

Economic Analysis of Georgia – Romania Interconnection

Methodology Note



June 2020

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Acronyms and Abbreviations

ATC	Available Transmission Capacity
BA / BIH	Bosnia and Herzegovina
BG	Bulgaria
EIRR	Economic Internal Rate of Return
ENTSO-E	European Network of Transmission System Operators for Electricity
FOR	Forced Outage Rate
GWh	Gigawatt hour
HPP	Hydro-power plant
HVDC	High voltage direct current
MW	Megawatt
MWh	Megawatt hour
NPV	Net Present Value
NTC	Net Transmission Capacity
O&M	Operations & Maintenance
OHL	Overhead line
PSHPP	Pump-storage hydro power plant
RES	Renewable Energy Sources
Res Hydro	Hydro power plants with Reservoirs
RoR Hydro	Run-Of-River hydro power plants
RS / SRB	Serbia
SEE	South-Eastern Europe
SRMC	Short Run Marginal Cost
SS	Substation
ToR	Terms of Reference
TPP	Thermal power plant
TR	Transformer
TRM	Transmission Reliability Margin
TSO	Transmission System Operator
TTC	Total Transfer Capacity
TTF	Total Transfer Flow
TYNDP	Ten Year Network Development Plan
WB	World Bank
WPP	Wind Power Plant

1 INTRODUCTION

The objective of this assignment is to carry out an economic assessment of the proposed submarine cable interconnection between Georgia and Romania through analysis on electricity markets in Europe and South Caucasus. With respect to this, export/import situation as well as wholesale prices for Romania and Georgia, but also for the neighbouring countries/regions have been analysed.

Interconnection project of 1,000 MW capacity should enable the exchanges of electricity between Georgia and other countries in South Caucasus region with Romania and SEE region. This interconnection project should improve the operation indicators of Georgian power system taking into account its specifics as almost completely hydro system with different levels of excess and lack of generation during the year. Electricity exchange with Europe should enable usage of compatibility between Georgian and South East European power systems.

To satisfy the goal, the Study included the technical and economic evaluation of the interconnection by performing electricity market analysis and economic analysis.

The study defined the level of loading factor of Black Sea Submarine Cable and corresponding level of transmission tariff. It took in account the existing situation in Caucasus region (including experience of existing HVDC station operation), including the trends of generation and transmission building vs plans, the trends of demand growth. It defined:

- the risks and challenges not to having loaded the interconnection cable and measures how to overcome the risks (for example, guaranteed long term contracts from neighbouring countries)
- weak points of transmission systems of Caucasus, including the grid, generation, markets...etc and measures of solving these weaknesses
- opportunities of potential trade via Caucasus region for the other neighbouring regions such as Central Asia countries

The analyses has been focused on the project benefits in the period 2030-2040 since its construction could be realized in the late 20's. Market simulations have been carried out for expected development of demand and supply in this period, but also for 2 additional Scenarios that reflect deviation of relevant parameters. Economic assessment took into account calculated benefits and assessed costs in several sensitivity scenarios with different discount rates, economic lifetime of the project or different VOLL values.

This report gives description of methodologies and data sets that have been used for the technical and economic studies. Approval of this Report is necessary precondition for continuation of the work on the Study. We understand that most of the data or results of the analysis would be confidential and cannot be publicly disclosed or made available to third parties without prior approval of the Georgian State Electrosystem (GSE) and the World Bank.

Main results are presented in the form of slides.

2 DEFINITION OF SCENARIOS AND STUDY APPROACH

In order to identify the technical and economic benefits of proposed interconnection between Georgia and Romania, the following 3 Scenarios have been assessed:

- a) Generation development plans and load growth in Georgia according to the following:
 - i. Pessimistic Scenario (G1L3):
G1: **20%** of new capacity is commissioned as per schedule + remaining **80% with 10 years delay**
L3: 7% of annual demand growth rate
 - ii. Base Case Scenario (G2L2):
G2: **40%** of new capacity is commissioned as per schedule + remaining **60% with 5 years delay**
L2: 5% of annual demand growth rate
 - iii. Optimistic Case (G3L1):
G3: **80%** of new capacity is commissioned as per schedule + remaining **20% with 5 years delay.**
L1: 3% of annual demand growth rate
- b) Generation development plans in Armenia and Azerbaijan according to the following:
 - i. Pessimistic Scenario: **40%** of new capacity is commissioned as per schedule + remaining **60% with 10 years delay**
 - ii. Base Case Scenario: **80%** of new capacity is commissioned as per schedule + remaining **20% with 5 years delay**
 - iii. Optimistic Case: **100%** of new capacity is commissioned as per schedule.
- c) Annual demand growth rate in Armenia and Azerbaijan - **Same in all Scenarios:**
 - i. AM: 2% growth rate between 2025 and 2030, after 2030 annual growth rate = 2.3%
 - ii. AZ: 0.7% till 2025, after 2025 annual growth rate = 2%

- d) In these scenarios no commercial exchanges with Russia have been assumed

More details of the expected demand and generation development is given in section 3.

In all Scenarios expected demand and generation development for Romania are based on ENTSO-E Sustainable Transition Scenario.

Expected fuel and CO₂ emission tax as well as prices in Turkey and SEE region (as relevant market area) have been defined on the basis of ENTSO-E TYNDP2018 Global Climate Action Scenario (in which CO₂ price reaches €126/t in 2040).

In addition to these three main scenarios, additional sensitivity scenarios have been analysed:

- 1. Sensitivity Scenario 1 and 2: with commercial exchanges with Russia
 - a) Period of analyses: **only 2030 and 2040**, in two variants of **cross-border capacities: 350 MW and 1,000 MW and export** price at Russian market that corresponds to Nord Pool Spot prices (average from Finish market as \$48.9/MWh have been applied in the analyses).
 - b) All other assumption as in above described Base Case
- 2. Sensitivity case 3: with CAPEX higher for 15%

3. Sensitivity case 4: Discount rate of 8%.

Electricity market analyses and economic assessment have been carried out in order to perform technical and economic evaluation of the project feasibility. Correlations and connections between determined steps are presented in the diagram below (Figure 2.1).

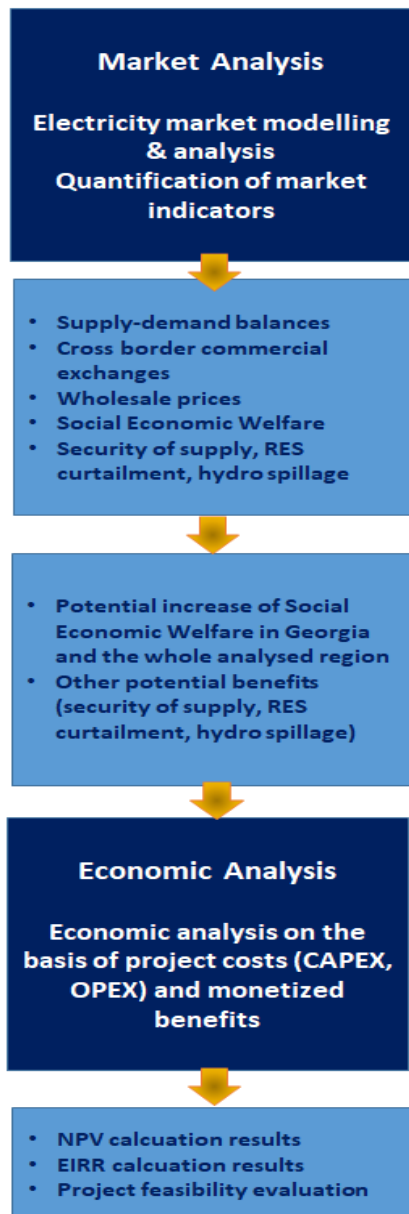
In the first step market modelling is carried out in Antares software tool with all technical and economic data and all relevant assumptions have been applied with the aim to enable simulations of the regional market operation in 3 determined Scenarios: Base Case and 2 Alternative ones.

In the second step, market simulations have been performed for all years, from 2030-2040 on full 8760 hours with chronological sequence. The market simulations represent dispatch simulation for pre-determined expansion plan in South Caucasus based on maximization of social economic welfare, under defined transmission network constraints as limiting factors for cross border trade. Results of electricity market analysis include supply-demand balance of Georgia, Romania and neighbouring South Caucasus, cross-border electricity exchanges among countries in focus as well as towards neighbouring regions modelled as spot markets (Turkey, Central South European countries) and wholesale electricity prices.

To quantify and analyse the possible benefits and risks of Georgia-Romania interconnection, we have carried out a comparative assessment of scenarios with and without project, providing the following primary results of the market simulations:

- overview of electricity balance (generation, consumption, imports and exports),
- cross-border power exchanges for each border in the region,
- location and hours of market congestions
- amount and cost of CO2 emissions for each market area,
- total generation cost for each market area,
- wholesale electricity prices for each market area
- overview last trends of generation/transmission developments in Caucasus/Romania/Turkey

Figure 2.1: Work Flow Diagram and Correlation Between Market and Economic Analyses.



After analysing different market parameters, change in social-economic welfare (SEW) is calculated in order to fully evaluate overall benefits of the new interconnection for region as a whole and separately for individual countries, in our case for Georgia.

According to ENTSO-E definition, this is measured through the following benefits:

- Potential increase of Social Economic Welfare for the whole analysed region and specifically for Georgia - change in social economic welfare based on total surplus approach where producer and consumer surplus for the bidding areas of interest as well as the congestion rent between them, with and without the project are calculated.
- Potential savings due to the improved adequacy in Georgia or in any of the neighbouring countries - value of Lost Load are utilized in order to monetize potential decrease in energy not supplied (ENS) depending on the Scenario (analyses showed that this HVDC interconnection does not have an impact on generation adequacy in Georgia).

Above mentioned benefits and as well as estimated costs presented in chapter 4, serve as an input for the economic analysis. On the basis of monetized benefits and estimated costs, NPV and EIRR calculation are performed to evaluate project profitability. Considering outputs of all three steps, final economic feasibility evaluation is given.

Within economic assessment, several sensitivity scenarios have been carried out with changes of the following parameters:

- Increased CAPEX for 15%
- Discount rate: 8%

3 MARKET ANALYSIS METHODOLOGY AND INPUT DATA

3.1 Methodological approach and software tool

Methodological approach

Generation operation and electricity market simulations have been performed with the aim to obtain optimal system dispatching subjected to cross border network constraints, as well as generation portfolio characteristics. In market simulations carried out by Antares (described in this chapter below), equilibrium between the generation and demand of electricity is established in each hour, taking into account availability of primary energy sources, prices of fuel, but also constraints in available weekly hydro generation or grid limitations. Implicitly perfect market assumption are applied within the market simulation. In that case, the system marginal price is set by the operating cost of the most expensive unit on-line during a given time period. With inelastic consumer bid curve, which is typical in electricity markets, the total dispatch cost minimization provides maximization of the social economic welfare.

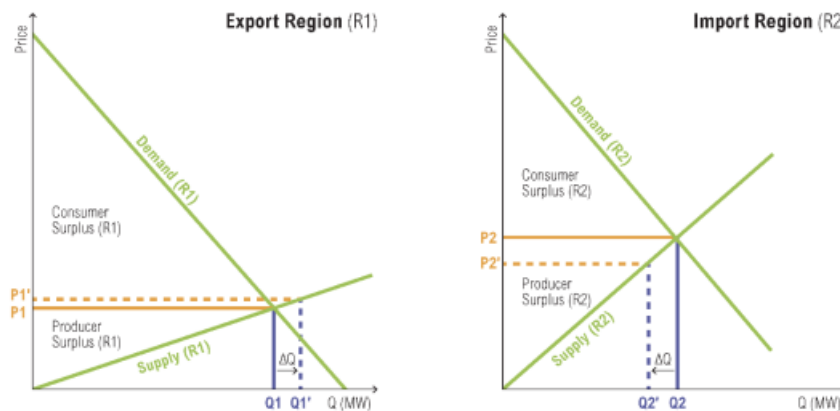
The simulations provide as the main output the chronological optimal generation dispatch and wholesale prices, as well as cross border electricity exchanges. Another important output of the market simulations are supply-demand balances per country, as well as indicators of security of supply.

With the aim to carry out economic analyses of the proposed interconnection project, the following indicators have been determined:

1. Impact on Social Economic Welfare (SEW) of Georgia produced by the proposed interconnection with Romania. This presents the most common economic indicator for measuring benefits of transmission investments. This metric values transmission investment in terms of total generation costs savings, since a project that increases cross border network capacity between two market areas (in this case countries), allows generators in the lower priced area to export power to the higher priced area. In line with the latest ENTSO-E Cost-Benefit methodology CBA 2.0 [2], in this Study, change in social economic welfare is measured using the total surplus approach where producer and consumer surplus for the market areas of interest as well as the congestion rent on their borders are calculated in case with and without the project:
 - Generation fleet will be more efficiently and economically engaged with introduction of new interconnection and this will be reflected in the sum of the producer surpluses.
 - With introduction of new interconnection, higher potential for electricity exchange between low-price and high price areas will be enabled, which will be followed by prices harmonization (reduction of the differences between the prices) and changes in the consumer surpluses.
 - Finally, the new interconnection will lead to a change in total congestion rent for the TSOs.

The SEW benefit is quantified on hourly basis, based on Antares market simulation results, as a difference between calculated total surplus with and without proposed interconnection in operation. The total SEW benefit for each horizon year is calculated by summarizing the benefit for all the hours of the year and same process is repeated for all analysed years in the period 2030-2040.

Figure 3.1: Impact of New Interconnection on Change of Market Surplus.



Source: ENTSO-E.

In addition to the social economic welfare quantification and its breakdown (consumer surplus, producer surplus, congestion revenue) for Georgia, the overall regional total social economic welfare has been calculated as well.

2. Impact on power system adequacy and security of supply in Georgia produced by proposed interconnection has been carried out within market simulations which provides the main indicators of system adequacy and security of supply (energy not served and loss of load duration).

The analytical work within market studies includes operational simulation based on development plans for the Georgian, Armenian, Azerbaijan, Romania power systems as well as power systems of neighbouring countries for the years between 2030 and 2040. Therefore, market optimization of the power system operation is simulated in regional context, encompassing the influence from SEE region, as well as Southern Caucasus countries and Turkey.

Figure 3.2: Region Presented in Antares Market Model.



Cross-border capacities (NTC values) are used as network constraints to cross border electricity trade within the Antares market model. These values are estimated (see chapter 3.2.6) taking into consideration planned investments into transmission network as per relevant countries' transmission

network development plans (e.g. Ten-Year Network Development Plan for Georgia 2019-2029, ENTSO-E TYNDP2018).

NTCs are net transmission capacities regularly used as cross-border capacities available for commercial exchanges. NTCs take into account cross-border, internal and operational (voltage) constraints, ensuring that commercial exchanges up to NTC values do not create problems in the operation of the power system.

Within the Antares market model, power systems/market areas/countries are presented with different level of details:

- Georgia, Armenia, Azerbaijan and Romania:
 - Demand: Total demand defined at hourly level, modelled in one demand centre
 - Conventional generating units (TPP, NPP): unit by unit, with corresponding technical and economic parameters (min and max capacity, operating costs, availability, other operating constraints, etc.);
 - Conventional generating units (HPP, PSHPP): run-of-river, storage (daily, weekly, seasonal), pump-storage; with corresponding technical and economic parameters (capacity, available weekly generation for hydro power plants, other operating constraints, etc.);
 - Renewable sources (wind, solar, biomass): total capacity per technology + generation at hourly level with hourly profiles which correspond to the given capacity factors; this generation is treated as “must run”;
 - Small and Run-of-river HPPs will be also treated as must-run. Operation of HPPs with reservoirs will be optimized within simulations.
 - Grid constraints at interconnections with neighbouring systems: defined as NTCs (chapter 3.2.6)
- Other systems in the South Caucasus and SEE region (Turkey, Hungary, Serbia, Bulgaria):
 - These systems are modelled as spot markets with defined interconnection capabilities and wholesale prices assumed on the basis of current prices (HUPEX, IBEX, SEEPEX, EPIAS) and average prices obtained as a result in TYNDP2018 analyses for Global Climate Action Scenario in 2030 and 2040

Global Climate Action (GCA) Scenario represents a global effort towards full speed decarbonisation. The emphasis is on large-scale renewables and even nuclear in the power sector. Residential and commercial heat become more electrified, leading to a steady decline of gas demand in this sector. Decarbonisation of transportation is achieved through both electric and gas vehicle growth. Energy efficiency measures affect all sectors. Power-to-gas production sees its strongest development within this scenario.(Source: ENTSO-E).
- Russia & Ukraine
 - The exchanges with these systems are estimated as marginal and irrelevant for this Study.

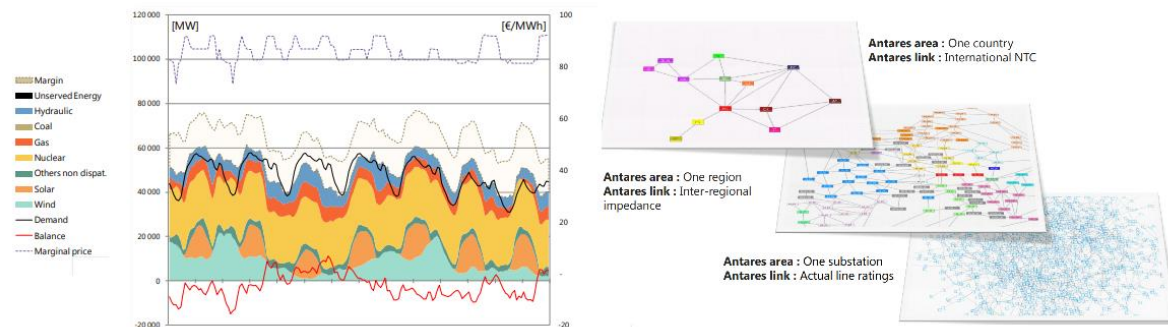
Software tool for market analysis

For conducting the generation dispatch and electricity market analysis, following software tool is deployed:

Antares

Antares is a software tool developed by RTE, for electricity market, adequacy and power system analyses. It performs economic dispatch optimisation on the basis of social welfare maximization, taking into technical and economic parameters of generation portfolio such as hydro inflows and HPPs characteristics, thermal generation features, wind and solar power intermittency, chronological load profiles, as well as available cross border transfer capacities.

Figure 3.3: Illustration of Antares Modelling & Features.



Source: <https://antares-simulator.org/>

Antares is today used for studies ranging from operation planning (a few months) to long term expansion issues (2050). Some of the reference studies include ENTSO-E studies (Ten Year Network Development Plans (TYNDP), Mid Term Adequacy Forecasts (MAF)), eHighway2050, adequacy studies and generation studies. This software tool was also used for similar studies:

- Power Market Study for Belarus: Study in which a detailed power market model was developed and simulations to determine impact of market opening (and other elements of the new Electricity Market Law) on the cost of electricity in Belarus were carried out
- Moldova-Romania B2B link: Study in which economic assessment of the B2B link was carried out
- Ukraine HVDC connection to ENTSO-E, currently underway: Study in which economic assessment of the asynchronous interconnection of Ukraine and ENTSO-E is carried out

3.2 Input data and assumptions

In this chapter, we review the current and expected status of analysed power systems for the period 2030-2040, along with an overview of the data, assumptions and proxies that we will use to develop the corresponding model in the Antares software tool.

We present all relevant parameters so that the reader may check their plausibility and confirm their usability for the upcoming forecasts and analyses.

For Georgia, Armenia and Azerbaijan, input data, encompassing existing and planned generation units with their techno-economic characteristics, demand forecast and transmission infrastructure development, which have been used for the market modelling are mainly obtained from the World Bank. Nevertheless, some of data have been updated and revised considering modelling requirements and approach planned to be applied in the Study. Also, part of the necessary data have been obtained from relevant data sources (ENTSO-E TYNDP2018, MAF2018, exchanges in the SEE region). All data relevant for market simulations and economic assessment are summarized in this chapter.

In case of data that have not been provided but for which typical data exist and can be applied, technical and economic databases developed at ENTSO-E (official ENTSO-E Market Modelling Database) are used. These data are presented in the following three Tables.

Table 3.1: General Technical and Economic Parameters for TPPs.

Category #	Fuel	Type	Efficiency range in NCV terms %	Standard efficiency in NCV terms %	CO ₂ emission factor kg / Net GJ	Variable O&M cost €/MWh	Min Time on hours	Min Time off hours	Start-up fuel consumption - warm start Net GJ /MW start	Start-up fix cost (e.g. wear) warm start €/MW. start	Heat Rate (GJ/MWh) %
1	Nuclear	-	30% - 35%	33%	0	9	12	12	14.0	21	10.91
2	Hard coal	old 1	30% - 37%	35%	94	3.3	8	8	18.0	70	10.29
3		old 2	38% - 43%	40%		3.3	6	6	18.0	50	9.00
4		New	44% - 46%	46%		3.3	5	5	18.0	42	7.83
5		CCS	30% - 40%	38%		6.6	7	7	18.0	50	9.47
6	Lignite	old 1	30% - 37%	35%	101	3.3	11	11	18.0	70	10.29
7		old 2	38% - 43%	40%		3.3	9	9	18.0	50	9.00
8		New	44% - 46%	46%		3.3	8	8	18.0	42	7.83
9		CCS	30% - 40%	38%		6.6	10	10	18.0	50	9.47
10	Gas	conventional old 1	25% - 38%	36%	57	1.1	5	5	7.6	68	10.00
11		conventional old 2	39% - 42%	41%		1.1	5	5	7.6	45	8.78
12		CCGT old 1	33% - 44%	40%		1.6	3	3	7.6	73	9.00
13		CCGT old 2	45% - 52%	48%		1.6	3	3	7.6	43	7.50
14		CCGT new	53% - 60%	58%	5.70	1.6	2	2	7.6	25	6.21
15		CCGT CCS	43% - 52%	51%		3.2	4	4	7.6	43	7.06
16		OCGT old	35% - 38%	35%		1.6	1	1	0.2	52	10.29
17		OCGT new	39% - 44%	42%		1.6	1	1	0.2	20	8.57
18	Light oil	-	32% - 38%	35%	78	1.1	1	1	0.2	36	10.29
19	Heavy oil	old 1	25% - 37%	35%	78	3.3	3	3	7.6	70	10.29
20		old 2	38% - 43%	40%		3.3	3	3	7.6	50	9.00
21	Oil shale	old	28% - 33%	29%	100	3.3	11	11	18.0	60	12.41
22		new	34% - 39%	39%		3.3	8	8	18.0	42	9.23

Source: ENTSO-E Database.

Table 3.2: Additional Technical Parameters for TPPs.

Category #	Fuel	Type	Unavailability				Minimum stable generation	Ramp up rate	Ramp down rate	Fixed generation reduction
			Forced outage		Planned outage					
			annual rate	Mean time to repair	annual rate	winter				
			%	Days	number of days	% of annual number of days				(% of max power)
1	Nuclear	-	5%	7	54	15%	50%	For all unit types, hourly ramp rate is equal to the average unit size.	For all unit types, hourly ramp rate is equal to the average unit size.	0%
2	Hard coal	old 1	10%	1	27	15%	43%			0%
3		old 2	10%	1	27	15%	43%			0%
4		new	7.50%	1	27	15%	43%			0%
5		Lignite CCS	7.50%	1	27	15%	43%			0%
6	Lignite	old 1	10%	1	27	15%	43%			0%
7		old 2	10%	1	27	15%	43%			0%
8		new	7.50%	1	27	15%	43%			0%
9		Hard coal CCS	7.50%	1	27	15%	43%			0%
10	Gas	conventional old 1	8%	1	27	15%	35%			0%
11		conventional old 2	8%	1	27	15%	35%			0%
12		CCGT old 1	8%	1	27	15%	35%			0%
13		CCGT old 2	8%	1	27	15%	35%			0%
14		CCGT new	5%	1	27	15%	35%			0%
15		CCGT CCS	5%	1	27	15%	35%			0%
16		OCGT old	8%	1	13	15%	30%			0%
17		OCGT new	5%	1	13	15%	30%			0%
18	Light oil	-	8%	1	13	15%	35%			0%
19	Heavy oil	old 1	10%	1	27	15%	35%			0%
20		old 2	10%	1	27	15%	35%			0%
21	Oil shale	old	10%	1	27	15%	40%			0%
22		new	7.50%	1	27	15%	40%			0%

Source: ENTSO-E Database.

Table 3.3: Additional Economic Parameters for TPPs.

Start-up fuel consumption - cold start	Start-up fix cost (e.g. wear) cold start	Start-up fuel consumption - hot start	Start-up fix cost (e.g. wear) hot start		
Net GJ /MW. start	€/MW. start	Net GJ /MW. start	€/MW. start	Transition time [h] from hot to warm	Transition time [h] from hot to cold
21.0	94	10.5	49	12	72
21.0	81	10.5	42	12	72
21.0	57	10.5	31	12	72
21.0	81	10.5	42	12	72
21.0	94	10.5	49	12	72
21.0	81	10.5	42	12	72
21.0	57	10.5	31	12	72
21.0	81	10.5	42	12	72
9.7	70	4.1	33	8	48
9.7	59	4.1	28	8	48
9.7	79	4.1	44	8	48
9.7	62	4.1	27	8	48
9.7	36	4.1	22	8	48
9.7	62	4.1	27	8	48
0.3	52	0.2	31	2	3
0.3	24	0.2	17	2	3
0.3	38	0.2	24	2	3
9.7	94	4.1	49	8	48
9.7	81	4.1	42	8	48
21.0	88	10.5	46	12	72
21.0	57	10.5	31	12	72

Source: ENTSO-E Database.

Specific data for each modelled power system has been presented in the following chapters.

For simulations of the market operation, all technical and economic parameters for all technologies are relevant having in mind that engagement of different generating units (or technology clusters) are carried out according to their short-run costs, which include fixed and variable O&M costs, environmental and fuel costs.

Specific (short-run) operating costs are determined for generating units that use natural gas, lignite, coal or uranium as primary fuel. These specific operating costs have been based on specific technical parameters of the plants/clusters (max capacity, efficiency) and forecasted fuel costs that are indicated for each power system separately.

Hydro power plants and RES are modelled as technologies that participate in the wholesale electricity market with the lowest operating costs and for this analysis we assumed no variable operating costs for hydro power plants and for RES (RES is considered to be under feed-in or premium). Thus, operating costs do not have an impact on the priority of these technologies in the merit order list or calculation of the wholesale prices (marginal costs).

New HPPs in Georgia are built as privately-owned power plants and remuneration for their generation is under special agreements with the state-owned Energy System Commercial Operator (ESCO) according to which the specified portion of available generation from these plants have to be taken by ESCO and paid for at the agreed price. In this case, even if there is an excess of generation that cannot be evacuated by the system (and which is “spilled”), payment has to be made (take-or-pay arrangement). Therefore, in market dispatch simulation, they have priority of dispatch, with costs determined by PPAs (US\$/MWh). For storage HPPs under PPA, dispatch simulation is performed in such manner that enables the optimal utilization of water and maximization of revenues. The data on PPA tariffs for power plants in Georgia and Armenia as well as off-take obligations are based on the relevant data received by the World Bank from respective entities in each of the countries. These

costs are considered in the ex-post analyses and calculation of the social–economic welfare (by including them to the overall economic costs of supply).

3.2.1 Georgia

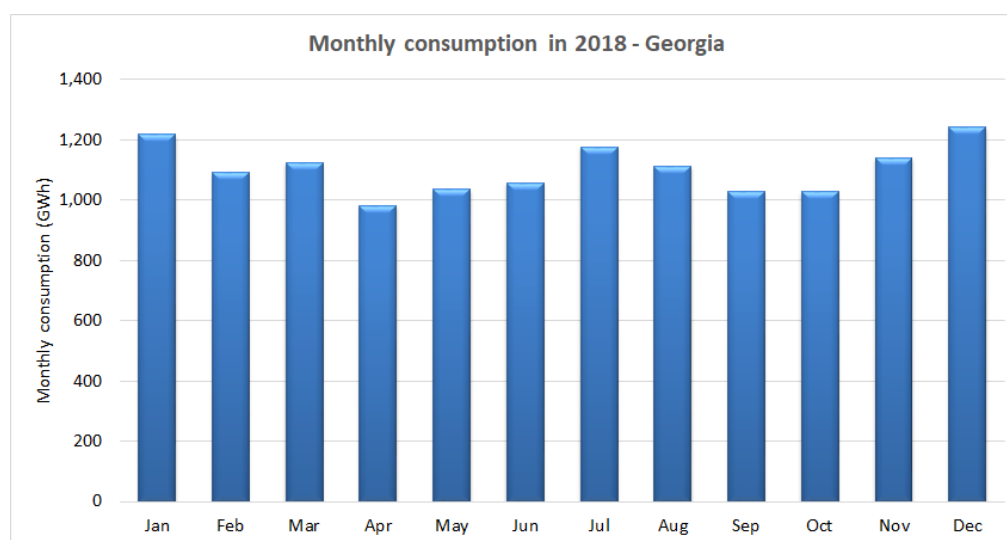
The electricity sector in Georgia - mostly private owned -- is an important foundation for development of the Georgian economy. Therefore, the development of the power infrastructure is a government priority. Given availability of significant hydropower resources, all generation capacity expansion scenarios include new HPP capacity. The economic viability of the new interconnection with Romania is evaluated considering the objective of further expansion of electricity exports.

Electricity Demand

In 2018, annual electricity consumption in Georgia was 13.24 TWh. It includes transmission and distribution losses (around 569 GWh). The maximum hourly load is observed during winter period (Figure 3.4), and in 2018 it reached 2,113 MW (on 31.12.2018. 19:00 PM). The overall electricity load factor for Georgia in 2018 was 71%, which can be considered as a high value.

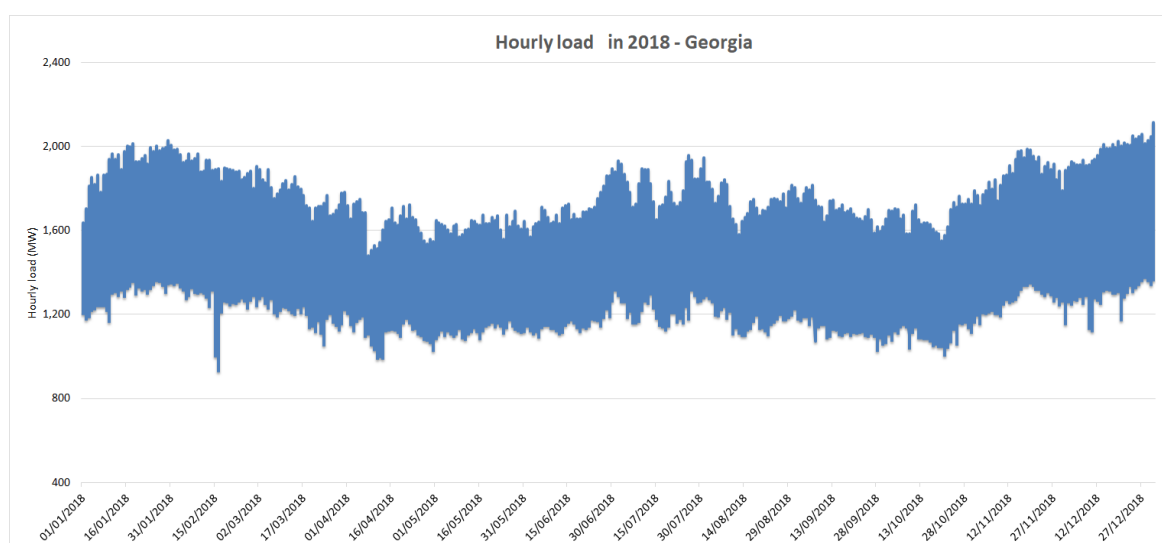
The highest monthly consumption was observed during the winter season (December, January) but, recently, consumption during summer months also increased most likely driven by the increase in air-conditioning load. The lowest consumption occurs in April, as shown in Figure 3.4.

Figure 3.4: Georgia Monthly Consumption in 2018.



Source: GSE.

Figure 3.5: Georgia Hourly Load in 2018.



Source: GSE.

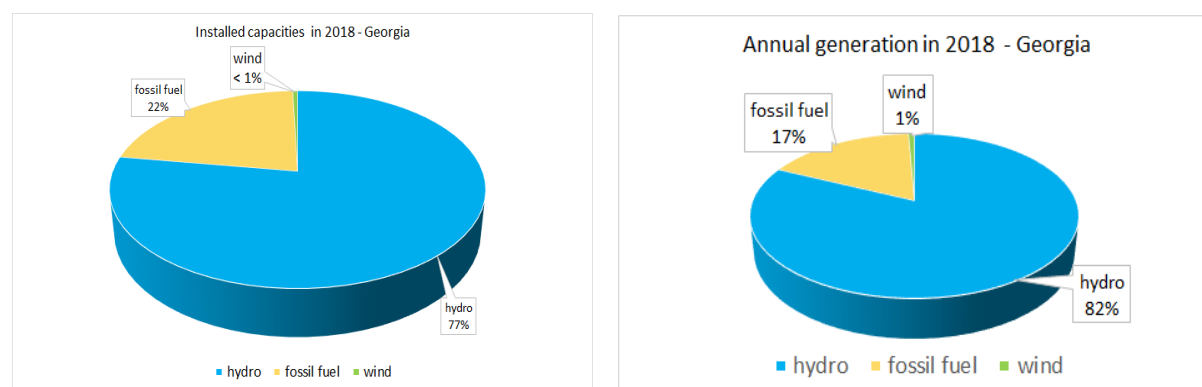
Electricity Generation

Currently, Georgia has about 4,200 MW of installed capacity. Hydro power accounts for 77% (around 3,250 MW), thermal generation - 22% (around 925 MW), and other renewable energy sources (wind) – 1% (20 MW). The thermal generation is comprised of 913 MW of gas-fired power plants and 13 MW of coal.

The total generation (with self-consumption of power plants) in 2018 was about 12,150 GWh, of which 9,950 GWh was generated by HPPs (about 82%), 2,115 GWh by TPPs (around 17%) and 85 GWh from wind power plants (around 1%).

The list of power plants with installed capacities are presented in Table 3.4.

Figure 3.6: Georgia Installed Capacities per Technology and Generation Mix in 2018.



Source: GSE.

Table 3.4: Georgia Installed Generation Capacity.

Installed capacities [MW] in 2018		
Plant	Type	Capacity
Enguri HPP	Storage	1300
Vardnili 1 HPP	Storage	220
Khrami 1 HPP	Storage	112.8
Kharmi 2 HPP	Storage	110
Shaori HPP	Storage	40.3
Dzevrula HPP	Storage	80
Jinvali HPP	Storage	130
Vartsikhe HPP	ROR	184
Shuakhe HPP	ROR	178.7
Lajanuri HPP	ROR	113.7
Dariali HPP	ROR	108
Other ROR and Small HPPs	ROR	673.4
Total hydro		3251
Mtkvari	Gas	300
Tbilsresi	Gas	272
Gpower	Gas	110
Gardabani	Gas	231.2
Tkibuli TPP	Coal	13.2
Total thermal		926
Kartli	wind	21
Total wind		20.7
Total		4198

Source: ESCO.

Electricity Imports and Exports

Since Georgia is connected with Russia and Azerbaijan synchronously and also with Turkey with HVDC connection, Georgia is exchanging electricity with its neighbors. Currently, Georgia is also connected synchronously with Armenia, with 110 kV lines, but that connection is used only in isolated “island” mode.

Having in mind the following facts:

- annual thermal generation is limited at level around 2,200 GWh
- electricity from RES is still negligible, below 100 GWh
- electricity from HPPs can vary significantly (15%, 2,000 GWh) and it depends of hydrological conditions
- relatively high growth of consumption

Currently, as it can be seen in Table 3.5 and on

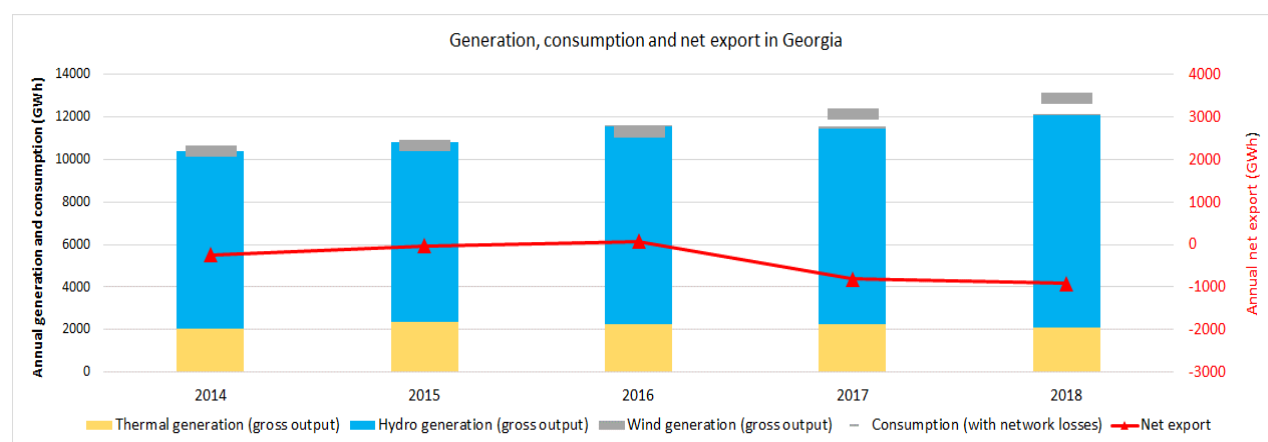
Figure 3.7 , Georgia is becoming an importing country.

Table 3.5: Georgia Electricity Balance in 2014- 2018 (GWh).

Year	2014	2015	2016	2017	2018
Thermal generation (gross output)	2,035	2,379	2,236	2,233	2,114
Hydro generation (gross output)	8,334	8,459	9,327	9,210	9,949
Wind generation (gross output)	0	0	9	88	84
Total generation (Net output)	10,154	10,598	11,363	11,316	11,932
Consumption (with network losses)	10,400	10,631	11,285	12,127	12,853
Net export	-246	-33	78	-811	-921

Source: ESCO.

Figure 3.7: Georgia Annual Generation, Consumption and Net Export in 2014-2018.



Source: Based on Data from GSE and ESCO.

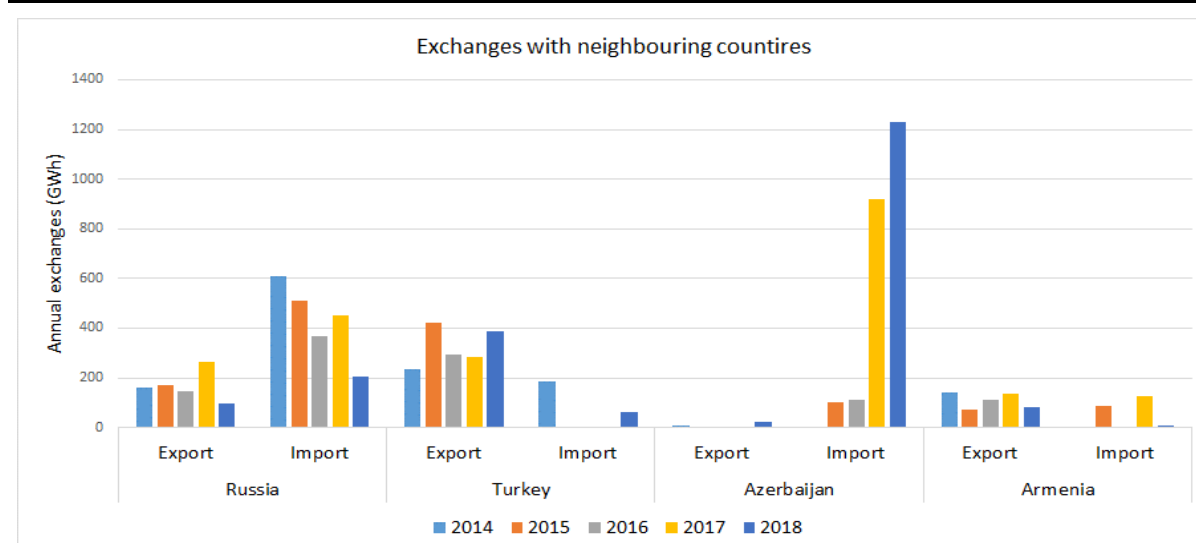
Georgia exports electricity to Turkey and Armenia, while importing mainly from Azerbaijan. With Russia electricity is exchanged in both directions. In the last two years Georgia's import has increased, as it can be seen in Table 3.6 and Figure 3.8.

Table 3.6: Georgia Electricity Exports and Imports.

Year	Russia		Turkey		Azerbaijan		Armenia	
	Export	Import	Export	Import	Export	Import	Export	Import
2014	160	607	237	184	8	2.1	141	0
2015	170	511	420	0	0	102	71	87
2016	148	369	295	0	5	110	111	0
2017	262	452	285	0	2	917	138	127
2018	97	207	386	64.4	23.1	1,230	82.3	7.8

Source: ESCO.

Figure 3.8: Georgia Power Flows.



Source: ESCO.

In Table 3.7 and Figure 3.9 monthly exports/imports are presented. Given that Georgia is a hydro-dominated power system and peak load is in winter, Georgia has a seasonal pattern of electricity exports and imports. During “wet” spring and summer months, Georgia exports excess of electricity generated by HPPs even all TPPs are not operating, while during “dry” winter months when consumption is at maximum level, generation from available thermal and hydro capacities is not sufficient and Georgia imports electricity.

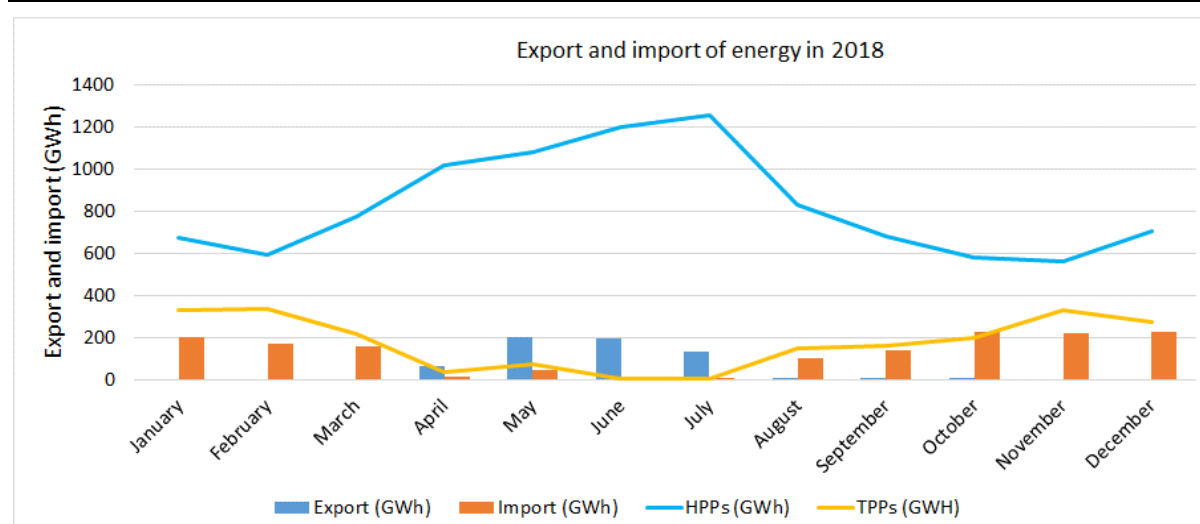
In future period, by commissioning new HPPs, it could be expected that Georgia becomes net exporter of electricity, despite the fact that consumption is growing. However, seasonal pattern of export opportunities will still remain, with the needs for import during winter season.

Table 3.7: Georgia Monthly Electricity Exchanges in 2018.

2018	January	February	March	April	May	June	July	August	September	October	November	December
Export (GWh)	0	0	0	62	200	195	132	0	0	0	0	0
Import (GWh)	202	168	161	11	44	6	1	100	139	230	219	228

Source: ESCO.

Figure 3.9: Georgia Monthly Electricity Exchanges in 2018.



Source: ESCO.

Electricity Demand Forecast for 2030-2040

The Study assumption used for electricity consumption growth in Georgia is based on data used in TYNDP of Georgia. Three different demand forecasts have been analysed:

- Low (L1) with assumed annual growth rate of 3% and
- Base Case (L2) with assumed annual growth rate of 5% and
- High (L3) with assumed annual growth rate of 7%

It is expected that in base case annual demand will reach 18,485 GWh in 2025 and, after that, it will continue to grow with average growth rate of 5% between 2025 and 2040, reaching 38,429 GWh in 2040.

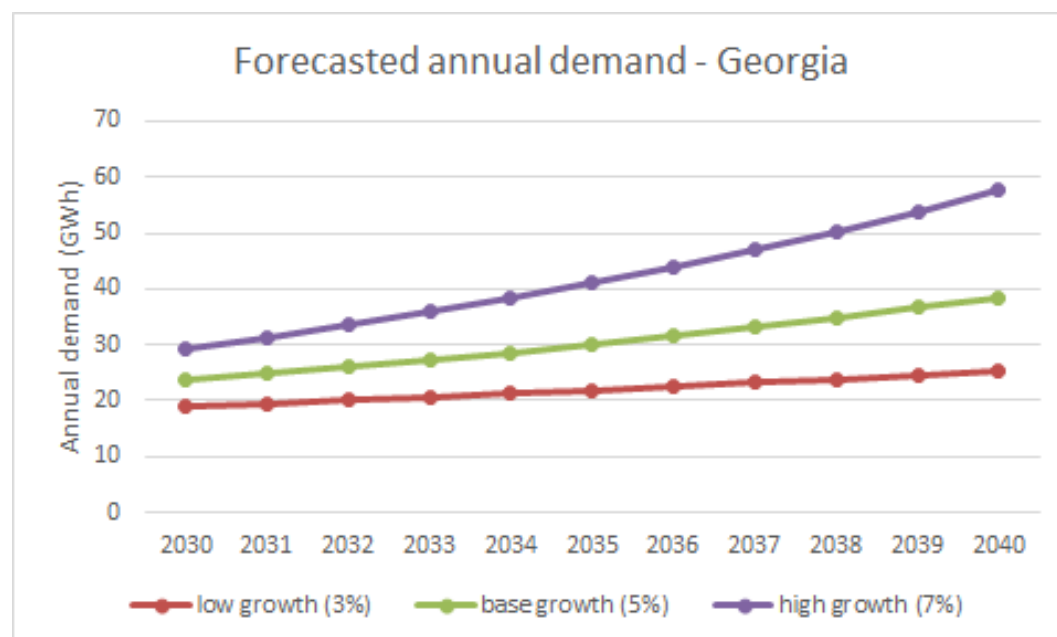
The overview of annual electricity consumption development for the target years analysed within this Study is provided in the table below and depicted on Figure 3.10 and Figure 3.11.

Table 3.8: Georgia Forecasted Annual Electricity Consumption in different scenarios.

Year	Scenario	Annual growth	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Forecasted annual electricity consumption in Georgia [TWh]	L1	3%	18.87	19.44	20.02	20.62	21.24	21.88	22.53	23.21	23.90	24.62	25.36
	L2	5%	23.59	24.77	26.01	27.31	28.68	30.11	31.62	33.20	34.86	36.60	38.43
	L3	7%	29.26	31.31	33.50	35.84	38.35	41.04	43.91	46.99	50.27	53.79	57.56

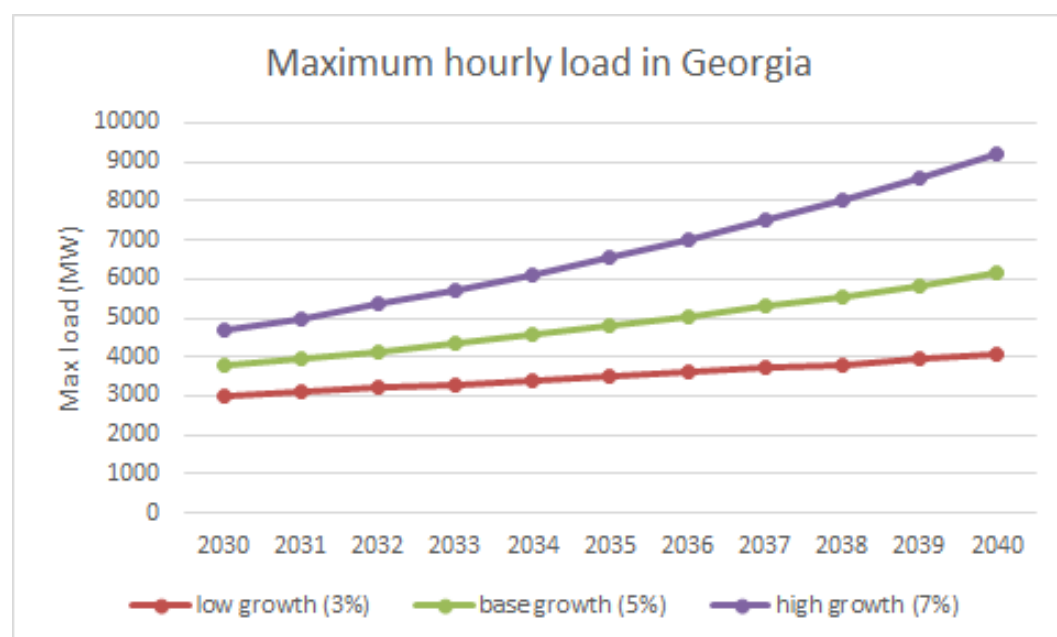
Source: GSE.

Figure 3.10: Georgia Forecasted Annual Demand in different scenarios



Source: Based on data from GSE.

Figure 3.11: Georgia Forecasted Maximum Hourly Load.



Source: Based on data from GSE.

Generation Expansion in 2030-2040

Different scenarios for Generation expansion plan applied in this Study are based on Georgian TYNDP and data provided by WB, but with somewhat more optimistic expectations than applied by GSE in TYNDP.

There are three different scenarios, with following assumptions:

- Scenario G1 in which the following assumption is applied: Timely commissioning of 20% of total installed capacity of prospective power plants and postponement of rest capacity (80%) by 10 years (Table 3.9)
- Scenario G2 in which the following assumption is applied: On time commissioning of 40% of total installed capacity of prospective power plants and postponement of rest capacity (60%) by 5 years (Table 3.10)
- Scenario G3 in which the following assumption is applied: On time commissioning of 80% of total installed capacity of prospective power plants and postponement of rest capacity (20%) by 5 years (Table 3.11).
- The above described assumptions are related to development in the period 2025-2035. In the period after 2035 no new HPPs are encompassed.

As being said, installed capacities for period 2030-2040 for all three scenarios are given in table below. Additional, detailed information about commissioning of new power plants under all these scenarios are given in Appendix in Table 5.1.

Table 3.9: Georgia Generation Expansion Plan for 2025 – 2035 – Scenario G1.

Year	Hydro	Thermal	Wind	Solar	Biomass	Total
2018	3251	926	21	0	0	4198
2030	4099	1156	483	202	0	5940
2031	4261	1156	483	202	3	6105
2032	4465	1156	483	202	3	6309
2033	4675	1156	483	202	3	6519
2034	5207	1156	483	202	3	7051
2035	5643	1406	715	303	3	8070
2036	5904	1406	1065	303	3	8681
2037	6466	1656	1065	303	3	9493
2038	6752	1906	1065	303	3	10029
2039	6936	1906	1065	303	3	10213
2040	7000	1906	1527	505	3	10941

Source: Data from the World Bank and comments from GSE

Table 3.10: Georgia Generation Expansion Plan for 2025 – 2035 – Scenario G2.

Year	Hydro	Thermal	Wind	Solar	Biomass	Total
2018	3251	926	21	0	0	4198
2030	5982	1156	830	353	3	8324
2031	6178	1156	830	353	3	8520
2032	6599	1156	830	353	3	8941
2033	6814	1156	830	353	3	9156
2034	6952	1156	830	353	3	9294
2035	7000	1406	1177	505	3	10091
2036	7000	1406	1527	505	3	10441
2037	7000	1656	1527	505	3	10691
2038	7000	1906	1527	505	3	10941
2039	7000	1906	1527	505	3	10941
2040	7000	1906	1527	505	3	10941

Source: Data from the World Bank and comments from GSE.

Table 3.11: Generation Expansion Plan of Georgia for 2025 – 2035, Scenario G3

Year	Hydro	Thermal	Wind	Solar	Biomass	Total
2018	3251	926	21	0	0	4198
2030	6661	1156	1062	454	3	9336
2031	6726	1156	1062	454	3	9401
2032	6866	1156	1062	454	3	9541
2033	6938	1156	1062	454	3	9613
2034	6984	1156	1062	454	3	9659
2035	7000	1406	1177	505	3	10091
2036	7000	1406	1527	505	3	10441
2037	7000	1656	1527	505	3	10691
2038	7000	1906	1527	505	3	10941
2039	7000	1906	1527	505	3	10941
2040	7000	1906	1527	505	3	10941

Source: Data from the World Bank and comments from GSE.

Basic techno-economic parameters for TPPs (existing and new) are presented in following table.

Table 3.12: Basic Parameters of Existing and New TPPs in Georgia.

Thermal plant	fuel type	Commissioning year	Nominal output (MW)	Heat rate at Pmax [GJ/MWh]	fuel price [\$/GJ]	fixed O&M costs [\$/kW*year]	variable O&M costs [\$/MWh]
Mtkvari	Gas	1989	300	11.02	5.3	38.4	4.4
Tbilsresi	Gas	1965	272	11.32	5.3	38.4	4.4
Gpower	Gas	2006	110	7.67	5.3	12	3.6
Gardabani CCGT	Gas	2016	231.2	7.17	5.3	10	3.6
Tkibuli	Coal	2016	13.2	10.55	1.24	35	3.6
Gardabani CCGT 2	Gas	2020	230	7.17	5.3	10	3.6
CCGT-1	Gas	2035	250	7.17	5.3	10	3.6
CCGT-2	Gas	2037	250	7.17	5.3	10	3.6
CCGT-3	Gas	2038	250	7.17	5.3	10	3.6

Source: Based on data from the World Bank

Also, within the market simulations, three different hydrological conditions are considered - average, dry and wet. The expected annual electricity production in these three conditions is derived from

electricity supply and demand balances of Georgia for 2012, 2016 and 2018, respectively, as shown in Table 3.13.

Table 3.13: Annual Generation of Current HPPs in Specific Hydrological Conditions.

HPP	dry (GWh)	average (GWh)	wet (GWh)
Enguri HPP	3173	3549	4019
Vardnili 1 HPP	586	662	738
Khrami 1 HPP	267	226	194
Kharmi 2 HPP	363	338	311
Shaori HPP	99	131	128
Dzevrula HPP	119	159	131
Jinali HPP	297	339	280
ROR and small HPPs	2315	3920	4148
Total	7219	9324	9949
Ratio	0.77	1	1.07

Source: ESCO.

For new HPPs, the following approach has been applied:

- Average generation and monthly distribution are taken from excel file sent by WB (G1-G2-G3 scenarios of Georgia. xls)
- Ratio between average and dry/wet hydrology is the same as in case of existing plants (*Table 3.13*)

For RES modelling, hourly profiles of capacity factors for wind and solar generation are taken for 2015 and 2016, respectively as provided by WB team. For wind, the average annual capacity factor is 33% (2015), while for the solar it is 18% (2016).

Fuel Costs

Local gas production in Georgia is rather low (less than 0.5% of total annual consumption), therefore, demand of Georgia on natural gas is mainly balanced by import. Generation costs thus depend on the price for imported gas, mainly from Azerbaijan). According to the data obtained from the World Bank and forecasts from World Bank Commodity Database, gas price in the period 2025-2040 will be at the level of US\$5.3/GJ (\$5.6/mmBtu), while price for coal is assumed at the level of US\$1.24/GJ (\$36.5 /Mt). Price for coal and gas will stay at the same level in the period from 2025 till 2040.

3.2.2 Armenia

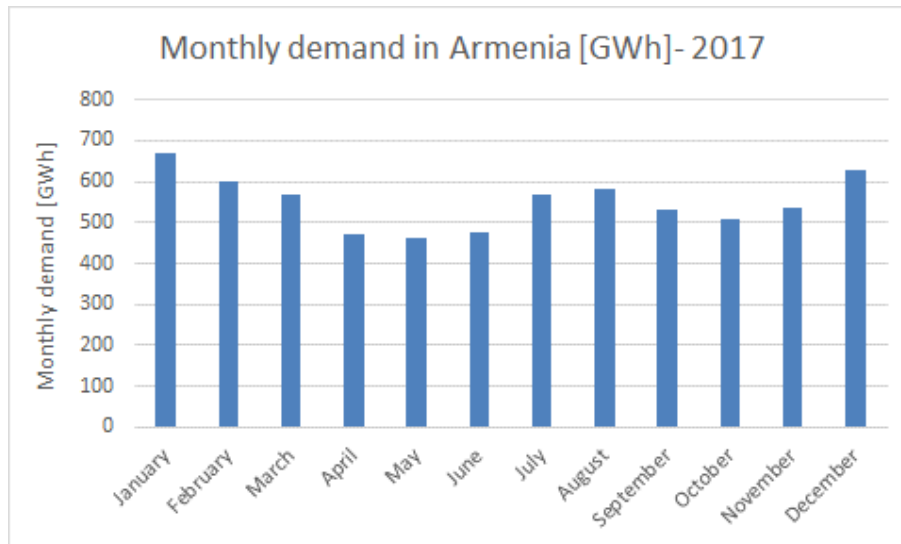
Electricity Demand

In 2017 the total domestic annual consumption was 6,421GWh. This value included both transmission losses (129GWh or 2% of annual demand) and distribution losses (669GWh or 10% of annual demand). The maximum hourly load of 1,175 MW was observed on 24th of January at 7:00 PM. The electricity load factor in Armenia was 64%.

Considering the correlation between temperature changes and consumption, the highest monthly values were observed during winter (January, February and December), while the lowest ones were observed during spring (April and May), as shown in

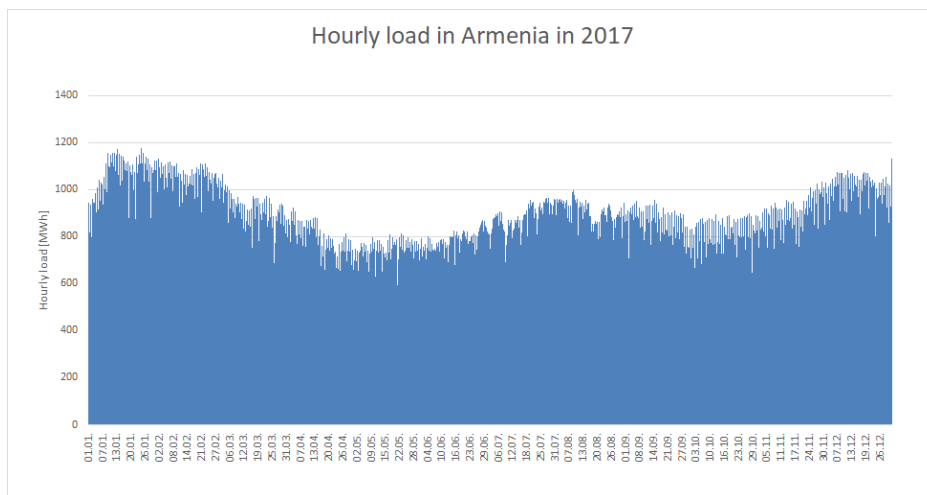
Figure 3.12

Figure 3.12: Armenia Monthly Consumption in 2017.



Source: Armenia Public Services Regulatory Commission (PSRC).

Figure 3.13: Armenia Hourly Load in 2017.

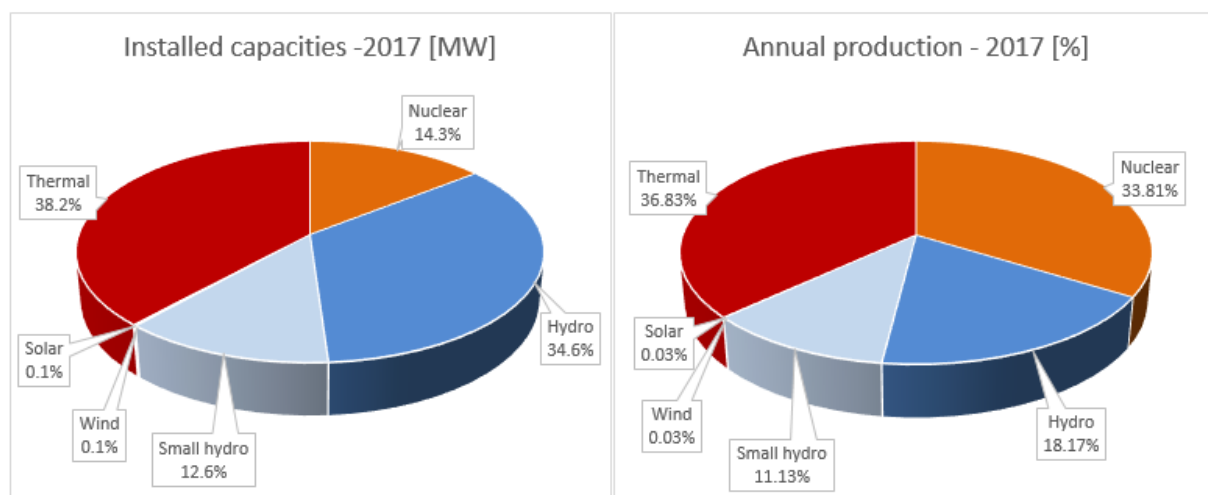


Source: Electric Power System Operator (EPSO).

Electricity Generation

Armenia's electricity generation mix consists primarily of nuclear, thermal, and hydropower. In 2017, gas-fired thermal generation account for 37%, nuclear – for 34%, from nuclear, hydropower for 29%, There is 2.89MW wind power plant.

Figure 3.14: Breakdown of Installed Generation Capacity and Annual Electricity Generation (2017).



Source: PSRC.

Electricity Exports and Imports

Armenia is currently net exporter of electricity. Armenian power system is synchronously connected with Iran, and connects from time-to-time in island mode with Georgia. Interconnections with Azerbaijan and Turkey are out of operation.

As previously mentioned, considering the fact that Armenia has no domestic production of gas, it imports it from Russia and in addition, has signed the contract with Iran where it obliged to deliver 3 kWh electricity for each cubic meter of Iranian gas. This contract is effective until 2027.

Currently, Armenia has surplus generation capability primarily due to supply from hydropower plants in spring and summer. From 2014 till 2017 Armenia's annual exports varied between 1229-1440GWh. In the same period, a smaller amount of imports was recorded (174-320GWh). These imports were limited to covering the peak demand in winter and the maintenance periods of nuclear power plant.

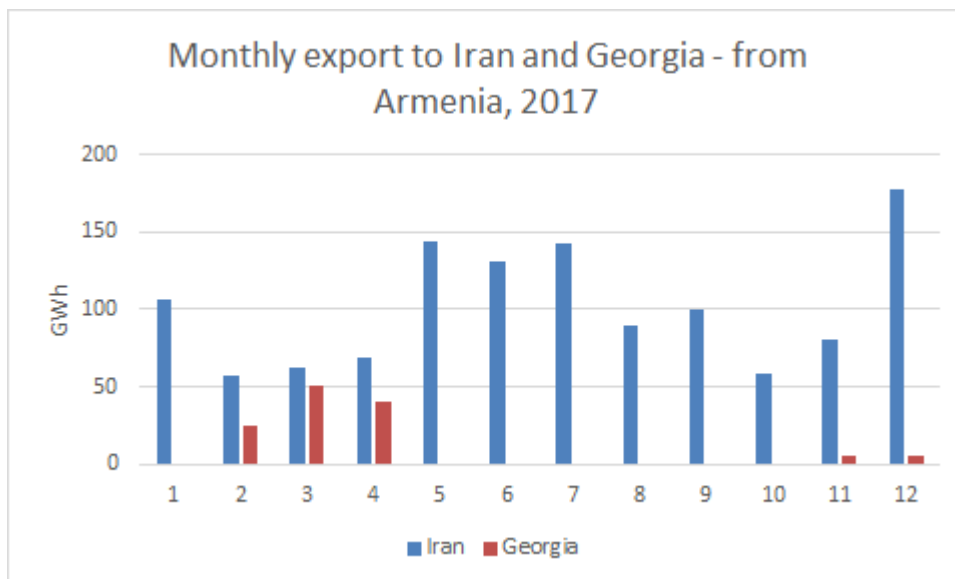
Table 3.14: Armenia Electricity Balance in 2014-2017.

Electricity balance of Armenia	2014	2015	2016	2017
Gas [GWh]	3290	2801	2581	2871
Nuclear [GWh]	2464	2788	2381	2619
Hydro [GWh]	1992	2205	2350	2269
Solar [GWh]	0	0	0	2
Wind [GWh]	3	3	3	2
Electricity generation [GWh]	7750	7798	7315	7764
Industry [GWh]	1244	1341	1631	1655
Households [GWh]	1934	1876	1854	1907
Others [GWh]	2175	2150	1845	2066
Transmission losses [GWh]	139	129	129	124
Distribution losses [GWh]	790	687	706	669
Final (Households+Industry+Others) [GWh]	5352	5368	5329	5623
Total consumption [GWh]	6281	6183	6164	6421
Net imports [GWh]	206	174	276	320
Net exports [GWh]	1314	1424	1229	1440

Source: PSRC.

In 2017, as a part of “gas-for-electricity” swap agreement with Iran, Armenia exported 1218GWh to Iran, while export to Georgia was realized during February-May and during November/December.

Figure 3.15: Armenia Monthly Exports to Iran and Georgia (2017).



Source: PSRC.

Electricity Demand Forecast for 2025-2035

Within this Study the assumptions used for determining electricity consumption growth in Armenia, as well as the total electricity demand from 2025 till 2040 were based on the data provided by World Bank.

From 2025 - 2030, annual electricity demand growth is expected at a rate of 2% based on the electricity demand projection prepared by the World Bank while afterwards its growth will be somewhat higher with an average annual rate of 2.3%. Considering all the above mentioned, annual electricity demand in Armenia will increase from 8,138GWh in 2030 to 10,224GWh in 2040.

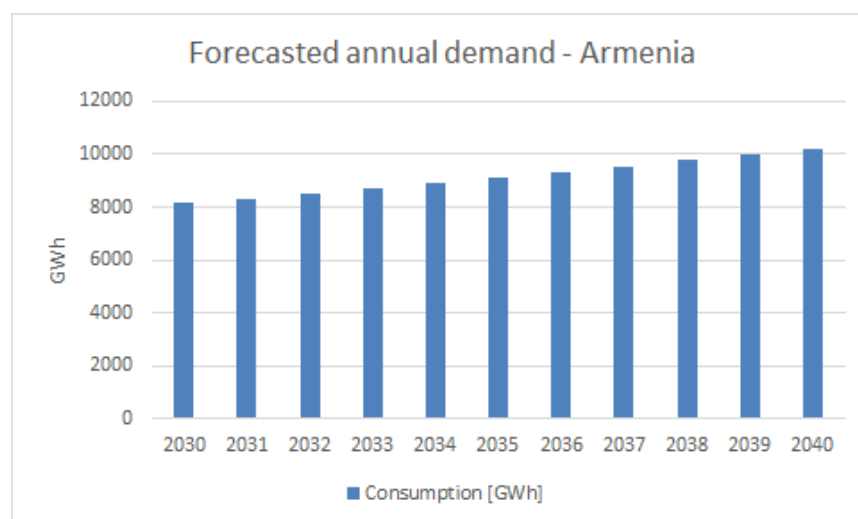
The overview of annual electricity consumption, annual growth rates and maximum hourly load for all target years is provided in the table below and presented on Figure 3.16 and Figure 3.17: This demand forecast will be considered as referent one and indicated as L1.

Table 3.15: Armenia Forecasted Annual Electricity Consumption and Peak Load – Referent demand forecast (L1).

Armenia	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Consumption [GWh]	8138	8327	8520	8717	8919	9126	9335	9550	9770	9994	10224
Peak load [MW]	1450	1483	1518	1553	1589	1626	1663	1701	1740	1780	1821

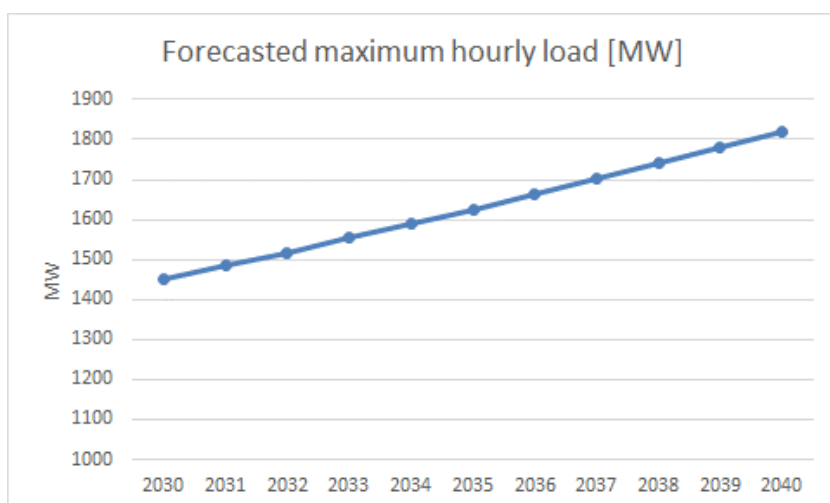
Source: World Bank.

Figure 3.16: Armenia Forecasted Annual Demand and Annual Demand Growth Rate– Referent demand forecast (L1).



Source: World Bank.

Figure 3.17: Armenia Forecasted Maximum Hourly Load – Referent demand forecast (L1).



Source: World Bank.

In all analysed scenarios, in addition to natural demand, we have not included exports to Iran under “gas-for-electricity” agreement (1,218 GWh at annual level) assuming that this contract will be finished by the end of 2028, as given in the datasets provided by World Bank. Export to Georgia (around 126GWh at annual level) is not included in analyses as committed export. Exchange with Georgia has been the result of market simulations.

Generation Expansion in 2030-2040

According to the least-cost generation expansion plan till 2035 and additional information provided by WB for the period after 2035, a few small hydro power plants are expected to be commissioned by 2020, new CCGT power plant of 225MW is projected for 2021 and more than 1100MW of solar capacity by 2035, reaching additional 1500 MW of solar plants in 2040.

The least-cost plan also assumes that ANPP will be decommissioned in 2026 after operating life extension investments are completed in 2020.

Development scenarios indicated as G1, G2 and G3 are presented in Table 3.16. These Scenarios takes into account the following:

- i. Pessimistic Scenario: **40%** of new capacity is commissioned as per schedule + remaining **60% with 10 years delay**
- ii. Base Case Scenario: **80%** of new capacity is commissioned as per schedule + remaining **20% with 5 years delay**
- iii. Optimistic Case: **100%** of new capacity is commissioned as per schedule.

Table 3.16: Armenia Generation Expansion Plan for 2030 – 2040 – all three scenarios.

Year	Installed capacities independent from scenario [MW]						Solar [MW]			Total [MW]		
	Gas	Nuclear	Hydro RoR	Small HPPs	Hydro Storage	Wind	Optimistic	Base	Pesimistic	Optimistic	Base	Pesimistic
2030	893	0	561	415	404	2.9	1052	989	455	3328	3264	2731
2031	893	0	561	415	404	2.9	1052	997	455	3328	3273	2731
2032	893	0	561	415	404	2.9	1052	1052	455	3328	3328	2731
2033	893	0	561	415	404	2.9	1056	1055	457	3332	3331	2732
2034	893	0	561	415	404	2.9	1081	1075	467	3357	3351	2742
2035	893	0	561	415	404	2.9	1406	1395	1184	3682	3671	3460
2036	893	0	561	415	404	2.9	1406	1395	1209	3682	3671	3485
2037	893	0	561	415	404	2.9	1406	1395	1374	3682	3671	3649
2038	893	0	561	415	404	2.9	1406	1396	1374	3682	3672	3649
2039	893	0	561	415	404	2.9	1506	1481	1414	3782	3757	3689
2040	893	0	561	415	404	2.9	1506	1486	1414	3782	3762	3689

Source: World Bank and comments from GSE.

The expected annual electricity production for three different hydrological conditions (average, dry and wet) and basic data for all hydro power plants in Armenia are given in Table 3.17.

Table 3.17: Armenia Annual Generation for all HPPs for Dry, Average and Wet Years.

Hydro power plant	Type	Commissioning year	Nominal Output Power [MW]	Annual generation [GWh] for different hydrological conditions		
				Dry	Average	Wet
Vorotan Cascade	Storage	1970	404	833	941	1119
Sevan-Hrazdan Cascade	RoR	1940	561	475	466	632
Existing SHPP	RoR (Small)	2006	353	689	864	513
New SHPP 1	RoR (Small)	2018	20	39	49	29
New SHPP 2	RoR (Small)	2019	20	39	49	29
New SHPP 3	RoR (Small)	2020	21.7	42	53	32

Source: Based on data from PSRC.

Table 3.18: Armenia TPP Data.

Thermal Plant Name	Fuel type	Commissioning year	Decommissioning year	Nominal Output Power [MW]	Heat Rate at Pmax [GJ/MWh]	Fuel price [\$/GJ]	Fixed Operating & Maintenance Costs [\$/kW-year]	Variable Operating & Maintenance Costs [\$/MWh]	CO2 emission [kg/NET GJ]
ANPP	NUCLEAR	1975	2026	400	17.36	0.385	64	0.8	0
Hrazdan TPP	CHP	1969	2020	400	10.95	5.42	13.8	3.6	57
Hrazdan-5 TPP	CHP	2011	2050	440	8.29	5.42	13	3.6	57
YTPC CCGT	CCGT	2011	2050	227	7.40	5.42	13	3.6	57
CCGT-1 250	CCGT	2021	2050	225.6	6.76	5.42	13	3.6	57

Source: Based on data from World Bank.

The PPA tariff of 5.7 c/kWh was considered for TPP CCGT – 1 250, as suggested by the WB.

The hourly profiles of wind and solar capacity factors are taken for the year 2016. For wind, capacity factors are taken from publicly available databases developed by ETH Zurich (<https://www.renewables.ninja/>) while for solar capacity factors were provided by the World Bank team. Average annual capacity factor for wind is quite low and amounts to 13.4%, while for the solar it is at the level of 18.7%.

There is also a PPA tariff defined for solar power plant Masrik of 4.1 c/kWh throughout a year.

Fuel Costs

Armenia has no domestic production of gas or other fuels for its thermal power plants. Generation costs thus depend on the price for imported gas (mainly from Russia, and with smaller amount from Iran). According to the data obtained from the World Bank, gas prices and uranium dioxide prices will stay the same level in the period from 2025 till 2035. The expected gas price is at the level of \$5.41/GJ (US\$5.71/mmbtu), while for uranium it amounts to \$0.39/GJ (US\$0.41/mmbtu).

Table 3.19: Forecasted fuel prices in Armenia

Fuel type	Unit	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gas	\$/GJ	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.41	5.41
UO2	\$/GJ	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39	0.39

Source: World Bank.

3.2.3 Azerbaijan

Azerbaijan plays a significant energy role in the region, because it is a supplier of natural gas and can export electricity.

In the last period, large investments in power generation and transmission facilities have resulted in improvements in the quality of power supply, enhanced billing and collection, and reduction of losses.

Electricity Demand

Consumption in 2016 was over 21,000 GWh with peak load of 3,681 MW. Monthly consumption is given in Table 3.20.

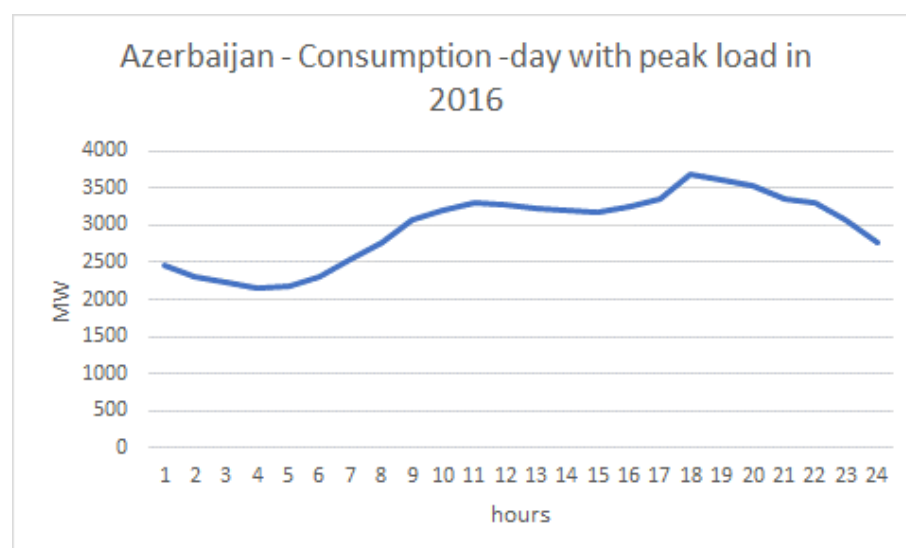
Table 3.20: Azerbaijan Monthly Consumption in 2016.

Month	Energy GWh
1	2040.8
2	1869.1
3	1907.1
4	1651.7
5	1554.7
6	1608.0
7	1827.2
8	1968.2
9	1536.2
10	1731.8
11	1914.9
12	2074.9
Maximum	21684.6

Source: World Bank.

Only one daily consumption diagram has been available (day with maximum hourly load in 2016) and it has been used for development of hourly demand profile for 2016. The level of the hourly loads have been scaled to match monthly consumptions presented in the table above.

Figure 3.18: Azerbaijan Hourly Load During Peak Day in 2016.



Source: World Bank.

Electricity Generation

Azerbaijan has an installed generation capacity of 7,845 MW, with 6,440 MW in thermal power plants (mostly running on domestic gas), and 1,160 MW in hydro power plants. Installed capacity in renewable energy sources (small HPPs, solar, wind and biomass) is 145 MW.

The biggest power plant is TPP Mingcevir (2400 MW available).

Table 3.21: Azerbaijan Installed Generation Capacity in 2018.

Technology	Installed Capacity[MW]
Thermal	6440
Hydro	1160
Small Hydro	15
Wind	60
Solar	40
Biomass	37

Source: Azerenerji.

Electricity Imports and Exports

Construction of new generating units and increase of reliability of the existing units, showed the potential for higher electricity export from Azerbaijan. As it can be seen from Table 3.22¹, exports increased two times, from 500 GWh to 1,300 GWh. Export in 2018 reached 1,450 GWh, while since May 1, 2019, Azerbaijan has started supplying electricity to Greece, Romania, Bulgaria and Hungary through Georgia and Turkey². During first semester in 2019, export reached 900 GWh.

Table 3.22: Azerbaijan Electricity Balance.

Electricity Balance [GWh]	2014	2015	2016	2017
Hydro generation	1,300	1,600	1,900	1,700
Thermal generation	21,400	20,900	20,700	20,500
RES & Others	2,000	2,200	2,400	2,100
Self-consumption of electricity industry	4,000	3,900	4,000	3,800
Total generation	20,700	20,800	21,000	20,500
Consumption (with losses)	20,300	20,600	20,000	19,300
Import	124	108	114	108
Export	489	265	1,906	1,282
Balances	400	200	1,000	1,200

Source: World Bank.

Electricity Demand Projection for 2030-2040

In the last 10 years (2007-2017) consumption increased with moderate growth rate of 0.7% per year (in average). Having in mind recent estimations of expected economic growth (GDP growth rate of around 2% [16]) and further implementation of energy efficiency measures, it is assumed that consumption will continue to increase with the same rate of 0.7% per year till 2025. It might be realistic to expect that after 2025 this growth rate will become higher and reach rate of 2% per year, which will be applied for the whole period between 2025 and 2040.

¹ Source: State Statistical Committee of the Republic of Azerbaijan.

² Source: AzerNews.

With this assumption, electricity demand at generation level (demand that includes transmission losses and does not include self-consumption of power plants) in the period 2030-2040 increases from 25,493 GWh to 31,075 GWh. Electricity demand at generation level and peak loads in each year of the period 2030-2040 is presented in Table 3.23.

Table 3.23: Azerbaijan Annual Electricity Consumption for the period 2030-2040 – Referent Demand Forecast (L1)

Azerbaijan	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Consumption [GWh]	25493	26003	26523	27053	27594	28146	28709	29283	29869	30466	31075
Peak load [MW]	4061	4142	4225	4309	4395	4483	4573	4664	4758	4853	4950

Source: World Bank.

Hourly loads are determined with respect to hourly loads in 2016 that has been determined on the basis of the data for only one day- day with peak load and monthly distribution of consumption.

Generation Expansion Plan for 2030-2040

According to [17]³, there are big plans for further expansion of the power sector in Azerbaijan and they include rehabilitation and modernization of the existing units as well as construction of the new ones. These plans are based on “Strategic Roadmap for the Development of Utilities in Electricity and Thermal Energy, Water and Gas Supply (action plan for 2017-2020 and future plans for the years thereafter)”. According to these plans, in the next few years, electricity generation will reach 27,000 GWh in 2022. Generation expansion that is expected in the period 2030-2040 is presented in Table 3.24. Three development scenarios are based on the following assumptions:

- i. Pessimistic Scenario: **40%** of new capacity is commissioned as per schedule + remaining **60% with 10 years delay**
- ii. Base Case Scenario: **80%** of new capacity is commissioned as per schedule + remaining **20% with 5 years delay**
- iii. Optimistic Case: **100%** of new capacity is commissioned as per schedule.

Table 3.24: Azerbaijan Generation Expansion Plan for 2030 – 2040 – all three scenarios.

Year	Installed capacities independent from scenario [MW]				Solar [MW]			Wind [MW]			Total [MW]		
	Gas	Hydro RoR	Hydro Storage	Biomass	Optimistic	Base	Pesimistic	Optimistic	Base	Pesimistic	Optimistic	Base	Pesimistic
2030	7360	369	986	62	150	137	84	810	770	360	9737	9684	9221
2031	7360	369	986	62	150	137	84	810	770	360	9737	9684	9221
2032	7360	369	986	62	170	160	92	910	870	400	9857	9807	9269
2033	8280	369	986	62	170	160	92	910	870	400	10777	10727	10189
2034	8280	369	986	62	190	182	100	1010	970	440	10897	10849	10237
2035	8280	369	986	62	190	182	127	1010	970	770	10897	10849	10594
2036	8280	369	986	62	190	182	127	1010	970	770	10897	10849	10594
2037	8280	369	986	62	210	202	156	1110	1070	870	11017	10969	10723
2038	8280	369	986	62	210	202	156	1110	1070	870	11017	10969	10723
2039	8280	369	986	62	250	238	190	1150	1122	946	11097	11057	10833
2040	8280	369	986	62	250	238	190	1150	1122	946	11097	11057	10833

Source: Based on data from World Bank.

³ [17] Market_Analysis_Azerbaijan_2019.pdf

(https://www.aserbaidshchan.ahk.de/fileadmin/AHK_Aserbaidshchan/Publikationen/Marktanalyse_Aserbaidshchan_2019/Markt_Analysis_Azerbaijan_2019.pdf)

The expected generation expansion in Azerbaijan will mainly rely on the growth of renewable sources (wind, solar, biomass), which are foreseen to reach 1.4 GW or 13% in 2040 in base case. If we add hydro power plants to the mix, the total renewables share will account to 25%.

Within the market simulation, three different hydrological conditions are considered - average, dry and wet. The expected annual electricity production for 2030 and different hydrological conditions is given Table 3.25. Since most of the favorable locations for hydro power plants are already exploited, no additional HPPs are expected to be commissioned in the period 2030-2040.

Table 3.25: Annual Generation for all HPPs for Dry, Average and Wet Years in 2025.

Annual generation [GWh]	Dry	Average	Wet
ROR	461	512	563
HPPs with reservoirs	1,250	1,388	1,527
Total	1,710	1,900	2,090

Source: Based on data from World Bank.

The gradual decommissioning of older fossil fuel fired units is expected but they will be replaced with the new ones. Installed capacity of thermal units will reach 8.3 GW in 2033, including addition of 2 new units of around 1,000 MW in the period 2025-2035.

Technical parameters for modeling generation portfolio in Azerbaijan are based on official ENTSO-E Market Modeling common base data, presented at the beginning of this chapter.

This level of generation expansion as well as moderate increase of demand will enable increase in Azerbaijan's electricity export.

To enable export of generation excess, generation expansion plan will be followed with extensive transmission network expansion, which will include reinforcement of the corridors towards Iran, Georgia and Russia. Expected cross-border capacities, in the form of NTC are presented in section 3.2.6.

Fuel Costs

Natural gas prices for local consumption in Azerbaijan in 2019 is around \$100/thousand cubic meters (tcm). Having this in mind and forecasts given by the World Bank in the latest Commodity Prices forecast, natural gas price for local consumption in 2030 is estimated at the level of \$96.6/tcm (US\$2.73/mmbtu and US\$2.59/GJ). However, it is assumed that costs of electricity exported from Azerbaijan are related to export prices of gas which are \$196/tcm, and this price has been used as the gas price in our analyses.

3.2.4 Romania

Electricity Demand

The Romanian power system is one of the largest in the region of South East and Central East Europe. The recorded annual net electricity consumption was at a level of 57,900 GWh in 2018 and 55,800 GWh in 2017. The maximum hourly load is observed during winter period, and in 2018 it reached 8,920 MW (on 27.02.2018. 19 h). The minimum hourly load is observed during spring time, and in 2018 it was at a level of 4,091 MW (on 08.04.2018. 14 h). Therefore, the overall electricity load factor for Romania in 2018 was 74%, which can be considered as a high value.

The Study assumption used for electricity consumption growth in Romania is based on ENTSO-E TYNDP2018 Sustainable Transition Scenario, which foresees that the annual electricity consumption in Romania will:

- Reach 60,900 GWh in 2025

- Continue to grow with average growth rate of 0.93% between 2025 and 2030, i.e. reach 63,800 GWh in 2030
- Continue to grow with average growth rate of 1% between 2030 and 2040, i.e. reach 70,466 GWh in 2040.

The overview of annual electricity consumption development for the target years analysed within this Study is provided in the table below:

Table 3.26: Forecasted Annual Consumption in Romania in 2030 – 2040.

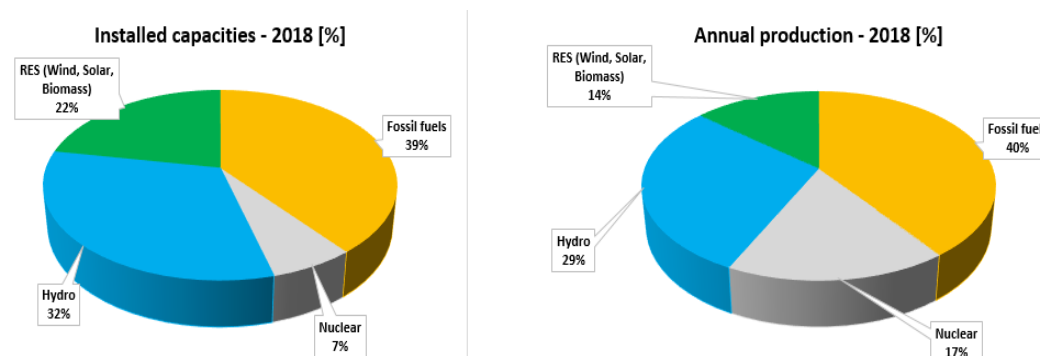
Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Annual electricity consumption - Romania [GWh]	63826	64461	65102	65750	66404	67065	67732	68406	69087	69774	70466

Source: ENTSO-E TYNDP 2018 Sustainable Transition Scenario.

Electricity Generation Expansion Plan

Romania has 19,766 MW of installed generation capacity. The generation mix is comprised of fossil fuel units (39%), nuclear units (7%), hydro units (32%), as well as renewables (22%). This makes generation portfolio of Romania one of the largest and most diversified in the SEE region.

Figure 3.19: Romania Installed Capacity and Annual Generation (2018).



Source: ENTSO-E TYNDP 2018 Sustainable Transition Scenario.

In 2018, the annual electricity production in Romania was 60,700 GWh, which made Romania an electricity exporter (2,100 GWh or 3.5% of domestic production). Most of the electricity surplus was exported to the west (Serbia, Hungary).

The generation expansion plan for Romania is constructed according to ENTSO-E TYNDP 2018 Sustainable Transition Scenario, which covers the period till 2040:

Table 3.27: Romania Generation Expansion Plan for 2025 – 2035.

RO	Gas	Hard Coal	Hydro PSP	Hydro ROR	Hydro RES	Lignite	Nuclear	Oil	Biomass	Solar	Wind	Total
2030	3241	110	0	3291	3331	3415	2630	0	500	2000	4200	22718
2031	3241	110	0	3291	3331	3249	2630	0	500	2300	4430	23082
2032	3241	110	0	3291	3331	3129	2630	0	500	2600	4660	23492
2033	3241	110	0	3291	3331	2839	2630	0	500	2900	4890	23732
2034	3241	110	0	3291	3331	2547	2630	0	500	3200	5120	23970
2035	3241	0	0	3291	3331	2249	2630	0	500	3500	5350	24092
2036	3241	0	0	3291	3331	1951	2630	220	500	3800	5580	24544
2037	3241	0	0	3291	3331	1653	2630	440	500	4100	5810	24996
2038	3241	0	0	3291	3331	1653	2630	660	500	4400	6040	25746
2039	3241	0	0	3291	3331	1653	2630	880	500	4700	6270	26496
2040	3241	0	0	3291	3331	1653	2630	1100	500	5000	6500	27246

Source: ENTSO-E TYNDP 2018 Sustainable Transition Scenario.

The expected generation expansion in Romania till analyzed 2040 will mainly rely on the constant growth of renewable sources (wind, solar, biomass), which are foreseen to reach 12 GW or 44% in 2040. If we add hydro power plants to the mix, the total renewables share will account to 68%. The gradual decommissioning of older fossil fuel fired units is expected as well - on the level of 2.1 GW installed capacities in period 2025-2040. The replacement for these units and the source of base power is expected to come from commissioning of two new nuclear units in Cerna Voda (1.3 GW), expected between 2025 and 2030.

Technical parameters for modeling generation portfolio in Romania are based on official ENTSO-E Market Modeling common base data (presented at the beginning of this chapter).

Hourly profiles of capacity factors for wind and solar generation are taken for 2016 (same as for other analyzed systems). For wind, the average annual capacity factor is 23%, while for the solar it is 14%.

Within the market simulation, three different hydrological conditions are considered - average, dry and wet. The expected annual electricity production for 2025 in different hydrological conditions is given in

Table 3.28. Since most of the favorable locations for hydro power plants are already exploited, only additional 76 MW of RoR hydro power plants are expected to be commissioned in the period 2025-2035. This will increase the total hydro production for rather modest 1.5%.

Table 3.28: 2025 Annual Generation for all HPPs for Dry, Average and Wet Years.

Annual generation [GWh]	Dry	Average	Wet
ROR	8297	10371	11408
HPPs with reservoirs	4443	5553	6109
Total	12740	15924	17517

Source: Consultant estimate.

Fuel and Environmental Costs

For analyzed period (2030-2040), fuel and CO2 prices have been estimated on the basis of ENTSO-E TYNDP 2018 Global Climate Action Scenario that covers period till 2040 and presented in Table 3.29:

Table 3.29: : Forecasted Fuel Prices for 2030-2040

	Type/Year	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
<i>\$/net GJ</i>	Nuclear	0.53	0.53	0.53	0.53	0.53	0.53	0.47	0.47	0.47	0.47	0.47
	Lignite	1.24	1.24	1.24	1.24	1.24	1.24	1.1	1.1	1.1	1.1	1.1
	Hard coal	3.03	3.01	2.99	2.97	2.94	2.92	2.9	2.88	2.86	2.84	2.5
	Gas	9.89	9.52	9.15	8.78	8.4	8.03	7.7	7.37	7.04	6.71	5.5
	Light oil	24.49	23.97	23.44	22.91	22.38	21.85	21.38	20.91	20.44	19.97	17.1
	Heavy oil	20.11	19.67	19.24	18.8	18.36	17.92	17.53	17.14	16.75	16.36	14
	Oil shale	2.58	2.58	2.58	2.58	2.58	2.58	2.3	2.3	2.3	2.3	2.3
<i>\$/ton</i>	CO ₂ price	94.7	99.4	104.1	108.8	113.5	118.1	122.8	127.5	132.2	136.9	141.6

Source: Consultant estimate based on data from ENTSO-E TYNDP 2018 Global Climate Action Scenario.

3.2.5 Neighbouring countries and regions: Turkey, Russia, SEE region

In our market simulation model, power systems in Central Europe (i.e. Hungary, Bulgaria, Serbia) and Turkey have been considered as spot markets, in which market prices are insensitive to price fluctuations in Romania, Georgia, Armenia and Azerbaijan while exchange with these markets are constrained with available cross-border capacities represented by Net Transfer Capacities (NTCs).

Impact of Russian market has not been considered assuming that full utilization of the HVDC GE-RO of 1,000 MW can be realized with electricity excess from South Caucasus markets.

Also impact of exchanges with Burstyn island (Ukraine) has been neglected having in mind rather restricted cross-border capacities between Romania and Burstyn island – 150 MW.

Wholesale market prices in the period from 2030 to 2040 are assumed in accordance with TYNDP 2018 Global Climate Action Scenarios results (TYNDP 2018 Scenario Building Outputs data file). Table 3.30 shows average yearly prices on the modelled external markets.

Table 3.30: Average Yearly Prices on External Markets.

	Price (\$/MWh)			
	Hungary	Serbia	Bulgaria	Turkey
2030	103.10	103.23	105.56	101.72
2031	103.34	103.43	105.56	95.19
2032	103.58	103.64	105.55	88.65
2033	103.82	103.84	105.54	82.12
2034	104.06	104.05	105.54	75.59
2035	104.30	104.25	105.53	69.06
2036	104.54	104.46	105.53	62.53
2037	104.78	104.67	105.52	56.00
2038	105.02	104.87	105.52	49.47
2039	105.26	105.08	105.51	42.94
2040	105.51	105.28	105.51	36.40

Source: ENTSO-E TYNDP 2018 Global Climate Action Scenario.

In order to model the variation of hourly prices throughout the year, we used market prices at respective electricity markets in the last two years to create an hourly pattern, which has been scaled up to average annual price forecasted in ENTSO-E TYNDP 2018. Thus, the hourly profile of electricity prices for Hungary are based on the observed market prices from 2017 to 2018 on the Hungarian Energy Exchange (HUPEX), as well as prices from SEEPEX, IBEX and EPIAS as respective Energy Exchanges from Serbia, Bulgaria and Turkey.

3.2.6 Cross-border Capacities

GSE TYNDP for the period 2019-2029, estimates the following reinforcements in the Georgian network:

Between:	Interconnection Links (2025):
Georgia - Turkey	Actual B2B (2x350 MW)

	+ New B2B (3rd Akhaltsikhe 350 MW, Batumi 350 MW) and corresponding cross-border lines
Georgia - Armenia	New B2B (2x350 MW in Ayrum)
Georgia - Azerbaijan	There are plans for reinforcement of connection with Azerbaijan (changes of conductors on 330 kV Gardabani link)
Georgia - Russia	New 500 kV interconnection line Ksani-Stepantsminda-Mozdok

On the basis of considerations given in GSE TYNDP 2019-2029 and TYNDP 2018, the NTC values presented in Table 3.31 are determined and these values have been applied as cross-border capacities within market simulations in this Study.

Table 3.31: Assumptions on NTC Values for 2030-2040.

NTCs													
From	To	Season	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Armenia	Georgia	Summer	700	700	700	700	700	700	700	700	700	700	700
Georgia	Armenia	Winter	700	700	700	700	700	700	700	700	700	700	700
Armenia	Central Asia	Summer	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Central Asia	Armenia	Winter	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200	1200
Georgia	Turkey (B)	Summer	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Turkey (B)	Georgia	Winter	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Georgia	IPS/UPS	Summer	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
IPS/UPS	Georgia	Winter	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Georgia	Azerbaijan	Summer	1260	1260	1260	1260	1260	1260	1260	1260	1260	1260	1260
Azerbaijan	Georgia	Winter	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
Romania	Bulgaria	Summer	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500	1500
Bulgaria	Romania	Winter	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1400
Romania	HU	Summer	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400	1400
HU	Romania	Winter	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300
Romania	RS	Summer	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300
RS	Romania	Winter	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300	1300

Source: Consultant estimate.

4 ECONOMIC ANALYSIS

Economic assessment of the HVDC Georgia-Romania interconnection has been carried out on the basis of determined benefits and estimated CAPEX and OPEX.

In order to conduct an economic analysis, the following categories (results comprehensive market simulation in different Scenarios) of Project benefits would be evaluated:

- Change in social economic welfare of the analysed region and separately for Georgia.
- Savings due to the potentially improved generation adequacy – reduction in Expected Energy Not Served.

Economic Benefits

- *Expected Energy Not Served and its monetization*

Generation Adequacy is measured by using ENS indicator (Energy Not Supplied) obtained through market simulations for different Scenarios and case with and without project. The change in ENS (MWh) is multiplied by VoLL (€/MWh) to give the monetized impact that project has on security of supply. The Value of Lost Load (VOLL) is a measure of the costs associated with unserved energy (the energy that would have been supplied if there had been no lacks in supply) for consumers. It is generally measured in €/kWh. It reflects the mean value of an outage per kWh (long interruptions) or kW (voltage dips, short interruptions), appropriately weighted to yield a composite value for the overall sector or nation considered.

The reference value for VOLL that is used within this Study is assessed at the level of \$1,000/MWh as the real cost of outages for system users. A level of VOLL that is too high would lead to over-investment, a value that is too low would lead to an inadequate security of supply because the cost of measures to prevent an outage are erroneously weighed against the value of preventing the outage. The optimal level should correspond to the consumer's willingness to pay for security of supply.

The VOLL of \$1,000/MWh (value used among ENTSO-E members) could be considered as too high for South Caucasus region and, having this in mind, implementation of lower VOLL value (e.g. \$500/MWh) was done.

- *Social Economic Welfare*

Social Economic Welfare for the whole analysed region in different Scenarios has been calculated as the difference between total costs in cases with and without project. These indicators give the sum of the benefits for all market participants (consumers, producers, TSOs) in all analysed market zones (countries).

Social economic welfare for Georgia has been calculated as the sum of the changes in Consumer and Producer Surpluses and congestion rents for different Scenarios and cases with and without project.

Economic Costs

In order to conduct an economic analysis, the operational expenditures (OPEX) and capital expenditures (CAPEX) components are assessed on the basis of available information and EKC's in-house databases for the projects of this type and scope.

CAPEX value is based on investment cost components, depending on the possible HVDC capacity of 1,000 MW or 2,000 MW. Within this Phase of the Study, only capacity of 1,000 MW is investigated.

CAPEX is also dependent of the level of financing and in this analyses, we are assuming that the whole level of financing is depleted, which is known as a robust case.

The estimation of the investment costs for the Georgia-Romania HVDC interconnection have been based on the available information in [18] (Table 4.1), but also on data related to similar projects presented in TYNDP2018 [1] and analysed in [24]: *IceLink, HVDC of 1,000 MW and line long more than 1000 km, investment cost between \$2 and \$2.7 billion*. Based on these data, and main parameters of HVDC Georgia-Romania:

- technology of the HVDC connection will be VSC (more expensive, but more controllable technology).
- Length of the line is 1100 km (distance assessed by GoogleMaps).
- Capacity of the convertor stations are 1,000 MW.

investment costs are estimated and presented Table 4.2.

Table 4.1: Techno-Economic Data on Completed and Contracted VCS HVDC Interconnection Projects [18].

Project name	Rated power MW	Line length			Contracted cost ($C_{ref,i}^{con}$)			Source(s)
		SMC ⁺ km	UGC ⁺ km	OHL ⁺ km	Line M€*	Converters M€*	Total M€*	
EstLink1	350	74	31	-	84.8		84.8	[25]
EWIC	500	186	76	-	291.1	130.6	421.7	[26], [27]
NordBalt	700	400	13	40	268.7	169.9	438.6	[28], [29]
Åland	100	158	-	-	99.1		99.1	[30]
Skagerrak4	700	138	92	12	127.0	131.9	258.9	[31], [32], [33]
NordLink	1,400	516	54	53	936.5 ^a	395.9 ^a	1,332.3	[34], [35]
NorthSeaLink	1,400	720	7	-	890.0	408.9	1,298.9	[36], [37], [38]
COBRA	700	299	26	-	250.0	170.0	420.0	[39], [40]
IFA2	1000	208	27	-	320.2 ^b	270.0	590.2	[41], [42]

⁺ SubMarine Cable (SMC), UnderGround Cable (UGC), OverHead Line (OHL)

^{*} Currency other than € was converted with the monthly average exchange rate [24] corresponding to the press releases' date of publication.

^a When calculating the converter and cable costs of the NordLink project, equal length-specific submarine cable cost for both the Nexans and ABB contract were assumed.

^b The HVAC cable on the UK side has been excluded from Prysmian's total contract volume of 350 M€ [42] by assuming a cost-equivalent length factor of 2.5.

Table 4.2: Estimated Investment Cost for HVDC Georgia – Romania Interconnection.

HVDC Georgia - Romania, VSC technology, line capacity 1000 MW				
	Lenghts	Line costs	Converters costs	Total costs
	Km	MUSD\$	MUSD\$	MUSD\$
HVDC	1,195	1,800	500	2,300
Reinforcement in Georgia				36
Reinforcement in Romania				35
TOTAL CAPEX				2,371

*-Assumed ratio USD\$: EUR = 0.89

It is important to note that these investment costs include reinforcements in internal Georgian and Romanian networks which would be possible needed in case of 1,000 MW HVDC connection. This estimated CAPEX has been applied as referent value, but economic assessment included additional option with +15% of CAPEX.

Concerning operating costs, we are assuming 1.5% for the first 10 years, which gradually increases to 2.2% until the end of the useful life.

These assumptions have been adequately applied for interconnection economic lifetime of 40 years which is in line with current practice.

Economic Assessment

Economic assessment has been performed for calculated benefits and costs. Utilised economic performance indicators are composed of EIRR and Net Present Value. Referent value of discount rate is 6%. Additional analyses has been made with higher discount rate of 8%.

Net Present Value is to be composed of the discounted cash flow taking into account the aforementioned benefits.

IRR represents a breakeven point in case of net present value analysis due to the discounting process. By comparing Internal Rate of Return and Net Present Value, the profitability analysis of the different scenarios has been conducted.

Economic assessment took into account calculated benefits and assessed costs in several sensitivity scenarios for different discount rates and level of CAPEX.

5 APPENDIX

Table 5.1 includes different options of generation commissioning:

- **G1 scenario** means timely commissioning of 20% of total installed capacity of prospective power plants and postponement of rest capacity (80%) by 10 years;
- **G2 scenario** – on time commissioning of 40% of total installed capacity of prospective power plants and postponement of rest capacity (60%) by 5 years;
- **G3 scenario** – on time commissioning of 80% of total installed capacity of prospective power plants and postponement of rest capacity (20%) by 5 years.

Table 5.1: Georgia Generation Expansion Plans for 2020-2035.

New Power Plants	Source	Type	Installed Capacity (MW)	Scenario G3	Scenario G2	Scenario G1
Mestiachala 2	HPP	ROR	30	2019	2019	2019
Avani	HPP	ROR	3.5	2019	2019	2019
Zemo Orozmani	HPP	ROR	1.12	2019	2019	2019
Mestiachala 1	HPP	ROR	20	2019	2019	2019
Rachkha	HPP	ROR	3.03	2019	2019	2019
Aragvi 2	HPP	ROR	1.95	2019	2019	2019
Skhalta	HPP	ROR	9.8	2020	2020	2020
Stori 1	HPP	ROR	20.03	2020	2020	2020
Lakhami 1	HPP	ROR	6.4	2020	2020	2020
Lakhami 2	HPP	ROR	9.5	2020	2020	2020
Khadori 3	HPP	ROR	5.4	2020	2020	2020
Zekari	HPP	ROR	1.98	2020	2020	2020
Chapala	HPP	ROR	0.43	2020	2020	2020
Tbilisi Sea	HPP	ROR	0.6	2020	2020	2020
Chartali	HPP	ROR	1.99	2020	2020	2020
Mashavera 1	HPP	ROR	1.56	2020	2020	2020
Mashavera 2	HPP	ROR	1.52	2020	2020	2020
Zemo Karabulakhi	HPP	ROR	1.03	2020	2020	2020
Boko	HPP	ROR	1	2020	2020	2020
Khrami	HPP	ROR	1.13	2020	2020	2020
Gardabani 2	TPP	CCGT	230	2020	2020	2020
Khobi 2	HPP	ROR	46.7	2021	2026	2031
Mtkvari	HPP	ROR	53	2021	2026	2031
Samkuristskali 1	HPP	ROR	4.8	2021	2026	2031
Samkuristskali 2	HPP	ROR	26.28	2021	2026	2031
Sashuala 1	HPP	ROR	6.99	2021	2026	2031
Sashuala 2	HPP	ROR	4.57	2021	2026	2031
Narovani	HPP	ROR	0.84	2021	2026	2031
Lopota 1	HPP	ROR	5.9	2021	2026	2031
Dvirula	HPP	ROR	1.998	2021	2026	2031
Kasleti 1	HPP	ROR	8.1	2021	2026	2031
Baisubani	HPP	ROR	5.36	2021	2026	2031
Akhalsopeli	HPP	ROR	5	2021	2026	2031
Torzila	HPP	ROR	1.686	2021	2026	2031
Kvemo Orozman	HPP	ROR	0.63	2021	2026	2031
Jagon-Nashumi	HPP	ROR	1.991	2021	2026	2031
Naceshari	HPP	ROR	1.97	2021	2026	2031
Lahlachala	HPP	ROR	12	2021	2026	2031

Deka	HPP	ROR	1.2	2021	2026	2031
Patara Zekari	HPP	ROR	1.89	2021	2026	2031
Plato	HPP	ROR	9.5	2021	2026	2031
Borjomi	HPP	ROR	2.3	2021	2026	2031
TOTAL WPP-1	WPP	W	289.15	2021	2026	2031
TOTAL SPP-1	SPP	S	126.25	2021	2026	2031
Gardabani	BPP	B	3	2021	2026	2031
Goginauri	HPP	ROR	4.72	2022	2027	2032
Nakra	HPP	ROR	7.5	2022	2027	2032
Khelra	HPP	ROR	3.3	2022	2027	2032
Ifari	HPP	ROR	3	2022	2027	2032
Baramidze	HPP	ROR	7.8	2022	2027	2032
Buja 1	HPP	ROR	1.72	2022	2027	2032
Buja 2	HPP	ROR	1.05	2022	2027	2032
Buja 3	HPP	ROR	1.99	2022	2027	2032
Laskadura	HPP	ROR	6.6	2022	2027	2032
Udzilaurta	HPP	ROR	8.48	2022	2027	2032
Darchi	HPP	ROR	16.9	2022	2027	2032
Zoti	HPP	ROR	44.31	2022	2027	2032
Lukhra	HPP	ROR	5.2	2022	2027	2032
Bakhvi 2	HPP	ROR	20	2022	2027	2032
Dzegvi	HPP	ROR	15.7	2022	2027	2032
Sorgiti 1	HPP	ROR	13	2022	2027	2032
Sorgiti 2	HPP	ROR	10	2022	2027	2032
Chordula	HPP	ROR	1.973	2022	2027	2032
Gubazeuli 6	HPP	ROR	3.06	2022	2027	2032
Barisakho	HPP	RES	13.52	2022	2027	2032
Fona	HPP	ROR	10.62	2022	2027	2032
Sadmeli 2	HPP	ROR	4	2022	2027	2032
Meneso	HPP	ROR	8.2	2022	2027	2032
Akavreta	HPP	ROR	20	2022	2027	2032
Tita	HPP	ROR	4.51	2022	2027	2032
Khada 1	HPP	ROR	2.6	2022	2027	2032
Shavi Aragvi 1	HPP	ROR	3	2022	2027	2032
Nakhidura	HPP	ROR	9.04	2022	2027	2032
Khevi	HPP	ROR	3.08	2022	2027	2032
Metekhi 1	HPP	RES	36.73	2023	2028	2033
Kheledula 3	HPP	ROR	50.77	2023	2028	2033
Mazhieti	HPP	ROR	12.28	2023	2028	2033
Ghebi	HPP	ROR	14.34	2023	2028	2033
Ghere	HPP	ROR	9.41	2023	2028	2033
Chiora	HPP	ROR	14.15	2023	2028	2033
Sakaura	HPP	ROR	11.58	2023	2028	2033
Magana and Leqandre Cascade	HPP	ROR	8.5	2023	2028	2033
Akhalkalaki	HPP	ROR	9.88	2023	2028	2033
Nakra 1	HPP	ROR	8.8	2023	2028	2033
Nakra 2	HPP	ROR	12.8	2023	2028	2033
Tbilisi	HPP	ROR	20.2	2023	2028	2033
Kiziladjlo	HPP	ROR	4	2023	2028	2033
Digomi	HPP	ROR	17.5	2023	2028	2033
Oqropilauri	HPP	ROR	4.36	2023	2028	2033
Bzhuzha 2	HPP	ROR	5	2023	2028	2033

Khrami 3	HPP	ROR	16.07	2023	2028	2033
Khada 2	HPP	ROR	1.1	2023	2028	2033
Shavi Aragvi	HPP	ROR	5.3	2023	2028	2033
Lajanuri 1	HPP	ROR	5.2	2024	2029	2034
Lajanuri 2	HPP	ROR	5.4	2024	2029	2034
Lajanuri 3	HPP	ROR	5.4	2024	2029	2034
Tsablari 2	HPP	ROR	24	2024	2029	2034
Oni 1	HPP	ROR	122.46	2024	2029	2034
Kamara	HPP	ROR	13.5	2024	2029	2034
Jonouli 2	HPP	ROR	32	2024	2029	2034
Vedi	HPP	ROR	24.06	2024	2029	2034
Namakhvani Cascade	HPP	RES	433	2024	2029	2034
Nenskra	HPP	RES	280	2025	2030	2035
Cirmindi	HPP	ROR	15.67	2025	2030	2035
Dizi	HPP	RES	250	2025	2030	2035
TOTAL WPP-2	WPP	W	289.15	2025	2030	2035
TOTAL SPP-2	SPP	S	126.25	2025	2030	2035
Oni 2	HPP	ROR	83.7	2026	2031	2036
Mtkvari Cascade 4	HPP	ROR	78.1	2026	2031	2036
Khobi 1	HPP	ROR	60	2026	2031	2036
Paldo	HPP	ROR	7.4	2026	2031	2036
Mleta	HPP	ROR	4.88	2026	2031	2036
Kvesheti	HPP	ROR	10.37	2026	2031	2036
Bochorma	HPP	ROR	5	2026	2031	2036
Akhaldaba	HPP	ROR	73.79	2026	2031	2036
Qvedi	HPP	ROR	1.73	2026	2031	2036
Andeziti	HPP	ROR	1.1	2026	2031	2036
Khudoni	HPP	RES	702	2027	2032	2037
Tskhenistskali Cascade	HPP	ROR	357.1	2028	2033	2038
Kvanchiani	HPP	RES	230	2029	2034	2039
Ieli	HPP	RES	80	2030	2035	2040
TOTAL WPP-3	WPP	W	578.3	2030	2035	2040
TOTAL SPP-3	SPP	S	252.5	2030	2035	2040

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