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ELECTRICITY MARKET DESIGN FOR ZERO-MARGINAL COST SYSTEMS: WHAT HAVE WE LEARNED FROM MARKETS OF HYDRO SYSTEMS IN LATIN AMERICA?

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Large reductions in the cost of renewable energy technologies – particularly wind and solar – as well as various instruments to achieve decarbonization targets (e.g., renewable mandates, renewable auctions, subsidies, and carbon pricing mechanisms) are driving a rapid growth of investments in these generation technologies worldwide.

Despite overall benefits of producing electricity using renewables instead of relying on fossil fuels, incorporating large amounts of solar and wind generation can be challenging for power systems. Solar irradiance and wind speeds are variable and, to some extent, unpredictable, which can compromise the stability of the power grid. Private investors, electric utilities, and independent system operators (ISOs) are addressing this challenge through a combination of measures that include the geographical diversification of resources, the utilization of energy storage, and the implementation of demand-response programs.

Another feature of renewables that is making market participants, lenders, policymakers, and regulators concerned is their effect on equilibrium prices of electricity. Most wholesale electricity markets set real-time prices (also referred to as spot prices or locational marginal prices depending on implementation) as the marginal cost of producing one incremental unit of electricity at any given instant. Under this paradigm, there are concerns that increasing levels of generation from technologies with near-zero marginal cost such as renewables will inevitably depress spot prices to the point that revenues from the energy spot market will be insufficient to cover the capital costs of merchant generation technologies. This has raised questions about the ability of current electricity markets based on spot pricing to incentivize investments that will deliver efficient and reliable power systems in situations with high shares of renewables.

This article uses the experience of the hydro-dominated Latin American electricity markets to highlight parallels between renewable-driven energy systems of the 21st century and hydro-driven systems that Latin America has been operating for decades, particularly in the 1990s. The experience of several countries in Latin America has been that liquidity of long-term financial instruments are essential to incentivize investments in generation capacity. This is particularly important in situations where spot prices are extremely volatile, alternating between periods with high prices, driven by scarcity pricing mechanisms, and extended periods of time with zero prices, when hydro resources are abundant. In many Latin American countries, regulators have imposed minimum mandatory forward contracting requirements to ensure a minimum level of liquidity of long-term financial instruments, complementing voluntary bilateral markets for these products. Centralized auctions for long-term contracts are also common in the region, as market-based mechanisms to procure electricity and ensure some tariff stability for retail customers when there is no competition in the retail segment. The mandatory long-term products can be simple forward energy contracts (as in Chile and Peru), energy bundled with reliability products (as in Brazil), or contracts for a standalone reliability product (as in Colombia), with energy contracts traded in bilateral markets. The experience of countries in Latin America dealing with systems with high shares of generation from near-zero marginal cost resources can be useful for electricity markets in other parts of the world, particularly in

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case the new renewable-dominated systems do not have enough liquidity of long-term financial contracts to hedge risk.

The overall experience of Latin America's long-term markets to attract and retain investors in new generation has been positive. However, there are some issues related to the design of both long- and short-term markets that need to be addressed. For instance, auctions for long-duration contracts facilitate investments and benefit lenders; however, they can introduce inflexibilities to the market, preventing cost reductions in technology from being passed on to consumers. Short-term markets will also need to be improved to accommodate increasing shares of generation from renewables. Some of the needed enhancements will require mirroring features of short-term markets in the United States (U.S.) and in Europe, such as increasing the temporal granularity of real-time prices, introducing multi-settlement mechanisms (absent in many prominent Latin American Markets, such as Brazil and Chile), and allowing emerging technologies and demand-side resources to participate in wholesale markets. In this vein, there could be learning opportunities both for Latin America and for electricity markets in the U.S. and Europe, in order to find the best market design to accommodate increasing shares of generation with zero marginal cost.

Pricing of electricity: What does the theory say?

The foundations of electricity pricing were developed in the mid-1980s, with Professor Fred Schweppe in particular having made significant contributions to the underlying theory and practice. Spot pricing is fundamental to the design and operation of electricity markets worldwide and has powerful implications for the efficiency induced by these signals in market-based. Under some specific assumptions (such as perfect competition), if the wholesale electricity price in each period and location only reflects the short-run marginal cost of an incremental change in demand (plus the cost of reducing demand when capacity is scarce), without consideration of capital costs, a spot market can guarantee efficient operation of generation units in the short term and incentivize entry and exit of generation units of the right size, with the right technological characteristics, and at the right locations in a transmission network.

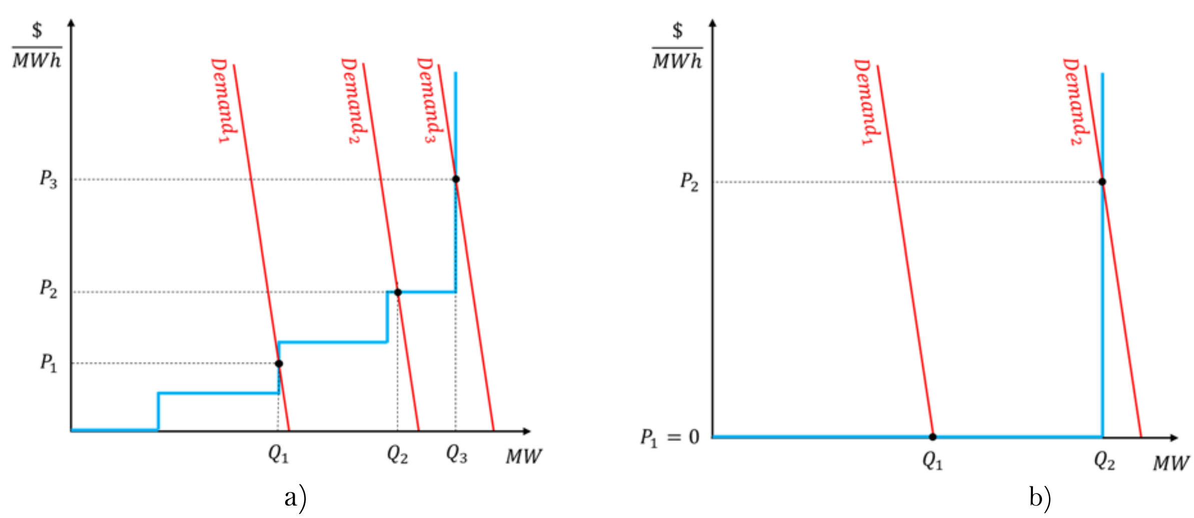

Figure 1: a) Supply and elastic demand curves for a system with a mix of different conventional generation units, b) Supply and elastic demand curves for a system where all units have zero marginal cost.

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Figure (1a) illustrates supply and demand curves for a hypothetical system with four generation units with different marginal costs. The intersection of supply and demand curves defines both the spot price and the demand level that must be supplied with the available generation units. Note that, for most demand levels, the intersection point occurs at one of the horizontal segments of the supply curve, which means that spot prices coincide with the marginal cost of some generation unit (e.g., the resulting spot price for Demand_2). However, the intersection of supply and demand can also occur at vertical segments of the supply curve, when generation capacity is scarce. In these cases, the resulting spot prices are higher than the cost of the most expensive generation unit running in the system (e.g., the resulting spot prices for Demand_1 and Demand_3) and are often referred to as scarcity prices. In equilibrium, this set of spot prices—including scarcity prices—allows all efficient units to cover both operation and capital costs.

The supply curve in Figure (1a) is representative of most historical and current systems, with a steeply-sloped demand curve (low elasticity) and a supply curve (also called a "merit order curve") formed by a portfolio of units with different marginal costs, such as solar, wind, hydro, nuclear, coal, gas, and/or diesel generation. In those systems, supply sets the spot price most of the time, meaning that prices are equal to the short-run marginal cost of the most expensive unit in operation. In such cases, many of the low-priced generation units recover a large fraction of their investment during times when more expensive generators set the spot price. This is particularly true for renewables, which have extremely low variable costs (typically only a few dollars per MWh, linked to wear and tear and other operating costs) and which can be considered as virtually equal to zero for all intents and purposes. For example, a wind unit that runs at a time when demand is high and when the spot price is set by a diesel generator earns a short-run profit that is equal to the difference between the marginal costs of the diesel unit and the wind generator. In the relatively mature markets of the U.S. and Europe, the somewhat predictable behavior of the supply and demand curves has resulted in relatively stable spot prices, which eases the predictability of revenues needed by generators to secure financing with lenders.

In contrast, electricity systems with high renewable shares may have much less variety in the variable cost of generation technologies. Figure (1b) shows supply and demand curves for a hypothetical system where all generators have zero marginal cost, akin to how supply curves would look in a system with lots of generation from abundant hydro, wind, and solar resources. Note that, in those cases, anytime demand is low enough, spot prices are equal to zero. However, when demand goes up, prices can increase dramatically, allowing all technologies to recover their investment costs. While all generation units benefit from scarcity prices, their occurrence in the case depicted in Figure (1a) is particularly important to ensure that peaking units (e.g., diesel generators) are able to recover their investment costs. Otherwise, incentives to entry and exit of capacity work in the same manner in both examples. Note that in the situation depicted in Figure (1b), there is a more extreme discrepancy between "peak" spot prices (potentially very high scarcity prices) and "off-peak" prices (virtually zero), which provides incentives for demand-side resources to adjust consumption, achieving a similar effect to increasing or decreasing generation capacity in the long run.

Hence, conceptually there is nothing that prevents the application of the classic spot pricing theory to systems with high shares of generation from resources with zero marginal cost. As we show in Figures (1a) and (1b), the only difference is that, in systems with lots of generation from technologies with zero marginal cost, scarcity pricing becomes the main mechanism to ensure cost recovery in the long run, since spot prices are likely to be zero for extended periods of time. If liquid financial markets to hedge the price-volume risk over different time frames are in place, the optimal capacity expansion mix is secured (and financeable). In these situations, consumers can also define their optimal reliability needs and their participation in the market as active demand response based on private preferences (e.g., risk aversion).

In mature electricity markets following these design principles, spot prices can increase dramatically during scarcity times due to high price caps (as seen in Australia and Texas). In practice, however, the administrative estimate of the Value of Lost Load (VoLL) used to determine price caps is sometimes driven by political instead of technical considerations, which can introduce distortions. A relatively recent development regarding price formation in periods of scarcity (which will be addressed in the following section) has been the implementation of sloped Operating Reserve Demand Curves (ORDCs), employed in some markets in the U.S. and in Mexico, where price-dependent curves replace vertical demand curves for operating reserves.

In practice, low price caps, illiquid financial markets for long-term contracts, and the lack of demand response can pose real challenges for electricity markets in their purest form, which choose to rely solely on spot pricing – including scarcity pricing – to provide expansion incentives. These challenges are especially pronounced for countries with fast load-growth rates – or countries with increasing levels of decommissioning of existing generation capacity – where the lack of new supply may result in shortages. Furthermore, it is likely that these challenges will become even more pronounced with increasing shares of generation from renewables. Not only is there tendency to a "feast or famine" situation with regards to equilibrium prices, as illustrated in Figure (1b) above, but the technological disruption of renewables has profoundly altered the landscape of expectations for the electricity sector. In particular, there are significant uncertainties regarding the rate at which the cost of renewables will continue to fall and their share in the expansion mix will continue to rise; as well as the rate at which additional innovations such as the emergence of distributed energy resources, demand response and storage technologies will be disseminated. This combination of spot price volatility and uncertainty with regards to the future evolution of the system creates an environment that may threaten potential investments and loans, creating an even greater motivation for long-term markets for financial and/or reliability products.

Spot pricing in hydro systems in Latin America: One form of scarcity pricing

Latin America is formed by 16 countries and has a power system with roughly 400 GW of installed capacity, where hydropower accounts for about 50% of the generation mix. Load growth rates have historically hovered at around 5% per year in a region where energy consumption is around 1,500 TWh/y. Figure 2 shows a general sketch of the main wholesale market design elements.

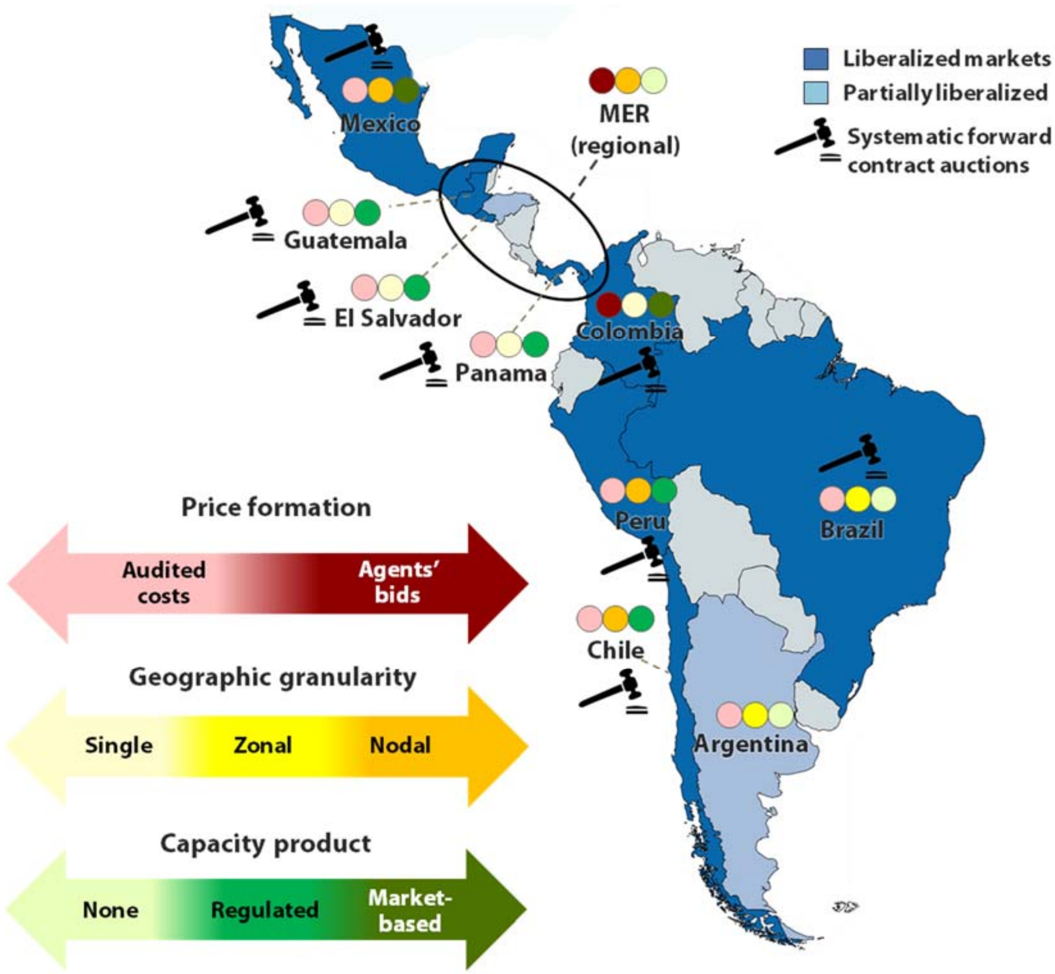

Figure 2: Outlook of wholesale market design elements in Latin America.

On the pricing side, only Colombia and the Central American regional electricity market (MER) have adopted a bid-based scheme for generation dispatch and spot price formation, as depicted in shades of red in Figure 2. All other countries in the region utilize cost-based arrangements, where generators only report their directly attributable marginal production costs (i.e., fuel costs) to build the merit order curve for the dispatch and pricing of electricity done by the ISO. *Water values* are used as proxies for marginal production costs for hydro plants, which are calculated by the ISO based on a set of administratively-defined assumptions and with the aid of stochastic optimization models. Given the cost-based merit order curve, spot prices are defined as the cost of the marginal unit needed to meet demand in each settlement period.

While cost-based markets have some disadvantages compared to bid-based ones, most countries in Latin America opted for cost-based market designs for the following reasons: (i) to ensure *transparency* (the dispatch and spot prices are calculated by computer models with well-known algorithms, with the software and system data publicly available to all market participants); (ii) to ensure *efficiency* in the dispatch of hydro plants in cascade with independent owners and multiple water uses; and (iii) to avoid potential issues with *market power* that could arise in bid-based markets. When electricity markets were first implemented in Latin America, regulators perceived that it was important to tackle these issues to imbue investors with confidence to invest in new generation capacity, which was the main goal of the industry reform in these countries. In addition, regulators were concerned that the cost of implementing a bid-based dispatch and pricing mechanism could be prohibitively high due to the need to set up sophisticated trading platforms and market power mitigation mechanisms as well as educating state-owned companies to bid rationally into these markets.

On the other hand, one of the main criticisms of the current centralized scheme used to determine water values has to do with the sensitivity of probabilistic simulation models to input parameters, such as the probability distribution of future hydrological conditions. Despite efforts made by ISOs to ensure transparency and replicability of results, conflicts (sometimes leading to court cases) occur frequently because of discrepancies between the assumptions made by the authority and each firm's private view of what should and should not go into the simulation model. This is because assumptions about input parameters affect not only the centralized estimate of the value of water, but also dispatch decisions, prices, and revenues for private firms that participate in the market.

As highlighted in Figure 3, there are several interesting commonalities and contrasts between the renewable-dominated systems that may become prominent in the future and hydro-dominated systems such as those in Latin America (especially prior to the introduction of large amounts of thermal capacity in the 1990s and 2000s).

	Hydro-based systems	Renewable-based systems
Timescale of main variability components	Weekly, seasonal and interannual	Hourly and daily
Effect on short-term system operations	Hydro provides reserves	Renewables require reserves
What kind of support generation is needed?	Resources to remain on (off) for entire dry (wet) seasons	Fast-acting resources to make up for sudden imbalances
Risks of shortage	Rationing (energy-constrained)	Blackouts (capacity-constrained)
Price formation	Based on probability and cost of rationing	Based on probability and cost of sudden blackouts

Figure 3 – Parallels between renewable- and hydro-dominated markets

The first common feature is related to the volatility of spot prices. Systems with high shares of generation from generation resources with zero marginal cost commonly face extended periods of time when spot prices are zero, followed by periods with high prices when renewable resources are not available. This happens because these systems are typically designed to ensure that demand can be supplied even in the most adverse weather conditions considered in the simulation model, which, in practice, do not occur frequently. For this reason, it has been common for hydro-dominated systems in Latin America to face excess energy and low spot prices for extended periods of time. Nevertheless, in extremely dry seasons, some demand rationing may occur, and prices can climb up to the price cap. This phenomenon is illustrated in Figure 4, which shows the observed monthly spot prices in the Brazilian Southeast system from January 1993 until August 1997, when the electricity market reform was being discussed in the country. As we show , the spot price was close to zero in 36 out the 56 months depicted, and the longest low-price period lasted for almost two years (21 months). This behavior is similar for other countries in the region with lots of hydro resources and it is similar to the price behavior expected in renewable-driven systems. It merits noting, however, that price volatility in hydro-based systems occurs at a different timescale: they tend to exhibit low volatility of spot prices in the short term, as large reservoirs can easily transfer hydro energy from off-peak to peak hours.

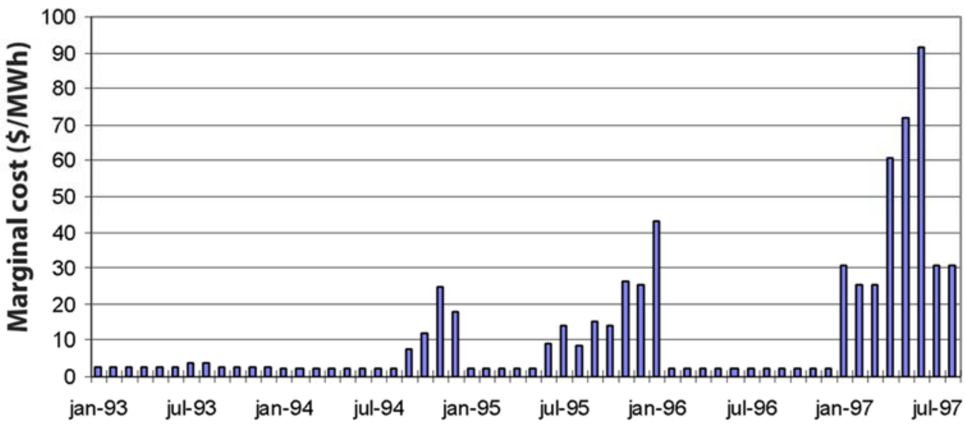

Figure 4 - Historical monthly spot prices in the Brazilian system ($/MWh)

The second commonality has to do with the principle used to estimate the value of water in cost-based markets in Latin America and the idea behind the implementation of sloped Operating Reserve Demand Curves (ORDCs) in U.S. markets. Sloped ORDCs are constructed based on the notion that stochastic fluctuations in the supply-demand balance must be accommodated by dispatching part of the system *reserves*, or short-term operational flexibility, committed in the ex-ante market. If a lower amount of reserves is procured, therefore, there is a chance that the system will not be able to respond and shortages will be necessary – a situation that can be represented using a probabilistic simulation model representing multiple sources of uncertainty. By multiplying this probability of shortage as a function of the amount of online reserves by the value of lost load (VoLL), one obtains an estimate for the demand side's marginal willingness to pay for an incremental amount of reserves to avoid a shortage. It is clear from this depiction that increasing the VoLL has a direct influence on the shape of the ORDC, thus leading to a more conservative assignment of resources in the short term, pressuring spot prices upwards and inducing a larger capacity margin at the market equilibrium, thus leading to a more reliable system in the long term.

A very similar logic applies to the calculation of water values in hydro-dominated systems. Provided that all generation resources available have zero marginal cost, the water value can be approximated by the product of the VoLL (or, more precisely, the cost of rationing) multiplied by a probability of energy shortages, reflecting the opportunity cost of not having water for generating power in the near future. Water values are calculated by *simulating* the system operation over several periods using a probabilistic model that considers different scenarios of hydrological conditions (e.g., dry, average, and wet). Figure 5 illustrates how a *probabilistic* simulation model weights the future opportunity cost of water according to the probabilities of each scenario to define today's marginal value of hydropower. When the system is unable to meet demand in a given dry scenario and stage, the opportunity cost of water is equal to the cost of rationing, as the only alternative to replace a reduction in hydro generation is to curtail demand. In scenarios with intermediate inflows, the value of water is usually equal to the cost of the cheapest thermal plant in the system that could increase its output if hydro generation were reduced. In contrast, the water value is zero in scenarios where dams are overflowing, which is often the case in extremely wet seasons.

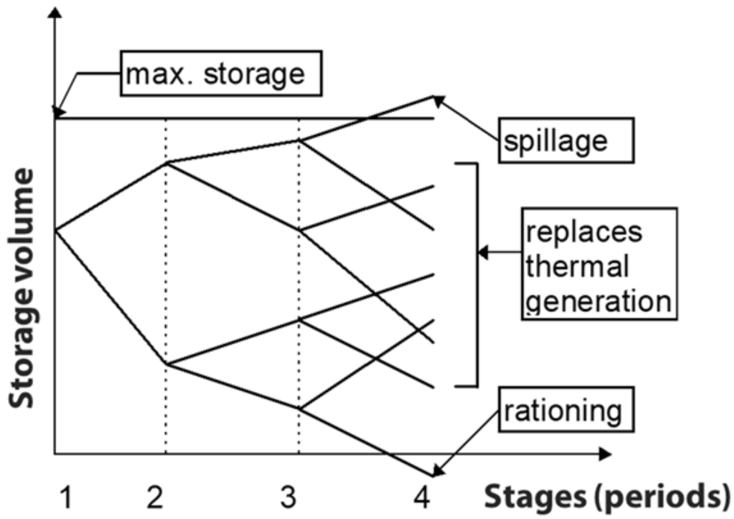

Figure 5 – Calculation of the opportunity cost of water.

The third parallel we see between these two types of systems is the challenge of incentivizing efficient investments in situations with highly volatile spot prices. As we mentioned in the previous section, theory states that volatile spot markets give generators and consumers incentives to engage in long-term financial contracts to hedge risks. However, in situations where markets for long-term contracts are illiquid or insufficiently mature, it can be difficult for developers to gain access to project finance agreements from lending entities to support new investments in generation capacity. It was because of the high volatility spot markets with extended periods with zero prices, the lack of liquidity of long-term contracts, and the pressing need for new generation capacity that many countries in Latin America chose to implement centralized auctions for long-term contracts. Long-term contracts can also provide insurance against both policy uncertainty and political risk, helping investors to reduce the risk premium that is required to justify investments.

Figure 6 shows two examples of actual merit order curves of the Brazilian system for two historical snapshots in wet and average weeks. Note that the availability of hydro resources can have a large effect on spot prices and on incentives for market-based system expansion.

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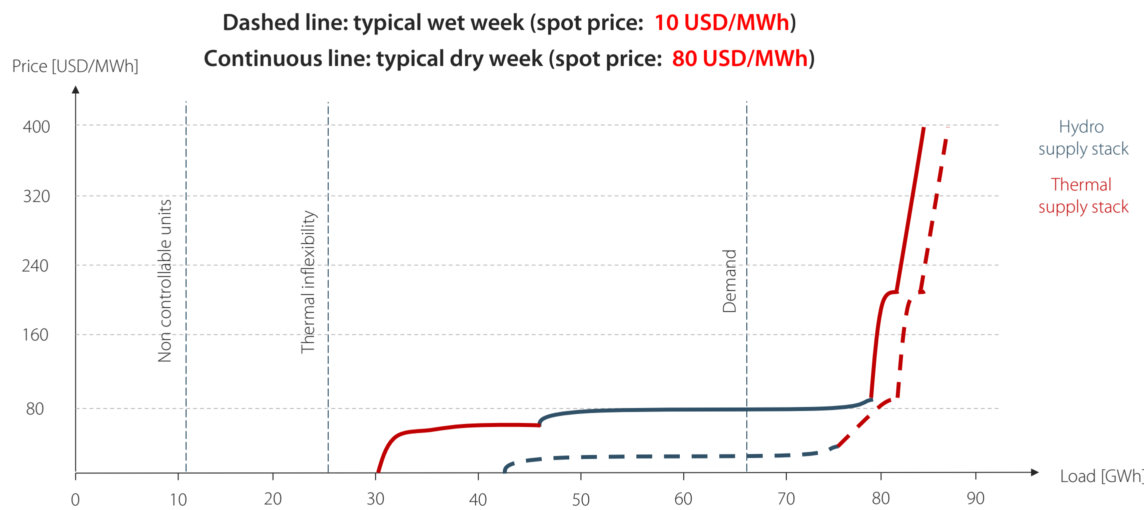

Figure 6 – Examples: variance of the merit-order curves in Brazil

The need for hedging instruments: Centralized auctions for long-term contracts

Since the initial implementation of the Latin American market reforms in the 1990s, several countries introduced capacity mechanisms to aid in ensuring resource adequacy (as indicated in Figure 2 in shades of green). Capacity mechanisms are designed to correct potential issues that result from price caps that are set too low (leading to artificially low spot prices on average and thus insufficient incentives for system expansion) and also as instruments to stabilize revenues for generators in light of volatile signals from spot markets. They operate just as capacity markets do in the U.S., relying on an administrative definition of what constitutes the "firm capacity" product that drives a component of agents' remuneration.

At the time of the initial market reforms in Latin America in the 1990s, most implementations of capacity mechanisms were in the form of a regulated capacity payment (as seen in Colombia, Chile and Peru), where the capacity price is determined by the regulator based on an administrative estimate of the cost of new entry. At that time, Brazil was the only country that imposed a forward contracting requirement on load-serving entities and deregulated consumers, to mandatorily cover a high percentage of their loads through energy contracts, which had to be negotiated bilaterally and backed by firm energy. These initial designs, however, faced numerous challenges in practical implementation during the following decade. In the case of capacity payments, experience showed that both the administrative definition of the capacity price and the capacity product could have a large impact on investment incentives for individual firms. In addition, forward contracting requirements alone did not ensure that regulated distribution companies had incentives to choose the least-cost contracts for retail customers, thus leading to self-dealing issues and inflated prices. The previous challenges, combined with the fact that short-term prices did not provide adequate incentive for generation expansion (given the absence of liquid marketplaces for financial hedging), motivated a "second wave" of market reforms in Latin America in the 2000s, following the "first wave" of reforms in the 1990s. This second wave of reforms was focused on improving the mechanisms used to ensure resource adequacy and led to the introduction of market-based capacity products (or reliability products) in some countries.

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Brazil pioneered this new wave of reforms in 2004, introducing a mechanism that put auctions front and center and served as an inspiration to several other countries – such as Chile in 2005 and Colombia and Peru in 2006. These new designs typically combined centralized auctions with the quantity-based mechanism that required a minimum level of contracting for loads. Implementation details vary among countries, particularly regarding the following core elements – which can be used to describe most auction mechanisms for long-term contracts introduced in real-world electricity markets over the years:

a) *Demand-side obligations*: These include, among others, (i) the assignment of responsibility for forecasting the demand several years ahead for the procurement of contracts, (ii) a mechanism for assigning the cost of forward contracts to consumers, and (iii) rules to specify under which conditions agents can opt out of the standard mechanism to procure their own demand. For example, while the auctions in Colombia only involve the purchase of a "reliability product", the auctions in Peru and in Chile involve only a forward contract, while Brazil requires contracts for "bundles" of reliability products and forward contracts.
b) *Supply-side liabilities*: These include, among others, (i) what exactly generators' reliability commitments entail regarding firm supply backing, (ii) penalties for noncompliance with contract clauses, and specific obligations for energy and/or reliability delivery, often tailored to physical attributes of different generation technologies.
c) *Auction design elements:* These include, among others, the definition of (i) lead times, (ii) contract duration, and (iii) eventual technology segmentation of potential suppliers, such as differentiating between existing projects and new projects for contracting purposes.

In practice, the implementation of minimum contract requirements and centralized auctions by Latin American regulators in the 2000s emerged as a practical short-term solution to issues that were primarily related to the lack of investments in past periods, when demand was growing too fast compared to new capacity additions. Consequently, there was a need to take some action to accelerate private investments in new capacity. Furthermore, although it might not have been their primary intent to correct for the market failure that results from incomplete financial markets for risk-sharing, there is now robust empirical and theoretical evidence that mechanisms that introduce this type of financial contracts can indeed improve market liquidity and market efficiency.

Long-term electricity auctions are now one of the driving forces for the expansion of the power sector in Latin America. To date, more than 100,000 MW of new generation capacity from all technologies have been contracted and delivered at competitive prices via those auctions. In addition, since the late 2000s, countries all over the world have started using different variants of these auctions as mechanisms to procure power from renewables and to support the development of these technologies – thus promoting robust *investment markets.*

Despite the success of auction mechanisms in Latin America, there is now evidence that some aspects of the original design elements of these auctions could be improved. For instance, some of the first contracts were auctioned for periods that were excessively long, which led to excessively rigid commitments that ended up allocating too much risk to customers. Other design and implementation issues are related to the bundling of energy and reliability in a single product, contract enforcement, and the selection criteria used in centralized auctions when contracts incorporate different sources of risk in their contract and indexation clauses (e.g., fossil fuel price risk, renewable generation profile risk, and spot price risk). Administrative definitions of firm capacity and firm energy could also result in biases against emerging technologies and impair them to compete on equal footing against, for instance, conventional generation technologies.

Improvements needed in Latin America to accommodate high shares of renewables

While current market designs in Latin America have served their purpose, they were not originally tailored to accommodate increasing shares of generation from variable and unpredictable resources in short time intervals. As introduced previously, hydro-dominant systems, while having their own share of challenges, have relatively high short-term flexibility compared to systems with high shares of generation from renewables (e.g., wind and solar PV). This explains why, in general, most markets in Latin America have rather simple mechanisms to settle imbalances in the short term, lacking most of the advanced features of more highly developed electricity markets. Going forward, we recommend improving several design elements in the wholesale market as described in the following table.

Design element	Current status in Latin America	Suggested improvement
Wholesale spot price formation	In many cases, spot prices are computed ignoring transmission constraints and without co-optimization of energy and reserves.	Spot prices should be computed considering all transmission and generation constraints, plus reserves, simultaneously. This approach ensures that all constraints are reflected in spot prices.
Temporal granularity of spot prices	Most countries in the region compute prices at hourly time intervals, with the exception of Perú (every 30 minutes) and Brazil (3 load blocks in weekly prices).	A time granularity of at least 1 hour is recommended to allow spot prices to better reflect the physics of the system, which is particularly important for units that impart flexibility. Increasing the frequency of dispatch and settlement intervals also decreases the need to activate reserve products.
Spatial granularity of spot prices	Some countries employ a simplified version of nodal or zonal pricing using merit-order curves to determine the spot price for pre-specified pricing zones (Brazil), which can also be a single large pricing zone that includes the whole country (e.g. Colombia).	Countries should implement Locational Marginal Pricing (LMP) with mechanisms to allow market participants to hedge congestion risks. LMP provides efficient signals for the entry and exit of generation units by reflecting information about the incremental value of generation at each location in the transmission network.
Cost- or bid-based arrangements for dispatch and price formation	With the exception of Colombia, all short-term electricity markets in Latin America to date have been cost-based markets.	Whenever possible (political will, human capital and sufficient competition), we recommend bid- instead of cost-based markets. Practical experience indicates that having a central agency that relies on a single view of the future to make decisions may lead to conflicts and legal disputes. Concerns about coordination of hydro units in cascaded systems, multiple water uses, and market power concerns can be addressed with a combination of property rights and active market monitoring.
Scarcity pricing	Countries with lots of hydro resources have a form of scarcity pricing mechanism that reflects the administratively-calculated	While there isn't enough demand response for scarcity prices to naturally emerge, we recommend that the VoLL or cost of deficit parameter used in simulation models should be

	socioeconomic cost of curtailing demand sometime in the future if hydro resources are not available (as assessed by a simulation model). To our best knowledge, Mexico is the only country that has implemented sloped Operating Reserve Demand Curves.	at least equal to the price at which demand would be willing to reduce consumption (in line with the resource-adequacy target of the system). The use of a sloped Operating Reserve Demand Curve (ORDC) can also improve price formation during times when reserves are scarce and prevent abrupt price drop-offs.
Ancillary services	In most countries the provision of ancillary services is mandated by regulations that only compensate units for the directly attributable costs of providing the service (e.g., fuel costs). In most cases, energy and reserve products are not co-optimized.	We recommend migrating to schemes that co-optimize the provision of energy and ancillary services. We also recommend remunerating ancillary services based on uniform price, ensuring that all agents that provide the same service are remunerated equally. Mechanisms that only compensate for the directly attributable costs of providing these services are discriminatory and do not provide incentives for the entry of efficient units in the long-term.
Multi-settlement markets	Most countries use day-ahead scheduling and only one settlement. In both Chile and Colombia, for example, day-ahead prices are not used to settle any transaction, relying solely in real-time prices.	We recommend implementing day-ahead markets that will allow forward financial commitments to be settled against real-time prices and evaluate the need for additional settlements.
Capacity mechanism	Countries rely on different criteria to define firm energy and firm capacity values, both of which determine remunerations for firms that contribute to the system with these products. Some countries also employ administrative capacity payments without necessarily aiming for an explicit resource-adequacy target.	Countries that choose to rely on capacity mechanisms should pay attention to the definition of firm capacity of renewables and energy storage technologies. We recommend crediting firm capacity based on some reliability metric that treats all resources, including demand-side ones, equally. We also recommend that countries define a resource-adequacy target that is aligned with the administrative estimate of the cost of unsupplied demand used to price scarcity – ensuring consistency between value assessments of additional transmission reinforcements (planned centrally) and the profitability of new generation investments (based on market signals).
Centralized auctions for long-term energy contracts or minimum contracting requirements	Centralized auctions for contracts are used in many countries as a mechanism to ensure that distribution companies will procure power at the least possible cost for retail consumers. Brazil also relies on centralized auctions for contracts, with physical backup as a resource-adequacy mechanism.	Countries should consider reducing the duration of mandated contracts and explore options to introduce more liquidity into long-term financial markets, fostering participation of financial agents and retail aggregators. Contracts of long duration (e.g., 15-20 years) can be effective at incentivizing generation investments, reducing risk for generation firms. However, they also prevent customers from benefiting from cost reductions due to technological disruptions in generation technologies, locking customers into prices that might become too high compared to average spot prices. Additionally, we recommend that regulators consider counterparty and price risks as part of the selection criteria used in centralized auctions.

Conclusions

There are several aspects of the electricity markets in Latin America that could be improved. Some of the needed enhancements will require mirroring features of short-term markets in the U.S. and in Europe, such as increasing the temporal granularity of real-time prices, opening wholesale markets to demand-side resources as well as emerging technologies, and introducing multi-settlement systems. Long-term markets could also be improved by ensuring that contracting requirements and auction mechanisms allow all technologies to compete on equal footing. Reducing the duration of contracts would also allow consumers to benefit from technological disruptions in generation technologies in the coming decades. It is also possible to introduce more liquidity into markets for long-term contracts by implementing marketplaces for these instruments and opening them to financial agents and retail aggregators

Nevertheless, the experience in Latin America (Brazil, in particular) shows that many hydro systems in the region have operated with lots of generation with zero marginal cost for decades and have still managed to incentivize investments in new generation capacity. However, in those situations, long-term markets for sufficiently liquid financial contracts are essential to secure generation financing, allowing investors to reduce their exposure to the high volatility of spot prices. Additionally, some types of long-term contracts can also provide insurance against both policy uncertainty and political risk, which can be large in some countries in the region.

Finally, from our perspective, the experience of some countries in Latin America that have relied in markets for long-term contracts offers some learning opportunities for countries with advanced short-term markets (e.g., the U.S. and western Europe). This experience could be useful if the volatility of spot prices due to increasing shares of generation from renewables becomes a barrier to incentivize investments in new generation capacity.

For further reading

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