Assessment of Fiscal Costs and Tariff Impacts of Power Purchase Agreements

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Contents

Abbreviations

BCM	Billion Cubic Meters
CCGT	Combined Cycle Gas Turbine
ESCO	Electricity Sector Commercial Operator
GDP	Gross Domestic Product
GNERC	Georgian National Energy Regulatory Commission
GSE	Georgian State Electrosystem
HPP	Hydro Power Plant
IFC	International Finance Corporation
IMF	International Monetary Fund
kWh	Kilowatt Hour
LCP	Least Cost Plan
LRAIC	Long-run Average Incremental Cost
MW	Megawatt
PPA	Power Purchase Agreement
TCM	Thousand Cubic Meters

Assessment of Fiscal Costs and Tariff Impacts of Power Purchase Agreements

Objective of the Note

The objective of this Note is to present the results of an assessment of the potential impacts of Power Purchase Agreement (PPAs) in the Georgian power sector, in terms of their fiscal costs and tariff impacts. This analysis was undertaken in response to a request from the Ministry of Finance of Georgia to assess the fiscal risks of: (i) all PPAs[1] signed by the Government for development of new power plants; and (ii) the PPAs considered by the Government for the Namakhvani cascade of HPPs (which includes Namakhvani and Tvishi HPPs) and Koromkheti HPP.

Summary of the Analytical Approach

For the purposes of this Note, rather than calculate the fiscal risks as originally requested, which is a complicated exercise requiring estimates of probability distributions of key variables such as gas prices or electricity export prices[2], the potential impacts of the PPAs were estimated in two parts: (a) their fiscal costs and (b) their tariff impacts[3].

(a) The fiscal costs to the state budget may arise due to surplus energy from projects which are not part of the least cost generation expansion plan (LCP).

(b) Additional tariff impacts could arise from the higher cost of these projects when compared to the least cost option. It should be noted that if these impacts are not passed through to tariffs, they could create quasi-fiscal costs in the form of losses on the balance sheet of the state-owned Electric System Commercial Operator (ESCO).

We note that this analysis does not take into account the financial costs to the state budget which may result from other provisions in the PPAs, such as payment delays by ESCO for energy delivered, termination payments in case of political and other force majeure events, and other payments that may be due considering the risks undertaken by the Government.

The evaluation of the impacts of the PPAs for hydropower projects required multiple analytical steps, including updating the 2013 least cost generation expansion plan to determine the lowest cost combination and timing (of commissioning) of projects to meet the domestic electricity demand, an update of the demand forecast, and development of the detailed tariff model of the power sector. To simulate the impacts of the PPAs under negotiation, the subject hydropower projects were "forced" into the supply mix thereby replacing other least cost options. The analytical approach for evaluation of fiscal costs and tariff impacts of PPAs, related economic and financial analyses, and the tariff models were all

[1] The Ministry of Energy requested to exclude 750MW Khudoni HPP from the analysis given the uncertainties around this project.

[2] In order to evaluate the fiscal risk from PPAs, assumptions would need to be made about the probability distribution of certain key input variables materially impacting the results of the analysis (e.g. export prices in major markets). For the purposes of this analysis, it would be hard to agree on a reasonable probability distribution which draws upon the observed frequency of values for such key input variables. Therefore, the analysis is confined to evaluation of fiscal costs under the base-case values for key inputs.

[3] The Bank used the same approach to estimating the costs and tariff impacts, results of the estimation were shared with the Government in June 2016.

reviewed by the Ministry of Energy, Ministry of Finance, and the Georgian National Energy and Water Supply Regulatory Commission (GNERC). The analysis was done using the inputs and assumptions from Ministry of Energy, including the key terms of signed PPAs[4] and the indicative PPA terms for Namakhvani cascade, Koromkheti HPP, and Nenskra HPP (see Table 1 of the Technical Annex for details). The key underlying assumptions for the power sector tariff model were discussed and agreed with GNERC. The key macroeconomic assumptions were agreed with the Ministry of Finance and the IMF.

Key Findings

The following are the key findings from the assessment of fiscal costs and tariff impacts of PPAs:

a. *PPAs for projects which are not part of the LCP may create an estimated fiscal cost of GEL1.2 billion (US$474 million) in present value terms due to surplus energy beyond the level required by the system to meet demand.* The projects which are not part of the LCP are estimated to create fiscal cost because they would not be dispatched at full capacity given electricity demand constraint, and thus would result in surplus energy.

   Tvishi HPP (part of the Namakhvani cascade) and other projects (for example, Shuakhevi HPP) are not expected to create fiscal costs given that: (i) they are relatively small compared to the projected electricity demand; and (ii) the PPA prices for these projects are below the estimated annual marginal cost of electricity supply, which means they would be fully dispatched under market conditions.

   - The fiscal cost from Nenskra HPP is the largest followed by Namakhvani HPP (part of the Namakhvani cascade) and Koromkheti HPPs. Nenskra HPP has the largest impact because it has the highest indicative PPA tariff starting at 7.55 USc/kWh with 3% annual escalation, off-take liability of 34 years, and estimated annual generation of 1.2 billion kWh per year, which is 9 percent of projected total domestic demand in 2023.[5]

Table 1: Estimated Annual Fiscal Cost under PPAs (million GEL).

	2022	2023	2024	2025	2026	2027	2028	2030	2032	2034	2036	2041	Total for 2022-2041
Nenskra	-	225	231	238	250	252	260	276	293	310	329	382	**5632**
Namakhvani	39	36	37	38	38	39	41	43	47	44	48	0	**631**
Koromkheti	18	18	18	18	18	18	18	18	18	18	18	0	**268**
Total	**57**	**280**	**286**	**294**	**306**	**309**	**319**	**337**	**358**	**372**	**395**	**382**	**6531**

Source: World Bank team estimate.

   - The fiscal cost may be reduced to GEL611 million (US$247 million) in present value terms, through exports of electricity (assuming that the surplus energy is exported at 85 percent of the prevailing market price in Turkey). However, the fiscal cost cannot be eliminated entirely because the average wholesale electricity market price in Turkey is about 4.5 USc/kWh whereas the PPA tariffs for these projects are higher (starting from 6.2 USc/kWh).

   If only Namakhvani cascade and Koromkheti HPP are built, the fiscal cost would be GEL219 million (US$89 million) in present value terms. The fiscal cost may be reduced to GEL91

[4] PPA tariff, escalation, term, off-take obligations of ESCO.

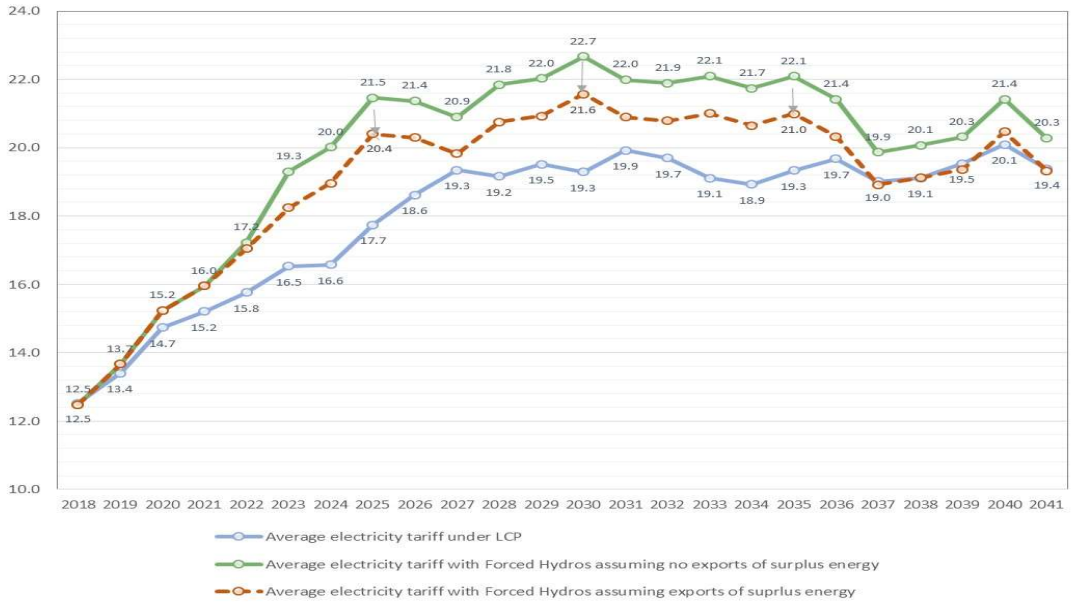
[5] Demand inclusive of technical losses.

million (US$37 million) through electricity exports.[6] This fiscal cost would be comprised of US$26.3 million for Namakhvani cascade and US$10.3 million for Koromkheti HPP.

b. *The additional financial cost arising from Namakhvani, Koromkheti, and Nenskra PPAs would result, on average for the period of 2022-2036[7], in a 12 percent higher annual tariff[8] increase in nominal terms.* The additional energy cost that consumers would need to pay due to construction of projects,[9] which are not part of the LCP, is estimated at GEL0.4 billion (US$185 million) in present value terms[10] compared to the costs associated with a supply mix that represents the LCP. Therefore, construction of projects which are not part of the LCP would require higher tariff. For instance, in 2025, the tariffs in nominal terms compared to 2018 level would need to be 15 percent higher than under LCP even if surplus energy is exported at 85% of prevailing export tariff (see Figure 1).

    - The PPA for Nenskra HPP accounts for the biggest share in the total additional financial costs.
    - If only Namakhvani cascade and Koromkheti HPP are built, then the 2025 tariff in nominal terms compared to 2018 level would be 10 percent higher than under LCP even if surplus energy is exported at 85% of prevailing export tariff (see Figure 1 in the Technical Annex).

Figure 1: Average Electricity Tariff Requirement under Different Scenarios (Tetri/kWh)



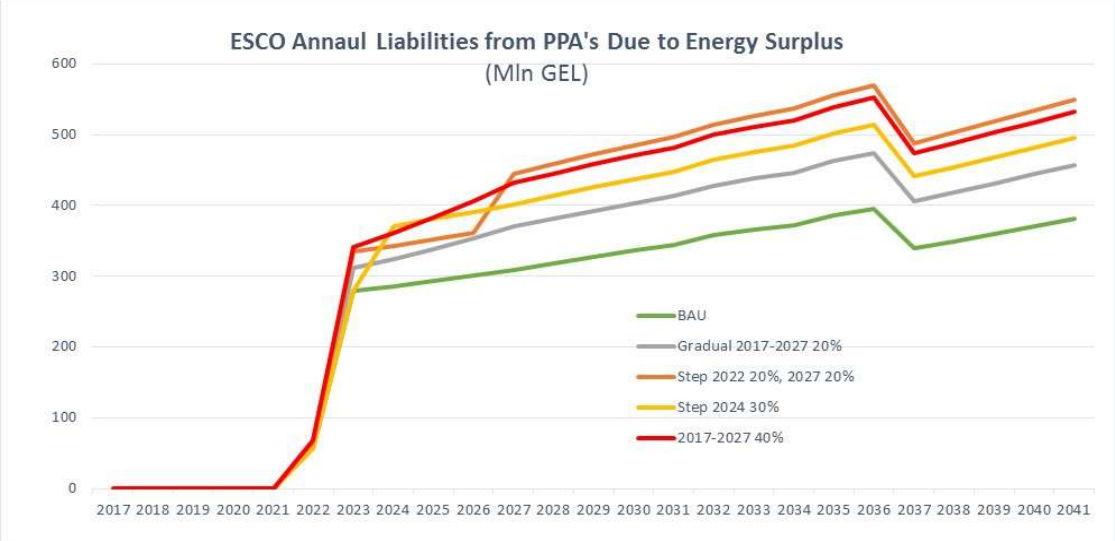
Source: World Bank team estimate.

[6] At 85% of export tariff to Turkey.
[7] The duration of PPAs for Namakhvani and Koromkheti HPPs.
[8] Assuming tariffs are set at fully cost recovery level following the requirements of the existing methodology.
[9] Namakhvani cascade and Koromkheti HPP, which are not part of LCP, are assumed to be commissioned in 2022 and Nenskra HPP, which is not part of LCP either, is assumed to be commissioned in 2023.
[10] Discounted at 13.5 percent, which is the allowed cost of capital as per existing power tariff-setting methodology.

Impacts of Exchange Rate Depreciation on Fiscal Cost from PPAs

The estimated fiscal cost and tariff impact from the PPAs is sensitive to the exchange rate of the Georgian Lari (GEL) to the United States Dollar (US$) because the PPA tariffs are set in US cents. Therefore, depreciation of the GEL against US$ would impact the fiscal cost from PPAs. The analysis includes stress tests to evaluate the impacts under various assumptions for depreciation of the GEL against US$. Those scenarios were agreed with the Ministry of Finance. The annual fiscal cost may increase from GEL350 million in 2023 to more than GEL500 million by 2026 depending on the deprecation scenario for GEL. Summary of impacts of all scenarios is presented on the Figure below.

Figure 2: Fiscal Cost from PPAs under Various Scenarios for GEL Exchange Rate Depreciation



Source: World Bank team estimate.

Other Important Findings

c. In the medium-term (2018-2022), according to the LCP updated for the purposes of this analysis, Georgia would need an additional 140MW of generation capacity to meet the increasing demand. The additional capacity is comprised of a number of small hydropower plants with capacities ranging from 1MW up to 24MW.

d. In the long-term (from 2023 to 2041), under the LCP, Georgia would need to construct 1500MW of new thermal capacity (of which about 700 MW would be to replace retired thermal plants) coupled with 2500MW of additional small and mid-sized hydropower projects. The new thermal capacity would be needed in increments to replace the existing aged and inefficient thermal power plants and to balance the hydropower plants in order to meet the incremental demand. According to the LCP, two 250MW combined cycle gas turbines (CCGT) will be required in the years 2025 and 2026. After considering the retirement of aged thermal plants, the net additional requirement for thermal capacity as per the LCP would be 800MW.

Technical Annex

Analytical Approach

In order to evaluate the fiscal cost and tariff impact from construction of projects with PPAs, the World Bank used an analytical approach, which included the following key steps:

1. Update of the electricity demand forecast for Georgia taking into account the electricity savings from energy efficiency measures identified in the National Energy Efficiency Action Plan. Unconstrained electricity demand (no impact from the change of electricity price on demand) was projected first to be used for the update of the LCP.
2. The 2013 LCP prepared by the Bank was updated to determine whether the projects with PPAs would be required to meet the projected electricity demand. Those HPPs cannot be viewed in isolation and should be evaluated as part of the other supply options available to Georgia for meeting the projected electricity demand at the lowest economic cost.
3. Long-run average incremental cost of supply (LRAIC) was computed and used as a target level of electricity price to be achieved during evaluation period of 2017-2041.
4. Dispatch of LCP was simulated to derive dispatch of each power plant.
5. Dispatch was simulated for Forced Hydro Scenario, which assumes Namakhvani cascade, Koromkheti HPP, and Nenskra HPP would be constructed in 2022 and 2023 as planned by the Government.
6. Impacts of LCP and Forced Hydro Scenarios on the average cost of electricity service were computed. The tariff impacts were computed consistent with the current methodology for setting of electricity tariffs for generation, transmission, dispatch services, and distribution companies.
7. Fiscal cost of Forced Hydro Scenario was evaluated. This was computed as the difference between the total maximum average generation for the months that the Government plans to provide off-take guarantees and simulated generation of those HPP projects during the same months multiplied by their respective PPA tariffs under consideration.

Key Inputs and Assumptions. The evaluation of the LCP and dispatch simulation was conducting using various modules of PSR[11] software, which is widely used by the power industry globally. The key changes since the previous LCP include:

Electricity Demand

a. The demand growth is estimated using real GDP growth and electricity price[12] increase as explanatory variables (linear model). The GDP growth rate was based on IMF forecasts from World Economic Outlook (Apr. 2017). The annual electricity price increase was assumed to

[11] https://www.psr-inc.com/psr-en/presentation/

[12] It is important to differentiate between the term *price* as used here from the term *tariff*. The LRAIC indicates the price that would need to be charged to recover the *economic cost of new investments required* in the system, over the period to 2041. The tariff is, in contrast, a regulated price decided on by the GNERC, and may reflect the cost of investments in the system in a different manner.

increase at an average rate of 1.6 percent per year to reach LRAIC by 2041. Under these assumptions, the annual electricity demand will grow at an estimated 3.9% per year in the period from 2017 to 2041. The high-case and low-case growth rates are 4.7 percent and 2.7 percent respectively.

Electricity Generation

b. *Generation from hydropower projects*. For most of the existing and potential large hydropower projects with storage, generation was modelled based on the historical hydrology data for main rivers. For other projects where hydrology data was not available, generation was assumed to equal the monthly patterns or profiles presented in the relevant feasibility or pre-feasibility study documents.

c. *Generation from solar projects*. The generation from potential solar PV projects was modelled using the daily capacity factors derived based on the solar PV maps for respective regions. The capacity factors were derived based on the historical solar irradiation data.

d. *Generation from wind projects*. The generation from potential wind projects was based on estimated daily capacity factors using historical observations of wind speeds at the sites with the highest potential. The wind speeds were obtained from National Centers for Environmental Prediction wind speed forecasts and then converted to hourly load factors using System Advisory Model from National Renewable Energy Laboratory.

e. *Cost assumptions for generation projects*. The capital costs and estimated commissioning dates for HPP projects were based on the data provided by the Ministry of Energy. The capital cost assumptions from the Ministry of Energy are largely based on the feasibility or pre-feasibility studies conducted by USAID. The cost assumptions for thermal projects are based on recently completed and operational CCGT project in Georgia. The estimates for wind and solar projects were determined based on observed installed overnight costs in Europe.

f. *Gas prices*. Under the analysis carried out in 2013, the economic price of gas was assumed to equal $250/tcm, which was the marginal price of commercial purchases from Azerbaijan. Currently, the economic price is assumed to equal $150/tcm. It equals the price of "Social Gas" at a plant gate, which is derived from blending in-kind gas from North-South gas pipeline, options and supplemental gas from South Caucasus gas pipeline and commercial gas from SOCAR (State Oil Company of Azerbaijan). The price of gas is expected to increase to the European average import price of $244/tcm by 2030, given that domestic gas demand growth (including from power generation) is expected to reduce availability of the Social Gas for power sector, and therefore gas would need to be purchased at prevailing market prices.

g. *Export market prices.* The day-ahead market price in Turkey, the main export market, reduced from USc8.5 c/kWh in 2014-2015 to USc4.5/kWh currently. Market prices also reduced in Russia – from around USc3/kWh to USc2/kWh.

h. *Import tariffs.* The import tariffs were updated based on the most recent data provided by the Ministry of Energy and assume a 1 percent annual escalation in price. In the case of Armenia, the team's understanding is that the trade arrangement is a non-monetary swap. Georgia supplies 1.1 kWh of energy per each 1 kWh received from Armenia. The volumes

are limited to 250 GWh of imports from Armenia and 275 GWh of exports to Armenia. Imports are capped at 400 MW of transmission capacity from Azerbaijan and 480 MW of transmission capacity from Russia

Table 1: Import Prices

Source	Tariff (USc/kWh)
Peak imports from Russia	5.3
Off-peak imports from Russia	6.3
Imports from Azerbaijan	3.8

i. *Constraint on new gas-fired thermal capacity.* The new thermal capacity build-up was constrained at 1500MW to ensure that it does not exceed 22 percent of the total installed capacity considering energy security considerations. Supply of an estimated 24 bcm of additional gas for the planning period will be required to meet the needs of 1750MW of thermal generation. The supply of the additional gas was considered technically feasible through North-South gas pipeline.

Electricity Dispatch from Hydropower Project with PPAs

Namakhvani HPP. The estimated dispatch from this project during the months of April-September is expected to be below the maximum average for those months, and, thus, it is not expected to be dispatched at full contracted quantity given constraints imposed by demand.

Tvishi HPP. This project is not expected to create contingent liabilities for the sector due to limited dispatch caused by electricity demand constraints during the months of April-September. In other words, the maximum average amount of energy from those projects could be fully dispatched into the system. However, it should be noted that the projects would still create significant additional costs for consumers given that those are more expensive compared to alternatives such as gas-fired CCGT projects.

Koromkheti HPP. The estimated dispatch from this project during the months of April-September is expected to be below the maximum average for those months, and, thus, it is not expected to be dispatched at full contracted quantity given constraints imposed by demand.

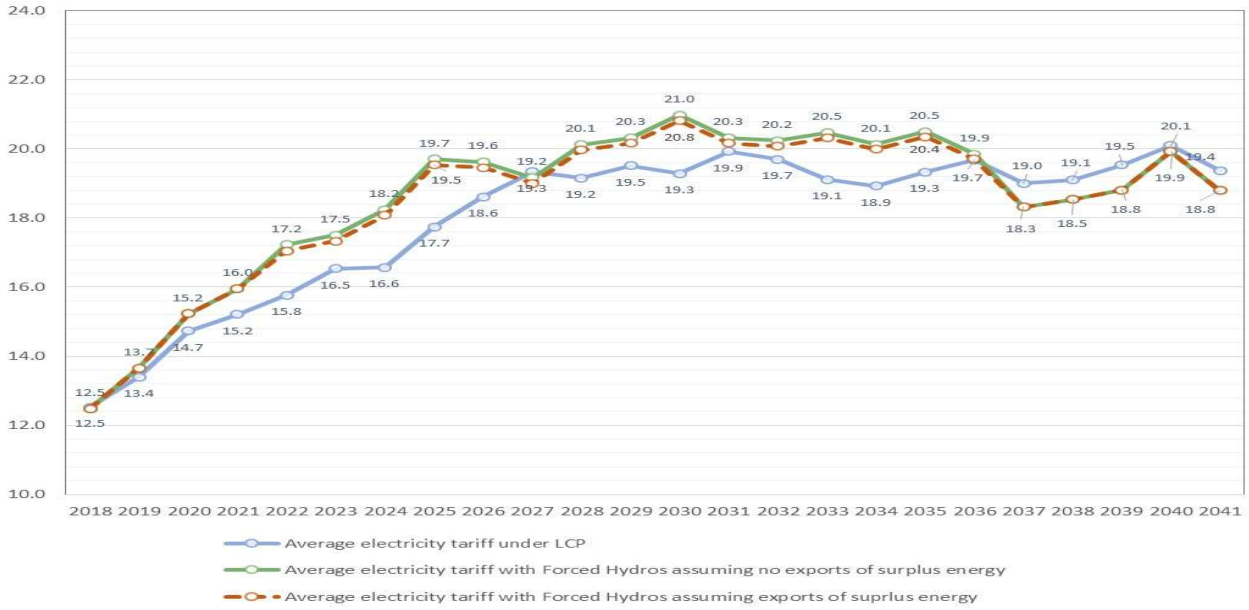
Nenskra HPP. This project is expected to create financial costs given that it would create unnecessary surplus energy into the power system.

Table 2: PPA Terms for Namakhvani Cascade and Koromkheti

PPA terms	Nenskra	Namakhvani Cascade	Koromkheti
PPA duration	34 years	15 years	15 years
Off-take guarantee	Entire annual generation	For energy generated in September-April of each year	For energy generated in September-April of each year
PPA tariff	USc 7.55/kWh	USc 6.2/kWh	USc 6.4/kWh
Escalation	3% per year	2.5% per year	No escalation

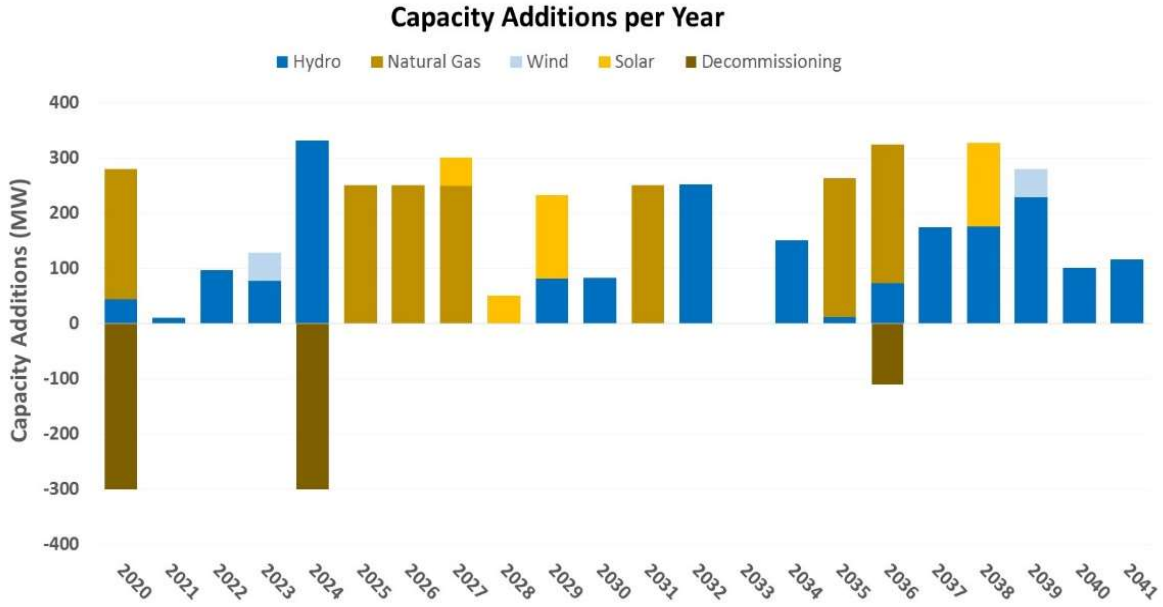
Source: Ministry of Energy.

Figure 1: Average Electricity Tariff with Namakhvani cascade and Koromkheti (Tetri/kWh)



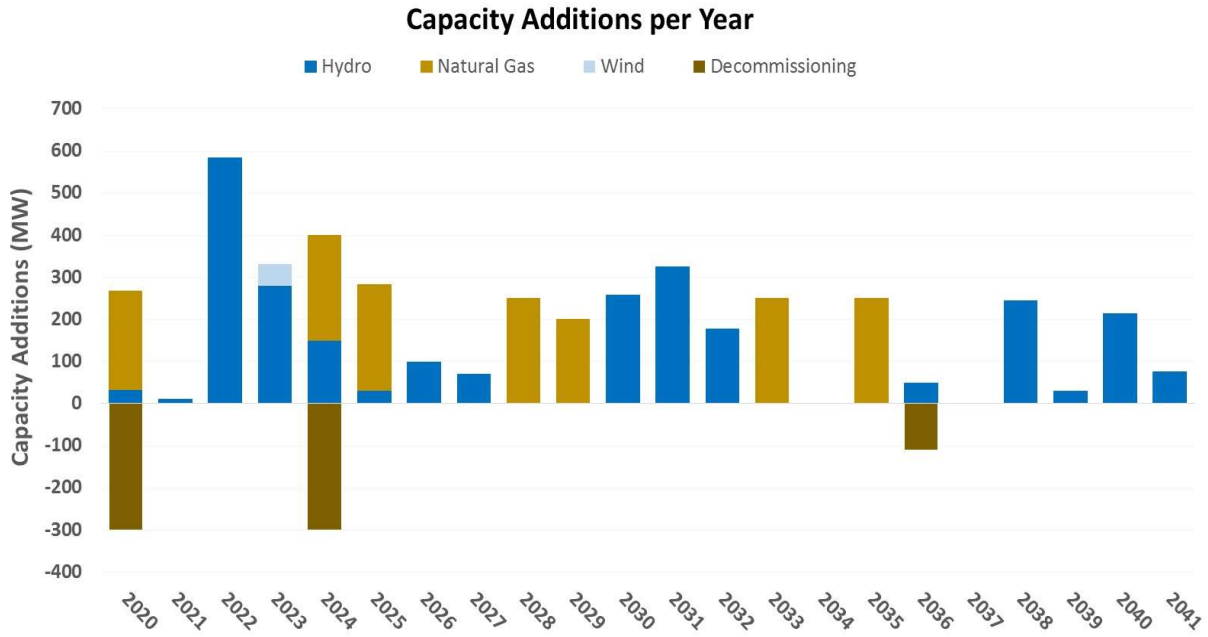
Source: World Bank team estimate.

Figure 2: New Capacity Additions under LCP



Source: World Bank team estimate.

Figure 3: New Capacity Additions under Forced Hydro Scenario



Source: World Bank team estimate.

Table 3: ESCO annual liabilities from PPAs due to energy surplus, millions

	Nenskra (in US$)	Nenskra (in GEL)	Namakhvani (in US$)	Namakhvani (in GEL)	Koromkheti (in US$)	Koromkheti (in GEL)	Total (in US$)	Total (in GEL)
2017	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2022	0.0	0.0	15.4	38.8	7.2	18.1	22.6	56.8
2023	90.6	225.3	14.7	36.5	7.2	17.9	112.5	279.7
2024	93.3	230.9	14.8	36.6	7.2	17.8	115.3	285.4
2025	96.1	237.9	15.2	37.5	7.2	17.8	118.5	293.2
2026	99.0	245.0	15.3	37.9	7.2	17.8	121.5	300.7
2027	102.0	252.3	15.8	39.1	7.2	17.8	125.0	309.2
2028	105.0	259.9	16.5	40.9	7.2	17.8	128.8	318.7
2029	108.2	267.7	17.1	42.3	7.2	17.8	132.5	327.8
2030	111.4	275.7	17.4	43.0	7.2	17.8	136.0	336.5
2031	114.8	284.0	17.4	43.0	7.2	17.8	139.3	344.8
2032	118.2	292.5	19.0	47.1	7.2	17.8	144.4	357.4
2033	121.8	301.3	18.9	46.9	7.2	17.8	147.9	366.0
2034	125.4	310.3	18.0	44.5	7.2	17.8	150.6	372.6

	Nenskra (in US$)	Nenskra (in GEL)	Namakhvani (in US$)	Namakhvani (in GEL)	Koromkheti (in US$)	Koromkheti (in GEL)	Total (in US$)	Total (in GEL)
2035	129.2	319.7	19.6	48.5	7.2	17.8	156.0	386.0
2036	133.0	329.2	19.6	48.5	7.2	17.8	159.9	395.6
2037	137.0	339.1	0.0	0.0	0.0	0.0	137.0	339.1
2038	141.2	349.3	0.0	0.0	0.0	0.0	141.2	349.3
2039	145.4	359.8	0.0	0.0	0.0	0.0	145.4	359.8
2040	149.7	370.6	0.0	0.0	0.0	0.0	149.7	370.6
2041	154.2	381.7	0.0	0.0	0.0	0.0	154.2	381.7

Table 4: Composition of LCP and Forced Hydro Expansion Scenarios

LCP			Forced Hydro		
Year	Plant Name	Installed Capacity (MW)	Year	Plant Name	Installed Capacity (MW)
2020	Larsi-2 HPP	4.2	2020	Larsi-2 HPP	4.20
2020	Kvesheti HPP	10.37	2020	Qvedi HPP	1.73
2020	Qvedi HPP	1.73	2020	Pona HPP HPP	10.62
2020	Pona HPP HPP	10.62	2020	Sadmeli2 HPP	4.00
2020	Sadmeli2 HPP	4	2020	Bokva HPP	2.50
2020	ZemoOroz HPP	1.12	2021	Baisuban HPP	5.34
2020	Bokva HPP	2.5	2021	Akhalsop HPP	5.00
2021	Baisuban HPP	5.34	2022	Namakhvani	333.00
2021	Akhalsop HPP	5	2022	Tvishi	100.00
2022	Kasleti2 HPP	8.1	2022	Koromkheti	150.00
2022	Stori 1 HPP	20	2023	Tbil WPP	49.50
2022	Khokhni3 HPP	1.99	2023	Nenskra	280.00
2022	Mazhieti HPP	12.28	2023	ZemoOroz HPP	1.12
2022	Vedi HPP	24.06	2024	Enguri 8 HPP	150.30
2022	TsirmindiHPP	15.67	2024	CCGT250a	250.00
2022	Barisakh HPP	13.52	2025	Natanebi HPP	8.40
2023	Tbil WPP	49.5	2025	Ipari HPP	3.00
2023	Kheori HPP	1.37	2025	Kasleti2 HPP	8.10
2023	Khadori3 HPP	5.4	2025	Kvesheti HPP	10.37
2023	Natanebi HPP	8.4	2025	Chartala HPP	2.51
2023	Ipari HPP	3	2025	CCGT250b	250.00
2023	Nakra HPP	7.5	2026	Nakra HPP	7.50
2023	Nakra-2 HPP	12.8	2026	Nakra-2 HPP	12.80
2023	Bokhorma HPP	5	2026	Stori 1 HPP	20.00
2023	Ghebi HPP	14.34	2026	Khokhni3 HPP	1.99
2023	Chiora HPP	14.15	2026	Mazhieti HPP	12.28
2023	Chartala HPP	2.51	2026	Vedi HPP	24.06
2023	Mashave1 HPP	4.2	2026	TsirmindiHPP	15.67
2024	Samkhur1 HPP	4.8	2026	ZemoKar HPP	1.03

LCP			Forced Hydro		
Year	Plant Name	Installed Capacity (MW)	Year	Plant Name	Installed Capacity (MW)
2024	Aragvi-2 HPP	1.95	2026	Mashave1 HPP	4.20
2024	Sashual1 HPP	7.3	2027	Khadori3 HPP	5.40
2024	Sashual2 HPP	6.3	2027	Khelra HPP	3.30
2024	Narovan HPP	0.84	2027	Lukhra HPP	5.20
2024	Khelra HPP	3.3	2027	Nakra-1 HPP	8.80
2024	Lukhra HPP	5.2	2027	Akhalqal HPP	15.00
2024	Nakra-1 HPP	8.8	2027	Ghebi HPP	14.34
2024	Dzegvi HPP	15.7	2027	Barisakh HPP	13.52
2024	Akhalqal HPP	15	2027	Mashave2 HPP	4.02
2024	Bakhvi-2 HPP	20	2028	CCGT250c	250.00
2024	Akhaldab HPP	93	2029	GT100a	100.00
2024	Khokhni1 HPP	1.06	2029	GT100b	100.00
2024	Khokhni2 HPP	1.55	2030	Samkhur1 HPP	4.80
2024	Machakh2 HPP	19	2030	Kheori HPP	1.37
2024	Paldo HPP	7.4	2030	Aragvi-2 HPP	1.95
2024	Zekari HPP	1.6	2030	Sashual1 HPP	7.30
2024	Khrami-3 HPP	16.07	2030	Sashual2 HPP	6.30
2024	Khrami-4 HPP	14.97	2030	Kamara HPP	22.20
2024	Tsakvisi HPP	0.24	2030	Dzegvi HPP	15.70
2024	KvemoOro HPP	0.63	2030	Bakhvi-2 HPP	20.00
2024	Mashave2 HPP	4.02	2030	Bokhorma HPP	5.00
2024	ZemoKar HPP	1.03	2030	Akhaldab HPP	93.00
2024	Lentekhi	81	2030	Artana HPP	4.37
2025	CCGT250a	250	2030	Khokhni1 HPP	1.06
2026	CCGT250b	250	2030	Khokhni2 HPP	1.55
2027	Gardab-2 PV	50	2030	Machakh2 HPP	19.00
2027	CCGT250c	250	2030	Paldo HPP	7.40
2028	Gardab-1 PV	50	2030	Chiora HPP	14.15
2029	Akhalts-1 PV	50	2030	Zekari HPP	1.60
2029	Kaspi PV	50	2030	Khrami-3 HPP	16.07
2029	Marneuli PV	50	2030	Khrami-4 HPP	14.97
2029	Lajanur1 HPP	5.2	2031	Enguri 7 HPP	173.60
2029	Lajanur3 HPP	5.4	2031	Tsageri	151.00
2029	Tbilisi HPP	20.2	2032	Lajanur1 HPP	5.20
2029	Kamara HPP	22.2	2032	Lajanur2 HPP	5.40
2029	Artana HPP	4.37	2032	Lajanur3 HPP	5.40
2029	Kvirila HPP	6.6	2032	Lakhami2 HPP	9.50
2029	Udzilaur HPP	8.48	2032	Mestiac1 HPP	23.70
2029	Lopota HPP	9.54	2032	Narovan HPP	0.84
2030	Lakhami2 HPP	9.5	2032	Tbilisi HPP	20.20
2030	Mestiac1 HPP	23.7	2032	Kvirila HPP	6.60

LCP			Forced Hydro		
Year	Plant Name	Installed Capacity (MW)	Year	Plant Name	Installed Capacity (MW)
2030	Mestiac2 HPP	27	2032	Udzilaur HPP	8.48
2030	Sakaura HPP	12	2032	Lopota HPP	9.54
2030	Mleta HPP	1.97	2032	KvemoOro HPP	0.63
2030	Laskadur HPP	6.6	2032	Lentekhi	81.00
2030	Chapala HPP	0.43	2033	CCGT250d	250.00
2030	Andezit HPP	1.1	2035	CCGT250f	250.00
2031	CCGT250d	250	2036	Zoti	48.00
2032	Lakhami1 HPP	6.4	2038	Oni cascade	177.20
2032	Samkhur2 HPP	26.28	2038	Kasleti1 HPP	8.10
2032	Enguri 8 HPP	150.3	2038	Lakhami1 HPP	6.40
2032	Ghere HPP	9.41	2038	Samkhur2 HPP	26.28
2032	Mukhra	60	2038	Mestiac2 HPP	27.00
2034	Tsageri	151	2039	Ghere HPP	9.41
2035	Kasleti1 HPP	8.1	2039	Sakaura HPP	12.00
2035	Lajanur2 HPP	5.4	2039	Mleta HPP	1.97
2035	CCGT250e	250	2039	Laskadur HPP	6.60
2036	Darchi HPP	16.9	2039	Chapala HPP	0.43
2036	Leqarde HPP	20	2040	Kheledul HPP	50.77
2036	Metekhi1 HPP	36.7	2040	Machakh1 HPP	30.00
2036	CCGT250f	250	2040	Tsakvisi HPP	0.24
2037	Enguri 7 HPP	173.6	2040	Meneso HPP	8.20
2038	Oni cascade	177.2	2040	Ludji	65.00
2038	Ksani PV	50	2040	Mukhra	60.00
2038	Gldani PV	50	2041	Darchi HPP	16.90
2038	Algeta PV	50	2041	Leqarde HPP	20.00
2039	Martkopi WPP	50.4	2041	Metekhi1 HPP	36.70
2039	Dolra 3 HPP	17.69	2041	Andezit HPP	1.10
2039	KhertvisiHPP	65			
2039	Avani HPP	4.6			
2039	Magana HPP	20.6			
2039	Baramidz HPP	8.4			
2039	Kheledul HPP	50.77			
2039	Machakh1 HPP	30			
2039	Tsablari HPP	24			
2039	Meneso HPP	8.2			
2040	Tvishi	100			
2041	Enguri 6 HPP	50.6			
2041	Ludji	65			