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Energy and nuclear power planning study for Armenia

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FOREWORD

The use of nuclear power in a country poses specific requirements on the national infrastructures that largely surpass those experienced in general industrial and energy development planning. The relatively high expenditures associated with the construction of a nuclear power plant, and the implications for the country and the power utility involved, require that the decision for use of this technology be a sound one. The problem is further complicated in the case of developing countries primarily due to scarcity of financial resources and the fact that investments in the energy and electricity sectors are competing with those needed for general development and public welfare.

Consequently, the appropriate authorities must carry out careful planning of the future energy and electricity facilities of the country in order to make timely decisions. At the start of this planning, it is required to identify the expected levels of energy/electricity demand and the options that are available to meet these demands, taking special note of the national energy resources and potential imported sources. Further analyses would be needed for the optimization of the supply facilities to meet the demand in the most efficient and economic manner with due consideration of the environmental impacts and resource requirements. This type of analysis should also consider other alternatives to expanding the system, such as measures at the demand side that would reduce the level of expected demands.

In accordance with its mandate of promoting the use of nuclear energy for peaceful uses worldwide, the IAEA has developed a systematic approach along with a set of computer based models for elaborating national energy strategies covering analyses of all of the above aspects. Under its Technical Co-operation Programme, the IAEA provides assistance to developing Member States to help strengthen national capabilities for conducting such studies, by transferring the analytical tools along with training and providing expert advice.

The present report is the outcome of such a technical co-operation programme and describes the results of the Energy and Nuclear Power Planning (ENPP) study for Armenia conducted by the Energy Strategy Centre of the Ministry of Energy, in co-operation with several national organizations. It demonstrates how the IAEA's set of energy planning tools can be utilized for comprehensive national analyses involving: (i) energy and electricity demand analysis and projections, (ii) least-cost electric system expansion analysis, (iii) energy resources allocation to power and non-power sectors, (iv) environmental impact analysis, and (v) financial analysis of the envisaged nuclear power development plan.

This study is not a typical one for several reasons. Firstly, similar to other east European countries, Armenia is going through a process of re-organization as a result of the transition from a centrally planned economy to a market oriented one. Secondly, the Armenian nuclear power plant (unit #2 of two) is currently under operation in the country and the study provided the opportunity to verify its economic competitiveness with other options, including future expansion of nuclear capacities and decommissioning strategy of existing units.

Finally, it should be noted that Energy Strategy Centre of the Ministry of Energy, Armenia was fully responsible for all phases of the study, including the preparation of the present report. The IAEA's role was to provide overall co-ordination and guidance throughout the conduct of the study, and to guarantee that adequate training in the use of IAEA energy planning models was provided to the members of the national team. The IAEA officer responsible for this publication was A.I. Jalal of the Department of Nuclear Energy.

EDITORIAL NOTE

CONTENTS

SUMMARY

1. Objectives and Scope of the Study

The Energy and Nuclear Power Planning (ENPP) study for Armenia has been conducted under the technical cooperation programme of the International Atomic Energy Agency (IAEA). The objective of the study was to analyze the electricity demand as part of the total final energy demand in various scenarios of Armenian socioeconomic and technological development, and to develop economically optimized electric generating system expansion plans for meeting the electric power demand, and to assess the role that nuclear energy could play within these optimal programs. The specific objectives of this study were:

- To define the role that nuclear power could play in the future electricity supply in Armenia, based on a least-cost expansion planning analysis of the country's power system.
- To analyze the environmental impacts of such a nuclear power development.
- To evaluate the financial viability of the envisaged nuclear power development program.
- To train a group of Armenian experts in the use of the IAEA's energy models.

2. Organization of the Study

The Group of Experts from the Energy Strategy Centre (ESC), the Armenian Ministry of Energy, has conducted the study with the technical assistance rendered by the International Atomic Energy Agency. A number of Expert Missions were arranged by the IAEA for providing technical assistance to the national team for the implementation of this study. In addition, the IAEA provided extensive training to the members of the national team on the use of various computer based planning models used for the analysis of various aspects of energy and electricity planning.

Similar to other IAEA technical cooperation projects, the ENPP study was conceived as a joint effort of Armenia and the IAEA where each side had its own clear, well-established responsibilities:

- Armenian experts had full responsibility for the conduct of the study, including data collection and preparation, execution of the computer runs, interpretation and improvement of results, etc., up to the production of the draft report of the study;
- The IAEA experts provided guidance and coordination throughout the conduct of the study, on-the-job training of the national team and transfer of know-how, and the necessary methodologies and computerized planning tools to Armenia.

This distribution of tasks was thus conceived so that by the end of the study, the energy planners in Armenia will have gained sufficient experience in the use of the methodologies and computer programs provided by the IAEA and could utilize them independently for carrying out future planning studies.

3. Methodological Approach

Nuclear power is one of the several technological options for electricity generation. The future role of nuclear power can only be determined if the future development of the electricity sector is analyzed in detail by considering the expected future requirements of electricity and all possible supply options. Further, since electricity may substitute other fuels for some of the categories of energy end-use, and the electricity generation has to compete with energy demand in other sectors for the available primary energy supplies, it is desirable to analyze the evolution of energy demand and supply for the entire energy system at the national level. Such an integrated approach is provided in the set of planning methodologies developed by the IAEA. The various models used for carrying out this study are: (i) MAED for energy and electricity demand analysis and projections, (ii) WASP-IV for formulation of least-cost power capacity expansion plans, (iii) BALANCE for energy resources allocation to power and non-power sectors, (iv) SIMPACTS for assessment of environmental impacts of alternative plans for electricity generation systems, and (v) A simplified financial analysis model for determining financial viability of the envisaged nuclear power development plan. All these models are inter-linked with each other to ensure consistency and to provide feedback information from one model to another. The use of these models, however, requires development of scenarios with consistent assumptions on evolution of demography, economy, technology development, energy resource development, future prices and costs, etc. The major assumptions for these scenarios are summarized in the following section.

4. Major Assumptions

4.1. Demography

Population growth is one of the important factors determining the future evolution of energy and electricity demand. For the present study, Armenian population is foreseen to grow from 3.2 million inhabitants in 1999 to 3.26 million inhabitants in 2020. Urban population is projected to increase, reaching 2.24 million inhabitants in 2020 against 2.15 million in 1999 while the rural population is estimated to decrease reaching 1.02 million inhabitants in 2020, against 1.05 million inhabitants in 1999. According to these assumptions, in 2020 about 69% of Armenian population will inhabit in urban areas, against 67% in 1999. The urban population average growth rate would be around 0.28%. This is because of both economic adjustment characteristic of this period and impact of the migration from villages to towns. Other demographic parameters, such as living standard of the population, etc. have been linked with the assumed economic activity for different scenarios.

4.2. Economy

The level of economic activity and the structure of the economy are the most important factors for projecting the future energy and electricity demand. While the present study was conducted, the macroeconomic long term forecasts were available from the Government's Program of Macro-economical Development of the Republic of Armenia prepared by the Department of Macro-economical Analysis and Perspective Programming of the Main Department of State Policy and Long term Program of the Ministry of Finance and Economy of the Republic of Armenia. Two main scenarios, named Reference and Low scenarios, have been developed based on the judgment of experts of a given field, covering plausible ranges for future evolution of the main driving parameters.

For Reference Scenario, the GDP was estimated to grow by 6.0%/year on the average over 2000-2020 period, whereas for the Low Scenario, GDP was assumed to grow at about 4.0% per year. The structure of economy was also assumed to be different in the two scenarios as the growth of value-added by various sectors will be different. In the Reference scenario, as the GDP growth is higher than that in the Low scenario, mainly led by the manufacturing sector, the share of industry will increase faster than that in the Low scenario. Figure 1 shows the overall growth of GDP assumed in these scenarios.

Corresponding to these assumptions on GDP and Population, the per capita GDP will increase from US $$_{1999}$ 462 in 1999 to US $$_{1999}$ 1552 and US $$_{1999}$ 1019 in 2020, respectively in the Reference and Low scenarios.

4.3 Other Assumptions

The on-going efforts on restructuring and financial rehabilitation of the energy sector aiming at improved energy supply and use efficiency, quality of service, tariff rationalization, payment discipline and greater transparency in commercial transactions, will continue and have considerable impact on future energy supply and demand situation. All these are reflected in details of the scenarios assumptions in terms of consumers' behavior, intensity of energy use by different sectors of the economy and supply options.

Additionally, in view of very high import dependence for meeting energy demand, the supply security concerns are also reflected in the scenarios by developing a few variants of supply cases, viz. with and without new nuclear power plants. Armenia views nuclear power as semi-indigenous. Although, the country is dependent on imports for nuclear fuel supplies and spare part, and will import new nuclear power plants, if decided to build in future, the technical human resource is available to safely operate and maintain nuclear power plants.

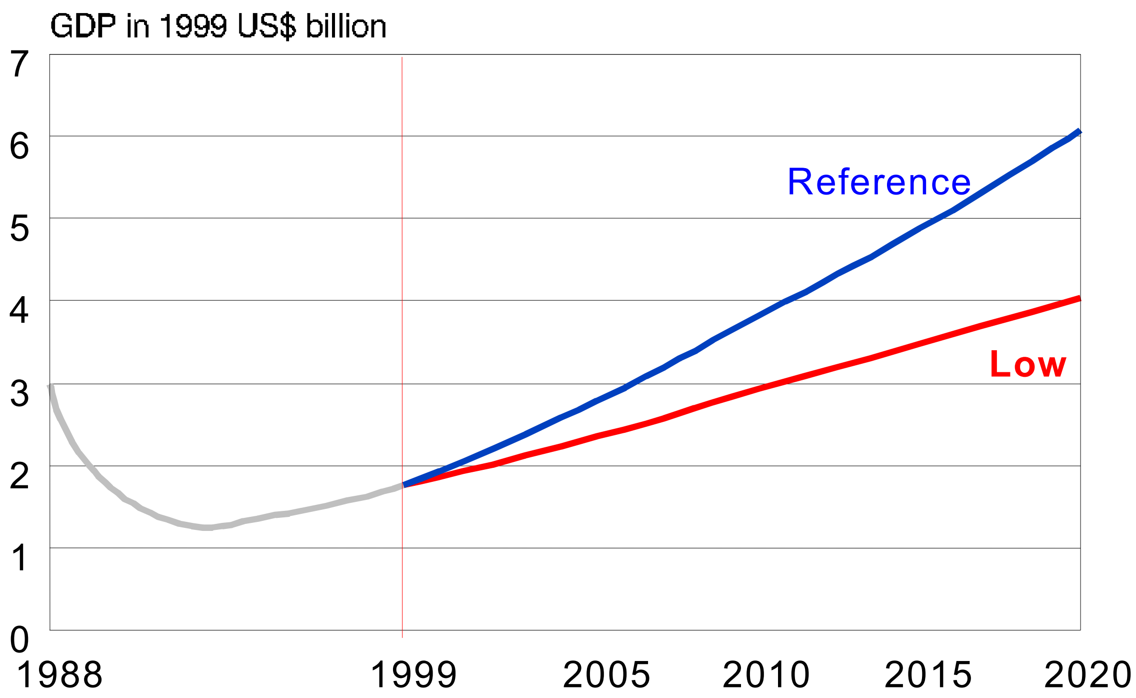


Figure 1. GDP in Two Economic Growth Scenarios

5. Main Findings

5.1. Energy and Electricity Demand

For the above mentioned two scenarios, future demand for energy and electricity have been projected using the IAEA's model MAED. Figure 2 shows the evolution of final commercial energy demand in these scenarios.

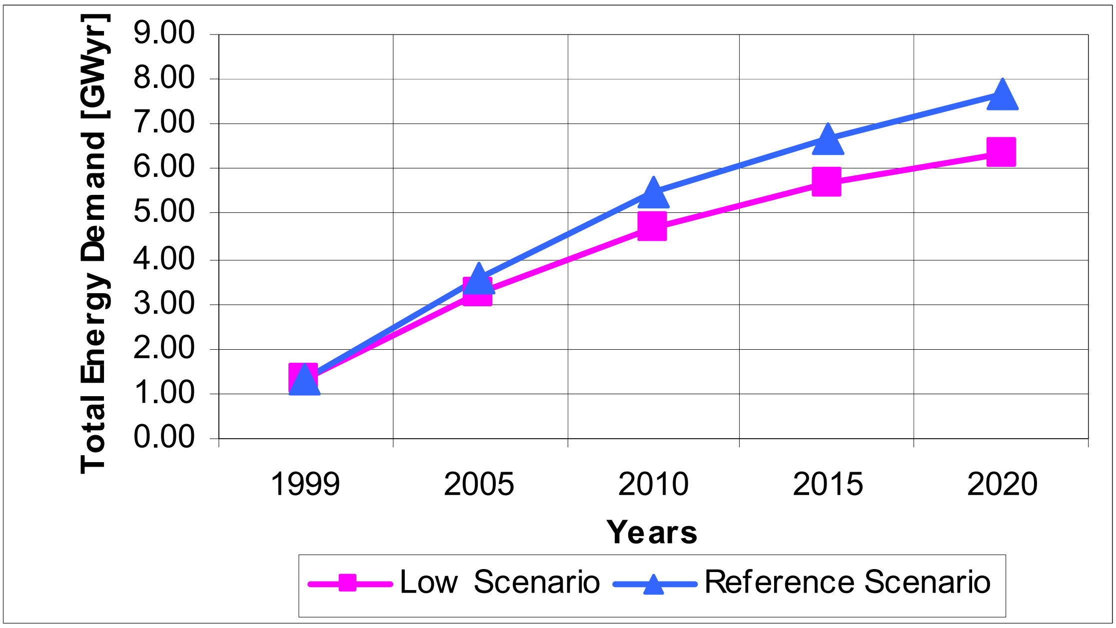


Figure 2. Projections of Final Energy Demand in Two Scenarios

The overall increase in commercial energy demand is estimated as about 5.8 times in the Reference scenarios and about 4.8 times in the Low scenario. In the year of 2020, the final energy demand begins to show important differences between the scenarios in line with the assumptions for socioeconomic and technological development. In Low Scenario, with low annual growth rate of GDP and only slight technological improvements, the total final energy demand reaches the same level as in Reference Scenario for the year 2015. In Reference Scenario, with the intense rehabilitation and renovation process occurring in all fields of activity, the final energy demand is about 0.8 GWyr higher than in Low Scenario for the same year.

The sectoral breakdown is shown in Table 1. In 1999, the total final energy demand of the country was about 1.3 GWyr, including: about 32.6% in Industry, 31.7% in Transportation and 35.7% in Household/Service. The share of energy demand for Industry will increase in both scenarios – though to a lesser extent in the Low scenario, while that of transport will decrease. The share of energy consumption by the Households/Service sector will also increase in both scenarios. This increase in share is higher for the Reference scenario than that for the Low scenario due to higher income level in the Reference scenario.

As for the distribution of the total energy demand by energy forms, in 1999 the structure of energy consumption was as follows: 23.8% substitutable fossil fuels, 7.9% district heat, 31.1% electricity and 37.2% motor fuels. Electricity is being used for many thermal uses like space heating. Its share will decrease in both scenarios from about 31% in 1999 to 16-17% by 2020. The shares of substitutable fossil fuels and district heat will, instead, increase as the electricity tariff are rationalized and more effective infrastructure is developed for district heating and supply of other energy sources, and will reach about 55% to the total demand in 2020 as listed in Table 2 and illustrated in Figure 3.

In the case of electricity, the total consumption in 1999 was about 0.41GWyr, which was consumed by 31.1 % in Industry, 3.7% in Transportation, and 65.2% in Household and Service. The project growth rates for electricity demand in the two scenarios are shown in Table 3.

Table 1. Final Energy Demand by Sector (1999-2020)

Sector	Growth rate [%]	Amount [Gwyr]		Share [%]	
	2020	1999	2020	1999	2020
Low Scenario	7.7	1.30	6.3	100.	100.
1. Industry	8.3	0.44	2.34	32.8	37.0
- Agr/Constr/Min	9.5	0.15	0.98	33.7	41.9
- Manufacturing	7.7	0.29	1.36	66.3	58.1
2. Transport	5.8	0.42	1.38	31.9	21.8
3. Households/Service	8.5	0.47	2.62	35.3	41.3
Reference Scenario	8.7	1.33	7.67	100.	100.
1. Industry	9.6	0.44	3.02	32.8	39.4
- Agr/Constr/Min	10.4	0.15	1.18	33.7	39.2
- Manufacturing	9.2	0.29	1.84	66.3	60.8
2. Transport	6.9	0.42	1.72	31.9	22.4
3. Households/Service	9.1	0.47	2.92	35.3	38.1

5.2 Least-Cost Plan for Expansion of the Electricity Generation System

In formulation of the least-cost Reference Case expansion plan, the electricity demand projected in Reference and Low Demand Scenarios has been used along with taking into account the external demand and a number of constraints on fuel supply limitations, system reliability, and some physical constraints.

The least-cost analyses show that for the near term future, the most economical strategy is to (a) rehabilitate all existing hydropower plants, (b) continue to operate two 50 MW combined heat and power units at TPP Yerevan 1 and the two 150 MW power-only units at TPP Yerevan 2, as well as two 50 MW CHP units at TPP Hrazdan 1, (c) complete construction and put into operation Hrazdan 5 (300MW), and (d) complete the rehabilitation of the 200 MW units Hrazdan 2-1 and Hrazdan 2-3.

Additionally, this analysis suggests the development of about 2794 MW of new installed capacity for power generation, comprising: Hydro 231 MW, Combined Cycle Power Plant 600 MW, CHP Combined Cycle Plant 668 MW, Nuclear 1280 MW and Wind 15 MW. The least-cost plan for the Reference scenario is shown in Figure 4.

In view of various uncertainties about the future evolution of energy/electricity demand and supply system, nuclear power development and possibility of importing natural gas from the additional sources, it is necessary to explore alternative plans for expansion of electricity generation system. The alternative expansion plans are considered for both Reference and Low Demand Scenarios. There is no nuclear option in these alternative expansion plans; this is the main difference from the two expansion plans described below.

The analyses have shown that nuclear power can significantly help in reducing the energy import dependence of the country. Although nuclear power plants are relatively expensive to build, their operating costs are very small compared to fossil fuel based power plants. This makes the overall economic costs of nuclear power plants very attractive.

Table 2. Summary of Energy Demand by Energy Form

Energy Form	Growth Rate 1999-2020 [% per year]	Amount [Gwyr]		Share [%]	
		1999	2020	1999	2020
Low Scenario					
Total commercial	7.72	1.33	6.34	100.00	100.00
of which:					
Substitutable Fossil fuels	10.84	0.32	2.75	23.79	43.34
District heat supply	10.14	0.10	0.80	7.88	12.55
Electricity	4.43	0.41	1.03	31.11	16.23
Motor fuels	6.24	0.50	1.77	37.22	27.88
Reference Scenario					
Total commercial	8.69	1.33	7.67	100.00	100.00
of which:					
Subsitutable Fossil fuels	11.51	0.32	3.12	23.79	40.72
Distric heat supply	11.59	0.10	1.05	7.87	13.67
Electricity	5.60	0.41	1.30	31.11	16.96
Motor fuels	7.35	0.50	2.20	37.23	28.65

In Reference Demand Case, the Nuclear power will be contributing about 50% of total power generation in 2020, replacing 1.4 billion m^3 of natural gas consumption for power generation, and in Low Demand Case - about 58% of total power generation, replacing 1.3 billion m^3 of natural gas consumption (Figure 5).

6. Investment Requirements

In case of Reference Demand Scenario with Nuclear Option, the cumulative investments for capacity additions have been worked out as US$ 2.9 billion, and the cumulative system operation costs as US$ 4.6 billion. If compared to the case of Reference Demand Scenario without Nuclear Option, the cumulative investments in case with nuclear option are US$ 0.6 billion higher because the capital costs of nuclear power plants are relatively higher than those of gas fuel based power plants. On the other hand, the system operation costs in case of Reference Demand Scenario with Nuclear Option are lower by about US$ 0.5 billion, compared to those in Reference Demand Scenario without Nuclear Option. This difference is due to low fuelling costs of nuclear power plants.

Table 3. Projected Growth Rates of Electricity Consumption in Two Demand Scenarios

Demand Scenario	Growth Rate of Electricity Consumption (per annum)			
	1999-2005	2005-2010	2010-2015	2015-2020
Reference Scenario	8.4	6.7	4.0	2.9
Low Scenario	7.3	4.7	3.2	2.1

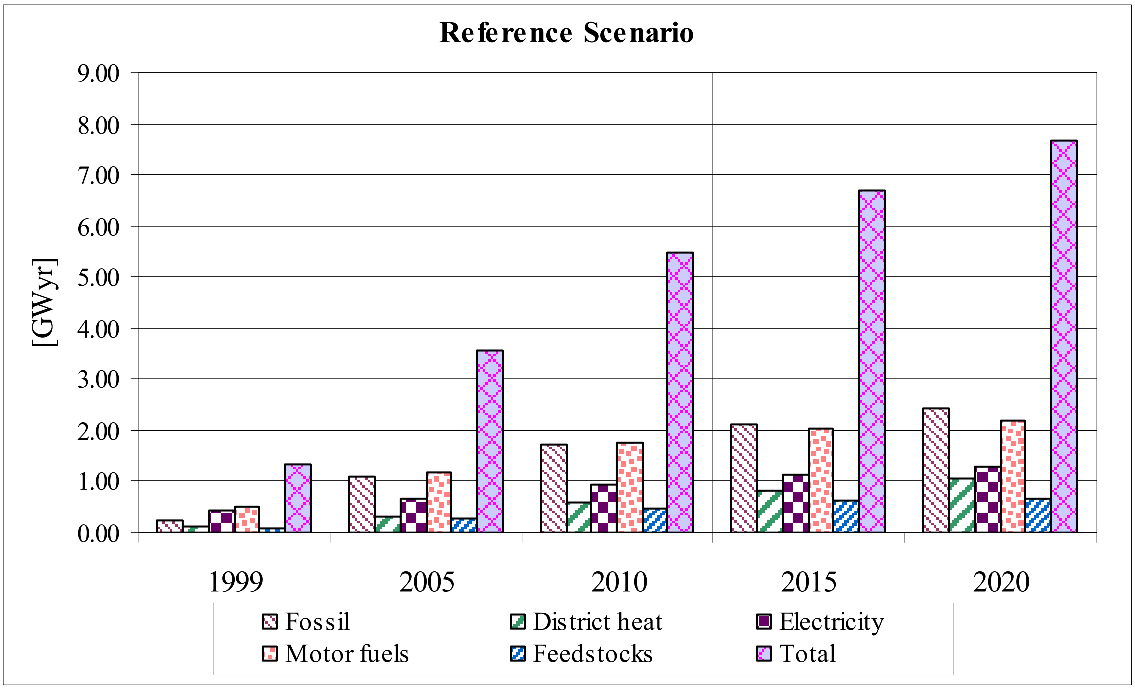


Figure 3. Distribution of Final Energy Demand by Energy Form for both Scenarios

The sum of cumulative investments and operation costs is thus higher by US$ 0.17 billion in case of Reference Demand Scenario with Nuclear Option, as compared to that in case without nuclear option. The similar situation can be viewed for the Low demand Scenario Cases. It may be noted that these values in scenarios with nuclear option are not much different from those in scenarios without nuclear option (Table 4).

7. Conclusions

The detailed analyses carried out in this study show that the demand for energy and electricity would continue to increase during the years at about 7-9% per annum. Due to increased use of energy, the environmental emissions from the energy sector will also increase, threatening with the severe degradation for natural environment. The study has shown that in order to combat those problems, the following measures should be implemented:

- Rehabilitate all existing hydropower plants as soon as possible.
- Rehabilitate existing thermal power plants and CHP units.
- Implement aggressively demand-side management campaign and carrying out cost-effective measures without delay.
- Keep the operating nuclear power plant till its design life with enhanced nuclear safety, not only relevant to the plant, but also considering the system measures, such as strengthening of the HV transmission system, interconnection to neighboring countries, provision of adequate levels of spinning reserve, and load management to increase the low system load at night.
- Add Shnokh, Megri and Gekhi HPPs, as well as 75 MW small hydro between 2012 and 2017, and add 15 MW of wind farm, and implement other renewable projects.Add gas-fired CHP Combined Cycle Plants (668 MW) according to heat demand and electricity demand growth.
- Maintain Hydro-Potential Stocks of Lake Sevan. Reduction of Irrigation Losses.

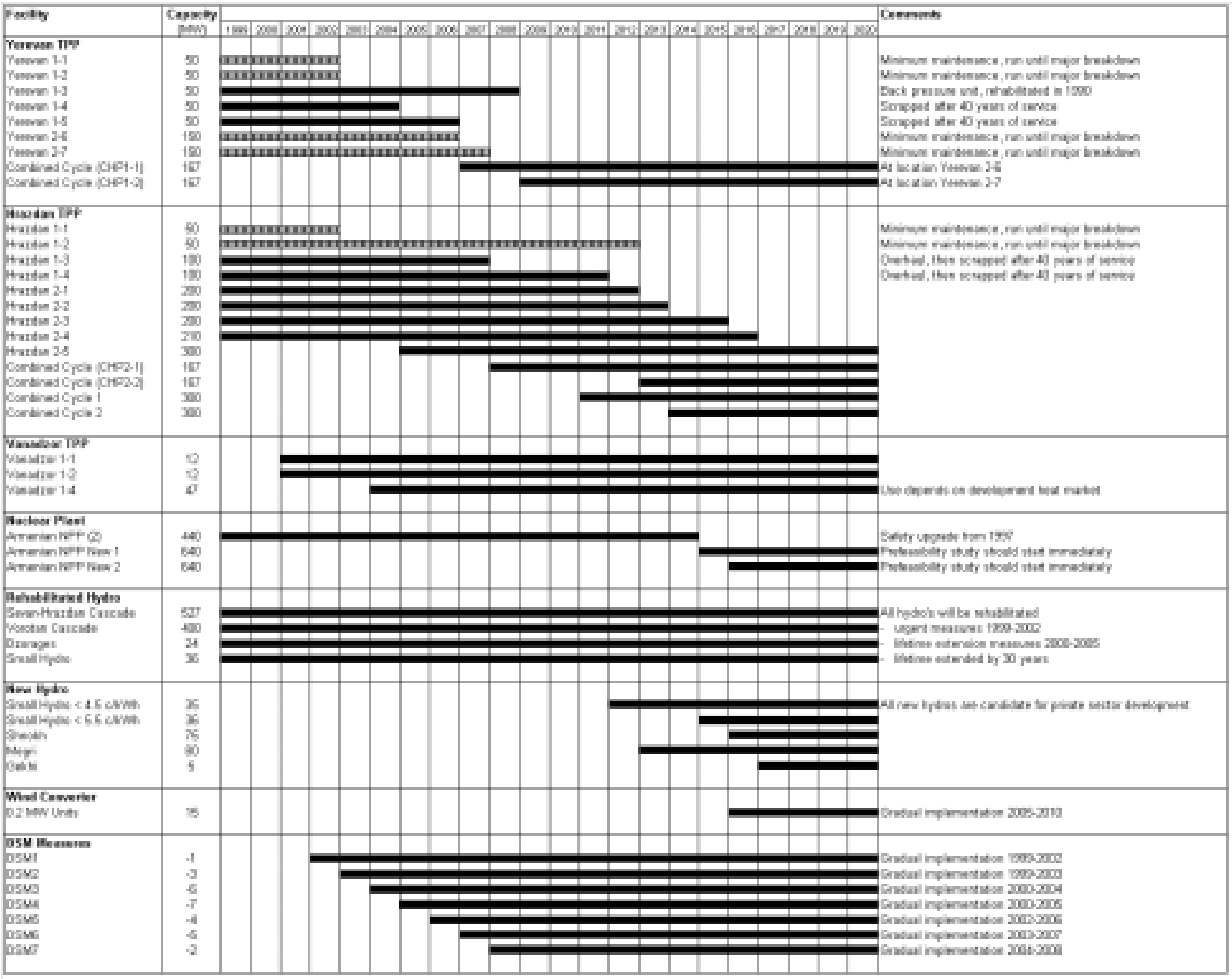


Figure 4. Least Cost Expansion Plan for the Power Sector Reference Demand Scenario

- Rehabilitate and further develop gas and electrical interconnections to neighboring countries. Rehabilitate and expand underground gas-storage. And maintain a reasonable stock of crude oil and/or petroleum products.Develop nuclear power on the basis of modern technologies in parallel with the old units decommissioning process.
- Introduce tax incentives to stimulate private sector involvement in development of renewable energy projects, which would help to decrease Armenia's dependency on fuel imports, it would also be of benefit to the environment.

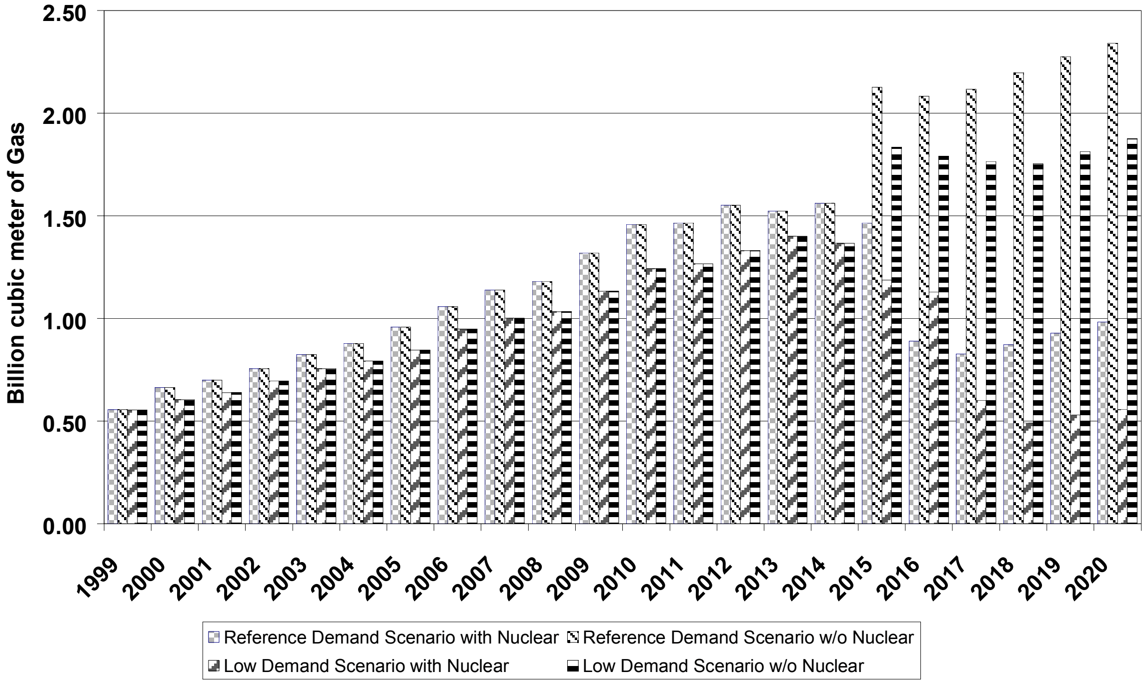


Figure 5. Natural gas consumption for power generation in different supply cases

Table 4. Cumulative Investments and Operation Costs (Million US$ of 1999)

Scenarios	Investments	Operation Costs	Total
Reference Demand Scenario			
Case with Nuclear Option	2854.0	4545.4	7399.4
Case without Nuclear Option	2220.0	5004.5	7224.5
Low Demand Scenario			
Case with Nuclear Option	2658.0	3894.2	6552.2
Case without Nuclear Option	2024.2	4260.1	6284.3

During the course of this study, the Working group of the Energy Strategy Centre has acquired very valuable expertise on energy, electricity and nuclear power planning. This capability will be used in future ESC planning studies.

1 INTRODUCTION

1.1. Purpose and Scope of the Study

1.1.1. Background

The socioeconomic development of a nation cannot be achieved without consumption of energy necessary to satisfy the needs of services (transport, cooking, etc.) and the production of goods needed by the society (equipment, basic materials, etc.). This energy is consumed in different ways: electricity, motor fuels, thermal energy, etc.

Energy systems have such a specific feature: the implementation cycle of the energy generating facilities is, as a rule, longer than that of energy consuming facilities. Consequently, the decision for installing new energy supply facilities or expanding the existing ones should precede the decision of implementing new consumers for several years. This imposes the need to estimate for several years ahead, what would be the consumption level in the near future.

Moreover, taking into account the fact that both capital costs and fuel prices are continuously changing, it is obviously necessary to perform a systematic energy planning activity, as an attempt to estimate the future energy demand in different variants (scenarios) of the country's socioeconomic and technological development in order to optimize the energy supply.

Having in view the inherent uncertainty in estimating the future development both of countries with stable economy and, especially, of countries with the economy in transition, such as Armenia, a sound solution might be the elaboration of some coherent socioeconomic and technological development scenarios, that include a plausible range of a country in order to forecast the total energy and the electricity demand corresponding to each of those scenarios.

The Energy and Nuclear Power Planning study for Armenia, conducted under the technical cooperation program of the IAEA had in view the forecasting of the overall energy demand in various scenarios of Armenia's socioeconomic and technological development, and the economic optimization of the electric energy generating system expansion in order to meet both the electric power demand and the requirements of the Energy Sector of Armenia, as a whole. An assessment of a role that nuclear energy could play within this optimal program, was the main part of the study objectives.

1.1.2. Objectives of the Study

The objectives identified for the study were as follows:

- To establish the role that nuclear power could play in the future electricity supply of Armenia on the basis of least-cost expansion planning analysis of the country's power system,
- To analyze the environmental impacts of such a nuclear power development,
- To evaluate the financial viability of the envisaged nuclear power development program, and
- To train a group of Armenian experts in the use of the IAEA's models.

1.1.3. Scope of the Study

It was obvious, that to achieve the above-mentioned objectives, the study should include:

- a detailed analysis of overall energy demand, including electricity, and its future evolution,
- assessment of future supply potential of indigenous energy resources,
- analysis of possibilities of import of various fuels,

- evaluation of future options for electricity generation,
- formulation of alternative expansion plans for electric sector development,
- assessment of environmental impacts of future electricity generation, and
- analysis of the financial requirements of the envisaged nuclear power program.

Further, in view of the long term implications of electricity sector development (due to long gestation times for different power plants and their long operating lives) a 22-year time horizon was considered appropriate for the study. The base year, as a reference, was chosen the year of 1999, because a large amount of data required for various analyses was available for that year.

Similar to other IAEA technical cooperation projects, the ENPP study was conceived as a joint effort of Armenia and the IAEA where each part had its own clear, well-established responsibilities:

- Armenian experts had full responsibility for the conduct of the study, including data collection and preparation, execution of the computer runs, interpretation and improvement of results, etc., up to the production of the draft report of the study;
- The IAEA experts provided guidance and coordination throughout the conduct of the study, on-the-job training of the national team, transfer of know-how and the necessary methodologies and computerized planning tools to Armenia.

The distribution of tasks was conceived in such a way that, by the end of the study, the energy planners in Armenia should have gained sufficient experience in the use of the methodologies and computer programs provided by the IAEA and could apply them independently for carrying out future planning studies.

1.2. Institutional Setup and Process for Energy and Electricity Planning

The Energy Strategy Center of the Ministry of Energy of Armenia is responsible for the development of short, medium and long term plans for the energy sector. The ESC co-operates with various institutions and departments, considers different energy sources and develops the overall national energy plan. The energy plans are worked out within the framework of national macro-economic development plans.

Like other economy sectors, the energy sector also has to compete for resources during the process of planning. From the economic point of view, the investment allocations for different sectors, as a rule, should be determined on the basis of economic efficiency. However, in accordance with the objectives of socioeconomic development of the nation, the sectoral shares are determined on the basis of social marginal productivity, although the detailed analysis required for that is not always possible, since the resources are not always available.

As to the specific energy forms, the Ministry of Energy of Armenia is responsible for planning, policy formulation and implementation of development programmes related to natural gas and electricity sectors. The MoE is also responsible for development and dissemination of new and renewable energy technologies.

The Ministry of Environment (and Natural Resources) of Armenia is responsible for planning and implementation of development programmes related to coal and water resources. The Private Companies are responsible for delivery of oil, oil products and LPG.

1.3. Methodological Approach

Nuclear power is one of the various technological options for producing electricity. The future role of nuclear power can be determined only if the future development of the electricity generation sector is analyzed in details, considering future requirements of electricity and all possible supply options. The electricity sector is a part of the overall energy system, because the electricity may substitute other fuels for some categories of energy end-use. So, for a realistic analysis, it is necessary to analyze the evolution of demand and supply of the whole energy system at the national and regional level. Further, future supply potential of all indigenous energy resources, as well as import possibilities of various fuels, have to be analyzed. Based on the analysis mentioned above, the least-cost analysis of alternative strategies for electric system expansion can be done, and the possible role of nuclear power in the future electricity generation in the country can be determined. This approach has been followed in the present study.

The financial resources in Armenia, like in other developing countries, are very limited. Although nuclear power is competitive compared to other electricity generation options, it is a very capital-intensive technology. A realistic program for nuclear power development should be financially viable for the country. The present study, thus, includes financial analysis of the envisaged nuclear power program.

To carry out all the above-mentioned analyses, the IAEA's set of methodologies for energy and nuclear power planning have been used. The specific models used are:

- MAED for energy and electricity demand analysis and projection of electric load profiles,
- WASP-IV for least-cost electric system expansion analysis,
- BALANCE for energy resources allocation to power and non-power sectors,
- SIMPACTS for environmental impact analysis, and
- A simplified financial analysis model.

Energy and Electricity Demand Analysis Model (MAED)

The Model for Analysis of the Energy Demand, MAED, is a simulation model designed to evaluate medium and long term demand for energy in a country or a region. The methodology comprises the following basic sequences of operation:

- Breakdown of the structure of the country's final energy consumption into a multitude of individual categories of end-use in a consistent manner;
- Identification of the social, economic and technical factors influencing each category of final energy demand;
- Specification (in mathematical terms) of the functional links between energy consumption and the factors governing that consumption;
- Reconstruction of the country's structure of final demand based on socioeconomic and technical data for the base year of the study;
- Construction of "scenarios of socioeconomic and technical development"; which consists of establishing possible future situations of the country under study with respect to the evolution of demographic, macroeconomic, socioeconomic and technical factors;
- Evaluation of the energy consumption corresponding to each scenario.

The main features of the MAED approach are different from those of time trends and econometric methods. The design of MAED was to overcome some of previous models' weaknesses such as the analysis based on price elasticity, which is no longer satisfactory under the present world energy price fluctuations. The main features of MAED are to reflect:

Structural changes affecting medium and long term energy demand by means of a detailed analysis of the social, economic and technical system. This approach takes into account, in particular, the changing social needs of individuals, for example, for cooking and other appliances in households, transportation and others; and the policies for national development including industrialization, and policies on transportation, housing, services and national security. Trends in the potential market for each final energy form: electricity, coal, gas, oil, solar energy, etc.

The MAED for WINDOWS model consists of two modules. Module 1 is basically an updated version of the MEDEE-2 model developed for the International Institute for Applied Systems Analysis (IIASA) for analysis of the evolution of overall energy, including electricity, demand in a region or country. Module 1 is used to determine the future demand for all forms of energy in all sectors of the economy.

The electricity demand projected with the help of Module 1 of the MAED model is in the form of annual electricity requirements at the user end. This demand has to be converted to hourly demand at the generation system level so that the requirements of the electricity generation system expansion could be planned. The distribution of electrical load over time, which characterizes the pattern of electricity usage, is crucial for selection of the generating units to be added and for their loading in the system. The WASP-IV requires as input, projections of system peak demand and load duration curves.

Module 2 uses annual electricity requirements in different sectors of the economy and converts them into hourly system load by taking into account system losses (auxiliary consumption, transmission losses and distribution losses), seasonal variation of electricity consumption in different sectors and hourly load pattern of demand in these sectors; and rearranges the hourly system load in decreasing order to work out the system peak demand and load duration curves.

Electric System Expansion Optimization Model (WASP-IV)

The WASP-IV (Wien Automatic System Planning package) Model determines the electricity generating system expansion plan that adequately meets demand for electric power at minimum cost while respecting user-specified constraints. WASP-IV is directed to long term planning and is intended to address a number of critical issues in generation planning, including generating unit size, system reliability, details of the existing system, seasonal variation in loads and hydroelectric availability, and appropriate simulation of future system operation. It utilizes probabilistic simulation to estimate system production costs, unserved energy and reliability, and dynamic programming for optimization of system expansion policies. WASP-IV is organized in a modular way, which permits the user to monitor intermediate results, avoiding waste of valuable computer time due to possible input data errors.

WASP-IV permits to find the optimal expansion plan for a power generating system over a period of more than thirty years, within the constraints specified by the planner. The information needed by the model includes the load forecast, characteristics of the power plants already in operation or firmly committed; characteristics of the power plants that can be used as alternatives for system expansion; the constraints to be considered in the analysis, such as the number of units of each candidate plant that can be added in a given year; reliability criteria, such as, the Loss-of-Load probability (LOLP) and minimum reserve margin to be satisfied by each expansion policy; investment and O&M costs of each plant type as well as other technical and economic parameters. The optimum solution is evaluated and reported in terms of minimum discounted total cost including investment, operation and energy-not-served costs. This solution displays the optimal expansion schedule of power plant addition to the power system selected from the list of expansion alternatives specified by the user.

The WASP-IV computer code is organized in a modular form.

Module 1, LOADSY (Load System Description), processes information referring to the annual and period peak loads and the load duration curves for each period of the year, over the study period. These data may be directly imported from the MAED model.

Module 2, FIXSYS (Fixed System Description), processes information describing the existing power plants and also refers to the firmly committed additions or retirements.

Module 3, VARSYS (Variable System Description), processes information related to the various candidate plants taken into account for expanding the electric generating system.

Module 4, CONGEN (Configuration Generator), calculates all possible year-to-year combinations of candidate unit additions, which together with the FIXSYS plants meet the demand of electricity with the imposed reliability level.

Module 5, MERSIM (Merge and Simulate), uses the probabilistic simulation of the system operation for estimating associated production costs, the amount of unserved energy and reliability level of each configuration retained by CONGEN. MERSIM can be used to simulate the system operation for the best solution provided by the current DYNPRO run and in this mode of operation is called REMERSIM.

Module 6, DYNPRO (Dynamic Programming Optimization), determines the optimum expansion strategy of plant additions over the study period by means of a dynamic programming algorithm.

Module 7, REPROBAT (Report Writer of WASP in a Batched Environment), writes up a partial or total report for the optimum or near optimum power system expansion plans.

In addition, WASP-IV allows conducting sensitivity studies on different parameters such as fuel prices, discount and escalation rates, construction time, and energy-not-served cost. Such capability allows the planner to make comparisons of different plant descriptions of both the candidate and existing power plants within the optimized expansion system; and to explore alternative ways of power system expansion as dictated by new policies and constraints within the national development requirements.

Overall Energy Demand-Supply Balancing Model (BALANCE)

With the BALANCE module, the analyst evaluates the energy system configuration that will balance energy supply and demand. BALANCE uses an iterative, non-linear, equilibrium approach to determine the energy supply and demand balance. In this process, an energy network is designed to trace the flow of energy from primary resources to useful energy demands in the end-use sectors. Energy networks are typically constructed in such a way that demand nodes are located at the top of the network and energy supply resources are at the bottom of the network with conversion process nodes located in the middle. Once the network is constructed and historical energy flows are simulated, the module forecasts future energy demands and prices.

Energy prices are computed by estimating costs for energy extraction and conversion processes through to the demand nodes. This process is referred to as the up-pass sequence. Demands are simulated by computing energy flows from demand nodes through conversion processes down to the supply resource nodes. This process is referred to as the down pass node sequence. In the down pass sequence, when the Model computes energy flows, price estimates from the previous up pass sequence are used to determine the market shares of competing energy alternatives (i.e., input links). The model employs a market share algorithm using a logic function to estimate the penetration of supply alternatives. The market share of a specific commodity is sensitive to the commodity’s price relative to the price of alternative commodities. User-defined constraints (e.g., capacity limits), government policies (taxes, subsidies, priority for domestic resource over imported resource, etc.), consumer preferences, and the ability of markets to respond to price signals over time (i.e., due to lag times in capital stock turnover) also affect the market share of a commodity.

As market shares of energy are dependent on the energy prices and energy prices are dependent on the quantity of fuel demands, BALANCE uses an iterative process to bring network prices and quantities into equilibrium. The up pass and down pass sequences are repeated until the difference in energy flows (i.e., quantities) on network links changes very little from one iteration (i.e., down pass) to the next and the processes converge within a user specified tolerance level.

Since energy purchase decisions are not always solely based on price, premium multipliers are used in BALANCE to simulate the preference that consumers have for some commodities over others. Premium multipliers are used to simulate the market behavior when competing resources have different levels of quality or convenience. It can also be used to simulate the market behavior when high capital costs discourage the use of a specific technology or process. In addition, the Model uses a lag parameter to simulate the time that is required in order prices and demands to reach an equilibrium or balance. In general, capital-intensive industries have longer lag times than those, which require relatively small capital investments.

The equilibrium modeling approach used in the BALANCE Module is based on the concept that the energy sector consists of autonomous energy producers and consumers that carry out production and consumption activities, each optimizing individual objectives. In contrast, optimization models of the entire energy sector, such as linear programming formulations, can take on the interpretation central planning authority, which has control over all energy flows and prices in the entire energy sector. Using the market share, algorithm sets BALANCE apart from other modeling techniques.

The BALANCE approach simulates the more complex market behavior of multiple decision-makers that optimization techniques may not be able to capture as they assume a single decision maker. Every sector (electric, industrial, residential, etc.) pursues different objectives and may have very different views of what is “optimum”. The equilibrium solution develops an energy system configuration that balances the conflicting demands, objectives, and market forces without optimizing among all the sectors of economy.

Environmental Assessment Model (SIMPACTS)

To assess the environmental impacts of alternative plans for electricity generation system expansion, SIMPACTS programme has been used in this study. Electricity can be generated from a variety of primary energy sources — fossil fuels (oil and natural gas), uranium, hydro and other renewable (solar, wind, etc.). Use of each of these primary sources damages the natural environment (soil, water or atmosphere). In the present analysis, a comparison has been made only at the power plant level.

The assessment methodology is based on the “Damage Function Approach or Impact Pathway Analysis”, which traces the fate of a pollutant from its point of emission, followed by dispersion on a local scale (up to 50 km of the source location) and regional scale (1000’s of km downstream of the source) and, finally, receptor uptake (i.e., exposure or dose). Damages are aggregated across all receptors that are influenced by a pollutant. The SIMPACTS model is designed to estimate these effects. SIMPACTS will determine the environmental impacts of the Power Sector. The information on electricity generation by each type of plant and the corresponding quantities of emissions emitted to the atmosphere has been used in this analysis and has been obtained from the WASP-IV analyses. The emission factors for various pollutants, worked out by the user based on fuel characteristics and technology, are used for evaluating the emissions of various pollutants from electricity generation.

Financial Analysis Model

Financial analysis of the envisaged nuclear power development plan has been carried out with a simplified financial analysis spread sheet based model. This model has been designed to analyze financial viability of an investment program of a power utility. It uses standard methodology for preparing yearly projected financial statements, viz. Balance Sheets, Income Statements, Cash Flow Statement, on the basis of information provided by the user on schedule of future investments, sources and terms of financing, inflation and escalation rates, projected revenues, etc. It also works out important financial ratios, which are helpful for assessing financial viability of a proposed investment program.

Integration of Various Models

It can be noted that different models interact with each other and pass on relevant information, which is used for further analysis. The models also provide feedback information, which in certain cases necessitates revision of the analysis made with the previous model. For example, the environmental analysis or the financial analysis may require revision of electric system expansion plan worked out with the help of WASP-IV. Likewise, overall energy demand-supply balance may require revision of allocation of primary energy sources to electricity generation. This iterative process integrates the entire energy system and ensures consistency.

1.4. IAEA Support for the Study

The study was launched in May 2000 when an IAEA expert mission visited Armenia to assist in finalizing the program of the project. It was envisaged that about three years period would be required to carry out various activities identified for the study. During this period, the national team has been in constant touch with the IAEA's experts and has had regular meetings for review of the progress of the study. Several members of the national team were provided with formal, as well as on-the-job, training by the Agency on the use of these models. Besides, a number of technical meetings of the IAEA experts and the national team were arranged in Vienna and Yerevan for reviewing the work and providing technical guidance for the study. A total of 6.25 man-months of Expert Services, 2 man-months of national team visit to IAEA and 4 man-months of training of the members of national team were arranged by the IAEA for this project. This technical support from IAEA greatly helped the national team to develop capability for undertaking such a comprehensive study and enabled the latter to complete the study successfully within the stipulated time.

1.5. Organization of Study Report

The report consists of 13 chapters. After this introductory chapter, the 2nd chapter describes the Energy-Economy Setting in the country. It reviews historical evolution of demography, economy and energy supplies and consumption. Chapter 3 explains the major elements of different scenarios constructed for the study. Chapter 4 describes the future evolution of energy and electricity demand worked out under different scenarios. Chapter 5 gives the projections of electricity demand and the peak power demand. Chapter 6 reviews the opportunities of regional energy evolution of Trans-Caucasian region. Chapter 7 focuses on the electricity generation system expansion analysis. Chapter 8 describes the analysis results of the generation system expansion. Chapter 9 describes the energy network for Armenia; data and main assumptions used in the BALANCE analysis, study approach, and explains the results of energy supply cases obtained by BALANCE model. Chapter 10 gives the projections of the external costs and physical impacts of the investigated scenarios (SIMAPACTS model). Chapter 11 explains the financial evaluation for the basic case, a sensitivity and risk analysis that was carried out to check the critical variables and the relevant performances. Chapter 12 elucidates some important aspects of the development of nuclear energy, taking into account such specific conditions and tendencies, which are formed and developed in Armenian economy and, in particular, in fuel - energy complex of the country. Material, presented in this chapter, is based on summarizing of the results of investigations, presented in the previous chapters of the report, and certain investigations on decommissioning of existing units of Armenian NPP. And finally, Chapter 13 summarizes the main conclusions and recommendations resulting from all the analysis.

2 GENERAL ENERGY-ECONOMIC SETTING

2.1 General Background

Geography and Climate

Armenia is a small landlocked mountainous country with very limited natural resources, and from the energy point of view, the hydroelectric power is the only indigenous source of energy.

Having an average elevation of about 1,700 meters above the sea level (ranging from 3,000 to 400-1,000 meters), Armenia is the most mountainous country of the Caucasus region. The lowest elevation (380m above sea level) is in the Debed River valley, and the highest - 4,090 m above sea level is the Mt. Aragats. Mt. Ararat, Armenian name - Masis (5,165 m above sea level) is visible from many places of the southwest region, and, though it was annexed by Turkey in 1920, it still remains the country’s national symbol. (According to the Old Testament, Noah's ark came to rest on that historical site.).

Lake Sevan is one of the largest highland fresh-water lakes in the world, located about 1,900 m above sea level. Its total area is about 1,400 sq. km. Main rivers are: Arax (1,072 km total, 158 km within the territory of Armenia), Arpa (126 km, 90 km in Armenia), Hrazdan (146 km), Debed (178 km, 152 km in Armenia), and Vorotan (179 km, 119 km in Armenia).

Armenian climate is continental with hot summer and cold winter due to the highland character of a landshaft. The situation was even worsened because of the forests cutting. In winter temperature may reach –46 °C, while in July and August temperature may grow up to 42°C. Summer period is very long and dry, its duration is about four months. The average precipitation is around 300 mm per year.

Total land area of the country is 29,800 sq. km. The arable land is only 17%, meadows and pastures about 30% and forest and woodland about 12%.

Administratively, Armenia is divided into 10 regions (Marzes), plus the capital city Yerevan (Table 2.1). For the scope of this study, it has been divided into three macro regions and Yerevan, as follows:

These four macro-regions can be characterized by elements shown in Table 2.2.

Table 2.1. Armenian Regions

Macro Region	Marzes
Northern	Lori, Shirak, Tavush
Central	Aragatsotn, Armavir, Gegharkunik, Kotayk
Southern	Ararat, Sunik, Vayots Dzor
Yerevan	Yerevan City

Demography

The demographic situation was much changed during the period of 1990-1998 because of mass migration and fall in birth rates. In fact, the natural growth rate per thousand of population declined about 5 times, from 16.3 in 1990 to 3.3 by the end of 1999. This sharp fall was mainly due to the decrease of the birth rate, which nearly halved reducing from 22.5 per thousand to 9.6. The worsening demographic situation was caused by the social and economic conditions, as well as by decline in the standard of living of a substantial part of the population, and also by

Table 2.2. Dimensions and Population (1995)

Region	RA	North	Center	South	Yerevan
Square, sq. km	28464	9173	10164	8912	215
Population, thousand persons	3766.9	905.5	1076.3	535.7	1249.4
Population density person/sq. km	132.3	98.7	105.9	60.1	5811.2
Square, %		32.2%	35.7%	31.3%	0.8%
Population, %		24.0%	28.6%	14.2%	33.2%
Composition of population, %					
rural	38.5%	37.3%	57.3%	53.2%	16.8%
urban	61.5%	62.7%	42.7%	46.8%	83.2%

the imbalance within the age structure of the population. However, some perceptible improvement can be seen comparing the first quarter of 2000 with the same period of 1999. In particular, the birthrate increased by 0.2 points per thousand, while the death rate decreased by 0.6 points. As a result, the natural growth rate improved from 2.3 in the first quarter of 1999 to 3.2 in the same quarter of 2000 (Table 2.3).

Population growth, during the period under consideration, was also affected by migration. The current system of migration flows registering does not reflect the real migration picture in the country, and, consequently, it neither can provide the other demographic indicators, since it includes mostly air travel, while accurate data on the other means of transportation are not available. In order to evaluate migration flows in 1998-1999 the Ministry of Statistics and Eurostat conducted a sample survey under the TACIS project “Migration Research”.

During the survey, there were monitored passenger flows at the airports and at the bus stations in the main towns of Armenia. According to the results of this survey and other data provided by the Department of Civil Aviation, the1992-1999 migration, computed as the difference between the number of departures and arrivals, was estimated at 622,000. Meanwhile, the 1989-1991 migration inflows exceeded outflows mostly due to the huge inflow of refugees. The most part of emigration was registered during 1992-1994, as a result of the blockade, the energy crisis, and the overall worsening of social and economic conditions. Since 1995 and up to 1999, migration flows have been stabilized.

According to the survey results, more than half of the migrants (52.5%) migrate because of the lack of job opportunities and the inability to attain sufficient standards of living. The educational structure of migrants shows that about 61% of migrants have secondary and secondary vocational education, and 22% have higher education.

Macroeconomic Background

After obtaining the independence of the Soviet Union, Armenia experienced several years of economic difficulties due to the collapse of regional trade- and payment agreements. Additional disruptions to trade flows were caused by the blockade. During 1992 and 1993, the output has dropped over 60 percent, and prices have risen more than 110 times compared to 1991.

The year 1994 can be seen as the year of reversal of the negative trend. Since then, the Government has implemented the economic programs featuring tight financial policies and far reaching structural reforms. As a result, the consolidated government budget deficit declined from more than 16% of GDP in 1994 to 6% in 1997. Inflation fell from several thousands

Table 2.3. Demographic Statistics (per thousand)

Years	Population, end of period	Birth rate	Death rate	Natural growth rate	Child mortality
1985	3361.7	24.1	5.9	18.2	24.8
1990	3574.5	22.5	6.2	16.3	18.5
1991	3648.9	21.6	6.5	15.1	17.9
1992	3722.3	19.2	7.0	12.2	18.5
1993	Not Available				
1994					
1995					
1996					
1997					
1998					
1999					
2000	3211.4	9.6	6.3	3.3	15.0

Source: National Statistical Service

percent in 1993 to about 22% in 1997, going below 10% in 1998. GDP grew by an average yearly rate of 5.4% over the 1994-1999 period.

Despite the good results obtained over the last years, many sources of vulnerability remain, which, unless addressed forcefully, may complicate macroeconomic management and delay the transformation of the economy.

In the 1998 October-December issue of the Economic Trends of Armenia, published by the European Commission, the following statement has been reported:

"Data for 1998 show a fairly good picture of the Armenian economy: a real growth of 7.2%, an annual rate of inflation falling from 13.8% to 8.7% and a slight improvement in the trade deficit as a percentage of GDP. Dram depreciation against the dollar, on average, was 2.9%, which is surely not a bad result in a year marked by exchange rate instability all around the world. Finally, the budget deficit, at 3.2% of GDP, was lower than the 4.7% registered in 1997."

Armenia is not rich in mineral deposits and raw materials. There are only a few items of considerable industrial value: copper, bauxite, molybdenum, precious metals, perlite, diatomite and coal. This factor, together with the high level of literacy and of highly qualified people, determined the economic structure that was built up under the central planning system of the former Soviet Union.

1988 was the last year when Armenian economy was stabile. Table 2.4 shows evolution of the main changes in GDP structure since 1988 up to the base year (1999).

The share of Manufacturing Sector in the GDP for the base year (1999) has dropped more than 3 times compared with 1988. The manufacturing sector provided for about 21% (6.7% of 21% was a contribution of Energy Sector) of GDP in 1999. However, the conditions for industry development were not much favourable, taking into account the low level of industrial production in 1999, when production was seriously affected by the 1998 Russian crisis.

Table 2.4. Composition and changes of GDP by main sectors

Years	1988	1994	1999
GDP at constant 1999 prices (billon $)	**3.2**	**1.4**	**1.8**
% of total GDP			
GDP	100	100	100
Of which:			
Manufacturing	67.8	29.1	21.0
Agriculture	12.7	43.5	26.2
Construction	9.7	6.7	8.8
Service	9.8	20.7	44.0

The share of Agriculture Sector in total GDP for the base year (1999) decreased by 40%, compared with 1994. Nevertheless, there was registered a significant increase in the share of this sector in 1994 (by 243%, compared with 1988).

It can be noticed that there is little difference between the shares of Construction Sector in total GDP when comparing the data for the base year and the year of 1988.

As for the Service component, the main contribution came from the trade sector: the sector, having been enlarged, increased its production by 111% during the period 1988 - 1994, and by 113% during the period 1994 -1999.

On the whole, Armenian economy could quickly resume a growth path after the fall in 1999; its slow growth in 1999 (3.3%) could be explained mainly by the shock caused by the October shootings in the Armenian National Assembly, and also by the widespread political uncertainty. Nevertheless, most of the problems were overcome, judging by 6% GDP growth in 2000.

These indicators, as well as the current economic conditions on the whole, are still raising hopes and pointing to improvements in near future.

From this point of view, there is no need to view the positive results attained in 2000 as an anomaly, they may be rather considered to be the beginning of a positive trends.

Per capita GDP, household money income and consumption

In 1999, GDP per capita in Armenia was US$ 487.6, that is, 2.6% lower than it had been a year ago. The year-on-year depreciation of the dram regarding the US dollar was the only reason for the higher increase of GDP per capita in drams (both nominal and real) than that in US$ (Tables 2.5 and 2.6).

2.2 Pattern of Energy Consumption and Supplies

2.2.1. Energy Demand

The total energy supply in Armenia, during the last few years, had improved with the steady trend to increase, that reflect the economic recover [1-20].

The total primary energy consumption in Armenia in 1988 amounted to 9961 ktoe, comprising about 97.1% in the form of fuels for energy uses and 2.9% as non-energy use products (Coal 3.2%, Oil Products 39.2%, LPG 0.5%, Natural Gas 45.7%, Hydro 1.3% and Nuclear 12.5%); while the consumption of fuels for non-energy uses (oil products and natural gas) amounted to some 292 ktoe (Table 2.7).

Table 2.5. Per capita GDP indicators

Years	1995	1996	1997	1998	1999
Per capita GDP [1]					
in current thousands of drams	138.9	175.2	212.5	252.7	260.9
in US$ [2]	342.2	423.8	432.9	500.4	487.6
Per capita GDP, year-on-year % change					
in nominal (dram) terms	178.2	26.1	21.2	18.9	3.2
in real (dram) terms	6.5	5.5	3.0	6.9	3.1
in US$ terms	101.7	23.8	2.1	15.6	-2.6

[1] Taking into account midyear population.

[2] Based on period average nominal exchange rate.

Source: National Statistical Service, CBA and AET calculations.

Since 1988, the demand for final energy in Armenia has been decreasing rapidly as a result of breakdown of former Soviet Union.

Some other data for years 1996-1998 are also available.

The data on the primary energy supply during the last years, in thousand tones of oil equivalent, are summarized in Table 2.8.

Table 2.6. Indicators of household money income and expenditures

Years	1996	1997	1998	1999
Household nominal income, bln drams	433.1	495.4	581.3	627.1
Household nominal expenditures, billion drams	422.4	500.8	578.9	631.7
Difference between nominal income and expenditures, % of income	2.5	-1.1	0.4	-0.7

Source: National Statistical Service and AET calculations.

Table 2.9 shows, that the country total energy consumption during 1996-1998 had steady increase at a rate, but the increase of GDP was sensitively greater.

The increasing trend in total final consumption of energy is clearly shown on Figure 2.1.

Table 2.10 and Figure 2.2 show that the data on energy consumption by economy sectors during the three years of reference did not differ much.

Most of the energy (about 80%) was utilized by the Industry, Transport and Residential sector. Agriculture utilized only 6%.

Table 2.7. Energy Balance for 1988

ktoe	Coal	Oil product	LPG	Natur. gas	Distr. heat	Hydro	Nucl.	Electr.	Total
Primary products				20		131	1243		1394
Imports	324	3980	51	4756					9110
Exports				-220				-251	-471
Stock change		-72							-72
Primary consumption	324	3908	51	4555	0	131	1243	-251	9961
*ARMENERGO									
* input		1671		1313		131	1243		4359
* output					757			1316	2073
* self consumption					3			101	104
*ARMGASPROD (self consump.)				22				1	24
* DISTRICT HEATING & INDUSTY BOILERS									
* input		73		787				37	897
* output					595				595
* TRANSPORT/DISTR. LOSSES (technical)				132	217			127	476
Available for consumption	324	2163	51	2301	1135	0	0	799	6773
* Statistical difference	0	0	0	0	0	0	0	0	0
* Final consumption by industry	3	253	1	707	459			353	1776
* Final consumption by residents	289		30	1033					1353
* Final consumption by services. commerce, administration	31	83	1	285	594			261	1256
* Final consumption by construction		105		57				22	184
* Final consumption by transport		1590	20	25				39	1674
* Final consumption by agriculture				34	82			124	239
* Non energy use		132		159					292

Source:BCEOM, MEF, 1993.

Table 2.8. Primary energy supply, ktoe

Year	Coal & Wood	Petroleum Products	Gas (Natural+LPG)	Nuclear	Hydro	Electricity (-Exp +Imp)	Total
1996	22	411	900	606	135	-	**2074**
1997	16	437	1137	418	119	- 5	**2122**
1998	17	477	1220	415	132	- 32	**2229**
1999	8	380	1053	542	103	- 21	**2065**

Table 2.9. The country total energy consumption

Years	1996	1997	1998	1999
Total Final Consumption (Ktoe)	984	1.088	1.186	1009
Consumption Increase (%)		10.6%	9.0%	-14.9%
GDP increase (%)	5.9%	3.3%	7.2%	3.3%

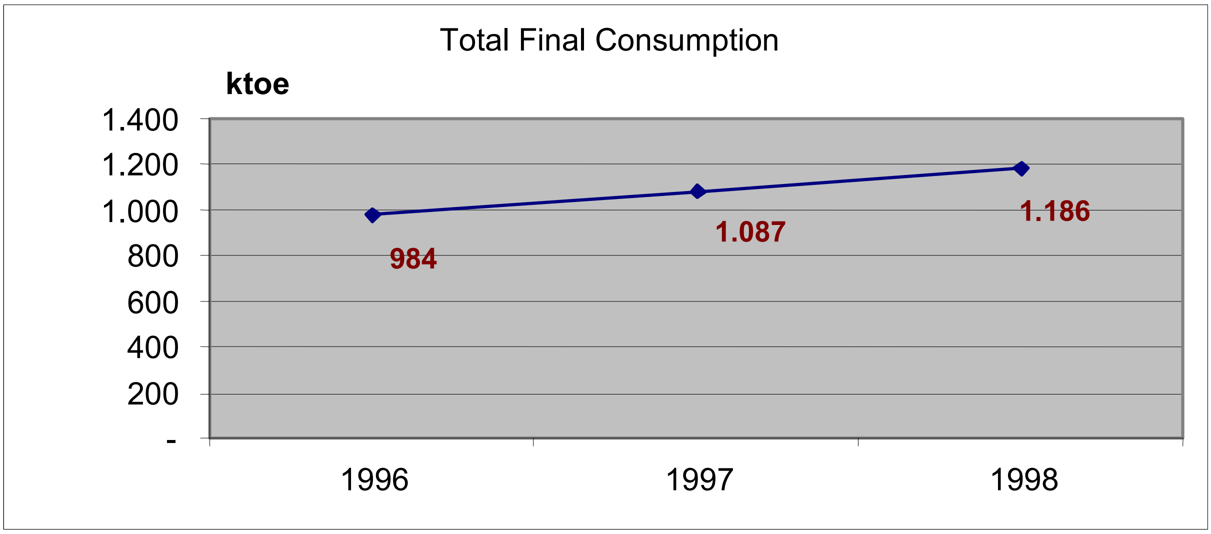
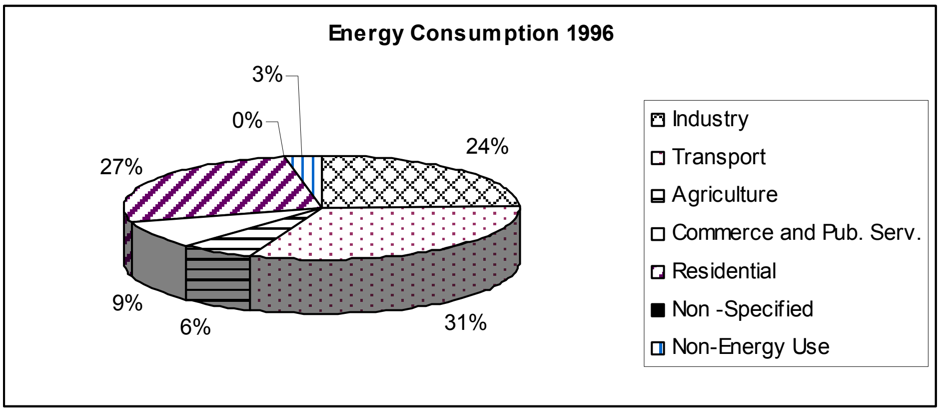
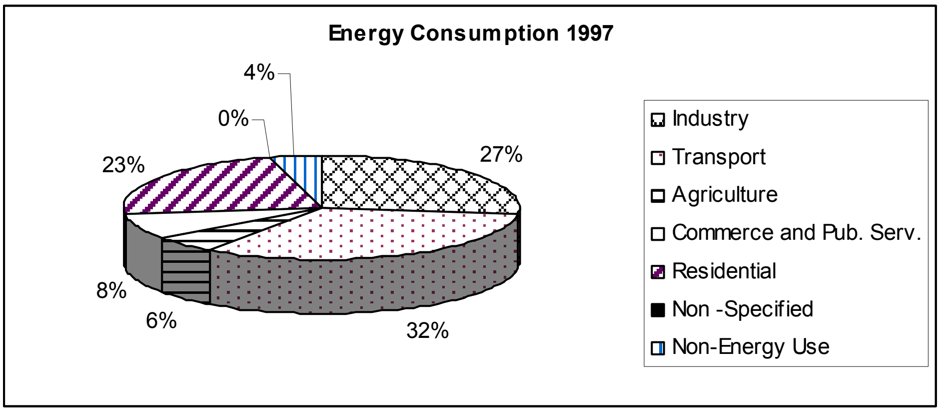


Figure 2.1. Total Final Consumption

Table 2.10. Total Final Energy Consumption

Sector	Total Final Consumption (ktoe)		
Economy Sector	1996	1997	1998
Industry	240.16	295.00	290.53
Transport	310.00	350.00	379.10
Agriculture	59.11	62.01	64.99
Commerce and Pub. Serv.	84.00	84.00	117.58
Residential Sector	260.99	250.68	294.98
Non –Specified	-	-	10.00
Non-Energy Use	30.00	45.00	28.50
Total Energy Consumption	**984**	**1,087**	**1,186**





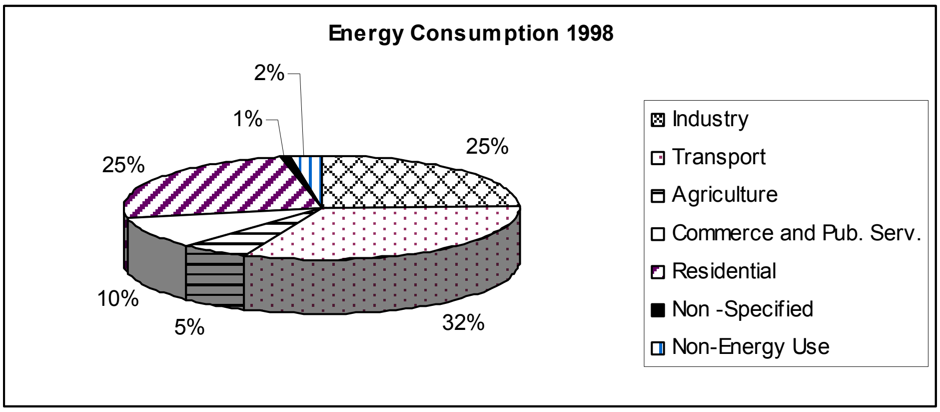


Figure. 2.2. The Structure of Energy Consumption in 1996, 1997 and 1998

2.2.2. Energy Consumption by Regions

The data on energy consumption by regions (Table 2.11, Figure 2.3) show a prevalence of Yerevan City, which was responsible for about 50% of the total consumption.

The sum of energy consumption by both Yerevan City and the central region (Figure 2.4) was about 67-69% of the total consumption. This reflects the fact that the economy was most developed in the area around the capital, including itself. The population in Yerevan and central region, during the years under reference, was also about 62% of the total.

2.3. Energy Resources

2.3.1. Fossil Fuels

Armenia does not have any oil or gas reserves. Only small quantities of coal [21-31] and little hydro resources are available. They are described below.

Table 2.11. Energy Consumption by Regions

Year	Macro Regions				
	North	**Center**	**South**	**Yerevan**	**Total Final Consumption**
1996	155.88	205.67	168.38	454.33	984.3
1997	163.46	222.21	177.88	523.14	1,086.7
1998	164.19	279.20	208.19	534.11	1,185.7

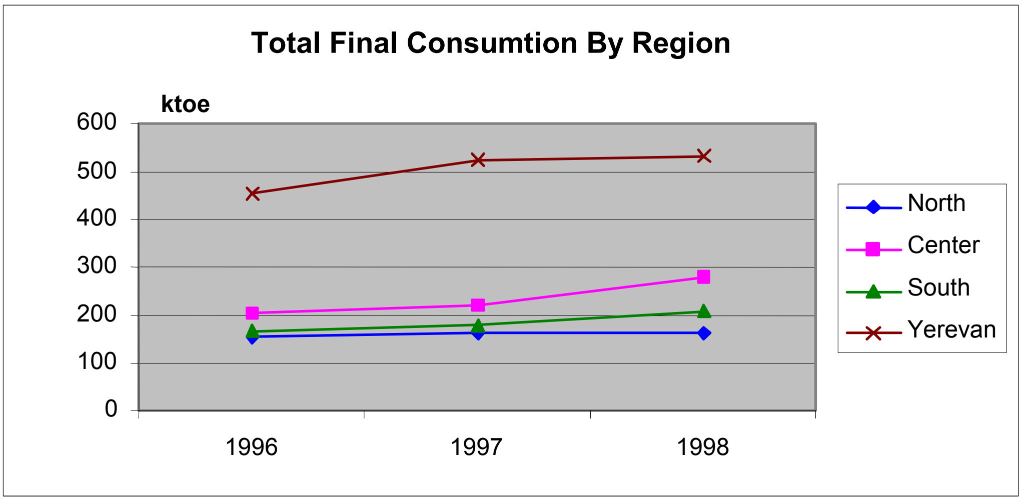


Figure 2.3. Total Final Consumption by Regions

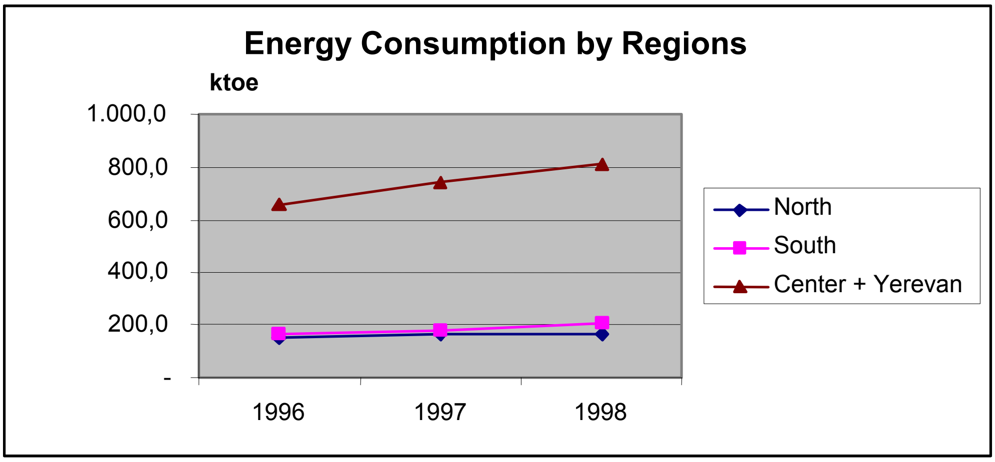


Figure 2.4. Energy Consumption by Regions (Center + Yerevan together)

Djadjur Coal Deposit. The Djadjur coal deposit is located in northwestern Armenia. MEI has recalculated the coal resources at Djadjur for five of the existing six coal beds, and the results have been waiting for the approval by the State Committee on Reserves. The new estimates are as follows: Indicated=260,113 tones, Inferred=336,224 tones, and Hypothetical resources are estimated at 200,000 tones. These estimates exclude coal which was less than 0.2 m thick and lay in depth more than 2000 m.

According to the U.S. Geological Survey (USGS) analyses, apparent rank of the Djadjur coal is the lower end of subbituminous and upper end of the lignite range. The six coal beds at Djadjur are of variable quality. Ash yield ranges from 9-26%, calorific values range from 3675-4601 kcal/kg, and sulphur contents range from less than 1 to 3%.

Lernut Coal Deposit. The Lernut deposit is mostly like the Djadjur coalfield, even though it has been studied separately. The resource estimates are based upon the data obtained when drilling 398 cubic meters of trenches, 126 m of shafts, and 68m of adios. Lernut is estimated to contain 40,000 tones of hypothetical coal.

Maisian Region. The coal in the Maisian deposit is, probably, also associated with the Djadjur coalfields and is located 7 km north of Gyumri. The first information on this deposit dates back to 1890, and, since 1951, the area had been explored systematically. The resource information is based upon 9 boreholes with the total depth of 1185 m, the adios totalling to 231m in length, and 817 cubic meters of trenches, as well as one shaft of 122 m in length. The hypothetical resource of the coal in the Maisian region is estimated to contain 10,000 tones.

Sotsk Deposit. The resource estimate was based on data collected when drilling as many as 40 m of shafts, 705 cubic meters of trenches, and 3 boreholes totalling to 200m. The deposit is estimated to contain 4000 tones of hypothetical coal.

Arevik Coal Deposit. The Arevik coal deposit is in southernmost Armenia, near the Iranian border, close to the town Megri. There are six beds in Arevik, with estimated 195,000 tones of indicated coal and 2,800 tones of inferred coal. The average calorific value of the Arevik coal is 5998 kcal/kg and average ash yield is 14.92%.

Idjevan Coal Deposit. The Ministry's calculation for the coal resources at Idjevan includes 9,780,000 tones of inferred coal and 88,000,000 tones of hypothetical coal. The ash yield varied from 16.2-14.8%, with an average value of 15.7%, sulphur varies from 0.44-8.9%, with an average value of 4.05%, and the calorific value range: from 7175-8638 kcal/kg, averaging- - 8086 kcal/kg. These estimates were based upon the exploratory work covering 64 boreholes totalling to 4337m in depth, 2151m of horizontal adios, 1000m of vertical or sub-vertical shafts, and 800 cubic meters of trenches.

Ghermanis Deposit. The Ghermanis reserve estimate has been calculated to be 309,400 tones of (indicated and inferred) coal. This coal deposit has an average calorific value of 5000-6000 kcal/kg, ash yield - of 17.1-45.3%, and sulphur content - of 2-3%. Information was collected during the study of 6510 m of boreholes, 367m of exploratory shafts, 4410 cubic meters of trenches, 730m long admit, and also, some geophysical logging information was used.

Shamut Coal Deposit. The Shamut coal deposit's reserves were estimated as 3,623,000 tones of inferred and 5,000,000 tones of hypothetical coal. The average calorific value was reported to be 6750 kcal/kg. According to the USGS analyses, the apparent rank of the Shamut coal ranges from sub bituminous to the lower end of the bituminous scale. The quality of the Shamut coal is affected by the large amounts of carbonaceous shale intermixed with the coal. Ash yield ranges from 49-75%. This is turn affect the calorific values, which range only 2369-5947 kcal/kg.

Antaramut Coal Deposit. Coal reserves of the Antaramut coal deposit have not yet been estimated, there have been calculated hypothetical resources only - 0.3 million tones. According to the Armenian Government official reports, the average ash yield totals to 28.8-32.3%, and calorific value – to 4762-5325 kcal/kg.

Peat deposits in Armenia. The peat in the Gelute deposit is located in the Gugark region, 125 km northwest of Yerevan. This peat contains 80% of moisture, 20.7% of ash, and it has a calorific value of 3050 kcal/kg. Using the analogy with the peat dried absolutely in the laboratory, this deposit was estimated to contain 2,052,000 indicated tones of peat.

The Masrik peat deposit is located in the Vardenis region of Eastern Armenia. This deposit consists of three sub deposits with the following characteristics; Ghilli-1 has an average thickness of 1.39m, and its resources are estimated at 337,100 tones of peat; Ghilli-2 has an average thickness of 0.82m and has resources estimated at 33.600 tones; and the Vardenis-1 sub deposit has an average thickness of 1.02m and contains 3.200 tones of peat.

None of the coal deposits in Armenia have been studied in details sufficient to determine the full extent of the resource or the complete character of the coal.

During the fall of 1996, the USGS and MEI jointly drilled three exploratory boreholes, in fulfillment of the Ministry's State Plan of Coal Exploration, which had been prepared for that purpose. Coal was not found. That year, the USGS had resumed drilling with plans to expand out from the known coal locality. The USGS and MEI approaches to coal explorations were fundamentally different. The MEI approach to coal explorations focused intensely on small local areas, known to contain coal, almost like the mining operation that would expand its known reserves. The USGS, on the other hand, was conducting the extensive fieldwork for the purpose of regional coal exploration.

2.3.2. Hydro Resources

Hydro Power is the only indigenous source of energy of some relevance for Armenia [32-48], besides, there could be produced the small amount of energy from domestic coal and wood.

Reliable independent international studies have estimated that theoretically available hydro potential of Armenia is as high as 21.8 TWh/year, of which about 85% is the potential of large and medium rivers, and the remaining 15% - of small rivers. The same studies estimate the technically available potential at about 7-8 TWh/year, of which the economically exploitable potential is about 3.2 TWh/year, which is a quite high figure for a small country like Armenia. The hydro potential of two large Armenian rivers (Hrazdan and Vorotan) is well developed. The potential of the third large system Pambak-Dzoraget-Debet (with a potential total capacity of 169 MW), with the exception of the Dzora HPP (26 MW), is relatively undeveloped. At present, there are 17 Hydroelectric Power Plants (HPP) operating in small rivers, with an annual generation of 120-130 GWh. The projected power generation of two cascade power plants and several small HPPs is about 1500 GWh, which is about 45% of the economically exploitable potential.

During the 1992-1994 energy crisis caused by blockade, the hydro potential of Sevan Lake was overexploited by drawing excessive water from the lake for hydro generation. Outflows from the lake have been reduced during the last years to just cover the irrigation needs of Armenia. This outflows reducing resulted in a proportional reduction of power generation to about 500-600 GWh/year. But successful protection of water level of the lake, which has been registered in the Directory of Wetlands of International Importance within the Ramsar Convention, still hangs in the balance.

Hydro energy is operating at a low level of capacity (with a loading factor equivalent to 20% of its nominal capacity) because, after the intense use of lake Sevan water during 1950s –1960s, and during the last economy crisis of 1995, Armenia has been trying to restore the original water level of lake Sevan.

Although the most attractive hydropower sites in Armenia are already exploited, there is still an appreciable hydro potential that can be developed. The most detailed studies were carried out in 1994, aiming at developing the projects for all medium- and several small-scale hydropower facilities (Table 2.12).

Lahmeyer International Company conducted a study in 1994, but only six small hydro schemes were investigated in detail. Since the study was based on the principle of "head-discharge-specific cost relationship" established for all hydro schemes intended for investigation, the remaining 188 small hydro schemes have been classified according to their expected specific generation costs.

The data on the total remaining hydro potential in Armenia are summarizing in Table 2.13.

The projected costs could be considerably lower if hydro-mechanical and electrical equipment would be produced in Armenia. The prospects for this are reasonable for small-scale hydro projects. It is recommended to establish a joint venture with the foreign turbine manufacturer, or to organize a production under the license, to shorten the development time.

2.3.3. Geothermal Resources

Armenia appears to have very good potential for the existence and use of geothermal energy for both power generations, and/or district heating and other direct use [49-76]. The country has a large zone of very high heat flows deep within the earth, and there are extensive areas of volcanic activity, some of which are very young in geological terms.

The country can be divided into three zones depending on the natural flow of heat from within the earth. These zones are aligned in a general northwest to southeast direction, as shown in Figure 2.5.

Table 2.12. Overview of Potential Medium Size Hydropower Projects in Armenia

Scheme	**Head (m)**	**Flow (m^3s)**	**Capacity (MW)**	**Energy (GWh/a)**	**Plant Factor**	**Constr. (Years)**	**Cost (mUS$)**	**Specific Cost (USc/kWh)**
Schnokh	236	37	75	321	0.49	4.5	132	5.3
Loriberd	70	3	2	7	0.43			
	46	20	8	27	0.38			
	274	21	48	169	0.40			
			58	203	0.40	4.0	159	10.0
Akhurian	41	29	10	25	0.28	0.7	24	10.6
Argichi	258	10	22	48	0.25	3.0	51	13.4
Surmali	52	60	27	103	0.45	4.5	98	12.7
Gekhi	100	6	5	21	0.45	1.5	10	5.5
Megri	70	180	84	500	0.68	5.0	159	4.3
Sum Medium Scale Hydro			281	1221			633	
Sum Hydro <10USc/kWh			222	1045			460	
Sum Hydro <6 USc/kWh			164	842			301	

Note: - Megri is a binational project with Iran and features two hydropower schemes. Cost and output are based on the new 1996 data furnished by MoEn. Figures shown here represent Armenia's share. The Iranian share is the same size.

Surmali is on border with Turkey. If cost of dam is shared between Turkey and Armenia, the generation cost will be about 9 UScc/kWh.

Specific generation cost was calculated for a 50-year lifetime, and there was considered 10% annual discount rate.

1994 costs were escalated by 5% to account for inflation.

The northern zone has low heat flow values, so that it is of less interest for geothermal development.

The southern zone, in general has low heat flow, but does show occurrence of volcanism, besides, there exist the thermal waters deep within the sedimentary basins; the depth of these waters allows the heating to occur.

The central zone has very high heat flows (up to 90 mW/m^2, or more), and it was also characterized by high frequency of volcanic eruptions in the recent geologic past (including those within the last 10,000 years). This zone presents the most favorable conditions for geothermal energy, and the greatest likelihood of finding high temperature geothermal systems if these exist.

In geological terms, the Republic of Armenia shows regions of tectonic uplift (typical of the Caucasus region) and widespread volcanism. The Eurasian Plato collides with part of the greater African Plato (in particular the Anatolia sub-Plato) and this intersection is a key factor in the geothermal phenomenon seen in Armenia. The proximity of Ararat Vulcan (and its smaller neighbor) and the volcanic centre Aragats also clearly attest to the volcanic forces, which act in the region.

Key applications would appear to be both electricity generation and district heating schemes for serving the large- or high-density population centres. Possible uses of the various geothermal prospects are:

Djermakhpur Martouni	Electricity generation
Vayoc Dzor, Vardenis, Mukhan, Agnalich	District heating
Nor Yedesia	Power and/or district heating

For electricity generation, the following cost estimation was done for a conventional 55 MW geothermal steam power plant (Table 2.14).

The specific generation cost in Table 2.14 has an accuracy of ± 30%, because of the still rather incomplete information, but even if it were 30% higher, the price would be sufficiently attractive to compete with the best hydro projects.

In general terms, the harsh and long winters in Armenia can be considered as a good basis for geothermal district heating, provided that the good quantities of moderate temperature fluids could be obtained at reasonable cost. There are a number of prospect areas where moderate temperature fluids are likely to exist at depths of 2500 m, or more, and where district heating could be an attractive means of supplying thermal energy to the people.

The crucial step facing the Ministry of Mineral Resources (or perhaps, the Ministry of Energy) is to *quantify the extent of geothermal energy deposits in Armenia*. This will require a multi-disciplinary effort focusing on geothermal resources; this has not happened to date. While Armenian specialists and scientists are highly competent in their specialty, it is recommended that internationally experienced scientists/engineers familiar with geothermal resource investigations provide complementary abilities.

In particular, reviews should be made of each of the most attractive prospects to evaluate the results of work done to date and, importantly, to elaborate the further investigations that are best suited to the particular prospects based on results expected, and cost and time to obtain

Figure 2.5. Zones of Natural Heat Flow

these. Good scientific work, undertaken prior to major drilling works, can provide considerable savings in ultimate development costs.

Internationally, geothermal resources make significant contributions to the electric energy supply of some countries, and large amounts of energy are also tapped for heating and industrial purposes. Armenia has the potential for utilizing also the power of the earth for the benefit of the people, but quantitative evaluation of the potential is an essential step toward this ultimate goal.

2.3.4. Alternative Supply Options

The prospects for electricity generation with the use of the solar energy, wind and biomass have been briefly investigated in the 1994 study [77-83]. The following conclusions are made:

- The local capabilities for undertaking the research and engineering works aiming at developing the alternative energies in the country are good; and appropriately skilled and trained personnel for the related industries is available.
- The work has been already done, and the available database, especially on solar and wind energy resources, is adequate for immediate use in related projects; for wind energy, however, some additional profile measurements should be done at prospective sites.
- The resources of the country are good in regard to the solar energy, but the wind potential considered being moderate (except at some specific sites). The bio-energy resources in Armenia are limited.

Table 2.13. Overview of Remaining Hydro Potential in Armenia

Selection	Number of Schemes	Aggregate Capacity (MW)	Aggregate Generation (GWh)
All schemes identified			
medium scale	7	281	1,221
small scale	194	172	597
Total (%)	201	453	1,818 (100%)
Schemes with specific generation cost below USc 10 per kWh			
medium scale	4	222	1,045
small scale	140	160	548
Total (%)	144	382	1,593 (88%)
Schemes with specific generation cost below USc 6 per kWh			
medium scale	3	164	842
small scale	29	71	260
Total (%)	32	235	1,102 (61%)

Note: 84 MW capacity and 500 GWh/a energy, given in a table above, are the data related to the Megri HPP situated on a border with Iran.

2.3.4.1. Solar Power

Armenia has an average annual insulation value of 1,700 kWh/m^2, which is favourable for the use of solar energy (the corresponding value for Central Europe is 1,000 kWh/m^2 only). As a result of the low prices for fossil fuels, the solar thermal power plants of utility scale nowadays are not commercially viable for any country of the world. Armenia's economic situation is such that it cannot, at this stage, afford the research and development costs associated with the commercialization of this type of plant. Therefore, this option was not further pursued.

Small-scale photovoltaic (PV) systems have been rapidly becoming more popular in many countries of the world. In view of the frequent energy supply interruptions and growing environmental awareness in Armenia, there may be a (limited) number of consumers for whom a photovoltaic solar home system (SHS) could be of interest, even if the cost of a kilowatt-hour supplied be many times higher than that of grid supplied power.

The SHS is an individual power generating system designed mainly to provide electricity supply in case of grid interruption; but since the energy has to be stored, the battery will be necessary too, to accumulate it. In order to supply consuming devices with power, an inverter

Table 2.14. Cost Estimate for 55 MW Geothermal Unit

Development Phase	Activity	Cost Estimate (Million 1996 US$)	Duration
Exploration / Feasibility	Scientific investigations	0.2	1 year
	Exploratory drilling	6.3	1 year
	Feasibility evaluation	0.2	6 months
Development Drilling	Drilling	18.3	2 years
Steam field	Design	2.1	1 year
	Construction	21.0	2 years
Power Plant	Design	6.3	1 year
	Construction	62.0	2 years
Total Capital Cost		116.4	5.5 years
Annual Well Development and Connection Cost (5% annual rundown, 5 MW well-size)		1.2	
Annual Operation, Maintenance and Repair Cost		2.1	
Cost in USc per kWh (10% discount rate, 25 year lifetime, 7300 hrs/a)		5.0	

Note: 1994 prices were escalated by 5% to account for inflation

will also be required. The system would be able to supply electricity for room lighting, operating TV/radio devices, and using a small refrigerator for several hours a day. The inverter would be grid-connected to send the surplus SHS energy into the grid. In case the power demand of the household is higher than the power output of the SHS, the grid will supply the deficit (if power is available). The SHS could be implemented in three phases (Cost Estimate for the SHS Program is given in Table 2.15)

Table 2.15. Cost Estimate for the SHS Program

Phase	I	II	III
PV System Costs	US$ 5,300	US$ 3,000	US$ 2,500
Number of Systems.	50	10000	10000
Total Costs	US$ 265,000	US$ 30 million	US$ 25 million
Total Peak Power	20 kW	4MW	4MW
Annual Energy	27MWh	5,440 MWh	5,440 MWh
Annual OMR Cost	US$ 6,600	US$ 0.75 million	US$ 0.63 million
Cost in US$ per kWh	1.76	1.00	0.83

Phase I Demonstration of Solar Home Systems

A limited number of solar home systems (about 50) will be imported and installed all over the country. Since the aim of this phase is to demonstrate the technology of the systems, only well tried and reliable components should be selected.

Phase II Integration of Local Subsystems

In order to reduce the costs, subsystems or components like charge regulators, inverters, and batteries should be supplied by local industry. The components may be developed by local industry, or manufactured under license.

Note: Cost level 1994, 10% discount rate. Lifetime is 20 years, but for inverter and battery only 7 years.

Phase III Local Manufacturing of Solar Home Systems

Eventually, the entire solar home system should be manufactured in Armenia, since the local manpower is available, and the required joint ventures could be created during the foregoing phase.

At the same time, taking into account that the prices would be at least 10 times higher than the generation costs of hydro, thermal and geothermal power stations, it can be said that there is not much opportunity for the SHS program implementation.

2.3.4.2. Wind Power

The mean wind velocities throughout Armenia are rather low, and the potential of wind energy is, consequently, limited. However, there are a number of candidate sites with favourable conditions, featuring mean wind velocities above 6 m/s. The most promising sites are from north to south, Pushkin-Pass (not far from Vanadzor), Aragaz, Sevan Lake and Sisian-Pass. The specific generation cost of a 300 kW horizontal axis wind turbine is calculated as follows (Table 2.16).

The capital cost can be considerably reduced if standard wind turbines are mass-produced under license in Armenia. This possibility should be considered seriously. The specific costs for wind converters are decreasing due standardization, higher production numbers and improved designs.

If the wind converter, referred to in Table 2.16, can be, in the future, manufactured and installed for US$ 900/kW, and this appears to be well possible, then the specific cost for one wind-generated kWh will drop to 5 USc, and that would be comparable with the corresponding costs for the best hydro- and geothermal projects.

Table 2.16. Cost Estimate for 300 kW Wind Converter for 6-7 m/s Average Wind Velocity

Item	**Estimate**
Total Capital Cost Annual OMR Costs Annual Energy Generation	US$ 475,000 US$ 14.000 978 MWh
Cost in USc/kWh (10% discount rate, 20 year lifetime)	7.7 USc/kWh

Note: if wind velocity averages 4-5 m/s, output reduces by 27% and specific generation cost increases to 10.5 USc/kWh.

The promotion of the use of wind energy in Armenia is, therefore, well justified. This can be done mainly by:

- developing major projects, such as the installation of wind farms,
- creating incentives in view of the dissemination of small wind energy converters.

It is, however, necessary to further improve the wind database (e.g. measurement of the wind profile up to, say, 50 m) in order to better assess the site-specific wind potential.

2.3.4.3. Other Options

Other alternative energy supply options, which have been addressed, include:

- waste incinerator for major cities,
- biogas from animal manure, sewage and landfill areas,
- use of plantations and ponds to grow biomass.

Except for waste incineration (a 10 MW plant is under discussion for Yerevan), no noteworthy electricity supply contributions of these categories can be expected.

2.3.5. Imported Energy Supply Sources

2.3.5.1. Natural Gas

Natural Gas is presently being imported from Russia. The designed capacity of the high-pressure gas transportation network of Armenia is 17 billions m^3/year.

There were built five main gas pipelines, which ensured gas delivery from the three sides: Georgia, North and West Azerbaijan (Figure 2.6). Three high-pressure gas pipelines, with combined capacity of 45 mcm/day, enter the country along the eastern border with Azerbaijan. These pipelines have been shut down for years. Two other gas lines come from Tbilisi, Georgia, and have capacity of 15 mcm/day. Those lines were sabotaged in Georgia and were out of commission for a period of time, but now they are partly operational and supply sparingly Armenia with Russian natural gas. There are underground storage facilities for natural gas with the useful gas storage volume of 140 mln. m^3. Gas distribution in Armenia is performed through the high-, medium-, and low-pressure distribution networks. During the times of the Soviet Union, natural gas consumption in Armenia was firmly above 5-6 bcm/year. In 1989, the natural gas consumption reached 5.76 bcm. But further on, the consumption plummeted: to 4.6 bcm in 1990, 4.5 bcm in 1991, 1.9 bcm in 1992, 0.78 bcm in 1993, 0.85 bcm in 1994, 1.0 bcm in 1995, 1.12 bcm in 1996 and 1.2 bcm in 1997. Natural gas is the most important source of energy covering about 50% of the total energy supply. The Gas and Nuclear energy supply trends are shown in Figure 2.7

The high-pressure transportation network of Armenia consists of 2000 km length, 273-1200 mm diameter and 12-55 bar pipelines (comprising 67 distribution points and 139 corrosion protection stations).

In Abovian, the underground storage facilities for natural gas have been located; they have the following technical characteristics:

- geometrical volume: 1.735 mln. m^3
- maximal possible pressure: 125 bar, buffer pressure 25 bar
- nominal gas storage volume: 220 mln. m^3
- projected useful gas storage volume: 180 mln. m^3
- gas distribution in Armenia is performed through:

Figure 2.6. The scheme of Armenian main gas pipelines

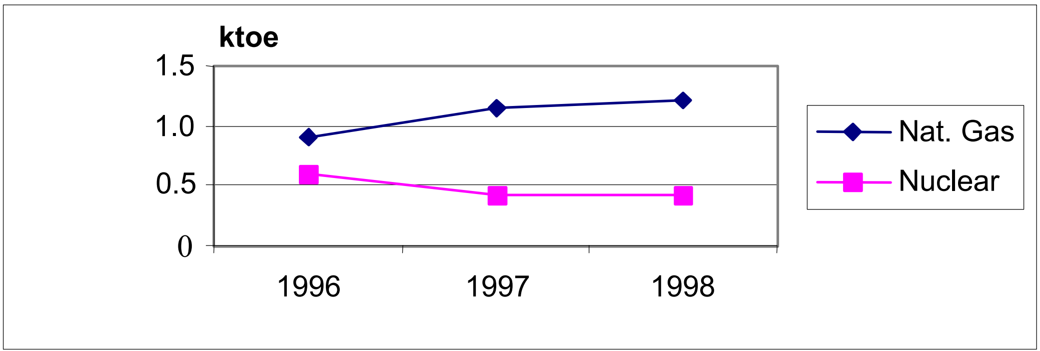


Figure 2.7. The Natural Gas and Nuclear Energy Supply Trends

the high-pressure distribution network, with the following technical characteristics:

- length: 558 km
- diameter: 50-500 mm
- nominal pressure: 6-12 bar

:the medium-pressure distribution network, with the following technical characteristics:

- length: 2656 km
- diameter: 50-500 mm
- nominal pressure: 0.05-6 bar

- the low-pressure distribution network (comprising 1797 distribution points and 854 corrosion protection stations) of a total length - 6041 km.

2.3.5.2. Petroleum Products

Petroleum Products, imported from the neighbouring countries, are mostly utilized for the needs of transport, industry, and residential (heating) sectors and as a secondary fuel (mazut) in Thermal Power Plants.

2.3.5.3. Electricity Trade

At present, Armenia is exporting electricity to the neighbouring countries (mainly Georgia and Iran), but it is expected that, in the near future, the additional source of energy will be required, as the economy improves and the increasing living standard demands the additional energy.

Today, the value of the Primary Source of Energy per capita is around 0.55 toe/capita, compared with the 1.05 toe/capita of Turkey and the 2.4 and 3.2 toe/capita of Belarus and Ukraine, respectively (Figure 2.8).

2.4. Electricity Sector Development

2.4.1. Energy Sector Organization

The commercial-oriented management in the energy sector was strengthened by subdivision of these enterprises into legally and economically independent utilities.

In the power sector, independent power plants were established, such as: Hrazdan Thermal Power Plant, Yerevan Thermal Power Plant, Vanadzor Thermal Power Plant, Armenian Nuclear Power Plant, Sevan-Hrazdan Cascade of Hydro Power Plants, Vorotan Cascade of Hydro Power Plants and several small Hydro Power Plants.

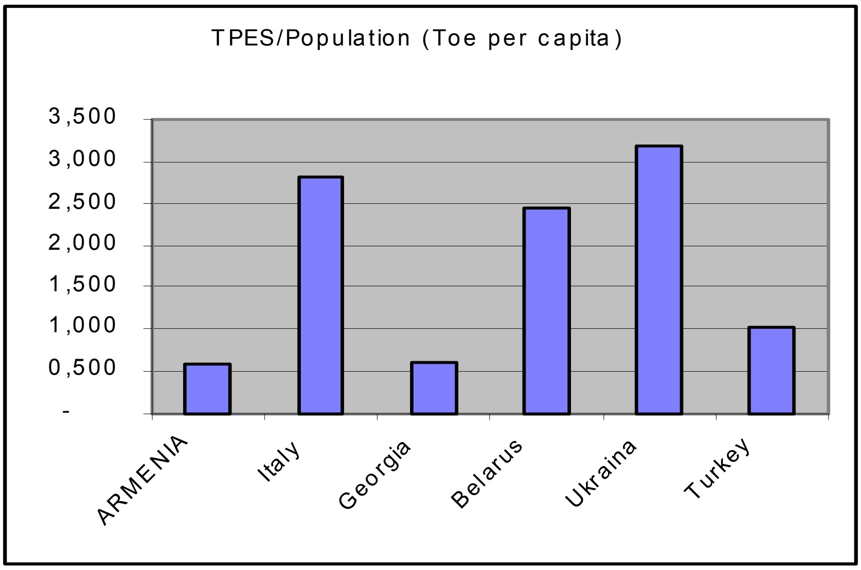


Figure 2.8. The Primary Energy Source (TPES) per Capita

Transmission function was separated from the “ArmEnergo”, and the High Voltage Transmission Company has been created; the functions of interconnection, dispatch and wholesale were assigned to the “ArmEnergo” State Closed Joint Stoke Company. Thus, a basis for creation of a real energy wholesale market was established, wile the “ArmEnergo” was authorized to be a wholesale buyer-reseller of generated electricity and to take responsibility to realize dispatching with the purpose of efficient supply of the electricity.

The distribution and wholesale trade are implemented by 4 regional distribution utilities.

2.4.2. Power Generation Capacity

The total installed capacity of the entire Armenian power system is about 3200 MW. The peak demand of the system was 1260 MW in 1997 and 1071 MW in 1999, respectively.

The installed capacity of the Thermal Power Plants in Armenia is 1754 MW. TPPs operate with gas and mazut. Table 2.17 shows the evolution of thermal power capacity structure in Armenia over the last 35 years, and data on the electricity generation over the last 3 years.

The Armenian Nuclear Power Plant started its operation between 1976 and 1980 with two VVER – 440/230 reactors, totalling to 815 MW generating capacity. It was the most important energy generating station by 1988, when it was brought to a standstill after the Spitak earthquake. The severe energy crisis, that broke out after the collapse of the Soviet Union, obliged the Armenian Government to restart Unit 2 of the ANPP in November 1995, after extensive renovation and additional measures for improving the seismic safety of the plant. The restarting of this power unit boosted electricity generation in Armenia and contributed decisively to the stabilization of its power system.

Armenia began supplying Georgia with some of its surplus electricity in late-1998. Iran and Armenia have also linked their electric grids, allowing the power sales in both directions, driven by seasonal differences in demand between the two countries.

Table 2.18 provides data on the capacity and the electricity generated by the ANPP.

Table 2.19 shows the evolution of structure of hydropower capacity in Armenia over the last 52 years and electricity generation over the last 3 years.

The total installed capacity of Armenian Hydro-Power Plants is a little more than 1000 MW. The Sevan-Hrazdan cascade (7 plants) accounts for 55% of this capacity. The Votoran cascade (3 plants) contributes with about 40%. The remaining 5% is the installed capacity of the small HPPs.

Table 2.17. Data on the Capacity and the Electricity Generation by Power Plants

Plant	**Units**	**Commissioning year**	**Generation (GWh)**		
(MW)			**1996**	**1997**	**1999**
Hrazdan TPP	1100		1561.0	2273.3	1964.2
Section 1	2 X 50	1966-1967			
	2 X 100	1969			
Section 2	3 X 200	1971-1974			
	1 X 210	1974			
Yerevan TPP	550		754.0	758.4	474.2
Section 1	5 X 50	1963-1965			
Section 2	2 X 150	1966-1968			
Vanadzor TPP	94	1964-1976	1.9	-	-

2.5. Grid System

The high-voltage transmission network of Armenia consists of 1323 km of 220 kV lines and 3169 km of 110 kV lines. There are 14 substations of 220 kV and 119 substations of 110 kV. The capacity of the existing high-voltage network is considered to be sufficient for the current and forecasted domestic loads.

Table 2.18. Data on the Capacity and the Electricity Generation by the Armenian NPP

Plant	Units	Commissioning	Generation (GWh)		
(MW)			1996	1997	1999
Armenian NPP	815		2324.0	1617.6	2078.3
Unit 1	440	1976	(out of operation)		
Unit 2	440	1980/1995	(re - commissioned after renovation)		

Table 2.19. Data on the Capacity and the Electricity generation by HPPs

Plant	Units	Commissioning	Generation (GWh)		
(MW)			1996	1997	1999
Sevan-Hrazdan HPPs	550		593.0	534.7	346.6
Sevan	34.0	1949			
Hrazdan	81.6	1959			
Argel	224.0	1953			
Arzni	70.6	1956			
Kanaker	102.0	1936			
Yerevan 1	44.0	1961			
Yerevan 3	5.0	1956			
Vorotan HPPs	400		889.0	759.7	727.6
Spandarian	75.0	1984			
Shamb	168.0	1977			
Tatev	157.0	1970			
Small HPPs	56.0	1913-1954	87.0	86.1	125.0

The high-voltage transmission network of Armenia has the interconnections with the neighbouring countries (Table 2.20).

The medium- and low-voltage distribution system comprises 35, 10, 6 and 0.4 kV lines with the following characteristics:

- 35 kV voltage level: 2675 km with 278 substations.
- 10 kV voltage level: 8470 km of overhead lines and 2900 km of cables.
- 6 kV voltage level: 1270 km of overhead lines and 2055 km of cables.
- 0.4 kV voltage level: 13570 km of overhead lines and 2160 km of cables.
- 10625 substations 10/0.4 kV.
- 850,000 connections (of which 740,000 in the residential sector).

Table 2.20. Armenian Intersystem Connections

Country	Connection type	Current situation
Azerbaijan	One line HVL-330 kV (107 km)	Out of use
Georgia	One line HVL-220 kV (65 km)	Operational
Turkey	One line HVL-220 kV (65 km)	Out of use
Iran	One line HVL-220 kV (78.5 km)	Operational

2.6. Induction of Private Power Sector

One of the key objectives of the Armenian Government is to create a mixed economy with such a structure that allows the most enterprises be privately owned and managed. For this purpose, the Law on Enterprise and Entrepreneurial Activity was enacted in 1992 to define the basic principles of entrepreneurship, rights to property, pricing, rendering services, etc. The Real Estate law was adopted in January 1996.

The main objectives of the power sector reforming were both the increased roles of the private sector and further privatization. The environment, where the investment risk can be understood clearly and be managed properly, will have more opportunities to attract private capital. A rational regulatory framework with well-defined procedures and transparency in the decision-making policy, can greatly improve the chances of private sector participation. Thus, implementing the regulatory reform, the Armenian power sector will facilitate the appropriate private investments attraction.

At the same time, the distribution sub-sector is being separated from generation and transmission to facilitate the introduction of competition in power generation.

In accordance with the Law on the Program for the Privatization of the State Property of Armenia, during the period 1998-2000, the denationalizations and incorporation of gas and power sector enterprises had to be completed. It was foreseen to implement the privatization process in the energy sector of Armenia in the following sequence:

- Privatization of gas- and electricity distribution enterprises.
- Privatization of large power plants.
- Organization of wholesale energy market.

The privatization of electrical distribution companies was supposed to be implemented during 2001. Ongoing privatization of 4 electricity distribution companies had to be based on the Laws of Armenia: “On Privatization of State Property During 1998-2000” enacted in December 17, 1997, and “Privatization of Yerevan, Northern, Southern and Central Electric Networks CJSC” enacted in August 12, 2000.

As that is defined by the Law of Armenia “Privatization of Yerevan, Northern, Southern and Central Electric Networks CJSC”, the main purposes of privatization of electricity DisCo are:

- Reliable and uninterruptible electricity supply to the consumers in accordance with the technical regulations of Armenia;
- Increase of the management efficiency, maximum reduction of losses;
- Attraction of investments for renovation, expansion and development of electricity distribution networks;

- Improvement of the billing and collection and, as a result, improvement of the financial condition of the energy sector companies;
- Completion of the state budget of Armenia.

Actually, the Selling Memorandum, pilot contract and the privatization concept have been already prepared. Four foreign companies are in the shortlist for tendering, EBRD is ready to participate in purchase of 20% share.

A big attention is paid to the structure accomplishment and commissioning of the Unit N5 at Hrazdan Thermal Power Plant. The negotiations with the EBRD with the purpose of private investors' attraction gave a confidence that the question would be solved soon.

The negotiations with the ABB are going on concerning the building of a new 160 MW combined-cycle unit on Yerevan TPP.

According to the Government decision, Vanadzor TPP is being privatized in complex with Vanadzor Chemical combine. Now the transfer of ownership is taking place.

The limited possibilities of Sevan-Hrazdan HPP cascade water flow and the importance of Vorotan HPP cascade for the National Power System has been taking into account. It should be recorded that at a first stage of the privatization of these strategic assets, the Government of Armenia will maintain their control package. In a further evolution of the economic and political situation, the capital markets will gradually realize the stocks possessed by the Government during 5-8 years on the base of their free sale.

Particular attention has to be paid to the questions of privatization of scientific-researches and designing organizations in Armenia. Because the big intellectual potential is concentrated within those institutions, it will be required further studies to make it possible to resolve the problems relevant to such organizations privatization.

On the basis of a special Statement of the Government of Armenia, such institutions as the Armenian NPP, Institute of Energy and “Armenergo” cannot be privatized. At the present, the transmission networks are excluded from the “Armenergo”. Because of the investments required a special program of HV networks renovation would be elaborated.

In the natural gas sector, the denationalization has already been completed, and the “ArmRusGasprom”has been established

In the oil sector, the situation is even clearer. The sector has been de-regulated and operates in a fully competitive environment.

There is no special treatment for energy enterprises. Industrial activities are classified as:

- monopolies reserved for the public sector - in the energy sector, this only applies to the nuclear generation;
- private enterprises operate under license. In energy, this class covers the construction and operation of hydro plants and renewable sources of energy, as well as the exploration and production of subsoil resources of oil, gas and coal.

Thirty-two energy enterprises are included in the current privatization program. Some of these enterprises are to be privatized by international auction.

2.7. Investments in Energy Sector

The first implementation phase of the development policy 1998-2001 was focused on:

- measures on financial improvement and strengthening of financial discipline;

- measures on continuous upgrading the metering and billing system of power consumption;
- measures on reduction of technical and commercial losses of electricity;
- implementation of flexible price formation and tariff policy;
- improvement of operation and maintenance level of exhausted and obsolete fixed assets;
- initiation of the implementation of measures on renovation of the power sector.

The second phase of development for 2001-2015 will ensure transition of fuel-energy complex of Armenia to a new improved level of operation. It is envisaged that, on this stage, a package of measures, targeted at the total re-equipping of the power sector, will be implemented, as well as the new technologies will be introduced and large-scale utilization of national energy resources will be also implemented.

The Investment program stipulates:

1. In Hydro power:
    - rehabilitation of the existing Hydro Power Plants,
    - development of 230-250 MW economically feasible new hydro potential (Megry, Shnokh, Gekhi) and,
    - construction of small and micro HPP’s with capacity of 75 MW with private investments.
2. In Thermal power:
    - operation of existing aggregates and units to complete exhaustion of their technical resource;
    - commissioning of new 300MW Unit on Hrazdan TPP,
    - refurbishment of Yerevan TPP on the basis of two ABB modern Combined Cycle (CHP) units;
    - development of geothermal sources with the private investments.
3. In Nuclear Power:
    - studying the possibilities of furhter development of nuclear energy on the basis of modern technologies;
4. Development of alternative energy, including up to 50 MW grid-connected wind farm, with participation of private investments;
5. Implementation of energy saving campaign.

Along with the refurbishment and development of generating capacities, the main attention is paid to rehabilitation of transport and distribution networks, interconnections and equipment of the Power System with devices of dispatcher control and communication.

The problems that should be regulated at the governmental level also include stimulation of the local energy resources development, energy saving, environmental protection, scientific-technical progress and professional development.

The Government is undertaking an open economic policy and is actively seeking reforms in the energy sector.

The policy of the Government aims at international co-operation. Considering the assistance provided, the focus will primarily be on the commercializing operations to achieve cost recovery, eliminating subsidies and promoting investments in the energy sector. And, finally, on embarking upon a meaningful and productive privatization program, focusing not only on a short term critical management, but also on an attraction of substantial new investments and long term capacity building. These, in turn, will support the economic growth of Armenia.

2.8. Environmental Aspects

Environmental aspects are the most important components of the energy security. The measures include the following:

- Increase of nuclear safety level of Armenian NPP;
- Preservation of unique ecological system of lake Sevan by decrease the level of water release up to minimum for irrigation requirements;
- Strict registration of ecological indicators while taking decisions on implementation of projects on reconstruction, development and commissioning of new capacities.
- Control of detrimental emissions of thermal power plants;
- Introduction of new "green" technologies.

2.9. Energy Efficiency as National Source of Energy

Energy efficiency is also considered to be a factor increasing the energy security – that means not only the reduction of energy consumption in the country, but also reduction of dependence on the external sources. In this regard, the following is being undertaken:

- Implementation of State incentives for general energy saving;
- Increase of energy efficiency of technological cycles in industrial spheres of economy;
- Increase of energy efficiency of technological cycles of generation, transmission and distribution;
- Recovery of gas and heat supply.

2.9.1. Energy Efficiency by Sectors of Economy

Agriculture

Elaboration and implementation of measures aiming at the reduction of water losses in the irrigation system of the Republic is among the problems of great concern (e.g., according to the studies of LI 1994, underproduction of the Sevan-Hrasdan Cascade, owing to the non-efficient utilization of water was 100 mln kWh annually)

Industry

In Armenia, the key problems of industry arise because of the high percentage of its branches being highly energy-intensive. For the future, there will, probably, have to be undertook a long term restructuring in this sector in order to make it possible to ensure a transition from the high energy-intensive industries to the less energy-intensive ones; but nowadays, there still remains much to do to improve the efficiency of energy use.

The main causes of energy waste are:

- Installations are grossly over-sized, even for the full-capacity operation. In the present situation of running at low load, consequence of over-sizing is even more dramatic;

- The pieces of equipment are generally old, their design did not include energy saving features;
- Maintenance is insufficient;
- Lack of energy management and monitoring system.

The considerable potential energy saving through the short term and medium-term measures, and the existence of compressed air systems in a large part of industry makes this area one of the first targets for action.

Household and Service

Residential and service sectors buildings are in a very bad condition. Years of heating lack and poor maintenance have been causing serious deterioration. Residences built in the past couple of decades were of poor design, with no regard for thermal efficiency. Compounding the design problem was very poor construction, with poor materials.

One more cause of over-consumption is low efficiency of existing lamps and electrical appliances; a considerable reduction, up to 70% in some cases, could be reached by replacing them by more efficient ones.

Transport

Transport sector needs the same measures to be implemented as in other sectors relevant to norms, standards (fuel quality, consumption, etc.), introduction of new technologies, etc.

There are no specific regulations or laws pertaining to energy use, other than speed limits. There are norms for energy consumption for all activities in all companies.

There is a big potential of energy saving by increasing the efficiency of production in all sectors of Armenian economy, but Armenia needs a long time for replacement of old equipment and implementation of new technologies.

2.10. Legal and Institutional Framework

2.10.1. General Considerations

The scope of this is a preliminary overview of the regulations and key permissions that will impact the settlement and the development of the activities of the power system with reference to the whole complex of transactions described in the contractual scheme of the projects; in other words, the whole legal framework in which the SPV has to operate.

2.10.2. Legal form of the SPV Company

In setting up the Special Purpose Vehicle Company described here, the shareholders should take into consideration the following aspects:

- the legal framework established for foreign investment
- the legal form allowed for new companies
- the registration requirements for a new company
- the partnership of Armenian energy state owned companies

2.10.2.1. Law on Foreign Investment

The basic provisions regulating the investment climate are set by the Law on Foreign Investment adopted in Armenia on July 31, 1994.

Under the term Foreign Investor, the law recognizes any foreign company, a citizen, a person without citizenship, an Armenian citizen permanently residing outside of Armenia, or an international organization, which invests in Armenia. Foreign Investment is any form of property including financial means and intellectual property, which is invested by a foreign investor directly in the territory of Armenia in any economic or other venture.

A Foreign Investment Company is a company of any legal form recognized under Armenian Law, which is founded by a foreign investor, or in which he is a participant.

Foreign investors are allowed to make the following types of investments in Armenia:

- establishment of fully foreign-owned companies, or representations, affiliates, branches, or purchase of existing companies,
- establishment of new joint companies with the participation of Armenian companies or citizens, or the purchase of a portion of shares in an existing company,
- purchase of different types of securities officially recognized by Armenian legislation,
- procurement of permission for use of land, or a concession agreement for use of Armenian natural resources with participation of an Armenian company or Armenian citizens,
- procurement of other property rights,
- other allowed forms including those based on agreements with Armenian companies or citizens.

Foreign investors take responsibility for any violation of Armenian laws and regulations. Foreign investors can use their property to satisfy their obligations in accordance with these responsibilities.

Incentives

Currently, there is no generalized investment incentives program, but there is incentive available to exporters (no export duty and a VAT refund on goods and services exported) and the ability to carry losses forward indefinitely.

Main incentives for foreign investment can be summarized in the following points:

- 100% ownership permitted;
- long term land leases freely permitted (but taxes on use of land are into force);
- corporate tax holidays available for investments over US$ 1 million;
- no duties on import of statutory capital, raw materials and equipment;
- no export duty;
- VAT on exports is refunded;
- losses may be carried forward indefinitely;
- free operation of foreign currency accounts;
- no restrictions on remittances;
- no restrictions on staff recruitment;
- no sectoral or geographic restrictions, some incentives for investment in earthquake zone;

- Investment guarantee including 5-year protection clause and MIGA membership.

Measures of protection and Restrictions

Under the Law on Foreign Investments, effective since 1994, in case of changes in Legislation, foreign investments, in accordance with the investor's preference, may be subject to the laws existing at the time when investments were made, but only for a period of 5 years, as provided in Art.7 of the law.

Moreover, Art. 8 of the Law provide that "Foreign investments in Armenia shall not be subject to nationalization. Also, government bodies cannot confiscate foreign investments.

Confiscation with full compensation can occur only by a court decision when an emergency is declared in accordance with the legislation. (Art.9).

Investors are entitled to full compensation through a court order for damages as a result of illegal actions or performances by the government bodies or their officials.

Compensation is to be paid promptly at current market prices or prices determined by independent auditors. If the payment is delayed, interest will be added.

Funds may be converted and transferred through virtually all-domestic banks.

There are no restrictions on conversion and repatriation of capital and earnings including branch profits, dividends, interest, royalties or management or technical service fees.

There are no limitations on wire transfers. Foreign investors may freely repatriate their property, profits or other assets that result from their investment after payment of all due taxes. Interest and dividend income (except for the dividend income of non-resident legal entities - but the SPV company will be established a resident company) is not subject to any tax.

Bilateral investment treaties

Bilateral investment treaties on investment and investment protection exist with 23 countries including: Argentina, Canada, China, Cyprus, Egypt, France, Georgia, Greece, Iran, Kyrgyztan, Romania, Turkmenistan, Ukraine, United Kingdom, United States and Vietnam.

Armenia is also signatory to the CIS Multilateral Convention on the protection of Investor Rights, and 26 further treaties are under negotiation.

The treaties set forth investment conditions for investors of each party to be no less favourable than for national investors; it protects investment against expropriation and nationalization, and regulates dispute settlements between the companies and the governments of each party.

Foreign Exchange Regulations

The attention must be paid in economic statement projections (and cost evaluation) on the exchange rate: exchange rate provisions have be allocated taking into consideration that investment costs and lending reimbursement are mostly paid in dollars (or in Euro) against revenues produced in Drams. Protection considerations on convertibility of the Armenian currency are of key importance.

The DRAM is freely convertible und a managed float. Consequently, operations of the CBA in the foreign exchange market are very limited, and the exchange rate of the Dram is largely maintained by financial market activity.

According to Resolution No.8 on Foreign Exchange Regulations and Administration of Control, which came into effect in August 1996, there are no restrictions on current account operations; physical and legal entities are allowed to act as foreign exchange dealers after being licensed by the CBA. The CBA has approved licensing regulations for additional foreign exchange dealers.

The CBA determines a daily exchange rate as the midpoint of the previous day's buying and selling operations in the financial market. Foreign exchange dealers and banks are free to set exchange rates for their own transactions. Like resident banks, foreign banks are authorized to participate in the domestic foreign exchange market without restrictions.

All legal and physical entities can open hard currency accounts in Armenian or foreign banks without any restrictions. Residents and non-residents of Armenia can make all regular international banking transactions. Though the Dram is the legal tender of the Republic of Armenia, non-residents can freely carry out all operations in foreign currency, (NB: this practice is prohibited amongst residents).

The present Law On Foreign Investment surely provide, under specific project conditions, for some tax exemptions and for Profit Repatriation, but in the present transitional Armenian situation, where the reserve of valued currency is much more limited than in western countries, the risk of not being able to convert all the amount of local currency (in which the profit is) still persist. It should be verified with the governmental authorities any possibility of mitigation of such a risk also in a case- by- case approach.

A juridical response to this problem is given by the agreement Armenia signed with the International Monetary Fund.

On May 29 1997, Armenia signed up to Article VIII of the International Monetary Fund's Articles of Agreement and accepted the obligations implied by Sections 2, 3 and 4 of the Article. IMF members accepting the obligations of Article VIII undertake to refrain from imposing restrictions on the making of payments and transfers for current international transactions and from engaging in discriminatory currency arrangements or multiple currency practices without IMF approval.

Armenia's acceptance of Article VIII gives confidence to the international community that it will pursue sound economic policies obviating the need to implement restrictions on making payments and transfers for current international transactions, and thereby contributing to a multilateral payments system free of restrictions.

2.10.2.2. The Legal form of the SPV Company

In this section, the relevant aspects of the constitution of the SPV Company and of its official registration are considered.

Law on companies

Types of companies that can be established in Armenia under the Law on Companies of 1992 are summarized in paragraph "Overview on the legal form of companies in Armenia".

From this overview, it clearly appears that the legal form of the SPV company is the joint-stock company which is regulated by a specific law: the Law on Joint-stock companies.

Overview on the legal form of companies in Armenia

An important distinction: Armenian law makes a special distinction between "juridical persons" and "physical persons". An enterprise, which is a juridical person, is an independent legal entity separate from its owners. This enterprise's property, rights, and liabilities are distinguished from its owner's other properties, rights and liabilities. The liabilities of an enterprise, which is a juridical person, are the responsibility of that legal entity. Both juridical persons and physical persons have the same rights in areas of economic activity. All businesses - juridical persons -

are subject to double taxation, e.g. they have to pay the so-called "profit tax" in addition to personal income taxes paid by their owners or employees.

The Enterprises and Entrepreneurial Activities Law (passed February 1992) establishes the following legal forms of businesses:

- Individual Businessman,
- Personal/family enterprise,
- Economic partnership (full or limited),
- Production co-operatives,
- Joint stock company,
- Limited liability company,
- Public service enterprise,
- Joint venture status,
- Subsidiaries.

Registration

Law on State Register of Enterprises (September 1993) stipulates that an enterprise or an individual entrepreneur is legitimate to start operations after being licensed (if necessary) and receiving a state registration certificate. Registration is made to the State Register's local division where the business is to be established.

Foreigners have the same rights to establish business enterprises as Armenian citizens, except that they are not allowed, unless otherwise authorized, to participate in the following forms of enterprises: consumer (service) co-operatives, collective farms, state and local government enterprises, and state enterprises of special significance. It is illegal for enterprises or individuals to conduct economic activity without registering with the State Register.

Registration procedures are as follows:

An enterprise, or an individual entrepreneur is granted the right to start his/her operations only after receiving a state registration certificate. The law provides for two types of registration: initial registration when a state registration card is filed into the State Register for a business being registered, and current registration, when additions and amendments are made to the registration card. A local division of the State Register for a fee conducts registration. The local division ensures that the completed registration card is sent to the central state registration body where it is assigned a state registration code, a registration number, and a registration certificate is issued.

Joint ventures and foreign enterprises must file additional documents to determine the financial stability and legal status of the foreign investment party. These documents include the founding contract and bank statements verifying financial stability of the founders. To register an affiliate or subsidiary, the charter or by laws showing affiliations to the parent company and a letter of intent will be required.

Accounting regulation

At the present no indications are available on the statutory accounting procedures acting in Armenia. This aspect needs more inquiries with regard to Depreciation and net income calculation. Normally different depreciation rate is affecting equipment (and particularly energy equipment) and buildings. As an assumption for financial projections in the project evaluation base building depreciation will be based on a 4% rate and equipment depreciation on the lifetime of the equipment.

Competition Law

At present, no indications are available of competition regulation. The lack of an anti-monopoly law means that some sectors have been controlled by the monopolies, and it is very hard to break them down. Even in case of a privatization of the energy generation branch of the sector, it must be reminded that the process will evolve by steps, and that the crucial problem of energy tariffs detailed in Chapter 10 will imply policy reform due to the problem of covering production costs.

Law on Safe Use of Nuclear Energy in Peaceful Purposes

This Law is to regulate public relationships concerning the use of nuclear power in peaceful purposes, as well as the other public relationships arising as a result of the utilization of nuclear energy.

The purpose of this Law is to set forth a legal framework and principles for relationship regulation concerning the use of nuclear power, which should insure protection of people's life, health, property and environment, support the development of nuclear science and technology, and assist in the reinforcement of internationally accepted guidance for safe use of nuclear energy.

This Law is comprised of 12 Sections and 37 articles.

The 1st Section of the Law is titled "General Provisions" (Articles 1-6). This Section defines the main concepts used in the Law. This will help those governed by this Law (especially non-specialists of this field) to accurately and correspondingly comprehend the main concepts of this Law, which are frequently mentioned. This section also introduces Armenia legislation for safe usage of nuclear power with peaceful purposes, as well as specific articles are designed to define the principles of and objectives for legal regulation of nuclear power usage, the subject of this Law, the ownership right and safety rules and norms for facilities related to nuclear power usage.

The 2nd Section of the Law is titled "Jurisdictions of the GoA, entities of state authority, regional authority, and local authority in respect to nuclear power usage" (articles 7-10). Taking into consideration the importance and significance of the nuclear power usage sphere, separate articles are devoted to define the rights and obligations of state authorities and local authorities, to insure accurate and smooth organization and implementation of activities within the field. The Law empowers the state with greater authority because of the outstanding role and responsibility of the state in this area.

The 3rd Section of the Law is titled as "The rights of legal entities and physical persons in respect to the usage of nuclear power" (articles 11-14). This Section sets forth the rights for implementing activities within the sector of nuclear power usage, particularly: the right for implementing activities within the nuclear power usage sector of Armenia shall be entitles only to the persons (legal and physical) licensed according to the defined procedure (the procedure for granting licenses is set forth in Article 18). This Section defines the right for access to the information pertaining to the usage of nuclear power, the right for compensation against nuclear damage, the rights related to medical treatment for people subjected to radiation.

The 4th Section of the Law is titled "Safety Regulation by the State with Respect to Usage of Nuclear Power" (Articles 15-17). This Section defines that the State Management Body authorized by the GoA and reporting directly to the GoA shall implement safety regulation within the nuclear power usage sector. This Section sets forth the jurisdiction of the above-mentioned entity, as well as the rights and obligations of state inspectors serving in this entity.

The 5th Section of the Draft Law is titled “Licensing Pertaining to the Area of Nuclear Power Usage” (Article 18). This Section describes the licensing procedure which, according to this Law, is defined not only by this Law, but by other legislative and legal acts as well. This Section regulates such issues as entities subject to licensing within the area of nuclear power usage, license term, license termination, etc.

The 6th Section of the Law is titled as “Operation of Facilities Involved in Nuclear Power Usage” (Articles 19-20). This Section defines the boundaries for activities and responsibilities of organization operating the above-mentioned facilities, and the jurisdiction of that organization.

The 7th Section of the Law is titled as “Sources of Ionizing Radiation and Radioactive Waste” (Articles 21-24). This Section regulates the state system for record of and control over the sources of ionizing radiation and radioactive waste, particularly, according to the Draft Law: sources of ionizing radiation subjected to safety regulation, as well as existing and future radioactive waste within Armenia are subject to record, measurement and control by the state, whereas the procedure for recording shall be set forth by the GoA upon its submission by the regulatory body. This Section regulates the transportation of nuclear and radioactive material, prevention of and reaction to the possible potential emergency situations during the transportation of nuclear and radioactive material, as well as the storage and burying of radioactive waste.

The 8th Section of the Law is titled as “The Physical Protection of Facilities Related to Nuclear Power Usage” (Articles 25-26). This Section defines that the physical protection of facilities related to nuclear power usage is a complex of technical and organizational undertakings. This Section defines the purposes of physical protection of facilities related to nuclear power usage, and the requirements to such protections.

The 9th Section of the Law is titled as “The Legal Limitations in respect to Nuclear Power Usage” (Articles 27-30). This Section defines the special legal regime for the location of a facility related to nuclear power usage, which facility has important significance from the perspective of safety. This Section also defines the limitation of rights for the persons located within the territory of enterprises dealing with facilities related to nuclear power usage, limitation of rights to work in such facilities, as well as limitation of rights for organizing public events within and next to the territory of nuclear facilities’ locations and radioactive waste locations.

The 10th Section of the Law is titled as “Guarantees for non-dissemination of nuclear, radioactive and special purpose materials, radioactive waste, special purpose equipment and technologies” (Articles 31-32). This Section sets forth the state system for supervision and control over nuclear and special purpose materials, equipment, and technologies, their export limitations: particularly, the export of such materials, equipment and technologies is prohibited to such countries which failed to accept the obligation for peaceful usage and to ensure the physical protection of the mentioned materials, equipment and technologies, etc.

The 11th Section of the Law is titled as “Nuclear Damage and Compensation” (Articles 33-36). This Section regulates issues related to the responsibility for nuclear damage and its compensation, defines who shall bear the responsibility, justification of responsibility for nuclear damage and its compensation, manners and boundaries for compensation responsibility against the mentioned damage.

The 12th Section of the Law is titled as “The Responsibility in the Case of Violation of the Legislation of Armenia with regard to Nuclear Power Usage with Peaceful Purposes” (Article 37). As the final provision of the Law, this Section defines the responsibility of legal entities and physical persons, as well as the citizens, conducting activities within the mentioned sector, in the case of violation of the Legislation of Armenia with regard to nuclear power usage with peaceful purposes - meaning all the possible manners of responsibility (criminal, administrative, civil, etc.)

2.10.2.3. Armenian Partnership and Privatization

The possibility of an Armenian partner entry in the SPV has been considered:

- As a single partner in joint venture company or
- As a member a new established Armenian closed Joint stock company gathering energy state owned companies

In both the cases the potential Western partners as the development agencies will pay attention to the present statute of the potential Armenian partners and most them are state owned companies owned primarily by the Ministry of Energy on the privatization process of energy companies planned in the next years.

In that optic, potential sponsors and lenders should pursue their inquiry on 1999 Amendments on the 1997 Law of Armenia on Privatization of State Property and on the decrees the Armenian Government will act with regard with the TPP privatization program.

Concerning the existing organization of energy sector, the commercial oriented management in the energy sector was strengthened by subdivision of these enterprises into legally and economically independent utilities.

2.10.3. Licenses and key permissions on energy projects

The regulatory system of Armenia apparently doesn’t comply any Law on Concessions but specific regulation is provided by Law on Land property with reference to foreign investment and by the Energy Law with reference to license granting for energy generation activities (as for transmission and distribution).

The licence-granting framework for the projects the SPV have to consider is detailed in the following scheme:

According to the Law on Energy, two types of licenses are granted:

1.a. license for activities (extraction, import, transportation, distribution of natural gas, generation, import-export, distribution and transmission of thermal and electric energy, etc., industrial construction of power plants, OHL, substations, distribution networks, boiler houses, gas lines, gas distribution stations, etc.).

The license is granted by the Energy Regulatory Commission (ERC) in accordance with the Armenian Law on Energy, article 15, clause “a”.

1.b. special qualification license to legal and physical persons for implementation of certain activities.

The license is granted by the ERC in accordance with Armenia Law on Energy, article 15, clause “b”.

- No preliminary licenses exist.

- Each subject possessing license for activities should submit a financial report of activity by the end of calendar year. The report is analyzed by Armenia ERC. The report is not subject to approval by the ERC. The materials of the report are used for more impartial and sound calculation of tariffs or payments against the services of the subjects for the next reporting period. On the basis of detailed analysis of financial reports, the ERC may recommend more rational allocation of expenses.
- No license for water utilization is available at present.

Documents for Construction

As stated by Armenia Law on Energy (articles 15 and 36, and the ERC Resolution No. 39, dated 28.08.1998), to obtain a license for construction of energy facility, the following documents should be presented:

- The copies of constituent documents and registration certificate (in the State Registration Department) of the company;
- a statement on shareholders and their share holding (shares);
- special qualification license (see license type 1.b);
- copies of declarations published in republican press about intention to be engaged in licensed activities;
- feasibility study of the construction of the facility;
- financial guarantees in accordance with the procedure defined by ERC;
- statement on payment of state duty.

The last two documents have to be presented after the ERC makes positive decision on granting license for construction.

Documents for Activity

According to the same law references enounced for construction, to obtain a license for the activities that are to be carried out after fulfillment of construction mounting and start-and-adjustment activities, the following documents should be submitted together with the above mentioned ones:

- technical characteristics of the activity;
- the structure of the operating organization and its personnel;
- geographical region of the licensed activity (only for distribution activities);
- the list of main and auxiliary technological equipment, buildings, constructions, transportation means, etc.;
- list of leased main and auxiliary technological equipment, buildings, constructions, transportation means, etc.;
- copies of the acts of the last control of authorities performing technical and ecological monitoring;
- copies of the audit conclusions (if performed for the last year);
- price-list of paid services connected with the main activity (only for distribution activity);

- short- and long- term development plans;
- quarterly reports.

The Procedure of Granting and Obtaining the License

- A person submits an application and the documents to the ERC in two copies;
- The ERC registers the application and the documents and checks their conformity with the requirements. The ERC should inform the applicant about the results of such checking within 10 days;
- Upon positive result, the ERC should proceed to the licensing procedure and make decision within 90 days period from the date of application registration;
- In case the additional tests are required during the period of licensing, including attracting the independent experts, this period is prolonged up to 30 days;
- Upon adoption of positive decision, the license should be submitted to the applicant within 10 days from the date of adoption of the decision. In case of negative decision, the copy of the ERC resolution with refusal reasoning should be given to the applicant within the same period;
- In future, an individual may apply for obtaining the license without limitations, after considering the remarks raised by the ERC in respect of the previous application.

In case the requirements of the License on Construction (or industrial construction) are observed after the construction, the ERC may grant to the initiator a License for activity under simplified procedure within one-month period upon availability of:

- relevant application;
- all documents submitted to the ERC on issuing a License for construction and during construction (technical and financial reports, and etc.);
- permissions foreseen by Armenia legislation.

No other licenses are required. Upon necessity, the ERC may require other statements. These requirements do not extend to the following types of licensed (to be licensed) activity:

a) electricity import/export

b) natural gas import/export.

Restrictions on Ownership of Operation Licenses

Art. 38 of 1997 Energy Law provide that.

“No operation Licensee may own shares in any other operation Licensee, and no operation Licensee may merge with any other operation Licensee, without the Energy Commission’s approval.

Furthermore, and that is of key interest for western potential partners, “No person (legal person) that exercises more than 35% ownership or control of a generation, transmission or distribution operation Licensee, may, without Energy Commission approval, own any shares, hold shares of, or have financial participation in any other operation Licensee.”

2.10.4. Fiscal Framework

Fiscal framework has been in constant evolution, and it is strongly recommended that the establishing SPV Company monitor the changes in law in order to apply to the Ministry of Finance for total or partial exemption, and to define accurate risk mitigation against legal changes.

2.10.4.1. Corporate Profit tax

As predicted in the Law on foreign investment, foreign companies are subject to the same tax regime as Armenian companies.

According to Armenian Law on Making Amendments and Additions in the Armenian Law on Profit Tax, adopted on 26 December, 2000 (Article 33): the amount of a profit tax, taken as a ratio to the taxable profit, shall be 20%.

Specific privileges apply to the corporate taxation if foreign investment in company exceeds AMD 500 million (about US$ 1 Million). This means that profit tax will not be charged during 2 years after the investment is made, and 50% profit tax reduction will be done for the five-year period beginning from the third year of investment.

The 50% profit tax reduction period is set to decrease over time and to be eliminated by 2003.

In application to the CCPP projects investments made in 2001 may benefit only from the 50% deduction for four subsequent years.

A formal application to the Ministry of Finance should be done before the constitution of the SPV Company, in order to obtain grace period for, at least, 5 years from the break-even point year.

2.10.4.2. VAT

According to the Armenian Law on VAT (Art.9) adopted on 14 May 1997, the tax rate of VAT is determined in the amount of 20% of taxable turnover of goods and services.

When establishing the basic assumptions for the financial evaluation of the project, it must be taken into consideration that, as provided for the duties, products and services imported, especially in construction period, should be exempted from VAT.

Moreover, this exemption should be extended also to the local expenditures on products and services, at least during the construction period, and for all costs related to this period.

For that purpose, a formal application to the Ministry of Finance should be presented before the constitution of the SPV Company.

2.10.4.3. Duties and Import declaration

Armenia uses the Harmonized Code System for tariff classification. Customs Tariffs and regulations are provided by the Law of GOAM of May 12, 1997. All exports from Armenia are duty free. Tariffs are set in ad valor terms and levied on C.I.F. values.

The import tariff schedule is rated either 0 or 10 percent. The ten-percent tariff is levied on the items consisting mainly of consumer goods and luxury items.

According to the above-mentioned law, no duties are paid by a foreign investor for the import of goods, which constitute his investment in the enterprise, or for materials to be used by the foreign investment company for production. Thus this exemption is also acting for energy plants.

However a formal declaration of exemption from to the Ministry of Finance and Economy should be requested before the constitution of the SPV Company.

Concerning personal use items imported by foreign personnel of companies with a foreign investment, these are also non-dutiable. Nor are duties levied on export of products (goods, services) manufactured by foreign investment companies, or on import of products (goods, services) for internal use by these companies, except in cases specified by Armenian legislation and/or international agreements.

A customs declaration form must be presented along with a pro forma invoice or a contract indicating the specifications, quantity, and value of the goods being imported.

2.10.4.4. Land and Property Taxes

When considering tax rates on land and property, the SPV should, first of all, ascertain its rights both to own the plant and to construct the plant on a specific site.

Foreigners have no right to own land - they can only lease it, or temporarily use it by agreement. However, foreigners have a right to own all other types of property and have equal rights with Armenian citizens to establish different types of companies.

Also, a company registered by a foreigner in Armenia, like an Armenian business entity, has the right to buy the land. Exploitation of natural resources is to be made only upon concession agreements with the Government of Armenia or other appropriate state bodies.

Land Taxes

According to the Armenian Law on Land Tax (adopted on 27 April, 1994), the tax rates are being established as it is given below.

Chapter 2. Tax Rates and the Procedure on Calculation of Land Tax

Article 4. The land tax rate for the agricultural lands (including land lots allotted for housing in settlements and garden plots) shall be determined in the amount of 15% of the calculated net income determined by the cadastral evaluation.

Article 5. For the non-agricultural lands, the land tax shall be determined at the following rates:

a) for the lands used for the purposes of industry (including mines and territories damaged as a result of industrial activity), transport, radio communication, television, defence, for the lands occupied by gas-mines, as well as for the lands of the water stock, the land tax shall be determined in regard to the cost of the cadastral evaluation of the given type of soil in the corresponding zones of cadastral division, at the following rates:

- inside the settlements – 1%
- outside the settlements – 0.5%;

b) the land tax rate for the lands of the forest stock (with the exception of the agricultural types of soil included in them) shall be determined at the rate of 1% of the average value of the unused lands in the corresponding zones of cadastral division, according to the cadastral evaluation;

c) the land tax for other non-agricultural lands shall be determined at the rate of 1% of the cost of the given type of the soil, according to the cadastral evaluation.

Property tax

According to the Armenian Law on Property Tax (adopted on 27 December, 1997), the property rates are being established as it is given below.

Chapter 3. Property Tax Rates

Article 7. Property Tax Rates for Buildings

The property tax for buildings shall be calculated at the following annual rates:

- for buildings of public and productive importance – 0.6%;
- the property tax rate for other dwellings shall constitute:

Social taxes

Social contribution in charge to the employer amounts at 36% of salary.

Taxable Base	Tax Rates
up to 3 million drams	0% of taxable base
from 3 million drams up to 10 million drams	100 drams plus 0.1% of the amount exceeding 3 million drams of the taxable base
from 10 million drams up to 20 million drams	7100 drams plus 0.2% of the part exceeding 10 million drams of the taxable base
from 20 million drams up to 30 million drams	27100 drams plus 0.4% of the part exceeding 20 million drams of the taxable base
from 30 million drams up to 40 million drams	67100 drams plus 0.6% of the part exceeding 30 million drams of the taxable base
in excess of 40 million drams	127100 drams plus 0.8% of the part exceeding 3 million drams of the taxable base

3 DEFINITION OF SCENARIOS OF ARMENIAN DEVELOPMENT

3.1. Introduction

The primary objective of the study is to define future energy demand, primary energy supplies from indigenous sources, fuel import possibilities, etc.

The analyses carried out by means of the MAED model assume the description of functional relationships between the energy system and the socioeconomic system. It is also important to have in view the influences on the national economy induced by the foreign economic background: the fluctuation of international energy prices, the evolution of foreign trade, the country relations with other countries, access to modern technologies, etc.

As it was mentioned, the MAED model has been conceived for the analysing and forecasting both the medium and long term demand for energy by economic sector and industry subsector, as well as by categories of final energy use.

In order to understand the energy consumption mechanism, the first step was to select a base year, for which the energy consumption by economic sector and by categories of final uses was to be reconstructed using the MAED model. In a second step, two probable socioeconomic, technological and one demographic development scenarios of Armenia were constructed and the corresponding demand of energy was estimated.

In the MAED methodology, a scenario means a set of coherent evolutions of the parameters related to the socioeconomic, technological and demographic development of the country. Out of the multitude of scenarios analyzed during the ENPP study, two scenarios have been retained for the study: a low (pessimistic) and a reference (normal), practically covering the extreme possible situations of Armenia and representing an intermediate evolution.

3.2. Reconstruction of the Base Year of the Study

The application of the MAED model requires, at a first stage, the selection of a base year for the study, chosen among the recent past years, which will be considered to be representative of the economic and energy background of the country.

At the outset of the ENPP study in 2000, it was decided to select the year 1999 as a base year for which the National Statistical Service had published the yearly statistics reports, namely:

- "The socioeconomic status of the Republic of Armenia in January-December 1999" related to the economic activity and demographic information necessary for the study;
- The Energy Balance and the Structure of the Energetic equipment, regarding the energy consumption by economic sectors and sub sectors.

After the selection of the base year, the statistical data for that year were restructured in order to meet the MAED model requirements. In the process, it was also necessary to make intermediate calculations and hypotheses in order to make up for the lack of some statistic data.

Tables 3.1 and 3.2 present the regrouping of Armenia economic sectors according to the requirements of the MAED model related to the GDP formation and the final energy consumption, respectively. In addition, the forms of energy were grouped according to the following categories of final use:

- motor fuels;
- specific and thermal uses of electricity;
- fossil fuels direct use;

- centralized thermal energy generated both in boiler-houses and thermal plants;
- special treatment: feedstock for the chemical industry and other industries;
- non-commercial fuels (coal and wood, etc.).

Reconstruction of the base year involves a quite long period since it requires carrying out the following activities:

- statistical data collection;
- reorganization of the statistical data according to the MAED requirements;
- intermediate calculations and hypotheses owing to lack of some statistical data;
- determination of the final energy for the base year using the MAED model and comparison of the results with the statistical consumptions;
- input data improvement and new iterations by means of MAED model until obtaining results similar to the true consumptions.

Details concerning the above-mentioned stages of the study are shown in the following sections.

3.2.1. GDP and Demography

The MAED model reflects the level of economic activity in terms of the total Gross Domestic Product (GDP) and of the GDP structure by economic sectors. Table 3.3 presents the GDP structure for the base year of the study (1999).

3.2.2. Final Energy Consumption in the Base Year

Table 3.5 shows the total Armenian energy balance in 1999.

According to Table 3.5, the total commercial final energy consumption in 1999 was 1009.12 ktons of oil equivalent (ktoe), out of which a share of industry was 17.0%, residential - 22.7%, services - 13.0%, construction - 3.1%, transport - 31.6%, agriculture - 7.7%, and non energy uses - 4.9%.

The final energy consumption in the base year by energy forms was as follows:

- fossil fuels - 609.9 ktoe (60.4% of the total consumption),
- district heat - 79.0 ktoe (7.8%),
- hydro - 102.3 ktoe (10.1%),
- nuclear - 162.6 ktoe (16.1%),
- electricity - 312.0 ktoe (30.9%),
- non-commercial uses - 6.2 ktoe (0.8%).

3.2.3. Energy Consumption by Sector

3.2.3.1. Agriculture, Construction and Mining Sectors

In 1999, the Agriculture sector consumed 77.45 ktoe, namely 7.7% of the total final energy consumption of Armenia. This consumption consisted in motor fuels 38.21 ktoe (49.3%) and electricity for specific uses 39.23 ktoe (51.7%).

Table 3.1. Regrouping of Armenia Economic Sectors according to the Structure of GDP Formation in the MAED Model

Economic sector in the MAED Model	Economic sector of the Armenian statistics
Agriculture	1. Agriculture
Construction	2. Construction
Mining	3. Mining Non-metallic minerals, Gold, Cooper
Manufacturing Basic materials Machinery & Equipment Non-durable Goods Miscellaneous	4. Manufacturing industry Chemical materials Non-Chemical materials Metallurgy Building Materials Fabricated metal product and equipment Food industry, beverages and tobacco. Textiles, leather and products. Wood and products, and furniture Other branches of industry and handicrafts
Energy	5. Energy
Transport	6. Transport and telecommunications
Services	7. Commerce, Services, Banking, financing, Public administration

Construction sector consumed 30.98 ktoe, representing 3.1% of the total final energy consumption of Armenia, and had the following distribution: motor fuels - 27.11 ktoe (87.5%) and electricity - 3.87 ktoe (12.5%).

Since the MAED model required the Mining sector energy consumption separately, then the total consumption of the Mining sector was excluded from the Industry sector.

The Mining Sector consumption in 1999 assumed 2.98 ktoe - representing 0.003% of the total final energy consumption. It consisted of: motor fuels - 0.5 ktoe (16.8%) and electricity -2.48 ktoe (83.2%).

Table 3.2. Regrouping of Armenian Economic Sectors according to the Structure of Energy Consumption in the MAED Model

Economic sector in the MAED Model	**Economic sector of the Armenian statistics**
Agriculture	1. Agriculture
Construction	2. Construction
Mining	3. Mining Non-metallic minerals, Gold, Cooper
Manufacturing Basic materials Machinery & Equipment Non-durable Goods Miscellaneous	4. Manufacturing industry Chemical materials Non-Chemical materials Metallurgy Building Materials Fabricated metal product and equipment Food industry, beverages and tobacco Textiles, leather and products Wood and products and furniture Other branches of industry and handicrafts
Transport	5. Transport and telecommunications
Services	6. Commerce Services Banking, financing Public administration
Households	7. Residential

3.2.3.2. Manufacturing Sector

In 1999, the energy consumption of this sector was 220.8 ktoe (including non- energy uses), representing 21.9% of Armenian commercial final energy consumption.

The distribution by energy forms was the following:

Table 3.3. GDP Formation in the Base Year (1999)

Sector	GDP		Growth rate[1)]	Share
	10^9 AMD	10^9 US$[3)]	(%)	(%)
1. Agriculture	244.71	0.46	+1.3	26.2
2. Construction	82.19	0.15	+0.5	8.8
3. Mining	7.66	0.014	-10.0	0.8
4. Manufacturing	125.72	0.24	+4.9	13.5
4.1. Basic materials[2)]	17.69	0.033	+1.2	14.1
4.2. Machinery & Equipment[2)]	14.61	0.027	+0.6	11.6
4.3. Non-durable Goods[2)]	86.65	0.163	+6.23	68.9
4.4. Miscellaneous[2)]	6.78	0.013	+3.0	5.4
5. Energy	62.58	0.12	-7.7	6.7
6. Transportation	86.34	0.16	-18.7	9.2
7. Services	324.82	0.61	+1.0	34.8
TOTAL	**934.03**	**1.756**	**-**	**100**

Source: National Statistical Service

Notes:1) Relative to 1998 GDP

2) Relative to Total Manufacturing

3) 1999 constant prices, exchange rate 531.91 AMD/US$

The demographic information for the base year is given in Table 3.4, listing all demographic parameters requested by the MAED model.

Notes:1) Relative to 1998

2) Relative to total population

3) Where the centralized district heating and public transport are available

4) Age- range from 15-64

The Basic Materials subsector consumed 74.3 ktoe (without feedstock), representing 34.0% of the sector total consumption, and 7.4% of Armenian commercial final energy consumption. This subsector consumption consists in: electricity -15.1 ktoe (20.3%), fossil fuels- 48.5 ktoe (65.3%) and centralized thermal energy - 10.7 ktoe (14.4%).

Table 3.4. Demographic Indicators in the Base Year (1999)

Parameter	Unit	Statistic	Growth rate[1)] (%)	Share[2)] (%)
Total population	million	3.2	0.14	-
Urban population	million	2.15	0.16	67.2
Rural population	million	1.05	0.09	32.8
Population living inside large cities[3)]	million	1.8	0.16	56.3
Potential labour force[4)]	million	1.97	0.14	61.6
Labour force actually working	million	0.81	0.20	25.3
Number of dwellings	million	0.77	0.5	-
Household size	pers/dwel	4.16	-	-

Source: National Statistical Service

- electricity - 51.6 ktoe (23.6%),
- fossil fuels direct use - 83.0 ktoe (38.0%),
- centralized thermal energy - 35.0 ktoe (16.0%),
- feedstock - 48.8 ktoe (22.3%).

The Machinery and Equipment subsector had consumption of 12.6 ktoe, namely 5.7% of the total consumption of the Manufacturing sector, and 1.2% of Armenian commercial final energy consumption. That was distributed as follows:

- electricity - 4.4 ktoe (34.9%),
- fossil fuels - 5.0 ktoe (39.7%),

district heating - 3.2 ktoe (25.4%).

The Non-durable goods subsector consumed 79.4 ktoe, namely 36.4% of the total consumption of the Manufacturing industry, and 7.9% of Armenia commercial final energy consumption. That consumption consisted in:

- electricity - 30.7 ktoe (38.7%),
- fossil fuels - 29.0 ktoe (36.5%),
- district heating - 19.7 ktoe (24.8%).

The Miscellaneous subsector consumed 4.7 ktoe, representing 2.1% of the total consumption of the Manufacturing industry, and 0.5% of Armenian commercial final energy consumption. That one consists in:

- electricity -1.5 ktoe (31.9%),
- fossil fuels -1.9 ktoe (40.4%),
- centralized heats supply - 1.3 ktoe (27.7%).

The feedstock consumed 48.8 ktoe, representing 22.3% of the total consumption of Manufacturing sector, and 4.8% of Armenian commercial final energy consumption.

3.2.3.3. Transportation Sector

The energy consumption of this sector in 1999 was of 319.3 ktoe, representing 31.6% of the total commercial final energy consumption and mainly consisting in:

- motor fuels - 307.8 ktoe (96.4%) for road transport, which included very low amount of diesel (0.01%) for manipulating locomotive engines in the railways depots,
- electricity - 11.5 (3.6%) for electric railway transport, as well as for the subway, tram and trolley-bus public transport in cities.

3.2.3.4. Service Sector

In 1999, the service sector consumed 131.3 ktoe, namely 13% of the total commercial final energy consumption, consisting in:

- electricity - 93.4 ktoe (71.1%),
- fossil fuels - 28.4 ktoe (21.6%),
- thermal energy -7.5 ktoe (5.7%),
- coal and wood - 2.0 ktoe (1.5%).

It should be noticed the high share of electricity and fossil fuels energy for space heating, hot water and cooking in hospitals, hotels, restaurants and other services, as well as the low share of centralized heats supply.

3.2.3.5. Household Sector

During the base year, the household sector consumed 229.24 ktoe, representing 22.7% of Armenian final energy consumption. That was distributed the following way:

- electricity -110.0 ktoe (48.0%),
- fossil fuels -76.6 ktoe (33.4%),
- district heat -36.5 ktoe (15.9%),
- coal and wood -6.2 ktoe (2.7%).

3.2.4. Comparison of the Base Year consumption with the MAED Results

Based on the existing statistical data for the base year, the values of the MAED model input parameters were determined, and the demand for final energy was estimated, using the model.

- In order to obtain results similar to the statistical consumptions by economic sectors and energy forms, a few iterations were made, and correspondingly, the input data of the model were gradually improved. Thus, at the end of a process of a base year input data validation, the MAED results were very close to the statistical consumptions (see Table 3.6).

3.2.5. Concluding Remarks

During the reconstruction of the base year consumption, some difficulties occurred in adjusting the statistical information so that to make it compatible with the requirements of the MAED model. These problems were related to:

- lack of some statistical data: GDP formation by industrial branches; breakdown by end-uses of some energy consumptions; efficiencies and useful energy consumption; breakdown of heat by temperature ranges in Manufacturing sector; distribution of energy consumption of the Transportation sector and of the volume of urban transportation by modes of transport, etc;
- compatibility of the available statistical data with the requirements of the MAED model, which required the transfer of some consumptions from one sector to another, i.e.: motor fuels from Services and Household sectors to Transportation sector and thermal uses from Transportation sector to Services;
- limits of the MAED model emphasized by Armenian particular condition within the study period: a big share of the thermal energy generated in cogeneration plants and thermal plants and also utilized in sectors like Agriculture, Construction and Mining for which the model does not allow such form of energy.

3.3. Scenario Selection and Definition

3.3.1. Scenario Approach

The MAED model requires the determination of the future evolution of all parameters affecting the various categories of energy demand, e.g.:

- GDP level and structure;
- Improvement in energy efficiency;
- Market penetration of competing energy forms;
- Total population and its distribution;
- Population's living standard, etc.

While establishing the development scenarios for Armenia, a proper consideration was paid to the Government's Program of Macro-economical Development of the Republic of Armenia, prepared by the Department of Macro-economical Analysis and Perspective Programming of the Main Department of State Policy and Long term Program of the Ministry of Finance and Economy of the Republic of Armenia.

The most important determinants of the Energy demand that can be reflected in the MAED model are indicated in Table 3.7.

As far as the study period is concerned, a range of about 20 years has been considered sufficient for determining the energy demand and supply strategy, under the present conditions in the country.

The study period was selected between 1999-2020, with the intermediate reference years: 2005, 2010, 2015, and 2020.

3.3.2. Major Policy Issues

3.3.2.1. Economic Growth

In the field of economic growth, the following data were taken into consideration:

- The speed and the manner the country will move through the transition period leading to a market economy;
- Increase of the national production of goods to satisfy the domestic demand and possible export markets;

Table 3.5. The total Armenian energy balance in 1999

1000 t.o.e	Coal&	Oil product				LPG	Natural gas	District heat	Hydro	Nuclear	Electricity	Total
	Wood	mazut	Gasoline	Diesel	other							
Primary products	6.20						15.00		103.10	541.80		666.10
Imports	2.00	17.20	252.50	78.60	31.50	13.00	987.40				39.80	1 422.00
Exports							-5.50				-60.50	-66.00
Stock change		0.00			0.00		42.70					42.70
Primary consumption	8.20	17.20	252.50	78.60	31.50	13.00	1 039.60	0.00	103.10	541.80	-20.70	2 064.80
*POWER SECTOR												
* input		0.50					680.00	72.20	103.10	541.80	608.30	2 005.90
* output								57.80	103.10	178.79	200.74	540.43
* self consumption									0.84	16.23	16.10	33.17
*GAS SECTOR (self consump.)							90.90					90.90
* DISTRICT HEATING & INDUSTY BOILERS												
* input							51.10					51.10
* output								40.90				40.90
* TRANSPORT/DISTR. LOSSES (technical)								19.70			116.74	136.44
Available for consumption	8.20	16.70	252.50	78.60	31.50	13.00	217.60	79.00	102.26	162.56	312.02	1 009.12
* Statistical difference	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00			0.00	0.00
* Final consumption by industry		4.50					78.52	35.00			54.03	172.05
* Final consumption by residential	6.20				5.70	9.23	61.62	36.50			109.99	229.24
* Final consumption by services, commerce, administration	2.00	1.60			2.80	1.69	22.30	7.50			93.40	131.30
* Final consumption by construction			17.68	9.43							3.87	30.98
* Final consumption by transport			219.40	46.37	23.00	2.08	16.99				11.49	319.34
* Final consumption by agriculture			15.42	22.79							39.23	77.45
* Non energy uses		10.60					38.17					48.77
North	2.41	1.24	51.51	14.93	2.21	2.47	25.93	4.40			35.17	140.27
Centre	1.38	1.34	55.30	37.73	3.47	2.73	103.83	13.10			75.55	294.41
South	1.03	0.85	35.35	16.51	2.21	1.00	21.03	1.90			80.70	160.57
Yerevan	1.38	13.27	110.47	9.43	23.63	6.80	66.83	59.60			120.60	412.00
Electrical Energy mln. kWh	Production	Self cons			Output	Import	Export	Distribution	North	Centre	South	Yerevan
Total	5 715.90	399.75			5 316.15	462.54	703.60	4 719.00	599.90	1 197.70	1 080.50	1 840.90
Arm NPP	2 078.30	188.60			1 889.70	162.40		1 090.80	190.90	319.20	142.20	438.50
Hr TPP	1 964.20	143.60			1 820.60	156.46		3 628.30	409.00	878.50	938.40	1 402.40
Yer TPP	474.20	58.00			416.20	35.77						
Sev-Hr Casc	346.60	5.15			341.45	29.34						
Van TPP					0.00	0.00						
Vor Casc	727.60	3.28			724.32	62.25						
Small HPP	125.00	1.12			123.88	10.65						

- Investments stimulation;
- Integration of Armenia into the European and world economy;

Incorporation of environmental issues in energy and electricity planning with the view of reducing the damage to the environment.

3.3.2.2. Population

In regard to the population, the following was considered to be of much importance:

- Providing decent living to the population;
- Improvement of the social system.

3.3.2.3. Industry

Regarding the Armenian industry, the following was taken into consideration:

- Development of industries with high values added;
- Reduction of the thermal energy and materials intensities;
- Technological upgrading by combining rehabilitation of existing equipment and introducing new technologies.

3.3.2.4. Transport

As to the items of transport, there was considered the following:

- Reduction of subsidies, and stimulation of efficient transport modes feasible both for passenger and freight transport;
- Transportation upgrading by rehabilitation of existing infrastructure (road and railway transport) and extension of that infrastructure.

3.3.2.5. Agriculture

In agricalture, the items of great importance are:

- Development of agricultural production that could be able to meet the domestic demand and be good for export as well.
- Implementation of new high efficiency mechanization modes.

3.3.2.6. Household/Service

In this area, the most important problems are:

- Providing decent energy levels suitable for both urban and rural areas;
- Reducing the pollution level in urban areas;
- Increasing significantly electrical appliances owners number;
- Developing the service sector by extending the existing one and meeting the request of adding new services corresponding to the development of commerce, banking activities, communications, etc.

Table 3.6 Verification of Base Year Final Energy Consumption with MAED Results

Sector/Energy Form	MAED Results, ktoe	Statistics, ktoe	Difference ktoe	Difference %
Agr/Constr/Min/Man:				
Fossil (substitutable)	83.012	83.020	-0.008	-0.010
Centralized heat supply	34.982	35.000	-0.018	-0.051
Electricity	97.134	97.130	0.004	0.004
Motor fuel	65.319	65.320	-0.001	-0.001
Feedstocks	48.770	48.770	0.000	-0.001
Total commercial (incl. feedstocks)	329.217	329.240	-0.023	-0.007
Of which manufacturing:				
Fossil (substitutable)	83.005	83.020	-0.015	-0.018
Centralized heat supply	34.982	35.000	-0.018	-0.051
Electricity	51.558	51.550	0.008	0.016
Feedstocks	48.770	48.770	0.000	-0.001
Total commercial (incl. feedstocks)	218.310	218.340	-0.030	-0.014
Transportation:				
Electricity	11.520	11.490	0.030	0.264
Motor fuel	307.864	307.840	0.024	0.008
Total	319.384	319.330	0.054	0.017
Household/Service:				
Fossil (substitutable)	106.761	106.940	-0.179	-0.168
Centralized heat supply	43.974	44.000	-0.026	-0.059
Electricity	203.277	203.390	-0.113	-0.056
Total commercial	354.011	354.330	-0.319	-0.090
Non-commercial fuels	6.204	6.200	0.004	0.066
Total (commercial + non-commercial)	360.216	360.530	-0.314	-0.087

3.3.3. Basic Assumptions

3.3.3.1. International Considerations

Armenian economic development will depend on the rate and extension of its integration into the European and Regional cooperation.

It will also depend on the foreign capital participation in the reconstruction of the Armenian economy, which finally, will be conditioned by the internal stability.

From both the economic and energy point of view, international economic and political stability will be much favourable for the Armenian industry appropriate and sound development.

At present, Armenia exports agricultural products, equipments, textiles, jewelleries and other consumption goods. Tourism development is forecast in the future, with small investments. Concerning exports, these may reduce considerably by increasing energy utilization efficiency in all sectors.

Table 3.7. Main Factors Affecting the Energy Demand in MAED Model

Category	**Factors**
1. Macroeconomics	Total GDP GDP structure by economic sectors
2. Demography	Total population Distribution in rural/urban/large cities Total labour force Household size (inhabitants/household)
Consumption sector 3.1 Industry (Agriculture, Construction, Mining and Manufacturing) 3.2 Transportation 3.3 Service 3.4 Household	Specific energy intensity for each category of end-use Improvement of efficiency Electricity penetration into the heat market Volume of freight and passenger transportation Distribution of freight and passenger transportation Specific energy consumption and load factor of each mode of transport Sector labour force Floor area Specific energy consumption by end-use category - Space and water heating; - Electrical appliances; - Air conditioning Electricity penetration Type, size and share of dwellings - single family house, apartment, room; - demolition rate; - share of dwellings with hot water facilities; - share of dwellings with air-conditioning; - improvement of insulation; - electrical appliances endowing.

3.3.3.2. Economic Growth

At present, Armenia experiences economic upsurge with an average annual GDP growth rate of 6.0%; and also:

- Gradual change of the GDP structure by increasing the share of Services, Industry and Transports;
- Utilization of foreign resources, especially for investments leading to the economy upgrading;
- Increase of labour productivity in all sectors.

The future evolution of this structure relies on the following assumptions:

- Agriculture contribution to total GDP is projected to increase from 0.46 bill US$ in 1999 to 0.82 bill US$ in 2020.
- The value added of the construction sector is estimated to increase throughout the study period from 0.15 bill US$ in 1999 to 0.47 bill US$ in the year 2020, due to the new investments in this sector and the increase of rehabilitation and modernization of old buildings.
- The mining sector participation in GDP is foreseen to increase from 0.01 bill US$ in 1999 to 0.2 bill US$ in 2020. This sector will increase its activity as the enlargement of mining area and growth of existing production.
- The value added of the manufacturing sector is expected to increase from 0.24 bill US$ in 1999 to 1.33 bill US$ in 2020, and the changes in the structure of the value added of this sector are expected as well. As to the manufacturing's structure, the value added of basic materials industries is projected to increase from 0.03 bill US$ in 1999 to 0.24 bill US$ in 2020, the value added of Non-durable goods industries is estimated to increase from 0.16 bill US$ in 1999 to 0.72 bill US$ in 2020, and the machinery & equipment

The distribution of GDP by kind of economic activity is presented in Table 3.8.

Table 3.8. Share of Sector's GDP billion US$

Years	**1999**	**2005**	**2010**	**2015**	**2020**
Total GDP	1.76	2.79	3.82	4.87	6.07
Agriculture	0.46	0.63	0.75	0.80	0.82
Construction	0.15	0.24	0.31	0.39	0.47
Mining	0.01	0.04	0.09	0.14	0.20
Manufacturing	0.24	0.42	0.64	0.95	1.33
of which:					
-Basic Materials	0.03	0.07	0.13	0.19	0.24
-Machinery and Equipment	0.03	0.06	0.10	0.19	0.36
-Non-durable goods	0.16	0.28	0.40	0.55	0.72
-Miscellaneous	0.01	0.01	0.02	0.02	0.02
Energy	0.12	0.18	0.24	0.30	0.37
Services	0.77	1.28	1.78	2.29	2.88

Table 3.9. Population Growth Forecast

Year	1999	2005	2010	2015	2020
Total Population (mln.)	3.2	3.22	3.24	3.25	3.26
Growth rate (% p.a.)	0.14	0.14	0.14	0.14	0.14
Rural Population (mln.)	1.05	1.04	1.03	1.03	1.02
Growth rate (% p.a.)	-0.03%	-0.13%	-0.15%	-0.17%	-0.18%
Share (%)	32.8%	32.3%	31.8%	31.7%	31.3%
Urban Population (mln.)	2.15	2.18	2.21	2.22	2.24
Growth rate (% p.a.)	0.27%	0.27%	0.28%	0.29%	0.29%
Share (%)	67.2%	67.7%	68.2%	68.3%	68.7%
Population Inside Large Cities (mln.)	1.8	1.83	1.86	1.87	1.89
Share in Total Population (%)	56.25%	56.83%	57.41%	57.54%	57.98%
Persons per Household	4.16	3.79	3.72	3.53	3.40
Total Households (mln.)	0.77	0.85	0.87	0.92	0.96
Potential Labor Force (mln.)	1.97	1.99	2	2.01	2.03
Participating Labor Force (mln.)	0.81	1.29	1.45	1.68	1.83

industries is expected to increase from 0.03 bill US$ in 1999 to 0.36 bill US$ by the end of planning period.

- The value added of services sector is forecast to grow from 0.77 bill US$ in 1999 to 2.88 bill US$ in 2020 due to the development of both existing and new categories of services.

3.3.3.3. Population

Armenian population is foreseen to grow from 3.2 million in 1999 to 3.26 million in 2020. The elements regarding the overall evolution of population both in urban and rural area within the study period are presented in Table 3.9.

Urban population is projected to increase, reaching 2.24 million in 2020 against 2.15 million in 1999, while the rural population is estimated to decrease, reaching 1.02 million inhabitants in 2020 against 1.05 millions inhabitants in 1999. According to these assumptions, in the year 2020, about 69% of Armenian population will live in urban areas against 67% in 1999. This could be explained by the economic adjustment characteristic of that period, as well as by the impact of the migration from villages to towns.

The household size, expressed by the number of persons per dwelling, is estimated to decrease from 4.16 (in 1999) to about 3.4 in the year 2020 due to the decreasing trend of demographic growth. As far as potential labour force is concerned (population between 15 and 64 years old), an average annual growth rate of 1.6 % is foreseen, meaning a growth from 1.97 million persons in 1999 to 2.03 million in 2020.

3.3.3.4. Industry

In this sector, it was assumed that there would be:

- Increased the number of energy-capacious industries (due to the rehabilitation of the chemical complex and several huge factories like “Nairit”, “Rubber” etc.) within the Basic Materials sub sector, and decreased both the consuming goods production and the Miscellaneous sub sector itself, while the share of Machinery and equipment sub sector would grow.
- Increased the District Heating share growth within the total energy consumption in industry.

3.3.3.5. Transport

The main objectives to be achieved in this sector are:

- Development of the road network;
- Extension of the electric transportation for freight and passengers;
- Restructuring of urban transport in order to increase traffic fluency;
- Increase of population mobility especially by increasing the share of private motorcars;

3.3.3.6. Household

In this sector, it is anticipated that there will be:

- Increase of production of centralized thermal energy for space- and water heating, to the detriment of fossil fuels direct use;
- Slight decrease of the number of people living together in one dwelling (household size);
- Increase of electricity consumption per dwelling due to the growth of the number of electrical appliances owners;
- Improvement of the thermal insulating for both the existing dwellings and new constructions;
- Slight penetration of the electricity utilization for air-conditioning purposes.

3.3.3.7. Service

For this sector, it is anticipated to achieve:

- Increase of the specific electricity consumption due to the enlargement of the number of electrical appliances owners;
- Slight penetration of the air conditioning and electricity utilization for space heating and hot water purposes.

3.3.4. Scenario Selection

At the time this study was being conducted, the macroeconomic long term forecasts were available to be extracted from the Government's Program of Macro-economical Development of the Republic of Armenia, prepared by the Department of Macro-economical Analysis and Perspective Programming of the Main Department of State Policy and Long term Program of the Ministry of Finance and Economy of the Republic of Armenia.

Generally, only two scenarios, named Reference scenario and Low scenario, were developed based on the opinions of experts working within that field, covering plausible range for future evolution of the main driving parameters. A limited number of scenarios facilitate the comprehension of the spirit of the scenario and the differences between scenarios.

3.3.5. General Description of the Scenarios

3.3.5.1. Reference Scenario

The Reference Scenario assumes that these policies fully achieve the targets. Some items of the Government's plan are considered to be of particular importance:

- Trade and exchange policies. Armenian trade deficit during 1998-2001 is expected to narrow in relation to GDP from 30% to about 24%, reflecting export growth averaging round 13% /year combined with moderate import growth of 4%/year. The growth in export expected to be led by minerals, non-precious metals, and labor-intensive light manufactured products (food, textile, machinery, etc.).
- Privatization policies. Privatization program must go on in order to complete the program approved by the Parliament in December 1997.
- Financial sector reform and development. The Armenian banking system is still fragile at the present. To address this issue, the CBA (Central Bank of Armenia) continues strengthening prudential regulation during the period 1998-2001. The CBA also continues to monitor the timeliness and accuracy of the financial reporting by banks and improve the process of banking supervision.
- Energy sector reforms. The ongoing restructuring and financial rehabilitation of the energy sector aims at improving supply efficiency, quality of service, payments discipline and to promote a greater transparency in the commercial transactions of the sector. Electricity tariffs increased, over the 1995-1999, from 12 drams to 21.6/25 drams (depending on different kind of voltage level of electricity supplied), however they still need further adjustments in order to meet market requirements. The changes in the average tariffs are part of the Energy sector financial improvement plan that includes also such indicators as improvement in energy bills collection and reduction in technical and commercial losses.

The achievement of the above mentioned targets are expected to foster the Armenian productive system. The restructuring of the energy sector, its increased efficiency and quality also play a key role in supporting the Armenian industry development. In the Basic Scenario, it is assumed that the Government programs address a stable and self-sustained economic growth, which is assumed to last for the overall 2000-2010 periods.

GDP is estimated to have a growth rate 6.0% per year during the 2000-2020 and is based on the considerations given below.

The GDP growth is mainly driven by the industry (+8.6%/year). The machinery and equipment sub sector increases its weight in the industrial structure at the expenses of energy intensive industries (chemical sector, metallurgy, etc.) and consumer goods sub sector, also by precious mineral processing.

The tertiary sector (+6.5%/year) also increases its share in the "value added" (VA) structure. The most significant growth rates are expected to come from sectors related to tourism and restoration (hotel, restaurants, etc) and commerce. The communication and transport sectors also grow up at a fast pace (+5.8%/year). As to transport sector, in particular, public passenger transportation, it is supposed to increase significantly, while total freight traffic is supposed to follow the production of material (industry, agriculture, and construction). Rail transportation follows the growth of GDP.

Agriculture (+2.8%/year), though decreases its share in GDP, is increasing its absolute Value Added production.

The recovery of the internal consumption is expected to push the economic growth for the next 2-3 years, and then the net exports will take over internal consumption in driving the expansion.

The favorable economic trend creates new business opportunities and reduces the emigration flow.

It is expected that in the following 20 years, GDP will have the average growth rate of about 6.0%/year.

The achievement of this scenario hypothesis implies an adequate development of the infrastructures needed (roads, railways, telecommunication networks, energy infrastructures, etc.).

3.3.5.2. Low Scenario

In Low scenario, it is assumed that the short term objectives set by the Government's economic reforms program were only partially achieved.

The trade policy of the Government and its strategy to attract foreign investments obtain results below expectations, also as a consequence of further delays in the entrance of Armenia in the World Trade Organization (WTO).

The Armenian banking system reform also slows down compared to the expected trend.

The Russian crisis lasted, on alternate phases, well beyond the year 2000. It contributes to depress the regional trade.

Political tensions also last in the Trans-Caucasian region, so contributing to worsen the economic picture.

The financial/economic environment discourages internal and, most of all, foreign investments for the permanence of high levels of risk.

The trade balance remains negative in the medium term and the internal demand is unable to sustain the GDP growth at the target levels.

The low investments delay the industrial recovery, delaying, at the same time, the process of modernization of the sector.

GDP is assumed to grow by 4.8%/year on average over 2000-2010 period. In particular, a 3.8%/year increase is assumed for the 2010-2020 period. A slight recovery is expected for the following quinquennium in which GDP grows by 5.0%/year.

The tertiary sector expects a growth of GDP during the 2000-2005 (+4.4%/year) and confirms this tendency for the following five-year period (+5.4%/year).

Industry substantially aligns its growth (+6.2%/year) to that of the 2000-2005 GDP, but is expected to speed down its pace during the 2005-2010 period (+6.0%/year). The tendency recorded in the Scenario A of an increasing weight for the light manufacturing sectors at the expenses of energy intensive industries (chemical sector, metallurgy, etc.) is less evident in this scenario.

Agriculture (+3.3%/year in the 2000-2010 period) decreases its share in the overall VA, but at a slower pace than in Reference scenario.

In the following 2010-2020 decade, GDP is expected to grow at about 4.04%/year. During the planning period, the population growth rate is assumed to remain substantially stable (0.14%/year).

3.4. Detailed Description of the Reference Scenario

3.4.1. GDP Growth

The Reference scenario considers that the GDP average increase is estimated by 6.0% p.a. during the planning period, as mentioned above. The GDP projections, until 2020, for the basic scenario are presented in Table 3.10.

Table 3.11 gives the growth rates of various sectors of the economy as projected for this scenario. Table 3.12 shows the forecasting shares of various economical sectors in total GDP.

3.4.2. Specific Energy Intensity in Industry

The assumed evolution of the final energy intensities in industry for the Reference scenario is presented in Table 3.13.

Table 3.10. GDP Growth Forecast for Reference Scenario

Year	**Total GDP** (10^9 US$_{1999}$)	**Average annual growth rate (%)**	**Per capita GDP** (US$_{1999}$/capita)
1999	1.76	3.30	462.11
2005	2.79	8.00	727.17
2010	3.82	6.50	989.35
2015	4.87	5.00	1253.88
2020	6.07	4.50	1551.67

During the period 1999-2010, energy intensities in industry are expected to increase generally due to two major factors:

- achievement of rehabilitation of existing (old) technologies with low efficiency in all sectors;
- slightly increase of automation share in some technological processes.

Table 3.11. Projected Growth Rates of Gross Domestic Product [% p.a.] (Reference Scenario)

Sector	**1999 – 2005**	**2005 - 2010**	**2010 - 2015**	**2015 - 2020**
Agriculture	5.40%	3.40%	1.40%	0.40%
Construction	7.40%	5.80%	4.40%	4.00%
Mining	20.00%	15.00%	10.00%	8.00%
Manufacturing	10.00%	9.00%	8.00%	7.00%
Energy	7.50%	6.00%	4.50%	4.00%
Services	8.70%	6.95%	5.16%	4.66%

From 2010 untill the planning period end, the energy intensities in total industry are expected to slightly decrease according to the following factors:

- the structural adjustments of the manufacturing industry (decreasing of the basic materials share in manufacturing sector);
- development of high-technological processes in industry with higher energy efficiency.

Agriculture

Motor fuels and electricity use are the main categories of end-use of energy in the Agriculture sector.

During the period 1999-2020, the specific energy intensity for motor fuels is projected to increase with an average annual growth rate of 6.2%. This is expected to be due to two contradicting causes: on the one hand, increase in the use of tractors and highly performing agricultural equipment that will replace part of the existing equipments, and, on the other hand, the increase of the use of agricultural equipment, meaning an increase of the mechanization rate aiming at replacing manpower in agriculture.

Table 3.12. Projected Shares of Economical Sectors in Gross Domestic Product Unit: %

Sector	**1999**	**2005**	**2010**	**2015**	**2020**
Agriculture	26.2	22.6	19.5	16.4	13.4
Construction	8.8	8.5	8.2	8.0	7.8
Mining	0.8	1.5	2.3	2.9	3.4
Manufacturing	13.5	15.0	16.9	19.4	21.9
Energy	6.7	6.5	6.4	6.2	6.1
Services	44.0	45.8	46.7	47.1	47.5

Table 3.13. Summary of Final Energy Intensity in Industry (Reference Scenario) Unit: kWh/US$

Sector	**1999**	**2005**	**2010**	**2015**	**2020**
Agriculture					
Motor fuels	0.97	2.50	3.50	3.47	3.38
Electricity, specific uses	0.99	1.42	1.53	1.52	1.50
Thermal uses	0.01	2.80	2.87	2.85	2.83
Construction					
Motor fuels	2.04	2.87	3.34	3.26	3.16
Electricity, specific uses	0.29	0.42	0.51	0.53	0.54
Thermal uses	0.00	0.00	0.00	0.00	0.00
Mining					
Motor fuels	0.01	2.50	2.73	2.67	2.62
Electricity, specific uses	2.00	2.15	2.18	2.19	2.19
Thermal uses	0.00	0.00	0.00	0.00	0.00
Manufacturing					
Motor fuels	0.00	0.00	0.00	0.00	0.00
Electricity, specific uses	1.77	2.05	2.23	2.11	1.79
Thermal uses	7.63	7.77	8.10	7.55	6.80
TOTAL	**4.42**	**9.30**	**10.54**	**10.26**	**9.46**

The specific energy intensity of electricity duirng1999-2020 is expected to increase at average by 2.0% p.a., and will reach the level of 1.5 kWh/US$ in 2020, due to animal farm and irrigating systems rehabilitation and modernization.

Construction

In this sector, a reduction of the motor fuel energy intensity from 3.34 kWh/US$ in 2010 to 3.16 kWh/US$ in 2020 is foreseen. Upgrading technological processes, and increasing mechanization and labour productivity is expected to achieve this reduction of 0.6% yearly.

In the same time, a small quantity of electricity is being consumed in the construction sector, however, keeping in view the data of some developing countries, it is assumed that electricity intensity growth rate in this sector will be 3.0 % p.a. during the next twenty years.

Mining

The analyses concerning the efficiency of the mining sector foresee that the inefficient units should be gradually changed in the next years, while the modernization units should be brought to a proper mechanizing and fanning installations endowing.

It is assumed that the electricity intensity will increase from 2.0 kWh/US$ in 1999 to 2.2 kWh/US$ in 2020, and the energy intensity for motor fuels will gradually decrease up to 0.4% p.a. in average during the last decade of the planning period.

Manufacturing

The factors determining the change of energy demand in the Manufacturing sector include changes in sub-sectoral contribution in value added of Manufacturing sector, changes in energy intensities, changes in energy efficiencies and penetration of new energy sources and technologies.

It was noted that, also as a consequence of the privatization program in progress for many Armenian industries, significant energy efficiency improvements should be taken into account.

As a matter of fact, reference scenario, though representing a “business, policies and behaviors as usual” scenario, already embodies a slight efficiency improvement. This efficiency improvement assumes a slow but steady process of modernization and restructuring of old plants, disabling of obsolete plants, and some structural changes, at different levels, in the individual industrial sectors. One of the sectors mostly affected by these adjustments is the metallurgy (copper) sector.

During the planning period, the intensity of thermal uses is projected to decrease of about 0.5% p.a., while the intensity of specific electricity uses is estimated to increase of about 2.1% p.a. till 2010, due to rehabilitation of energy intensive industries, and will decrease of about 2.2% p.a. till 2020. The motor fuels trend is not very clear due to relatively small quantities of the fuels used. The reduction in intensity of thermal use is believed to be a result of energy conservation measures and technological improvements over this period, while the increase of intensity of electricity is an effect of higher automation in the manufacturing sector. In this case, the effect in automation and improvements in the end-use efficiency have been assumed to lead to an overall increase of the intensity of electricity use.

3.4.3. Specific Energy Intensity in Transportation

The transportation sector implies four types of transportation activities:

- freight transportation,
- intercity passenger transportation,

- urban passenger transportation,
- miscellaneous transport (includes military, government and miscellaneous uses)

Synthetic elements concerning the specific energy intensity for freight transportation are presented in Table 3.14, and in Table 3.15 for the passenger transportation.

Freight Transport

Freight transportation activity levels have been projected on the basis of a linear equation linking freight ton-km with the sum of the value added of the Agriculture, Mining, Manufacturing, and Energy sectors. The constant and slope of the linear equation were determined by fitting a straight-line equation to 1999 data and plan target for 2020. Projected average growth rates of ton-km for the period 1999-2020 is 7.8% p.a.

The shares of trucks and pipelines in freight transportation are projected to decline while the share of trains is estimated to increase respectively in the period 1999-2020.

Trucks

The share of truck transportation in total freight transportation is projected to decrease from 58.1% in 1999 to 55.8% in 2020. It is important to notice, that it was foreseen a considerable growth of the long distance transport share in truck transport (from 10.7% to 22.7%) during the planning period, especially after the de-blockage of communications and rehabilitation of industry. If so, it is expected a decrease of the share of local trucks transport in whole truck transport from 89.3% in 1999 to 77.3% in 2020.

Trains

At present, railway transports have been providing 26.0% of the freight transport. In the future, it is forecasted a high increase of railway traffic correlated with the above-mentioned notes attaining a share of 37.4% of the total freight transport in 2020.

The specific energy consumption for transportation of 1 ton-km is estimated to decrease for electric freight trains from 0.24 kWh to 0.12 kWh through 1999-2020.

Pipeline

Pipelines are utilized for gas transport. It is forecasted that this type of transport will reduce its actual share in total transport of freight from 15.9% in 1999 to 7.15% in 2020.

Passenger Transport

Intercity Transport

In the case of intercity passengers transport, it is estimated that the increase of population mobility will be about 7.1% yearly, through 1999-2020.

Taking into account the possibilities of extending facilities for passenger intercity transport, it was forecasted the increase of the share of the motor car transport from 43.1% in 1999 to 46.2% in 2020, and the decrease of the share of the bus transport from 53.7% in 1999 to 50.4% in 2020. Within the cost of the train transport, it was mentioned to keep constant the share of electric trains transport during the planning period.

At the level of 2020, it was estimated an average energy specific consumption per passenger-km of 0.36 kWh for motorcars, 0.23 kWh for buses, 0.06 kWh for electric trains, and 1.24 kWh for planes.

It was assumed that the number of persons per train would increase gradually during the time to reflect improvements in the quality of service. For airplanes, the load factor of 56.5% was assumed to increase gradually up to 64.5% throughout the next 20 years. The energy intensities (fuel use/100-km) of intercity car, bus and train were assumed to decline by 22.7%, 4.0% and 0.4% respectively by 2020.

The activity of the urban passenger transport is forecasted to increase throughout the whole study period with an average annual rate of 5.3%. In addition, it is estimated that the share of cars in the intercity transport will increase as a result of increased needs of population mobility. This variable is thus expected to increase from 50.5% in 1999 to 63.8% in 2020.

As far as mass transport is concerned, it was forecasted the increase in the subway transportation, as well as in tram- and trolley-buss transportation share from 15.2% in 1999 to 22.3% in 2020. This option is also justified from the point of view of the energy specific consumption, which for the electric mass transport is forecasted to reduce: from 0.18 kWh/pkm in 1999 to 0.11 kWh/pkm in 2020.

3.4.4. Life Style

Life style, living standard and comfort requirements are the main socioeconomic factors influencing the energy demand in the household department and services sector.

Household

It was considered a necessity to provide a decent living standard for population for the analyzed period. In this respect, it was forecast that after 1999, the average surface of new dwellings would increase for all categories of dwellings. Thus, in 2020, it is estimated an increase with about 23.9% of the new single-family dwellings surface and the apartments surface, both categories being provided with district heating mainly.

Service

The services sector is forecast to evolve according to the development of socioeconomic activities. This requires the modernization and the extension of the existing services, as well as the setting up of new services, necessary in the market economy. In parallel, it was estimated a normal thermal comfort and the penetration of the air conditioning in certain services.

It is assumed an increase of electricity requirement both by increasing the service ownership rate and by covering the heating and hot water consumptions.

3.4.5. Specific Energy Intensity in Household/Service

Household

The evolution of specific energy consumption in dwellings for the Reference scenario is presented in Table 3.17.

The energy consumption for a dwelling consists in the needs for heating, hot water, cooking, electric appliances and lighting appliances, and also the air conditioning.

The heating requirements represent the biggest component of the useful energy needs per dwelling. The demand for heating is expected to increase till the end of planning period according to improvement of socioeconomic situation in the country, and due to increase of heating area.

The energy demand for hot water is foreseen to increase within the period 1999-2020 from 472.9 kWh per dwelling and per year to 2275 kWh per dwelling and per year, by providing both the necessary fuel and the necessary drinking water flows for well supplying a great number of towns.

Table 3.14. Activity Levels and Energy Intensities in Freight Transport (Reference Scenario)

Year	**1999**	**2005**	**2010**	**2015**	**2020**
Total activity (%)	100.00	100.00	100.00	100.00	100.00
Total activity (10^9 tkm):	2.05	4.74	7.09	8.80	10.00
Truck	58.10	57.52	56.94	56.37	55.81
Local	89.30	86.30	83.30	80.30	77.30
Long-distance	10.70	13.70	16.70	19.70	22.70
Train	26.00	28.34	30.89	33.67	37.04
Electric	100.00	100.00	100.00	100.00	100.00
Steam	0.00	0.00	0.00	0.00	0.00
Diesel	0.00	0.00	0.00	0.00	0.00
Pipelines	15.90	14.14	12.17	9.95	7.15
Energy intensity (kWh/tkm)					
Truck					
Local	0.41	0.41	0.41	0.41	0.41
Long-distance	0.35	0.35	0.35	0.34	0.34
Train					
Diesel	0.00	0.00	0.00	0.00	0.00
Electric	0.20	0.18	0.17	0.16	0.15
Steam	0.00	0.00	0.00	0.00	0.00
Pipelines	0.00	0.00	0.00	0.00	0.00

The energy intensity of cooking was considered to increase (about 3.14% yearly) from about 535.7 kWh per dwelling in 1999 to about 1025.6 kWh per dwelling in 2020. This would be due to the assumptions regarding the increase in the traditional way of cooking.

The specific electricity consumption is foreseen to grow, with an average yearly rate of 5.8%, during the whole study period due to the important growing shares of dwellings equipped with electric appliances. Therefore, the growth of specific uses of electricity necessary per dwelling can be estimated from 565 kWh in 1999 to 1853.8 kWh in 2020.

As far as the use of air conditioning installations in dwellings is concerned, it was forecasted a small penetration of its share into the total energy demand, with expected specific consumption in 2020 of about 2474.2 kWh/dw/year.

Service

The demand for useful energy in service sector mainly consists of the energy for space- and water heating and the electricity for specific uses. Table 3.19 presents the evolution of energy intensities of service sector for the Reference Scenario.

One of the main components of the energy used in service sector is the energy usually spent on space heating and hot water production.

Table 3.15. Activity Levels and Energy Intensity in Passenger Transport (Reference Scenario)

Year	1999	2005	2010	2015	2020
Passenger transport, intercity:					
Total activity (10^9 pas-km)	1.44	3.26	4.67	5.57	6.10
Share by mode (%)					
Car	43.09	43.56	44.27	45.15	46.16
Bus	53.68	53.07	52.28	51.38	50.39
Train	3.23	3.20	3.17	3.12	3.07
Steam	0.00	0.00	0.00	0.00	0.00
Diesel	0.00	0.00	0.00	0.00	0.00
Electric	100.00	100.00	100.00	100.00	100.00
Plane	0.00	0.17	0.29	0.35	0.38
Energy intensity (kWh/pas-km)					
Car	0.36	0.35	0.33	0.32	0.31
(Passengers/car)	2.50	2.48	2.43	2.35	2.26
Bus	0.23	0.24	0.25	0.25	0.25
(Passengers/bus)	19.80	18.60	18.04	17.70	17.47
Train					
(Passengers/train)	50.00	60.00	72.00	86.40	103.68
Steam	0.00	0.00	0.00	0.00	0.00
Diesel	0.00	0.00	0.00	0.00	0.00
Electric	0.06	0.05	0.04	0.03	0.03
Plane	1.24	1.19	1.15	1.12	1.08
(% of seats occupied)	56.50	58.50	60.50	62.50	64.50
Passenger transport, urban:					
Total activity (10^9 pas.-km):	1.84	2.27	2.91	3.87	5.44
Share by mode (%)	100.00	100.00	100.00	100.00	100.00
Car	50.52	53.55	56.76	60.17	63.78
Motor fuel	100.00	100.00	100.00	100.00	100.00
Electric	0.00	0.00	0.00	0.00	0.00
Mass transit	49.48	46.45	43.24	39.83	36.22
Motor fuel	84.80	83.28	81.61	79.77	77.75
Electric	15.20	16.72	18.39	20.23	22.25
Energy intensity (kWh/pas.-km)					
Car					
(Passengers/car)	2.00	1.93	1.87	1.81	1.75
Motor fuel	0.58	0.58	0.57	0.57	0.56
Electric	0.00	0.00	0.00	0.00	0.00
Mass transit					
Motor fuel	0.34	0.33	0.33	0.33	0.32
(Passengers/bus)	15.00	15.00	15.00	15.00	15.00
Electric	0.18	0.16	0.14	0.12	0.11
(Passengers/train)	25.00	29.00	33.06	37.03	40.73

Table 3.16. Electricity Penetration in Transportation Sector (Reference Scenario)

Year	1999	2005	2010	2015	2020
Share of electric trains in:					
-total freight transport by rail	0.18	0.18	0.18	0.19	0.20
-total intercity travel by train	0.03	0.03	0.03	0.03	0.03
Share of electric mass transit in total intracity mass transport	0.08	0.08	0.08	0.08	0.08

Table 3.16 presents the evolution of the electricity penetration into the Transport Sector.

Urban (Intracity) Transport

The average energy demand per surface unit in old buildings of service sector is estimated to increase from about 102 kWh/sqm/yr in 1999 to 250 kWh/sqm/yr in 2010, with further decreasing to 243 kWh/sqm/yr in 2020. As for the new modern buildings, it was estimated that the demand for the thermal energy would be of 244 kWh/sqm/yr in 2005, and thereafter would slowly decrease to 226 kWh/sqm/yr in 2020.

Table 3.17. Energy Intensity (Useful) assumed for the Household Sector (kWh/dw/yr) Reference Scenario

Year	1999	2005	2010	2015	2020
Space heating:					
Constructed before base year	2013.6	4553.3	7511.4	9010.0	10011.0
Single family/Central heating	1912.1	3242.7	4755.0	5941.4	5918.8
Apartment/Central heating	1406.9	2651.2	3644.6	3643.2	3641.6
Room heating					
Constructed after base year	0.0	8981.9	11778.4	12131.8	12495.7
Single family/Central heating	0.0	4915.5	5000.5	5150.5	5305.0
Apartment/Central heating	0.0	3274.7	3513.4	3618.8	3727.4
Room heating					
Water heating	472.9	1193.1	1731.1	2070.2	2275.0
Cooking	535.7	750.0	922.4	1005.5	1025.6
Air conditioning	2466.0	2475.1	2479.6	2479.3	2474.2
Electrical appliances	565.0	1050.9	1429.2	1700.8	1853.8

The penetration of electricity into various thermal uses is shown in Table 3.18.

The electricity necessary to cover the services sector demand is spent on lighting, electric equipment operation and utilization of appliances. In this respect, it was assumed that, in parallel with the services modernization and rehabilitation, the increase of appliances and equipment quantity would as well cause the growth of electricity demand that will change from 70 kWh/sqm/yr in 1999 to 90 kWh/sqm/yr in 2020 (old buildings). Regarding the buildings constructed after 2005, it is estimated that they will be better equipped than the existing ones, and therefore, there will be the greater specific electricity demand by the service sector, namely, 74 kWh/sqm/yr in 2005, and 94 kWh/sqm/yr in 2020.

Table 3.18. Electricity Penetration in Household and Service Reference Scenario

Year	**1999**	**2005**	**2010**	**2015**	**2020**
Specific electricity consumption in:					
- Dwellings for uses other than space/water heating, cooking and A.C.(kWh/yr/dw)	565	1051	1429	1701	1854
- Old-service sector buildings (kWh/yr/sqm)	70	80	85	88	90
- New-service sector buildings (kWh/yr/sqm)	0	84	89	93	95
Electricity penetration into thermal uses for:					
- Space heating household	0.304	0.097	0.063	0.043	0.034
- Water heating household	0.636	0.307	0.200	0.132	0.093
- Cooking household	0.518	0.264	0.144	0.082	0.048
- Thermal uses service sector	0.500	0.205	0.144	0.105	0.077

Table 3.19. Energy Intensity Assumed for the Service Sector Reference Scenario

Year	**1999**	**2005**	**2010**	**2015**	**2020**
Space and water heating (useful: kWh/sqm/yr)					
Buildings constr. before base year	102.0	190.0	250.0	245.6	243.0
Buildings constr. after base year	0.0	244.1	238.4	232.6	226.7
Air conditioning (useful);					
Specific consump. (kWh/sqm/yr)	50	50	50	50	50

The penetration of electricity in thermal uses in the Service sector was estimated to be 7.7% in 2020 against 50% in 1999.

The utilization of air conditioning installations was considered to reduce, namely by 15% in 1999, reaching 35% in 2020.

3.5. Detailed Description of the Low Scenario

Some parameters were forecasted to change from the Reference Scenario, affecting:

- the GDP growth rates and structure of sector shares in total GDP;
- activities relavant to Transport sector;
- Household and Services sectors.

3.5.1. GDP Growth

The assumption for setting up this scenario is based on the following forecast: GDP growth rate till 2005 will be 5% p.a., during 2005-2010 - 4.5% p.a., during 2010- 2015 - 3.5 % p.a., and 3% p.a. - untill the end of planning period.

In 2020, GDP will be 4.04×10^9 US$, against 1.76×10^9 US$ in 1999. The GDP growth for the Low Scenario is given in Table 3.20.

Table 3.21 shows the forecasting shares of various economical sectors in total GDP for Low scenario.

Table 3.20. GDP Growth Forecast Low Scenario

Year	Total GDP (10^9 US$$_{1999}$)	Average annual growth rate (%)	Per capita GDP (US$$_{1999}$/capita)
1999	1.76	3.3	462.1
2005	2.35	5.0	611.9
2010	2.93	4.5	754.9
2015	3.48	3.5	887.7
2020	4.04	3.0	1018.9

Table 3.21. Projected Shares of Economical Sectors in Gross Domestic Product Unit: %

Sector	1999	2005	2010	2015	2020
Agriculture	26.2	24.3	22.5	20.1	17.8
Construction	8.8	8.3	7.8	7.4	7.1
Mining	0.82	1.49	2.08	2.51	2.93
Manufacturing,	13.5	14.4	15.5	17.3	18.9
of which:					
Basic Materials	14.1	16.4	18.2	19.2	18.8
Machinery & Equipment	11.6	13.1	15.0	17.7	21.6
Consumer goods	68.9	67.5	64.8	61.8	58.4
Miscellaneous	5.4	3.0	2.0	1.3	1.2
Energy	6.70	6.58	6.46	6.36	6.24
Services	44.0	44.9	45.6	46.3	47.0

3.5.2. Transport Sector

Different levels of GDP and per capita GDP in two scenarios result in significant differences in values of various parameters of Transport sector, such as freight activity, intercity and intracity passenger activity and number of cars, which in turn determines the energy demand of this sector (see Tables 3.22-3.24).

3.5.3. Household and Service Sectors

The main parameters of Household and Service Sectors that were changed for Low Scenario showed in Tables 3.25 and 3.26.

Table 3.22. Activity Levels in Freight Transport (Low Scenario)

Year	1999	2005	2010	2015	2020
Total activity (%)	100.0	100.0	100.0	100.0	100.0
Total activity (10^9 tkm):	2.1	4.4	6.1	7.2	7.9
Truck	58.1	57.6	57.2	56.7	56.2
Train	26.0	28.0	30.0	32.0	34.0
Pipelines	15.9	14.4	12.8	11.3	9.8

Table 3.23. Electricity Penetration in Transport Sector, Low Scenario

Year	1999	2005	2010	2015	2020
Share of electric trains in:					
-total freight transport by rail	0.18	0.18	0.18	0.18	0.19
-total intercity travel by train	0.03	0.03	0.04	0.04	0.04

Table 3.24. Activity Levels in Passenger Transport

Year	1999	2005	2010	2015	2020
Passenger transport, intercity:					
Total activity (10^9 pas-km)	1.4	3.0	4.2	5.1	5.7
Share by mode (%)	100.0	100.0	100.0	100.0	100.0
Car	43.1	39.3	38.3	37.3	36.0
Bus	53.7	57.1	57.8	58.7	59.9
Train	3.2	3.4	3.5	3.6	3.6
Plane	0.0	0.2	0.3	0.4	0.5
Passenger transport, urban:					
Total activity (10^9 pas-km):	1.8	2.2	2.6	3.0	3.6
Share by mode (%)	100.0	100.0	100.0	100.0	100.0
Car	50.5	52.5	54.6	56.8	59.1
Mass transit	49.5	47.5	45.4	43.2	40.9

Table 3.25. Energy Intensity (Useful) Assumed for the Household Sector (Low Scenario) (kWh/dw/yr)

Year	1999	2005	2010	2015	2020
Space Heating					
Constructed before base year					
Single family/Central heating	2013.6	4533.3	7404.3	8707.5	9481.5
Apartment/Central heating	1912.1	3227.2	4685.4	5739.6	5624.8
Room heating	1406.9	2637.8	3590.4	3518.6	3448.2
Constructed after base year					
Single family/Central heating	0.0	8981.9	10921.8	11911.2	12950.1
Apartment/Central heating	0.0	4915.5	5625.5	5794.3	5968.1
Room heating	0.0	3274.7	3747.7	3860.1	3975.9
Water Heating	472.9	1148.4	1659.5	1938.5	2069.7
Cooking	535.7	680.0	800.0	880.0	936.9
Air Conditioning	2466.0	2475.2	2480.0	2480.1	2474.8
Electrical appliances	565.0	992.0	1320.0	1547.0	1701.7

Table 3.26 Electricity Penetration in Household and Service sectors (Low Scenario)

Year	1999	2005	2010	2015	2020
Specific electricity consumption in:					
- Dwellings for uses other than space/water heating, cooking and A.C. (kWh/yr/dw)	565	992	1320	1547	1702
- Old-service sector buildings (kWh/yr/sqm)	70	75	80	83	84
- New-service sector buildings (kWh/yr/sqm)	0	82	87	90	92
Electricity penetration into thermal uses for:					
- Space heating households	0.304	0.115	0.067	0.047	0.037
- Water heating households	0.636	0.355	0.205	0.145	0.111
- Cooking households	0.518	0.292	0.158	0.089	0.052
- Thermal uses service sector	0.500	0.241	0.157	0.112	0.082

4 ANALYSIS OF ENERGY DEMAND

4.1. Analysis of Total and Per Capita Final Energy Demand

4.1.1. Total Final Energy Demand Forecast

The two scenarios of socioeconomic and technological development of Armenia retained for the ENPP study are defined by the macroeconomic parameters and presented in Table 4.1 and Figure 4.1.

The evolution of the final energy demand through the 1999- 2020 period resulting from the analyses performed by means of Module 1 of MAED model is presented in Tables 4.2 and 4.3, and in Figure 4.2.

As shown in Table 4.2, in the year 2020 the final energy demand (including non-commercial energy) is estimated to be 6.34 GWyr in Low scenario and 7.67 GWyr in Reference scenario, against 1.34 GWyr in the base year (1999). The commercial energy demand in 2020 is foreseen to be 6.34 GWyr (Low scenario) and 7.67 GWyr (Reference scenario) against 1.33 GWyr in 1999. The average annual growth rate of commercial final energy demand during the period from 1999 to 2020 is 7.7% in Low scenario and 8.7% in Reference scenario.

For a clearer illustration of the development of the final energy demand, Figure 4.3 presents the values obtained for the reference years 2005, 2010, 2015 and 2020 against the Base year 1999 for two scenarios.

It can be noticed that in 2005 the energy demand in Reference scenario exceeds by 20.9% the similar value of the Low scenario.

4.1.2. Trends of the Final Energy Per Capita and GDP Per Capita

The evolution of the final energy per capita and the GDP per capita is presented in Figure 4.4 and Table 4.4, while the average annual growth rates of the final energy and GDP per capita are shown in Table 4.5.

Table 4.1. GDP Evolutions for the Two Scenarios

Year	Total GDP [1)]		Growth Rate [2)] [%]	
	Low Scenario	Reference Scenario	Low Scenario	Reference Scenario
1999	1.76	1.76	-	-
2005	2.35	2.79	5.00	8.00
2010	2.93	3.82	4.77	7.32
2015	3.48	4.87	4.37	6.59
2020	4.04	6.07	4.04	6.09

1) Total GDP expressed in billon US$ (1999): 1 US$ = 531 AMD (1999)

2) Average annual growth rate versus the base year

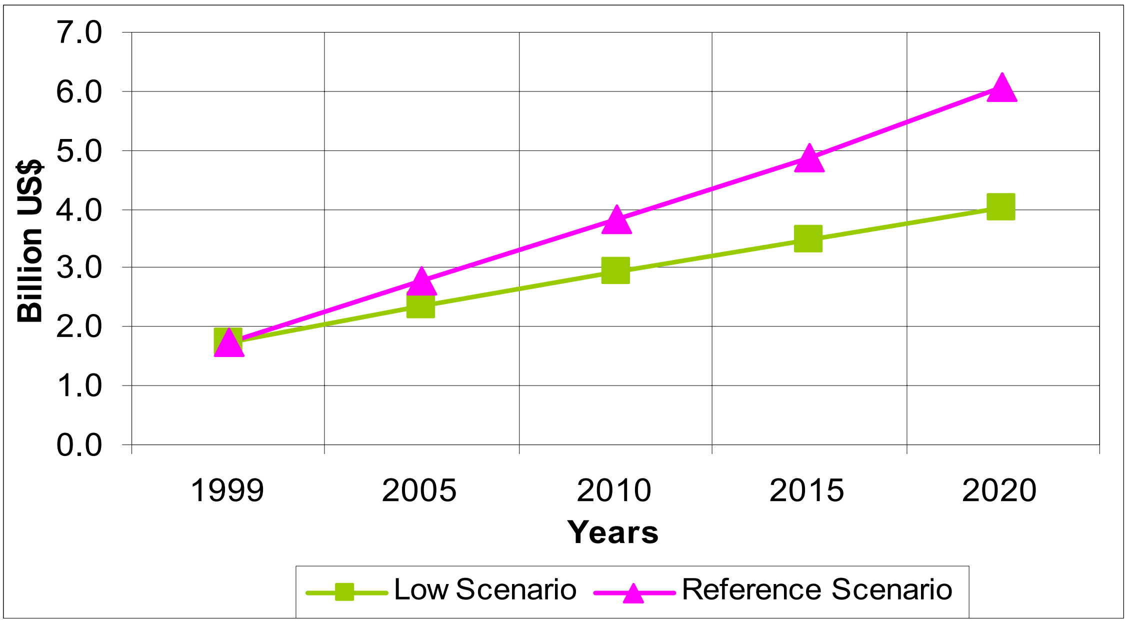


Figure 4.1. Trends in GDP

Table 4.2. Total Final Energy Demand and Average Growth Rates

Year	Final Energy Demand [(1)] [GWyr]		Growth Rate [(2)] [%]	
	Low Scenario	Reference Scenario	Low Scenario	Reference Scenario
1999	1.34	1.34	-	-
2005	3.24	3.58	15.87	17.80
2010	4.69	5.48	12.07	13.67
2015	5.66	6.71	9.42	10.59
2020	6.34	7.67	7.69	8.66

Including non-commercial fuels

Average annual growth rate versus the base year (1999)

Table 4.3. Total Commercial Final Energy Demand and Average Growth Rates

Year	Final Energy Demand [(1)] [GWyr]		Growth Rate [(2)] [%]	
	Low Scenario	Reference Scenario	Low Scenario	Reference Scenario
1999	1.33	1.33	-	-
2005	3.24	3.58	15.85	17.78
2010	4.69	5.48	12.07	13.67
2015	5.66	6.71	9.42	10.59
2020	6.34	7.67	7.69	8.66

(1) Commercial final energy
(2) Average annual growth rate versus the base year (1999)

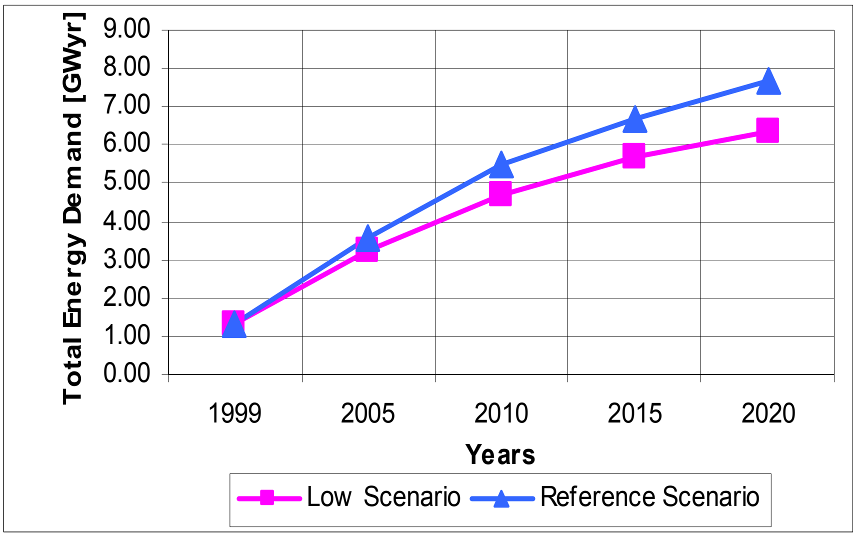


Figure 4.2. Trends in the Demand for Final Energy

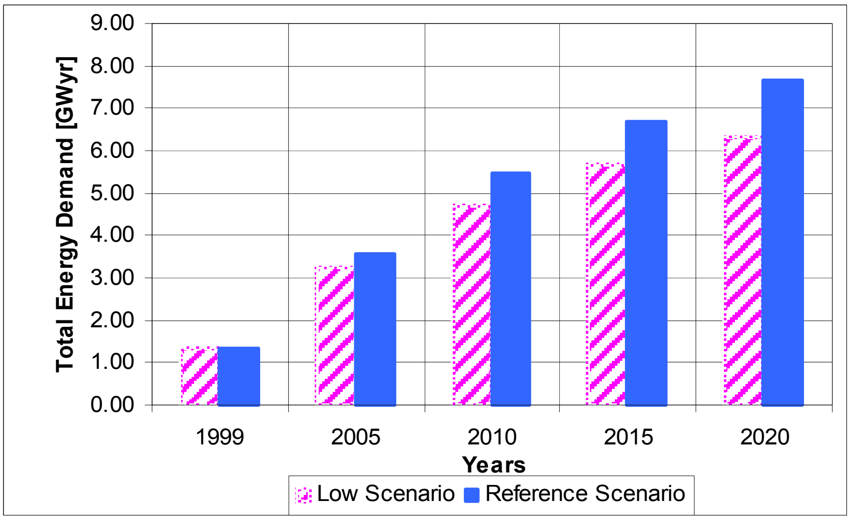


Figure 4.3. Comparison of Total Final Energy Demand for the Two Scenarios

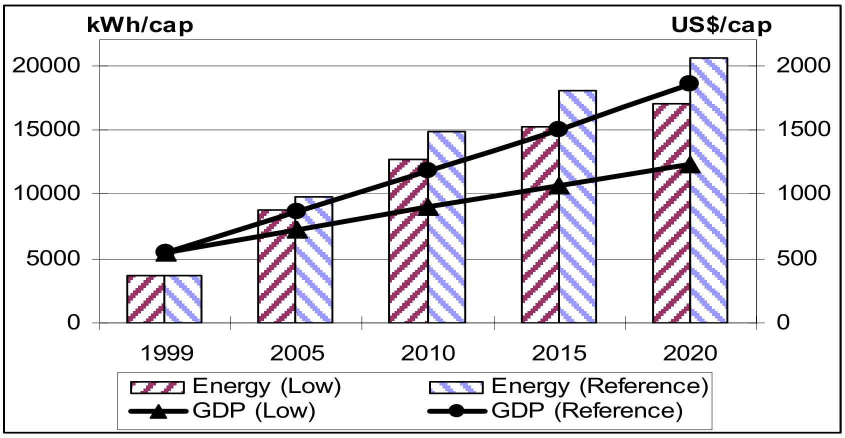


Figure 4.4. Trends of Per Capita Final Energy and GDP per Scenario

Table 4.4. Trends of Per Capita Final Energy and GDP per Scenario

Years	Population [10^6]	Energy per Capita (1) [kWyr/cap]		GDP per Capita (2) [US$/capita]	
	Two Scenarios	Low Scenario	Reference Scenario	Low Scenario	Reference Scenario
1999	3.2	0.42	0.42	550.00	550.00
2005	3.22	1.01	1.11	729.81	866.46
2010	3.24	1.45	1.69	904.32	1179.01
2015	3.25	1.74	2.06	1070.77	1498.46
2020	3.26	1.94	2.35	1239.26	1861.96

1) Total final energy
2) GDP is expressed in 1999 US$ (1 US$ 1999 = 531.5 AMD)

Table 4.5. Growth Rate of Final Energy per Capita and GDP per Capita in the Two Scenarios

	Energy per Capita [%]		GDP per Capita [%]	
Year	Low Scenario	Reference Scenario	Low Scenario	Reference Scenario
1999	-	-	-	-
2005	15.9	17.8	4.8	7.9
2010	7.5	8.8	4.4	6.4
2015	3.8	4.1	3.4	4.9
2020	2.2	2.6	3.0	4.4

For this reason, the main assumption was made when setting up the two scenarios: rehabilitation of heavy industry, which would affect increasing the energy intensities till 2010, and, after 2010, the improvement of economical situation in the country will reduce the energy intensities till 2020 both by improving technologies and, especially, by changing the structure of the economy.

The forecasted final energy demand per capita for the year 2020 represents 1.94 kWyr in the Low scenario and 2.35 kWyr in the Reference scenario against 0.42 kWyr in 1999. The GDP per capita in 2020 reaches 1240 US$ in the Low scenario and 1862 US$ in the Reference Scenario against 550 US$ in 1999.

Consequently, for the year 2020, the final energy demand per capita in Reference scenario is projected to be 21% higher than in Low scenario, while the GDP per capita in the Reference scenario is expected be 50.2% higher than in the Low scenario.

Having in view the inter-relation between the two indices, it can be noticed a stronger variation of the average annual growth rate of GDP per capita within the study period against that of the final energy demand per capita. Table 4.6 and Figure 4.5 present the GDP per capita and final energy demand per capita for Armenia in the years 1999 and 2020, compared to those achieved in some selected ECE-UN countries, at the level of 1988.

4.2. Analysis and Comparison of the Sectoral Energy Demand

The sectoral final energy demand resulting from the analyses performed by means of the MAED program, is summarized in Table 4.7 and Figure 4.6, and presented in more detail in Tables 4.8 and 4.9.

4.2.1. Industry Sector

This sector covers four categories of activities: Agriculture, Construction, Mining and Manufacturing. In 1999, this sector had a final energy consumption of 0.44 GWyr, namely 32.8% of the total final energy demand of Armenia. Manufacturing, one of the biggest energy consumer of the economy, registered an energy consumption of 0.29 GWyr in 1999, namely 66.3% of the industry energy consumption, and 23% of the total final energy consumption of Armenia.

Figure 4.7 illustrates the evolution of the energy demand versus value added of the Manufacturing sector, estimated for the two scenarios.

In the MAED model, forecasting of the Industry energy demand is related to the evolution of the economic activity (expressed in terms of value added) and to the energy intensities. The assumption made about the evolution of these parameters for setting up the two scenarios is presented in Section 3.4.

In the Low Scenario, the total final energy demand in the Industry sector changes from 0.44 GWyr in 1999 to 1.22 GWyr in 2005, 1.73 GWyr in 2010, 2.10 GWyr in 2015 and 2.34 GWyr in 2020 with an average annual growth rate of 8.3% throughout the whole period. The share of this sector energy demand within the total energy demand of Armenia increases from 32.8% in 1999 to 37.0% in 2020.

The Manufacturing sector energy demand varies and expected to be: 0.29 GWyr in 1999, 0.61 GWyr in 2005, 0.91 GWyr in 2010, 1.17 GWyr in 2015, and 1.36 GWyr in 2020, the share of this sector within the total energy demand will decrease from 66.3% in 1999 to 58.1% in 2020.

The final energy demand of Agriculture, Construction and Mining sectors for the Low Scenario varies and will be 0.15 GWyr in 1999, 0.62 GWyr in 2005, 0.82 GWyr in 2010, 0.93 GWyr in 2015, and 0.98 GWyr in 2020, with the share of these sectors in the total energy demand of Armenia increasing from 33.7% in 1999 to 41.9% in 2020.

In the Reference Scenario, the final energy demand of the Industry sector varies and is expected to be 0.44 GWyr in 1999, 1.42 GWyr in 2005, 2.16 GWyr in 2010, 2.65 GWyr in 2015 and 3.02 GWyr in 2020, the share of the sector in the national energy demand increasing from 32.8% in 1999 to 39.5%in 2020.

The final energy demand, at the level of the year 2020, in the Reference scenario (7.67 GWyr) is by 21.0% higher than that in the Low Scenario (6.34 GWyr).

Table 4.6. Comparison of Final Energy Demand per Capita and GDP per Capita of Armenia with some Selected Countries

Country	**Population (Million)**	**GDP per Capita (US$ 1988/cap)**	**Final Energy per Capita (kgce/cap)[(1)]**
Austria	7.6	15470	3583
Belgium	9.9	14490	4429
Canada	26.0	16960	7943
Denmark	5.1	18450	4043
Switzerland	6.6	27500	4087
Finland	5.0	18590	5918
France	55.9	16090	3236
Germany, F.R.	61.3	18480	4241
Greece	10.0	4800	1933
Ireland	3.5	7750	2699
Italy	57.4	13330	2586
Yugoslavia	23.6	2520	1397
U.K.	57.1	12810	3471
Norway	4.2	19920	5487
Netherlands	14.8	14520	4117
Poland	37.9	1860	3036
Portugal	10.3	3650	1347
Spain	39	7740	1906
U.S.A.	246.3	19840	7466
Sweden	8.4	19300	5533
Turkey	53.8	1280	953
Hungary	10.6	2460	2727
Armenia 1988	3.5	826	2759
Armenia [(2)] 1999	3.2	550	455
Armenia[(2)]-Low 2020	3.26	1240	2100
Armenia[(2)]-Reference 2020	3.26	1862	2545

Note: (1) - without feedstock.
(2)- US$ 1999.

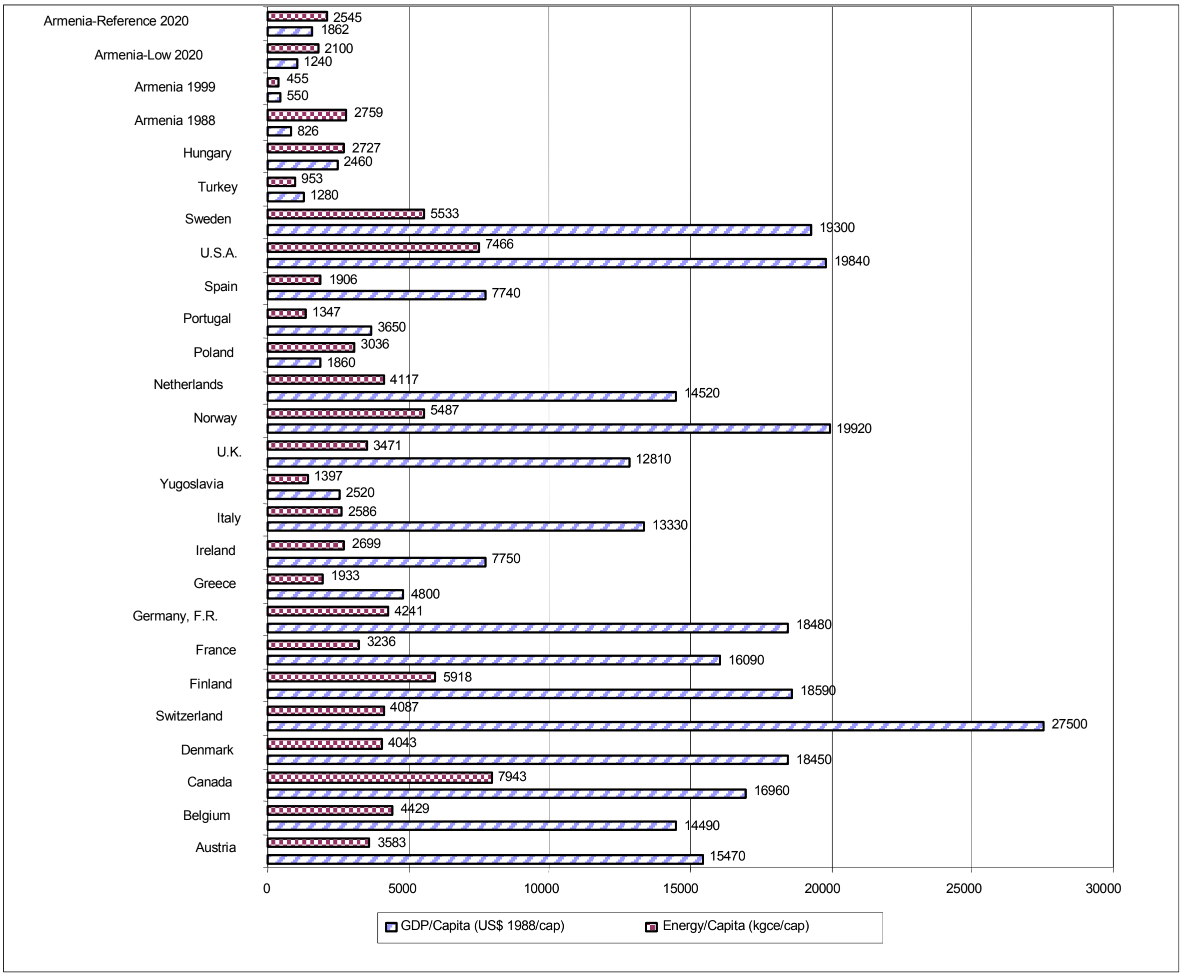


Figure 4.5. Comparison of the MAED Results/Per Capita Values of Final Energy in Selected Countries

Table 4.7. Final Energy Demand Forecast by Sector (1999-2020)

Sector	**Growth rate [(*)] [%]**	**Amount [GWyr]**		**Share [%]**	
	2020	**1999**	**2020**	**1999**	**2020**
Low Scenario	7.7	1.3	6.3	100.0	100.0
Industry	8.3	0.4	2.3	32.8	37.0
- Agr/Constr/Min	9.5	0.1	1.0	33.7	41.9
- Manufacturing	7.7	0.3	1.4	66.3	58.1
Transportation	5.8	0.4	1.4	31.9	21.8
Household/Service	8.5	0.5	2.6	35.3	41.3
Reference Scenario	8.7	1.3	7.7	100.0	100.0
Industry	9.6	0.4	3.0	32.8	39.4
- Agr/Constr/Min	10.4	0.1	1.2	33.7	39.2
- Manufacturing	9.2	0.3	1.8	66.3	60.8
Transportation	6.9	0.4	1.7	31.9	22.4
Household/Service	9.1	0.5	2.9	35.3	38.1

[(*)] Average annual growth rate versus the base year (1999).

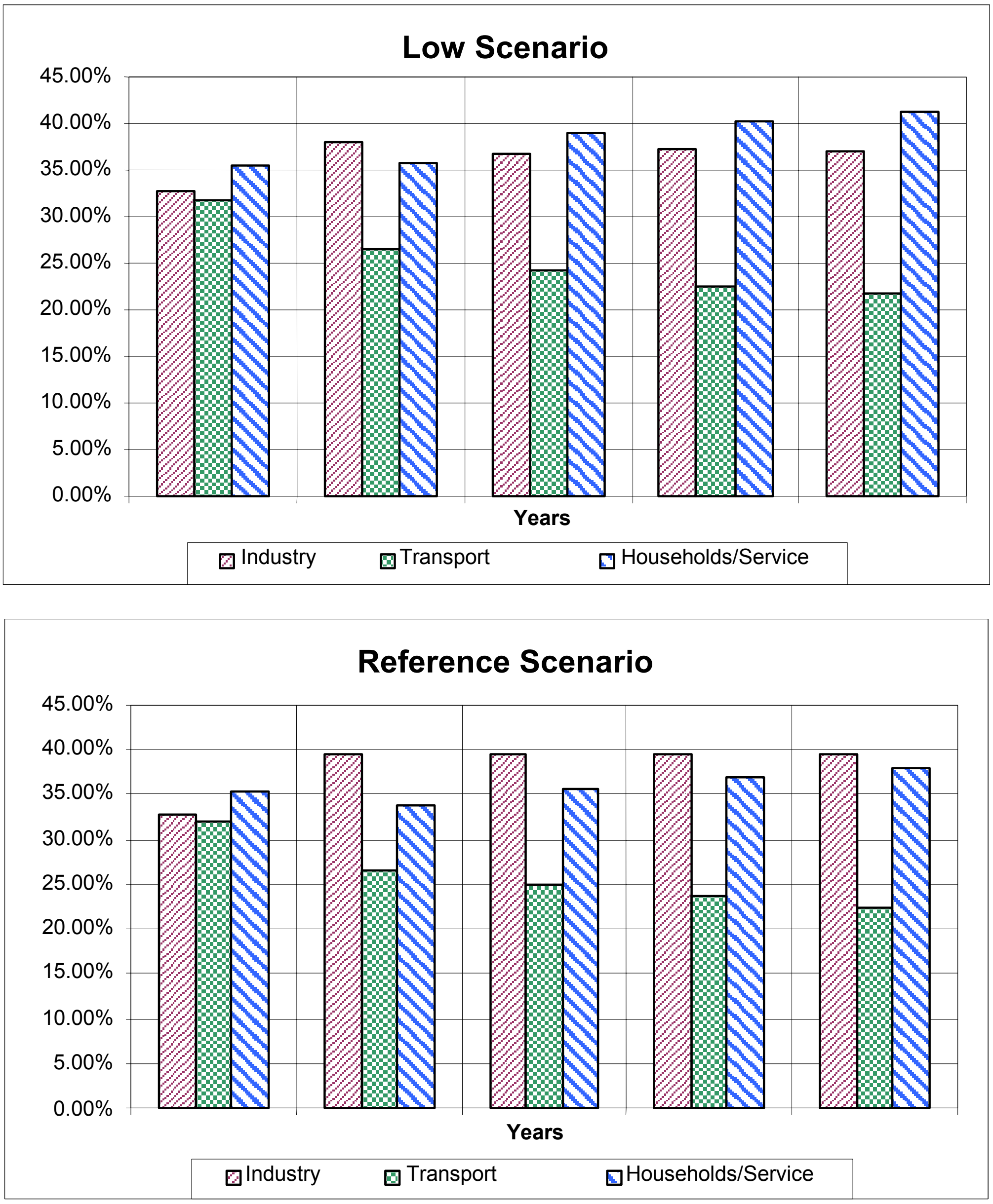


Figure 4.6. Final Energy Demand by Sector for both Scenarios

Table 4.8. Final Energy Demand by Sector (Low Scenario)

Low Scenario	**1999**	**2005**	**2010**	**2015**	**2020**
A. Final Energy Demand, GWyr					
Industry	0.44	1.22	1.73	2.10	2.34
- Agr/Constr/Min	0.15	0.62	0.82	0.93	0.98
- Manufacturing	0.29	0.61	0.91	1.17	1.36
Transport	0.42	0.86	1.14	1.28	1.38
Households/Service	0.47	1.16	1.82	2.28	2.62
Total	1.33	3.24	4.69	5.66	6.34
B. Share of Total [%]					
Industry	32.84%	37.80%	36.85%	37.18%	36.97%
- Agr/Constr/Min	33.69%	50.34%	47.29%	44.39%	41.87%
- Manufacturing	66.31%	49.66%	52.71%	55.61%	58.13%
Transport	31.85%	26.48%	24.25%	22.55%	21.77%
Households/Service	35.31%	35.72%	38.90%	40.27%	41.26%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
C. Growth Rate [%]					
Industry	-	18.72	13.31	10.32	8.33
- Agr/Constr/Min	-	26.94	16.86	12.24	9.46
- Manufacturing	-	13.14	10.97	9.11	7.65
Transport	-	12.45	9.38	7.13	5.78
Households/Service	-	16.20	13.12	10.37	8.52
Average	-	15.97	12.13	9.47	7.72

Table 4.9. Final Energy Demand by Sector (Reference Scenario)

Reference Scenario	**1999**	**2005**	**2010**	**2015**	**2020**
A. Final Energy Demand, GWyr					
Industry	0.44	1.42	2.16	2.65	3.02
- Agr/Constr/Min	0.15	0.71	1.00	1.11	1.18
- Manufacturing	0.29	0.70	1.16	1.54	1.84
Transport	0.42	0.95	1.37	1.58	1.72
Households/Service	0.47	1.21	1.95	2.47	2.92
Total	1.33	3.58	5.48	6.71	7.67
B. Share of Total [%]					
Industry	32.84%	39.62%	39.42%	39.59%	39.45%
- Agr/Constr/Min	33.69%	50.40%	46.40%	41.97%	39.19%
- Manufacturing	66.31%	49.60%	53.60%	58.03%	60.81%
Transport	31.86%	26.51%	24.98%	23.51%	22.44%
Households/Service	35.31%	33.87%	35.59%	36.90%	38.12%
Total	100.00%	100.00%	100.00%	100.00%	100.00%
C. Growth Rate [%]					
Industry	-	21.65	15.64	11.93	9.65
- Agr/Constr/Min	-	30.11	19.05	13.48	10.44
- Manufacturing	-	15.91	13.42	11.01	9.20
Transport	-	14.35	11.24	8.55	6.89
Households/Service	-	17.09	13.81	10.94	9.09
Average	-	17.91	13.73	10.63	8.69

Average annual growth rate versus the base year (1999).

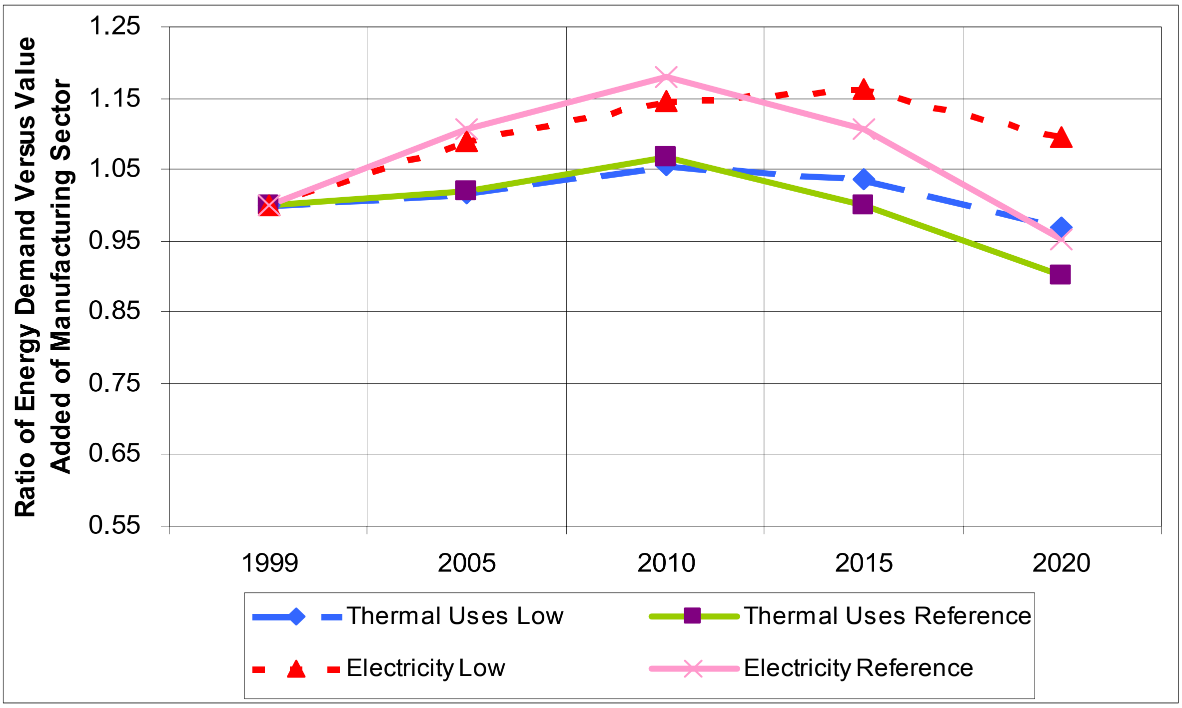


Figure 4.7. Energy Demand Versus Value Added of the Manufacturing Sector

4.2.2. Transport Sector

The Transport sector mainly covers two kinds of activities: freight transportation and passenger travel (urban and intercity). The characteristic parameters of the Transport sector energy demand are: ton-km of freight and passenger-km of travel. The assumptions regarding the evolution of these parameters are presented in Chapter 3.4 and are illustrated in Figure 4.8.

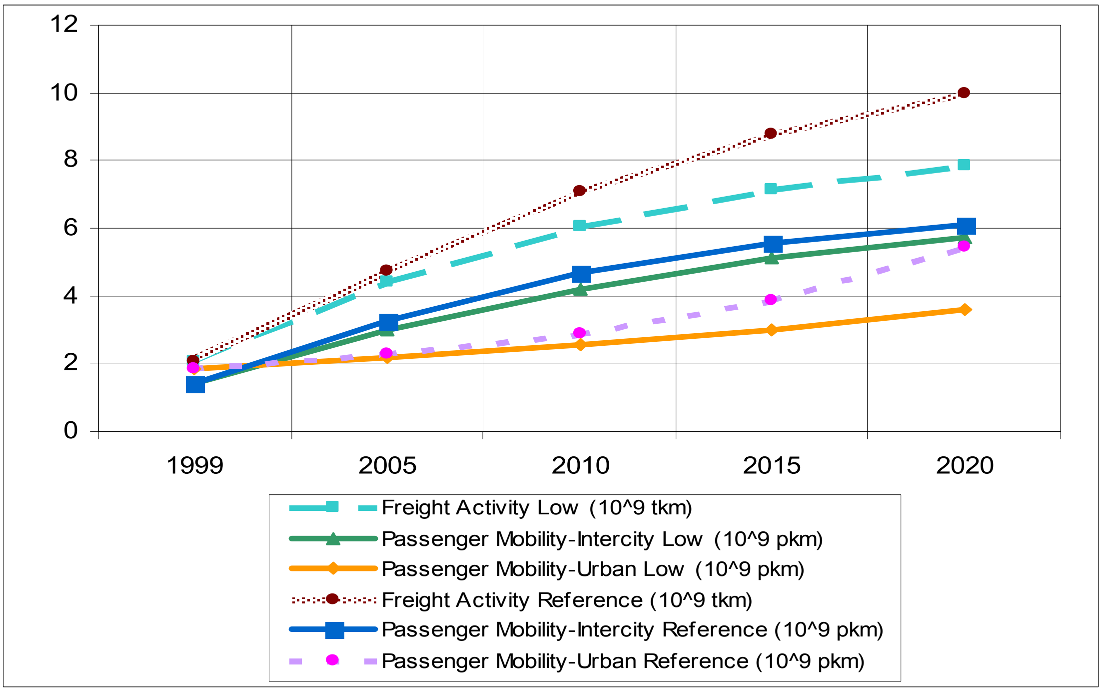


Figure 4.8. Principal Determining Factors of Energy Demand of the Transport Sector

The energy demand for the Transport sector is estimated to represent 1.38 GWyr in the Low scenario and 1.72 GWyr in the Reference scenario in 2020 against 0.42 GWyr in 1999. This represents an average annual growth rate within the study period of 5.78% in Low scenario and 6.89% in the Reference scenario.

Table 4.10 presents the evolution of the energy demand for the Transport sector by types of activities in the two analyzed scenarios. The energy demand for passenger travel is estimated to grow from 0.14 GWyr to 0.35 GWyr in 2020 in Low scenario, and from 0.14 GWyr to 0.47 GWyr in 2020 in Reference scenario. The energy demand for freight transport is projected to be 0.25 GWyr in 2020 against 0.07 GWyr in 1999 in Low scenario and 0.32 GWyr in Reference scenario, representing an average annual growth rate within the study period of 6.4% in the Low scenario and 7.7% in the Reference scenario.

4.2.3. Household/Service Sector

The energy demand in the Household sector is influenced both by the variation of the number of dwellings, determined by the evolution of the total population and the number of persons per dwelling, and by the specific energy demand for various final facilities (cooking, space heating, hot water preparation, specific electric appliances, etc.) depending on a range of factors, such as: tradition, living standard, population income, etc., and their implications on the ownership of various appliances (hot water facilities, air conditioning, electrical appliances, etc.)

The energy demand forecast for the Service sector was achieved by projecting manpower in the sector, the specific area per employee and the specific energy consumption per square meter. The projections of the main parameters determining the energy demand of this sector are illustrated by Figure 4.9 (Household) and Figure 4.10 (Service), and the assumptions on which these projections are based are presented in Chapter 3.4.

In both scenarios, the energy demand for Household/Service sector was projected to increase very fast within the period 1999-2005 due to the removal of constraints existed until 1999 regarding the energy supply for this sector and improvement of social-economic situation in Armenia.

The final commercial energy demand for the Household/Service sector in year 2020 will reach 2.62 GWyr in Low scenario and 2.92 GWyr in Reference Scenario against 0.48 GWyr that was achieved in 1999. The share of this sector in the total energy demand is expected to be, at the end of the study period, between 38.1% (Reference) and 41.3% (Low), against 35.7% in 1999.

In 2020, the Household/Service sector energy demand for the Reference scenario will be 11.6% higher than for the Low scenario.

4.3. Analysis of Final Energy Demand by Energy Form

The MAED forecast of final energy demand by energy form is summarized in Table 4.11, and detailed results for the two scenarios are shown in Table 4.12 and illustrated in Figures 4.11 and 4.12. Two major types of energy: commercial and non-commercial are considered.

In 1999, the distribution of total final energy demand by form was: 99.4% for commercial energy (out of which 37.2% was motor fuel, 31.1% - electricity, 26.8% - fossil fuels and 4.9% - feedstock), and 0.6% for non-commercial energy.

4.3.1. Non-commercial Energy

It was assumed that the use of non-commercial fuels would decrease, both scenarios, until it falls down to 0.0 GWyr in 2015. This decreasing is expected to be due to the substitution of non-commercial fuels by natural gas as a result of rehabilitation of gas distribution system.

Table 4.10. Breakdown of the Total Final Energy Demand by Activities in the Transportation Sector

Scenario / Activities	Amount [GWyr]				
	1999	**2005**	**2010**	**2015**	**2020**
Low Scenario					
Total	0.42	0.86	1.14	1.28	1.38
%	100.00	100.00	100.00	100.00	100.00
- Freight	0.07	0.14	0.19	0.23	0.25
%	15.87	16.65	17.03	17.72	17.82
- Passenger	0.14	0.20	0.26	0.31	0.35
%	33.06	23.82	22.81	24.09	25.26
intercity	0.05	0.09	0.13	0.16	0.17
%	10.85	10.98	11.53	12.40	12.51
urban	0.09	0.11	0.13	0.15	0.18
%	22.21	12.84	11.28	11.69	12.75
- Miscellaneous	0.22	0.51	0.68	0.74	0.79
%	51.06	59.53	60.16	58.19	56.92
Reference Scenario					
Total	0.42	0.95	1.37	1.58	1.72
%	100.00	100.00	100.00	100.00	100.00
- Freight	0.07	0.15	0.23	0.28	0.32
%	15.88	16.17	16.57	17.73	18.42
- Passenger	0.14	0.22	0.30	0.38	0.47
%	33.06	23.38	21.87	23.96	27.52
intercity	0.05	0.11	0.15	0.18	0.19
%	10.85	11.09	10.93	11.25	11.06
urban	0.09	0.12	0.15	0.20	0.28
%	22.21	12.29	10.94	12.72	16.46
- Miscellaneous	0.22	0.57	0.84	0.92	0.93
%	51.06	60.44	61.55	58.31	54.07

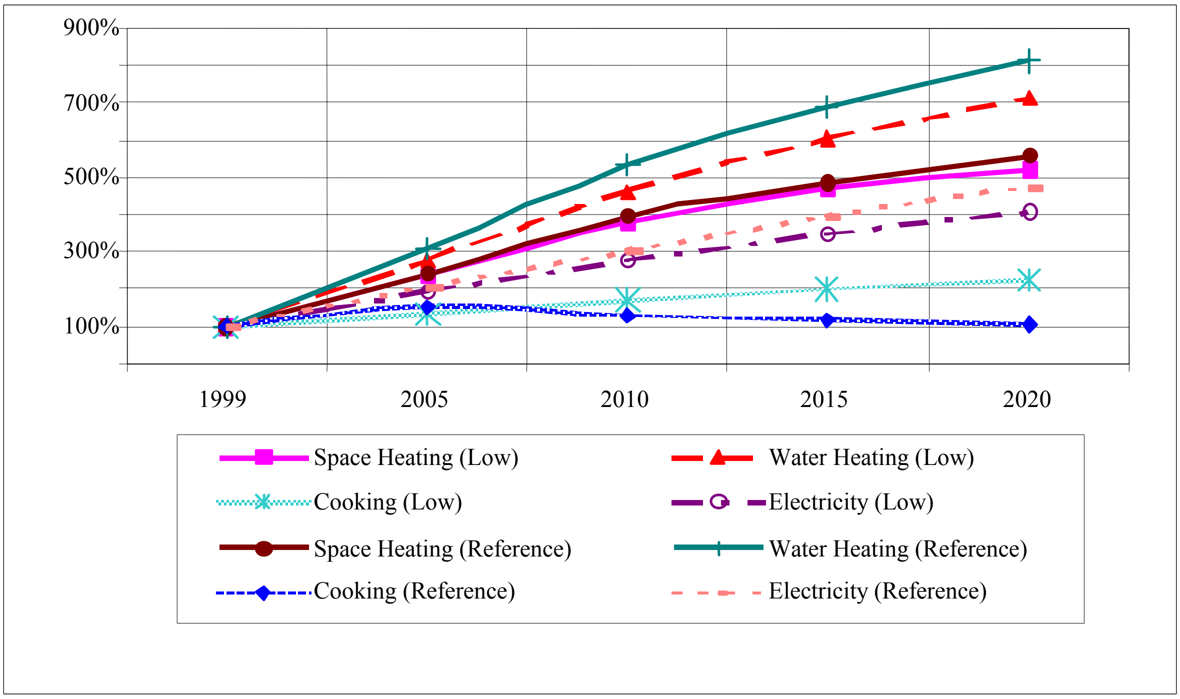


Figure 4.9. Specific Energy Demand by End-use in the Household Sector

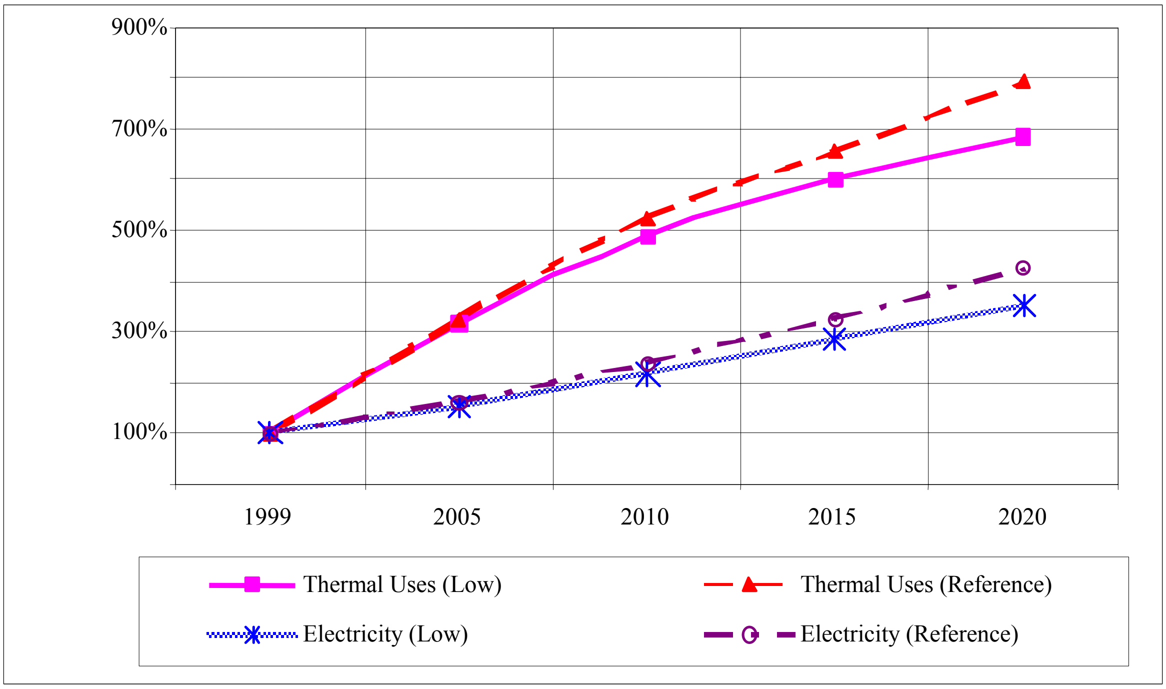


Figure 4.10. Principal Determining Factors of Energy Demand of the Service Sector

4.3.2. Commercial Energy

As it has been already stated in Chapter 3, commercial energy forms were classified, according to the MAED model structure, and divided into the groups: fossil fuels, electricity, motor fuels and feedstock. Specifically, for the purposes of the study, it was said that fossil fuels included some petroleum products (i.e. fuel oil, kerosene, etc.) and natural gas. Motor fuels consisted of some petroleum products such as gasoline, diesel, LPG, natural gas and aviation fuel.

Table 4.11. Summary of Energy Demand Forecast by Energy Form

Energy Form	Growth Rate (*) 1999-2020 [% per year]	Amount [GWyr]		Share [%]	
		1999	2020	1999	2020
Low Scenario					
Total commercial	7.72	1.33	6.34	100.00	100.00
of which:					
Fossil	10.84	0.32	2.75	23.79	43.34
District heat supply	10.14	0.10	0.80	7.88	12.55
Electricity	4.43	0.41	1.03	31.11	16.23
Motor fuels	6.24	0.50	1.77	37.22	27.88
Reference Scenario					
Total commercial	8.69	1.33	7.67	100.00	100.00
of which:					
Fossil	11.51	0.32	3.12	23.79	40.72
District heat supply	11.59	0.10	1.05	7.87	13.67
Electricity	5.60	0.41	1.30	31.11	16.96
Motor fuels	7.35	0.50	2.20	37.23	28.65

(*) Average annual growth rate versus the base year (1999).

The following description presents the results of the MAED forecasts by energy form.

4.3.2.1. Fossil Fuels

In the MAED model, fossil fuels were considered to be consumed for thermal uses, i.e. for water- and space heating, steam generation and direct heating in Industry; as well as for cooking, water- and space heating in Household/Service. Hence, the forecast for fossil fuels consumption in Industry was done basing on the growth of the industrial value added and the specific energy intensity of thermal uses, whereas for Household and Service sectors, it was took into account the growth of population and the floor area in the Service sector.

In 1999, the fossil fuels demand was about 43.7% for Manufacturing and about 56.3.0% for Household/Service sectors.

The fossil fuels demand will increase from 0.25 GWyr in 1999 to 1.00 GWyr in 2005, 1.52 GWyr in 2010, 1.88 GWyr in 2015 and 2.12 GWyr in 2020 in the Low scenario.

Table 4.12. Distribution of Final Energy Demand by Energy Form

Energy Form	1999	2005	2010	2015	2020
Low Scenario					
-Fossil	0.25	1.00	1.52	1.88	2.12
-District heat supply	0.10	0.29	0.50	0.66	0.79
-Soft solar	0.0000	0.0002	0.0007	0.0013	0.0021
-Electricity	0.41	0.63	0.79	0.93	1.03
-Motor fuels	0.50	1.04	1.43	1.64	1.77
-Feedstock	0.06	0.27	0.44	0.55	0.63
Total commercial	1.33	3.24	4.69	5.66	6.34
Reference Scenario					
-Fossil	0.25	1.10	1.70	2.12	2.44
-District heat supply	0.10	0.33	0.60	0.82	1.05
-Soft solar	0.0000	0.0002	0.0007	0.0015	0.0024
-Electricity	0.41	0.67	0.93	1.13	1.30
-Motor fuels	0.50	1.19	1.77	2.02	2.20
-Feedstock	0.06	0.29	0.48	0.61	0.68
Total commercial	1.33	3.58	5.48	6.71	7.67

This demand is expected to reach 1.10 GWyr in 2005, 1.70 GWyr in 2010, 2.12 GWyr in 2015 and 2.44 GWyr in 2020 in the Reference scenario.

The share of fossil fuels within the total commercial energy is foreseen to increase from 18.9% in 1999 to 33.4% in 2020 in the Low scenario and 31.8% in the Reference scenario. This increase of the fossil fuels share in the total commercial energy would be due to the restructuring of the economic and the growth of natural gas penetration into the thermal uses in Manufacturing.

The fossil fuels demand will increase from 0.25 GWyr in 1999 to 1.00 GWyr in 2005, 1.52 GWyr in 2010, 1.88 GWyr in 2015 and 2.12 GWyr in 2020 in the Low scenario. This demand is expected to reach 1.10 GWyr in 2005, 1.70 GWyr in 2010, 2.12 GWyr in 2015 and 2.44 GWyr in 2020 in the Reference scenario.

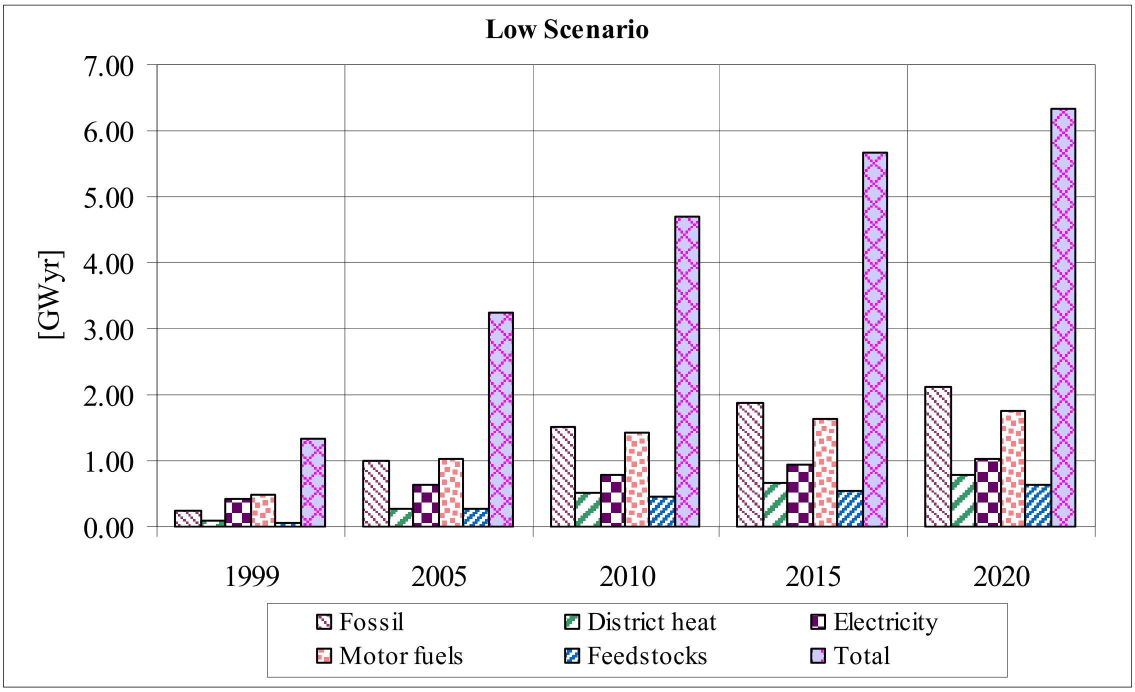


Figure 4.11. Distribution of Final Energy Demand by Energy Form (Low Scenario)

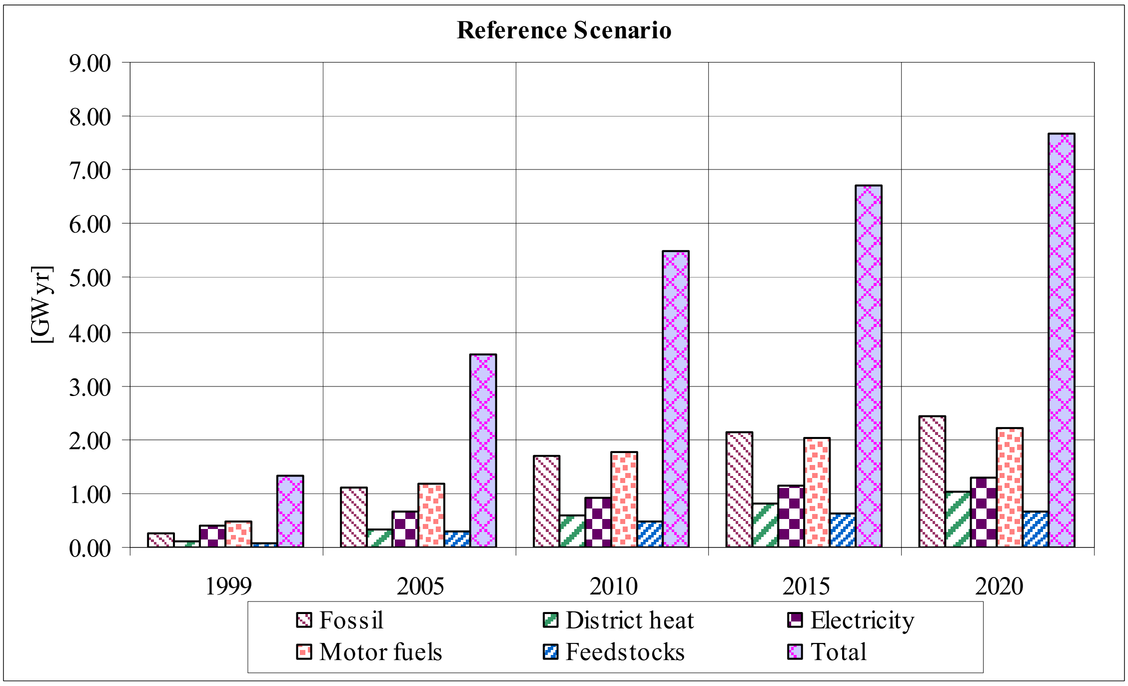


Figure 4.12. Distribution of Final Energy Demand by Energy Form (Reference Scenario)

The share of fossil fuels within the total commercial energy is foreseen to increase from 18.9% in 1999 to 33.4% in 2020 in the Low scenario and 31.8% in the Reference scenario. This increase of the fossil fuels share in the total commercial energy would be due to the restructuring of the economic and the growth of natural gas penetration into the thermal uses in Manufacturing.

4.3.2.2. District Heating

Total district heat demand is expected to be 0.29 GWyr in 2005, 0.50 GWyr in 2010, 0.66 GWyr in 2015 and 0.79 GWyr in 2020 in Low scenario; as well as 0.33 GWyr in 2005, 0.60 GWyr in 2010, 0.82 GWyr in 2015 and 1.05 GWyr in 2020 in Reference scenario.

The average annual growth rate of the district heating demand during the study period represents 10.14% in the Low scenario and 11.59% in the Reference scenario.

The results showed that by the year 2020, the share of the district heating in Industry should decrease from 10.63% to 8.11% in Low scenario and to 10.44% in Reference scenario, respectively, and the corresponding ratio of the Household/Service sector would properly increase.

4.3.2.3. Electricity

The total electricity demand in 1999 was about 0.41 GWyr (about 3.63 TWh), which was consumed the following way: 31.1 % by industry, 3.7% by Transportation sector, and 65.2% by Household and Service. The results, in detail, are given in Table 4.13. The forecast of electricity demand was based on:

- the trend of the specific electricity intensity, determined by the growth of end-use efficiencies, in parallel with the growth of electricity penetration into thermal uses in Manufacturing;
- improvement of social economic situation in Armenia;
- the growth of the number of dwellings, the service floor area in Household/Service sector.

The share of electricity in total commercial final energy is expected to decline from the level of the year 1999 (31.1%) to 16.2% in the Low scenario and 17.0% in the Reference scenario in year 2020.

Table 4.13. Electricity Demand per Sector (GWyr)

Year	**1999**	**2005**	**2010**	**2015**	**2020**
Low Scenario					
Industry	0.129	0.214	0.292	0.362	0.414
Freight transport	0.012	0.025	0.035	0.041	0.046
Passenger transport	0.003	0.004	0.004	0.004	0.004
Households	0.146	0.198	0.227	0.243	0.256
Services	0.124	0.190	0.236	0.275	0.309
Total	0.414	0.631	0.793	0.926	1.029
Reference Scenario					
Industry	0.129	0.258	0.390	0.500	0.586
Freight transport	0.012	0.028	0.042	0.053	0.064
Passenger transport	0.003	0.004	0.004	0.005	0.006
Households	0.146	0.196	0.242	0.263	0.280
Services	0.124	0.186	0.249	0.305	0.363
Total	0.414	0.672	0.928	1.126	1.300

These represent average annual growth rates over the study period of about 4.4% in the Low scenario and 5.6% in the Reference scenario.

The share of Transport sector in the total electricity demand in 2020 is foreseen to increase at up to 4.9%, the share of Industry is projected to increase up to 40.2% and the share of Household/Service sector is projected to decrease up to 54.9% in the Low scenario, and the share of Transport and Industry sectors is projected to increase theirs value up to 5.4% and 45.1% respectively, while the share of Household/Service sector is projected to decrease (49.5%) for Reference scenario.

4.3.2.4. Motor Fuels

In 1999, the motor fuels demand was about 0.50 GWyr, including 82.5% for Transport, 10.2% for Agriculture, 7.3% for Construction and 0.1% for Mining. The share of motor fuels in the total national demand was about 37.0%.

The motor fuels demand was estimated to be 1.05 GWyr in 2005, 1.43 GWyr in 2010, 1.64 GWyr in 2015 and 1.77 GWyr in 2020, in the Low scenario; and 1.19 GWyr in 2005, 1.77 GWyr in 2010, 2.02 GWyr in 2015 and 2.20 GWyr in 2020 in Reference scenario, respectively.

These imply that the demand is expected to grow with an average annual growth rate of about 6.3% in the Low scenario and 7.4% in the Reference scenario. As a result, the motor fuels weight in the country's total energy demand would decrease from 37.0% in 1999 to 27.9% in 2020 in the Low scenario and to 28.7% in the Reference scenario.

4.3.2.5. Other Energy Forms

This category includes the demand for the natural gas and oil products as feedstock in the heavy and petrochemical industry, respectively.

These sectors of the Armenian economy are very energy intensive. In 1999, the demand for feedstock represented about 4.83% of the total final energy demand of the country.

Due to the fact that the MAED methodology treatment of feedstock demand was not conceived for modelling of economic crisis, such as the actual one in Armenia, the present study adopted the hypothesis of keeping the feedstock demand on the level recorded in 1988, considering that it will be separately calculated using other methods and basing on a clear strategy concerning the heavy and petrochemical industry.

4.3.3. Comparison of Results of Various Scenarios

A comparative analysis of the two scenarios adopted was worked-out for the reference years: base year (1999), 2005, 2010, 2015 and 2020.

In 1999, the total final energy demand in the country was about 1.3 GWyr, in percentage can be divided into: 32.6% in Industry, 31.7% in Transportation and 35.7% in Household/Service. The structure of energy demand was: 18.8% - fossil fuels, 7.8% - district heat, 30.9% - electricity and 37.0% -- motor fuels.

The final energy demand forecast results for the two scenarios in 2010 indicate the following data:

- Low scenario: 4.69 GWyr (36.8% in Industry, 24.3% in Transportation and 38.9% in Household/Service);
- Reference scenario: 5.48 GWyr (39.4% in Industry, 25.0% in Transportation and 35.6% in Household/Service).

The structure of energy demand by energy form in 2010 would be represented with the following data: 17.6% fossil fuels, 9.0% district heat, 23.5% electricity and 39.5% motor fuels for the Reference scenario.

Very little differences in 2010 demand were observed when comparing the scenarios results for fossil fuel and district heating; that can be explained by the assumption (done for both scenarios) that it would be a period of restructuring of the economic programs and the effect of these policies would be noticed in the subsequent period.

In 2020, the breakdown of the total demand of final energy in Armenia for the two scenarios would be as follows:

- Low scenario: 6.34 GWyr (37.0% in Industry, 21.8% in Transportation and 41.2% in Household/Service);
- Reference scenario: 7.67 GWyr (39.5% in Industry, 22.4% in Transportation and 38.1% in Household/Service).

In year 2020, the final energy demand will begin to show significant differences between the scenarios in line with the assumptions for socioeconomic and technological development. In the Low Scenario, with low annual GDP growth rate and only slight technological improvements, the total final energy demand reaches the same level as in the Reference Scenario for the year 2015. In the Reference Scenario with the intense rehabilitation and renovation process occurring in all fields of activity, the final energy demand is about 0.8 GWyr higher than in the Low Scenario for the same year.

In the total final energy demand, fossil fuels would represent 43.3-40.7%, district heat - 12.6-13.7%, electricity - 16.2-17.0% and motor fuels - 27.9-28.7% in the last year of the planning period.

4.4. Comparison of Final Energy Demand Results with other Studies Forecasts

The results obtained from the utilization of the MAED model in forecasting the Armenian final energy demand could not be compared with those of other studies, basically because of the lack of reports published on such studies.

Analysis of electricity demand and comparison with other studies is given in Chapter 5.

5 ANALYSIS OF ELECTRICAL LOAD DEMAND

5.1. Introduction

The energy demand forecasted for the two scenarios is expressed in terms of final energy (at the gate of the consumer), i.e. it excludes losses in conversion, transmission and distribution and the energy sector's own consumption.

In order to determine the amount of electricity that should be supplied by power plants, the losses in transmission and distribution were added to the total demand of electricity (MAED_D1\Final_D Sheet\Table 13a).

Technical Losses

Technical losses are discussed here because their effects are so inter-related. They affect all segments of the power system. Generally, most of technical losses were incurred in the distribution network. The distribution losses add to the transmission losses and then to generation losses, as they flow through those system components.

Technical losses are a major problem associated with managing an electric power system. Electricity cannot be produced and transported without incurring some amount of technical losses. These losses are undesirable because no revenue is gained from them though they consume transmission and distribution capacity and create excessive heat in connectors and equipment.

The most common means of reducing technical losses require capital expenditures. They include installing shunt capacitors, installing new substations and lines, and reconstructing existing facilities to increase their capacity. Because the reduction of technical losses is dependent on capital projects, this topic is not covered by the study. But we can say there exist operating or maintenance remedies, however minor they may be. These remedies are discussed below.

Studies performed in 1997 indicated technical losses at the distribution level in the range of 9% to 21% of the kilowatt-hours delivered to the Yerevan Distribution Company during peak periods. The studies were based on the very sketchy information and many assumptions, causing their accuracy to be suspect.

The identification and reduction of technical losses require reliable load information on end-user demand and information from the system (load profile and the electrical characteristics of distribution system components such as length, size, type and loading of line and equipment supplying the demand). Although adequate information on the Armenian system was not available, the 9% to 21% estimate was somewhat confirmed by tests conducted at several substations in Yerevan. Whatever the true value of technical losses, it is clear that they are at the high to very high end of the range. Yerevan's losses are probably similar to those in other cities, and losses are thought to be higher in rural areas.

There are some operating and maintenance techniques than can be used to minimize technical losses. These techniques will present major challenges in Armenia because of the condition of the electric network and the shortage of resources.

The primary operating technique is to reconfiguring the network to minimize the electrical impedance (related to length of line) between the source and the load centers by appropriately opening and closing switches. A thorough analysis is required before reconfiguring the network; otherwise, other problems, such as reduced service reliability or even higher technical losses may occur with the new configuration. Other difficulties related with the reconfiguring the Armenian network to minimize losses include failed cables, circuit breakers and transformers, and the general lack of load and voltage information that is vital to computing where the worst losses occur.

Generation, transmission and distribution operating and maintenance requirements study

Maintenance techniques to reduce losses include ensuring that load carrying electrical contacts are clean and correctly aligned, keeping equipment connecting jumpers as short as possible, and ensuring that insulating oil is free of impurities.

Another effective means of reducing technical losses is lowering customer demand through energy conservation programs.

Generally, the high technical losses facing the distribution companies in Armenia are a result of deteriorated equipment; another reason is that of 0.4 and 6(10) kV overhead lines extention for many kilometers. The high level of technical losses was embedded in the design of the Armenian distribution networks. Any capital investment in the 0.4 kV overhead networks should consider the economic value of reconfiguring and reconstructing the 6(10) kV networks. This would decrease not only the technical losses on these networks (from the current 27% to 7-8%), but also prevent theft from open overhead lines, thus decreasing commercial losses as well.

Table 5.1 presents the resulting demands for electricity in the two scenarios taken into account for the economic optimization of the electric generating system expansion.

Table 5.1. Electricity Generation Requirements[1)] Unit: GWh/year

Scenario		1999	2005	2010	2015	2020
Low	Final Energy	3627.4	5354.3	6944.3	8109.8	9017.0
	Losses in T & D	1527.6	1136.2	1412.7	1452.5	1465.5
	Electricity Generation	5155.0	6490.4	8357.0	9562.3	10482.5
Reference	Final Energy	3627.5	5884.4	8128.4	9866.3	11387.7
	Losses in T & D	1527.5	870.6	962.6	1033.7	1043.3
	Electricity Generation	5155.0	6755.0	9091.0	10900.0	12431.0

[1)] Net generation

Proper planning of the electricity supply to cope with the increasing demand is required not only to cover the annual electricity demand, but also to meet the corresponding peak and hourly loads requirements every year. The distribution of electrical load during the time, being a pattern characteristic of electricity consumption, is a very important item taken into account when selecting the generating units which are to be added to the existing system each year, this is of key importance also for the power system optimal operation maintenance.

The Electric Module of MAED is designed to convert the total annual electricity demand (in terms of energy) of each economic sector to the power demand (load curve), first for each sector and then for the total system, it transforms the hourly load curve of the power system into period load duration curves (LDC), i.e. into the format required by the WASP model.

5.2. Assumptions on Electricity Consumption Pattern

In Electric Module of the MAED model, electricity consumers are aggregated into two major sectors, i.e. Industry (including Agriculture, Construction, Mining and all Manufacturing, and Transportation sub sectors considered by Module 1) and the Household/Service sector.

Due to the large share of the Household / Service sector in the total electricity consumption in Armenia, a particular use of the Electric Module has been adopted by grouping, according to the requirements of Electric module of the MAED model.

In this way, each sector and subsector considered in Module 1 is represented also in Electric Module as a type of client, i.e.:

- Industry/Transportation:
  - Manufacturing
    - Basic materials;
    - Machinery & equipment;
    - Non-durable goods;
    - Miscellaneous;
  - Agriculture (including irrigations);
  - Construction;
  - Mining;
  - Transportation.
- Household/Service:
  - Household;
  - Service.

The consumption features of each sub sector, as well as its share within the sector and the share of sector within the total consumption, determine the pattern of the load curve for the whole system.

The characteristics of the electricity demand of each sector were determined on the basis of four "load modulation coefficients" shaping the hourly consumption changes, i.e.:

- the coefficients determined by the annual rate of growth of electricity consumption of the sector (trend coefficient);
- the modulation coefficients expressing the electricity consumption of each sector according to the type of day for each season;
- the seasonal coefficients to express variations of electricity consumption of each sector according to the time of the year or season;
- the hourly variation of the electricity consumption of each type of client for each sector, season and type of day. This is accompanied by the share of each sub sector in the total daily consumption of electricity for the sector.

The multiplication of these coefficients for a given hour in the year by the average electricity demand of the sector allows obtaining the value of the electric load imposed by the sector at the respective hour.

Regarding the future evolution of these coefficients, the following assumptions have been made:

- trend coefficients were derived from the growth of electricity demand during the study period;
- daily weight coefficients have been considered constant within the study period;
- clients' shares within the total daily consumption of the sectors were predicted based on the changing trends in the future, meaning the reduction of the Basic materials and Non-durable goods shares and the growth of Machinery & Equipment subsector share;
- hourly variation of the electricity consumption of the various clients was generally considered constant.

5.3. Analysis of Consumption and Load Duration Curves

5.3.1. Reconstruction of the Load Curves for the Base Year

The determination of the load characteristics for the MAED study requires hourly load records by type of client for a minimum of one year. In Armenia, such records are not available, due to the total changes of structure and characteristics of electricity consumption in all sectors. There were available the hourly load records for whole Power System in 1999 only.

The main problem in reconstructing the load curves for the base year was to aggregate the Power System load curve with chosen samples curves of economic subsectors previously mentioned.

Finally, the load curves reconstructed with Electric Module of MAED have been compared with the actual load curves for the total system in the base year. Table 5.2 shows the actual and reconstructed peak load and electricity consumption by period (season) in the base year. As can be seen in this table, the results of MAED were in close agreement with the statistical data for the base year.

There are differences between an actual and calculated data, which may be due to averaging of weekdays.

Table 5.2. Comparison of Actual and Reconstructed 1999 Peak Load and Energy Requirements by Period

Period (season)	**Peak load (MW)**		**Energy (GWh)**	
	Actual	**MAED**	**Actual**	**MAED**
Winter	1071	959	1585	1491
Spring	947	860	1384	1238
Summer	792	730	1237	1198
Autumn	957	942	1154	1196

5.3.2. Future Consumption Shares

A factor, which has a special impact on the peak load, is represented by the share of each type of client in the total electricity demand of the sector. The big share of the Household /Service sector, which have varied within the range of 65.2-54.9% and 65.2-49.5% for the Low and Reference scenarios, can be noticed. On the other hand, the relatively significant share of Agriculture (12.6-10.7%) is mainly due to the irrigation with seasonal consumption, increasing in summer.

Table 5.3 shows the evolution of various clients' shares within the two sectors: Industry/Transport and Household/Service, for the two scenarios.

The share of Basic Material sub sector is assumed to increase from 13.9% in 1999 to 19.4% for the Low and 18% for the Reference scenario in 2020.

It can be noticed that the first major sector includes the big share of the Non-durable Goods sub sector. Its share is projected to decrease from 28.2% in 1999 to 23.7% in 2020 (for the Low scenario) and to 25.2% for the Reference scenario.

The share of the Machinery & Equipment sub sector is estimated to increase rapidly for both scenarios during the planning period (8.7% and 12.2% respectively). Transportation is foreseen to increase its share during the first 10 years of planning period (up to 11.7% in Low and 10.5% in Reference scenario), and after that - to decrease to the base year level.

The share of the miscellaneous sub sector is projected to be kept quite identical in the two scenarios.

The shares of Agriculture/Construction/Mining sub sectors in Industry sector are projected to decrease from 46.9% in1999 to 41.4% for Low and 37.5% for Reference scenarios.

Within the second major sector, the Household sub sector has a decreasing share trend over the time under study, 24.8% and 21.6% of the total sectors in 2020 for Low and Reference Scenarios respectively, and Service Sector will decrease its share from 29.9 to 28.0% in 2020 for Reference scenario. The picture for Low scenario is vice versa.

5.3.3. Future System Peak Load

In 1999, the losses in transmission and distribution were about 27% of the total consumption. It was estimated that in the future the losses would decrease to 16% in 2005, 14% in 2010, 13% in 2015, and 12% afterwards due to the step-by-step technical renovation of the Power sector of Armenia. That latter figure was taken into account when establishing the electricity generation requirements throughout the study period (see Table 5.1).

Based on the electricity requirements, consumption shares of each sub sector and their load characteristics, the peak load value, as well as its average annual growth rate was established for the reference years (Table 5.4). The peak load annual growth rate follows the electricity demand trend.

In the Reference scenario, the growth rates are 5.9% until 2010 and 5.2-4.6% between 2010 and 2020, and for Low scenario, the growth rate is expected to decrease after 2005 from 4.6% to 3.6%.

Under these conditions, in 2020, the peak load is estimated to be about 2006.9 MW in the Low scenario and 2467.9 MW in the Reference scenario.

Table 5.5 summarizes the main features of the electricity generation system for the reference years. It can be noticed a slight decrease of the load factor by 2020, with quite low differences between scenarios.

5.3.4. Comparison of MAED Results with other Load Forecasts

Another forecast was done by Energy Research Institute (ERI) in the paper entitled "Technical-Economic Report to the Government of the Republic of Armenia - The Perspectives of Development of the Power System of the Republic of Armenia, including nuclear energy, till 2010, with estimation up to 2020, Armenia - Yerevan, 1998".

Table 5.3. Consumption Share by Type of Client Unit: %

		1999	2005	2010	2015	2020
Low scenario	Industry/Transport:					
	Manufacturing					
	Basic materials	13.9	14.4	16.2	18.7	19.4
	Machinery & equipment	4.0	4.4	5.3	6.7	8.7
	Non-durable goods	28.2	24.6	23.7	23.9	23.7
	Miscellaneous	1.4	0.7	0.5	0.3	0.3
	Transport	10.6	11.9	11.7	11.1	10.9
	Agr./Constr./Mining	42.0	44.1	42.6	39.2	36.9
	Household/Service:					
	Household	54.0	51.0	49.0	46.9	45.3
	Service	46.0	49.0	51.0	53.1	54.7
Reference scenario	Industry/Transport:					
	Manufacturing					
	Basic materials	13.9	15.6	19.2	20.4	18.0
	Machinery & equipment	4.0	4.8	6.1	8.4	12.2
	Non-durable goods	28.2	25.2	24.5	25.1	25.2
	Miscellaneous	1.4	0.7	0.6	0.4	0.3
	Transport	10.6	10.8	10.5	10.5	10.7
	Agr./Constr./Mining	42.0	42.9	39.0	35.2	33.5
	Household/Service:					
	Household	54.0	51.2	49.3	46.3	43.5
	Service	46.0	48.8	50.7	53.7	56.5

Table 5.4. System Peak Load Requirements

Year	Low scenario		Reference scenario	
	MW	Growth, % p.a.	MW	Growth, % p.a.
1999	1071.0		1071.0	
2005	1263.0	4.7	1340.7	5.8
2010	1564.7	4.6	1805.3	5.9
2015	1805.4	4.0	2164.2	5.2
2020	2006.9	3.6	2467.9	4.6

The average energy demand per surface unit in old buildings of service sector is estimated to increase from about 102 kWh/sqm/yr in 1999 to 250 kWh/sqm/yr in 2010, with further decreasing to 243 kWh/sqm/yr in 2020. As for the new modern buildings, it was estimated that the demand for the thermal energy would be of 244 kWh/sqm/yr in 2005, and thereafter would slowly decrease to 226 kWh/sqm/yr in 2020.

In this paper, some main researches were:

- The long term demand forecast with the account of Armenian participation in Regional Energy Market;
- Possible Scenarios of Armenian Power System development;
- Planning of Armenian Power System generation capacities development;

Table 5.5. Main Features of Electricity Generation System

Year	Peak (MW)		Energy (GWh/yr)		Load factor (%)	
	Low	Reference	Low	Reference	Low	Reference
1999	1071.0	1071.0	5155	5155	61.0	61.0
2005	1263.0	1340.7	6490	6755	61.2	61.8
2010	1564.7	1805.3	8357	9091	61.0	61.7
2015	1805.4	2164.2	9562	10900	60.5	60.9
2020	2006.9	2467.9	10482	12431	59.5	60.6

- The characteristics of recommended Least Cost Plan of Armenian Power System generation capacities development, and other.

Figure 5.1 is given below for better understanding of the results obtained.

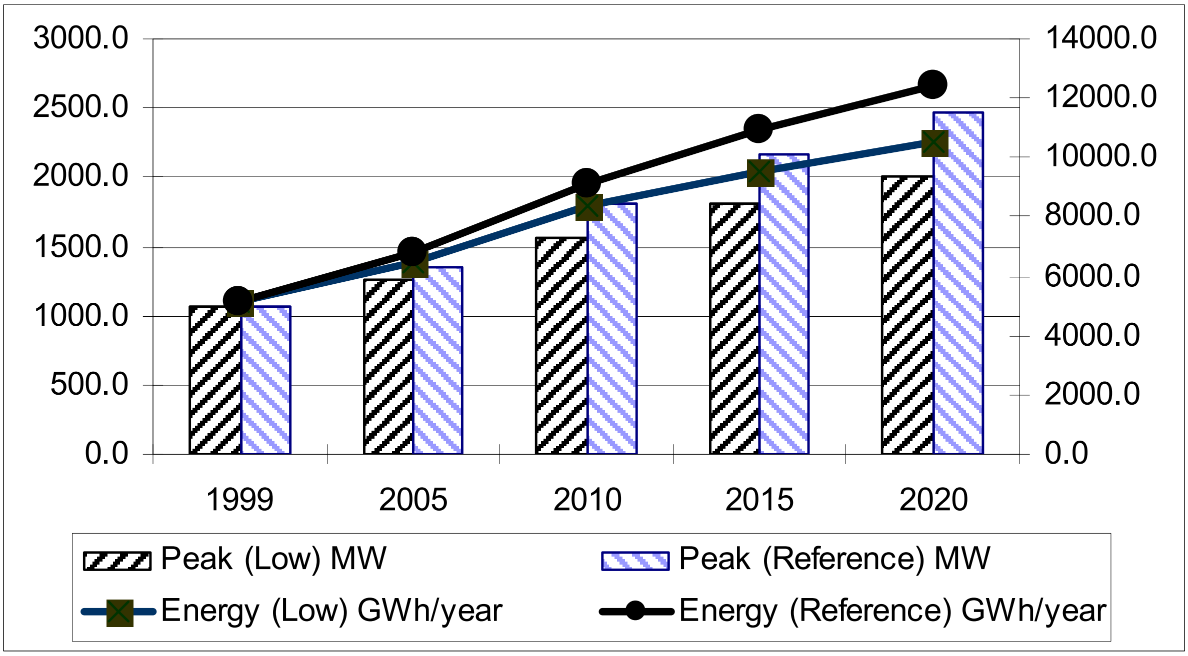


Figure 5.1. Forecast of Energy Generation and Peak Load

Table 5.6 shows the comparison of MAED Reference scenario and ERI forecasts (with export) of electricity generation and peak load requirements.

Figures 5.2 and 5.3 present also the evolution of the peak load and electricity generation in the two scenarios taken into account in the MAED study, as well as according to the ERI normal scenario forecasting.

5.4. Conclusions

After 1999, a growth of peak load is projected with an average annual rate of about 4.2% until 2020 in the Low scenario, about 5.4% in the Reference scenario. Under this growth, the system peak load, in 2020, will reach around 2007 MW in the Low scenario and 2468 MW in the Reference scenario. Regarding the year-by-year increase of the peak load, we can say that it varies in the Low scenario of about 50 MW/year during 1999-2020. For the Reference scenario, this increase is more significant: about 72 MW/year, respectively, during the same years. Concerning the load factor, it can be noticed almost constant trend by the end of the study for the Reference scenario, its highest value reaching 61.8% in 2005 in the Reference scenario

Table 5.6. Comparison of MAED and ERI Forecasts for Reference Scenario

Year	Peak load				Electricity generation			
	ERI	MAED	Difference		ERI	MAED	Difference	
	MW	MW	MW	%	GWh	GWh	GWh	%
2005	1590	1341	249	15.68	9070	6755	2315	26%
2010	1800	1805	-5	-0.30	11140	9091	2049	18%
2015	2100	2164	-64	-3.06	12600	10900	1700	13%
2020	2200	2468	-268	-12.18	13600	12431	1169	9%

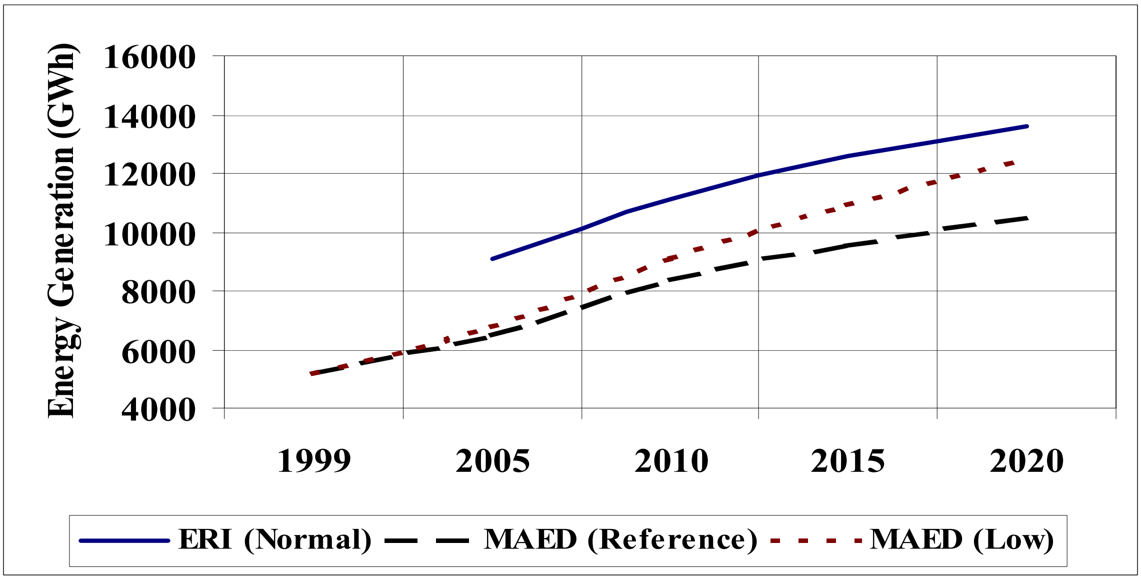


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Figure 5.2. Comparison of Forecast of Energy Generation

The study of load curves by means of MAED methodologies requires a great number of input data concerning the various types of customers, the shape of the daily consumption and its variation during the year, etc. All these data involve a careful survey of the main consumers being able to determine their features as accurately as possible. Certain work will be undertaken in this respect in the country, in order to bring up to date the already existing data and, at the same time, referring to an ever larger number of important customers, and taking into account the evolution of the structure of various economic branches.

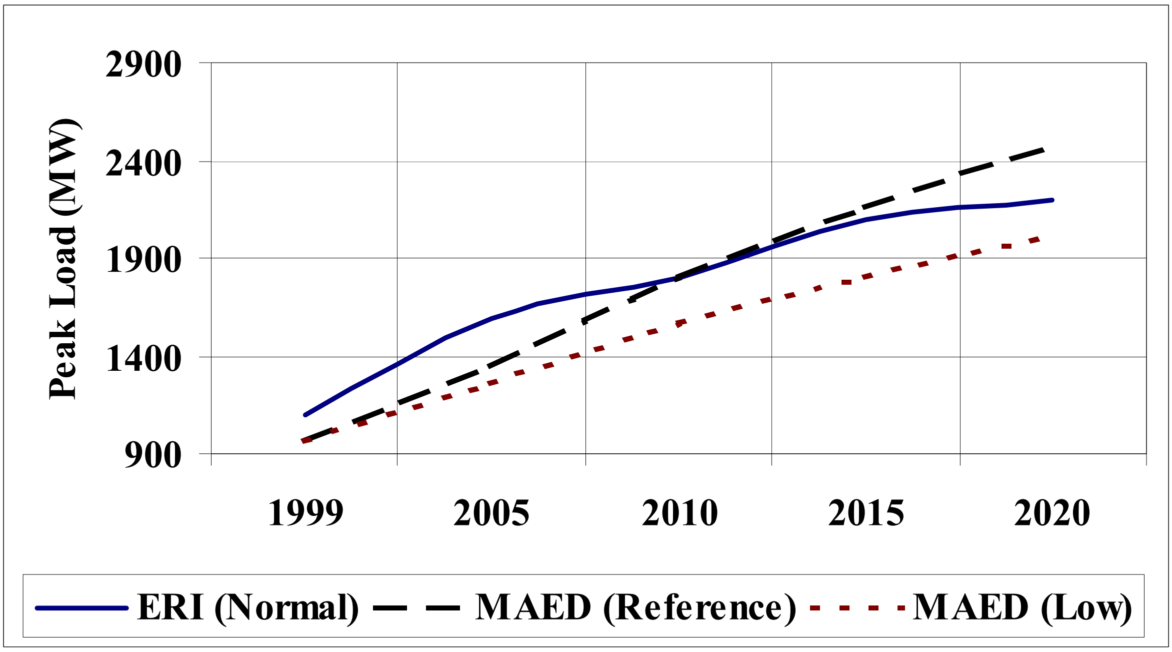

Figure 5.3. Comparison of Forecast for Peak Load

6 PRELIMINARY REGIONAL ENERGY INTERCONNECTION PLANNING STUDY

6.1. Introduction

The concept of regional co-operation considers the creation of energy community based on co-ordination of capital markets, new technologies and energy resources. The practical realization of this concept has significant importance for the South Caucasus region, as well as for the global environment. The main point here is the fact that the conditional border between the Eastern countries possessing fossil fuel resources (Russia, Middle Asia, Iran, Azerbaijan, etc.) and the Western countries with the most important consumers (Europe, Turkey) pass through South Caucasus region.

However, the complicated geo-political conditions of the region, economic difficulties of the transaction period, differences of restructuring of energy spheres and other problems do not allow to realize the regional co-operation in the form adequate to developed market relations [84-106]. As a result, the energy environment of the region is distorted at present.

Scope of the present study is to develop a comprehensive and self-consistent energy scenario for the Trans-Caucasian Region (Armenia, Georgia, Azerbaijan, Turkey, and Iran), with particular focus on energy exchanges and on the electricity system.

A regional energy scenario has been worked out from the national scenarios using the BALANCE module of the ENPEP energy model.

This exercise does not want to produce an exhaustive forecast of regional energy demand and exchange flows, but simply represents a first attempt of regional approach to a scenario work. Its main result, we think, lies in making evident the potential existing for energy exchanges and for regional energy system improvements coming from an increased interconnection.

6.2. Present Situation and Development Perspectives of Power Sector of Trans-Caucasian Region

6.2.1. Present Situation and Development Perspectives of Power Sector of Turkey

Geography. Turkey is located in the territory of the Southwest Asia. Turkey has borders with the Bulgaria and Greece in northwest, Armenia, Georgia, Azerbaijan (Nakhichevan) in the northeast, with Iran in and East, in the southwest and northeast with Iraq, and Siria in the South. Major cities: Ankara (capital), Istanbul, Izmir, and Adana. The territory is 780580 km^2. The territory of the country in general is of mountainous topography.

Population of Turkey is 66.5 million (1999).

Economy. Gross Domestic Product (1999 market exchange rates) - $227.4 billion. Real GDP growth rate (1999) is 5.3%, (2000) 3,6-4%. Current Account balance (2000) is 5.1 billion. Major Trading Partners: Italy, United States, Saudi Arabia, and Russia. Merchandise Exports (January - May 2000) $12.7 billion (around half going to the EU). Merchandise Imports (January - May 2000) $20.3 billion. Merchandise trade Balance (January - May 2000) -$7.8 billion. Major export products: agricultural, textiles, iron, steel. Major import products: oil, machinery, and chemicals, iron, steel.

Energy overview. Proven Oil Reserves (1/1/00): 299 million barrels. Oil Production (1999): 9,000 barrels per day (bbl/d) of which 65,000 bbl/d is crude oil. Oil Consumption (1999): 624,000 bbl/d. Net Oil Imports (1999): 555,000 bbl/d. Crude Oil Refining Capacity (1/1/00): 690,915 bbl/d. Natural Gas Reserves (1/1/00): 314 billion cubic feet (Bcf). Natural Gas Production (1998): 20 Bcf. Natural Gas Consumption (1998): 370 Bcf. Net Natural Gas Imports (1998): 350 Bcf. Coal Production (1998): 67.5 million short tons (Mmst). Coal Consumption

(1998): 78.4 Mmst. Net Coal Imports (1998E): 10.9 Mmst. Estimated Recoverable Coal (1996): 8.2 billion short tons of lignite. Electric Generation Capacity (2000): 26 GW (44% hydroelectric, 28% coal/lignite, 18% gas, and 9% fuel oil as of 1998). Electricity Generation (1998): 106.7TWh. Electricity Consumption (1998E): 102.2 TWh.

Electricity sector of Turkey comprises two state companies: Turkish corporation of electricity generation and transmission (TEAS) and Turkish corporation of electricity distribution (TEDAS). These two separate companies were established by the Decree of the Council of Ministers in 1993 on the basis of the only company TEK established in 1970. Besides, the state encourages the establishment of private companies of generation, including in the form of independent power producers (IPP), concessions, etc.

6.2.1.1. Structure of generation and electricity transport

During the passed 25-year period the electricity sector of the country was developed in a very dynamic way. Complete specific consumption of primary resources during this period increased from 0,63 to 1,09 tons equivalent fuel (TEF) per capita, i.e. 2.2% in average p.a.. Per capita consumption of electricity increased from 328 to 1751 kWh/per capita, i.e. 6,9% p.a.. During this period the electricity intensity of Gross Domestic Product increased for about 2,9 times, whereas the total GDP energy intensity didn't change practically and made about 0,34-0,35 TEF/k US$ - 90).

The stabile growth of electricity generation is observed during the whole considered period. Utilization of gas in electricity sector at the end of 80-ies and comparatively high rates of electricity generation on the basis of this fuel – almost 12% annual growth, are characteristic.

Stabile reduction of electricity consumption for own needs of the power plants is also noteworthy. To a certain extent this is due to the reduction of share of TPPs (from 77,5% in 1973 to 61,6% in 1998) in the total electricity generation. During the last decade of the considered period the average factor of system load was significantly increased which evidences about increase of share of industrial load. The main indicators of effectiveness of TPPs were increased – specific consumption of equivalent (oil) fuel. During the last 7 years the reduction of specific consumption for 15g equivalent oil or 21 g e. f. is considered as a good indicator.

The state company TEAS is the main electricity producer. It controls the transmission networks of 66 kV and higher. In 1996, the installed capacity of power plants of TEAS made nearly 90% of total capacity of the country. About 6,5% made the capacity of the so-called "independent producers". The share of independent producers and concessionaires is insignificant. The latter are mainly owners of HPP`s. The continuous growth of that share in installed capacities, as well as in electricity generation up to 1990 was observed. Subsequently, after some decline in 1996, the share of TEAS again increased in 1999–90% of the total generation.

TEAS corporation also controls the transmission networks 380/154/66 kV. The electricity transport grid is organized on 380/154 kV voltage levels and is foreseen for transmission of electricity from base power plants to big electricity distribution centers (Figure 6.1).

During 1980-1996, the development of transformer capacities is characterized by a graph presented in Figure 6.2.

Electrical interconnections connect Turkey with seven neighboring countries. As of 1999, these connections were characterized by parameters presented in Table 6.1.

Figure 6.1. Transmission network of Turkey

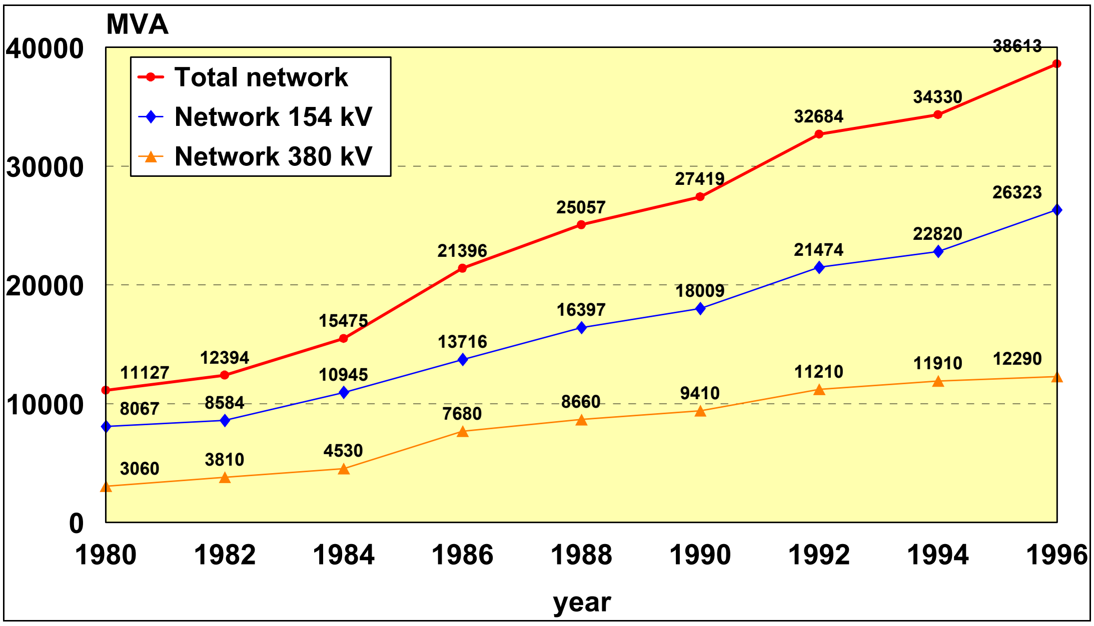

Figure 6.2. Development of transformer capacities of electricity transport grid of Turkey

* capacity of interconnection is limited by regional network or by capacities of auto-transformers 220/154kV, 154/132kV.

6.2.1.2. Electricity consumption structure

The electricity is distributed in the country by Turkish company TEDAS. The company with 7 branches in the composition controls the distribution networks of 34,5 kV throughout the whole country, except the Anatolian part of Istanbul and province Kaizeri. Private companies Atkas and Kaizeri serve the latter respectively. TEDAS serves 63 provinces from 79, the remaining 16 are served by private companies. The total number of the customers throughout the country is 17.2 mln. (1996). TEDAS and its daughter enterprises buy electricity mainly from TEAS and insignificant amount (2-3%) – from independent and private producers.

Table 6.1. Interconnections of Turkey

Name	Voltage kV	Length km	Capacity MW	Note
Babaeski – Dimodichev (Bulgaria)	380	136	500	Import
Khopa – Batumi (Georgia)	220	28	300*	Import
Kars – Gumri (Armenia)	220	78.4	300*	Out of operation
SS 3 – Zakho (Iraq)	380	16+	500	
Igdir – Babek (Nakhichevan)	154	87.3+	100*	Export
Dochubeiazit – Bazargan (Iran)	154	73	100*	
Gachgach – Kamishli (Syria)	66	5.7+	40*	Out of operation
Aralik – Sederek (Nakhichevan)	34.5	44.5	40*	Export

+ OHL length up to border

In 1996, TEDAS realized 36,4 TWh electricity and its daughter enterprises - 28,2 TWh. The volumes of realization of private companies Aktas and Kaizeri were 5,2 and 1,1 TWh respectively, which makes about 8,8%.

The electricity consumption during 1973-1997 in different spheres of economy is presented in table 6.2.

Analysis of the data evidences, though gradually subsiding, but still dominating role of the industrial consumption. During the past period, the share of electricity consumption by population and municipal sector increased significantly, surmounting in 1995 40% border. Noteworthy also is the growth of total consumption, which actually is being doubled every 7-8 years.

In the industry, the most energy intensive are ferrous metallurgy, chemical and petrochemical spheres, mining, light and textile industries (Table 6.3).

During the whole period, stabile growth of ferrous metallurgy and machine-building and rapid development of light and textile industries is observed. During the last decade, the paces of development of non-ferrous, woodworking industries were slackened noticeably. Significant decrease in chemical and petrochemical industries took place.

6.2.1.3. Electricity development forecasts

For long term electricity development forecasts, it is necessary to analyze the macro-economic indicators of development, drawn by respective state structures, including TEAS Corporation. Besides, strategic forecasts of European Commission are available for countries of EU and, on regional level, in particular for Middle East region for up to 2020. The latter are elaborated for four different scenarios of development of world economy. So-called “Traditional wisdom” scenario is assumed as reference for this investigation, the principle approaches of which for the development up to 2020 are presented here below (Table 6.3)

The reference scenario is based on the so-called classic evaluation of the most likely development of events. Notwithstanding the certain progress, still many social-economic problems exist in the world and in the Middle East region. In the long term perspective, the economic growth is somewhat slowed down.

Table 6.2. Structure of Electricity consumption in different spheres of economy, TWh

Sphere	1973	1980	1990	1996	1997	1990/73 %	1997/90 %
Industry	6,44	12,15	27,34	38,39	41,29	8,88	6,07
%	61,1	59,5	58,4	51,8	50,4	-	-
Transport	0,10	0,15	0,35	0,48	0,40	7,65	1,92
%	1,0	0,7	0,7	0,7	0,5	-	-
Agriculture	0,05	0,16	0,58	1,83	2,01	15,51	19,43
%	0,5	0,8	1,2	2,4	2,5	-	-
Municipal economy	1,76	3,54	7,40	14,11	17,26	8,81	12,86
%	16,7	17,4	15,8	19,0	21,1	-	-
Population	1,39	3,50	9,06	16,43	18,51	11,66	10,75
%	13,2	17,2	19,4	22,1	22,5	-	-
Energy *)	0,61	0,86	1,87	2,73	2,21	6,81	2,42
%	5,8	4,2	4,0	3,7	2,7	-	-
Other	0,18	0,04	0,22	0,20	0,21	1,16	0,00
%	1,7	0,2	0,5	0,3	0,3	-	-
TOTAL:	**10,53**	**20,40**	**46,82**	**74,17**	**81,89**	**9,17**	**8,31**

*) Includes utilization of coalmines, oil-and-gas production, non-generating expenses, and covering of other energy requirements.

Table 6.3. Dynamics of electricity consumption in industry, TWh

Sphere	1973	1980	1990	1996	1997	1990/73 %	1997/90 %
Ferrous metallurgy	0,84	1,82	4,84	8,13	8,66	10,85	8,67
Chemical & petrochemical	0,66	1,22	3,37	1,95	2,00	10,06	-7,2
non-ferrous metallurgy	0,23	1,52	2,55	2,94	2,81	15,20	1,40
Mining	1,21	2,00	3,99	5,53	5,36	7,27	4,31
Machine-building	0,30	0,39	1,14	1,77	2,03	8,17	8,60
Food & tobacco industries	0,85	1,54	2,59	2,94	3,25	6,77	3,30
Wood-working industry	0,61	1,02	1,32	2,35	2,25	6,98	2,30
Light and textile industries	1,22	1,74	3,92	6,33	8,42	7,11	11,54
Other	0,52	0,90	3,02	6,46	6,53	10,80	11,64
TOTAL:	**6,44**	**18,15**	**27,34**	**38,39**	**41,29**	**8,87**	**6,06**

General description of reference scenario "Traditional Wisdom"

The growth of population – 2,3% p.a. during 1974 – 1992, was reduced during the next decade – 2,1%. For the period 2000 – 2010 the growth of population is forecasted on the level of 1,4% p.a. and 1,3% during the following years up to 2030.

During 1974-1992, the average Gross Domestic Product made about 4,85%. Subsequently, right up to 2010 it is forecasted that the GDP growth will be on the level of 4,75, about 0,6%-points higher than average indicator of Middle East region. During 2010-2020, GDP growth is assumed at 3,5% p.a. During the decade following the considered forecast period, the GDP growth will reduce and make 2,5% p.a. Nearly such tendencies of the economic growth are put in the basis of the development forecasts for the whole region.

It is assumed that the producers from the Middle East will cover the world demand of oil as before. The price for a barrel of fuel achieved $21 in 2000. It will be $29 in 2010, $31 in 2020 and $35 in 2030. During the nearest decade linear increase of oil cost is assumed.

It is assumed that the prices for natural gas will not be changed up to 2020 due to increase of competition in gas market (development of new deposits, new gas mains, etc). Such assumption is based also on the fact that the “trustworthy reserves/extraction” ratio of main actual and potential suppliers of Turkey (Iraq, Iran, Turkmenistan, Saudi Arabia, Kuwait, etc.) exceeds 100 years period as of 01.01.1999, and for the present and main supplier-Russia this indicators make 85 years. During the following decade of the forecast period insignificant, about 2%, annual increase of natural gas price is assumed.

The international prices on coal will undergo some increase. International trading with cheap coal will become rather active. Import of cheap coal will force out the unprofitable mining in the country.

Increase of effectiveness of TPP`s through introduction of new technologies will take place by 2020. In the following 2020-2030 decade – the effectiveness of conversion of organic fuel into electricity will remain on the level of previous years.

The electricity demand will increase mainly in communal-general service sector and in industry. During 2000-2020, the increase of electricity demand will surpass the GDP growth. In the following decade, this indicator will approach the average European level of 2000, and the growth of electricity consumption will slow down.

Electricity Demand and Generation forecasts

At first it is necessary to specify some terms in interpretation of IEA:

- net generation=gross generation - own needs of the plant (houseload),
- generation=gross generation - generation of PSP,
- demand=gross generation + import – export.

Electricity demand forecasts up to 2010, made by state corporation TEAS, are rather reliable and in general comply in different sources (Electricity Information-98, IEA/OECD publication, Report on the Development of the Electricity sector in Turkey-97, etc.).

The electricity demand forecasts between 2010-2020, unfortunately are characterized with more divergence. For example, in Hydropower and Dams World Atlas-1999, the volumes of generation for that period are forecasted to be of 347,3-623,8TWh/p.a. Even for 2010, this forecast is higher at 20% than the forecast of TEAS. There is significant difference also between our forecast on reference scenario –481,5TWh for 2020 (see the Preliminary report) and forecast of TEAS – 583,11TWh (see the above mentioned Report-97). The estimations of TEAS are based on the assumption of average annual demand growth at 7,2%, which seems to be unrealistic. More real is the assumption that the electricity demand growth will 1,5-1,6-times exceed the GDP growth. This means that during the interval 2010-2020, the demand growth rate should be approximately 5,6%. This indicator is put in the basis of demand calculations for 2010-2020.

For the following decade of the considered period, no more- or- less reliable investigations are available. The assumption of reduction of GDP relative electricity intensity to the value 1,2-1,3 times exceeding the annual GDP growth seems reasonable. This means that during 2020-2030, the annual average growth of electricity demand would be 3,0-3,3%.

The forecast data on development of electricity demand were calculated on the basis of the provisions given in table 6.4. In the same table, the volumes of electricity generation are given, and their dependence on import-export balance is presented.

Thus, upon realization of forecasted development, the power sector of Turkey will achieve, by 2015, such a level of electricity generation, as, for example, that of Greece in 2000.

Table 6.4. Electricity demand and generation forecasts

Name	2000	2005	2010	2015	2020	2025	2030	Notes
Average annual demand growth, %	8.85*)	8.24	7.75	5.8	5.4	3.3	3.0	*) 2000/1999
Electricity demand, TWh/p.a.	134.31	199.56	289.82	384.00	500.00	590.00	685.00	
GDP electricity intensity, % annual growth, %	100.0 -	116.0 3.00	133.0 2.77	147.6 2.10	162.0 1.88	169.0 0.85	170.0 0.47	2000-100%
Electricity generation, TWH/p.a.	130.0	193.57	281.12	372.5	485.0	572.3	664.5	upon 3% balance-import
Same	127.6	189.6	275.4	364.8	475.0	560.5	650.7	upon 5% balance-import
Electricity demand, kWh/h annual growth, %	1995 -	2751 6.64	3709 6.16	4585 4.33	5568 3.96	6152 2.02	6696 1.71	

Development of generating capacities

By 31.12.97, the following total installed capacities were in operation in Turkey:

- lignite and coal firing TPP`s – 6534 MW;
- oil products firing TPP`s – 1720 MW;
- natural gas firing TPP`s – 3500 MW;
- TPPs with renewable sources and GeoTPP`s – 36 MW;
- Hydro power plants – 10100 MW.

Total generating capacities – 21890 MW.

According to the energy sector development program elaborated by TEAS Corporation, introduction of additional capacities is foreseen, that, together with the existing ones, will ensure the generation of 290 TWh/p.a. by the end of 2010. At present, these additional capacities are in different stages of readiness (Table 6.5).

Table 6.5. Level of readiness of additional capacities

Level of readiness	1997-2000			2001-2005			2006-2010		
	Total	**Gas**	**Hydro**	**Total**	**Gas**	**Hydro**	**Total**	**Gas**	**Hydro**
Under construction	5880	3040	1800	1710	-	1710	-	-	-
Licensed	360	360	-	12290	4260	4360	2000*)	-	-
Planned	-	-	-	3500	3500	-	18430	4200	6950
TOTAL	**6240**	**3400**	**1800**	**17500**	**7760**	**6070**	**20430**	**4200**	**6950**

*) NPP

There is no reliable information on orders for construction and commissioning of additional capacities during 2011-2020 periods. However, TEAS has its own considerations how to meet the 583,1 TWh demand planned for 2020. In table 6.6 the planned data of total installed capacity are presented.

Table 6.6. Increase of installed capacities by sources at the end of considered year, MW

Primary energy sources	Additional capacities						
	1997	**2001**	**2010**	**2022**	**1997-2001**	**2002-2010**	**2011-2020**
Lignite and coal	6534	7841	11741	17941	1307	3900	6200
Imported coal	-	-	2500	9000	-	2500	6500
Natural gas	3500	10691	18391	33791	7191	7700	15400
Oil products	1720	2439	4189	8039	719	1750	3850
Nuclear fuel	-	-	2000	10000	-	2000	2000
Renewable sources	36	100	600	1000	64	500	400
Hydro energy	10100	12628	25336	29101	2528	12708	3765
TOTAL (TEAS)	**21890**	**33699**	**64757**	**10809**	**11809**	**31058**	**44115**

Upon drafting the consolidated schedule of development of generating capacities up to 2030, the following was assumed:

- For 1997-2010, the forecasts of TEAS are accepted without changes;
- The forecast of TEAS for 108,87 GW total installed capacity in 2020 is reduced to 100GW;

- For 2021-2030, the forecasts are based on indicators of electricity demand (see table 2.3.) and on usage-factors of installed capacities assumed to be 0,61 and 0,64 for 2025 and 2030, respectively;
- For the last two decades of the forecasted period, some preference is given to TPPs firing imported coal and oil products (based on considerations of Baku-Jerkhan project), as distinct from TPP`s firing domestic solid fuel (see Explanations 2.1.);
- All forecasts of development of capacities are based on the principle of demand covering, i.e. the electricity import-export balance was not taken into consideration;
- The schedule of decommissioning of generating capacities is drawn in accordance with chronology of commissioning of the capacities (TEAS, Electricity generation-Transmission Statistics, August 1997). The lifetime for TPP`s firing all types of fuel is assumed to be 30 years, for TPP`s on renewable sources and Geo TPP`s - 15-20 years, HPP`s - 80 years. By 2030, small HPP`s with 40MW total capacity, having been in operation up to 1955, should be decommissioned.

System load forecasts

To forecast electricity loads, it is advisable to analyze first of all the characteristics of load (generation) curves for the previous period. For the periods 2015-2020-2025-2030, a gradual increase of peak load factors K_{MAX} within 74 - 78% is accepted. The values of forecasted peak loads upon zero import-export balance received on the basis of stated premises are given in table 6.7.

Table 6.7. Forecast levels of peak loads and main characteristics of generation schedule

Description	2005	2010	20105	2020	2025	2030
Installed capacity of the system, GW	45.99	64.76	81.05	100.00	110.50	122.50
Electricity demand, TWh/p.a.	199.56	289.82	384.00	500.00	590.00	685.00
Use factor of installed capacity, %	49.53	51.10	54.10	57.08	60.90	63.83
Maximum load factor (hourly), %	69.2	71.3	74.0	75.0	76.5	78.0
Generation peak capacity (hourly), %	31.83	46.21	59.98	75.0	84.53	95.55
Factor of completing of annual curve, %	71.57	71.59	73.08	76.10	79.66	81.83

As a whole, the tendency of consolidation of annual generation schedule is obvious. However, K_{MAX} =80,9% for 2020, forecasted by TEAS, is expected to reduce to 75,0%, and such hypothesis seems to be more reasonable.

During the last years, the operation indicators have been improved significantly. The electricity consumption for own needs (household) was stable and kept on the level of 5%, the electricity losses in TEAS system were decreasing from 5,0-5,5% (in 70-80-ies) to 2,1-2.5%. In distribution companies, the situation was a little worse: instead of expected 6-7%, at the end of 90-ies, the electricity losses were 12-15%.

6.2.2. Present situation and perspectives of development of power sector of Azerbaijan

Geographical situation. Republic of Azerbaijan is situated in the territory of Caucasus, on the West Coast of Caspian Sea. Azerbaijan has borders with Russia in the North, with Georgia in the West, with Armenia and Turkey (Nakhichevan) in the Southwest, with Iran in the South. The capital of Azerbaijan is Baku. The territory equals to 86600 m^2 km. Almost the half of territory has mountainous topography. Peninsulas and bays indent Caspian coastline with 800km length. The highest point of the territory is 4466m a. s. l., the lowest point – Caspian plain (-28m.).

Population of Azerbaijan is 7.630.000 (1999), with 1% annual growth. 53% of the population lives in cities. The biggest cities are – Baku, Gyandja, Mingechaur, Nakhichevan, Sumgait, Evlakh.

Economy. One of the economically high-developed countries of former USSR, Azerbaijan suffered severe economic crisis in 90s. Thus, compared with 1990, the main economic indicators have significantly changed (Table 6.8).

The volumes of production have decreased: in power sector for 34%, in machinery sector for 83%, in chemical and petro-chemical – for 83%. It became possible to overcome the crisis in 1997 increasind the GDP to 3,9 billion US$ with the annual growth rate 5,7%. Expected rate of economic growth for visible period makes 6 - 8%. The volume of direct external investments increased up to 15 mln. US$ in 1993, to 546 mln. US$ in 1996, 1300 mln. US$ in 1997, and 1600 mln. US$ in 1998. According to different estimations, the total volume of direct investments in oil-gas sector will reach 23 billion US$ by 2010.

Table 6.8. Dynamics of main economic indicators of Azerbaijan

Description	1990	1991	1992	1993	1994	1995	1995/1990	
							%/p.a.	%
Population, mln.	7.2	7.24	7.33	7.40	7.46	7.51	+0.85	+4.3
GDP, billion US$	27.3	27.1	21.0	16.1	13.0	11.4	-16.0	-58.2
GDP per capita, US$/per capita	3792	3743	2865	2176	1743	1518	-20.1	-60.0
Generation of primary energy, Mt o.e.	20.4	19.0	18.2	16.0	15.0	14.7	-6.77	-27.9
Consumption of primary energy, Mt o.e.	19.7	18.1	15.4	16.3	16.1	13.0	-8.67	-34.0
Electricity generation, TWh	23.2	23.4	19.7	19.1	17.6	17.0	-6.42	-26.7
Consumption of primary energy /GDP, toe./ths. US$	0.72	0.67	0.73	1.01	1.24	1.14	+9.62	+58.3

Energy resources. Azerbaijan has rich natural reserves of oil and gas. Nevertheless, either oil or natural gas as well as high quality coal, electricity and other kinds of energy resources are imported. The main energy resource is mazut (about 80%). Total consumption of energy and energy products in 1980-1990 period increased from 20,0mln. t o.e. to 23,0 mln. t o.e. In 1996, the consumption was reduced for 46%, and stability and some growth were observed only in 1997. Reliable oil reserves are evaluated to be of 3-11 billion barrels, gas - 300-800 billion m^3.

Hydro-resources, coal and wood reserves are also available. There is a significant potential of renewable sources (wind-, solar-, biomass) and energy savings.

Theoretical gross hydro potential makes 43,5 TWh/year, technically available potential – 16 TWh/year, economically sound for the development – about 7 TWh/year (about 10% is developed). Average long term precipitation – 405mm, volume of atmospheric precipitation – 31.5 billion m^3. The biggest rivers are Kura 1515 km and Araks 1072km of Caspian basin. There are 52 dams with 21.7 billion m^3 of total capacity of water reservoirs. Most of the dams are multipurpose (irrigation, energy, outflow regulation, water supply and other).

Electricity generation (according to 1998 data). Installed capacity of power plants of Azerbaijan (8 TPPs and 5 HPPs) is 5045 MW. A share of TPPs is 83.3% (natural gas and mazut) or 4200 MW, a share of HPP is 16,7% or 845 MW. Upon 18.2 billion kWh of annual consumption, the electricity generation made 17.9 billion kWh, 89.1% of which, or 15.9 billion kWh, was produced by TPPs, and 10.9% or 1.953 kWh (average long term 2050GWh) - by HPPs, under the balance equal to (-) 0.250 billion kWh. Azerbaijan imports electricity from Russia, Turkey, Iran and Georgia. A project for establishment of common with Georgia and Turkey power system was developed in the framework of Tacis program.

Electricity transportation. Transportation grid of Azerbaijan (Figure 6.3) is established with 500/330/220/110 kV lines for transportation of electricity from basic plants to big electricity distribution centres. Main transits of electricity are directed to the East of the country, considering the extremely irregular allocation of consumption (about 80% is concentrated in Apsheron peninsula). 500 kV main network is able to provide the direct transit of electric energy practically through the whole territory of the country, and ensures the capacity supply from the biggest power plant of Transcaucasian region – Azerbaijan TPP 2400MW (300MWx8).

Characteristics of interconnections are given in table 6.9.

Nakhichevan (South – West enclave of Azerbaijan) has no own sources of electricity and imports electricity entirely from Turkey (298 mln. kWh) and Iran (299 mln. kWh).

Electricity distribution grids with 35/10/6kV voltage distribute electricity.

Forecasts for the development of power sector of Azerbaijan. Forecasts for the economic development for two scenarios: "traditional wisdom," or basic, and "restrictions of free market relations," or pessimistic, are given in table 6.10 (upper line – basic, lower-pessimistic scenario).

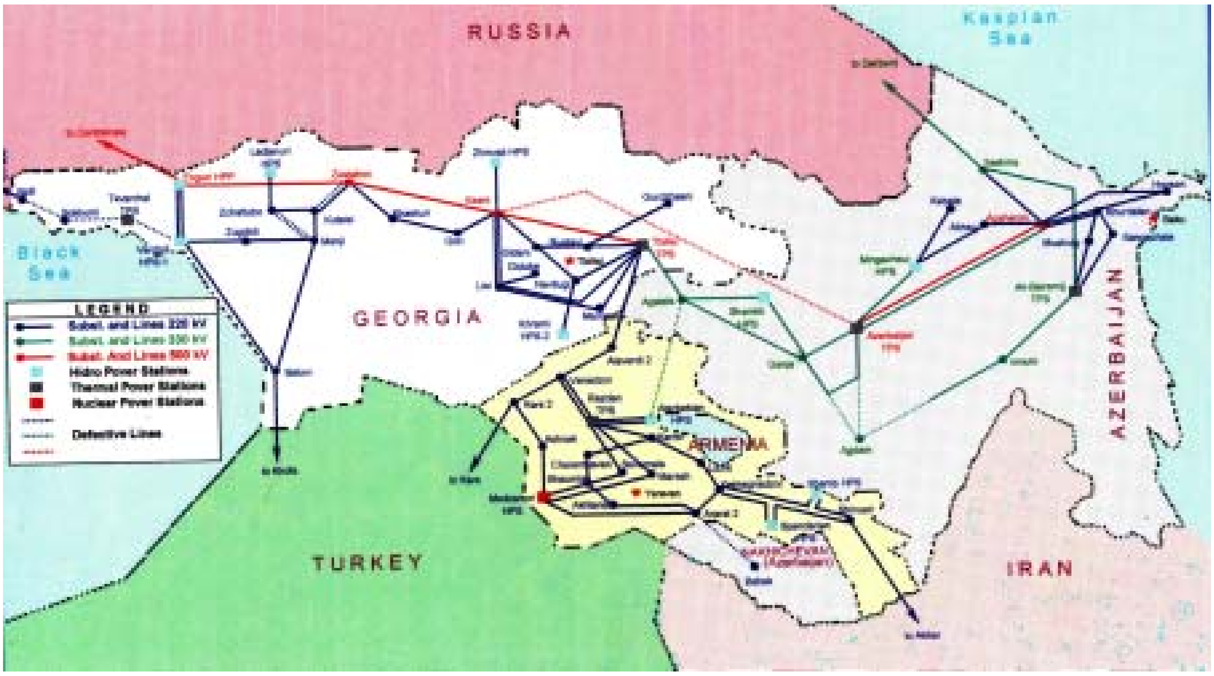

Figure 6.3. Trans-Caucasian Power System

Data given in the table show the hydrocarbon raw materials export opportunities of the country. Data on macroeconomic development for 2000-2001 time period were taken from Caspian Oil and Gas (IEA) review. Forecasts for further period are developed according to the main principles.

Electricity demand Forecasts for internal market for 2 above-mentioned scenarios of the development of economy are given in Table 6.11 (upper line-basic, lower line-pessimistic scenario).

Monotonous reduction of energy intensity of GDP up to the end of forecasting period is planned in basic option. In pessimistic option this tendency is foreseen after 2020.

Table 6.9. Interconnections of Azerbaijan

Name of IC	**Voltage kV**	**Length km**	**Capacity MW**	**Note**
Az TPP – Ksani (Georgia)	500		1000	Reverse
Akstafa – TbTPP (Georgia)	330		400*	Reverse
Akstafa – Hrazdan TPP (Armenia)	330	107	400*	Out of operation
Yashma – Derbent (Russia)	330	110	500	Reverse
Babek (Nakhichevan) – Igdir (Turkey)	154	96	100*	Import
Sederek (Nakhichevan) – Aralik (Turkey)	34.5	44.5	40*	Import
Nakhichevan – Iran	35		50	Import

Table 6.10. Development of main macroeconomic indicators

Population	2000	2005	2010	2015	2020	2025	2030
Population, mln.	7.9	8.3	8.8	9.2	9.7	10.1	10.6
GDP, billion US$	16.0 16.0	22.4 21.4	31.5 27.3	41.3 34.9	57.7 44.5	73.6 54.1	89.5 62.7
GDP average annual growth, %/year	7.0 6.0	7.0 5.0	6.5 5.0	6.0 5.0	6.0 5.0	5.0 4.0	4.0 3.0
GDP per capita, US$/per capita	2024 2024	2702 2578	3574 3103	4684 3788	5945 4586	7287 5356	8443 5915
Generation of primary energy, Mt o.e.	20.1 20.1	44.1 34.1	89.1 57.1	122.2 86.1	144.2 109.1	167.0 133.0	192.0 158.0
Consumption of primary energy, Mt o.e.	16.3 16.3	20.9 20.1	24.8 23.0	34.6 29.6	42.0 35.0	53.0 42.0	65.0 50.0

It is necessary to analyze the respective indicators of Azerbaijan power sector in retrospective for forecast evaluations of required installed capacities. Since 1995, up to 1997 the use-factor of installed capacities of power plants (upon absence of commissioning of new capacities) decreased from 54 to 38%. This is explained by the reduction of electricity generation from 23.4 to 16.8 TWh/year. According to the data of Table 3.4, the level of demand achieved in the beginning of 90-th, can be achieved in 2006-2007. In case of realization of the program of commissioning of new capacities and achieving 12-14% growth of total installed capacities, the expected level of the system coefficient will make about 48% in 2007. Basing on this value and predetermining the character of its change on the analogy with other countries of Central East region, it is possible to evaluate the possible values of installed capacities (see Table 6.12).

In the above-mentioned Caspian Oil and Gas review, the development of hydro-energy is not foreseen until 2020, which accordingly intends the continuous generation - 1.5TWh/year. Such assumption is in contradiction with the program of the development of hydro-energy sector (Hydropower and Dams, World Atlas-1999), according to which increase of the installed capacity of HPPs up to 1.88GW and annual generation up to 5.62TWh is foreseen. This option seems more realistic, as it meets the requirements of diversification, which is an important aspect of planning even for such rich in hydrogen raw materials country as Azerbaijan is.

Table 6.11 Forecasts for electricity demand and generation

Description	2000	2005	2010	2015	2020	2025	2030
Average annual growth of demand, %	0.6 0.6	5.53 5.43	6.5 5.8	6.8 5.8	6.2 5.4	4.0 3.0	3.0 2.5
Electricity demand, TWh/year	17.5 17.5	22.9 22.8	31.4 30.2	43.7 40.0	59.1 52.0	71.9 60.2	83.3 68.0
Electricity intensity of GDP, %	100 100	93.5 97.4	91.1 101.1	92.7 104.8	93.6 106.8	89.3 101.7	85.1 99.1
Electricity consumption per capita, kWh/per capita	2215 2215	2675 2662	3568 3432	4750 4348	6093 5360	7118 5960	7858 6415

In basic option, the forecasts for the development of installed capacities of HPPs are based on this concept. In pessimistic scenario, the realization of the program of hydro-energy development is delayed for 8-10 years. The most intensive development of thermal energy is foreseen in 2010-2020, when annual growth of capacities will make 6.5%.

For the realization of long term plan of power sector development of Azerbaijan, 1.8 billion US$ will be required only up to 2010 - 300mln.US$, of which is foreseen for the development of electric grids.

The development of generating capacities is foreseen as follows:

Hydro Power Plants. As the hydro-potential of the country economically advisable for the development is insignificant, the further development of hydro energy of Azerbaijan intends, in general, construction of small HPPs with 300 MW total capacity and some comparatively big plants with total capacity 720 MW.

The construction of Enikend HPP with 112,5 MW capacity and 320GWh annual generation had to be finished by 1999. This multiple purpose project of the cascade on the middle flow of Kura River had comparatively low price - $1100/kW.

The realization of all hydro-energy projects will allow to increase the total installed capacity of HPP up to 1880 MW and annual generation up to 5,62 TWh, i.e. about 80% of economically sound hydro potential will be developed. This is a very high indicator.

Table 6.12. Forecasts of installed capacities

Description	2005	2007	2010	2015	2020	2025	2030
Use factor of installed capacities, %	47.0 46.5	48.0 48.0	51.0 50.0	53.0 52.0	55.0 53.5	56.5 54.5	58.0 56.0
Installed capacities, GW	5.40 5.40	5.67 5.67	7.03 6.89	9.41 8.78	12.26 11.10	14.52 12.60	16.40 13.86
Including HPP, MW	985 985	1185 985	1519 1175	1666 1365	1880 1519	1920 1666	1940 1880
Including TPP, MW	4415 4415	4485 4485	5511 5715	7744 7415	10380 9581	12600 10934	14460 11980

Thermal energy. The main potential of thermal energy of Azerbaijan is concentrated on Azerbaijan TPP. Construction of new unit N10 with 300MW capacity is underway here. Thus, the installed capacity of this power plant will increase up to 2700MW. In the short term perspective of 5-10 years, this relatively new TPP can provide generation volumes enough not only to satisfy the internal market, but also to ensure the electricity export.

At the same time, the negotiations are carried on with the Siemens, General Electric, ABB, EDF and other western companies for the development of thermal energy of Azerbaijan on the basis of high-performance steam-gas turbines (CC) of 500MW capacity. These new plants on the basis of CC obviously are called for the replacement of already worked-out resources of

TPPs of Azerbaijan. Meanwhile, it should be taken into account that the installation of CC, of such big unit capacities will require the modification of the gas supply system of electricity sector of the country, as the processing cycle of these devices requires high enough pressure levels of natural gas before combustion chambers of gas turbine devices – 30-35 bar.

Thus, in the process of development of electricity sector of Azerbaijan, special stress is laid on the development of thermal energy. This is contributed not only by sufficient reserves of local organic fuel (gas, oil), but also by the closeness of countries, which are rich in energy resources, such as Russia, Iran, Kazakhstan, Uzbekistan, and Turkmenistan. Meanwhile, the development of electricity sector of Azerbaijan will depend in many respects on the external investments.

Construction of wind- and solar-energy parks is foreseen in the region of Apsheron peninsula.

As already mentioned, the electricity transport grid together with inter one are enough developed and oriented to solve the problems of regional importance. Thus, the main purpose of interconnections is the import of peak and export of base capacities to bordering countries.

The transit of electricity through Georgia to Turkey is considered as one of the main export directions. It is conducted by Georgia-Azerbaijan main-line (OHL 500kV). For the establishment of high-capacity transit, an important sector is missing – interconnection of Georgia with Turkey with 500/400kV voltage level. In case of establishment of such connection, wide technical opportunities for the export of electricity to Turkey, other countries of Middle East can be created for Azerbaijan.

Other possible export direction is the transit through Georgia to Russia. However, this perspective seems somewhat obscure due to the rehabilitation of the construction of Rostov NPP. Moreover, Azerbaijan has, and, even despite the commissioning of enough maneuverable CCs, will have sharp deficiency of peak capacities, which are imported from Dagestan by 330kV interconnection Yashma-Derbent (Caspian Coast) at the expense of availability of high-head Chirkeysk HPP in Dagestan. The possibility of peak capacity import from Georgia is not excluded. Oversaturation of power system of Azerbaijan by low manoeuvrable thermal capacities can adversely affect the competitiveness in the regional market of electricity and capacity. In other words, upon the organization of intensive energy exchange within the energy environment of the region, Azerbaijan will be induced to import expensive peak electricity at the expense of export of cheap base electricity. Another way is the construction of highly manoeuvrable but expensive gas turbine facilities, which, according to International experience, in principle, is an undesirable, but induced measure. However, the necessity of the development of gas turbine capacities in many respects depends on the cultural standard of consumer services in the internal market.

6.2.3. Present situation and perspectives of development of power sector of Georgia

Geographical situation. The Republic of Georgia is situated in the territory of Caucasus, on the East Coast of Black Sea. Georgia borders with Russia in the North, with Turkey in Southwest, with Armenia and Azerbaijan in Southeast. The capital of Georgia is Tbilisi. The territory equals to 69700 km^2. Northern part of the territory has mountainous topography; the most part of the country has flat nature with slight subtropical climate.

Population of Georgia makes 5.7 mln. (1998). The biggest cities of Georgia are Tbilisi – 1200000, Kutaisi - 238000, Rustavi– 137000.

Economy. One of the economically high-developed countries of the former USSR, Georgia suffered severe economic crisis in 90-th. Thus, compared with 1990, in 1995 GDP volume dropped for more than 5 times and made 2.01 billion US$ against 11.97 billion US$. The crisis was overcome in 1996 (GDP-US$3,54 billion.). Expected economic growth rate for the foreseeable period makes 5-10%.

Energy resources. Georgia does not possess natural reserves of oil and gas for industrial usage. Oil, natural gas, high quality coal, electricity and other kinds of energy resources are imported.

Local energy resources are hydro resources, coal and wood. There is a significant potential of renewable sources (hydro-, wind-, helio-, biomass) and energy savings.

Average long term precipitation – 1390 mm, total annual volume of atmospheric precipitation – 96.9 billion m^3. The total theoretical hydro-potential is evaluated to be 139 TWh (or 15.9 GW), 68 TWh of which, or about 49%, is considered as technically available. Economically available potential, according to the evaluations of 1998, makes 32 TWh/year. At present, 13.8% of technically available potential is developed. Installed capacity of HPPs makes 2730 MW, the nominal annual energy generation – 9.41 TWh. Actual generation during the last years didn't exceed 75% of nominal generation, because of water deficiency in the region and deterioration of hydropower and electric-technical equipment.

Electricity generation. Installed capacity of power plants of Georgia (according to the data of 1998) – 4820 MW. Share of TPPs is 43.3% (natural gas and mazut) or 2090 MW (at present only 800 MW in TPP is available), share of HPPs is 56,6% or 2730 MW. Own generation of electricity during 1990-1997 periods was reduced from 14.24 TWh up to 7.17 TWh, i.e. about two times. Import of energy from neighbouring countries made 4.48 TWh in 1990, export – 1.29 TWh. In 1997, these indicators made 653 and 462 GWh respectively. In 1997, the own generation was slightly stabilized: upon 7994 mln. kWh of annual consumption, the electricity generation made 8080 mln. KWh; under capacity use factor of about 40%, only 21% of electricity, or 1698 mln. KWh, was generated by TPPs, and 79%, or 6390 mln. KWh, by HPPs, with the balance (-) 94 mln. kWh.

Electricity transportation. The transportation network of Georgia is established on 500/330/220/110 kV voltage for transportation of electricity from basic plants to big electricity distribution centres. Main 500 kV networks are able to ensure direct transit of capacity practically through the whole territory of the country. Losses in the network make 28%.

Main interconnections of Georgia are as shown in Table 6.13.

Privatized electricity distribution companies with voltage level equal to 35/10/6kV distribute the electricity.

Table 6.13. Interconnections of Georgia

Name of IC	Voltage kV	Length km	Carrying capacity MW	Note
Inguri – Central (Russia)	500		1000	Import
Batumi – Khopa (Turkey)	220		300*	Export
TbHPP – Alaverdi (Armenia)	220	65.3	300*	Import
Ksani – AzHPP (Azerbaijan)	500		1000	
TbHPP – Akstafa (Azerbaijan)	330		400*	Import

Forecasts for the development of Georgian energy sector. Following volumes of electricity generation are expected in Georgia:

4.6 billion US$ are required for the realization of long term plan for the development of electricity sector of Georgia only by 2010.

	Moderate scenario			Basic scenario			Optimistic scenario		
	GDP growth	**Compared to energy**	**TWh**	**GDP growth**	**Compared to energy**	**TWh**	**GDP growth**	**Compared to energy**	**TWh**
By 2010	3.0	1.60	14.4	4.5	1.50	17.3	6.0	1.40	20.0
By 2020	2.5	1.40	20.0	3.0	1.30	25.4	4.0	1.25	32.5
By 2030	2.0	1.20	25.3	2.5	1.20	34.0	3.0	1.15	45.5

The development of generating capacities is expected as follows:

Hydro Power Plants. Traditionally, electricity sector of Georgia was based on hydro energy. The primary task of Georgia is the rehabilitation of existing hydro capacities. Non-developed technically available hydro potential of the republic makes about 60 billion kWh/year. Development of hydro energy undoubtedly meets the vital requirements of the increase of energy security of Georgia.

It is advisable, from the technical-economic point of view, to develop the hydro potential of Georgia to meet the requirements of a rather developed regional market of electricity and capacity, in which the large and high-paid demand for peak capacities can be formed.

At present, Khudoni HPP-700MW is under construction. Construction of 3 plants (Tvishi-100MW, Namakhvani-210MW and Zoneti-90MW) on the river Rioni is foreseen by the development plan. Besides, construction of several hydro accumulating stations with 1100 MW total capacity in turbine regime is foreseen. Construction of 5 new small HPPs with 12 MW total installed capacities is foreseen.

Thermal energy. General potential of thermal energy of Georgia is concentrated at Tbilisi TPP (HPP). Construction of new unit N10 with 300MW capacity is foreseen here.

Taking into account the availability of coal deposits (450-700 mln. t) in Georgia, construction of TPP on the basis of modern energy technologies firing coal would be a good option. Low calorie content of these reserves and the necessity of import of large volumes of lime can be serious obstacles for the realization of this project.

Construction of 334MW TPP on the basis of CC is planned in the East of Georgia (it is notable, that the construction of NPP with 4000 MW capacity was foreseen in this area in the beginning of 80-th).

Construction of three wind parks with capacities: 150 MW, 50 MW and 15MW respectively, are also foreseen. Rather detailed energy saving program was developed.

In case of achievement of high systematic indicators of economic growth (up to 10%/year GDP), inadequacy of energy equipment of the country will require, already at the end of coming decade, not only to increase in a radical way the volumes of electricity import, but also to develop new capacities at the maximum pace. Taking into account the world-wide experience, such problem can be solved only upon the development of thermal capacities on Steam gas facilities, which, in its turn, will require the establishment of new gas supply system for these plants.

As it was already mentioned, the transportation network together with interconnections is developed enough and is oriented at solution of regional problem. Thus, the main purpose of interconnections is the import of basic capacities and export of peak capacities to the neighboring countries. Nevertheless, further development of interconnections of Georgia is foreseen as follows:

- Establishment of 500 kV energy connection Azerbaijan (AzTPP) – Georgia (Ksani SS) – Turkey (SS Kars) by means of construction of Akhltskhe SS 500/400 kV on the border with Turkey and overhead line 500kV from the latter to Ksani SS.
- Construction of parallel OHL 500kV (through the territory of Abkhazia) to the existing interconnection Georgia-Russia OHL 500kV Caucasioni, because of extremely low safety indicators of the latter (OHL500kV Caucasioni is located in the area of maximum storm activity on the whole territory of CIS, crosses the mountainous region with complex topography of Caucasian ridge in the altitudes up to 4000m).

These projects confirm the image of Georgia as transit country, but contribute poorly to the increase of the level of energy security. Even upon present condition of redundancy of installed capacities, power system of Georgia is unable to ensure stabile contractual obligations on delivery of electricity to Turkey. Thus, the contract, concluded for the delivery of Georgian electricity to Turkey in 2000, was signed for volumes two times less than the previous-years (1998-1999) volumes of delivery of electricity from Russia, Azerbaijan and Armenia (in the last case, the generation of electricity with imported fuel was practiced). Thus, Georgia can realize the export responsibilities only at the expense of infringement of interests of own consumers, who, as is known, have already suffered from large-scale shadings.

6.2.4. Present situation and perspectives of development of power sector of Iran

Geographical situation. Islamic Republic of Iran is situated in the territory of Middle East, between Persian Bay and Caspian Sea. Iran has borders with Azerbaijan and Armenia in the Northwest, with Turkmenistan and Afghanistan in the Northeast, with Turkey in the West, with Iraq in the Southwest. The capital of Iran is Teheran City. The territory is 1648 ths. km^2.

Population. During the last 30 years, the population of Iran increased 2,5-3 times and made 66.500.000 in 1999. The average growth of population during 1980-1999 made 2.8%, but during the last three years, it reduced almost two times. The biggest cities are: Teheran, Meshed, Isfakhan, Tabriz, Shiraz, Akhvez, Kermanshakh and Gom.

Economy of Iran is based on the export of oil. GDP Energy intensity during 1980-1996 increased for 2.0% p.a. on average. During 1980-1996 period, the annual GDP growth made 3.28%, during 1980-1985 - 2.2%. In 1999, the GDP volume made 200 billion US$ upon 2.5% growth. The expected rate of economic growth for 2000 is 4.2%, and for the future 3-5%.

Energy resources. Iran has very rich natural reserves of oil (9.2% of world reliable reserves) and gas (14.2% of world reserves). Iran possesses also hydro, coal and other resources. Total theoretical hydro-resources of the country make 176 TWh/year. Almost all technically available potential is evaluated as economically feasible – 50 TWh/year, or more than 28% of theoretical. Almost 60% of this potential is concentrated along Karun River (840 km). There is a significant potential of renewable sources (hydro-, wind-, solar-, biomass) and energy savings.

Electricity generation. During 1980-1985, the installed capacity of all power plants increased from 5.30GW up to 27.80GW, i.e. for 10.7% p.a. in average. Later on, the rates of introduction of new capacities decreased slightly and made 6.6% during 1985-1996, which, nevertheless, is a rather high indicator.

According to 1996 data, the total installed capacity of power plants of the Ministry of Energy of IRI made 22.42GW (or 82.8% of the total capacity installed in the country). The share of HPPs is 8.8%, steam turbine TPP`s – 51.8%, gas turbine TPP`s – 16.8%, CC – 19.7% and diesel plants – 2.9%. Besides, there are also other plants, including other generators (not for common use) with 4.66 GW total installed capacity. Average loading factor during the last 4-5 years is on the stable level – about 60%. Average efficiency factor of thermal power plants makes 32.5 – 32.8%. Overwhelming majority of TPP`s operates using natural gas (about 85%).

In the structure of generation, steam turbine TPP`s have high specific weight, i.e. almost 73% of generation of power plants of common use, CC – 11.5% and HPP`s – 8.6%. During the last years, the total losses in grids and own needs of power plants made 23 – 25%. Thus, high level of capacity use of steam-turbine facilities and low level of steam-gas facilities is characteristic.

Upon 16.8% share of installed capacity, gas turbine facilities generate 6.57% electricity (peak plants).

About 10% of capacities operate for isolated grids. Peak loads take place in summer months and make 16.000MW. Electricity generation in 1998 made 95,3 billion kWh, only 8% of which on the basis of HPP. However, per capita electricity consumption makes only 1203kWh/year (USA-12711 kWh/year, Russia 5805 kWh/year, Turkey 1280 kWh/year). In the structure of consumption, the following sectors dominate: residential sector - 34%, and industry – 33%. In 1996, the electricity export made 384GWh or about 0.55% of total consumption.

Electricity transportation. According to 1996 data, electricity transportation grid of Iran (Figure 6.4) is established on 400 (7407km), 230(14943km), 132 (11102km), 66 and 63 (24036km) kV voltage levels and is foreseen for electricity transportation from base power plants to big electricity distribution centres. Transformer capacities: 400kV – 15.330MVA, 230kV – 29552MVA, 132kV – 9491MVA, 66 & 63kV - 23687MVA. Losses in the grids make 13,1%. 16 regional energy companies (including one in the capital) execute electricity distribution. After Teheran, Guylan, Khuzestan and Mazandaran are characterised with high density of consumption.

Interconnections of Iran are developed extremely poorly and, in general, are out of operation. The share of electricity exchange with neighbouring countries is only 0,4% of total generation. Generally, electricity exchange (annual 0 saldo) is carried on with Armenia by 220kV interconnection. Negotiations are carried on concerning the import of electricity from Armenia and Turkmenistan. In the closely future, electricity import from Azerbaijan is improbable.

The electricity is distributed on up to 34,5kV levels. The total length of OHL of distribution networks is 35 thousand km, transformer capacities - 38.203MVA.

Forecasts on development of Iranian electricity sector. During 1980–1995, the average annual energy consumption growth was 5.3%, and electricity consumption growth - 9.3%, corresponded to the average annual GDP growth at 3.16%. Thus, the mentioned period is characterized with rapid growth of electricity consumption. Subsequently, the relative GDP electricity intensity decreased to 1.8% in terms of each percent of GDP growth. The long term forecast of generation and electricity consumption is possible only upon optional approach of forecasts of the economic development and population growth.

The elaborations of European Commission (XVII Directorate General) on development of energy sector of Middle East region up to 2020 are taken as a basis. It is assumed that the social-economic development of IRI complies with the rates of development of this region.

Three development scenarios are considered:

- Pessimistic scenario – contradictions and instability in the global system resist the integration process. Geopolitical coalitions are established and the effectiveness of free competition is reduced, GDP growth is reduced to 2.2-2.3% by 2030 (In Europe the DGP growth is reduced up to 1.2% during 2000-2030).
- Base scenario – the policy of "traditional wisdom" is continued, in long term the economic growth is slightly slowed down, unemployment is reduced, some inflation is available, GDP growth is reduced up to 2.5-2.6% p.a. by 2030 (in Europe GDP growth is reduced from 2.9 up to 1.6% during 2000-2030)
- Optimistic scenario – global economic integration takes place, the International institutions are restructured for better understanding and solution of common economic problems, the International policy is aimed at improvement of ecological situation and economic growth, GDP growth makes 2.6-2.3% p.a. in Europe, in the region - 4.3-2.8%

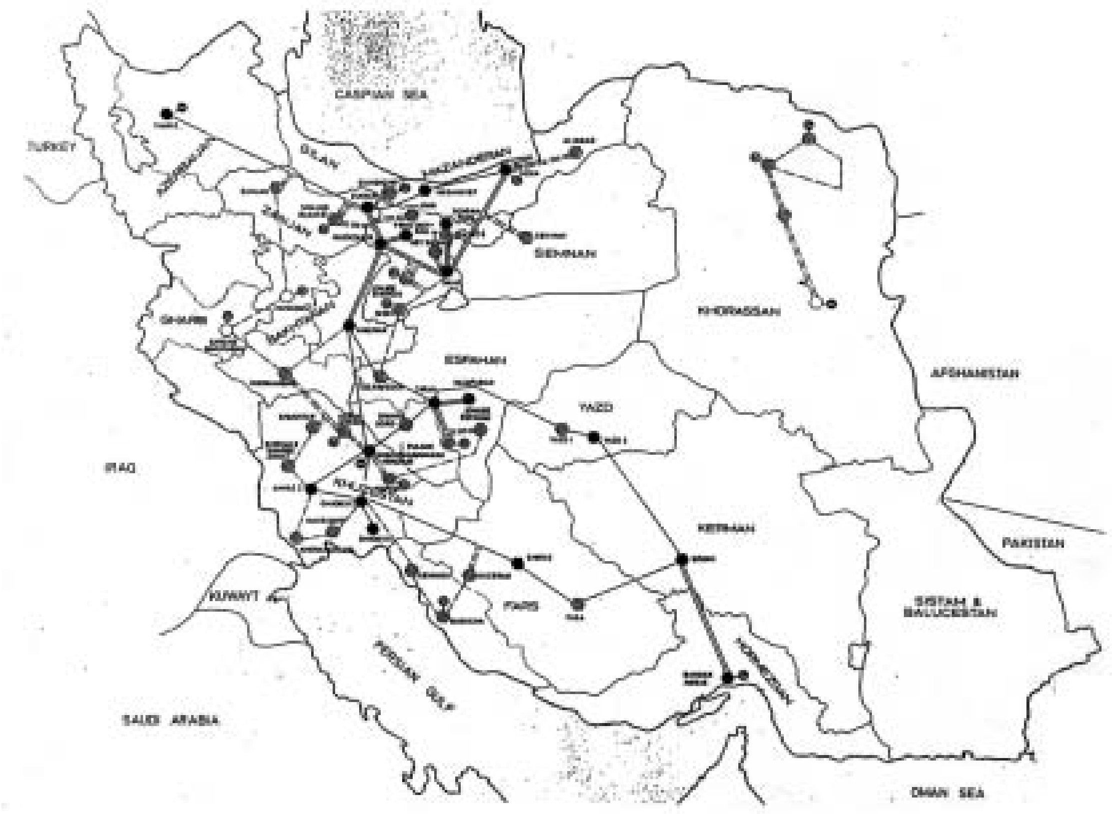

Figure 6.4. Electricity transportation grid of Iran

Upon calculations of electricity consumption, it is assumed that during 2000-2010 the growth of energy consumption will make 1.4-1.5% per each percent of GDP growth. In subsequent decades this indicator will reduce to 1.2-1.1%, that is, as previously, still significantly higher than Middle European indicator of 90-th – 0.7-0.8%. Forecast calculations of these scenarios are given in table 6.14. There are no publications available concerning the volumes of investments to electricity sector of Iran.

The following development of generation capacities is assumed:

Hydropower plants. Despite the significant reserves of gas and oil, the Ministry of Energy of IRI plans intensive use of hydro resources. General idea about the plans for the near 10-20 years is shown in table 6.15.

It is foreseen to develop 80% of technically available potential, i.e. to reach the level of 40 TWh/year up to 2020. 13 GW of total capacity (annual generation 22.2 TWh) is under construction, and it is planned on river Karun. Up to 2020, about 330 MW have to be added to currently operative small HPPs with 20 MW of total installed capacity.

Thermal energy. It is foreseen to construct a number of new TPPs, i.e. Mitsubishi constructs 2000MW Sharid Rai TPP in Khazvin, 1290MW CC in Rashta, doubling the capacities up to 1500MW in TPP in Tabriz. Thermal energy sector develops rapidly that requires the attraction of foreign investments in billions of amounts during the nearest years. Iran received proposals on investments to be done in this sector both in form of direct credits and under BOT model - build - operate - transfer (of property). Contracts under BOT are for 15-20 years time period. The negotiations are carried on in this respect with foreign energy companies on decomplecting and recomplecting of capacities in Bandar Abbas, Shaid Radzhani, Alborts, Ramin and Kerman power plants. Thus, the main stress in the process of the development of electricity sector of Iran is given to the development of thermal energy contributed by rich reserves of deposits of organic fuel (gas, oil).

Table 6.14. Forecasts of electricity consumption growth of Iran

Description	**2000**	**2010**	**2020**	**2030**	**2010/ 2000, %**	**2020/ 2000, %**	**2030/ 2000, %**
Population, mln.	67.6	79.2	91.9	105.6	1.6	1.5	1.4
GDP, billion US$-99							
pessimistic scenario	207.8	291.0	382.5	475.5	3.43	2.78	2.22
basic scenario	208.4	312.5	430.0	552.5	4.14	3.26	2.54
optimistic scenario	208.9	318.0	446.0	585.5	4.30	3.44	2.76
Electricity consumption, TWh							
pessimistic scenario	101.0	166.8	237.8	302.0	5.15	3.61	2.44
basic scenario	102.0	179.0	262.0	345.0	5.80	3.92	2.79
optimistic scenario	103.0	184.0	275.0	370.0	6.02	4.12	3.00

Nuclear energy. In visible prospect Iran plans to generate up to 20% of electricity in NPP, thus releasing significant volumes of oil and natural gas for export. Iran declared about its intention to develop nuclear technologies only in peaceful purposes. In February 1998, the State Department of USA sharply condemned the nuclear program of Iran, mentioning its fuel resources sufficient for the development of energy sector of the country, capital intensity of NPP and possible perspectives of use of the latter for the creation of nuclear weapon.

Construction of Iranian NPP began in 1974 in Bushera (South-West of Iran). In 1979, due to the Islamic revolution, the construction was interrupted, being 80% completed.

Table 6.15. Forecasts of Iranian HPP`s development

Implementation phase	HPP capacity, MW	Capacity of water reservoir, billion m^3	Note
HPPs under construction	10040	23.691	
Including:			
Karun-1 (expansion)	1000	3.005	Start in 2001.
Karun-3	3000	2.750	Commissioning 2001
Karun-4	1000	2.190	Commissioning 2005
Seymarekh	640	3.216	Commissioning 2007
Research works for new HPPs	5198	-	
2.1. Karun-5	1000		On rivers Zalaki, Kashkan, Zab, Karun and others
Elaboration of schemes of new HPPs	2215	10.951	
3.1. Bakhtiyari	1000	2.800	On rivers Khersan, Bakhtiyari, Karun and others
Total:	**17453**	**34.642**	

6.3. Study Results

6.3.1. Turkey

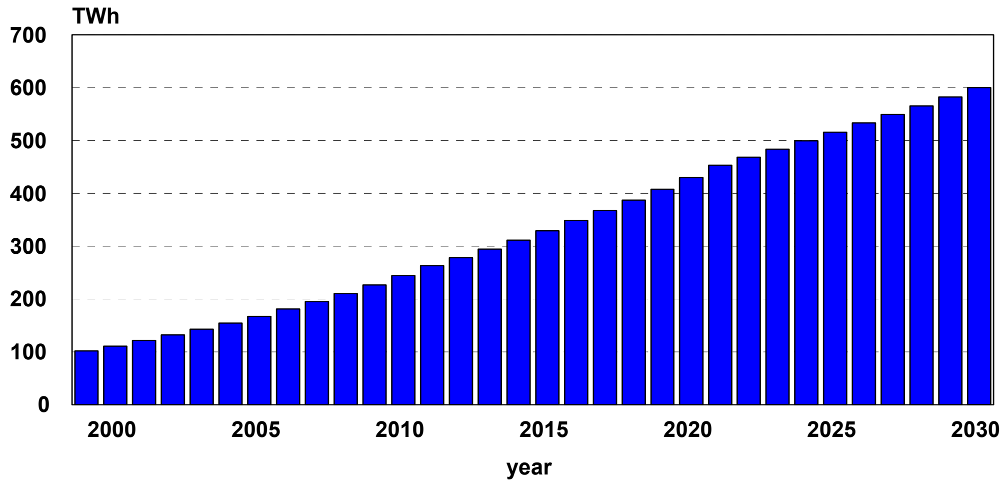

Figure 6.5. Electricity demand

In January 1995, despite the sharp reaction of USA, the contract for the sum of 780mln. US$ was concluded with Russia, that continued the construction of 1000 MW nuclear unit. Despite the uncertain terms of commissioning, the construction of second phase of NPP is foreseen after the first unit commissioning. Iran foresees intensive development of nuclear energy in co-operation with Russia and China. Thus, the intensive negotiations are conducted with Russia on the construction of additional 3-4 units with similar capacities.

Intensive development of thermal and nuclear energy, construction of HPPs on dams leads to the problem of capacities regulation in daily regime. Commissioning of significant volumes of regulating capacities should be expected on gas turbine facilities, which operate, in general, firing natural gas and, partially, diesel oil. Intensive increase of generating capacities requires adequate development of electricity transportation grid in common with interconnections, as well as distribution grids. Sound location of the country, as well as the specificity of annual load curve - increase of electricity consumption in summer period - is an important argument for mutually beneficial electricity exchange of Iran with Northern bordering countries. As mentioned above, such precedent already exists - Iran exports electricity to Armenia in wintertime and imports in summer time. Such regimes are also extremely beneficial for Armenia, which has certain problems with the operation of NPP in summer period.
Further development of Iran - Armenia - Georgia - Russia electrical transit with 400/500kV voltage level can significantly affect the increase of efficiency and management of energy systems of the region. Besides seasonal regulation, Iran can gain the access to cheap peak capacities of Georgia. Important direction of the development of interconnections of Iran United Power System (UPS) is Middle Asia. There, as well as in Caucasian direction, Iran may gain significant benefits from parallel operation, in particular taking into consideration peak capacities of HPPs of Turkmenistan and other countries.

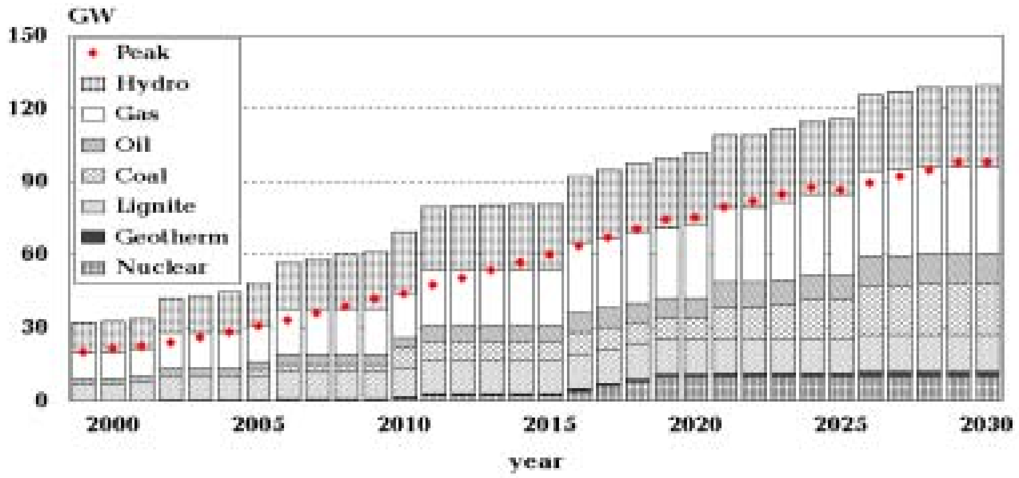

Figure 6.6. Capacity contribution by Plant Type

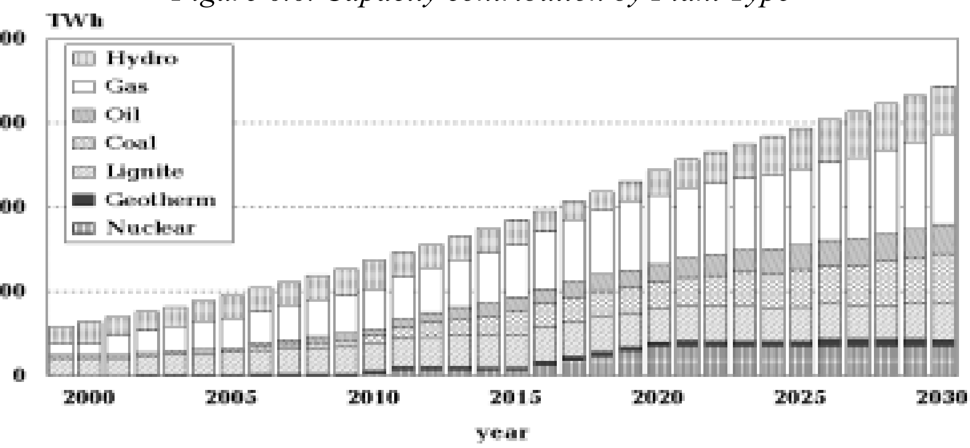

Figure 6.7. Energy contribution by Plant Type

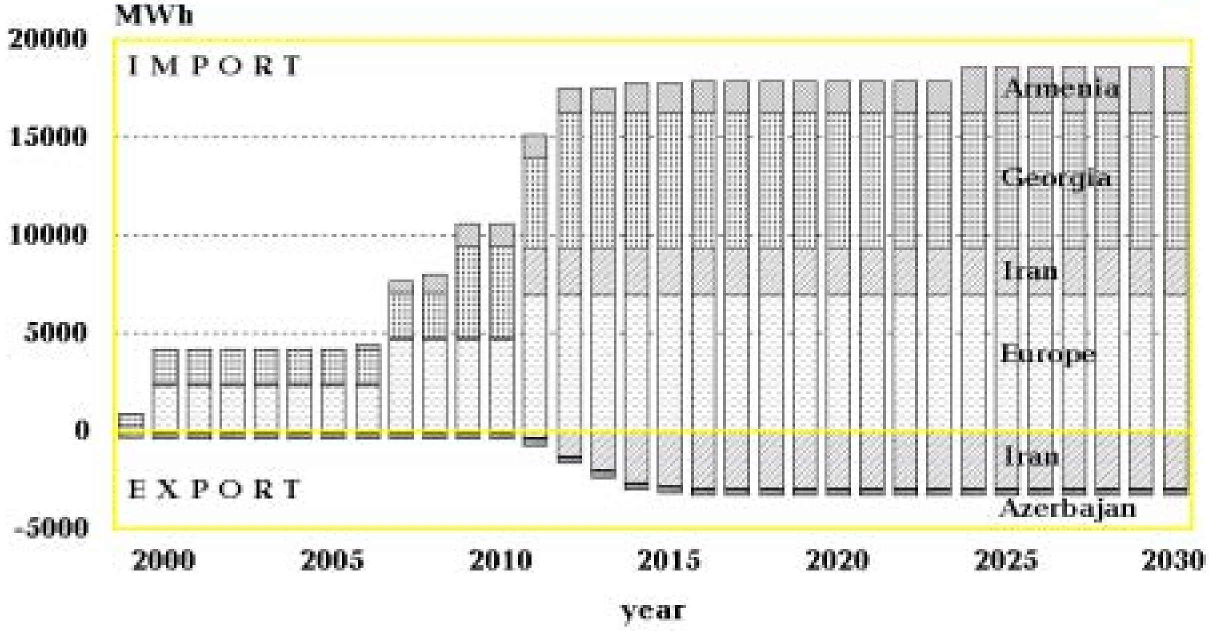

Figure 6.8. Electricity Export - Import Balance

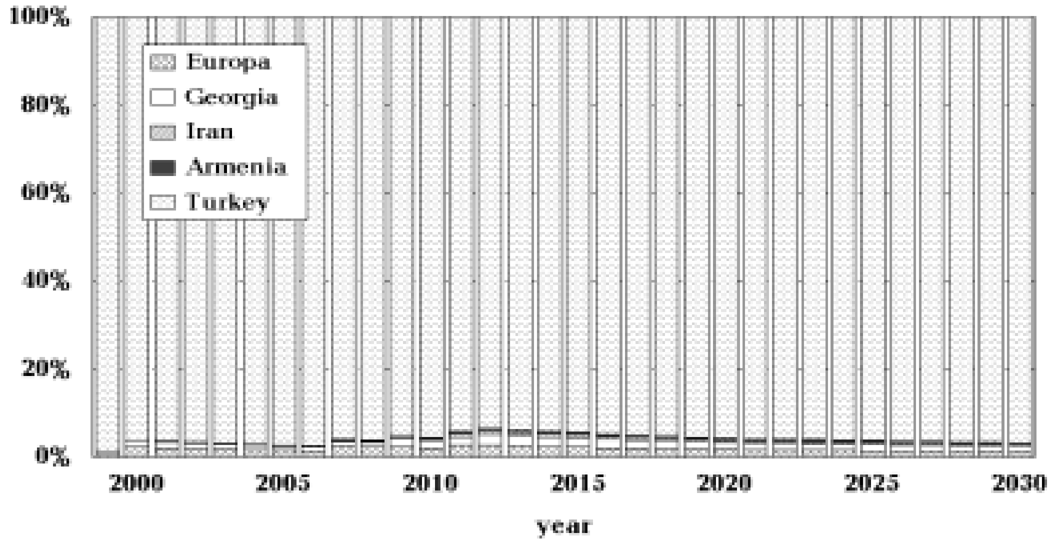

Figure 6.9. Import ratio on electrical market

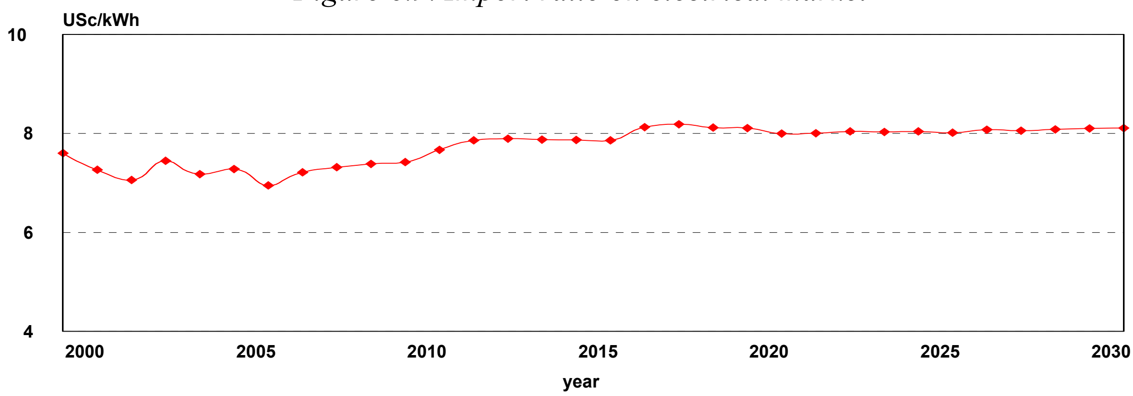

Figure 6.10. Average long term electricity tariff (without External Cost on generation)

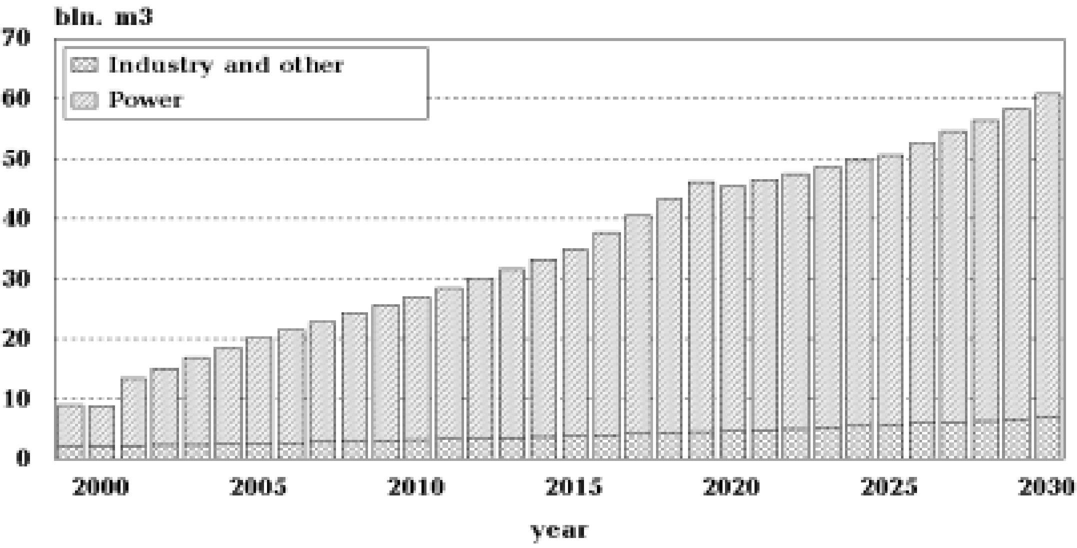

Figure 6.11. Natural Gas Consumption in all Sectors

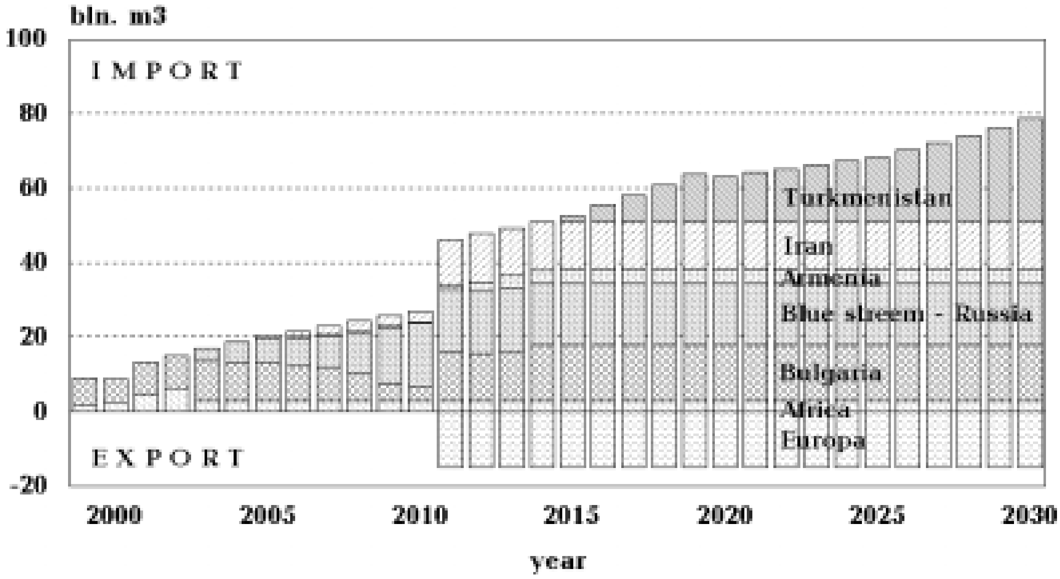

Figure 6.12. Natural gas Re-export - Import Balance

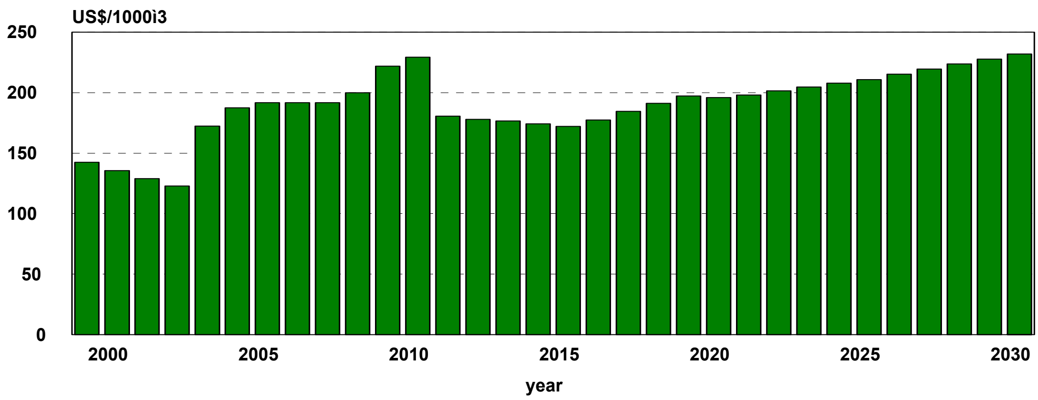

Figure 6.13. Average long term Natural Gas price

6.3.2. Georgia

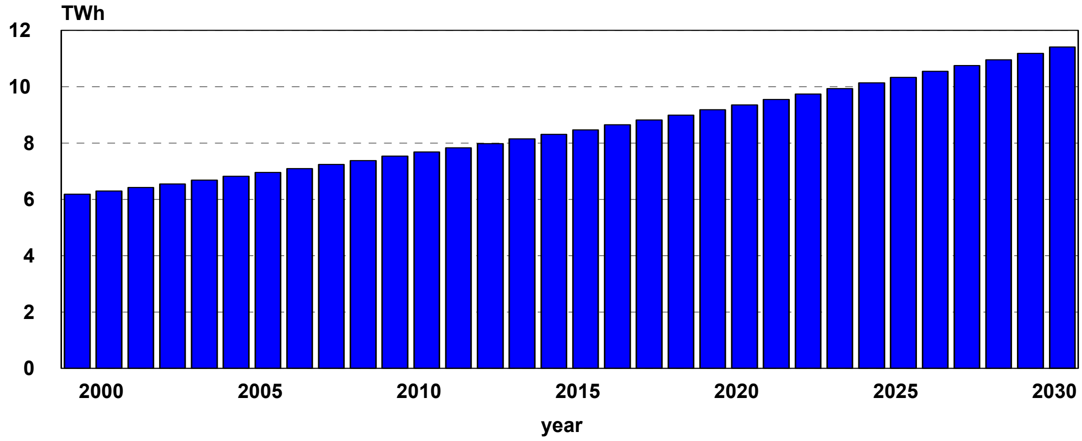

Figure 6.14. Electricity demand

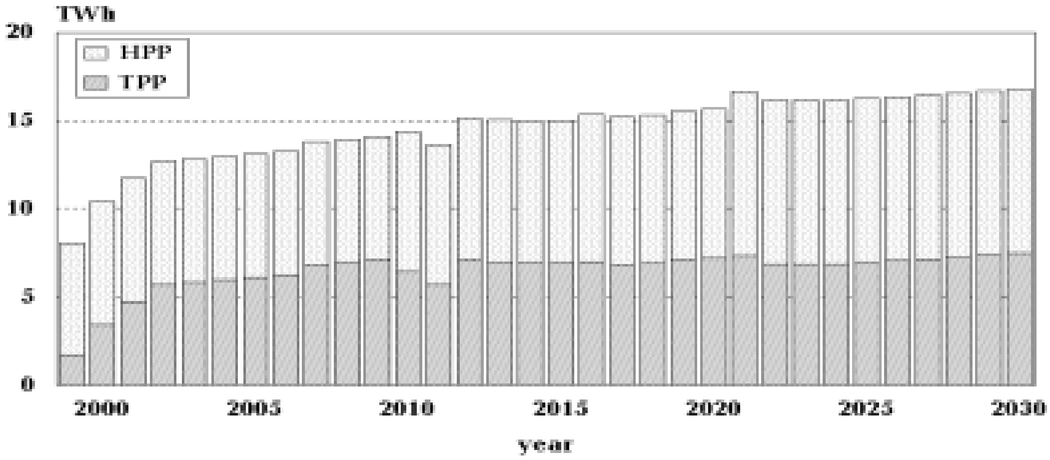

Figure 6.15. Energy contribution by Plant Type

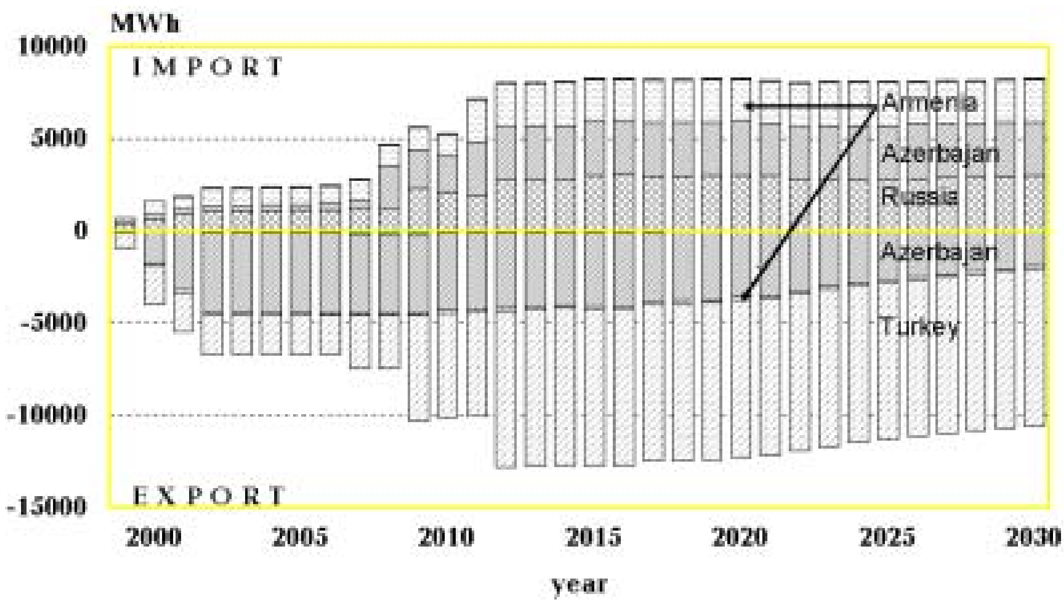

Figure 6.16. Electricity Export - Import Balance

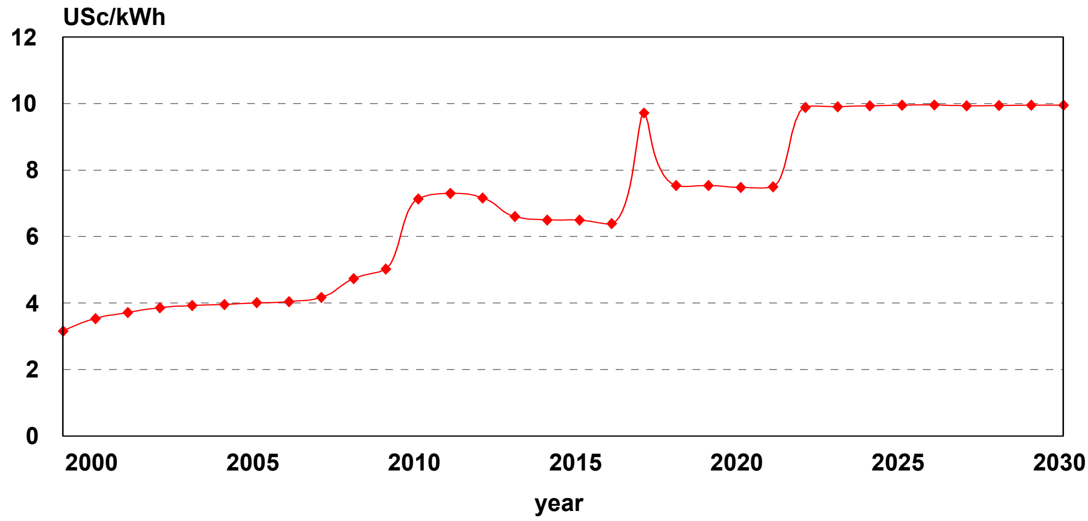

Figure 6.17. Average long term electricity tariff (without External Cost on generation)

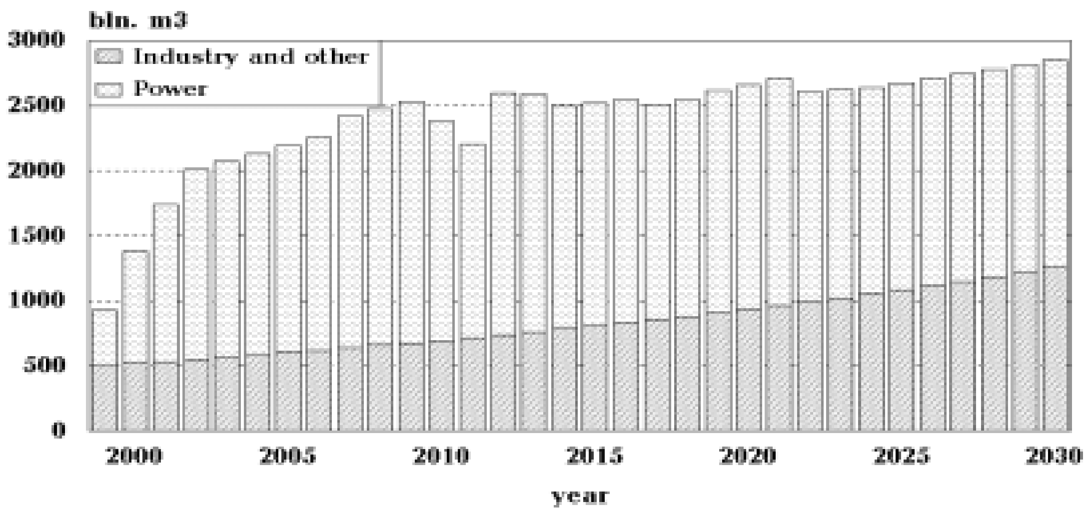

Figure 6.18. Natural Gas Consumption in all Sectors

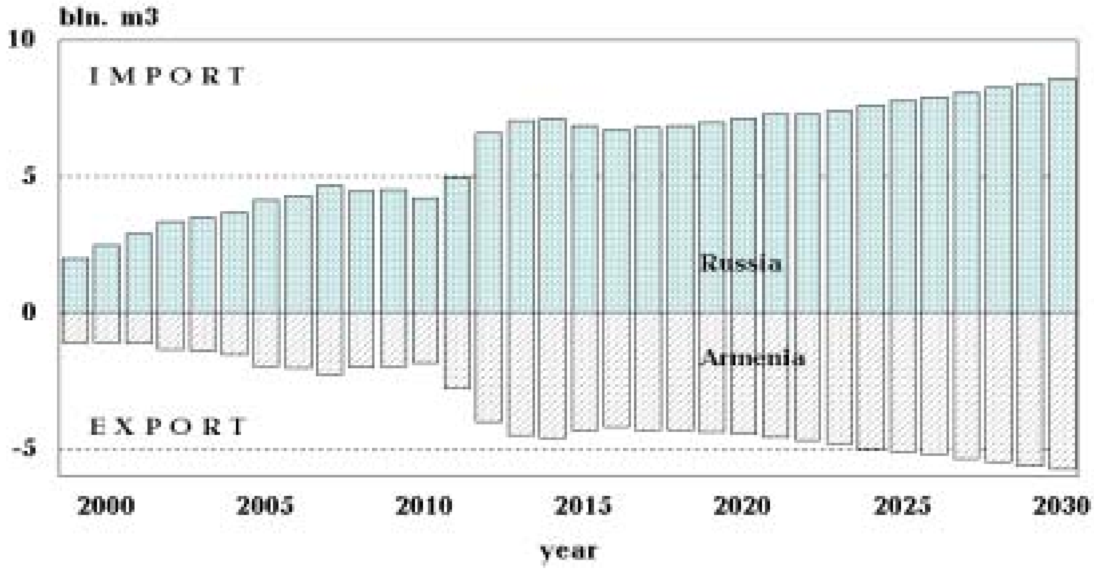

Figure 6.19. Natural gas Re-export - Import Balance

6.3.3. Azerbaijan

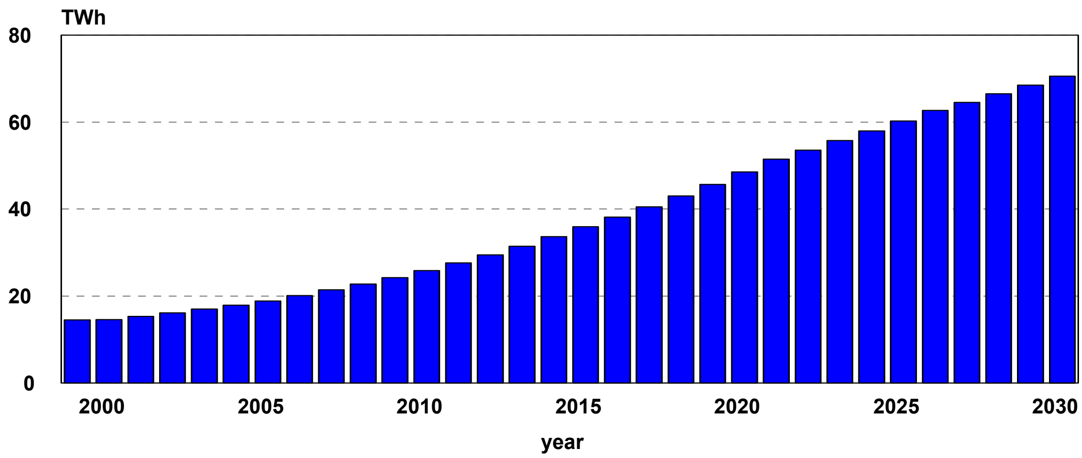

Figure 6.20. Electricity demand

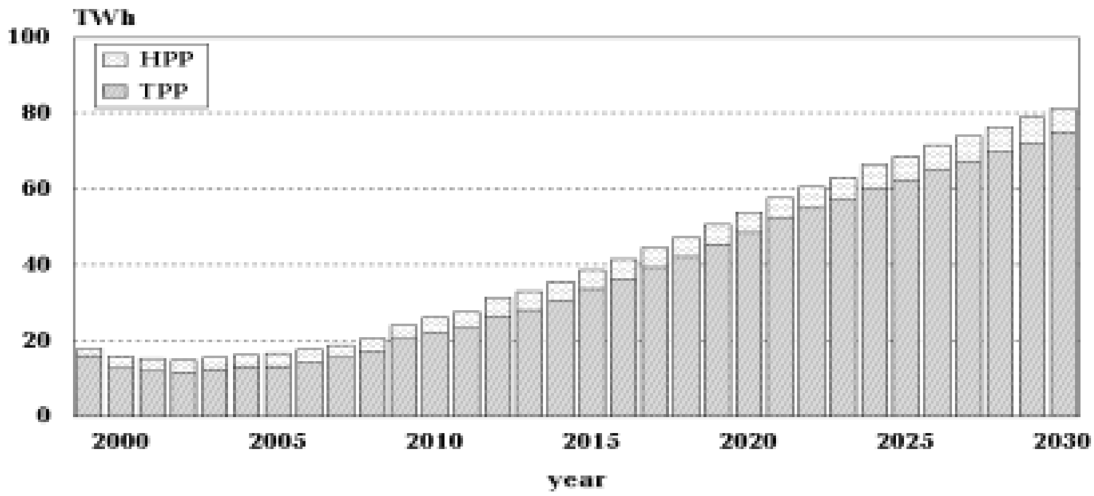

Figure 6.21. Energy contribution by Plant Type

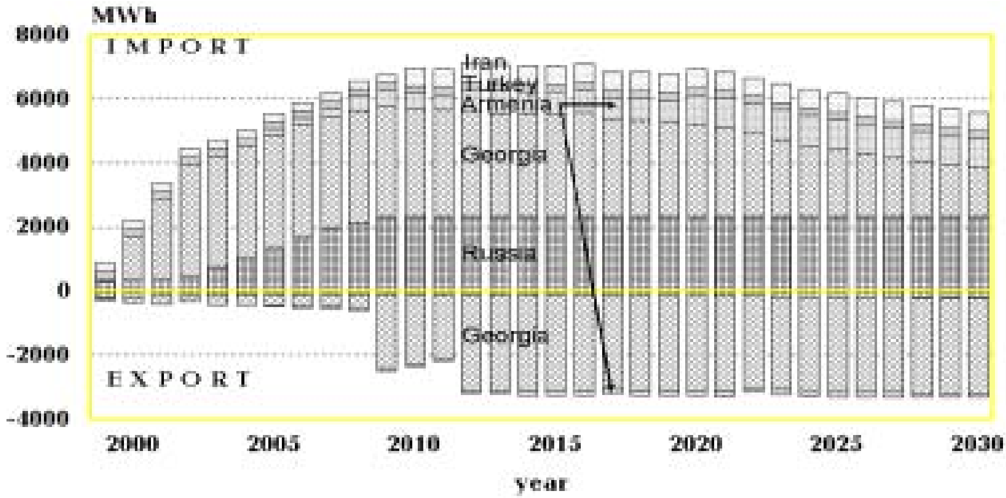

Figure 6.22. Electricity Export - Import Balance

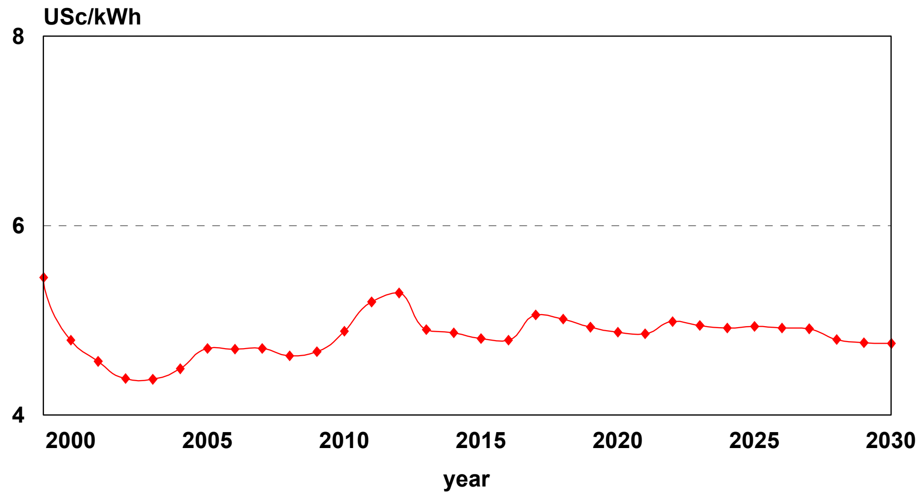

Figure 6.23. Average long term electricity tariff (without External Cost on generation)

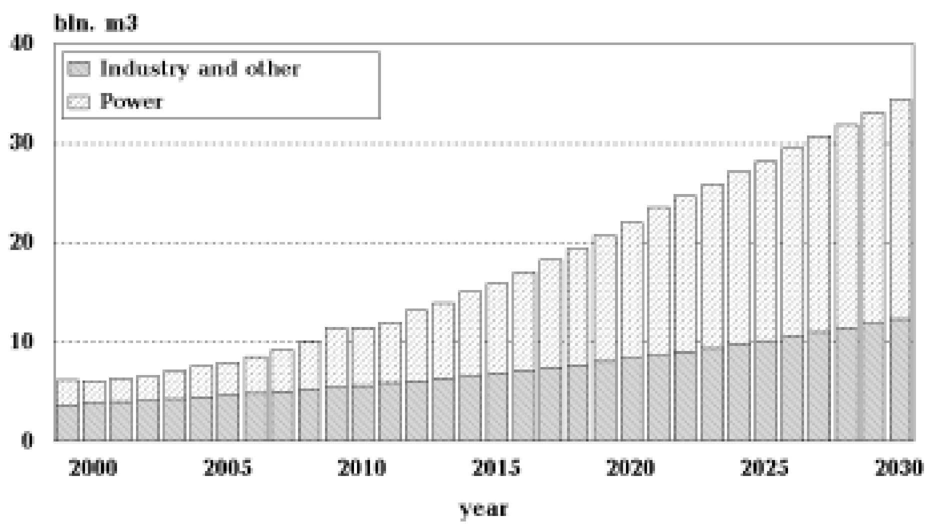

Figure 6.24. Natural Gas Consumption in all Sectors

6.3.4. Iran

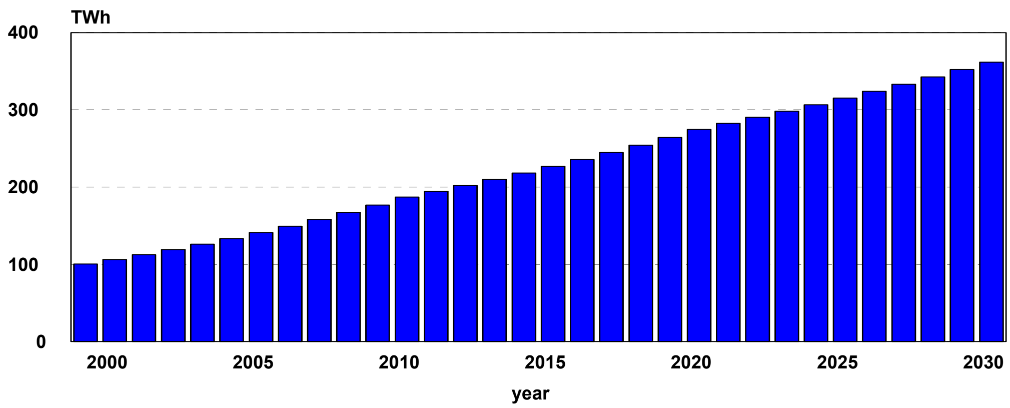

Figure 6.25. Electricity demand

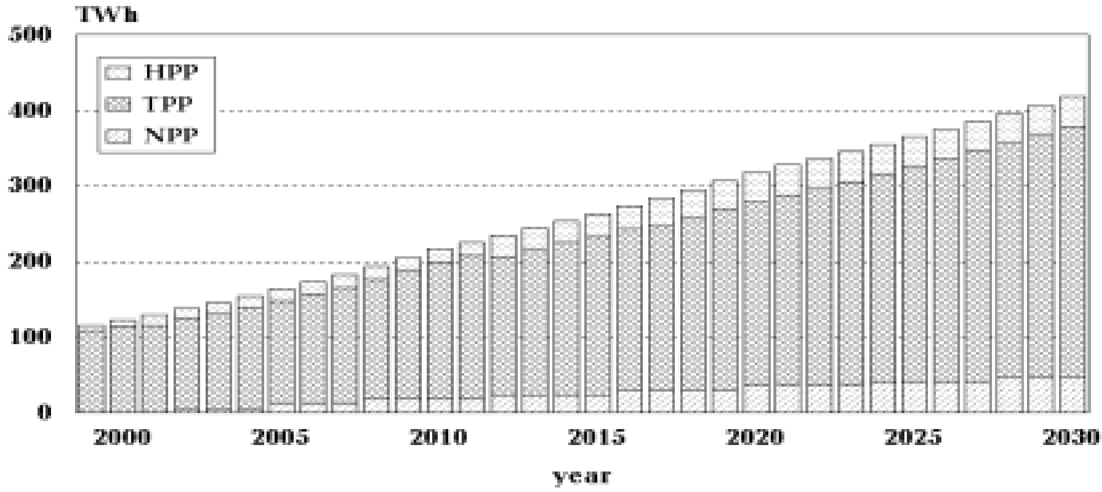

Figure 6.26. Energy contribution by Plant Type

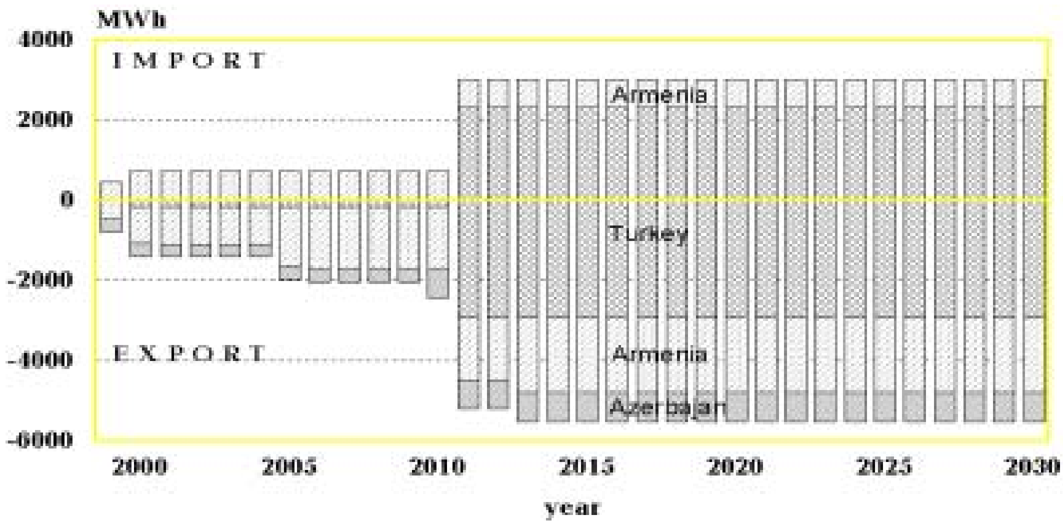

Figure 6.27. Electricity Export - Import Balance

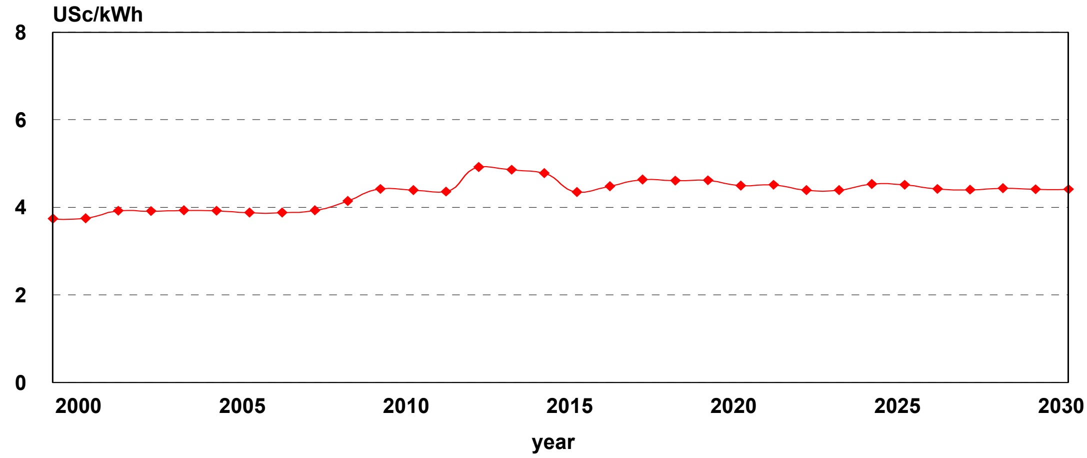

Figure 6.28. Average long term electricity tariff (without External Cost on generation)

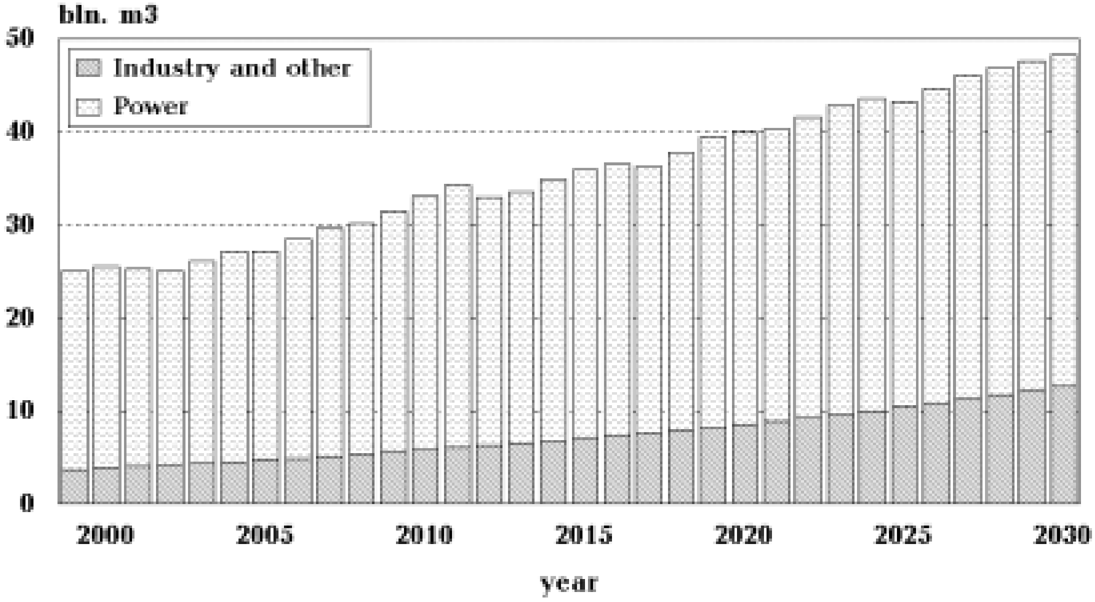

Figure 6.29. Natural Gas Consumption in all Sectors

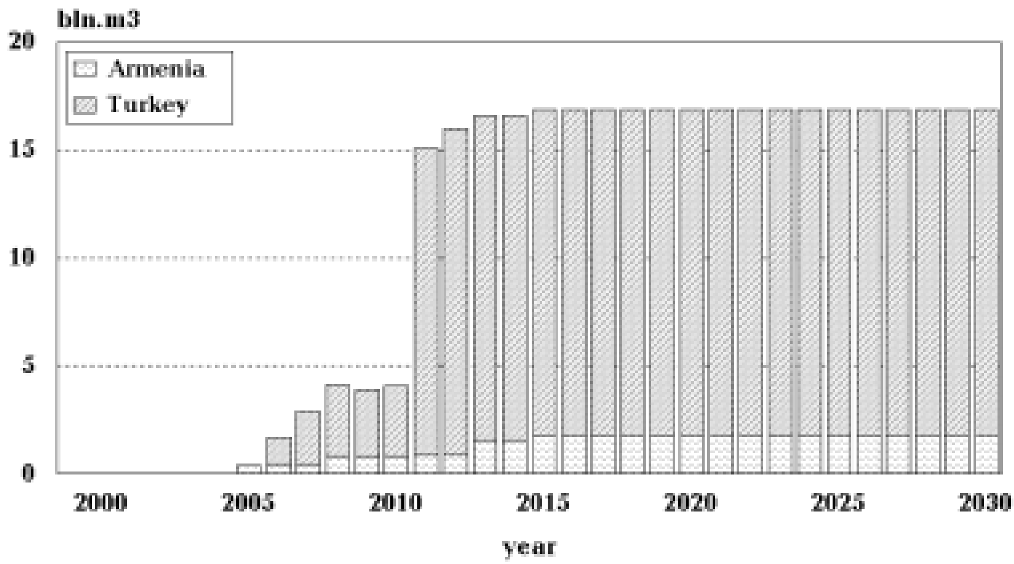

Figure 6.30. Natural gas Export Balance

6.4. Conclusions

Several main conclusions can be done when analyzing the present study results:

1. The BALANCE module of ENPEP is completely applicable for Regional Energy Interconnection Planning Studies.
2. The quality of studies and the results received depend very much on retrospective, and, particularly, perspective database volume.
3. Even if the national power systems in the region are adequately developed in order to meet energy security requirements, the power exchange between the Countries will be significant in the future.
4. The electricity tariffs in most of the countries, where the sustainable development is maintained, will be stable.
5. The integration processes of power systems can be more attractive and profitable for small countries.

7 ELECTRICITY GENERATION SYSTEM EXPANSION ANALYSIS

7.1. Introduction

Chapter 5 presents the data on electricity demand in Armenia till 2020 for the two scenarios under review in this study. In order to meet these levels of electricity demand, optimal expansion plan for the power generating system have been determined using the WASP IV model (ENPEP-Package).

When comparing the level of electricity demand in Armenia in the near future with the level of electricity generation before 1999, it should be noticed that the existing power plants are able to cover the demand forecasted for both scenarios only by the certain point of the study, but it would be necessary to perform rehabilitation works for some units. These works would extend the operation of thermal units beyond their design life or improve the current performance of some other units.

The key feature of Armenian electric power system is the existence of a quite important installed capacity of cogeneration units. At present, the opportunity of concluding the cogeneration units is being analyzed; taking into account the remaining investments needed to rehabilitate the heat supply and define the amount of thermal energy that should be supplied by each plant. Since the WASP program cannot analyze thermal energy supply, the cogeneration plants were modelled exogenously so that they might cover the thermal energy demand.

Another issue that influenced the optimization process of the power plants expansion program is the fact that the one thermal power plant of Armenia is under construction in Hrazdan. This plant had been initially designed with 4 units of 300 MW each, with different stages of completion and various percentage of remaining investments costs. Due to the money shortage, a decision was made to complete the first unit only.

7.2. Basic Input Data

The Ministry of Energy of Armenia provided statistical data on the operation of existing power plants. These data have been analyzed and processed according to the WASP-IV model requirements. Some other information, which was not available from the Ministry of Energy, was extracted from the study "Least Cost Capacity Development" made by Lahmeyer International, and also from other technical papers. The data were adjusted to local conditions.

7.2.1. Planning Period

The time horizon considered in the WASP study for the generation expansion analysis was taken as 2000-2020. It includes several years when decisions on investments for short and medium term may need to be made.

In addition, the study also considered a (2020-2025) to account the plants operation during several years of post-planning period (intensive in capital cost requirements). Within this post-planning period, the electricity demand will be kept constant on the level of 2020 so that neither retirements nor additions of units will be necessary.

7.2.2. Load Forecasts

Based on these electricity requirements, on the consumption share of each subsector and its load characteristics, the peak load value, as well as its average annual growth rate was established for the Reference and Low scenarios by means of MAED module. The external demand was taking into account for both scenarios. The load duration curves resulting from Electric Module of MAED for the four periods of the reference years have not been used. In the analyses of WASP model, since the several cogeneration plants with limited output of electricity were under the modelling, it was necessary to define these limitations for 12 periods of each plant.

7.2.3. Existing and Committed Generating Units

7.2.3.1. Existing System

The installed capacity of the existing thermal power plants in Armenia amounts to 1,756 MW. After completion of the new Hrazdan 5 unit, which is currently under construction, 300 MW of additional thermal capacity will be added.

The Armenian nuclear power plant at Medzamor has a capacity of 880 MW, installed in two 440 MW units. In 1989, the plant operation was halted as a precautionary measure, several months after the December 1988 earthquake, although the station was undamaged. With Russian assistance, it has been possible to rehabilitate and re-commission 440 MW Unit 2.

The total capacity of the hydropower plants in Armenia is 988 MW. This is the only indigenous source of energy.

The Armenian power system in 1999 had a total installed capacity of almost 3,144 MW, not accounting for the closed down Medzamor Unit 1.

Thermal Plants

The thermal power plants are located in Yerevan, Hrazdan and Vanadzor. All thermal power plants with the capacity equal to or less than 100 MW(e)[1] - and these are the oldest - are designed as combined heat- and power plants, having steam extractions for industrial purposes and/or district heat (DH) supply.

The industrial steam demand has sharply decreased in the past years, mainly because Armenian large industrial complexes have difficulty to import (and pay for) raw materials and/or have lost their markets. They have stopped or greatly reduced production. Keeping the remaining export industry alive is one of the priorities of the Government. Usually, one 50 MW CHP plant is in operation in Yerevan to produce the required amounts of industrial heat. Also in Hrazdan, where the industries cater mainly for the domestic market, industrial heat is supplied only if there is a demand. One 50 MW unit is sufficient for this purposes.

No heat is currently supplied to the industries in Vanadzor, because of demand nonattendance. But all units of Vanadzor TPP were rehabilitated due to the recovery of a chemical complex in Vanadzor.

Depending on the ability to pay, the DH demand in Yerevan, Hrazdan and Vanadzor can be met to only a limited extent.

The CHP units are the smallest, oldest and most inefficient thermal units. Their electrical capacity is not of need for the system, and they keep operating only because of the increase of expected heat requirements.

Considering the surplus of the existing thermal generation capacity and the uncertain development of the power demand, it would be useful to envisage the mothballing of unneeded larger and newer plant e.g. the 200 MW units at Hrazdan power station. The main advantages of this option are the ability to respond very quickly on any unexpectedly rapid growth of the demand and the possibility to defer all expenditures for plant conversion or rehabilitation until decommissioning is required.

The following tables (7.1 and 7.2) give an overview of the thermal capacity and technical data of existing thermal plants.

Table 7.1. Overview of Existing Thermal Plants

Thermal Plant	Units (MW)	Code Name	Total Capacity (MW)	Year of Commissioning	Remarks
Yerevan TPP Section 1 Section 2	 3 x 50 2 x 150	 TYR1 TYR2	450 150 300	 1963-1965 1966-1968	Cooling towers, generally condensing type turbines - Section 1 is common header type and provides district and industrial heat. - Unit 3 is back pressure type - Section 2 consists of block units.
Hrazdan TPP Section 1 Section 2	 2 x 50 2 x 100 3 x 200 1 x 210	 TH11 TH12 THR2 THR2	1110 100 200 600 210	 1966-1967 1969 1971-1974 1974	- Dry cooling towers, condensing type turbines - Section 1 is common header type and provides district and industrial heat. - Section 2 consists of block units.
Vanadzor TPP	 2 x 12 1 x 47	 TVN1 TVN4	71 24 47	 1964-1965 1976	- Cooling towers, backpressure type turbines, common header type. - Provides district heat. - Provides industrial heat.
All Plants			1631		- All plants equipped for dual firing (natural gas and mazut)

Table 7.2. Technical Characteristics of Existing Thermal Plants

	Name	Code	Num.of Units	Capacity (MW)		Heat Rate kcal/kWh)		Fuel Type	FOR %	Scheduled Mainten.
				Min	Max	Base Load	Average Incremental			
1	Yerevan TPP S-1	TYR1	3	40	45	1324	1313	Natural Gas	13.0	62
2	Yerevan TPP S-2	TYR2	2	60	143	3637	2519	Natural Gas	20.0	30
3	Hrazdan TPP S-1	TH11	2	30	45	1563	1205	Natural Gas	20.0	30
4	Hrazdan TPP S-1	TH12	2	60	90	1531	1205	Natural Gas	11.0	62
5	Hrazdan TPP S-2	THR2	4	80	175	3046	2047	Natural Gas	11.0	62
6	Hrazdan TPP S-2	THR5	1	120	270	2692	1830	Natural Gas	7.5	42
7	Vanadzor TPP S-1	TVN1	1	4.4	11	1674	1154	Natural Gas	10.5	51
8	Vanadzor TPP S-1	TVN4	1	22	44	1674	1154	Natural Gas	10.5	51
9	Armenian NPP	NPP1	1	300	380	2837	2837	Nuclear Fuel	7.0	45

Nuclear Plant

The Armenian nuclear power plant was shut down in March 1989 following the 1988 earthquake. The NPP is a Soviet build VVER-440 model in two units (2 x 440 MW), commissioned in 1976 and 1980. This model (not the Chernobyl design) does not meet international safety standards. At their July 1992 conference, the G-7 First Ministers organization recommended a phase-out as soon as practical of all unsafe nuclear plants of Soviet design including the VVER-440/230, the model in Armenia. The government, however, had no choice but to consider the nuclear option as a matter of necessity to gain some degree of energy independence, and recommissioning Medzamor unit 2 took place in November 1995 after a general rehabilitation and earthquake conditioning. Retirement of Medzamor is scheduled for late 2015.

Hydroelectric Power Plants

The only indigenous electricity source in Armenia seems to be hydropower, which, therefore, is of strategic importance. Without the hydropower, the energy blockade of the past few years would have resulted in a complete collapse of the electricity supply in the country.

Figure 7.1 illustrates the water balance of Lake Sevan, which feeds the Sevan-Hrazdan Cascade. Lake Sevan is Armenia's most important strategic energy buffer. This was clearly demonstrated by the role played by the Sevan-Hrazdan Cascade in covering the country's essential electricity needs in 1992-1995.

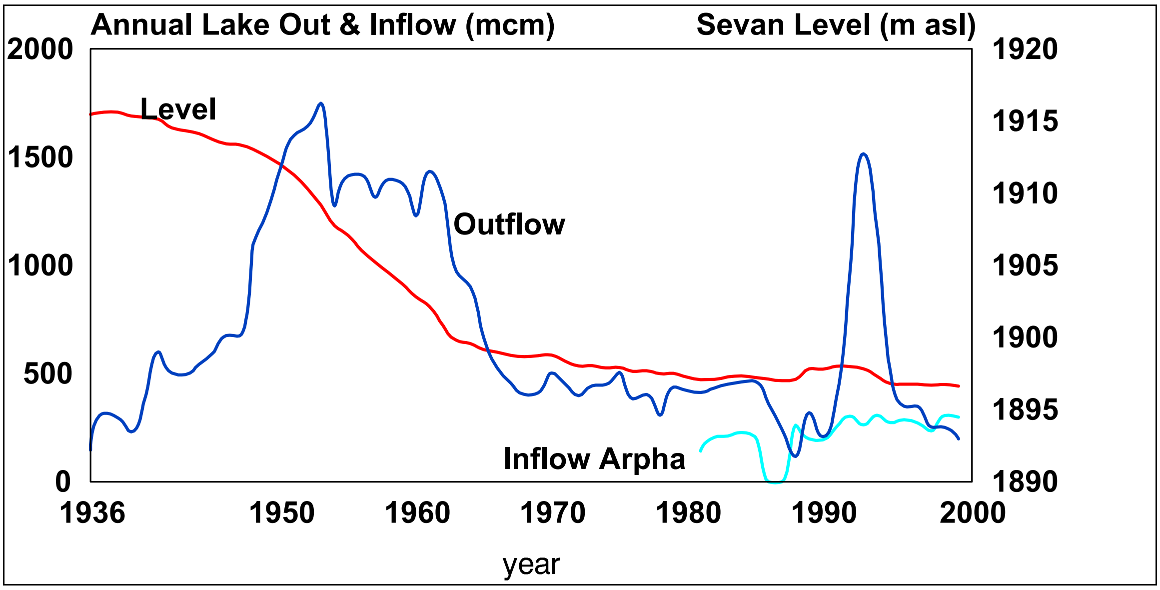

Figure 7.1. Water Balance of Lake Sevan

As soon as sufficient thermal and/or nuclear power is available, releases from Lake Sevan should be reduced to increase the lake level by 2 to 3 meters for environmental reasons and to build up a stock of water which can be exploited, should crisis situations again lead to an energy blockade. Therefore, in our power system simulations, for the first 12 years of operation (1999-2010) only releases required for irrigation can be considered, reducing the output of the Sevan-Hrazdan Cascade to almost half. The overview of Hydropower Plants is given in table 7.3.

Note: The power and generation data shown here are statistical averages and may not reflect operating conditions in future.

Table 7.3. Overview of Hydropower Plants

Hydropower Plant	Comm. Year	Capacity (MW)	Head (m)	Energy (GWh/a)	Plant Factor	Remarks
Sevan-Hrazdan Cascade						Energy outputs shown are such that level of Lake Sevan will not drop further. Output of Sevan-Hrazdan Cascade will be reduced to 360-487 GWh/a for next 12 years to increase level of Lake Sevan by 2.5 m.
Sevan	1949	34	60	50	0.17	
Hrazdan	1959	79	136	136	0.20	
Argel	1953	211	285	378	0.21	
Arzni	1956	67	118	138	0.24	
Kanaker	1936	96	169	151	0.18	
Yerevan 1	1961	40	84	83	0.24	
Yerevan 3	1956	5	37	5	0.12	
Subtotal		532		941		
Vorotan Cascade						
Spandaryan	1984	75	295	154	0.24	
Shamb	1977	168	268	272	0.19	
Tatev	1970	157	569	580	0.42	
Subtotal		390		1006		
Dzorages	1930	25	105	85	0.39	
Small Hydro	n.a.	31		55	0.20	
Total Hydro in Armenia		988		2087	0.24	

The code names and capacities of existing HPPs, which have been used in FIXSYS module of WASP-IV model, are given in table 7.4.

It could well be that due to the increase in electricity prices; there will be a shift from pumped irrigation toward gravity irrigation, which would lead to higher irrigation releases from Lake Sevan. A study is required to find the best compromise for the use and storage of Lake Sevan water, considering technical, economic, social and strategic aspects.

7.2.3.2. International Interconnections

Armenia's HV transmission system was designed as part of the Trans-Caucasian Network, with the following connections to neighbouring countries (Table 7.5).

Georgia (with one 500 kV and one 220 kV transmission lines) and Azerbaijan (with one 330 kV transmission line) were linked to the Soviet Interconnected System. The Trans-Caucasian interconnected network was operated as an integrated system with central control from Tbilisi.

Currently a 220 kV transmission line to Iran is under operation. In the absence of any other active interconnection, this line is of considerable importance for stability and frequency control of the Armenian power system.

Table 7.4. Existing Hydropower Plants

	N	Hydro Plant	Code Name	MW
Hydro A	1	Sevan	SEVA	34.0
	2	Hrazdan	HRAZ	81.6
	3	Argel	ARGE	224.0
	4	Arzni	ARZN	70.6
	5	Kanaker	KANA	102.4
	6	Yerevan 1	YER1	44.0
	7	Yerevan 3	YER3	5.0
Hydro B	8	Tatev	TATE	157.2
	9	Shamb	SHAM	171.0
	10	Spandaryan	SPAN	76.0
	11	Her-Her	HerH	1.3
	12	Dzorages	DZOR	25.0
	13	Small	SMAL	31.0

Table 7.5. Regional HV Transmission Interconnections

Connected Countries	Type of Connection	Present Status
Armenia – Azerbaijan	330 kV single circuit transmission line (107 km); max. capacity: 420 MW(*)	not in operation
Armenia – Georgia	220 kV single circuit transmission line (65 km); max. capacity: 250 MW	under operation
Armenia – Turkey	220 kV single circuit transmission line (65 km); max. capacity: 300 MW	not in operation
Armenia – Iran	220 kV single circuit transmission line (65 km); max. capacity: 200 MW	under operation

(*) Capacity constrained by number of transformers in Atarbekian substation.

It can be viewed from Table 7.5 that Armenia has a good developed international interconnection system. It’s very important from the point of view of electricity export increasing in the near future.

7.3. Candidate Plants for Future Electric System Expansion

For future development of the electric power generating system, both thermal power plants (including nuclear) and hydro power plants, were considered as candidates for expansion.

Since Armenia has no domestic energy resources, except for hydro, the fuel needed for the expansion candidates and existing thermal plants, is supposed to be supplied as imported fuel.

According to that, the estimated energy and peak demands for the planning period are given in Table 7.6.

Table 7.6. Estimated Peak Demand and Energy

Peak Demand (MW)						
Year	Low			Reference		
	Local	Export	Total	Local	Export	Total
1999	1044	27	1071	1044	27	1071
2005	1263	78	1341	1341	105	1446
2010	1565	241	1805	1805	180	1985
2015	1805	359	2164	2164	365	2529
2020	2007	461	2468	2468	505	2973
Energy (GWh)						
Year	Low			Reference		
	Local	Export	Total	Local	Export	Total
1999	5155	241	5396	5155	241	5396
2005	6490	265	6755	6755	529	7284
2010	8357	734	9091	9091	906	9997
2015	9562	1338	10900	10900	1839	12739
2020	10482	1949	12431	12431	2543	14974

7.3.1. Thermal Supply Options

The present situation in Armenia is characterized by an overcapacity of thermal power plants, uncertain development of the industrial power/heat demand and a still existing but largely uncovered district heat demand.

7.3.1.1. New CHP Plant Options

Combined cycle power plant or the installation of topping gas turbines in front of existing boilers will prove to be more economical than steam plant.

Two combined cycle power plants of the cogeneration type with different capacity (167 MW(e)$_l$ + 130 Gcal/h) were assessed for Yerevan TPP and Hrazdan TPP. Both plants have 2 gas turbines and 2 heat recovery steam generators each, ensuring:

- a high plant availability,
- a favourable part load heat rate.

The technical characteristics of both plants are the same; there is only one difference in the shape of distribution of heat production per months.

The results of investigations of candidate plants are summarized as follows (Table 7.7, 7.8).

Table 7.7. Overview of Investigated Thermal Supply Options

Option	Power (MW)	Heat (Gcal/h)	Costs (1999mUS$)	Remarks
CHP Combined Cycle Plant	167	130	117.0	Special arrangement with two GT and two ST units, additional standby/reserve boiler with 50% of total heat output capacity is included in price
Power plant Combined Cycle	300	--	196.4	Standard arrangement with two GT and one ST unit
New Nuclear	640 (2x320)	--	709.0	At Medzamor, partly using existing facilities

Table 7.8. Technical Characteristics of Thermal Candidates

	Code Name	Capacity (MW)		Heat Rate (kcal/kWh)		Fuel Type	FOR (%)	Scheduled Mainten. (days/yr)
		Min	Max	Base Load	Average Incremental			
1	CHP1	97	165	1146	856	Natural Gas	8.5	40
2	CHP2	97	165	1146	856	Natural Gas	8.5	40
3	CC2	120	267	1982	1378	Natural Gas	9.0	30
4	NNUC	330	600	2837	2837	Nuclear Fuel	7.0	45

In case of breakdown of one gas turbine the remaining CC output is 50% of the full plant capacity, while at the breakdown of one heat recovery steam generator (HRSG) the output amounts to about 83%. Below 50% of the total load one gas turbine is shut down and the other runs at full load. The plant efficiency is almost that of full load operation, only reduced by the declining steam turbine efficiency, which in this case operates at half load.

The high exhaust gas temperatures of modern gas turbines generally make supplementary firing in the HRSGs uneconomical. It may be applied, however, when a particularly high steam turbine output is to be achieved.

The high-pressure (HP) steam parameters have to be chosen in accordance with the available vacuum of the steam turbine and the maximum admissible wetness of the low-pressure (LP) exhaust steam of 11-12%. In order to attain the low stack temperatures of about 100°C at the HRSG outlet in case of natural gas or distillate oil firing, a LP steam cycle is accommodated near the cold end of the HRSG feeding its steam into the LP turbine.

Feed-water preheating shall principally be effected by a feed-water-preheating loop in the HRSG, since any steam extracted from the turbine to feed regenerative feed-water pre-heaters would reduce the electrical output of the steam turbine generator.

Cogeneration plants are generally built up of a base load plant (in our case the CC) and peak load boilers operating in the winter season over a restricted period of the year. For the CHPP of 130 Gcal/h, a peak-load steam boiler for the industrial process steam and two hot water peak-load boilers were considered having a total heat capacity of 130 Gcal/h (50 % base load, 50 % peak load).

As to the capital investment cost of the Yerevan CHPP alternative, it was assumed that the gas would be provided at the required pressure and that the transmission to the national grid would be available.

7.3.1.2. New CC Plant Options

Power-only combined cycle plants of 300 MW have been investigated. Contrary to the CHP versions described in section 7.2.4.1.1, there is only one HRSG per plant, as is common practice. The CC's are assumed to be gas-fired, but retrofitting them to allow the use of light fuel oil as a substitute for gas is cheap (less than 0.2 mln.US$).

Dual firing even with heavy fuel oil, is possible, but increases the investment and especially the OMR costs. This has not been considered.

7.3.1.3. New Nuclear Units at Medzamor

Perspective opportunities for small and medium size reactors utilization in Armenian National Grid

The researches show that the use of reactors of commensurable power in Armenian National Grid is economically and ecologically expedient. However, the commensurability of nuclear blocks with operating capacity of whole Power System (in a series of regimes the capacity of NPP can reach 60-70% of operating capacity of the Power System) dictates the necessity for carrying out the special researches of survivability of the power system, in order to analyse the influence of emergency perturbations in the power system on parameters of operation of technological tracts of NPP [107-115].

One of the main characteristics of the Power System operation is the Survivability. The Survivability is understood as ability of a Power System to withstand the inadmissible modifications of operation parameters.

A methodology of calculation of numerical values of survivability with application of Matrix and Boolean algebra and Probability theory was represented in [116]. The content of the method is brought to form some rectangular matrix of the response, reflecting the condition of power system when different affects influents its elements.

One of the most important criteria of survivability is the stability of the Power System under dynamic disturbances. The symptom of the system instability is the unlimited increase of somr part of relative angles of generators, which are oriented towards the arbitrarily chosen sychronously rotating ax.is [117-122].

In Power Systems with the large generation of electricity on NPP, it is necessary to consider the singularities of NPP operation.

According to common principles [123-125], the NPP is considered safe, if during its long operation under all conditions, including emergency, the serious damage of the fuel rods in the reactor core is eliminated, and also the localization of radioactive emission, and appropriate NPP's personnel protection, as well as the protection of the neighboring population and environment from the radiation effect should be ensured.

The emergency perturbations in the Power System can immediately result in origination of such emergency regime of NPP operation, as:

- a regime accompanied with the emergency reduction of coolant flow, as well as of feed and make-up water;
- cut-off of the NPP auxiliaries;

- operation of reactor facility under the unexpected dumping and encreasing of an electrical load, and also during other emergency situation at the power unit, which depend on the work conditions of the Power System.

In this case, the survivability criterion for such kind of Power System should be not only the stability accident- and after-accident conditions, but also the keeping in admissible limits the basic technological parameters of the NPP should be such a criterion.

The reducing of System frequency, as well as of voltage on bus-lines of NPP, calls a diminution of turnovers of drives of NPP auxiliaries and, as a result, reduction of main circulating pumps (MCPs) and Feed-pumps (FP).

When the frequency and voltage in a system are reduced, two factors should be indicated, which can cause the scram of the unit, or the reduction of its power, with the aid of technological protection system. It will aggravate even more the emergency situaiton in the power system:

1. Lowering the coolant flow-rate and, as a result, its temperature increase up to the emergency level on the output of the reactor can cause the activation of the emergency protection system, and the reactor capacity reducing.
2. The decreasing the water level in a steam generator when both the frequency and voltage fall low enough and this condition lasts long, can cause the steam generator emergency proteciton actuation, and reactor scram.

From the above-stated follows, which the important controlled parameters of the NPP are: the coolant flow, feed water flow-rate, steam generator steam pressure, and a temperature difference in the reactor core.

Thus, the criteria of power system survivability from the view of the NPP security assurance are as follows:

1. The dynamic stability.
2. The frequency of the power system.
3. The neutron capacity of the reactor facility.
4. The electrical capacity of the MCP.
5. The steam pressure in the steam generator.
6. The temperature differences in the reactor core.

Thus, the dynamic regime does not influence the survivability of the power system, if during the transient process the values of parameters of any of above-mentioned criteria of survivability do not go out of the admissible limits.

Using the above-mentioned algorithms the Survivability of Armenian Power System was calculated for two scenarios:

1. The isolated regime of operation.
2. Parallel, with the power systems of the neighboring countries, regime of operation.

Researches show that in the first scenario, the Total System Survivability of Armenian National Grid that includes Armenian NPP (400 MW) is 0,952 for winter regimes, and 0,948 for summer regimes of operation.

We have better result in the second scenario, for which the Total System Survivability is 0,960-0,992 depending on the neighboring country's power system connection.

For both scenarios, the introduction of the appropriate tools of anti-accident control allows to reach security of a sufficient level of survivability, as well as reliability and safety of operation of the reactors of such capacity.

The offered algorithms and criterion of survivability allow analyzing the problems of influence of the power system emergency situations on the reactor operation parameters. Such researches allow judging about the perspectives of operation of small and medium size reactors within the Armenian National Power Grid from the view of necessity of the ensuring the reliable and safe operation of such reactors in emergency situations of the power system.

Thus, basing on the analysis, we can conclude that the use of the reactors with capacities more than 500-600 MW in Armenian National Power Grid would be not expedient, taking into account the emergency situations in the power system.

Characteristics and comparative estimations for modern nuclear energy units

Leading companies of the West and Russia continue to seek the new concepts that could allow increasing both the safety level and economic indicators of future NPPs. Even now, the USA, Italy, England and Russia introduce the new generation water-cooled reactors into the market.

The development of new generation reactors is based on the following safety criteria:

- The frequency of accidents related to the reactor core destruction – not more than 10^{-5} reactor/year.
- The frequency of major accidents that may cause the increase of radiation up to 25 bar (or 0,25 J/kg) at the distance of 1 km from NPP site – not more than 10^{-6} reactor/year.

The gist of a concept of new generation reactors is a reactor designed with a specific internal safety. This concept unifies two fundamental features of embodiment that provides the unconditional termination of fission reaction in a core in emergency situations and guaranteed diversion of afterheat without the use of any active system and/or participation of operator. The above-mentioned approach requires the reduction of unit electrical capacity to 640 MW and large-scale utilization of passive security systems.

The following types of reactors are designed on the basis of passive security systems concept: AP-600- produced by American company " Westinghouse", PIUS - designed by Swedish company "ABB Atom", SIR- designed under the direction of British company "Rolls-Royce", MARS- developed by energy faculty of Roman University and other.

A project of NPP with VVER-640 reactor is also developed on the basis of concept of passive and active security systems combination. Project is developed in accordance with Russian Federal program "Pollution-free energy" and based on the experience of construction of Nuclear Power Plants with water-moderated under-pressure reactor (PWR) in Russia and abroad.

PIUS reactor, safety concept

PIUS reactor of PWR type has the orientation toward the maximum use of "passive" security systems. Upon designing the NPPs with such reactors, the problem of assuring the core cooling in emergency situations without dependency on both operability level of active equipment and accuracy of operators under extremely conservative estimations of serious accidents probability can be resolved.

Steam generators are constructed according to the single-pass direct-flow scheme. Circulating pack less pumps with wet stators are installed in a lower parts of a steam generators. Pumps return the coolant to reactor, delivering it to the outlet part of hydraulic route. Hydraulic route of PIUS reactor has an ability of coolant active letting-through from the underground part of the reactor into its vessel filled with borated water, due to which, in emergency situations, the coolant convection through the relief occurs.

In case the coolant temperature at the core outlet rises over the prescribed safety limit (as a result of either non-adequate core cooling or over-increase of its capacity), the increase of a frequency of pumps rotation takes place. If, after that frequency achieves its maximum permissible value, the required reduction of coolant temperature in underground (lifting) part of circulating route doesn't take place, the boron water supply from the tank with its reserve to the core inlet, realized under the pressure of the cold liquid filling the tank, will be reducing.

Such approach gives the unique feature to the PIUS reactor – a guarantee of security irrespective of operation of any protection means.

The PIUS reactor core is composed of standard fuel assemblies for PWR type reactors. However, there is a fundamental distinction in its structure - the boron shim at the expense of the change of absorber concentration and coolant temperature is foreseen instead of absorber rod of control system. It allows using effectively the burnable poison within the nuclear fuel.

Main technical characteristics of the PIUS reactor are presented in Table 7.9.

Table 7.9. Main technical characteristics of PIUS type reactor

Parameter	**Value**
Thermal power, MW	2000
Electrical power upon the STP condenser temperature of cooling water (salt), 14 ^{o}C), MW (el)	640
Nominal flow of heat-carrier through active zone, kg/h	13000
Water temperature at the outlet from active zone, ^{o}C	290
Equivalent diameter of active zone, m	3.76
Diameter of fuel rod, mm	9.5
Vessel size: internal volume, m^3 height, m internal diameter, m wall thickness, m	330044127-10

Adopted principles and technical solutions, ensuring the safety of NPPs with PIUS type reactors, are tested on mathematical model by RIGEL computer software. Analysis of modelling results has allowed to study the consequences of major accidents - gap of total section of primary circuit main pipeline, leakage in main steam line, depressurization in primary circuit system in the result of faulty actuation of safety valves, stoppage of feed water supply etc. It is possible to localize these accidents even without additional security systems and active zone disturbance. It is sufficient if the necessary temperature in reactor vessel with necessary volume of borated water re-serve will be sustained, hermicity of double protective casing of reactor vessel will be preserved and necessary conditions for progression of natural circulation of borated water through active zone will be developed.

It is expected that the capital investments for construction of NPP with PIUS reactors will be lower than the construction of traditional NPP with PWR type reactors. Operation costs, including the costs for technical maintenance and personnel salary, will be lower than for NPP with PWR type reactors, in spite of rather higher price of nuclear fuel.

SIR reactor

SIR belongs to reactors of new generation, and its designing is being done by the consortium of companies, headed by British company "Rolls-Royce". That is a version of single-unit reactor cooled by water under pressure, based on the idea of maximum possible utilization of passive security means. A core, 12 sections of steam generator, and pressurizer are placed within the SIR vessel. Six circulating pumps of primary circuit are installed on the vessel wall. Steam generators are made according to the single-pass direct-flow scheme with in-tube steam generation.

Primary circuit circulating pumps are of packless type with horizontal installation of rotor. The NPP containment vessel, in which the reactor is installed, has a ventilation system, interconnected with water reserve tank, intended to reduce the vessel pressure in emergency situations. Tanks are cooled at the expense of ambient air convection. Main technical characteristics are presented in Table 7.10.

Table 7.10. Main technical characteristics of SIR reactor

Parameter	Value
Thermal power, MW	1000
Electrical power, MW (el)	320
Volume of primary circuit system (including pressurizer), m3	450
Pressure of primary circuit heat carrier, MPa	15,6
Primary circuit heat carrier flow, kg/s	7500
Temperature of heat carrier at the outlet from active zone, ^{0}C	318
Power density of active zone, kW/y	55
Steam pressure, Mpa	5,5
Steam superheating, ^{0}C	44
Heat-exchange surface in steam generator, m^2	1114

Single-unit configuration of a reactor allows reducing the level of radiation dozes taken by the NPP personnel, as well as risking level, connected with the radioactive atmospheric emissions. This feature of SIR simplifies the operations on NPP decommissioning at the expiration of lifetime. Practically the whole equipment of the plant, except the core, reactor vessel and the elements of its internal saturation, after the 30-year time limit, passes into the low-level waste category.

The standard SIR-type reactor has 320MW capacity, but it can be potentially increased up to 400 MW. Reactor can be applied in NPPs, which conform to 320, 640, 1280 MW(e) capacity.

Periodicity of nuclear fuel overloads - 24 months. Specific capital expenses for construction of NPP with the given reactor - up to 1550 US$/kW.

MARS reactor

A project of multi-purpose improved Mars reactor cooled by the water under pressure and intended for both the NPP. Nuclear cogeneration plant has been developed in Italy.

The thermal power is limited by 800MW and its design is based on the utilization of passive security systems. That has predetermined the application of emergency cooling system, which operates on natural circulation of coolant under the provision of adequate heat outlet from the core in any emergency situation.

Distinctive feature of this reactor is its constructive design: all elements of primary circuit system are placed in containment shells, filled by fluid, that has low enthalpy, and it is under such a pressure, that allows the complete relieving of the stress of both the primary circuit equipment and pipe lines. This containment shell is made from reinforced concrete pre-stressed vessels, or from steel elements.

As it was mentioned above, high safety level of this reactor is based on the concept of passive operation principles. In accordance with this, the natural circulation is used for the removal of heat of the residual energy.

High-level risk is usually connected with the high pressure and high internal energy of reactor coolant, because the abruptions of a coolant circuit with subsequent core destruction are possible in such cases. In MARS reactor, the possibility of high-pressure circuit abruptions is ruled out, because the pressure drop between the coolant circuit and its environment is reduced to zero. That is achieved due to the fact that the whole system of primary circuit, including reactor vessel, is placed in the shell, filled by cold water with the same pressure as in the circuit. Even upon the shell damage, the water leakage is insignificant, that ensures the possibility of reliable stoppage and cool down of the reactor, due to the fact that the shell is made from pre-stresses reinforced concrete, and the water, filled in it, is cold. Along with the use of natural circulation upon afterheat outlet, such configuration of reactor system reduces the possibility of dangerous accidents progression.

NPP power unit with VVER-640 reactor

Basic project of NPP with VVER-640 is developed in accordance with the scientific-technical sub-program “Environmentally appropriate energy” (main idea: "Secure nuclear power plant"), included in Russian Federal Target Program "Fuel and Energy".

The main purpose of the given project is the construction of competitive NPP of an average power and enhanced security.

Definition: “New generation NPP”- implies the availability of wide experience of the previous series of NPPs with the Russian VVER-type reactors and foreign NPPs with the reactors of similar design, on the basis of which it has become possible to ensure the compliance with the modern international and Russian safety requirements along with competitiveness with best international models by technical-economic indicators.

The NPP power unit includes B-407 reactor system and one turbo-facility. The thermal scheme of power unit is two-circuit. First circuit consists of VVER-640 (B-407) type thermal reactor, four main circulation loops, steam pressurized and auxiliary equipment, placed inside of hermetic casing. Each loop includes: horizontal steam generator, main circulating pump, and main circulating pipeline Ø 620 made from stainless steel.

The second circuit consists of steam generation part of steam generators, main steam lines, turbo-unit, de-aeration systems, feed water heating and delivery to steam generators, auxiliary equipment. Turbo facility is a single-shaft unit with one high- and intermediate-pressure cylinder and two double-flow low-pressure cylinders. Titanium blade of 1200 mm length is used at the last stage. The generator has a complete water-cooling system, and it doesn't require the use of hydrogen. The house load electricity supply is executed with 6 kV, 0.4 kV and 220 V direct current voltages.Main parameters of reactor system are presented in Table 7.11.

Table 7.11. Main technical characteristics of MARS reactor

№	Parameter	Unit of measure	Value
1	Nominal capacity	MW (th)	600
2	Power of active zone	MW (th)	582
3	Inlet temperature of heat carrier	^0C	216
4	Outlet temperature of heat carrier	^0C	246
5	Operating pressure	Pa	70CH105
6	External diameter of fuel pin	cm	0,978
7	Length of active zone	cm	260
8	Fuel assembly lattice	-	15x15
9	Number of fuel rods in installation	unit	204
10	Lattice spacing	cm	1,3
11	Number of assemblies	unit	96
12	Equivalent diameter of active zone	cm	216
13	Heat transfer surface in active zone	m^2	1564
14	Linear capacity of energy liberation	W/cm	114,3
15	Average heat flow in active zone	W/cm^2	37,2
16	Average specific power of active zone	kW/liter	63

Taking into account Russian safety requirements, the power unit, on the whole, complies with international tendencies and standards of nuclear energy development and belongs to the category of evolution projects intended to use the passive security systems. Optimum combination of passive and active elements in security systems, use of equipment, units and systems that were checked in domestic practice, and application of such solutions as dual containment vessel, pool-type water cooling, etc., allows to increase significantly the safety, reliability and efficiency of power plants.

The NPP with VVER-640 is intended for electricity generation under base-load operation. The possibility of heat supply to outside consumers is foreseen. Power unit equipment is designed, taking into account the electricity generation in daily load curve regime. The estimations of reliability of core and power unit systems operation were carried out in order to enable the power maneuvering regime implementation, which have shown the sufficiency of technical solutions, accepted in the project. In conjunction with validation of operability of active zone fuel elements, exploitation reliability level allows to use the NPP for wide spectrum of operation regimes in power sector.

The investigations results show that the project of average-power NPP with VVER-640, oriented on the use of technical solutions regarding the main equipment, that were verified by long term exploitation experience of NPP with VVER-1000 and supplemented by modern requirements on implementation of multi-stage protection, "internal self-protection" characters, and also on combination of active and passive protection systems, complies with the safety criteria currently reqired for NPPs, and allows to ensure the reduction of the level of ecological impact on environment.

According to the principle of multi-stage protection, the NPP is designed, constructed and exploited in such a way that radioactive materials are being shielded with several physical barriers. The barrier system of the NPP with VVER-640 includes:

- fuel matrix;
- shells of fuel elements;
- boundary of coolant circuit that is cooling the active zone;
- system of hermetic barriers.

Four protection "levels" for NPP are foreseen for the provision of efficient protection of barriers of NPP with VVER-640. Each "level" of NPP protection ensures certain efficiency of barriers protection from the impact, typical for the given level. With this purpose, the appropriate technical and/or organizational measures on prevention and/or reduction of the impact are foreseen for each "level".

Wide exploitation experience and stored knowledge on VVER type reactors in the Republic of Armenia, as well as the technical economic indicators and safety concept, meeting the international standards, provide the grounds to recommend the power unit with VVER-640 as perspective for the construction in Armenia.

One of the suggestions of representatives of the Armenian Government was to replace Medzamor, after decommissioning, with a new 640 MW nuclear unit.

A low investment cost, of US$ 1100 per kW, was adopted to investigate this option. This price would be equivalent to the lowest cost experienced in the Western industrialized countries, discounted by US$ 200 to account for the existing infrastructure (access roads, switchyard, service buildings, etc.). The maintenance cost was taken as US$ 36 per kW per year.

7.3.2. Hydro Supply Options

Although the most attractive hydropower sites in Armenia are already exploited, there is still an appreciable hydro potential that can be developed. In the medium term, hydro is practically the only technology, which can economically increase the share of indigenous resources in electricity generation.

Fairly detailed studies were carried out in 1994 for all medium and some small-scale hydropower projects. The results for the medium size projects (above 5 MW capacity) are summarized as follows (Table 7.12).

The code names and capacities of new HPPs, which have been used in VARSYS module of WASP-IV model, are given in Table 7.13.

Note: - Megri is a binational project with Iran and features two hydropower schemes. Cost anoutput based on new 1999 data

- figures shown here represent Armenia's share. The Iranian share is of the same size.
- Specific generation cost is for a 50-year lifetime and 10% annual discount rate.

The projected costs would be considerably lower if the hydro mechanical and electrical equipment could be produced in Armenia. The prospects for this are reasonable for small-scale hydro projects. A joint venture with a foreign turbine manufacturer, or production under license is recommended to shorten the development time.

Table 7.12. Overview of Potential Medium and Small Size Hydropower Projects in Armenia

Scheme	Head (m)	Flow (m^3/s)	Capacity (MW)	Energy (GWh/a)	Plant Factor	Constr (Years)	Cost (mln. US$)
Schnokh	236.0	37.0	75.0	321.0	0.49	5.0	142.0
Gekhi	100.0	6.0	5.2	21.0	0.45	2.0	10.0
Megri	70.0	180.0	79.5	500.0	0.68	5.0	186.0
Sum Small Size Hydro < 4.5 USc/kWh			35.0	55.0	0.18	4.0	70.0
Sum Small Size Hydro < 5.5 USc/kWh			36.0	57.0	0.18	4.0	73.0

Table 7.13. Hydroelectric Projects Candidates

Hydro type	##	Code Name	MW
Hydro A	1	SM1	35
	2	MGR	79.5
	3	SM2	36
Hydro B	4	SHNO	75
	5	GEKH	5.2

Small hydropower development would be much suitable for the private sector. The «Armenergo», or the Government should guarantee a reasonable tariff for the power supplied into the Grid.

7.3.3. Wind Power

The mean wind velocities throughout Armenia are rather low, and the potential of wind energy is, consequently, limited. However, there are a number of candidate sites with favourable conditions, featuring mean wind velocities above 6 m/s. The most promising sites are, from north to south: the Pushkin-Pass (not far from Vanadzor), Aragaz, Lake Sevan, and the Sisian-Pass.

In spite of the fact that the most efficient wind generators have nowadays nominal power in the range 0.6-1.0 MW and can be installed accordingly to higher density than in the past, the experts also evaluated for Armenia the opportunity/necessity for potential wind farms to employ wind turbines with a power rate of 200 kW and a capacity factor around 0.17, due to the territorial characteristics as well. The consequence is, that due to scale effect, the unit investment cost is higher in case of employment of smaller generators.

7.3.4. Energy Saving by DSM Measures

In order to roughly evaluate the energy saving potential during the planning period, the following DSM measures were considered:

- replacement of 6 most used in households 100W incandescence bulbs by compact fluorescent lamps; that number includes also the lamps to be replaced at workplaces,
- implementation of conservative saving methods for use in all power consuming processes in the various branches of the economy.

Table 7.14. Overview of Potential DSM Measures in Armenia

Code Name	Installed Capacity (MW)	Energy Generation (GWh)	Construction Time (Years)	Specific Investment Cost (without IDC) (US$/kW)
DSM1	1.3	11.4	4.0	125.0
DSM2	2.9	25.4	4.0	136.4
DSM3	5.6	49.1	4.0	300.0
DSM4	7.4	64.8	5.0	357.1
DSM5	3.6	31.5	4.0	433.3
DSM6	4.8	42.1	4.0	560.6
DSM7	1.9	16.6	4.0	750.0

The extent and rate of realization of the above measures are considered depending on the incentives and costs.

The overview of Potential DSM Measures in Armenia is given in Table 7.14.

7.4. Other Input Information

7.4.1. Economic Parameters

The study was carried out basing on 1999 US$ constant prices (i.e., without taking into account the inflation).

A real-term economic discount rate of 10% per annum has been adopted as «base case». Rates of 8% and 12% p.a. have been used for the sensitivity analysis.

7.4.2. Target Reliability and Value of Energy not served

The probable duration of time of load loss, used in the study has been 30 hours per year, assuming no fuel supply constraints.

In addition, the analyses were performed regarding the unsupplied energy. The unit price for the unsupplied energy was assumed to be 1.0 US$/kWh.

7.4.3. Project Costs

Table 7.15 shows the project costs for the candidate plants. The values of project investment costs, given in this table, have been obtained as a result of various pre-feasibility and feasibility studies conducted.

7.4.4. Fuel Prices

The fuel prices used within the WASP analyses are at the level of 1999, the base year of the study. As previously indicated, no inflation effects were considered for these prices, and the prices are 8,5 US$/GCal for natural gas (Russian), and 1,8 US$/Gcal for nuclear fuel.

It was assumed to keep constant all prices, except for gas, which price will be increasing on about 2.3% p.a. since 2005.

In the analysis it has been assumed that both water and wind energy can be used free of charge to generate electricity.

Table 7.15. Project Cost and Economic Parameters

New Thermal Power Plants						
Project	Project Cost with IDC (US$/kW)			Plant Life	% IDC	Construction Time
	Domestic	Foreign	Total	(years)	DR=10%	(years)
CC2	189	757	946	25	22.7	6
NNCL	319	1278	1597	50	26.0	7
CHP1	168	672	840	25	15.6	4
CHP2	168	672	840	25	15.6	4
Hydro Power Plants						
HYDA						
SM1	0	2371	2371	50	15.6	4
MGR	0	2888	2888	50	19.2	5
SM2	0	2404	2404	50	15.6	4
HYDB						
SHNO	0	2337	2337	50	19.2	5
GEKH	0	2176	2176	50	8.1	2
Wind Farms						
Wind	0	2069	2069	30	22.7	6

Note: Data are given for the net capacities.

7.4.5. Optimization Constraints

As for CHPP plants, the maximum allowed numbers of unit reviewed under the study period has been limited due to the fact that output of these units depends on heat demand. The heat demand that will be covered by these units was calculated externally, and there were defined limitations for production of electricity by these types of plants.

For the reliability index “Loss of Load Probability”, a value of one day/year (0.31%) was taken into account.

The minimum reserve margin was set to be 25%, and the maximum reserve margin was set to be 70% in the first part of the study period, when the most of units with relatively high values of forced outage rates were in operation, and due to the overcapacity of the system in those years. The value of the maximum reserve margin decrease up to 50%, taking into account the reduction of the share of those units in the total installed capacity, due to retirement.

7.4.6. Plant Loading Order

The loading order of power plants was requested to generate by WASP following a basic economic loading order based on the operation of the plants at full capacity.

It was assumed for these calculations that the spinning reserves contribution for hydro project A was 6% of capacity and hydro project B was 30% of capacity.

With all the above-mentioned technical and economic assumptions and data, 4 WASP cases were developed. The results of these cases are described in next Chapter 8.

8 RESULTS OF THE ANALYSIS OF THE GENERATION SYSTEM EXPANSION

The analysis for determining the optimal expansion plans for the power generation system was performed for the two scenarios of the electricity demand discussed in Chapter 7.

The reference optimal solutions have been obtained using an annual discount rate of 10%, while keeping constant the levels of investment and operating costs throughout the study period. All costs are expressed in US$ constant money of 1999.

Sensitivity analyses on the optimal expansion plans have been performed for variations of the discount rate.

8.1. Screening Curves Analysis

A simplified comparative analysis of the expansion candidates was carried out taking into consideration both the construction of new plants and rehabilitation of some thermal power plants to cover the future electricity and heat demand, as it has been discussed in Chapter 7.

In order to facilitate optimization by means of WASP and to reduce the number of alternatives subject to analysis, a new arrangement of the candidate plants was made outside the WASP model. The analysis was based on a ranking economic criterion of expansion candidates, which was determined by calculating for each plant the total cost per kW according to the capacity factor of the plant.

The results of this analysis are shown in Figure 8.1.

The results show that existing hydro plants are cost-effective options.

As for the new candidate plants, the above analysis proved that for the values of the load factor adequate for base load operation (70-80%), the combined cycle plants with natural gas are competitive with the nuclear units. Other types of plants based on fuel gas are less economical than the nuclear plant. For this reason, for the WASP only nuclear units and combined cycle plants were considered for base load operation.

8.2. Results of the Reference Optimal Solutions

In the formulation of the least-cost Reference Case expansion plan, electricity demand projected in the Reference and Low Demand Scenarios has been used along with taking into account the external demand and a number of constraints on fuel supply limitations, system reliability and other physical constraints. The least-cost plan has been worked out through an iterative process with a number of successive runs of BALANCE and WASP-IV programs. These cases for two electricity demand scenarios are not only the least–cost expansion plans for future development of the electricity sector in Armenia, under specified assumptions, they also represent the most plausible cases under the present perceptions for evolution of the energy and electricity sector in the country.

The main decisions associated with both generation system development plans are:

- rehabilitate all existing hydropower plants as soon as possible,
- operate two 50 MW combined heat and power units at TPP Yerevan 1 and two 150 MW power-only units at TPP Yerevan 2, as well as two 50 MW CHP units at TPP Hrazdan 1 with absolute minimum maintenance until there is a major break down. Then take these units out of service,
- rehabilitate and keep in good running condition three 50 MW units at TPP Yerevan 1 and two 100 MW CHP units at Hrazdan 1,

- complete construction and put into operation Hrazdan 5, provided that the costs for construction completion do not exceed MUS$ 60,
- at Vanadzor, keep two 12 MW and one 47 MW CHP units in good running condition,
- put into operation: Megri, Shnokh and Gekhi HPP as well as 71 MW small hydro power plant between 2012 and 2017,
- put into operation 15 MW of wind power after 2015.

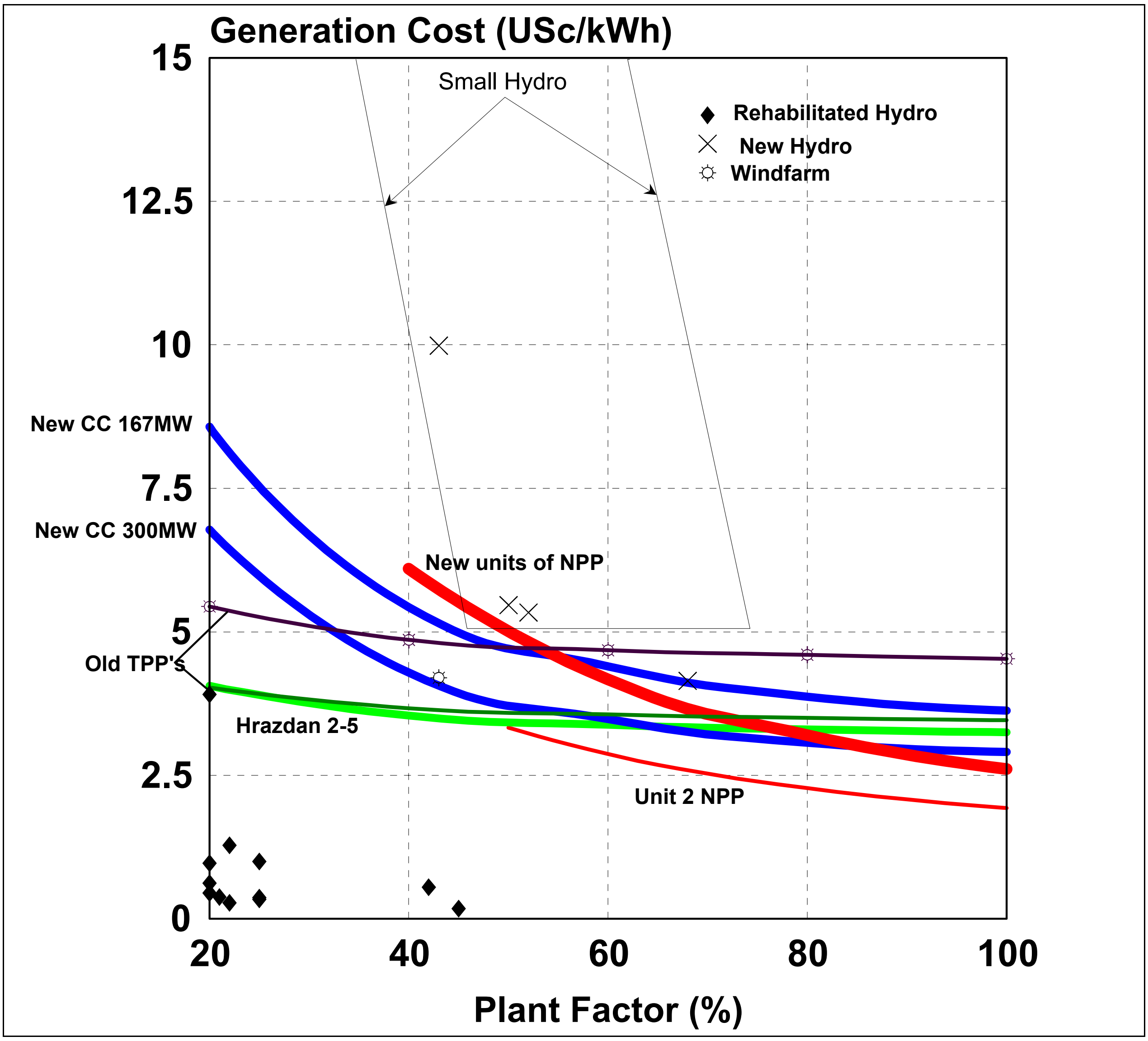

Figure 8.1. Specific Generating Costs (10% Discount Rate)

The future additions of electricity generation capacities for the Reference Demand Scenario expansion plan are presented in Figure 8.1. This plan suggests development of about 2794 MW (new installed capacity) of power generation capacity over the next 22 years period, comprising: Hydro 231 MW, Combined Cycle Power Plant 600 MW, CHP Combined Cycle Plant 668 MW, Nuclear 1280 MW and Wind 15 MW.

It can be noted that there are no new additions till 2007. One thermal condensing type unit of 300 MW, which is under construction, is assumed to exploit in 2005. Two additional cogeneration units are needed to cover the heat demand in 2007 and 2008. It's necessary to add new combined cycle unit in 2011 to meet the electricity demand. As it was mentioned above, Armenian NPP will retire at the end of 2014, and the first unit of a new NPP will substitute this plant in 2015. In addition, the second NPP unit will come into operation in 2016.

The following figures (8.2 and 8.3) show when and what power plant would be available for operation for the Reference and Low Demand Scenarios.

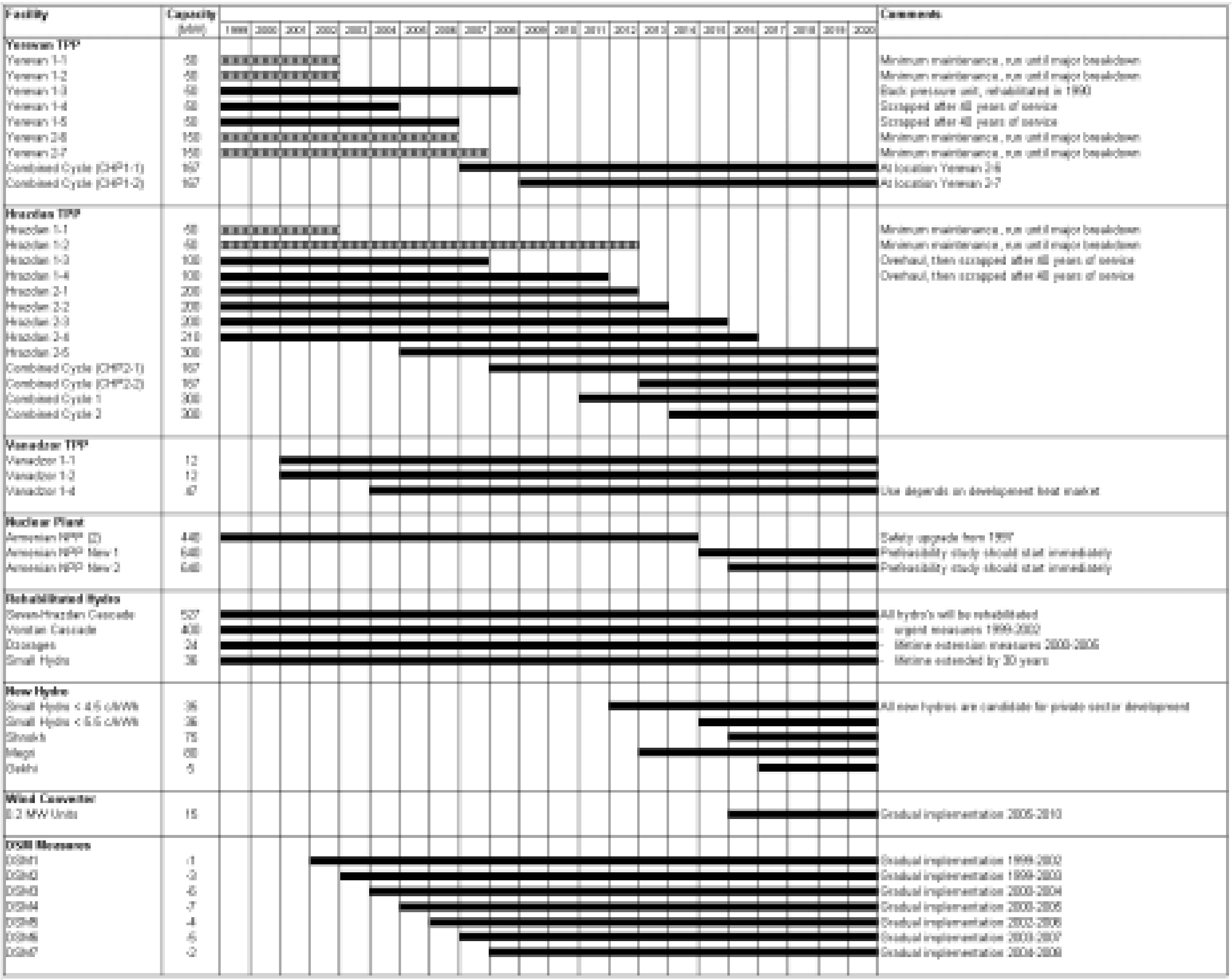

Figure 8.2. Least Cost Expansion Plan for the Armenian Power Sector - Reference Demand Scenario

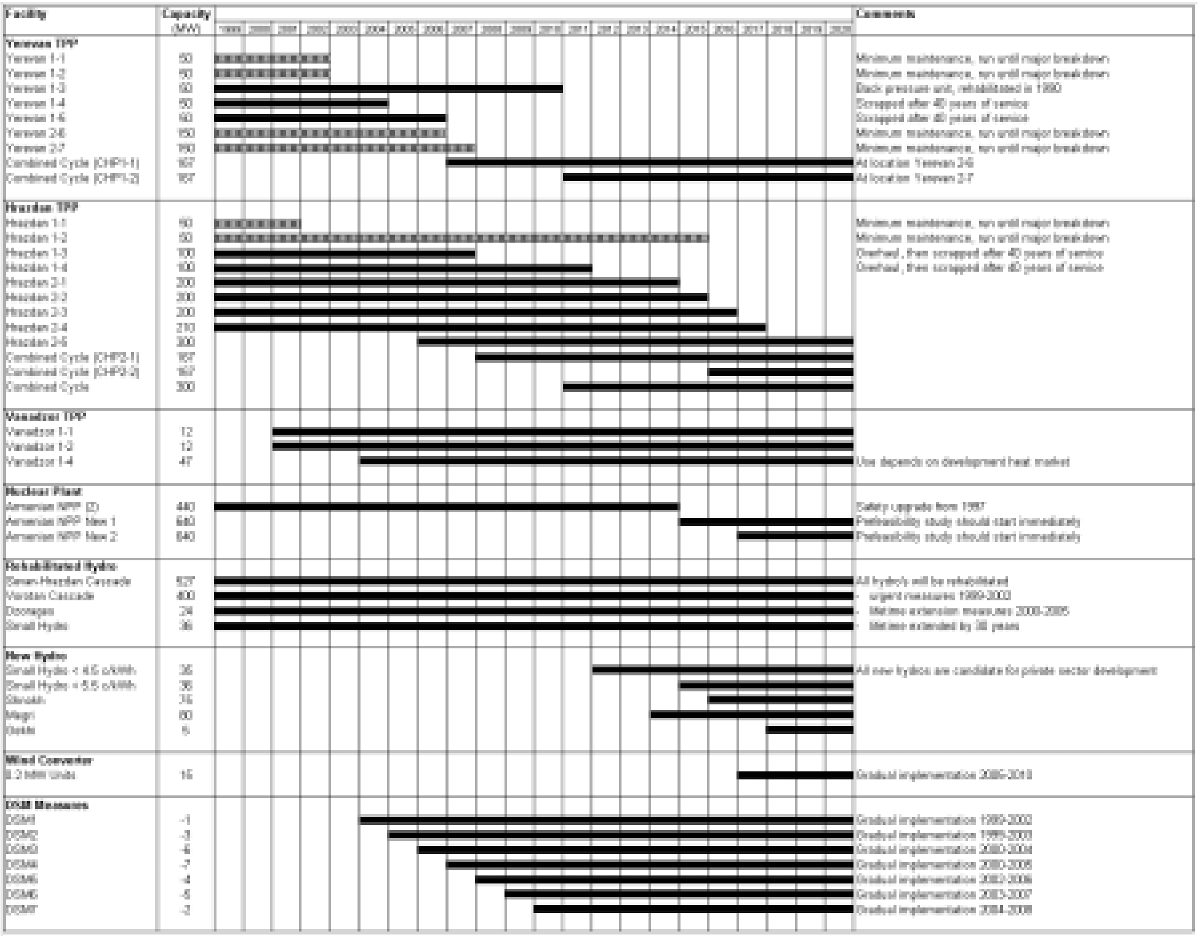

Figure 8.3. Least Cost Expansion Plan for the Armenian Power Sector- Low Demand Scenario

The main differences between these two scenarios are the date of putting into operation or retirement existing, committed and new units. The number of combined cycle units in Reference Demand Scenario is more than in Low Demand Scenario by one unit.

The shares of different power generation technologies in total installed capacity for Reference and Low Demand Scenarios are shown in Table 8.1 and Table 8.2. It may be noted that the share of hydropower in total installed capacity is assumed to decrease from 40.8% in 1999 to 31.3% in 2020 for Reference Demand Scenarios, and to 33.3% in 2020 for Low Demand Scenarios, while the share of nuclear power capacity is foreseen to increase from 15.2% in 1999 to 30.0% in 2020 for Reference Demand Scenarios, and to 31.9% in 2020 for Low Demand Scenarios. The remaining installed capacity is based on natural gas.

Figures 8.4 and 8.5 show the future evolution of total installed power capacity and peak demand for Reference and Low Demand Scenarios.

The corresponding electricity generation mix is given in Fig 8.6 and Fig 8.7 for both scenarios. It may be noted, that the nuclear power contributed about 41% into the total electricity generation in the terminal year. Although the share of hydroelectric generation decreased during the study period, the contribution of hydro power plants is assumed to have a significant share in the total generation of the last year of planning period - about 15% for Reference Demand Scenario, and about 18% for Low Demand Scenario.
The figures 8.8 and 8.9 illustrate the main characteristics of the least cost plans for the Reference and Low Demand Scenarios.

Table 8.1. Future Installed Electricity Generation Capacity Mix by Fuel Reference Demand Scenario

Year	1999	2005	2010	2015	2020
Total Installed Capacity (MW)	2508	2897	3070	3658	4003
% Shares					
Hydro	40.8%	35.3%	33.3%	32.1%	31.3%
Gas	44.1%	51.6%	54.3%	51.5%	38.3%
Nuclear	15.2%	13.1%	12.4%	16.4%	30.0%

Table 8.2. Future Installed Electricity Generation Capacity Mix by Fuel Low Demand Scenario

Year	1999	2005	2010	2015	2020
Total Installed Capacity (MW)	2508	2630	2977	3471	3762
% Shares					
Hydro	40.8%	38.9%	34.4%	33.8%	33.3%
Gas	44.1%	46.5%	52.0%	48.1%	33.7%
Nuclear	15.2%	14.4%	12.8%	17.3%	31.9%

It can be seen, that the energy contribution of Hrazdan 5 and CHP-s does not reach its full potential. This is mainly due to the very low variable operating cost of the nuclear plant. The combined cycle units and renewable ones nowadays can cover much of the energy demand.

The energy resource requirements for operation of the electricity generation system developed in two scenarios are given in figure 8.10. It may be noted, that in the year of 2014, about 1.56 billion m^3 of natural gas will be required to operate the gas-fired combined cycle units and the combustion turbine for Reference Demand Scenario, and 1.37 billion m^3 of natural gas for Low Demand Scenario. The decrease in consumption of natural gas up to 0.89 billion m^3 in the power sector in 2016 will be due to coming into operation of the second unit of a new Nuclear.

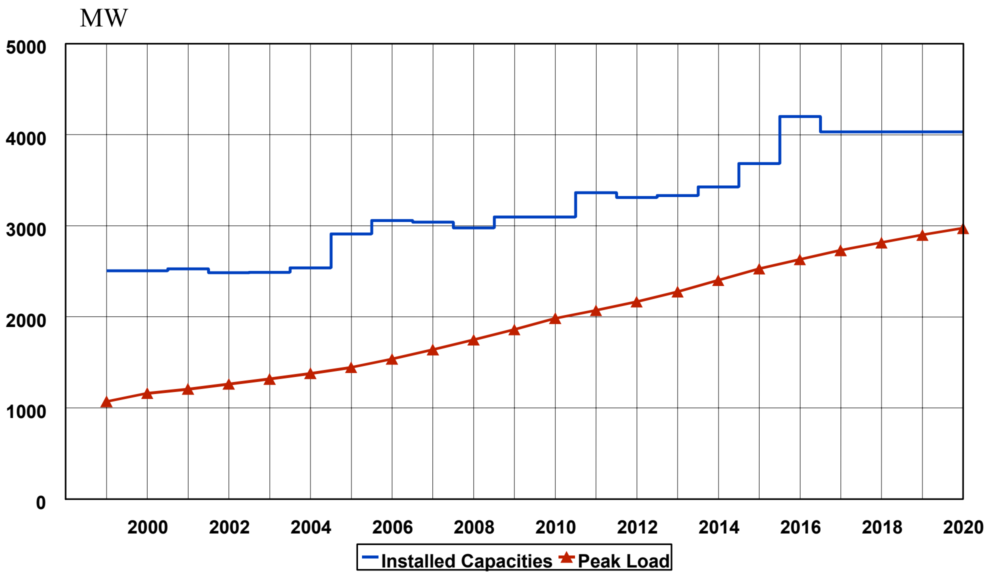

Figure 8.4. Installed Electricity Generation Capacities and Peak Load Reference Demand with Nuclear

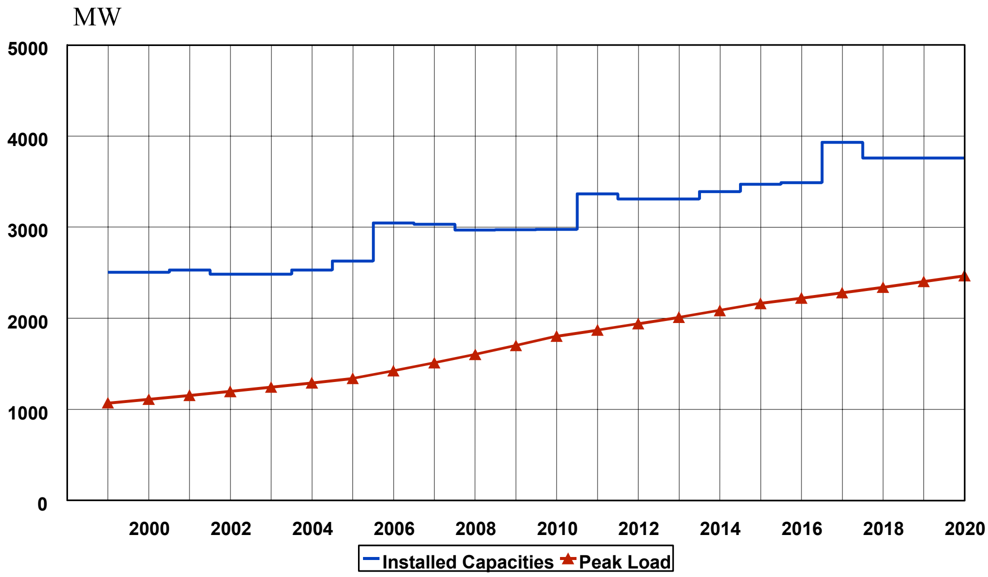

Figure 8.5 Installed Electricity Generation Capacities and Peak Load Low Demand with Nuclear

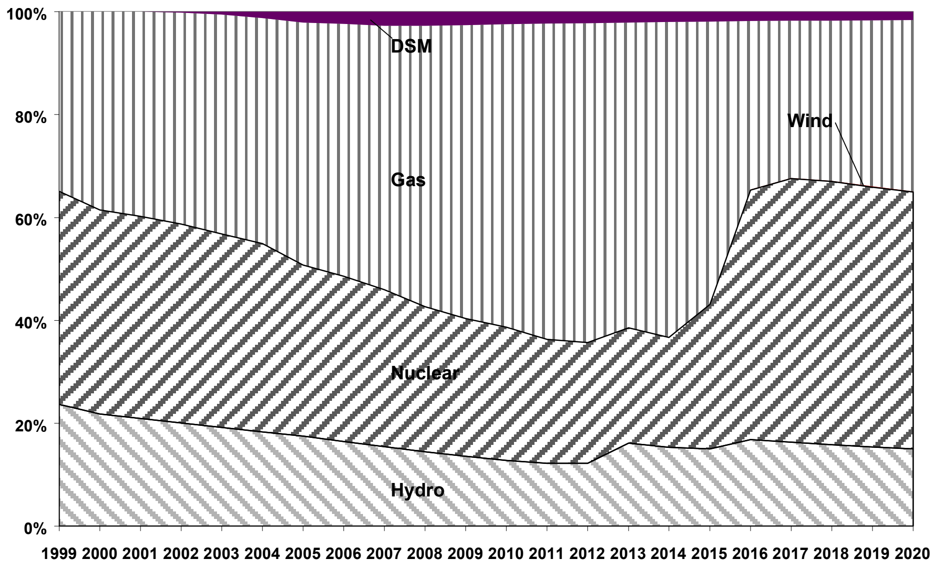

Figure 8.6. Future Electricity Generation Mix by Fuel Reference Demand with Nuclear

Power plant for Reference Demand Scenario, and up to 0.60 billion m^3 in 2017 for the Low Demand Scenario, correspondingly.

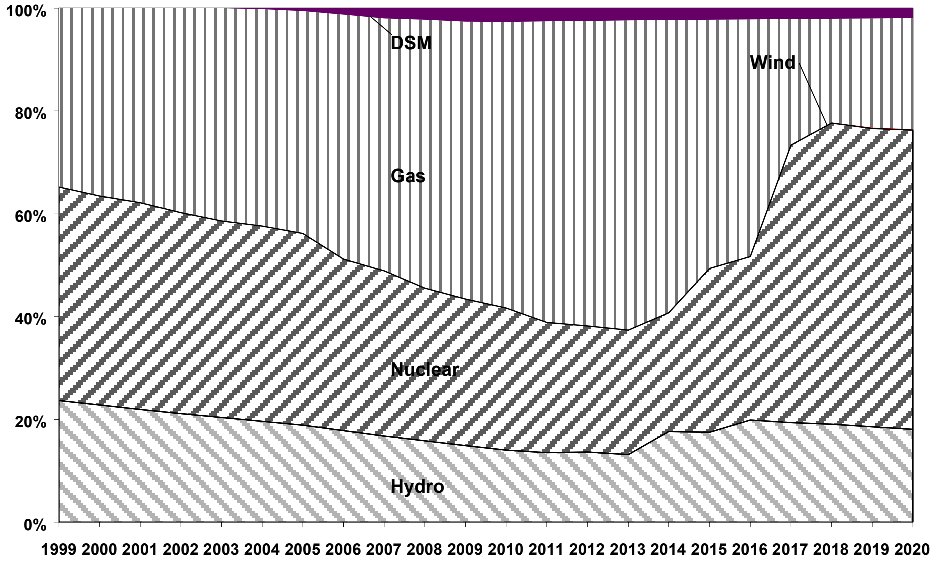

Figure 8.7. Future Electricity Generation Mix by Fuel Low Demand with Nuclear

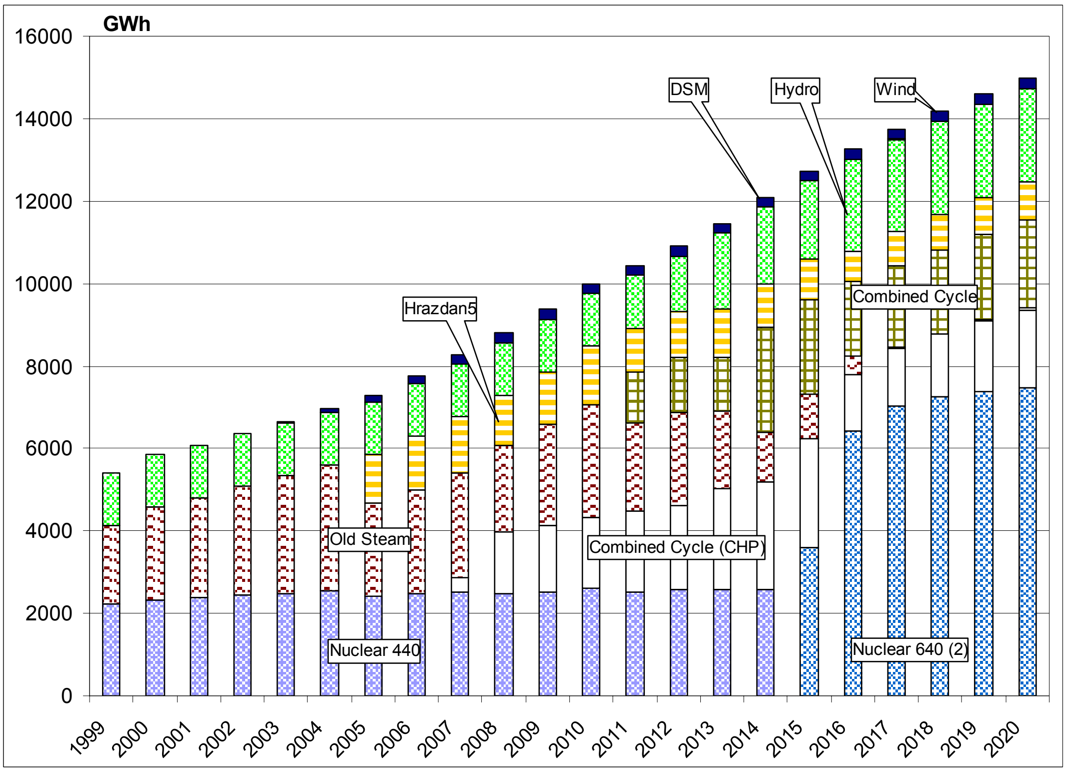

Figure 8.8. Energy Contribution by Plant Type, Reference Demand with Nuclear

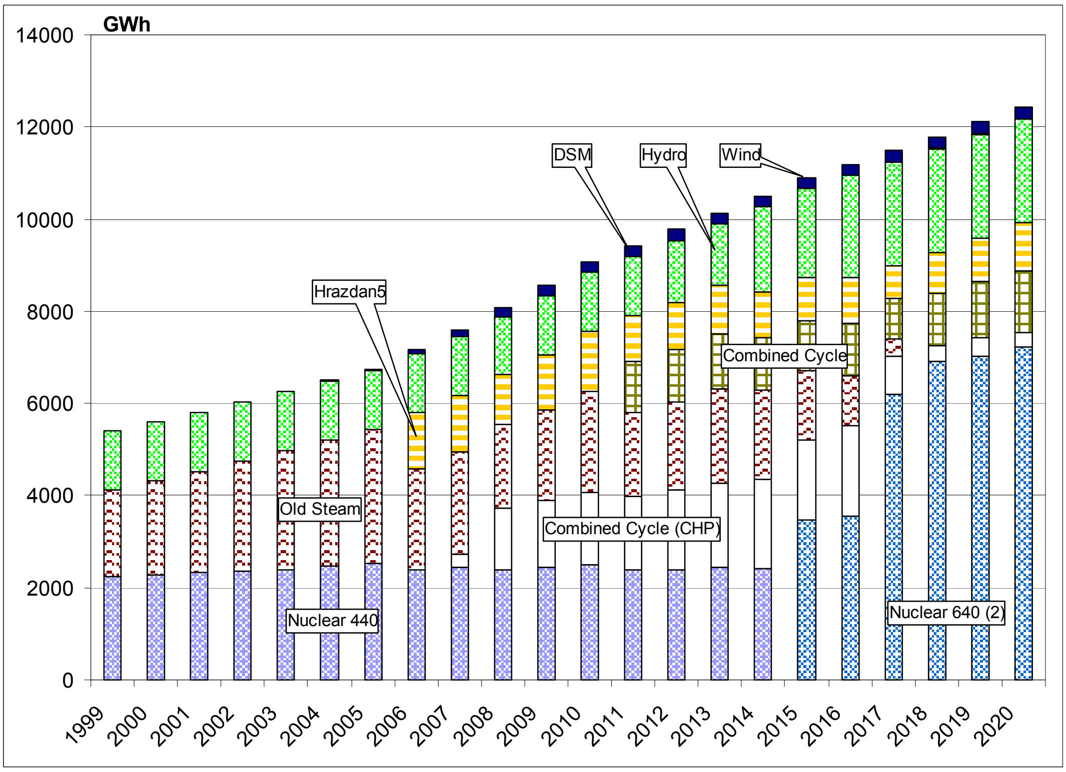

Figure 8.9 Energy Contribution by Plant Type, Low Demand with Nuclear

8.3. Alternative Expansion Plans

In view of various uncertainties about future evolution of energy/electricity demand and supply system, taking into consideration the trends of nuclear power development and possibility of importing natural gas from additional sources, the necessity arose to explore alternative plans for expansion of electricity generation system.

The alternative expansion plans were considered for both Reference and Low Demand Scenarios. There is no nuclear option included into these alternative expansion plans, which is the main distinction from the two expansions plans mentioned above.

Figures 8.11 and 8.12 show when and what power plant would be available for operation for the Reference and Low Demand Scenarios without nuclear option.

Only the nuclear power capacity additions in these two scenarios have been replaced by thermal capacity based on natural gas.

Figures 8.13 and 8.14 show the future evolution of total installed power capacity and peak demand for Reference and Low Demand Scenarios.

The future electricity generation mix for Alternative plans is shown in Figures 8.15 and 8.16. It may be noted, that, since nuclear power plant in these two cases have been replaced by gas-fired plants, the share of electricity generation based on gas will increase up to 83% and 80% in 2020 for Reference and Low Demand Scenarios, correspondingly.

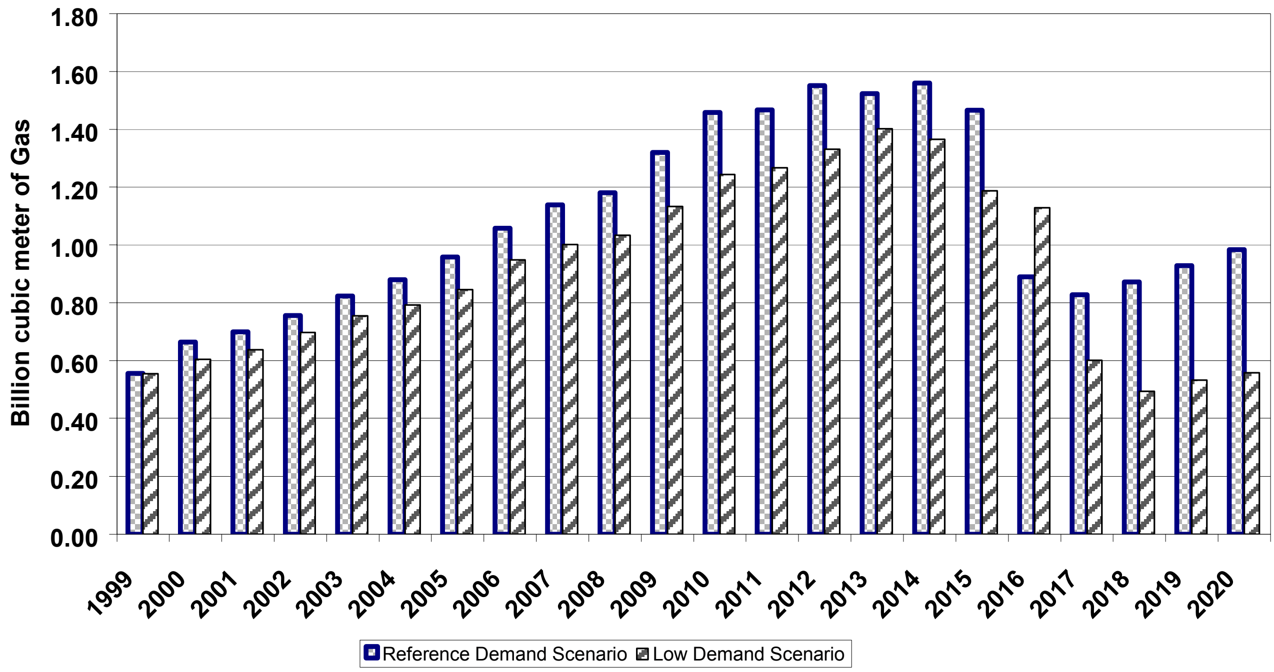

Figure8.10 Natural Gas Consumption in the Power Sector for Reference and Low Demand Scenarios with Nuclear

The energy resource requirements for operation of the electricity generation system developed in two Alternative scenarios are given in Figure 8.19.

The loss of load probability expressing the likelihood that the full demand cannot be met, is expected to never exceed 30 hours per year (Figures 8.20 and 8.21), and in reality, it is much less because of the possibility to temporarily over-exploit the waters of Lake Sevan for additional hydropower generation.

8.4. Investment Requirements

Tables 8.5, 8.6, 8.7 and 8.8 show the approximate capital requirements for the years 1999-2020 for the least cost plans with- and without a new nuclear plant for both scenarios. Note, that no cost is included for the system expansion beyond the year 2020. Note also, that no costs have been included for 'normal' maintenance of power plants, rehabilitation of district heating systems, expansion of underground gas storage facilities, the gas pipeline to Iran, and the costs for purchasing gas and mazut to build up a strategic fossil fuel reserve.

Table 8.9 gives the cumulative investments and cumulative system operation costs (O&M and fuel costs) for the next 22-year period for all cases. In case of Reference Demand Scenario with Nuclear Option, the cumulative investments for capacity additions have been estimated as US$ 2.9 billion, and the cumulative system operation costs - as US$ 4.6 billion. Compared with the case of Reference Demand Scenario without Nuclear Option, the cumulative investments in the case with nuclear option are US$ 0.6 billion higher because of the fact that capital costs of nuclear power plants referred to in this case, are relatively higher compared to that for gas fuel based power plants. On the other hand, the system operation costs in the case of Reference Demand Scenario with Nuclear Option are lower on about US$ 0.5 billion compared to that of the case of Reference Demand Scenario without Nuclear Option. This difference is due to low fuelling costs of nuclear power plants.

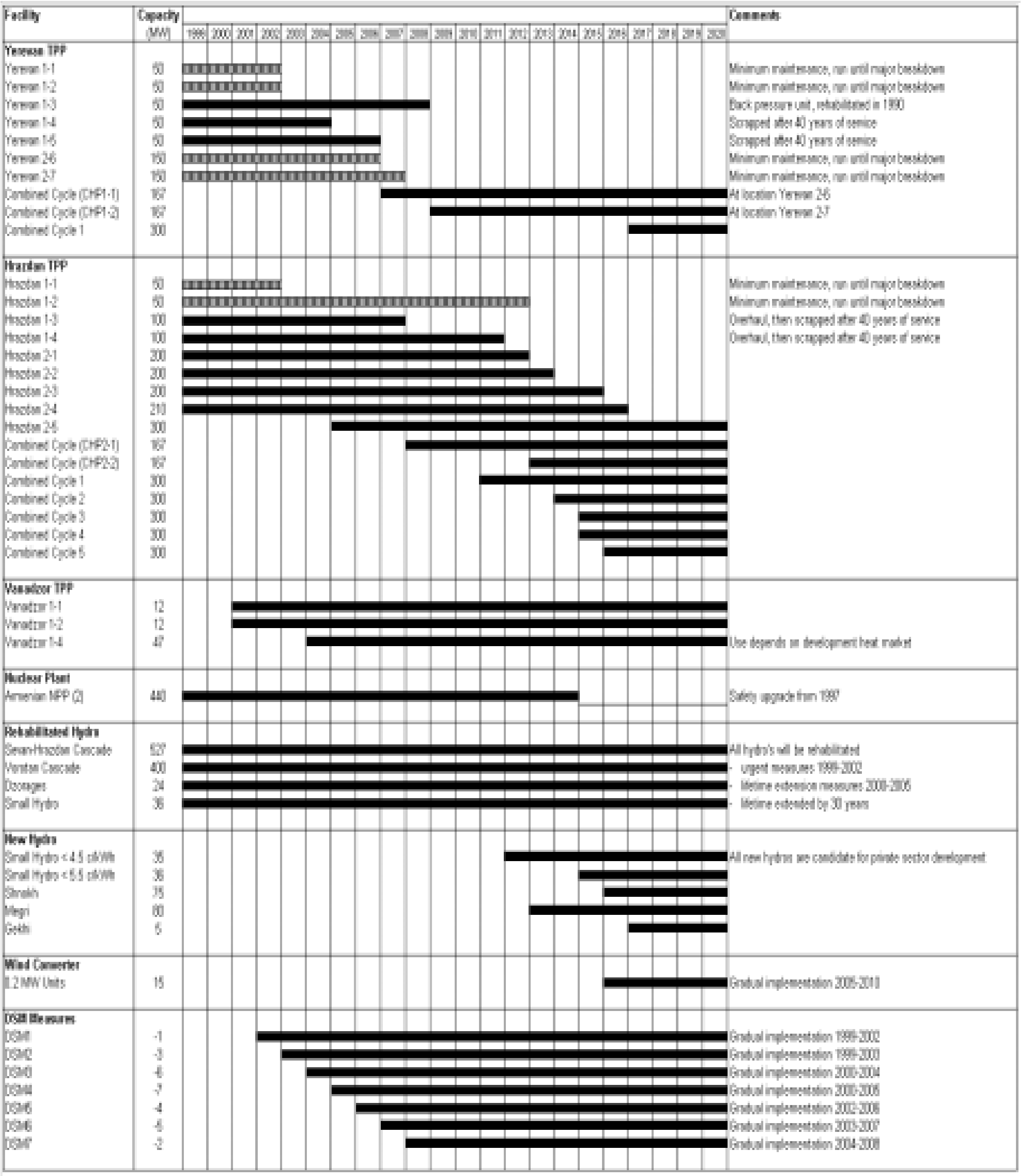

Figure 8.11. Least Cost Expansion Plan for the Armenian Power Sector - Reference Demand Scenario

The sum of cumulative investments and operation costs is thus higher by US$ 0.17 billion in the case of Reference Demand Scenario with Nuclear Option, compared to that of the case without nuclear option. The similar situation can be viewed for the Low demand Scenario Cases. It may be noted, that these values for scenarios with nuclear option are not much different from those for the cases without nuclear option.

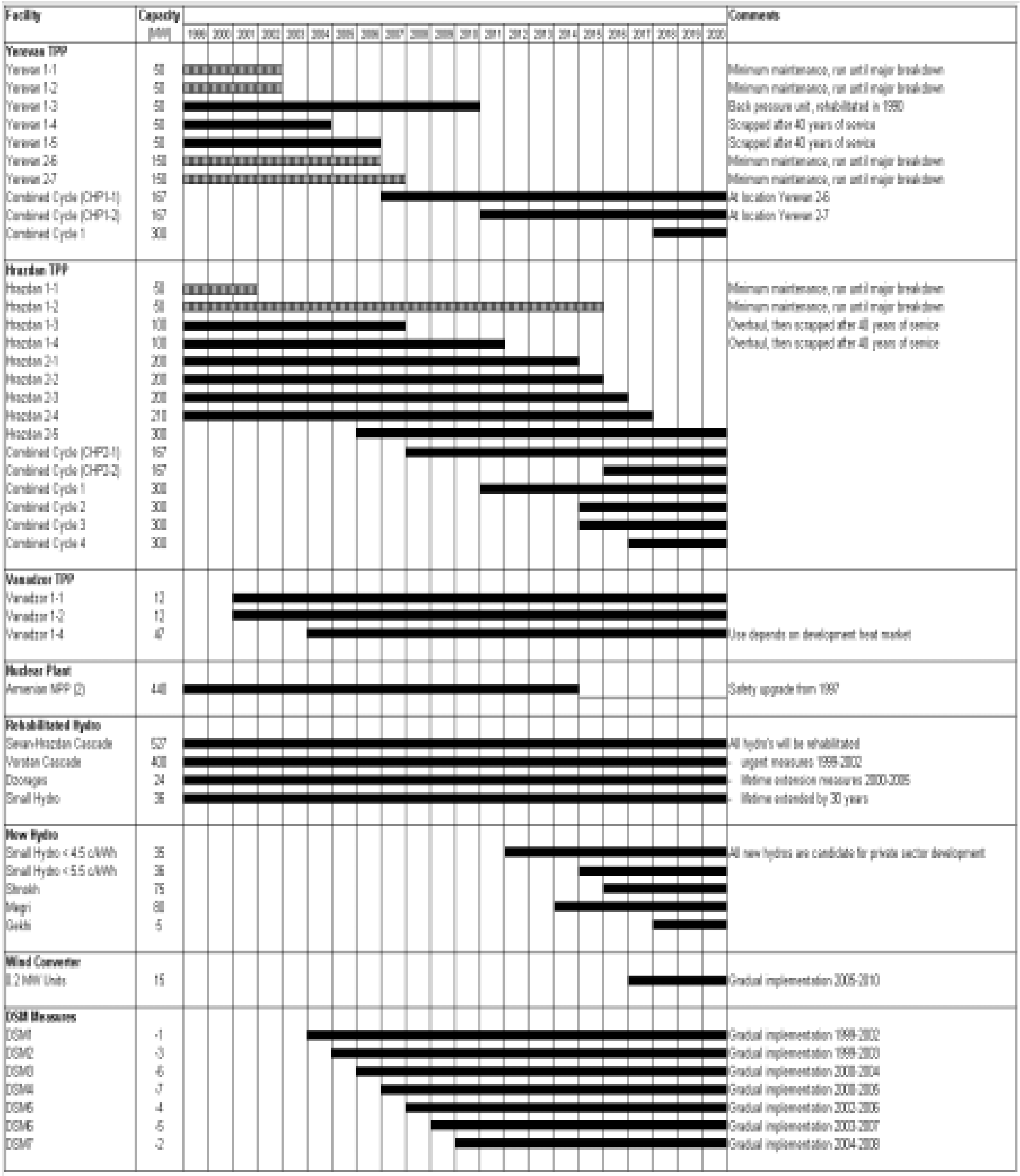

Figure 8.12. Least Cost Expansion Plan for the Armenian Power Sector - Low Demand Scenario

The capacity mix worked out in the Alternative expansion plans is given in Tables 8.3 and 8.4.

Table 8.3. Future Installed Electricity Generation Capacity Mix by Fuel - Reference Demand Scenario

Year	1999	2005	2010	2015	2020
Total Installed Capacity (MW)	2508	2913	3097	3622	3919
Shares, %					
Hydro	40.8%	35.1%	33.0%	32.4%	32.0%
Gas	44.1%	51.3%	53.8%	66.8%	66.5%
Nuclear	15.2%	13.0%	12.3%	0.0%	0.0%

Table 8.4. Future Installed Electricity Generation Capacity Mix by Fuel - Low Demand Scenario

Year	1999	2005	2010	2015	2020
Total Installed Capacity (MW)	2508	2630	2977	3408	3636
Shares, %					
Hydro	40.8%	38.9%	34.4%	34.4%	34.5%
Gas	44.1%	46.5%	52.0%	64.8%	64.4%
Nuclear	15.2%	14.4%	12.8%	0.0%	0.0%

Figures 8.17 and 8.18 illustrate the main characteristics of the Alternative plans for Reference and Low Demand Scenarios

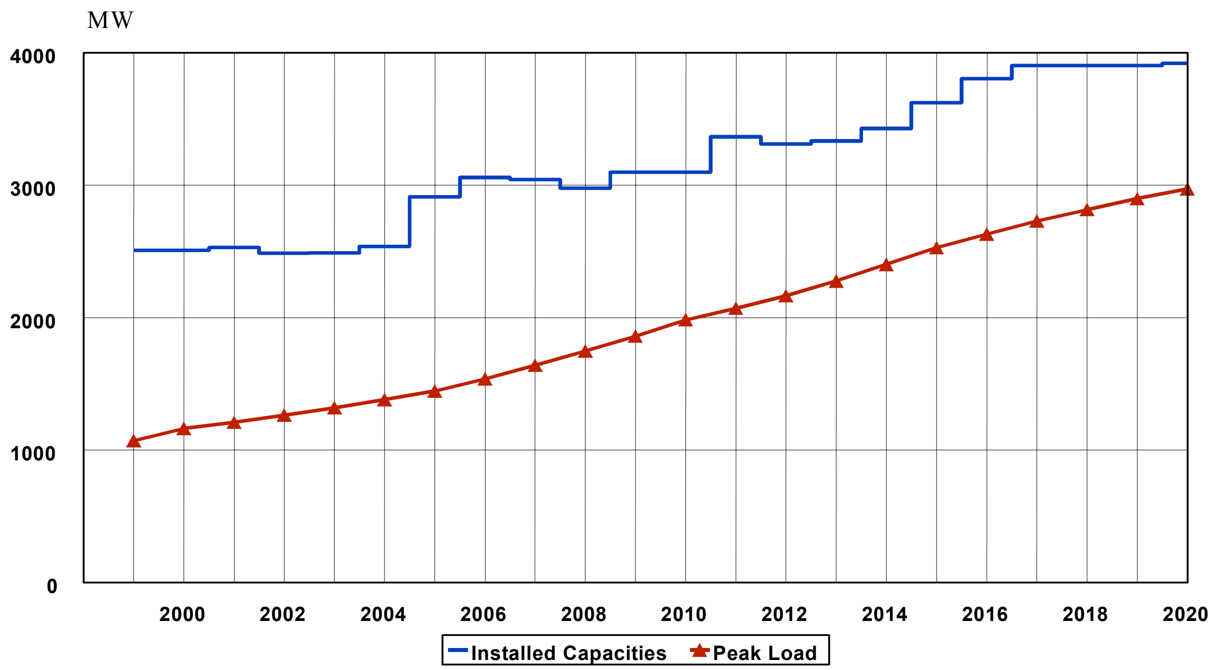

Figure 8.13. Installed Electricity Generation Capacities and Peak Load - Reference Demand - without Nuclear

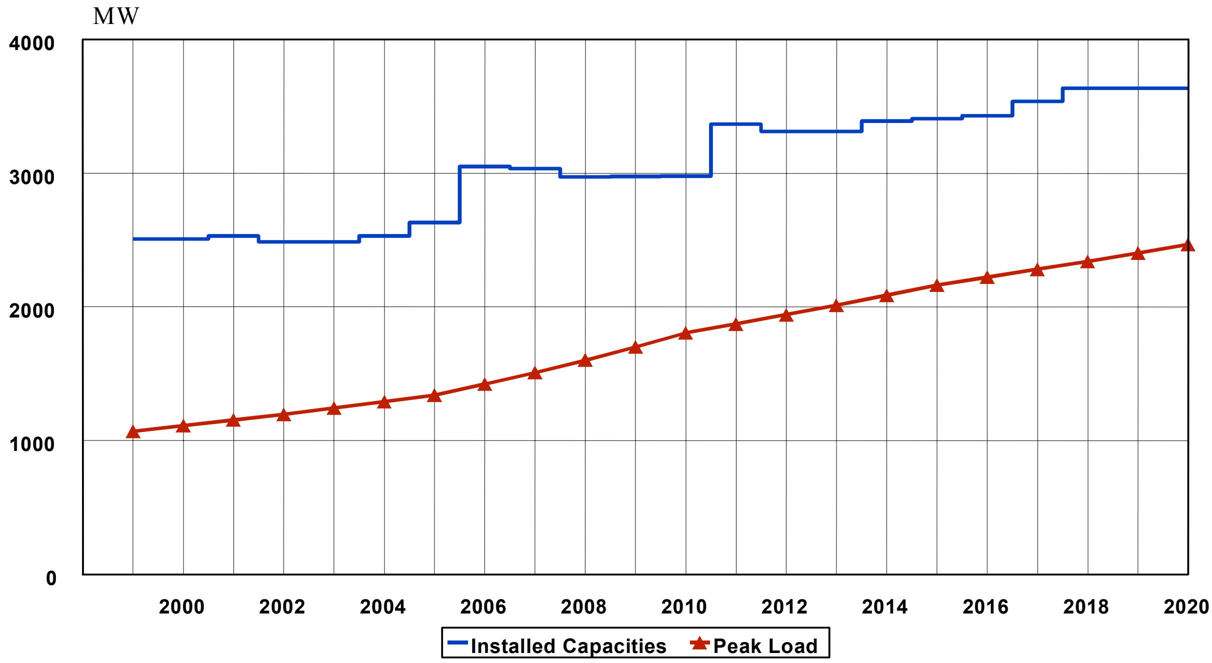

Figure 8.14. Installed Electricity Generation Capacities and Peak Load - Low Demand - without Nuclear

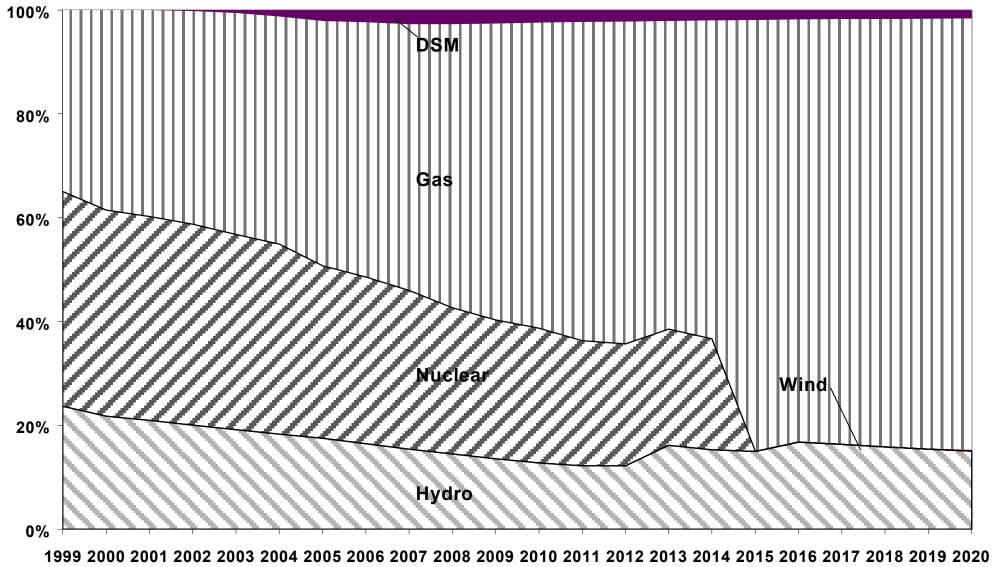

Figure 8.15. Future Electricity Generation Mix by Fuel - Reference Demand - without Nuclear

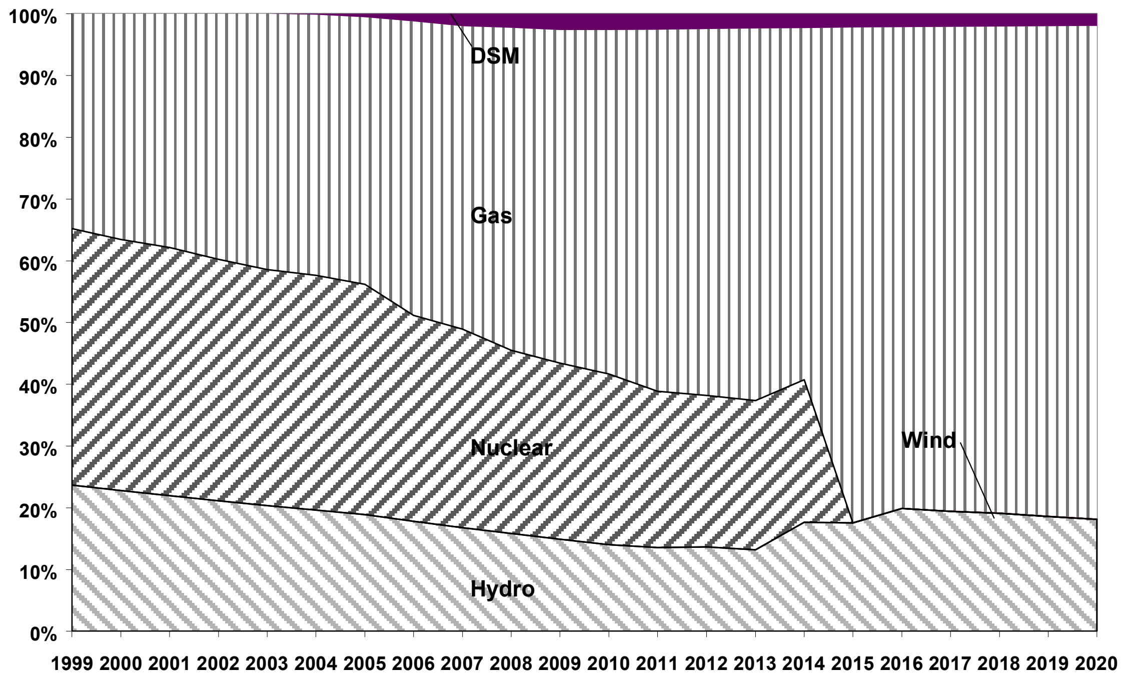

Figure 8.16. Future Electricity Generation Mix by Fuel - Low Demand - without Nuclear

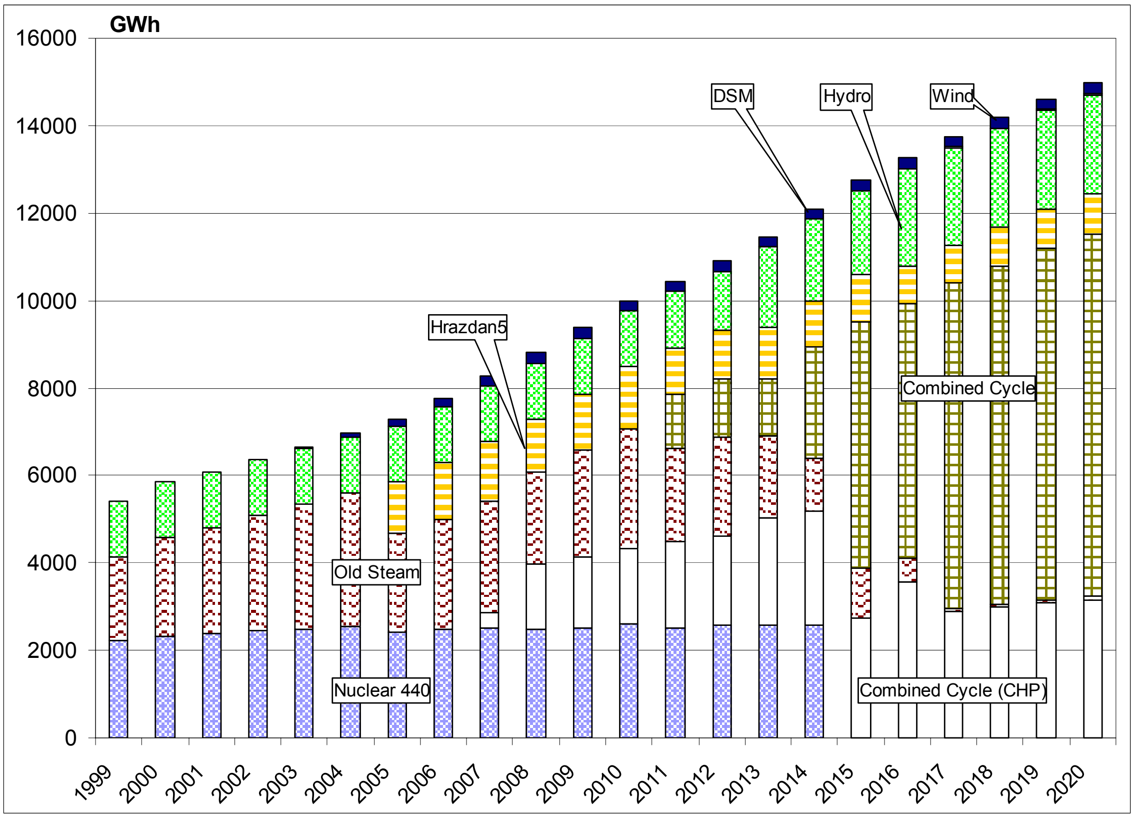

Figure 8.17. Energy Contribution by Plant Type - Reference Demand - without Nuclear

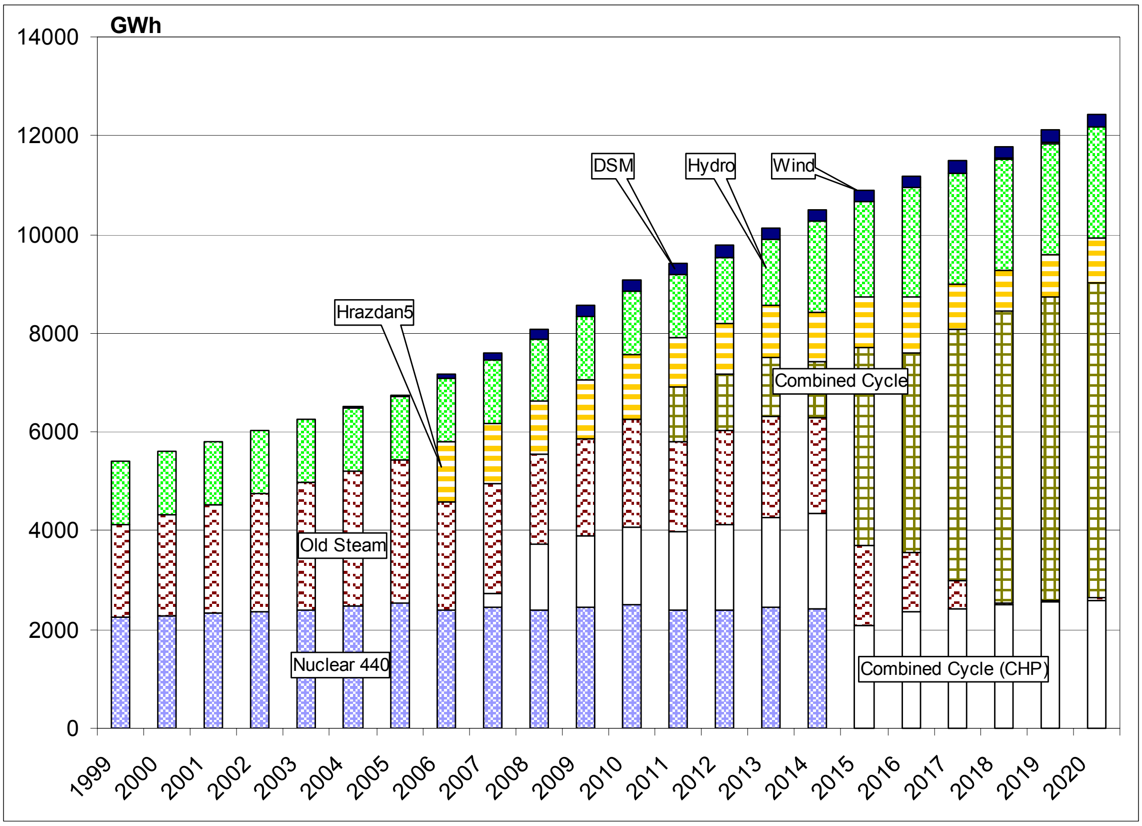

Figure 8.18. Energy Contribution by Plant Type - Low Demand - without Nuclear

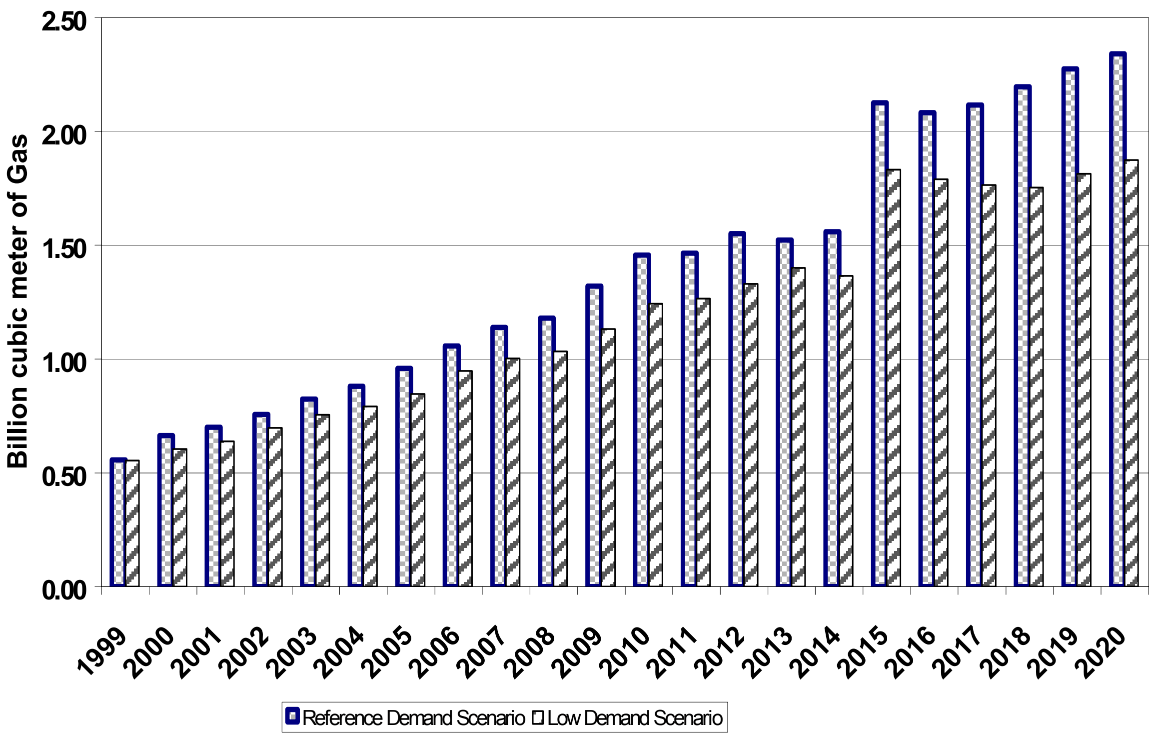

Figure 8.19. Natural Gas Consumption in the Power Sector - Reference and Low Demand Scenarios - without Nuclear

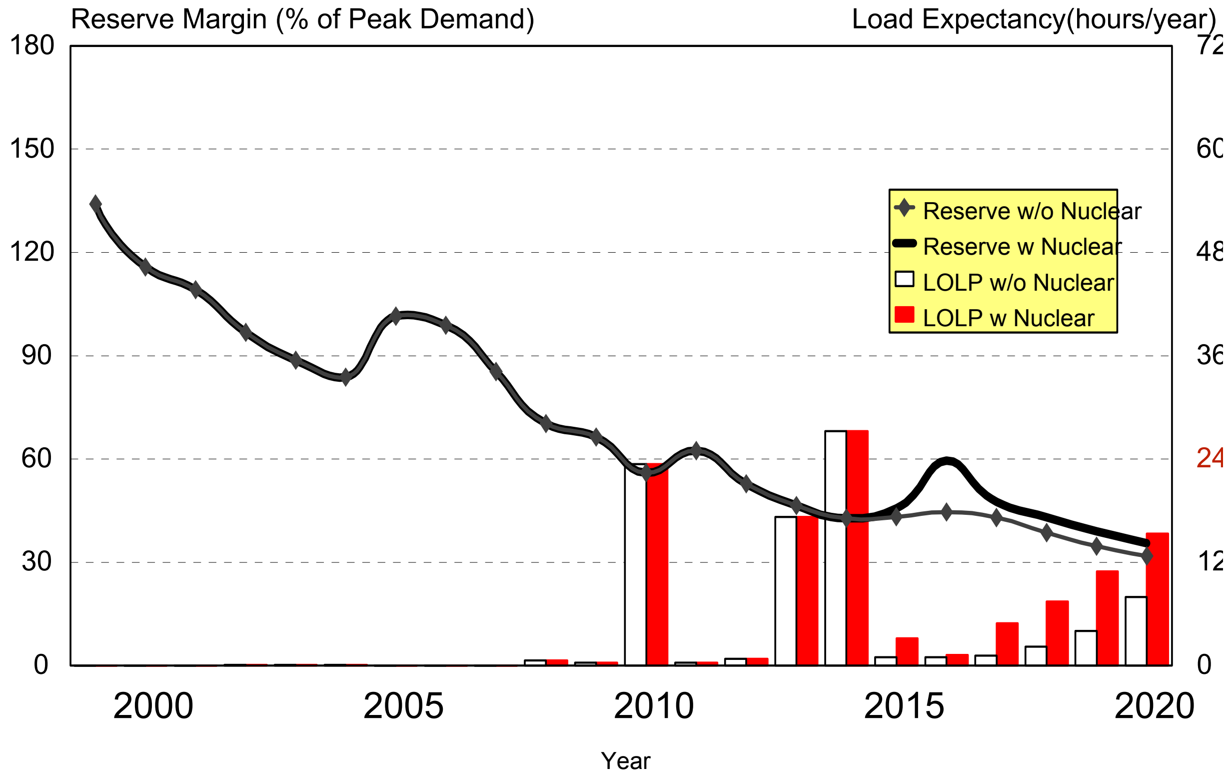

Figure 8.20. Expected System Reserve and Reliability - Reference Demand Scenario - with and without Nuclear Option

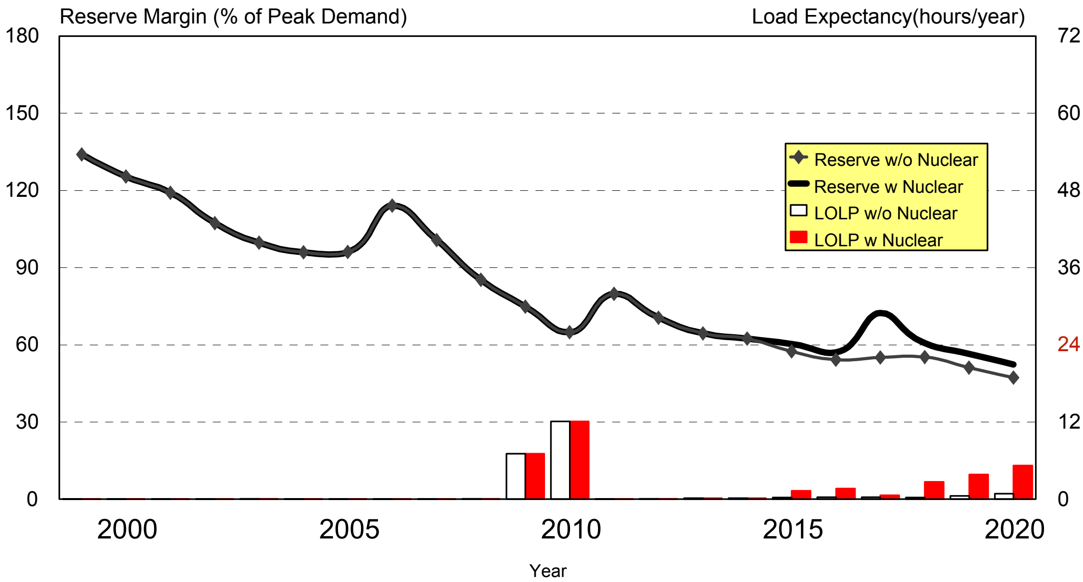

Figure 8.21 Expected System Reserve and Reliability - Low Demand Scenario - with and without Nuclear Option

Table 8.5. Capital Requirements in the Armenian Power Sector in million 1999 US$ - Least Cost Plan with New Nuclear – Reference Demand Scenario

Facility	Capacity (MW)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum
Yerevan TPP																								
Combined Cycle (CHP1-1)	167					6.1	30.6	56.4	23.9															117.0
Combined Cycle (CHP1-2)	167							6.1	30.6	56.4	23.9													117.0
Hrazdan TPP																								
Hrazdan 2-5	300					30.0	30.0																	60.0
Combined Cycle (CHP2-1)	167						6.1	30.6	56.4	23.9														117.0
Combined Cycle (CHP2-2)	167											6.1	30.6	56.4	23.9									117.0
Combined Cycle 1	300							5.5	13.7	42.4	72.6	48.5	13.5											196.2
Combined Cycle 2	300										5.5	13.7	42.4	72.6	48.5	13.5								196.2
Nuclear Plant																								
Armenian NPP New 1	640										16.3	31.4	114	141	227	143	35.9							709.3
Armenian NPP New 2	640											16.3	31.4	114	141	227	143	35.9						709.3
New Hydro																								
Small Hydro < 4.5 c/kWh	35										3.6	18.3	33.7	14.3										69.9
Small Hydro < 5.5 c/kWh	36													3.8	19.1	35.2	14.9							73
Shnokh	75													5.2	21.5	48.4	50.3	16.3						141.7
Megri	80										6.8	28.1	63.4	65.9	21.3									185.5
Gekhi	5																	3.3	7.1					10.4
Wind Converter																								
0.2 MW Units	15												0.7	1.7	5.2	8.9	5.9	1.7						24.1
DSM Measures																								
DSM1	-1	0.03	0.1	0.1																				0.23
DSM2	-3	0.03	0.1	0.2	0.1																			0.43
DSM3	-6		0.1	0.4	0.8	0.3																		1.6
DSM4	-7		0.1	0.4	0.9	0.9	0.3																	2.6
DSM5	-4				0.1	0.4	0.8	0.3																1.6
DSM6	-5					0.1	0.7	1.3	0.5															2.6
DSM7	-2						0.1	0.4	0.7	0.3														1.5
Sum		0.06	0.4	1.1	1.9	37.8	68.6	101	126	123	129	162	330	475	508	477	250	57.2	7.1					2854

Note: Capital requirements don't include IDC.

Table 8.6. Capital Requirements in the Armenian Power Sector in million 1999 US$ - Least Cost Plan with New Nuclear – Low Demand Scenario

Facility	Capacity (MW)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum
Yerevan TPP																								
Combined Cycle (CHP1-1)	167					6.1	30.6	56.4	23.9															117.0
Combined Cycle (CHP1-2)	167									6.1	30.6	56.4	23.9											117.0
Hrazdan TPP																								
Hrazdan 2-5	300						30.0	30																60.0
Combined Cycle (CHP2-1)	167						6.1	30.6	56.4	23.9														117.0
Combined Cycle (CHP2-2)	167														6.1	30.6	56.4	23.9						117.0
Combined Cycle	300							5.5	13.7	42.4	72.6	48.5	13.5											196.2
Nuclear Plant																								
Armenian NPP New 1	640										16.3	31.4	114	141	227	143	35.9							709.3
Armenian NPP New 2	640												16.3	31.4	114	141	227	143	35.9					709.3
New Hydro																								
Small Hydro < 4.5 c/kWh	35										3.6	18.3	33.7	14.3										69.9
Small Hydro < 5.5 c/kWh	36													3.8	19.1	35.2	14.9							73.0
Shnokh	75													5.2	21.5	48.4	50.3	16.3						141.7
Megri	80											6.8	28.1	63.4	65.9	21.3								185.5
Gekhi	5																		3.3	7.1				10.4
Wind Converter																								
0.2 MW Units	15												0.7	1.7	5.2	8.9	5.9	1.7						24.1
DSM Measures																								
DSM1	-1			0.03	0.1	0.1																		0.2
DSM2	-3			0.03	0.1	0.2	0.1																	0.4
DSM3	-6				0.1	0.4	0.8	0.3																1.6
DSM4	-7				0.1	0.4	0.9	0.9	0.3															2.6
DSM5	-4						0.1	0.4	0.8	0.3														1.6
DSM6	-5							0.1	0.7	1.3	0.5													2.6
DSM7	-2								0.1	0.4	0.7	0.3												1.5
Sum				0.06	0.4	7.2	68.6	124	95.9	74.4	124	162	230	261	459	429	391	185	39.2	7.1				2658

Note: Capital requirements don't include IDC.

Table 8.7 Capital Requirements in the Armenian Power Sector in million 1999 US$ - Least Cost Plan without New Nuclear – Reference Demand Scenario

Facility	Capacity (MW)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum
Yerevan TPP																								
Combined Cycle (CHP1-1)	167					6.1	30.6	56.4	23.9															117.0
Combined Cycle (CHP1-2)	167							6.1	30.6	56.4	23.9													117.0
Hrazdan TPP																								
Hrazdan 2-5	300					30.0	30.0																	60.0
Combined Cycle (CHP2-1)	167						6.1	30.6	56.4	23.9														117.0
Combined Cycle (CHP2-2)	167											6.1	30.6	56.4	23.9									117.0
Combined Cycle 1	300							5.5	13.7	42.4	72.6	48.5	13.5											196.2
Combined Cycle 2	300										5.5	13.7	42.4	72.6	48.5	13.5								196.2
Combined Cycle 3	300											5.5	13.7	42.4	72.6	48.5	13.5							196.2
Combined Cycle 4	300											5.5	13.7	42.4	72.6	48.5	13.5							196.2
Combined Cycle 5	300												5.5	13.7	42.4	72.6	48.5	13.5						196.2
Combined Cycle 6	300													5.5	13.7	42.4	72.6	48.5	13.5					196.2
New Hydro																								
Small Hydro < 4.5 c/kWh	35										3.6	18.3	33.7	14.3										69.9
Small Hydro < 5.5 c/kWh	36													3.8	19.1	35.2	14.9							73
Shnokh	75													5.2	21.5	48.4	50.3	16.3						141.7
Megri	80										6.8	28.1	63.4	65.9	21.3									185.5
Gekhi	5																	3.3	7.1					10.4
Wind Converter																								
0.2 MW Units	15												0.7	1.7	5.2	8.9	5.9	1.7						24.1
DSM Measures																								
DSM1	-1	0.03	0.1	0.1																				0.23
DSM2	-3	0.03	0.1	0.2	0.1																			0.43
DSM3	-6		0.1	0.4	0.8	0.3																		1.6
DSM4	-7		0.1	0.4	0.9	0.9	0.3																	2.6
DSM5	-4				0.1	0.4	0.8	0.3																1.6
DSM6	-5					0.1	0.7	1.3	0.5															2.6
DSM7	-2						0.1	0.4	0.7	0.3														1.5
Sum		0.06	0.4	1.1	1.9	37.8	68.6	101	126	123	112	126	217	324	341	318	219	83.3	20.6					2220

Note: Capital requirements don't include IDC.

Table 8.8. Capital Requirements in the Armenian Power Sector, in million, 1999 US$ - Least Cost Plan without New Nuclear – Low Demand Scenario

Facility	Capacity (MW)	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Sum
Yerevan TPP																								
Combined Cycle (CHP1-1)	167					6.1	30.6	56.4	23.9															117.0
Combined Cycle (CHP1-2)	167									6.1	30.6	56.4	23.9											117.0
Hrazdan TPP																								
Hrazdan 2-5	300						30.0	30																60.0
Combined Cycle (CHP2-1)	167						6.1	30.6	56.4	23.9														117.0
Combined Cycle (CHP2-2)	167														6.1	30.6	56.4	23.9						117.0
Combined Cycle 1	300							5.5	13.7	42.4	72.6	48.5	13.5											196.2
Combined Cycle 2	300											5.5	13.7	42.4	72.6	48.5	13.5							196.2
Combined Cycle 3	300											5.5	13.7	42.4	72.6	48.5	13.5							196.2
Combined Cycle 4	300													5.5	13.7	42.4	72.6	48.5	13.5					196.2
Combined Cycle 5	300														5.5	13.7	42.4	72.6	48.5	13.5				196.2
New Hydro																								
Small Hydro < 4.5 c/kWh	35										3.6	18.3	33.7	14.3										69.9
Small Hydro < 5.5 c/kWh	36													3.8	19.1	35.2	14.9							73.0
Shnokh	75													5.2	21.5	48.4	50.3	16.3						141.7
Megri	80											6.8	28.1	63.4	65.9	21.3								185.5
Gekhi	5																		3.3	7.1				10.4
Wind Converter																								
0.2 MW Units	15													0.7	1.7	5.2	8.9	5.9	1.7					24.1
DSM Measures																								
DSM1	-1			0.03	0.1	0.1																		0.2
DSM2	-3			0.03	0.1	0.2	0.1																	0.4
DSM3	-6				0.1	0.4	0.8	0.3																1.6
DSM4	-7				0.1	0.4	0.9	0.9	0.3															2.6
DSM5	-4						0.1	0.4	0.8	0.3														1.6
DSM6	-5							0.1	0.7	1.3	0.5													2.6
DSM7	-2								0.1	0.4	0.7	0.3												1.5
Sum				0.06	0.4	7.2	68.6	124	95.9	74.4	108	141	127	178	279	294	273	167	67	20.6				2024.2

Note: Capital requirements don't include IDC.

Table 8.9. Cumulative Investments and Operation Costs (Million US$ of 1999)

Scenarios	Investments	Operation Costs	Total
Reference Demand Scenario Case with Nuclear Option	2854.0	4545.4	7399.4
Reference Demand Scenario Case without Nuclear Option	2220.0	5004.5	7224.5
Low Demand Scenario Case with Nuclear Option	2658.0	3894.2	6552.2
Low Demand Scenario Case without Nuclear Option	2024.2	4260.1	6284.3

8.5. Sensitivity Analysis

In order to study the effect of discount rate on the power system expansion program worked out in all cases, various sensitivity analyses have been performed. The results of these sensitivity analyses are described below.

Sensitivity analyses on the generation expansion program have been performed by decreasing and increasing discount rates for both capital cost and the operating cost for the reference value of 10% to 8% and 12% for all scenarios. If the discount rate is decreased to 8%, the nuclear power plants program becomes more attractive that that based on natural gas combined cycle units. The increase of the discount rate to 12% is in favour to the gas combined cycle units.

Figures 8.22 and 8.23 show the system present values at 8%, 10% and 12% discount rate for the Reference and Low Demand forecast scenarios with and without nuclear option.

It can be seen, that the main differences in present worth are caused by the thermal or nuclear replacement policy for Armenian NPP.

In terms of energy independence, the alternative expansion plan in which Armenian NPP is replaced by Combined Cycle Plants is somewhat less attractive, and it could be argued that the security of gas supply to Armenia has to be enhanced in that case. Therefore, the bars in the figure are shown without the costs for a new gas pipeline connection to Iran.

The scenario in which Armenian NPP is replaced by a new nuclear plant is only slightly more expensive and would have the advantage of fuel diversification with a reduced dependency on imported fossil fuel. This plan, however, has clear disadvantages with respect to operational flexibility.

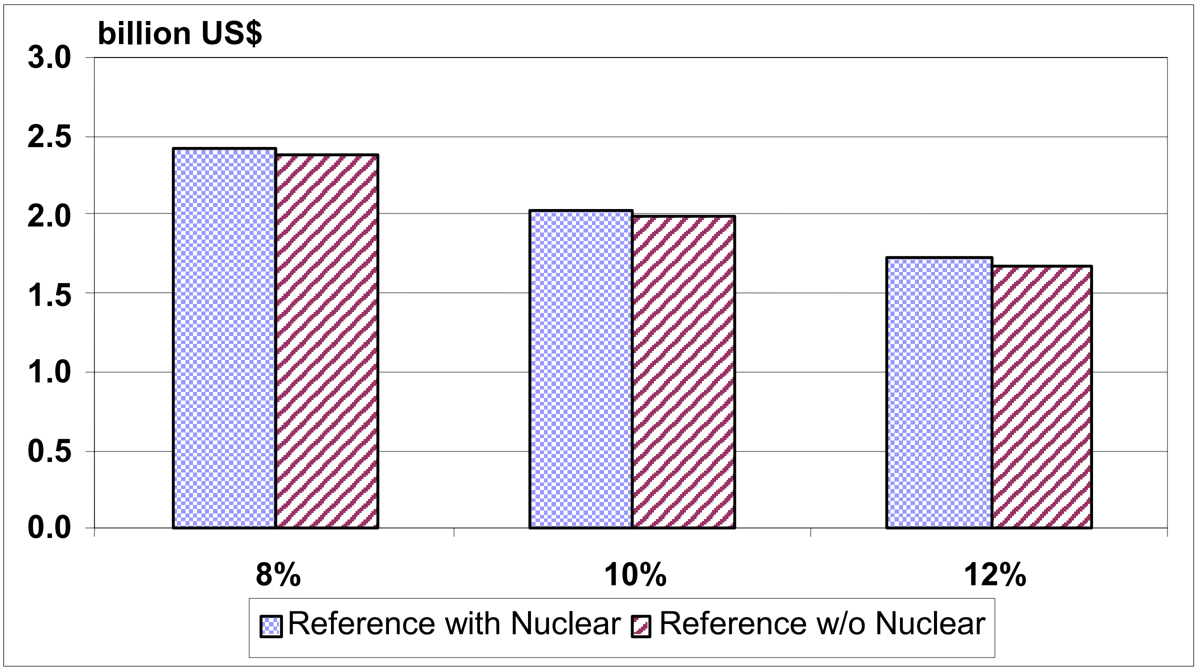

Figure 8.22. System Present Values

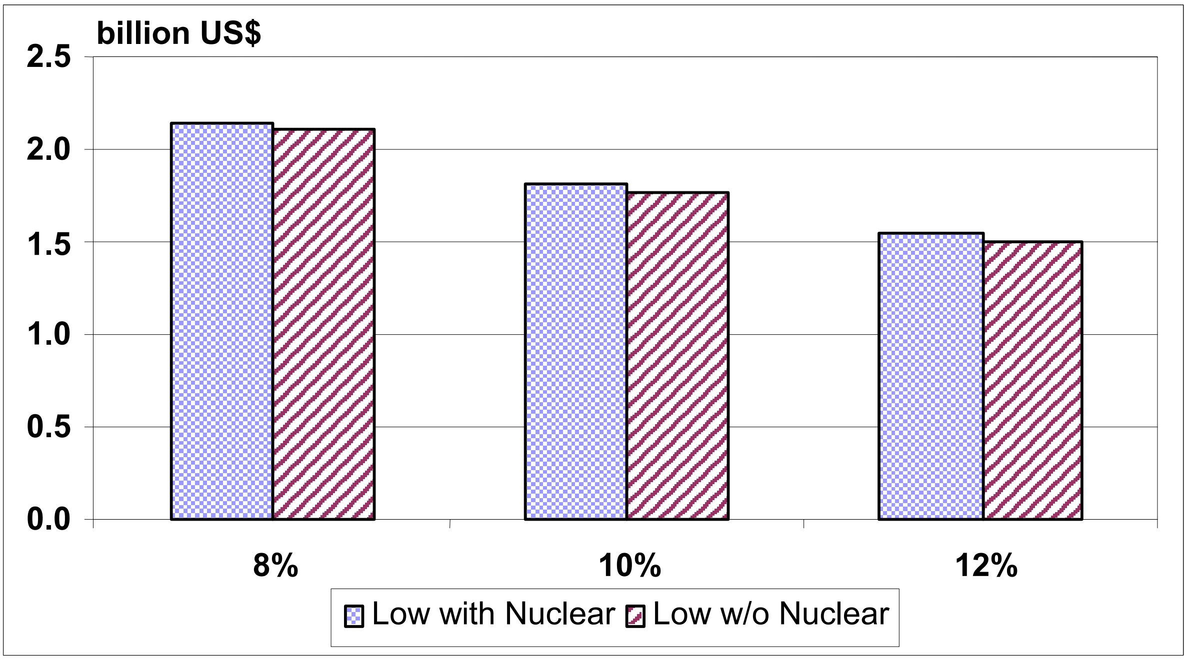

Figure 8.23. System Present Values

8.6. Conclusions

The preceding analysis of power generation capacity expansion has shown that all possible energy supply sources will be required for electricity generation in order to meet the future demand of electricity.

The analyses have shown that nuclear power can significantly help in reducing the energy import dependence of the country. Although nuclear power plants are relatively expensive to build, their operating costs are very small compared to fossil fuel based power plants. This makes the overall costs economics of nuclear power plants very attractive.

It can be seen, that in Reference Demand Case, the nuclear power will be contributing about 50% of power generation in the year of 2020, replacing 1.4 billion m^3 of natural gas consumption for power generation, and for Low Demand Case - about 58% of power generation, replacing 1.3 billion m^3 of natural gas consumption (Figure 8.24).

Further, the proposed program for nuclear power development is quite insensitive to variation in important parameters (capital cost and discount rate). It is therefore clear that all efforts should be made to implement the envisaged nuclear power development plan.

It is declared, that the Government of Armenia has an intention for the country to become less dependent on imported gas, and the scenario with the nuclear option is still of great interest for the Armenian decision makers. It is for this reason, that the Ministry of Energy of Armenia requested the presentation of two least–cost plans, i.e., one, in which gas-fired combined cycle units replace the Armenian NPP, and another, in which a new nuclear power plant replaces it.

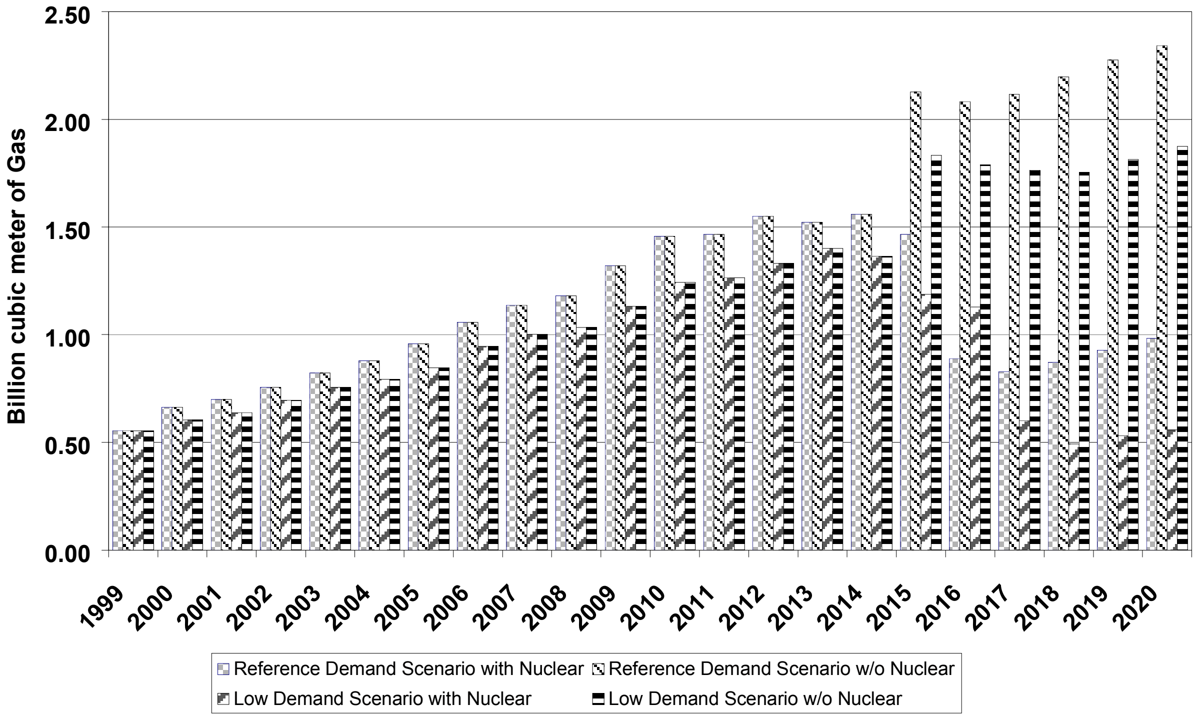

Figure 8.24. Natural Gas Consumption

9 OVERALL ENERGY SUPPLY – DEMAND ANALISYS

9.1. Introduction

In this study - Integrated Energy and Electricity Planning for Nuclear Power Development in Armenia, the following aspects needed the detailed analysis in context of an overall study of medium to long term development of energy system of Armenia:

1. investigation of elaborated solutions on optimal development of power energy in the general context of development of energy sector of Armenia;
2. estimation of existing potential of natural gas import and prospects for the further development of gas-transport communications;
3. sensitive analysis of impact of different technical-economic and scenario factors on the electricity generation cost – as a certain integral indicator of a quality of energy system development planning.

This chapter describes the energy network of Armenia; data and main assumptions used in the BALANCE analysis; the study approach, and results of energy supply cases analysis. This analysis was carried out by means of examining the structure and factors which give rise to energy demands from the various final consumers in each sector (residential, services, industry, agriculture, transport, construction and mining) in order to determine the required amount of final energy and the form that this energy should take: steam, hot water, fuels, electricity, etc.

The objective of this study is to evaluate, by iteration between the BALANCE and WASP programmes, that the optimal capacity expansion plan obtained using the WASP analysis is consistent with the requirements of various fuels for non-electric sector under the given set of assumptions on future availability of supplies of various fuels and their prices.

9.2. Energy Network

The energy supply/demand network represents fuel delivery, energy production, conversion, transport, distribution, and utilization activities in a country, as well as the flows of energy and fuels among those activities.

The sector-structure of Armenian energy system created with the BALANCE programme is displayed in Figure 9.1.

The whole energy system is divided into 24 sectors:

- Resources - Coal and Wood, Mazut, Kerosene, Diesel, Petrol, Jet fuel, Liquid propane gas, Natural gas.
- Power generation (separate - combined heat and power aggregates on Yerevan, Hrazdan and Vanadzor TPP's), Electricity transport and distribution, Electricity Export/Import.
- District heating - Boiler houses, steam- and hot water transport and distribution systems.
- Demand site - Residential, Manufacturing, Services, Transport, Agriculture, Construction, Mining.

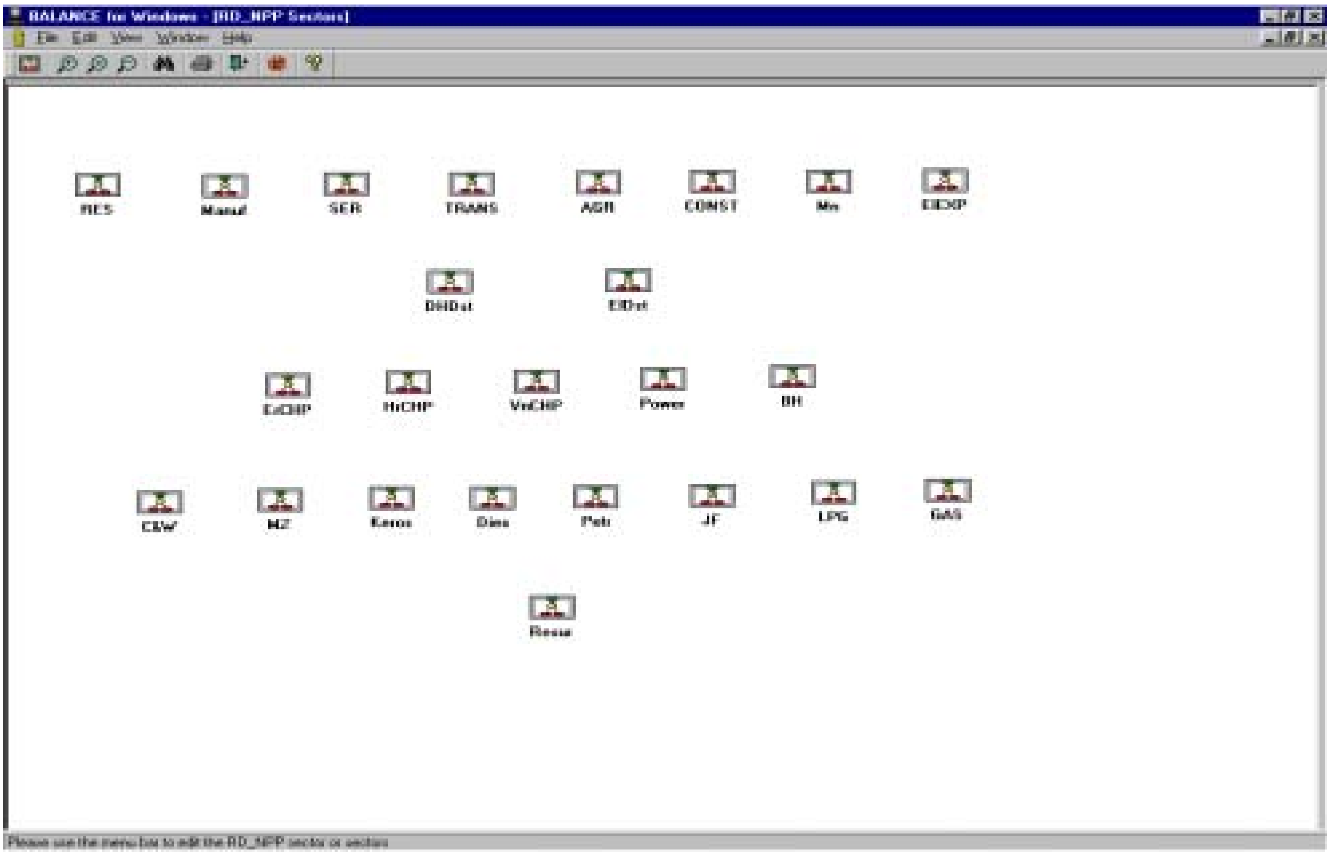

Figure 9.1. Sector-structure of Armenian energy system

Note: RES-residential, Manuf-manufacturing, SER-services, TRANS-transportation, AGR-agriculture, CONST-construction, Min-mining, ELEXP-electricity export, DHDst-district heating distribution, ELDst-electricity distribution, ErCHP-Yerevan CHP, HrCHP-Hrazdan CHP, VnCHP-Vanadzor CHP, BH-boiler houses, C&W-coal and wood, MZ-mazut, Keros-kerosene, Dies-diesel, Petr-petrol, JF-jet fuel, Resour-resources.

9.2.1. Resources

As it was mentioned in Chapter 2, Armenia does not possess its own domestic energy resources, except for hydro and small quantities of coal and wood (wind, solar). Therefore, almost all types of energy resources on primary level were modeled only by "Resource node".

11 nodes simulating the extraction and import of following energy resources are presented in the given sector: coal and wood, mazut, kerosene, diesel, petrol, jet fuel, liquid propane gas, natural gas, synthesis gas, nuclear fuel and electricity.

It has to be noted, that reserves of coal and wood are limited, except for the synthesis gas, which is a secondary product of chemical manufacturing, the use of synthesis gas is restricted.

It was assumed that the prices of the energy resources are permanently changing. The initial prices are taken into consideration, and price growths for each energy resource at primary level are presented in Figure 9.2.

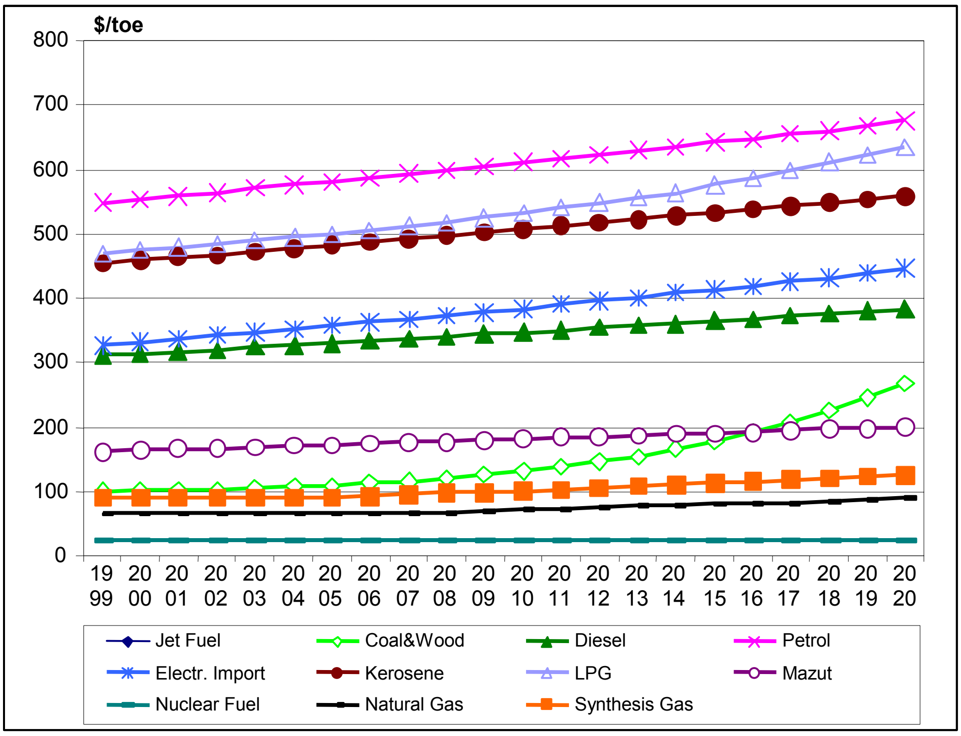

Figure 9.2. Prices for Energy Resources

9.2.2. Fossil Fuel Delivery Sectors

The delivery of energy resources (Coal and wood, Mazut, Kerosene, Diesel, Petrol, Jet fuel and Liquid propane gas) to other sectors is usually performed through the allocation nodes. All these sectors are identical. There are demand nodes in each of the sectors for modeling the stockpiling process of energy resources. In these nodes, the growth rate of consumption of the given type of energy resources increases proportionally to general consumption. The transportation of the resources in these sectors is neglected.

9.2.3. Natural Gas Delivery Sector

Natural gas delivery scheme is given in Figure 9.3. Losses relevant to the transportation of imported natural gas and operating and maintenance costs are modeled through the transport node (GRL). The pricing nodes change the price (20%) of the imported gas according to the value added tax (VAT). In Abovian, there are underground storage facilities for natural gas. The resource and demand nodes have been used to simulate process of gas consumption and accumulation.

As a next step, the natural gas consumer market was analyzed and the following main consumers have been identified:

Power sector. The Armenian thermal power sector has a total installed capacity of 1.756 MW. The thermal power plants are located in Yerevan, Hrazdan and Vanadzor. Each of the TPPs has certain CHP-capabilities having steam extractions for industrial purposes and/or district heating, and is equipped with bivalent burners using gas and mazut as a fuel.

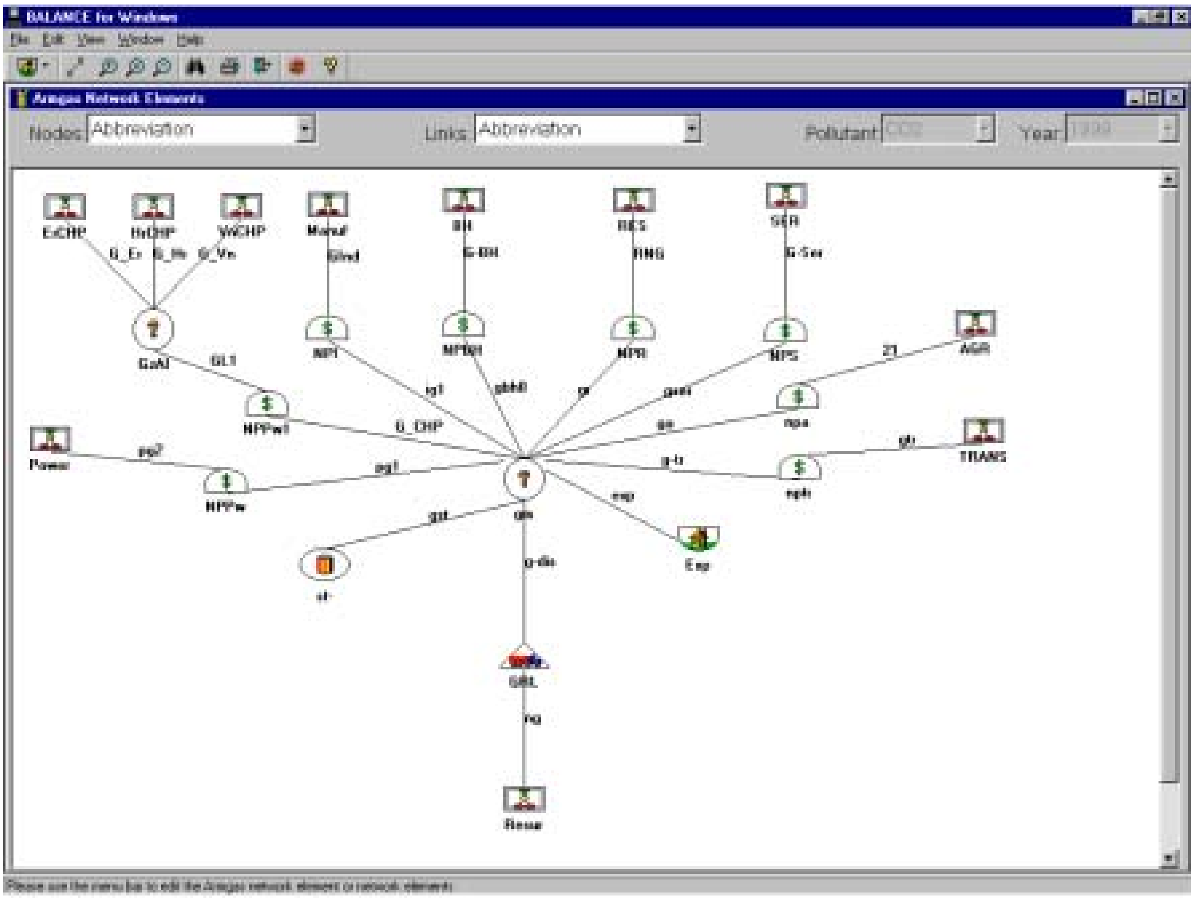

Figure 9.3. Natural Gas Delivery Sector

Assessment of the reliability/availability was done taking into consideration the fact that most of the equipment is - by several reasons - obsolete and needs rehabilitation or replacement.

In addition, the energy consumption declined considerably (about 50% from 1988 to 1999) due to the economic problems with the most dramatic reduction in the industrial sector, where demand has plummeted to about 20% compared to 1988.

As a result of the availability of district heating and natural gas being limited during the years of energy crisis, the resident consumers have substituted the thermal energy heating by the electrical one, and that resulted in a steady growth of the residential electricity consumption.

But such a situation could require - within a short term period, and considering the relevant economic/industrial development of the country - a high potential for natural gas as a primary energy resource.

Moreover, such a perspective will be supported by regulations issued by the Ministry of Energy to strengthen the implementation of energy efficiency measures in Armenia, which may result in a future replacement of outdated power generation units by high efficiency gas driven CCHP-units.

In addition, the refurbishment of the decentralized district heating systems, together with the reconstruction of natural gas city distribution networks, should also be considered as key projects in terms of fulfilling energy efficiency issues.

Making the decision to replace the outdated thermal power plants with the high efficiency gas fueled CCHPs, it has to be noted, that the modern gas turbine units require a gas system pressure in the range of 25 barg (e.g. GT8) to 40 barg (e.g. GT26). Such a requirement will become a key design parameter for any future gas transmission/distribution network in Armenia.

Industrial sector. The industrial sector, as mentioned, was subjected to a tremendous breakdown after the disintegration of the Soviet Union, whereas the other sectors, for example agriculture, food industry and commercial - had modest declines, and, especially, the service sector was well developing at that time.

After the reconstruction of the gas distribution networks and further development in the consumer/retail, the tourism sector, respectively, will make necessary for certain industrial sectors a considerable gas demand in the future.

A global improvement in utilization of natural gas in the industrial sector will come when the potential consumers of the past, like cement industry, chemical industry (Nairit) or mining industry, re-enter the local markets and participate considerably in the export market.

Residential sector. As mentioned above, this sector contains a high potential for gas utilization, but depends badly on the development of the relevant infrastructure.

9.2.4. Power Sector

Power system representation in BALANCE model is displayed in Figure 9.4.

The definition of optimal structure for different sizes and types of units for the whole power system has been done by WASP model.

Thermoelectric Process nodes simulate the operation of existing and candidate thermal and nuclear power plants.

The modeling of wind farms is done for Renewable and Conversion nodes.

Within the Power sector of the BALANCE model, hydro power plants are modeled only considering the electricity annual production. These plants operate at base load. This leads to the certain alterations in participation of different groups of plants in the electricity demand supply, since the role of hydro power plants in setting up the peak load and the system reserve margin is not considered. In order to adjust to a certain extent, the mode of representation of hydro power plants in the BALANCE model, the results from the WASP model regarding the operation of hydro power plants were analyzed for the same study period and electricity demand. Using the values for the average hydrological condition, hydro unit operation at base load was defined in accordance with the BALANCE model methodology.

The differences between the capacity of hydro power plants involved in the load curve in WASP and the capacity of the unit, defined according to the BALANCE methodology, were considered as representing the reserve. The reserve was defined as pseudo - thermal unit but with the economic and availability parameters of hydro plants and highest (in comparison with other thermal power plants) user defined loading order.

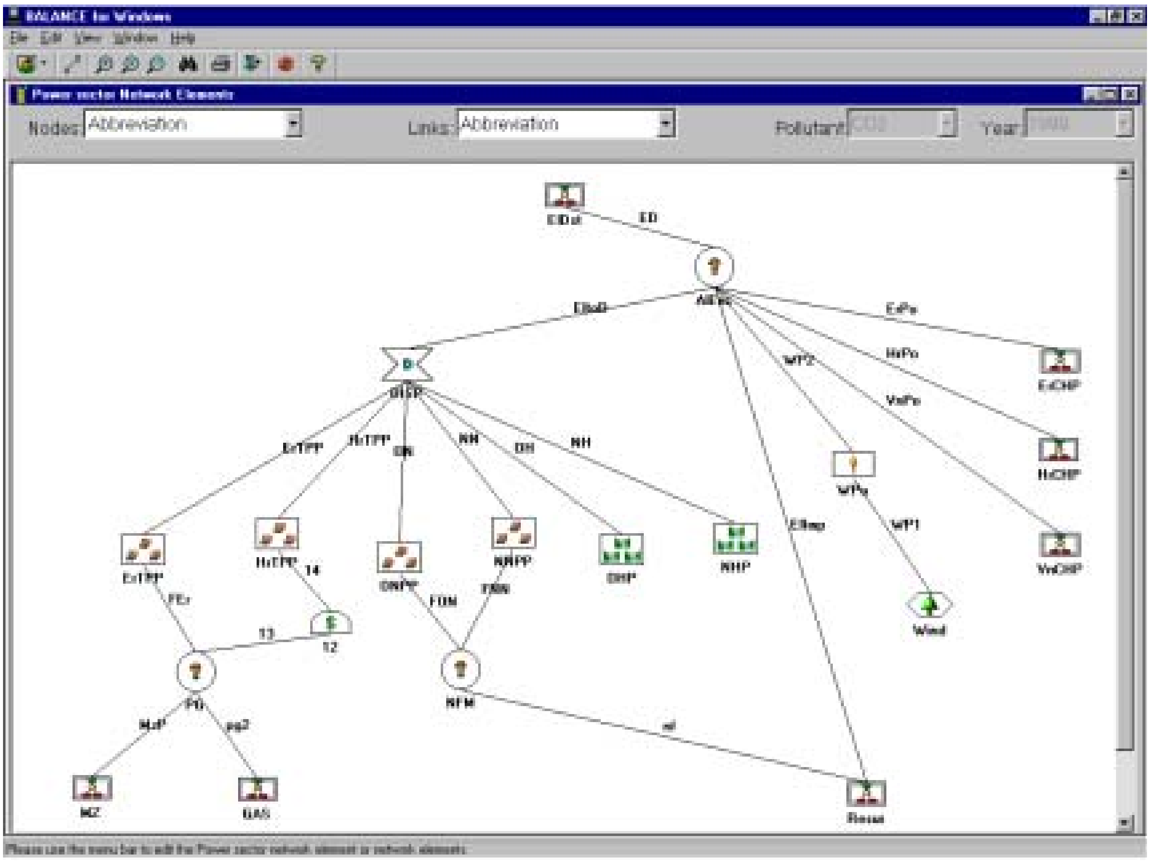

Figure 9.4. Power Sector

The electricity generated by co-generation processes is linked to a common allocation node AlExc, which subtracts co-generated electricity from the total requirements to be met by dispatchable units. In AlExc node, the selection and distribution process establishment is executed from two sources – electricity imported from Iran and dispatched electricity. Since the amount of electricity import and export is restricted, the amounts of energy extracted from the dispatch node will be proportional to the growth of load.

9.2.4.1. Combined Heat and Power Plants Sectors

The most significant characteristic, particularity of this network, is the existence of a centralized heat and electricity co-generation system.

All thermal power plants with capacity up to 1500 MW(e)l – and these are the oldest – are designed as combined heat and power plant, having steam extractions for industrial purposes and/or district heat supply.

The simulation of Combined Heat and Power plants is considered in a way separate from the power sector, as the BALANCE has no direct opportunity of modelling the co-generation process as a type of facility that would allow dispatching the operation of these plants for heat and electricity production.

The co-generation plants are concentrated in three largest cities of Armenia. Three sectors have been used to simulate the operation of these co-generation plants, which are Yerevan CHP, Hrazdan CHP and Vanadzor CHP sectors.

The co-generation processes were represented using multiple output link nodes, which had fuel as input and heat and electricity as output products.

All existing co-generation units, as well as the units that are to be constructed, have been combined in two multiple output nodes for Yerevan TPP (ErOld, ErN) and Hrazdan TPP (HrOl, HrN). There is no candidate plant in Vanadzor TPP. The units have been grouped in two refinery nodes (Vnsm, Vn47) in order to model the operation of existing CHP units in Vanadzor. The detailed description and technical characteristics of these CHPs are given in Chapter 8.

The uncertainty of the heat demand by the industrial sector makes it necessary to keep some of the Old Combined Heat and Power Plants in operation/reserve for several years.

Heat production (high pressure steam) is the priority link, and, as a result, it will control the fuel supply for the multi-output process. The heat production of these units is limited according to the customers' demand, and the relative cost of heat may be compared with that of other sources. The electricity output is related to heat production.

9.2.4.2. Electricity Transportation and Distribution Sector

Losses, operating and maintenance costs connected with transportation and distribution of electricity are modeled through transport nodes. Pricing node changes the price (20%) of the electricity at generation level by using the value added tax multiplier. The entered values of transportation and distribution losses are given in Chapter 5.

The export of electricity was simulated by one demand node in ElEXP sector. Currently, Armenia is exporting electricity to Georgia and Iran. The connection line with Georgia is used in radial way only to feed the Georgian load (80 MW about).

At present, the single circuit line interconnecting Armenia and Iran represents the only interconnecting line between the two electric power systems, with normal import/export regime of about 40-80MW. Import/export management depends on the season, because normally in winter Armenia imports energy, while in summer Armenia exports energy to Iran.

9.2.5. District Heating Sector

District Heating systems are the principal source of space heating in Armenia. About 80% of population is connected to either separate district heating (Boiler House) or co-generation system. At average, the boiler houses are old and badly maintained due to the current economic transition. The design of boiler houses is such that most of them have the possibility to operate in dual fuel fire regime (gas/mazut).

9.2.5.1. Boiler Houses Sector

As it was mentioned above, the boiler houses can operate in a dual fuel fire regime (gas/mazut) that may be changed every year. Also the average emission factor may be changed every year, due to the fact that boiler houses network structure have been modified by including “dummy” processes, so that each process uses only one type of fuel.

9.2.5.2. District Heating, Steam and Hot Water Distribution Sector

The Armenian District Heating system consists of 3 types of sub-systems: district heating by co-generation plants, district heating by large Heat Only Boiler Houses and district heating by small decentralized boiler houses.

District heating system is used to supply hot sanitary water and space heating (in winter). Currently, hot sanitary water supply has been definitely stopped, and heat for space heating is supplied only by co-generation facilities and partly (less than 50% of connected circuits) by large heat only boiler houses. Heat supply by small-decentralized heat only boiler (and partly by large heat only boilers) has been interrupted, leaving the population on their own charge.

People have to warm their dwellings (or part of them) by individual heating devices. The temperature level in dwellings has been bellowing the comfort standards during the cold seasons.

Consumers' heat supply from different sources has been modeled by means of allocation and decision processes.

Actually, the district heating system has heavy heat losses. The district heating system is designed with 80% of average efficiency ratio upon full load and may have an efficiency ratio below 50% upon low load. The transport and distribution network is responsible for a large amount of heat conduction losses, as a result of a poor condition of insulation.

15% of energy input is lost in the transport and distribution pipes for space heating, and 7% is lost in transport pipes of high-pressure steam for thermal needs in industry.

9.2.6. Demand Side

9.2.6.1. Household Sector

Several location nodes are defining the role, that the competing energy sources will play in future energy supply for space heating, water heating and cooking purposes. The conversion nodes are used to simulate the following technologies: wood-heating-stove, wood-water-heating-stove, wood-cooking-stove, kerosene-heating-stove, kerosene-water-boiler, gas heating stove, gas-water-boiler, gas-cooking-stove, LPG-cooking-stove, electric-stove, electric-water-boiler and electric-cooking-stove. The technical characteristics of these technologies are given in Table 9.1.

9.2.6.2. Manufacturing Sector

The following assumptions were taken into account for simulation of energy distribution in Manufacturing sector: steam is used for technological processes of some manufacturing plants that have been grouped in one demand node; electricity consumption of manufacturing sector is defined at final level and doesn't compete with other energy sources.

The allocation node is used to define the future shares of gas and mazut, depending on relative prices.

One multiple input node is combining the necessary quantity of gas and mazut for non-energy use purposes.

9.2.6.3. Service Sector

Three demand nodes represent the use of energy resources in the service sector for the thermal purposes, air conditioning and electricity consumption by appliances.

The following energy resources participate in competition for thermal usage in the service sector: liquid propane gas, natural gas, kerosene, district heating, mazut, coal, wood and electricity.

9.2.6.4. Transport Sector

Transportation sector demand consists of: diesel consumption by rail transport (passenger and freight), cars, freight trucks and buses; petrol consumption by cars, freight trucks, motorcycles and buses; jet fuel consumption for air planes; liquid propane gas and natural gas consumption for cars, freight trucks, and buses; and electricity consumption by rail transport (passenger and freight), trams, trolleybus and subway.

There are six allocation nodes in transport sector, but the possibility for competition of two fuels (LPG and natural gas) is given only for one node.

Table 9.1. Input Data for Conversion Nodes by Type of the Processes

	Power, kW	Annual operation time, h	Investment costs, $/kW	Life time, year	Effici-ency, %	Energy, ktoe	Ash, kg/Gj	SO2, kg/Gj	NOx, kg/Gj	CO2, kg/Gj
LPG-cooking-stove	2	500	13.0	15	50.0	8.6E-05	0.0	0.0	0.076	53.5
Gas-heating-stove	2	500	10.0	15	61.0	8.6E-05	0.0	4.3E-05	0.054	55.14
Gas-Cooking-stove	2	500	10.0	15	50.0	8.6E-05	0.0	4.3E-05	0.056	55.15
Gas-Water-boiler	2	500	10.0	10	60.0	8.6E-05	0.0	2.5E-05	0.031	31.64
Kerosene-heating-stove	2	500	14.0	10	48.1	8.6E-05	0.0	0.24	0.0029	74.80
Kerosene-water-heating-stove	2	500	16.0	10	22.0	8.6E-05	0.0	2.4E-05	0.0029	74.79
Wood-cooking-stove	2	500	7.0	7	12.0	8.6E-05	4.5E-05	0.024	0.037	0.0
Wood-heating-stove	2	500	7.0	15	45.0	8.6E-05	0.0015	0.081	0.124	0.0
Wood-water-heating-stove	2	500	7.0	15	20.0	8.6E-05	6.4E-05	0.035	0.053	0.0
Gas-boiler-big	10000	2500	21.0	25	85.0	2.15	0.0	3.7E-05	0.055	57.21
Gas-boiler-small	1000	2500	23.0	20	78.0	0.215	0.0	0.0	0.140	63.68
Mazut-boiler-big	10000	2500	153.4	20	85.0	2.15	0.0	9.4E-05	0.193	75.01
Mazut-boiler-small	1000	2500	191.8	20	78.0	0.215	0.0	9.8E-05	0.202	78.54

9.2.6.5. Agriculture Sector

The structure of energy flow in agriculture sector was simulated in the following manner:

- there is no competition between motor fuels (diesel, petrol);
- electricity is used for specific purposes;
- direct connection of district heating link with allocation node and connection of gas and mazut to the same allocation node are done through the conversion nodes.

District heating, gas and mazut are used for heating purposes in agriculture sector.

9.2.6.6. Construction and Mining Sectors

Construction and Mining sectors have the similar structure. Three demand nodes in each sector define the consumption of diesel, petrol and electricity for specific purposes in these sectors.

As the investigations shown, the model created completely met the requirements needed for the solution of issued task. Moreover, in case of need, the potential for detailed elaboration of certain sectors of Armenian energy is laid in the model for the purpose of in-depth investigations.

9.3. BALANCE Modelling Results

9.3.1. Comparisons of Power Dispatching Results

According to the assumptions of the availability of indigenous (coal and wood only) and imported fuels, discussed in Section 9.2, the power system expansion plan, that is formulated using WASP model, was analyzed by the BALANCE model. Several WASP and BALANCE iterations were carried out to formulate the power system expansion plan.

In the present analysis, both Reference and Low energy demand scenarios have been used for analysis of two main energy supply cases, e.g. Reference Energy Demand Cases with and without New NPP and Low Energy Demand Cases with and without New NPP.

As it was described in Section 8.3, only the nuclear power capacity additions in these two scenarios have been replaced by thermal capacity based on natural gas. This is the main difference between these two scenarios.

First of all, it is necessary to be convinced in consistency of the obtained results with Power sector performance in WASP and BALANCE models. Comparisons of power dispatching results by WASP and BALANCE are presented in the following figures (Figures 9.5-9.8).

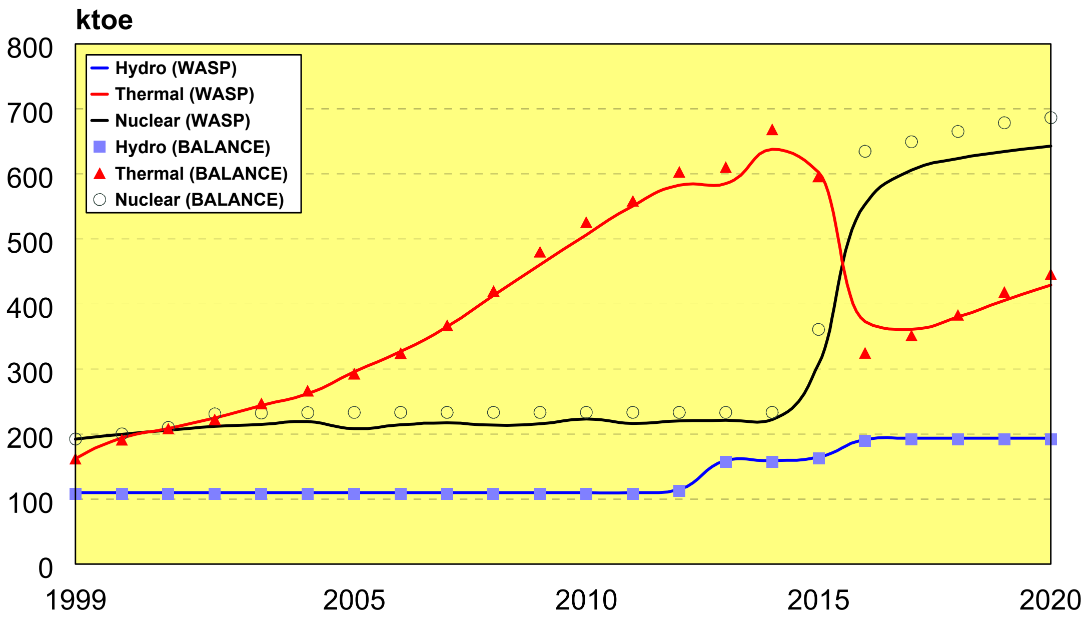

Figure 9.5. Power Dispatching Results – Reference Demand – Nuclear Scenario

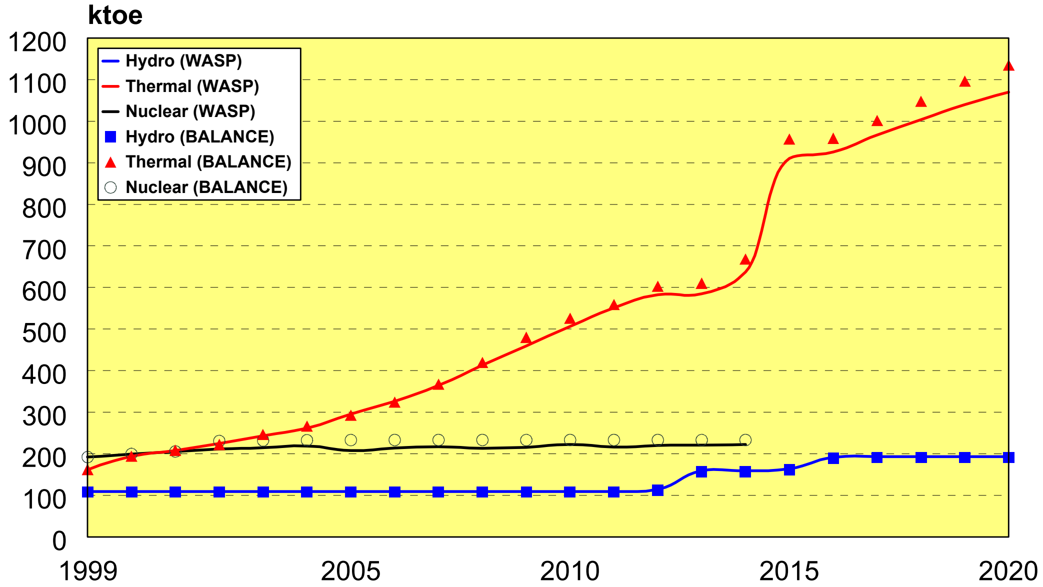

Figure 9.6. Power Sector Dispatching Results – Reference Demand – CC Scenario

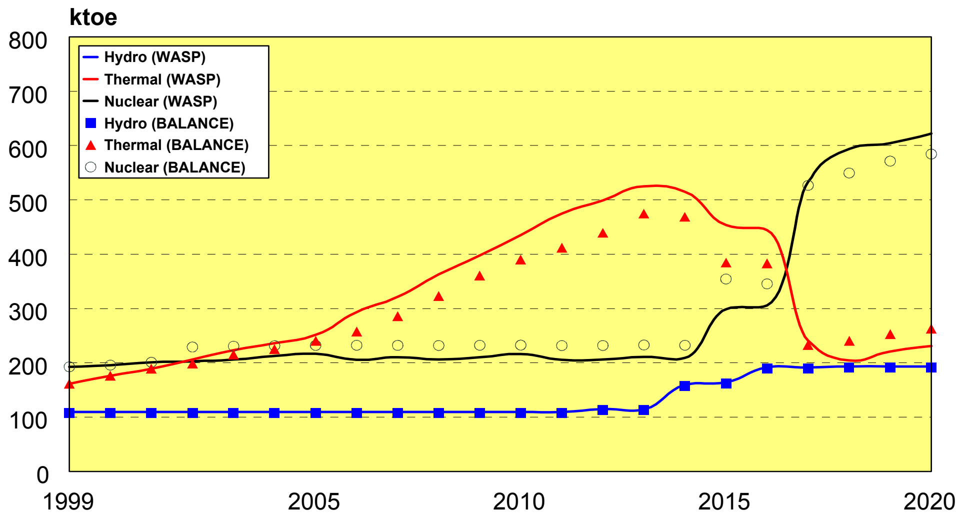

Figure 9.7. Power Sector Dispatching Results – Low Demand – Nuclear Scenario

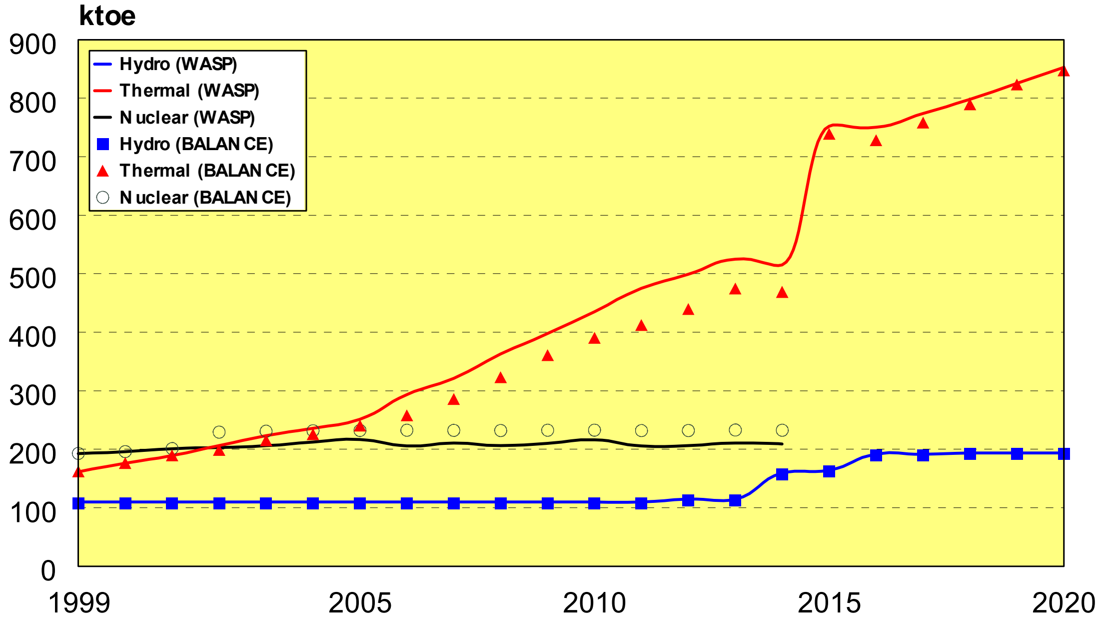

Figure 9.8. Power Sector Dispatching Results – Low Demand – CC Scenario

Figures 9.5-9.8 show that results obtained by BALANCE model are consistent with WASP results and the differences between the results are in acceptable limits. Thus, identity of power sector simulation in WASP and BALANCE models allows to present the further description of energy sector as a whole and to carry out appropriate analyses.

9.3.2. Energy Supply Balances and Level of Energy Independency

According to the final iteration results of BALANCE, the primary energy demand will increase up to 6.7%-8.0% p.a. during the planning period for Reference demand. The yearly energy demands of different types of fuels for selected scenarios are given in Figures 9.9-9.12.

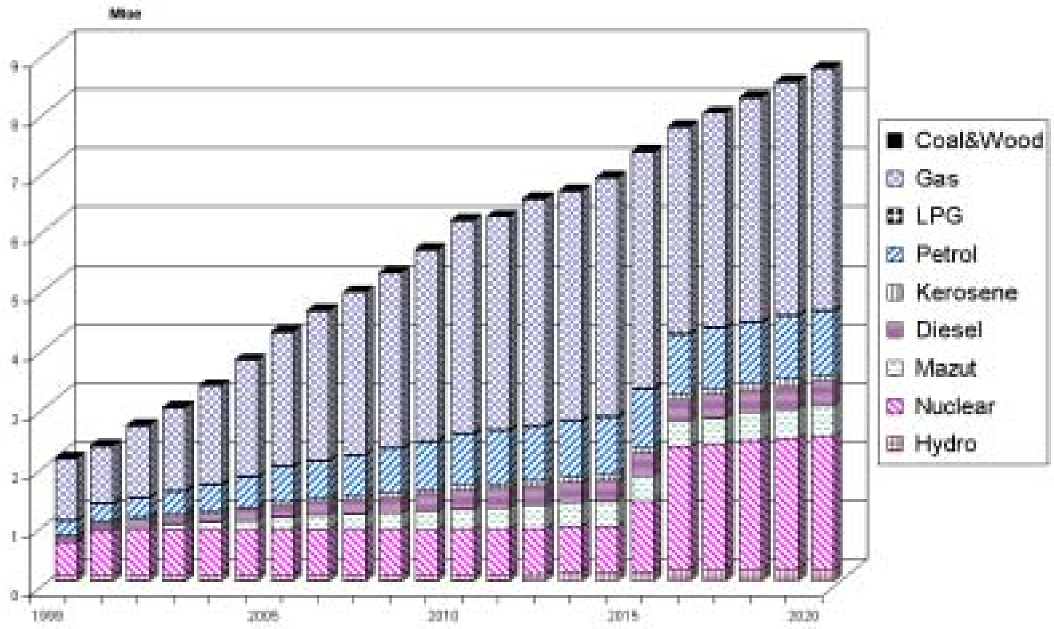

Figure 9.9. Reference Demand – Nuclear Scenario

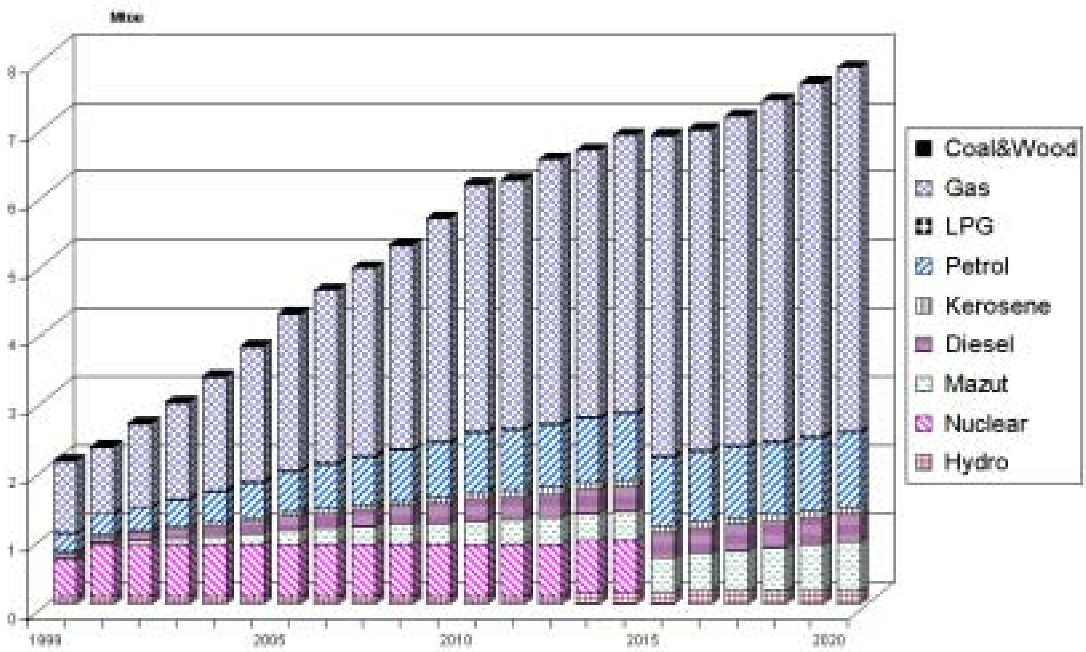

Figure 9.10. Reference Demand - CC Scenario

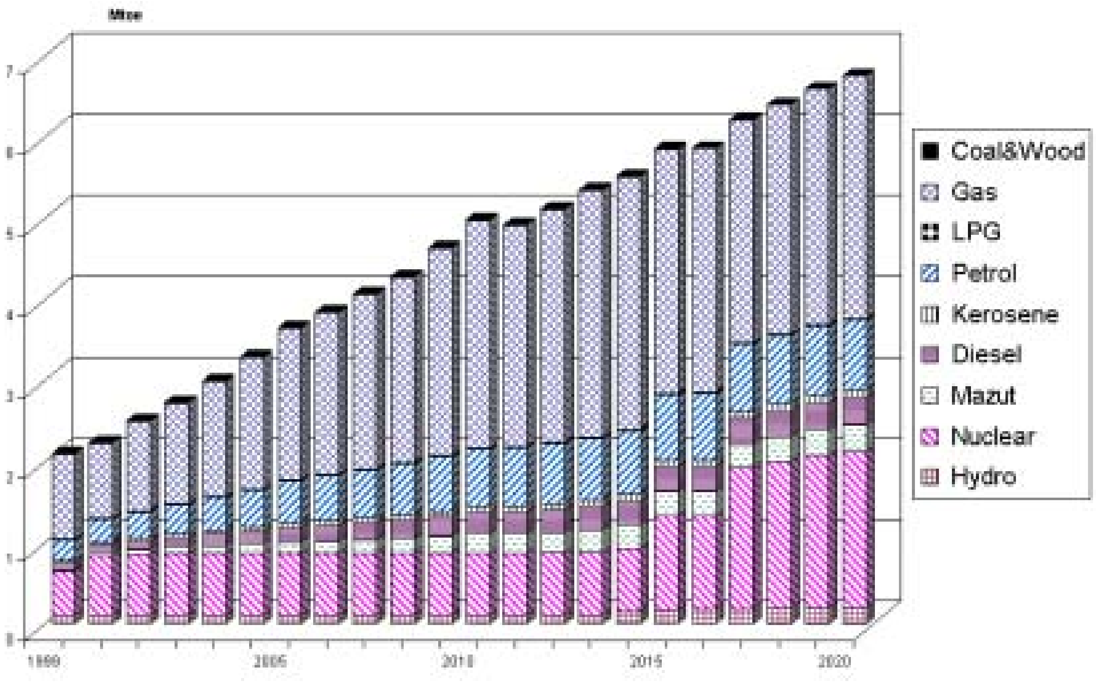

Figure. 9.11. Low Demand - Nuclear Scenario

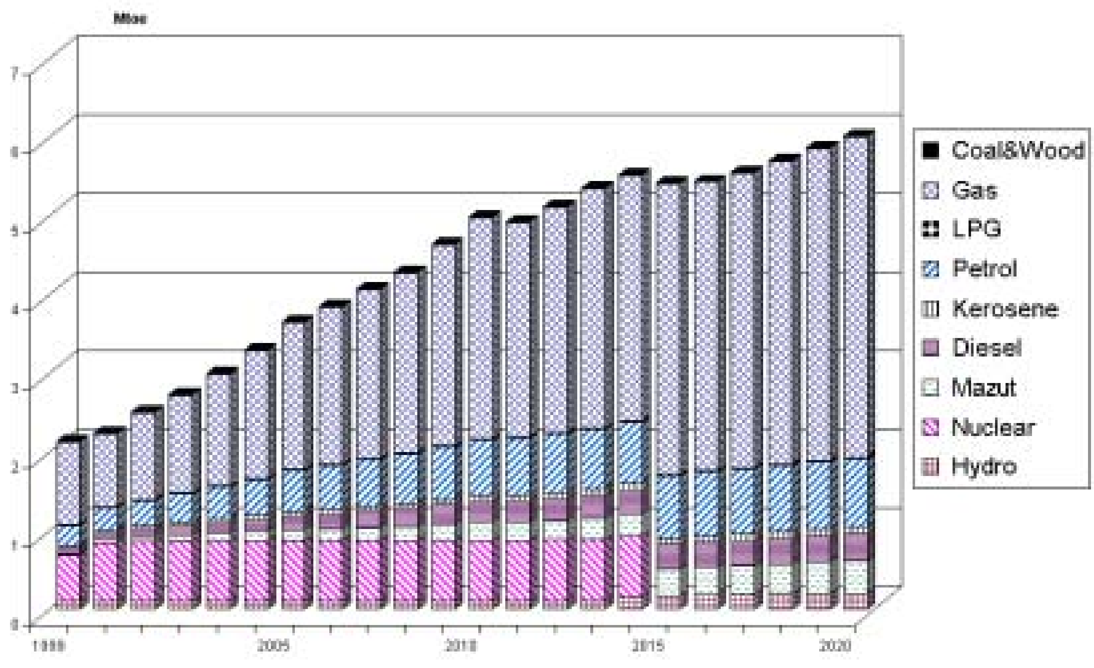

Figure 9.12. Low Demand - CC Scenario

The shares by fuel in the year 2020 for Reference demand Nuclear/CC scenarios will be: Coal&Wood 0.1%; Kerosene 1.2/1.4%; Diesel 4.7/5.2%, Petrol 12.4/13.7%; LPG 0.3/0.4%; Mazut 6.0/9.1%; Nuclear 26.0/0.0%; Gas 47.1/67.6%; and Hydro 2.2/2.4% respectively.

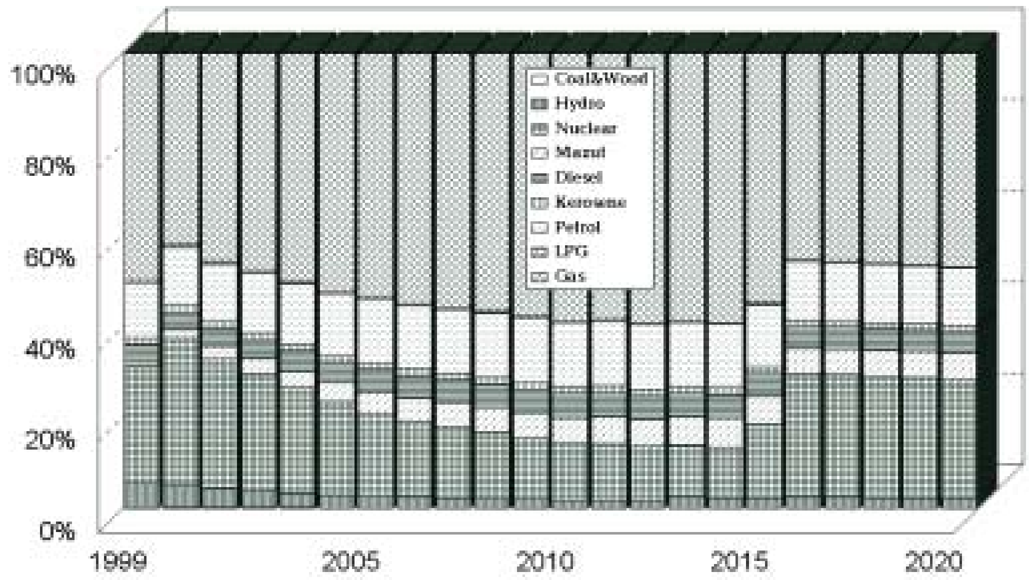

Figure 9.13. Shares by Fuel - Reference Demand - Nuclear Scenario

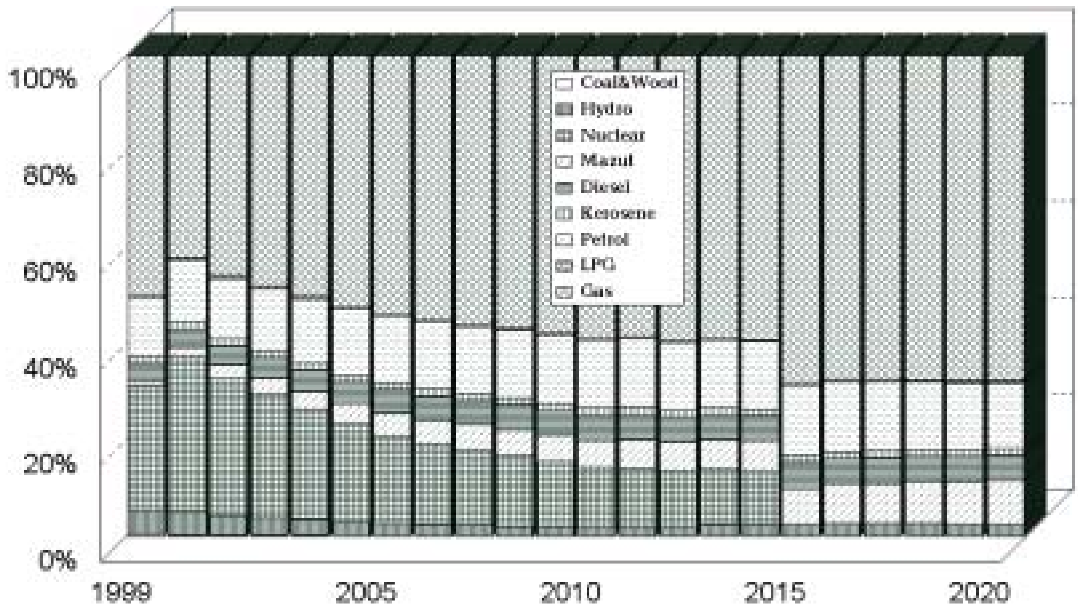

Figure 9.14. Shares by Fuel - Reference Demand – CC Scenario

On the basis of Figure 9.13, 9.14, it can be mentioned that, after the commissioning of two NPP units, despite the increase of primary energy demand, sufficient level of energy independency (38.2%) may be ensured (in 2020) in the Reference Demand Nuclear Scenario, at the same time, for Reference Demand CC scenario this indicator would dramatically reduce to 2.5% after decommissioning of Unit 2 of Armenian NPP.

The shares by fuel in the year 2020 for Low Demand Nuclear/CC Scenarios will be: Coal&Wood 0.1%; Kerosene 1.3/1.5%; Diesel 5.0/5.6%, Petrol 12.8/14.4%; LPG 0.3%; Mazut 5.0/7.1%; Nuclear 28.5/0.0%; Gas 44.2/67.8%; and Hydro 2.8/3.2% respectively.

According to the data (Figures 9.15, 9.16), fuel independency in Low Demand has similar indicators as in Reference Demand (31.4% for Nuclear Scenario and 3.3% for CC Scenario).

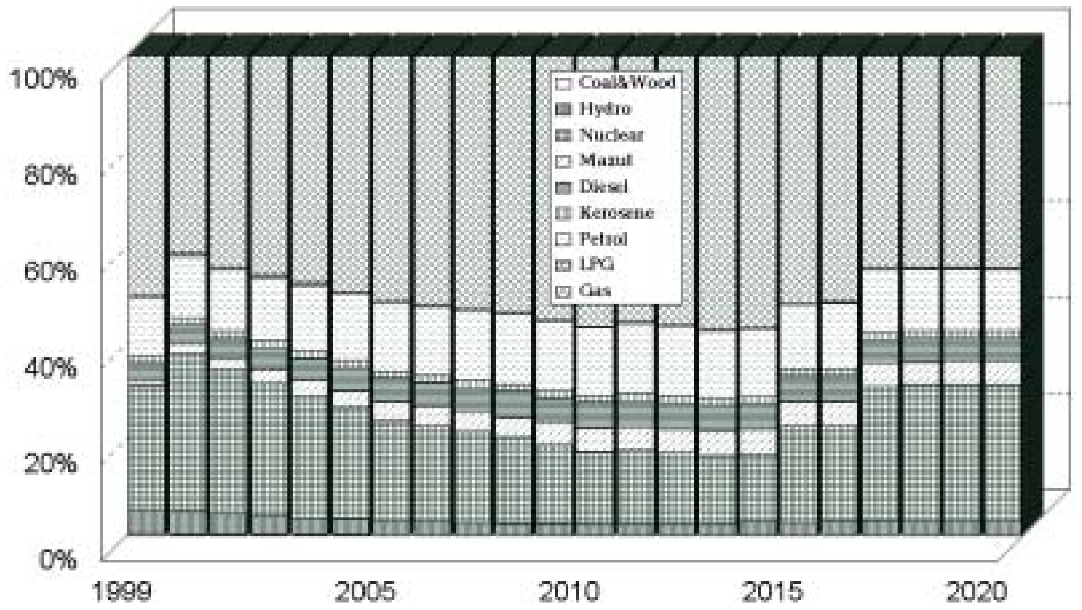

Figure 9.15. Shares by Fuel - Low Demand – Nuclear Scenario

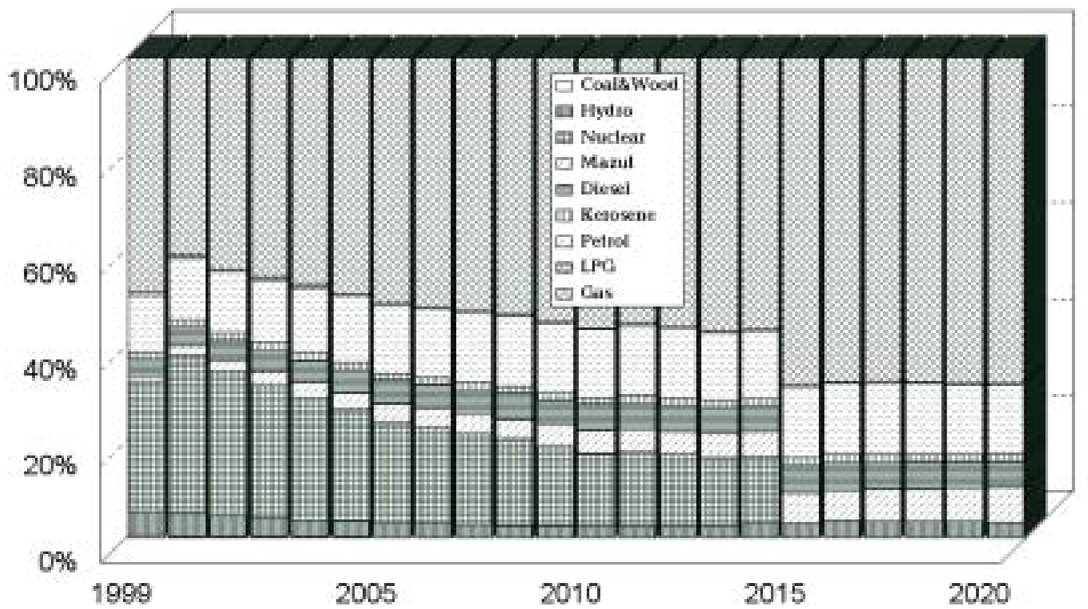

Figure 9.16. Shares by Fuel - Low Demand – CC Scenario

Analysis of obtained results shows that demand of primary energy at the end of planning period (2020) for CC Scenario is lower than that for Nuclear Scenario.

Demand	**CC scenario, ktoe**	**Nuclear Scenario, ktoe**
Reference	7849	8722
Low	6014	6764

This can be explained by the fact that the efficiency of CC plants is significantly higher than the efficiency of NPPs, however, in this case it is necessary to consider the gas price and difficulties connected with its delivery.

Moreover, it is necessary to mention that natural gas and electricity will play the key rolet for the energy balance of the country. At the same time, the volumes of electricity generation in TPP's and prices of electricity generated directly depend on the possible conditions for gas supply. In this respect, these issues are considered in the following sub-chapters 9.3.3 and 9.3.4.

9.3.3. Natural Gas

The Reference and Low demands of gas for all sectors of economy, power sector (including CHPs) and boiler houses are given in Figure 9.17:

- By 2004, gas supply barely covers the demand for all scenarios;
- It takes about 3 years for construction of the first imported gas pipeline from Iran with capacity of about 2500 ktoe. Capacity of existing and new gas pipelines (after 2005) will be sufficient to cover gas demand for scenario with new NPP.
- Gas usage in the power sector will increase in the period 2000-2014; however, after 2015 the gas consumption will decrease due to the fact that new NPP units will be commissioned between 2015 and 2017 for scenarios with new NPP.
- In 2015, gas supply is unable to cover the demand, and it will be necessary to construct the second gas pipeline from Iran with the same capacity for Reference Demand - CC Scenario.

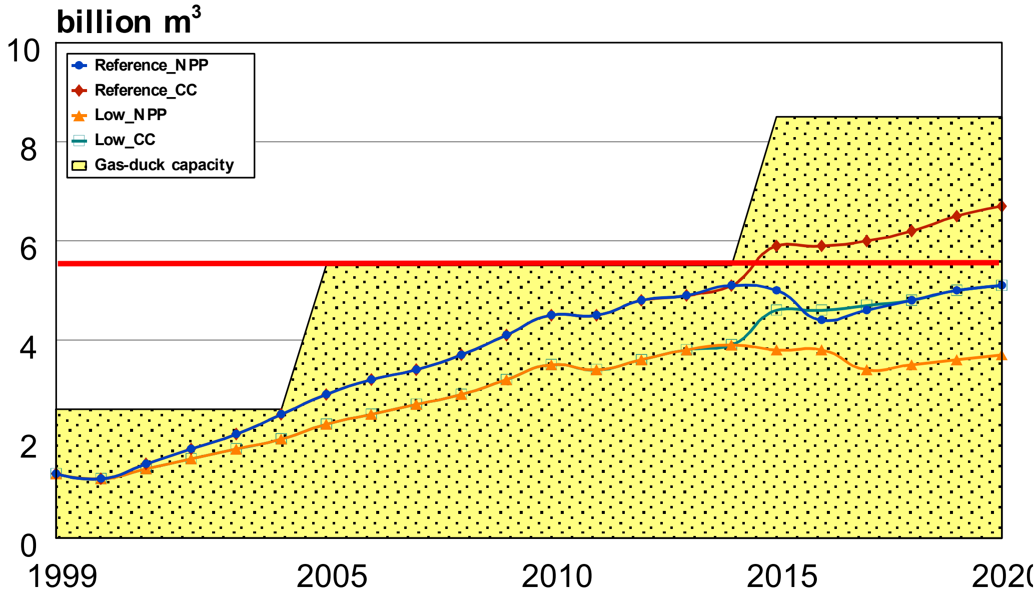

Figure 9.17. Gas Consumption – All Demand Scenarios

The comparison of the gas demands for two cases indicates that in the alternative expansion plan (Reference/Low Demand CC Scenarios), the demand for the gas is higher on 29-36% in 2020. In terms of relative quantities, in CC Scenario, the level of gas usage in power sector in 2020 is higher on 110.9% in comparison with the Nuclear Scenario. Figure 9.19 shows the implementation date of a new gas pipeline connecting Armenia with Iran by the year 2005, and possible addition of the second gas pipeline in 2015 in case the power sector is expanded with combined cycle units only.Gas prices at the final level for all scenarios are given in Figure 9.18.

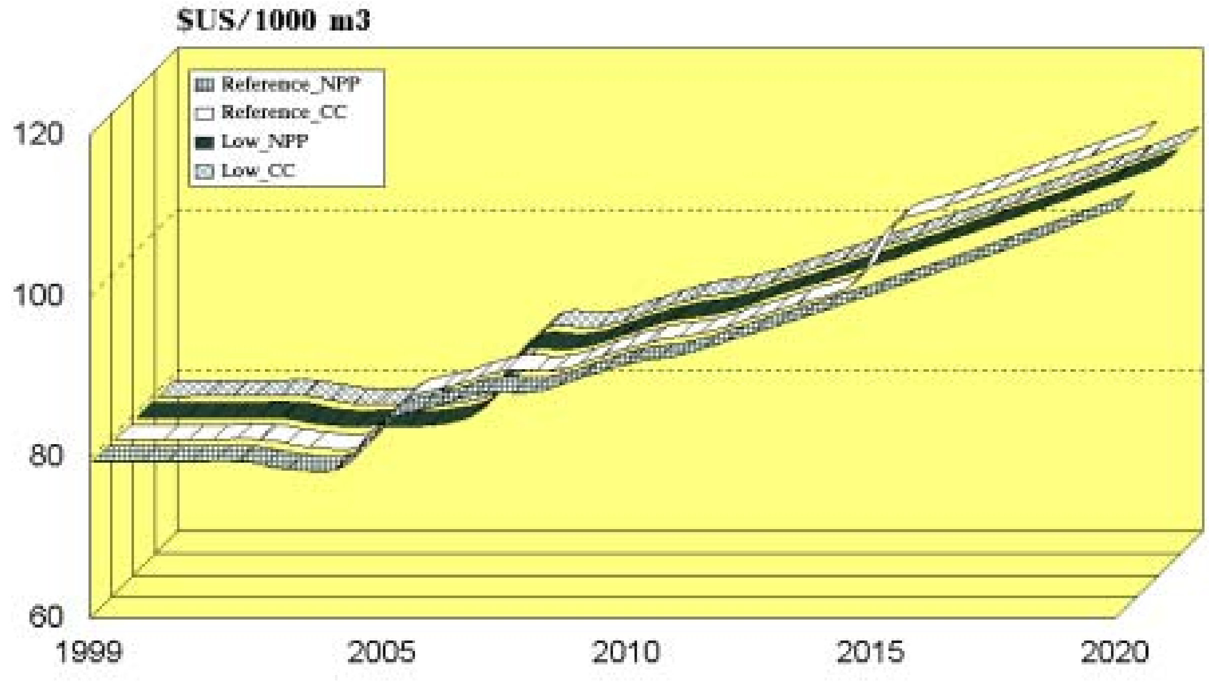

Figure 9.18. Gas Prices – All Demand Scenarios

In case of CC scenario, construction of additional gas duct in 2015, which is necessary for gas supply ensuring, will lead to rather high increase of prices in gas market. In particular, it will affect badly the generation cost of TPP's.

9.3.4. Electricity (Input sources for Power Generation)

The share of hydro generation decreases from about 8.1% in 1999 to 5.4/7.3% (for Reference Demand – Nuclear/CC Scenarios, respectively) by 2020;

At present, about 51.1% of generation is based on gas, and its share will increase up to 61.0% by 2014, but then it will sharply decrease up to 30% by 2020 for Nuclear scenario and increase up to 85.5% for CC scenario.

The share of mazut will increase gradually from nearly zero up to 2.4% by 2014, but then it will decrease to 1.0% by 2020 for nuclear scenario and increase up to 7.5% for CC scenario.

The share of nuclear power will increase from 40.7% in 1999 up to 63.7% in 2020 for Reference Demand and 68.1 % for Low Demand Scenarios.

The share of mazut in power generation in Low Demand – Nuclear Scenario is negligible (about 0.2%) at the end of the planning period, but for CC scenario, it will reach the level of 5% in the corresponding year. The shares of hydro in electricity generation by source differ by 2.6% for these two cases.

Distributed electricity costs for all scenarios are shown in Figure 9.19.

It can be noted, that there are no significant differences between the scenarios. The average long term distribution cost is about 4.9 USc/kWh.

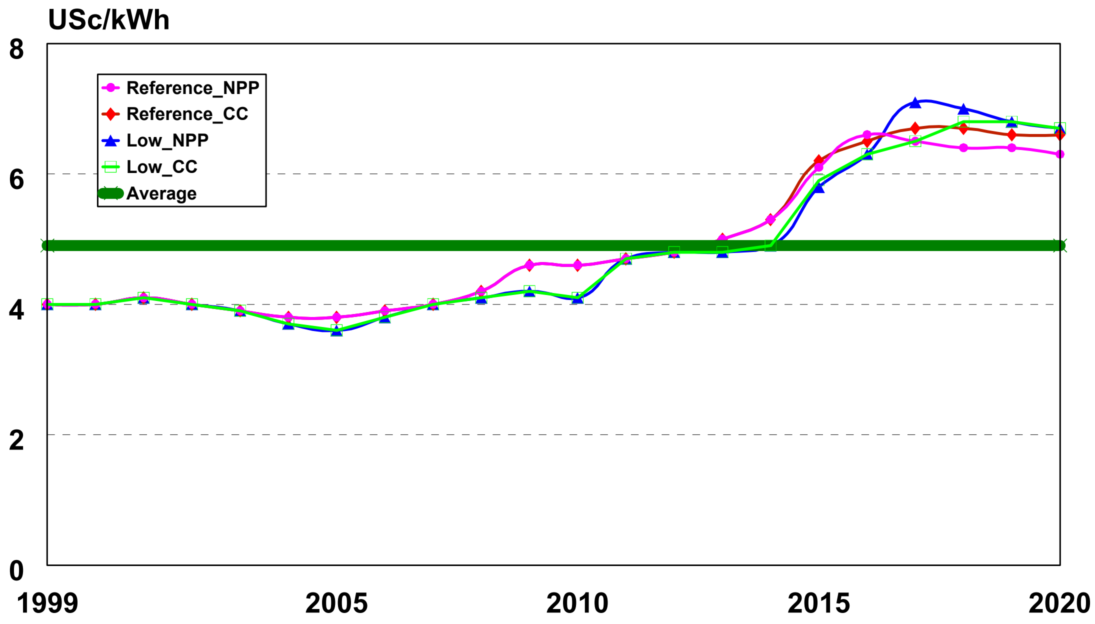

Figure 9.19. Cost of Electricity

Thus, it is possible to ascertain that one of the most important economic indicators of development program - electricity cost - is practically identical for all scenarios. However, upon decision-making, it is necessary to take into account the following important factors:

Nuclear scenario significantly exceeds CC scenario by several indicators (Energy independence (see Figures 9.13 – 9.16), diversification level, ecological characteristics and others).

Upon the significant share of electricity and heat generation in Thermal Power Plants, the cost of Electricity (and heat) will strongly depend on the cost of imported gas in all scenarios. At that, price risk of natural gas for long term period is rather high.

Thus, the probability of such a situation, that cost of Electricity upon implementation of Nuclear Scenario will comply with planned values, is higher than that of a situaton when the CC Scenario is under consideration. Certainly, such a statement will be practical if assuming that the volumes of investments and implementation terms of separate projects of the Development Program are not much deviated.

It is clear, that formulated tasks are subject to serious analysis, the information on which is presented in Section 9.4

9.3.5. Heat and Steam

As it was mentioned in previous sections, the thermal energy in Armenia is produced by:

- TPPs
- Regional district heating systems
- Local district heating systems
- Individual boilers
- Personal heating installations.

The latest elaborations in the sphere of heat supply of Armenia denote that, upon new conditions of market relations, it is advisable to implement the decentralization of heat supply system. However, it is difficult to expect the total decentralization of heat supply system in the country with developed centralized district heating system even in the future. In this respect, the nodes, which produce the tendency of partial decentralization (e.g. individual boilers, personal heating installations etc.), are foreseen for such sectors as Residential, Services, Manufacturing and Agriculture, that allows representing the development of centralized heat supply system in the model. Dynamics of thermal energy generation in TPP, BH and decentralized sources in different sectors is presented in Figures 9.20, 9.21.

It can be noted (see Figure 9.22, 9.23) that in 2020, about 24/28% of total heat demand will be produced by decentralized heat systems in Residential, 10/13% in Services, 13/6% in Manufacturing, and about 8/9% in Agriculture sectors for Reference/Low demand scenarios, respectively.

Supply of the centralized heat to the consumers has been modeled for CHP units and BH, as it was described in sections 9.2.4.1 and 9.2.5.1.

About 5% of the total electricity demand and 51.4% of the heat demand were covered by this system in 1999, and it is assumed that more than 17% of the total electricity demand and about 45% of the heat demand will be covered by this system in 2020.

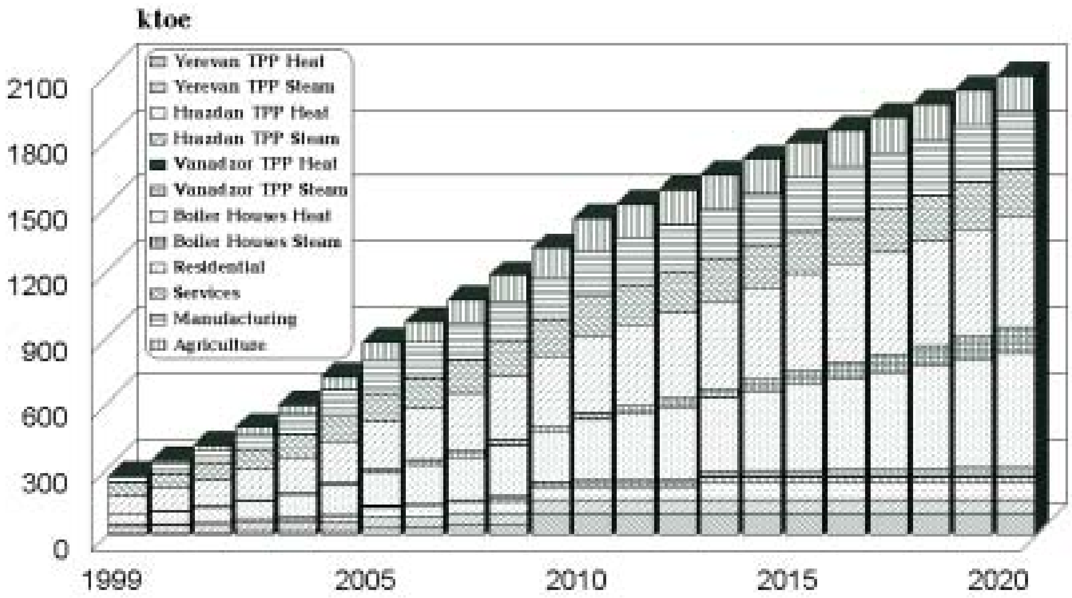

Figure 9.20. Structure of Heat Demand Covering (by centralized and decentralized sources) – Reference Demand

Information on heat (district heating and hot water) and steam production by this type of source for Reference and Low Demand Scenarios is given in Figures 9.22, 9.23.

Total heat supply by CHP's and BH's is expected to be 227 ktoe in 2005, 428 ktoe in 2010, 563 ktoe in 2015 and 689 ktoe in 2020 in Reference scenario; 204 ktoe in 2005, 378 ktoe in 2010, 489 ktoe in 2015 and 573 ktoe in 2020 in Low scenario

The main consumer of steam is manufacturing sector.

The steam demand in Manufacturing sector will be changed from 38 ktoe in 1999 to 74/61 ktoe in 2005, 127/91 ktoe in 2010, 187/125 ktoe in 2015 and 258/157 ktoe in 2020 with an average annual growth rate of 9.6/7% during the whole period for Reference/Low Demand respectively.

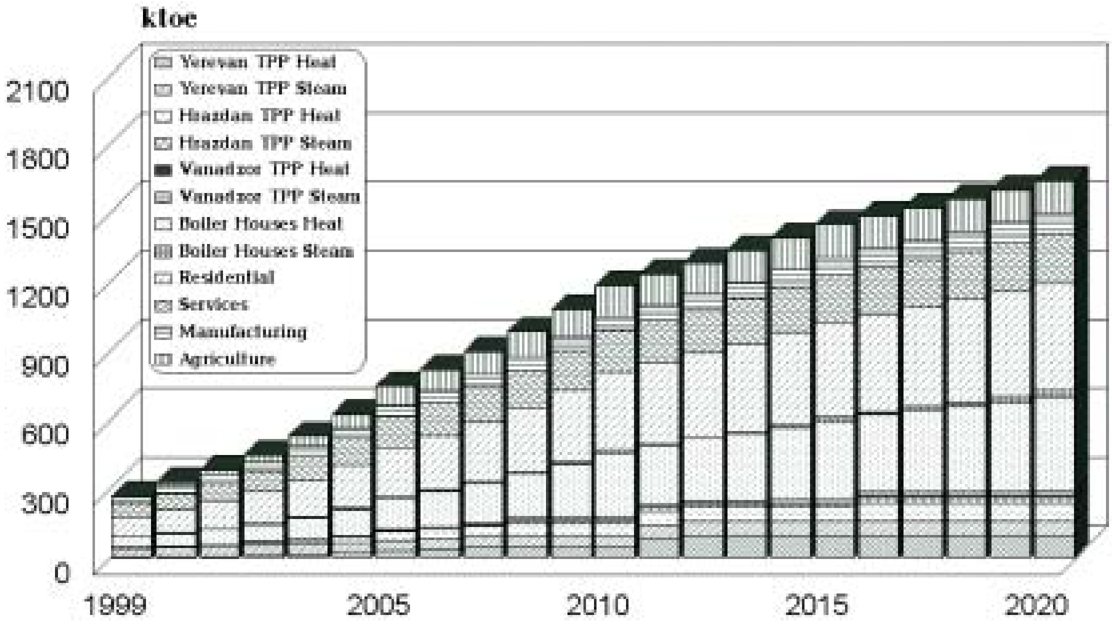

Figure 9.21. Structure of Heat Demand Covering (by centralized and decentralized sources) – LowDemand

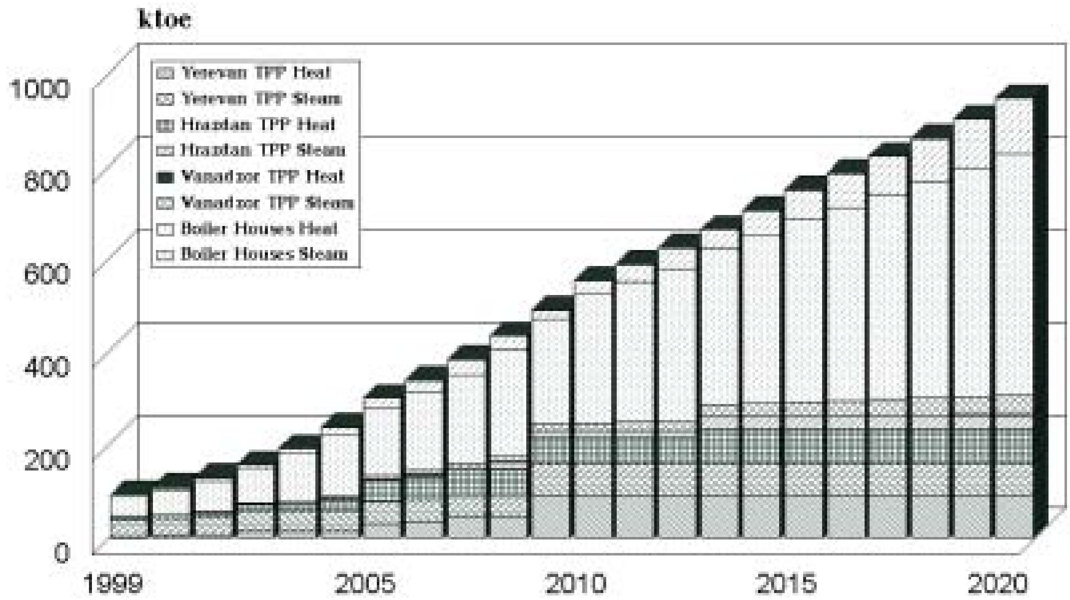

Figure 9.22. Heat and Steam Production - Reference Demand

9.3.6. Emissions

The main emission sources are power, manufacturing and transport sectors. At present, emissions from stationary sources, such as energy production and industrial activities, are relatively low due to the transition from heavy fuel oil to natural gas and non-full operation regime of Power Plants, caused by general decrease of energy demand in industry.

Total CO_2 emissions for different scenarios are presented in Figure 9.24.

The share of selected air pollutants, summarized for all years of planning period, is presented in Figure 9.25.

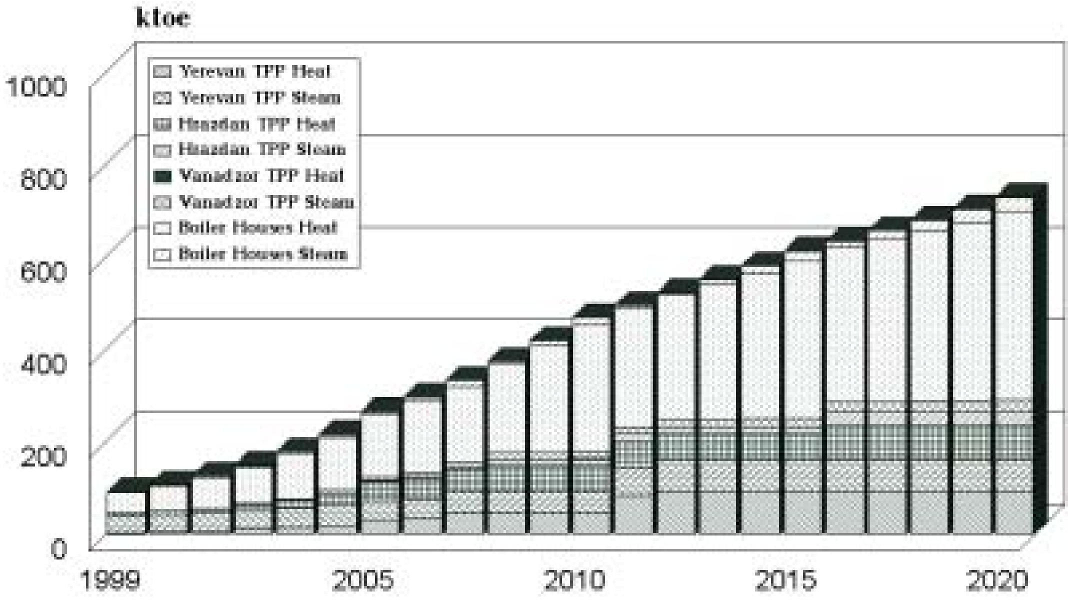

Figure 9.23. Heat and Steam Production - Low Demand

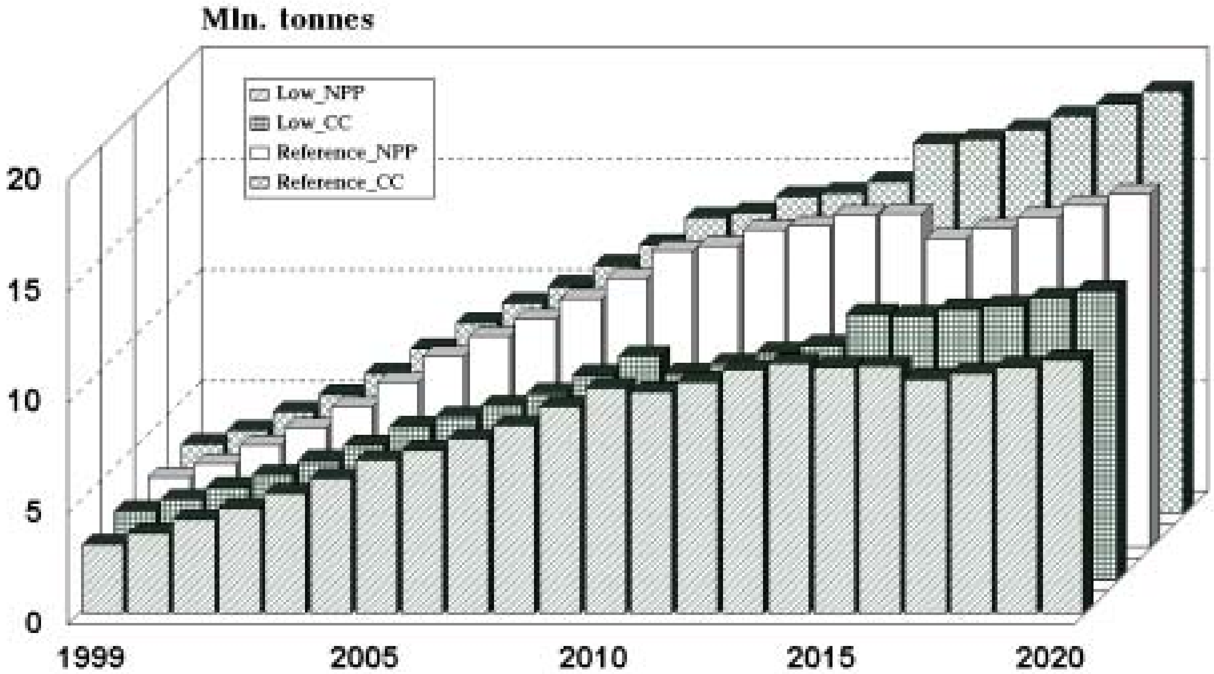

Figure 9.24. Expected Level of CO_2 Emissions of Energy Sector

The expected shares of CO_2 emission from different sectors for Reference and Low Demand scenarios are shown in the following figures (Figures 9.26 - 9.29).

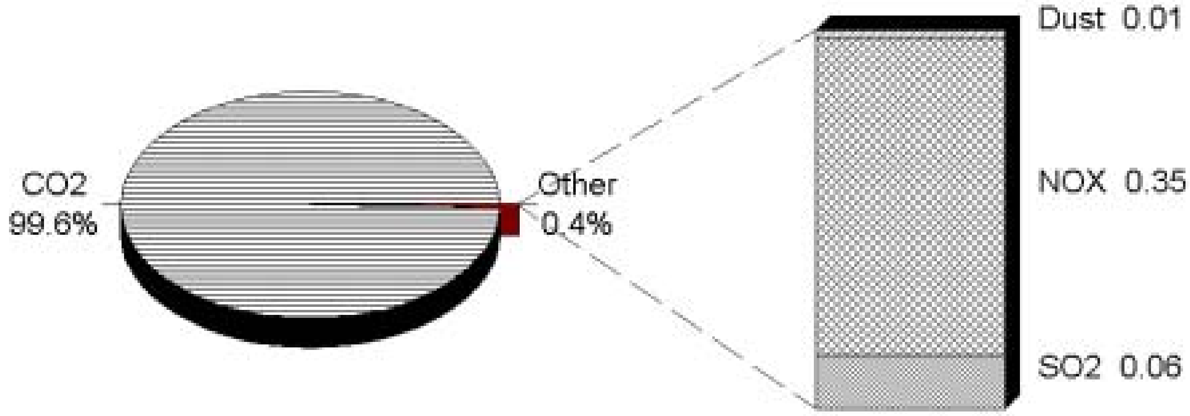

Figure 9.25. Shares of air pollutants

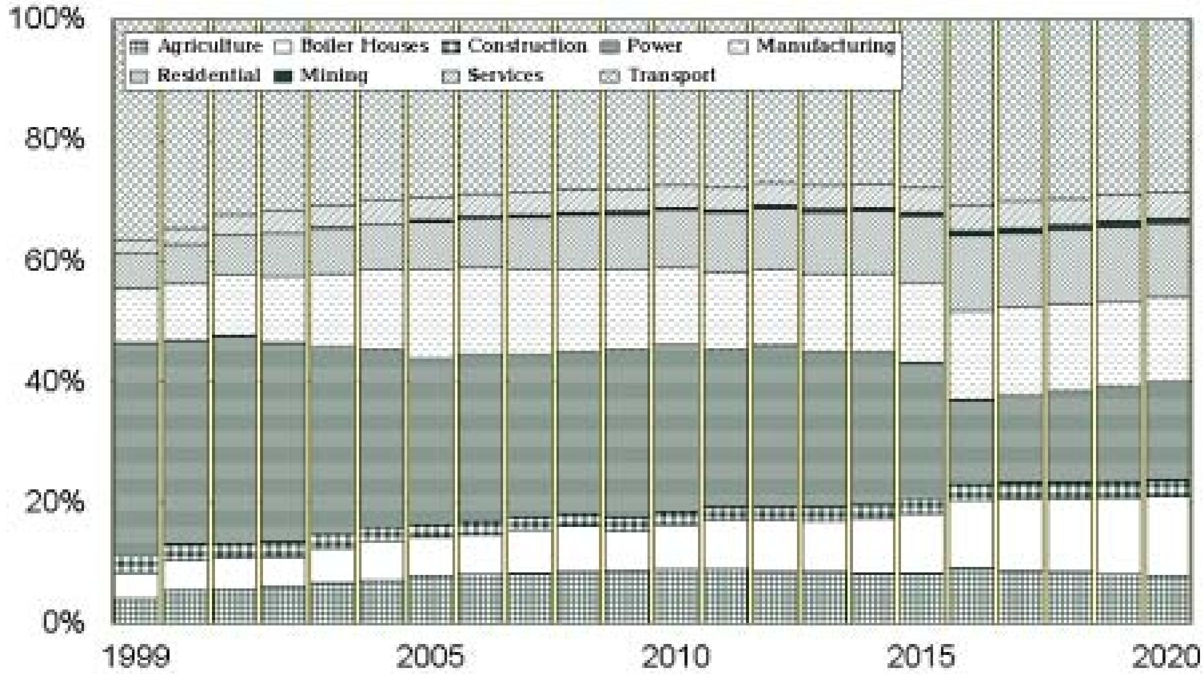

Figure 9.26. Shares of CO_2 per Sector – Reference Demand - Nuclear Scenario

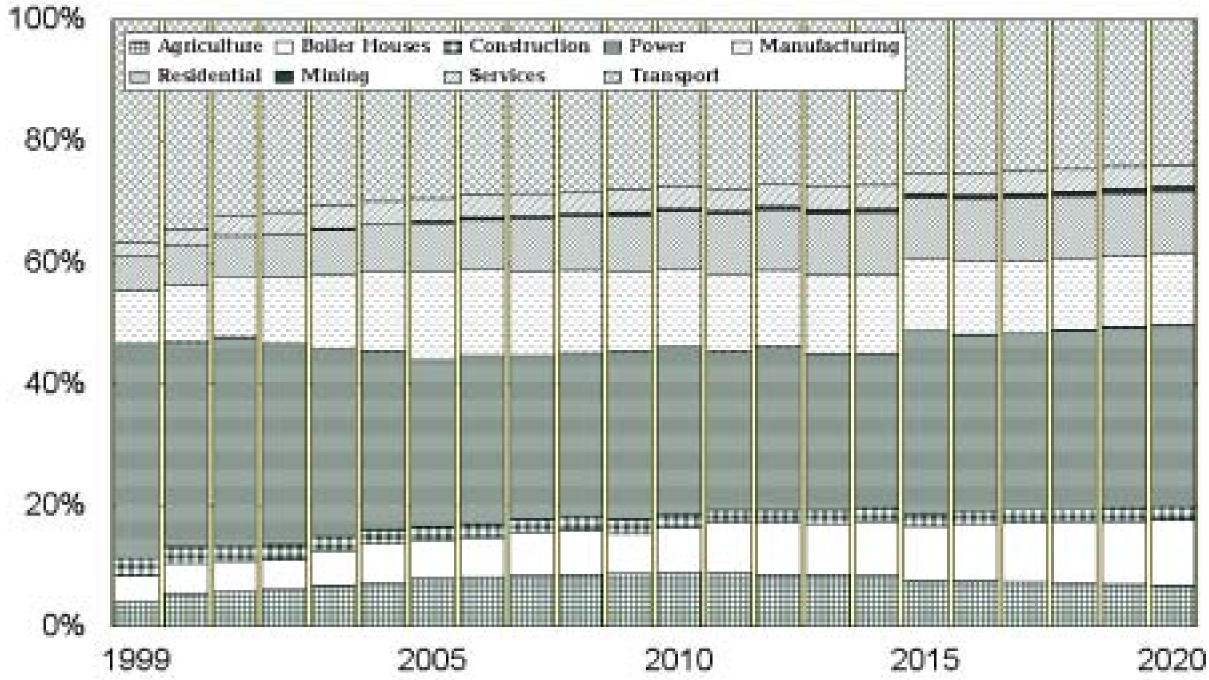

Figure 9.27. Shares of CO_2 per Sector – Reference Demand - CC Scenario

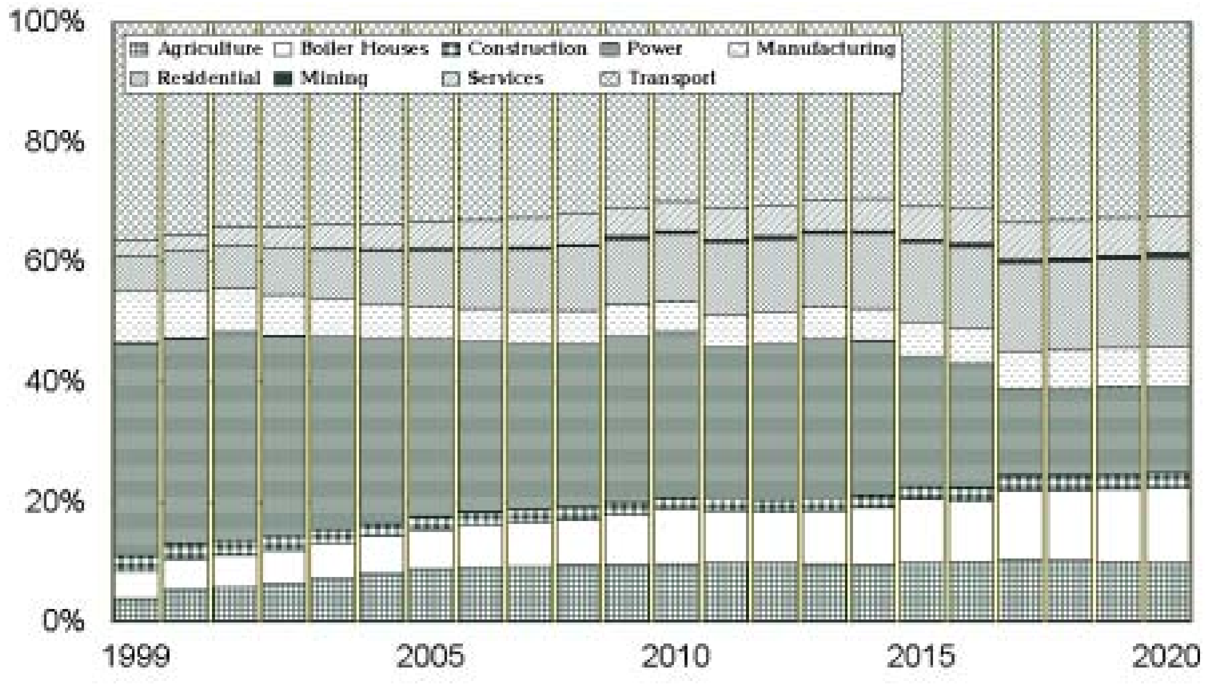

Figure 9.28. Shares of CO_2 per Sector – Low Demand – Nuclear Scenario

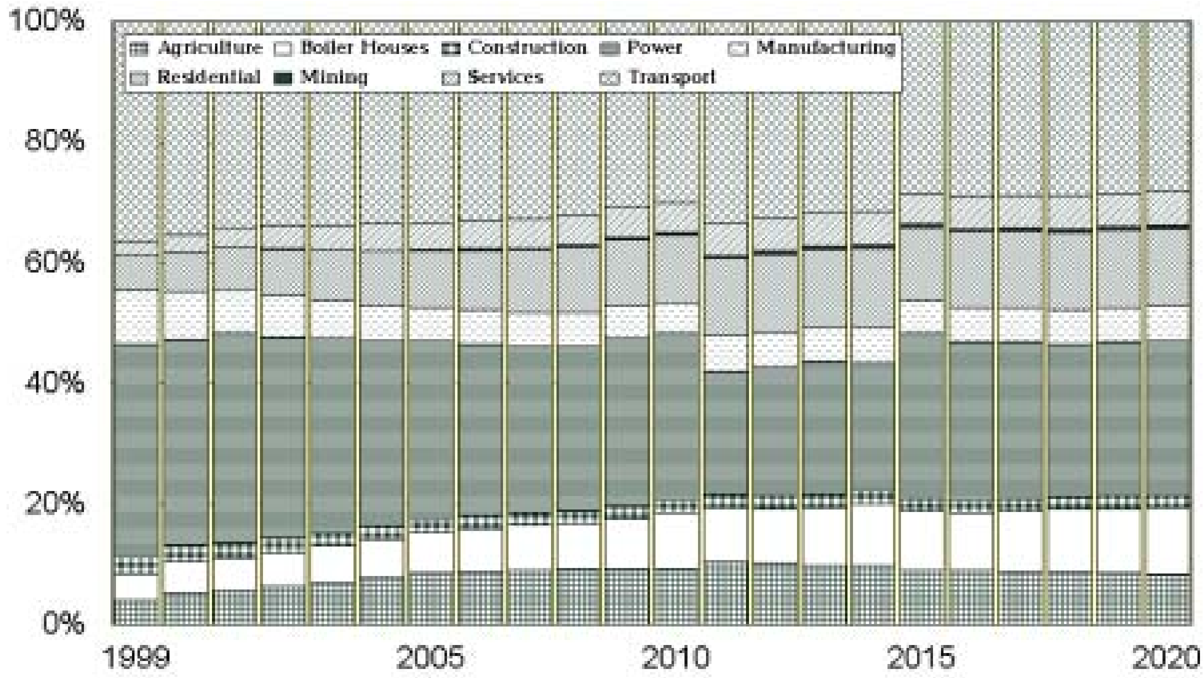

Figure 9.29. Shares of CO_2 per Sector – Low Demand - CC Scenario

9.4. Sensitivity analysis of BALANCE scenarios

Investigations carried out for definition of optimal scenario of energy system development in DEMAND-SCENARIO coordinates gave the results, upon which a number of indicators (energy independence, diversification etc.), characterizing the planning quality, are clearly shown. Un-ambiguity and definiteness of those indicators significantly facilitate the process of Multi-Objective Decision Making

However, one of the main indicators - Electricity long term generation cost - is practically identical for different cases. In this respect, Sensitivity analysis of the influence of different factors exactly on Electricity long term generation cost is of the great interest for Decision making process.

The following factors were considered on the basis of a “priori” planning experience:

- Interest rate,
- Demand,
- Scenarios,
- External cost,
- Gas price growth rate,
- Nuclear fuel price growth rate.

Mathematical statement of Sensitivity analysis task may be defined as determination of definition the area of final solutions variation upon possible changes of "a priori" accepted factors.

Experiment Planning Theory (EPT) was used as the methodological basis of investigation, due to the significant amount of factors, included in Sensitivity analysis, and, therefore, significant volume of calculation work and difficulty in elaboration and analysis of obtained results.

Experiments' planning is of a great importance upon setting of investigations, aimed at the study of complex systems and different multi-factor objects. The task of EPT is to summarize experimental data in such a way that any unitary experiment, made on some model, may be appropriately transferred on unrestrictedly large category of phenomenon, which are recognized as a similar to the given phenomenon, according to the criteria, resulted from similarity theory.

The connection between the investigated parameter F and influencing factors x_i, x_j is presented as a surface $F = f(x_i, x_j, ...)$, situated in multidimensional space. The function responses to the change of any influencing parameter x_i by the change of F. Therefore, the value F is called response surface, response function or just response.

As it was already mentioned, the following factors and variability intervals were selected for the given planning (table 9.2).

Fractional factorial experiment 2^{6-3} is carried out in accordance with Table 9.2.

Using the results of experiments, carried out in accordance with planning matrix, the coefficients of regression of linear equation (b_0, ... , b_6) were defined by the following formula (9.1):

$$b_i = \sum_{n=1}^{6} x_{in} F_n \times N^{-1} \qquad (9.1)$$

where

x_{in} is the value x_j in n experiment,

F_n is the value of optimization parameter in the same experiment,

N is the number of experiments.

Table 9.2. Fractional factorial experiment

Factors	**Interest Rate**	**Demand**	**Scenario**	**External Cost**	**Gas Price Growth Rate**	**Nuc. Price Growth Rate**	**Cost, USc/kWh**
Variable	x_1	x_2	x_3	$x_4=x_1\times x_2$	$x_5=x_1\times x_3$	$x_6=x_2\times x_3$	
Max level	0.12	Reference	Nuclear	with EC	0.045	0.03	
Min level	0.08	Low	CC	without EC	0.023	constant	
1	+	+	+	+	+	+	**3.345**
2	-	+	+	-	-	+	**2.791**
3	+	-	+	-	+	-	**3.140**
4	-	-	+	+	-	-	**2.850**
5	+	+	-	+	-	-	**3.261**
6	-	+	-	-	+	-	**2.977**
7	+	-	-	-	-	+	**3.010**
8	-	-	-	+	+	+	**3.064**
3.0548	**0.1344**	**0.0388**	**-0.0234**	**0.0754**	**0.0768**	**-0.0022**	
b_0	**b_1**	**b_2**	**b_3**	**b_4**	**b_5**	**b_6**	**1%**

Thus, the following objective function is obtained (9.2):

$$F = 3.0548 + 0.1344x_1 + 0.0388x_2 - 0.0234x_3 + 0.0754x_4 + 0.0768x_5 - 0.0022x_6 \quad (9.2)$$

Taking the error of variance as one percent, the confidential interval for factors of regression will be $\Delta b_0 = 0.037796$.

The regression coefficient may be considered statistically significant, if its absolute value is equal or exceeds the value of confidential interval.

Excluding the components with non-significant factors, we shall finally have the following simplified regression equation (9.3):

$$F = 3.0548 + 0.1344x_1 + 0.0388x_2 + 0.0754x_4+0.0768x_5 \quad (9.3)$$

After the calculation of regression coefficients and verification of their significance, the statistical analysis of regression equation was carried out. For this purpose, the hypothesis of adequacy of given equation was verified, e.g. whether the obtained linear equation conforms to investigate phenomenon, or more complex model is necessary.

For the statistical analysis of the above-mentioned equations of regression, the hypothesis about adequacy of the equations (9.3) was checked using the Fisher criterion.

After additional inclusion of x_3 in brief response function, inadequacy dispersion is equal to $S^2_{ad} = 0.000170174$ and dispersion of the experiences is $S^2_{ad} = 0.0001167$. The calculated value of Fisher criterion at 1% significance level ($F_{calc} = 1.46$) has appeared considerably less then tabulated ($F_{tab} = 8.65$) one; therefore the hypothesis about adequacy of linear equations is not rejected, and, finally, we shall have the response function (9.3).

Ranked values of the coefficients of regression equation are presented in Figure 9.30. Further analysis is carried out on the basis of influence level of the factors, presented in this Figure.

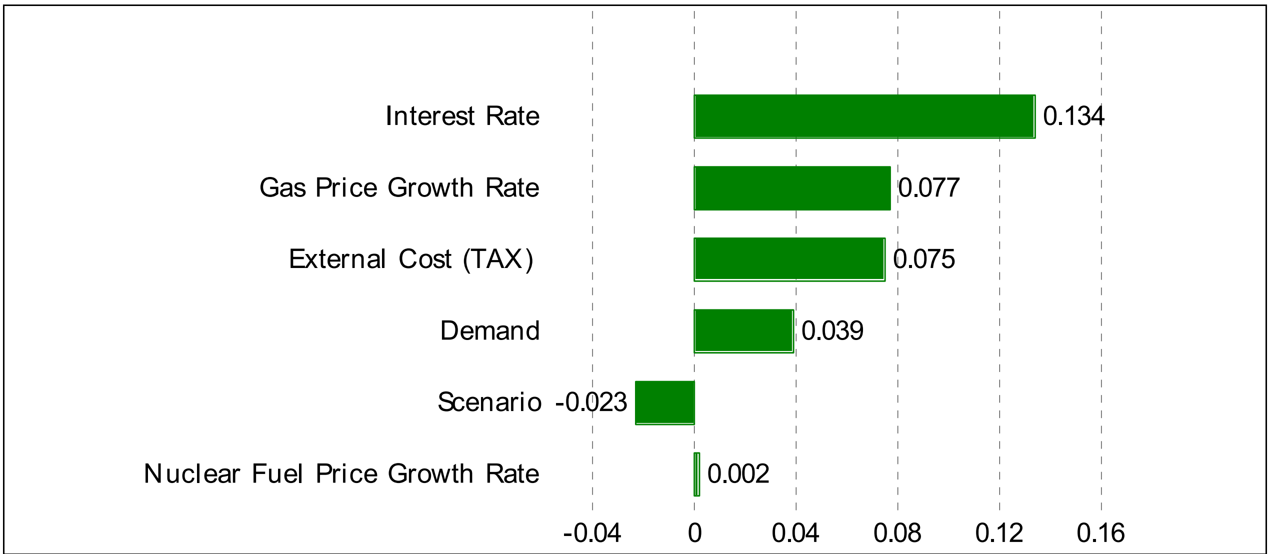

Figure 9.30. Ranked values of the regression coefficients

The strongest influence on Electricity long term generation cost is made by (1) Interest rate – considered as some integral economic indicator of certain projects and the Program taken as a whole. Essentially, it means that, upon the realization of certain projects of Development Program, such tasks as: financial planning; problems regarding sources of finance and the arrangement of financing; problems on foreign exchange and earnings; problems on fiscal and legal issues will be of special significance. In this connection, subsequent chapters of the report are devoted to these issues.

The next factor, which has the influence on studied parameter (2), is gas cost. Despite the fact that the Program makes provision for implementation of high-efficient CC units, the unforeseen change (increase) of gas cost may have dramatic consequences for development program. On this background, insignificant influence of the change of Nuclear Fuel Cost (6) justifies, one more time, the economic advisability of the development of Nuclear Energy.

The significant influence (3) of External Cost on objective function indicates the necessity of performance of strong policy, aimed at limitation of emissions. At the same time, the radical measure for the reduction of emission level is Nuclear Energy development. The investigations showed, that for the reference demand - Nuclear Scenario, a level of greenhouse gases emission for the whole planned period would be lower than the emission level of 1990. Thus, in case of ratification of Kyoto Protocol by the Parliament of Armenia, the nuclear energy development may ensure free quotas on greenhouse gases.

The coefficient upon (4) DEMAND factor indicates the necessity of the establishment of developed market interrelations in energy system, DSM, performance of aggressive energy saving policy etc.

Insignificant coefficient of the influence of scenario selection (5) on Electricity long term generation cost additionally justifies the conclusions, made in chapter 8.5, on economic adequacy of CC and Nuclear scenarios, where the data on Present Value of different scenarios are presented.

To find out the extremum value of the response function (9.3) that is actually conforming to the definition of possible value of Electricity long term generation cost, is of special interest. Upon the classical statement of the task of extremum seeking, for example, step-by-step gradient method can be implemented. However, in the given investigation, we will confine ourselves to the substitution of (9.3) reasonable boundary values of the factors (Table 9.3).

Table 9.3. Boundary Values

Number of Factor	**Factor**	**Limit Value**
1	Interest Rate	7.0%
2	Gas Price Growth Rate	2.5%
3	External Cost (TAX)	without
4	Demand	Low
5	Scenario	Nuclear

Upon the substitution of boundary values of the factors in response function, theoretically minimum value of Electricity long term generation cost are calculated, which comes out as 2.69 USc/kWh.

10 ENVIRONMENTAL ANALYSIS OF ALTERNATIVE ELECTRICITY EXPANSION PLANS

10.1. Introduction

Among the various factors responsible for degradation of natural environment, the most polluting one related with the use of energy [126-154]. Presently, more than 99% of total energy demand in Armenia is being met by using commercial (traditional) fuels, and the remaining – by using coal and wood.

In this part of the analysis, the environmental implications of only the Power sector of Armenia has been examined because of the following:

1. At present (the base year-1999), the primary consumption of commercial energy in Armenia (more than 64% of it) is used for electricity generation. About 33% of the present electricity generation is based on fossil fuels (natural gas) which gives rise to emission of 1 267 213 tons of CO_2, 3355 tons of NOx, 960 tons of CO; and 9 tons of SO_2. These emissions and other wastes are expected to increase in the coming decades due to the foreseen increase in electricity production, which will be based on fossil fuels.
2. The power sector is an organized sector, and it is easier to apply alternative strategies for environmental emission reductions (e.g. fuel substitution, application of new technologies, etc.) compared to other sectors.
3. The country specific data (e.g. emission factors, etc.) are not available/reliable for energy supply and use facilities of various economic sectors, such as Mining, Transportation/ Transmission, Residential, Manufacturing, Construction, etc.

10.2. Environmental Policies, Legal and Regulatory Framework for Power Sector

It is essential to establish an appropriate legal and institutional framework for commercial activities. Privatization, land reform, and enterprise restructuring will not have the desired effects on efficiency and growth without clearly defined property rights and a hard-budget constraint for enterprises. The program, thus, calls for important legislative initiatives with respect to banking system reform, bankruptcy and collateral. In addition, the continuous development of appropriate institutional mechanisms for the implementation and effective enforcement of these laws will remain a goal of the medium-term program.

Armenia is a member of the following international organizations:

1. International Monetary Fund (IMF),
2. World Bank (WB),
3. European Bank for Reconstruction and Development (EBRD),
4. International Atomic Energy Agency,
5. Energy Charter,
6. Black Sea Economic Cooperation (BSEC).

Status of Armenia's access to the international environmental conventions etc:

1. United Nations Framework Convention on Climate Change (the text of the Convention was adopted at the United Nations Headquarters, New York on the 9 May 1992; was open for signature at the Rio de Janeiro from 4 to 14 June 1992, and thereafter at the United Nations Headquarters, New York, from 20 June 1992 to 19 June 1993. The Convention entered into force on 21 March 1994) – Armenia has ratified it.

2. Kyoto Protocol (adopted in Kyoto, Japan, on 11 December 1997, was open for signature from 16 March 1998 to 15 March 1999 at United Nations Headquarters, New York) – Ratification is required.
3. Convention on Long-range Transboundary Air Pollution (signed in 1979 and entered into force in 1983) - Armenia has announced its accession.
4. Montreal Protocol on Substances that Deplete the Ozone Layer (came into force on January 1st, 1989) – Ratification is required.
5. Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal (was adopted in 1989 and entered into force on 5 May 1992) – Ratification is required.
6. Convention on Environmental Impact Assessment in a Transboundary Context (Espoo, 1991) – Armenia has ratified it.

Armenia is faced with a number of environmental problems, but has severely limited resources to address them. The Government has taken a number of steps to ease environmental degradation, including a reduction in the amount of water drawn from Lake Sevan to generate hydroelectricity. The Government is working closely with the International Atomic Energy Agency and other bilateral donors to strengthen its capacity to regulate the safety of the recently recommissioned Medzamor nuclear power plant. Investment assistance is also being sought to upgrade the safety and monitoring features of the plant to bring it closer to international standards. The Government also plans to draft a National Law on the Environment. Finally, two grants from the World Bank's Institutional Development Fund will contribute to mitigating environmental problems by assisting in prioritizing problems, and develop the regulatory framework and institutional capability to implement regulations. One grant is to develop an action plan to restore Lake Sevan's ecological balance and economic potential; the second, currently under consideration, is to support the preparation of a National Environmental Action Plan. The environmental issues have started receiving considerable attention in Armenia during the last few years.

10.3. Methodology

For the present analysis, the SIMPACTS programme has been used to calculate the external costs of alternative expansion plans.

The assessment methodology that is employed is based on the “Damage Function Approach or Impact Pathway Analysis”, which traces the fate of a pollutant from its point of emission, followed by dispersion on a local scale (up to 50 km of the source location) and regional scale (1000s of km downstream of the source) and, finally, receptor uptake (i.e., exposure or dose).

Damages are aggregated across all receptors that are influenced by a pollutant. Local concentrations are typically estimated using a Gaussian model. Meanwhile, regional values are calculated by complex dispersion models, which take into account the pollutant removal by chemical transformation and deposition (dry and wet).

Impacts are characterized in physical terms (ex., number of asthma attacks) by using Exposure Response Functions (ERF). For public health impacts, the ERF are linear with no threshold. Whereas, for damages to crops and materials, the ERF are non-linear. For agricultural products, it is even possible to have a 'benefit' from increasing the background concentration of certain pollutants, like sulphur dioxide (SO_2).

Impacts are monetized by multiplying the number of cases by “unit cost” values (e.g. US$ per asthma attack).

The programs in the AirPacts package are based on 'Simplified' impact models, which permit the user to obtain approximate estimates of the burdens to human health and the surrounding environment. In most cases, the values provided by AirPacts are within a factor of two of the results obtained using more sophisticated models that are usually data and time intensive.

The AirPacts tools offer the user (the environmental impact analyst or decision-maker) with several important advantages. First, the models require minimal input data, which are readily available to the analyst. Second, the estimates are obtained quickly. Third, the methodology is simple and transparent. Forth, the simplified approach allows the analyst to check for consistency the results given by detailed assessments (i.e., a sort of "sanity check").

The current version of AirPacts consists of four "Simplified" Impact Assessment modules. For the current study the QUERI and RUWM models have been used.

QUERI assesses the (respiratory) impacts to human health and the associated costs due to primary and secondary pollutants that are emitted in to the air. The model uses a semi-empirical approach in which correlations derived from existing IPA studies are used to approximate the physical impacts and their associated costs.

The RUWM model approximates the physical impacts and damage costs to human health from exposure to primary and secondary atmospheric species. By contrast to QUERI, the RUWM model uses different simplifying assumptions to solve analytically the damage function equation. In the assessment, it is assumed that the local and regional populations are uniformly distributed throughout the appropriate impact domains. The meteorological data for the local scale refer to average or typical conditions and assume a constant windrose distribution (uniform wind speed along all directions in a plane).

10.4. Environmental Impacts under Different Scenarios

10.4.1. Scenario Definition

Two scenarios of Expansion of Armenian Power Sector were developed in the frame of TC project:

1. Scenario with nuclear option (Reference/Low Demand),
2. Scenario without nuclear option (Reference/Low Demand).

The first scenario with new NPP (Reference) suggests development of about 2794 MW (new installed capacity) of power generation capacity over the next 22 years period, comprising: Hydro 231 MW, Combined Cycle Power Plant 600 MW, CHP Combined Cycle Plant 668 MW, Nuclear 1280 MW and Wind 15 MW.

In view of various uncertainties about future evolution of energy/electricity demand and supply system, nuclear power development, possibility of importing natural gas from additional sources, it is necessary to explore alternative plans for expansion of electricity generation system.

There is no nuclear option in the alternative expansion plan, this is the main difference from the described above expansion plan. The nuclear power capacity additions in this scenario have been replaced by thermal capacity based on natural gas.

The environmental impacts of all type of electricity generating facilities (HPPs, NPPs, TPPs) have been determined by SIMPACTS model.

10.4.2. Input Data

Electricity can be generated from a variety of primary energy sources –fossil fuels (oil and natural gas), uranium, hydro and other renewable (solar, wind, etc.). Use of every one of these primary sources damages the natural environment (soil or water or atmosphere). In the present analysis a comparison has been made at the power plant level only.

The information on electricity generation by each type of plant and the corresponding quantities of emissions emitted to the atmosphere have been used in this analyses, had been obtained from the WASP analyses.

Some of the input data according to requirements of AirPacts model have been obtained from different sources, and some of them were based on assumptions and relative comparisons with other studies.

10.4.2.1. Thermal Power

The combustion by products includes sulphur dioxide and nitrogen oxides, which contribute to acid rain, and carbon dioxide, which is the major contributor to global warming.

Table 10.1 compares emissions of major pollutants from gas-based power plants. The power technologies considered in this comparison are gas fired combined cycle and gas fired steam power plants. Among the gas-based power plants, natural gas fired combined cycle power plant is the cleanest technology due to their high efficiency. The codes used for power generating plants are the same as in WASP.

The most polluting sources are the gas based old power generating units located in Yerevan, Hrazdan and Vanadzor.

The description and values of some types of input data used for calculation of impacts of different emission sources are given in Table 10.2.

The thermal plants that were taken under consideration are located in Hrazdan and Yerevan.

It was assumed that regional population density is 50 persons per square km.

Table 10.1. Emission of Major Pollutants Tons Per GWh of Electricity Generation From Various Power Generation Options in Armenia (Plant Level Only)

Emmision	CO_2	SO_2	NOx	CO	Particulates
TYR1	712.2	0.005	1.7	0.5	0.04
TYR2	693.2	0.005	1.6	0.5	0.04
TH11	712.2	0.005	1.7	0.5	0.04
TH12	712.2	0.005	1.7	0.5	0.04
THR2	664.8	0.005	1.8	0.5	0.03
THR5	569.9	0.004	1.5	0.4	0.03
TVN1	712.2	0.005	1.7	0.5	0.04
TVN4	712.2	0.005	1.7	0.5	0.04
CC2	415.5	0.003	1.1	0.3	0.02
CHP1	415.5	0.003	1.1	0.3	0.02
CHP2	415.5	0.003	1.1	0.3	0.02

Note: Identification of codes is given in Chapter 7.

10.4.2.2. Hydro Power

It is quite obvious, that the impacts of hydropower projects are extremely site-specific. Contributing factors include dam height, topography, region, land cover, and population density. As a general rule though, the impacts of hydropower projects increase with the size of the reservoir. This means that for an assessment of a potential future hydro dam, the analyst will first have to estimate the area flooded by the reservoir. According to this, some of the dams have not been taken into account (mainly candidate HPP's) due to their small sizes and insignificant effect that they could have. External costs of the existing dams have been calculated according to the annual expected loss of life from failure of the hydro dam.

The map and input data for HPPs of Vorotan cascade are given in Figure 10.1.

It was assumed that shapes of reservoirs for Shamb and Tatev HPPs are triangular, and for Spandaryan HPP - rectangular.

The input data for HPPs are given in Table 10.3.

Table 10.2. AirPacts Input Data

Region	**Yerevan**	**Hrazdan**	**Hrazdan**	**Hrazdan**	**Hrazdan/ Yerevan**	**Hrazdan**
Local receptor density (person/sq.km)	180	150	150	150	150/180	150
Mean wind speed at 10 m height, (m/s)	2.8	3	3	3	3/2.8	3
Mean ambient temperature (K)	285	280	280	280	280/285	280
Pasquill Distribution for Hrazdan and Yerevan	A 0.5	B 1.0	C 2.0	D 26.5	E 60.0	F 10.0
Stack Parameters	TPP 50		TPP 200	TPP 300	CHP 167*	CC 300
Height (m)	80.0	150.0	180.0	220.0	180.0	220.0
Exit diameter (m)	7.0	7.5	8.4	10.0	8.4	10.0
Exhaust gas temperature (K)	433.0	449.0	430.0	415.0	430.0	415.0
Flue gas velocity (m/s)	21.4	29.0	24.0	28.0	24.0	28.0
Efficiency (%)	28	28	30	35	48	48
Electricity generation (GWh)	268.2	29.7	1587.1	1194.2	1052.1	1255.7
	A	B	C	D	E	F
Pasquill class distribution(%)	0.50	1.00	2.00	26.50	60.00	10.00
Type of pollutants	PM_{10}	SO_2	NO_X	CO	Nitrates	Sulfates
Pollutant depletion velocity (cm/s)	0.99	1.06	2.35	2.94	0.67	0.76

* The same data were used for Yerevan TPP (longitude – 315.5, latitude – 40.15,) and Hrazdan TPP (longitude – 315.3, latitude – 40.5). Size of local domain is 9847 km^2.

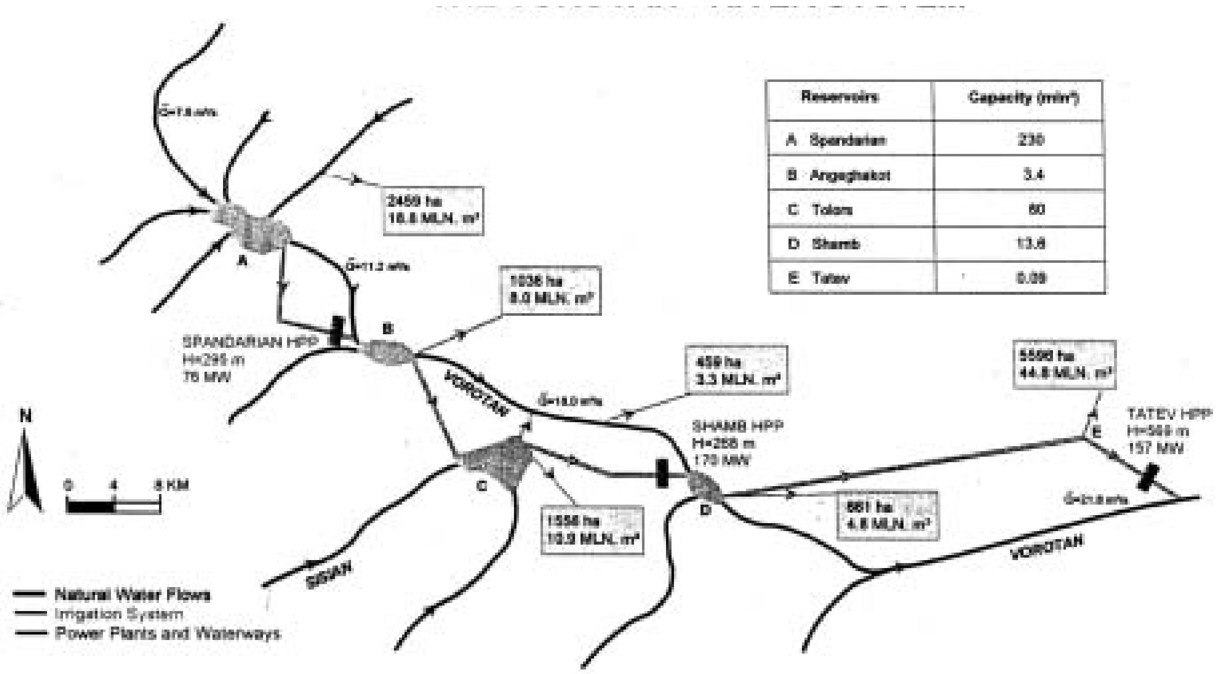

Figure 10.1. The Vorotan river system

10.4.2.3. Nuclear Power

Nuclear power plants do not produce gases such as CO_2 CO, SO_2 and NOx, which are responsible for acid rain and global warming. Although, some radioactive materials are released to the environment during normal operation of nuclear power plants and other nuclear fuel cycle facilities, the amounts released are very small and strictly kept within the permissible limits.

10.5. Health Impacts and other Damages

10.5.1. Thermal Power

Since the objective of the present environmental analysis is to compare alternative plans for future expansion of the power sector in Armenia, particularly with reference to nuclear power, the power system expansion plans for the Reference and Low Demand Scenarios without nuclear option, discussed in Chapter 7, have been analyzed from the environmental point of view.

Impacts are quantified using Exposure-Response functions. The following types of ERF from different types of pollutants have been selected for this study (Table 10.4).

As it has been mentioned before, four development scenarios for power sector are considered in this study, and obtained results of the physical impacts to human health are given in Table 10.5.

10.5.2. Nuclear Power

Three models have been used to calculate health impact and external costs of nuclear plants (NukPactsAir, NukPactsAccidents and NukPactsWaste).

10.5.2.1. NukPactsAir

The impact pathways for health effects on the general public from atmospheric releases of radionuclides, described below, are presented for quantifying and valuing the adverse effects on human health resulting from the routine release of radionuclides to the atmosphere from nuclear facilities, these are:

1. The inhalation of radionuclides in the air;
2. The external irradiation from radionuclides immersed in clouds;
3. The external irradiation from deposited radionuclides; and
4. The ingestion of radionuclides in agricultural products.

The input data used for this analysis are given in Table 10.6.

The estimation of the expected occurrence of cancers, fatal and non-fatal, following radiation exposure, is given in table 10.7

Table 10.3. HydroPacts Input Data

Dam characteristics	**Tatev HPP**	**Spandaryan HPP**	**Shamb HPP**
Dam Height (m)	59	83	69
Plant Capacity (MW)	157	76	170
Average Plant Capacity Factor (%)	42.2	23.1	18.3
Turbine Flow (m3/s) all Turbines	33	30	75
Additional Head Correction (m)	510	212	199
SITE CHARACTERISTICS			
Region ID	2	2	2
Terrain index (TI)		7	
Type of terrain	2	1	1
Average Accident Warning Time (hours)	2	0.5	1
Average terrain incline (degrees)	1.69	2.715	1.32
Average river incline (degrees)	1.88	0.634	0.66
POPULATION AND LAND USE CHARACTERISTICS			
Population density in river basin (persons/km2)	20	10	15
Population at risk of accident (persons)	800	120	400
Share of people resettled/compensated (%)	100	100	100
COST CHARACTERISTICS			
2000 GDP per capita (US$2000 per capita)	550	550	550
1995 GDP per capita (US$1995 per capita)	2074	2074	2074
Fraction of costs internalized (fraction)	1	1	1

Table 10.4. Exposure Response Function

Exposure Response Function	Pollutant
Bronchodilator use - Asthmatic Children	PM10
Bronchodilator use - Asthmatic Adults	PM10
Bronchodilator use - Asthmatic Children	Nitrates
Bronchodilator use - Asthmatic Adults	Nitrates
Bronchodilator use - Asthmatic Children	Sulphates
Bronchodilator use - Asthmatic Adults	Sulphates
Lower Respiratory Symptoms - Asthmatic Children	PM10
Lower Respiratory Symptoms - Asthmatic Adults	PM10
Lower Respiratory Symptoms - Asthmatic Children	Nitrates
Lower Respiratory Symptoms - Asthmatic Adults	Nitrates
Lower Respiratory Symptoms - Asthmatic Children	Sulphates
Lower Respiratory Symptoms - Asthmatic Adults	Sulphates
Restricted Activity Days - Adults over 18	PM10
Restricted Activity Days - Adults over 18	Nitrates
Restricted Activity Days - Adults over 18	Sulphates
Work Days Lost - Adults employed	PM10
Work Days Lost - Adults employed	Nitrates
Work Days Lost - Adults employed	Sulphates
Respiratory Hospital Admissions – ALL	PM10
Respiratory Hospital Admissions – ALL	SO2
Respiratory Hospital Admissions – ALL	Nitrates
Respiratory Hospital Admissions – ALL	Sulphates
Cardiovascular Hospital Admissions – Adults > 65	PM10
Cardiovascular Hospital Admissions – Adults > 65	Nitrates
Cardiovascular Hospital Admissions – Adults > 65	Sulphates
Chronic Bronchitis - Adults over 18	PM10
Chronic Bronchitis - Adults over 18	Nitrates
Chronic Bronchitis - Adults over 18	Sulphates
Congestive heart failure	CO
Infant Mortality (YOLL) - Infants up to 1	PM10
Infant Mortality (YOLL) - Infants up to 1	Nitrates
Infant Mortality (YOLL) - Infants up to 1	Sulphates
Short term Mortality (YOLL) – ALL	SO2
Short term Mortality (YOLL); ALL	CO
Long term Mortality (YOLL) – Adults over 30	PM10
Long term Mortality (YOLL) – Adults over 30	Nitrates
Long term Mortality (YOLL) – Adults over 30	Sulphates

Table 10.5. Impacts (Regional) to Human Health for Different Scenarios (over 22 years)

Pollutants	Exposure Response Function	Refer. with New NPP	Reference without New NPP	Low with New NPP	Low without New NPP
Morbidity					
PM_{10}	Bronchodilator use - Asthmatic Children	9342	12044	8240	11069
	Bronchodilator use - Asthmatic Adults	22725	29299	20046	26926
	Lower Resp. Symptoms - Asthmatic Children	11973	15437	10561	14186
	Lower Resp. Symptoms - Asthmatic Adults	61799	79678	54512	73224
	Restricted Activity Days - Adults over 18	18943	24423	16710	22445
	Work Days Lost - Adults employed	1996	2573	1761	2365
	Respiratory Hospital Admissions – ALL	1.3	1.6	1.1	1.5
	Cardiovascular Hospital Adms. - Adults > 65	23	29	20	27
	Chronic Bronchitis - Adults over 18	29.0	37.5	25.6	34.4
Nitrates	Bronchodilator use - Asthmatic Children	409993	535511	364247	489326
	Bronchodilator use - Asthmatic Adults	997239	1302588	885956	1190233
	Lower Resp. Symptoms - Asthmatic Children	525430	686284	466805	627098
	Lower Resp. Symptoms - Asthmatic Adults	2711942	3542145	2409362	3236663
	Restricted Activity Days - Adults over 18	831201	1085719	738445	992068
	Work Days Lost - Adults employed	87589	114406	77815	104538
	Respiratory Hospital Admissions – ALL	56	73	50	67
	Cardiovascular Hospital Adms. - Adults > 65	999	1304	887	1192
	Chronic Bronchitis - Adults over 18	1275	1665	1133	1522
Sulfates	Bronchodilator use - Asthmatic Children	1100	1436	978	1312
	Bronchodilator use - Asthmatic Adults	2676	3492	2377	3190
	Lower Resp. Symptoms - Asthmatic Children	1410	1839	1252	1680
	Lower Resp. Symptoms - Asthmatic Adults	7276	9494	6465	8674

	Restricted Activity Days - Adults over 18	2231	2910	1982	2659
	Work Days Lost - Adults employed	235	307	209	280
	Respiratory Hospital Admissions – ALL	0.2	0.2	0.1	0.2
	Cardiovascular Hospital Adms. - Adults > 65	2.7	3.5	2.4	3.2
	Chronic Bronchitis - Adults over 18	3.4	4.5	3.0	4.1
SO_2	Respiratory Hospital Admissions – ALL	0.2	0.3	0.2	0.2
Mortality					
PM_{10}	Infant Mortality (YOLL) - Infants up to 1	13.9	17.9	12.3	16.5
	Long term Mortality (YOLL) - Adults over 30	130	167	114	154
Nitrates	Infant Mortality (YOLL) - Infants up to 1	610	797	542	728
	Long term Mortality (YOLL) - Adults over 30	5691	7434	5056	6793
Sulfates	Infant Mortality (YOLL) - Infants up to 1	1.6	2.1	1.5	2.0
	Long term Mortality (YOLL) - Adults over 30	15.3	19.9	13.6	18.2
SO_2	Short term Mortality (YOLL) – ALL	0.2	0.2	0.1	0.2
CO	Short term Mortality (YOLL); ALL	13.4	17.3	11.8	15.9

Table 10.6. Inputs for NukPactsAir

Average annual wind speed (metres per second)	**3**
Effective chimney height (metres)	**150**
Emission strength of radionuclide i: (Bq per second)	
H - 3	11098.4
C - 14	951.3
Co - 58	1.2
Co - 60	7.5
Kr - 85	5549.2
I - 131	6.0
I - 133	0.4
Xe - 133	0.08
Cs - 134	1.7
Cs-137	4.2
Population density in local area (persons per km^2)	127.3
Density of agricultural product k: (tonnes product per km^2)	
Cattle	4.6
Sheep	0.5
Grains	41.8
Green vegetables	7.0
Root vegetables	14.0
Milk (dairy cows)	1.5
Percentage of total land area given to product k: (% of total area)	
Cattle	100%
Sheep	100%
Grains	100%
Green vegetables	100%
Root vegetables	100%
Milk (dairy cows)	100%

Difference between two scenarios (with/without NPP) is within 22-25%.

Table 10.7. Occurrences of Health Effects in Population for Planning Period

Types	Cases
Occurrence of health effects in local population	
Fatal cancer	0.19
Non-fatal cancer	0.45
Severe hereditary effect	0.038
Occurrence of health effects in regional population	
Fatal cancer	0.66
Non-fatal cancer	1.59
Severe hereditary effect	0.13
Occurrence of health effects in global population	
Fatal cancer	4.69
Non-fatal cancer	11.26
Severe hereditary effect	0.94

10.5.2.2. NukPactsAccidents

In order to estimate, with some probability, the impacts of nuclear accidents (for existing NPP and new NPP), the NukPactsAccidents model have been used. Due to the assumption that in Nuclear Development Scenarios the old NPP will be replaced by the identical NPP with the same type of reactor, the number of incidents that may occur in case of accident was calculated, and it is shown only for one NPP (Table 10.8). The probability of accident occuring in calculations was assumed to be 10^{-5} for the existing NPP, and 10^{-6} - for a new NPP.

10.5.2.3. NukPactsWaste

The external costs, associated with the wastes produced by the nuclear power plant, have been calculated according to the electricity generated in the base year. Those costs equal to about 830 $US/TWh.

10.6. External Costs of Alternative Electricity Expansion Plans

The results of calculations for different type of sources (Figure 10.2) show that External Specific Costs of electricity generation are the lowest for HPPs, and NPPs (new, old).

Since the shares of some types of power generation technologies in the total installed capacities vary according to the selected options, and due to the fact that external specific costs of generation for NPPs are rather less (Figure 10.3), the external costs (discounted) for scenario without the NPP are higher (by 5.6 and 4.9 mln. US$ for Reference and Low Demand Scenarios respectively) if compared with the nuclear scenario. The ratio of the Total External Cost as percent of GDP up to 2014 for both scenarios is almost the same. There will be a big difference between these two scenarios starting from 2015, when the old NPP will be replaced by a new one for one scenario, and by CC plant for the other (Figure 10.4).

Table 10.8. Number of Incidents in Case of Nuclear Accident

Types of Deseases	Incidents
Local (<100 km)	
No. of fatal cancers	820
No. of severe hereditary effects	164
No. of non-fatal cancers	1968
No. of early diseases	4
Regional	
No. of fatal cancers	2783
No. of severe hereditary effects	557
No. of non-fatal cancers	6680
No. of early diseases	0

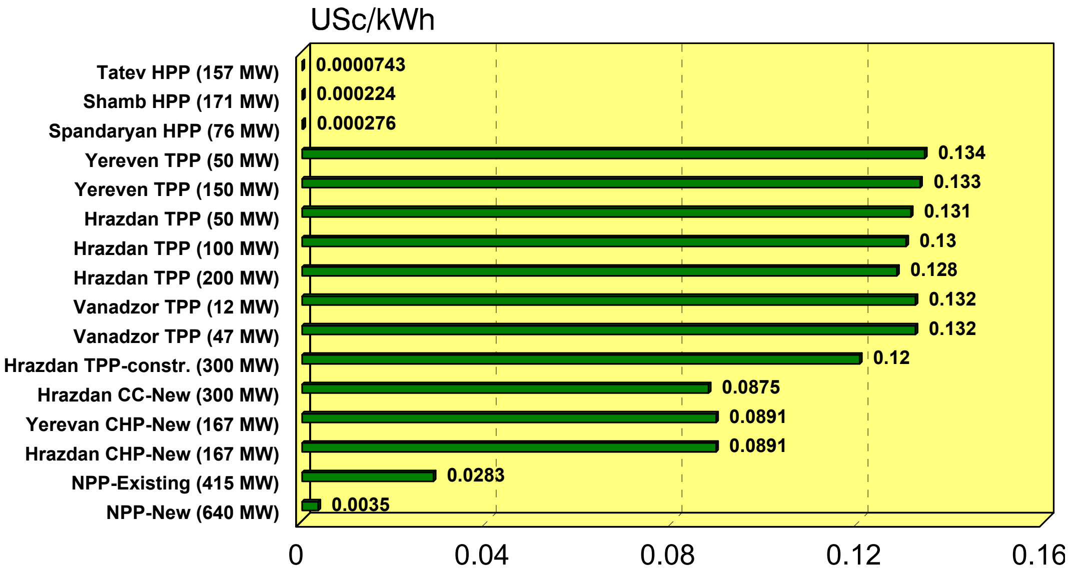

Figure 10.2. External Specific Cost of electricity generation by type of source (USc/kWh)

10.7. Conclusions

Basing on the preceding analysis, it was ascertained that the power system expansion plan of the Scenario with a new NPP is much better, from the environmental point of view, than that of the Scenario without a new NPP. The later gives rise to very high emissions of SO_2, NOx, and CO. As for radioactive emissions from nuclear power plants, such emissions are obviously higher for the Scenario with a new NPP, but they would be strictly controlled and contained within permissible limits.

Due to the limited indigenous energy resources, the future electricity generation will require to enlist all available technological options. However, the use of nuclear power can significantly help to reduce the future environmental emissions of SO_2, NOx, and CO pollutants, not causing any serious threat to the environment by radioactivity releases.

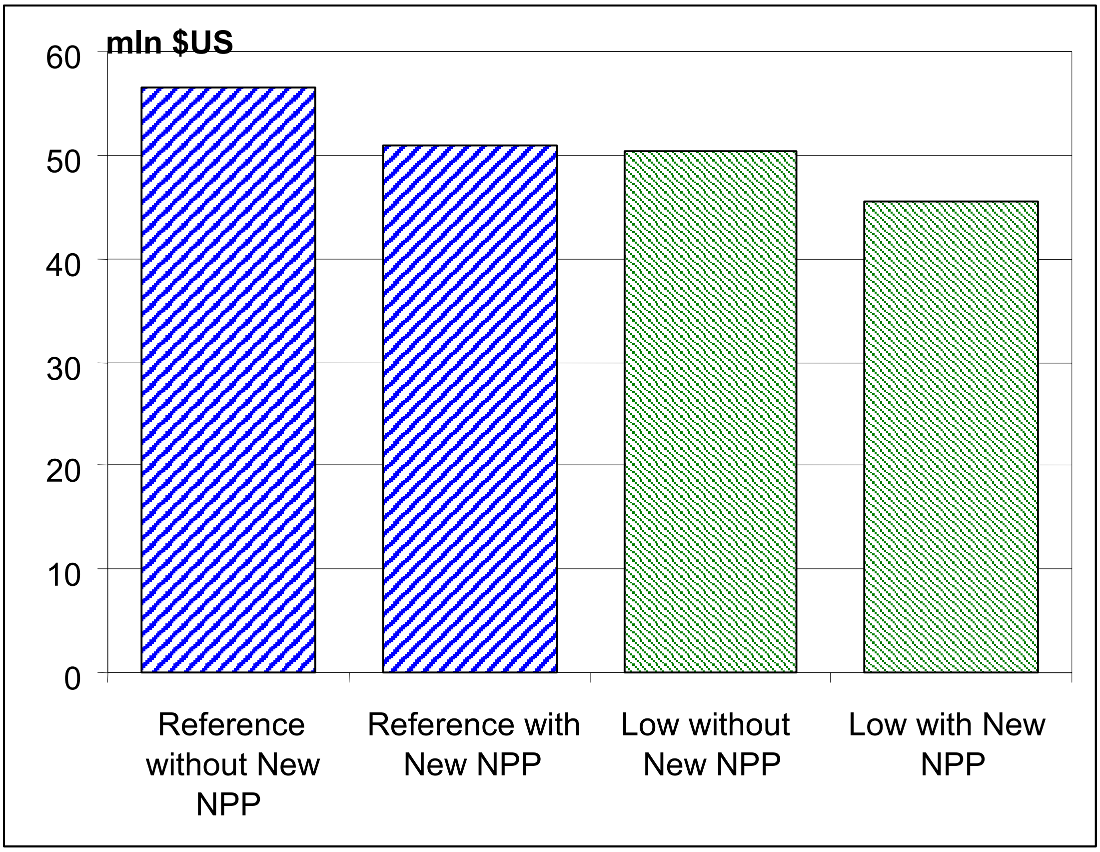

Figure 10.3. Total External Costs (discounted, DR-10%) in Different Scenarios for the Whole Planning Period

Nuclear power plants require somewhat higher investments than the fossil fuel fired ones, however, the gap becomes trivial if remembering that fossil fuel fired power plants are equipped with SO_2 and NOx emission control devices. And besides, the use of nuclear power becomes economically attractive when the total system costs are considered. It is thus clear that the increased use of nuclear technology for electricity generation in Armenia in the coming decades will be not only helpful in reducing the environmental degradation, but also cost effective. On the basis of the analysis carried out, it can be concluded that the use of nuclear power for the future power generation would be maximum feasible from the environment protection point of view.

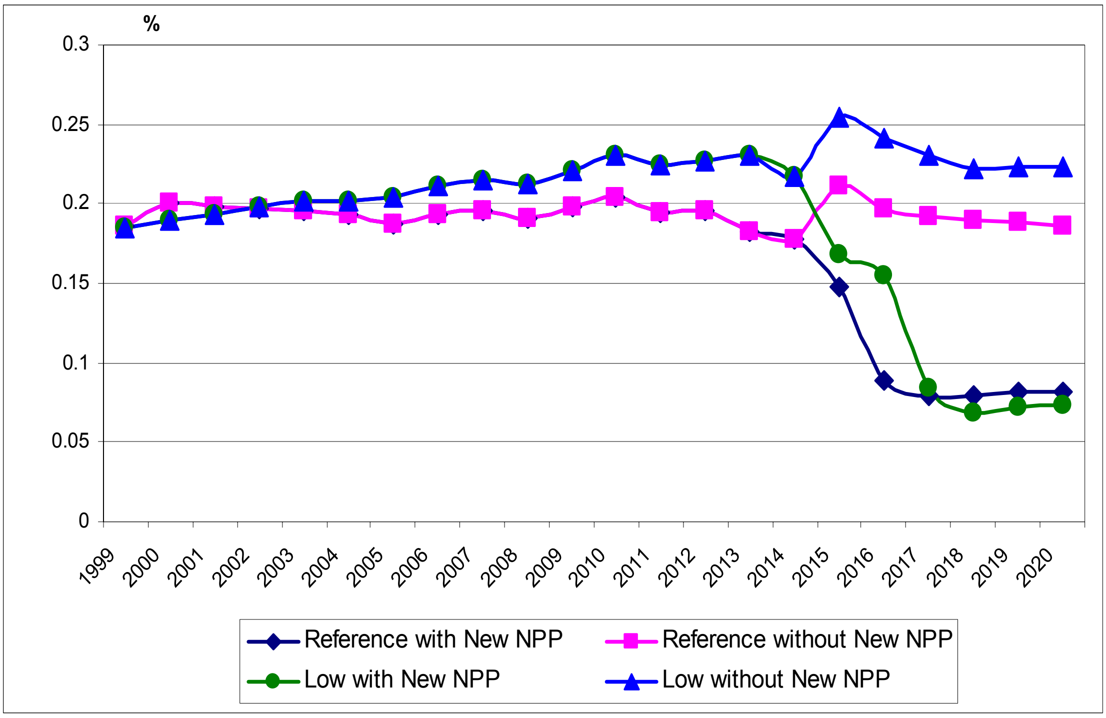

Figure 10.4. Ratio of Total External Cost in GDP

11 NPP ECONOMICAL AND FINANCIAL EVALUATION

11.1. Methodological Approach

The financial analysis and evaluation are to ensure that, for the objectives determined by the decision makers and within the given confidence levels of a feasibility study, the following requirements are met:

- the most attractive of the possible project alternatives is determined under the prevailing conditions of uncertainty;
- the critical variable and possible strategies for managing or controlling risks are identified;
- the flow of financial resources required during the investment, start-up and operations phases is determined, and the financial resources available at the lowest costs are identified for the time required and will be used in the most effective way.

To achieve such objectives, the appraisal of investment projects has considered being a main tool both of the net-present-value method (referred as NPV) and the internal-rate of return method (IRR). Another key indicator is the Pay Back Time (PBT). After the financial evaluation for the basic case, a sensitivity and risk analysis is carried out to check the critical variables and the relevant performances.

The allocation of financial resources to a project (equity, short and long term loans) constitutes an obvious and basic pre-qualification for investment decisions, for project formulation and pre-investment analysis, as well as for determining the capital cost.

The financial analysis should be done focusing on the figures of the Balance Sheet and the Income Statements, and taking into account the following ratios:

- long term debt-equity and long term debt-net-worth ratio,
- current ratio or current-assets-to-current-liabilities ratio,
- long term debt-service coverage,
- debtors-creditors ratio,
- output-capital ratio.

In order to determine the necessary selling price, an 11-year period after the entering in operation has been considered for the project dynamic pay-back, corresponding, if evaluated, approximately to a total 13-year period for the pay-back (not discounted cumulate cash flow, or break even). A 14-year period is generally the maximum standard admitted by most financial institutions and development banks when they evaluate the intervention in the financing of the project.

11.2. Basic Assumptions

The evaluations have been performed under the following assumptions:

Planning horizon

Construction phase: 7 years

Production phase: 30 years

Inflation /escalation of prices

No inflation rate has been adapted to the base case: prices and costs are therefore estimated at constant price.

Depreciation

Linear depreciation during the 30 years lifetime of the plant (corresponding to the analysis period of production).

The NPP project can be envisaged for a longer period, at least 50-60 years. No salvage value (residual value at the end of project life) is considered.

Discounting rate - 10%

Currency

In order to make easier the interpretation of the financial appraisal for the potential foreign investors and lenders, the model has been developed in US$ (corresponding to long term loan currency).

Usually, evaluations are issued with the relation to the origin of the expenses: costs billed locally are expressed in local currency; costs billed abroad (investment costs of foreign suppliers, loan repayment to development banks) are expressed in foreign currency.

The output (sales, cash flows, etc) is usually expressed in foreign currency.

Interest during construction phase

In fixed investment costs estimation, the interests have been allocated at the rate of 7% to be calculated on the value of EPC costs. These interests represent the remuneration, during the whole period of construction, of the capital contribution to local and foreign investors in the 100% equity structure.

11.3. Financial Evaluation

Financial evaluation has been carried out with the use of the main parameters summarized in Table 11.1.

Table 11.2 and Figure 11.1 show the disbursement schedule.

The main parameters are summarized in Table 11.3.

Table 11.1. Main parameters of the Leveraged Evaluation

Project features	Value
Installed capacity	1280MW
Performance rate	81%
Construction cost	1.42 billion US$
Equity	32.3%
Loans	65.7%
Grants	2.0% years
O&M Annual cost	109 mln. US$
Terms of the loans	15 years (after com.)

Table 11.2. Disbursement Schedule of the Various Components

Interests on loan - 7%							**mln. US$**	
Year	**-7**	**-6**	**-5**	**-4**	**-3**	**-2**	**-1**	
Year	-6	-5	-4	-3	-2	-1	0	
Percent of Works	2%	5%	16%	20%	32%	20%	5%	
Annual Capital Cost	28 396 000	70 990 000	227 168 000	283 960 000	454 336 000	283 960 000	70 990 000	
Cumulate Totals	28 396 000	99 386 000	326 554 000	610 514 000	1 064 850 000	1 348 810 000	**1 419 800 000**	
Grant	567 920	1 419 800	4 543 360	5 679 200	9 086 720	5 679 200	1 419 800	
Net Annual Capital Cost	*27 828 080*	*69 570 200*	*222 624 640*	*278 280 800*	*445 249 280*	*278 280 800*	*69 570 200*	
Interests During Implementation	*9 939*	*44 724*	*149 079*	*8 676 398*	*30 640 704*	*52 605 010*	*63 164 772*	
Cumulate Interests During Implementation	9 939	54 662	203 741	8 880 139	39 520 843	92 125 853	**155 290 625**	
Total Disbursement per Year	***27 838 019***	***69 614 924***	***222 773 719***	***286 957 198***	***475 889 984***	***330 885 810***	***132 734 972***	
Total Cost of the Project							**1 391 404 000**	
Total Cost Including Interests							**1 546 694 625**	
Loan	283 960	709 900	2 271 680	241 366 000	386 185 600	241 366 000	60 341 500	**932 524 640**
Loan+Interests	283 960	993 860	3 265 540	244 631 540	630 817 140	872 183 140	932 524 640	**932 524 640**
Net Equity Disbursement	27 544 120	68 860 300	220 352 960	36 914 800	59 063 680	36 914 800	9 228 700	**458 879 360**
IDC covered by Equity	9 939	44 724	149 079	8 676 398	30 640 704	52 605 010	63 164 772	**155 290 625**
Total Equity Disbursement	27 554 059	68 905 024	220 502 039	45 591 198	89 704 384	89 519 810	72 393 472	**614 169 985**

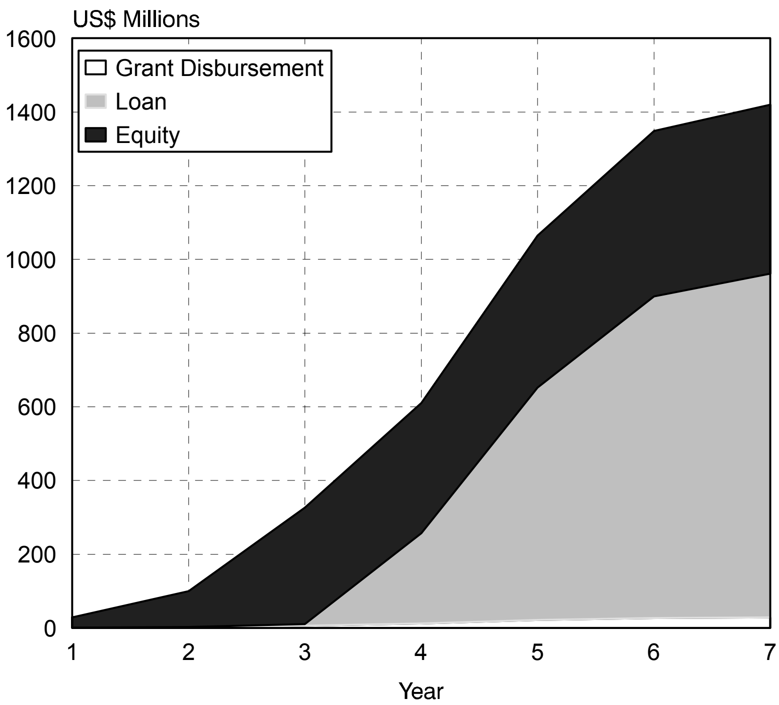

Figure 11.1. Disbursement Schedule of the Various Contributions

Table 11.3. Main Indicator of the Leveraged Evaluation

Project features	**Value**
Selling price (during debt repayment)	3.5 Usc/KWh
Selling price (after debt repayment)	2.5 Usc/KWh
IRR	11.28 %
NPV [US$ millions]	67.59 mln. US$
Payback	18
Payback (dynamic)	26

11.4. Sensitivity Analysis of the Leveraged Evaluation

Also in this “leveraged” evaluation a set of simulation has been executed with different input data in order to test the sensitivity of different parameters on the base case conditions.

In all cases, the IRR doesn’t change dramatically. It means that, in case the Government understands the advantage for the country energy safety of the development of the nuclear energy and the necessity of it’s financing, the presented financial analysis of new nuclear units feasibility will be quite reasonable.

In this regard, the next passage covers the project implementation risks and the methods of their mitigation.

	Case	IRR	Other
1	Base case	11.28%	
2	What if term of capital cost is 10%?	9.57%	
3	What if term of capital cost is 20%?	8.07%	
4	What if load factor down to 75%?	9.28%	
5	What is minimum price to be able to repay loans and what is the irr in such case?	4.6%	2.488kWh
6	What if term of loans is 10 years after completion instead of 15?	9.81%	
7	What if interim interest (interest during construction) is capitalized, ie added to loans?	11.6%	
8	What if no tax holiday and tax rate of 30%(instead of 15%)?	8.89%	
9	What if no tax holiday and tax rate of 20%?	9.74%	

11.5. Project Risk Analysis

Power projects usually involve risk for all parties involved (the power purchaser, project developer and lenders). The parties involved agree on how risks are to be shared, that is often the key to a successful project. Consequently, the successful mitigation of the risks of commercial, political, non-political or force majored events is critical to a project’s financial feasibility. A specific Contractual Structure of the Project (agreements, contracts, and measures associated with the Project) is to be envisaged to ensure the risk mitigation.

11.5.1. Risk and Mitigation Overview

As explained above, the bankability of projects based on off-balance sheet financing is crucially dependent on the risk mitigation. The Project Company together with their investors and lenders may be exposed to certain adverse events, which could have the effect of impairing the projects ability to service its debt and distribute dividends to shareholders.

The main classes of risk are those which:

- delay the commercial start-up of the Project, thus adding cost and deferring receipt of income;
- increase the capital or operating costs of the Project, thus diluting returns and ability to service debt;
- disrupt or suspend the Project’s regular operations, giving rise to income loss and possible contractual penalties;

- affect the quality or volume of key inputs and outputs, leading to under-performance and consequent reduction in income.

Although many specific risks will be under the control of the Project Company, some risks such as macro economic events and acts of third parties or of Government will not.

The final project structure to be established in the feasibility phase must be designed in order to ensure that the risks are allocated to those Project parties best equipped to absorb or manage them. In addition to a carefully crafted contractual framework aimed to make the Project bankable and to protect the Project Company to the maximum extent, the commercial structure of the Project envisages the use of the following basic mitigates to address particular risk areas:

- warranties, performance guarantees, indemnities, liquidated damages and penalties furnished by third parties;
- insurance covering the cost of repair or replacement of assets and for loss of revenues arising from damage to assets;
- a receivables account providing liquidity for PPA payments;
- provisions for the payment of a termination sum by way of compulsory purchase of NPP in the event of Off taker default;
- a debt service reserve equal in amount to six month's debt service;
- mitigation of political risk through the involvement of Multilateral Agencies and Export Credit Agencies.

There follows a summary analysis of the principle risks, indicating how these are dealt with and mitigated by proper mechanisms in the various contracts.

11.5.2. Risks Prior to Completion

Construction Cost Overruns

- Risk: Increase in cost of completing the NPP due to contractor cost overruns, change orders, exchange rate movements or inflation.
- Mitigation: Fixed price Turnkey EPC Contract with limited ability for contractor-driven change orders. Unavoidable changes by the Project Company are cushioned by a contingency sum.

Constructor's Delay in Project Completion

- Risk: Failure to meet the Project's completion deadline can result in loss of income.
- Mitigation: The Turnkey EPC Contract to provide for delay liquidated damages in an acceptable amount. Delay caused by Force Major should give relief from contractual deadlines/penalties under the PPA, and additional protection should be afforded by a Delay in Start-up insurance.

Delay in Completion of Fuel Supply

- Risk: Completion of the Project may be thwarted by a delayed completion of the gas supply facilities.
- Mitigation: The Fuel Supply Agreement should provide acceptable liquidated damages to cover Fuel Supplier's liability for delay damages under the PPA as well as loss of revenue under the PPA. A delay caused

by Force Major under the Fuel Supply Agreement should have a deadline relief under the PPA. Additionally, the debt service reserve (L/C) should provide an additional cushion far deferral of income consequent to such delays.

Delay in Obtaining Licenses and Consents

- Risk: Non-availability of licenses for the transmission facilities and for the operation of the NPP would prevent the Project from entering into commercial operation.
- Mitigation: To the extent possible according to Armenian license application procedures, all material environmental and other licenses for construction and operation of the NPP and the fuel delivery facilities should be in place before non-recourse debt is available. Delay caused by act or omission of Governmental authority should enable deadline extension under the PPA

Failure or Delay in Technical Completion

- Risk: The failure of the plant to generate at the required output levels could lead to loss of income and penalties under the PPA.
- Mitigation: Failure to meet guaranteed performance levels (e.g. capacity and heat rate) under stringent tests should trigger performance-liquidated damages under the EPC Contract.

Interest Rates

- Risk: Increase in interest rates adds to the debt service burden and reduces cover ratios.
- Mitigation: Fixed rate finance and hedging for floating rate debt should be maximized.

Political Risks

- Risk: Imposition of new taxes/duties, or delay caused by Governmental authority.
- Mitigation: Change in law provisions of the PPA should allow additional/higher taxes to be compensated by tariff increases. Force Major provisions in the PPA should provide performance relief for Government actions or inaction.

11.5.3. Risks During Operation

Operating Performance

- Risk: Income is also reduced if the energy produced is less than the energy requested on a dispatch order (subject to exceptions for Force Major, scheduled allowance and other events). Other risks include excessive heat rate (over-consumption of fuel, leading to greater cost) and breakdown through mechanical defect.
- Mitigation: an experienced operator should operate the plant under an O&M Agreement, which includes penalties and bonuses for under/over performance. “Maintenance Agreements” should be concluded with the

EPC Contractor. Sensitivity analysis should be made to demonstrate robustness of Project to poor performance.

Increase in Operating Costs

- Risk: Unbudgeted cost increases (labour, insurance, and maintenance) could act to dilute the net income to the Project.
- Mitigation: The operational budgets should be based on prudent assumptions and include a maintenance reserve account. An experienced operator should operate the plant.

Dispatch and System Problems

- Risk: The Power Plant is not dispatched or off taker is unable to receive power into its system.
- Mitigation: Offtaker is obliged under the PPA to continue with Capacity Tariffs irrespective of dispatch or its ability to receive power. These capacity payments should cover the fixed costs for the project and the take-or-pay obligations under the Fuel Supply Agreement.

Transmission-related Problems

- Risk: Transmission losses between the Power Plant and the substations, or breakdown of transmission lines, could impact the Project cash flow.
- Mitigation: Under the PPA, the measurement point far delivery of energy is at the NPP.

Commercial Tariff Increases to Fuel Supply

- Risk: An increase of fuel cost, be it through an increase in gas prices, inflation or exchange rate movements could erode net income and put pressure on debt service and equity return.
- Mitigation: Under the PPA gas cost should be a pass-through to Offtaker.

Force Major

- Risk: Force Major events affecting the Power Plant or the fuel supplier can cause interruption of income from the PPA and possibly increased costs arising from repairs.
- Mitigation: The PPA should provide for Force Major affecting the NPP or the fuel supplier that Offtaker will continue to pay capacity payments without any availability penalties falling due. After abandonment caused by a Force Major Offtaker would have the right to terminate with/without buy-out liability. The NPP would be covered by an all-risks and business interruption insurance. Finally, the six-month debt service reserve provides a buffer for lenders in the event of Force Major.

Change in Law

- Risk: Modifications to existing laws or the introduction of new laws (especially tax or environmental laws) could increase the plant's capital or operating costs or reduce its income.

- Mitigation: increased costs caused by a change in law will be passed through to Offtaker by means of tariff revision under the PPA. Since in addition a change of law is considered to be Force Major event under the PPA, the Project Company will continue to receive capacity payments in any case.

Inflation

- Risk: Increase of operating costs (including fuel) driven by higher inflation could reduce net income.
- Under the PPA, costs in local currency should be indexed to Armenian inflation and costs in US$ should be indexed to the US inflation.

Exchange Rate Movements

- Risk: The Project's income may be fixed in Armenian Dram. A weakening of the Dram will increase (in Real terms) those Project costs denominated in US Dollars. Similarly, Dram devaluation will increase (in Real terms) the Project's debt service burden related to its dollar-denominated borrowings.
- Mitigation: The PPA should provide far a periodically exchange rate adjustment of the Capacity and Energy Payment and O&M Fees covering the non-Dram fixed and variable costs.

Interest Rate Movements

- Risk: Rises in interest rates increase the Project's debt service burden.
- Mitigation: Fixed rate finance and hedging of any floating rate debt will be maximized.

Payment Default by Offtaker

- Risk: Non-payment of the PPA tariffs by Offtaker would deprive the Project of its basic income stream. In case of a buyout Offtaker's payment default would prevent the creditors to be paid out.
- Mitigation: By way of payment support, an Escrow Account would provide initially a continuous liquidity for monthly tariff payments. Armenia acting through its Ministry of Finance and Economy shall provide the Project Company with a Performance Guarantee as additional support for the payment and reimbursement obligations of Offtaker under the PPA. The Project Company can resort to the Performance Guarantee if payments due are not available.

Environmental Risks

- Risk: Infringement of environmental norms by the Project Company could result in the halting of operations. The introduction of new and tighter environmental standards during the plant operation could lead to new investment cost to upgrade the plant to the new standards.
- Mitigation: The plant should be designed and built with latest technology equipment and EPC test requirements should ensure that the plant comfortably complies with Armenian and World Bank standards. The operator should have substantial experience of conforming to

environmental requirements. New investment cost due to a change in law bringing about new environmental norms should be a pass-through under the PPA.

Political Risks

- Risk: Non-availability of foreign exchange or expropriation/nationalization of the Project assets.
- Mitigation: Armenia's current pro-foreign investment and privatization policies are unlikely to be reversed. After the election of new Government, it appears certain that Armenia's current pro-foreign investment and privatization policies will be continuing.
- This notwithstanding, the involvement of Multilateral Agencies & Export Credit Agencies as major lenders/guarantors would provide confidence to international commercial lenders. Additionally, the debt service reserve would provide a cushion for the US$ debt.

12 SOME ASPECTS OF NUCLEAR DEVELOPMENT

The purpose of the present chapter is to elucidate some important aspects of the development of nuclear energy, taking into account such specific conditions and tendencies, which are formed and developed in economy of Armenia and, in particular, in fuel-energy complex of the country. Material, presented in this chapter, is based on the results of investigations, presented in the previous chapters of the report, and certain investigations on decommissioning of existing units of Armenian NPP.

12.1. Energy Security and Independence

It is obvious that in the countries with complete absence of own fuel resources (deposits), such as Armenia, the issues of provision of energy security and independence take on primary priority. The concept of energy security for Armenia conditions is formed in the following way: Energy Security - ability for the reliable energy supply for all requirements of a person, society and country under stable development and in extreme conditions.

Ensuring the Energy Security is the main task and responsibility of the State Institutions without exceptions. This should include the participation of private and public organizations of Armenia, too.

As it was mentioned above, these very principles were laid in the base of the long term planning of Armenian energy development.

Figure 12.1 shows the level of energy independence of Armenian power sector upon the implementation of "nuclear" scenario.

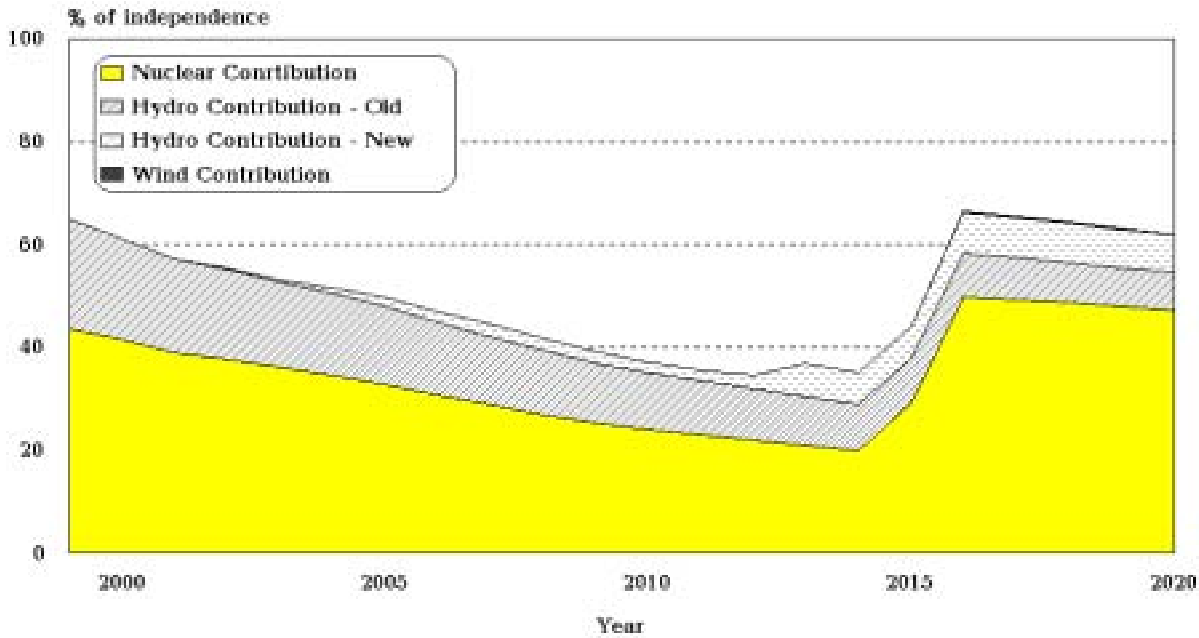

Figure 12.1. Percentage of Armenian electricity sector independence from imported energy sources - Reference demand-Nuclear scenario

Figure 12.1 shows that sufficiently high level of energy independence and, consequently, energy safety may be obtained upon nuclear energy development. Summarizing the experience of energy crisis, broken out in the beginning of 90th, we can assert that, upon having 40% energy independence indicator, it can be assured the normal functioning of practically all the life-support systems of Armenia in wide range of emergency situations.

As for the alternative Combined Cycle scenario, the decommissioning of Unit 2 of Armenian NPP will dramatically affect the level of country's energy security and independence (Figure 12.2).

12.2. Ecological Aspect

The problem of Sevan Lake, the only large water reservoir (basin) in the territory of Armenia, takes special place among the complex of ecological issues of Armenia. The problem has long enough history, and it was originated because of the use of Sevan hydro potential in 30-50th of 20th century for energy purposes. Incidentally, such use of hydro-energy resources is natural for many developing countries, which have no own fuel deposits.

In spite of Governmental program on Sevan lake restoration, the hydro-potential of the Lake was demanded again for electricity generation during the hard years of energy crisis in the beginning of 90s. Thus, the ecology of the whole region of Southern Caucasus has been damaged one more time. Only after re-commissioning of Unit 2 of Armenian NPP, the water outflows from Sevan Lake were restricted to the volume that was necessary for irrigation needs.

Possessing a free installed hydro capacities and some, hardly restored hydro potential, it is difficult to restrain the temptation of cheap electricity generation under the conditions of unsettled market economy, increase of fuel prices and others. In this situation, availability and development of nuclear capacities represent the constraint for voluntary decision-making.

12.3. Social Aspect

Construction of NPP in Armenia started at the end of 60s of the past century. During a long enough period that has passed since that, 2-3 generations of high-level specialists of different profiles have grown in the country.

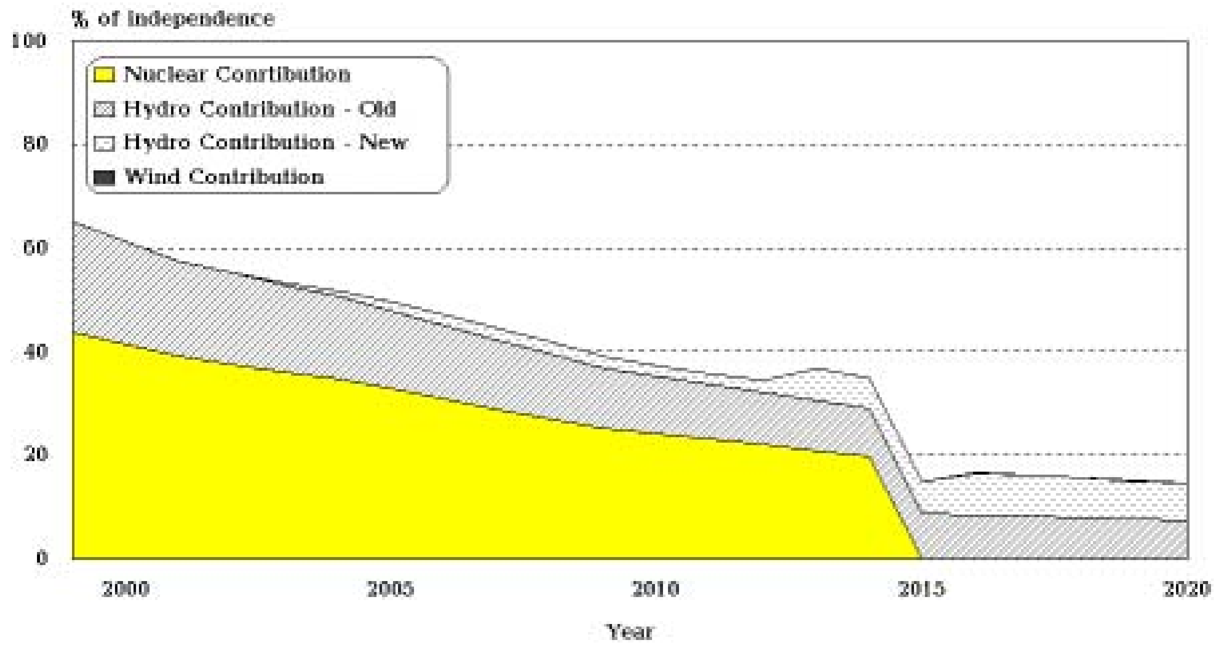

Figure 12.2. Percentage of Armenian electricity sector independence from imported energy sources - Reference demand - CC scenario

Training of technical staff is carried out not only in the republic. As a rule, key specialists pass the probation period in leading nuclear training centres of CIS and other countries. Many specialists have the experience of work in similar NPPs of CIS countries (Russia, Ukraine) and countries of former Eastern Block (Bulgaria, Hungary, Eastern Germany, Czechoslovakia).

Table 12.1. Nuclear companies and staff

Name of Company	Number of employers
Armenian NPP	1600
Atomservice	100
Hydro energy construction	50
Armenergomontage	100
Energorepairemen-Garant	70
Chemical protection	33
Armenergoadjustment	15
Armenergorepairement	26
Energy insulation	12
Energy Institute	20
Energy Strategy Centre	10
Armatom Institute	90
Engineering University (Nuclear Energy department)	11
Atomseismicproject	15
TOTAL	**2152**

It must be mentioned that the availability of scientific potential that can be directly engaged in the elaborations in the sphere of nuclear technologies is of particular importance.

The list of companies and number of employees, directly engaged in the sphere of nuclear energy is very spacious (Table 12.1).

Thus, decommissioning of NPP means not only the deactivating of a certain energy object, but also the shutdown of a whole science-intensive and high technology sphere of the country. At that, “Safe store” technology of NPP decommissioning will require the high-qualified personnel. However, the latter will be actually taken out from goods production sphere.

In case of realization of a project of new NPP units, it is expected that more than 10.000 workers will be employed in the construction process. Considerable part of industry and transport infrastructure of the country will be involved. For the country that suffers a transition period, such huge construction may be a locomotive for the whole economy.

Analysis of the impact of commissioning periods of NPP' new units. Sensitivity analysis of different scenarios for the development of generating capacities of Armenian NPP is presented in Chapter 8.5. It is obvious that, in case of realization of nuclear scenario, the key project of the program will be the construction of new units of Armenian NPP. At that, the problem of commissioning period for new units will be tightly connected with the decommissioning period of existing units of NPP. In this connection, the conducting of sensitivity analysis of the impact of commissioning periods of NPP' new units with simultaneous decommissioning of exhausted units is of special interest.

Accordingly, it is important to carry out the sensitivity analysis by the periods of project realization. PV is accepted as criteria of sensitivity analysis (as in previous cases).

The results of the calculation of the Present Value of nuclear scenario' different options are presented in figure 12.3.

On the assumption of the calculation results for different scenarios, the PV values differ slightly in rather wide range of commissioning periods for new capacities. However, the "late" commissioning (2018 or later) of even one of the planned new nuclear units is improbable, since it may occur only in case of possibility of prolongation of operation resource of Unit 2 of the ANPP for 3-5 years, or upon the condition of timely creation of capacities, alternative to Unit 2.

On the other hand, the following circumstances represent the obstacles for "early" commissioning the new units:

- Project capital intensity (financing provision),
- Preparation and decommissioning of existing units of ANPP,
- Development of intra-system and inter-system transportation networks,
- Conducting the complex of measures on the increase of stability and reliability of power system operation, taking into account the operation of new units and other.

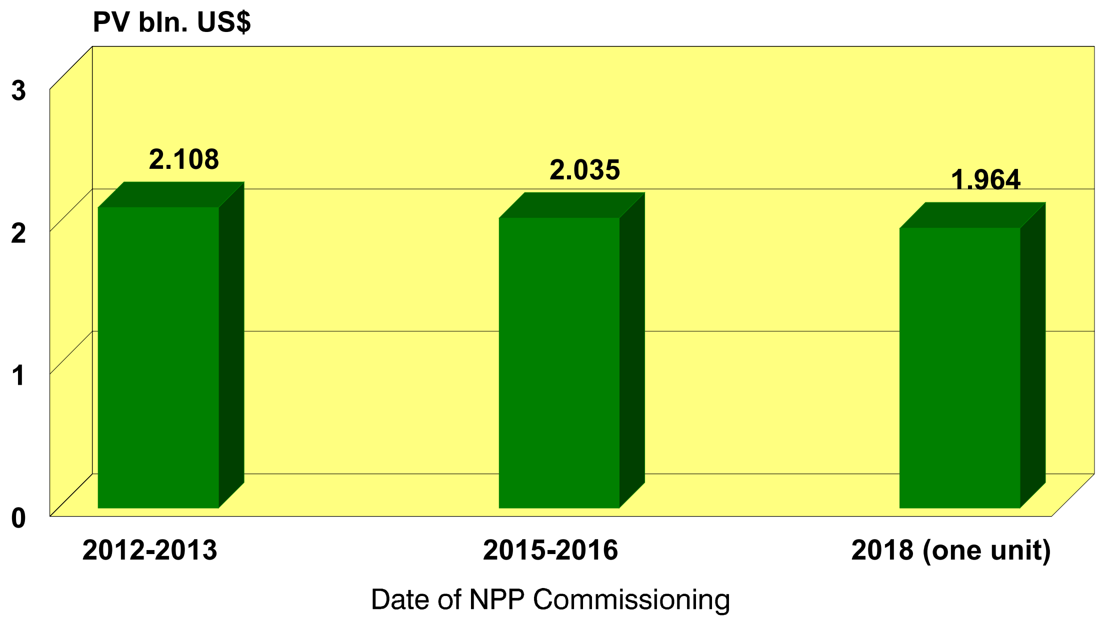

Figure 12.3. Present Value upon different periods of the commissioning of NPP new capacities

Thus, the organic solution by the periods of commissioning new nuclear units is their accurate co-ordination with the periods of decommissioning of operating Unit 2 of the ANPP. In other words, the optimal development plan may be achieved upon the acceptation of the postulate on consideration of new nuclear power units (unit) as alternative to the existing, under the natural period of decommissioning of the latter.

12.4. Issues of Armenian NPP Decommissioning - Decommissioning Strategy

Possible decommissioning strategies currently applied worldwide [155-173] are:

- Safe Store or Safe Enclosure Period (SAFESTORE/SEP);

- Early dismantling;
- Entombment.

From the survey of Armenian specific boundary conditions, the most suitable strategy to be considered for the decommissioning of Armenian NPP (Unit 1 and 2) seems to be the SAFESTORE, even if some dismantling activities for systems or components which cannot bear a long storage period should be envisaged, also having in mind the specific seismic condition of the site.

In fact, four considerations are pushing strongly in favor of this choice:

the need of funding in the short/medium term is minimized, and this seems specifically important in the Armenian situation due to the lack of funds[1] cumulated in the past to finance the decommissioning activities;

the possibility to adopt a tariff system for the electric power[2] system, that can allow to cumulate, in the coming years, the resources needed. This approach can suggest postponing the dismantling activities until the resources needed have been piled up. This could be done reasonably in a period of 40-50 years from now[3]. Vice versa, the most urgent activities to bring the plant in a safe state could be financed in the short term in different ways (donors, governmental funding, international loans, etc.);

- lack (at least in the short term) of suitable solutions for radioactive waste disposal. In fact, to achieve a complete site release, all the waste has to be removed and delivered to a repository. For the low level waste (LLW), a solution should be defined at a national level, but the process to decide, localise and built a LLW repository seems to be all but an easy task. Apart from usual difficulties in this field (e.g. public acceptability), some specific factor (i.e. Armenian region seismic peculiarity) could make quite difficult to find a reasonable solution. The similar problem can arise for the spent fuel disposal;
- a legal framework (viz. a nuclear law establishing clearance levels for weakly contaminated material, licensing procedure, etc.) should be established in advance to allow a complete decommissioning of the plant.

On the basis of the above considerations, SAFESTORE strategy is suggested for the Armenian NPP (both Units 1 and 2). The main characteristics of the proposed strategy can be summarised as follows:

- SAFESTORE status to be reached should be defined considering both the need to reduce short term expenses and the need to grant for the whole period safe conditions (i.e. to avoid the possible spreading of contamination in the environment also in case of seismic events). This will imply to carefully evaluate the best plant configuration to be

[1] A mechanism to cumulate funds using a levy on the kWh produced on ANPP is – in principle- in place but it never becomes really operative.
[2] The possibility to apply the same principle to the whole energy sector might be, in principle, evaluated too.
[3] In the present document, for sake of simplicity, a specific date (i.e. 2050) is taken as a reference. Obviously a more detailed optimization process will be needed to define the optimum SAFESTORE period.

reached, as well as to evaluate characteristics and status of buildings and structure;

- SAFESTORE period should last about 40 years to allow cumulating needed funds to afford decommissioning activities in a situation that, at that time, must be of self-sufficiency for Armenia;
- as a reference date, we will assume the year 2065 as the date for SAFESTORE completion and to begin the final plant dismantling. This activity should last about 10-12 years. The site should be therefore released for unrestricted use by the year 2080, considering other 4–5 years for the site restoration. At that time, it is assumed that a final solution for waste disposal (and for fuel disposal) will be available.

The proposed strategy should be applied both to Unit 1 and to Unit 2, even though in a different time frame.

Activity to bring Unit 1 in SAFESTORE condition should be started as soon as adequate funding is available. For Unit 2, of course, the activity starting point is a function of the final decision on the plant shutdown date.

For the scope of the present study, the reference date of 2015 for the shutdown of Unit 2 has been assumed. From a technical point of view the impact of this date is, however not really important due to the fact that to move back and forth this date doesn't change the main technical conclusions presented in the following. The only technical aspect that can be impacted refers to the possible overlapping of activities on Unit 1 and 2, but the consideration of this aspect implies a level of details in the activity planning that is clearly beyond the scope of the present study.

The optimal strategy is to start the decommissioning of Unit 1 as soon as possible, and to carry out as many activities as possible while Unit 2 is still in operation, then proceed to put into SAFESTORE conditions both units. The advantages of such a strategy are the following:

- possibility to utilize plant personnel, which is, in any case, needed for the operation of Unit 2, also to participate in most of the projects related to Unit 1 decommissioning (operation, maintenance, health physics people etc.) at no additional cost.
- possibility to set up the general framework to make decommissioning activities feasible, with reference to both regulatory/institutional aspects and to technical issues (waste treatment, final disposal of waste, partial dismantling, room sealing, decontamination), well in advance of the shutdown of Unit 2, when the timely resolution of the above mentioned problems will become critical to reduce decommissioning time-scale and associate costs.

In the past, the spent fuel was sent for reprocessing to Russia, without the obligation of receiving back the wastes generated. After the disintegration of the Soviet Union, the Russian Parliament has prevented any additional spent fuel to be brought in Russia for reprocessing from any of the external republics. Therefore, at the ANPP, the spent fuel has been stored in both of the spent fuel pools of Unit 1 and Unit 2.

In 1996, "Framatome" signed an agreement to construct on the ANPP site a NUHOMS-type dry storage for spent fuel (40 Millions of Francs) under the license of the US Company Vectra, to store the spent fuel accumulated up to that date. Today, the construction of that module has been completed.

The facility has been built to accommodate up to 612 fuel assemblies (the inventory unloaded before the ANPP restart). However, the NUHOMS concept is typically modular concept, and it will be possible, if needed, to increase the storage capacity. Due to the fact that having enough capacity to store unloaded spent fuel on-site might be a critical issue, different scenarios have been considered.

It should be also considered that decommissioning activities on Unit 1 may also make difficult or impossible in the future to store spent fuel on Unit 1 SF pool. Therefore, it is necessary to carry out carefull evaluation of needs and timing for building additional dry storage capacity, also having in mind that minimum decay time for the spent fuel before dry storage is 5 years.

The plant will remain in SAFESTORE conditions for 40-50 years after the unloading of the last fuel element, and plant security and monitoring provisions will be sufficient also for the dry storage facility so that no additional costs will be considered during the passive storage. Minimum decay time for the spent fuel before dry storage is 5 years.

At the end of the storage period, the fuel will have to be transported off-site for final disposal or reprocessing at a cost derived from current international studies. If equipment and systems are needed to assure off-site transport, their costs will be included in the economic evaluation.

An Evaluation of various alternatives has been carried out. In particular, according to international practices, reprocessing and both wet and dry storage alternatives have been investigated. Three options for interim dry storage has been more in-depth studied, i.e. NUHOMS, Metal casks, and Concrete casks.

Reprocessing option is available as a hypothetical alternative at average international technical and economic conditions, including the return of Vitrified High Level Waste (VHLW). The return of VHLW will be assumed to occur 20 years after definitive plant shutdown for final cost evaluation.

The complete list of the interventions to be implemented at the plant to bring both Units in SAFESTORE can be only defined on the basis of a detailed work plan for the decommissioning activities that goes beyond the limit of the present study.

13 CONCLUSIONS AND RECOMMENDATIONS

The Energy Strategy Centre under the technical assistance rendered by the International Atomic Energy Agency has carried out the Energy and Nuclear Power Planning Study for Armenia. The main conclusions and recommendations of the study are reported here.

13.1. Conclusions

13.1.1. Energy and Electricity Demand

The demand for commercial energy has been projected to increase at a growth rate of about 8.7% per annum in the Reference Scenario, i.e., from 1008.9 ktoe in 1999 to 5773.7 ktoe in 2025. Since the economic growth in Low Scenario has been assumed to be lower by 2% per annum throughout, as compared with Reference Scenario, the growth rate of final energy will be less, i.e., 7.7% per annum, and it will reach 4776.8 in 2025.

The future demand for electricity has been projected to grow by 4.4-5.6% p.a. in different scenarios, as shown below:

Growth Rate of Electricity Demand (% per annum)	**1999-2005**	**2005-2010**	**2010-2015**	**2015-2020**
Reference Scenario	8.5%	6.8%	4.0%	2.8%
Low Scenario	7.4%	4.6%	3.3%	2.1%

The peak demand corresponding to the above projections at the end of each period and at the end of planning horizon has been worked out as:

Peak Demand (MW)						
Year	**Low Scenario**			**Reference Scenario**		
	Local	**Export**	**Total**	**Local**	**Export**	**Total**
1999	1044	27	1071	1044	27	1071
2005	1263	78	1341	1341	105	1446
2010	1565	241	1805	1805	180	1985
2015	1805	359	2164	2164	365	2529
2020	2007	461	2468	2468	505	2973

The net power generation capacity additions over the 22 years study period will range from 2714 MW to 3094 MW in different scenarios.

13.1.2. Overall Energy Demand-Supply Balance

It is expected that, in order to meet the projected energy demand, the country will continue to be dependent on energy imports. After the commissioning of two new NPP units, despite the increase of primary energy demand, the sufficient level of energy independency (38.2%) may be ensured (in 2020) in the Reference Demand Nuclear Scenario; at the same time, for Reference Demand CC scenario, this indicator will be dramatically reduced to 2.5% after the decommissioning of Unit 2 of Armenian NPP. Fuel independency in Low Demand has similar indicators with Reference Demand (31.4% for Nuclear Scenario and 3.3% for CC Scenario).

13.1.3. Least-Cost Plan for Expansion of Electricity Generation System

A total of 3094 MW of power generation capacity has to be added over the period 1999 to 2020 to meet the electricity demand as projected in the Reference Scenario and 2794 MW in the Low Scenario.

The contribution of nuclear power in total capacity additions is 1280 MW, which remains unchanged under the wide variation of certain important parameters, for example - capital cost, discount rate and prices of alternative fuels.

In order to analyze the main uncertainties surrounding the future development of electric sector in Armenia, alternative plans for future expansion of electricity generation system have been formulated and analyzed. Two alternatives assume the same electricity demand and all other supply assumptions as in the Reference and Low Scenarios, except for the nuclear power development.

Analysis, conducted by BALANCE model to estimate the growing demand for electrical energy that may be met by replacing generating plants which already reached the end of their lifetime, for two alternative plans in the framework of whole energy system, shows that the scenario with a new NPP is able to compete with the scenario without the nuclear option and is more preferable from the point of view of energy supply diversification.

13.1.4. Investment Requirements

Cumulative investments and system operation costs (O&M and fuel costs) over the next 22 years period for all cases are given in the table below. In case of Reference Demand Scenario with Nuclear Option, the cumulative investments for capacity additions have been worked out as US$ 2.9 billion, and the cumulative system operation costs as US$ 4.6 billion. Compared with that of the Reference Demand Scenario without Nuclear Option, the cumulative investments in the case with nuclear option are US$ 0.6 billion higher because the capital costs of nuclear power plants included in this case are relatively higher compared to that for gas fuel based power plants. On the other hand, the system operation costs in case of Reference Demand Scenario with Nuclear Option are lower by about US$ 0.5 billion, compared to that of Reference Demand Scenario without Nuclear Option. This difference is due to the low fuelling costs of nuclear power plants.

The sum of cumulative investments and operation costs is thus higher by US$ 0.17 billion in case of Reference Demand Scenario with Nuclear Option, compared to that of a scenario without nuclear option. The similar situation can be viewed for the Low demand Scenario Cases. It may be noted that these values for scenarios with nuclear option are not much different from those for the cases without nuclear option.

Million US$ of 1999

Scenarios	Investments	Operation	Total
Reference Demand Scenario Case with Nuclear Option	2854.0	4545.4	7399.4
Reference Demand Scenario Case without Nuclear Option	2220.0	5004.5	7224.5
Low Demand Scenario Case with Nuclear Option	2658.0	3894.2	6552.2
Low Demand Scenario Case without Nuclear Option	2024.2	4260.1	6284.3

13.1.5. Environmental Assessment

On the basis of the preceding analysis, it has been observed that the power system expansion plan worked out in the Scenario with New NPP is much better, from the environmental protection point of view, compared to that in the Scenario without New NPP. The later gives rise to very high emissions of SO2, NOx, and CO. As for radioactive emissions from nuclear power plants, such emissions are obviously higher for the Scenario with New NPP, but these are strictly controlled and contained within permissible limits.

Due to the limited indigenous energy resources, future electricity generation will require involving of all available technological options. However, the use of nuclear power can significantly help to reduce the future environmental emissions of SO2, NOx, and CO pollutants, while not causing any serious threat to the environment even having radioactivity releases.

Nuclear power plants require somewhat higher investments than fossil fuel fired power plants, however, the gap becomes trivial when fossil fuel fired power plants are equipped with SO2 and NOx emission control devices. Further, the use of nuclear power becomes economically attractive when the total system costs are considered. Thus, it is clear that the increased use of nuclear technology for electricity generation in Armenia in the coming decades will be not only helpful in reducing the environmental degradation, it will also be cost effective.

13.1.6. Financial Analysis

The financial analysis of the envisaged nuclear power development plan shows that the plan is financially viable under the assumed terms of financing. These terms have been assumed in line with the internationally accepted practices and the recent policy of the Government for private power producers in Armenia.

For the new nuclear units, it has been assumed that the Government will provide equity to the extent of 29.4% of its investment and the remaining funds will be generated from foreign and local loans (68.6%) and grants (2%). However, as the nuclear power plant becomes operational and starts generating revenues, the surplus earnings, available after meeting all operational costs, debt servicing and dividend payment, can be used also for investment in decommissioning of old units.

13.2. Recommendations

The main recommendations of the report are:

- Rehabilitate all existing hydropower plants as soon as possible.
- Rehabilitate existing thermal power plants and CHP units.
- Implement aggressively demand-side management campaign and carrying out cost-effective measures without delay.
- Keep the operating nuclear power plant till its design life with enhanced nuclear safety, not only relevant to the plant, but also considering the system measures, such as strengthening of the HV transmission system, interconnection to neighbouring countries, provision of adequate levels of spinning reserve, and load management to increase the low system load at night.
- Add Shnokh, Megri and Gekhi HPPs, as well as 75 MW small hydro between 2012 and 2017, and add 15 MW of wind farm, and implement other renewable projects.Add gas-fired CHP Combined Cycle Plants (668 MW) according to heat demand and electricity demand growth.
- Maintain Hydro-Potential Stocks of Lake Sevan. Reduction of Irrigation Losses.

- Rehabilitate and further develop gas and electrical interconnections to neighboring countries. Rehabilitate and expand underground gas-storage. And maintain a reasonable stock of crude oil and/or petroleum products.Develop nuclear power on the basis of modern technologies in parallel with the old units decommissioning process.
  - Introduce tax incentives to stimulate private sector involvement in development of renewable energy projects, which would help to decrease Armenia's dependency on fuel imports, it would also be of benefit to the environment.

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ABBREVIATIONS

AMD	Armenian Drams
BALANCE	Overall Energy Demand-Supply Balancing Model
bbl/d	Barrels Per Day
bcf	Billion Cubic Feet
bcm	Billion Cubic Meter
CC	Combined Cycle
CCPP	Combined Cycle Power Plant
CF	Complete Factorial Experiment
CHP	Combined Heat and Power Plants
DH	District Heat
ENPP	Energy and Nuclear Power Planning
EPC	Engineering Procurement Construction
EPT	Experiment Planning Theory
ERF	Exposure Response Functions
FP	Feed-Pumps
GDP	Gross Domestic Product
GW	Gigawatt
GWh	Gigawatt·hour
GWyr	Gigawatt·year
HP	High-Pressure
HPP	Hydro Power Plant
HRSG	Heat Recovery Steam Generator
IPP	Independent Power Producers
IRR	Internal Rate of Return
kcal	Kilocalories
kg	Kilogram
kgce	Kilograms of coal equivalent
km	Kilometres
ktoe	Kiloton of Oil Equivalent
kV	Kilovolt
kWh	Kilowatt·hour
L/C	Debt Service Reserve
LDC	Load Duration Curves

LLW	Low Level Waste
LOLP	Loss-of-Load Probability
LP	Low-pressure
LPG	Liquid Pressure Gas
MAED	Energy and Electricity Demand Analysis Model
MCP	Main Circulating Pump
mmst	Millions Short Tons
NPP	Nuclear Power Plant
NPV	Net Present Value
O&M	Operation and Maintenance
OMR	Operation and Maintenance Requirements
PBT	Pay Back Time
pkm	Passenger·Kilometres
PPA	Power Purchases Agreement
PSP	Pumped Storage Plant
PV	Photovoltaic System
PWR	Water Moderated Under Pressure Reactor
SF	Spent Fuel
SHS	Solar Home System
SIMPACTS	Environmental Assessment Model
sqm	Square Meters
TEF	Tons Equivalent Fuel
TI	Terrain Index
tkm	Tonne·Kilometres
toe	Ton of Oil Equivalent
TPES	The Primary Energy Source
TPP	Thermal Power Plant
TWh	Terra Watt Hour
VAT	Value Added Tax
VHLW	Vitrified High Level Waste
VVER	Water Water Energy Reactor
WASP-IV	Wien Automatic System Planning package
YOLL	Years of Life Loose

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