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ARMENIA'S ENERGY INDEPENDENCE ROADMAP

YEREVAN 2024

ARMENIA'S ENERGY INDEPENDENCE ROADMAP

PART 1 ARMENIA ENERGY PROFILE

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SUMMARY INTRODUCTION

Strategic goal and objectives

The lack of proven natural gas and oil resources in the Republic of Armenia requires significant fuel imports to meet energy demand in the economy and households, making the country highly dependent on external energy sources.

Reducing the imported primary energy supplies and increasing the share of domestic renewable energy sources (RES) certainly contributes to the country's energy security and independence.

Enhancing energy security through the development of one's natural resources has been proclaimed as a permanent strategic priority for sustainable development, collectively declared by the International Energy Agency member states, including Armenia: "…An important means of enhancing energy security is diversification of energy supply and distribution with various types of energy and sources. Utilization of renewable energy resources mitigates dependence on imported fuel and enhances energy security as they can contribute to reduced import dependency."

Armenia has significant potential for the development of renewable energy sources. The Armenia Energy Independence Roadmap (Roadmap) aims to establish strategic objectives to enhance energy independence and contribute to Armenia's commitments under the Paris Agreement by maximizing the utilization of Armenia's renewable energy potential.

However, the penetration rate of variable energy resources into electrical networks largely depends on the development of the technical capabilities of energy infrastructures and, in addition, must be economically justified. The study claims to cover key aspects of the development of domestic natural energy resources, alternative technologies, the market, the economy, and the legal and regulatory framework. The global trends in the use of available types of renewable energy resources, such as solar photovoltaic, solar thermal, wind, geothermal, biofuel, and others, are to the possible extent reflected in the visions presented in the Roadmap, and at the same time, they mostly align with the trends and priorities outlined by the existing government strategy for energy independence.

As declared in the 2022 budget message, the Government's policy aims at increasing energy independence and security, ensuring a reliable supply of high-quality electricity and gas for consumers.

It also states that the fundamental direction of sustainable development of the energy sector is an economically justified, efficient and responsible use of renewable energy potential; the development of nuclear energy; building of a reliable export-oriented power system, new generating facilities with modern technologies along with regional integration of the power system, diversification of energy supply, the introduction of energy efficiency and energy saving policies, and digital transformation of the energy field.

Certain preconditions for the accelerated power sector development have been built by legal and regulatory tools, creating beneficiary conditions for commercialization of the local renewable energy resources.

In 2022, a new model of gradual liberalization of the electricity market was implemented, the purpose of which is to create a competitive environment and stimulate investment and trade. The establishment of the unified electricity and gas market within the Eurasian Economic Union has been declared.

The construction of "Masrik-1" 55 MW network-scale solar photovoltaic plant is ongoing. The construction of "Ayg-1" 200 MW and "Ayg-2" 200 MW solar photovoltaic stations starts within the "Masdar Armenia" investment program. Another solar photovoltaic plant with a total capacity of about 120 MW is under preparation of tender packages. The construction of commercial and autonomous solar photovoltaic stations with an installed capacity of up to 5 MW and 150 kW, respectively, is underway at an accelerated pace. Modernization of energy infrastructures, such as transmission and distribution networks, substations, overhead lines, etc. is ongoing. The 400 kV Armenia-Georgia high voltage DC substation with a total installed capacity of 1,050 MW will be put into operation in three stages of 350 MW per stage. According to the RA energy sector's long-term (until 2040) development plan, the Armenia-Iran 400 kV overhead line will make an important step toward regional integration. The transmission line and substation will enable the increase of electricity exchange capacity between the power systems of Armenia and Iran from the present 350 MW to 1200 MW with increased reliability and energy security of the power systems of Armenia.

The Armenian government is currently considering options for the construction of a new nuclear power plant to replace the current Metsamor nuclear power plant in 2036.

Increasing the share of domestic carbon-neutral and carbon-free energy sources in the energy mix while decreasing the reliance on imported primary energy supplies to a minimal level requires the implementation of the following strategies:

A) Development of carbon-neutral and carbon-free energy sources and their viable operation within the power network;

B) Diversification of interconnections with the regional power systems for maximizing resilience, reliability, and thereby creating additional power reserves for the power grids;

C) Upgrading of the power infrastructures with the introduction of cutting-edge technologies for automated power grid operations; smart power storage facilities; liberalized market-based legislation for electricity producers;

D) Successive upgrading of energy efficiency to the highest known standards in all spheres of the economy and social life;

E) Development of the potential of autonomous energy grids and microgrids combined with solar photovoltaic, and solar thermal technologies, as well as other alternative technologies with the possibility of their commercial use.

F) Transition from fossil fuel-based energy production and consumption (with oil and natural gas) to renewable energy sources (such as wind and solar power, lithium-ion, or other types of energy storage).

While the provisions of the Roadmap do not contradict the state policy in the featured goals and objectives of the energy independence of Armenia, they, however, are much more ambitious and focused on achieving significantly accelerated utilization of domestic renewable energy resources. The Roadmap considers a significant level of integration of variable renewable energy sources (VRE) to go along with deepening integration with the neighboring networks as a factor of steady-state and secure operation of the electricity networks, along with enhanced penetration of the off-grid clean energy generation technologies.

Within the existing legal framework and regulations, the formulated strategies are hardly realistic. Therefore, it is crucial to introduce specific legal and regulatory alterations. These modifications are vital to create favorable circumstances that will facilitate the desired progress toward energy independence.

TPES STRUCTURE AND LEVEL OF ENERGY INDEPENDENCE

The level of energy independence of the Republic of Armenia has been assessed based on the forecasts of the Energy Balance made for 2030, 2040, and 2050. For the two main forecast scenarios – Basic and Accelerated, and an additional Aggressive scenario for 2040 - the following assumptions have been admitted:

Baseline Development Scenario: retrospective (2010-2020) demand growth rates in the main consumption sectors will be maintained;

Accelerated Development Scenario modifies the Baseline Scenario, providing

- more intense development of solar PV supply;
- increase in the electric vehicles and agricultural machinery fleet;
- partial replacement of gas heating devices with electric ones;
- expansion of the use of Solar Water Heating installations;
- introduction of Biofuel technologies;
- transmission and distribution networks reconstructed to a limited extent.

The Aggressive Development Scenario calls for a significant increase and extensive incentives for renewable energy producers so that the indicators adopted for the accelerated 2050 scenario will be achieved by 2040.

One of the initial indicators of the energy balance is the primary energy supply (PES) by type of energy resource. To calculate, the initial data were converted from the named units into normalized units of energy. According to the IEA standard, a tone of oil equivalent (toe) is used as a conventional unit calculated based on the calorific values of a given energy resource.

The total primary energy supply is calculated as:

$$TPES = PES_{EE} + PES_{NG} + PES_{Other\ FF} + PES_{NE} + PES_{HE} +$$
$$+ PES_{SPV} + PES_{SWH} + PES_{WE} + PES_{BG} + PES_{BF\&W},$$

where

PES_{EE} – primary energy supply (PES) of electrical energy,

PES_{NG} – PES of natural gas,

$PES_{Other\ FF}$ – PES of $other\ fossil\ fuel\ (oil\ products, coal)$,

$$PES_{NE} - PES\ of\ nuclear\ energy,$$

$$PES_{HE} - PES\ of\ hydro\ energy,$$

$$PES_{SPV} - PES\ of\ solar\ PV,$$

$$PES_{SWH} - PES\ of\ solar\ water\ heating,$$

$$PES_{WE} - PES\ of\ wind\ energy,$$

$$PES_{BG} - PES\ of\ biogas,$$

$$PES_{BF\&W} - PES\ of\ biofuels\ and\ waste.$$

The level of energy independence coefficient EIC is estimated as:

$$EIC = \frac{PES_{DES}}{TPS} \cdot 100\ \%,$$

where

$PES_{DES} = PES_{NE} + PES_{HE} + PES_{SPV} + PES_{SWH} + PES_{WE} + PES_{BG} + PES_{BF\&W}$ - PES from domestic energy sources.

For each of the considered scenarios, the following TPES diagrams were constructed and energy independence coefficients were calculated. For comparative analysis, the EIC for 2020 is also given, calculated based on officially published data from the Statistical Committee of the Republic of Armenia.

EIC for 2020 Historical

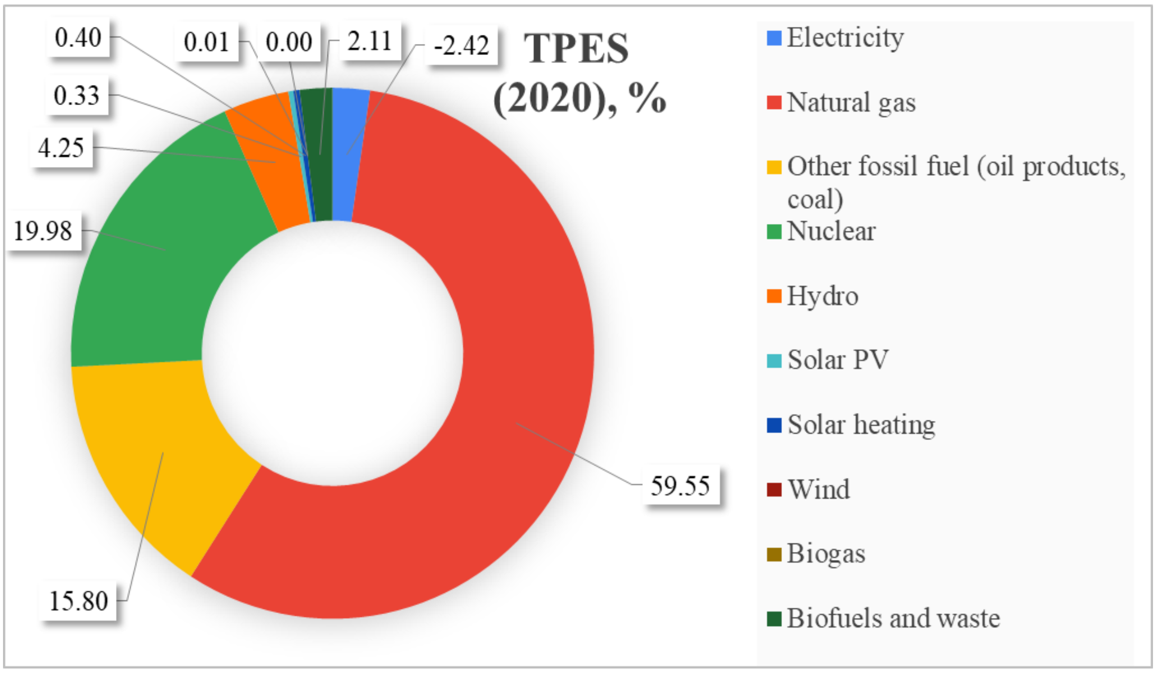


Figure 1. TPES diagram for 2020 (historical).

Energy independence coefficient for the Baseline scenario EIC = 27.1 %.

EIC for Baseline scenario by 2040

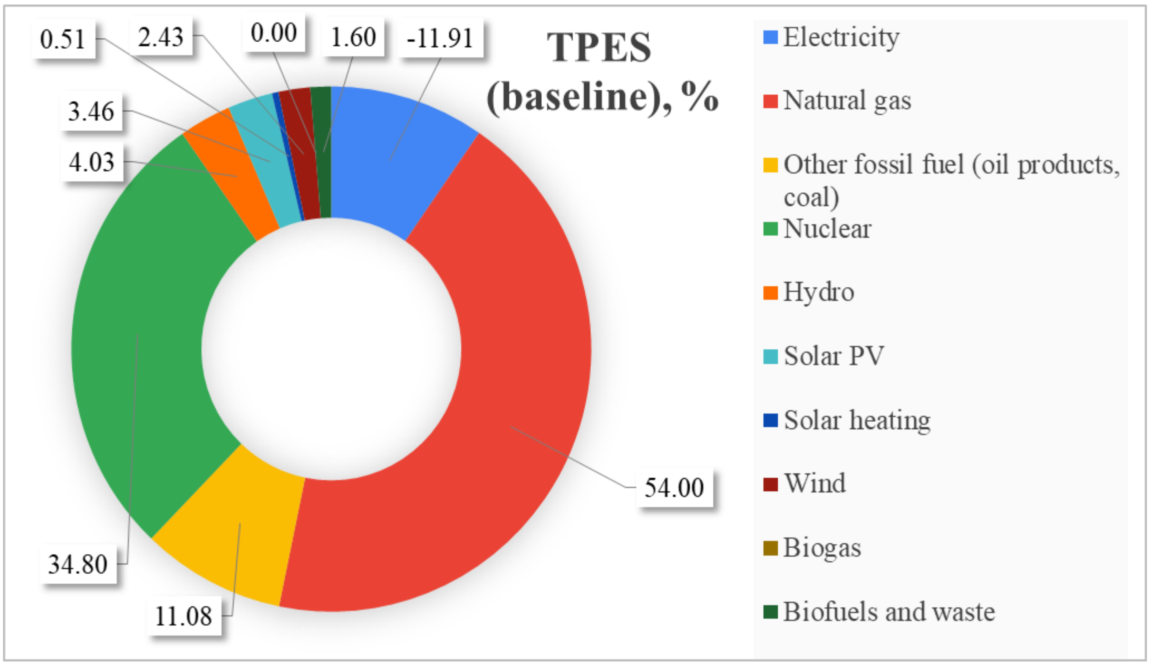


Figure 2. TPES diagram for Baseline scenario by 2040.

Energy independence coefficient for the Baseline scenario EIC = 46.8 %.

EIC for Accelerated development scenario by 2040

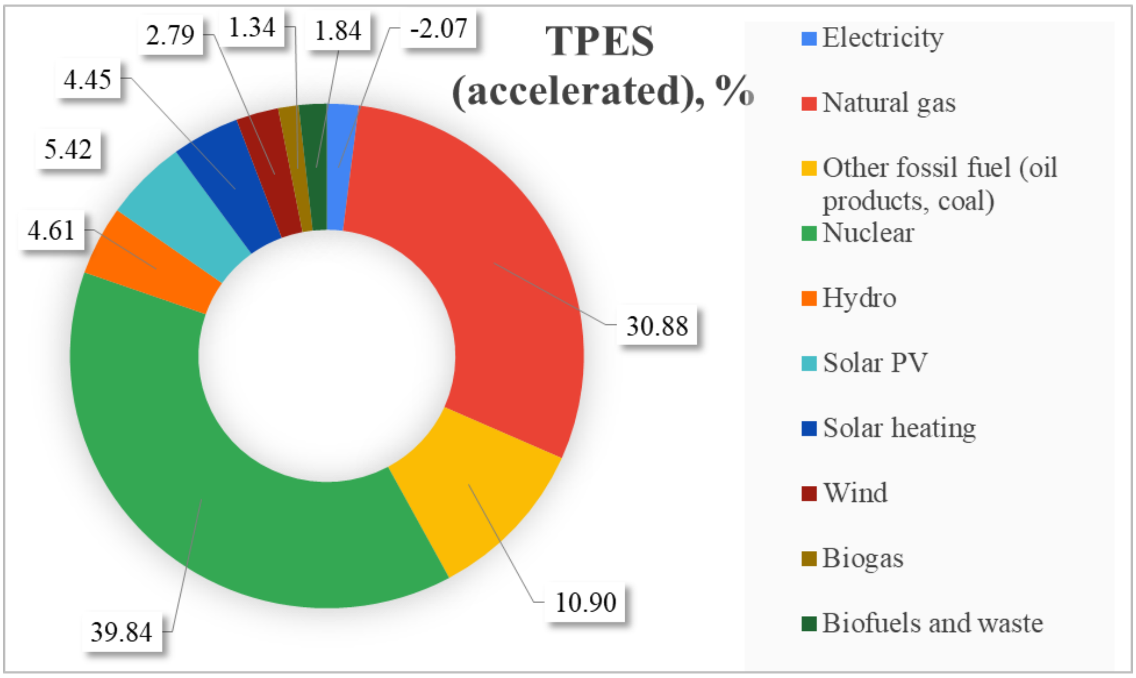


Figure 3. TPES diagram for Accelerated development scenario by 2040.

Energy independence coefficient for the Accelerated development scenario EIC=60.3 %.

EIC for Aggressive Development Scenario by 2040

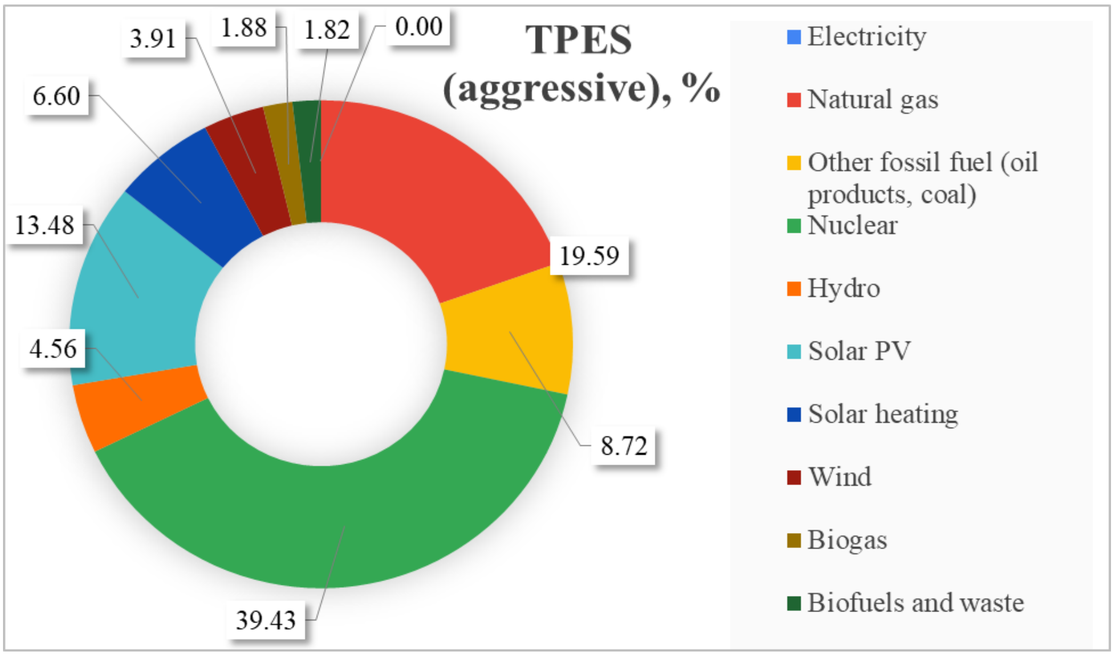


Figure 4. TPES diagram for Aggressive development scenario by 2040.

Energy independence coefficient for the Aggressive development scenario EIC = 71.7 %.

Conclusion

An analysis of the results in all three forecast scenarios compared to 2020 shows an increase in the energy independence of Armenia. In particular, compared to EIC = 27.1 % in 2020, the EIC by 2040 presents as:

- 46.8 % for Baseline scenario,
- 60.3 % for Accelerated development scenario,
- 71.7 % for Aggressive development scenario

The accelerated development and the Aggressive development scenarios in terms of the technical feasibility of maintaining steady state and transitional regimes of the power system, as well as the necessary costs of strengthening the electrical network infrastructures, and the legal aspects between the subjects of the power system in the context of the liberalization of the electricity (and capacity) market, will require further detailed study.

METHODOLOGY

The roadmap is based on the results of the investigations for assessment of the domestic resources of renewable energy and technologies available for their utilization; it analyzes the possible impacts and ways to level these impacts to maintain the stability of markets and the technological stability of the power system while replacing energy imports.

The study considers three scenarios based on Energy Balance forecasts: baseline, accelerated, and aggressive development.

Energy Balance forecasts have been made for 2030, 2040 and 2050. Forecasts were made according to the following two main scenarios: Baseline and Accelerated. For 2040, an Aggressive scenario was also considered. The main approaches to the formation of initial data for energy balances, as well as the results of calculations, have been presented.

The Baseline scenario assumes that the retrospective 2010-2020 growth rates of demand in the main consumption sectors will be maintained and the use of energy resources to cover demand in the future will be in line with the "Strategic Program for the Development of the Energy of the Republic of Armenia until 2040", adopted as an Appendix N 1 to the Decree of the Government of the Republic of Armenia N 48-L dated January 14, 2021.

The Accelerated scenario assumes a modified baseline scenario with more intensive development of solar photovoltaic energy, as well as electric vehicles and other machinery demand increase (instead of vehicles powered by natural gas and oil products), partial replacement of gas heating devices with electric ones, scaling up the use of solar water heating installations, introduction of biofuel technologies, reconstruction of electricity transmission and distribution networks. The details of the accelerated development scenario are given in the section below.

The Aggressive scenario assumes a significant increase in the capacity of recycling and stimulation of the use of renewable energy sources, which in turn should largely inspire energy source conversion:

- Significant displacement of cars and mechanisms running on natural gas and oil products by electric ones
- Replacement of gas heating and hot water appliances with electric ones
- Widespread use of solar photovoltaic and solar water heating installations
- Widespread adoption of biofuel technologies While all three scenarios are theoretically feasible, they differ in terms of the level of technological interventions required, the required legislative changes, the amount of investment, and the level of political support the changes may require.

The study considers the timelines for introducing new generating capacities from the point of view of the power system's secure operation; forecasted scenarios for energy consumption have been developed and analyzed.

The study performed cost-benefit analyses for main energy resources, however, it doesn't cover the macroeconomic aspects of the intensive use of renewable energy sources. The study provides an international experience that can be suitable for follow-up, narrowly focused studies.

The research was based on various reliable data sources and forecasts, namely, expected economic developments, new generating capacities, consumption trends, strategic programs for the development of the energy industry, etc.

The "basic" scenario is developed through precise modeling and planning of the electric power system operational regimes while taking into account various factors such as criteria for the reliability and safety of the energy system operation, principles of building fuel and energy balances, diversification of energy resources, and our beliefs regarding the security and independence of the energy industry. We believe that this approach is crucial in evaluating the country's energy independence.

Based on the fundamental approach we adopted, and analyzing global energy trends, we have apprised the significance of key aspects such as nuclear energy, the development of solar energy, power system interconnections, energy efficiency, electrification in transport, heating, and other areas. At the same time, several additional points were analyzed:

1. The “Aggressive” scenario highlights the introduction of large solar energy capacities, taking into account the increased level of electrification of end consumers, mainly due to the transport industry and heat supply.
2. The introduction of a more advanced wind power resource assessment method has revealed a greater potential for wind energy than previously recognized.
3. Further analysis of electricity market liberalization and its influence on energy security.
4. Discussion of hydrogen supply and demand in the energy context of Armenia.
5. Analysis of electricity flows in the network under different representative regimes and corresponding assessment of integration factors for renewable energy sources.
6. Analysis of the entire energy balance (demand and supply) under three different scenarios.
7. Identification of potential areas requiring further research.

In the most daring scenarios we have presented, such as Aggressive, the volumes of solar and wind energy differ significantly from the existing (conventional) vision, which, nevertheless, is justified, although associated with several key factors, such as the trend in the development of electric transport, agreements on parts of electricity backup in neighboring power systems, electrification of heating for the end consumer, increasing the capacity of distribution networks, the introduction of autonomous grids, etc.

Research in the field of hydrogen markets is also important.

All these issues require further detailed study.

The importance of the roadmap is not just for new and daring scenarios for the energy industry development, but also highlighting aspects that require a more detailed study of the necessary steps and the associated risks and benefits in achieving greater energy security and independence.

ARMENIA ENERGY PROFILE

Domestic Resources. Energy Security and Diversification

A significant part of the energy in Armenia is generated with the help of hydrocarbons, which are entirely imported, while hydropower and nuclear energy are considered domestic resources. In 2021, imported energy resources in the total volume of primary energy supply amounted to 81.2 %. In 2021, energy imports increased by 8.3 % compared to 2020. This is mainly due to an increase in imports of petroleum products and natural gas.

ELECTRICITY GENERATION

Electricity generation is one of the most developed areas in the economy of Armenia. The electricity generation is represented by NPP, TPP, HPPs, and alternative sources. The main domestic sources of primary energy – nuclear and hydropower – in 2021 amounted to 60.4 % and 22.0 %, respectively. Thanks to the recently undertaken steps by the RA government, the solar water heating (SWH) industry is constantly increasing. The assessment of wind potential and geothermal energy exploration is expected in the near future.

As of January 1, 2022, the installed capacity of the power system was 3420 MW, from which

- Thermal power plants – 1783.36 MW, from which operational – 1356 MW
- NPP – 440 MW
- HPPs – 1397.18 MW, including small HPPs 431.38 MW
- Solar PV plants – 225.89 MW, including autonomous 136.08 MW.

Nuclear Power

Armenian NPP produced 1998.4 Mln. kWh electricity in 2021 which is around 25.8 % of the total production. These indicators were reduced against those of 2020 due to the maintenance activities undertaken for the extension of the ANPP operation lifetime. According to its Strategic Program, the PA government is prioritizing the further extension of the operating life of the Armenian NPP until 2036. The government intends to provide funding for the building of a new 1,000 MW reactor to maintain nuclear power in the country’s energy mix.

Hydropower

Hydropower is the most developed among the other renewable energy resources in Armenia. It is presented by two major HPP cascades owned by “International Energy Corporation” CJSC and “Contour Global Hydro Cascade” CJSC, as well as by several small HPPs. The HPPs of “International Energy Corporation” CJSC produced 456.5 Mln. kWh and “Contour Global Hydro Cascade” CJSC – 940.7 Mln. kWh electricity in 2021, which accordingly amounts to 5.9 % and 12.1 % of the total electricity production. Thus, the production of large hydroelectric power plants in 2021 increased in comparison with 2020, including 1.5 times at the hydroelectric power station of “Contour Global Hydro Cascade” CJSC.

In 2021, there were 190 private small HPPs (up to 30 MW) with a total installed capacity of 388.56 MW and actual electricity generation of 804.6 million kWh. Another 22 SHPPs with a total installed capacity of about 52,277 MW were under construction.

Solar Photovoltaic

The total installed capacity of the licensed solar PV plants reached 51 MW in 2021 and electricity production amounted to 89.6 Mln. kWh.

The autonomous 9,224 energy producers with a capacity of about 184,029 MW signed power purchasing contracts with "Electric Networks of Armenia" CJSC. The total installed capacity of the autonomous solar PV systems reached 136.1 MW with 204.1 Mln. kWh electricity annual production, according to estimates based on the Solar Map of Armenia. Another 622 autonomous energy producers with a total capacity of 130,45 MW have received technical conditions for construction. The amount of electricity produced by autonomous PV producers has increased significantly.

The amount of electricity produced by autonomous solar PV installations in 2021 increased by about 1.8 times compared to 2020. (Source: PSRC) Considering the potential of solar energy, the RA government aims to increase the share of solar energy production to at least 15 % or 1.8 billion kWh by 2030. For this purpose, it is necessary to build about 1000 MW of solar plants, including autonomous ones.

During the next 2 years, within the framework of public-private partnership, the construction of industrial-scale solar plants "Masrik-1" and "Aig-1" with a capacity of 55 MW and 200 MW, respectively, is expected. In addition, a program for the construction of 5 photovoltaic plants with a total capacity of 120 MW is being prepared.

According to PSRC's official website, useful supply among the autonomous producers in the electricity exchange amounted to 73.9 million kWh in 2021, and delivery from licensed solar PV plants was 88.7 million kWh. Since only part of the electricity produced by autonomous producers (73.9 million kWh) is supplied to the power system, it does not allow for estimating the primary generation of solar PV systems.

The share of the energy produced using solar PV technologies in the primary production of renewable energy carriers was 11.9 % in 2021. The growth of solar energy production is significant as the result of encouraging the development of PV and SWH installations. In 2020 the share of energy production using solar technologies was 2.7 %, then in 2021, it increased to 4.7 % (Source: Armstat).

The Government of Armenia promotes the development of solar water heating technologies. The data of the customs service on water heating technology components imported to Armenia in 2021 were analyzed. According to expert estimates, the implementation of various initiatives led to an increase in energy production by 1.1 times compared to 2020.

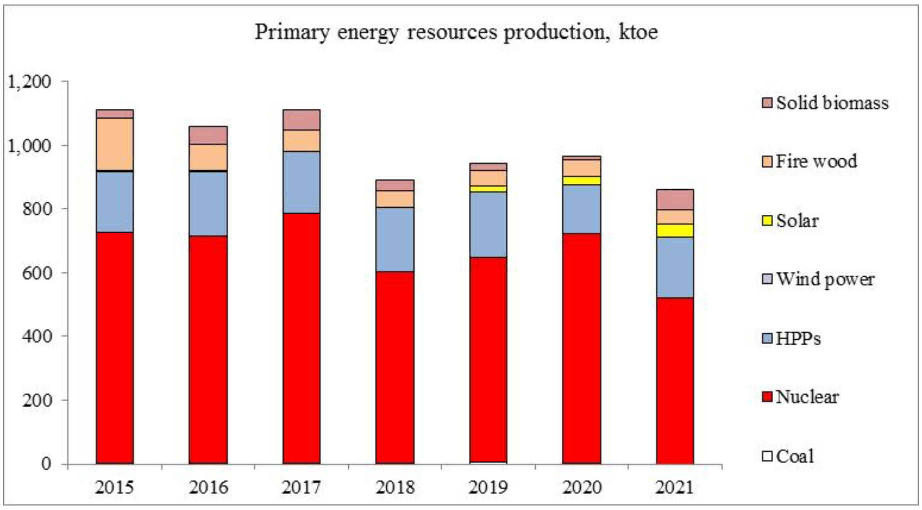


Figure 6. Primary energy resources production, ktoe.

Wind Power

Two wind power plants (WPP) operated in Armenia in 2022. The total supply of useful electricity from the WPPs was 1.4 million kWh in 2021.

The wind energy potential is under evaluation to prepare tender packages for competitive tariff proposals for construction of small and on-grid wind farms with a total capacity of up to 500 MW in accordance with the baseline scenario of the least-cost energy development plan for wind generation capacity, providing an annual generation of more than 1 billion kilowatt-hours (kWh), equal to 17 % of current electricity consumption. In the longer term, a doubling of this capacity appears to be economical and will improve Armenia's energy security and independence.

A memorandum on the construction of wind power plants was signed by the Government of Armenia with Access Infra Central Asia Ltd. (UAE) for 150 MW of installed capacity and Acciona Energia Global S.L. (Spain) for 207 MW in Kotaik and Gegharkunik Marzes. The Projects' area identification, wind measurements, and negotiations with local communities launched in 2018.

The expected changes in the global market in the coming years may also enable other renewable energy plants besides solar to compete with traditional base plants with power accumulators.

As for the public-private partnership, the Government of Armenia will sign contracts for the construction of the network scale power stations exclusively on a competitive basis, attracting investors by ensuring their access to the power market with state guarantees.

In all the least-cost development scenarios, solar and wind technologies are considered the new generation capacities. This fact emphasizes the importance of creating a policy and institutional environment aimed at developing these technologies. It is also important to reduce dependence on imported energy sources as much as possible and increase Armenia's energy security and competitiveness.

THERMAL ENERGY

Thermal Power Plants

There are four large thermal power plants in Armenia. The “Yerevan TPP” CJSC, which although is a combined cycle production unit, operated in condensation mode during 2021 and produced 1652.7 Mln. kWh of electricity. The “Hrazdan TPP” OJSC condensing power unit, owned by “Gazprom Armenia” CJSC, produced 1576.9 Mln. kWh of electricity. “Hrazdan-5” condensing power unit owned by “Gazprom Armenia” CJSC was not operated in 2021.

A new 254 MW combined cycle production unit has been operated by “ArmPower” CJSC since 29 November 2021 with 148.1 Mln. kWh electricity production. Shares of the mentioned plants in the total electricity production accordingly amount to 21.3 % - Yerevan TPP, 20.4 % - Hrazdan TPP, and “ArmPower” CJSC - 1.9 %. So, the shares of “Yerevan TPP” CJSC and “Hrazdan TPP” OJSC respectively increased against those of 2020.

Some amount of electricity was also produced at small-scale combined cycle power plants. Total electrical energy production of “Yerevan State Medical University after Mkhitar Heratsi” and “ArmRuscogenaration” CJSC cogeneration plants in 2021 amounted to 6.0 Mln. kWh or 0.08 % of the overall production.

The share of centralized heat supply in the overall energy balance of Armenia is quite small (0.55 %). Thermal energy is equally consumed by households and the service sector.

District heating

During the Soviet period, gas-fired district heating systems served over 60% of residential areas in Armenia and provided heat to over 90% of the country’s apartment buildings. The severe energy blockade of the early 1990s and regular sabotage in the gas pipeline spurring interruptions in the gas supply to Armenia led to the failure of the district heating systems. In such conditions, after the restoration of the gas supply, the hot water supply and space heating were organized mainly with individual gas boilers in housing and communal services. There are only a few low-capacity boiler houses in Armenia designed for a separate building or a group of apartment buildings. The district heating is used only in one section of Yerevan, covering some 35 multi-apartment buildings. There are currently no reported plans to refurbish or expand district heating networks.

Combined Cycle Power Plants

At present, centralized heat supply in Armenia is implemented by small combined cycle power plants. The "Yerevan State Medical University after Mkhitar Heratsi" and “Lus Astkh” LLC produce heat for their own needs, and "ArmRuscogeneration" CJSC supplies heat to the apartment housing blocks of Hovhannisyan, Varuzhan, Isahakyan, Tumanyan, Kuchak and Narekatsi of the Avan administrative area of Yerevan. In 2021, amounts of the thermal energy produced by the "ArmRuscogeneration” CJSC were 11.3 thousand GJ, which is 70% less than in 2020, and the electricity supply to the grid was 1.9 Mln. kWh. Thermal energy losses remain high in the distribution which was 9000 GJ in 2021 (79.6% of the produced energy). There was no heat supply from the main thermal power plants –“Hrazdan TPP” and “Yerevan TPP”. Electricity at the "Hrazdan TPP" was produced by condensing-type units. The Combined cycle unit at “Yerevan CHPP” in 2021 operated in condensing mode.

Solar Water Heating

Thanks to the supporting policy of the RA Government, all solar technologies, including solar thermal increased significantly in 2021 compared to 2020. Solar thermal energy used for domestic and industrial water heating, as well as for technology processes, such as fruit drying. There is no regular source of information about the penetration of solar water collectors and their distribution in various areas, such as the food and service industries. Some experts estimate an amount of 648.7 TJ of thermal energy use based on solar energy, based on data from the tax office. However, the share of this type of energy in the balance of renewable energy is still insignificant.

Wood and Other Biofuels

The sources of firewood (solid biomass) in the Armenian market are sanitary logging, illegal logging, fallen dry wood, woodworking and furniture production waste, and imports. However, the data provided by the RA Statistical Committee on the firewood and agricultural residuals used for the energy purposes consumed in the households are based on the surveys. According to RECS[1] data, an average HH in Yerevan consumes 4.7 m^3. of wood during the heating season, while the consumption reaches 7.1 m^3 in other cities and towns. Meanwhile, the average consumption of wood per season is 8.1 m^3 in villages. The surveys and assessments from 2014-2018 showed that firewood has been largely used for heating, hot water and food preparation, especially in rural areas. Over 70 % of rural HHs routinely use firewood as one of their heating fuel sources. The annual demand for firewood in Armenia is up to 2 million m^3 and accounted for 2.6 percent of the Total Primary Energy Supply (TPES) in 2017. This significantly exceeded the reported firewood supply and renewal capacity of forests in Armenia. Such excessive use of firewood for heating in rural households (HH) resulted in continuous forest degradation and deforestation [4-6]. There are significant heat losses due to the low energy efficiency (EE) of houses.

Data on the timber products and firewood used for energy purposes in the industrial sector are available and provided by the RA Statistical Committee. The amounts of timber products and firewood consumed in the households are provided by the RA Statistical Committee based on the surveys.

The annual **biogas potential** of about 135 million m^3 is just beginning to be developed. Despite purchase guarantees and established feed-in tariffs for electricity generated using biogas, only one biogas power plant has been built in Armenia, which is currently not operating.

Geothermal Energy

Geothermal research in Armenia has revealed the exact locations of geothermal energy sources for the construction of geothermal power plants. At the Jermaghbyur site, geological and geophysical explorations have found that high-pressure (20-25 atmospheres) hot water (up to 250°C) is available at a depth of 2 500 m to 3 000 m. If these data are confirmed, it would be possible to construct Armenia's first geothermal power plant with 25 MW capacity in this area.

[1] Residential Energy Consumption Survey. Analytic Report. Economic Development and Research Center. UNDP. Yerevan, October 2015.

ENERGY CONSUMPTION

In 2021 the main sector of the energy consumption was the ***households'*** with 34.7 % against the total amounts of the final consumption for energy purposes. The ***transport*** share was 32.5 %. The share of the ***service*** sector was 15.7 %, and industry – 13.4 %.

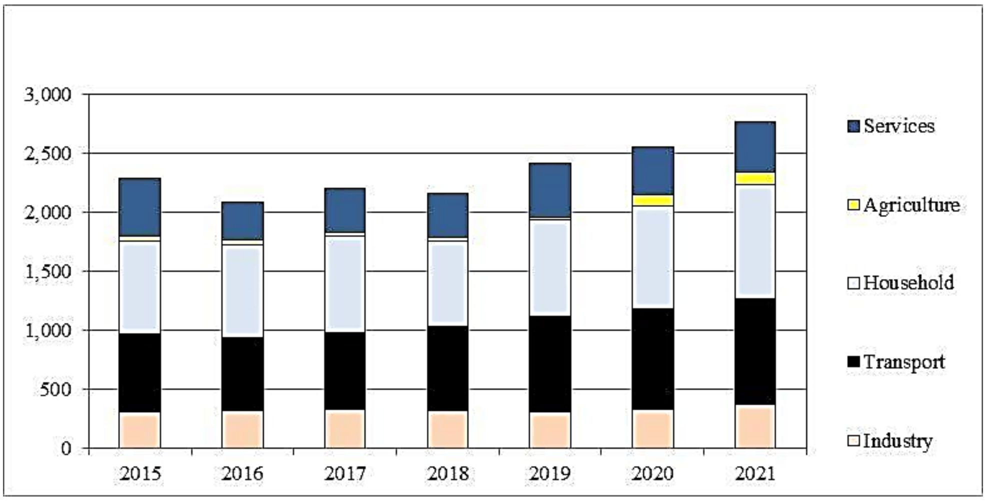


Figure 7. Final energy consumption by sectors, ktoe.

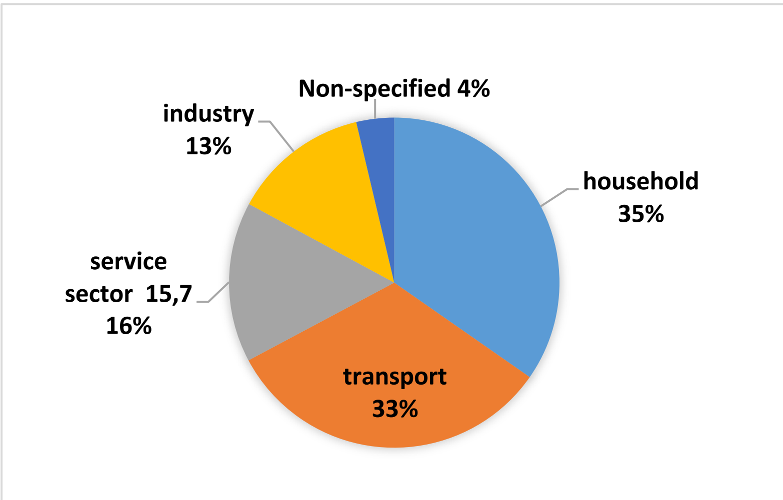


Figure 8. Final energy consumption by sectors, %.

The consumption of energy resources in households increased by 11.4 % in 2021 compared to 2020. This is mainly conditioned by the increase of biogas by 611.5 %, as well as by the increase in the consumption of natural gas by 6.7 %, of coal by 41.0 %, and of electricity by 3.9 %.

The residential sector consumed 0.9 Mtoe in 2020, accounting for 33 % which is the highest share of total final consumption (TFC) in the country, higher than the industry sector and exceeding commerce and public services (which includes commercial and public building energy consumption). It has grown by 42 % since 2009, and according to recent studies, significant residential energy demand growth is expected over the next years[2] (Figure 10). Residential energy consumption consists mainly of

[2] https://www.iea.org/data-and-statistics/charts/armenian-energy-demand-by-end-use-2018-2036

heating (both space and water, which fluctuates annually with outdoor temperature), cooling, cooking, lighting, and appliances.

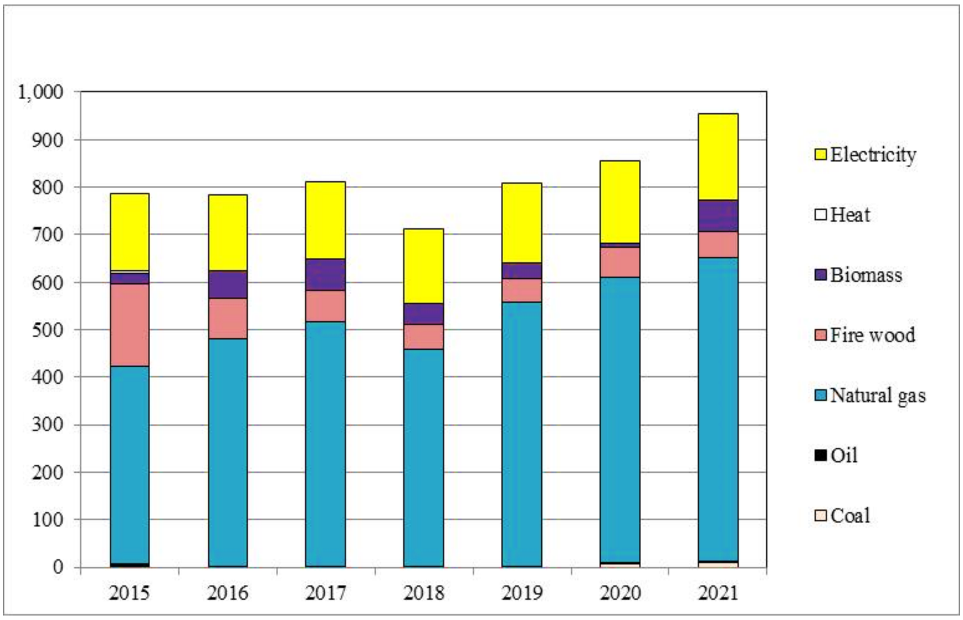


Figure 9. Final Energy Final energy consumption in households, ktoe.

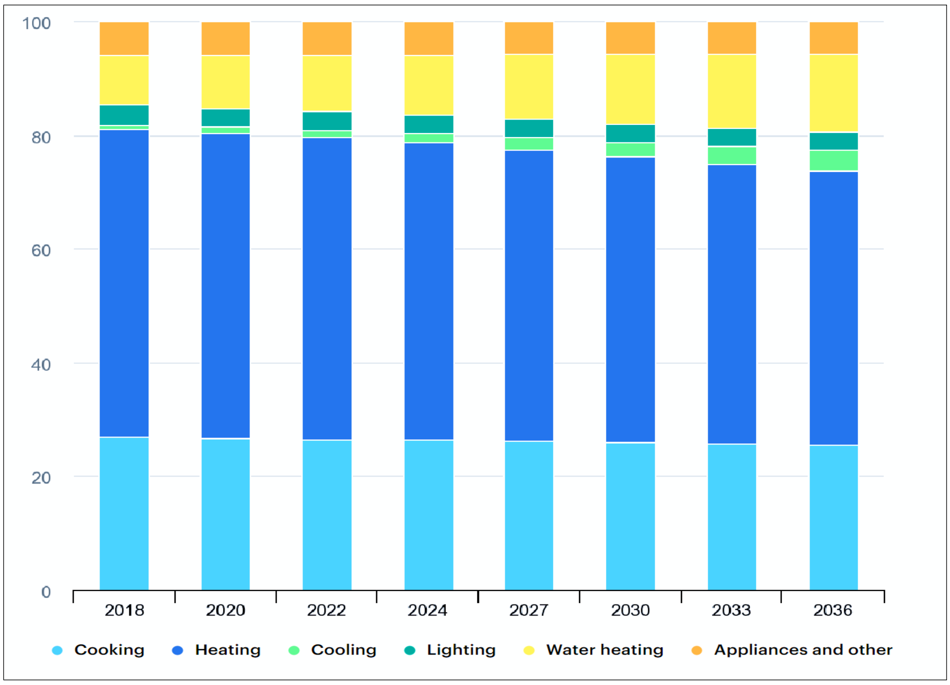


Figure 10. Armenian energy supply and demand by end-use, 2018-2036, %.

The energy intensity in the households was almost at the same level in 2015- 2017 (around 285 ktoe per billion AMD). Since 2019 there is an increase in energy intensity, which in 2021 increased by 11.4 % compared to 2020. This is mainly due to the increase of energy resources consumption and increase in value added in the household by 0.02 % (according to the section "11.10. Production of gross domestic products" of the «Statistical Yearbook of Armenia, 2022», value added in the household sector in 2020 amounted to 2.7436 billion drams, and in 2021 – 2.7441 billion drams).

INSTITUTIONAL FRAMEWORK AND GOVERNANCE

The Ministry of Territorial Administration and Infrastructures (MTAI) is the executive authority responsible for developing and implementing energy policy, guiding relevant market reforms through the undertaking of the national EE action plans and target monitoring. It develops relevant primary and secondary legislation, as well as investment plans for state-owned enterprises.

The Public Services Regulatory Commission (PSRC) is an independent regulator operating in the energy, water and telecommunication sectors responsible primarily for tariff methodology and review, licensing procedures and import/export regulation. The PSRC also regulates water, waste, telecommunications and rail transport.

The Ministry of Environment (MENV) is the executive authority responsible for designating and implementing the national policy in the areas of environmental protection and sustainable use of natural resources. It has also been assigned the role of setting the targets and monitoring the progress towards the country's commitments under the UN Framework Convention on Climate Change as well as the drafting the Nationally Determined Contribution[3] (NDC).

Urban Development Committee (UDC) elaborates and implements the policy of the Government of the Republic of Armenia in the field of urban development, inter alia including the development and enforcement of energy efficiency technical regulations, norms and standards in the building sector. Key responsibilities include the planning and ensuring the implementation of the provisions for energy efficiency and energy saving regulation in the construction sector.

The Ministry of Economy (MEC) is the entity responsible for quality control assurance. Among its responsibilities are the setting of energy efficiency standards and norms of products produced or imported, as well as monitoring the implementation of their requirements and the certification of compliance.

The Renewable Resources and Energy Efficiency Fund (R2E2) is a state entity assigned with the role to support investments in energy efficiency and renewable energy through the implementation of financing mechanisms for the application of efficient and clean technologies.

The Statistics Committee (ArmStat) is the main provider of energy-related data and statistics. The National Statistical Service of the Republic of Armenia (ArmStat) is the government institution responsible for collecting and validating energy data. Armenia has adopted the international energy statistics methodology and standards and has released energy balances in the internationally comparable format since 2015.

[3]https://www4.unfccc.int/sites/ndcstaging/PublishedDocuments/Armenia%20First/NDC%20of%20Republic%20of%20Armenia%20%202021-2030.pdf

LEGISLATION. KEY POLICIES

Armenia relies on imports of natural gas and oil for most of its energy needs, which exposes it to supply risks and dependence on a single supplier. As the government considers energy security and the development of indigenous sources to be of prime importance for the energy sector, renewables, and efficiency measures are key areas. To satisfy expected demand growth while increasing reliability, the government aims to increase capacity and promote domestic energy sources.

In 2013, the government developed a National Energy Security Concept that outlines strategies for fuel diversification mainly through renewables and nuclear power, building fuel reserves and increasing power generation capacity. In 2014, the government approved the Action Plan for 2014-2020 for implementing the security concept. The security concept complements previous energy sector development strategies as part of the 2005 Context for Economic Development to 2025, including the National Program on Energy Saving and Renewable Energy (2007) and MTAI's Action Plan (2007). The Long-Term (up to 2036) Development Pathways program for Armenia's energy sector, approved in December 2015, outlines possible least-cost strategies to develop the whole energy system.

These strategies and action plans are the main energy policy documents. They set out targets and objectives for the energy sector, in line with the following principles:

- Make full use of the economically and environmentally sound potential of renewables and energy efficiency across the whole economy.
- Develop nuclear power for electricity supply.
- Integrate Armenia into regional energy markets and participate in regional projects.
- Diversify supply sources of primary energy resources.
- Gradual liberalization of the domestic electricity market

In 2014, the government developed the Scaling-Up Renewable Energy Program Investment Plan. It is an update of the Renewable Energy Road Map developed in 2011 and includes comprehensive analyses of renewable energy potential, costs and benefits, and the viability of specific technologies. It also sets targets and objectives for renewables to 2025, including a plan for financing. The investment plan describes the first geothermal and solar PV projects, which are being developed by the government and serve as examples for other investors.

The government's ambitious plan to increase renewables to 28 % of the power generation mix by 2036 (from 7 % in 2012) includes small hydro, wind, solar PV and geothermal, but excludes biofuels. To reach this target, Armenia will need to have 634 MW of new renewable energy capacity installed by 2036. Estimated projected capacity additions comprise 148 MW of small hydro and 266 MW of large hydro, 150 MW of wind, 30 MW of geothermal, and 40 MW of solar PV.

The RA government's decision N 48-L of January 14, 2021, approved the "Strategic plan for the development of the energy sector of the Republic of Armenia (until 2040), the schedule ensuring the implementation of the strategic plan for the development of the energy sector of the Republic of Armenia (until 2040).

The program was developed taking into account the recent developments in the energy field, and technological changes, as well as to outline and integrate the guidelines for the sustainable development of the energy sector.

The main goal of the program is strategic planning of the energy sector. The separate sections present the vision and main priorities of the Government of the Republic of Armenia for the development of the energy sector, the development of power generation capacities, the development of the high-voltage power transmission network, the distribution power network, the power market, regional energy cooperation, heat supply, gas supply, energy saving, digital energy, knowledge-based energy, management of state companies. The schedule provides the dates of implementation of the programs, responsible bodies, funding sources, and other details.

The following energy development vision will underlie all energy-related decisions, energy-related relations with neighboring countries, integrating into more global energy markets, and developing relationships with key partners.

- competitive and non-discriminatory,
- inclusive and diversified, with a high level of energy independence,
- clean and energy-saving,
- sustainable development of regional significance,
- reliable and safe, digitized and innovative, knowledge-based, high-tech, predictable and transparent,
- affordable and equitable for all, reasonably accessible to vulnerable segments of the population, and attractive to investors.

The directions and plans for the development of the energy system were gathered and outlined in the document.

ENERGY SECURITY

Electricity and gas demand are expected to continue growing as living standards rise and poverty is reduced. Significant investment will be needed to meet these rising energy needs, as large portions of the electricity and gas networks date to the Soviet era, and infrastructure modernization is needed to maintain and improve supply reliability. In its Energy Security Concept, the government estimates approximately 1000 MW will be retired by 2026, so new investments will be required to satisfy growing demand if the country does not want to become even more reliant on imports. The proposed new 1000 MW nuclear plant accounts for planned new capacity, but financing is yet to be secured.

The sustainability and decreased reliance on imports that renewable energy sources offer make it a priority to enhance their contribution to 28 % by 2036, with additional capacities of 414 MW of hydro (small and large), 150 MW of wind, 30 MW of geothermal and 40 MW of solar PV required to meet this target.

In electricity, regional integration and supply diversity are advancing with a 400 kV double-circuit high-voltage interconnection with Iran under construction, as well as a high-voltage interconnection with Georgia with a back-to-back high-voltage direct current connection. These interconnections will strengthen regional integration, expand the market and improve the security of supply, allow increasing grid-connected variable renewable energy sources, and serve as a resource for energy storage.

EMERGENCY RESPONSE

Oil product storage facilities

According to a 2008 Energy Charter report, Armenia's oil product storage facilities are of adequate capacity, as requirements far exceed annual consumption. Up to 1.2 Mt of light oil products and 0.9 Mt of fuel oil can be stored, but most depots do not comply with modern standards and many need repairs. Meanwhile, upgrades to the Abovyan underground gas storage facility in 2012 doubled its capacity to 135 mcm.

Emergency response concerning nuclear power

Emergency response concerning nuclear power has received increased attention since the Fukushima accident in 2011. Armenia is a party to the Non-Proliferation Treaty, has an Additional Protocol with the International Atomic Energy Agency (IAEA) and has ratified the Comprehensive Nuclear Test Ban Treaty. In 2011, the IAEA inspected its nuclear power station for operational safety, deeming the plant acceptable.

Armenia also works closely with the United States in managing nuclear safety. In 2013, the US National Nuclear Security Administration (NNSA) conducted two emergency response training sessions in Armenia, with 28 participants from relevant authorities, civil protection agencies and other specialized parties. The NNSA also provides direct emergency management assistance to Armenia and other countries.

Also in 2013, Armenia signed an agreement with Belarus on information exchange and cooperation in nuclear safety and radiation protection. Belarus commissioned its first nuclear power plant (NPP) in 2021, and several activities were carried out within the framework of Armenia's agreement to assist Belarus.

Natural gas storage facilities

Armenia is not under any international obligation to hold oil stocks. Requirements are legislated by the former Soviet laws, and most of the time stock availability is determined by the country's financial situation rather than by strict adherence to the legislation.

ENERGY EFFICIENCY

Energy efficiency is crucial to Armenia's economy. Given the country's extreme dependence on imports for fossil fuel supplies, any energy conserved by citizens, businesses and infrastructure translates into financial savings, reduced pollution and greater energy security. The potential for energy efficiency in all sectors has been repeatedly assessed as high, despite the relatively low energy intensity of the economy. Although the government has taken legal action to promote efficiency through various programs and policies, the potential for efficiency improvements remains largely untapped.

Development and adoption of the next revision of the NEEAP is one of the steps on the pathway to energy efficiency that was initiated in 2004 with Armenia's first Law on Energy Saving and Renewable Energy.

Energy efficiency measures are based on the second NEEAP, which involves setting energy efficiency targets for all sectors up to 2020. The R2E2 Fund, established in 2006 within the framework of the Energy Efficiency Project with the support of the Armenian government, the World Bank and revolving fund financing, has initiated energy efficiency measures in schools, kindergartens, universities, hospitals, and other social and administrative buildings, as well as for municipal street lighting systems.

Regulatory reform has supported achievements in the power sector since the mid-1990s. A commitment to cost-recovery tariffs has facilitated investment in infrastructure and attracted substantial private-sector investment, resulting in improved reliability, service quality and operational efficiency in the sector.

All areas of Armenia's economy have great potential for energy saving, including transport, industry, apartment buildings, budget public sector, fuel and power system, etc. The Government of the Republic of Armenia is consistent in creating a new culture of energy saving and implementing institutional reforms for this purpose, promoting investments in alternative energy sources, which can lead to energy security, addressing environmental issues, and boosting energy saving in all sectors of the economy.

In recent years, considerable work has been done by the RA government in the field of energy efficiency and energy saving, prioritizing it as a means of increasing the energy security of the country, increasing economic competitiveness, and reducing the negative impact on the environment, as well as global warming.

The policy pursued by the RA government is to promote energy saving in all branches of the economy, which is defined in the Law on "Energy Saving and Renewable Energy" and the "National Program of Energy Saving and Renewable Energy".

Efforts are being made to improve the regulatory framework for energy efficiency in Armenia aligned with the strategy, including a new national program and a revised NEEAP. The government is also working to align with policies and market protocols set out by the European Union, as well as the Eurasian Economic Union, where Armenia is a treaty member. In 2017, Armenia signed the EU-Armenia Comprehensive and Enhanced Partnership Agreement (CEPA), which includes the EU’s standard political clauses in various spheres, including provisions on cooperation in the energy sector, the environment, and climate change. The roadmap for CEPA implementation was adopted as an Annex to the Prime Minister’s Decision No. 666-L dated June 1, 2019. On March 1, 2021, CEPA entered into force and Armenia began gradually harmonizing its national legal and regulatory framework with the key elements of the EU acquis specified in the EU Energy Efficiency Directives and Regulations.

The minimum energy characteristics became mandatory requirements for the procurement of energy-consuming equipment for state needs.

The "Energy Saving and Renewable Energy 2022-2030 Program" was adopted, in which the planned measures were collected and consolidated. Different energy efficiency and energy-saving projects are implemented in various fields, some with the support of international donors.

A state support program for energy-efficient renovation of apartments and individual residential houses has been launched. According to this program, the government will subsidize the interest rate of the loans borrowed from commercial banks. During 2021, the energy-saving renovation of 22 apartment buildings and 2 public buildings was completed (repair of the roof, replacement of windows, repair of staircases, thermal insulation of external walls), and renovation of another 37 multi-apartment buildings is ongoing.

Renewable energy and energy saving are important directions of the development of the energy sector of Armenia. Adhering to the UN Sustainable Development Agenda 2030, in particular Goal 7, "Affordable, clean, reliable, sustainable and modern energy access", and the Paris Agreement, the Government of Armenia makes continuous efforts to the creation of an attractive legislative environment for investments and the economically efficient development of the renewable energy potential, responsible consumption, large-scale energy efficiency, and energy-saving measures.

MARKET LIBERALIZATION

A new wholesale market model featuring direct contracts, a balancing mechanism, and long-term direct capacity contracts launched in February 2022 will provide purchase options to consumers. The reform assumes that a free and open energy market will help promote investments from the international community and strengthen regional integration. Wholesale traders will also be introduced to the new market. Their job will be to create conditions in trade relations with both local and neighboring countries allowing the parties to make mutually beneficial transactions. The market liberalization program will be implemented over a period of five years and will assist the government in three directions: development of the energy market, diversification of energy supply, and interstate trade to promote electricity trade.

REGIONAL INTEGRATION

Regional integration is also a key component of Armenia's energy policy. Electricity export to Iran is realized on electricity-for-gas swapping agreement and was 85.7 % amounting to 852.6 mln. kWh of the overall exported electricity in 2021. The import from Iran amounted to 64.9 mln. kWh in 2021, which is mainly conditioned by the power system regimes. Armenia's electricity interconnection with Georgia is not fully functional, maintaining small, seasonal "island mode" because their systems are asynchronous. Electricity export to Georgia is mainly organized in the emergency switch off the 500 kW Caucasian power transmission line feeding Georgia's power system from Russia and in 2021 it was practically absent. In high flood seasons, the power supply to the Northern parts of Armenia is performed from Georgia in the island mode and amounted to 287.0 mln. kWh in 2021. Planned increased interconnections with Georgia via a set of back-to-back high-voltage direct current stations and with Iran will help form an envisioned "North-South Corridor", facilitating trade with Russia and possibly other countries. The connection with Iran is operating under limited conditions. Armenia plans to increase its electricity production to sell more to Georgia and Iran during the summer months, and to rely on electricity imports in the winter if necessary. To synchronize its system with those of its neighbors, and to provide electricity at competitive prices, Armenia will have to open its relatively closed electricity market.

REVIEW AND ANALYSES OF PREVIOUS STUDIES IN ARMENIA

According to the RA Law on Energy, one of the main principles of the state policy in the field of energy is the promotion of the energy independence of the Republic including ensuring diversification and maximum use of generation capacities of imported and local energy resources.

To strengthen the economic and energy independence of the Republic of Armenia, on November 9, 2004, the RA Law on Energy Saving and Renewable Energy was adopted.

According of the "Republic of Armenia Energy Sector Development Strategic Program to 2040", adopted as an Appendix N 1 to the Decree of the Government of the Republic of Armenia N 48-L dated January 14, 2021, the vision of the Government of the Republic of Armenia for the development of the energy sector includes:

- inclusiveness and diversification, energy independence at the highest level,
- clean and energy-efficient sustainable development.

The Action Plan of the Strategic Program provides for the implementation of measures aimed at:

- Increased energy independence through increased share of solar generation,
- Construction of Small Hydropower Plants increasing total installed capacity,
- Construction of small and utility-scale Wind Power Plants,
- Gradual expansion of implementation of such projects that will enable the use of individual heating and hot water generation systems based on renewable resources, such as the installation of solar water heating systems,
- In the framework of the Comprehensive and Extended Partnership Agreement signed between the European Union and the Republic of Armenia, adapt 65 regulations, instructions and guidelines (buildings and facilities, energy-consuming equipment and means of transport) to the RoA legislation which are aimed at the promotion of energy efficiency,
- Development of the National Program on Energy Efficiency and Renewable Energy for 2021-2030,
- Establish new parameters for energy efficiency and energy saving, and develop and adopt national standards ensuring their implementation,
- Establishment of climate change, energy and energy efficiency projects implementation unified institution,
- Improvement of management efficiency of state-owned energy companies.

In this context, this chapter presents a review and analysis of several previous studies conducted in Armenia.

Renewable Energy

Renewable Energy Roadmap for Armenia prepared by Danish Energy Management A/S. 2011

According to the report, it was stated that the Armenian Renewable Energy Roadmap identifies the economically and financially viable potential of renewable energy (RE) in Armenia. RE can be grouped into the following three main groupings:

- electricity from small hydropower (SHPP), wind power, photovoltaics (PV), geothermal power, and biomass;
- heat from heat pumps, solar thermal power, geothermal power, and biomass;
- energy for transportation from gas and liquid fuels extracted from biomass.

The report presents the estimated RE Technical Potential in Armenia:

Technology Type	Capacity
PV	>1000 MW
Wind	300-500 MW
Geothermal	25 MW
Hydro	250-300 MW
Solar Thermal	>1000 MW
Heat Pumps	>1000 MW
Biofuel	100 thousand tons/year

One of the most important results of the Renewable Energy Roadmap for Armenia project was the establishment of national targets for renewable energy technologies in all three energy sectors.

Several factors were taken into consideration during the development of the Roadmap, such as targets, technologies, legislative measures, and possible impact on the environment.

Energy demand for Armenia in the electricity, thermal energy, and transportation sectors were developed for various scenarios including the base case, where the demand can be fulfilled by utilizing a variety of energy sources such as renewable energy, fossil fuels, and nuclear power.

Base Case Demand Scenario Forecast

Sectors	Year, GWh		
	2010	2015	2020
Electricity	4500	5 700	6 600
Thermal Energy	11 270	11 900	12 600
Transportation Fuel	7 593	8 121	8 659

The results of the Roadmap project are presented in the table below.

RE Penetration for Different Years

Energy Type	2011-2013	2014-2015	2016-2020	2011-2020
Electricity				
Generation, GWh	18 000	12 800	44 900	75 800
Renewable without large hydro, GWh	1 360	1 380	6 070	8 800
Percent of RE as of total generation*	2%	2.8%	4%	3.3%
Investment in RE, mln. $	$32	$21	$54	$108
Transportation				
Generation, GWh	26 000	20 100	61 200	107 300
Renewable, GWh	140	290	730	1 150
Percent of RE as of total generation*	0.21%	0.57%	0.49%	0.43%
Investment in RE, mln. US dollars	74	-	-	74
Total Generation, GWh	67 900	49 700	149 600	267 200
Subtotal of RE generation, GWh	1 560	1 750	7 170	10 500
RE percent of total generation*	2.3%	3.5%	4.8%	3.9%
Total RE supply with large hydro and biomass, GWh	12 150	7 580	23 700	43 400
Total RE with large hydro and biomass percent of total generation*	18%	15%	16%	16%
Total Investment, mln. $	$238	$161	$504	$903

* *Total percentages are cumulative for the particular period*

The Scaling-Up Renewable Energy Program in Low-Income Countries (SREP) seeks to demonstrate the economic, social and environmental viability of low-carbon development pathways in the energy sector. SREP does this by supporting the deployment, in low-income countries, of renewable energy technologies.

Given the growth in demand and the need to retire aging generating assets, Armenia will potentially face a major supply-demand gap once the NPP is retired in 2021. At least 360 MW of new capacity will be needed by 2026 to meet peak demand and maintain an adequate reserve margin. This gap will increase to 650 MW by 2030.

A mix of policy, legal, regulatory, and institutional reforms has helped to achieve remarkable results in the energy sector. The reform efforts have included the development of domestic energy resources that have helped to improve Armenia's security of energy supply.

Each of the potential renewable energy resources was evaluated against five criteria and prioritized accordingly. The five criteria reflect the Government's strategic objectives and the clear recognition that SREP funding should be used to have a transformative impact on the energy sector. The criteria considered were: the cost-effectiveness of the technology, the potential for scaling up the technology, the maturity of the market, the potential for job creation, and the effect of each technology on the stability of the grid. Three investment priorities emerged from the discussion. These were:

1. Geothermal Power Development. SREP resources would be used for further exploration of Armenia's most promising geothermal site: Karkar.

2. Development of Utility-Scale Solar PV. SREP resources would be used to develop roughly 30 MW of utility-scale solar PV. The rapid decline in solar PV costs in recent years has made utility-scale solar PV more affordable and more competitive with the other power generation options available to Armenia.

3. Development of Distributed Geothermal Heat Pump and Solar-Thermal Projects. SREP resources would be used to demonstrate the viability of geothermal heating and cooling and solar thermal hot water heating for industrial facilities, commercial buildings, and residences. Substantial solar thermal and geothermal heat resource potential exists in Armenia but the use of these technologies is not yet widespread.

Section 3 of the Report describes Armenia's renewable energy sector and includes an assessment of the potential for different renewable energy options, a description of Armenia's business environment for renewable energy, as well as a description of the barriers facing renewable energy development in Armenia.

This section presents the results of an assessment of the renewable resource potential and describes the progress made to date in the deployment of renewable energy technologies.

Renewable Energy Resource Potential in Armenia by Technology:

Small hydropower is the most widespread renewable energy technology deployed to date in Armenia except for large hydropower. Over 90 MW of undeveloped small hydropower projects with a potential for generating almost 300 GWh have been identified throughout Armenia in addition to the operating and licensed projects.

Armenia has several areas with promising wind resources. The most promising areas that have been identified and characterized to date are the Zod (Sotq) Pass, Karakach Pass, Pushkin Pass, Sisian Pass, and the Fantan community region. Together these sites are estimated to have 300 to 500 MW of developable resource potential.

Armenia has no installed geothermal power plants, but preliminary data suggest that geothermal resources suitable for power production might exist in Armenia. Total geothermal resource potential estimates for Armenia range from 0 to 75 MW. It is assumed that a maximum of 25 MW of geothermal power is developable by 2020 in Armenia and it is assumed to include only the Karkar site.

Technology	Capacity (MW)	Generation (GWh/yr)
Wind	300 – 500	650 – 1,000
Solar PV	835 – 1,170[a]	1,735 – 2,120[a]
Concentrating solar power (CSP)	1,170	2,360
Distributed solar PV	1,280	1,779
Geothermal power	28.5	200
Landfill gas	2.5	20
Small hydropower	91	335
Biogas	4	30
Biomass	30	230
Total (electricity)[c]	**3,750 –4,300**	**7,340 – 8,100**
Solar thermal hot water	n/a	260
Geothermal heat pumps	n/a	4,430
Total (heat)		**4,690**

Armenia has good solar PV resources, with annual average global horizontal irradiation (GHI) ranging from 1,490 kWh/m^2 to over 2,100 kWh/m^2. In addition to utility-scale solar PV, distributed solar PV mounted on building rooftops could also be deployed throughout Armenia, although these plants would likely have higher costs and lower capacity factors than large-scale, ground-mounted plants.

Armenia receives relatively low direct normal irradiation compared to most of the locations where concentrating solar thermal power (CSP) is successfully deployed. An analysis of the theoretical performance of CPV plants deployed in Armenia revealed that CPV is expected to have lower capacity factors than flat-plate solar PV installations.

Armenia's biomass resources could be potentially used for power generation. The biomass resource assessment suggests that there are sufficient forestry residues to support a 4 MW power plant in Armenia and sufficient grain crop residues to support a 25 MW power plant.

Armenia has the potential for biogas-based power production at livestock farms, at the Nubarashen landfill, and at the Aeratsia wastewater treatment plant.

Armenia has significant potential for geothermal heating and cooling in residential buildings. If land is available, geothermal heat pumps could theoretically be deployed anywhere and could cover a large portion of Armenia's space heating and cooling load. The coefficient of performance (COP) for geothermal heating in Armenia is reportedly 5.0 to 6.0. Only one existing large-scale geothermal heating project has been implemented in Armenia. In 2009, an 860 kW geothermal heat pump was installed at a commercial building on Northern Avenue in Yerevan.

There is significant potential for solar thermal hot water heating technologies in Armenia. This technology has been deployed in several demonstrations over the past decade, but the total penetration is small (less than 4 MW of total installed capacity).

The comparative cost of renewable energy technologies is an important factor when determining their viability and attractiveness for inclusion in Armenia's energy portfolio.

Section 4 presents the priorities for renewable energy technologies.

For the study, resources with higher production potential were given higher priority.

- Market maturity/immaturity. The extent to which the technology is used or the resource is already exploited in Armenia, and there is experience with it.
- Cost-effectiveness. The cost of the electricity or heat generated by the technology, as measured by the levelized energy cost (LEC).
- Potential for job creation. The extent to which the use of a technology or exploitation of a resource creates jobs.
- Effect on power grid stability. The extent to which certain technologies had a negative or positive impact on system operation and dispatch.

The table below presents the quantitative rankings assigned to each technology under each criterion.

	Power grid stability	Cost-effectiveness	Potential for job creation	Scale-up potential	Market immaturity	**Average score**
Geothermal heat pumps	2	1	1	1	1	**1.2**
Solar thermal heating	2	3	1	2	1	**1.8**
Utility-scale solar PV	3	2	2	2	1	**2**
Geothermal power	2	2	2	3	1	**2**
Small HPPs	1	1	2	3	3	**2**
Distributed solar PV	**3**	4	1	2	1	**2**
Agricultural biogas	2	1	3	4	1	**2.2**
Landfill biogas	2	1	3	4	1	**2.2**
Wind	2	2	3	3	1	**2.2**

The prioritization exercise described in Section 4 has led to the selection of four focus areas: geothermal power, solar PV, geothermal heating and solar thermal heating.

Section 5 describes those projects, the transformational impact of each, the activities envisioned for each, and the expected co-benefits.

SREP resources would be used for further exploration of Armenia's most promising geothermal site: Karkar. The geothermal power project would include the following activities:

- Project preparation. This step is required to procure the contractors required to do the work necessary to confirm the geothermal resource, as well as the feasibility and transaction advisory.
- Geothermal resource confirmation. This step requires carrying out exploratory drilling at the site to determine whether or not power could be produced from the resource.
- Feasibility study for Karkar site.
- Transaction Advisory Services. The government would procure the project as a Public Private Partnership (PPP).
- Investment in plant. It is expected that the private sector will make the capital investment required for the generation of electricity (the power plant itself).

The geothermal project is expected to create the following environmental, social, and gender co-benefits:

- Minimized land use for energy generation.
- Reduction of pollutant emissions.
- Job creation.
- Targeted job creation for women.
- Potential improvement of transportation infrastructure.
- Potential improvement in the reliability of the power grid. Compared with seasonally variable energy sources such as hydropower and diurnally variable energy sources like wind and solar, geothermal can provide increased grid stability and reliability.
- Cultural heritage.
- Energy security.
- Remediation of contaminated land.
- Discovery of new cultural knowledge and artifacts.

Based on a preliminary review of available data and an analysis of the generic risks that face this type of project development, the project is expected to have relatively limited negative environmental and social risks.

SREP resources would be used to develop roughly 28 MW of utility-scale solar PV. The rapid decline in solar PV costs in recent years has made utility-scale solar PV more affordable and more competitive with the other power generation options available to Armenia.

The utility-scale solar PV project would include the following activities:

- Project preparation.
- Capacity building. Capacity building will be needed in two areas, given the lack of experience with solar PV in Armenia:
    - Support to the system operator in managing a power grid
    - Support to the Public Services Regulatory Commission (PSRC) and MENR for in design of a legal and regulatory framework
- Establishing a feed-in tariff (FiT) for utility-scale solar PV.
- Procurement of private operators through competitive tender. The government would decide at the time of appraisal, in discussion with SREP and the MDBs, which procurement modality will work best in Armenia.
    - Feasibility study.
    - Transaction Advisory Services.
    - Investment in 28 MW project.

The development of a utility-scale solar PV project could have several environmental, social, and gender co-benefits. The solar PV project is expected to create the following social, environmental and gender co-benefits:

- Reduction of pollutant emissions.
- Job creation.
- Targeted job creation for women.
- Potential improvement in the reliability of the power grid. Solar PV is a variable resource and therefore could have some negative effects on grid reliability. However, aside from that, if grid

enhancements are required to interconnect the solar PV plant to the grid, the project's development could result in the improvement of power system reliability in Armenia as a whole.

- Cultural heritage.
- Energy security.
- Remediation of contaminated land.
- Reduced water resource use.

SREP resources would be used to demonstrate the viability of geothermal heating and cooling and solar thermal hot water heating for industrial facilities, commercial buildings, and residences.

The geothermal heat pump and solar thermal projects would involve the following activities:

- Project preparation and public awareness.
- Capacity building and public outreach. The government expects that capacity building and public outreach will be needed because of the limited experience with geothermal heat pumps and solar thermal heating in Armenia.
- Pilot projects in public buildings.
- Private projects through commercial bank on-lending.
- Specifically, geothermal heat pump and solar thermal heating projects are expected to create the following social, environmental and gender co-benefits:
- Targeted job creation for women.
- Potential for improvements in domestic air quality. The deployment of renewable energy alternatives can offset the need for these dirty fuels and improve household air quality in households that currently use wood or coal for heating.
- Stabilization of energy prices for consumers. By providing a new source of heat energy for domestic consumption, these technologies can help stabilize energy prices for consumers.
- Job creation and industrial development.
- Distributed nature of the energy supply.

The table below presents a plan for financing the projects described in Section 5. It shows the proposed contributions or grants from SREP as well as estimates of the amounts anticipated from MDBs and the private sector. As the table shows, roughly US$ 40 million of SREP funding is expected to catalyze nearly five times as much investment, most of it from the private sector (as equity or debt), and the commercial lending windows of the MDBs.

SREP Project	SREP	Government of Armenia	MDBs[4]	Private Sector (Equity)	Commercial Banks/Capital Markets	Other Development Partners	Total
Geothermal Development	**(Million US$)**						
Project Preparation	0.25		0.0				0.25
Geothermal Resource Confirmation	9.00		0.0				9.00
Feasibility Study for Geothermal Plant at Karkar Site	1.000		0.0				1.00
Transaction Advisory Services			1.0				1.00
Investments in 25 MW plant		2.00	0.0	28.13	64.63		95.75
Subtotal: Geothermal Development	**10.25**	**2**	**1**	**28.13**	**64.63**	**0**	**107**
Development of Utility-Scale Solar PV							
Project Preparation Grant	0.50		0.00				0.50
Capacity Building			0.00			2	2.00
Feasibility studies	0.50		0.00				0.50
Transaction Advisory Services	1.00		0.00				1.00
Investment in 28 MW project(s)	24.50	0.75	24.50	21.00			70.75
Subtotal: Development of Utility-Scale Solar PV	**26.5**	**0.75**	**24.5**	**21**	**0**	**2**	**74.75**
Development of Geothermal Heat Pump and Solar-Thermal Projects							
Project Preparation Grant	0.25		0.00				0.25
Capacity Building and Public Awareness	1.00		0.00			1	2.00
Pilot Projects in Public Buildings			15.00				15.00
Private Projects			30.00			15	45.00
Subtotal: Geothermal and Solar Thermal Projects	1.25	0	45	0	0	16	62.25
Grant Total	**38**	**2.75**	**70.5**	**49.13**	**64.63**	**18**	**244**
SREP Leverage	**5.34**						

[4] Includes debt provided by the MDBs commercial lending windows.

Scaling Up Renewable Energy Program (SREP), Revision. 2019

The objective of the Geothermal Exploratory Drilling Project (GEDP) was to assess whether the geothermal resource at Karkar is suitable for power generation. Phase I, which was completed in January 2017, supported the drilling of two slim exploration wells (B-1 and B-2), including the construction of associated infrastructure and well logging and testing services. B-1 and B-2 were drilled to depths of 1,500 m and 1,682 m respectively. The bottom hole temperatures measured in the two wells were around 115˚C for B-1 and around 125˚C for B-2. The technical information gathered from drilling wells B1 and B2 does not provide conclusive proof of the existence of a geothermal resource at Karkar given that no geothermal flow was found. The results indicated that the geothermal plant would not be economically viable compared with other supply options and that the minimum tariff required to make the project financially viable would be significantly above the average supply cost for Armenia.

The total cost of the SREP-supported solar program is estimated at US$150 million and is expected to be financed with 25 percent equity and 75 percent commercial debt. The Government intends to request up to US$4 million of IBRD funds in the form of a guarantee and up to US$26 million in SREP funds in the form of loan guarantees to help mobilize commercial capital, as per the project proposal approved by the SREP Sub-Committee on May 23, 2018.

The geothermal heat pump and solar thermal component form part of the EBRD GEFF program. Under this program, EBRD extends loans to local private banks (PBs) and financing institutions to on-lend to companies/commercial users for green economy investments, including energy efficiency and renewable energy investments, covering inter solar PV, geothermal heat pumps, solar water heaters, and biogas.

Specifically, geothermal heat pump and solar thermal heating projects are expected to create the following social, environmental, and gender co-benefits:

- Potential for improvements in domestic air quality.
- Stabilization of energy prices for consumers.
- Job creation and industrial development.

Armenia has a sufficient RE potential5, which has not yet been realized, even with the current GEFF facilities that are in place with local financial institutions:

- Solar PV – 835-1,169 MW
- Solar thermal hot water generation – 254 GWh/yr
- Geothermal heat pumps – 4,423 GWh/yr.

The reallocated funds will be supported by additional Technical Assistance funds for the implementation of the following activities within the EBRD GEFF Program under the geothermal heat pump and solar thermal component:

- Project management and implementation support to GEFF sub-borrowers implementing SREP-eligible RE technologies (biogas, geothermal, solar PV, and solar thermal).
- Support the market penetration of the SREP-eligible RE technologies:

  a) Outreach events to international manufacturers and suppliers of the target technologies.

  b) Outreach to local vendors and service providers (trade fair/exhibition/conferences) including TFP; c) Series of workshops for PFIs and their selected clients to promote the business case for investing in the target technologies.

- Visibility activities, including preparation of video case studies on SREP-eligible technologies and sub-projects, Capacity building of local technology and service providers (through R2E2 Fund within the limit of 75.000 EURO).

SREP funds will mobilize additional investment funding as per the below table:

Source	Financing (USD million)
EBRD	11.25
SREP	2.25
Private	2.25
Total	15.75

EBRD - ACTION PLAN FOR POWER GRID STRENGTHENING TO SUPPORT RENEWABLE PROJECTS – ARMENIA, prepared by Pöyry Italy S.r.l. (2020)

According to the study the following conclusions have been presented by the Consultant:

- Investments relating to the power part, both for the construction of new substations and lines and for the reconstruction and upgrading of existing ones, are substantial in the short-term years (2020, 2021).
- The medium and long-term investment planning shows an investment reduction for the upgrading and new substations and lines with the minimum at 2024. The medium-term investment plan should be updated and reinforced up to the complete renovation of the existing infrastructures and according to new network requirements.
- Consultant assumes that investments will be directed to the weak points and bottlenecks of the power grid as well as to improve the grid safety and reliability taking into consideration the greater reserve margins of power that the VREs require to be maintained
- Consultant assumes that the 400 kV interconnection work with Georgia and Iran that is currently underway will be completed by 2022, in any case before the wide diffusion of the VREs in the Country. The follow-up of the work must be strictly carried out to avoid delays.
- Considering the above, the Consultant deems that the investment program for Power Systems is properly developed but it should be completed in order not to be a barrier to the integration of a substantial share of VRE into the Grid. In particular, three high-voltage substations need urgent rehabilitation (Marash, Shahumyan-2, Egheknadzor), for which investment is required
- It is necessary to upgrade the Dispatching system including, SCADA, Telecontrol, and new digital devices for protection and control (Smart Control). The upgrading actions under implementation by EPSO have been covered by an already active investment program of 9,7 Mil € (8.5 million already implemented in the period 2015-2019 and 1.2 million € will be finalized in 2020).
- Some of the Consultant's recommendations require investments for the regulatory part (e.g. upgrading of the Grid Code) which do not require significant investments but are urgent to be able to immediately regulate the grid integration of the VREs.
- The adoption of the recommendations for the smart control systems will become more important as greater the penetration of the VRE will be.

The strengthening works recommended by the Consultant concern, in synthesis, the following items.

- technical regulatory framework improvement (0,45 Mil € of investment)
- complete the process of renewing the transmission and distribution Power infrastructure by revamping number three high voltage substations (24 Mil € of investment).
- optional investment for battery storage for frequency regulation (4,3 Mil €) has been also proposed.
- dispatching, control and communication systems need to be updated by introducing SCADA/EMS, this activity is under implementation and is already covered by funding.

The upgrading to the technical regulatory framework will allow the development of the VREs in an organic way and be compatible with their friendly integration into the electrical grid. Rehabilitation of the existing 220/110 kV substations must be carried out until they are completely renewed. An optional investment has been also proposed by the Consultant battery storage system for frequency adjustment for an initial approach to battery storage technology. Further investment in battery storage systems for grid stabilization will be evaluated when the share of VRES is significant (20-30%) based on the frequency variations of the grid that will be measured.

The table below shows the total investments for the Armenian grid for 2020-24 (Mil € without VAT).

	Investor	Investment status	Investment Program Directions	Total	Note
1.	ENA	Already planned	The foreseen volume of investments purposed for maintaining the SAIDI and SAIFI indexes on the existing level, ensuring safety, replacing the worn-out equipment with new ones	176,92	
2.	ENA	Already planned	The estimated volume of investments aimed at reducing the incidence and the average duration of voltage deviations from the permissible value.	28,07	
3.	ENA	Already planned	The estimated volume of investments for new consumers' joining and implementation of targeted distribution network development programs	33,60	
4.	ENA	Already planned	The estimated volume of Investments aimed at improving of the commercial metering system	59,10	
5.	ENA	Already planned	The estimated volume of investments to be made in other areas for the organization of distribution networks	6,97	
Total ENA				304,67	
6.	HVEN	Already planned	Upgrading and reconstruction of existing substations	57,36	
7.	HVEN	Already planned	Upgrading and reconstruction of existing high-voltage lines	1,82	
8.	HVEN	Already planned	Upgrading of control and protection system by a new digital device. (SCADA, telecontrol, telecommunication)	0,00	Refer to item 14 by EPSO
9.	HVEN	Already planned	Construction of new substations	172,73	
10.	HVEN	Already planned	Construction of new high-voltage lanes	75,44	

	Investor	Investment status	Investment Program Directions	Total	Note
11.	HVEN	Already planned	Investment in infrastructure (buildings, production equipment and tools, office devices, etc.)	2,27	
12.	HVEN	Already planned	Investment for personal safety, training	20,45	
13.	HVEN	Already planned	Other	1,82	
Total HVEN				331,91	
14.	EPSO	Already planned	Modernization of the Dispatching system	0,60	Action under implementation. An investment of € 3,182 million has already been used in the period 2015-2019
15.	EPSO	Already planned	SCADA/EMS/optical grounding wire	0,60	Action under implementation. An investment of € 4,263 million has already been used in the period 2015-2019
Total EPSO				1,20	8,5 Mil € in the period 2015-2019
16.	Consultant	Recommen ded	Regulatory upgrading (Grid Code, Reliability and Security Indicators of Electric Power system, Standard cost for connections)	0,45	Action for PSRC
17.	Consultant	Recommen ded	Upgrading and reconstruction of existing substations/lines, Construction of new substations/lines	24,00	Upgrading of N° 3, 220 kV substations. Action for HVEN
Total CONSULTANT for the period 2020-2024				24,45	
OPTIONAL investments suggested by Consultant in 2020-2024					
A	Consultant	Recommen ded	Battery storage for frequency regulation	4,30	Action for EPSO
Exchange rate AMD/USD: 476,19 (16/07/2019)					
Exchange rate €/USD: 1,1					

Pumped storage power plants

Pumped storage power plants are not sources of renewable energy. However, in many scientific articles are considered as an important element in supporting the development of uncontrolled sources of RE (solar, wind).

The predictions of the daily electricity demand pattern in Armenia enabled the determination of the longest time intervals for dispatch in each month, under all potential scenarios. The pumped storage power plant has a capacity of 200 MW for pumping (energy consumption) and 150 MW for generation (electricity production) mode.

The following main conditions were taken into account when choosing the scheme for installing structures and determining the main indicators:

- reasonability of topographical and geological conditions considered during the selection of platforms,
- implementation of the variants of such platforms that have inner basins,
- modern rotary aggregates implemented as a key unit.

Initially, three variants of PSPP platforms are recommended in the results of our studies and territorial reviews;

1. Aghbyurak PSPP – next to Akhpar water-storage basin
2. Tolors PSPP – next to Tolors water-storage basin
3. Shamb PSPP – next to Shamb water-storage basin

Main indicators of PSPP

PSPP	Aghbyurak PSPP	Tolors PSPP	Shamb PSPP
Static pressure, m	355.0	383.5	416.6
Rated pressure, m			
turbine regime	334.2	374.5	406.5
pumping regime	369.5	390.5	423.5
Estimated flow, m^3/s			
turbine regime	54.0	48.0	40.0
pumping regime	45.0	43.0	45.0
Rated capacity, MW			
turbine regime	150	150	150
pumping regime	200	200	200

Energy Efficiency

National Energy Efficiency Action Plan 2010 for RA prepared by Foundation to Save Energy. 2010.

The action plan proposes a set of relevant measures to the Government of Armenia to improve the current legal status and enforcement of legislation put in place, for capacity-building (mainly in the public sector) and institutional setting, for creating awareness across all sectors and a general environment that is more in favor of energy efficiency improvement in the following sectors:

- residential buildings;
- public and private service sector;
- industry;
- transport;
- agriculture.

The proposed sectoral energy savings are based on potential assessments and have been adjusted to the target year. They are shown in the Table below:

Estimated energy savings cumulated for each sector until 2020:

Energy saving target adopted in 2020	(%)
Residential/Households	23,0
Industry	41,6
Transport	17,1
Public and commercial services	14,6
Agriculture	3,5

Armenia has taken important steps to encourage more efficient use of energy. The potential is mainly untacked due to several reasons that can be summarized in a list of barriers to addressing energy efficiency:

- The legal framework needs to be implemented and enforced. Especially in the building sector, the existing building code needs binding provisions regarding the thermal quality of new and existing buildings.
- Creating awareness about energy efficiency needs a lot of information and know-how provided to all energy consumers (private, business, service sector, etc.).
- Private consumers (i.e. households) miss general and simple information on what can be done to reduce energy demand in daily life, such as in housing, use of electric appliances, etc.
- Many political decision-makers and private businesses still fail to see the value in energy efficiency investments, despite the successes of donor-sponsored pilot projects and programs.
- The natural gas tariff encourages wasteful use by some smaller customers.

There tariff structure does not provide an incentive for consumers to use less energy. Furthermore, there are no other financial incentives available that would encourage saving energy.

The list of measures is given, including:

- Horizontal and cross-sectoral measures,
- Sectoral presentation and assessment of energy efficiency improvement programs, energy services, and other measures to improve energy efficiency, in particular:
  - upgrading existing legislation and all by-laws (standards, norms) to reflect the necessary efforts to be made in increasing the energy of buildings
  - establish necessary capacities on the enforcement level
  - train students at university and employees of companies in the planning/design and construction sector to comply with new integrated design and building standards
  - develop pilot projects to demonstrate building best practices (for rehabilitation and new buildings) and
  - provide further incentives to promote energy-efficient construction at all levels.
- Energy efficiency improvement measures in the public and private service sectors,
- Energy efficiency improvement measures in industry sectors (including energy production),
- Energy efficiency improvement measures in the transport sector,
- Energy efficiency improvement measures in the agricultural sector.

Second National Energy Efficiency Action Plan for Armenia prepared by Econoler. 2015

There are two main sources to finance EE projects:

a) Local Financial Institutions: Banks and Universal Credit Organizations

The total loan portfolio of local financial institutions (LFIs), which includes banks and universal credit organizations (UCOs) increased from 3.026 Bln. USD in 2010 to 4.625 Bln. USD in 2015, i.e. 8,88 % per year.

b) International Financial Institutions

International financial institutions (IFIs) provided more than 87.96 Mln. USD for EE lending through LFIs, which generated (leveraged) 23.30 Mln. USD or more than 26 % additional investments/contribution from other sources in EE business in 2010-2015.

The biggest portion of EE loans in 2010-2015 was provided to Industry, more than 35 %, about 22 % to the power sector/generation, and 18 % to small and medium enterprises (SMEs), with the transport sector being blended with industry and SMEs as well. About 14 % were invested in municipal infrastructure projects. The smallest share of lending went to public buildings - about 0.3 %.

The following three directions are presented as the main important issues of energy efficiency:

Legislation and regulations

a) EE Invest/lending climate and banking regulation improvement event (ILCIE)
b) Introduction of a compulsory energy audit (label) system for industry
c) Improving university curricula in the areas of energy efficiency.

Capacity building events

d) Combined Study tour and Capacity Building Workshop on EE financing
e) Capacity building for LFIs on EE financing
f) Industrial Energy Audit Analysis for Bankable Projects for Energy Engineers and ESCOs
g) Capacity building for LFIs on Energy Audit
h) Capacity building for LFIs and ESCOs on performance contracting.

Awareness raising

i) Development of an online information portal on EE Business
j) Establishment of a web portal of all energy efficiency product and service vendors, financiers, consults, governmental and non-governmental institutions
k) Establishing and operating an EE business information center
l) Combined Study tour and Capacity Building Workshop on EE Awareness Raising.

NEEAP presents progress in the Covenant of Mayors East Movement. It is a horizontal measure with regards to the cross-sectoral nature, local policy and planning elements, as well as emerging synergies with the national and international policies and programs, as well as financial measures. As of 01.07.2015, there are 10 signatories of the Covenant of Mayors in Armenia.

Key measures proposed for implementation in residential and public buildings are as follows:

- Thermal insulation of building envelopes;
- Replacement of roof coats with galvanized iron plates or new coating materials;
- Application of thermal insulation materials (15-20 cm thickness) on ceilings of the last floors of the buildings with balks;
- Replacement of wooden windows with new energy-efficient ones;
- Replacement of entrance doors of multi-apartment buildings;
- Replacement of inefficient incandescent lamps with energy-efficient lighting, etc.

Also, the following so-called low-cost measures aimed to save heat on premises are envisaged:

- Insulation of windows and doors with the application of silicone, foam rubber, sealants, polyvinyl chloride, and foam plastic;
- Installation of door closers;
- Installation of heat-reflecting screens behind radiators;
- Construction of tambours;
- Heat insulation of internal heat distribution networks in basements and attics, etc.

Key measures proposed in the transport sector are introduced below:

- Introduction of bikeways;
- Shift to natural gas as a fuel for municipal and public transport.

In the renewable energy sector, the following measures are proposed:

- Installation of individual (apartment level) solar water heaters;
- Installation of solar water heaters for collective use for hot water supply and pools;
- Installation of PV modules for electricity generation for illumination of entrances and yards of multi-apartment buildings.

Chapter 4 is dedicated to individual measures.

The overall buildings sector in the NEEAP is split between several sections, according to the NEEAP methodology and template.

The public buildings, grouped with the services sector, are presented in Public and Private Services. Of the overall 80 million km2 of the nationwide building stock, 83% are residential buildings, and the remaining 17% - public buildings.

Energy consumption in the buildings sector has decreased over the past 5 years.

The current tariff structures need to be reviewed and revised to introduce built-in incentives for energy efficiency and conservation while providing a minimal consumption block to low-income households at an affordable tariff.

The energy efficiency issues of the buildings sector are related to the poor energy performance of the building envelopes in both residential and public buildings, inefficiencies of internal energy infrastructures (heating, lighting, hot water, and cooling systems), as well as poor behavioral practices in energy management. For new construction, the main issues are the overarching failure to comply with the building codes regulating building thermal protection and general energy performance, as well as the overall law technical capacity of the professionals in the construction sector to design and construct energy-efficient buildings. Most of the investments in energy efficiency in buildings have positive economic features and can be financed with loan financing under close-to-commercial terms. However, there are several persistent barriers, such as legislative, institutional, socio-economic, and low awareness that impede large-scale uptake of energy efficiency investments in the market.

The Armenian housing sector comprises about 95 million km², of which 54 % are in urban settlements and 29 % are in multi-apartment buildings. About 30 % of all multi-apartment housing is made of panel or monolith concrete. Only 40 % of the overall housing stock is over 40 years old. The private houses, comprising one-third of all housing space are relatively well maintained.

The 2002 Law on Apartment Building Management did not adequately legislate and enforce the rights and responsibilities of condominiums. Clarification and a redefinition of the roles of owners on the one hand and of the management organizations on the other hand are urgently needed.

To address the issues within the housing sector, the conservation and maintenance of common space and supporting infrastructure in urban housing, the Armenian Government with assistance from partners (international aid organizations) has pursued major policy reform efforts that concern utility supply, public utility regulation, organization of multi-apartment building management bodies and condominiums, housing policies, municipal budget autonomy, revenues, etc.

According to the results of donor-funded pilot projects, an average residential building in Armenia has 30-50 % potential for energy saving at current energy prices.

The barriers to energy efficiency investments in multi-apartment residential buildings can be summarized as follows:

- Lack of housing strategy or clear policy on state/local government responsibilities to vulnerable groups;
- Clear separation of responsibilities among state and local authorities;
- Private-sector involvement in the housing industry and finance;
- Improvements mechanisms for eviction, foreclosure, and bankruptcy to conduct legally transparent and sustainable transactions in real estate, including sales and other transfers of nonperforming loans and,
- Implementation and enforcement of acting laws and regulations in the field of multi-apartment building maintenance and management
- Weak capacity for building management, project development, financial planning and management, fund-raising, human resources, reporting, and customer/member relations.
  - Survey revealed up to 20 % HOA managers still initiate cash-paid service recruitment
  - Up to 20 % of HOAs implement maintenance work no more frequently than once every 1-2 years
- Lack of financial resources due to low maintenance fee rates and low collection;
- Poor creditworthiness due to their new status, slow development, failure to collect service fees, and failure to conduct creditworthy accounting, bookkeeping, and reporting.
- Difficulty securing the necessary number of votes for strategic decision-making with respect to heat supply issues; the situation is exacerbated by the growing number of autonomous apartment-level solutions) and the significant share of absentee households (~20%);
- The need, often, to sign individual loan repayment and service supply contracts with each household due to mistrust and lack of experience in purchasing utility services from the intermediary.
- Lack of overall awareness and understanding of the legal-regulatory framework, rights and responsibilities related to the homeowners' associations, and benefits of EE, in general.

NEEAP 2 recommends the following effective financing schemes for residential energy efficiency:

- Design a Financing Scheme with features customized to the economic features of MAB retrofit projects, with ‘soft’ terms, and combined with grant financing and technical assistance;
- Seeking grant resources to support energy efficiency programs for low-income households from state social safety funds to replace traditional tariff subsidies for natural gas;
- Cultivate public-private partnerships with private maintenance or energy service companies with municipalities, private housing maintenance firms, and HOAs to facilitate the elimination of institutional barriers while attracting private capital;
- Utilize lessons learned from demonstration projects to inform government policies on the choice of institutional and regulatory reforms, and test-drive the programs on a small-scale pilot scale, roll out to offer a standard solution in regular commercial banks/local financial institutions (LFIs);

- Seek opportunities to capitalize on the environmental benefits of energy efficiency in residential buildings, for instance through environmental funds or carbon financing;
- Value of Non-monetary Savings considering that residential energy efficiency may not always bring financial savings but significant non-monetary improvements in lifestyle, comfort, health and environment;
- When loan-financing residential energy-efficiency programs for multifamily buildings, have special provisions (grants) for vulnerable households so that they may participate;
- Enable the participation of the HOAs in Residential EE investment projects by finding creative solutions for loan financing to HOAs;
- Collect adequate data through monitoring and evaluation to document impacts and fine-tune the programs for improved effectiveness;
- Create security funds to insure loans for condominiums in the case of collateral deficiency;
- Provide funds for reconstruction, energy efficiency measures, preparation of technical and financial documents as well as for the application of innovative technologies;

In addition to the investments and measures to help reduce the building sector's demand for heating energy, the residential sector needs support dealing with the growing electricity prices. It is recommended that the energy social safety nets make a transition from tariff subsidies to subsidized energy efficiency programs for low-income households. To help manage the electricity consumption within affordability limits, it is proposed to offer replacement LED light bulbs to low-income families.

Another tool that helps the population deal with the energy demand-side management, for the middle- to high-income range population, is appliance energy labeling.

Schools, universities, colleges, kindergartens, medical institutions, and athletic facilities comprise 92% of all public buildings. Over 40% of all public buildings are located in the capital of Armenia. The majority of public buildings are under governmental ownership, control, and direct co-financing. The majority of public buildings have very low energy performance, largely due to the age, poor condition of the building envelope as well as lack of adequate energy management. On average such buildings have 10-70% potential for energy saving. The current financing scheme of public institutions per person (per patient bed in hospitals, per student at educational facilities) created a possibility to utilize borrowed resources for energy efficiency retrofits and cover the investments from savings.

R2E2 estimated with incremental investments of about \$17-20 per m^2 (this is equivalent to approximately 10% of the common average \$200/m^2 for comprehensive building rehabilitation) the natural gas consumption for heating can be reduced twice. These improvements are achieved by a comprehensive energy efficiency improvement package including insulation of walls/finishing, replacement of doors and windows, replacement of windows by walls, and roof insulation, after an efficient heating system has already been put in place.

The demand for energy-efficient construction and renovation is much larger than the funds currently available in Armenia. To this purpose, this component aims to attract (international) concessional finance to further increase the number of funding in new and public buildings to be rehabilitated incorporating the energy efficiency requirements.

Typical measures include:

- Insulation of walls and roofs,
- replacement windows and doors
- replacement of street-lighting systems,
- heating system replacement/upgrade
- replacement of windows by walls.

Urban lighting costs of Armenian municipalities account for more than USD 5 million per annum (power costs and maintenance). The capital city of Yerevan has the largest energy consumption and saving potential in its lighting sector: it accounts for approximately 80 percent of all urban lighting energy use in the country.

The R2E2 energy efficiency credit line for public buildings also finances street-lighting projects and the available loan funding can be adequate to address the demands of other local governments for energy efficiency retrofits in public street-lighting systems.

The use of energy in the agricultural sector has been growing over the past two decades. According to the Ministry of Agriculture (MoA) of the Republic of Armenia, 93% of existing agricultural machinery originated during Soviet times and is technologically obsolete. The agricultural sector accounts for only 2% of total final electricity consumption.

The following measures need to be implemented in order to further improve the energy efficiency and competitiveness of the agricultural sector:

- Addressing the problem of regular electricity supply at a relatively low cost through effective use of solar, land, underground, and water energy alternatives in mountainous and border villages.
- Farmer education on irrigation management which is necessary for sustainable irrigation practices and will not only help optimize the water but also save substantial amounts of energy.
- Continue the modernization of the agricultural machinery and equipment park as well as the equipment park database management, as 92% of current tractors and 80% of combined harvesters are more than 25 years old. There should be a program directed to individuals or the cooperatives encouraged to integrate into the mechanizators community.
- The current database of agricultural machinery lacks quality information and is poorly managed. To be able to support and track the effect of the fuel-efficient technology adaptation in the country, one needs to have access to indicators on the use of existing modern equipment being utilized in the country.
- Continue focusing on the gravity irrigation programs. To avoid huge costs of inefficient electricity use in those systems the gravity irrigation system needs to be installed where possible.
- Focus on wastewater collection and waste management in general. Investing in new technologies directed to wastewater cleaning will substantially improve the energy use of this sector, as well as the volumes of water saved.
- Armenia has significant water resources ensuring the development of aquaculture. In this context, an important problem is the excess use of water and electricity by this sector.
- To make the use of agricultural resource potential more effective, special attention should be paid to the promotion of the creation of greenhouses in farming entities. The following activities need to be implemented:
  - Provision of tax privileges for the import of main equipment and construction materials needed for the creation of greenhouses,
  - Provision of affordable targeted loans for the creation of greenhouses for farmers.

Industry, SMEs and Power

The industry sector is a significant energy consumer in the country, at 18% of national final energy consumption in 2012. This sector is expected to grow its energy consumption dramatically reaching 30-31% in the next five years. The analysis of the energy intensity of the industrial sector reveals a visible reduction of the energy use per unit of industrial output.

The industry sector consumes about 18% of natural gas imported into Armenia. Almost 30% of natural gas is consumed in the power industry for the generation of electricity.

The affordability of tariffs for both natural gas and electricity has become a major concern not only for the population but also the large industrial consumers and SMEs. Energy efficiency can help the local producers remain competitive under the conditions of growing energy prices.

Recent pilot projects and technical assistance programs implemented by donors have identified the great potential to improve energy efficiency in the industry through the implementation of energy management systems, building capacity in energy auditing, and application of best available technology practices for energy efficiency. It has been estimated that these initiatives could reduce energy intensity by 20% with a reasonable financial return on investment.

Considering the potential in Armenia for cost-effective projects that can significantly reduce energy intensity and deliver important operational efficiency in the industrial and SME sectors, it is recommended to seek opportunities for wider implementation of resource efficiency initiatives. Implementation of ISO 5001-compliant energy management systems, conducting energy audits, and dissemination of knowledge about benchmarking practices will contribute to the increased quality of economic growth and clean production in Armenia.

Armenia does not have any domestic fossil fuel resources which puts the country in a perilous state of energy insecurity. National economic development is tightly linked to energy prices and the availability of imported energy resources. The NEEAP proposes stronger support for solar water heaters, distributed solar PV systems, and piloting of geothermal heat pumps for building heat.

According to recent studies supported by USAID to investigate the Energy-Fuel Balance of Armenia, the transport sector in Armenia’s economy was the second biggest energy consumer for 2010-2012. According to Armenia's Third National Communication on Climate Change and GHG Inventory, there were about 434,600 units of registered road transport (RT) vehicles in Armenia, of which 70% (about 300,000) in running condition.

The first NEEAP defined several measures, as listed below, aimed at reducing energy consumption growth in the transport sector, with a special focus on road and rail transport.

- Development of legislative background on fuel efficiency and emission norms
- Dissemination of information on technologies and energy saving
- Continuous replacement of minibusses by larger passenger buses and route optimization
- Expansion and modernization of the electrified public transport
- Expansion and modernization of the rail transport network (passenger and freight)
- In addition, two new measures, as listed below, were integrated into the second NEEAP, including:
- Continuous switching of road vehicles from gasoline to CNG
- Development of an integrated electro-transport network and services to cover unsatisfied demand for public transportation services in the greater Yerevan area.

Implementation of the Yerevan public transportation fleet optimization strategy and replacement of minibusses with larger urban buses started in 2005. The main aims of the strategy are to:

- optimize the public RT route grid and reduce the annual running distance of the fleet
- replace minibuses with larger ones
- achieve the overall modernization of the public RT fleet.

Significant public transport infrastructure development is needed to cover the huge unmet demand for public transportation services in the greater Yerevan area. The main focus should be placed on the development of the integrated electro-transport network for the greater Yerevan area with an essential expansion of the Yerevan Metro.

1. Significant development of the public transport infrastructure by introducing an integrated electro-transport network (IETN) for the capital Yerevan with two transport hubs to the Zvartnots International Airport (West Hub) and to the cities of Abovian and Charentsavan (North Hub, based on Almast station in Nor Zeytun district of Yerevan, see V3 Report).
    a. First phase. By 2025, a 7-station new metro line with West HUB connecting the metro with the Zvartnots International Airport will be put into operation, which will double the metro's annual turnover.
    b. Second phase. In 2030, the commissioning of ITEN new 9-station metro line with North HUB (to the cities of Abovian and Charentsavan, on the base of the Almast Rail station). ITEN turnover will more than triple in comparison with the 2010 level. Annual electricity consumption will increase from the current 120 million kWh level to 375-400 million kWh in 2030.
    c. Energy savings achieved from the implementation of this measure will be at least 3 times more than the savings from the V3 measure and will mainly occur after 2020. More detailed estimates should be made through a properly conducted analysis based on consistent and adequate primary data.
2. Encouraging import of gas-fired public transportation vehicles, electro mobiles, and hybrid cars (via duty and tax incentives).
3. Modernizing the electro-transport fleet; introducing modern Unified Ticket for Public Transport (including electro-transport, trolleybuses, metro, electric rail, and urban busses)
4. Development of the related infrastructure (services, operation and maintenance).
5. Attracting direct investments and technology transfer, introducing private-public partnership mechanisms, and establishing effective collaboration with local authorities are essential to accomplishing the strategic goals.
6. Developing the appropriate roadmap and action plan is crucial to the successful implementation of this measure.

Other components include advertising public transport use, promotion of the “sustainable green transport for cities” concept, and introducing a modern ticketing system, including monetization of gains from increasing the sustainability of the transport sector and its level of independence from fuel imports.

Armenia: Energy Efficiency Roadmaps prepared by Foundation to Save Energy. 2017

The study states the importance of energy efficiency for Armenia from the perspective of:

- creating conditions for economic growth while improving the country’s energy security;
- reducing the energy intensity of national economy products, increasing economic efficiency and competitiveness;
- maintain a secure, sustainable and affordable energy supply while mitigating climate change;
- help meet rising energy demand by exploiting “missed opportunities” for energy savings in new construction;
- improve the quality of life in Armenia, create jobs and help the local economy;
- reduce utility bills for all consumer groups;
- reduce the use of limited natural resources and pressure on endangered forest resources.

In the 1st NEEAPs of Armenia (as in all of the European countries), common EE improvement measures include:

- Building audits and certification
- EE Projects in public administration buildings, schools, hospitals, street lighting
- Energy management

- EE in tendering procedures for public procurement.

In 1st NEEAPs, the public sector is given an exemplary role in:

- EE equipment procurement
- Public-private voluntary agreements
- Awareness campaigns ◦ Public training, education, guidance
- Training and EE-related publications for professionals
- Energy audits.

The energy-saving potential in public buildings for 2017 is presented in the following table.

Total Area of public buildings in Armenia (m²)	13,787,397
Total energy consumption in Public Buildings (MWh/year) *	1,764,787
Annual Energy Saving Potential (MWh/year) *	896,181
(* based on R2E2 experience with 56 projects.	
Average energy consumption before EE in public buildings	128 kWh.m/yr
Average energy consumption after EE	63 kWh.m/yr
Average energy saving rate	51%
Investment need (AMD) at an average of AMD 8400/m² for typical ESMs	115,814,134,238
Investment need (USD) - exchange rate 473	$244,850,178
Total Financing currently available (GEF and KfW)	$ 27,270,296

According to the study, the ways to Eliminate Gaps and Move Forward include:

- Continued reform
  - Enforcement of the recent amendments of the Law on Energy Saving and Renewable Energy
  - Adoption/ enforcement of bylaws on energy auditing and EE in public procurement
  - Development/ enforcement of EE standards, codes, and labeling for all uses
- EE funding
  - Continued operation and expansion of R2E2 Fund operations
  - Smooth integration of E5P grant co-financing for non-bankable projects
  - Leveraging IFIs & LFIs resources to address underserved segments of the EE financing market
- New/improved housing legislation
  - Create a favorable investment environment in multi-apartment buildings
  - Introduce private sector participation through private maintenance companies and ESCOs
- Tariff reform
  - Revise tariffs to incentivize energy efficiency
  - Low-income assistance for the implementation of energy efficiency measures
- EE-integrated renewables
  - Incentives for wider combined energy efficiency-integrated renewable energy application
- Information and outreach
  - Improvement of energy efficiency data collection and periodic energy balance calculation

    - Development and provision of technical assistance in the best available energy efficiency technologies for the industrial and agricultural sectors (e.g., greenhouses and aquaculture)
- Capacity Building
    - Strengthen capacities among HOAs, SMEs, ESCOs, and municipalities to plan and implement EE
    - Strengthening the institutional capacity of the State to develop and implement EE policy.
    - Create/assign capacities to oversee NEEAP implementation, conduct MRV

In-Depth Review of the Energy Efficiency Policy of Armenia prepared by Energy Charter. 2017

The report provides *General recommendations:*

The government should continue to work on the long-term energy strategy to ensure that energy policy goals respect and fully reflect the potential of energy efficiency and renewable energy to contribute to wider political, economic, social, and environmental goals. Energy Efficiency and Renewable Energy should continue to be a high priority in all sectors and future energy-related policies should be supported by detailed analysis of energy efficiency potentials in the economy, and the barriers which delay the realization of these potentials. The institutional framework to support the implementation of Energy Efficiency policies, including the Ministry of Energy and Natural Resources, should be strengthened. The government should ensure the effective implementation of the second National Energy Efficiency Action Plan (NEEAP).

Electricity, Gas and Heating Sectors

The modernization of the generation, transmission and distribution infrastructure needs to continue, to further minimize losses and utilize the existing energy-saving potential. The Government, with the support from the PSRC, should review the market model as new interconnections develop and ensure the adaptation of balanced market rules to reconcile with EU legislation. The Government should continue the promotion of renewable energy in a cost-effective way. The ongoing efforts by the distribution company (Electric Network Armenia) to introduce smart technologies in metering should be encouraged. Feasibility studies, including assessments on the efficient use of heat, should be carried out as a basis for future decisions on the development of co-generation.

Industry

The Government should consider a more proactive energy efficiency policy for the industry sector. The Government should assess the further expansion of mandatory energy auditing for large industries, consider voluntary auditing also for SMEs as well as incorporate a standardized approach to energy auditing. It should also encourage further industrial enterprises to implement actions to deliver cost-effective energy savings including the already adopted energy auditing system for the large energy consumers. The Government should consider extending the policy toolkit to include various incentive schemes for industrial enterprises that undertake energy audits to support the implementation of the audits' recommended measures as well as other justified actions.

Buildings

The Government should put efforts into effective enforcement of recently adopted legislation in the building sector. The relevant technical regulations and standards should be adopted as soon as possible in order to improve the effectiveness of the whole regulatory system in the building sector. The Government should continue striving to make public buildings a model for energy efficiency and ensure the application of the latest best international standards regarding the performance of various building components. The Government should encourage local authorities to undertake energy audits of all public buildings and develop dedicated programs for improving the energy performance of public buildings to implement the requirements of the audits. The Government should require that special energy efficiency criteria be introduced in procurement procedures for public expenditures on goods, services, and works, with particular emphasis on the public building sector. The Government should continue its efforts to raise public awareness by providing information on end-use energy efficiency measures, both in residential and public buildings.

The Government should also further encourage energy efficiency improvement by providing innovative financial mechanisms and creating attractive conditions for the application of energy performance contracting and ESCOs.

Lighting and Energy Using Products

Authorities need to allocate sufficient resources for compliance, monitoring, and verifying advertised performance for different appliance groups on energy efficiency requirements, regardless of whether they are imported or locally manufactured. The Government should create the necessary conditions to support local authorities in developing and implementing projects for high-efficiency public lighting. The Government should continue to encourage the purchase of highly efficient household appliances.

Transport

The Government should improve the quality of urban planning, including transport infrastructure elements and traffic management. The Government should introduce policy packages (regulations and incentives) that encourage more rapid turnover of the old vehicle fleet. Such measures could be in the form of discouraging the import of old vehicles, incentives encouraging quick fleet renewal by owners, vehicle fuel economy labels, and tax and fiscal measures stimulating the purchase of more efficient vehicles.

Energy Efficient Buildings in Armenia: A Roadmap (Insights and pathways for better buildings in Armenia, 2020-2040) prepared by IEA. 2020

Energy-efficient technologies and materials can be widely deployed given, among other conditions, the right governance and policy environments, functioning markets and access to financing. Due to the poor condition of many buildings, basic structural repairs may be needed before an energy efficiency intervention is logical or feasible.

Conceptually, a 20-year roadmap could be divided into five-year intervals across four categories of activity: policies and financing; markets and capacity; projects and technologies; and future readiness.

National study and detailed gap analysis between the performance objectives of the Framework Guidelines for Energy Efficiency Standards in Buildings and implementation of current building energy efficiency standards in Armenia prepared by Andre Ohanian. 2021

- In 2004, Armenia voted for the interstate building code "Thermal performance of buildings", which takes into account the requirements of EU codes and standards/methodologies.
- A corresponding document was developed in 2008 under the UNDP-GEF project.
- In 2009, proposals for energy audits and the certification of residential buildings were developed under the same project. In 2013, legal and institutional measures were drafted looking to improve energy efficiency in urban development (legislation improvements are currently under discussion).

The following building codes are currently in force:

• RACN 24-01-2016 "Thermal Protection of Buildings"
• RACN II-7.02-95 "Building thermophysics of building envelope"
• RACN II-7.01-2011 "Construction Climatology"
• RACN 22-03-2017 "Artificial and Natural Lighting"

During 2013 – 2016, two National Standards were developed to support the improvement of buildings' energy performance, enabling the implementation of important instruments such as the building energy passports and energy audits:

• AST 362-2013 "Energy conservation. Building energy passport. Basic rules. Standard form";
• AST 371-2016 "Methodology for performing energy audit in residential and public buildings".

The study states that in the Law on Energy Saving and Renewable (2004) (Amendments 2016, 2017) new provisions for mandatory technical provisions for energy efficiency in new residential building construction, as well as in new construction, capital renovation, or reconstruction with the use of state budget funds was developed.

National Program on Energy Saving and Renewable Energy (Adopted by Protocol Decision No.2 dated 18.01.2007) foresees specific targets for the improvement of EE in buildings with a particular focus on thermal insulation only.

The building sector is recognized as the most significant energy consumer in Armenia. Natural gas is the main fuel consumed by households, making up to 86% of the total fuel consumption.

According to the study below topics are not reflected in the existing calculation methodology of EPB and certification system and should be included further on:

- Efficiency of heating, ventilation and air conditioning control systems;
- Efficiency of heating and cooling generation;
- Cooling losses in building systems;
- Lighting, appliances, pumps and ventilators with or without useful heat gains inside heated volume;
- Renewable sources for both heat and electricity, taking into account the perimeter the energy is produced;
- Final energy consumption in kWh/(m^2.y) and kWh/y;
- Primary energy consumption in kWh/(m^2.y) and kWh/y • CO_2 emissions calculation in $kgCO_2$/y.

The study made the following recommendations:

- Technical assistance for legal-regulatory support;
- Capacity building for quality project design (energy audits, technical design, surveillance, monitoring and verification), and capacity building of project promoters;
- Design risk assurance schemes based on cash flow from generated savings;
- Low-interest loans;
- Seek opportunities for private sector participation through energy service companies
- Internalization and quantification of non-monetary benefits, such as avoided greenhouse gas emissions, increased service and utilization of public institutions (e.g. universities, policlinics, hospitals, art facilities, etc.);
- In public buildings – seek opportunities to join donor and IFI efforts to scale up the individual successes to country-wide public building energy efficiency retrofitting program packaged with public sector energy management and optimization of public budget expenses;
- In residential buildings – design tailor-made, simplified, easy-to-use loan products that are supported by grants and guarantee schemes.

	Gap	Proposed actions (Elements)
1.	Need to complete legal-regulatory reforms and enforcement	• Harmonization with EU Acquis • Enhance capacity building • Market liberalization and integration in regional markets
2.	Insufficient Technical and Institutional Capacities of EE Promoters	• TA to improve capacity of EE promoters • Internalization and quantification of non-monetary benefits
3.	Lack of Tailor-Made, Affordable Financing Schemes for Upscaling Investments in Building EE	• Low-interest debt financing • Grant co-financing • Leveraging of national social services • Guarantee vehicles
4.	Lack of Adequate Resources to Overcome Barriers for Country-Wide Public Building Energy Efficiency Roll-Out Program	• Expansion of lending schemes to public and municipal infrastructure energy efficiency • Grant co-financing • Design an exemplary energy efficiency upgrade campaign • Public Energy Management Program
5.	Untapped Market for Multi-Apartment Residential Building EE Investments	• Grant technical assistance for developing an enabling investment environment • Grant co-financing for concessional lending • Credit guarantees to reduce the imposed margins
6.	Absence of EE Product and Service Delivery Mechanisms for Rural Households Leading to Fuel Poverty and Dramatic Deforestation	• Grant technical assistance for developing an enabling investment environment • Grant co-financing for concessional lending • Credit guarantees to reduce the imposed margins • Monetize the benefits of mitigated deforestation
7.	Lack of Awareness on the Benefits of Energy Efficiency among Decisions Makers, Service Vendors and End-Users	• Nation-wide public outreach campaign

ENERGY MARKET

ENERGY MARKET STRUCTURE AND SECURITY THREATS

NUCLEAR POWER IN ARMENIA

Historical overview

While renewable generation is the primary candidate for increasing energy independence of Armenia, the role of other main technologies has to be investigated. Nuclear power has played an important role in national energy security, and some future developing nuclear technologies have even more potential to aid the country's energy independence. Hydrogen has been one of the most anticipated newcomers in the market, but the costs and constraints on its generation and applications mean that its role in Armenia's energy independence is not as obvious. Natural gas, while an imported fuel, can play an important transitional role, and remain as a backup necessary in a system with a high share of VRE generation, such as Armenia will likely become in the future.

The role of nuclear power is crucial for understanding the history of energy security in Armenia. Being the second-smallest country (after Slovenia) that uses nuclear power to generate electricity, Armenia can be considered an outlier in terms of the kind of country that one would expect to possess nuclear energy. The excessive cost of building nuclear power plants (NPPs) has been a major impediment to the development of nuclear power worldwide, along with concerns about environmental risks following Chernobyl and Fukushima. Metsamor NPP, Armenia's sole nuclear power plant, was built to serve a much larger economy of Armenia, a part of the Soviet Union. Built in the late 1970s, the NPP consisted of two units with a combined capacity of 815 MW and was the first power plant to be constructed in a highly seismic region in the USSR.[5] Two additional units were planned, but the project was canceled following the Chernobyl incident in 1986.[6]

Just two years after Chernobyl, in 1988, an earthquake with a magnitude of 6.8 occurred in northern Armenia, resulting in massive damage and casualties. Despite the power plant not being damaged, it was decided to close it down, and the two units were turned to prolonged shutdown. However, following the collapse of the Soviet Union, the economic crisis, and the war with Azerbaijan, the role of nuclear power in national energy security became evident. The Transcaucasian grid did not function following the Armenian-Azerbaijani border closure, and the country found itself in an economic and physical blockade covering most of its borders. With technical and economic help from the Russian Federation, Unit 2 was restarted in 1995, after 7 years of shutdown.[7] Having operated since then, Unit 2 has been providing a stable base load of electricity supply, accounting for roughly a third of national demand. Its operational lifetime is being extended to 2026 (at an estimated cost of \$330 million), and, upon meeting safety requirements, could be extended further to 2036, at an additional cost of \$150 million.[8]

ANPP is a government-owned company. Commissioned in 1980, its operating capacity is 385 MW (installed capacity is 440 MW); annual generation is approximately 2 400 GWh, covering 37% of domestic supply. The plant's USD 300-million rehabilitation in 2017-2018 to extend its service lifetime

[5] Armenia Nuclear Power Profile, IAEA https://cnpp.iaea.org/countryprofiles/Armenia/Armenia.htm
[6] ibid
[7] ibid
[8] Republic of Armenia Energy Sector Strategic Development plan

to 2026 has been fully implemented. The government intends to operate the existing ANPP until at least 2036, requiring an additional USD 150-million investment according to forecasts.

The most important role of the Armenian nuclear power plant is baseload power generation. The role of dispatchable power generation in Armenia has been divided between nuclear and gas-powered plants. The sources such as solar and wind, depend on the weather conditions so cannot be adjusted to meet the changing demand. Hydropower, while produced through a steady flow of water, is likewise subject to seasonal variability, as the amount of water flowing in the rivers changes throughout the year. Annual load profile from 2020 can be used to illustrate this example.

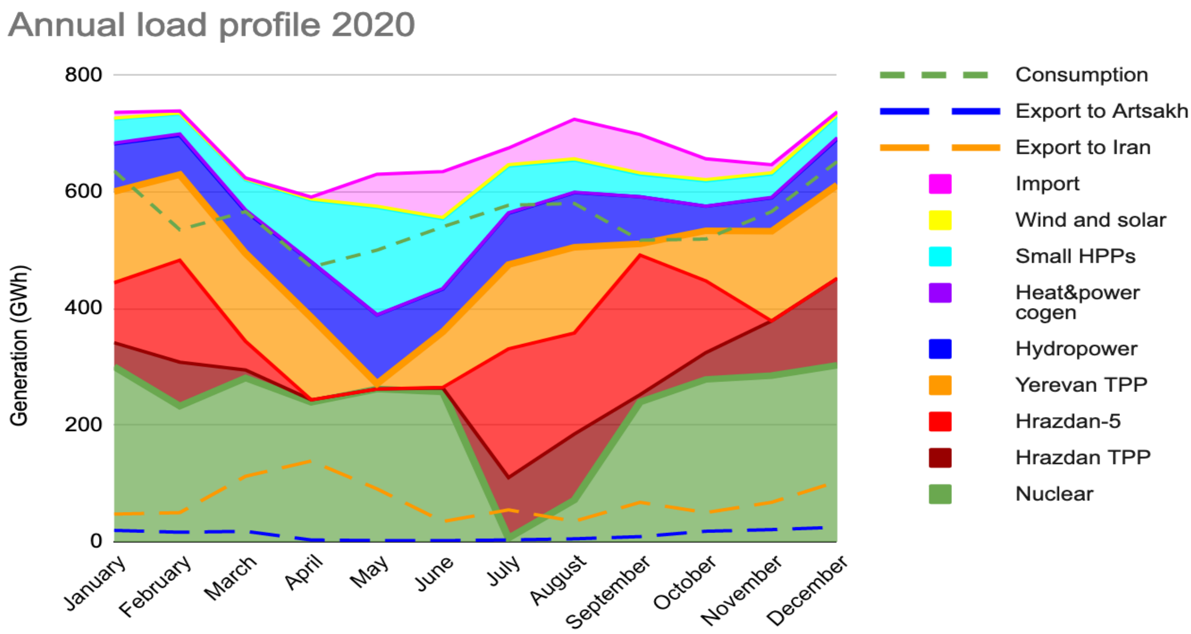


Figure 11. Annual load profile for 2020. Data source: PSRC.am.

Several things are worth noting. Firstly, one can see a more or less stable output of energy from nuclear power throughout the year. For the period when the NPP is not operating (either due to maintenance works or refueling), natural gas takes over, as it is the only other source of energy that can be readily adjusted to meet demand. Secondly, there are two peak demand periods - a lesser one in July-August, and then the highest one in the winter months. Thirdly, the availability of renewable energy resources varies throughout the year and is mostly not in favor of matching the demand. Hydropower is largely available in the spring season, when the waters melt, but is at its lowest during the winter season. Solar power is highest during summer and early autumn, but likewise low in winter. The only renewable power source that has a larger output in winter is wind; however, it has very low capacity as of today.

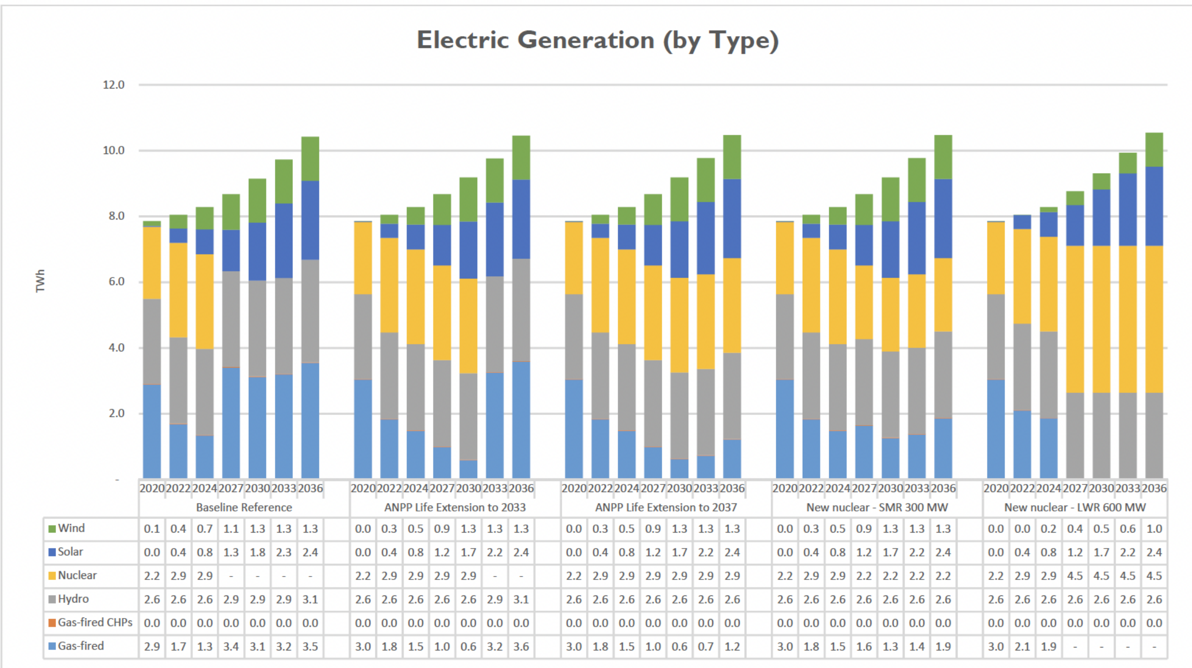
These points help to highlight the critical importance of nuclear power in Armenia's energy systems as of today, as well as at least in the near future. Removing it would leave the overwhelming majority of power systems reliant on imported gas. A similar conclusion has been reached by several recent studies.

Recent studies

The USAID Least-Cost Scenario,[9] when modeling the future system without any technology constraints, generates an almost fully renewable energy mix for Armenia by 2036. However, the model does not take into account the technical constraints in terms of grid stability and variability of wind and solar energy sources. Compensating for these would require much additional expense on strengthening grid balancing mechanisms and providing significant storage facilities. Recognizing this, the document provides an additional model with more technically feasible constraints, namely by limiting the rate of implementation of renewable energy into the grid. In that case, the shutdown of nuclear power results in a reliance of the electricity sector on gas for roughly one-third of the generation.

Finally, nuclear scenarios were considered, either through forced construction of a new nuclear power plant (300 and 600 MW being considered) or through extension of the existing one for 5-10 years. The results demonstrate that the provision of nuclear power by 2036 results in a relatively small reduction in wind and solar generation (compared to restrained baseline scenario), as well as in some reduction in hydropower; the most significant effect comes with natural gas, with a 35-55 % decrease in the projected consumption, and complete degasification of the power grid as early as 2027, if a 600 MW NPP is constructed by that year.

The nuclear scenarios come at a marginal difference in the overall system costs (compared to the baseline scenario) and reductions in GHG emissions, but at a significant increase in new generation investment costs (more than doubling in the case of a new NPP construction).



Baseline Reference	2020	2022	2024	2027	2030	2033	2036
Wind	0.1	0.4	0.7	1.1	1.3	1.3	1.3
Solar	0.0	0.4	0.8	1.3	1.8	2.3	2.4
Nuclear	2.2	2.9	2.9	-	-	-	-
Hydro	2.6	2.6	2.6	2.9	2.9	2.9	3.1
Gas-fired CHPs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired	2.9	1.7	1.3	3.4	3.1	3.2	3.5

ANPP Life Extension to 2033	2020	2022	2024	2027	2030	2033	2036
Wind	0.0	0.3	0.5	0.9	1.3	1.3	1.3
Solar	0.0	0.4	0.8	1.2	1.7	2.2	2.4
Nuclear	2.2	2.9	2.9	2.9	2.9	-	-
Hydro	2.6	2.6	2.6	2.6	2.6	2.9	3.1
Gas-fired CHPs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired	3.0	1.8	1.5	1.0	0.6	3.2	3.6

ANPP Life Extension to 2037	2020	2022	2024	2027	2030	2033	2036
Wind	0.0	0.3	0.5	0.9	1.3	1.3	1.3
Solar	0.0	0.4	0.8	1.2	1.7	2.2	2.4
Nuclear	2.2	2.9	2.9	2.9	2.9	2.9	2.9
Hydro	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Gas-fired CHPs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired	3.0	1.8	1.5	1.0	0.6	0.7	1.2

New nuclear - SMR 300 MW	2020	2022	2024	2027	2030	2033	2036
Wind	0.0	0.3	0.5	0.9	1.3	1.3	1.3
Solar	0.0	0.4	0.8	1.2	1.7	2.2	2.4
Nuclear	2.2	2.9	2.9	2.2	2.2	2.2	2.2
Hydro	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Gas-fired CHPs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired	3.0	1.8	1.5	1.6	1.3	1.4	1.9

New nuclear - LWR 600 MW	2020	2022	2024	2027	2030	2033	2036
Wind	0.0	0.0	0.2	0.4	0.5	0.6	1.0
Solar	0.0	0.4	0.8	1.2	1.7	2.2	2.4
Nuclear	2.2	2.9	2.9	4.5	4.5	4.5	4.5
Hydro	2.6	2.6	2.6	2.6	2.6	2.6	2.6
Gas-fired CHPs	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas-fired	3.0	2.1	1.9	-	-	-	-

Figure 12. USAID's nuclear scenarios. Source: Armenia Least-Cost Energy Development Plan: 2020-2036, USAID 2019, p. 65.

Similar conclusions are reached by the 2021 World Bank report.[10] Namely, in case of the closure of NPP in 2026 and no new one being built, gas will replace a significant portion of nuclear power. This is especially evident when differentiating between seasons: while solar energy can be counted on

[9] "Armenia Least Cost Energy Development Plan: 2020-2036, November 2019, page 4"

[10] Republic of Armenia Maximizing Finance for Development in the Power Sector, World Bank 2021

to meet peak demand in summertime, 900 MWs of power will have to be provided by natural gas during the winter season. Even in summertime, however, there can be points when the gas power plants will be utilized at high capacity.

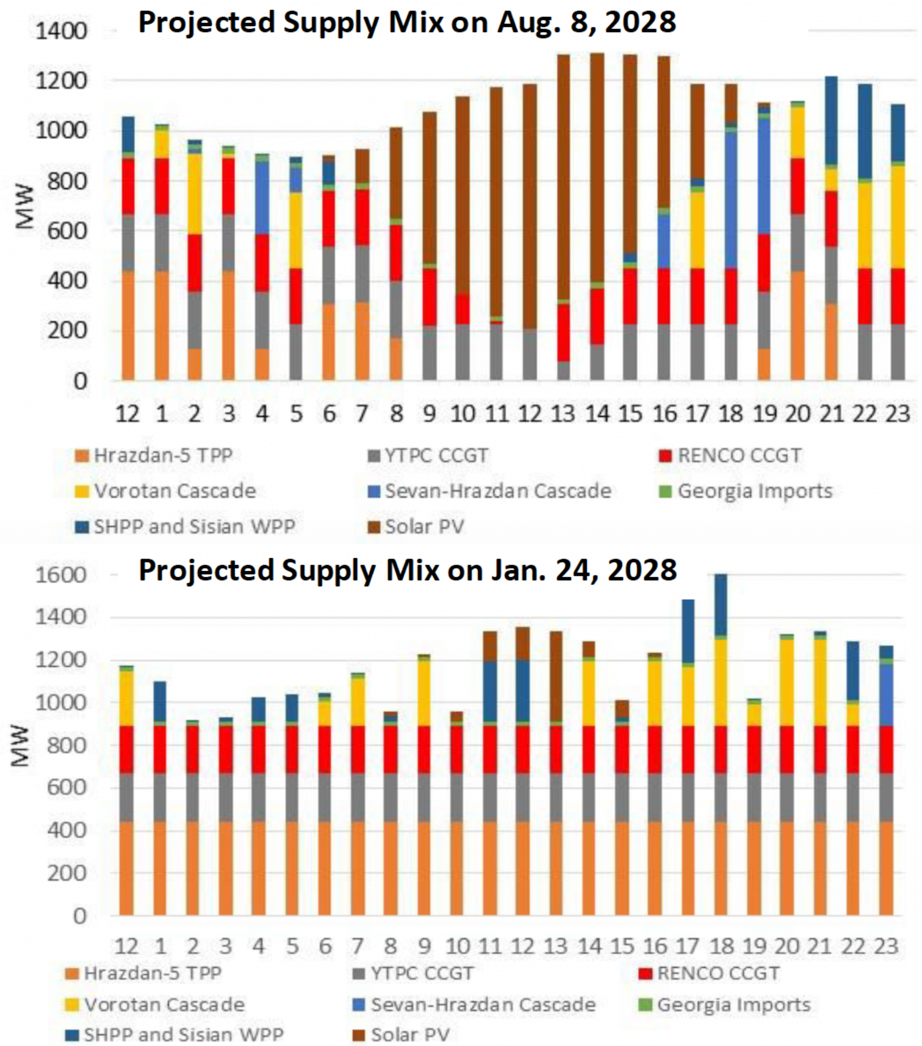


Figure 13. Projected supply mix during peak demand in summer and winter.
Source: Republic of Armenia: Maximizing Finance for Development in the Power Sector, World Bank 2021, p 38.

A 2015 report from IAEA focuses on the role of nuclear power in Armenia.[11] It likewise notes the importance of nuclear power, not only in bringing a more diversified mix of supply, but also in contributing to environmental well-being, by mitigating the emissions that would result from gas-powered generation instead. Considering the ANPP as a domestic source of electricity (despite fuel being imported), it argues that decommissioning of the ANPP will reduce energy independence, and that attracting equivalent capacity is a necessary prerequisite for decommissioning the existing ANPP, noting in passing that Armenia's renewable energy generation potential is limited.[12]

[11] Nuclear Power in Countries with Limited Electrical Grid Capacities: The Case of Armenia, IAEA 2015
[12] Ibid, p 32

Baseload supply

To understand what the role of nuclear power is in Armenia's energy systems, present and future, it is crucial to see the role of baseload supply. While one may get an equal amount of energy from a dispatchable or a non-dispatchable source, the functioning of the electric grid requires not simply providing a certain amount of energy at the right time to meet the demand but also doing so at the right power. The variability of solar and wind energy generation makes this a challenging task, especially since a minimal level of demand has to be met all the time throughout the day. Electricity grids require a certain amount of controllable energy generation to meet that demand and take over when variable sources are not available - a task usually performed by fossil fuels, nuclear power, and more reliable renewable sources such as hydropower. Alternatively, the solution would be to implement storage technologies that would accumulate energy generated by wind and solar technologies, and then utilize it when needed.

The use of hydropower as the main source of stable baseload supply, and as an adjustment mechanism for a fluctuating demand, is practiced in countries such as Switzerland and Norway. In particular, water reservoirs and dams are used to accumulate the potential energy of masses of water and then released on demand to generate the additional power. However, the natural endowment of water resources in Armenia is not enough for using hydropower in such a manner, at least to the extent of replacing current gas and nuclear generation. Firstly, the volume of water resources available, as well as the geography of the country, place limits on how much water can be accumulated for power-generating purposes. The water resources can vary significantly over the year,[13] and limited reservoir capacity of Armenian HPPs does not allow for sufficient accumulation and baseload capacity generation of hydraulic energy.[14] Furthermore, straining the water resources results in environmental costs, in particular, a significant reduction in the level of Lake Sevan, as has been observed in the period 1950-1970 and, more shortly, early 1990s.[15] The problem is exacerbated further by the fact that when demand is at its highest in the winter period, hydropower generation is at its lowest.

This leaves natural gas and nuclear power as the two candidates for baseload generation for the foreseeable future. It should be noted that there already is enough capacity for gas-powered stations to provide the majority of the baseload, as such is the case when the NPP is not working. On the other hand, the current output of the NPP by itself is insufficient to fully meet the baseload demand, hence the significant reliance on gas within the electricity network. It is important to note that neither the World Bank nor USAID scenarios envision any construction of new thermal power plants in Armenia as part of their projections. The government itself, following the replacement of Hrazdan TPP (410 MW) with a new Yerevan CCGT-2 (250 MW) in 2022, does not have any plans of developing thermal power in the foreseeable future; it is considering putting Hrazdan TPP (410 MW) out of commission due to low efficiency, once Yerevan CCGT-2 and the 400 kV Armenian-Iranian transmission line are constructed.[16]

While neither nuclear energy nor natural gas can be considered fully independent energy sources, there are significant differences between the two fuels when it comes to the energy independence and security of Armenia.

An important aspect of energy security and independence is vulnerability to external price formation. Relying on imported fuel leaves the country susceptible to price fluctuations, both as a result of supply disruptions and long-term trends. Such risks can be mitigated by intergovernmental agreements fixing the price, but the rising prices will limit the extent to which such agreements can

[13] Based on data taken from psrc.am

[14] Nuclear Power in Countries with Limited Electrical Grid Capacities: The Case of Armenia, IAEA 2015, p 22

[15] Ibid, p 29

[16] Republic of Armenia Energy Sector Development Strategic Program to 2040, Yerevan 2020

mitigate the long-term price changes. The difference between nuclear power and gas power is that fuel costs are a much larger part of the latter than of the former. This results in larger variability of the levelized cost of electricity (LCOE) of natural gas as a function of fuel cost, when compared to nuclear.

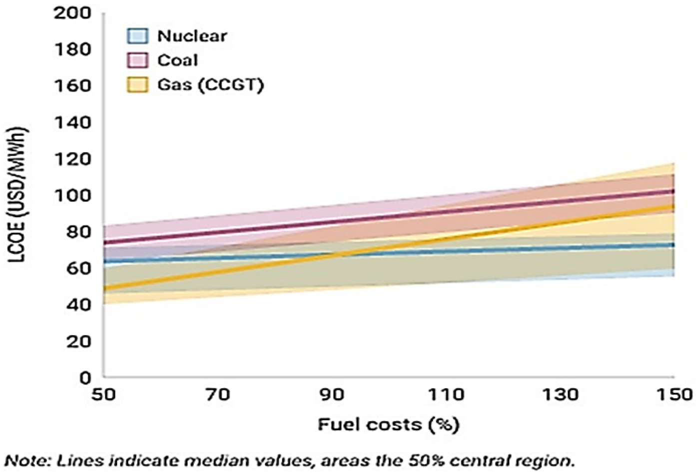


Figure 14. LCOE as a function of fuel cost. Taken from Projected Costs of Generating Electricity (IEA, 2020), p 88.

An additional factor is the infrastructural requirement for the transportation of the fuel. While natural gas is currently transported via pipelines in Armenia, transportation of nuclear fuel does not require such extensive pre-built infrastructure. As such, the number of potential suppliers of uranium for Armenia is larger than the number of gas suppliers.

Moreover, while fuel is imported in both cases, the local reserves are far more limited for natural gas than for nuclear power. The Abovyan Underground Gas Storage facility has a volume of 140 million cubic meters[17] - only one-twentieth of the total amount of gas imported in 2021.[18] On the other hand, nuclear power plants require fuel replenishment only every 1-2 years, while the current ANPP operates on a three-year cycle.[19]

These factors demonstrate that, despite not being energy-independent in the strict sense, nuclear power plants have a number of advantages over gas-power stations when it comes to energy security. Added to these advantages is the much lower level of pollution (in particular of carbon emissions) of nuclear power generation as compared to natural gas.

Financing Nuclear Power

The obvious disadvantage of nuclear power is the extremely high investment cost required to build an NPP. The overnight costs for constructing a nuclear reactor are on average projected to be \$3600/kWe, but can go as high as \$6900/kWe.[20] Similar numbers were used by other studies. USAID study, in particular, uses \$4074.89/kWe for a new VVER-1200 plant.[21] The World Bank suggests a minimum of \$5833/kWe, though it does not include a new NPP into its model due to uncertainty

[17] Gazprom Armenia has plans to expand the facility to 250 million cubic meters (Armenia 2022 Energy Policy Review, IEA 2022)

[18] Data on Abovyan storage taken from USAID, data on annual imported gas taken from www.psrc.am

[19] Armenia Nuclear Power Profile, IAEA https://cnpp.iaea.org/countryprofiles/Armenia/Armenia.htm

[20] Projected Costs of Generating Electricity, OECD-NEA 2020

[21] USAID least-cost scenario; there they used OECD-NEA Projected costs from 2015

regarding its justification.[22] Additional costs can come in the form of discount rates, which are especially impactful given the high capital costs of nuclear power. Moreover, the construction of NPPs often faces delays,[23] further increasing the costs. Many Generation III FOAK reactors have faced significantly larger construction times than initially estimated (sometimes by a factor of two or three), with similar increases in costs.[24] The safer estimate comes from Lazard at 7 675 – 12 500 USD/kWe.[25]

To construct a new NPP the size of one block of Metsamor (about 400 MW) would therefore require funding on the scale of 3-5 billion USD,[26] and almost certainly higher when considering a certain discount rate and international experience with overspending. It is not surprising that extending the lifetime of the existing ANPP reactor until 2036 is the preferred option, at $480 million - only one-tenth the cost of constructing a new one of equal capacity. Such practice is widespread,[27] as the costs of extending the life of an NPP are significantly lower than the costs of constructing a new one.[28] However, safety requirements will eventually put before Armenia the choice of either constructing a new nuclear plant, or proceeding without one.

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[22] Republic of Armenia Maximizing Finance for Development in the Power Sector, World Bank 2021; they suggest that a new 600 MW NPP would require at least $3.5 billion of investments.
[23] Shykinov, Nick, et al. "Importance of Advanced Planning of Manufacturing for Nuclear Industry." Management and Production Engineering Review, vol. 7, no. 2, 1
June 2016, pp. 42–49, 10.1515/mper-2016-0016
[24] Projected Costs of Generating Electricity, OECD-NEA 2020, table 8.2
[25] Lazard's Levelized Cost of Energy Analysis – Version 14.0, Lazard 2020
[26] 400 MW at $7,600 – 12,500 per kW
[27] Nuclear Power – Analysis - IEA
[28] Projected Costs of Generating Electricity, OECD-NEA 2020

HYDROPOWER

Hydroenergy is the most developed among the other renewable energy resources in Armenia. It is presented by two major HPP cascades owned by “International Power Corporation” CJSC and “Contour Global Hydro Cascade” CJSC, as well as by several small HPPs.

The Sevan-Hrazdan hydropower cascade was commissioned in 1940-1962 and since 2003 operated by the “International Power Corporation” CJSC. The company in 2020 was acquired by the "Hrazdan Energy Organization" OJSC which belongs to the Tashir Group of Companies. With the installed capacity of 539.9 MW the Sevan-Hrazdan Cascade produced 456.5 mln. kWh in 2021 which amounts to 5.9 % of the total electricity production.

The Vorotan Complex of hydroelectric power stations commissioned 1970-1989. Since 2015, the "ContourGlobal Hydro Cascade" CJSC acquired and operates the cascade of three hydroelectric power stations with an overall capacity of 404.2 MW. The complex produced 940.7 Mln. kWh electricity in 2021, which amounts to 12.1 % of the total electricity generation.

In 2021, there were 190 private small HPPs (with a capacity of up to 30 MW) with a total installed capacity of 388.56 MW and actual electricity generation of 804.6 million kWh. Another 22 SHPPs with a total installed capacity of about 52,277 MW were under construction.

There are several promising opportunities for the development of medium-sized hydropower plants, including at Lori-Berd (60 MW) and Shnogh (76 MW) in the northern part of Armenia.

OIL PRODUCTS

There is no oil extraction in the territory of Armenia and all the oil products are imported. Some types of imported oil products are used in limited amounts for the production of varnish, paints, and other products in Armenia. Imported bitumen and mazut are utilized for non-energy purposes either.

In 2021, 77.9 % of liquid petroleum gasses were used by the transport sector. The share of liquid petroleum gas consumption in the industry was only 0.41 %, in the service sector 21.26 %, and in households 0.47 %. Other oil products are consumed for non-energy purposes and are 12.4 % of total oil product consumption.

In 2021, the main volume of diesel fuel in the amount of 83.4 % was consumed in the transport sector. The industrial sector uses around 8.5 % of diesel fuel. Diesel fuel is used by different types of mechanisms (drilling rigs, cranes, telescopic towers, and other mechanisms). The main consumers of the industrial sector were the mining industry and non-ferrous metallurgy. Around 7.9 % of the diesel fuel was utilized by the agriculture sector (tractors, combines, and other mechanisms). The housing sector consumed 0.16 % of diesel fuel.

Insignificant amounts of diesel fuel are also consumed by diesel generators which are reserve sources for power production. Data on this sector's consumption isn't available. Minor volumes of diesel fuel were also used for non-energy purposes in the chemical industry and other sectors. The share of diesel consumed for non-energy needs was 0.67 % compared with total consumption.

The **transport sector** consumes 99.37 % of motor gasoline.

Armenia has one of the world’s highest levels of gasification in the transport sector. Over 70 % of vehicles run on natural gas, with a higher rate in Yerevan. Most use gas in the form of compressed natural gas (CNG), though some vehicles are designed to run on LNG. There are about 400 CNG filling stations, one for approximately every 38 km of road. All are privately owned, including seven by

Gazprom Armenia. Nearly all vehicles running on CNG are also able to use motor gasoline, providing flexibility in case of a gas supply disruption. The demand for natural gas in the transport sector is expected to decline in the coming years as the government promotes the use of electric vehicles. The number of electric vehicles in the country is currently assumed to be less than 0.5 % of the total fleet.

GAS

Armenia's natural gas sector is a subsidiary of Russia's Gazprom, a monopoly, controlled and owned by Gazprom Armenia. According to the 2021 Energy Strategy, the Armenian government intends to revise the gas sector legislation by 2024, and in 2022 it will start developing a new Gas Law.

Armenia, along with other EAEU members, plans to launch a common gas market in 2025.

The gas for domestic consumption comes entirely from Russia through pipelines passing through Georgia, which is about 85 % of Armenia's gas supply. The rest of the gas is imported from Iran but is only used in a gas-for-electricity swap.

Such heavy reliance on a single source poses potential security risks as it is the largest share of the country's total primary energy supply since for the residential sector and road transport natural gas is their main fuel.

Substantially increased the size of the Abovyan gas storage facility nevertheless remains under the control of Gazprom.

There have also been significant developments in the use of natural gas vehicles (NGVs); in fact, Armenia is one of the leading countries in transport sector natural gas use. The benefits of NGVs are both economic and environmental, owing to their low GHG emissions. At the beginning of 2022, more than 80% of vehicles in Armenia were running on natural gas and the country had 358 gas-charging stations.[29]

COAL

In 2021, the share of imported coke, semi-coke, anthracite, peat, and other coal types consumed for energy purposes was only 0.4 % of total energy consumption. About 89.9 % of coal was used in the household sector.

There are lignite deposits in Jajur and Dilijan. They have no industrial significance, and according to the expert estimations around 500 families collect the lignite manually.

The Armstat supplied data on the volumes of coal consumption in the industrial sector. Information about the mining and consumption of the lignite was revealed using expert assessments.

Limited amounts of crude and other solid residues are also imported to Armenia.

[29] https://www.iea.org/reports/armenia-energy-profile/energy-security-2

POWER SYSTEM

Electricity Transmission Network

High-voltage electricity transmission networks are state-owned, and their natural development is one of the strategic issues of the energy sector. The development of the high-voltage transmission network includes two sets of actions aimed at the modernization of the existing infrastructures and the expansion of the transmission network. The first set of actions is aimed at the modernization of substations of the high-voltage transmission network and overhead transmission lines, while the second set of actions is focused on the installation of the monitoring system for transmission capacity, automation (SCADA system expansion) as well as electricity system reliability and safety indicators and development of new infrastructures for the regional integration.

In the high-voltage transmission network, 13 substations of 220 kV, two substations of 110 kV, and one switching point on the border with Iran as well as 1960 km electrical transmission lines with 5600 towers are currently being operated. Five above-mentioned substations (220/110/10 kV “Haghtanak”, 220/35/10 kV “Kamo”, 220/110/10 kV “Gyumri-2’, 220/110/35 kV “Vanadzor-2” and 220/110/35 kV “Alaverdi 2”) have been completely reconstructed.

Five more substations are currently under reconstruction, in particular:

- With the support of the International Bank for Reconstruction and Development, which provided USD 36 million within the scope of the loan agreement “Electricity Supply Reliability Project - Additional Financing”, 220kV substation “Haghtanak” was reconstructed in 2019; the reconstruction of 110kV substations “Charentsavan-3”, “Vanadzor-1” and 220kV substation “Zovuni” is envisaged.
- With the support of the Asian Development Bank, which provided about 24.02 million SDR within the scope of the loan agreement «Power Transmission Rehabilitation Project», the reconstruction of 220 kV “Agarak- 2” switching point to the substation, and reconstruction of “Shinahayr” substation are planned to be implemented, along with the second stage of SCADA communication and automation system investment program.
- With the support of the International Bank for Reconstruction and Development, which provided USD 39.86 million within the scope of the Loan Agreement “Power Transmission Network Improvement”, a new 220 kV substation of Yerevan TPP was constructed and commissioned replacing the previous substation of 110 kV. The reconstruction of 220 kV “Ashnak” substation is underway as well as reconstruction of the “Ararat-2” substation is envisaged to be implemented.
- With the support of the International Bank for Reconstruction and Development, which provided about USD 35.5 million within the scope of the loan agreement “Electricity Supply Reliability”, the modernization of the 230 kilometers of 220 kV overhead transmission line along Noraduz- Lichq-Vardenis- Vayq-Vorotan-1 between Hrazdan TPP and 220 kV “Shinuhayr” substation is carried out, which has increased the export capacity to Iran by about 50 MW. Within the scope of the savings made as a result of the concluded agreements aimed at reconstruction of the above-mentioned overhead transmission line, the reconstruction of about 50 kilometers of overhead transmission line “Larvar” and “Noyemberyan” of 110 kV is being conducted. The lines, which have been in operation since 1962 under the influence of aggressive chemicals, have become corroded and negatively affect the provision of reliable and uninterrupted power supply to consumers.
- The following programs are being implemented for the regional integration process:
- With the support of the Export Development Bank of Iran and “Sanir FZE”, which provided EUR 107.9 million, a 400 kV Iran-Armenia double-circuit overhead transmission line and 400 kV

“Noravan” substation are under construction. The construction of the power transmission line and the substation will enable to increase of the electricity exchange capacity between both countries’ power systems from 350 MW to 1200 MW also by improving the reliability of the power systems’ parallel operation and energy security of the Republic of Armenia.

- The construction of the “Caucasus Electricity Transmission Network” (transmission line/substations) is aimed at the connection of Armenian and Georgian power systems by 500 kV overhead transmission line ensuring the reliability of asynchronous-parallel operation of the two countries’ systems by constructing 500/400 kV HVDC back-to-back station of 350 MW capacity, 500/400 kV overhead line with the length of 8 km from the station to Georgian border in Ayrum at the first stage, new substation of 400/220 kV in Ddmashen equipped with two 440/220 kV autotransformers and 400 kV single-circuit overhead transmission line from Ddmashen to Ayrum substation with double-circuit supports. Implementation of the project will ensure the power exchange of electricity with 350 MW capacity. Within the scope of this stage of the project, investments will amount to about EUR 188.2 million and the transmission capacity with Georgia will be 350 MW, which is intended to be increased to 1000 MW during the next two stages depending on power flow volume.

In addition to the above-mentioned, another substation - 220/110/35 kV “Litchq” - will be reconstructed at the company’s expense, and the financing options and dates of investment projects for the reconstruction of the remaining three substations (220/110/10 kV “Shahumyan-2”, 220/110/10 kV “Marash” and 220/110/35 kV “Yeghegnadzor”), for will be considered.

In addition to the above-mentioned, along with the construction of solar plants, it will be necessary to invest additionally about USD 70 million in the transmission network.

Investments aimed at system automation in the high-voltage electric network are being conducted, in addition to infrastructure investments. SCADA Automated control system will be installed by 2023 which will ensure a new level of dispatch and technological dispatch. With a view to considering the changing requirements of the power system of Armenia, the system will have a scalable modular structure and the possibility to select operating characteristics. As a result, accident elimination time in the power system will be significantly reduced and the level of reliability of power supply to consumers will increase.

It is worthwhile to mention that the Electricity System Transmission Network Development Plan (2020-2024) was developed in 2019, which, based on international experience and up-to-date models considered the possible developments of the energy sector within that period and the volume of necessary investments for the least cost development of the respective transmission network including the investments which will be aimed at reconstruction of high-voltage power transmission lines and expansion of the Transmission network. This will be continuous work and the development plan will be reviewed in 2022 including the period for the next ten years, and afterwards will be biennially updated.

Investments in the Transmission Network will reach about USD 550 million by 2030.

Distribution Network

The Electricity Networks of Armenia CJSC (ENA) operates the distribution networks as a Universal Supplier distributing and supplying electricity to about one million consumers including residents, commercial organizations, and industrial enterprises operating lines of 110 kV and below. The ENA activity is regulated by the Public Services Regulatory Commission. Till 2022, ENA has been the sole electric power distributor in the country.

Power System Operator

The Electric Power Systems Operator CJSC (EPSO) is responsible for the strategic functioning of the Armenian energy system. EPSO is a public legal entity that has an exclusive license to carry out activities such as:

System dispatching and management of the national transmission and generation network, as well as interconnections with neighboring countries, in particular with Iran (synchronous connection) and Georgia (synchronous connection only if Georgia is disconnected from the Russian network) through its Dispatching Center; defines network configuration and regulation set point, while operations are carried out by others.

Sets operational orders for adjustments, settings and switching on/off generation groups; the Dispatching Center issues instructions to regulate and network set-up, though the operation process is not automatic: each substation or power plant has its local operational team responsible for the work.

EPSO doesn't use an Automatic Energy Management System for its operations. Network regulation is carried out based on a statistical approach due to the daily repetition of loads according to the following principle:

- Nuclear Power Plant (NPP) – basic generation
- Thermal Power Plants (TPP) – basic generation and partial regulation
- Hydraulic Power Plants (HPP) – regulation

The EPSO, with its current technical and technological equipment, is unlikely to cope with the management of the network when many generating variable capacities are connected to the network. Significant investments will be required to modernize the entire technical equipment and communication systems.

Electricity Market

The Government of Armenia approved a new Energy Sector Development Strategic program in January 2021 that establishes a basis for the sector's transition through 2040. Key government priorities include maximum use of the country's potential for renewable energy and energy efficiency, increasing power interconnections with neighbors, and gradual liberalization of the domestic electricity market.

In February 2022 featuring a new wholesale market model, direct contracts, a balancing mechanism, and long-term direct capacity contracts. Free and open trade, as well as cooperation among all energy market participants, as envisioned by these reforms, would help promote investments from the international community and strengthen regional integration.

Market Liberalization and Electricity Trade Program (MLET) envisages implementation of Retail Market Trading Rules and Contracts, updated Distribution Network Code and Updated Wholesale Market Trading Rules & Contracts, Updated Transmission Network Code & Reliability and Security Indicators, Development of Annual Adequacy Forecast and Market Management System Development.

The changes in the laws on "Energy" and "Energy Saving and Renewable Energy" are envisaged to entitle the renewable energy power plants to sell electricity in the new electricity market exclusively under competitive terms without a power purchase guarantee and Public Private Partnership agreement; to generate and consume at different metering points of the power system.

An automated information technology platform – Armenian Energy Exchange (AEX) is envisaged for implementation in Armenia. The platform will enable the Armenia Wholesale Electricity Market Operator and System Operator, as well as Market Participants to interact and organize the wholesale trading of electricity through enabling electronic communications and trade in different segments of the market, performance of energy transactions and settlements, configuring data visualizations, and empowering users to explore market results. The online Market Management System (MMS) platform will also allow for total transaction and information exchange automation, ensure transparency through controlled access to energy market information, and ensure security and maintenance of the market records and reports.

Tariffs

Electricity and natural gas tariffs are regulated by the PSRC on a cost-plus basis that allows a set rate of return for the operators after accounting for fixed and variable costs. The tariff-setting procedure is fully transparent.

For electricity generators participating in the balancing market controlled by the power system operator, the tariff structure has two components (energy and capacity) for payments; for other generators, a one-part tariff is applied.

The gas supply system uses a single tariff structure. At the retail level, electricity rates for residential consumers increased by 70 % from 2009 to 2019, and natural gas rates rose by 172 % from 2005 to 2019. In 2016, the import gas price was reduced from USD 165 per 1 000 m^3 to USD 150 under the purchase agreement for Gazprom Armenia. The current gas price at the border is USD 165 per 1 000 m^3.

Implementation of new tariff adjustment mechanisms for **reactive energy**, the necessity to fix monthly service fees, etc. is envisaged.

Feed-in tariffs

Under the Law on Energy, small HPPs and other plants generating electricity from renewables are afforded feed-in tariffs for a period of 15 or 20 years from their license date. The tariffs are specified on an annual basis to account for exchange rate fluctuations between the Armenian dram and a foreign currency (USD or EUR). Feed-in tariffs were introduced in 2007, and from then until January 2020, 375 MW of small hydropower, 4.23 MW of wind power and 10 MW of solar photovoltaic power were commissioned.

Technical rules

Armenia uses state standards for technical applications. They are aligned with the directives of the International Organization for Standardization (ISO), the International Electrotechnical Commission and the European Committee for Standardization (CEN). With a government resolution in 2012, Armenia was on its way to harmonizing its standards with those of the European Union. The National Institute of Standards had worked out an action plan for 2013-2015, including a schedule of harmonization up to 2020, but Armenia instead joined the Customs Union with Belarus, Kazakhstan, Kyrgyzstan and Russia. This is likely to result in a different set of standards for harmonization.

Modernization of the Electrical Systems

The modernization of the following systems is necessary to enable domestic renewable energy sources development:

- Transmission systems,
- Distribution systems
- SCADA and Energy Management System (EMS)
- Modernization of Metering Systems,
- Communication and information technology

There is a risk for the transmission grid due to the massive increase of VREs estimated as medium-low and it will be drastically reduced as soon as the international connections are completed.[30]

The Power Systems should be properly developed in order not to be a barrier to the integration of a substantial share of VRE into the grid, in particular, three high-voltage substations need urgent rehabilitation (Marash, Shahumyan-2, Egheknadzor).

The Dispatching system needs to be upgraded including SCADA, Telecontrol, and new digital devices for protection and control (Smart Control). The Smart Control systems will become more important as greater the penetration of the VRE will be.

[30] EBRD - Action Plan for Power Grid Strengthening to Support Renewable Projects – Armenia. PÖYRY ITALY S.r.l. 143000147S0NT004_B 15/01/2020.

ARMENIA'S ENERGY INDEPENDENCE ROADMAP

PART 2 RENEWABLE ENEGRY POTENTIAL

Developed by: Tigran Gnuni, Aram Harutyunyan, Armen Danielyan,
Régis Danielian, Garnik Balyan, Suren Shatvoryan (Team Leader)

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RENEWABLE ENERGY POTENTIAL. INVESTMENTS AND DEPLOYMENT TIMELINE

1. SOLAR ENERGY RESOURCES

Armenia has significant solar energy potential: average annual solar energy flow per square meter of horizontal surface is around 1700 kWh (the European average is 1000 kWh). One fourth of Armenia is endowed with solar energy resources of 1850 kWh/m². Under different conditions, the average annual incident total solar radiation (i.e., radiation integrated during the year per unit of horizontal surface) on the territory of Armenia ranges from 140 to 155 kcal/cm².

Actual sunshine hours for cities of Armenia, such as Yerevan - 2700, Martuni – 2750, for Ashtarak – 2837, for Vanadzor – 2019, for Ijevan – 1827 hours.

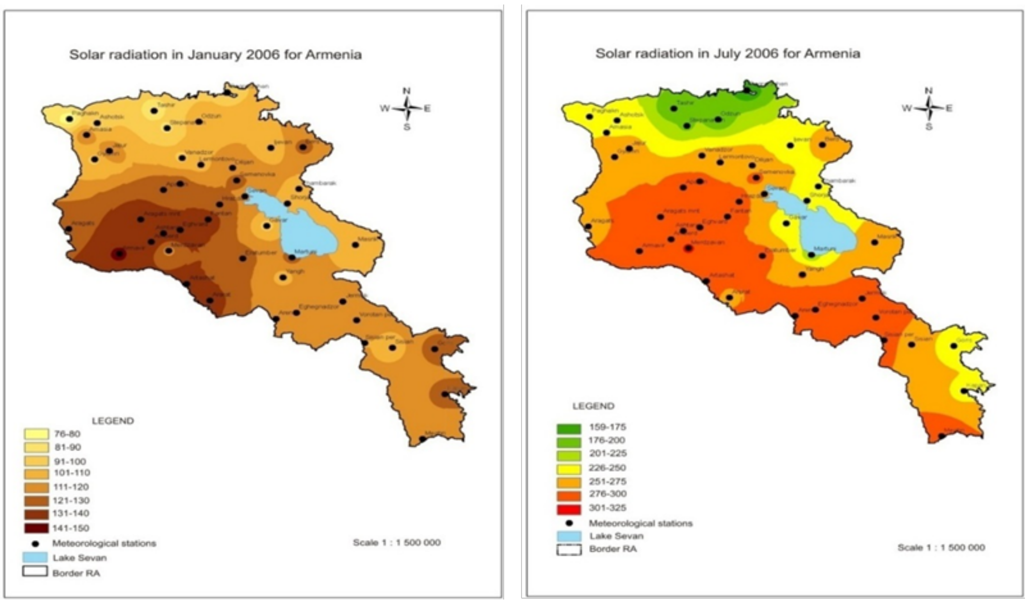

Figure 1. Merged Solar Radiation (W/m²) Maps for January and July 2006
Source: Scientific Applied Centre of Hydrometeorology and Ecology of Armenia (Armstatehydromet).[1]

The yearly average solar irradiation in Armenian regions: Yerevan – 1647 kWh/m², Martuni – 1740 kWh/m², Ughedzor (Kochbek) – 1786 kWh/m², Jermuk – 1682 kWh/m², Gyumri – 1624 kWh/m². Compared with Central Europe, this average value is 1000 kWh/m², particularly, in Poland, Czech Republic, and Slovakia 950-1050 kWh/m², in Hungary – 1200 kWh/m², in Bulgaria – 2000 kWh/m². The surface sunshine on the Lake Sevan basin may be considered a record – 2800 hours. The portion of the direct annual radiation upon the entire territory is also significant – 65-70 %.

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[1] The application of CM-SAF data for monitoring of climate system over Armenia. Armstatehydromet, Scientific Applied Centre on Hydrometeorology and Ecology. D. Hovhannisyan, R. Hollmann, A. Hovsepyan, D. Melkonyan, L. Vardanyan, H. Melkonyan. Yerevan 2009.

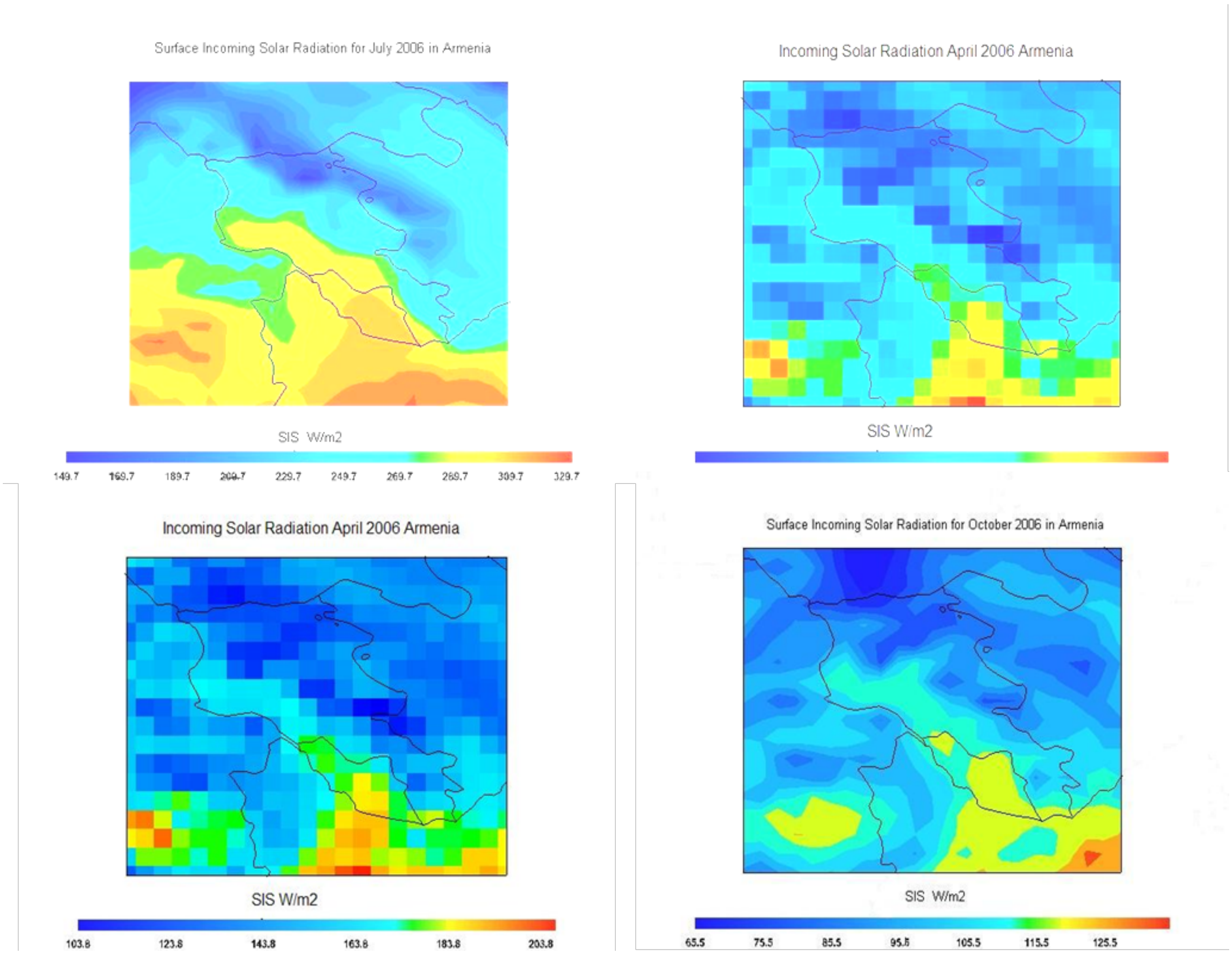

Figure 2. Surface Incoming Solar Radiation W/m² (Armenia).

Data on mean daily total (Etot) and diffused (Edif) irradiation (MJ/m²) and ambient temperature Tamb (°C) monthly average by months for Yerevan are shown in Table 1. The maximum values for incident solar total radiation are received for 6th-7th months, and the maximum values for solar diffused radiation – for 5th-6th months of the year (see Figure 2). Yerevan-agro is at 10 km from Yerevan, at open site in v. Parakar. The winter months account for 11–15 % of the average annual solar radiation. These values increase as the elevation of the site increases. The energy of the beam (direct) radiation is 60-65 % of the total radiation energy.

Table 1. Daily total (Etot) and diffused (Edif) irradiation (MJ/m²) and ambient temperature Tamb(°C) monthly average by months on 1 m² of horizontal surface, Yerevan, 40.10 N. Lat.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
E_{tot}	6.34	10.13	14.04	19.18	24.97	28.22	27	25.11	20.15	14.85	8.06	5.13
E_{dif}	4.05	5.96	7.02	8.2	8.23	7.78	6.88	6.34	5.38	4.86	3.89	3.1
T_{amb}	-3.7	-2.3	4	11.1	15.9	20.1	24	24.2	20	13.9	6.2	-1.2

Table 2. Monthly and annual total solar radiation incident on horizontal surface, MJ/m².

	Yerevan	Sevan	Ughedzor (Kochbek)
January	200	281	311
February	267	357	392
March	417	518	537
April	540	545	573
May	720	666	654
June	821	768	764
July	858	825	817
August	754	743	743
September	594	580	589
October	428	435	445
November	251	285	299
December	171	234	272
Yearly	6021	6237	6396

Table 3. Monthly and annual direct solar radiation on surface normal to sunlight beams, MJ/m².

	Yerevan	Sevan	Ughedzor (Kochbek)
January	178	387	391
February	243	386	384
March	364	441	408
April	450	442	409
May	667	565	534
June	826	734	749
July	861	774	848
August	810	775	804
September	740	704	743
October	534	587	616
November	312	440	461
December	175	373	373
Yearly	6160	6599	6720

1.1. Demand overview

The residential sector in Armenia consumed 0.9 Mtoe in 2020, accounting for 33 % which is the highest share of total final consumption (TFC) in the country, higher than the industry sector and exceeding commerce and public services (which includes commercial and public building energy consumption). It has grown by 42 % since 2009, and according to the recent studies, significant residential energy demand growth is expected over the next 15 years[2] (see

[2] https://www.iea.org/data-and-statistics/charts/armenian-energy-demand-by-end-use-2018-2036.

Figure 3, Figure 4). The residential energy consumption consists mainly of heating (both space and water) which fluctuates annually with outdoor temperatures.

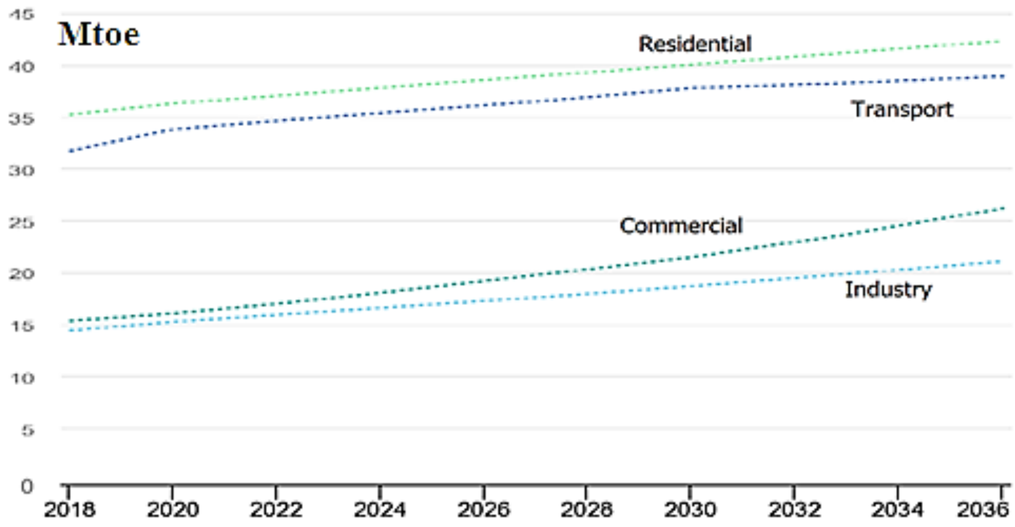

Figure 3. Armenian residential energy demand by end use, 2018-2036.
Note: Includes non-specified consumption of electricity and natural gas.
Source: IEA, Total final energy consumption in Armenia by sector, 2018-2036, IEA, Paris.

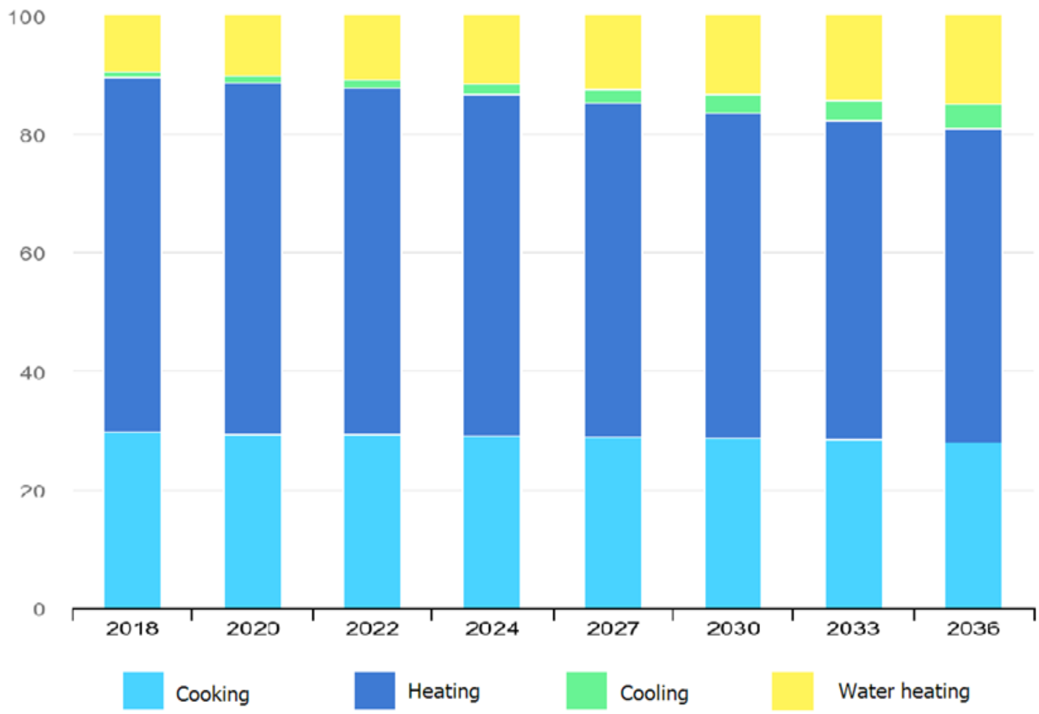

Figure 4. Armenian residential energy demand by end use, 2018-2036.[3]
Source: IEA (2020d), World Energy Balances (database), www.iea.org/statistics/; USAID, 2019.

[3]https://www.iea.org/data-and-statistics/charts/total-final-energy-consumption-in-armenia-by-sector-2018-2036.

Total demand for each end use in 2020 based on projections: cooking – 9.68 PJ; heating – 19.52 PJ; cooling – 0.36 PJ (more than quadrupling to 1.61 PJ in 2036); water heating – 3.38 PJ (nearly doubling to 5.85 PJ in 2036).

Based on the national data for residential gas consumption for 2016-2021 by months[4], the share of gas consumption for water heating and space heating has been defined as 34.6 % and 65.4 % correspondingly. The energy demand for water heating was equal to 3.38 PJ[5] (equivalent to 938 888.9 MWh) for 2020. With the tendency for growing, this amount will almost double by 2036, reaching 5.85 PJ, equivalent to 1 625 000 MWh (see Figure 4).

It is evident that, along with the many benefits arising from the mass adoption of solar technologies, such as environmental and commercial benefits, as well as the creation of high-quality jobs, the application of solar technologies has a huge potential for energy savings.

1.2. Solar Water Heating Market Potential

The potential for solar water heating will count the amount of technically available solar energy utilization resources that can replace traditional energy resources such as gas and electricity.

The energy used for water heating is a significant part of the total energy demand in the residential and commercial sectors. Currently, the energy consumed for water heating with natural gas and electricity amounts to 3.38 PJ (equivalent to 940 GWh). Almost irrespective of the season and region, the share of natural gas for water heating purposes in Armenian households comprises around 72 %, and the second main option – electricity is 16 % [6]. The rest of 12 % are various biomass of local origin. The amount of energy produced with natural gas for water heating is 2.43 PJ (675 GWh), and with electricity 0.54 PJ (150 GWh).

Table 4. Main energy sources for water heating, %.

	Yerevan	Other cities	Rural area	Total
Electricity	22.9	13.2	10.1	15.8
Natural gas	75.9	78.7	62.1	72.2
Wood	0.8	7.3	22.3	9.8
Biofuel	0.0	0.1	4.0	1.4
Other	0.4	0.7	1.5	0.6

Source: Residential Energy Consumption Survey. Analytic Report. UNDP, Yerevan, October 2015.

The technically achievable potential of solar thermal technology is well over 1000 MW. Exploiting this potential will create capacity to generate more than 2 GWh of heat annually,

[4] See in the chapter Gas Demand Forecast

[5] https://www.iea.org/data-and-statistics/charts/armenian-energy-demand-by-end-use-2018-2036

[6] Residential Energy Consumption Survey. Analytic Report. UNDP, Yerevan, October 2015

covering more than 90 % of current water heating demand, improving the energy poverty and sanitary situation, and will displace 154,203,323 m² of imported natural gas.

2. SOLAR WATER HEATING TECHNOLOGIES

Development of the off-grid and micro-grids solar PV power in combination with thermal technologies, and other alternative technologies upon their commercial utilization possibilities have a potential to assure massive decreasing of the natural gas demand.

The technical potential of solar water heating (SWH) was evaluated in terms of its contribution in the national energy security development by end-use and primary energy reduction.

The SWH technologies are clean, reliable, and cost-effective method of harnessing solar energy effectively to satisfy 70-90 % of the residential hot water requirements round the year, dropping to only about 25 % in the winter season.[7]

The climatic conditions and the solar radiation of Armenia are good to benefit from SWH used for private individual, or multi apartment residential, public and commercial buildings. The SWH technology is one of the most promising RE alternatives for immediate large-scale deployment in Armenia being technologically mature and having proven economic viability in Armenia. However, it is assumed that less than 4 MW of total installed capacity is currently in operation in Armenia.

The most spread SWH technologies present by two classes of the Active Solar Water Heating Systems and Passive Solar Water Heating Systems.

The Active Solar Water Heating Systems equipped with a circulation pump for A. Direct circulation through the collectors and into the home which are good for relatively warm climates with rare freezing temperatures; and B. Indirect circulation systems with two circuits: the pumps circulate a non-freezing heat-transfer fluid in the closed-loop systems through the collectors and a heat exchanger to heat the water that flows into the home. This option is for climates likely to go below freezing temperatures.

The Passive Solar Water Heating Systems are open-loop thermosyphon systems with which directly heat the water that’s used in the house. This system is the most common system which is good for relatively warm climates with rare freezing temperatures.

Passive solar water heating systems are typically less expensive than active systems, but they're usually not as efficient. However, passive systems can be more reliable and may last longer.

There are various options for equipping the SWH depending on demand, climatic and technical conditions of operation. The SWH almost always requires a backup system for cloudy days to cover increased demand and to prevent freezing in the external parts of the SWH. A backup system may also be part of the solar collector, such as rooftop tanks with thermosyphon systems. Photovoltaic-powered pumps and controllers work when the sun is

[7] https://omafra.gov.on.ca/english/engineer/facts/sol_wat.htm Solar Water Heating Technology

out, shut off at night and use no grid power to operate. AC-powered pumps and their controllers depend on the grid for power and for freeze protection.

The size of the solar collector depends on the water storage capacity and is typically based on a ratio of about 1 square meter of panel for each 50–70 liters of tank volume. For a house with 3–4 occupants, a 200–275 liter storage with a 2.5–5 m² panel is recommended. For 5–6 occupants, a 270–360 liter storage with a 3.75–6 m² panel area[8].

The SWHs vary in design and effectiveness. Specific types and models of SWH are not discussed here, as this would belong to the market research matter that should be considered separately.

2.1. Solar Water Heating. Assumptions and Technical data.

Technology Penetration There are no documented studies of rooftop availability for SWH known so far. In this study, the potential for penetration of the SWH technology is attempted by assessing a massive segment of identical buildings by scale, purpose and energy intensity such as individual family houses of around 400,000 in Armenia[9] . The study assumes favorable economics for SWH for virtually all buildings in the residential and commercial sectors.To assess the potential of SWH, a conditional (averaged) model of an individual family house, as one of the most common class of buildings in Armenia, was considered. It is assumed that the building has a sufficient roof area for the deployment of an SWH system, sized to supply hot water to cover the needs of 4-5 residents with an average daily consumption of 300 liters.

The overall living space of the individual family houses counted 65 million square meters.[10] *For an averaged two-story family house useful area for accommodation of an averaged family-scale a rooftop SWH installation is assumed to be of a size of the 1/4 of the total area per each of the 400,000 houses with total 65 million square meters:*

$$65Mm^2/400000/4 \approx 40m^2.$$

After deducting a half of the space for the house engineering infrastructures (chimneys, antennas, etc.), the remaining surface is assumed sufficient for installation of a SWH system with standard 300 L tank system which in practice requires around 4 m² area.

The Daily Water Heating Energy assumed with the incoming water temperature of 14 °C, and the hot water temperature of 58 °C, and for the total hot water production of 240 L per day used by the average household of four people.[11] *This assumption is quite consistent with the climatic conditions and sanitary standards of Armenia.*

With the yearly average solar irradiation of 1700.0 kWh/m² on a horizontal surface, a conditional SWH system with a 300-liter storage tank with 80 % efficiency generates daily,

[8] https://www.level.org.nz/energy/water-heating/solar-water-heating/collector-panels/

[9] https://www.armstat.am/file/article/bn_fond_2020_1.pdf.

[10] https://www.armstat.am/file/article/bn_fond_2019_1.pdf page 6

[11] The data of the US DoE. https://www.energy.gov/energysaver/solar-water-heaters#:~:text=There%20are%20two%20types%20of,passive%2C%20which%20don't.

averaged over a year 15,4 kWh of thermal energy to supply hot water for about eight hours a day for the demand of 4 - 5 residents. The required rooftop area is 4 m² as standard models of the same scale. The correct tilt orientation of the solar collectors increases the incident energy by up to 20 % compared with the horizontal surface, so it offsets the 80 % efficiency decrease. Thus, the annual energy production *per SWH unit* will make 5633 kWh.

Such reference model can be used further to evaluate multi-apartment buildings, town-houses and, with applying specific factors, it can be defined for other type of residential, industrial, and public buildings, considering technological, legal, architectural, urban planning aspects to be harmonized with the use of technical solutions based on SWH technology.

2.2. Cost-benefit Analysis

The large-scale penetration of SWH technology in the segment of residential family houses in the national scale requires significant investment costs. The main cost comparison is made for the cost of displaced natural gas and electricity (which in turn has a significant share of natural gas) from the residential water heating needs and the energy sectors, aiming at evaluation the viability of substituting electricity and natural gas with solar energy.

The reference SWH model with an average 15.4 kWh of thermal energy generated per day, annually substitutes

$$15.4 \text{ x } 365 = 5633.12 \text{ kWh}$$

of energy, out of which 72 % is incremental to the natural gas which is equal to the amount of 384 m³ of natural gas[12] , and 16 % of electricity amounted to 901 kWh.

Solar yearly irradiation per m²	1693.0	kWh (horizontal surface)
SWH unit capacity	5.0	kW
SWH surface	4.1	m²
Number of SWH units	400000	Units
Solar irradiance incident per SWH, yearly	7012	kWh
SWH efficiency	80	%
Annual Energy Generation per SWH	5633	kWh
Total for 400000 SWH units, annual	2.253,2	GWh

Based on the adopted assumptions, solar irradiation data and the technical parameters as per table below, it is easy to calculate the annual thermal energy generated by the 400.000 rooftop SWHs to be equal to 2,253,248 MWh or 2,253.2 GWh. This amount is almost 9 times higher than 260 GWh supposed by the known recent-years assessments.[13]

[12] 1 m³ of natural gas is equivalent to 10.55 kWh of energy.

[13] In-Depth Review of the Energy Efficiency Policy of Armenia. Energy Charter Protocol on Energy Efficiency and Related Environmental Aspects PEEREA. Energy Charter Secretariat, 2017, Belgium. PDF. ISBN 978-905948-186-2

With an actual ratio between natural gas of 72 % and electricity of 16 % used to cover residential water heating demand, the volume of natural gas to be displaced will be 154,203,323 m³, and electrical energy – 356,013,184 kWh.

Energy resources	Actual proportion	Substitution	Unit
Electricity	15.8 %	356,013,184	kWh
Natural gas	72.2 %	154,203,323	m³
Overall for Wood, Biofuel, Other	11.8 %		

The scenario under consideration assumes that by 2041 the SWH will be installed on 400.000 individual family houses, and by 2051 this amount will rise up to 600.000.

The residential tariffs assumed unchanged for the considering period: 40 AMD per kWh for electricity and 143.7 AMD per m³ of natural gas averaged conditional tariffs have been applied for the calculation.

The calculation shows that by 2041 SWH will substitute about 153.7 million cubic meters of natural gas and save 360,519.6 MWh of electrical energy, and 230.6 million cubic meters of natural gas and 540,779.5 MWh of electrical energy by 2050.

The saved amount of electricity in turn is generated by use of natural gas. So, the emission reduction due to the SWH shall be calculated in two components: direct gas burning and electricity component.

Years	2025	2030	2035	2040	2045	2050
SWH Penetration, %	15	30	50	75	90	100
Installed SWH, *unit*	52000	166000	286000	400000	500000	600000
Substituted Natural Gas, *x1000 m³*	19,990.9	63,817.1	109,949.9	153,776.2	192,220.2	230,664.2
Substituted Electricity, *mil. kWh*	46.9	149.6	257.8	360.5	450.6	540.8

For the investment cost calculation basis, an average turn-key price in the market of Armenia of 430000 AMD per unit of an up to 300 liters evacuated tube SWH is adopted.

The cost for investment in the installation of the overall 400.000 SWH by 2040 will require an amount of AMD equal to 430000 x 400000 = 172,000,000,000 which is in yearly average term is equal to 9,555,555,555 AMD[14] .

[14] At the current (12/07/2022) exchange rate 411 AMD for 1 USD, this is equal to 23,249,527 USD.

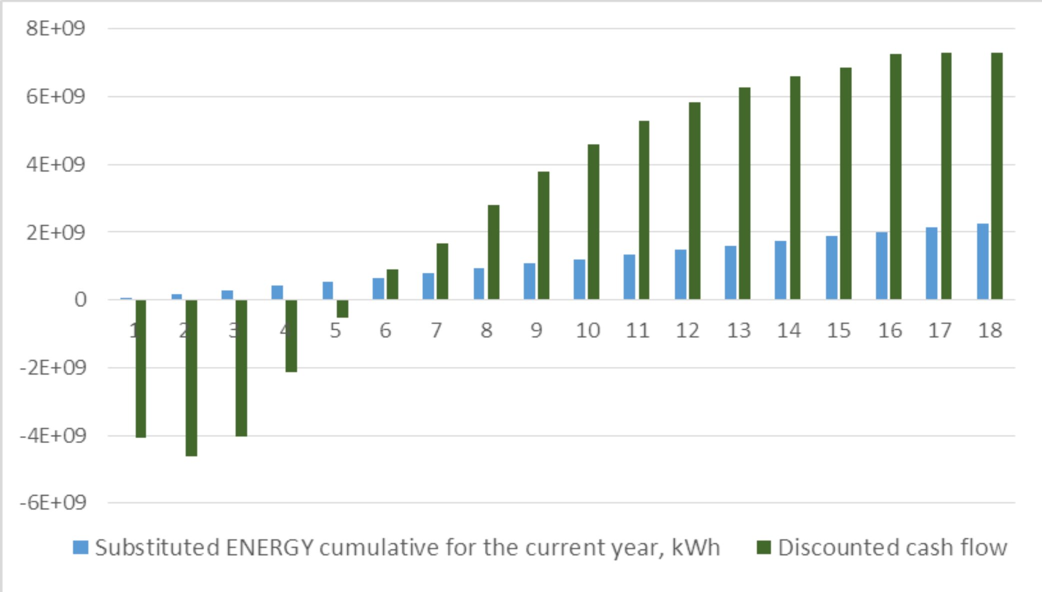

Figure 5. Cash flow vs Substituted Energy, 2023-2040.

As a result of a simplified cash flow analysis, the following indicators of economic efficiency were obtained:

Net present value (NPV), AMD	129 663 043 947
Payback period, years	5
Internal rate of return, %	20

The SWH system generates positive cash flows starting in the sixth year after it pays for itself, and over the next 20 years, it operates with little O&M costs.

The above estimations and assumptions did not provide for the presentation of an exact and universal quantitative result, since intended exclusively to present the scale of the potential and the vision of possible solutions by a very rough assessment aimed at increasing the energy independence of Armenia. That is why some factors, such as specific conditions in the different climatic zones of Armenia, exact classification of the buildings by architectural parameters such as consideration of the tilt orientation (the correct positioning of the solar collectors can increase the incident energy for up to 15 % compared with the horizontal surface) omitted while for the industry master planning, for instance, they would be of high importance for the precise quantitative calculations. In order to avoid multiple assumptions for such a long-term period for consideration, the interest rate and discount factor have been omitted from the calculation.

Years	2025	2030	2035	2040	2045	2050
SWH Penetration, %	15%	30%	50%	75%	90%	100%
Installed SWH, unit	52000	166000	286000	400000	500000	600000
Substituted Natural Gas, m^3	19,990,902	63,817,109	109,949,959	153,776,167	192,220,209	230,664,250
Substituted Electricity, kWh	46,867,558.4	149,615,667.2	257,771,571.2	360,519,680	450,649,600	540,779,520

2.3. Policy Recommendations

In recent years, the Armenian government demonstrated some progress toward acceleration of the development of solar thermal energy. However, there is no systematic support for enhancing SWH use. The existing experience is through the limited government or donor programs offering grants, soft loans, and tax and import-duty exemptions focused on communities that do not have access to gas. For example, between August 2017 and November 2018, commercial banks provided soft loans with funds from the KfW German Development Bank for an energy efficiency credit program that helped the installation of 1364 solar water heaters. Similarly, with UNDP funding, the R2E2 Foundation and the SDGs National Innovation Lab have installed solar thermal systems in several communities not connected to a gas pipeline. In both cases, solar photovoltaic systems were provided together with solar thermal installations.[15]

Since the main principles of the state policy of Armenia in the field of energy are defined by several laws, such as the RA Law on Energy and the RA Law on Energy Saving and Renewable Energy, the Decrees of the Government of Armenia such as "Energy Sector Development Strategic Program to 2040"[16], and by action plans, and roadmaps which touch upon priority development of energy efficiency and renewable energy resources, and EU – Armenia Comprehensive and Enhanced Partnership Agreement (CEPA) which inter alia applies definite obligations for energy efficiency, energy generation from renewable energy sources supposing scheduled implementation of higher standards in the energy security and energy independence as a term for progressing on the way to the European Union, Armenia should choose to go a step ahead of the EU policy in the sphere of power, especially regarding the available natural resources.

As evidenced by the experience of other countries which have rich solar resources, with an appropriate institutional framework and supportive policies, solar thermal energy in Armenia will develop rapidly. For instance, Greece (with average sunshine hours equal to 2540) since 2010, based on the EU Regulation on the Energy Efficiency of Buildings[17] (revised in 2017), obliged 15 % of the reference building to produce hot water by solar collectors on their roofs. Thus, all new buildings must produce at least 15 % of their hot water from solar heating using rooftop solar collectors. In practice, solar collectors cover most of the hot water demand in Greece.

Appropriate legislation and regulation can provide incentives to undertake energy efficiency measures under state-based monitoring and enforcement.

- Development of a strategy targeting creation a local industry for manufacturing of solar energy utilization products and components based on an enlarged and diversified portfolio, including accelerating deployment of locally-made cost-effective solar water heaters
- Setting new development targets on the energy saving in residential sector through utilization of solar technologies

[15] Armenia 2022 Energy policy review. International Energy Agency
[16] Decree of the Government of the Republic of Armenia N 48-L dated January 14, 2021, Appendix N 1
[17] https://ypen.gov.gr/wp-content/uploads/2020/11/KENAK_FEK_B2367_2017.pdf) (article 9, paragraph 3.5)

- Issuing new regulations for residential and other hot water consuming buildings regarding the obligatory solar energy use
- Establishing special revolving funds under a partnership of commercial and financial institutions to enable the market with the commitment of private businesses.
- Demonstration in the practice of the technical and financial feasibility of an innovative energy efficiency transaction program through the government's commitment to making appropriate changes in the legal and regulatory framework to assure long-term funding
- Implementation of the pilot projects for demonstrating the effects and laying down the foundation for sustainable operations over time is required.

3. SOLAR PV TECHNOLOGY

3.1. Cost of Solar PV Technologies

The cost of solar PV technologies is rapidly declining, and so far, no trend has been noticed to slow down this process. For utility-scale solar PV, in 2021, the global weighted average LCOE of newly commissioned projects fell by 13 %, year-on-year, from USD 0.055/kWh to USD 0.048/kWh. This was driven by a decline in the global weighted average total installed cost for this technology of 6 %, from USD 916/kW in 2020 to USD 857/kW for the projects commissioned in 2021.[18] This trend created a good background for penetration of solar PV technologies into the residential sector, mainly in the form of roof-top installations to cover the energy needs of the inhabitants as well as supplying the surplus electricity to the grid.

In order to assess the potential of solar PV technology in Armenia, the segment of individual family houses, comparable in scale, energy intensity and identical in purpose, is considered below for the case of 400,000 units, similar to that considered earlier for SWH. The study suggests that SWH is cost effective for virtually all buildings in the residential and commercial sectors.

The overall area of the 400,000 individual houses in Armenia is assumed to be 65 million square meters. With a 60 m² of average available rooftop area, even after offsetting the limitations on the placement of solar panels such as engineering infrastructures (chimneys, antennas, conditioners, etc.), it will be sufficient even if we cover half of the rooftop area with solar PV panels (a standard model 400 W, 2 m² panels), then we get:

$$30\, sq.m. \times\ 400000\ \times\ 200\, Watt\ per\ sq.m. = 2400\, MW,$$

which would translate into 6 kW installed capacity per house.

However, we assumed a much more modest rate below 4 kW per house (conditional 10 panels with 400 W each), then we arrive at 1600 MWs of potential for the residential / off-grid solar. The area of solar panels per house will need 20 square meters; assuming efficiency of 20 % and solar irradiation of 1720 kWh per year, we get:

$$20\, sq.m. \times\ 0.2 \times 1720\, kWh\ per\ sq.m.\ per\ year\ =\ 6.88\, MWh\ per\ year$$

While 1720 kWh per year is solar irradiation on flat surface, and ideally tilted panels would be generating more, we assume that the direction of rooftops is random, and not necessarily placed towards the sun. With generation of 6.88 MWh per year per house, we get 2.75 TWh per year from residential / off-grid solar. It should be noted that this is generation alone. If this energy is stored in residential storage or transported through the grid, then the final supply will be lower due to losses.

However, the potential for solar photovoltaic technologies in Armenia is expected to be almost twice as high, as this study does not include large segments of multi-story apartment buildings, industrial plants, and public and service buildings.

[18] https://irena.org/-/media/Files/IRENA/Agency/Publication/2022/Jul/IRENA_Renewable_Power_Generation_Costs_2021.pdf

3.2. Cost – Benefit Analysis

The energy output of a solar PV system E (kWh) is a function of the average annual solar radiation on tilted panels H, total area of the panel A (m^2), solar panel efficiency R (%), performance of the PV system PR (depends on losses from shadow, temperature losses, losses in DC and AC cables; losses in the inverter, losses due to dust) can be presented as

$$E = f(H, A, R, PR).$$

The assumptions of the cost-benefit analysis model are as follows:

Annual average solar irradiation on a horizontal surface	1720	kWh/m²
Average area of PV panel	2,2	m²
Average Efficiency of PV panel	0,185	%
Capacity per 1 m² of average PV panel	0,219	kW
Capacity per PV panel (2.2m² average)	0,475	kW
Total area of a PV System (10 PV panels module)	23,9	m²
Number of PV panels in a PV system	10	Pics
PV System Performance	0,78	
Total Capacity of a PV System (10 panels)	3,71	kW
Annual generation per PV System (10 panels)	5397	kWh
Annual generation per 1 kW installed	1456	kWh
Cost per 1kWh generated, AMD	-7,0	AMD
Cost per 1kW installed, 1000 AMD	-410	AMD
Cost per 3,56kW capacity PV System, 1000 AMD	-1520	AMD
Savings per 1kWh gen. by PV System (Aver. tariff - Cost per 1kWh)	36,11	AMD
Annual savings (per 1 kWh x Annual generation per 1kW installed)	52572	AMD
Life cycle of PV System	25	Years

A summary of the conclusions based on the analysis is as follows.

The cost of investments conventionally assumed for AMD 410,000 per kW of installed capacity, which in comparison with the market value, in the model is deliberately overestimated by us to level out the costs that are not counted in this simplified analysis. However, the cost is still within the range of the current rate of the international market, while the tendency shows further decline of the cost.[19]

With a yearly penetration rate of 20000 solar PV systems, by the end of the 18th year, 400,000 individual family houses will be equipped with 3.56 kW solar PV systems. The total installed capacity will be 1,482,627 kW, which will allow to generate 2,158,705,558 kWh of electricity (2.158 GWh) annually, which is equivalent to 204616640.6 m³ of natural gas in

[19] Monocrystalline Solar Panels (the most energy-efficient solar panel option) on average cost $1 to $1.50 per watt; Polycrystalline Solar Panels, a bit less energy-efficient, cost $0.90 to $1 per watt. https://www.forbes.com/home-improvement/solar/cost-of-solar-panels/.
* General storage review is presented in the separate chapter.

terms of energy value – 10.55 kWh per m³. If the penetration tendency continues further to the 25th year[20], 560000 solar PV systems will be installed reaching 2.075.678 kW in total and yearly generate 3.022.187.782 kWh of electricity (3.022 GWh) equivalent to 296694129 m³ of natural gas. For the comparison, this amount exceeds the amount of electricity generated by Armenian NPP. The analysis reveals the following indicators:

Payback period	3	years
Internal rate of return (IRR)	12	%

3.3. Mini-grids and Storage

International experience suggests that isolated energy systems should not rely too heavily on variable renewable energy sources, such as solar PV and wind energy. Their share should be kept under 15% of the generation to ensure the system's sustainability and security. Therefore, besides the advanced development of Armenia's interconnections with neighboring power grids, the solution to maximizing the use of variable renewable energy resources, such as solar PV and wind energy, is seen in the enhanced penetration of autonomous mini- and microgrids.

Autonomous microgrid solutions can reduce stress on the central grid, improving the power system's resilience and lowering consumers' dependence on the central grid. A microgrid is a locally connected system incorporating distributed generation, consumption, and storage within clearly defined electrical boundaries. Microgrids can operate independently off-grid (where it is technically and economically unviable to build an electricity network) or grid-connected. This capability is crucial in emergencies, such as natural disasters or grid failures, able to provide power to critical consumers and essential services when the main grid fails. As a complement to solar power generation, microgrids can ensure power supply reliability and lower electricity costs. Solar installations can be combined into microgrids that provide additional benefits to the grid. They can also be entered into the wholesale market so that they can sell to the main grid. By doing this, solar installations can ensure power supply reliability and lower electricity costs. To fully benefit from microgrids, it is necessary to digitize them to predict and optimize local demand and supply.

Mini-grids are larger configurations, which can power residential and large commercial consumers, universities, factories, islands, etc. While mini-grids are considered to be the best solution for rural electrification, providing access to electricity in remote areas, for Armenia's case, which has a high degree of electrification, the advantages of mini-grids will be added flexibility and resiliency. Mini-grids can have storage, smart technologies, renewable generation, electric vehicle charging, etc. all of which can provide benefits to the system. However, proper market mechanisms, such as facilitating aggregators and compensating flexibility services, are necessary in order to exploit the benefits of mini-grids.[21]

On the other hand, battery storage is a way to increase grid resiliency and increase use of renewable energy sources. Due mainly to growing deployment of large-scale lithium-ion

[20] The life cycle is considered over a 25-year period.
[21] Unlocking the Potential of Distributed Energy Resources (IEA).

batteries on the grid, pumped hydro's share of U.S. energy storage dropped from 78 % in 2021 to 67 % in 2022 with battery and thermal storage accounting for the remainder.

Numerous R&D projects are known, aimed at creating new and optimizing and improving known energy storage technologies intended for different purposes, and differing in their technical solutions. Some of such recent ones are listed below:

New battery for residential, commercial applications.
Dutch manufacturer MG Energy Systems is offering a new storage system in two versions, with capacities of 5.8 kWh and 7.2 kWh and nominal capacities of 230 Ah and 280 Ah.

August 23, 2022 Emiliano Bellini. The MG LFP 24 V battery is available in two versions, with storage capacities of 5.8 kWh and 7.2 kWh and nominal capacities of 230 Ah and 280 Ah. The smallest device measures 517 mm x 294 mm x 193 mm and weighs 41 kg. The largest measures 652 mm x 294 mm x 193 mm and weighs in at 53 kg.
https://www.pv-magazine.com/2022/08/23/new-battery-for-residential-commercial-applications/

Hydrogen bromide flow battery for large-scale renewables storage.
Dutch startup Elestor has secured funds to bring its hydrogen bromide (HBr) flow battery technology closer to commercial production. It said the system could achieve a levelized cost of storage below $0.05/kW.
The manufacturer claims the system has a depth of discharge of 100% and a round-trip efficiency ranging from 65% to 75%. The containerized version has a power output of 200 kW and a storage capacity of 2,000 kWh. Each cube container measures 12.2 m x 2.4 m x 2.9 m and has a gross weight of 42 tons.
Dalessi claims the battery could potentially achieve an LCOS lower than $0.05/kW.

US startup unveils plug-and-play solid-state battery for residential applications.
Zendure has developed a residential storage system using a semi-solid state battery with 6.438 kWh capacity. Each unit is scalable with up to four batteries, bring the capacity of one unit to 32 kWh and of two units to 64 kWh. The system can be used with solar panels.
The SuperBase V 6400 (SBV) measures 73 cm x 34.6 cm x 44.2 cm, including its real wheels, and weighs in at 59 kg (130 lbs). The semi-solid state Satellite battery B6400 measures 69 cm x 28.5 cm x 27.4 cm and weighs in at 46 kg (101 lbs).
The battery pack, according to the manufacturer, contains 42 % more energy than lithium iron phosphate (LiFePO4) batteries.

Toshiba tested the inverter in a simulated microgrid with a grid frequency of 50 Hz, a 40 % renewable energy rate, and five 20 kW/14.9 kWh batteries. The system also featured a diesel synchronous generator with a capacity of 125 kVA, and two load banks to vary the power load.

"It was demonstrated that under load fluctuations of 50 kW, grid frequency reductions were suppressed by 70%, from 2.4 Hz (50.0 to 47.6 Hz) to 0.6 Hz (50.0 Hz to 49.4 Hz)," the company said, in reference to the test results. "The frequency threshold for power supply interruptions due to grid frequency fluctuations in East Japan is set at 48.5 Hz, and verifications using actual equipment ensured that the frequency did not fall below this threshold, demonstrating the realization of a stable power supply that avoids power outages."
The company conducted a second test on a 20 kW PV system without batteries, and found that the grid frequency was suppressed by approximately 30%, from 1 Hz (50.0 to 49.0 Hz) to 0.7 Hz (50.0 to 49.3 Hz).
https://www.pv-magazine.com/2022/08/29/grid-forming-inverter-to-stabilize-microgrids/

Ammonia heat pump for wastewater.
Aalborg CSP will connect a 2.5 MW ammonia heat pump to a district heating system operated by E.ON Denmark. The facility will be located at a local wastewater treatment plant.

Aalborg CSP has revealed plans to install a large-scale heat pump for wastewater to optimize a green district heating system operated by E.ON Denmark, a unit of German energy company E.ON, in Frederikssund, Denmark.

"The order for E.ON Denmark consists of turnkey contract for a heat pump with associated exchanger, piping and purification system, which will be extracting the energy from the treated wastewater before it is subsequently discharged into the local environment at Roskilde Fjord," Aalborg CSP said in a statement. "The heat pump itself, which applies the natural refrigerant ammonia (to be completely renewable and nontoxic), will have a maximum output of approx. 2,500 kW."
https://www.pv-magazine.com/2022/08/29/ammonia-heat-pump-for-wastewater/

3.4. Policy Recommendations

Within the most interesting and important application of photovoltaics for Armenia shall be considered agricultural photovoltaic installations with PV panels installed on cultivated lands in an almost horizontal plane to produce agricultural crops and generate PV electricity. The agricultural plants will be protected from strong solar radiation and generate significant savings by saving water and electricity for powering irrigational pumps.

On the other hand, microgrids, and in particular agricultural microgrids, shall become an important factor for the penetration of green energy technologies, enabling distributed electricity generation, consumption, and storage without the impact of variability on grid modes. With the ability to operate independently of the main grid, mini-grids can also connect or disconnect from the main grid upon their choice, based on the demand or supply conditions. Microgrids can have storage, use smart technologies, serve electric vehicle charging, other local consumers. Microgrids are a serious factor in addressing the technical aspect of the variability of renewable energy sources, and contribute to expanding opportunities to increase the share of variable energy generation in the energy balance of the country as a whole.

A targeted state policy, including legislation, technical regulation, market mechanisms, social, and financing aspects is necessary to develop and introduce to stimulate the development of agricultural microgrids.

4. BIOGAS

4.1. Resources

Almost two-thirds of biogas production in 2018 in the world was used to generate electricity and heat (with an approximately equal split between electricity-only facilities and co-generation facilities). Around 30 % was consumed in buildings, mainly in the residential sector for cooking and heating, with the remainder upgraded to biomethane and blended into the gas networks or used as a transport fuel.

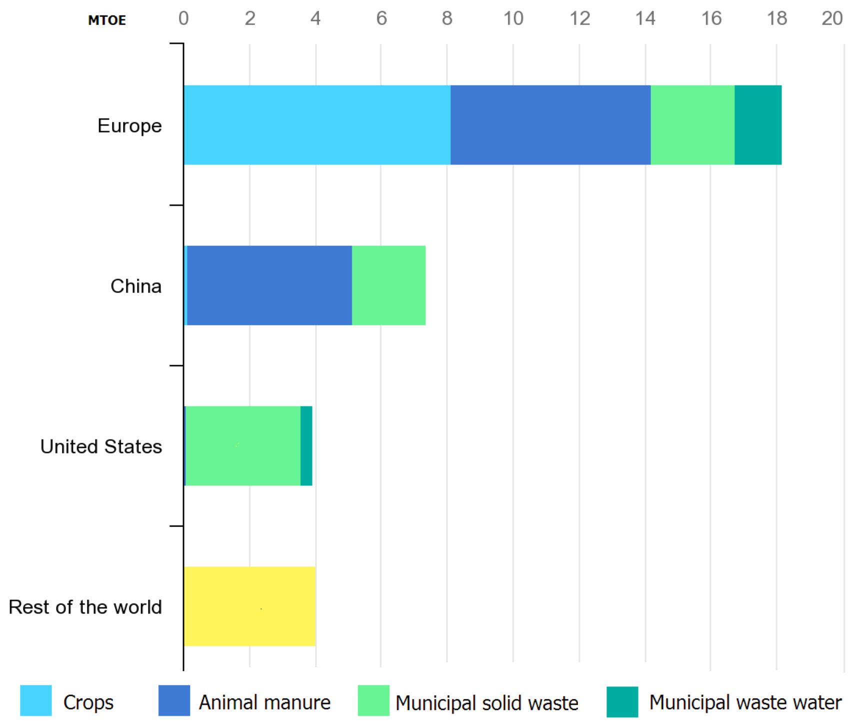

Figure 6. Biogas production by region and by feedstock type, 2018.[22]

Generation of electricity from biogas is an established technology which has been widely implemented around the globe. Today there is around 18 GW of installed power generation capacity running on biogas around the world, most of which is in Germany, the United States and the United Kingdom. Capacity increased on average by 4% per year between 2010 and 2018. In recent years, deployment in the United States and some European countries has slowed, mainly because of changes in policy support.

This is most commonly done with a CHP engine with some form of heat recovery and use. A CHP engine can be linked to any operating anaerobic digester. For it to be economic, a CHP engine requires a minimum size. Operators of biogas plants are trying to maximize efficiency and income streams by increasing the utilization of heat. There is also a growing interest in trigeneration which generates electricity, heat and cooling when needed.

[22] IEA, Biogas production by region and by feedstock type, 2018, IEA, Paris https://www.iea.org/data-and-statistics/charts/biogas-production-by-region-and-by-feedstock-type-2018, IEA. License: CC BY 4.0

The relatively high costs of biogas power generation mean that the transition from feed-in tariffs to technology-neutral renewable electricity auction frameworks (such as power purchase agreements) could limit the future prospects for electricity-only biogas plants. However, unlike wind and solar PV, **biogas plants can operate in a flexible manner and so provide balancing and other ancillary services to the electricity network**. Recognizing the value of these services would help to spur future deployment prospects for biogas plants.

Where local heat off-take is available, the economic case for biogas co-generation is stronger than for an electricity-only plant. This is because co-generation can provide a higher level of energy efficiency, with around 35 % of the energy from biogas used to generate electricity and an additional 40-50 % of the waste heat put to productive use.

The levelized cost of generating electricity from biogas varies according to the feedstocks used and the sophistication of the plant, and ranges from USD 50 per megawatt-hour (MWh) to USD 190/MWh. A substantial part of this range lies above the cost of generation from wind and utility-scale solar photovoltaic (PV), which have come down sharply in recent years.[23]

The natural degradation of organic material by micro-organisms under anaerobic conditions leads to the production of biogas. The percentage of methane in the gas determines its calorific value, as the other constituents do not contribute to the energy content. It consists of 50–75 % methane, 25–50 % carbon dioxide, water vapor, and traces of oxygen, nitrogen and hydrogen sulfide.[24]The methane content of biogas provides a calorific value high enough to find use in many energy applications, including power generation. Biogas has a generally accepted mean calorific value of about 25 MJ/m^3 (1 m^3 of biogas is an equivalent of energy in 0.93 m^3 of natural gas or in 1.25 kg of coal).

Biogas can be obtained from a wide range of different feedstocks: agricultural waste (livestock manure, plant residues), industrial waste (sewage sludge, food industry waste, slaughterhouse waste) and household waste.

Livestock manure directly used as fertilizer in agriculture can cause environmental problems, such as soil and water contamination, odors and pollution. Moreover, natural degradation of manure leads to emissions of methane and carbon dioxide during storage. Therefore, the use of this resource for energy generation brings various environmental and climate benefits, such as displacing the use of fossil fuels and reducing GHG emissions released into the atmosphere by avoiding methane emissions during storage. It also contributes to mitigate odors associated with manure storage and removes pathogens[25].

Biogas can be used for the same purposes as natural gas, including heating, electricity generation and, after being upgraded, as a fuel for vehicles. As well as having similar traits to natural gas, biogas has a lower impact on the environment. Upgraded biogas (biomethane) can be injected into natural gas pipelines. Furthermore, biogas sludge can be used for the production of biofertilizer for farms as it has a high level of phosphorus and is expected to reduce the use of chemical fertilizers and pesticides. The largest underutilized resources for

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[23] https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane.

[24] A. Wellinger, J. Murphy, D. Baxter (Eds.); The biogas handbook. Science, production and applications, Woodhead Publishing Limited, Cambridge, UK (2013).

[25] S. Dagnall, J. Hill, D. Pegg, Resource mapping and analysis of farm livestock manures – assessing the opportunities for biomass-to-energy schemes Bioresour Technol, 71 (2000), pp. 225-234.

biogas production are in the agricultural sector. Animal husbandry is the main source of environmental pollution in rural areas. The predominant sources of pollution from this industry are unorganized emissions from collection-ponds and manure storage facilities, which release harmful substances. Anaerobic treatment of livestock waste in biogas plants has several benefits, including: a sharp reduction in environmental contamination and pathogens; the elimination of odors associated with livestock production.

Another major source for biogas extraction is landfill disposals of municipal solid waste (MSW). The average annual generation of MSW in Armenia today is estimated to be 1600 metric tons/day. The traditional disposal of MSW is in engineered landfills or else in mass burn incineration both of which generate serious environmental problems. Land for disposal is becoming increasingly scarce in urban areas and incineration emits toxic gasses unless expensive sorting techniques are employed.

The first waste-to-energy project in Armenia – Nubarashen Landfill Gas Capture project was implemented under the Kyoto Clean Development Mechanism (CDM) jointly by the Municipality of Yerevan and Japanese Shimizu Corporation to achieving reduction of GHG and generating income from selling carbon credits with annual capacity 2.16 Mln t CO_2 equivalents by capture of methane and its combustion in a flaring unit. The biogas was not used for heating or electricity generation purposes due to not justified economic viability of such supplies. Biogas is produced in Anaerobic Digestion (AD) plants, wastewater treatment plants or recovered from landfill sites. In recent years, biogas production in AD plants has become one of the most attractive renewable energy sources worldwide.

There are about 170 thousand farmers and collective farms are engaged in cattle breeding in Armenia. Poultry farming is the most mechanized livestock sector in Armenia, equipped with modern technologies. Currently, more than a dozen medium and large poultry farms operate in Armenia, which are engaged in the production of poultry meat and eggs. About 700 million eggs and 7-8 thousand tons of poultry are produced annually in Arax Poultry Factory JSC, Lusakert Pedigree Poultry Factory JSC and Arzni Pedigree TTK JSC are among the large poultry farms engaged in egg production, which produce about 40% of the eggs produced in the republic. "Araks Poultry Factory" OJSC is again the leader in poultry production in Armenia.

Lusakert Biogas Plant was the first and the only industrial sized, state-of-the-art biogas facility in Armenia based on organic waste from poultry plant that generates methane gas through anaerobic digestion, and then the biogas used to generate electric power. The project was successfully implemented with CDM in 2008. The installed electrical capacity is 0.84 MW and 900 kW is the heat capacity. The average annual electricity production was 3 million kWh. Due to the plant's operation, annual reduction of CO_2 is equivalent to 11000 tons. Presently the biogas plant is out of operation due to multiple organizational and technical issues.

Animal husbandry is another major feedstock for biogas production. As of 01/01/22, the number of livestock in the livestock sector of Armenia amounted to 559,627 heads. Commercial organizations involved in industry - 4562.

The following technical parameters were taken into account for the biogas potential case study.

Data for daily manure production per animal vary significantly in various sources - from 29.5 to 50 kg/day, so we take an amount of 33 kg/day.

Data on the amount of biogas output from 1 kg of cattle manure varies in different sources from 0.036 m³ to 0.06 m³, so to avoid overestimation, we used 0.04 m³.

Biogas from cow manure with 1 kg produced as much as 40 liters of biogas, while chicken dung with the same amount produced 70 liters. Biogas has a high energy content which is not less than the energy content of the fuel fossil[26]. The calorific value of 1 m³ biogas is equivalent to 0.6 - 0.8 liters of kerosene.

Compared to commercial quality natural gas' calorific value of 39 MJ/m³, the average calorific value of biogas is about 21-23.5 MJ/m³, meaning that 1 m³ of biogas corresponds to 0.5-0.6 l diesel fuel or an energy content of about 6 kWh.[27]

The calculation for the number of about 155,000 cattle involved in the production of biogas, reaching this number at the end of the 10th year (life cycle of a biogas plant), and with the condition that this number is maintained at a stable level in the future reveals following numbers:

Annual biogas output from manure, m³	74474400	m³
Energy content of the annual output of biogas, kWh	476 583 070	kWh/year
Amount of biogas equivalent to natural gas, m³	69261192	m³

4.2. Cost – Benefit Analysis

The actual number of cattle available for biogas production may vary from year to year. In order to estimate the hypothetical potential for biogas production, it is assumed that 2,580 livestock farms, each with an average of 60 cattle, could be involved in biogas production, in a total of 154,800 cattle.

Cattle livestock involved in biogas production	154800	
Number of biogas production units	2580	
Number of livestock for a biogas production unit	60	cattle

Following technical data and assumptions have been taken into account:

Natural gas tariff per 1 m³	143,69	AMD
Natural gas tariff per 1 m³	0,37	USD
Cattle livestock involved in biogas production	154800	heads
Number of biogas production units	2580	units
Average biogas production unit for	60	cattle
Average capital investment per biogas unit	30000	USD
Project life cycle	10	years
Discount rate	0.5	%

[26] M. Kaltschmitt, D. Thrän and K. R. Smith, "Renewable Energy from Biomass" in Encyclopedia of Physical Science and Technology, ed. by R. A. Meyers (Academic Press, 2001), pp 203-228.
[27] http://www.worldbioenergy.org/uploads/Factsheet%20-%20Biogas.pdf

Energy content from 1m³ of biogas	6,39	kWh
Daily average cow manure yield	33	kg
Daily manure yield for biogas production c	5108400	kg/day
Yearly manure output from 155000 cattle population	1859457600	kg/year
Amount of biogas output from 1 kg of cattle manure	0,04	m^3
Amount of biogas from yearly manure output from 155000 cattle	74378304	m^3
Amount of biogas equivalent of natural gas by calorific value (0.93 m^3)	69171823	m^3
Energy content from yearly manure biogas output from 155000 cattle	475277362,6	kWh/year

If the biogas farm penetration rate over ten years reaches 2,880 farms with total livestock of about 155,000 animals, the produced biogas will be comparable to about 70 million cubic meters of imported natural gas. The economic feasibility of investment is highly efficient providing a payback period of 3 to 4 years. Environmentally friendly fertilizers for farmers as a by-product of biogas production can be taken into account to offset the costs of biogas production.

4.3. Policy Recommendations

Although the market potential in Armenia appears to be good, technology penetration faces several hurdles. The main issue is the initial capital costs. Some form of subsidy, such as low-interest loans or other innovative financial mechanisms, needs to be adopted. Institutional support policies along with a trained workforce must be created for the successful development of the biogas industry in Armenia. Policy development should include, for example, the following components:

- Biogas technology promotion;
- Establishing mandatory requirement digestion of slurry for farms over a certain size;
- Implementing targeted policies to incentivize energy generation from livestock manure via such specific financing schemes for microscale digestion aimed at a higher level of energy security and independence for the farmers, reduced use of solid fuels for domestic cooking and heating, reduced deforestation;
- Making available training for microscale digestion operation, maintenance, and safety checks.

5. BIOMASS

5.1. Resources

Armenia is poor with natural forests. The economic and energy crisis of 1990s in Armenia had extremely negative impacts on forestry. The extensive unsustainable use of forest resources for heating purposes started in the energy crisis period of the 1990's and continued for over ten years, contributing significantly to deforestation and air pollution, as well as detrimental health impacts. In those years, for energy purposes, forests were subjected to wide-scale logging, including illegal logging, which, according to the experts' assessments, amounted to a volume of 0.8-1.0 million cubic meters annually[28]. Between 1990 and 2010, Armenia lost 24.5 % of its forest cover - around 85,000 ha.[29] Armenia's forests and forest lands are the property of the State. For the purpose of increasing the forest cover, the Forest Code defines the right for community and private ownership over self-established forests.

Wood logs from the existing forests are the only source for firewood in Armenia because there are no large scale energy crop plantations. Firewood is used in small towns and villages, especially ones close to the existing forested areas, for heating and cooking. Since 2007, use of firewood has decreased with provision of natural gas to most of the small towns and villages in Armenia. However, economic difficulties and an increase in the price of natural gas could reverse this trend. Table 5 provides the amount of the annual authorized wood from the existing forests, as well as an estimate of illegal cuttings from governmental and nongovernmental sources.

Based on capabilities for growing energy crops such as fast growing trees and nearby agricultural residues to minimize transport cost associated with the harvesting or collection of these materials, three locations for energy purposes generation biomass have been identified (studies conducted in the mid-1990s) in Armenia. In addition, the locations were selected based on the low cost of retrofitting existing equipment compared to new construction.

In the area of south-west Armenia within the Ararat Valley, sufficient biomass can be generated to fire a 25 to 35 MW boiler. An estimated 63 % of biomass can be generated from dedicated crops on unused or degraded agricultural land, the rest coming from agricultural residues. The second site around Lake Sevan in central Armenia can produce enough biomass for a 35 MW facility at Hrazdan with 58 % of the biomass coming from dedicated tree crops and much of the rest coming from existing plantations. The third area is in north-eastern Armenia where conditions are colder, forest residues are available, and energy crops would comprise only 10 % of the biomass supply. Biomass from this location would be sufficient enough to supply a 20 MW system in Vanadzor.

Agricultural waste which consists of by-products not suitable for animal feed is mainly burned in the fields in Armenia after harvesting. In the mountainous rural regions of Armenia, manure dried during the summer is used as the major source of fuel for heating stoves. There is no accurate quantitative data on this energy source, however share of households using

[28] The Second National Communication (SNC) of the Republic of Armenia. (UNFCCC) 2010.

[29] According to the U.N. FAO, 9.3 % or about 262,000 ha of Armenia is forested, 5.0 % (13000) of this is classified as primary forest. Armenia had 21,000 ha of planted forest.

manure as a heating source, according to the expert's estimation, is around 130,000 households which is 60% of rural housing.[30]

5.2. Industry and Market Potential

Given the scarcity of forest resources in Armenia, biomass should be considered an important natural resource that ensures the conservation of climate and biological diversity. At the same time, the sustainable use of forest and other biological resources, in particular forestry and agricultural waste, can bring significant benefits to the conservation and reproduction of biological resources, and thereby contribute to the energy security and independence of Armenia.

Wood processing residues created by sawmilling operations are also collected and used as an energy source. Wood chips are used in simple handicraft stoves for heating living spaces and barns. In early 2011, there was a small amount of pellets available in the marketplace prepared from wood chips, again for home heating purposes using simple stoves.

Even though it is technically possible to use biomass for heat and electricity generation, necessary infrastructures for collection and processing of agricultural residues and forestry waste in central locations to be used for electricity generation are missing.

There are approximately 30 000 hectares of saline soil areas in Ararat Valley which are not suitable for agricultural use. Since 1994, 52 different types of hybrid fast growing poplar trees had been tested in various locations throughout Armenia included a 50 hectare test plantation site that was established in the Armavir region. Test results have been promising, especially in saline soil areas, but no large commercial-scale short rotation plantations have been established yet in Armenia.

In this regard, test results have indicated that certain types of hybrid trees can be grown on these saline soil areas. These areas could be an ideal source for energy or lumber production thereby easing pressure on other scarce prime forest resources elsewhere in Armenia. The preliminary evaluation of biomass and fuel supply, conversion facility conditions, business conditions, local know-how, and necessary infrastructural/institutional revealed that opportunities for profit and environmental benefit clearly existed in this area of potential commercial endeavor.

Biomass can be burned to generate electricity and thereby back out harmful fossil fuel emissions such as SO_2, NOX, particulates, and entrained heavy metals. In addition, tree planting on agricultural land and scrub land will raise standing inventories of above ground biomass and soil organic matter. Multiplied over many tens of thousands of hectares, the economic and social benefits, such as creating jobs could be quite large. A final benefit is the reversal of deforestation throughout the country.

It can be assumed that such fast-growing trees will mature in seven years in productive soils, but they will require between 10 to 11 years maturing in saline soils. After trees have matured, there will be approximately 900 m^3 wood per hectare from which 60 % can be used for lumber production and the reminder as firewood or wood chips for direct burning. The total

[30]National Energy Saving Program, 2007.

income to be expected per hectare from such an operation will be approximately 15 000 000 AMD per annum.

It is estimated that there are 200 000 residences within a 10 km radius of established forests in Armenia. Assuming that 30 % of the residences are not occupied and that on average five people are living in each of the remaining houses, the total number of residents will be around 700 000. If half of these residents are using firewood as their primary source of heating and cooking, then it can be concluded that approximately 350000 people in Armenia or approximately 12 % of the population are using firewood as their primary source of energy. Accordingly, it is highly desirable to reduce this amount to about 6 % in an effort to reduce pressure on scarce forests throughout Armenia. Another option would be to establish short rotational fast growing tree plantations to create a steady source of firewood without depleting additional prime forest resources.

Biomass production is relatively labor intensive, which is one of the reasons it is more expensive than fossil fuels. Growing, harvesting, and transporting biomass fuels all require local labor, as does maintaining the equipment, which contribute to the high cost of bio fuel. However, this means that jobs will be created in areas with a depressed agricultural economy.

Finally, the table below presents a summary overview of the potential for biomass including estimated investment costs per cubic meter and likely breakeven tariffs in the mid to longer term. Table 5 presents the outputs expected for Biomass between what Armenia has today and anticipates by the year 2030.

Table 5. Overview of the Potential for Biomass by 2030.

Biomass (firewood from forests)	2010	2015	2020	2030
Biomass production, *m^3*	335000	200000	200000	100000
Existing forests, million m^3	42	44	46	51
Preservation of forests, *AMD/m^3*	32	95	100	105
Investment cost of new planting, *AMD/m^3*	5555	6500	7300	9000
Operation cost of new planting (120 years), *AMD/m^3*	16500	18800	22000	29000
Wholesale cost, USD/m3	18	22	28	45

5.3. Cost – Benefit Analysis

The surveys and assessments from 2014-2018 implemented by different organizations and initiatives showed that fuelwood has been largely used as a heating fuel, especially in rural areas. The annual demand for fuelwood in Armenia varied from 0.5 to 2 million m^3. [31] This significantly exceeded the reported fuelwood supply and renewal capacity of forests in

[31] Residential Energy Consumption Survey, Analytic Report (October 2015). Available: http://www.edrc.am/images/Publications/Statistical_Surveys/undp_recs_2015_eng.pdf
Annual Report by the State Forest Monitoring Center SNCO, 2017.

Armenia. Such excessive use of fuelwood for heating in rural households resulted in continuous forest degradation and deforestation [4-6].

The use of inefficient heating devices, together with the humidity level of the firewood, and significant heat losses due to the low energy efficiency of houses, puts additional pressure on forest resources. This causes the high consumption rate of fuelwood while efficient thermal insulation can reduce the heating demand by at least 40 %.[32]

The cost-benefit analysis on marketable approaches to reduce the use of fuelwood and dung for heating in rural households[33] assessed the economic feasibility and sustainability of various approaches and products as well as their potential for scaling up. The study analyzed options with the partial and full energy needs for heating in rural households.

The energy efficiency measures and renewable energy installations require lower investment cost, have higher internal rate of return, and therefore were considered as the most feasible. The CBA also showed that currently, the market price of straw briquettes in forest-adjacent areas is not competitive with the price of fuelwood and does not provide incentives to shift to briquettes. Meanwhile, in the areas far from the forest the price of wood is higher and there are more incentives to use straw briquettes, especially if the households use own straw with input of own workforce and barter the straw to briquettes in the existing briquetting units.

The cost - benefit analyses concluded that for forest adjacent areas the replacement of existing inefficient heating devices, particularly single-point stoves (and boilers), with locally produced efficient devices are economically most feasible measures for rural HHs as it does not require big investments. For forest distant areas the suggestion is to combine the replacement of heating devices and shift from fuelwood to straw briquettes as alternative fuel, which can ensure even higher fuelwood savings. These approaches were used for design and implementation of the project pilot interventions in Lori, Shirak and Kotayk marzes. [34]

Furthermore, the cost-benefit analyses considered the mix of wood and dung as one of the widely used heating options in rural households in many regions of Armenia. The calculations showed that at present the shift from fuelwood/dung to straw briquettes is not economically viable, especially as people often do not pay for dung produced by their own livestock.

Meanwhile, the calculations showed that insulating the walls and roof is economically viable in a longer term. Though this measure requires a higher upfront investment, it can significantly reduce the energy expenses and the annual use of fuelwood. The combination of different EE and RE measures should be considered to ensure the highest fuelwood savings.

[32] Strategic Program of the Energy Sector Development in Armenia (up to 2040), Republic of Armenia Government decision N48-L from 14.01.2021.

[33] Arabyan G. Feasibility study and cost-benefit analysis on the approaches to reduce the use of fuelwood/dung for heating in rural Armenia. GIZ ECOserve project report, July 2020. https://biodivers-southcaucasus.org/uploads/files/Final%20English.pdf.

[34] Avetisyan L., Ghavalyan A., Galstyan S., Mnatsyan A. Promotion of Energy Efficiency and Use of Alternative Energy in Rural Households to Reduce Forest Degradation in Armenia. Proceedings of the 7th International Renewable and Clean Energy Conference. 2020. Yerevan http://nature-ic.am/en/projects/7th-International-Renewable-and-Clean-Energy-Conference/1037.

5.4. Policy Recommendations

Sustainable use of biomass resources with increasing energy efficiency and thermal insulation of houses, replacement of inefficient heating devices with shifting to alternative solid biomass fuel with the focus on increased availability of sustainable biofuels, promotion of end-use EE, affordable financing, awareness raising and financial mechanisms can enable biomass to contributing in the energy independence and energy security on Armenia.

In the near term it is advisable to establish large scale short rotation energy crop plantations primarily to support the demand for fire wood and secondarily for electricity generation. Measures to reduce greenhouse gas emissions and sequester carbon can be an integral part of this plan as well and should be factored into the overall economics of such a proposed scheme.

The excessive use of fuelwood for heating in rural households is conditioned by the thermal energy losses due to the lack of proper thermal insulation, use of inefficient heating devices, the lack of affordable fuel alternatives and others. It resulted in continuous forest degradation and deforestation. The main solutions include energy efficiency and renewable energy measures, such as thermal insulation of houses, use of efficient heating devices, shift to alternative solid biomass fuel and others.

Ensuring the quality of heating devices and solid biomass fuel is crucial. This implies the need for institutional capacities for quality-testing and certification. Rural household heating energy issues including the energy efficiency devices as well as the efficient and affordable biomass fuels should be reflected in the sectoral policies on energy, forest and agriculture.

The Action Plan for Promoting Energy Efficiency and Alternative Biomass Fuel formulates relevant activities at the national level to ensure collaboration and stakeholder involvement, capacity building and awareness, financial incentives, etc.

The capacity building should target the local producers of stoves and alternative biomass fuel along with the financial mechanisms to make the price of the straw briquettes more competitive. This should be combined with pilot and demonstration projects on specific examples to become the basis for replication and wider use.

6. BIO-ETHANOL

6.1. Resources

A preliminary feasibility assessment for implementing a commercial scale bio-ethanol fuels program for Armenia was conducted by an international consultant from the USA in 2008.[35] A substantial study concluded with the following main findings and recommendations.

1. A research mandate specifying 10 percent blending to provide the overall incentive and necessary push for establishing a new bioethanol industry in Armenia.

2. The most promising bioethanol feedstocks that can be produced in large quantities on marginal lands in Armenia in the near to midterm include Jerusalem artichokes, cattle corn, sweet sorghum, and possibly chicory.

3. The preferred scenario for developing a new bioethanol industry in Armenia today is promoting several (2 – 3) smaller bioethanol processing facilities in separate locations throughout the country based on the most appropriate conventional processing technology currently available for a given local feedstock for providing bioethanol fuels in the near to midterm, and at least two additional processing facilities to be located elsewhere, based upon the most promising cellulosic conversion technology in the mid to longer term.

4. The findings of an extensive institutional, legal, and regulatory review point to a need for classifying and treating bioethanol as a renewable energy resource. Legislation may be necessary for a successful biofuel industry.

5. The findings and results of the preliminary sectoral environmental review indicate that the overall environmental impacts of biofuel production and usage in Armenia would be considered positive, including the reduction of greenhouse gas (GHG) emissions over time.

6. The prospect for creating a new and sustainable bioethanol fuel industry utilizing marginal lands and/or surplus lands not presently being tilled for the production of food is quite promising in Armenia in the near to midterm, especially in rural areas that are currently experiencing extremely high rates of unemployment and low economic growth rates.

The preferred scenario was the two to three smaller fermentation facilities for selected localized feedstocks in the near to midterm with a total combined capacity of 14,000 tons of bioethanol per annum by 2014. Construction of one (or more) larger cellulosic conversion plants in the mid to longer term with a total combined capacity of 35,000 tons of bioethanol per annum by 2020.

The feasibility study report provides summarized findings and recommendations based on the research of the advantages and disadvantages that should be recognized when considering a decision on whether or not to implement a nationwide bio-ethanol program; detailed analysis of land availability and targeted locations by regions (marzes) and communities for the initial bio-ethanol production program in Armenia; appraisal of Armenian bio-ethanol feedstock availability and production costs; bio-ethanol conversion technologies; analyzed the sustained production potential and technical requirements for cultivation for preferred feedstocks.

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[35] Enertech International, Inc. 48 Greenwood Shoals, Suite 200 Grasonville, Maryland 21638 and BBI International 123 G Street Salida, Colorado 81201, USA.

6.2. Potential Fuel Market for Bio-Ethanol

The majority of cars from Western Europe, Japan, and the United States built to operate with E85 petrol (younger than 10 years old in 2020). Assuming that by 2020 nearly all the country's cars will be able to use E10 petrol mix (10 % level of blending), the total estimated level of bio-ethanol will be approximately 49,100 tonnes per annum.

The financial analysis assumes a sales price for bioethanol of 410 AMDs per liter ($1.34/liter) at plant start-up, but it is expected that oil and petrol prices will remain at the recent high level.

While bioethanol contains about 30 % less energy per liter than petrol, bio-ethanol has a higher octane number that enhances its value as a blend component for higher priced mid level and premium petrol. The bio-ethanol price used in the analysis assumes that domestically produced bioethanol will not be subject to the 120 AMD per liter import tax on imported petrol. The price the plant receives for bio-ethanol is the single most important metric in determining financial viability of the proposed plants.

The relatively small size of the bio-ethanol plants and their limited contribution with regards to the overall petrol use, the market risk for bio-ethanol in Armenia is limited. At expected blend levels of the bio-ethanol produced should be readily absorbed into the petrol market. Its high octane value further makes it an attractive blend component. To avoid fuel quality issues from other sources (e.g. blending water) being attributed to the introduction of bio-ethanol, a rigorous testing and quality control protocol is recommended to demonstrate that the addition of bio-ethanol improves overall fuel quality.

Armenia's dependence on imported petrol and the associated high domestic petrol prices helps to create an opportunity for domestically produced bio-ethanol. The proposed bioethanol plants would augment petrol supply by a total of about 10 %, which can readily be absorbed by the petrol market. Introduction in the supply chain can be easily achieved through splash-blending at the fuel depots. The bio-ethanol price in the financial model is set at $1.34/liter.

6.3. Likely Bio-Ethanol Co-Products

Distiller's grains are the residues that remain after high quality cereal grains have been fermented by yeast. In the fermentation process, nearly all of the starch in the grain is converted to bio-ethanol and carbon dioxide, while the remaining nutrients (proteins, fats, minerals, and vitamins) undergo a three-fold concentration in the beer, which after distillation and centrifugation of the still bottoms, yields distillers wet grains (DWG) and "thin stillage."

The thin stillage is subsequently concentrated via evaporation and the "heavy syrup" is added back to the DWG. This material is then dried to 10% moisture, producing dried distiller's grain and soluble (DDGS). Front-end fractionation as proposed for this project separates the non-starch components (germ and fiber) of the corn from the starch.

The addition of the soluble fraction increases the protein and vitamin potency of the final product and removes the logistical problems associated with marketing wet feed. It also provides a solid baseline by-product that can be marketed while allowing development of both the wet feed and special blend feed markets. DDGS is the most common and highest volume form of feed product derived from a dry mill facility. The DDGS yield from corn is 198.2 kg/ton of feed corn.

DDGS derived from feed corn contains nutrients that have been demonstrated by numerous experiments to have important growth promoting properties for dairy and beef cattle, poultry and swine. For dairy cattle the high digestibility and net energy content of DDGS and DWG, compared to other feed ingredients (soybean meal, canola meal, brewers spent grains as examples), as well as the high fat content, results in feeds that yield greater milk production. For beef cattle, the improved ramen health, energy effect of the fiber, and palatability have been shown in feedlot studies to result in faster and more efficient gains.

Per ton of Jerusalem artichoke, the expected feed co-product yield is 64.2 kg. In addition, the Jerusalem artichoke processing plant is expected to produce dry ice and liquid carbon dioxide (CO_2) as co-products whether solid, liquid, or in a gaseous form as safe for use in the food industry and associated applications that utilize the greatest amount of CO_2.

The revenues from the co-products described above are crucial for the profitability of bioethanol plants if no direct financial subsidies are being made available by the Government. Further discussions with the potential buyers of these products are recommended to gauge their level of interest and potential sales volumes and prices. The high prices of imported feed corn in Armenia provide an opportunity to sell distiller's grains, a substitute for feed corn, at a relatively high price. In the case of the Jerusalem artichoke co-product, animal trials with species relevant to Armenia are required to ascertain its value.

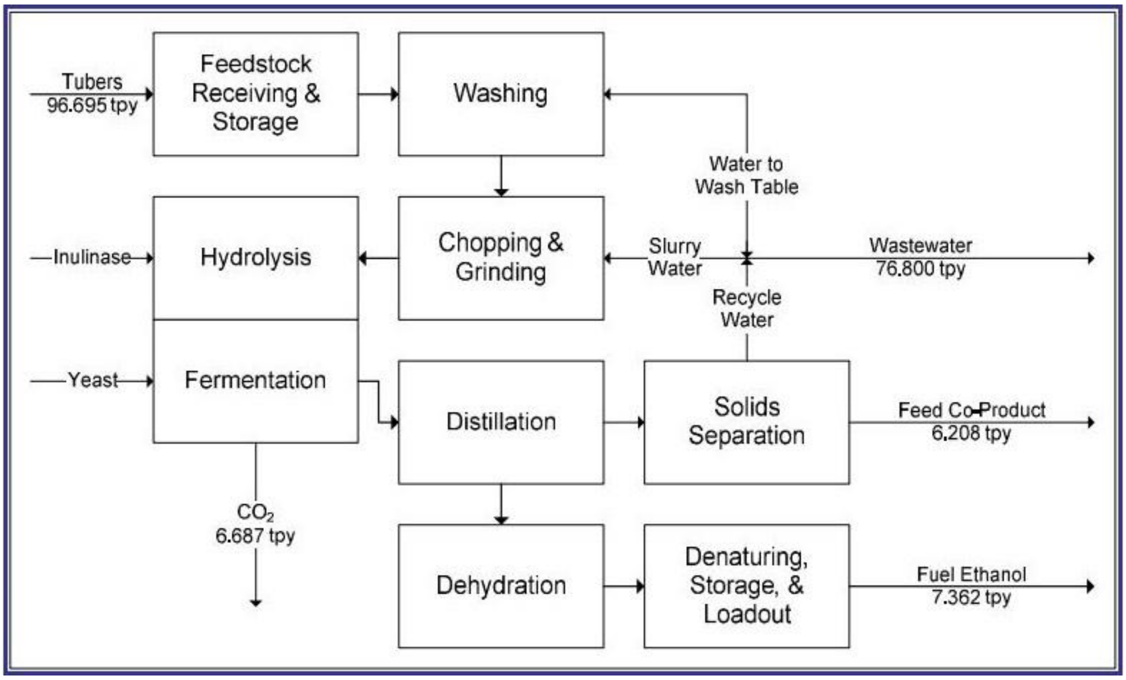


Figure 7. Jerusalem artichoke process plant diagram.

7. WIND ENERGY RESOURCES. INVESTMENTS AND DEPLOYMENT TIMELINE

In loving memory of Sona Mnatsakhanyan

Wind is a natural phenomenon, coming from the movement of the air during equilibrium phase between high air pressures to lower pressure area. The Coriolis effect of the earth induces a non-straight line of the wind direction between both areas.

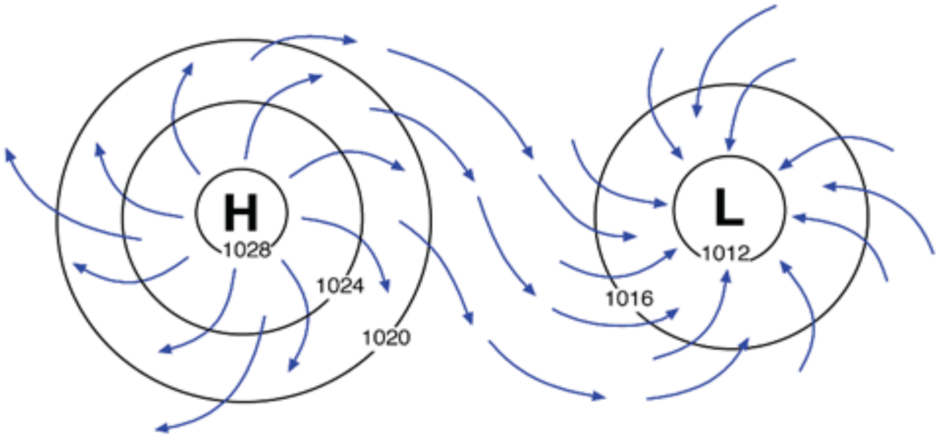


Figure 8. Wind formation between high to low pressure areas[36].

The wind speed varies always on a spot, but can be faithfully statistically described with a Weibull distribution[37]. Good and precise observations of the wind are the only way to allow the correct energy production forecast, taking in count all time variation (over one year) of the wind, in order to enhance the energy grid mix in «real time».

Typically the statistical distribution of the wind over time can be represented as following:

$$f(v) = \frac{k}{\lambda}\left(\frac{v}{\lambda}\right)^{(k-1)} e^{-\left(\frac{v}{\lambda}\right)^{k}} \qquad \text{eq.1}$$

with: v: speed of the wind (m/s)
k= Weibull shape parameter
$\boldsymbol{\lambda}$ (or l)= Weibull scale parameter

A small value of *k* means a very variable wind. A larger *k*-parameter means a more constant wind. For wind, as a natural phenomenon, *k* remains between 1 and 3.

For example, even with very similar average wind speed, the statistical distribution of the wind speed can differ a lot.

[36] https://mrcc.purdue.edu/living_wx/winds/index.html
[37] https://en.wikipedia.org/wiki/Weibull_distribution
Of course ∫0f(ν)dν=1

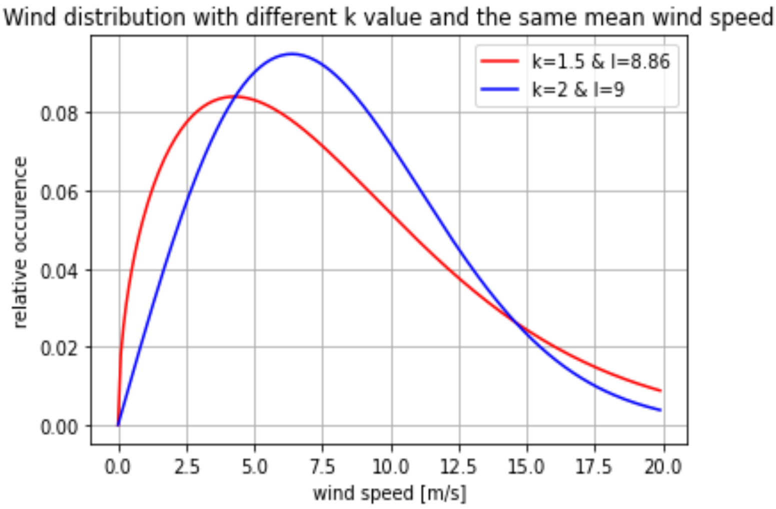


Figure 9. Typical statistical wind distributions, in this case with 8 m/s mean wind speed in both cases.

Both curves have an identical mean wind speed (in our case of 8 m/s), we see that the Weibull shape parameter, *k*, change the distribution of the wind, much more than the Weibull scale parameter (**λ** or l).

The statistical description of wind remains the most critical parameter in order to correctly model any production calculation, the simple average wind speed is not enough and can bring numerous biases. A precise statistic of the wind speed distribution is necessary.

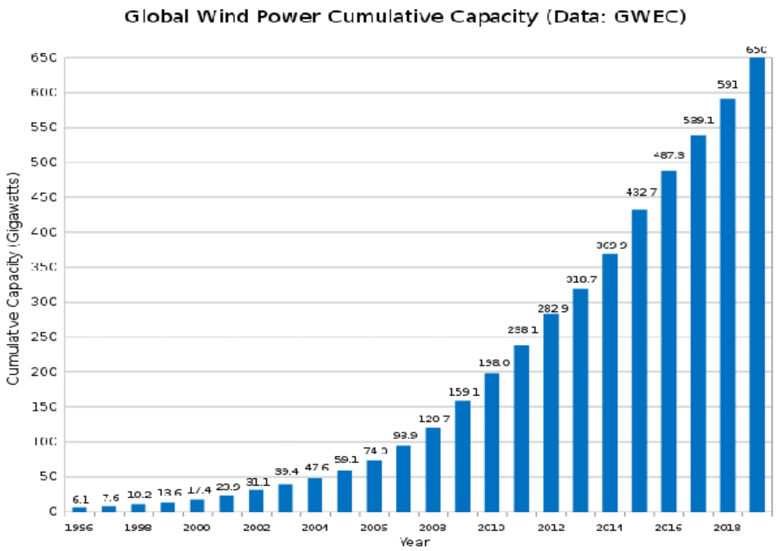


Figure 10. Cumulative capacity for Wind power[38]

Though, regardless of the non-predictable aspect of the wind, and thanks to statistical prediction based on wind measurements in time and space, wind energy became a mature industry with an exponential growth over the last two decades.

[38] https://www.spikegeek.com/wind-power-statistics-2021/

Fully integrated in the grid, and depending on the country's wind potential, this renewable energy proved to be efficient when wisely integrated and prepared.

Some countries can sometimes cover most of their needs only with Wind energy, such Denmark, or Netherland. Others can see wind turbines as one of the best suppliers to compensate for very fluctuating oil and gas prices, without any CO_2 emissions.

In any case, wind energy solutions could help Armenia in order to help to reach further independence and reduce Greenhouse Gas Effect (Paris Agreements signed by Armenia).

7.1. Wind Map Actual Status in Armenia

In 2003, Elliott & al published a report, funded by the US Aid program, to investigate the Wind Energy potential of Armenia with a precise wind atlas.

Wind Energy remains marginal, with only 4 turbines in duty[39], in the northern part of the country (4x660kW, less than 0.05% of the electrical production of Armenia). A couple of projects remain in standby.

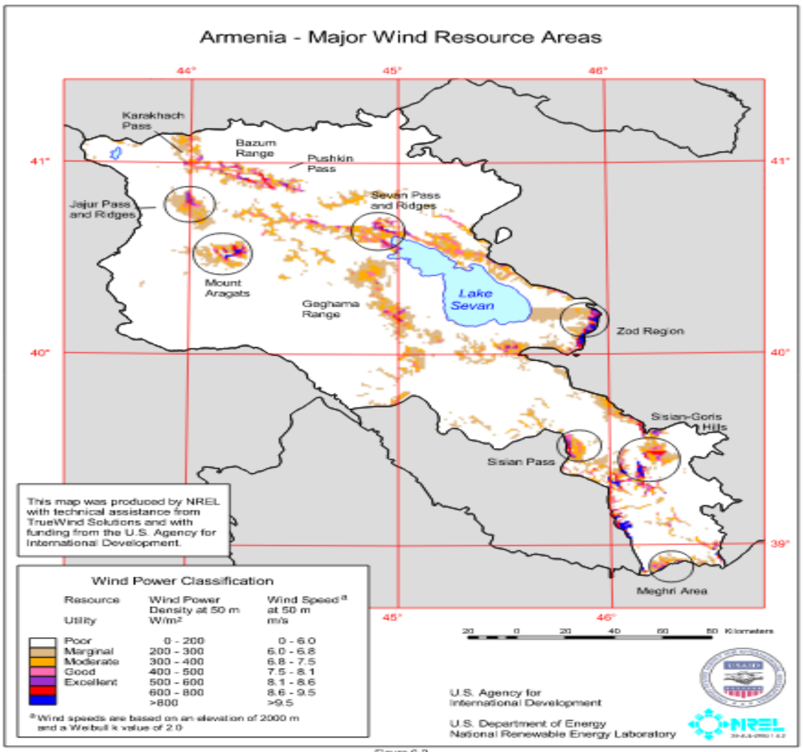


Figure 6-2

The Wind Map, provided by Elliott in 2003, models the longitudinal wind speed at 50m (and only 50m) above the ground:

Figure 11. Wind Map of Armenia with longitudinal wind speed at 50 m above the ground, from Elliott & al (Wind Energy Resource Atlas of Armenia).

The resolution reaches 1km². The wind speed was provided by TrueWind Solution. This ensemble of data was used as an initial estimation of the wind resources of Armenia that is displayed in Elliott's document.

[39] http://www.minenergy.am/en/page/545

All the calculations made by Elliotts & Al were made from this wind map, and not from local measurements with large but realistic assumptions.

The wind speed and the wind power density at 50m above the ground remain the solely provided information (Figure 18), with the following starting hypothesis:

- the normalized elevation of 2000 m above sea level, consequently the estimated air density[40] is 0.95 g/cm³.
- Weibull k-parameter of 2 (rather steady wind, default value for wind distribution over time). Wind speed is described throughout a classic Weibull probability distribution[41].
- An installed capacity of 5 MW/km² (rather low compared to nowadays technology).

No other altitudes are taken into account, whereas nowadays, most turbines easily reach 100m or more.

The study also gathers some raw data at different places over the country, but the numerous biases, (low) frequency of measurements and poor maintenance of the meteorological masts can hardly bring reliable sources to derive conclusions and carry on other profitable calculations.

The Armenian authorities and other related stakeholders, such as R2E2 and the Ministry of Energy, are still using a more than two-decade-old map as a basis for general strategy projections of wind energy potential, without any other reliable source of measurements, or any other or deeper modelling built with modern flow tools such WAsP, Meteodyn WT or even open source software such WindSim.

Other initiatives have conducted local investigations with good quality but without permanent measurements, the authorities still take Elliott's wind map as a global reference, and did not upgrade their different models due to lack of awareness of these underlying issues, other data sources or relevant specialists.

To conclude, having a reliable wind resource map only manifests the first step toward a clear vision of Wind Energy production potential for a specific place and/or a country. In this regard, relying on a more than 15 years old map can only bring some discrimination and biases. That's why a regular wind map update, especially for developing country, can provide the necessary back-office work to constantly follow up the evolution of wind power production potential in function of new turbines technology, grid modelling upgrade,

The Global Wind Atlas (GWA), provided by the Danish Technical University since 2015, with the sustain of the International Finance Corporation and the World Bank Group will allow to revise the entire vision that Armenia, or any other country or area in similar situation, can have about Wind Energy, and at the same time increase its energy production independency.

[40] Air density in function of the altitude, follows the equation: ρ(h)=p0MRT01-LhT0gMRL-1, with p_0=sea level standard atmospheric pressure = 101.3kPa; h = altitude [m]; T_0 = sea level standard temperature = 288.15K; g = gravitation constant 9.8m/s²; L = Temperature lapse rate 6.6mK/m; R = ideal constant gas 8.3145 J/(mol.K); M = Molar mass of dry air 0.03kg/mol.

[41] https://en.wikipedia.org/wiki/Weibull_distribution

7.2. Methodology: New Vision throughout the Global Wind Atlas (GWA)

Until now, the wind map used by Armenian authorities as a base for all their global modelling was the one provided by Elliott & Al in 2003. Since then, only local measurements occurred, but the data were not included to upgrade the entire vision of Wind Energy over Armenia.

Since 2015, with the first version of the Global Wind Atlas (GWA), and with the benefice of past experience[42] such as IRENA and the Masdar Institute, the GWA increased its capacities, with now the second version available online.

The GWA uses at the beginning a large scale to end to a micro scale wind climate data, going from 70km x 70km to reach at the end a 1km x 1km resolution (identical to Elliott's Wind map), but this time with wind speed at 50m, 100m, 150 and 200m above the ground, and much more information, as indicated below:

Table 6. Elliots & Al (2003) and GWA available information.

	Elliott	GWA		Elliott	GWA
Speed @ 50m above the ground	✓	✓	WInd Power Density @ 200m	x	✓
Speed @ 100m	x	✓	Roughness	x	✓
Speed @ 150m	x	✓	Ruggedness	x	✓
Speed @ 200m	x	✓	Wind Rose @ 50m	x	✓
WInd Power Density @ 50m	✓	✓	Wind Rose @ 100m	x	✓
WInd Power Density @ 100m	x	✓	Wind Rose @ 150m	x	✓
WInd Power Density @ 150m	x	✓	Wind Rose @ 200m	x	✓

From this point on, new perspectives open up before us in order to reshape and refine Armenian wind energy potential self-knowledge.

The wind power installed capacity potential varies a lot in Elliott's studies[43], from ~5000MW (Good to Excellent Utility Scale) to ~11000 MW (Moderate to Excellent Utility Scale), at 50m above the ground, with a total installed capacity of ~5 MW/km².

These calculations were made with large assumptions, by adding the area with good or moderate wind speed (>7m/s), and multiplying this surface with a standard installed capacity of 5MW/km². The report also indicates the capacity of different areas, but roughly.

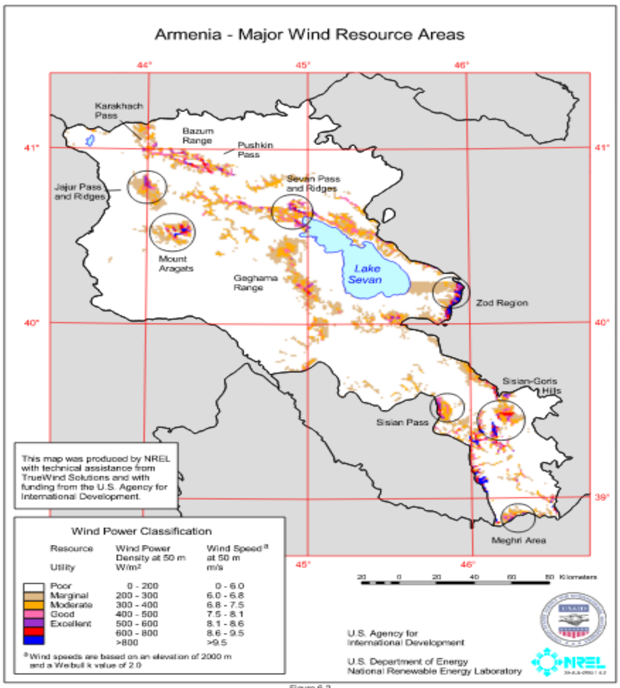
[42] https://globalwindatlas.info/about/introduction

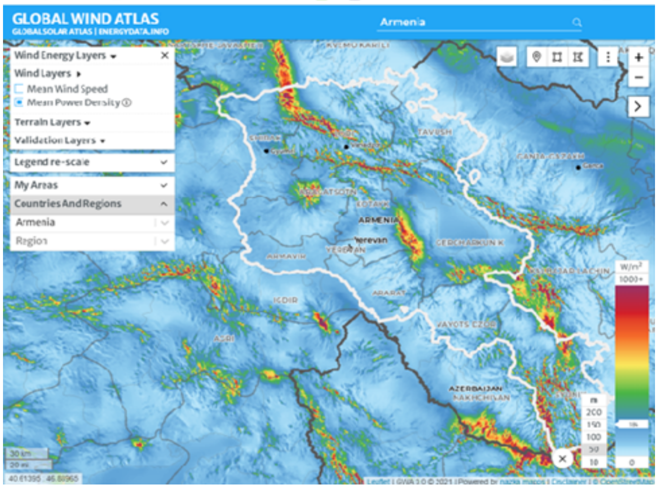
[43] p42, Wind Energy Resource Atlas of Armenia, D. Elliott & al, 2003 https://www.nrel.gov/docs/fy03osti/33544.pdf

The Global Wind Atlas, as a tool, continuously updated with new features, opens up a brand-new vision about the Wind Power capacity, with a tremendous amount of data, at different scales.

7.3. Elliotts and GWA comparison. The facts.

We could first compare the data provided in 2003 by Elliott with the ones from the GWA. As previously said, we have only one wind map at 50m above the ground, with the direct corresponding wind power capacity.





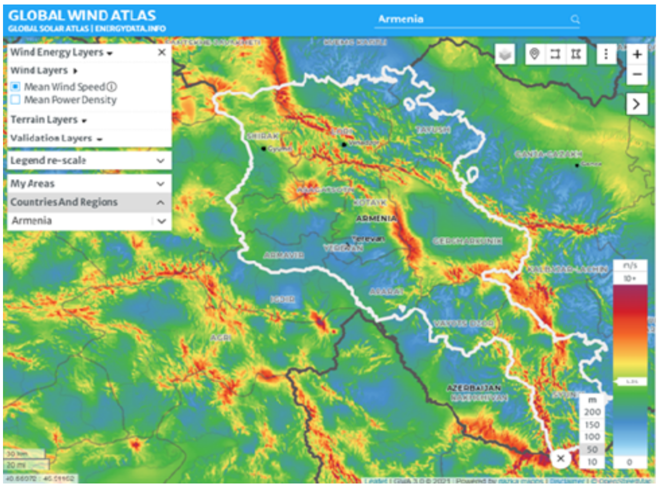


Figure 12(top), Figure 13 (bottom left) & Figure 14 (bottom right). Direct comparison between Elliott's Wind Map at 50 m above the ground (wind speed and wind power capacity) and the GWA (left: Speed; right: Power).

The direct relation between the speed and the power capacity being[44]:

$$P[W/m^2] = \frac{1}{2}\rho\underline{u}^3 = \frac{1}{2}\rho\left(\frac{u}{\Gamma(1+\frac{1}{k})}\right)^3 \Gamma(1+\frac{3}{k}) \quad \text{eq. 2}$$

with

- ρ the air density [kg/m³]
- u the mean wind speed [m/s]
- Γ, the Gamma function
- k, Weibull parameter

We clearly see that the k-parameter is critical for the calculation of the Power capacity, especially with increasing mean speed of the wind. When the velocity of the wind starts to become interesting to efficiently produce some energy (>6m/s.).

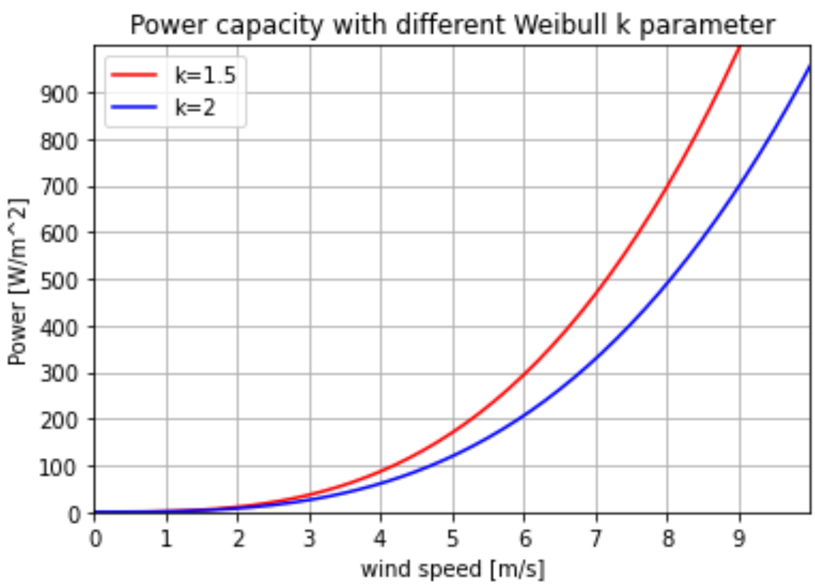


Figure 15. Power capacity with different k Weibull parameter in function of the mean wind speed.

The mean Wind Speed among the country for both maps (Elliott & GWA, Fig. 12 & 13) remains very similar, but the Wind Power Capacity (Fig 2 & 4) shows a dedicated and sharper global overview with the GWA.

If we go deeper, we can then clearly compare both calculations.

The installed power capacity assumption, as previously mentioned, reaches in Elliott's study[45] exactly 4900MW/km² at 50m, with 3.5 % of the windiest area (representing 1000km²

[44] https://journals.sagepub.com/doi/pdf/10.1260/014459806779367509

[45] p51, Wind Energy Resource Atlas of Armenia, D. Elliott & al, 2003 https://www.nrel.gov/docs/fy03osti/33544.pdf

over the 28400 km² of the country), and more than double to ~11000 MW/km² taking in count almost 8% windiest area:

Table 7. Estimation of the Mean Wind Speed (m/s), Power Density (W/m²) and the estimated Total Capacity Installed (MW) from Elliott's study.

Table 7.1 Armenia – Wind Electric Potential

Good-to-Excellent Wind Resource at 50 m

Wind Resource Utility Scale	Wind Class	Wind Power at 50 m W/m²	Wind Speed at 50 m m/s*	Total Area km²	Percent Windy Land	Total Capacity Installed MW
Good	4	400-500	7.5-8.1	503	1.8	2,500
Excellent	5	500-600	8.1-8.6	208	0.7	1,050
Excellent	6	600-800	8.6-9.5	165	0.6	850
Excellent	7	>800	>9.5	103	0.4	500
Total				979	3.5	4,900

Moderate-to-Excellent Wind Resource at 50 m (Utility Scale)

Wind Resource Utility Scale	Wind Class	Wind Power at 50 m W/m²	Wind Speed at 50 m m/s*	Total Area km²	Percent Windy Land	Total Capacity Installed MW
Moderate	3	300-400	6.8-7.5	1,226	4.3	6,150
Good	4	400-500	7.5-8.1	503	1.8	2,500
Excellent	5	500-600	8.1-8.6	208	0.7	1,050
Excellent	6	600-800	8.6-9.5	165	0.6	850
Excellent	7	>800	>9.5	103	0.4	500
Total				2,205	7.8	11,050

*Wind speeds are based on an elevation of 2000 m and a Weibull k value of 2.0

Assumptions
Installed capacity per km² = 5 MW
Total land area of Armenia = 28,400 km²

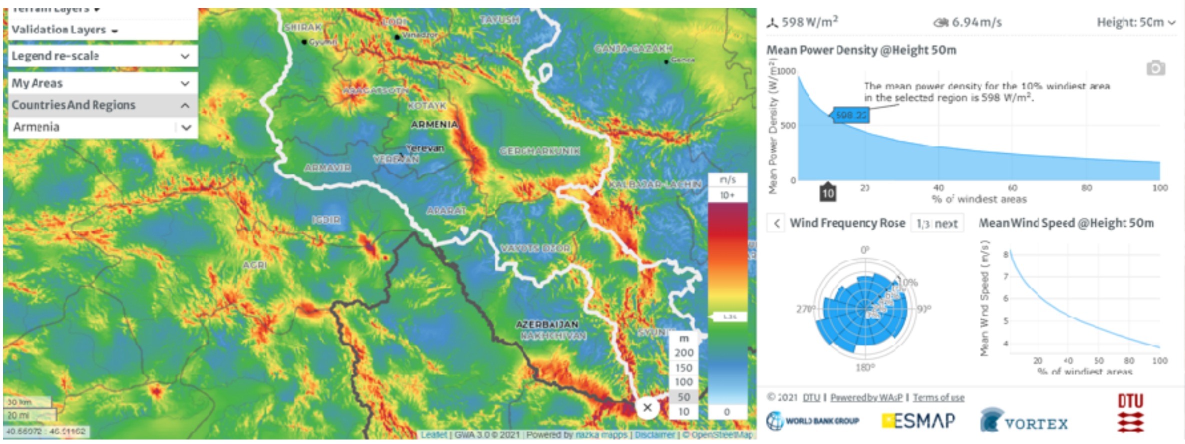


Figure 16. Data from the GWA at 50 m above the ground, Mean Wind Speed and Mean Power Density.

With a Weibull parameter of k=2 and ρ=0.95g/m³ (we consider an altitude of ~2000m above the sea level), the Eq 1 fits well with Elliott's calculation (Wind Speed <-> Power Density at 50 m).

There is about a factor of ~1.4 % (300-400 W/m²), 1% (400-600 W/m²), 0.8 % (600-800 W/m²) and 0.6 % (800-1000W/m²) between the Wind Power Density and the Total Capacity Installed, due to exploitability of the considered area. More difficult with higher altitude.

The GWA offers a different estimation (method and final results) with a global power density reaching 598W/m² (i.e. 598MW/km²) within the 10% windiest area, and 801MW/km² for the 4% windiest area (data available on the clickable graph on right part of the screen):

If we compare the windiest area and their mean wind speed and mean wind power from the GWA and Elliott, then we clearly see the biases and its influence on the total installed capacity modelling, underestimating and not taking in count the technological evolution of the wind turbines, being able now to produce much more power with the same wind speed than for 20 years.

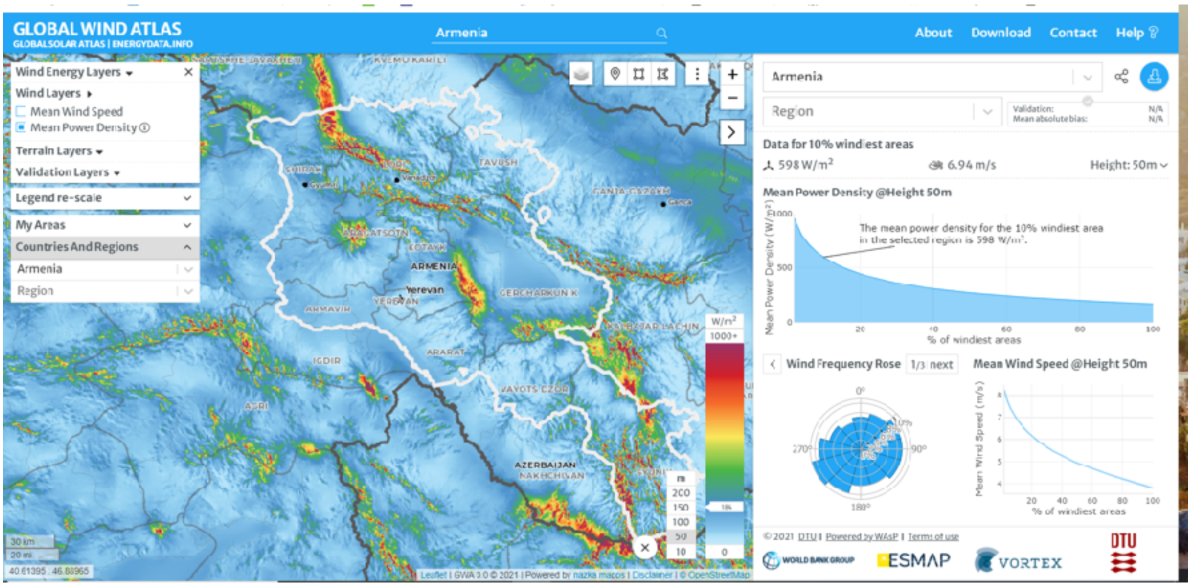


Figure 17. Data from the GWA at 50m above the ground, Mean Wind Speed and Mean Power Density.

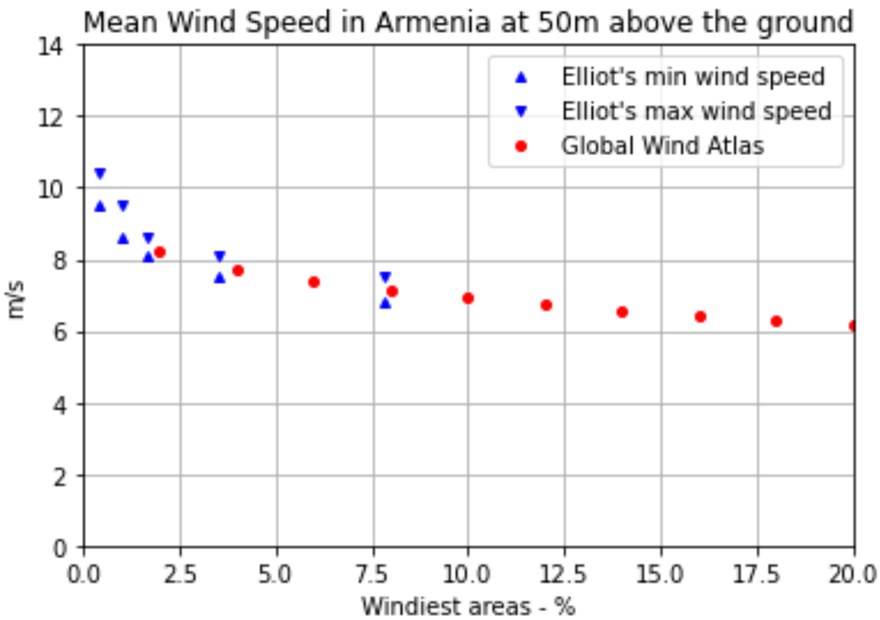


Figure 18. Mean Speed and Mean Power Density at 50m above the ground, with the 20% windiest area.

The Mean Wind Speed in function of the windiest area is very similar between Elliott and the GWA. But the Mean Wind Power differs a lot between Elliott and GWA, all because of the

Weibull parameter, k=1.3 with the GWA, instead of 2 with Elliott. The value chosen by Elliott is more a default one than a measured one. As the wind is a natural phenomenon, it differs from place to place.

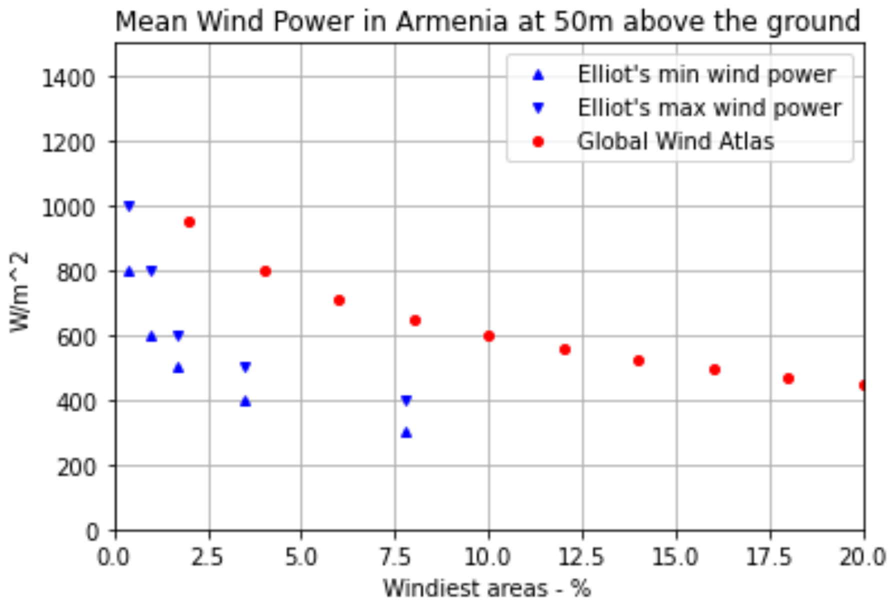


Figure 19. Mean Speed and Mean Power Density at 50m above the ground, with the 20% windiest area.

The wind time distribution has a Weibull k parameter between 1 and 3. Logically 2 is a good default value.

Though, the GWA allows us to have a sharper evaluation of the k-parameter for Armenia, thanks to an upgraded statistical distribution of the wind.

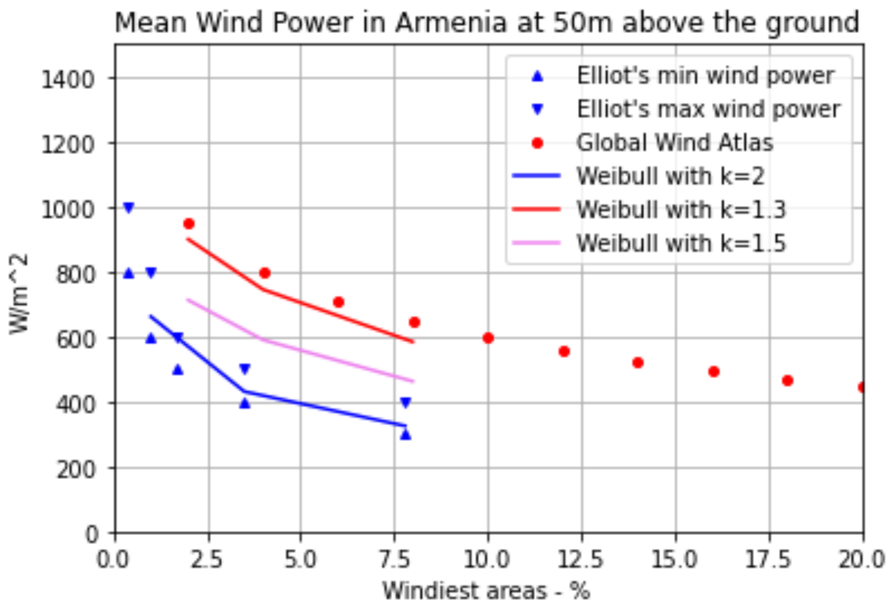


Figure 20. Mean Power production for Armenia with GWA and Elliott's scenario.

We clearly see that the Elliott's study and the GWA remain rather good correlated with the Mean Wind Speed within the 10% windiest area, a contrario we identify a clear underestimation of the Wind Power Density due to the different choice of k-parameter (2 for Elliott and ~1.3 for the GWA).

The k-parameter remains one of the most critical one, as it links the wind speed and the modelling of the power we can take from, that evolves with new technologies.

Elliot claims that about 11 000 MW full installed capacity can be reached for Armenia. Based on the same assessments (5MW/km² and wind power density >300W/m²), we can calculate what would be the capacity of Armenia with the provided updates of the GWA:

Table 8. Recap of Elliot Installed Power capacity calculation.

Wind Power	Percent windy land, %	Surface (km²)	**Elliott**
300-400W/m²	4,3	1226	6150 (=1226*5MW/km²)
400-500W/m²	1,8	503	2500
500-600W/m²	0,7	206	1050
600-800W/m²	0,6	165	850
>800W/m²	0,4	103	103
Total	**7,8**	**2205**	**11050 MW**

Following the same calculation's logic and bias related to the installed capacity per km² (5MW/km²), we can re-estimate the full installed capacity under the GWA modelling:

Table 9. GWA Installed Power Capacity calculation

Wind Power, W/m²	Percent windy land, %	Surface, km²	**GWA**
300-400	16	4544	22720 (=4544*5MW/km²)
400-500	8	2272	11360
500-600	6	1704	8520
600-800	6	1704	8520
>800	4	1136	5680
Total	**40**	**11360**	**56800 MW**

The Global Wind Atlas, with the last technology updates[46], updates the estimation of the wind capacity of Armenia calculated by Elliott by a factor of ~5.

Even with great care and minimizing of the GWA, we can easily claim that about 10 % of the Armenian territory has extremely good potential.

[46] Mnatsakanyan & Danielian, 7th International Renewable and clean Energy Conference, Erevan https://drive.google.com/file/d/1S-ut5rgPCImH--a7lnvNRuqu-8zQt-Le/view

Below 500 W/m² the productivity could be not good enough, especially for a country such Armenia that cannot afford such efficiency flexibility.

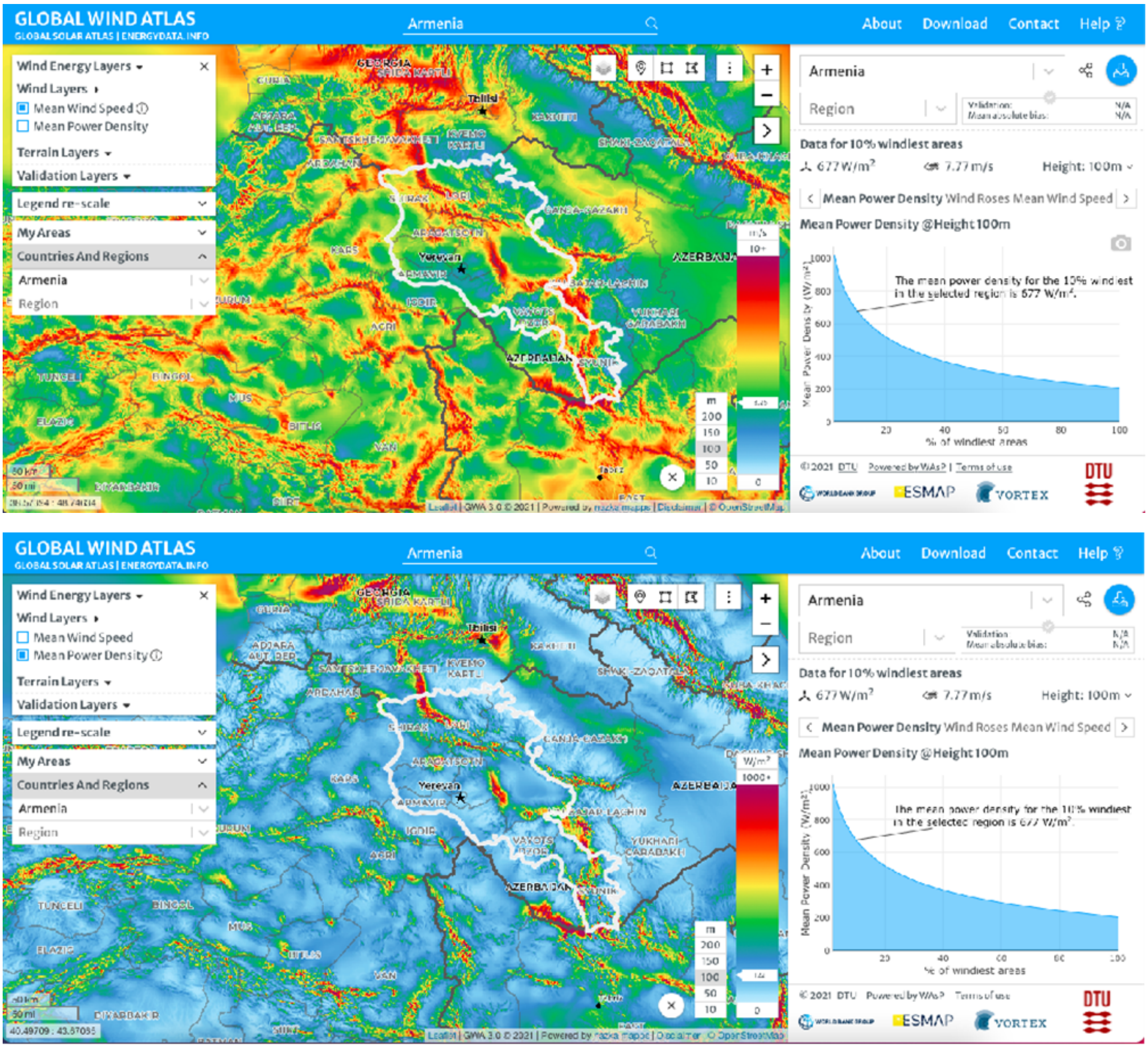
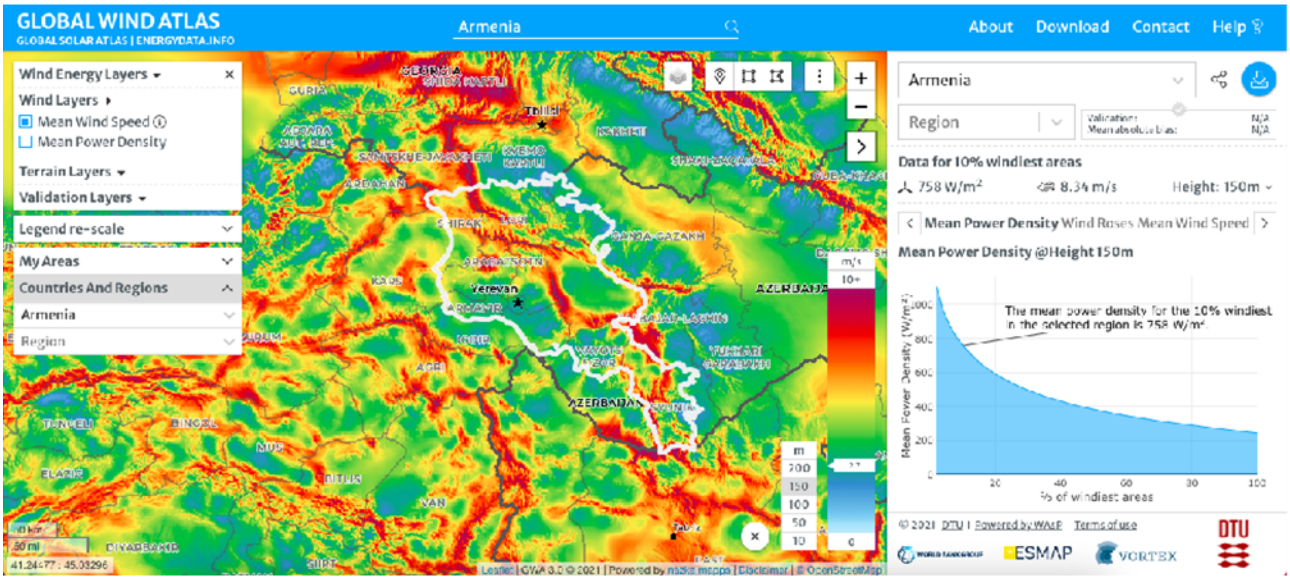


Figure 21. Figure 22. Mean Wind Speed and Mean Power Density at 100 m above the ground.

Based on the same logic, we will explore the capabilities of Armenia with higher altitude.

7.4. Analytical perspectives, 100 m and 150 m installed capacity expectations



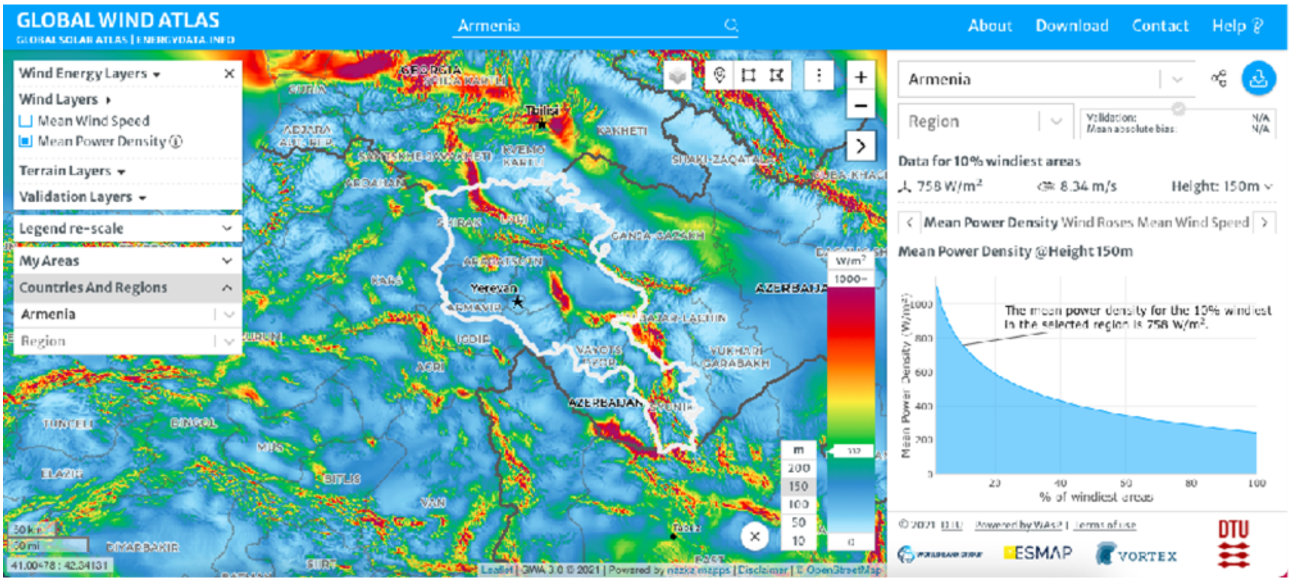


Figure 23. (top) & Figure 24. (bottom). Mean Wind Speed and Mean Power Density at 150 m above the ground.

- At 100m above the ground, we have 14% of the Armenian territory with more than 600W/m².
- At 150m above the ground, we have 18% of the Armenian territory with more than 600W/m².

7.5. Typical Case of study scenario

Wind energy should not solely be seen under the global capacity point of view. For instance, for Armenia, the goal is not to replace other source with this energy, and we should not only focus on the potential «installed capacity».

Armenia has many regions with abundant wind resources to increase wind energy production at fair prices.

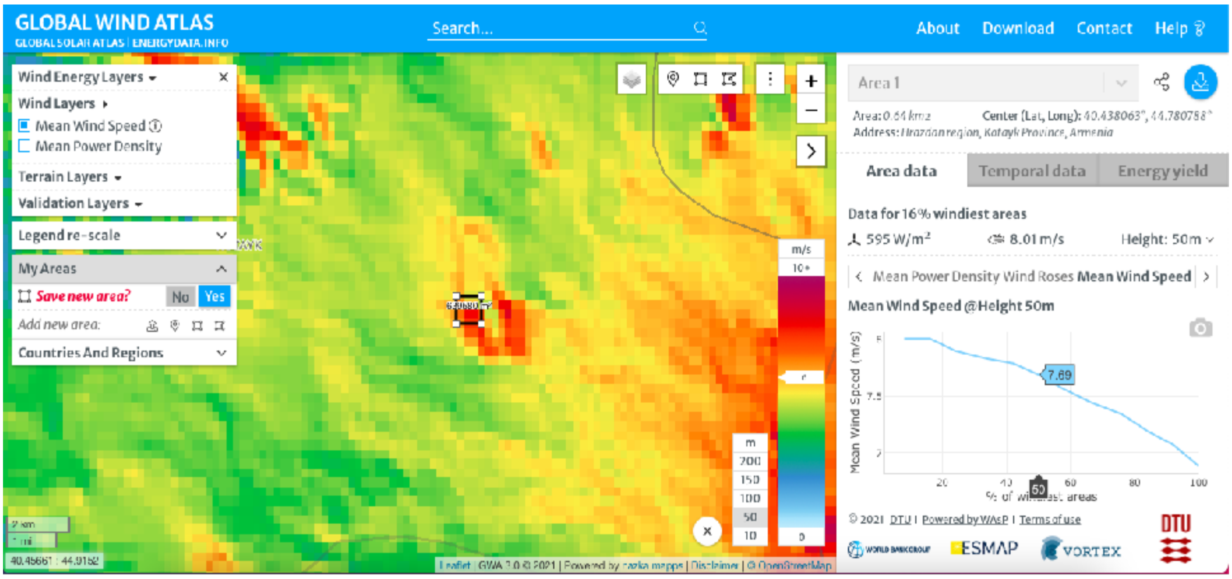
Wind turbine installations depend on numerous parameters: Windy area, transport possibilities, distance from the main grid, nature protected area, at some distance from villages.

A potential good area is located between Yerevan and Sevan Lake, 3 km south from Lernanist, having the advantage of being windy and close to industrial areas, main electric lines and transportation roads:

This area is large enough to offer multiple possibilities (10 turbines at least). It can be good example of the power production capacity calculation for a typical wind farm.

Figure 25. Area of interest western from Sevan Lake (40.428015 N; 44.784567E).

Figure 26. Area of interest west of Lake Sevan.



The typical selected area has a mean wind speed of more than 7.5m/s at 50 m above the ground, and a mean wind power of ~600 W/m².

The GlobalWindAtlas can also in this case give us a good overview of the wind intensity over a year and daytime, allowing us to foresee the potential modulation of the wind:

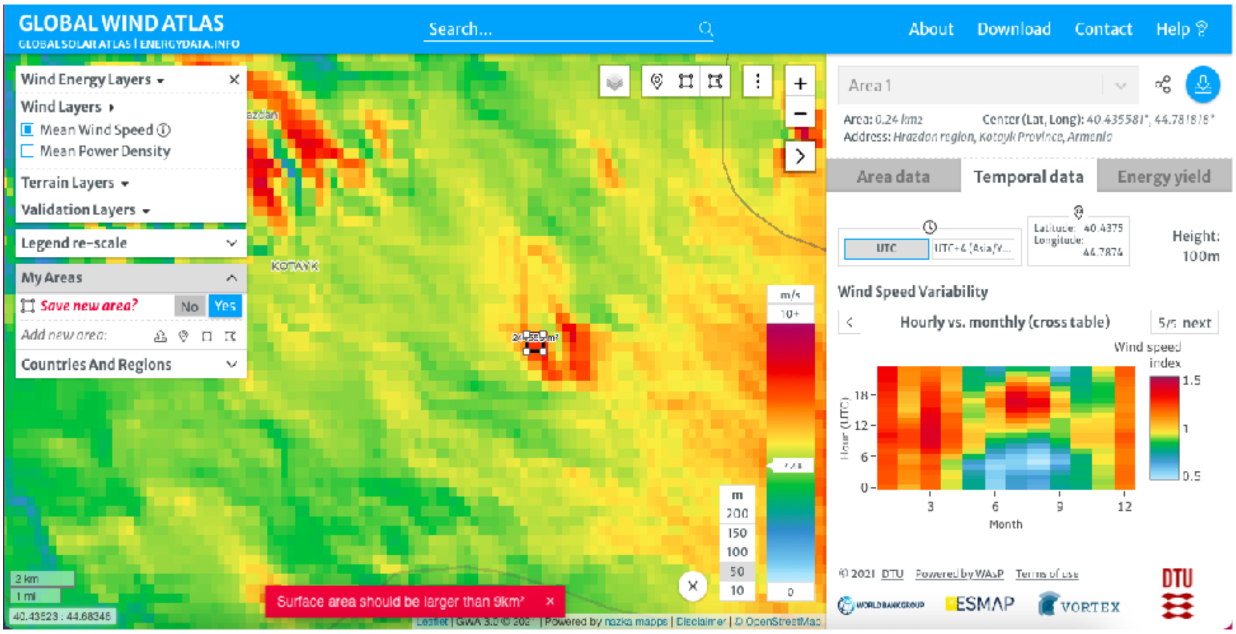


Figure 27. Wind intensity typical modulation (during the day over a year).

Due to intermittency of wind, and in order to optimize the efficiency of the grid with clever switch or modulation from one source to another, some sharp and live monitoring and forecast are necessary with meteorological mast, radar or any other method (e.g. Lidar).

This area could perfectly combine with solar panels as we foresee that the wind will blow up to 50% more than average during winter, when days are shorter and the weather is more likely to be cloudy, i.e. when solar becomes less productive.

Two websites allow us to freely estimate the typical power production[47] of various turbines in function of the air density, mean wind speed, Weibull parameter:

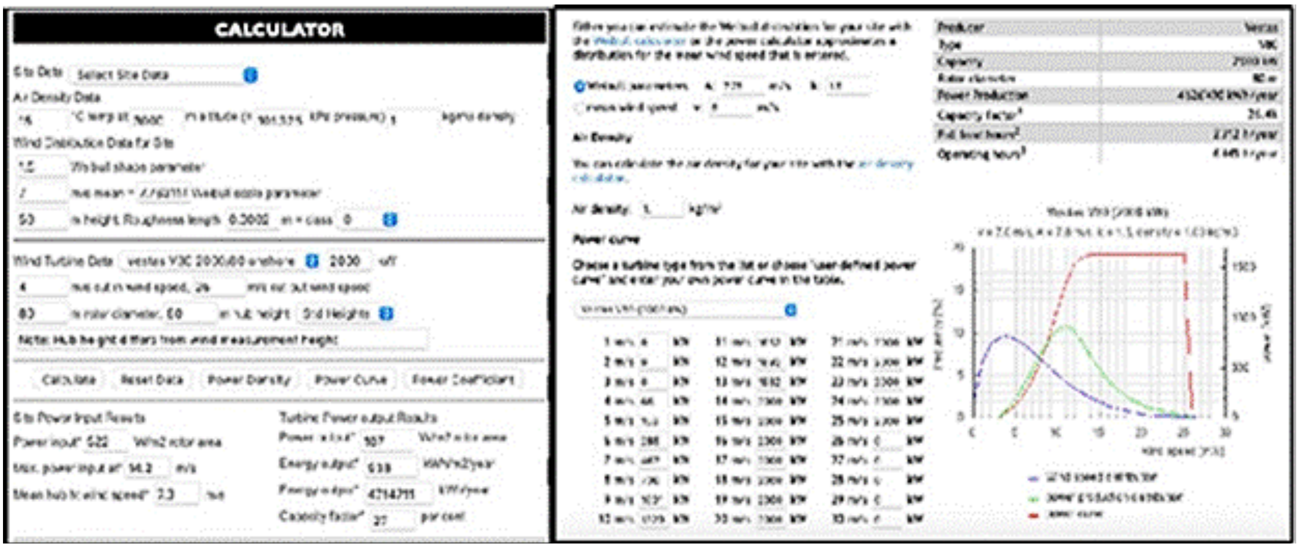
- https://wind-data.ch
- http://drømstørre.dk/wp-content/wind/miller/windpower%20web/en/tour/wres/pow/index.htm

If we choose, as a typical example of a turbine such V80 [48] (2MW), with a 50 m high mean wind speed of 7 m/s, with a Weibull parameter k = 1.5, and a roughness length close to 0:

[47] Power Production of the turbine:∫0vcutf(v)P(v)dv=∫0vcutkv(k-1)e-vkP(v)dv
With f(v) the distribution function of the wind, kv(k-1)e-vk, eq.1; and P(v) the Power curve of the considered turbine (manufacture data-sheet, in red -graphics on the right side- on the Figure 19).
[48] https://en.wind-turbine-models.com/turbines/19-vestas-v80-2.0

	drømmestrørre.dk	wind-data.ch
Full Capacity Factor	27 %	26,4 %
Power production/year	4714711 kWh/year =4.7GWh/year	4686490 kWh/year =4.7GWh/year
Full loaded hours		2312 hours/year
Operating hours		6445 hours/year (74 % of the time)

Figure 28. Rough estimation of the power production for a V80, from two different websites.



Both web sources give almost the same power production prediction, about 4.7 GWh/year.

The electricity production in Armenia reaches roughly 8000 GWh/year (all sources included, Nuclear, Gas, Hydro, Solar,…).

- One single turbine (for instance a V80 2MW), in such condition could cover 0.063% or Armenia power production.
- One wind farm of ten turbines: 0.6%
- Ten wind farms with ten turbines each (100 all in all): 6%.

More realistically, with more recent and effective material, a turbine, with a 90m hub height, such the V90 (3MW), with mean wind speed of 8m/s and a Weibull parameter k=1.5, and a roughness length close to 0:

	wind-data.ch
Full Capacity Factor	29 %
Power production/year	7642742 kWh/year =7.6 GWh/year
Full loaded hours	2546 hours/year
Operating hours	6777 hours/year (77 % of the time)

- One single turbine, in such condition could cover ~0.1% or Armenia energy production
- One wind farm of ten turbines covers 1%
- Ten wind farms with ten turbines each (100 turbines all in all) cover 10%.

The main wind turbines manufacturers[49] around the world gathers many know-hows, and not only the building of the turbines themselves. They can take care of the sitting and power production capacity forecasting, services, all in all, each step of the life of the turbine(s) can be handled by the manufacturers, and they should closely enter the loop of the integration of the wind energy for Armenia.

Furthermore, one of the big assets of renewable energies (such as sun and wind) is their ability to be pre-build, and being assembled on the site, like a Lego© construction. It reduces de facto the time to erect the ensemble (and future dismantlement) and their global cost.

7.6. Areas with the greatest and effective potential in Armenia

The wind map provided by the GWA allows a new and better overview of the area with the greatest potential. We now have to correlate them with the actual infrastructure and needs.

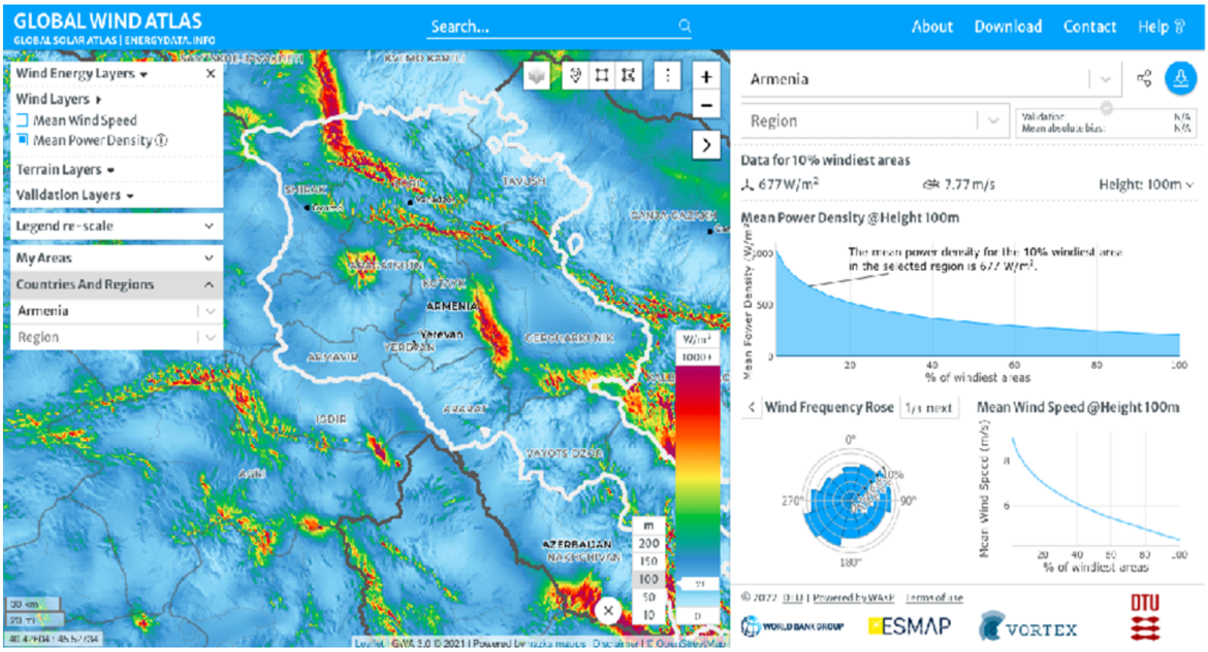


Figure 29. Power Density 100 m above the ground Mean for the northern part of Armenia.

The Syunik region, being very mountainous, is not the very best place to install some wind turbines as the windiest places are located at the top of the mountains, hardly reachable. They could and should focus on solar, or other source of energy.

[49]https://www.windpowerengineering.com/bloomberg-new-energy-finance-ranks-oems-reviews-markets/

The larger the windiest area is, the better it is, offering multiple solutions, taking in count the position of the main electric supply lines throughout the territory of Armenia. Building wind farms close to the main lines will de facto decrease the overall cost, as the wind farm need to be connected to them.

The publication made by Söderbom & al[50] gives us very precious hints about the cost of km of road in different countries, including Armenia (and Georgia that has comparable economic statistics than Armenia). We can conclude that an approximate price of 100 000 $/km is good basic to include in the total price calculation.

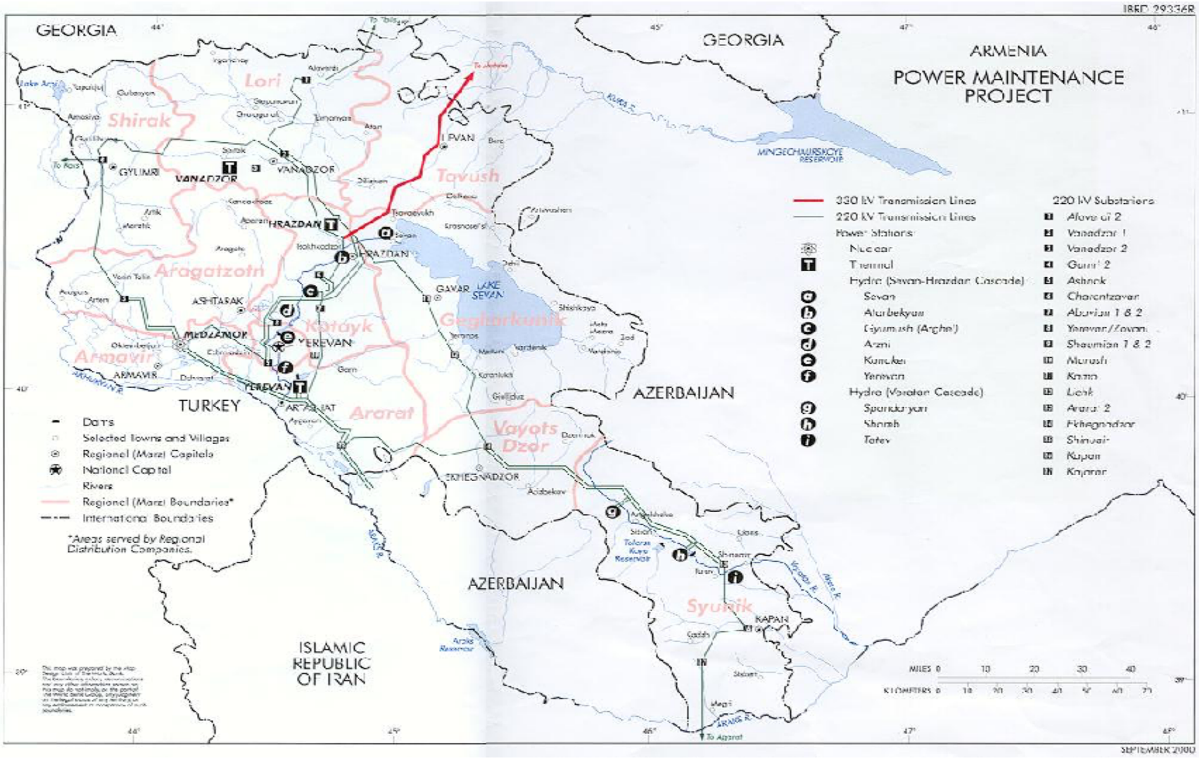


Figure 30. Main electric lines over the territory of Armenia.

The northern part gathers numerous large areas with very good potential and near to most of the population of Armenia. Road density, international connection proximity (harbor and airport) must also be taken into account, as the material, technicians, will come from abroad.

Here are a couple of areas with the greatest interest for us. They are not the only ones, but they give us a rather good overview of the areas of interest that are big enough to welcome a wind farm within the best conditions.

All calculations made with: https://wind-data.ch/.

[50] http://www.soderbom.net/13_05_02_Unit%20cost%20paper.pdf

Near Sevan lake:

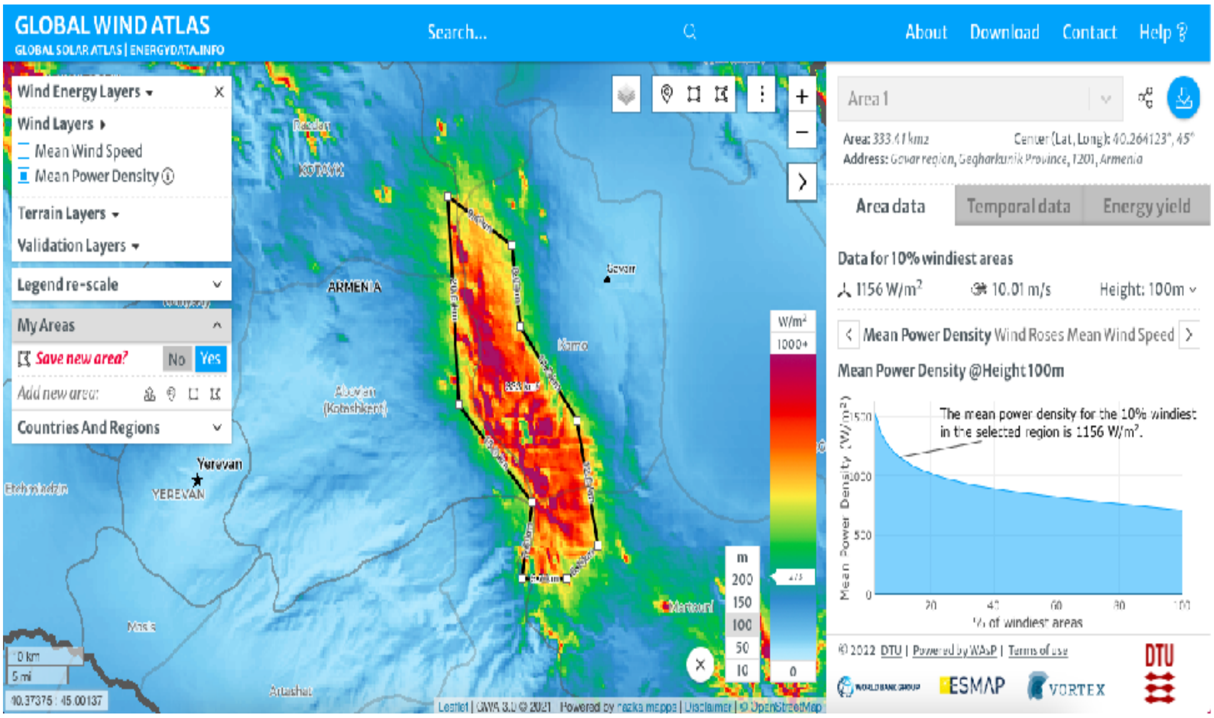
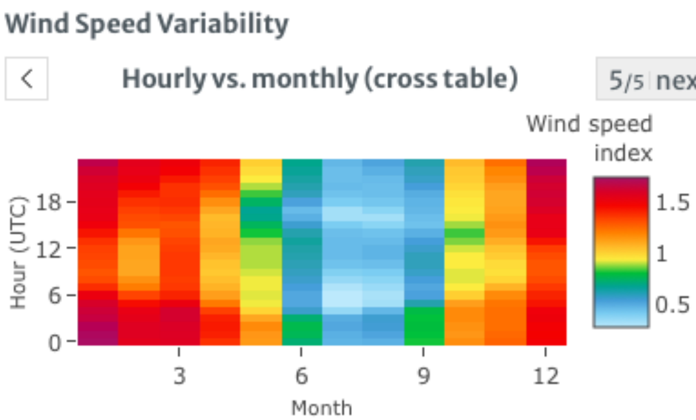


Figure 31. Sevan Lake area of interest.

- Surface: ~333 km²
- Mean wind speed: 10m/s @ 100 m above the ground
- Mean Power density: ~1156 W/m²
- Wind speed variability



	k=1.5	k=2
With a V82 (1.65 MW)	Power Production: 5.4 GWh Capacity factor: 37.5 % Full load hours: 3284 yearly Operating hours: 6626 yearly	Power Production: 6.6 GWh Capacity factor: 45.5 % Full load hours: 3984 yearly Operating hours:7634 yearly
With a V80 (2 MW)	Power Production:6.8 GWh Capacity factor:38.8 % Full load hours: 3396 yearly Operating hours: 7068 yearly	Power Production:7.8 GWh Capacity factor:44.5 % Full load hours: 3900 yearly Operating hours:7903 yearly
With a V90 (3MW)	Power Production:9.5 GWh Capacity factor:36.2 % Full load hours: 3172 yearly Operating hours:7068 yearly	Power Production: 10.8 GWh Capacity factor: 41.3 % Full load hours: 3619 yearly Operating hours: 7903 yearly

The distance between Gavar or Eranos to the Area of Interest reaches 5 to 10 km. It means that about ~7 km of road will be necessary to bring all the elements of the turbines on site. It means that about 1.000.000 $ would be needed to build the road to transport the turbines on site.

Near Aragaz:

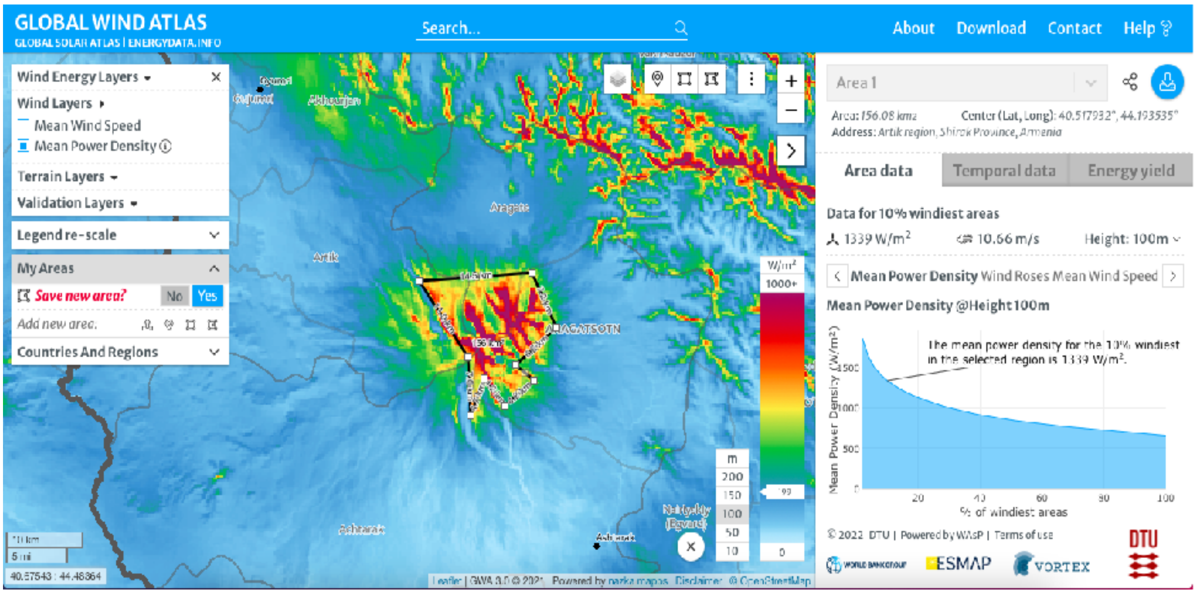
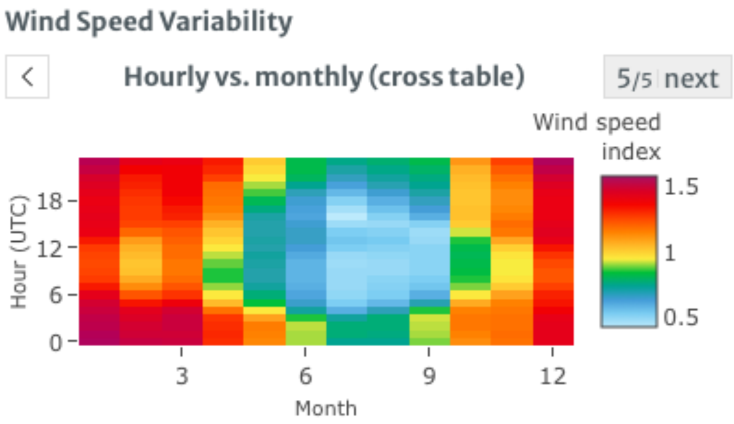


Figure 32. Mount Aragats area of interest

- Area: ~156 km²
- Mean wind speed: 10.66 m/s @ 100 m above the ground
- Mean power density: ~1339 W/m²
- Wind speed variability:



	k=1.5	k=2
With a V82 (1.65MW)	Power Production:5.5GWh Capacity factor:38.2% Full load hours: 3345/year Operating hours: 6566/year	Power Production:6.8GWh Capacity factor:47% Full load hours: 4114/year Operating hours:7569
With a V80 (2MW)	Power Production:7.08GWh Capacity factor: 40.4% Full load hours: 3535/year Operating hours: 7088/year	Power Production:8.3GWh Capacity factor:47.2% Full load hours: 4136/year Operating hours:7951/year
With a V90 (3MW)	Power Production: 9.95GWh Capacity factor: 37.8% Full load hours: 3316/year Operating hours: 7088/year	Power Production: 11.6GWh Capacity factor: 44.1% Full load hours: 3863/year Operating hours: 7951/year

A road leads directly to almost the top of Aragatz top, the H20, it means that the road construction to site would be minimal, maybe a couple of kilometers, meaning a further investment for the road to transport the turbines on site reaching 2 to 3 hundred thousand USD.

Northern Sevan-Hrazdan Line (very similar to Semenovka project)

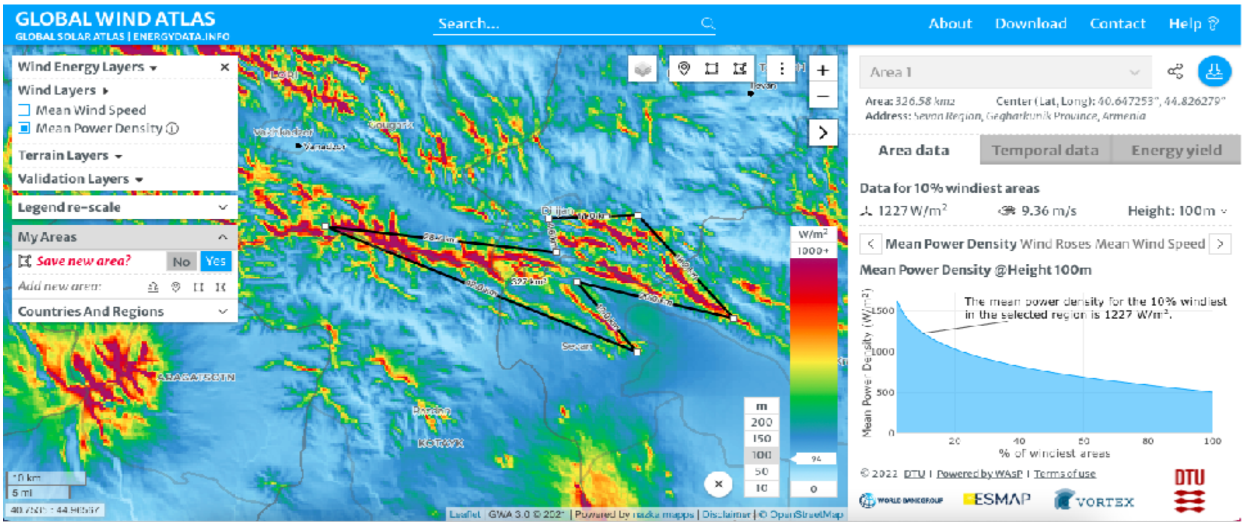
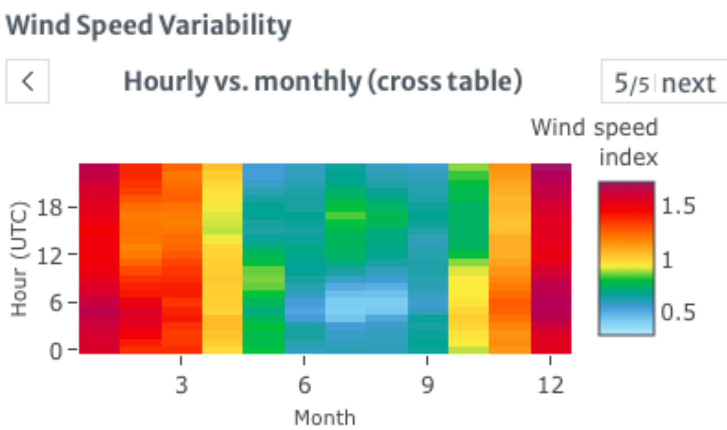


Figure 33. Sevan-Hrazdan area of interest

- Area: ~327 km²
- Mean wind speed: 9.36 m/s @ 100 m above the ground
- Mean power density: ~1227 W/m²
- Wind speed variability:



	k=1.5	k=2
With a V82 (1.65MW)	Power Production:5.3GWh Capacity factor:36.4% Full load hours: 3191/year Operating hours: 6656/year	Power Production:6.3GWh Capacity factor:43.4% Full load hours: 3802/year Operating hours:7646
With a V80 (2MW)	Power Production:6.5GWh Capacity factor: 36.9% Full load hours: 3230/year Operating hours:7015/year	Power Production:7.3GWh Capacity factor:41.4% Full load hours: 3630/year Operating hours:7823/year
With a V90 (3MW)	Power Production: 9GWh	Power Production: 10GWh

	Capacity factor:34.3% Full load hours: 3003/year Operating hours: 7015/year	Capacity factor: 38.2% Full load hours: 3343/year Operating hours: 7823/year

Here too, a roadpass nearby, the H52, allowing a good transport of each part of the turbines. Maybe a road would need to be built, but in km range or so, so, a further investment of 200 000 - 300 000$.

These three examples are very instructive as they all show, in spite of the distance between the areas, a similar trend, with very windy in winter, less during summer. This time pattern of wind intensity could perfectly fit a clever mix of the grid especially with solar energy.

Sotq (Zod)

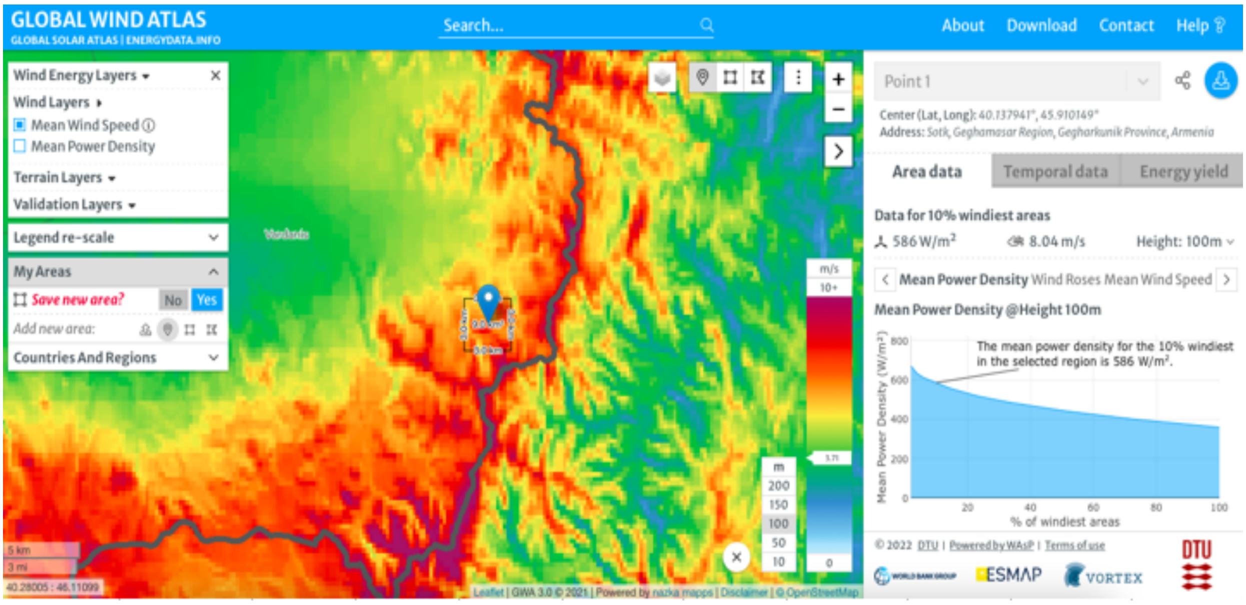


Figure 34. Zod project position

For a single turbine V90:

	k=2
1.8 MW	6027 MWh produced over one year

Karakhach

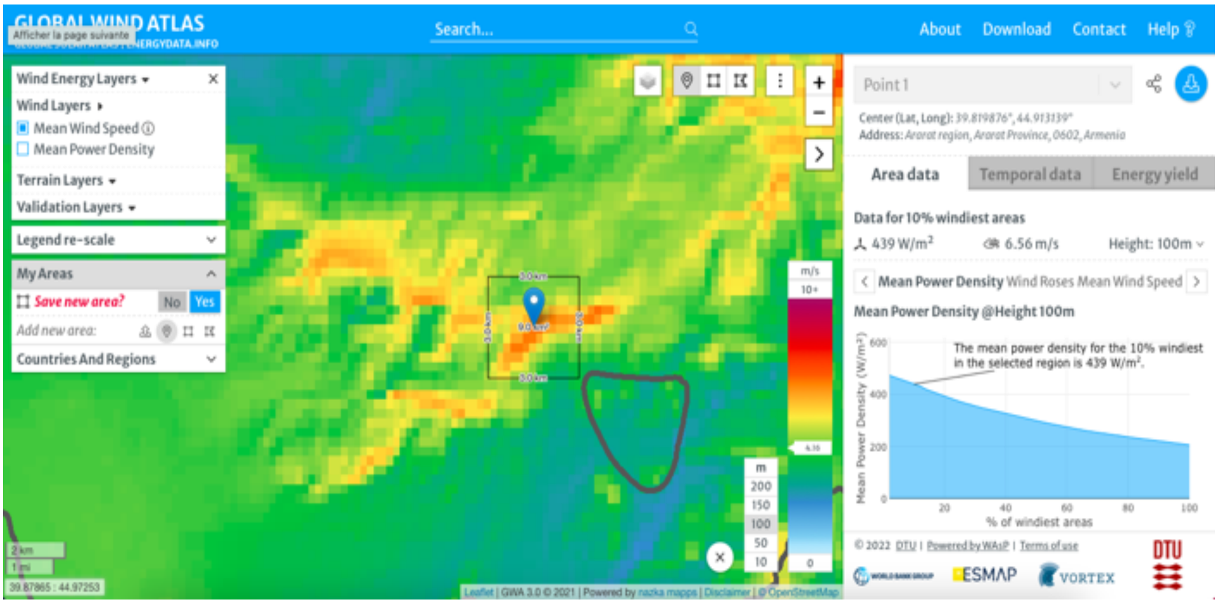


Figure 35. Karakhach project.

For a single turbine, with a mean wind speed of ~6.6 m/s

	k=2
With a V90, 1.8 MW	4487 MWh produced over one year

Syunik

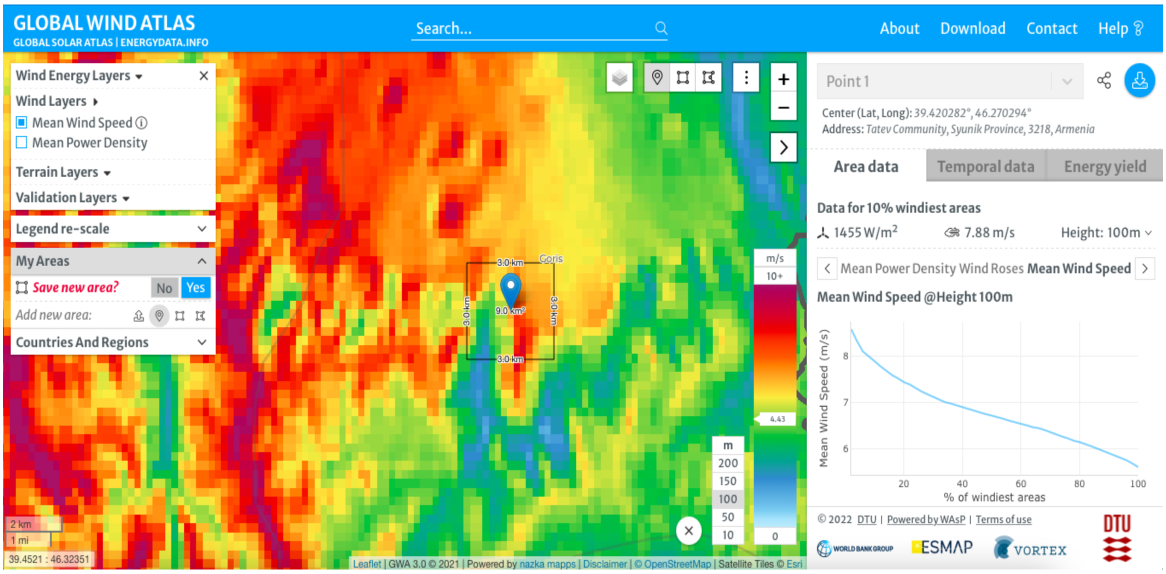


Figure 36. West and south West project in Syunik.

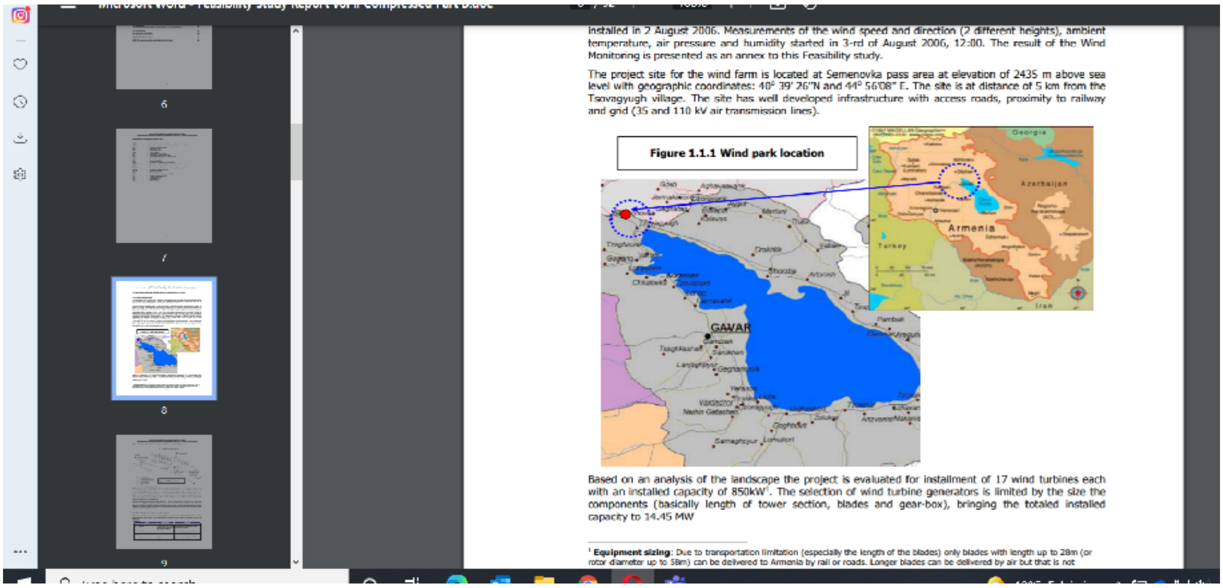
For a single turbine, with a mean wind speed of ~6.5 m/s

	k=2
With a V90, 1.8 MW	4630 MWh produced over one year

These projects are less productive of the site that we have selected. The potential is rather low, and at the top of that they are located far from any main electric lines, and with a km long road to construct in order to bring the turbines.

Nonetheless, measurements data remains absolutely necessary before erecting a wind farm. These measurements, as formerly said, can be made with direct static meteorological mast, or pseudo static Lidar to have exact and sharp, in time and space, the wind profile of the considered spot.

Interestingly, the document made in 2007, "Renewable Energy economic potential of Gehgarkunik", written in partnership with the Danish Energy Management and British Energy, a consultant company, offer numerous valuable information.



installed in 2 August 2006. Measurements of the wind speed and direction (2 different heights), ambient temperature, air pressure and humidity started in 3-rd of August 2006, 12:00. The result of the Wind Monitoring is presented as an annex to this Feasibility study.

The project site for the wind farm is located at Semenovka pass area at elevation of 2435 m above sea level with geographic coordinates: 40° 39' 26"N and 44° 56'08" E. The site is at distance of 5 km from the Tsovagyugh village. The site has well developed infrastructure with access roads, proximity to railway and grid (35 and 110 kV air transmission lines).

Figure 1.1.1 Wind park location

Based on an analysis of the landscape the project is evaluated for installment of 17 wind turbines each with an installed capacity of 850kW[1]. The selection of wind turbine generators is limited by the size the components (basically length of tower section, blades and gear-box), bringing the totaled installed capacity to 14.45 MW

[1] **Equipment sizing**: Due to transportation limitation (especially the length of the blades) only blades with length up to 28m (or rotor diameter up to 58m) can be delivered to Armenia by rail or roads. Longer blades can be delivered by air but that is not

Figure 37. Position of the wind energy project.

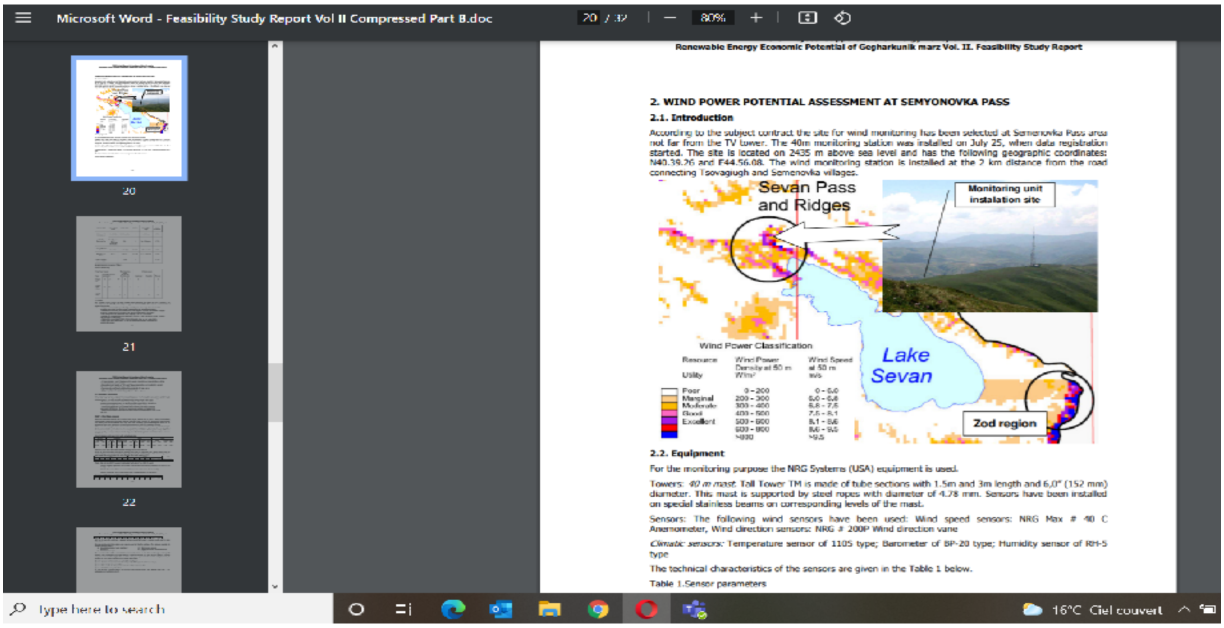
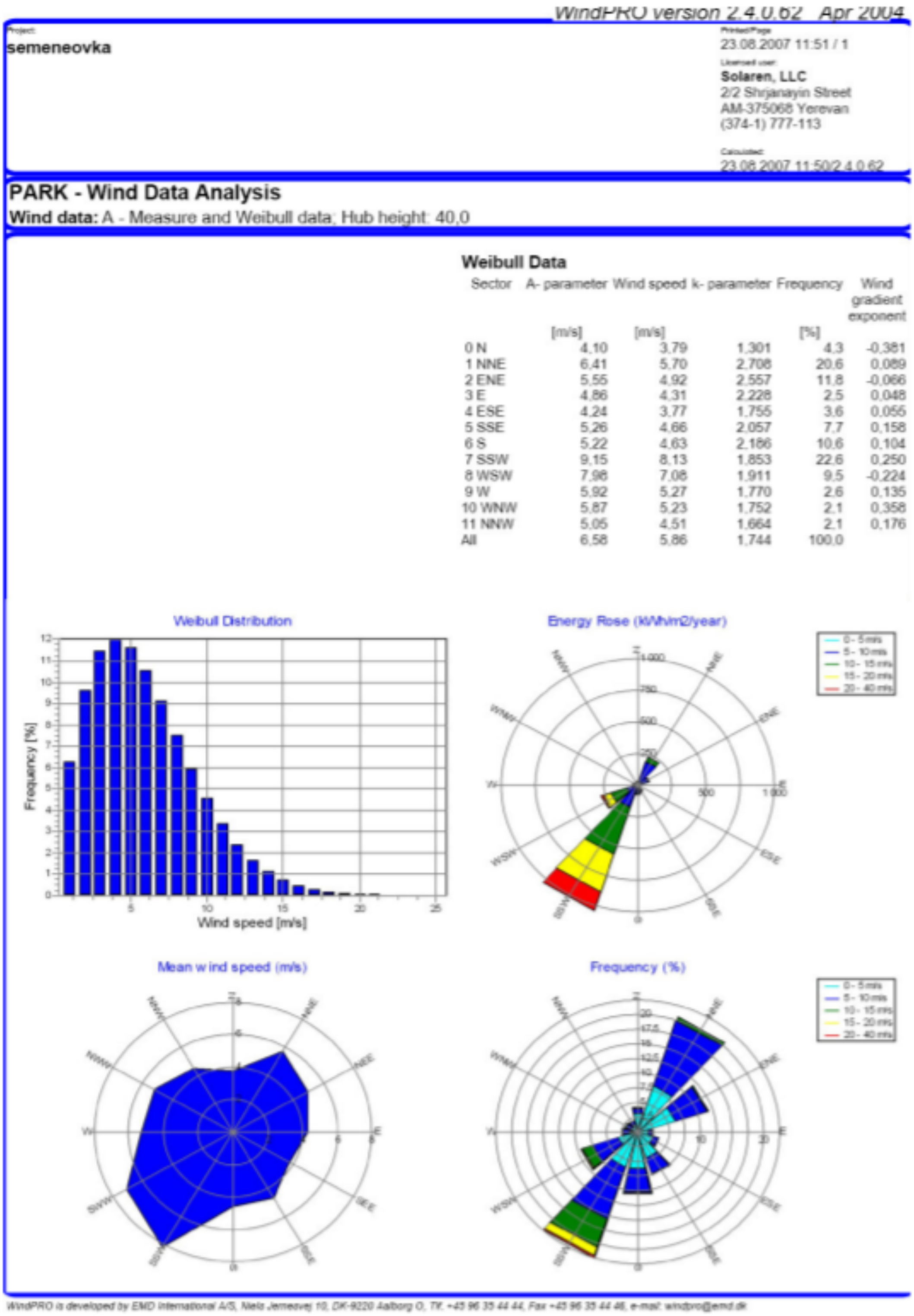


Figure 38. Position of the wind energy project with the wind map.


WindPRO version 2.4.0.62 Apr 2004

Project: semeneovka

Printed/Page: 23.08.2007 11:51 / 1

Licensed user: Solaren, LLC, 2/2 Shrjanayin Street, AM-375068 Yerevan, (374-1) 777-113

Calculated: 23.08.2007 11:50/2.4.0.62

PARK - Wind Data Analysis

Wind data: A - Measure and Weibull data; Hub height: 40,0

Weibull Data

Sector	A- parameter [m/s]	Wind speed [m/s]	k- parameter	Frequency [%]	Wind gradient exponent
0 N	4,10	3,79	1,301	4,3	-0,381
1 NNE	6,41	5,70	2,708	20,6	0,089
2 ENE	5,55	4,92	2,557	11,8	-0,066
3 E	4,86	4,31	2,228	2,5	0,048
4 ESE	4,24	3,77	1,755	3,6	0,055
5 SSE	5,26	4,66	2,057	7,7	0,158
6 S	5,22	4,63	2,186	10,6	0,104
7 SSW	9,15	8,13	1,853	22,6	0,250
8 WSW	7,98	7,08	1,911	9,5	-0,224
9 W	5,92	5,27	1,770	2,6	0,135
10 WNW	5,87	5,23	1,752	2,1	0,358
11 NNW	5,05	4,51	1,664	2,1	0,176
All	6,58	5,86	1,744	100,0	

Figure 39. Statistics of the wind distribution for the wind energy project.

The information available by the Public Service Regulatory Commission of Armenia[51] allow us to have a good overview over the past years of the relative energy of the mix.

After a couple of calculations, we can split the different sources of energy in function of the month and year as:

[51] psrc.am

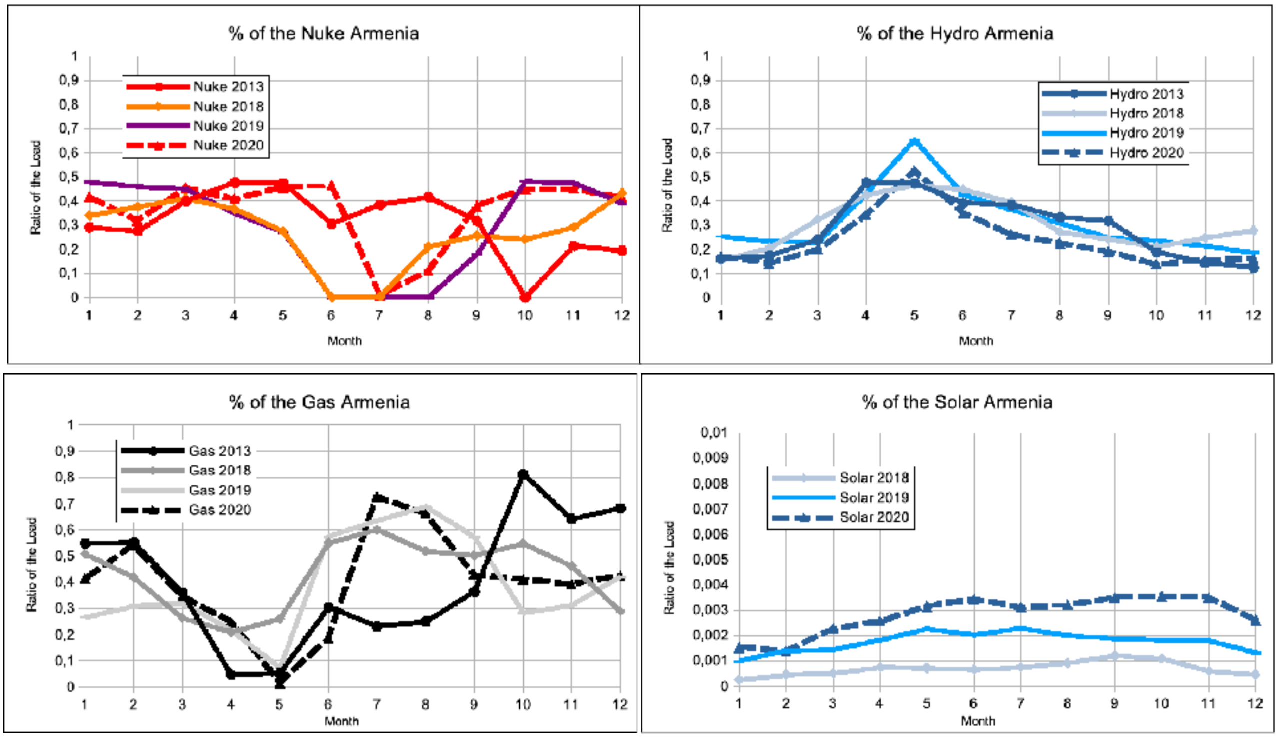


Figure 40. Mix ratio for different source of energy over a year in 2013, 2018, 2019 and 2020.

We can see that:

- Hydro remains always in duty with a peak between April and July, with almost identical mix ratio from year to year
- Nuclear and Gas remain heavily used, especially during winter, but with high fluctuation
- Solar is marginal, but constantly growing.

When we focus on the year 2020, typical in term of energy mix, we have:

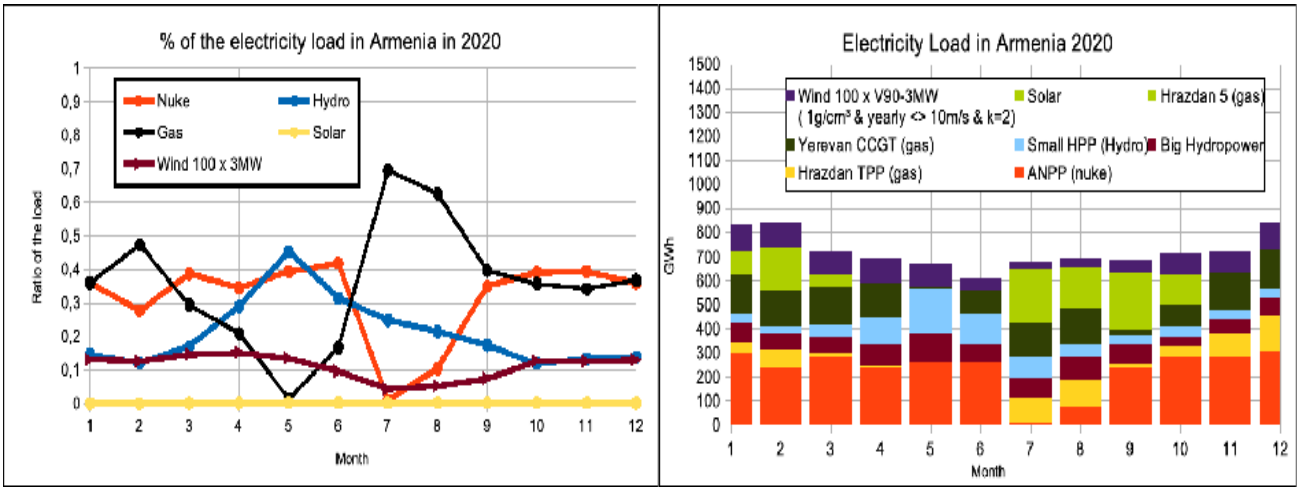


Figure 41. Mix ratio for different source of energy over a year in 2020.

Now, if we simulate 100 typical wind turbines[52] in the energy mix for this particular year (2020), we will have the following ratio in the global energy mix, taking of course in count the monthly variation of relative wind speed:

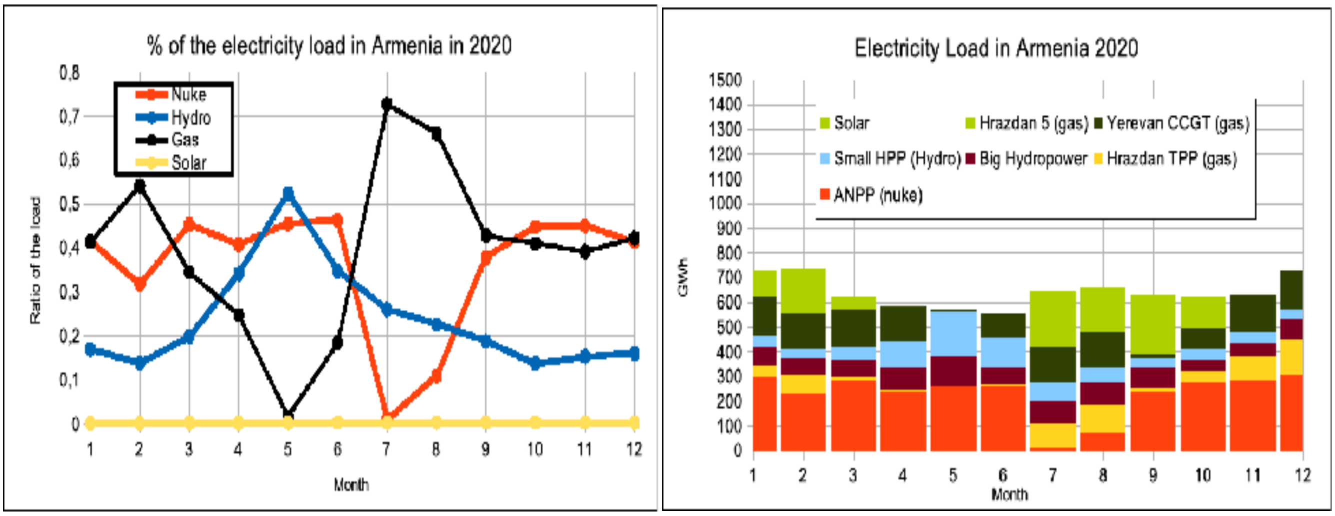


Figure 42. Mix ratio for different sources of energy over a year in 2020 with 100 wind turbines in duty.

100 Turbines with each 3 MW could cover about 15% of the electricity production of Armenia, especially during winter and autumn, spring and summer being less windy (~8%).

As Armenia welcomes a huge sun energy potential, a Solar Water Heating system will be implemented in order to cover the heating process.

According to different survey campaigns, the amount of sun during winter decreases to ~25% of summer sun radiation quantities. Days are shorter, more cloudy,

This is also the period of time when heating system are the most under stress and needed by the population.

[52] V90 3 MW with a yearly mean wind speed of 10 m/s, including monthly production variation, with an air density of 1 g/cm^3 because of the altitude.

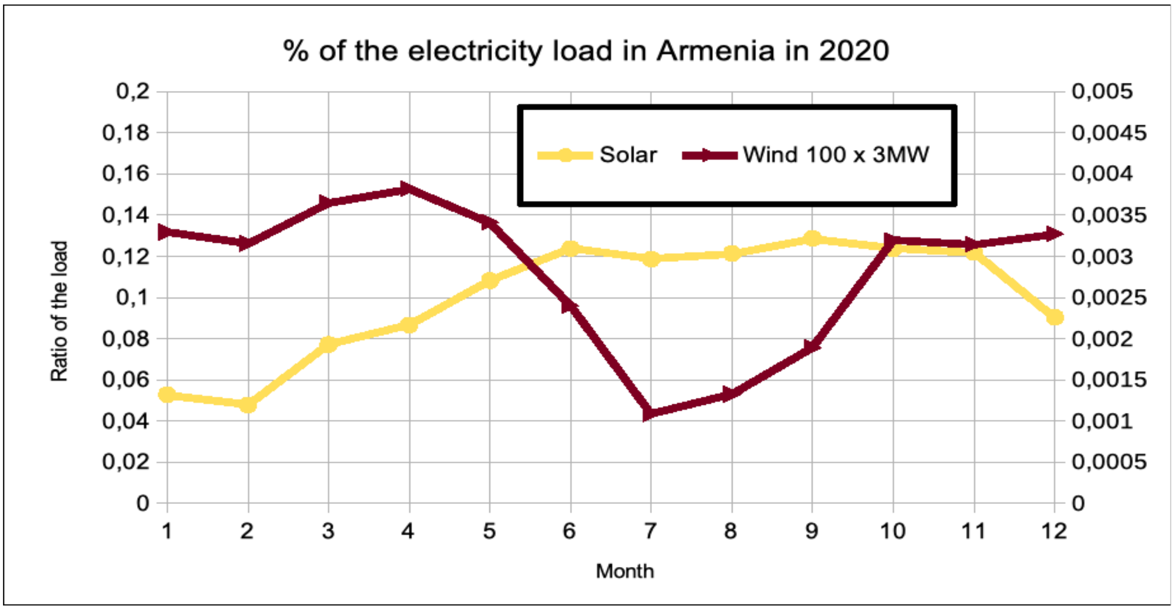


Figure 43. Ratio of energy production by Wind and Sun in 2020.

As electricity generation from Solar PV and Solar Water Heating system are based on the same principle, the variation of sun i.e. of heat production will vary in parallel.

We can see that the Wind and Sun compensate perfectly in function of the period of the year. Wind energy can compensate for the loss of the Solar heating system in winter.

7.7. Global Costs and Time Frame Estimation

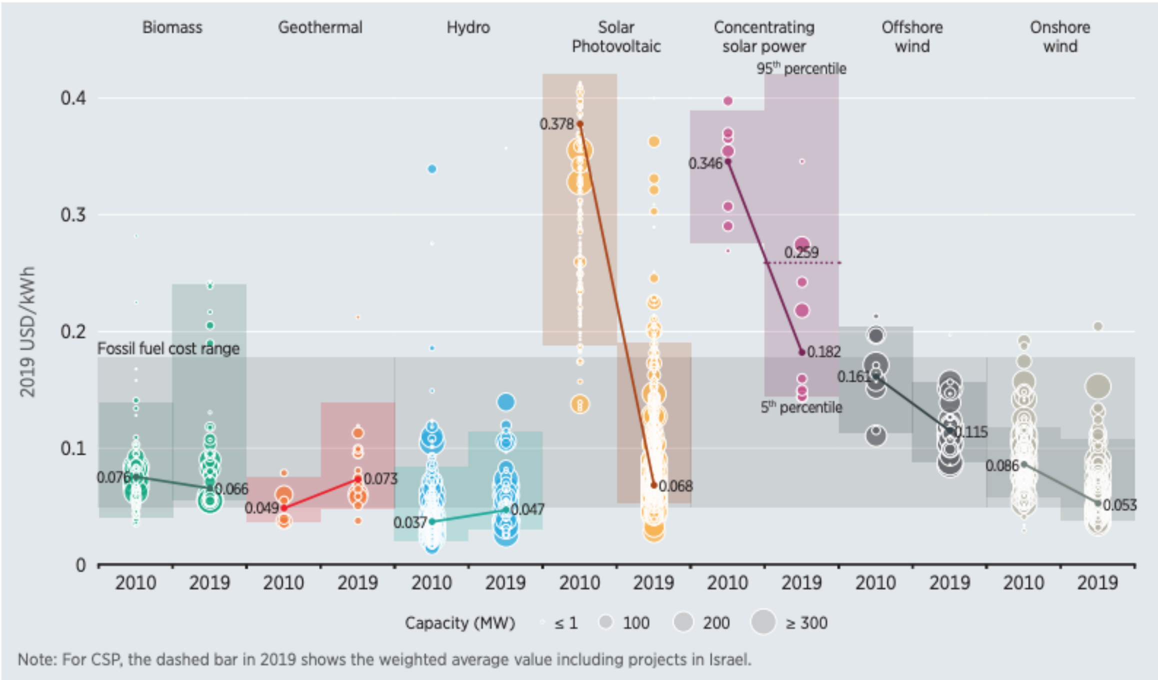
Estimating the overall costs of wind farms is complex as the cost is not directly proportional to the number of installed turbines. In fact, the larger the wind farm, the lower the overall costs per kWh. Additionally, each case is closely linked to local constraints, which further complicates the estimation process.

The market of wind energy is very flexible and open. A lot of providers, along with a huge second hand market, allow a rather good business competition in order for the clients to get the best price.

This kind of products don't come along with a price list, when directly bought from the manufacturer, as many parameters can change the final price, though, to have a rough idea of the involved amount of money, the V90 (3MW) we talk about formerly reached the price of 1 million €.

All studies regarding the LCOE[53] (Levelized Cost of Energy) of wind energy (on shore) compared to other ones, claim that this source is one of the lower other the life span of the considered power plant.

[53] https://en.wikipedia.org/wiki/Levelized_cost_of_energy



Source: IRENA Renewable Cost Database.

Note: This data is for the year of commissioning. The diameter of the circle represents the size of the project, with its centre the value for the cost of each project on the Y axis. The thick lines are the global weighted-average LCOE value for plants commissioned in each year. Real weighted average cost of capital (WACC) is 7.5% for OECD countries and China and 10% for the rest of the world. The single band represents the fossil fuel-fired power generation cost range, while the bands for each technology and year represent the 5th and 95th percentile bands for renewable projects.

Figure 44. Global LCOEs for different type of renewable energy[54].

The cost of wind energy can hardly be correctly modelled before concrete projects are set, as this type of energy can benefit from numerous international help because of the Global Warming issue. Nonetheless, as wind energy has been proved to be extremely cost efficient[55], it should also be the case for Armenia, if wisely handled.

Regarding the construction of the wind farm itself, we have to roughly take in count of the following parameters, after validation of the site made by the authorities (because of nature and landscape protection, etc) based on correct modelling after data compiling from measurements.

What	Approximate Duration	Approximate Cost
Sitting: Pre-selection of the sites thanks to different wind maps available. Modelling of the power production with different scenarios.	2 month-persons	2000 $/person/month All in all 4000 $
Measurements	6 months, better 12.	50 000$

[54] https://www.thinkgeoenergy.com/irena-renewables-cost-report-geothermal-remains-competitive-choice/
[55] https://weatherguardwind.com/how-much-does-wind-turbine-cost-worth-it/

Authorization, land renting, administration,	6 month-persons	2000$/person/month Total ~12 000$
Turbines acquisition throughout normal buying process or refurbish		~1 000 000 $ for a V90 3MW
Transport, road construction	6 months	100 000 $/km [24] as road construction is expensive
Connection to the grid, building of the lines to existing ones	2 months	~1 000 000$
Post construction service (per year per 10 Turbines over a year)		1000$/person/month ~12 000$
Total	12 months at least	The cost was reduced with a higher number of turbines, but about 1000 000 $/turbines + infrastructure construction.

The road construction represents an important part of the investment, and also rather hard to estimate. Though we can assume that the amount of 100 000 $/km is relevant[56].

If we gather all necessary information, modelling, and cost estimations for the 3 main sites that we have selected as the best to install some wind farm, we can have for each of them a rough cost per kWh.

Site 1: West from Sevan Lake

Number of Turbines	**10 x 1.6 MW**	**10 x 2 MW**	**20 x 1.6 MW**	**20 x 2 MW**
GWh/year generation (**with k=1.5**)	10 x 5.4GWh=54GWh	68	108	136
Transport + road cost	1000 000$	1000 000$	1000 000$	1000 000$
~Turbines cost + connection	10 000 000$	12 000 000$	20 000 000$	24 000 000$
~$/kWh	0.22$/kWh	0.19$/kWh	0.194$/kWh	0.184$/kWh

Number of Turbines	**10 x 1.6 MW**	**10 x 2 MW**	**20 x 1.6 MW**	**20 x 2 MW**
GWh/year generation (**with k=2**)	10 x 6.6GWh=66GWh	78	132	156
Transport + road cost	1000 000$	1000 000$	1000 000$	1000 000$
~Turbines cost + connection	10 000 000$	12 000 000$	20 000 000$	24 000 000$
~$/kWh	0.167$/kWh	0.167$/kWh	0.16$/kWh	0.16$/kWh

56 http://www.soderbom.net/13_05_02_Unit%20cost%20paper.pdf

Site 2: Aragatz

Number of Turbines	10 x 1.6 MW	10 x 2 MW	20 x 1.6 MW	20 x 2 MW
GWh/year generation (**with k=1.5**)	10 x 5.5 GWh=55 GWh	70	110	140
Transport + road cost	300 000$	300 000$	300 000$	300 000$
~Turbines cost + connection	10 000 000$	12 000 000$	20 000 000$	24 000 000$
~$/kWh	0.19 $/kWh	0.18 $/kWh	0.184 $/kWh	0.174 $/kWh
Number of Turbines	**10 x 1.6 MW**	**10 x 2 MW**	**20 x 1.6 MW**	**20 x 2 MW**
GWh/year generation (**with k=2**)	10 x 6.8GWh=68GWh	83	136	166
Transport + road cost	300 000$	300 000$	300 000$	300 000$
~Turbines cost + connection	10 000 000$	12 000 000$	20 000 000$	24 000 000$
~$/kWh	0.15$/kWh	0.148$/kWh	0.149$/kWh	0.146$/kWh

Site 3: North from Sevan Lake

Number of Turbines	10 x 1.6MW	10 x 2MW	20 x 1.6MW	20 x 2MW
GWh/year generation (**with k=1.5**)	10 x 5.3GWh=53GWh	65	106	130
Transport + road cost	200 000$	200 000$	200 000$	200 000$
~Turbines cost + connection	10 000 000$	12 000 000$	20 000 000$	24 000 000$
~$/kWh	0.192$/kWh	0.187$/kWh	0.191$/kWh	0.186$/kWh

Number of Turbines	10x1.6 MW	10x2 MW	20x1.6 MW	20x2 MW
GWh/year generation (**with k=2**)	10x6.3 GWh = 63 GWh	73	126	146
Transport + road cost	200 000 $	200 000$	200 000$	200 000$
~Turbines cost + connection	10 000 000 $	12 000 000$	20 000 000$	24 000 000$
~$/kWh	0.162 $/kWh	0.167$/kWh	0.16$/kWh	0.166$/kWh

Obviously, we get the range of estimation given by Figure 33, even though it is a higher range. We took into account the most critical parameters of the cost, transport and road, the turbine and their connection to the grid, and pondered on the energy generation per year.

The lowest price is 0.16$/kWh, reaching 0.22$/kWh at maximum. This is just a rough estimation that should be refined and sharpened.

We can also set the following schedule of installed capacities according to both lower (k=1.5 and all in all, 30 Turbines installed) and higher (k=2, 60 Turbines installed) scenarii.

	2025	**2030**	**2035**	**2040**	**2045**	**Total in 2050**
1.6MW 10x3 with k=1.5	5 Turbines 27 GWh	10 Turbines 54GWh	15 Turbines 81 GWh	20 Turbines 108 GWh	25 Turbines 135 GWh	**30 Turbines 162 GWh**
2MW 20x3 with k=2	10 Turbines 78 GWh	20 Turbines 156 GWh	30 Turbines 234 GWh	40 Turbines 312 GWh	50 Turbines 390 GWh	**60 Turbines 468 GWh**

Even though, the cost of wind turbine can become some kind of challenging, such source of energy bring a greater independence especially on the following points:

- Less dependence on gas/oil price market fluctuation and blackmail because of low price deal.
- Imported know how
- Greater environment survey
- De-concentration of energy production over the country, with multiple sources of energy.

On top of that, and very recently, the Armenian currency has seen its value increase compared to the € or the $. It means that for the same amount of Armenian dram, one can get roughly 16% more compared to early 2022, or even 2019 (pre-COVID period).

This rate has been seen once in 2008-2009, never since then:

Figure 45. Euro vs Armenian Dram over the last 5 years.

Buying on the international market becomes "cheaper" for Armenia, for now, but the rate can change drastically for Armenia, positively or negatively. But as Armenia is out of the usual change range, this parameter must be kept under sight with the greatest attention.

7.8. Potential academic partnership and main manufacturers

As formerly said, the main manufacturers[57] come from Europe and USA, even though China closely follows:

Ranking	Manufacturer	Country	website
1	Vestas	Denmark	https://www.vestas.com/en
2	General Electric	USA	https://www.ge.com/renewableenergy/wind-energy
3	Goldwind	China	https://www.goldwind.com/en/
4	Nordex	Germany	https://www.nordex-online.com/en/product/platforms/#deltaplatform
5	Siemens Gamesa	Germany/Spain	https://www.siemensgamesa.com/en-int

The choice of the turbines can be very complex, and many parameters come into play, such as politics, partnership with a specific country, second hand wind turbines, help from an international organization.

Though, one type of turbine still in production could meet Armenia's needs, and with acceptable constraints, the 2MW platform (hub height between 80 and 100m):

- From Vestas: https://www.vestas.com/en/products/2-mw-platform/V90-2-0-MW
- From GE: https://www.ge.com/renewableenergy/wind-energy/onshore-wind/2mw-platform
- From Goldwind: https://www.goldwind.com/en/assets/2efb45c18bfa7f4dd5274b008a336507.pdf

These companies also offer some services on sitting, transportation, LCOE, smart grid, and maintenance with Turn-Key solutions.

They should be involved at all stages of the project, along with all involved institutions (investors, government, academics) agreeing on every step.

Although some experience is already available with Armenian institutions with a focus on renewable energy, to enhance the overall projects and know-how academic partnerships with internationally recognized leaders should be initiated to deal with the local parameters and constraints (especially mountainous area).

Furthermore, surveys on wind and meteorological parameters with a greater time and space resolution can also be used for other purposes (micro-scale weather forecast, global warming monitoring, humidity, etc.).

The following academic institutions (non-exhaustive list) could fit within an efficient partnership, following the degree of country-to-country's alliance:

[57] https://gwec.net/gwec-releases-global-wind-turbine-supplier-ranking-for-2020/

- Greece, Center for Renewable Energy Sources and Saving:
  http://www.cres.gr/kape/index_eng.htm
- Denmark, Wind Energy Department of the Danish Technical University:
  https://windenergy.dtu.dk/english
- France, Ecole des Mines de Paris:
  https://www.persee.minesparis.psl.eu/Accueil/Presentation/
- Netherlands, Hanze University, Groningen:
  https://www.hanze.nl/eng/research/strategic-themes/energy

7.9. Conclusions

The Global Wind Atlas allows to open up new perspectives regarding wind energy potential for countries in development with few resources, allowing some precise investigation within a very short time frame.

With the help of the Global Wind Atlas, we have shown that Armenia largely underestimates its own wind power production capacity, allowing a full change of the global vision of Wind Energy for Armenia.

Thanks to this free and online tool, some very precise study case can be considered and giving a global and local sharp prediction of wind turbine potential production, prior of in situ measurements for sitting.

Actually, wind energy represents less than 1 % of the electricity production, and even less, due to maintenance problems.

We believe that with goodwill and investment support mechanisms in place, Armenia could easily meet 5 % of its electricity needs from wind power alone.

This source of energy could quickly ease small hydropower downstream of Sevan Lake, critical regarding water consumption.

Wind Energy, similar to Solar, could be a good turnkey solution to ease (and only ease) the Armenian power grid of pricey (gas) and/or critical raw material (water, nuclear) dependence.

The most critical points are the choices of the places where the wind farms could be build and their number.

The government of Armenia should define the areas by their potential capacity for energy production, in the function of all the parameters mentioned (protected area, windy spot, relative intermittence, grid proximity, etc.) to maximize the energy production with the best efficiency.

Foremost, sharp monitoring with high-frequency measurements (0.1 Hz at least) of all physical parameters (such as wind, temperature, and humidity at different heights) should be realized in order to have the best mapping of these variables, which could also be useful to monitor the global warming and become a major actor of a clever quickly switching energy grid policy.

8. HYDRO POWER

The state policy and strategic plans of the Republic of Armenia in the field of hydropower are determined by the regulatory framework and strategic development programs adopted in this area.

8.1. Legal framework

The main legal acts regulating the hydropower industry are:

- Law of the Republic of Armenia "On Energy”.
- Law of the Republic of Armenia "On Energy Saving and Renewable Energy Sources”.
- Decree of the President of the Republic of Armenia of October 23, 2013 "On approval of the concept of energy security of Armenia" NNK-182-N,
- Decree of the Government of the Republic of Armenia dated November 1, 2007, No. 1296-N “On approval of the activity program of the Ministry of Energy of the Republic of Armenia, by the provisions of the national security strategy of the Republic of Armenia”.
- Decree of the Government of the Republic of Armenia dated July 31, 2014, No. 836-N “On approval of the action plan for 2014-2020, ensuring the implementation of the provisions of the energy security concept of the Republic of Armenia”.
- The Protocol Decision “On Approving the Strategy for the Development of the Energy Sector in the Context of the Development of the Economy of the Republic of Armenia”, approved by paragraph No. 1 of the Protocol No. 24 of the meeting of the Government of the Republic of Armenia on June 23, 2005;
- The Protocol Decision "On Approval of the National Program for Energy Saving and Renewable Energy Sources of the Republic of Armenia", approved by paragraph No. 9 of the Protocol No. 2 of the meeting of the Government of the Republic of Armenia on January 18, 2007;
- The Protocol Decision "On the approval of the strategic program for the development of hydropower", approved by paragraph 12 of Protocol No. 35 of the meeting of the Government of the Republic of Armenia on September 8, 2011.
- The Protocol Decision “On approval of long-term (until 2036) ways of developing the energy system of the Republic of Armenia”, approved by paragraph 13 of Protocol No. 54 of the meeting of the Government of the Republic of Armenia on December 10, 2015.

8.2. Hydro Power Capacity Projections

The development opportunity of new HPPs according to the Hydro Energy Development Concept of RA of 29 December 2016 has mostly been completed. There is a challenge of raising the productivity of the existing SHPPs to correspond to the international technical and environmental standards.

Below are projections for the commissioning of large hydropower capacities in the medium and long term perspective, defined by the energy sector strategic documents of the Republic of Armenia.

Hydro Power Capacity Projections, MW

Power plant	2023	2027	2030	2033	2037
Loriberd HPP	66	66	66	66	66
Meghri HPP	-	-	-	-	130
Shnogh HPP	75	75	75	75	75
Small HPPs	400	400	400	400	400
Sevan - Hrazdan Hydro cascade	560	560	560	560	560
Vorotan Hydro cascade	404	404	404	404	404
Total	**1505**	**1505**	**1505**	**1505**	**1635**

Currently, the energy potential of the Debed River with its tributary Dzoraget and the Araks River remains unused.

The HPPs envisaged to build:

HPP	Progress status
Arax River: Meghri HPP (capacity 130 MW and generation around 800 million kWh yearly).	An agreement between the Government of the Republic of Armenia and an Iranian company was signed in 2010 based on the "construction-management-operation-transfer" principle. The construction has not started. The contract expired.
Debed River: Shnogh HPP (with a capacity of about 75 MW and an annual production of 300 million kWh yearly).	Construction in progress (?)
Dzoraget River: Loriberd HPP (capacity of about 66 MW, generation 200 million kWh yearly).	Construction in progress (?)

The pumped storage power plant (PSPP) is envisaged for commissioning in the master plan for the development of the energy system. The pumped storage power plant will cover the peak load of electricity exports and will become a tool for leveling the nighttime minimum load regime. A high peak electricity tariff is justified in the theory of energy economics and is widely used in international practice. The application of such an approach can significantly contribute to the reduction and/or equalization of the cost of electricity in the domestic market.

ARMENIA'S ENERGY INDEPENDENCE ROADMAP

PART 3 MODELING
THE DEVELOPMENT OF ENERGY INDEPENDENCE

Developed by: Tigran Gnuni, Aram Harutyunyan, Armen Danielyan,
Régis Danielian, Garnik Balyan, Suren Shatvoryan (Team Leader)

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1.2.1 Requirements for the Development of the Power System in Terms of the Country's Energy Independence

One of the most important factors of national sovereignty is energy independence, and the electricity sector is the core of energy independence, which is characterized by several main aspects:

- The diversified primary energy sources for the electricity generation facilities. For a landlocked country such as Armenia, the larger the diversity of such primary energy sources, the higher the energy security. Diversifying the primary energy mix is vital for increasing and sustaining energy independence.
- Developed interconnections with the power grids of neighboring countries. Interconnections are especially important for allowing for domestic variable renewable energy sources capacity generation development. Although this point may seem paradoxical, such "dependence" on the interconnections increases the country's energy security and, consequently, reduces its energy dependence.
- Development of transmission and distribution networks along with the connection of new capacities to the power system.
- Penetration and development of innovative Storage Technologies, including chemical batteries at plant and/or grid level, as well as hydro accumulative storage using the landscape and climatic conditions of Armenia.
- Integration of Smart Grid technologies into the power system that are able to predict meteorological conditions, the magnitude and rate of change of consumption, as well as for timely planning of necessary power reserves, ensuring reliable power supply and secure operation of the system.

When forecasting and planning modes of generation and development of the electric power industry, first, it is necessary to assess the rate of domestic electricity consumption. In this study, scenarios for possible future electricity consumption are presented in detail in the relevant sections.

The table below presents the estimated total volumes of domestic electricity consumption by sector and by year. [1]

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[1] The methodology for calculating electricity demand by consumption sector is based on regression equations based on historical data trends for 2007-2022 posted on the official website of the RA Public Services Regulatory

Table 1. Electricity demand forecast for 2025 - 2050, M kWh.

Consumption by	2025	2030	2035	2040	2050
Agriculture	132	121	111	102	102
Industry	2,401	2,686	3,005	3,362	4,064
Service	1,158	1,239	1,326	1,420	1,604
Population	2,161	2,355	2,567	2,798	3,253
Transport	79	70	62	55	55
Non-specified	443	536	647	782	1,043
TOTAL	6,374	7,007	7,718	8,518	10,120
%	9.71	9.93	10.15	10.37	18.81

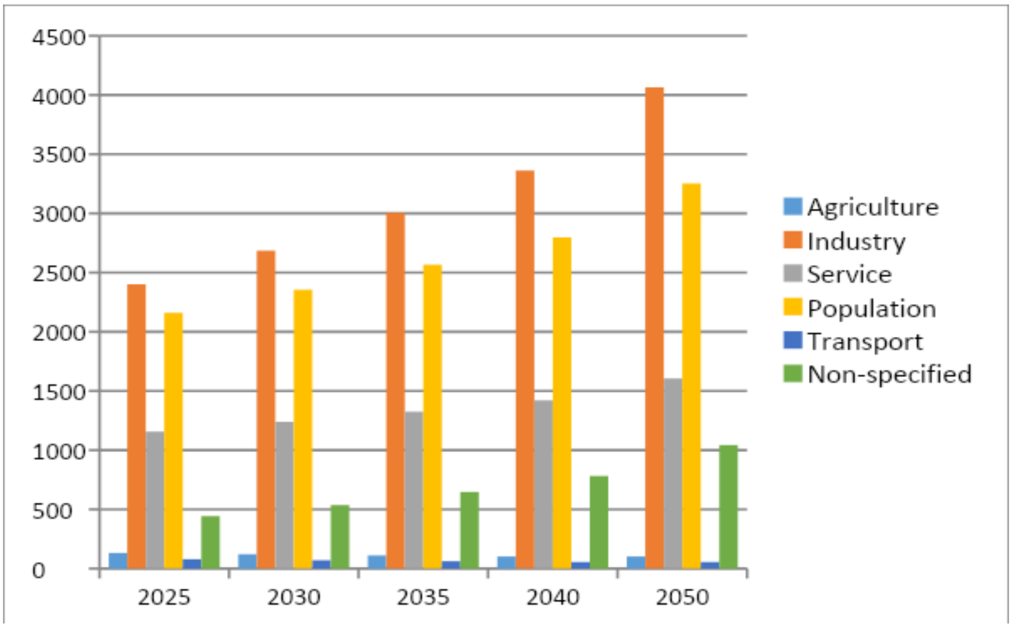

Figure 1. Electricity demand forecast 2025 - 2050, Mln. kWh.

Modeling, calculation and development of the results were carried out based on the highest consumption growth scenario, to identify the most problematic regime situations, according to the demand and supply forecasts and problems considered.

In the process of the development of the "Armenia’s Energy Independence Roadmap", there were considered and taken into account the RA Government's legal acts and regulations such as “The Strategic Development Plan of the Republic of Armenia till 2040”, the “Rules for Transmission and Distribution Grids”, the requirements for the development of the "Ten Year Network Development Plan" and the requirements for forecasting and planning of system regimes.

Commission and described in chapter «Forecast of domestic energy demand in the Republic of Armenia for 2025-2040/50» of this report.

1.2.2 Predictive Balances of the Power System from the Point of View of the System Reliability and Safety

In order to evaluate the regimes and trends of the electric power system for the energy independence plan, prognostic power balances for 2025, 2030, 2035, 2040 and 2050 have been developed. The power system development plan is designed with consideration of the requirements for the power system's reliability and the safety of power installations and equipment.

The forecast of electricity balances is based on the actual modes of the RA energy system in 2021.

For every period under consideration, generation balances were developed for the peak regime (evening peak demand, at 19:00-22:00), semi-peak regime (daytime, 12:00-15:00 with the *highest solar generation*), and minimum regime (night time, 01:00-05:00, when consumption is at its lowest), as representative regimes throughout the day. The results are shown in the tables below.

The balances presented below show the trends of new capacity introductions to Armenia's power systems, as well as development of interconnections. The rate of renewable capacity development is directly linked to the rate of interconnection developments. Based on international experience, in terms of system sustainability and security, the share of renewable sources should not exceed 15 % of generation for isolated energy systems; otherwise, the operation and overall maintenance of the system will be problematic in terms of ensuring the specified technical indicators. Therefore, the advanced development of Armenia's interconnections with neighboring Iran and Georgia must be a precondition for the development of domestic renewable resources for energy independence purposes. Otherwise, the threshold of 15 % of renewable energy is unlikely to be exceeded.

1.3 Power balance 2025

The table below shows the balances of the three regimes characteristic for the year 2025.

Table 2. Power balance for 2025, MW.

	2025		**Winter**	**Summer**	**Spring**
	Power Plant		**Peak (evening peak)**	**Semi-peak**	**Minimum**
1	**ANPP**	ANPP-440	430	360	400
		ANPP-1000			
2	**TPP**	Hrazdan Unit 5	0	0	0
		Yerevan CCGT	225	180	210
		ArmPower CCGT	254	160	210
3		Sevan HPP	0	15	0

	2025		Winter	Summer	Spring
	Power Plant		**Peak (evening peak)**	**Semi-peak**	**Minimum**
	International Power Corporation (IPC) Hydro Cascade	Hrazdan HPP	0	36	0
		Argel HPP	55	65	0
		Arzni HPP	22	15	0
		Kanaqer HPP	23	24	5
		Yerevan HPP	25	22	5
4	**Contour Global Hydro Cascade**	Spandaryan HPP	38	0	0
		Shamb HPP	160	0	0
		Tatev HPP	111	0	15
5	**Small HPP (SHPP)**		85	150	205
6	**Solar PV Power Plants (SPP)**	Masrik-1	0	51.7	0
		AYG-1	0	188	0
		AYG-2	0	0	0
		5 sites (with total capacity 120 MW)	0	0	0
		Solar PV plants commissioned and planned by PSRC	0	197.76	0
		Solar PV other potential	0	0	0
7	**Total Solar PV Commercial**		0	437.46	0
8	**Wind Power Plant (WPP)**	Acciona	-	-	-
		Semyonovka	-	-	-
		Zod	-	-	-
		Karakhach 1 pass	-	-	-
		Karakhach 2 pass	-	-	-
		Syuniq	-	-	-
		In service WPP (as of 2021)	6.3	1.5	3.2
9	**Total Wind Power Plant**		6.3	1.5	3.2
10	**Total Power Plants, Σ**		1434	1466	1053

	2025		Winter	Summer	Spring
	Power Plant		**Peak (evening peak)**	**Semi-peak**	**Minimum**
11	Domestic Demand		1258	1036	435
12	**Solar PV residential**		0	136.2	0
13	**Interconnections**	Iran	-176	-566	-618
		Georgia	0	0	0

Based on current progress of the transmission infrastructure development, it is expected that the substation Ddmashen 400 kV, the high voltage line Ddmashen 400 kV to Ayrum substation and the 400 kV high voltage direct current (HVDC) converter substation will not be commissioned until 2025. According to the “Republic of Armenia Energy Sector Strategic Development Plan till 2040”, the new 400 kV interconnection between Armenia and Iran should be put into operation by 2025. The regime planning calculations show that in the case of the implementation of the abovementioned scenarios, the Armenia-Iran 400 kV transmission line to the Noravan 400 kV substation will transmit up to 550 MW of power to the Iranian system. An important point is that in the case of simultaneous operation of the currently operating 220 kV together with the planned 400 kV line the total capacity of interconnection between Armenia and Iran will be about 1200 MW.

It should also be noted that the Hrazdan-5 unit is not presented in the balance sheet because of the shutdown for re-equipment during 2021 - 2022. However, the Hrazdan-5 unit will work as a backup power plant until the 400 kV Armenia-Iran interconnection will be commissioned, mainly in the event of halting the operation of the ANPP or any other thermal power plant in the RA power system.

According to the forecast, by 2025 the entry of new renewable energy capacities into the system is quite rapid; these new entries include licensed solar plants of up to 5 MW and large grid connected plants. By 2025, Masrik 55 MW, Ayg-1 200 MW, and 5 smaller solar PV plants with a total installed capacity of 120 MW are expected to enter the system. According to the preliminary forecasts, the entry of the 200 MW solar plant Ayg-1 into the system may be delayed. However, in order to assess the network capacity, the entry of the latter was considered in 2025. Residential solar plants with a capacity of up to 150 kW are also being developed. It should be noted that in the case of residential solar plants, the amount of total capacity presented in the balance sheet is the value that will have an impact on the power system in the semi-peak mode.

Wind energy development is not present till 2030 due to the system capacity and self-sufficiency factors, as well as by its low competitiveness and attractiveness for the RA government compared to solar energy potential, whereas the wind capacities are promising.

In terms of nuclear and thermal power plants, no new entries are foreseen for this period.

1.4 Power balance 2030

The table below shows the balances of the three regimes characteristic for the year 2030.

Table 3. Power balance for 2030, MW.

	Power Plant		2030		
			Winter	**Summer**	**Spring**
			Peak (evening peak)	**Semi Peak**	**Minimum**
1	**ANPP**	ANPP-440	420	385	400
		ANPP-1000			
2	**TPP**	Hrazdan Unit 5	420	300	300
		Yerevan CCGT	225	195	210
		ArmPower CCGT	254	240	250
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	0	15	0
		Hrazdan HPP	0	36	0
		Argel HPP	55	65	0
		Arzni HPP	22	15	0
		Kanaqer HPP	23	24	5
		Yerevan HPP	25	22	5
4	**Contour Global Hydro Cascade**	Spandaryan HPP	38	76	0
		Shamb HPP	160	160	0
		Tatev HPP	111	86	64
5	**Small HPP (SHPP)**		85	150	205
6	**Solar PV Power Plants (SPP)**	Masrik-1	0	51.7	0
		AYG-1	0	188	0
		AYG-2	0	188	0
		5 sites (with total capacity 120 MW)	0	112.8	0
		Solar PV already commissioning and planning by PSRC	0	197.76	0
		Solar PV other potential	0	107.74	0
7	**Total Solar PV Commercial**		0	846	0

	Power Plant		2030		
			Winter	Summer	Spring
			Peak (evening peak)	Semi Peak	Minimum
8	**Wind Power Plant (WPP)**	Acciona			
		Semyonovka			
		Zod			
		Karakhach 1 pass			
		Karakhach 2 pass			
		Syuniq			
		In service WPP (as of 2021)	6.3	1.5	3.2
9	**Total Wind Power Plant**		6.3	1.5	3.2
10	**Total Power Plants, Σ**		1844	2617	1442
11	**Domestic Demand**		1382	1139	478
12	**Solar PV residential**			162	
13	**Interconnections**	Iran	-112	-1290	-614
		Georgia	-350	-350	-350

According to the estimates, by 2030 the 400 kV interconnection, that is the Ddmashen – Ayrum HVDC substations, will be put into operation. Therefore, the capacity of Armenia-Iran interconnection will reach its maximum possible limit. The Armenia-Georgia interconnection through the 400 kV substation of the HVDC in the first stage is planned with an installed capacity of 350 MW.

Solar power plants will continue to connect to the Armenian energy system, in particular, with an installed capacity of up to 5 MW and the AIG-2 solar power plant with a capacity of 200 MW. The development of residential solar plants will also continue.

As mentioned, new developments in wind energy are not planned until 2030.

In the balance for 2030, the Hrazdan 5-unit also appears among the thermal power plants as the 400kV Armenia – Iran new interconnector assumed operational.

1.5 Power Balance 2035

The table below shows the balances of the three regimes characteristic for the year 2035.

Table 4. Power balance for 2035, MW.

	Power Plant		2035		
			Winter	**Summer**	**Spring**
			Peak (evening peak)	**Semi Peak**	**Minimum**
1	**ANPP**	ANPP-440	420	385	400
		ANPP-1000			
2	**TPP**	Hrazdan Unit 5	420	360	300
		Yerevan CCGT	225	195	210
		ArmPower CCGT	254	240	250
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	0	15	0
		Hrazdan HPP	0	36	0
		Argel HPP	55	65	0
		Arzni HPP	22	15	0
		Kanaqer HPP	23	24	5
		Yerevan HPP	25	22	5
4	**Contour Global Hydro Cascade**	Spandaryan HPP	38	76	0
		Shamb HPP	160	160	0
		Tatev HPP	111	86	64
5	**Small HPP (SHPP)**		85	150	205
6	**Solar PV Power Plants (SPP)**	Masrik-1	0	51.7	0
		AYG-1	0	188	0
		AYG-2	0	188	0
		5 sites (with total capacity 120 MW)	0	112.8	0
		Solar PV already commissioning and planning by PSRC	0	197.76	0
		Solar PV other potential	0	107.74	0
7	**Total Solar PV Commercial**		0	846	0
8	**Wind Power Plant (WPP)**	Acciona	160	80	160
		Semyonovka	27.2	13.6	27.2
		Zod	16	8	16

	Power Plant		2035		
			Winter	Summer	Spring
			Peak (evening peak)	Semi Peak	Minimum
		Karakhach 1 pass	16.8	8.4	16.8
		Karakhach 2 pass			
		Syuniq			
		In service WPP (as of 2021)	6.3	1.5	3.2
9	**Total Wind Power Plants**		226.3	111.5	223.2
10	**Total Power Plants, Σ**		2064	2787	1662
11	Domestic Demand		1523	1254	526
12	**Solar PV residential**			210.6	
13	**Interconnections**	Iran	-191	-1043	-786
		Georgia	-350	-700	-350

In order to diversify the domestic energy mix, the Armenia-Georgia 400kV HVDC substation will continue expanding with another 350 MWs capacity. As a result, the total installed capacity of the HVDC will reach 700 MW. The relevance of the development of interconnections to Georgia is due to the construction of an underwater power transmission cable line from Georgia to Romania through the Black Sea, in order to supply electricity to Europe. Under these forecasts, Armenia's participation in that program is very important, especially for the export of electricity produced domestically with new capacities in semi-peak regimes, for which it is necessary to have a strong interconnection with the energy system of Georgia. In that case, the third stage of the development of the HVDC will also be possible, adding another 350 MW, bringing the total installed capacity of the HVDC to 1050 MW.

No new licensed solar capacity is planned to enter the system for 2035. The development of residential solar plants in the on-grid version is anticipated up to 2040 and 2050, but not in large volumes. This is due to the fact that the participation of residential solar plants in the grid takes place by transmitting electricity from low voltage level to high, mainly starting in 0.38 kV and in some cases 6(10) kV networks, which has a number of negative consequences if the output of those residential installations is not consumed at its own voltage level. In particular, a significant increase in electricity losses along the entire length of the power transmission, and a decrease in the quality of the supplied electricity, which for the prevention requires strengthening the elements of the distribution and transmission networks - power lines, transformers, and other electrical equipment, which needs for additional investments, and may require an increase in tariffs. The residential on-grid solar power plant capacity is anticipated to be about 320 MW.

The entry of new wind energy capacities into the energy system is foreseen in 2035. The power balance was developed based on the wind potential for the locations where the corresponding studies for the assessment of the technical and economic values of the available wind power potential have been made. If new promising wind energy projects are identified, this will not lead to fundamental discrepancies in part of this roadmap, because we are assessing the ability of the system to absorb new wind capacity. Therefore, we consider the entry of Acciona 200 MW, Semyonovka 34 MW, Zod 20 MW, Karakhach-1 20 MW into the power system until 2035.

1.6 Power balance 2040

The table below shows the balances of the three regimes characteristic for the year 2040.

Table 5. Power balance for 2040, MW.

	Power Plant		2040		
			Winter	**Summer**	**Spring**
			Peak (evening peak)	**Semi Peak**	**Minimum**
1	ANPP	ANPP-440			
		ANPP-1000	980	800	870
2	TPP	Hrazdan Unit 5	420	280	300
		Yerevan CCGT	225	180	210
		ArmPower CCGT	254	180	250
3	International Power Corporation Hydro Cascade (IPC)	Sevan HPP	0	15	0
		Hrazdan HPP	0	36	0
		Argel HPP	55	65	0
		Arzni HPP	22	15	0
		Kanaqer HPP	23	24	5
		Yerevan HPP	25	22	5
4	Contour Global Hydro Cascade	Spandaryan HPP	38	76	0
		Shamb HPP	160	160	0
		Tatev HPP	111	86	64
5	Small HPP (SHPP)		85	150	205
6		Masrik-1	0	51.7	0

	Power Plant		2040		
			Winter	Summer	Spring
			Peak (evening peak)	Semi Peak	Minimum
	Solar PV Power Plants (SPP)	AYG-1	0	188	0
		AYG-2	0	188	0
		5 sites (with total capacity 120 MW)	0	112.8	0
		Solar PV already commissioning and planning by PSRC	0	197.76	0
		Solar PV other potential	0	107.74	0
7	**Total Solar PV Commercial**		0	846	0
8	Wind Power Plant (WPP)	Acciona	160	80	160
		Semyonovka	27.2	13.6	27.2
		Zod	16	8	16
		Karakhach 1 pass	16.8	8.4	16.8
		Karakhach 2 pass	144	72	144
		Syuniq			
		In service WPP (as of 2021)	6.3	1.5	3.2
9	**Total Wind Power Plant**		370.3	183.5	367.2
10	Total Power Plants, Σ		2768	3119	2276
11	Domestic Demand		1681	1384	581
12	Solar PV residential			210.6	
13	**Interconnections**	Iran	-387	-1245	-995
		Georgia	-700	-700	-700

One of the guarantees of ensuring the energy independence and development of RA is the provision of continuous trends in the development of nuclear energy. Therefore, we note that at the time of decommissioning of the current 440 MW NPP in 2036, a new NPP with an installed capacity of about 1000 MW should already be in operation in the Armenian power system. Under high dependence on imported gas, a new nuclear power plant will substantially strengthen the reliability and safety of the power system operation on its way to increasing energy independence. The roadmap provides that by 2040, a new nuclear power plant with an installed capacity of about 1000 MW should be put into operation. The capacity of the new nuclear power units is a very complex and multi-faceted process that requires extensive research. Within the framework of this study, we only state that Armenia definitely needs a new nuclear power plant. To determine the capacity and number of new nuclear power units, it is necessary to perform a separate in-depth scientifically justified study. With the existing dependence on natural gas imports, the preservation and development of nuclear power will ensure the energy independence of Armenia. Although nuclear fuel is still dependent on imports, nonetheless it addresses several strategic issues. It reduces the risk caused by the heavy reliance on a single primary energy source, provides reliable baseload generation, and helps to use renewable energy sources leading to lowering carbon emissions; ensures the reliability and safety of the system operation. The HPPs could also operate in base load, but Armenia's limited water resources can only allow this at certain peak hours or in cases of excessive precipitations.

In terms of large-scale solar plants, no new capacities are planned to connect the grid during the specified period. The development trends of on-grid residential solar capacity will reach up to 350 MW. No changes are planned regarding interconnections.

1.7 Power balance 2050

The table below shows the balances of the three regimes characteristic for the year 2050.

Table 6. Power balance for 2050, MW.

	Power Plant		2050		
			Winter	**Summer**	**Spring**
			Peak (evening peak)	**Semi Peak**	**Minimum**
1	**ANPP**	ANPP-440	-	-	-
		ANPP-1000	980	800	870
2	**TPP**	Hrazdan Unit 5	420	280	300
		Yerevan CCGT	225	180	210
		ArmPower CCGT	254	180	250
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	0	15	0
		Hrazdan HPP	0	36	0
		Argel HPP	55	65	0
		Arzni HPP	22	15	0
		Kanaqer HPP	23	24	5
		Yerevan HPP	25	22	5

4	**Contour Global Hydro Cascade**	Spandaryan HPP	38	76	0
		Shamb HPP	160	160	0
		Tatev HPP	111	86	64
5	**Small HPP (SHPP)**		85	150	205
6	**Solar PV Power Plants (SPP)**	Masrik-1	0	51.7	0
		AYG-1	0	188	0
		AYG-2	0	188	0
		5 sites (with total capacity 120 MW)	0	112.8	0
		Solar PV already commissioning and planning by PSRC	0	197.76	0
		Solar PV other potential	0	483.74	0
7	**Total Solar PV Commercial**		0	1222	0
8	Wind Power Plant (WPP)	Acciona	160	80	160
		Semyonovka	27.2	13.6	27.2
		Zod	16	8	16
		Karakhach 1 pass	16.8	8.4	16.8
		Karakhach 2 pass	144	72	144
		Syuniq	208	104	208
		In service WPP (as of 2021)	6.3	1.5	3.2
9	**Total Wind Power Plant**		578.3	287.5	575.2
10	**Total Power Plants, Σ**		2976	3599	2484
11	Domestic Demand		1997	1645	690
12	**Solar PV residential**			315.9	
13	**Interconnections**	Iran	-279	-1219	-744
		Georgia	-700	-1050	-1050

In case of commissioning the third stage of enhancing the 400 kV transformer substation of the Armenia-Georgia HVDC, the connection with the Georgian system will be strengthened by another 350 MW and will amount to 1050 MW. If the electricity trade with Georgia continues developing, which can happen only under favorable long-term contracts concluded with neighboring countries, the further development of solar and wind potential and the entry of new capacities into the system become possible. However, in this case, it is also necessary that the innovative and economically efficient technologies of electricity storage are integrated in the Armenian energy system.

With the above-mentioned developments, it is possible to enter additional 400 MW of new solar and 266.5 MW of new wind capacities in the Armenian grid by 2050.

It should be noted that this road map envisages developments up to 2040, and 2050 is considered only as a possible future development, provided all the above-mentioned circumstances and favorable conditions are met.

The table below shows the installed capacities in MW of the power plants in operation in the RA power system as of 2025 and entering the system according to the considered years.

Table 7. Capacities of power plants in operation by years, MW.

	Power Plant	**2025**	**2030**	**2035**	**2040**	**2050**
1.	ANPP-440	440	440	440		
2.	ANPP-1000				1000	1000
3.	Hrazdan Unit 5	485	485	485	485	485
4.	Yerevan CCGT	237.4	237.4	237.4	237.4	237.4
5.	ArmPower CCGT	254	254	254	254	254
6.	International Power Corporation (IPC) Hydro Cascade	561.1	561.1	561.1	561.1	561.1
7.	Contour Global Hydro Cascade	404.2	404.2	404.2	404.2	404.2
8.	Small HPP (SHPP)	430	430	430	430	430
9.	Solar PV residential	252.2	300	320	350	400
10.	Total Solar PV Commercial	465.38	900.38	900.38	900.38	1300.38
11.	Total Wind Power Plant	6.5		275	455	721.5
12.	Total Power Plants, Σ	**3,536**	**4,012**	**4,307**	**5,077**	**5,794**

The table below shows the entry of new capacities (MW) into the power system of Armenia according to the considered years.

Table 8. New capacities in operation by years, MW.

	Power Plant	**2025**	**2030**	**2035**	**2040**	**2050**
1.	ANPP-440	440				
2.	ANPP-1000				1000	
3.	Hrazdan Unit 5	485				

4.	Yerevan CCGT	237.4				
5.	ArmPower CCGT	254				
6.	IPC Hydro Cascade	561.1				
7.	CG Hydro Cascade	404.2				
8.	Small HPP (SHPP)	430				
9.	Solar PV residential	252.2	47.8	20	30	50
10.	Total Solar PV Commercial	465.38	435			400
11.	Total Wind Power Plant	6.5		268.5	180	266.5
12.	Total Power Plants, Σ	**3,536**	**483**	**319**	**1,230**	**767**

The presented installed capacities for 2025 correspond to the capacities envisaged for commissioning by 2025, as well as those available today.

1.8 Absorbing VRE. Analysis of Technical Issues of RE Integration into the Power Grid. Implementation Timeline

Table 9. Commissioning of new capacities with renewable sources, MW.

	Power Plant	**2025**	**2030**	**2035**	**2040**	**2050**
1.	Solar PV residential	252.2	47.8	20	30	50
2.	Total Solar PV Commercial	465.38	435			400
3.	Total Wind Power Plant	6.5		268.5	180	266.5
4.	Total Power Plants	**724**	**483**	**319**	**230**	**767**

Table 10. Total capacities of power plants with renewable sources according to the considered years.

	Power Plant	**2025**	**2030**	**2035**	**2040**	**2050**
1.	Solar PV residential	252.2	300	320	350	400
2.	Total Solar PV Commercial	465.38	900.38	900.38	900.38	1300.38
3.	Total Wind Power Plant	6.5	6.5	275	455	721.5
4.	Total Power Plants, Σ	**724**	**1,207**	**1,525**	**1,755**	**2,522**

On the basis of the presented balances, modeling was carried out by using the PSSE computer program. As a result of the implementation of the modeling and calculation process, an analysis of the operation of the power system in peak, semi-peak and minimum mode situations, as well as interconnections in the maximum load mode situations, was carried out. The performed calculations aim to assess whether the system is ready for such new capacities and the supply of energy to neighboring systems. The process of modeling and calculation of stabilized modes for characteristic modes of all calculation years, identification of overloaded network sections, calculation of voltage modes and evaluation of results was carried out.

1.9 The grid security and reliable operation aspects

From the point of view of ensuring the reliability and safety indicators of the system, the presence of baseload generation power plants is very important, which, however, given present technologies, is ensured by the presence of nuclear, thermal and hydropower plants. In the case of Armenia, with insufficient hydropower resources, the main emphasis remains on nuclear and thermal power plants. In the period of 2040-2050, according to our estimation, in the case of further development of electricity storage technologies, the role of ensuring baseload generation can also be partially assumed by renewable energy sources.

The evaluation of the reliability and safety indicators of the system is carried out by performing calculations of the dynamic stability of the system. To solve such problems, the network regulation provides ten-year network development programs, within the framework of which detailed modeling, calculations, and problem identification of the planned modes are carried out. However, within the framework of this energy independence roadmap study, we have carried out dynamic stability calculations, emergency shutdown of some large solar and wind plants due to system disturbances, and system behavior evaluation calculations. The calculations were carried out for the years 2040 and 2050, considering the situations with maximum solar and wind power plant output. In particular, the behavior of the system was observed in the cases of emergency shutdown of the solar Ayg-1 200 MW, Ayg-2 200 MW, and wind Acciona 200 MW power plants.

In particular, the following emergency situations were considered:

- Emergency disconnection of the 200 MW Ayg-1 solar plant from the system.
- Emergency disconnection of the 200 MW Ayg-2 solar plant from the system.
- Emergency disconnection of the 200 MW Ayg-1 solar plant from the system followed by the disconnection of the 200 MW Ayg-2 solar plant from the system which happened after a few seconds after the first event.
- Disconnection of the 200 MW Acciona wind farm from the system.

The analysis of calculation results shows that in cases of emergency disconnection of the mentioned plants from the system, the stability of the RA system is not disrupted. Due to the consideration of stricter regime situations, the flow of the Armenia-Iran interconnection to Iran changed its flow direction to Armenia as a result of the emergency situation. In the emergency situation, an option was considered according to which the Yerevan CCGT and Hrazdan Unit 5 thermal plants are turned off. However, it should be noted that in the event of a shutdown of thermal plants, a serious voltage regulation issue arises due to the lack of reactive power because all thermal plants of the RA power system operating in the active power base also supply reactive power. This also applies to the 440 MW NPP operating in the system and should also apply to the new 1,000 MW nuclear plant planned to be commissioned by 2040. Without the provision of reactive power services, the operation of the grid is not possible, and the inflow through the Armenia-Iran intersystem connection will not exceed 200 MW.

1.10 Power balances for 2025-2050.

Below are the electricity balances by generating stations, domestic consumption and transmission (export) of electricity through inter-system connections for the years 2025, 2030, 2035, 2040, 2050.

Table 11. Power balance for 2025.

	Power Plant		2025			
			Total Capacity		Electricity Generation	
			MW	%	Bln. kWh/year	%
1	**ANPP**	ANPP-440	440	13.4	2.7	28.9
		ANPP-1000				
2	**TPP**	Hrazdan Unit 5	485	29.7		39.1
		Yerevan CCGT	237.4		1.65	
		Armpower CCGT	254		2	
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	561.1	17.1	0.456	4.9
		Hrazdan HPP				
		Argel HPP				
		Arzni HPP				
		Kanaqer HPP				
		Yerevan HPP				
4	**Contour Global Hydro Cascade**	Spandaryan HPP	404.2	12.3	0.94	10.1
		Shamb HPP				
		Tatev HPP				
5	**Small HPP (SHPP)**		430	13.1	0.82	8.8
6	**Solar PV Power Plants (SPP)**	Masrik-1	55		0.11	
		AYG-1	200		0.32	

	Power Plant		2025			
			Total Capacity		**Electricity Generation**	
			MW	**%**	**Bln. kWh/year**	**%**
		AYG-2				
		5 sites (total 120 MW)				
		Solar PV already commissioning and planning by PSRC	210.38		0.337	
		Solar PV other potential				
7	Total Solar PV Commercial		465.38	14.2	0.767	8.2
8	**Wind Power Plant (WPP)**	Acciona				
		Semyonovka				
		Zod				
		Karakhach 1 pass				
		Karakhach 2 pass				
		Syuniq				
		In service WPP (as of 2021)	6.5		0.00397	
9	Total Wind Power Plant		6.5	0.2	0.00397	0.04 %
10	**Total Power Plants, Σ**		3284	100.0	9.3	100 %
11	Domestic Demand				6.374	
12	**Solar PV residential**		252.2		0.315	
13	**Interconnections**	Iran	550		3.3	
		Georgia				

Table 12. Installed Capacity and Electricity Generation by 2025.

	Installed Capacity		Electricity Generation	
Power Plant	**MW**	**%**	**Bln. kWh/annual**	**%**
ANPP	440	13.4	2.7	28.9
TPP	976.4	29.7	3.65	39.1
IPC Hydro Cascade	561.1	17.1	0.456	4.9
CG Hydro Cascade	404.2	12.3	0.94	10.1
SHPP	430	13.1	0.82	8.8
Solar PV	465.38	14.2	0.767	8.2
Wind PP	6.5	0.2	0.00397	0.04
Total	**3,284**	**100.0**	**9.3**	**100.0**

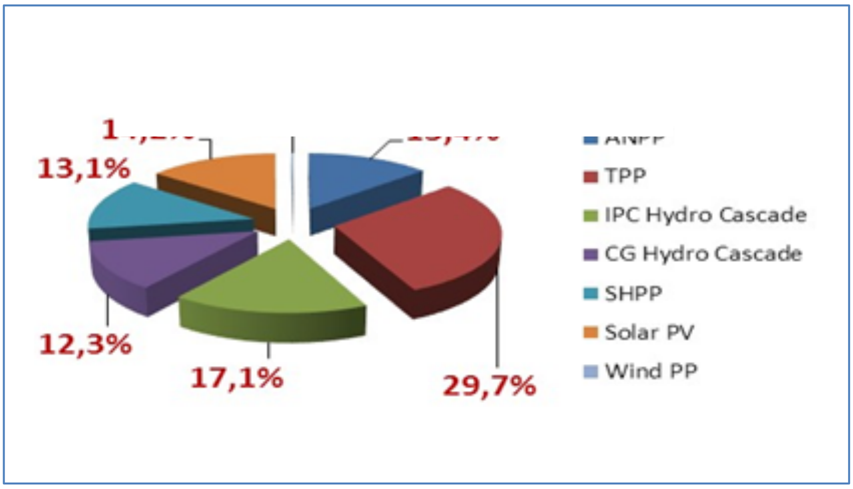

Figure 2. Power Plants Capacity by 2025, %.

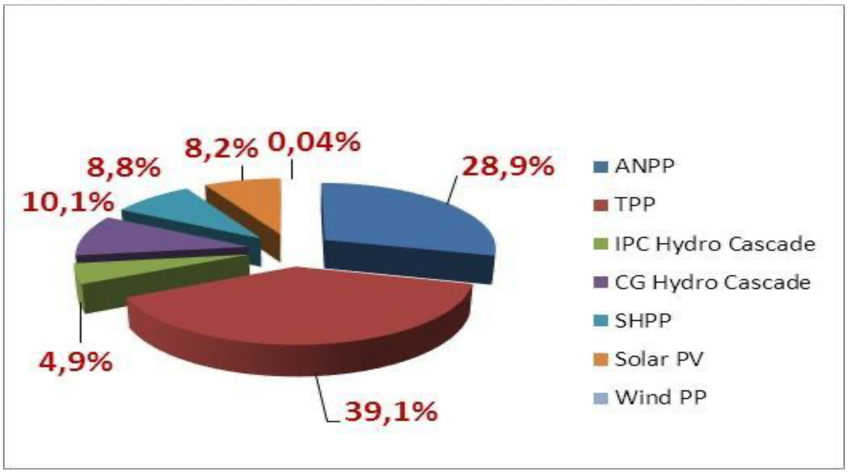

Figure 3. Electricity Generation by Power Plants by 2025, %.

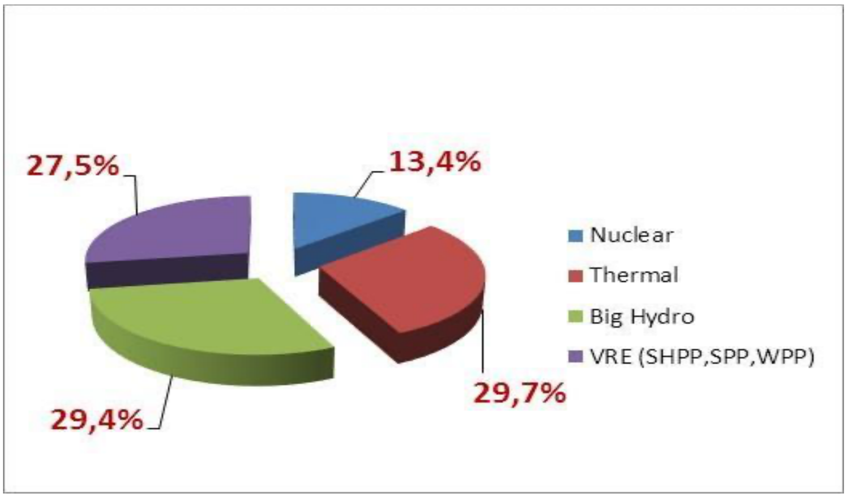

Figure 4. Installed capacity by types of generation by 2025, %.

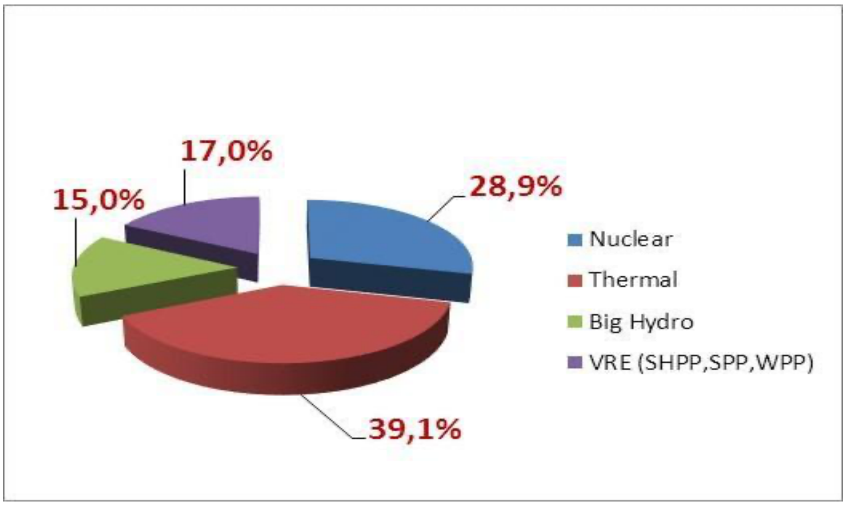

Figure 5. Electricity generation by type of generation by 2025, %.

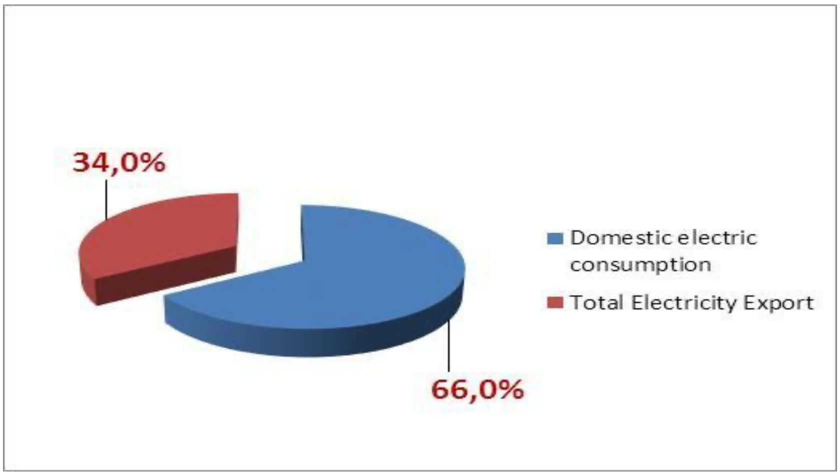

Figure 6. Domestic electricity consumption and export by 2025, %.

Table 13. Electricity Generation and Consumption, 2025.

	Bln. kWh/annual	%
Power Plants Generation	9.3	96.7
Solar PV residential	0.315	3.3
Domestic Electric Consumption	**6.374**	**66.0**
Total Electricity Export	**3.3**	**34.0**
Iran Export	3.3	34.0
Georgia Export	-	-
Total Electricity Generation	**9.7**	**100**

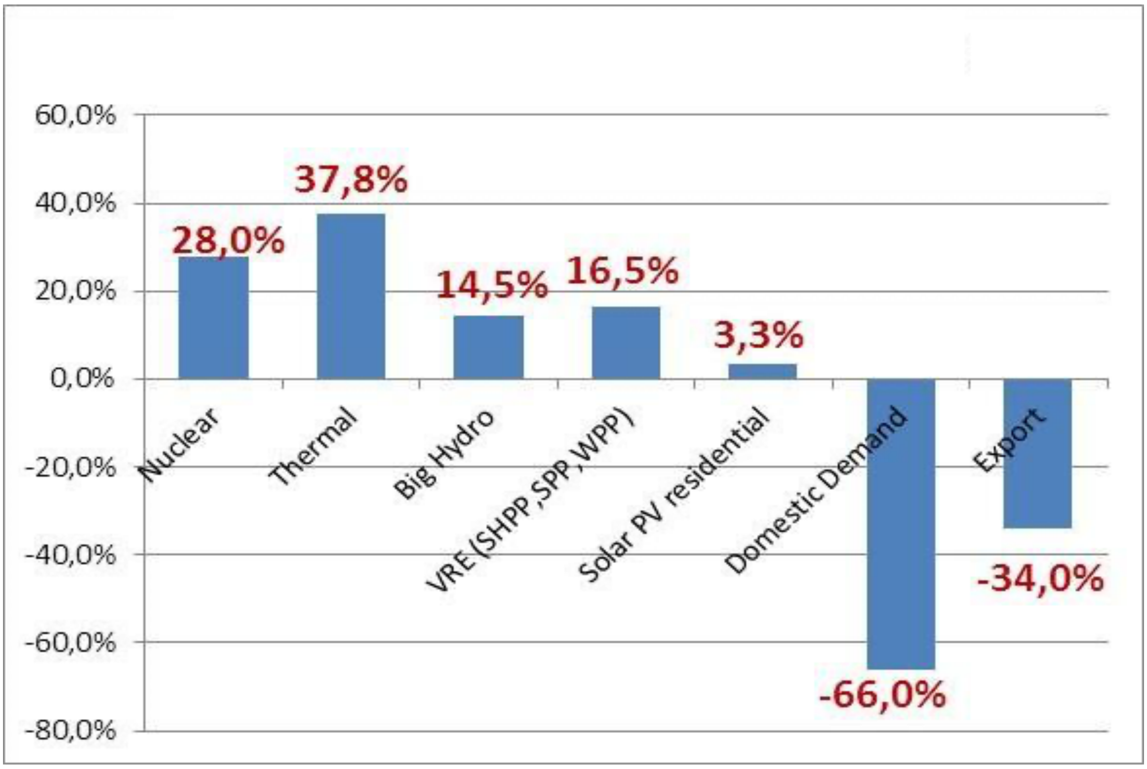

Figure 7. Electricity generation and consumption balance for 2025, %.

Table 14. Elements of electricity balance, 2025.

Total Electricity Generation by plant type	Bln. kWh/annual	%
Nuclear	2.70	28.0
Thermal	3.65	37.8
Large Hydro	1.40	14.5
VRE (SHPP,SPP,WPP)	1.59	16.5
Solar PV residential	0.32	3.3
Domestic Demand	-6.37	-66.0
Export	-3.28	-34.0
Total	**9.65**	**100.0**

Table 15. Electricity balance for 2030.

	Power Plant		**2030**			
			Total Capacity		Electricity generation by Power Plant	
			MW	**%**	**Bln. kWh/annual**	**%**
1	**ANPP**	ANPP-440	440	11.9	2.7	24.3
		ANPP-1000				
2	**TPP**	Hrazdan Unit 5	485	26.3	1.083	42.6
		Yerevan CCGT	237.4		1.65	
		Armpower CCGT	254		2	
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	561.1	15.1	0.456	4.1
		Hrazdan HPP				
		Argel HPP				
		Arzni HPP				
		Kanaqer HPP				
		Yerevan HPP				
4	**Contour Global Hydro Cascade**	Spandaryan HPP	404.2	10.9	0.94	8.5
		Shamb HPP				
		Tatev HPP				
5	**Small HPP (SHPP)**		430	11.6	0.82	7.4
6	**Solar PV Power Plants (SPP)**	Masrik-1	55		0.11	
		AYG-1	200		0.32	
		AYG-2	200		0.32	
		5 sites (with total capacity 120 MW)	120		0.192	
		Solar PV already commissioning and planning by PSRC	210.38		0.337	
		Solar PV other potential	115		0.184	
7	**Total Solar PV Commercial**		900.38	24.3	1.463	13.2
8	**Wind Power Plant (WPP)**	Acciona				
		Semyonovka				
		Zod				

	Power Plant		2030			
			Total Capacity		Electricity generation by Power Plant	
			MW	%	Bln. kWh/annual	%
		Karakhach 1 pass				
		Karakhach 2 pass				
		Syuniq				
		In service WPP (as of 2021)			0.00397	
9	**Total Wind Power Plant**		6.5	0.2	0.00397	0.04
10	**Total Power Plants, Σ**		3719	100.0	11.1	100
11	Domestic Demand				7.007	
12	Solar PV residential		300		0.375	
13	**Interconnections**	Iran	1200		3.4	
		Georgia	350		1.1	

Table 16. Installed Capacity and Electricity Generation by Power Plants by 2030.

	2030			
	Installed Capacity		**Electricity generation**	
Power Plant	**MW**	**%**	**Bln. kWh/year**	**%**
ANPP	440	11.8	2.7	24.3
TPP	976.4	26.3	4.733	42.6
IPC Hydro Cascade	561.1	15.1	0.456	4.1
CG Hydro Cascade	404.2	10.9	0.94	8.5
SHPP	430	11.6	0.82	7.4
Solar PV	900.38	24.2	1.463	13.2
Wind PP	6.5	0.2	0.00397	0.04
Total	**3,719**	**100.0**	**11.1**	**100.0**

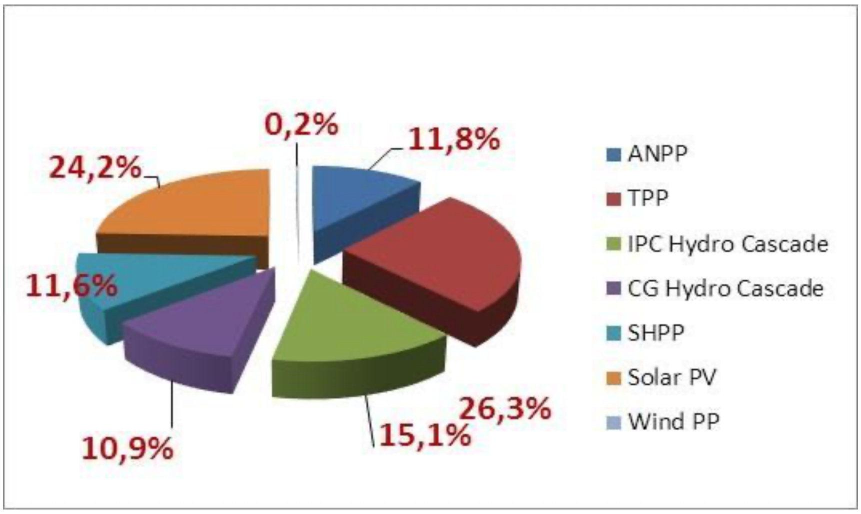

Figure 8. Power Plants Capacity by 2030, %.

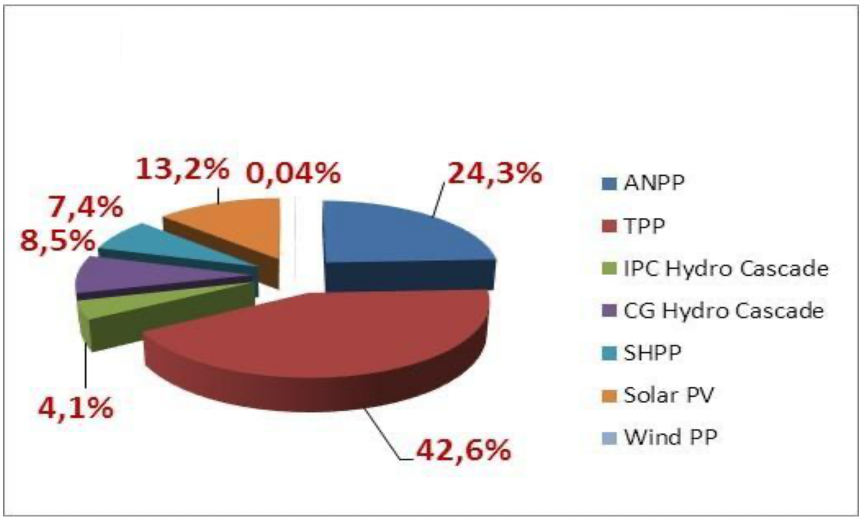

Figure 9. Electricity Generation by Power Plants, 2030.

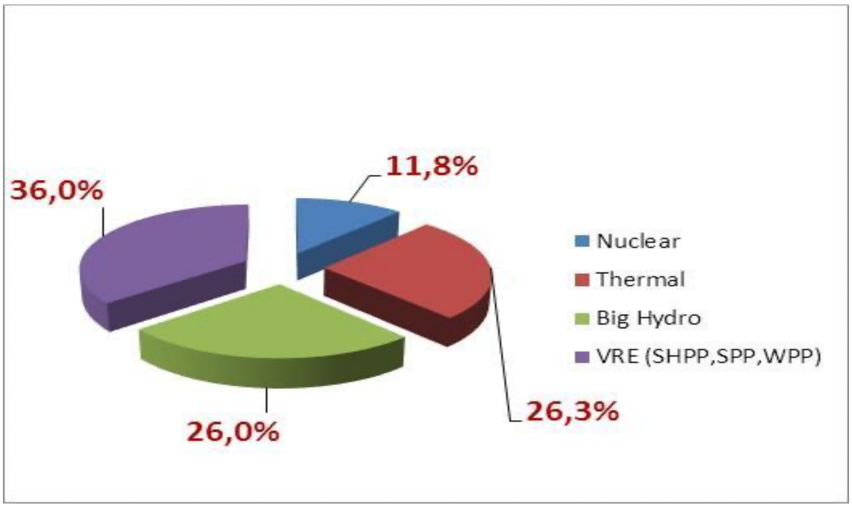

Figure 10. Installed capacity by type of generation by 2030, %.

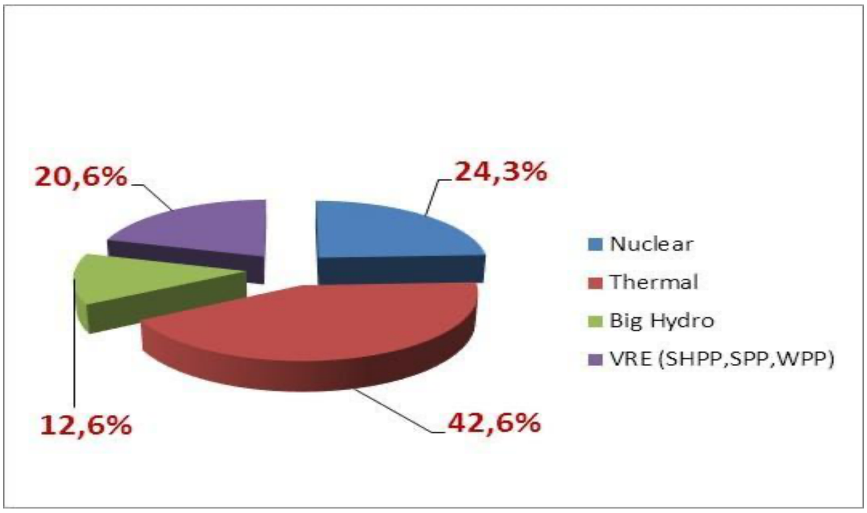

Figure 11. Electricity generation by type of generation by 2030, %.

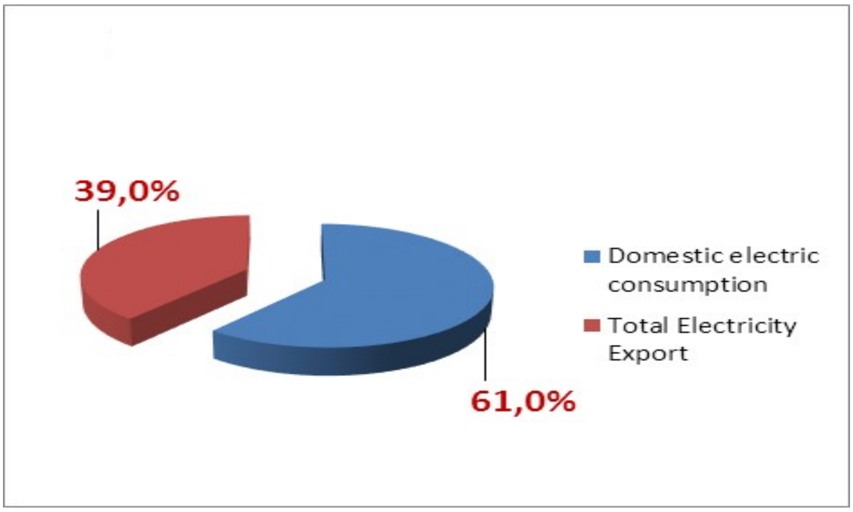

Figure 12. Domestic electricity consumption and export by 2030, %.

Table 17. Electricity generation and consumption, 2030.

	Bln. kWh/annual	**%**
Power Plants Generation (utility scale)	11.1	96.7
Solar PV residential scale	0.375	3.3
Domestic electric consumption	**7.007**	**61.0**
Total Electricity Export	**4.5**	**39.0**
Iran Export	3.4	29.4
Georgia Export	1.1	9.57
Total Electricity Generation	**11.5**	**100**

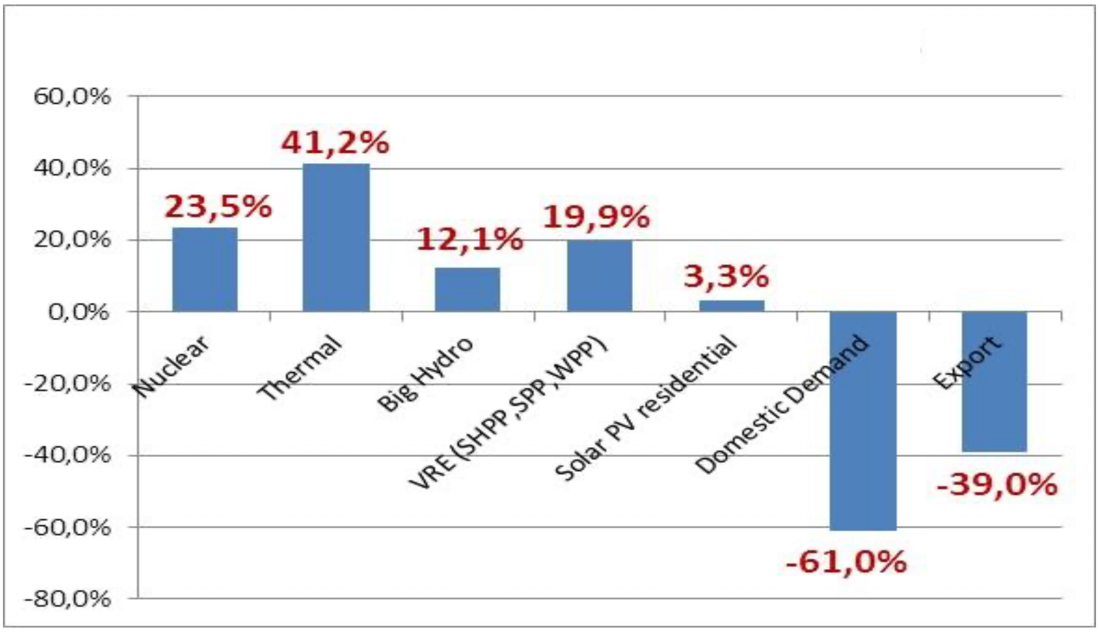

Figure 13. Electricity generation and consumption balance for 2030, %.

Table 18. Elements of electricity balance, 2030.

	Bln. kWh/annual	**%**
Total Electricity Generation	11.49	100.0
Nuclear	2.70	23.5
Thermal	4.73	41.2
Large Hydro	1.40	12.1
VRE (SHPP,SPP,WPP)	2.29	19.9
Solar PV residential	0.38	3.3
Domestic Demand	**-7.01**	**-61.0**
Export	**-4.48**	**-39.0**

Table 19. Electricity balance for 2035.

<table>
<tr><th rowspan="3"></th><th rowspan="3" colspan="2">Power Plant</th><th colspan="4">2035</th></tr>
<tr><th colspan="2">Total Capacity</th><th colspan="2">Electricity generation by Power Plant</th></tr>
<tr><th>MW</th><th>%</th><th>Bln. kWh/annual</th><th>%</th></tr>
<tr><td rowspan="2">1</td><td rowspan="2">ANPP</td><td>ANPP-440</td><td>440</td><td rowspan="2">11.0</td><td>2.7</td><td rowspan="2">22.7</td></tr>
<tr><td>ANPP-1000</td><td></td><td></td></tr>
<tr><td>2</td><td>TPP</td><td>Hrazdan Unit 5</td><td>485</td><td>24.5</td><td>1.083</td><td>39.7</td></tr>
</table>

	Power Plant		2035			
			Total Capacity		Electricity generation by Power Plant	
			MW	%	Bln. kWh/annual	%
		Yerevan CCGT	237.4		1.65	
		Armpower CCGT	254		2	
3	International Power Corporation (IPC) Hydro Cascade	Sevan HPP	561.1	14.1	0.456	3.8
		Hrazdan HPP				
		Argel HPP				
		Arzni HPP				
		Kanaqer HPP				
		Yerevan HPP				
4	Contour Global Hydro Cascade	Spandaryan HPP	404.2	10.1	0.94	7.9
		Shamb HPP				
		Tatev HPP				
5	Small HPP (SHPP)		430	10.8	0.82	6.9
6	Solar PV Power Plants (SPP)	Masrik-1	55		0.11	
		AYG-1	200		0.32	
		AYG-2	200		0.32	
		5 sites (with total capacity 120 MW)	120		0.192	
		Solar PV already commissioning and planning by PSRC	210.38		0.337	
		Solar PV other potential	115		0.184	
7	Total Solar PV Commercial		900.38	22.6	1.463	12.3
8	Wind Power Plant (WPP)	Acciona	200		0.6	
		Semyonovka	34		0.0718	
		Zod	20		0.061	
		Karakhach 1 pass	21		0.063	
		Karakhach 2 pass				
		Syuniq				
		In service WPP (as of 2021)			0.00397	

	Power Plant		2035			
			Total Capacity		Electricity generation by Power Plant	
			MW	%	Bln. kWh/annual	%
9	**Total Wind Power Plant**		**275**	**6.9**	**0.800**	**6.7**
10	**Total Power Plants, Σ**		**3987**	**100.0**	**11.9**	**100**
11	Domestic Demand				**7.718**	
12	Solar PV residential		**320**		**0.4**	
13	**Interconnections**	Iran	**1200**		**3.4**	
		Georgia	**700**		**1.2**	

Table 20. Installed capacity and electricity generation by the Power Plants by 2035.

	2035			
	Installed Capacity		**Electricity generation**	
Power Plant	MW	%	**Bln. kWh/annual**	%
ANPP	440	11.0	2.7	22.7
TPP	976.4	24.5	4.733	39.7
IPC Hydro Cascade	561.1	14.1	0.456	3.8
CG Hydro Cascade	404.2	10.1	0.94	7.9
SHPP	430	10.8	0.82	6.9
Solar PV	900.38	22.6	1.463	12.3
Wind PP	275	6.9	0.800	6.71
Total	3,987	100.0 %	11.9	100.0

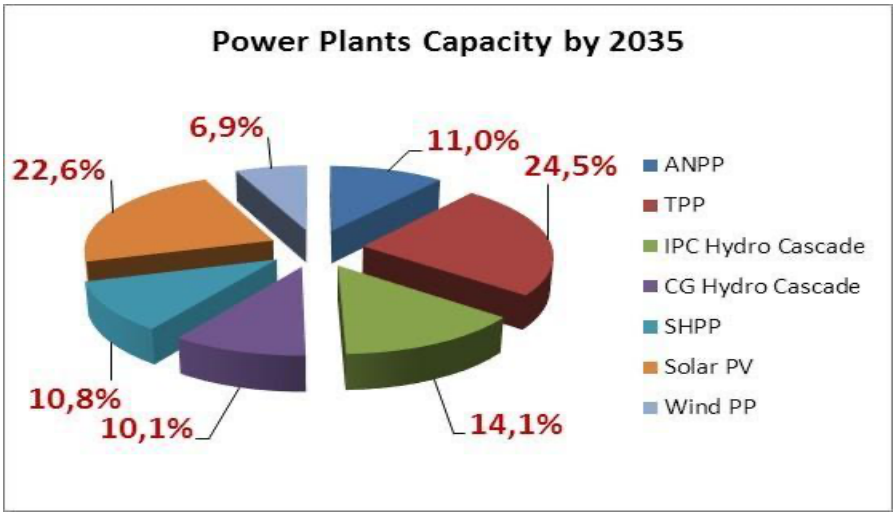

Figure 14. Power plants capacities by 2035, %.

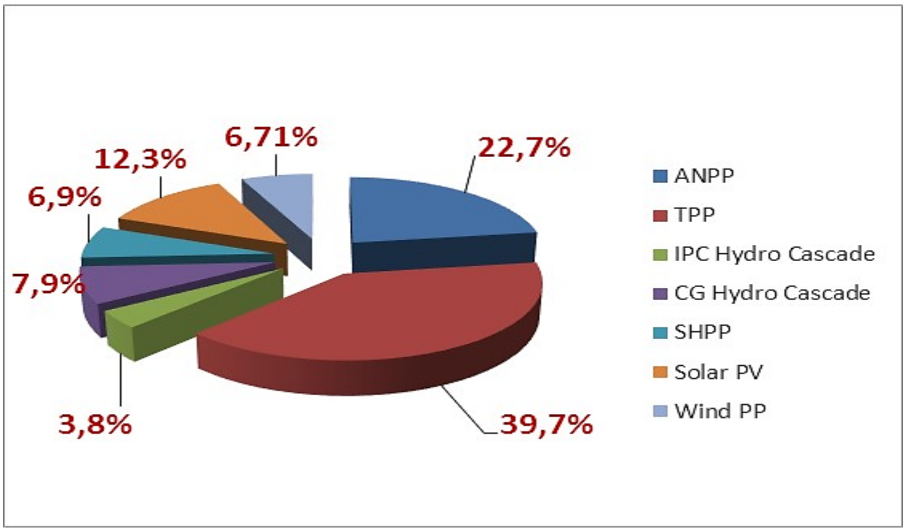

Figure 15. Electricity generation by Power Plants by 2035, %.

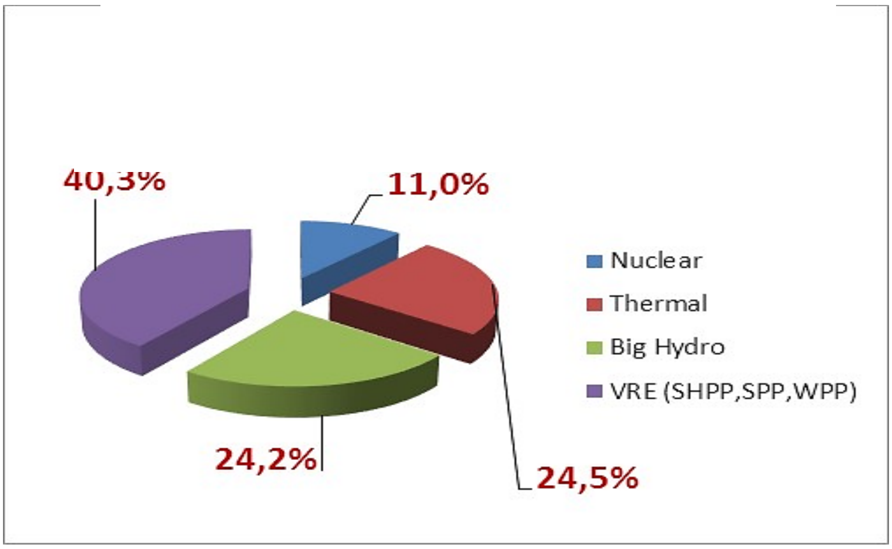

Figure 16. Installed capacity by type of generation by 2035, %.

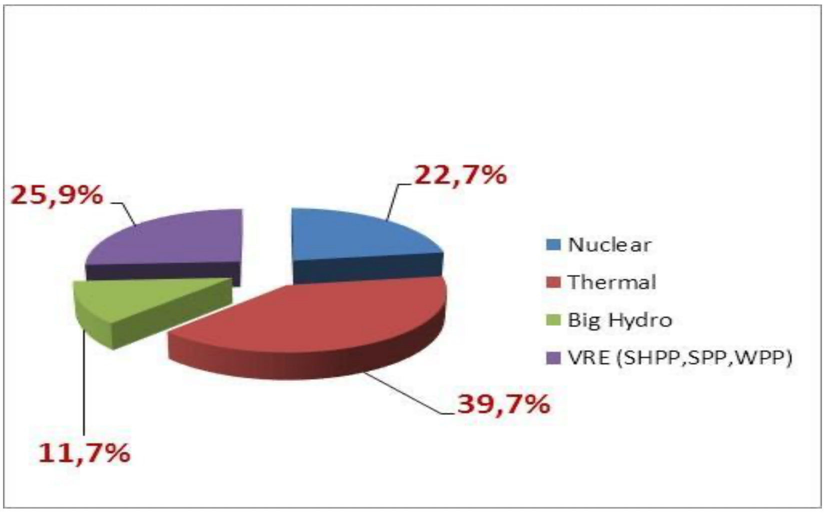

Figure 17. Electricity generation by type of generation by 2035, %.

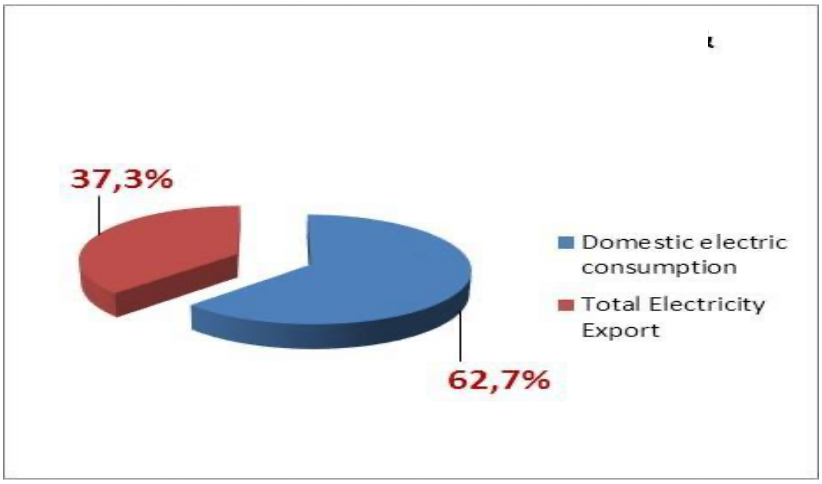

Figure 18. Domestic electricity consumption and export by 2035, %.

Table 20. Electricity generation and consumption, 2035.

	Bln. kWh/annual	**%**
Power Plants Generation	11.9	96.5
Solar PV residential	0.438	3.5
Domestic electricity consumption	**7.718**	**62.5**
Total Electricity Export	**4.6**	**37.5**
Iran Export	3.4	27.6
Georgia Export	1.2	9.75
Total Electricity Generation	**12.3**	**100**

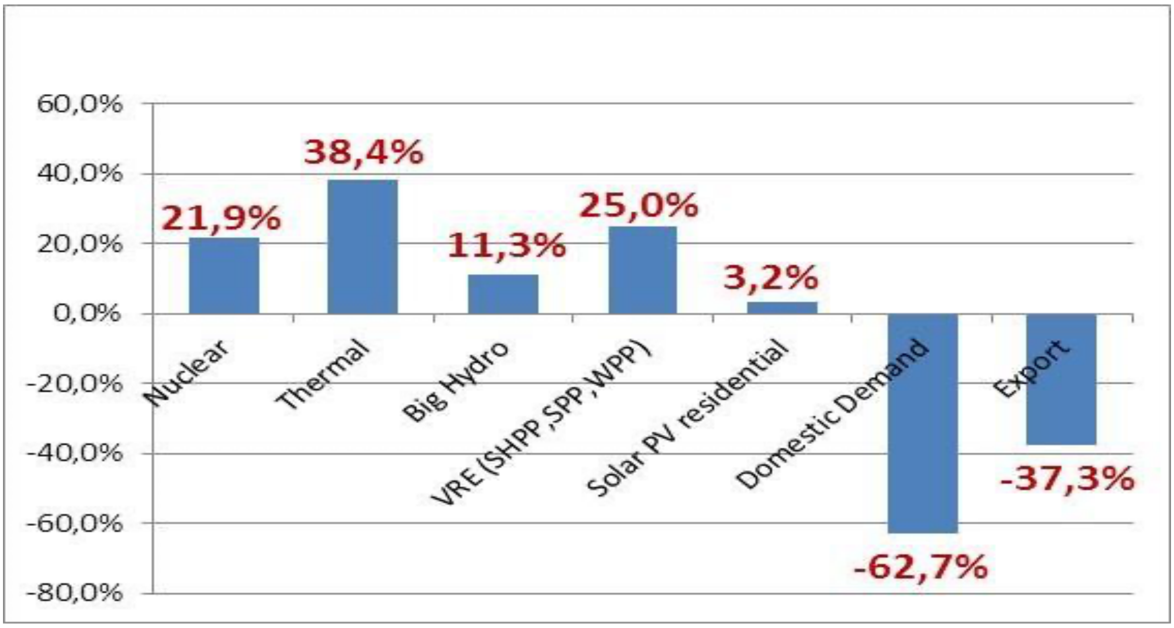

Figure 19. Electricity generation and consumption balance for 2035, %.

Table 21. Elements of electricity balance. 2035.

	Bln. kWh/annual	**%**
Total Electricity Generation	**12.31**	**100.0**
Nuclear	**2.70**	**21.9**
Thermal	**4.73**	**38.4**
Large Hydro	**1.40**	**11.3**
VRE (SHPP,SPP,WPP)	**3.08**	**25.0**
Solar PV residential	**0.4**	**3.2**
Domestic Demand	**-7.72**	**-62.7**
Export	**-4.59**	**-37.3**

Table 22. Electricity balance for 2040.

	Power Plant		**2040**			
			Total Capacity		**Electricity generation by Power Plant**	
			MW	**%**	**Bln. kWh/annual**	**%**
1	**ANPP**	ANPP-440		21.2		39.3
		ANPP-1000	1000		6.32	
2	**TPP**	Hrazdan Unit 5	485	20.7	1.083	29.4

	Power Plant		2040			
			Total Capacity		Electricity generation by Power Plant	
			MW	%	Bln. kWh/annual	%
		Yerevan CCGT	237.4		1.65	
		ArmPower CCGT	254		2	
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	561.1	11.9	0.456	2.8
		Hrazdan HPP				
		Argel HPP				
		Arzni HPP				
		Kanaqer HPP				
		Yerevan HPP				
4	**Contour Global Hydro Cascade**	Spandaryan HPP	404.2	8.6	0.94	5.8
		Shamb HPP				
		Tatev HPP				
5	**Small HPP (SHPP)**		430	9.1	0.82	5.1
6	**Solar PV Power Plants (SPP)**	Masrik-1	55		0.11	
		AYG-1	200		0.32	
		AYG-2	200		0.32	
		5 sites (with total capacity 120 MW)	120		0.192	
		Solar PV already commissioning and planning by PSRC	210.38		0.337	
		Solar PV other potential	115		0.184	
7	**Total Solar PV Commercial**		900.38	19.0	1.463	9.1
8	**Wind Power Plant (WPP)**	Acciona	200		0.6	
		Semyonovka	34		0.0718	
		Zod	20		0.061	
		Karakhach 1 pass	21		0.063	
		Karakhach 2 pass	180		0.54	
		Syuniq				
		In service WPP (as of 2021)			0.00397	
9	**Total Wind Power Plant**		455	9.6	1.340	8.3

<table>
<tr><th rowspan="3"></th><th rowspan="3" colspan="2">Power Plant</th><th colspan="4">2040</th></tr>
<tr><th colspan="2">Total Capacity</th><th colspan="2">Electricity generation by Power Plant</th></tr>
<tr><th>MW</th><th>%</th><th>Bln. kWh/annual</th><th>%</th></tr>
<tr><td>10</td><td colspan="2">Total Power Plants, Σ</td><td>4727</td><td>100.0</td><td>16.1</td><td>100</td></tr>
<tr><td>11</td><td colspan="2">Domestic Demand</td><td></td><td></td><td>8.518</td><td></td></tr>
<tr><td>12</td><td colspan="2">Solar PV residential</td><td>350</td><td></td><td>0.438</td><td></td></tr>
<tr><td rowspan="2">13</td><td rowspan="2">Interconnections</td><td>Iran</td><td>1200</td><td></td><td>5.0</td><td></td></tr>
<tr><td>Georgia</td><td>700</td><td></td><td>3.0</td><td></td></tr>
</table>

Table 23. Installed Capacity and Electricity generation of Power Plants by 2040.

2040	**Installed Capacity**		**Electricity generation**	
Power Plant	**MW**	**%**	**bln. kWh/annual**	**%**
ANPP	1000	21.2	6.32	39.3
TPP	976.4	20.7	4.733	29.4
IPC Hydro Cascade	561.1	11.9	0.456	2.8
CG Hydro Cascade	404.2	8.6	0.94	5.8
SHPP	430	9.1 %	0.82	5.1
Solar PV	900.38	19.0	1.463	9.1
Wind PP	455	9.6	1.340	8.34
Total	**4,727**	**100.0**	**16.1**	**100.0**

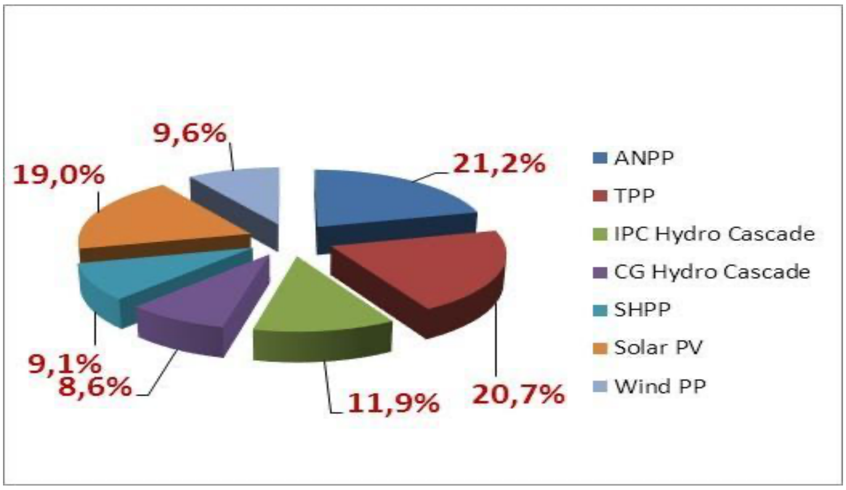

Figure 20. Power plants capacity by 2040, %.

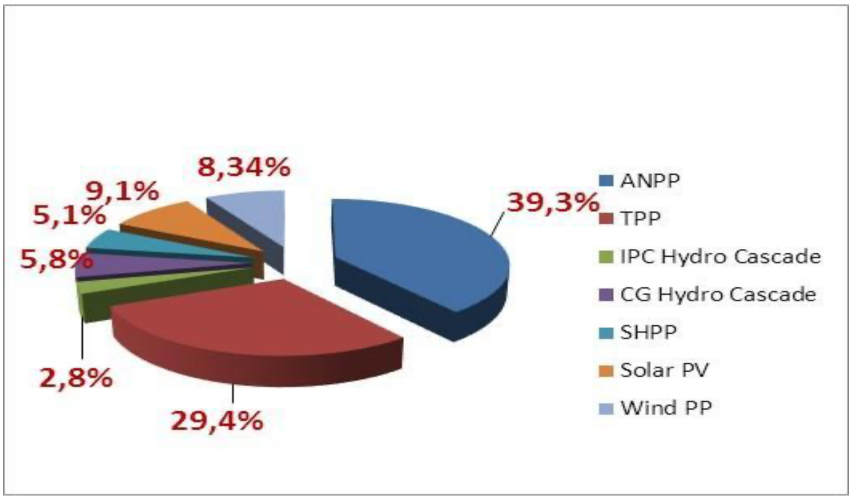

Figure 21. Electricity generation by power plants by 2040, %.

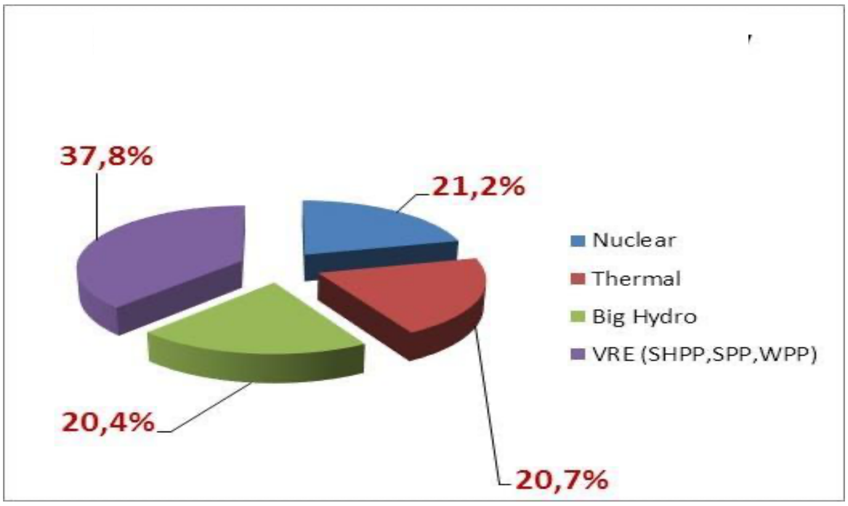

Figure 22. Installed capacity by type of generation by 2040.

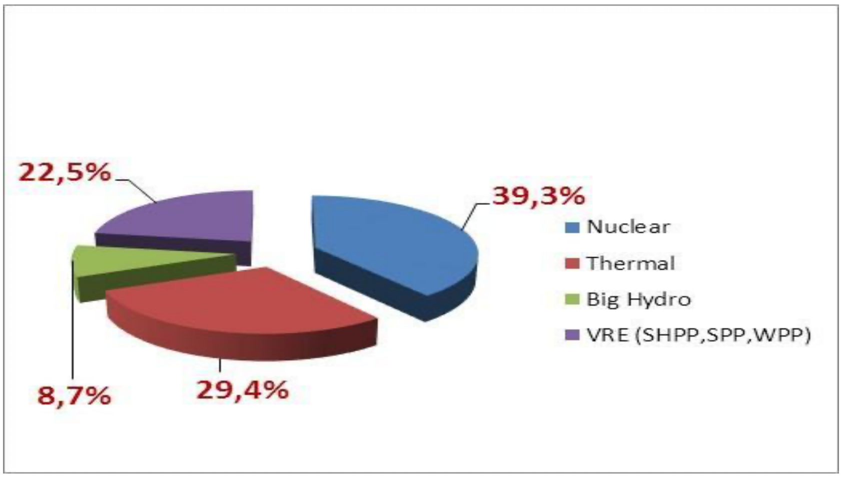

Figure 23. Electricity generation by type of generation by 2040, %.

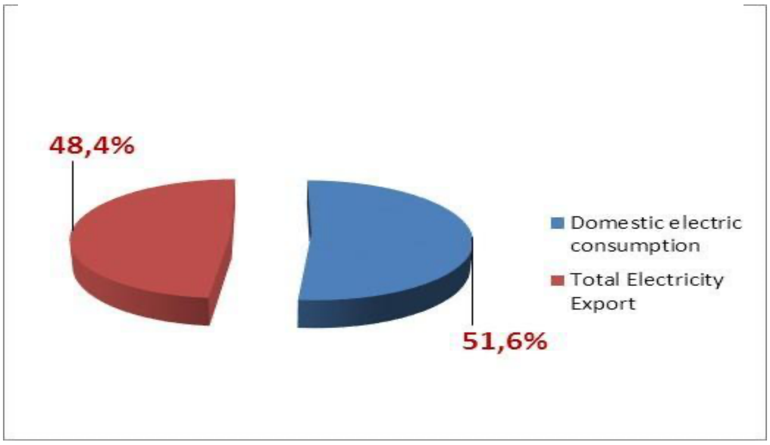

Figure 24. Domestic electricity consumption and export by 2040, %.

Table 24. Electricity generation and consumption, 2040.

2040	Bln. kWh/annual	%
Power Plants Generation	16.1	97.3
Solar PV residential	0.438	2.7
Domestic electric consumption	**8.518**	**51.6**
Total Electricity Export	**8.0**	**48.4**
Iran Export	5.0	30.2
Georgia Export	3.0	18.17
Total Electricity Generation	**16.5**	**100**

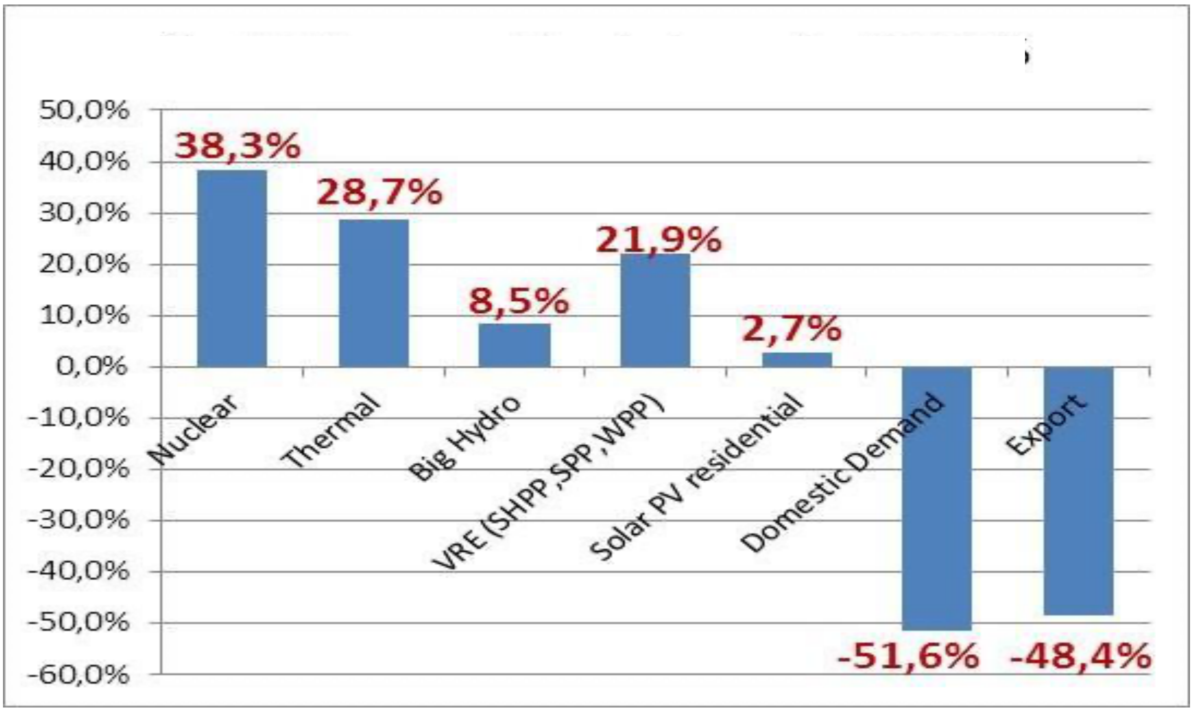

Figure 25. Electricity generation and consumption balance for 2040, %.

Table 25. Elements of electricity balance, 2040.

2040	Bln. kWh/annual	%
Total Electricity Generation	**16.51**	**100.0**
Nuclear	6.32	38.3
Thermal	4.73	28.7
Large Hydro	1.40	8.5
VRE (SHPP,SPP,WPP)	3.62	21.9
Solar PV residential	0.44	2.7
Domestic Demand	**-8.52**	**-51.6**
Export	**-7.99**	**-48.4**

Table 26. Electricity balance for 2050.

	2050		Total Capacity		Electricity generation by Power Plant	
		Power Plant	**MW**	**%**	**Bln. kWh/annual**	**%**
1	**ANPP**	ANPP-440		18.5		36.6
		ANPP-1000	1000		6.32	
2	**TPP**	Hrazdan Unit 5	485	18.1	1.083	27.4
		Yerevan CCGT	237.4		1.65	
		ArmPower CCGT	254		2	
3	**International Power Corporation (IPC) Hydro Cascade**	Sevan HPP	561.1	10.4 %	0.456	2.6
		Hrazdan HPP				
		Argel HPP				
		Arzni HPP				
		Kanaqer HPP				
		Yerevan HPP				
4	**Contour Global Hydro Cascade**	Spandaryan HPP	404.2	7.5	0.94	5.4
		Shamb HPP				
		Tatev HPP				
5	**Small HPP (SHPP)**		430	8.0	0.82	4.7
6	**Solar PV Power Plants (SPP)**	Masrik-1	55		0.11	
		AYG-1	200		0.32	
		AYG-2	200		0.32	
		5 sites (with total capacity 120 MW)	120		0.192	
		Solar PV already commissioning and planning by PSRC	210.38		0.337	
		Solar PV other potential	515		0.824	
7	**Total Solar PV Commercial**		1300.38	24.1	2.103	12.2
8	**Wind Power Plant (WPP)**	Acciona	200		0.6	
		Semyonovka	34		0.0718	

	2050		Total Capacity		Electricity generation by Power Plant	
		Power Plant	MW	%	Bln. kWh/annual	%
		Zod	20		0.061	
		Karakhach 1 pass	21		0.063	
		Karakhach 2 pass	180		0.54	
		Syuniq	260		0.56	
		In service WPP (as of 2021)	6.5		0.00397	
9	**Total Wind Power Plants**		721.5	13.4	1.900	11.0
10	**Total Power Plants, Σ**		5394	100.0	17.3	100
11	**Domestic Demand**				10.12	
12	**Solar PV residential**		400		0.5	
13	**Interconnections**	Iran	1200		4.2	
		Georgia	1050		3.5	

Table 27. Installed capacity and electricity generation of Power Plants by 2050.

2050	Installed Capacity		Electricity generation	
Power Plant	**MW**	**%**	**Bln. kWh/annual**	**%**
ANPP	1000	18.5	6.32	36.6
TPP	976.4	18.1	4.733	27.4
IPC Hydro Cascade	561.1	10.4	0.456	2.6
CG Hydro Cascade	404.2	7.5	0.94	5.4
SHPP	430	8.0	0.82	4.7
Solar PV	1300.38	24.1	2.103	12.2
Wind PP	721.5	13.4 %	1.900	11.00
Total	**5,394**	**100.0 %**	**17.3**	**100.0**

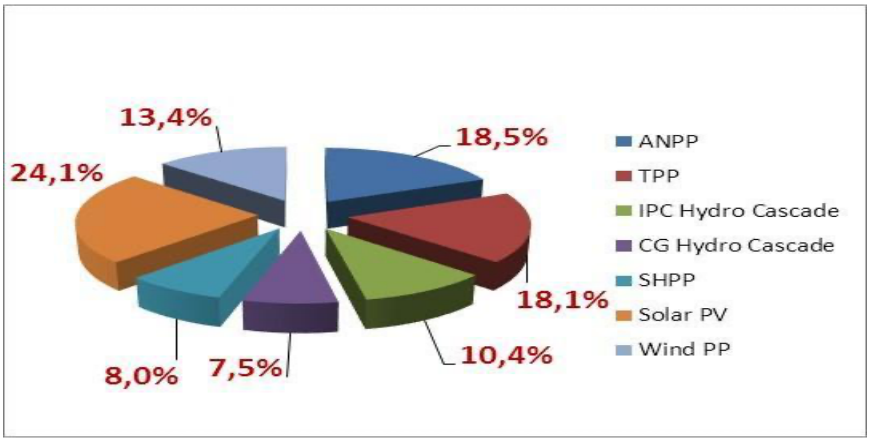

Figure 26. Power plants' capacity by 2050, %.

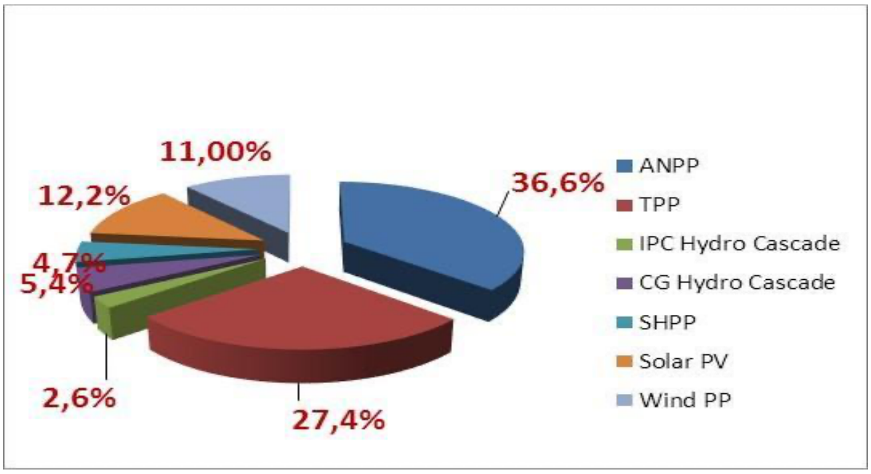

Figure 27. Electricity generation by power plants by 2050, %.

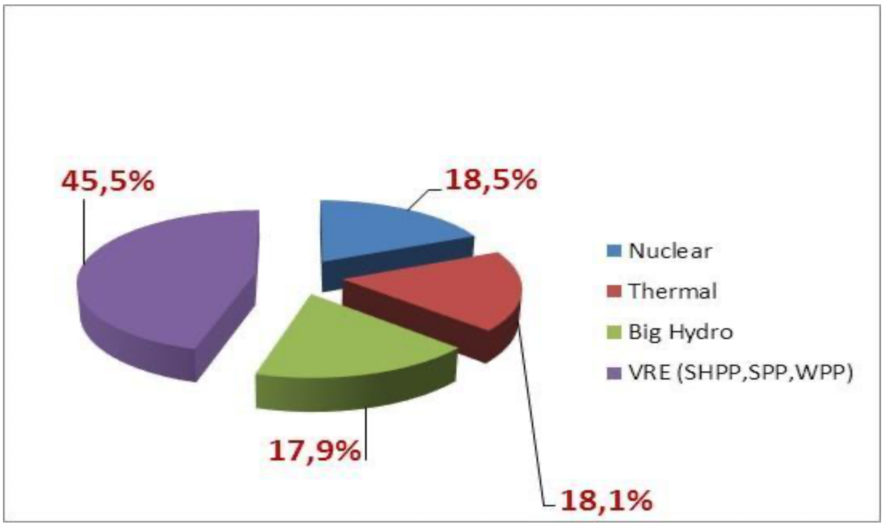

Figure 28. Installed capacity by type of generation by 2050, %.

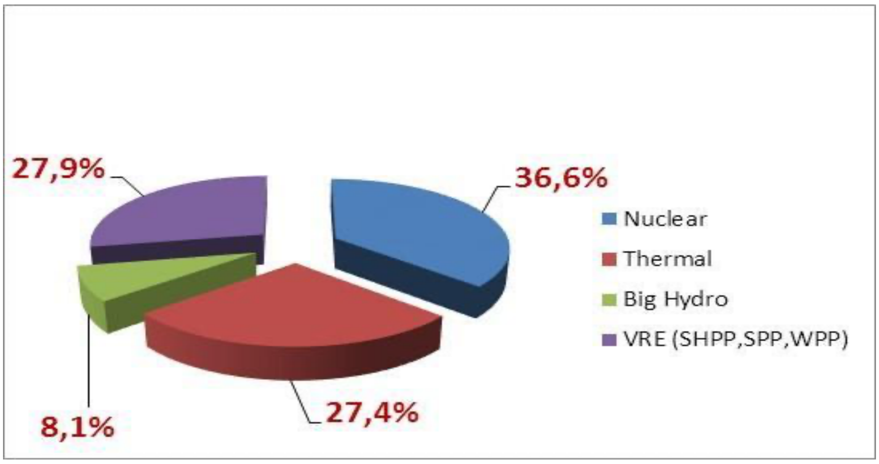

Figure 29. Electricity generation by type of generation by 2050, %.

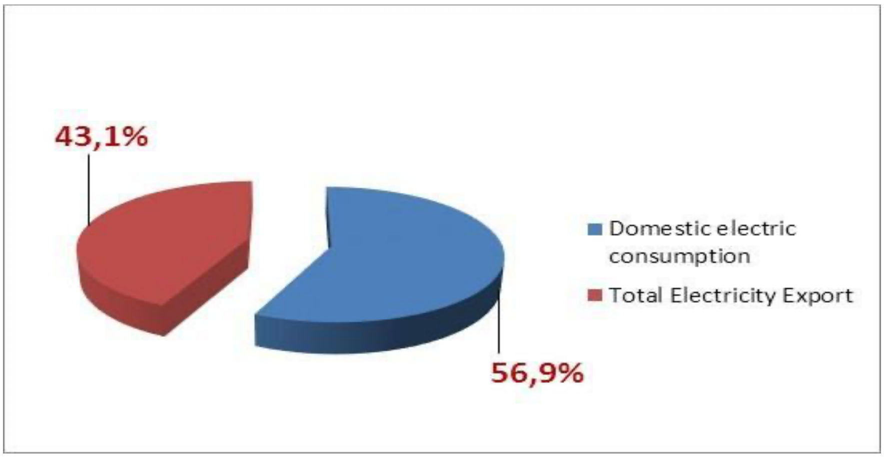

Figure 30. Domestic electricity consumption and export by 2050, %.

Table 28. Generation and consumption of electricity, 2050.

	Bln. kWh/annual	%
Power Plants Generation	**17.3**	**97.2**
Solar PV residential	**0.5**	**2.8**
Domestic electric consumption	**10.12**	**56.9**
Total Electricity Export	**7.7**	**43.1**
Iran Export	**4.2**	**23.4**
Georgia Export	**3.5**	**19.69**
Total Electricity Generation	**17.8**	**100**

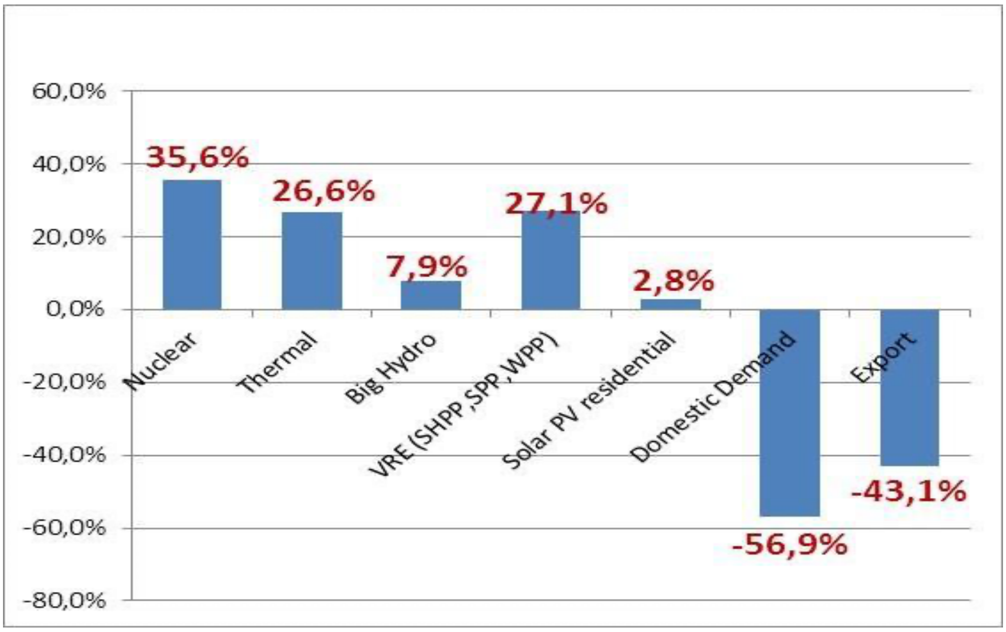

Figure 31. Electricity generation and consumption balance for 2050, %.

Table 29. Elements of electricity balance, 2050.

	Bln. kWh/annual	**%**
Total Electricity Generation	**17.77**	**100.0**
Nuclear	6.32	35.6
Thermal	4.73	26.6
Large Hydro	1.40	7.9
VRE (SHPP,SPP,WPP)	4.82	27.1
Solar PV residential	0.5	2.8
Domestic Demand	**-10.12**	**-56.9**
Export	**-7.65**	**-43.1**

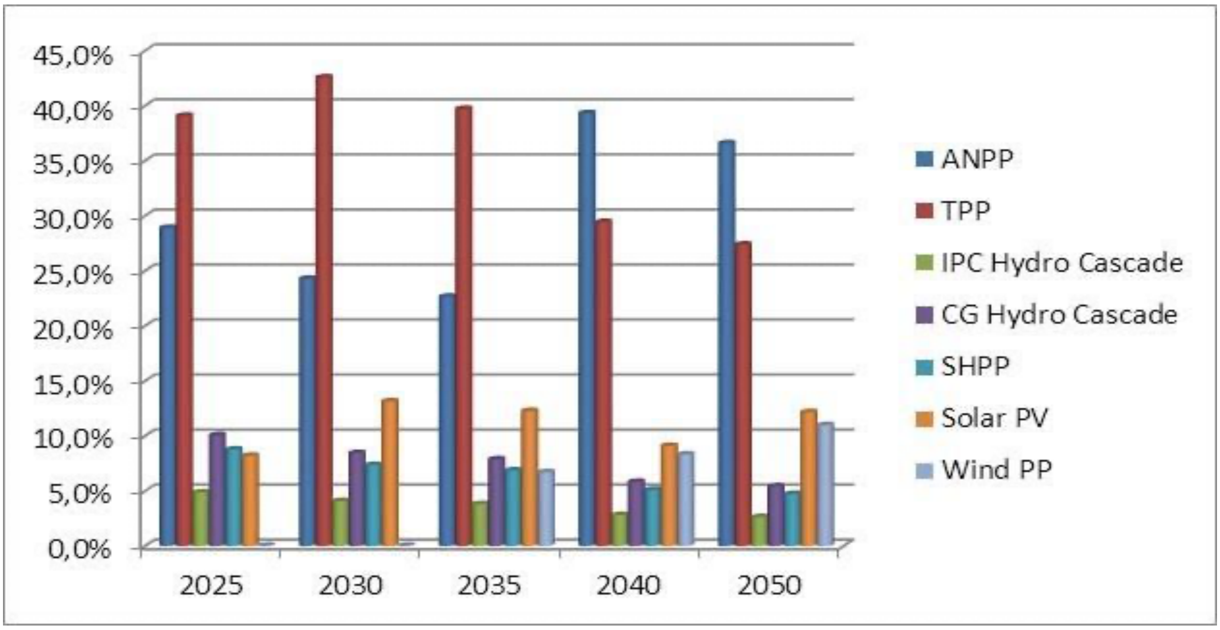

Figure 32. Electricity Generation by Power Plants for 2025-2050, %.

Table 30. Electricity Generation by Power Plants for 2025-2050, %.

Power Plant	2025	2030	2035	2040	2050
ANPP	28.9	24.3	22.7	39.3	36.6
TPP	39.1	42.6	39.7	29.4	27.4
IPC Hydro Cascade	4.9	4.1	3.8	2.8	2.6
CG Hydro Cascade	10.1	8.5	7.9	5.8	5.4
SHPP	8.8	7.4	6.9	5.1	4.7
Solar PV	8.2	13.2	12.3	9.1	12.2
Wind PP	0.0	0.0	6.7	8.3	11.0
Total Electricity generation (Bln. kWh/annual)	9.3	11.1	11.9	16.1	17.3

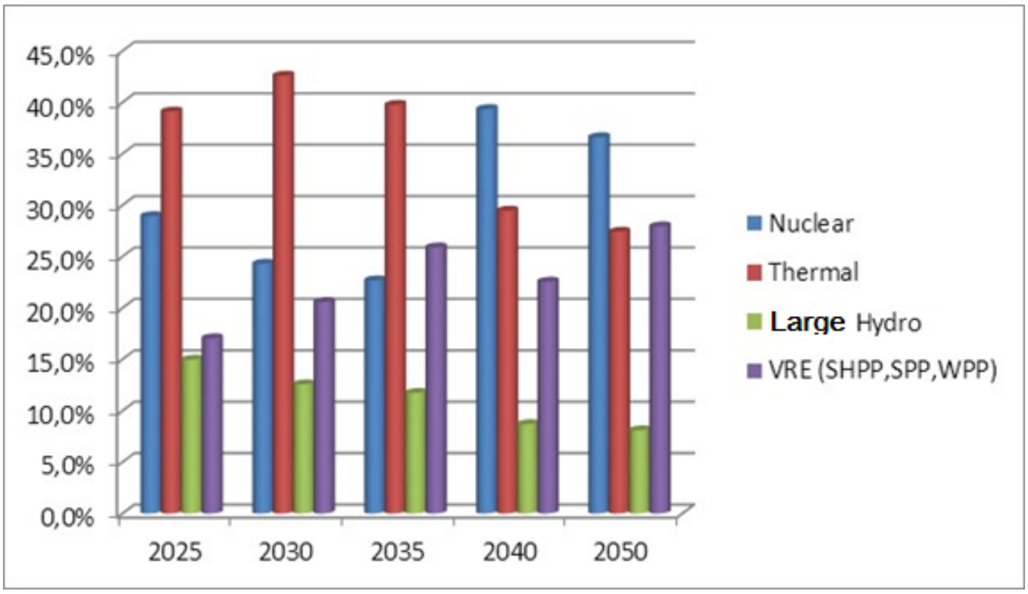

Figure 33. Electricity generation by type of generation in power system for 2025-2050, %.

Table 31. Electricity generation by type of generation in power system for 2025-2050, %.

Type of Generation	2025	2030	2035	2040	2050
Nuclear	28.9	24.3	22.7	39.3	36.6
Thermal	39.1	42.6	39.7	29.4	27.4
Large Hydro	15.0	12.6	11.7	8.7	8.1
VRE (SHPP,SPP,WPP)	17.0	20.6	25.9	22.5	27.9
Total Electricity generation* (bln. kWh/year)	9.3	11.1	11.9	16.1	17.3

* Solar PV residential generation is not included in power system total generation value.

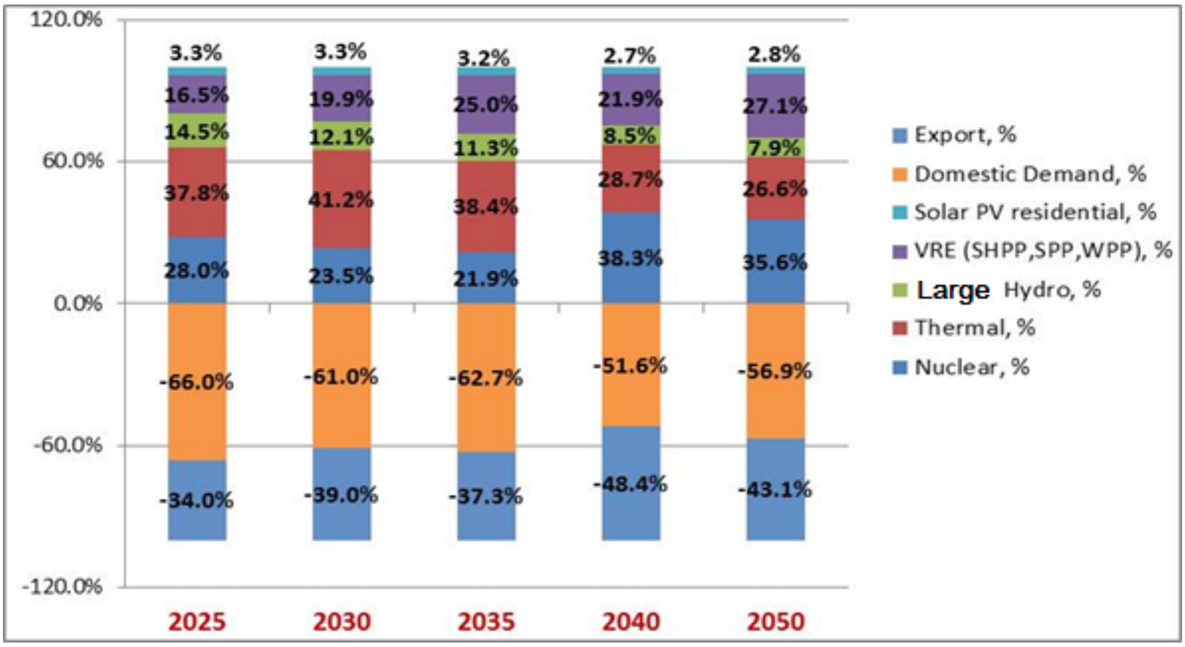

Figure 34. Total electricity generation, domestic demand and export for 2025-2050, %.

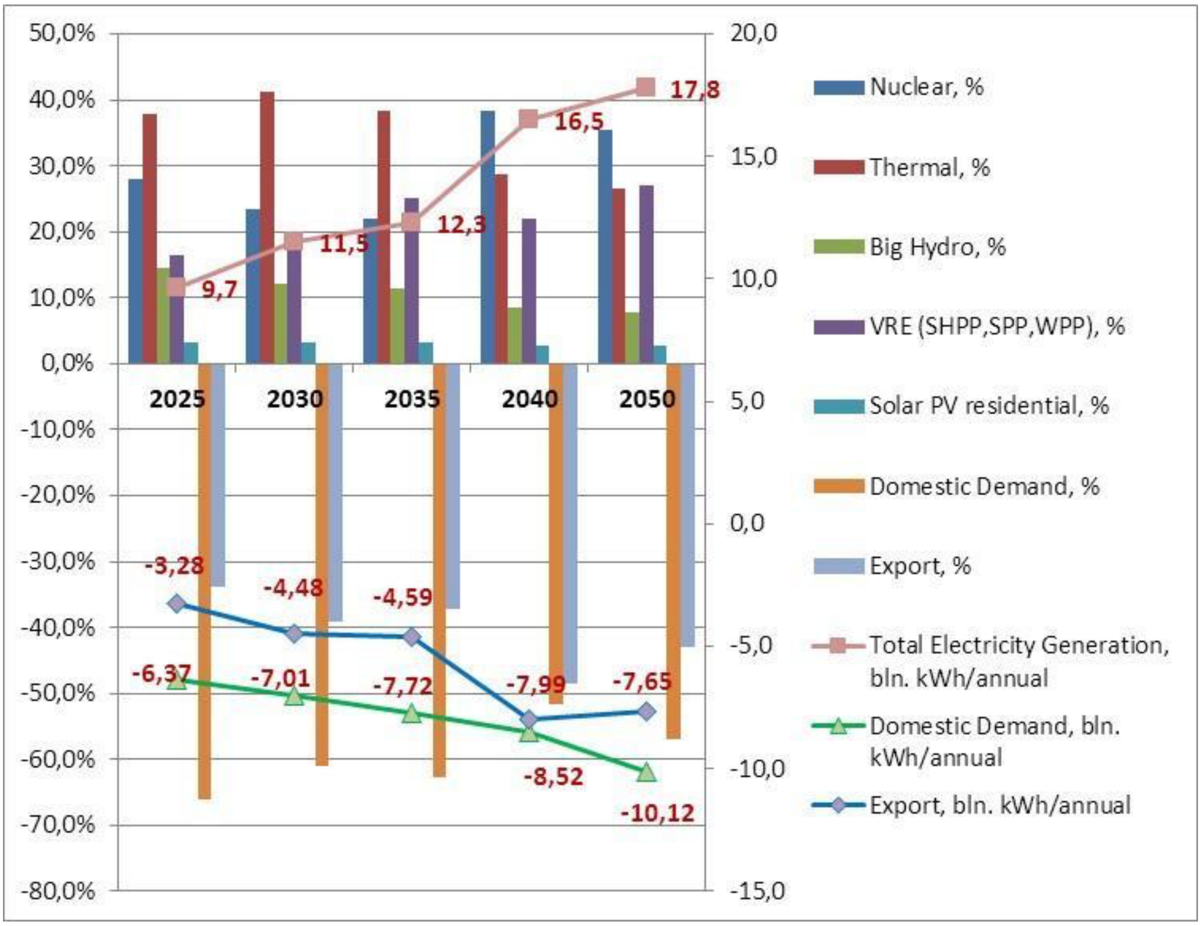

Figure 35. Total electricity generation, domestic demand and export for 2025-2050, % and Bln. kWh/annual.

Table 32. Total electricity generation, domestic demand and export for 2025-2050, % and Bln. KWh/annual**.**

	%					Bln. kWh/year				
Years	Nuclear	Thermal	Large Hydro	VRE-SHPP, SPP,WPP	Solar PV residential	Domestic demand	Export	Total Electricity Generation	Domestic Demand	Export
2025	28.0	37.8	14.5	16.5	3.3	-66.0	-34.0	9.7	-6.37	-3.28
2030	23.5	41.2	12.1	19.9	3.3	-61.0	-39.0	11.5	-7.01	-4.48
2035	21.9	38.4	11.3	25.0	3.2	-62.7	-37.3	12.3	-7.72	-4.59
2040	38.3	28.7	8.5	21.9	2.7	-51.6	-48.4	16.5	-8.52	-7.99
2050	35.6	26.6	7.9	27.1	2.8	-56.9	-43.1	17.8	-10.12	-7.65

In the electric power system, the electricity output of electric power plants with renewable sources (including residential solar plants) will have the following picture by year:

Table 33. Electricity generation of SHHP, RSPP, SPP, WPP for 2025-2050, in % and Bln. kWh/year.

	Bln. kWh/year					%						
Year	SHPP	RSPP	SPP	WPP	**Sum**	SHPP	RSPP	SPP	WPP	Total	SPP, WPP	SPP, WPP, RSPP
2025	0.82	0.315	0.767	0.00397	**1.906**	8.50	3.27	7.94	0.04	**19.7**	**7.98**	**11.25**
2030	0.82	0.375	1.463	0.00397	**2.662**	7.14	3.26	12.73	0.03	**23.2**	**12.76**	**16.03**
2035	0.82	0.400	1.463	0.800	**3.482**	6.66	3.25	11.88	6.50	**28.3**	**18.38**	**21.63**
2040	0.82	0.438	1.463	1.340	**4.060**	4.97	2.65	8.86	8.12	**24.6**	**16.97**	**19.63**
2050	0.82	0.500	2.103	1.900	**5.322**	4.61	2.81	11.83	10.69	**29.9**	**22.52**	**25.33**

The data presented in the "SPP, WPP" column corresponds to the large solar and wind generation, the data presented in the "SPP, WPP, RSPP" column correspond to the large solar, residential solar and wind generation, the data presented in the "Total" column correspond to the large solar, residential solar, wind and small hydro-generations. The information is presented in nominal (bln. kWh/annual) and percentage units.

If we only consider generation with renewable sources and a new nuclear power plant, then the electricity balance will be as shown in Table 34:

Table 34. Electricity generation of VRE (SHHP, SPP, RSPP, WPP), Nuclear, Domestic Demand for 2025-2050, %.

Year	VRE (SHPP,SPP, RSPP,WPP)	Nuclear	Total	Domestic Demand	Residual unbalance
2025	19.7	28.0	47.7	-66.0	-18.3
2030	23.2	23.5	46.7	-61.0	-14.3
2035	28.3	21.9	50.2	-62.7	-12.5
2040	24.6	38.3	62.9	-51.6	11.3
2050	29.9	35.6	65.5	-56.9	8.6

Table 34 shows that the abovementioned generation will not be sufficient to cover the internal demand of RA by 2040, even with the operation of a new nuclear power plant; and in the case the latter is absent, this applies to 2040 and 2050, as well.

Table 35. Electricity generation of Thermal Power Plants for 2025-2050, Bln. kWh/year, %.

	Bln. kWh/year				**%**			
Year	Hrazdan Unit 5	Yerevan CCGT	ArmPower CCGT	Sum	Hrazdan Unit 5	Yerevan CCGT	ArmPower CCGT	Total
2025	0	1.65	2	**3.65**	0.00	17.10	20.72	**37.8**
2030	1.083	1.65	2	**4.733**	9.43	14.36	17.41	**41.2**
2035	1.083	1.65	2	**4.733**	8.80	13.40	16.25	**38.4**
2040	1.083	1.65	2	**4.733**	6.56	9.99	12.11	**28.7**
2050	1.083	1.65	2	**4.733**	6.09	9.28	11.25	**26.6**

As can be seen from the table, no new TPPs are planned in Armenia. As for the Hrazdan Unit 5, only 1/3 of its theoretical generating potential was considered.

1.11 Conclusions

According to international experience in the absence of developed interconnections, generation from renewable energy sources should not exceed 15 % of the total generation in terms of ensuring reliable and safe operation of the power system. From the above tables it can be seen that in 2025, the electricity production of renewable sources in the RA power network exceeds the specified permissible threshold reaching 19.8 %, and this trend will continue in 2030 and 2035, reaching 23.2 % and 28.2 % respectively. In 2040, the share of variable renewable energy generation in the system drops to 24.6 % due to the planned entry of a new 1000 MW nuclear power plant, but once again rises almost to the 30 % threshold in 2050. However, it should be noted here that the share of generation by small hydropower plants is in the range of 4.6 – 8.5 %, which is a relatively predictable seasonal type of energy, while the volatility of wind and solar generation is difficult to predict.

To ensure a high share of renewable generation and increase the level of energy independence while maintaining a secure and reliable energy system, it is important to provide the following critical requirements:

- Set up strong connections with neighboring networks (Iran and Georgia) based on long-term contractual commitments.
- Construct a new nuclear power plant.
- Build hydroelectric power stations.
- Integrate smart grid technologies.
- Implement energy storage technologies, especially at low-level networks.

The results of the study show that the internal consumption of RA cannot be met only via renewable sources, even purely from overall energy balances perspective. Moreover, there is also another important issue, such as the reliability and safety of the grid, which cannot be maintained without baseload generation. It appears that baseload generating power plants responsible for frequency regulation and the stability and maintaining of grid regimes are thermal and nuclear power plants. And even in the case of observing the electricity balance by itself, it is obvious that without the entry of a new nuclear plant into the RA system it will not be possible to ensure the self-sufficiency of the RA system even by 2050.

Therefore, it is obvious that to ensure the energy independence of RA, a new nuclear power plant is needed, which must be put in operation by 2040. In the absence of significant energy storage (which will remain problematic in the near future), the output of solar plants in full and wind plants in part, And during no sunshine hours - at night, early in the morning, as well as days with little sunshine, the grid's power demand must be covered by baseload generation, mainly the new nuclear plant, and, depending on demand, thermal plants.

From the presented generation balances, it can be seen that the self-sufficiency of Armenia's domestic electricity consumption (without the participation of thermal plants) can be ensured only by 2040 due to the entry into the system of a new nuclear power plant with an installed capacity of 1000 MW. However, this does not mean that in 2040 it will be possible or necessary to stop the operation of the three thermal plants operating in the RA energy system. This is due to the following very important factors:

- The Armenian grid needs power plants with the possibility of working on a reserve basis (mainly thermal plants), which should replace the nuclear power plant for periodic (mainly annual) recharge of the latter or ongoing and planned repairs, or in cases of forced emergency shutdown. Incidentally, according to reliability and safety indicators, the system must have a reserve equal to the installed capacity of the largest power unit operated in the system, which will be the new nuclear power plant by 2040, 1000 MW. Therefore, Hrazdan Unit 5 – 485 MW, Yerevan CCGT - 237.4 MW, Armpower CCGT - 254 MW power plants operating in the grid should be at least in reserve.

- Keeping thermal plants in operation will allow the Armenian government to conduct a flexible policy along with the trends of price changes in the international markets of primary energy carriers and innovative technologies.

- In case of the long-term operation of the current electricity-for-gas contract between Armenia and Iran, the presence of the Yerevan CCGT thermal plant is mandatory, and in case of revision of the contract and increase in volumes, the presence of other operational thermal plants is also possibly required.
- In case of an emergency malfunction or accident on the generation side, it should be possible to guarantee base load supply for (in worst case) 9 hours.

Considering that by 2050 the operating periods of Hrazdan Unit 5 and Yerevan CCGT thermal plants will expire, one could continue operating them as reserve capacities after 2050, if:

- The introduction of a new nuclear power plant with an installed capacity of 1000 MW into the Armenian grid will be implemented by 2040.
- It is possible to ensure provision of voltage and reactive power regimes in the absence of thermal plants.
- The entry of new hydropower plants and pumped storages into the system will be considered.
- The Armenian grid will be equipped with energy storage technologies, to ensure the reliability and safety of the system, in the periods of low renewable generation. However, it should be noted that these technologies remain quite problematic and economically unattractive. Serious problems also arise for the recycling and storage of depleted Li-Ion chemical batteries, which also need to be studied in depth.
- The price of natural gas supplied to Armenia will increase, reaching European prices.
- A long-term agreement will be signed with the energy systems of the neighboring countries regarding the provision of reserve capacities, in case of planned or emergency shutdown of Armenia’s baseload generation plants, or in case of emergency situations in the Armenian grid in general.
- Deep integration of Smart Grid technologies for intelligent management of Armenia’s power system, forecasting and prediction and prevention of emergency situations.
- Implementation of enabling legal-legislative changes and improvements. Revision of tariff policy.

Failure to comply with the above conditions and the decommissioning of thermal power plants can create a danger of the collapse of the power system and, consequently, reduce the energy independence of the country, making it more dependent on imports.

1.12 Further studies

Due to the increase in electricity consumption and the emergence of new generating capacities using renewable sources, further in-depth studies of distribution networks are needed.

The study should evaluate capability of the distribution networks to absorb and transmit the increased electricity flows, and the investment volume needed to ensure a certain amount of new renewable capacity to be brought into the grid.

These are the most important issues for the increased deployment of variable renewables in the future, whether for on-grid autonomous producers in 0.38/0.22 kV networks or new licensed electricity producers connected to medium voltage networks.

However, a deeper study of this issue is beyond the scope of a high-level study, such as a roadmap, but is necessary for the practical implementation of the provisions of the roadmap, and therefore this topic should be considered the subject of a separate study.

The in-depth studies should be based on the modeling of distribution networks, regime calculations, and technical-economic and financial-technical assessments.

2. DOMESTIC ENERGY DEMAND FORECAST FOR 2025-2040/50

2.1 Basic Provisions and Definitions

The forecast of domestic energy demand in the Republic of Armenia is based on the forecast of the main components of energy and, in particular, the demand for electricity, natural gas and oil products. The volumes of coal consumption in Armenia for energy needs, as well as heat supply from cogeneration power plants (CHP) are insignificant and practically do not affect the level of energy independence. However, they are included in the Total Primary Energy Supply (TPES).

When compiling the energy balance for the indicated energy components, the following standard items for TPES/Consumption were taken into account:

- TPES: import, export, stock changes, nuclear power stations main activity electricity generation (MA El. Gen.), thermal power stations (MA El. Gen.), combined heat and power stations (CHP), non-specified transformation output, large hydro power stations (MA El. Gen.), small hydro power stations (MA El. Gen.), wind power stations (MA El. Gen.), solar power stations,
- Consumption: consumption of the energy branch, distribution losses, industry, transport, households, agriculture, services.

The methodological basis for compiling the energy balance of Armenia for 2030 and 2040/2050 is the manual published by the IEA, Eurostat and the Organization for Economic Co-operation and Development (OECD). In accordance with the requirements of the IEA standards, energy balances should be compiled using the oil equivalent (ktoe).

During the compilation of the 2017 Energy Balances the Excel program was developed by the Center for Economic Development and Research (Armenia) within the framework of the UNDP-GEF project “Armenia's Third Biennial Update on the UNFCCC”. The program is freely accessible on the UN website. Energy balance is represented in the form of a standard spreadsheet format, which reflects amounts of the energy resources extracted, produced, imported, exported, stored, processed, converted, transported, distributed and used in various sectors in Armenia during the forecasting period. During the compilation of the energy balance, it is necessary to take into account the flows of energy carriers and all types of the energy by their generation, recycling, transformation, distribution, storage and final consumption cycles, as well as energy costs and possible losses for their own needs.

Energy Balance forecasts have been made for 2030, 2040 and 2050. Forecasts were made according to the following two main scenarios: Baseline and Accelerated. For 2040, an Aggressive scenario was also considered. This chapter presents the main approaches to the formation of initial data for energy balances, as well as the results of calculations.

2.1.1 Baseline scenario

The Baseline scenario assumes that the retrospective 2010-2020 growth rates of demand in the main consumption sectors will be maintained and the use of energy resources to cover demand in the future will be in line with the "Strategic Program for the Development of the Energy of the Republic of Armenia until 2040", adopted as an Appendix N 1 to the Decree of the Government of the Republic of Armenia N 48-L dated January 14, 2021.

2.1.2 Accelerated scenario

The Accelerated scenario assumes the possibility of modifying the baseline scenario, taking into account the more intensive development of solar photovoltaic energy, an increase in the fleet of electric vehicles and agricultural machinery (based on a reduction in the vehicles using natural gas and oil products), partial replacement of gas heating devices with electric ones, scaling up the use of solar water heating installations, introduction of biofuel technologies, limited reconstruction of transmission and distribution networks. The details of the accelerated development scenario are given in point 2.7 of this section.

2.1.3 Aggressive scenario

The Aggressive scenario assumes a significant increase in the possibility of recycling and stimulation of the use of local renewable energy sources, which will lead to a significant:

- Increase in the fleet of electric vehicles and machinery (based on a reduction in the vehicles using natural gas and oil products),
- Replacement of gas heating devices with electric ones,
- Scaling up the use of solar water heating installations,
- Introduction of biofuel technologies,
- Reinforcement of transmission and distribution networks.

Below are the main assumptions by type of energy resources used to compile forecast energy balances for 2030 and 2040/2050.

3. BALANCE COMPILATION AND APPLIED APPROACHES: BASELINE AND ACCELERATED SCENARIO

3.1 Electricity Balance

Armenia exports electricity to Iran and to Georgia as well as imports electricity from the mentioned countries. The construction of a 400 kV double-circuit transmission overhead line with Iran is in progress. This line will allow to export to Iran up to 5000 GWh of electricity annually. The construction of a 700 kV DC back-to-back substation and 400 kV transmission line with Georgia is in progress. The implementation of this project will allow to export to Georgia up to 3,000 GWh of electricity annually.

The domestic demand forecast for electricity is one of the key issues for planning the development of the power system. The methods of strategic management and regression analysis theories have been widely used to predict electricity demand.

Three main scenarios and eight sub-scenarios have been developed to forecast electricity demand in the economy. The main scenarios for forecasting changes in GDP are presented based on:

- the trend of previous years, in current prices
- the complex percentage, in current prices
- the complex percentage, constant 2010 US$.[2]

Theoretical foundations for forecasting domestic demand for electricity, collection and analysis of historical macroeconomic data, collection of historical data and demand forecast on electricity consumption by sectors of the economy, forecast of electricity demand in other sectors (household, transport, non-specified) and forecast of internal electricity demand of the Republic of Armenia in 2025-2040/50 for all eight sub-scenarios are given in Annex 1.

3.2 Development scenarios: Baseline, Accelerated, and Aggressive

For the **Baseline scenario** for the development of demand for electricity by consumption sectors, the following regression equations were used, determined based on trends in historical data (see Annex 1), million kWh:

$$W(t) = W_{economy}(t) + W_{households}(t) + W_{transport}(t) + W_{non-specified}(t) \quad (1)$$

where:

$$W_{economy}(t) = W_{agriculture}(t) + W_{industry}(t) + W_{service}(t) \quad (2)$$

$$W_{agriculture}(t+1) = W_{agriculture}(t) \cdot (1 + 0.0178), \quad (3)$$

$$W_{industry}(t+1) = W_{industry}(t) \cdot (1 + 0.0176), \quad (4)$$

$$W_{service}(t+1) = W_{service}(t) \cdot (1 + 0.0172), \quad (5)$$

[2] https://keydifferences.com/difference-between-nominal-and-real-gdp.html#Definition IEA data published with periodic updates

$$W_{household}(t) = 28.935 \cdot t - 56453, \tag{6}$$

$$W_{transport}(t) = 133.6 \cdot (t - 2006)^{-0.104}, \tag{7}$$

$$W_{non-specified}(t) = 12.06 * (t - 2006) + 212.8. \tag{8}$$

The presented equations are used for electricity demand forecasts under the Reference scenario for all considered years 2030-2040/2050.

The **Accelerated development scenario** assumes the achievement of the following indicators, which are the initial data for compiling electricity balances.

The following figure and tables show the results of compiling the electricity balance for the **Basic and Accelerated scenarios** in named and relative units. The electricity balance for the Aggressive scenario is given below in section 1.3 separately.

Table 36. Accelerated development scenario, by years, Million kWh.

	2030	**2040**	**2050**
Import	0	0	0
Export[3]	0	0	0
Generation			
TPPs[4] and CHPs	0	0	0
NPP[5]	Baseline	increase up to 6320	stay on level 6320
Large HPPs	Baseline	Baseline	Baseline
Small HPPs	Baseline	Baseline	Baseline
Wind power	Baseline	increase up to 1340	increase up to 1900
Solar PV	increase up to 1936.9	increase up to 2605	increase up to 3816
Consumption			
Industry	Baseline	Baseline	Baseline
Transport[6]	increase up to 252.3	increase up to 757.1	increase up to 1438.2
Households[7]	slight decrease	increase up to 3617.4	increase up to 4612.2
Agriculture[4]	Baseline	increase up to 107.2	increase up to 185.4
Services[5]	slight decrease	increase up to 2373	increase up to 2775.7

[3] Export of electricity is considered only as a commercial activity provided for by regional agreements

[4] TPPs will operate only to cover the commercial component under regional agreements

[5] NPP output will increase due to the commissioning of new unit

[6] Consumption will increase due to the reduction of vehicles using natural gas (in 2030 by 6.5%, in 2040 by 30% and in 2050 by 50%) and oil products (in 2030 by 5%, in 2040 by 20% and in 2050 by 25%)

[7] Consumption will increase due to partial replacement of gas heating devices with electric ones (natural gas decrease in 2030 by 10%, in 2040 by 30% and in 2050 by by 40%), taking into account the restrictions imposed by the scaling up of the use of solar water heating installations (increase in energy supply from SWH installations in 2025-2030 by an average of 34.3%, in 2030-2035 by 12.4%, in 2035-2040 by 7.3%, in 2040-2045 by 4.8% and in 2045-2050 by 3.8%%) and introduction of biofuel technologies (biogas production increase in 2025-2030 by an average of 26.5%, in 2030-2035 by 10.5%, in 2035-2040 by 7.0%, in 2040-2045 by 4.9% and in 2045-2050 by 2.8%%).

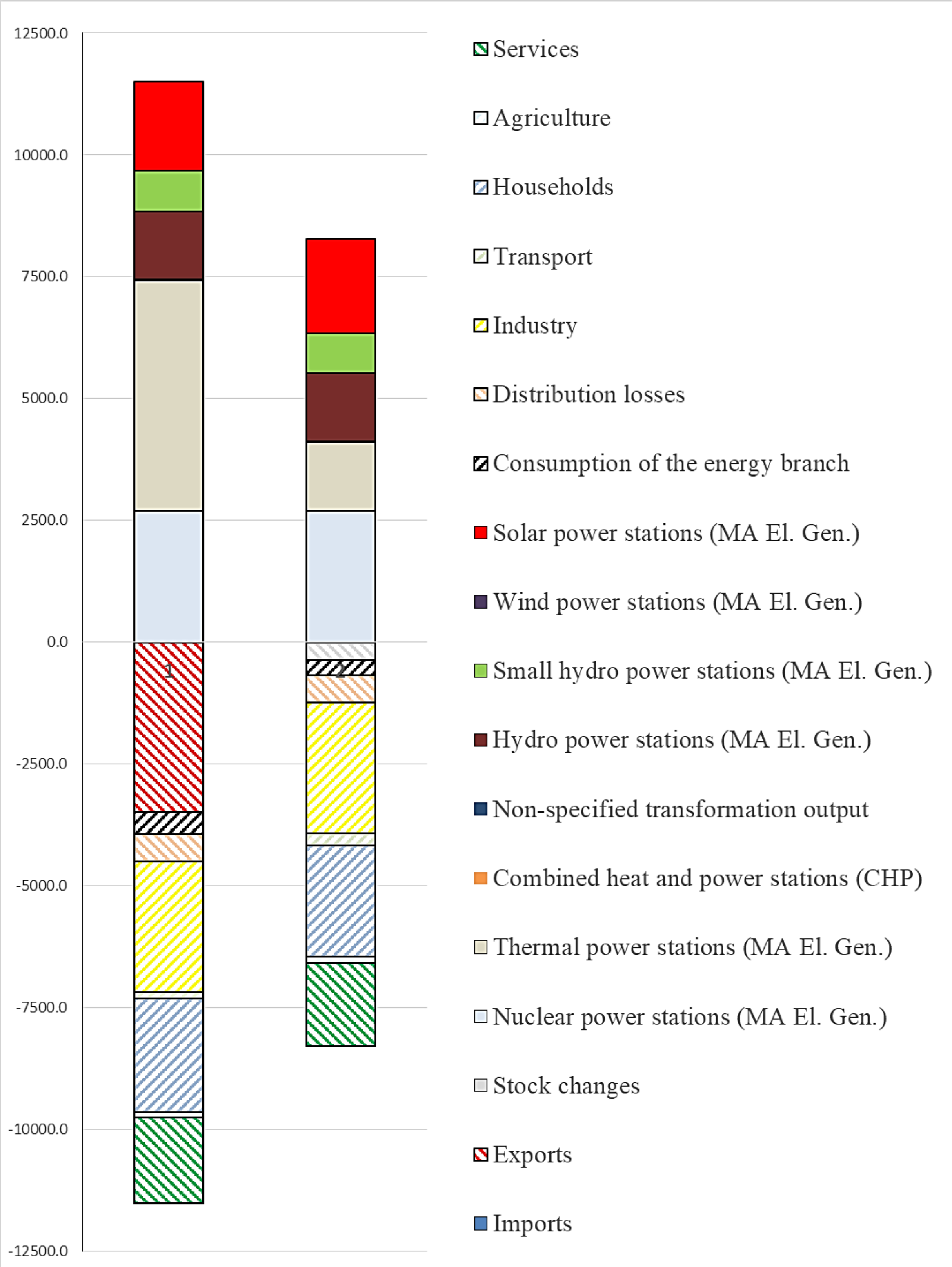

Figure 36. Electricity Demand forecast for 2030, Mln. kWh: 1. Baseline, 2. Accelerated development

Table 37. Electricity Balance 2030, million kWh.

N	Baseline	Accelerated development	Difference
1. Import	0.0	0.0	0.0
2. Export	-3487.6	0.0	-3487.6
3. Stock changes	0.0	-368.0	368.0
4. Nuclear power stations (MA El. Gen.)	2700.0	2700.0	0.0
5. Thermal power stations (MA El. Gen.)	4733.0	1402.6	3330.4
6. Combined heat and power stations (CHP)	17.3	17.3	0.0
7. Non-specified transformation output	0.0	0.0	0.0
8. Hydro power stations (MA El. Gen.)	1396.0	1396.0	0.0
9. Small hydro power stations (MA El.Gen.)	820.0	820.0	0.0
10. Wind power stations (MA El. Gen.)	4.0	4.0	0.0
11. Solar power stations (MA El. Gen.)	1838.0	1936.9	-98.9
12. Consumption of the energy branch	-440.9	-300.2	-140.7
13. Distribution losses	-561.0	-561.0	0.0
14. Industry	-2686.0	-2686.0	0.0
15. Transport	-126.1	-252.3	126.2
16. Households	-2332.8	-2284.2	-48.7
17. Agriculture	-121.0	-121.0	0.0
18. Services	-1752.8	-1704.2	-48.6
Total generation	11508.3	8276.8	3231.5
Total consumption	-11508.3	-8276.8	-3231.5

Table 38. Electricity Balance 2030, %.

N		Baseline	Accelerated development	Difference
1.	Import	0.0	0.0	0.0
2.	Export	-30.3	0.0	-30.3
3.	Stock changes	0.0	-3.2	3.2
4.	Nuclear power stations (MA El. Gen.)	23.5	23.5	0.0
5.	Thermal power stations (MA El. Gen.)	41.1	12.2	28.9
6.	Combined heat and power stations (CHP)	0.2	0.2	0.0
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	12.1	12.1	0.0
9.	Small hydro power stations (MA El. Gen.)	7.1	7.1	0.0
10.	Wind power stations (MA El. Gen.)	0.0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	16.0	16.8	-0.9
12.	Consumption of the energy branch	-3.8	-2.6	-1.2
13.	Distribution losses	-4.9	-4.9	0.0
14.	Industry	-23.3	-23.3	0.0
15.	Transport	-1.1	-2.2	1.1
16.	Households	-20.3	-19.8	-0.4
17.	Agriculture	-1.1	-1.1	0.0
18.	Services	-15.2	-14.8	-0.4
	Total generation	100.0	71.9	28.1
	Total consumption	-100.0	-71.9	-28.1

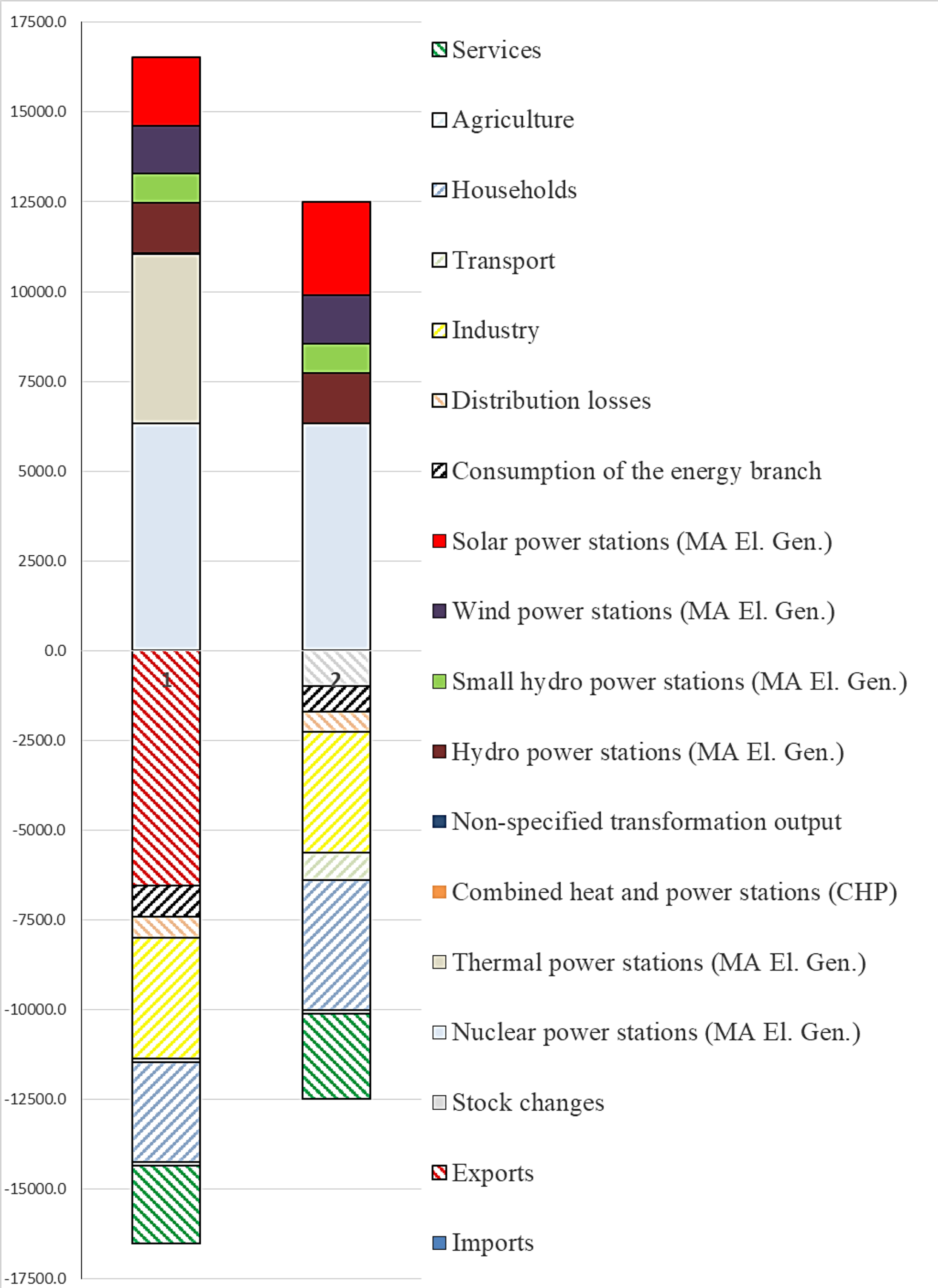

Figure 37. Electricity Demand forecast for 2040, million kWh: 1. Baseline, 2. Accelerated development.

Table 39. Electricity Balance 2040, million kWh.

N		Baseline	Accelerated development	Difference
1.	Import	0.0	0.0	0.0
2.	Export	-6556.4	0.0	-6556.4
3.	Stock changes	0.0	-992.7	992.7
4.	Nuclear power stations (MA El. Gen.)	6320.0	6320.0	0.0
5.	Thermal power stations (MA El. Gen.)	4733.0	0.0	4733.0
6.	Combined heat and power stations (CHP)	13.3	13.3	0.0
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	1396.0	1396.0	0.0
9.	Small hydro power stations (MA El. Gen.)	820.0	820.0	0.0
10.	Wind power stations (MA El. Gen.)	1340.0	1340.0	0.0
11.	Solar power stations (MA El. Gen.)	1901.0	2605.0	-704.0
12.	Consumption of the energy branch	-863.3	-705.2	-158.1
13.	Distribution losses	-580.0	-580.0	0.0
14.	Industry	-3361.8	-3361.8	0.0
15.	Transport	-104.6	-757.1	652.5
16.	Households	-2775.7	-3617.4	841.7
17.	Agriculture	-102.0	-107.2	5.2
18.	Services	-2179.5	-2373.0	193.5
	Total generation	16523.3	12494.3	4029.0
	Total consumption	-16523.3	-12494.3	-4029.0

Table 40. Electricity Balance 2040, %.

N	Baseline	Accelerated development	Difference
1. Import	0.0	0.0	0.0
2. Export	-39.7	0.0	-39.7
3. Stock changes	0.0	-6.0	6.0
4. Nuclear power stations (MA El. Gen.)	38.2	38.2	0.0
5. Thermal power stations (MA El. Gen.)	28.6	0.0	28.6
6. Combined heat and power stations (CHP)	0.1	0.1	0.0
7. Non-specified transformation output	0.0	0.0	0.0
8. Hydro power stations (MA El. Gen.)	8.4	8.4	0.0
9. Small hydro power stations (MA El. Gen.)	5.0	5.0	0.0
10. Wind power stations (MA El. Gen.)	8.1	8.1	0.0
11. Solar power stations (MA El. Gen.)	11.5	15.8	-4.3
12. Consumption of the energy branch	-5.2	-4.3	-1.0
13. Distribution losses	-3.5	-3.5	0.0
14. Industry	-20.3	-20.3	0.0
15. Transport	-0.6	-4.6	3.9
16. Households	-16.8	-21.9	5.1
17. Agriculture	-0.6	-0.6	0.0
18. Services	-13.2	-14.4	1.2
Total generation	100.0	75.6	24.4
Total consumption	-100.0	-75.6	-24.4

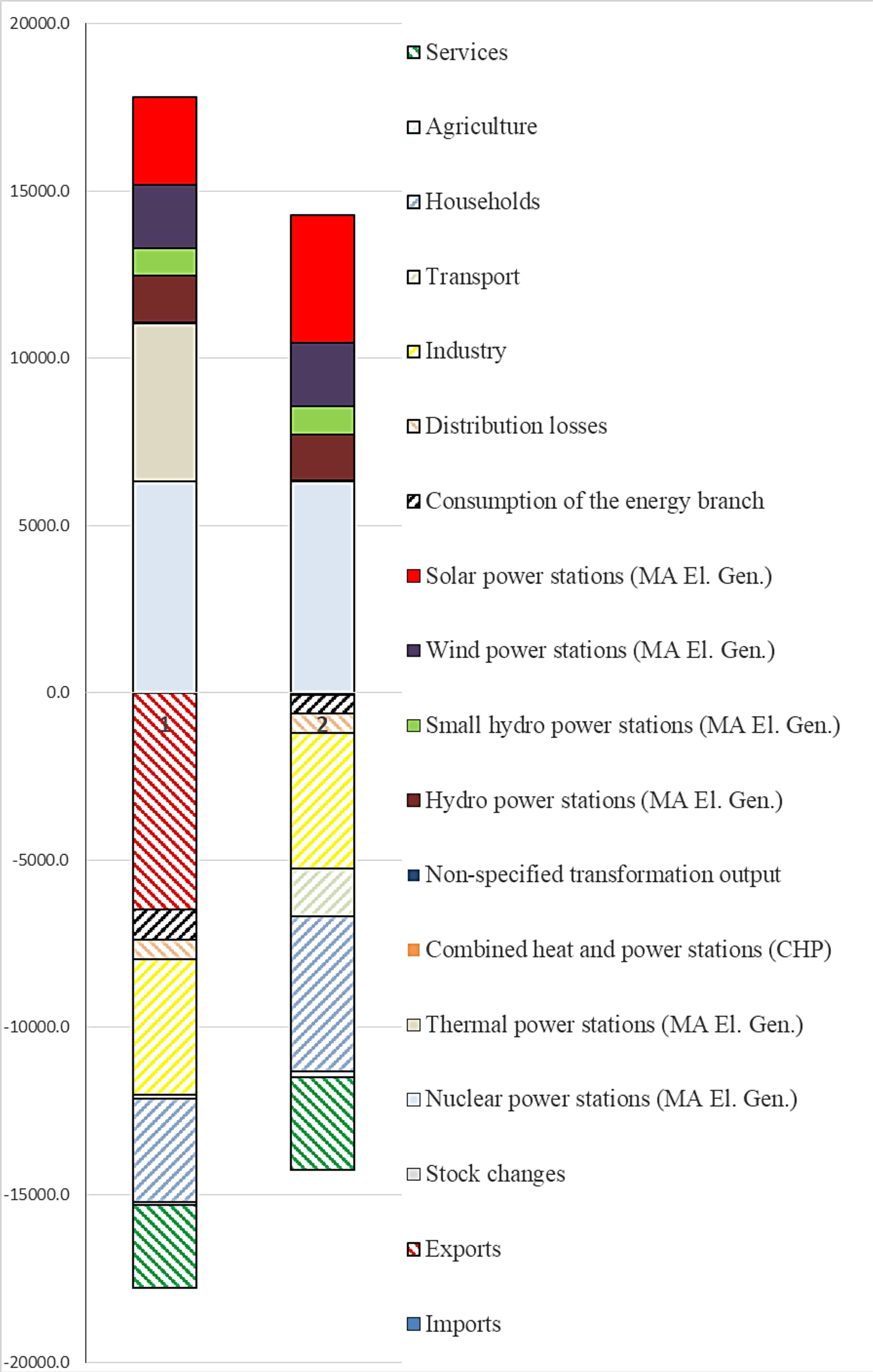

Figure 38. Electricity Demand forecast for 2050, million kWh: 1. Baseline, 2. Accelerated development.

Table 41. Electricity Balance 2050, Mln. kWh.

N	Baseline	Accelerated development	Difference
1. Import	0.0		0.0
2. Export	-6471.5		-6471.5
3. Stock changes	0.0	-58.0	58.0
4. Nuclear power stations (MA El. Gen.)	6320.0	6320.0	0.0
5. Thermal power stations (MA El. Gen.)	4733.0	0.0	4733.0
6. Combined heat and power stations (CHP)	13.3	13.3	0.0
7. Non-specified transformation output	0.0	0.0	0.0
8. Hydro power stations (MA El. Gen.)	1396.0	1396.0	0.0
9. Small hydro power stations (MA El. Gen.)	820.0	820.0	0.0
10. Wind power stations (MA El. Gen.)	1900.0	1900.0	0.0
11. Solar power stations (MA El. Gen.)	2603.0	3816.0	-1213.0
12. Consumption of the energy branch	-901.7	-546.8	-354.9
13. Distribution losses	-585.0	-585.0	0.0
14. Industry	-4063.9	-4064.0	0.1
15. Transport	-119.6	-1438.2	1318.6
16. Households	-3073.8	-4612.2	1538.4
17. Agriculture	-102.0	-185.4	83.4
18. Services	-2467.8	-2775.7	307.9
Total generation	17785.3	14265.3	3520.0
Total consumption	-17785.3	-14265.3	-3520.0

Table 42. Electricity Balance 2050, %.

N		Baseline	Accelerated development	Difference
1.	Import	0.0	0.0	0.0
2.	Export	-36.4	0.0	-36.4
3.	Stock changes	0.0	-0.3	0.3
4.	Nuclear power stations (MA El. Gen.)	35.5	35.5	0.0
5.	Thermal power stations (MA El. Gen.)	26.6	0.0	26.6
6.	Combined heat and power stations (CHP)	0.1	0.1	0.0
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	7.8	7.8	0.0
9.	Small hydro power stations (MA El. Gen.)	4.6	4.6	0.0
10.	Wind power stations (MA El. Gen.)	10.7	10.7	0.0
11.	Solar power stations (MA El. Gen.)	14.6	21.5	-6.8
12.	Consumption of the energy branch	-5.1	-3.1	-2.0
13.	Distribution losses	-3.3	-3.3	0.0
14.	Industry	-22.8	-22.9	0.0
15.	Transport	-0.7	-8.1	7.4
16.	Households	-17.3	-25.9	8.6
17.	Agriculture	-0.6	-1.0	0.5
18.	Services	-13.9	-15.6	1.7
	Total generation	100.0	80.2	19.8
	Total consumption	-100.0	-80.2	-19.8

3.3 Natural Gas Balance

The total length of the main natural gas pipelines and pipes' branches operated in the gas transportation system amounts to 1682 km. Transportation of the gas carried out through the 1583.8 km length gas pipeline. Unused pipelines are in operational reserve mode.

The underground gas storage facility (UGSF), located in Abovyan, is also used to store gas reserves. UGSF has strategic importance since it ensures the reliability of the gas supply in the country while being used to cover the seasonal and peak demand of the gas.

Natural gas transportation and distribution systems, as well as UGSF are owned by Gazprom Armenia.

Natural gas supplies to the domestic market of the RA are carried out from Russia and Iran.

Forecasting domestic demand for gas is a key issue when planning measures aimed at increasing energy independence. The methods of strategic management and regression analysis theories have been widely used to predict gas demand.

For forecasting the demand of gas in economy 4 main sectors were considered:

- power sector
- households
- industry
- transport

Natural gas consumption in the power sector depends on the demand for electricity and the characteristics of TPPs including CHP. A detailed description of the forecasts for the households, industry and transport is given in Annex 2.

Trends in demand for natural gas, determined on the basis of historical data, can be described by the following regression equations (see Annex 2), Mm^3:

$$V_{agriculture}(t) = 0.85 \cdot (4.05 \cdot t - 8107.2), \quad (9)$$

$$V_{industry}(t) = 23691 \cdot ln\, ln\,(t) - 180072, \quad (10)$$

$$V_{service}(t) = 0.85 \cdot 235.32 \cdot (t - 2013)^{0.0554}, \quad (11)$$

$$V_{household}(t) = 0.85 \cdot 486.286 \cdot (t - 2012)^{0.156}, \quad (12)$$

$$V_{transport}(t) = 133.6 \cdot (t - 2006)^{-0.104}\ . \quad (13)$$

The presented equations are used for natural gas demand forecasts under the Reference scenario for all considered years 2030-2040/2050.

The accelerated development scenario assumes the achievement of the following indicators, which are the initial data for compiling natural gas balances:

- natural gas consumption at the TPPs will be close to zero (the exception will be CHP), as TPPs will operate only for the commercial component under regional agreements;
- consumption of natural gas in the energy sector will also decrease due to the commissioning of a new NPP unit;

- the use of electric vehicles will replace vehicles, running on natural gas (in 2030 by 6.5 %, in 2040 by 30 % and in 2050 by 50 %);

- consumption of natural gas will decrease (in 2030 by 10 %, in 2040 by 30 % and in 2050 by 40 %), due to the partial replacement of gas-fired heaters in households and services with electric ones;

- natural gas consumption will decrease due to the increase in the use of solar water heating installations (increase in energy supply from SWH installations in 2025-2030 by an average of 34.3 %, in 2030-2035 by 12.4 %, in 2035-2040 by 7.3 %, in 2040-2045 by 4.8 % and in 2045-2050 by 3.8 %), as well as due to introduction of biofuel technologies (biogas production increase in 2025-2030 by an average of 26.5 %, in 2030-2035 by 10.5 %, in 2035-2040 by 7.0 %, in 2040-2045 by 4.9 % and in 2045-2050 by 2.8 %).

The following figure and tables show the results of compiling the ***natural gas balance for the Basic and Accelerated scenarios*** in named and relative units. The natural gas balance for the Aggressive scenario will be given later separately in chapter 4.

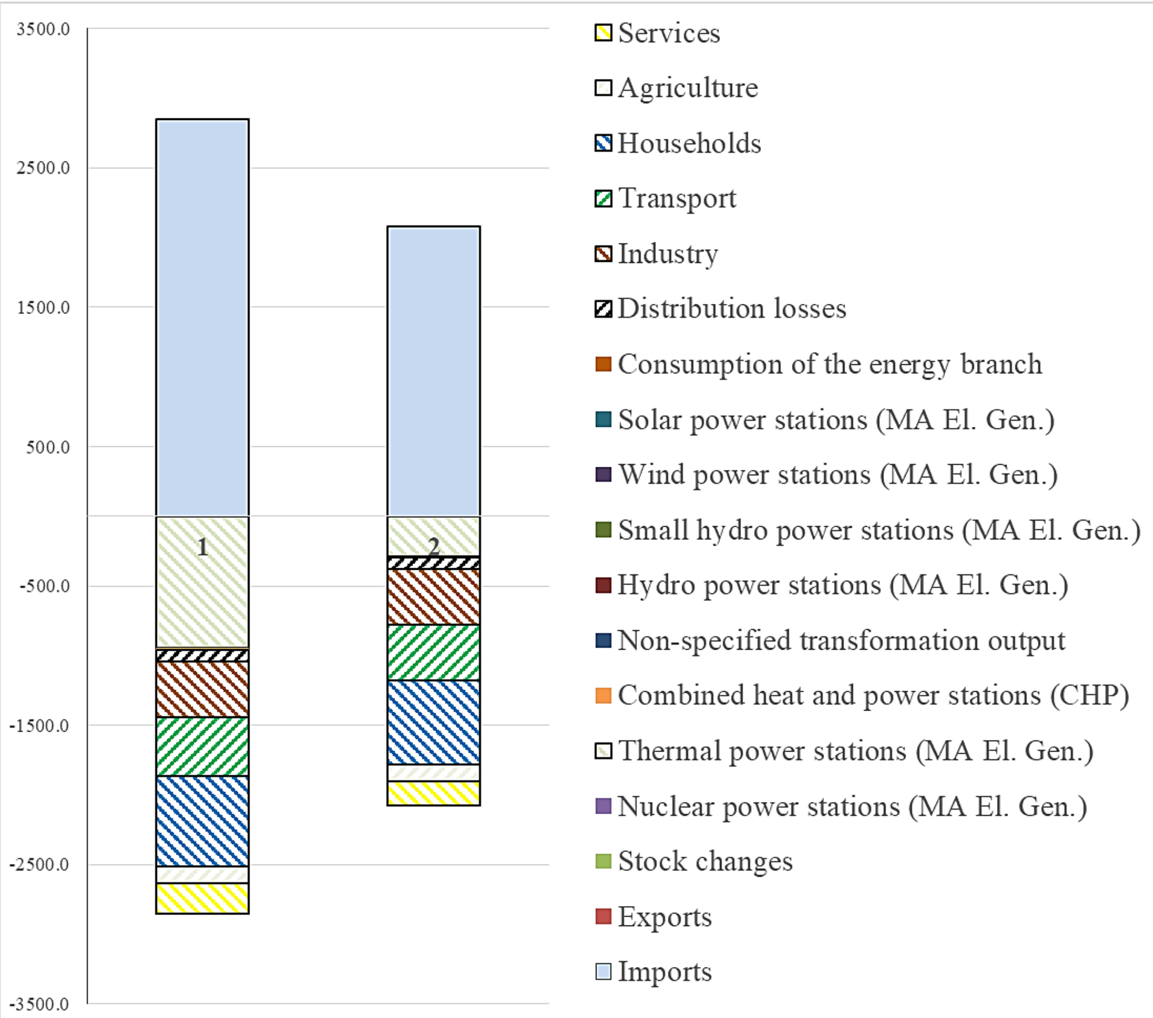

Figure 39. Natural Gas Demand Forecast for 2030, Mm³: 1. Baseline, 2. Accelerated development

Table 43. Natural Gas Balance 2030, Mm^3.

N		Baseline	Accelerated development	Difference
1.	Import	2851.4	2076.4	775.0
2.	Export	0	0.0	0.0
3.	Stock changes	0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-948.2	-286.0	-662.2
6.	Combined heat and power stations (CHP)	-3.9	-3.9	0.0
7.	Non-specified transformation output	0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0	0.0	0.0
12.	Consumption of the energy branch	-5.9	-5.9	0.0
13.	Distribution losses	-83.3	-83.3	0.0
14.	Industry	-399.6	-399.6	0.0
15.	Transport	-424.9	-398.3	-26.7
16.	Households	-644.8	-601.7	-43.1
17.	Agriculture	-121.0	-121.0	0.0
18.	Services	-219.8	-176.7	-43.1
	Total generation	2851.4	2076.4	775.0
	Total consumption	-2851.4	-2076.4	-775.0

Table 44. Natural Gas Balance 2030, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	72.8	27.2
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-33.3	-10.0	-23.2
6.	Combined heat and power stations (CHP)	-0.1	-0.1	0.0
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0.0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0.0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0.0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0.0	0.0	0.0
12.	Consumption of the energy branch	-0.2	-0.2	0.0
13.	Distribution losses	-2.9	-2.9	0.0
14.	Industry	-14.0	-14.0	0.0
15.	Transport	-14.9	-14.0	-0.9
16.	Households	-22.6	-21.1	-1.5
17.	Agriculture	-4.2	-4.2	0.0
18.	Services	-7.7	-6.2	-1.5
	Total generation	100.0	72.8	27.2
	Total consumption	-100.0	-72.8	-27.2

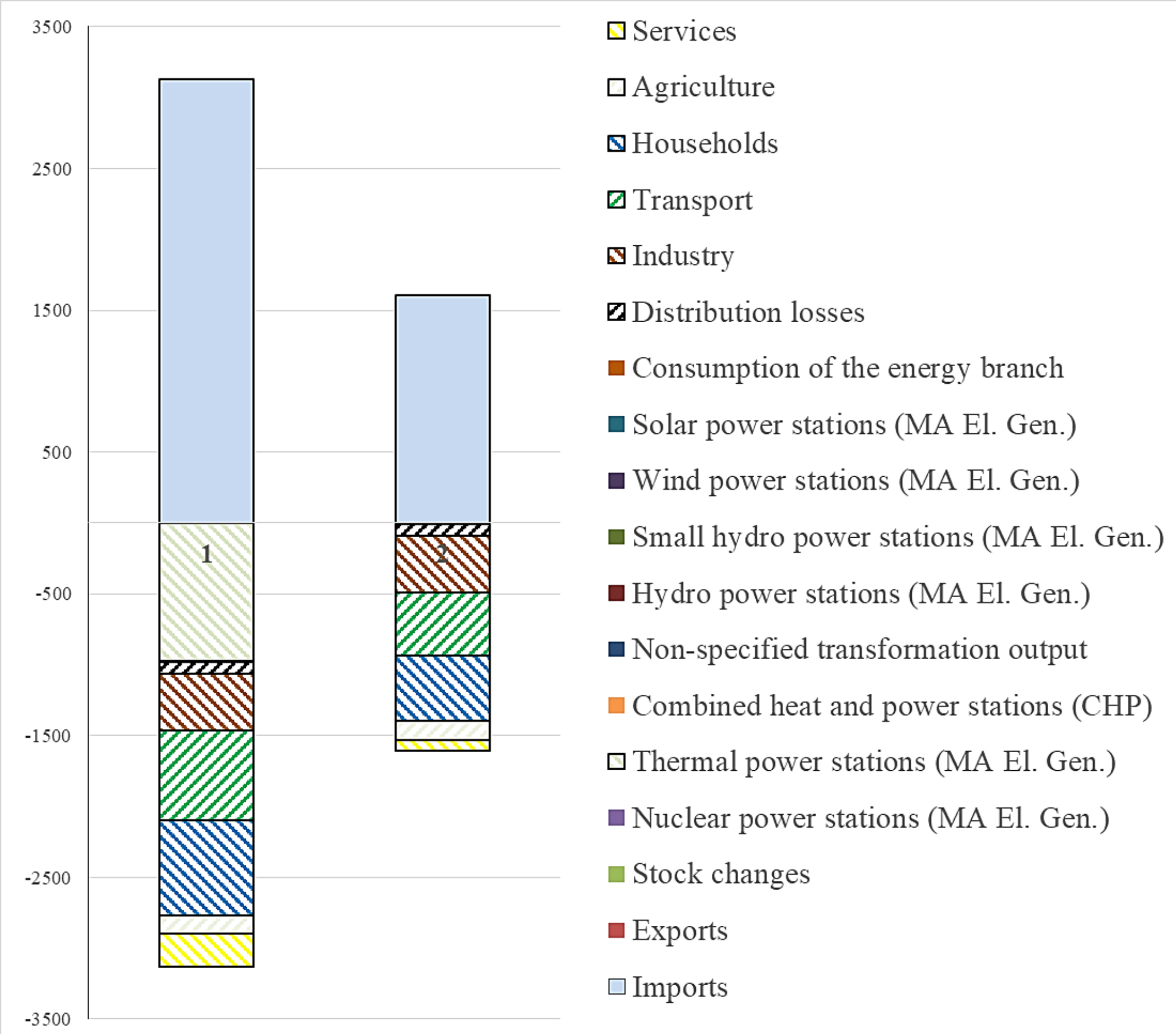

Figure 40. Natural Gas Demand Forecast for 2040, Mm³: 1. Baseline, 2. Accelerated development.

Table 45. Natural Gas Balance 2040, Mm³.

N		Baseline	Accelerated development	Difference
1.	Import	3128.6	1606.5	1522.1
2.	Export	0	0.0	0.0
3.	Stock changes	0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-972.0	0.0	-972.0
6.	Combined heat and power stations (CHP)	-3.8	0.0	-3.8
7.	Non-specified transformation output	0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0	0.0	0.0
12.	Consumption of the energy branch	-5.9	-5.9	0.0
13.	Distribution losses	-83.3	-83.3	0.0
14.	Industry	-399.6	-399.6	0.0
15.	Transport	-633.5	-443.5	-190.0
16.	Households	-668.88	-465.0	-203.9
17.	Agriculture	-131.0	-131.0	0.0
18.	Services	-230.68	-78.2	-152.5
	Total generation	3128.6	1606.5	1522.1
	Total consumption	-3128.6	-1606.5	-1522.1

Table 46. Natural Gas Balance 2040, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	51.3	48.7
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-31.1	0.0	-31.1
6.	Combined heat and power stations (CHP)	-0.1	0.0	-0.1
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0.0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0.0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0.0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0.0	0.0	0.0
12.	Consumption of the energy branch	-0.2	-0.2	0.0
13.	Distribution losses	-2.7	-2.7	0.0
14.	Industry	-12.8	-12.8	0.0
15.	Transport	-20.2	-14.2	-6.1
16.	Households	-21.4	-14.9	-6.5
17.	Agriculture	-4.2	-4.2	0.0
18.	Services	-7.4	-2.5	-4.9
	Total generation	100.0	51.3	48.7
	Total consumption	-100.0	-51.3	-48.7

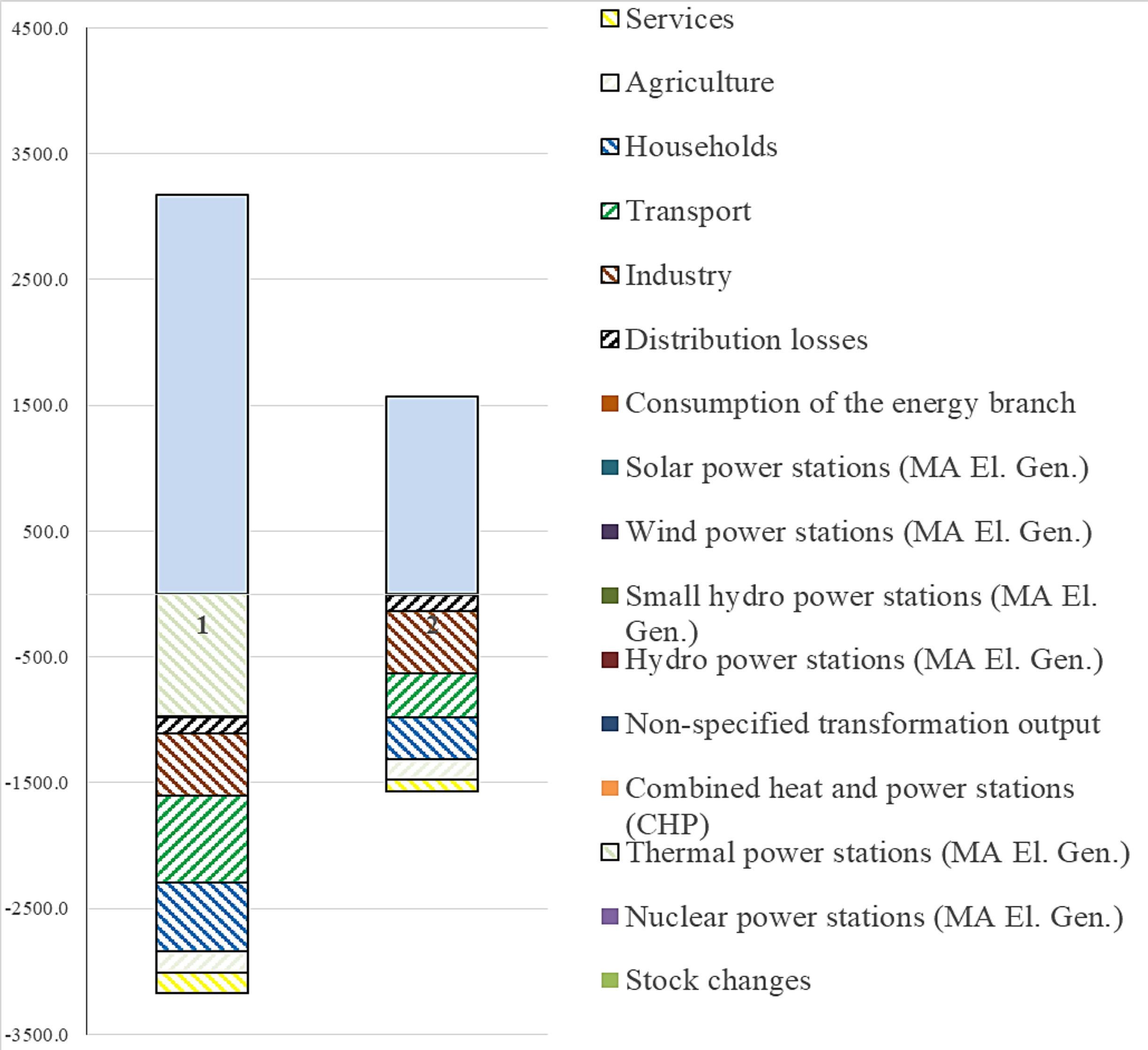

Figure 41. Natural Gas Demand Forecast for 2050, Mm³: 1. Baseline, 2. Accelerated development.

Table 47. Natural Gas Balance 2050, Mm^3.

N		Baseline	Accelerated development	Difference
1.	Import	3175.0	1571.8	1603.2
2.	Export	0	0.0	0.0
3.	Stock changes	0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-972.0	0.0	-972.0
6.	Combined heat and power stations (CHP)	-3.8	-3.8	0.0
7.	Non-specified transformation output	0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0	0.0	0.0
12.	Consumption of the energy branch	-6.4	-6.4	0.0
13.	Distribution losses	-124.0	-124.0	0.0
14.	Industry	-498.1	-498.1	0.0
15.	Transport	-690.4	-345.2	-345.2
16.	Households	-546.5	-333.7	-212.8
17.	Agriculture	-166.0	-166.0	0.0
18.	Services	-167.9	-94.5	-73.3
	Total generation	3175.0	1571.8	1603.2
	Total consumption	-3175.0	-1571.8	-1603.2

Table 48. Natural Gas Balance 2050, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	49.5	50.5
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-30.6	0.0	-30.6
6.	Combined heat and power stations (CHP)	-0.1	-0.1	0.0
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0.0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0.0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0.0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0.0	0.0	0.0
12.	Consumption of the energy branch	-0.2	-0.2	0.0
13.	Distribution losses	-3.9	-3.9	0.0
14.	Industry	-15.7	-15.7	0.0
15.	Transport	-21.7	-10.9	-10.9
16.	Households	-17.2	-10.5	-6.7
17.	Agriculture	-5.2	-5.2	0.0
18.	Services	-5.3	-3.0	-2.3
	Total generation	100.0	49.5	50.5
	Total consumption	-100.0	-49.5	-50.5

3.4 Thermal energy balance

Share of the thermal energy in the overall energy balance of Armenia is quite small. Thermal energy in Armenia is consumed only in the domestic market.

In the beginning of 1990’s, energy crisis occurred in Armenia caused by the irregular gas supply due to Armenia’s low solvency and regular explosions of the gas pipeline. That was the reason for the collapse of the centralized heat supply systems. After the restoration of gas supply for the preparation of hot water and heating, individual gas heating equipment was widely used.

Currently, centralized heat supply in Armenia is implemented by small combined cycle power plants. "Yerevan State Medical University after Mkhitar Heratsi" foundation and “Lus Astkh” LLC produce heat energy for its own needs, and "ArmRuscogenartion" CJSC realizes heat supply to Hovhannisyan, Varuzhan, Isahakyan, Tumanyan, Kuchak and Narekatsi blocks of Avan administrative area in Yerevan.

Rehabilitation of large district heating systems is a very costly and time-consuming task. Improvement in the efficiency of heat supply can be achieved by creating incentives for the introduction of small-scale combined cycle installations at selected facilities, such as educational establishments, hospitals, indoor sports facilities. One of the consumers of gas, and with steady growth, are greenhouses used in agriculture. To reduce gas consumption in greenhouses, solar collectors, local small-sized combined cycle thermal installations, photovoltaic facilities for forced ventilation control, etc. can be used.

Although the share of thermal energy in the Energy Balance is insignificant, it is expected that in the future it will be partially covered by heat generation from SWH installations under the following scenarios:

- in Baseline scenario it will substituted natural gas in 2030 up to 18.9 million m^3, in 2040 up to 57.3 million m^3 and in 2050 up to 152.3 million m^3;
- in Accelerated development scenario it will substitute natural gas up to 60.4 million m^3 in 2030, up to 93.0 million m^3 in 2040, and up to 218.5 million m^3 in 2050.

The thermal energy balance for the Aggressive scenario will be given later separately in section 1.3.

3.5 Oil products balance

The following data should be presented in the balance of oil products:

- motor fuel types (motor gasoline, diesel oil, petrol for jet engines, aviation kerosene)
- liquid oil gasses,
- mazut and oil bitumen,

- other oil products (other kerosene types, special types of gasoline, lubricants, paraffin and other oil products).

There is no raw oil extraction or oil refining in the territory of Armenia and all the oil products are imported. Some types of the imported oil products are used in the limited amounts for the production of varnish, paints and the other products in Armenia. Imported bitumen and mazut are utilized for non-energy purposes either.

The main oil products used for energy purposes are motor gasoline, diesel oil and liquefied petroleum gas (LPG). According to the IEA methodology, jet gasoline and aviation kerosene for countries with a small area should be included in the line of international aviation bunkers and excluded from further consideration. Other petroleum products are used for non-energy purposes, for example, light petroleum products in the manufacture of paints and varnishes, mazut and oil bitumen in road construction and etc.

An analysis of historical data shows that the demand for motor gasoline and diesel fuel is increasing by 1 % annually. Using this value of demand growth rates allows to form the Baseline scenario.

The Accelerated development scenario assumes a change in the structure of the car park. In particular the use of electric vehicles will replace:

- vehicles, running on motor gasoline and diesel oil in 2030 by 5 %, in 2040 by 20 % and in 2050 by 25 %;
- agricultural machines, running on diesel fuel in 2030 by 3 %, in 2040 by 10 % and in 2050 by 15 %.

The following figures and tables show the results of compiling the ***motor gasoline and diesel oil balance for the Basic and Accelerated scenarios*** in named and relative units. The balance of these oil products for the Aggressive scenario is given separately in section 1.3.

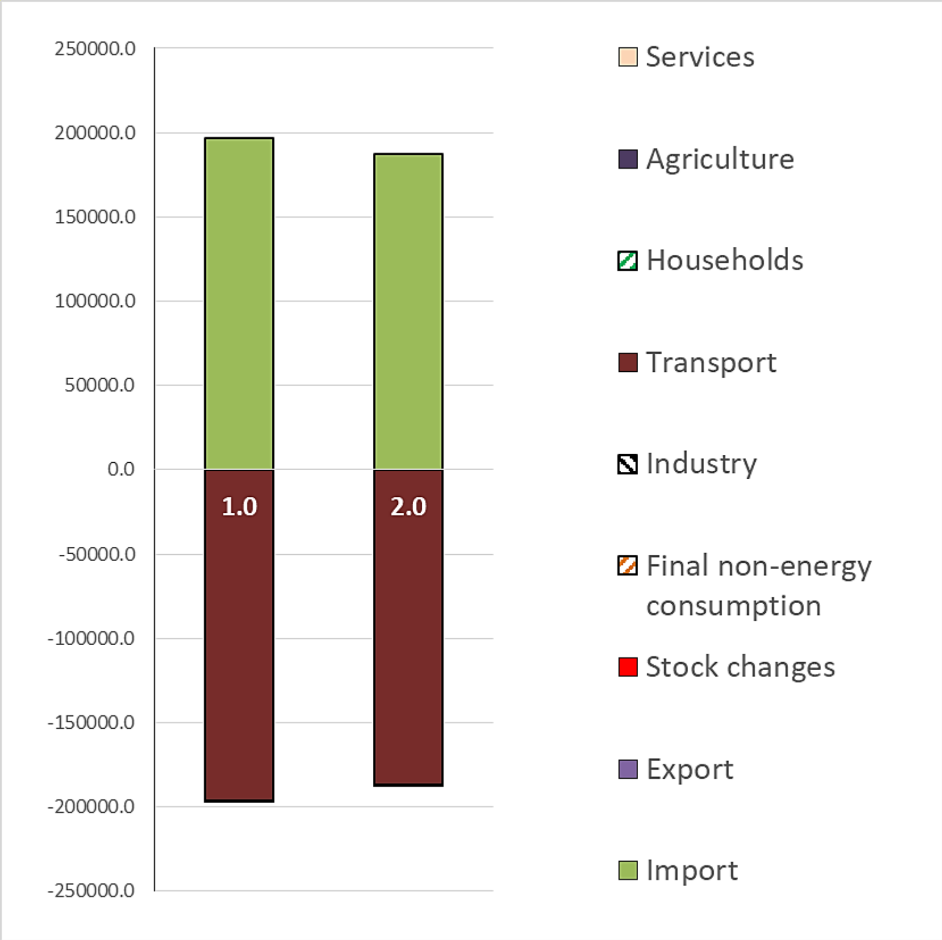

Figure 42. Motor Gasoline Balance for 2030, t: 1. Baseline, 2. Accelerated development

Table 49. Motor Gasoline Balance 2030, t.

N		Baseline	Accelerated development	Difference
1.	Import	196872.5	187059.4	9813.1
2.	Export			0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-20.1	-20.1	0.0
7.	Industry	-79.1	-79.1	0.0
8.	Transport	-196260.2	-186447.2	-9813.0
9.	Households	-513.0	-513.0	0.0
10.	Agriculture			0.0
11.	Services			0.0
	Total generation	196872.5	187059.4	9813.1
	Total consumption	-196872.5	-187059.4	-9813.1

Table 50. Motor Gasoline Balance 2030, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	95.0	5.0
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	0.0	0.0	0.0
7.	Industry	0.0	0.0	0.0
8.	Transport	-99.7	-94.7	-5.0
9.	Households	-0.3	-0.3	0.0
10.	Agriculture	0.0	0.0	0.0
11.	Services	0.0	0.0	0.0
	Total generation	100.0	95.0	5.0
	Total consumption	-100.0	-95.0	-5.0

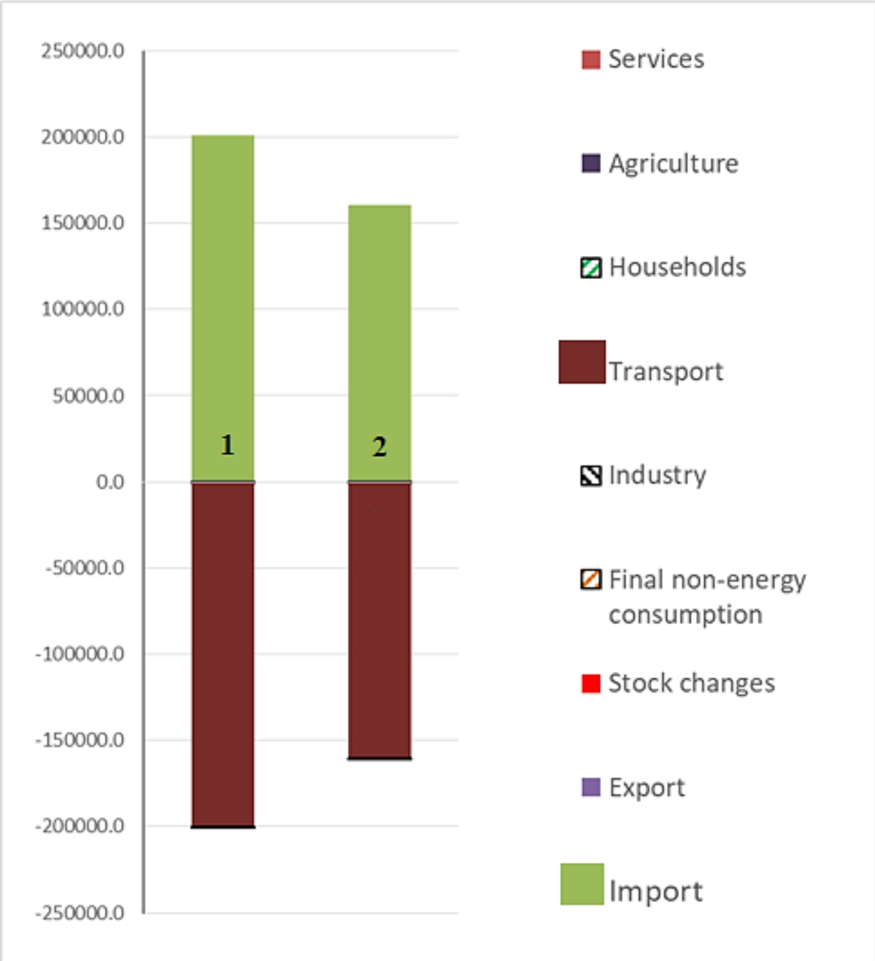

Figure 43. Motor Gasoline Balance for 2040, t: 1. Baseline, 2. Accelerated development.

Table 51. Motor Gasoline Balance 2040, t.

N		Baseline	Accelerated development	Difference
1.	Import	200900.9	160842.7	40058.2
2.	Export			0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-20.1	-20.1	0.0
7.	Industry	-79.1	-79.1	0.0
8.	Transport	-200288.7	-160230.4	-40058.2
9.	Households	-513.0	-513.0	0.0
10.	Agriculture			0.0
11.	Services			0.0
	Total generation	200900.9	160842.7	40058.2
	Total consumption	-200900.9	-160842.7	-40058.2

Table 52. Motor Gasoline Balance 2040, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	80.1	19.9
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	0.0	0.0	0.0
7.	Industry	0.0	0.0	0.0
8.	Transport	-99.7	-79.8	-19.9
9.	Households	-0.3	-0.3	0.0
10.	Agriculture	0.0	0.0	0.0
11.	Services	0.0	0.0	0.0
	Total generation	100.0	80.1	19.9
	Total consumption	-100.0	-80.1	-19.9

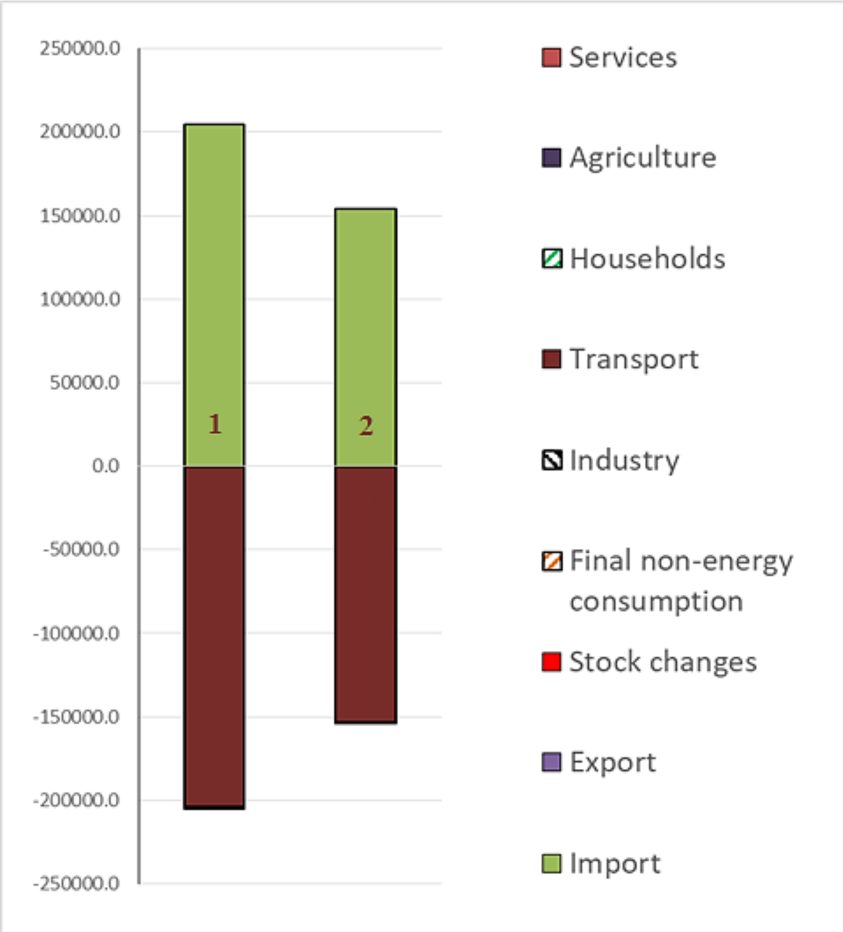

Figure 44. Motor Gasoline Balance for 2050, t: 1. Baseline, 2. Accelerated development.

Table 53. Motor Gasoline Balance 2050, t.

N		Baseline	Accelerated development	Difference
1.	Import	204843.0	153894.0	50949.0
2.	Export			0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-15.0	-15.0	0.0
7.	Industry	-82.0	-82.0	0.0
8.	Transport	-203796.0	-152847.0	-50949.0
9.	Households	-950.0	-950.0	0.0
10.	Agriculture			0.0
11.	Services			0.0
	Total generation	204843.0	153894.0	50949.0
	Total consumption	-204843.0	-153894.0	-50949.0

Table 54. Motor Gasoline Balance 2050, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	75.1	24.9
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	0.0	0.0	0.0
7.	Industry	0.0	0.0	0.0
8.	Transport	-99.5	-74.6	-24.9
9.	Households	-0.5	-0.5	0.0
10.	Agriculture	0.0	0.0	0.0
11.	Services	0.0	0.0	0.0
	Total generation	100.0	75.1	24.9
	Total consumption	-100.0	-75.1	-24.9

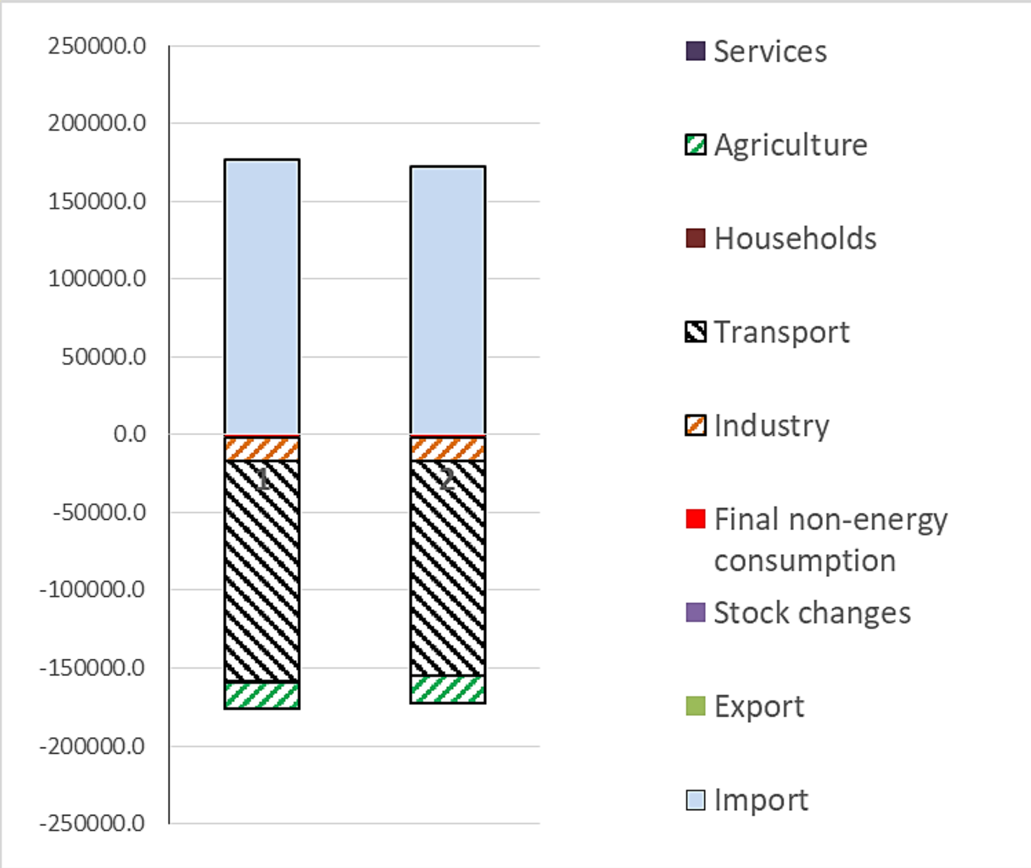

Figure 45. Diesel Oil Balance for 2030, t: 1. Baseline, 2. Accelerated development.

Table 55. Diesel Oil Balance 2030, t.

N		Baseline	Accelerated development	Difference
1.	Import	176450.8	171678.3	4772.5
2.	Export	0.0	0.0	0.0
3.	Stock changes			
4.	Consumption of the energy branch	0.0	0.0	0.0
5.	Distribution losses	0.0	0.0	0.0
6.	Final non-energy consumption	-1735.4	-1735.4	0.0
7.	Industry	-15266.3	-15266.3	0.0
8.	Transport	-141755.8	-137503.1	-4252.7
9.	Households	-366.7	-366.7	0.0
10.	Agriculture	-17326.6	-16806.8	-519.8
11.	Services			0.0
	Total generation	176450.8	171678.3	4772.5
	Total consumption	-176450.8	-171678.3	-4772.5

Table 56. Diesel Oil Balance 2030, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	97.3	2.7
2.	Export	0.0	0.0	0.0
3.	Stock changes			
4.	Consumption of the energy branch	0.0	0.0	0.0
5.	Distribution losses	0.0	0.0	0.0
6.	Final non-energy consumption	-1.0	-1.0	0.0
7.	Industry	-8.7	-8.7	0.0
8.	Transport	-80.3	-77.9	-2.4
9.	Households	-0.2	-0.2	0.0
10.	Agriculture	-9.8	-9.5	-0.3
11.	Services	0.0	0.0	0.0
	Total generation	100.0	97.3	2.7
	Total consumption	-100.0	-97.3	-2.7

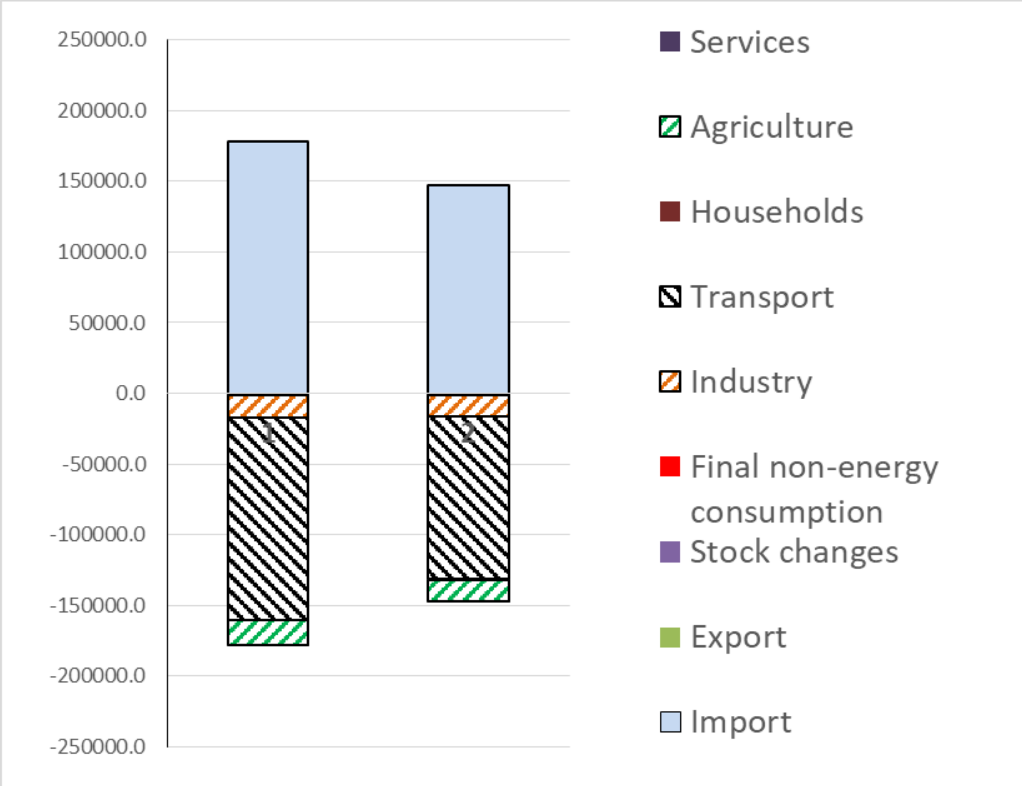

Figure 46. Diesel Oil Balance for 2040, t: 1. Baseline, 2. Accelerated development.

Table 57. Diesel Oil Balance 2040, t.

N		Baseline	Accelerated development	Difference
1.	Import	177993.4	147395.0	30598.4
2.	Export	0.0	0.0	0.0
3.	Stock changes			0.0
4.	Final non-energy consumption	-1735.4	-1735.4	0.0
5.	Industry	-15226.3	-15028.2	-198.1
6.	Transport	-143338.4	-114670.7	-28667.7
7.	Households	-366.7	-366.7	0.0
8.	Agriculture	-17326.6	-15593.9	-1732.7
9.	Services			0.0
	Total generation	177993.4	147395.0	30598.4
	Total consumption	-177993.4	-147395.0	-30598.4

Table 58. Diesel Oil Balance 2040, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	82.8	17.2
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Final non-energy consumption	-1.0	-1.0	0.0
5.	Industry	-8.6	-8.4	-0.1
6.	Transport	-80.5	-64.4	-16.1
7.	Households	-0.2	-0.2	0.0
8.	Agriculture	-9.7	-8.8	-1.0
9.	Services	0.0	0.0	0.0
	Total generation	100.0	82.8	17.2
	Total consumption	-100.0	-82.8	-17.2

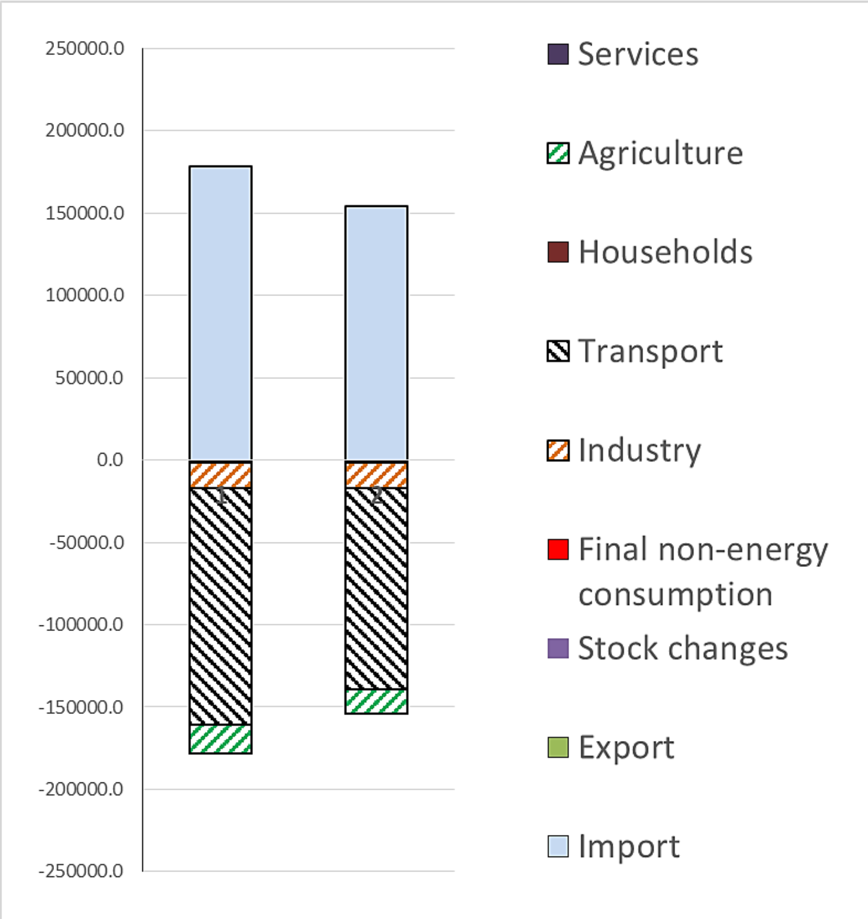

Figure 47. Diesel Oil Balance for 2050, t: 1. Baseline. 2. Accelerated development.

Table 59. Diesel Oil Balance 2050, t.

N		Baseline	Accelerated development	Difference
1.	Import	178396.2	154248.6	24147.6
2.	Export	0.0	0.0	0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-1735.4	-1735.4	0.0
7.	Industry	-15290.9	-15290.9	0.0
8.	Transport	-143437.6	-121922.0	-21515.6
9.	Households	-385.7	-385.7	0.0
10.	Agriculture	-17546.6	-14914.6	-2632.0
11.	Services			0.0
	Total generation	178396.2	154248.6	24147.6
	Total consumption	-178396.2	-154248.6	-24147.6

Table 60. Diesel Oil Balance 2050, %.

N		Baseline	Accelerated development	Difference
1.	Import	100.0	86.5	13.5
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-1.0	-1.0	0.0
7.	Industry	-8.6	-8.6	0.0
8.	Transport	-80.4	-68.3	-12.1
9.	Households	-0.2	-0.2	0.0
10.	Agriculture	-9.8	-8.4	-1.5
11.	Services	0.0	0.0	0.0
	Total generation	100.0	86.5	13.5
	Total consumption	-100.0	-86.5	-13.5

Coal Balance

Armenia does not have industrial coal deposits, as well as coal-fired thermal power plants. There are lignite deposits in Jajur and Dilijan. They haven't got any industrial significance, and according to the expert estimations around 500 families collect the lignite manually.

A certain amount of imported coal is used for non-energy purposes, such as peat as fertilizer.

Imported coal is consumed for energy purposes mainly in terms of anthracite in the household sector.

Since the share of coal in the Energy Balance is negligible, it is assumed that in the future it will remain at the current level.

3.6 Balance of wood and other biofuels

Wood and other types of biofuels are considered renewable energy sources. Types of the biofuels are:

- industrial wastes,
- solid household wastes,
- solid biomass (including charcoal),
- biogases,
- firewood and timber in Armenia are revealed in the following ways:
- sanitary deforestation (solid biomass),
- illegal deforestation (solid biomass),
- fallen dry wood (solid biomass),
- wastes from woodworking and furniture manufacturing (industrial wastes),
- manure.

Estimating the amount of wood and firewood consumed on the farm, as well as manure, is a complex task.

Based on the analysis of historical data, it is assumed that in the future the share of wood and firewood in the Energy Balance will remain at the current level.

3.7 Other renewable energy balance

This section observes hydro, wind, solar and geothermal energy.

Hydro energy is the most developed among the other renewable energy resources in Armenia.

Total installed capacity of seven HPPs (Sevan-Hrazdan cascade of HPPs) owned by the "International Energy Corporation" CJSC amounts to 561.4 MW. Total installed capacity of three HPPs (Vorotan cascade of HPPs) owned by "Contour Global Hydro Cascade" CJSC amounts to 404.2 MW.

Electricity generation will remain at the current level in the future.

At present 188 small HPPS were operated in Armenia with a total installed capacity amounted to 376.0 MW. It is planned that:

- by 2030 the installed capacity of small HPPs will reach 430 MW with an annual output of 820 million kWh;
- by 2040/2050 the installed capacity and electricity generation of small HPPs are taken at the level of 2030. This is due to the development of economically accessible hydropower potential by 2030, as well as the tightening of environmental requirements.

The above mentioned volumes of generation of small HPPs are used in both Baseline and Accelerated development scenarios.

Currently four wind power plants (WPP) operated in Armenia with average electricity generation of 1.5-1.8 million kWh/annual. It is expected that the share of wind farms is expected to grow slowly until 2030 and gradually accelerate thereafter. In both the baseline scenario and the accelerated development scenario, it is planned to achieve:

- in 2030 an installed capacity of 6.5 MW with an annual output of 4.0 Mln. kWh;
- in 2040 an installed capacity of 455.0 MW with an annual output of 1340 Mln. kWh;
- in 2050 an installed capacity of 721.5 MW with an annual output of 1900.0 Mln. kWh

Armenia has significant potential for solar energy production. Solar energy is represented by solar water heating and PV power plants. At present amounts of the hot water and electricity produced by the solar technologies increased significantly due to the policy realized by the RA Government. The net metering method was applied for the autonomous consumers in the PV sector.

Electricity generation from solar PV installations will grow to cover domestic demand for electricity, and the projected annual production volumes for the Baseline and Accelerated scenarios are presented in paragraph 2.1 of this section.

In addition, an increase in heat production from SWH installations is expected, the value of which for the Baseline and Accelerated scenarios is given in paragraph 2.3 of this section.

Geothermal energy in Armenia is represented by several small scale pilot installations which haven't been included in the energy balance due to their insignificant production volumes.

As a solid biomass for energy purposes, Armenia uses combustible wood and manure. A description of the biofuel balance is presented in paragraph 3.7 of this section.

The biogas installation located in Lusakert, which began operation in 2008 and operated until 2014, operates as a power plant using biogas technologies. The station's capacity allows processing 200-250 tons of bird droppings daily with the formation of biogas containing 60-70

% methane. The annual amount of generated electricity can reach up to 5.5 GWh. Individual low-power biogas plants are not widely used.

A description of the biogas balance is presented in paragraph 3.7 of this section.

4. AGGRESSIVE DEVELOPMENT SCENARIO

As noted earlier, the Aggressive Scenario assumes a significant increase in the use of renewable energy sources compared to the Accelerated Scenario. The prerequisites for the implementation of the aggressive development scenario are given in Section 1.

The Aggressive development scenario was predicted only for 2040 and assumes the achievement by this date of the indicators which have been accepted for the accelerated scenario of 2050.

The following figure and tables present the results of compiling the balances of electricity, natural gas and oil products for the Baseline, Accelerated and Aggressive scenarios in 2040 in named and relative units.

4.1 Electricity Demand forecast for 2040

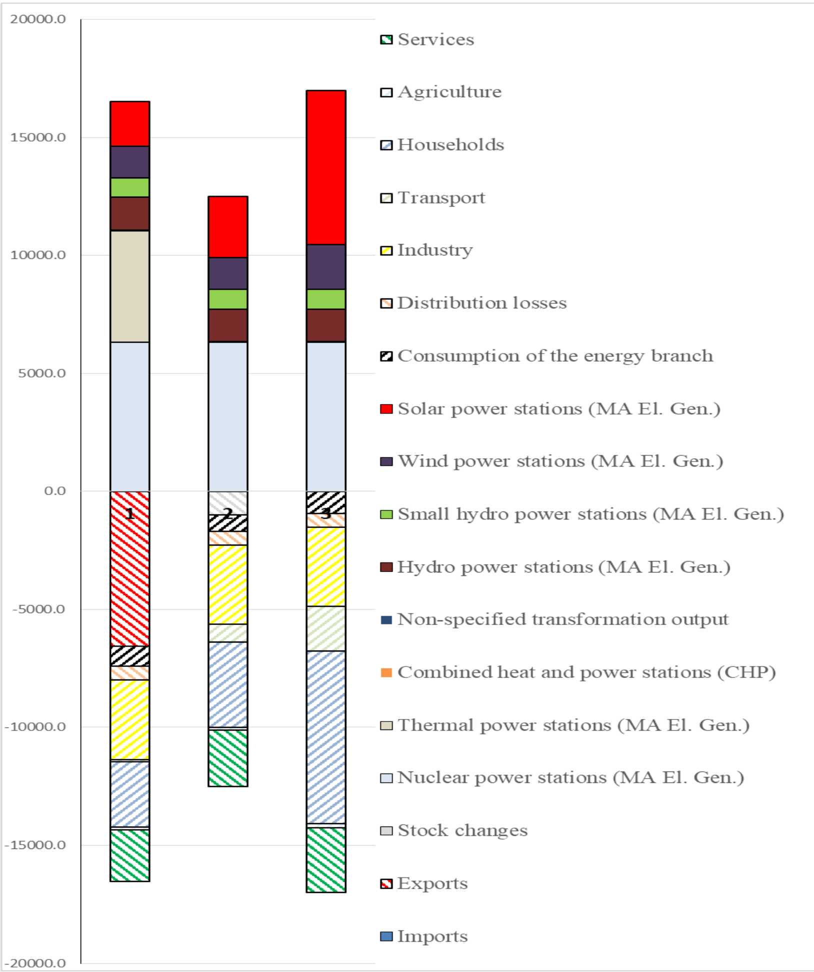

Figure 48. Electricity Demand forecast for 2040, Mln. kWh: 1. Baseline, 2. Accelerated, 3. Aggressive.

Table 61. Electricity Balance 2040, Mln. kWh.

N		Baseline	Accelerated	Aggressive
1.	Import	0.0	0.0	0.0
2.	Export	-6556.4	0.0	0.0
3.	Stock changes	0.0	-992.7	0.0
4.	Nuclear power stations (MA El. Gen.)	6320.0	6320.0	6320.0
5.	Thermal power stations (MA El. Gen.)	4733.0	0.0	0.0
6.	Combined heat and power stations (CHP)	13.3	13.3	13.3
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	1396.0	1396.0	1396.0
9.	Small hydro power stations (MA El. Gen.)	820.0	820.0	820.0
10.	Wind power stations (MA El. Gen.)	1340.0	1340.0	1900.0
11.	Solar power stations (MA El. Gen.)	1901.0	2605.0	6544.8
12.	Consumption of the energy branch	-863.3	-705.2	-930.2
13.	Distribution losses	-580.0	-580.0	-580.0
14.	Industry	-3361.8	-3361.8	-3361.8
15.	Transport	-104.6	-757.1	-1895.5
16.	Households	-2775.7	-3617.4	-7301.5
17.	Agriculture	-102.0	-107.2	-185.8
18.	Services	-2179.5	-2373.0	-2739.3
	Total generation	16523.3	12494.3	16994.1
	Total consumption	-16523.3	-12494.3	-16994.1

Table 62. Electricity Balance 2040, %.

N		Baseline	Accelerated	Aggressive
1	Import	0.0	0.0	0.0
2	Export	-39.7	0.0	0.0
3	Stock changes	0.0	-6.0	0.0
4	Nuclear power stations (MA El. Gen.)	38.2	38.2	38.2
5	Thermal power stations (MA El. Gen.)	28.6	0.0	0.0
6	Combined heat and power stations (CHP)	0.1	0.1	0.1
7	Non-specified transformation output	0.0	0.0	0.0
8	Hydro power stations (MA El. Gen.)	8.4	8.4	8.4
9	Small hydro power stations (MA El. Gen.)	5.0	5.0	5.0
10	Wind power stations (MA El. Gen.)	8.1	8.1	11.5
11	Solar power stations (MA El. Gen.)	11.5	15.8	39.6
12	Consumption of the energy branch	-5.2	-4.3	-5.6
13	Distribution losses	-3.5	-3.5	-3.5
14	Industry	-20.3	-20.3	-20.3
15	Transport	-0.6	-4.6	-11.5
16	Households	-16.8	-21.9	-44.2
17	Agriculture	-0.6	-0.6	-1.1
18	Services	-13.2	-14.4	-16.6
	Total generation	100.0	75.6	102.8
	Total consumption	-100.0	-75.6	-102.8

4.2 Natural Gas Demand Forecast for 2040.

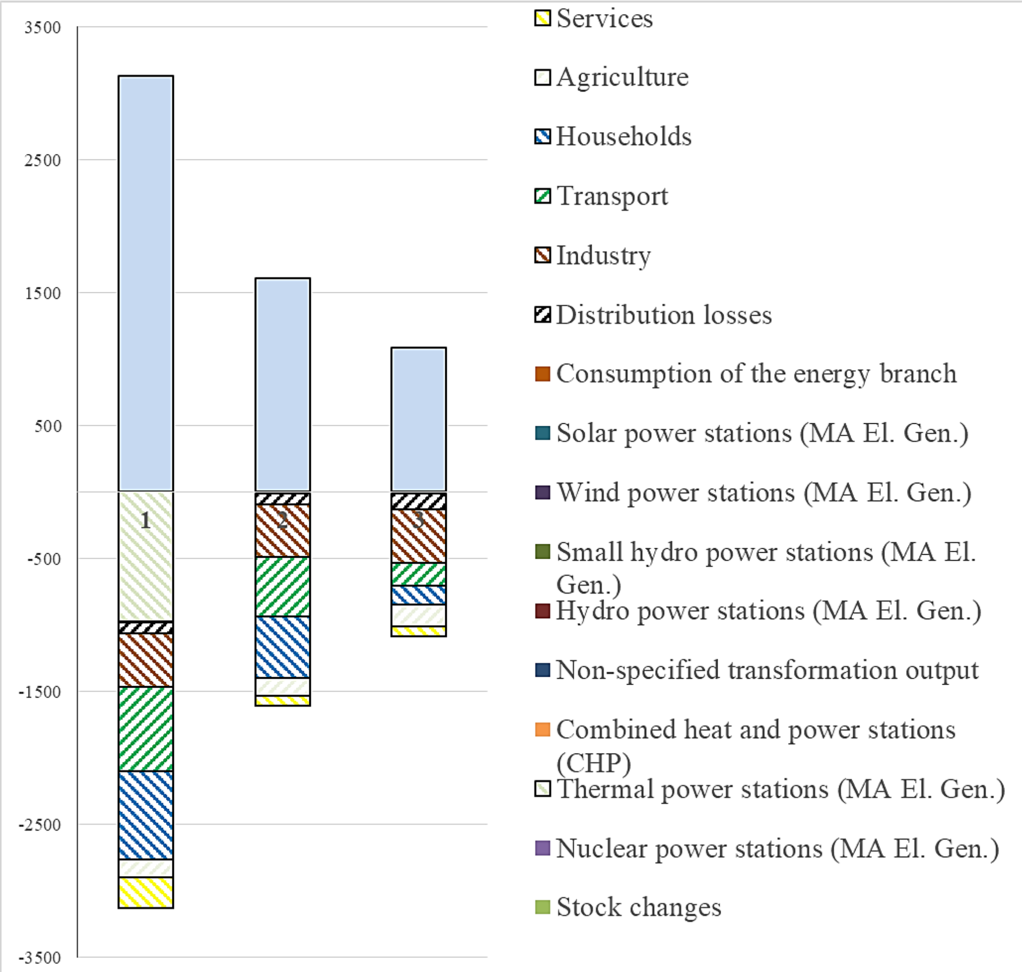

Figure 49. Natural Gas Demand Forecast for 2040, Mm³: 1. Baseline, 2. Accelerated, 3. Aggressive.

Table 63. Natural Gas Balance 2040, Mm³.

N		Baseline	Accelerated development	Aggressive
1.	Import	3128.6	1610.3	1084.6
2.	Export	0	0.0	0.0
3.	Stock changes	0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-972.0	0.0	0.0
6.	Combined heat and power stations (CHP)	-3.8	-3.8	-3.8
7.	Non-specified transformation output	0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0	0.0	0.0
12.	Consumption of the energy branch	-5.9	-5.9	-6.4
13.	Distribution losses	-83.3	-83.3	-124.0
14.	Industry	-399.6	-399.6	-399.6

N		Baseline	Accelerated development	Aggressive
15.	Transport	-633.5	-443.5	-172.6
16.	Households	-668.9	-465.0	-143.0
17.	Agriculture	-131.0	-131.0	-166.0
18.	Services	-230.7	-78.2	-69.2
	Total generation	3128.6	1610.3	1084.6
	Total consumption	-3128.6	-1610.3	-1084.6

Table 64. Natural Gas Balance 2040, %.

N		Baseline	Accelerated development	Aggressive
1.	Import	100.0	51.5	34.7
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-31.1	0.0	0.0
6.	Combined heat and power stations (CHP)	-0.1	-0.1	-0.1
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	0.0	0.0	0.0
9.	Small hydro power stations (MA El. Gen.)	0.0	0.0	0.0
10.	Wind power stations (MA El. Gen.)	0.0	0.0	0.0
11.	Solar power stations (MA El. Gen.)	0.0	0.0	0.0
12.	Consumption of the energy branch	-0.2	-0.2	-0.2
13.	Distribution losses	-2.7	-2.7	-4.0
14.	Industry	-12.8	-12.8	-12.8
15.	Transport	-20.2	-14.2	-5.5
16.	Households	-21.4	-14.9	-4.6
17.	Agriculture	-4.2	-4.2	-5.3
18.	Services	-7.4	-2.5	-2.2
	Total generation	100.0	51.5	34.7
	Total consumption	-100.0	-51.5	-34.7

4.3 Motor Gasoline Balance for 2040.

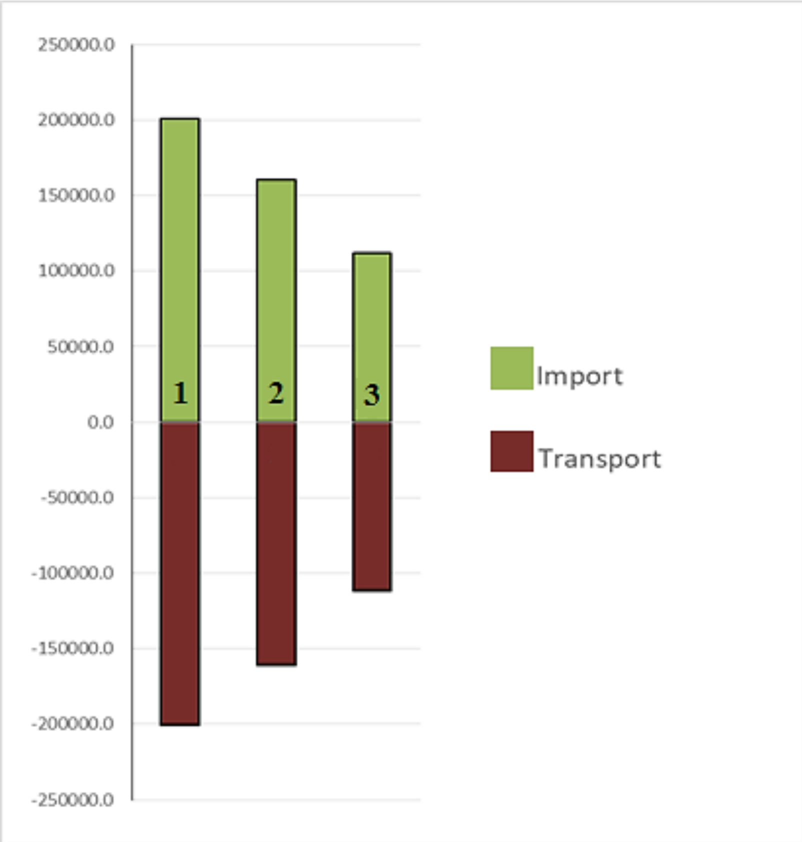

Figure 50. Motor Gasoline Balance for 2040, tons: 1. Baseline, 2. Accelerated, 3. Aggressive.

Table 65. Motor Gasoline Balance 2040, t

N		Baseline	Accelerated development	Aggressive
1.	Import	200900.9	160842.7	111879.3
2.	Export			0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-20.1	-20.1	-20.1
7.	Industry	-79.1	-79.1	-79.1
8.	Transport	-200288.7	-160230.4	-111267.0
9.	Households	-513.0	-513.0	-513.0
10.	Agriculture			0.0
11.	Services			0.0
	Total generation	200900.9	160842.7	111879.3
	Total consumption	-200900.9	-160842.7	-111879.3

Table 66. Motor Gasoline Balance 2040, %.

N		Baseline	Accelerated development	Aggressive
1.	Import	100.0	80.1	55.7
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	0.0	0.0	0.0
7.	Industry	0.0	0.0	0.0
8.	Transport	-99.7	-79.8	-55.4
9.	Households	-0.3	-0.3	-0.3
10.	Agriculture	0.0	0.0	0.0
11.	Services	0.0	0.0	0.0
	Total generation	100.0	80.1	55.7
	Total consumption	-100.0	-80.1	-55.7

4.4 Diesel Oil Balance for 2040

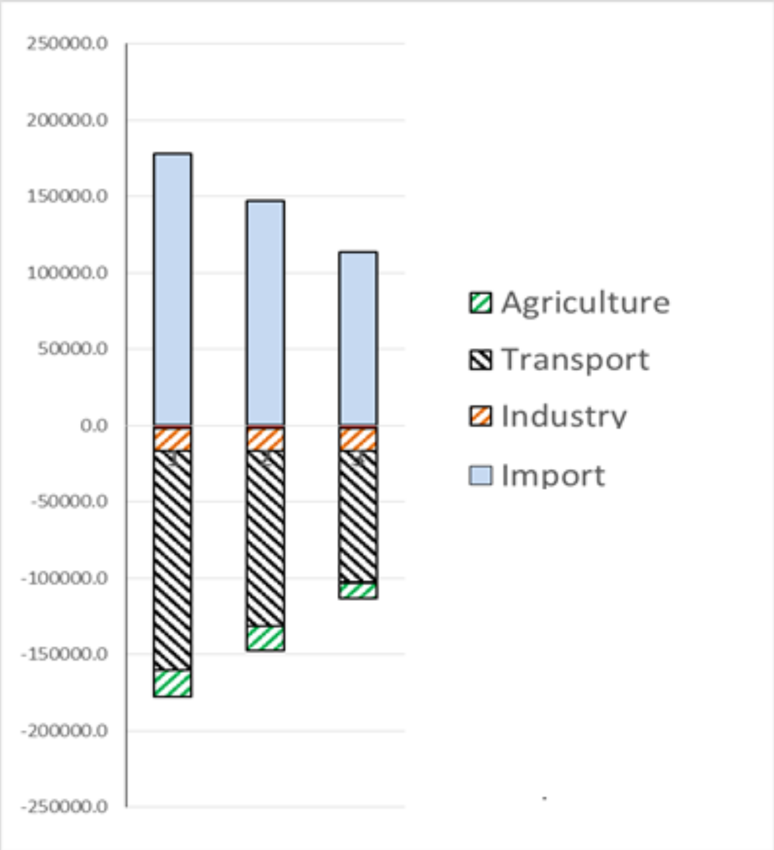

Figure 51. Diesel Oil Balance for 2040, t: 1. Baseline, 2. Accelerated, 3. Aggressive.

Table 67. Diesel Oil Balance 2040, t.

N		Baseline	Accelerated development	Aggressive
1.	Import	177993.4	147395.0	113529.4
2.	Export	0.0	0.0	0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-1735.4	-1735.4	-1735.4
7.	Industry	-15226.3	-15028.2	-15028.3
8.	Transport	-143338.4	-114670.7	-86003.0
9.	Households	-366.7	-366.7	-366.7
10.	Agriculture	-17326.6	-15593.9	-10396.0
11.	Services			0.0
	Total generation	177993.4	147395.0	113529.4
	Total consumption	-177993.4	-147395.0	-113529.4

Table 68. Diesel Oil Balance 2040, %.

N		Baseline	Accelerated development	Aggressive
1.	Import	100.0	82.8	63.8
2.	Export	0.0	0.0	0.0
3.	Stock changes	0.0	0.0	0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-1.0	-1.0	-1.0
7.	Industry	-8.6	-8.4	-8.4
8.	Transport	-80.5	-64.4	-48.3
9.	Households	-0.2	-0.2	-0.2
10.	Agriculture	-9.7	-8.8	-5.8
11.	Services	0.0	0.0	0.0
	Total generation	100.0	82.8	63.8
	Total consumption	-100.0	-82.8	-63.8

The Baseline, Accelerated and Aggressive scenarios have been studied in Chapter 2 in terms of the technical aspects of integration of variable renewable energy sources into the electricity networks, such as strengths and weaknesses of the power infrastructures for their capability to respond to the accelerated introduction of the untapped renewable energy resources, the power network regimes (steady and transitional) regulation, the grid security and reliable operation aspects and the measures to be implemented in the power system for the reinforcement of electric networks (external and in-house), as well as the issues associated the liberalization of the electricity market. For this purpose, predictive electricity balances for 2025-2050 of the power system from the point of view of the system reliability and safety have been developed.

5. TPES STRUCTURE AND LEVEL OF ENERGY INDEPENDENCE

The level of energy independence of the Republic of Armenia has been assessed based on the forecasts of the Energy Balance have been made for 2030, 2040 and 2050.

For the two main forecast scenarios – Basic and Accelerated, and an additional Aggressive scenario for 2040 - the following assumptions have been admitted:

Baseline Development Scenario: retrospective (2010-2020) demand growth rates in the main consumption sectors will be maintained;

Accelerated Development Scenario modifies the Baseline Scenario, providing

- more intense development of solar PV supply;
- increase in the electric vehicles and agricultural machinery fleet;
- partial replacement of gas heating devices with electric ones;
- expansion of the use of Solar Water Heating installations;
- introduction of Biofuel technologies;
- transmission and distribution networks reconstructed to a limited extent.

Aggressive Development Scenario calls for a significant increase in the use of renewable energy sources, which assumes that the goal of Accelerated development by 2050 will be accomplished by 2040.

One of the initial indicators of the energy balance is the primary energy supply (PES) by type of energy resource. To calculate, the initial data were converted from the named units into normalized units of energy. According to the IEA standard, a tone of oil equivalent (toe) is used as a conventional unit calculated based on the calorific values of a given energy resource.

The total primary energy supply is calculated as:

$$TPES = PES_{EE} + PES_{NG} + PES_{Other\ FF} + PES_{NE} + PES_{HE} +$$
$$+PES_{SPV} + PES_{SWH} + PES_{WE} + PES_{BG} + PES_{BF\&W} \quad (14)$$

where

PES_{EE} − primary energy supply (PES) of electrical energy,
PES_{NG} − PES of natural gas,
$PES_{Other\ FF}$ − PES of $other\ fossil\ fuel\ (oil\ products, coal)$,

$$PES_{NE} - PES\ of\ nuclear\ energy,$$
$$PES_{HE} - PES\ of\ hydro\ energy,$$
$$PES_{SPV} - PES\ of\ solar\ PV,$$
$$PES_{SWH} - PES\ of\ solar\ water\ heating,$$
$$PES_{WE} - PES\ of\ wind\ energy,$$
$$PES_{BG} - PES\ of\ biogas,$$
$$PES_{BF\&W} - PES\ of\ biofuels\ and\ waste.$$

The level of energy independence is estimated based on the following coefficient

$$EIC = \frac{PES_{DES}}{TPS} \cdot 100\ \%\ , (15)$$

where

$PES_{DES} = PES_{NE} + PES_{HE} + PES_{SPV} + PES_{SWH} + PES_{WE} + PES_{BG} + PES_{BF\&W}$ - PES from domestic energy sources.

For each of the considered scenarios, the following TPES diagrams was constructed and energy independence coefficients was calculated.

For the purpose of comparative analysis, the EIC for 2020 is also given, calculated on the basis of officially published data of the Statistical Committee of the Republic of Armenia.

5.1 EIC for 2020 historical

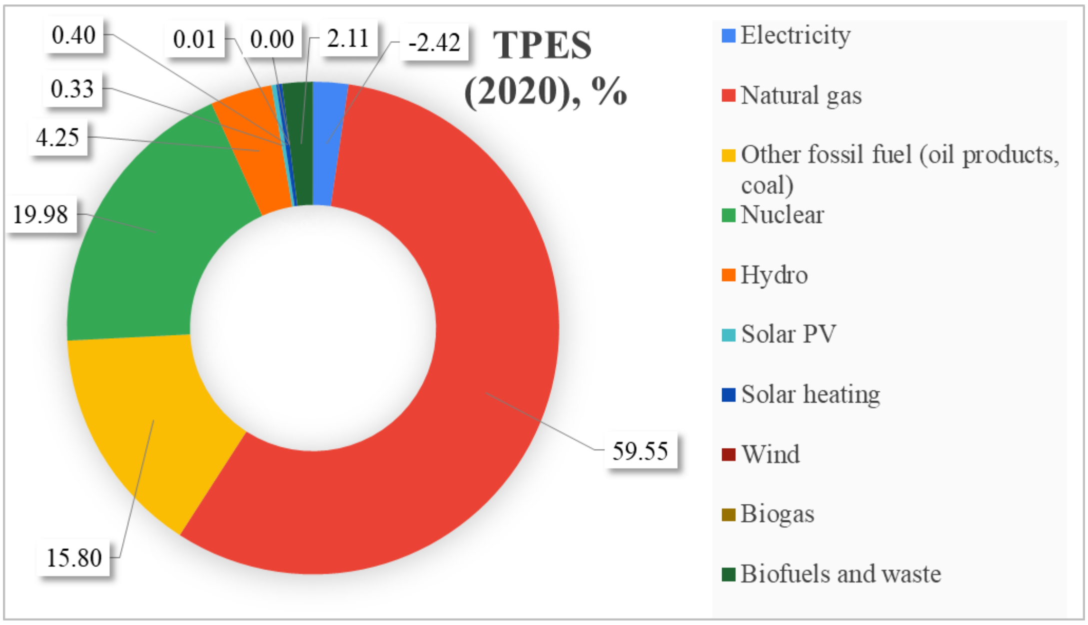

Figure 52. TPES diagram for 2020 (historical).

Energy independence coefficient for the Baseline scenario EIC = 27.1 %.

5.2 EIC for Baseline scenario by 2040

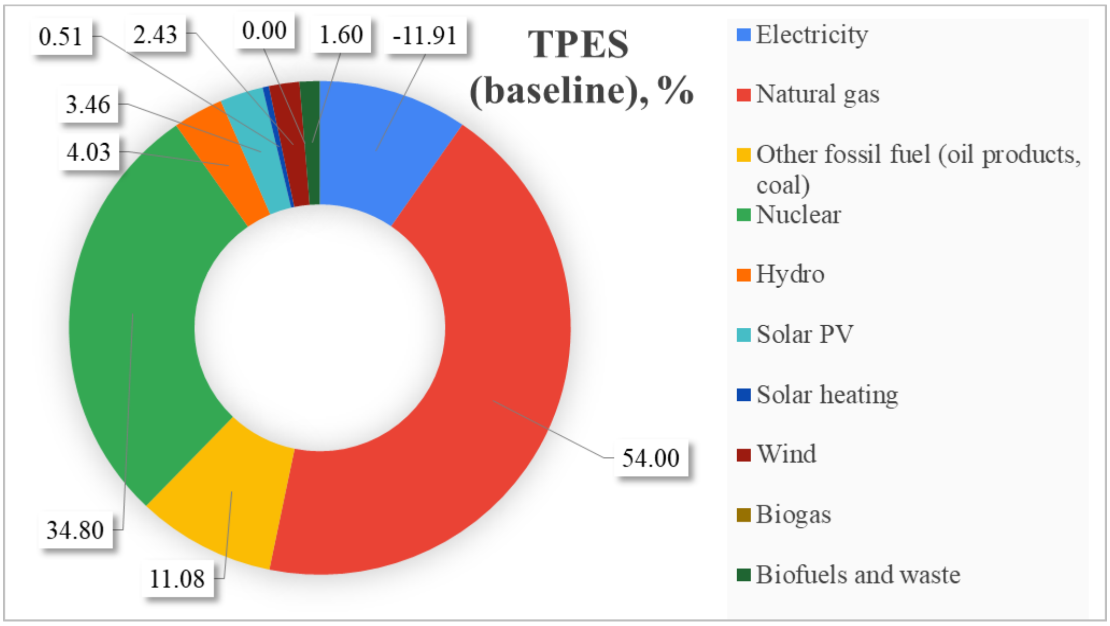

Figure 53. TPES diagram for Baseline scenario by 2040.

Energy independence coefficient for the Baseline scenario EIC = 46.8 %.

5.3 EIC for Accelerated development scenario by 2040

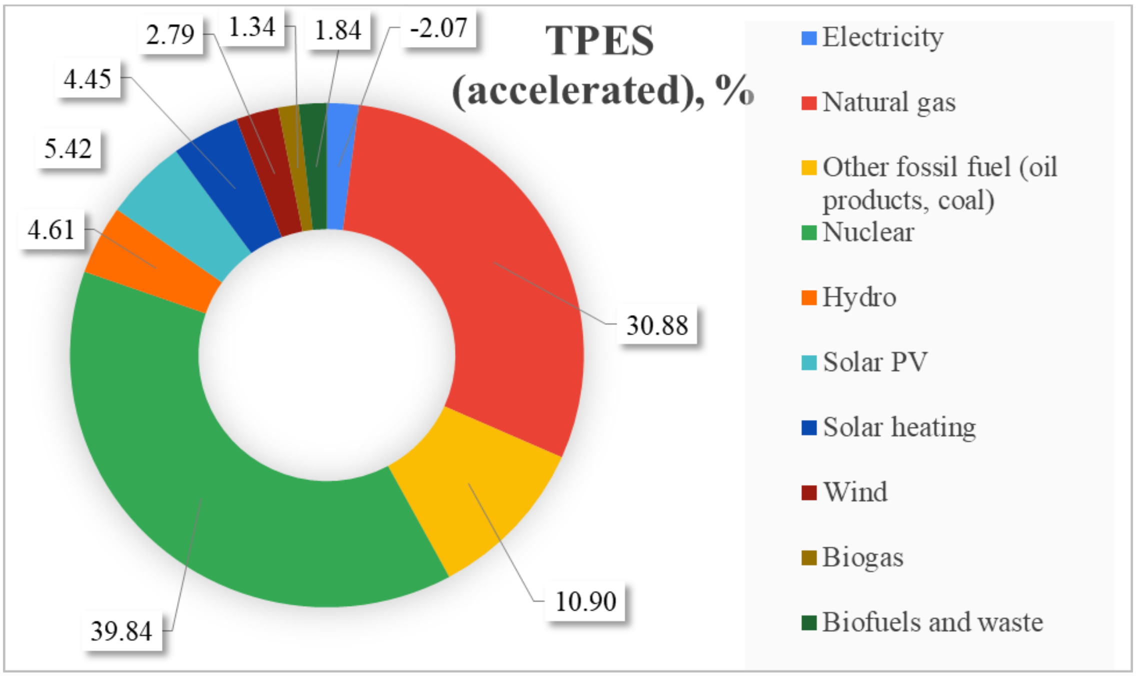

Figure 54. TPES diagram for Accelerated development scenario by 2040.

Energy independence coefficient for the Accelerated development scenario EIC=60.3 %.

5.4 EIC for Aggressive development scenario by 2040

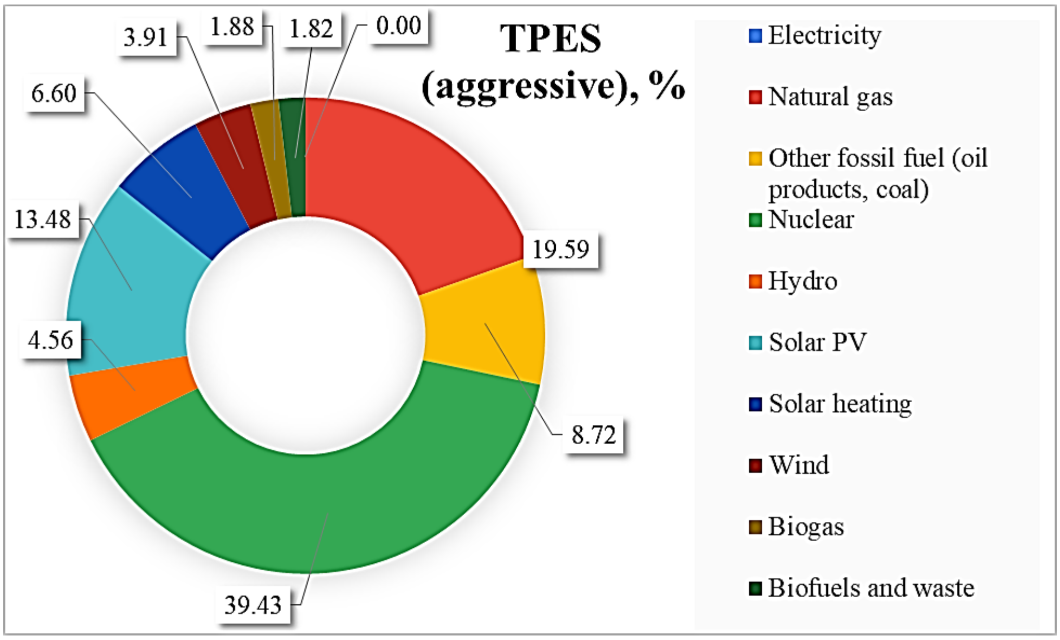

Figure 55. TPES diagram for Aggressive development scenario by 2040.

Energy independence coefficient for the Aggressive development scenario EIC = 71.7 %.

5.5 Summary

An analysis of the results in all three forecast scenarios compared to 2020 show an increase in the energy independence of Armenia. In particular, compared to EIC = 27.1 % in 2020, the EIC by 2040 presents as:

- 46.8 % for Baseline scenario,
- 60.3 % for Accelerated development scenario,
- 71.7 % for Aggressive development scenario

The Accelerated development and the Aggressive development scenarios in terms of the technical feasibility of maintaining steady state and transitional regimes of the power system, as well as the necessary costs of strengthening the electrical network infrastructures, and the legal aspects between the subjects of the power system in the context of the liberalization of the electricity and capacity market, will require further detailed study.

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https://psrc.am

Annex 1.

Forecast of domestic demand for electricity in the Republic of Armenia for 2025-2040/50

1. Theoretical foundations for forecasting domestic demand for electricity

The methods of strategic management [1, 2] and regression analysis [3, 4, 5, 6] theories have been widely used to predict electricity demand.

To predict the demand for electricity in sectors of the economy, the principle of decomposition of influencing factors [7] was used, which is represented by the following equation.

$$W_{\Sigma} = \sum_j W_j = GDP \sum_j s_j \cdot e_j \quad , \qquad (1)$$

where:

W_{Σ} – total electricity demand, million kWh;

j – the index of the economy sector;

W_j - demand for electricity in the j-th sector of the economy, million kWh;

GDP – gross domestic product, mln USD;

s_j – the structure of the economy, which shows the share of the j-third sector of the economy in GDP, in relative units;

e_j – electric intensity in the j-th sector of the economy, million kWh/USD

This approach makes it possible to predict the demand for electricity, taking into account not only historical (retrospective) data on changes in GDP, but also the demand for electricity in various sectors of the economy.

An analysis of data on different countries provided by the World Bank (WB) and the International Energy Agency (IEA) shows that GDP growth leads to changes in the structure of the economy (an increase in the share of services, a decrease in the share of agriculture), as well as a decrease in the electricity intensity of economic sectors.

However, forecasting overall electricity demand, especially for developing countries, including Armenia, remains a complex issue with a high level of uncertainty.

To solve the task set, the following algorithm was used:

- Collection of historical macroeconomic data on the development of Armenia;
- Collection of historical data on electricity consumption in the sectors of the Armenian economy;
- Calculation of energy efficiency in sectors of the economy;
- Comparative analysis of collected historical data and identification of the impact of trends in macroeconomic indicators on electricity demand;

- Determining, on the basis of historical data, the needs of sectors of the economy for electricity using regression analysis;
- Determination of the forecasted demand for electricity in the economy sectors using formula (1).

To reduce the uncertainties inherent in long-term forecasts, scenario calculations were performed.

Forecasting demand for electricity in other sectors (household, transport, non-specified)

To solve the task set, the following algorithm was used:

- Collection of historical data on electricity consumption in the other sectors;
- Comparative analysis of collected historical data and determination of their impact on electricity demand;
- Determination of the demand for electricity in the other sectors under consideration using regression equations derived from historical data.

2. Collection and analysis of historical macroeconomic data for Armenia

As macroeconomic indicators, GDP, the share of economic sectors in GDP and the population were considered.

The sources of data on GDP were the official websites of the World Bank, Trading Economics, Statista and the Statistical Committee of the Republic of Armenia [8, 9, 10].

Figure 1 shows the change in Armenia's GDP in 2007-2020 and the forecasts obtained as a result of approximations.

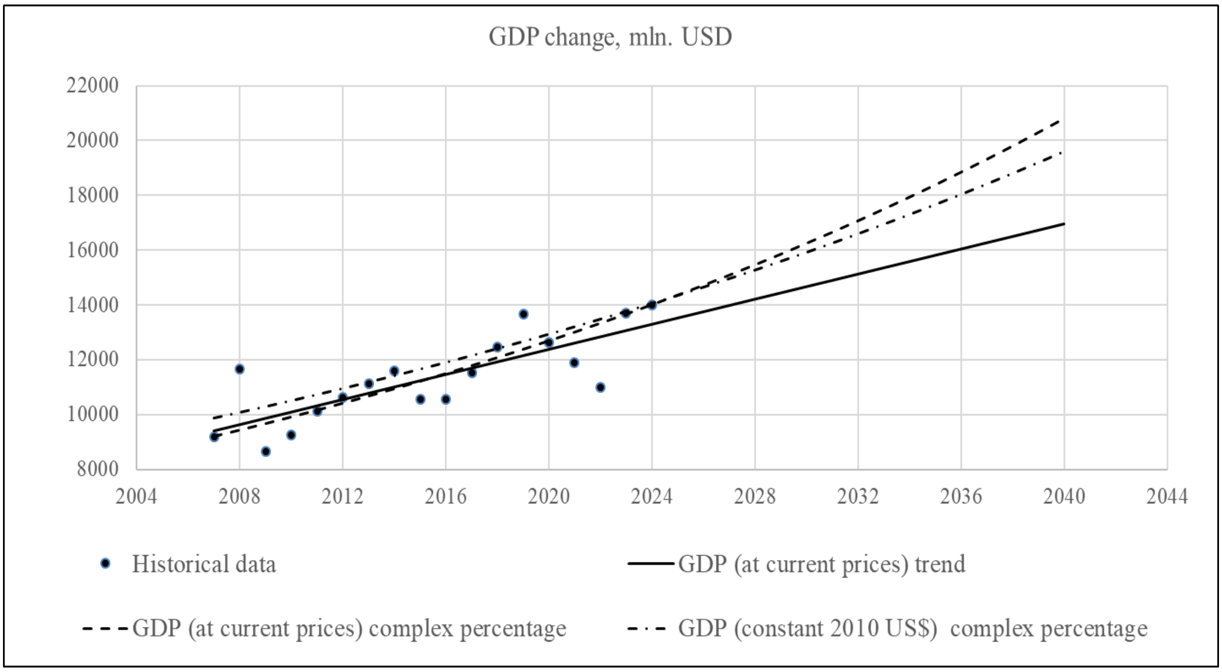

Figure 1. Armenia's GDP by years.

On figure 1, the solid line shows the trend in GDP (in current prices) change, which can be described by the expression:

$$GDP_1(t) = 229.11 * (t - 2006) + 9171.9, \quad (2)$$

where $GDP_1(t)$ - forecastted value of GDP (in current prices) in the *t*-th year.

On figure 1, the dotted line shows the trend in GDP (in current prices) change in the case of complex percentage approximation, which can be described by the expression:

$$GDP_2(t) = GDP_2(t-1) * (1 + r), \quad (3)$$

where $r = \sqrt[13]{\left(\frac{GDP_2(2020)}{GDP_2(2007)}\right)} - 1 = 0.025$ - the rate of change in GDP (in current prices) for 2007-2020.

On figure 1, the dash-dotted line shows the trend in GDP (constant 2010 US $) change in the case of complex percentage approximation, which can be described by the expression:

$$GDP_3(t) = GDP_3(t-1) * (1 + r), \quad (4)$$

where $r = \sqrt[13]{\left(\frac{GDP_3(2020)}{GDP_3(2007)}\right)} - 1 = 0.021$ - the rate of change in GDP (constant 2010 US$) for 2007-2020.

It should be noted that the deviation of GDP values calculated using all three approximation options from historical data is characterized by the correlation coefficient CORREL = 0.79.

The source of historical data on the shares of economic sectors in GDP, characterizing the change in the structure of GDP, is the official website of Statista [11].

The development trends of each sector of the economy, depending on the GDP, can be represented by the following expressions:

$$S_{agriculture} = 0.007 \cdot GDP + 1725.7, \quad (5)$$

$$S_{industry} = 0.067 \cdot GDP + 2472.4, \quad (6)$$

$$S_{service} = 0.823 \cdot GDP - 4029.5, \quad (7)$$

Historical and forecast data on changes in the structure of GDP in nominal and relative units are presented in Figures 2 and 3. Another item included in the GDP structure is the financial activity component, which in this study is calculated using the following formula:

$$S_{other} = GDP - \left(S_{agriculture} + S_{industry} + S_{service}\right). \quad (8)$$

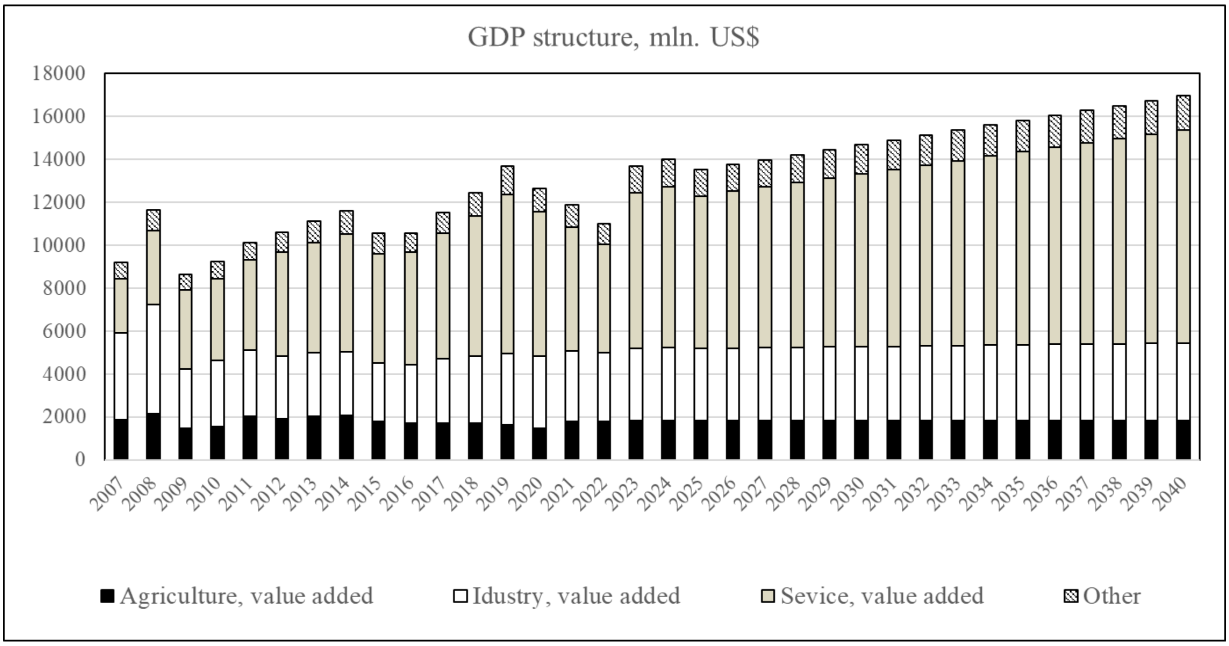

Figure 2 . The structure of GDP by nominal units.

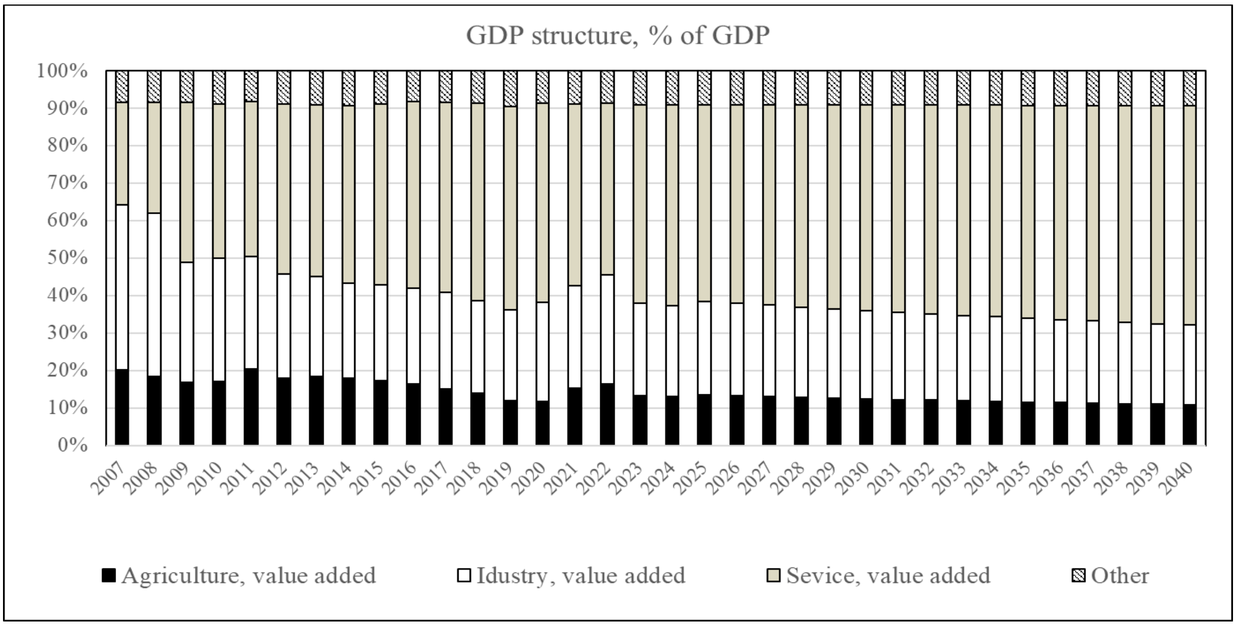

Figure 3 . The structure of GDP in relative units.

Figure 3 shows that the change in the structure of GDP over the years retains the trends of developing countries, that is, with the growth of GDP, the share of the service sector increases, and the share of the agricultural sector decreases.

The correlation coefficients of historical data and trends in the sectors of the economy are equal.

- 0.05 for agriculture,
- 0.14 for service,
- 0.89 for industry.

The official websites of the World Bank, Worldometers and the Statistical Committee of the Republic of Armenia were the source of historical data on the population [12, 13]. Figure 4 shows the historical and forecasterd population change data.

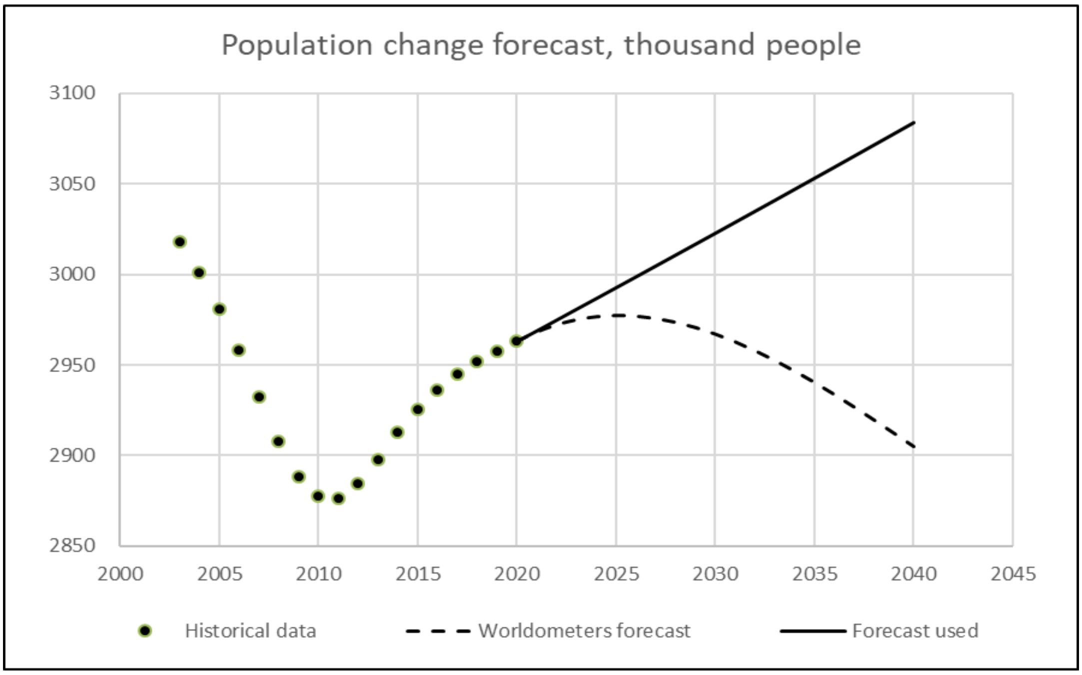

Figure 4. Historical and forecast data on population change.

In contrast to Worldmeters' pessimistic view of population change forecasts, this study used an annual growth forecast of 0.2 %.

3. Collection of historical data on electricity consumption by sectors and demand forecast

Assessment of demand for electricity in sectors of the economy (industry, service and agriculture)

The assessment of demand for electricity in the sectors of the economy was carried out according to the algorithm given in Chapter 1.

The source of information on electricity consumption was the historical data posted on the official website of the RA Public Services Regulatory Commission [16].

Taking into account the data presented in the energy balances of the Republic of Armenia, as well as the results of the surveys conducted with the specialists of the Electric Networks of Armenia CJSC, the following approach was applied to the indicated data:

- electricity consumption in industry was increased by an amount equal to 35 % of electricity consumption by other consumers,
- electricity consumption in service was increased by an amount equal to 45 % of electricity consumption by other consumers,

- the volumes of consumption by non-specified consumers were taken equal to 20 % of the volumes of electricity consumed by other consumers.

The forecast of demand for electricity in the sectors of the economy was implemented according to three main scenarios.

Scenario 1. Forecast of changes in GDP based on the trend of previous years, which is in line with $GDP_1(t)$ presented in Chapter 2. Collection and analysis of historical macroeconomic data for Armenia (above).

Sub-scenario 1.1

- the share of the j-th sector of the economy in GDP (in relative units) changes in accordance with the trend of previous years, calculated according to expressions (5), (6) and (7).
- the electricity intensity of the j-th sector of the economy is reduced by 0.2 % due to increased energy efficiency starting from 2022.
  The electrical intensity of a sector of the economy is determined by the following formula:

$$e_j = \frac{W_j}{S_j} = \frac{W_j}{GDP \cdot s_j}, \tag{9}$$

where W_j - electricity consumption in the j-th sector of the economy.

The historical and forecasted values of the electrical intensity used in this sub-scenario are shown in Figure 5.

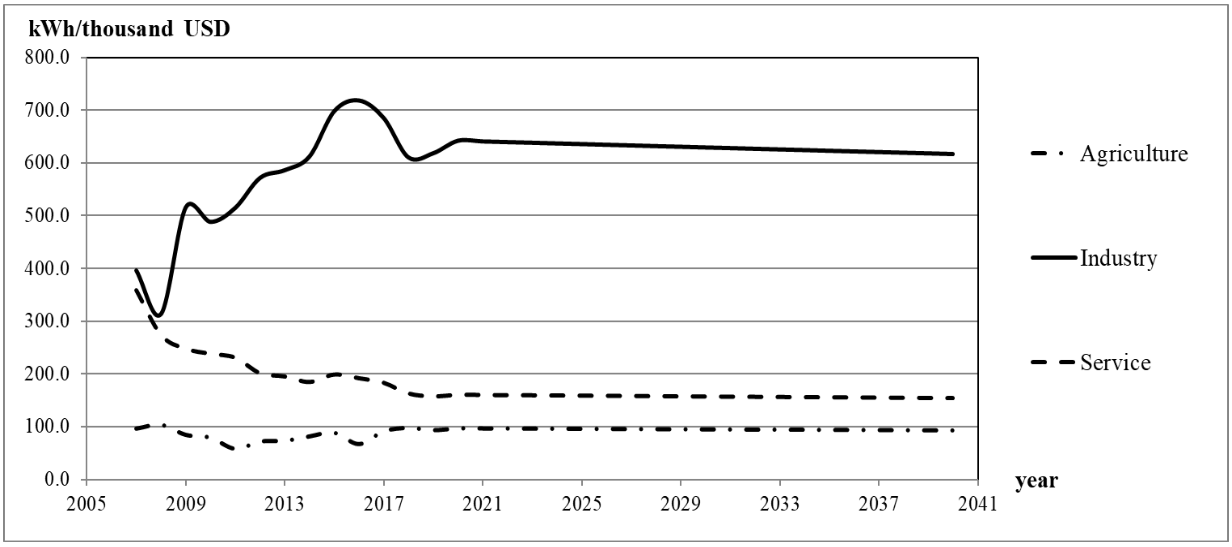

Figure 5. Electrical intensity of the sectors of the economy.

Sub-scenario 1.2

- the share of the j-th sector of the economy in GDP (in nominal units) changes in accordance with the trend of previous years, calculated according to expressions (5), (6) and (7).

- the electricity intensity of the j-th sector of the economy is changes according to the trend of GDP change in previous years, ie $e_j = f(GDP)$:

The values of the electrical intensity used in this sub-scenario are shown in Figure 6.

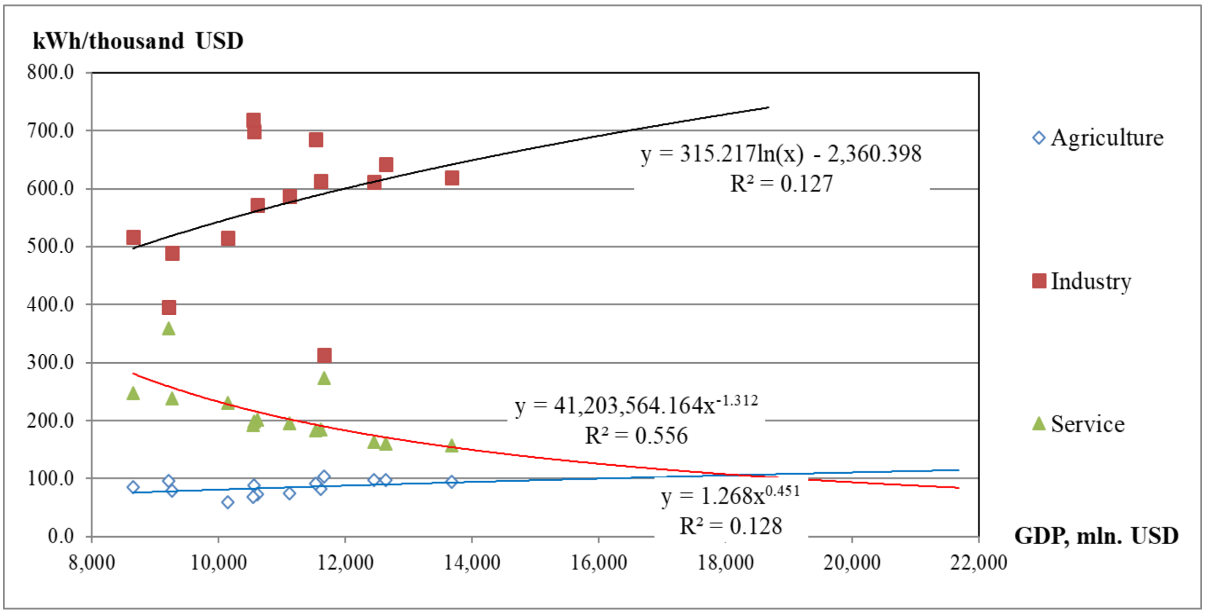

Figure 6. Electrical intensity of the sectors of the economy.

Sub-scenario 1.3

- the share of the j-th sector of the economy in GDP (in nominal units) changes in accordance with the trend of previous years, calculated according to expressions (5), (6) and (7).
- the electricity consumption in the j-th sector of the economy is changes according to the trend of GDP change in previous years, ie $W_j = f(GDP)$:

The values of the electricity consumption used in this sub-scenario are shown in Figure 7.

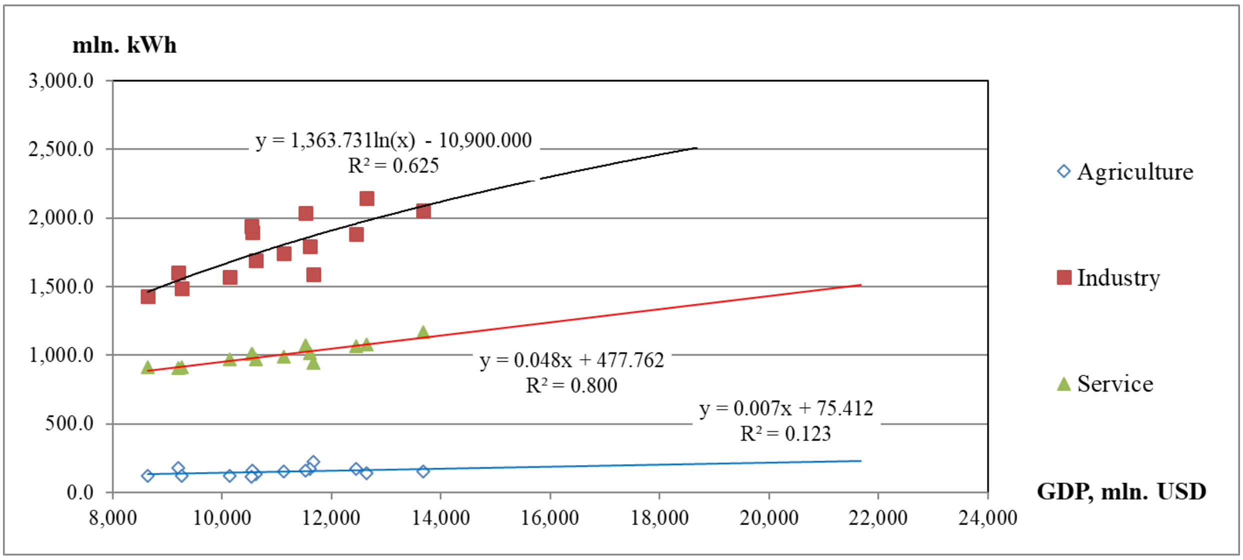

Figure 7. The values of electricity consumption in sectors of economy.

Scenario 2. Forecast of changes in GDP based on the complex percentage, which is in line with $GDP_2(t)$ presented in Chapter 2.

Sub-scenario 2.1

- Repeats the approaches of sub-scenario 1.1.

Sub-scenario 2.2

- Repeats the approaches of sub-scenario 1.2.

Sub-scenario 2.3

- Repeats the approaches of sub-scenario 1.3.

Scenario 3. Forecast of changes in GDP (constant 2010 US$) based on the complex percentage, which is in line with $GDP_3(t)$ presented in Chapter 2.

Sub-scenario 3.1

- the share of the *j*-th sector of the economy in GDP (in relative units) changes in accordance with trend of GDP per capita (constant 2010 US$) change:

$$s_{agriculture} = -17.15 \cdot ln(GDP\ per\ capita) + 157.97, \quad (10)$$

$$s_{indusry} = 131853.08 \cdot (GDP\ per\ capita)^{-1.02}, \quad (11)$$

$$s_{service} = 47.3 \cdot ln(GDP\ per\ capita) - 344.8: \quad (12)$$

- the electricity intensity of the *j*-th sector of the economy is reduced by 0.2 % due to increased energy efficiency starting from 2022 (as it was accepted in the sub-scenario 1.1).

Sub-scenario 3.2

- forecast for GDP change were not used;
- forecast of share of the *j*-th sector of the economy in GDP were not used;
- forecast of electricity demand in *j*-th sector of the economy was made by applying a complex percentage to historical data:

$$W_{agriculture}(t+1) = W_{agriculture}(t) \cdot (1 + 0.0178), \quad (13)$$

$$W_{industry}(t+1) = W_{industry}(t) \cdot (1 + 0.0176), \quad (14)$$

$$W_{service}(t+1) = W_{service}(t) \cdot (1 + 0.0172). \quad (15)$$

Assessment of demand for electricity in other sectors (household, transport, non-specified)

The forecast of electricity demand in other sectors was carried out according to the algorithm given in Chapter 1.

The source of information on electricity consumption was the historical data posted on the official website of the RA Public Services Regulatory Commission [16]:

Historical data on electricity consumption by the household in 2020-2021, as well as the forecast up to 2040, are shown in Figure 8.

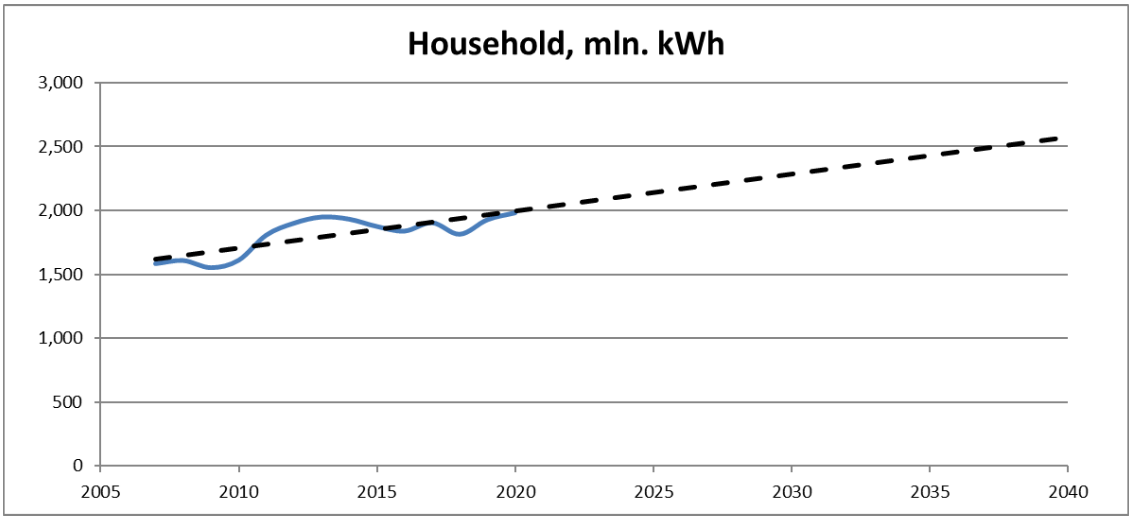

Figure 8. Electricity consumption by the household.

Trend of change can be determined by the following formula:

$$W_{household}(t) = 28.935x - 56453, \tag{16}$$

where $W_{household}(t)$ – electricity demand by the household, million kWh.

The correlation coefficient between historical and calculated by (16) data on household electricity consumption is CORREL=0.64.

Historical data on electricity consumption in transport in 2020-2021, as well as the forecast up to 2040, are shown in Figure 9.

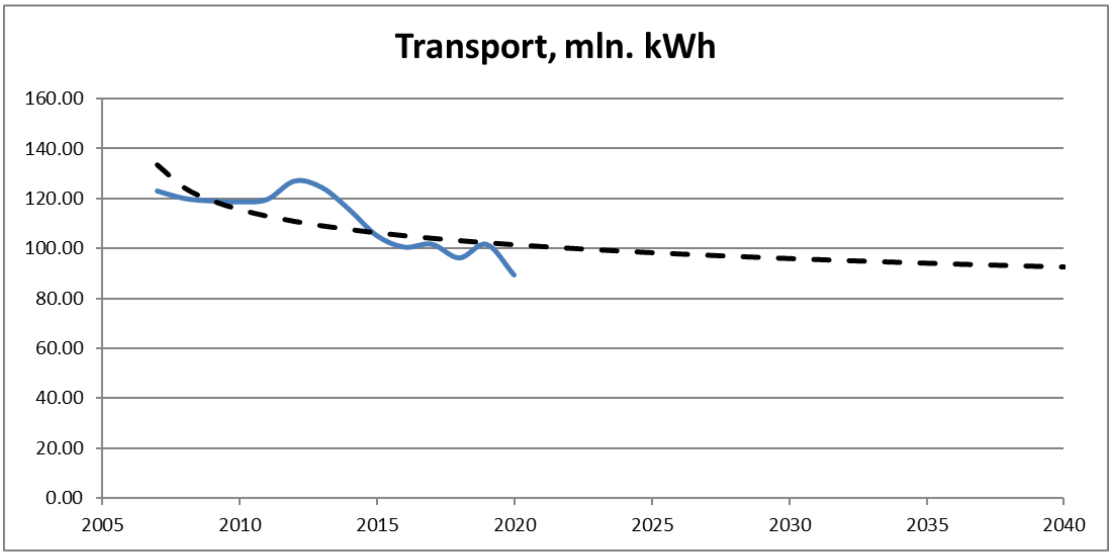

Figure 9. Electricity consumption in transport.

Trend of change can be determined by the following formula:

$$W_{transport}(t) = 133.6 \cdot (t - 2006)^{-0.104}, \tag{17}$$

where $W_{transport}(t)$ – electricity demand in transport, million kWh.

The correlation coefficient between historical and calculated by (17) data on transport electricity consumption is CORREL=0.8.

Historical data on electricity consumption by non-specified consumers in 2020-2021, as well as the forecast up to 2040, are shown in Figure 10.

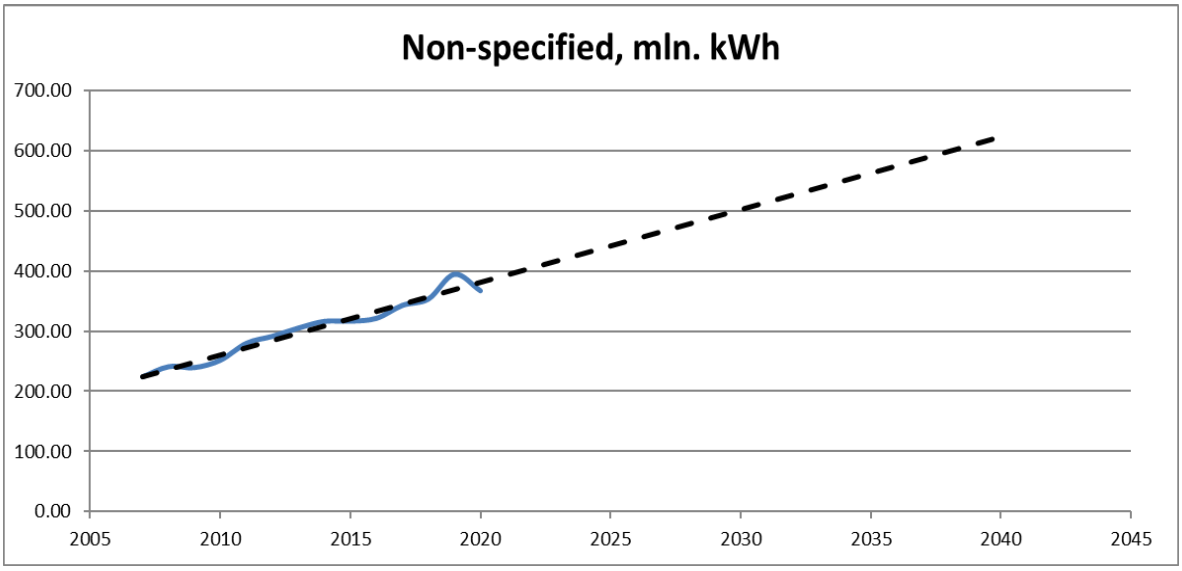

Figure 10. Electricity consumption by non-specified consumers.

Trend of change can be determined by the following formula:

$$W_{non-specified}(t) = 12.06 * (t - 2006) + 212.8\,, \qquad (18)$$

where $W_{non-specified}(t)$ – electricity demand in non-specified sectors, million kWh:

The correlation coefficient between the historical trend of electricity consumption and calculated by equation (18) for non-specified sectors is equal to CORREL=0.98.

4. Forecast of internal electricity demand of the Republic of Armenia in 2025-2040/50

The following formula was used to forecast domestic demand for electricity in the Republic of Armenia in 2025-2040:

$$W(t) = W_{economy}(t) + W_{population}(t) + W_{trandport}(t) + W_{non-specified}(t) \quad (19)$$

For the estimate for 2050, a linear approximation was used.

Electricity demand forecasts for 8 sub-scenarios are given in the table below.

Scenario	Sub-scenario	Electricity demand forecast, million kWh					
		Consumption sector	2025	2030	2035	2040	2050
1	1.1	*Agriculture*	*175*	*174*	*175*	*172*	*170*
		Industry	*2155*	*2176*	*2149*	*2228*	*2280*

		Service	*1156*	*1265*	*1128*	*1531*	*1799*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6166**	**6499**	**6539**	**7220**	**7948**
	1.2	*Agriculture*	*169*	*176*	*183*	*189*	*203*
		Industry	*2156*	*2293*	*2428*	*2560*	*2825*
		Service	*1112*	*1133*	*1146*	*1156*	*1175*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6117**	**6485**	**6843**	**7195**	**7903**

Scenario	Sub-scenario	Electricity demand forecast, million kWh					
		Consumption sector	2025	2030	2035	2040	2050
	1.3	*Agriculture*	*170*	*178*	*186*	*194*	*210*
		Industry	*2072*	*2183*	*2286*	*2381*	*2574*
		Service	*1127*	*1182*	*1237*	*1292*	*1401*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6050**	**6426**	**6795**	**7157**	**7885**
2	2.1	*Agriculture*	*176*	*175*	*175*	*175*	*174*
		Industry	*2184*	*2242*	*2309*	*2385*	*2536*
		Service	*1236*	*1467*	*1726*	*2014*	*2581*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6277**	**6768**	**7296**	**7864**	**8992**

Scenario	Sub-scenario	Electricity demand forecast, million kWh					
		Consumption sector	2025	2030	2035	2040	2050
	2.2	*Agriculture*	*174*	*185*	*197*	*210*	*236*
		Industry	*2255*	*2476*	*2719*	*2988*	*3517*
		Service	*1128*	*1150*	*1162*	*1166*	*1175*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6237**	**6695**	**7165**	**7654**	**8628**
	2.3	*Agriculture*	*176*	*189*	*204*	*221*	*254*
		Industry	*2153*	*2321*	*2489*	*2657*	*2864*
		Service	*1166*	*1257*	*1359*	*1475*	*1700*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6176**	**6650**	**7138**	**7642**	**8518**

Scenario	Sub-scenario	Electricity demand forecast, million kWh					
		Consumption sector	2025	2030	2035	2040	2050
3	3.1	*Agriculture*	*169*	*162*	*151*	*137*	*110*
		Industry	*2045*	*2039*	*2033*	*2027*	*2014*
		Service	*1254*	*1488*	*1755*	*2061*	*2661*
		Population	*2140*	*2285*	*2429*	*2574*	*2864*
		Transport	*98*	*96*	*94*	*93*	*93*
		Non-specified	*442*	*502*	*562*	*623*	*743*
		TOTAL	**6150**	**6572**	**7026**	**7514**	**8485**
	3.2	*Agriculture*	*132*	*121*	*111*	*102*	*102*
		Industry	*2401*	*2686*	*3005*	*3362*	*4064*
		Service	*1158*	*1239*	*1326*	*1420*	*1604*
		Population	*2161*	*2355*	*2567*	*2798*	*3253*
		Transport	*79*	*70*	*62*	*55*	*55*
		Non-specified	*443*	*536*	*647*	*782*	*1043*
		TOTAL	**6374**	**7007**	**7718**	**8518**	**10120**

Annex 2.

Forecast of domestic demand for gas in the Republic of Armenia for 2025-2040/50

The methods of strategic management [1, 2] and regression analysis [3, 4, 5, 6] theories have been widely used to predict gas demand.

Data from the statistical committee, the public services regulation commission and the meteorological service were used as the initial information. The share of gas consumption by other sectors is insignificant and was not considered. Initial information is presented in the tables below.

Table 1. Average monthly temperatures, t°C.

	1	2	3	4	5	6	7	8	9	10	11	12
2016	-2.1	3.8	8.2	13.9	18.2	22.9	26.2	28.2	20.1	12.6	3.3	-4.6
2017	-8.7	-8.4	6.2	13.1	18.7	24.1	28.6	29.3	24.4	12.8	7.1	1.3
2018	2	5.5	11.1	13.8	18.7	23.9	30	26.7	22.8	15.2	7.2	3.6
2019	0.2	2.7	6	11.5	19.5	26.1	27.6	27.7	20.1	15.8	3.9	2.9
2020	-0.7	1.6	10.5	11.1	18	24.4	27.2	24.8	24.1	14.9	6.9	1.1
2021	-4.5	3.8	6.6	16.2	21	27	27.5	27.9	21.8	12.3	7.2	0.2

Table 2. Historical data on gas consumption in the households' sector, Mm^3

	1	2	3	4	5	6	7	8	9	10	11	12	Total
2016	97.3	73.0	52.1	31.2	23.9	21.7	21.7	22.1	22.9	35.3	67.8	111.9	580.9
2017	128.5	108.7	65.1	34.5	24.4	21.2	22.2	22.2	21.9	29.0	52.2	91.7	621.6
2018	90.2	69.2	52.4	32.4	25.8	24.2	22.5	23.6	24.2	29.4	66.0	94.4	554.3
2019	110.7	89.7	85.1	48.8	27.6	23.4	24.4	24.9	26.1	29.1	75.7	103.3	668.8
2020	123.8	113.6	68.3	55.8	33.0	26.3	26.2	26.2	27.5	30.7	70.6	122.7	724.7
2021	147.6	100.6	98.4	39.1	27.1	23.8	24.6	24.8	25.4	42.6	82.4	129.7	766.1

Table 3. Historical data on gas consumption in industry, Mm^3

	1	2	3	4	5	6	7	8	9	10	11	12	Total
2016	11.5	13.0	18.3	17.2	17.2	16.1	19.7	10.3	17.9	15.6	14.8	14.2	185.8
2017	12.8	13.4	16.7	21.8	21.0	16.4	14.6	20.7	18.4	18.7	18.0	17.6	210.1
2018	14.0	17.2	21.3	19.1	19.9	24.4	17.7	19.7	12.5	26.1	17.8	16.8	226.5
2019	11.9	14.1	16.9	13.3	17.2	19.0	18.8	20.5	21.1	16.3	24.3	15.1	208.5
2020	12.9	13.8	22.4	16.4	21.5	23.3	18.1	18.2	21.6	21.9	25.2	23.9	239.2
2021	13.6	17.0	15.9	19.0	25.7	22.2	19.8	23.7	23.0	23.2	24.3	26.7	254.1

Table 4. Historical data on gas consumption in transport, Mm^3

	1	2	3	4	5	6	7	8	9	10	11	12	Total
2016	32.2	33.5	38.0	34.9	37.2	38.4	42.8	45.2	41.8	42.6	39.9	40.6	467.1
2017	34.7	32.7	37.0	36.8	38.3	39.8	44.5	45.9	41.5	42.6	40.5	43.3	477.6
2018	36.6	34.7	39.4	38.2	41.1	47.9	54.5	54.4	51.1	52.3	50.5	52.1	552.8
2019	43.7	41.9	46.6	45.5	48.1	48.4	51.6	52.9	49.5	50.6	48.4	49.9	577.1
2020	42.5	40.8	35.2	26.1	35.0	37.4	41.3	44.6	45.0	39.6	41.0	44.4	472.9
2021	36.0	35.9	39.3	38.7	41.7	42.5	45.7	46.1	44.7	45.0	43.3	46.5	505.4

Table 5. Correlation coefficient between the average monthly temperature and gas consumption

	in households	in industry	in transport
2016	-0.940	0.32	0.55
2017	-0.936	0.51	0.71
2018	-0.908	0.24	0.55
2019	-0.936	0.45	0.69
2020	-0.940	0.25	0.02
2021	-0.953	0.38	0.51

Table 5 shows that a very inverse correlation exists between the average monthly temperature and gas consumption in the households sector. Correlations between the average monthly temperature and gas consumption in industry is weak and in transport is medium.

The very inverse correlation between average monthly temperature and gas consumption in the households sector is due to the use of gas for heating. Picture 1 presents the data of table 1 in graphical form.

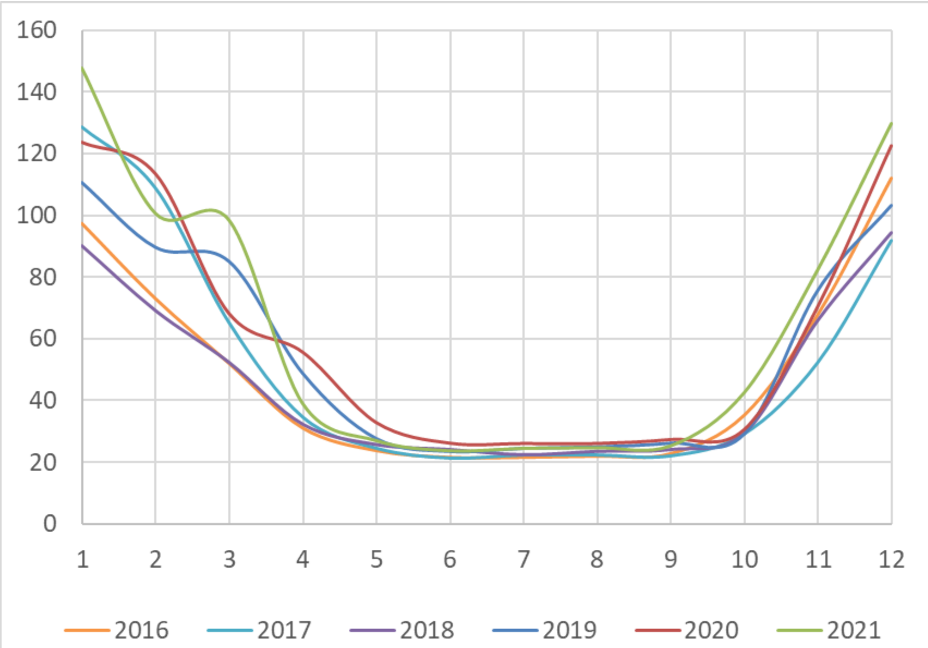

Figure 1. Historical data on average monthly gas consumption in the households sector, Mm^3

Picture 1 shows that average gas consumption in the household sector during June-September was 23.9 Mm^3 with a deviation equal to 4.1. In the winter months, the picture is not so clear. For example, average gas consumption during January was 116.4 Mm^3 with a deviation equal to 47.5, average gas consumption during February was 92.5 Mm^3 with a deviation equal to 41.3 etc.

Table 6 shows the correlation between GDP and gas consumption during 2016-2020.

Table 6. Correlation coefficient between GDP and gas consumption during 2016-2020

in households	0.559
in industry	0.629
in transport	0.717

Table 6 shows that correlations between GDP and gas consumption in households' sector, industry and transport is medium.

Picture 2 shows historical data on annual gas consumption in the energy, households' sector, industry and transport.

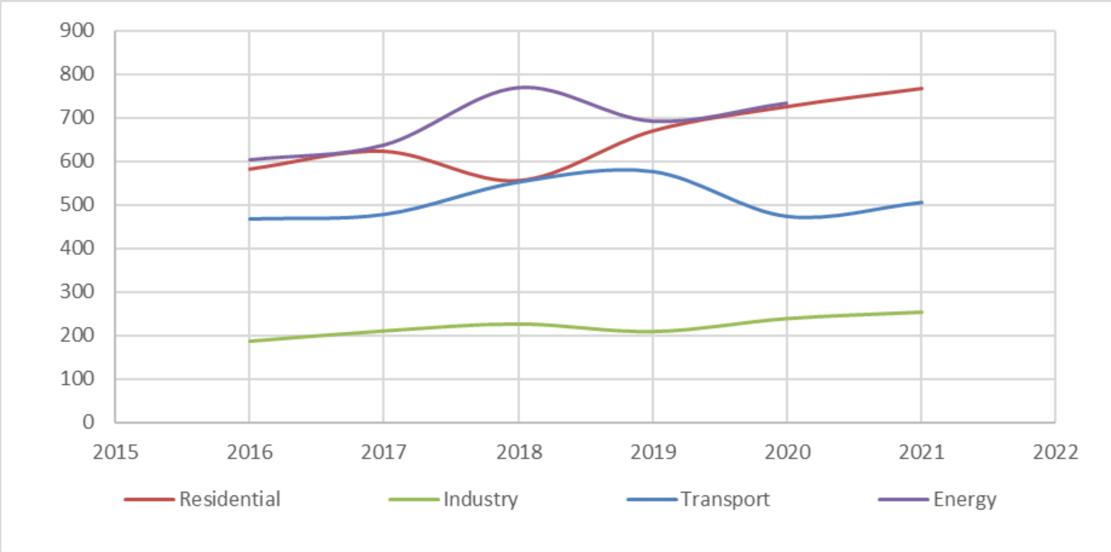

Figure. 2. Annual gas consumption in energy, households sector, industry and transport, Mm^3

Trends of annual gas consumption by years without developing RE and increasing EE can be described by the following regressions:

- $486.286*(x-2012)^{0.156}$ with a correlation coefficient of 0.79 (high) in households sector,
- $23691*\ln(x) - 180072$ with a correlation coefficient of 0.90 (very high) in industry,
- $133.6*(x-2006)^{-0.104}$ with a correlation coefficient of 0.23 (weak) in transport,
- $4.05*x-8107.2$ with a correlation coefficient of 0.19 (weak) in agriculture,
- $235.32*(x-2013)^{0.0554}$ with a correlation coefficient of 0.42 (weak) in services,

where x - year number.

Based on the above equations, Table 7 shows the gas demand forecast.

Table 7. Gas demand forecast, Mm^3

Year	Energy	Households	Industry
2030	972.8	763.3	353.7
2035	1089.8	793.1	412.0
2040	1206.7	817.8	470.1
2050	1440.5	857.7	586.0

Note. Due to the low value of the correlation coefficient in transport, the use of the regression equation is not advisable.

Table 7 shows that the main potential for reducing gas consumption is in the energy and households sectors.

In case of replacing the capacities of thermal power plants with PV systems, it should be considered that in winter, overheating of PV systems is minimized due to the lower ambient temperature, and the efficiency of the panels increases. But at the same time, daylight hours are reduced, resulting in reduced system performance. Depending on the region, the performance of solar systems can drop from 2 to 8 times. Vacuum solar collectors, on average, can produce up to 60 % of the thermal energy you need for hot water. It is possible to obtain about 90 % of the amount of energy required for hot water supply in the summer months, and about 25 % in the winter. For flat solar collectors, the figure will be approximately the same in summer, but in winter the share of energy for hot water supply will be much less, and this is due to the greater heat loss of flat collectors at low air temperatures. At the same time, Picture 1 shows that the average gas consumption in the households' sector in the winter months can exceed summer consumption by 4-5 times. This means that gas consumption issues will remain relevant in the winter months.

The gas consumption of thermal power plants is expected to decrease in the following manner:

Name of TPP	Decrease the share of TPPs production, Mm^3
«Hrazdan» OJSC	122.4
«Gazprom Armenia» CJSC «Hrazdan 5» TPP	196.9
«Yerevan TPP» CJSC (CC energy unit)	249.2

Note: ArmPower CJSC does not have sufficient historical data to predict the construction of a new thermal power plant.

It should also be noted that a decrease in production at TPPs will lead to a decrease in the stability of the energy system, since in an emergency it is required to use the primary reserve, which is focused on rotating generators, including TPPs. Alternatively, negotiations with Iran could help improve the situation.

ARMENIA'S ENERGY INDEPENDENCE ROADMAP

PART 4 INTERNATIONAL EXPERIENCE

Developed by: Tigran Gnuni, Aram Harutyunyan, Armen Danielyan, Régis Danielian, Garnik Balyan, Suren Shatvoryan (Team Leader)

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1. GENERAL INFORMATION

The development of new renewable generation technologies, as well as their rapidly decreasing costs, have provided Armenia with an opportunity to enhance its energy system. Not only is it a pathway that few have taken so far, with practical experience being limited, but the country faces many limitations of its own. It is important, therefore, to make most of what the international experience has been so far, to avoid inefficient regulations and subsidies, and to build a system which will develop in an economically efficient manner. The room for error is much smaller for Armenia when compared to the economically developed countries with much larger financial endowment, able to bear the consequence of inefficient decision-making. In this section, four different countries with different experiences were studied; while different from Armenia in some ways, they were similar in another, providing some valuable lessons to be drawn for our country's energy systems.

No country has conditions identical to Armenia, which means that there is no ideal prototype that Armenia could follow to achieve greater energy independence. Therefore, this chapter explores the correlation between energy security, self-sufficiency, and renewable energy through case studies across the reviewed countries in order to draw lessons that might be relevant to Armenia.

Almost all developed countries that today rely mainly on clean power generation (some combination of nuclear power and renewables) have been doing so for the past 30 years (IEA data review). However, there are some countries like Denmark that have succeeded in replacing fossil fuels with wind and solar power, reducing their dependence on fossil fuels in their electricity generation mix from over 95 % in 1990 to around 10 % today. Among the other countries that considerably reduced their dependence on fossil fuels are Finland, Germany, and the UK.

The following criteria were used to form a list of countries for consideration:

1. The country is an OECD member and has advanced legislation and resources to make possible effective implementation of substantial energy policies.
2. Population is between 1 to 10 million.[1]
3. The country shares similarities with Armenia in terms of energy/electricity, highlighting common challenges in energy security/independence/renewables.

The final selection of the countries for review is Denmark, Switzerland, Israel, and Ireland.

Denmark has made a very impressive shift from almost entirely fossil-dependent to renewable dependent system, even more impressive considering that a major portion (60%) is supplied by intermittent sources (mostly wind, some solar). Denmark has also been noted as the European country to have most improved in terms of energy security/independence metrics and has been long noted as one of the highest (if not the highest) energy-secure economies in

[1] Countries that fully rely on renewables for electricity but are too small (such as Iceland, or some islands) cannot be used, as Armenia's demand is much larger than theirs. If Armenia had a population of 400,000, it would be very easy to meet its needs with renewables. Likewise, countries that are too big (such as the UK and Germany) also are not appropriate due to a different scale of both demand and resource availability.

Europe and OECD. In many ways, Denmark has already done the transition that we want for Armenia. However, this has come at a cost - Denmark has the second-highest electricity price for household consumers in Europe (0.29 Eur per kWh, with more than half of it coming in the form of taxes).

Switzerland has a very similar topology to Armenia, and its electricity generation comes primarily from a mix of hydropower and nuclear power. We intend to look into Switzerland's decision to phase out nuclear power as they decided to keep the existing ones operating as long as it's safe but will no longer provide licenses for construction of new nuclear power plants. We want to investigate how Switzerland plans to replace its nuclear power using renewables, and at what cost. This will help us to understand Armenia's case, and our future decision whether to phase out nuclear power in our country.

Israel has a very different power mix than Armenia with almost all of it coming from fossil fuels. What is similar is that Israel has been very restricted in its ability to trade power with neighboring countries. At the same time, given its abundant solar potential, one would expect solar power to have been critical in energy independence, yet it has barely been developed as measured by its share in the electricity mix. We intend to study how Israel dealt with political isolation (including the role of interconnectors), how it took a very different path compared to Armenia, relying almost entirely on imports of fossil (until the discovery of their offshore reserves), and what lessons we can learn from that.

Ireland can likewise provide some significant lessons for Armenia. On one hand, Ireland's power system evolution is similar to Denmark (started fossil-dominated, increased wind over time), but less impressive (only 40% of low-carbon generation, compared to Denmark's over 80%). However, Ireland's limited interconnection capacity has led them to develop alternative ways to deal with high wind-power generation - a constraint that Armenia has to face as well. Ireland has also liberalized its markets relatively recently, being another point of comparison for Armenia.

International energy trends and their impact on Armenia

Energy systems around the world are undergoing a significant transition. Concerns over climate change have resulted in many countries developing plans to phase out carbon-based generation, and to move towards low-carbon electricity sources. However, the development of renewable energy technologies has profound implications not only for the energy systems specifically, but for the larger geo-political aspects as well. The more widespread distribution of renewable resources, as opposed to fossil fuels, provides an opportunity to enhance energy independence and security, for those countries who have traditionally been net importers.[2] The concern has become even more acute in European countries following the current Russian-Ukrainian conflict. An added complication was the decrease in support for nuclear power after

[2] A New World: Geopolitics of the Energy Transformation (IRENA, 2019)

the Fukushima incident in 2011[3], with the EU only recently declaring nuclear power "green" again.[4]

Despite a widespread call for moving to low-carbon energy, relatively few countries have made significant shifts in that direction. While few exceptions such as Denmark have considerably replaced carbon-based generation with renewable energy, most countries with low-carbon power systems have been so for a while. The conventional low-carbon sources of hydropower, nuclear power, and occasionally other sources such as geothermal and biomass, have been dominant in the power mix of such countries as Switzerland, Norway, Austria, France, Finland, Sweden, and Iceland, to name a few.[5] One should therefore be cautioned from drawing the inference that Armenia's challenge is to simply copy the global leaders of low-carbon power generation. The fact is that most of those countries were low carbon *before* the current de-carbonization process took force. The "low-hanging fruits" of conventional generation had been picked, and a wholly different challenge is faced by those who wish to advance much further through newer technologies. Denmark, as shall be seen, benefited greatly from being located within the European electricity market.

Denmark

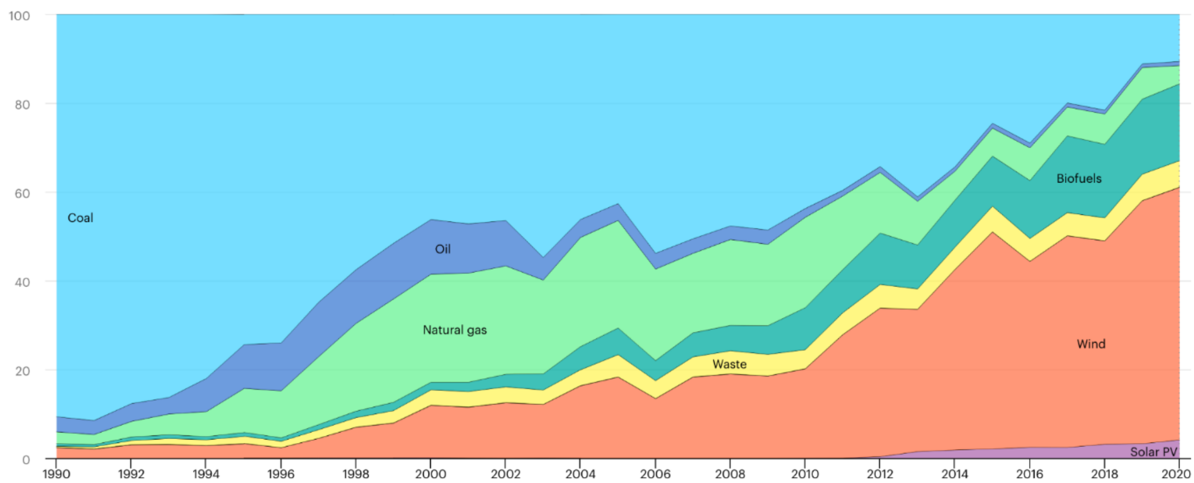

Figure 1. Evolution of Denmark's electricity mix, 1990-2020. Source: IEA

Denmark has made a very impressive shift from almost entirely fossil-dependent to a renewable-dependent electricity system, even more impressive considering that a major portion of domestic generation (60 %) is provided by intermittent sources (mostly wind, some solar).[6] Denmark has also been noted as the European country to have most improved in terms of

[3] Impacts of the Fukushima Daiichi Accident on Nuclear Development Policies (OECD-NEA, 2017)

[4] EU taxonomy: Complementary Climate Delegated Act to accelerate decarbonization | European Commission

[5] Based on analysis of IEA data

[6] IEA Denmark country profile

energy security/independence metrics, and has been long noted as one of the highest (if not the highest) energy-secure economies in Europe and OECD.[7,8,9] The improvement in energy security has been correlated with the development of Denmark's renewable potential, as imported coal has been replaced by local wind generation.

The role of energy markets

The path that Denmark undertook in achieving high energy security and renewable generation can be used to draw lessons for Armenia. Denmark started off with a much lesser share of renewable generation than Armenia and is currently at a much higher one. The shift has happened not only in electricity generation, but also in heating, where biofuel and waste have been gradually replacing coal and natural gas as the main providers of heat. In addition, Denmark has achieved remarkable levels of energy security, with less than 30 outage minutes per year, most of them occurring on the distribution grid level.[10] This has been achieved, in no small part, thanks to the effective electricity market. Being part of the Nordic electricity market, the country participates in day-ahead, intraday, and balancing markets for electricity. Combined heat and power generators provide a reliable generation source in the absence of wind, while flexible pricing programs and voluntary curtailment from the grid play modest roles, yet are expected to become more prevalent in the future.[11] Producers can be additionally compensated for simply making reserves available, on top of being paid at the market price if those reserves have to be activated.[12] When the normal operating conditions are under threat, the system switches to heightened alert mode, during which the market is suspended and the system operator directly regulates the electricity system, while grid companies have ready contingency plans to deal with a major disturbance.[13]

The role of interconnectors

While Denmark's electricity markets have made considerable advances, one cannot explain Denmark's ability to integrate high levels of intermittent sources and maintain a high quality of supply by studying its system in isolation. In particular, an important aspect of the Danish electricity network is its interconnection with the regional electricity markets. The country is connected both to the Nordic market (joining the Scandinavian and Baltic countries) and to the Central European networks through Germany, actively participating as both a buyer and a seller in these regional networks. In fact, so great is Denmark's level of interconnection, that the total power capacity of the interconnectors until 2020 exceeded national peak demand.[14]

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[7] Competing Dimensions of Energy Security: An International Perspective (Sovacool and Brown, 2010)
[8] Energy policymaking in Denmark: Implications for global energy security and sustainability (Sovacool, 2013)
[9] Historical energy security performance in EU countries (Matsumoto et al, 2018)
[10] Security of Electricity Supply Report 2018 (Energinet, 2018)
[11] Security of Electricity Supply in Denmark (Danish Energy Agency, 2016)
[12] Ibid.
[13] Ibid.
[14] Development and Role of Flexibility in the Danish Power System (Danish Energy Agency, 2021)

Both sides of Denmark's trade are dominated by more traditional sources of generation, being hydropower in the Nordic market and thermal generation in Germany, providing a more predictable and reliable source of power to match Denmark's own far more intermittent generation. In 2020, net imports accounted for roughly one-fifths of the domestic electricity supply - a proportion that has been growing over the recent decades.[15] While one-fifth may not seem as big a portion overall, one has to remember that security of supply is concerned not only with overall supply numbers over some period of time, but with the ability to match demand and supply *at any particular point in time*. As an example, in 2016 Denmark used its interconnectors to balance variation in wind production 78% of the time - by exporting energy when wind power is too high, and importing when it is too low.[16] The availability of interconnectors with massive capacity, connected to large regional markets, makes it easier for a relatively small country of Denmark to be able to balance its increasingly intermittent power generation.

It should be also noted that being connected to the Nordic market provides Denmark

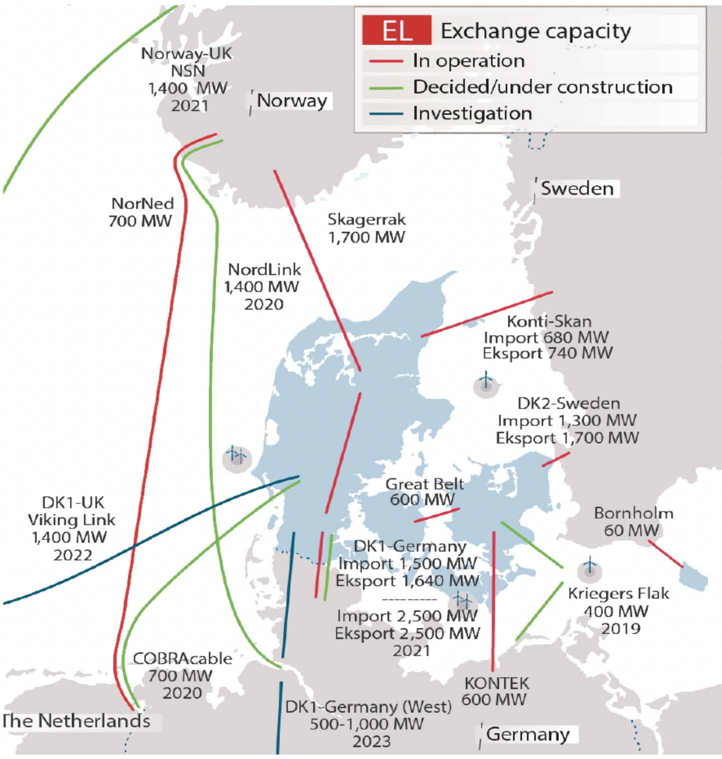

Figure 2. International transmission links
between Denmark and nearby electricity markets (Danish

benefits not only in terms of electricity supply, but also access to larger reserves for balancing system stability.[17]

[15] Energy Statistics (Danish Energy Agency, 2020)

[16] Energy Policies of IEA Countries: Denmark 2017 Review (International Energy Agency, 2017)

[17] Development and Role of Flexibility in the Danish Power System (Danish Energy Agency, 2021)

Flexibility and demand-side management

While availability of dispatchable generation (combined heat and power) and interconnectors has allowed to integrate VRE generation in the grid, over recent years, as the proportion of VRE increased, other factors have become more prevalent. Demand-side flexibility, accurate forecasting, and sector-coupling are major tools in managing the growing variable wind generation in recent years.[18] The installation of smart meters has allowed us to better track the consumption of electricity, and adjust tariffs to incentivize adjustments in demand. In addition, data collection and real-time estimations on weather patterns have allowed for a more proactive approach in balancing and scheduling the electricity supply.[19] More recently, aggregators have been introduced in Denmark, which regulate the consumption of a portfolio of smaller units (such as heat pumps, EVs) and sell system services to the grid.[20]

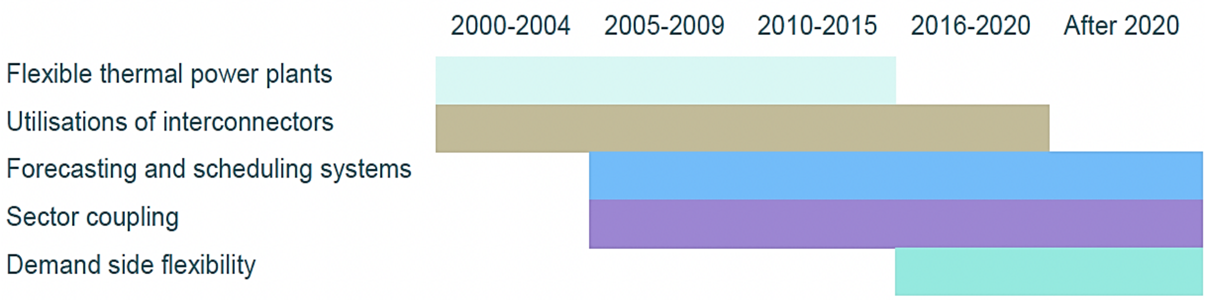

Figure 3. Main mechanisms for dealing with VRE intermittency in the Danish system

The cost

While the renewable potential and geographical location no doubt played a big role in Denmark's ability to achieve high energy security and renewable integration, one cannot ignore the costs. Denmark has the second-highest electricity price for household consumers in Europe (0.29 Eur per kWh, with more than half of it coming in the form of taxes). A major part of this has been Public Service Obligations (PSOs), which is a tariff aimed at subsidizing wind power and combined heat and power plants.[21] The latter have been particularly hit by increased renewable generation, reducing their annual load and income; needing a standby source of dispatchable power to cope with wind variability, the government seeks to subsidize these CHPs. While the total CHP installed capacity has exceeded peak demand until 2020,[22] most of it appears to have been laid dormant for most of the year,[23] being kept alive at the expense of the consumer. This practice has been deemed problematic by EU regulation, and Denmark envisions a phase-out of the subsidy, leaving the CHPs as market players and increasing the

[18] Ibid.
[19] Ibid.
[20] Ibid.
[21] Development and Role of Flexibility in the Danish Power System (Danish Energy Agency, 2021)
[22] Ibid.
[23] Energy Policies of IEA Countries: Denmark 2017 Review (International Energy Agency, 2017)

country’s reliance on interconnection.[24] The costs of maintaining system balance, transmissions and interconnections are among those that Denmark’s consumers have to pay for a highly secure network with large VRE shares.

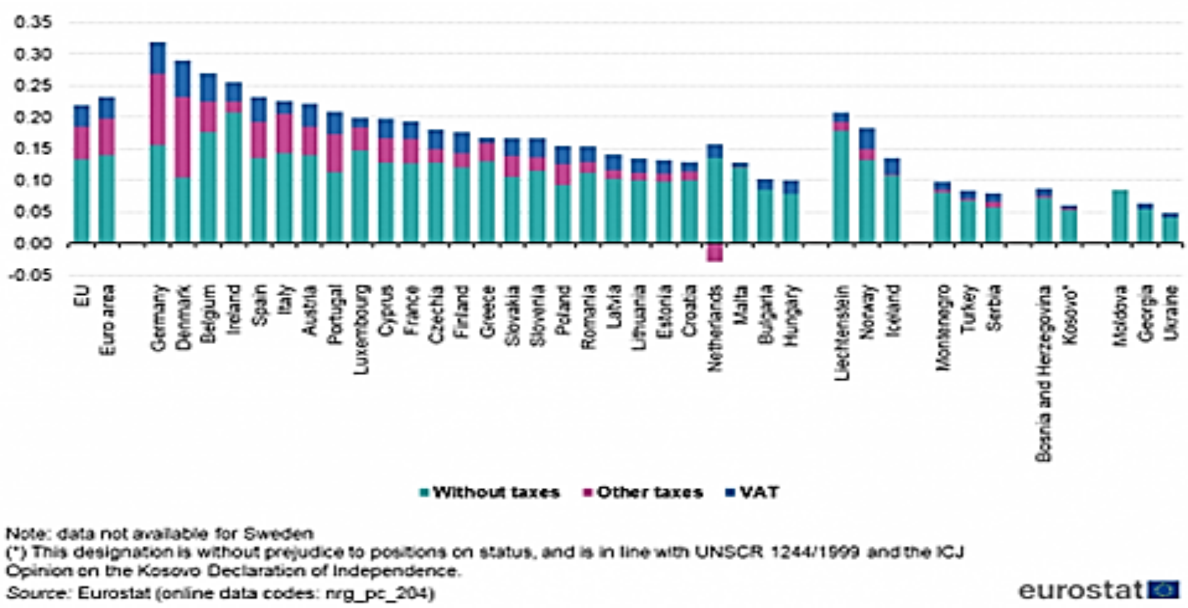

Figure 4. Electricity prices for household consumers. First half 2021 (Euro per kWh)

Lessons for Armenia

The Danish experience can provide several important lessons for Armenia’s plans. As was said, Denmark underwent the transformation from a heavily fossil-dominated energy system to a much more renewable-based one, especially in heating and electricity, in a span of 30 years. Its policies and practices show what Armenia ought to consider, in particular if it aims to increase its energy security via low-carbon generation.

The role of interconnection

One cannot underestimate the extent to which the connectedness to regional European electricity markets aided Denmark in getting so far; if not by making it possible in the first place, then at least by providing a lower-cost solution. A relatively small country that is well interconnected to large regional markets is at advantage not only in terms of electricity supply, but also maintenance of grid stability and balancing. While Armenia is unlikely to achieve as high a degree of VRE integration within the next decades, it is also far more limited in interconnections compared to Denmark. Being currently a net exporter of electricity to Iran, Armenia will also have to start considering the role of interconnectors in supplying power to balance variable wind and solar generation. This will be of particular importance in the winter months, when demand is at its highest, yet solar and hydropower generation are at the lowest.

[24] Development and Role of Flexibility in the Danish Power System (Danish Energy Agency, 2021)

The issue isn't as much about being a net exporter or importer, but being able to import electricity from Georgia and Iran when it is most needed.

Market solutions to VREs

Armenia is only beginning to liberalize its electricity markets, and the main form of demand-side flexibility is by "browning out", i.e. scheduled cuts in supply to selected parts of the grid in order to manage demand. The experience of Denmark shows how important market structure and functioning are to managing the fluctuating supply of VREs. On one hand, it is unlikely that Armenia's VRE generation will reach such high shares as in Denmark in the near future. This is partly since the main source of VRE in Armenia is solar power, while it is wind power in Denmark. Solar power tends to have a much-higher rate of auto-correlation, i.e. the generation curves of solar panels are strongly correlated, making every additional unit less valuable; this aspect is not as strong for wind.[25] Given in addition Denmark's large natural endowment with wind potential, there can be times when wind generation alone is enough to meet the demand for the whole day;[26] such is not possible for solar power, which is absent at night. While this limits the scope to which Armenia can rely on its VRE generation, the higher autocorrelation of solar power means more predictable timings when demand-side flexibility would be needed. Given the limitations of interconnectors, Armenia should pay attention to its electricity market development, including increased price responsiveness and voluntary demand-curtailment as possible solutions, as well as reasonably accurate weather forecasting. As noted earlier, one of such demand-side approaches can be implementation of flexible and cost-reflective tariffication systems, to adjust consumer behavior to the varying electricity supply.

Costs of high VRE and high energy security

An obvious point of difference between Armenia and Denmark is the availability of financial resources. Public Service Obligations, construction of high-capacity interconnection lines, grid stability and management are costly features of Danish electricity markets. Even with a much friendlier geopolitical environment and arguably better endowment of renewable generation potential, Denmark has to price its consumers accordingly to keep a stable supply - even by European standards. The solutions that Armenia will seek have to be according to its own limitations, especially if it seeks both cost-effective electricity markets that involve cross-border trade, and high self-reliance that would require supporting domestic dispatchable capacity. This, in turn, means evaluating the benefits provided by traditional generators such as natural gas, nuclear power, and hydropower, and compensating them accordingly. Among these is the provision of grid stability due to the inertia of rotating turbines of these traditional

[25] The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables (OECD-NEA 2019)
[26] Development and Role of Flexibility in the Danish Power System (Danish Energy Agency, 2021)

generation types[27] - something that would become increasingly relevant in a system with growing solar power share. The experience of Denmark can help Armenia identify the costs and benefits of various elements in a system with high VRE generation, and to provide market mechanisms accordingly, in order to move forward in a cost-effective manner.

Switzerland

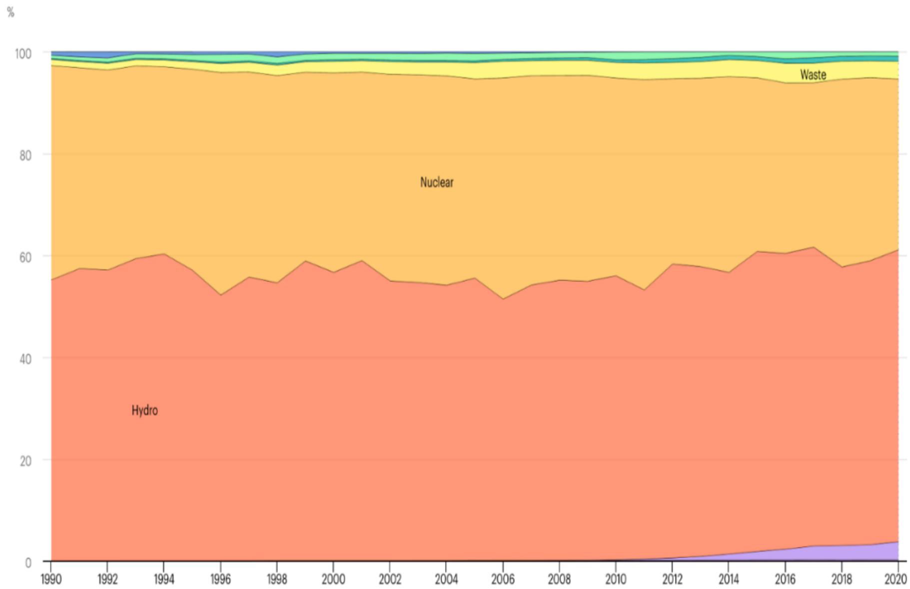

Figure 5. Timeline of Switzerland's electricity mix, 1990-2020. Source: IEA.

Switzerland is quite similar to Armenia, both in terms of topology and its electricity mix. The generation is mainly divided between hydropower (two-thirds) and nuclear power (one-third). Like Denmark, Switzerland is well-connected to its neighboring countries, both importing and exporting electricity. In theory, Switzerland's electricity system is what many other countries would strive for, with low carbon and highly controllable generation; such generation mix requires less mechanisms, either in the system or market design, to balance the grid. However, the Swiss have introduced a ban on construction of new nuclear power plants following a referendum in 2017. Once the existing NPPs' lifetime is expired, the country seeks to replace it with alternative sources, including solar and wind generation.

Use of reservoirs

One of the advantages of the Swiss system is widespread use of hydropower reservoirs (both naturally formed and pumped storages), which account for roughly a third of the annual electricity supply.[28] The use of hydropower, both in terms of accumulating reservoirs and on-

[27] The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables (OECD-NEA 2019)
[28] Statistique Suisse de l'Électricité 2020 (Office fédéral de l'énergie OFEN), *in French*

the-river generators, has been the traditional source of power in Switzerland's electricity system, with nuclear power becoming the other major player since the 1970s.[29] It is the reservoirs that fill in the primary role of load adjustment, generating power when the demand rises, while nuclear and on-the-river generators play more of a baseload role.[30] While this role will become more relevant in the future (with the replacement of nuclear power by VRE), pumped storage reservoirs also perform an important role of seasonal storage - the energy accumulated in summer months is released in winter.[31] This is an important advantage of the geographical structure of Switzerland, as most storage technologies (including chemical batteries and compressed air storage) do not hold energy for such long periods of time.[32]

Nuclear phase-out and regional trade

Like Denmark, Switzerland is well interconnected with its neighbors. The country primarily imports electricity from France, Germany, and Austria, and exports to Italy.[33] Energy is imported primarily in winter months, when the demand is high and the hydropower is less available, while exports occur in summer.[34] Being located in the heart of Europe, Switzerland is an important strategic player in the regional electricity markets; however, cooperation has been stifled due to EU requirements on regulatory and market reforms, which would bring Switzerland closer to EU regulation.[35] As it appears that agreements have not been reached,[36] Switzerland remains outside of the EU's electricity markets, making scheduling and trading across interconnectors harder, which in turn could put more stress on the Swiss grid. The fact that much of electricity trade passes through Switzerland (including up to 30% of electricity exchanged between Germany and France)[37], while Switzerland is not connected to the regional flow based market coupling, means that there are growing cases of congestion in the grid. This requires re-dispatching measures by using hydraulic energy, which ends up being used for grid balancing and not for the consumers, resulting in suboptimal resource allocation.[38]

The problems with trade are especially significant in light of rejection of new nuclear builds; while the country has been a net exporter over the years, the phase-out of nuclear power is likely to turn it into a net importer instead.[39] The reliance of the Swiss system on nuclear power, especially during the winter months (when nuclear accounts for almost half of generation), means that the country will likely become more dependent on imports during

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[29] Ibid.
[30] Ibid.
[31] Des lacs d'accumulation pour réussir le tournant énergétique (Association suisse pour l'aménagement des eaux, 2019), *in French*
[32] Ibid.
[33] Statistique Suisse de l'Électricité 2020 (Office fédéral de l'énergie OFEN), *in French*
[34] Protection du climat et énergie nucléaire (Swissnuclear, 2021), *in French*
[35] Energy Policies of IEA Countries: Switzerland 2018 Review (International Energy Agency, 2018)
[36] https://www.epexspot.com/en/news/missing-swiss-eu-electricity-agreement-endangers-achievements-eu-internal-energy-market , September 2021
[37] Approvisionnement en électricité de la Suisse en 2025: Résumé de l'étude "Analyse Stromzusammenarbeit Schweiz - EU" (Office fédéral de l'énergie OFEN 2021), *in French*
[38] Ibid.
[39] Energy Policies of IEA Countries: Switzerland 2018 Review (International Energy Agency, 2018)

winter, notwithstanding a growing share of renewable generation.[40,41] The inability to achieve full agreements and trade across borders not only generates economic inefficiency, but also puts security of supply under constraint in extreme scenarios as early as by 2025.[42] Unlike Denmark, Switzerland is yet unable to take full advantage of regional electricity trade - an issue that will become more prevalent as the VRE share increases. This could be one of the reasons why the Swiss have repeatedly rejected limiting the operational lifetime of the existing NPPs, even if they have banned constructions of new ones.[43] While there isn't a schedule as to when the existing NPPs will close down, it is likely to take place before 2035 (considering the lifetime of the plants), leaving 15 years for Switzerland to find a mix of alternative solutions to fully replace nuclear power.

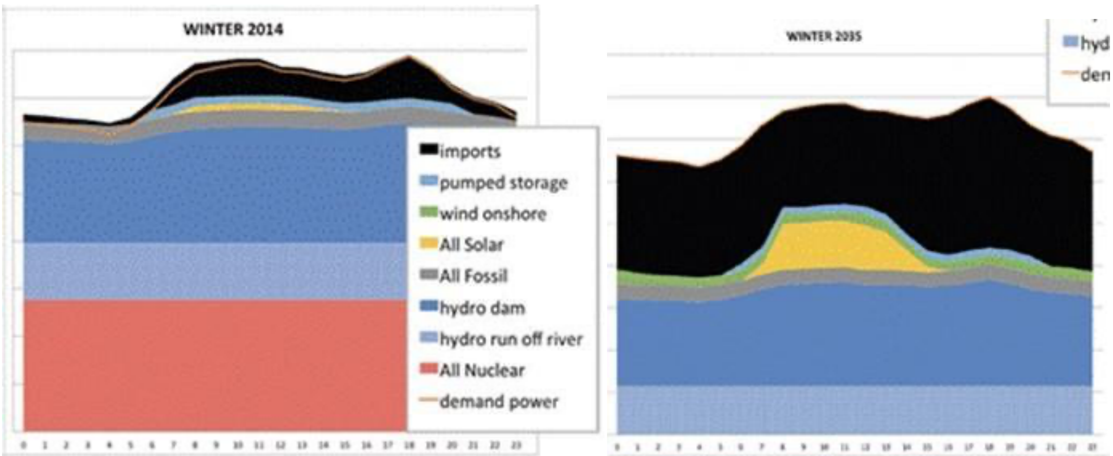

Figure 6. A comparison of modelling results for Swiss electricity supply in winter in 2014 (left) and 2035 (right).[44] Despite a growing share of renewables, imports will become much more prevalent; alternatively, gas-based plants have to be built.

The costs

The phase-out of nuclear power means that the electricity system will have to find alternative ways to replace it. While imports are the most obvious solution, the limited progress on the EU-Switzerland energy agreement makes it unclear exactly to what extent the country will rely on imports. Moreover, importing nuclear-generated electricity from France or fossil-generated electricity from Germany goes against the whole premise of nuclear phase-out and renewable energy promotion.

Therefore, development of renewable energy potential is seen as the other key alternative. Expansion of existing hydropower storage capacity, solar and wind power, as well as biogas

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[40] Ibid.

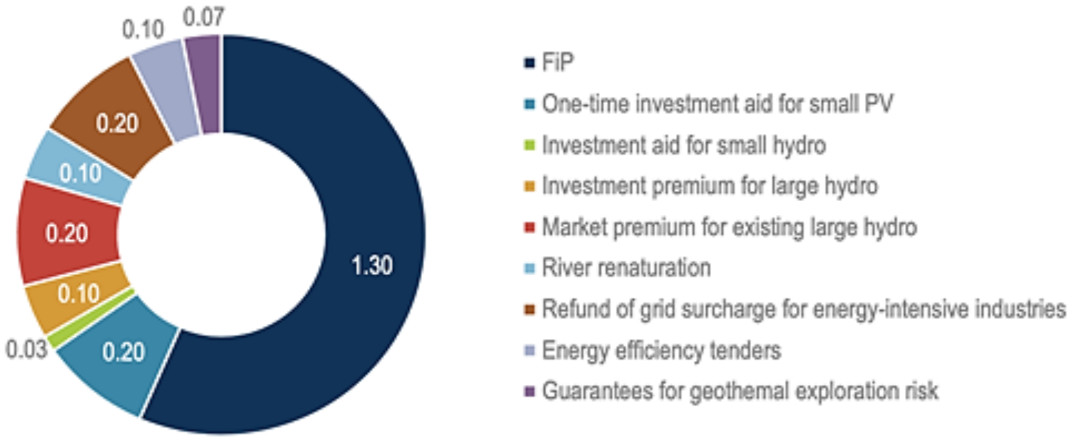
[41] Modelling the energy future of Switzerland after the phase out of nuclear power plants (Diaz Redondo and van Vliet, 2015)

[42] Approvisionnement en électricité de la Suisse en 2025: Résumé de l'étude "Analyse Stromzusammenarbeit Schweiz - EU" (Office fédéral de l'énergie OFEN 2021), *in French*

[43] Energy Policies of IEA Countries: Switzerland 2018 Review (International Energy Agency, 2018)

[44] Modelling the energy future of Switzerland after the phase out of nuclear power plants (Diaz Redondo and van Vliet, 2015)

are among the options. The Energy strategy 2050 includes shifting to Feed-in Premiums (FiP) instead of Feed-in Tariffs (FiT) for the promotion of renewables.[45] This should incentivise producers to provide more supply during high-demand (high-price) hours. While the expected benefits to a producer from FiP are lower (as there is no fixed guaranteed price), this will allow to subsidize a larger pool of applicants overall.[46] This is partly due to previous revenues generated by network surcharge not being sufficient to cover all the applicants for FiT scheme.[47] Hydropower generators have likewise been receiving a market premium, their financial struggles being additionally affected by having to pay royalties to local communities for using water.[48] These royalties have been set at a very high rate, and the government is considering decreasing them to better reflect the market value of the resource. All these activities have to be covered by the consumer, whose grid surcharge was increased to 2.3 Swiss cents per kWh, to generate 1.3 billion CHF for supporting renewables (projected for 2018).[49]



Source: IEA based on information provided by SFOE.

Figure 7. Allocation of network surcharge by funding mechanism.

Lessons for Armenia

Like Denmark, Switzerland presents a potential pathway for Armenia's future electricity system. Dispatchable low-carbon generation in the form of nuclear and hydropower is a luxury few countries can afford; nonetheless,

1. The role of interconnection

Once again, the role of interconnection comes up. Being situated suitable for imports, exports, and being a "middleman" in regional electricity trading, Switzerland benefits from its location and is well-connected to its neighbors. However, unlike Denmark, Switzerland has

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[45] Energy Policies of IEA Countries: Switzerland 2018 Review (International Energy Agency, 2018)
[46] Ibid.
[47] Ibid.
[48] Energy Policies of IEA Countries: Switzerland 2018 Review (International Energy Agency, 2018)
[49] Energy Policies of IEA Countries: Switzerland 2018 Review (International Energy Agency, 2018)

faced political and regulatory issues in fully coordinating its market with the neighboring country. This not only limits the potential for trade, but also results in congestion due to lack of proper scheduling, resulting in economic and energy inefficiencies. This is an important lesson for Armenia - maximizing the potential for trade is not only a technical question of interconnection capacity, but also a question of regulatory alignment. If Armenia will especially become an energy player in the North-South link, it will need to develop proper scheduling arrangements and synchronize its markets with Iran and Georgia. Armenia and Georgia have both undertaken to rely on EU directives regarding cross-border trade, and Armenia is also part of EAEU, which is planning to launch its own common electric power market in 2025 (Armenia has no common borders with EAEU, but trade could take place via Georgia).[50] On the other hand, Armenia has been a major exporter to Iran since 2010. There are therefore three potential trade partners for Armenia, and it is important to have harmonized market arrangements and trading mechanisms with all three of those.

2. Renewable resource development

The availability of reservoirs is one of the great advantages of the Swiss system, providing efficient storage for meeting demand spikes. It is going to become only more prevalent in the future, as a means of balancing VRE generation. Armenia currently contains only three small pumped-storage units, although a study conducted in 2008 identified 11 sites, three out of them being particularly promising.[51] Identification of latest studies, or conduction of new ones, would be beneficial, especially if the economic case for these storages increases in the future. While Armenia's topology does not allow reaching such high shares as Switzerland's or Georgia's, the development of these storage may be one of the smaller measures in achieving high energy security.

Likewise, Armenia should consider switching from FiTs to FiPs as a prospective instrument for subsidizing renewable energy, should a need for subsidy be recognized. A fixed FiP, which would simply add a top-up to the wholesale market price, would help renewable generation to recuperate their costs, but would still reflect the decreasing value and increasing costs of growing VRE generation in the system. The difficulties that small hydropower plants are facing, following the removal of FiT programs for them, shows the dangers of pushing producers beyond economic efficiency, to a point where they would not have built those small HPPs in a free market. FiPs are also likely to cost less than FiTs, meaning that a larger number of consumers will benefit from it. Finally, while in Switzerland hydropower generators have to pay royalties to communities for utilising water resources, in Armenia the water issue will also become more relevant, especially due to climate change. Considerations of implementing some forms of market mechanism, creating a market for water to optimize its distribution across various uses (energy - industry (including agriculture) - residential) can be one of the considerations.

[50] Energy Policies of IEA Countries: Armenia 2022 Review (International Energy Agency, 2022)
[51] Ibid.

3. Nuclear phase-out

Switzerland’s decision to phase out nuclear power leaves it at uncertainty as to how the resulting gap will be met. Increased dependence on imports, development of domestic renewable potential, as well as utilization of natural gas are among the possibilities, depending on how the situation will evolve. Armenia would pretty much face the same options; however, it is important to recognize the much more limited trade capacity that Armenia possesses. If a larger reliance on natural gas is ruled out as a matter of environmental concern and import dependence, then renewable development potential is the only option left; estimates should therefore be made as to what extent this is a possibility. While the public and government opinion appears to be much more pro-nuclear in Armenia than in Switzerland, such opinion has to be informed by the costs of new nuclear build. Switzerland has not laid out a specific roadmap for nuclear energy decommissioning, preferring instead to permit the full lifetime operation of the existing plants; Armenia, however, appears to face a much more limited range of opportunities due to both geopolitical and economic constraints, and proper planning on behalf of the government is more imperative.

Israel

Israel has historically found itself in a similar predicament as Armenia - a small country, surrounded by hostile states, with (until relatively recently) no oil and gas reserves. The country has an excellent potential for solar power; intuitively, the development of solar power would align extremely well with Israel’s energy security and independence. In practice, Israel has remained overwhelmingly fossil fuel dominated. The only major trend is oil and coal being replaced by natural gas, but the development of solar power remains abysmally low.

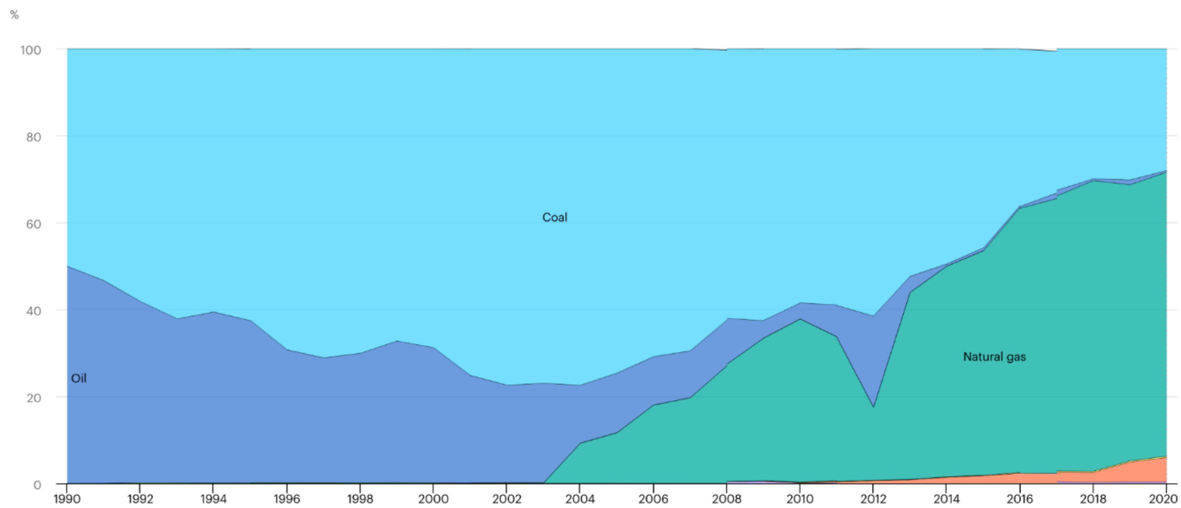

Figure 8. Timeline of Israel’s electricity mix, 1990-2020. Source: IEA

Reliance on fossils

Israel's electricity mix, and energy in general, has been completely dominated by fossil fuels throughout the years. Moreover, in the period between 1976 and 2003, the country relied almost completely on imports.[52] In an ironic way, Israel has a capacity to completely switch to energy independence; the recent discoveries of Tamar and Leviathan fields have significantly shifted the national policy. The amount of recoverable gas under Israel's waters appears to be enough to cover power generation for 40 years.[53] Nonetheless, Israel aims at 40% renewable generation by 2030, through primarily developing solar power.[54]

Small renewable installations benefit from various tax exemptions and can benefit from FiT schemes.[55] However, the levelized electricity cost of these small installations is significantly higher than natural gas.[56] Finding space (most of the available land is located far from consumption centers, including the Negev desert) and adjusting transmission infrastructure have been among the problems for deployed large scale solar plants, as has been the lack of a liberalized wholesale market which would provide a proper cost-benefit framework for solar installations.[57] In short, availability of cheap gas (not taxed for its carbon pollution) and lack of planning for renewable integration have been among the barriers to the development of solar power generation in Israel; while centralized planning is not as necessary, the non-liberalized market structure has left little room for alternative pathways of development. With the new plans to drastically increase deployment of renewables, it remains to be seen as to how Israel will achieve it.

Interconnection

The geopolitical situation of Israel has resulted in it, involuntarily, being an "energy island", not being able to benefit from electricity trade with its neighbors. Nonetheless, the country has sought to establish electric connection with Europe, via the EuroAsia interconnection. A 1000 MW underwater direct current cable, the interconnector will link Israel, Cyprus, and Greece, costing an overall 2.5-3 billion USD, of which 800 million will go into the Israel-Cyprus section.[58] The government recently signed a memorandum of understanding, moving one step closer to constructing the cable.[59] Being able to sell cheap solar electricity to Europe, and rely on imports for Israel's own security, are among the reasons that Israel is considering the projects, as is strengthening its geopolitical ties with Europe.[60]

[52] Energy imports, net (% of energy use) - Israel
[53] Energy Policy Formulation in Israel Following its Recent Gas Discoveries (Dagoumas and Flouros, 2017)
[54] Israel's new roadmap targets 40% of renewable power generation by 2030 | Enerdata
[55] Accelerating Climate Action in Israel (OECD, 2020)
[56] The sun is shining, so why isn't Israel making hay of its solar energy? (Times of Israel, 2021)
[57] Accelerating Climate Action in Israel (OECD, 2020)
[58] Supercharged: The EuroAsia Interconnector and Israel's Pursuit of Energy Interdependence (Mitchell, 2021)
[59] Israel connects to European electricity grid: Minister Dr Yuval Steinitz has signed memorandum of understanding for laying the world's longest underwater power cable | Ministry of Energy
[60] Supercharged: The EuroAsia Interconnector and Israel's Pursuit of Energy Interdependence (Mitchell, 2021)

Grid security

Being surrounded by hostile nations, Israel has become one of the leaders in some aspects of grid security. While the country is not alone in facing climatic risks, it has a considerable experience with cyber attacks, and is certainly one of the few facing constant threats of missile damage. Since at least the early 2010s, the Israeli government has been planning on reinforcing top infrastructure sites against potential missile damage.[61] So far as is known, two power plants and two switching stations had hardening constructed for them; the sites were picked based on what the consequences of damaging them would be.[62] One of the questions was as to who would pay for such practices in the future, the government or the industry. Moreover, the question as to how to use anti-missile batteries had to be considered; with the numbers being limited, it was suggested that power stations and IAF bases would have to be prioritise, as they are key to eventually winning a war.[63]

The country also has to be ready against cyber-attacks, especially in the face of increasing energy digitization and data management. The Israeli Electric Corporation allocates significant funds to cybersecurity research and participation in international programs; it also is directly involved in cybersecurity in the ways described as follows.[64] The Advanced Cyber Center serves as a command-and-control center, ready to respond to cyberthreats based on predefined models of defense. Israeli Electric Corporation also partners with companies that provide cybersecurity training, as well as management and monitoring systems for energy sites and companies. Periodic drills and training are conducted, including hiring hackers to test the security of the system. What distinguishes Israel's approach to cyberthreats is its strategic (rather than tactical) approach, meaning that a comprehensive strategy is developed instead of handling attacks one at a time once they occur.

Lessons for Armenia

Israel's fossil-dominated energy system is far beyond Armenia's in terms of renewable development; nonetheless, not only are there some aspects of the Israeli grid from which Armenia can learn, but the reasons why solar remained underdeveloped in Israel can also point to some lessons for Armenia.

4. The role of interconnection

As with Denmark and Switzerland, interconnectors come in. Israel's consideration of building the EuroAsia link, despite its costs and the fact that Israel can be fully self-reliant with its newly discovered oil&gas fields, shows how important trade is, not only from the viewpoint of economic efficiency, but also from geopolitical aspects. Linking Israel to Cyprus and Greece would increase the political bonds between the countries, especially as Egypt is also

[61] Securing the Electrical System in Israel: Proposing a Grand Strategy (Weinstock and Elran, 2017)
[62] Ibid.
[63] Securing the Electrical System in Israel: Proposing a Grand Strategy (Weinstock and Elran, 2017)
[64] Ibid.

considering a similar project. Armenia has a similar relationship with Iran, exporting a considerable amount of energy to Iran and so increasing its importance. Further developing the trade with Georgia and possibly EAEU would strengthen Armenia's importance in the region, which would benefit strategically.

5. Renewable energy development

Several factors have so far prevented Israel's development of local renewable energy. Consideration of VRE generation's impact on the grid requires planning and foresight, to be able to upgrade a grid that can manage fluctuations in supply and flows. Armenia should therefore anticipate how much renewable deployment will take place, and adjust its grid development accordingly. Moreover, a functioning wholesale market and localized decision-making can help prevent bureaucratic costs and inefficiencies. Finally, as OECD notes, Feed-in Tariffs, by providing fixed remuneration, are unable to reflect the value and costs that renewables bring to the system, risking further inefficiencies. Feed-in Premiums, to which Switzerland is switching and which Denmark have utilized, better incentivise optimal behavior from producers. Taxing gas producers for pollution is also another way to provide advantage to low-carbon generation, if politically feasible.

6. Grid security

Like Israel, Armenia is in a hostile geopolitical environment; considerations have to be taken to protect critical infrastructure (including energy) from external attacks. Development of the cybersecurity center for the grid, implementation of strategic approaches to cyberthreats and scenario modelling, training and simulations are practices that are well-worth adopting. Among these are possibilities of decentralization and island mode functioning, in particular of the Syunik grid. Identification of critical lines substations and generators, and protecting them by anti-missile batteries and hardening structures are likewise worth considering, though within the smaller budget. It is not necessary to copy the costly practices of the Israeli Army, but development of strategic approach and preparedness to attacks on the grid, both physical and cyber, is a necessary component of Armenia's energy security and independence. The utilization of Armenia's developed IT sector is well worth considering.

Ireland

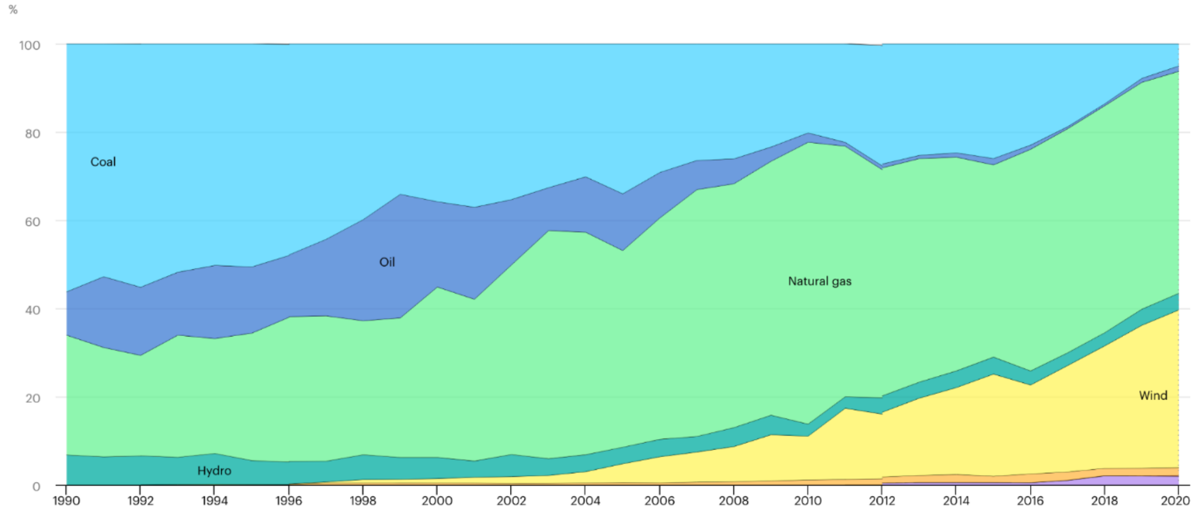

Figure 9. Timeline of Ireland's electricity mix, 1990-2020. Source: IEA

Ireland's path has been in some way similar to Denmark; a fossil-dominated start, with a growing share of significant wind power generation (up to 40%). While this may not seem as impressive as Denmark's achievement, one of the factors to be considered is the limited interconnection capacity. The country is connected to Northern Ireland and Britain, but so far remains isolated from the rest of the European grid;[65] unlike Denmark's far greater interconnectivity with both Nordic and Central European markets, Ireland's island geographic has resulted in it being somewhat of an "island" grid. The country therefore struggled with wind curtailment and generation management, and has sought alternative solutions, including some innovative market designs, to integrate VRE generation into the grid.

Ancillary services

The limited ability to integrate VRE through interconnections led Ireland to reformulate its design of electricity markets. The DS3 program, "Delivering a Secure Sustainable Electricity System", was initiated in 2011, foreseeing Ireland's grid requirements in a high-VRE energy system.[66] One of the recognized problems was the need for new system services, to balance the frequency and power in the grid. The procurement for these services provided energy producers with additional flows of income, which was especially useful in light of lower electricity prices on the market. While conventional generators have been the most active providers of system services, wind power, demand side-units, interconnections, and occasionally batteries have also contributed to various services.[67] A separate mechanism, qualification trial process, was established to test new technologies and see which services they can provide.[68]

[65] Energy Policies of IEA Countries: Ireland
[66] https://ietresearch.onlinelibrary.wiley.com/doi/epdf/10.1049/iet-rpg.2020.0614
[67] ibid
[68] ibid

Summary definitions of DS3 system services[a]		
Service name	Abbreviation	Short definition
Synchronous inertial response	SIR	Stored kinetic energy*(SIR factor[b] – 15)
Fast frequency response	FFR	MW delivered between 2 and 10 s
Primary operating reserve	POR	MW delivered between 5 and 15 s
Secondary operating reserve	SOR	MW delivered between 15 and 90 s
Tertiary operating Reserve 1	TOR1	MW delivered between 90 s and 5 min
Tertiary operating Reserve 2	TOR2	MW delivered between 5 and 20 min
Replacement reserve – synchronised	RRS	MW delivered between 20 min and 1 h
Replacement reserve – desynchronised	RRD	MW delivered between 20 min and 1 h
Ramping Margin 1	RM1	Increased MW output and/or MW reduction that a unit can provide within 1 h and maintain for a further 2 h
Ramping Margin 3	RM3	Increased MW Output and/or MW Reduction that a unit can provide within 3 h and maintain for a further 5 h
Ramping Margin 8	RM8	Increased MW output and/or MW reduction that a unit can provide within 8 h and maintain for a further 8 h
Fast post-fault active power recovery	FPFAPR	Active power (MW) >90% of pre-disturbance output within 250 ms of voltage >90% of nominal voltage
Steady-state reactive power	SSRP	(Mvar capability)*(% of capacity that Mvar capability is achievable)
Dynamic reactive response	DRR	Mvar capability during large (>30%) voltage dips

List of system services defined in 2013 following consultations with stakeholders taken from Delaney et al, 2019.

Technology class	Services proven
wind – wind farm control	FFR, POR, SOR, TOR1
wind – emulated inertia	FFR, POR
demand-side management (DSM)	FFR, POR, SOR, TOR1
synchronous compensator and flywheel hybrid	FFR, POR, SOR, TOR1
centrally dispatched generating unit (CDGU)	FFR
HVDC interconnectors	FFR

Table 1. Results of QTP in assessing ability to provide system services, Delaney et al, 2019.

The TSOs maintain and update lists of technologies and the services they can provide; in 2019, tests are being run for the ability of solar power plants and aggregated automated residential demand response to provide system services.[69] Competitive tenders for system services are run for the new entrants, to stimulate newbuilds by reducing risk and uncertainty for the investor.[70] The investments are particularly important, as the country could lose 2.4 GWs of thermal capacity by the mid-2020s, mainly due to emission restrictions.[71] The shift from older capacity remuneration (availability of capacity) to service-based provisions (based on competitive reliability) has also incentivized conventional generation plants to enhance their flexibility.[72] It has likewise reduced the costs of the capacity mechanism by 200 mln EUR, as

[69] https://ietresearch.onlinelibrary.wiley.com/doi/epdf/10.1049/iet-rpg.2020.0614

[70] Ibid.

[71] Energy Policies of IEA Countries: Ireland

[72] https://ietresearch.onlinelibrary.wiley.com/doi/epdf/10.1049/iet-rpg.2020.0614

only those providers whose bids are successful receive the capacity payment.[73] Like Switzerland, Ireland is planning to shift to premiums on top of market prices as a form of support for renewables, as opposed to fixed feed-in tariffs.[74]

Interconnections

Ireland functions as a more isolated grid; its two interconnections are with Northern Ireland (300 MW) and the UK (500 MW), resulting in a 7.4% level of interconnection.[75] While the country has made significant advances in managing non-synchronous generation within its grid, the importance of interconnections for the next stages is recognized. Three new interconnection projects are being pursued, including one to France, to provide a link to the EU electricity markets following the UK's withdrawal from the organisation.[76] There is therefore potential of 2700 MWs of additional interconnection potential,[77] which would greatly facilitate the ability to efficiently integrate VRE generation.

Demand response

Demand response has played an increasingly important role in Ireland's system. The demand-side aggregators have access to 700 MW of electricity customers' resources.[78] The important part of benefit for demand response is reduction in peak demand; the "top" 200 MWs of power are required in the Irish grid for only 8 hours per year. Meeting this demand would require a gas peaking plant with costs of around 120 million euros, while demand management could avoid these investment costs.[79] This illustrates the reason why a shift from availability-based capacity market reliability-based one has shifted the focus to load-shedding opportunities.[80]

Table 2. Services and contracted volumes of DS3 System Services for DSU Gate 2[81].

FFR, MW	POR, MW	SOR, MW	TOR1, MW	TOR2, MW	RRD, MW	RM1, MW	RM3, MW	RM8, MW
111	129	132	177	152	297	481	43	42

The key driver of electricity demand for the upcoming years in Ireland could be data centers and other large energy users; while demand in other segments is expected to stay constant, an extra 10 TWh-s (over a third) could be added through data centers and large energy users by 2027.[82]

73 Energy Policies of IEA Countries: Ireland
74 Ibid.
75 Ibid.
76 Ibid.
77 Ibid.
78 Demand Response Association of Ireland
79 Ibid.
80 https://ietresearch.onlinelibrary.wiley.com/doi/epdf/10.1049/iet-rpg.2020.0614
81 Demand-side unit's system services, from Delaney et al. 2019
82 Energy Policies of IEA Countries: Ireland

Analysis

The role of interconnection

Once again, the role of interconnectors has to be emphasized. While Ireland has traditionally had limited interconnection capacity, new projects are being pursued to improve the system reliability. Brexit likewise requires new electricity trading arrangements between Ireland and the UK, as some form of market coupling is to be introduced. Like Ireland, Armenia has limited trade capacity; any potential expansion of that capacity should be explored, to facilitate implementation of VRE in the grid.

Demand response

The variability of VRE generation could provide industrial and commercial consumers of electricity with opportunities to earn additional income, through providing services to the grid by load shifting or load shedding. The two seasonal peaks of demand (summer and winter) can also be investigated, as reducing the load on those occasions can reduce the overall capacity required for the system. While large-scale producers and IT firms would be primary actors in demand-side response, aggregators for residential consumers will provide even more benefits, although corresponding institutional arrangements are required.

Ancillary services

The reformulation of ancillary services based on the needs of the grid has allowed Ireland to utilize its energy generation more effectively. Both supply and demand-side actors have engaged in the market for system services. Armenia will likewise have to identify its own list of system services and corresponding remuneration, based on what are the particular needs of the Armenian grid. Through grid modelling and consultations with stakeholders, Armenia should develop a framework for procuring system services and thereby avoiding excess investments in capacity and grid enforcement.

Conclusion

The international experience provides a lot of learning opportunities for Armenia. Many technological and regulatory solutions are noted and described in other parts of the report; here, four countries were selected and analyzed in more depth, and their similarities and differences with Armenia highlighted. The purpose was to develop a certain “emergent” role model, based on the collective experience of these four countries. None of them is fully similar to Armenia, or presents an ideal role model, but the collective lessons can be briefly summarized as follows:

Interconnections are critical for Armenia; all four countries seek to develop their trade capacity, which allows (among other things) to integrate a higher share of VRE. This demonstrates that their primary goal is not energy independence in the sense of fully isolated self-sufficient mode. Indeed, Israel is seeking interconnection despite having enough gas reserves to sustain itself for many years, while Ireland has been struggling with being physically isolated due to its location. **Higher interconnectedness and grid resiliency as a result are the priority goal, especially in systems with high share of VRE generation.**

Proper regulatory development is critical. Whether it is effective ancillary services procurement, more system-efficient subsidization of variable generation, or regulatory harmonization with neighboring countries, the regulatory environment has to enable various technologies to enter the market. This is, again, especially true for high shares of VRE generation. **Armenia needs regulatory change to achieve the theoretically achievable levels of independence or will achieve it at a much higher cost.**

Ultimately, it is unlikely that achieving higher levels of VRE, energy security, and independence, can be assured without increasing the costs to the consumer and/or the taxpayer. While goals can be reached more efficiently than in other countries, by learning from their mistakes and benefiting from their research, we cannot rule out that, at least in the medium-term, higher costs will have to be induced, especially for such projects as construction of nuclear power plant, interconnectors, storage, etc. **Public support of the selected strategy will be important, and benefits have to be clearly highlighted and communicated, especially if they come in the form of mitigation of future risks, rather than dealing with the problems of today.**

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2. MARKET LIBERALIZATION AND ECONOMICS

General information

The liberalization of electricity markets is a complex process; it can entail such issues as privatization of generation facilities, vertical unbundling, introduction of retail competition, and introduction of a voluntary bidding-based wholesale market. Given the complexity and institutional requirements for a liberalized electricity market, a properly planned liberalization process is necessary, otherwise the costs may outweigh the benefits (e.g. UK of a better transition, vs California as "textbook-case of reforms gone bad"[83]). These costs can be caused by a variety of factors: constantly changing reforms and rules of the game (deterring investments or even supply on the electricity market), insufficient competition and inefficient regulation as a result of unbundling and privatization (resulting in market power, e.g. California), deregulation of some aspects of the market without corresponding deregulation of other aspects (e.g. introducing retail competition without much freedom on the supply side and the wholesale market, in continental Europe).[84] An analysis of Armenia's market reforms and existing gaps has been provided by USAID[85] and is a different topic altogether; however, insofar as electricity market liberalization relates to the energy independence and security, additional topics (namely systemic costs and security of supply) are covered here in the context of future market liberalization. The main gaps identified by the USAID analysis can be summarized in brief as follows:

- Regulatory approval of new entrants cannot be conditional on the Ministry's consent.
- Tendering should be used only after market entries are not enough to meet system adequacy requirements.
- Ownership of Electricity System Operator and High-Voltage Electricity Networks should be separated from the shares of other electricity undertakings.
- The duties and responsibilities of Public Service Regulatory Commission should be specified and optimized

[83] Lessons Learned from Electricity Market Liberalization (Joskow, 2008)
[84] Ibid.
[85] Armenia Electricity Market Gap Analysis, USAID 2021

Systemic costs

The introduction of high shares of VRE generation into the system will lead to growing systemic costs. These come in several forms, usually broken down into a few general categories.[86,87]

1. Profile Costs.

The variation of energy generation results in conventional generators constantly changing their output to meet the residual load. While there is little decrease in capacity of conventional generation sources, the energy generation from those sources is decreased. In other words, the full-load hours of conventional generators are reduced, and the levelized cost of electricity rises, while overproduction may occur in periods of high VRE generation. In addition, the conventional generators often need to increase their flexibility and ramp-up speed, to match sharp declines or rises in wind and solar power output. Note that this is the case even if the variability of wind and solar power was perfectly predictable.

2. Balancing costs

Additional balancing costs come due to the unpredictable nature of VRE variation; this requires frequency regulation and stand-by options for balancing the grid. In other words, not only is the VRE output variable over time, but also less predictable than for conventional generation. In other words, quick response and real-time solutions are required to balance the actual supply. These include non-scheduled ramping up and down costs and frequency regulation approaches; the inefficiencies in plant scheduling can also result in additional costs.

3. Grid / connection costs

Finally, the locations of high VRE generation are often far from the demand centers and grid infrastructure, requiring new infrastructure to transmit electricity and introducing additional grid costs as a result. Local congestion and distribution-level issues can also require grid strengthening, owing to the often distributed nature of VRE generation.

While the grid can adjust to these changes over time, somewhat reducing the systemic costs, these costs can grow rapidly as the share of VRE in the system increases. The increase of these costs depends on the particulars of each system, grid, and geography, but the rough shape (in this case, for wind power) is shown below.

[86] System LCOE: What are the costs of variable renewables? (Ueckerdt et al, 2013)
[87] The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables (OECD-NEA, 2019).

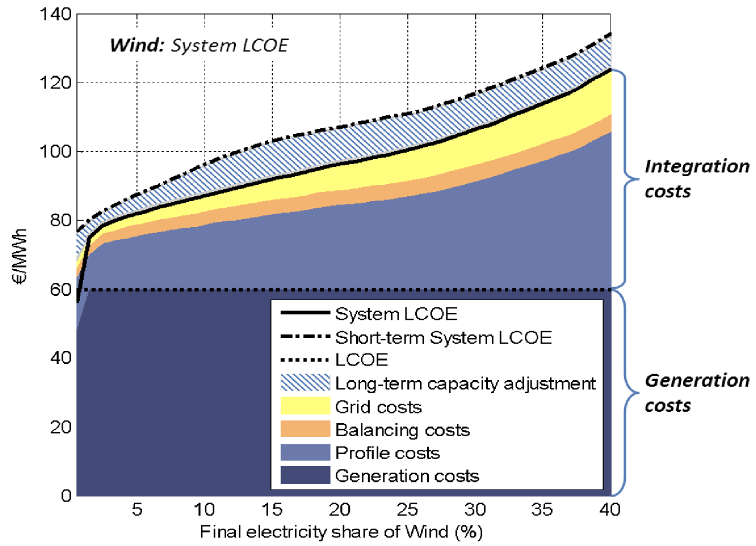
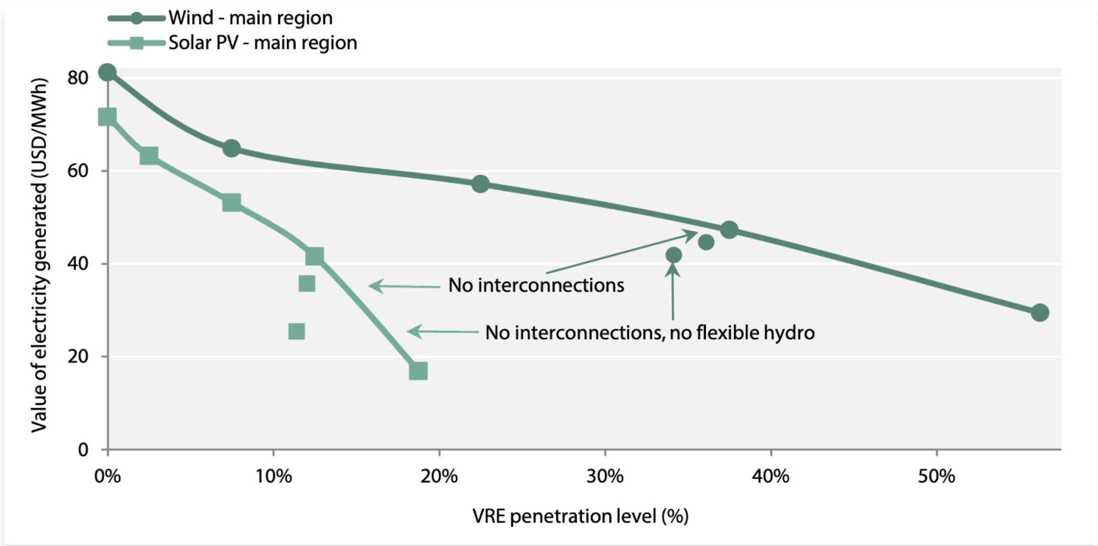


Figure 11. Systemic costs of growing shares of wind power, from System LCOE: What are the costs of variable renewables?

While grid and balancing costs tend to grow mildly, the profile costs can rapidly grow in a more exponential fashion. With the share of VRE in the system growing, less generation is produced by conventional, dispatchable plants, which need to remain available for periods of low VRE generation.[88] This is partly due to the autocorrelation of wind and solar generation; the power output of these sources tends to vary homogeneously over time. The effect is stronger with solar power plants, as they all peak near noon and share a similar generation profile throughout the day. As a result, the overproduction costs of solar power grow much more rapidly as their share in the system increases.[89] Another way to look at it is that the value of VRE drops rapidly as its share in the system increases (see the graph below).

Figure 12. The marginal value of wind and solar PV as a function of their share in the grid, from OECD-NEA, 2019.



[88] See for example the discussion on CHP plants in Denmark in the International Experience Section
[89] System LCOE: What are the costs of variable renewables? (Ueckerdt et al, 2013)

These costs can be mitigated to various extents by storage, interconnections, and demand-side management. This requires a mix of institutional and governmental arrangements, to provide incentives for the integration of costs by market processes on one hand, and to have centralized decision-making (normally via independent system operator) for those aspects where it is more efficient. Balancing of the two approaches is required, as too much government intervention in the market can deter the market mechanisms and disincentivize action by private actors (this will be discussed further below).

Analysis

The model used by OECD-NEA for the decreasing marginal value of VRE (shown above) assumed a continent-scale system, which meant a considerable reduction in the autocorrelation effect. Armenia is a much smaller country, and the autocorrelation of solar and wind VRE is therefore much higher. This means that the value of VRE would drop faster, in the absence of storage, interconnections, and demand-side solutions. In all three, Armenia is limited: interconnections are available only with Georgia and Iran, long-term storage (pumped hydropower) potential is limited, and demand-side solutions require complex institutions and a more liberalised market. At the same time, the smaller financial assets at Armenia's disposal mean that there is a smaller margin for error compared to first-world economies. The implications are clear - economically efficient pathways have to be pursued. Insofar as it is reasonably possible, such pathways have to be sought by market instruments, which are more flexible in adjusting to technological change and require far less concentration of political power and knowledge of centralized decision-makers. An overinvestment in VRE, especially without appropriate coping mechanisms, would result in economic and system costs, including the cost of power disturbances in the grid. An underinvestment would result in a lower level of energy independence and security than is otherwise achievable, and higher cost of electricity generation than could be achieved.

Institutional approaches for dealing with systemic costs

The systemic costs have a range of technological solutions - storage, demand-side management, plant flexibility, smart grid, etc. The goal of this section is to provide institutional solutions that would incentivise and facilitate the implementation of these technologies.

1. Shifting to free spot market prices or feed-in premiums

Under its current approach to VRE development, the Armenian Government implements tenders and fixed tariffication for new solar power projects. This is done to secure investments and reduce risk for the producers. However, what is good for the individual producer is not necessarily good for the system. The optimal economic level of output would be at a point where marginal cost of VRE generation becomes equal to its marginal value; ideally, these should incorporate the costs and benefits that VRE brings to the system. As was discussed earlier, the systemic costs that VRE imposes are largely a result of their variability and unpredictability. It would be in the general interest of the stakeholders to incentivise VRE to incorporate, and therefore minimize, these systemic costs. While some of these costs may be hard to attribute and end up being shared by the system overall, there are certain mechanisms that can considerably improve the system efficiency.

One of these would be to remunerate VRE generation based on the value that it brings to the system at a given point in time. The varying electricity price, while introducing more uncertainty on the market, would incentivise VRE producers to invest into storage, shifting energy to scarcity hours. At the same time, energy storage can reduce the variation in electricity prices, by reducing the number of high-price hours and bringing the median price down.[90,91,92] In essence, the market would somewhat self-stabilize in the long-term. While this could slow down the investment rate of VRE generation, the slower pace would actually bring VRE deployment closer to the general investment cycle in the energy sector, allowing the system to adapt and absorb variable generation more easily. There isn't much improvement for energy security in having mass solar power (over)generation near noon, but unchanging reliance on fossil fuels for other hours.

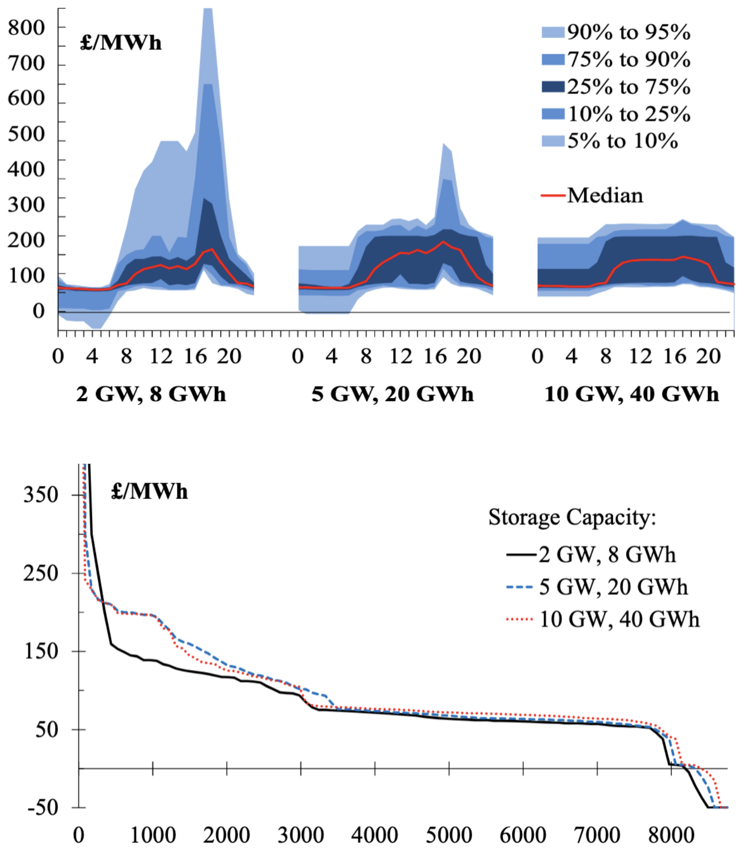


Figure 13. The estimated effect of greater storage installations on prices in the UK grid by 2030 (top), and the resulting price-duration curve (bottom). The Long-Run Impact of Energy Storage on Electricity Prices and Generating Capacity (Green and Staffell, 2015).

90 Impact of Optimal Storage Allocation on Price Volatility in Electricity Markets (Masoumzadeh et al, 2017)

91 On the impact of increasing penetration of variable renewables on electricity spot price extremes in Australia - PMC (Rai and Nunn, 2020)

92 The Long-Run Impact of Energy Storage on Electricity Prices and Generating Capacity (Green and Staffell, 2015)

Prior to wholesale market liberalization, the tariffs for electricity suppliers will be regulated administratively. Time varying feed-in tariffs (which offer higher rates for periods of high demand) could be proposed, based on the estimates made by the system operator.

2. Attributing grid and connection costs

While in theory all external costs should be internalized, it can be hard to attribute specific grid extensions and strengthening to this or that plant. For such cases, it is easier to socialize the costs and have the consumer pay for it through electricity tax. However, there are cases where grid costs are clearly attributable: for example, building a new connection to the grid for a remotely situated renewable energy generation plant.

3. Ancillary services

Ancillary services are a range of procured services at the disposal of the system operator, to manage unscheduled short-term frequency and power issues in the grid. These include the ability to provide reserve power on short notice, the ability to ramp up or ramp down output at a certain rate, as well as reactive power management.[93] i.e. the players on the market (mostly suppliers, but also consumers) offer the readiness to provide a certain service (quickly increase power output, decrease consumption, provide reserves, etc), and are compensated for that. Efficient identification and procurement of these services can not only help the system operator to manage the grid, but also have significant savings in costs.

Analysis

The current practice of auctioning utility scale renewable installations with guaranteed fix-price is beneficial for the investors, but not necessarily for the system. The decreasing marginal value that VRE brings to the system, as well as the plans to shift to more market-based price formation are arguments for shifting to feed-in premiums. Not only will this provide a more optimal level of solar generation, but it will incentivise future storage investments for decreasing prices. A development of ancillary services required specifically for the Armenian grid is also recommended, to provide incentives for flexibility that are optimal for the system. The high cost of utility-scale batteries makes it more necessary to fully identify and reward the various system services which they can supply, providing them with multiple sources of revenue (see the graph below for examples). Moreover, innovative ancillary services are a necessary precondition for achieving higher demand-side participation and flexibility, for such potential grid service providers as industrial players and electric vehicles.[94]

[93] See for example Ireland's approach in the International Experience section.

[94] Demand-side flexibility for power sector transformation

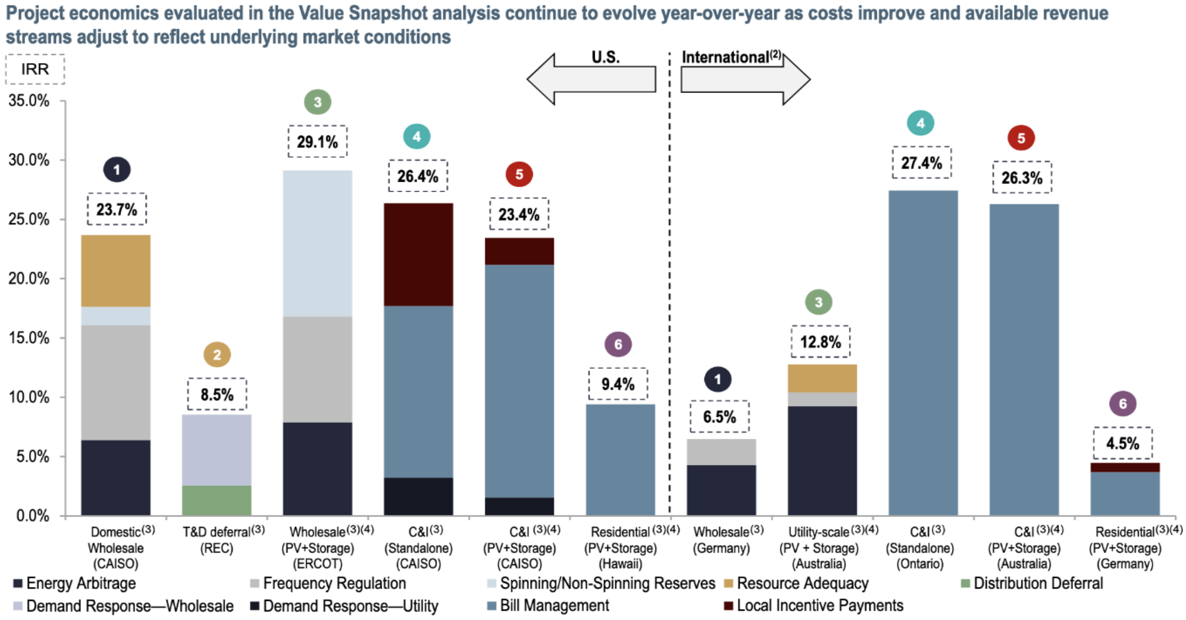


Figure 14. Value Snapshot Case Studies. Taken from Lazard's Levelized Cost of Storage Analysis - Version 7.0

Capacity markets, strategic reserves, and energy-only market

In a liberalized wholesale electricity market, producers of electricity bid on how much energy they will be able to provide and at what price (usually determined by the marginal cost). The system operator then procures power generation until the required demand is met. The price-setting generator is the one with the highest bid that has been procured. The difference between the market price and the marginal cost of generating plants is called "infra-marginal rent"; it is the revenue used to cover the remaining (non-variable) costs.

If the generating capacity is not enough to meet the demand, buyers bid for scarce energy as the prices increase, beyond the marginal cost of the last plant in the merit order curve. This large increase of prices during scarcity hours (when demand is higher than supply) leads to the creation of additional revenue for the producers, known as "scarcity rent". In theory, there are few hours during the year when the scarcity rent becomes very high, allowing the producers (especially the plants with highest marginal cost) to cover their fixed costs, and therefore incentivising new investments.

In practice, there is often a regulatory limit set on how high the prices can rise. This is done due to worries about market power and in order to protect the consumer, as producers may raise the price unnecessarily high once there is scarcity. The result of this price cap is what's called "the missing money" problem. The prices on the electricity market don't go high enough to cover fixed costs and incentivise new investments (especially for what normally are the price-setting generators, with high marginal cost). Therefore, policy-makers have been looking for alternative ways to ensure growing capacity and maintaining the security of supply. Various forms of capacity-remuneration - paying producers for installed capacity in addition to sold electricity - have been introduced. Nonetheless, it should be pointed out that some markets -

such as Denmark, Norway, Netherlands, and Texas, - continue operating on energy-only markets, without any capacity remuneration.[95] However, there too concerns have been expressed - Denmark is open to a strategic reserve solution in light of projected growth of VRE share and reduction in thermal plant capacity.[96] Calls for tighter price controls have been raised in Texas following its grid failure in February 2021 and the extremely high bills that some consumers ended up paying.[97]

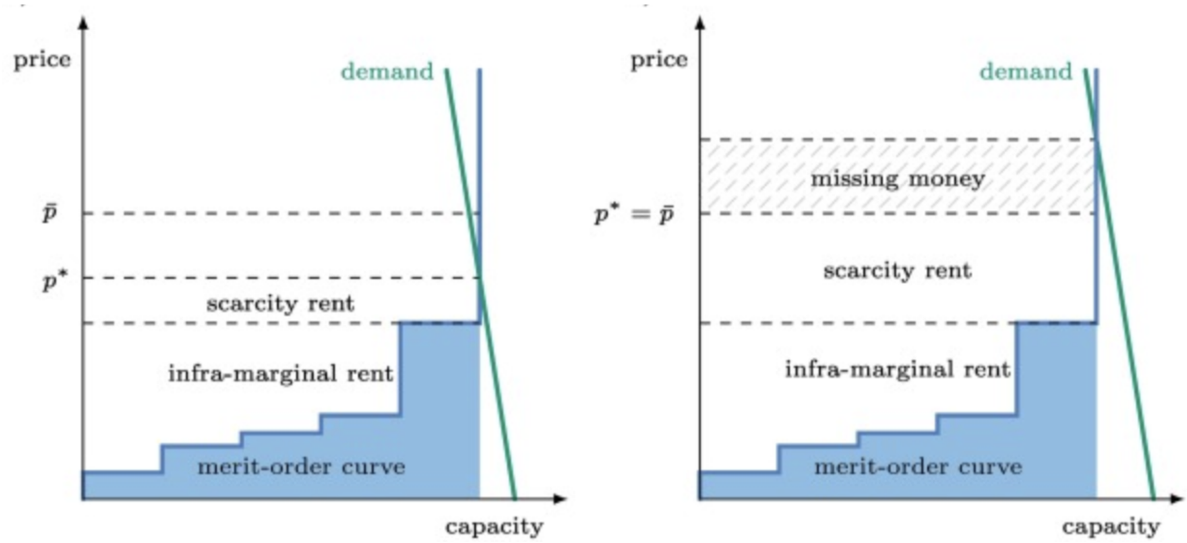


Figure 15. An illustration of the "missing money" problem ($p*$ is market price, $\bar{p}$ is the price cap). Illustration from: A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms (Bublitz et al, 2019).

While demand is not too high above supply, the market price is below the price cap (left); however, at times of high scarcity, the market price is not allowed to go above the price cap (right), limiting the rent that producers can gain and resulting in "missing money".

Two main capacity-based approaches are distinguished for providing additional incentives for investment and dealing with the missing money problem: market-wide capacity remuneration and a strategic reserve.[98] The difference is that a market-wide capacity remuneration can be applied for by producers who also sell on the energy market (though restrictions can apply as to what kind of technology is acceptable). A strategic reserve, on the other hand, means that the producer cannot participate in any other market, and has to be activated in coordination with the system operator specifically when additional reserves are required.

Both approaches have their merits and demerits, and the optimal solution is still debated between scholars and policy-makers. Theoretically, energy-only markets should provide sufficient incentives for new investments, concerns over market power and system security have been major barriers for choosing this approach. The latter needs to be emphasised - high

95 Strategic Reserves versus Market-wide Capacity Mechanisms P. Holmberg and T. Tangerås

96 Liberalisation of the Danish power sector, 1995-2020

97 https://www.econ.cam.ac.uk/research-files/repec/cam/pdf/cwpe2149.pdf

98 A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms (Bublitz et al, 2019) for more detailed description and breakdown of the various approaches

scarcity hours occur, by definition, when generating capacity is unable to meet demand; traditionally, this has meant that the system operator has to forcibly curtail some consumers. The high security standards of having uninterrupted power supply (partly due to complicated physics of grid balancing, partly due to seeing electricity as a necessary basic good) have made this an unacceptable solution for many regulators - whether rightly or wrongly. It is for this reason that increased demand-side management and flexibility is seen as one of the enablers of having an effective energy-only market in a high VRE environment.[99]

Table 3. A brief overview of various approaches to provide security and incentivize investments in relatively deregulated electricity markets. Based on discussions in: Papavasiliou (2020), Bublitz et al (2019), Hogan (2017), Holmberg and Tangeras (2021), Bhagwat et al (2017)

Approach	Energy-Only Markets	Market-wide Capacity Mechanisms	Strategic Reserve
Description	Allowing prices to rise high enough in hours of scarcity, incentivising new investments by increased profits	Providing capacity remuneration to generators in addition to energy market revenues	Isolating a generator from the energy markets, providing it with capacity remuneration in order to be directly procured by system operator when needed
Markets	Texas, Denmark, Netherlands, Norway	UK, US (except Texas), France, Spain, etc	Belgium, Finland, Germany, Sweden
Advantages	No need for additional capacity spending Theoretically optimal choice	Straightforward way of securing system adequacy and incentivising new investments	Straightforward way of securing system adequacy Relatively easy to regulate and manage
Disadvantages	Concerns about market power, politically unfavorable Higher risk of capacity shortages	Hard to determine optimal system capacity volume Installed capacity does not always equal availability	Hard to determine optimal strategic reserve volume Uncertainty regarding the size of the reserve increases investment uncertainty

Analysis of merit order equilibrium

The current excess capacity of power generation in Armenia means that investments are not, strictly speaking, necessary for security of supply. However, that can change in the future, as gas power plants get phased out and as demand grows. The decision will have to be taken whether to have energy-only markets, market-wide capacity mechanisms, or a strategic reserve. The small market size of Armenia makes it more susceptible to market manipulation, especially given that a large portion of generation is owned by a small number of producers. Creation of

[99] Liberalization of the Danish power sector, 1995-2020

a spot market for electricity would therefore be much more beneficial in case of market coupling with Georgia and (potentially) with the EU. This would significantly reduce the opportunities for market power and abuse. On the other hand, the more complex regulatory requirements for market-wide capacity mechanisms, and the difficulty of their implementation for most renewable technologies, makes it questionable as to how extensive the benefits would be, compared to the institutional and system-wide costs.

A strategic reserve appears to be the most natural initial choice for Armenia's energy system. The introduction of high shares of renewables would make prices on the wholesale market more volatile, while the requirement for reserve capacity will remain. One of the natural gas plants would become a strategic reserve unit, while the rest of the producers would operate under an energy-only market. In the future, provided substantial interconnection, market dilution, and demand-side response, an overall energy-only market can be introduced. Additionally, a utility-scale storage system could be maintained directly under the network operator's authority, to aid in grid stability. An example of Italy can be given, where Terna, transmission systems operator, plans a 35 MW storage project for managing grid congestion.[100]

Assuming that the voluntary spot market will be present by around 2035-2040, the following analysis will estimate the effects of the merit order curve in that period. A simplified analysis looking only at the internal demand and projected generation capacities will allow us to highlight considerations for electricity pricing and trade with neighboring countries. **For the purpose of the following analysis, several simplifying assumptions are made:**

1. An isolated liberalized market within Armenia
2. Wholly spot-market based system, i.e. no forward contracts
3. The bidding prices are set as following (assuming that current tariffs[101] for fuel-based generation reflect the marginal costs of generation):
    a. 1 AMD/kWh for solar and wind
    b. 2 AMD/kWh for hydropower
    c. 6 AMD/kWh for nuclear
    d. 16 AMD/kWh for CCGT-1
    e. 20 AMD/kWh for CCGT-2
    f. 25 AMD/kWh for Hrazdan-5
4. The generation potential from renewables sources is fully utilized
5. Full capacity availability of all conventional generation in the spot market
6. Imports, storage, and demand-side flexibility are ignored.

The estimates at three points of time in 2035 are provided below.[102]

[100] Innovation landscape for a renewable-powered future

[101] Based on data from https://aex.setcenter.am/pages/337

[102] Graphs generated using the code from Merit Order and Marginal Abatement Cost Curve in Python | by Himalaya Bir Shrestha | Towards Data Science (Bir Shrestha, 2021)

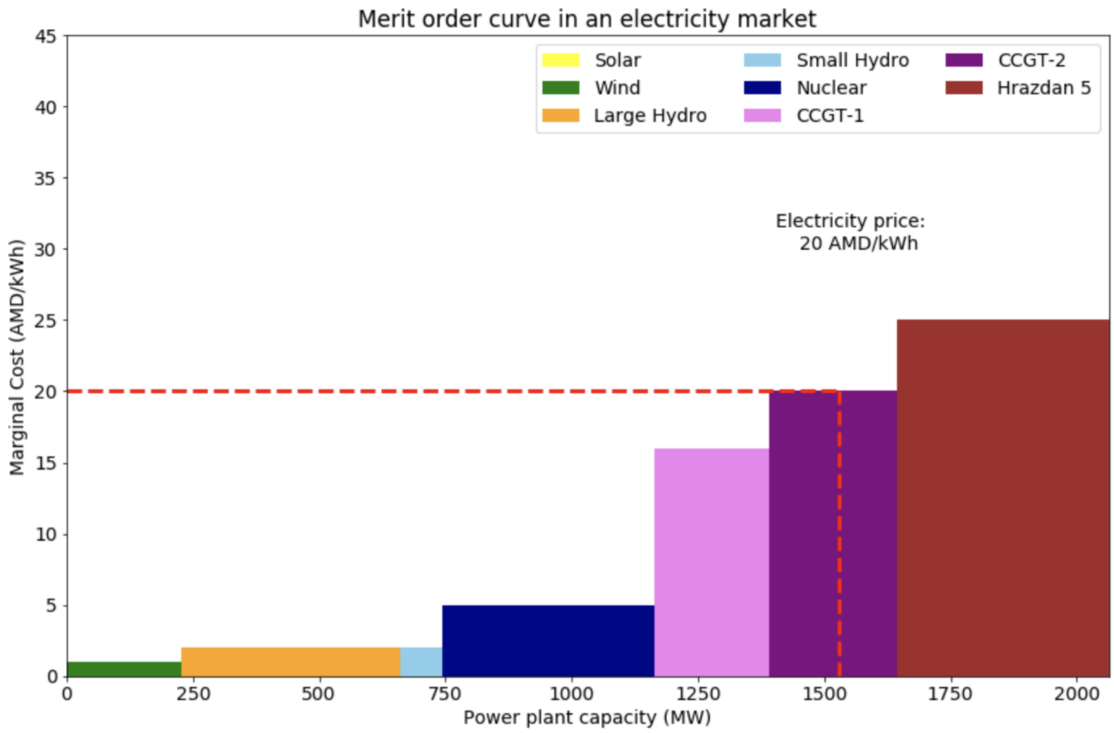


Figure 16. Estimated merit order at peak demand, winter 2035.

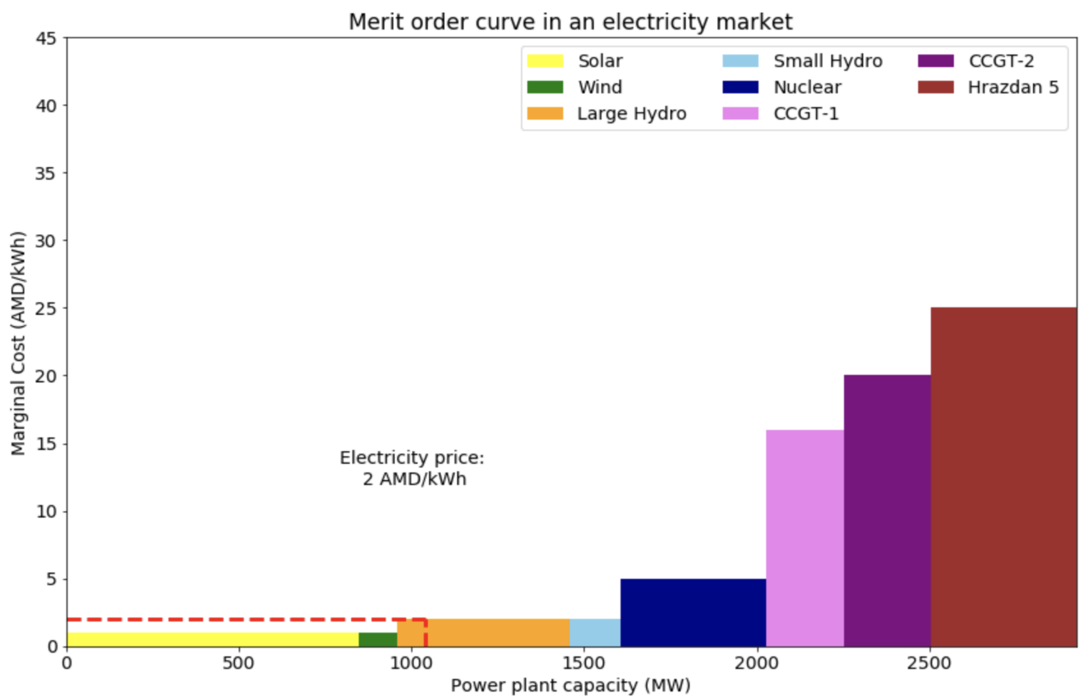


Figure 17. Estimated merit order at mid-peak demand, summer 2035.

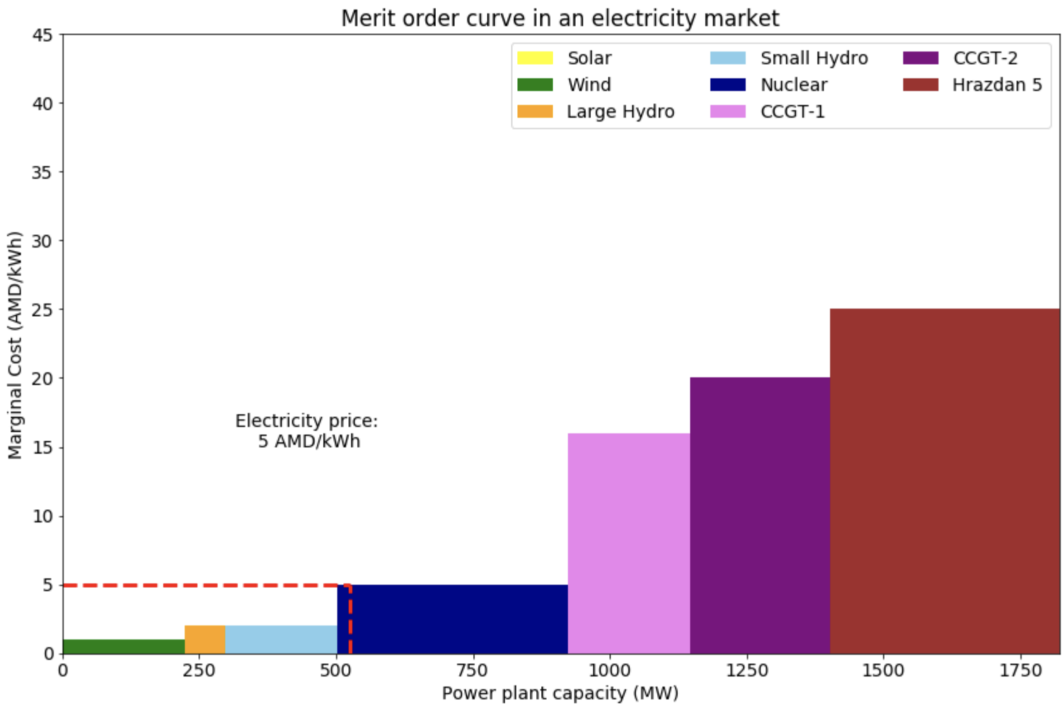


Figure 18. Estimated merit order at minimum demand, spring 2035.

As can be seen, projected local generation at peak demand in winter will be insufficient to meet consumption. Most likely, both CCGTs will be utilized to provide additional power. It is at this point that average prices will be highest during the year, which means that the price set by CCGTs will provide marginal profits for the low-carbon generation. If we assume that the current tariffication per kWh of CCGTs is not below their marginal costs, then the market price will be set at around 15-20 AMD in today's money. Note that that is substantially lower compared to the current remuneration received by many hydropower, and all solar and wind, plants.[103] The average spot price for the rest of the year will be even lower. This means that renewable generation will struggle economically, unless at least one of the following conditions is met:

1. Subsidisation of low-carbon generation
2. Sufficiently high economic rent during limited hours within a year

One solution for implementing the second condition is to have Hrazdan-5 unit as a strategic reserve, with administratively set higher electricity price during its operation, which would mostly occur during non-operable hours of the NPP. However, given that Hrazdan-5 is likely to operate when solar power doesn't (i.e. during evening hours of high demand, and low supply precisely due to low solar output), the solar producers are unlikely to sufficiently benefit from the economic rent. Subsidisation appears inevitable if large-scale solar generation is to be deployed. This is in line with OECD-NEA's conclusion that "most VRE capacity would not be

[103] Based on data from https://aex.setcenter.am/pages/337

on the market without the availability of guaranteed feed-in tariff (FITs) or production tax credits.[104]

Prices would be low for many hours of the year. Mid-peak demand in summer could fully be satisfied with variable renewable generation, if the day is windier than average. This could result in close-to-zero wholesale prices; *in fact, for an isolated system, the limited flexibility of the NPP would lead to negative prices*, as renewable generation will have to be curtailed. At a moment of minimum demand in spring, wind and hydropower could be sufficient to meet the demand, on a day windier than average.

At none of these points is Hrazdan-5 projected to be generating power; its role as a back-up is suitable for periods when nuclear power is out, if other thermal generators have a parts fault, or if the generation by renewables is much lower than expected (see the graph below). Its size, comparable to the current NPP, makes it a suitable solution to the N-1 principle.

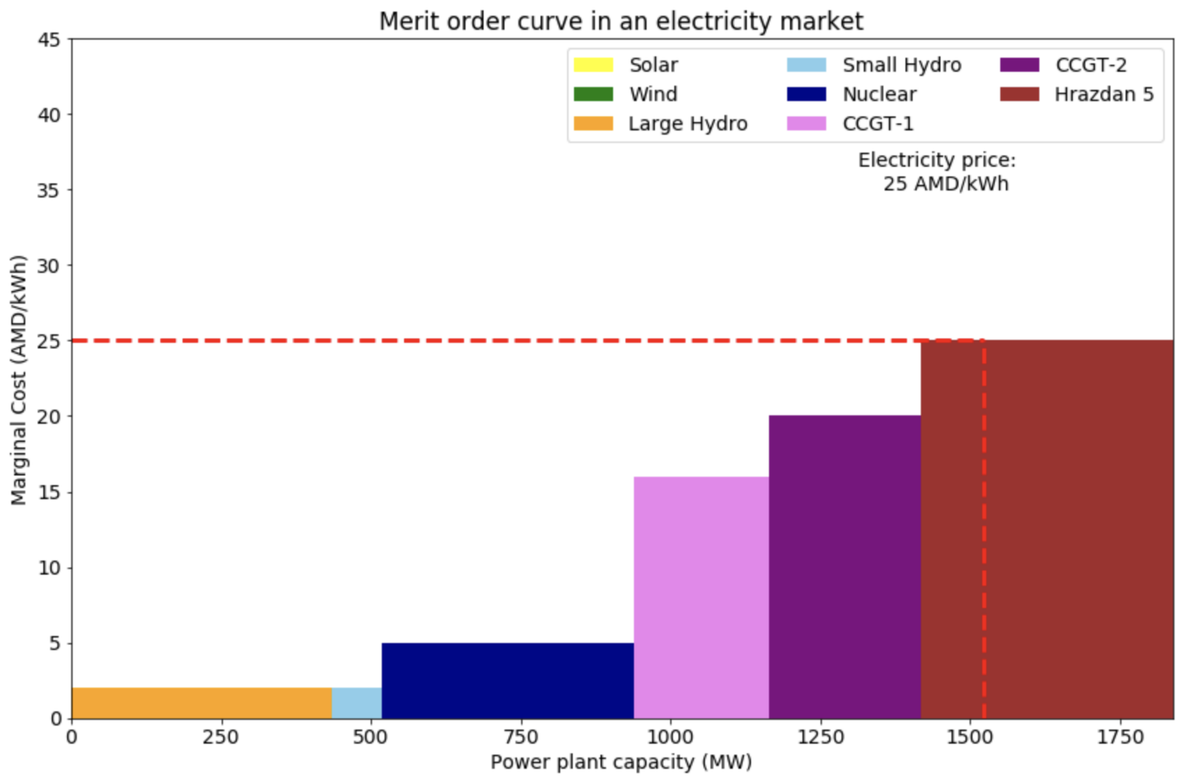


Figure 19. Estimated merit order at peak demand with no renewables, winter 2035.

If we compare with 2040 (see the graphs below), a sensitivity analysis could be conducted for a larger (1000 MW) nuclear power plant. While this would enhance energy independence and lower the reliance on gas, the problem of low wholesale prices is only more exacerbated. A large nuclear power plant would mean that the prices are more rarely set by natural gas, although the period when nuclear power is not available (during maintenance works or refueling) would still have more gas-determined wholesale prices. This can be mitigated if multiple smaller nuclear reactors are installed instead of one big one.

[104] The Costs of Decarbonisation: System Costs with High Shares of Nuclear and Renewables

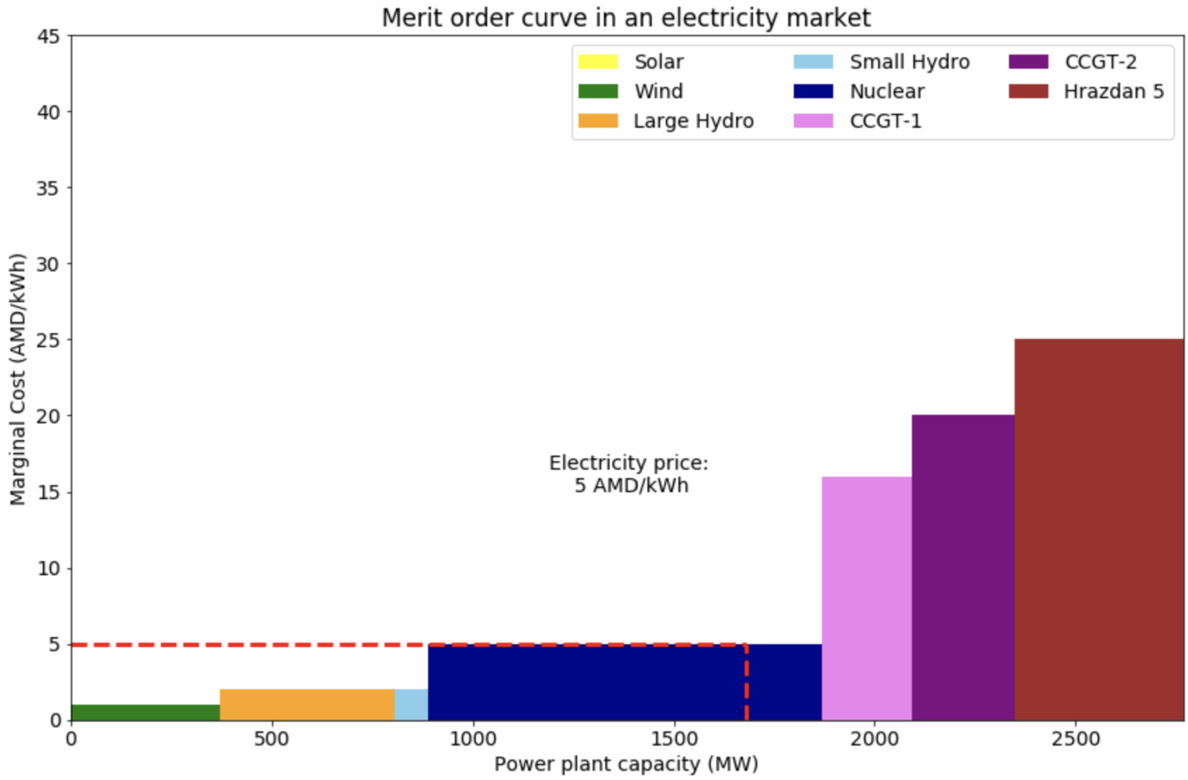


Figure 20. Estimated merit order at peak demand, winter 2040.

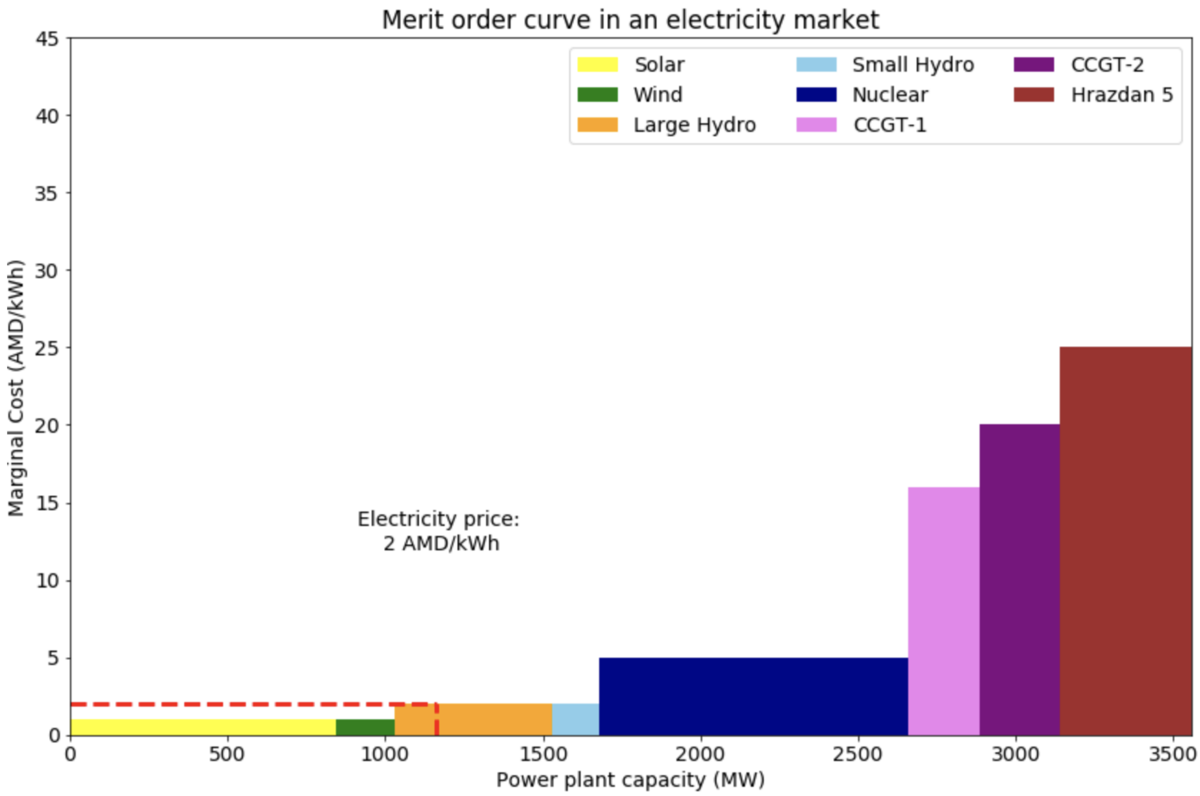


Figure 21. Estimated merit order at mid-peak demand, summer 2040.

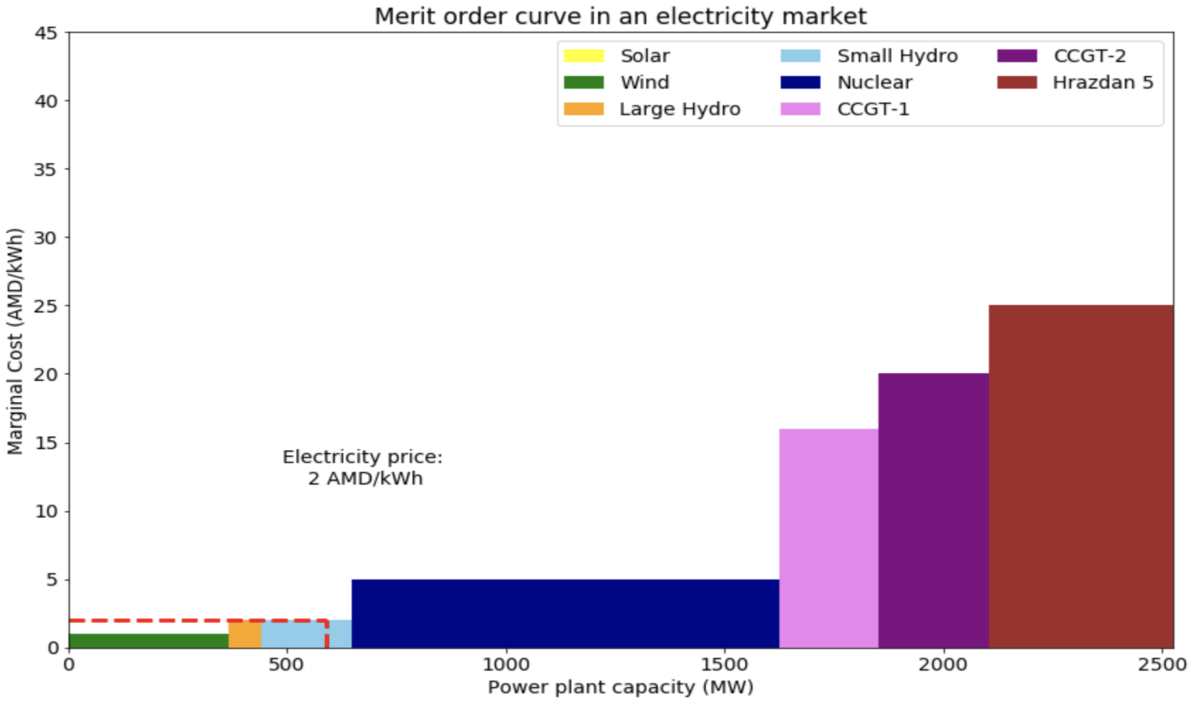


Figure 22. Estimated merit order at minimum demand, spring 2040.

As can be seen, a 1000-MW nuclear power plant would result in gas power not being utilised even during an average winter peak demand, although in case there is no renewable generation, one gas-powered plant is still required.

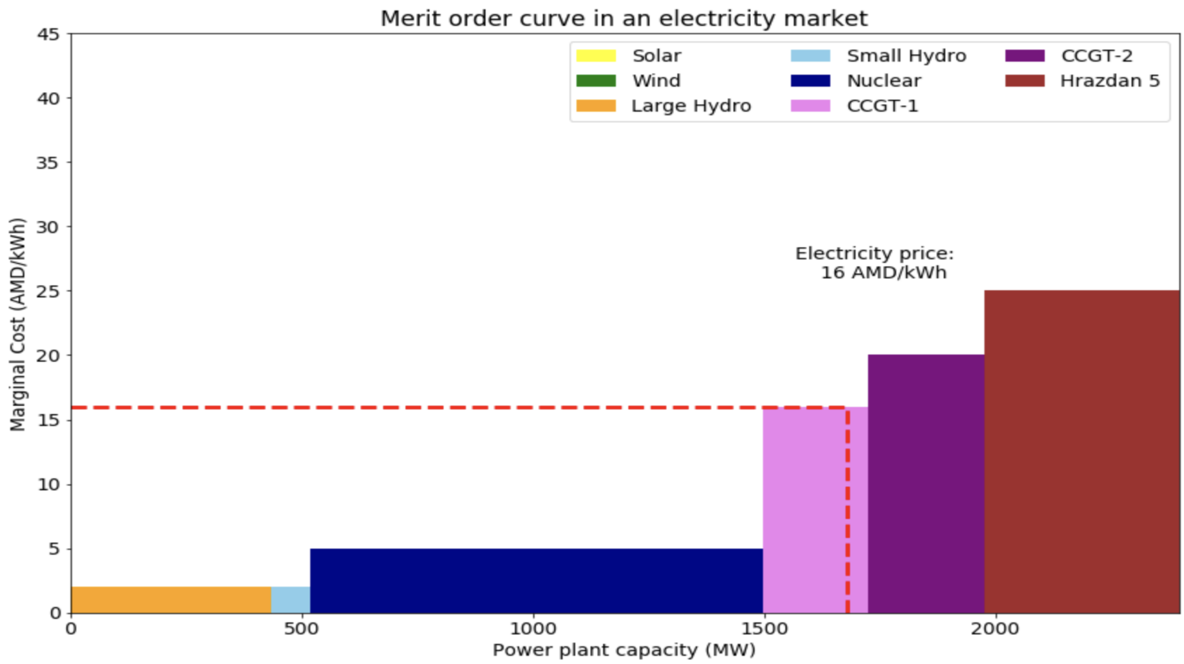


Figure 23. Estimated merit order at peak demand with no renewables, winter 2040**.**

The rest of the gas capacity would operate under the conditions when demand is sufficiently high and the nuclear plant is out of operation. The effect of a large nuclear plant is that prices would be low for much of the time. In periods with low VRE generation and no nuclear power generation, the prices will be high, set by the natural gas plants. However, it is precisely during low VRE generation periods that prices are high, and therefore VRE producers will make little revenue from these periods. What these periods of high scarcity can promote is investment into storage (batteries, pumped hydropower) and demand-response mechanisms. It can therefore be expected that, following the liberalization of the wholesale market, the major advances will be in *adjusting* to high VRE generation and optimising its value within the system, as opposed to investments into new VRE capacity.

The trade-offs between high energy security and energy investment are also visible in the configuration of nuclear power. If there are a number of smaller nuclear power plants with a cumulative capacity of 1000 MWs, then the plants could alternate for refueling and maintenance works, reducing reliance on natural gas at any given point in time. However, this would mean lower prices of electricity, as natural gas will rarely be the price-setting technology. Therefore, having multiple smaller NPP blocks could deter investment.

The small size of Armenia's market could also raise concerns regarding market power. The two ways in which spot electricity markets can be manipulated by the firms are physical withholding and financial withholding.[105] The first constitutes a producer withholding capacity on one of its plants in order to generate higher profits on its other plant(s). The second constitutes a producer bidding higher than its marginal cost of generation.

The analysis therefore reveals that the following conditions are highly desirable for the liberalization of the electricity spot market prices:

1. Integration of the spot electricity markets with Georgia

The Armenian electricity market is very small, and variable renewable generation will result in low prices and price volatility that disincentives new investments. Having a common market with Georgia would mean less market power, higher security and efficiency in trading variable generation, but also lower electricity prices on average. It would also lead, in the absence of out-of-market financing, to a more efficient allocation overall.

2. Availability of high interconnection capacities

The ability to trade with neighboring countries and the potential for imports will limit market power; the availability of exports will allow for better management of the variable generation. While these points are true in general, they are also the technical requirements for properly exploiting the international benefits of liberalized markets.

3. Regulatory certainty

Stable regulatory framework is necessary; the rules of the liberalized market have to be known beforehand. In Armenia's case, the size and participation of the nuclear power plant has to be known beforehand, as it can have a significant impact on the prices.

[105] https://www.cairn.info/revue-d-economie-politique-2019-3-page-325.htm?contenu=article

4. High scarcity prices on the wholesale market

The low-price environment means that there is a limited amount of hours during which economic rent can be high enough. While low-carbon technologies can find additional sources of revenue by selling abroad, the systems optimality for Armenia can be heightened by incentivising storage and generation during the periods of high demand and low supply. In practice, this will mean periods when the nuclear plant is not producing power. At the same time, for the sake of security, it is preferable that the nuclear plant operates at peak demand periods - winter and summer. An intuitive solution would be to have the NPP on maintenance and refuelling during spring, when hydropower generation is high and solar generation is moderately high. That could allow these renewable sources to make more profits.

Conclusion

Armenia faces the following challenge: the goal for higher energy independence requires implementation of renewable generation, but an efficient integration of variable renewable generation is achievable under liberalized markets, with efficient day-ahead market and system services procurement, which are important for intermittent and uncertain solar and wind power generation. However, the internal market of Armenia (particularly in case of a large nuclear power plant) may be too small for liberalization, and so can only be liberalized in tandem with a regional market, i.e. Georgia and possibly the EU, via Georgia. Ultimately, a trade-off between economic efficiency and energy independence will arise,

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3. INNOVATION TECHNOLOGIES. DEVELOPMENT AND DEPLOYMENT TIMELINE FORECAST. FUTURE TECHNOLOGIES

Thorium Reactors and implications for energy independence

The possibility of using thorium instead of uranium as a nuclear fuel is a perspective that could provide significant benefits to nuclear power generation. The particular advantage for Armenia, in the context of energy security and independence, is the higher conversion ratio that thorium-based reactors could provide.[106] In order to define the conversion rate in the context of nuclear science, we need to differentiate between fissile and fertile nuclear fuel. Nuclear energy is generated by an interaction of heavy nuclides (normally an uranium isotope) with particles called neutrinos. Bombarded by neutrinos, certain nuclides undergo fission, releasing energy in the process; these are considered fissile nuclides. However, other nuclides absorb the neutrino instead, and are considered fertile nuclides. Since fissile material is the one that releases energy, it is desirable to have more of it leftover after the nuclear reaction, so that it can be used again. The conversion ratio is the rate of production of fissile material divided by the rate of consumption of fissile material. While most PWR designs have a conversion ratio between 0.5 and 0.7, utilizing thorium could bring that value closer to 1, if not higher.[107] In case of commercial and technological progress of thorium-based designs, it is recommended that Armenia considers implementing thorium in its future nuclear power generation, especially given the lack of local uranium reserves. Successful introduction of thorium could allow Armenia to have longer fuel cycles, becoming less reliant on fuel imports at any given moment in time.

Small Modular Reactors and Implications for Energy Independence

Small Modular Reactor (SMR) is an up-and-coming technology that presents a substantially different approach to construction and operation of nuclear power plants. The main distinguishing factors of the technology are its size (typically considered less than 300 MW), its modularisation - fabrication of modules in a factory, which are then transported and installed on site, as opposed to on-site construction, and modularity (the plants being composed of a larger number of small reactors). The initial costs of SMRs are expected to be considerably higher than those of traditional power plants, as the former do not benefit from the economies of scale. A number of factors, such as shorter construction times, learning curve, and co-sitting economies are expected to eventually reduce the costs; even so, most current estimates demonstrate a higher overnight cost per installed capacity, when compared to standard reactors.[108] The rate of cost reduction will depend on the global deployment of this technology, with projections ranging from less than a GW of installed capacity to over 20 GWs.[109] While

[106] Introduction of Thorium in the Nuclear Fuel Cycle: Short- to long-term consideration (OECD-NEA, 2015)
[107] Same as previous.
[108] Economics and finance of Small Modular Reactors: A systematic review and research agenda (Mignacca and Locatelli, 2020)
[109] Small Modular Reactors: Nuclear Energy Market Potential for Near-term Deployment (OECD, 2016)

the technology has not yet commercially matured, it is being eyed on by a number of countries. These include Canadian SMR roadmap development,[110] US government granting licensing to NuScale's reactors,[111] and the UK government's cooperation with Rolls-Royce to deliver SMR plants by 2030.[112]

It is therefore likely that the reasons to prefer SMR plants to traditional ones will come down to the benefits of having multiple smaller reactors, as opposed to one or two large ones. The potential advantages of SMRs for Armenia, assuming comparable overnight costs with traditional NPPs, are discussed next.

3.1. Affordability

While the per-MW cost of SMRs is likely to be equal or higher than for large reactors, the ability to install smaller capacities can reduce the overall costs. The shorter construction period likewise means shorter payback time, reducing the financial burden. In addition, SMRs would be easier to adjust to the changing market; if the demand rises and more nuclear capacity is required, modules can be added in the future. All of these can be of important benefit for Armenia, whose financial resources are very limited and who will most likely have to borrow money in order to construct an NPP.

3.2. Modularity

Some SMR designs have longer refueling cycles,[113] resulting in a lower susceptibility to risks of nuclear fuel supply interruption, and higher energy security as a result. However, the main advantage comes due to having multiple smaller modules as opposed to a few larger ones. Maintenance and refueling schedules can now be distributed across time, with only one module having to shut down at a time, while others continue operating. As was discussed in the beginning of this section, the periodic downtakes of Armenia's NPP output are compensated by gas-powered generation. However, having multiple smaller modules would provide a more stable base load of nuclear generation, and reduce the periods of high reliance on natural gas.

3.3. Safety

The smaller size of SMRs has led to design simplifications. While SMR would share many state-of-the-art safety features common to all nuclear power plants, the simpler design means that there are fewer things that can go wrong.[114] Additionally, having several smaller reactors instead of one or two big ones distributes the risk, decreasing the scale of a likely accident should one occur. The considerations of safety are particularly important for Armenia, given its high seismicity; a reduction in nuclear accident risk means not only higher energy security overall, but higher level of energy independence as well, since natural gas is currently the main alternative to nuclear power generation.

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[110] SMR Roadmap

[111] NuScale SMR receives US design certification approval : Regulation & Safety - World Nuclear News

[112] Rolls-Royce on track for 2030 delivery of UK SMR: New Nuclear

[113] Small Modular Reactors: Challenges and Opportunities (OECD, 2021)

[114] Same as previous.

3.4. Load following

Load following is the ability of a power plant to adjust its output to the changing demand. Traditionally this is done by plants for which the major cost is variable (e.g. natural gas and coal). For those plants with high fixed costs and relatively low variable costs (such as nuclear) load following is not economically preferable, especially given the mechanical weariness that the parts incur from increasing and decreasing the output. However, having multiple smaller modules would allow to spread the load following between them, reducing the mechanical and economic strains. An alternative option is to maintain stable output while directing part of it from grid electricity supply to cogeneration, in particular district heating, desalination, and hydrogen production.[115] In Armenia's case, however, district heating and desalination may not be relevant; district heating has practically ceased to exist in the 1990s,[116] while no suitable large bodies of salty water are available for desalination. Hydrogen generation remains an alternative if SMR co-generation is deployed; its likelihood is discussed further below.

Conclusion on Nuclear

The question of an appropriate level of nuclear power is different from estimating the potential of other low-carbon generation sources, since there is no resource limitation, practically speaking. The cost-benefit analysis would ideally have to be conducted for a dynamically evolving system, but the upfront planning and investment required of nuclear power makes it more of a driving force, around which other technologies will have to adapt. Direct state involvement likewise introduces a significant political aspect.

The national energy strategy indicates construction of a new NPP "with replacing capacity" on the current ANPP's site; we consider a 1000 MW power plant. We assume that the existing NPP will be extended until 2036. We take the estimate of 7 675 – 12 500 USD/kWe from Lazard 2020 for a new nuclear plant, excluding interest. It should be noted that the construction costs could be somewhat reduced for Armenia, as the construction site and corresponding basic infrastructure are already identified – Metsamor NPP. Around 20 % of capital costs come from site development and civil works,[117] though it is hard to estimate how much of this would be already covered in our case.

Capacity	New 1000 MW NPP
Cost of construction	7.6 – 12.5 USD billion

The effect of having multiple smaller units instead of fewer larger, other things being equal, is reduction in one-time reliance on natural gas. Thus, if there is one large 1000-MW plant, with only one reactor, whenever it is unable to supply due to refueling or life extension works, 1000 MW of alternative source have to be on standby to provide that power. However, with

[115] Economics and finance of Small Modular Reactors: A systematic review and research agenda (Mignacca and Locatelli, 2020).
[116] In-Depth Review of the Energy Efficiency Policy of Armenia (International Energy Charter, 2017)
[117] Nuclear Power Economics | Nuclear Energy Costs.

three smaller 300 MW reactors,[118] these can alternate between each other as to when refueling or maintenance works occur, so that one is always supplying power. That way, only 300 MWs of standby power have to be available at any given time.

An illustration of this point for 2021, imagining a scenario with 2x200 MW instead of 1x400 MW reactors, is given below. The effect is particularly big since the lifetime extension took almost half a year to complete. While this is not a standard yearly procedure, it is likely to occur at one point during NPPs lifetime, as the costs of life extension are much lower than of building a new one. These extended periods could therefore leave the nation especially reliant on imported fuel; the effect is similar but smaller for refueling and ordinary maintenance works that require short-time interruptions in nuclear power supply. While the total volume of mitigated imported energy may not change, the reliance *at a given point in time* changes, hence reduction in the need of required reserve capacity and lower cost / higher energy security as a result. Needless to say, having even a larger number of smaller reactors (e.g. five of NuScale's 45 MW reactors) would make this effect even stronger, and such is expected to be one of the advantages of SMRs.

Conventional reactors (e.g. Russian VVER-1000) have several disadvantages compared to small modular reactors (as discussed in this section). Nonetheless, they are considered within the main technological options and therefore are envisioned in our scenarios. The maturity of conventional nuclear technology translates into lower market uncertainty and forecast. This is especially true due to comparison with modular reactors, whose development and competitiveness will depend on the existence of the corresponding demand and serial production. In addition, as mentioned within this section, the cost per unit of installed capacity is lower for large reactors, due to economies of scale.

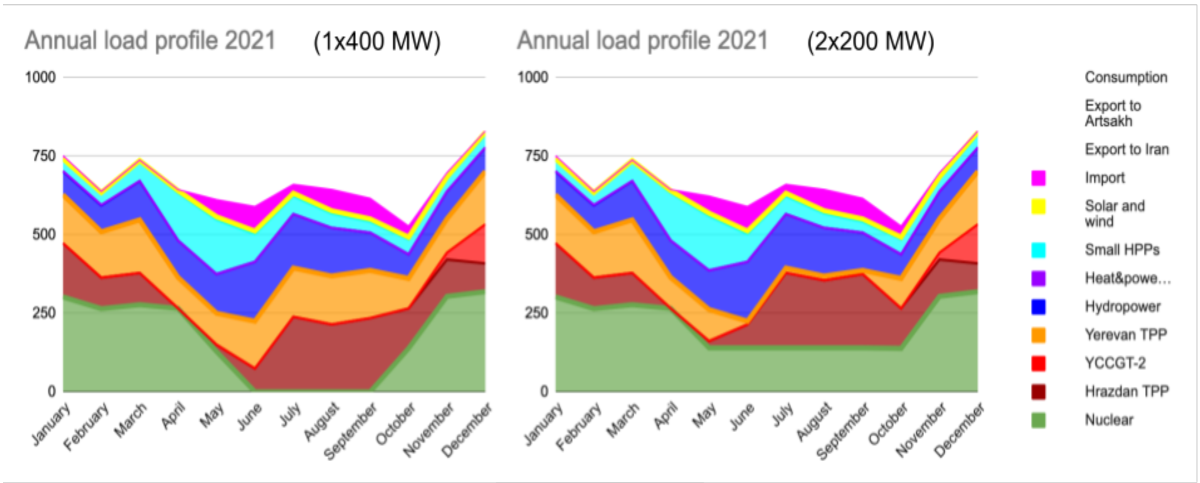

Figure 24. Load models for 2x200 MW and 1x400 MW. Data for monthly electricity generation by source is taken from psrc.am

118 Examples of such smaller reactors can be the BREST-300 or Rolls Royce's 470 MW.

Hydrogen and Implications for Energy Independence

Supply and infrastructure

Hydrogen is increasingly seen as an important component of the future energy systems. A number of countries have developed strategies and roadmaps for hydrogen.[119] The European Commission projects the share of hydrogen in the EU's primary energy mix to 13-14 % by 2050.[120] The main applications are expected to be in hard-to-decarbonize sectors (such as heavy industry and heavy duty transport); power storage and generation (aiding with variable sources) is also projected as one of the applications, as well as potentially building heating.[121]

The question of hydrogen applications in Armenia (and their implications for energy independence) can be divided into two parts: the question of supply and the question of demand. The most intuitive candidate for hydrogen generation would be excess solar energy in summertime. However, potential exports of electricity to Iran may also be a viable alternative use for excess solar generation. In addition, should SMR technology be implemented in Armenia, hydrogen cogeneration is possible through load following. In either case, this would depend on the relative value of alternative uses for this excess energy generation, mainly whether hydrogen conversion or power export is more valuable. On economic considerations, production of hydrogen would therefore make sense only insofar as the value of hydrogen will be higher than the value of electricity exports, as well as the costs of local production being lower than the cost of production and transportation of hydrogen from abroad. The latter will depend on multiple factors; international shipping of hydrogen can, on certain occasions, be cost-competitive with local generation, as in some regions the availability of renewables makes hydrogen production much cheaper.[122] At the same time, Armenia's land-locked geography makes this less likely.

In Armenia particularly, the cost of hydrogen generation from renewables in the long term is estimated to be around 2.4-2.8 USD per kg, which is higher than in some other areas in the region, especially to the south.[123] While hydrogen production using fossil fuels is currently cheaper, countries with optimal mix of renewables for hydrogen generation could become cost-competitive by mid-30s *(see the graph below)*. These countries could develop hydrogen generating facilities before Armenia does, and, if being located nearby Armenia, could undermine Armenia's domestic hydrogen production (assuming that transportation costs are likewise relatively low). It should be noted that no major hydrogen demand centers are projected in the wider geographical area near Armenia,[124] making regional market development less of a possibility in the near term.

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[119] Green Hydrogen Cost Reduction Scaling Up Electrolysers to Meet the 1.5°C Climate Goal (IRENA, 2020)

[120] Picturing the value of underground gas storage to the European hydrogen system (Guidehouse, 2021)

[121] Same as previous.

[122] Hydrogen Insights: A perspective on hydrogen investment, market development and cost competitiveness (Hydrogen Council, McKinsey&Company, 2021)

[123] Visual inspection of figure 10.6 from Projected Costs of Generating Electricity, OECD-NEA 2020

[124] Hydrogen Insights: A perspective on hydrogen investment, market development and cost competitiveness (Hydrogen Council, McKinsey&Company, 2021)

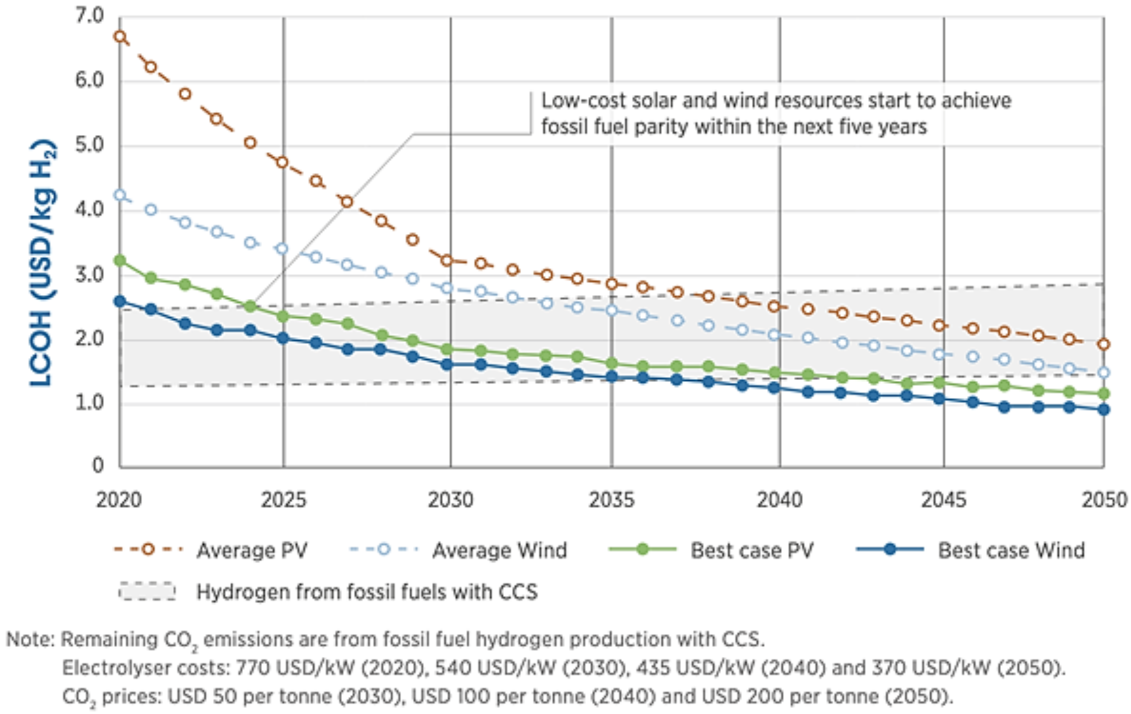

Figure 25. Hydrogen production cost from solar and wind vs. fossil fuels.
Source: Hydrogen: A Renewable Energy Perspective (IRENA, 2019).

The scope of application would also raise the issue of infrastructure. The infrastructural requirements for large-scale implementation of pure hydrogen are considerable. For the 1,841 km of natural gas transmission pipelines and 11,346 km of distribution pipelines that are in operation,[125] the cost of repurposing them for hydrogen use would be on the scale of billions of dollars.[126] If the eventual goal were pure hydrogen systems, Armenia would benefit from retrofitting existing pipelines as opposed to constructing new ones, as the costs of repurposing are much lower. However, a more realistic solution would be a partial use of hydrogen through blending it with natural gas; "hydrogen blends up to 20% on a volumetric basis can make use of an important fraction of the existing natural gas distribution infrastructure and would require minimal infrastructure and end-use equipment adaptation."[127] While this wouldn't bring independence from natural gas, it could reduce the vulnerability to imported gas price fluctuations. The ability to blend hydrogen into existing natural gas infrastructure is determined by the weakest link; therefore, an evaluation of the ability of Armenia's natural gas infrastructure to integrate hydrogen would be required. Truck delivery could be deployed as an alternative, but the applications would have to be on a smaller scale (such as niche applications in heavy industry).

Storage is another issue for hydrogen. While one could consider the possibility of retrofitting parts of the Abovyan storage facility for hydrogen, from an energy security point of view, the impact of repurposing is possibly negative. Due to lower volumetric energy density

[125] Data on natural gas pipeline lengths taken from "Gazprom Armenia" CJSC - Companies of the system
[126] See the table on cost estimates on page 17-18
[127] Projected Costs of Generating Electricity, OECD-NEA 2020

of hydrogen, “a retrofitted natural gas storage site could hold around 24% of the original energy volumes”.[128] One could convert hydrogen to ammonia and store it as such, due to ammonia having higher energy density; however, “converting hydrogen to ammonia requires between 7% and 18% of the energy contained in the hydrogen, and similar level of energy is lost if the ammonia needs to be reconverted back to high-purity hydrogen”.[129] Nonetheless, ammonia is becoming increasingly favored as a storage mechanism for hydrogen. On the other hand, in terms of storing hydrogen as a gas, the large-scale options are by utilizing depleted gas reservoirs (not available in Armenia), aquifers, and hard rock and salt caverns.[130] However, these depend on geological conditions, and a separate study is required for assessing the feasibility of underground H2 storage in Armenia.

In terms of water impact, as an illustrative case, a 243 MW hydrogen-powered turbine operating on 10% annual load factor (800 hours) would require around 140,000 cubic meters of water to generate its hydrogen supply through electrolysis, which could in the end provide 200 GWhs of electricity.[131] This is a tiny fraction of the annual freshwater consumption in Armenia, which is around 3 billion cubic meters.[132] However, in terms of electricity required for producing those 200 GWhs, 940 GWhs of input would be required.[133]. This demonstrates the severe disadvantage of hydrogen storage for the grid, due to all losses in conversions and storage.

The local supply of hydrogen will be less advantageous from an economic point of view for Armenia insofar as importing hydrogen becomes cheaper. In case Armenia stays geographically semi-isolated, this could raise transportation costs and contribute to local production being more competitive.[134] For instance, hydrogen produced in northern Iran, where renewables are more favorable, could be transported to Armenia via pipelines at an estimated transportation cost of 0.09-0.47 $/kg,[135] but shipping from other regions of the world to Georgia and then delivery by pipelines to Armenia would most likely cost well over $2/kg[136] in transportation costs alone. In addition, hydrogen could be generated in Russia using fossil fuels and then delivered by pipelines, although transportation costs could be around $2/kg in that case as well.[137] Assuming that local production of hydrogen remains competitive, both with regards to imports and to alternative uses of electricity (e.g. exporting electricity vs using it to produce hydrogen), the question of applications remains.

[128] Picturing the value of underground gas storage to the European hydrogen system (Guidehouse, 2021)
[129] Ibid.
[130] Large-scale compressed hydrogen storage as part of renewable electricity storage systems - ScienceDirect
[131] Power to Gas: Hydrogen for Power Generation, table 3
[132] https://www.worldometers.info/water/armenia-water/
[133] Power to Gas: Hydrogen for Power Generation, table 3
[134] Transportation costs can reach up to $2/kg for long-distance pipelines, and $2.62 for long-distance truck delivery (Figure 7, Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure)
[135] Figure 7, Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure, transmission pipeline cost for 100-1,000 km
[136] Ibid, transmission pipeline cost for 100-1,000 km (0.09-0.47 $/kg) + shipping costs (2+ $/kg). Major component of the shipping costs is storage cost.
[137] Ibid, transmission pipelines for 1,000-10,000 km range

Demand

The estimated costs of locally produced hydrogen make it an unlikely competitor for the everyday demand of transportation and heating, even in a decarbonized future. The heating in particular is less likely due to availability of much cheaper and more efficient alternatives, such as heat pumps.[138] Competing with electrical heat-pumps would require hydrogen prices to be below $2/kg in most regions of the world (*see graph below*); this is likely to hold true for Armenia as well, given relatively low electricity prices. For as long as the cost of locally produced hydrogen in Armenia is expected to be above $2 per kg, as was noted earlier, then it becomes an unlikely candidate for this application. It should be noted that electrolyzer costs of $370/kW would most likely drive the costs of local-PV produced hydrogen in Armenia below $2 per kg.[139] While this is projected to happen by 2050, it is possible that an unexpectedly fast technological development would result in steeper cost reduction.

Likewise in transportation, fuel-cell electric vehicles are costlier than battery electric vehicles.[140] The advantage of fuel cell vehicles lies over long ranges; even if we take a car traversing from one end of Armenia to another (circa 300 km), fuel cells would need to cost around USD 40/kW.[141] In other words, under standard projections, fuel cells are unlikely to be competitive with battery electric vehicles in Armenia, given its short driving distances. **Even under the assumption of relatively high 150 USD/kWh battery costs, fuel cell costs would need to be well below USD 50/kW (and likely around half of that).** It should be noted that IEA takes USD 50/kW as long-term capital cost of fuel cells, compared to battery cost of USD 100/kWh.[142] Moreover, extensive use of hydrogen-based heating and transportation would require corresponding infrastructure costs in retrofitting gas pipelines, boilers, etc, while the alternative electrification-based solutions will rely on grid and off-grid infrastructure.

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[138] Hydrogen for heating? Decarbonization options for households in the European Union in 2050 (International Council on Clean Transportation, 2021)

[139] See figure on the previous page.

[140] Figure 10.9, *Projected Costs of Generating Electricity, OECD-NEA 2020.*

[141] The Future of Hydrogen: Seizing today’s opportunities, figure 55

[142] IEA G20 Hydrogen report: Assumptions

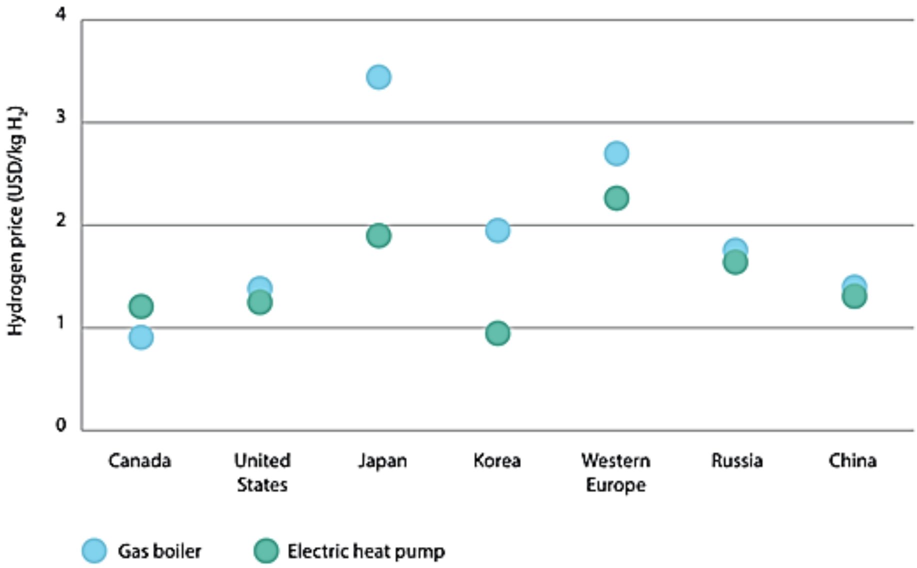


Figure 26. Hydrogen prices needed to become competitive against natural gas boilers and electric heat pumps in selected markets by 2030.
Source: Projected Costs of Generating Electricity, OECD-NEA 2020.

Using hydrogen as a long-term storage for power is a technical possibility, by, for example, using excess solar generation in summertime to produce hydrogen, which is then stored and converted back into power in wintertime. The high variable cost of hydrogen-based generation would make it a more suited candidate for peak demand management.[143] However, given the low roundtrip efficiency,[144] less than half of initial energy input would be reusable as a power source. Combined with the costs of storage, it is unlikely that locally generated hydrogen would be used as seasonal storage for power in the near-term. Nonetheless, an example can be taken of the Netherlands retrofitting 440 MW gas power plant to hydrogen generation;[145] depending on the economic competitiveness of the technology, similar plans could be made in the future for a gas plant in Armenia. An estimated retrofit cost of 200,000 Euros per MW (as opposed to newbuild 650,000 Euros per MW),[146] could be applied to Yerevan CCGT-2 (as an example) resulting in 50 million euros of investment.

[143] CO_2-free flexibility options for the Dutch power system (Aurora Energy Research, 2021)
[144] Energy Storage Analysis (Penev et al, 2019)
[145] Hydrogen: A Renewable Energy Perspective (IRENA, 2019)
[146] CO_2-free flexibility options for the Dutch power system (Aurora Energy Research, 2021)

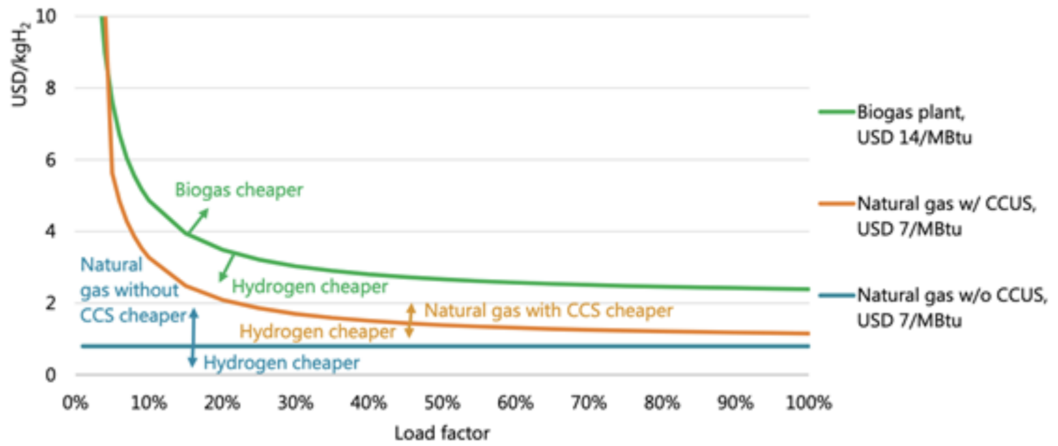
Infrastructure	Technical indicator	Retrofit cost	Cost as % of new built	Retrofit cost data
Gas transmission pipelines	1,841 km	368 - 920 Mln EUR	10 - 18.5%	Data in Euros taken from [1], figure 4 for 28-37 inch diameter Pipelines
		1.1 - 2.2 Bln USD	27%	Data in Dollars taken from [3]
Gas distribution pipelines	11,346 km	2.27 - 5.67 Bln EUR	14.3 - 27.8%	Data taken from [1], figure 4 for <28 inch diameter pipelines
		1.13 - 2.27 Bln USD	28.6 - 33%	Data in Dollars taken from [3]
Yerevan CCGT-2 plant	250 MW	50 Mln EUR	30.7%	Data taken from [2], slide 85

Some estimates of the order of magnitude for retrofitting existing infrastructure in Armenia for pure hydrogen.

Sources used for calculations:
[1] Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure (ACER, 2021)
[2] CO_2-free flexibility options for the Dutch power system (Aurora Energy Research, 2021)
[3] Global hydrogen pipelines' costs by type 2021

The advantage of hydrogen as a storage and reserve power backup comes at low load factors (see the graph below); with prices of hydrogen around $2/kg, it is economically competitive against natural gas, if the latter includes carbon capture and storage. Nonetheless, in case of war, import of natural gas could become difficult, while hydrogen can be generated locally. Given in addition hydrogen's economic advantage over other low-carbon solutions for discharge periods above 20-45 hours,[147] as well as Armenia's limited potential for hydro storage, a hydrogen strategic reserve could be established to provide backup power.

[147] The Future of Hydrogen: Seizing today's opportunities, figure 64



Notes: Arrows indicate areas where hydrogen costs and load factors mean that competing generation technologies or hydrogen are cheaper. CAPEX = USD 1 000/kW for CCGT without CCS and hydrogen-fired CCGT, USD 1 870/kW for CCGT with CCS, USD 2 000/kW for biogas engine; gross efficiencies (LHV) = 61% CCGT without CCS and hydrogen-fired CCGT, 53% CCGT with CCS, 45% biogas engine. Economic lifetime = 25 years. More information on the assumptions is available at www.iea.org/hydrogen2019.

Figure 27. Break even for hydrogen CCGT against other flexible power generation options. Source: Hydrogen: A renewable energy perspective (IRENA 2019).

An alternative to utilizing a CCGT plant with hydrogen would be fuel cells, which could similarly take stored hydrogen and turn it back into electricity. A breakdown of projected costs for fuel-cell plus storage can be seen in the below Table 3:

Table 4. Costs by Component for a 100 MW, 10-hour HESS System[148]

Category	Cost Component	Low 2020 Values	Low 2030 Values	Moderate 2020 Values	Moderate 2030 Values	High 2020 Values	High 2030 Values
PEM electrolyzer	Capital cost ($/kW)	1,353	393	1,503	437	1,653	481
	Rectifier cost ($/kW)	117	84	130	94	143	103
	Compressor cost ($/kW)	35	35	39.3	39.3	43	43
Storage	Storage ($/kWh)	2	1.69	3.66	3.09	10	8.45
	Storage DOD (%)	70%	70%	70%	70%	70%	70%
	Effective storage ($/kWh)	2.86	2.4	5.23	4.44	14.29	12.10
Stationary fuel cell	Capital cost ($/kW)	1,188	854	1,320	949	1,452	1,044
	Inverter ($/kW)	60	41	67	45	74	50
C&C ($/kW)		1.35	0.95	1.5	1.06	1.65	1.16
Grid integration ($/kW)		18	15	19.89	16.3	22	18
Grand total ($/kW)		**2,793**	**1,440**	**3,117**	**1,612**	**3,488**	**1,824**
Grand total ($/kWh)		**279**	**144**	**312**	**161**	**349**	**182**

Costs by Component for a 100 MW, 10-hour HESS System, Adapted from (Hunter et al., In Press), from 2020 Grid Energy Storage Technology Cost and Performance Assessment

Taking low 2030 values as estimates for our projection, we arrive at 1,440 USD/kW and 144 USD/kWh costs for hydrogen storage. A 100 MW, 10-hour (1 GWh) hydrogen electric

148 2020 Grid Energy Storage Technology Cost and Performance Assessment, (Hunter et al, 2020)

storage system (with fuel cells) would therefore cost 144 million USD, as well as 2.851 million USD in fixed operation and management costs per year.[149]

Conclusion on hydrogen

Overall, the potential for large-scale development of hydrogen use in Armenia remains uncertain in the long-term, though less likely within the timeframe of this roadmap (up to 2040). High capital costs of new hydrogen infrastructure development mean that repurposing the existing lines is the more viable alternative (unless delivery is done on a smaller scale by trucks), but even repurposing costs are significantly high. Even then, availability of parallel lines and ensuring security of natural gas supply *during and after* the conversion are listed as among the necessary conditions for any serious consideration of pipeline repurposing.[150] As with SMRs, large-scale implementation of hydrogen in Armenia depends on outside development, both in regard to technological advances and the regional market.[151] Niche applications in some aspects of heavy industry or transport, that would not require extensive infrastructure, may be viable; overall, it is strongly preferable to have a primarily demand-driven hydrogen market development, so as to avoid sunk costs in stranded assets.[152] The prospects of hydrogen development in the context of energy independence are uncertain and subject to the following constraints:

1. The costs of local hydrogen production may make it less competitive if substantially (to cover transportation costs) cheaper production develops in the region;

2. The relative value of exporting Armenia's electricity instead of using it to generate hydrogen can decrease the prospects even further, including the possibility that electricity can be used for pumped storage;

3. Even disregarding the two points above, the competitiveness of hydrogen applications with alternative *low-carbon* solutions can be low in many cases;

In conclusion, even if the global market develops, hydrogen in Armenia may well be a predominantly imported fuel as natural gas is now, and the economic incentives for local production in that case would remain low and confined to niche applications. Under those conditions, large-scale hydrogen development is unlikely to have a significant impact on the energy independence of Armenia, except through diversification of primary energy suppliers. The potential is more pronounced for cases of long-term isolation, as could occur during military action, as well as for storage of excess electricity when there is less demand for exports. In that case, hydrogen could provide back-up for the power system and act as a strategic reserve. While an introduction of hydrogen-based CCGT or fuel cell reserves for the grid is the

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[149] ibid, table 6

[150] Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure (European Union Agency for the Cooperation of Energy Regulators, 2021)

[151] Same point could be made regarding Georgia, Study on the potential for implementation of hydrogen technologies and its utilization in the Energy Community p 44-45

[152] Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure (European Union Agency for the Cooperation of Energy Regulators, 2021)

most likely application to have a positive impact on energy independence, an evaluation of storage possibilities (in terms of ammonia, as well as aquifers or cavern salts) is required. Additional evaluation of gas infrastructure and its ability to blend in hydrogen should be made. CO_2 taxes would also make hydrogen more competitive against natural gas as a grid flexibility source.

Natural gas and implications for energy independence

On one hand, natural gas is the dominant primary energy source and the main imported source of energy. The strategy proposed in this roadmap will therefore inevitably result in a lower share of natural gas in Armenia's energy mix. At the same time, its benefits (flexibility, dispatchability, and storage) make it a valuable back-up for systems with highly variable generation. Lack of hydropower storage reserves only strengthens these points; and while under certain favorable conditions hydrogen may replace it in the future, the prospects are far from certain.

Counter-intuitively, maintaining a certain level of gas-powered capacity would therefore be beneficial for Armenia from an energy independence point of view. With flexible long-term storage backup, reaching a certain level of VRE generation will be harder, and natural gas remains the main candidate, especially given that large infrastructure already exists.

The current gas-powered plants are the following:

Power Plant	**Installed Capacity**	**Commission date**
Hrazdan TPP	410 MW	1966
Hrazdan 5	467 MW	2013
Yerevan CCGT-1	228.6 MW	2010
Yerevan CCGT-2	250 MW	2022
Total	1355.6 MW	

According to the government strategy, Hrazdan TPP is to be decommissioned once Iran-Armenia 400 kV line and Yerevan CCGT-2 are constructed. That would decrease the total gas capacity to slightly over 1000 MW. Theoretically, these 1000 MW could serve as a back-up (by N-1 principle) in case a single 1000-MW nuclear reactor is constructed. Whether that would be the cost-efficient back-up, given growing interconnection, is not so straightforward, given the more cheaply generated hydropower in Georgia. At the same time, the question arises as to how these plants will remain financially profitable, as the VRE generation grows. Continual capacity remuneration will require large financial resources, while the need of all 3 remaining plants for daily operation will decrease, especially as the producers with highest marginal cost. Therefore, while gas-powered generation will likely continue to be important for Armenia, overcapacity of natural gas and corresponding economic inefficiency are projected to be a significant problem. Lack of a competitive liberalized market and corresponding ancillary services will make remuneration of these gas-powered plants even less optimal.

Once again, under certain favorable conditions (available technology and demand), one of the CCGT plants could be repurposed for hydrogen generation. This could increase the economic efficiency of the system, but would require corresponding demand and competitiveness of hydrogen as a form of storage.

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4. STORAGE TECHNOLOGIES

Overview

The purpose of this study is to review existing storage technologies, their potential and applications. Storage plays a critical role in a system with high shares of variable generation; the road towards energy independence means lesser reliance on gas, which is an important provider of flexibility. Chemical and mechanical forms of storage are considered, with hydropower, flywheels, and li-ion (the three most widespread forms of storage) are given additional attention.

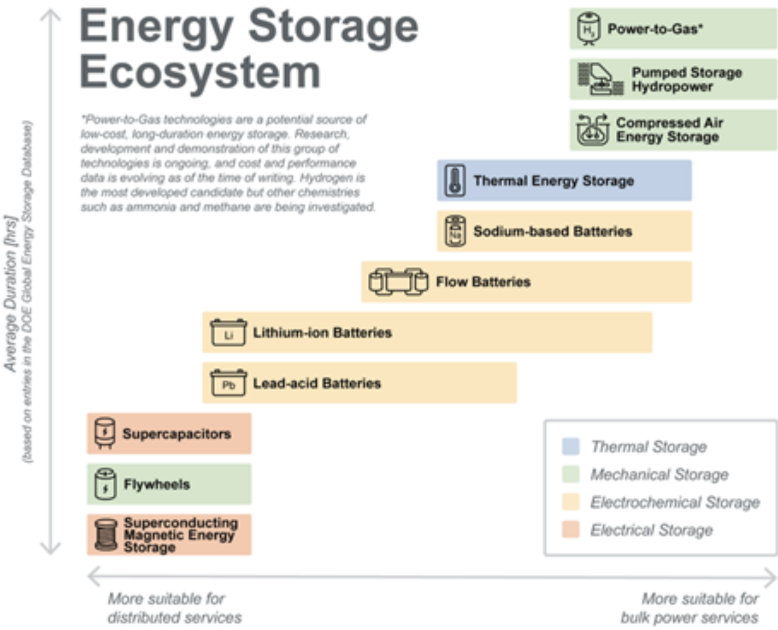

Figure 28. Ecosystem of energy storage technologies and services.
Source: USAID Grid-Scale Energy Storage Technologies

Power-to-gas is an evolving storage technology, with the main candidate being hydrogen. It is mentioned in the discussion on hydrogen within the report; additional research would be required to identify ammonia or hydrogen gas storage possibilities, which is not conducted within this report.

Compressed air storage is used very little and depends on finding a suitable underground cavern. Without having specific estimates for Armenia, it is hard to use this in modeling.

As pumped hydropower is the main candidate for efficient longer storage, its development should be prioritized. While various chemical batteries are discussed, Li-ion is by far the most popular on the market due to its performance. **USAID Least-Cost Energy Development Plan (hereafter "LCEDP")** study included Li-ion and Pumped hydro as the two storage technologies for its modeling. More data for pumped hydropower and lithium ion will be provided, but the tables on pages 2-3 show data already compiled by the US department of Energy.

Table ES.1. Summary of compiled 2018 findings and 2025 predictions for cost and parameter ranges by technology type – BESS.[(a)]

Parameter	Sodium-Sulfur Battery		Li-Ion Battery		Lead Acid		Sodium Metal Halide		Zinc-Hybrid Cathode		Redox Flow Battery	
	2018	**2025**	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**	**2018**	**2025**
Capital Cost – Energy Capacity ($/kWh)	400-1,000 **661**	(300-675) **(465)**	223-323 **271**	(156-203) **(189)**	120-291 **260**	(102-247) **(220)**	520-1,000 **700**	(364-630) **(482)**	265-265 **265**	(179-199) **(192)**	435-952 **555**	(326-643) **(393)**
Power Conversion System (PCS) ($/kW)	230-470 **350**	(184-329) **(211)**	230-470 **288**	(184-329) **(211)**	230-470 **350**	(184-329) **(211)**	230-470 **350**	(184-329) **(211)**	230-470 **350**	(184-329) **(211)**	230-470 **350**	(184-329) **(211)**
Balance of Plant (BOP) ($/kW)	80-120 **100**	(75-115) **(95)**	80-120 **100**	(75-115) **(95)**	80-120 **100**	(75-115) **(95)**	80-120 **100**	(75-115) **(95)**	80-120 **100**	(75-115) **(95)**	80-120 **100**	(75-115) **(95)**
Construction and Commissioning ($/kWh)	121-145 **133**	(115-138) **(127)**	92-110 **101**	(87-105) **(96)**	160-192 **176**	(152-182) **(167)**	105-126 **115**	(100-119) **(110)**	157-188 **173**	(149-179) **(164)**	173-207 **190**	(164-197) **(180)**
Total Project Cost ($/kW)	2,394-5,170 **3,626**	(1,919-3,696) **(2,674)**	1,570-2,322 **1,876**	(1,231-1,676) **(1,446)**	1,430-2,522 **2,194**	(1,275-2,160) **(1,854)**	2,810-5,094 **3,710**	(2,115-3,440) **(2,674)**	1,998-2,402 **2,202**	(1,571-1,956) **(1,730)**	2,742-5,226 **3,430**	(2,219-3,804) **(2,598)**
Total Project Cost ($/kWh)	599-1,293 **907**	(480-924) **(669)**	393-581 **469**	(308-419) **(362)**	358-631 **549**	(319-540) **(464)**	703-1,274 **928**	(529-860) **(669)**	500-601 **551**	(393-489) **(433)**	686-1,307 **858**	(555-951) **(650)**
O&M Fixed ($/kW-yr)	10	(8)	10	(8)	10	(8)	10	(8)	10	(8)	10	(8)
O&M Variable (cents/kWh)	0.03		0.03		0.03		0.03		0.03		0.03	
System Round-Trip Efficiency (RTE)	0.75		0.86		0.72		0.83		0.72		0.675	(0.7)
Annual RTE Degradation Factor	0.34%		0.50%		5.40%		0.35%		1.50%		0.40%	
Response Time (limited by PCS)	1 sec		1 sec		1 sec		1 sec		1 sec		1 sec	
Cycles at 80% Depth of Discharge	4,000		3,500		900		3,500		3,500		10,000	
Life (Years)	13.5		10		2.6	(3)	12.5		10		15	
MRL	9	(10)	9	(10)	9	(10)	7	(9)	6	(8)	8	(9)
TRL	8	(9)	8	(9)	8	(9)	6	(8)	5	(7)	7	(8)

(a) An E/P ratio of 4 hours was used for battery technologies when calculating total costs.
MRL = manufacturing readiness level; O&M = operations and maintenance; TRL = technology readiness level.

Table ES.2. Summary of compiled 2018 findings and 2025 predictions for cost and parameter ranges by technology type – non-BESS.

Parameter	Pumped Storage Hydropower[a]				Combustion Turbine	CAES[a]	Flywheel[b]	Ultracapacitor[c]
Capital Cost – Energy Capacity ($/kW)	1,700-3,200 **2,638**				678-1,193 **940**	1,050-2,544 **1,669**	600-2,400 **2,400**	240-400 **400**
Power Conversion System (PCS) ($/kW)	Included in Capital Cost				N/A	N/A	Included in Capital Cost	350 (211)
Balance of Plant (BOP) ($/kW)								100 (95)
Construction and Commissioning ($/kW)							480 [d]	80 [d]
Total Project Cost ($/kW)	1,700-3,200 **2,638** [f]				678-1,193 **940**	1,050-2,544 **1,669**	1,080-2,880 **2,880**	**930 (835)**
Total Project Cost ($/kWh)	106-200 **165**					94-229 **105**	4,320-11,520 **11,520**	**74,480 (66,640)**
O&M Fixed ($/kW-year)	15.9				13.0	16.7	5.6	1
O&M Variable (cents/kWh)	0.00025				1.05	0.21	0.03	0.03
System Round-Trip Efficiency (RTE)	0.80				0.328	0.52	0.86	0.92
Annual RTE Degradation Factor							0.14%	0.14%
Response Time		FS	AS	Ternary	From cold start: 10 min Spin ramp rate: 8.33%/min Quick start ramp rate: 22.2%/min	3-10 min	0.25 sec	0.016 sec
	Spinning-in-air to full-load generation	5-70 s	60 s	20-40 s				
	Shutdown to full generation	75-120 s	90 s	65-90 s				
	Spinning-in-air to full load	50-80 s	70 s	25-30 s				
	Shutdown to full load	160-360 s	230 s	80-85 s				
	Full load to full generation	90-220 s	280 s	25-60 s				
	Full generation to full load	240-500 s	470 s	25-45 s[g]				
Cycles at 80% Depth of Discharge	15,000				Not Relevant	10,000	200,000	1 million
Life (Years)	>25				20	25	>20	16
MRL	9 (10)				10	8 (9)	8 (9)	9
TRL	8 (9)				9	7 (8)	7(8)	8

(a) E/P = 16 h
(b) E/P = 0.25 h
(c) E/P = 0.0125 h
(d) 20 percent of capital cost
AS = adjustable speed; FS = fixed speed.

Pumped hydropower storage

Armenia currently contains three small pumped-storage units, which transport water to reservoirs at higher elevations using electric pumps during off-peak hours, allowing stored water to be released through turbines during peak periods. Pumped storage is useful in helping electrical systems adjust quickly to network fluctuations in response to rapid increases or decreases in production by intermittent RES, e.g. due to changes in sunlight or wind conditions. The need for such a rapid reaction is likely to become more important as Armenia's share of VRE increases. Several studies since the 1980s have identified opportunities for further pumped-storage capacity, including one completed in 2008 that identified 11 sites, of which three were regarded as particularly promising." Armenia 2022 Energy Policy Review.

Three sites for pumped storage were identified, totaling 450 MW. The pumping power is 200 MW for each site. A more detailed technical description can be found in the original 2008 study, on the last three pages: http://energinst.am/files/Report%20full%20GAES.PDF .

Tamara Babayan provides estimates of energy storage capacity for these sites:

Table 5. The pumped energy storage capacities.

Site Name	Estimated Generating Capacity (MW)	Energy Storage Capacity (MWh)
Aghbyurak	150	1,161
Tolors	150	1,254
Shamb	150	1,362

Source: Renewable Energy In Armenia (Tamara Babayan, 2017)

Based on these numbers, these sites could each provide between 7-9 hours of supply at full power. The most intuitive use for these is for peak demand, by storing cheap energy (in a period of high solar generation) and then using it later in the evening. The current winter peak is 1300 MW, and summer peak is 1040 MW. The three pumped storage sites could, if combined, provide almost half of summer peak, and one-third of the winter peak. In the future, as peak demand on the grid grows, these proportions will decrease, but will still be important.

The table for pumped hydropower is given below. Investment costs are not expected to change over the years, as costs are largely dependent on geographical sites. USAID LCEDP study also assumes investment costs constant regardless of the year. Lifetime is significantly different based on source, but this could be due to renovation and lifetime extension being considered. Also note that variable cost (of supplying electricity) is not necessarily the same as O&M costs over plants lifetime.

The advantages are the efficiency of mechanical storage (esp. long-term), long lifetime and ability to provide output for a longer period of time. However, highly specific geographical requirements limit the potential capacity that can be deployed.

Table 6. Pumped hydro storage characteristics

Investment cost	2,792 $/kW (LCEDP) 2,638 $/kW, 165 $/kWh Energy Storage Technology and Cost Characterization Report 1,700-5,100 $/kW (Fact Sheet | Energy Storage (2019) | EESI) 1,504-2,422 $/kW; 150-242 $/kWh USAID Grid-Scale Energy Storage Technologies Primer (2021) 1,962 $/kW (mean), 897 $/kW (median) Projected Costs of Generating Electricity – NEA 2020 Edition
Variable cost	1.41 USc/kW (LCEDP) 0.00025 USc/kWh Energy Storage Technology and Cost Characterization Report
Lifetime	80 years (LCEDP); 30-60 years EESI; 40 years USAID Primer >25 years Energy Storage Technology and Cost Characterization Report
Self-discharge time	Mechanical, no losses
Charge up time	5.8 - 6.8 hours for full charge up (own calculation)
Discharge time	7 - 9 hours at peak output (own calculation)
Reaction time	Several seconds to minutes (depending on tech) USAID Primer
Round-trip eff.	70-85% EESI; 80%+ for new installations USAID Primer 80% Energy Storage Technology and Cost Characterization Report

Note: charge and discharge times are calculated specifically for the three sites identified in Armenia, taking into account their storage capacity, turbine power, and pump power.

Li-ion

Table 3. Advantages and Disadvantages of Select Electrochemical Battery Chemistries Adapted from (Fan et al. 2020)		
Storage Type	**Advantages**	**Disadvantages**
Lithium-Ion	• Relatively high energy and power density • Lower maintenance costs • Rapid charge capability • Many chemistries offer design flexibility • Established technology with strong potential for project bankability.	• High upfront cost ($/kWh) relative to lead-acid (potentially offset by longer lifetimes) • Poor high-temperature performance • Safety considerations, which can increase costs to mitigate • Currently complex to recycle • Reliance on scarce materials.
Flow (Vanadium-Redox)	• Long cycle life • High intrinsic safety • Capable of deep discharges.	• Relatively low energy and power density.
Lead-Acid	• Low cost • Many different available sizes and designs • High recyclability.	• Limited energy density • Relatively short cycle life • Cannot be kept in a discharged state for long without permanent impact on performance • Deep cycling can impact cycle life • Poor performance in high temperature environments. • Toxicity of components
Sodium-Sulfur	• Relatively high energy density • Relatively long cycle life • Low self-discharge.	• High operating temperature necessary • High costs.

Source: USAID Grid-Scale Energy Storage Technologies Primer

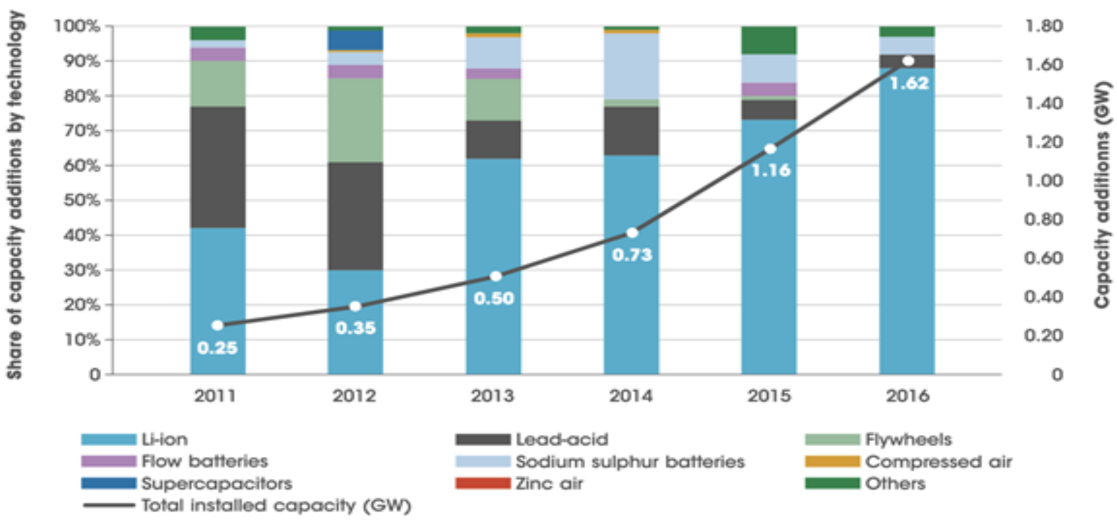

Figure 29. Increasing share of Li-ion in annual battery storage capacity additions globally. Source: Utility-scale batteries – Innovation Landscape Brief (IRENA, 2019)

Over the 2010s, Li-ion batteries have come to dominate battery storage additions globally. This is due to their performance, not necessarily cost, as they can charge quickly and have high energy density.

Li-ion capital costs have been falling rapidly, with power components cost potentially reaching $100/kW by 2030. and energy components cost likewise almost $100/kWh by 2030. However, it should be noted that for grid-level storage, there are additional storage system costs, as these storage systems have more components than just batteries. The cost projections for a grid-level Li-ion storage system are shown below.

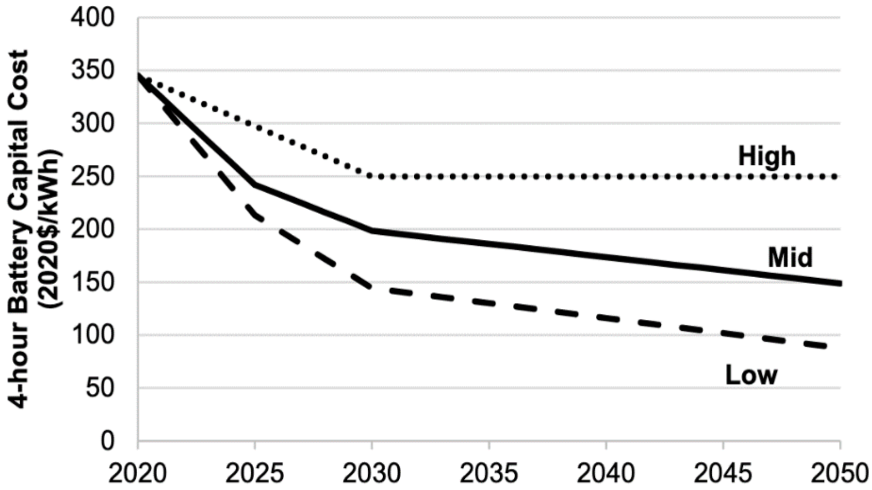

Figure ES-2. Battery cost projections for 4-hour lithium ion systems.

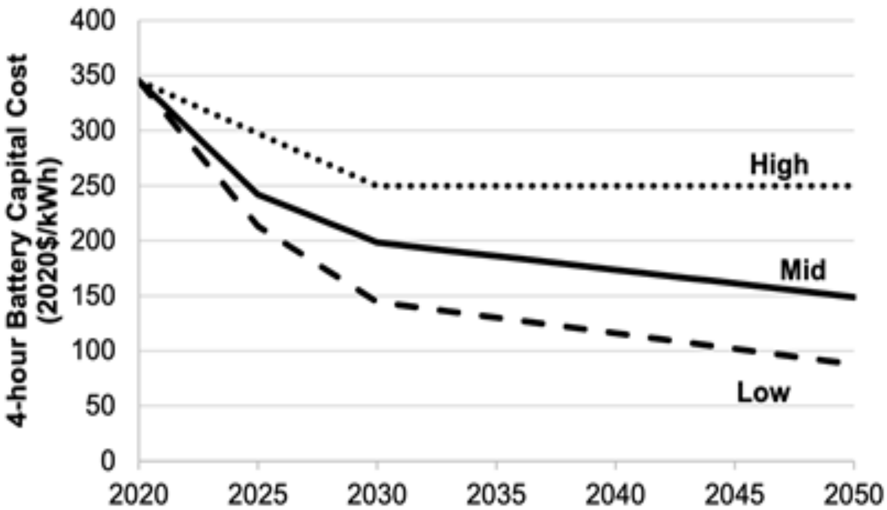

Figure 30. Battery cost projections for 4-hour lithium ion systems.
Source: Cost Projections for Utility-Scale Battery Storage: 2021 Update

Li-ion has high energy and power density, and (very importantly) can charge up relatively quickly. Its experience in the market makes it a well-tested technology, with various applications, such as frequency regulation, reduced RE curtailment, and capacity firming (see the list of projects on pp 8-9).

Table 7. Li-ion storage characteristics

Investment cost	852 $/kW by 2025; 442 $/kW by 2030 (LCEDP) 1,446 $/KW by 2025; 362 $/kWh by 2025 Energy Storage Technology and Cost Characterization Report 1,408-1,947 $/kW; 352-487 $/kWh USAID Grid-Scale Energy Storage Technologies Primer (2021) 242 $/kWh by 2025, 198 $/kWh by 2030, 186 $/kWh by 2035, 174 $/kWh by 2040 Mid-value numbers are taken for every 5 years. For a full list by projection (low, mid, high) and year (2020-2050) see p.14 of the link Cost Projections for Utility-Scale Battery Storage: NREL 2021 Update
Variable cost	5.61 USc/kW (LCEDP) 0.03 USc/kWh Energy Storage Technology and Cost Characterization Report
Lifetime	25 years (LCEDP); 10-15 years EESI; 10 years USAID Primer 10 years Energy Storage Technology and Cost Characterization Report
Self-discharge time	Months-years Critical Review of Flywheel Energy Storage System (2021)
Charge up time	2-3 hours https://batteryuniversity.com/article/bu-409-charging-lithium-ion
Discharge time	Minutes to hours USAID Primer
Reaction time	Subseconds to seconds USAID Primer
Round-trip eff.	85 – 95% EESI; 86-88% USAID Primer 86% Energy Storage Technology and Cost Characterization Report

Table 8. Comparison of flywheels with other mechanical storage systems

Properties	Flywheel	Compressed air	Pumped hydro
Specific power	High	Medium	Low
Specific energy	High	Medium	Low
Power density	High	Medium	Low
Energy density	High	Medium	Low
Lifespan	Low	Medium	High
Life-cycle	High	Low	Medium
Efficiency	High	Medium	Medium
Self discharge rate	High	–	–
Scale	Low	Medium	High
Maintenance	Low	Medium	Medium
Energy capital cost	High	Low	Low
Power capital cost	Low	Medium	High
Scale	Medium	High	High
Impact on environment	Extremely low	Medium to low	High to medium

Source: Flywheel energy storage systems: A critical review on technologies, applications, and future prospects – (Choudhury, 2021)

Flywheels are rotating devices that store kinetic energy and then release it over relatively short periods of time. While flywheels do not have the high energy density and storing time of Li-ion batteries, their extremely fast response time (within quarter of a second) makes them a useful asset for primary frequency response. Flywheels are the third largest storage technology globally, after pumped hydropower and li-ion batteries. What also distinguishes them is very low operational cost and environmental impact, as well as longer lifetime than for chemical batteries. The largest flywheel plant globally is Beacon Power's 20 MW system in the United States.[153] Being a mature technology, their cost is not expected to change much.[154]

[153] 20 MW Flywheel Energy Storage Plant
[154] An Evaluation of Energy Storage Cost and Performance Characteristics

Table 9. Flywheel storage characteristics

Investment cost	2,880 $/KW; 11,520 $/kWh Energy Storage Technology and Cost Characterization Report 2400 $/kW Mongrid et al (2020) 1,080-2,880 ($/kW); 4,320-11,520 ($/kWh) USAID Grid-Scale Energy Storage Technologies Primer (2021)
Variable cost	0.03 USc/kWh Energy Storage Technology and Cost Characterization Report 5.6 $/kW-year Flywheel energy storage systems: A critical review on technologies, applications, and future prospects - Choudhury
Lifetime	20,000-100,000 cycles EESI; 20 years USAID Primer >20 years Energy Storage Technology and Cost Characterization Report
Self-discharging time	Several hours Critical Review of Flywheel Energy Storage System (2021)
Charge up time	Seconds to few minutes USAID Primer 10 seconds – 10 minutes Critical Review of Flywheel Energy Storage System (2021)
Discharge time	Seconds to few minutes USAID Primer 10 seconds – 10 minutes Critical Review of Flywheel Energy Storage System (2021)
Reaction time	Subseconds USAID Primer
Round-trip eff.	70 – 95% EESI; 86%–96% USAID Primer 86% Energy Storage Technology and Cost Characterization Report

Analysis and Conclusion

Battery costs are expected to drop significantly within the next decades. At the same, the increased use of raw materials (such as lithium, rare earth metals, etc) can affect the costs of production. The primary goal for Armenia should be development of pumped hydropower storage; this would be essential for medium-term storage. Chemical batteries (primarily lithium ion) should be considered for short-term storage (1-4 hours), mainly utilizing excess daytime generation for evening peak hours, but also managing variations throughout the day. Flywheels can be considered for primary frequency response. Compressed air storage opportunities should be separately explored in Armenia, as they have highly specific geographical requirements.

What is important to note regarding costs is that flywheels, pumped hydropower storage, and compressed air storage are not expected to experience significant cost reductions, as these are already mature technologies. The main factor will therefore be with chemical batteries.

For this, it is important

a) To provide proper incentives and market mechanisms, so that storage technologies are deployed economically on the market

b) To have proper decision-making on system operator's level, to decide when to invest into storage for grid management, based on costs and demand.

The two factors will interact. A proper market mechanism can incentivize sufficient storage installations, reducing the need for system operator's intervention. An important aspect is providing multiple sources of revenue (through well-designed ancillary services, wholesale market, and energy arbitrage) for storage, because the capital costs remain high. On the other hand, an intervention that is too large or inefficient could deter and disincentivize market investments, making it harder for the liberalized electricity market to evolve.

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ARMENIA'S ENERGY INDEPENDENCE ROADMAP

PART 5 DISTRICT HEATING. SMART GRID. PUBLIC TRANSPORTATION

Developed by: Tigran Gnuni, Aram Harutyunyan, Armen Danielyan,
Régis Danielian, Garnik Balyan, Suren Shatvoryan (Team Leader)

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DISTRICT HEATING

District heating (DH) is one of the options for decarbonizing the heat industry, particularly in densely populated areas. Along with electrification and hydrogen, it is a major solution for removing reliance on natural gas. The current prevalence of district heating and various policies related to it vary across the European countries, with Nordic countries having the largest rates of district heating use.[1] Globally, DHs meet about 8% of the heating needs.[2] While fossil fuels are the most widespread in heat generation for DH, sources such as biomass, waste, heat pumps, and solar thermal systems have been used.[3] An example of such transitioning from mostly fossil fuel-based DH to renewable-based (mostly biomass) one is Denmark, although it should be noted that 80% of biomass is imported in order to sustain such transition.[4] The latest (4th generation) low-temperature district heating technologies provide further cost-efficient ways to integrate renewables and waste heat; successful implementations exist worldwide.[5]

While heat-only plants can be used for DH, combined heat-and-power (CHP) plants allow for more efficient utilisation of resources and make district heating more efficient.[6] A biomass CHP can function as a baseload for heat supply, while a heat-only fossil fuel-based plant acts as variable generation (though solar heating and electric boilers increasingly act as a support).[7] Biomass can come in the form of biowaste, wood pellets, straws, etc; in addition, combustible waste and industrial heat can serve as a fuel. Some innovative ways of recovering heat have been developed, such as using heat from data centres for district heating.[8]

While biomass and waste have been more prevalent sources of heat for DH, solar thermal systems are another competitor on the market.[9] Given that the demand for heating is highest in winter time, when solar energy generation is at its lowest, thermal storage systems can be deployed for seasonal heat storage. In fact, approximately half of thermal storage systems worldwide are deployed with DH, and, in turn, half of DH thermal storage systems are for seasonal storage.[10] For the purposes of seasonal storage for domestic heating, hot water storage ("sensible storage") is the usual application.[11] Storage of hot water underground in aquifers and boreholes is the most widespread application, though water tanks can also be deployed.[12] Combined with seasonal thermal storage, certain solar thermal DH systems can almost completely cover annual space heating demands for local residents, even in such locations as Canada.[13]

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[1] See A review of heat decarbonisation policies in Europe | ClimateXChange
[2] District Heating – Analysis - IEA
[3] Ibid
[4] Something is sustainable in the state of Denmark: A review of the Danish district heating sector - ScienceDirect
[5] Successful implementation of low temperature district heating case studies - ScienceDirect
[6] Regulation and planning of district heating in Denmark
[7] Ibid
[8] District Heating – Analysis - IEA
[9] See SOLAR HEAT WORLD WIDE for examples of such projects
[10] Innovation outlook: Thermal energy storage
[11] See IRENA-IEA-ETSAP Technology Brief 4: Thermal Storage for a brief review of thermal storage technologies
[12] Innovation outlook: Thermal energy storage
[13] Ibid, p 94

Heat pumps can likewise be utilised for district heating, by transferring low-temperature heat from sewage water or seawater.[14] While this would increase the electricity demand, grid requirements would be lower than in case of individual heat pumps, as no upgrade of low-voltage lines in buildings is required. Likewise, geothermal district heating is a niche application based on local geological conditions, and successful projects exist in Europe and the US.[15]

In Armenia, district heating was prevalent during the soviet period but collapsed rapidly in the 1990s. Given the current state of the heat sector and limited budgets, it has been argued that restoration of district heating in Armenia has to be achieved through involvement of the private sector and implementation of co-generation.[16] Some restoration projects took place, most notably UNDP's restoration of Avan district central heating; the co-generation plant was able to provide heat at a tariff lower than the cost of individual boilers.[17] The project had 9 million USD invested in it as of 2012 (3 years after it had been commissioned), and supplied heat to 30 apartment buildings.[18] It should be noted, however, that the preferential feed-in tariff for electricity from co-generation was deemed of critical importance for the success of district heating reconstruction; without state support, the renovation of district heating solution was deemed infeasible.[19] Reducing commercial risk and increasing investor confidence was what made restoration of Avan DH feasible.[20]

Therefore, while the national potential for co-generation DH restoration is estimated at 120-140 MW (together with peak boilers of 300-350 MW),[21] the economic efficiency of district heating restoration remains under question. Moreover, the technical requirements can further complicate the restoration, as many district heating buildings have been replaced by other commercial or public infrastructure. A 2003 study found that, among space heating options, low-capacity boiler house would be the cheapest per MWh, followed by individual natural gas heating and rehabilitation of Yerevan TPP centralised heating;[22] however, the choice of technologies did not include biomass-based heating, and the study itself is 20 years old. This highlights the need for a more recent, similarly comprehensive comparative study of the various heating options.

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[14] Something is sustainable in the state of Denmark: A review of the Danish district heating sector - ScienceDirect

[15] District Heating – Analysis - IEA, although there is "development of new deep geothermal solutions that do not require a permeable aquifer" (*ibid*)

[16] https://unece.org/fileadmin/DAM/energy/se/pdfs/gee21/projects/cs/CS_Armenia.pdf

[17] Improving Energy Efficiency of Municipal Heating and Hot Water Supply - Lessons Learned from the UNDP-GEF Project in Armenia (UNDP, 2012)

[18] Ibid

[19] Ibid

[20] https://unece.org/fileadmin/DAM/energy/se/pdfs/gee21/projects/cs/CS_Armenia.pdf

[21] Ibid

[22] Heat Supply Options for Armenia

To properly estimate the potential of district heating in reducing energy dependence of Armenia, the following points need to be evaluated:

1. The current state and the rehabilitation potential for central heating infrastructure. Regulatory grounds for district heating implementation / rehabilitation in the existing buildings stock on a large scale.
2. The potential for new installations for the existing building stock. Low-carbon resources (biomass, waste, underground heat) available for district heating.
3. **A comparative economic analysis of heat supply options, including individual boilers, district heating / boiler houses, and electric heating.**

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SMART GRID

General Information

Successful implementation of smart grid requires proper technical evaluation, cost-benefit analysis, and technological availability; but the major prerequisite is the involvement of various stakeholders. In other words, the “why?” precedes the technology. Why implement a smart grid? The question is reasonable in light of the fact that traditional grids in developed countries have been functioning well, with few interruptions and blackouts. The same can be said of Armenia, where high rates of electrification and excess power capacity have resulted in a relatively reliable energy system. The more limited financial resources that the country possesses (as opposed to the highly developed economies) make the question only more poignant - why invest in smart grid?

To properly evaluate this question, it is important to understand what is the key difference between traditional and smart grid? The traditional energy system does not contain much ability to control and monitor the situation in real time; while generation has been mostly dispatchable and under control, malfunctions in the transmission and distribution grids are detected and fixed post-factum, once the problem occurs. Moreover, demand has remained largely inelastic: as consumers do not observe the cost of electricity generation in real time, there is little incentive to adjust to supply. In the absence of real-time management tools, risks have therefore been managed to a significant extent by the physical configuration of the grid. Large transmission capacities to match inelastic peak demand, reserve generation, alternative transmission routes, - in short, redundancy has been a major factor in mitigating risks.[23,24] Spare parts, spare capacity, spare routes for electricity transmission, - the essential approach has been overhedging the risks through investments in excess physical configuration.

In contrast to that, smart grid provides better real-time monitoring, informational flow, and control of the grid, from generation to consumption. The digital dimension is enhanced. Management of risks is significantly shifted from infrastructural redundancy to the management of electricity flow itself, while the physical infrastructure is monitored and managed through real-time and predictive analytics. It is therefore important to emphasise that the basic philosophy of smart grid is the anticipation and real-time management of risks and fluctuations, as opposed to overhedging through infrastructural investments.

The advantage of smart grid is especially prevalent in light of growing variable renewable generation (VRE) of wind and solar. The fluctuating supply and demand have to be matched, and keeping the grid balanced is now a more challenging task. Moreover, the distributed nature of VRE generation further complicates the issue, increasing the pathways of electricity flow, including from the consumers. Add in potential electrification rates of transport and heating, and the number of actors and interactions in the electricity system grows further, making real-time control and monitoring even more critical.

It is important to highlight the advantages of smart grid in light of Armenia’s energy independence and security. Higher energy independence would require a shift towards higher

[23] Reimagining Grid Resilience

[24] A Brief Analysis on Differences of Risk Assessment Between Smart Grid and Traditional Power Grid

reliance on VRE and lower reliance on natural gas; naturally, this would result in a less controlled supply, and hence the challenge of matching supply and demand in real time. A direct result of this issue is frequency control, the major provider of which for Armenia is currently the Iranian grid. The ability to manage higher self-reliance in energy depends on the support of interconnectors and storage; however, both are limited in the case of Armenia. The interconnection with Georgia is expected to be DC-to-DC, leaving Iran as the only synchronised grid for Armenia, which increases the risks to the system in case something happens to the interconnector. Storage potential is likewise limited, with relatively small pumped hydropower capacity, while utility-scale chemical batteries remain a costly investment, though prices are falling. While redundancy remains an important factor in risk mitigation, grid stability will become an issue when recognizing that redundancy for grid stabilisation purposes is limited, with only one synchronised interconnection. None of this is to say that smart grid is the only solution, but that smart management in light of scarce resources and possibilities (which is especially true given Armenia's situation) will allow for a better grid security, and consequently higher levels of energy independence while maintaining high quality of supply.

Conventional Grid	Smart Grid
Mechanically operated	Digitized
Unilateral	Bi-directional
Centralized Power generation	Distributed Generation
Radially connected	Dispersed
Small number of sensors	Many
Less monitoring capabilities	Highly monitored
Manual control	Automated control
Less security issues	Vulnerable to security issues
Slow responsive actions	Fast response

Differences between conventional and smart grid.

Source: A Comprehensive Review of Recent Advances in Smart Grids: A Sustainable Future with Renewable Energy Resources[25]

Government Strategy and Advanced Metering Infrastructure

The importance of smart grid technologies is recognized in the national energy strategy[26], which states that:

"Information technology and new related opportunities are continuously transforming markets by offering completely new business models and lifestyles based on data management and energy is a part of that transformation throughout the world. Sustainable and smart energy is one of the most important conditions for dynamic development of the economy aimed at improving human lives and their living standards."

"The Information Technology sector of Armenia, which is competitive in the global market, shall be widely used in order to solve different energy sector-related issues. In this regard,

[25] www.mdpi.com/journal/energies

[26] ՀՀ Կառավարություն որոշում առ 14 հունվարի 2021 թ. N 48-Լ. https://www.arlis.am/DocumentView.aspx?docID=149279

the organization of trade in the wholesale electricity market will be primary and this will be completely carried out through the electronic platform in the next few years."

"Along with the wholesale market electronic trading platform, it is planned to develop the unified information system for remotely transmitting and managing the information on the consumption and other necessary indicators from the electricity metering system of the consumers connected to the Distribution Network, which will promote the liberalization process of the Retail Electricity Market. Meanwhile the SCADA management system will be installed in the power system which will enable the System Operator not only to collect the necessary data but also to carry out automatic remote control of the network equipment."

One of the goals of the national strategy is to modernize the metering system by 2027. In more detail, this means that

"All consumers shall be connected to the Automated System of the Electrical Energy Metering which will enable the consumers to receive data of commercial metering devices on the basis of remote operation, ensuring availability of the data in real time for consumers and new suppliers in the Retail Electricity Market as well as for the Market Operator, creating a favorable environment for liberalization of the Retail Market."

Though smart meters are not the only feature of the smart grid, they are a necessary component. Data collection and transmission is key for proper operation of smart grid, as decisions (deliberate by agents, or in-built by algorithms) are made based on real-time situation analysis. This infrastructure for collection and transmission of consumption information is known as Advanced Metering Infrastructure (AMI).

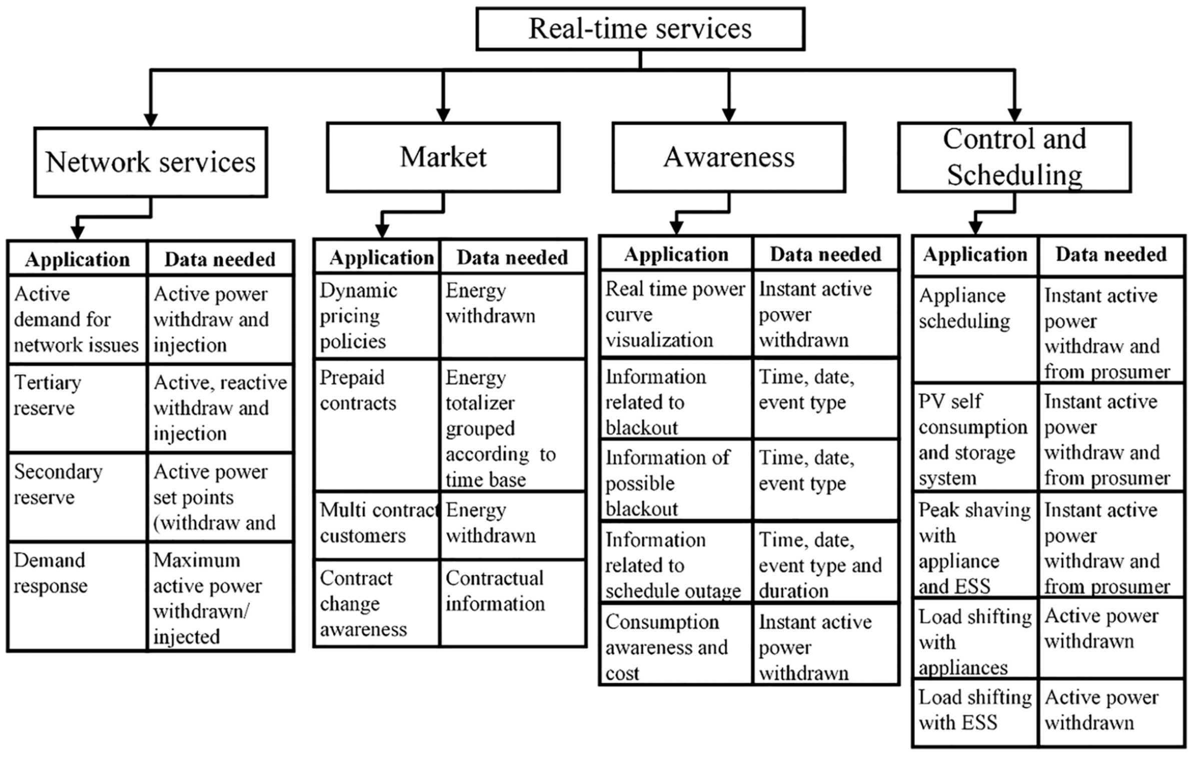


Figure 1. Services provided by AMI.
Source: Rathor and Saxena, 2019.

"Smart grids have major implications at the distribution level, but little at the TSO level. Some 80 % of smart grid investment is at DSO level, very little at TSO. Despite talk of electricity highways, HVDC etc, most non-hydro renewable sources are connected to low-voltage distribution networks rather than the high-voltage grids."[27]

The ability to provide different services for the consumers and grid likewise depends on the resolution of the data that is available through smart meter collection. An estimation of various services and requirements is shown in the table below.

Table 1. Real-time services: time requirements and stakeholders involved. ***Source***: The Role of Smart Meters in Enabling Real-Time Energy Services for Households: The Italian Case.[28]

Category	Code	Use Case	Data Required	Maximum Sampling Time	Maximum Latency	Interested Stakeholders		
						Customer	DSO	Retailer
Awareness	A1	Dashboard for consumption and production awareness	energy data withdrawn and injected (only prosumers)	15 min	15 min	X	-	-
	A2	Ex-post analysis of an electric event (e.g., defrost cycle)	Active power withdrawn, injected, produced	1 min	1 h	X	-	-
	A3	Consumption awareness and cost estimation (revenue estimation for prosumers)	Instant active power withdrawn (injected and produced for prosumers)	15 min	1 h	X	-	X
	A4	Contractual information	All data regarding contractual information	-	15 min	X	X	X
	A5	warning for exceeding available power thresholds	event type, instant active power, timestamp	30 s	5 s	X	-	-
	A6	Warning for exceeding power thresholds (chosen by the customer)	event type, instant active power, timestamp	-	30 s	X	-	-
	A7	Information about a scheduled outage	event type, date, time, duration	-	1 h	X	X	-
	A8	information about a possible blackout	event type, date, time	-	1 h	X	X	-
	A9	information about a recently occurred blackout	event type, date, time	-	1 h	X	X	-
	A10	realtime power curve visualization	Instant active power withdrawn (injected and produced for prosumers)	1 s	1 s	X	-	-
Market	M1	Dynamic pricing contracts (ToU, RTP)	energy withdrawn	15 min	1 min	X	-	X
	M2	Prepaid contracts	energy totalizers grouped according to timebands	15 min	15 min	X	-	X
	M3	multi-contract customer	energy data withdrawn (injected/produced for prosumers)	15 min	15 min	X	-	X
	M4	contract change awareness	Contractual information	-	15 min	X	-	X
Scheduling & control	SC1	Scheduling for appliances	Instant active power withdrawn (injected/produced for prosumers)	5 s	5 s	X	-	-
	SC2	PV self-consumption with appliances and storage systems	Instant active power withdrawn (injected/produced for prosumers)	1 s	30 s	X	-	-
	SC3	Peak shaving with appliances and storage systems	Instant active power withdrawn (injected/produced for prosumers)	1 s	2 min	X	X	-
	SC4	Load shifting with storage systems	Active power withdrawn (interval average)	1 min	1 min	X	X	-
	SC5	Load shifting with appliances	Active power withdrawn (interval average)	1 min	1 min	X	X	-
	SC6	Monitoring for elderly people	Instant active power withdrawn (injected for prosumers)	15 min	15 min	X	-	-
Network services	N1	Active demand for network issues	Active power set point (withdrawn/injected) active power (interval average)	1 min	10 s	X	X	-
	N2	tertiary reserves	Active power set point (withdrawn/injected) reactive set point, active power (interval average), reactive power (interval average)	3 min	1 min	X	X	-
	N3	secondary reserves	Active power set point (withdrawn/injected) reactive set point, active/reactive power	3 min	1 min	X	X	-
	N4	reactive power exchange	active/reactive power set points	-	1 min	X	X	X
	N5	Demand Response	Max active power withdrawn/injected set point	-	1 min	X	X	-
Diagnostics	D1	Supply service anomalies monitoring	rms voltage, outages registers	30 s	1 min	X	X	-

[27] Electricity Transmission Grids - World Nuclear Association

[28] https://www.mdpi.com/1996-1073/10/2/199/htm

Energy Management Systems (EMS)

EMS ensures the reliability and secures the operating points for the Supervisory Control and Data Acquisition (SCADA). It could also be considered as a large-scale optimizer for the entire grid.[29] While the general term "EMS" can also apply to more localized energy management systems, such as homes or batteries, the grid-level applications are considered here.

Table 2. Grid-level energy management systems with consideration of renewable energy sources. ***Source***: Rathor and Saxena, 2019.

Ref.	Configuration	Solution Approach	Objective of EMS
Liao and Ruan[128]	Standalone/PV/ESS	Linear programming	Improved system, dynamic performance, and efficiency. The solar cell array powers the steady-state energy, and the battery compensates the dynamic energy
Ismail et al[129]	Stand-alone PV/ESS/ microturbine (MT)	Linear programming	To minimize cost using PV and ESS, during excess load demand MT is utilized
Dash and Bajpai[130]	Stand-alone PV/ESS/FC	Linear programming	EMS aims to divert excess energy of PV to the electrolyzer
Finn and Fitzpatrick[131]	Grid-connected WT	Linear programming	WT is used to supply load during high demand periods
Ozbilen et al[132]	WT/Hydro/FC	Linear programming	To manage intermittent renewable power, hydrogen energy storage is proposed to be utilized during peak load periods
Abedi et al[133]	PV/WT/FC	Differential algorithm + fuzzy	Minimize cost, power balancing, and fuel consumption by utilizing RES energy
Dahmane et al[134]	Standalone WT/PV/ESS/ diesel	Linear programming	Cost-saving by utilizing PV as the main source of energy, WT used as a supplement of PV, and diesel generator is as an additional source to charge ESS batteries

Abbreviations: EMS, energy management system; ESS, energy storage system; PV, photovoltaic; RES, renewable energy sources; WT, wind turbine.

Smart Inverters

Inverters have to be used for solar and wind power generation. As the current produced by these sources is DC, an inverter is required to turn it into AC prior to feeding into the grid. This reduces the overall inertia of the system (as it lacks a rotational turbine at synchronised frequency), reducing the controllability of system voltage and frequency.[30] Smart inverters, however, are an emerging technology that includes such functions as circuit disconnection, charging of batteries, and maximum power point tracking.[31] The inverters can adjust output based on price signals, switch between feeding the grid and the battery, as well as self-monitor and send information in case malfunctions are detected.

[29] https://mdpi-res.com/d_attachment/energies/energies-13-06269/article_deploy/energies-13-06269-v2.pdf?version=1606902271

[30] Impact of Smart Inverters on Feeder Hosting Capacity of Distribution Networks | IEEE Journals & Magazine

[31] Frontiers | A Mini-Review on High-Penetration Renewable Integration Into a Smarter Grid | Energy Research

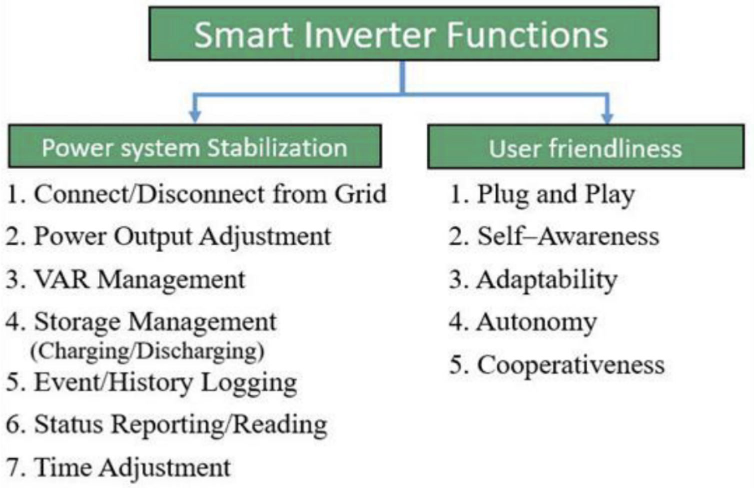


Figure 2. Smart inverter capabilities[32].

One of the main advantages of smart inverters is the ability to provide and receive both active and reactive power, making them an important asset in management of distributed generation. Normally, voltage drops as distance from the feeder connection grows; tap-changers and transformers are therefore adjusted to lift the voltage at the further nodes, so that it stays constant throughout. However, introduction of distributed generation (e.g. solar panels on the rooftops) results in voltage *increase* on the nodes, and the mechanism for lifting voltage on the further nodes backfires. It is here that smart inverters come into play, by supplying or absorbing reactive power to balance out the voltage.

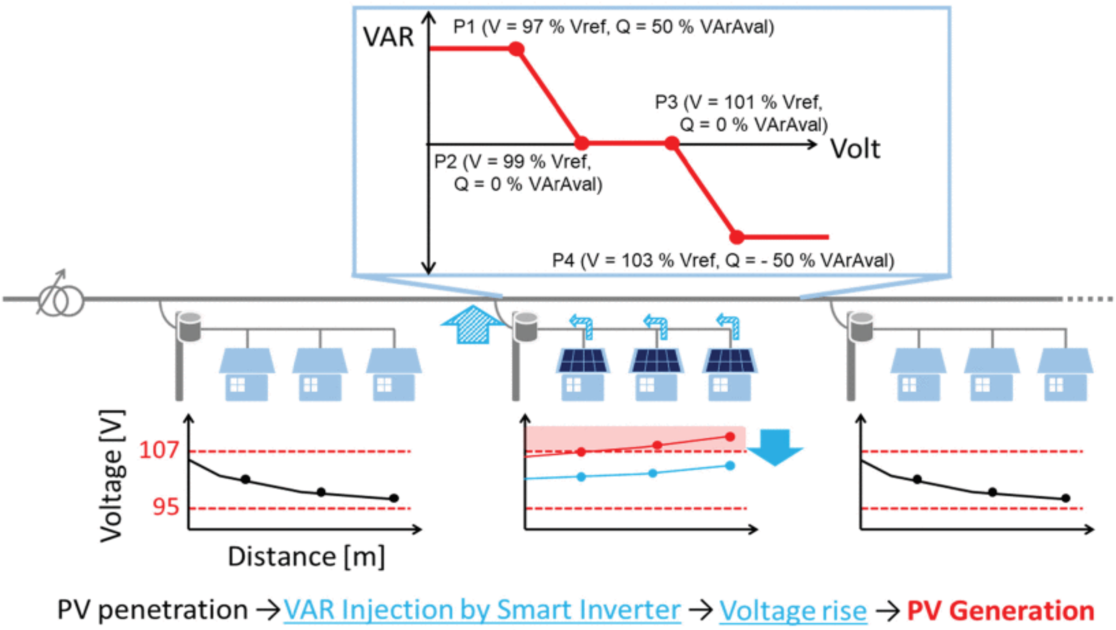


Figure 3. The benefits of smart inverters for distributed generation. Source: Impact of Smart Inverters on Feeder Hosting Capacity of Distribution Networks | IEEE Journals & Magazine

32 https://www.aimspress.com/fileOther/PDF/energy/Energy-07-06-971.pdf

While the normal approach to this voltage rise would be limiting the feeder hosting capacity (the amount of generation that can be attached to the distribution network), the authors of the study show, through grid modelling, that smart inverters allow to significantly increase this limit, in some cases almost doubling it. The utilisation of smart inverters would therefore increase Armenian grid's potential for distributed generation absorption, allowing for a higher level of energy independence.

Table 3. Overall, the following advantages are present with smart inverters[33]

Function	Description
Connect/disconnect from the grid	The inverter can switch the solar panels off the grid, either by setting the power output to zero (virtual disconnect) or by physically operating the switch to disconnect the inverter (physical disconnect)
Power adjustment	The inverter can reduce and increase reactive power to balance frequency changes in the grid "Other than the pure active power, the system has a reactive power component also. When considering the inverter circuits, the inverters will remain purposeless during night hours when the renewable sources are not available. This decreases the efficient use of these inverters. One way to rise the productive operation of these inverters is to generate reactive power in each time when the renewable sources are not existing by operating them as VAR compensators. As the number of grid-tied inverters rises, their usage part as VAR compensators will support to reduce the necessity of additional capacity banks as well as in the grid voltage regulation."
VAR management	A. Unity Power Factor, Q = 0 The inverter is designed to function with a unity power factor, with partial or without re-injection of reactive power to the grid. B. Fixed Power Factor, Q(P) The inverter function with a moderately leading power factor. It provides a regulation to reduce the voltage deviations attributable to active power output variations. C. Variable Power Factor, Q(P,R/X) This method lets the inverter to flow the reactive power back into the grid by operating with a variable power factor. D. Volt/Var Control This technique would allow the inverter to reply with a customized var reply, intended by the local utility, by monitoring its own terminal voltage. Each of these volt/var functions can be considered as a "Mode". The following modes have been recognized as a preliminary set for large collections of inverters. With a single transmission instruction from the utility the inverters can be switched between these modes. 1) PV1 – Normal Energy preservation Mode This mode is used as the normal state of operation for an inverter. (Inverters have one volt/var characteristic during on-peak hours and a different one during off-peak hours.)

[33] copied from https://www.aimspress.com/fileOther/PDF/energy/Energy-07-06-971.pdf.

	2) PV2 – Maximum Var Sustenance Mode Provide support for reactive power needs. This directs the distributed inverters to generate as many capacitive vars as possible. 3) PV3 – The Static Var Mode Proposed to be used in cases where var generation does not differ with local voltage. 4) PV4 – The Passive Var Mode This one is same as the PV3, with the exception that the percent var settings are assumed to be zero. The PV inverter volt/var control function can provide suitable voltage support for voltage deviations in primary and secondary sides due to variations in PV output. Voltage deviations caused by usual load variations also can be reduced as well.
Storage management	Automatic charging and discharging management for storage of VRE generation, allowing to control and balance grid stability
Event/history logging	Monitoring the behaviour of inverters and recording abnormal events or conditions
Status reporting/reading	The inverter monitors the status of the system, mainly to detect and prevent cyberattacks
Time adjustment	Setting the time for VRE generation to schedule functions and keep track of events

Machine Learning

Machine Learning is another emerging technology, used for analyzing large volumes of data for predictions or decisions; its applications in energy range from security assessment and load forecasting to non-technical loss estimations in the grid.

Table 4. Applications of machine learning[34]

ML algorithms	Definitions	Typical algorithms	Application scenarios
Supervised learning	A ML approach that learns a function via example input-output pairs.	Logistic regression; naive Bayesian classifier; decision trees; K-nearest neighbor algorithm.	Substation clustering and classification; Security and stability assessment (Li and Yang, 2017); electricity price and load forecasting (Ghasemi et al., 2016).
Unsupervised learning	A self-organized learning which helps find unknown patterns in knowledge base without pre-given labels	K-means clustering; self-organizing map; autoencoders; generative adversarial networks.	Clustering analysis of typical days (Chen et al., 2019); Cascading analysis of power grids (Yan et al., 2013).
Semi-supervised learning	A ML approach that combines labeled and unlabeled data during training	Self-training algorithm; co-training algorithm; graph-based method.	Non-intrusive load monitoring; non-technical loss detection in the smart grid.
Reinforcement learning	A ML approach concerned with how to maximize reward by taking actions	Q-learning; temporal difference learning; Monte Carlo learning.	Dynamic pricing and energy consumption scheduling (Kim et al., 2015); supply-demand Stackelberg game of smart grid.

One of the more novel applications is in **non-intrusive load monitoring**. Normally, in order to obtain measurements of the power load of appliances or heating efficiency of a

[34] Frontiers | A Mini-Review on High-Penetration Renewable Integration Into a Smarter Grid | Energy Research

building, intrusive measures are required, e.g. putting sensors on appliances that would monitor their consumption. This has higher costs[35] and can raise concerns over physical privacy. Likewise, for heating loss estimation on-site inspection is required, also costly and intrusive.[36] Collecting data using smart meters avoids that, as alternative methodologies have been developed for estimating factors such as load and heat power loss coefficient.

Chambers and Oreszszyn propose "Deconstruct" methodology, which infers loss coefficient from analysing the external temperature and solar irradiance and power consumption of the building. Using weather and smart meter data can therefore be a non-intrusive approach for analysing heating efficiency of the buildings.

Faustine et al review methodologies for non-intrusive load monitoring (NILM). The idea is to analyse the load profile of the consumer to understand consumption patterns and infer which appliances are turned on and when. Latest technologies incorporate machine learning into the process, allowing to analyse large chunks of data. NILM analysis can then be used by both consumers to better understand their consumption patterns, and by system operator to analyse the demand response to various changes.

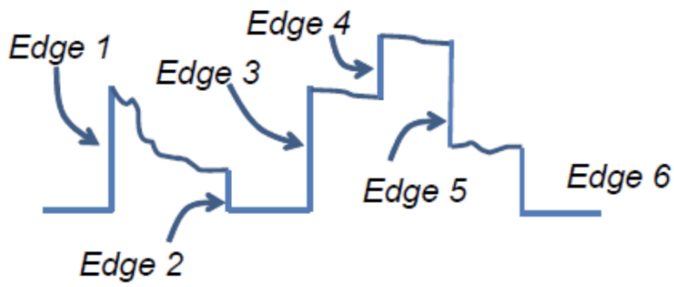


Figure 4. An example of edge-based approach in NILM, where the jumps and drops are used to infer which appliances are turned on and off[37]

Pricing approaches

While maintaining quality of supply is important, the shift to VRE generation also introduces demand-side challenges. One of the potential ways to adjust demand is through pricing policy. Currently, many countries (including Armenia) have a pre-set time-of-use (ToU) electricity tariff; a higher tariff is paid during the day, when more generation is required to meet demand, and a lower tariff during the night. While this type of tariff is easy to implement, it is relatively inefficient at reflecting the real-time cost of generating electricity, in particular when it comes to peak consumption. With the implementation of smart meters and greater flows of information, alternative pricing schemes can be implemented.

1. Real-time pricing

Real-time pricing would be considered as one of the approaches that maximizes social welfare. The price for consumers would reflect the spot price of wholesale electricity, with the

[35] Faustine et al, 2017
[36] Deconstruct: A scalable method of as-built heat power loss coefficient inference for UK dwellings using smart meter data (Chambers and Oreszczyn, 2019)
[37] Taken from Faustine et al, 2017 ;

retailer revealing the price a day ahead or on an hourly basis, so that consumers adjust accordingly.[38] While this would incentivise demand-responsiveness, it is a costly solution to implement, as real-time pricing "requires advanced infrastructure and intelligent metering technologies where the high penetration of intelligence increases the exposure to cyber threat".[39] While dynamic pricing would result in lower electricity bills overall, the cost of infrastructure required to operate such a system can significantly cut the gains.[40] It also requires active consumers who follow a constantly changing electricity price, unless automated price-based appliances are used.

2. Critical Peak Pricing

A compromise between a simpler static pricing and a complex dynamic pricing is critical peak pricing. Here, ToU pricing is utilized, while additional price is imposed only for critical load hours, which are usually shared beforehand. While critical peak pricing does not perfectly reflect the wholesale market price, it has an effect on reducing peak consumption.

The following examples of critical peak pricing are observed worldwide.

In Ontario, Canada, Ontario Energy Board's Time-of-Use pricing scheme is available with three different pre-set rates: off-peak, mid-peak, and on-peak.[41] The prices vary from 8.2 cents per kWh (off-peak), to 11.3 cents per kWh (mid-peak), to 17.0 cents per kWh (on-peak). The time periods also vary based on the season, as peak demand periods are different in winter and in summer, as well as whether it is a weekday or a weekend (see the graph below).

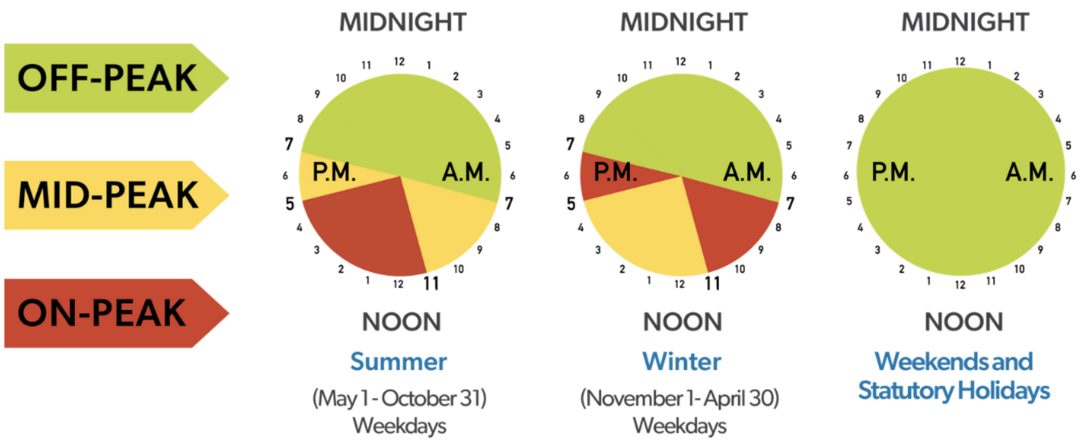


Figure 5. Peak pricing periods for Ontario's TOU scheme.

[38] A Comprehensive Review of Recent Advances in Smart Grids: A Sustainable Future with Renewable Energy Resources

[39] Ibid.

[40] E.g. Impacts of Raw Data Temporal Resolution Using Selected Clustering Methods on Residential Electricity Load Profiles | IEEE Journals & Magazine

[41] Electricity rates | Ontario Energy Board

HydroQuebec, another Canadian supplier, notifies its residential consumers about peak hours the day before. The consumers can then reduce their consumption and save money on electricity bills.[42]

Pacific Gas and Electricity Company, located in the US, likewise has a peak-pricing scheme based on the day, hours, and season.[43]

Eversource Energy, a utility company in Connecticut, has a variable peak pricing scheme. For the workdays, from 12 noon to 8 p.m, the price is published on the website the afternoon before.[44] That way, the consumers can see how much electricity will cost during the next day, and adjust their consumption accordingly.

A larger overview from 2015 of various pilot projects and their effects is shown below, on page 14. Many of those projects combined smart grid technology and pricing to achieve results, while others simply relied on consumer's awareness.

3. Day-ahead pricing

"Day-Ahead Pricing policy is a time-dependent pricing scheme that is set day ahead. Such a pricing scheme is more attractive to consumers since they have the ability to schedule their energy consumption, and therefore they may benefit from the operation during the off-peak periods"

Source: A Comprehensive Review of Recent Advances in Smart Grids: A Sustainable Future with Renewable Energy Resources

[42] Dynamic pricing – Residential customers | Hydro-Québec
[43] PG&E's Time-of-Use rate plans
[44] Variable Peak Pricing FAQ

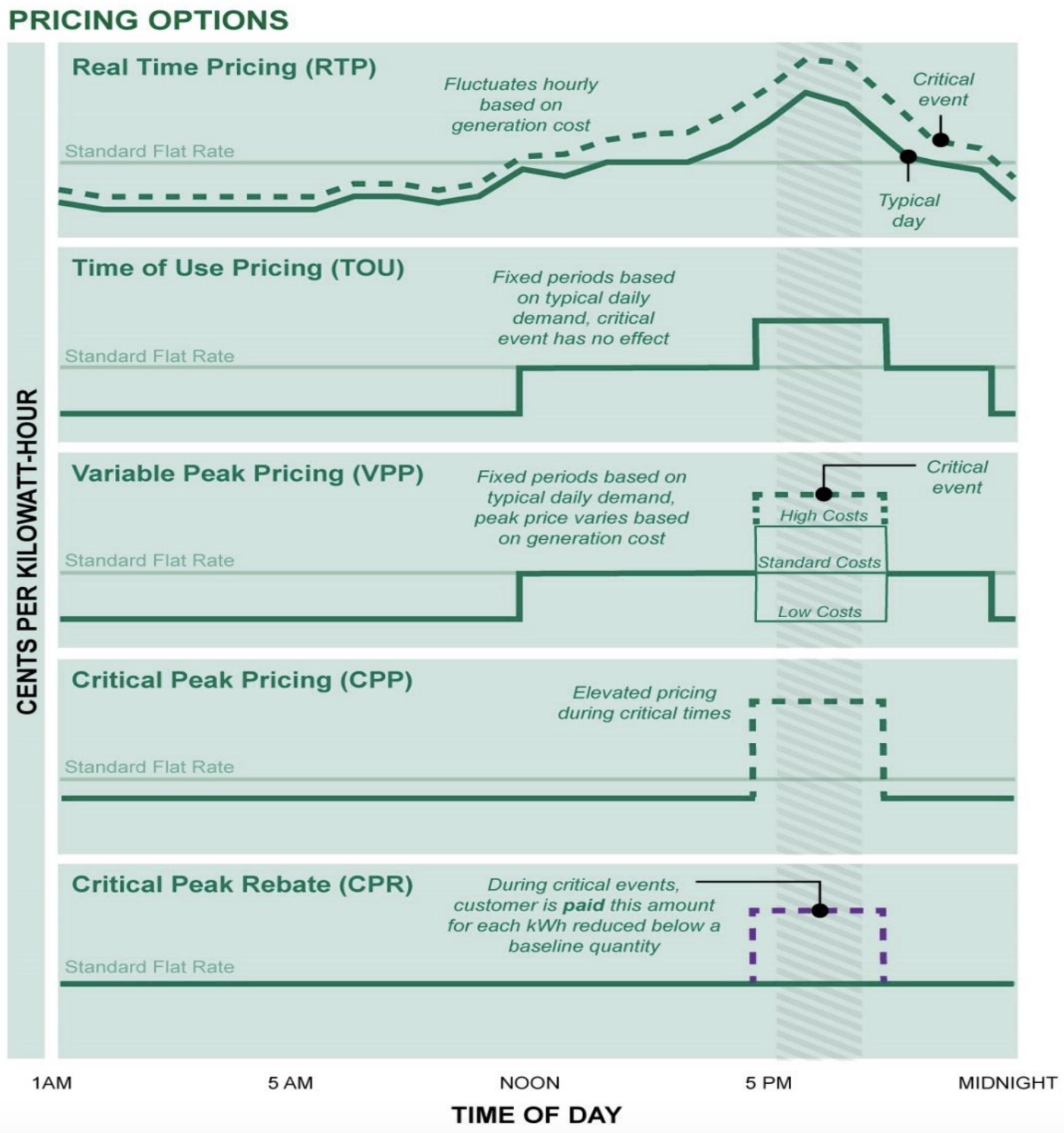


Figure 6. A graphic presentation of various pricing schemes, from A Primer on Time-Variant Electricity Pricing

UTILITY	PILOT NAME	TVP STRUCTURE	OPT-IN OR DEFAULT	TECHNOLOGY	AVERAGE IMPACTS ON PEAK LOAD (DAILY)	AVERAGE IMPACTS ON PEAK LOAD (CRITICAL EVENT DAY)	NOTES
New Jersey Public Service Electric and Gas*[1]	2008 myPower Pricing Pilot	*TOU-CPP*	Opt-in	None	-5%‡	-19%‡	*86% of pilot participants saved on average $160.*
				Smart Thermostat[24]	-21%	-47%	
Baltimore Gas and Electric*[2]	2008 Smart Energy Pricing Pilot	*CPR*	Opt-in	None	-	-23%	*Given the outcomes of their pilot, BG&E has extended the peak time rebate program to residential customers with smart meters.*
				Energy Orb[25]	-	-27%	
				Energy Orb + A/C Switch[26]	-	-31%	
		TOU-CPP	Opt-in	None	-2%	-20%	
				Energy Orb + A/C Switch	-4%	-33%	
Oklahoma Gas and Electric**[3]	2011 Smart Study Together Pilot	*TOU-CPP*	Opt-in	None	-6%	-17%	*Given pilot results, OG&E found that if adoption of the VPP rate reached 20% of the residential population, they would be able to avoid a 210 MW peaker plant investment. They have almost reached the goal with over 100,000 residential customers enrolled.*
				IHD[27]	-8%	-23%	
				Smart Thermostat	-6%	-34%	
				IHD + Smart Thermostat	-7%	-32%	
		VPP	Opt-in	None	-10%	-16%	
				IHD	-10%	-18%	
				Smart Thermostat	-18%	-28%	
				IHD + Smart Thermostat	-21%	-32%	
Sacramento Municipal Utility District**[4]	2012 Smart Pricing Pilot	*TOU*	Opt-in	None	-10%	-	*SMUD estimates savings of $12-140 million from making the rates accessible to the residential base depending on the tariff and technology employed.*
				IHD	-13%	-	
			Default	IHD	-6%†	-	
		TOU-CPP	Default	IHD	-12%†	-9%†	
		CPP	Opt-in	None	-	-21%	
				IHD	-	-25%	
			Default	IHD	-	-14%†	

* Distribution and transmission only company
** Vertically integrated company
‡ These reductions are an average between customers with and without central A/C.
† While per-customer effects were smaller in default groups, aggregate effects may be larger due to higher participation rates.

Figure 7. Impacts from some pilot pricing schemes, from A Primer on Time-Variant Electricity Pricing

Automatic Generation Control (AGC)

"AGC systems enable a grid operator to centrally and automatically manage the output of interconnected generators, storage devices, and controllable loads to maintain system frequency and inter-area transmission flow schedules."[45] This is used to balance out the

[45] Grid-Friendly Renewable Energy: Solar and Wind Participation

imbalances in transmission flows and grid frequency (area's control error, ACE) that can occur due to uncertainties in demand and supply.

ACG can also be used in cases of disturbances, such as a generator malfunction, loss of a transmission line or a major load. Conventional generators can have ACG function added as a supplementary control in the turbine governing system. Based on calculations of the required grid balance, economic efficiency, and technical specificities of each unit and of the grid, desired generation setpoints are set for each generator. Two automated setpoints are set for each generator: the basepoint and the regulation. The base point is the economic dispatch point, while more technical parameters (such as ramp rates and operating limits) are used to set the regulation point.[46]

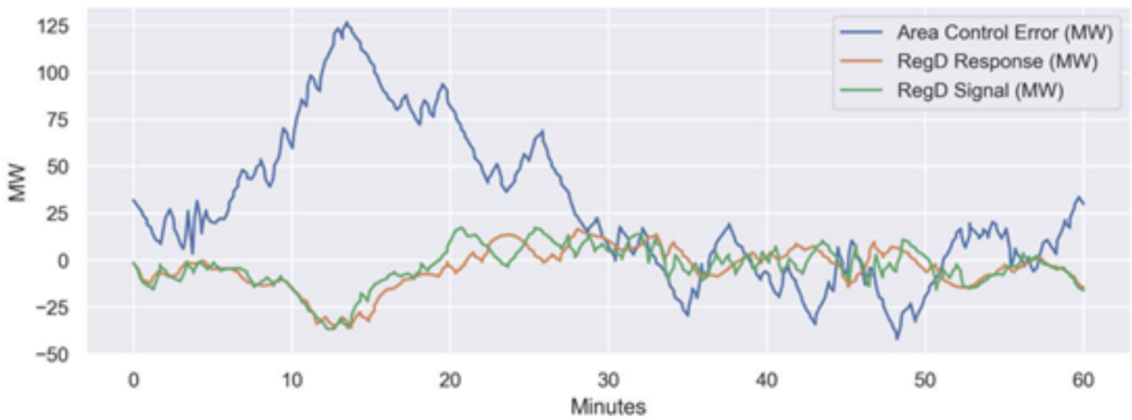


Figure 8. Using a regulation signal to correct the ACE in ERCOT. Figure adapted from Kirby et.al 2010.

An example of how the regulation product (RegD) works in the Texas grid. "The ACE is trending up, the RegD signal increases generator output and reduces participating loads; when the ACE trends down, generator output is increased and loads are reduced to help restore ACE to zero." Taken from Grid-Friendly Renewable Energy: Solar and Wind Participation.

VRE can also participate in providing ACG services; for example, a solar plant willingly curtails part of its power output (using the inverter), and then provides it when requested by the system operator. VRE can also reduce their output through ACG, when there is overproduction in the system. Given that the marginal costs for generating electricity are near-zero for such sources as solar and wind, they will only participate in ACG if the economic benefits offered by the regulator are higher than what they would otherwise gain from the market.[47] AGC can also be incorporated with energy storage systems and, as the smart grid develops, with electric vehicles.[48] Many countries combine their efforts to build common ACG systems. "Denmark's National Transmission System Operator (Energinet. dk) has established a secondary regulating strategy for building larger markets of automated secondary reserves in collaboration with the German and Nordic Transmission System Operators".[49] Energinet.dk purchases 90 MW of

[46] Grid-Friendly Renewable Energy: Solar and Wind Participation
[47] Ibid
[48] https://mdpi-res.com/d_attachment/energies/energies-14-02376/article_deploy/energies-14-02376-v2.pdf?version=1619314219
[49] ibid

reserves per month to balance out flows in the Danish grid.[50] Germany has a decentralized ACG, as there are four regions operated by different TSOs.[51] Spain and Northern American countries likewise deploy ACG in their system.[52]

While ACG has existed for quite a while, various control methods have been developed as the technology progressed. A table summarizing the advantages and disadvantages of each control method is presented below. A more detailed overview of each type and recent literature and models can be found at [Automatic Generation Control Strategies in Conventional and Modern Power Systems: A Comprehensive Overview].

[50] ibid
[51] ibid
[52] ibid

Table 5. ACG control methods.

Sr. No	Control Method	Main Advantages	Drawbacks
1	Classical Control Methods	• Simple and easily implementable • Quickly provide transient and stability information's • Low initial cost and plan structure • Feedback controller	• Poor dynamic performance • Only valid for LTI and SISO systems • No very accurate and has poor quality • Low resistance to sensor and actuator faults
2	Optimal and Sub-optimal Control Methods	• Work in the MIMO system • Can handle non-linearities and delays • Can handle constraints on input and output.	• Requires observers • Complex structures and requires special configuration for a problem • Requires large storage space
3	Adaptive Control Methods	• Worked cell for a non-linear system with uncertain parameters and slow time response [51] • Offer a quick approach to change parameters in response to changes in process dynamics • Suitable for a system with limited conditions	• The complication in a system with large time delays • Risk of failure of estimation module • Mostly not consider the transient response • Not practical for a system having a large dimension
4	Variable Structure Control Method	• Low sensitivity to parameters uncertainties • Handles non-linearities • Worked for a large order system • Finite-time convergence • Versatile control features	• Complex structure • State equation requires an observer • Chattering issue due to imperfect implementation
5	Robust Control Methods	• Used in multivariable systems • Provides the best functionality for a system with uncertainties and external disruptions • Past knowledge about uncertain inputs is not required.	• Not practical for a system having large dimensions and extensive parameter variations
6	Model Predictive control methods	• Can handle constraints explicitly • Optimizes the current time slot, while keeping future time slots in account • Works effectively in a system of multi-variable with bounds • Good capability of shifting the peak load	• Complex algorithm, which takes a longer time to execute than the ordinary one
7	Digital Control Methods	• Precise and reliable method [20] • The proposed controller has a smaller size • Adaptable and less noisy	• Appropriate selection of the digital controller is only feasible if the program requirements and the digital controller features are well defined.
8	Fuzzy logic-based control methods	• Instinctive design. • The rules demonstrate control action • Controllers may be set up through practice and the use of novel rules. • A specific model is not required.	• Problem with comprehensive rules and their durability. • Use of trial-and-error for optimization • Large number of tuning parameters • Stability is not certain.
9	ANN-based Control Methods	• Works well for a system with nonlinearities and uncertainties • Ideally suitable for multivariable and complex systems • No exact model is required [21] • Can be applied as feed-forward control.	• A large number of parameters are required for the adjustments • Size and structure are important to be determined • Can mostly be used in the trained region
10	Neuro-fuzzy based Control Methods	• Combines properties of a neuro network and fuzzy logic • Ideal for small system power systems • Can perfectly tackle system uncertainties and non-linearities.	• Problem with comprehensive rules and their durability for bulky power systems. • Difficulties in the analysis of the control system • Weak constraints handling

Demand management and the role of aggregators

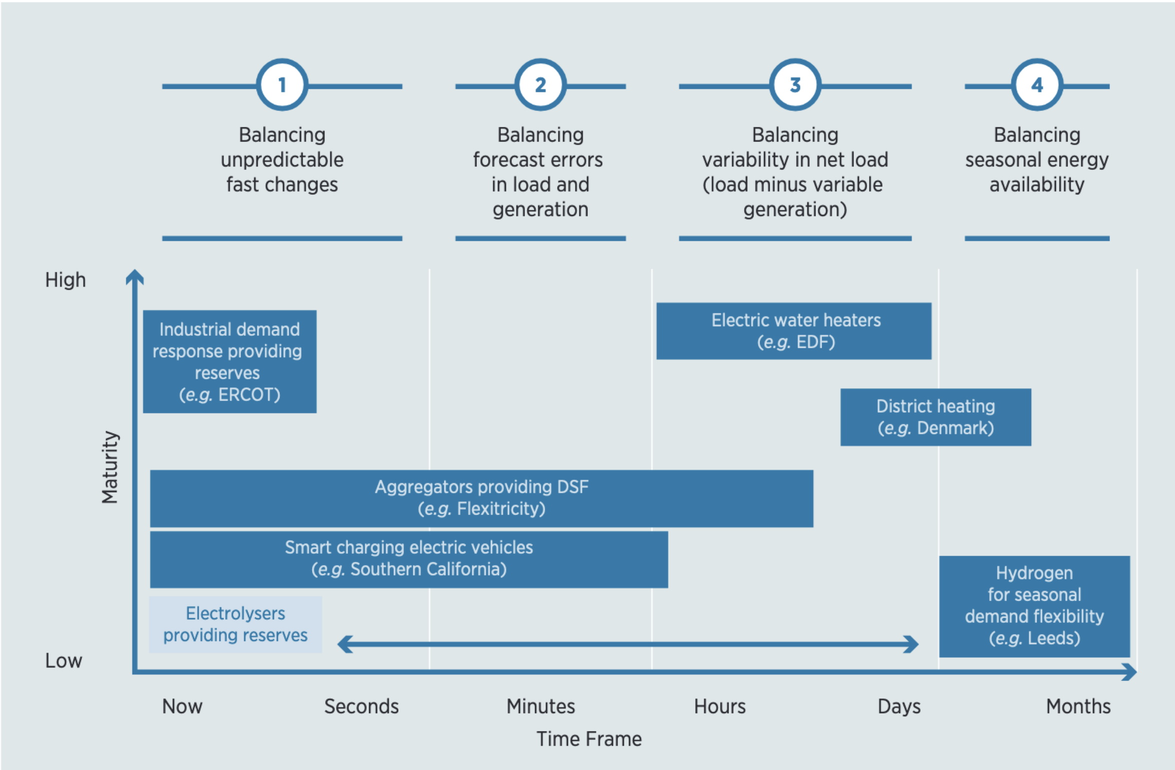


Figure 9. Demand-side flexibility real applications classified by technological maturity and flexibility time scale. ***Source:*** Demand-side flexibility for power sector transformation

Demand-side management is an important tool for matching supply and demand. While pricing strategies incentivise adjusted consumption on behalf of the consumers, smart technologies allow for automated demand response based on algorithms or centralised control. An important role here can be played by aggregators. The idea is that an individual consumer may not care much about adjusting demand, especially if the gains are negligible. However, a large number of consumers adjusting their demand can produce not only significant overall economic gains, but also provide significant services to the system by shifting the load to match supply. For example, an aggregator could purchase the right to utilize a heat pump from an individual household, being obligated to keep the comfort conditions within certain limits. The aggregator purchases such rights from a large number of households, and then provides a service of load reduction or shifting to the system operator when there is a shortage of supply.

Table 6. Key features of leading aggregators. **Source:** Aggregators – Innovation Landscape Brief.

Aggregator	Country / Region	Key features
AGL	Australia	• AGL's VPP consists of a network of behind-the-meter batteries providing a range of benefits to the household, the retailer and the local network. The VPP aims to both cut consumer electricity costs and help maintain grid stability in South Australia (AGL, n.d.).
Eneco CrowdNett	Netherlands	• Founded in 2016, Eneco CrowdNett is a Dutch-based aggregator of home batteries and provides grid services through a network of behind-the-meter batteries owned by prosumers. • Consumers are provided batteries at a discount and receive an additional EUR 450 annually in exchange for access to 30 % of the battery capacity at any time during the day (Hanley, 2016).
Energy & meteo systems (emsys)	Germany	• Emsys supports power aggregators in efficient market integration of their power assets. • Emsys's offering in VPP includes: connection to distributed power plants through various interfaces, real-time data management, remote control of wind and PV (e.g., to avoid negative spot market prices), generation forecast optimisation, energy scheduling, trading on the day-ahead and intraday spot markets, provision of balancing power by distributed power plants (primary, secondary and tertiary control), provision of balancing power by wind farms (tertiary control in Germany), demand-side management and balancing group management. • Emsys is one of the first aggregators to execute primary control using batteries in the German balancing power market.
Next Kraftwerke	Europe	• Next Kraftwerke is a network of multiple power-producing and power-consuming units of varied sizes distributed across Europe. • Next Kraftwerke forecasts the approximate production and consumption of energy on a real-time basis for the balancing group. It then transmits the schedule to the TSO on a daily basis and trades the forecasted volumes on the day-ahead market on the stock exchange. Deviations from the forecast are compensated through intraday trading. • Next Kraftwerke's VPP delivers ancillary services (primary reserve, secondary reserve, tertiary reserves) in seven European TSO zones and uses its algorithms to send optimised schedules to the networked units to benefit from peak pricing on wholesale markets. • The VPP consists of around 5 500 units amounting to over 4 500 MW (Next Kraftwerke, n.d.).
Stem	United States	• This California-based start-up with artificial intelligence technology focuses on behind-the-meter energy storage systems and VPPs. • It uses energy storage systems to reduce the cost of electricity for commercial consumers. The batteries are charged when the cost of electricity is low and discharged when the cost of electricity is high (typically during peak demand period). • Stem can use its software to reduce the net demand of its customers, thereby reducing the demand of the whole area when the existing supply system cannot supply in the local area (Stem, 2019).

EVs could also be charged using smart algorithms, to ease the burden on the grid. With a price-based charging algorithm, EVs can be coordinated to minimise costs and reduce peak hour consumption. In large numbers, a centralised algorithm is not necessary: with sufficient numbers, "egoistically" charging EVs would also achieve the optimal consumption pattern.[53] In addition to smoothening the load curve and adjusting it to supply, EVs could function as a form of distributed storage for residential homes.[54] Examples of existing electric vehicle projects are 6000 EV charges that provide a 30 MW virtual battery through an aggregator (in California) to reduce system load, and 10 vehicle-to-grid chargers in Denmark with 100 kW

[53] Price of anarchy in electric vehicle charging control games: When Nash equilibria achieve social welfare

[54] Taibi, 2018

overall maximum power, once again under an aggregator becoming participants in the power system.[55]

Advanced weather forecast

More precise forecasting helps reduce the uncertainty of VRE generation and better plan the dispatch of various generators and balancing of the grid. For this, years of data have to be collected to provide better grounds for modelling and predictions. The use of artificial intelligence can greatly enhance the precision of renewable energy generation prediction from 88 % accuracy to 94 %, while 30% improvements in accuracy for solar irradiation predictions have been achieved.[56]

Other tools for transmission grids with high VRE

Synchronous Condenser

Source: Synchronous Condenser – ENTSO-E

"A synchronous condenser (also called a synchronous capacitor or synchronous compensator) is a DC-excited synchronous machine (large rotating generators) whose shaft is not attached to any driving equipment. This device provides improved voltage regulation and stability by continuously generating/absorbing adjustable reactive power as well as improved short-circuit strength and frequency stability by providing synchronous inertia. Its purpose is not to convert electric to mechanical power or vice versa, but to make use of the machine's reactive power control capabilities and the synchronous inertia. It constitutes an interesting alternative solution to capacitor banks in the power system due to the ability to continuously adjust the reactive power amount. Synchronous condensers are perfectly suited to controlling the voltage on long transmission lines or in networks with a high penetration of power electronic devices as well as in networks where there is a high risk of 'islanding' from the main network.

- ***System inertia:*** *Inertia is an inherent feature of a synchronous condenser as it is a rotating machine. The benefit of inertia is improved voltage 'stiffness', which improves the overall behaviour of the system.*
- ***Increased short-term overload capability:*** *Depending on the type, a synchronous condenser can provide more than two times its rating up to a few seconds, which enhances system support during emergency situations or contingencies.*
- ***Low-voltage ride through:*** *Even under extreme low voltage contingencies, it remains connected and provides smooth, reliable operation.*
- ***Fast response:*** *By using modern excitation and control systems, a synchronous condenser is fast enough to meet dynamic response requirements.*

[55] Demand-side flexibility for power sector transformation

[56] Innovation landscape for a renewable-powered future

- ***Additional short-circuit strength:*** *Another feature of a synchronous condenser is that it provides real short short-circuit strength to the grid, which improves system stability with weak interconnections and enhances system protection.*
- ***No harmonics:*** *A synchronous condenser is not a source of harmonics and can even absorb harmonic currents. This feature enables ease of integration into existing networks. Typical applications of a synchronous condenser include: HVDC (provides short-circuit strength and dynamic reactive power support); Wind/Solar (increases short-circuit ratio); Grid Support (improves weak AC grid performance, voltage support during faults and contingencies, limits ROCOF); and Regulation (can replace dynamic voltage regulation and inertia from retired units). Disadvantages include higher level of losses, mechanical wear and a slower response time compared to power electronic technologies. It should also be mentioned that over the last three decades, a preference for synchronous condensers was given to alternatives based on highly dynamic, low-loss and low-maintenance power electronics solutions. As of today, in a world with the massive penetration of renewable energies, they again constitute a robust solution to ensure system stability in a scenario of the high penetration of renewable generation, and thus they play a role in the planning of the future grid."*

Synchronous condensers are a well-established technology. An example is Denmark using it on their HVDC interconnections to aid grid stability. Armenia could use this on the future Armenia-Georgia DC interconnection.

Enhanced flexibility of conventional generators

Enhancing the ramp-up and power performance flexibility of conventional generators has been one of the approaches in managing VRE systems; an example can be brought of CHP plants' enhanced flexibility in Denmark.[57] Similar technologies could be introduced in Armenia's CHP generation; more importantly, potential for gas-powered plants' flexibility should be explored.

Dynamic Line Rating

Source: Dynamic Line Rating: Innovation Landscape Brief

"DLR refers to the active varying of presumed thermal capacity for overhead power lines in response to environmental and weather conditions. This is done continually in real time, based on changes in ambient temperature, solar irradiation, wind speed and wind direction, with the aim of minimising grid congestion." The ampacity of the line depends on multiple factors, including weather conditions and tension. Normally, the rated ampacity of a line is fixed, anticipating worst conditions; however, with sensor monitoring, it is possible to evaluate in real time what the current ampacity is, and optimise electricity flows accordingly. This means that most of the time de-facto ampacity is higher than rater (static) value, allowing to avoid unnecessary investments into the grid. This is especially useful for wind power transmission, as areas that generate lots of wind power would correspondingly be ones where

[57] Development and Role of Flexibility in the Danish Power System

the temperature is cooler, and the ampacity is higher. DLR has been introduced in a number of countries, often leading to dozens of percentage point increases in ampacity.

DLR can be used overall in Armenia's transmission system; while it is relatively uncostly, priority could be given to the specific lines which could be placed under transmission constraint due to VRE integration. Moreover, the new lines that would be built for connecting future wind turbines to the grid could also be employed with DLR; as these areas are by definition windy, the investment cost could therefore be economised.

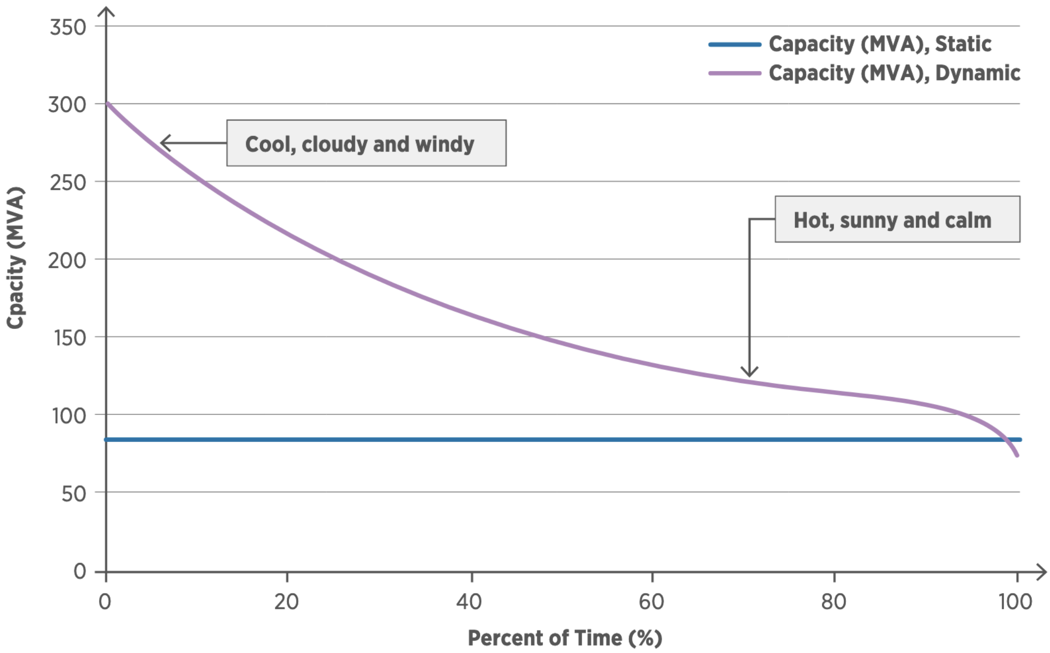


Figure 11. Schematic comparison of static and dynamic current limit.
Source: Dynamic Line Rating: Innovation Landscape Brief.

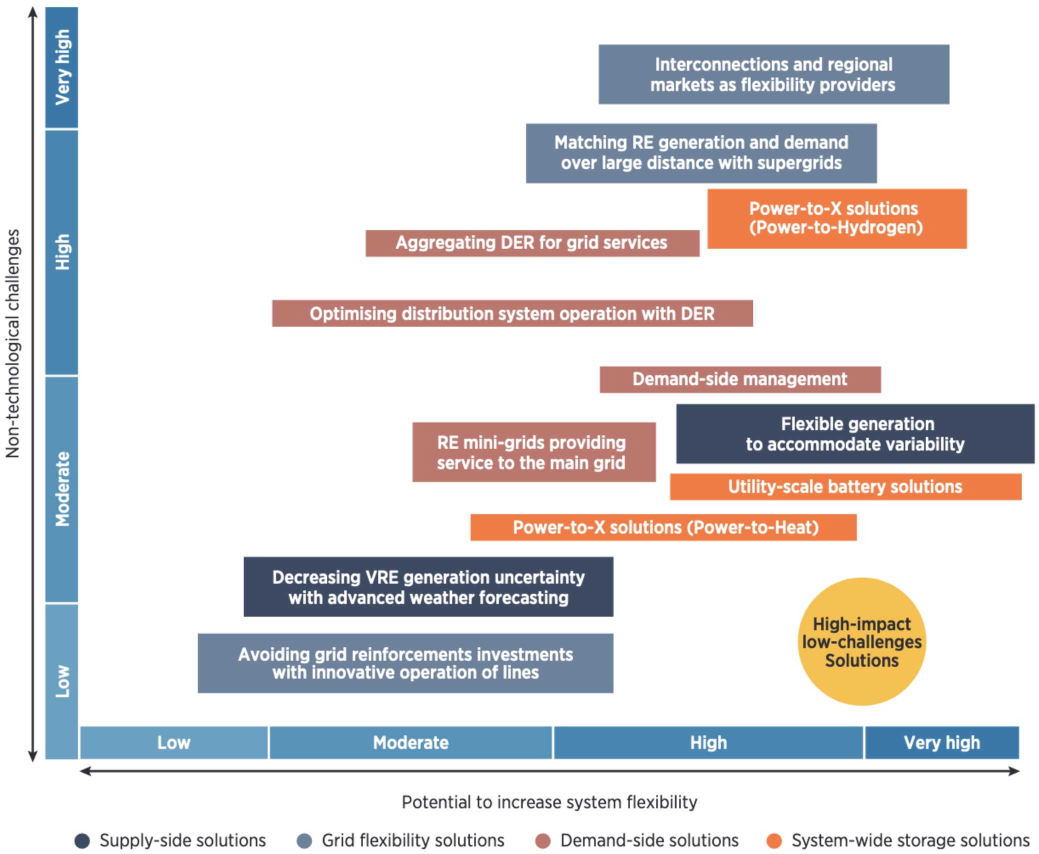
Conclusion

As was outlined in the introduction, limited availability of resources to handle high VRE shares makes smart energy and other solutions a priority for Armenia's energy independence. Smart grid (and the other solutions described above) has significant potential to increase the attainable level of independence and security; however, substantial investment costs and institutional complexity are often required (see the graphs on the next page). In both cases, Armenia is limited as of now. The financial resources are relatively scarce, and the institutional development is behind that of first-world countries.

In some places, compromises have to be made. Real-time pricing for residential consumers might be the best solution in theory, but requires more extensive infrastructure and regulatory framework than simpler (such as critical-peak pricing) approaches. Power-to-hydrogen solutions are not only technologically and non-technologically complex, but are unlikely to have a significant positive impact on energy independence for Armenia.[58] Decreasing VRE uncertainty and innovative operation of lines (such as dynamic line rating) are among the low-

[58] See the discussion on hydrogen

hanging fruits, while aggregators may play a significant part in the future. Some approaches (such as innovative ancillary services) can cut costs and provide significant potential for energy independence increase, but require a more liberalized market and efficient regulation. A mapping of various solutions will provide an idea of the costs and benefits for energy independence in Armenia's context. In the absence of liberalized markets and efficient regulation, advanced on system operator's level are expected first, while institutional development and liberalization should be prioritised in the medium to long-term.



Note: Non-technological challenges include required regulatory changes, required changes in the role of actors, and other challenges.

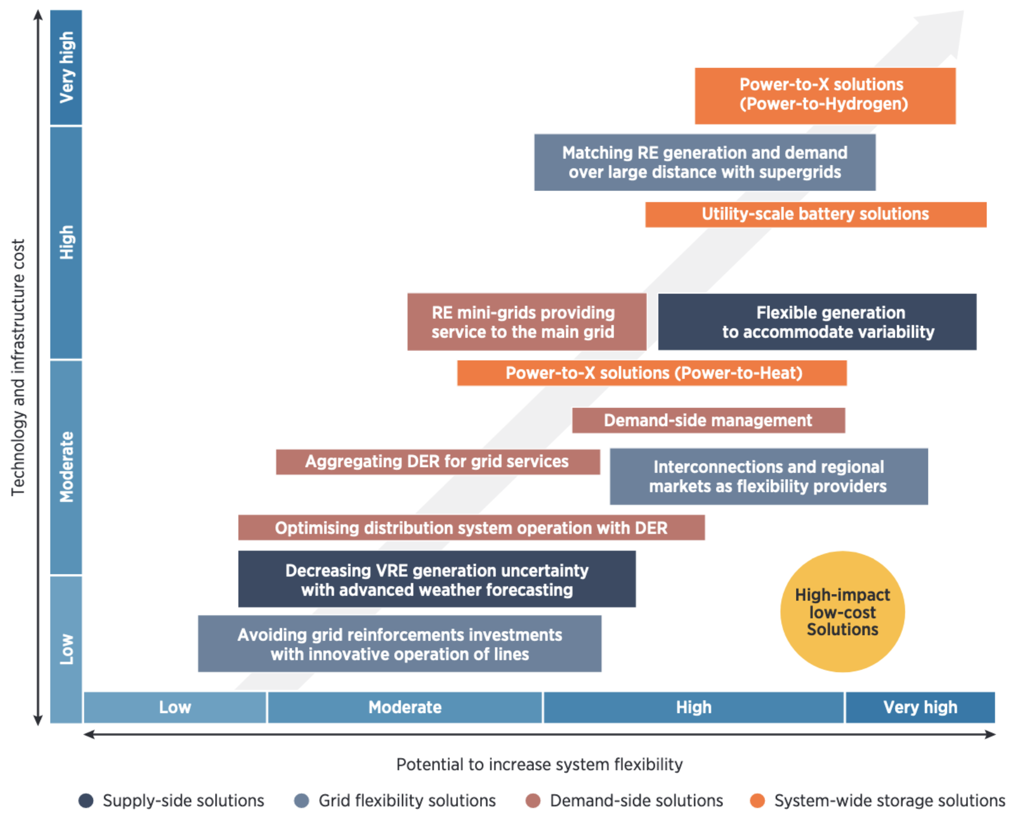


Figure 12. Flexibility potential vs technology costs (top) and non-technological costs (bottom) of various solutions, by Innovation landscape for a renewable-powered future (IRENA, 2019).

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PUBLIC TRANSPORTATION

In its Nationally Determined Contribution, Armenia specifically mentions electric transportation as the main contributor toward GHG mitigation for the transport sector. The Yerevan Master Plan for 2006–2020 plans to increase the passenger share of trolleybuses from 3% to 24%. While replacing diesel and gasoline vehicles by electric ones is one way to reduce dependency on natural gas and petroleum products, cutting the overall demand for vehicles through public transportation can be an additional important measure. The shift to low-carbon public transportation is a way to cut demand and reduce fossil fuel-dependency simultaneously, and is an important factor for large-scale decarbonisation of the transport sector, particularly when it comes to metropolitan and inter-city travel.[59,60] At the same time, it should be noted that, depending on occupancy rates and the type of technology being used, private cars can be more energy efficient than public transportation.[61]

There are many options for integrating public transportation with local and renewable-based energy. Electric, hybrid, and biofuel-based buses have been deployed around the world, with bus rapid transit (BRT) systems being particularly advantageous due to such features as dedicated bus lanes and off-board fare collection.[62] BRT systems also tend to have lower capital costs compared to other public transportation, such as light rails (1.5 - 2.6 times more expensive) and metro (5 - 9 times more expensive).[63] Rail-based systems have likewise been integrated with renewables: an example can be the Bay Area Rapid Transit System in the US, which procures electricity under two power purchase agreements with a wind farm and a solar PV plant, covering 90% of its needs.[64] In addition, it has its own solar systems installed at various locations, providing an additional source of renewable power.[65] A number of other cities power their metro systems in part from renewables, such as solar, wind, biogas, and hydropower.[66]

Transportation represents about ⅓ of the energy consumption in Armenia,[67] characterized by its out-of-age bus, truck and car parks. The share of cars is particularly high in Yerevan, with almost 40% of vehicles being registered there.[68] Development of efficient public transportation in the capital, as well as inter-city communication, should be the primary focus from the point of view of energy savings. Introducing new routes and bus networks can reduce the required number of public transportation vehicles in Yerevan by a factor of two, while the total annual mileage can be reduced by a factor of four.[69] It would cost an estimated 120 mln USD to purchase a new public transportation fleet for Yerevan accordingly; however, replacing all those vehicles with electric ones would cost about three times higher, at 354 mln USD.[70] In

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[59] The Renewable Route to Sustainable Transport, a working paper based on REmap
[60] Transportation in a 100% renewable energy system - ScienceDirect
[61] OECD Proceedings Towards Sustainable Transportation p 48
[62] Renewable Energy Policies for Cities : Transport (Irena, 2021)
[63] Ibid
[64] Ibid
[65] Ibid
[66] Ibid, p 23
[67] Https://www.Iea.Org/Countries/Armenia
[68] Reforms of Yerevan Transport System in the Context of Low-Carbon Development Policy
[69] Ibid
[70] Ibid, with an exchange rate of 1 AMD = 0.0021 USD (as of 2020).

case of an all-electric vehicle fleet, with all costs combined, the municipality will need 71 million USD annually over a period of 12 years, resulting in a total financial commitment of 852 million USD over that period.[71] The main options for electric buses in Yerevan would be the renovation and upgrading of existing trolleybus lines, using opportunity charge buses (i.e. fast recharging throughout the network) for high frequency routes, and battery e-buses with various charging regimes.[72]

Purchasing new fossil fuel bus units will lock Armenia into high carbon emissions by the public transport sector for approximately the next 2 decades, and does not take advantage of the country's very low carbon grid factor and the availability of a national power source for buses.[73]

On December 10, 2021, the National Assembly adopted the law "On Amendments to the Tax Code of the Republic of Armenia", according to which VAT exemption for the import and disposal of electric vehicles (large, medium and small buses, cars, motorcycles and mopeds) was extended until January 1, 2024. On March 17, 2022, a quota was set for the import of vehicles with electric motors into the RA territory without payment of import duties, in the following quantities: for 2022 – 7000 pcs.; for 2023 – 8000 pcs. The mentioned tariff privilege is planned until 2023 December 31 inclusive.

However, such growth rates are inadequate to achieve a substantial effect in energy independence increase. Considerable growth in the rate of replacement of ICE vehicles with electric vehicles in the coming years is required, which can be done through the introduction of a new legislative framework and using financial instruments.

To properly estimate the potential of public transportation in reducing energy dependence of Armenia, the following points need to be evaluated:

1. The potential of public transport to reduce the demand for private transportation, for travel within cities and between them.
2. The potential to supply public transportation with alternative forms of energy (including electricity)
    a. an analysis of grid constraints and necessary investments in case of electrified transportation, particularly in Yerevan.
    b. public transportations is mainly used during daytime, so a particular attention must be paid to the source of (green) energy to fulfill the needs in terms of electricity.
    c. green energy can be very dependent on day to day weather (sun and wind), so the Yerevan Transport needs to be in constant communication with the main electricity providers.
    d. development of centralized optimization algorithms and traffic management for public transportation operation in the cities.

[71] ibid

[72] E-Mobility Options for ADB Developing Member Countries (SDWP No. 60), p 97

[73] ibid

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ARMENIA'S ENERGY INDEPENDENCE ROADMAP

MAJOR STEPS AND MILESTONES

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1. VISION

The state energy policy, as declared in the budget message of 2022 of the Government of Armenia, aims at increasing the level of energy independence and security to ensure consumers with a reliable supply of high-quality electricity and gas.

It also states that the fundamental direction of sustainable development of the energy sector is an economically justified, efficient and responsible use of renewable energy potential; the development of nuclear energy; building of a reliable export-oriented power system, new generating facilities with modern technologies along with regional integration of the power system, diversification of energy supply, introduction of energy efficiency and energy saving policies, and digital transformation of the energy field.

Certain preconditions for Armenian power sector development have been built by legal and regulatory tools, creating beneficial conditions for commercialization of the local renewable energy resources.

The new model of the gradually liberalizing electricity market has been put into place since 2022. It aims to create a competitive environment and stimulate investment and trade. The efforts for the formation of common electricity and gas markets for the Eurasian Economic Union are supposed to follow up.

The roadmap as a whole follows the goals and objectives of the state policy of energy independence of Armenia. However, the roadmap sets a much more ambitious level of utilization of domestic renewable energy resources; envisages a high level of penetration of the most up-to-date network technologies and off-grid solutions; promotes the most advanced market-based policies and instruments aimed at maximizing the possible use of the country's domestic renewable energy potential.

The roadmap outlines a pathway to fundamental transformation through the integration of modern, clean energy sources and establishing effective institutional mechanisms to pave the way for attaining higher levels of independence. A significant update of the existing legal and regulatory framework will be important to achieve the ambitious goals of boosting Armenia's energy independence.

Thus, the roadmap features the vision of achieving sustainable, safe and efficient operation of the Armenian power system, integrated with the regional energy infrastructure and capable of maintaining the required level of independence from a single supplier.

According to the roadmap, the full de-gasification of electricity generation can be achieved by 2040, with natural gas serving as a backup source for extreme events or during nuclear plant refueling or maintenance when it will be substituted by a combination of natural gas and electricity imports, depending on prices. Over spring and early fall, hydropower will continue to provide much of its clean electricity generation; solar power will be at its highest in the summer, while wind will be high in the winter.

In heating, fossil fuels will likewise remain important, though alternative sources such as heat pumps, solar thermal energy, and biogas will substitute significant shares of natural gas. The use of natural gas in the transportation industry will remain significant, however, with the rise in electrified public and private transportation, the demand for both natural gas and petroleum products will gradually decrease. The increased demand for electricity for heating and transportation will be covered by various environmentally friendly energy sources, such as nuclear, hydropower, wind, solar, bioenergy, etc.

The country's energy system will be integrated with neighboring energy systems of Georgia and Iran, becoming part of regional electricity markets, which will eliminate the risks associated with importing fossil fuels.

While nuclear power will remain a key contributor to security, the role of natural gas in the electric power industry will be reserved only for backup options.

The rapid technological development and changes in the domestic economy may be harder to predict even over the next two decades, which is part of the reason why this roadmap does not go beyond 2040-2050. However, it is essential to have the right set of incentives and rules to move the energy system to a more efficient paradigm, no matter how precise the roadmap scenarios are. The proper institutional arrangements should be a precondition to the expansion and diversification of generation capacities.

The variability of wind and solar energy creates additional challenges to power system operation. In such conditions, the industry needs to establish an effective regulatory framework for the functioning of electricity markets that promotes flexible operation management on both the production and demand sides and provides fast and appropriate price signals to manage constantly changing supply and demand. The introduction of a flexible pricing system and competition in retail trade in the power system will lead to more efficient energy consumption. Battery storage, pumped hydropower reserves, and imports will aid in managing the variable renewable generation on a daily basis, while smart grid and market transactions will facilitate the process. The country will have, by then, an abundance of data on meteorological and weather conditions, demand and supply variations, and other information required for efficient management of the grid. It will have a developed security system (both cybersecurity and physical enhancement) to protect the critical infrastructure and energy markets against external threats.

Decentralized energy generation, efficient development of autonomous grids (mini- and microgrids), and other distributed generation systems integrated with end-users such as electric vehicle chargers, will reduce the load on central grids and thereby contribute to the stability of operational regimes and energy security. Specific regulations, in this regard, should address end-of-life disposal management (e.g. chemical batteries for electric vehicles, charger depots).

In a more general sense, we envision a system where costs and benefits are fully accounted for and balanced accordingly, including such things as environmental costs, costs of grid management, as well as corresponding benefits. In any case, proper government regulation should be aimed at adjusting market behavior to achieve the optimal outcome; in other cases (for example, network expansion and strengthening) centralized decisions will be made based on modeling and specific cost-benefit analysis. A developed production of local energy, diversified supply, and efficient utilization of energy domestically are the key features that such a system will have.

Taking into account the pace of development in the introduction of new capacities and technologies and the degree of transformation of the energy industry of Armenia as a whole. It is necessary to periodically update the road map taking into account development trends in both the technical and geopolitical aspects of Armenia. Practice shows that this must be done at least every two years, while collecting information and monitoring development trends and changes in the main directions of development must be carried out continuously.

2. RENEWABLE ENERGY POTENTIAL

Solar energy resources

Armenia has significant solar energy potential: average annual solar energy flow per square meter of horizontal surface is around 1700 kWh (the European average is 1000 kWh). One fourth of Armenia is endowed with solar energy resources of 1850 kWh/m². Under different conditions, the average annual incident total solar radiation (i.e., radiation integrated during the year per unit of horizontal surface) on the territory of Armenia ranges from 140 to 155 kcal/cm².

The study evaluated the potential of solar water heating (SWH) and photovoltaic systems (PV) to contribute to national energy security through end-use and primary energy reduction.

A conditional SWH system with a 300-liter storage tank with assumed 80 % efficiency generates daily, averaged over a year, 15.4 kWh of thermal energy to supply hot water for about eight hours a day for the demand of 4–5 residents with the annual energy production per SWH unit around 5633 kWh. With penetration rate of 400,000 rooftop SWHs by 2041, it is able to replace yearly about 153.7 million m³ of natural gas and 360 519.6 MWh of electricity to cover water heating demand, and by 2050 - 230.6 million m³ of natural gas, and 540 779.5 MWh of electricity.

With the same penetration rate of solar PV systems, 400,000 individual family houses equipped with 3.56 kW solar PV systems will generate 2.16 GWh annually, which is equivalent to 204.6 million m³ of natural gas (in terms of energy value 10.55 kWh per m³). If the penetration tendency continues further to the 25th year, 560,000 solar PV systems will be installed reaching 2 075.8 MW in total and yearly generate 3.02 GWh equivalent to 296.7 million m³ of natural gas.

Biogas

Biogas can be used for the same purposes as natural gas, including heating, electricity generation and, after being upgraded, as a fuel for vehicles. Biogas can be obtained from a wide range of different feedstocks: agricultural waste (livestock manure, plant residues), industrial waste (sewage sludge, food industry waste, slaughterhouse waste) and household waste.

The largest underutilized resources for biogas production are in the agricultural sector. Animal husbandry is the main source of environmental pollution in rural areas. There are about 170 thousand farmers and collective farms are engaged in cattle breeding in Armenia.

If the biogas farm penetration rate over ten years reaches 2 880 farms with total livestock of about 155 000 animals, the produced biogas will be comparable to about 70 million m³ of imported natural gas. The economic feasibility of investment is highly efficient, providing a payback period of 3 to 4 years.

Another major source for biogas extraction is landfill disposals of municipal solid waste (MSW). The average annual generation of MSW in Armenia today is estimated to be 1600 metric tons/day.

Biomass

Armenia is poor with natural forests. Wood logs from the existing forests are the only source for firewood in Armenia because there are no large scale energy crop plantations.

Considering the potential for using energy crops such as fast-growing trees and nearby agricultural residues, three sites for biomass production for energy purposes were identified in Armenia (study conducted in the mid-1990s). In the area of south-west Armenia within the Ararat Valley, sufficient biomass can be generated to fire a 25 to 35 MW boiler. An estimated 63 % of biomass can be generated from dedicated crops on unused or degraded agricultural land, the rest coming from agricultural residues. The second site around Lake Sevan in central Armenia can produce enough biomass for a 35 MW facility at Hrazdan with 58 % of the biomass coming from dedicated tree crops and much of the rest coming from existing plantations. The third area is in north-eastern Armenia where conditions are colder, forest residues are available, and energy crops would comprise only 10 % of the biomass supply. Biomass from this location would be sufficient to supply a 20 MW system in Vanadzor.

Bio-ethanol

A preliminary feasibility assessment for implementing a commercial scale bio-ethanol fuels study concluded with the following main findings and recommendations.

- A research mandate specifying 10 percent blending to provide the overall incentive and necessary push for establishing a new bio-ethanol industry in Armenia.
- The most promising bioethanol feedstocks that can be produced in large quantities on marginal lands in Armenia in the near to midterm include Jerusalem artichokes, cattle corn, sweet sorghum, and possibly chicory.
- The preferred scenario for developing a new bio-ethanol industry in Armenia today is promoting several (2 – 3) smaller bioethanol processing facilities in separate locations.
- The findings of an extensive institutional, legal, and regulatory review point to a need for classifying and treating bio-ethanol as a renewable energy resource.

Wind energy resources

Wind is a natural phenomenon, coming from the movement of the air during equilibrium phase between high air pressures to lower pressure area. Wind energy solutions can help Armenia achieve in the future a reasonable level of independence and reduce the effects of Green House Gas Effect.

The Global Wind Atlas (GWA), produced by the Technical University of Denmark since 2015 with the support of the International Finance Corporation and the World Bank Group, allows us to assess the wind energy potential of Armenia. The largest the windiest area is, the better it is, offering multiple solutions, taking in count the position of the main electric supply lines throughout the territory of Armenia. Building wind farms close to the main lines will de facto decrease the overall cost, as the wind farm need to be connected to them.

The following sites are of greatest interest:

- Sevan Lake area
- Mount Aragats area
- Sevan-Hrazdan area
- Sotq (Zod) area
- Syunik

At present, wind energy represents less than 1 % of the electricity production, and even less, due to maintenance problems. We believe that with appropriate investment support mechanisms in place, Armenia could easily meet 5 % of its electricity needs from wind power alone.

Hydro power

The state policy and strategic targets of the Republic of Armenia in the field of hydropower are determined by the regulatory framework and strategic development programs adopted in this area. The development opportunity of new HPPs according to the Hydro Energy Development Concept of RA of 29 December 2016 has mostly been completed. There is a challenge of raising the productivity of the existing SHPPs to correspond to the international technical and environmental standards.

A further increase in the number of small hydropower plants is expected. However, this growth will slow down due to a decrease in the volume of economically attractive hydro resources and stricter environmental requirements.

The pumped storage power plant (PSPP) is envisaged for commissioning by the master plan for the development of the energy system. PSPP, as a rule, are not considered as a renewable energy facility, but will become an effective tool for leveling the load curve.

Power System

Taking into account the natural potential of Armenia of solar and wind resources and the pace of introduction of new capacities based on renewable energy sources (at this stage, mainly solar), Armenia has great potential for further renewable energy development. However, introducing variable renewable energy sources requires ensuring the stability, safety and reliability of the power system. This can only be guaranteed by having base load capacities, such as thermal and nuclear power plants, as well as pumped power stations if water resources are regularly refilled. Gas, nuclear and hydro resources are therefore necessary for a reliable and safe power system operation. Additionally, two factors such as strengthening interconnections with neighboring power grids and constructing pumped storage stations are important for the development of variable renewable energy sources. Thus, the power system's development until 2040 was modeled taking into account all of the above considerations.

2. TPES STRUCTURE AND LEVELS OF ENERGY INDEPENDENCE BY SCENARIOS

The formation of energy development scenarios was based on an understanding of the importance of the role of energy independence for national sovereignty. The level of energy independence of the Republic of Armenia has been assessed based on the forecasts of the Energy Balance have been developed for 2030, 2040 and 2050.

The electricity sector plays a critical role in national energy independence, and its sustainability is determined by the following paramount attributes:

- For a landlocked country such as Armenia, diversification of the primary energy mix is vital for increasing and sustaining energy independence.
- Developed interconnections with power grids of neighboring countries. Interconnections are especially important as they allow for the growth of variable renewable energy capacities and increase country's independence.
- Development of transmission and distribution networks; connecting new power capacities.
- Penetration and development of innovative Storage Technologies, including chemical batteries at plant and/or grid level, as well as hydro accumulative storage using the landscape and climatic conditions of Armenia.
- Integration of Smart Grid technologies into the energy system, capable of predicting meteorological conditions, the magnitude and rate of change in consumption, as well as timely planning of the necessary power reserves, ensuring reliable power supply and safe operation of the system.

The study was based on various reliable data sources and forecasts, namely: expected economic development, commissioning of new generating capacities, demand trends in various consumption sectors (including industry, agriculture, services, residential sector, transport, and non-energy consumption), strategic development programs the energy sector, etc. Based on the results of a thorough study, three different scenarios for the development of the fuel and energy balance of the Republic of Armenia were formed. The scenarios – Baseline, Accelerated, and Aggressive - differ from each other according to the parameters described in detail in the full version of Roadmap.

One of the initial indicators of the energy balance is the primary energy supply (PES) by type of energy resource. To calculate, the initial data were converted from the named units into normalized units of energy. According to the IEA standard, a tone of oil equivalent (toe) is used as a conventional unit calculated based on the calorific values of a given energy resource.

The Baseline scenario includes all aspects of the transmission plan – safety, security, and reliability of the power system for 2040. It was developed through precise modeling and planning of the electric power system operational regimes while taking into account various factors such as criteria for the reliability and safety of the energy system operation, principles of building fuel and energy balances, diversification of energy resources and requirements for ensuring the security and independence of the energy industry. Despite the main milestone being set for 2040, the study considered prospective developments for 2050, taking into account the opportunities for expanding integration and penetration of wind and solar power plants into the overall energy system.

The Accelerated scenario takes the goals of the baseline scenario for 2050 and shifts them to 2040, the realization of which mostly depends on the economic affordability and maturity of the technologies to be applied. The existing technological and economic development trends are showcasing a relatively high probability of the Accelerated scenario. For the Accelerated scenario, the transmission plan of the power system also has been performed in all the main aspects through precise modeling and planning of the electric power system operational regimes on the same principles as for the Baseline scenario. There is only one main difference: the probability of changing plans in the case of the Accelerated scenario is higher than in the Baseline scenario. In this case, a revision of the transmission plan will be necessary.

The Aggressive scenario presupposes considerably higher wind and solar energy integration.

- about 2.5 times more production in solar PV installations compared to the accelerated scenario,
- about 1.5 times more in solar water heating installations,
- about 1.4 times more in wind power plants.

Justification for this scenario requires more in-depth research, which should, among other things, take into account the need to significantly strengthen distribution and transmission networks, create storage technologies such as pumped storage solutions for transmission systems, or use Li-Ion batteries for on-grid and off-grid solar photovoltaic installations in low voltage networks, or their mixed their mixed options in general. The preference for the mix option is conditioned by the fact that the behavior of the Li-Ion batteries during transient regimes of the power system is yet not satisfactorily investigated, and therefore use of such a storage method is questionable. On the contrary, pump storage technology has no such issues.

An in-depth transmission plan for distribution and transmission networks for the Aggressive scenario was not conducted as it is done for the Baseline and Accelerated scenarios. This is due to the uncertainty of the timing and occurrence of the various factors that are necessary consider for the Aggressive scenario. All in-depth transmission plan modeling, calculations and results described in detail in the main part of roadmap.

In the tables below, the 2040 forecasted balances of main fuel and energy resources expressed in nominal units are presented.

Electricity Balance 2040, million kWh

N		Baseline	Accelerated	Aggressive
1.	Import	0.0	0.0	0.0
2.	Export	-6556.4	0.0	0.0
3.	Stock changes	0.0	-992.7	0.0
4.	Nuclear power stations (MA El. Gen.)	6320.0	6320.0	6320.0
5.	Thermal power stations (MA El. Gen.)	4733.0	0.0	0.0
6.	Combined heat and power stations (CHP)	13.3	13.3	13.3
7.	Non-specified transformation output	0.0	0.0	0.0
8.	Hydro power stations (MA El. Gen.)	1396.0	1396.0	1396.0
9.	Small hydro power stations (MA El. Gen.)	820.0	820.0	820.0
10.	Wind power stations (MA El. Gen.)	1340.0	1340.0	1900.0
11.	Solar power stations (MA El. Gen.)	1901.0	2605.0	6544.8
12.	Consumption of the energy branch	-863.3	-705.2	-930.2
13.	Distribution losses	-580.0	-580.0	-580.0
14.	Industry	-3361.8	-3361.8	-3361.8
15.	Transport	-104.6	-757.1	-1895.5
16.	Households	-2775.7	-3617.4	-7301.5
17.	Agriculture	-102.0	-107.2	-185.8
18.	Services	-2179.5	-2373.0	-2739.3
	Total generation	16523.3	12494.3	16994.1
	Total consumption	-16523.3	-12494.3	-16994.1

** MA El. Gen. means Main Activity Electricity Generation*

Natural Gas Balance 2040, million m³.

N		Baseline	Accelerated	Aggressive
1.	Import	3128.6	1610.3	1084.6
2.	Export	0	0.0	0.0
3.	Stock changes	0	0.0	0.0
4.	Nuclear power stations (MA El. Gen.)	0.0	0.0	0.0
5.	Thermal power stations (MA El. Gen.)	-972.0	0.0	0.0
6.	Combined heat and power stations (CHP)	-3.8	-3.8	-3.8
7.	Hydro power stations (MA El. Gen.)	0	0.0	0.0
8.	Small hydro power stations (MA El. Gen.)	0	0.0	0.0
9.	Wind power stations (MA El. Gen.)	0	0.0	0.0
10.	Solar power stations (MA El. Gen.)	0	0.0	0.0
11.	Non-specified transformation output	0	0.0	0.0
12.	Consumption of the energy branch	-5.9	-5.9	-6.4
13.	Distribution losses	-83.3	-83.3	-124.0
14.	Industry	-399.6	-399.6	-399.6
15.	Transport	-633.5	-443.5	-172.6
16.	Households	-668.9	-465.0	-143.0
17.	Agriculture	-131.0	-131.0	-166.0
18.	Services	-230.7	-78.2	-69.2
	Total generation	**3128.6**	**1610.3**	**1084.6**
	Total consumption	**-3128.6**	**-1610.3**	**-1084.6**

Motor Gasoline Balance 2040, t

N		Baseline	Accelerated	Aggressive
1.	Import	200900.9	160842.7	111879.3
2.	Export			0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-20.1	-20.1	-20.1
7.	Industry	-79.1	-79.1	-79.1
8.	Transport	-200288.7	-160230.4	-111267.0
9.	Households	-513.0	-513.0	-513.0
10.	Agriculture			0.0
11.	Services			0.0
	Total generation	**200900.9**	**160842.7**	**111879.3**
	Total consumption	**-200900.9**	**-160842.7**	**-111879.3**

Diesel Oil Balance 2040, t

N		Baseline	Accelerated	Aggressive
1.	Import	177993.4	147395.0	113529.4
2.	Export	0.0	0.0	0.0
3.	Stock changes			0.0
4.	Consumption of the energy branch			
5.	Distribution losses			
6.	Final non-energy consumption	-1735.4	-1735.4	-1735.4
7.	Industry	-15226.3	-15028.2	-15028.3
8.	Transport	-143338.4	-114670.7	-86003.0
9.	Households	-366.7	-366.7	-366.7
10.	Agriculture	-17326.6	-15593.9	-10396.0
11.	Services			0.0
	Total generation	**177993.4**	**147395.0**	**113529.4**
	Total consumption	**-177993.4**	**-147395.0**	**-113529.4**

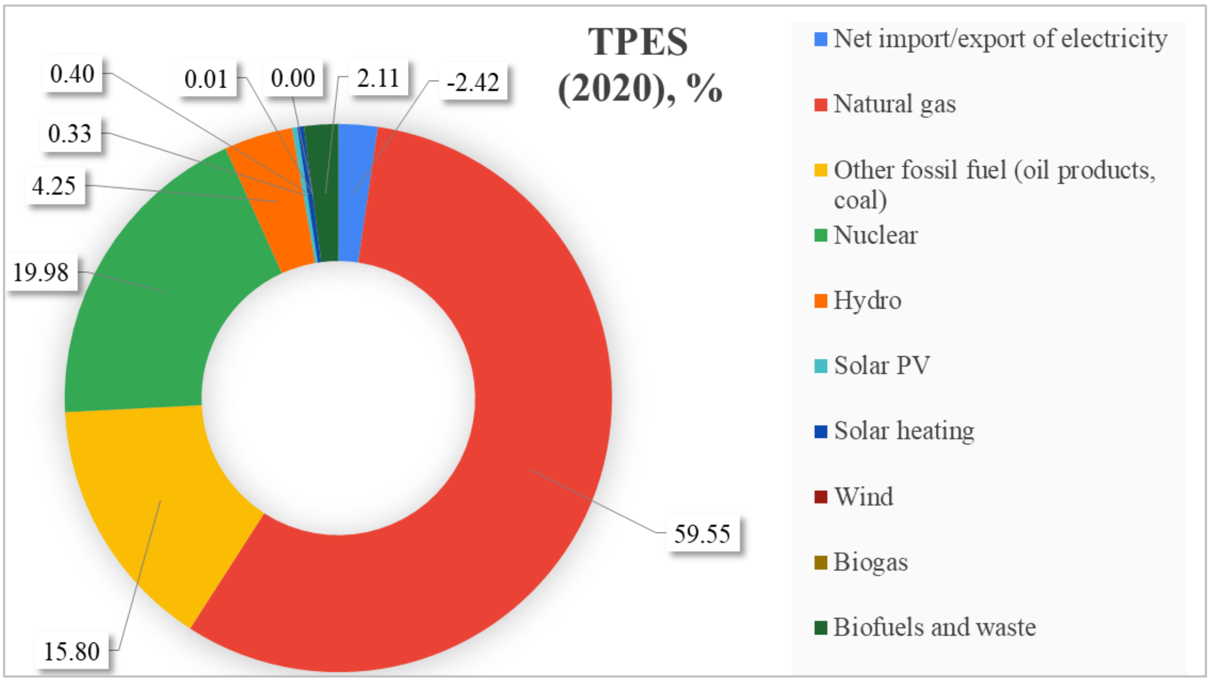
To assess the level of energy independence in each scenario, the values of the total primary energy supply (TPES) were determined and energy independence coefficients (EIC) were calculated. For the purpose of comparative analysis, the indicators of 2020 are given on the basis of official data published by the RA Statistical Committee. These indicators are presented in the table below.

TPES*, ktoe	Net electricity imp./exp.	Natural gas	Other fossil fuel (oil prod., coal)	Nuclear	Hydro	Solar PV	Solar thermal	Wind	Biogas	Biofuel and waste	Total	EIC, %
2020	-87.1	2141.2	568.1	718.2	152.9	11.7	14.3	0.2		75.9	3595.4	27.1
Baseline	-563.7	2554.9	524.4	1646.7	190.5	163.5	23.9	115.2		75.9	4731.3	46.8
Accelerated	-85.4	1276.3	450.6	1646.7	190.5	224.0	183.8	115.2	55.3	75.9	4132.9	60.3
Aggressive	0	818.2	364	1646.7	190.5	562.8	275.7	163.4	78.6	75.9	4175.8	71.7

*Total Primary Energy Supply

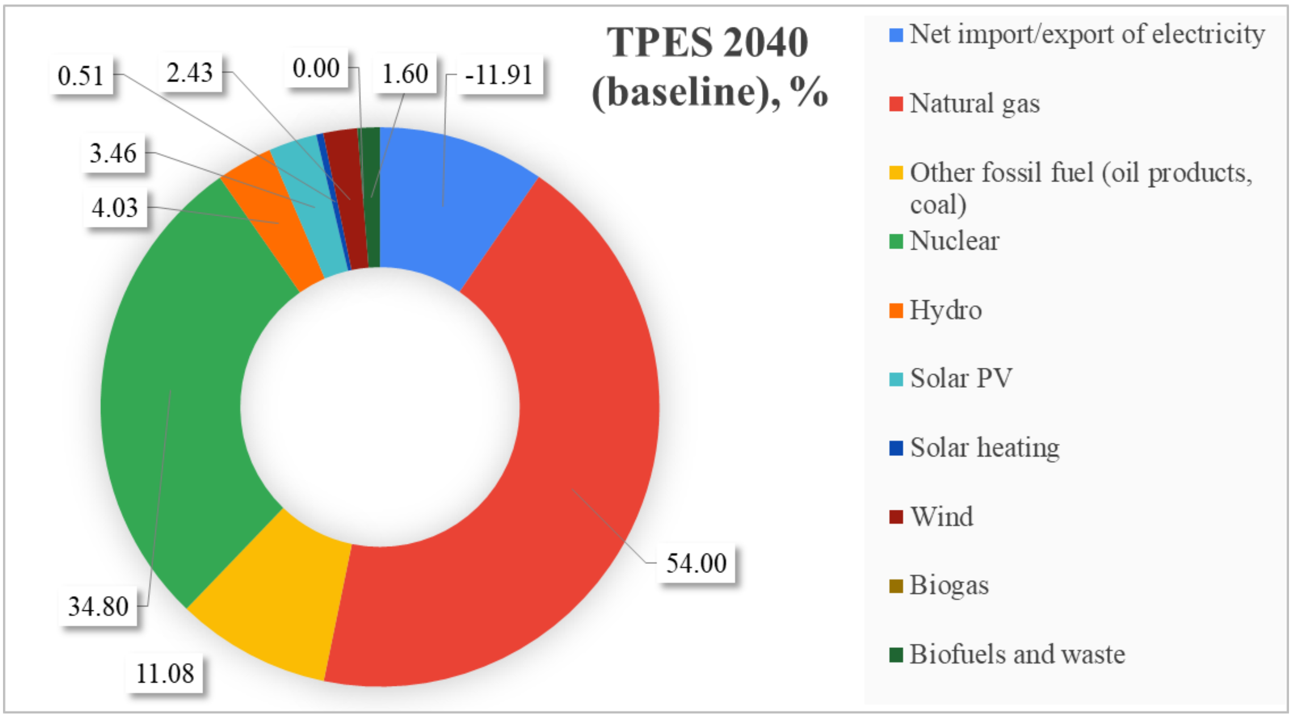
It should be noted that these figures do not fully reflect, and likely underestimate, the potential impact of the steps proposed in Roadmap. The effect of some steps, such as new trend in public transport, geothermal energy development, energy efficiency interventions and etc., was not quantified within this study and requires a separate analysis, though their impact may be significant. The quantitative effects of some of the steps presented in this Roadmap, such as new trends in public transport changes, development of geothermal energy, energy efficiency measures, etc., have been determined based on qualitative analysis and require separate study, since their impact may be more significant.

EIC for Baseline scenario by 2020



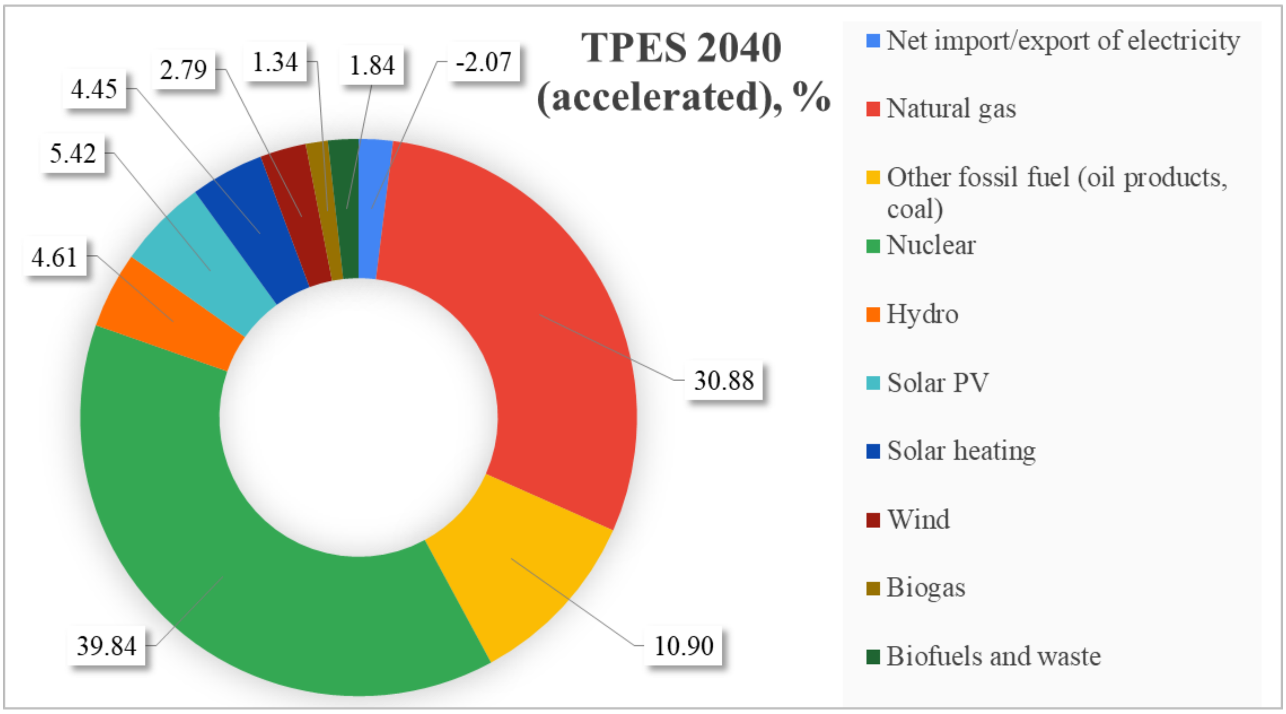
Historical Energy independence coefficient EIC = 27.1 %

EIC for Baseline scenario by 2040



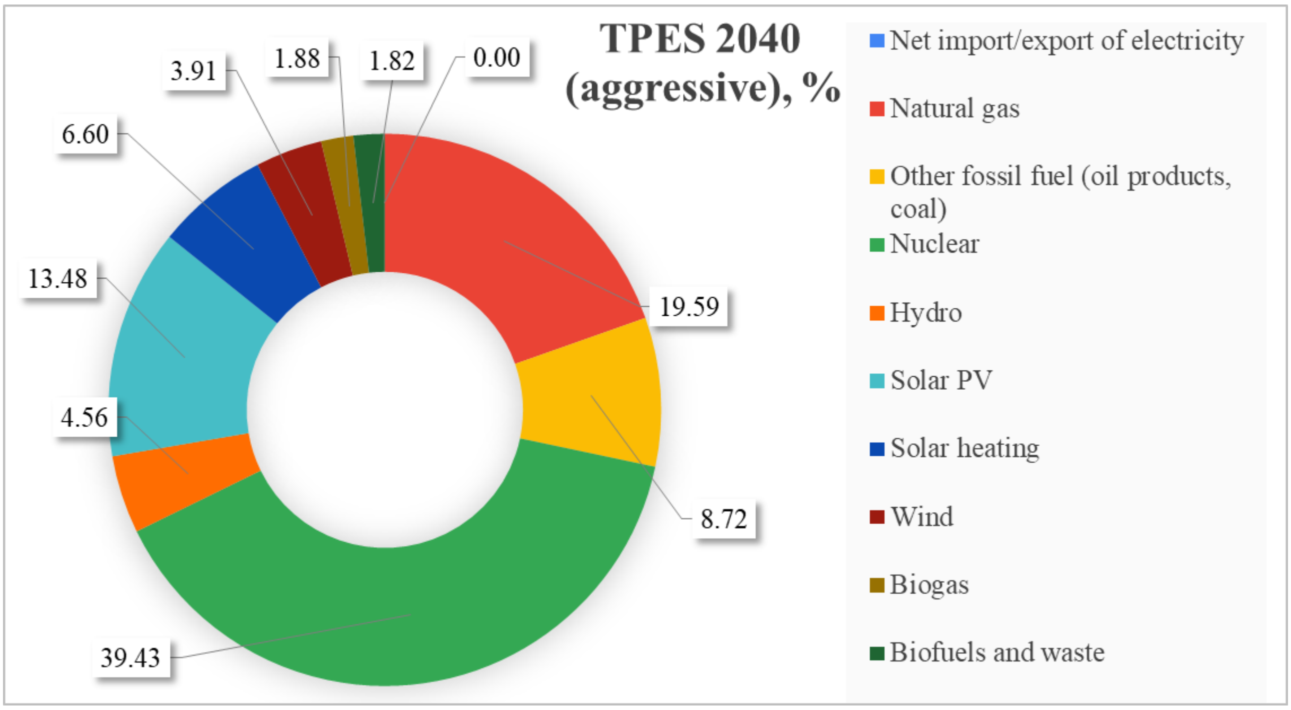
Energy independence coefficient for the Baseline scenario EIC = 46.8 %

EIC for Accelerated development scenario by 2040



Energy independence coefficient for the Accelerated development scenario EIC=60.3 %

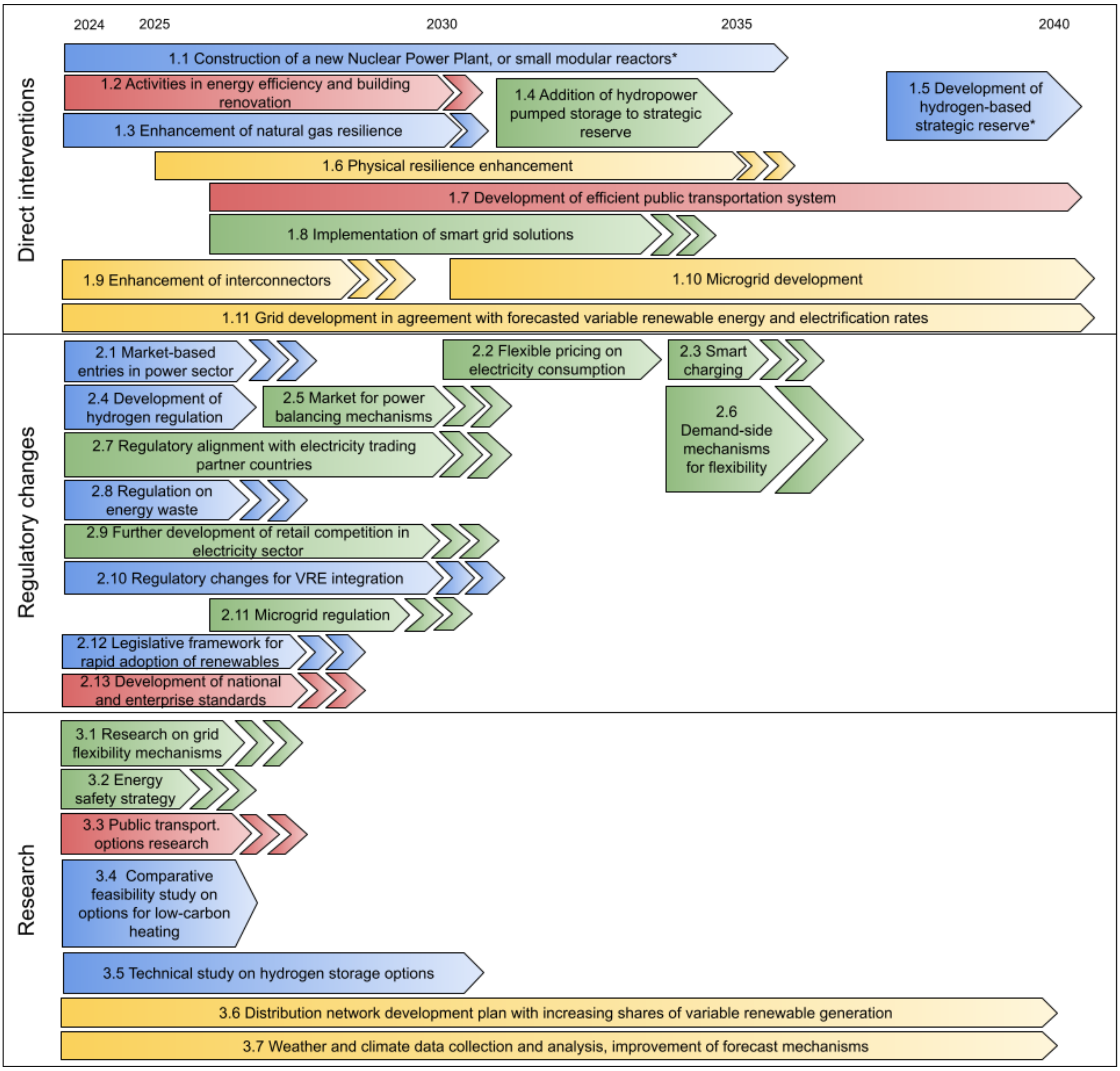
EIC for Aggressive development scenario by 2040



Energy independence coefficient for the Aggressive development scenario EIC = 71.7 %

3. ROADMAP

The diagram below shows the proposed Roadmap - the actions that need to be taken by 2040 to achieve a greater level of energy independence.



The advised actions have been grouped into three categories. Direct interventions entail actions to be undertaken directly by centralized decision-making, representing out-of-market mechanisms. These include constructions of strategic reserves, nuclear power, grid enhancement and so on. Regulatory changes entail actions aiming to incentivize or create certain markets and services that would be critical to achieve the possible higher level of energy independence. These would in turn result in higher rates of development for renewable generation, low-carbon technologies, and other changes that are envisioned as primarily market-driven. Finally, research activities should be associated with a series of studies, modelling, and simulations that will serve as the basis for the creation of regulatory mechanisms and decision-making aimed at attracting investment.

The implementation of the proposed actions is sequential and has certain prerequisites, presented in the form of steps. A detailed breakdown of each step is presented below.

The steps themselves are independent of scenarios, but some of the suggested actions are driven by technology developments. They are marked with an asterisk and are described at the end of the sub-clauses.

In addition to grouping by categories, the steps are colored according to the domain of energy which they are primarily aimed at, as follows: blue – refer to the supply aspect; red – primarily indicate the consumption side; yellow – refer to grid transmission infrastructure; green – refer to the operation and regulation of the electrical grid.

Direct Interventions

1.1 Construction of a new nuclear power plant, or small modular reactors (2024 - 2036)

Prerequisites: None

This step entails the selection of an appropriate nuclear power technology option and provider, construction of new nuclear power capacity to replace the Metsamor NPP, and commissioning by 2036. Provision of reliable power output throughout the year as a result.

1.2 Activities in energy efficiency and building renovation (2024 – 2030)

Prerequisites: None

These entail the implementation of programs and activities with regard to energy efficiency (primarily on the consumer side), in accordance with a number of nationally adopted legislations, such as the National Program on Energy Saving and Renewable Energy (2022-2030). Reduction in energy consumption rates and losses in energy flows as a result.

1.3 Enhancement of natural gas resilience (2024 – 2030)

Prerequisites: None

This step entails maintaining of existing natural gas suppliers, as well as strategic planning and intergovernmental agreements to secure national gas consumption. This also includes the expansion of the Abovyan storage facility to provide a strategic reserve of natural gas.

Enhanced security of natural gas supply as a result.

1.4 Addition of hydropower pumped storage to strategic reserve (2031 – 2035)

Prerequisites: *3.1 Research on grid flexibility mechanisms*

Construction of pumped hydropower storage facilities (totaling up to 450 MW) to be used in daily balancing of the electrical grid as an out-of-market mechanism.

Enhanced power system resilience and higher integration rate of variable renewable generation as a result.

1.5 Development of hydrogen-based power strategic reserve (2037 – 2050)*

Prerequisites: *2.4 Development of hydrogen regulation, 3.1 Research on grid flexibility mechanisms, 3.5 Study on hydrogen storage options in Armenia*

Development of a hydrogen-based strategic reserve (possibly involving retrofit of an existing CCGT plant) to serve as an out-of-market mechanism for providing back-up to the electrical grid in periods of scarcity. Enhanced power system resilience and availability of locally sourced long-term storage options as a result.

*Conditional on development of hydrogen technology, availability of storage facilities, and sufficiently low cost of locally produced hydrogen.

1.6 Physical resilience enhancement (2025 – 2035)

Prerequisite: *3.2 Energy safety strategy development*

Addition of defense measures to critical energy infrastructure to protect from physical damage.

1.7 Development of efficient public transportation system (2024 – 2040)

Prerequisite: *3.3 Public transportation options research*

Implementation of an efficient public transportation system on a national scale, with priority given to electrified or other locally sourced energy-based transportation. This step will reduce the transportation system's critical reliance on imported fuels as a result.

1.8 Implementation of smart grid solutions (2025 – 2035)

Prerequisite: *3.2 Energy safety strategy development*

Addition of a range of smart grid solutions to enhance the control and management of the power grid. Higher efficiency of power flow, grid resilience, integration of variable renewable generation, stable-state of operational regimes are some of the major benefits as a result of this step. Includes establishment of a cybersecurity center to test and monitor the cyber safety of the electrical grid and digital markets.

1.9 Enhancement of interconnectors (2024 – 2028)

Prerequisite: none

Construction of additional capacities for power flow trade with Iran and Georgia, potentially also with the EU. The step will enhance power system resilience, as well as allow for higher integration rates for variable renewable generation as a result.

1.10 Microgrid development (2030 – 2040)

Prerequisites: *1.8 Implementation of smart grid solutions, 2.10 Regulatory changes for VRE integration in the grid, 2.11 Microgrid regulation*

Isolated energy systems should not rely too heavily on variable renewable energy sources, such as solar PV and wind energy. Their share should be kept under 15% of the generation to ensure the system's sustainability and security. Therefore, the solution to maximizing the use of variable renewable energy resources, such as solar PV and wind energy, is seen in the enhanced penetration of autonomous mini- and microgrids. Implementation of microgrid solutions will relieve stress from the central grid and provide enhanced resilience to the power system. This step will provide higher resilience and opportunity to develop distributed and local energy generation, as well as lower dependence of consumers on the central grid.

1.11 Grid development according to the forecasted expansion of variable renewable energy generation and electrification rates of the consumption sector (2024-2040)

Prerequisites: *in parallel with: 3.6 Distribution network development plan and, 3.7 Weather and climate data collection and analysis, improvement of existing forecast mechanisms.*

Expansion and enhancement of the electrical grid allows for higher integration of variable energy generation, as well as additional power flow due to the growth and expansion of electricity consumers, such as electrified transportation and heating.

Regulatory Changes

2.1 Shift to market-based entries in the power sector (2024 – 2026)

Prerequisite: none

In accordance with the recommendation made by the USAID study, a gradual shift from tendering to market-based entries of new power generation capacities. A more efficient integration of variable renewable generation in particular will be an outcome of this step.

2.2 Flexible pricing system of electricity consumption (2030- 2033)

Prerequisite: *1.8 Implementation of smart grid solutions*

Introduction of a flexible pricing system for residential and commercial consumers of electricity depending on daily and seasonal fluctuations in real costs of power generation. This step will result in higher efficiency of energy consumption and grid flow management.

2.3 Smart charging (2033 – 2035)

Prerequisite: *1.8 Implementation of smart grid solutions, 2.2 Flexible tariffs on electricity consumption*

Introduction of smart charging framework and programs for electric transportation to facilitate the integration of high numbers of electric vehicles in power system operating regimes. Higher rates of EV integration is achievable, as well as higher system resilience achieved as a result.

2.4 Development of hydrogen regulation (2024 – 2026)

Prerequisite: none

Development of national standards and regulation on hydrogen use and storage.

2.5 Market for power balancing mechanisms (2026 – 2030)

Prerequisite: *3.1 Research on grid flexibility mechanisms*

Introduction of a market for ancillary and balancing services, to incentivize higher flexibility and storage solutions in power systems. Better management of power flows, higher system resilience and rates of variable renewable generation and storage achievable as a result.

2.6 Demand-side mechanisms for flexibility (2033 – 2036)

Prerequisite: *1.8 Implementation of smart grid solutions, 2.2 Flexible tariffs on electricity consumption, 2.5 Market for power balancing mechanisms*

Introduction of demand-side mechanisms in the markets for ancillary and balancing services, incentivizing higher flexibility on the consumer side. Better management of power flows, higher system resilience and rates of variable renewable generation and storage achievable as a result.

2.7 Regulatory alignment with electricity trading partner countries (2024 – 2030)

Prerequisite: None

Regulatory alignment and synchronization of electricity flow (including common day-ahead markets) with electricity trading partner countries, to reduce financial and technical losses in the grid. The step will enhance power system resilience, as well as allow for higher integration rates for variable renewable generation as a result.

2.8 Regulation on waste associated with end-of-life equipment (2024 – 2026)

Prerequisite: None

Development of a regulatory framework for managing energy-related waste and life cycle treatment of energy infrastructure, in particular, but not limited to, recycling and disposal of chemical batteries and solar panels. Lower environmental constraints on the development of energy generation and storage will be achieved as a result of this step.

2.9 Further development of retail market in the electricity sector (2024 – 2030)

Prerequisite: None

Expansion of retail competition in the electricity sector, particularly for large industrial consumers, leading to a more efficient consumption of electricity. A higher share of electricity is traded through liberalized mechanisms as a result.

2.10 Regulatory changes for VRE integration (2024 – 2030)

Prerequisite: None

Introduction of regulatory changes to better reflect the costs and benefits of renewable energy sources, such as zonal or nodal pricing, efficient trading through distributed generation, and switch to feed-in premiums from feed-in tariffs. A higher rate of VRE integration is achievable as a result of this step.

2.11 Microgrid regulation (2026 – 2028)

Prerequisite: None

Development of regulatory standards for management and trading within microgrids.

2.12 Development of legislative framework for rapid adoption of renewable energy sources (2024 – 2027)

Prerequisite: None

Alignment of the existing regulation on renewable energy with the EU directives, including in areas of biogas, solar thermal, as well as off-grid power generation. Establishment of a framework for financial and technical support to incentivize rapid development of local energy generation in accordance with its value to energy independence.

2.13 Development of national and enterprise standards (2024 – 2027)

Prerequisite: None

Development of national and enterprise standards on technical and engineering features, such as inverters, control and data acquisition, and photovoltaic panels.

Topics for Future Research

3.1 Research on grid flexibility mechanisms (2024 – 2026).

Prerequisite: none

Research on the need for flexibility in grid management and determination of economic value derived from various flexibility services, to form a basis for balancing and ancillary market design.

3.2 Energy safety strategy development (2024 – 2025)

Prerequisite: none

Development of a strategy on cyber and physical resilience of the energy infrastructure against external threats and attacks.

3.3 Public transportation options research (2024 – 2026)

Prerequisite: none

Research on various options of locally sourced energy-based public transportation development for urban and regional travel.

3.4 Comparative study on options for locally sourced heating (2024 – 2026)

Prerequisite: None

A techno-economic comparative assessment of potential options for reducing natural gas-based heating in various regions and cities in Armenia, through comparing local competitiveness and feasibility of electrification, biogas, district heating, solar thermal, hydrogen, etc.

3.5 Study on hydrogen storage options (2024 – 2030)

Prerequisite: none

A technical study on possibilities for long-term hydrogen storage in geological formation in Armenia.

3.6 Distribution network development plan (start at 2024)

Prerequisite: none

Distribution network development plan for the expansion and enhancement of the electrical grid.

3.7 Weather and climate data collection and analysis, improvement of forecast mechanisms (2024 – 2040)

Prerequisite: none

Continuous collection and accumulation of data on weather and climate patterns, their impact on energy generation and consumption, as well as corresponding improvements of forecast technologies and accuracy.

4. CONCLUSIONS AND RECOMMENDATIONS

4.1 Power System

According to international experience in the absence of developed interconnections, generation from renewable energy sources should not exceed 15 % of the total generation in terms of ensuring reliable and safe operation of the power system. Our study shows that by 2025, the electricity production of renewable sources (namely solar, wind, residential and small hydro power plants) in the RA power network exceeds the specified permissible threshold reaching 19.8 %, and this trend will continue in 2030 and 2035, reaching the 23.2 % and 28.2 % respectively. In 2040, the share of variable renewable energy generation in the system drops to 24.6 % due to the planned entry of a new 1000 MW nuclear power plant, but once again rises almost to the 30 % threshold in 2050. However, it should be noted here that the share of generation by small hydropower plants is in the range of 4.6 – 8.5 %, which is a relatively predictable seasonal type of energy, while the volatility of wind and solar generation is difficult to predict. Therefore, to ensure such high shares of renewable generation strong interconnections with the neighboring grids (Iran and Georgia) shall be established based on the long-term contractual obligations, construction new nuclear power plant, construction pumped hydropower plants, integration smart grid technologies, integration storage technologies especially in the low voltage grids level, There are the most important conditions on the way to increase degree of renewable energy integration and ensure the level of energy independence of RA around ensuring power system safety and reliability.

Thus, the results of the study show that the internal consumption of RA cannot be met only via renewable sources, even purely from overall energy balances perspective. Moreover, there is also another important issue, such as the reliability and safety of the grid, which cannot be maintained without baseload generation. It appears that baseload generating power plants responsible for frequency regulation and the stability and maintaining of grid regimes are thermal and nuclear power plants. And even in the case of observing the electricity balance by itself, it is obvious that without the entry of a new nuclear plant into the RA system will not be possible to ensure the self-sufficiency of the RA system even by 2050.

It is obvious that to achieve higher energy independence, Armenia needs a new nuclear power plant to put in operation by 2040. In the absence of energy storage capacities (which will become problematic in the near future), the output deficiency in specific hours during the day should be covered by baseload generation, mainly the nuclear plant, and, depending on demand, thermal plants.

From the presented generation balances, it can be seen that the self-sufficiency of Armenia's domestic electricity consumption (without the participation of thermal plants) can be ensured only by 2040 due to the entry into the system of a new nuclear power plant with an installed capacity of 1000 MW. However, this does not mean that in 2040 it will be possible or necessary to stop the operation of the three thermal plants operating in the RA energy system. This is due to the following very important factors:

- The Armenian power system shall have power plants able to work on a reserve basis (mainly thermal plants), which should replace the nuclear power plant when it will be recharging, undergo regular maintenance and planned repairs, or in case of emergency shutdown. According to reliability and safety indicators, the system must possess a reserve capacity equal to the installed capacity of the largest power unit operated in the power system. This could be the new, 1000 MW capacity nuclear power plant by 2040. Therefore, Hrazdan Unit 5 - 485 MW, Yerevan CCGT - 237.4 MW, Arm power CCGT - 254 MW power plants operating in the grid should be at least in reserve.
- Keeping thermal plants in operation will allow the Armenian government to conduct a flexible policy along with the trends of price changes in the international markets of primary energy carriers and innovative technologies.

- In case of the long-term operation of the current electricity-for-gas contract between Armenia and Iran, the presence of the Yerevan CCGT thermal plant is mandatory, and in case of revision of the contract and increase in volumes, the presence of other operational thermal plants is also possibly required.
- In case of an emergency malfunction or accident on the generation side, it should be possible to guarantee baseload supply for (in worst case) several hours.

Considering that by 2050 the operating periods of Hrazdan Unit 5, Yerevan CCGT and Armpower CCTG thermal plants will expire, one could continue operating them as reserve capacities after 2050, if:

- A new nuclear power plant with installed capacity of 1000 MW will be commissioned by 2040.
- It is possible to ensure provision of voltage and reactive power regimes in the absence of thermal plants.
- The entry of new hydropower plants and pumped storages into the system will be considered
- The Armenian power grid will be equipped with energy storage technologies, to ensure the reliability and safety of the system, in the periods of low renewable generation. However, it should be noted that these technologies remain quite problematic and economically yet unattractive. Serious problems also arise for the recycling and storage of depleted Li-Ion chemical batteries, which also need to be studied in depth.
- The price of natural gas supplied to Armenia will increase, reaching European prices.
- A long-term agreement will be signed with the energy systems of the neighboring countries regarding the provision of reserve capacities, in case of planned or emergency shutdown of Armenia’s baseload generation plants, or in case of emergency situations in the Armenian grid in general.
- Deep integration of Smart Grid technologies for intelligent management of Armenia’s power system, forecasting and prediction and prevention of emergency situations.
- Implementation of enabling legal-legislative changes and improvements. Revision of tariff policy.

Failure to comply with the above conditions and the decommissioning of thermal power plants can create a danger of the collapse of the power system and, consequently, reduce the energy independence of the country, making it more dependent on imports.

4.2 Wind Energy Resources

Using the Global Wind Atlas, we have concluded that Armenia's wind resources are largely underestimated. This radically changes the global vision of wind energy prospects in Armenia. Thanks to this free and online tool, some very precise study case can be considered and giving a global and local sharp prediction of wind turbine potential production, prior of in situ measurements for sitting.

At present, wind energy represents less than 0.5% of electricity production, including due to maintenance problems. We believe that with appropriate investment support mechanisms in place, Armenia could reasonably meet up to 10% of its electricity needs from wind power alone.

This source of energy is able to ease hydropower downstream of Sevan Lake. Wind Energy, similar to Solar, could be a good turnkey solution to ease (and only ease) the Armenian power grid of pricey (gas) and/or critical raw material (water, nuclear) dependence.

The most critical points are the choices of the places where the wind farms could be build and their number.

The government of Armenia should be aware of the precise areas that could welcome wind energy production, in the function of all the parameters priory mentioned (protected area, windy spot, relative intermittence, grid proximity, etc.), to maximize the energy production with the best efficiency.

Foremost, sharp monitoring with high-frequency measurements (0.1 Hz at least) of all physical parameters (such as wind, temperature, and humidity at different heights) should be realized in order to have the best mapping of these variables, which could also be useful to monitor the global warming and become a major actor of a clever quickly switching energy grid policy.

The Key Performance Indicator for each wind turbine, or farm, selected all over Armenia with the best potential spots reaches more than 66 %, meaning that they will produce energy more than 66 % of the time over a year (around 6000 hours/year). The full production capacity will be reached more than 33% of the time (about 3000 hours/year). A realistic and cautious KPI would then reach 60 % with 30 % of full capacity.

4.3 Solar Energy

Solar Thermal Energy

Solar thermal technologies in Armenia have enormous potential to replace electricity and natural gas. This cost-effective technology has potential for replacing about 153.7 million cubic meters of natural gas and save 360,519.6 MW of electricity annually by 2041. As evidenced by the experience of other countries with rich solar resources, for instance, Greece, with an appropriate institutional framework and supportive policies, solar thermal energy in Armenia can develop rapidly. In order to achieve the potential, it is essential to create an appropriate environment through:

- Developing a local industry to manufacture cost-effective solar thermal systems.
- Setting targets for energy savings in the residential sector through the use of solar technologies.
- Introducing new regulations for residential and other hot water consuming buildings to mandate the use of solar energy.

Solar PV

Solar photovoltaic technology with residential rooftop installation alone, with a total capacity of 1,600 MW can generate 2.75 TWh per year from residential / off-grid solar, equivalent to 260,663,507.109 m^3 of natural gas. To achieve this realistic target by 2040, a targeted state policy, including incentives, consumer benefit programs, proper technical regulation, the use of market incentive mechanisms, and social and financial aspects it is necessary to implement.

An interesting and important application of Solar PV for Armenia can be installation of PV panels on cultivated lands in an almost horizontal plane to generate electricity and produce crops. The plants will be protected from strong solar radiation and generate significant savings by saving water and electricity for powering irrigation pumps.

Solar PV provides an ideal solution for establishing Microgrids in general, and agricultural microgrids in particular enabling distributed electricity generation, consumption, and storage without the impact of variability on grid modes.

4.4 Biogas

Biogas remains a neglected untapped energy resource, although it has serious potential to contribute to Armenia's energy independence. The main issue is the initial capital costs. Some form of subsidy, such as low-interest loans or other innovative financial mechanisms, must be adopted.

For the successful development of the biogas industry in Armenia, institutional support policies along with a trained workforce must be created. Policy development should include, for example

- Biogas technology promotion;
- Establishing mandatory requirement digestion of slurry for farms over a certain size;
- Implementing targeted policies to incentivize energy generation from livestock manure via such specific financing schemes for microscale digestion aimed at a higher level of energy security and independence for the farmers, reduced use of solid fuels for domestic cooking and heating, reduced deforestation;
- Making available training for microscale digestion operation, maintenance, and safety checks.

4.5 Biomass

Biomass can contribute to Armenia's energy independence and security through the sustainable use of biomass resources. At the same time, it is necessary to improve the energy efficiency of homes, replace inefficient heating devices, switch to environmentally friendly biomass fuel, raise awareness, and use incentive financial mechanisms.

In the near term it is advisable to establish large scale short rotation energy crop plantations primarily to support the demand for fire wood and secondarily for electricity generation. Measures to reduce greenhouse gas emissions and sequester carbon can be an integral part of this plan as well and should be factored into the overall economics of such a proposed scheme.

The capacity building should target the local producers of stoves and alternative biomass fuel along with the financial mechanisms to make the price of the straw briquettes more competitive. This should be combined with pilot and demonstration projects on specific examples to become the basis for replication and wider use.

4.6 Bio-ethanol

Armenia’s dependence on imported petrol and the associated high domestic petrol prices helps to create an opportunity for domestically produced bio-ethanol. The proposed bioethanol plants would augment petrol supply by a total of about 10 %, which can readily be absorbed by the petrol market. Introduction in the supply chain can be easily achieved through splash-blending at the fuel depots. The bio-ethanol price in the financial model is set at $1.34/liter.

While bioethanol contains about 30 % less energy per liter than petrol, bio-ethanol has a higher octane number that enhances its value as a blend component for higher priced midlevel and premium petrol. The bio-ethanol price used in the analysis assumes that domestically produced bioethanol will not be subject to the 120 AMD per liter import tax on imported petrol. The price the plant receives for bio-ethanol is the single most important metric in determining financial viability of the proposed plants.

The relatively small size of the bio-ethanol plants and their limited contribution with regards to the overall petrol use, the market risk for bio-ethanol in Armenia is limited. At expected blend levels of the bio-ethanol produced should be readily absorbed into the petrol market. Its high octane value further makes it an attractive blend component. To avoid fuel quality issues from other sources (e.g. blending water) being attributed to the introduction of bio-ethanol, a rigorous testing and quality control protocol is recommended to demonstrate that the addition of bio-ethanol improves overall fuel quality.

4.7 Smart Grid

Smart energy and other modern solutions are a technological priority for Armenia's energy independence. The smart grid has significant potential to handle a large share of variable renewable energy sources and increase the achievable level of energy independence and security; however, this comes with significant institutional complexity and investment costs.

In some places, compromises have to be made. Real-time pricing for residential consumers might be the best solution in theory, but requires more extensive infrastructure and regulatory framework than simpler (such as critical-peak pricing) approaches.

Decreasing VRE uncertainty and innovative operation of lines (such as dynamic line rating) are among the low-hanging fruits, while aggregators may play a significant part in the future. Some approaches require a more liberalized market and efficient regulation. A comparison of various solutions provides an idea of the costs and benefits in the context of Armenia's energy independence. In the absence of liberalized markets and efficient regulation, advances on the system operator's level are expected first, while institutional development and liberalization should be prioritized in the medium to long term.

4.8 Nuclear Power

The analysis of nuclear power's role in Armenia's energy sector highlights it as the only baseload alternative to largely replace natural gas power generation. A construction of new nuclear power plant to replace Metsamor is therefore a crucial step for Armenia's energy independence. The two major candidate technologies are conventional large reactors, with technological maturity and operational experience, as well as up-and-coming small modular reactors, which would be more suitable for Armenia's demand and resilience, but which relatively lack real-world applications and experience.

4.9 Hydrogen

Overall, the potential for large-scale development of hydrogen use in Armenia remains uncertain in the long-term, though less likely within the timeframe of this roadmap (up to 2040). High capital costs of new hydrogen infrastructure development mean that repurposing the existing lines is the more viable alternative (unless delivery is done on a smaller scale by trucks), but even repurposing costs are significantly high.

The prospects of hydrogen development in the context of energy independence are uncertain and subject to the following constraints:

1. The relatively high costs of local hydrogen production;

2. The relative value of exporting Armenia's electricity instead of using it to generate hydrogen can decrease the prospects even further;

3. Even disregarding the two points above, competitiveness of hydrogen applications with alternative low-carbon solutions is low in many cases;

In conclusion, even if the global market develops, hydrogen in Armenia may well be a predominantly imported fuel as natural gas is now, and the economic incentives for local production in that case would remain low and confined to niche applications. Under those conditions, large-scale hydrogen development is unlikely to have a significant impact on the energy independence of Armenia, except through diversification of primary energy suppliers. While an introduction of hydrogen-based CCGT or fuel cell reserves for the grid is the most likely application to have a positive impact on energy independence, an evaluation of storage possibilities (in terms of ammonia, as well as aquifers or cavern salts) is required.

4.10 Storage Technologies

The primary goal for Armenia should be development of pumped hydropower storage; this would be essential for long-term storage. Chemical batteries should be considered for mid-term storage (1-6 hours), mainly utilizing excess daytime generation for evening peak hours, but also managing variations throughout the day. Flywheels can be considered for primary frequency response, but require accurate forecast, as the storage duration is low. Compressed Air Storage opportunities should be separately explored in Armenia, as they have highly specific location requirements.

What is important to note regarding costs is that flywheels, pumped hydropower storage, and compressed air storage are not expected to experience significant cost reductions, as these are already mature technologies. The primary factor that will have a significant impact is the chemical batteries.

For this, it is important

a) To provide proper incentives and market mechanisms, so that storage technologies are deployed economically on the market

b) To have proper decision-making on system operator’s level, to decide when to invest into storage for grid management, based on costs and demand.

The two factors will interact. A proper market mechanism can incentivize sufficient storage installations, reducing the need for system operator’s intervention. An important aspect is providing multiple source of revenue (through well-designed ancillary services, wholesale market, and energy arbitrage) for storage, because the capital costs remain high.

4.11 Market Liberalization and Economics

The goal for higher energy independence requires implementation of renewable energy generation. An efficient integration of variable renewable generation is achievable under liberalized markets, with efficient day-ahead market and system services procurement, which are important for intermittent and uncertain solar and wind power generation. However, the internal market of Armenia (especially with a large nuclear power plant) may be too small for liberalization, and so can only be liberalized in tandem with a regional market, i.e. Georgia and possibly the EU, via Georgia. Ultimately, a trade-off between economic efficiency and energy independence will arise.

4.12 International Experience

The international experience provides a lot of learning opportunities for Armenia. Many technological and regulatory solutions are noted and described in other parts of the report; here, four countries were selected and analyzed in more depth, and their similarities and differences with Armenia highlighted. The purpose was to develop a certain "emergent" role model, based on the collective experience of these four countries. None of them is fully similar to Armenia, or presents an ideal role model, but the collective lessons can be briefly summarized as follows:

Interconnections are critical for Armenia; all four countries seek to develop their trade capacity, which allows (among other things) to integrate a higher share of VRE. This demonstrates that their primary goal is not energy independence in the sense of fully isolated self-sufficient mode. Indeed, Israel is seeking interconnection despite having enough gas reserves to sustain itself for many years, while Ireland has been struggling with being physically isolated due to its location. Higher interconnectedness and grid stability as a result are the priority goal, especially in systems with high share of VRE generation.

Proper regulatory development is critical. Whether it is effective ancillary services procurement, more system-efficient subsidization of variable generation, or regulatory harmonization with neighboring countries, the regulatory environment has to enable various technologies to enter the market. This is, again, especially true for high shares of VRE generation. The theoretically achievable level of independence will not be reached without appropriate legislative changes, or it will come at a higher cost.

Ultimately, achieving higher levels of energy security and independence is associated with higher cost to be paid by the society, particularly by the consumer and/or the taxpayers. The higher costs will have to be induced by costly actions, such as construction of nuclear power plant, enhancing interconnectors, building storage infrastructures, etc. Public support of the selected strategy will be of a critical importance, therefore benefits have to be clearly highlighted and communicated, especially if they come in the form of mitigation of future risks, rather than dealing with the problems of today.

4.13 Public Transportation

The shift to low-carbon public transportation is a way to reduce fossil fuel-dependency, and, simultaneously, is an important factor for large-scale decarbonisation of the transport sector, particularly when it comes to metropolitan and inter-city travel. Public transportation can in many instances provide a cheaper and more effective alternative for low carbon transitions, compared to maintaining the same demand for private vehicles while trying to electrify them. A developed public transportation system also provides higher system resilience, in case of natural gas supply disruptions.

4.14 District Heating

While the national potential for co-generation DH restoration is estimated at 120-140 MW (together with peak boilers of 300-350 MW), the economic efficiency of district heating restoration remains under question. To properly estimate the potential of district heating in reducing energy dependence of Armenia, the following points need to be evaluated:

1. The current state and the rehabilitation potential for central heating infrastructure.
    a. Regulatory grounds for district heating implementation / rehabilitation in the existing buildings stock on a large scale.
2. The potential for new installations for the existing building stock.
    a. Low-carbon resources (biomass, waste, underground heat) available for district heating.
3. A comparative economic analysis of heat supply options, including individual boilers, district heating / boiler houses, and electric heating.

5. Further studies

The roadmap has raised several questions beyond a high-level study, such as a roadmap. However, these questions must be studied to practically implement the roadmap's provisions.

Due to the continuous increase in electricity consumption and the emergence of new generating capacities using renewable sources, further in-depth studies of distribution networks are needed. The study should evaluate the capability of the distribution networks to absorb and transmit the increased electricity flows, and the amount of investment required to incorporate new renewable capacity into the network. This includes the development and spread of autonomous isolated and hybrid mini-grids.

These are the most significant questions for the future's wider deployment of renewable energy sources, whether they are grid-connected off-grid producers on 0.38/0.22 kV networks or new licensed electricity producers connected to medium voltage networks. These studies should be based on distribution network modeling, performance calculations, technical-economic and financial-technical evaluations.

Research on flexibility options will build the foundation for developing market-based regulation to enable higher rates of renewable energy integration.

The increasing digitalization of power system operation necessitates additional research into energy security, cybersecurity threats, and improving physical resilience.

In the transport sector, exploring various options for developing public transport, electrifying it, and reducing individual transport usage is relevant.

In the heating sector, a comparative techno-economic analysis of low-carbon heating options will highlight the optimal route for degasification in different regions and cities in Armenia.

A feasibility study of hydrogen storage options will provide clarity on hydrogen's prospects for energy independence.

In addition to highly specialized research, there is a general task of swiftly adapting the national energy strategy to the rapidly transforming fuel and energy market, digital technology penetration, changes in the structure of international transport and energy communications, and regional and global geopolitics. Timely adaptation to the changes should serve the objectives of ensuring stability, security, reliability, and, therefore, the country's energy independence. The above objectives should be accomplished by regularly updating the energy independence roadmap, using monitoring data and data analysis every two years.

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