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Brazil: Utilities

Reshaping Brazilian Power Utilities

Equity Research

Public Consultation #33/2017 sets the stage for sector transformation

A new sector model is shaping up…

Since the new Ministry of Mines and Energy (MME) cabinet took office on May 12, 2016, public consultations were launched aiming to improve the regulatory framework for power utilities (mostly distribution and generation) towards the new business environment. Areas of focus include (1) a more pronounced share of unconventional renewables in the energy mix (with negligible variable production costs but high dispatch variability), (2) the advent of distributed energy in Brazil (e.g., rooftop solar generation) and its implications, (3) enhanced technologies for metering and the prosumer concept, and (4) increased socio-environmental concerns.

…aligned with best practices in LatAm

We provide our qualitative assessment of the 18 measures proposed by the MME to improve the regulatory framework in Brazil. We also compare the proposals with what we see as best practices in LatAm (Chile, Colombia, Mexico and Peru) and find many similarities, which we see as a positive.

Overall positive for power distribution…

We see the proposed regulatory changes for distributors switching to rental of the grid (replicating the power transmission model) as a key measure. This should allow companies to adapt to the advent of distributed energy, while providing the means to finance the next wave of capex focused on improving the quality of the provision of services.

…and for power generation

We view the planned solutions to (1) improve the pricing formation for energy, (2) introduce new types of auctions to cope with demand, and (3) expand the free market, creating a more efficient generation model. Such measures should result in less external intervention from the government, simplifying risk management and increasing the attractiveness of the business vs. market-based measures.

Topical points, in our opinion

We see two topics of investor discussion: (1) a proposed special treatment for Eletrobras as outlined by the MME in the scenario of privatization of assets, and (2) generators potentially not being fully reimbursed for resolving the Generation Scaling Factor (GSF) issue, discussed within.

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Exhibit 1: Related Research

Country	Publish date	Report
Chile	January 27, 2017	2017 Outlook: Revisit PTs as power prices decline: E.CL to Buy (add to LatAm Spotlight List)
Brazil	January 4, 2017	2017 Outlook: Assume coverage; Raise view to Attractive; Ratings,SL restack; EQTL top pick
Brazil	October 21, 2016	Power transmission sector in the spotlight
Brazil	February 16, 2016	Still prefer generation and transmission vs. distribution; Consolidation roadmap
Brazil	November 25, 2015	HPP auction #12-2015 results
Brazil	August 19, 2015	Provisional Measure #688-15 proposes solution for the GSF issue (hydrological risks) and terms for expiring generation concessions re-auctioning process
Brazil	July 22, 2015	PM 677-15 – What if replicated for other generators
Brazil	April 29, 2015	Detailing the approved 4th tariff revision cycle's final parameters
Brazil	January 28, 2015	Rationing risks - demand reduction and rainfall levels remain key
Chile	July 23, 2014	Revisiting Chilean utilities electricity-tax reforms, El Niño, solar generation opportunity
Brazil	February 5, 2014	Risk from drought exists, but power rationing appears unlikely
Brazil	October 9, 2012	Draft Law MP#579 - Deeper look into the proposed amendments
Brazil	September 12, 2012	Concession renewal structure makes sense; but not the initial inputs

Source: Goldman Sachs Global Investment Research.

The dawn of a new Power Sector in Brazil: qualitative assessment and LatAm references

We analyze the 18 proposals envisioned by the MME's Public Consultation #33/2017 which focuses on adapting Brazilian power sector regulations to the new business environment, which contemplates:

1. A more pronounced share of unconventional renewable electricity sources in the Brazilian / global matrix (e.g., solar, wind, biomass, geothermal among others) at negligible variable electricity production costs but higher dispatch variability;
2. The advent of distributed energy in Brazil including (i) rooftop solar generation (or behind the meter power generation), (ii) micro / mini generation, (iii) energy storage (e.g., Li-ion batteries), and (iv) electric vehicles (EVs);
3. Enhanced technologies for metering (e.g., digital metering), micro / smart grids and the introduction of cloud-based systems for optimized electricity management, and the concept of prosumer (the consumer that consumes but also produces fully or partially its electricity needs);
4. Socio-environmental concerns that prevent, for example, the development of large hydro power plants with accumulation reservoirs in Brazil vs. run-of-the-river power plants that have been developed in the past 10 years.

We note enhanced industry efficiency (such as smart grids, cloud systems for micro-mini grids, distributed energy) has prompted discussions to improve the regulatory framework. Decreasing economies of scale and reduced entry barriers in light of new technologies (such as more efficient wind turbines, improved load factors for solar power combined and overall lower capex / MW for renewables) are significantly reducing the costs to produce electricity – gradually turning the provision of this service into a less capital and labor intensive one.

According to the Ministry of Mines and Energy, the Public Consultation period ends on August 4, 2017. The Ministry stated it plans to analyze the contributions and present a Provisional Measure (PM) to Congress by September 2017. As per the official timeline for the Provisional Measures' sanctioning, approval is required after 120 days (by January 2018) to avoid expiration. Once a PM is converted into law, it is regulated by the Brazilian Regulatory Agency (ANEEL).

We divide the report into three sections:

- **Section 1:** Background of changes in the Brazilian utilities' regulatory framework – in which we recap the main improvements in the sector rules in Brazil and provide the context for the proposed changes by the Public Consultation.
- **Section 2:** Qualitative assessment of the proposed changes in the Brazilian power sector.
- **Section 3:** Best practices in LatAm: comparison of the proposed new Brazilian model with the regulatory frameworks in Chile, Colombia, Mexico and Peru.

Section 1: Background of changes in the Brazilian utilities' regulatory framework

The early years (1934 – 1971)

Since 1934, when the Decree #26,234 (the Water Code) was implemented and set a 30 to 50-year concession period for utilities (depending on how relevant the capex was), the power sector in Brazil experienced a series of regulatory improvements aimed to provide a market-friendly environment for investments, as well as the conditions to render such public service with minimum required quality standards and at the lowest possible electricity tariffs. Once the Water Code was regulated by the former National Council of Water and Electricity (CNAEE) in 1957 – further changed into the National Water and Energy Department (DNAE) and currently the National Electricity Agency (ANEEL) – a cost plus model was adopted in Brazil with a minimum guaranteed return of 10% p.a. This was later (1972) increased to a range of 10-12% according to the concession power (Law # 5,655/71). Between 1945 and 1965, all of the power utility companies at the federal and state levels were created, with the sector being 100% state-owned until 1995.

The gradual exhaustion of the state-owned model (1972-1993)

The law #5,655/71 created the first sector charge of the Brazilian power sector: the Reversal Global Reserve (RGR) with the original purpose of providing means for the concession power to reimburse concessionaires upon concession maturity and expand and improve the service rendering. It also created the CRC account (Account for Results Compensation) to track the deficit in the minimum guaranteed sector remuneration (10-12% returns). Between 1972 and 1993, the state-owned companies accumulated a deficit of US$26bn given the poor efficiency in the service rendering, thus evidencing the exhaustion of the state-owned model which prompted the revision of the model to allow private investments in the power sector. As a first measure to prepare for the privatization of the sector, the federal government extinguished the CRC and the guaranteed minimum return methodology but maintained the cost plus regime for the sector (Law #8,631/93) and paid the US$26bn deficit by the issuance of federal debt.

The privatization wave (1994 – 2002)

Several laws/decrees were enacted between 1995 and 1998 focused on attracting private capital to invest in the power sector, notably: (i) Law #8,987/95 and Decree #1,717/95 (set the concession and permission regimes as per article 175 from the Brazilian Constitution), (ii) Law #9,074/95 and Decree #2,003/96 (create the independent power production – PIE category for privatized companies and set the rules for new and renewal of power concessions), (iii) Law #9,427/96 and Decree #2,335/97 (creates the regulator ANEEL and the economic-financial regime for power concessions, (iv) Law #9,433/97 (creates the National Policy for Hydro Resources and the National System for Hydro Resources management), and (v) Law #9,648/98 and Decree #2,655/98 (restructures Eletrobras, creates the Wholesale Electricity Market (MAE) currently the Electricity Clearing House (CCEE), and the National System Operator (ONS)).

In summary, such measures were mainly subsidized by a technical report from the Coopers & Lybrand consulting firm (the RE-SEB project) and were anchored into three main pillars: (1) the setting of clear rules for the sector, (2) the creation of an independent regulator, and (3) long term concession contracts. The conclusions of the RE-SEB project also pointed towards the (i) deverticalization of the power sector, and (ii) need to incentivize free competition in the power generation and commercialization businesses, while maintaining as regulated the power distribution and transmission businesses. Several generation, transmission and distribution companies were privatized between 1995 and 2002.

In the second half of the 1990s, following the implementation of the Brazilian Real monetary regime and FX parity until 1999, several privatized power companies issued USD denominated debt to finance their capex plans. The combination of (i) international crises (Mexico – 1994, Asian Tigers – 1997, Russia – 1998), (ii) the adoption of flexible FX regime (1999), and (iii) the power rationing in Brazil (2001-2002) due to below average rainfall conditions and dismal investments for generation capacity ramp-up, prompted another sector crisis and the need to rethink the regulatory model to avoid further power rationing situations in Brazil. The federal government had to inject capital to bailout the power sector through the BNDES (National Development Bank) in the form of debt and equity in 2002-2004.

The new sector model (2003 – 2012)

Discussions to improve the power sector model started in early 2003 and culminated with the publication of Provisional Measures #144 and #145, as of December 11, 2003. These measures were converted into Laws #10,848 and #10,847, as of March 15, 2004. The main objectives of the new sector model were threefold: guarantee the supply of electricity, promote fair tariffs (the lowest possible tariffs to keep rendering the service aligned with required quality standards) and promote the social inclusion in the power sector, notably through the universal access of electricity in the entire Brazilian territory.

Among the changes in the model, we highlight the creation of (i) the Electricity Planning Company (EPE) with the purpose of providing studies to support the Ministry of Mines an Energy (MME) in the formulation and implementation of rules and the planning of the electricity & energy sectors in the broad scope of the National Energy Policy, (ii) the Committee to Monitor the Power Sector (CMSE) to evaluate permanently the robustness of the supply of electricity, (iii) the Electricity Clearing House (CCEE) substituting the MAE, and (iv) two electricity trading markets, the regulated (ACR) between distributors and generators, and the free market (ACL) between generators, traders and free customers. Moreover, the new model envisioned 100% of the electricity demand for distribution companies to be contracted solely through regulated auctions (reverse auctions in which the lowest bid in terms of PPA prices wins), as well as new methodologies for the calculation of the power plants' availability / firm energy and for the contracting of electricity from new hydro and thermal plants.

Following the publication of the Decree #5,163 as of July 30, 2004, with the detailed regulations for the Law #10,848/04, the government hosted an auction to re-contract legacy generation plants on December 7, 2004, with three different types of 8-year contracts with the electricity delivery starting in 2005, 2006 and 2007 in the regulated market. The first new energy auction for greenfield generation investments took place one year later (December 16, 2005).

At the distribution and transmission levels, the new model set a Return on Asset (ROA) based methodology with tariff revision processes every 3 to 5 years – starting with distribution companies in 2003 and followed by transmission companies in 2005. This was on top of the annual tariff adjustment process and also the possibility of extraordinary tariff revision whenever there is an imbalance in the financial-economic equilibrium of concessions (with this mechanism being used three times since 2005 to date).

Between 2005 and 2011, there was no need to implement relevant structural changes in the model, which proved to work well in the context of the growing Brazilian economy (the super commodity cycle took place between 2003 and 2014). Nevertheless in 2008, the failed attempt of the State of Sao Paulo to privatize the pure generation company Cesp (auctioned was scheduled for March 26,

2008) prompted a discussion to define the concession renewal terms for state-owned companies (that were not privatized in the late nineties) , as per Law#9,074/95, that had concessions mostly expiring on July 7, 2015. To this extent, a study group was created at the MME by June 2008 in order to assess the pros and cons of either renewing or re-auctioning the maturing concessions. This discussion ultimately led to the Provisional Measures #579 (as of September 11, 2012) and #591 (as of November 29, 2012) and further converted into the Law #12,783 (as of January 11, 2013) that defined the concession renewal terms for expiring generation and transmission concessions controlled by state-owned companies. The introduction of the Provisional Measure #579/12 marked the third power sector crisis in 20 years (1993-2012).

Another sector crisis: Provisional Measure #579/12 (2012-2015)

When the terms of the Provisional Measure #579/12 were announced on September 11, 2012, the news was positively received by sector members. Why? Conceptually, the proposal to renew the concessions for power generation and transmission state-owned companies for a 30-year period, with the upfront payment of any non-depreciated portion of their fixed assets (net PP&E) by replacement cost and the maintenance of average prices enough to cover the O&M cost to produce electricity plus a margin, was technically sound. The main scope of the Provisional Measure was to achieve a 20% reduction in electricity tariffs in 2013 on a yoy basis by the voluntary decision to move forward the concession renewal for expiring concession from 2015 to January 2013. This was done by excluding from the contracted prices the component to remunerate non-depreciated assets – thus reducing the average contracted prices accordingly.

As we published on September 12, 2012 (“Concession renewal structure makes sense; but not the initial inputs”), technically the proposal could be perceived as solid. However, when the government detailed the residual value of the power generation plants with expiring concessions (which were significantly lower vs. market expectations), as well as the initial proposal that the residual value for all the transmission companies with old transmission assets (the acronym RBSE which comprises transmission assets built until May 31, 2000) would be zero, the positive reaction turned negative and a significant sell-off in the sector occurred.

The main problem was the average depreciation rate used in the calculation of how depreciated the assets were. Given the sector was vertically integrated until 1994, the regulator used the average depreciation rate of 3.0-3.3% per year for all the assets (including generation assets from their commercial start-up to date), and a 2.0-2.2% depreciation rate per year for generation plants beginning 1994-95 onwards. This was based on the regulatory depreciation for generation that sets 45-50 years of useful life vs. the 30-35 years for the transmission and distribution sectors. As a result, none of the state-owned companies in the generation business renewed the concessions (e.g., Cemig, Cesp, Copel and Celesc) besides Eletrobras that is controlled by the federal government.

In the case of expiring transmission concessions, the government reevaluated and agreed that the residual value for old transmission assets was not zero in the Provisional Measure #591 and thus 100% of the exposed companies (e.g., Eletrobras, CTEEP, Cemig and Copel among others) accepted the renewal terms.

The reduction in end customers’ electricity tariffs beginning January 24, 2013 after the conversion of the two PMs into the Law #12,783/13 came at the same moment the power system was beginning to experience supply issues associated to rainfall levels below historical average. As such, by providing a positive signal to electricity demand (through lower tariffs) in a moment when the supply and demand balance was becoming tighter led to a gradual increase in power rationing risks.

Despite the significant increase in generation capacity through the new energy auctions since December 2005 to 2016 of 69.3 GW (or 46.1% of the 150.4 GW installed generation capacity by YE16), the bulk of the auctioned projects (or 56.2%) were from sources with above average dispatch variability, such as run-of-the-river hydro plants, small hydro plants, biomass and latter wind pants and more recently solar. Thus, the reservation capacity of the power system in Brazil – which is measured by the amount of months in a year that the existing reservoir capacity could cover the demand without a single drop of rainfall – reduced from eight months in 2005 to 4.3 months in 2016. With the dry season in Brazil lasting seven months every year (May to November), the system became significantly dependent on rainfall and the Beta of the spot electricity price (measured by its volatility) increased significantly. Depending on the level of rainfall vs. the historical average, the spot price could vary between the minimum R$30-35/MWh to the maximum of R$800-850/MWh in a matter of months.

The tightness of the power and water supply balance became center-stage in Brazil in 2014-15 when the country faced the worst drought of recorded history (data is available since 1930). As a result, the government started to implement several short-term oriented measures focused on avoiding the risk of a formal rationing in Brazil that prompt a sizeable pick-up in the judicial questioning of sector rules.

After the 18% reduction in average distribution tariffs in 2013, the Brazilian distributors witnessed a 20% average increase in tariffs in 2014 and 51% in 2015, mainly as a consequence of the pass-through of above average thermal dispatch costs to prevent a formal rationing in Brazil. Given the sizeable pick up in tariffs in the overall recessionary cycle of the Brazilian economy, the distributors started to face sizeable working capital concerns, lower volumes and over-contracted status, as well as an increase in delinquency rates. As a result, the government introduced the tariff flags in January 2015 in order to mitigate the working capital impact, as well as providing a proper pricing signal for electricity demand in times of above average thermal dispatch and thus electricity purchase costs. Also, the regulator ANEEL approved by April 2015 the regulatory parameters for the fourth tariff revision cycle that improved the cash flow generation perspectives for the sector.

The regulator also set the conditions for the renewal of state-owned distribution companies (with concessions expiring mostly on July 7, 2015) that introduced stricter quality standards covenants, as well as capital restrictions (e.g., limiting distribution of dividends) to make sure the companies would fulfill the capex to meet the required quality standards in a transitioning five-year period as a condition to renew the concessions for another 30 years.

With the main short term issues for power distributors addressed, the focus of the government (MME and ANEEL) shifted towards power generation. The main short term issues were: (1) the above average GSF impacts in 2014-15 negatively weighting on the working capital and even solvency conditions of some power generators (PM #688/15), (2) the conditions for re-auctioning the expired generation plants that decided not to renew concession under the Law 12,783/13 terms, and (3) the conditions to renew the free market contracts of Eletrobras-Chesf (PM #677/15 that was converted into Law #13,182 as of November 3, 2015). By year end 2015, the government successfully mitigated the GSF risks / liabilities in the regulated market (PM #688/15 that was converted into Law #13,203 as of December 8, 2015), re-auctioned 29 expired generation plants with accretive returns (November 25, 2015) and set positive renewal terms for Eletrobras-Chesf free market contracts, while also creating a Northeast Electricity Fund to invest in new generation capacity in the region.

Once the main short term issues for power generators were addressed, the focus of the government (MME and ANEEL) shifted towards power transmission. Two main short term issues: (1) defining the residual value, accrual and pass-through terms for the old transmission assets (RBSE receivables), and (2) attracting private capital to invest in greenfield transmission assets in order to avoid bottlenecks in the offloading of the sizeable ramp up in generation capacity in Brazil due to lack of transmission capacity (in light of the 82% of the projects under development witnessing start-up delays as of February 2016). The government proposed the solution for the RBSE through the MME Decree #120 (as of April 20, 2016), while addressing the lack of interest from private players to invest in new transmission assets. This was done by increasing both the regulatory returns for such investments towards 9.5-9.7% in real terms (from 5.5-6.6% previously) and the start-up date up to five years from up to three years previously (in order to accommodate environmental licensing delays without jeopardizing start up dates).

Setting the stage for the new power sector model (2016 to date)

The new MME cabinet took office on May 12, 2016, and immediately introduced an open dialogue practice that has been well received by the sector's stakeholders. At the time the cabinet was put in place, the sector's discussions quickly evolved to the separation of short and long term agendas to be implemented. Three main issues to address in the short term agenda include: (1) the over-contracted status of power distributors, (2) the unsettled GSF risks in the free market (that has disrupted the normal functioning of the short term electricity market in Brazil since December 2015), and (3) the final ruling about the RBSE reimbursement process in light of the questioning filed by ABRACE (The Brazilian Association of Large Industrial Energy Consumers). For the long term agenda, a public consultation was launched by the MME (#21 as of June 24, 2016) to gather contributions from all of the Brazilian utilities sector's stakeholders focused on improving the regulatory framework of the power sector in Brazil.

As previously outlined, the need to improve the sector model was based on the consensus view by the sector's stakeholders that the current regulatory structure is no longer effective (1) in providing the correct pricing signal for short term electricity prices, (2) in guaranteeing the supply of electricity in the lowest possible cost, (3) offering a secure and predictable business environment that is key to reinstating the secular defensiveness of the power sector and (4) most important, encouraging private investors to resume investing in the sector (both Brownfield and Greenfield). Further sector participants also saw the need to adapt the regulatory framework to the new business environment (as discussed on page 3).

Approximately one year after the Public Consultation #21/16, the MME published a new version (Public Consultation #33, as of July 5, 2017) that consolidates all of the contributions received into 18 points of improvements for the regulatory framework and associated changes in the laws they are based on, which we analyze in the Section 2 below.

Section 2: Qualitative assessment of the proposed changes in the Brazilian power sector

Exhibit 2: Summary of proposals from Public Consultation #33/2017 - Part 1

Measure	Proposal	Our assessment
1.1: Self-production	• Consolidate the legal framework for electricity self-producers, defined as consumers who receive concession grants to generate electricity at their own risk; • Electricity sector charges apply to self-producers with minimum capacity of 3.0 MW; • Self-producers have the right to use transmission and distribution networks; • Self-producers should be classified as independent power producers.	In the broader context of expanding the free market, the inclusion of the concept of self-producers and their specific characteristics in the sector laws #9,074/95 and #10,848/04 is important. Moreover, by clarifying the rules for self-producers and the associated costs / obligations, we believe it eliminates the adverse incentive from a relative allocation point of view for customers that opt to become a self-producer with the sole purpose of paying less sector charges / costs.
1.2: Lower required threshold to obtain access to the free market	• Grant access to the free market for high and average tension consumers above a 75kW demand threshold until 2018E; • Access should be granted on a gradual basis, by lowering the demand threshold to (1) 2,000kW in 2020, (2) 1,000kW in 2021, (3) 500kW in 2022, (4) 400 kW in 2024 and (5) 75kW in 2028, versus the previous 3,000kW threshold; • The Ministry of Mines and Energy has the option to allow access of low tension consumers to the free market, so long as it does not threaten the sustainability of the market.	This proposal adheres to the objective of expanding the free market and is aligned with the experience elsewhere in LatAm, notably Colombia, Peru and Chile (please refer to pages 16-27), which have lower thresholds for customers eligible to become free customers vs. current thresholds in Brazil. In our view, the larger the free market as a percentage of the total electricity market in Brazil, the more efficient the electricity pricing formation, especially given the free market would be the basis to set the electricity price per source on a marginal cost basis – as it occurs in Chile, Peru, Colombia and Mexico.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 3: Summary of proposals from Public Consultation #33/2017 - Part 2

Measure	Proposal	Our assessment
2.1: Reduce contracted status obligation for distributors, trading companies and free customers	• The Ministry of Mines and Energy can lower the required contracted status of power distributors, trading companies and free customers to a percentage of their total demand.	By allowing the companies and large customers to manage their contracted status independently (as in Chile) while enabling hedge strategies in a secondary / derivative energy market (as in Colombia) is an important tool, in our view, to mitigate risks and to reduce government interference in electricity contracting.
2.2: Lower transmission transaction costs	• Reduce expenses related to managing payments for transmission assets; • Potential creation of a centralized clearing house for transmission contracts, so long as it results in overall savings for the system; • The CCEE (Brazilian Electricity Clearing House) could be granted the right to centralize transmission contracts.	Given the sizeable number of transmission companies and / or Special Purpose Enterprises (SPEs) in Brazil, we see the potential centralization of payments and receivables for transmission installations as an important initiative to reduce systemic costs, especially given the economies of scale nature of the business (dilution of fixed costs by operating several assets from a single dispatch center). It should also alleviate working capital management issues for small transmission companies given that sometimes the lack of payment of a single company could be negligible for the overall system delinquency levels, but represent 100% of the revenue generation of such a company – a diminishing possibility whenever a centralized management occurs given that the clearing house would have the control to avoid such payment inefficiencies.
2.3: Maximum cohesion between energy prices and operations	• (1) Include the possibility of plants with temporary power generation to optimize the usage of electricity / energy sources to meet the load needs, (2) turning the Mechanism to Reallocate Electricity (MRE) into last resort electricity management tool, (3) treatment and remuneration of ancillary energy services to be set by ANEEL, (4) utilization of hourly energy prices until 2020, (5) include the possibility of energy prices being set by generation players, (6) making public the algorithms used for energy price formation and operational planning of the power dispatch, and (7) need of financial guarantees for daily closing positions.	Very important measures that also consolidate best practices in LatAm (Chile, Peru, Colombia and Mexico). We see the introduction of new types of auctions to meet peak load and/or back up power facilities – conditioned to the creation of hourly energy prices – as relevant tools to optimize the supply and demand model and/or minimize costs. Also, a fully functional spot electricity price that allows free customers to set the pricing reference per source for both the marginal cost and the spot price of the system would improve significantly, in our opinion, the robustness of pricing given by market participants - as occurs in Chile, Mexico and Peru - instead of the government/regulator. The potential creation of a secondary / derivative energy market (as per point 2.1) would help to mitigate availability risks and allow hedging strategies.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 4: Summary of proposals from Public Consultation #33/2017 - Part 3

Measure	Proposal	Our assessment
2.4: Lower generation transaction costs	• Centralize the administration of regulated energy contracts, thereby lowering disparities between distribution companies with different electricity tariffs; • The CCEE (Brazilian Electricity Clearing House) could be granted the right to centralize regulated energy contracts, so long as it does not generate more costs compared to another company contracted by public bidding process; • The pass-through of the electricity purchase costs to be based on the weighted average contracted price.	This measure would allow a more efficient electricity purchase process for end customers. The CCEE is a natural candidate to centralize the acquisition of electricity in the regulated market, as it already processes the financial closing of electricity contracts in Brazil. There are similar successful experiences of centralized electricity contracting for the regulated market in LatAm (e.g., Mexico). This proposal should be further detailed by the analysis of regulatory impact by ANEEL, in our view, to better understand the implications on a region by region basis. Nevertheless, we believe providing a similar price reference for legacy contracts upon maturity and renewal for all distributors in the Brazilian territory should reduce asymmetry in electricity prices and eliminate arbitration / short term gains for distributors in the spot market.
2.5: Separation between supply availability and energy	• For generation companies, the compensation of the "availability" component of the contract has the counterpart of commitment to deliver reliability to the system, which will be measured as declarations of firmness for the operational dispatch; • The commercialization of the “energy” component would be the responsibility of the generation company, and therefore energy contracts would be financial instruments for risk management against the volatility of energy market prices; • Similar reasoning could be applied to consumers, which explains the existence of the flexibility to contract the different components of “availability” and “energy” of new supply contracts; • The Reserve Auction category is eliminated.	Although there are countries in LatAm (e.g., Colombia and Mexico) which separate the firm supply (“availability”) from the energy supply, this proposal is the one that, in our opinion, may require several regulatory discussions and impact analysis before it is implemented in order to continue respecting existing contracts and further transition into the new modalities. But we view this is as an important measure to adapt the sector model in Brazil to the new business environment. In Colombia (for more details please refer to page 24) since 1996, regulations have been set to remunerate capacity and further reliability (2006 onwards) of supply. The secondary / derivative electricity trading market in Colombia through a clearing house (Energy Exchange) provides a timely and accurate pricing signal and is also a mechanism for hedging electricity contracts, short or long positions, similar to any equity market. As such, the ENFICs or OEFs (Firm Electricity Supply Obligations) are a useful tool to de-risk the power supply in Colombia by allowing such hedging strategies and avoiding power rationing risks. There are plenty of international references (US, Colombia, among others) to calculate the availability fee / charge in US$/MWh and in Colombia the OEFs contracts could be three months up to 20 years. In Mexico, the greenfield generation auctions since 2015 to date include three types of contracts / revenue streams: (i) availability, (ii) energy, and (iii) green energy certificates (CELs). With a clear pricing formula and correct pricing signal, we don’t see issues for financing such revenues streams (Project Finance, Green bonds, multilateral agencies, etc.).

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 5: Summary of proposals from Public Consultation #33/2017 - Part 4

Measure	Proposal	Our assessment
3.1: Lower over-contracted status of power distributors given the migration to the free market	• Power distributors would be allowed to sell excess energy to free market customers, trading companies and generators based on over-contracted volumes. Transactions would be executed through a centralized mechanism, established in accordance with the framework set by regulator ANEEL; • Costs related to involuntary over-contracted status of power distributors shall be covered by all consumers on both the free and regulated markets, proportionally to their electricity consumption.	There are several mechanisms to normalize the contracted status of a given distributor currently (Mechanism to Compensate for Surpluses and Deficits – MCSD, reverse auction, among others), but we deem important that the proposal defines the regulatory treatment post the exhaustion of all such options and how a distributor would mitigate any remaining over-contracted volumes when customers migrate to the free market. This proposal aims to ensure that any gains or losses arising from such unmet surpluses or deficits should not have any positive or negative implications for distributors, with the costs associated being fully compensated by a sector charge applied to all end customers and not only regulated customers. These are key areas of focus for the proposed expansion of the free market.
3.2: New framework for electricity tariffs	• Legal authorization for the definition of differentiated tariffs by time; • Establishes the binomial tariff, leaving the details of the matter for regulation yet to be detailed; • The only guideline put forward is that the distribution and transmission usage fee components (with the exception of tariff charges and losses) will not be charged on a volumetric basis.	Volumetric charging of the distribution service hampers the sustainable insertion of energy efficiency measures or micro and distributed mini-generation. Lower volumes from energy savings represent loss of revenue for the distributor to cover the network infrastructure costs and could become a transfer of the avoided cost to other consumers that remained serviced by the distribution company. For distributors, we see the implementation of the rental of the grid methodology (replicating the current one for power transmission) as a key measure to maintain the sustainability of the business. In our view by having a more predictable / stable cash flow and excluding the management of electricity purchases / volume risks, the distributors could be eligible to leverage up the balance sheet towards the transmission levels (or a 1.0 to 1.5x incremental net debt to EBITDA vs. the current 1.5-2.0x proxy for distributors) to finance capex to improving the quality of the service rendering. The binomial tariff is also a key area of focus for the separation of availability and energy types of supply in the new model (despite that it could be kept in the same energy bill).
3.3: Subsidies to incentivized energy sources	• Turn the discount in the fees for the usage of the distribution and transmission grids (TUSD and TUST fees) into a premium for incentivized energy sources, with a percentage fixed on an R$ per MWh basis; • Existing plants will keep the discount until the concession / authorization maturity, with no possibility of renewal of such incentive; • New plants for which the concession / authorization will be granted between January 1, 2018 and December 31, 2029 will benefit from the premium to incentivized sources; • No incentives beginning January 1, 2030 onwards.	We look for subsidies to be created with a clear purpose and an end date. The possibility of applying a premium over the PPA price for incentivized energy sources has been used world-wide, mainly in the form of carbon credits and / or green certificates. In the early stages of an industry's development, such as in the wind industry in Brazil (2009 to 2016) and more recently in the solar industry (since 2014 to date), we see the granting of subsidies as an effective way to foster investment across the entire supply chain.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 6: Summary of proposals from Public Consultation #33/2017 - Part 5

Measure	Proposal	Our assessment
3.4: Rationalization of discounts at the CDE tracking account	• Discounts to electricity tariffs granted by the means of the CDE tracking account should be converted to R$/MWh; • Total annual discounts granted by the CDE should not exceed the amount disbursed in 2016; • Total annual discounts could be accrued annually by the power distributors' average tariff adjustment.	This is an isonomy-oriented and also budget-restriction measure that would support, in our opinion, the overall effort to rationalize subsidies in the tariffs, as well as providing a more efficient and isonomic tariff signal to end customers across all Brazil.
3.5: Cost rationalization of regulated contracts (CCEARs)	• Risk exposure to the spot market will be allocated to (1) electricity vendors in the case of Quantity Regulated Contracts (preferred contracting option) or (2) power distributors (with full pass-through to customers) in the case of Availability Regulated Contracts; • Power generators will be able to rescind Availability CCEARs with variable costs above the maximum spot price established by ANEEL.	This would allow power plants with variable costs (CVUs) above the spot price ceiling set by ANEEL to rescind their contracts, which would be an important measure to reduce the Beta of the spot price in Brazil (as previously defined). On top of such options, the government could consider, in our view, assessing the possibility of modernizing such plants (e.g., closing the cycle for gas-fired thermal plants, converting fuel oil plants into by fuel ones operating also with natural gas, etc.) or to add new turbines to cover peak loads or interruptive / occasional supply situation, thus being considered as back up facilities. In Chile there are several back up thermal plants only dispatched whenever hydrology or ice melting conditions are below historical average that run on both diesel and natural gas. Given the oversupply status of the LNG global market by using this source instead of diesel, the dispatch costs reduce to US$60-70/MWh instead of US$125-150/MWh using diesel, as per our Project Finance model assumptions.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 7: Summary of proposals from Public Consultation #33/2017 - Part 6

Measure	Proposal	Our assessment
4.1: Fund receivables related to old transmission assets (RBSE) with proceeds from RGR tracking account	• The objective is to allocate resources from the Global Reversion Reserve (RGR) for the payment of the tariff component related to the old transmission asset receivables (RBSE). However, in order to allocate from the RGR accounts, there should not be legal injunctions related to the RBSE receivables.	We believe further detail is needed to assess whether the proceeds raised by the RGR sector charge on an annual basis would be enough to fulfill RBSE payments.
4.2: Elimination of energy quotas and privatization	• In cases of privatization, the federal authority may grant new concession rights for a period of 30 years, without prior reversal of the assets linked to the respective public service; • The privatization process would imply the decoupling of such power plants from quota-price system, and would allow the new concession owners to sell their energy at free market prices; • Privatizations must be followed by CDE quota payments by the acquirer, and would equal to a third of the economic benefit of the new concession agreement. The remaining two-thirds of the economic benefit associated with generation privatizations would be destined to Federal Government in the form of a monthly bonus grant; • Provides incentives for privatization of federal state-owned companies by 2019, by reducing 1/3 of the economic benefit that would be directed to the federal government. Such incentive provides an increase in the value captured by the holders of privatized assets; • Concessionaires will have the possibility to exchange the reimbursement rights of the non-depreciated value for the direct sale of those assets to the new concession winner (i.e., the right to have those assets remunerated via tariff or reimbursement payments).	This is an important measure for transitioning this model into a more free-market prone one, as well as eliminating an exogenous interference in prices (the quota-based price), as per the Law #12,783/13. The proposed change in the regime of privatized assets into Independent Power Producers (PIEs) was implemented since July 7, 1995 (Law #9,074/95). We see as a topic of investor discussion the special conditions set for the state-owned company Eletrobras in the proposal. The proposal sets that for state-owned companies controlled by the federal government and that renewed the concessions under the terms of the Law #12,783/13, the transfer of the economic benefit would be reduced to 1/3 for privatized generation assets and 2/3 for privatized transmission and distribution assets. This proposal contrasts with the overall isonomy-oriented approach taken in essentially all of the measures of the Public Consultation.
4.3: Anticipate the convergence of CDE's tracking account	• The gradual convergence of the CDE charges for the S/SE/CW and N/NE regions by January 2023; • The CDE charges will also be adjusted to potentially include the payment of the incentive premium for renewable sources (instead of the current discounts), and the payment of quotas associated with new generation grants associated with privatizations.	Another isonomy-oriented measure. The proposal to converge the CDE charges for the S/SE/CW and N/NE is not new (as per Law #13,360 as of November 17, 2016) and was envisioned by January 1, 2030. What is new is the proposed CDE convergence for January 1, 2023. We see this as an important measure for the sector as, according to our analysis, the S/SE/CW regions subsidized a 0.9% average volume growth per year in the N/NE regions given that the former pay 4.5x higher CDE charges vs. the latter. This would also corroborate to a more efficient tariff signal, one of the key objectives of the new sector model proposal.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 8: Summary of proposals from Public Consultation #33/2017 - Part 7

Measure	Proposal	Our assessment
4.4: Extend concession rights for power plants with less than 50MW of capacity	• Authorizations to operate hydro power plants with capacity between 3MW and 50MW will have a duration of up to 35 years; • The concession authority can extend such authorization for an additional 30 years, so long as the following conditions are observed: (1) payment of the required concession payment, (2) payment of the Financial Compensation for Hydro Resources Utilization to the municipality where the asset is located and (3) the asset must be in commercial operation.	This measure is a simplifying one and also isonomy-oriented. It sets the same terms for both concessions and authorizations for power plants between 3MW and 50MW and also allows the concession authority to change the regime from concession into authorization upon concession maturity.
4.5: Resolve judicial disputes related to hydrological risk	• The reimbursement to hydroelectric generation players for the negative impacts of out-of-merit power dispatches (GFOM) retroactive to 2013, through the extension of concession maturity until these liabilities are fully recovered by generators.	This proposal looks to solve the GSF liability issue retroactively to 2013 by granting additional concession term to fully offset – on an NPV basis – the negative short term cash outflows to fulfil such payments. It is unclear to us whether all the generation companies would agree to this proposal, since the GFOM compensation provides only partial coverage of such losses. Given every generation company would have to lift the injunctions currently preventing the functioning of the short term energy market in Brazil, the proposal will need the support of all participants to fully address this issue and avoid the short term electricity market financial closing to be legally blocked for the ones that do not accept.
4.6: Pay in installments CDE and ESS liabilities upon the lifting of pertaining legal lawsuits	• Pay in up to 120 fixed monthly installments accrued by the Selic rate since its occurrence until the financial closing of any CDE and/or ESS (sector charges) liabilities; • This proposal is only valid for sector agents that lift the pertaining legal lawsuit that is preventing such payment and opts for such special sector charge payment regime by December 31, 2017.	As per the federal government Special Regime for Federal Taxes Liabilities (REFIS), this would be the equivalent of a REFIS for sector charges, thus allowing companies with past due liabilities with CDE and ESS charges to pay in several installments, as long as the companies lift the lawsuits in place preventing these payments.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

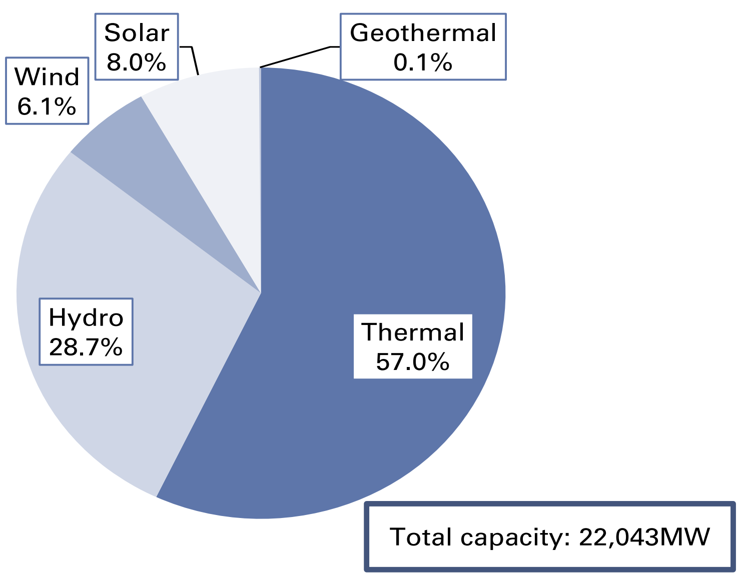
Section 3: Best Practices in LatAm: comparison of the proposed new Brazilian model with the regulatory frameworks in Chile, Colombia, Mexico and Peru

In this section, we highlight the regulatory framework for Chile, Colombia, Mexico and Peru in relation to each of the 18 proposals to improve the Brazilian regulatory framework that applies to such countries.

Exhibit 9: Chile's Power Utility Market snapshot

Country	GDP	Total Generation Installed Capacity
Chile	**US$247.0bn**	**22,043.0 MW**

Chilean snapshot



Economic data (2016)	
GDP (US$bn)	247.0
Population (MM)	17.9
GDP per capita (US$)	13,791.2
Electricity data (2016)	
Electricity generation (GWh)	73,877.0
Electricity demand (GWh)	67,825.0
Transmission network (km)	31,553.3
Average distribution tariff (US$/MWh)	121.7

Source: Company data, Goldman Sachs Global Investment Research, Ministry of Mines and Energy.

Exhibit 10: Examples of Similar regulation across LatAm

Chile	
Topic	**Description**
1.1: Self-production	• There are two classes of self-producers, namely: (1) *local self-producer*, which generates energy to consume in its own premises and (2) *remote self-producer*, which can use distribution and transmission networks to supply other of their facilities.
1.2: Lower required threshold to obtain access to the free market	• The minimum load level required for customers to be able to buy energy at the free market was reduced from 2 MW to 0.5 MW. This lifted most non-residential customers out of the captive market and significantly increased competition. • Free customers freely negotiate electricity prices with generators and set conditions through supply contracts.
2.1: Reduce distributors' contracted status obligation	• Price Incentives to Reduce Demand - Generators were allowed to offer price incentives for regulated customers to reduce their consumption in case of rationings, implying a more rational allocation of available energy. This was an adjustment to the sector legislation from the late 1980s, which required / forced generators to pay the outage costs (equivalent to the cost of one additional KWh under shortages / rationing).
2.2: Lower transmission transaction costs	• Distinguishes between trunk transmission, sub-transmission and additional systems. The trunk system consists of the set of transmission lines with greater capacity, the use of which is shared by various users of the system. The sub-transmission system consists of the set of lines that directly supply distribution zones determined from the trunk system. The additional system, for its part, consists of lines dedicated to the supply of large industrial customers or the offload of energy from specific plants • CNE holds competitive auctions for new transmission assets in which i) bidders propose discounts to cap transmission revenues for the whole concession period and ii) the bidder willing to receive the lowest revenues will be contracted. • Generally speaking, final consumers pay 20% of electricity transmission costs and generators the remaining 80%, through special pricing formulas.
2.3: Maximum cohesion between energy prices and operations	• Spot prices are calculated on an hourly basis by the Chilean System Operator CDEC based on (1) the marginal operating cost of each plant (declared by generators, together with its fuel availability); (2) electricity demand at a specific time and (3) CDEC dispatch system / decisions – and are calculated using a computer model. • System Operator CDEC sets the order of dispatch, giving priority to plants with lower marginal operating costs. That means generators will not necessarily produce the energy they have contracted – if there is available capacity at lower cost, CDEC will require the higher-cost generator to buy energy from the lower-cost generator. These trades will be settled monthly using the spot prices determined by CDEC. • Technically, under normal conditions, spot price corresponds to the marginal cost of the most expensive dispatching thermal plant. In the case of shortages, the spot price will be equal to the outage cost, which is based on consumer willingness to accept an incentive for not consuming one more kWh at specific percentages of demand restriction.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 11: Examples of Similar regulation across LatAm

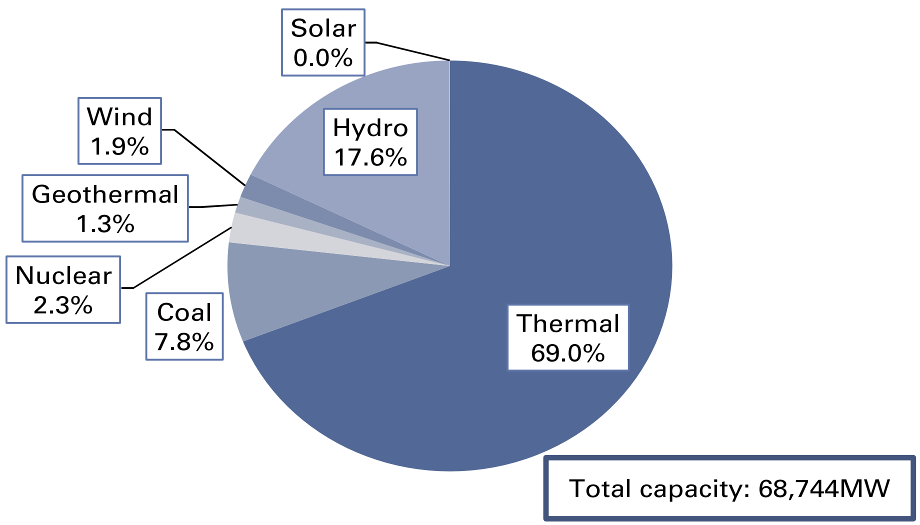
Chile	
Topic	**Description**
2.4: Lower generation transaction costs	• CDEC (National System Operator) is the agency responsible for (1) coordinating the Chilean system dispatch, (2) verifying generators' marginal cost calculations, (3) ratifying energy transfers between generators, and (4) resolve smaller / ordinary disputes among generators • Generators' Bankruptcy Contingency Plan - In the case of a generator not being able to meet its contracted supply obligations (i.e., due to bankruptcy), the remaining generators would have to deliver the contracts of the failed company, minimizing the effects of a single generator bankruptcy over the whole system.
2.5: Separation between supply and energy	• Regulated prices became more flexible as new contracts between generators and distributors should be done through public auctions. New contracts were thereby required to have a maximum length of 15 years, and resulting auction prices were required to be periodically indexed (adjusted to FX, inflation, NG or coal costs, depending on the contract / auction). Nevertheless, node prices would still be calculated, being used i) as a reference for existing contracts and ii) as a cap price at substations. This system reduced generators'/investors' risks by providing the basis for the development of project finance structures for new projects. • Generation companies determine their contracts based on forecasts of demand growth, marginal costs and price system, trying to i) supply deficit companies during supply restriction times and ii) buy energy in the spot market during times when the system's marginal costs are lower than their costs.
3.2: New framework for electricity tariffs	**Current regulation** • Distribution companies are responsible for delivering electricity to end customers (at voltages below 230 kV) being remunerated through a tariff that covers not only electricity purchases and transmission costs, fixed operating costs, sector charges but also the remuneration of the invested capital over the asset base. • Distribution in Chile is a price-cap-regulated business. According to current regulations, distributors adjust tariffs in two ways: i) through annual adjustments, and ii) through periodic tariff revisions every four years. As per current regulation, the regulatory asset bases (RAB) for distributors are fully updated on every four years to reflect the market value of assets at a prudent spending reference. • The Chilean distribution tariff structure has a complexity level comparable to other countries, varying according to i) connection tension (high or low) and ii) consumption hours (peak versus non-peak hours). Such tariff structure comprises four factors: i) a fixed tariff (average 5% of total tariff), ii) distribution fee / VAD (40%), iii) energy purchase costs (40%) and iv) a maximum power availability tariff (15%) –which are all included in the tariffs charged to residential customers. **Ongoing studies for new distribution regulatory framework** • It is recommended to incorporate in the tariff study both the determination of the VAD and the determination of the tariff factors that allow calculating the final tariffs, analyzing the possibility of incorporating direct subsidies to lower income sectors. • Modifying the current regulatory WACC of 10%, considering a long-term market rate and the levels of business risk. • Adjustments to the regulation so as to incorporate flexible tariff schemes, through the incorporation of smart metering, stimulus to efficiency, sale of green energy and net metering. • Removing the volumetric characteristics of the low tension tariffs, dismantling hidden subsidies, and actually identifying and incorporating smart metering.
3.3: Subsidies to incentivized energy sources	• Provide adequate financing conditions for ERNC generation projects; promote the installation of solar panels and the development of solar power generation; promote the development of geothermal capacity with improved concession and exploration rules; develop additional hydro capacity with coordinated efforts between the Ministry of Mines and Energy, the General Water Authority, the Environmental Ministry and the Ministry of Public Affairs, which includes the proposal of clear rules for water rights.
3.1 3.4, 3.5, 4.1, 4.2, 4.3, 4.5, 4.6	• **NA**

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 12: Mexico's Power Utility Market snapshot

Country	GDP	Total Generation Installed Capacity
Mexico	**US$1,046bn**	**68,743.5 MW**

Mexican snapshot



Economic data (2016)	
GDP (US$bn)	1,046.0
Population (MM)	127.5
GDP per capita (US$)	8,203.9
Electricity data (2016)	
Electricity generation (GWh)	261,734.4
Electricity demand (GWh)	218,072.3
Transmission network (km)	59,604.1
Average distribution tariff (US$/MWh)	75.0

Source: Company data, Goldman Sachs Global Investment Research, Ministry of Mines and Energy.

Exhibit 13: Examples of Similar regulation across LatAm

Mexico	
Topic	**Description**
1.1: Self-production	• Mexico's Energy Regulation Commission (CRE) defines 2 distinct classes of self-producers, namely: (1) *local self-producer*, which generates energy to consume in its own premises and (2) *remote self-producer*, which can use distribution and transmission networks to supply other of their facilities.
1.2: Lower required threshold to obtain access to the free market	• The Mexican free energy market has a lower threshold of 1MW. • Consumer has to decide to register as a Qualified User before the CRE, or those consumers under the protection of Legacy contracts. • Qualified Users are free to participate in the Wholesale Electricity Market (MEM) either directly, or through a Qualified Service Provider (i.e., commercialization companies).
2.2: Lower transmission transaction costs	• The charge will be made through the postal stamp mode, which is determined based on the injections or withdrawals made by network users, weighted by the voltage level, depending on whether the users are Generators or consumers. • The tariffs are divided into two blocks depending on the voltage level (voltage greater than or equal to 220 kV and less than 220 kV); • 30% will be charged to generators and 70% to consumers.
2.3: Maximum cohesion between energy prices and operations	• The short-term energy market in Mexico works like any other market: on the one hand, there is a demand for electricity from qualified users and distribution companies and, on the other hand, there is a supply of electricity by generators. A characteristic of this market is that the electricity supply is given by the variable costs, that is to say, that generator that counts on the technology with the lowest variable cost is the first to be dispatched. • From 2018 onwards, bids for purchase and offers for sale of energy will be presented for use one hour in advance. Also in these markets will be able to offer ancillary services in addition to "availability~ and "energy" components of contracts.
2.4: Lower generation transaction costs	• CENACE (National Energy Control Center) is the agency responsible for indicating the dispatch instructions according to the most economical offers, subject to system reliability restrictions.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 14: Examples of Similar regulation across LatAm

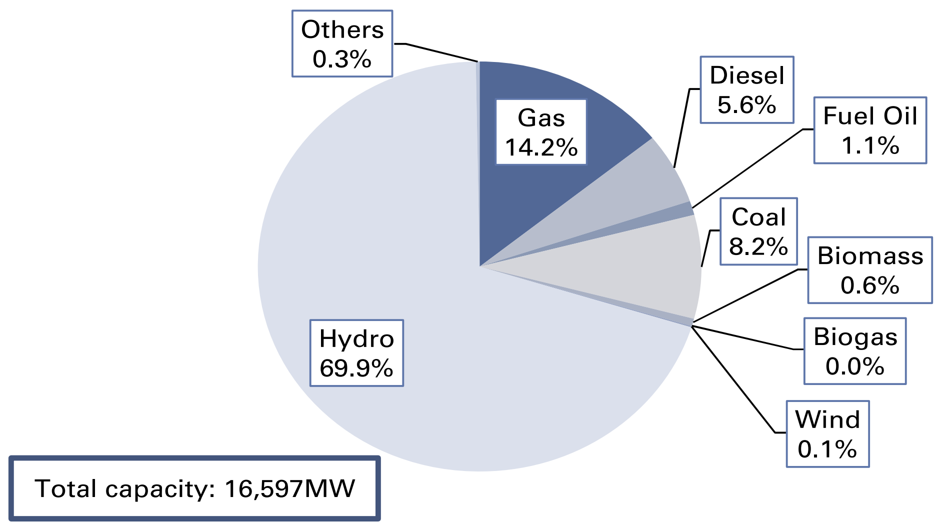
Mexico	
Topic	**Description**
2.5: Separation between supply and energy	• The prices of the Wholesale Electricity Market are Nodal Prices (i.e., they are calculated in each node of the system based on 3 components: energy, availability and losses). • The “availability component” refers to an associated Product that generators can offer for sale, by which they acquire the obligation to ensure the supply of energy production to be offered in the future in the short-term Energy Market. • With the breakdown of such components, in addition to the marginal cost of generating electricity, energy prices capture economic signals that indicate how saturated the system networks are, as well as the level of transmission losses. • Such market structure encourages the free negotiation between agents so they can sign contracts, in which they agree on the purchase and sale of electricity or any associated product in its own terms (price, contract duration, delivery time and others).
3.2: New framework for electricity tariffs	• The Basic Service Providers (SSB) are distribution companies that are responsible to supply electric services to all users who do not participate in the Wholesale Electricity Market. Currently, the only Basic Service Provider is the Federal Commission of Electricity (CFE), nevertheless, any interested party may request a permit from CRE to provide this service. In addition, SSBs (1) sell their electricity at regulated tariffs, (2) have medium to long term PPA contracts with generation companies, and (3) are required to provide universal service in the area they operate, having access to the Universal Electric Service Fund. • Qualified Service Providers (SSC) are providers of commercialization services, purchasing electricity from the Wholesale Electricity Market in order to provide electricity to qualified users. The SSC activity requires permission from the CRE, which requires information such as area of operation, number of end users, expected sales as well as submit a business plan.
3.3: Subsidies to incentivized energy sources	• Generators will receive CELs (Clean Energy Certificates) for every megawatt-hour of clean energy generated to sell in the market. Likewise, large electricity consumers and other obligated participants, require that a percentage of the electricity they consume comes from clean sources. To verify that they are consuming this percentage, they have to buy CELs for the amount required by the Secretary of Energy. This creates an offer and demand for CEL, which can be exchanged through contracts, in the CEL market, in monthly auctions organized by CENACE or in an annual liquidation. • Market participants can submit offers to buy and sell CELs at any price through the CEL market, which will be organized at least once a year by CENACE, and may also be freely negotiated through bilateral contracts or long-term auctions.
2.1, 3.1 3.4, 3.5, 4.1, 4.2, 4.3, 4.5, 4.6	• **NA**

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 15: Colombia's Power Utility Market snapshot

Country	GDP	Total Generation Installed Capacity
Colombia	**US$282.5bn**	**16,597.1 MW**

Colombian snapshot



Economic data (2016)	
GDP (US$bn)	282.5
Population (MM)	48.7
GDP per capita (US$)	5,806.8
Electricity data (2016)	
Electricity generation (GWh)	65,935.2
Electricity demand (GWh)	65,639.0
Transmission network (km)	25,492.2
Average distribution tariff (US$/MWh)	79.7

Source: Company data, Goldman Sachs Global Investment Research, Ministry of Mines and Energy.

Exhibit 16: Examples of Similar regulation across LatAm

Colombia	
Topic	**Description**
1.1: Self-production	• Self-producers have been contemplated by the Colombian regulation since 1994, first defined as generators who producer energy in order to satisfy their own needs. In 1998, regulator CREG first allowed self-producers to sell excess energy to the overall market in rationing scenarios, and only in 2014 could they sell their excess energy to the market in any scenario, under similar regulation for power generators.
1.2: Lower required threshold to obtain access to the free market	• The Colombian free energy market has a lower threshold of equal or above 100 kW or 55,000 kWh-month.
2.1: Reduce distributors' contracted status obligation	• Electricity retailers are obliged to supply all energy needs of residential and non-residential customers in their respective areas of operation. • Nevertheless, retailers have the flexibility to contract energy with generators under three different formats (detailed in item 2.3), namely: (1) by operating in the Energy Exchange, (2) signing bi-lateral energy contracts or (3) contracting "Firm Energy Obligations" (detailed in item 2.5). With the Energy Exchange accounting for the majority of transactions in the market, power retailers have lower risk of reaching an over-contracted status.
2.2: Lower transmission transaction costs	• The state-owned transmission company, Interconexión Eléctrica S.A. ("ISA") is responsible for (1) the administration of charges related to the use of the Colombian transmission network ("STN") by generators and distributors, (2) remuneration of other transmission operators and (3) collection and submission of data to regulator CREG, in order to assist with the calculation of sector charges.
2.3: Maximum cohesion between energy prices and operations	• In Colombia, power generators and retailers execute transactions in the Wholesale Energy market (MEM) the three possible formats being: (1) by operating in the Energy Exchange, (2) signing bi-lateral energy contracts or (3) committing to "Firm Energy Obligations" (detailed in item 2.5). All generators with capacity above 20MW and all retailers that supply user connected to National Energy Grid (SIN) are required to operate under the MEM. • With respect to the Energy Exchange, generators announce prices and energy availability on an hourly basis, with those who offer the lowest prices being selected to dispatch energy to the system. Energy prices should reflect variable costs of power generators in addition to their cost of capital. • The energy price of the last plant that covers the system's demand at a given hour and which remunerates all generators dispatching at a given hour is denominated the Exchange Price.

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 17: Examples of Similar regulation across LatAm

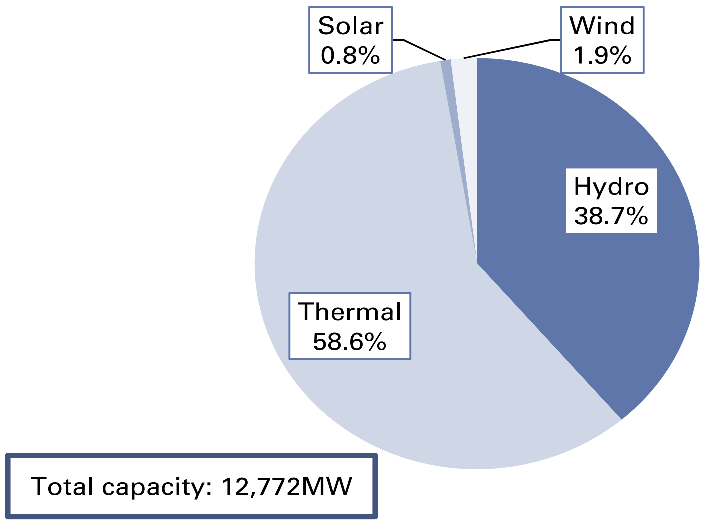
Colombia	
Topic	**Description**
2.4: Lower generation transaction costs	• The National Center of Dispatches (CND), through its subsidiary ASIC (Manager of Commercial Transactions) is responsible for (1) overseeing long-term energy contracts, (2) liquidate transactions in the Colombian energy exchange and (3) maintain databases required for the plain functioning of the national grid.
2.5: Separation between supply and energy	• In order to give generators the incentive to invest in capacity expansion and reduce exposure to the volatility of energy prices during rationing periods, Colombian regulator CREG introduced the Availability Charges system (*Note: Cargo por Confiabilidad).* Such system is based on the concept of "Firm Energy Obligation" or OEF, defined as a maximum energy quantity that generators can compromise during periods with rationing risks. • Generators who are granted an OEF have the right to receive a fixed remuneration (embedded in electricity tariffs) in exchange for power dispatches whenever prices in the Energy Exchange exceed a certain threshold. As a result, not only the volatility of spot prices is reduced, but generators have access to a stable source of cash flows.
3.2: New framework for electricity tariffs	• Electricity tariffs in Colombia - collected by energy retailers - have a binomial structure, namely: (1) a variable charge that is proportional to each user's energy consumption and (2) a fixed charge intended for the remuneration of generation, transmission and distribution assets.
3.3: Subsidies to incentivized energy sources	• Companies involved in the production and use of energy from non-conventional renewable sources of energy have the right to reduce from its income tax payables up to 50% of the total investment of the project during the first five years. The only restriction is that in no case the value to be deducted must be greater than 50% of the net income of the taxpayer before subtracting the value deducted. • Exempts equipment and materials associated with non-conventional renewable projects from the application of Value Added Tax (VAT). • Allows the use accelerated depreciation for non-conventional renewable projects, in such a way that the amount of depreciation taken each year is higher during the earlier years of an asset's life, and therefore posing a tax benefit from an NPV standpoint.
3.1 3.4, 3.5, 4.1, 4.2, 4.3, 4.5, 4.6	• **N/A**

Source: Ministry of Mines and Energy, ANEEL, Goldman Sachs Global Investment Research.

Exhibit 18: Peru's Power Utility Market snapshot

Country	GDP	Total Generation Installed Capacity
Peru	**US$192.1bn**	**12,772.2 MW**

Peruvian snapshot



Economic data (2016)	
GDP (US$bn)	192.1
Population (MM)	31.8
GDP per capita (US$)	6,045.8
Electricity data (2016)	
Electricity generation (GWh)	48,326.4
Electricity demand (GWh)	43,211.0
Transmission network (km)	26,758.5
Average distribution tariff (US$/MWh)	105.5

Source: Company data, Goldman Sachs Global Investment Research, Ministry of Mines and Energy.

Exhibit 19: Examples of Similar regulation across LatAm

Peru	
Topic	**Description**
1.1: Self-production	• Since the General Electricity Law of 1982, self-producers have been contemplated by the Peruvian regulation and are defined as a natural or legal person authorized by the Ministry of Energy and Mining (MEM) to produce electricity as part of their main activities to totally – or partially – fulfill their needs, using for this purpose no more than 50% of their total generation.
1.2: Lower required threshold to obtain access to the free market	• The Peruvian Free Energy Market determines that customers with annual demand greater than 0.2MW and lower than 2.5MW are able to choose between being regulated or free customers if they meet the legal conditions. Customers with annual demand greater than 2.5MW are designated as free customers.
2.1: Reduce distributors' contracted status obligation	• Electricity marketers are obliged to supply all energy needs of residential and non-residential customers in their respective areas of operation within one year. There is only a single distributor supplying each area that cannot have its contracted status reduced without approval of the MEM.
2.2: Lower transmission transaction costs	• Transmission costs in Peru are paid by both generators and final customers and are composed of (1) the annuity of the replacement cost and (2) transmission O&M costs. The sum of these two components is also known as Total Efficient Cost.
2.3: Maximum cohesion between energy prices and operations	• In Peru, for the Regulated-Market, the Generation-Level Price (PNG) is a weighted average between three components, which are (1) the auctioned prices, (2) the Basic Energy Price and (3) the Basic Availability Price. The Energy Price remunerates the variable costs of power plants' activities while the Availability Price repays the power plants' fixed costs, such as investments and O&M costs. Both of them are defined annually by OSINERGMIN which seeks to prevent any financial pressure in the industry. For the free-market, prices are freely negotiated between the generators and free customers. • The short-term energy market in Peru works with nodal prices which are calculated one day before the real energy dispatch in order to fill the scheduled operation determined by the National Interconnected System Operations Committee (COES). • From a long-term perspective, energy prices reflect the interaction between (1) demand for electricity from qualified users and distribution companies and (2) supply of electricity by generators. A characteristic of this market is that the electricity supply is given by the generator with the lowest variable cost (the first to be dispatched, thus a merit order for electricity dispatch to cover demand needs).

Source: Ministry of Energy and Mining (MEM), OSINERGMIN, Goldman Sachs Global Investment Research.

Exhibit 20: Examples of Similar regulation across LatAm

Peru	
Topic	**Description**
2.4: Lower generation transaction costs	• The Supervisory Organization for the Investment in Energy and Mining (OSINERGMIN) is responsible for the determining and updating prices which compose the final generation price. Moreover, it organizes the energy auctions in the country which are responsible for the entrance of new projects to the Peruvian energy matrix.
2.5: Separation between supply and energy	• As already mentioned, in the generation level, OSINERGMIN defines annually the remuneration parameters for both energy and availability in order to provide incentives for agents to invest in their power plants. Energy prices remunerate the energy that is actually generated while Availability remunerates fixed investments and O&M costs, so agents can expect to receive an annual compensation regardless of the actual dispatch of their power plants. In this context, regulators expect to achieve a high reliability to the system's capacity of providing energy in any given scenario.
3.2: New framework for electricity tariffs	• There have been recent important changes to the Peruvian distribution regulation, which include a tariff component called Factor Q, which provides monetary incentives to companies which present high quality service, with the benchmark tariff model being also reinforced in the new regulation. Finally, Technical Responsibility Areas (ZRT), which are exclusive concession areas, were created to generate incentives for distributors to invest in their networks' enhancement.
3.3: Subsidies to incentivized energy sources	• In Peru, the MEM supports renewable generation projects by setting a minimum participation of non-conventional renewable sources via its National Plan for Renewable Energy. In this context, there have been already four clean energy auctions in the country, which are held by the OSINERGMIN, with 64 projects (1,274MW or 10% of Peru's installed capacity) being auctioned to date. • Incentives to non-conventional renewable projects include: (1) prioritized daily energy dispatch; (2) prioritized access to transmission and distribution networks when there is spare capacity; (3) stable long-term tariffs, set via auctions and (4) assured purchase of all energy produced.
3.1 3.4, 3.5, 4.1, 4.2, 4.3, 4.5, 4.6	• **NA**

Source: Ministry of Energy and Mining (MEM), OSINERGMIN, Goldman Sachs Global Investment Research.

Disclosure Appendix

Reg AC

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