago del Estero*	21.0%	0.0%	20.4%	41.4%
La Pampa	21.0%	2.5%	18.5%	42.0%
La Rioja	21.0%	1.4%	20.0%	42.4%
La Plata*	21.0%	15.5%	6.4%	42.9%
GBA*	21.0%	16.1%	6.4%	43.6%
Entre Ríos	21.0%	0%-13%-18%	24.7%	45.7%
Resto PBA*	21.0%	24.1%	6.0%	51.1%

* There are some additional charges, different than taxes, not included here.

Source: ADEERA (2016). Note: In Entre Rios, the provintial tax goes to the Fondo de Desarrollo Eléctrico de Entre Rios (FDEER), and represents 0%, 13% or 18% depending on the quantities consumed.

Overall, then, it is perfectly possible to move to a tariff structure that better reflects the structure of costs of the distribution service for residential users, combined with social tariffs that compensate low-income users for the loss of current cross-subsidies benefiting them and a redefinition of the tax structure that favors clean and renewable generation *vis-à-vis* polluting fossil fuel sources.

5. Concluding Remarks

The two main and general adaptations needed to properly deal with the challenges posed by the changing environment in the electricity sector discussed in this paper—institutional and average annual distribution tariff restructuring—are indeed key in order to further advance in many other adaptations regarding social tariffs and the tax structure, as briefly discussed above, but also regarding real-time pricing both in distribution, transportation and generation. Indeed, the tariff-rebalancing plus social tariff and tax-design corrections explored or implied in the previous section, despite their importance, are only a first step in reforms addressing dilemmas that will become more relevant in the future. Presenting the full list of such issues is beyond the scope of the paper, but we can surely identify some of them in order to get a flavor of the questions and challenges ahead.

5.1 Wholesale Price Corrections

A correct decentralized decision on whether to develop DER or not requires that all the relevant costs attached to that investment be compared with all the relevant costs avoided by reducing the use of the energy conventionally delivered through the distribution company, including not only variable distribution charges but also variable transportation and generation costs in each place and time. The introduction of more intermittent renewable resources expected in the future will both magnify these real-time cost and (under price-bid systems) price differences and allow good use of them in order to guide decentralized decisions on new investments in various DER such as storage, devices to program and shift demand during the day, etc.

Regarding generation, prices sanctioned in a wholesale market presumably reflect the cost of the last unit dispatched. Yet such representation is generally imperfect for several reasons. Considering a cost-based design, a salient limitation is that opportunity (economic) costs diverge from the direct fuel costs declared by each generator due to both opportunities to exercise short-term market power (which can be a good incentive to incentivize new entry) and the existence of generators' constraints on energy or start limits, most of which arise because of physical and financial inflexibilities that become more relevant with increasing shares of variable and unpredictable generation from renewable resources. While this limitation could be avoided in bid-based systems, allowing bids to better reflect the opportunity costs of various generators at different hours of each day, the resulting larger hourly price variations over time and across regions is frequently suspected of being the result of market power by pivotal generators, prompting "pro-competitive" interventions consistent with setting price caps based on cost computations, again limiting price signals.[28]

In that regard, the Argentine system is not only cost based, but also has other features that significantly depress wholesale price variations over time. For instance, considering monthly intervals, the average cost of energy and capacity in the MEM during 2016-2018 ranged from 7.3 cents US$/kWh in the summer to 9 cents US$/kWh in the winter, which yields a maximum ratio (highest-to-lowest monthly cost of generation) of 1.33. Since these average monthly costs include both energy and capacity ("reserve power") costs, they are less volatile than true marginal costs. Furthermore, wholesale prices paid by residential users are regulated at levels much lower than average monthly costs, with monthly variations also much lower than those observed in the average generation costs (in fact, seasonal reference prices are set only twice a year, with fixed nominal values for 5 and 7 months), so that the ratio of highest-to-lowest seasonal US$ price is determined by changes in the exchange rate and not related with the different costs of generation in each season of the year.

Thus, as sanctioned prices do not reflect variable (or even annual average) costs of generation due to various averaging of annual fixed costs (contained in the monotonic price) and remaining fiscal subsidies which distort prices seen by both supply and demand, a clear task ahead is to move fast to de-averaging wholesale electricity prices and equating supply and demand hourly prices (reflecting at least direct incremental costs).

5.2 Asymmetric Information on Fixed vs. Variable Distribution Costs

Under a rebalanced, cost-reflective tariff structure, changes in the quantity of electricity demanded from the distribution company by existing residential users leave the firm indifferent in terms of profits: fixed distribution costs are recovered with fixed charges, and variable distribution costs—whatever the level of consumption—are recovered with variable distribution charges, minimizing (but not eliminating as discussed further below) the conflict of interest

[28] All price-bid systems have various types of regulatory interventions aiming at the reduction of price volatility, including in particular the separate remuneration of capacity and ancillary services, which means that *ceteris paribus* price variations in price-bid systems are not necessarily larger than price variations in cost-based systems. In Colombia, for instance, generators have to offer their energy at the same price for the entire day, which prevents them from reflecting different marginal and opportunity costs varying with the load at different hours. See Wolak (2002, 2003), Hogan (2014) and Muñoz et al. (2018).

between the distribution company and potential *prosumers* (and eventual intermediaries). But, let us contemplate the hypothesis that *prosumers* might decide to exit the distribution company, and then ask what happens if the regulator wants to implement an efficient tariff structure but thinks that the variable cost of distribution is higher than its true level (and thus that fixed distribution costs are less relevant)?

The answer is that in that case she would set a variable charge at a higher-than-efficient level (and a fixed charge lower than the implied average incidence of each residential user on fixed distribution costs), compensating for an income deficit to cover fixed costs through fixed distribution charges with a variable surplus collected as a positive margin between variable distribution costs and charges. This means that, if for any reason the demand faced by the distribution company falls *vis-à-vis* its present or expected level, that would impose a net income loss on it. On the contrary, if the regulator believes that fixed costs are higher than what they are in reality, the variable distribution charge will be set below its true economic cost (and the fixed charges above the individual impact on fixed costs), so that if the for any reason the demand faced by the distribution company is lower than expected, then that would impose a net income gain on it (as it saves some of the variable losses it suffered with artificially low variable distribution charges without having to return the fixed income obtained through high fixed distribution charges).

Of course, in the face of DER development implying the risk of a reduced demand faced by the distribution company both because of the price-elasticity of demand of those users and prosumers who remain connected to the network and because of prosumers who decide to exit it, the regulated firm would prefer to be protected by convincing the regulator that its fixed costs are higher than they are. Regulators should be aware of this biased incentive (adverse selection) and be cautious about cost figures reported by regulated firms who lobby to set fixed distribution charges (or other fixed transfers) above true fixed distribution costs.

5.3 Inefficient Duplication of the Network with Exit

Even setting the stage for implementing the right price signals in order to correctly invest in DER and for having various different generation sources competing on equal conditions (after environmental taxes or charges are imposed on some technologies), as done before by equating variable distribution charges (including taxes) with variable (social) distribution costs, users who exit from the network might impose a significant cost to the rest. If residential users massively decide to abandon the distribution network (because they become sufficiently confident that new DER will suffice to provide them with their consumption needs, for instance if enough storage capacity becomes available), then the relevant economic dilemma changes radically *vis-à-vis* the one discussed before: even when investing in DER is attractive in order to reduce the electricity bill paid by some residential users, if these users abandon the distribution network then the same common and fixed costs incurred by the entire distribution network will have to be supported by fewer residential users. The fixed cost of the distribution network, which we previously allocated as equal amounts or fractions to each residential user, is in fact a joint or common cost for serving all (or at least a bunch, neighboring) residential users, so that if one of them exits the network to depend fully on DER then the total cost of the electricity service to be borne by the remaining users increases (notice that this is beyond the fact that fixed distribution costs are sunk costs, as this issue would be one of a transition, where distribution companies lose in the short to medium term if some residential users exit, but not in the longer term when assets are fully amortized).[29]

This potential situation poses a question on whether connection to the network for DER *prosumers* should be mandatory, or subsidized. Indeed, a more natural solution, such as the introduction of a menu of two-part tariffs (M2PT) including a "low user scheme" (with a lower fixed charge and higher variable charge from the distribution company) might not work sufficiently well to avoid defection by high-consumption residential users. While that scheme would probably avoid disconnection by low-user electricity users not reached by the social tariff scheme offering rebates, it is not sure that it would reduce the incentive of (medium and high-

---

[29] The situation may be considered thusly: the current distribution network has a $100/year cost that is 100 percent fixed, common and sunk to serve its 100 residential users. (If only 70 percent of the cost had this feature, and 30 percent were variable cost, the problem would be qualitatively the same, so we leave variable costs out.) Assume also that, for some residential users (with good sun-orientation, space, etc.), self-generation costs $0.5/year, with variable cost equaling zero as well. Then, when technology for DER develops and residential users see the options, 10 users install their own generating plant but remain as users of the utility (and become potential DER generators injecting their excess production to the network). Then, if the fixed charge faced by each user is 1 percent of the total distribution cost (each residential user paying equal fixed charges which add up to the total fixed cost of the network, as we did in our rebalancing exercise), nothing changes for the distribution company, and the new situation is efficient and sustainable. But, if DER technology develops further and 5 residential users decide to disconnect from the network, then the remaining 95 percent of users will have to pay an additional 6 percent of total cost as a fixed charge to make-up for the missing users failing to contribute to the joint fixed cost. If, on the other hand, the fixed cost was fixed and sunk but not joint, then that exit would leave the distribution firm with 5 percent of its assets irrecoverable, but in the longer term the cost of the network would be $95/year instead of $100/year, so the total cost of energy would go down.

consumption) prosumers to disconnect themselves from the distribution network (since the lower fixed charged they face would allow a tariff reduction similar to the tariff increase attached to some minimum level of electricity delivered by the distribution company within the low-user scheme).

References

Agterberg, P. 2017. "How to Manage Upcoming Challenges in the Electricity Market?" OECD Working Party 2 on Competition and Regulation. Paris, France: OECD.

Baker, P., R. Blundell and J. Mickelwright. 1989. "Modeling Household Energy Expenditures Using Micro-Data." *Economic Journal* 99: 720-738.

Borenstein, S. 2016. "The Economics of Fixed Cost Recovery by Utilities." *Electricity Journal* 29(7).

Corneli, S., and S. Kihm. 2015. "Electric Industry Structure and Regulatory Responses in a High Distributed Energy Resources Future." *Future Electric Utility Regulation*, Berkeley Lab.

Costa, P., J. Montero and R. Roson. 2018. "The Impact of Disruptive Technologies on Infrastructure Networks." GOV/RPC/NER (2018)3, OECD, 11th Meeting of the Network of Economic Regulators.

Cramton, P. 2017. "Electricity Market Design." *Oxford Review of Economic Policy* 33(4): 589-612.

De Figueiredo, R., P.T. Spiller and S. Urbiztondo. 1999. "An Informational Rationale for the Administrative Procedures Act." *Journal of Law, Economics and Organization* 15(1).

Glachant, J-M. 2012. "Regulating Networks in the New Economy." *Review of Economics and Institutions* 3(1).

Hancevic P., W. Cont and F. Navajas. 2016. "Energy Populism and Household Welfare." *Energy Economics* 56: 404-34.

Hansen, J.P., and J. Percebois. 2017. *Electricity in Transition: What Europe and the Markets Couldn't Tell You.* Paris, France: Odile-Jacob.

Hogan, W. 2014. "Electricity Market Design and Efficient Pricing: Applications for New England and Beyond." Available at: https://sites.hks.harvard.edu/fs/whogan/Hogan_Pricing_062414.pdf.

Komives K., V. Foster, J. Halpern and Q. Wood. 2005. *Water, Electricity and the Poor: Who Benefits from Utility Subsidies?* Washington, United States: World Bank.

Littlechild, S. 2011. "Regulation and Customer Engagement." *Economics of Energy & Environmental Policy*.

MIT. 2016. *The Utility of the Future: An MIT Energy Initiative Response to an Industry in Transition*. Cambridge, United States: MIT.

Mercados Energéticos. 2018. *Análisis Prospectivo de la Generación Eléctrica en Argentina*. Report for Tecpetrol, May.

Muñoz, F.D., S. Wogrin, S.S. Oren and B.F. Hobbs. 2018. "Economic Inefficiencies of Cost-based Electricity Market Designs." *Energy Journal* 39(3).

Natale O., F. Navajas and M. Panadeiros. 2018. "Descarbonizar el Sistema Energético Argentino: Algunas Reflexiones." In: J.M. Fanelli, editor. *Desarrollo Sostenible y Ambiente en la Argentina*. Buenos Aires, Argentina: Siglo XXI.

Navajas, F. 2004. "Structural Reforms and the Distributional Effects of Price Changes in Argentina." In: E. Bour, D. Heymann and F. Navajas, editors. *Latin American Macroeconomic Crisis, Trade and Labour*. London, United Kingdom: MacMillan.

Navajas, F. 2009. "Engel Curves, Household Characteristics and Low-User Tariff Schemes in Natural Gas." *Energy Economics* 31(1): 162-168.

Navajas, F. 2018. "Impuestos y Cargos Específicos en las Tarifas de los Servicios de Infraestructura." Nota Técnica IDB-TN-1473. Washington, DC, United States: Inter-American Development Bank. Available at: https://publications.iadb.org/handle/11319/9032.

Peterson, C., and A. Ros. 2018. "The Future of the Electric Grid and its Regulation: Some Considerations." *Electricity Journal* 31.

Pérez-Arriaga I., J.D. Jenkins and C. Batlle. 2017. "A Regulatory Framework for an Evolving Electricity Sector: Highlights of the MIT Utility of the Future Study." *Economics of Energy and Environmental Policy* 6: 71-92.

Pollitt, M. 2008: "Electricity Reform in Argentina: Lessons for Developing Countries." *Energy Economics* 30: 1536–67.

Urbiztondo, S. 1997. "Confusing Fixed and Variable Costs under Ramsey Regulation." Documento de Trabajo 3. La Plata, Argentina: Universidad Nacional de la Plata.

Urbiztondo, S. 2008. "Tarifa Social y Buenos Modales Regulatorios: El Límite a los Subsidios Cruzados." In: F. Navajas, editor. *Tarifa Social en los Sectores de Infraestructura en la Argentina*. Buenos Aires: Editorial Temas.

Urbiztondo, S. 2017. "Estimación de la Demanda Residencial de Gas Natural en el Gran Buenos Aires: Período 1993–2017." *Indicadores de Coyuntura* 590. Buenos Aires, Argentina: Fundación de Investigaciones Económicas Latinoamericanas.

Villar, J., R. Bessa and M. Matos. 2018. “Flexibility Products and Markets: Literature Review.” *Electric Power System Research* 154: 329-340. Available at: https://www.sciencedirect.com/science/article/abs/pii/S0378779617303723.

Wolak, F. 2003. “Designing Competitive Wholesale Electricity Markets for Latin American Countries.” OECD-IADB, First Meeting of the Latin American Competition Forum. Available at: http://www.stanford.edu/~wolak.

Wolak, F. 2004. “Lessons from International Experience with Electricity Market Monitoring.” Mimeographed document. Available at: http://www.stanford.edu/~wolak.

Wolak, F. 2017. “Efficient Pricing: The Key to Unlocking Radical Innovation in the Electricity Sector.” OECD Working Party 2 on Competition and Regulation. Paris, France: OECD.

Wolak, F. 2018. “Evidence from California on the Economic Impact of Inefficient Distribution Network Pricing and a Framework for a Proposed Solution.” Stanford, United States: Stanford University: Mimeographed document. Available at: https://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/nber_disribution_network_wolak.pdf.

Appendix 1. Three Provincial Examples of Institutional Design and Public Hearing Experiences

Área Metropolitana de Buenos Aires (AMBA)

The AMBA includes the City of Buenos Aires and neighboring municipalities in the Province of Buenos Aires historically attended by SEGBA, the national electricity company dissolved by the reform by Law 24.065 in 1992. The regulation of the two distribution companies succeeding SEBGA, Edesur and Edenor, is delegated to ENRE, an entity relatively autonomous in terms of its design. Members of its directory are designated through public contest, proposed by the National Executive Power based on a short-list of proposed candidates selected by a respectable evaluating committee and later confirmed by the National Senate; tariff decisions require public hearings; it regulates two distribution companies of similar size, with a regulatory framework and contractual design which years ago served as a benchmark for most modern regulation at the provincial level; but 2 of its 5 members are designated by the provinces, introducing a political / partisan flavor to the institution. The regulator's recent experience during the K-era (2003-2015, under the presidencies of Néstor Kirchner in 2003-2007 and Cristina Fernández de Kirchner in 2008-2015) in fact proved quite negative (something that necessarily reduced the quality of its technical staff) and its recent normalization is still far from representing the reconstruction of an autonomous and technically oriented entity. In any case, as discussed in the following cases, public hearings conducted by ENRE—for instance, to discuss the major contractual adaptation of both Edenor's and Edesur's concession contracts after the intervention in the K-era—involve requests and proposals presented by the regulated firms. For its part, the regulator remains silent regarding its approach, questions and intentions until it publishes its resolutions, which include innovations not necessarily discussed in those hearings.

Córdoba

In Córdoba no private firms are involved in the provision of electricity services. There are 204 cooperatives providing services in the interior of the province (covering 30 percent of the provincial population), and EPEC (*Empresa Pública de Energía de Córdoba*), a SOE as its name indicates, distributes electricity in the entire province of Córdoba, with cooperatives in smaller cities and towns as wholesale clients. EPEC is a vertically-integrated firm which had to reluctantly adjust to the national reform and deregulation of the electricity sector since 1992 regarding its generation units and open access rules granting commercial by-pass freedom to large users. EPEC is perhaps the most inefficient distribution company in Argentina, clearly captured by its labor union and local suppliers. This has resulted in poorly contracted inputs and an overstaffed and overpaid labor force, imposing significant extra costs on all electricity users in Córdoba (measured not only by its higher tariffs but also by the investment subsidies it receives from the provincial government).[30] Further proof of that is that EPEC's governance includes an organ acting as consulting and advisor regarding the objectives and commitments periodically (from 3 to 5 years) agreed between the firm and the provincial government, and this organ is formed by EPEC's General Manager and the general secretaries of the labor union *Luz y Fuerza* of Córdoba, Regional and Río Cuarto. So, the leaders of the involved labor unions are primary actors defining Cordoba's electricity policies and management.

This SOE and the cooperatives in the interior of the province are regulated by the *Ente Regulador de Servicios Públicos* de Córdoba (ERSEP), created in 2000 by Provincial Law 8.835, with regulatory powers over all provincial public services including potable water provision, electricity, passenger interurban transportation and highway accesses to Córdoba. ERSEP can adopt resolutions that close the administrative window. Its directory is composed of 6 members with 5-years fixed-terms and only one possible reelection.

ERSEP's webpage informs that, as a result of Law 8.835, its decisions are adopted with democratic participation of official and opposing parties, which further denotes its political nature. This recognition (which shows the non-technical culture of its management, who sees a merit in what in fact is a negative aspect of regulatory institutionalism—whereby political consensus is key regarding policy orientation and regulatory frameworks, leaving the day-to-day implementation to a technical body subject to transparency and participatory interests' assurances), together with the obvious centrality of EPEC regarding the overall policy-making political economy in Cordoba, has only one interpretation: Córdoba has a very deficient institutional design, both regarding its regulator and the provision contract, which allows for (as is the case) a very poor standard of regulatory quality and services, ill-prepared to adjust to the new challenges posed by forthcoming technological possibilities and emerging social and environmental demands.

[30] See http://www.lavoz.com.ar/politica/lo-que-nos-cuesta-epec-ademas-de-la-energia-que-factura.

Still, ERSEP has a long experience regarding public hearings, as since 2007 it has held these hearings to decide on tariff increases requested by EPEC and electric cooperatives or to deal with multiple other issues in the various sectors under its supervision. How is this possible? Can a SOE and a politically controlled regulator implement an inefficient electricity policy at the same time that there is a mature mechanism of public hearings in place? The answer is yes, since it seems that those hearings are not meaningfully designed and so do not really help to improve regulation. Indeed, after consultation with Law 8.835 and some of ERSEP's calls to public hearings, it is easy to verify that while public hearings are mandatory regarding tariff innovations and the regulator has to consider and respond to all comments and considerations made by all participating agents in those hearings before it decides on the issue, it is not required (and ERSEP does not do it on its own initiative) to present and expose to debate its own regulatory analysis and preliminary proposals anticipating the regulator's vision on the decisions it is about to make, prior to the hearing, so that those public hearings generally result in unorganized criticisms of the requested tariff modifications presented by the regulated firms (EPEC in the case of electricity), not properly reporting, constraining and improving the decision finally made by ERSEP. Indeed, this procedure (i.e., calling public audiences to discuss proposals by regulated firms while the regulator remains silent until it makes its decision) is generalized across the various regulatory jurisdictions in the country.

Tucumán

In 1992 Provincial Law 6.423 created the regulator of energy (*Ente Provincial Regulador de Energía de Tucumán*, EPRET, a role previously filled by preexisting *Dirección de Energía de la Provincia*) and the electricity distribution company (*Empresa de Distribución Eléctrica de Tucumán*, EDET), which was given in concession to private operators in 1995. In 2011, on the other hand, Provincial Law 8.479 created the *Ente Único de Control y Regulación de los Servicios Públicos Provinciales* de Tucumán (ERSEPT), concentrating in only one regulatory entity both the electricity and water and sanitation (W&S) services (integrating EPRET and ERSAC into ERSEPT).

Considering these two pieces of legislation, until 2011 the electricity service provided by EDET in Tucumán had a sector-specialized regulator (EPRET) which we can infer was not designed as an autonomous entity. First, except for formulating its budget—included in the general budget of the public administration and subject to legislative approval—it lacked constraints in terms of the designation and stability of its directors and authorities, as well as in regard to required public hearings and consultations prior to its regulatory interventions and decisions, which clearly did not include setting tariffs. Second, its mission included seeing that tariffs were just and reasonable, but under Law 6.423 both tariffs and the control of quality of services and required investments were said to be guaranteed by the concession contract. This created a design of regulation by contract as if that would effectively avoid interpreting disputes and conflicting interests to react to unexpected or unforeseen shocks. Third, EPRET was at a strategic disadvantage against the distribution company: it had to regulate only one firm in only one sector, which makes it more difficult to attribute eventual failures in the quality of service or cost overruns to the regulated firm and not (as its critics will most likely do) to the regulator's own faults (i.e., incorrect interventions or omissions to intervene). In that regard, the anticipated technical expertise, vision, authority and relevance of EPRET regarding the most appropriate interpretation and adaptation to unforeseen developments in the electricity sector under its regulatory responsibility in the province of Tucumán were negligible.

Yet, since 2012, with ERSEPT, the institutional design was significantly changed, creating an autarkic entity with authority to control and regulate both energy and W&S services across all the provincial territory, with more clearly defined authority over tariff control and regulation (Article 2.6), a more autonomous design (regarding 4-year stability with only 1 reelection of its 3-member directory, the introduction of a users' representative within the ERSEPT, and mandatory public hearings or documented consultations in various occasions), with a better-standing *vis-à-vis* each regulated private firm (EDET in electricity and SAT, *Sociedad Aguas del Tucumán*, in W&S).

This better institutional framework seems, on the surface at least, to go together with some mixed signals on regulatory quality. On the one hand, ERSEPT declares in its webpage that its vision is "to be an efficient, independent, impartial and transparent institution, assuring that public services under its jurisdiction are provided with continuity, regularity, economic security and quality" and "to be a technical body, specialized in the regulation and control of the energy and W&S systems in order to contribute to the development of a competitive and efficient economy, incentivizing the rational and efficient use of provincial energy and hydro resources and the conservation of the environment." Such a basically correct unilateral declaration (combining efficiency, independence, transparency and technical specialization as salient criteria guiding its own role) gives room for some optimism about the sufficient development of its technical capabilities, particularly in a country like Argentina where the cost of declaring politically motivated and biased goals is not always penalized. Yet, among other missing details, ERSEPT's webpage does not (readily at least) contain information about its public hearings and consultations, so its participation in those key instances cannot easily be appraised. In regard to the norms themselves, Article 18 of Law 8.479 on Public Hearings and Written Consultations offers no binding provisions on how such actions should be conducted; in particular, it does not mention any specific information or communication about the regulator's view or intentions to be discussed in those hearings and consultations. In contrast, the regulation under this article passed by EPRET in 2006 (Resolution 574/06, of November 15) indicates that the content of the publication of an announcement for a public hearing has to include "a brief explanation of its subject with a precise indication of the place where interested participants could see and obtain copies of presentations and other pertinent documentation." It does not, however, require the regulator to include in its own preliminary analysis a notice to participants of the central issues on which it will be expecting enlightening contributions. In fact, the regulator—through its designated instructor in charge of preparing in advance the public hearing—has to remain "impartial" about the information presented by the various interested parties, which means that the regulator is expected to remain silent regarding its own position and understanding until after the public hearing is finished, when it will decide expressly based on all information presented).

Appendix 2. A Methodological Note on Welfare Computations

We follow a simple methodology to evaluate aggregate welfare from final outcomes in individual utility assuming some aggregation (i.e., social welfare) function. Some formal definitions are required. Each household has a strong separable indirect utility function $V(q^e, m)$, where $q=p(1+t)$ is the unit end-user price of electricity, t is the applicable tax-rate and $m=Y-A(1+t)$ denotes disposable income, equal to income Y less the tariff fixed charge including taxes $A(1+t)$. Social welfare is the aggregation of individual utilities $W = W(V_1, \cdots, V_H)$.

For the empirical implementation, we make auxiliary assumptions on the shape of the social-welfare and individual-utility functions. A simple parameterization (see for example, Newbery, 1995, and Navajas, 2004)[31] assumes that the social welfare function is additive in utility levels, $W = \sum_h U_h / H$, and that individual agents have iso-elastic utilities on consumption or real expenditure of the type $U^e = (g_h)^{1-v} / (1-v)$ for $0 < v$ and $v \neq 1$, or $U^e = \log(g_h)$ for $v = 1$, where g_h is household *h* expenditure per equivalent adult, and *v* is interpreted as a coefficient of inequality aversion. Under these assumptions, household *h* social marginal utility of income can be computed by the expression $\beta_h = (g_h)^{-v}$, i.e., the inverse of expenditures per equivalent adult raised to the coefficient *v*. Additionally, under the assumption of an additive-cum-isoelastic-utility specification, social welfare can be approximated by the weighted sum of expenditures per equivalent adult, $W = \frac{1}{H}\sum_h \left[\frac{(g_h)^{1-v}}{(1-v)}\right]$, and the corresponding measure of relative welfare change becomes[32]

$$\frac{\Delta W}{W} = \frac{\sum_h \beta_h \cdot \Delta g_h}{\sum_h \beta_h \cdot g_h} \qquad (1)$$

Now, notice that a change in the unit price of electricity *q* exerts a welfare marginal impact given by the partial derivative

$$\frac{\partial W}{\partial q_h^e} = \sum_h \frac{\partial W}{\partial V_h} \frac{\partial V_h}{\partial q_h^e} = -\sum_h \beta_h x_h^e \qquad (2)$$

---

[31] An alternative specification that assumes a weighted welfare function of indirect utility functions arrives at the same results without the need for specifying the form of utility functions. The adopted specification facilitates the computing of percentage welfare changes from household expenditures.

[32] Using the definition of $\beta_h = (g_h)^{-v}$ we obtain $W = (1/H(1-v))\sum_h \beta_h g_h$. Thus, the percentage variation in welfare is given by $\Delta W / W = \sum_h \beta_h \Delta g_h / \sum_h \beta_h g_h$.

where $\beta_h = \frac{\partial W}{\partial V}\frac{\partial V_h}{\partial m_h}$ is the social marginal utility of household *h* income, x_h^e is the quantity of energy (electricity or natural gas) consumed by *h*, and Roy's identity has been used. Welfare impacts of discrete changes in energy prices can be approximated by[33]

$$\Delta W = -\sum_h \beta_h x_h^e (P_{h1} - P_{h0}) \tag{3}$$

Hence, we approximate the total transfer received by household *h* by $x_h^e(P_{h1} - P_{h0})$, the percentage of the transfer in terms of total income as $x_h^e(P_{h1} - P_{h0}) / g_h$, the total welfare change by (3), and the percentage welfare change as

$$\frac{\Delta W}{W} = -\frac{\sum_h \beta_h x_h^e (P_{h1} - P_{h0}) + \sum_h \beta_h (A_{h1} - A_{h0})}{\sum_h \beta_h g_h} \tag{4}$$

This expression is computed, and the results are reported in the main text, for alternative values of the income inequality aversion coefficient *v*.

[33] In expression (3), x_h^e can be approximated from a Taylor expansion by $x_h^e(P_0)[1+\eta_{x,P}(P_{h1} - P_{h0}) / P_{h0}]$, where $\eta_{x,P}$ is the direct price-elasticity of demand (for electricity or natural gas). In the empirical evaluation later, we do not exploit this loop, given that the magnitude of the jumps in prices are very large and would imply large quantity corrections even with very low price-elasticity values (such as those reported for natural gas and electricity in several empirical papers).