Latin American Power Overview

Outlook, Financial Performance, Regulatory Risk and Investments

September 2019

FitchRatings

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Electricity Profiles

Latin American Power Overview

Outlook, Financial Performance, Regulatory Risk and Investments

Stable Ratings Outside of Argentina: Latin American electric corporates outside of Argentina (CC) have a Stable rating trajectory, as leverage steadies amid slowing investments, with a median rating of currently 'BB+'. The majority of issuers hold Stable Outlooks at 65%, with 26% holding Negative Outlooks and 9% holding Positive Outlooks. This would indicate a downgrade/upgrade ratio of 3:1 in the next 12–24 months compared with a downgrade/upgrade ratio of 5:1 in 2018 for the sector. The average rating in Fitch Ratings' portfolio, excluding Argentina, is 'BBB–' shifting toward 'BB+' as coverage of Argentine Country Ceiling (CCC) constrained issuers increased steadily since 2017.

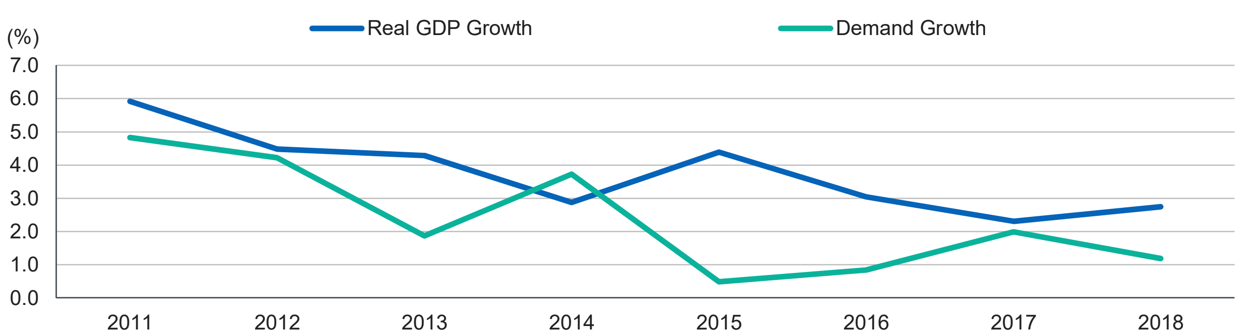
Stable Credit Metrics: Fitch expects Latin American electric corporates' median gross leverage, as measured by total debt/EBITDA, will remain stable at approximately 4.0x in 2019, in line with the 4.1x median reported for 2017 and 2018. We estimate consolidated gross revenue in U.S. dollar terms for rated electric corporates will decline by 2.2% in 2019, after a modest increase of 0.7% in 2018. Consolidated EBITDA margins remained flat at 29% in 2018 when compared with 2017 margins. Aggregate capex, as a percentage of revenue, is expected to be inline by an average of approximately 14% in the next two years after slowing to 13% in 2018 down from 15% in 2017.

Regulatory Risk: Latin American countries, on average, have a median regulatory score supportive of a 'BBB' rating. The highest overall score is held by Chile (A/Stable) followed by Peru (BBB+/Stable) and Colombia (BBB/Negative). Fitch has seen positive overall developments in improving transparency and a movement toward a more independent regulatory environment in countries such as Colombia and Peru. Argentina has the lowest overall regulatory score of 'B', representing a regulatory-based system where not-for-profit Compania Administradora del Mercado Mayorista Electrico or CAMMESA, which is subsidized by the government, is the sole off-taker of generation companies.

Ripe for Investment: Fitch estimates aggregate installed capacity in Latin America will increase by 7% to 364GW in 2021 from 341GW in 2018. The largest growth in the region is from nonconventional renewable energy, defined as wind and solar, which is expected to reach 8% of total installed capacity by 2021, with the largest investment plans in Chile and Argentina. We believe more investment is needed, particularly in Argentina, where approximately 35% of installed capacity is inefficient, and in Chile, which laid out a clear plan to decarbonize its generation matrix. Brazil (BB–/Stable) remains a hotbed for renewable investment with renewables comprising 10% of total installed capacity and a pipeline of 2.3 GW currently under development.

Heightened Political Risk: Fitch believes uncertain political environments continue to inhibit investment in some countries, particularly Argentina and Mexico (BBB/Stable). The primary presidential election results in Argentina sparked a negative market reaction stressing the Argentine peso and increasing the probability of regulatory reforms, which can have an adverse effect on issuers. In Mexico, the current administration seems determined to preserve the government's role in controlling the sector through CFE, dampening reform efforts toward a more competitive and reliable system. The shift in policy priority and the decision to cancel the clean energy auctions raised concerns regarding CFE's ability to fund these projects at the pace required to maintain a balanced system with healthy reserve margins and lower prices.

Electricity Demand Versus GDP Growth



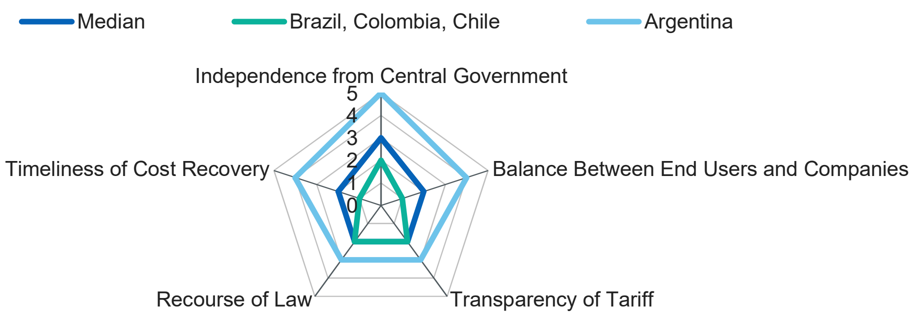
Source: Fitch Ratings, Regulatory Filings.

Regulatory Risk Assessment

Fitch has assessed the regulatory risk among countries scoring each market's independence from the central government, timeliness of cost recovery, recourse of law, transparency of tariffs and balance between end users and companies assigning a score consistent with our ratings scale from 'A' (highest) to 'CCC' (lowest). The median score was 'BBB' with each variable comfortably in the 'BBB' category except independence from the central government with a median score of 'BB'. Government intervention remains a key theme limiting most markets. This is particularly the case in Argentina and Mexico where the government is actively involved and subsidies to the system make off-takers highly dependent on the government.

In Mexico, Fitch views the regulatory framework as highly dependent on the central government, which maintains the planning and control of the electric system and the provision of all power activities as an indispensable public service. We consider Argentina's regulatory risk the highest among rated peers. The country has the lowest overall regulatory score given the high level of government intervention and a history of government delays in payments and implementing social programs designed to benefit end users. Chile has the highest overall score with 'BBB' remaining the archetype which other countries have referred to when developing more competitive and independent regulatory systems. Chile stands out with an 'A' score in both balance between end users and companies and timeliness of cost recovery, when compared with Argentina, which has a 'CCC' score in independence from the central government.

Latin American Regulatory Score



Note: 1.0 = A; 2.0 = BBB; 3.0 = BB; 4.0 = B; 5.0 = CCC.
Source: Fitch Ratings.

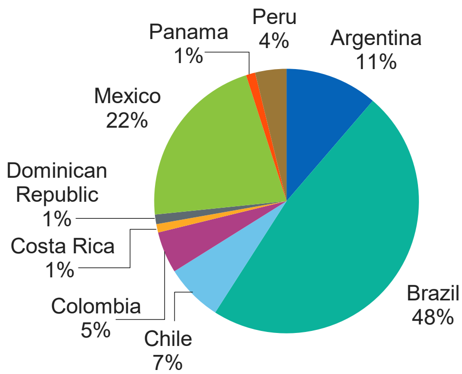
Generation

Installed Capacity

Total aggregate installed capacity in Latin America stood at 341GW in 2018 representing a CAGR increase of 4% since 2011. Hydroelectric is the single-largest source of energy capacity comprising 45% of supply, mainly due to Brazil, where hydroelectric power represents 63% of total installed capacity, or 163GW. Brazil represents 48% of aggregate installed capacity among the countries reviewed in this report. Colombia and Costa Rica (B+/Negative) have a high concentration of hydroelectric power per installed capacity representing 68% and 66%, respectfully. Thermal power represented 34% in 2018 down from 41% in 2011. The Dominican Republic (BB–/Stable) and Argentina have the highest percentage of thermal/installed capacity with 77% and 64%, respectively, in 2018 followed by Peru with 57%, Mexico with 54% and Chile with 53%. Chile has the highest coal/installed capacity at 22%.

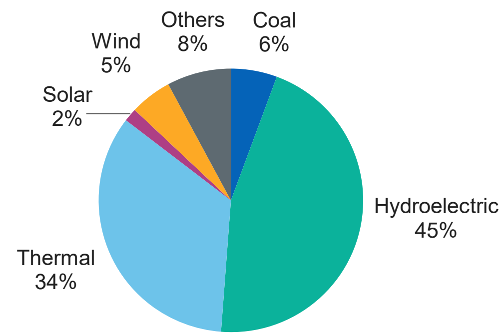
Nonconventional renewables (NCR), defined as solar and wind, represented 7% of total installed capacity, with wind at 5% followed by solar at 2%. Chile and Brazil have the highest NCR/installed capacity at 16% and 10%, respectively. Chile has the highest solar ratio at nearly 10%, as the country has the best photovoltaic radiation, where a solar farm can have a capacity factor as high as 35% versus a normal capacity factor range of 20% to 25%. Brazil's renewable capacity is mostly comprised of wind at nearly 9%. NCR increased to 7% in 2018 up from 1% in 2011. This is the result of Argentina's RenovAR, or Renewables Argentina, program. Fitch expects an additional 2.6GW will be added by 2021 and renewables will represent 8% of total installed capacity. Following Argentina, Peru has a CAGR of 166% representing 5% of total installed capacity, followed by Chile and Brazil with 53% and 35% CAGRs, respectively.

2018 Installed Capacity by Country



Source: Fitch Ratings, Regulatory Filings.

2018 Installed Capacity by Technology



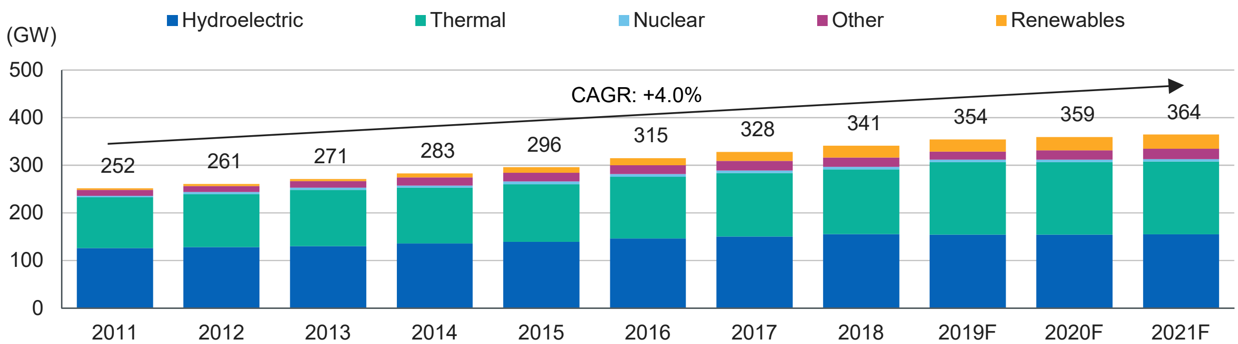
Source: Fitch Ratings, Regulatory Filings.

Growth and Expansion

Total installed capacity in the region grew at a CAGR of 4% between 2011 and 2018 propelled by Peru at 9%, Chile at 6%, Brazil at 5% and Argentina at 4%. Peru's expansion is explained by the addition of nearly 1.7GW of hydroelectric capacity and 3.4GW of thermal power capacity from 2011 to 2016. Chile added 3GW of thermal power capacity, mostly coal, and 4GW of renewable capacity during the same period. Brazil added 21GW of hydroelectric capacity followed by 14GW of renewables and 9GW of thermal power over the past seven years. Argentina is in the midst of an expansion plan but in 2018 the country added 7GW of thermal power and nearly 1GW of NCR.

Fitch forecasts total installed capacity will increase to 364GW in 2021 representing a CAGR of 4% with most of the growth from Argentina, Brazil, Mexico and Peru. Fitch estimates renewables will comprise 8% of total installed capacity in 2021. This coupled with hydroelectric, which is expected to be 155GW in 2021, will represent 51% of total installed capacity for the countries reviewed.

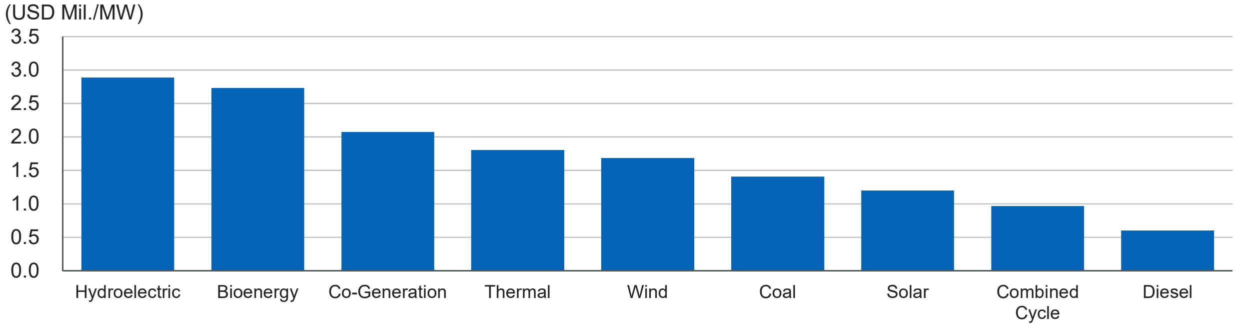
Evolution of Installed Capacity



F – Forecast.
Source: Fitch Ratings, Regulatory Filings.

Among the projects under development and assessed in Fitch's analysis we estimate hydroelectric remains the most costly, when viewed in U.S. dollars invested/MW to be installed, averaging USD2.0 million/MW. This figure is mainly skewed by Empresas Publicas de Medellin E.S.P.'s (EPM; BBB/Rating Watch Negative) Ituango project at 2,400MW in Colombia and AES Gener S.A.'s (BBB–/Stable) Alto Maipo project at 531MW. Both projects suffered setbacks and cost overruns. The Ituango project experienced unprecedented landslides jeopardizing the project and total monetary damages have not been finalized. The Alto Maipo delay was the result of the contractor backing out of the project due to technicalities relating to the drilling of tunnels. Since then, AES Gener contracted STRABAG International GmbH and construction is 80% complete at the publication of this report. The project is expected to go on line in 2021–2022.

Budgeted Capex per Technology



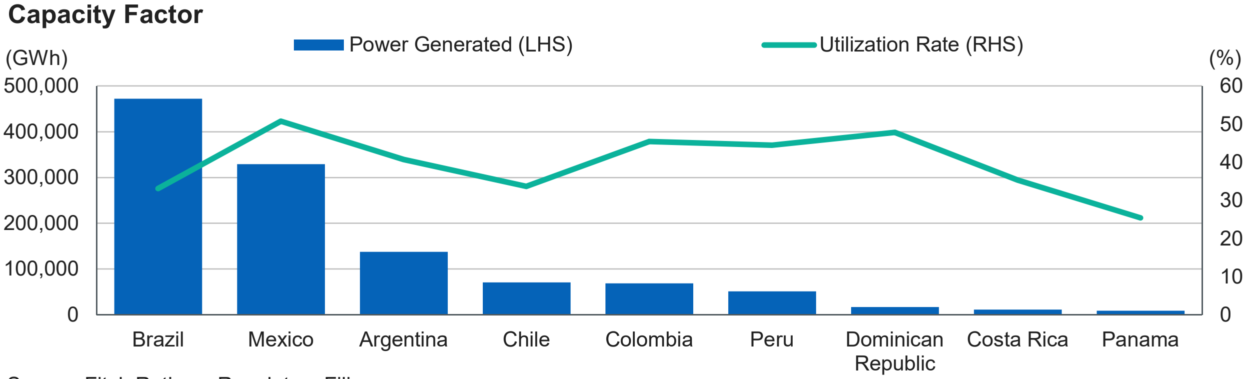
Source: Fitch Ratings, Fitch Solutions.

When comparing the cost benefit of either developing a project or making an acquisition Fitch assessed a selected portfolio of M&A deals that closed since 2016. We determined that, on average, acquisitions cost/MW of installed capacity was USD1.3 million/MW, less than the average cost of developing a project.

Power Generated

Fitch estimates the median implied capacity rate was 41% among the countries reviewed in 2018. We believe the implied capacity factor can be a measure to determine how efficient the power systems are operating, although comparison between countries is difficult due to the different generation technology matrices. Brazil, Chile and Panama had the lowest capacity factors at 33% and 34%, respectively, while Colombia, the Dominican Republic and Mexico had the highest. Argentina, Colombia and Peru are closest to the median. Fitch expects Argentina's and Colombia's capacity factors will decline by 2021 as more renewable projects are added to the grid in Argentina and Ituango goes online in Colombia.

Capacity Factor



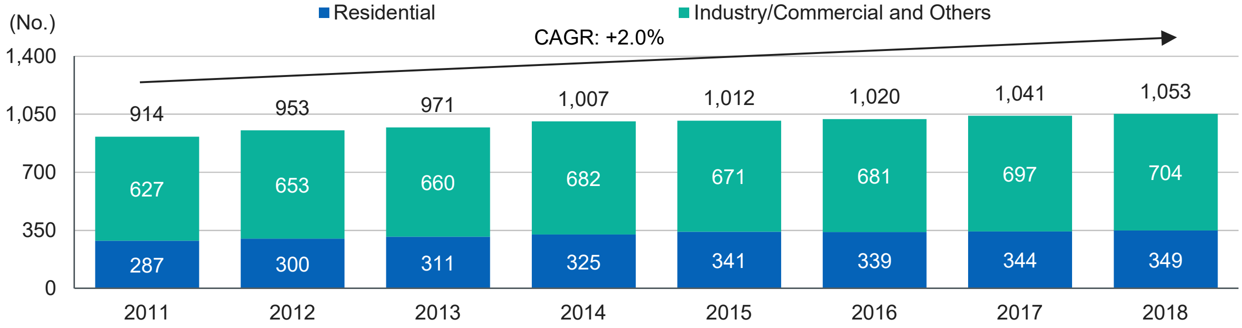
Source: Fitch Ratings, Regulatory Filings.

Distribution

Fitch estimates electricity demand grew at a 2.0% CAGR from 2011 to 2018, as residential consumption averaged 33%. Peru and Panama (BBB/Stable) grew the largest increasing 6.9% and 3.4%, respectively, followed by Chile at 3.1%, Mexico at 2.9% and Colombia at 2.8%. Argentina's consumption remained flat and is explained by revised regulations which increased the cost of consumption to end users. Colombia is the only country in which residential demand is consistently higher than industrial demand and the average from 2011 to 2018 is 68%. Chile's residential demand was, on average, 49%, while Brazil had the lowest level at 28%.

Energy losses remained relatively flat from 2013 to 2018, with the Dominican Republic having a material improvement in 2018 at 24%, down from 35% in 2013, followed by Argentina where energy losses were 16.1% in 2018 up from 11.9% in 2013. The Dominican Republic's energy losses remain the highest at 2.0x the median.

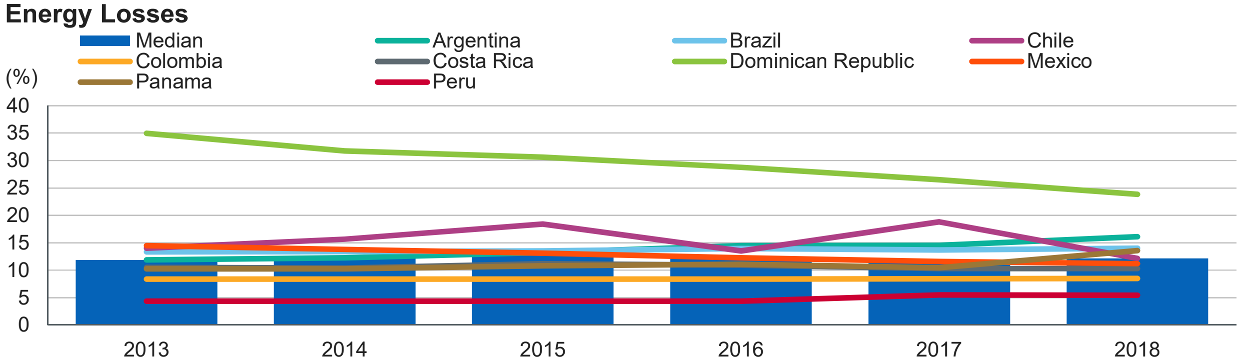
Demand by Client Type



Source: Fitch Ratings, Regulatory Filings.

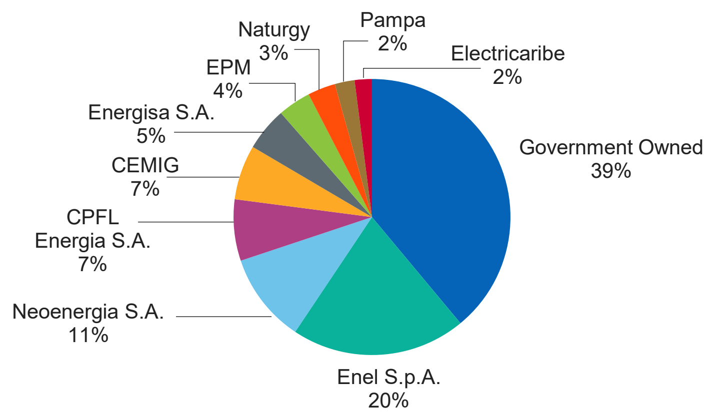
Government owned and operated entities comprised the largest distribution companies among the review we conducted, mainly driven by Mexico, where Comision Federal de Electricidad (CFE; BBB/Stable) has a monopoly on electricity distribution. Among private entities, Enel S.p.A. (A–/Stable), the holding company of Enel Americas S.A. (BBB+/Stable) and Enel Chile S.A. (AA[cl]/Positive), is the single-largest private operator, with the largest number of clients served in Argentina, Brazil, Chile, Colombia and Peru. Thereafter, Brazilian utilities, given the sheer size of the market, represent some of the largest entities when measured by clients served. These entities are Neoenergia S.A., CPFL Energia S.A. (AAA[bra]/Stable) and Energisa S.A. (BB/Stable) with 20.9% of Brazilian clients served by Enel's subsidiaries. EPM represents the second-largest distribution entity, behind Enel's Codensa S.A. E.S.P. (AAA[col]/Stable), along with Panamanian subsidiary Elektra Noreste, S.A. (BBB/Stable).

Energy Losses



Source: Fitch Ratings, Regulatory Filings.

Market Share



Electricaribe – Electrificadora del Caribe S.A. E.S.P. (Electricaribe). Pampa – Pampa Energia S.A. Naturgy – Naturgy Energy Group, S.A. EPM – Empresas Publicas de Medellin E.S.P. (EPM). CEMIG – Companhia Energetica de Minas Gerais (CEMIG).
Source: Fitch Ratings.

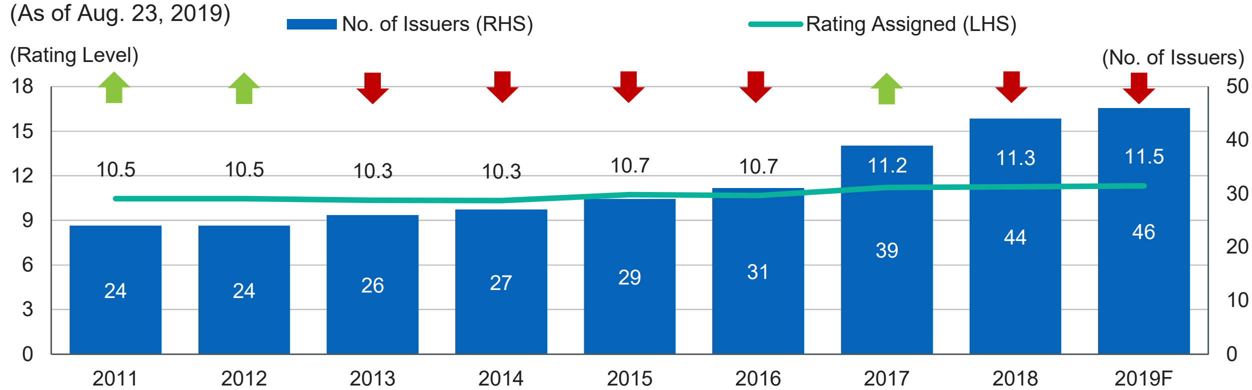
Fitch expects further consolidation in this segment with Sempra Energy's (BBB+/Stable) announced sale of its Luz de Sur asset in Peru with 1.1 million clients and Chilquinta Energia S.A. (AA[cl]/Stable) in Chile with 688,000 clients. Per public sources, Sempra is in the process of receiving bids. Fitch expects Enel Americas may be a likely bidder, given the company's dominate position in the region, strong balance sheet and support from parent Enel. We expect the process to be highly competitive given Chile and Peru are two of the most stable regulatory environments in the region with growth potential. Due to the scale and potential to improve profitability through efficiencies, we believe there may be interest from these companies in the Luz de Sur asset and Chilquinta Energia. Fitch expects Electrificadora del Caribe S.A. E.S.P. (Electricaribe) in Colombia, serving 2.6 million clients, will potentially be for sale in the near to medium term. We estimate the median acquisition of distribution companies from 2016 to 2018 was 7.5x enterprise value/EBITDA and USD674,000/per the number of clients served when reviewing four transactions closing since 2016.

Corporates

Ratings Observations

The average rating in Fitch's portfolio gradually shifted toward a 'BB+'. This is explained by an increase in issuers from Argentina beginning in 2017, where a Country Ceiling of 'CCC' caps ratings. The mean Rating Outlook trajectory for the sector is Negative as a result of Negative Sovereign Outlooks in Argentina and Colombia.

Rating Trajectory
(As of Aug. 23, 2019)

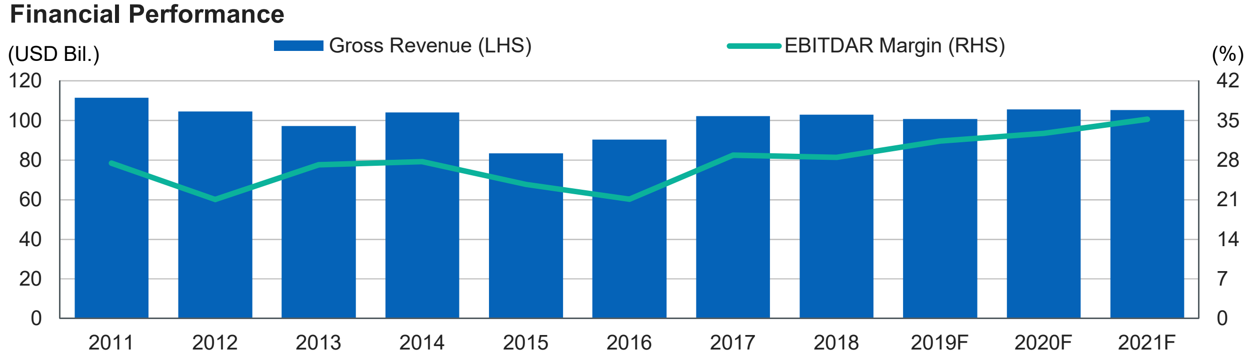


= Positive Outlook. = Negative Outlook. F – Forecast. Note: 1 = AAA; 2 = AA+; 3 = AA; 4 = AA–; 5 = A+; 6 = A; 7 = A–; 8 = BBB+; 9 = BBB; 10 = BBB–; 11 = BB+; 12 = BB; 13 = BB–; 14 = B+; 15 = B; 16 = B–; 17 = CCC; 18 = CC; 19 = C; 20 = RD.
Source: Fitch Ratings.

Financial Performance

Fitch estimates total gross revenue in U.S. dollar-denominated terms increased by 0.7% in 2018 when compared with 2017. Forecast gross revenue will decline by 2.2% in 2019. EBITDA margins were consistent at 29.0% in 2018 when compared with 2017. Consolidated average gross leverage, defined as total debt with equity credit/EBITDAR, slightly increased to 4.1x in 2018 when compared with 4.0x in 2017. FFO/interest coverage remained strong at 6.8x in 2018 when compared with 5.1x in 2017. The improvement is partially explained by lower interest rates in Brazil. We estimate total debt with equity credit/EBITDAR will decline to 3.3x in 2021 and FFO/interest coverage will remain flat at 4.8x.

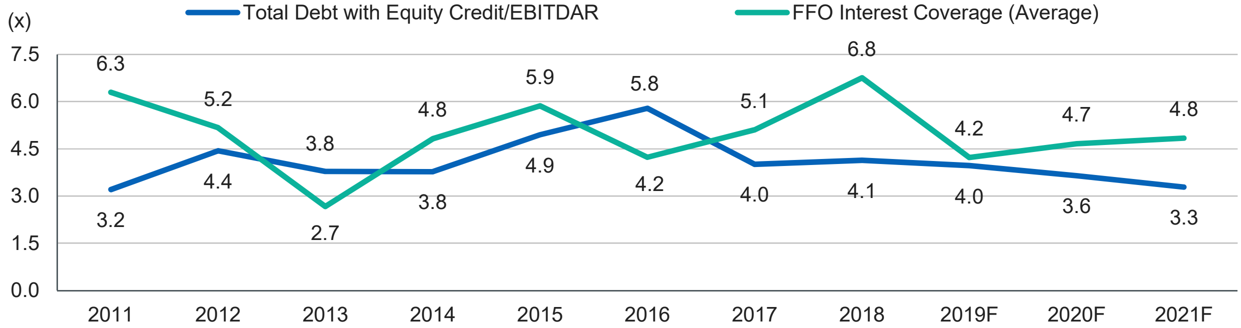
Financial Performance



F – Forecast.
Source: Fitch Ratings, Fitch Solutions.

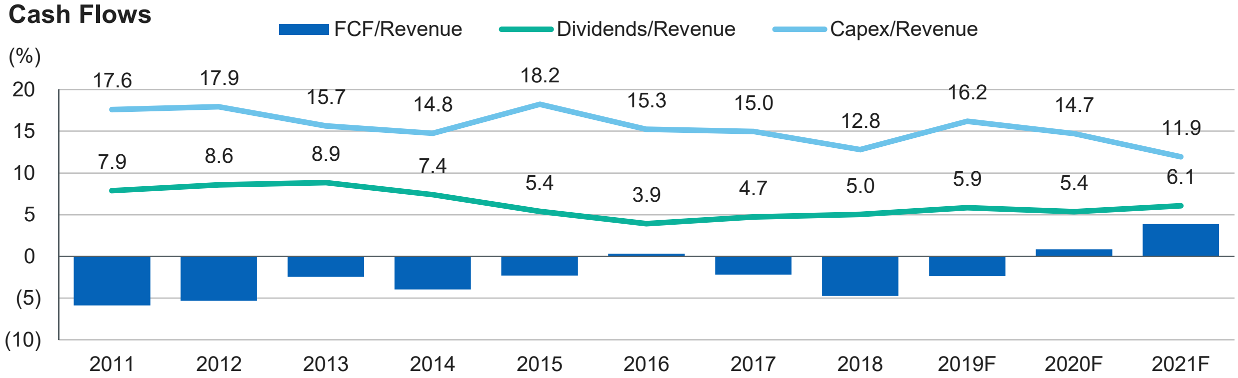
Cash outflows declined to 13% of revenue in 2018, the lowest level observed since 2011. Dividends represented 5% of total revenue in 2018. FCF remained negative from 2011 to 2018 with a slight positive uptick in 2016. Fitch estimates capex will increase in 2019 to 16% of total revenue scaling down to 12% in 2021. Dividends will remain in a range of 5% to 6% and FCF will be negative in 2019 before turning positive in 2020 and 2021 when most expansion plans are scheduled to be completed.

Leverage Metrics



F – Forecast.
Source: Fitch Ratings, Fitch Solutions.

Cash Flows

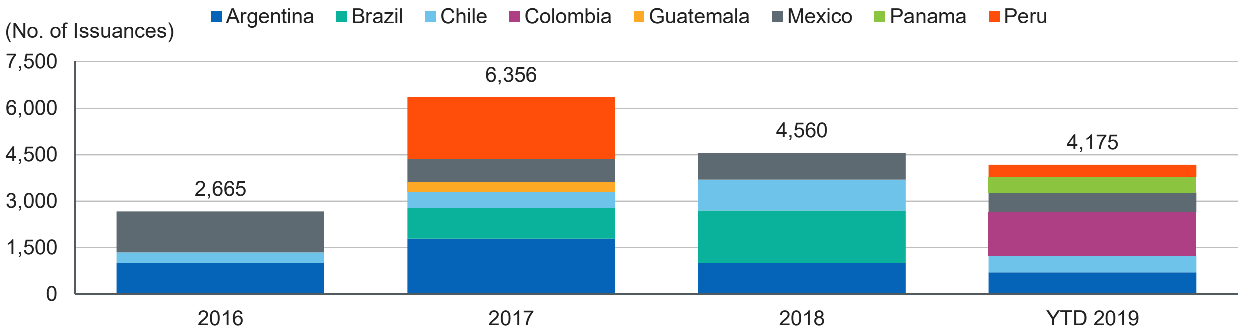


F – Forecast.
Source: Fitch Ratings, Fitch Solutions.

Capital Market Activity and Refinancing

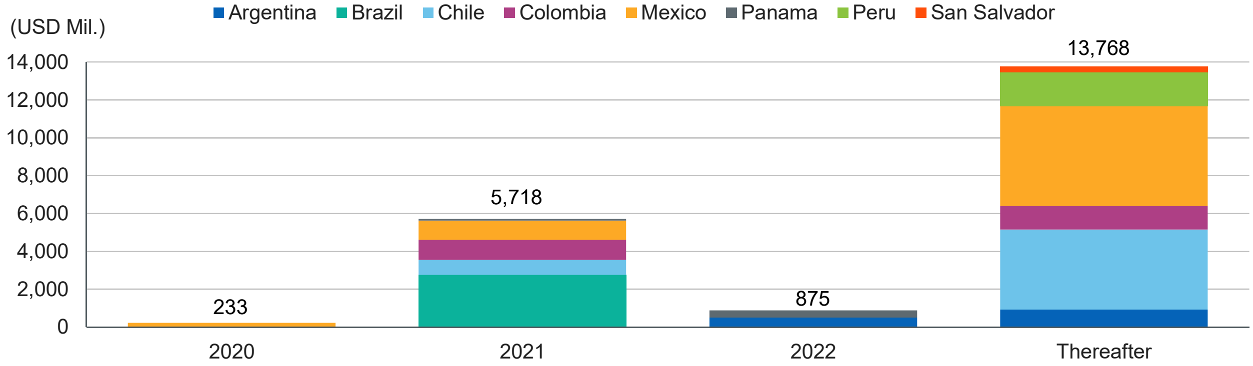
A total of USD17.8 billion of international bonds were issued by Latin American electric utilities since 2016 with 2017 having the highest volume at USD6.4 billion. Argentine issuers comprised 25% of the total volume after positive regulatory reforms during 2015–2016 and new power purchase agreement awards to expand capacity in the country, followed by Mexico at 20%, Brazil at 15%, and Peru and Chile at 14%. Fitch estimates a total of USD233 million in international bonds maturing in 2020 followed by USD5.7 billion in 2021, with USD2.8 billion from Centrais Eletricas Brasileiras S.A. (Eletrobras; BB–/Stable), USD1.0 billion from CFE and USD800 million from Engie Energia Chile S.A. (BBB/Positive) and AES Gener. We estimate Latin American electricity utilities have a total of USD20.6 billion of international bonds outstanding.

International Issuances



Source: Dealogic.

Debt Maturity Profile for Electric Corporates



Source: Dealogic.

Outlooks

2019 Fitch Ratings Outlooks
Fitch Ratings 2019 Outlook: Latin American Energy (Oil and Gas) (Downward Rating Trajectory) (December 2018)
Fitch Ratings 2019 Outlook: Latin American Power (General Sector Stability; Trouble Spots in the Southern Cone) (December 2018)

Related Research

Latin America Electricity Handbook (January 2019)
Latin America Oil and Gas Handbook (November 2018)

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Argentine Electricity Sector

Regulatory Uncertainty, Inefficiency and FX Risk Cloud Outlook

Macroeconomic Instability: The Argentine electricity sector arguably felt the most acute effects of macroeconomic instability and policy changes since President Mauricio Macri's election in 2015. Upon taking office, the Macri administration introduced several measures to lower generation costs, improve system reliability and increase end user tariffs in order to reduce the electricity sector cash flow deficit and government subsidy reliance. These measures were severely challenged by devaluation. Moreover, the increase in electricity tariffs partially propelled inflation to 46% in 2018 and nearly to an estimated 50% for 2019.

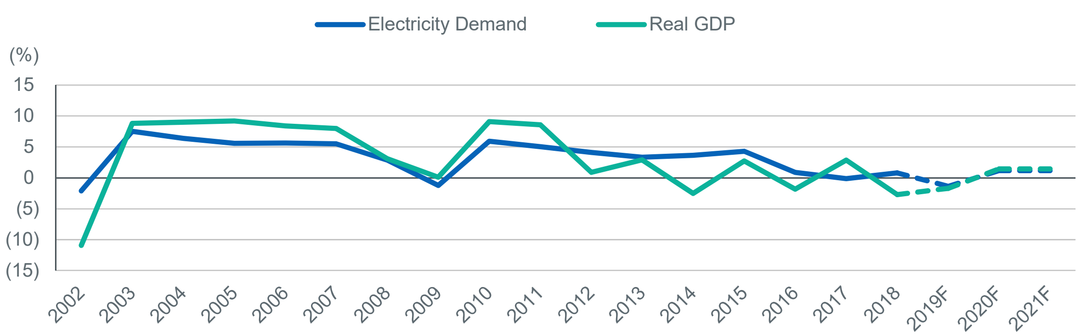
Reliance on Government Subsidies: Argentina's electricity sector relies heavily on government subsidies paid to Compania Administradora del Mercado Mayorista Eléctrico S.A. (CAMMESA), which are transferred to power-generation companies (GenCos). Fitch estimates CAMMESA received USD3.4 billion of subsidies in 2018, or approximately 35% of the implied costs. Subsidies decreased 21% from USD4.5 billion in 2017, which represented a subsidy of approximately 48% of the system's entire revenue. Fitch expects continued volatility in timely payments from CAMMESA in 2019 as the government lowers its fiscal deficit to comply with International Monetary Fund terms.

Devaluation Drives Energia Base Revision: In February 2019, the government reduced the capacity payments made to GenCos under Energia Base (formerly Resolution 19/2017 and now Resolution 1/2019) to lower deficits caused by the 2018 peso depreciation. Fitch estimates approximately 60% of Argentina's installed capacity operated under Energia Base, representing approximately USD6.1 billion in annual costs. To lower the USD3.6 billion deficit (35% of the cost of the system) in 2018, the government amended the remuneration scheme, which lowered the capacity payment of efficient power plants by 10%, while imposing a marginal-cost scheme whereby plants that dispatched less than 30% per year will only receive 70% of their implied capacity payment, which Fitch estimates will lower the deficit to USD3.0 billion per year.

FX Exposure: Fitch believes the largest threat to the system remains FX risk. Presently, cash inflows to CAMMESA from distribution and transmission companies are in pesos, which CAMMESA transfers to GenCos to pay remuneration schemes. From April 2018 through December 2018, Fitch estimated transfers to CAMMESA increased 14% due to peso depreciation. Moreover, Fitch does not expect any material developments to address FX risk in 2019 and 2020, as strict guidelines limit how much the government is allowed to defend the peso. As a result, Fitch estimates 2019 peso/U.S. dollar average FX rate will be 44.40, which can represent 39% of the total cost of the system in 2019.

Investment Opportunities: Argentina could be a dynamic market for investors once macroeconomic conditions improve. Fitch estimates 35% of Argentina's installed capacity is inefficient and only 40% of RenovAR Rounds 1 and 1.5 projects awarded will commence operations by 2019. Also, major transmission expansion-and-distribution investments are needed to improve system consistency. Generally, all of the 4,466MW of RenovAR projects awarded in the three pending auctions might cost approximately USD6.7 billion and the need to expand transmission capacity can represent an investment of approximately 1.4% of 2018 GDP.

Argentina Electricity Demand Versus GDP Growth



F – Forecast.
Source: Fitch Ratings, CAMMESA.

Primary Market Considerations

Growth Prospects

Growth prospects for the Argentine power sector continue to be constrained by

- A high degree of government intervention;
- Macroeconomic weakness;
- A lack of interest from private investors;
- High borrowing costs; and
- FX volatility.

Argentine electricity consumption growth is primarily supported by residential demand, which is 56% of consumption, followed by industrial and large commercial at 29% and commercial at 15%. In the short to medium term, electricity supply growth will decrease in line with real GDP growth. Fitch expects the cost of the system will gradually decrease as new more efficient combined-cycle plants are scheduled to go online in 2020, coupled with renewable power sources, which may account for nearly 10% of electrical capacity after 2021. Furthermore, Argentina's ramped-up gas production from 2017 and 2018 is expected to further lower the cost to the system, as average gas prices are expected to be lower than the historical average of nearly USD7.00MMBTU, caused by liquefied natural gas imports.

Fitch estimates Argentina will require approximately 990MW of new installed capacity per year for the next 10 years to account for the 13.3GW of inefficient installed capacity. It will also need associated transmission infrastructure to maintain a balanced supply-and-demand market. Given scarce and challenging financing markets, Fitch expects new investments will be on hold in the short to medium term, deterring private investment in the sector. A lack of financing may cause inefficient units to be used more, resulting in a higher system cost, assuming no further expansion.

Pricing

Following the Argentine peso devaluation of 2001–2002, the government froze all regulated transmission and distribution tariffs and revoked all price-adjustment provisions and inflation-indexation mechanisms. This led to Argentina's residential/industrial energy tariffs to fall significantly below those of most Western countries. Spot prices were calculated based on the price of natural gas, which is regulated by the government, even if a plant uses more expensive fuels. This caused the system to ignore supply-and-demand dynamics, resulting in distorted pricing. This contrasts with the precrisis years, in which CAMMESA determined the spot price based on the marginal cost of the last unit to be dispatched.

Since 2002, the short-term marginal cost for many plants was set at ARS120/MWh (USD2.70/MWh at current official exchange rates). In contrast, the average marginal break-even marginal cost in 2014 was ARS550/MWh (USD67/MWh), which included power-capacity fees, the cost of generation with liquid fuels and other minor items.

The pricing scheme was reorganized by Argentine regulators in March 2013, moving away from a margin-based system to a regulated system, whereby generator income is driven by regulated revenues. Previously, independent GenCos would sell their output in the Argentine Wholesale Electricity Market (WEM) through private contracts with purchasers (typically large industrial users) or to CAMMESA through special transactions. CAMMESA operates the WEM.

CAMMESA became the single fuel buyer and seller for power plants after March 2013 and free bilateral trading was suspended. After the suspension, large buyers were required to buy electricity directly from CAMMESA. Generators then moved to regulated remuneration, which was expected to cover fixed and variable costs, and include an additional return:

- **Fixed costs:** capacity remuneration based on target availability.
- **Variable costs:** remuneration for operation and maintenance costs, as electricity generators are not allowed to incur fuel costs.
- **Additional remuneration:** Partly paid by cash paid to the generators with the remainder accumulated in a fund that will be used to finance generation investments.

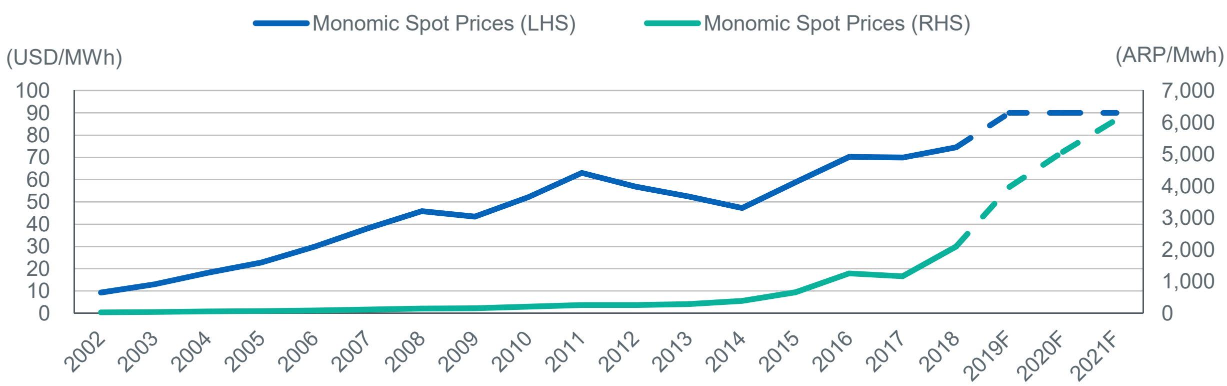
To mitigate price volatility for end users, CAMMESA manages a stabilization fund financed from the difference between the regulated and spot prices. The stabilization fund activates when spot prices exceed the regulated price and is replenished when the regulated price exceeds the spot price.

Although the fund is supposed to balance in the long run, it often runs a substantial deficit. This deficit resulted from an emergency regulation implemented by the government, which modified the spot-price calculation and adjusted the regulated price to below the spot price. The deficit was covered with government subsidies. In 2015, subsidies to CAMMESA peaked at approximately USD8.7 billion. Subsidies have decreased since then and in 2018 the system's deficit was USD3.6 billion.

The transmission sector operates under monopoly conditions, with transmission companies authorized to charge different rates for their services. Distributors are regarded as a public service operating under monopoly conditions and have regulated tariffs that are subject to quality-of-service specifications. Distribution companies may obtain electricity on the Argentine WEM at a seasonal rate, which is defined by the Argentine Ministry of Energy as a cost cap of electricity bought by distributors that can be passed on to regulated customers. Argentine regulators neglect to fully review electricity tariffs and fully recognize that the cost increases have negatively affected both distribution and transmission companies, which reduced investment in these important market segments.

Since President Macri's election in late 2015, the government introduced new remuneration schemes, most recently Resolution 1/2019, which was an amendment to Resolution 19/2017. The idea was to gradually increase market-correcting regulations, so the nation can shift toward a more balanced market that is less dependent on government support. First, Energia Base was updated, increasing remuneration fees to be denominated in U.S. dollars, but settled in pesos. Second, the government announced increases in transmission and distribution tariffs, ultimately passing the cost of the system to end users. Since 2014, the CAGR of monomic prices in U.S. dollars increased 12%.

Monomic Spot Prices (U.S. Dollar Basis)



Source: CAMMESA.

Regulatory Overview

Regulatory Framework

The Argentine electricity sector is governed by the Electric Regulatory Framework law of 1992 that promotes efficiency and competition in the industry. This law allows for private-sector participation and separates the electricity services into generation, transmission and distribution activities. It also comprises the creation of a competitive wholesale electricity market, as well as transmission and distribution monopolies that reward efficient operators. These last two activities are regulated by the government and as such, require a concession to operate.

Regulatory Bodies

The Secretaria de Energia (SE) oversees the Argentine electric industry by developing and coordinating the government's policies for the sector. In addition, the SE grants and renews operating concessions for generation, distribution or transmission, and regulates the overall electrical supply.

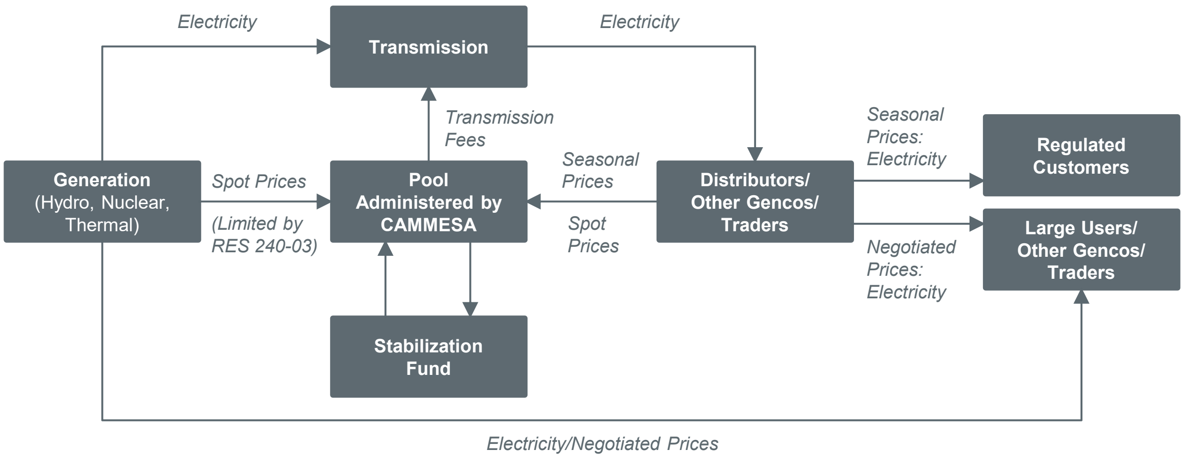
Ente Nacional Regulador de la Electricitdad (ENRE) is responsible for regulating distribution and transmission companies, as well as establishing electricity tariffs. It monitors and supervises public-service companies, enforces regulatory initiatives and maintains safety and environmental standards for the country's electricity sector.

CAMMESA manages the wholesale electricity market by coordinating the electricity dispatch, ensuring the system's stability and the overall operation of the WEM. CAMMESA is a mixed-capital company 20% owned by the Argentine government, with the remaining balance by market participants (generation, transmission and distribution companies and large industrial customers).

Industry Structure

The Argentine electricity sector is organized along three major market activities: generation, transmission and distribution, with all electricity transactions conducted through the WEM, which acts as a clearinghouse for electricity trading.

Wholesale Electric Market (WEM)

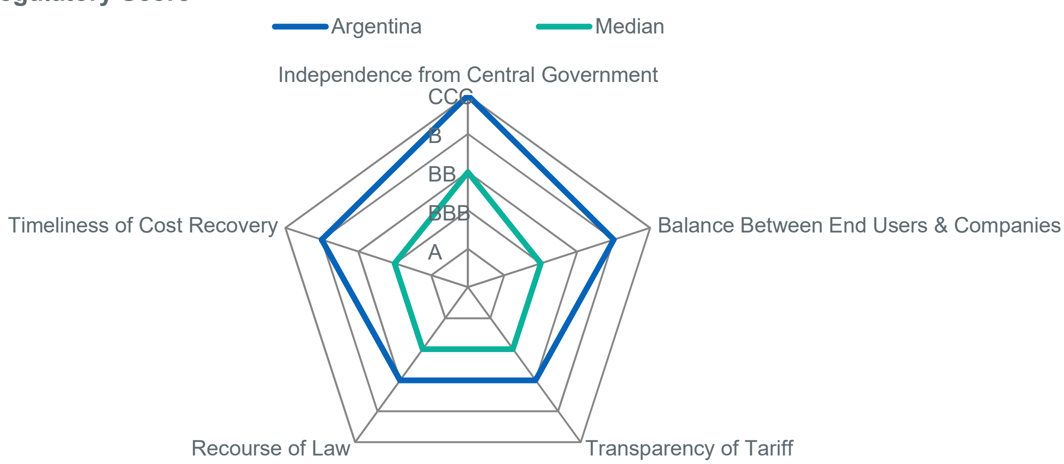


RES – Resolution. Gencos – Generation Companies.
Source: Endesa-Chile 20-F filing.

Regulatory Risk

Fitch considers Argentina's regulatory risk one of the highest among rated peers given the high government intervention and history of government delays in payments and implementing social programs designed to benefit end-users. On average, Argentina's rated regulatory risk is comparable with a 'B' category, while the median for the region commensurate with a 'BB' category.

Argentine Regulatory Score



Source: Fitch Ratings.

Select Regulatory Events Timeline

Select Regulatory Events
(2015 – Present)

2019	Oct.	Presidential Elections
	April	Res. No. 14/19 - partially amended SGE Res. No. 366/18, maintaining in effect the power capacity reference price, effective since February 2019, until October 2019.
	Feb.	Revision to Energia Base (Res. 1/2019)
2018	Feb.	Transfer of Edenor & Edesur's Concession Jurisdiction to Buenos Aires City and Province
	Jan.	Changes to Res. 46/2017 (Plan Gas)
2017	Dec.	Distributed Generation of Renewable Energy (Law 27/424)
	Oct.	Restructuring of Argentine Government's Energy Sector Assets (Decree No. 882/17)
	Mar.	New PPAs under Resolution No. 287/17 for projects consisting new co-generation and the termination of existing gas turbine units in combined cycle with a term of 15 years.
	Feb.	New Remuneration Scheme "Energia Base" (Resolution No. 19/2017)
		Revised integral tariff revision (RTI) process (Res. 63/17). The ENRE approved a new rate of return for Edenor & Edesur.
2016	Mar.	New Power Plant auction (Res. 21/2016).
	Jan.	Tariff Adjustment implemented by ENRE (Res. No.7/2016) to take effect in February 2016 and conclude in February 2017.
2015	Dec.	President Macri declared a state of emergency for national electricity system to remain in effect until Dec. 2017

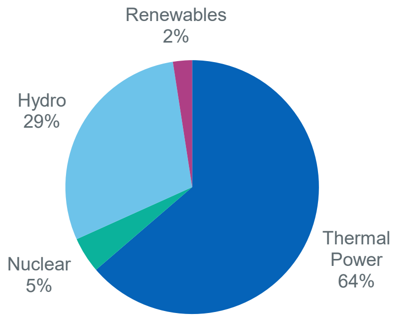
Source: Fitch Ratings.

Generation

Installed Capacity

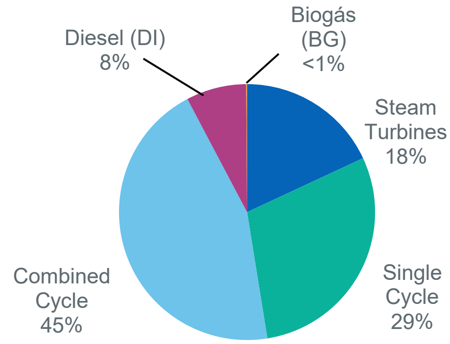
As of January 2019, Argentina had a total installed capacity of 38.6GW, of which 64% is thermal sourced. Within the 24.6GW of thermal capacity, 18% are steam turbines, 29% single-cycle gas, 45% combined cycle and 8% diesel fuel. Fitch estimates approximately 13.6GW or 55% of thermal capacity is inefficient, representing 35% of total installed capacity of the country.

Total Installed Capacity — 2018



Source: CAMMESA.

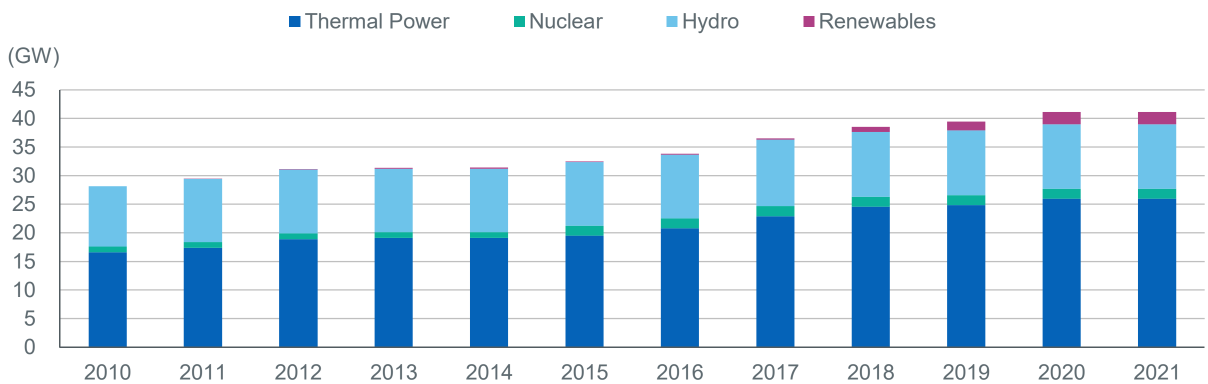
Thermal Installed Capacity



Source: CAMMESA.

Fitch estimates total installed capacity of Argentina will increase to 41GW by 2021, where thermal will continue to represent two-thirds of the market. But as the current pipeline suggests, renewables will represent 5%. Moreover, of the 26GW of thermal capacity, Fitch expects nearly three-quarters of the thermal installed capacity will be combined cycle attributed to Resolution 287/17, where MSU Energy will have 750MW of it capacity as closed cycle and Albanesi with 783MW.

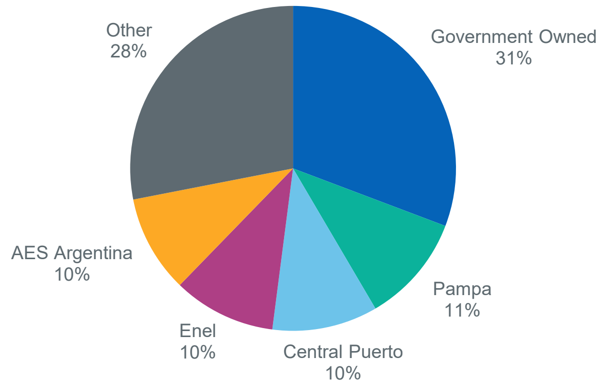
Installed Capacity



Source: MINEM.

As of 2018, the government has the largest market share by installed capacity with 31% of total installed capacity, and the four largest private entities, which are Pampa, Central Puerto, Enel and AES Argentina, accounted for 41% of installed capacity. The remaining 28% of capacity is comprised by smaller companies such as Albanesi, Genneia and Capex. As part of President Macri's energy reform, the government intended on selling some government assets, and as of now has only sold Brigadier Lopez (280MW), which had an expansion plan of 140MW. Fitch expects with a stabilized market and contingent on the result of the presidential election, the government will engage in further asset sales.

Market Share by Installed Capacity 2018

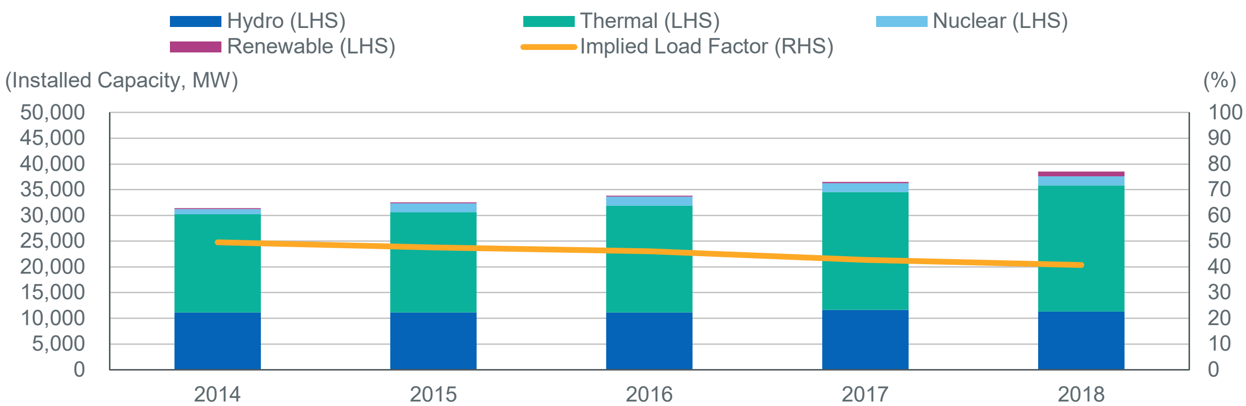


Source: CAMMESA.

Power Generated

Fitch estimates the market's implied load factor was 41% out of total installed capacity in 2018, slightly less than 43% in 2017. We believe the Argentine electricity system currently operates at industry average base load and needs to increase efficiency of the installed capacity to a level in order to avoid diminishing returns due to over usage an high costs; especially given capacity is highly concentrated on thermal energy sources. This load factor can be relieved by increasing renewable energy.

Utilization Rate

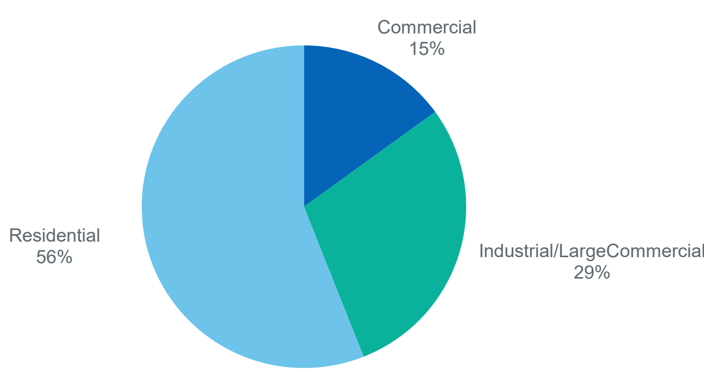


Source: CAMMESA.

Distribution

There are 29 distribution entities within Argentina, most of which are owned by the province, but the two largest private entities are Edenor and Edesur. Edenor is a majority owned by Pampa Energia and Edesur by Enel Americas. Residential users comprised of nearly 60% of total demand in 2018 and distribution companies demanded about 80% of total power generated.

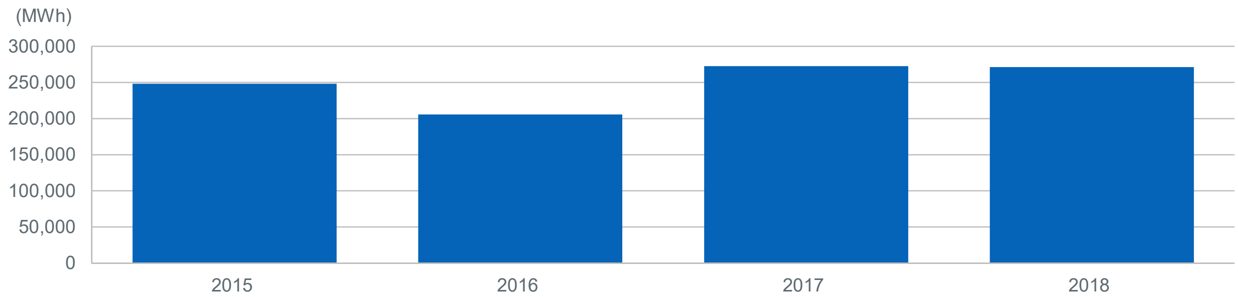
Argentine Electricity Demand



Source: CAMMESA.

Electricity demand increased by about 9% between 2015 and 2018, due to the low cost supported by subsidies by the government and the elimination of the inflation adjustments provision in concession and the devaluation of the peso during this time period. In 2018, demand decreased by 1% due to the elimination of subsidies and new regulatory framework, which allows distribution entities to increase tariffs by inflation, electricity costs increased to end users, and had a material impact on demand. Fitch expects daily average demand to move in line with real GDP assuming no changes in tariffs.

Annual Demand

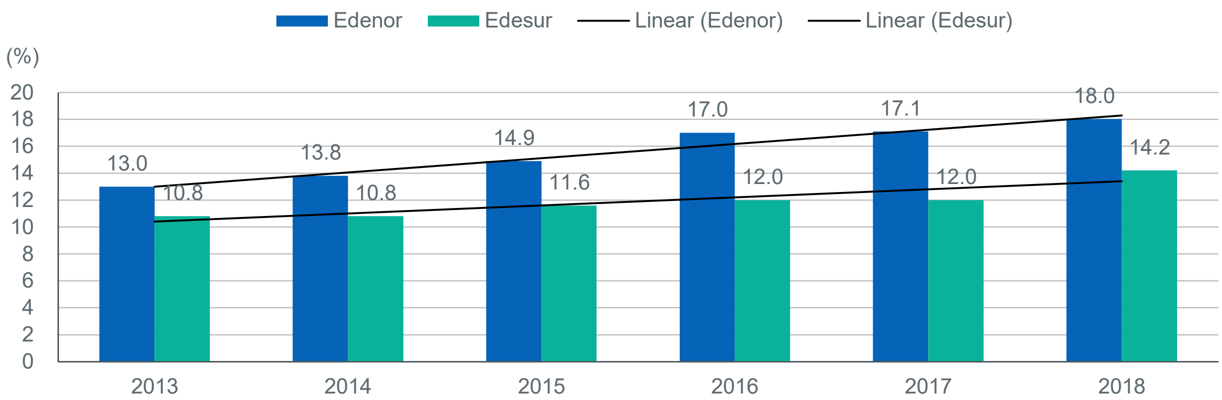


Source: Fitch Ratings, company filings.

Energy Loses

Distribution companies in Argentina realize high energy losses and concessions awarded to private entities, Edenor and Edesur, do not allow them to pass on to customers the cost of additional energy purchased to cover any energy losses that exceed the loss factor contemplated by our concession, which is on average 10%. Distribution companies prior to the crisis of 2002, were able to reduce high energy losses and where reimbursed under their concessions. Fitch expects energy losses to continue to be relatively high through 2020 as the Argentine economy recovers.

Energy Losses



Source: Fitch Ratings.

Transmission

Recently, the condition of the Argentine electricity market provided little incentive to generators and distributors to further invest in increasing their generation and distribution capacity, respectively, which would require material long-term financial commitments. Although there were several investments in generation during 2017, which would increase the installed capacity power in the coming years, the highest density of investments was concentrated in the GBA area. It is still necessary to make several investments on the transmission and distribution system to guarantee the delivery of this electricity to the customer and reduce the frequency of interruptions.

Argentine Transmission System

Source: Argentine Ministry of Energy.

Corporates

Ratings

Company Name	Long-Term Foreign Currency IDR	Long-Term Local Currency IDR	Outlook
AES Argentina Generacion S.A.	CCC	CCC	—
Albanesi S.A.	CCC	CCC	—
Capex S.A.	CCC	B–	Negative
Central Puerto S.A.	—	—	—
Genneia S.A.	CCC	CCC	—
MSU Energy S.A.	CCC	CCC	—
Pampa Energia S.A.	CCC	B–	Negative

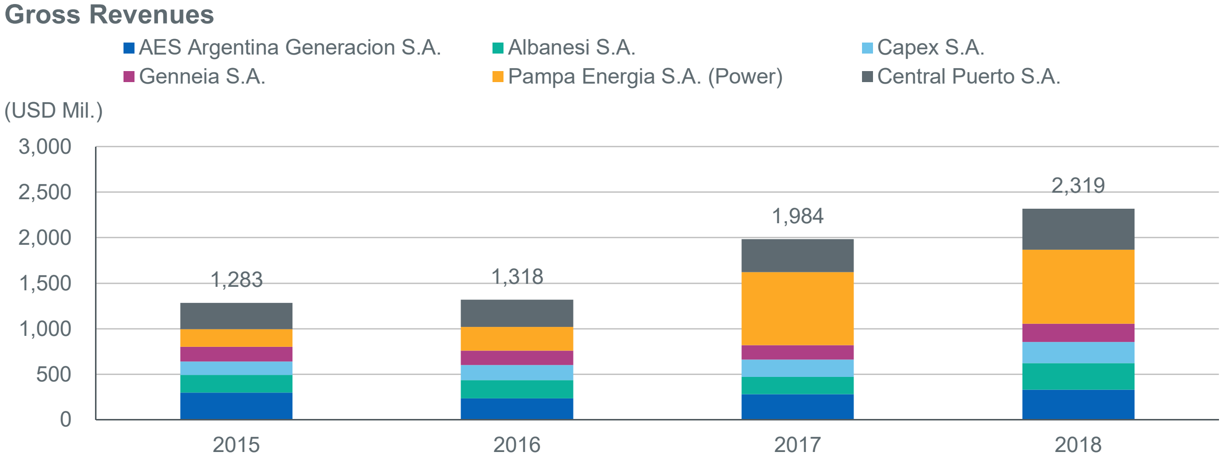
Source: Fitch Ratings.

Financial Performance

Fitch's electricity portfolio consists mostly of power generations companies, with the exception of Pampa Energia, an integrated energy company. For comparison, the following references to Pampa below consider only Pampa's power generation business.

Fitch observed that gross revenues in U.S. dollars increased by 8% in 2018 compared with 2017, excluding MSU Energy, which has yet to realize a full year of operations for all its facilities. The revenue increase is predominately explained by an increase of capacity in line with the 6% increase of total installed capacity of the country in 2018. Compared with 2017, gross revenues in U.S. dollars increased by 87% due to an increase in remuneration schemes associated to Energia Base payments, which comprises of approximately 60% of total payments.

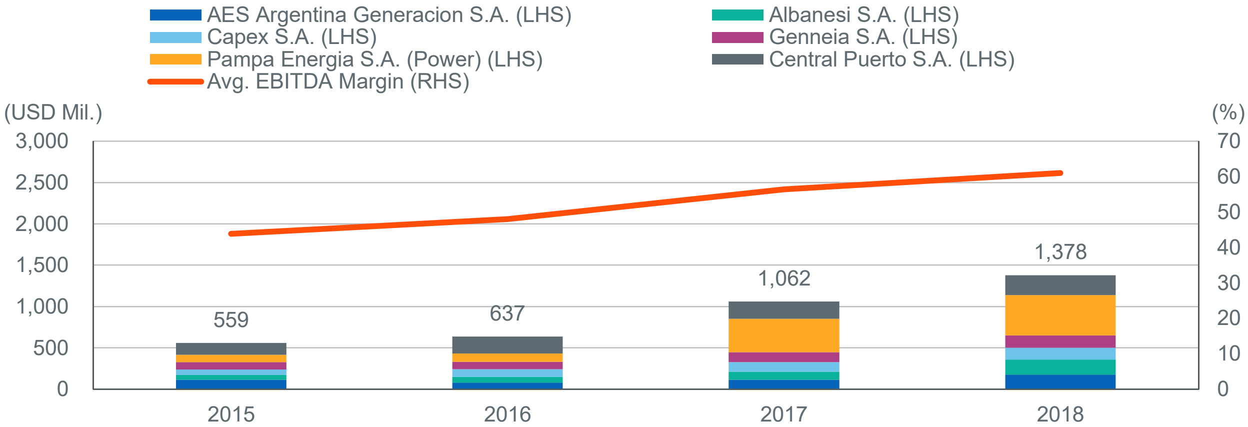
Gross Revenues



Source: Fitch Ratings, company filings.

Within Fitch's rated portfolio, EBITDA margins remain strong averaging 61% in 2018, a 9% increase compared with 2017 and a 39% improvement compared with 2015 EBITDA margins. Fitch expects EBITDA margins will improve in 2019 due to peso depreciation, which on average is 70% of operating costs for Fitch's rated portfolio while 100% of revenues are U.S. dollar denominated.

EBITDA



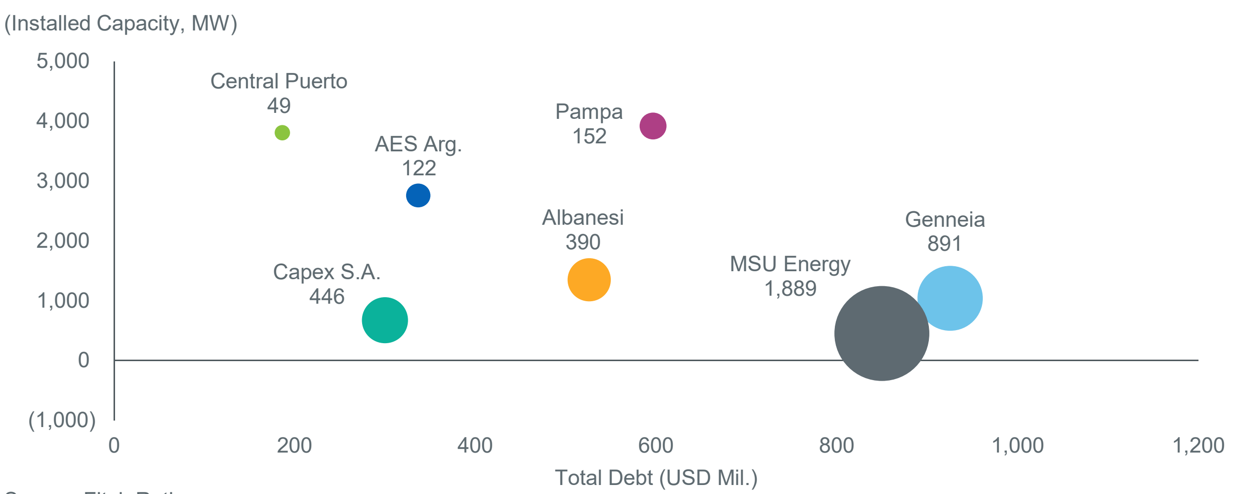
Source: Fitch Ratings, company filings.

Fitch believes a relevant metric to compare GenCos in Argentina is looking at their EBITDA/MW of installed capacity ratio, given they each operate under different remuneration schemes. Fitch's estimates illustrate there is a significant variance within its rated portfolio, best demonstrated by companies such as MSU Energy, Genneia and Albanesi, who were awarded purchase power agreements (PPAs) under Resolution 21, 286 and RenovAR. Furthermore, Albanesi and MSU Energy were awarded PPAs under Resolution 21. Similarly, Genneia has a high EBITDA/MW ratio due to its expansion in renewables under the RenovAR program, which Fitch estimates may increase to USD186,000/MW in 2021 once it completes its expansion pipeline. Moreover, thermal-based GenCos benefit from not incurring fuel costs, as CAMMESA provides gas and diesel fuel to the GenCos.

Comparatively, when plotting total debt/installed capacity, MSU Energy, Genneia and Albanesi have the highest debt/installed capacity due to them incurring debt to finance expansion plans, which are estimated to go online by first-half 2020. MSU Energy is expected to add an additional 300MW of installed capacity by June 2020, decreasing its total debt/MW ratio to USD1.1 million/MW from USD1.9 million/MW, remaining the highest in Argentina. Genneia will improve its ratio to USD640,000/MW, and Albanesi is expected to increase to approximately USD450,000/MW in 2020 considering the successful issuance of USD300 million of debt in 2019. Argentina's three largest power GenCos by installed capacity (Pampa Energia, Central Puerto and AES Argentina) have the lowest debt/MW ratios, due to their conservative expansion plans and capital structures.

Counterparty Risk

Total Debt (USD000)/MW



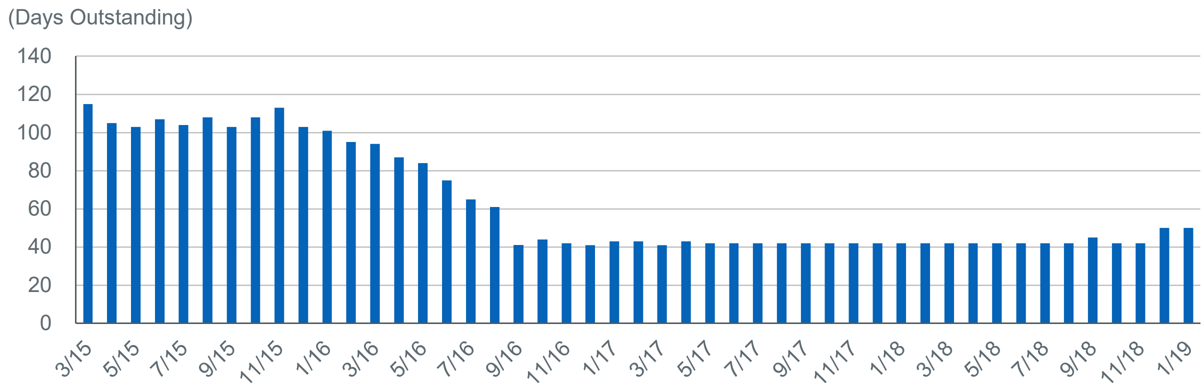
Source: Fitch Ratings.

Payment Delays

Ratings of Argentine utility companies are limited by the country ceiling of Argentina (B) as well as by the sector's exposure to receipt of subsidies from the government. Fitch believes Argentine GenCos face a heightened counterparty risk, as they depend on payments from CAMMESA, which acts as an agent on behalf of an association representing agents of electricity generation, transmission, distribution, as well as large consumers or wholesale market participants (Mercado Mayorista Eléctrico; MEM).

Although CAMMESA's payment track record has been consistent and on time, since 2015, historically, payments have been volatile given that the agency depends partially on the Argentine government for funds to make payments. The notable exceptions were a delay in September and December 2018 and January 2019 in the FX portion of CAMMESA's payment to market participants due to Argentina's currency crisis. Per the chart below, CAMMESA's payment days reach over 100 in 2015, but are normalized to 42 on average, increasing slightly to 50 in December 2018 and in January 2019 due to the peso devaluation during that period. To Fitch's knowledge, CAMMESA has not defaulted on any payments and has been paying interest on its delayed payments.

CAMMESA Payments

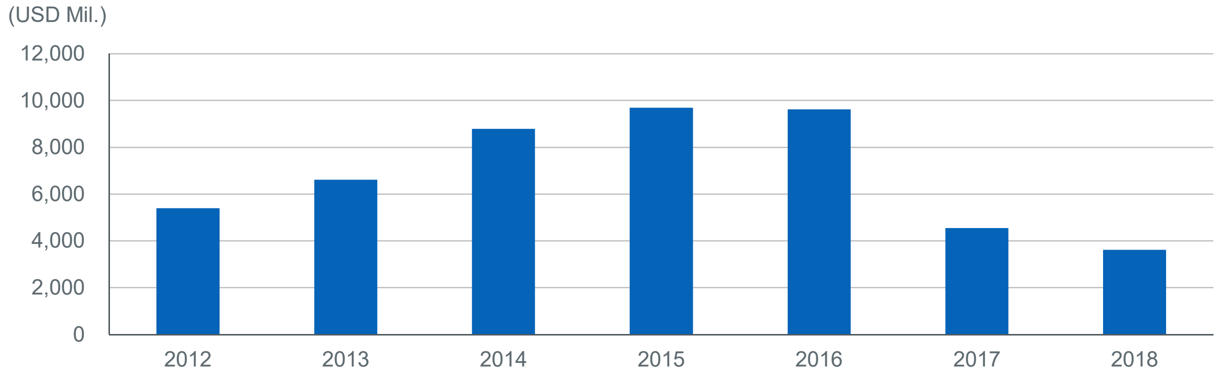


Source: CAMMESA.

Government Subsidies

Fitch estimates that government transfers to CAMMESA decreased 21% in 2018 compared with 2017 and 63% since 2015 when President Marci was inaugurated. Transfers to CAMMESA gradually decreased as tariffs increased in 2017 and 2018. Transmission and distribution tariffs were revised to narrow the deficit between cash inflows from end users to CAMMESA and outflows to generators from CAMMESA, but the tariff increases are not enough to keep the system balanced. Concurrent with the nominal decrease in transfers to CAMMESA, Fitch estimates the government was subsidizing less as far as a percentage of the total cost of the system. Per Fitch estimates, the USD3.6 billion of transfers in 2018 represents a subsidy of 35% of system cost, possibly USD10.2 billion in 2018, up 7% from USD9.5 million in 2017, when USD4.5 billion represented a 48% subsidy. In Fitch's view, this was a positive development compared with 2015 and 2016, when the system was entirely subsidized.

Government Transfers to CAMMESA



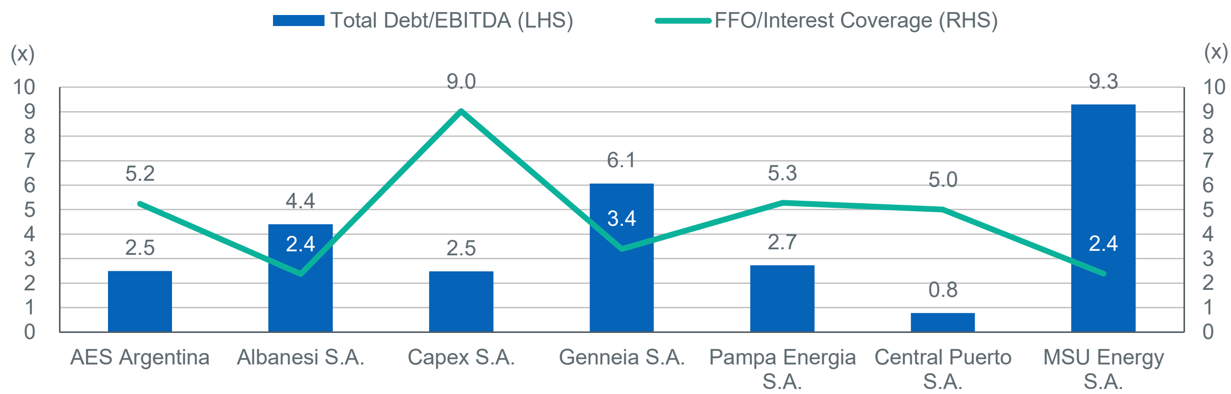
Source: Fitch Ratings, Argentine governement.

Fitch expects CAMMESA to rely on the government for more support as inflation and peso devaluation risks remain high, and cash payments to CAMMESA will not cover its PPAs. Since 2019 is an election year, Fitch believes the government will support CAMMESA and will not increase tariffs, given the current economic challenges of high inflation and high unemployment. After the election, there may be a short-term amendment to Energia's bases, which, again per Fitch's estimates, represents 60% of the cost of power generation or USD6.1 billion. This is a difficult option, as Argentina needs improvements to its installed capacity and an adjustment in Energia Base will further discourage efficiency investment, and further extend Argentina's current challenges.

Liquidity

On average, Argentina power companies are under-leveraged for their rating levels, as they are all restrained by the country ceiling of Argentina (B/Negative). Pampa, Central Puerto, AES Argentina and Capex SA are strongly positioned to weather any delays in payments, given their strong cash balances, while, Albanesi, Genneia and MSU Energy have tighter EBITDA to interest expense ratios and robust committed capex programs.

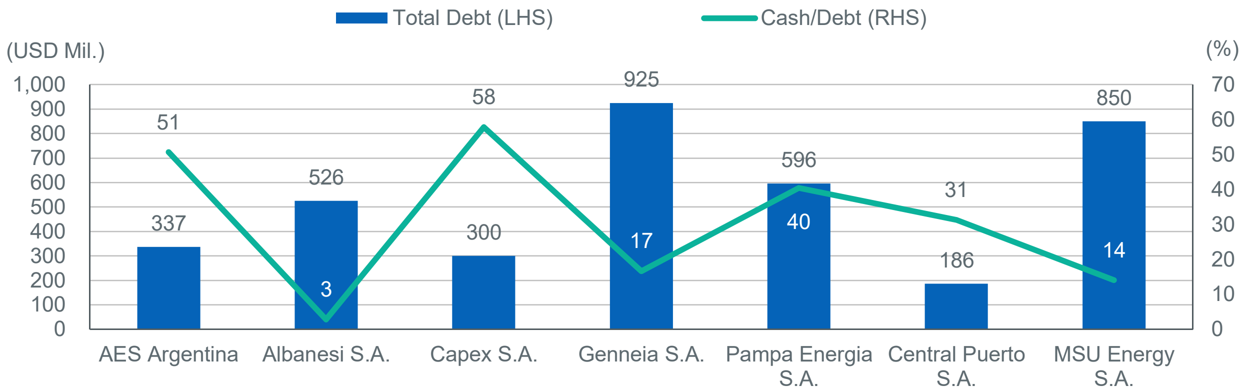
Credit Metrics — 2018



Source: Fitch Ratings, company filings.

Liquidity is a concern for the smaller, capex-committed companies such as Albanesi, Genneia and MSU Energy, compared with the rest of the portfolio who, on average, have a cash/total debt ratio of 42% coupled with a strong maturity profile. The smaller entities have weaker liquidity profiles, with cash covering less of a portion of debt, modestly covering expected interest expenses and less tolerant liquidity profiles to weather a delay in payments from CAMMESA, making them more risky than their counterparts, reflected in Albanesi and MSU Energy's ratings of 'B–'. Fitch estimates Genneia's liquidity will improve in 2019 and 2020 as a majority of expansion projects have been completed.

Cash Profile — 2018



Source: Fitch Ratings, company filings.

Appendix

Project Pipeline

Project Name	Sub-Sector	Value (USD Mil.)	Size (MW)	Operator	Status	Timeframe End
El Bracho Closed Cycle Plant, Tucuman	Thermal	320	261	YPF SA	Completed	2016
Rawson Wind Farm Expansion, Chubut (III)	Wind	33	25	Genneia	Completed	2017
Barker Thermal Power Plant, Buenos Aires	Thermal	225	150	MSU Energy	Completed	2017
General Rojo Thermal Power Plant, Buenos Aires	Thermal	225	150	MSU Energy	Completed	2017
Piedra Buena Power Plant Expansion, Santa Cruz	Thermal	140	100	Pampa Energia	Completed	2017
Loma La Lata Thermal Plant Expansion, Neuquen	Thermal	338	375	Pampa Energia	Completed	2017
CTLL	Thermal	90	105	Pampa Energia	Completed	2017
Pilar	Thermal	103	100	Pampa Energia	Completed	2017
Ing. White	Thermal	92	100	Pampa Energia	Completed	2017
Loma Campana	Thermal	78	105	YPF SA	Completed	2017
Timbues Thermal Power Plant, Santa Fe	Thermal	181	170	Albanesi	Completed	2018
Albanesi Power Plant, Rio Cuarto, Cordoba	Thermal		1,134	Albanesi	At planning stage	2018
La Castellana Wind Farm, Buenos Aires	Wind	148	99	Central Puerto	Completed	2018
Achiras	Wind	74	48	Central Puerto	Completed	2018
Chubut Norte I	Wind	50	28	Genneia	Completed	2018
Puerto Madryn I Wind Farm, Chubut	Wind	110	70	Genneia	Completed	2018
Ullum I, II & III Solar Plant, San Juan, Cuyo	Solar	79	82	Genneia	Completed	2018
Villalonga I Wind Farm, Bahia Blanca, Buenos Aires	Wind	82	55	Genneia	Completed	2018
Villa Maria Thermal Power Plant, Cordoba	Thermal	225	150	MSU Energy	Completed	2018
Corti Wind Farm, Bahia Blanca, Buenos Aires	Wind	175	100	Pampa Energia	Completed	2018
Mario Cebreiro	Wind	139	100	Pampa Energia	Completed	2018
YPF Thermoelectric Power Plant, Tucuman	Thermal	410	410	YPF SA	Completed	2018
Mendoza Thermal Power Plant Expansion, Lujan de Cuyo, Mendoza	Con-generation	91	93	Central Puerto	Under construction	2019
Neochea	Wind	31	38	Genneia	Under construction	2019
Pomona I Wind Farm, Rio Negro	Wind	135	101	Genneia	Under construction	2019
Puerto Madryn II Wind Farm, Chubut	Wind	236	150	Genneia	Completed	2019
Iglesia - Guanizuli Solar Plant, San Juan	Solar		80	Jinko Solar	Completed	2019
Genelba Gas-Fired Power Station Expansion Project, Marcos Paz, Buenos Aires	Thermal	350	196	Pampa Energia	Under construction	2019
Coronel Rosales Wind Farm, Buenos Aires (Corti) II	Wind	51	50	Pampa Energia	Under construction	2019
Coronel Rosales Wind Farm, Buenos Aires (Corti) IV	Wind	61	60	Pampa Energia	Under construction	2019
Coronel Rosales Wind Farm, Buenos Aires (Corti) III	Wind	51	50	Pampa Energia	Under construction	2019

Continued on next page.
Source: Fitch Ratings, Argentine Secretary of Energy.

Project Pipeline (Continued)

Project Name	Sub-Sector	Value (USD Mil.)	Size (MW)	Operator	Status	Timeframe End
Del Bicentenario I (PEBSA I) Wind Farm, Santa Cruz	Wind	125	100	Petroquímica Comodoro Rivadavia S.A.	Under construction	2019
Del Bicentenario II (PEBSA II) Wind Farm, Santa Cruz	Wind	31	25	Petroquímica Comodoro Rivadavia S.A.	Under construction	2019
Arroyo Seco Cogeneration Plant, Santa Fe	Con-generation		100	Albanesi	At planning stage	2020
Ezeiza Closed Cycle Plant, Buenos Aires	Thermal	160	150	Albanesi	At planning stage	2020
Rio Cuarto Closed Cycle Plant, Cordoba	Thermal		113	Albanesi	At planning stage	2020
San Pedro Closed Cycle Plant, Buenos Aires	Thermal		105	Araucaria Energy - Stoneway	At planning stage	2020
San Lorenzo Cogeneration Plant, Santa Fe	Con-generation	384	330	Central Puerto	Under construction	2020
La Genoveva I Wind Farm, Bahia Blanca, Buenos Aires	Wind	105	87	Central Puerto	Under construction	2020
La Florida - Biomass	Biomass	51	19	Genneia	Under construction	2020
Chubut Norte III Wind Farm, Chubut	Wind	59	58	Genneia	Under construction	2020
Chubut Norte IV Wind Farm, Chubut	Wind	84	83	Genneia	Under construction	2020
Villa Maria Closed Cycle Plant, Cordoba	Thermal	163	100	MSU Energy	Under construction	2020
Barker Closed Cycle Plant, Buenos Aires	Thermal	163	100	MSU Energy	Under construction	2020
General Rojo Closed Cycle Plant, Buenos Aires	Thermal	163	100	MSU Energy	Under construction	2020
San Jorge Wind Farm, Tornquist, Buenos Aires	Wind	125	100	Petroquímica Comodoro Rivadavia S.A.	Under construction	2020
El Mataco Wind Farm, Tornquist, Buenos Aires	Wind	125	100	Petroquímica Comodoro Rivadavia S.A.	Under construction	2020
Canadon Leon Wind Farm, Santa Cruz	Wind	180	100	YPF SA	Under construction	2020

Source: Fitch Ratings, Argentine Secretary of Energy.

Related Research

Fitch Affirms Argentina at 'B'; Outlook Negative (May 2019)
Sector Navigators (March 2018)

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Brazilian Electricity Sector

Growth in Demand and Low to Moderate Sector Risk Will Support New Investments

Better Than Average Risk: At low to moderate, Fitch Ratings considers Brazil's (BB–/Stable) electricity sector risk to be better than the average risk of other sectors within the country. The main pillars of the current regulatory framework were established in 2004. The federal government is addressing systemic problems affecting companies' cash flows, despite its intention to promote a lower tariff to final customers, and is having discussions to improve the regulatory framework and reduce the sector's risk. Credit profiles of participants in this sector benefit from a strategic importance to sustain the country's economic growth and foster new investments.

Risks Vary Among Segments: The transmission segment has the sector's lowest business risk, with highly stable and predictable EBITDA and margins typically above 80% with no volumetric risk. Credit profiles of distribution companies (DisCos) remain linked to volatility in demand, the ability to control manageable costs and secure positive results in periodic tariff reviews. Their capacity to temporarily absorb non-manageable costs above those included in the tariff is crucial. The risk in the generation segment varies according to the energy source; long-term power purchase agreements (PPAs) can provide some predictability to cash flow.

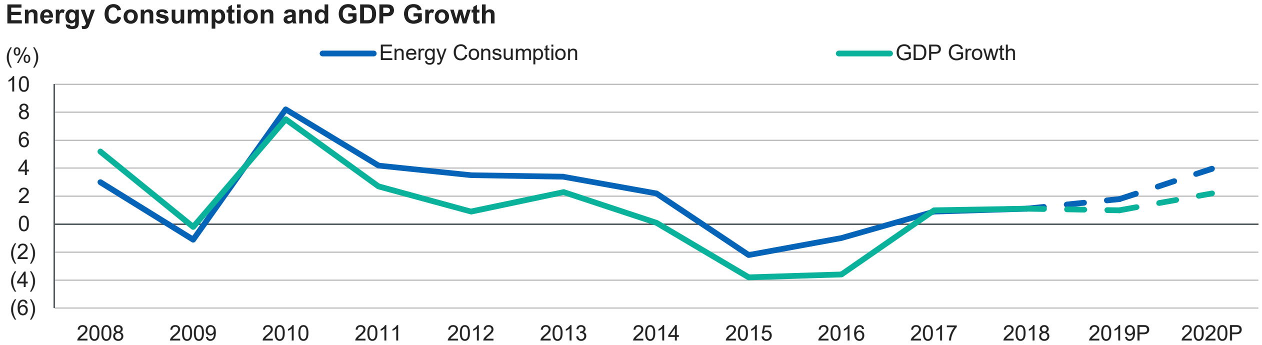
Demand Tracks GDP Growth: Energy consumption in Brazil closely followed the country's economic behavior as the residential segment was the main supporter of CAGR of 2.0% in the last five years. The commercial segment followed this trend, although results from Brazil's industrial sector suffered in the economic recession in 2015 and 2016. Companies in the Brazilian electricity sector should benefit as GDP is expected to increase by 1.0% in 2019 and 2.2% in 2020, according to Fitch's projections.

ANEEL to Promote Capacity Injections: The Brazilian energy regulator, the National Agency of Electric Energy or the Agencia Nacional de Energia Eletrica (ANEEL), should promote new auctions to expand transmission and generation capacity to meet demand growth. Fitch foresees strong competition to build new transmission assets and a variety of sources participating on generation bids, with the continuity of many wind farm projects included on the bids, and more solar projects. New hydroelectric and thermal plants should also participate in the expansion plan and these sources continue to be the most prevalent in the Brazilian energy matrix.

Credit Availability to Support Projects: Fitch does not see credit availability as a constraint for the development of new power projects in Brazil. Banks and capital markets continue to play an important role in financing the electricity sector despite the volatility of the nation's economy. Banco Nacional de Desenvolvimento Economico e Social (BNDES; BB–/Stable), which historically financed most of the capex for green-field projects, experienced a decline in lending due to a more aggressive debt capital market. Long-term financing at reasonable financial costs should remain.

Hydrology Risk to Remain: Electricity production in Brazil still relies heavily on hydroelectric plants, which pose a hydrology risk to the system, despite the growth of wind farms in the last 10 years. Hydroelectric plants accounted for 72% of the country's effective energy generated in 2018 and represented 64% of total installed capacity at year end. Fitch foresees reservoirs will be below average at YE 2019, despite the recovery in first-half 2019. Hydroelectric generators should continue to be negatively affected by a generation scaling factor (GSF) below 1.0, which affects sales capacity.

Energy Consumption and GDP Growth



P – Projection.
Source: Fitch Ratings, Energy Research Company.

Primary Market Considerations

Growth Prospects

Growth in demand for electricity is expected to continue closely following GDP performance. CAGR for demand in electricity in the past 10 years was 2.0%, while Brazil's GDP CAGR for the same period was 0.9%. Consumption experienced a positive recovery of 1.2% in 2017 and 1.1% in 2018 after declining in the previous two years, with weaker performance in 2015 and 2016, reflecting the Brazilian economic recession in the industrial segment. Residential and commercial segments have been the main drivers of higher demand in electricity. The organization responsible for demand projection, the Energy Research Company, or Empresa de Pesquisa Energertica (EPE), forecasts annual growth in demand to average 2.3% for 2018–2027. Growth in 2018 was lower and the weak economic recovery in 2019 should lead to another year of repressed growth.

Energy Consumption per Consumer Category

(GWh)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	CAGR (%)
Residential	94,746	100,776	107,215	111,971	117,646	124,908	132,399	131,314	132,893	134,368	137,615	3.8
Industry	175,834	161,799	179,478	183,576	183,425	184,685	179,618	169,574	164,034	167,398	169,625	(0.4)
Commercial	61,813	65,255	69,170	73,482	79,226	83,704	89,255	90,383	88,185	88,292	88,631	3.7
Others	56,079	56,477	59,820	64,006	67,808	69,838	74,987	75,099	74,985	77,103	78,950	3.5
Total (Regulated and Free)	**388,472**	**384,306**	**415,683**	**433,034**	**448,105**	**463,134**	**474,823**	**465,714**	**461,780**	**467,161**	**474,820**	**2.0**

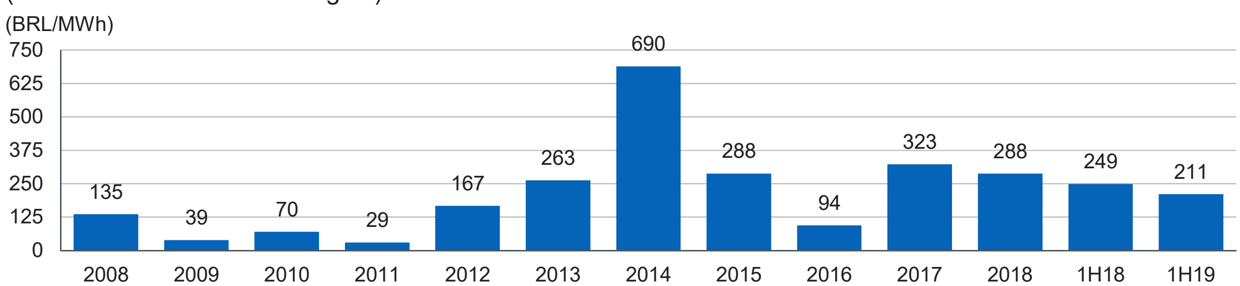
Source: Fitch Ratings, Energy Research Company.

The risk of a supply/demand imbalance due to a failure to meet growth in demand as a result of generation and transmission infrastructure constrains is being mitigated by the government's recurring auctions promoted by ANEEL. The Ministry of Mines and Energy, or Ministerio de Minas e Energia (MME), through EPE, consistently prepares a 10-year plan, which is used by ANEEL to aid the bidding process for all generation and transmission capacity additions in the country. The main hurdle that could cause delays to the entrance of new capacity relates to the potential long lead times for obtaining the environmental permits required to initiate construction and operation of generation plants and transmission lines.

Pricing

Generators may sell electricity to DisCos through auctions promoted by the regulator with a price cap or to commercialization companies and unrestricted consumers through bilateral negotiations. DisCos are only allowed to acquire energy through auctions. In the case DisCos do not have PPAs to support demand, they become exposed to the spot market to buy a complementary energy volume. The price in the spot market is based on the settlement price of differences, or preço de liquidação das diferenças (PLD), which is based on a formula defined by ANEEL. The historically high volatility of the PLD is considered a risk for generators and distributors as it may affect cash flow generation.

Spot Market Energy Prices
(Southeast/Central-West Region)



Note: The spot market price is based on the preço de liquidação das diferenças or settlement price of differences.
Source: Fitch Ratings, Electric Energy Commercialization Chamber.

The government set the maximum PLD at BRL513.89/MWh in 2019 from BRL505.18/MWh in 2018. The maximum PLD corresponds to the highest unit variable cost or custo variavel unitario (CVU) of a gas thermal plant in operation. At the same time the minimal PLD was raised to BRL42.35/MWh from BRL40.16/MWh and reflects the highest price between the annual revenue generation of the hydroelectric plants on the quota regimen and expectations for the generation cost of Itaipu Binacional. The effective PLD is settled weekly based on the operational marginal cost, which is the cost necessary to meet an additional 1MWh of demand, using the existing resources.

Brazil's energy tariffs used to be among the lowest in the region, mainly due to the country's energy matrix based on low-cost hydroelectric generation. The unfavorable hydrological conditions increased energy acquisition costs and pressured tariffs on end users, with higher participation of more expensive thermal plants and other energy sources in the Brazilian energy matrix. The higher energy costs were directly transferred to consumer tariffs through DisCos' annual tariff adjustments, with the adoption of a tariff flag mechanism in 2015 to mitigate DisCos' liquidity risk. This specific risk is associated with potential disbursement mismatch in energy purchases due to potential massive thermal plants dispatch that may occur between two tariff adjustments, as monthly cash disbursements to acquire energy can be higher than contemplated on a tariff.

In order to adjust system revenue depending on hydrology conditions, ANEEL defines four different tariff flags: green, yellow, red level one and red level two. These are applied on a monthly basis to end user tariffs. The green flag means normal conditions and no extra cost for consumers, while the yellow and the two red levels mean BRL0.015, BRL0.04 and BRL0.06 per KWh of consumption, respectively. The entire revenue from the tariff flag is centralized in a pool and transferred to distributors in accordance with each particular need to cover cost deficits. Depending on the extra energy cost, revenue from a tariff flag may not be enough to cover the entire gap.

Regulatory Overview

Regulatory Framework

The main pillars of Brazil's current regulatory framework were implemented in 2004 and cover the generation, transmission and distribution segments of the electricity industry. Among the objectives arising from the regulation are the safety and expansion of the generation and transmission capacities, efficiency and quality for the distribution companies, universalization of the electric-energy service to the entire population and the lowest tariff possible to end consumers. For the generation segment, the objective of the regulation is to encourage private and public investment and ensure an adequate supply of electric energy in the country. The implementation of the new regulatory framework created two different environments for selling energy: the regulated contracting environment, or the ambiente de contratação regulada (ACR) and the unrestricted contracting environment, or the ambiente de contratação livre (ACL).

The ACR allows distributors to acquire energy through ANEEL-promoted public auctions to ensure energy supply for captive users. DisCos' demand forecasts are the main factor in determining the volume of energy to be contracted by the system and the additional generation capacity to be built. According to the model, DisCos are obligated to sign PPAs supplying 100%–105% of the entire estimated needs for the next five years. DisCos are subject to penalties in the event of failure to comply with the minimal level established in this rule. The energy contracted above 105% is not contemplated in the tariff and therefore is sold in the spot market, representing price risk to the DisCos in the event the spot prices are lower than the price mix on the PPAs.

The ACL allows energy commercialization through bilateral contracts between generators and trading companies, unrestricted consumers, importers and exporters of electric energy. These contracts are generally for shorter terms in nature compared with those under ACR. The prices and volumes of energy transactions under ACL are freely established. A consumer is considered potentially unrestricted when, among other factors, demand exceeds 3MW. In the case of consumers with energy contracted equal to, or greater than, 500kW energy can be contracted directly from small hydroelectric plants or from special sources such as biomass, wind and solar.

Once a potentially unrestricted consumer opts for an ACL contract, the consumer can only return to the regulated environment if the local distributor is notified five years in advance, or sooner, at the distributor's discretion. This requirement is designed to ensure the distributor can contract the supply of energy necessary to meet the returning consumer's demand. In order to minimize the effects arising from migrating unrestricted consumers, under certain circumstances, DisCos can reduce the amount of energy contracted from the generators that was initially estimated.

Energy generators are qualified to sell electric energy in both environments, whether public utility concession holders, independent producers or self-producers, and trading companies. All contracts are registered with the Electric Energy Commercialization Chamber, or Camara de Comercializacao de Energia Eletrica (CCEE). Similar to DisCos' requirement to contract energy needs, energy sellers are required to support contracts with physical generation capacity or third-party energy purchase contracts. All DisCos must communicate energy needs and contractual requirements for each of the preceding five years to the MME.

Based on this information, the MME defines the total amount of energy to be sold in the ACR and the list of generation units that can participate in the auctions, which may be from different sources. Energy auctions are prepared by CCEE, based on guidelines from the MME, mainly using the lowest tariff offered to allocate contracts. Each generating company selling energy through an auction signs a regulated environment energy purchase and sale contract, or contrato de compra e venda de energia no ambiente regulado (CCEAR) with each distribution company, proportional to the distributor's estimated demand.

The energy auctions for new generation projects, which are designed to promote the construction of new capacity to meet distributors' consumption growth, can be held from three to six years before the date of initial delivery. The purpose of different timeframes for the auctions is to correct demand supply imbalances. The typical duration of a CCEAR is 15 to 30 years. Auctions for existing electric generation assets are held one to two years before the initial energy delivery date and the contracts range from one to five years. MME may promote specific auctions to contract energy provided by alternative sources, such as biomass, wind, small hydroelectric plants and more recently, solar. These contracts are intended to meet specific energy policy proposals. Auctions can be nominated as structure project auctions, which seek to promote specific projects considered strategic for Brazil, such as hydroelectric power plant Belo Monte, and reserve auctions, which are designed to increase the reliability of the system.

Regulatory Bodies

The following institutions are the main entities defining policies and rules guiding and influencing the electricity sector in Brazil:

Ministry of Mines and Energy

MME is the federal government entity responsible for conducting Brazil's energy policies. MME's main obligations include formulating and implementing energy policies. The organization is responsible for establishing the planning for the national energy sector, monitoring supply security and granting concessions.

National Agency of Electric Energy

ANEEL is a regulatory body that is part of MME and is in charge of setting regulation and supervising the sector, while seeking to make services universally available. ANEEL's mission is to provide favorable conditions for the electric power market to develop a balance between market participants, while benefiting end users.

Electric Energy Commercialization Chamber

The CCEE is comprised of generation, distribution and commercialization agents, and unrestricted consumers. The organization's main responsibilities include recording all ACR and ACL contracts, measuring and recording generation and consumption data for all CCEE agents, calculating the PLD for the spot market and promoting electric energy auctions, as delegated by ANEEL.

National System Operator

The National System Operator or Operador Nacional do Sistema (ONS) is responsible for coordinating and controlling the electric energy generation and transmission operations in the National Interconnected System, or Sistema Interligado Nacional (SIN). The ONS is supervised and regulated by ANEEL and the organization's objectives and main responsibilities include ordering the dispatches of generating agents when dispatching is handled on a centralized basis.

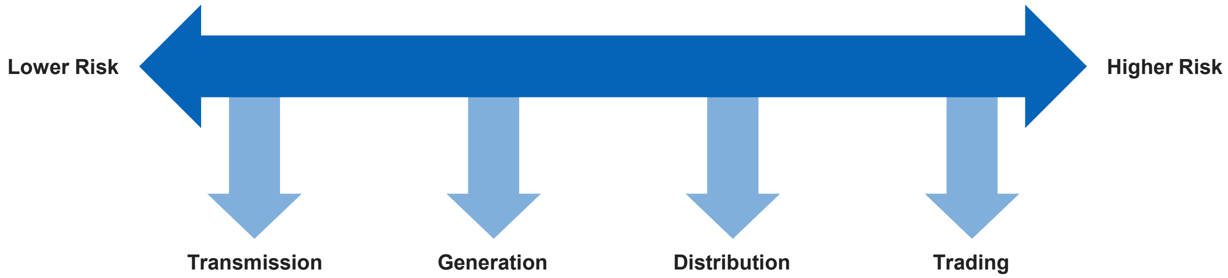
Energy Research Company

EPE's purpose is to provide services for studies and research designed to support planning in the energy sector, such as electric energy, petroleum, natural gas and derivatives, coal, renewable energy sources and energy efficiency.

Industry Structure

The Brazilian electricity sector is organized in three main segments: generation, transmission and distribution. There are also several energy trading, or commercialization, companies in the country. Fitch considers the transmission segment carries the lowest risk, with a natural monopoly, no volumetric risk, predictable regulated tariffs and high operating margins. The risk in the generation segment varies with the source but typically benefits from some predictability in cash flow provided by PPAs and usually has lower business risk than the distribution segment. We consider Brazil's DisCos business risk higher than in other countries in the region as it carries not only demand volatility but also higher uncertainty related to tariff reviews, which can be retroactive and can have a higher effect on cash flow generation. The highest risk is in trading companies, mainly due to the volatility of energy prices and low margins.

Scale of Risk

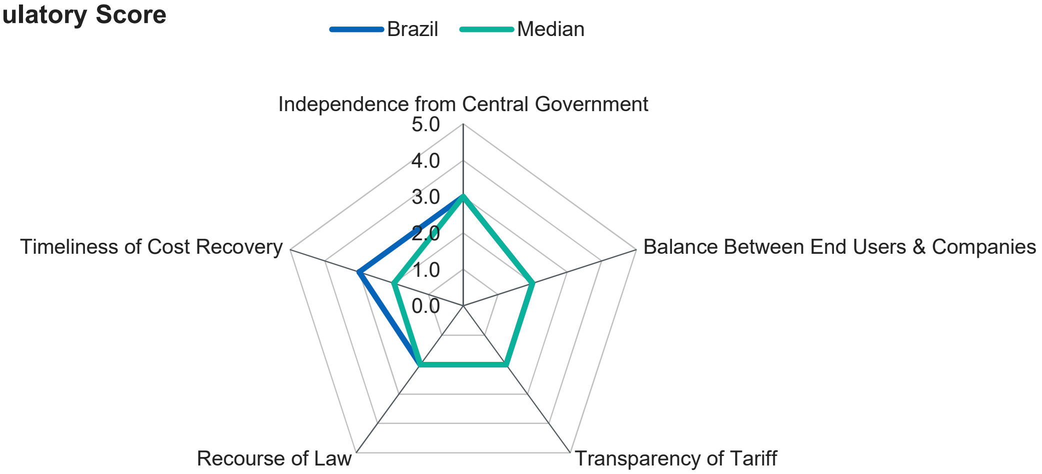


Source: Fitch Ratings.

Regulatory Risk

Fitch considers Brazil's regulatory risk for the energy sector as low to moderate. The regulator is sensitive to companies' needs in order to keep the balance of the concessions, despite a track record of changes in rules. Tariff settings for new projects are predefined, while tariff adjustment mechanisms for existing concessions, including those related to distribution companies, are being generally respected. Brazil's rated regulatory risk is comparable with a 'BBB' category, while the median for the region is commensurate with a 'BB' category.

Brazilian Regulatory Score



Note: 1.0 = A; 2.0 = BBB; 3.0 = BB; 4.0 = B; 5.0 = CCC.
Source: Fitch Ratings.

Select Regulatory Events Timeline

Select Regulatory Events Timeline

Year	Month	Event
2019	June	Auction of 402MW of generation capacity.
	Jan.	Start of the fifth DisCos tariff review cycle.
2018	Dec.	Publishing of the 2027 energy 10-year expansion plan.
		Eletrobras' DisCos subsidiaries auction: CEAL and Amazonas.
		Auction of 7,200km of transmission lines for a total of 8,400km in 2018.
	Aug.	Auction of 2.1GW of generation capacity for a total of 3.1GW in 2018.
		Eletrobras' DisCos subsidiaries auction: CERON, Eletroacre and Boa Vista.
2017	Dec.	Auction of 3.8GW of generation capacity for a total of 4.5GW in 2017.
		Auction of 4,900km of transmission lines for a total of 12,300km in 2017
	July	Publishing of the decree regulating electric energy trading.
	Feb.	Eletrobras' DisCo subsidiary auction: Celg Distribuicao S.A.
2016	Oct.	Auction of 6,100km of transmission lines for a total of 8,600km in 2016.
	Sept.	Auction of 180MW of generation capacity for a total of 709MW in 2016.
2015	Nov.	Auction of 1.5GW of generation capacity for a total of 5.4GW in 2015.
	July	Auction of 2,500km of transmission lines for a total of 5,400km in 2015.
	May	Creation of the tariff flag system.
	Jan.	Start of the fourth DisCos tariff review cycle.

Discos – Distribution companies. Eletrobras – Centrais Eletricas Brasileiras S.A. (Eletrobras). CEAL – Companhia Energetica de Alagoas. Amazonas – Amazonas Distribuidora de Energia S.A. CERON – Centrais Eletricas de Rondonia S.A. Eletroacre – Eletrobras Distribuicao Acre. Boa Vista – Boa Vista Energia S.A.
Source: Fitch Ratings.

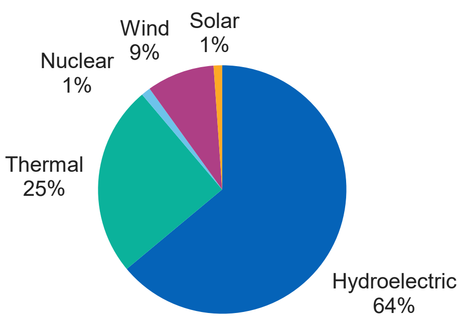
Generation

Brazil's power generation segment is predominately based on run-of-the-river and dam-based hydroelectric plants, representing 64% of the country's 165,468MW of installed capacity as of July 2019. An important amount of the remaining generating capacity is derived from thermal plants fired by gas, diesel, coal and sugar cane bagasse at 25% and, more recently, wind farms at 9%. To supply electricity to meet the growing demand, Brazil expects to add 22GW to installed capacity in the next few years through 205 projects under construction and 388 projects about to start the construction phase.

Centrais Eletricas Brasileiras S.A. (Eletrobras; BB–/Stable) had the largest market share in installed capacity at 26.3% as of 2018. Among the 10 largest energy generation companies, four are also state-owned companies at 15.4% of installed capacity: Itaipu, Petroleo Brasileiro S.A. (Petrobras: BB–/Stable), Companhia Energetica de Minas Gerais (CEMIG; B+/Positive) and Companhia Paranaense de Energia (COPEL; AA[bra]/Stable).

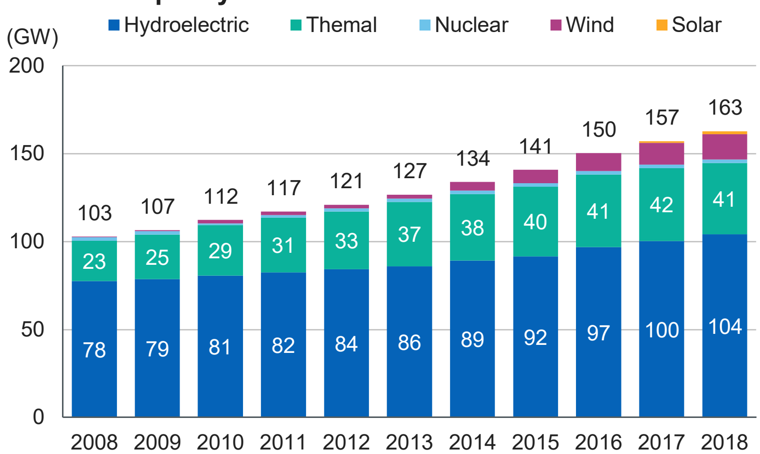
The five largest private companies are Engie Brasil Energia S.A. (BB/Stable), China Three Gorges Brasil Energia Ltda. (CTG Brasil), CPFL Energia S.A. (AAA[bra]/Stable), Enel Brasil S.A. (AAA[bra]/Stable) and AES Tiete Energia S.A. (AA+[bra]/Stable) representing 16.1%. The remaining 57.6% of capacity is diversified, since there are many generators in the country. Fitch expects an increase in the market share of private companies in energy generation in installed capacity in the future due to the reduction of the presence of state-owned agents in the development of new projects under construction, mainly Eletrobras, and some privatizations.

2018 Installed Capacity



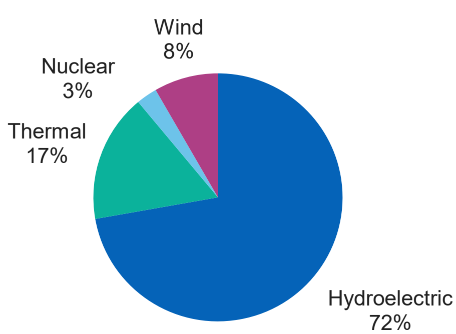
Source: Fitch Ratings, Energy Research Company.

Installed Capacity



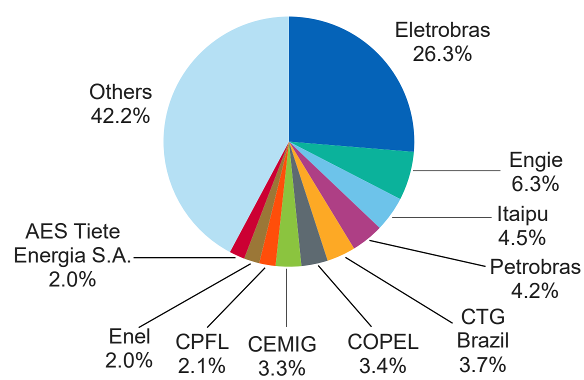
Source: Fitch Ratings, Energy Research Company.

2018 Energy Dispatch



Source: Fitch Ratings, National System Operator.

Installed Capacity per Issuer

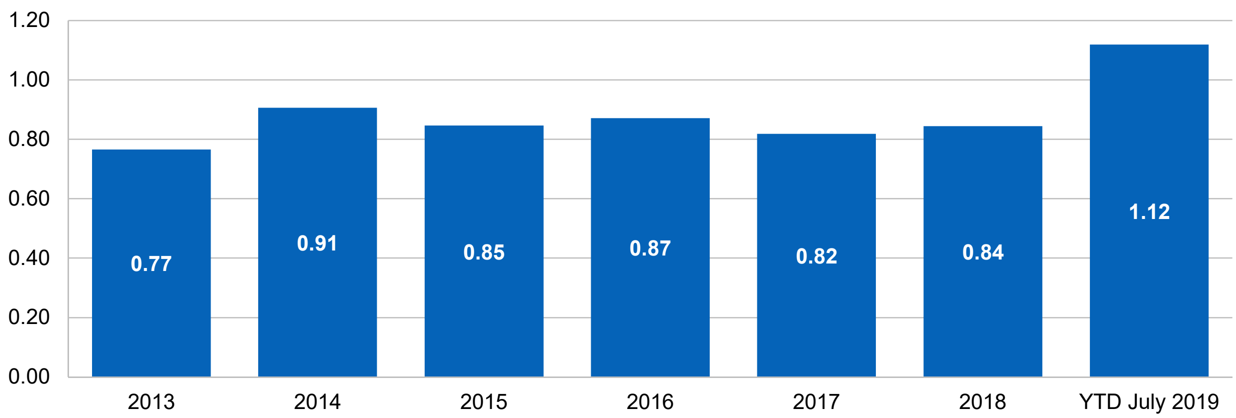


Eletrobras – Centrais Eletricas Brasileiras S.A. (Eletrobras). Engie – Engie Brasil Energia S.A. Itaipu – Itaipu Binacional. Petrobras – Petroleo Brasileiro S.A. (Petrobras). CTG Brasil – China Three Gorges Brasil Energia Ltda. COPEL – Companhia Paranaense de Energia (COPEL). CEMIG – Companhia Energetica de Minas Gerais (CEMIG). CPFL – CPFL Energia S.A. Enel – Enel Brasil S.A.
Source: Fitch Ratings, Engie Brasil Energia S.A.

In Brazil, the ONS dispatches power plants to optimize the use of the generation system. Brazil initiated the energy reallocation mechanism, or the mecanismo de realocação de energia (MRE), given the country's dependence on hydrology and the goal to reduce the risk associated with this energy source. MRE is designed to share the hydrology risk among all the hydroelectric plants and allocates to each plant an amount of energy to be commercialized, or assured energy, regardless of individual production. MRE transfers excess generation from plants generating above assured energy to those generating below assured energy. ANEEL is responsible for setting the assured energy levels of each hydroelectric generation project based on statistical models, which can be revised.

Considering the MRE is important in reducing hydrological risk for generators, all the hydroelectric plants' effective dispatch may be lower than the entire assured energy in certain circumstances. When this scenario occurs, the called GSF is below 1.0 and hydroelectric generators cannot count on total assured energy to meet energy sales obligations. In order to mitigate this risk, which became frequent in the last few years, companies are trying to leave part of the assured energy uncontracted or are buying energy from third parties to build in protection. The regulator also offered another possibility to generators, which was to contract specific insurance to cover total or part of the exposure to a GSF below 1.0. Hydroelectric generators considered this insurance attractive only for sales contracts to DisCos at the ACR.

Generation Scaling Factor: Yearly Average



Source: Fitch Ratings, Electric Energy Commercialization Chamber.

Distribution

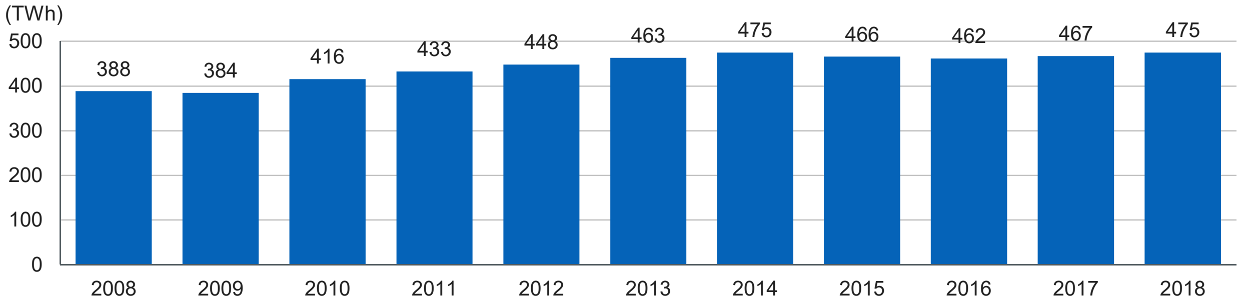
The electric energy distribution market is divided among 109 entities (53 concessionaires) covering the entire country, with approximately 84 million connections at YE 2018. Residential users represent the bulk of connections at approximately 86%. The federal government, through the Light for All Program or Programa Luz Para Todos (PLPT) and in partnership with distributors, seeks to provide electricity distribution service to all Brazilians. DisCos' tariffs in Brazil are regulated, with annual adjustment and tariff reviews every three to five years.

ANEEL is entrusted with adjusting and revising distribution tariffs according to stipulations under each distribution concession. To calculate annual tariff adjustments a distributor's revenue is divided into two components: Portion A and Portion B. Portion A seeks to compensate a distributor's non-manageable costs, such as energy purchases, sectorial charges and energy transportation, which are fully passed through to end users. Portion B seeks to compensate distributors for manageable costs, such as personnel, material, third-party services and others. Portion B seeks to remunerate the capital invested and is adjusted annually by the General Market Price Index or Indice Geral de Preços do Mercado (IGP-M).

The annual tariff adjustment also includes financial components, comprised of non-manageable cost variations between two annual tariff adjustments, with the expectation to compensate those variations through tariffs in the following 12 months. ANEEL reviews distribution concession tariffs every three to five years, depending on the concessionary, as each one has its own calendar, to reassess the calculation for Portion B of the tariff. These reviews are designed to ensure DisCos receive necessary revenue to cover what the regulator considers efficient costs and an adequate compensation for investments.

The DisCos already passed the fourth tariff review and in Fitch's view this cycle is not negatively pressuring the companies' operational cash flow, which is different from the previous two review cycles. During the tariff review and the annual tariff adjustments, an additional adjustment factor (X factor) is also applied. The purpose of the X factor is to pass to consumers potential productivity gains related to market growth and an increase in consumption of existing customers. In most cases, the X factor works to reduce the IGP-M's effect on the annual tariff adjustments. The X factor has three components: Pd, linked to the DisCos' productivity gains; Q, incorporating the service quality; and T, which adjusts through a defined period the operational costs of each DisCo to an efficient operational cost.

Energy Consumption



Source: Fitch Ratings, Energy Research Company.

Transmission

Electricity transmission infrastructure plays a key role for the Brazilian energy sector, given the size of the country and sometimes the long distance between generation and consumption locations. Generation capacity additions are sometimes developed in more remote regions of the country, while demand is more concentrated in south and southeast regions. This resulted in significant investment needs in the country to maintain a strong electricity market and prevent supply and demand imbalances due to transmission constraints.

Brazil's SIN includes the entire electric energy transmission infrastructure and covers all the country, with the exception of part of the North Region. SIN's main network was comprised of 145,500km of transmission lines at YE 2018 with voltages from 230kV to 800kV. Power transmission companies receive the permitted annual revenue, or receita anual permitida (RAP), established in the concession contract. The RAP compensates concessionaires for making power transmission facilities available to users of the basic grid and transmission subsystems and is not linked to the volume of power transmitted. The source to pay transmission companies is from the Transmission System Usage Tariff, or tarifa de uso do sistema de transmissão (TUST), charged to distributors, generators, unrestricted consumers and special consumers, with the diversified client base and guaranteed payment structure being positive characteristics.

RAP is subject to annual adjustments to offset inflation rate fluctuations, as measured by the IGP-M or the Broad Consumer Price Index, the Indice Nacional de Preços ao Consumidor Amplo (IPCA), and investments previously approved by ANEEL. RAP can be adjusted under certain extraordinary circumstances, such as changes to tax legislation and investments not previously approved by ANEEL. RAP adjustment also includes surplus or deficit revenue corrections during any previous year, an adjustment portion, and adjustments due to operational interruptions, planned or not. The adjustments occur every July 1, based on the period from June of the previous year to May of the reference year. Tariff reviews occur every five years for the concessions granted after 2006, while previous concessions are subject to a 50% RAP reduction after 15 years of operations.

Corporates

Brazilian Electricity Portfolio

Issuer	National Scale	LT FC IDR/ LT LC IDR	Outlook
Aliança Geracao de Energia S.A.	AAA(bra)	—	Stable
Alupar Investimento S.A.	AAA(bra)	BB/BBB–	Stable
Ampla Energia e Servicos S.A.	AAA(bra)	—	Stable
Celg Distribuicao S.A.	AAA(bra)	—	Stable
Companhia Energetica do Ceara (Coelce)	AAA(bra)	—	Stable
CPFL Energia S.A.	AAA(bra)	—	Stable
CPFL Geração de Energia S.A.	AAA(bra)	—	Stable
CPFL Paulista S.A.	AAA(bra)	—	Stable
CPFL Piratininga S.A.	AAA(bra)	—	Stable
CPFL Energia Renovaveis S.A.	AAA(bra)	—	Stable
Companhia de Transmissao de Energia Eletrica Paulista S.A. (CTEEP)	AAA(bra)	—	Stable
EDF Norte Fluminense S.A.	AAA(bra)	—	Stable
Eletropaulo Metropolitana Eletricidade de Sao Paulo S.A.	AAA(bra)	BB+/BBB–	Stable
Enel Brasil S.A.	AAA(bra)	—	Stable
Energisa S.A.	AAA(bra)	BB/BB+	Stable
Energisa Minas Gerais – Distribuidora de Energia S.A.	AAA(bra)	BB/BB+	Stable
Energisa Mato Grosso do Sul – Distribuidora de Energia S.A.	AAA(bra)	—	Stable
Energisa Mato Grosso – Distribuidora de Energia S.A.	AAA(bra)	—	Stable
Energisa Paraiba – Distribuidora de Energia S.A.	AAA(bra)	BB/BB+	Stable
Energisa Sergipe – Distribuidora de Energia S.A.	AAA(bra)	BB/BB+	Stable
Energisa Sul Sudeste – Distribuidora de Energia S.A.	AAA(bra)	—	Stable
Energisa Tocantins – Distribuidora de Energia S.A.	AAA(bra)	—	Stable
Energisa Transmissão de Energia S.A.	AAA(bra)	—	Stable
Engie Brasil Energia S.A.	AAA(bra)	BB/BBB–	Stable
RGE Sul Distribuidora de Energia S.A.	AAA(bra)	—	Stable
Taesa S.A.	AAA(bra)	BB/BBB–	Stable
AES Tiete Energia S.A.	AA+(bra)	—	Stable
Eneva S.A.	AA+(bra)	—	Stable
Centrais Eletricas de Santa Catarina S.A. (Celesc)	AA(bra)	—	Stable
Celesc Geracao S.A.	AA(bra)	—	Stable
Centrais Eletricas Brasileiras S.A. (Eletrobras)	AA(bra)	BB–/BB–	Stable
Companhia Paranaense de Energia (COPEL)	AA(bra)	—	Stable
Copel Distribuicao S.A.	AA(bra)	—	Stable
Copel Geracao e Transmissao S.A.	AA(bra)	—	Stable
Furnas Centrais Eletricas S.A.	AA(bra)	BB–/BB–	Stable
Itaipu Binacional	AA(bra)	—	Stable
Centrais Eletricas do Para S.A. (Celpa)	AA–(bra)	—	Stable
Companhia Energetica do Maranhao (Cemar)	AA–(bra)	—	Stable
Light S.A.	A+(bra)	BB–/BB–	Stable
Light Energia S.A.	A+(bra)	BB–/BB–	Stable
Light Serviços de Eletricidade S.A.	A+(bra)	BB–/BB–	Stable
Companhia Energetica de Minas Gerais (CEMIG)	A–(bra)	B+/B+	Positive
CEMIG Distribuicao S.A.	A–(bra)	B+/B+	Positive
CEMIG Geracao e Transmissao S.A.	A–(bra)	B+/B+	Positive
Matrix Comercializadora de Energia Eletrica S.A.	BBB(bra)	—	Stable

LT – Long-Term. FC – Foreign Currency. LC – Local Currency. IDR – Issuer Default Rating.
Source: Fitch Ratings.

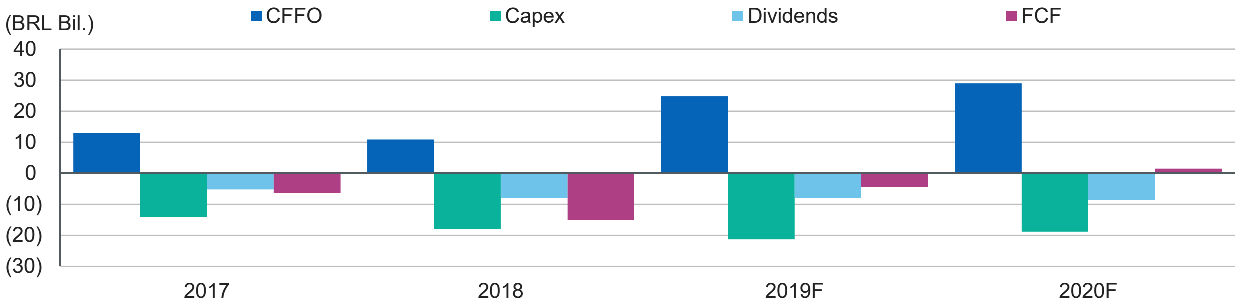
Credit Profile

Fitch's electricity portfolio in Brazil consists of a large number of companies operating in different segments. Ratings tend to be higher than those assigned to issuers in other sectors. Typically 100% of revenue for power companies is in Brazilian reals and Foreign Currency (FC) Issuer Default Ratings (IDRs) are limited by Brazil's Country Ceiling (BB). The exception is the FC IDR of Eletropaulo Metropolitana Eletricidade de Sao Paulo S.A. (BB+/Stable) as the analysis of this entity incorporates the *Parent and Subsidiary Rating Linkage* criteria and enables the FC IDR to be rated one notch above the Country Ceiling. Fitch considers the legal, operational and strategic ties between Eletropaulo and its indirect controlling shareholder Enel Americas S.A. (BBB+/Stable) as strong. We also consider, as appropriate, a maximum three-notch distance between the Local Currency IDRs for Brazilian power companies and the Brazilian Sovereign Rating of 'BB–' due to the regulated nature of this sector. There is no exception to this standard in Fitch's current portfolio of Brazilian power companies.

Cash Flow

On a combined basis, Fitch expects its portfolio of rated Brazilian power companies to present higher cash flow from operations in 2019 and 2020, mainly driven by distribution companies that should benefit from higher energy sales and the recovery through the tariff of non-manageable costs incurred in 2018. This scenario tends to mitigate increasing capex and somewhat stable dividend payments, delivering more favorable FCFs compared with the previous two years.

Fitch's Electric Energy Portfolio: Cash Flow

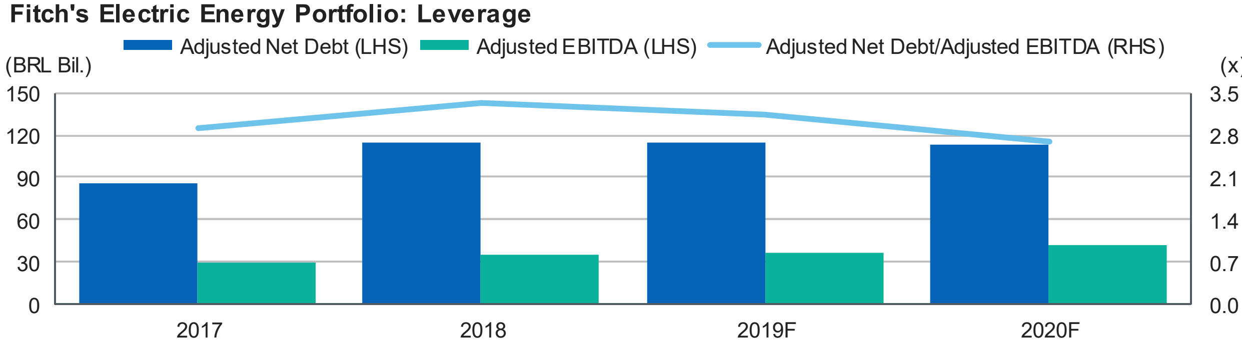


CFFO – Cash flow from operations. F – Forecast.
Source: Fitch Ratings.

Leverage

Fitch estimates overall net leverage for Brazilian power companies to decline in the next couple of years. According to our projections, this ratio should remain in the range of 2.5x–3.5x, which is considered as appropriate for the sector. For companies with operations more related to transmission and generation, adjusted net debt/adjusted EBITDA would trend toward 2.0x, which is very conservative considering the higher predictability of results in these segments.

Fitch's Electric Energy Portfolio: Leverage



F – Forecast.
Source: Fitch Ratings.

Liquidity

Brazilian power companies usually benefit from high financial flexibility and carry strong cash balances to support short-term debt maturities. The sector has ample access to the debt capital market and to bank financing to support capex for new projects and rollover debt, if necessary. BNDES is also an alternative to funding. For this sector, it is crucial to raise cash through debt with a long-term maturity schedule, mainly when the purpose is to support new projects.

Outlooks

2019 Fitch Ratings Outlooks
Fitch Ratings 2019 Outlook: Latin American Corporates (Navigating the New Political Landscape) (December 2018)

Related Research

Latin American Corporate View as of April 2019 (Fitch Forecasts Evolved In an Active Last 12 Months) (June 2019)
Latin America Electricity Handbook (January 2019)

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Chilean Electricity Sector

Shifting Dynamics Set the Pace for a Greener Energy Matrix

Decarbonization Agreement: An agreement between Chilean power-generation companies and the government puts the country on the path toward phasing out coal generation by 2040 with a fully decarbonized energy matrix. AES Gener S.A. (BBB–/Stable) and its subsidiaries Empresa Eléctrica Angamos S.A. (BBB–/Stable), Empresa Eléctrica Cochrane SpA (BBB–/Stable) and Guacolda Energia S.A. (BB/Negative) are mainly coal-fired power plants. Fitch Ratings believes AES Gener's has limited room to execute a decarbonization strategy without affecting leverage given its current capital structure. This, as Alto Maipo, AES Gener's USD3.0 billion run-of-the-river project, is still under construction and expected to start operating by YE 2021.

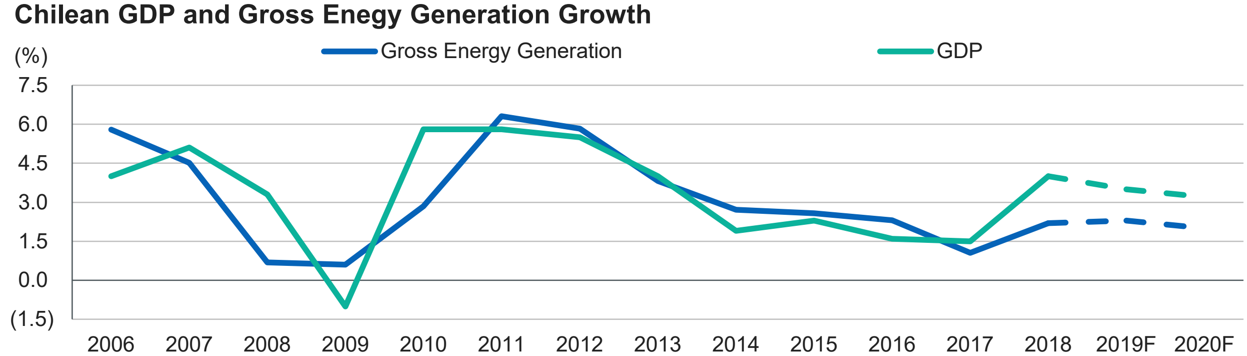
Well-Positioned GenCos: Engie Energía Chile S.A.'s (BBB/Positive) installed capacity is concentrated almost exclusively in thermal sources, and coal represents approximately 58%. As the company successfully concluded an intensive investment program with Infraestructura Energetica Mejillones (IEM), Fitch believes that Engie will be able to finance its energy transition program, shifting toward more renewable energy sources. The agreement is credit neutral for Enel Generación Chile S.A. (BBB+/Positive) and Colbún S.A. (BBB/Stable), as both companies are well positioned to meet this challenge, with generation assets more concentrated in hydro, renewables and natural gas.

Increased Participation of Renewables: Fitch expects renewable energy generation in Chile will continue to grow in 2019–2020 as new projects come online and the Sistema Interconectado del Norte Grande (SING) and Sistema Interconectado Central (SIC) systems are now fully integrated. Renewables projects with expected commercial operation date (COD) during 2019–2020 represent approximately 650MW of installed capacity with nearly USD2 billion in total investments. The most prominent projects are Cabo Los Leones II (205MW of wind-generation power), Parque Eólico San Gabriel (183MW of wind-generation power) and Cerro Dominador, the first concentration solar power (CSP) plant in Chile with 110MW of installed capacity and an estimated USD1,147 million investment.

Transmission System Consolidation: The connection of Chile's two biggest grids in June 2019 will be a positive in the long term. Fitch believes the expansion of Chile's energy transmission grid is crucial to securing energy from the north, especially in providing new renewable energy capacity and grid connections, and reducing system bottlenecks. Fitch anticipates the expansion bidding process will represent approximately USD732 billion in new investments for 2019.

Energy Distribution: Following a review of the energy transmission business in 2016 under the newly passed transmission law, preliminary discussions are underway to create a new energy distribution law. Fitch does not expect significant market effects from revisions to the law, though margins could narrow slightly. Fitch also does not see any significant cash flow impact from regulatory changes, such as a new technical standard or a change in conditions to transfer from regulated to "free" customers. Sector ratings reflect the energy distribution market's low-risk profile for Chilquinta Energia S.A. (AA(cl)/Stable), Compañia General de Electricidad S.A. (A+(cl)/Stable) and Enel Distribucion Chile S.A., subsidiary of Enel Chile S.A. (AA(cl)/Positive). All operate as a natural, indefinite monopoly in defined concession areas.

Chilean GDP and Gross Enegy Generation Growth



Source: Banco Central de Chile — Comision Nacional de Energia.

Primary Market Considerations

Growth Prospects: Demand Correlated Closely to GDP

Electricity demand growth in Chile is highly correlated with GDP growth, as industrial activity accounts for approximately 60% of the country's total electricity consumption. Demand growth was weak between 2014 and 2016, as the economy expanded by less than 2.0%, but showed improvement in 2018 as GDP grew by 3.8%. Fitch maintains a conservative outlook for Chilean GDP, projecting 3.5% growth for 2019 and 3.2% for 2020.

Energy demand in the northern zone of the national electric system (SEN) is closely linked to mining activity. The development of large mining projects such as Codelco's (A–/Stable) underground operation in Chuquicamata, El Teniente's new mine level, BHP Billiton's (A/Stable) Spence expansion project and Teck Resources' (BBB–/Stable) second stage of Quebrada Blanca. All are expected to accelerate economic growth and energy demand from mining activities.

Renewables Potential

Chile's potential to develop renewable energy is enormous. The Atacama Desert has one of the highest levels of solar radiation. Chile's natural resources combine mountain ridges and shorelines, both highly conducive to wind and hydropower. Moreover, declining technology costs allow Chile to tap its vast potential for solar and wind projects. However, to successfully integrate renewable energy sources into the grid, Chile will require additional investment in transmission infrastructure in Fitch's view.

Hydroelectric generation is the most prevalent source of renewable electrical power in Chile, with over 6,600MW of installed capacity in operation, distributed evenly between hydraulic reservoirs and run-of-the-river plants. According to a study of basins by the Ministry of Energy, Chile's hydroelectric potential is 15,938MW, with the greatest potential concentrated in the Biobío (18%), Baker (12%) and Palena (11%) basins. Large-scale river-run projects currently under construction face significant cost overruns due to geological conditions. They are Alto Maipo (531MW), a subsidiary of AES Gener and Los Condores (150MW), owned by Enel Generación Chile S.A. (BBB+/Positive).

Total potential solar energy for Chile is approximately 1,300MW, according to Asociacion de Generadoras de Chile, the guild representing Chilean generation companies. Solar energy actually has over 1,800MW under operation, with 220MW under construction with expected COD in 2019–2020. Geographically, solar energy is concentrated in the north of the country, where the first concentrated solar power plant (SCP) in Latin America is under construction. The plant also includes a thermal storage system with molten salts that will permit 24-hour stable energy delivery, as a complement to more intermittent solar energy.

Currently there are 1,300MW of wind farms in operation spread throughout the country, with 418MW under construction with expected COD in 2019–2020. Wind energy has become one of the most dynamic sources of energy in the world and Chile has been developing new projects since 2001. However, exhaustive studies have shown that the full power potential of wind energy in Chile may be mitigated since it depends on atmospheric conditions. This means that exhaustive wind measurements are required for a precise evaluation of the actual exploitable energy potential at a site.

To a lesser extent, Chile also generates energy from biomass and geothermal sources. Wood and pulp companies such as Empresas CMPC S.A. (BBB/Stable) and Empresas Copec S.A. (BBB/Stable) use cogeneration plants that take advantage of the energy residues (black liquor and bark) from other industrial processes such as the production of cellulose, biomass is used to produce electricity for its own industrial processes, injecting the excess energy into the grid,. There is approximately 500MW of installed biogas capacity in operation. In 2017, in a joint operation between ENAP and Enel Chile, the first geothermal generation of 48MW of installed capacity was launched. Chile lies within the Pacific "ring of fire," (a large ring of volcanoes and geothermal formations that roughly ring the Pacific Ocean, from the Americas to Asia) and geothermal energy is transmitted by thermal conduction to the surface, and is a highly available resource through the Andes Mountains.

Pricing

Market-Based Pricing for Electricity in Spot Market

Chile's Coordinador Eléctrico Nacional (CEN) runs the electricity system to minimize energy costs while monitoring service quality of generation and transmission companies. To minimize operating costs and improve efficiency, the lowest cost producer available is usually required to satisfy demand at any moment in time. As a consequence, at any specific level of demand, the appropriate supply will be provided at the lowest possible production cost available in the system. As a result, the system defines a marginal cost on an hourly basis as the price at which generators trade energy in the spot market, in terms of both injections (sales) and withdrawals (purchases) to balance their contracted sales in the production determined by the CEN.

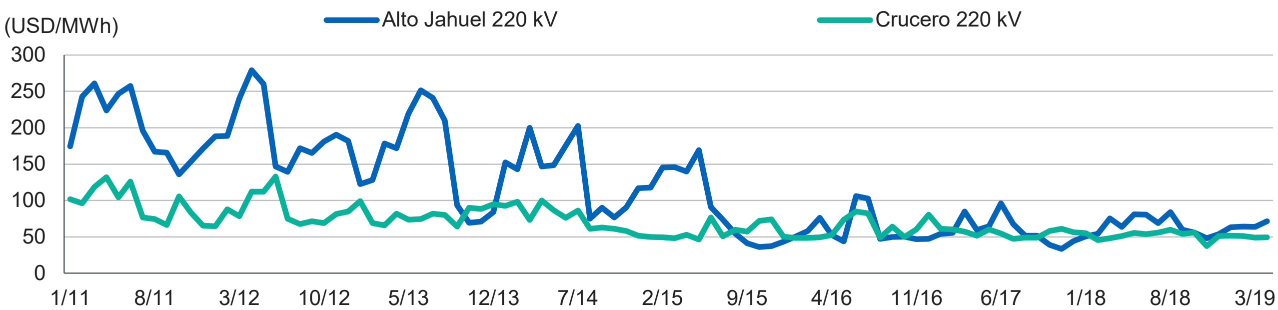
The CEN also ensures energy supply reliability in the system. Each generation unit in the system receives a "capacity payment" set by the CEN based on the generation capacity of each power plant and its availability as a primary resource. This capacity payment is the "firm capacity," and depends primarily on the availability, the type of technology of the power plant and the resources or fuel type used to generate electricity. It is the maximum capacity a generator may supply to the system at certain peak hours, considering statistical data, maintenance time and extremely dry conditions for hydroelectric power plants, but differs from firm capacity because it does not consider the power plants' contribution to the security of the entire system.

As part of the integration of SING and SIC in 2017 the SEN was created, reaching 3,100km and covering almost the entire nation, from the city of Arica in the north to the island of Chiloé in the south. As of April 2019, the SEN provides energy to more than 98.5% of the country, has an installed capacity of 24,868,5MW and 34,522.3km of transmission lines.

The chart below presents the average marginal cost for two specific nodes in the system; SING Crucero 220, in the north, represents what most mining customers pay for energy, while Alto Jahuel 220, south of Santiago, the capital city with a population of more than 6 million has strong energy demand from both residential and industrial customers. For the past two years, average marginal costs have been converging between these two nodes due to low prices for coal, natural gas and oil. The injection of energy from renewable sources such as wind and solar, introduce new low variable costs compared with thermal generation.

As part of the energy agenda set by the government, Fitch expects renewable energy sources in the coming years to reach 20% energy generation by 2025.

Marginal Costs — Sistema Electrico Nacional (SEN)



Note: Kilovolts refers to the energy capacity of the node that can be injected or withdrawn per second.
Source: Coordinador Electrico Nacional.

Regulatory Framework

The Electricity Law (passed in 1982) and the General Law of Electric Services (1985) created the current electricity regime, making Chile a pioneer in deregulating and privatizing the electricity industry. Various amendments have strengthened the regulatory model and promoted development and diversification of generation, including two laws commonly known as Short Law I (2004) and Short Law II (2005). The regulations provide economic incentives for companies that operate efficiently. Prices are set using a market-based, marginal-cost model, which determines the most efficient distribution of electricity.

Regulatory Bodies

Ministry of Energy

This agency develops and coordinates the Chilean government's energy sector plans, policies and standards. It also advises the government on energy-related matters.

National Energy Commission (CNE)

The CNE calculates tariffs for regulated customers, forecasts electricity demand and outlines a 10-year recommendation plan to expand the electric system. CNE's recommendation outlines the amount and the timing of new capacity necessary to meet its growth forecast. Generation companies are not required to follow the recommended plans. The CNE is dependent on the Ministry of Energy.

Superintendent of Electricity and Fuels (SEC)

This regulator enforces compliance with laws, regulations and technical standards of power generation, distribution and transmission, as well as those for fuel liquids and natural gas businesses. It is dependent of the Ministry of Energy.

National Electric Coordinator (CEN)

Recently created from the integration of the former Economic Load Dispatch Centers (CDEC) with operations in SING and SIC, CEN operates all electrical installations in order to:

- Preserve operational security and safety in the electrical system;
- To guarantee the most economic operation for all the installations of the electrical system;
- Ensure open access to all transmission systems, in accordance with the law.

Main Responsibilities of CEN

- Coordinate the installations of the national electric system to operate self-sufficiently, according to technical norms determined by the Commission, laws and regulations.
- Direct medium-sized systems in which there is more than one generating company, in accordance with the Law, regulations and technical standards.
- Deliver in a timely, complete and accurate manner all the information necessary for the fulfilment of its functions, and conduct audits of such information.
- Formulate the operation and maintenance programs for the fulfilment of its functions.
- Issue the necessary instructions for compliance with the purposes of the coordinated operation.
- Ensure electrical companies comply with the technical regulations and requirements that the Coordinator publishes, including the provision of complementary services defined by CEN.
- Prepare a report of complementary services and other functions in accordance with the law.

Industry Structure

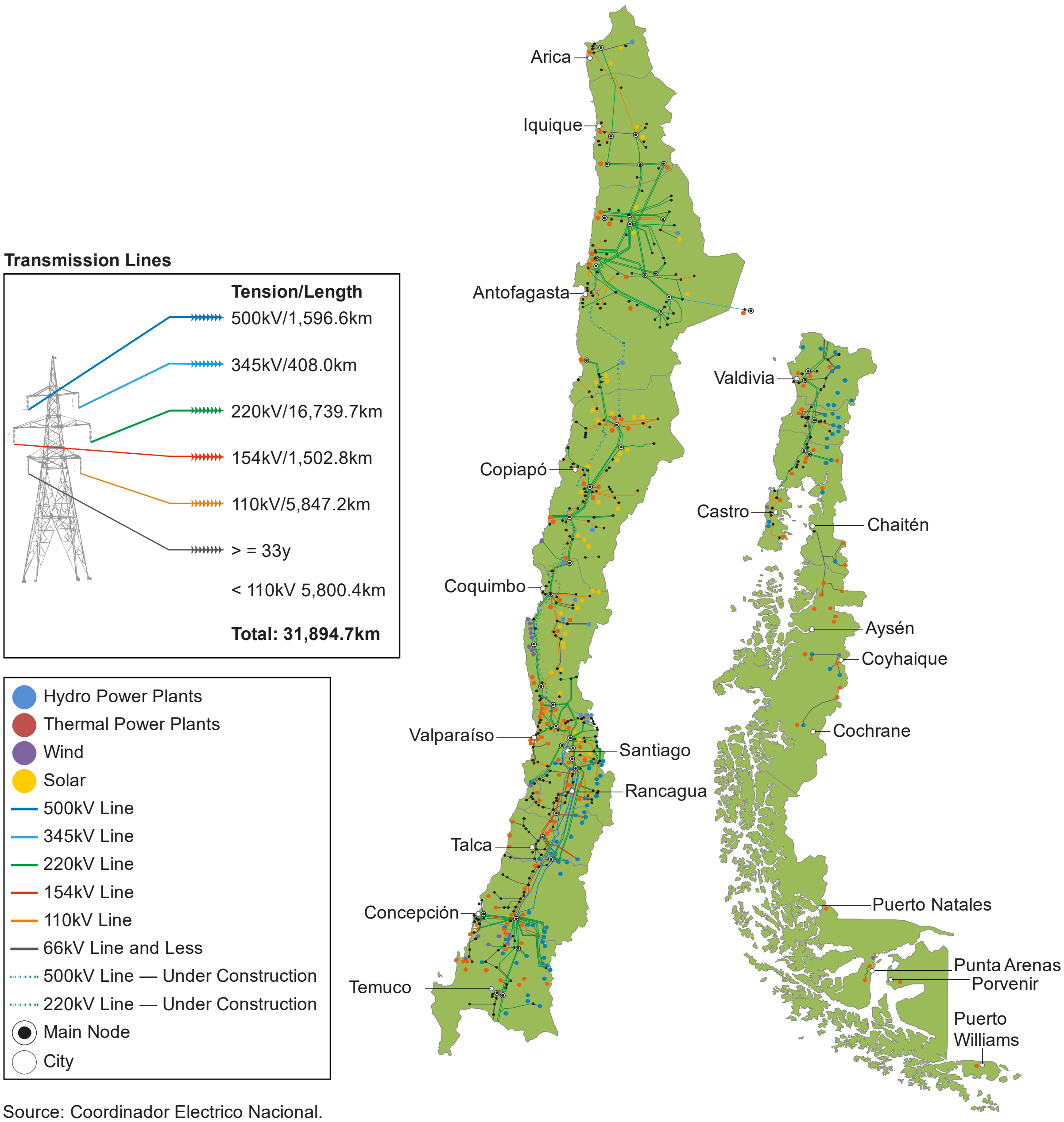
Chile's electric utility industry is organized into three market segments: generation, transmission and distribution. It is a competitive market, with private competitive investment in generation and regulated private investment in electricity transmission and distribution. Due to geographic challenges in the south of the country, the Chilean electricity sector is physically divided into three main networks, the SEN and two smaller isolated networks (Aysén and Magallanes).

In November 2017, the SEN was created to integrate the SIC and the SING. It extends from Arica in the north to Chiloé in the south, its total installed capacity is 24,868.5MW, and, as of April 2019, covers more than 3,100km with nearly 34,522km in transmission lines and serves 98.5% of Chile's population. In 2018, gross energy generation reached 76,290GWh.

Small electric systems cover areas between the ice fields south of the country. Both systems in Magallanes and Aysen are vertically integrated. Empresa Electrica de Magallanes S.A. (Edelmag) (AA(cl)/Stable), operates 109.2MW of installed capacity in the Magallanes region, with total energy sales of 332,225MWh in 2018. While Edelaysen operates 60.3MW of installed capacity in the Aysen and Coyhaique regions, with total energy sales of 6,317MWh in 2018.

Electric Systems in Chile

(2017)

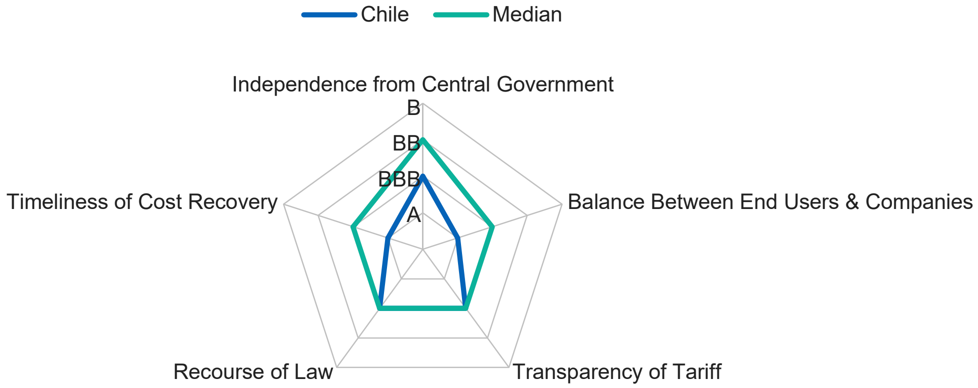


Source: Coordinador Electrico Nacional.

Regulatory Risk

Fitch considers Chile's regulatory risk among the lowest of rated peers given the low government intervention and independence from the central government's decision making. Fitch assesses a very strong balance between end users and companies. On average, Chile's rated regulatory risk is comparable to a 'BBB' category, and a 'BB' median for the region.

Chile Regulatory Score



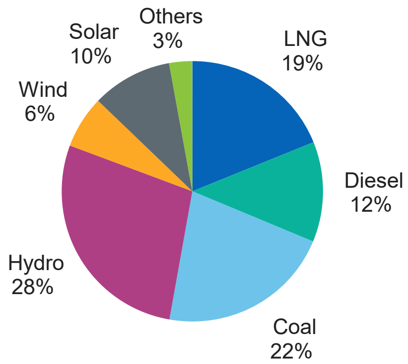
Source: Fitch Ratings.

Generation

Installed Capacity

As of April 2019, the SEN's total installed capacity was 24,868.5MW, of which 27.9% was hydro, including reservoir and river sources. Thermals account for 52.8%, with coal being the most prevalent with 21.5%, liquefied natural gas (LNG) second with 18.8% and diesel at 12.4%. Renewables account for 16.4% of the SEN's total capacity, solar being the most prevalent with 9.9% and wind at 6.5%. Other energy sources, such as biomass and geothermal, represent 2.9%.

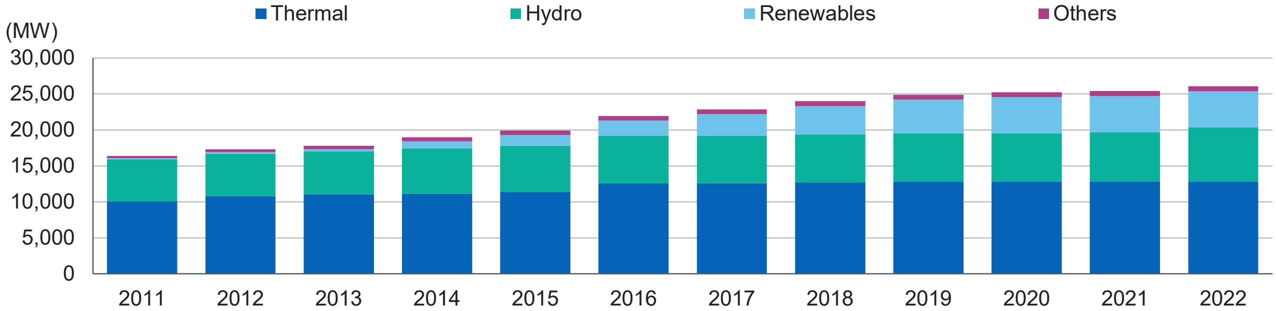
Total Installed Capacity (MW)
(April 2019)



Source: Coordinador Electrico Nacional.

Fitch estimates Chile's total installed capacity will increase to 26GW in 2022, when thermals will continue to represent nearly 50% of the market, but renewables will reach approximately 20%. Moreover, hydro generation is expected to increase to 7.5GW in 2022, as large run-of-the-river projects like Los Condores and Alto Maipo come online 2021 and 2022 respectively. In line with the decarbonization agreement between the government and generation companies, Fitch does not expect a large increase in thermal capacity, as only small back-up units act as peaking plants for specific nodes in the pipeline. The large combined-cycle project El Campesino is not considered in the chart below, as the environmental approval for the LNG port is still in process.

Installed Capacity



Source: Coordinador Electrico Nacional/Asociacion de Generadores.

Projects Under Construction

No.	Name	Company	Technology Type	Installed Capacity (MW)	Estimated COD	System	Total Investment (USD Mil.)
1	Parque Eolico Sarco	Mainstream Renewable Power	Wind	170.0	March 2019	SEN	354
2	Arrebol	Besalco	Wind	10.0	March 2019	SEN	20
3	Parque Eolico Aurora	Mainstream Renewable Power	Wind	129.0	March 2019	SEN	400
4	Crucero	Crucero SpA	Solar	3.0	March 2019	SEN	4
5	Ranguil	Energia Chile SpA	Solar	3.0	March 2019	SEN	5
6	Ovalle	Impulso gestion	Solar	3.0	March 2019	SEN	3
7	Laurel	E-Management	Solar	8.6	March 2019	SEN	13
8	Rovian	Grenergy	Solar	8.0	March 2019	SEN	7
9	Doñihue	Grenergy	Solar	7.5	March 2019	SEN	7
10	Placilla	Grenergy	Solar	9.0	March 2019	SEN	9
11	Casuto	CVE Group	Solar	3.0	April 2019	SEN	4
12	Huatacondo	Austrian Solar — Sojitz	Solar	100.0	April 2019	SEN	150
13	Cruz	iEnergia	Solar	3.0	April 2019	SEN	4
14	Las Perdices	Oenergy	Solar	3.0	April 2019	SEN	5
15	Teno	Inersa	LPG	43.0	April 2019	SEN	30
16	Norte Chico	Verano Capital	Solar	2.4	May 2019	SEN	3
17	Los Girasoles	E-Management	Solar	3.0	May 2019	SEN	3
18	Tucuquere	Rden Solar	Solar	3.6	June 2019	SEN	4
19	Las Lechuzas	Oenergy	Solar	3.0	June 2019	SEN	5
20	Las Codornices	Oenergy	Solar	3.0	June 2019	SEN	5
21	CH de Pasada El Pinar	Aaktei Energia SpA	Hydro	12.0	July 2019	SEN	23
22	PE La Flor	Vientos de Renaico	Wind	30.0	July 2019	SEN	54
23	Parque Eolico San Gabriel	Acciona	Wind	183.0	July 2019	SEN	360
24	Almeyda	Acciona	Solar	60.0	Oct. 2019	SEN	101
25	Pajonales	Prime Energia	Diesel	100.0	Oct. 2019	SEN	50
26	Hornopiren	Nanogenera SpA	Hydro	0.3	Dec. 2019	SMH	3
27	Melinka	Ilustre Municipalidad de Guaitecas	Wind	0.4	Dec. 2019	SMA	4
28	Arica I	Skysolar Group	Solar	40.0	Jan. 2020	SEN	50
29	Cerro Dominador	EIG	CSP/Solar	110.0	May 2020	SEN	1,147
30	Cabo Leones II	Ibereolica	Wind	204.7	May 2020	SEN	271
31	Los Condores	Enel Generacion Chile S.A.	Hydro	150.0	March 2021	SEN	957
32	San Victor	EPA S.A.	Hydro	3.0	June 2021	SMA	10
33	Alto Maipo — Las Lajas	AES Gener S.A.	Hydro	267.0	Dec. 2021	SEN	3,048
	Alto Maipo — Alfalfal II			264.0	Dec. 2021	SEN	
34	Hidroñuble		Hydro	136.0	July 2022	SEN	350
—	—	—	**Total**	**2,078.5**	—	—	**7,463**

COD – Commercial operation date.
Source: Generadoras de Chile.

Energy Generated

In 2018, total energy generated in the SEN registered 75,641GWh. Thermal sources represented 54.5%. Coal, the most significant resource, represented approximately 39% of the total energy generated with LNG nearly 15% and hydro at 28.2%. Solar, wind and biomass increased their share of total energy generated in the SEN in 2018, compared with last year, representing 7%, 5% and 3%, respectively.

Fitch estimates fossil fuel-based generation will continue to represent at least 50% of the energy generated in the SEN during 2019–2020, with coal still significantly participating in gross energy generation, despite efforts to decarbonize the energy matrix (coal also remains a more price-competitive alternative when compared with LNG). Fitch estimates load factors for the most efficient coal-fired units in the system in the range of 80%, while efficient combined-cycle units have load factors of 30%–35%. Load factors for hydroelectric generation will be subject to accumulated rainfalls and favorable snowmelt conditions.

In addition, Chile has seen a squeeze in hydrological energy generation. In 2018, gross generation rose 2.2% from 2017 to 76.290GWh. Of that total, hydro generation represented 28.2% in 2018, compared with 39% in 2007. Hydro generation companies such as Enel Generacion Chile and Colbun complement their generation mix with thermal units, including coal and combined-cycle units, to serve their purchase power agreements (PPAs). Favorable hydrological and snow-melt conditions boost operating margins for these companies, since hydro generation has a lower variable cost than thermal units.

On Jan. 1, 2010, Law No. 20,257 or the NCRE Law, defined nonconventional renewable energy sources. It also required that generating companies prove that a mandated percentage of their electrical output comes from renewable energy sources. This percentage for each year is presented in the table below. For 2018, NCRE energy from renewable sources represented 17.4% in the SEN, above the mandatory 10% for that year.

Mandated NCRE Energy Injection

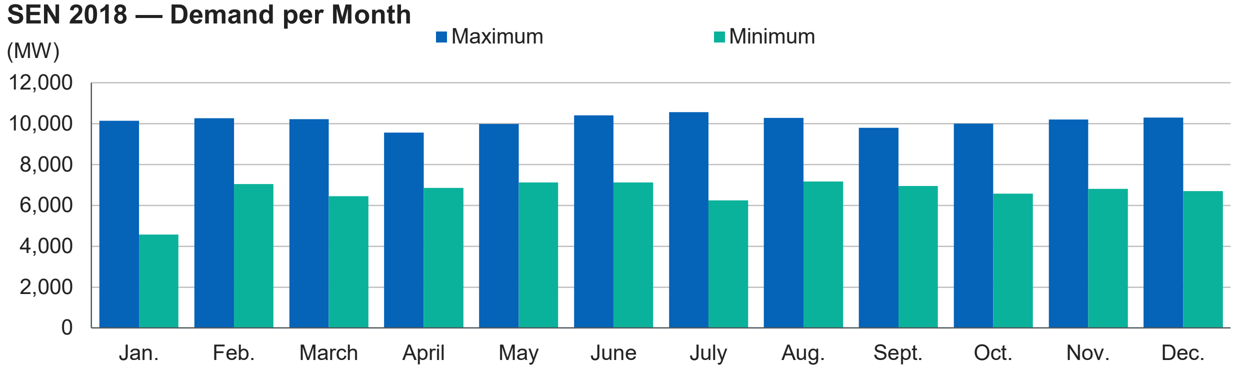
(%)	Law 20,257	Law 20,698
2010	5.0	—
2011	5.0	—
2012	5.0	—
2013	5.0	5.0
2014	5.0	6.0
2015	5.5	7.0
2016	6.0	8.0
2017	6.5	9.0
2018	7.0	10.0
2019	7.5	11.0
2020	8.0	12.0
2021	8.5	13.5
2022	9.0	15.0
2023	9.5	16.5
2024	10.0	18.0
2025	10.0	20.0

Source: Comision Nacional de Energia — Anuario Estadistico 2018.

Energy Demand Dynamics

Fitch estimates the minimum and maximum energy demand, on a monthly basis, for the SEN is between 4.5GWh and 10.6GWh, from 2018 to first-quarter 2019. Maximum demand in the system is generally reached between 6:00 p.m. and 11:00 p.m., local time. The SEN operates under a marginal cost basis, and peak demand is met by back-up units, mostly diesel-based plants, during the end of summer and fall when hydro generation usually declines.

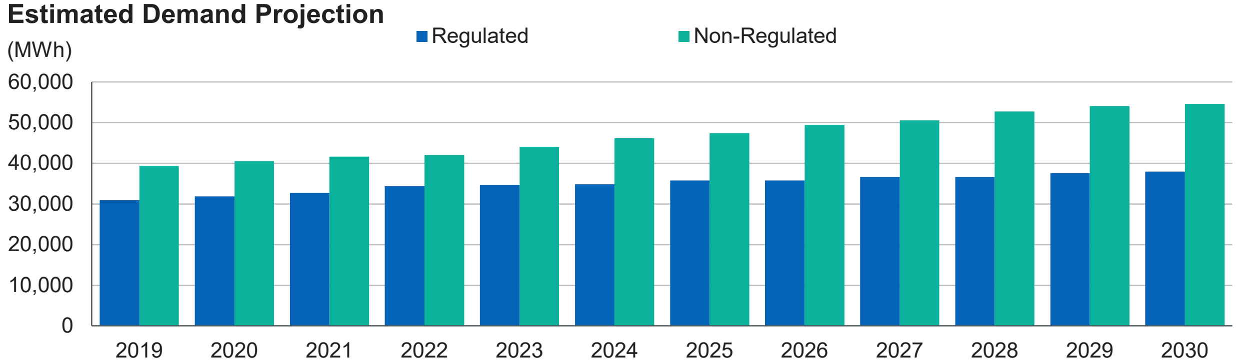
SEN 2018 — Demand per Month



Source: Generadoras de Chile.

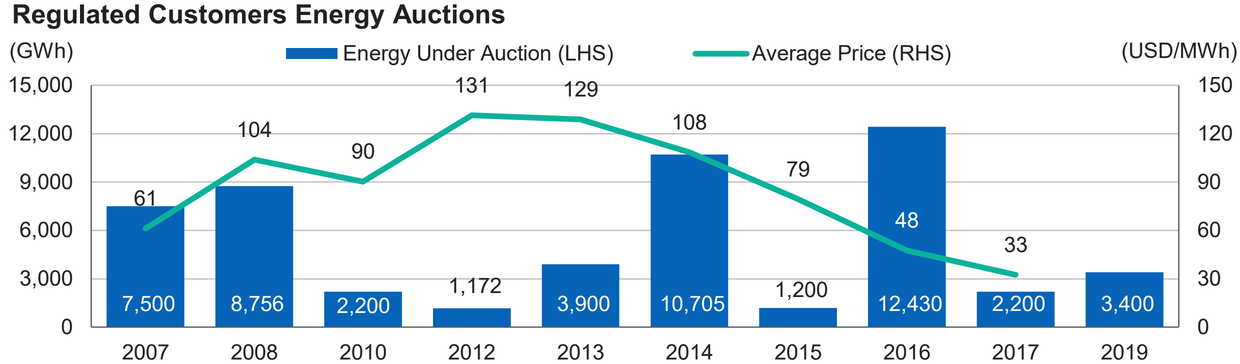
Demand is calculated yearly by the CNE, and encompasses both regulated and unregulated customers. The demand forecast of regulated customers is developed within the framework of the bidding processes for energy supply for regulated clients contained in the "Bidding Report of the General Law of Electrical Services." The demand forecast report forecasts "free" customers, and the results help determine node prices, charges and bidding.

Estimated Demand Projection



Source: Cordinador Electrico Nacional.

Regulated Customers Energy Auctions



Source: Comision Nacional de Energia.

Distribution

There are four major distribution companies within Chile, most of which are owned by large foreign conglomerates. These companies represent approximately 98% of the energy distributed in the country. The remaining portion is allocated among 12 minor distribution companies with little space to grow given geographical limitations and demand of the concession area. Distribution companies operate under a regime of public service concession, are obliged to provide electricity service to all customers and are subject to regulated tariffs for connected customers with less than 5,000kW capacity, except for customers with between 500kW and 5,000kW of capacity who exercise their option to choose a "free" or nonregulated tariff scheme. Customers with "free" fare can negotiate with any supplier (distributor or generator) and must pay a regulated toll for use of the distribution network.

Demand from regulated clients is served by distribution companies. In 2018 regulated customers reached 32,863GWh, representing approximately 44% of the total electricity generated in the system.

Distribution companies receive their revenue under the Valor Agregado de Distribucion (VAD), which is established every four years by the Ministry of Energy, following the technical report of the CNE. The VAD estimates an average cost that incorporates all the investment and operating costs of theoretical company operating in the country. The VAD also presumes the company is efficient in investment policy and management. As a consequence, the final VAD does not necessarily recognize costs effectively incurred by distribution companies.

Main Distribution Companies in Chile

Parent Company	Distribution Company	No. of Clients (Mil.)	Energy Sold (GWh)	Concession Area (sq km)	Regulatory Cycle (Years)	Next Regulatory Cycle	SAIDI (Hours)
Enel Spa (A–/Stable)	Enel Distribucion Chile S.A.	1.9	16,782	2,105	4	2020	3.0
Naturgy Energy Group (BBB/Stable)	Compañia General de Electricidad S.A. (CGE)[a]	2.9	12,220	N.A.	4	2020	12.4
Sempra Energy (BBB+/Stable)	Chilquinta Energia S.A.[b]	0.7	2,948	10,611	4	2020	7.0
Ontario Teachers Pension Plan/Alberta Investment Management Corporation (AIMCO)	Inversiones Electricas del Sur S.A. (SAESA Group)[c]	0.9	3,572	N.A.	4	2020	26.9

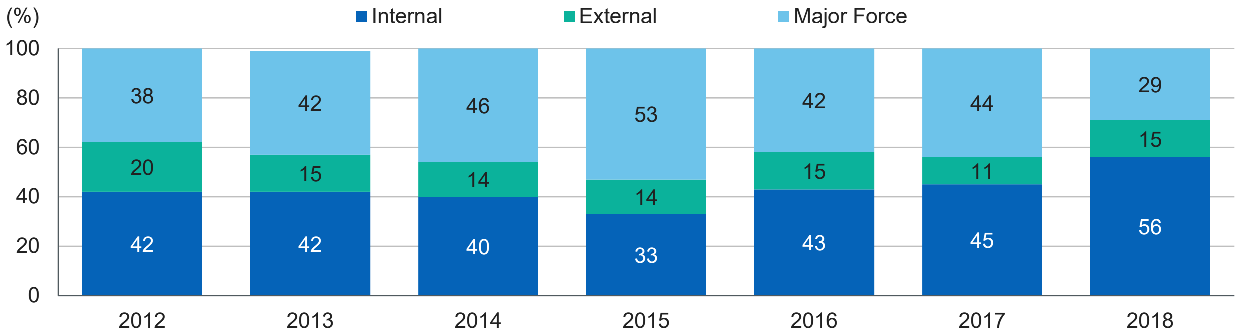
[a]Does not include clients and energy sold from Argentine subsidiaries. [b]Includes: Chilquinta Energia S.A., Casablanca S.A., Litoral S.A., Luzlinares S.A. and Luzparral S.A. [c]Includes SAESA, Frontel, Luz Osorno and Edelaysen.
Source: Annual reports/Coordinador Electrico Nacional.

Service Quality

The system average interruption duration index (SAIDI) indicator represents the average duration of interruptions customers experience over a period of time. Power outages can be generated by external causes, like supply interruptions from electricity generation and transmission segment companies or major natural events, such as earthquakes.

Distribution companies report interruptions to the SEC and carry out a first qualification, thus giving rise to the SAIDI indicator. Subsequently, the SEC carries out a detailed analysis of the interruptions, classifying them within the categories defined above.

SAIDI — Reported by Companies on Average Interruption Hours per Customer



Source: Superintendencia de Electricidad y Combistibles.

Transmission

In 2016, a new transmission law was passed to prevent the transmission system from being an obstacle to generation sources and to boost the development of nonconventional renewable sources. The main points of the law are:

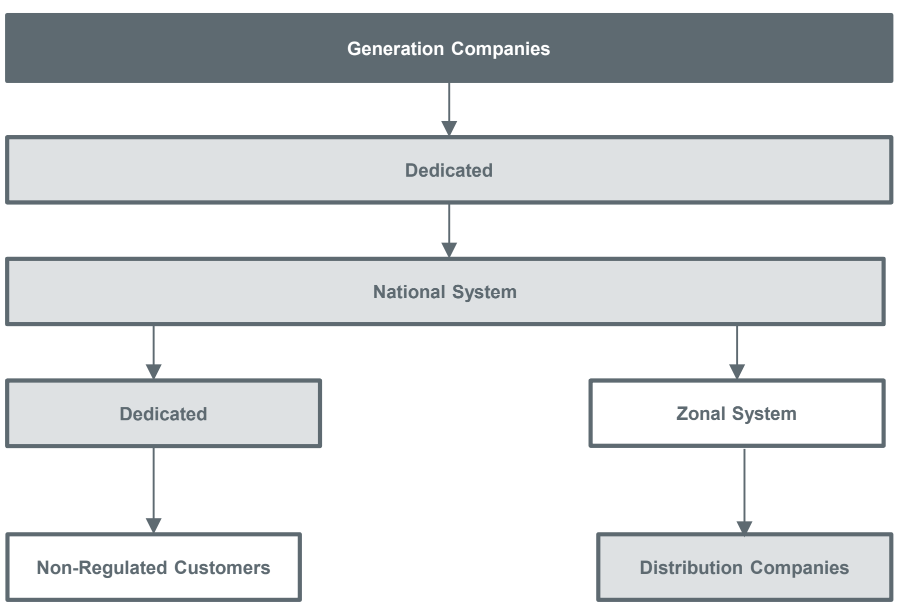
- The use of capital asset pricing model (CAPM) methodology, including a new valuation process for legacy assets of all transmission systems, with the goal of an internal rate of return (IRR) of a maximum of 7% after taxes;
- Introduction of a remuneration scheme for national, zonal and dedicated transmission systems with no exposure to volume or price risks;
- Introduction of development hubs to ensure long-term energy and transmission planning for areas with a high potential for power generation where development poles can be established.

National System: Defined as the economically efficient and necessary facilities to supply overall system energy load, and contribute to form a common market.

Zonal System: All facilities used by groups of consumers (regulated or unregulated) located in a distribution concession zones

Dedicated System: Injection lines from generation units and lines exclusively used by non-regulated customers.

Transmission Market



Source: Transelec S.A. / Coordinador Electrico Nacional.

Upcoming Transmission Auction

Project	Construction Period (Months)	Referential Investment Value (USD Mil.)	Referential COMA (USD 000)
New Substation Parinas 550/220kv	36	54.31	868.98
New Line 2x500kv Parinas — Likanantai/Energized 220kv	48	105.62	1,698.98
New Line 2x220kv Lagunas — Nueva Pozo Almonte/First Circuit	48	19.17	306.77
New Substation JMA 220kv	36	19.11	305.77
New Line 4x220kv from Substation Los Pelambres to Segment Line 2x220kv Los Piuquenes — Tap Mauro	36	14.97	239.63
New Substation Nueva la Negra 220/110kv	36	14.69	235.11
Bypass Line 1x220kv Atacama — Esmeralda/Line 1x110kv Esmeralda — La Portada & Decommissioning Line 1x110kv Mejillones — Antofagasta	30–48	13.35	213.70
New Line 2x110kv from Substation Caldera to Line 1x110kv Cardones — Punta Paredones	36	2.51	40.17
New Line 1x110kv Crrillos — Kozan	36	2.20	35.27
New Substation La Ruca 110kv	24	6.49	103.90
New Substation Chagres 44kv	36	4.08	65.36
New Line 2x220kv Candelaria — Nueva Tuniche & Substation Nueva Tuniche 220kv	48	19.57	313.17
New Line 1x66kv La Esperanza — El Manzano	36	3.86	61.88
New Substation La Señoranza 220/66kv	36	8.70	139.29
New Line 2x500kv Entre Rios — Ciruelillos/Energized 220kv	84	359.28	5,748.60
New Line 2x500kv Ciruelillos — Pichirropulli/Energized 220kv	84	84.49	1,351.98
Total	**—**	**732.40**	**11,728.56**

Source: Minister of Energy — Decree 4 Exent, published Jan. 9, 2019.

Corporates

Ratings

Company Name	Long-Term Foreign Currency IDR	Long-Term Local Currency IDR	National Scale Rating	Outlook
AES Gener S.A.	BBB–	BBB–	A+(cl)	Stable
Chilquinta Energia S.A.	NR	NR	AA(cl)	Stable
Colbun S.A.	BBB	BBB	AA–(cl)	Stable
Compania General de Electricidad S.A. (CGE)	NR	NR	A+(cl)	Stable
Empresa Electrica Angamos S.A.	BBB–	BBB–	NR	Stable
Empresa Electrica Cochrane SpA	BBB–	BBB–	NR	Stable
Enel Chile Chile S.A.	NR	NR	AA(cl)	Positive
Enel Generacion Chile S.A.	BBB+	BBB+	AA(cl)	Positive
Engie Energia Chile S.A.	BBB	BBB	AA–(cl)	Positive
Guacolda Energia S.A.	BB	BB	NR	Negative
Transelec S.A.	BBB	BBB	AA–(cl)	Stable

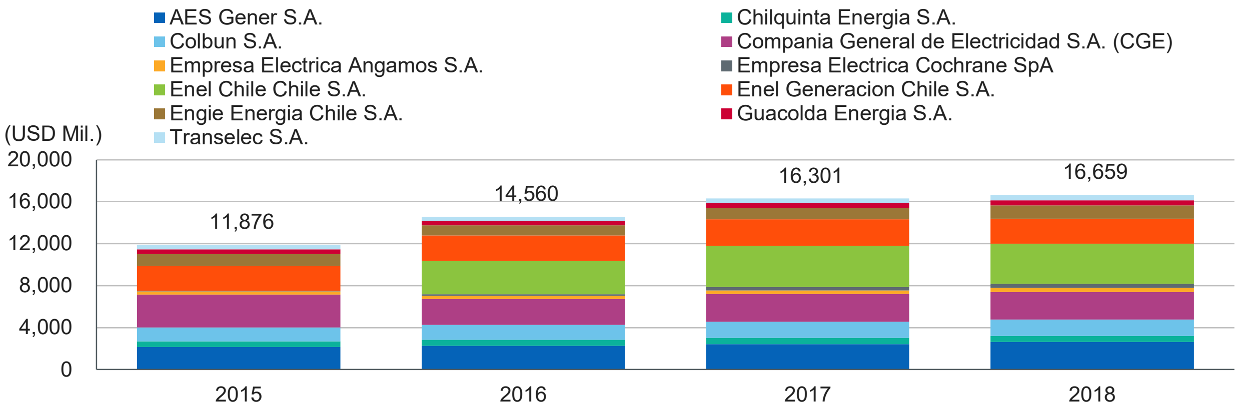
Source: Fitch Ratings.

Stable Ratings: Fitch estimates Chilean energy companies will maintain relatively stable credit profiles in 2019, despite the industry's challenges. Most companies in this sector have solid capital structures that enable them to withstand volatile conditions, combined with strong credit strengths that include funding flexibility, adequate liquidity and, to a varying extent, diversified asset portfolios. Key concerns are mainly related to significant regulatory changes and potentially large investment programs that could reduce financial flexibility.

Financial Performance

Fitch's electricity portfolio consists mostly of relevant players in the generation, transmission and distribution businesses. Fitch observed that gross revenues (in U.S. dollars) increased by 2.2% in 2018 compared with 2017. The revenue increase is primarily due to being indexed to the U.S. and Chilean C.P.I's, as electricity revenues encompass both indexes. To a lesser extent, companies like Angamos and Cochrane started operating at full capacity in 2018, as new PPAs are in full force. In the case of Engie Energia Chile, the 21% revenue increase is due to a step-up of energy contracted with regulated clients at favorable prices.

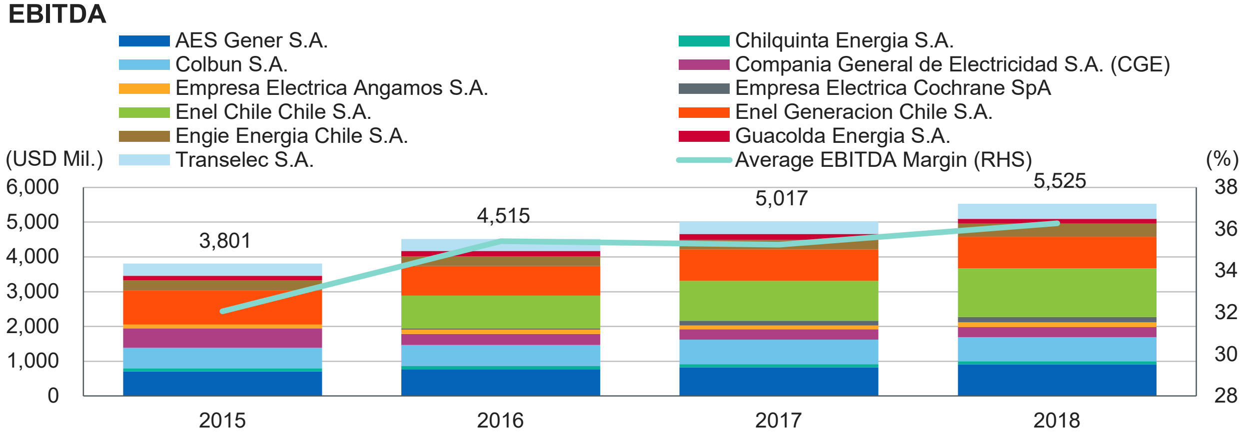
Gross Revenues



Source: Fitch Ratings, company filings.

Within Fitch's rated portfolio, EBITDA margins remain strong, averaging 36% in 2018, in line with 35% historical estimates. Fitch expects EBITDA margins will reach 30%–35% in 2019 for all generation companies mainly concentrated on coal, like AES Gener, its subsidiaries Angamos, Cochrane and Guacolda, and Engie Energia Chile. While Enel Generacion Chile and Colbun present a more balanced generation portfolio between hydro and thermal assets, Fitch anticipates EBITDA margins in the range of 40%–45% in 2019. In the transmission business, Transelec will maintain higher EBITDA margins above 80%, mainly due to the low business-risk profile. Fitch considers the regulatory environment in Chile to be solid and stable while providing certainty in determining regulated transmission revenues and returns on future investments. For the energy distribution business, Fitch believes EBITDA margins will remain around 15% which is expected from regulated revenues derived from a stable and predictable operator operating in a natural monopoly for an indefinite term within a concession area.

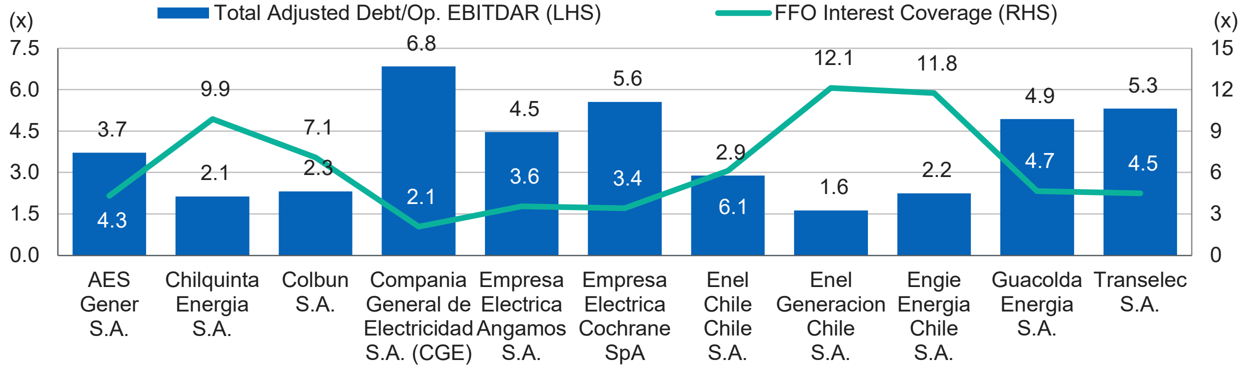
EBITDA



Source: Fitch Ratings, company filings.

The Chilean electricity market is mostly U.S. dollar-denominated due to long-term U.S. dollar-dominated contracts. Most generation companies have a low exposure to local currency costs. On average, nearly 10% of costs are denominated in Chilean pesos. Most companies have FX swaps to mitigate some of the currency risk stemming from debt denominated in local currency. Fitch estimates a 10% depreciation of local currency would lower gross leverage by approximately 0.1x.

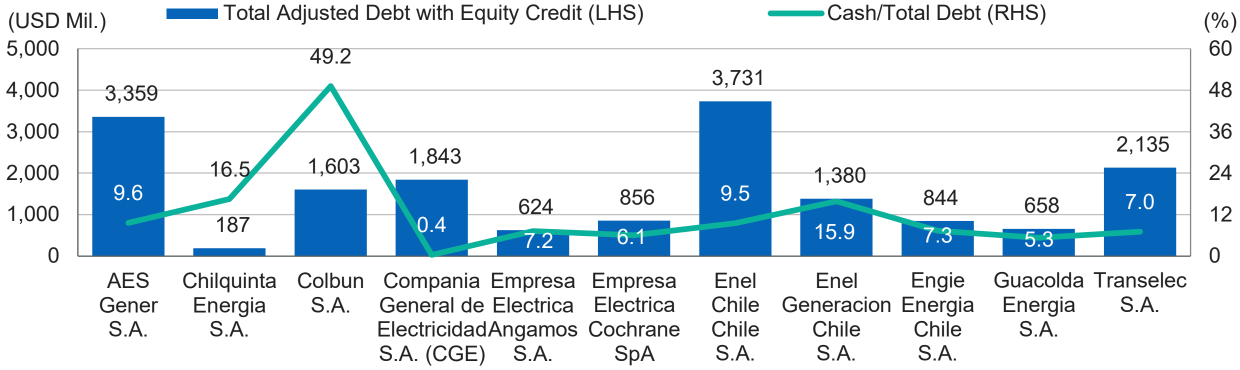
Credit Metrics — 2018



Source: Fitch Ratings, company filings.

Fitch estimates adequate liquidity for Chile's electricity portfolio. Most companies have broad access to local and international markets, coupled with adequate cash flow generation, and readily available cash is mostly allocated in U.S. dollars on banking instruments with high liquidity. Additionally, all companies in the portfolio have a comfortable amortization schedule, combined with secured committed revolving credit lines that further enhance their liquidity profiles.

Cash Profile — 2018



Source: Fitch Ratings, company filings.

Issuer		Business profile						Financial profile		
Name	IDR/Outlook	Operating Environment	Management and Corporate Governance	Regulatory Risk	Commodity Price and Market Risk	Market	Asset Base and Operations	Profitability	Financial Structure	Financial Flexibility
AES Gener S.A.	BBB+/Sta	a	bbb	bbb+	bbb-	bbb-	bbb-	bbb-	bb+	bbb-
Colbun S.A.	BBB/Sta	a+	bbb+	bbb+	bbb	bbb+	bbb	bbb	bbb	bbb-
Engie Energia Chile S.A.	BBB/Pos	a+	bbb+	bbb+	bbb+	bbb	bbb	bbb+	bbb	bbb
Empresa Electrica Angamos S.A.	BBB-/Sta	a+	bbb	bbb+	bbb	bbb-	bbb	bbb-	b	bbb-
Empresa Electrica Cochrane SpA	BBB-/Sta	a+	bbb	bbb+	bbb+	bbb-	bbb	bbb-	b	bbb-
Enel Generacion Chile S.A.	BBB+/Pos	aa	bbb+	bbb+	bbb	bbb+	bbb	bbb+	a	a-
Guacolda Energia S. A.	BB/Neg	a+	bbb	bbb+	bbb-	bbb-	bb	bb	bb	bb

Source: Fitch Ratings.

Importance: Higher | Moderate | Lower

Decarbonization Agreement

In June 2019, the government announced a schedule for disconnecting 1,046MW of electrical power generation from eight of the oldest electrical-generation plants that rely on fossil fuels. After 2024, working roundtables will be established every five years to create new disconnection schedules and move toward a total withdrawal of the carbon park by 2040. The schedules will take into account analysis economic, social and environmental impacts, along with the overall security and reliability of the energy system. The goal is that by 2040 the energy matrix will be completely decarbonized and that by 2050 Chile will be a carbon-neutral country.

Following the announcement, the government defined the operational status of strategic reserve for all units being disconnected and retired from the grid. All units under this “Power Regulation” cannot be summoned to dispatch energy on a daily basis, but must be available to dispatch with a 60-day notice from the regulator. Fitch believes that the reserve scheme allows the plants to remain operational for up to five years for security reasons to ensure adequate energy for the grid. Fitch estimates that the companies under this scheme will receive approximately 60% of the capacity payment. Additionally, the operators will receive corresponding power remuneration according to the operating status of each unit.

With the increased participation of NCRE sources in the country, Fitch believes that to successfully incorporate NCREs as a key contributor to the country's power matrix, the country’s national grid must be more flexible. Interconnection of the National Transmission System is crucial to secure the energy supply from the north, especially in relation to new renewable energy capacity, grid connection and system bottleneck reduction. Fitch estimates the transmission system will also require additional investments in the country’s transmission infrastructure and storage, alongside a conventional fuel source to support the intermittence of renewables.

Decarbonization Calendar

Company		Total	June 2019	May 2020	Jan. 2022	Nov. 2022	Dec. 2023	May 2024	Dec. 2040
AES Gener	Units	6	—	—	—	Ventanas 1	—	Ventanas 2	Norgener NT1 & NT2, Campiche, Nueva Ventanas
	MW	1,095	—	—	—	114	—	208	773
Angamos	Units	2	—	—	—	—	—	—	Angamos 1 & 2
	MW	558	—	—	—	—	—	—	558
Guacolda	Units	5	—	—	—	—	—	—	Guacolda Units 1,2,3,4 & 5
	MW	760	—	—	—	—	—	—	760
Cochrane	Units	2	—	—	—	—	—	—	Cochrane 1 & 2
	MW	550	—	—	—	—	—	—	550
Engie Energia Chile	Units	9	U12 & U13	—	U14 & U15[a]	—	—	—	CTA, CTM1, CTM2, Hornitos & IEM
	MW	1,501	170	—	268	—	—	—	1,063
Enel Generacion Chile	Units	3	—	Taracapá	—	—	Bocamina I	—	Bocamina II
	MW	636	—	158	—	—	128	—	350
Colbun	Units	1	—	—	—	—	—	—	Santa Maria
	MW	350	—	—	—	—	—	—	350
Total	**Units**	**28**	**2**	**1**	**2**	**1**	**1**	**1**	**20**
	MW	**3,582**	**170**	**158**	**268**	**114**	**128**	**208**	**2,536**

[a]Tocopilla units U14 and U15 could extend until May 2024, subject to Engie’s completion of its renewable plan.
Source: Fitch Ratings, company filings.

Outlooks

2019 Outlooks
Fitch Ratings 2019 Outlook: Latin American Corporates (Navigating the New Political Landscape) (December 2018)
Fitch Ratings 2019 Outlook: Latin American Sovereigns (November 2018)

Related Research

Chile (March 2019)
Fitch Affirms Chile at 'A'; Outlook Stable (February 2019)
Chile After the Elections (March 2018)

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Colombian Electricity Sector

Stable Outlook with Long-Term Risks for Generation Companies

Capacity Expansion Meets Medium-Term Demand: A February 2019 auction produced a capacity-expansion plan for Colombia's electricity sector that eases medium-term electricity supply-and-demand uncertainty beyond 2022. The expansion brings an additional 4,010MW online over the next three years, an approximately 23% increase in installed capacity. The auctioned 2022 firm energy obligations (committed electrical output, backed by a power plant, under periods of scarcity [OEFs]) will be 250.5GWh per day, of which 164.3GWh were assigned in the auction, including 3.15GWh from the Ituango hydroelectric project. Fitch Ratings estimates this will cover 226.8GWh of expected electricity demand under the government planning unit's (UPME) high-demand scenario projections for 2022–2023.

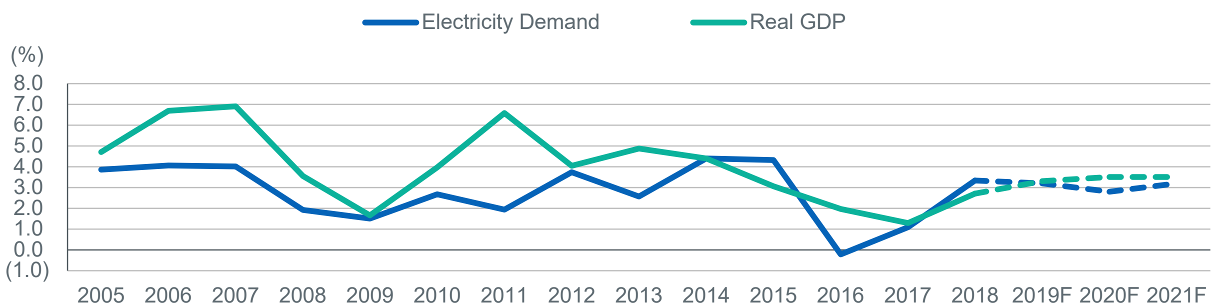
Higher Capacity Could Pressure Prices: The expected capacity expansion (including a fully operational Ituango plant) could exert downward pressure on electricity spot prices, leading to recontracting risk given the relatively short contract tenures normal in the Colombian market. This could pressure EBITDA growth for generation companies (GenCos) over the medium term. Fitch does not expect a material deterioration of the credit profile of its rated companies, given their conservative capital structure and manageable capex requirements over the next few years. Also, GenCos are looking to extend contracts with customers in the nonregulated market as a hedge against recontracting risk.

Increased Appetite for Renewable Projects: The government continues to encourage expansion of the electricity system through nonconventional renewable projects. The government's recently approved national development plan for 2018–2022 calls for an increase in installed capacity of solar and wind assets to 1,500MW from 22.4MW. In the latest February 2019 auction, regulators granted 1,160MW to wind projects and 238MW to solar projects. Another auction for long-term electricity contracts is expected to further expand the installed capacity of these projects. The government's first significant act to encourage investments in nonconventional renewable projects was Law 1715 of 2014, which provided tax benefits to companies to invest in wind and solar projects.

Heavy Investment from Distribution Companies: Execution risk for large generation, transmission and distribution (T&D) projects is an ongoing concern for the sector. Electricity distribution companies are encouraged to invest in their asset base to maintain their revenue structure. A new regulatory tariff incorporates depreciation of the regulatory asset base of each company. Although Fitch foresees a neutral effect of the financial profile of rated companies in this segment, those with a limited track record in executing significant capex, coupled with lagged investments and limited access to external funds to finance capex, could see heightened risks.

Fair and Balanced Regulatory Framework: Tariff-setting procedures for T&D companies are transparent and inclusive, consistent with the investment-grade assessment of these factors under Fitch's Rating Navigator. Fitch views the strength of these regulatory structures as a positive, despite the occasional lag in the tariff-review cycle. For the generation business, the regulatory framework has evolved to ensure long-term system reliability and reduce sector pressures, such as the situation during the 2015–2016 severe drought season.

Colombia Electricity Demand Versus Real GDP Growth



Source: Fitch Solutions, XM Compañía de Expertos en Mercados S.A. E.S.P., Energy mining planning unit (UPME), National Administrative Department of Statistics of Colombia (DANE).

Primary Market Considerations

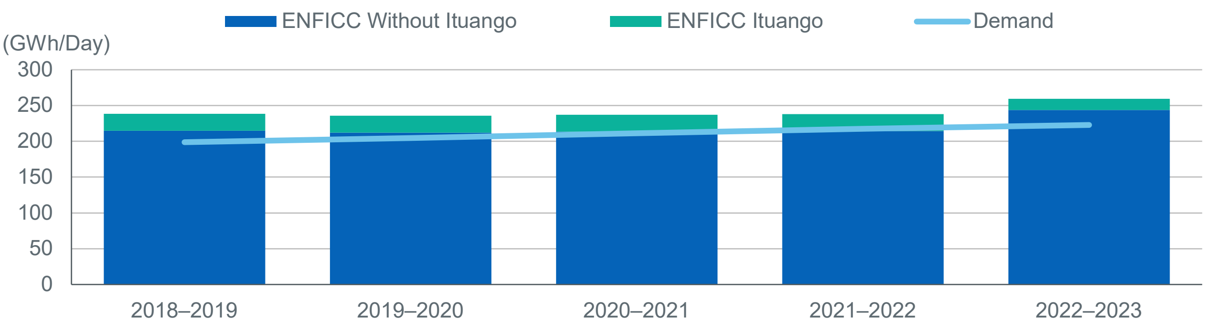
Growth for the Colombian electrical power sector in the medium term will be driven by:

- Expansion in generation capacity to accommodate expected demand from 2022 onward;
- Government encouraging development of nonconventional renewable projects;
- Investments in electricity transmission to ease network constraints;
- Investments in electricity distribution driven by the new regulatory framework.

Empresas Publicas de Medellin E.S.P.'s (EPM) 2,400MW Ituango hydroelectric project is expected to be delayed until 2021, which will put pressure on the country's reserve margin over the next three years, particularly in the event of a drought. Electricity demand, as projected by the government's planning unit in its latest forecast scenario of January 2019, is expected to grow at an annual average rate of around 3.5% during 2019–2022. Therefore, under the government's high-demand scenario, demand will reach around 79,000GWh during December 2021–November 2022, which is not covered by the verified Energia en Firme para el Cargo por Confiabilidad (ENFICC) of the current generation matrix by 2022, excluding the Ituango project, which is defined as the maximum electricity generation under low-hydrology conditions.

The imbalance between electricity supply and demand for 2022 was a key reason the government held a third auction for reliability charge in February 2019 (two other actions were previously held in 2008 and 2011). As a result of this auction, it was assigned 164.3GWh per day, which adds 86.2GWh of previous allocation, to reach 250.5GWh of OEF by 2022–2023. The closing price of the OEF was USD15.1/MWh from December 2022, 11% lower than previous auctions. Also, the regulation included an incentive scheme to promote an earlier commercial operation date (COD) of the projects. Specifically, for projects able to start operations before November 2021, they will be remunerated at the closing price of the auction plus USD2/MWh until December 2022. The COD of some of these projects in 2021 will ease pressures of the limited reserve margin expected for that year.

Electricity Supply and Demand Balance
(2019–2023)



ENIFCC – Energía Firme para el Cargo por Confiabilidad (Certified maximum "firm" energy provision). Note: Demand projections revised in January 2019.
Source: Energy mining planning unit (UPME), XM Compañía de Expertos en Mercados S.A. E.S.P.

Pricing

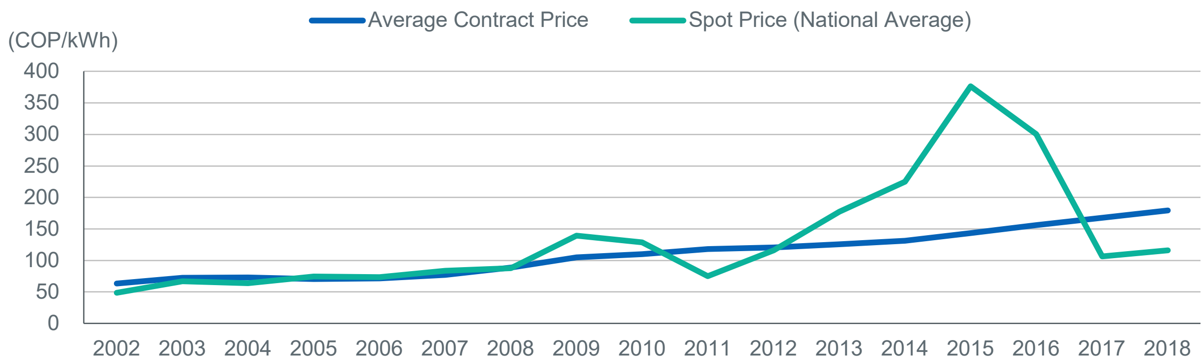
Colombian electricity prices in the generation segment are set by a competitive process and are determined mainly in two different markets: the spot market that works under a day-ahead methodology and the electricity contract market. In the spot market, GenCos offer a price and declare available electricity for each hour for the next day. Prices are mostly a function of variable costs of their assets and the opportunity costs, which in turn are function on expectations around current and future hydrology. The prices are ordered from lowest to highest and the price of the marginal resource that satisfies the demand for each hour is the spot price for that hour and it is the rate at which all the dispatched GenCos are remunerated.

The other market where prices are determined is the electricity contract market, which performs as a financial hedge to cope with the volatility of spot prices. The contracts are bilateral and nonstandardized, which serves both the electricity required to meet the demand of the regulated market, in which contract tenures are typically around one to three years, and the nonregulated market, whereby GenCos try to extend contract tenures. The government is planning an auction later in 2019 in which it will offer long-term electricity contracts that aim to expand the participation of nonconventional renewable assets in the electricity matrix.

Prices in the spot market are structurally volatile, mostly due to the country's reliance on hydroelectric generation to meet the bulk of electricity demand, coupled with limited accumulated-watershed capacity. Spot prices tend to change quickly, reflecting current weather trends. Dry or drought-like weather means that a higher proportion of demand is met by supplementing hydroelectric generation with thermoelectric generation, which has higher variable costs. Under normal-to-high hydrology conditions, more than 80% of the daily electricity demand is met with hydroelectric assets. However, that figure could fall to 50% under a drastic drought, such as the last El Niño in 2015–2016.

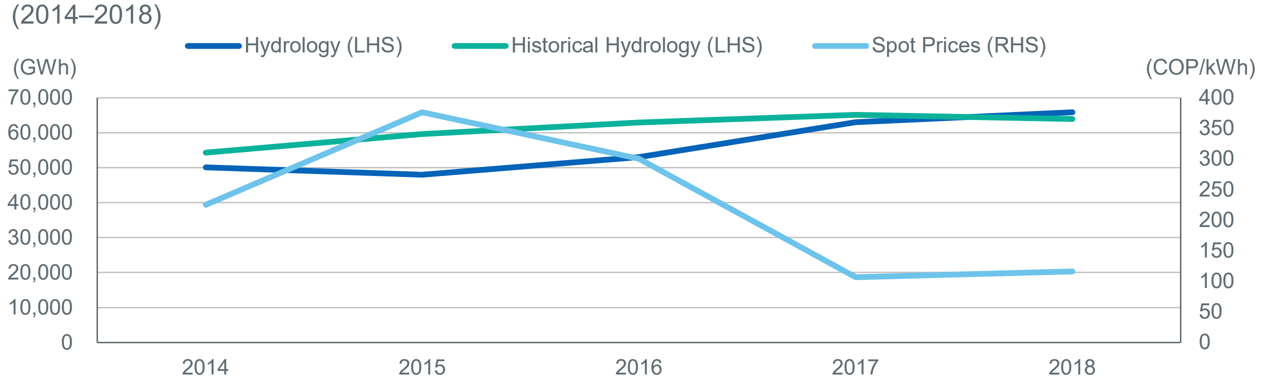
For 2019–2021, Fitch anticipates electricity prices in the spot market will remain on average higher than in 2017 and 2018. This is due to a gradual decline in the reserve margin, an expected higher utilization of thermal electric assets to meet daily demand and sustained electricity demand growth. Since there is no planned capacity expansion in 2019 and 2020 OEF is expected to remain stable in those years. For the next two to three years, the market manager, XM Compañía de Expertos en Mercados S.A. E.S.P. (XM), a subsidiary of Interconexion Electrica S.A E.S.P. (ISA: BBB+/Stable), foresees that the system will require in some periods of time sustained thermal generation of 70GWh per day in next two years. The capacity expansion expected to be incorporated in 2022 would ease pressures in the system and may result in downward pressures in prices in the medium term, if Ituango and additional nonconventional renewable projects come online during those years.

Electricity Prices
(2002–2018)



Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

Hydrology and Spot Prices
(2014–2018)



Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

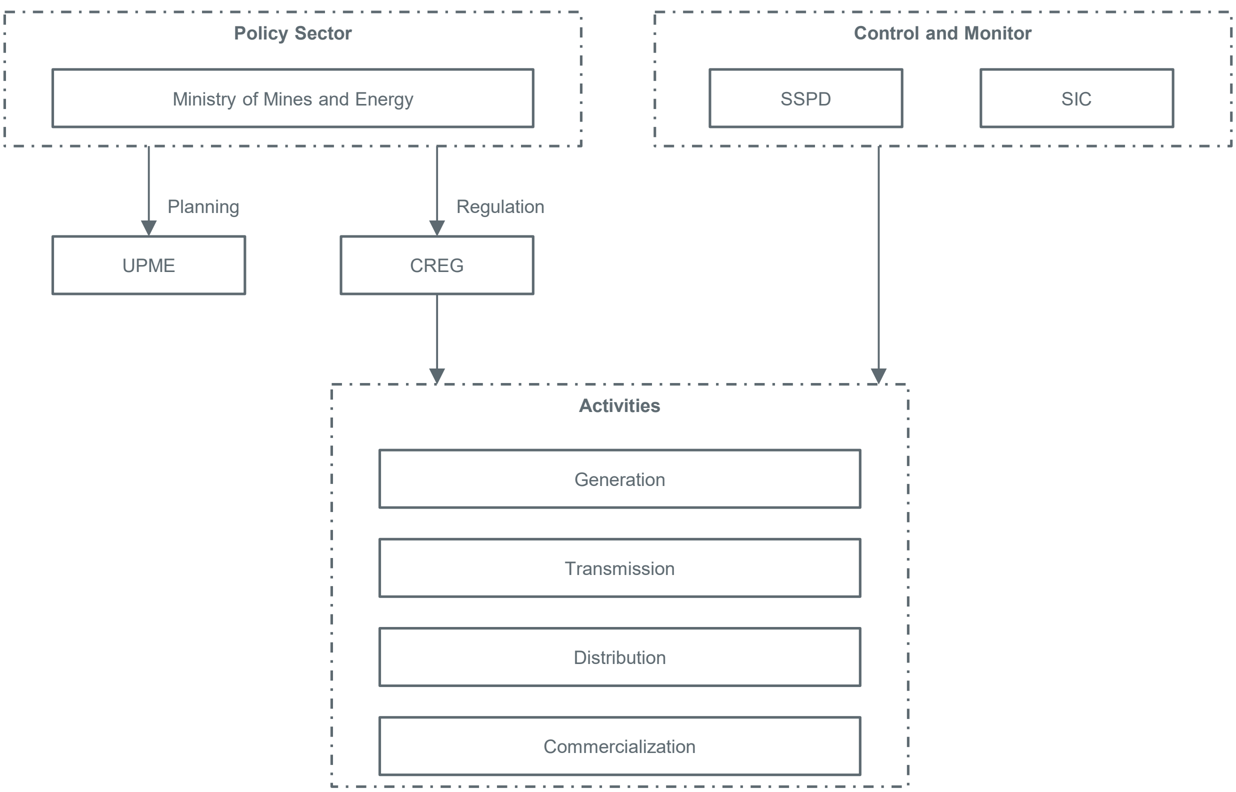
Regulatory Overview

The Colombia electricity market is governed by Law 142 (Law of Domestic Public Services) and Law 143 (Electric Law of 1994). These laws effectively separated the electricity market into four main activities: generation, transmission, distribution and commercialization. Recently approved national development plan allowed integration among the activities. The Regulatory Commission for Energy and Gas (Comision de Regulacion de Energía y Gas [CREG]) will adopt the measures to implement the vertical integration in one single company or companies with a single controlling shareholder.

Regulatory Bodies

The Colombian Ministry of Mining and Energy (MME) coordinates and oversees Colombia's electricity sector. CREG has administrative, financial and technical autonomy, and is attached to the MME. It comprises 11 members, including the minister of mines and mining, the finance minister, the director of national planning and eight additional experts appointed by the president. All members are appointed for renewable four-year terms. In addition, a government planning unit, attached to MME, oversees development and expansion of the electricity sector.

Organizational Structure



CREG – Regulatory Commission for Energy and Gas. SIC – Superintendence of Industry and Commerce.
SSPD – Superintendence of Residential Public Services. UPME – Energy Mining Planning Unit.
Source: CREG.

Industry Structure

The Colombian electricity sector is organized along four major market activities: generation, transmission, distribution and commercialization. At YE 2018, there were 248 companies registered in the wholesale electricity market, comprised of 73 GenCos, 16 transmission companies 37 DisCos and 122 commercialization companies. Regulations allow the participation of public and private companies, both local and foreign, in each of the market segments. XM is the market manager of the electricity sector in Colombia. Among its duties are the planning and coordination of the operation, generation and transmission resources of the national interconnected system, which includes generating electricity to meet daily demand, managing the electricity commercialization system in the market and managing the regulated remuneration of the electricity transmission companies.

Regulatory Risk

Fitch considers the Colombian regulatory framework within the electricity industry as market supportive and adequately balancing the interests between end users and utilities. Also, the utility regulation has historically presented little government interference. According to regulator guidelines, although CREG is an entity attached to the MME, decisions are taken with votes of at least seven members, so it must include the favorable vote of at least half of the expert members. Also, the tariff-setting procedure for T&D and other regulatory projects is transparent and inclusive; it allows for, and incorporates comments from, market players. This is consistent with an investment-grade assessment of these factors under Fitch's Rating Navigator. Fitch positively views the strength of these regulatory structures, despite the occasional lag in the tariff-review cycle.

Regulatory Timeline

2019	Feb.	Auction Process for OEF allocation — 164.3 Gwh/day assigned at USD15.1 per Mwh.
	Feb.	Auction Process for long-term electricity contracts. No contracts assigned. New auction process announced for 2019.
	Jan.	Res. CREG 015/2019. Modifies rate of return for electricity distribution activity from 2019.
2018	Oct.	Res. CREG 127/2018. (Consultation) Mechanism for incorporating electricity storage in the SIN.
	Aug.	Res. CREG 104/2018. Announcement of OEF expansion auction process for 2022–2023.
	July	CREG 083/2018. Assignment of OEF for existing plants for 2019–2022.
	Feb.	Res. CREG 015/2018. New methodology for the remuneration of electricity distribution activity.
2017	Dec.	Res. 201/2017. Reviews methodology to determine firm energy forsolar power plants.
	Nov.	Res. CREG 167/2017. Methodology established to determine firm energy forwind power plants.
	Sept.	Res. CREG 140/2017. Defines new marginal scarcity price for reliability charge.
2016	Nov.	Res. CREG 177/2016 (Consultation). New methodology for remuneration of electricity transmission.
	Nov.	Res. 195/2016. Sets regulated revenues for companies that use imported natural gas for generation by restriction.
	April	Res. 051/2016. Ends scheme of differential tariffs to encourage voluntary energy savings amid El Niño phenomenon.

Regulatory Timeline (Continued)

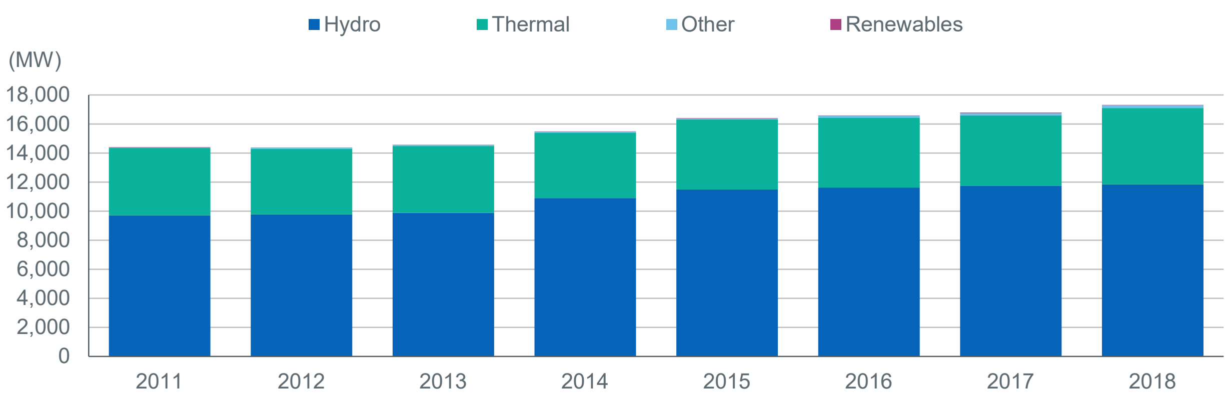
2016	Nov.	Res. CREG 177/2016 (consultation). New methodology for remuneration of electricity transmission activity.
	Nov.	Res. 195/2016. Sets regulated revenues for companies that use imported natural gas for generation by restriction.
	April	Res. 051/2016 Ends the scheme of differential tariffs to encourage voluntary energy savings amid El Niño phenomenon.
	March	Res. CREG 029/2016. Sets a scheme of differential tariffs to encourage voluntary energy savings amid El Niño phenomenon
2015	Nov.	Superintendent of Residential Public Services intervened in Termocandelaria S.C.A E.S.P. For administration purposes, after the company declared itself declared unavailable to generate amid the scarcity condition.
	Oct.	Res. 172/2015. Sets a maximum price for daily dispatch in the wholesale energy market (MEM).
	Oct.	Res. 171/2015. Established measures to increase the participation of minor plants in MEM.

Generation

Installed Capacity

At YE 2018, Colombia had a net installed capacity of 17,312MW, of which 63% was centrally dispatched hydroelectric plants (power plants with installed capacity higher than 20MW). The balance is mostly comprised of thermal electric assets and minor plants, while nonconventional renewable power plants (wind and solar plants) still represent a very limited stake in the Colombian electricity matrix. Within the 5,087MW of centrally dispatched thermal electric capacity, 42% are natural gas power plants, 32% coal-fired plants and the balanced are liquid-fuel plants.

Colombia Generation Installed Capacity by Power Source

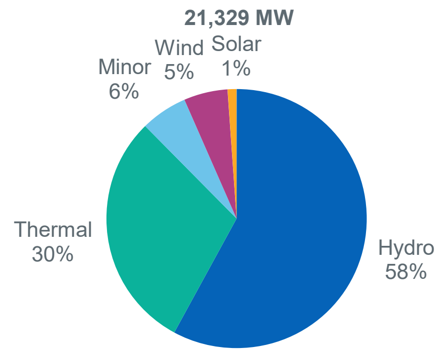


Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

The February 2019, an OEF auction was completed with the incorporation of additional 4,010MW in the Colombian electricity matrix by 2022, of which 1,240MW are thermal electric assets, including both new and expanded existing plants, 1,372MW of hydroelectric plants (including 1,200MW that is 50% of the installed capacity of Ituango project) and 1,398MW in nonconventional renewable projects (1,160MW of wind power and 238MW of solar power). Therefore by 2022, Colombia plans to provide a more diversified electricity generation matrix, as hydroelectric plants reduce their participation in the electricity matrix to 58% from 63% at YE 2018, while wind and solar power plants would increase their stake to 6%.

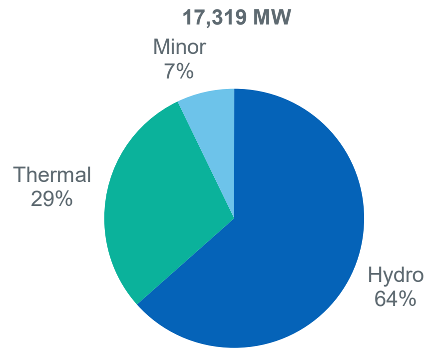
The Colombian electricity generation market is concentrated, although there are 73 companies registered as GenCos, with the five largest GenCos representing roughly 70% of the country's net installed capacity. At YE 2018, Emgesa S.A E.S.P. was Colombia's largest generation company in terms of installed capacity, covering 20% of Colombia's generation matrix. During 2018, Emgesa increased its installed capacity to 3,501MW from 3,467MW at YE 2017, following capex for its existing assets. EPM is expected to retake the lead in installed capacity by 2022, due to the expected COD of the Ituango hydroelectric project.

Expected Electricity Generation Matrix
(2022)



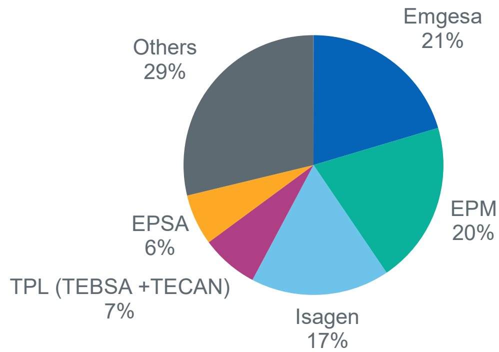
Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

Current Electricity Generation Matrix
(2019)



Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

Net Installed Capacity by Entity
(2018)

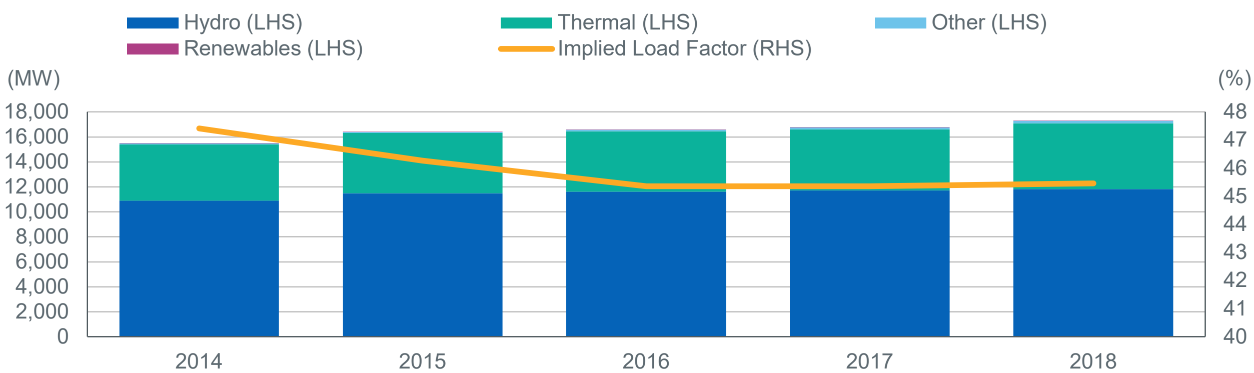


EPSA – Empresa de Energia del Pacifico S.A. E.S.P. EPM – Empresas Publicas de Medellin E.S.P.
GEB – Grupo Energia Bogota S.A. E.S.P. ISA – Interconexion Electrica S.A E.S.P. TPL – TermoCandelaria Power Ltd.
Source: Energy company reports.

Power Generated

Colombia's electricity generation mix of hydro and thermal sources has been high volatile, depending on anticipated or prevailing hydrology conditions. Under normal conditions, hydroelectric generation meets more than 75% of the daily demand, while the balance is covered by the most efficient thermal assets, especially coal-fired and natural gas power plants. Moreover, thermal assets located on the Caribbean coast are key to meeting demand in that region, given the historical transmission bottlenecks that constrain the supply of electricity from lower variable-cost assets in central Colombia. During low-hydrology conditions, such as the 2015–2016 El Niño phenomenon, thermal electric generation met more than 50% of daily electricity demand, including costly liquid fuels power plants.

Utilization Rate
(2014–2018)

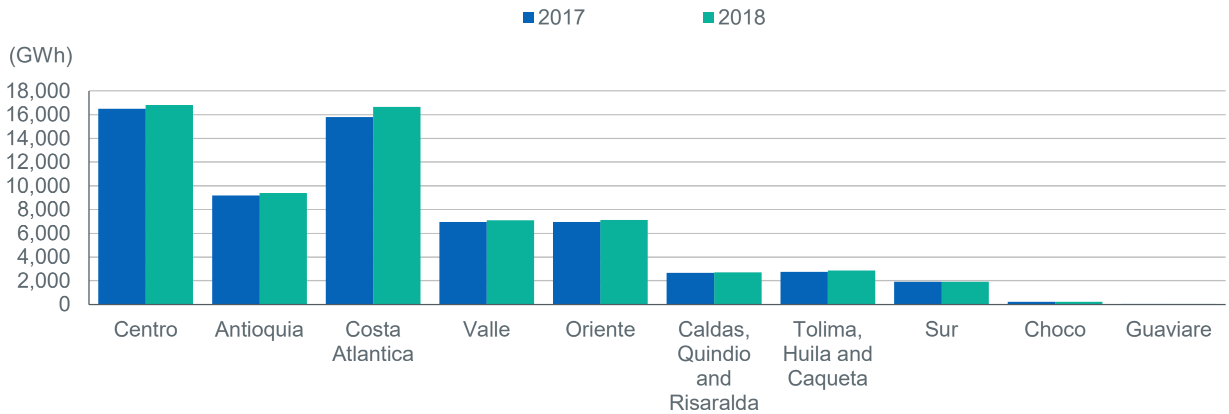


Source: Fitch Ratings, XM Compañía de Expertos en Mercados S.A. E.S.P.

Distribution

The electricity distribution segment in Colombia is served by 37 registered distribution companies (DisCos). Electrificadora del Caribe (Electricaribe) is the largest DisCo in Colombia in terms of demand served in gigawatts/hour, holding about 24% of 2018 demand and serves seven Departments in the Caribbean Coast. The government intervened in the company, through the Superintendence of Residential Public Services, amid a financial distress condition that could affect the continuity of service provisions in its relevant area. The government is encouraging investors to take on company's operations. Codensa S.A. E.S.P. (AAA(col)/Stable) is the second largest DisCo in Colombia, serving around 22% of Colombia's demand in gigawatts per hour.

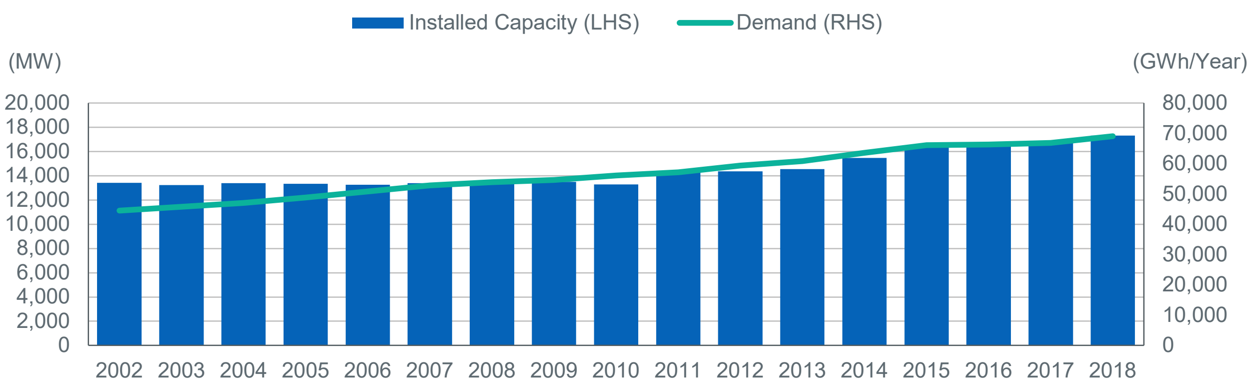
Electricity Demand by Region



Source: Fitch Ratings, XM Compañía de Expertos en Mercados S.A. E.S.P.

Colombian electricity demand is mostly driven by the regulated sector, which accounts for about two-thirds of consumption. This leads to relatively low volatility over time, compared with other countries in the region in which the nonregulated market has a higher stake in the demand. During 2016–2017, demand growth was sluggish, mostly as a result of low GDP growth, coupled with the lagged effects of a government energy-saving initiative taken in 2015 amid a severe drought that stressed the electricity supply. In 2018, electricity demand rebounded, recording 3.3% growth for 2018 and 4.1% growth for first-quarter 2019, compared with first-quarter 2018.

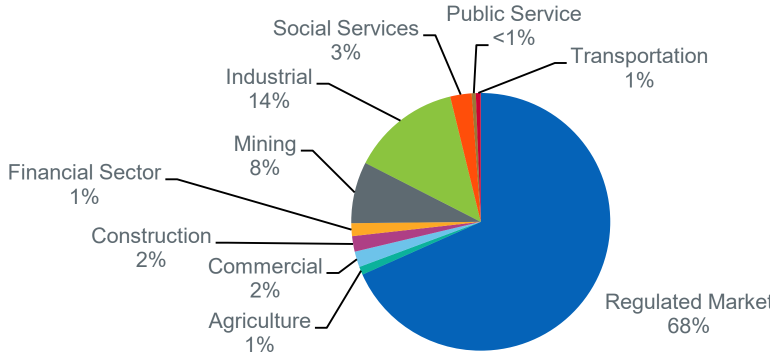
Colombia Electricity Demand and Installed Capacity



Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

In February 2018, CREG released the final methodology for remuneration of electricity distribution activity and lower rate of return that applies to the sector. The new remuneration methodology incorporates significant changes in the distribution activity, as it includes the asset base depreciation in the companies' revenues structure. This means they will have to execute capex that at least compensates depreciation expenses, so as to maintain revenues.

Colombia — Electricity Demand by Sector

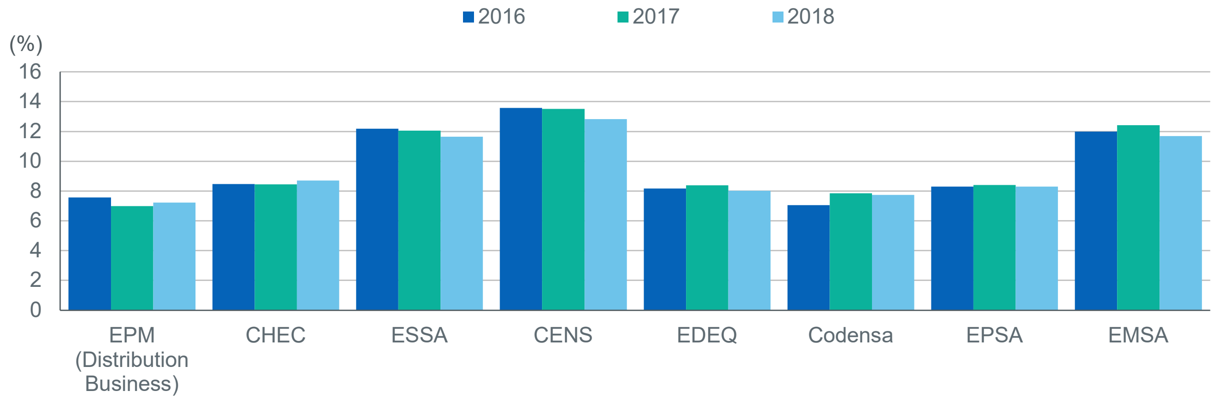


Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

Energy Loses

Fitch-rated companies that participate in the electricity distribution segment maintain low to moderate energy losses levels. It is expected that companies have a positive path of reduction or maintenance of energy losses in the medium term, as a result of the significant capex to be executed in the following years, driven by incentives provided by the new methodology to remunerate electricity distribution activity.

Energy Losses by Company
(2016–2018)



CENS – Centrales Electricas del Norte de Santander S.A. E.S.P. CHEC – Central Hidroelectrica de Caldas S.A. E.S.P.
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Source: Fitch Ratings, company energy reports.

Transmission

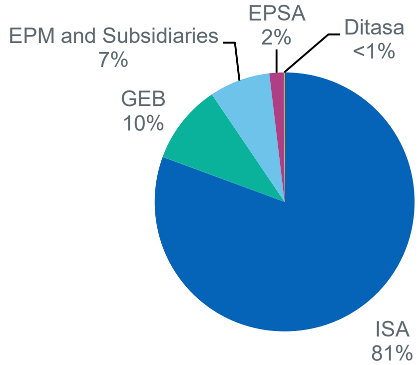
The Colombian electricity transmission network, particularly the grid that serves the northern coast, has historically experienced important bottlenecks that prevent the systems from matching the daily ideal dispatch. This has required encouraging the installation of thermal-electric assets on the Caribbean coast so as to meet the demand in that region. These assets can generate “out-of-merit” electricity, that is, they are called to dispatch electricity even though they are not in the baseload on a specific date. Restrictions are found both in the National Transmission System (Sistema de transmisión nacional [STN]), which limits the capacity to carry all the electricity consumed by the Caribbean coast with hydroelectric assets, which are mostly located in the center of the country. Also, there are restrictions for the Caribbean coast that constrain electricity transmission, including assets located in the region. In 2018, the government auctioned a project to build a 1,000MW transmission line across the Guajira region, which should enable the development of large-scale regional wind and solar projects.

National Transmission System as of 2016

Source: UPME (Unidad de Planeacion Minero Energetica).

Colombia's electricity transmission business is a regulated natural monopoly. Transmission expansion projects are executed through government-run auctions that aim to provide projects required by the system. Projects are granted to investors that present the lowest offer. These projects are remunerated through guaranteed revenues for 25 years and then are incorporated as an existing regulated asset and remunerated according to the existing electricity transmission regulatory framework. ISA, GEB and EPM own and operate the vast majority of transmission lines in Colombia (220kv or above).

Transmission Network by Company
(Powerlines of 210kV or above — First-Quarter 2019)



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GEB – Grupo Energia Bogota S.A. E.S.P. ISA – Interconexion Electrica S.A E.S.P.
Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

Corporates

Fitch's portfolio of electricity companies with international scale ratings comprises six companies, three of which are pure GenCos, two are conglomerates that participate in the electricity transmission business in Colombia at the holding level, among other businesses in Colombia and the region, and one is an integrated company that participates at all levels of the electricity business in Colombia, along with other businesses in Colombia and abroad. Within this group, five have IG ratings between 'BBB' and 'BBB+', reflecting low business risk profiles, asset robustness and diversification predictable cash flow generation and generally solid credit metrics.

The portfolio of Fitch companies with only national ratings comprises nine companies, six of which are pure or mostly DisCos, one GenCo, one transmission company and the other an integrated company with a distribution business expected to represent around 60% of the total EBITDA generation. Within this group, eight companies rated at the maximum level in national scale 'AAA(col)', reflecting low business risk profile, manageable regulatory risk, and low to moderate leverage metrics.

List of Issuers

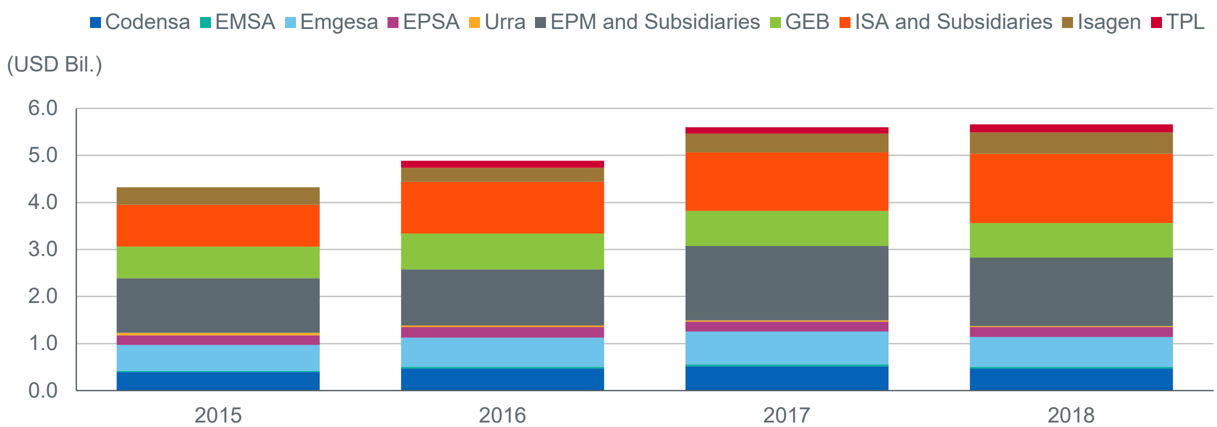
International Rated Issuers

Issuer	**LT IDR/NLTR or bond issuance/Rating Out or Watch**
Emgesa S.A. E.S.P	BBB/AAA(col)/Stable
Empresas Publicas de Medellin E.S.P. (EPM)	BBB/AAA(col)/Rating Watch Negative
Grupo Energia Bogota S.A. E.S.P. (GEB)	BBB/AAA(col)/Stable
Interconexion Electrica S.A. E.S.P.	BBB+/AAA(col)/Stable
Isagen S.A. E.S.P.	BBB/AAA(col)/Stable
TermoCandelaria Power Ltd.	BB+/Stable
Issuers with National ratings only	**NLTR or Bond Issuance/NSTR/rating Outlook or Watch**
Central Hidroelectrica de Caldas S.A. E.S.P.	AAA(col)/F1+(col)/Rating Watch Negative
Centrales Electricas del Norte de Santander S.A. E.S.P.	AAA(col)/F1+(col)/Rating Watch Negative
Codensa S.A. E.S.P.	AAA(col)/F1+(col)/Stable
Electrificadora de Meta S.A. E.S.P.	AAA(col)/F1+(col)/Stable
Empresa Electrificadora de Santander S.A. E.S.P.	AAA(col)/F1+(col)/Rating Watch Negative
Empresa de Energia del Pacifico S.A. E.S.P. (EPSA)	AAA(col)/F1+(col)/Stable
Empresa de Energia del Quindio S.A. E.S.P.	AAA(col)/F1+(col)/Rating Watch Negative
Empresa de Urra S.A. E.S.P.	A(col)/F1(col)/Stable
Transelca S.A. E.S.P.	AAA(col)/Stable

Source: Fitch Ratings.

International rated companies that participate in the Colombian generation electricity sector maintained moderate growth over the last few years, amid sluggish electricity demand in 2016 and 2017, and low spot prices in 2017 and 2018. In the medium term, GenCos are expected to record higher EBITDA growth, driven by higher demand, linked to GDP growth of 3.3% and 3.5% for 2019 and 2020, respectively, as well as higher spot prices, compared with levels recorded in 2017 and 2018, given the expected reduction in the system's reserve margin, as it has not contemplated material capacity incorporation in 2019 and 2020. Thus, Fitch-rated GenCos could have temporary EBITDA gains in a scenario in which spot prices reflect a lower flexibility in the system and a higher proportion of thermal electric generation to cover the daily demand.

EBITDA Evolution
(2015–2018)



EMSA – Electrificadora de Meta S.A. E.S.P. EPSA – Empresa de Energia del Pacifico S.A. E.S.P.
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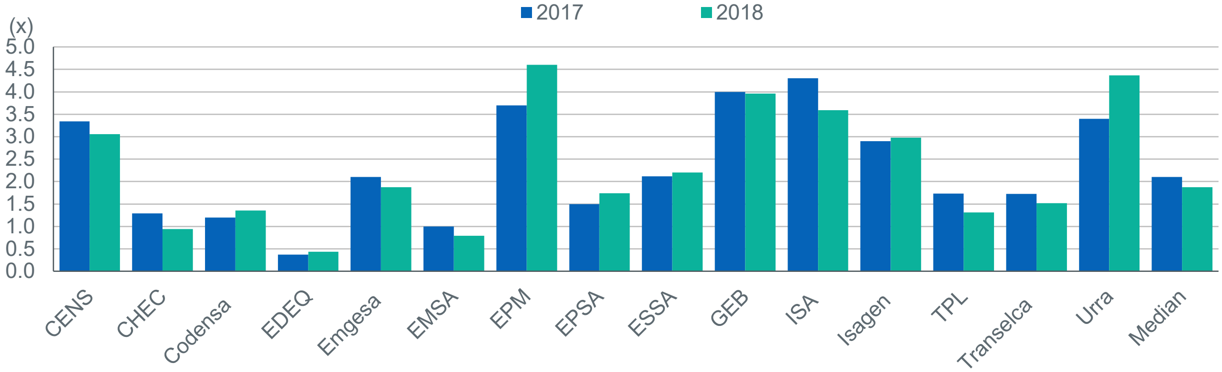
TPL – TermoCandelaria Power Ltd.
Source: Fitch Ratings.

Leverage — Electric Sector
(2017–2018)



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ISA – Interconexion Electrica S.A E.S.P. TPL – TermoCandelaria Power Ltd.
Source: Fitch Ratings.

Reliability Charge Encourage Capacity Expansion

The reliability charge is the mechanism that has been applied in the Colombian electricity sector to incentivize companies to invest in installed capacity expansion, when a future imbalance in the supply and demand of electricity in the medium term is foreseen. The scheme ensures that under low hydrology conditions, the Colombian matrix has enough firm energy to meet the forecasted electricity demand. Under this mechanism, companies receive a fixed payment for up to 20 years in the case of new plants, subject to the obligation of dispatching its allocated OEF in a scarcity situation, that is, when scarcity price, as defined by the regulator, surpasses the spot price. Reliability-charge revenues represent the high stake of EBITDA generation for companies with a higher proportion of thermal assets in their matrix, as they typically maintain low to moderate load factors, so revenues for electricity generation are not as high as in the case of GenCos with high proportion hydroelectric assets.

Regulatory Initiatives Mitigates Business Risks for GenCos

Fitch believes that financial pressures stemming from the volatility of hydrology are currently more under control of the companies and their commercial policies, since regulatory initiatives derived from the 2015–2016 El Niño minimize the probability of companies being required to dispatch energy at negative gross margins. The price-setting mechanism now covers the costs of 98% of GenCos receiving reliability charges in the event they are obligated to dispatch under a scarcity scenario. Additionally, the presence of the new liquefied natural gas plant on the Caribbean coast secures gas supply for up to 400 million cubic feet per day, in addition to Colombia's locally sourced gas production, which limits the possibility of using costly liquid fuels in electricity generation.

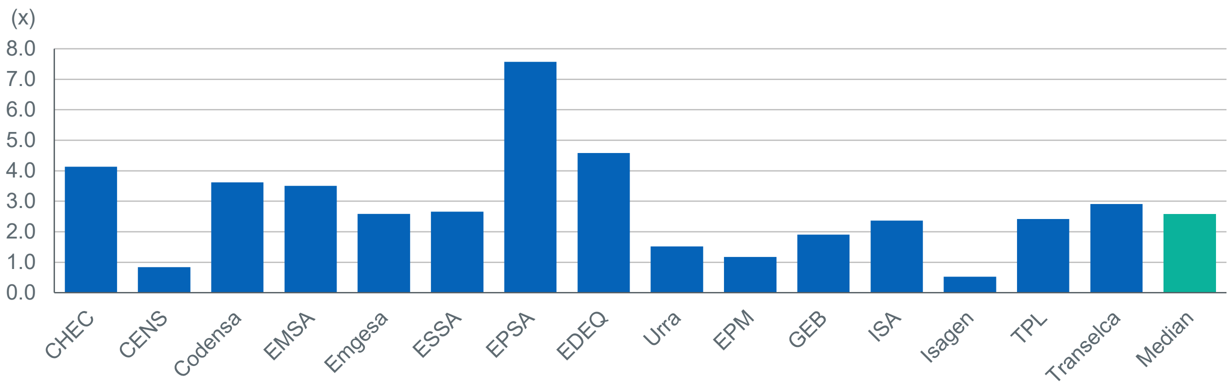
Stable Credit Metrics

Generally speaking, corporates in the Colombian electricity market have maintained moderate leverage metrics, in line with its ratings. Temporary leverage deviation has been observed when companies embark in significant capex programs to expand capacity or strengthen their asset base. Most of these companies have proven to have ample access to loan and capital markets, which adds to the companies' financial flexibility and liquidity metrics across the investment cycle.

Issuers across this portfolio have consistently maintained or improved their investment-grade profiles over the last seven years. Only EPM recorded a rating downgrade during the period, to 'BBB' from 'BBB+' in 2018. EPM's ratings downgrade reflected the technical complications related to the company's Ituango hydroelectric project and Fitch's view that these will materially affect the company's ability to reach medium-term deleveraging targets. In terms of Rating Outlooks or

Watches, only EPM maintains a Rating Watch Negative, reflecting the continued uncertainty around the project's development.

Liquidity — Colombian Electric Companies
(Cash Plus CFO / Short-Term Debt, 2018)



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Source: Fitch Ratings.

Liquidity

Generally, companies in Fitch's portfolio that participate in the electricity sector maintain adequate liquidity levels, supported by healthy cash balance, stable cash from operations and manageable debt-maturity profiles. Issuers with international ratings in the Colombian electricity market have ample access to financing through local and international markets that contribute to their financial flexibility and credit profiles. In local markets, companies place bonds with maturities of up to 30 years that match with the long-term nature of their projects and mitigate the refinance risks for the next debt maturities.

Electricity Generation Projects to be Incorporated by 2022 from Latest Auction

	Condition	Total Net Installed Capacity (MW)	Firm Energy Obligation (Gwh)
Thermal Project			
Termovalle Expansion	Special	40.0	5.5
El Tesorito	New	200.0	4.6
PW-CON3	New	150.0	2.9
TERMOSOLO1	New	148.0	2.8
TERMOSOLO2	New	80.0	1.5
TERMOYOPALG3	New	50.0	1.1
TERMOYOPALG4	New	50.0	1.1
TERMOYOPALG5	New	50.0	1.1
TERMOEBR	Special	19.4	0.4
TERMOPROYECTOS	Special	19.4	0.4
TERMOCARIBE 1	New	150.0	2.9
TERMOCARIBE 3	New	42.0	0.8
Termocandelaria - CCGT Conversion	Special	241.0	5.6
Total Thermal		1,239.8	30.8
Wind Projects			
Parque Beta	New	280.0	0.2
Casa Electrica	New	176.3	0.9
Parque Alpha	New	212.0	0.2
Windpeshi	New	195.0	0.8
Tumawind	New	197.8	0.3
Chemesky	New	98.9	0.2
Total Wind Projects		1,160.0	2.5
Solar Projects			
El Paso solar	Special	68.0	0.2
La Loma Solar	New	170.0	0.5
Total Solar Projects		238.0	0.8
Hydro Projects			
Ituango	Special	1200	3.2
Escuela de Minas	Special	55.0	0.15
Miel II	New	116.8	0.2
Total Hydro Projects		1,371.8	3.5
Total Projects		4,009.6	37.5

Source: XM Compañía de Expertos en Mercados S.A. E.S.P.

Related Research

Fitch Revises Colombia's Outlook to Negative; Affirms IDR at 'BBB' (May 2019)
Colombia (May 2019)

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Costa Rican Electricity Sector

Generation Expansion on Hold

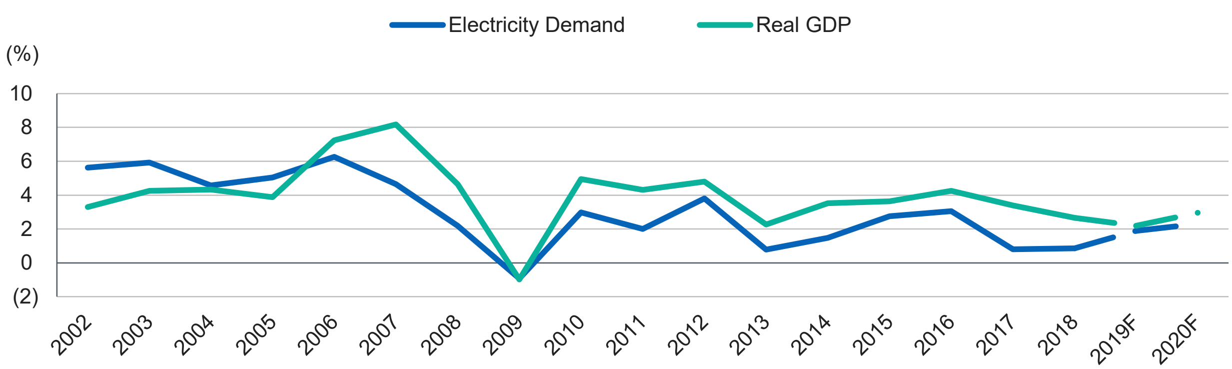
Lower Investment Needs: The Generation Expansion Plan or Plan de Expansion de la Generacion (PEG) 2018–2034 showed reduced expectations for growth in electricity demand due to a slowdown in Costa Rica's (B+/Negative) economy. The Diquis Hydroelectric Project, at 650MW, a pillar of the previous strategy, was not part of the optimal minimum cost plan and was canceled as the National Electric System, or Sistema Electrico Nacional (SEN), cannot absorb the additional generation. No new state-owned additions to the system are expected until 2026. PEG estimates total capital investments of close to USD497 million for 2020–2026 compared with a 2014 estimate of USD5 billion.

Production Dynamics: Fitch Ratings notes generation by private entities and from distributors increased as a share of gross energy production. Private generation grew at a CAGR of 10.4% during 2011–2018 while generation from distribution grew 9.1% during the same period, compared with 0.6% for Grupo ICE. Total generation for Grupo ICE dropped to 77.9% at YE 2018 from 86.7% in 2011. Private companies' share rose to 12.9% at YE 2018 from 7.5% in 2011 and distribution companies' generation rose 9.2% at YE 2018 from 5.8% in 2011. By law, private generation is capped at 30% of total installed capacity.

Energy Matrix Concentrated on Renewables: The Costa Rican generation matrix has a strong base in hydroelectric, geothermal and wind plants. Green energy generation represented 93.8% of total electricity, on average, during the past eight years. Non-renewable generation, such as thermoelectric and bagasse, function as a backup during the dry season. However, as of 2015, wind generation increased and compensated for most of the seasonal decline in hydroelectric generation, even exceeding geothermal generation. Additional capacity requirements from 2028 and beyond will be covered by wind and solar projects.

Regulatory, Political Interference a Risk: The Costa Rican electricity sector is highly exposed to regulatory interference risk, given the lack of clear and transparent electricity tariff schedules. Distribution companies propose electricity tariffs for end users to the regulator annually, while regulatory and political interference affected the tariff adjustment process in recent years. Tariffs are set using two mechanisms: through the quarterly adjustment of variable costs of fuel in place since 2013 and an ordinary tariff review that considers operating costs.

Costa Rican Electricity Demand Versus Real GDP Growth



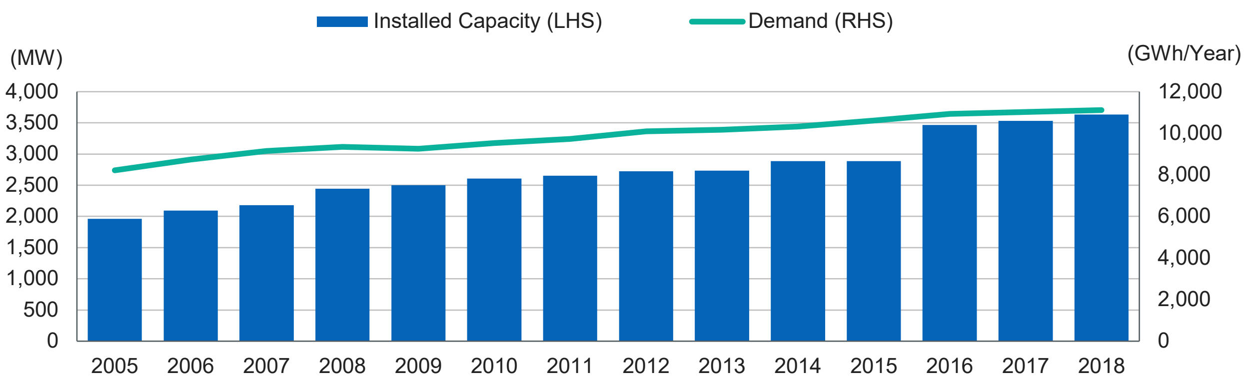
F – Forecast.
Source: Fitch Solutions, National Center for Energy Control, Central Bank of Costa Rica.

Primary Market Considerations

Growth Prospects Revised Downward

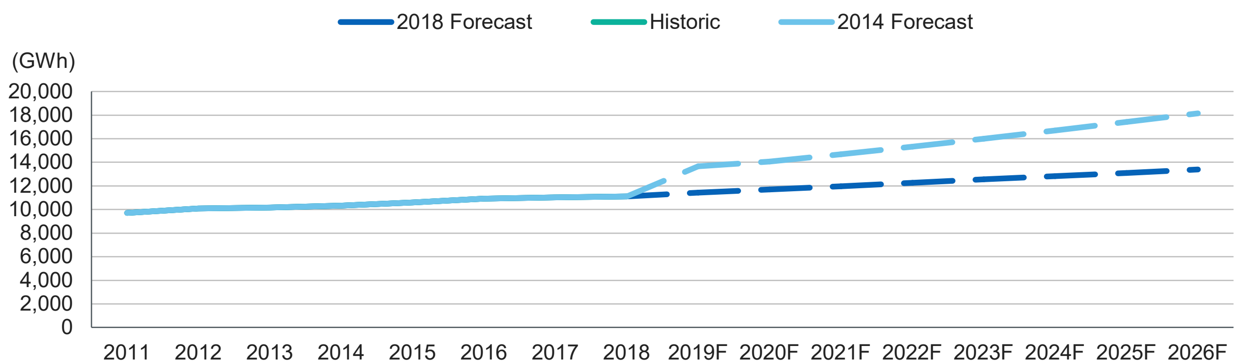
Costa Rican electricity consumption is positively correlated with GDP, growing at an average rate of approximately 1.8% over the past 10 years. Growth in electricity demand is primarily supported by commercial and residential activity, accounting for 66.9% of consumption in 2018 and, therefore, plays an important role in the growth rate of the sector. Electricity demand is expected to grow at a CAGR of 2.3% during 2019–2026 compared with the previous estimate of 6.3% according to the Instituto Costarricense de Electricidad's (ICE) PEG 2018–2034. ICE is the government-run electricity services provider that along with Radiografica Costarricense S.A. and Compania Nacional de Fuerza y Luz S.A. (AAA[cri]/Stable) form the Instituto Costarricense de Electricidad y Subsidiaries' (Grupo ICE; B+/Negative). Lower growth prospects are the result of a challenging macroeconomic environment and a change in consumption patterns.

Costa Rican Electricity Supply and Demand Balance



Source: Fitch Solutions, National Center for Energy Control.

Estimated Demand Projection

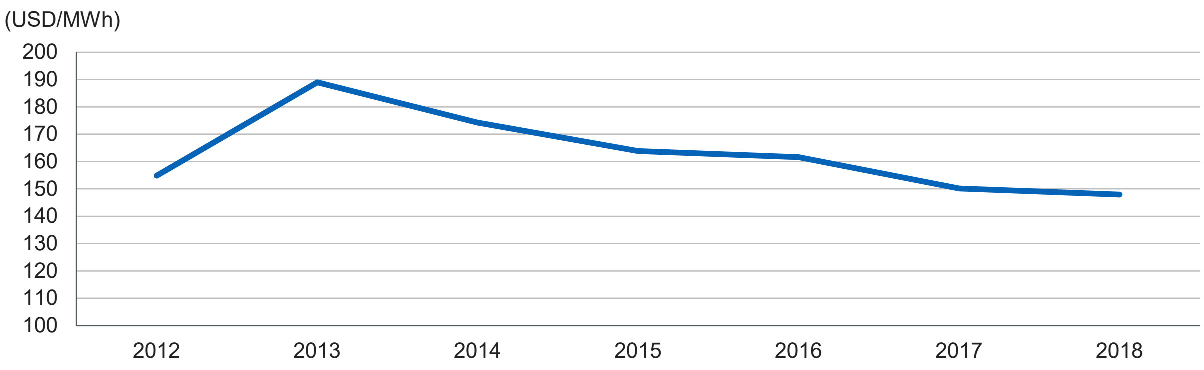


F – Forecast.
Source: Fitch Solutions, National Center for Energy Control, Costa Rican Institute of Electricity.

Pricing

All tariffs are regulated and set by the Regulatory Authority for Public Services or Autoridad Reguladora de Servicios Publicos (ARESEP) to cover the total cost of energy. Every year companies submit an electricity tariff for end users to the regulator for approval. Tariffs are adjusted to reflect fuel cost variations on a quarterly basis since 2013. Electric tariffs also include a component to remunerate capital investments as long as the tariffs are included in the company's investment plan approved by the regulator. New asset additions will be recognized in tariffs according to their annual execution progress, measured as the ratio between the projects built or equipment installed by the company, and the amount of projects or equipment recognized by the regulator for that year.

Average Distribution Price

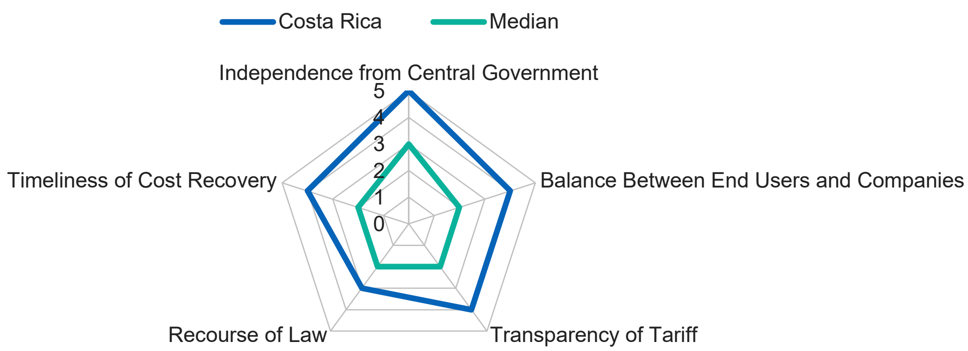


Source: Fitch Solutions, Regulatory Authority for Public Services.

Regulatory Framework

The electric industry in Costa Rica is regulated by ARESEP, or Law 7593, and Decree Law No. 449. There are laws and regulations applicable to the electric power sector but no general industry law was enacted. Private generation was regulated by Law 7200, later reformed by Law 7508, which capped private generation at 30% of the total installed capacity. The electricity sector is exposed to high regulatory interference risk, given the lack of clear and transparent electricity tariff schedules and extensive participation of the government in policies, planning, regulation and operation of the SEN. Fitch considers Costa Rica's regulatory risk as high, in line with the 'B' category.

Costa Rican Regulatory Score



Note: 1.0 = A; 2.0 = BBB; 3.0 = BB; 4.0 = B; 5.0 = CCC.
Source: Fitch Solutions.

Regulatory Bodies

Regulatory Authority for Public Services

The ARESEP is an autonomous government entity that regulates public utility companies and modifies, approves or rejects changes in tariffs and pricing proposed by public utilities.

General Comptroller of the Republic

The General Comptroller of the Republic or Contralor General de la Republica (CGR) is a constitutional body and an auxiliary of the legislative assembly overseeing the use of public funds to improve the management of the public treasury and contribute to political and citizen control.

Ministry of Environment and Energy

The Ministry of Environment and Energy or Ministerio de Ambiente y Energia (MINAE) is responsible for the nation's energy agenda. MINAE generates guidelines ensuring legal compliance with regulations related to the activities of the energy sector. This is in order to promote evaluation, measurement and monitoring of the works, activities and projects in MINAE's purview.

National Center for Energy Control

The National Center for Energy Control or Centro Nacional de Control de Energia (CENCE) directs and manages the operation of SEN to meet the country's demand in electricity and make effective energy exchanges, such as importing and exporting, with the Regional Electricity Market or Mercado de Electricidad Regional (MER).

Industry Structure

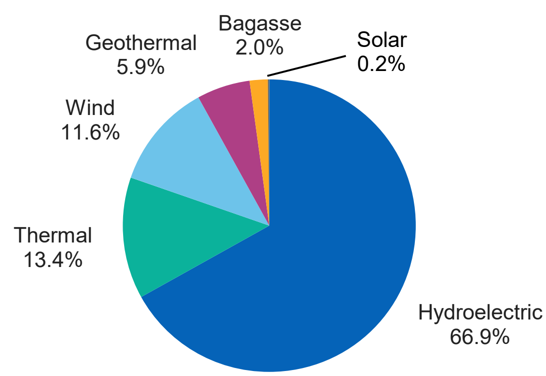
The Costa Rican electricity system is operated by CENCE, which is part of Grupo ICE, and dedicated to short-term administration and planning. MINAE is responsible for long-term planning and administration, which is covered by the National Energy Plan guiding the actions of market participants. PEG 2018–2034 seeks to guide the long-term expansion of electrical development, generation, transmission and distribution of Grupo ICE and the integration of the development projects of other companies in the electricity sector.

Generation

Installed Capacity

SEN's total installed capacity was 3,528.5MW, as of May 2019, of which 66.9% was hydroelectric, 13.4% thermal, 11.6% wind, 5.9% geothermal, 2.0% bagasse and 0.2% solar.

Total Installed Capacity
(As of May 2019)

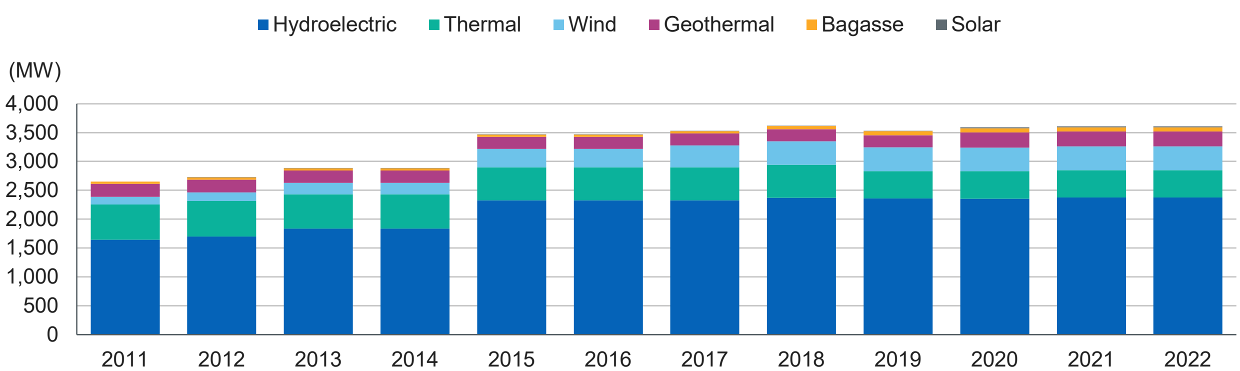


Total Installed Capacity 3,528.5MW

Source: Fitch Solutions, National Center for Energy Control.

According to PEG 2018–2034, no new state-owned additions to the system are expected until 2026 when the geothermal operation of Borinquen I goes online. On the private side, there are three hydroelectric projects in the pipeline for 2021.

Installed Capacity



Source: Fitch Solutions, National Center for Energy Control, Costa Rican Institute of Electricity.

Recommended Generation Expansion Plan for 2019–2026

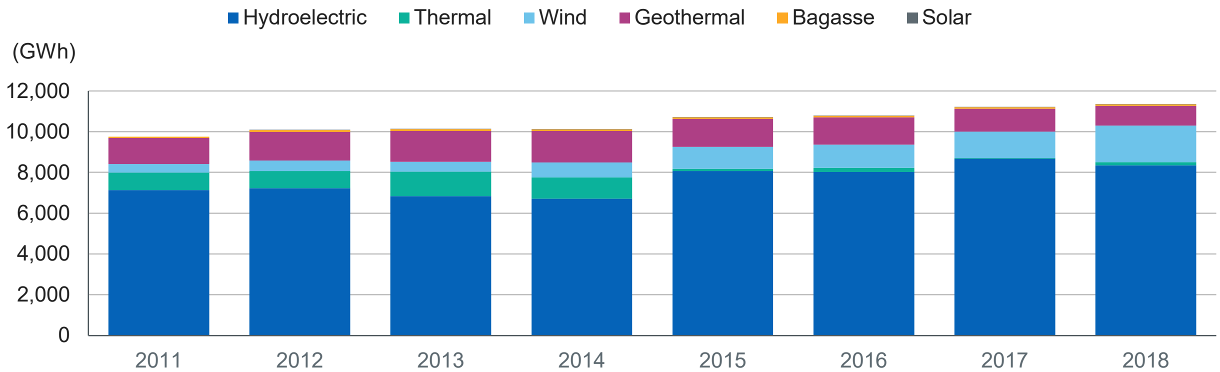
No.	Name	Company	Technology Type	Installed Capacity	Estimated	Estimated Total Investment
1	San Rafael	H. Solis	Hydroelectric	7	2021	27
2	Rio Bonilla 1320	H. Solis	Hydroelectric	6	2021	22
3	Rio Bonilla 510	H. Solis	Hydroelectric	6	2021	24
4	Borinquen I	Grupo ICE	Geothermal	55	2026	424
			Total	**74**	**—**	**497**

H. Solis – Constructora Hernan Solis S.R. Ltda. Group ICE – Instituto Costarricense de Electricidad or Costa Rican Institute of Electricity.
Source: Fitch Solutions, Costa Rican Institute of Electricity.

Energy Generated

SEN's total energy generation was 11,355GWh in 2018, representing a CAGR of 2.6% since 2011. Hydroelectric generation represented 73.5%, wind was 15.8%, geothermal 8.5%, thermal sources were 2.1% and solar was 0.1% as of 2018. Costa Rica managed to produce an average of 93.8% of total energy generation from green sources in the last eight years.

Energy Production by Source

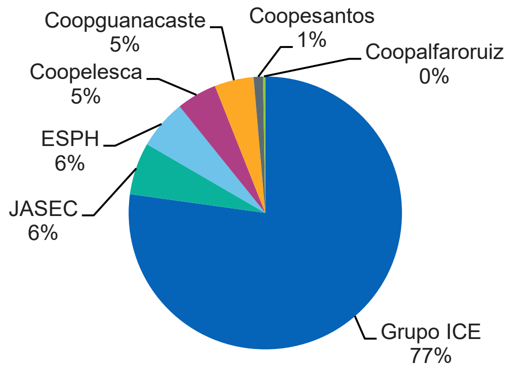


Source: Fitch Solutions, National Center for Energy Control.

Distribution

Energy distribution is mainly concentrated in the state-owned company Grupo ICE, which accounted for 77.2% of the energy distributed in 2018. The company has a service area of 39,600km^2 or 77.5% of the country's territory. The remainder of the market consists of two municipal distributors and four electric cooperatives. Distribution companies operate under a regime of public service concession and provide electricity service to all customers and are subject to regulated tariffs set by ARESEP.

2018 Energy Distribution Market Share



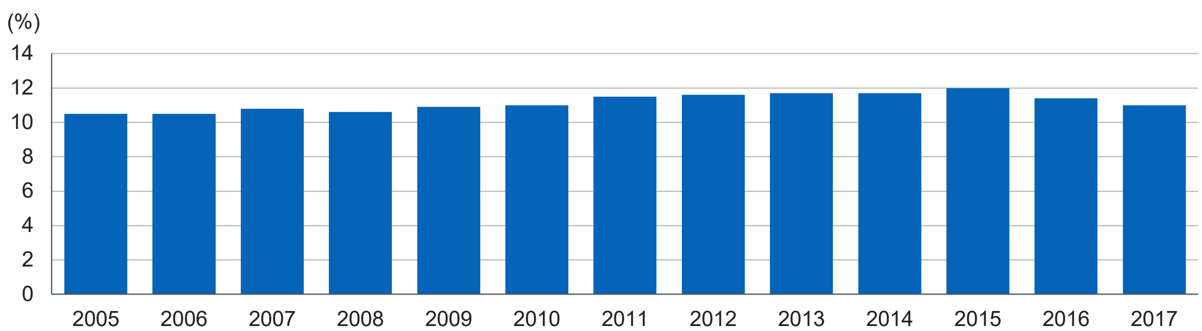
JASEC – Junta Administrativa de Servicio Electrico Municipal de Cartago or Municipal Electric Service Administrative Board of Cartago. ESPH – Empresa de Servicios Publicos de Heredia or Public Services Company of Heredia. Coopelesca – Cooperativa de Electrificacion Rural de San Carlos R.L. or Rural Electrification Cooperative of San Carlos. Coopguanacaste – Cooperativa de Electrificacion Rural de Guanacaste R.L. or Rural Electrification Cooperative of Guanacaste. Coopesantos – Cooperativa de Electrificacion Rural Los Santos R.L. or Rural Electrification Cooperative of Santos. Coopalfaroruiz – Cooperativa de Electrificacion del Canton de Alfaro Ruiz R.L. or Rural Electrification Cooperative of Canton Alfaro Ruiz. Grupo ICE – Instituto Costarricense de Electricidad or Costa Rican Institute of Electricity.
Source: Fitch Solutions, Public Service Regulating Authority.

Distribution Companies in Costa Rica as of 2018

Distribution Company	No. of Clients (000)	Energy Sold (GWh)	Concession Area (Km^2)
Costa Rican Institute of Electricity	1,343	7,464	39,600
Municipal Electric Service Administrative Board of Cartago	98	597	1,103
Public Services Company of Heredia	86	566	104
Rural Electrification Cooperative of San Carlos	96	460	4,851
Rural Electrification Cooperative of Guanacaste	78	447	3,915
Rural Electrification Cooperative of San Carlos	46	108	1,275
Rural Electrification Cooperative of Canton de Alfaro Ruiz	7	26	252

Source: Fitch Solutions, Regulatory Authority for Public Services.

Energy Losses



Source: Fitch Solutions, Costa Rican Institute of Electricity.

Transmission

Grupo ICE is the institution responsible for planning, building, operating, maintaining and expanding the transmission network in Costa Rica. The transmission system extends from Peñas Blancas, the border with Nicaragua, to Paso Canoas, the border with Panama, and from Sixaola in the Caribbean to Santa Cruz on the Nicoya Peninsula. The transmission grid is fully interconnected, including the connection lines with the aforementioned countries, which feed the Electric Interconnection System of the Countries of Central America or Sistema de Interconexion Electrica de los Paises de America Central for the MER. Costa Rica had a total of 2,373km of transmission lines, distributed in 1,724km of links at 230kW and 650km of 138kW as of 2017.

Related Research

Fitch Ratings: Costa Rica Debt Approval to Ease Financing Constraints (July 2019)
Fitch Affirms ICE at 'B+'; Outlook Negative (July 2019)
Costa Rica (January 2019)

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Dominican Republic Electricity Sector

Energy Matrix Evolving but Sector Still Vulnerable to High Fuel Prices

Losses Elevated but Moderating: Extremely high electric distribution losses showed signs of moderation. Losses for the LTM ended December 2018 fell to 28.4% from 31.5% in December 2016, declining in every month except January 2018, when figures were flat. By comparison, losses were 36% and 35% in 2009 and 2010, respectively. These improvements reflect distribution company efforts to upgrade networks, improve metering systems, fortify select circuits and raise awareness among the population. Fitch Ratings views these efforts as key to the long-term financial health and viability of the system.

Energy Matrix Diversification: The percentage of the Dominican Republic's (BB–/Stable) petroleum-derived electric generation fell to 38% in 2018 from 88% in 2000. This phenomenon coincided with an influx of private capital in the generation segment during 2000–2004 leading to 1,180MW of new generation capacity and the repowering of some existing capacity with an emphasis on natural gas and coal. EGEHID, the state-owned and sole Dominican hydroelectric power producer, increased capacity to 616MW in 2018 from 402MW in 2000, increasing hydroelectric's generation share overall. We view these developments as an important step in ensuring the balance and stability of the sector over the long term.

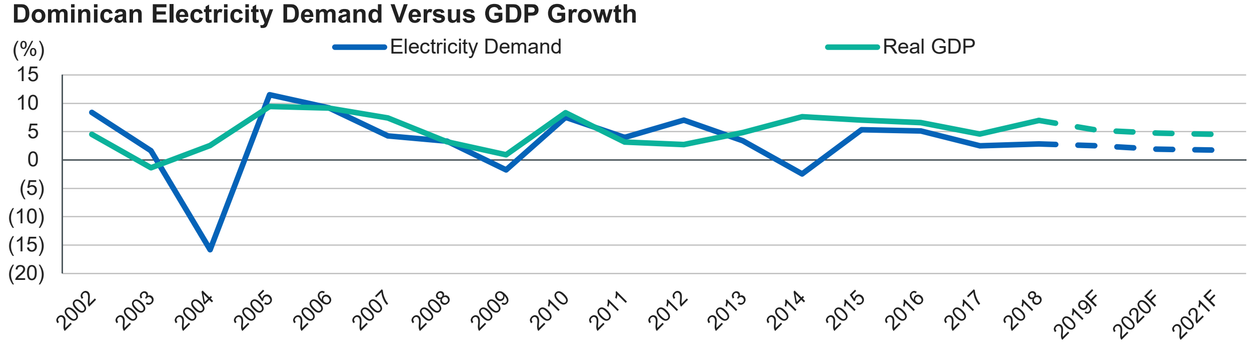
Sector Prone to Financial Deficits: While the country made strides to broaden its energy matrix, the sector remains susceptible to increases in commodity prices, particularly Fuel Oil #6 or heavy fuel oil, which still accounts for about one third of generation. Electricity spot prices were 99% correlated with Fuel Oil #6 prices during 2009–2018. After fuel oil prices rose in 2018, the three state-owned distribution companies owed USD600 million to private generation companies as of YE 2018, approximately four times the total at YE 2017.

Natural Gas Conversion: The CDEEE may award new power purchase agreements (PPAs) of between seven and 10 years to power generators converting to less expensive natural gas from petroleum-derived fuel oil. The CDEEE expects 430MW at Barrick Gold's Quisqueya I & II and 300MW at CESPM to move to natural gas. An additional 210MW have the potential for conversion. All told, 940MW may be converted, equivalent to approximately 24% of the country's installed capacity. Fitch believes this will translate into lower energy costs due to the relatively low price of natural gas as a generation input.

New Unit to Pressure Prices: Punta Catalina is a USD2 billion, 752MW coal-fired power plant comprised of two 376MW units. The first unit is in the testing phase and is expected to begin operation in 2019, while the second is scheduled to go online at YE 2019. Fitch expects the entry of Punta Catalina to put downward pressure on spot prices, given the size of the project at approximately 19% of current installed capacity, and the plant's anticipated highly competitive position in the country's variable cost merit-based dispatch curve. The project is a key part of the CDEEE's strategic goal to balance the energy generation matrix, lower energy generation costs and reduce the electricity sector's financial deficit.

Electricity Reliability Improved: The country experienced 36 complete blackouts during 2000–2005, including 10 in 2004 when rising oil prices, a weaker currency and delays in government payments stressed the sector. However, there were only five complete blackouts during 2006–2018. The average frequency quality of the electric grid, measured in hertz, also improved, to 94.7% in 2018 from 63.3% in 2005. The improvement can be attributed to upgraded frequency variation protections in the electric grid and more generation units participating in frequency regulation.

Dominican Electricity Demand Versus GDP Growth



F – Forecast.
Source: Fitch Ratings, Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

Primary Market Considerations

Growth Prospects

Historically, the Dominican electricity market was limited by high costs, the need to import fuel, a lack of private and foreign investment, reliance on government subsidies, high electric losses and power grid failures. In a more general sense, a lack of commercial development and little subsequent electric demand in the northern and eastern parts of the country put a cap on sector growth. Currently, the only segment of the market open to private competition and ownership is electric generation, which in the past 20 years expanded from one state-owned, vertically-integrated company to approximately 20 individual firms.

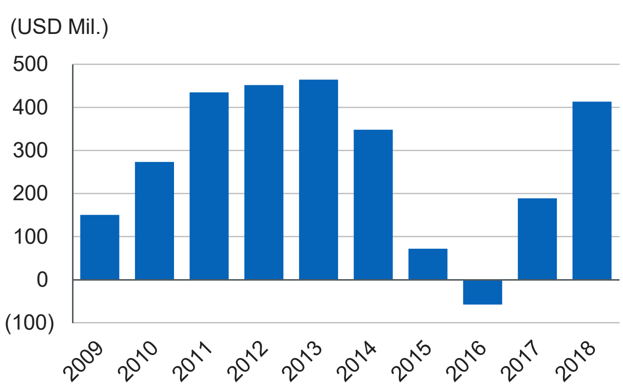
Efforts on behalf of the government are currently underway to improve the electric grid infrastructure by upgrading network technology, installing protection switches and encouraging frequency regulation among generation companies. These initiatives are beginning to bear fruit as blackouts were greatly reduced. In addition, the Dominican Corporation of State Electric Companies, or Corporacion Dominicana de Empresas Electricas Estatales (CDEEE), is leading an initiative to reduce losses by installing telemeters and raising community awareness about electricity theft. While progress in these areas lays the groundwork for a more economically and operationally viable electric system, a number of additional steps are necessary to improve the market's functionality.

The government, through the CDEEE, has an ambitious plan to diversify the electric generation mix away from expensive heavy fuels. In addition to the CDEEE directly sponsoring the Punta Catalina coal power plant, which will add 752MW of gross capacity, the CDEEE also proactively advocated for private investment of USD780 million to develop 360MW of new wind and solar projects. The Superintendence of Electricity, or Superintendencia de Electricidad (SIE), announced in 2018 a favorable recommendation for the construction of a 360MW liquefied natural gas (LNG) power plant and gas import facility by a foreign investor in the northwestern part of the country. The SIE is also offering new PPAs to fuel oil power plants converting to natural gas. These tangible actions illustrate the opportunities to grow and diversity the generation segment of the market and are expected to significantly lower the cost of electricity in the near to medium term and reduce financial strain on the system.

Pricing

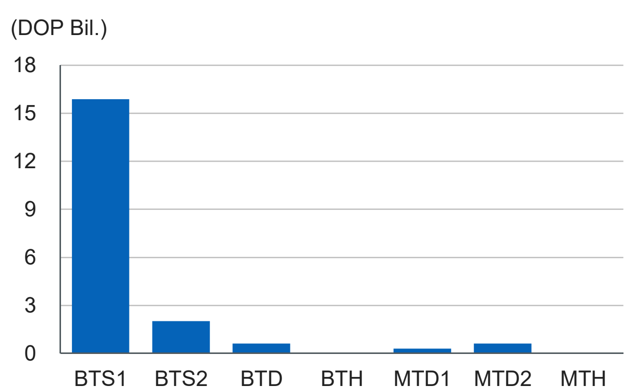
Electricity rates for regulated end users are set at the end of each month by the SIE but remained unchanged since 2013. Each month the SIE determines the indexed rates, which are calculated using September 2003 as the base month. The SIE makes adjustments to the indexed rates for a number of factors, such as inflation, as measured by the U.S. Consumer Price Index (CPI), the Dominican peso/U.S. dollar FX rate, high sulphur fuel oil prices, coal prices, natural gas prices, collection rates and the share of fuel in the generation mix. The SIE assigns indexed fixed charges and indexed energy charges based on consumption in seven categories of users, four low tension (BTS1, BTS2, BTD and BTH) and three medium tension (MTD1, MTD2 and MTH) users. The latter five categories (BTD, BTH, MTD1, MTD2 and MTH) correspond to larger users and are assigned maximum firm capacity charges.

Total FETE Amounts by Year



FETE – Fondo de Estabilizacion de la Tarifa Electrica or the Electricity Tariff Stabilization Fund.
Source: Dominican Corporation of State Electric Companies.

2018 FETE by Tariff Type



FETE – Fondo de Estabilizacion de la Tarifa Electrica or the Electricity Tariff Stabilization Fund.
Source: Dominican Corporation of State Electric Companies.

The Electricity Tariff Stabilization Fund, or Fondo de Estabilizacion de la Tarifa Electrica (FETE), pays the distribution companies the difference between the indexed rates and the rates applied to end users. In the case of a surplus, FETE collects the funds. Low consumption users generally pay lower rates than high consumption users. FETE paid distribution companies a total of USD413 million in 2018, roughly in line with 2011–2013, when fuel prices were relatively high. When commodity prices were particularly low in 2016, FETE had a surplus of USD57 million. Of the subsidies paid in 2018, 92% went to the BTS1 and BTS2 categories, which are residential customers on networks with a tension lower than 1,000 volts.

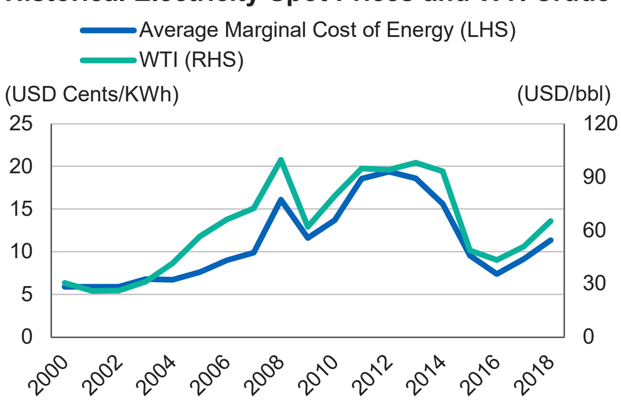
Economic transactions between generation companies, distribution companies and unregulated users are conducted in either the contract market or the spot market. The contract market includes PPAs typically specifying the term, price, form of payment, the amount of energy or capacity to be provided, guarantees and standard provisions. Of the energy acquired by distribution companies in 2018, 51% was acquired in the contract market. By law, a maximum of 80% of energy in the system may be contracted. Energy demand not covered by contracts is bought in the spot market.

The spot price is defined as the marginal cost to supply one additional MWh and is calculated every hour by the Coordinating Body of the Interconnected National Electric System, or Organismo Coordinador del Sistema Electrico Nacional Intercontectado, (OC-SENI) per the General Electricity Law 125-01. Historically, spot prices in the Dominican Republic were highly related to fuel prices, exhibiting a 94% correlation from 2000 to 2018 and a 97% correlation from 2009 to 2018. Electricity prices to end users are consistently approximately 8DOP/KWh and have little to do with spot prices, as the spot price risk is largely borne by the Dominican government through FETE and generation companies.

Fitch expects electricity spot prices in the Dominican Republic to moderate to USD77.10/MWh in 2021. This is primarily due to the expectation that over time nearly 1,000MW of gross coal, wind and solar capacity will be added to the system. This capacity will be extremely competitive on the system's dispatch curve and will displace more expensive Fuel Oil #6. Given Fuel Oil #6 comprised 33% of generation in 2018, it will likely continue to be the system's marginal generation fuel in 2021.

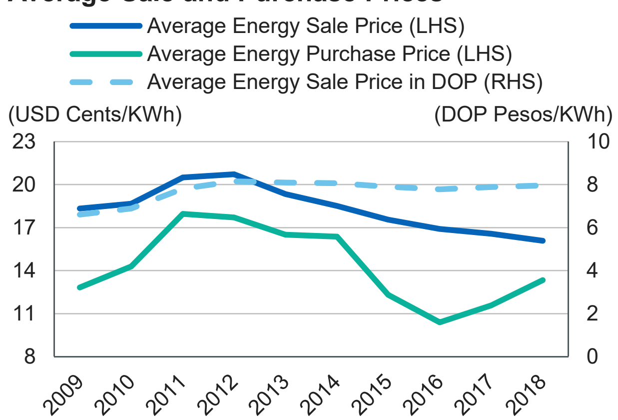
However, Fitch estimates a 15% drop in the price over this timeframe, in accordance with expected West Texas Intermediate prices and the high correlation between the two prices. The average maximum marginal cost sets a ceiling on the system's marginal cost, however, generators are compensated when they are forced to dispatch at below marginal costs. The maximum marginal cost is calculated each month by the SIE using a base maximum cost and adjusted for the U.S. CPI and heavy fuel oil prices.

Historical Electricity Spot Prices and WTI Crude



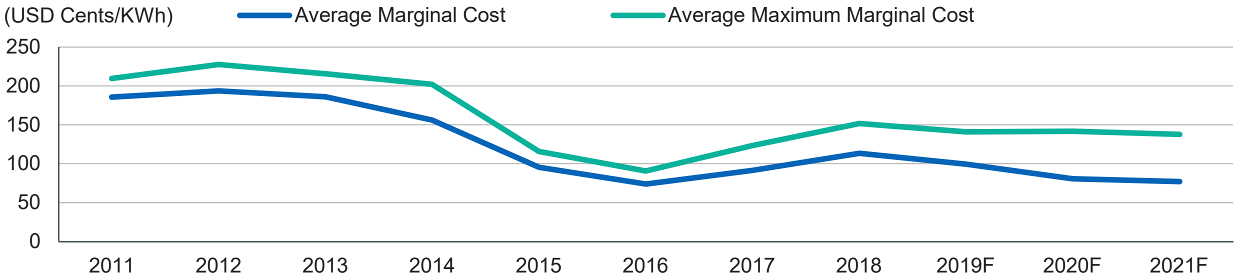
WTI – West Texas Intermediate. Bbl – Barrel.
Source: Dominican Association of the Electrical Industry, Superintendence of Electricity, U.S. Energy Information Administration.

Average Sale and Purchase Prices



Source: Dominican Corporation of State Electric Companies.

Average Marginal Cost and Average Maximum Marginal Cost



F – Forecast.
Source: Fitch Ratings, Superintendence of Electricity.

Regulatory Events

(Select Regulatory Events 1997 to Present)

2020	**May**	**Presidential election.**
2018	**November**	**Via Resolution SIE-103-2018-PS, the SIE grants provisional interconnection to conduct testing for a portion of Punta Catalina, a CDEEE-sponsored 752MW coal-fired plant consisting of two generation units.**
	March	**Via Resolution SIE-012-2018-RCD, the SIE issued a favorable recommendation for a definitive concession for the Manzanillo Power Land, a proposed 360MW natural gas power plant and liquefied natural gas import facility.**
2017	**May**	**The CDEEE announces its intention to grant private operators renewable energy concessions for 361MW of wind and solar projects at an estimated construction cost of USD780 million.**
2016	**August**	**The CDEEE announced public international bidding (CDEEE-LPI-001-2016) for a five-year PPA beginning in 2017 for 900MW of capacity and associated energy on behalf of the state-owned distribution companies.**
	May	**Danilo Medina elected president of the Dominican Republic.**
2013	**August**	**The Energy and Mining Ministry is created by Law 100-13 to be the public administrative body in charge of energy and mining policy.**
2003	**September**	**The government of president Hipolito Mejia repurchased Union Fenosa S.A.'s shares in two distribution companies, EDESUR and EDENORTE, which caused financial distress at the companies.**
2001	**July**	**General Electricity Law 125-01 gave legal power to the SIE and created the CDEEE to lead and coordinate electric companies. The law also created the state transmission company, ETED, and hydroelectric company, EGEHID.**
1998	**March**	**Decree 118-98 created the SIE under the Industry and Commerce Secretary of State.**
1997	**June**	**General Public Company Reform Law 141-97 broke up the vertically integrated government entity, CDE, into two generation companies and three distribution companies in order to facilitate partial privatization.**

SIE – Superintendencia de Electricidad or Superintendence of Electricity. CDEEE – Corporacion Dominicana de Empresas Electricas Estatales or Dominican Corporation of State Electric Companies. PPA – Power purchase agreement. EDESUR – EDESUR Dominicana S.A. EDENORTE – EDENORTE Dominicana S.A. ETED – Empresa de Transmision Electrica Dominicana. EGEHID – Empresa de Generacion Hidroelectrica Dominicana.
Source: Fitch Ratings, Fitch Solutions.

Regulatory Framework

The General Electricity Law Number 125-01, enacted on July 26, 2001, regulates all aspects related to the production, transmission, distribution and commercialization of electricity in the Dominican Republic. The law created the two main regulatory agencies overseeing the Dominican electricity sector: the SIE and the National Energy Commission, or Comision Nacional de Energia (CNE). An important aspect of Law 125-01 is the recognition and promotion of private sector participation in the development of the electricity sector by applying the same rules and norms as for state-owned companies. The Law also seeks to avoid monopolies by only allowing a single company to perform one of the following functions of generation, transmission or distribution, with the exception each of the three distribution companies may control up to 15% of the maximum generation demand of the system.

Regulatory Entities

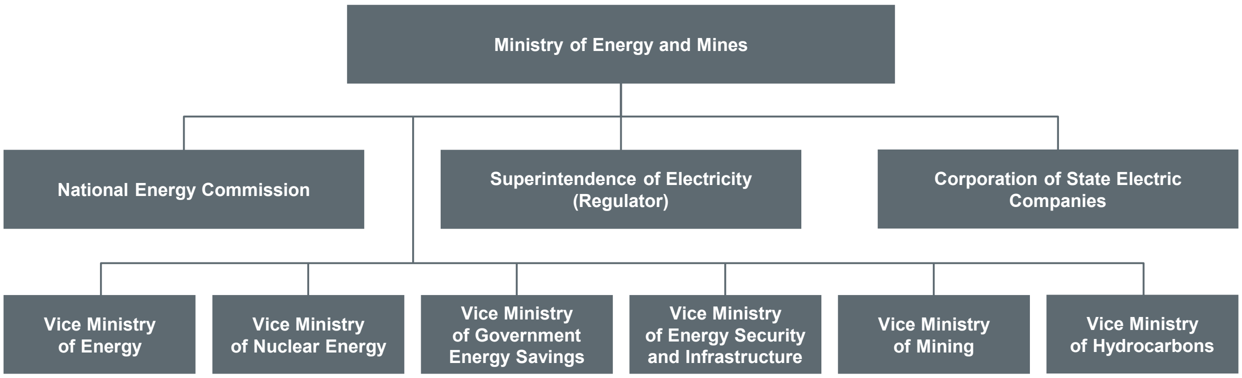
The SIE is the regulatory entity charged with oversight and supervision of the Dominican electricity sector to ensure compliance with laws, regulations and technical norms. The SIE also sets tariffs and usage fees, subject to price regulations, and its purview includes generation, transmission and distribution activities along with electricity marketing. The General Electricity Law 125-01 established the activities of the energy subsectors of electricity, hydrocarbons, alternative energy sources and rational energy consumption. The CNE is responsible for encouraging the sustainable development of the Dominican energy sector, including conventional energy, renewable energy, biofuels and for formulating energy sector policy.

The CDEEE is the administrator for all Dominican state-owned and majority state-owned electricity sector companies and serves as a regulatory body for generation, transmission and distribution in the Dominican electricity sector. Created by Article Number 138 of the General Electricity Law 125-01, the CDEEE leads and coordinates state electric companies in improving rural and suburban electrification and administering supply contracts with independent power producers.

The Ministry of Energy and Mining, or Ministerio de Energia y Minas (MEM), is the public administrative body charged with formulating and administering energy, metals and mining policy. The MEM creates strategies, plans, programs, projects and services for electric energy, renewable energy, nuclear, natural gas and mining subsectors. MEM was created by Law 100-13 in 2013 and reports to the President of the Dominican Republic. As established by Article 9 of Law 100-13, the CNE, CDEEE and SIE, along with the National Geological Service, or Servicio Geologico Nacional, are all agencies of MEM.

The OC-SENI was created on Oct. 29, 1998 by Resolution 235 of the Secretary of State of Industry and Commerce to coordinate the Dominican Republic's national electricity grid. The OC-SENI regulates and plans the dispatch of units and determines economic transactions among wholesale market agents, namely the state-owned distribution companies, the state-owned transmission company and public and private generation companies.

Dominican Electricity Sector Governance Structure



Source: Ministry of Energy and Mines.

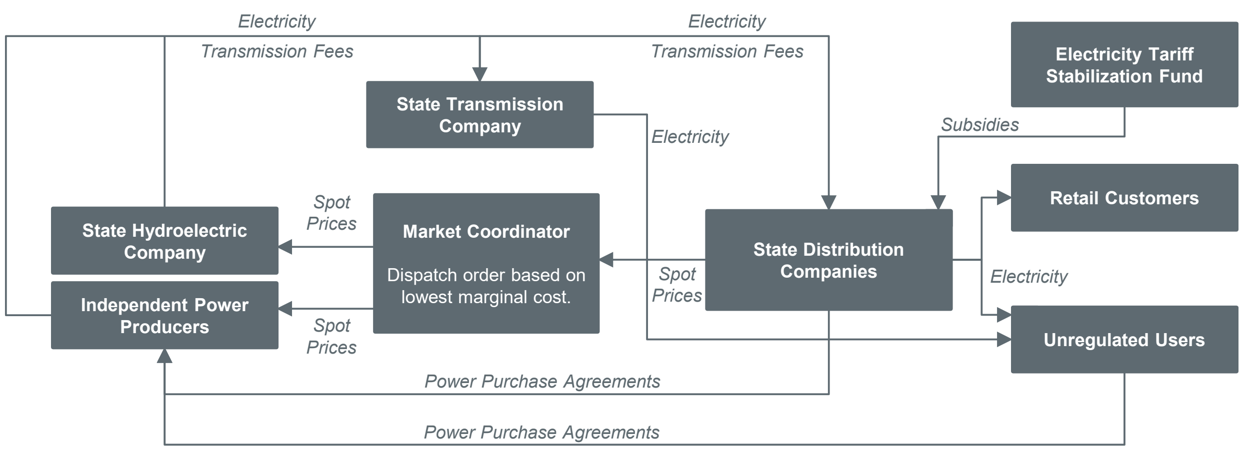
Industry Structure

Following Public Company Reform Law No. 141-97 in 1997, the Dominican electricity market was restructured in the mold of the Chilean regulatory model and the Bolivian capitalization model. The aforementioned law allowed for private ownership of distribution and thermal generation companies up to 50% and the formation of completely private generation companies. Prior to 1997, all segments of the energy market were vertically integrated under state control. The objectives of the restructuring were to create a competitive generation market, a rational regulatory framework for distribution and to provide the capital necessary for system improvements.

The Dominican electricity market currently is a decentralized market with approximately 20 generation companies and a state-owned transmission company Empresa de Transmision Electrica Dominicana (ETED). The market includes three state-owned distribution companies, EDESUR Dominicana, S.A.; EDENORTE Dominicana, S.A.; and Empresa Distribuidora de Electricidad del Este, S.A (EDEESTE), which serve their respective regions of north, south and east. The country has one electric grid, the Interconnected National Electrical System, or Sistema Electrico Nacional Interconectado (SENI), which in 2018 had 3,981MW of gross installed capacity and supplied 15,701.68GWh of electricity.

The Dominican Republic operates on a variable cost merit system whereby OC-SENI dispatches energy in order of the lowest production cost, as measured in USD/MWh. This means typically hydroelectric and renewable power is dispatched first, followed by combined cycle and coal, with fuel oil-derived sources usually entering the grid last. Generators either enter into contracts with distributors to provide a certain amount of electricity, regardless of where it is produced, or they sell electricity on the spot market. The latter is calculated every hour and defined as the variable production cost of the last unit dispatched to satisfy one additional kWh of demand.

Dominican Wholesale Electricity Market

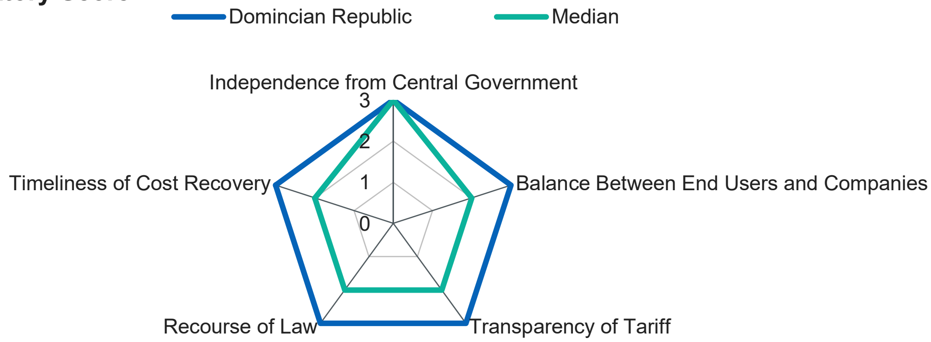


Source: National Energy Commission.

Regulatory Risk

Fitch considers the Dominican Republic's regulatory risk to be moderate and in line with regional peers with respect to independence from the central government. The country's risk with respect to other factors is above the regional median due to tariff transparency and delays in payments to the system from the government. We deem the Dominican Republic's overall regulatory risk to be commensurate with the 'BB' category, which is below the regional median of 'BBB'.

Dominican Regulatory Score

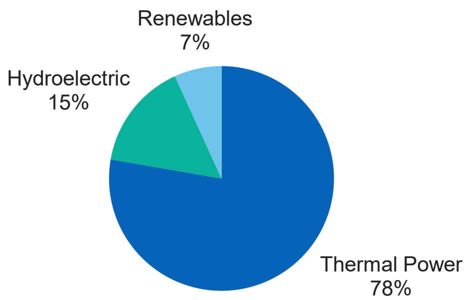


Source: Fitch Ratings.

Installed Capacity

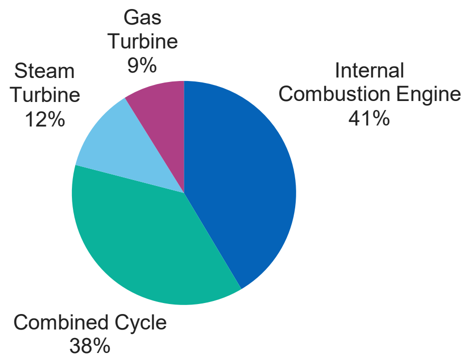
The Dominican Republic had a total installed capacity of 3,981MW as of YE 2018, of which 78% was derived from thermal power. Within this 3,094MW of thermal capacity, 1,282MW were from internal combustion engines, 1,163MW were from combined cycle capacity, 375MW were from steam and 274MW were from gas turbines. Combined cycle capacity grew to 1,163MW in 2018 from 175MW in 2000, as AES Andres B.V. (BB–/Rating Watch Negative [RWN]) added 319MW of capacity in 2003 and Dominican Power Partners (DPP; AA[dom]/RWN) completed a cycle closure in 2017 with an additional 359MW. Combined cycle expansions were encouraged by regulatory authorities due to efficiency. Combined cycle plants feature heat recovery boilers that turn an additional turbine and, generally speaking, increase electricity generation by 50% without consuming additional fossil fuels.

2018 Total Installed Capacity



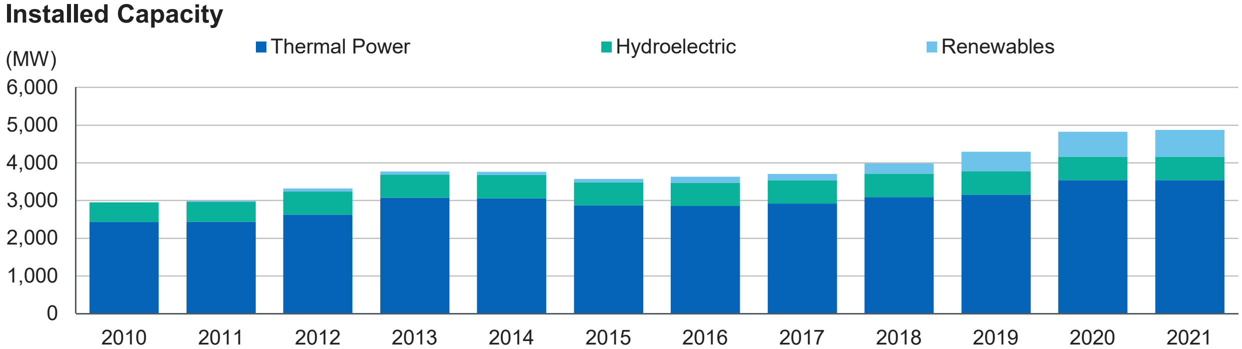
Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

2018 Thermal Installed Capacity



Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

Installed Capacity



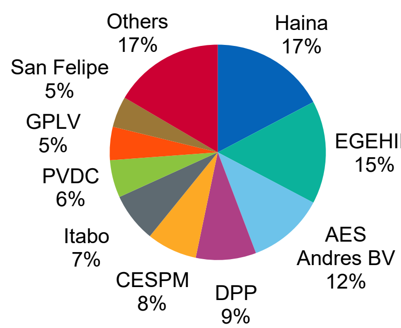
Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic, Superintendence of Electricity.

Fitch expects the Dominican Republic to increase installed capacity to 4,875MW by 2021. This is chiefly driven by the expected additions of Punta Catalina, a CDEEE-sponsored 770MW coal-fired power plant and a pipeline of various wind and solar projects championed by the CDEEE. These projects underscore the electric authorities' commitment to diversifying the country's energy matrix and thereby reducing dependence on petroleum-derived products. The projects would also potentially lower marginal electricity prices and government subsidies to the industry, which totaled USD413 million in 2018.

The largest consolidated competitor in the generation market as of 2018 was The AES Corporation (BB+/Stable) with 28% of the country's installed capacity. This total includes AES Andres with 459MW, DPP with 359MW and Empresa Generadora de Electricidad Itabo, S.A. (BB–/Stable) with 294MW. Other large issuers include Empresa Generadora de Electricidad Haina, S.A., which is half privately owned and half owned by the government, at 687MW and Empresa de Generacion Hidroelectrica Dominicana (EGEHID), the state-owned hydroelectric company, at 616MW.

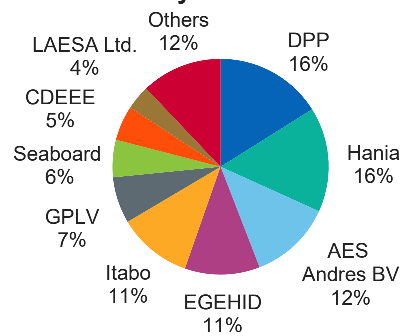
The top five market competitors in 2018 controlled 68% of installed capacity despite the presence of 20 total unconsolidated firms in the market. Electric generation in 2018 was similarly concentrated, but in a slightly different order, given that dispatch is based on the lowest variable cost, hydrological conditions and the outage at AES Andres. Fitch expects this market concentration to moderate in the next several years as the government is encouraging the development of more renewables and natural gas and this has attracted foreign investors not currently operating in the country.

2018 Market Share by Installed Capacity in 2018



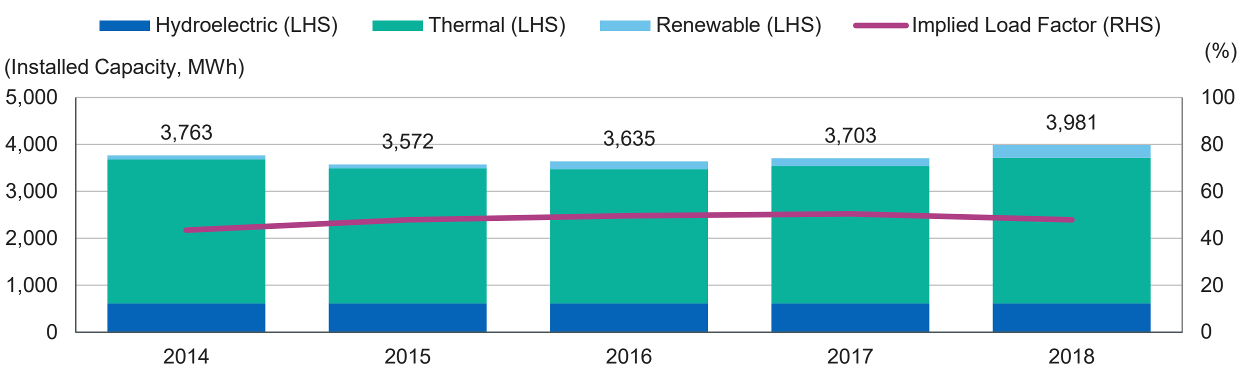
San Felipe – Empresa Generadora San Felipe Limited Partnership. GPLV – Generadora Palamara La Vega S.A. PVDC – Pueblo Viejo Dominicana Corp. Itabo – Empresa Generadora de Electricidad Itabo, S.A. CESPM – Compañia de Electricidad de San Pedro de Macoris. DPP – Dominican Power Partners. EGEHID – Empresa de Generacion Hidroelectrica Dominicana. Haina – Empresa Generadora de Electricidad Haina, S.A.
Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

2018 Market Share by Generation



CDEEE – Corporacion Dominicana de Empresas Electricas Estatales or Dominican Corporation of State Electric Companies. Seaboard – Seaboard Corporation. GPLV – Generadora Palamara La Vega S.A. Itabo – Empresa Generadora de Electricidad Itabo S.A. EGEHID – Empresa de Generacion Hidroelectrica Dominicana. Haina – Empresa Generadora de Electricidad Haina, S.A. DPP – Dominican Power Partners.
Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

Utilization Rate



Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

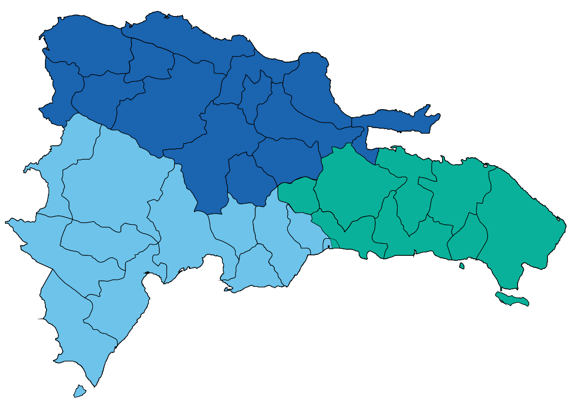
Power Generated

Fitch estimates the Dominican market's implied load factor was 48% of total installed capacity in 2018, slightly less than the 50% reported in 2017. The decline in overall load can be attributed to the increase in renewable energy capacity, which typically features more variable generation than thermal electric sources. Also contributing to slightly lower usage rates is a decline in EGEHID's production levels, which reported a record high in 2017.

Distribution

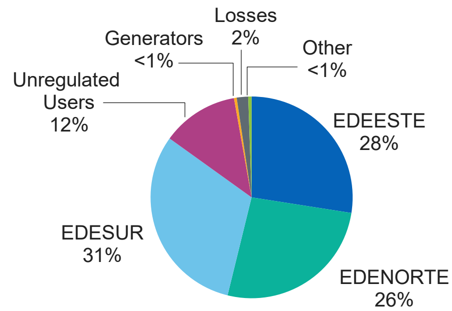
Following the restructuring of the Dominican electricity sector in 1999, private corporations acquired 50% of EDESUR, EDENORTE and EDEESTE. However, in 2003 the government repurchased the remaining 50% of EDESUR and EDENORTE and in 2004 purchased 50% of EDEESTE. Today, all three companies are wholly owned by the Dominican government and in 2018 accounted for 85% of electric demand, with unregulated users making up 12%. Unregulated users are typically industrial users, such as CEMEX, S.A.B. de C.V. (BB/Stable), Domicem S.A., and Falconbridge Dominicana S.A., which have all obtained a license to withdraw electricity directly from the grid. This group of users grew steadily since 2001, when licenses were first granted and, as of September 2018, there were 218 unregulated users on file.

Distribution Concession Areas
(Total Clients = 2,347,524)



EDENORTE — EDENORTE Dominicana S.A. EDESUR — EDESUR Dominicana S.A. EDEESTE — Empresa Distribuidora de Electricidad del Este, S.A.
Source: Consorcio Comercial del Caribe S.A.

2018 Electricity Grid Withdrawals



EDESUR – EDESUR Dominicana, S.A. EDENORTE – EDENORTE Dominicana, S.A. EDEESTE – Empresa Distribuidora de Electricidad del Este, S.A.
Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

EDENORTE, EDESUR and EDEESTE have the exclusive right to sell electricity to regulated users within their concession areas and the obligation to provide service to any requesting customer. These companies may sign PPAs directly with generation companies. However, the General Electricity Law dictates that no more than 80% of the electric grid's demand may be contracted and contract signings must be the result of a bidding process supervised by the SIE. This rule is to ensure electric prices reflect market conditions. The three companies are comparable in terms of size and at YE 2018 EDENORTE had 1,001,058 clients, while EDESUR and EDEESTE had 843,705 and 706,974, respectively.

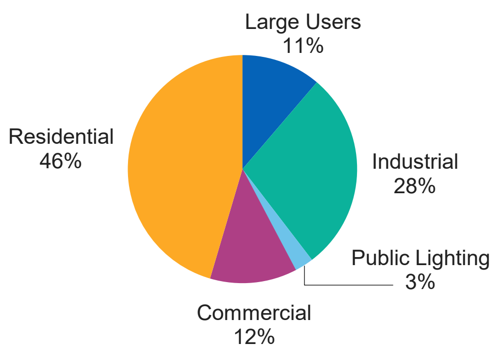
2018 Key Distribution Company Data Points

(USD Mil.)	EDENORTE	EDESUR	EDEESTE	Total
Active Contracts	1,001,058	843,705	706,974	2,551,737
Billed Contracts	990,902	807,383	666,465	2,464,750
Billed Contracts (%)	99.0	95.7	94.3	96.6
Energy Purchases (GWh)	4,231	5,058	5,017	14,305
Energy Purchases	578	649	678	1,905
Monomic Purchase Price (USD cents/kWh)	13.7	12.8	13.5	13.3
Average Sale Rate (USD cents/kWh)	15.6	17.1	15.3	16.1
Purchase/Sale Margin	12.5	24.8	11.8	17.1
Total Debt	116	117	123	356
Electricity Tariff Stabilization Fund	147	137	109	394
Concession Area Size (km^2)	19,061	17,939	11,700	48,700
Exchange Rate (DOP/USD)	49.5	49.5	49.5	49.5

EDENORTE – EDENORTE Dominicana, S.A. EDESUR – EDESUR Dominicana, S.A. EDEESTE – Empresa Distribuidora de Electricidad del Este, S.A.
Source: Dominican Corporation of State Electric Companies.

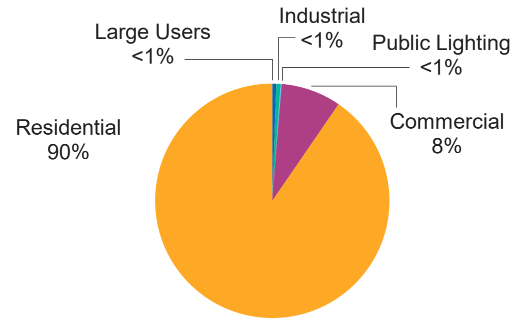
Similar to other markets in the region, residential users make up approximately 90% of electricity customers. However, at 45% of consumption, these users make up a larger portion of electric demand than in other Latin America countries. Commercial demand at 12% of energy usage, lags behind regional peers, indicating room for further growth and development. EDESUR, located in the southern part of the country, where Santo Domingo is located, has a disproportionate market share of the combined industrial and commercial energy consumption at 52%, even though the company has only 36% of residential demand, which is more in line with the market share of the population.

2018 Consumption by User Type
(Based on 9,607.52GWh)



Source: Superintendence of Electricity.

2018 User Type by Number of Clients
(Based on 2,357,800 Clients)



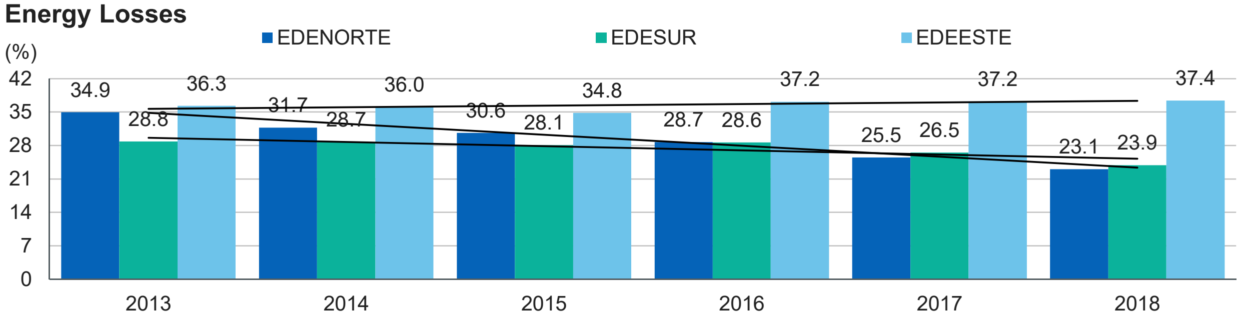
Source: Superintendence of Electricity.

While the three major state-owned distribution companies are subject to many challenges and phenomena one private company, Consorcio Energetico Punta Cana–Macao S.A. (CEPM) (AAA[dom]/Stable), is free of these problems. CEPM is a private company operating a fully vertically integrated isolated electricity system in the eastern tourist regions of Punta Cana-Bavaro and Bayahibe. CEPM has 300MW of installed generation capacity and 1,237km of low, medium and high-tension power lines. The company provides energy to 65% of the national tourism sector and more than 33,000 residential customers. Electricity losses for CEPM are typically just north of 5%, as 100% of the company's customers use smart meters.

Energy Losses

Electricity losses in the Dominican Republic stand out as being notably high, when compared with other Latin American countries. Loss levels for 2018 totaled 28.4%, down from 31.5% in 2016. Losses are composed of technical losses, which are due to transmission and distribution infrastructure weakness, and nontechnical losses, which are due to a high propensity for theft and nonpayment by end users. The downward trend in losses can be attributed to a conscious effort by the CDEEE to upgrade networks, install telemeters, billing users who were not being charged previously and raising public awareness. As part of the CDEEE's 2017–2020 Strategic Plan, USD120 million–USD150 million is being invested annually with a goal of reducing losses to 20% by YE 2020.

Energy Losses

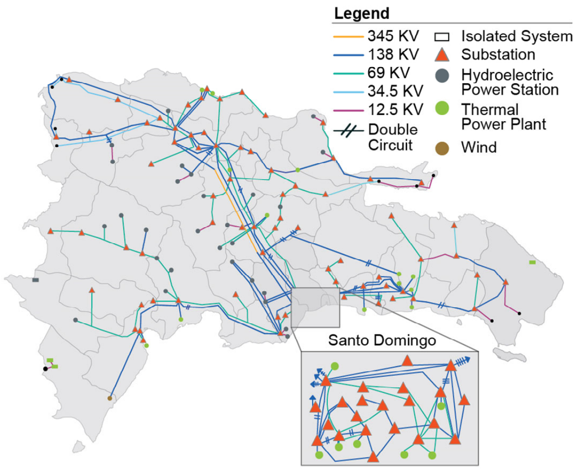


EDENORTE – EDENORTE Dominicana, S.A. EDESUR – EDESUR Dominicana, S.A. EDEESTE – Empresa Distribuidora de Electricidad del Este, S.A.
Source: Dominican Corporation of State Electric Companies.

Transmission

The country's electric transmission system is operated by ETED. General Electricity Law 125-01 called for the creation of ETED to own and operate all of the country's transmission lines and systems. The law also stipulated the company be wholly owned by the Dominican Republic with the authority to enter into commercial contracts and conduct business independently. The country's transmission network consisted of 5,362km of lines at YE 2018, the majority of which were 138KV.

Map of Electricity Transmission Lines



Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

2018 Length and Capacity of Transmission Lines

Voltage Level (kV)	Length of Transmission Lines (km)	Installed Capacity of Transformers and Autotransformers (MVA)
69	1,575	—
138	3,162	2,903
230	275	500
345	350	2,100
Total	**5,362**	**5,503**

MVA – Mega volt amps.
Source: Coordinating Body of the Interconnected National Electrical System of the Dominican Republic.

Appendix: Project Pipeline

Project Pipeline

Project Name	Sub Sector	Value (USD Mil.)	Size (MW)	Operator	Status	Timeframe End
Quisqueya 1	Thermal	350	215	Barrick Gold Corporation, Empresa Generadora de Electricidad Haina, S.A.	Completed	2014
Quisqueya 2	Thermal	350	215	Barrick Gold Corporation, Empresa Generadora de Electricidad Haina, S.A.	Completed	2014
Central San Felipe	Thermal	205	185	Empresa Generadora San Felipe Limited Partnership	Completed	2016
Larimar Wind Farm I	Wind	120	50	Dominican Government, Empresa Generadora de Electricidad Haina, S.A.	Completed	2016
Monte Plata Solar Project I	Solar	57	34	Phanes Group, Soventix Chile SpA, General Energy Solutions, Inc.	Completed	2016
San Pedro de Macoris Biomass Plant	Biomass	90	30	Empresa Generadora de Electricidad Haina, S.A.	Completed	2016
Los Mina Power Plant Expansion	Combined Cycle	260	114	The AES Corporation	Completed	2017
Larimar Wind Farm Project II	Wind	100	48	Empresa Generadora de Electricidad Haina, S.A.	Completed	2018
Montecristi Solar	Solar	88	58	Montecristi Solar FV S.A.S.	Completed	2018
Parque Solar Canoa Solar Project I	Solar	40	25	Dominican Government, Potentia Renewables Inc.	Under Construction	2019
Monte Plata Solar Project II	Solar	53	35	Phanes Group, Soventix Chile SpA, General Energy Solutions, Inc.	Project Finance Closure	2019
Matafongo Wind Park	Wind	70	34	Grupo Eolico Dominicano C. por A.	Completed	2019
Agua Clara Wind Park	Wind	110	50	Inkia Energy Inc.	Completed	2019
WCG Solar Park	Solar	110	50	WCG Energy LTD	Under Construction	2019
Parques Eolicos del Caribe (Pecasa)	Wind	128	50	Akuo Energy SAS	Under Construction	2019
Puerto Plata Wind Park	Wind	107	46	Jasper Caribbean Windpower LLC	Under Construction	2020
Los Guzmansitos Wind Park	Wind	125	48	Poseidon Energias Renovables S.A.	Under Construction	2020
Punta Catalina	Thermal	1,950	770	Dominican Corporation of State Electric Companies	Testing	2019–2020
Parque Solar Natural World Energy	Solar	110	100	Natural World Energy Corporation, S.R.L.	Regulatory Approval	2020–2021
Manzanillo Power Land	Thermal	633	360	Energia 2000 S.R.L.	Regulatory Approval	2023

Source: Superintendence of Electricity; Corporation of State Electric Companies; Consorcio Comercial del Caribe S.A.; Dominican Association of the Electrical Industry; Coordinating Body of the Interconnected National Electrical System of the Dominican Republic; Empresa Generadora de Electricidad Haina, S.A.; The Regional Committee for Central America, the Caribbean and the Regional Energy Integration Commission.

Outlooks

2019 Fitch Ratings Outlooks

Related Research

Dominican Republic – Ratings Navigator (April 2019)
Presentation: Dominican Republic Sovereign Credit Rating Outlook (May 2018)

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Mexican Electricity Sector

Private Investments Needed, Despite Rhetoric

Sector Improvements Require Investments: Fitch Ratings estimates that Mexico will require an average investment of USD8 billion a year, or a total of USD120 billion, in electricity infrastructure to address the government's 15-year expansion plan. Fitch expects that around USD100 billion is required to increase 70.3GW of capacity to the grid and support electricity demand growth of 3.0% a year to replace inefficient capacity. Another USD20 billion is required for the transmission and distribution (T&D) segment to interconnect the three systems, accommodate additional capacity from renewables and improve energy losses and congestion.

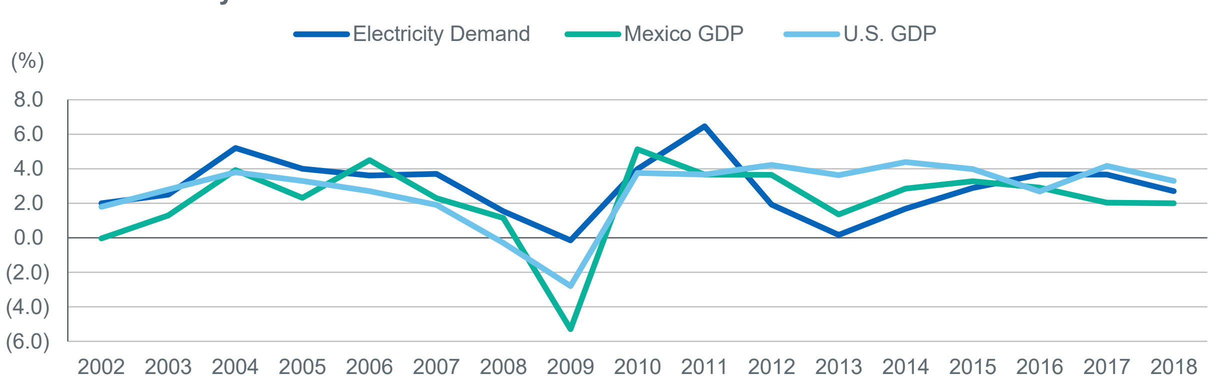
Private Participation Needed: Mexico requires considerable private investment in its electricity sector to accommodate demand growth and prevent financial pressure on the Federal Electricity Commission (Comision Federal de Electricidad [CFE]; BBB/Stable). However, the new administration's strategy toward a state-centric approach has raised investor concerns, and the system development could face material delays. Financing could materialize through long-term productive infrastructure projects (Proyectos de Infraestructura Productiva de Largo Plazo, PIDIREGAS), although there is no official acknowledgement that CFE will adopt the plan, which could pressure financial metrics should it be forced to bear investments equivalent to around 4.0% of capacity growth per year and T&D modernization.

New Administration, Uncertain Development: The new administration is inclined to preserve CFE as monopoly, dampening reform efforts toward a more competitive, reliable system. The shift in policy priority and the decision to cancel the clean energy auctions raised concerns regarding CFE's ability to fund these projects at the pace required to maintain a balanced system with healthy reserve margins and lower prices. The development plan outlines 15.5GW of new capacity that will be added by CFE until 2025. Successive drops in average prices to USD20.15/MWh in the third auction from USD47.78/MWh in the first auction demonstrate the long-term clean energy auctions' effectiveness for the system.

Spot Prices to Remain High: To reduce energy prices, the system will depend on future projects meeting their execution schedules. Delays in modernizing T&D lines and adding generation capacity and gas pipelines could pressure energy prices in the short to medium term. Fitch expects prices in the National Interconnected System (Sistema Interconectado Nacional [SIN]) to remain high at USD80–USD90/MWh on average in the next four years and gradually decrease as modernization of T&D lines improve congestion rates and efficient capacity enters the system. Prices in the SIN averaged USD45.9/MWh, USD66.0/MWh and USD84.3/MWh in 2016, 2017 and 2018, respectively.

Clean Energy Initiatives: Mexico has committed to disassociate economic growth from pollution emissions in signing the Paris Agreement in 2016. The reform set out an agenda to reduce greenhouse gas emissions and support the country's target to generate 35% of its power from renewable sources by 2024. The first three long-term contract auctions will add approximately 7.5GW of nonconventional renewable capacity by June 2020, setting Mexico very close to its clean energy goal. This expansion reinforces investment requirements in T&D grid lines, as wind and solar power plants are far from the highest consumption demand centers and exhibit lower capacity factors, depending on the time of the day.

Mexico Electricity Demand Versus Real GDP Growth



Source: Fitch Ratings, Sistema de Informacion Energetica.

Primary Market Considerations

Growth Prospects

Electricity demand is expected to grow at an average annual rate of 3.0% in the next 15 years, according to the National Electric System Development Program (Programa de Desarrollo del Sistema Eléctrico Nacional [PRODESEN]), 2019–2033, in line with the country's GDP expectations. Fitch estimates that Mexico will require total investment of USD120 billion in electricity infrastructure, of which USD100 billion will be directed for generation assets and USD20 billion for T&D assets.

To sustain this growth, Mexico estimates it will need to build 70,313MW of installed capacity in2019–2033, of which 42% will correspond to combined-cycle plants (29,294MW) and 53% to renewable technologies (36,928MW). The balance will be composed of other clean and thermal plants, including nuclear. The additional capacity, if executed as planned, will have substantial impact on the dispatch merit order curve, contributing to lower prices in the system.

To complement the installed generation capacity growth, the country will need a large investment in the T&D lines to integrate its main systems, decrease energy losses and congestion, and increase capacity to accommodate lower capacity factors from renewables. The National Electricity System (Sistema Electrico Nacional, [SEN]) comprises three systems: Baja California, Baja California Sur and the National Interconnected System (Sistema Interconectado Nacional [SIN]), which operates in isolation and forms its own pricing. The modernization and interconnection of T&D lines is detrimental to the market, as congestion, energy losses and lack of connectivity between the systems significantly increase electricity prices in various nodes.

One option is to finance the expansion with PIDIREGAS through the Independent Power Producer (IPP) program and the Financed Public Works (Obra Pública Financiada [OPF]) program. However, it is still uncertain whether CFE will adopt this strategy under the new administration. These programs allow CFE to avoid risks related to the development of the project and to secure competitive development prices as a result of an international bidding process.

The IPP allows private companies to bid for the construction, operation and maintenance of the generation facility and sell the generated power to CFE through a long-term agreement (usually 25 years). The OPF addresses T&D infrastructure needs, while CFE enters into short-term agreements (1–2 years) under which a private company builds the project, but does not operate/maintain it. Private participants place their bids to receive a total payment on the project's completion.

Pricing

The ability to obtain generally lower energy prices will depend heavily on projects meeting their execution schedules on a timely basis. Delays in modernizing T&D lines and adding generation capacity and gas infrastructure could pressure energy prices in the short to medium term.

Recent delays in gas projects have affected prices during the summer season by limiting natural gas supply to efficient combine cycles and forcing the dispatch of less efficient thermal power plants. Mexico's central, south and southeast have suffered from a natural gas supply deficit, and prices in 2019 will likely surpass 2018's.

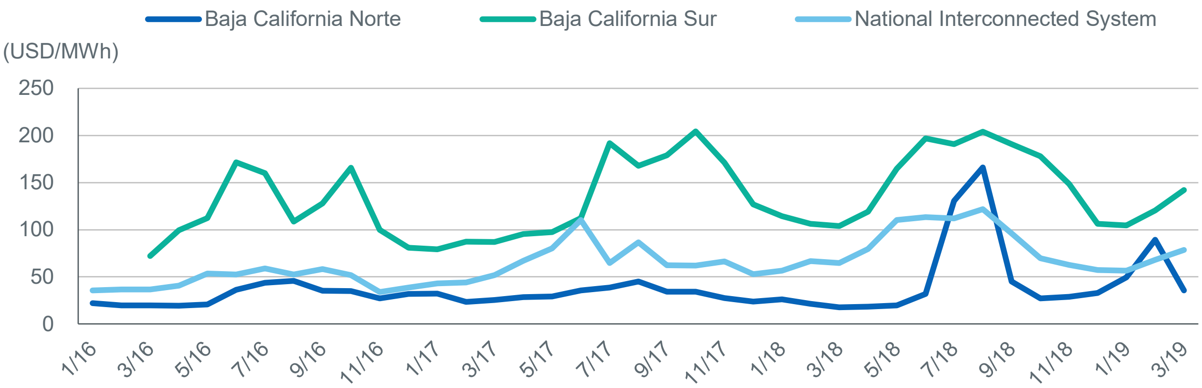
The Infraestructura Marina del Golfo pipeline (IMG), a joint venture between TransCanada Corporation (60%) and Infraestructura Energetica Nova, S.A.B. de C.V. y Subsidiarias (40%), with the capacity to export 2.6bcfd of natural gas from Texas to the Mexican states of Tamaulipas and Veracruz, was originally expected to start operations in 2018 but was not completed until June 2019. Supply to pipeline-scarce regions will remain hampered until other projects come online, such as the Tuxpan-Tula and Tula-Villa de Reyes pipelines in the central region and the reconfiguration of the Cempoala compression station and the Mayakan pipeline interconnection with IMG in the south.

In 2016–2018, electricity prices in the isolated Baja California system were around 40% lower than those in the SIN, averaging USD29.70/MWh, USD31.50/MWh and USD47.20/MWh in 2016, 2017 and 2018, respectively. Nevertheless, prices peaked beyond USD165/MWh in August 2018 and could remain high due to capacity constraints in that isolated system. The Baja California system is connected with the California Independent System Operator (CAISO).

Electricity prices in the isolated Baja California Sur system during the last three years were twice those of the SIN, averaging USD119.90/MWh, USD133.30/MWh and USD152.00/MWh in 2016, 2017 and 2018, respectively, as the region lacks access to natural gas and its supply is based on diesel and bunker-run plants.

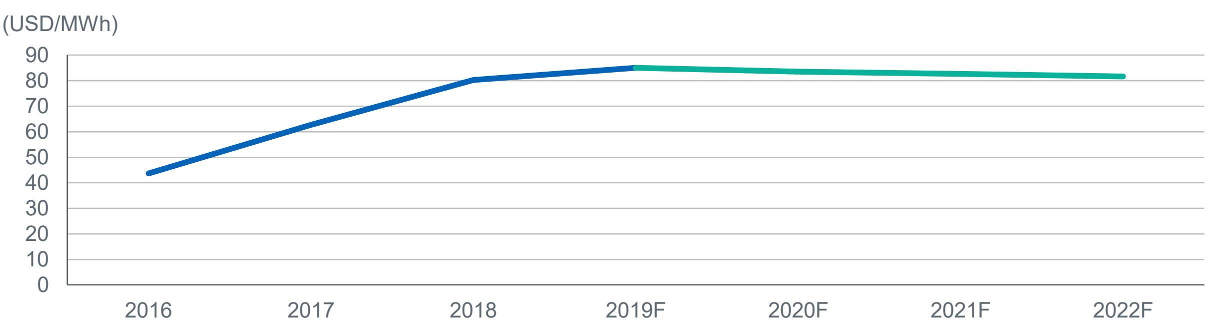
Prices for the SIN averaged USD45.90/MWh, USD66.00/MWh and USD84.30/MWh in 2016, 2017 and 2018, respectively. Fitch expects prices in the SIN to remain around USD80/MWh–USD90/MWh on average during the next four years and slowly start to decline as new efficient capacity enters the system and incremental investment occurs in transmission lines, decreasing congestion fees.

Electricity Prices



Source: Centro Nacional de Control de Energía.

Mexican Spot Prices



F – Forecast.
Source: Fitch Ratings, Centro Nacional de Control de Energia.

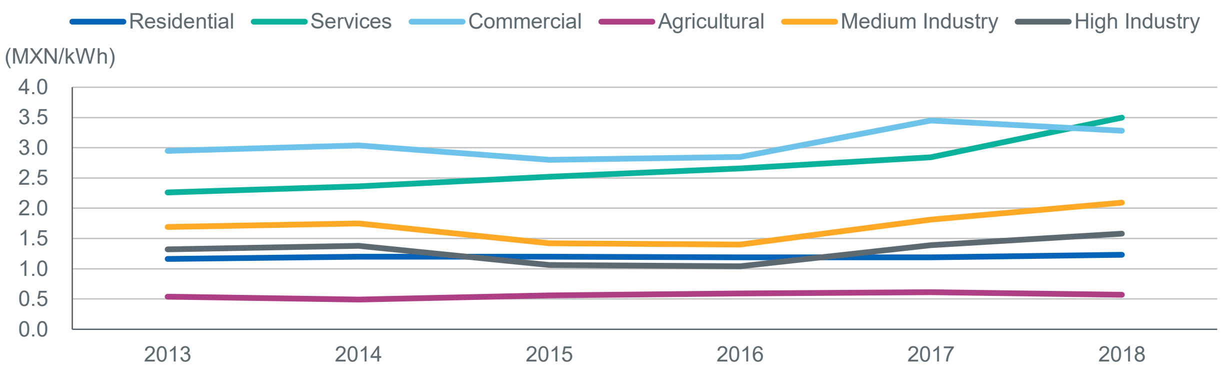
Mexico's hourly short-term market was established in February 2016 and mimics the order merit dispatch, following energy reform market rules. The local marginal price is the marginal cost of generation, which is equal to the variable production cost of the most expensive unit generating at each hour. The prices are determined on the day-ahead market and the real-time market. Prices in the various nodes vary due to marginal transmission losses and system congestion.

In Mexico, there are specific tariffs for different consumers. Electricity rates charged to high and medium tension industrial, commercial and high-consumption residential customers are adjusted on a monthly basis, factoring in fuel costs. Rates charged to low-consumption residential users, agricultural and public lighting customers are adjusted on a monthly basis by the government, usually factoring in a social discount. As a result, regulatory entities set subsidies to agricultural and low-usage residential customers, enforced by CFE. The government has historically partially compensated CFE for these subsidies since the energy reform.

Fitch expects that subsidies will remain significant in the residential and agricultural sectors, absent new initiatives to reduce costs or increase prices in the system. Subsidies from the government to CFE during 2018 were high, at around USD4.2 billion. The new administration reinforced its commitment to sustain the subsidies for low-income population, especially in states with hotter climates, where electricity prices are extremely expensive.

Preferential tariffs will likely persist in the medium term due to their social component and the political cost of its elimination. Mexico's favorable tariffs to the subsidized segment are among the lowest in Latin America. However, Mexico's tariffs for nonsubsidized customers are among the highest in the region due to cross-segment subsidies, high levels of nontechnical losses, congestion, and an elevated participation of less efficient thermal generators.

Average Electricity Prices By Category



Source: Secretaria de Energía.

Recent Events

Select Regulatory Events (2013–Present)

Year	Month	Event
2018	Dec.	Fourth power, transmission auctions are canceled.
	Dec.	Andrés Manuel López Obrador becomes president of Mexico.
2017	Nov.	Mexico conducts its third power auction, awarding 2,462MW of wind, solar and natural gas energy.
2016	Oct.	Mexico conducts its second power auction, awarding 3,161MW of wind, solar and geothermal energy.
	March	Mexico conducts its first power auction, awarding 2,085MW of wind and solar energy.
	Jan.	Mexico opens up day-ahead and real-time trading in a new wholesale power market.
2014	Aug.	President Peña Nieto signs into law the 21 components of comprehensive energy reform.
2013	Dec.	Energy reform approved by Congress, transforming the Federal Electricity Commission into a state-owned productive enterprise and opening the electricity sector to private sector participation.

Source: Fitch Ratings.

Regulatory Framework

Industry Structure

It is unclear how the new government will execute and fund the sector development outlined in the energy reform. The recent suspension of the generation and transmission auctions and the slowdown in permits awarded limit the purpose of the reform to an open market with private funding. Absent a return to investor-friendly measures, investments could continue to rely heavily on government funding and CFE will likely remain the dominant player in the short to medium term.

Before the energy reform, Mexico's electric industry operated under a vertically integrated model dominated by CFE on the generation, transmission and distribution segments. CFE was also responsible for the overall planning, development and operation of the national electricity system, and private generators could only operate under a restricted basis.

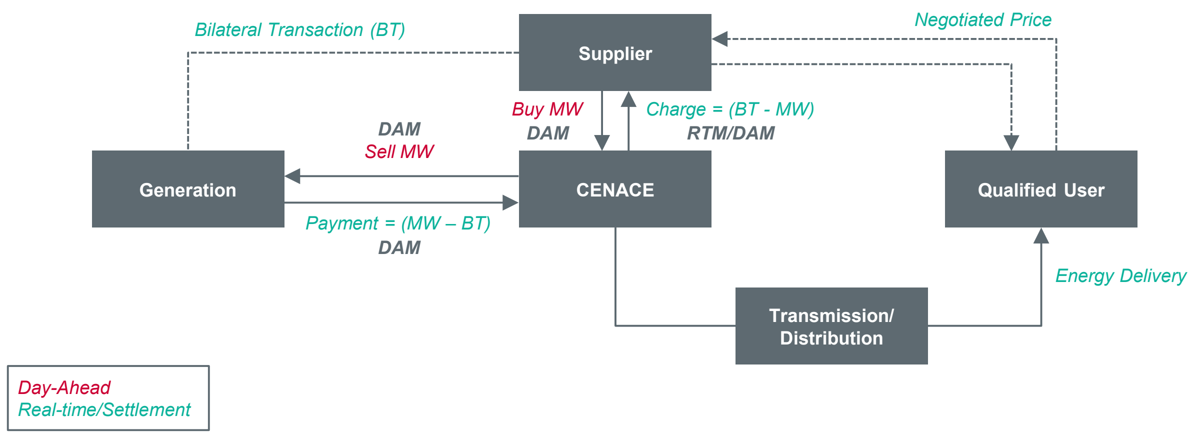
The energy reform created a competitive landscape to increase growth prospects in the wholesale market by fully opening the market to private competitors, underpinning market demand with a commitment to lower energy prices.

Some of the main changes in the power sector are:

- Generation and commercialization activities are now opened to the private participants (previously reserved for CFE), while supply to regulated consumers will remain under CFE control;

- A wholesale market is created for the generation segment, generation dispatch at merit order is established and there is a unique central dispatch operator for all generators;
- Qualified users can participate in the wholesale power market and acquire their energy through contracts entered with power generators;
- Private parties can finance, install, maintain, manage, operate and expand T&D networks.

Qualified Supply in the Mexican Wholesale Electricity Market



DAM – Day-ahead market. RTM – Real-time market. CENACE – Centro Nacional de Control de Energía.
Source: Sistema de Informacion Energetica.

The reform established clean energy power auctions under a new contract regime based on new market products and parties. To date there have been three auctions with bidders — major international participants and some local firms — offering packages for three market products: capacity, cumulative energy and Clean Energy Certificates. While the first two auctions offered contracts with CFE only, the third auction was open to private buyers. Nevertheless, CFE remained responsible for 91% of energy and Clean Energy Certificates purchased on the last public sale. The term of the contracts are set at 15 years for power, and 20 years for the Clean Energy Certificates.

Clean Energy Certificates are a new tradeable product designed to fulfill the minimum clean energy consumption levels for CFE and qualified users (consumption greater than 1MW). One certificate is equivalent to 1MWh and it has no expiration date. Energy users must comply with minimum generation requirements of 5% sourced from renewables in 2018, stepping up to 5.8% in 2019, 7.4% in 2020, 10.9% in 2021 and 13.9% in 2022.

Regulatory Framework — Regulating Entities

The Finance Ministry (Secretaria de Hacienda y Credito Publico [SHCP]) is responsible for the economic and fiscal characteristics of contracts and tender/auctions designated by the Secretariat of Energy (Secretaria de Energia [SENER]). SHCP sets electricity tariffs annually, except for high-tension users. Under the electricity law, rates are required to cover CFE’s costs.

SENER sets the energy policy and plans national infrastructure projects, such as generation and transmission grid expansion. It also defines the clean energy portfolio and supervises CFE.

The Energy Regulatory Commission (Comisión Reguladora de Energía [CRE]) manages the wholesale market by issuing interconnection and generation permits, registering qualified users in the market and issuing Clean Energy Certificates.

The National Center for Energy Control (Centro Nacional de Control de Energía [CENACE]) operates and controls the market and system. It supervises power auctions, records short-term transactions and allocates the electricity injected into the system by generators to the purchaser. CENACE also monitors electricity prices in the short-term market and ensures compliance.

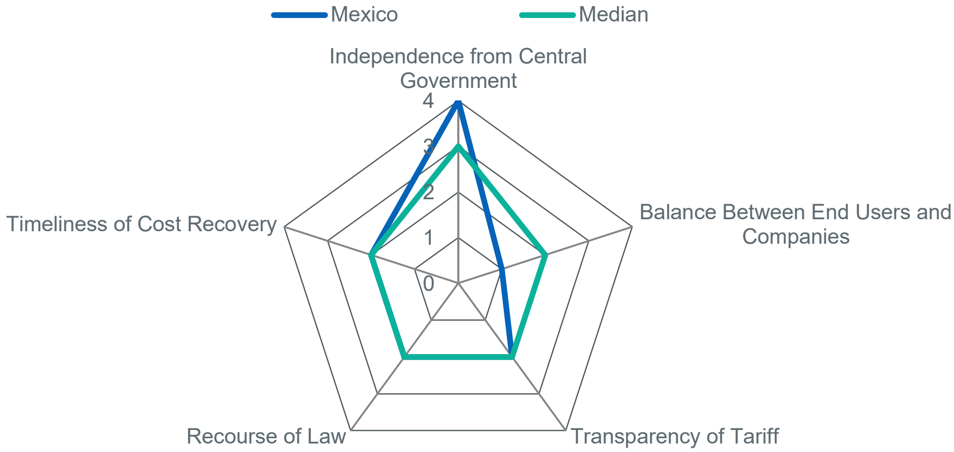
CFE, through its subsidiaries, operates in the generation, transmission, distribution and commercialization of electricity. Its generation subsidiaries operate plants and engage in third-party contracts with IPPs. CFE's transmission subsidiaries operate the national transmission grid, and it can hire third parties through bidding processes to expand and operate transmission lines. Its distribution subsidiaries operate the general distribution grid, which executes the expansion and improvement of the distribution grid. In the commercialization subsidiaries, it operates as the only basic services supplier.

Qualified users have demand higher than 1MW and can participate in the wholesale power market and acquire their energy through contracts entered with power generators, or be represented by a supplier of qualified services. Qualified services suppliers can sell power to qualified users and represent exempt generators to place their power in the wholesale market.

Regulatory Risk

Fitch considers Mexico's regulatory risk one of the lowest among rated peers, despite high government intervention. On average, Mexico's rated regulatory risk is comparable to a 'BBB' category, compared with a 'BB' median for the Latin American region.

Regulatory Risk



Note: 1 = A; 2 = BBB; 3 = BB; 4 = B.
Source: Fitch Ratings.

Fitch views the regulatory framework as highly dependent on the central government. The government maintains the planning and control of the SEN and the provision of the T&D activities as an indispensable public service.

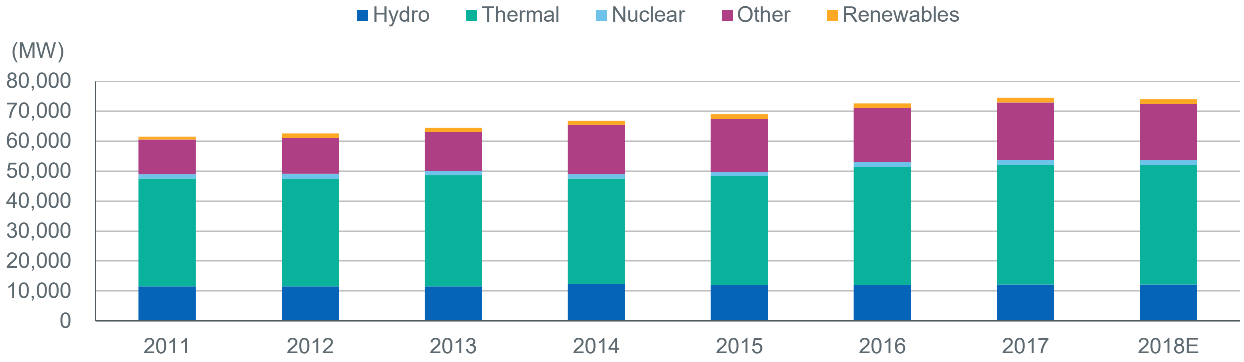
The balance between end users and investors is weak, as regulators focus on minimizing electricity costs for end users in detriment of an adequate return on investment for sector participants. As a result, the government only partially compensates CFE for subsidies to agricultural and low-usage residential customers.

Fitch views the transparency of tariff-setting procedures and recourse to law as strong, with clear procedures established by regulatory entities. CRE grants generation permits and determines transmission and distribution tariffs on a timely basis. The electricity law gives electricity companies recourse to appeal unfavorable regulatory decisions.

Generation

Mexico generation capacity stood at 75,685 MW in 2017, representing an average annual growth of 2.5% during the last 10 years. Mexico remains highly dependent on fossil fuel generation technologies, accounting for around 70% of installed capacity and 81% of generation in 2017, despite recent efforts to increase diversification of electricity sources. The combined-cycle plants represented around 37% of the system capacity, or 27,600MW. Higher investments in natural gas-fired plants contributed to the country's increased imports of natural gas from the U.S. to 4.6bcfd in 2018 from 799mcfd in 2007. Hydroelectric technology accounted for 16.7% of the installed capacity and the balance was shared among coal, natural gas turbines and nonconventional renewables.

Mexico Generation Installed Capacity by Power Source



Source: Fitch Ratings, Fitch Solutions, SIE.

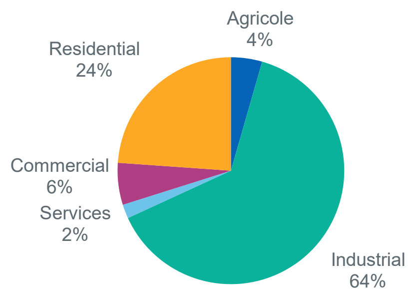
Peak demand totaled 45,167MW in the SIN and 47,903MW in the SEN during 2018, according to SENER. These figures compare with 39,840MW and 42,677MW in 2015, respectively, representing a CAGR of 4.3% and 3.8%.

CFE remains the largest generator by installed capacity and generation, despite having the system's least effective plants. CFE installed capacity represented 59.2% of the country's total capacity in 2018, compared with 63.8% in 2011, and generated 54.2% of the country's electricity in 2018, compared with 59.7% in 2011.

IPPs' installed capacity was 19.2% of total capacity and generated 30.1% in 2018. The remaining electricity capacity and generation is attributed to private companies that generate electricity mainly for self-supply, cogeneration and exports.

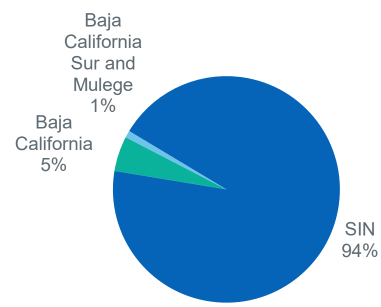
Consumption varies among users and regions, given their different economic activities. It is estimated that industrials constitute 64% of consumption, while the SIN represented 94% of total consumption in 2018.

Customers by Sector



Source: Secretaria de Energía.

Consumption By System



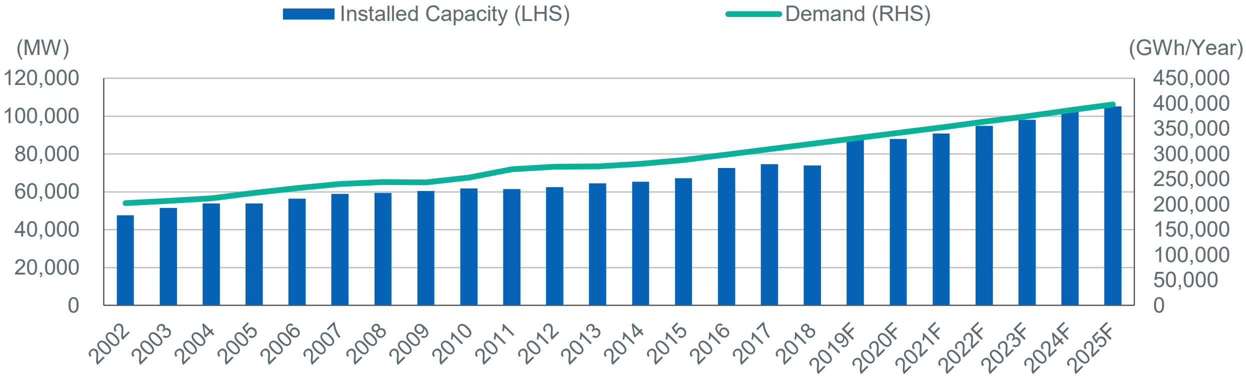
SIN – National Interconnected System (Sistema Interconectado Nacional).
Source: Secretaria de Energía.

Future Growth

The government's agenda includes expanding the country's installed capacity to around 130GW by 2032. This plan requires an additional 70,313MW of capacity, while some less efficient capacity will be retired, with combined cycle and renewables representing 45% and 35% of total capacity, respectively. Fitch estimates that Mexico will require a total investment of around USD100 billion for generation capacity during the next 15 years to address the growth plan.

The flagship of this expansion will be combined-cycle plants, driven by their high efficiency, low cost and reduced emissions technology. CFE has a designated plan to convert its power generation fleet to natural gas. The growth plan will require an additional 29,294MW of new installed capacity from natural gas-fired plants, according to SENER, requiring around USD33.5 billion in investments. Natural gas power is set to completely displace fuel oil in power generation.

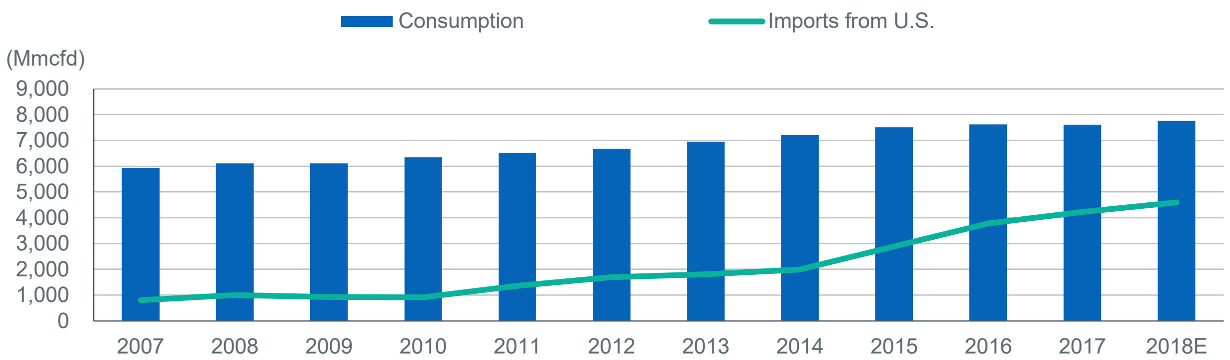
Mexico Electricity Supply and Demand Balance



Source: Sistema de Informacion Energetica.

This growth will likely be accompanied by investment in gas supply and transportation capacity. The additional 29,294MW of combined-cycle capacity to be added to the system could increase gas transportation needs by around 5.2bcfd, considering combined-cycle efficiency of 7,500 Btu/MWh. This expansion requirement will be mitigated by the additional 2.6bcfd of capacity added by the IMG. Gas supply will likely have to come from imported sources, as production in Mexico is expected to continue to decline by approximately 5% per year. National gas consumption totaled around 8.0bcfd in 2018.

Historical Natural Gas Consumption

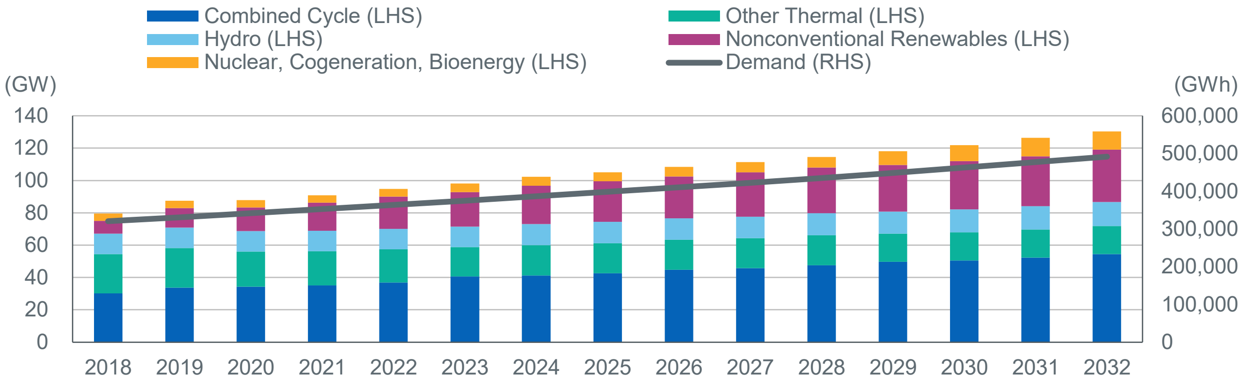


Mmcfd – Million cubic feet per day.
Source: Secretaria de Energía, Energy Information Administration.

Nonconventional renewables will be the second thrust of the growth. Mexico held three renewable auctions for private investments to address this agenda. The first clean energy auction in early 2016 awarded 2,085MW of new capacity (1,691MW solar and 394MW wind) and five million Clean Energy Certificates with an average price of USD41.80/MWh.

The investment plan establishes that by 2033, around of 43% of Mexico's installed capacity be sourced from combined-cycle plants and around 35% from renewable, including hydro.

Installed Capacity Forecast By Technology



Source: Programa de Desarollo del Sistema Electrico Nacional 2018–2032.

The second auction awarded 3,161MW of capacity (1,853MW solar, 1,283MW wind and 25MW geothermal) and around nine million Clean Energy Certificates. The average price was USD33.47/MWh.

The third auction awarded 2,562MW of capacity (1,323MW solar, 689MW wind and 550MW thermal) and around five million Clean Energy Certificates. The third auction reported among the lowest global prices, at an average of USD20.60/MWh.

Long-Term Electricity Auction Results

Contracted Capacity (MW)	First Auction	Second Auction	Third Auction
Result Date	March 2016	September 2016	November 2017
Solar	1,691	1,853	1,323
Wind	394	1,283	589
Geothermal		25	
Natural Gas			550
Average Price (USD/MWh)	41.8	33.47	20.57

Source: Secretaria de Energía.

Distribution

CFE has exclusive authority to distribute electricity in Mexico. The power distribution system is extensive and supplies electricity to around 98.5% of the country's population. CFE had a total distribution network of 838,831km and provided electric power service to over 43 million users at the end of 2018.

One of the sector's main challenges is the high technical and nontechnical losses in the network. During 2018, electricity losses totalled 31,455GWh, or 13.45%, of which 5.92% was due to technical losses and 7.54% was due to nontechnical losses.

Transmission

CFE has the exclusive right to transmit electricity in Mexico and receives service income from CENACE based on CFE-regulated tariffs.

The SEN is composed of three separate systems: the SIN (seven regions), Baja California (one region) and Baja California Sur (two regions). The three systems operate isolated from each other and have different transmission prices.

The SEN also has 13 international interconnections in the U.S., Guatemala and Belize. The Baja California system is connected with the CAISO, while the SIN is connected with the El Paso Electric Company System and the Electric Reliability Council of Texas System.

The SEN transmission network registered a capacity of 76,697MW (97.6% in the SIN) with total length of 108,018km at YE 2018.

PRODESEN 2018–2032 Projects Pipeline

No.	Year	Technology	State	Transmission Region	Installed Capacity (MW)	Estimated Capex (MXN Mil.)
1	2019	Carboelectric	COAH	Río Escondido	129	3,459
2	2019	Combined Cycle	NL	Monterrey	857	15,796
3	2019	Combined Cycle	SIN	Los Mochis	887	16,352
4	2019	Combined Cycle	CHIH	Moctezuma	907	16,708
5	2019	Combined Cycle	NL	Monterrey	950	17,502
6	2019	Efficient Cogeneration	NL	Monterrey	1	58
7	2019	Internal Combustion	BCS	Mulegé	8	435
8	2019	Internal Combustion	NL	Monterrey	15	854
9	2019	Wind	TAMS	Güémez	58	1,558
10	2019	Wind	TAMS	Güémez	60	1,612
11	2019	Wind	OAX	Ixtepec	396	10,639
12	2019	Wind	SLP	San Luis Potosi	105	2,821
13	2019	Wind	OAX	Ixtepec	15	403
14	2019	Wind	OAX	Ixtepec	252	6,770
15	2019	Wind	NL	Monterrey	250	6,717
16	2019	Wind	TAMS	Reynosa	431	11,580
17	2019	Wind	TAMS	Reynosa	99	2,660
18	2019	Wind	TAMS	Güémez	50	1,330
19	2019	Hydroelectric	VER	Poza Rica	6	226
20	2019	Hydroelectric	VER	Poza Rica	8	303
21	2019	Hydroelectric	OAX	Temascal	14	517
22	2019	Solar	ZAC	Aguascalientes	40	846
23	2019	Solar	GTO	Querétaro	30	714
24	2019	Solar	CHIH	Juárez	30	714
25	2019	Solar	SON	Hermosillo	110	2,139
26	2019	Solar	SLP	San Luis Potosi	170	3,306
27	2019	Solar	SON	Hermosillo	100	1,945
28	2019	Solar	CHIH	Juárez	30	714
29	2019	Solar	SON	Hermosillo	22	514
30	2019	Solar	GTO	Querétaro	30	714
31	2019	Solar	GTO	Querétaro	60	1,269
32	2019	Solar	SLP	Saltillo	40	846
33	2019	Solar	AGS	Aguascalientes	140	2,723
34	2019	Solar	COAH	Laguna	83	1,752
35	2019	Solar	SON	Hermosillo	180	3,500
36	2019	Solar	SON	Obregón	90	1,750
37	2019	Solar	CHIH	Moctezuma	150	2,917
38	2019	Solar	CHIH	Moctezuma	148	2,878
39	2019	Solar	SON	Hermosillo	125	2,431
40	2019	Solar	CHIH	Juárez	80	1,692
41	2019	Solar	MOR	Puebla	70	1,480
42	2019	Solar	SLP	San Luis Potosi	300	5,834
43	2019	Solar	AGS	Aguascalientes	30	706
44	2019	Solar	BC	Mexicali	41	867
45	2019	Solar	GTO	Querétaro	30	714
46	2019	Solar	AGS	Aguascalientes	100	1,945
47	2019	Solar	COAH	Laguna	101	1,966
48	2019	Solar	AGS	Aguascalientes	126	2,450

Continued on next page.
Source: Programa de Desarollo del Sistema Electrico Nacional 2018–2032.

PRODESEN 2018–2032 Projects Pipeline (Continued)

No.	Year	Technology	State	Transmission Region	Installed Capacity (MW)	Estimated Capex (MXN Mil.)
49	2020	Combined Cycle	SIN	Los Mochis	766	14,111
50	2020	Wind	OAX	Ixtepec	200	5,373
51	2020	Wind	ZAC	Aguascalientes	76	2,042
52	2020	Wind	JAL	Aguascalientes	64	1,719
53	2020	Wind	GTO	Querétaro	63	1,693
54	2020	Wind	OAX	Ixtepec	110	2,955
55	2020	Wind	QRO	Querétaro	30	806
56	2020	Wind	PUE	Puebla	70	1,881
57	2020	Wind	PUE	Puebla	150	4,030
58	2020	Wind	YUC	Mérida	30	806
59	2020	Wind	YUC	Mérida	30	806
60	2020	Wind	NL	Reynosa	269	7,227
61	2020	Wind	COAH	Río Escondido	149	4,003
62	2020	Wind	COAH	Río Escondido	100	2,687
63	2020	Wind	TAMS	Güémez	96	2,571
64	2020	Wind	COAH	Río Escondido	100	2,687
65	2020	Solar	GTO	Querétaro	30	714
66	2020	Solar	SON	Obregón	99	1,925
67	2020	Solar	AGS	Aguascalientes	300	5,834
68	2020	Solar	SON	Hermosillo	99	1,925
69	2020	Solar	TLAX	Central	200	3,889
70	2020	Solar	AGS	Aguascalientes	95	1,847
71	2020	Solar	ZAC	Aguascalientes	80	1,698
72	2020	Solar	SON	Obregón	200	3,889
73	2020	Solar	SON	Hermosillo	100	1,945
74	2020	Turbogas	NL	Monterrey	550	8,442
75	2020	Turbogas	SON	San Luis Rio Colorado	340	5,220
76	2021	Bioenergy	BCS	La Paz	16	849
77	2021	Bioenergy	BCS	Los Cabos	24	1,273
78	2021	Combined Cycle	JAL	Guadalajara	874	16,106
79	2021	Internal Combustion	CHIH	Chihuahua	111	5,889
80	2021	Wind	ZAC	Aguascalientes	30	806
81	2021	Wind	YUC	Mérida	64	1,719
82	2021	Wind	TAMS	Monterrey	300	8,060
83	2021	Wind	TAMS	Güémez	300	8,060
84	2021	Wind	VER	Temascal	40	1,075
85	2021	Solar	CHIH	Juárez	150	2,917
86	2021	Solar	ZAC	Saltillo	200	3,889
87	2021	Solar	SON	Hermosillo	125	2,431
88	2021	Solar	ZAC	Saltillo	150	2,917
89	2021	Solar	DGO	Durango	100	1,945
90	2021	Solar	ZAC	Saltillo	400	7,779
91	2021	Solar	TLAX	Central	500	9,723
92	2021	Solar	COAH	Laguna	150	2,917
93	2021	Solar	ZAC	Saltillo	150	2,917

Source: Programa de Desarollo del Sistema Electrico Nacional 2018–2032.

Related Research and Criteria

Corporate Rating Criteria (February 2019)
The Future of the Mexican Electricity Market (Taking Mexico to its Full Potential) (June 2016)
Mexico’s Energy Reform (Long-Term Positive for Mexico and Pemex; Challenging for CFE) (February 2014)

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Panamanian Electricity Sector

Infrastructure Investments and Natural Gas to Reduce Price Volatility

Infrastructure Projects to Strengthen System: Panama's (BBB/Stable) state transmission company, ETESA (BBB/Stable), plans to construct a fourth transmission line to connect hydroelectric generation in the west with demand in Panama City in the east by 2023. Fitch Ratings notes past transmission bottlenecks were largely addressed with the launch of a third transmission line in 2017. The administration of newly-elected President Laurentino Cortizo, who took office in July 2019, expressed interest in reinforcing transmission capacity between the capital city and Colon, an area near the Panama Canal with recently added and planned liquefied natural gas (LNG) power plants.

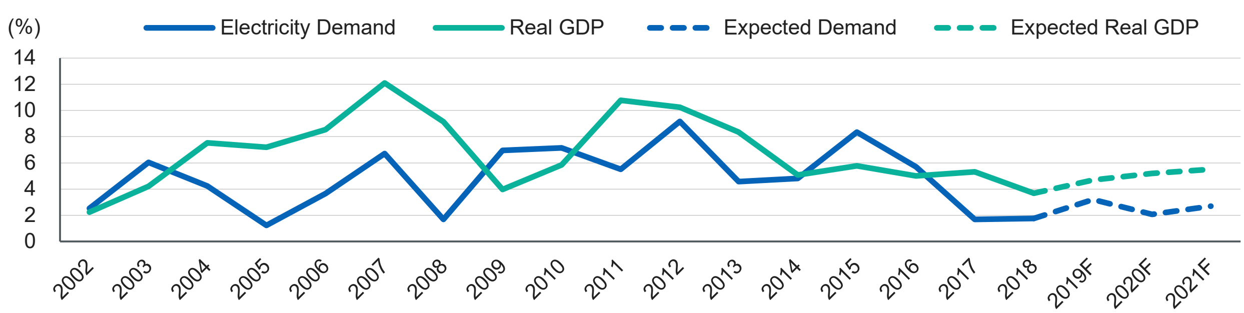
Prices Vulnerable to Hydrology Shocks: Fitch estimates Panama's current installed generation capacity would be sufficient to meet demand during a hydrology shock similar to the one that occurred in 2014. After adding more than 1,300MW in capacity since 2014, a nearly 50% increase, the system is better equipped to handle dry conditions. Dry spells would however require greater fuel oil and diesel usage, resulting in higher prices, a scenario that occurred in April 2019, when the spot price reached 111.57 Panamanian balboas (PAB)/MWh, a 14% yoy increase. While the system enjoys a higher reserve margin, capacity is still economically inefficient and would likely spark political pressure for extraordinary subsidy payments.

LNG to Play a Larger Role: Hydroelectric power is a mainstay in Panama's generation mix. However, the government stated in the National Energy Plan that the most economically feasible hydroelectric projects were already developed. While the government indicated its long-term goal of de-carbonization, it signaled a preference for natural gas to act as a bridge energy source. AES Colon became the country's first natural gas plant in 2018. A 423MW natural gas power plant is under construction and another 671MW facility is pending financial closure. Both are in the province of Colon. Fitch believes LNG will reduce price volatility during low hydrology levels since LNG can be approximately 40% cheaper than heavy fuel oil.

Regional Integration Increases Efficiency: The 1,800km Central American Electrical Interconnection System, or Sistema de Interconexion Electrica de los Paises de America Central (SIEPAC), high-voltage transmission line was completed in 2013 for USD500 million and connects Panama to six Central American countries. Panama was able to import a net 94,310MWh in 2014 with SIEPAC, when hydrology was low. The new government supports expanding SIEPAC to Colombia (BBB/Negative), which has a net installed capacity of 17,312MW, or four times that of Panama. We believe expanded interconnection will improve system efficiency by reducing price volatility as demand and supply are pooled among a greater number of countries.

Subsidies Support Sector: Approximately 75% of end users consume 300kWh or less per month and receive subsidies. The government provided USD153 million in total subsidies in 2018, which meaningfully reduced costs for low-consumption users. This lowers the potential for delinquent accounts at the distribution level and, in turn, helps ensure that distribution companies meet contractual obligations with generators. The government has a history of providing supplemental subsidies when energy costs rise markedly, as in second-half 2018, when USD82 million of subsidies were considered additional.

Panamanian Electricity Demand Versus Real GDP Growth



F – Forecast.
Source: Fitch Solutions, National Public Services Authority, National Dispatch Center, Empresa de Distribucion Electrica Metro-Oeste, S.A., Elektra Noreste S.A., Empresa de Distribucion Electrica Chiriqui S.A.

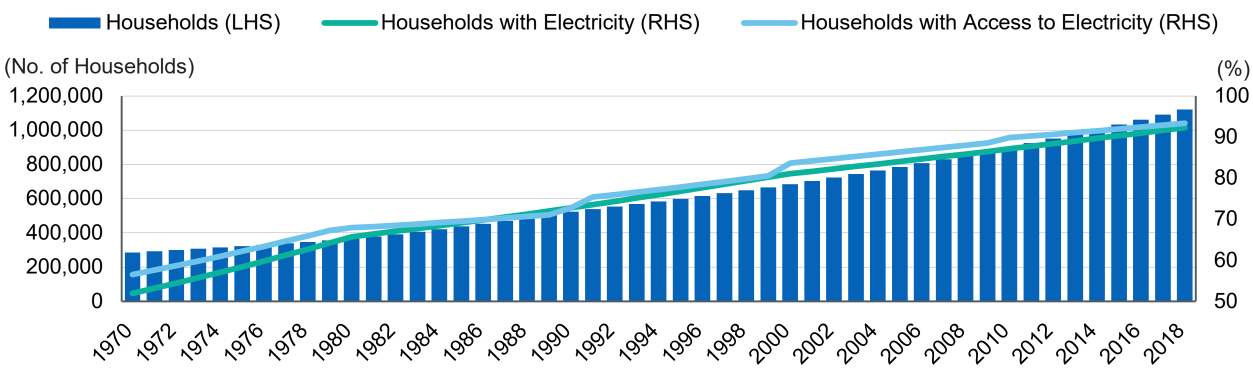
Primary Market Considerations

Growth Prospects

Electricity demand in Panama grew steadily, in line with GDP, population growth and residents' access to electricity. Growth in demand retreated or paused during times of higher prices, such as the commodity price run-up in 2008 and the low hydrology conditions of 2014. This indicates a certain degree of price elasticity on the part of consumers. Demand was relatively subdued in 2018 due to milder than usual weather resulting in less use of air conditioning. However, growth is expected to resume in the future at a moderate rate of approximately half of GDP growth. Increases in thermal generation capacity are also expected to better balance the country's energy mix and result in lower costs and lower prices, which will be supportive of demand.

Panama made strides in improving household electrification rates in the past several decades. The percentage of households with electricity increased to 92.3% in 2018 from 51.9% in 1970, as the population tripled, reaching the country's goal of 95% by 2019. Through the Rural Electrification Office, or Oficina de Electrificacion Rural (OER), the government extended networks to rural areas and installed isolated systems to provide access in more remote locations. Not surprisingly, given a relatively high GDP per capita and commercial development, Panama has the highest electricity consumption rate, measured as sales in GWh per client, among Central American peers. Panama is a relatively mature and stable market within the region.

Panamanian Electrification Rates



Source: National Energy Secretary.

On the supply side, hydroelectric power has been prominent in Panama's generation mix, historically comprising the majority of installed capacity. Heavy fossil fuels, such as diesel and bunker fuel, supplemented production particularly during dry spells. The country added coal capacity in 2011 when GDF Suez, now Engie S.A. (A/Stable), started the 120MW Bahia Las Minas plant. Minera Panama S.A. and AES Colon added 300MW of coal and 381MW of natural gas capacity, respectively, in 2018. Panama added wind capacity in 2013 with a 20MW project by Union Eolica Panamena S.A. Wind and solar total 459MW of installed capacity as of 2018. Fitch believes the National Public Services Authority, or Autoridad Nacional de los Servicios Publicos (ASEP), would be amenable to more such projects as 171MW of wind power is expected to go online in 2020.

The National Energy Secretary stated in the 2015–2050 National Energy Plan the long-term goal of de-carbonization but also the need for a transition period of up to several decades. The plan notes the country's theoretical hydroelectric potential is 3,000MW but the current hydroelectric capacity is approximately 1,800MW with the most economical sites already developed. The remainder would be small and medium-capacity projects of 50MW or less. In order to meet future demand, the plan cites the need to continue to develop conventional sources, such as petroleum and natural gas. A preference for natural gas was indicated as the widening of the Panama Canal could allow Panama to become an LNG hub. The interest in natural gas is evidenced by the concession awarded to Martano, Inc. to build a 400MW LNG power plant, which Fitch expects to be operational by 2021.

Newly-elected President Laurentino Cortizo's administration indicated a priority to promote renewable energy sources and to replace inefficient bunker C, or Fuel Oil No. 6, plants with cleaner and cheaper natural gas generation. Social priorities include encouraging energy consciousness, efficient use by citizens and extending greater electricity coverage to rural and indigenous areas.

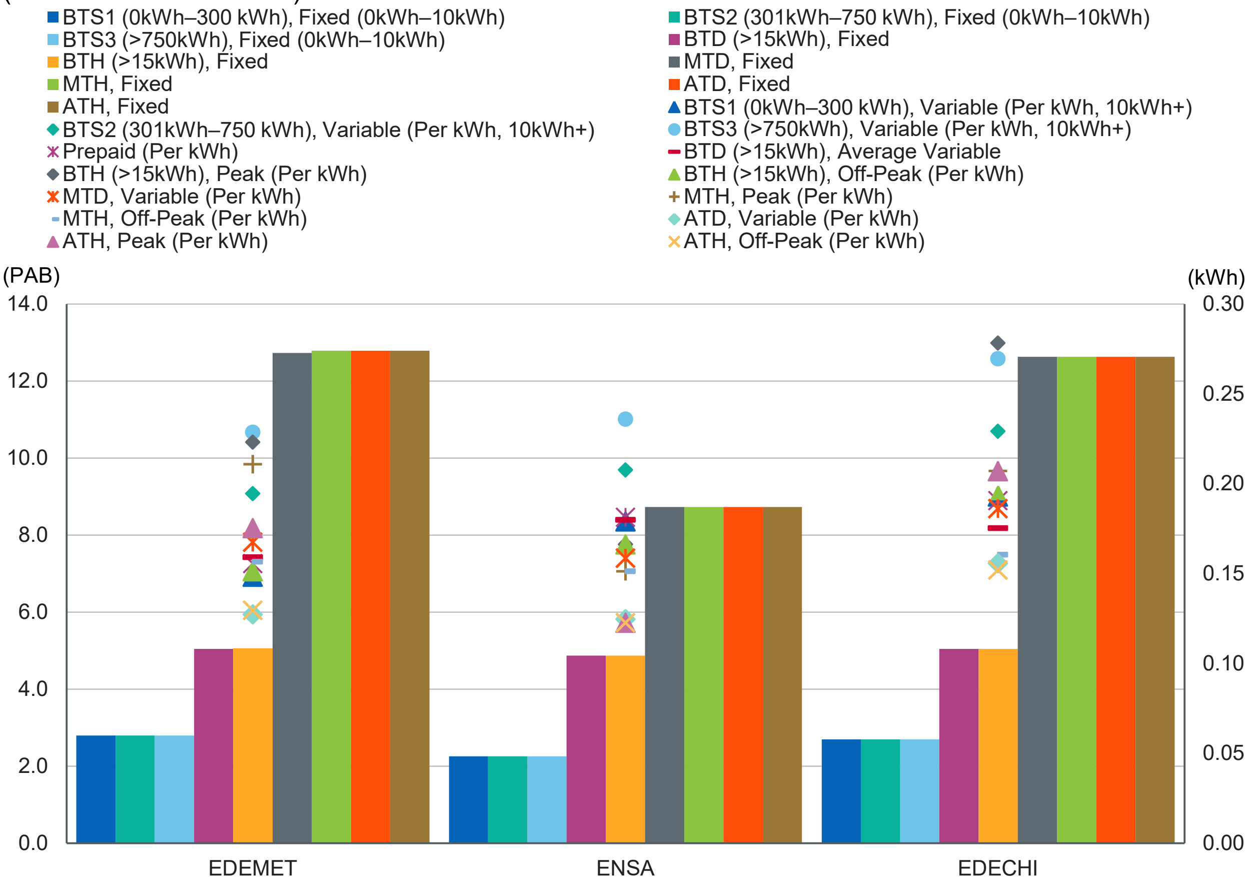
The administration's infrastructure priorities include reinforcing the transmission system to transport electricity from natural gas projects in Colon to Panama City and completing the interconnection with Colombia. The latter would extend Central America's SIEPAC connection to Colombia, which has a diverse energy supply and 17,312MW of installed capacity. Although Panama's electricity trade balance is generally positive, Fitch believes integration with Colombia, which is also connected with Venezuela and Ecuador (B–/Stable), would help Panama during times of low hydrology in the near term and might be necessary to meet the country's long-term demand.

Pricing

Panama's electricity sector regulator, ASEP, publishes baseline rates that apply for end users every four years, in line with the timeframe that it determines and applies to the maximum allowed revenue for distribution companies. This allows distribution companies to incorporate into electricity rates expenses incurred, such as investments to improve service and infrastructure, marketing activities, public lighting and energy losses deemed unavoidable, among other items.

Summary Applicable End User Fixed and Variable Charges

(As of Second-Half 2019)

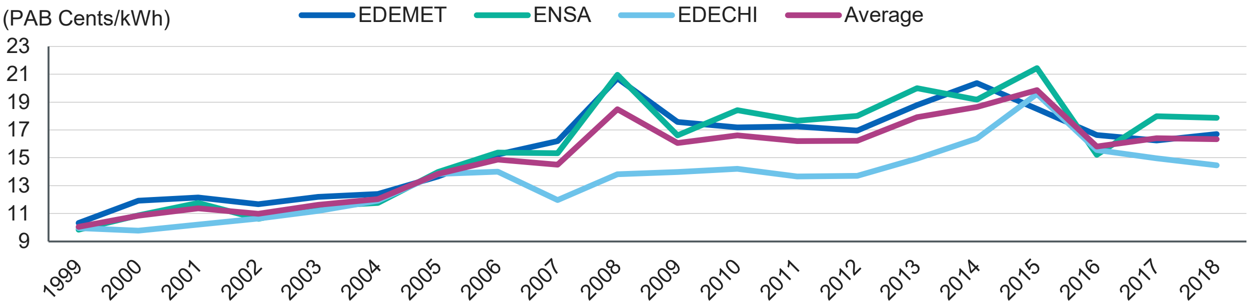


PAB – Panamanian balboa. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority.

Following certain amendments to the original maximum allowed revenue for the 2018–2022 distribution tariff period the current baseline electricity rates are effective from 2019 to 2022. Below is a summary of fixed and variable charges that various categories of users pay as of second-half 2019. Every six months, distribution, marketing and public lighting charges are adjusted to reflect changes in the consumer price index. Transmission, transmission losses and generation charges are adjusted by cost variations. Each month the Fuel Variation Charge, or Cargo Tarifario por Variacion del Combustible (CVC), is determined by calculating the difference in realized energy costs with those estimated in thermal energy contracts and in the spot market. This amount is added to the variable rate that all regulated users pay.

Empresa de Distribucion Electrica Chiriqui S.A.'s (EDECHI) customers do not currently pay the CVC while the Western Tariff Fund, or Fondo Tarifario de Occidente (FTO), subsidy program is in place. Over time, prices paid by end consumers rose with inflation and increases in commodity prices. Improvement in hydrology conditions between 2015 and 2018 caused prices to moderate. Historically, EDECHI's customers paid less due in large part to lower generation costs and access to low-cost run-of-river hydroelectric production in western Panama.

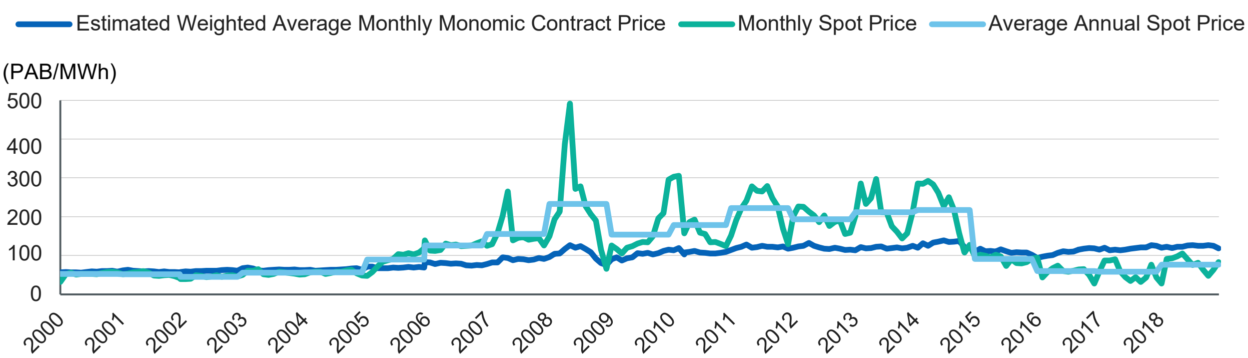
Historical Average Price Paid by Customers



PAB – Panamanian balboa cents. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority.

The country's contracting requirements for distribution companies, along with subsidies, have the benefit of reducing volatility and smoothing electricity prices for end users. The annualized standard deviation of monthly spot price changes from 2000 to 2018 was 90%, while that of monomic contract prices was 16%. This can be particularly beneficial during times of high demand due to air conditioning use from April to June and when fuel prices rise, such as in 2008. Since then, Panama added coal, natural gas, wind and, to a lesser degree, solar to the generation mix. The country is now less susceptible to run-ups in prices of petroleum-derived products. Monomic prices exceeded spot prices due to relatively subdued commodity prices and improved hydrology from 2015 to 2018. Still, the predictability contracting provides should not be overlooked.

Historical Monomic and Spot Prices

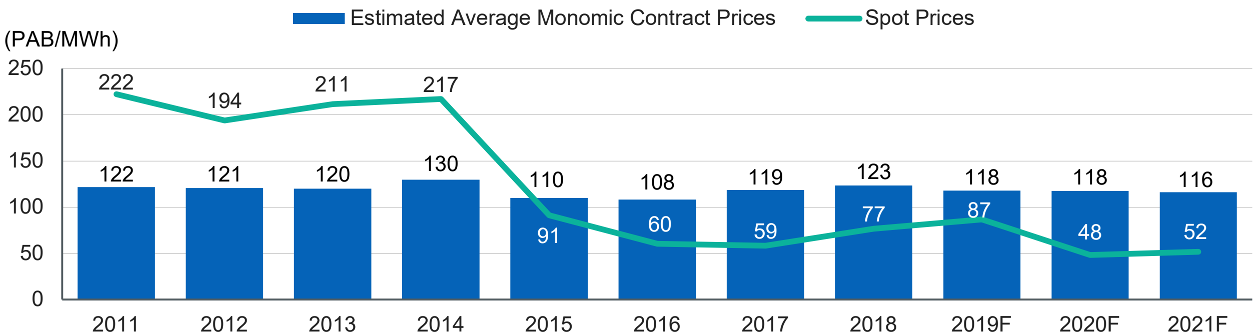


PAB – Panamanian balboa.
Source: National Public Services Authority, National Energy Secretary.

Fitch expects limited variation in monomic contract prices through 2021 as distribution firms are largely committed to long-term power purchase agreements (PPAs) through this timeframe. Spot prices increased to PAB118.56/MWh in April 2019 from higher demand due to dry conditions coupled with lower hydrology, particularly in the eastern portion of the country.

We expect prices will moderate for the remainder of the year as the high demand season has passed and hydrology shows signs of normalizing. Spot prices are expected to fall further in 2020 and 2021 assuming normalized hydrology, along with the entrance of more thermal capacity, should help stabilize the country's energy mix in the future.

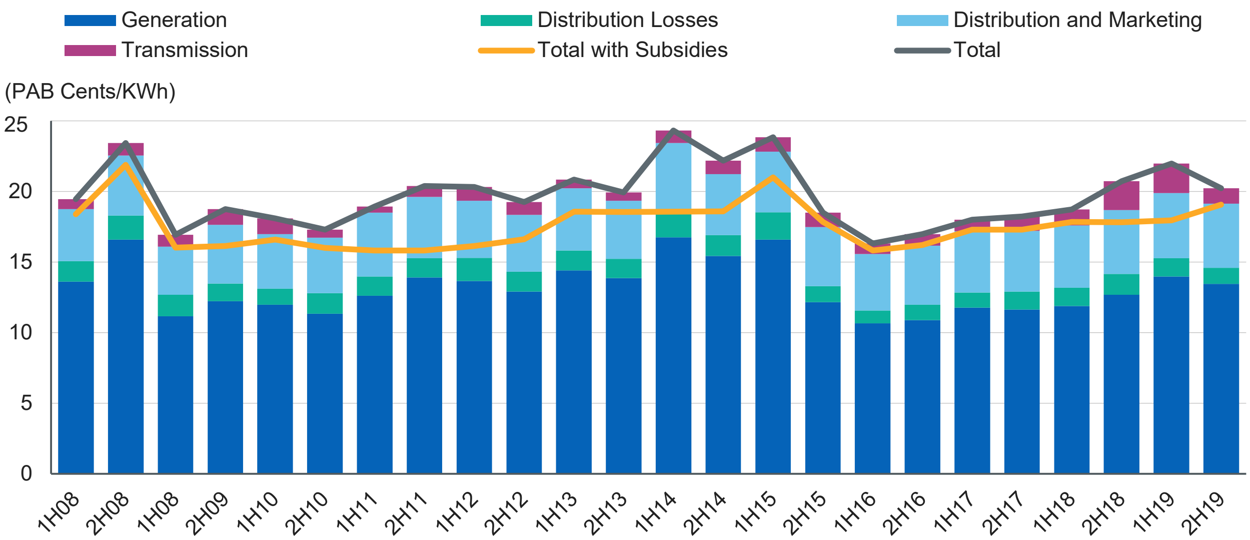
Historical and Forecast Monomic Contract and Spot Prices



PAB – Panamanian balboa. F – Forecast.
Source: Fitch Ratings, National Public Services Authority, AES Panama, S.R.L.

As a net importer of petroleum products, 65%–70% of Panama's electricity prices can be attributed to generation costs. Distribution activities, including losses, account for 25%–30% of total costs, while transmission is 3%–5% and increased to 10% in second-half 2018 and first-half 2019, as Empresa de Transmision Electrica S.A. (ETESA) was allowed to recover some of the investment it made in building the third transmission line. Subsidies, which are available for users who consume 300kWh or less per month, have the ability to smooth and lower prices paid by end users. This can be particularly important during times of higher generation costs, such as increasing fuel prices in second-half 2018 when subsidies lowered consumer prices by 14%, or low hydrology in first-half 2014, when end prices were lowered by approximately 24%.

Breakdown of Average Total Price of Electricity

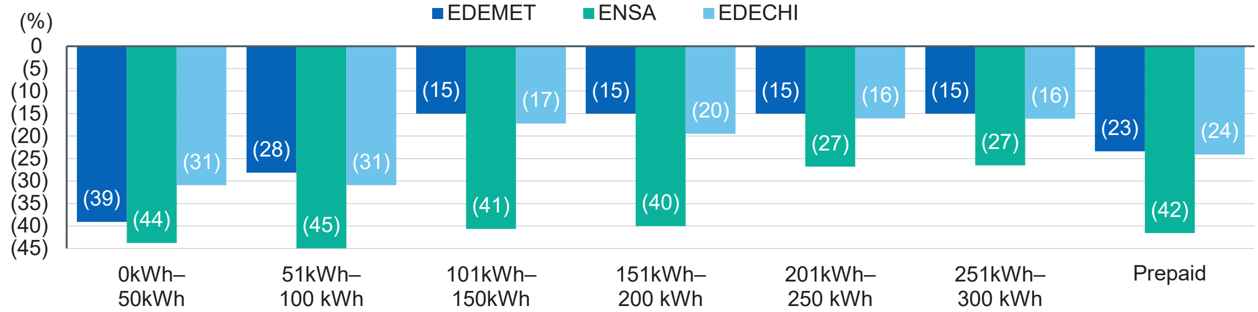


Note: Figures for 2019 are estimates.
Source: National Authority on Public Services.

The Tariff Stabilization Fund, or Fondo de Estabilizacion Tarifaria (FET), was originally established in 2004 as a transitory measure to mitigate the effects of high fuel prices on electricity costs for end consumers. West Texas Intermediate (WTI) was approximately USD40 per barrel in 2004. ASEP notes since the inception of FET, fuel prices were more volatile than expected and in 2012 the government focused on subsidies for customers with 500kWh of monthly consumption or less. This revision called for limiting subsidies to customers with up to 300kWh of monthly usage beginning in 2017 and was the prevailing subsidized consumption level. The FET subsidy is paid to distribution companies every six months based on the cost to hold subsidized customers' rates constant and a fuel variation cost based on bunker fuel and natural gas reference prices.

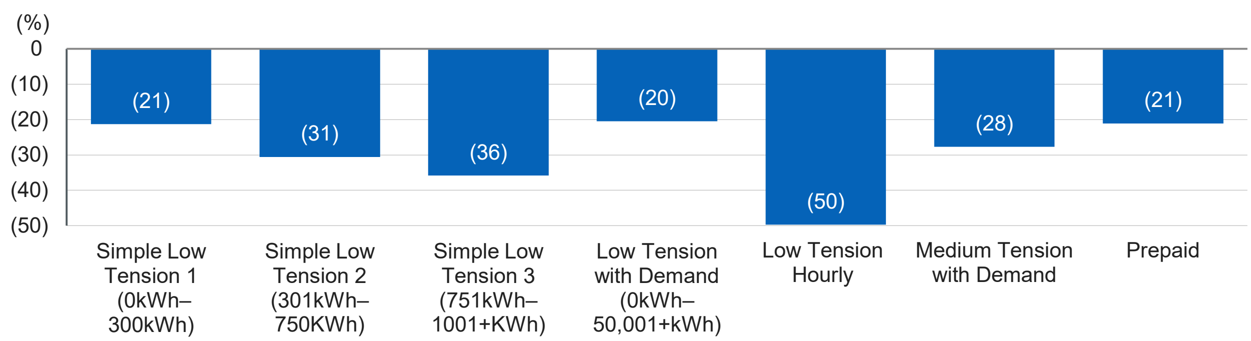
Empresa de Distribucion Electrica Metro-Oeste S.A.'s (EDEMET) reported 71% of customers consumed 300kWh or less in second-half 2018, while 72% of Elektra Noreste S.A.'s (ENSA; BBB/Stable) and 80% of EDECHI's customers are in this category. EDEMET received USD48 million in subsidies, ENSA received USD65 million and EDECHI USD40 million in 2018. ASEP is responsible for administering subsidies.

Estimated Credit Percentage by Usage Level from FET for 2H19



FET – Fondo de Estabilizacion Tarifaria or Tariff Stabilization Fund. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority.

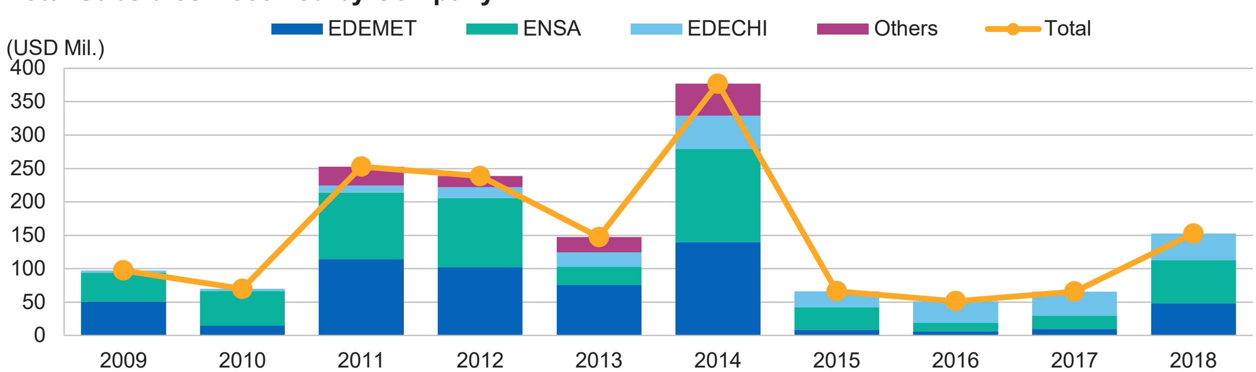
Average Estimated Credit Percentage By User Type from FTO for EDECHI Customers for 2H19



FTO – Fondo Tarifario de Occidente or Western Tariff Fund. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority.

The now defunct Energy Compensation Fund, or Fondo de Compensacion Energetica (FACE), was introduced in 2011 and was designed to be a smoothing mechanism to hold rates at first-half 2011 levels. FACE would pay distribution companies if the rates presented to ASEP for a given period were above first-half 2011 levels, or if the rates presented were below this level, the distribution companies would pay FACE. After raising the reference rate several times in subsequent years and paying a total of USD275 million to distribution companies in 2014, FACE was discontinued in early 2016. The FTO was approved in 2015 to ensure EDECHI's customers' electricity rates did not rise from first-half 2015 levels until YE 2016. The FTO was subsequently extended until YE 2017 but excluded medium and high-tension users. The program was extended again to YE 2019 but is currently slated to end at that time. EDECHI received USD31 million in 2018 from the FTO. Other subsidies received largely reflect compensation paid to generation companies for lost production due to delays in completing the third transmission line.

Total Subsidies Received by Company



EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority.

Recent Events

Year	Month	Event
2019	May	Laurentino Cortizo of the Democratic Revolutionary Party is elected president of Panama.
	April	ETESA issues a 30-year USD500 million international bond.
2018	August	The first natural gas power plant in Central America, the 381MW AES Colon, is inaugurated.
	July	2018–2022 Tariff regime and maximum allowed revenue takes effect for EDEMET, ENSA and EDECHI.
2017	October	ETESA's third transmission line enters into operation.
	July	2017–2021 Tariff regime and maximum allowed revenue takes effect for ETESA.

ETESA – Empresa de Transmision Electrica S.A. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A.
EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: Fitch Ratings, Fitch Solutions.

Regulatory Framework

The legal foundation of the Panamanian electricity market is Law No. 6 of 1997 establishing the rules governing electricity generation, transmission and distribution activities. The law sets forth the norms and coordination for expansion planning, integrated operation of the national electricity system, economic regulation and supervision. The law includes sale and ownership restrictions such as the transmission company shall be 100% owned by the state, thermoelectric and distribution company stakes must be sold in blocks of 51% or more, and hydroelectric companies may be sold in blocks up to 49%. Buyers may be national or foreign. The law sets a 50-year limit on hydroelectric and geothermal concessions, 25 years for transmission and 15 years for distribution. Finally limits are imposed on vertical integration stipulating companies may only engage in one segment among generation, transmission, and distribution and marketing. Certain exceptions to this apply, such as distribution companies being allowed to serve up to 15% of transmission and generation if accounting and management functions are separate from distribution businesses.

Executive Decree No. 22 of 1998 modified Law No. 6 of 1997 to define control of a distribution or generation company as the party that is owner of more than 50% of the capital, either directly or through a subsidiary, of the company. This party has a right to elect the majority of the company's board of directors, can veto board or shareholder decisions, and has the right to manage the company through a management contract. The party may name, replace or remove a manager, legal representative, president, secretary or treasurer, and has the right to commit the company through an agreement or contract with any market agent without board or shareholder approval. The Decree also addresses force majeure-qualifying events, such as wars and revolutions, requirements for generation companies to obtain a license, terms for regulatory intervention, verification of variable cost for dispatch, transmission network expansion and rural electrification, among other provisions.

Regulatory Bodies

ASEP is the public services regulator for Panama and a dependency of the Panamanian government created by Law 26 of 1996 to regulate, supervise and ensure the quality of public services. ASEP's sectors of purview are electricity, water and sewer, telecommunications, and radio and television. The regulator is charged with enforcing compliance with the Rights and Duties of Users Rule adopted in August 1997, which establishes the fundamental norms and principles by which users and public service companies do business with one another.

The National Energy Secretary, or Secretaria Nacional de Energia (SNE), is part of the Presidency of the Republic of Panama and has the mission of establishing and promoting the country's energy policy. Among its objectives are guaranteeing the security of energy supply, attaining electricity access for the entire country, promoting efficient and rational energy and electricity use, and promoting R&D of Panama's potential natural resources. The SNE also states it is authorized to promote energy sector openness toward a diversified energy matrix capable of reducing costs, adverse social and environmental effects, vulnerability, and dependence on limited resources.

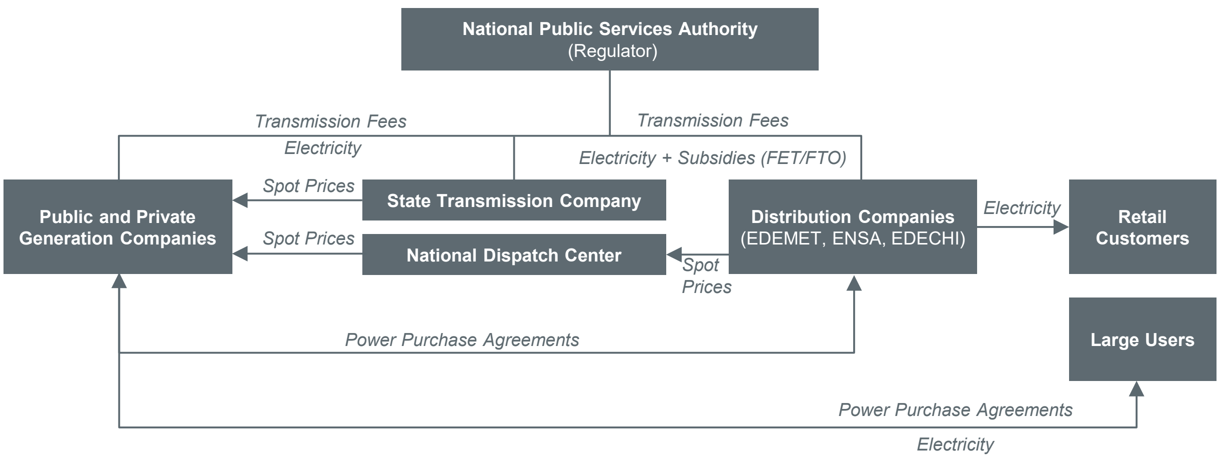
The National Dispatch Center, or Centro Nacional de Despacho (CND), is the non-profit coordinator of Panama's wholesale electricity market responsible for physical dispatches and managing the spot market. CND's services include calculating the system marginal cost, settling spot and international market transactions, and coordinating contract and spot market transactions. CND also certifies and verifies the meters of the Commercial Electricity Metering System and maintains, operates and programs the control system for the country's electricity grid. The CND was formerly known as the Integrated System Operations Center from 1977 until 1999 at which time the market was opened and the CND became a dependency of the state transmission company ETESA.

Industry Structure

Electricity service in Panama was provided by the private sector until 1961 when the Hydraulics and Electrification Resources Institute, or Instituto de Recursos Hidraulicos y Electrificacion (IRHE), was created as an autonomous institution. With the subsequent gradual nationalization of nationwide companies between 1972 and 1978, IRHE broadened its reach to include the entire country, not including the Panama Canal. Law Number 6 of 1995 reauthorized partial private sector participation in the generation segment and Law 26 of 1996 created the Water, Electricity and Telecommunications Regulatory Entity. After Law 6 of 1997 restructured the IRHE, eight companies were created: four generation, three distribution and one transmission. Public bidding processes were conducted in 1988 to sell stakes of between 49% and 51% of the generation and distribution companies with employees having the option to own between 2% and 10% and the State retaining the remainder. The number of individual generation firms increased to 67 in 2018 from eight in 1998 and installed capacity grew to 4,152MW from 1,049MW. The transmission company created from IRHE's restructuring, ETESA, remained wholly owned by the government.

Due to the requirement distribution companies contract 100% of expected short-term regulated user demand, the majority of economic transactions are carried out through PPAs between distribution and generation companies with 94% of the energy demanded via a PPA in 2018. Distribution companies must award PPAs through a public process and the contracts must be approved by ASEP. The spot market is largely designed for generation companies to sell energy to each other if production is insufficient to cover contractual obligations. Spot market dispatch is managed by the CND and based on variable generation cost. Run-of-river hydroelectric is typically dispatched first since the variable cost is considered to be zero. Electricity is transported through ETESA and both distribution and generation companies pay transmission fees based on availability.

Organizational Structure — Wholesale Electricity Market

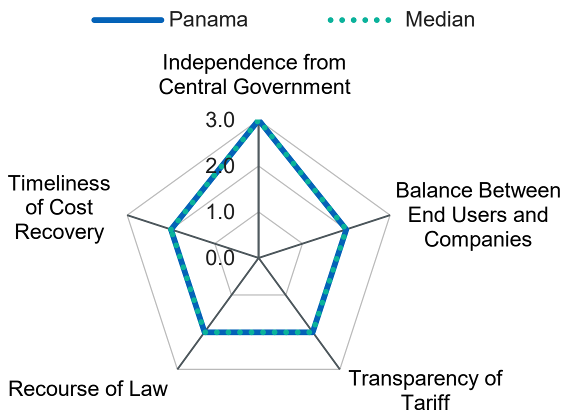


FET – Fondo de Estabilizacion Tarifaria or Tariff Stabilization Fund. FTO – Fondo Tarifario de Occidente or Western Tariff Fund. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A. Note: The National Dispatch Center coordinates market operations, transactions and is dependent on the State Transmission Company.
Source: National Energy Secretary, National Dispatch Center.

Regulatory Risk

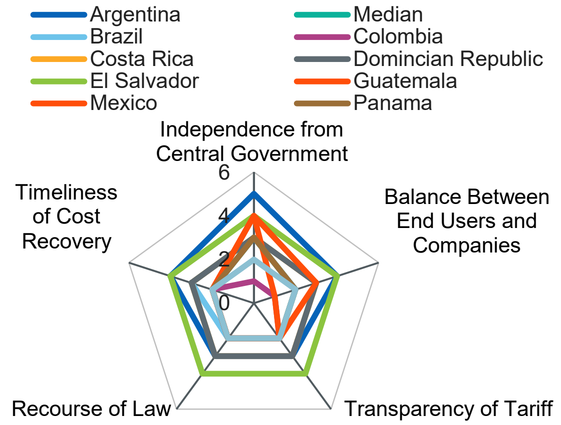
Fitch considers Panama's regulatory risk to be in line with regional peers and at the median for Latin America as a whole on the five points considered: Independence from the Central Government, Balance Between End Users and Companies, Transparency of Tariff, Recourse of Law, and Timeliness of Cost Recovery. While risk from central government involvement is considered moderate, we rate the country's Timeliness of Cost Recovery, Balance Between Companies and End Users, Tariff Transparency, and Recourse of Law as being strong. Panama compares favorably with Central American peers El Salvador (B–/Stable) and Guatemala (BB/Negative), which have stronger central government interference in the utility sector.

Panamanian Regulatory Score



Note: 1.0 = A; 2.0 = BBB; 3.0 = BB; 4.0 = B; 5.0 = CCC.
Source: Fitch Ratings.

Latin American Regulatory Score

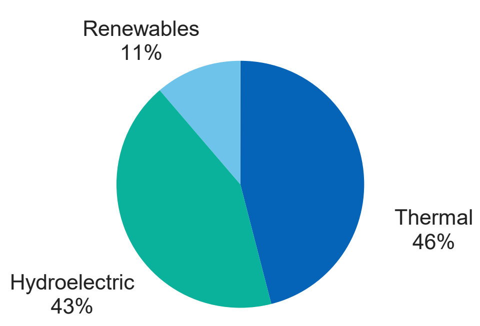


Note: 1.0 = A; 2.0 = BBB; 3.0 = BB; 4.0 = B; 5.0 = CCC.
Source: Fitch Ratings.

Installed Capacity

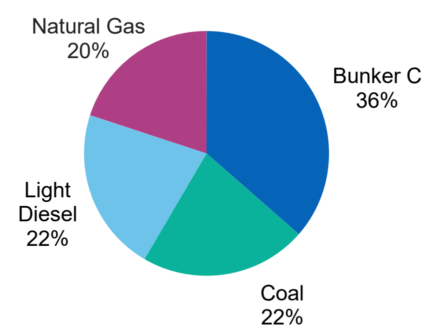
Panama had a total installed capacity of 4,153MW as of YE 2018, of which 1,909MW, or 46%, was derived from thermal sources. Of this thermal capacity, 36% is powered by Bunker C, which is a type of heavy fuel oil sometimes referred to as Fuel Oil Number 6. The additions in 2018 of 300MW of coal capacity by Minera Panama and a 381MW natural gas-fired plant by AES Colon helped to balance the remaining thermal capacity among those sources along with light diesel. Given Panama's proximity to the equator, the country is among the world leaders in rainfall received and has a significant amount of installed hydroelectric capacity at 1,776MW, or 43% of the country's total. This hydroelectric capacity is split fairly evenly between reservoir and run-of-river, the latter being more seasonal and intermittent. While hydroelectric power is low cost, it has high variability and the country's increasing thermal capacity serves as a valuable back up during periods of low hydrology.

2018 Total Installed Capacity
(Total Capacity: 4,153MW)



Source: National Energy Secretary.

2018 Thermal Installed Capacity
(Total Capacity: 1,908MW)

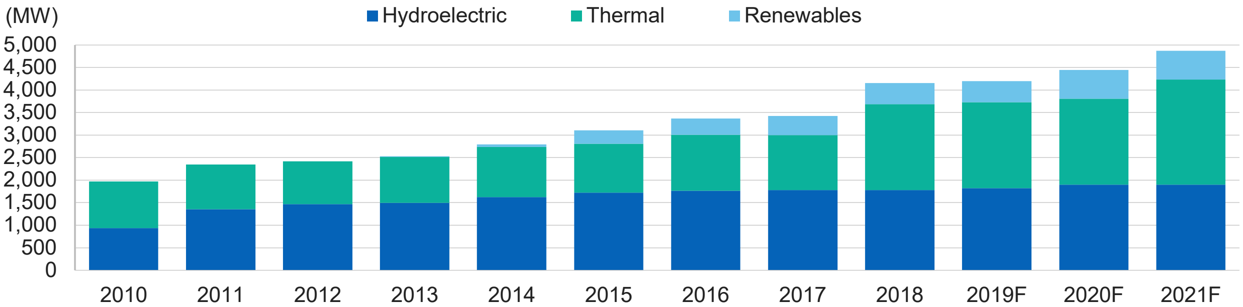


Source: National Energy Secretary.

Fitch expects Panama to add approximately 714MW of new generation capacity between 2019 and 2021, which includes 423MW of natural gas, 171MW of wind power and 120MW of hydroelectric power. A Chinese consortium, Martano, will provide the 423MW of natural gas, which will be a combined cycle LNG plant located in the province of Colon. Other noteworthy projects include a 105MW wind farm by the Spanish company Fersa Energias Renovables S.A. and a 63MW run-of-river hydroelectric plant near the Costa Rican border by the Norwegian company SN Power AS.

Competition in the generation market is relatively open; however, new entrants must obtain a license from ASEP, or in the case of hydroelectric and geothermal projects, a concession. Investors in new projects are responsible for acquiring the necessary land, performing financial studies and determining the price to offer services in order to obtain a PPA, which is negotiated and signed directly with off-takers, as the marketplace is competitive.

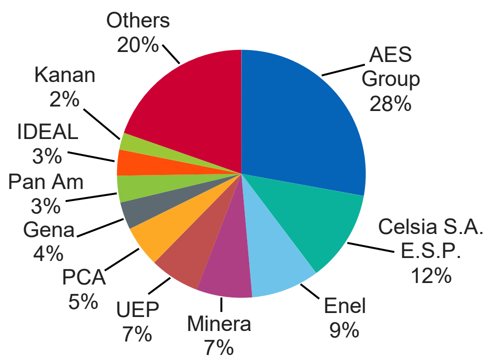
Installed Capacity by Power Source



F – Forecast.
Source: National Energy Secretary, AES Panama, S.R.L.

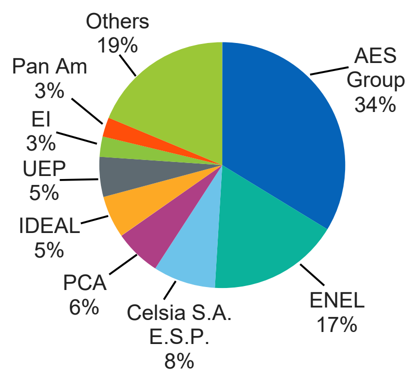
Generation is the most fragmented segment of the electricity sector and has the greatest number of private sector participants. Altogether, 67 individual companies contribute to power production. The largest consolidated competitor is The AES Corporation's (BB+/Stable) companies AES Panama, S.R.L. (BBB–/Stable), AES Changuinola S.R.L. (A+[pan]/Stable) and the newly-inaugurated AES Colon. The group's assets are historically hydroelectric with a current total of 704MW. However, the group added a 381MW LNG plant, AES Colon, in 2018 and a 72MW Bunker C barge as emergency capacity in 2015 due to low hydrology. Celsia S.A. E.S.P., a subsidiary of Grupo Argos S.A. (AAA[col]/Stable), has a total of 493MW consisting of comparable amounts of hydroelectric, coal and light diesel with 9.9MW of solar added in 2015. Enel S.p.A. (A–/Stable) has the third-largest consolidated capacity with a 300MW hydroelectric plant, Enel Fortuna, in Chiriqui and 67MW of solar capacity.

2018 Market Share by Installed Capacity
(Total Capacity: 4,153MW)



Kanan – Kanan Group. IDEAL – IDEAL Panama S.A. Pan Am – Pan Am Generating Ltd. Gena – Generadora del Atlantico S.A. PCA – Panama Canal Authority. UEP – Union Eolica Panamena S.A. Minera – Minera Panama S.A. Enel – Enel Fortuna S.A.
Source: National Energy Secretary

2018 Market Share by Generation
(Total Generation: 11,189GWh)

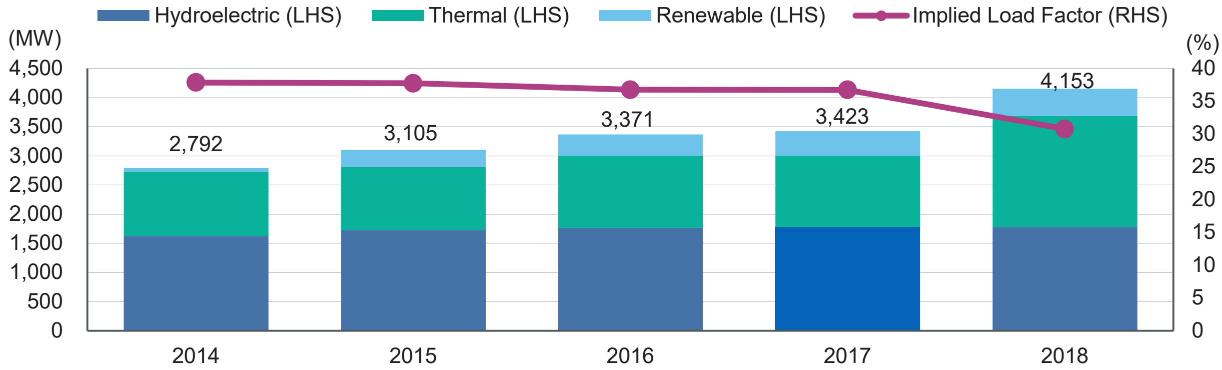


Pan Am – Pan Am Generating Ltd. EI – Electron Investment S.A. UEP – Union Eolica Panamena S.A. IDEAL – IDEAL Panama S.A. PCA – Panama Canal Authority. Enel – Enel Fortuna S.A.
Source: National Energy Secretary

Power Generated

Panama's utilization rate was predictably 37%–38% in recent years. A decline to 31% in 2018 can be explained by the mid-year entrance of a significant amount of thermal capacity at 681MW, which did not have a full year of production. Hydrology consistently improved from 2014 to 2018 with hydroelectric generation increasing to 70% in 2018 from 52% in 2014 with a load factor increase to 50% from 35% during this timeframe. The positive effect on the country's overall load factor from hydroelectric improvement was partially offset by the increase in renewable capacity to 578MW in 2018 from 57MW in 2014, a tenfold increase. Certain renewables, particularly solar, have complementary effects with hydroelectric power, despite lower load factors, and could be used to moderately hedge against low hydrology.

Utilization Rate

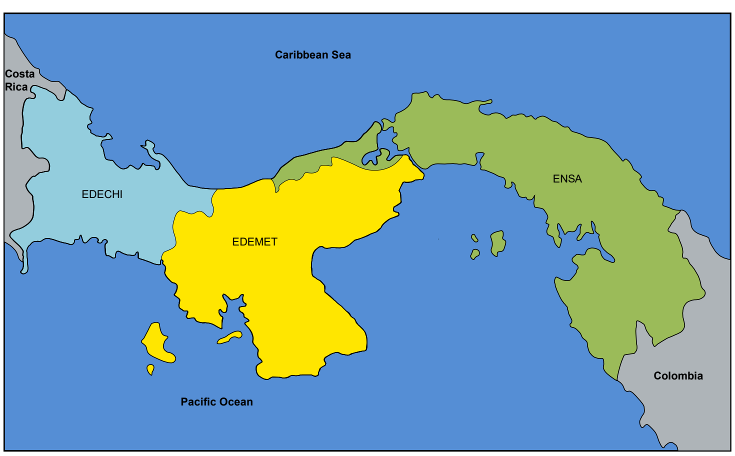


Source: National Energy Secretary.

Distribution

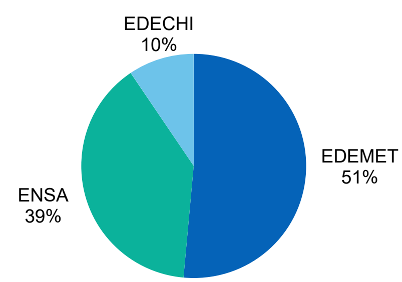
The privatization of IRHE in 1998 created three electric distribution companies that are 51% owned by foreign utility companies with approximately 48% held by the Panamanian government and 1% employees. The companies' concession contracts, which last for 15 years and expire in 2028, provide the exclusive right to distribute and market electricity in defined geographic zones, as shown in the map on page 12. EDECHI operates in western Panama and includes the provinces of Chiriqui and Bocas del Toro. EDEMET's concession area includes the western portion of Panama City and the provinces of Cocle, Veraguas, Herrera and Los Santos. ENSA's region includes the eastern portion of Panama City, Colon, the Gulf of Panama and the regions of Guna Yala and Darien. EDEMET and EDECHI are majority owned by Naturgy Energy Group, S.A. (BBB/Rating Watch Negative [RWN]), while ENSA is owned by Empresas Publicas de Medellin E.S.P. (EPM; BBB/RWN).

Concession Areas



EDECHI – Empresa de Distribucion Electrica Chiriqui S.A. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A.
Source: Naturgy Energy Group, S.A.

2018 Demand Breakdown by Distributor
(Total Demand: 9,625GWh)



ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A. EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A.
Source: National Public Services Authority.

EDEMET's and ENSA's concession areas have the largest populations as they share the capital city region. EDECHI's concession area in the western portion of the country is more sparsely populated. ENSA enjoys the highest number of clients per km of distribution lines, given much of its concession area is in and around Panama City with a limited population in Darien. This density lowers capex requirements and technical losses. Customer demand in 2018 was 9,626GWh with EDEMET capturing 51.4% of the market, ENSA 39.1% and EDECHI 9.5%. Energy losses were less for EDECHI, despite a lower market share, due to a relative lack of "red zones", or designated problem areas.

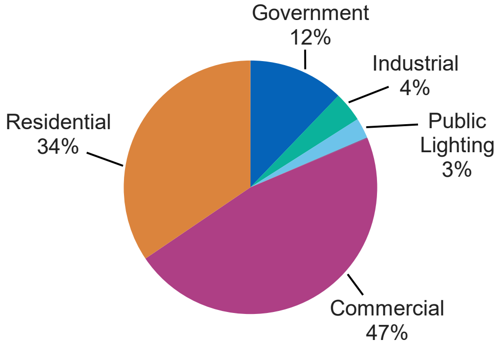
Residential customers accounted for 89% of total users and 34% of consumption in 2018. Commercial consumption was 47%, government was 12% and industrial 4% in 2018. Average monthly residential consumption in 2018 was 246MWh, considerably lower than commercial consumption of 3,183MWh, government at 6,806MWh and industrial at 14,541MWh. However, average industrial consumption is down considerably from a peak of 20,159MWh in 2016, while other categories reported very modest declines in average consumption rates during this time period. Total distribution sales were 8,427GWh in 2018, which included large block purchasers such as petro terminals and the Panama Canal Commission at 671.3GWh.

2018 Distribution Company Information

Data Point	EDEMET	ENSA	EDECHI	Total
Number of Clients (Actual)	490,396	458,981	156,906	1,106,283
Energy Purchases (GWh)	4,952	3,764	910	9,626
Energy Sales (GWh)	4,278	3,229	852	8,360
Losses (%)	13.6	14.2	6.4	13.2
Length of Aerial Distribution Lines (km)	16,219	10,796	6,690	33,705
Length of Underground Distribution Lines (km)	2,508	1,104	196	3,808
Total Length of Distribution Lines (km)	18,727	11,900	6,886	37,513
Clients per km of Distribution Lines	26	39	23	29
Tariff Stabilization Fund (USD Mil.)	48	65	8	121
Western Tariff Fund (USD Mil.)	0	0	31	31
Total 2018 Subsidies (USD Mil.)	48	65	40	153
Sales (USD Mil.)	749	684	168	1,601
EBITDA (USD Mil.)	50	91	36	177
Debt (USD Mil.)	500	294	78	871

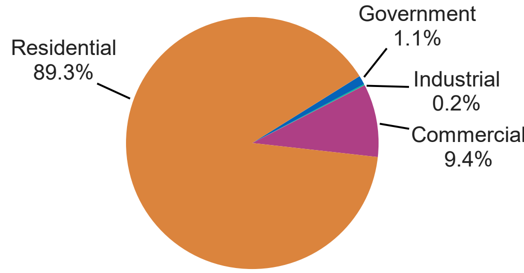
EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority, Empresa de Distribucion Electrica Metro-Oeste, S.A., Elektra Noreste S.A., Empresa de Distribucion Electrica Chiriqui S.A.

2018 Consumption by User Type



Note: Based on distribution sales of 8,427GWh.
Source: National Energy Secretary.

2018 User Type by Number of Clients



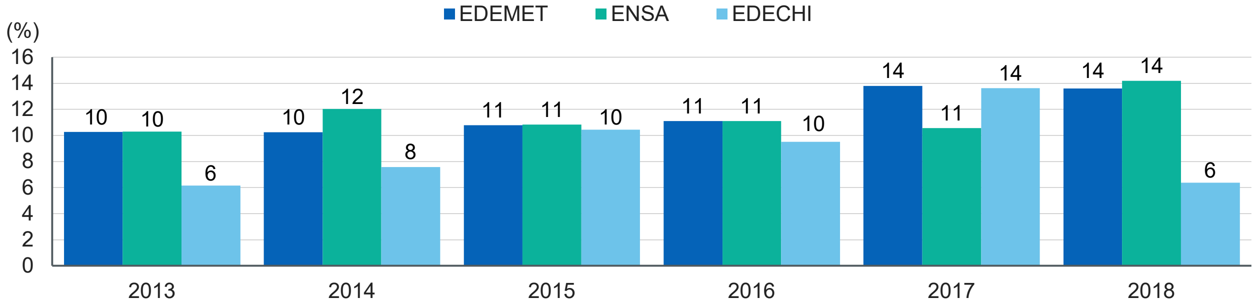
Note: Based on 1,103,845 clients.
Source: National Energy Secretary.

Energy Losses

Energy losses in Panama are generally in line with other Latin American electricity markets. Losses for the system as a whole were 13.15% in 2018, an increase from 12.49% in 2017. Losses can be broken down into technical losses and nontechnical losses. Technical losses are losses deemed to occur naturally in the distribution lines as a product of the amount of energy injected into the system. Nontechnical losses are due to exogenous factors such as theft, clandestine connections and dangerous areas that are unbillable and uncollectible.

Tariff reviews, which occur every four years, usually allow distribution companies to pass along all of the calculated technical losses and approximately 60% of nontechnical losses as an incentive to improve loss rates. For the 2018–2022 tariff cycle, EDEMET's tariff includes an 8.79% loss allowance, 7.66% for technical and 1.13% for nontechnical, while EDECHI's tariff is 8.07% the first year, declining to 7.71% in the final year, due to some moderate nontechnical losses in earlier years. ENSA's tariff is 11.08% in the first year and falls to 9.94% in the last year, 7.66% of which is for technical losses. Increased levels of recognized nontechnical losses, called "red zones", are areas with losses of more than 20%. ENSA's concession area includes Colon at 15% of its market, a dangerous area with substantially higher losses.

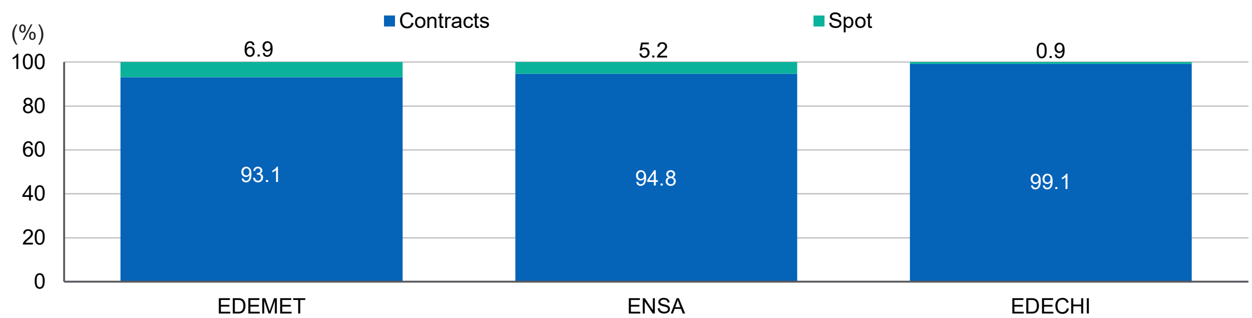
Energy Losses by Distribution Company



EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A. Note: Energy losses are calculated as the percentage of energy received.
Source: National Public Services Authority.

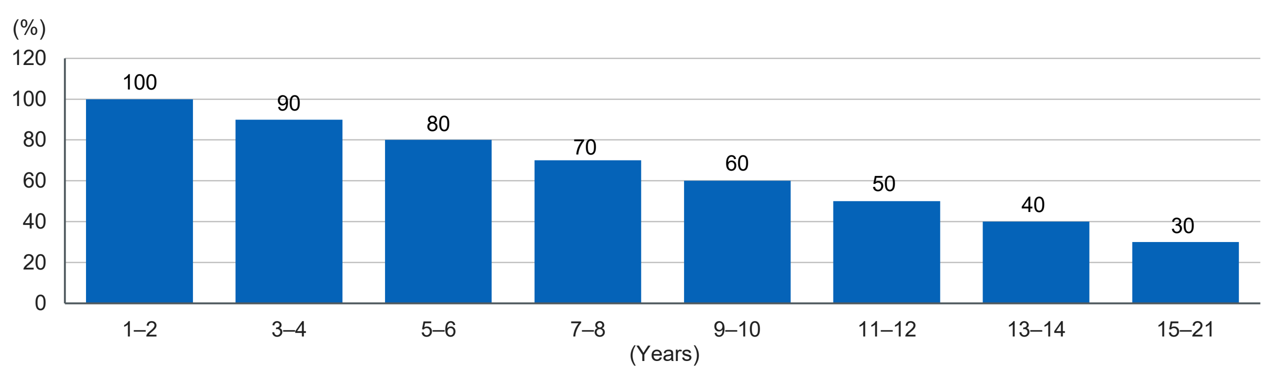
Electricity purchased by distribution companies was 94.3% contracted out of the 9,626GWh, while 5.7% was on the spot market. The highly contracted nature of the market is due to a regulatory requirement that distribution companies have 100% of the following two years of projected maximum demand contracted. For years three and four, the percentage required is 90%, which continues to fall until it reaches 30%, where it remains for the remainder of a given 20-year period. This ensures adequate generation will be available to meet the system's expected demands and lessens the likelihood of energy shortages and blackouts. EDEMET and EDECHI each had approximately 85% of contracted purchases with hydroelectric producers in 2018 due to geographic proximity to hydroelectric production in western Panama and the remaining 15% with thermal producers. Meanwhile, ENSA's contractual mix was roughly 50% hydroelectric and 50% thermal.

2018 Distribution Company Energy Purchases Breakdown



EDEMET – Empresa de Distribucion Electrica Metro-Oeste, S.A. ENSA – Elektra Noreste S.A. EDECHI – Empresa de Distribucion Electrica Chiriqui S.A.
Source: National Public Services Authority.

Distribution Company Contractual Requirements

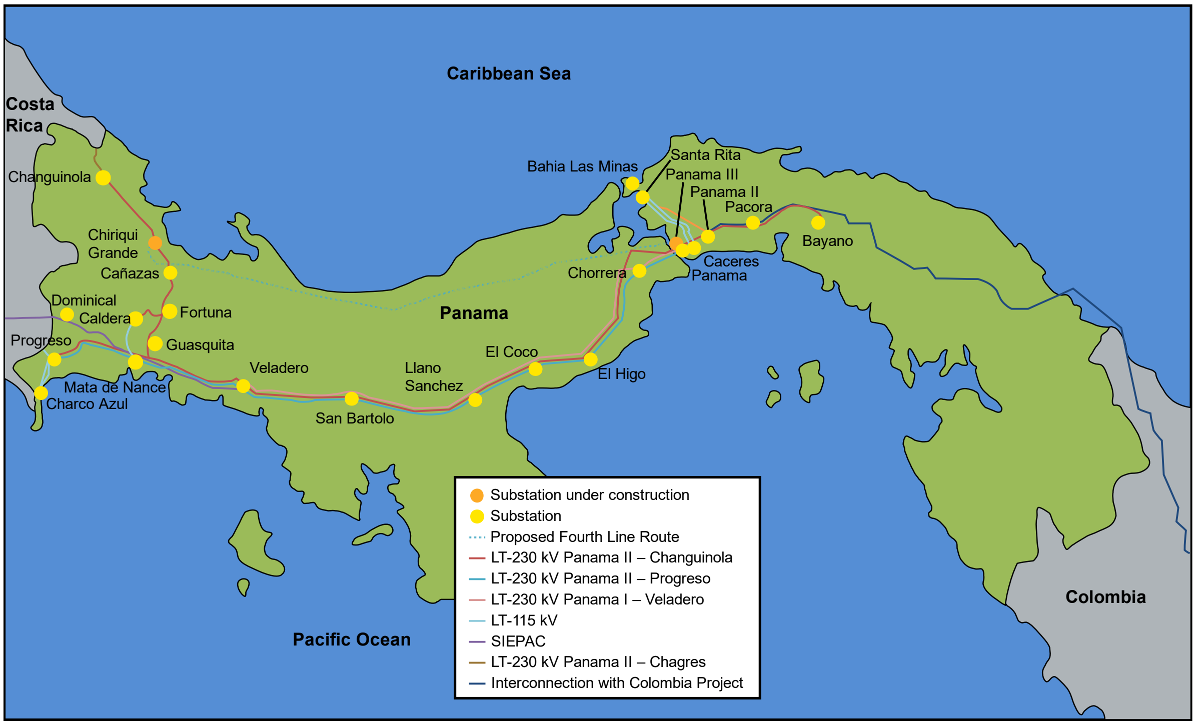


Source: Empresa de Transmision Electrica S.A.

Transmission

ETESA is wholly owned by the Panamanian government and is the exclusive provider of electric transmission in the country in accordance with Electric Sector Law 6/97. The company's main assets are three transmission lines, which total 3,395km and traverse the country from hydroelectric power generation in western Panama to population centers in the east, namely Panama City. The company has plans for a fourth cross-country transmission line, which will run along the northern shore and have an expected length of 317km and a cost of USD550 million. Electricity Law 6/97 is the regulatory law governing the company's activities including services, tariffs, rights and obligations. Tariff cycles determine the maximum allowed revenue for the company and are every four years with the current one from 2017 to 2021.

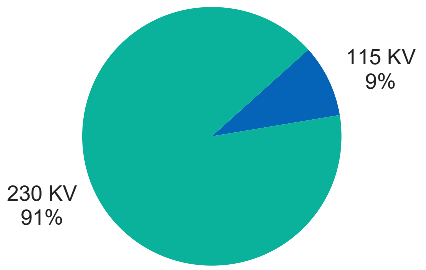
Panama Transmission Map



SIEPAC – Sistema de Interconexion Electrica de los Paises de America Central or Central American Electrical Interconnection System.
Source: Empresa de Transmision Electrica S.A.

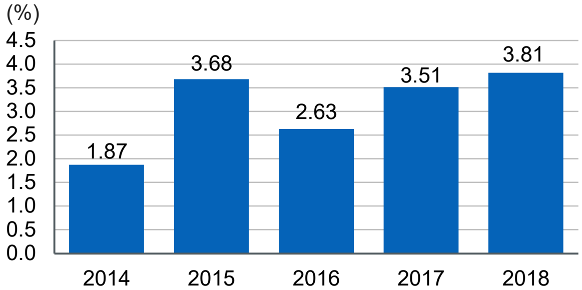
ETESA's revenue was USD131 million in 2018 and was composed of 83% energy transmission fees with the remainder being ancillary services, such as connection fees and services provides by the CND. Both generation and distribution companies pay ETESA transmission fees and amounts not paid by a given company may be redistributed among remaining market participants. Transmission fees are not price or volume dependent but rather are based on system availability and can only be reduced if the frequency or duration of interruptions exceeds predetermined thresholds. As a transmission company operating high voltage lines ETESA's losses are considerably lower than distribution companies and totaled 3.82% in 2018.

2018 Voltage Breakdown
(Total Lines 3,395km)



KV – Thousand volts.
Source: National Public Services Authority.

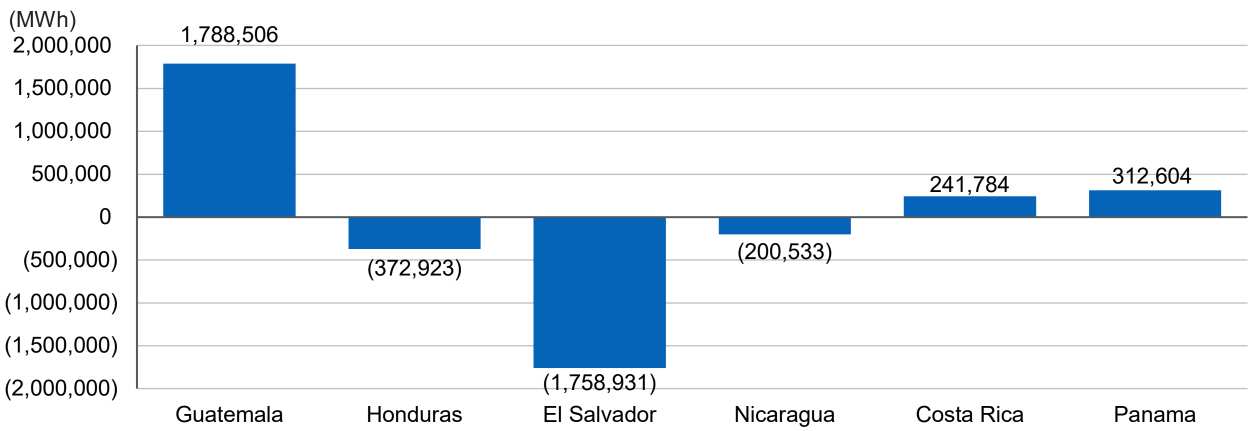
Transmission Losses



Note: Transmission losses are calculated as the percentage of energy delivered by the transmission system.
Source: National Public Services Authority.

Panama, Costa Rica (B+/Negative), Nicaragua (B–/Negative), Honduras, El Salvador and Guatemala now enjoy a greater degree of electric interconnection with the completion of the 1,800km SIEPAC transmission line in 2013. The Regional Electricity Market was established among these member countries to facilitate electricity imports and exports. Given a large hydroelectric capacity, Panama historically is a net exporter of energy, exporting 325,783MWh and importing 13,249MWh in 2018. Of the exports, 89% were sold by contracts and 11% in the spot market. Nearly all of the exported generation was hydroelectric and destined for El Salvador, which accounted for 75% of all imports within the region in 2018. Guatemala with strong coal capacity and a diversified generation matrix claimed 68% of exports among the countries in 2018. During years of low hydrology, Panama can become an importer of electricity as was the case in 2014 when net imports totaled 94,310MWh.

2018 Net Export–Import Balance by Country



Source: National Dispatch Center.

Plans are underway to build a 500km transmission line to connect Panama and Colombia. The line would have an energy transportation capacity of 400MW and run from the Cerromatoso substation in the Cordoba Department of Colombia to the Panama II substation in the province of Panama. Interconexion Electrica Colombia–Panama S.A., which is owned by Interconexion Electrica S.A. E.S.P. (BBB+/Stable) (Colombia) and Empresa de Transmision Electrica S.A. (BBB/Stable) (Panama), is responsible for planning, building and operating the line. Following the approval of a Social and Environmental Impact Study in 2018, it is expected the project will be completed by YE 2020. Fitch believes interconnection with Colombia, which has a net installed capacity of 17,312MW, would help to control and stabilize electricity prices in Panama, particularly during periods of lower hydrology.

Appendix A: Project Pipeline

Project Name	Sub Sector	Value (USD Mil.)	Size (MW)	Operator	Status	Timeframe End
Chuspa	Hydroelectric	31	10	Navitas International Solutions	Under Construction	2019
San Andres	Hydroelectric	43	10	Hidroelectrica Santo Domingo S.A.	Under Construction	2020
Burica	Hydroelectric	200	63	SN Power AS	Under Construction	2020
La Huaca	Hydroelectric	18	5	Hidronorth Corporation	Concession Awarded	2020
Anton	Wind	180	105	Fersa Energias Renovables S.A.	Concession Awarded	2020
Toabre, Phase I	Wind	150	66	Recursos Eolicos S.A., Audax Renovables S.A.	Concession Awarded	2020
Gas to Power Panama	Thermal	400	423	Martano, Inc.	Under Construction	2021

Source: Empresa de Transmision Electrica S.A., AES Panama, S.R.L.

Related Research and Criteria

Empresa de Transmision Electrica S.A. (April 2019)
Corporate Rating Criteria (February 2019)
Panama (February 2019)

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Peruvian Electricity Sector

Challenging Market Conditions to Continue

Spot Prices to Remain Pressured: Fitch Ratings forecasts spot prices in Peru (BBB+/Stable) will continue to recover at a slow pace after reaching an average bottom of $9.53/MWh in 2017. Spot prices should begin to reflect actual natural gas plants' generation costs after 2022, when continuous growth in demand absorbs the excessive oversupply in the system. Fitch expects capacity additions of 500MW and annual growth in demand of around 4.2% through YE 2022 resulting in prices above $20/MWh.

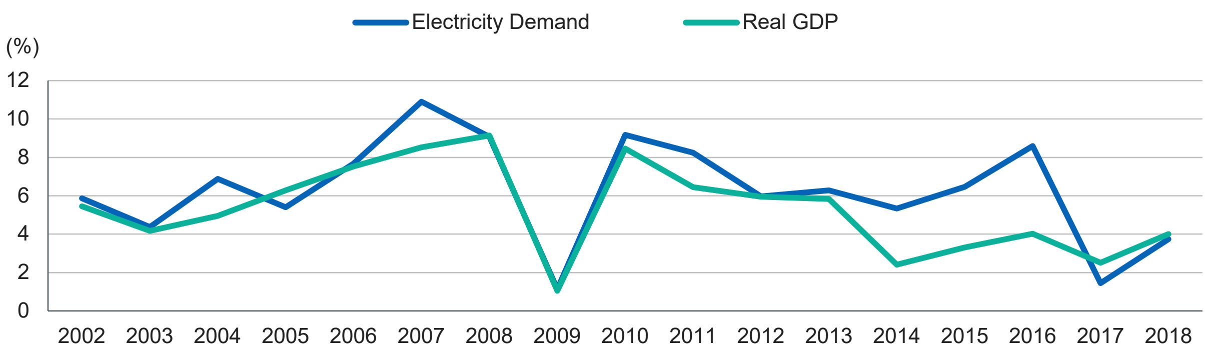
GSP Suspension Heightens Volatility: Construction on the Gasoducto Sur Peruano Pipeline (GSP) to extend natural gas supply to the southern region in Peru, as the supply gap was closing, was halted in light of the Odebrecht S.A. corruption scandal. As a result, approximately 1.5GW of thermal capacity in the southern part of Peru is inefficient from a cost perspective. This leads to periods of high price volatility when drought conditions hurt the output of much needed hydroelectric plants. There are few indications the GSP will be completed before 2023 at the earliest.

Asset Diversification Provides Buffer: Access to different generation technologies gives issuers the flexibility to navigate the seasonal aspects of Peru's supply and demand dynamics and optimize output. Fenix is the most exposed to asset concentration, operating one natural gas-fired plant. Orazul's assets consist of two base-load hydroelectric plants and one thermal generation plant, while Kallpa's assets consist of a hydroelectric plant and two thermal generation plants.

Flexible Cost Positions: A flexible cost structure allows companies to survive periods of depressed prices, as a fixed-cost structure forces generation sales into the spot market under unattractive margins to partially recover such costs. Orazul and Kallpa have the most flexible cost structures among the generation companies (GenCos) in Peru. Orazul benefits from being vertically integrated, while Kallpa has a lower percentage of take or pay natural gas supply and distribution agreements than peers such as Fenix.

Natural Gas Infrastructure Offers Cushion: Fitch estimates the system could easily accommodate another 1,200MWh of thermal generation with the current natural gas infrastructure. TGP's pipeline registered a maximum 72% usage rate during the dry season, despite being fully contracted, translating to around 258 million cubic feet per day (mmcfd) of spare capacity in the busiest season for thermals. The Camisea Gas Project Consortium (CGPC) could also easily accommodate additional supply as it currently reinjects 288mmcfd, on average, back into the Camisea field.

Peruvian Electricity Demand Versus GDP Growth



Source: Fitch Ratings, Comite de Operacion Economica del Sistema.

Growth Prospects

The growth in demand for electricity in Peru typically follows the country's GDP growth rate. Electricity consumption levels are low, relative to most countries in the region, reflecting the low GDP per capita level of Peru. Demand in energy grew at an annual average of 5.6% in the past decade. Fitch's base case assumes average annual growth of around 4.2% in the medium term, considering an expected increase in mining activities. At this growth rate demand will absorb the excessive oversupply of energy by 2023 and the system will most likely need additional capacity thereafter to avoid spikes in energy prices.

Currently, Peru's natural gas infrastructure consists of Transportadora de gas del Peru, S.A.'s (TGP; BBB+/Stable) pipeline and the CGPC, which could support about 1,200MWh of additional thermal generation. The TGP pipeline, which is operated in the central region, had a 72% capacity usage rate during the dry season, which translates to around 258mmcfd of spare capacity in the busiest season for thermals. The CGPC also has spare capacity and currently reinjects about 288mmcfd into the Camisea field due to lack of demand.

Gas transportation constraints in southern Peru prevent the efficient usage of 2,000MW of high cost, backup, diesel-run generation plants. These plants would ideally be converted to natural gas if a pipeline existed in this region, requiring about 500mmcfd of natural gas. As the GSP is not a medium-term solution, alternatives for supplying these cold reserve plants in the south with natural gas are being considered. These alternative supply means include trucking, pipelines and/or a floating storage regasification unit. Imported/regasified gas would almost certainly be free of regulations constraining prices, making them less competitive.

Major hydroelectric projects are an alternative for growth. These plants, however, would likely need contractual incentives from distribution companies (DisCos) and/or regulators, as was the case with the Cerro del Aguila and Chaglla power projects. Nonconventional renewables, such as wind and solar, have lower firm capacity and stronger incentives would need to be developed for investments in these sources of energy. The system recently subsidized these projects under contracts with energy prices above $200/MWh but there appears to be minimal appetite for similar projects.

Pricing

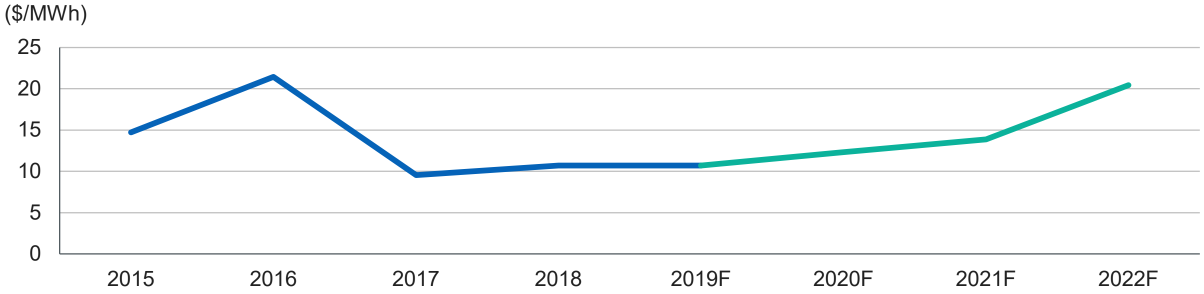
The Peruvian electricity market is vastly oversupplied. During the height of Peru's wet season in January 2018 the effective capacity of renewable generators was 4,228MW, compared with peak demand of 6,576MW, resulting in a shortfall of only 2,350MW for the thermal generators, which had an installed gas thermal supply of 4,028MW.

Due to the desire of thermal generators to continue producing to cover fixed costs, generators have an incentive to under declare costs to continue to dispatch energy. This resulted in an average annual spot price in Peru of $7.80/MWh in 2018, significantly lower than the total fuel cost of a hypothetical Peruvian gas thermal generator of around $28.12/MWh.

The oversupply in the system is a result of lower than expected growth in recent years after a very rapid rise in demand in the last decade. Growth in demand for electricity was 1.5% and 3.7% in 2017 and 2018, respectively. This compares with a 7.5% CAGR during the prior 15 years. Two massive hydroelectric projects, totaling more than 1,000MW in aggregate, began operating in 2016 and 2017, contributing to oversupply. Pricing pressure due to excess capacity was exacerbated by the use of fixed contracts between GenCos and Camisea, resulting in fuel costs being excluded from the variable cost pricing mechanism. Consequently, spot prices being established are below the cost of production. These contracts were encouraged by the government to incentivize gas consumption from the country's large gas field, Camisea.

Fitch expects capacity additions of 500MW and annual growth in demand of around 4.2% through YE 2022. This should result in the market being balanced after 2022 and prices above $20/MWh. In a scenario of a balanced market, GenCos would no longer be under pressure to increase capacity usage and would be fully dispatching under contracted obligations. Therefore, GenCos would not have the incentive to understate variable costs in order to dispatch in the spot market.

Historical Spot Prices



F – Forecast.
Source: Fitch Ratings, Comite de Operacion Economica del Sistema.

Regulatory Framework

Industry Structure

Peru's electric utility industry is organized along market segments: generation, transmission and distribution. The generation and distribution businesses are separated into distinct operating companies. GenCos produce and sell electricity to DisCos, other GenCos and large industrial customers. GenCos sell electricity either in the spot market, under regulated contracts with DisCos or under unregulated contracts with large industrial users. DisCos procure energy for regulated clients through long-term contracts granted in public bids. These regulated contracts have fixed prices capped by the Supervisory Body for Investment in Energy and Mining, or Organismo Supervisor de la Inversion en Energia y Mineria (OSINERGMIN). Regulated clients accounted for 56% of total energy sales in 2013. Large industrial users can buy energy from DisCos or GenCos and contracted prices between GenCos and large industrial users are freely negotiated among the parties. Spot prices are determined based on marginal generation costs. The dispatch order of GenCos is made by the unit with the lowest variable cost available, which is mainly based on the source of energy used to produce electricity.

Tariffs for regulated residential users pass through energy, transmission and distribution costs. Energy costs are calculated as the average of prices included in the power purchase agreements (PPAs) of DisCos, which are obligated to contract 100% of energy and capacity for the next 24 months. DisCos pay regulated prices for purchases of energy not included in long-term contracts. Residential customers with consumption levels lower than 100kWh receive subsidies financed by users with consumption levels higher than this threshold, a cross-segment subsidy. These subsidies are relatively small and do not significantly alter electric tariffs.

DisCos are incentivized to operate efficiently. The regulatory framework allows DisCos to reap the economic benefits of increasing productivity but also requires them to bear the financial burden of operating inefficiently. For example, a DisCo's inability to pass through higher costs from increasing levels of electricity loss encourages efficient operations. DisCos are required to distribute power to regulated customers and enter into long-term PPAs to cover long-term demand expectations. To enter into PPAs, distribution companies request open biddings, which are conducted by OSINERGMIN.

Electricity tariffs for residential consumers are regulated, while industrial customers are free to enter into bilateral PPAs directly with GenCos. End-user tariffs are in line with the region, with industrial tariffs being significantly lower than residential tariffs as a result of industrials' ability to negotiate directly with the GenCos. Transmission concessions and construction result from public biddings conducted by the Ministry of Energy and Mines, or Ministerio de Energia y Minas (MINEM) or by the Private Investment Promotion Agency, or Agencia de Promocion de Inversiones Privadas (ProInversion). The concessions are granted as a build-own-operate-transfer (BOOT) at no cost for a maximum of 30 years plus the construction period. After the concession period is over the assets must be transferred to the government at no cost.

Transmission tariffs are set to allow transmission companies to cover O&M costs and receive an adequate return on investment, currently using a 12% discount rate. Concessionaries are remunerated for the availability of transmission lines and, consequently, they are not exposed to volume risk. The characteristics of this system provide stability and predictability to a concessionary's cash flows and support investment-grade ratings.

Regulating Entities

The legal framework for Peru's free market is governed by the Law of Electricity Concessions (Law No. 25844) of 1992 and subsequent amendments. This law establishes the legal framework for the electricity sector and governs generation, transmission, distribution and commercialization of electricity. The electricity laws also govern generation prices, capacity payments and other electricity sector charges.

There are three types of agents in the Peruvian electricity market: promoters, regulators and direct agents. The promoters are the MINEM and ProInversion. Regulators include the Committee of Economic Operation of the System, or Comite de Operacion Economica del Sistema (COES); OSINERGMIN; and the Agency for Environmental Assessment and Enforcement, or Organismo de Evaluacion y Fiscalizacion Ambiental (OEFA).

Other regulators are the Ministry of Environment, or Ministerio del Ambiente (MINAM); the National Institute for the Defense of Free Competition and the Protection of Intellectual Property, or El Instituto Nacional de Defensa de la Competencia y de la Proteccion de la Propiedad Intelectual (INDECOPI); and the Ombudsman's Office, or Defensoría del Pueblo. The direct agents are the electric companies, such as GenCos, distributors and transmitters, and the customers.

COES is the agency responsible for coordinating the operation of the National Interconnected System, or Sistema Electrico Interconectado Nacional (SEIN), at minimal cost and thereby making better use of energy resources. COES also plans the development of the transmission system and manages the short-term market. COES determines which generation units to dispatch to minimize energy costs. OSINERGMIN determines the reference prices based on the electricity pricing policy established by the MINEM and supervises and monitors the power concession contracts. OEFA supervises and monitors the effects on the environment, according to the policies of MINAM, and environmental standards to national regulations.

INDECOPI advocates for competition in the electricity market and the rights of consumers. MINEM is responsible for proposing and adopting rules and regulations for the sector, granting concessions and authorizations, and reviewing and approving expansion plans for the SEIN. ProInversion is the entity responsible for promoting investments not dependent on the Peruvian state by agents under the private regime and boosting Peru's competitiveness and sustainable development to improve the welfare of the population.

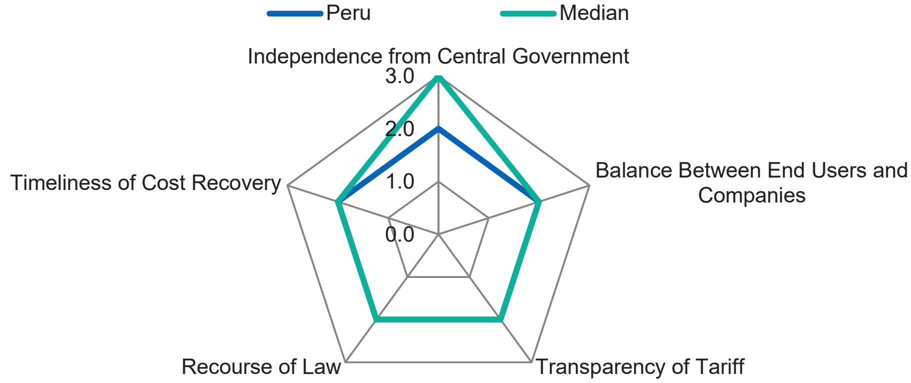
Regulatory Risk

The Peruvian regulatory framework is considered to be balanced, independent from the central government and to have a transparent tariff-setting process. This is mainly supported by the balanced mix of the regulator's board of directors (BoD), which is composed of political appointees and individuals with a technical foundation in the industry. The BoD is composed of five members proposed by MINEM, the Ministry of Economy and Finance, and the Presidency of the Council of Ministries.

BoD members are elected through an open recruitment process and terms can be renewed to maintain regulatory stability. Local regulation establishes minimum requirements for the regulator's BoD members, which are established by law and include at least 10 years of experience, professional adequacy, graduate studies and several limitations designed to prevent conflicts of interest. The Peruvian regulatory framework is considered to be moderately balanced between end users and investors, and focused on minimizing electricity costs for end users, while ensuring an adequate return on investment for the sector participants. All three sectors, generation, distribution and transmission, have tariffs aiming to promote efficiency, while maintaining an attractive structure to provide incentives for investments.

Transparency of tariff-setting procedures in Peru is considered strong, with clear procedures established by the General Electricity Law and complementary regulations. The regulator reviews tariffs on a timely basis. Distribution companies can recover costs through tariffs and the tariff-setting procedures are public and subject to public hearings. The General Electricity Law gives electricity companies recourse to appeal unfavorable regulatory decisions. Fitch believes the regulatory framework is positive and supportive of investment-grade ratings in all three sub-segments of generation, transmission and distribution.

Peruvian Regulatory Score



Note: 1.0 = A; 2.0 = BBB; 3.0 = BB; 4.0 = B; 5.0 = CCC.
Source: Fitch Ratings.

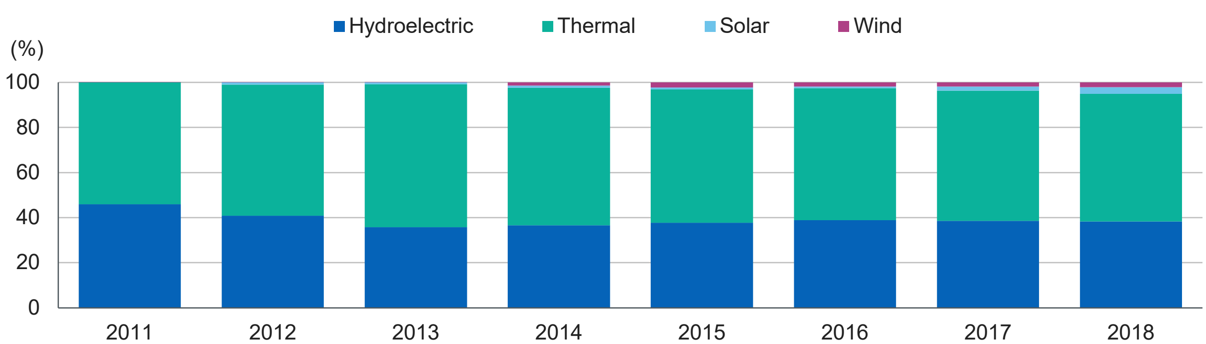
Generation

Peru's SEIN had a total installed capacity of 13,052MW as of 2018. Thermal power plants accounted for 57% of this capacity, while hydroelectric and nonconventional renewables contributed to the remaining 38% and 5%, respectively. Spot prices were affected by optimal hydroelectric conditions as hydroelectric sources accounted for 58% of generation and total renewable generation sources constituted 62% of total generation. Only 38% of the generated energy was sourced from thermals. The country increased installed capacity by nearly 150% between December 2008 and December 2018. Two large hydroelectric projects and two dual-fuel cold reserve plants in the south added more than 2GW of new capacity. Peru's implied capacity factor was high at around 50% over the past decade.

There are two fuel sources which form the bulk of Peru's thermal generation capacity: natural gas and diesel. Diesel is generally dispatched under exogenous interruptions to gas supply or suspension of more efficient capacity due to unscheduled maintenance. These plants do not freely declare fuel prices and thus have considerably high variable costs. Two of these diesel plants are Nautilus Inkia Holdings LLC's (Inkia; BB/Negative) four Puerto Bravo units, jointly known as Samay I, and Engie S.A.'s (A/Stable) three Ilo units. As part of Peru's cold reserve plants, they represent approximately 1,200MW of installed capacity across the two plants. The plants were commissioned as part of Peru's plan to gasify the southern node. The GSP project, a 34-year BOOT concession, was estimated to have a final construction cost between $3.5 billion and $4.0 billion, covering approximately 600 miles.

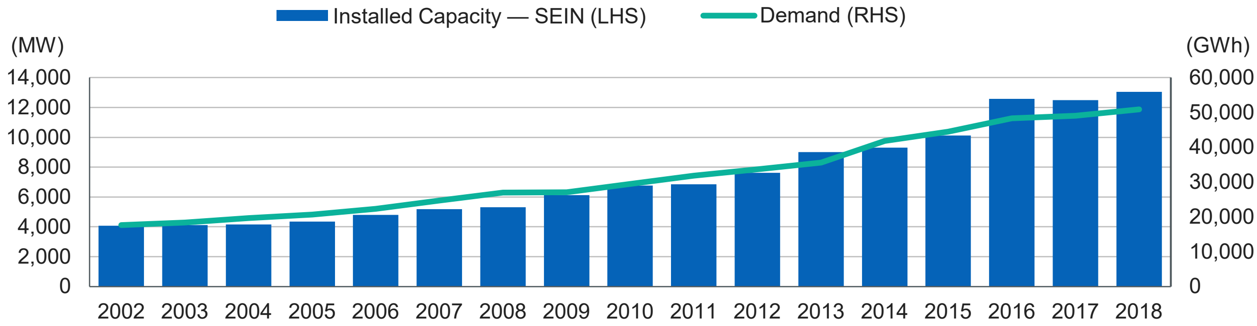
The Ilo and Samay plants, completed in 2016, were designed to use diesel, while the GSP was being constructed. The existing gas thermal would supply the bulk of peaking demand in the interim, with diesel being dispatched under extraordinary circumstances. The GSP consortium began construction in May 2015 in Ticumpinia, Cuzco, south of the Camisea fields, with an expected completion date of May 2019. The consortium members included Enagas S.A. (A–/Stable), Grupo Grana y Montero S.A.A. and Odebrecht. However, with Odebrecht embroiled in the Lava Jato scandal, construction ground to a standstill within two years. No new engineering, procurement and construction contractors were chosen to finish construction.

Peruvian Installed Capacity by Source



Source: Fitch Ratings, Ministerio de Energia y Minas, Comite de Operacion Economica del Sistema.

Peruvian Electricity Supply and Demand Balance



SEIN – Sistema Electrico Interconectado Nacional.
Source: Fitch Ratings, Comite de Operacion Economica del Sistema.

Distribution

Distribution activity is a natural monopoly and a stable, low-risk business. DisCos are granted exclusive concessions to operate in a specific geographic area and distribution concessions are permanent and can only be revoked if a company fails to provide a quality service or meet safety standards. The distribution system continues to expand. DisCos are capable of providing electricity to more than 85% of the population. Luz del Sur S.A.A. and Edelnor S.A., subsidiaries of Sempra Energy (BBB+/Stable) and Endesa S.A. (A–/Stable), respectively, represented approximately 61% of total distribution sales.

Ramped up construction of new generation capacity coincided with growth in capacity contracted by DisCos. The economic slowdown left DisCos over contracted, paying for excess capacity. This situation was further exacerbated by a downward revision in the thresholds for determining large users. As a result, more users left the regulated system to negotiate directly with GenCos. Large GenCos, with DisCo contracts representing between 45% and 70% of total contracted capacity, experienced significant declines in volume sales between 2016 and 2018.

Transmission

Peru's SEIN covers almost the entire country at 87% of installed capacity. The transmission grid in Peru is divided into four different systems: the primary; the secondary; the Guaranteed Transmission System, or Sistema Garantizado de Transmision (SGT); and the Complementary Transmission System, or Sistema Complementario de Transmision (SCT). The primary and secondary were established by Law No. 25844 and the regulatory framework for transmission was changed by Law No. 28832, due to several deficiencies and low incentives to invest. This law also created the SGT and SCT. The SGT must follow the country's transmission plan, which benefits both GenCos and users, but does not necessarily need to be part of the country's transmission plan. Transmission lines for this system are built independently from the central plan and revenues may be established by OSINERGMIN or negotiated between the owner and the users of the transmission line.

The geographic distribution of GenCos and consumers is one of the main issues in the market. The most efficient GenCos, hydroelectric and combined-cycle power plants are concentrated in the center of the country, while many industrial consumers, such as mining units, are located in the northern and southern regions. The electricity system, therefore, requires an extensive and reliable transmission grid. To achieve this, the government publishes transmission plans identifying the investment requirements to maintain or improve the quality and reliability of the transmission system over the next 10 years. These plans assess expected capacity and demand growth.

Corporate

Fitch-rated GenCos in Peru are Fenix Power Peru S.A. (BBB–/Stable), Orazul Energy Peru S.A. (BB/Stable), Kallpa Generacion S.A. (BBB–/Stable) and Inkia. Peruvian GenCos' credit ratings reflect their market position and business strategy as they navigate industry's headwinds. Fitch evaluates each company's business strategy, including contracted position, cost structure flexibility, asset and technology diversification, and operational integration as key factors to alleviate cash flow volatility, while maintaining healthy liquidity and capital structures. Industry headwinds include overcapacity risk, subdued demand from regulated contracts and increased competition due to the price declaration system. The above mentioned issuers have adequate contracted positions with PPA sales to regulated DisCos and unregulated clients representing between 80% and 95% of adjusted revenues, excluding transmission pass throughs.

Exposure to spot sales exist, however, DisCos do not have sufficient demand to use all of their contracted capacity. This resulted in higher spot sales than projected. The current scenario of suppressed spot prices in the midst of PPA contract renegotiations pressured operating cash flows and liquidity levels. In response to this challenge, Fenix's shareholders, led by parent company Colbun S.A. (BBB/Stable) with 51% ownership, provided the company with a three-year cash support agreement of up to $101 million in early 2019.

In addition to shareholder support, a flexible cost structure is another factor that should allow companies to survive this period of weak prices. A fixed-cost structure forces generation sales to the spot market under unattractive margins to partially recover such costs. Fenix has the highest fixed costs, which limits its operational flexibility. The company's long-term agreements are based on a 90% take or pay structure for gas supply and 100% take or pay structure for transportation and distribution. Kallpa has a more flexible cost structure with natural gas supply, transportation and distribution agreements based on a 52%, 100% and almost 81% take or pay structure, respectively. As a vertically integrated company, Orazul provides natural gas to its own thermal generation plant to avoid dispatching in a low spot price environment.

Asset base and technological diversification mitigates cash flow concentration and gives issuers the flexibility to navigate the seasonal aspects of Peru's supply and demand dynamics. Fenix is the most exposed to asset concentration, operating a single 565MW natural gas-fired plant. Orazul's assets consist of two base-load hydroelectric plants with a combined 380MW of installed capacity and one 176MW thermal generation plant. Kallpa's assets consist of a 555MW base-load hydroelectric plant and two thermal generation plants with aggregate installed capacity of 1,063MW. In Peru, Inkia owns a 625MW diesel thermal plant in addition to the plants of its subsidiary Kallpa. Inkia has a broad geographic footprint throughout Latin America with more than 3.5GW of installed capacity.

Fitch expects Fenix's leverage metrics, measured as total debt/EBITDA, to decline close to 5.0x by 2021 as spot prices gradually improve, making up for improved cash flow. We forecast Orazul to maintain gross leverage of above 5.0x through the rating horizon, which is weak for the rating level. Fitch expects Kallpa to deleverage toward 3.5x during the next three to four years as it benefits from increasing spot prices. Inkia presents a generally weaker capital structure relative to large, multi-asset energy peers in the region. Fitch forecasts Inkia's leverage will decline from around 5.0x to below 4.0x over the next three years, putting the company at the upper limits of its rating category. Fenix's ratings benefit from the strong support provided by Colbun and a commitment to bolster Fenix's liquidity under current market conditions, despite a weaker operational position compared with other GenCos in the country.

Peer Comparison

Company	IDR	Financial Statement Date	Gross Revenue (USD Mil.)	Operating EBITDA Margin (%)	Operating EBITDA/ Interest Paid (x)	Total Debt with Equity Credit/ Operating EBITDA (x)	Total Net Debt with Equity Credit/ Operating EBITDA (x)
Fenix Power Peru S.A.	BBB–						
	BBB–	2018	201	17.7	2.1	9.8	9.1
	BBB–	2017	193	22.1	3.4	8.3	7.1
	NR	2016	217	28.5	4.6	5.9	5.5
Nautilus Inkia Holdings LLC	BB						
	BB	2018	1,612	32.4	3.4	5.8	5.4
	BB	2017	1,777	24.2	2.5	7.0	6.1
	BB	2016	1,517	24.2	2.8	7.4	6.9
Orazul Energy Peru S.A.	BB						
	BB	2018	156	58.5	3.0	5.8	5.3
	BB	2017	203	49.5	6.6	5.4	5.2
	BB	2016	128	45.1	12.1	1.3	1.2
Kallpa Generacion S.A.	BBB–						
	BBB–	2018	538	52.7	5.8	3.7	3.6
	BBB–	2017	590	39.0	3.0	4.6	4.4
	NR	2016	487	34.7	3.9	6.1	5.8

IDR – Issuer Default Rating. NR – Not Rated.
Source: Fitch Ratings, Fitch Solutions.

Related Research and Criteria

Peruvian Corporate Credit Indicators: First-Quarter 2019 (Operational Performance Stable as Issuance Remains Slow) (June 2019)
Peruvian Electricity Sector (January 2015)

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