CAREC Energy Reform Atlas
Case Studies Report

November 2021

This document, the Case Studies Report, contains the following case studies, which feed into and inform the separate Tariff Reform Toolkit:

- *Georgia, United States ("US"): an example of cost of service ("COS") ratemaking;*
- *Colombia: an example of standard performance-based ratemaking ("PBR"); and*
- *the United Kingdom ("UK"): an example of next generation PBR.*

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Table of contents

Table of figures

List of acronyms

AOM	Administration, operation and maintenance
APSA	Asset purchase and sale agreement
ARP	Alternative rate plan
ASIC	Administrator of the Commercial Exchange System (*Administrador del Sistema de Intercambios Comerciales*)
BETTA	British Electricity Trading Transmission Arrangements
BPI	Business plan incentive
BR	Baseline revenue
C&I	Commercial and industrial
CAC	Energy Trading Advisory Committee (*Comité Asesor de Comercialización*)
CAGR	Compound anual growth rate
CAPM	Capital Asset Pricing Model
CEGB	Central Electricity Generating Board
CND	National Dispatch Center (*Centro Nacional de Despacho*)
CNO	National Council for Operations (*Consejo Nacional de Operación*)
CoD	Cost of debt
CoE	Cost of equity
COS	Cost of service
CREG	Commission of Energy and Gas Regulation (*Comisión de Regulación de Energía y Gas*)
DECC	Department of Energy and Climate Change

DNO	Distribution network operator
DORC	Depreciated optimized replacement cost
DSM	Demand-side management
ECCR	Environmental compliance cost recovery
EDF	Électricité de France
EEP	*Empresa de Energía del Pacífico*
EMC	Electric membership corporation
EP Act	Energy Policy Act
EPM	*Empresas Públicas de Medellín*
ESM	Earnings sharing mechanism
EV	Electric vehicle
FCR	Fuel cost recovery
FERC	Federal Energy Regulatory Commission
GDP	Gross domestic product
GEMA	Gas and Electricity Markets Authority
GPC	Georgia Power Company
GW	Gigawatt
GWh	Gigawatt-hour
ICR	Interim cost recovery
IOU	Investor-owned utility
IPP	Independent power producer
IQI	Information quality incentive
IRP	Integrated resource planning
ISA	*Interconexión Eléctrica S.A.*
ISO	Independent system operator
ITS	Integrated transmission system
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
LAC	Liquidator and Accounts Administrator (*Liquidador y Administrador de Cuentas*)
LO	License obligation
MEAG	Municipal Electric Authority of Georgia
MEM	*Mercado de Energía Mayorista*
MFF	Municipal franchise fee
MME	Ministry of Mines and Energy (*Ministerio de Minas y Energía*)
Muni	Municipally owned utility
MW	Megawatt
MWh	Megawatt-hour

NCCR	Nuclear construction cost recovery
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NGET	National Grid Electricity Transmission plc
OATT	Open-access transmission tariff
ODI	Output delivery incentive
OEFs	Firm energy obligations (*obligaciones de energía firme*)
OFFER	Office of Electricity Regulation
Ofgem	Office of Gas and Electricity Markets
OPC	Oglethorpe Power Corporation
PBR	Performance-based ratemaking
PCC	Power control center
PCD	Price control deliverable
PES	Public electricity supplier
PPA	Power purchase agreement
PSC	Public Service Commission
PURPA	Public Utility Regulatory Policies Act
RAV	Regulatory asset value
REC	Regional electricity company
RFP	Request for proposal
RIIO	Revenue = Incentives + Innovation + Outputs
RIIO-T2	RIIO for Transmission, 2nd generation price control
RO	Renewables obligation
ROC	Renewables obligation certificate
ROE	Return on equity
RPE	Real price effects
RPI	Retail price index
RTO	Regional transmission organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SDL	Local distribution system (*Sistema de Distribución Local*)
SHET	Scottish Hydro Electric Transmission plc
SIC	Superintendence of Industry and Commerce (*Superintendencia de Industria y Comercio*)
SIN	National Interconnected System (*Sistema Interconectado Nacional*)
SPTL	Scottish Power Transmission Limited
SSE	Scottish and Southern Energy
SSEB	Scotland Electricity Board

SSPD	Superintendent of Public Utilities (*Superintendencia de Servicios Públicos Domiciliarios*)
STN	National Transmission System (*Sistema de Transmisión Nacional*)
STR	Regional Transmission System (*Sistema de Transmisión Regional*)
TO	Transmission owner
Totex	Total expenditure
TVA	Tennessee Valley Authority
TWh	Terawatt-hour
UIME	Energy and Mining Information Unit (*Unidad de Información Minero Energética*)
UIOLI	Use-it-or-lose-it
UK	United Kingdom
UPME	Commission of Energy-Mining Planning (*Unidad de Planeación Minero-Energética*)
US DOE	United States Department of Energy
WACC	Weighted average cost of capital

1 Introduction

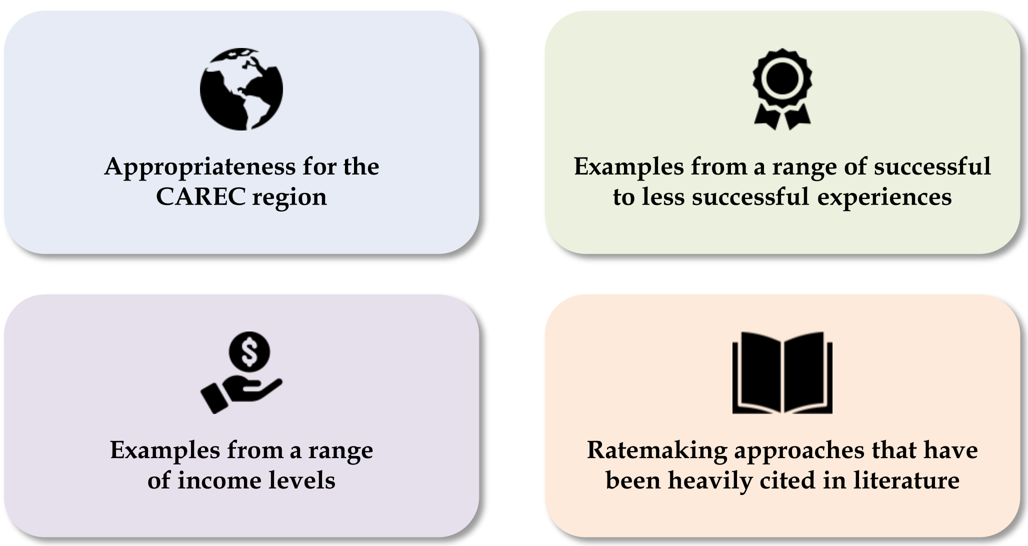
In conjunction with the separate Tariff Reform Toolkit, the following Case Studies Report surveys the various ratemaking approaches that have been implemented around the world, focusing on three particular case studies:

- **Georgia, United States ("US")**, which presents an example of cost of service ("COS") ratemaking;
- **Colombia**, which exemplifies standard performance-based ratemaking ("PBR"); and
- **the United Kingdom ("UK")**, which presents an example of next generation PBR.

1.1 Rationale for selection of case studies

The three cases presented in this Case Studies Report were selected based on a variety of considerations, as summarized in Figure 1 below. The main goal in the selection of case studies was to include jurisdictions that exemplify a diverse range of ratemaking approaches (i.e., COS and PBR examples), geographies, and stages of economic development, while also focusing on relatively successful jurisdictions from which key lessons could be learned. Ultimately, each of the three jurisdictions selected – Georgia (US), Colombia, and the UK – offer specific insights for the Central Asian region.

Figure 1. Criteria used to select case studies



The electricity sectors in most of the Central Asia Regional Economic Cooperation ("CAREC") member countries are currently characterized as having significant state ownership and tariffs that are not necessarily cost reflective. Given this context, the US state of Georgia demonstrates the use of ***cost-of-service ratemaking*** as a first step in the process to reaching cost reflective tariffs. COS ratemaking, described in detail in the separate Tariff Reform Toolkit, is a traditional form of utility regulation, where changes in rates are linked to an evolution in the underlying costs incurred by a utility associated with providing electric service.

Colombia exemplifies an alternative approach to COS ratemaking, where regulators move away from a focus on costs, and instead begin considering ways to incentivize better utility performance through the tariff structure. For electricity transmission and distribution, Colombia employs standard ***performance-based ratemaking***, specifically through revenue cap mechanisms, to incentivize regulated utilities to improve their efficiency. The UK is even further along in the implementation of a PBR regime, utilizing a ***next generation PBR framework*** to assess the performance of regulated utilities against a set of expected outcomes.

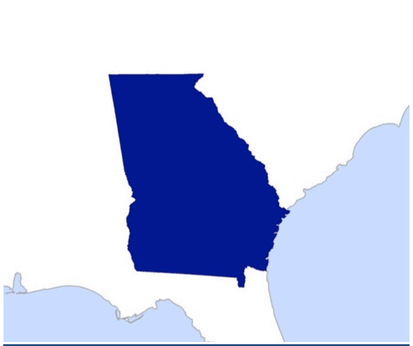
The three selected jurisdictions also highlight a range of successes in the electricity sector. Georgia (US) has maintained a vertically integrated utility structure for many decades, due to its provision of reliable, low-cost electricity. Colombia has successfully transitioned away from a state-owned model, into a dynamic and competitive electricity market. The UK demonstrates how unbundling and tariff reform may evolve and improve over decades. Especially due to its early steps toward electricity market reform and its evolution through multiple market and tariff frameworks, the UK is frequently cited in literature discussing best practices in electricity regulation.

1.2 Comparison of jurisdictions

A summary of the three selected jurisdictions is presented in Figure 2.

Figure 2. Overview of selected jurisdictions

Georgia (US)



Key facts	
Population (2019)	10.6 million
GDP growth (CAGR, 2014-2019)	3.3%
GDP per capita (2019)	$51,559
Installed capacity (2020)	40.2 GW
Net generation (2020)	110.96 TWh
Peak demand (2019)*	16.6 GW
Load growth (CAGR, 2014-2019)*	0.5%
Distribution lines (2015)	>180,000 miles
Transmission lines (2015)	>17,500 miles

Colombia

Key facts	
Population (2019)	50.3 million
GDP growth (CAGR, 2014-2019)	2.4%
GDP per capita (2019)	$6,429
Installed capacity (2018)	17.7 GW
Generation (2019)	76.83 TWh
Peak demand (2020)	10.4 GW
Load growth (CAGR, 2014-2019)	2.1%
Distribution lines	500,000 km
Transmission lines	14,000 km

United Kingdom

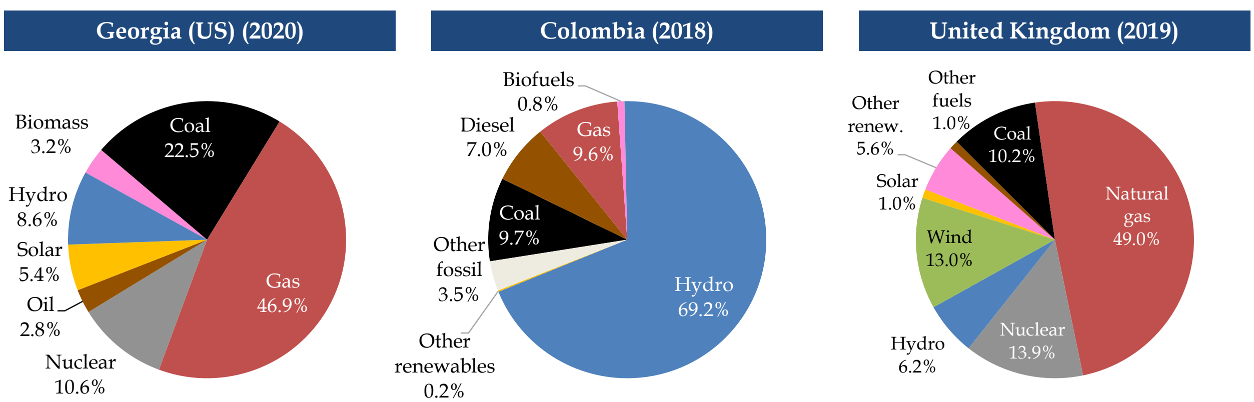
Key facts	
Population (2019)	66.7 million
GDP growth (CAGR, 2014-2019)	3.5%
GDP per capita (2019)	$42,330
Installed capacity (2020)	66.6 GW
Generation (2019)	267 TWh
Peak demand (2019)	48.2 GW
Load growth (CAGR, 2014-2019)	-1.0%
No. of distributors	14
No. of transmitters	3

Note: Statistics marked with * are for Georgia Power Company only, not for the whole state, due to data availability.

The jurisdictions span a ***range of socioeconomic conditions*** (from an average GDP per capita of $6,429 in Colombia, to $51,559 in Georgia (US)) and a ***range of population sizes*** (from 10.6 million in Georgia (US), to 66.7 million in the UK). The jurisdictions also vary widely in terms of the ***size and growth of their electricity markets***: annual electric generation ranges from 76.83 terawatt-hours ("TWh") in Colombia, to 267 TWh in the UK; Colombia's electric load is growing almost at the same rate as its GDP growth, Georgia's (US) load growth has slowed in recent years,[1] while the UK has seen a decrease in load between 2014 and 2019. In contrast, the total installed capacity and peak demand[2] of each system are somewhat comparable, providing a point of similarity between the jurisdictions.

The fuel mix in each of the selected jurisdictions is shown in Figure 3. The electricity systems of both Georgia (US) and the UK are comprised of mostly gas, nuclear and coal capacity, with a smaller presence of hydro capacity. On the other hand, Colombia's electricity sector is heavily dominated by hydro, with a much smaller presence of fossil-fired capacity. Non-hydro renewable resources are more common in the UK (accounting for 19.6% of installed capacity) and Georgia (US) (8.6%), relative to Colombia (less than 1%). The UK has a particularly significant presence of wind energy (13% of installed capacity), which is not the case in both Georgia (US) and Colombia. Nearly 70% of Colombia's installed capacity is attributable to a single resource type (hydro), whereas Georgia (US) and the UK are more diversified (where neither jurisdiction has one fuel source representing more than 50% of total installed capacity).

Figure 3. Installed capacity by fuel type for selected jurisdictions



The jurisdictions also represent a diverse range of geographic conditions. Georgia (US) has a largely consistent climate, most of the state is at a low elevation, and due to its location, Georgia (US) imports around 10% of its electricity needs from other states. Colombia hosts a mix of coastline, mountains, rainforests and plains, and conducts minimal electricity trade with neighbouring countries (only around 2% of electricity generation). The UK is an island nation, with both upland and lowland areas.

[1] Data for Georgia's load growth was not available statewide, and as such is presented for Georgia Power Company only.

[2] Similar to the above, figures for Georgia's peak demand represents peak demand for Georgia Power Company only.

1.3 Overview of the COS ratemaking example: Georgia, US

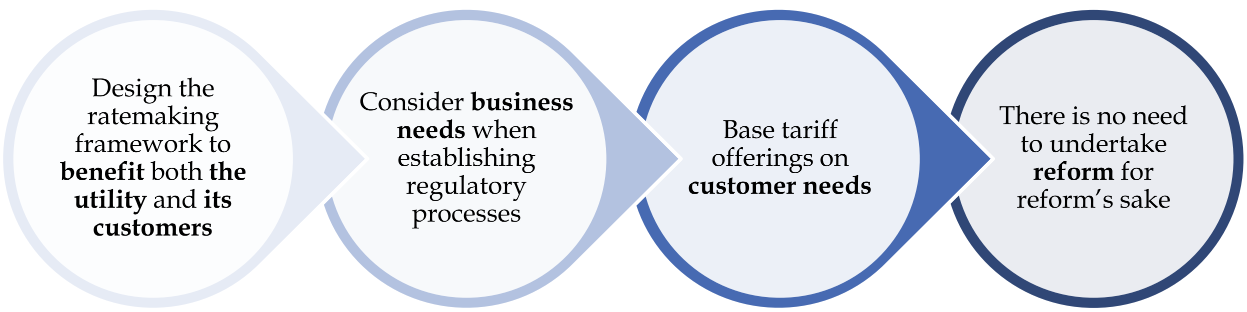
Under Georgia Code §46-2-23, the Georgia Public Service Commission ("PSC") in the US has exclusive authority to determine just and reasonable rates to be charged by all regulated entities under its jurisdiction. While Georgia's (US) electric sector comprises of 41 electric membership corporations ("EMCs" or "coops") and 52 municipally owned utilities ("munis"), there is only one vertically integrated electric utility that is fully regulated by the PSC – Georgia Power Company ("GPC"), an investor-owned utility ("IOU").

GPC is regulated under a COS regime, whereby the PSC authorizes GPC to recover certain expenses and a set return on equity ("ROE") through the rates charged to its customers. Through this process, the PSC aims to set rates that are just and reasonable, while also providing GPC with enough revenue to provide safe, reliable service and remain financially viable.

As part of the rate setting process, GPC conducts and files a COS study with the PSC. The aim of the COS study is to separate GPC's investments, expenses, and revenues among its jurisdictions (retail and wholesale), and then further among rate groups or classes within each jurisdiction. This study helps determine GPC's revenue requirement and ascertain how well GPC's costs are being recovered from each jurisdiction (retail and wholesale) and customer group. Based on the COS study, GPC proposes modifications to its rates to help make tariffs more cost reflective. The PSC reviews GPC's rate request, and reaches a final decision on tariffs.

The PSC also sets an earnings band (currently between 9.5% and 12% ROE), which enables GPC's earnings sharing mechanism ("ESM"). Under the ESM, any excess earnings above the upper band of ROE is shared with its customers, at a percentage set during the rate case. GPC is also subject to an interim cost recovery ("ICR") mechanism, which ensures its financial stability if projected retail earnings fall below the lower band of ROE.

Figure 4. Key takeaways from the Georgia (US) case study



The Georgia (US) case study provides several key points for the consideration of CAREC members (as illustrated in Figure 4):

- **design the ratemaking framework to benefit both the utility and its customers:** the use of an ESM, even as part of a traditional COS ratemaking framework, allows customers to benefit from excess earnings in the form of partial refunds when GPC's revenues exceed a pre-determined level. At the same time, the ESM and ICR mechanisms reduce the need for regulatory intervention to correct windfall profits, and allows GPC to adjust to projected revenue shortfalls and maintain a consistent ROE. This allows borrowing costs to remain manageable for GPC when investing in new assets. The ESM and ICR thus successfully balance ensuring GPC's financial viability with maintaining affordable electric service for customers;

- **consider business needs when establishing regulatory processes:** the PSC must come to a decision on GPC's rate requests within 180 days of GPC's filing, or else GPC is legally entitled to 100% of its requested rates. This deadline encourages timely resolution of rate cases, and removes the uncertainty associated with prolonged litigation. Furthermore, since 1996, GPC has followed an alternative rate plan ("ARP"), which pre-determines increases in its rates based on cost growth forecasts through a rate plan every three years. Under the pre-determined rates of the ARP, GPC is able to recover service costs in a timely manner. The ARP reduces the regulatory lag GPC would face under annual rate cases, whereby it would need to petition every year for cost recovery and await the PSC's decision. The APR also provides benefits to customers through the enhanced predictability of rates;
- **base tariff offerings on customer needs:** GPC offers a wide variety of tariff options. For residential customers, tariffs are designed to cater to a wide range of needs, including those with electric vehicles ("EVs"), price-sensitive customers, and those who prefer predictable, consistent rates. In this way, customers are able to choose the tariff option that best suits their needs; and
- **there is no need to undertake reform for reform's sake:** Georgia (US) underwent consultations on electricity sector restructuring in the 1990s. However, the PSC chose not to proceed with restructuring efforts, due in large part to local considerations, such as the presence of an integrated transmission system and electricity prices that were already below the national average. To this day, there is only limited retail competition in the state, and the PSC has signaled that there will not be further consideration of regulatory reforms in the near-term. The design of Georgia's (US) electricity sector, both in terms of its market structure and its use of COS ratemaking, has proven effective in meeting the needs of customers, and therefore has continued in its current form for decades.

1.4 Overview of the standard PBR example: Colombia

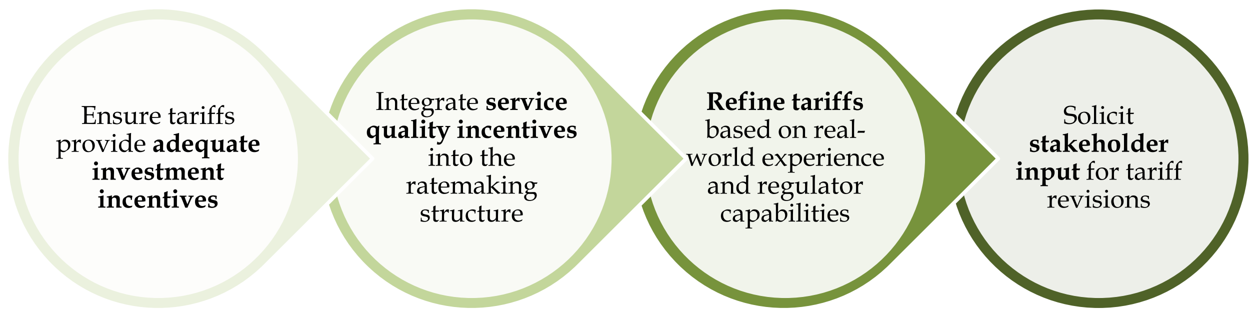
Pursuant to Laws 142 and 143 of 1994, the Commission of Energy and Gas Regulation ("CREG" or *Comisión de Regulación de Energía y Gas*) is responsible for setting tariffs for the provision of electricity service to regulated users in Colombia (i.e., residential and small commercial customers that have their prices administratively set by CREG). In setting tariffs, CREG must consider factors such as: cost reflectiveness, international competitiveness, cost-efficiency, service quality, reliability of service delivery, business sustainability, and management of externalities.[3] Colombian end-users are charged a unified cost of service tariff by retailers, established in CREG Decision 119 of 2007. This unified cost of service aggregates costs from each step of the electricity value chain (generation – which is mostly competitively set, as well as transmission, distribution,

[3] CREG. *Metodología de remuneración de actividad de distribución de energía eléctrica para el periodo tarifario 2015-2019.* December 23, 2014. pp. 402-403.

marketing/retail, and other costs). Of these cost components, transmission and distribution have been regulated under a form of PBR (known as a revenue cap) since 1999 and 2018, respectively.

At a high level, under the revenue cap mechanism, a maximum revenue per utility is established. This maximum revenue is adjusted by an inflation factor (RPI), less an efficiency factor (X), also known as an RPI-X mechanism. A benchmarking exercise is undertaken to determine the X factor. Tariff levels change based on the regulator's methodology, not in response to changes in a transmission or distribution utility's actual cost of service. Therefore, utilities that are able to achieve productivity or efficiency gains are rewarded, whereas utilities that are unable to achieve efficiency targets are penalized. While there are slight differences in the tariff methodology for transmission and distribution, this high-level approach is common to both segments.

Figure 5. Key takeaways from the Colombia case study



The Colombia case study provides several key points for the consideration of CAREC members (as illustrated in Figure 5):

- **ensure tariffs provide adequate investment incentives:** in previous iterations of Colombia's distribution tariff methodology, all electric assets were remunerated as if new, regardless of their in-service years. This did not provide adequate incentives for utilities to update and replace aging assets. In the current distribution tariff methodology, the regulatory asset base calculations account for the useful life of assets. Furthermore, under the revenue cap methodology, the revenue associated with existing assets (including remuneration of administration, operation and maintenance ("AOM") expenses) is fixed at the start of the tariff term, based on historical benchmark values. Therefore, distributors must increase their investment in electric assets in order to raise their allowed revenues. This change in methodology was initiated to address deficiencies in levels of new investment, AOM expenses, service quality and line losses;
- **integrate service quality incentives into the ratemaking structure:** service quality indicators related to the frequency and duration of service interruptions are tracked for each distributor and are compared against CREG-determined targets. Allowed revenues for distributors may be increased or decreased based on their performance on these indicators. CREG's targets evolve over time to incentivize efficiency and continuous service improvements;
- **refine tariffs based on real-world experience and regulator capabilities:** the latest distribution tariff methodology, established under CREG Decision 015 of 2018, worked to address deficiencies identified under previous tariff regimes in terms of new investment,

AOM expenses, service quality and line losses.[4] At the same time, the method for calculating allowed AOM expenses for existing distribution assets employs more sophisticated methods (i.e., stochastic frontier modeling) than that used for transmission assets (which dates back to 2009), demonstrating how CREG is enhancing its methodology over time; and

- **solicit stakeholder input for tariff revisions:** transmission and distribution tariffs are in effect for five years, pursuant to Law 142 of 1994. However, these tariffs may remain in effect past this five-year duration, until CREG establishes a revised methodology. Before establishing a revised methodology, CREG must first publicize a draft resolution for its proposed new tariffs and solicit and consider stakeholder comments. The process can take many years; for example, while the most recent distribution tariff methodology was established in 2018, the consultation process for this revision began in 2013.[5]

1.5 Overview of the next generation PBR example: United Kingdom

The UK electricity market is a mature competitive market, having been among the first movers in power sector restructuring. The transmission and distribution sectors have operated under evolving PBR mechanisms for almost two decades, which were adapted over time to meet changing circumstances. These price controls are implemented by the Office of Gas and Electricity Markets ("Ofgem"), which is the executive arm and the independent economic regulatory body of the gas and electricity markets in the UK. Ofgem is responsible for protecting consumers by promoting competition and regulating monopoly companies. Ofgem derives its regulatory powers from the Gas Act 1986, the Electricity Act 1989, the Competition Act 1998, the Utilities Act 2000, and the Enterprise Act 2002.

Since 2013 (for transmission services) and 2015 (for electricity distribution services), Ofgem has implemented a modified PBR framework to better meet future investment and innovation needs. This framework is known as RIIO, where **R**evenue = **I**ncentives + **I**nnovation + **O**utputs. It was developed over the course of a multi-year stakeholder consultation process that started in 2008.

Simplistically, under the RIIO model, the transmission and distribution operators are expected to deliver outputs that are set during their respective price control reviews. Categories by which performance is monitored include customer engagement, quality of service, efficient cost of service, efficient financing, managing uncertainty, and emissions reductions. Several of these incentives are linked to the percentage of allowed revenue, where the allowed revenue is based on forward-looking revenue requirements of each regulated utility over the term of the price controls.

Figure 6. Key takeaways from the UK case study

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[4] Pérez, D.M. and A.H. Castro. "702 – Impacto en la remuneración del uso de la infraestructura de transporte de electricidad con la nueva metodología regulatoria en Colombia." *CIGRE*. May 2019.

[5] CREG Resolución No. 015 de 2018. January 29, 2018.

The UK case study provides several key points for the consideration of CAREC members (as illustrated in Figure 6):

- **adapt the ratemaking framework to the changing environment:** the framework for the electricity transmission and distribution price controls has changed significantly as compared with the regime that was put in place at privatization. Ofgem routinely makes modifications to its PBR regulations after each regulatory period, to adapt to changes in the environment or improve a particular mechanism that did not work as anticipated;
- **provide incentives to encourage cost efficiency and quality service:** Ofgem has put in place incentives for TOs and DNOs so they can continue to innovate, deliver services efficiently, and provide an appropriate level of network capacity, security, reliability, and quality of service. TOs and DNOs are also able to keep some of the benefits if the business is able to operate at a lower cost or exceed target levels – of performance standards or customer service – at the same cost; and
- **clarify objectives for electricity reforms upfront:** the UK was clear with its objectives when it began its electricity market restructuring in the 1990s. Providing a clear path for reform allows industry players to prepare for the changes in the marketplace. Transitional mechanisms (such as three-year vesting contracts) were also implemented to provide some time to develop the design, set up operations, and stabilize the functioning of the market.

2 Georgia, US (COS ratemaking)

The state of Georgia, located in the south-eastern United States, is the eighth most populous US state. Georgia's electric sector includes one investor-owned utility ("IOU"), Georgia Power Company ("GPC"), along with 41 electric membership corporations ("EMCs" or "cooperatives" – i.e., utilities owned by their members) and 52 municipally owned utilities ("munis" – i.e., electric systems owned by cities or, in one instance, a county). GPC is the only one of the state's electric utilities that is fully regulated by the Georgia Public Service Commission ("PSC"),[6] and thus the case study in this section will focus largely on GPC.

GPC operates as a vertically integrated utility, providing electricity to retail customers within its service territory across the state of Georgia, and to wholesale customers in the southeastern United States. This case study highlights the application of cost of service ("COS") ratemaking, as GPC is regulated under a COS regime, whereby the PSC authorizes GPC to recover certain expenses and a set return on equity ("ROE") through the rates charged to its customers. GPC files proposed rates with the PSC every three years and undergoes a regulatory approval process. Through this process, the PSC aims to set rates that are just and reasonable, while also providing GPC with enough revenue to provide safe, reliable service and remain financially viable.

Despite the momentum in many US states in the late 1990s for unbundling vertically integrated utilities in favor of competitive markets, Georgia lawmakers and regulatory bodies decided against restructuring its electricity market following a number of public workshops and hearings. This case study also demonstrates how some existing characteristics may lead a jurisdiction to favor keeping a vertically integrated utility intact.

2.1 Overview of the Georgia (US) market

Generation

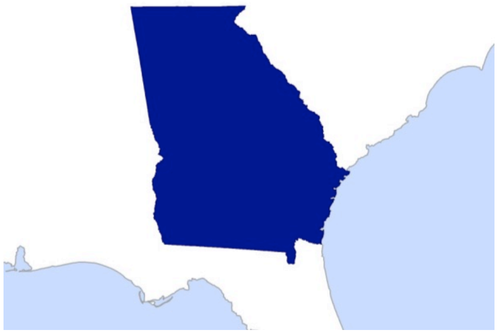
As of 2020, Georgia had over 40 gigawatts ("GW") in installed capacity and generated over 110 terawatt-hours ("TWh") of electricity annually, as shown in Figure 7. Georgia relies primarily on fossil-based sources for electricity generation, however nuclear power represents an important contribution to meeting the state's electricity needs. Renewable energy resources (specifically hydro, biomass, and solar) represented only 17% of installed capacity and 9% of net generation in 2020. GPC owns nearly half of the installed capacity in the state. Oglethorpe Power Corporation ("OPC"), the second-largest market participant by installed capacity, is a generation cooperative owned by and supplying 38 EMCs. Georgia meets roughly 10% of its electricity consumption from out-of-state resources.[7]

Figure 7. Georgia (US) market snapshot

[6] Georgia Public Service Commission. *Electric*. Accessed April 23, 2021.

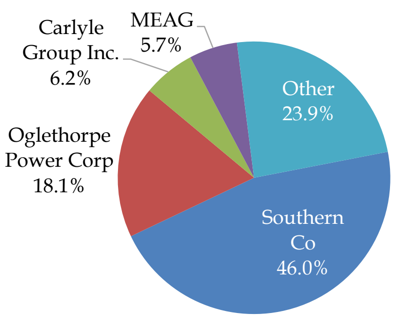
[7] US EIA. *Georgia – Profile Analysis*. November 19, 2020.

Georgia (US)

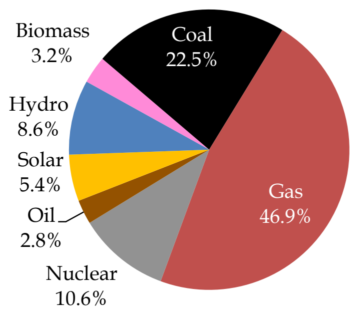


Key facts	
Population (2019)	10.6 million
GDP growth (CAGR, 2014-2019)	3.3%
GDP per capita (2019)	$51,559
Installed capacity (2020)	40.2 GW
Net generation (2020)	110.96 TWh
Peak demand (2019)*	16.6 GW
Load growth (CAGR, 2014-2019)*	0.5%
Distribution lines (2015)	>180,000 miles
Transmission lines (2015)	>17,500 miles

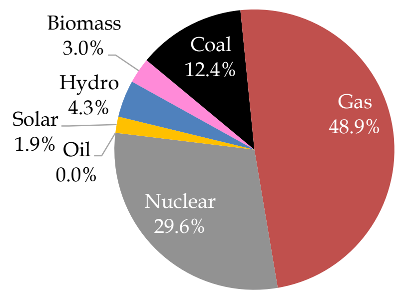
Top market players by capacity (2020)



Installed capacity by fuel type (2020)



Net generation by fuel type (2020)



Note: Statistics marked with * are for GPC only, not for the whole state, due to data availability.

Sources: Georgia Power Company, commercially available third-party database, United States Census Bureau, United States Bureau of Economic Analysis, United States Energy Information Administration, Georgia Transmission.

As mentioned above, GPC is an IOU that is fully regulated by the Georgia PSC. GPC is the largest electric utility in the state and is an operating subsidiary of Southern Company. GPC owns 18 generating plants, 19 hydroelectric dams and several solar energy facilities,[8] which serve approximately 2.6 million customers in 155 of Georgia's 159 counties.[9] In 2019, GPC had a total generating capacity of 14.4 GW. GPC is heavily dependent on fossil fuel-fired generation resources, which comprise over half of its installed capacity. In 2019, the mix was approximately 50% gas/oil, 19% coal, 22% nuclear, and roughly 9% renewable energy resources.[10] GPC in some cases co-owns generating facilities with other generators. GPC has wholesale contracts for capacity and energy with cogenerators and other providers both within and outside the state of Georgia. GPC typically issues requests for proposals ("RFPs") for new generation capacity. In addition to traditional power purchase agreements ("PPAs"), GPC also utilizes asset purchase

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[8] Georgia Power. *Generating Plants*. Accessed April 27, 2021.

[9] Georgia Power. *2020 Facts and Figures*. 2020.

[10] Ibid.

and sale agreements ("APSAs"), which involve the purchase of an existing generating asset already in commercial operation.

Transmission

Georgia has an Integrated Transmission System ("ITS"), jointly owned by GPC, Georgia Transmission (an entity created in 1996 after a restructuring of OPC), the Municipal Electric Authority of Georgia ("MEAG"), and the city of Dalton (Dalton Utilities). GPC owns approximately 12,622 of the over 17,500 transmission line miles in the state of Georgia. Initially, GPC owned nearly all of the transmission lines; however, in January 1975, GPC entered into separate contracts with each of the other utilities, selling them ownership interests and equal access to the transmission facilities, before there was any federal mandate for an open-access transmission tariff ("OATT"). The ITS is also interconnected with neighboring utilities through transmission tie lines. Exporting generators that wish to interconnect with the ITS may interconnect through any of the Georgia Integrated Transmission System participants (namely GPC, Georgia Transmission, MEAG, or Dalton Utilities).

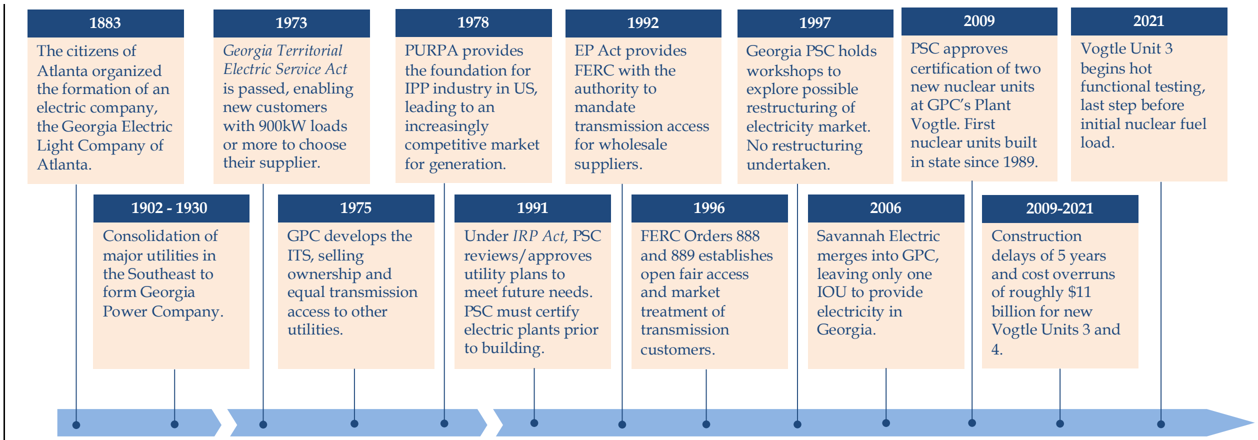
Distribution

There are three types of electric utilities that provide retail electric service in Georgia: IOUs, customer owned utilities (EMCs/coops) and munis. GPC is the only electric IOU remaining in Georgia, following a merger with Savannah Electric, another Southern Company subsidiary, in 2006. Southern Company Services, also a Southern Company subsidiary, operates a Power Control Center ("PCC") in Birmingham, Alabama, which coordinates the integrated operations of the Southern electric system, including generation and transmission facilities in Georgia. The Georgia PSC fully regulates GPC, but has otherwise limited oversight of the remaining generators and distributors with regards to ratemaking.

There are 41 EMCs and 52 munis in the state. Of the EMCs, 38 distribute power supplied by OPC, while the remaining three distribute power received from the Tennessee Valley Authority ("TVA"). Each EMC is owned by its customers and is self-regulating, with their rates set by their Board of Directors. Of the 52 munis, 49 purchase their power from MEAG. The remaining three munis of Dalton, Chickamauga and Hampton are unaffiliated with MEAG.

Some retail competition has been present in Georgia since 1973, with the passage of the *Georgia Territorial Electric Service Act*. This Act provides customers with manufacturing or commercial loads of 900 kW or greater a one-time opportunity to choose their electric supplier (i.e., for the life of the premises) when they add a new load to the network. It also provides eligible customers the opportunity to transfer from one electric supplier to another provided all parties agree. The PSC resolves territorial disputes and customer complaints involving customer choice and approves requests for transfer of retail electric service. Key events in the history of Georgia's electric sector are shown in Figure 8 below.

Figure 8. Timeline of key events for Georgia's (US) electric sector

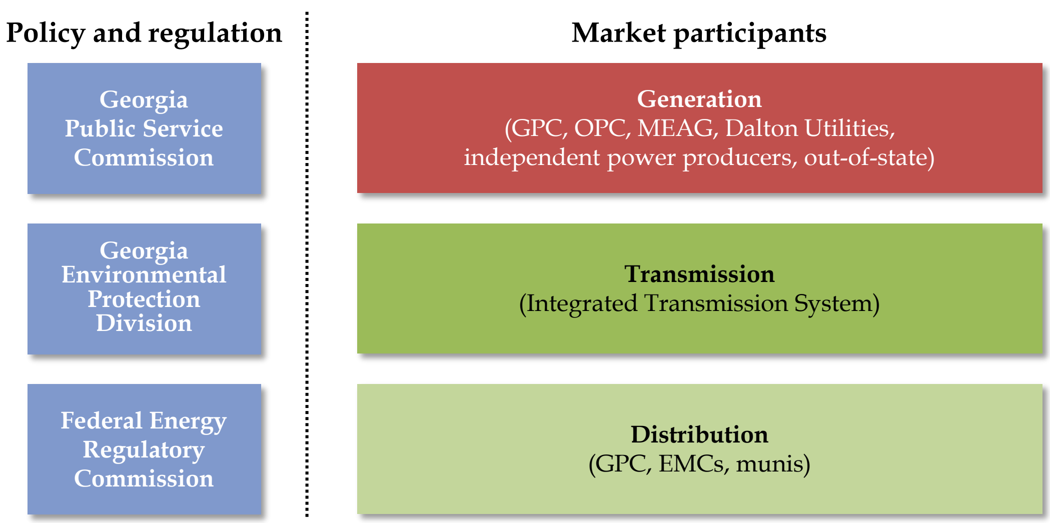


Sources: Georgia PSC, GPC, Reuters, others.

2.2 Georgia's (US) current institutional and legal framework

Georgia's market structure is illustrated below in Figure 9.

Figure 9. Georgia (US) market structure



Source: Southface Institute and Vote Solar.

As Georgia's only IOU, GPC is fully regulated by the PSC. This includes market administration, monitoring and rate setting. The Federal Energy Regulatory Commission ("FERC") is responsible for implementing and enforcing statutes from the United States Congress. Among other duties, FERC regulates interstate oil and natural gas pipelines, interstate electric transmission lines (including transmission rates), and oversees the body that sets mandatory reliability standards for the interstate transmission system.[11] Beyond that, generating and distribution entities in

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[11] Greenfield, Lawrence R. "An Overview of the Federal Energy Regulatory Commission and Federal Regulation of Public Utilities." *FERC*. June 2018.

Georgia receive minimal oversight from the PSC. This section will focus specifically on the regulation of GPC.

Regulation at the federal level

The principal economic and policy regulator at the federal level for the electric power industry in the United States is FERC, an independent regulatory agency within the US Department of Energy ("US DOE"). FERC is charged with implementing, administering, and enforcing most of the provisions of the statutes that regulate the electric utility industry passed by the US Congress. FERC oversees wholesale electric rates and service standards, as well as the transmission of electricity in interstate commerce. FERC ensures that wholesale and transmission rates charged by utilities are just and reasonable and not unduly discriminatory or preferential. It also reviews utility pooling and coordination agreements. Finally, FERC reviews rates set by the federal power marketing administrations, makes determinations as to exempt wholesale generator status under the *Energy Policy Act* ("EP Act"), and certifies qualifying small power production and cogeneration facilities.

Regulation at the state level

At the state level, the Georgia PSC is responsible for overseeing electric power companies, and any "persons owning, leasing or operating public gas plants or electric light and power plants furnishing service to the public."[12] Pursuant to the *Integrated Resource Planning Act* ("IRP Act") of 1991, the PSC has the responsibility to review and approve supply- and demand-side resource options filed by the utility companies. Prior to enactment of the IRP Act, the PSC did not review a utility's management decisions pertaining to the need, planning, and construction of expensive electricity generation facilities until the company applied for financing approval, or filed for recovery of these costs in rate case proceedings after the plants were partially built or completed.

The PSC has exclusive power to "determine just and reasonable rates and charges to be made by any person, firm or corporation subject to its jurisdiction."[13] However, as noted previously, while GPC is under full PSC ratemaking jurisdiction, the PSC has limited authority with respect to EMCs or munis, who must only file their rates with the PSC for informational purposes.

2.3 Ratemaking in Georgia (US)

GPC is regulated under a COS ratemaking regime. GPC is entitled to recovery of just and reasonable rates from its customers, which are calculated by taking into account GPC's operating expenses and costs, investment in new infrastructure, and target ROE, among other components. The details of this system, including how rates are approved by the PSC and notable elements, are discussed in the subsections below.

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12 Georgia Code. *Public Utilities and Public Transportation*. G.A. § 46-2-21.

13 Georgia Public Service Commission. *Staff Report on Electric Industry Restructuring - Docket Number 7313-U*. January 1998. p. 21.

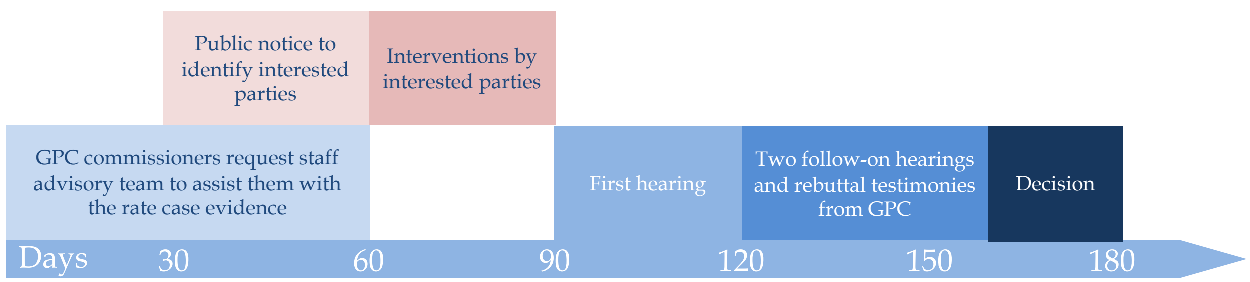
2.3.1 Ratemaking process

For GPC to increase or revise its rates, it must first file a rate case with the PSC. Proposed new rates go into effect 30 days from the filing date, under law. However, Commissioners traditionally order a five-month suspension of proposed rates to study the request. 30 to 60 days after filing, GPC must publish a notice of hearing in newspapers of general circulation in its service area.

The PSC designates two separate staff teams to handle the rate case: an ***advocate staff***, which will present their own case in the rate proceeding, generally in opposition of the utility's request; and ***an advisory staff***, to support and answer questions raised by Commissioners during the proceeding. The advocate staff will issue its own independent rate recommendation at least 10 days before the date of the first hearing.

The PSC issues a scheduling order and may hold a pre-hearing conference with all interested parties. During this adjudication process, other parties (such as corporations and environmental groups) may petition the PSC to intervene; if the PSC approves their requests for intervention, these parties may make their own arguments in the rate case. For the 30 days after the first published notice of the proceeding, the PSC will consider requests to intervene. The PSC grants requests either at the pre-hearing conference or on the first day of the hearing. The intervenors can also request information from the utility, which GPC generally must provide. The next stages in the adjudication process, involving three separate sets of hearings, are shown below in Figure 10.

Figure 10. Adjudication timeline for rate cases



Note: timespans for hearings indicated above represent the timeframe in which a hearing is held, not the length of a hearing. The first hearings typically last three to five days.

Source: Georgia PSC.

The PSC considers the arguments made and must legally come to a decision on GPC's proposed rates within 180 days of filing; if it does not do so, GPC is entitled to 100% of its request. GPC and/or intervenors may request a rehearing or appeal the PSC's decision to the courts.

Rather than filing annual rate cases, GPC has followed an alternative rate plan ("ARP") since 1996. The ARP predetermines increases in rates based on cost growth forecasts through a rate plan every three years. This allows for earnings sharing between GPC and its customers, as detailed later in Section 2.3.3, and leads to more predictable rates for customers as rate changes are determined in advance for the upcoming three-year period. The ARP also allows GPC to recover service costs in a timely manner, without the regulatory lag of annual rate cases.[14] GPC does not file a general rate case in the interim period unless its projected earnings drop below a set ROE, in which case GPC may petition for an interim cost recovery ("ICR") tariff. The last rate case was filed in June 2019, with a rate case occurring in 2013 prior to this.[15]

2.3.2 Georgia Power Company rates and rate design

To establish the rates that it will charge, and for which it will petition the PSC for approval, GPC conducts cost of service studies. GPC has filed COS studies with the PSC as part of its rate applications for several decades. A COS study is used to separate GPC's electric investments, expenses, and revenues among its service jurisdictions (namely retail and wholesale), and then further among rate groups or classes in each jurisdiction. The general principle of cost causation is followed, by which the customers that lead GPC to incur a particular cost should be the ones to remunerate GPC for said costs. At the same time, there are many costs that stem from the planning, design, construction, and operation of GPC's power system as a whole, which serves all customers; these costs are apportioned to different customer classes based on various cost allocators. COS studies are one tool used to determine GPC's revenue requirement and ascertain how well its costs are being recovered from each jurisdiction and customer group.[16] Based on the COS study, GPC assesses its current rate options and rate design, and proposes modifications to make its tariffs more cost reflective.

Generally, GPC's rates comprise of three components:

- a ***basic service charge*** to recover costs that are independent of the demand or energy use of a customer (including costs related to the generation, transmission, and distribution of electricity from power plants to homes and businesses);[17]
- a set of ***tariff riders*** that are common to all customers, which are described in detail below; and
- a ***variable charge*** (also called an "energy charge") measured in kilowatt-hours ("kWh"), to recover energy-related expenses.

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[14] Georgia Power Company. *Direct testimony of David P. Poroch, Sarah P. Adams, and Michael B. Robinson on behalf of Georgia Power Company – Docket No. 42516.*

[15] Rate cases have traditionally occurred at least every three years, however the Georgia PSC established in 2016 that the 2013 Georgia Power accounting order would continue in effect until December 31, 2019. (Source: Georgia Public Service Commission. *Order Adopting Settlement Agreement as Modified – Docket No. 42516.* December 17, 2019. p. 3.)

[16] Georgia Power Company. *Direct testimony of Lawrence J. Vogt on behalf of Georgia Power Company – Docket No. 42516.*

[17] In its most recent rate case, GPC adjusted the basic service charges to better reflect the customer costs calculated in its COS study. Customer costs include the costs of billing, metering, and customer assistance. Aligning the basic service charge with the results of the COS study helps make tariffs more cost reflective and helps send better price signals to GPC's customers. (Source: Georgia Power Company. *Direct testimony of Larry T. Legg on behalf of Georgia Power Company – Docket No. 42516.*)

Some commercial and industrial ("C&I") customers also pay a ***demand charge*** measured in kilowatts ("kW") to recover demand-related expenses.[18]

The aforementioned riders that all GPC customers pay include those for: Environmental Compliance Cost Recovery ("ECCR"), Nuclear Construction Cost Recovery ("NCCR"), Demand-Side Management ("DSM"), Municipal Franchise Fee ("MFF"), and Fuel Cost Recovery ("FCR"). ECCR charges recover the costs of installing and operating mandated environmental controls. NCCR charges recover financing costs related to the construction of two new nuclear units at Plant Vogtle. DSM charges recover program costs for demand-side management programs. MFF charges recover fees paid to the cities for allowing GPC to conduct business within their city limits and on their rights-of-way. Lastly, FCR charges recover costs related to GPC's use of fuels in its generating plants and energy purchased on an economic dispatch basis. All charges and fees are presented to the PSC for review, feedback, and approval before they are added to customer bills.

GPC offers several non-traditional pricing options for its C&I and residential customers. For C&I customers, current tariff options include time-of-use rates, real-time pricing, price-protection products, and flat billing. Residential tariff offerings are summarized in Figure 11.

Figure 11. GPC residential tariff offerings

Rate	Description
Residential Service	A basic rate plan available to all residential customers. Customers are charged a basic service charge, along with variable energy charges. Electricity rates vary by amount consumed and time of year (summer or winter).
Nights & Weekends	Customers are billed a basic service charge, along with variable energy charges. Electricity rates differ by time of day (i.e., on-peak or off-peak), also known as a time-of-use rates.
FlatBill	Customers pay a fixed amount per month regardless of usage. Bills consist of a basic service charge, and an energy charge (multiplied by a risk adder, not to exceed 10%). Energy charges are calculated by examining historical usage per month, and the resulting annual bill is divided into 12 equal monthly payments.
Smart Usage	Customers are incentivized to shift electricity consumption to off-peak hours, and to avoid using multiple appliances at once. Customers pay a basic service charge, variable energy charges (with different rates for on-peak and off-peak hours), and a demand charge based on their maximum 60-minute energy demand (in kW) for the billing month.
Plug-In EV	Tariff is structured to incentivize nighttime electric vehicle ("EV") charging, by lowering electricity rates between 11 p.m. and 7 a.m. (called "super off-peak" hours). Customers pay a basic service charge, and a variable energy charge with electricity rates that differ based on time of day.
PrePay	Customers add money to their account, which is reduced based on their electricity usage and days of use. Customers pay a basic service charge ($0.59 per day, including applicable riders), and variable energy charges with rates that differ based on the time of year (summer or winter).
Pay by Day	Customers pay a fixed daily price for the whole year. Similar to the PrePay option, customers add money to their account, which is reduced for each day of use. Similar to the FlatBill option, the daily price is calculated by taking into account a customer's historical usage. Monthly usage amounts are multiplied by a usage charge (energy charges and applicable riders). A basic service charge and risk adder are added to this amount. The monthly sums are added to form an annual amount, which is converted to a daily rate based on the number of days in the contract period.

Source: GPC.

2.3.3 Other notable elements of the ratemaking regime

GPC's rates have been determined on a COS basis since its inception. Under this regime, GPC is allowed to recoup its capital and operating costs from consumers and earn a set ROE. Notably,

[18] Note, residential customers on the Smart Usage tariff (discussed in Figure 11) also pay demand charges.

the ratemaking regime also includes an earnings sharing mechanism ("ESM") and allows for interim cost recovery (see Figure 12). The rationale for the ESM is that it motivates GPC's management to improve efficiency, and helps avoid the possibility of unscheduled regulatory interventions due to windfall profits. The ICR in turn allows GPC to adjust to projected revenue shortfalls and maintain a consistent ROE.

Figure 12. Summary of earnings sharing mechanism and interim cost recovery

Design element	Rationale	Pros	Cons
Earnings sharing mechanism and interim cost recovery	To ensure that GPC delivers reasonable ROE and to prohibit intervention from excessive windfalls	Incentivizes GPC to deliver consistent ROE and provide accurate cost forecasts	No cost recovery is available if actual ROE is found to be lower than the bottom end of the earnings band

In June 2019, GPC filed its most recent rate request, requesting a rate increase of $942 million to be spread out over the 2020-2022 period. Following a proposed settlement agreement between GPC and parties to the rate case, the Georgia PSC approved a rate increase of $909 million over the same period.[19] Following this settlement, the Georgia PSC authorized an ROE of 10.5%.[20] Factors cited for this rate increase include an increase in GPC's compliance costs related to ash pond closures, storm damage costs, and capital investments in the retail rate base. The settlement retains the ESM, with an earnings band set between 9.5% and 12% ROE. If actual retail earnings rise above 12% ROE, as determined in the Annual Surveillance Report,[21] GPC will refund 40% of earnings above that level to customers. Another 40% of excess earnings would be applied to regulatory assets,[22] and the remaining 20% would be retained by GPC.[23]

The ICR mechanism, first approved in GPC's 2010 rate case, will continue for the current term: if retail earnings are *projected* to be lower than 9.5% ROE (the lower end of the earnings band), GPC may file for an ICR tariff, which would adjust GPC's ROE earnings to 9.5%. However, GPC is not entitled to cost recovery if *actual* ROE is found, after the fact, to be below the lower end of the earnings band.

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[19] Balasta, Selene. "Ga. regulators approve Georgia Power rate case settlement." *S&P Global Market Intelligence.* December 17, 2019.

[20] Georgia Public Service Commission. *Order Adopting Settlement Agreement as Modified – Docket No. 42516.* December 17, 2019. p. 5.

[21] Earnings in excess of the earnings band established by the Georgia PSC are disclosed in the Annual Surveillance Report. In this report, GPC also provides data on its retail rate of return, including calculations, ratemaking principles and workpapers.

[22] A regulatory asset is an accounting mechanism unique to utilities. They are usually authorized by commissions to allow utilities to defer costs related to various matters (including, in many states, extreme weather) for future recovery. Georgia Power has regulatory assets related to coal combustion residual asset retirement obligations, retired generating plants, and storm damage, among others. (Georgia Power Company. *Settlement Agreement – Georgia Power Company's 2019 Rate Case. Docket No. 42516.* December 11, 2019.)

[23] Georgia Power Company. *Settlement Agreement – Georgia Power Company's 2019 Rate Case. Docket No. 42516.* December 11, 2019.

2.4 Georgia's (US) experience with restructuring discussions

While GPC has never been restructured into separate generation, transmission, and distribution companies, national trends led the PSC to launch proceedings in the 1990s to assess the viability of a competitive electricity market in Georgia. This section discusses the context behind those proceedings, the limited retail competition present in Georgia, and why competitive restructuring failed to materialize.

2.4.1 Electricity restructuring in the United States in the 1990s

Beginning in the 1990s, several states undertook measures to require or encourage vertically integrated utilities to disaggregate into separate generation, transmission, or distribution entities. Also, participation in independent system operators ("ISOs") or regional transmission organizations ("RTOs") was encouraged at the federal level. The current transition of the electric power supply industry from a regulated monopoly structure to a competitive market environment was initiated by the enactment of the *Public Utility Regulatory Policies Act* of 1978 ("PURPA"), the *EP Act* of 1992, and FERC Orders No. 888 and 889 in 1996. FERC Orders 888 and 889 established open access rules, the setting of transmission access rates, disclosure of transmission capacity information, the functional unbundling of transmission, and introduced the ISO concept. These Orders were the basis behind much of the restructuring efforts in North America during the late 1990s and early 2000s.

2.4.2 Limited retail competition in Georgia (US)

Georgia has limited retail competition as a result of the Territorial Act of 1973. As mentioned earlier, the Territorial Act of 1973 began a process that ultimately outlined service territories for utilities serving residential and small commercial customers, and introduced customer choice provisions only for large customers.

Customers with connected loads of less than 900 kW must take electricity from their local supplier. However, customers with connected loads of 900 kW or more are able to choose their electric supplier. A large load premises must be within 300 feet of the lines owned by the secondary supplier for this provision to apply. For the few remaining areas still unassigned by the Territorial Act, any supplier may serve the premises if chosen by the large load customer. Under the Territorial Act, once a customer chooses a supplier, the chosen electric supplier has the exclusive right to serve that customer for the life of the premises.

The Territorial Act was a compromise that came about through negotiations by electric utilities doing business in the state of Georgia at the time. The load level for competition was set at 900 kW because this was considered large enough to make the investment necessary to serve that load economically justifiable.[24]

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[24] Georgia Public Service Commission. *Staff Report on Electric Industry Restructuring - Docket Number 7313-U*. January 1998. p. 25.

Advantages of the current structure include reliable electric service that is provided at a reasonable price, compared to other states and the nation as a whole.[25] However, one disadvantage is that no party can sell power, except to a utility – even an individual owning a few solar panels. There are two schools of thought on the issue of the Territorial Act. Some believe that it has worked well to foster price stability, while others believe that it should be repealed and the market should be allowed to develop more freely.

Figure 13. Summary of limited retail competition

Design element	Rationale	Pros	Cons
Limited retail competition	To allow only customers with large loads to select their electricity supplier	Reliable electric service at consistent rates	Does not allow small retail customers to choose electricity provider

2.4.3 Proceedings on restructuring the electricity market

Beginning in April 1997, the PSC held four workshops to examine issues related to electric industry restructuring in Georgia. The goal of these workshops was to raise awareness of the issues involved in restructuring the electric industry and to examine the advantages and disadvantages of restructuring. The workshops also began a consideration of the appropriate regulatory and legislative steps required for successful restructuring. Presenters at the workshop included representatives from IOUs, munis, EMCs, independent power producers, and power marketers. Also present were consumer advocates, environmentalists, members of various governmental agencies, including members of the State Legislature, and representatives from the residential, commercial, and industrial customer classes. Presenters focused their discussion on the structure of the industry in Georgia and what modifications may be necessary to establish a more efficient framework for the future.

After the workshops were completed, the Staff continued to compile data and information from the written comments, white papers, focus group reports, presentations, and transcripts. The participants at the workshops and in the focus groups reached a general consensus on restructuring: if generation became open to competition, distribution service should remain a state regulated service with preexisting territories maintained as such. However, from the point of view of state policy makers, the regulatory system was working well in Georgia. At the time, electric rates were generally at or below the national average – a trend which continues to hold true. Due to the relatively low cost of electricity in the state, Georgia decided that there was no urgent need to restructure the electric industry. The ultimate decision also had to do with specific design elements, such as the ITS and the existing competition structure that developed out of the Territorial Act of 1973. The studies conducted by the PSC in 1998 essentially marked the end of

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[25] In 2019, Georgia ranked 25th highest (out of 50 states) for its average price of electricity to ultimate customers, taken as a composite of residential (31st), commercial (26th) and industrial (33rd) electricity rates. The US average was 10.54 cents/kWh, whereas Georgia's average was 9.86 cents/kWh. (Source: US EIA. *Table 2.10. Average Price of Electricity to Ultimate Customers by End-Use Sector.* October 21, 2020.)

restructuring efforts in Georgia. The PSC writes that "[a]bsent federal action, the electric industry in Georgia will remain traditionally regulated in its present form."[26]

[26] Georgia Public Service Commission. *Electric*. Accessed April 28, 2021.

3 Colombia (standard PBR)

Colombia is the fourth largest economy in Latin America with a gross domestic product ("GDP") of US$395 billion as of 2019.[27] Similar to most Latin American energy markets, Colombia's energy mix is dominated by hydro, with hydroelectric resources accounting for 69% of the total installed capacity of nearly 18 gigawatts ("GW"). Prior to 1994, Colombia's electricity sector was owned and managed by the state. However, legislation in 1994 began a transition to a restructured market. This transition included functional unbundling and introduction of competition in electricity generation, facilitated by a wholesale energy market. There is significant private investment in Colombia's market, with numerous market players across the generation, transmission, distribution and retail segments.

Colombia's regulator for the electricity sector, the Commission of Energy and Gas Regulation ("CREG" or *Comisión de Regulación de Energía y Gas*), is responsible for setting tariffs for electricity transmission, distribution, and retail (for regulated customers). Currently, all transmission and distribution tariffs are regulated under a form of performance-based ratemaking known as a "revenue cap." Simplistically, a revenue cap model sets a maximum level of revenues for a utility. This revenue level is adjusted for inflation and desired efficiency improvements, incentivizing the utility to improve its cost-effectiveness. CREG sets and periodically updates the methodology for calculating transmission and distribution tariffs. This case study includes a detailed discussion of the major components of transmission and distribution PBR tariffs in Colombia, based on current methodologies.

3.1 Overview of the Colombia market

As of 2018, Colombia had nearly 18 GW of installed capacity, and in 2019 generated nearly 77 TWh of electricity annually, as shown in Figure 14. The vast majority of Colombia's installed capacity and electricity generation stems from hydroelectric facilities (69% and 71%, respectively). Under average to wet hydrological conditions, electricity demand is met with very little oil-fired generation. During dry periods, however, oil-fired generation may play a substantial role. Fossil-based resources, including natural gas and coal-fired generation, represent the second largest category of electric generation resources. Non-hydro renewable resources comprise only a small percentage of capacity and generation (0.2% for both). However, the government is taking active measures to encourage non-conventional renewable energy (i.e., solar and wind) capacity growth, such as issuing multiple tenders for long-term contracts. By the end of 2022, solar and wind capacity is expected to reach over 2,800 megawatts ("MW") from under 50 MW in 2018.[28]

Electric load has increased at a compound annual growth rate ("CAGR") of 2.4% between 2014 and 2019, largely tracking growth in economic output.[29] However, in 2020, both load and peak

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[27] The World Bank. *GDP (constant 2010 US$) – Colombia, Brazil, Mexico, Argentina, Peru, Chile*. Accessed April 30, 2021.

[28] Minenergía. *Colombia sumará más energía limpia a su matriz energética gracias a nueva subasta de renovables.* November 10, 2020.

[29] GDP had a CAGR of 2.1% during the same period. (Source: World Bank data.)

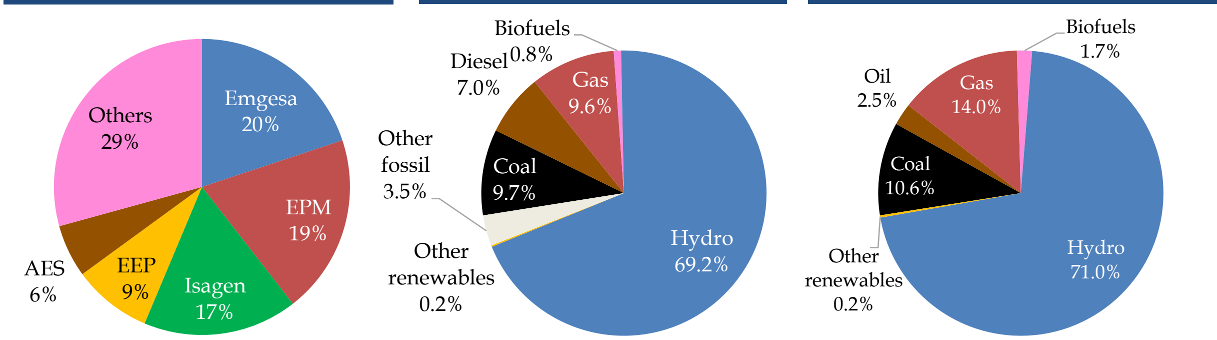
demand decreased by roughly 2% year-over-year, likely due to the impacts of the COVID-19 pandemic.

Figure 14. Colombia market snapshot

Colombia

Key facts	
Population (2019)	50.3 million
GDP growth (CAGR, 2014-2019, constant 2010 USD)	2.4%
GDP per capita (2019)	$6,429
Installed capacity (2018)	17.7 GW
Electricity generation (2019)	76.83 TWh
Peak demand (2020)	10.4 GW
Load growth (CAGR, 2014-2019)	2.1%
Distribution lines	500,000 kilometers
Transmission lines	14,000 kilometers

Top market players by capacity (2018) | **Installed capacity by fuel type (2018)** | **Generation by fuel type (2018)**



Notes: sources for generation and installed capacity differ in their classification of fuel types. Therefore, category names in the two charts above also differ, as some smaller sources have been grouped into "Other fossil." Furthermore, transmission lines are defined as those above or equal to 220 kilovolts ("kV").

Sources: World Bank, UPME, IEA, XM, CREG.

Colombia also has interconnections with Ecuador and Venezuela. In 2020, Colombia imported roughly 1,302 gigawatt-hours ("GWh") and exported almost 251 GWh of electricity,[30] compared to over 70,000 GWh in domestic demand.[31] Historically, the vast majority of these transactions have occurred between Colombia and Ecuador.[32]

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[30] UPME. *Indicadores Intercambios*. Accessed May 3, 2021.

[31] XM. *23. Demanda de electricidad – Demanda de energía nacional*. Accessed April 30, 2021.

[32] UPME. *Boletín estadístico de minas y energía 2016-2018*. November 2018. p. 84.

Colombia's energy market has a large number of participants: as of April 2021, there were 92 registered generators, 15 transmitters, 40 distributors, and 127 retailers/marketers.[33, 34] The two largest market players by installed capacity are the privately-owned Emgesa, and Empresas Públicas de Medellín, which is owned by the municipality of Medellín, Colombia.

Colombia initiated restructuring of its energy market following the 1991 El Niño-related drought, which resulted in an extreme shortage of energy supply and rolling blackouts. In December 1992, the national government restructured the Ministry of Mines and Energy, dissolving the National Commission of Energy (the regulator) and creating three special administrative units: the Commission of Energy and Gas Regulation ("CREG"), the Energy and Mining Information Unit ("UIME" or *Unidad de Información Minero Energética*) and the Commission of Energy-Mining Planning ("UPME" or *Unidad de Planeación Minero-Energética*).[35] This was followed in 1994 by the Law of Public Utilities and the Law of Electricity, which established the current institutional arrangements for regulation of public utilities, including the electricity sector.[36] Colombia's market structure is summarized below:

- ***pool:*** since 1995, the short-term market in Colombia has been a single-node, bid-based, day-ahead power pool. All power plants with installed capacity over 20 MW must participate in the power pool;[37]
- ***contracts:*** retailers contract for energy supply from generators to serve regulated demand (i.e., demand primarily from residences and small businesses, whose tariffs are regulated). Unregulated customers can negotiate directly with suppliers, and do not need to be served by a retailer.[38] The pool is used to settle imbalances between contracted quantities and actual demand;[39]
- ***governance:*** the market is regulated by an independent regulatory commission ("CREG"). The Ministry of Mines and Energy ("MME" or *Ministerio de Minas y Energía*) formulates Colombia's energy policy; ISO functions are performed by the state-owned company Interconexión Eléctrica SA ("ISA"), through its subsidiary "XM";
- ***assuring competition:*** market competition and performance are overseen by three separate entities. Unlike the market design of other hydro-dominated markets, Colombia's power market design is not focused on competition issues. There are few

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33 XM – PARATEC. *Número de agentes por actividad*. Accessed April 30, 2021.

34 The Spanish word *comercializadores* can be translated as either 'retailers' or 'marketers.' For consistency, 'retailers' will be used throughout this case study.

35 In 1997, UIME was merged into UPME.

36 Ley 142 de 1994 and Ley 143 de 1994.

37 Power plants with 10-20 MW in installed capacity can choose to participate in the pool. Power plants smaller than this size are not centrally dispatched. (Source: Rudnick, Hugh and Constantin Velásquez. "Learning from Developing Country Power Market Experiences: The Case of Colombia." *World Bank Group Policy Research Working Paper 8771.* March 2019. p. 13.)

38 Ibid. p. 16.

39 Ibid.

restrictions on either thermal plant or hydro plant bids, for instance, and vertical integration is permitted;[40]

- ***assuring supply:*** Colombia relies on firm energy payments to incent resources to be available during scarcity periods, thereby maintaining adequate energy supply to meet demand.

3.2 Colombia's current institutional and legal framework

The main institutions governing the power sector in Colombia include (see Figure 15):

- **MME – *energy policy*:** the Ministry of Mines and Energy is the highest authority in the energy sector and is responsible for formulating the national energy policy;
- **CREG – *regulator*:** the Commission of Energy and Gas Regulation ("CREG") is the regulating authority for the electric power, natural gas, liquefied petroleum gas and liquid combustibles sectors. Its main objective is to ensure that service is provided to the greatest number of individuals possible, at the lowest possible cost to users, and with adequate remuneration for companies that allows for quality, coverage and expansion;[41]
- **SSPD – *supervision*:** the Superintendent of Public Utilities ("SSPD" or *Superintendencia de Servicios Públicos Domiciliarios*) is responsible for supervising compliance with CREG's regulations;
- **CAC – *market monitor*:** the Energy Trading Advisory Committee ("CAC" or *Comité Asesor de Comercialización*) was established by CREG to assist in monitoring and reviewing the commercial aspects of the wholesale energy market;
- **UPME – *planning*:** the Planning Unit for Mining and Energy ("UPME" or *Unidad de Planeación Minero-Energética*) is a special administrative unit attached to the MME, responsible for mining and energy sector planning. Its main objectives are to plan the development and use of mine and energy resources, provide the necessary information to formulate policy and make decisions, and support MME in achieving its objectives and goals;[42]
- **SIC – *antitrust authority*:** the Superintendence of Industry and Commerce ("SIC" or *Superintendencia de Industria y Comercio*) investigates, corrects and sanctions restrictive commercial competitive practices, as well as oversees mergers of companies operating in the same productive activities to prevent the concentration or monopolization of certain industries;

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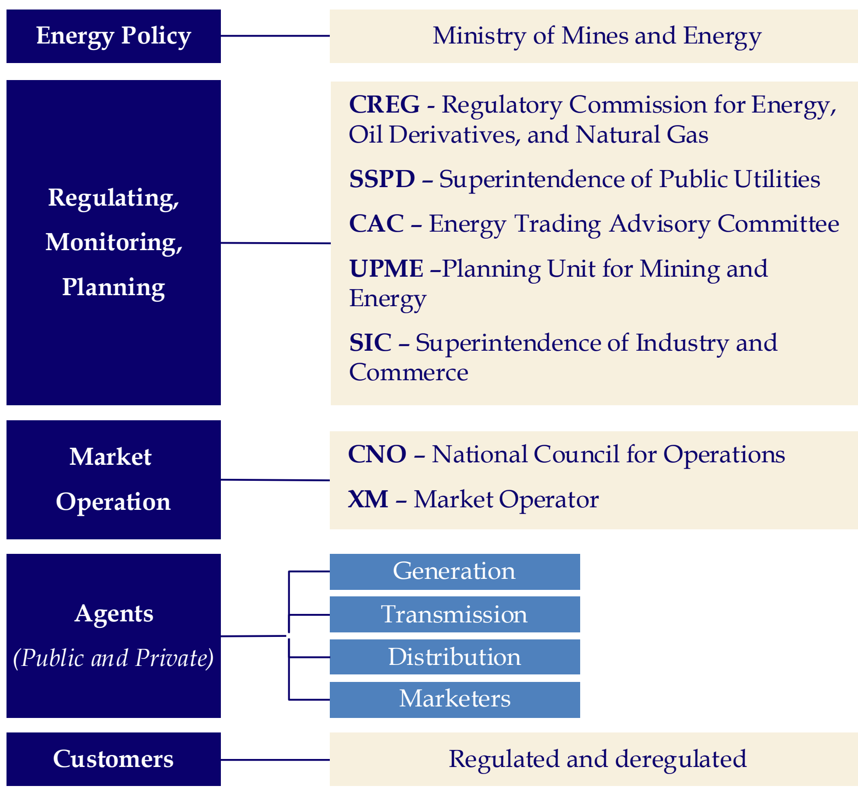
[40] Utility companies incorporated before 1994 are allowed to engage in more than one part of the electricity value chain, only under separate accounts per business. Utility companies incorporated after Laws 142 and 143 of 1994 can only engage in complementary activities (e.g., generation and retail) at one time. (Zapata Lugo, José V and Daniel Fajardo Villada. "The Energy Regulation and Markets Review: Colombia." *The Law Reviews.* August 5, 2020.)

[41] CREG. *Objetivo*. Accessed May 4, 2021.

[42] UPME. *Quiénes Somos*. Accessed May 4, 2021.

- **CNO**: the National Council for Operations ("CNO" or *Consejo Nacional de Operación*) is a consultative entity responsible for establishing technical standards to facilitate the efficient integration and operation of the National Interconnected System ("SIN" or *Sistema Interconectado Nacional*); and
- **XM – *market operator*:** XM is the system operator. The company, a subsidiary of ISA, is responsible for operating the SIN and managing the Colombian wholesale energy market. XM is broken up into several agencies, including ASIC and CND:
    - **ASIC:** the Administrator of the Commercial Exchange System ("ASIC" or *Administrador del Sistema de Intercambios Comerciales*) is responsible for the registration of contracts and the settlement and billing of all transactions that take place on the wholesale energy market; and
    - **CND:** the National Dispatch Center ("CND" or *Centro Nacional de Despacho*) is the agency responsible for planning, overseeing, and controlling the integrated operation that encompasses generation, interconnection, and transmission resources of the SIN.

Figure 15. Colombia electricity institutional framework



Generation

In 2018, the five largest players in Colombia in terms of generation capacity were Emgesa, Empresas Públicas de Medellín ("EPM"), Isagen, Empresa de Energía del Pacífico ("EEP"), and AES Chivor & CIA. Together, these entities represented 71% of the country's total installed capacity, as shown in Figure 14. As of April 2021, Colombia had 92 registered electricity generators in the SIN,[43] composed of public and private participants. The market is dominated by a handful of large plants (nearly 60% of the total generation in 2020 was produced by 15 plants).[44]

<u>Transmission</u>

Colombia's SIN covers 96% of the population and 48% of the country, stretching from the northeast to the southeast.[45] The SIN is split into the National Transmission System ("STN" or *Sistema de Transmisión Nacional*) for voltages above 220 kV, and the Regional Transmission System ("STR" or *Sistema de Transmisión Regional*) for voltages below 220 kV.[46,47] ISA, a state-owned utility, owns 71% of the STN. The next largest transmission owners in Colombia are Grupo Energía Bogotá and Transelca, with 10% market share each.[48] Free access to the STN is guaranteed, pending compliance with market requirements.

<u>Distribution and retail</u>

As of April 2021, there were 40 distribution companies operating in Colombia, consisting of private, public, and mixed-ownership entities. Distribution companies are not allowed to have market shares (directly or indirectly) greater than 25% of Colombia's total load (including exports). The electrification rate in Colombia is over 99%.[49] In 2020, residential customers made up 42% of total load, followed by commercial customers (25%) and industrial customers (21%).[50]

Retailers are active market participants licensed to sell energy to both regulated and non-regulated customers, as well as to act as brokers. The difference between regulated and non-regulated costumers is based on the volume of energy demand:

- ***non-regulated*** customers must have a six-month average monthly demand above 55 megawatt-hours ("MWh") or a six-month average monthly peak demand above 100 kilowatts ("kW"). Non-regulated customers are eligible to engage freely with suppliers and retailers;[51] and

[43] XM – PARATEC. *Número de agentes por actividad*. Accessed April 30, 2021.

[44] XM. *24. Ofterta y generación – Generación por recurso*. Accessed May 4, 2021.

[45] MaRS. *Market Information Report: Colombia*. April 2017. p. 2.

[46] XM. *Redes sistema interconectado nacional*. Accessed May 4, 2021.

[47] For ratemaking purposes, the STR is considered part of the distribution system.

[48] XM – PARATEC. *Líneas de transmisión por agentes operadores*. Accessed May 4, 2021.

[49] The World Bank. *Access to electricity (% of population) – Colombia*. Accessed May 4, 2021.

[50] Sistema Único de Información de Servicios Públicos Domiciliarios.

[51] Rudnick, Hugh and Constantin Velásquez. "Learning from Developing Country Power Market Experiences: The Case of Colombia." *World Bank Group Policy Research Working Paper 8771.* March 2019. p. 16.

- ***regulated*** customers are those who do not meet the thresholds described above. Regulated customers account for almost 70% of total energy demand[52] and have their prices administratively set by CREG.

3.2.1 Regulation and policy setting

The **Ministry of Mines and Energy** sets policies for the energy sector in Colombia. At its establishment in 1940, the ministry was named the Ministry of Mines and Petroleum; MME moved to its current name in 1974. Law 2 of 1973 gave the executive branch (represented by MME) the necessary powers to act as the entity responsible for optimal development of Colombia's energy supply resources.[53] The MME is responsible for regulating generation, interconnection, transmission, and distribution and is in charge of transmission and generation programs.[54] UPME (the Mining and Energy Planning Unit) supports the MME in its objectives.

CREG is the regulatory body for utilities in Colombia. It regulates electricity, combustible gas, and liquid fuels.[55] Pursuant to Laws 142 and 143 of 1994, CREG's overarching function is to promote competition between entities providing public services and regulate public service monopolies where competition is not possible.[56] CREG furthermore sets tariffs and interconnection and usage charges for electricity transmission and distribution, defines unregulated and regulated users in the electricity market, establishes regulations for the national transmission system, and issues technical regulations regarding security, reliability and quality of electricity.[57]

3.2.2 Regulatory oversight of charges

Pursuant to Laws 142 and 143 of 1994, CREG is responsible for setting tariffs for the provision of electricity service to regulated users in Colombia. Colombian end-users are charged a unified cost of service tariff by retailers, established in CREG Decision 119 of 2007. This unified cost of service aggregates costs from each step of the electricity value chain (generation – which is mostly competitively set, as well as transmission, distribution, marketing/retail, and other costs).[58] The high-level formula is displayed below in Figure 16.

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52 XM. *23. Demanda de electricidad – Demanda de energía nacional*. Accessed May 4, 2021.

53 Minenergía. *Historia*. Accessed May 5, 2021.

54 Zapata Lugo, José V and Daniel Fajardo Villada. "The Energy Regulation and Markets Review: Colombia." *The Law Reviews*. August 5, 2020.

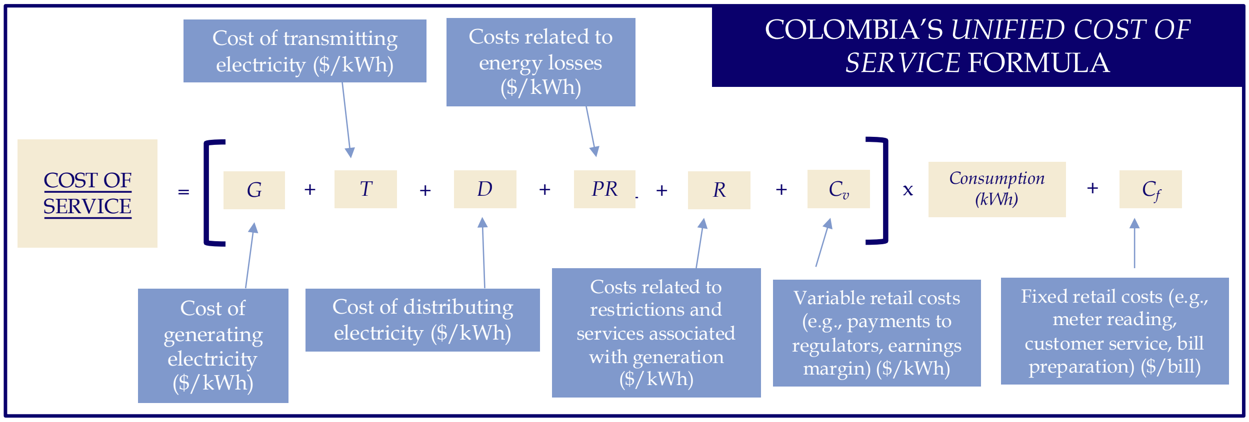
55 CREG. *Misión y Visión*. Accessed May 5, 2021.

56 CREG. *Funciones*. Accessed May 5, 2021.

57 Zapata Lugo, José V and Daniel Fajardo Villada. "The Energy Regulation and Markets Review: Colombia." *The Law Reviews*. August 5, 2020.

58 CREG. *Estructura Tarifaria – Energía Eléctrica*.

Figure 16. Colombia's unified cost of service formula



Source: CREG.

Of the service providers covered by the tariff components above, transmission and distribution entities are currently regulated under a form of performance-based ratemaking known as a "revenue cap." At a high level, under a revenue cap mechanism, a maximum revenue per utility is established. This maximum revenue is adjusted by an inflation factor (RPI) less an efficiency factor (X), also known as an RPI-X mechanism. A benchmarking exercise is undertaken to determine the X factor. Tariff levels change based on the regulator's methodology, usually not in response to changes in a transmission or distribution utility's actual cost of service. Therefore, utilities that are able to achieve productivity or efficiency gains are rewarded, whereas utilities that are unable to achieve efficiency targets are penalized.[59]

Transmission and distribution tariffs are in effect for five years, pursuant to Law 142 of 1994. However, these tariffs may remain in effect past this five-year duration, until CREG establishes a revised methodology. Before establishing a revised methodology, CREG must first publicize a draft resolution for its proposed new tariffs and solicit and consider stakeholder comments.[60] Further details about ratemaking in the transmission and distribution segments are outlined below.

3.2.3 Transmission ratemaking

Electricity transmission tariffs (i.e., tariffs for use of transmission lines of 220 kV or higher) are currently regulated by CREG Decision 011 of 2009.[61] Since CREG Decision 004 of 1999, transmission tariffs have been determined under a revenue cap methodology, where the revenue cap is established as the sum of the annual cost of assets, cost of administration, operation and maintenance ("AOM"), and cost of land and service, less other revenues. Major components of

[59] CREG. *Metodología de remuneración de actividad de distribución de energía eléctrica para el periodo tarifario 2015-2019.* December 23, 2014. p. 405.

[60] See for example: CREG Resolución No. 015 de 2018 and CREG Resolución 11 de 2009.

[61] While CREG has issued two proposed resolutions changing the transmission tariff formulas (one in 2014, and one in 2016) there has been no official resolution updating the formulas since 2009.

the tariff methodology are shown below in Figure 17, and the formula for calculating the transmission operator's annual income is shown in Figure 18.

Figure 17. Main components of transmission tariff methodology

Component	CREG Decision 011 of 2009
PBR method	Revenue cap
Asset valuation	New Replacement Value; remunerates all assets as if new
AOM costs	Costs included are those recognized and incurred by the transmitter
Investment value	New value calculated every five years
Non-electric assets	5% of electric asset annual equivalent cost added to capital base to reflect annual equivalent cost of non-electric assets
Service quality incentives	Calculated based on transmitter's historical performance. Maximum number of hours of unavailability set. If transmitter exceeds this number, they must compensate consumers (reflected on end-user's bill)

Source: Andrade-Becerra, Andrés et al.

Figure 18. Formula to calculate annual income of transmission operator

$$IAT = CAEA\,(1 + \%\,ANE) + VAOM + CAET + CAES - Ol$$

where IAT = the transmission operator's annual income; CAEA = the annual equivalent cost of the transmitter's electric assets valued at replacement cost; %ANE = the percent multiplier for non-electric assets; VAOM = administration, operations and maintenance ("AOM") expenses; CAET = the annual equivalent cost of land for the transmitter; CAES = the annual equivalent cost of easements; and Ol = other income gained from charges of use for using the transmitter's assets in non-transmission activities.

Source: Andrade-Becerra, Andrés et al.

To set the tariff, each type of transmission asset is first assigned a unified cost, including costs to put the asset into service, and a useful lifetime (between 10 and 40 years, depending on the equipment). Then, CREG approves the asset inventory of each transmission operator that will be remunerated, taking into account whether any assets are shared with other operators or are a result of government contributions.[62]

An annuity is calculated for each asset, using its unified cost and useful life and a weighted average cost of capital ("WACC").[63] Adding up the annuities for all assets of a transmission operator gives the figure for the annual cost that the operator must recover. This annual cost is

[62] Trillos González, Carlos Ignacio. "Una descripción de los cargos regulados en las tarifas de energía eléctrica vigentes en Colombia en 2012." *Universidad EAFIT, Escuela de Administración, Maestría en Administración MBA, Trabajo de Grado.* p. 28.

[63] Pursuant to CREG decision 083 of 2008, the WACC is 11.5% annually before taxes. (Source: Ibid.)

then increased by 5%, based on CREG's estimate of the additional investment in non-grid assets that an operator must make (e.g., for buildings and vehicles).[64]

Annual AOM costs are added to the annual asset cost, along with 5.69% of the value of the land occupied by substations and, if necessary, easement costs. Deducted from this total cost is 33% of any revenues made by the transmission operator as a result of using regulated assets for non-transmission activities.[65]

By way of service incentives, a maximum number of hours per year for which equipment may be out of service is established. If this number of hours is exceeded, the required compensation to customers is deducted from the maximum revenues authorized for the transmission operator.[66]

Efficiency incentives are embedded within the tariff formula shown in Figure 18. The tariff component that remunerates AOM expenses (VAOM, as shown in Figure 18) is calculated using the utility's historic AOM costs, an upper and lower limit on annual cost increases, and the utility's regulated asset base. AOM expenses to be remunerated are expressed as a percentage of the utility's electric asset replacement cost.[67] To be eligible for remuneration, the percentage of annual recoverable AOM expenses must not exceed a 0.4% increase in a reference percentage, nor be less than 1% of the utility's electric asset replacement cost. The reference percentage is equivalent to the average AOM costs from 2001 to 2008 for each utility, divided by the utility's electric asset replacement cost for 2008. There is also a mechanism to update values when projected and actual AOM expenses differ.[68] By using a percentage to represent AOM expenses (rather than absolute values) and measuring their evolution against a historical benchmark, CREG is able to incentivize continued efficiency in transmission operations.

CREG has issued regulatory proposals to make changes to the transmission tariff methodology. Proposed changes include transitioning the method for remunerating transmission assets to a depreciated optimized replacement cost ("DORC") method and establishing quality metrics based on efficiency data.[69] These proposals have not yet been formalized in a CREG decision, so they are not yet binding on transmission tariffs.

[64] Ibid.

[65] Ibid. p. 29.

[66] Ibid.

[67] The electric asset replacement cost is determined based on each utility's regulated asset base.

[68] CREG Resolución No. 011 de 2009. February 11, 2009.

[69] Andrade-Becerra, Andrés et al. "Economic Assessment of Changes in the Regulation of the Transmission Activity in Colombia." *Journal of Engineering Science and Technology Review,* vol. 12, no. 6, 2019, p. 14.

3.2.4 Distribution ratemaking

The distribution system is split into four voltage levels. The STR includes Level 4 lines (greater than or equal to 57.5 kV and below 220 kV). The local distribution system ("SDL," or *Sistema de Distribución Local*) includes Levels 3 to 1 lines (less than 57.5 kV).[70]

PBR was first used to regulate distribution tariffs under CREG Decision 099 of 1997, which established a "price cap" mechanism for the STR and SDL. The STR moved to a revenue cap mechanism, pursuant to CREG Decision 082 of 2002, while the SDL remained under price cap.[71] Electricity distribution tariffs are currently regulated by CREG Decision 015 of 2018, under which a revenue cap model is used to set tariffs for both the STR and SDL. The transition to using revenue cap for all parts of the distribution system in Colombia was motivated by several factors, including to provide revenue stability for grid operators (as the revenue adjustment mechanism at the start of each price cap tariff period was to be eliminated), facilitate users' moving to higher voltage levels, and facilitate the incorporation of distributed generation.[72]

The latest distribution tariff methodology, established under CREG Decision 015 of 2018, worked to address deficiencies identified under previous tariff regimes in levels of new investment, AOM expenses, service quality and line losses.[73] Figure 19 provides a high-level overview of the main components of the current methodology.

Figure 20 shows the formula used to calculate monthly revenues for operators in Levels 2 and 3, and Figure 21 shows the formula for calculating annual revenues for asset investment. Revenues are calculated by the Liquidator and Accounts Administrator ("LAC" or *Liquidador y Administrador de Cuentas*), an entity that is part of the system operator XM, according to the methodology set out by CREG.

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[70] CREG Resolución No. 015 de 2018. January 29, 2018.

[71] CREG. *Metodología de remuneración de actividad de distribución de energía eléctrica para el periodo tarifario 2015-2019.* December 23, 2014. p. 419.

[72] Ibid. p. 455.

[73] Pérez, D.M. and A.H. Castro. "702 – Impacto en la remuneración del uso de la infraestructura de transporte de electricidad con la nueva metodología regulatoria en Colombia." *CIGRE.* May 2019.

Figure 19. Main components of distribution tariff methodology

Component	CREG Decision 015 of 2018
PBR method	Revenue cap for STR and SDL
Asset valuation	Depreciated replacement cost; stability in regulated asset base
AOM costs	AOM costs for existing assets compared to reference costs set for regulatory period. AOM for expansion included at set percentage of new investment
Land value	6.9% of land value added to asset base
Non-electric assets	2% of electric asset value added to capital base for non-electric assets
Service quality incentives	Service quality of each distributor compared against levels for average duration and frequency of service disruptions in one year. Levels set by CREG, and are to decrease by 8% every year. Revenue cap raised or lowered based on performance

Source: Ropero Gutiérrez, Cesar Alejandro.

Figure 20. Formula for calculating monthly revenues for distribution Levels 2 and 3

$$IA = \left[\boldsymbol{IAA} * fM + \frac{IAAOM - IRM}{12} \right] * \frac{IPP_{m-1}}{IPP_0}$$

Where IA = monthly revenue for the distribution operator; IAA = the annual revenue for investment in assets; fM = the factor used to calculate monthly values of IAA; IAAOM = the annual revenue for AOM expenses; IRM = the annual revenue received by the distribution operator for use of its assets for non-distribution activities; IPP_{m-1} = the producer price index in the previous month; and IPP_0 = the producer price index on the closing date.

Note: formulas for levels 1 and 4 follow the same general structure, with slight variations.

Source: Adapted from CREG.

Figure 21. Formula for calculating annual revenue for asset investment of a distribution operator

$$\boldsymbol{IAA} = BRA * r + RC + BRT$$

where IAA = the annual revenue for investment in assets; BRA = the regulated asset base, including both electric and non-electric assets; r = the rate of return set by CREG; RC = recovery of capital spent for assets remunerated as part of the regulated asset base; and BRT = the regulatory land base.

Source: Adapted from CREG.

Following CREG Decision 015 of 2018, distribution operators had to submit their revenue requests to CREG for approval. Distribution operators also had to present an investment plan for the tariff period (2019-2023) for regulatory approval. Annual planned investments could not exceed 8% of the distribution operator's existing asset base,[74] and must also be followed up with

[74] Enel. Colombian Regulatory Framework. June 2017. p. 8.

annual updates, as certain components of the tariff formula are updated yearly (e.g., asset base and AOM costs for new investment).

CREG determined that distribution assets for the 2019-2023 tariff period would be valued based on a depreciated replacement cost method, which takes into account the useful life of assets and their number of years in service in order to calculate the appropriate remuneration for operators.[75]

Service quality is incentivized using indicators such as the System Average Interruption Duration Index ("SAIDI") and the System Average Interruption Frequency Index ("SAIFI"). CREG establishes goals for each of these, and the distribution operator reports its annual performance on the indicators. Based on its performance, its annual revenue level may be increased or decreased. The distribution operator must also compensate the worst-served users. CREG plans to reduce the levels of SAIDI and SAIFI by 8% each year, until SAIDI reaches 2 hours/year and SAIFI reaches 9 times/year.[76]

Efficiency incentives are embedded in the treatment of AOM costs. AOM costs for existing assets to be remunerated through tariffs are first determined by calculating a distribution operator's average annual demonstrated and remunerated AOM between 2012 and 2016. This value is then compared against efficiency models to arrive at the level of AOM to be recovered through tariffs.[77, 78]

Rates of return (WACC) for the regulated asset base in 2020-2022 were set by CREG Decision 007 of 2020. The rates of return are 11.64% (2020), 11.50% (2021), and 11.36% (2022).[79]

3.3 History of restructuring and recent developments

Prior to 1994, Colombia's energy sector was owned and managed by the state. Reforms were triggered by a variety of challenges that the sector was experiencing. These challenges included tariffs that could not cover the cost of service, mounting levels of government debt to finance the sector, stagnation in the growth of coverage, poor service quality, and power rationing due to supply deficits.[80]

Colombia's Constitution of 1991 established competition and free entry in the field of public services as key principles for achieving efficiency in this sector. Pursuant to this Constitution, the

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75 Ropero Gutiérrez, Cesar Alejandro. "Comparación económica del cambio de metodología para remunerar la actividad de distribución de energía eléctrica: caso Colombia." *Universidad de la Costa, Trabajo de Grado para obtener el título Profesional de Ingeniero Eléctrico.* 2020. p. 60.

76 Ibid.

77 Ibid. p. 84.

78 CREG Resolución No. 015 de 2018. January 29, 2018.

79 CREG Resolución No. 007 de 2020. January 17, 2020.

80 Benavides, Juan and Ángela Cadena. "Mercado eléctrico en Colombia: transición hacia una arquitectura descentralizada." *FEDESARROLLO.* October 15, 2018. p. 14.

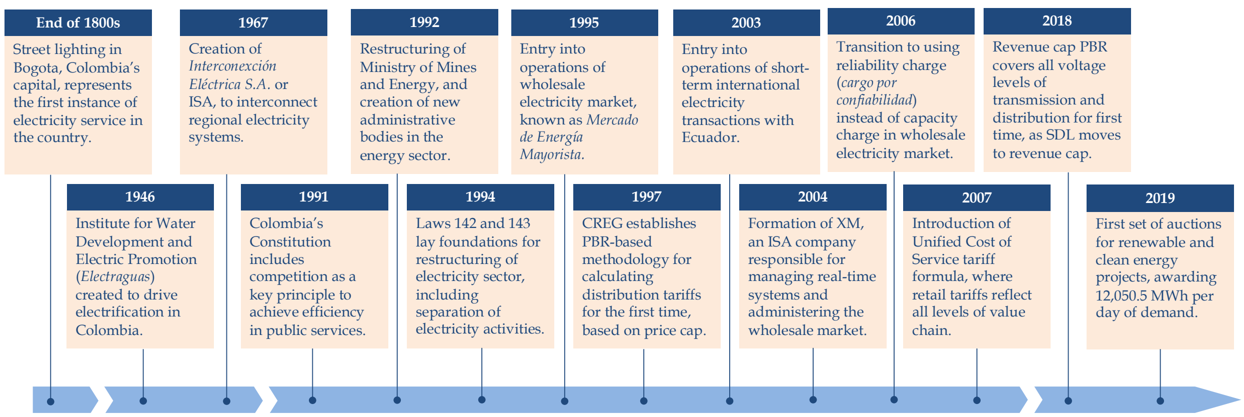
state aimed to transition towards regulating and monitoring, rather than administering, the provision of public services.

The Law of Public Utilities and the Law of Electricity (the "Laws"), both enacted in 1994, laid the regulatory foundations of a reformed electricity market. The key features of the Laws consist of:

- allowing participation of the private sector in public services;
- creating the conditions for competitive pricing in generation;
- requiring functional separation of generation, transmission, distribution, and retail activities; and
- setting the foundations and guidelines of the wholesale electricity market ("MEM", or *Mercado de Energía Mayorista*), which came into operation on July 20, 1995.

A timeline of key events in Colombia's electricity sector is presented in Figure 22.

Figure 22. Timeline of key events



Sources: CREG, UPME, XM, Zapata Lugo and Fajardo Villada.

A second major reform occurred in 2006, with the introduction of a reliability charge (*cargo por confiabilidad*) for generators and firm energy obligations ("OEFs" or *obligaciones de energía firme*) in the MEM. Prior to this, generators were compensated through a capacity charge (*cargo por capacidad*) scheme, which aimed to pay generators a fraction of anticipated revenues during drought years in advance and over time if they could, in theory, provide electricity during droughts.[81] In contrast, reliability charges represent the payments generators receive for having generation resources available to meet their firm energy commitments (OEFs).[82] OEFs are auctioned among generators and amount to a commitment from generators that they will provide a certain amount of energy during shortage conditions. The use of OEFs allows generators to count on stable remuneration for a set period of time, which they receive through end-users

[81] Santa María, Mauricio et al. "Capítulo 3. Comportamiento de los precios de electricidad en el Mercado Mayorist en Colombia: ¿qué dice la evidencia?" El mercado de la energía eléctrica en Colombia: características, evolución e impacto sobre otros sectores. *FEDESARROLLO.* October 2009. p. 7.

[82] Acolgen. *Análisis de la evolución del cargo por confiabilidad*. p. 5.

indirectly through the generation component of retail tariffs. The switch was intended to introduce competition (with generators aiming to provide firm energy at lowest possible cost), and to create a positive signal for investing in new capacity, among other aims.[83]

[83] Santa María, Mauricio et al. "Capítulo 1. Resumen ejecutivo: mensajes principales y recomendaciones de política." *El mercado de la energía eléctrica en Colombia: características, evolución e impacto sobre otros sectores.* *FEDESARROLLO*. October 2009. p. 12.

4 United Kingdom (next generation PBR)

Since privatization and deregulation in the 1990s, the United Kingdom ("UK") has experienced several iterations of market design and is currently structured around a bilateral market with a centralized balancing market. Its electricity retail market is also fully liberalized and consolidation among and between generators and retailers has created large energy companies. Moreover, the UK implemented a performance-based ratemaking mechanism two decades ago that has adapted to meet changing circumstances.

4.1 Overview of the UK market

Generation

The UK[84] electricity market is a mature competitive market. It was among the first movers in power sector restructuring, and its market reform has generally been considered a success. Except for some old nuclear reactors, the entire sector is privately owned and fully unbundled, with privatization and unbundling beginning in the early 1990s. The current market design is structured around a bilateral market with a centralized balancing market. The electricity retail market is also fully liberalized, and consolidations between generators and retailers have created several large energy companies. There are just over 60 generators in the UK, led by Électricité de France ("EDF"), RWE, and Scottish and Southern Energy ("SSE"), as shown in Figure 23.

In 2019, grid-connected installed capacity in the UK reached 67 GW, with a peak load of 48 GW.[85] Thermal (i.e., coal and gas-fired) generation capacity in the UK accounted for 56% of the total power generation fleet. Electricity demand has been decreasing at an annual average rate of -1.6% since 2010. Renewable resources, which have been growing in the past few years, now supply nearly 37% of total generation (up from 2.8% in 2000). Projected coal and nuclear retirements, future growth in offshore wind generation, and an emphasis on sustainable development have created both opportunities and challenges in the UK electricity market.

The UK has a wholesale electricity market where generators sell electricity to suppliers through bilateral contracts, over-the-counter trades, and spot markets. It has been open to competition since 1990 with the creation of the Electricity Pool ("Pool"). The Pool was replaced with the New Electricity Trading Arrangements ("NETA") in England and Wales and subsequently by the British Electricity Trading Transmission Arrangements ("BETTA") in 2005, which extended the previous arrangements to Scotland.

Figure 23. UK snapshot

[84] In this case study, we refer to the electricity market in the UK, excluding Northern Ireland, which runs on a separate network.

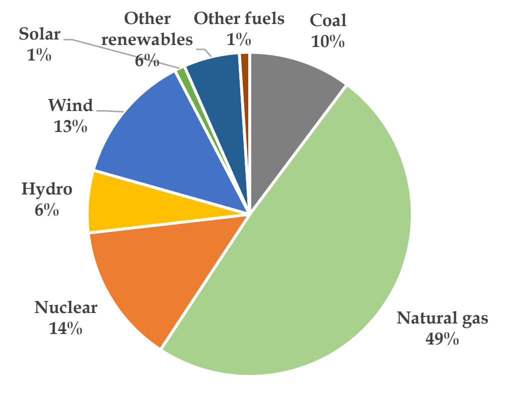
[85] Department for Business, Energy & Industrial Strategy. *Digest of UK Energy Statistics. Chapter 5: Electricity*. Available online at https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes.

United Kingdom

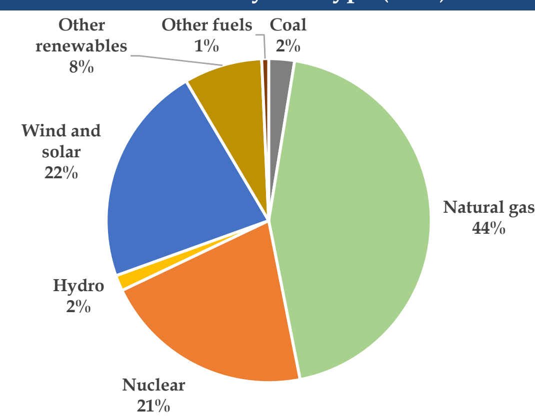
Key facts

Population (2019)	66.7 million
GDP growth (CAGR, 2014-2019)	3.5%
GDP per capita (2019)	US$ 42,330
Installed capacity (2019)	66.6 GW
Net generation (2020)	267 TWh
Peak demand (2019)	48.2 GW
Load growth (CAGR, 2014-2019)	-1.0%
No. of electric distribution companies	14
No. of electric transmission companies	3

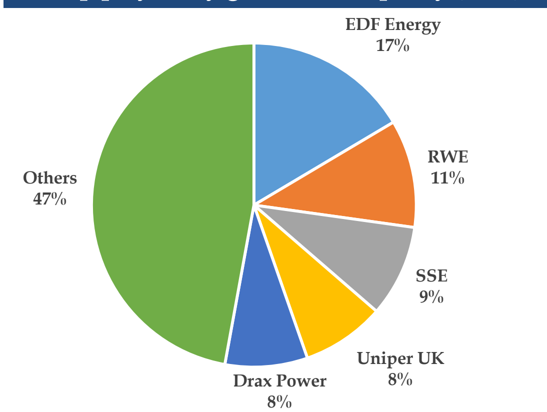
Installed capacity by fuel type (2019)



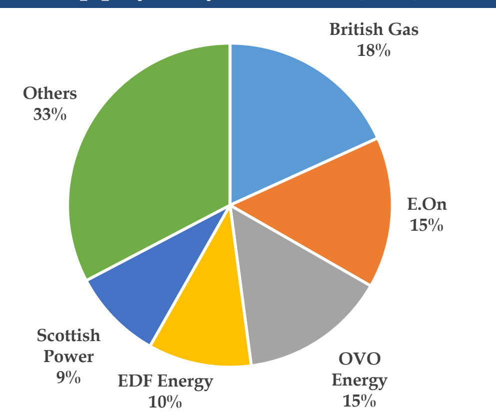
Generation by fuel type (2019)



Top players by generation capacity (2019)



Top players by retail sales (2019)



Source: Office for National Statistics; Department for Business, Energy & Industrial Strategy. Digest of UK Energy Statistics. Chapter 5: Electricity. Available online at https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes.

Transmission

The transmission assets are owned and maintained by three regional monopoly Transmission Owners ("TOs"), namely: National Grid Electricity Transmission plc ("NGET"), Scottish Power Transmission Limited ("SPTL"), and Scottish Hydro Electric Transmission plc ("SHET").[86] These three TOs must ensure that sufficient transmission capacity is available to the UK transmission network. National Grid Electricity System Operator ("ESO") is the sole System Operator of the electricity transmission grid and has the responsibility for ensuring that electricity supply and demand are balanced, and the system remains within safe technical and operating limits.

Distribution and retail

Currently, there are 14 distribution network operators ("DNOs")[87] in the UK and each is responsible for a distribution service area. They are regulated by the Office of Gas and Electricity Markets ("Ofgem") through license conditions and price controls. Most DNOs are part of holding companies, some of which are also involved in the generation and/or supply businesses.[88]

Electricity retail supply is legally separated from distribution. The major electricity suppliers include British Gas, E.On, OVO Energy, EDF Energy, and Scottish Power, who control nearly 70% of the market (see Figure 23).[89] Competition among suppliers was introduced to improve service quality to consumers, encourage consumer switching, and create pressure for lower and more innovative tariffs.

4.2 The UK's current institutional and legal framework

The energy sector in the UK is governed by the Department of Energy and Climate Change ("DECC"), a ministerial department, which became part of the Department for Business, Energy & Industrial Strategy in 2016. The electricity and gas markets are regulated by the Gas and Electricity Markets Authority ("GEMA"), which operates through Ofgem. This section provides an overview of the regulatory bodies in the UK energy market and their responsibilities.

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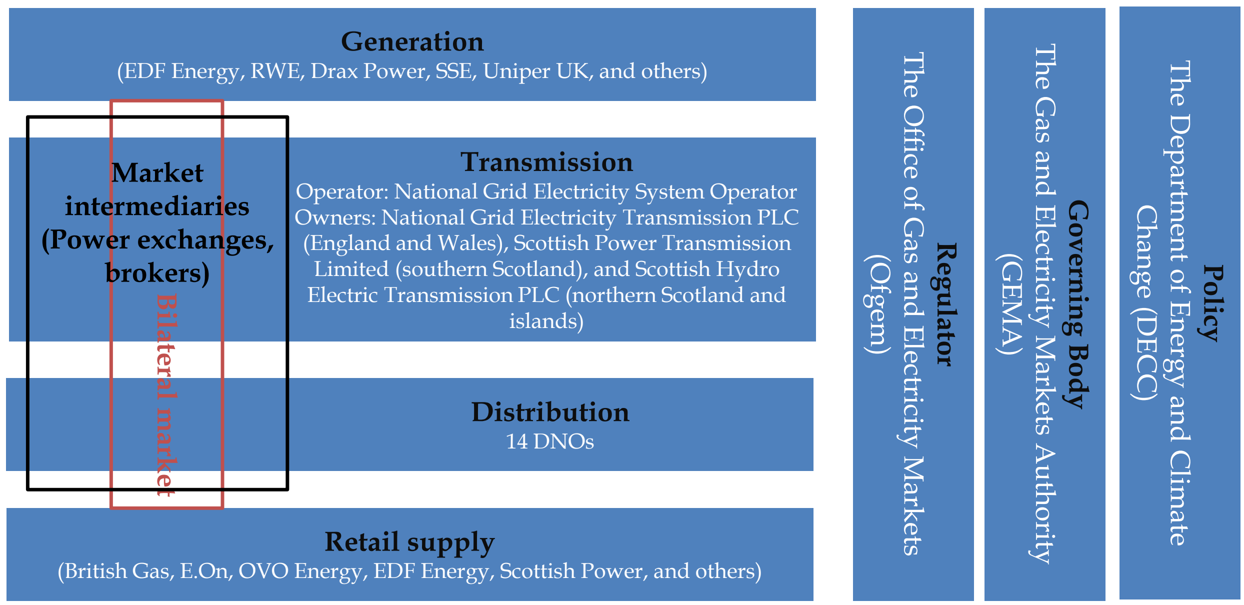
[86] These are the three Onshore Transmission Owners ("TOs"). There are also Offshore TOs.

[87] These DNOs include: Electricity North West Limited, Northern Powergrid (Northeast) Limited, Northern Powergrid (Yorkshire) plc, London Power Networks plc, South Eastern Power Networks plc, Eastern Power Networks plc, Scottish Hydro Electric Power Distribution plc, Southern Electric Power Distribution plc, SP Distribution Ltd, SP Manweb plc, Western Power Distribution (East Midlands) plc, Western Power Distribution (West Midlands) plc, Western Power Distribution (South West) plc, and Western Power Distribution (South Wales) plc.

[88] The 14 DNOs are owned by six companies. SSE, which owns Scottish Hydro Electric Power Distribution plc and Southern Electric Power Distribution pls, is active in generation (UK), supply (NI), and distribution (UK). ScottishPower Energy Networks (which includes SP Distribution Ltd and SP Manweb plc) is owned by Scottish Power, who operates as a retailer in the UK. Northern Powergrid is owned by Berkshire Hathaway. (Source: Ofgem. *The GB electricity distribution network.*)

[89] Department for Business, Energy & Industrial Strategy. Digest of UK Energy Statistics. Chapter 5: Electricity. Available online at https://www.gov.uk/government/collections/digest-of-uk-energy-statistics-dukes.

Figure 24. UK electricity market structure



Source: Ofgem <https://www.ofgem.gov.uk/electricity>

4.2.1 Regulation and policy setting

DECC sets the electricity policies in the UK. It is responsible for ensuring that the market has a secure supply of energy by promoting policies that encourage investments in the UK's energy infrastructure. It also ensures the delivery of low-carbon energy at the least cost to consumers.

Ofgem is the executive arm and the independent economic regulatory body of the gas and electricity markets in the UK.[90] It is responsible for protecting consumers by promoting competition and regulating monopoly companies. Ofgem derives its regulatory powers from the Gas Act 1986, the Electricity Act 1989, the Competition Act 1998, the Utilities Act 2000, and the Enterprise Act 2002.[91] Ofgem's functions include administering a price control regime for network operators, monitoring the quality of services by setting guaranteed standards of performance, and deciding upon proposed industry code changes. Ofgem operates under the direction and governance of **GEMA**, which makes all major decisions and sets policy priorities for Ofgem.[92]

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[90] The Utility Regulator regulates the electricity, gas, and water sectors in Northern Ireland.

[91] Ofgem <https://www.ofgem.gov.uk/about-us/who-we-are>

[92] GEMA consists of non-executive and executive members. It determines the strategies, sets policies, and takes decisions on various matters such as price controls and implementation. Its powers are provided for under the Gas Act 1986, Electricity Act 1989, Competition Act 1998, Utilities Act 2000, and the Enterprise Act 2002.

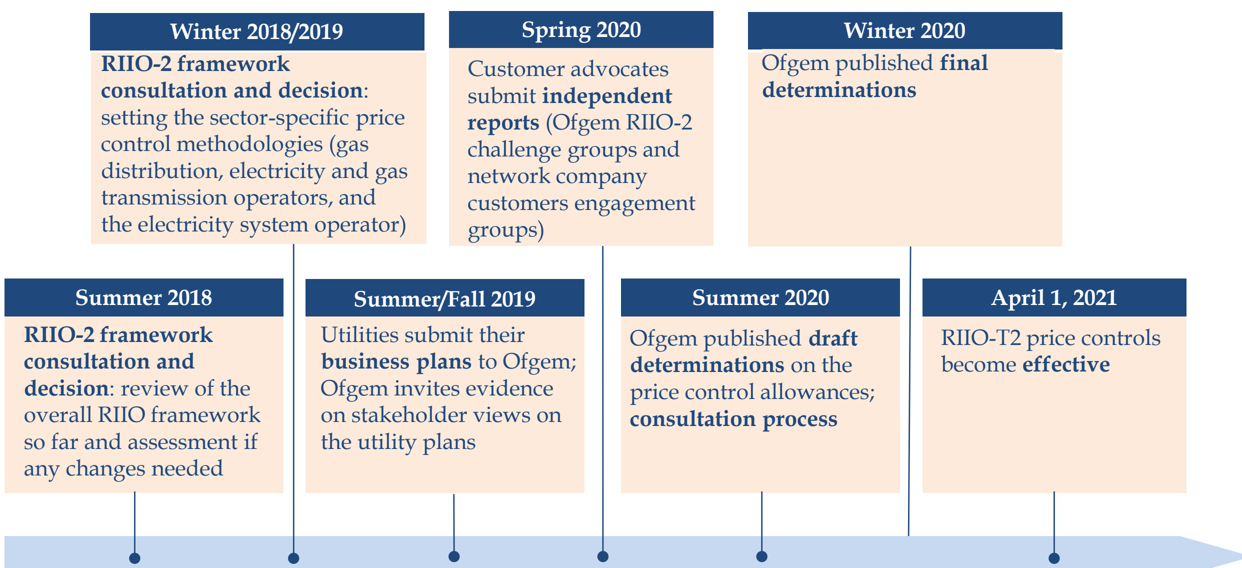
4.2.2 Regulatory oversight of energy network industries

In addition to controlling the transmission and distribution networks through license conditions, **Ofgem** also regulates these two sectors through price controls.[93] The UK uses PBR regime in setting these price controls for the natural monopoly networks. Introduced in the early 1990s, PBR was implemented in the form of an RPI-X price cap mechanism, where the RPI is the inflation in the Retail Price Index and X is an efficiency factor target. This means that electricity transmission, distribution and delivery rates were allowed to increase by inflation minus expected efficiency gains.

From 2013 (for transmission services) and from 2015 (for electricity distribution services) a modified framework was implemented to better meet future investment and innovation needs. This framework is known as RIIO, where **R**evenue = **I**ncentives + **I**nnovation + **O**utputs. It was developed over the course of a multi-year stakeholder consultation process that started in 2008.

The ratemaking process in the UK typically takes about 3 years from the time of Ofgem's issuance of key issues for the next price control review to the implementation of the arrangement. Figure 25 shows the process during the most recent 2nd generation price control review under the RIIO framework for the transmission sector (known as RIIO-T2).[94] During the price control review, each utility is required to submit detailed forward-looking business plans, which serve as the basis of analysis and review by technical experts at Ofgem and stakeholders.

Figure 25. Ratemaking process for RIIO-T2



Source: Ofgem <https://www.ofgem.gov.uk/regulating-energy-networks/2021-price-control-review-riio-t2>

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93 Within the same framework, Ofgem also regulates gas transmission and distribution networks, and the electricity system operator.

94 RIIO-T1 covered the 2013-2021 period. RIIO-T2 will run from 2021 to 2026.

4.2.2.1 Transmission sector under the RIIO model

Under the RIIO model, the transmission operators are expected to deliver outputs that are set during the transmission price control review. A list of these outputs and other key components is shown in Figure 26 below. Several of the incentives are linked to the percentage of allowed revenue.

Figure 26. Key components of RIIO-T2

Category	Output / Component	Features / Incentives / Challenges
Customer engagement	Ofgem established Challenge Groups; Companies are required to establish Consumer Engagement Groups (DNOs), User Groups (TOs)	No financial incentive as appropriate performance metric can't be defined
Quality of Service	* License Obligations * Price Control Deliverables: - Service level outputs - Performance level outputs	Output Delivery Incentives: financial and reputational consequences for out- or underperformance Consumer safeguards if specific investments are not Delivered
Efficient Cost of Service	Network companies under RIIO-T2 forecast GBP 24 bn of total expenditure – Ofgem has allowed GBP 20.3 bn of baseline total expenditure, i.e. 15% below proposed	TOs are expected to achieve annual 1.2% efficiency improvements
Efficient Financing	Lowest ever WACC allowance for TOs, cost of debt and cost equity are indexed to protect against forecast error: - Capital Asset Pricing Model analysis **minus** 0.25% adjustment as outperformance expectation for equity investors for the cost of equity - Index of utility bond yields **plus** 0.25% allowance for transaction and liquidity costs for the cost of debt	Allowed ROE: 4.30%, outperformance incentives: 0.25%, for a total ROE of 4.55% (at notional gearing of 60%) Allowed return on debt: 1.82% Allowed return on capital: 2.81%
Managing uncertainty	Totex are approved for demonstrated need, certainty and efficient delivery projects. Uncertainty mechanisms: - volume drivers: adjusted for actual volumes; - re-opener mechanisms: if changes are necessary when more certainty is available; - Pass-through mechanisms: for limited control costs; - Indexation: to protect against forecast error; - Use-it-or-lose-it allowances: when need is identified, but the costs are not certain yet (e.g. cyber security)	Over 50% of Totex are subject to Price Control Deliverables; Re-opener applications are subject to materiality threshold of 0.5% of base revenues; Input prices are subject to Real Price Effect adjustments (e.g. labor and materials)
Path to Net Zero* and Innovation	Flexibility to facilitate investments for Net Zero and efficient cost of service Clear certainty: base allowance Unclear certainty: uncertainty mechanisms to allow investments when certainty improves	A variety of re-opener mechanisms to address changes in different policy and other areas (e.g. Net Zero policies, technological changes, gas and heating policies, demand and generation connection volume, and others)

* On June 27, 2019, the UK set a legally binding target to reduce emissions to net-zero by 2050 (as required under the Climate Change Act 2008, as amended by the Climate Change Act 2008 (2050 Target Amendment) Order 2019 (SI 2019/1056)).

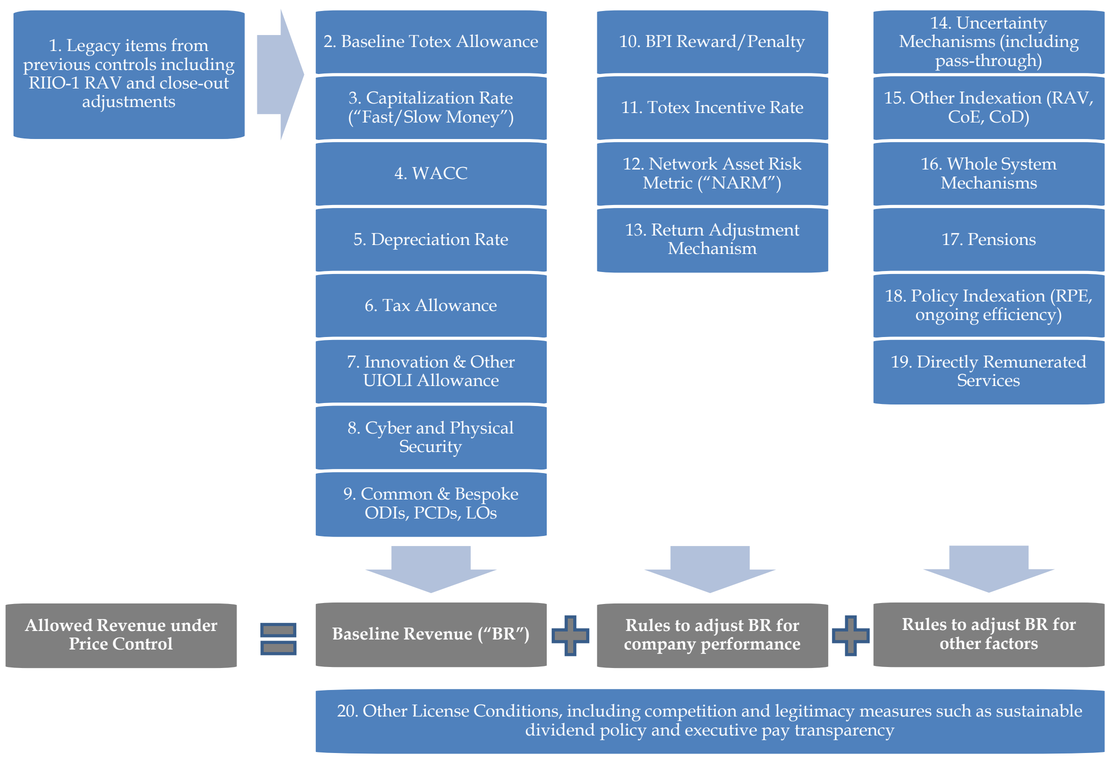
Source: Ofgem. *RIIO-T2: Final Determinations*. December 8, 2020.

Ofgem reviews the TOs' capex forecasts to ensure that projected investments are adequate to maintain the operation of the network and to ensure that customers do not carry the costs of unnecessary investment or any operational inefficiency. Prior to the start of the regulatory period, TOs (as well as DNOs) are required to submit business plans that include, among other data, the utilities' forecasts for network replacement and capacity additions for the next five years. For the forecasted network replacement, Ofgem evaluates each utility's forecasts against its own asset replacement policies in the past and against the expenditure forecasts of other utilities, considering the age profile of assets on the individual networks.

Financial models are also used by Ofgem and its consultants to determine whether the regulated energy network is financeable under the proposed control. Financeability is assessed using a range of different financial ratios along with qualitative assessment. If there are concerns, adjustments can be made to the control to ensure that the network can finance its functions.

The UK's PBR regime employs a "building blocks" approach that calibrates the terms of the indexing formula based on forward-looking revenue requirements of each regulated utility over the term of the price controls. In particular, revenue requirements are set based on estimates of the likely capital and operating costs and return of and return on an efficient asset base. Actual allowed revenues for each utility vary depending on how well it performs against a number of incentives. Figure 27 shows the components of revenue requirements under the UK's building blocks approach.

Figure 27. Components of the Allowed Revenues



Notes: RAV – Regulatory Asset Value; UIOLI – Use-It-Or-Lose-It; ODI – Output Delivery Incentive; PCD – Price Control Deliverable; LO – License Obligation; BPI – Business Plan Incentive; CoE – Cost of Equity; CoD – Cost of Debt; and RPE – Real Price Effects.

Source: Ofgem. *RIIO-T2 Draft Determinations.*

4.2.2.2 Distribution sector under the RIIO model

The distribution sector is currently under the RIIO-ED1 price control, which began in 2015 and will run until 2023. The consultation process to determine the framework and rates for RIIO-ED2 commenced in 2019 and is expected to produce final determinations by the end of 2022. RIIO-ED2 is scheduled to be in effect from 2023 to 2028.

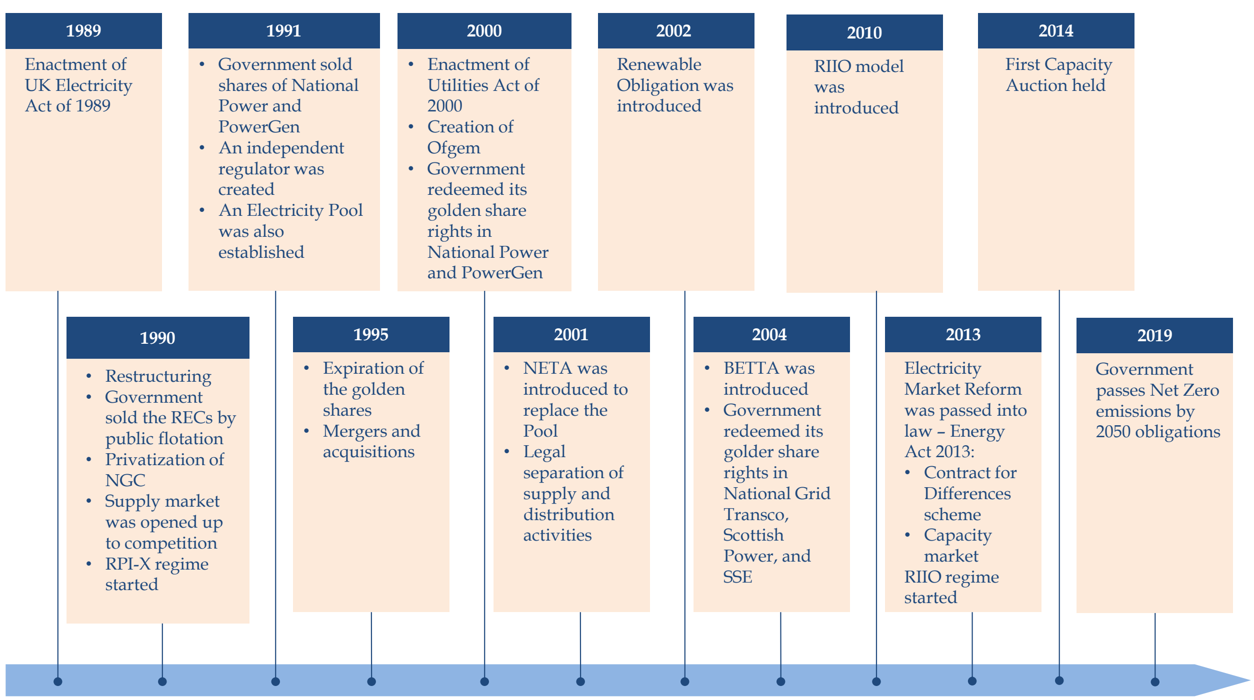
4.2.2.3 Generation and retail sectors

Unlike the transmission and distribution sectors, the generation and retail markets are fully liberalized with no price controls. Retail prices are set by energy suppliers based on their costs and other factors related to their business and market forces. Ofgem's role in these two unregulated sectors is mainly limited to monitoring, although it also approves or vetoes changes to market rules and transmission access and charges.

4.3 History of restructuring and recent developments

The UK electricity market was one of the first to be restructured and unbundled in the world (after Chile, which reformed its market in the early 1980s). The full sector reform included restructuring, privatization, regulation, and competition. The UK's experience shows that having clear objectives for the restructuring program, providing for mechanisms to facilitate the transition, and establishing an independent regulator are vital components to restructuring efforts. This section discusses the context behind the UK's restructuring decisions, and how its current regulatory institutions developed.

Figure 28. Timeline of key events in the UK's electricity market evolution



<u>**Prior to restructuring**</u>

Pre-restructuring, the electricity industry structure in the UK was characterized by the vertical integration of generation, transmission, distribution, and supply. The Central Electricity Generating Board ("CEGB"), which owned and operated the generation stations and transmission system in England and Wales, dominated the nationalized electricity industry. Electricity produced by CEGB was sold in bulk to the 12 Area Boards, which were separate public corporations responsible for the distribution and retail of electricity in their respective regions. There were two vertically integrated boards (called the Scotland Electricity Boards or "SSEBs") in Scotland.

An Electricity Council—composed of three full-time members, the chairs of the 12 Area Boards, and three representatives from the CEGB—played the primary role of coordinating matters of industry-wide concern. Its duties included advising the government on behalf of the industry as a whole, and promoting and assisting the maintenance and development of an efficient and economical system of electricity supply.[95]

Restructuring

In February 1988, the Government published its proposal to restructure and privatize the electricity supply industry in England and Wales. The restructuring was driven by broader political objectives to restructure the wider economy and improve efficiency by privatizing utility services, including telecommunication and electricity sectors.

The UK Electricity Act of 1989—enacted into law on July 1989—laid the legislative foundations for the restructuring and privatization of the electricity sector in the UK. Provisions in the Act included change in ownership (from the state to private investors) and the introduction of competitive markets.

The new structure was introduced on March 31, 1990. England and Wales restructured their electricity industry, and the 12 Area Boards were transferred to the 12 Regional Electricity Companies ("RECs"), serving the same regional areas of England and Wales. The CEGB's assets were split into 3 generating companies (National Power, PowerGen, and Nuclear Electric)[96] and a transmission company (National Grid Company, or "NGC").

Scotland restructured its electricity market separately from England and Wales. The SSEBs were replaced by the ScottishPower and Scottish Hydro-Electric, while the nuclear stations were placed in a state-owned company called Scottish Nuclear.[97] Vertical integration was maintained in the new structure in Scotland.

Privatization

The Government sold the RECs in December 1990 by public flotation in the stock market. 55% of the shares went to individual investors, 30% to institutional investors, and 15% to foreign

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95 Simmonds, Gillian. "Regulation of the UK Electricity Industry." *Centre for the Study of Regulated Industries*. May 2002.

96 Nuclear power stations were transferred to Nuclear Electric.

97 Scottish Nuclear became part of British Energy in 1996.

investors.[98] The government also retained some rights (which were referred to as the "golden shares") in the RECs until March 1995.

The NGC was also privatized in December 1990. Ordinary shares in the NGC were transferred to the RECs. The Government auctioned off its 60% share in the two generating companies—National Power and PowerGen—in March 1991. The Government held a 40% share in these two generation companies until March 1995 (which was extended until 2000). The two Scottish companies (Scottish Hydro-Electric and Scottish Power plc) were also floated in June 1991.

Creation of the regulator

The UK Electricity Act of 1989 established an independent regulator of the electric power sector, headed by the Director General of Electricity Supply, which was supported by the Office of Electricity Regulation ("OFFER"). OFFER was created not only to regulate the newly privatized electricity industry but also to be an independent entity from the Parliament. This was done to protect OFFER's regulatory decisions from political control, subsequently providing long-term regulatory certainty and encouraging market entry and investment.[99]

Establishment of the electricity pool

An Electricity Pool ("the Pool") was also established under the Electricity Act of 1989. It was set up to facilitate a competitive bidding process. NGC operated the Pool and administered its settlement system on behalf of pool members. Generators were required each day—on a day-ahead basis—to provide details of the price at which they were prepared to make generation available. NGC provided a forecast of system demand on a day-ahead basis, prepared a schedule of generation to meet this estimate, and determined the pool price.

Acquisitions and consolidations

After restructuring the electricity sector by separating generation, transmission, and distribution, the Government focused on increasing the level of competition among generators. The generators divested some of their generating assets to new market participants to avoid referral to the Monopolies and Mergers Commission, and to gain permission to merge with electricity retailers. Subsequently, horizontal and vertical consolidations in the market led to the creation of the "Big Six" energy suppliers in the UK, and eventually five dominant players.

Opening up of the supply market to competition

The supply market was opened up to competition in three phases:

- **first wave** (April 1990) – customers with a peak load greater than 1 MW were able to choose their suppliers;

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[98] EIA. Electricity Reform Abroad and US Investment. September 1997. p. 24.

[99] Department of Energy & Climate Change. *Ofgem Review Final Report*. July 2011. p. 8.

- **second wave** (April 1994) – customers with peak load of more than 100 kW were able to choose their supplier; and
- **third wave** (September 1998 to May 1999) – the remaining part of the electricity market (customers with peak load below 100 kW) was opened up to competition.

Merging of the gas and electricity regulators into a single regulator

The electricity sector's institutional framework was further reformed with the enactment of the Utilities Act of 2000. Key provisions of the Act included the replacement of an individual regulator (the Director General of Electricity Supply) with a regulatory board, GEMA, and combining them into one regulatory office for both the gas and electricity sectors—Ofgem.

New Electricity Trading Arrangements ("NETA")

In 2001, NETA was introduced to replace the Pool.[100] NETA relied on bilateral contracts between generators and suppliers to provide power, with the NGC running a balancing market to settle real-time imbalances between generation and demand. The introduction of NETA aimed to solve the perceived problem of price manipulation by major generators and encouraged long-term bilateral contracts (between the generators and the suppliers).

Legal separation of supply and distribution activities

The Utilities Act 2000 also split the supply and distribution activities, and required these businesses to be licensable separately. This means that the requirements for the companies to unbundle came not directly through legislation as such, but rather through a change in the conditions of their licenses. Furthermore, the Act introduced a UK-wide license and removed the use of public electricity suppliers ("PES") and second-tier licenses. This allowed all suppliers to supply customers nationwide.

Renewables Obligation

In April 2002, the Renewables Obligation ("RO") was introduced in England and Wales and Scotland. Under the RO mechanism, electricity suppliers were required to source an increasing proportion of electricity from renewable sources, rising from a 3% commitment in 2012 to 48% in 2019/2020.[101] This obligation could be achieved by presenting Renewable Obligation Certificates ("ROCs") or paying into a 'buy out' fund (for example, the buy-out payment for 2019/2020 was set at £48.78 per ROC).[102] Owners of renewable units could obtain ROCs for the renewable energy

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[100] Some of the key differences between NETA and the Pool include: (i) self-dispatch – each generator under NETA was responsible for determining the level of output from its generation units whereas under the Pool, the NGC scheduled on behalf of the generator, (ii) paid as bid – all trades were valued at the bid price for that trade rather than at the bid price for the most expensive trade for a given time period, (iii) ex-post price – the cash-out price was determined after the event rather than in the pool, to name a few.

[101] Department for Business, Energy and Industrial Strategy. *The Renewables Obligation for 2019/20*. September 2018.

[102] Ofgem. *Renewables Obligation Annual Report 2019-20*.

they generated through accreditation of their generating station and by meeting the requirements for ROC issuance.

British Electricity Trading and Transmission Arrangements ("BETTA")

The Energy Act 2004 enabled the expansion of NETA to include the Scottish transmission grid, forming the single UK-wide set of arrangements for trading energy known as the BETTA. NGC became the single system operator in England, Wales, and Scotland. BETTA was established to overcome the separation of the trading arrangements between England and Wales and Scotland and introduce a common set of wholesale electricity trading and transmission arrangements.

RPI-X cap regime

With the separation of the regulated (transmission and distribution) and unregulated (generation and supply) businesses, the regulator established a price cap mechanism called the RPI-X cap, to protect customers in the transmission and distribution sectors where there is a lack of competition. The RPI-X cap was set in such a way that utilities needed to make efficiency gains to maintain profitability. Efficiency improvements achieved over and above those assumed in the price cap were to be retained by utilities.

The framework for the electricity price control changed significantly when compared with the regime that was put in place at privatization.[103] Furthermore, the objectives of the price control changed and adapted to the needs of the time. In the past, the incentives in the UK were focused on improvements in cost efficiency. Over time, additional objectives—such as service quality and environmental or social-related targets—were introduced. A target is set *ex ante* and the utilities are rewarded (penalized) if they outperform (underperform) relative to the goals set during the price review.[104] Moreover, Ofgem also provided several incentives to encourage quality customer service and efficient investments in infrastructure. These incentives included the low carbon networks fund, distributed generation incentive, customer satisfaction incentive, customer reward scheme, innovative funding incentive, and the information quality scheme ("IQI").

Ofgem used the IQI[105, 106] scheme to further encourage TOs and DNOs to reveal their efficient costs and discourage inflated capital expenditure forecasts through a reward and penalty

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103 For more information about the changes for each price control, see Ofgem's *History of Energy Network Regulation*. February 27, 2009. Available online at https://www.ofgem.gov.uk/ofgem-publications/51984/supporting-paper-history-energy-network-regulation-final.pdf

104 DNOs will be rewarded or penalized according to the following parameters: (1) customer interruptions (customer minutes lost through interruptions each year), (ii) customer satisfaction, (iii) percentage of units that are lost in distributing electricity to customers, and (iv) efficiency of connection of distributed generation.

105 Also referred to as the "sliding scale incentive" in previous regulatory periods.

106 The IQI scheme was intended to mitigate the information asymmetry between Ofgem, the regulator, and the distributors in capex forecasting and provide incentives to distributors to provide the most efficient level of capex for the requirements of the network over the regulatory period. It aims to reduce the risk of under-investment, reduce the opportunity for distributors with high capex allowances to make high returns for underspend, and reward distributors with low capex allowances for delivering against this.

framework.[107] It provided incentives for a TO or DNO to not only propose efficient and prudent costs as part of its regulatory review, but also to realize timely investment when needed (rather than to game the system so as to time investment with PBR terms). The IQI provided incentives by giving additional income to TOs or DNOs whose forecasts were close to Ofgem's assessment. This incentive was realized by providing TOs and DNOs with a higher incentive rate than those distributors with higher capex forecasts, thereby increasing their reward for outperformance.

The IQI, which became a key feature of the UK approach, specifically also addresses the information asymmetries problem that regulators have historically been concerned with under cost of service and also, to some degree, under the building blocks approach.

<u>RIIO model</u>

As discussed in Section 4.2.2, Ofgem launched a comprehensive review of the RPI-X framework that it used to regulate the electricity and gas networks in March 2008. The review concluded that there was a need for a new regulatory framework built on the elements of the previous approach, while incorporating new elements. Although the RPI-X framework was a success, Ofgem acknowledged that the regime did not provide sufficient incentives for the network companies to make adequate investments which can accommodate future needs.

On October 2010, Ofgem introduced the RIIO model. It builds on the success of the previous RPI-X regime but meets the investment and innovation challenge by placing more emphasis on incentives to drive the innovation needed to deliver a sustainable energy network. Instead of incentivizing the regulated companies to improve their operating efficiency, RIIO is designed to "reward companies that innovate and run their networks to better meet the needs of consumers and network users."[108] The RIIO model measures key delivery outputs such as customer satisfaction, reliability and availability, safety, connection terms, environmental impact, and social obligations required by the government. Companies that deliver these outputs would earn a higher return relative to the previous RPI-X regime. Poorly performing companies, however, would "face much more intrusive and heavy-handed regulation and lower returns."[109]

Ofgem completed the first price review of RIIO for the transmission companies in early 2013 and implemented RIIO for the distribution companies in 2015. Ofgem's 2019/20 Annual Report on RIIO-ED1 found that all DNOs are on track to meet or exceed the output targets, while one DNO group has already overspent their available total allowance (2015-2023 period) and another DNO group is expected to exceed their allowance by the end of RIIO-ED1.

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[107] The Information Quality Incentive Mechanism is determined by the following formula:

(Allowed Expenditure – Actual Expenditure) * Efficiency Incentive + Additional Income

[108] Ofgem. *RIIO – a new way to regulate energy networks*. Factsheet 93. October 2010. p. 2.

[109] Ibid. p. 2.

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