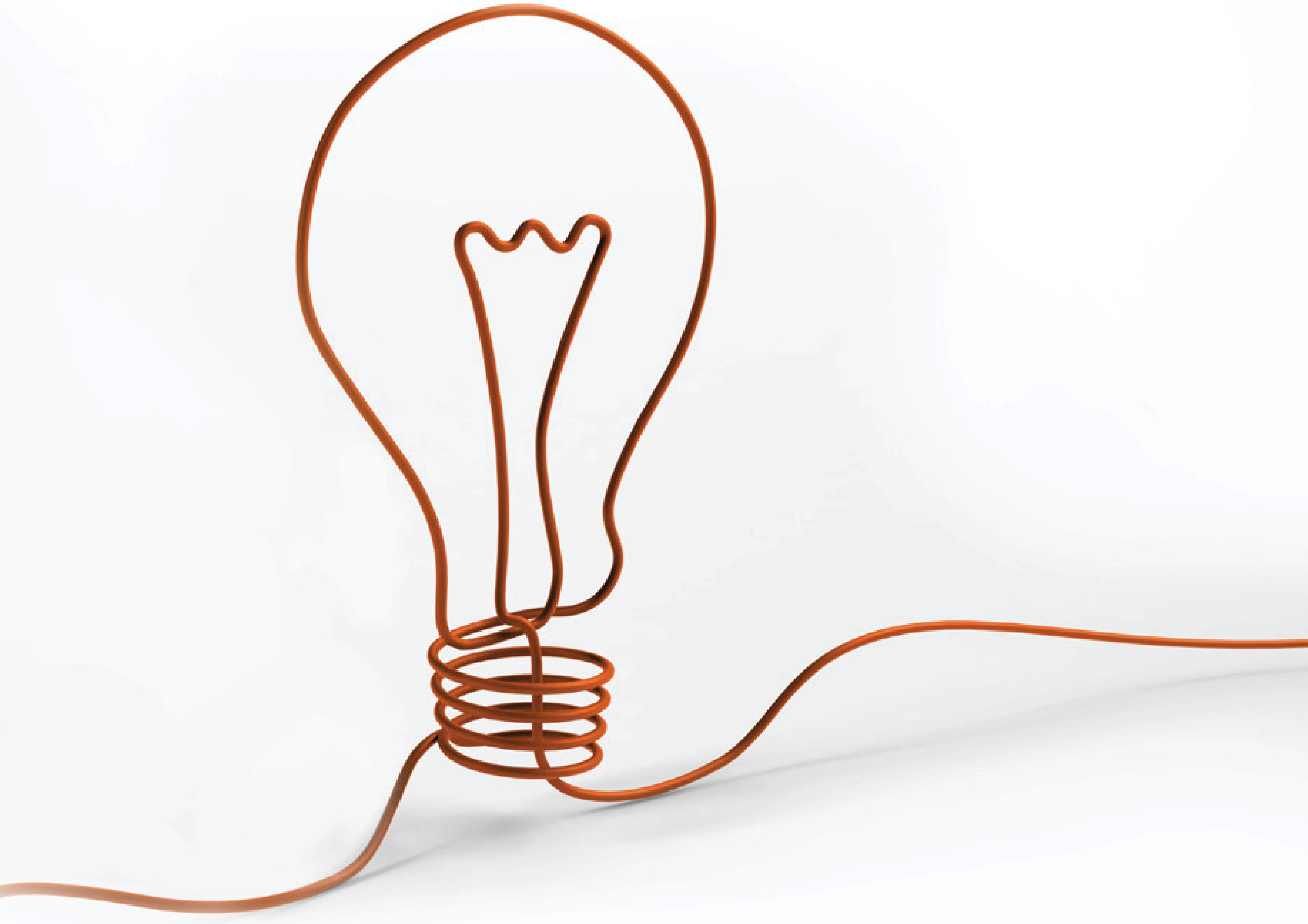
Georgia's Energy Sector
Changes Create Opportunities



Georgia | Energy
March 6, 2019

Eva Bochorishvili
Head of Research | evabochorishvili@gt.ge | +995 32 2401 111 ext. 8036

Mariam Chakhvashvili
Senior Analyst | mchakhvashvili@gt.ge | +995 32 2401 111 ext. 7897

Table of Content

Terms and Definitions

ADB – Asian Development Bank
ATC – Available Transfer Capacity
CAGR – Compound Annual Growth Rate
CFD – Contract for Difference
COGS – Cost of Goods Sold
DAM – Day-ahead Market
DSO – Distribution System Operator
EAV – Export Allowed Volume
EBITDA – Earnings Before Interest, Taxes, Depreciation and Amortization
EBRD – European Bank for Reconstruction and Development
EIB – European Investment Bank
EnC – Energy Community; International organisation which brings together the European Union and its neighbours to create an integrated pan-European energy market
EPIAS – Turkish Energy Exchange
ESCO – Electricity Market Operator in Georgia
EU – European Union
FDI – Foreign Direct Investments
GC – Guaranteed capacity
GEMM – Georgian Electricity Market Model
GeoStat – National Statistics Office of Georgia
GNERC – Georgian National Energy and Water Supply Regulatory Commission
GoG – Government of Georgia
GSE – Georgian State Electrosystem
HIPP – Hydropower Investment Promotion Project
HPP – Hydropower Plant
IDM – Intraday Market
IFC – International Finance Corporation
IPI – Industrial Production Index in Turkey
KfW – German development bank
MCP – Market Clearing Price in Turkey
MCQ – Market Clearance Quantity in Turkey
MoESD – Ministry of Economy and Sustainable Development of Georgia
MOU – Memorandum of Understanding
NEMO – Nominated Electricity Market Operator
NPP – Nuclear Power Plant
OPIC – Overseas Private Investment Corporation
OTC – Over-the-counter
PP – Power Plant
PPA – Power Purchase Agreement
PPP – Public-Private Partnership
TDA – Transmission and Dispatch Agreement
TPP – Thermal Power Plant
TSO – Transmission System Operator
TYNDP – Ten-Year Network Development Plan of Georgia 2018-28, prepared by GSE
USAID – The United States Agency for International Development
WACC – Weighted Average Cost of Capital
WB – World Bank
WPP – Wind Power Plant

kV – Kilovolt, unit of voltage
kW – Kilowatt, unit of power
kWh – Kilowatt hour, unit of energy

1 MW = 1,000 kW
1 GW = 1,000,000 kW
1 TW = 1,000,000,000 kW

1 MWh = 1,000 kWh
1 GWh = 1,000,000 kWh
1 TWh = 1,000,000,000 kWh

Executive summary

Electricity is a capital-intensive sector with reasonable profits. Georgia's investor-friendly regulations, upgraded transmission networks and export opportunities have attracted substantial investment in recent years. The energy sector was the second-largest FDI recipient in 2007-17. The sector's EBITDA margin averaged 19% in 2012-17, above the business sector's level of 13%.

Electricity consumption in Georgia increased by 1.6x (4.4% CAGR) in 2008-18 and is expected to double by 2030. Electricity consumption is correlated with GDP, and in recent years growth in consumption has been driven by the non-residential sector. We project average annual growth of 5.7% in consumption in 2019-30, with the commercial sector being the key driver. As a result, by 2030, electricity consumption is expected to almost double and reach 24.5TWh.

Despite growth, generation capacity is still insufficient to satisfy demand. Since 2012, Georgia's installed capacity has increased by 25.3%, reaching 4.2GW in 2018. However, this was not enough to satisfy the growing demand, and Georgia became a net importer of electricity after having been a net exporter in 2007-11.

Georgia can become a net exporter of electricity again. Georgia has a solid pipeline of power plants, supported by government policy. Currently, 150 ongoing projects (installed capacity 5.4GW) are at various stages of development with identified investors. However, government policy has tightened significantly since 2016, which makes full implementation of the pipeline less likely. Nonetheless, we estimate that even partial implementation of these 150 projects will make Georgia a net exporter of electricity from 2021. Without the addition of new capacity, Georgia might need to import electricity, even in the summer months.

A new wave of reforms will result in a competitive market model and attract new types of investor. Georgia became a member of the Energy Community of EU and its neighbours in 2017, obliging it to harmonize its legislation with EU standards in the energy sector by 2025. This will eventually lead to a new market model with more competitive and transparent rules for power trading. This new energy market is expected to attract new types of investor, and it opens up the possibility of trading via Turkey to Eastern European countries, since Turkey is connected to the EU market and has a compatible market structure.

We expect fundamental changes in the energy market. Upcoming reforms should shorten the settlement period from one month to one day/hour, introduce an imbalance settlement mechanism, diversify power trading channels via the creation of day-ahead and intraday markets, increase the number of direct consumers, enhance power trading activities, and unbundle distribution and supply. In the context of these upcoming changes, we believe that future market prices will be dictated by neighbouring market prices and decisions on the integration of electricity generated from old regulated HPPs and from HPPs with Power Purchase Agreements.

Turkey remains an attractive export market for Georgia. Despite the dramatic fall in Turkish electricity prices in 2012-18, Turkey's geographic proximity, its compatible market structure, and the expected growth in prices will see it remain an attractive export destination, in our view. Another promising export market is Armenia, despite its small size, as the country is expected to face an electricity deficit due to the decommissioning of a nuclear plant in 2026.

1. Overview of Georgia's energy sector

Georgia has vast untapped potential for electricity generation. Georgia's hydropower potential is estimated at 40 terawatt hours, of which 25% is developed. Georgia also boasts wind, solar and other renewable energy resources, which are not yet sufficiently developed.

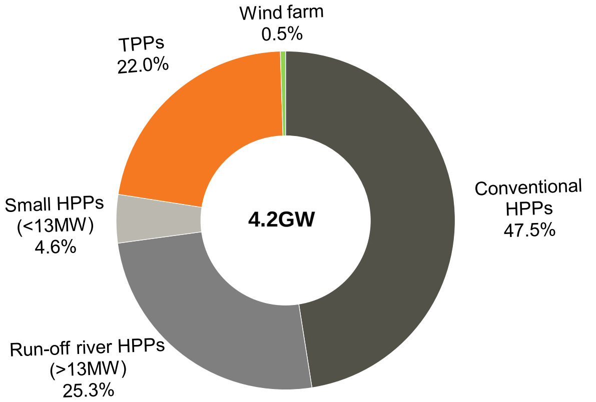
Energy sector was underdeveloped despite abundance of hydro resources and major transformation started since 2000s. Investor friendly regulations, improved payment discipline, simplified licensing, upgraded transmission networks and export opportunities attracted substantial investments and resulted in uninterrupted power supply.

Energy sector was the second largest FDI recipient, accounting for 13.2% of total, over 2007-17. On top of this, government, IFIs and local bank funding supported to substantial improvement in transmission and generation capacities.

Georgia's installed capacity totalled 4.2GW in 2018, up from 3.3GW in 2008. Currently, Georgia has 83 hydro (3,250MW), 6 thermal (924MW) and 1 wind (20.7MW) power plants. Despite the substantial growth in generation in recent years, it is still insufficient to fully satisfy the increased demand for electricity, due to opposite seasonality of consumption (peaks in winter) and generation (peaks in summer). In 2018, electricity supply stood at 13.7TWh, of which domestic generation was 12.1TWh and imports - 1.5TWh. From demand side, domestic consumption was 12.6TWh, transmission losses and self-consumption stood at 0.5TWh and 0.6TWh was exported.

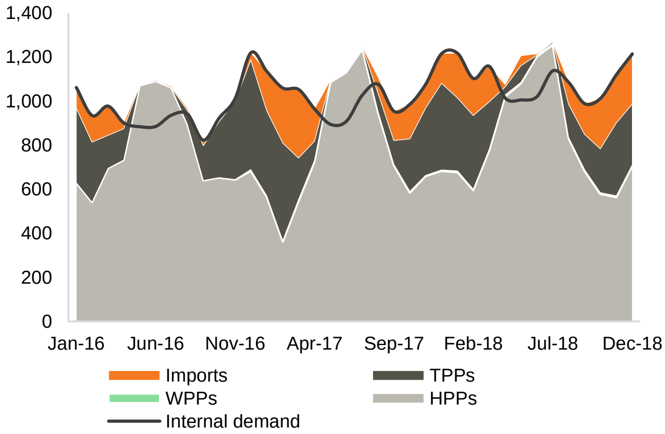
Electricity consumption in Georgia increased 1.6x to 12.6TWh over 2008-18, a CAGR of 4.4%. The growth of electricity consumption has escalated since 2016 driven by non-residential sector.

Figure 1: Installed capacity of Georgia, December 2018



Source: ESCO

Figure 2: Electricity supply and consumption, GWh

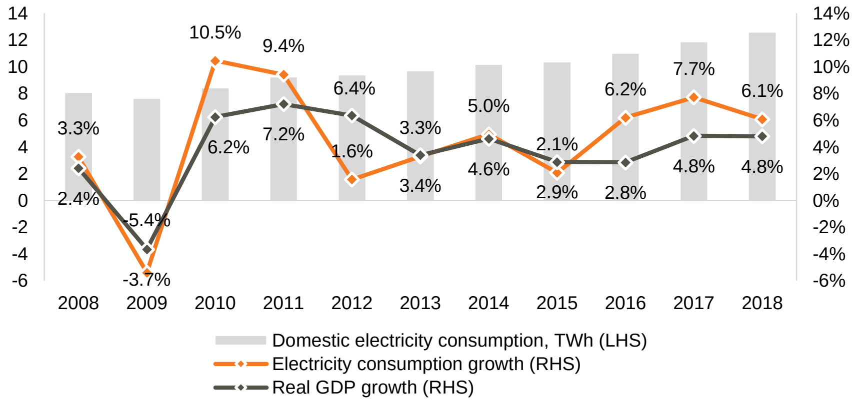


Source: ESCO

2. Drivers of electricity consumption in Georgia

Electricity consumption highly correlated with GDP growth, driven by non-residential consumers. The growth of electricity consumption has escalated since 2016 and has averaged 6.7% over 2016-18, almost twice the average 3.7% growth of 2007-15.

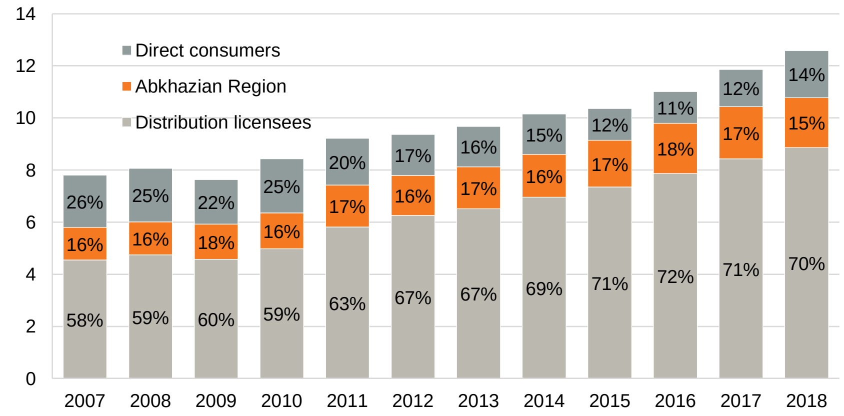
Figure 3: Electricity consumption and GDP dynamics



Source: ESCO, GeoStat

There are two distribution licensees in Georgia - Telasi and Energo-Pro Georgia. They supply electricity to almost all consumers in Georgia, except in the Abkhazian Region and a couple of direct consumers. Distribution licensees' electricity consumption has almost doubled since 2008 and reached 8.9TWh in 2018, increasing at a 6.5% CAGR. The Abkhazian Region's consumption increased at a CAGR of 4.2% over 2008-18, contributing on average 1.1ppts per annum to the overall consumption growth. The group of direct consumers included different companies over the years, thus annual changes are incomparable.

Figure 4: Electricity consumption, TWh

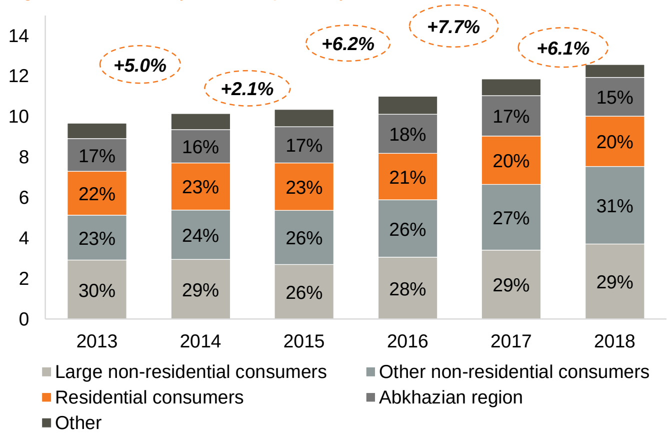


Source: ESCO

Non-residential end-users have the most substantial influence on the dynamics of overall consumption growth. Non-residential subscribers' share of consumption increased from 53% in 2013 to 60% in 2018, as their electricity consumption increased by a CAGR of 8.0%. For comparison, the residential sector's electricity consumption increased by a CAGR of 2.7% over 2013-18. In 2018, the non-residential sector contributed 7.5ppts to the overall 6.1% y/y growth, while residential sector's contribution was a mere 0.8ppts, and Abkhazian region and losses subtracted cumulatively 2.3ppts from growth.

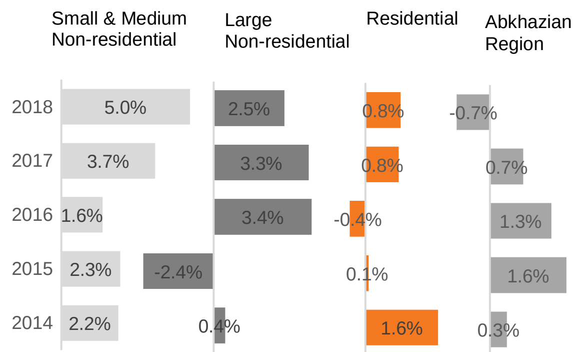
From non-residential end-users, small and medium-sized companies have increased their electricity consumption the most. The non-residential sector includes a vast range of companies from small non-profit organizations to large-scale companies, such as Georgian Manganese. To detect energy-intensive organizations role in overall electricity consumption growth, we have grouped non-residential entities into two broad categories: 1) large non-residential users and 2) other non-residential users combining small and medium-sized entities. Over 2013-18, the second category contributed most to the overall consumption growth, and medium-sized companies within this category had highest average growth rate (+13.1%), followed by small non-residential consumers (+10.3%). Large companies' electricity consumption increased by average 5.3% over 2013-18.

Figure 5: Electricity consumption by end-users, TWh



Source: GNERC
Note: Category "Other" includes self-consumption of stand-by power plants and losses in distribution grid

Figure 6: Contributions to overall consumption growth, ppts



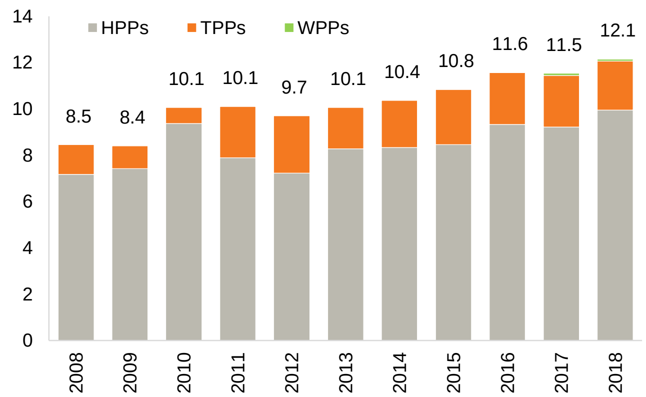
Source: GNERC
Note: Category "Other" includes self-consumption of stand-by power plants and losses in distribution grid

Electricity consumption and hydro generation in Georgia have opposite seasonality. However, the seasonality of consumption has been changing in recent years.

In 2018, 72.8% of electricity demand was satisfied by hydro power, only 0.6% was met by wind generation; the remaining deficit was filled by thermal power generation (15.5% of total supply) and imports (11% of total supply).

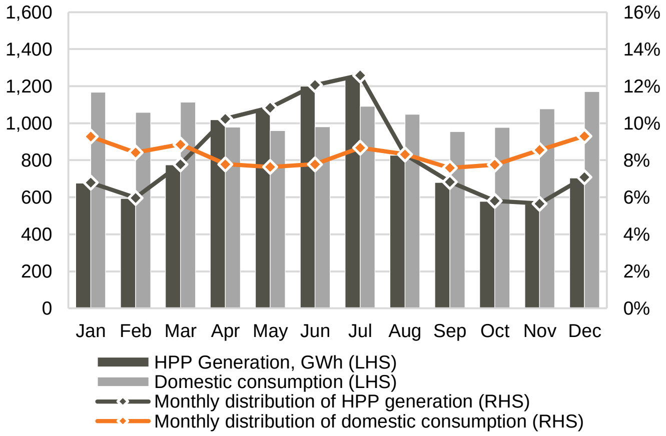
Hydro power generation is highly seasonal, with 44% of annual generation falling in the summer from May to August, while only 32.4% of annual consumption falls on this period. This opposite seasonality results in electricity exports in the summer and a need for thermal power generation or imported electricity in the winter. Electricity imports in Georgia increased by a 16.5% CAGR over 2012-18.

Figure 7: Electricity generation, TWh



Source: ESCO

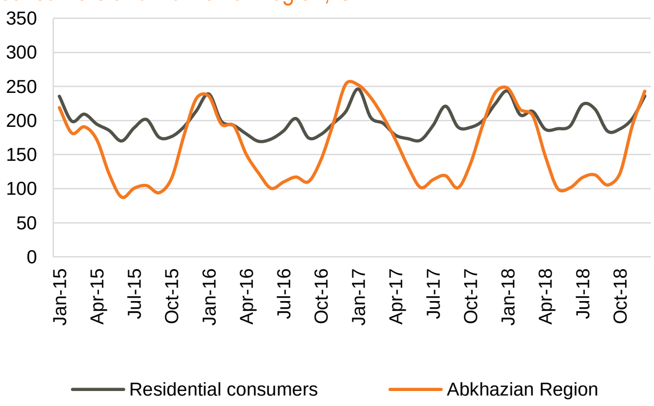
Figure 8: Seasonality of consumption and generation, 2018



Source: ESCO

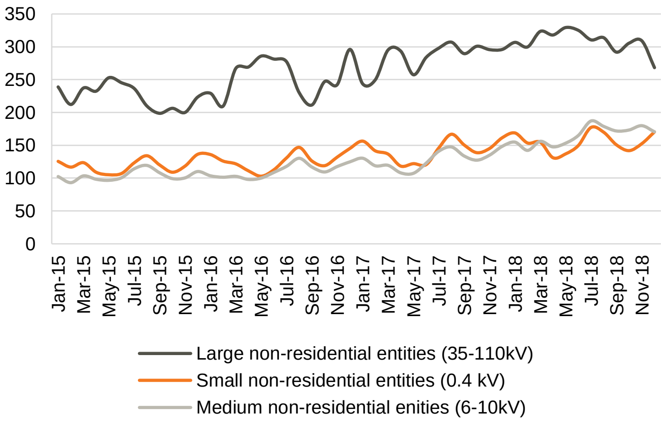
Consumption is becoming flatter, mainly due to an increase of the non-residential sector's share of the overall consumption mix. Importantly, this sector's electricity usage, unlike residential sector, is linked to overall business production capacities rather than seasonality or weather conditions. This fact contributed to decreased seasonality of electricity consumption and this trend expected to continue in the future. Pattern is evident in seasonal growth rates, e.g. electricity consumption growth averaged 3.4% in the winter and 5.7% in the summer, over 2008-18.

Figure 9: Seasonality of electricity consumption by residential consumers and Abkhazian region, GWh



Source: GNERC

Figure 10: Seasonality of electricity consumption by non-residential consumers, GWh



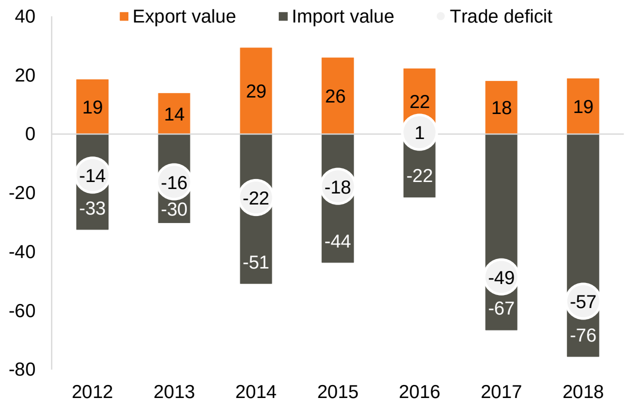
Source: GNERC

Georgia was a net exporter of electricity during 2007-11, but has become a net importer of electricity since 2012. The only exception was 2016, when Georgia ended with net exports of a mere 80.6GWh. In 2017, imports increased by dramatic 213% y/y, explained by Enguri's closure due to maintenance works. In contrast, high imports of 2018 was on the back of increased domestic consumption. In 2018, Georgia spent US$ 75.8mn on electricity imports and earned only US$ 19mn from electricity exports, resulting in a US$ 56.8 deficit in electricity trade.

Figure 11: Electricity imports and exports, TWh

Source: ESCO

Figure 12: Electricity imports and exports, US$ mn



Source: GeoStat

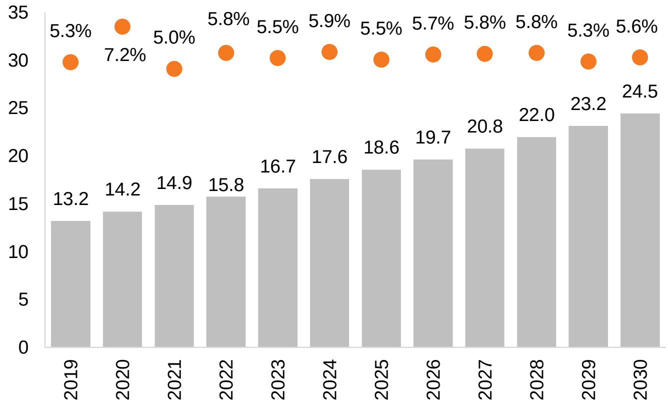
3. Expected growth of electricity consumption

We forecast average annual 5.7% growth of electricity consumption over 2019-30, based on Vector Auto Regression (VAR) model. (Model description is provided in Annex 6) We project electricity consumption in Georgia to rise to 24.5TWh by 2030 – 1.9x higher than 2018 consumption.

We expect the main driver of the electricity consumption growth to be the non-residential sector, with an expected average growth rate of 6.0% over 2019-30. Our expectations for the residential sector's and Abkhazian Region's electricity consumption growth over the same period are 4.8% y/y and 5.5% y/y, respectively.

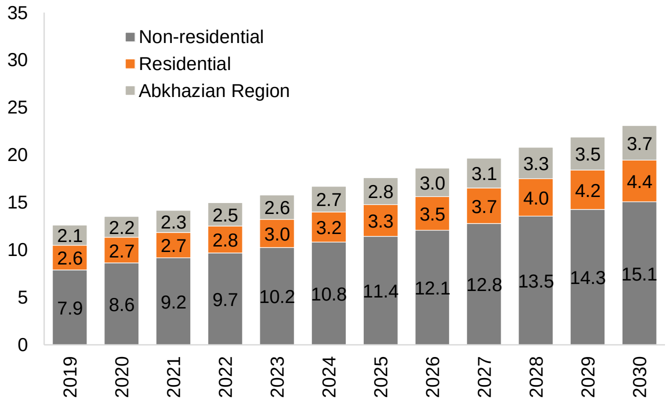
MoESD forecast is more optimistic with 7% average annual growth projection over 2020-28. This forecast is provided in 10-Year Network Development Plan of 2018-28.

Figure 13: Forecast of electricity consumption, TWh



Source: GNERC, Galt & Taggart Research
Note: Forecast is based on Vector Auto Regression model

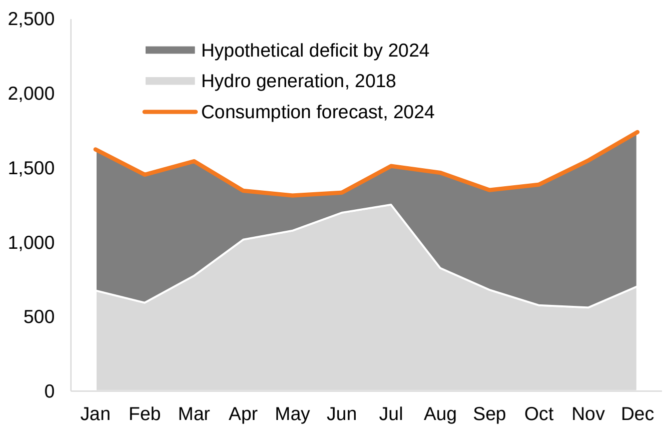
Figure 14: Forecast of electricity consumption by end-users, TWh



Source, ESCO, Galt & Taggart Research

Without new generation capacities, expected reduction in seasonality of consumption will create need for imports even in the summer. Based on the generation level of 2018 (12.1TWh, including 9.9TWh of hydro, 0.08TWh of wind and 2.1TWh of thermal power generation) and expected consumption, imports will be needed even during summer from 2022. In 5-year period, the need for imports and thermal generation expected to reach 5.5TWh.

Figure 15: Hypothetical deficit by 2024



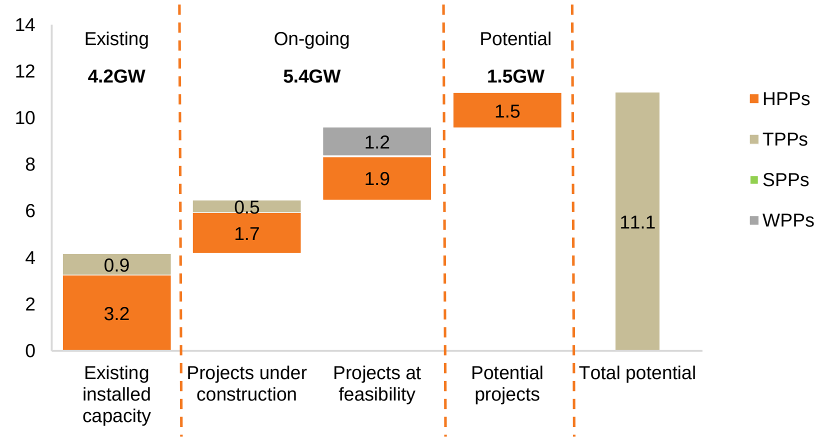
Source: ESCO, Galt & Taggart Research

4. Pipeline of power plants and generation forecast

4.1 Pipeline

Government promotion policies mainly through Power Purchase Agreements with ESCO and supportive export mechanisms, led to the solid pipeline of power plants in Georgia. Currently, there are 150 ongoing projects (5.4GW) at various stages of development with identified investors and another 98 HPP (1.5GW) potential projects.

Figure 16: Pipeline of power plants by development stages



Source: MoESD, Galt & Taggart Research
Note: As of Dec-18

From above mentioned 150 ongoing projects 50 HPPs (1.7GW) and 2 TPPs (0.5GW) are at the construction and licensing stage. The remaining 98 projects are either on feasibility studies or awaiting construction MoUs. Most of the projects (c. 86%) in pipeline are small scale projects (below 50MW). The implementation of the full pipeline would need US$ 8.6bn over 2019-26 and would more than double the existing installed capacity (4.2GW) of the country once completed.

Table 1: On-going projects with MoUs by stage of development

Stage of development	Number of projects	Estimated installed capacity, MW	Estimated annual generation, GWh	Estimated investment, US$ mn
HPPs at construction and licensing stage	50	1,744	6,005	3,006
TPPs at construction stage	2	530	2,400	420
HPPs at feasibility stage	73	1,885	8,862	3,262
WPPs at feasibility stage	19	1,219	4,680	1,896
Other renewables at feasibility stage	6	31	67	31
Total on-going projects	**150**	**5,408**	**22,014**	**8,616**

Source: Ministry of Energy, Galt & Taggart Research
Note: As of Dec-18

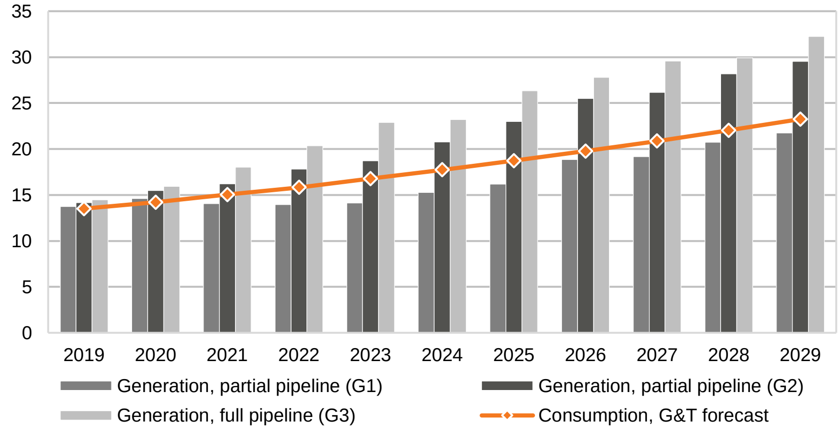
4.2 Generation forecast

Full implementation of the pipeline of power plants is less likely. Investors developing projects in the pipeline are in wait and see mode due to ongoing legislative changes (see chapters 5&6). Furthermore, there is a risk that projects can become technically or economically unfeasible after proper research is done. Considering the above, we believe that timely commissioning of all projects currently at feasibility, licensing and construction stages is not realistic.

Ministry of Economy approved three different scenarios for generation forecast. The Ten-Year Network Development Plan (TYNDP) for 2018-28, a document approved by the MoESD in December 2017, envisages three different development scenarios for both consumption and generation of electricity. Generation scenarios differ in terms of the probability of commissioning of the projects at various stages of development:

- The G1 scenario foresees full commissioning of the HPPs under construction, implementation of 50% of the HPPs at licensing stage and no implementation of the HPPs at feasibility stage. In our opinion, this scenario has highest chances of implementation, but will fail to satisfy the increased demand for electricity and Georgia will remain a net importer of electricity for the upcoming decade.
- In the G2 scenario, 25% of projects at feasibility stage are added to the G1 scenario. We consider this to be achievable – and positive – scenario. It is highly likely that a quarter of projects at feasibility stage will be technically and economically feasible even in the changed environment. This scenario gives Georgia an opportunity to become a net exporter of electricity starting from 2022.
- In the G3 scenario, it is assumed that all projects at feasibility, licensing and construction stages are commissioned on time, which makes this scenario the least probable one.

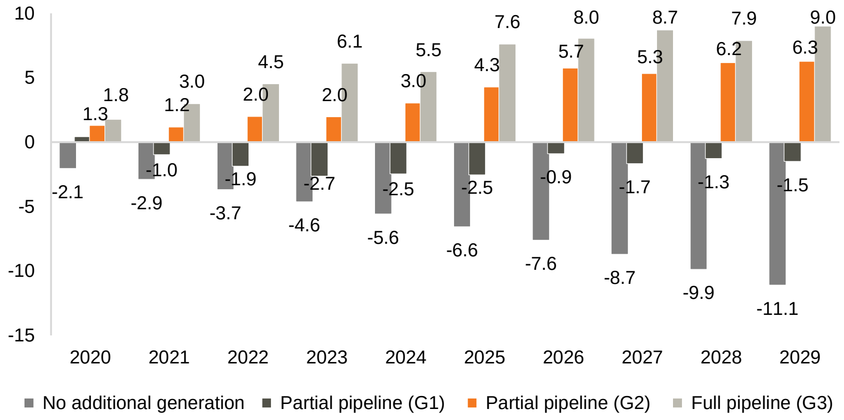
Figure 17: Generation forecast scenarios for 2019-29, TWh



Source: GSE, TYNDP, Galt & Taggart Research
Note: Forecast includes generation of all types of power plants, including thermal, hydro and wind.

Georgia has potential to become net exporter of electricity. Development of G2 and G3 scenarios from above, in combination with electricity consumption's average annual 5.7% growth estimation, will make Georgia net exporter of electricity. If the pipeline is fully implemented, Georgia will have an opportunity to export up to 9TWh of electricity by 2030. By contrast, if no additional power plant is added to the system, Georgia will need 11TWh of net imports by 2030.

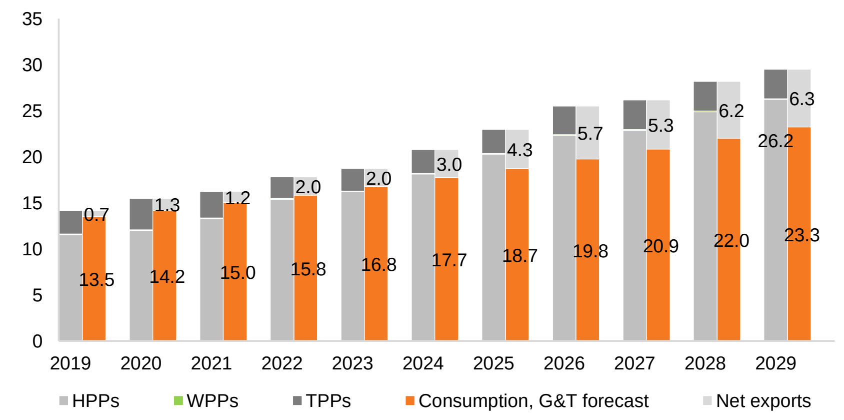
Figure 18: Forecast of net exports of electricity according to different scenarios, TWh



Source: GSE TYNDP, Galt & Taggart Research
Note: G1 scenario foresees 100% commissioning of the HPPs under construction, 50% commissioning of HPPs at licensing stage and no implementation for the HPPs at feasibility stage. In G2 scenario, 25% of projects at feasibility stage are added to the G1 scenario. In G3 scenario, it is assumed that all projects at feasibility, licensing and construction stages are commissioned on time.

G2 scenario is expected to lead to 6.3TWh net exports. As mentioned above, we consider the TYNDP's G2 generation scenario most feasible, but believe that there might be delays in the commissioning date. This scenario, together with our projection of 5.7% growth in consumption, expected to lead to 6.3TWh of net exports in 2029, on the back of 26.2TWh hydro generation. For this scenario to be implemented investment environment and export possibilities will be the most critical factors.

Figure 19: Forecast of electricity generation, consumption and net exports over 2019-29, TWh



Source: GSE, Galt & Taggart Research
Note: Consumption forecast annual growth of 5.7%; Generation forecast per TYNDP G2 scenario: 100% implementation of PPs at construction stage, 50% at licensing stage, 25% at feasibility stage

5. Investment environment

Investments in electricity sector have been encouraged by the Government of Georgia (GoG) since early 2000s. The GoG, with the assistance of donor organizations, has screened and identified potential power plant projects, developed an investment promotion strategy and actively promoted investment in the sector. In 2006, the electricity market moved from being vertically integrated to a privatized and partially unbundled market of bilateral contracts. The change included favourable tariff regimes for the development of hydropower by the private sector, decentralization of the transmission and distribution of electricity, and improvement of the power supply efficiency. The state program - Renewable Energy 2008 - encouraged private sector investments in the energy sector and developed clear investment promotion mechanisms. The Memorandum of Understanding (MoU) specifying investors' rights and obligations regarding the construction of renewable power plants became major document regulating energy investments.

MoU is a document signed between the Government of Georgia, the investor and any related party, such as a transmission licensee or state-owned company ESCO. MoUs define the preliminary parameters of the power plant (PP), the project duration, deadlines, and milestones, etc. In general, MoUs have feasibility and construction phases: after completion of the feasibility stage, the investor decides whether to continue with construction of the plant or not. Under the general framework, MoUs also grant incentives to investors, such as a long-term power purchase guarantee (in form of PPA) and guaranteed access to interconnection lines (in form of TDA), discussed in the following chapters.

This chapter provides description of major supportive mechanisms from the government, their impact on generation capacities as well as recent changes in government's promotion policy and developments in Turkey.

5.1 Power Purchase Agreements (PPA)

Different HPPs have different PPA terms, raising concerns about transparency of overall process. A Power Purchase Agreement (PPA) is long-term power sales contract between the power plant owner and state-owned company ESCO. PPA policy has changed several times since its adoption in 2008 and different HPPs have different PPA terms. The PPAs mainly differ in terms of the duration of the contract, purchase period and price. In general, all PPAs consider the purchase of electricity for predefined months for 10 or 15 years from the start of operation. The PPA months vary from 3 to 12 months of the year, but mostly they are selected from the period between September and April. The tariff granted per PPA is most commonly used as the criterion for investor selection, thus the tariff range varies from USc 3/kWh to USc 8/kWh.

PPA strategy changed since 2017. Despite generating impressive pipeline of projects in energy sector, PPAs were considered as disruption to competitive markets. Moreover, IMF raised concerns about the PPA building contingent liability for government and creating fiscal risks. These two factors resulted in a moratorium on PPAs in 2016, followed by legislative changes eliminating PPAs in 2017 and finally tightened procedures for granting PPAs introduced in a new PPP law in 2018.

New PPP law defines exemptions to get PPA. The law about public-private partnerships (PPP) was approved by the Parliament of Georgia in May 2018. The law defines the general framework for PPP projects' initiation, partner finding and monitoring (details provided in Annex 2). New investors might get a PPA only if they meet the requirements under PPP legislation and pass a tough process of evaluation. According to Public-Private Partnership (PPP) law, PPA can be granted to the projects of state interest with the duration over 5 years and budget over GEL 5mn.

Most of projects with PPAs will be constructed. The pipeline of investment projects with PPAs at different stages of development is estimated at around US$ 3bn over the next 5-7 years. This includes about US$ 1.8bn for two large projects: Nenskra and Khudoni. Some projects with PPAs might fail due to shortcomings identified in prospective technical and economic studies, but we do not expect this number to be high. Currently, about 100 projects (3.8GW) at the feasibility stage do not have a PPA and thus guaranteed tariff.

5.2 Identification of new sites for investments

Government promoted investments through publicly available studies. Starting in the early 2000s, the GoG, with the assistance of donor organizations and various engineering companies, identified potential sites for building power plants all over Georgia. These were feasibility or reconnaissance studies giving some preliminary information for the projects. All these projects were later included in the list of potential power plants and the materials were made publicly available. The list currently includes 98 potential HPPs. The projects from the list are tendered for investment, with the selection rules predefined.

Table 2: Potential HPPs by stage of research

Stage of development	Number of projects	Estimated installed capacity, MW	Estimated annual generation, GWh	Estimated investment, US$ mn
Pre-feasibility study	49	773	3,713	1,551
Investment proposal	36	319	1,576	564
Engineering design	3	198	842	496
Feasibility study	5	182	1,013	317
Other	5	44	230	63
Total potential projects	**98**	**1,516**	**7,374**	**2,991**

Source: Ministry of Energy, Galt & Taggart Research
Note: As of Dec-18

Projects could also be initiated by private investors, encouraged by simplified MoU procedures. Investors willing to develop renewable energy projects not listed in the ministry's list of potential PPs had to submit a preliminary study to the Ministry of Energy and upon approval were granted the feasibility MoU with the right to move to the construction stage. At the early stage of this initiative, during 2014-15, these projects were granted predefined PPA terms (on average USc 6/kWh for the Sep-Apr period for 10 years), but this PPA terms are not in force now. This initiative incentivized engineering companies in Georgia to carry out research and development and resulted in several promising projects that are currently at feasibility stage.

Government-supported pilot wind project increased interest in non-hydro renewables. State-owned company Georgian Energy Development Fund constructed a 20.6MW wind power plant in 2015, creating a success story for the first non-hydro renewable energy project in Georgia. This fact, along with affordability of technologies, increased interest in non-hydro renewables. Non-hydro PPs were also able to benefit from simplified procedures mentioned above. Currently, the pipeline of power plants includes 19 wind (1.2GW) and 5 solar (0.3GW) projects at feasibility stage. The PPA granted to the Kartli wind farm was USc 6.68/kWh for full annual generation over the first 10 years of operation. No other non-hydro renewable project from the pipeline has a PPA tariff or any tariff incentive.

5.3 Export procedures and Turkey as main export direction

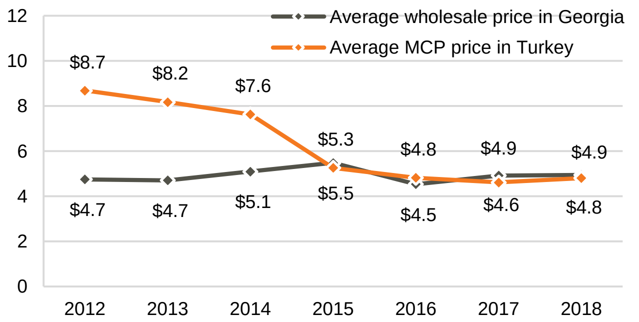
Turkey promoted as main export market. The Turkish electricity market was initially promoted as a strategically important and profitable export market for Georgia. Turkish electricity prices were high (c. USc 9/kWh in 2012) and demand seasonality in Turkey coincided with the hydro supply curve in Georgia. The only constraint for exports was the limited interconnection capacity between Georgia and Turkey as the only interconnection line available in 2008 had limitations on transfer capacity (it could export up to 100MW only in island mode). The government eliminated technical constraints for electricity exports to Turkey through the construction of the Meskheti (known also as Akhaltsikhe-Borchka) interconnection line in 2014. This investment, which was financed by KfW sovereign loan, mitigated the constraint and increased the interconnection capacity to 700MW. Furthermore, the intergovernmental agreement between Georgia and Turkey considers construction of additional two interconnection lines, which will double Georgia's export capacity.

Investors were granted priority access to Meskheti line. The interest in the Turkish market was so high that, despite the increased transfer capacity, investors were concerned about congestion on the transmission line. This apprehension led to prioritizing new constructions over old ones through capacity allocation rules and long-term transmission and dispatch agreements (TDAs). The TDA approach was adopted together with the Renewable Energy 2008 policy and is still functional. The TDA grants the power plant developer a long-term right to export to Turkey in selected months. In most cases, the right is take-or-pay, obligating the state to compensate for the loss of profit in case export volumes are limited due to reasons other than force majeure. The TDA terms depend on the importance of the project and mostly replicate the duration of PPA terms.

TDAs were granted to about 40 projects with total capacity over 2GW. Some projects are already commissioned, while others are at different stages of development. After duly commissioning all projects with TDAs, the export capacity of new transmission lines might not be enough to export all the generated energy. If this happens, export allocation rules consider an auction between the TDA owners to allocate limited capacity.

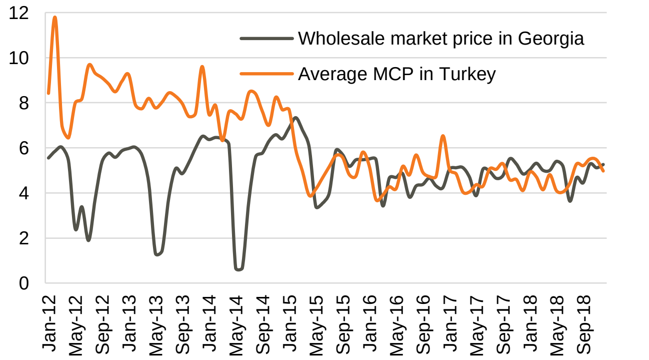
Turkish market prices almost halved since 2012. The Turkish government's active promotional strategy for new generation capacities and the activation of the day-ahead market, along with low global fuel prices, resulted in a decrease in market clearing prices. In Turkey prices decreased from an average annual price of USc 8.7/kWh in 2012 to USc 4.8/kWh in 2018. In contrast, wholesale electricity prices on Georgian market slightly increased in last 3 years and came close to Turkish price level. These factors incentivized Georgian companies with TDAs to use their option for local sales or to sign additional agreements with the government and limit exports to May-August in favour of increased local supply. This trend toward voluntary limitation of TDAs has continued over the last two years.

Figure 20: Average annual prices in Georgia and Turkey, USc/kWh



Source: ESCO, EPIAS, GeoStat

Figure 21: Average monthly prices in Georgia and Turkey, USc/kWh



Source: ESCO, EPIAS

Export procedures and applicable fees

Electricity export is allowed only in case of surplus in Georgia. Electricity exports from Georgia is limited by two factors: Export Allowed Volume (EAV) and Available Transfer Capacities (ATC). The EAV is defined by GSE based on the forecasted annual balance; while ATC is defined for each transmission line mutually by Georgia and the neighbouring country. The EAV is the energy left over from the total generation after full satisfaction of domestic consumption, reduced additionally by the energy needed to keep parallel synchronous operation with the country selected by GSE. GSE allocates export capacities to applicants via public auctions at www.gcat.com.ge, taking into consideration the aforementioned constraints, as well as priority groups of applicants.

The limiting factors for exports over 2015-18 were both the EAV and the ATC. With regard the latter, Turkey capped the ATC of the Meskheti transmission line for some months (e.g. April and May) due to congestion on internal lines.

Exporters pay additional charges of USc 1.4/kWh or more. Electricity exporters are obligated to pay service fees, a guaranteed capacity fee and auction fee if applicable:

- The service fees include payment for transmission, dispatch and ESCO service (regulated by GNERC), and totals 2.4 tetri/kWh (USc 0.9/kWh), effective until 2020.
- The guaranteed capacity (GC) fee is paid by local consumers and exporters and changes monthly. It depends on: 1) the number of days TPPs were operational or on a stand-by mode, 2) amount of daily GC payments to TPPs defined by GNERC and 3) amount of electricity consumed or exported. The GC fee increased dramatically after the Gardabani combined cycle power plant was commissioned in November 2015. The fee is significantly lower during the summer months when most TPPs are under maintenance and do not receive guaranteed capacity payments. Based on our observations, we recommend exporters to use USc 0.5/kWh as the guaranteed capacity fee estimate for their projections for the main export months (May through August).
- The auction fee is payable only in case of congestion during the export auction. During the auction, companies indicate an auction fee on the web-platform and if there is congestion in their priority group, the company with the highest auction fee is granted export rights. Auction fees are only paid by the winner and only in the case of congestion in their priority group.

Most of the costs are due even in the case of no exports. From above mentioned service fees, the transmission and dispatch fees are linked to the allocated capacity, while the guaranteed capacity fee and ESCO service fee are linked to actually exported volumes of electricity. The fees are not paid when exports are stopped due to force majeure situations or by limitation of ATC by any of the countries involved.

Considering that these costs are to be paid out of the profit taken from exports, the Turkish market is becoming even less attractive.

Table 3: Fees to be paid by Exporters

	tetri/kWh	USc/kWh*
Dispatch fee (GSE)	0.412	0.154
Transmission fee (GSE)	1.323	0.496
Transmission fee (SakRusEnergo)	0.278	0.104
Transmission fee (EnergoTrans 400kV)	0.380	0.142
ESCO service fee	0.019	0.007
Total service fees	2.412	0.904
Guaranteed capacity fee	*varies by month from USc/ 0.15/kWh to USc 0.7/kWh*	
Auction fee	*varies by auction*	

Source: GNERC
**Exchange rate GEL/US$ = 2.6686 per NBG average monthly rate of Dec-18*

6. Electricity market on the edge of changes

Due to tightening of PPAs granting procedures and the decrease in Turkish market prices, the investment environment is significantly changed. Projects evaluation process now requires more in-depth analyses of power-selling opportunities and market prices in Georgia and neighbouring countries. Despite this challenges, there are new opportunities in the market stemming from Georgia's new wave of reforms in electricity sector.

Georgia has signed a protocol concerning the accession of Georgia to the treaty establishing the Energy Community of EU and its neighbours, in October 2016, ratified by the Georgian parliament in spring 2017. With this agreement, Georgia undertook an obligation to synchronize Georgian legislation with EU standards in the energy sector and to do so in tough deadlines. As Georgia is not directly connected to Energy Community member countries, it is exempt from several directives. However, major changes apply to the market structure in the electricity and natural gas sectors, energy efficiency and environmental law. Implementation of EU directives and regulations, stretched between 2018 and 2025, involves, among other things, adopting of a new market model and new national goals and action plans for renewable energy and energy efficiency purposes.

New market rules will open up path to a new type of investors. Energy Community regulations will bring a more competitive and transparent market model to Georgia. The upcoming law on energy, renewable energy and corresponding secondary legislation will define the new investment promotional mechanisms, provide new channels for power sales and give an understanding of the expected market environment. Within this framework, Georgia is planning to implement day-ahead and intraday markets. Creation of trading platforms will open up new opportunities for Georgian developers and attract investors believing in a European model of energy trading. Turkey is member of European Network of Transmission System Operators for Electricity (ENTSO-E), new market model for Georgia might also open possibilities of power trade through Turkey to Eastern European countries.

Donors assist, Georgia does. There are several grant programs from different countries that are assisting Georgia in reaching its goals regarding the Energy Community (EnC), integrating specific *acquis* into the Georgian legislation, assessing the impact of new regulations on stakeholders and finding optimal solutions for the country. Generally, donor organizations are assisting in every aspect of the transition process, but the deadlines set by the Energy Community are tight and tough to meet.

Table 4: Timetable for implementation of the acquis communautaire per energy community charter treaty for electricity

N of directive/regulation		Description of directive/regulation	Deadline
Directive	2008/92/EC	Community procedure to improve the transparency of gas and electricity prices charged to industrial end-users (recast)	31-Dec-17
Regulation	1099/2008	Energy statistics	31-Dec-17
Directive	2009/28/EC	Promotion of the use of energy from renewable sources	31-Dec-18
Directive	2009/72/EC	Common rules for the internal market in electricity	31-Dec-18
Regulation	714/2009	Conditions for access to the network for cross-border exchanges in electricity	31-Dec-18
Directive	2005/89/EC	Measures to safeguard security of electricity supply and infrastructure investments	31-Dec-19

Source: Protocol concerning the accession of Georgia to the treaty establishing the Energy Community

Georgia plans to deregulate the market and adopt day-ahead and intraday trading mechanisms. Market deregulation and creation of day-ahead trading platforms were first proposed by USAID's Hydropower investment promotion project (HIPP) in 2012, as it was seen as the best development scenario for the Georgian energy sector. This project proposed market deregulation to take place before 2015. The market was not ready for proposed measures as it would require dramatic changes in the market structure, legislation and habits of market participants, etc. Since then, the government and donor organizations have been working towards capacity building and increased awareness of market participants to make the market modernization smooth for all stakeholders. Some steps have been taken, but a lot more action and modernization is required.

Process of transition is stretched between 2018 and 2025. The full implementation of EU standards requires the adoption of legislative documents in addition to the law on energy. Establishment of certain institutions and implementation of specific software and programming solutions are the most critical and time-consuming tasks for creating the 'perfect' market. Finally, capacity building of market participants is critical in Georgia. The possibility of hourly trading will create a need for new job positions in companies, e.g. power traders, forecasters, etc.

Before the adoption of the full package of new laws and regulations, we can only discuss the most probable versions of the future market structure. In this chapter, we describe our expectations regarding the future market model.

6.1 Expected market structure and trading principles

The EU market model incentivizes market players (both consumers and generators) to plan accurately as shortages/surpluses are penalized. Currently, in Georgia, the trade of electricity is done on a monthly basis and there is no punishment for unsupplied electricity. In this approach, both consumers and suppliers have an incentive to sign contracts above their planned volumes to ensure their cash stream predictions. The EU market model restrains over-contracting through punishment – whoever is causing the imbalance should pay the cost occurred because of that imbalance. Moreover, if their low consumption or high generation disrupted the system (e.g. imports were stopped and penalties followed), the costs should also be paid by the perpetrator.

Daily trade brings accurate planning and reduces imbalance. In our opinion, besides the incorporation of the imbalance settlement mechanism into the market rules, one of the main game-changers for the future market will be the shortening of the settlement period from one month to one day/hour. In the new market, where imbalance is punished, having the possibility to trade electricity every day or during the day is a big advantage for companies as it is easier to plan a day ahead rather than a month ahead. This is especially important for companies generating energy from renewable energy sources, as they are highly dependent on weather conditions. This will change the process of electricity trade and create demand for organized power markets.

Channels of power sales will diversify. We expect upcoming changes to legislation due to Energy Community requirements to modify not only the list of market participants but also the channels and structure of power sales. In our opinion, the sellers in the wholesale energy market will be power-generating companies, power traders and importers, while buyers will be other power traders, power suppliers and exporters. Buyers might become sellers if they need to sell any extra energy they bought previously but are not planning to use. Based on our knowledge of EU markets, the energy trade between these market participants can be conducted on one or all of the following markets:

- **Day-ahead market (DAM)** is an organized auction held a day before actual delivery. Market participants bid on the desired volume and price of electricity they want to sell or buy. The bids and offers are matched via a special algorithm and a unified market price is formed for each hour of the delivery day. The price setting algorithm maximizes the welfare of market participants.

- **Intraday continuous market (IDM continuous)** is a market where bids and offers are continuously placed and matched on an organized platform.

- **Balancing and Ancillary Services Market** – this market will serve for Transmission System Operator (TSO) as a mechanism for optimal (cheapest, effective, timely) balancing of the system when needed (in case of emergency, to increase system security, and balance the imbalances).

- **Bilateral agreements outside DAM and IDM.** The increased number of market participants might create demand for the development of a complex Over-the-counter (OTC) market for transparent and competitive pricing of bilateral contracts.

New markets need time to gain credibility. In the EU, energy markets are organized by nominated market operators (NEMOs). The management of imbalances and their settlement is the responsibility of the Transmission System Operator (TSO). Thus, Georgia needs to define the responsible bodies through new legislation. In our opinion, day-ahead and intraday markets will start functioning in a trial version by 2020. As for the system-service market, we think that initially there will be no separate market for it, but it will be realized through bilateral contracts and/or a mechanism including the DAM merit order. A complex market for system services might appear after several years of successful operation of DAM and IDM markets. We acknowledge that the uninterrupted operation and transparency of the market is necessary for several years to anchor energy prices and investment decisions.

Market participants need capacity building. Implementation of these markets needs not only legislative changes, funding, technical and digital support, but also increased awareness of market participants and training for new job positions created by the new market model. Power traders will need qualified personnel for planning and trading the electricity, as well as market operators, and a regulatory authority will need to train staff for the new market model. As mentioned above, donor organizations are supporting government in this process.

6.2 Transformation of market participants

Direct consumers

Number of direct consumers trading on wholesale market expected to rise. The Energy Community charter treaty states that Georgia must ensure that the eligible direct customers are: from 2019 all non-household consumers and from 2020 - all consumers. The enlarged number of direct consumers will serve as a guarantee of more transparent and competitive markets.

Government decided to gradually comply with the requirements of the Energy Community Charter Treaty in order to make the transition process smoother and the timeline of the changes has been extended.

From May 2018, the changes to the legislation made it obligatory for companies with an average monthly consumption of electricity over 15MWh to be registered as direct consumers; other companies have the right to voluntarily and irreversibly become a direct consumer. Only 3 companies were mandatorily added to the group of direct consumers: GFDC Georgia, Geo Servers and Kutaisi Investments. In addition, Energo-Pro Georgia (the largest distribution licensee) has voluntarily registered its head office as a direct consumer.

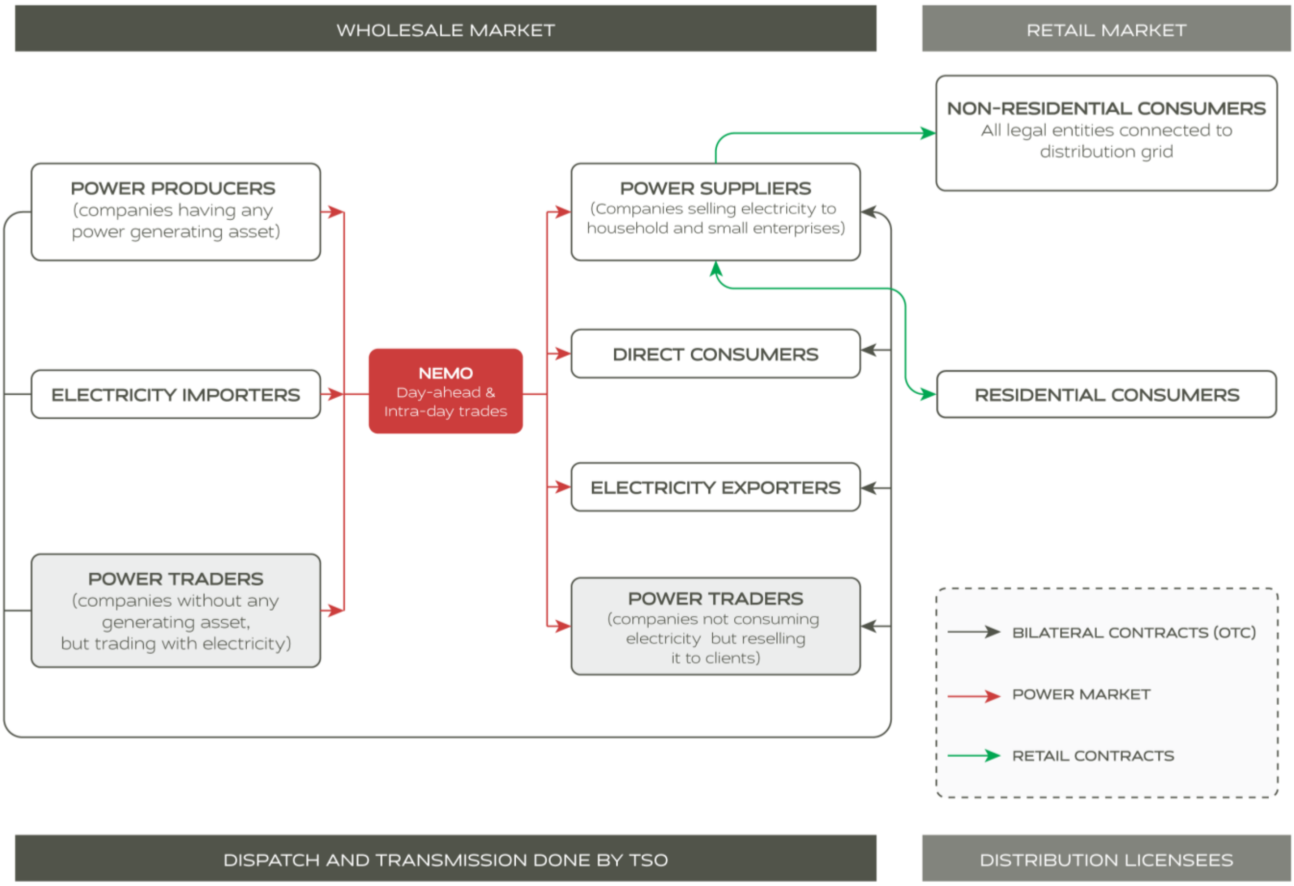
Before this amendment wholesale market was dominated by 2 distribution licensees (Energo-Pro Georgia and Telasi), which supply electricity to the residential and non-residential consumers all over Georgia. Direct consumers purchase electricity directly from suppliers and sidestep the distribution companies. Despite the gradual decrease in eligibility criteria from average annual consumption of 3GWh to any legal entity without limitation of consumption, the number of registered direct consumers decreased from 6 to 2 (both having affiliated suppliers) over 2015-17. This reduction in the number of direct consumers was explained by lower prices offered by distribution licensees (due to access to cheap electricity of Enguri/Vardnili), discouraging companies to become direct consumers.

Power traders

Most companies have flat consumption over the year, while deregulated HPPs generation is highly seasonal, meaning that electricity price might vary over the year. When these companies become direct consumers, in addition they will have to pay all service fees to the respective electricity suppliers and the guaranteed capacity fee to ESCO, previously included in their power bill with distribution licensees. This creates additional expenses and increases risks for companies willing to or obligated to be registered as direct consumers. This risks can be mitigated by the new type of market players - power traders.

Increased number of direct consumers creates need for power traders. Following a recent amendment to the law, stemming from Energy Community requirements, the power trade activity has been allowed in Georgia since January 1, 2019. Power traders have right to trade with electricity, without owning generating plant. The GNERC has the right to monitor their activities, but the wholesale supply/trade of electricity does not require a special license. Power traders can trade electricity on the wholesale markets and re-sell it to direct consumers on a contractual base.

Diagram 1: Expected electricity market structure in Georgia



Source: Galt & Taggart Research

Distribution and supply

Distribution and supply activities should be unbundled. EU legislation obliges Georgia to make the retail market as competitive as possible, meaning that each household should have the right and option to change its power supplier. In order to achieve this goal, distribution licensees' activity, as it is known in today's market, should be unbundled into distribution and supply activities:

- The distribution itself will remain a natural monopoly, regulated by the GNERC, but it will not have the right to sell electricity; its activity will be the maintenance of a low-voltage transmission network and physical delivery of electricity to end-users, for which it will receive the tariff set by the GNERC.
- Power suppliers will be able to buy electricity at a wholesale market and will not have limits on price setting. End-users like household and non-household consumers will choose power supplier, based on their offered tariff or payment schedule, etc.

After required legislative amendments and the resulted unbundling of suppliers and distributors, the retail prices (including for residential consumers) expected to be linked to market prices, not set by the GNERC. EU legislation allows the government to take measures to ensure tariff safety for specific group of end-users (e.g. socially vulnerable population).

Integration of regulated generation in deregulated market

Currently deregulated market share is very small. Despite small number of regulated PPs (11 HPPs and 5 TPPs), they account for 80.6% of total generation. Half of the remaining 20% of generated electricity has a PPA with ESCO. This part is not regulated by the GNERC but has a selling price set by the Government of Georgia for most of the year. The remaining minor part of the market has the right to set the selling price at their discretion, but the buyer's side does not offer an opportunity for negotiations.

Policymakers are still discussing the method of integrating lowest priced Enguri/Vardili's generation in new deregulated market model. Some believe that this cheap energy should be directed to vulnerable consumers. Others believe that Enguri should be allowed to trade in the organized wholesale markets. Both of these approaches mean that Enguri will no longer be able to decrease the weighted-average tariffs on the wholesale market.

The largest HPPs, Enguri/Vardnili, constructed back in the 1970s, have the lowest generation tariff. They are under state ownership, located partially on the occupied territory of Abkhazian Region. Their tariff for 2018-20 is set by the GNERC at 1.8 tetri/kWh for Enguri and 4.0 tetri/kWh for Vardnili. Currently distribution companies have long-term contracts with Enguri and Vardnili, granting them access to the cheapest electricity. In 2018, generation of these HPPs reached 4.7TWh, up to 40% of domestic generation. Notably, the Abkhazian Region is also supplied by Enguri and Vardnili HPPs and has priority over distribution companies, consuming 40.4% of their generation in 2018. Even the remaining 59.6% of generation is enough to decrease the average purchase tariff of electricity to 7.5 tetri/kWh for distribution companies, compared to average wholesale price of ESCO - 12.9 tetri/kWh in 2018.

We expect that in order to achieve competitiveness and transparency on the market, GNERC will eliminate price caps for all power plants. Electricity generated from HPPs with PPAs will also be integrated into the open-market (see options in next chapter).

6.3 Expectations on wholesale market prices

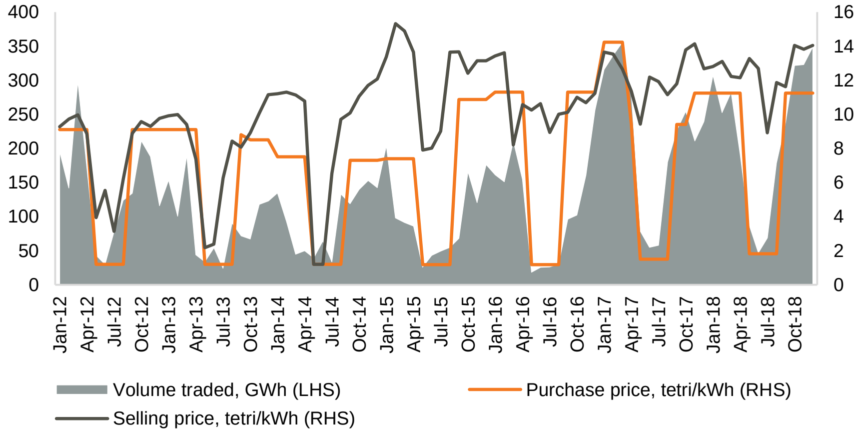
PPAs might dictate the prices in the future. Currently, electricity generated from HPPs with PPAs is purchased by ESCO and sold as balancing electricity to distribution licensees and direct consumers. This balancing electricity accounted for 19.4% of total consumption in 2018 and the rest was traded via bilateral contract. Notably, it is quite common practice in Georgia to link the price of bilateral agreements to the selling price of the balancing electricity (e.g. 10% below the balancing market sales price), especially in the winter months (September-April). Consequently, the price of balancing electricity impacts electricity wholesale market prices.

In 2018, more than half of balancing electricity came from imports, up to 40% of balancing electricity was purchased from PPA holders and the rest was balancing electricity purchased at about USc 0.6/kWh. Currently, due to its high share, import volume and price have the most significant impact on the balancing electricity selling price. But in line with the commissioning of new HPPs with PPAs, and expected growth of their share, the dependency will move towards the PPA price unless the price setting rules are changed.

According to current market rules, electricity sales in Georgia can be conducted through:

- Power Purchase Agreement (PPA) to ESCO – discussed on pg. 14
- Bilateral agreement - power selling and purchase agreement between power producer and consumer (either distribution company or direct consumer)
- Balancing electricity sale to ESCO - the volume of electricity supplied to the grid without bilateral contract.

Figure 22: Balancing electricity volumes and prices



Source: ESCO

Dependency on PPA price might increase the prices in the market. Considering the current pipeline, we estimate that third of electricity supply will be sold via PPAs by 2023 from the current 7.7%. Furthermore, the selling price of ESCO might reach USc 6.0/kWh in 2022 from the current USc 5.3/kWh (December-2018). Leaving current market rules unchanged, this would lead to increased market prices. We think that this influence of PPAs is one of the reasons why policymakers consider PPAs the main distorting element in the competitive market.

PPAs challenge formation of competitive market. One of the most challenging questions that policymakers face today is how to integrate the existing PPAs into the day-ahead market without causing major disruptions. Integrating the electricity purchased by ESCO into the open market can cause some price distortions and limit the volumes traded on the day-ahead platform. There are several options for PPA integration into the open market suggested by international consultants; we list the two most widely discussed options below (In both cases, PPA holders are safe to receive their planned revenues):

- Single buyer: when ESCO or a designated state agency buys electricity from PPA owners on PPA terms and then resells it to the open market either via bilateral contracts or in day-ahead or intraday markets. In our opinion, this solution will make the above-mentioned impact of PPAs on the market even stronger.
- Contract for Differences (CFDs): when the generator company is obliged to trade on the market and ESCO (or its legal successor) only pays for the difference between the PPA price and the market price. If the market price is lower than the PPA price, the difference will be compensated by ESCO and vice versa. ESCO will get the money for covering CFDs either from the state budget or by making collections from all end-users of electricity. In our opinion, this scheme will decrease or eliminate the impact of PPAs on the wholesale market price, especially if the share of electricity traded on the day-ahead markets exceeds the share of bilateral contracts. It is worth noting, that PPA holders will have an incentive to bid the lowest possible price, causing the market clearing price on day-ahead market to go down rather than up. The policy makers are aware of this loophole, and plan to address the issue.

Neighbouring market prices' impact on local prices expected to increase. Above discussed deregulation of the market and introduction of CFD-type mechanism for PPAs will completely change the price-setting practice in Georgia. As power trade and planning will be on a daily basis, the import and export markets will probably have more influence on the Georgian market than they do today.

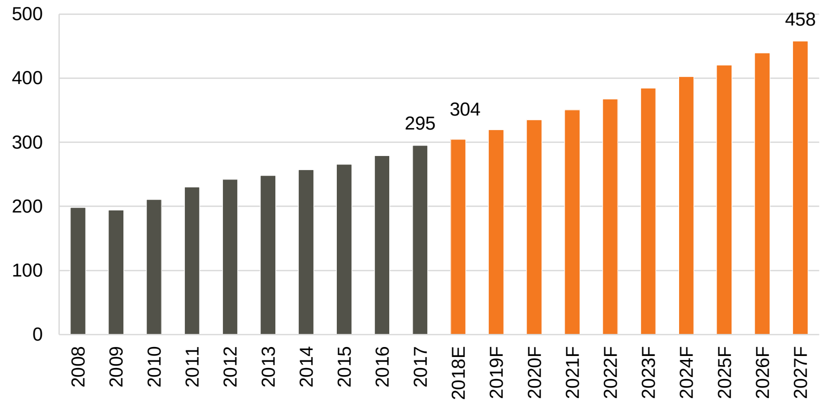
We can assume that either the import or export price will dictate market clearing prices on both day-ahead and intraday markets. In summer months, when there is a surplus of electricity, which is supposed to increase in line with the commissioning of new run-off river HPPs, the market prices will be linked to the major export markets (reduced by the transmission and other service fees). In winter months, the import price will be the market price setter. From neighbouring markets, we expect that Turkish market prices can have largest influence on Georgian market prices both in the summer and the winter (price forecast for Turkish market is on page 27). Turkey has been the main export market for Georgia since 2014 when the Meskheti interconnection line was commissioned. In 2018, Turkey became import provider for Georgia for the first time and this practice may continue.

7. Export markets

7.1 Turkish electricity market

Electricity consumption in Turkey is about 300TWh per annum and is expected to increase to 500TWh by 2030. Turkey is the 18th largest economy in the world, with GDP amounting to US$ 851.1bn in 2017. In line with economic developments, electricity demand in Turkey has been growing at a CAGR of 4.34% over 2010-17. The base case scenario of Turkey's Ministry of Energy indicates that electricity consumption is expected to increase by 4.5% annually and reach 458TWh in 2027, up by 55% from 295TWh in 2017.

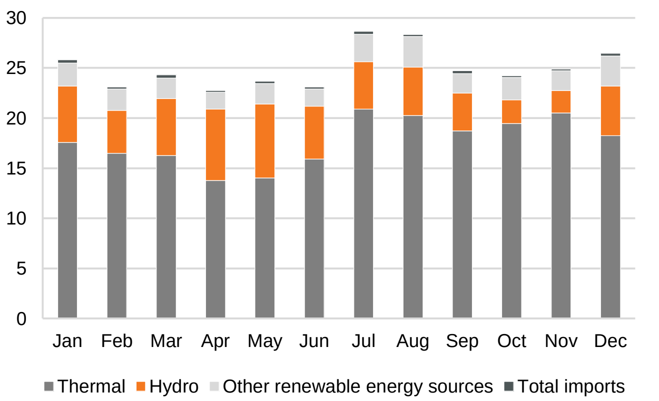
Figure 23: Electricity consumption forecast for Turkey, TWh



Source: EPIAS
Note: Base case scenario

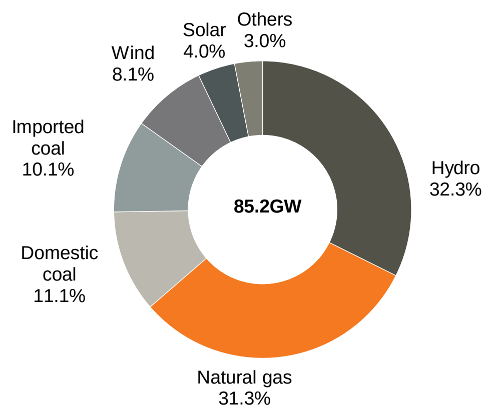
Turkey's installed capacity stood at 85.2GW in 2017 and is largely dependent on imported sources – natural gas and coal. On average, 3.1GW of new capacity has been added annually over the last 15 years to Turkey's generation mix. Turkey is meeting its rising demand for electricity through domestic generation, half of which depends on imported sources. Imported electricity satisfied only 1% of demand in 2017, of which a 20% came from Georgia, and the rest from Bulgaria and Turkmenistan. Considering the policy level support for renewables and other local resources, such as coal, investments in renewable energy sources and coal power plants in Turkey are expected to accelerate.

Figure 24: Electricity generation in Turkey and imports in 2017, TWh



Source: EPIAS

Figure 25: Turkey's installed capacity by type

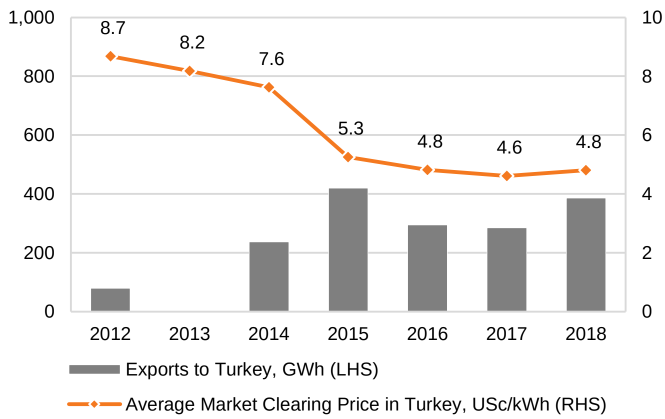


Source: EPIAS
Note: As of Dec-2017

Turkish electricity consumption peaks in the summer. Since most of the generation in Turkey is distributed evenly over the year, deficits occur in the summer, creating an opportunity for Georgian exporters. Both existing (Meskheti) and planned (Alkhaltsikhe-Tortum) interconnection lines between Georgia and Turkey were conceived with the export opportunity in mind. In order to meet high demand growth and bridge seasonal deficits, the Turkish Government has various support mechanisms in place for local generation capacities, especially renewable energy sources.

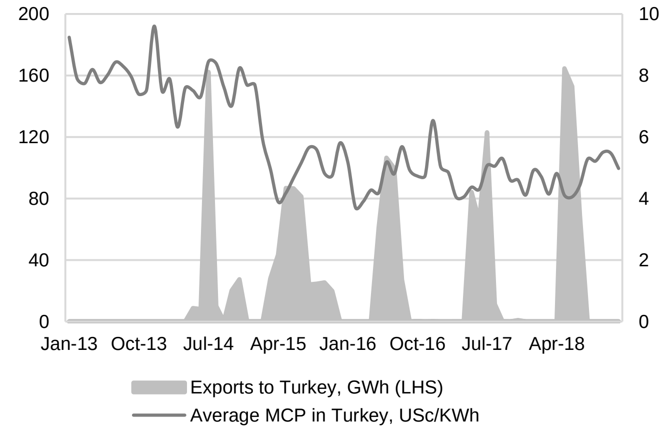
Almost a third of electricity in Turkey is traded on the organized electricity market. Development of the market started in 2009 and progressed at an impressive speed, as it moved from monthly settlements to day-ahead and intra-day markets. The organized electricity market is operated by EPIAS and uses a transparent market platform, where the Market Clearing Price (MCP) is defined for each hour of the following day through day-ahead trades. The MCP fluctuates throughout the day and is much higher in peak hours. Turkey also has a balancing power market where local suppliers trade, designed to settle the imbalances of the day-ahead market.

Figure 26: Average annual MCP in Turkey and exports from Georgia



Source: ESCO, EPIAS
Note: 400kV Interconnection line Borchka-Akhaltsikhe (Meskheti) commissioned in summer of 2014, increasing the export capacity to Turkey from 100MW (only island mode) to 700MW

Figure 27: Average monthly MCP in Turkey and exports from Georgia



Source: ESCO, EPIAS

The market prices in Turkey have decreased dramatically, with the average annual MCP price decreasing to USc 4.8/kWh in 2018 from USc 8.7/kWh in 2012 (decrease of 44.7% y/y). The most significant fall was in 2015 (-31.3% y/y).

Turkey has been the main export market for Georgia since 2014, when the Meskheti interconnection line was commissioned. The Turkish market has several importing companies. It is at Georgia's discretion to allocate the export capacities between the exporting companies. The contract prices between Georgian and Turkish companies are a commercial secret, but to our knowledge it is quite common practice to link the off-take agreement price to the market clearing price in Turkey (available at www.epias.com.tr).

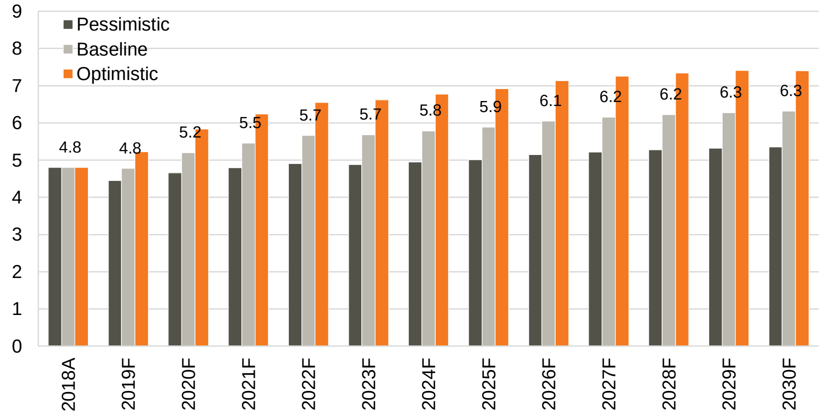
7.2 Forecast of MCP in Turkey over 2019-30

For Turkish market electricity price forecast, we studied electricity Market Clearance Price (MCP) in Turkey over 2012-18 and made projections for 2019-30. From various indicators affecting MCP prices in Turkey, we analysed 1) the Industrial Production Index (IPI) and 2) the electricity Market Clearance Quantity (MCQ). We have examined the relationship of these two indicators to MCP prices, as there is no other high-frequency data available influencing electricity prices in Turkey. Quantitative analysis reveals that the IPI has a positive influence on the MCP; for instance, a 1% change in the IPI causes a 0.35% change in the MCP, while the MCQ has inverse impact on the MCP – a 1% increase in the MCQ causes a 0.1% decrease in the MCP.

We used a Bayesian Vector Autoregressive (BVAR) model (description provided in Annex 7) to forecast the MCP over 2019-30. We have analysed three different scenarios for average monthly MCP price projections. A brief description of these scenarios follows:

- Baseline scenario: uses the BVAR model, where all variables are treated as endogenous.
- Pessimistic scenario: takes the forecasted IPI from the baseline scenario as an exogenous variable and assumes a 6% y/y decline in the IPI over 2019-30.
- Optimistic scenario: takes the forecasted IPI from the baseline scenario as an exogenous variable and assumes a 6% y/y increase in the IPI over 2019-30.

Figure 28: Forecast of average annual MCP prices over 2019-30, USc/kWh



Source: EPIAS, Galt & Taggart Research

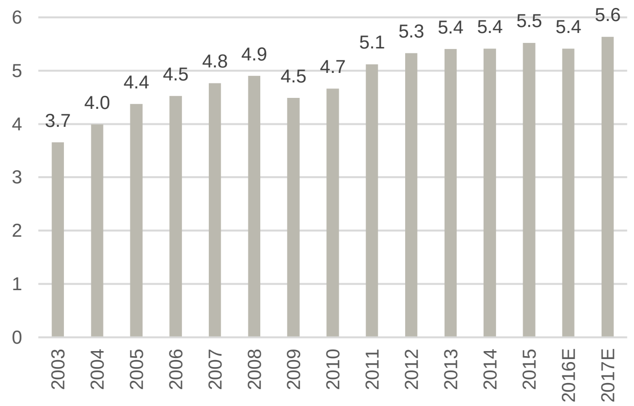
Our model-based forecast for MCP for the above-mentioned scenarios gives different price estimates:

- **The baseline scenario** predicts that annual average MCP prices in Turkey expected to rise to USc 6.3/kWh in 2030 from USc 4.8/kWh in 2018 (+31.6% 2030 vs. 2018).
- **In a pessimistic scenario**, the annual average MCP price expected to increase moderately to USc 5.4 in 2030 (+11.5% 2030 vs. 2018).
- **According to the optimistic scenario**, MCP prices in 2030 expected to climb to USc 7.4/kWh (+54.2% 2030 vs. 2018).

7.3 Armenian electricity market

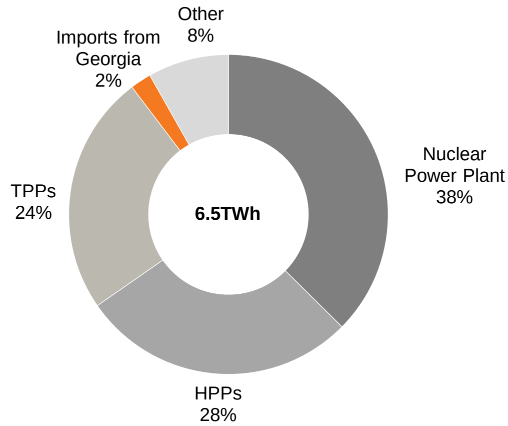
Armenia consumes only half the amount of electricity consumed by Georgia. Net consumption of electricity increased at a CAGR of 3.1% over 2003-17 and is expected to continue to grow at a rate of around 2% per annum. The current installed capacity of Armenia is 3.3GW, of which only 2.7GW is used. 50% of available capacity is more than 40 years old and needs to be replaced. More than one-third of electricity demand is satisfied by Armenia's Nuclear Power Plant (NPP), which is to be decommissioned in 2026. Retirement of the NPP has been postponed twice, most recently from 2021 until the commissioning of the new NPP (expected in 2026) because of the difficulty in securing financing. Besides the new nuclear plant, Armenia's pipeline includes several hydro, thermal and renewable energy projects, as well as works to improve energy efficiency. The 400kV Marneuli interconnection line between Georgia and Armenia is also expected to be one of the supply sources for the Armenian energy sector. The interconnection line will be commissioned by 2021 and will increase the transfer capacity from 100MW to 700MW, creating additional opportunities for Georgian exporters. If it does not put new generation capacity in place before, Armenia can expect a supply gap of roughly 830MW in 2026, taking into account the base-case forecast average annual peak demand growth of roughly 2% per annum.

Figure 29: Electricity consumption in Armenia, TWh



Source: Electric Networks of Armenia, Galt & Taggart Research

Figure 30: Electricity supply mix of Armenia in 2017, TWh



Source: Electric Networks of Armenia

Wholesale electricity prices in Armenia are unknown, as there is no transparent and competitive energy market available. Armenia has some plans to liberalize the market and create a day-ahead trade platform, but no specific dates have been set yet. Any move towards the liberalization of those markets will help Georgia to increase the liquidity and turnover of the market. Armenia has been an Observer to the Energy Community Treaty since 2011. Under its Observer status, it has no legal rights or obligations under the Energy Community legal framework. According to the policy recommendations paper of the Energy Community, the end-user electricity tariffs in Armenia, regulated by the regulatory authority, have increased from USc 5.2kWh in 2008 to USc 9.6/kWh in 2016. The same source states that the current average cost of generation in Armenia is roughly USc 3.5/kWh, but this is set to increase to USc 10-19/kWh should the gas price increase and a new nuclear plant be brought online in 2026. The increase in Armenia's generation costs is an additional opportunity for Georgian power plants with assumed lower production costs.

Electricity exports from Georgia to Armenia showed significant growth in 2016-17. Exports to Armenia decreased by 40.2% y/y in 2018 due to a high base in 2017 (+23.3% y/y) and 2016 (+57.4% y/y), but were still significantly higher than exports in 2015 (+16.2% y/y). The main exporter to Armenia is Georgian International Energy Corporation (GIEC). ESCO also exports to Armenia, generally in exchange for imports in the winter period.

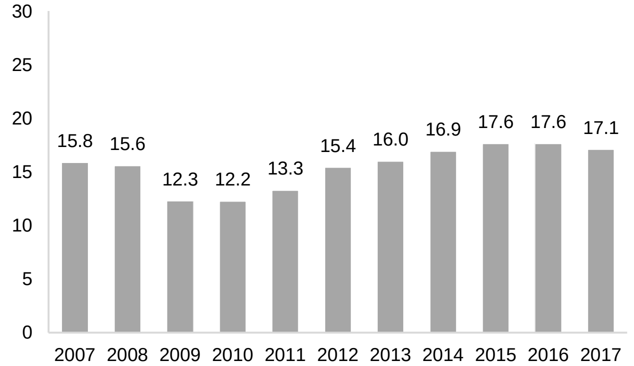
7.4 Azerbaijani electricity market

Azerbaijan's electricity consumption was 17TWh in 2017. It has increased at a CAGR of 2.1% over 2012-17. Households are the largest final energy consumers. Various studies forecast an increase in Azerbaijan's electricity demand by 0.6% per annum, reaching 21TWh in 2025.

Azerbaijan has one of the highest energy self-sufficiency ratios in the world. Azerbaijan is a major crude oil producer (ranking 26th in the world in 2016) and a significant producer of natural gas. As a result of this large hydrocarbon production, the country's energy production is more than four times above its energy demand. Azerbaijan's installed capacity of PPs is 8GW. This increased by 38.6% over 2008-17. More than 90% of electricity demand is satisfied by power plants working on fuel; the rest is produced by renewable energy sources. Azerbaijan's energy sector has a high rate of self-consumption; 70% of electricity generation is consumed domestically, 5% is exported and the rest is used for power plants' self-consumption or is lost during transmission.

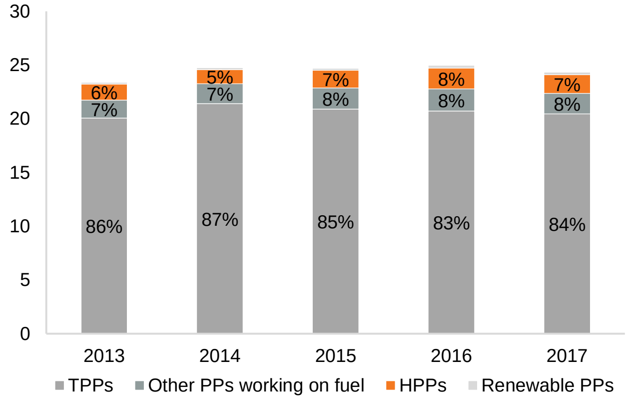
Electricity prices in Azerbaijan are administered rather than market-driven and are heavily influenced by oil prices. In 2017, the average price of imported electricity from Azerbaijan to Georgia was in the range of USc 4.8-5.2/kWh.

Figure 31: Electricity consumption in Azerbaijan, TWh



Source: State Statistical Committee of the Republic of Azerbaijan

Figure 32: Production of electricity in Azerbaijan, TWh



Source: State Statistical Committee of the Republic of Azerbaijan

EU4Energy program includes assistance of Azerbaijan in modernization of energy legislation. As part of the EU4Energy Governance project, the Energy Community Secretariat is tasked with preparing a methodology for the identification of key regional energy infrastructure projects which enhance cross-border energy trade. Azerbaijan is currently in the process of revising its legal framework for the energy sector and is soon to adopt new laws for its electricity market and energy regulator. Both legal acts will have a major impact on cross-border cooperation with Georgia.

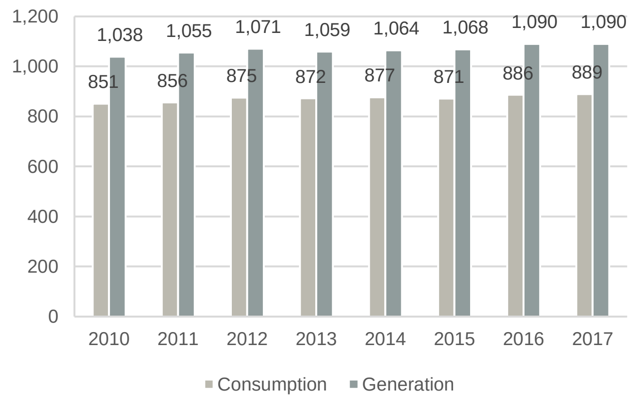
Azerbaijan became the main provider of imports to Georgia in 2017 and 2018, replacing most of Russian imports. Considering the energy resources of Azerbaijan and significantly low growth of consumption, it is unlikely that Azerbaijan becomes an export destination for Georgia.

7.5 Russian electricity market

Russia has 5th highest electricity consumption worldwide (c. 900TWh in 2017). The consumption in 2017 was mostly satisfied by domestic generation. Up to 20% of electricity is generated by renewable energy sources; the rest is produced from coal, natural gas or nuclear power plants. Russia is a net exporter of electricity, mainly exporting excess generation to Finland, Belarus, Lithuania, China, Kazakhstan and Georgia. Electricity is imported into Russia largely from Kazakhstan. Notably, export/import share in total electricity supply is very small in Russia.

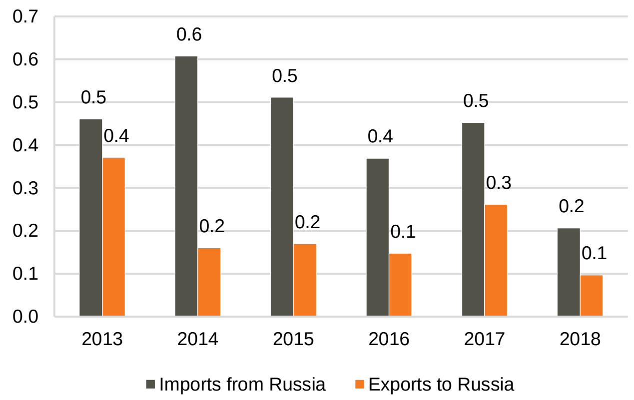
Main exporter of electricity from Georgia to Russia is ESCO. To our knowledge, the export price to Russia is significantly lower than to other markets (Turkey and Armenia), which explains ESCO being the sole exporter in this direction. Russia has day and night tariff regimes, and different prices for import and export of electricity. The cross-border electricity trade is conducted by one state-owned company, Inter-Rao. Georgian imports' share of Russian electricity consumption is minimal, so the Russian market is flexible in terms of receiving any amount of electricity that Georgia can offer at short notice. This flexibility has been the main advantage of the Russian market so far.

Figure 33: Electricity consumption and generation in Russia, TWh



Source: Global Energy Statistic Yearbook

Figure 34: Trade of electricity between Georgia and Russia, TWh



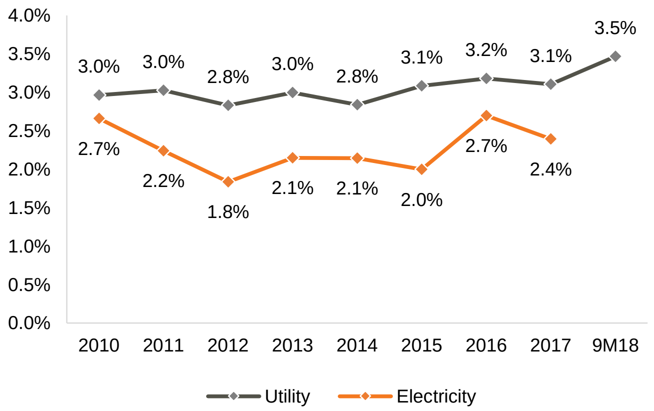
Source: ESCO

Foreign trade with Russia also increases the security of Georgian electricity system. To ensure security of supply, Georgia's electricity system is synchronized with one of its neighbours, with constant power flow to or from that country. In the summer months, the Georgian grid mainly works in parallel with Russia, exporting surplus electricity; while in the winter, dispatchers negotiate certain minimal flows from Russia or Azerbaijan on a monthly basis. Import or export capacities needed for synchronous operations are usually contracted by ESCO but can also be contracted by private investors.

8. Georgia's energy sector in figures

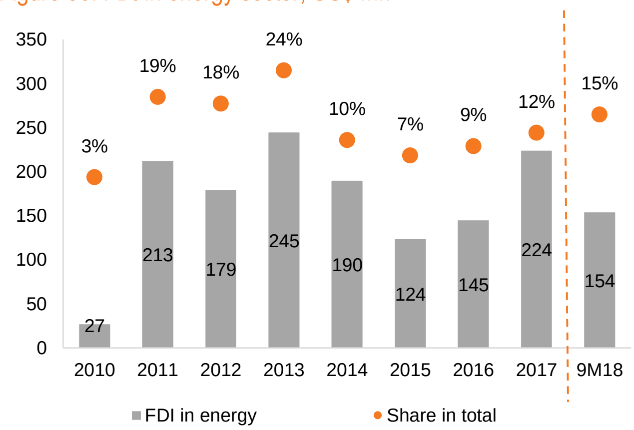
Major transformation of the sector since 2006 attracted substantial investments and resulted in uninterrupted power supply. Investor friendly regulations and reasonable tariff methodologies, improved payment discipline, simplified licensing, upgraded transmission networks and export opportunities made the sector attractive for investors. Result is substantially increased power generation capacity of the country. Over, 2007-17, energy sector was the second largest FDI recipient with 13.2% of total. Electricity has the lion's share in utility sector (electricity, natural gas, water supply) and generates 2.4% of GDP, while total utility sector accounted for 3.1% of GDP in 2017.

Figure 35: Energy sector's share of GDP



Source: GeoStat

Figure 36: FDI in energy sector, US$ mn



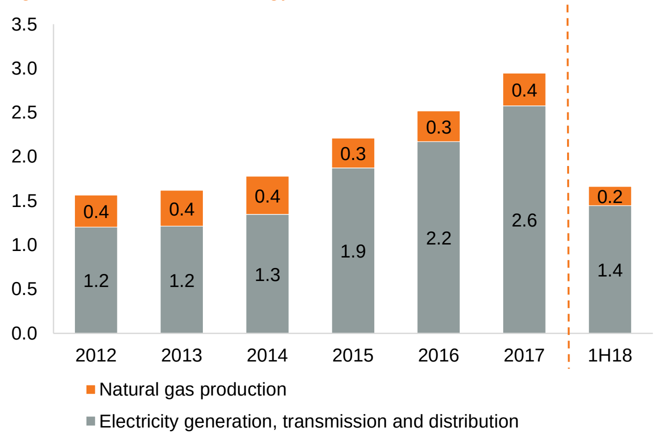
Source: GeoStat

8.1 Profitability of energy sector

Turnover of electricity sector has doubled since 2012. The electricity sector's turnover increased by a CAGR of 16.5% over 2012-17 and reached GEL 2.6bn in 2017. The reason behind the dramatic increase is the commissioning of the Gardabani TPP and the increase in distribution system operators' (DSO) tariffs over 2015-17. Overall, the energy sector's turnover, combining production, transmission and distribution of electricity and production of natural gas sectors, posted a CAGR of 13.5% over 2012-17 – above the average for the business sector.

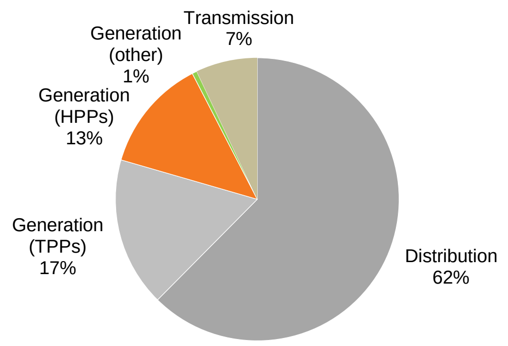
Turnover of electricity sector is mainly regulated or depends on regulated purchasers. Power generation in Georgia is partially regulated; only 11 out of 83 Hydro Power Plants (HPP) and all 5 Thermal Power Plants (TPP) had capped tariffs in 2018 (80.6% of total generation in 2018). Transmission and distribution activities are regulated with the tariff set by the Georgian National Energy and Water Supply Regulatory Commission (GNERC). The tariff methodology considers the operational costs, investments made, relevant payback period, and profit margin for companies. Consequently, the turnover and margins for most of the energy sector are predefined.

Figure 37: Turnover of energy sector, GEL bn



Source: GeoStat

Figure 38: Turnover of electricity sector, 2017

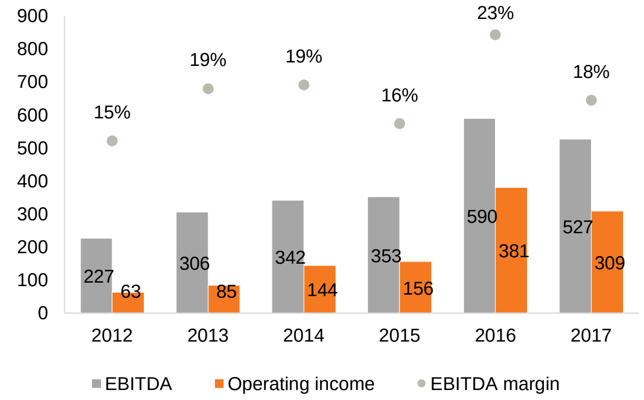


Source: GeoStat

Energy sector EBITDA margin is high. The EBITDA margin averaged 19% over 2012-17, with a drop in 2015 due to increased expenses linked to the GEL's depreciation. This effect on EBITDA was significant for the natural gas sector and TPPs, as their costs are mostly in FX while revenues in GEL. As the energy sector is capital-intensive, depreciation and amortization costs as well as interest expenses are quite high and can dilute the operating and net profits of the whole sector. As sector borrows mostly in FX, the mentioned GEL's depreciation also caused the net loss for the sector in 2015, which soon turned into net profit from 2016.

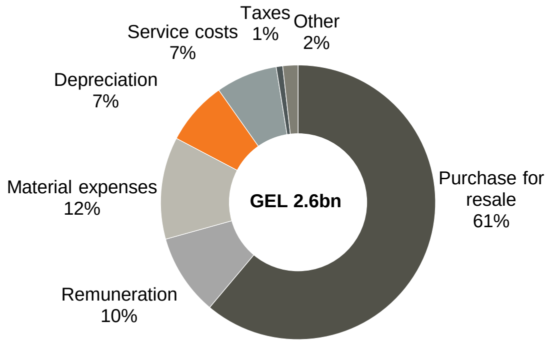
Cost structure of electricity sector sub-businesses varies. The value chain of the electricity business includes generation, transmission and distribution activities. The cost structures of these activities vary, as do the operating and net profit margins. The generation business has the highest depreciation and interest expenses and low remuneration costs; additionally thermal power plants have comparably high material expenses (natural gas). The transmission business, which has the smallest turnover, is the most capital-intensive and has high depreciation and interest expenses, so EBITDA is high but net profit is low. The distribution business has the highest turnover, however, due to high COGS (80%), the operating margins are low.

Figure 39: Profitability of energy sector, GEL mn



Source: GeoStat

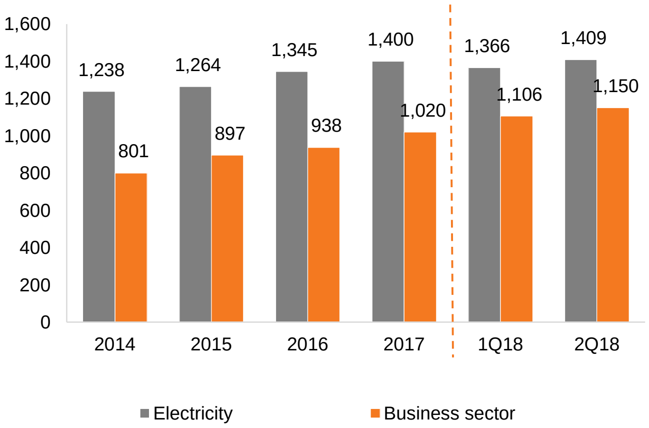
Figure 40: Structure of operating expenses of energy sector in 2017



Source: GeoStat

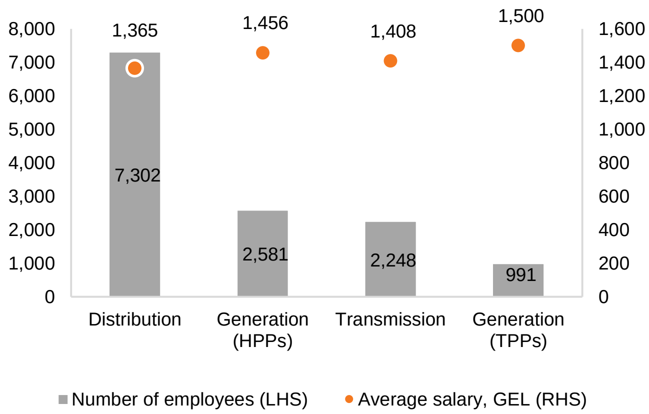
Electricity, unlike other utility sectors, pays above-average salaries. In 2017, the average monthly salary in the electricity sector was 37% higher than the average salary in Georgia at GEL 1,400. Other utilities such as water supply or sewage do not provide above-average salaries. The utility sector employs around 13,000 workers, which is 0.8% of the total workforce and 2.0% of business sector employees. Half of them (56%) works in the electricity distribution companies.

Figure 41: Average monthly salaries, GEL



Source: GeoStat

Figure 42: Electricity sector employment and remuneration in 2017

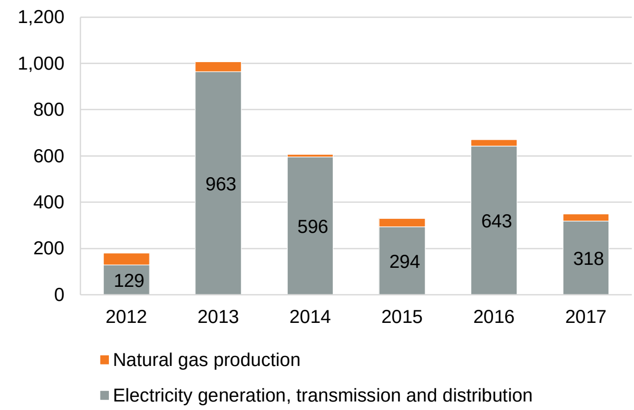


Source: GeoStat

8.2 Investments in the sector

GEL 2.9bn was invested in the electricity sector over 2012-17. The investments included the rehabilitation of the transmission and distribution grid, the renovation of old power plants and the construction of new generation capacities. Energy is a capital-intensive sector where a project's lifetime might be up to 50 years and the investment period up to 6 years. This results in a lag in profitability.

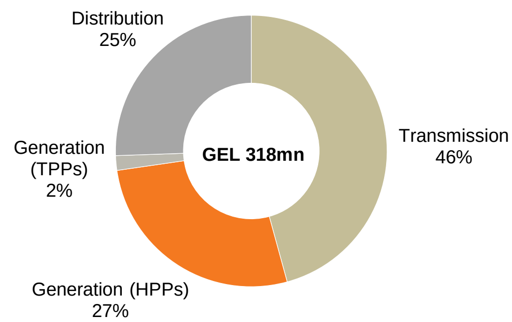
Figure 43: Investments in fixed assets, GEL mn



Source: GeoStat

Note: The figure includes investments in Georgian assets; international gas and oil pipelines are not included

Figure 44: Investments in electricity sector in 2017

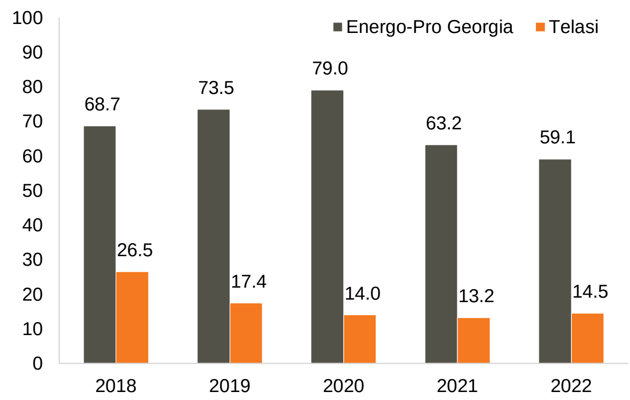


Source: GeoStat

Investments in transmission grid are estimated to be EUR 500-600mn over 2019-28. The GSE's Ten-Year Network Development Plan (TYNDP 2018-29) lists the projects needed to strengthen internal and cross-border transmission capacity and support the power plant pipeline and the exports of electricity. The TYNDP envisages nearly half of planned investments to take place before 2020, with international financial institutions (KfW, EBRD, WB, ADB) and GSE's own resources.

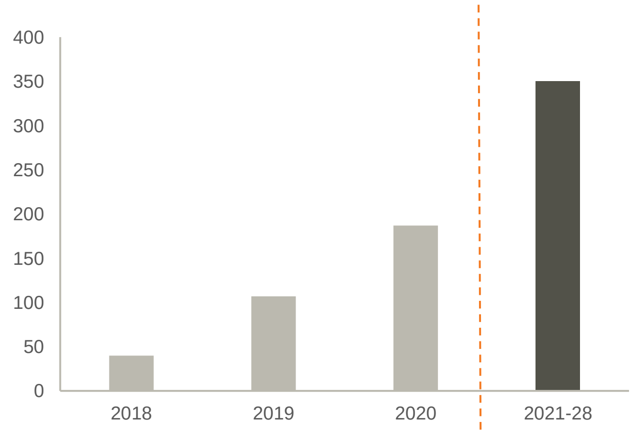
Distribution sector will invest about EUR 120mn in grid rehabilitation over 2019-22. According to 5 year's distribution network development plan, Telasi and Energo-Pro Georgia's investments over 2018-22 are estimated at GEL 85.6mn and GEL 343.5mn, respectively (actual data for 2018 not available yet). These investments will support the addition of new subscribers, the rehabilitation of amortized transmission lines, the construction of new substations, and an increase in transmission capacities.

Figure 45: Investment plans of distribution companies, GEL mn



Source: GNERC

Figure 46: Investment plans of transmission companies, EUR mn



Source: GSE, TYNDP

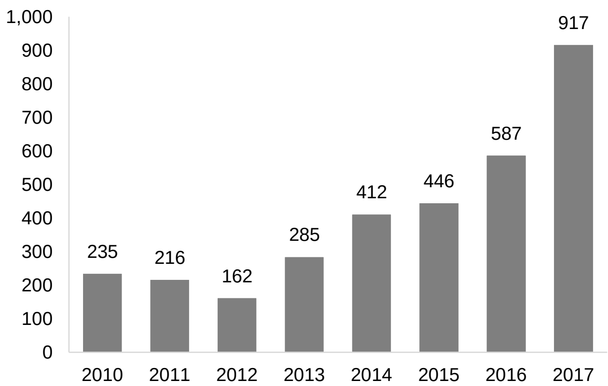
An estimated GEL 200mn earmarked for rehabilitation of old HPPs with regulated tariffs. Currently, only 11 HPPs constructed before 2008 with installed capacity above 40MW have a regulated tariff set by the GNERC. According to tariff methodology, prior to setting the tariff, the GNERC approves the investment plans of regulated HPPs. The latest tariff change was made in 2017, considering investments made and planned for 2017-19. The largest regulated HPPs in Georgia – Enguri (1.3GW) and Vardnili (0.2GW) HPPs – had to invest GEL 94.3mn and GEL 37.6mn, respectively, over 2017-19. Other regulated HPPs, mainly under Energo-Pro Generation's ownership, had to invest about GEL 50mn over the same period. Notably, the latest tariff change significantly effected tariffs of Enguri and Vardnili, set at 1.818 tetri/kWh (+21.5%) and 4.002 tetri/kWh (+39.0%), respectively. The 3-year rehabilitation plan for Enguri, discussed during tariff calculation, envisaged closing the plant for three to six months during 2019, along with other rehabilitation works. However, according to the electricity balance of 2019 approved by MoESD, the maintenance works will probably be postponed, with no specified dates.

8.3 Financing of energy sector

The projects in the energy sector are financed by both local and foreign sources. The infrastructure projects, such as transmission lines and grid rehabilitation, are mainly financed by IFI loans, while HPP construction funding structure is mixed. By our estimates, power and energy sector holds largest share (45%) in total IFI funding in Georgia.

Georgian banking sector loan portfolio in energy sector stood at GEL 982mn in 2018. Despite that portfolio more than doubled over 2014-18, its share in total as well as in corporate loanbook remains low at 3.7% and 6.7%, respectively. Importantly, these investments are almost risk-free with NPLs close to zero.

Figure 47: Georgian bank loans to energy sector, GEL mn



Source: NBG

Note: Outstanding loans as of end of period.

Table 5: Power plant projects financed by IFIs, US$ mn

Project	IFI	Year	Amount
Nenskra HPP*	EBRD	2018	214
Nenskra HPP*	EIB	2018	150
Nenskra HPP*	ADB	2018	314
Gori WPP	EBRD	2015	12
Dariali HPP	EBRD	2014	80
Shuakhevi HPP	EBRD	2014	87
Shuakhevi HPP	IFC	2014	105
Shuakhevi HPP	ADB	2014	90
Paravani HPP	EBRD	2011	69
Paravani HPP	IFC	2011	109
Mtkvari HPP	OPIC	2011	58
Total			**1,287**

Source: EBRD, IFC, ADB, OPIC

**Nenskra HPP loans are approved but not yet disbursed*

Annex 1: Electricity sector's value chain and tariff structure

The end-user tariff incorporates all the fees, profit margins and expenses incurred by the total value chain of the electricity business. The average household in Georgia pays on average 20 tetri/kWh for electricity, while commercial sector's average tariff is 18 tetri/kWh. The electricity fee includes VAT, profit for the distribution licensee, fees for the transmission licensees and the cost of electricity generation.

Diagram 2: Tariff structure of Telasi and Energo-Pro Georgia, average for 2018-20 USc/kWh

Generation tariff

	Telasi	Energo-Pro Georgia
Weighted average tariff (including imports and technical losses)	2.94	2.57

Transmission tariff & other fees

Tariff name	
Total transmission tariff	0.75
Dispatch tariff	0.14
ESCO service fee	0.01
Guaranteed capacity fee*	0.51
Total transmission & other fees	1.41

Distribution tariff (residential)

Average monthly consumption	Telasi	Energo-Pro Georgia
Layer 1 (0 -100 kWh)	0.28	0.58
Layer 2 (101-300 kWh)	1.56	1.85
Layer 3 (>301 kWh)	2.98	3.37

Distribution tariff (non-residential)

Voltage	Telasi	Energo-Pro Georgia
High (35-110 kV)	0.78	0.78
Medium (6-10 kV)	1.02	1.22
Low (220-380 V)	2.44	2.76

+VAT (18%)

Tariff for residential consumers

Average monthly consumption	Telasi	Energo-Pro Georgia
Layer 1 (0 -100kWh)	5.48	5.37
Layer 2 (101-300 kWh)	7.00	6.87
Layer 3 (>301 kWh)	8.69	8.57

Tariff for non-residential consumers

Voltage	Telasi	Energo-Pro Georgia
High (35-110 kV)	6.07	5.60
Medium (6-10 kV)	6.36	6.13
Low (220-380 V)	8.04	7.95

Source: GNERC
"Guaranteed capacity fee is variable and monthly defined by ESCO
Note: Tariffs are defined in local currency. Exchange rate GEL/US$ = 2.6531 as per NBG average monthly rate of Feb-19

Annex 2: Existing generation assets

HPP/TPP	Installed capacity, MW	Generation in 2018, GWh	Ownership	Year commissioned
Conventional HPPs				
Enguri	1,300.0	4,019	State	1978
Vardnili	219.9	738	State	1971
Zhinvali	130.0	280	GWP	1984
Khrami-1	112.8	194	Inter Rao	1947
Khrami-2	110.0	311	Inter Rao	1963
Dzevrula	80.0	131	Energo-Pro Georgia Generation	1956
Shaori	40.3	128	Energo-Pro Georgia Generation	1955
Total conventional HPPs	**1,993.0**	**5,801**		
Run-of-river HPPs				
Vartsikhe	184.0	848	Georgian-American Alloys	1977
Shuakhevi	178.7	0	Adjaristsqali Georgia LLC	2017
Lajanuri	113.7	414	Energo-Pro Georgia Generation	1960
Dariali	108.0	262	Dariali Energy	2016
Paravani	86.5	404	Georgian - Urban Energy	2014
Gumati	69.5	316	Energo-Pro Georgia Generation	1958
Kirnati	51.3	11	Adjar Energy 2007	2018
Rioni	51.0	314	Energo-Pro Georgia Generation	1933
Khelvachauri	47.5	186	Adjar Energy 2007	2016
Zahesi	36.8	202	Energo-Pro Georgia Generation	1927
Khadori	24.0	120	Eastern Energy Corporation	2004
Old energy	21.4	13	Old Energy	2018
Chitakhevi	21.0	102	Energo-Pro Georgia Generation	1949
Larsi	19.0	80	Energy LLC	2014
Ortachala	18.0	85	Energo-Pro Georgia Generation	1954
Atsi	18.4	89	Energo-Pro Georgia Generation	1937
Satskhene	14.0	11	Energo-Pro Georgia Generation	1992
Others (59 HPP with capacity below 13MW)	193.7	692	Various private investors	Various
Total run-of-river HPPs	**1,256.5**	**4,148**		
Total HPPs	**3,249.5**	**9,949**		
TPPs				
Gardabani Unit 9	300.0	620	Mtkvari-Energy	1991
Tbilsresi (Gardabani Units 3 and 4)	270.0	207	Georgian International Energy Corporation	1963
Gardabani TPP	231.2	1,213	Gardabani TPP	2015
Airturbine	110.0	64	G-Power	2006
Tkibuli coal power plant	13.2	12	Saknakhshiri	2011
Total TPPs	**924.4**	**2,115**		
Qartli wind farm	**20.7**	**84**	Qartli Wind Farm	2016
System Total	**4,194.6**	**12,149**		

Source: GSE, ESCO
Updated at 18.12.2018

Annex 3: Public-private partnership procedure

The law about Public-Private Partnerships (PPP) was approved by the Parliament of Georgia in May 2018. Later in August 2018, the Government of Georgia adopted the law for PPP projects' screening and implementation. The legal documents define the general framework for PPP projects' initiation, partner finding and monitoring:

1. The project initiation phase consists of two main parts: project concept and project feasibility, each of which is prepared by or on behalf of the entitled entity, evaluated by the Ministry of Finance and PPP Agency, and approved by the government of Georgia. The PPP agency should be created exclusively for the evaluation and monitoring of PPP projects. The process of approval by the government might be skipped only for small projects in some sectors (but not for energy) when the decision about proceeding with the investor selection is made by three evaluators: the PPP Agency, the Ministry of Finance and the entitled entity.

The project qualifies under PPP legislation if: 1) the value of the project exceeds GEL 5mn and the duration is more than 5 years; 2) the risks and investments are fairly shared between the private and public investors; 3) the project is of public interest. Furthermore, for some sectors, additional criteria might be added to qualify the project under PPP framework.

2. The private partner selection process includes the following processes:

- Listing the selection criteria – the selection criteria of the private partners can be different for each project, as defined by the Government of Georgia and entitled entity, e.g. the amount of private funding, and the quality and duration of the works.
- Creation of evaluation commission – for most PPP projects, a special evaluation commission is created and staffed by representatives of the PPP Agency, the entitled entity, the Ministry of Finance, and the MoESD, as well as representatives of other state agencies and/or independent experts. The commission members are initiated by applicable agency and approved by the Government. Small projects (to be defined by the government decree) are exempt from these rules, and are evaluated by the entitled entity and PPP Agency only.
- Evaluation – to ensure the most efficient partner from the private sector, the evaluation process has two stages: 1) pre-qualification and 2) bid comparison.
- Contract negotiation is led by the entitled entity.
- The contract should be signed by the private partner and the state representative.

3. Monitoring of the PPP project is conducted by the public partner and PPP Agency. The latter has the obligation to publish annually the progress of the PPP projects.

Energy sector in PPP legislation

Energy sector PPP projects should be agreed with the government regardless of the size of the project. For projects larger than 100MW, the initiation process must include a feasibility study conducted by an independent company.

The energy sector has some exemptions from general rules, e.g. private companies are allowed to initiate the project and the government has a right to allow closed and direct negotiations with only one partner, skipping the public tendering and evaluation procedure. The legislation also defines the rule for compensation of incurred costs if for the projects duly initiated by a private company is granted to another company.

Annex 4: List of figures

Annex 5: List of tables and diagrams

List of tables:

List of diagrams:

Annex 6: Description of VAR model for electricity consumption forecast in Georgia

To forecast electricity consumption in Georgia, we used vector autoregressive model (VAR). Based on VAR model, we separately forecasted electricity consumption for Abkhazian region and the rest of Georgia. In case of Abkhazian region, we used 12 lags of the electricity consumption and "December 2012" and "May 2018" were used as dummy variables suggested by the model specification. To forecast electrify consumption for the rest of Georgia, we used indices of electricity consumption and real gross domestic product (GDP), both lagged by 12 months; "December 2012" and "July-August 2017" were used as dummy variables stemming from model specification. Real GDP growth in VAR represents an exogenous variable and its projections over 2019-30 are obtained from separate forecast of GDP components (equations for consumption, investments, exports, imports) using Factor Bayesian VAR model, ECM model, and ARDL model.

The specification of the VAR model, which we use for forecasting electricity consumption for Georgia, has the following form:

$$Y_t = A_1 Y_{t-1} + \cdots + A_{\mathrm{p}} Y_{t-p} + B_1 X_t + \cdots + B_k X_{t-k} + C \times D_t + \zeta_t$$

Where, Y_t includes a set of observable endogenous variables (electricity consumption), X_t includes vectors of exogenous variables (real GDP growth), D_t contains vectors of deterministic components, and ζ_t is an unobservable zero mean white noise process with positive definite covariance matrix $E(\zeta_t, \zeta_t') = \Sigma_u$. A, B and C are parameter matrices of suitable dimension.

Forecasting electricity consumption is based on conditional expectations assuming independent white noise ζ_t. Thus, h-step forecast at T is represented by:

$$Y_{T+h|\mathrm{T}} = A_1 Y_{T+h-1|T} + \cdots + A_{\mathrm{p}} Y_{\mathrm{T+h}-p|\mathrm{T}} + B_1 X_{T+h} + \cdots + B_k X_{\mathrm{T+h}-k} + C \times D_{T+h}$$

The forecast are computed recursively for $h = 1,2,3$ ..., starting with ($h = 1$):

$$Y_{T+1|\mathrm{T}} = A_1 Y_T + \cdots + A_{\mathrm{p}} Y_{\mathrm{T}+1-p|\mathrm{T}} + B_1 X_{T+1} + \cdots + B_k X_{\mathrm{T}+1-k} + C \times D_{T+1}$$

The corresponding forecast errors are:

$$Y_{T+h} - Y_{T+h|\mathrm{T}} = \zeta_{T+h} + \phi_1 \zeta_{T+h-1} + \cdots + \phi_{\mathrm{h}-1} \zeta_{T+1}$$

Where, $\phi_s = \sum_{j=1}^{s} \phi_{\mathrm{s}-1} A_{j,}$ $s = 1,2$ ..., with $\phi_{\mathrm{s}} = I_k$ and $\mathrm{A_j} = 0$ for $j > p$ (Lütkepohl 1991). Thus, the forecast errors have zero mean, and, hence the forecasts are unbiased.

Annex 7: Description of BVAR model for electricity price forecast in Turkey

To forecast electricity market clearance price (MCP) in Turkey, we use Bayesian Vector Autoregressive model (BVAR) due to advantages of incorporating Bayesian inferences in VAR forecasting framework. The fundamental object in Bayesian forecasting is the predictive distribution (distribution of future data-points conditional on the currently observed data) and its ability to capture all relevant information about the unknown future events. Bayesian decision picks a forecast that minimizes the expected loss conditional on the available information. For precise estimation and forecasting performance Litterman's prior formulation (Minnesota prior) is used, which shrinks the parameters towards a stylized representation of the observed data in order to reduce parameter uncertainty and improve forecast accuracy.

The specification of the VAR model in its compact form may be written as:

$$\mathrm{Y_t} = \mathrm{X_t}\varphi + \varepsilon_\mathrm{t}$$

Where, $\mathrm{X_t} = (I_n \otimes M_{t-1})$ is $n \times nk$, $M_{t-1} = (Y'_{t-1}, \dots, Y'_{t-p}, z'_t)'$ is $k \times 1$ and $\varphi = \mathrm{vec}(\Phi_1, \Phi_2, \dots, \Phi_p, D)$ is $nk \times 1$. The unknown parameters of the model are φ and Σ.

Bayesian estimation of the core equation can be obtained from maximizing the following likelihood function:

$$L(Y|\varphi, \Sigma) \propto |\Sigma|^{-T/2} exp\left\{-\frac{1}{2}\sum\nolimits_t (Y_t - X_t\varphi)'\Sigma^{-1}(Y_t - X_t\varphi)\right\}$$

Joint prior and posterior distributions of the parameters are obtained through the Bayes rule (see details in Ciccarelli and Rebucci, 2003).

Disclaimer

Head of Research
Eva Bochorishvili | evabochorishvili@gt.ge

Economist
Lasha Kavtaradze | lashakavtaradze@gt.ge

Head of Analytics
Giorgi Iremashvili | giremashvili@gt.ge

Head of Sector Research
Bachana Shengelia | bshengelia@gt.ge

Senior Analyst
Mariam Chakhvashvili | mchakhvashvili@gt.ge

Analyst
Ana Nachkebia | ananachkebia@gt.ge

Analyst
Kakhaber Samkurashvili | ksamkurashvili@gt.ge

Analyst
Nino Peranidze | nperanidze@gt.ge

Analyst
Tatia Mamrikishvili | tmamrikishvili @gt.ge

Analyst
Nika Megutnishvili | nmegutnishvili@gt.ge

Address: 79 D. Agmashenebeli Avenue, Tbilisi 0102, Georgia
Tel: + (995) 32 2401 111
Email: research@gt.ge