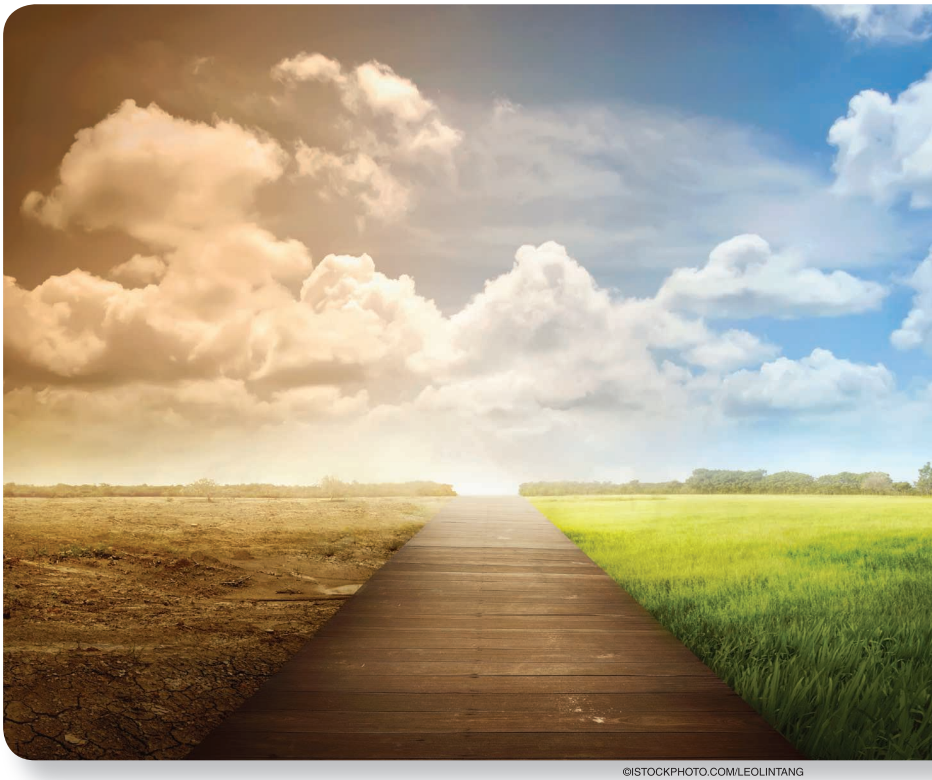
Distribution Network Rate Making in Latin America

An Evolving Landscape

FOLLOWING THE TREND OBserved in developed economies, various Latin American governments are committed to reducing greenhouse gas emissions, particularly in the power sector. In countries such as Chile, Peru, Colombia, Brazil, and Mexico, various regulatory policies have been issued to meet renewable-generation integration targets and satisfy the increasing demand from consumers for supply quality. Meanwhile, the integration of distributed generation (DG) in rural and urban areas as well as the increasing need to integrate electric vehicles (EVs) in urban areas are driving important reforms in the distribution sector.

Distribution networks are expected to increase reliability and integrate various distributed energy resources (DERs) by using an array of newly available technologies (including smart meters, online monitoring and control,



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and other smart grid and IT advances), enabling utilities to implement an active (rather than the historical passive or "fit-and-forget") approach to network operation, advanced operational measures, and nonwire solutions that will effectively displace costly investments. This environment poses challenges, but there are opportunities too. Understanding those opportunities and designing regulations accordingly is a priority in Latin American countries, where maintaining affordable energy is essential.

To ease the transition toward a more reliable and modern electricity network, regulators need to reshape frameworks that have historically focused on low costs (rather than the best value for money) and expand electricity coverage and access. Regulators in countries including Colombia, Peru, Chile, Brazil, and Argentina have implemented or are undertaking regulatory reforms in the distribution sector. The most important topics of debate (relevant to rate making) include enhancing reliability for consumers, connecting DERs, and providing secure and flexible services between distribution and transmission networks within an incentive- or performance-based price-control regime.

Well-designed incentive- and performance-based regulations use financial enticements to encourage distribution network owners to provide their (multiple) services securely and cost-effectively. Apart from encouraging network owners to be efficient, network users (that is, producers, consumers, and prosumers) should be motivated to improve their operational and deployment profiles. This is particularly relevant in the context of DERs, and it poses challenges related to the deployed meter technology and the fact that tariffs, to which network users react, present a limited level of spatiotemporal granularity and cost reflectiveness. Other important concerns include equity and fairness in tariff and reliability levels, especially in rural and other underdeveloped areas. Thus, regulators consider various policy concerns and objectives when deciding on network regulations, which are summarized in Figure 1. In the rest of this article, we focus on distribution network price controls, especially remuneration and tariffs. We summarize rate making in Latin America countries and discuss the Chilean and Brazilian experiences.

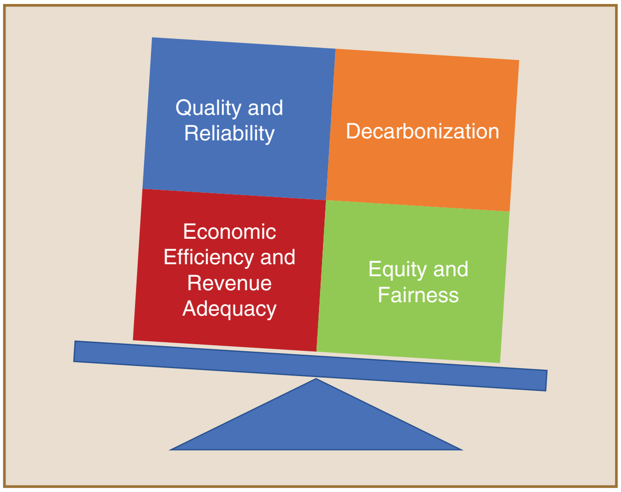

figure 1. The tetralemma for distribution network regulation in Latin America.

Rate Making in Latin America

Overview

Determining the regulated revenues for a distribution network company is a complex task with multiple conflicting objectives as well as determining rates, charges, or tariffs that the company is allowed to impose for billing and collecting fees from consumers. The design of such processes should consider that, in broad terms, remuneration will affect network owners' decisions (investments, operation, maintenance, administration, and so forth), while tariffs will impact network users (the locations they choose, their consumption and production profiles, and so on). While traditional objectives for appropriate remuneration center on revenue adequacy [to ensure that income is adequate to cover capital expenses (CAPEX) and operating expenses (OPEX), including a reasonable return on capital] and productive efficiency (for the regulated service to be provided at the most efficient cost), the objectives for tariff design focus on allocative efficiency (guaranteeing that effective charge signals are sent so that users can make cost-effective decisions about their consumption and production) and equity (ensuring that network tariffs feature desirable distributional characteristics, especially in terms of protecting vulnerable consumers). To achieve this, there are numerous regulations that emphasize/weigh conflicting objectives differently.

Latin America employs cost-of-service and incentive- or performance-based regulations (with a preference for the latter) to determine allowed revenues. In countries using the cost-of-service approach, such as Ecuador and Costa Rica, planners determine future network investments, and regulators ensure that a company's costs are fully recovered through appropriate charges. In countries applying incentive- or performance-based approaches, such as Chile, Brazil, Argentina, Colombia, and Peru, various regulations are used to compel network owners to make appropriate investment and operational decisions. In those countries, network tariffs are usually set ahead of time, ex ante, decoupling future real costs from regulated future revenues to originate incentives for companies to minimize costs. This is because revenues will be maintained at the permitted level for a given period of time, regardless of the company's actual costs. From time to time, however, ratchets will be applied, where the permitted revenue and associated tariffs are reset to 1) pass the achieved cost savings to network users and 2) ensure, despite information asymmetries, that revenues and costs are not unreasonably different.

The main features of price-control regulations in Latin America are shown in Table 1, including whether the mechanisms are cost-of-service or incentive based, the referential rates of return commonly used (note that under incentive-based regulation, real rates of return are endogenous and dependent on the performance of the companies), and the duration of the control periods. We also show whether the ownership of utilities is private, public, or mixed.

The region also features an array of tariff structures (that is, rules to determine how to charge different consumers) that vary across countries and user classes (such as residential, commercial, industrial, public lighting, and so forth). These tariffs present fixed (per user) and variable components [in U.S. dollars per kilowatt-hour (kWh) and U.S. dollars per kilowatt (kW)] as well as different spatiotemporal-granularity levels (in time, including peak and off-peak hours, winter and summer, and day and night, and in space, such as per company, per municipality, and per voltage level), and can be based on average or marginal (or incremental) network-cost principles. Regarding tariff components in the electricity bill, the energy cost is generally passed through to consumers on a dollar ($)/kWh basis, while the infrastructure cost (potentially including generation capacity and networks) is charged on by $/kW. This, however, depends on the country and user class. For residential consumers, for example, the combined cost of generation, transmission, and distribution is packed into a single $/kWh rate (which may change in time and location, albeit to a very limited degree).

Another tariff-related practice concerns the different treatment of transmission- and distribution network costs, which in Chile are included in the $/kWh and the $/kW rate, respectively (for an industrial consumer). Moreover, networks, depending on whether they belong to the transmission or distribution sector, can present completely different remuneration and pricing frameworks. For transmission, locational marginal prices (LMPs) can be observed in countries such as Chile, Peru, and Mexico, in which energy and part of the network costs are recovered via nodal prices that change with location and time according to real-time system conditions. This regime, however, cannot be observed in distribution networks in any country in Latin America (and probably the world), although the effects of LMPs on distribution networks are starting to be investigated in the academic literature, especially in the context of DERs. Table 2 presents three countries' tariff structures for residential and industrial consumers and their maximum temporal-resolution levels for residential and industrial loads.

The Good, the Bad, and the Ugly

Although Latin America has increasing levels of electrification, as shown in Figure 2, the power supply's reliability remains

table 1. Price-control regulation in Latin America.

	Argentina	Bolivia	Brazil	Chile	Colombia	Costa Rica	Dominican Republic
Utility ownership	Mixed	Mixed	Mixed	Private	Mixed	Public	Mixed
Price control	Incentive	Incentive	Incentive	Incentive	Incentive	Cost	Incentive
Referential rate of return	8.04% posttax (Edesur)	According to public utility companies included in the Dow Jones	8.09% posttax (benchmark company)	10% pretax (model firm)	11.8–12.4% pretax	4.24 posttax	9.02% pretax
Control period	4 years	4 years	4 years	4 years	4 years	1 year	4 years

	Ecuador	El Salvador	Guatemala	Honduras	Panama	Peru
Utility Ownership	Mixed	Private	Mixed	Mixed	Mixed	Mixed
Price control	Cost	Incentive	Incentive	Incentive	Incentive	Incentive
Referential rate of return	No public information	10% pretax	6.88% posttax	7–10% pretax	8.94% posttax	12% pretax
Control period	1 year	5 years	5 years	5 years	4 years	4 years

poor. Even in Chile, which has graduated from the list of developing countries and is part of the Organization for Economic Cooperation and Development, the average outage duration per year for each customer, measured by the System Average Interruption Duration Index (SAIDI), is roughly 15 h, which is approximately 15 times higher than in the United Kingdom.

Importantly, this lack of reliability is one of the negative consequences of regulation. In Chile, distribution network

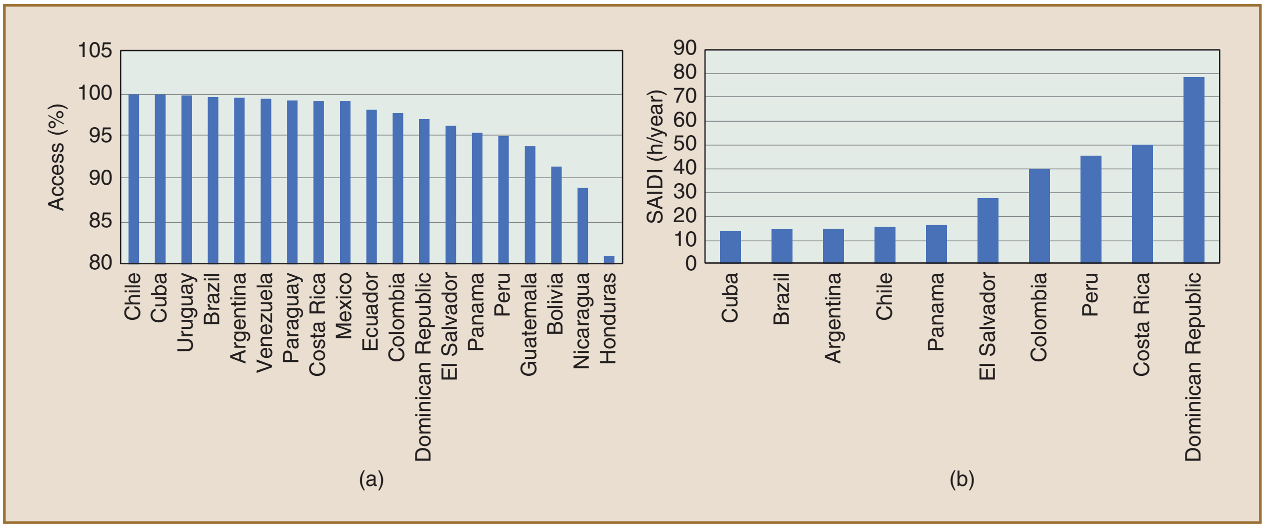

figure 2. The (a) electrification and (b) reliability levels in Latin America.

table 2. The end consumer's bills and their breakdown in three Latin American countries (in US$). All are low voltage.

		Santiago, Chile		Quito,* Ecuador		Rio de Janeiro, Brazil	
Sector	**Unit**	**Residential**	**Industrial**	**Residential**	**Industrial**	**Residential**	**Industrial**
Generation	US$/month	—	—	—	—	—	—
	US$/kWh	0.1	0.08	0.03	0.03	0.06	0.06
	US$/kW/month	—	6.99	—	—	—	—
Transmission	US$/month	—	—	—	—	—	—
	US$/kWh	0.02	0.02	0.01	0.01	0.03	0.03
	US$/kW/month	—	—	—	—	—	—
Distribution (including metering and billing)	US$/month	0.85	0.99	1.41	—	—	—
	US$/kWh	0.02	—	0.05	0.03	0.03	0.03
	US$/kW/month	—	9.2	—	4.18	—	—
Others	US$/month	—	—	—	—	—	—
	US$/kWh	0.001	0.001	0.01	0.01	0.03	0.03
	US$/kW/month	—	—	—	—	—	—
Total	US$/month	0.85	0.99	1.41	1.41	—	—
	US$/kWh	0.14	0.1	0.1	0.08	0.16	0.16
	US$/kW/month	—	16.2	—	4.18	—	—
Time resolution (maximum)		kWh rate with up to three levels in one day	kWh and kW rates with no time variations	No time variations	kWh rate with up to three levels in one day	No time variations	No time variations

*In Ecuador, there is a government subsidy of roughly US$0.05/kWh that reduces the overall bill to the values shown here.

> Policy makers are pushing regulators to include more sophisticated objectives in remuneration and tariff regimes.

price caps have been limited to relatively small values, lowering costs significantly in comparison with other developed countries. However, as illustrated in Figure 3, lower costs have an impact on service quality because of tradeoffs between network performance and expenses. In general, low-cost networks tend to be less reliable. Understanding this cost-performance balance is critical in developing countries because higher reliability levels might require funding increased levels of network investment and, hence, higher electricity bills.

After nearly 40 years of distribution network rate making in Latin America, the quality of service is becoming more critical. In addition, policy makers are pushing regulators to include more sophisticated objectives in remuneration and tariff regimes (apart from the historical ones focusing mainly on cost reductions). The goals include

- ✔ quality of service, even beyond reliability and voltage quality, including resiliency against hazards and customer satisfaction
- ✔ equity and fairness in tariffs and quality
- ✔ innovation and network modernization, evolving toward the smart grid
- ✔ decarbonization and renewables.

These objectives were initially de-emphasized by regulators to prioritize electrification, coverage, and access at a reasonable cost (notice that access is still a problem in countries such as Bolivia, Nicaragua, and Honduras, as indicated in Figure 2).

Remuneration should evolve, in our opinion, to enable distribution networks to innovate and become more active, such as by operating with smart grid technologies. This would improve the optimization of CAPEX and OPEX in network companies, driving new operational measures and nonwire solutions to deliver reliability and other services more effectively. With the increasing penetration of DERs, price signals will become more relevant for them to be adequately deployed and operated, potentially providing services to distribution and transmission networks. Increased levels of coordination will be needed at the interface between transmission and distribution systems. It is envisioned that network operators will be able to trade various security and

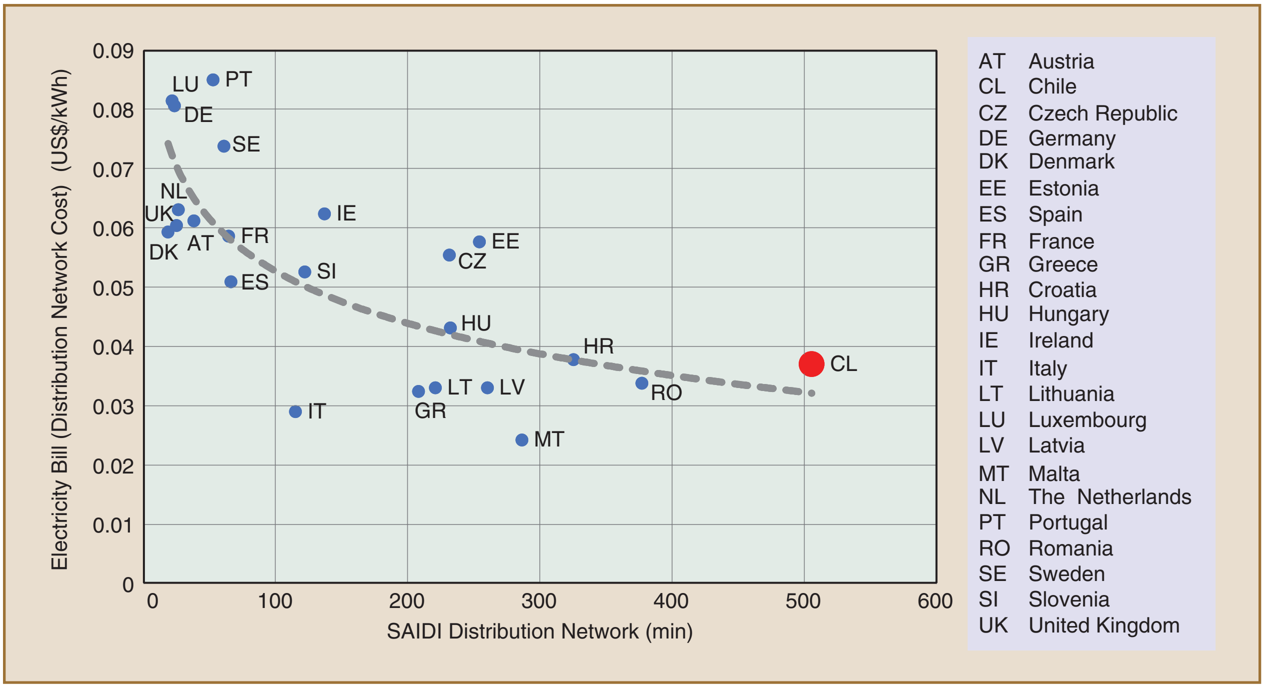

figure 3. Distribution network costs in capital cities versus SAIDI in all distribution networks. Due to the lower voltage levels in Chile's distribution networks (up to 23 kV), we have considered part of the subtransmission systems (which cover up to 110 kV) as distribution networks to properly compare values among countries.

flexibility services between regimes to achieve, through decentralized operation of various distribution systems and the transmission grid, optimal solutions systemwide.

These considerations are critical in countries where costs must be kept as low as possible while improving quality and addressing other objectives of the new energy policy agenda. To achieve those goals, new regulations must remunerate and charge for distribution networks. Next, we present relevant regulatory discussions from Chile and Brazil, whose authorities are conducting rate making reforms. We focus specifically on remuneration and tariffs.

Chile

The New Policy Landscape

In Chile, as in the rest of the world, new energy policies are evident. Today's agenda includes themes that go beyond the historical debates about limiting costs and improving access to electricity systems. Chile's energy policy has been reasonably successful in regulating network development, access, and costs (as shown in the previous sections) and progressed to incorporate two major objectives: 1) improve poor reliability by evolving toward a more resilient system and 2) decarbonize the energy sector by integrating renewables. There are other more specific objectives. In the context of distribution networks, they include the following:

- ✔ more DG and DERs
- ✔ an increased role for demand-side response and management
- ✔ including more innovative smart grid solutions
- ✔ increasing participation from the transport and heating/cooling sectors
- ✔ more buildings and communities that have their own generation, storage, energy-management systems and controls (such as microgrids)
- ✔ growing the number of initiatives to foster smart cities.

To address these objectives, the government began to change its approach to distribution network regulation by supporting the transition toward a more reliable, resilient, affordable, and sustainable energy sector. We now summarize the main aspects of the debate in Chile, focusing on remuneration. Aspects associated with tariffs will be discussed for Brazil.

The Remuneration Approach

The Philosophy

Distribution network remuneration in Chile, unchanged since 1982, is based on the idea of benchmarking the cost performance of real firms against model ones. The so-called model firm is a theoretical, virtual company created to calculate remuneration. It is optimally designed in a greenfield fashion at the beginning of each control period (such as every four years) to provide distribution network services in the same area as the corresponding real company. Because model firms are designed in a greenfield fashion, their infrastructures are valued at current market prices by using the replacement-cost concept. Once model firms have been constructed and valued, the final network tariffs to be applied to the real companies are calculated so that the model firms feature a 10% cost of capital (before taxes and assuming there is no leverage). The main idea behind model firms is to incentivize real companies to be economically efficient, since their revenues and costs are decoupled. Under this philosophy, the cost functions of real companies do not affect tariffs. The method simulates competition between a regulated incumbent monopolistic firm and a virtual one that was cost-effectively designed from scratch using the latest technologies.

Practical Implementation

In practice, model firms are determined by using characteristics from reality that reflect exogenous variables that are beyond the control of distribution companies, including

- ✔ locations and capacities of transmission-distribution entry points and primary substations
- ✔ locations and loads of demand points (including the current consumption and what is projected for the next 15 years)
- ✔ city road maps
- ✔ other constraints imposed by security standards and municipalities (for example, the use of underground rather than overhead lines).

Although today's model firms are calculated based on advanced computational mathematical models, during the 1980s and 1990s they were determined without significant support from computers. The complexity associated with the escalating number of companies to be regulated was simplified by using a sample of representative firms selected through clustering methods. More than 30 distribution companies were divided into six clusters according to their density metrics (companies with similar $/km–kW belonged to the same cluster). One firm per cluster was chosen as the basis for the model-firm remuneration process. Six model firms were determined, and each real company adopted the tariffs for its cluster.

For each representative firm, two model firms are determined through simultaneous studies, one undertaken by the regulatory authority and the other by the company. Hence, the final cost valuation (including the CAPEX and OPEX) of every representative firm is equal to the weighted average valuation of the studies: two-thirds and one-third for each authority's and firm's study, respectively. This mechanism avoids long negotiations between the authority and each company because each study is developed in isolation, and the company and authority do not have to agree on input parameters and results to determine their corresponding model firms.

To account for the possibility that the costs of real companies and model firms differ, a check is undertaken after the tariffs have been determined to verify that the aggregated profitability of the nationwide distribution sector is between 6 and 14%. At the company level, however, profits are allowed to rise above that range. To calculate profits, real companies' expenses are determined by considering their actual infrastructure (not that of model firms) and valued at current market prices by using the replacement-cost concept.

Arguments For and Against Current Remuneration Practices

There are advantages and disadvantages to the model-firm approach applied in Chile. Three of the chief benefits are 1) firms' perceived incentives to limit costs, 2) simplicity and low-cost implementation, and 3) the ability to deal pragmatically with significant information asymmetries between the regulator and firms since there is no reliance on real companies' expenses. The approach was exported to other countries in Latin America, such as Argentina, Peru, and Bolivia, and to Central America, demonstrating its attractiveness and practicality at a time when limiting costs (while improving coverage/access) for recently privatized companies was key. However, experts pose several questions about the method, since there is no evidence that it will deliver the objectives of the present energy-policy agenda.

Concerns Regarding Supply Security

As mentioned, one of the primary objectives of today's energy policy is to enhance the supply security and resiliency. Chile wants to reach a 1-h SAIDI by 2050 (uniformly distributed across the country), with an interim goal of 4 h in 2035. That would be a significant improvement from the current SAIDI, which averages 15 h at the national level and can climb higher than 50 h in regions such as Tarapaca, Atacama, and Araucania. Table 3 gives the geographical distribution of the SAIDI, which can change significantly by year depending on exogenous factors, such as natural hazards.

There is significant debate regarding how to improve the remuneration method to deliver efficient investments to ensure a more secure, reliable, and resilient future. As with any other incentive-based, network-remuneration method, the model-firm approach needs additional incentives (such as penalties and rewards) to discourage reliability degradation, since delivering adequate reliability usually requires spending more, which is clearly discouraged by an approach that aims to reduce expenses. There are security standards in Chile that establish limits for various reliability metrics, including the SAIDI, with associated penalties for distribution companies that fail to deliver. However, they are unlikely to be sufficient because reliability improvement requires network investments. Penalties will not encourage companies to make investments when there is insufficient funding or enough certainty about future revenue streams.

table 3. The SAIDI in hours per region and per year in Chile.

Region	Population	2012	2013	2014	2015	2016	2017	2018	Seven-Year Average
Aysen	103,158	23.1	27.9	26.1	29.9	19.7	31.2	14	24.6
Magallanes y Antartica Chilena	166,533	6.2	8.8	8.2	9.2	5.1	6	6.9	7.2
Arica y Parinacota	226,068	21	14.3	33.9	12.3	10.7	15.3	23.2	18.6
Atacama	286,168	25.9	19.5	22.8	**53.6**	11.1	22.6	16.4	24.6
Tarapaca	330,558	29.8	24.4	**59.9**	23.8	20.2	18.1	14.6	27.3
Los Rios	384,837	27.9	25.6	25.1	26.6	22.3	24.7	19.5	24.5
Antofagasta	607,534	18.6	14.9	25.2	22.9	15.9	16.3	11.7	17.9
Coquimbo	757,586	10	11.5	9.8	44	11.5	10.5	10.1	15.3
Los Lagos	828,708	30.1	24.2	25.9	23.9	18.4	22.3	17.2	23.2
O'Higgins	914,555	16.6	18.2	18	20.4	17.9	23.2	16.8	18.7
La Araucania	957,224	34.1	34.6	30.7	32.3	31.5	**51**	28.3	34.6
Maule	1,044,950	20.1	14.1	16.9	26	20.8	33.1	14.7	20.8
Valparaiso	1,815,902	12.4	9.3	10.1	17.2	9.4	10	7.1	10.8
Biobio y Nuble	2,037,414	28.6	19.3	20.6	19.3	16.9	20.5	13.2	19.8
Metropolitana de Santiago	7,112,808	8.9	7.7	8.4	8.8	8.2	13.6	8.5	9.2
Country level	**17,574,003**	**16.7**	**13.9**	**15.7**	**18.1**	**13.4**	**18.6**	**12.1**	**15.5**

Exceptional events are included. Values higher than 50 h are in red. Regions are sorted according to population.

There is no easy solution to this problem within the present paradigm because the model-firm philosophy is to remunerate a virtual company. Built in a greenfield fashion, model firms cannot properly capture the need for additional funding to improve reliability in real companies. The mismatch between the remuneration needed to cover the cost of a greenfield model firm and that of a hypothetically efficient real firm with legacy concerns can be mathematically proved. In mathematical programming terms, the solution to the optimization problem that determines the model firm's investments and assets from scratch will differ from the solution to the optimization problem that determines the efficient investments and assets of a firm subject to past decisions. Although the mismatch is self-evident (given the different building approaches of the real and model firms), it must be emphasized since it has profound impacts on remuneration adequacy.

Reliability, Fairness, and Affordability in Rural Networks

In the discussion of supply security and remuneration, another important aspect arises: fairness and affordability in rural networks, since the current system is ill-suited to remote areas. It is well known that delivering reliable power to consumers in rural areas is more costly than in urban areas (for example, Frontel versus Enel in Figure 4) because the number of connected customers per kilometer in cities is significantly higher than in provincial locations. Consequently, a cost-benefit analysis to balance investments against their reliability gains will justify worse reliability levels in rural areas and higher network tariffs. This techno-economic result is fundamentally problematic from a public policy perspective. This is particularly relevant in light of the Chilean energy policy that seeks uniformly distributed SAIDI across the country (that is, reliability fairness) at affordable costs.

Incurring higher costs to improve reliability in rural areas is no trivial matter, since provincial consumers, who already pay higher electricity bills (see Figure 4), are likely to have lower incomes. Equalizing reliability levels across a country may significantly raise network tariffs beyond affordable levels in rural areas. That would be the case if tariffs sought to be cost reflective (note that cost reflectivity is a key techno-economic principle and an important objective in tariff design, especially in the future context of DERs). Hence, cross subsidies between areas might be needed to achieve reliability fairness at affordable costs for rural consumers.

Finding the right balance between conflicting objectives (in this case, cost reflectivity and fairness) and resolving the political-economy conundrum becomes a complex task. There have been efforts in Chile to develop a concept called *equidad tarifaria* (*tariff equity*), which internalizes the cross subsidies within tariffs, tending to equalize them. Questions regarding the efficiency of the current mechanism have been posed, since the issue of balance can be alternatively resolved (and potentially more effectively) through subsidies in the form of separate payments that target consumers who really need the financial support and preserve the original cost-reflectivity levels in network tariffs. In light of the escalating need for reliability and fairness, this debate will become increasingly important during the coming years.

Concerns Regarding Decarbonization Through Grid Modernization

Effectively managing a distribution network with increased DER penetration and participation in new flexibility- and ancillary-services markets at the transmission level requires an active (rather than the historical passive) approach to its operation, which necessitates changes in the way system infrastructure is planned. Chile has an increasing number of DG projects and EV infrastructure, as shown in Figure 5. In the future, we expect to see a larger array of dispatchable resources at medium- and low-voltage levels, including demand response, energy storage (for instance, batteries, EVs, and thermal demand), DG [primarily photovoltaic (PV)], and equipment that will efficiently adapt the network to changing operating conditions on a minute-by-minute basis. This will require distribution innovation to promote cost-effective solutions

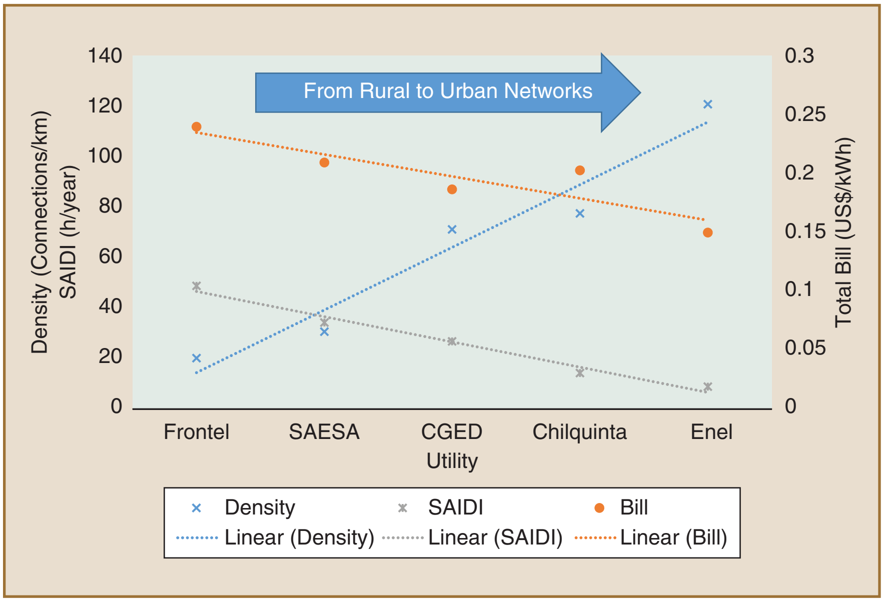

figure 4. The density, residential electricity bill, and SAIDI for the main distribution companies in Chile.

throughout the system level and during the long term. CAPEX and OPEX tradeoffs will be critical for minimizing the total expenditures of distribution companies that increasingly rely on operational measures and nonwire solutions, following the smart grid concept.

Modernizing distribution networks will require strategic short-term investments that must be remunerated. Future systems will extend beyond the conventional network infrastructure. For example, following ideas implemented in other jurisdictions, distribution systems are expected to become "market platforms," necessitating significant IT system enhancement (including communication, monitoring, processing, control, and so on). Incentivizing strategic investments for modernizing electricity grids is a major challenge for regulators. Under the model-firm paradigm, where remuneration is fixed for four years, and revenue streams beyond that point remain uncertain (and poorly correlated with real costs), it is difficult to foster strategic investments to reduce longer-term costs and remunerate advanced and innovative technical solutions. Without the certainty

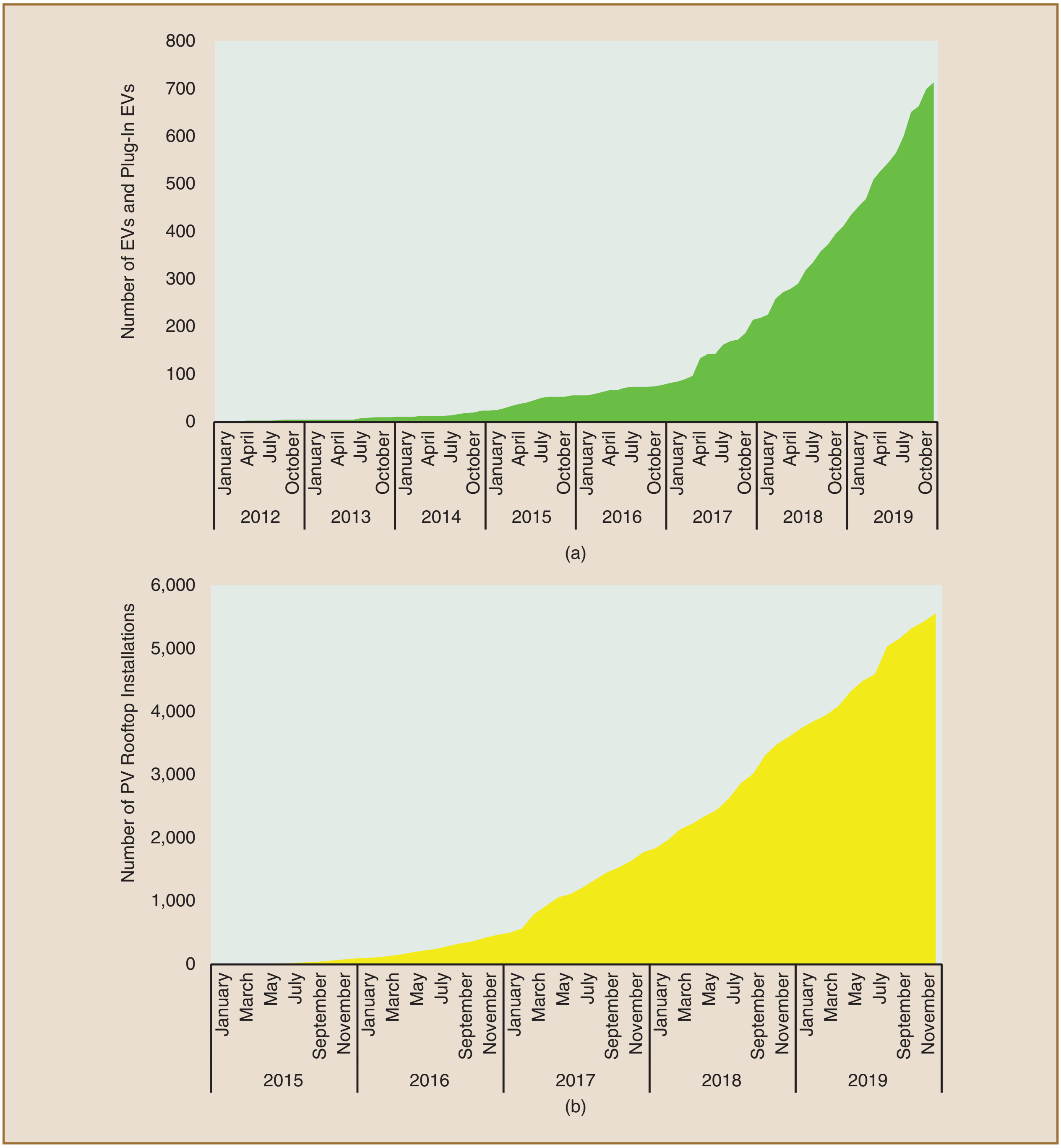

figure 5. The number of (a) EVs and (b) DER connections.

Recognizing uncertainty in the network-expansion-planning problem increases the value of smart grid technologies, which network planners and regulators must acknowledge.

that their investments will be adequately remunerated, companies are likely to prefer conventional solutions that may be less expensive during the short term but compromise the distribution system's economic performance (and the entire electricity system) through the longer term.

The debate about modernization and innovation includes the uncertainty related to planning network expansions. This is becoming increasingly important due to the many factors that must be considered, including the rapidly evolving costs of technologies, market prices, policies, and DER deployment. The need to find technical solutions to network uncertainty becomes a challenge, and regulators must properly scrutinize and incentivize proposals. With uncertainty, innovative solutions (such as battery energy systems and open soft points, which apply power-electronic devices to normally open portions of the distribution system) become more attractive as a means to more easily adapt to, cost-effectively deal with, and hedge against a number of scenarios that might happen in the future. In other words, recognizing uncertainty in the network-expansion-planning problem increases the value of smart grid technologies, which network planners and regulators must acknowledge.

The second important aspect of planning under uncertainty relates to regulatory scrutiny. It is important to recognize that an optimal-investment decision that was made under uncertainty cannot be evaluated and justified ex post facto, when complete information is available. From a stochastic-programming viewpoint, it is clear that an ex ante decision made under uncertainty may seem suboptimal at a later date. This argument has special relevance for incentive-based remuneration methods that face after-the-fact regulatory scrutiny and correction of the regulatory asset base (RAB), where companies face the risk of a backlash if investments are deemed unjustified. This is also important in Chile, where real companies' infrastructure, in every tariff period, is valued through a greenfield model firm that possesses perfect information, an approach that disregards legacies built under uncertainty and the optimal infrastructure needed to face future unknowns. Incorporating tools to deal with uncertainty in network regulation is becoming a must.

Other Concerns About Remuneration

There are other important concerns that arise in the debate surrounding the model-firm approach and are common to other remuneration methods. Among them the following:

- ✔ Model firms minimize costs within the distribution sector, in isolation from the rest of the power system. This relates to the discussion about the interface between transmission and distribution and the need to have a whole-system view of the planning and regulatory problem.
- ✔ The set of prices used to calculate the model firms' costs follows the concept of the replacement cost, valuing assets as new according to current market prices. This can cause fluctuations in a company's valuation and produce higher risks for investors.
- ✔ The real costs of capital to investors remain hidden during the regulatory process, since companies' expenses are valued by the replacement cost. Most importantly, this blindness includes the return that investors will ultimately receive and is a failure of monopoly regulation.
- ✔ A referential cost of capital equal to 10% (before taxes and assuming that there is no leverage) that is fixed by law (for model firms) may not appropriately reflect 1) market conditions at the time of the control and 2) real firms' risks, including those imposed by the remuneration approach. This problem should be fixed by calculating appropriate costs of capital every time tariffs are determined.
- ✔ Within the control period, there is no differentiation between the costs that distribution companies can and cannot control. Therefore, all variations in real costs, even those that cannot be managed by the companies, are passed to network owners. This increases the risk to investors, without a clear benefit.
- ✔ Despite its complexity, the remuneration mechanism is, in practical terms, too approximated (it relies on a small sample of companies, averages results from different sources in a two-thirds and one-third fashion, uses simplistic greenfield model firms, and so forth). Even for the same company, results can vary too much, depending on who determined them (the authority or the firm; see the values and biases in Figure 6). This implies that a network owner can realize a lower or higher cost of capital depending on the inherent randomness of the process, not on corporate efforts to reduce expenses.
- ✔ There is no coherence between the distribution of network owners' capital costs and efficiencies. Following the principle of comparing similar companies through yardstick regulation, firms with larger efficiencies should receive larger returns. This does not occur under Chile's remuneration approach, which does not measure firms' relative inefficiencies to mimic real competition.

- ✔ A major issue is the absence of stakeholder engagement, where parties contribute feedback and proposals through an advanced planning and remuneration process. In the current framework, it is unclear how decisions between companies and stakeholders to improve the distribution service (for example, installing new assets agreed among stakeholders to increase the supply quality) could be adequately remunerated.

The Path Forward

Since the price-control regime in Chile has remained almost untouched for nearly four decades, there is a consensus that some of its features have to be updated. Despite this agreement, there are heated debates about the level of change that is necessary. Although the current approach is being questioned in light of the new paradigm, there is a group of experts that defends it, supporting its arguments mostly on the system's simplicity and low-cost implementation. The group envisions a set of smaller changes in network remuneration. An opposite position supports a more radical change toward incentive-based remuneration methods, such as Revenue = Incentives + Innovation + Outputs in the United Kingdom, which recognizes and addresses the challenges associated with the new paradigm. Such approaches, however, would impose more complexity and require a greater effort by regulators to understand the costs and decisions of real firms. Chile's answer probably lies between the two extremes. The debate involves questions such as the following: Up to which point do real costs have to be recognized in the remuneration process? What would the new role, set of tasks, and burden be for regulators?

Some principles underlying Chile's remuneration method may need to be maintained to smooth any transition. Part of companies' real costs may need to be recognized (for example, by using a "brownfield" model firm) to encourage investments in quality and reliability and other desirable distribution-service outputs as well as to compensate investors for part of the risk they face. Recognizing companies' real needs and costs would increase regulators' burden of scrutiny and perhaps their responsibility in future investment decisions. A major concern involves the extent of the regulatory capture that could occur, since network companies have more technical expertise about network operation and planning.

Addressing the problem of information asymmetries is key, potentially requiring a different approach than the model-firm paradigm, where companies' real costs are practically ignored. There has been important progress to incentivize the quality of the information that companies provide to regulators, achieved by offering a menu of contracts (see the "For Further Reading" section), and this may inform the future debate in Chile.

Brazil

The Regulatory Framework

Brazil's installed generation capacity is roughly 167 GW (as of 2019), with a yearly energy consumption of 472 TWh (as of 2018), serving 84.6 million users (as of 2019). Consumers in Brazil fall into two broad groups: 1) free consumers, who bilaterally negotiate for energy and pay regulated charges (or network tariffs) for access to distribution and transmission networks, and 2) regulated consumers, who purchase energy at a controlled price derived from supply-contract auctions

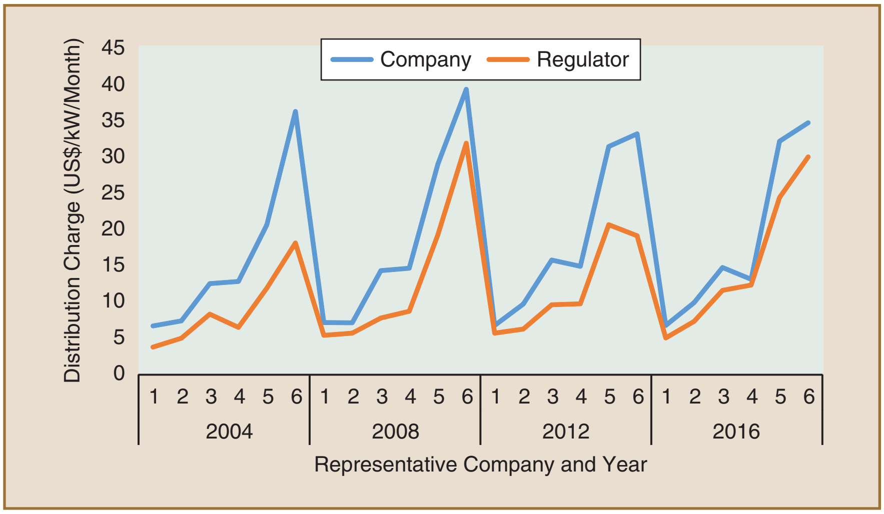

figure 6. The distribution charge per representative firm under the past four tariff controls, according to company and regulator studies, before the weighting process. Representative firms are sorted by connection density (number 1 presents the highest and corresponds to Santiago, Chile).

table 4. Tariff modalities in Brazil.

Tariff	User	Structure	Time-Dependent Pricing	Network Remuneration
Conventional	Low voltage	kWh only	No	Volumetric
Blue	High voltage	kWh and kW	Peak/off peak	Peak demand
Green	High voltage	kWh and kW	Peak/off peak	Peak demand
White	Optional for low voltage	kWh only	Peak/intermediate/off peak	Volumetric

and pay the network tariff. There are large consumers connected directly to the transmission network that do not pay charges for distribution networks. Regulated consumers account for approximately 70% of the energy consumption.

Brazil's regulation and tariff-structure framework was defined in 1968 with the objective of establishing general rules for distribution companies' charges. It was the responsibility of the National Electric Energy Agency (ANEEL) to define specific rules based on the legal framework's guidelines. In general, the regulatory framework deals with fixing and revising electricity tariffs, the general classification of consumers according to voltage levels, tariff structures, and special supply conditions (for example, rural areas and public lightning).

There are two tariff structures that can be applied to consumers connected to distribution networks:

1) binomial tariffs, which have two components, the first representing charges for energy, losses, and other expenses (for instance, the costs of governmental policies) in \$/MWh, and the second representing transmission and distribution charges in \$/kW
2) monomial tariffs, in which all components are summarized in a single volumetric tariff in \$/kWh.

To apply the tariffs, consumers are classified according to their voltage levels: group A (high voltage level) and group B (low voltage level), which are broken into subgroups. Group A is divided by voltage levels: A1 (≥230 kV), A2 (≥88 kV and <230 kV), A3 (>44 kV and <88 kV), A3a (≥30 kV and ≤44 kV), A4 (≥2.3 kV and <30 kV), and AS (<2.3 kV in the underground network). Group B is divided by consumer classes: B1 (residential), B2 (rural), B3 (other classes, such as commercial, industrial, and public power), and B4 (public lighting). Binomial tariffs are compulsory for high-voltage consumers, and monomial tariffs are mandatory for low-voltage users. The tariff menu offered to consumers is summarized in four modalities—conventional, blue, green, and white—as illustrated in Table 4.

The conventional tariff modality is a constant, flat rate used for almost all consumers connected to the low-voltage network. Since 2018, users with an electricity demand higher than 500 kWh have been able to opt for the white tariff, with time granularity for peak, intermediate, and off-peak hours. The peak period consists of the three consecutive working-day hours that have the highest demand. It is defined by the regulator as 5:30–8:30 p.m., which is not in line with the actual peak load. As many consumers increase their use of air conditioners, the peak load has shifted to 2–3 p.m. in many regions. However, the regulator has not updated the definition, which incentivizes consumers who opted for the white tariff to increase their consumption during the real peak time. Changes to this modality might not reduce the system's peak load, since many users will not necessarily (be able to) change their consumption behavior. High-voltage consumers can opt between the blue and green modalities. The green one has a higher volumetric component for the peak hour, which has motivated some consumers to build natural-gas cogeneration and diesel power plants to reduce their peak load. For users who cannot shift their load, the blue option may be more attractive.

The regulator periodically implements ratchets to revise the tariffs. Readjustments are made annually on a percentage of the costs that network companies cannot control. If the proportion of the uncontrollable costs increases or decreases, companies' revenues will be scaled to avoid rewarding or penalizing firms. Tariff reviews are carried out at the end of each control period. The regulated revenue is determined and decoupled from the evolution of the actual costs. The idea is for the regulated revenue to cover efficient costs. The relative efficiency of the distribution companies is measured through data-envelopment analysis. Thus, if a network company can establish a more efficient cost structure, incurring expenses that are lower than those included in the tariffs, it can capture those savings within the control period. During the periodic tariff review (which occurs, on average, every four years), efficiencies are passed on to the consumer. Distribution companies whose concession was renewed after 2015 have a revision every five years.

From the regulator's point of view, passing efficiency gains to companies encourages efforts to reduce the cost of providing the service. On the other hand, if uncontrollable costs are substantially altered, companies will face expenses that do not have tariff coverage during the period between revisions. In such cases, companies may request an extraordinary tariff revision to reestablish their financial balance. The regulator is responsible for judging the merits of this request and deciding whether to approve the application.

Brazil's price regulation incentivizes companies to save investment costs during the first years of the control period, toward the end of which the efficiency incentive becomes weaker than other enticements in the policy framework. Closer to the next ratchet, the incentive for companies to increase their RAB during the long term becomes stronger. This is due to the Averch–Johnson effect, which grows during the last part of the control period. It occurs because investors' costs of capital (used by network owners to discount future cash flows) may be lower than the regulator estimated to determine the allowed revenue. Although this effect is mostly associated with cost-of-service regulations, it may occur under incentive-based rules. Because this is counterintuitive, we illustrate the fundamentals in an example.

The Averch–Johnson Effect on Incentive-Based Regulation

Table 5 lists the profits (in net present value) from three investment options for a hypothetical distribution company whose revenues are regulated through an incentive-based approach, where income remains fixed during the four-year control period regardless of the firm's costs. In our example, the network owner realizes (after the referential network-expansion plan has been approved) that part of the planned investment (with a cost of US$100) can be eliminated without affecting reliability (for instance, there may be no way to exercise operational measures, such as demand control during peak hours, at a very low cost, which will be assumed to be negligible for simplicity). The question is whether the regulatory framework will incentivize the network owner to realize the saving or opt a different, inefficient result. Other data relevant to the problem include the investor's 7% cost of capital, the 8% regulated rate of return (used to calculate the company's revenues as the remuneration of the RAB minus the asset depreciation, that is, $\text{revenue}_t = \text{RAB}_{t-1} \times \text{rate of return} - \text{depreciation}_t$), and the assets' 20-year life span. The investment options are (see Table 5) as follows:

- ✔ *Option 1*: Undertake the investment (albeit not needed) at the beginning of the control period (as planned), which will be remunerated during the lifespan of the asset (including the four-year control period).
- ✔ *Option 2*: Eliminate the investment and save $100. Revenues will remain fixed as agreed during the control period (that is, assuming the initial investment of $100) to incentivize efficiency. Beyond the control period, revenues will be canceled since the investment was not undertaken.

table 5. Yearly revenues, costs, and profits of three investment options (in generic currency).

			Option 1			Option 2			Option 3		
Year	**Yearly Depreciation**	**RAB (Option 1)**	**Revenue**	**Investment Cost**	**Profit in Present Value**	**Revenue**	**Investment Cost**	**Profit in Present Value**	**Revenue**	**Investment Cost**	**Profit in Present Value**
		100		100	–100						
1	5	95	13		12.15	13		12.15	13		12.15
2	5	90	12.6		11.01	12.6		11.01	12.6		11.01
3	5	85	12.2		9.96	12.2		9.96	12.2		9.96
4	5	80	11.8		9	11.8		9	11.8	100	–67.29
5	5	75	11.4		8.13				13 (as in year 1)		9.27
6	5	70	11		7.33				12.6		8.4
7	5	65	10.6		6.6				12.2		7.6
8	5	60	10.2		5.94				11.8		6.87
9	5	55	9.8		5.33				11.4		6.2
10	5	50	9.4		4.78				11		5.59
11	5	45	9		4.28				10.6		5.04
12	5	40	8.6		3.82				10.2		4.53
13	5	35	8.2		3.4				9.8		4.07
14	5	30	7.8		3.02				9.4		3.65
15	5	25	7.4		2.68				9		3.26
16	5	20	7		2.37				8.6		2.91
17	5	15	6.6		2.09				8.2		2.6
18	5	10	6.2		1.83				7.8		2.31
19	5	5	5.8		1.6				7.4		2.05
20	5		5.4		1.4				7		1.81
21									6.6		1.59
22									6.2		1.4
23									5.8		1.22
24									5.4		1.06
Total					**6.72**			**42.12**			**47.24**

- ✔ *Option 3*: Delay the investment to the end of the four-year control period, increasing future revenues in comparison with option 1, since the asset will be newer (less depreciated).

Table 5 demonstrates that although option 2 is, from the network owner's perspective, more attractive than option 1 (as expected, since this is aligned with the primary objective of incentive-based regulation), option 3 provides higher long-term profits. This corresponds to an inefficient and unintended outcome of price-control regulation, since, from a central-planning perspective, the most efficient result is option 2, creating a need to increase the efforts to scrutinize investments (in volume and timing). This also incentivizes network owners to submit inflated forecasts of their planned network assets, as reported in other countries, such as the United Kingdom during the early 2000s under the retail price inflation minus expected efficiency improvements approach. Note that options 2 and 3 will become equally attractive if investors' capital costs and regulated rates of return are the same.

Concerns About the Low-Voltage Tariff Structure

The tariff structure applied to low-voltage-level consumers (group B) attempts to remunerate the electricity value chain's CAPEX and OPEX: generation, transmission, distribution, and other charges. The final tariff paid by each consumer is divided into two parts: 1) energy and 2) network. The energy tariff contains a large part of the distribution companies' unmanageable costs: energy purchases, transmission network losses, and charges related to consumption. The network tariff contains the remaining unmanageable expenses (distribution network losses, transmission costs, and charges related to peak loads) and the manageable ones, which are related to distribution companies' CAPEX and OPEX.

Although regulators recently allowed the group B electricity tariff to be multipart, the levy structure remains volumetric with no time dependency. Given the growth in DERs, mainly solar DG by prosumers, the volumetric tariff will not guarantee adequate remuneration because lower net energy sales reduce distribution companies' revenues. The growth of solar DG could potentially decrease firms' remuneration below the level required to recover CAPEX and OPEX. Therefore, there will be an increase in tariffs, originating a cycle of incentives for consumers to become prosumers, which is known as the death-spiral problem.

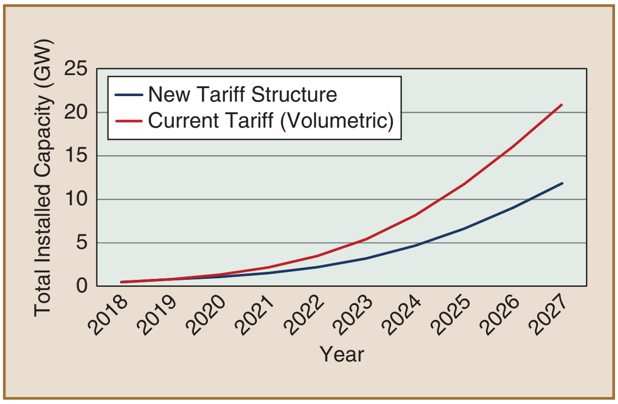

figure 7. The binomial tariff's impact on the penetration of DG for low-voltage consumers. (Data source: EPE, 2018.)

Concerns about the impact that low-voltage prosumers' volumetric tariff has on distribution companies are becoming increasingly important in Brazil because of the two net-metering mechanisms that have been in place since 2014. The first is called *local DG*, which is the standard net-metering approach, where prosumers install a rooftop solar panel on the place of consumption and use the distribution network to balance their energy consumption and production. In the second, called *remote DG*, prosumers install rooftop solar away from their premises (and potentially very far away), meaning that consumers use the distribution network to meet 100% of their load. Sharing DG among different consumers is also allowed under this approach. Hence, a wide variety of different business models has been created to take advantage of the situation, encompassing apartment dwellers who benefit from net metering by installing rooftop solar on beach houses to groups that lease land to share the benefits associated with the remote DG mechanism.

In local and remote DG arrangements, the monomial volumetric tariff is applied to the net monthly consumption of the prosumer or group of consumers. Generated energy that exceeds the monthly consumption is compensated with energy credits to be used for reducing the cost of consumption within the next five years. If the net consumption (generation minus demand plus past energy credits) is zero or negative for a month, the prosumer pays a minimum tariff for distribution network availability. However, the tariff for network availability represents, on average, 29% of the electricity bill, while transmission and distribution networks' CAPEX and OPEX account for 46%.

The regulator has been discussing new tariff structures for the distribution segment as well as changes to the net-metering mechanism for prosumers. Extending the binomial tariff to low-voltage-level consumers is one of the alternatives under consideration. According to the Energy Research Company (EPE), doing so could significantly impact the evolution of DG. Following the ten-year energy plan, applying the binomial tariff to all consumers could reduce the DG installed capacity from 21 to 12 GW by 2027, as illustrated in Figure 7. Although such a result could appear negative from an energy-policy perspective (since less DG would be connected), it would better balance the cost and benefits of system expansion.

Tariff-Structure Alternatives

During 2018 and 2019, ANEEL held two public hearings to discuss new tariff structures for low-voltage consumers and

table 6. Alternative tariff structures under discussion in Brazil.		
Alternative	**Name**	**Description**
—	Current	Present condition, used as a comparison parameter
One	New minimal payment	Increase minimum consumption levels
Two	Commercial cost	Definition of fixed tariff without differentiation among consumers, charged in U.S. dollars per consumer to recover commercial distribution costs (for example, billing and help desks)
Three	Fixed cost	Definition of fixed tariff without differentiation among consumers, charged in U.S. dollars per consumer to recover commercial and distribution network costs
Four	Differentiated fixed cost	Definition of fixed tariff for different consumer sizes, charged in U.S. dollars per consumer
Five	Load	Definition of a tariff in U.S. dollars per kWh for distribution-system-availability costs

changes to the net-metering mechanism. For the low-voltage consumers, ANEEL defined five alternatives to the purely volumetric tariff, carrying out a regulatory analysis for representative distribution companies based on the following principles:

1) *Revenue adequacy*: guaranteeing sufficient service remuneration
2) *Allocative efficiency*: encouraging productive consumer behavior during the short and long term
3) *Transparency and intelligibility*: simplicity of adoption and understanding
4) *Justice and nondiscrimination*: no competitive advantages to any consumer.

The alternatives under discussion are listed in Table 6. Alternative 1 proposes to increase the minimum amount of power prosumers must consume to use the distribution network (even if they consume zero or negative kWh), from 100 to 219 kWh, which is necessary to recover distribution network costs. This would reduce the distribution companies' cost-recovery risk. Still, consumers without DG would subsidize prosumers, since both would be exposed to volumetric tariffs. In alternative 2, the minimal consumption limit would be replaced by a fixed tariff per consumer. The analysis carried out by the regulator showed that cross subsidies remained in this approach, since all consumers would be charged by the same tariff regardless of their peak load levels.

Alternative 5, with a payment in $/kW, proved to be the most efficient in terms of cost allocation, since all consumers would be charged based on their (approximate) use of the network (although the time element is still missing, that is, when the peak load occurs). This approach's main problem concerns the cost of replacing all the low-voltage-level consumers' meters. Initial estimates show that the cost of new meters would represent a 13% increase for a typical electricity bill. In alternatives 3 and 4, a fixed payment to recover the distribution network costs would be applied. The difference is that, in alternative 4, the amount to be paid is based on a consumer's average consumption during the past 12 months, while in alternative 3 the fixed payment does not vary with consumption. According to the regulator, alternative 4 presents the better tradeoff between costs and benefits (especially when considering the transaction cost), since there would be no need to change the existing meters.

At the second hearing, the regulator proposed five alternatives for net metering. The mechanism would continue applying volumetric tariffs, but, contrary to today's practice, rates would vary for withdrawals and injections, differentiating prosumers' production and consumption. While consumption would continue paying for the entire electricity supply chain, production would pay for only part of it. Table 7 presents the alternatives. The first, for example, corresponds to the current practice, where the energy produced by DG is remunerated at a price that contains all components. Instead, alternative 5 remunerates DG production at the wholesale price (without including network and other sector charges), which is significantly lower than that of the first option. The chosen alternative will function temporarily, until a

table 7. Components included in the volumetric tariff to remunerate DG production.						
Alternative	**Distribution Network Tariff**	**Transmission Network Tariff**	**Sector Charges Applied to Peak Load**	**Distribution Network Losses**	**Sector Charges Applied to Consumption**	**Energy Tariff**
Status quo	X	X	X	X	X	X
One		X	X	X	X	X
Two			X	X	X	X
Three				X	X	X
Four					X	X
Five						X

prescribed DG-penetration threshold is reached, enabling regulators to make policies that actively promote DG during the short term and giving investors certainty about how long such a program will last.

Final Remarks

The transition toward economic, reliable, and low-carbon power networks in Latin America is not easy, since special care is needed to avoid raising electricity bills beyond affordable levels. Equity and fairness are highly relevant to the variety of tariff levels and desirable network-services outputs, such as quality and reliability levels, among network users, making network regulation and rate making particularly difficult. We illustrated the regulatory concerns in Latin America, with a focus on Chile and Brazil, related to finding the right distribution network price-control regulations to achieve energy policy goals in the most effective manner.

Balancing distribution-sector costs and benefits will require a more active network-operation approach to take advantage of innovative smart grid technologies and create opportunities for OPEX-based solutions (which are more cost-effective) to displace CAPEX-based solutions. Network users, especially DERs in the form of DG, storage, flexible demand, and so forth, will need to cooperate by deploying and managing their equipment properly. This will require the use of smart meters and new IT technologies, price signals, and other control signals that must be managed in real time.

Incentive-based regulations (which are preferred in most of Latin America instead of cost-of-service regulations) and tariff structures must evolve to align private and public policy objectives, incentivizing network companies and users (producers, consumers, and prosumers) to act accordingly. Under an evolved approach, regulators are expected to take a more active role in scrutinizing the data of real companies regarding costs, assets, and plans. Regulations would need to provide appropriate guarantees, rewards, and penalties for companies and users, motivating them to deploy efficient solutions aligned with public policy, especially reliability. They should also ensure that the resulting tariffs are affordable to all, including vulnerable consumers in rural areas. This evolution will be challenging in Latin America as it will require more regulatory resources, since the historical practice has relied on simpler approaches with a low burden and implementation cost.

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