



The latter must be assigned to the agents responsible for them. Costs related to balancing energy (reserve activation) can be assigned according to the imbalances registered between the last binding dispatch and the actual injection of each resource. Costs related to balancing capacity can be assigned either through an enhanced methodology for the calculation of the reserve requirement (fulfilling the cost-causality principle) or by using a moving average of imbalances, calculated for each resource, as a proxy of the responsibility for the incurrence of such costs.

**Long-term signals**

The Chilean system must guarantee that the future power system will be not only adequate (enough installed capacity) but also flexible enough to cope with renewable intermittency and variability. Proposals have been advanced for introducing specific tenders for flexible capacity, to be launched each time the system operator foresees a lack of flexible resources in the medium term. In order to introduce long-term signals for attracting flexible resources, it would be better to encompass such signals in the current capacity payment, rather than segmenting the market with targeted auctions. This can be achieved either by modifying the methodology for the calculation of firm capacity (considering a term that favours flexible resources) or by introducing a new product, a ‘flexible capacity payment’, with a specific administratively set price, which would be paid only to resources fulfilling a set of requirements.

**Conclusions**

At the beginning of this century, Chile – like many South American countries –

introduced long-term auctioning mechanisms with the objective of guaranteeing the security of electricity supply. These reforms, which are still in place, did not affect the design of short-term markets for energy and ancillary services. Renewable technologies represent a huge opportunity for the Chilean power sector, but they may significantly alter the current functioning of the electricity market. To make that market more resilient to the expected rapid increase in renewables, it must be reformed to guarantee their efficient integration. First, the new market design must be based on binding dispatches, which fix remuneration and responsibilities of market agents, second, ancillary services must be procured in a market environment, preferably through a co-optimization of energy and reserves. Third, the cost of keeping the system balanced should not be socialized, but rather assigned to agents according to their responsibility for the occurrence of that cost. Finally, the long-term signal conveyed by the capacity payment may need to be modified to attract flexible technologies.

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**BRAZIL CONSIDERS REFORM OF THE ELECTRICITY SECTOR**

**Carlos Batlle, Mário Domingos Pires Coelho, Pablo Rodilla and João Tomé Saraiva**

When Brazil’s electricity market failed to attract enough investments to meet the country’s rapid growth in demand, a 2004 law shifted the focus from the short-term market to long-term electricity contracts, as a way to provide investors with hedging tools against the significant volatility of spot prices. Since then, the market design has been based on two obligations: for demand to be 100% covered by long-term contracts, and for the contracts to

be 100% covered by firm energy certificates. These long-term contracts have been assigned through a variety of centralized electricity auctions. The regulator can also hold so-called reserve auctions, which are intended as a last-resource mechanism to increase the reserve margin of the entire system, in case it is deemed insufficient. These auctions have been used in recent years to foster the installation of renewable energy technologies.

This combination of auctions and long term contracts attracted the needed investments in generation; but as time progressed, it has showed increasing signs of stress. The government that took office in June 2016 asserted that a number of factors – including previous intervention in resource allocation and prices, inadequate and overly centralized risk allocation that led to judicial disputes, inadequacy of spot market prices as investment drivers, lack of transparency, and subsidized financing via the Brazilian Development Bank – had created the need for an overhaul of the legal framework to enable Brazil to adapt to a more decentralized power system.

In February 2018, the Brazilian Ministry of Mines and Energy, after several months of public consultation, sent the president a proposed Law for the Modernization and Expansion of the Free Market for Electricity. The law has four aims: (1) increasing the granularity of wholesale-market price formation, (2) introducing a mechanism to allow for the internalization of environmental externalities, (3) designing a new capacity product, and (4) widening the scope of the retail market. It complements another, more ambitious proposal to privatize the state-owned utility, Eletrobras, and grant new concessions for its generation plants to operate in the private sector.

The proposed law has not yet been submitted to Congress. However, on



March 13 this year, the Ministry of Mines and Energy published an ordinance establishing the main principles to guide future rule-making in the electricity sector. The proposed new regulatory framework attempts to enhance market signals to allow more decentralized risk management, with the expectation that this will further engage market agents to improve overall efficiency. Its proponents in the Government have consistently emphasized property rights and contract sanctity, including mechanisms to accommodate legacy obligations.

The main elements of the proposed reform are described below.

### **Change in the concession rules**

In 2012, then-President Dilma Rousseff's Government approved a package of laws (the 'MP 579'), supposedly aimed at reducing electricity prices. At that time, many hydropower plant concessions were expiring. Under this framework, the concessionaires could renew their concessions only if they agreed to be paid on a cost-plus basis, which would cover operational and maintenance costs plus a reasonable profit for electricity sales to the captive market, instead of continuing to function as independent power producers. Companies rejecting this proposal would have to auction off their concessions under the same cost-plus regime. Most expiring hydropower concessions were renewed under this arrangement; though it may not be a coincidence that plants covered by these concessions belonged to Eletrobras, the government utility.

Electricity produced by these power plants was then sold forward to distribution companies to fulfil the needs of the regulated market. Under the MP 579, these companies bore the hydrological risk of the new contracts. A sequence of dry years (2012–2016)

caused a hydro shortfall that resulted in dramatic price increases, creating a huge debt for the distribution companies.

The proposed 2018 law would make it possible to grant new concessions for Eletrobras' plants to the private sector for a period of 30 years (effectively privatising those concessions), allowing owners to trade electricity in the free market, in an attempt to increase liquidity and, as a result, market efficiency.

However, taking into account the particular characteristics of the Brazilian power system, especially the hydro system, the efficacy of this measure appears to be somewhat limited, because the management and planning of the hydro plants (both reservoir-based and run-of-the-river) in Brazil is fully centralized and controlled by the market and system operator (Operador Nacional do Sistema Elétrico, ONS). The proposed solution certainly transfers the volume and price risk from end users to power producers, but it is unlikely to induce more efficient management of the hydro resources.

A highly relevant factor underlying this new regulation is the great pressure that current hydro generators are putting on the Government to move towards bid-based dispatch, and away from central despatch based on ONS interpretation of the opportunity cost of hydro. During the severe drought of 2016, spot prices skyrocketed, and the ONS was accused of withholding hydro generation due to excessive risk aversion. Hydro generators found themselves in a contractually short position and incurred great losses buying energy in the spot market to meet their contractual commitments. Although it was crystal clear at the time of signing the contracts that the responsibility for hydro management resided with the hydro generators, most of the latter have taken legal action

arguing defencelessness in view of the de facto control that ONS has over despatch.

### **New market structure**

The design of the Brazilian wholesale market has been heavily influenced by its heavy reliance on hydro. Because of the significant multiannual hydro reservoirs, the system has not been subject to capacity constraints, so there was no need for intraday price differentiation or ancillary services markets. On the other hand, to ensure security of supply and the promotion of nonconventional renewables, the system has relied on calls for tenders for long-term energy contracts, supported financially by the regulated customers.

A key part of the proposed reform is the full redesign of the wholesale market, broadly aligned with, for example, the market design recently implemented in Mexico, consisting of three complementary markets: an energy market (including ancillary services), a capacity market, and a market for clean certificates. The declared objective is to create market signals to better align individual and societal goals in the power system of the future, which is expected to change significantly due to the deployment of nonconventional renewables as well as greater empowerment of end users. The main elements of the new market structure are described below.

### **More granular electricity pricing**

Electricity spot prices are currently calculated on a weekly basis for three tiers of load – peak, shoulder, and valley – linked to the traditional representation of demand in the stochastic dual-programming model used by the ONS in operational planning. This weekly aggregation has made sense because, due to the hydro regulation capability, the system was mainly energy constrained (as opposed



to traditionally capacity-constrained thermal systems) and there were consequently no significant intraday price differences. However, demand patterns are starting to change, deviating from the current load and price tiers. More importantly, the reduction of the system's storage capacity with less construction of new hydro plants, and the increasing penetration of variable energy resources, are expected to introduce an increasing capacity constraint, leading to more significant hourly price spreads. So hourly prices are a required feature to provide both generation and demand with incentives to efficiently adapt to the future price dynamics.

The proposed law would establish a target (January 2020) for prices to be set hourly, foreseeing that prices should be obtained ideally from an open-source tool that calculates the dispatch that minimizes operational costs each hour. The law formally introduces the possibility of deriving these prices from market bids of prices and quantities, to be implemented no earlier than 2022. This would occur only after one year of a shadow operation of the market and after studies, expected to last through 2020, to develop a bidding arrangement that deals effectively with the complexities of the Brazilian cascaded-hydro system.

### **New capacity product**

As already mentioned, long-term auctions for new generation plants have been the resource adequacy tool used in Brazil since 2004. Separate auctions are organized for new and existing power plants, with different lag periods (between the auction and when the plants should be available) and contract durations. A1 has a one-year lag and targets for existing plants; A3 and A5 have 3- and 5-year lag periods, respectively, and target new power

plants with different construction times. Contracts also differ according to the technology. For example, A3 and A5 offer 30-year forward contracts for hydropower plants and 15- to 25-year option contracts for thermal plants and renewable energy facilities.

A crucial factor in the current framework has been that free customers have not been obliged to procure their electricity through these long-term auctions for new generation, as long as in the medium term they are 100% covered by contracts. This has clearly led to free riding at the expense of regulated end users, who have borne fully the resource adequacy costs.

Under the proposed law, Brazil would move towards a capacity market mechanism involving both regulated and free end-users, although it is still to be determined how the capacity product will be defined. With such a particular and evolving power system mix, very different from the classic thermal systems in which capacity products have been defined to date, this task will certainly be a challenge. The Colombian reliability charge mechanism is a potential starting reference, although it is also currently undergoing a much-needed review. (See the article by Giraldo and Robinson in this Forum.)

### **Clean energy certificates scheme**

Nonconventional renewable sources have been promoted through the reserve auctions, and have been subsidized through discounts in transmission and distribution tariffs. Wind and solar power, for instance, have received a 50 per cent discount, and power plants using biogas from landfills have received a 100 per cent discount. The current regulation also includes a net metering mechanism as a further way to promote distributed generation. As has been well demonstrated in the literature, net metering is an inefficient and

unsustainable way to subsidize such technologies, since it leads to a significant imbalance in cost allocation, given that network costs are not monetized according to end users' actual use. Under the proposed law, this inefficiency would be tackled by redesigning end-user tariffs, adding a capacity charge to the existing volumetric one.

The establishment of a clean energy certificates market is an attempt to rationalize and combine the diverse subsidies that currently exist. As with the capacity product, how the regulation defines 'clean' is still to be determined. The final scope of the mechanism is likely to be broad to reflect the fact that, besides the new wind and solar photovoltaic plants, the current mix also contains large hydro, nuclear, and biomass plants.

### **Widened scope for the retail market**

Currently the unregulated (free) end market is limited to large consumers – those connected to voltages above 500 kilovolts (kV). The proposed legislation would lower this limit by 2026, enabling any end user connected to voltages higher than 2.3 kV to participate in the free market, enlarging the share of that market to more than 40 per cent.

An immediate effect of this policy would be that distribution companies, which entered into long-term Power Purchase Agreements (PPAs) to hedge the price of their captive demand, could be in a long contractual position. They would be allowed to trade these contracts in the new and wider market environment. In principle, it is assumed that any residual loss due to over-contracting will be passed through to consumers as a system-wide charge. If allocated only among captive demand, the natural consequence would be that the end users remaining under the regulated rates would be subsidizing the ones exiting to the free market.



It is not clear, either, which efficiency gains should be expected from the implementation of this measure or why it is supposed that the newly liberated end user will be able to sign better contracts than the ones resulting from the current centralized auctions. However, this relevant discussion, common to the whole South American continent, is beyond the scope of this paper.

**Other aspects**

The proposed law also opens the possibility of redesigning the current system of transmission and distribution tariffs, possibly moving from the current volumetric design to a more sophisticated format including a fixed charge, as mentioned earlier, as well as increasing time and spatial granularity.

One key flaw in the proposed law must be addressed: distribution companies play the role of regulated retailers for the captive end users, but despite their regulated nature, they are treated as market retailers, as they bear both volume and market price risks. For obvious reasons, it would be much healthier if these entities would merely pass through the wholesale market prices to their captive end users.

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**BALANCING  
DECARBONIZATION AND  
LIBERALIZATION IN THE  
POWER SECTOR:  
LESSONS FROM  
COLOMBIA**

**Iván Mario Giraldo and  
David Robinson**

All electricity models must meet multiple objectives, including efficiency in investment (resource adequacy), operations (merit order dispatch), and consumption (pricing), as well as environmental sustainability. The Colombian wholesale market scores high on most of these measures and

may be an interesting model for other countries to study. However, the country faces important challenges, in particular the integration of nonconventional renewable energy (NCRE), notably wind power, and its increasing reliance on fossil fuels to provide system security during El Niño events.

Since 1995 Colombia has built a wholesale electricity market based on the core principle that the market should allow free entry and promote efficient investment and operating decisions. Technology neutrality is central to this principle; it means that the market design should not subsidize or favour any particular technology. As in other countries, the market was designed before wind and solar photovoltaic energy became economically viable, and we argue that the design is no longer neutral because it does not adequately reflect the value of these renewables.

This article describes the Colombian wholesale electricity market, analyses the effect on it of El Niño climate events, and suggests options for revising the market to better integrate NCRE.

**The wholesale electricity market**

There are three related sets of transactions in the Colombia wholesale electricity market: spot, medium-term bilateral contracts (of one to two years), and long-term firm energy contracts (20 years). Spot prices are determined by the bid of the most expensive plant required to operate in the merit order. Bilateral contracts offer a hedge for retail suppliers and large unregulated users against spikes in the spot price, especially those due to severe droughts that reduce the water inflow to dams, occurring each three to five years with El Niño events. Imbalances of actual demand and generation compared to these contracts are settled at the spot market. Bilateral contracts account for

84 per cent and spot transactions 16 per cent of the aggregate income of these two types of transaction.

Colombia’s long-term firm market for firm energy is quite unique. With 70 per cent of power capacity consisting of large hydroelectric plants, and limited storage capacity (only 6 per cent of total capacity in reservoirs can save water for more than six months), the main characteristic of the Colombian wholesale power market is an extreme variation of water inflows coinciding with El Niño weather. Under normal conditions, hydro accounts for 85 per cent of total generation, but during El Niño events this share falls to 65 per cent, typically for five to twelve months. Other technologies are required to cover the hydro deficit during El Niño periods.

To ensure resource adequacy to cope with hydro deficits, in 1996 the government introduced a mechanism to remunerate backup capacity, and in 2006 the concept of ‘capacity’ was replaced by ‘firm energy’. This latter concept reflects the fact that a hydro plant’s firm (i.e. constant and reliable) generation during periods of water shortage does not depend on the plant’s capacity, but rather on the energy it can generate with close to 100 per cent probability during these periods from water inflows and reservoirs.

A key change introduced in 2006 for firm energy payments was moving from an administrative mechanism to a market-driven reliability charge, determined through auctions. These auctions occur when projections suggest that there will be inadequate firm energy to cover demand projected four years ahead. Market prices for firm energy are determined by the marginal offer selected through the auction. New power plants compete in a given auction to receive the reliability charge for 20 years in exchange for assuming