Report No. 11412-AM

Armenia
Energy Sector Review

June 30,1993

Infrastructure Division
Country Department IV
Europe and Central Asia Region

FOR OFFICIAL USE ONLY

ABBREVIATIONS AND ACRONYMS

Acronyms

ARMENERGO	Armenia Energy Company (electricity district heating)
ARMGAZ	Natural Gas Distribution Company
ARMGAZPROM	Natural Gas Transmission Company
ARMOIL	Armenia Oil Products Company
c.i.f.	Cost, Insurance, Freight
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
MEF	Ministry of Energy and Fuel
NPP	Nuclear Power Plant
TPS	Thermal Power Station

UNITS OF MEASURE

Mcm	million cubic meters
Bcm	billion cubic meters
TOE	metric tons oil equivalent
KTOE	thousand (kilo) TOE
t	metric tons
m^3	cubic meter
mm	millimeter
$000m^3$	thousand cubic meters
kgoe	kilograms oil equivalent

GROSS HEAT VALUES OF FUEL

1 Unit of Fuel tons or thous m^3	=	X/tons conventional (coal) fuel (TCF)	=	Y tons oil equivalent (TOE)	Gcal
Fuel		X =		Y =	
Conventional (coal) fuel		1.000		0.700	7.0
Coal (low quality)		0.814		0.570	5.70
Wood		0.266		0.186	1.86
Natural gas ($000m^3$)		1.182		0.827	8.27
Mazut (residual fuel oil)		1.370		0.959	9.59
Light fuel oil		1.290		0.903	9.03
Diesel/stove oil		1.450		1.015	1.02
Gasoline		1.490		1.043	1.04
Jel fuel		1.490		1.043	1.04
Kerosene		1.470		1.029	1.03
Liquified Petroleum Gas (LPG)		1.570		1.099	1.10
Bitumen		1.420		0.994	9.94
Crude oil		1.429		1.000	10.00

1 Gcal = 4.187 GJ = 3.968 million BTU = 1163 kWh
Hydro and Nuclear energy output converted to primary thermal equivalent at 250 gms OE/kWh

Exchange Rate

Armenia belongs to the ruble zone. At the time of the mission (May/June 1992), 100 rubles = US$1.00
As of December 1992 the rate was rubles 447 = US$1.00

Fiscal Year January 1 - December 31

ARMENIA: ENERGY SECTOR REVIEW

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This Energy Sector Review is based on the findings of a Joint World Bank/International Atomic Energy Agency (IAEA) mission which visited Armenia in May/June 1992. The Bank team was composed of Joseph Gilling, Senior Energy Economist (leader), Peter Law Gas Specialist; Kurt Schenk; Edwin Moore, Power Engineer (cons); Arnold Safer, Petroleum Specialist (cons). The IAEA team consisted of Bernard Gachot (nuclear safety specialist) and Antonio Godoy (seismic specialist) of the Safety Assessment Section, Division of Nuclear Safety.

ARMENIA ENERGY SECTOR REVIEW
EXECUTIVE SUMMARY

1. This review was prepared as part of the Economic and Sector Work program of the Europe and Central Asia Region of the World Bank to provide (a) assistance to the Government of Armenia in its program of reforms in the energy sector, and (b) a basis for the Bank's lending in the energy sector in Armenia. The review has been carried out in conjunction with the study on power demand and supply options in Eastern Europe and the Former Soviet Union (FSU) which is being jointly undertaken by the World Bank and the International Energy Agency (IAEA) at the request of the G7. A mission comprised of representatives of both agencies visited Armenia in May/June 1992. The review presents an analysis of the energy sector and makes recommendations concerning strategies for reform and development, technical assistance requirements, and investments.

2. This summary first reviews the current situation and its impact on the overall economy and on the energy sector, then outlines three scenarios for economic growth and their consequences for energy demand and supply requirements and options, followed by an examination of policy issues in the sector. It concludes with recommendations for energy strategy and priorities which are summarised in a matrix (Table ES2) and a table of investment requirements (Table ES3) to address immediate needs and lay the groundwork for sector reform and development in the longer term.

3. The formulation of an energy strategy for Armenia involves the setting of priorities based on tough economic choices in view of the severe constraints on recurrent and capital budgets. In this regard, the government is faced with choosing from a number of options discussed in this review for increasing and/or diversifying energy supply. Some of these options may be justified during the present emergency because of the current high economic value of energy attributable to shortages but they could prove costly in the long run with the eventual lifting of supply constraints. For this reason, the strategy recommendations in this review are based on economic criteria, including risk and uncertainty, to identify energy projects and programs according to their relevance both in the short term emergency conditions and the longer term conditions of peace.

A. Current Situation

4. Because of its landlocked position and the blockade resulting from the ongoing conflict with Azerbaijan over the region of Nagorno-Karabakh, Armenia is under a virtual state of siege. Transportation links and gas supplies via pipelines through Azerbaijan have been suspended since mid 1991. Civil strife in Georgia has also resulted in the disruption of gas supplies for periods up to 30 days in May and September 1992 and again in January 1993. Ongoing rail disruptions in Georgia have held up mazut (heavy fuel oil) shipments for over three months. Iran agreed to supply mazut but shipments are blocked from passing through the Azeri territory of Nachichevan. Political opposition in Turkey has blocked all but humanitarian aid and electricity can not be supplied through the existing interconnection.

5. Through the winter of 1992/93 with sub-freezing temperatures, economic activity (GDP) declined to about 50% of the 1990 level (the last year of undisrupted conditions) as a result of the transportation and energy disruptions; homes and offices were without heat, and electricity supply was rationed to a few hours per day. Transportation fuels were scarce and gasoline was reported to be selling on the private market at the equivalent of about US$ 5/US gallon, a very high price in relation to

incomes. Because of a lack of diesel fuel in the fall of 1992, farmers could not bring in much of the harvest and, with the restricted importation of foodstuffs, prefamine conditions are evident among portions of the population.

6. Under the present circumstance the immediate concerns of the government are to provide sufficient food and fuel for the survival of the population; humanitarian relief efforts are continuing. In the energy sector, the government is focussing on increasing and diversifying sources of supply by any means possible, including planning for the recommissioning of the nuclear power plant (NPP)[1] which has been shut down since early 1989, following the 1988 earthquake (the plant is located within 18 km of a seismic fault). The government is well aware of the national and international concerns about nuclear safety, but is also confronted by several major issues including:

- the increased dependency on Russia, Turkmenistan, Azerbaijan, and Georgia for fossil fuel imports under a no nuclear scenario
- the country's balance of payments problems resulting from fuel price increasing to world price levels in the near to medium term
- the large capital requirements for the power sector to ensure reliable electricity supply to help sustain economic recovery and growth regardless of the decision concerning the nuclear power plant.

7. Plans are also underway to develop the limited indigenous energy resources of coal and peat, oil and gas, and renewable energies including wind, solar, and hydro. In addition, construction of a gas pipeline from Iran is in preparation while reinforcement of the pipeline from Georgia is underway. Financing for the completion of the 300 MW Hrazdan 5 thermal power station has been obtained from EBRD. Finally, USAID and EC are supporting the development and implementation of energy conservation programs, part of which could be financed with assistance from the World Bank.

[1] The nuclear plant is a Soviet designed and built model VVER440/230.

B. Future Economic Scenarios

8. Armenia is attempting to work towards a resolution of the conflict with Azerbaijan, which has been the cause of the blockade. The time needed to resolve the conflict is quite uncertain, however, and will affect the rate of economic recovery and structural change as well as the level of energy demand and supply. Because of these uncertainties, a scenario approach has been used by the World Bank in preparing projections of GDP (Figure 1).[2] The high and low growth scenarios constitute a likely upper and lower bound respectively on economic growth.

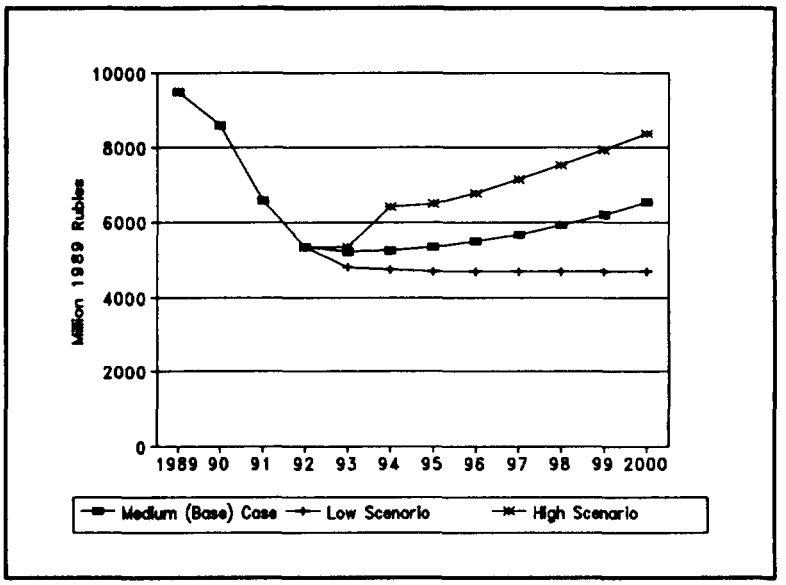

Figure 1 ***Macro Economic Scenarios - GDP Growth***

9. Under the ***high scenario***, the lifting of the transportation blockade in mid-1993, together with a rapid re-establishment of inter-republican trade and commercial support mechanisms, would result in initial rapid economic recovery followed by a period of structural change until 1996. Real growth of 3-5% would lead to restoration of 1990 output by about 2000. With the ***medium scenario***, there is the same assumption that the transportation blockade would be lifted in mid-1993, but the economy would not reach the 1990 level until after the year 2000. In the ***low scenario***, the transportation blockade would remain in place until the mid 1990s and the siege economy would become entrenched. The economy would be based on domestic labor, low inputs of capital, intermediate goods, and energy. Under this scenario, the economy would remain at about half its 1990 level.

10. For the purpose of energy sector planning, the medium scenario has been used as the base case for preparing demand projections. The impact of the high scenario and the low scenario on energy demand and facilities requirements has also been considered.

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[2] Armenia: Country Economic Memorandum, March 1993.

C. Energy Supply and Demand

Historical Requirement

11. Armenia's total primary energy supply requirement peaked in 1988 at about 10,100 ktoe (thousand tonnes oil equivalent), as shown in Figure 2, and dropped to 8300 ktoe in 1991. As with other FSU and East European countries, the energy intensity of the economy (kgoe per unit of GDP) has been several times that of countries with higher income per capita, and has doubled its former level because of the sharp drop in GDP without a corresponding drop in energy consumption. While Armenia imports 100% of fossil fuel needs, it exported about 20% of total electricity generation up to early 1989 when the nuclear plant was shut down. Internal production (hydro plus nuclear when it was operating in the past) accounted for about 50% of Armenia's electricity requirement up to 1988 when net exports were 2918 GWh. By 1991, Armenia became a net importer of electricity (1572 Gwh/yr or about 17% of domestic generation) as gas supplies via Azerbaijan were restricted.

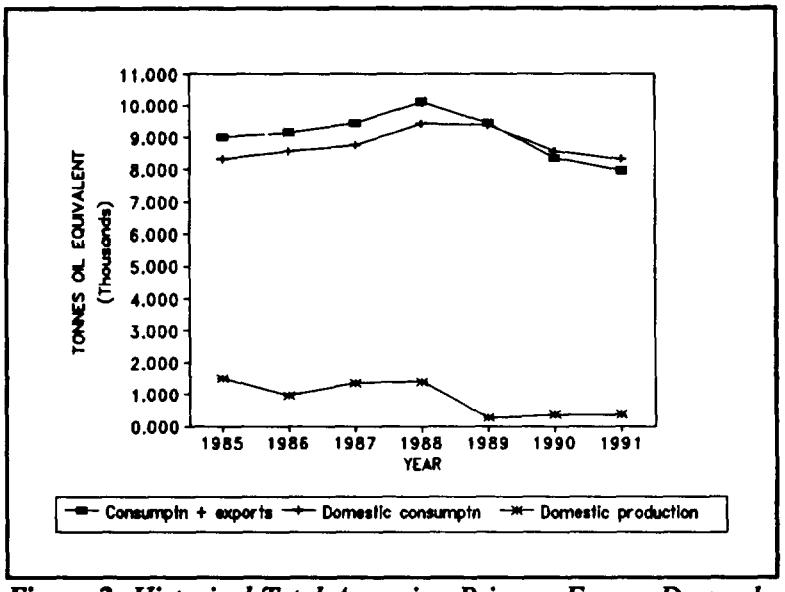

Figure 2 Historical Total Armenian Primary Energy Demand

12. With no gas production of its own, Armenia is totally dependent on imports from Russia and Turkmenistan through pipelines entering via Azerbaijan and Georgia. Throughout the 1980s, gas consumption continued to rise, and in 1989 reached its peak of 5.87 billion cubic meters (Bcm) per year (51% of total primary supply) with about one third used for power generation, and the remainder consumed by the industrial, commercial and residential sectors. The widespread availability of gas throughout Armenia has resulted in a high dependence on gas by the population (63% of whom have access), particularly for residential heating for households not supplied by district heating.

13. Heavy fuel oil is used for power generation and heating while light products (gasoline and diesel fuel) are used for transportation. Public transportation and rail services are largely electrified.

Projected Energy Demand

14. The demand for total primary energy is comprised of the requirements for power generation, heating, and transportation. The requirements for gas and mazut for power generation are determined by the total electricity supply requirement less domestic (hydro) generation and electricity imports. The demand for fuels for other uses has been projected on the basis of energy intensity in the economy which, when combined with the requirements for power generation, give the total primary energy requirement.

15. ***Electricity Demand.*** The base case demand scenario (Figure 3) is based on the assumption of an initial rapid drop in intensity (25% by 1996) due to a rebound in GDP, followed by a steady decrease of about 2% annually in electricity intensity. This rate is similar to that experienced in the high income industrialized countries during the 1970s and '80s following the energy price shocks. The 1990 level of intensity would be reached about 2010. Maximum demand is projected to reach a minimum level of about 1727 MW in 1995, rise to 1904 MW by 2000 and reach 2160 MW and 2452 MW in 2005 and 2010 respectively.

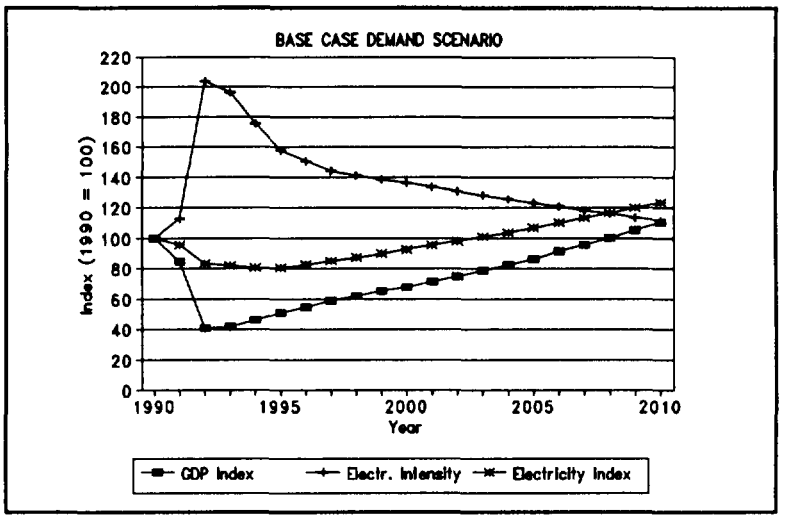

Figure 3 Base Case Electricity Demand Scenario

16. Further reduction in electricity intensity could be achieved with more rapid restructuring of industry and greater emphasis on energy efficiency. Under the low electricity demand scenario, power demand would reach about 1409 MW by 1995, 1326 MW by 2000, and 1566 MW by 2005.

17. ***Primary Energy Demand.*** As Armenia imports all fossil fuel requirements, it must pay the price demanded (or negotiated) with external suppliers. Hydrocarbon prices are moving rapidly toward world price parity and payable in hard currency. In the demand projections, price effects are taken into account in the assumptions concerning the drop in energy intensity of the economy due to restructuring of the economy and energy conservation efforts.

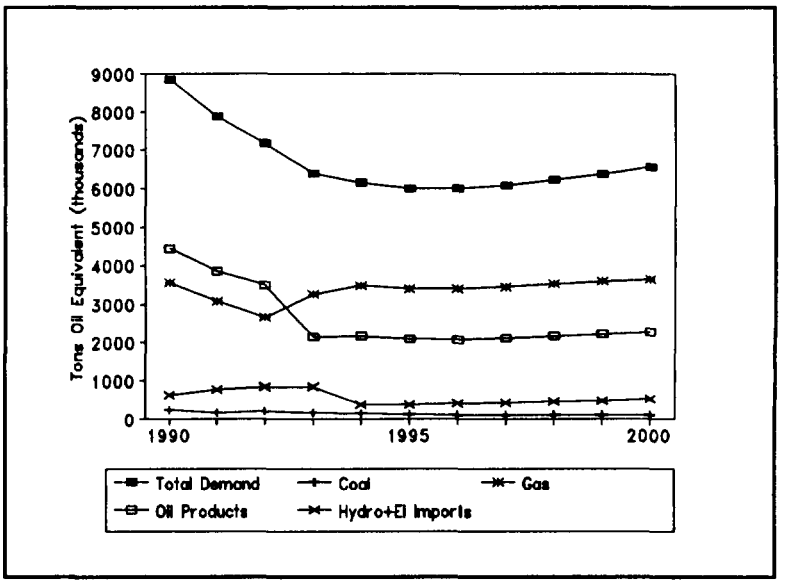

Figure 4 ***Primary Energy Demand Projections - Base Case Scenario***

18. Based on the projections of electricity and final energy consumption, the requirements for total primary energy expressed in thousands of tonnes of oil equivalent under the base case macro economic scenario are as shown in Figure 4, assuming that the nuclear plant remains closed. Total energy requirement is projected to decline to 6.0 million TOE by 1996 (68% of the 1990 level) as energy intensity declines faster than the economy grows. With a strengthening of economic growth to about 5% towards the end of the decade, energy demand would reach 6.5 million TOE by the year 2000.

19. In the low economic scenario, the availability of capital for energy conservation and restructuring would be tightly constrained with the result that energy intensity would be higher than under the base case. Therefore, despite the lower level of economic output, it is assumed that total energy requirements would be about the same as for the base case scenario. Alternatively, faster growth in the high economic scenario combined with greater investment in new, more energy efficient technology would lead to higher GDP for the same energy and, thus, a lowering of energy intensity. For these reasons, the electricity and primary energy requirements based on the medium economic scenario have been used as the basis for energy planning for all scenarios in this review.

20. Given uncertainties as to the composition of demand and availability of fuel imports, projections of the breakdown by fuel type (natural gas and oil products) as shown in Figure 4 are indicative. Because of the high degree of substitutability between mazut and gas for heating and power generation, the eventual composition of the energy demand projection is not so critical since the fuels are complementary in use. Natural gas consumption would increase significantly, as shown in Figure 4, with the assumed lifting of the blockade in 1993 and the increase of gas use in power generation to 70% of fuel requirements. In the period 1995-2000, gas use would remain flat at about 3 million TOE (or 2.5 Bcm per year as a result of energy efficiency improvements and a doubling of hydro production which could be obtained from new installations. The use of coal is not expected to increase unless the exploitation of domestic coal is found to be economic in the long run.

D. Energy Facilities and Supply Options

Electric Power System

21. ARMENERGOPROD operates and maintains all generating facilities except the NPP. Total nominal installed capacity is 2700 MW, excluding the NPP. Derating due to age, lack of maintenance, and operating constraints brings the effective installed capacity to about 1971 MW to supply a projected maximum demand in 1993 of 1788 MW (Table ES1). The nominal reserve margin would then be 10%; however, with units out of service for maintenance and/or repair, there would be a capacity shortage. A minimum 25% reserve should normally be planned.

22. The thermal power stations can burn either mazut or gas and provide steam and hot water for industrial use and district heating in addition to electricity. Both thermal and hydro plants are in need of repair and rehabilitation. Many of the plants are more than thirty years old and near the end of their service lives. Furthermore, the civil works of Yerevan thermal plant are in poor condition and no seismic design standards were incorporated in their design. Life extension may be economic in comparison with replacement or other alternatives but this possibility must be examined through detailed studies.

23. Under the base case demand projection, 300 MW of additional capacity to be provided by Hrazdan 5 are needed in the short run to provide a capacity reserve margin of 25% and permit the retirement of the oldest most inefficient units. Construction of the Hrazdan 5 unit is 60% complete and approximately US$90 million is required to complete the installation.[3]

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[3] Financing has been approved: EBRD US$6.5 million equivalent (loan); Government of Armenia US$32 million, and European Community about US$1.5 million equivalent (grant).

24. Armenia is also studying the economic viability of alternative sources of energy including the expansion of small hydro and the development of windpower. New hydro plants have been identified at about 40 sites. Some of these plants appear to be economic but others require further examination. Altogether, the plants could provide about 700 MW of capacity and 2200 Gwh/yr to bring total hydro production to about 30-33% of electricity requirements at the historical 1985-91 level. For planning purposes, it is assumed that a total of about 300 MW of renewable energy capacity will be installed in the period 1995-2000.

25. Interconnections exist with Georgia and Azerbaijan as part of the Transcausus grid developed under the Soviet system. Under peacetime conditions, Azerbaijan wheeled power through Armenia to Nachichevan and supplied additional power to Armenia. Although contracts exist with Georgia and Russia for power supply, power shortages there have reduced supply to Armenia to about 500 GWh/yr, or about 100 MW on an intermittent basis, and in the near term this situation is likely to persist.

Table ES1: Power Demand and Capacity

Mega Watts (MW)	Actual 1990	Estimate 1992	1993	1995	2000	2005	2010
Maximum Demand	2146	1813[4]	1788[5]	1727	1904	2160	2452
Existing Installed Capacity (excl NPP)	2700	2700	2700	2675	2078	2078	2078
Of which,							
Thermal	1746	1746	1746	1472	1125	1125	1125
Hydro	953	953	953	953	953	953	953
Additions				300 (Hrazdan 5)	300 hydro	300 thermal	400 thermal
Retirements				24	597		
Firm Imports	100	100					
Net Firm Capacity	2071	1971	1971	2250	2413	2713	3113
Reserve Margin %	(3)	9	10	30	27	26	27

[4] Early 1992, when fuel available. Reduced to less than 1000 MW by year end because of fuel shortages.

[5] Assuming no fuel shortage.

District Heating

26. Extensive district heating systems are operated in conjunction with thermal power stations in the three largest cities in addition to heating only systems.[6] These systems were very inefficient even when they were built and efficiency is further deteriorating with heat losses of up to 60% due to low combustion efficiency, inadequate water treatment, lack of insulation, steam and water leaks.

Petroleum

27. Armenia has no oil refining capacity and imports all of its petroleum products from refineries in the Russian Republic. There are no petroleum pipelines and all products are shipped via rail with small shipments by tank-truck. In 1990, total consumption of refined products was 1.8 million tonnes plus 2.6 million tonnes of mazut, while in 1991, total petroleum consumption declined by about 13%.[7]

28. About 60 days' storage capacity is available for mazut at the power stations and 35 days for light products. Stocks are now fully depleted; however, it has not been possible to replenish them due to the blockade. Gas and oil reserves sufficient for about 8-10 years' requirements were located during the Soviet era, but the economic feasibility of their development has not yet been determined. Prospects are promising and the government is seeking international investors to participate in the development of the resources as rapidly as possible.

Natural Gas

29. ARMGAZPROM operates about 1600 km of high pressure transmission lines. Three trunkline systems enter along the eastern border with Azerbaijan. Their capacity is 45 mcm/d while current requirements are about 22 mcm/d. Close to half the pipelines have been in operation for more than 20 years and much of the system is believed to be in need of replacement. Many of the pipelines are operated well below their design pressure in order to minimize the risk of pipeline failure.

30. The cost of the planned gas pipeline from Tabriz (Iran) to Goris (Armenia) for Phase I to supply 1 BCM/yr is estimated at US$ 73 million and for Phase II to increase supply to 3 BCM/yr, is US$ 210 million. The pipeline could be in service in 1995, depending on the availability of financing.

31. ARMGAZ is responsible for the distribution of piped natural gas to about 500,000 end-use consumers through about 11,000 km of low pressure steel mains. The 1988 earthquake caused serious damage to the distribution networks resulting in the loss of about 40,000 residential connections and destruction or damage to about 1300 km of distribution mains. A further 1000 km are considered to be in need of replacement due to age and corrosion at a cost of about US$ 5 million equivalent based on procurement in the FSU.[8]

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[6] District heating in Yerevan extends for a radius of about 20 km.

[7] The figures for 1992 are not available but a further decline is evident due to the blockade.

[8] Based on mid-1992 costs in Rubles converted at the then prevailing exchange rate of Rbs 100/US$; this is likely an underestimation of the real cost.

32. Armenia requires natural gas storage for both operational and strategic reasons. Salt cavities near Yerevan provide natural underground capacity sufficient to store about 210 Mcm or about 10 days' winter time demand. To make full use of the available capacity, EBRD will finance the installation of compressors at the storage site. As a high priority item, further compressors are required at the Airoum station (at a cost of US$3.5 million) to replace damaged units in order to increase throughput of the Georgia line.

Coal and Lignite

33. Indigenous lignite and coal are available with total verified reserves of about 5 million tonnes. Open pit mining of lignite would be required, while hard coal would be mined underground. The feasibility of coal development is being assessed with technical assistance funded by USAID. Peat is also available and could be used in the short term without much development as a household fuel, mainly in single family dwellings. Use as fuel for thermal power plants would require large investments since existing boilers are not designed for these fuels.

E. Strategic Issues

34. Regardless of which macroeconomic scenario will materialize, major constraints will continue to affect the energy sector, in particular, (a) the pace at which the blockade is lifted, (b) the pace of economic recovery and structural change, and (c) the limited availability of foreign exchange to pay for imports, repatriation of profits necessary to attract foreign investments, and debt service. In these circumstances, for analytical purposes, priorities have been divided in the near term, that is over the next three years to the end of 1995, and long term, beyond 1995.

35. Taking into account economic criteria and interdependency with long term economic and political prospects, near term priorities should place the greatest emphasis on:

- rebuilding fuel stocks to provide a minimum working storage and security against supply interruption,
- energy efficiency improvements,
- rehabilitation of existing facilities,
- debottlenecking existing supply and storage facilities.

Consultants financed by USAID are currently identifying and evaluating specific project components which meet these objectives. Possible financing under a proposed World Bank loan would initially focus on energy efficiency and supply reliability in the electric power sub-sector. Institutional development, also in the near to medium term, should emphasize increased commercialization including the installation of improved accounting and financial planning systems for sector entities, and their greater operating autonomy. Policy focus should be on energy pricing reform, the establishment of a regulatory framework for the sector including environmental considerations, and restructuring of the gas and power/heating sectors to permit private participation.

36. In the short term, it is also necessary to plan for long term sector requirements. A closer economic evaluation of in all subsectors and the evaluation of fossil fuel resources and energy alternatives should be carried out. Over the longer term, investments in power generating plant will be needed for plant life extension and/or replacements. Similarly, replacement of existing heating systems, possibly with boilers in individual buildings, may be more economic than rehabilitation. Additions to existing installed

power generating capacity could be needed before 2000 if demand grows more rapidly than projected. Investments in energy resource developments should be made in this period if they prove economic.

Nuclear Power Plant

37. The nuclear plant is a Soviet built VVER 440, model 230 in two units with total installed capacity of 815 MW. Although not the Chernobyl design, this model has serious design flaws. No damage was sustained during the 1988 earthquake, in part due to seismic upgrade work that had previously been carried out, nonetheless, the plant was shut down in early 1989 because of safety and environmental concerns.

38. According to the assessment of the IAEA mission, there are no ***apparent*** insurmountable conditions such as a seismic fault on the plant site or immediate area that would preclude further consideration of recommissioning the plant. Nonetheless, it is imperative to verify the non-existence of a seismic fault condition before carrying out further expensive engineering studies in preparation for recommissioning the plant.

39. The costs of upgrading and recommissioning the NPP to accepted standards have yet to be fully assessed. At the time of report writing, 50-60 Russian experts had recently started a feasibility study for the plant's recommissioning. The study is expected to take 18 months to complete. Initial estimates, to permit five years' further operation range from a minimum of US$70 million (IAEA) for recommissioning the plant with some upgrading (but not to international standards) to US$330 million (consultants to EBRD, March 1993), or to about US$370 million (based on Framatome's March 1993 report) for more extensive upgrading and recommissioning (including an initial fuel charge). The cost of further upgrading to international standards to permit operation to about 2010 (i.e. to the end of its normal service life of 30 years allowing for the period of shutdown), together with recommissioning, is estimated by consultants to EBRD at US$460 million. In the short term, however, regardless of whether or not it is to be recommissioned, the plant must be maintained in a safe shutdown condition; safety upgrades under current shutdown conditions are also urgently needed to ensure physical security. An amount nominally estimated at US$2-5 million/yr could be required.

40. Under a "high nuclear scenario" (capital costs of US$460 million to upgrade and recommission the plant to permit up to 15 additional years of operation), total investment costs are estimated to be US$256 million greater in the period 1993-2000 than in the "no nuclear scenario". This additional capital cost could be offset by net savings in fossil fuel costs of about US$79 million assuming world prices for nuclear and fossil fuels, but not allowing for the costs of disposing of spent fuel and nuclear wastes. Pay back of the incremental capital costs could be obtained in about 8-10 years, depending on fuel and waste disposal costs.

41. The World Bank is not in a position to judge whether any of these estimates are reasonable or whether the Armenian NPP could be upgraded to meet international safety standards at a cost low enough to compete with alternative energy sources. The policy of the relevant financial institutions would be a crucial factor in determining the likelihood of suitable financing. In view of the G7 policy to encourage the phase-out of unsafe Soviet designed reactors, financing from international financial institutions and Western official sources is unlikely even if it could be demonstrated that re-opening the reactor is technically and economically feasible. EBRD has included as a condition of its loan for Hrazdan 5 a requirement for prior consultation and, in the event the plant is recommissioned, an independent assessment of the safety of the plant. If not satisfactory to EBRD, the loan would be

cancelled and repayment due. The regional security situation should also be taken into account. With resolution of the siege conditions, other options seem more practical, such as additional thermal plant and electricity imports.

Energy Pricing

42. The government is fully aware of the pricing issues and intends to carry out reforms, although a timetable has not yet been set. Prices for both electricity and district heating have been raised in the face of increased energy supply costs. By mid-1992, the cost of petroleum and gas imports had gone up by a weighted average (in current roubles) of about 2,000 times the average 1990 level due to Russian price increases, and were at about 60 percent of world prices. At the same time, Government has also attempted to maintain a high degree of cross-subsidization to household consumers from industries as real household incomes continue to fall with inflation and unemployment. While charges for heat embody a cross-subsidy, the tariffs are high enough relative to income levels to provide some incentive to control consumption if meters and controls were available for residential consumers. Field trials indicate that residential gas use could be cut by roughly one-quarter through the installation of meters.

Balance of Payments and Fiscal Aspects

43. Based on the base case projections outlined above, total annual energy imports would reach about US$822 million by 1995, assuming world price parity, and would account for 24% of total imports under the medium GDP scenario. These figures compare with a cost of roughly US$ 100 million or 11% of imports in 1991.[9] Cost of imports in 1993 is projected at about US$ 250 million, but could vary considerably depending on product prices from FSU refineries, exchange rates, and volumes.

44. Under the Soviet regime, the petroleum sector had been a significant source of government revenues, In the period 1985-90 total taxes paid by ARMOIL averaged about 90% of gross profits and contributed Rbs 165 (US$ 80) million of tax in 1990. However, these revenues dropped to Rbs 24 (US$ 12) million in 1991 as gross margins were squeezed by rising oil import prices and government policy to limit retail price increases. Data are not presently available concerning the fiscal effects in other energy subsectors, however, it is clear that they are not able to generate tax revenues because of fuel shortages, restricted sales, low revenues, and high fixed costs due in part to over-staffing.

Energy and the Environment

45. Temperature inversions, high sulfur (3-5%) mazut used by power plants and industrial boilers, low quality diesel oil and gasoline used by badly tuned vehicles result in highly visible and severe atmospheric pollution which contributes to respiratory illness. As natural gas is a clean burning fuel it is low polluting and is clearly the preferred fuel. Boiler tune-ups and the installation of combustion controls to be carried out as part of the energy efficiency improvement program would also reduce emissions significantly.

46. The draw-down of Lake Sevan by 18 m from its original level during the period 1936 to 1978 was stopped in 1979 because of the impact on the ecology of the lake and on the local micro

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[9] Based on a cost of US$240/TOE for light products and US$110/TOE for mazut and natural gas.

climate. Under the national water resources plan, the government is aiming to raise the level by 6 m by 2000; however, fuel shortages have forced a further draw-down of about 1 m in 1992 for power generation. Increased thermal generation (requiring increased fuel imports) would be required to permit reduced hydro generation from the Sevan-Hrazdan cascade in order to raise the level of Lake Sevan. Increased efficiency in the use of water for irrigation would, however, permit greater power generation and/or recovery in the level of Lake Sevan and related studies are underway with FAO assistance. These studies should be closely coordinated, however, with hydro resource planning.

Financial Issues

47. ARMPETROLPRODUCT has historically been a profitable operation and has generated substantial revenues for government. The entities responsible for power, heating, and gas, however, have not been fully viable commercial operations. The government has a long term goal of introducing private sector participation in the energy sector. As a first step, it is necessary to increase the degree of commercialization in the sector through the establishment of improved metering, billing, and accounting systems, a register of fixed assets which reflects their current value, together with budgeting and planning systems. It is also essential that sector entities not only cover their operating costs including the costs of repair, maintenance, and depreciation but also provide for the financing of assets through the coverage of debt service and, to some degree, sector renewal and development through internal cash generation.

Institutions

48. The present structure of the energy sector casts Ministry of Fuel and Energy (MEF) in the role of policy maker, sector planner, regulatory agency, and, to some extent, chief executive of operations. A degree of centralization of decision making is necessary if not essential under the present emergency conditions for fuel procurement and allocation, but for the future MEF's role should focus on its policy and supervisory responsibilities. Steps have been taken to separate the operation from policy functions by creating ARMENERGOPROD State Company and ARMGASFUEL State Company as the parent companies of the operating entities. Further institutional development is required to strengthen the commercial orientation of these companies and to establish a regulatory framework which together are needed to encourage the participation of the private investors in the energy sector. Technical assistance in these areas is being provided by EC in parallel with the Hrazdan 5 thermal power project.

F. Financing and Technical Assistance

49. The recommended energy sector strategy and priorities together with investment and technical assistance (TA) requirements are summarised in the Sector Strategy and Priorities matrix, Table ES2 and Table ES3 respectively. In the matrix, the relevance of each measure in meeting both the short term and long term needs is assessed together with the associated risks. Prerequisites in terms of studies and preparatory work are also identified.

50. The capital investment requirements shown below have been estimated on the basis of world prices of early 1993 from western sources, although prices from FSU suppliers are expected to remain below world price levels at least in the near term. No attempt has been made to estimate the reduction in cost which might arise. No allowance has been made for inflation or interest during construction. The local content, that is Armenian, for which local financing would normally required could average 30-40% or more depending on the civil works content and degree of local supply of materials and equipment is possible. Engineering studies including detailed cost estimates are required in all cases and costs are based on experience elsewhere. More precise figures are not available. Capital requirements and sources of finance in the period 1993-2000 are broken down as follows. The funding requirements are shown for projects which would come on line in the period indicated.

51. *Immediate requirements (for winter 1993/94).* There is an urgent need to prepare for the coming winter by rebuilding fuel stocks at a cost of US$172 million of working capital to fill the existing gas and oil storage facilities and rebuild fuel inventories. Excluding the working capital requirements, there is a need for US$31.5 million in investments of which US$13 million are for the drilling of four oil and gas wells for which prospects are sufficiently promising to have attracted US$8 million (so far) in private sector financing primarily from the diaspora and a further US$1 million from USAID.[10] A portion of the proposed World Bank loan of US$20 million could be used to finance critical items particularly for energy conservation and repair materials and rehabilitation in the power sector.

52. Approximately US$3 million in funds from USAID could be available for the supply of kerosine heaters, energy conservation equipment, and materials for weatherization of buildings. Additional financing would be required to meet total program needs in this period. In the gas sector, approximately US$1 million is needed for welding rods and other materials to repair damaged and leaking pipelines and distribution networks.

53. Humanitarian assistance for kerosene and stoves has been pledged by the EC (ECU 8 million) and the Japan government (US$1 million).

54. A nominal amount of US$3 million has been include for nuclear safety pending a more precise estimate of requirements.

55. *Near to medium term, 1994-95.* In addition to the immediate needs, that is before the end of 1993, US$290.4 million of investments are estimated for 1994-1995, of which US$197.4 million would be for the power sector alone including US$89.4 million for Hrazdan 5 which is being financed by EBRD and Government of Armenia. Life extension work on existing hydro and thermal plants would begin in this period (cost US$73 million).

56. Major investments in the gas sector would be required including the Iran pipeline (US$73 million). The energy conservation program in district heating and the industrial sector would increase to US$8 million. A nominal amount of US$10 million has been included for the development of coal mining facilities. Further investments in oil and gas may be warranted but the amounts are not known.

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[10] The risk of coming up with dry holes, thereby discouraging future exploration, is recognized by the investors. The possibility of putting a well into production by next winter, however, is considered worth the risk.

57. *Long Term (1996-2000).* Approximately US$1 billion would be needed in this period of which US$771 million would be in the power sector for plant life extension work and the construction of new thermal and hydro plants and the rehabilitation of transmission and distribution networks. Additional investments in energy conservation particularly in the district heating system and industrial sector will be required but no estimate of requirments can be made until at least preliminary studies are completed.

58. **Technical assistance and preinvestment studies** are being funded by EC and USAID. These studies include (a) planning studies for electric power/district heating subsectors to evaluate the condition of the existing facilities, assess the requirements for rehabilitation of existing facilities and construction of new plant, (b) consultancies for financial planning and the development of commercial systems for metering and billing, and (c) studies the development of a regulatory framework. Draft Terms of Reference for consultancies to provide technical assistance in these matters are provide in Annex 6 to the main report. In addition, both EC and USAID are financing consultancies in energy conservation. The technical assistance program amounts to US$7.3 million in the short run, that is through 1995, of which US$4.6 million is funded. The balance is unfunded including US$2 million for feasibility and design studies for long term investments and US$0.7 million required for facilities and financial planning in the gas sector.

59. *Financing Plan.* Of the total financing requirement of US$524 million for the period 1993-1995 and a further US$994 million in 1996-2000 which is unfunded. Sources for US$128 million have been identified and US$100 million approved for the period 1993-1995. The balance of US$396 million remains unfunded in the same period.

Table ES2: ENERGY STRATEGY AND PRIORITIES (1993-5) MATRIX

Item	Earliest Available Date/Lead Time Status	Cost US$ millions	Relevance in Meeting Short Term Energy Needs	Prerequisites/ Risks	Relevance in Peace Time after Blockade lifted	Priority	Possible Source of Financing
1. Short Term Priorities							
Kerosene heaters Small diesel generators weatherization materials	Winter 1993/94	1.0	-meets minimal survival needs for heat and electricity for priority installations	- requires kerosene and diesel fuel available only in small tank truck shipments - high cost of kero restricts use to high income population	-kero heaters could be cheaper than central heating system for some uses	high	humanit-arian aid USAID
Rebuild fuel stocks	Part before winter 1993/94 and continuing	$172 at World prices	would ensure ability to operate industries	increased rate of supply required to fill. Storage in addition to providing for consumption	high, required as normal operating inventory	high	$1 million provided by Japan as humanitarian aid
Peat exploitation	-for winter 93/94 -further exploratory work possibly needed	0.5	-small heating use; existing power and district heating boilers not equipped to burn peat	-cutting and milling equipment needed -fuel for transport -low risk	-continue to use only if cost of peat energy less than other fuel; hold as strategic reserve	-high under siege condition	to be ident.
Equip existing gas storage at Yerevan with compressors	6-12 mo	0.5	enables use of storage facility	none	-required in any event	high	EBRD (approved) (part of Hrazdan 5 project)

Item	Earliest Available Date/Lead Time Status	Cost US$ millions	Relevance in Meeting Short Term Energy Needs	Prerequisites/ Risks	Relevance in Peace Time after Blockade lifted	Priority	Possible Source of Financing
Oil and gas (4 wells)	possibly by winter 1993/94	13	-could burn crude in boilers; -need refinery to provide transport fuels -install gas turbine for power generation	risk of dry holes	-net back value on crude export depends on production cost and market value -value as import substitute depends on cost of alternative fuels	high	$ 8 M pledged by private sector; $1M by USAID
Upgrade safety and security of NPP during shut down	6-12	3	does not increase supply	Risks associated in <u>not</u> doing upgrades		high	bilateral aid?
Energy Conservation in Supply and End-Use							
Power System repairs, loss reduction, and efficiency improvement	3-6 mo start up continue 3-4 yrs Studies underway with USAID funding	25 (initial require-ment)	-series of small steps save 5-10% of energy input to stations -restore service where failure has occurred due to overloading	-engineering studies to set priorities, specifications, and bid documents are under way	high	high	World Bank (partial)
Industrial Energy conservation boiler tune-ups; loss reduction	Winter 1993/94	5	high	should focus on high value added export industries dependence on mech. or distrib. & installation	high	high	USAID and EC for TA; investments World Bank

Item	Earliest Available Date/Lead Time Status	Cost US$ millions	Relevance in Meeting Short Term Energy Needs	Prerequisites/ Risks	Relevance in Peace Time after Blockade lifted	Priority	Possible Source of Financing
Gas distribution repairs	Winter 1993/94	2	reduce leakage	no minimum	high	high	World Bank
District Heating	Winter 1993/94	5	-payoff depends on operation of district htg system; no fuel, no heat, no loss saving	engineering studies underway	in short/medium term high priority; long term depends on economics of heating alternatives	study under way	USAID, EC funding TA; World Bank investments
Gas metering	6 mo min to obtain materials	20 ($60/con-nection)	up to 25% reduction possible if residential consumption metered	consumer response uncertain; need pilot project to assess	high	medium	to be identified
2. Medium Term Priorities							
Small Hydro-up to 150 MW identified at reconnaissance/prefe asibility level	18 - 36 mo for first units	10 ($600/kW of installed capacity)	-saves imported fuel -small contribution to total needs, less than 5% -power not firm unless storage available;	-studies available, status -engy design, cost estimates, bid docs needed -low risk; greatest uncertainty likely in cost estimating	-fuel saving	high	Unident.
Gas pipeline compressors at Airoum	9-15 mo	5	increase through-put on Georgia line by 125%	None	high	high	World Bank
Coal/lignite	2-3 years some studies done	10 (nominal)	-existing power/heating boilers not equipped for coal	feasibility studies under way	-depends on economic cost of alternative imported fuels	-medium	Unidentified

Item	Earliest Available Date/Lead Time Status	Cost US$ millions	Relevance in Meeting Short Term Energy Needs	Prerequisites/ Risks	Relevance in Peace Time after Blockade lifted	Priority	Possible Source of Financing
Renewables: Wind Solar Photo Voltaic Solar Heating	 12-18 mo? 12-18 mo? 12-18 mo?	 5-6 cts/kWh 10-15 cts/kWh ?	-short run contribution small	studies underway	-relevance depends on cost of alternative fuels	medium/low	unident.
3. Long Term Supply Options							
Iran gas pipeline	1995 engrg design complete; planning underway with Iran	$75 M Phase I $210 M Phase II	-supply diversification in medium/long term	- final agreements with Iran	-capacity of existing pipelines from Georgia and Azerbaijan is adequate for projected reqmts;reliability of Georgia line depends on resolution of internal conflict in Georgia	-depends on how long siege will last -lower in peacetime since alternative routes available	unident.

Item	Earliest Available Date/Lead Time Status	Cost US$ millions	Relevance in Meeting Short Term Energy Needs	Prerequisites/ Risks	Relevance in Peace Time after Blockade lifted	Priority	Possible Source of Financing
Recommission Nuclear Power Plant	1995 Framatome studies due March '93 on feasibility and cost of recommissioning	range or 330 - 460 indicated	-contribution depends on time needed to obtain financing and complete recommissioning works - would free up available gas and mazut for heating	verify non-existence of seismic fault - need detailed engineering, solution to waste disposal issues, and financing -ability to raise financing uncertain	-satisfy one third/half total power needs for 5 years -timing and cost uncertain -risks include: safety - seismic, security; operational accidents/failures -possible loss of international goodwill	to be determined	-none apparent
Rehabilitation and life extension of existing hydro and thermal power plants	1995	23 (hydro) 50 (thermal)	low	detailed engineering studies required; initial studies under way	high if less costly than plant replacement	depends on outcome of studies	Unident.
Expand Gas storage -has been reviewed by Bechtel and Gaz de France	1-2 years	?	-low priority until existing gas and petrol storage can be filled	-finalize engrg design and cost estimates	-provides additional operational storage and strategic storage	-medium/low	?

Table ES3. Armenia Energy Sector Financing Requirements

05/13/93 15:23	Total Cost	Required in Service Period: Immediate Winter 1993/94	Near/ Medium Ter 1994-95	Long Term 1996-2000	Possible/ Proposed Financing (or as noted)	Text Reference Chapter/ Section
A. Working Capital	US Dollars millions (mid 1993 constant prices)					
(refill existing storage, rebuild fuel stocks)						
Petroleum	155.0	155.0				
Gas	17.0	17.0				
subtotal	172.0	172.0	0.0	0.0		
B. Capital Investments						
1. Emergency household heating & electrical supply						
(kerosine heaters, weatherization, diesel generato	1.0	1.0			USAID	
2. Nuclear Plant Shutdown Safety Upgra	3.0	1.0	2.0			
3. Power Sector (base case, non-nuclear)						
Critical spares and equipment for repairs	25.0	10.0	15.0		World Bank	3K
loss reduction and effcy improvement						
Rehab/life exta - thermal plant (1470 MW)	368.0		50.0	318.0		3F, 3K
Rehab/life exta - hydro plants (950 MW)	143.0		23.0	120.0		3D, 3K
Rehab - transmission and distribution	50.0		10.0	40.0		3G, 3K
New Generating Plant						3D
Hrazdan 5 + transmission	89.4		89.4		EBRD & Govt Arm(apprvd)	
Small hydro plants (300 MW)	190.0		10.0	180.0		
Thermal plant (300 MW)	113.0			113.0		
Sub total	978.4	10.0	197.4	771.0		
4. Energy Conservation and Efficiency Improvements						3K
District Heating Repair, rehab, controls	5.0	1.0	4.0		USAID, World Bank	
Indstri boiler tune-ups, steam sys, power factor	5.0	1.0	4.0		USAID, World Bank	
Sub Total	10.0	2.0	8.0	0.0		
5. Natural Gas Transmission and Distribution						
Welding rods and materials	2.0	1.0	1.0		World Bank	
Georgia pipeline reinforcement	3.0	3.0			underway govt budget	
Booster compressors - Underground storage Yerev	0.5		0.5		EBRD (Hrazdan 5 proj)	
Compressors Airom	5.0		5.0		World Bank	5D
Meter calibration equipment	0.5		0.5			
Consumer metering	20.0		10.0	10.0		5C
Iran Pipeline Phase I	73.0		73.0			5D
Iran Pipeline Phase II (Goris - Yerevan)	210.0			210.0		
Distribution mains replacement (earthquake zone)	6.0		3.0	3.0		
Subtotal	320.0	4.0	93.0	223.0		
6. Petroleum Storage and Distribution						
Vehicles and equipment	3.0		3.0			
7. Energy Resource Development						
Peat	0.5	0.5				
Oil and Gas	13.0	13.0			Priv sector & USAID (pledged)	
Coal	10.0		10.0			
Subtotal	23.5	13.5	10.0	0.0		

Table ES3. Armenia Energy Sector Financing Requirements

05/13/93 15:23	Total Cost	Required in Service Period: Immediate Winter 1993/94	Near/ Medium Ter 1994-95	Long Term 1996-2000	Possible/ Proposed Financing (or as noted)	Text Reference Chapter/ Section
C. Technical Assistance and Studies						
Overall Sector Activities					All items funded	Annex 6
1. Restructuring & Instital Devlpmt			0.1		EC	
2. Regulatory Framework			0.1		EC	
3. Energy Data Management System		0.2			USAID	
4. Demand Analysis and Forecasting		0.1			USAID	
5. Energy, Macro Economic, Financial Planning		0.1			USAID	
4. Energy Resource Exploration and Evaluation		0.3			US/TDP, EC	
7. Strategic Fuels Reserve Requirements		0.1			USAID	
8. Energy Conservation and Efficiency Program		0.6			USAID	
9. Energy Savings Center and TA		2.0			EC	
Subsectoral Studies						Annex 6
1. Power Facilities Planning			0.6		EC	
2. Power/Heating Sector Financial Planning			0.3		EC	
3. Gas Facilities Planning			0.4		unfunded	5F, Annex 6
4. Gas Sector Financial Planning			0.3		unfunded	
5. Heating Facilities Planning		0.3			USAID, EC	
6. Fuels Contracting			0.1		EC	
7. Feasibility & design studies (total all subsectors)			2.0		unfunded	
Total Technical Assistance	7.3	3.6	3.7	0.0		
D. Grand Total Financing Required	1518.2	207.1	317.1	994.0		
Of which,						
Working Capital	172.0	172.0	0.0	0.0		
Capital Investments	1338.9	31.5	313.4	994.0		
Technical Assistance/studies	7.3	3.6	3.7	0.0		
E. Financing Plan						
Identified Sources						
EBRD (approved)	59.4		59.4			
EC (approved)	3.3	1.0	2.3			
World Bank (proposed)	20.0	10.0	10.0			
USAID (approved)	4.7	3.0	1.7			
Government of Armenia (approved)	33.0	3.0	30.0			
Private Sector (pledged)	8.0	8.0				
Total	128.4	25.0	103.4	0.0		
Unfunded	1389.8	182.1	213.7	994.0		
Total Requirements	1518.2	207.1	317.1	994.0		

I. ENERGY AND THE ECONOMY

A. Introduction

1.1 Armenia is a small landlocked country. Turkey lies to the west, Georgia to the north, Iran to the south, and Azerbaijan to the east with one physically separate province also to the south-west of Armenia (Map IBRD 23493R). Its land area is 29,800 square kilometers, and the ethnically homogeneous population numbers 3.5 million. With few natural resources, Armenians have learned to survive through skill, ingenuity, and trade with those around them. The level of education is high, and the Armenian diaspora has a strong tradition of successful entrepreneurship which should work to the country's advantage for its future development.

1.2 Two general problems dominate the immediate future. First, in common with all the republics of the former Soviet Union (FSU), Armenia is experiencing sharply falling output (which began in 1987) due in part to the disruption of the Soviet monetary, payments, trade and transport systems. Although a small country, Armenia was one of the most highly integrated republics in the Soviet system of production and trade and is suffering correspondingly now. Second, Armenia's difficulties are compounded by the political upheaval caused by the breakdown of the FSU. Trade routes have been blocked because of internal disruption in Georgia over Ossetia and conflict with Azerbaijan over the enclave of Nagorno-Karabakh, with the result that Armenia is an economy under siege. The Nagorno-Karabakh conflict absorbs a good deal of Armenia's scant resources while its trade, and, most importantly, its energy imports, have been cut to a trickle. During the 1991/92 winter, most of industry had to be shut down and heating for homes cut off in sub-freezing temperatures. Fuel stocks could not be rebuilt during the summer because of intermittent and inadequate supplies. Azerbaijan continues to put pressure on Georgia not to supply gas to Armenia which transits Azerbaijan from Turkmenistan. In addition, several hundred meters of pipeline were blown up in October in Georgia by nationalists and service was cut for 3-4 weeks.

1.3 With regard to energy, Armenia must import about 95% of its present requirements and, although there are some prospects for the development of oil and gas reserves, over the long run Armenia will continue to depend in large measure on trade not only for energy imports but also to earn the foreign exchange needed for payment. This would be the case even if the nuclear power plant were to be restarted since fuel and materials for operation would also need to be imported.

1.4 Armenia's priorities are twofold: (i) to secure normal trading relations with neighboring countries in order to restore access to energy and other essential inputs; and (ii) to pursue a process of reform that would allow a competitive economy and sustainable growth to emerge which would permit, inter alia, to earn the foreign exchange to pay for fuels and imported energy related equipment.

1.5 Progress in the resolution of the conflict with Azerbaijan and normalization of trading routes are prerequisites. Even with a prompt resolution of the conflict, the setting of priorities is crucial. The Government will have to distinguish between the essential and the merely desirable, and focus its energies on the key actions needed to safeguard welfare and move the reform program forward. Reforms

must be successful and seen to be successful. For this, careful design, sequencing and implementation of reforms in all sectors will be crucial.

1.6 Armenia is a striking example of the Soviet belief in economies of scale, central planning, and the achievement of political control through economic interdependence. This belief led to extreme specialization within the former Soviet Union and meant that industrial units were large. Heavy industry was seen as the vehicle of economic development. The artificially low price of energy favored uneconomic activities and waste, and promoted the use of transport over long distances at great economic cost. The nature of trade and production that was assigned to Armenia on this basis has little in common with its comparative advantage. As a result, the country has been saddled with a structure of highly concentrated production that corresponds only weakly with the composition of activity that is likely to evolve in a free market future.

1.7 Armenia's product composition also yields a high degree of dependence on trade with other republics, with both exports and imports representing over 50% of GDP during the 1980s. Armenia's role in the USSR economy was to process intermediate goods and materials procured from other republics and to supply a wide range of consumer and non-specialized producer goods. The country developed substantial capacity in light industry (textiles, knitwear and shoes), food processing, and heavy industry, exporting vehicle tires, caustic soda, synthetic rubber, and a large quantity of electric motors and cables and metal-cutting machine tools. For this, the country was dependent on imports of energy, agricultural and chemical inputs, wood and paper and other intermediate goods. Armenia also had a disproportionate share of the Soviet military-industrial complex, supplying high technology laser and electronics.

1.8 The decline in economic activity is aggravated by fiscal shortfalls which mean that the Government cannot finance public investment, including critical spare parts for the energy sector, or industrial production at the same level as in the past. The output fall itself, together with defiscalization of enterprise profits and weak administration of new and unfamiliar taxes, has sent Government revenue from over 50% of GDP in 1989 to an estimated 8% in 1992. In an effort to keep the fiscal deficit to 4% of GDP in 1992, the Government has already eliminated almost all subsidies to enterprises and has cut public investment to the bone, reducing future as well as current output. Even so, the deficit target is unlikely to be reached.

1.9 To these factors must be added the impact of the policy shock. Old systems are failing and new systems are not yet workable. New relative price signals are swamped by the huge increase in the price level, particularly for energy. Infrastructure and energy sector facilities are deteriorating leading to a declining quality of service for which higher prices are being charged. The struggle for survival under these conditions results in declining output, severely constrained maintenance and repair of facilities, and a virtual cessation of investment.

1.10 Overshadowing all these problems is the blockade. During the winter of 1991/92, economic activities became heavily constrained by the transport blockade by Azerbaijan and civil strife in Georgia, blocking Armenia's second major transport route. Lack of fuel and other imported inputs closed two-thirds of enterprises but, with the improvement of the situation in Georgia, supply conditions eased from the middle of March 1992. However, the destruction in May of the railway bridge near the border in Georgia sharply reduced raw material imports, leading to closures in a large number of state enterprises. Overall, during the first four months of 1992, road and rail transport fell to 18% and

industrial production fell to 48% of the levels of the same period in 1991. By September 1992, industry was operating at 20% of capacity. With the blowing-up in January 1993 of the gas pipeline from Georgia, electricity supply was reduced to a few hours per day, most industries were forced to close, and siege conditions became even more severe.

Organization of the Report

1.11 Within the difficult macroeconomic context described above, the remainder of Chapter I outlines three possible scenarios for overall economic development as prepared with the World Bank[1] with the Government of Armenia and upon which energy sector developments will depend. Historical energy supply and demand patterns are reviewed as a background to the energy demand projections which are presented as a conclusion to Chapter I. Chapter II reviews the energy sector organization, principal institutions, and main issues which are generic to all subsectors. The remaining chapters of the report discuss the issues and options relating to the individual subsectors including electric power/district heating, petroleum, and natural gas (Chapters III to V respectively).

1.12 Chapter III examines in further detail the demand projections for electricity and the alternatives for power generation including the option of recommissioning the nuclear power station. This last option is the subject of a broader study undertaken by the Bank and International Energy Agency (IEA) at the request of the G-7 to examine alternatives to nuclear power in the countries of Eastern Europe and the Former Soviet Union. Because of the close linkage of electricity and energy consumption to macro economic performance, the overall macro projections are first reviewed followed by a discussion of historical energy supply and demand (Section B) and demand projections (Section C) below.

Future Economic Developments in Armenia: Three Scenarios

1.13 The path the economy takes in the next year and into the future is heavily dependent on two crucial factors and their timing: (i) prospects for lifting the blockade and (ii) the degree to which new FSU monetary, trade and payment systems can be established. The following three scenarios (Figure 1.1) suggest the country's future path of economic development in terms of GDP according to specific assumptions about the speed with which the two fundamental constraints can be removed. It is further assumed that the flow of investment funds will be contingent on success in lifting the two principal constraints. Variants of these scenarios could be constructed - for instance, with different degrees of success in policy design and implementation - but the three presented below probably represent the upper and lower bounds available together with a medium case or base case.

[1] Armenia: Country Economic Memorandum, March 1993, Report Number 11274-AM.

1.14 *Low scenario.* If the transport constraint is not removed before the mid 90s, enterprises will close down through lack of energy and other inputs. A siege economy will become entrenched, with consequent deterioration and loss of capital equipment. The economy will depend on domestic labor-intensive activities that require little capital, intermediate goods, or energy input. GDP would fall to about one-half of the level of 1989 with no recovery until after 2000.

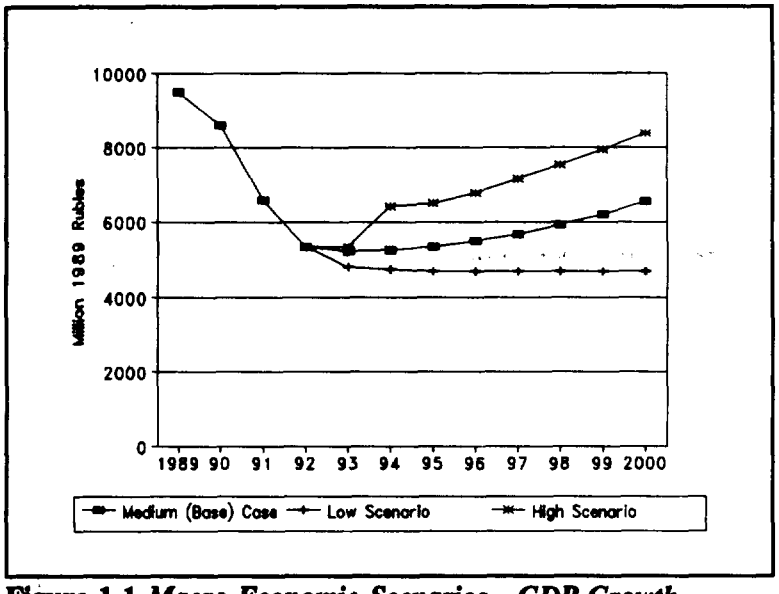

Figure 1.1 ***Macro Economic Scenarios - GDP Growth***

1.15 *Medium scenario.* The transport blockade continues through the winter of 1992/93 but is relieved in mid-1993. However, trade and investment are hampered by further deterioration and disruption within the CIS, and continuing depreciation of the ruble. Armenia cannot easily re-orient its trade to the west, lacking hard currency to furnish needed imported inputs. The banking sector is weakened by bankruptcies and default. Foreign investors hold back until the situation becomes more settled. Eventually the situation stabilizes in the mid-90s and sluggish growth emerges in the last few years of the decade.

1.16 *High scenario.* The transport blockade is lifted in mid-1993, inter-republican trade and payments systems stabilize, and the ruble slide is halted. This leads to a rapid upward shift in production in 1994 as existing capacity is brought back into use. There is then a plateau in aggregate activity during 1994 and 1995 while investment capital flows in, there are substantial changes in the composition of output and some degree of macroeconomic stabilization. From 1996 onwards, real growth resumes at between 3 and 5% per year, leading to a restoration of the 1989 level of output by the year 2005.

1.17 The Government's performance so far indicates that it will do its utmost to relieve the constraints blocking the economy and put the economy on a growth path. However, some of the constraints are largely or wholly beyond its control; and even on optimistic assumptions, it will be a long haul before economic growth is restored and living standards begin to rise. In the near term, the program will vary depending on the speed with which these constraints can be lifted. For instance, heavy fuel rationing was required in the 1992/93 winter to to maintain essential services and ensure that a critical minimum of industry and agriculture could continue to operate. Sectoral priorities are also likely to vary depending on the extent to which Armenia is battening down for survival or is able to pursue trading and other opportunities in the near future. It will also be important to keep the confidence of the population that the reform program is moving in the right direction and to look after people who are casualties during the transition. Minimum energy requirements must be provided as part of the overall social safety net within fiscal constraints. Under these difficult conditions priorities in the energy sector must be carefully determined.

B. Energy Supply and Demand

Historical Requirements

1.18 Armenia's total energy supply requirement peaked in 1988 at about 10,100 ktoe (thousand tonnes oil equivalent) as shown in Figure 1.2 and Table 1.1. While Armenia imports 100% of fossil fuel requirements, it exported about 2900 Gwh/yr or 20% of total electricity generation up to 1989 when the nuclear plant was shut down. By 1991, Armenia became a net importer of electricity (1500 Gwh/yr or about 17% of domestic generation) as gas supplies via Azerbaijan were restricted. Historically internal production (hydro plus nuclear when operating) accounted for about 15% of Armenia's total energy requirements. With the nuclear power plant out of service domestic hydro generation can supply about 5% of current energy requirements from all sources.

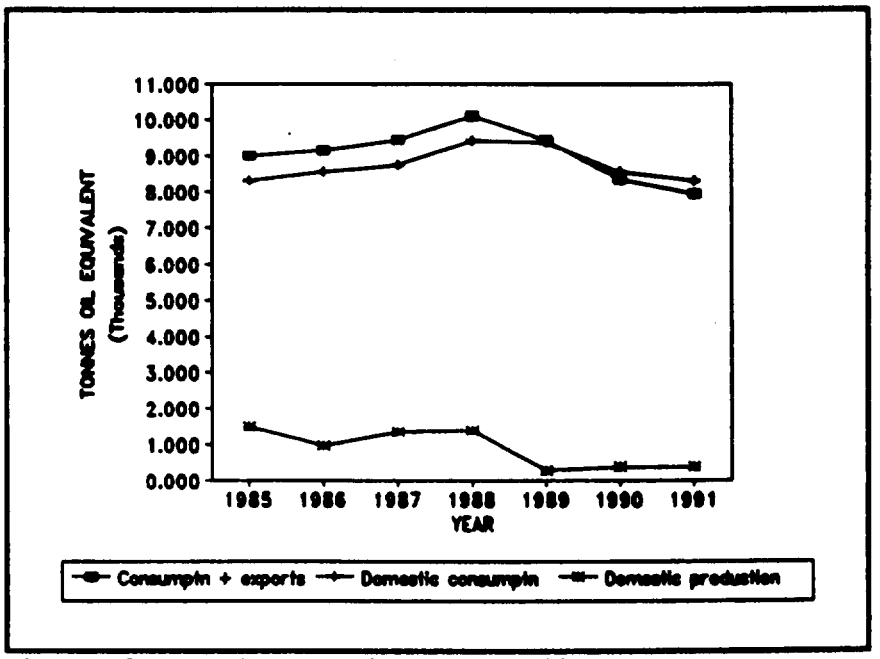

Figure 1.2 Armenia Energy Supply 1985-1991

1.19 Disruptions in fuel supply began in 1991 and remain severe. To understand the energy use patterns in an economy without constraints, 1990 has been used as a base for analysis and demand projections (Section E. below). An energy balance is also given in Annex 1.1.

Table 1.1 - Historical Energy Supply 1985-91

	1985	1986	1987	1988	1989	1990	1991
1. TOTAL ENERGY SUPPLY							
A. IMPORTS+STOCK EXCHANGE			(thousand tonnes oil equivalent)				
Oil Products							
LPG	35	34	32	30	27	26	21
gasoline	687	726	720	890	964	971	993
diesel	414	385	386	395	731	660	518
kerosene	9	11	9	11	11	13	13
jet	157	165	196	200	196	209	230
mazut	2367	2651	2400	2221	1872	2568	2261
other (bitumen, fuel oil)	155	163	175	217	298	305	320
sub total	3824	4134	3919	3963	4099	4164	4355
Gas (net imports)	3462	3845	3955	4439	4764	3551	3072
Coal	213	221	212	324	316	274	169
total supply	7499	8200	8086	8726	9178	8559	7596
B. DOMESTIC PRODUCTION							
Nuclear	1122	643	1011	1026	0	0	0
Hydroelectricity	378	315	342	358	268	363	361
C. ELECTRICITY TRADE							
Net exports	682	593	682	680	77	-214	-366
TOTAL NET FOR CONSUMPTION	8318	8564	8756	9430	9370	8708	8323
2. ELECTRICITY SUPPLY							
			(thousand toe)				
Generation							
mazut	1738	2166	2015	1624	1392	1987	1700
gas	836	1040	903	1297	1707	773	829
nuclear	1122	643	1011	1026	0	0	0
hydro	378	315	342	358	268	363	361
Total	4073	4164	4270	4303	3367	3122	2890
Electricity supplied by:			Gwh				
thermal generation	8007	10150	8999	8947	9693	8807	7970
nuclear	4808	2753	4331	4394	1177	0	
hydro	1619	1349	1464	1534	1149	1555	1546
Total generation	14434	14252	14794	14875	12019	10362	9516
imports	--	--	--	--	--	920	1572
exports	2925	2547	2928	2918	330	--	--
Net electricity supply (GWh)	11509	11705	11866	11957	11689	11282	11088

Note: Thermal equivalent of hydro, nuclear, and imports/exports - 1 Gwh = 233 toe

Source: Ministry of Energy and Fuel, Mission estimates

1.20 Because of anomalies in the available data, it has been necessary to reconcile figures from different sources. Part of the discrepancy is attributable to the difficulties in capturing data on private supply which is in addition to the supply reported by MEF through the parastatal supply system. In addition, there has been a draw-down in stocks over the past few years which is not fully recorded. MEF recognizes the deficiencies in the statistics and is taking steps to improve the energy data base. Technical assistance from an organization such as the IEA would enable MEF to improve the reporting system as quickly as possible.

1.21 In 1990, petroleum products supplied over half of Armenia's primary energy requirements and gas about 40%. Domestic hydro provided only 5% of total primary energy (and 15% of electricity generation) as shown in Figure 1.3. Further small hydro sites can be developed (para. 3.38) and have the potential to roughly double or possibly triple the supply of hydro energy.

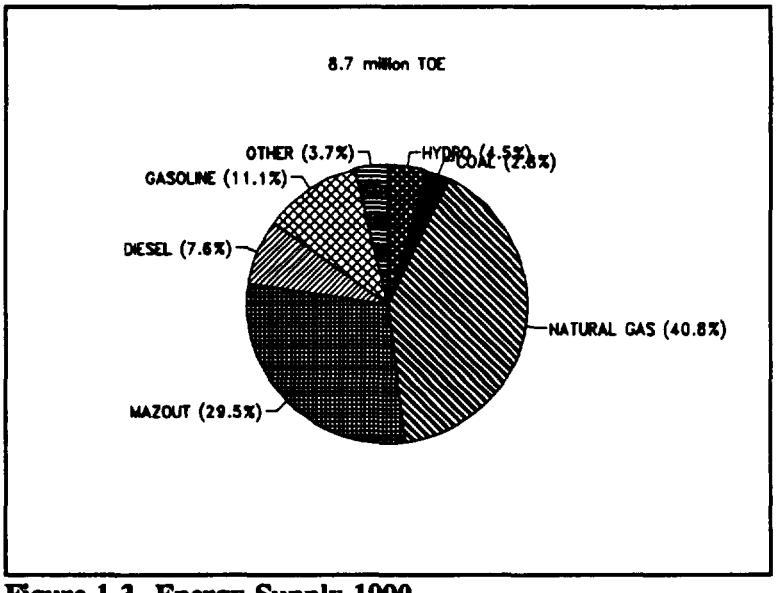

Figure 1.3 Energy Supply 1990

Composition of Final Demand

1.22 Under the present Armenian system of classification of energy consuming sectors, households account for about one-third of final consumption (Figure 1.4), followed by industry (28%), and commercial/official (20%). Transport appears as a relatively low 8% of total as the current classification includes only state operated transportation services and vehicle fleets.

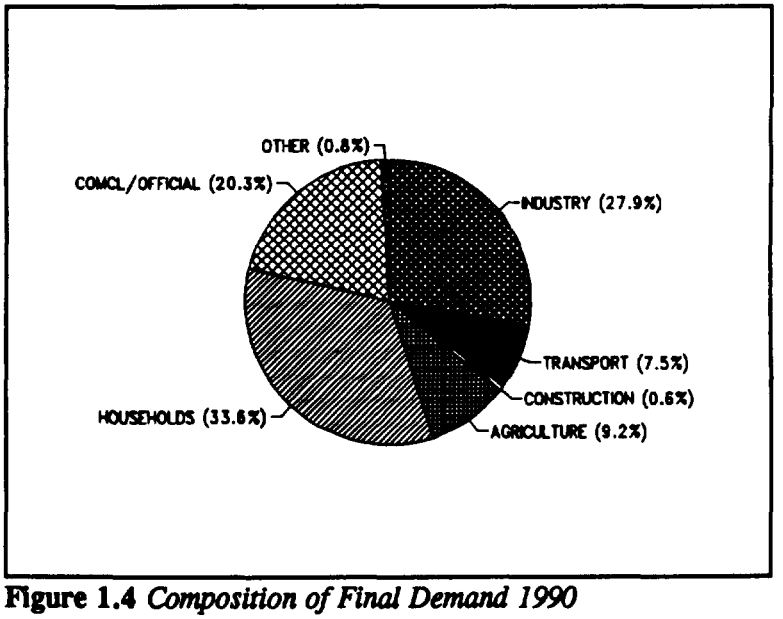

Figure 1.4 *Composition of Final Demand 1990*

Energy Intensity of the Economy

1.23 In 1990, Armenia's GNP per capita was about US$2380 and energy consumption about 2477 kgOE/capita giving an energy intensity of 1040 kgOE/000 $ GNP. Figure 1.5 shows a comparison of energy intensity with other countries in the range of US$ 1500 - 3500 GNP/capita. Armenia's energy intensity was roughly one-half that of Eastern European countries such as Bulgaria, Poland and Romania and comparable to that of Hungary and the former Federation of Yugoslavia with higher GNP/capita. Despite comparing favorably with formerly centrally planned economies, the energy intensity of Armenia's economy, however, was about double that of market economies with similar levels of GNP/capita including Brazil, Malaysia, Mexico, and Uruguay. While the high income (17,000 - 23,000 $GNP/capita) countries of Western Europe such as Austria, Germany, and Italy have energy consumption in the range 2700 - 3500 kgOE/capita or up to 40% greater than that of Armenia, energy intensity of the economy is less than one-fifth that of Armenia. In general, energy intensity is much lower in high income countries because of the low energy requirement of their much more developed service sector.

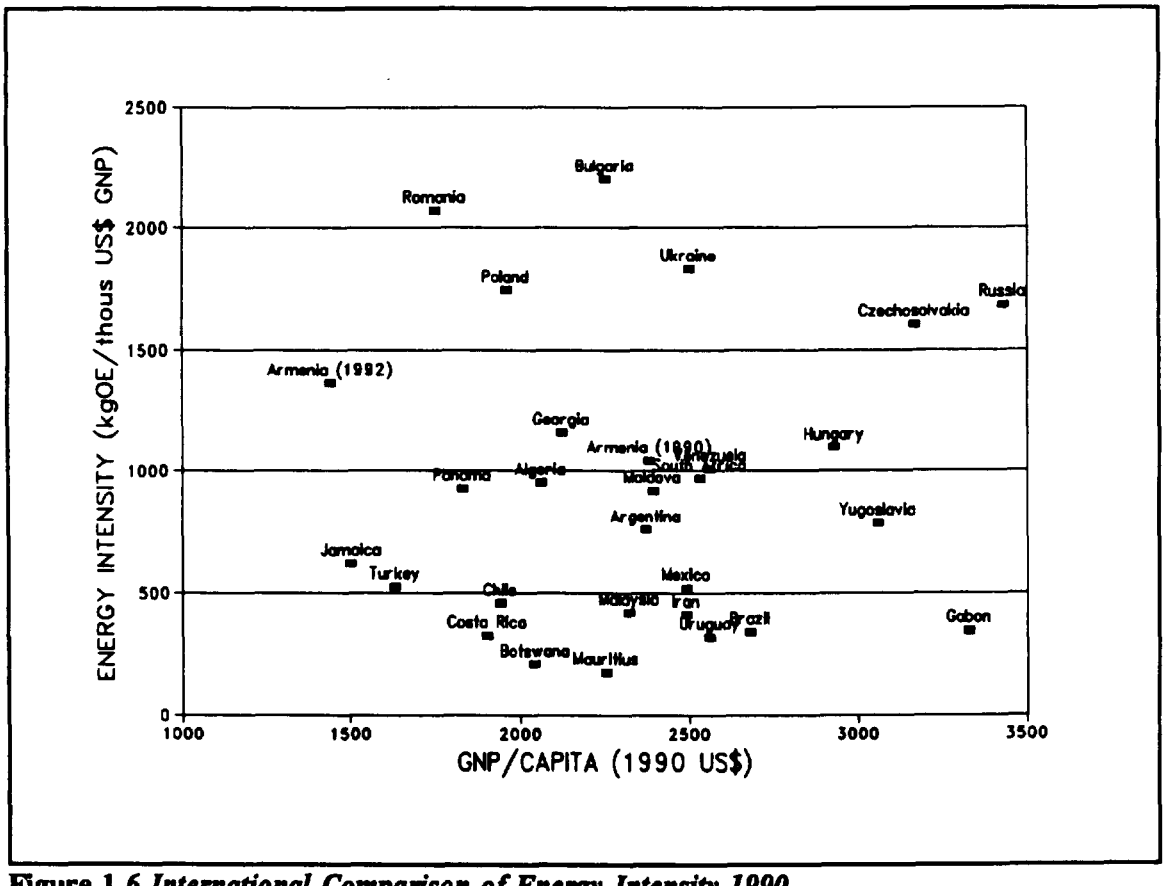

Figure 1.6 ***International Comparison of Energy Intensity 1990***

Energy Demand Projections

1.24 The demand for total primary energy is comprised of the requirements for power generation, heating, and transportation. The total demand for electricity minus the projected domestic power production and electricity imports will determine the net requirements for gas and mazut for thermal power generation. The demand for fuels for other uses has been projected on the basis of energy intensity in the economy, which when combined with the requirements for power generation gives the total primary energy requirement.

1.25 In the near term, under any of the three economic scenarios described above, Armenia's economy is expected to decline with a result that the energy intensity has increased as there is a high fixed energy component in the short run. As a result, the energy intensity has risen to about twice the 1990 level (Figure 1.6). Over the longer term, energy intensity is projected to decrease to the 1990 level by about 2003.

1.26 Total primary energy requirements to the year 2000 in tons oil equivalent are shown in Figure 1.7 and Table 1.2. Projections in physical units by fuel type are given in the corresponding subsector chapter. The combined effects of the decline in economic activity in the near term and the impact of the move to world prices are projected to result in a decline in total primary energy demand which would bottom out in 1996/97 at about 5.3 million TOE/yr or 60% of the 1990 demand. With GDP growth and following the working through of the price adjustments, total energy demand would begin to rise reaching 5.6 million TOE by 2000.

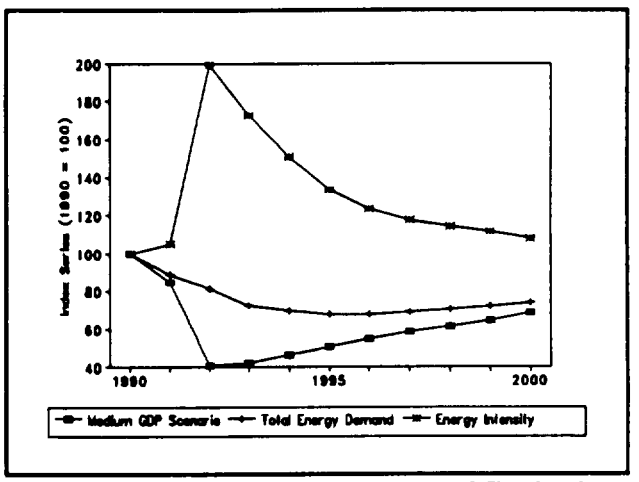

Figure 1.9 GDP and Energy Demand Projections

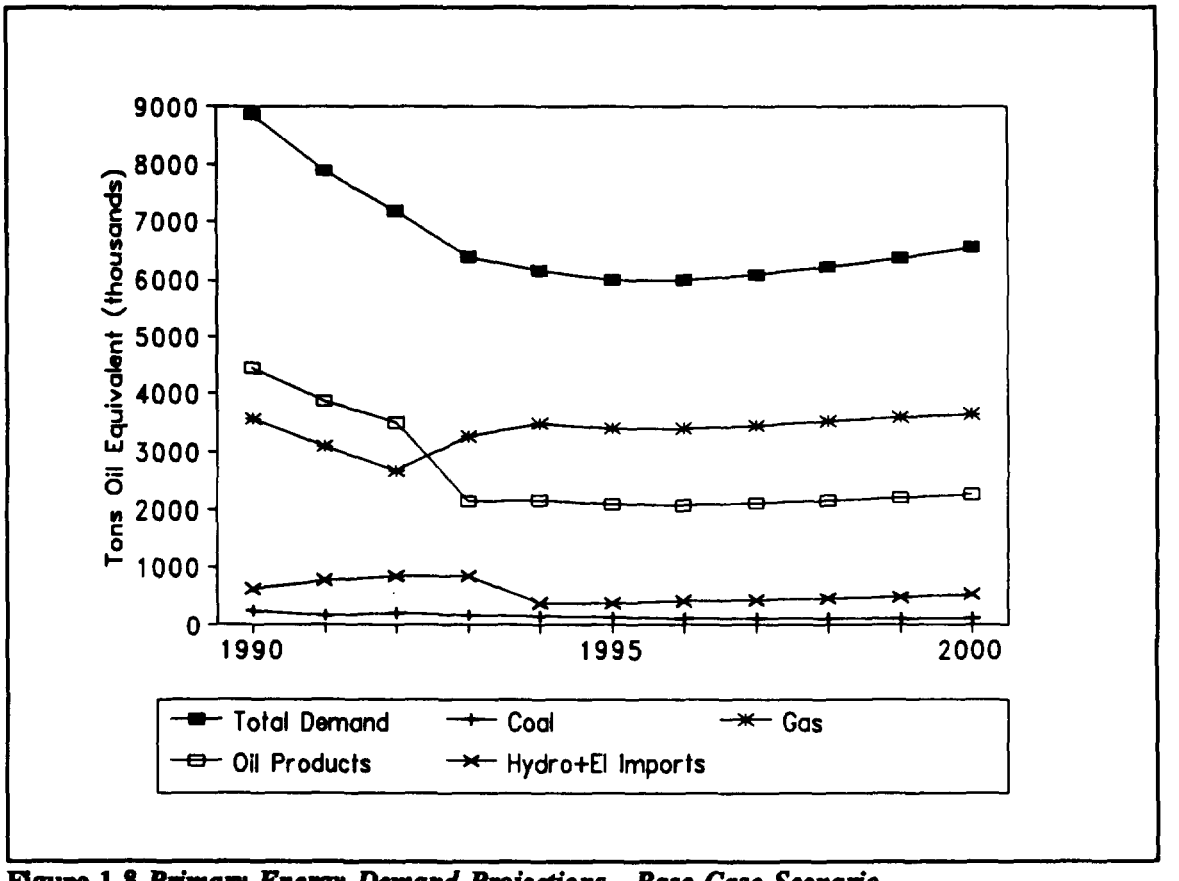

Figure 1.8 ***Primary Energy Demand Projections - Base Case Scenario***

Table 1.2: Base Case Energy Demand Projections to 2000

(thous TOE)	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
Hydro	393	387	714	714	375	375	402	429	456	483	538
Coal	243	168	193	159	140	129	122	117	113	109	106
Gas	3551	3072	2655	3261	3482	3399	3398	3439	3506	3582	3641
Oil Products	4433	3859	3491	2139	2148	2084	2075	2098	2146	2204	2258
Electricity Imports	230	393	125	125	0	0	0	0	0	0	0
Total	8850	7879	7178	6398	6145	5988	5998	6083	6221	6378	6542

1.27 The demand for electricity, discussed in detail in Chapter III, is projected to follow a similar pattern as the demand for primary energy (which includes energy required for electricity production).

D. Balance of Payments and Fiscal Aspects

1.28 *Balance of payments.* The move to world prices for energy is having a profound effect on Armenia's balance of payments. In 1990, total energy imports, which accounted for about 95% of supply, amounted to Rbs 298.1 million in and accounted for 8.5% of export earnings and 6.1% of total imports as shown in Table 1.3. In 1991 the value of energy imports rose to Rbs 646 million (or 11% of total imports and 17% of exports) largely in nominal terms as volume decreased by about 5% and there was no appreciable price increase in real terms. The cost of energy at world prices would have been about four times the 1990-91 level such that total energy imports would have accounted for about 25% and 44% of total imports in 1990 and 1991 respectively.

1.29 Assuming Armenia will be paying full world prices for energy at least by 1995 or four times higher in real terms than in 1992, then under the base case economic and energy demand scenarios, energy imports would cost about US$745 million and account for about 17% of imports and 17% of exports in 1995.[2] In volume terms, however, energy imports are projected to be 32% less in 1995 and 26% less in 2000 than in 1990 as the result of reductions in the energy intensity of the economy and a lower level of economic output. For 1993, the cost of energy imports is projected at about US$ 250 million assuming FSU prices move to about one-third of world price levels but could vary considerably in dollar value depending on exchange rate, FSU prices, and currency of trade as well as volume. At full world prices and volume indicate in Table 1.2, imported energy costs would be about US$822 million in 1995 and US$870 million in 2000.

Table 1.3: Energy Cost and Balance of Payments

Million Rubles (1990 Rubles)[3]	1990	1991	1993	1995	2000
1. Total energy imports	298	323	262	783	829
2. Total imports	4868	2905	1865	3218	3132
(1)/(2)	6%	11%	14%	24%	27%
3. Total exports	3523	1866	1097	1377	1959
(1)/(3)	9%	17%	24%	57%	42%
Net exports(imports)	(1346)	(1039)	(768)	(1882)	(1173)
GDP Index (base case)	100	85	42	51	68

[2] Corresponding to a weighted average cost of petroleum products of US$ 175/tonne and gas at US$100/TOE equivalent (US$2.50/million BTU) and the volumes in Table 1.2.

[3] At a 1990 exchange rate of 1.05 Rbs/$ and world energy prices as above for the years 1995 and 2000. 1993 energy imports valued at one-third of world prices.

1.30 *Fiscal Effects.* While all of the major energy sector enterprises in gas, petroleum and electricity are expected to recover full costs and generate tax revenues for the government, it appears that only the petroleum sector makes a real contribution as it is essentially a trading company with low capital requirement. The capital investments gas and electricity companies are financed in large measure from the state budget and charges for depreciation and capital (interest) costs do not fully recover these costs.

1.31 Taxes are levied on the gross receipts of the energy sector entities responsible for petroleum products, gas, and electricity. Tax data are not available for the gas and electricity sectors; however, for the petroleum sector both income and enterprise tax figures are available (Table 4.4). During the period 1985-90, total taxes paid by ARMOIL averaged about 90% of gross profits, most of which was retained by the center and a portion returned to Armenia. When petroleum prices began to increase rapidly in 1991, the government of Armenia reduced the enterprise tax to 28% of gross profit. Tax receipts declined from Rbs 165 million in 1989 and 1990 to Rbs 24 million in 1991 because of the joint effect of the lower enterprise tax and the reduced gross margin which dropped to one-third of the 1990 level.

1.32 Looking to the future, there is at present no reliable basis for projecting government revenues since retail prices and hence gross margins as a base for the enterprise tax for all forms of energy (except oil products sold in the private sector) are set by government on the basis of a set of often conflicting social and financial objectives. The cost of energy, on the other hand, is determined outside Armenia. As import prices rise, government is attempting to reduce the shock and inflationary effect by squeezing gross margins and, in consequence, the tax base. In order to increase its budgetary resources, the government will need to ensure a full pass through of the cost of fuels. Energy taxes provide an efficient and effective means of revenue collection and will need to be increased to as part of an overall package of fiscal reforms.

1.33 Data were not collected by the Energy Sector Review mission to enable an assessment of fiscal flows; however, it is evident that the sector is confronted with a major cash-flow problem and will generate little, if any, net revenue for the government. With the fuel shortages and lack of product to sell, with mounting arrears due to an inability to pay, with a reduction in industrial consumption which was expected to cross-subsidize household consumption, and with high fixed costs for salaries at high staffing levels, the ability of the energy enterprises even to cover operating costs is extremely doubtful.

II. ENERGY SECTOR OVERVIEW

A. Sector Organization

2.1 The Ministry of Energy and Fuel (MEF) has direct and/or supervisory responsibility for energy sector policy and operations (see organization chart Annex 2.1). The Minister of Energy and Fuel in turn reports to the State Minister responsible for Energy and Fuel. In addition to having responsibility for policy formulation in the sector, MEF also supervises sector operating entities grouped under two principal State Companies, one responsible for power and heating, the other for fuels, as well as sector construction trusts and research and design institutes. It continues to have direct responsibility for the nuclear plant.

2.2 MEF has been closely involved in operational matters of the sector entities as well as having responsibility (as it should have) for supervision of energy sector entities, strategy and policy matters. Some of the direct involvement in operations (for instance in supply rationing) is attributable to the emergency situation and would be considerably reduced under normal conditions. MEF in conjunction with other Ministries (notably Economics and Finance) is also responsible for pricing and tariff regulation. MEF thus is involved in sector planning, operating, and regulatory functions. To avoid conflicts of interest, these distinct responsibilities need to assigned to separate entities within an overall institutional and regulatory framework and technical assistance in this area is recommended.

B. Energy Sector Issues

2.3 This section highlights the major issues confronting the energy sector. Further analysis and recommendations concerning the resolution of the issues are to be found in the subsector chapters. Many of the most immediate and high priority issues in the energy sector stem from the shortages of petroleum products, gas, and electricity normally obtained through Azerbaijan and Georgia. Supplies could be increased virtually immediately through a political resolution of the conflict over Nagorno-Karabakh assuming that gas could flow and trains could pass.

2.4 **Need to rebuild fuel stocks.** The lack of fuel stocks and the uncertainties of delivery have resulted in a hand-to-mouth operation of generating facilities with the result that reliable electricity service cannot be maintained for industrial production. Rebuilding petroleum fuel and gas stocks would require significant working capital investments -- in the order of US$165 million at world prices -- to fill existing storage facilities. In order to rebuild fuel stocks it will also be necessary to increase the rate of fuel delivery so that supply exceeds consumption. Ensuring that stocks are rebuilt on an ongoing basis when they are drawn down will also require hard choices between current and future consumption.

2.5 **Need for economic criteria in project selection.** Because of the energy shortages, the government is pursuing a number of options simultaneously some of which could be mutually exclusive or could result in redundant investments. Large projects such as the Iran gas pipeline and the recommissioning of the NPP, if feasible, would compete for capital and could crowd out other investments in the energy sector or elsewhere in the economy. Most significantly, large supply projects would compete with smaller, less lumpy and potentially more cost effective energy conservation projects. Energy conservation and efficiency improvement projects on both the demand and supply sides are equivalent to projects which increase supply since both can satisfy the same end-use needs. To ensure that

overall energy needs are met at least cost it is essentially that all projects be evaluated according to economic criteria with due allowance for both political, technical, and commercial risk and uncertainty.

2.6 *Need for rehabilitation and replacement of facilities.* Existing facilities appear sufficient in terms of nominal capacity to meet current and future energy needs in all subsectors; however, rehabilitation and repair, and in some cases, replacement of facilities is urgently required. Lack of funds and difficulties in obtaining materials from suppliers has resulted in a depletion of available inventories and increasing deterioration of facilities. Earthquake damage to the gas distribution network remains unrepaired since 1988.

2.7 *Uneconomic pricing.* Low energy pricing in the past has lead to misallocation of resources in energy intensive industry and agriculture, inefficient electricity and heating supply systems, and wastage in consumption. By mid 1992, the price of energy imports was about 25% of world prices and are expected to reach world price levels in 1994. In October 1992, Turkmenistan increased the price under the existing supply contract to 80% of the world price. Electricity, gas, and heating tariffs have covered fuel costs but cost recovery for operations, maintenance, and depreciation has been insufficient to maintain and replace plant and equipment as needed let alone provide return on capital. Fuel price increases are being passed on to consumers through tariff increases but overall cost recovery is still inadequate. A heavy nominal cross-subsidy from industries to households is being maintained in the tariff structure for gas and electricity. In reality, industries can not operate at the levels assumed in setting the tariffs; hence, the overall level of revenues are considerably below financial requirements.

2.8 *Metering.* A lack of metering for gas consumption together with a lack of both heating controls and metering for residential consumption from central heating systems will nullify the impact of price reform on consumption as consumers will not be able to obtain feedback or adjust consumption in response to price increases (paras. 5.42)

2.9 *Environmental impacts.* Air pollution and the draw-down of Lake Sevan are the principal environmental impacts associated with the energy sector (paras. 2.18 - 2.19).

2.10 *Social impact.* In order to achieve price reform, price increases both real and due to inflation must be passed on to final consumers. The impact on low income consumers, however, will be increasingly severe and already is profound. Without increases in wages, many consumers would be obliged to pay a major portion of their incomes to meet heat and light bills. A social safety net is required to meet basic needs for electricity and heat (Chap 3, Sec. H).

C. Energy Resources and Supply Options

2.11 Armenia's indigenous energy resources which may be economic to develop are limited to hydro, peat, and coal and quite possibly oil and gas. The Government is also interested in developing renewable sources of energy including solar, windpower, and geothermal; however, it is unlikely that in the near term these sources could be economic or contribute substantially to energy independence.

2.12 *Hydro.* New hydro plants have been identified at about 40 sites. Some of these plants appear to be economic but others require further examination. Altogether the plants could provide about

700 MW of capacity and 2200 Gwh/yr to bring total hydro production to about 30-33% electricity requirements at the historical 1985-91 level.[4]

2.13 *Coal and Peat.* Indigenous lignite and coal are available with total verified reserves of about 5 million tonnes. Open pit mining of lignite would be required, while hard coal would be mined underground. The economic viability of coal development requires further investigation. Peat is also available and could be used without much development as a household fuel mainly in single family dwellings.[5] Environmental problems are evident in connection with the development of either peat or coal which should be examined as part of feasibility studies which are recommended.

2.14 *Oil and Gas.* About 300 wells have been drilled in Armenia since the late 1940s and many have encountered hydrocarbons but none have been developed. Approximately 20,000 line-km of seismic have been run but without benefit of modern interpretation methods. Initial estimates have been prepared with the assistance of the California State Energy Commission. The analysis of the geologic cross-sections (based in part on available well logs and cores) and structures has led to an initial estimate of reserves at 1.3 billion barrels of oil and 2.7 trillion cu ft of gas in place. Based on the 1990 rate of consumption and assuming 50% recovery of oil and gas, these reserves would be sufficient to meet the needs for 12-15 years of petroleum products and 7-8 years of gas. According to consultants' estimates[6], about US$ 0.4 million would be needed to prepare a package of materials and develop a regulatory and fiscal framework (a petroleum law) in order to attract international petroleum companies for hydrocarbon exploration and development.

2.15 Given the fuel shortages and potential for gaining some energy independence, the government attaches high priority to the development of these resources. Despite the risks of coming up with dry notes and the resultant risk that private sector investors could be discouraged from further exploration, the government is seeking funds to drill four oil and gas wells in 1993. If successful, a gas turbine would be installed to use gas for power generation to feed the netwokr. Pledges of US$9 million out of US$13 million required were obtained in May 1993.

2.16 *Renewable and alternative energies.* While the cost of technologies using solar (thermal and photovoltaic) and wind energy are decreasing in world markets, their cost to provide firm energy remains substantially higher than conventional sources. Although the operating costs are virtually zero, their high capital costs due in large measure to the need for energy storage increase the total cost of firm energy. Their contribution to meeting Armenia's energy needs or conferring any significant degree of energy independence is, thus, expected to be quite limited. For these reasons, development of these technologies is of low priority at least for the near to medium term.

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[4] Plants sizes range from one at 138 MW to many at 1 MW.

[5] About 80 small peat fields are known and believed to be capable of supporting production of 50,000 tonne/yr or enough fuel for 4,500 dwellings for 6 mo/yr. Further geological assessment is needed.

[6] CORE International Inc. consultants to US Trade an Development Agency.

2.17 *Geothermal.* Three sites for the development of hot dry rock geothermal energy have been located in Armenia (Map IBRD 24490). Development of this technology would require the creation of cracks in the hot rocks located at considerable depth below ground. Water would then be forced into the cracks to be converted to steam for use in conventional turbines. The exploitation of geothermal resources could help provide a degree of energy independence; however, the cost would be high. International experience with the technology is limited thereby further raising the costs and risks of successful development.

D. Energy and the Environment

Atmospheric Pollution

2.18 Concern for the environment is strong in Armenia and environmental legislation has already been passed by Parliament. The combustion of fuels is the main source of energy related environmental problems. Temperature inversions in Yerevan combined with the high sulfur (3-5%) mazut used by power plants and industrial boilers (all in need of combustion and emissions controls), low quality diesel oil and gasoline used by badly tuned vehicles result in highly visible and severe atmospheric pollution which causes respiratory illness. As natural gas is a clean burning fuel, it is low polluting particularly in comparison with mazut. Greater use of natural gas together with energy efficiency improvements will reduce emissions. The extent to which fuel handling and storage cause environmental problems has not been determined, however, the impact would be localized. The main risk is contamination of soils and groundwater.

Lake Sevan

2.19 Lake Sevan is the largest lake in Armenia[7] but with the high elevation, low humidity and abundant sunshine, evaporation amounts to 92% of average annual water inflow. In the mid-1930s, Soviet engineers recognized that the annual electricity generation could be increased by reducing the evaporation losses. Losses could be halved by drawing down the lake level by 50 m. The environmental and climatic consequences, however, were not considered. By 1978 after 18 m of draw-down, the ecology of the lake was noticeably changing as water temperatures increased particularly in the shallow end of the lake. In addition, the temperature moderating effect of the lake is reduced resulting in hotter summers and colder winters and a shortening of the growing season. To at least partially reverse these effects, the government has set a target to raise the level by 6 m by the year 2000 as part of the national water plan. A diversion tunnel from the Arpa river basin was driven to increase the inflow to Lake Sevan. Fuel shortages, however, have recently forced a further draw-down for power generation. Fuel requirements (and, hence, electricity costs) in the future will be greater than otherwise would be the case to permit reduced hydro generation from the Sevan-Hrazdan cascade and thereby raise the level of Lake Sevan.

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[7] Approximately 70 x 20 km by 100 m at the deepest point.

III. ELECTRIC POWER AND DISTRICT HEATING

3.1 As in other FSU republics, the electric power and district heating subsectors in Armenia are both operationally and organizationally combined. The issues which confront these subsectors are also common to the other energy subsectors namely the energy supply shortages, lack of revenues, deteriorating equipment, and insufficient resources to deal with the problems. In addition, a decision is required concerning the future of the nuclear power plant, whether to recommission it or close it completely. Although demand is projected under the base case scenario to remain below the 1990 level until about 2003 because of decreased economic output, higher electricity prices, and the implementation of energy conservation programs, investments in the order of US$ 978 billion would be needed for rehabilitation and new construction through the end of the decade for generation, transmission, and distribution in the power sector alone. Additional funds will be required for repair and rehabilitation of the district heating systems although extension is unlikely to prove economic.

A. Subsector Organization

3.2 MEF has supervisiory responsibility for the subsector while ownership and operational responsibility lies with the state enterprise, Aremenia Energy Production Company (ARMENERGOPROD). Organizationally, the NPP is a department within the MEF and the Director, NPP is designated as a Deputy Minister, MEF (see Organization Chart, Annex 2.1). Tariff increases are proposed by ARMENERGOPROD for approval by MEF in consultation with the Ministries of Finance and Economy. ARMENERGOPROD was the sole entity responsible for the operation of both electric power and district heating throughout the country until early 1992. The electric power operations are handled through 7 networks comprised of 43 distribution regions, 3 thermal power stations and 2 hydro power cascades. There are about 10,000 total staff allocated to the organizational units as shown in Annex 3.1.

3.3 The government would like eventually to privatize ARMENERGOPROD and has set up four subsidiary companies with responsibility for (i) generation, (ii) transmission and distribution outside Yerevan, (iii) distribution in Yerevan, and (iv) construction. It is unlikely, however, that any significant degree of privatization could be achieved until a degree of economic stability in the country can be achieved and power sector operations can reach a more normal steady state condition, particularly with regard to financial performanc. Technical assistance through EC funding is being provided in parallel with the Hrazdan 5 project to strengthening ARMENERGOPROD oriented on commercial lines. Further EC funded assistance is planned to develop a suitable regulatory framework as first step in developing an environment conducive to private sector participation.

B. Electricity Usage and Projections

Historical Consumption Patterns

3.4 Over the past decade there has been virtually no growth in total annual electricity consumption as shown in Table 3.1. Maximum consumption peaked in 1983 at 9572 Gwh and dropped to 8635 Gwh by 1991 despite a doubling of residential and commercial/official consumption and a 50% increase in agricultural use. These increases were met by a corresponding decrease in industrial consumption which declined by 50% (from 65% to 32%) over the decade from 5487 GWh in 1980. The percentage shares of each sub sector are presented in Table 3.2.

Table 3.1: Total Annual Electricity Consumption by Sectors
(GWh)

Sector/Year	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991
Residential	932	1000	1158	1334	1310	1383	1456	1517	1559	1791	2047	2405
Industrial	5487	5345	5240	5336	4562	4465	4505	4626	4555	3663	2852	2780
Commercial /Official	523	551	662	1040	1455	1078	1096	1028	1159	1143	1097	766
Transport	295	303	319	322	319	312	361	392	366	399	386	347
Construction	216	206	204	188	222	240	246	248	253	291	464	352
Agriculture	951	977	1101	1314	1455	1446	1404	1453	1436	1665	1759	1542
Other	44	50	62	38	13	15	18	110	157	274	416	443
Total	8448	8432	8746	9572	8907	8939	9086	9374	9485	9226	9021	8635

Source: Ministry of Energy and Fuel of Armenia (MEF)

3.5 The largest industries are electronic equipment, footwear, mining, textiles, wine and cognac, chemicals and tires and machine tools. Despite the decline in industrial production, in part because of the shutdown on environmental grounds of the synthetic rubber plant,[8] industry remains the largest consuming sector followed closely by the residential sector at 28% of total consumption.

[8] The plant has been restarted in 1992 but on a limited scale because of raw materials shortages.

Table 3.2: Historical Composition of Electricity Consumption

Percentage	1980	1985	1990	1991
Residential	11	16	23	28
Industrial	65	50	32	32
Commercial/Official	6	12	12	9
Agriculture	10	16	20	18
Other	8	6	13	13
	100	100	100	100

Historical Supply Patterns

3.6 In addition to meeting its own electricity needs, Armenia had been exporting electricity until 1989 to neighboring republics of the FSU via the Trans Caucasus system. After 1989 the importation of electricity began as shown in Table 3.3 which also shows total generation requirements and system maximum demand. As ARMENERGOPROD does not systematically record simultaneous system demand it has been necessary to estimate maximum demand attributable to the domestic load (excluding exports) on the basis of a 60% annual load factor which has been derived from an analysis of daily and seasonal load characteristics.

Table 3.3: Supply and Demand for Electricity

GigaWatt Hours	1980	1985	1986	1987	1988	1989	1990	1991
Gross Generation	13034	14891	14502	15194	15290	12124	10362	9516
Net Import	—	—	—	—	—	—	920	1572
Total Supply	13034	14891	14502	15194	15290	12124	11282	11088
Net exports	2234	3384	2747	3328	3334	335	—	—
Domestic Use	10800	11508	11705	11866	11956	11789	11282	11088
Transmission and Distribution Losses	1319 10.1%	1785 12.0%	1780 12.3%	1682 11.1%	1648 10.8%	1571 13.0%	1649 14.6%	1660 15.0%
Station Use [1]	1033 7.9%	784 5.3%	839 5.8%	810 5.3%	723 4.7%	992 8.2%	612 5.4%	793 7.2%
Losses and Station Use	2352 18.0%	2569 17.3%	2619 18.1%	2492 16.4%	2371 15.5%	2563 21.1%	2081 18.4%	2459 22.2%
Net Domestic Consumer demand (Sales)	8448	8939	9086	9374	9585	9226	9021	8635
Domestic Maximum Demand (MW)	2055	2189	2227	2258	2275	2243	2146	2110

Source: MEF

1. Station use is on average about 7.3% of unit generation for the electrical side and 33.2 KWh/Gcal for the heat production side of the plant. The figure shown includes both.

Load Characteristics

3.7 Daily and monthly load factors have ranged from 80% to 89% in the winter months and 70-82% in the summer months during the period 1988-91. The average working day load curves for December, during the winter peak period (Figure 3.1), show a morning and evening peak. In 1991 the peaks were more pronounced as residential heating loads increased and high load factor industrial loads declined. Annual load factors have been in the 60 - 62% range since 1988 but by 1991, had dropped to 59.5% because of the shift in load composition. With constraints in energy supply, load shedding begun in late 1991 will continue and load factors will be higher than usual as a large portion of demand goes unsatisfied.

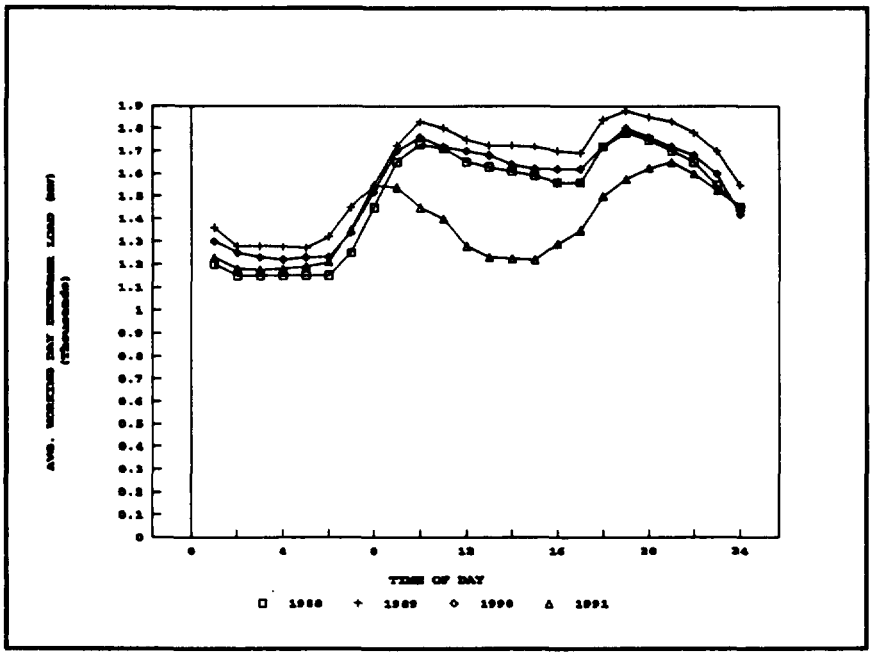

Figure 1.8 Hourly Load Pattern, December 1988-91

3.8 The normal seasonal pattern of energy consumption and peak load are evident from Figures 3.2 and 3.3. Maximum demand and load factors in winter months are higher than in summer because of the longer duration of the increased heating and lighting loads. The peak load in summer months is about 20% less than in winter and provides an opportunity for carrying out scheduled maintenance.

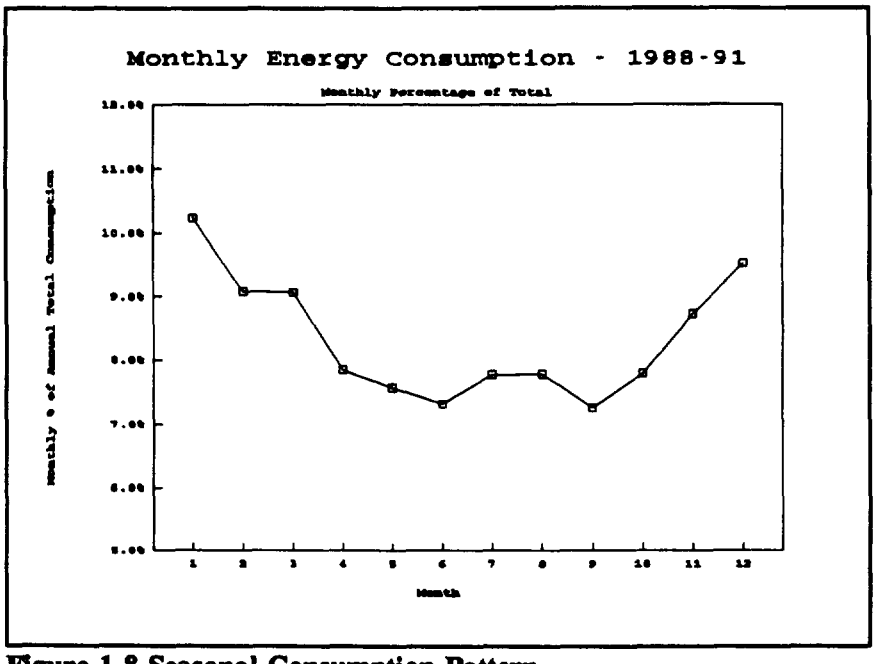

Figure 1.8 Seasonal Consumption Pattern

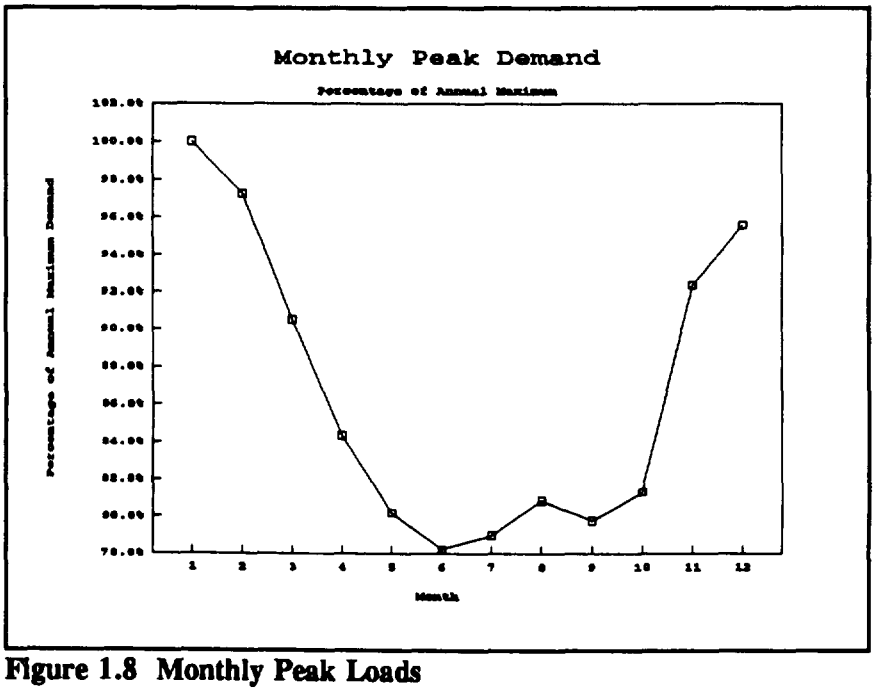

Figure 1.8 Monthly Peak Loads

Electricity Intensity

3.9 Electricity intensity in Armenia follows a similar pattern as overall energy intensity (paras.1.23). In 1990, the most recent year when end-use needs were almost fully satisfied, the electricity intensity of Armenia was roughly half that of many centrally planned economies including Bulgaria, Georgia, Romania, Russia, and Ukraine as shown in Figure 3.4[9] With the decline in GDP since independence, however, the electricity intensity has doubled despite a drop in electricity consumption. As a result, the 1992 data point for Armenia has moved upward to the left of the 1990 point. With the rise in GDP under the base case economic scenario and a reduction in energy intensity, Armenia's position would return to near its 1990 position in the period 2005-2010.

3.10 The patterns of changes in electricity intensity projected by the World Bank for Armenia in this analysis are based on the experience of other countries following price shocks and structural adjustment and were used to prepare two electricity demand growth scenarios. A base case and a low final demand projection, together with assumptions concerning the reduction of generation and supply losses, were used in generating capacity planning (Section III.D). Maximum demand and, hence, generating capacity requirements, was derived on the basis of the projected annual system load factor.

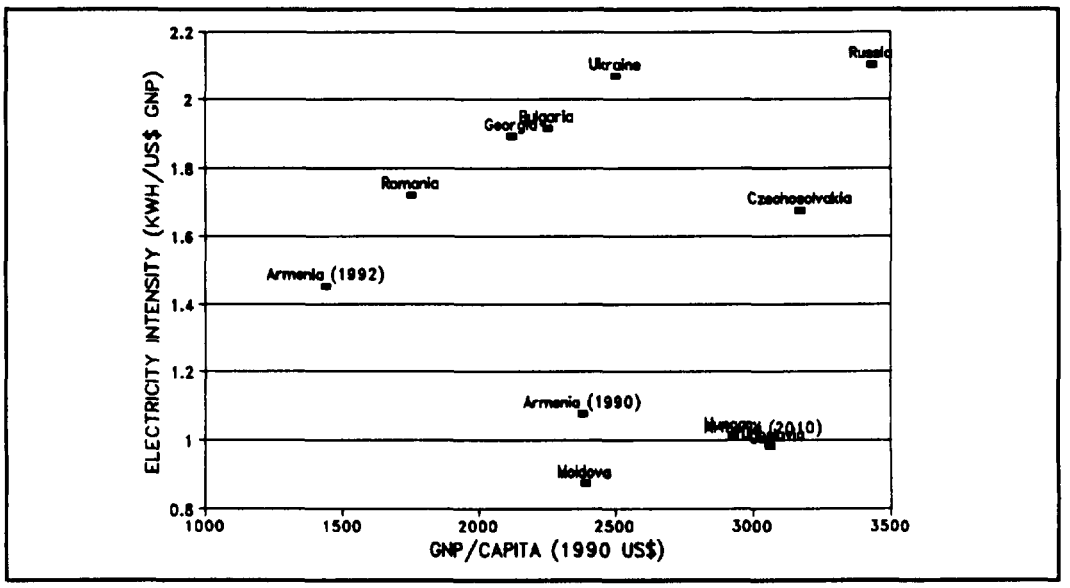

Figure 1.8 International Comparison of Electricity Intensity

[9] The supply of gas via Azerbaijan was restricted beginning in 1990; however, substitution by mazut was possible for power generation and heating needs.

Future Electricity Demand Scenarios

3.11 Because of the underlying uncertainty in the development of the economy as well as uncertainty in the rate of reduction of energy intensity, the electricity demand projections demand have a broad range of uncertainty. Two demand scenarios have therefore been examined using the base case economic scenario (para 1.15) and two scenarios of electricity intensity reductions.

3.12 The ***base case demand scenario*** (Figure 3.5 and Table 3.4) is based on the assumption of an initial rapid drop in intensity (25% by 1996) due to a rebound in GDP followed by a steady decrease of about 2% annually in electricity intensity. This rate is similar to that experienced in the high income industrialized countries during the 1970s and '80s following the energy price shocks. The 1990 level of intensity would be reached about 2010.

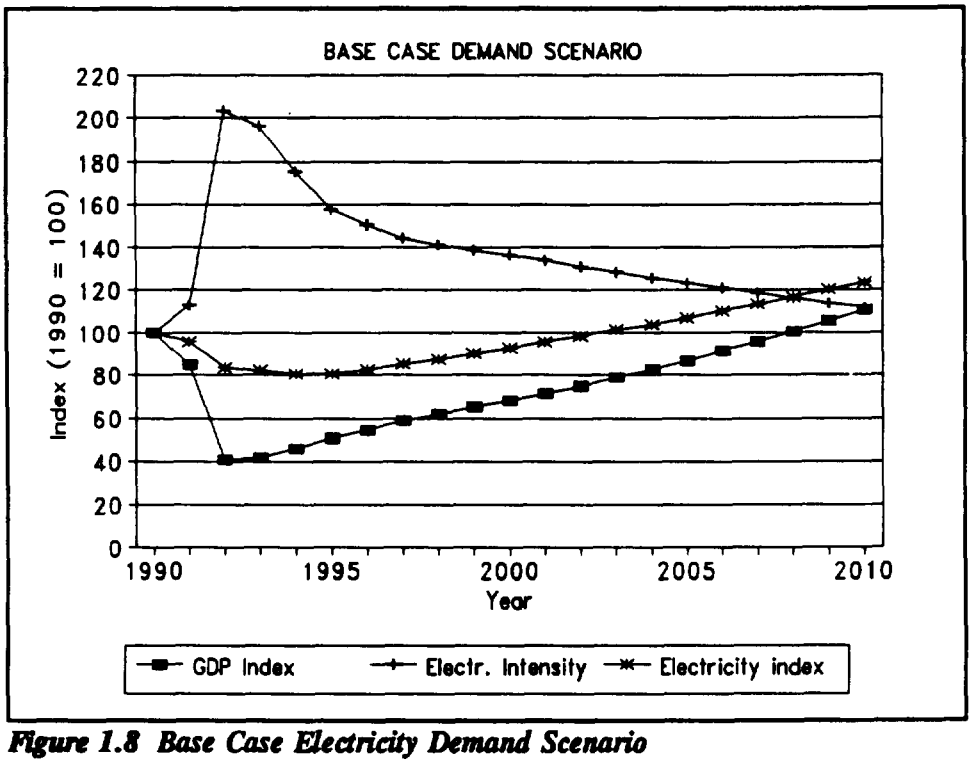

Figure 1.8 Base Case Electricity Demand Scenario

3.13 The ***low demand scenario*** (Figure 3.6) is projected on the assumption of a rapid initial decline in electricity intensity associated with structural adjustment and the closure of energy intensive industries followed by a steady pace of efficiency improvements from 2000 to 2010. The 1990 level of intensity would be reached in 1999 and would drop further to 82% by 2010. This scenario would require a heavier investment in restructuring, new plant and equipment, and a more aggressive energy conservation program than in the base case. In view of the likely financing constraints over the next

decade, this scenario has a lower probability of occurrence than the higher demand scenario retained as the base case.

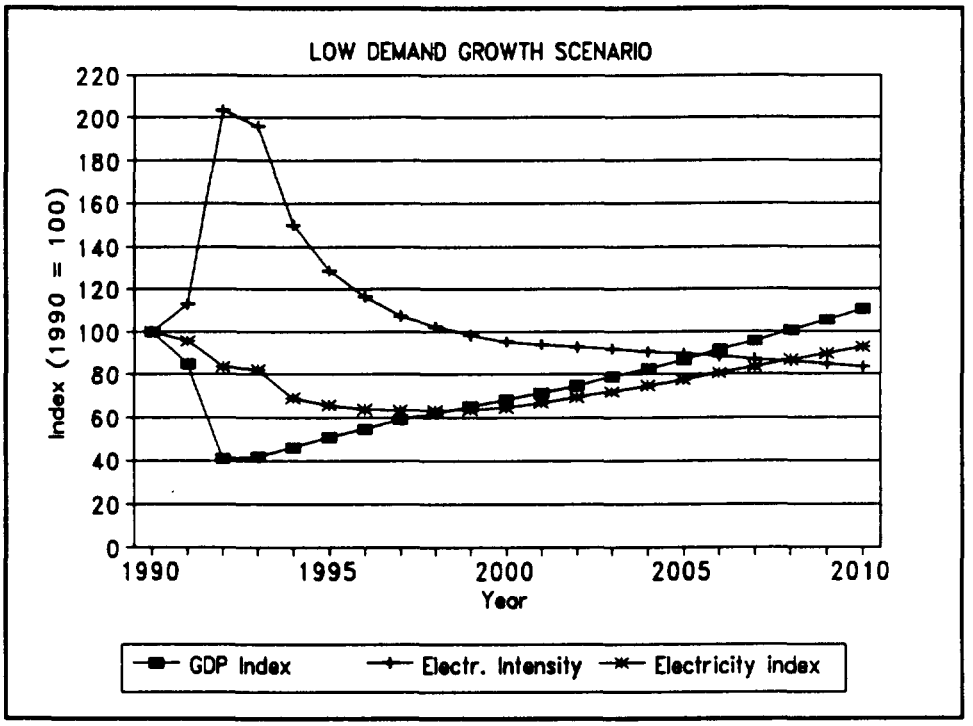

Figure 1.8 Low Electricity Demand Growth Scenario

Table 3.4 Base Case Electricity Demand Projection

	Actual 1990	Actual 1991	Est. 1992	1993	1994	1995	2000	2005	2010
Total Consumption (GWh)	9021	8635	7534	7429	7280	7252	8366	9651	11134
Losses/ Station Use	22	22	22	22	22	21	17	15.5	14
Total Generation	11282	11088	9531	9398	9210	9076	10007	11355	12887
Maximum Demand (MW)	2146	2110	1813	1788	1752	1727	1904	2160	2452

Maximum Demand

3.14 Maximum demand under the base case scenario as shown in Table 3.4 is projected to follow the same trends as total energy demand on the assumption that annual load factor will remain constant at 60%. Even when fuel becomes fully available, maximum demand will fall with the decline

in total energy consumption and projected loss reduction. Maximum demand is projected to reach a minimum level of about 1727 MW in 1995, rise to 1904 MW by 2000 and reach 2160 MW and 2452 MW in 2005 and 2010 respectively.

Composition of Demand

3.15 The composition of demand is projected to evolve from the base year of 1990 as the services sector (designated as "commercial/official" in the MEF electricity statistics) becomes more prominent in the overall economy. By 2000, the share of the residential category would decline to the 1990 level of 23% from the 1991 level of 28% while the "other" category (including transport and construction) is projected to remain constant at 13%. The share of the commercial electricity consumption would increase with a complementary decrease in the shares of residential, industrial, and agricultural consumption as shown in Table 3.5.

Table 3.5: Projected Percentage Composition of Electricity Consumption

	Actual 1990	Actual 1991	1995	2000
Residential	23	28	26	23
Industrial	32	32	30	28
Commercial/official	12	9	13	18
Agriculture	20	18	18	18
Other	13	13	13	13

3.16 Projected indexes of electricity consumption by category are compared with the base case index series for GDP in Figure 3.7. The graph indicates that the quantity of consumption in all categories except commercial/official would remain flat in the period 1995 to 2000 with the impact of higher electricity prices and efficiency improvements while GDP increases as shown. The commercial/official sector would grow at about twice the GDP rate (but starting from a low base of 9-12% of total consumption as the services sector expands.

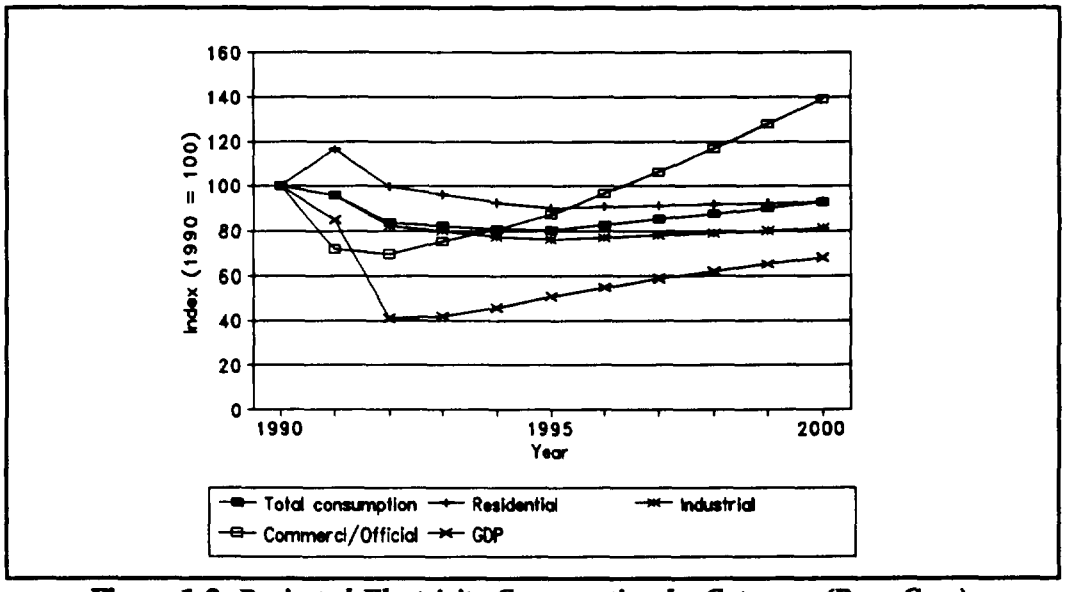

Figure 1.8 Projected Electricity Consumption by Category (Base Case)

C. Existing Generating Facilities

3.17 The existing generating facilities to meet the projected peak demand and energy requirements are reviewed below and the generation planning options are discussed in Section 3.D together with an assessment of the capacity and energy balances (Annexes 3.3 and 3.4). Further details are provided in Annex 3.1 and Map IBRD 24491.

3.18 Total nominal installed capacity is 2700 MW (excluding the 815 MW NPP), of which 1746 MW (or 65%) is steam thermal and 953 MW (35%) is hydro. Derating due to age and operating constraints plus the non-availability of the Sevan-Hrazdan Cascade during the winter, brings the effective installed capacity to about 1970 MW as shown in Table 3.6. Under the base case demand projections, the additional 300 MW capacity to be provided by Hrazdan 5 is needed immediately to meet peak load and provide a 25% reserve margin.

Table 3.6: Installed Generating Capacity

Type of Plant	Number of Units and Period of Commissioning	Nominal Installed Capacity (MW)	Effective Derated Capacity (MW)
Thermal			
Hrazdan	4 (1971-74)	1100	1070
Yerevan	6 (1963-67)	550	460
Kirovokan	2 (1964-76)	96	40
Sub total		1746	1570
Hydro			
Sevan-Hrazdan Cascade	6 stns (1936-61)	527	60
Vorotan Cascade	4 stns (1970-84)	402	340
Other Hydro	1 stn (1932)	24	0
Sub total		953	400
Nuclear (shut down)	2 (1971-76)	815	0
Total		3515[1]	1970[1]

Note: 1. Rounded

3.19 Table 3.7 shows electricity generation by source during the period 1980-92. Up to 1988, nuclear units provided about a third of electricity generation with 23% of the installed capacity. The share of thermal units in gross generation increased from about 55% in 1980 to 84% in 1991, although the total generation dropped 18% between 1989-1991 because of a steady dropped in electricity consumption together with the shutdown of the NPP. Hydro units provided 12% of gross generation in 1980 and increased their share to 16% in 1991. By 1991, electricity imports from Russia via Georgia and from Azerbaijan amounted to 1572 GWh or 14% of total electricity supply.

Table 3.7: Summary of Electricity Generation by Source

Year	Electricity Generation (Including Exports; excluding imports)	(Exports) imports	Generation by Type of Plant (GWh)			Share in Total Generation plus Imports (%) (Share in Total Installed and Imported Capacity%)			
			Thermal	Hydro	Nuclear	Imports[1]	Thermal	Hydro	Nuclear
1980	13034	(2234)	7146	1558	4330	–	55 (50)	12 (27)	33 (23)
1985	14892	(3384)	8007	1619	5266	–	54 (50)	11 (27)	35 (23)
1988	15290	(3334)	8947	1534	4810	–	59 (50)	10 (27)	31 (23)
1989	12124	(335)	9693	1149	1281	–	80 (56)	9 (31)	11 (13)
1990	10362	920	8807	1572	0	8 (4)	78 (62)	14 (34)	0 0
1991	9516	1572	7970	1546	0	14 (7)	72 (60)	14 (33)	0 0

Note: 1. Imported power assumed at 85% annual load factor.

Source: MEF

Thermal Plants

3.20 The existing thermal power stations at Hrazdan, Yerevan, and Kirovokan are conventional steam units equipped with extraction turbines and cooling towers. They are fired by mazout and/or gas and provide steam and hot water for industrial use and district heating in addition to electricity. Many of the units are more than thirty years old and in the case of Yerevan are near the end of their service lives. Furthermore, the civil works (particularly the foundations) of the Yerevan plant are in poor condition and no seismic design standards were incorporated as constructed. Although life extension at this plant is possible, and indeed work is underway to replace turbine/alternator sets, the general condition and inefficiency of the plant is such that it is likely to be more economic to retire it and replace it with a new plant. With the completion of the Hrazdan 5 unit (para. 3.41) and depending on future demand and available reserve margin, it may be possible to retire the oldest units in 1994.

3.21 Under normal operating condition, thermal units are loaded in a merit order decided by yearly average generation costs. Station use[10] is about 7-8% rather than the more normal 4-5% range

[10]Percentage of electricity used to operate equipment within the power station taken on the base of gross generation.

found in Western plants. Thermal unit availability [11] has averaged about 75-80% in the period 1980-1991. However, in the first quarter of 1992, availability was only about 45-50% of full capacity. This situation was caused by a combination of forced and planned outages as well as seasonal [12] and other [13] deratings. In the period 1980-1988, before the shut down of the nuclear units, the annual capacity utilization factors of conventional thermal plants averaged 54%, of the nuclear plants 61% and of the hydro plants 17%. During the first quarter of 1992 the capacity utilization factors of thermal units sank to a low of 33%, caused mainly by shortage of fuel which prompted operation of some thermal units at minimum loading.

Hydro Plants

3.22 Hydro power has been developed on the Sevan-Hrazdan and Vorotan cascades (Map IBRD 24491 and Annex 3.1). The Sevan-Hrazdan cascade with Lake Sevan at its head consists of six power plants with a total installed capacity of 527 MW. Limitations on the operating regime of the plants and the lack of seasonal storage on the tributaries feeding into the Hrazdan River (other than Lake Sevan) greatly restricts the flexibility of their use. Because sufficient installed capacity is available, the cascade can be used for peaking. Water release from Lake Sevan, however, is seasonal and is geared to irrigation requirements. As a result, the plants operate in a run-of-river regime with limited pondage to provide an average annual energy output of 1166 GWh. Operation of the hydro plants during the winter peak demand season is minimal and the Sevan-Hrazdan cascade provides no firm capacity during that period.

3.23 The Vorotan cascade consists of four plants with total capacity of 402 MW and annual energy of 1157 GWh.

3.24 Because of the current fuel shortages, there is little choice except to increase the use of water from Lake Sevan thereby further drawing down the lake level. This action is contrary to government policy which is to increase the lake level in order to counteract the environmental impact of the earlier drawdown (para. 2.19). It is likely, however, that greater benefit from the available hydro resource can be obtained through more efficient water management. It may also be found that, given the increased fuel costs, and hence opportunity cost of water, that water is more valuable at the margin for hydro generation than for irrigation.

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[11] Unit Availability Factor = 1 - Unit Unavailability Factor. And Unit Unavailability Factor is defined as the unit Adjusted Forced Outage Rate (AFOR) which includes forced outages, maintenance outages and deratings as follows: AFOR = (FOH+SHD+MH)/(FOH+SHD+MH+SH), where FOH = forced outage hours; SHD = operating hours during forced or scheduled deratings; MH = planned outage hours; and SH = service hours for the unit operating at full capacity.

[12] Thermal units are derated in the summer months by as much as 50% due to cooling tower constraints and high ambient temperatures. For instance, the output of the 200 MW units at Hrazdan is cut back to 100-110 MW.

[13] Caused by fuel shortages, in which case some thermal units may be operated at the minimum loading point.

3.25 Hydro plant availability to meet annual peak demand in winter is curtailed by the fact that the Sevan-Hrazdan cascade produces little firm power while it accounts for about 42% of total hydro installed capacity. Capacity utilization factors of the hydro units reached 40% in May 1992 when it became necessary to overdraft Lake Sevan; however, to avoid drawing down Lake Sevan, overall annual hydro capacity utilization should be no greater than about 30%.

Nuclear Power Plant

3.26 The only nuclear power station in Armenia is the Soviet-built model VVER 440-230 Medzamor plant rated at 2x408 MW. The first unit was commissioned in 1976 and the second in 1979. The plant was shut down in early 1989 after the earthquake in 1988, as a precautionary measure since the plant is located within 16 km of a seismic fault. No damage was sustained by the plant during the earthquake. Specialists from the International Atomic Energy Agency (IAEA) have identified a number of specific safety issues requiring urgent attention regardless of the future disposition of the plant (Annex 1).

3.27 Until recently, the government has not been pressing to recommission the NPP but is now seriously considering doing so as a matter of necessity in order for Armenia to gain some degree of energy security. Under an earlier resolution of Parliament, a public referendum was required before any decision to recommission the plant could be taken and, according to polls in 1990/91, over half the population was opposed. In view of the current energy shortages, Parliament authorized Government in March 1993 to take the decision without calling a referendum. The government obtained EC financial aid for technical assistance from Framatome (France) to evaluate the feasibility of recommissioning the NPP. The report was submitted to the Government at the end of March 1993; however, only partial results have been released to the World Bank by the Government. It is understood that about two years would be required to complete the detailed inspection and recommissioning work required to start unit 2 while a further year would be required for unit 1.

3.28 As Armenia has insufficient resources to finance the safety upgrades and refuelling required before start up, it will be seeking foreign assistance. Unofficially Russia has expressed interest in funding the reopening of the NPP using only Russian materials and personnel. Russia's interest apparently is partly motivated by its own shortage of power and the desire for imports from Armenia.

3.29 In order to ensure adequate safety standards should Armenia decide to re-open the NPP, EBRD has included as a condition of its loan to finance the completion of the Hrazdan 5 power plant that the Government should consult with the EBRD before taking the decision to reopen the NPP. If the plant is reopened without the approval of qualified and independent experts selected by the EBRD, then the loan would be canceled and repayment accelerated.

IAEA Evaluation of the Nuclear Power Plant

3.30 The IAEA team outlined the work required should the government wish to consider further the recommissioning of the NPP. The summary of their report shown in Annex 3.2[14] and the main conclusions of the mission are as follows:

- The design is similar to other VVER 440/230 NPPs and has the same generic problems as other plants of this type.
- The reactor is still partially loaded with irradiated fuel and, therefore, needs to be maintained at all times in safe shutdown conditions.
- There is a visible degradation of the structures and equipment owing to the extended period that the plant has been shutdown.
- There is apparently an absence of regulatory control.
- A good part of the trained and experienced operators have left the plant and the safety awareness of those currently in charge needs to be ensured.
- The physical protection of the plant, particularly in view of the current local political situation is weak.

3.31 The IAEA mission paid particular attention to the issue of seismic safety. The site seismic intensity was originally defined as grade 7 (0.10g) on the MSK scale and was not explicitly designed against seismic action. Upgrading was undertaken based on lessons learned in connection with the Kozloduy (Bulgaria) NPP and the 1977 earthquake in Romania. Upgrading, now approximately 70% complete, was carried to grade 8 (0.20g) or, in some cases, to grade 9 (about 0.40g) standard.[15] Following the 1988 earthquake, according to some Armenian institutions, site seismicity may be defined between grades 9 and 10 MSK (0.40 - 0.45g); however, the revision process for seismic standards in Armenia has not been concluded. If these values are confirmed then under current international practice and IAEA safety guidelines and codes, the design basis earthquake for the Armenia NPP would have values for peak ground acceleration approximately double those for Kozloduy and Bohunice (Slovakia) NPPs.

3.32 The IAEA team strongly recommended that positive confirmation should be obtained that there are no negative site related characteristics (such as geological, tectonic, or volcanic conditions) which would rule out restarting the plant due to seismic safety considerations. In particular, the non-existence of a fault capable of producing permanent ground displacement should be confirmed. If such

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[14] Report of the Safety Review of the Armenia Nuclear Power Plant, World Bank and IAEA Joint Mission to Armenia to Review the Energy Sector, Final Report, 4 August, 1992.

[15] The Armenia NPP is sometimes referred to as a VVER 440 model 270 because of the specific safety upgrades undertaken during construction; however, it is basically a model 230 in design.

faulting exists within 8-10 km, very detailed studies and field investigations are required to demonstrate that the fault cannot affect the site area.

3.33 The extent to which the Framatome report of March 1993 has addressed the issues raised by the IAEA is not known by the Bank; however, the tectonic fault issue should be resolved before committing funds for further engineering studies.

3.34 IAEA also recommended that ".... if a decision to restart the plant is finally taken by the Government of Armenia, it should only envisage a period of operation of about 5 years unless major reconstruction is undertaken. It should also be noted that longer annual outage periods should be anticipated in order to implement compensatory safety measures which are required even if the plant is scheduled to operate only for the above mentioned 5 years. Long term operation of the Armenia NPP, as with other VVER 440/230s, would require major plant reconstruction to accommodate the required safety modifications."[16]

Operational Considerations

3.35 The nuclear plant was designed to function as part of a regional supply system with the result that the 2x408 MW units would be large in relation to the total power requirement of Armenia which could drop to 1700-1900 MW in the period 1995-2000. A renewal of regional coordination and exchanges would be needed for reliable operation of the NPP jointly with the rest of Armenia's generating plants. Additional peaking capacity in the form of gas turbines may be needed for operational flexibility in the absence of power exchanges given the high proportion of base load plants in the system.

D. Generation Planning Options

3.36 Non-nuclear options based on the addition of conventional steam plants, gas turbines (open and combined cycle), and small hydro plants have been considered in this study as required to meet the base case and low case demand scenarios. The capacity and energy balances for these cases are shown in Annex 3.3 and 3.4. A rigorous least cost planning study needs to be carried out to determine the most economic size and type of plant required to meet demand after allowing for the impact of energy efficiency and DSM measures. Discussion of the non-nuclear generating options is presented below followed by a synopsis of the MEF scenario based on the re-opening of the nuclear plant.

3.37 For base case scenario (Annex 3.3), the balances show that beginning in 1995 with the completion of Hrazdan 5 (300 MW) and up to 2010, a total capacity addition of 1900 MW would be required to meet the projected load growth, provide at least a 25% reserve margin, and permit the retirement of 621 MW of the oldest plant for which life extension might be uneconomic. Because of their age, about half the thermal units would be due for retirement by 1995 and the remainder by 2000 assuming a 25 year life.[17] Detailed studies are needed, however, to determine the costs and benefits

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[16] Transmittal letter 7 August, 1992 to World Bank with the final IAEA mission report.

[17] Some life extension work has been carried out on the 5x50 MW units at Yerevan TPS through turbine and alternator replacement.

of life extension and should be carried out in as part of overall power system planning which are to be undertaken with the assistance of consultants financed by EBRD and USAID.

3.38 A number of small hydro plants totalling 300 MW may be economical to add to the system which could double the percentage of hydro generation to about 30% by 2000. While interconnections exist with Azerbaijan and Turkey, political differences are such that these could not be considered as providing firm power. There also exists an intertie with Georgia but in the short to medium term, Georgia is in deficit and is assumed unable to supply power.

3.39 Consideration must also be given in generation planning for the district heating requirements at the three thermal power stations.[18] Industrial steam and district heating demands are projected to decrease and for the purpose of the indicative planning carried out here, it is assumed that the heating requirements will not affect the plans for retiring power generating units.

Thermal Units

3.40 Construction of the Hrazdan 5 and 6 units (2 x 300 MW) began in 1988 and planning for units 7 and 8 also been started. Of the total cost of US$89.4 million required to complete Unit 5 (now 60% complete), approximately US$59.4 million has been approved by EBRD to finance foreign costs while the Republic of Armenia will provide the balance of US$30.0 million equivalent for local costs. Part of the boiler, turbine and generator are on site and orders have been placed with FSU firms for the remaining equipment. The loan would cover equipment, construction, interest during construction, and contingencies. Civil works for units 6-8 are partially complete (10-20%). A further review of the need for and timing of the Hrazdan 6 to 8 units is needed to compare with the alternative of life extension of existing plant.

3.41 The thermal plant now on the system is comprised of conventional steam units. The least cost planning studies should examine the optimum mix of plant including gas turbines and combined cycle for peaking and/or intermediate load. Despite the higher efficiency of combined cycle, conventional steam plants have an advantage in being able to burn mazut if gas is not available. Use of mazut during the peak period of gas demand in winter would reduce the seasonal variation of gas supply requirements and thereby delay the future need to reinforce gas transmission facilities.

3.42 Indicative costs and rehabilitation per kW of new thermal plant capacity in Armenia have been estimated on the basis of Western unit costs, experience in other FSU and Eastern European countries and shown in Table 3.8.

[18] Hrazdan, Kirovakan, and Yerevan.

Table 3.8: Unit Thermal Plant Costs

Unit Type	Approximate Unit Size (MW)	US$/kW
1. Gas turbines	120	375
2. Gas fired combined cycle	450	770
3. Conventional oil/gas steam	300	900
4. Rehabilitation/life extension	average	250

3.43 Conversion of the NPP to conventional thermal may be economic in the long term; however, completion of Hrazdan 6 first to complete the block formed with Hrazdan 5 would be likely be a lower cost sequence. USAID and EBRD have expressed interest in financing the studies for conversion of the nuclear plant; however, the Government wishes to hold these studies in abeyance until a decision is taken on the recommissioning of the NPP.

Hydro Units

3.44 Detailed cost estimates which reflect current costs under present conditions are not available for new hydro plants. Adjustments to earlier cost estimates using inflation indexes and current exchange rates leads to unusually low unit costs (less than $100/kW) in comparison with world prices. For the purpose of assessing the overall financial implications of hydro construction, it is assumed that the cost would be in the order of $600/kW of installed capacity. The cost of rehabilitating existing hydro is assumed to be $150/kW in the absence of engineering studies.

3.45 Conceptual designs for about 330 MW in five small hydro plants have been carried out and could provide about 1000 GWh per year of energy on average; however, the amount of firm energy is not known (Annex 4). It is the intention of MEF to carry out the detailed studies for these plants together with a further 700 MW of small and mini hydro plants which could provide an additional 1200 GWh per year.[19] It is assumed that 300 MW of new hydro capacity would be added by 2000 to provide about 870 GWh of energy thereby doubling the indigenous hydro generation to 30% of total generation.

3.46 ***Nuclear Power Costs.*** The costs of upgrading the safety standards to an international acceptable level and recommissioning the NPP are not yet fully known. IAEA has very tentatively estimated the costs of recommissioning the NPP, without safety upgrades, at a minimum of US$70 million based on experience with Bohunice and Kozloduy NPPs (Annex 3.2). A further US$2-3 million would be required for preliminary studies including the verification of the seismic fault situation. Because of the three year shutdown and the need for safety up-grades to acceptable standards, the cost of recommissioning would be considerably higher.

3.47 Framatome (March 1993) has estimated costs of safety upgrades for a further five years of operation together with recommissioning costs based on imports from both FSU and western countries.

[19] Consultants funded by USAID are currently reviewing these hydro projects.

FSU costs are estimated a Rbs 10 billion for materials and equipment plus 2000 man-years of labor while non-FSU costs are estimated at 30 million ECU for materials and equipment and up to 150 man-years. Based on end 1992 exchange rates[20] and assuming average costs at world prices of US$50,000 and US$100,000 per man-year (including all non-equipment costs) for FSU and non-FSU staff respectively, the total cost would amount to US$370 million equivalent.

3.48 Further estimates have been provided by consultants to EBRD based on assessments of VVER 400/330 reactors (operating in countries other than Russia) but not based on a field assessment of the Armenia NPP. Upgrading and recommissioning costs for five years' operation are estimated at US$330 million while for upgrading for longer term operation up to the end of the normal thirty year service life, (that is up to 2010 considering the period during which the NPP was out of service), total costs are estimated at US$460 million. The difference between the Framatome (US$370 million) and EBRD (US$330 million) estimates (for 5 years' operation) reflects not only the impact of assumptions on personnel costs but also the uncertainty in the scope of work required and its cost.

3.49 Fuel costs under both scenarios are estimated at about 1.0 UScent/kWh or the average for other VVER 440/330 reactors in the G-7 study.

E. Supply Scenarios

Non-Nuclear Scenarios

3.50 ***Base Case***. Under the base case scenario, the 1990 level of demand would be reached by about 2003 as shown in the capacity and energy balances in Annex 3.3. By 2010 a total of 1900 MW of capacity would need to be added to cover demand growth and plant retirements. The 300 MW Hrazdan 5 unit in 1995 would be followed by a total 400 MW of gas turbines (200 MW in 1996, and 100 MW in each of 1998 and 2010). If economic, these units could be converted to combined cycle. Gas turbines would provide low unit investment cost peaking capacity which appear needed to complement the existing base load thermal plants. While the hydro plants can provide peaking capacity, the amount of pondage and firm power are limited. Further investigation is needed to assess the optimum plant mix. Small hydro plants totalling 300 MW of firm capacity are assumed to be developable and installed in the period 1996-2000.

3.51 Existing units at the Hrazdan thermal power station are assumed to be rehabilitated through life extension programs. Further base load plant would be provided in the form of 900 MW of combined cycle plant in the period 2000-2010. This plant would permit the retirement of the remaining 2x150 MW of plant at Yerevan following the initial retirement of 5x50 MW in 1996. All of the Kirovakan plant (71 MW) would be retired by the year 2000. It is assumed that the nuclear plant would neither be recommissioned nor converted to conventional fuel.

3.52 ***Low Demand Scenario***. Assuming that the nuclear plant would not be recommissioned, the capacity balance (Annex 3.4) shows the required installation and possible retirement dates for various units. With the completion of the Hrazdan 5 unit in 1995, the Yerevan 5x50 MW units could be retired.

[20] Exchange rates at December 1992: Rbs 450/US$ and US$1.2/ECU.

Subject to a detailed evaluation, it is assumed that the remaining 2x150 MW units could be rehabilitated and their life extended to 2010. With the addition of 300 MW of new hydro, the thermal units at Kirovakan (2x12 and 1x75 MW) could also be retired by 1995 and 2000 respectively. A total of 300 MW of the oldest thermal units at Hrazdan could also be retired in 1997 under the assumptions of the low demand projections. A further 600 MW of gas turbine and combined cycle plant would be required to cover the 4% load growth in the period 2005-10.

Nuclear Power Scenarios

3.53 ***Ministry of Energy and Fuel Scenario.*** The Government of Armenia is considering the re-opening of the nuclear power plant not only to increase energy security but also to meet the high demand projection which has been the basis of its planning. Under the MEF scenario, demand in 2000 is projected to be about 2500 MW or 596 MW higher than the base case projection of this Review. Allowing for a 25% reserve margin, the additional capacity required in the MEF scenario would amount to 750 MW or 92% of the 815 MW capacity of the two existing nuclear units. The energy generated, assuming 65% annual load factor, would amount to about one-third of total generation requirements.

3.54 ***Base Case Demand Scenario.*** Recommissioning the Medzamor NPP would also be an alternative means of providing the additional capacity required under the base case scenario after commissioning Hrazdan 5 in 1995. Allowing for retirements of 621 MW, a total of 1200 MW of new capacity would be required by 2000 of which Hrazdan 5 would provide 300 MW. Of the remaining 900 MW, the NPP could provide about 90% of this requirement. The NPP would supply about 46% of total generation requirements under the base case scenario.

3.55 ***Low Demand Scenario.*** Under this scenario, the NPP could supply all the capacity required to meet load growth to about 2005 and permit the retirement of 646 MW of thermal plant for which life extension is assumed not to be economic.

F. Power Generation Investment and Financing Implications

Low Nuclear/No Nuclear Scenarios

3.56 The costs of the low nuclear/no nuclear alternative are very tentative pending the execution of a least cost planning study and the detailed evaluation of the existing units. Financial implications of the base and low demand cases are summarized in Tables 3.9-3.10. Capital requirements are based on unit costs per kW (Table 3.8) as used in other countries included in the overall G-7 study. Fuel costs are based on international prices estimated at US$ 2.50 per million BTU and US$115/tonne of mazut. Power tariffs would need to be increased to provide sufficient cash generation cover the local cost component estimated roughly at 40% of total costs.

3.57 Prior to the recommissioning or permanent closure of the NPP, a nominal amount of US$3 million per year is estimated to be required to maintain the NPP in a safe shut down condition. This amount is required under the moderate nuclear scenario as well as the non-nuclear alternative.

3.58 ***Base Case Demand Scenario.*** Financing implications are considered for the short (1993-1995) and medium (1996-2000) term only as the costs beyond 2000 are highly uncertain. Total

investments for the period 1993-2000 of US$892 million and fuel costs of US$ 1965 million are estimated as shown in Table 3.9.

3.59 *Short Term.* The immediate concern is for the short term, 1993-95, and in particular the emergency measures needed to ensure fuel supply for the 1993/94 winter. Emphasis must be placed on:

(a) rebuilding fuel stocks and increasing the rate of supply

(b) diversifying fuel supply sources

(c) improving the efficiency of energy supply and end-use to make best use of available supplies

(d) ensuring the safety of the NPP in the shut-down condition prior to shutting it down permanently or recommissioning it

(e) preparatory work and initiation of projects to be completed in the medium term.

3.60 The existing fuel storage facilities are empty because of the fuel blockade. Approximately 550,000 tonnes mazut would be required to fill existing storage capacity of the thermal power plants and bulk storage facilities. Total cost would be about US$60 million plus, say, a further $8 million in working capital for one-half the cost of filling the existing gas storage. These working capital costs have not been included in the investment costs in Table 3.9.

3.61 *Medium Term.* For the medium term, defined as 1996-2000, on the supply side emphasis would be on rehabilitation and life extension of existing plant and the construction of new plant if less costly than life extension. On the demand side, an aggressive program of conservation and demand side management is warranted to reduce the rate of demand growth and, hence, the required rate of supply expansion. The difference in costs between the low growth and base case scenarios indicates the potential amount of investment that would be warranted in conservation and economic restructuring assuming that end-use benefits and the level of economic output would be the same in both cases.

3.62 *Low Demand Scenario.* The financing requirements (Table 13) in the short term would be the same under the low demand scenario as for the base case. A more aggressive energy conservation and DSM program would delay the need for new generating plant but the type of plant would be the same in both cases. Total investments for the low demand scenario are estimated at US$999 million for the period 1993-2010.

Fossil Fuel Requirements

3.63 Fuel consumption and cost under the low growth non-nuclear scenario would be approximately 26% less than the base case during the period 1993-2000. Total undiscounted cost for the base case is estimated at US$ 2.0 billion and for the low demand case, US$1.5 billion.

Table 3.9: Financial Implications of Non-Nuclear Alternatives (Base Case)

Capital investments	$mio	Period 1993-95		Period 1996-2000	
New Plants		MW	$mio	MW	$mio
1. Conventional steam		300 1/	89		
2. Gas Turbine				300	113
3. Combined Cycle					
4. Small Hydro				300	180
Rehabilitation					
1. Hydro		150	23	800	120
2. Steam		200	50	1270	318
Total	892		162		730
Fuel Costs		Quantity	$mio	Quantity	$mio
Total Thermal Generation (TWh)		21.3		46.5	
Gas 2/ (Bm^3)		5.7	469	10.0	828
Mazut 3/ (M tonnes)		2.1	241	3.7	427
Total	1965		710		1255
Nuclear Plant Maintenance	24		9		15
Grand Total	2,881		881		2000

Notes:
1. Hrazdan 5, financed by EBRD and Government of Armenia
2. Gas cost $2.50 MBTU = $82.5/000 m^3
3. Mazut cost $115/tonne
4. Nuclear Plant Maintenance and Safekeeping $3 mio/yr2

Table 3.10. Financial Implications Low Demand Growth Scenario

Capital investments	$mio	Period 1993-95		Period 1996-2000	
New Plants		MW	$mio	MW	$mio
1. Conventional steam		300	89		
2. Gas Turbine					
3. Combined Cycle					
4. Small Hydro				300	180
Rehabilitation					
1. Hydro		150	23	800	120
2. Steam		200	50	900	225
Total	687		162		525
Fuel Costs		Quantity	$mio	Quantity	$mio
Total Thermal Generation (TWh)		18.3		25.8	
Gas 2/		4.9	405	6.7	553
Mazut 3/ (M tonnes)		1.8	207	2.5	288
Total	1,452		612		840
Nuclear Plant Maintenance	24		9		15
Grand Total	2,162		782		1,380

Notes:
1. Hrazdan 5, financed by EBRD and Government of Armenia
2. Gas cost $2.50 MBTU = $82.5/000 m^3
3. Mazut cost $115/tonne
4. Nuclear Plant Maintenance and Safekeeping $3 mio/yr

Cost Differences Between Scenarios

3.64 Both the base case and low demand scenarios would serve the same end-use requirement and would be associated with the same economic output. Savings in capital and fuel under the low scenario could be used to finance restructuring and energy efficiency improvements. The difference between the two scenarios in terms of undiscounted cash flow in the period 1993-2000 is US$205 million in capital and US$513 million in fuel costs for a total of US$718 million.

Nuclear Scenarios

3.65 ***Moderate Nuclear Scenario.*** Upgrading and recommissioning the NPP at an assumed cost of US$370 million would permit the retirement of 815 MW of thermal plant and, thereby, avoid US$204 million in rehabilitation and plant life extension costs which otherwise would be incurred.

Following five years of operation the the NPP would be retired and the investment and operating costs would be the same as for the no nuclear scenario. The net total investment costs in the period 1993-2000 would be US$1096 million.

3.66 ***High Nuclear Scenario.*** Under this scenario, investment costs are assumed at US$460 million while the avoided costs of thermal rehabilitation would be the same (US$204 million) as for the moderate nuclear scenario. Including the additional new plant to meet demand, total investment costs would be US$1148 million up to 2000. Each year of further operation beyond 2000 when new combined cycle gas turbine plant would be required in either the low nuclear or moderate nuclear cases would result in a deferment of investments totalling US$628 million for a saving of US$62.8 million per year at a discount rate of 10% in addtion to the fuel cost saving.

3.67 ***Fuel Costs.*** Fuel costs under both the moderate and high nuclear scenarios would be the same. Assuming an availability rate of 65% (at 815 MW) for the NPP, annual generation would be 4.64 TWh and would substitute for 250 gms oil equivalent of fossil fuel at an average cost of 2.7 UScts/kWh. This saving would be reduced by the cost of nuclear fuel at 1.0 cts/kWh resulting in total net savings of US$78.9 million per year.

Comparison of Financing Implications of Each Scenario

3.68 Tables 3.11 and 3.12 summarize the financing implications of the three scenarios for the base demand case in terms of investment costs and fossil fuel costs. Investment costs are shown for the period 1993 to 2000, while fuel costs are shown for the year 2000 alone as a representative year. The contribution of the nuclear plant would remain constant at 4.5 TWh per year while declining in percentage terms as demand grows.

Table 3.11. Investment Costs 1993-2000
(US$ millions)

Scenario	Nuclear Upgrade	Nuclear Construction	Thermal/Hydro Rehabilitation and Construction	Total
High Nuclear	460	–	688	1148
Moderate Nuclear	370	–	688	1058
Low Nuclear	–	–	892	892

Table 3.12. Fuel Requirements in the Year 2000

Scenario	Generation (TWh)			Fuel Cost (US$ millions)		
	Nuclear	Fossil	Total	Nuclear	Fossil	Total
High	4.64	5.36	10.0	46.4	144.7	191.1
Moderate	4.64	5.36	10.0	46.4	144.7	191.1
Low	–	10.0	10.0	–	270.0	270.0

G. Transmission and Distribution

Transmission Network

3.69 Armenia's bulk power transmission network consists of 164 km of 330 kV, 1320 km of 220 kV, and 3146 km of 110 kV lines. It was designed as part of the InterCaucasus Power Pool which in reality is no longer functioning due to regional conflicts and power shortages. As a result of the reduced power flows, the load carrying capacity of the existing network is generally more than adequate for projected loads although reinforcement is required to connect the planned Hrazdan 5 unit to the load center at Yerevan.

3.70 In the period 1980-91 transmission and distribution system losses increased from 10% to 15% of total supply[21] compared with the more typical levels of 9-10%. Transmission losses have been estimated from load flow studies to account for about 4% of total supply. Thus, distribution losses have increased from 6% of total supply to 11% in the period 1980-1991.

3.71 ***Interconnections.*** Interconnectors exist between Armenia and (a) Georgia (220 kV, 250 MW), Azerbaijan (330 kV, 400 MW; 110 kV, 50 MW), and Turkey (220 kV, 300 MW, not in service) (Annex 3.4). In addition there is a 110 kV line to Karabakh and 2 x 220 kV, 500 MW line to Nachichevan for wheeling power from Azerbaijan. As a result of the conflict with Azerbaijan, no exchange or wheeling is taking place. Although there is an existing contract with Russia to send 860 GWh (about 90 MW on a continuous basis) via Georgia, it is expected that not more than a total of 500 GWh will eventually arrive in Armenia on a intermittent basis because of the shortages in both Georgia and Russia.

3.72 At present, there are no contractual arrangements with Azerbaijan or Turkey. In the past, net power and energy from Azerbaijan retained by Armenia were charged at Rbs 4.75/kWh. The peak

[21] Total supply equals gross generation plus imports.

load in Nachichevan is about 130 MW. During 1991, about 1500 GWh was imported from Azerbaijan, of which about one-half was wheeled through to Nachichevan, but in 1992 imports from Azerbaijan have stopped. In late 1992, Turkey had initially agreed to supply surplus electricity to Armenia but rescinded the offer because of internal opposition.

Distribution

3.73 Total low voltage line length in Armenia is about 40,000 km with about 9000 transformers of average size of 322 kVA. Transformers and cables are manufactured in Armenia; however, both are constructed with aluminum wire which causes increased technical losses. In fact many fires in residences have been cause by faulty connections of aluminum cables.

3.74 Transformers are generally oversized; however, during the winter of 1991/92, parts of the Yerevan distribution system were 200 to 300% overloaded with the result that some 320 transformers and 300 km of underground cable were severely damaged or, in many cases, beyond repair. About two-thirds of the transformers are yet to be repaired or replaced. Overloading occurred because of the increased use of electric heaters given the lack of district heating or gas for space heating and will re-occur if adequate fuel supplies are not available in winter.

Yerevan Municipal System

3.75 The Yerevan Municipal system is the largest distribution network and operates as a subsidiary of ARMENERGOPROD. Of the 270,000 residential connections, about 70,000 are to private houses and the rest to state-owned apartments. In addition 700 industrial plants and 5000 small commercial enterprises are served. Before 1988, the average growth of consumers was about 5-8% per year. Since then, however, the number of connections has remained about constant. In 1991, electricity consumption amounted to 2130 GWh with technical losses estimated at 13% and unaccounted for (non-technical) losses a further 10%. These losses are high and could be cut in half through a loss reduction program together with improvements in metering and billing.

H. Power Subsector Financial Performance

Electricity Pricing and Tariffs

3.76 Table 3.8 gives a historical breakdown of tariff rates by sector and shows that electricity was practically given away at a fraction of economic cost despite tariff increases in 1991 and 1992. By February 1993 industrial tariffs had been increased to 10 Rbs/kWh plus 2 Rbs/kWh tax while the tariff for residential was increased to 1.5 Rbs/kWh. The cross-subsidy from industrial to residential consumers is part of the social safety net provided by government since at least 60% of the population is below the poverty line (para. 3.89).

Table 3.13 Electricity Prices by Sector (Rbs/kWh)

Sector	1990	1991	Jan 1992-June 1992	June 1992	Feb 1993
			rubles/kWh		
Residential	0.0272	0.0315	0.16	0.2	1.5
Industrial	0.0260	0.0600	1.7	4.8	12.0[1]
Agriculture	0.0077	0.0100	1.7	0.4	
Transportation	0.0190	0.0530	1.2	2.0	
Commercial/Municipality	0.0287	0.0711	1.7	2.0	

Note: 1. Including 2.0 Rbs/kWh tax.

3.77 The current tariff adjusting mechanism allows for changes to be made periodically to the industrial tariffs to maintain a level of net revenue to ARMENERGOPROD that is deemed adequate. The Ministry of Energy an Fuel must have the approval of both the Ministries of Finance and Economy to effect a tariff adjustment.

Metering and Billing

3.78 All connections are metered for electricity consumed (KWh) but maximum demand (kW) meters are not used even for large industrial consumers. Maximum demand meters should be installed as part of the much needed tariff reform. Residential consumers are responsible for reading their own meters each month and making payment to the local bank. If the bills are not paid on time, the bank can then collect the estimated bill from a customer's account. In view of this practice, many consumers do not keep deposit accounts with banks.

3.79 Prior to the sharp increases in electricity tariffs ARMENERGOPROD's accounts receivable averaged about two months' billing. Receivables have grown considerably and about 60% of household consumers did not pay their bills during the past winter. As of April 1992, government ministries had not paid their bills since early 1992 while the NPP has not paid since 1989. Accounts receivable had grown to 1083 million rubles, roughly US$ 10 million at the time.

I. District Heating

3.80 Centralized district systems supply heat in Yerevan, Hrazdan, and Kirovakan to public buildings, residences, and industries as well as to greenhouses in the agricultural sector. The systems operate as isolated networks supplied by individual boilers or in conjunction with thermal power plants thereby increasing their overall thermal efficiency to as much as 85%. Losses in the heat transmission and distribution networks are estimated, however, at 40%-60%. The shortages of fuel during the winter 1991/92 necessitated the complete shut down and draining of portions of the Yerevan and other district heating systems in early 1992 resulting in electrical overloads and damage to the networks due to the increased use of electric heaters.

3.81 The heating system in Yerevan operates in a 20 km radius around the city and supplies 5400 public buildings and 4400 apartment blocks. There are eight independent boiler houses and one combined heat and power plant (Yerevan thermal power station) which supplies steam to industries as well as heat to the municipal system.

3.82 Heat consumption is metered for large consumers such as industries; however, consumption by the population (apartments, houses, government offices) is not. There are no controls on radiators or room thermostats, hence no means of regulating temperature. If the temperature is too high (often the case for dwellings closest to the boiler house) the only control is to open a window. Because the systems are not properly balanced, about one-quarter of the most distant households do not receive enough heat.

3.83 In the short run it is essential to reduce losses in the district heating systems and improve the overall operating efficiency. In the longer term, the gradual replacement of the district heating systems with gas or light heating oil-fired boilers in apartment buildings and houses is likely to be found to be more economic than rehabilitating the district systems; however, further study is needed.

Energy Conservation

3.84 USAID is supporting efforts to improve the efficiency of power plant and heating station operations. Audits have been carried out on the Yerevan TPS and the District Heating Station 12 to identify opportunities for energy conservation. Monitoring equipment and combustion controls with pay-back periods of about five months are being installed on boiler in the Yerevan TPS and fuel savings of about 5% are anticipated. Further savings of about Rbs 5 million/yr could be achieved through the low cost modification of the pressure reduction system in the Yerevan TPS to eliminate energy wastage through steam throttling.

3.85 MEF is in the process of developing a broader energy conservation program with the help of the European Community and USAID and has identified economically justified energy conservation opportunities with a total technical potential of 30-35%. The lowest cost measures and most readily implementable involve the plugging of gaps around doors and windows. This is already being done since

heating is severely restricted because of fuel shortages. Longer term efforts will involve adding double glazing to windows, insulation in building walls and ceilings, and a change in building design and construction practices in response to the higher price of heat from central systems or fuel for own-use.

3.86 Short to medium term industrial energy conservation measures include boiler tune-ups, insulation for steam lines, and improved process controls. Longer term measures will require major retrofitting and equipment replacement with modern technology which should be evaluated in the context of overall industrial restructuring.

Heat Pricing

3.87 Households are charged at a flat rate of 4.0 Rbs per square meter per year at rates which are considerably below the average cost of supply estimated for the Yerevan municipal system at 165 Rbs/sq m/yr. The government approved heating charges are based on the bulk heat supply tariff shown in Table 3.14. Pricing reform, however, can have virtually no influence on heat consumption until thermostats and/or valves are installed to permit temperature control.

Table 3.14 - Prices for Heat from Central Systems

As of May 1992	Rubles/Gcal
Residential heating and hot water	430
Other heating and hot water	487
Industrial steam (depending on industry)	487-515 plus charge for non return of condensate

J. Social Impact of Electricity and Heating Tariffs

3.88 The Ministry of Economy estimated that, in early 1992, 60% of the population was under the poverty line of 700 Rbs/person for the first quarter of 1992 or 2880 Rbs/mo for a family of four. At that time, a typical professional level salary was 1500 Rbs/mo or 3000 Rbs/family with two wage earners. A heating tariff to cover the estimated costs of supply of 420 Rbs/mo for an apartment together with 750 Kwh/mo of electricity if priced at 2.0 Rbs/Kwh (less than the average revenue requirement of 2.5 Rbs/Kwh for ARMENERGOPROD) would result in an energy bill of 1920 Rbs/mo or nearly two-thirds of the monthly family income before allowing for food, rent, or clothing. Because of the severe impact on household consumers, the tariff was held to Rbs 0.2/kWh with the expectation that industrial consumption would cross-subsidize household consumers. Tariff increases, although clearly needed to cover production costs will quite evidently have severe social impacts at current wage levels. With

declining real incomes due to inflation (90% in the first quarter of 1992), the impact of real tariff increases would be compounded.

3.89 There is a distinct risk, already evident, of an inability or refusal of consumers to pay increased energy tariffs. As a result, arrears to ARMENERGOPROD are mounting. If the discipline of price increases is not enforced through improved bill collections and/or suspension of service, there is a risk that energy supply costs would not be covered and that demand management would not be achieved through the pricing mechanism.

3.90 Nonetheless, the provision of a minimum level of heat and light is justified on social grounds. Cross-subsidization of residential consumers is now provided for all levels of consumption even beyond the minimum required for basic needs and provides no incentive for conservation for higher income consumers many of whom use 2000 kWh or more per month. As residential consumption is metered, it would be feasible to introduce a progressive tariff charging a low tariff the first block, say, 100 kWh/mo, and a higher price for consumption in excess of basic needs. An analysis of electricity consumption patterns and income levels is needed and should be carried out as part of the demand forecasting and tariff analysis under the proposed technical assistance and studies program.

K. Overall Subsector Investment and Technical Assistance Requirements

3.91 ***Repair and Rehabilitation.*** At world prices and based on Western norms for maintenance expenditures, a minimum of some US$60 million/yr would be needed for routine maintenance of the Armenian power system; however, it is evident that much less than this equivalent amount has been spent at least over the last few years. As a result, a back-log of maintenance exists including an immediate need of US$25 million for critical spare parts and repair materials to maintain even the present level of service. Priorities are greatest for generating plant and distribution networks. Minor amounts are needed for the transmission network. Rehabilitation would also involve plant life extension and it is estimated (Table ES3) that US$ 368 million is needed in the period 1993-1995 for existing thermal power plants (1470 MW) and US$ 143 million for hydro plants (950 MW). A further US$ 50 million is tentatively estimated for rehabilitation of the transmission and distribution networks. In the period 1996-2000, a further US$ 478 million is projected for rehabilitation in the power sector.

3.92 ***Power Generation.*** In addition to the US$89 million for the Hrazdan 5 steam unit, investments totalling US$ 478 million are estimated for hydro plants (300 MW) and thermal plant (300MW) in the period 1994-2000 in the no nuclear scenario.

3.93 ***Technical Assistance.*** To assist Armenia in addressing the planning and policy issues in the power and heating subsectors, a program of technical assistance is recommended. The proposed program would consist of the following activities:

		US$ thousands
(a)	Power sector facilities planning study	550
(b)	Power/heating sector financial planning and institutional development	270
(c)	Heating facilities planning	300
		1120

EBRD, USAID, and the European Community are participating in the financing of this program. Draft terms of reference are shown in Annex 6.

3.94 The total financing requirements outlined above are summarised in Table ES3 in the Executive Summary.

IV. PETROLEUM

A. Overview

4.1 Armenia has no oil refining capacity and at present imports all of its petroleum products from refineries in the Russian Republic. There are no petroleum pipelines and all products are shipped via rail with the occasional small shipments by tank-truck. In 1990 total consumption of refined products was 1.8 million tonnes plus an equal quantity of mazut. Fuel shortages due to unreliable supply and regional transportation problems are the primary problems confronting the sector.

B. Subsector Organization and Institutions

4.2 Oversight for technical and policy issues for the petroleum sector is the responsibility of Ministry of Energy and Fuels through the Deputy Minister Fuels (Organization chart Annex 2.1). The Ministries of Economics and Finance are also concerned with pricing and taxation policies.

4.3 ARMPETROL Products Company (ARMPETROL) is the government owned oil products importing, storage, and distribution organization for Armenia. There are 1500 employees in 12 departments in the central administration which cover all areas relating to product procurement, quality control, distribution, maintenance and capital investment. Details of the organization and functional responsibilities can be found in Annex 4.1. ARMPETROL operates 18 major storage facilities throughout the country, and other smaller facilities including about 250 service stations. These stations are under the supervision of the managers of the storage terminals which supply them or, in the case of 24 distributors to special enterprises in Yerevan, the central administration.

4.4 It is the intention of the government to privatize ARMPETROL as soon as possible. The government will retain some ownership, possibly as much as 50%, while the balance will be sold first to employees and second to the public at large, including foreigners. The share price has not yet been determined. The privatized ARMPETROL will be required to sell petroleum products to government owned enterprises at controlled prices, but all petroleum product sales to the private sector will be at market determined prices. ARMPETROL will not have a monopoly on petroleum product imports or sales, but will compete with others who wish to enter the business in Armenia. ARMPETROL will operate independently under regulation by the Energy Ministry.

4.5 Since January 1992, ARMPETROL has stopped selling gasoline to the public who must buy from the private sector dealers. These dealers purchase the gasoline themselves in Russia, Georgia, or even Azerbaijan, bring it in by train or tank truck to Armenia, and distribute it either through leased ARMPETROL service stations or directly on the street from small tank trucks.

4.6 The ARMPETROL organization and facilities appear reasonably well positioned to be a successful private company although the monopsony position of the government for a major portion of ARMPETROL's sales at controlled prices may well reduce ARMPETROL's profitability and result in

outright losses. As long as ARMPETROL remains within the ruble zone and buys petroleum products in rubles, then no foreign exchange problem will arise. It appears increasingly likely, however, that the ruble zone will be abolished, Armenia will issue its own currency, and petroleum trade will be carried out in convertible currencies at world prices. As ARMPETROL will receive its revenues in local currency, the central bank would need to ensure convertibility to hard currency to permit product procurement.

C. Demand for Products

Historical Demand

4.7 Table 4.1 shows the historical data for petroleum consumption by product. In the period 1985-91 total oil demand grew at a 2.4% annual rate, while total mazut consumption generally remained flat with annual consumption varying depending on the availability of gas and industrial output. In 1991, mazut remained the largest component of total fuel consumption accounting for 52% of total, with light products 41%, and non-fuel products (bitumen and lubricating oils) 7%. The Table 4.2 divides the mazut consumption between industry and electric power generation.

4.8 From 1985-89, mazut consumption for electric power generation declined at a 3.7% annual rate but in 1990 and 1991, consumption increased for electric power generation as a result of disruptions in gas delivery. A similar trend can be seen in the industrial consumption of mazut, which declined by a 9.1% annual rate over the 1985-90 period, but also increased in 1991 because of gas shortages.

4.9 Consumption of light petroleum products used principally for transportation (gasoline, diesel, kerosine and aviation fuel) increased at a 5.7% annual rate over the 1985-91 period in part because of the increased demand for transportation for relief and reconstruction following the earthquake in 1988.

4.10 By sector, industry (including electric power generation) consumed 65%-70% of all petroleum products. Household use was the fastest growing sector, at a 12% annual rate, and represents private sector consumption of gasoline, diesel, and kerosine for heating. The commercial/official and transport sectors represent oil consumption, including aviation fuel, by government organizations.

Table 4.1 - Petroleum Product Consumption 1985-1991

Thousand TOE	1985	1986	1987	1988	1989	1990	1991	Growth Rate 1985-91
By Product:								
Gasoline	638	679	672	877	900	902	926	6.4%
Diesel	385	360	361	369	683	613	484	3.9%
Kerosine	8	10	8	10	10	12	12	7.0%
Mazut	2,197	2,477	2,242	2,075	1,749	1,839	2,112	-.6%
Lube Oil & Other	21	22	22	23	26	27	29	5.5%
Aviation Fuel	146	154	164	164	150	194	215	6.7%
Non Fuel	123	130	139	180	252	257	269	13.9%
Total	3,518	3,852	3,608	3,698	3,770	3,884	4,047	2.4%
By Sector (excl. non-fuel):								
Households	160	193	210	228	262	285	316	12.0%
Commercial/Official	335	290	265	366	694	572	405	3.2%
Industry	2,580	2,895	2,655	2,534	2,218	2,333	2,643	0.4%
Transport	383	414	433	422	408	428	477	3.7%
Total	3,458	3,792	3,563	3,550	3,582	3,618	3,841	1.8%

Source: Ministry of Energy and Fuel

Table 4.2 Mazut Consumption 1985-1991

Thousand TOE	1985	1986	1987	1988	1989	1990	1991
Electricity Generation	1118	1477	1374	1107	950	1347	1160
Industry	1079	1000	868	968	799	492	952
Total	2197	2477	2242	2075	1749	1839	2112

Source: Ministry of Energy and Fuel

4.11 The projections of total petroleum products demand are included in the overall energy projections discussed in Chapter I, Section E. Total petroleum demand is composed of final consumption in all sectors plus the mazut requirements for electricity generation. Demand is broken down here into

light products, essentially for transportation, and mazut for industrial use and electricity generation. Mazut for industrial and electricity generation can be substituted by natural gas depending on its availability and price.

4.12 The mazut requirement for electricity generation is projected on the assumption of a 70/30 split between gas and mazut and an average fuel consumption of 318 gmsOE/kWh generated in 1993 declining to 300 gms OE/kWh by 2000 with improved generating efficiency. Because of the flexibility for fuel substitution in the large industrial boilers, central heating systems, and power plants the assumption concerning the actual composition of fuel use is not critical for the purposes of these demand projections.

4.13 Based on the foregoing assumptions, the demand projections for petroleum products are shown in Figure 4.1. and in Table 4.3.

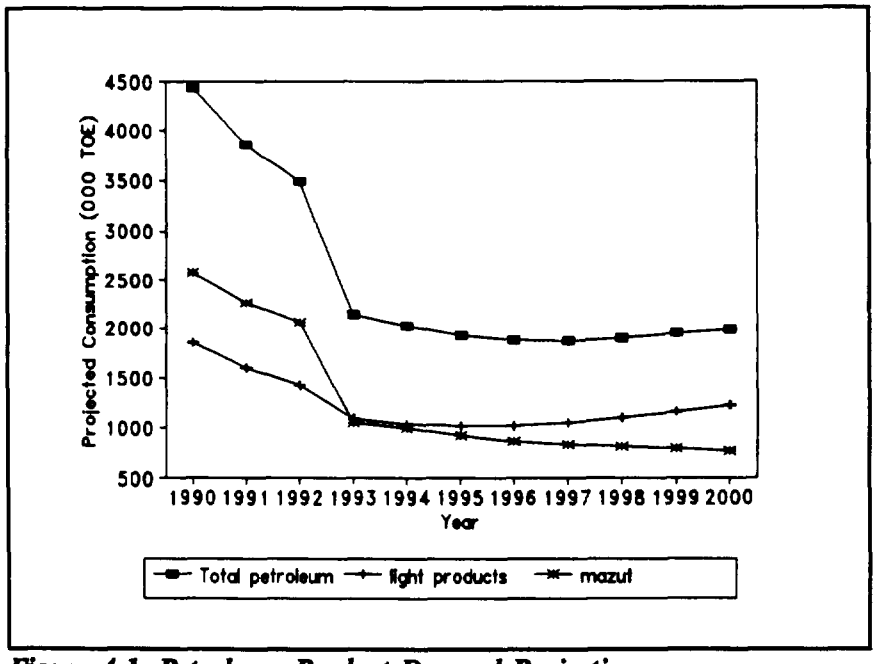

Figure 4.1 Petroleum Product Demand Projections

Table 4.3. Petroleum Product Demand Projections

Thous TOE	1990 Act	1991 Act	1992 Est	1993	1994	1995	1996	1997	1998	1999	2000
Mazut	2575	2263	2065	1046	1117	1075	1058	1053	1049	1050	1042
of which, Power gen	1987	1700	1581	575	729	710	711	712	713	715	707
Industry	588	563	484	471	389	364	350	341	337	334	332
Light Products	1858	1596	1426	1092	1030	1010	1015	1045	1096	1154	1219
Total	4433	3859	3491	2139	2148	2084	2075	2098	2146	2204	2258

Source: Mission estimates.

D. Petroleum Products Supply

Product Acquisition

4.14 Armenia has no petroleum refinery and at present obtains all its products from Russian refineries, primarily in Grozni. Diversification of supply in the longer term could be achieved by procuring products through the Black Sea port of Batumi (Georgia) and/or from the refinery at Batumi. At present all products are purchased in rubles; however, in the future it is likely that procurement from the FSU will be in foreign exchange which is extremely scarce. ARMPETROL has virtually no experience with petroleum product procurement outside of Russia, and if in the longer run, ARMPETROL seeks to diversify its supply then technical assistance regarding international oil contract negotiations, lifting of cargoes, and oil trading will be needed.

4.15 The Document Control Division of ARMPETROL handles the flow of information in the supply and distribution network and maintains the inventory control system. The system is largely not computerized and there is a large daily flow of data concerning supplies, deliveries, inventory levels, and financial transactions. The ARMPETROL central administration directly controls inventories control, with each terminal reporting back to the central administration daily and receiving instructions for the next day's activities. Communications are difficult because of the poor telephone system; however, a new teletype system is being installed. Technical assistance to computerize reports and improve the communication network would be a cost effective means of increasing the efficiency of ARMPETROL operations.

4.16 The resources, planning, and oil supply transport is the heart of the supply and distribution operation. It plans one month, three months and one year ahead, comparing planned to actual

receipts and deliveries and adjusting the continuous forward plans commensurately. The Document Control Division is responsible for scheduling transportation by rail into and by trucks out of the terminals. It is also responsible for working with the foreign suppliers, who are the agents for the Russian refineries which sell oil products to Armenia. These agents are the regional divisions of the Russian Oil Products Selling Company, RNP (Rusnefteprodukt) which is now responsible for all petroleum product sales within and outside the Russian republic.

Cost of Products

4.17 After 1990, ARMPETROL began buying oil products directly from the individual FSU republics. General contract terms are still negotiated between the governments of the republics. The contracts specify annual quantities to be delivered, current prices, and payment terms. Quantities can be renegotiated by the parties during the course of the year as conditions change. Renegotiations may be done at the operating levels, subject to government approvals.

4.18 Prices are set according to the seller's price list at the time of contract agreement. The seller may change the price at any time without notice to the buyer. A contract buyer, however, has the right to buy up to 20% more than his contract quantity at uncontrolled prices, which will be higher than the original contract prices. These uncontrolled prices appear to resemble spot prices, and are generally set by market forces within the FSU. Despite their rapid rise over the past year, they are still generally below world market prices for most petroleum products.

4.19 Under President Yeltsin's September 1992 decree, a cap on oil product prices in the Russina Federation has been set at 1.2 times each refinery's average production cost. The refineries differ widely in production cost with the result, for example, producer prices for gasoline at the Moscow refinery are estimated at 12,800 Rbs/t while at Saratov they are estimated at 26,800 Rbs/t, but the cost at Grozni is not presently available. Despite the rapid increase in the ex-refinery prices during 1992, they still remain at about 30-40% of world market parity. The Government of Russia, however, intends that product prices should reflect world market crude prices by mid 1994.

4.20 Payment terms are on delivery, with the buyer's bank in Armenia paying the seller's bank in Russia upon confirmation of shipment. The refineries do not handle these arrangements themselves, but rely on the RNP oil sales organization, which is directed from Moscow, and has regional sales offices where the refineries are located. The regional office of RNP will handle all aspects of the shipping (usually by rail) to the buyers specified destinations. ARMPETROL is in constant communication with the RNP office located near the Grozni refinery, based on a month to month plan of shipments and receipts which is continuously in flux due to changing rail schedules, refinery operating problems, payment issues, and delays caused by political or other disturbances.

Transportation

4.21 All oil is transported to Armenia by rail directly to ARMPETROL storage facilities, major industrial users, and thermal power plants. Within the country, there are 825 kilometers of main track, plus short branch lines south from Gumri (formerly Leninakan) and around the northeastern shore of Lake Sevan (Map IBRD 23943R). The international links include two in the north with Georgia and Azerbaijan, a third in the south with Azerbaijan (from Tabriz in Iran through Nachichivan), and a fourth out-of-gauge connection with Turkish railways at Ahurian in the northeast close to Gumri. Because of the current conflict with Azerbaijan and the historic enmity with Turkey, the only functioning international rail link in mid 1992 was from Georgia. This link was only partially functioning because bridges and track had been destroyed through civil war in Georgia. Continued civil unrest and theft of cargo severely restrict the delivery of oil products to Armenia.

4.22 Most of the petroleum products imported into Armenia come from the Russian refinery at Grozni, located about 100 kilometers west of the Caspian Sea and around 250 kilometers north of the Russian border with Azerbaijan and Georgia through the Caucasian mountains. Because of the closure of rail links from Azerbaijan, a total of more than 1800 kilometers of rail lines must be traversed for oil shipments between Grozni and Yerevan. In contrast, the link between the Baku refinery and Yerevan is less than 600 kilometers, and between Batumi and Yerevan about 700 kilometers.

4.23 The rail line from Russia to Georgia hugs the Black Sea coastline in a southeasterly direction and then turns inland in an easterly direction towards Tblisi. Another line from Batumi goes north and connects into the principal Georgian line, offering Armenia access to petroleum products from either the Batumi refinery or from other refineries which can ship products to the port of Batumi. At Tblisi, one spur of the east-west rail line turns south into Armenia.

Storage and Stocks

4.24 Total oil storage capacity is around 1.2 million tons, with the ARMPETROL having about 200,000 tons, industry having about 565,000 tons, and the electric power plants, under the state electric power organization, ARMENERGO, having the balance of about 350,000 tons at the generating stations which are supplied by rail. ARMPETROL operates 17 large bulk product terminals for gasoline and diesel storage with a total capacity of 100,000 and 52,000 tons respectively. Storage for other products (lubes, kerosine and aviation fuel) amounts to a further 45,000 tons. These facilities receive shipments by rail and deliver by truck racks. A new facility is planned near Yerevan and 18 smaller facilities serve the agricultural sector, with truck deliveries and receipts.

4.25 Diesel and gasoline storage facilities are adequate for about 35 days consumption at 1990 demand levels, but in 1991, however, average inventories held by ARMPETROL declined to about 14 days for diesel and 7 days for gasoline. In the first quarter of 1992, these quantities shrank further to about one-third of the 1990 inventories; however, an unknown but limited stock was also held by the private sector for direct sales to individual consumers (para. 4.27).

4.26 Storage capacity for mazut at thermal power stations is sufficient for about 30 days requirements at 1990 consumption levels, but by late 1992 were fully exhausted. In view of the supply disruptions, the need for a strategic petroleum reserve, should be examined under the proposed technical assistance program. Financing would likely be required to rebuild the stocks when that becomes possible.

Marketing and Distribution

4.27 Petroleum products are distributed by truck (mostly owned and maintained by the Ministry of Transport) from the 18 major and other smaller storage facilities through 210 service stations and directly to larger customers. In addition, there is a special enterprise of 24 service stations in Yerevan which supplies state owned enterprises and government requirements. The supply of gasoline and diesel for private consumption through ARMPETROL has ceased because of fuel shortages. Private sector operators are able, however, to obtain tank truck cargos which they sell through leased ARMPETROL service stations or directly from the truck.

Facilities Requirements

4.28 Relatively few investments in new facilities are needed in the petroleum sector compared with the power and gas sectors. With the diminished fuel supply of the last two years, ARMPETROL staff have been able to carry out routine maintenance to the main storage and delivery facilities at Oktembrian near Yerevan which are generally in good repair.[22] Nonetheless, there is a need for replacement equipment such as pumps, barrel handling lifts, several fire engines, and tank trucks.

4.29 Construction of a petroleum refinery is under consideration; however, it would confer no significant security of supply and, given its high cost, would not be economically justified given the availability of existing refining capacity in the region and with the possibility of competetion with Black Sea refineries to keep prices in line once world prices are reached and petroleum traded in hard currencies. The cost of the refinery is roughly estimated at US$500-600 million for a capacity of 6 million tons of crude per year. An additional US$250 million would be required for a crude oil pipeline. A products pipeline from Batumi would have a similar cost and might be justified as an alternative to rail transport; however, a feasibility study of this option would be required.

E. Pricing and Taxation

4.30 Oil prices were stable between 1985 and 1990 under the former Soviet regime. In 1991, prices began to rise, with gasoline, diesel and mazut prices averaging 2.5-2.8 times their 1990 levels in nominal terms. In the first four months of 1992, these prices reached 60-90 times their 1990 levels, in part due to inflation, with continuing rises to world market levels expected by mid 1994. In general, the Finance Ministry sets fuel prices based on costs (para. 4.17). In the present crisis, however, events seem to have overtaken any attempt to rationalize pricing policies. By May 1992, the ex-refinery price of

[22] Other ARMOIL storage facilities were not visited by the Mission and their condition is not known.

gasoline had risen to more than 9300 rubles per ton, plus transportation costs at 360 rubles per ton up from 5Rbs/t in 1991.[23] ARMPETROL was then selling it for 12,000 to 13,000 rubles per ton to priority customers designated by the government ministries. These customers include critical transport, municipal services, agriculture, and priority industries. Since all of these customers are government entities, the pricing to each of them appears to be based on ad hoc decisions. The average ARMPETROL markup on these sales is about 30%.

4.31 ARMPETROL'S Income Statement (Table 4.4) shows an *Enterprise Tax*, which during the Soviet regime (1985-90) averaged some 90% of gross profit. This tax was levied by Moscow, and a part of it was returned to the budget of the then Soviet republic of Armenia. The Armenian government then decided how to allocate those funds received from Moscow, either reinvesting them back into the ARMPETROL or for other purposes. Since Moscow controlled the cost of petroleum products sold to Armenia, the majority of the profits was captured through the Enterprise Tax. The cost of petroleum products to ARMPETROL was low and over the 1985-90 period, the cost of goods sold averaged only 45% of revenue. In 1991, with Armenia as an independent country, and Russian oil prices rising rapidly, cost of goods sold increased to 85% of revenue. At the same time, the Enterprise Tax, now wholly levied by Yerevan, was reduced to 28% of gross margin (termed "profit").

4.32 In May 1992, ARMPETROL's gross profit of around 3000 Rbs per ton was taxed at 28%, or about 800 rubles per ton, leaving a profit of 2200 rubles per ton before depreciation. ARMPETROL is allowed to deduct 10% of its acquisition costs for capital recovery, or around 900 Rbs per ton, leaving 1300 rubles per ton as net profit. ARMPETROL then pays another 25% income tax, or Rbs 300 per ton, leaving the company with 1000 Rbs per ton in after-tax profit, or 1900 rubles per ton in net cash flow (profit plus depreciation). This level of profitability may be adequate in the future; however, it must be assessed again on the basis of revalued assets (para. 4.40).

4.33 Total taxes (enterprise plus income tax) paid by ARMPETROL dropped from Rbs 166 million in 1990 to Rbs 24 million in 1991 as a result of changes in the tax structure, cost of products, and pricing decisions of the government of Armenia.

4.34 By May 1992, retail prices for gasoline sold by the private sector had risen to 25-30 Rbs per liter (30,000-36,000 rubles per ton) from Rbs 0.35-0.40/liter two years ago. Because of scarcity, private sector vendors receive a gross margin of Rbs 12-27/liter before distribution costs. Taxes of 28% on the gross margin are supposed to be paid to the government but in reality there is little way to monitor prices or volumes.

4.35 Mazut for industry and the power sector and aviation fuel are also imported by ARMPETROL. Markups on c.i.f. cost varies from 5-10% depending on the customer with industry paying the highest rates.

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[23] **Mid 1992 exchange rate 100 Rbs/US$.**

F. Financial Situation

4.36 Income statements and balance sheets for ARMPETROL PRODUCTS for the period 1985-91 are shown in Tables 4.4 and Annex 4.2 respectively. The Income Statement shows that the company over the 1985-90 period had an average annual revenue growth rate of 1.7% and a net profit growth rate of 33%. In 1991, revenues increased 44% to Rbs 480.1 million while net profits increased in nominal terms by 312% to Rbs 29.8 million.

4.37 Operating expenses throughout the whole period 1985-91 averaged 3.0%-3.5% of revenue, reflecting a low cost oil distribution operation by Western standards. Net profit relative to gross profit, which had averaged 3.5% over the 1985-90 period, increased to 56% in 1991. This left the company considerably more profit for reinvestment than had been the case during the Soviet regime. Return on Investment as measured by Net Profit relative to Net Worth averaged almost 23% over the 1985-90 period; in 1991, it reached 101%.

Table 4.4 ARMPETROL Products Income Statement 1985-91

Rubles thousands	1985	1986	1987	1988	1989	1990	1991
Revenue	306,876	336,550	333,829	318,705	343,902	333,532	480,618
Cost of goods	162,274	179,813	171,419	155,992	164,922	148,354	410,368
Operating expenses	6,443	6,617	7,494	7,592	9,437	10,039	16,828
Gross profit	138,159	150,120	154,916	155,121	169,543	175,139	53,422
Enterprise tax	125,592	130,878	136,072	140,751	154,888	155,504	14,751
Income tax	10,249	15,012	12,239	11,480	10,448	10,074	8,844
NET PROFIT	2,318	4,230	6,605	2,890	4,207	9,561	29,827
Memo Item							
Total taxes	135,841	145,890	148,311	152,231	165,336	165,578	23,595
Percentage of Cost	84.3	81.1	86.5	97.6	100.3	116.7	5.7

4.38 The Balance Sheet (Annex 4.2) shows that over the 1985-90 period total assets grew by around 20% per annum and total liabilities by around 28%, so that net worth grew by around 8% per annum. In 1991, total assets grew by 47% to Rbs 130.8 million and total liabilities by 77% to Rbs 101.3 million, and net worth by less than 5% to Rbs 29.5 million. This growth of net worth over the whole period is relatively high by Western standards for an oil distribution type of business.

4.39 The ratio of current assets to current liabilities shows a highly liquid, high turnover operation, with conservative financial management. From 1985-90, this ratio averaged around 2.3; in 1991 it was still at almost 1.4, despite the rapid escalation of inflation.

4.40 With the high inflation being experienced in 1992, and likely to continue for some time, the depreciation figures are undoubtedly grossly understated. For this reason, revaluation of assets and replacement cost accounting for facilities and equipment should be adopted. This accounting practice would have the effect of reducing long term assets and consequently the net worth. Nevertheless, the company appears to be highly profitable by Western accounting standards.

4.41 If ARMPETROL is to be privatized, its book value at the end of 1991 could reasonably be put at the approximate 30 million rubles net worth figure. On the other hand, in a market value context, a multiple of 3-5 times 1991 earnings would yield a valuation of 90-150 million rubles, in constant 1991 rubles. This figure would have to be inflated when valued at a later date.

V. NATURAL GAS

A. Introduction

5.1 With no gas production of its own, Armenia is totally dependent on imports from Turkmenistan through pipelines entering via Azerbaijan and Georgia. Throughout the 1980's, gas consumption continued to rise, and in 1989 reached its peak of 5.87 Bcm/yr when it provided 50% of the country's primary energy consumption, with about one third for power generation, and the remainder for the industrial, commercial and the residential sectors. Since 1989, the conflict with Azerbaijan has resulted in many supply interruptions and severe supply constraints, and civil unrest in Georgia and Ossetia resulted in a cessation of supply in mid 1992. Natural gas can be made available to most parts of Armenia through an extensive transmission and distribution system, and its widespread accessibility to towns and villages has resulted in high dependence by the population, particularly for residential heating. Piped natural gas is, however, augmented by road transport distribution systems for bottled LPG and coal.

5.2 Armenia is faced with a number of issues and investment decisions which will have a major impact on the development of the subsector. These include the need to:

(a) resume gas deliveries via Georgia and Azerbaijan;

(b) diversify gas imports to improve security of supplies;

(c) improve natural gas storage capability within the country as an insurance against external supply interruptions;

(d) restructure consumer prices to provide sufficient revenues to pay for gas imports, operations and maintenance costs, and to contribute to the financing of network rehabilitation and expansion;

(e) repair and replace the transmission and distribution infrastructure which suffered considerable damage in the 1988 earthquake; and

(f) reform and restructure the gas subsector institutions to promote an efficient and financially viable gas business.

A well defined strategy for natural gas which assesses economic priorities in relation strategic requirements and budget constraints within the context of an overall energy strategy remains to be developed, however. These issues would be addressed in the gas facilities planning studies which are part of the proposed technical assistance program (para. 5.55 and Annex 6).

B. Gas Subsector Organization

5.3 Gas subsector operations are carried out through the Armenian Gas Production Corporation (ARMGAZPROM) and the Armenia Gas Corporation (ARMGAZ), both of which are fully owned by the state as subsidiaries of the ARMGASFUEL State Company. These report to the Deputy Minister for Production within the Ministry of Energy and Fuel (organization chart, Annex 2.1).

ARMGAZPROM

5.4 ARMGAZPROM has primary responsibility for the:

- purchase, importation, storage, and high pressure transmission of natural gas;
- LPG bottling operations;
- management of the LNG storage project (uncompleted) at Abovian;
- production of machinery for gas transmission and handling; and
- construction of pipelines, above ground installations and underground storage facilities.

5.5 The operational departments report to the chief engineer, which include the three regional transmission departments at Abovian, Kirovakan and Goris (Annex 5.1). Other departments with similar reporting responsibilities include the Abovian (Yerevan) storage facility, the natural gas despatching center at Yerevan, road transportation and LPG operations. The latter includes facilities for the import of LPG by rail tanker, LPG storage in above and below ground tanks, and bottling operations which are carried out at four separate facilities. The transport department operates and maintains over 1000 vehicles.

5.6 There are three deputy general managers. The first has responsibility for a gas machinery production plant, accounts and finance. The second has responsibility for the personnel department and social services. The third deputy general manager has responsibility for construction activities and equipment supply. This division includes the Trans-Caucasian Construction Trust, whose principal responsibilities are the construction of pipelines, above ground installations and underground storage facilities both abroad and in Armenia. The trust has considerable experience and capability in construction of pipelines and related facilities in difficult and mountainous terrain. ARMGAZPROM retains about 4000 staff for all its activities.

ARMGAZ

5.7 The main responsibilities of ARMGAZ are the distribution of gas to the end user and the maintenance, repair and development of the low pressure distribution networks. The organizational structure is shown in Annex 5.2. The head office in Yerevan employs about 65 personnel to coordinate finances and the budget, engineering and economic planning, construction and personnel. Operations are carried out through its eleven regional distribution offices which service over forty districts throughout the country. Other departments include construction, training, safety, meter checking and transportation.

The transportation department has responsibility for the operation and maintenance of about 1200 vehicles. In addition to distribution of piped gas, ARMGAZ is responsible for the distribution of bottled LPG to end users, which is purchased from ARMGAZPROM at the bottling plants, and transported to 23 local distribution centers throughout the country.

5.8 The entity concerned with the importation and distribution of coal, the Office of Solid Fuel, was incorporated into ARMGAZ in August 1991. This is responsible for the distribution of about 0.5 million tons of coal annually. The coal is purchased at Rostov in Russia and delivered by rail to Armenia, and stored at 21 storage depots which supply 48 districts. The distribution operations employs about 300 workers, of which 18 are located in Head Office. The total staff of ARMGAZ is about 6,500 of which 1000 are involved in construction and repair.

5.9 An Institute for the design of natural gas projects is located in Yerevan and provides a design and engineering service to ARMGAZ and ARMGAZPROM for projects located both at home and abroad. The Institute was formerly a branch of a major Soviet gas design institute with headquarters in Kiev, but in 1991 became a separate entity. Currently, the Institute employs retains 300 employees which include experienced designers, geologists and technologists.

Staffing

5.10 The subsector employs some 10,500 workers serving about 600,000 consumers, which include the natural gas, LPG, coal distribution and construction operations. The overall consumer to employee ratio is about 60:1 which is high compared with 2-300:1 for the well developed gas industries of Western Europe and suggests that the subsector suffers from considerable overstaffing. The ARMGAZ staff of about 4000 covers transmission and storage operations for about 1600 km of high pressure network, although an unknown number of these staff are employed in the construction and social services departments (including kindergarten and sanatorium). Modern transmission utilities may employ the same numbers of employees to operate systems comprising more than 20,000 km transmission lines, associated storage and compression. The distribution operations appear to be suffering from similar levels of over-staffing.

Financial Performance

5.11 Lack of gas has resulted in rapidly declining revenues for the subsector, which has seriously undermined its financial viability. As of early 1992, projected total costs of ARMGAZPROM operations for 1992 were 10.2 billion rubles with a target profit level of 7.6% on total costs comprised of both gas and non-gas costs. The latter includes a cost for depreciation of assets and a 28% government tax on non-gas costs. Under normal conditions, a 25% tax is levied on net profits, with the remainder allocated principally for investment with a small contribution to a refugee fund, research and development and other miscellaneous uses. With the constraints on gas supply, ARMGAZPROM is clearly not in a position to meet this profit level. ARMGAZ similarly targets for an 8% profit level. However, lack of revenues has resulted in insufficient funds for the planned replacement of 110km of distribution mains

this year. ARMGAZ is also suffering from unpaid bills from both residential and industrial consumers totalling Rbs 35 million and Rbs 604 million respectively. At the price currently facing many Western European countries equivalent to US$100 per 000 m^3 as of November 1992, these arrears, if collected, could purchase about 16 million cu m of gas or less than 1% of annual requirements.[24]

Operations

5.12 Lack of spare parts for equipment and material are severely hampering the operations of the subsector. ARMGAZPROM requires large quantities of spare parts for its trucks, bulldozers, pipelayers and other equipment. Since much of the equipment is of West European or Japanese origin, it may only be purchased with hard currency. Other material urgently required ranges from welding rods to gas analyzers, flowmeters and personal computers.

5.13 There appears to be considerable scope for improvements in efficiency and competitiveness through subsector restructuring, which should proceed with the eventual aim of divesting the core business of its non-operating assets, establishing clear cost and profit centers, consolidation of duplicated functions, reducing manning levels consistent with the scale of operations and adopting measures for energy conservation and control. The social services departments may eventually be good candidates for operation by the private sector or municipal administrations. In addition, the Trans Caucasian Construction Trust may be a good prospect for eventual privatization. Here, the great experience and expertise within the Trust, especially in implementing construction and storage projects in extraordinarily difficult terrain, is an important asset. Operating as a separate cost-profit center, the Trust could compete for contracts both at home and abroad. However, at present the entity may not be attractive to the private sector due to lack of spare parts for its equipment and lack of engineering design capability. There is a need to carry out a comprehensive restructuring study of the subsector to assess the institutional requirements and design in support of sector reforms and efficiency improvements.

C. Natural Gas Consumption and Supply

Historical Natural Gas Consumption

5.14 The pattern of natural gas and LPG consumption in recent years is shown in Table 5.1 Until 1989, there were no supply constraints when total consumption of natural gas reached its peak of 5.87 Bcm/yr. Natural gas is of particular importance for power; it is used to generate power and heat in the Hrazdan, Yerevan, and Kirovokan power stations with combine capacity of 1756 MW, or 50% of total installed generating capacity. The plants are dual fired and in 1989 consumed 2.11 Bcm of natural gas (35% total consumption) and 2,072 tons of mazut. After closure of the nuclear plant in 1989, dependence on natural gas and mazut for power generation increased, but consumption declined to 1 Bcm and 1,773 tons respectively due to the energy blockade. It is reckoned that the thermal power plants together have a capacity to consume about 4 Bcm/yr when operating solely on natural gas.

[24] Based on a November 1992 exchange rate of Rbs 400/US$.

5.15 Natural gas consumption by the household and official and municipal consumers categories together accounted for a further 2.1 Bcm/yr in 1989 declining to 1.7 Bcm/yr in 1991. Household consumers are given high priority for the available supplies of natural gas, particularly in the winter heating period since their flexibility to switch the alternative fuels is limited. The shortages of natural gas have had a big impact on the industrial sector, with consumption falling from 1.7 Bcm/yr in 1988 to 1.0 Bcm/yr in 1991. Of this, about 0.13 Bcm has been lost from fertilizer industry where natural gas use as feedstock has ceased.

5.16 LPG is used almost exclusively by the residential sector for cooking, mainly in areas where natural gas is unavailable. However, small quantities are also used by the commercial and industrial sectors. Consumption of LPG declined steadily from 32,000/yr in 1986 to 21,000/yr in 1991 probably due to some substitution by piped natural gas and more recently higher prices and lack of supply.

Table 5.1: Consumption of Natural Gas and LPG

	1986	1987	1988	1989	1990	1991
NATURAL GAS (Bcm/yr)						
- Industry	1.36	1.49	1.60	1.43	1.14	0.94
- Power	1.27	1.12	1.60	2.11	0.99	1.04
- Oil & Chemicals	0.11	0.12	0.12	0.11	0.03	0.04
- Official/commcl	0.82	0.88	0.86	0.78	0.78	0.49
- Household	1.09	1.20	1.19	1.32	1.36	1.21
- Distribution Losses	0.04	0.04	0.09	0.11	0.09	0.06
TOTAL Natural Gas (Bcm/yr)	4.68	4.81	5.46	5.87	4.38	3.78
LPG ('000t/yr)						
-Industrial[a]	1.91	1.91	3.44	1.92	0.60	0.70
-Commercial/Official	-	-	0.38	0.63	1.94	1.21
-Household	30.57	29.30	27.39	24.84	23.57	19.11
TOTAL LPG ('000t/yr)	32.48	31.21	31.21	27.39	26.11	21.06

a Industrial consumption calculated by difference

Source: ARMGAZ

5.17 *Service coverage.* Within Armenia, there are about 710,000 individual household units dispersed over 28 cities and 950 rural villages, and consumers receiving piped natural gas and LPG by consuming sector are shown in Table 5.2. About 63% of total household units are connected to the gas supply network and a further 24% receive LPG. The number of households consuming LPG has

declined by 20% since 1986; however, many of these households have been connected to the piped gas network. As a result, there has been a 10% overall increase in consumers receiving piped natural gas over all categories since 1986.

Table 5.2: Number of Natural Gas and LPG Consumers (1986-1991)

		1986	1987	1988	1989	1990	1991
Piped Gas							
	- Industrial[a]	629	665	685	665	748	685
	- Population[b]	1,601	1,702	1,682	1,702	1,813	1,783
	- Household	413,295	431,671	394,900	427,651	445,109	451,279
LPG							
	- Household	213,873	206,756	194,011	183,688	172,017	170,453

a Includes power stations
b Includes commercial, official

Source: ARMGAZ

Gas Demand Projections

5.18 Consumption of natural gas over the remainder of this decade is dependent on a number of factors including (a) the progress in re-establishing natural gas imports, (b) the success of industrial restructuring, and (c) the influence of gas price increases and energy conservation measures in constraining consumer demand and encouraging end use efficiency. There appears to be substantial scope for reducing consumption through improved practices of energy conservation and demand management.

5.19 Within the household sector, current unconstrained consumption of natural gas per capita is estimated at about 1,570 m^3/yr when used for all cooking and heating needs (para. 5.42). This rate is about 3-4 times higher than consumption levels in Western Europe where the structure of gas pricing, consumer accountability through individual metering, and the standards of household insulation are effective measures in controlling demand. Broad estimates suggest that per capita gas consumption in Armenia could be reduced by at least 25% and possibly substantially more through a combination of rational pricing and energy conservation policies.

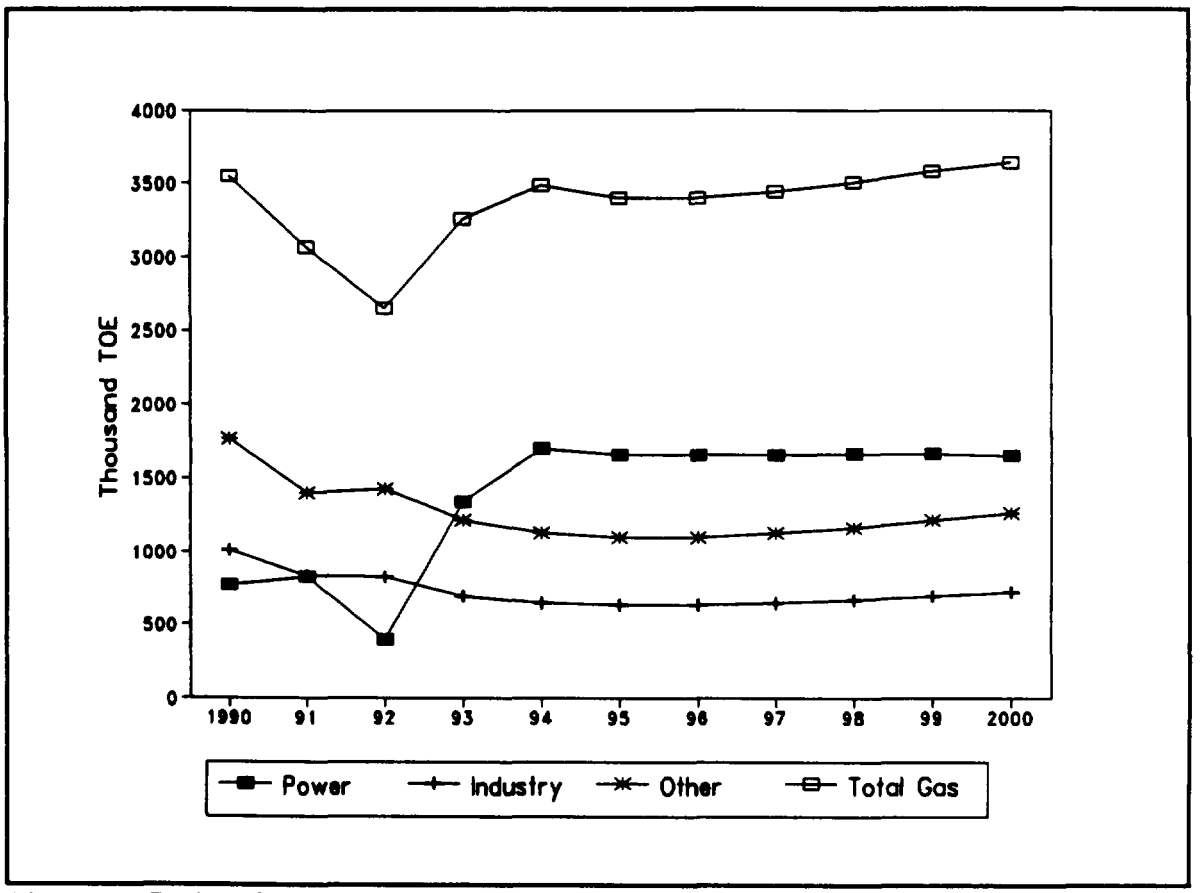

Figure 5.1 Projected Natural Gas Demand

5.20 As shown in Figure 5.1 and Table 5.3 , gas demand under the base case economic and electricity demand projections is projected to decline until 1995 to 3.4 million TOE (4.1 BCM) or about 96% of the 1990 level of 3.6 million TOE (4.3 BCM). By 2000 demand would return to slightly more than the 1990 demand. It has been assumed that in electric power generation use of gas and mazut would be divided 70/30. In the industrial sector, demand for gas is assumed to follow the same path as the demand for electricity. Household and commercial/ official use are combined as "other" in Table 5.3 and would account for about half of the total demand for gas through out the period 1990-2000.

Table 5.3. Projected Base Case Demand for Natural Gas

Thous TOE	1990 Actual	1991 Actual	1992 Est	1993	1994	1995	1996	1997	1998	1999	2000
Power[1]	773	829	395	1343	1700	1657	1659	1662	1665	1668	1650
Industry	1011	841	833	698	648	634	633	647	670	697	724
Other	1767	1402	1427	1220	1133	1108	1106	1131	1172	1217	1266
Total gas	3551	3072	2655	3261	3482	3399	3398	3439	3506	3582	3641

1. Assumes gas is used for 70% of power generation from mid 1993 onward following the lifting of the transportation blockade.

Natural Gas Supply and Prospects for Diversification

5.21 *Background.* Armenia's natural gas imports and re-exports to Nakhichevan since 1986 are shown in Table 5.4. Armenia has a 10-year purchase agreement for 5.2 Bcm/yr natural gas from Turkmenistan, and separate transit arrangements with Kazakhstan, Azerbaijan, Georgia and Dagestan. Under normal circumstances, 70% of supplies are delivered through Azerbaijan, and 30% through North Ossetia and Georgia. However, cessation of supplies from Azerbaijan in March 1992 resulted in complete reliance on deliveries from Georgia. Volumes delivered to Armenia have been irregular and given low priority to Georgia's own needs. As a result, Armenia has been receiving 7 Mcm/d in summer and 3-4Mcm/d in winter. This situation has resulted in chronic shortages of gas in Armenia where requirements are at least 22 Mcm/d in winter and about 10Mcm/d in summer.

Table 5.4: Imports and Re-exports of Natural Gas (BCM/yr)

	1986	1987	1988	1989	1990	1991
Imports	4.93	5.12	5.75	6.33	4.71	4.15
Re-Exports	0.14	0.20	0.27	0.31	0.38	0.35
Net Supply	4.79	4.92	5.48	6.04	4.33	3.80

Source: ARMGAZ

5.22 *Supply from Georgia.* The project to increase the deliverability of supplies of Turkemeni gas via Georgia involves the construction of a 22 km transmission line in parallel to the existing line and the completion of a compressor station on Georgian territory. This is a subproject of a larger scheme which will also provide a number of branch connections in the Tsblisi area, and there is agreement with

Georgia that about Rbs 220 million of the total costs would fall on Armenia. Although project financing was earlier controlled from Moscow, negotiations with the center to secure the finance required to complete the works have proved fruitless and the project is stalled. There are other serious obstacles to overcome, including the stripping of Armenia's construction equipment located in Georgia, harassment by bandits of Armenian construction teams working in Georgia and the supply of these teams with food and fuel. Nevertheless, completion of the works would allow delivery capacity of 10-11 Mcm/day, which is about half of Armenia's needs in the winter season.

5.23 *Supply from Iran.* In view of the difficulties with existing suppliers, there is a strong desire in Armenia to achieve diversification of gas supplies through a pipeline link with Iran, and to this end inter-governmental negotiations are underway. The government's strategy is to achieve diversification through importing gas from Georgia and Iran, in roughly equal quantities. The need for this pipeline is greatest during the blockade but would be considerably reduced when normal trade is restored as in the base case. Under normal trade conditions, existing pipelines from Georgia and Azerbaijan could handle the projected gas demand and the Iran pipeline would become redundant. The priority of the pipeline is very much linked with the expectations for the lifting of the blockade, the time required for construction and the volume and economic value of the gas it could deliver.

5.24 Iran has constructed a 30 inch, 75 bar pipeline which links the IGAT system in northern Iran to Tabriz. An imports pipeline could tie into this at Tabriz, running an estimated 150 km in Iran to the Armenian border town of Mehgri, and a further 110 km north in Armenia to Goris where it would interconnect with the Armenian transmission system. A pressure reducing and metering station would be required at the border since the Armenian system is designed for 55 bar. It is envisaged that the pipeline would initially supply about 3 Mcm/d (1 Bcm/yr) to Armenia, which could be increased to 10 Mcm/d (3 Bcm/yr) with the addition of four system compressor stations. There are a number of variations including pipeline routing, location of the tie-in point, and the number of compressor stations required.

5.25 Preliminary costings suggest that the first phase pipeline from Tabriz to Goris could cost about US$73 million.[25] The second phase including four compressor stations and an additional 240 km pipeline from Goris to Yerevan could require a further US$210 million. Construction costs are dependent on the terrain and source of the materials and there could be substantial variations on the preliminary costings, probably on the downside, but it is likely that Armenia would be well placed to undertake the complete construction works. However, the time required for feasibility studies, route surveys, procurement and construction would be about 30 months for the first phase, suggesting first gas to Armenia in early 1995 if financing were obtained very quickly.

[25] This cost estimate is low by Western standards. Unit costs, however, are comparable to estimates prepared by a Hungarian national firm for a similar pipeline in Hungary. The Hungarian estimate was about one-half that of a Western European firm.

5.26 There are a number of issues which need to be addressed in the early stages of project preparation. The magnitude of the project investments will require a long-term (10 year) supply contract which is structured to provide the basis for a stable energy trading relationship, and is consistent with Armenia's long-term objectives to achieve security of supplies without excessive cost. The following points are particularly important in this respect:

(a) *The gas price and its indexation to alternative fuels.* These should take account of the mix and value of the alternative fuels, which will be substituted by the imported natural gas in the Armenian market. It is recommended that the contract incorporate appropriate price review clauses which can accommodate unforeseeable changes which may occur in the Armenian energy market.

(b) *The seasonal flexibility of gas deliveries.* Since Armenia has high requirements for gas in winter, it would be advantageous to negotiate a low load factor or supply in the contract. This would have the beneficial impact of reducing requirements for seasonal storage, but may incur a higher purchase price. A realistic load factor of supply may be 80-90%, with 80% representing a peak flow rate of 3.4 Mcm/d and 10.3 Mcm/d for annual contract quantities of 1 Bcm/yr and 3 Bcm/yr respectively.

(c) *Take or pay commitments.* Gas supply contracts are normally structured so that the supplier takes the price risk and the buyer takes the volume risk through take or pay commitments. This is particularly important in the case of Armenia due to the difficulties in forecasting the way in which the market for natural gas will develop. The supply contract should be structured to avoid excessive risk that Armenia will commit to taking volumes which cannot be used, but which must be paid for.

5.27 *Multinational Schemes.* In the medium-term, Armenia appears well positioned to take advantage of large multinational gas supply schemes for transport of Iranian supplies to Eastern and Western Europe. Such schemes include supplies of Iranian gas to the Ukraine and perhaps to Western Europe. Ukraine and Iran are already actively discussing the possibility of a 1,500 km, 25 Bcm/yr capacity, pipeline link between the two countries. The driving force behind the scheme is Ukraine's great desire to achieve both physical and commercial diversification from the FSU, from which it imports 80 Bcm/yr as sole supplier, coupled with Iran's desire to further utilize its huge gas reserves. The pipeline route would pass through either Armenia or Azerbaijan, Georgia, and Russia. Armenia could benefit from participation in such a scheme through a pipeline link with Iran, particularly in terms of achieving good energy trading relationships.

D. Natural Gas Infrastructure

Transmission and Distribution

5.28 *Transmission.* A schematic of Armenia's high pressure transmission system is shown in Map IBRD 24489. The first high pressure transmission lines in Armenia were built in 1960 and today ARMGAZPROM operates about 1600 km of pipeline. Natural gas is imported through three trunkline systems entering along the eastern border with Azerbaijan. These transmission lines have a transportation capacity of 45 Mcm/d (compared with Armenia's current requirements of about 22 Mcm/d) when operated at maximum operating pressure of 55 bar. The most southern supply line is used to re-export gas to Nakhichevan. In 1991, an additional 1000 mm supply line entering the northern border with Georgia was completed.

5.29 The internal transmission system has developed a highly looped configuration giving good directional security of supplies and good access throughout most of the country. It has an unusual feature in that there is complete reliance on the delivery pressure at the borders and no supplemental compression is used. Close to half the pipelines have been in operation for more than 20 years and much of the system is believed to be in need of replacement, particularly where located in aggressive and salty soils. Although the full extent of the problem is not yet determined, many of the pipelines are operated well below their design pressure in order to minimize the risk of pipeline failure. Due to lack of financial resources, welding rods and other material and spare parts, ARMGAZPROM is not able to proceed with an adequate pipeline replacement program and other major projects, including completion of the 110 km Yerevan ring main system.

5.30 *Distribution.* ARMGAZ is responsible for the distribution of piped natural gas to end-use consumers in Armenia. This is distributed through 11,000 km of low pressure steel mains, to about a half million consumers. The 1988 earthquake caused serious damage to the distribution networks resulting in the loss of about 40,000 residential consumers from the system and destruction or damage to about 1300 km distribution mains. Current regulations in Armenia do not permit the use of polyethylene pipes in areas of high seismic activity. However ARMGAZ is conducting field trials with technical assistance from Gaz de France (para. 5.33) with 1 km of polyethylene mains at a location near Yerevan to assess its suitability. Repair and replacement of the earthquake damaged systems would cost and estimated Rbs 560 million.

5.31 The average age of the distribution networks is about 15 years, and 1000 km are considered to be in need of replacement due to age and corrosion caused by aggressive soils. Typically there are about twenty serious gas leak incidents each year and this is indicative of the poor condition of certain sections of the network. Overall leakage is estimated by ARMGAZ at about 2%, but the present system configuration does not allow leakage to be measured with any accuracy. This level is likely low. ARMGAZ has maintained an active mains renewal program with 600 km replaced since 1985 as shown in Table 5.5 and now prefers to construct pipelines above ground to reduce cost and corrosion. The average cost of construction of gas main has spiraled from Rbs 12,000/km in 1984 to Rbs 660,000/km

today, and further replacement is now severely hampered by lack of finance. The planned replacement of 110 km of main this year is unlikely to be achieved.

Table 5.5: Distribution Mains Replacement Program (1986-1992)

	1986	1987	1988	1989	1990	1991	1992[a]
Mains Replaced (km)	63	64	66	78	135	142	110

a Planned

Source: ARMGAZ

5.32 The existing natural gas supply network extends to about 63% of the population, with other communities reliant on alternative fuels, particularly coal and LPG (Table 5.2). It is not viable to introduce supplies of piped natural gas to those communities which are remotely located from the existing gas supply network. Extension of the network in this way would require new residential consumers to use gas for all household uses to provide a basis for economic viability. Such households would incur very substantial costs for gas burning appliances, most of which would need to be imported. Coupled with the prospect of rapidly increasing consumer prices to reflect international gas prices, present income levels, which are typically Rbs 1,200/month, could not sustain such a burden. In view of the limited financial resources, future investments in gas distribution networks should focus on rehabilitation and replacement of corroded and damaged mains rather than extension into new areas.

5.33 In 1990, ARMGAZ signed a technical cooperation agreement with Gas de France, to assist in identifying and exploiting opportunities for introducing modern Western technology in gas distribution operations in Armenia including the use of polyethylene pipe. The agreement also includes mobile leak detection equipment, cathodic protection equipment, manufacture of heating appliances, energy conservation and training. Cooperation has also started with Auer (France) for the manufacture of gas space heaters in Armenia. These would be suitable for apartments up to 60 m^2, but progress is inhibited due to lack of funds. A further joint venture for the manufacture of gas meters is underway with a Czech firm (para. 5.43).

Natural Gas Storage and Load Balancing

5.34 *Underground Storage.* Natural gas consumption in Armenia shows high seasonal variation due to the space heating requirements for the residential and commercial consumers in winter months. Consumption can reach about 22 Mcm/d during the heating season, which lasts from November to March, and falls to about 10 Mcm/d in summer. About 15 Mcm/d of the winter consumption is by

the commercial/official and household sectors. In periods when gas trading relationships were stable, the seasonal pattern of gas imports from Azerbaijan did not reflect the consumption requirements, and ARMGAZPROM developed a natural gas underground storage facility near Yerevan for load balancing comprised of 18 individual salt cavities equipped with injection and sendout facilities. Under design conditions, the facility has a capacity to store 210 Mcm of natural gas, which would normally be used for load balancing throughout the winter season. In the event of complete cessation of gas imports, there is sufficient storage to cover Armenia's total demand requirements for about 10 days during winter. On the basis of residential and commercial demand alone the capability should be nearer 20 days. However, the output capacity is restricted to 2.3 Mcm/d by only three discharge lines. ARMGAZPROM intends to add three further lines to increase the discharge rate to 6 Mcm/d.

5.35 Since the cessation of supplies from Azerbaijan, it has not been possible to utilize the facility effectively. This problem arises because the lack of gas has caused the transmission system pressures to fall to typically 8 bar in the Yerevan area, which is below the 17 bar minimum pressure (25 bar design) required for the storage facility compressors to operate. The possibilities to remedy the situation are:

(a) installation of booster compressors at the facility (estimated cost US$0.5 million), which would increase the pressure to the minimum operable to allow utilization of about 60 Mcm of the underground storage capacity,[26] and

(b) completion of the compressor station at Airom (estimated cost US$5 million) which would allow utilization of the facility and improve the pressure regime in other parts of the transmission system.

5.36 In view of the uncertain supply situation, this storage facility is an important asset both to balance load and to conserve supplies for use in winter in the event of external interruptions. In the long term and subject to an improved financial situation, there is scope to increase the capacity of the underground storage facility to 360 Mcm through the leaching of ten additional cavities. However an environmentally acceptable solution to the disposal of the resulting salt must be found.

5.37 *LNG Peak Shaving*. In 1981, construction work commenced on an LNG peak shaving facility at Abovian, which is close to Yerevan. In 1987, work all but ceased due to environmental concerns associated with the plant. As designed, the plant incorporates three 60,000 m^3 LNG storage tanks, equivalent to 110 Mcm of regasified LNG. Design send-out capacity is 11 Mcm/d, almost half of Armenia's daily natural gas demand in winter. Most of the necessary equipment is already on site, including the refrigeration compressors and electric substation, and civil works including control room and workshops are completed. Although the fabrication material for the cryogenic tanks is available, only the vessel containment structures have been erected. ARMGAZPROM estimates total project costs at

[26] This project is being financed by EBRD as part of the Hrazdan 5 project.

US$140 million in 1992 dollars, of which US$95 million is required to complete the work, although this estimate may be high.

5.38 LNG peak shaving plants are characterized by high output rates, but have relatively low storage volumes. As a result, LNG peak shaving plants are normally used in countries where the gas utility has a legal obligation to maintain supplies according to a very stringent winter severity criterion such as a 1 in 50 winter. Also, operation of such facilities requires very high level of operator technical expertise and training. Taking account of capital and operating costs, the interest on construction and interest on gas inventory maintained versus storage, typical costs can be equivalent to US$130-160/000m^3 of gas sent from storage. With such high associated costs, and in view of existing financial constraints, the completion of the plant for operational peak shaving has a low priority.

5.39 *Strategic Issues*. The future development of natural gas storage in Armenia must take account of (a) the characteristics in the expected growth of gas demand, (b) the flexibility of consumers to switch to alternative fuels, (c) the investments already incurred in storage facilities, and (d) the availability of natural sites which may be developed for underground storage and the comparative economics measured against other forms of storage. In this context, increased gas consumption by the household and population sectors is unlikely for the rest of this decade, due to the higher consumer prices and increased accountability achieved by individual metering. Assuming the thermal power plants continue to operate with the flexibility to switch to alternative fuels, this suggests a pattern of consumption which will not require substantial additional seasonal storage capacity for *operational* load matching. The principal reason for large investments in addition to natural gas storage capacity would be for *strategic* security of supply to cover for serious interruptions in pipeline imports. However, it is considered that financial resources may be more effectively used in providing additional mazut storage capacity for such emergencies, or investing in the Iranian pipeline to achieve supply diversity.

5.40 In view of the foregoing, the following strategy for the future development of natural gas storage is recommended:

(a) investments to fully utilize the existing salt cavity storage facility at Yerevan to its fullest extent.

(b) evaluation of the costs of increasing mazut storage to cover for major interruptions in supply as an alternative to increasing salt cavity storage or completion of the LNG facility.

Consumer Metering and Billing

5.41 The larger industrial and commercial consumers of natural gas are charged directly for the volumes they use as measured through metering devices installed at the individual premises. However, household consumers are not metered but are instead charged a flat rate dependent on the number of persons in the household and whether gas is used for water heating, cooking and space heating or combination of these. Monthly payments are made by the consumer through the banking system.

5.42 The absence of consumer meters is an important issue in the subsector, since lack of individual accountability discourages energy conservation and the adequate monitoring and cost accounting by the utility cannot be achieved. To assess the level of individual consumption in the residential sector, ARMGAZ has made several field trials using small numbers of imported consumer meters in regions with differing climatic conditions. These trials indicated that, on average, a single household member uses 20 m^3/month for cooking and 15 m^3/month for water heating. For space heating, a monthly consumption of 10m^3 for each square meter of floor space is representative. This usage equates to a consumption of about 3800 m^3/y for a typical household of 4-5 persons for cooking, water heating and space heating for a 30 sq m apartment. In Western European countries, consumption for a comparable household would be about one-half the level in Armenia and clearly shows the impact of a lack of accountability and energy saving practices within the residential sector. Indeed, based on the field trials ARMGAZ estimates that installation of individual consumer meters alone could result in savings of 25% within the residential sector, and it is estimated that savings could be even higher if metering were combined with an appropriate pricing policy.

5.43 A joint venture has been established between ARMGAZ and Hirana (CSFR) to manufacture industrial and residential consumer meters at a factory near Yerevan. At present, production capacity is limited by the output of a single automatic unit used to calibrate the meters, and limited stocks of meter parts. Additional automatic meter calibration units may only be acquired from abroad with hard currency, and five calibration units are required at an estimated total cost of US$0.5 million. Some ruble investments are also required to upgrade the factory. To date, 500 meters have been assembled, but management would envisage production increasing to at least 150,000/yr. The meters are of high quality and accuracy ($\pm$1.4%) with a wide range suitable for all normal residential uses, and there is export potential within Eastern Europe, the FSU countries and possibly Iran. With availability of finance to purchase meter components and calibration units, production could realistically be increased to 200,000 units per year by 1995.

5.44 Irrespective of whether the meters are produced in Armenia or must be imported, the installation for existing household consumers could be achieved before the end of this decade. Broad economic indications suggest the total expenditure would be about US$20 million, which assumes a supply and installation cost of US$60 per unit. Although the unit cost could be substantially lower depending on the origin of the meters, the program would need to be financed through ARMGAZ rather than the individual consumer. The costs may be compared with *annual* cost savings of US$22 million

on Armenia's energy bill, on the basis of a 25% reduction of residential gas consumption, and gas imports are priced at international levels.[27]

5.45 In the medium-term, an issue to be addressed is the widespread installation of gas-fired water heaters and space heaters in individual apartments as a substitute for central heating systems. Although this would be consistent with the principle of individual accountability, the costs of importing and installing the appliances would place a substantial financial burden on consumers. This issue may be resolved through a cost-benefit analysis as part of an integrated gas development plan for Armenia.

E. Fuel Supply Costs and Prices

5.46 Prior to the blockade by Azerbaijan, 30% of supply entered through Georgia and the remainder through Azerbaijan. The average transit distance from source is 3,470 km with the average price for gas transit set at Rbs 755/000m^3. In May 1992, the average purchase price paid by ARMGAZPROM at the Armenian border reached Rbs 1,625/000m^3. The gas was on-sold to ARMGAZ for Rbs 2089/000m^3, and finally the end user with prices structured in a three tier tariff system. Consumers regarded as essential, such as power generation and food industries, are charged Rbs 2,176/000m^3 (132% of import price), with non essential industrial users paying a premium price of Rbs 5,120/000m^3. These groups subsidize residential consumers, who are charged Rbs 300/000m^3 where metered.

5.47 The increases in the purchase (border) prices and consumer prices of natural gas, LPG and coal since 1985 are shown in Table 5.6. The figures show a dramatic increase since 1991 particularly in prices to power and industrial consumers which have largely been passed on to final consumers. Additional large price increases are anticipated as border prices continue to move towards world market levels, which the Ministry of Energy anticipates will be reached in 1993. Indeed, agreements had been reached in October 1992 to resume the supply of gas from Turkmenistan via Azerbaijan at a Ruble price equivalent to US$80/000 m^3, or US$2.00/MBTU compared to a typical border price in Western Europe of US$2.50/MBTU; however, Azerbaijan subsequently refused to permit the transit of gas to Armenia and the blockade continues.

5.48 Consumers of LPG and coal are facing similar price increases to natural gas. Currently, LPG is purchased by ARMGAZPROM at Rbs 2,200/ton. After bottling, it is transferred to ARMGAZ at Rbs 3,563/ton, distributed and sold to consumers at Rbs 6,182/ton or 16 times the current price of natural gas on a thermal equivalence basis. Since January 1992, the delivered price of coal purchased at Rostov has increased from Rbs 323/ton to Rbs 3,195/ton, with prices to end users increasing from Rbs 650/ton to Rbs 4,112/ton over the same period.

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[27] With gas at US$ 2.50/MBTU.

Table 5.6: Prices of Natural Gas, LPG, and Coal 1985-1992

	1985	1990	1991	mid 1992
NATURAL GAS (Rbs/000m³)				
Border Price	18	18	36	1,625
Residential				
- cooking	50	50	40	300
- heating	20	20	40	300
Commercial/Official	12	12	61	2,668
Power	30	30	61	2,688
Non-Essential Industries	30	30	71	5,120
COAL (Rbs/ton)[a]				
Border Price	30-40	30-40	380-450	2,140-3,195
Residential	9.5	9.5	550-650	3,120-4,122
LPG (Rbs/ton)				
Border Price				2,220
Residential	N/A	N/A	N/A	6,182

a. Range is for large lump and small lump coal.

Source: ARMGAZ

5.49 The future level of gas prices is a key determinant of the level of future investment in the gas subsector as well as decisions by consumers regarding their own investment in fuel using equipment. If prices are set too low, the subsector will see an inadequate return to any future investment needed to maintain or increase supplies. Also, if consumers see gas fuel prices that are too low, they will have inadequate incentives to limit their demand for gas or to use energy efficiently, and will make the wrong choices for their own current and future fuel use. Prices that are too high may lead to excessive investment, or to a reduced demand for gas by final users and an inappropriate choice of alternative fuels in preference to gas.

5.50 Continuation of gas prices at present levels would increase the financial dependence of ARMGAZ on government sources of finance, thus reducing its managerial independence and incentives for efficiency. In addition, it would not be consistent with the economic reforms envisaged by the Government and the objectives of improving the governments' own financial position. Progress, therefore, requires that prices should be increased with the primary objective of establishing the financial viability of the gas sector, and of reflecting its costs for developing and maintaining gas supplies.

5.51 A tariff study is needed to develop a tariff structure and price level that reflect the cost of supply to consumers according to their use of energy and responsibility for capacity costs.

Allocation of costs to individual customer or classes of customers should take into account a number of factors including: (a) customer contribution to system or subsystem peak demand, which affects capacity costs; and (b) location, which affects capacity and operating costs. Price adjustments should be on the basis of pre-established, published formulas, as part of an overall regulatory structure. Gas pricing should also be structured to assist in overall demand management. The larger consumers are normally offered a price incentive to install dual fuel equipment, thereby reducing the requirements for peak natural gas transport capacity and storage facilities. Seasonal price incentives to switch to alternative fuels during winter months where there is high demand may be made. On the other hand, the gas supplier may wish to enter into interruptible contracts which offer a price incentive in exchange for the possibility to interrupt supply.

F. Gas Subsector Investment and Technical Assistance Requirments

5.52 Financing requirements for capital investments and technical assistance are summarised in Table ES2 of the Executive Summary and details are given below.

5.53 *Capital Investment*: In view of Armenia's economic situation, development projects in the gas subsector will face strong competition from high priority projects in the other energy subsectors for the scarce financial resources which are available. Projects which support the resumption and diversification of gas supplies, and also which would increase storage capacity, should be regarded as the highest priority. The cost and timing of major gas subsector projects are shown below:

Table 5.7: Gas Subsector Investments

	Project	Indicative Cost[b] million US$	Target Project Completion[c]
•	Completion of Georgia supply line	3.0	
•	Booster compression at Yerevan UGS[a]	0.5	1992/3
•	Completion of Airom compressor station	5.0	1992/3
•	Iran Import pipeline - Phase I	73.0	1995
•	Iran Import Pipeline- Phase 2	210.0	1996
•	Replace Earthquake Damaged Networks	6.0	subject to financing

a Being financed by EBRD in connection with the Hrazdan 5 thermal power project.
b Based on estimates in Ruble prices mid 1992 and an exchange rate of Rbs 100/US$.
c Indicative timing assuming availability of financing in 1992 or early 1993.

Source: ARMGAZPROM, ARMGAZ, and Mission estimates.

5.54 In addition, there are a number of other projects which, due to their low investment requirements but potentially high benefits, may be regarded as candidates for priority financing. These include the provision of calibration equipment for meter manufacturing facility (US$0.5m) and the purchase of 120 tons welding electrodes (US$0.12m).

5.55 *Technical Assistance Needs*. Grant aid is also needed for the following two high priority Technical Assistance projects for which draft terms of reference are given in Annex 6.[28]

1. *Integrated Gas Development and Subsector Restructuring Study (US$600,000).*

The study would focus on physical and financial planning and institutional development as follows:

(a) physical planning
- evaluation of the current practices of gas utilization and metering and recommendations for improvements which could lead to savings in gas consumption
- consumer demand forecasting for short (up to 5 years, medium 5-10 years, and long term (10-20 years) based on macro economic projections, future fuel prices and fuel substitution possibilities, and gas requirements by consumer category
- evaluation of the existing transmission and distribution facilities and planning for rehabilitation, reinforcement, and development requirements to meet future demand
- preparation of capital cost estimates in local and foreign currencies
- technical and economic evaluation of the options identified in this report to diversify and increase the security of supply of gas

(b) financial systems and planning
- evaluation of existing accounting systems and recommendations for modifications as required for commercially oriented operations
- preparation of corporate financial statements including balance sheet, income statement, and funds flow statement
- recommendations concerning the installation of computerized accounting systems
- preparation an investment program and financing plan showing annual disbursements and borrowings in foreign and local currencies
- analysis of operating and maintenance costs
- analysis of tariff level and structure requirements to reflect the cost of service to each consumer group
- recommendations concerning a tariff adjustment mechanism

[28] In April 1993, EC agreed to finance technical assistance for general fuel supply contracting and negotiating which subsumes Item 2 below.

(c) institutional and organizational development
- review of the existing subsector organization and institutions and proposals concerning a revised structure which would separate policy making, regulatory and operational responsibilities within the sector
- recommendations concerning a regulatory framework including draft legislation for implementation
- analysis of functional requirements, recommended organization and reporting structure and staffing requirements

2. *Consultant services to assist in the structuring and negotiation of long term gas supply contracts. (Est. US$50,000).*

This study would provide the basis for, say, ten year contracts and would cover, among others, the following points (para. 5.25):

(a) the gas price and its indexation to alternative fuels;

(b) the need for seasonal flexibility of gas deliveries; and

(c) the volumes required, the capital and operating costs of the pipeline, and the financial risks to Armenia associated with take-or-pay commitments which may be sought be a supplier.

ARMENIA ENERGY BALANCE 1990

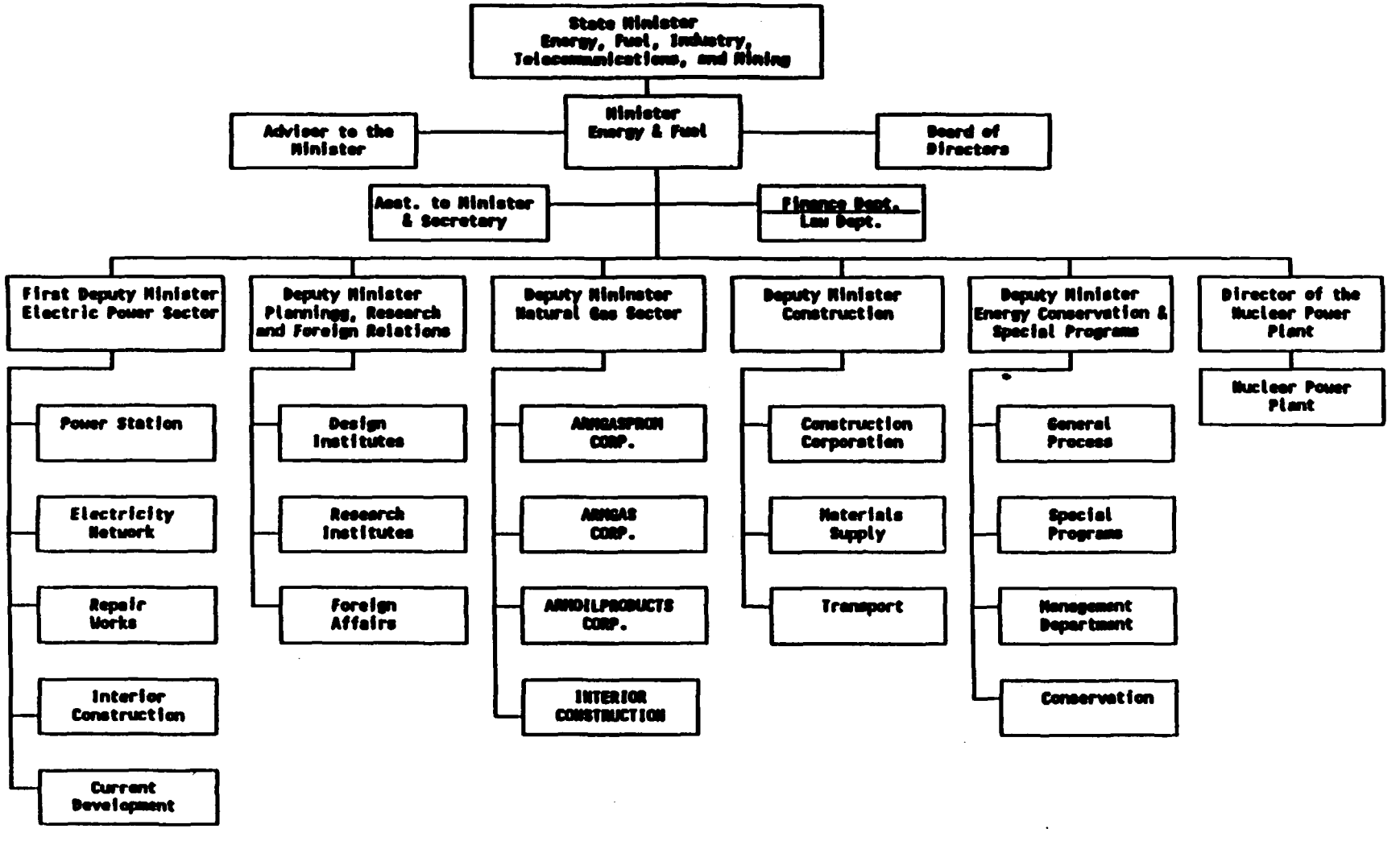
ANNEX 1.1

16-Oct-92

ARMENIA
ENERGY BALANCE 1990

	HYDRO	NUCLEAR	COAL	NATURAL GAS	TOTAL PRIMARY	NAPHTHA	DIESEL	KEROSENE	JET FUEL	GASOLINE	LPG	TOTAL LIQUID FUELS	PRIMARY+ LIQUID FUELS	ELECTRICI	HEATING	TOTAL ENERGY
SUPPLY	THOUSAND TONNES OIL EQUIVALENT - (1 TONNE = 10 GCAL)															
												0				
PRODUCTION	309				309							0	309			309
IMPORTS + STOCK CHANGE			243	3551	3794	2560	660	13	209	971	26	4446	8200	79	0	8320
EXPORTS					0											
CHANGES IN STOCKS					0											
TOTAL SUPPLY	309		243	3551	4103	2560	660	13	209	971	26	4446	8629	79	0	8708
					0											
					0											
CONVERSIONS	-309			-773	-1068	-1900	0	0	0	0	0	-1900	-3194	0	0	-3142
COMBINED HEAT AND POWER																
CONVERSION LOSS/DISTRICT HEAT	-255			-560	-815	-1436						-1436	-2251		705	-1546
GROSS ELECTRICITY GENERATION	-134			-213	-347	-545						-545	-891	891		
STATION USE				-15	-15	-38						-38	-53	53		
NET FROM CONVERSION	-134	0	0	-190	-332	-507						-507	-839	839	705	1544
												0	0	0	0	0
NET SUPPLY	0	0	243	2770	3021	508	660	13	209	971	26	2466	5435	918	705	7110
TRANSMISSION/DISTRIB LOSSES														142	352	495
NET AVAILABLE FOR CONSUMPTION	0	0	243	2770	3021	508	660	13	209	971	26	2466	5435	776	352	6615
FINAL CONSUMPTION																
INDUSTRY				1011	1011	508					3	591	1602	245		1847
TRANSPORT				0	0		75		209	177		461	461	33		493
CONSTRUCTION				0	0							0	0	40		40
AGRICULTURE				0	0		102			276		450	450	151		600
HOUSEHOLDS			243	1121	1364		140	13		151	21	333	1690	176	353	2226
COMMERCIAL/OFFICIAL				646	646		236			367	2	605	1251	95		1345
OTHER							19					19	19	37		56
TOTAL CONSUMPTION	0	0	243	2770	3021	508	660	13	209	971	26	2466	5487	776	353	6616

Source: Ministry of Energy and Fuel
Mission Estimates



MINISTRY OF ENERGY AND FUEL OF THE REPUBLIC OF ARMENIA

ANNEX 2.1

ANNEX 3.1

POWER SECTOR FACILITIES AND PLANNING OPTIONS

Annex P2

Armenia

The Sevan-Razdan Hydro Scheme

Overview

1. The Sevan-Razdan hydro scheme in northern Armenia is a unique case of the development of a cascade of six hydro stations to "mine" a large mountainous lake, Lake Sevan, to provide over 500 MW of hydro power and irrigation water for 100,000 hectares of land in the Ararat plain. The project was started in the 1930s and was based on lowering the level of Lake Sevan by 50 meters over about 50 years to obtain water while reducing the lake surface area to limit evaporation. To augment lake inflow the Arpa River was diverted to the lake from its normal southward flow to the Araks River. By 1978 the lake level had dropped 18 meters and it was decided to stop further reduction because of ecological effects. Summer water temperatures had increased, algae formation was evident, winters were colder, and fishing was affected. The lake level has now stabilized at 1898 meters and it is planned to increase the lake level 6 meters by year 2000.

Hydrology

2. Use of water in Lake Sevan was a deliberate plan to assist Armenia's industrialization because no other indigenous energy resources were available. The Soviet 1941-45 wartime energy needs accelerated the electricity production and lake drawdown. Lake Sevan is 75 km. long and 20 km. wide at an elevation of almost 2000 meters with a maximum lake depth of 100 meters. The lake is supplied by 28 small rivers and many streams but most of the inflow evaporates from the lake's large 1400 sq. km. surface area leaving only 8% for outflow to the Razdan River which flows 146 km. to the Araks River. The average annual inflow is 1.2 billion cu. m. but the evaporation is 1.1 billion cu. m. leaving only a natural outflow of 2 to 3 cu. m/s. In the 1930s a scheme was designed to utilize the 1100 meter head available over the Razdan River's path by augmenting the natural flow using the available storage. A 527 MW 6-plant cascade system was installed over 1936-62 (see below). High electricity production in the 1940s and 1950s required annual water uses in the 1.5 billion cu. m. range and accelerated the lake drawdown.

3. To slow the drawdown the Arpa River was diverted to Lake Sevan by constructing a 48 km. tunnel which increased the lake inflow by about 230,000 cu. m. In 1976 it was decided to stop the drawdown because of the environmental effects and the level was stabilized at about 1898 meters, an 18 meter drawdown from the original level. By this time thermal plants had been constructed to supply base loads and the hydro became peaking capacity, with water releases controlled mainly by irrigation requirements.

Hydro Cascade Scheme

4. The location of the six hydro stations are shown on Map__ and their characteristics are listed below.

Sevan-Razdan Hydro

Hydro Plant	Installed Capacity MW	No. & MW of Units	Annual Energy GWh	Nominal Head m	Design Discharge cu. m/s	Reservoir Storage m. cu. m.	Year Units Commis-sioned
Sevan	241	2 x 12	46	45	60	-	1949
Atarbekyan	661	2 x 33	129	138	60	-	1959
Gyumush	224	4 x 56	453	297	70	5.6	1953
Arzni	69	3 x 23	199	118	70	1.0	1956
Kanaker	100	4 x 12 2 x 26	225	173	55	0.1	1936 1941
Yerevan	44	2 x 22	114	91	62	0.3	1961
Total	527	19	1166	-	-	-	-

a. The Sevan plant at the outlet from Lake Sevan to the Razdan River provides the control for water releases. The river was diverted from the original river bed with rapids to a gated intake structure supplying penstocks for the two units housed in an underground power house 100 meters below the ground surface with a tailrace tunnel. Bypass valves with an energy dissipater can release water to downstream plants if Sevan units are down for maintenance.

b. The Atarbekyan plant is an above-ground 2-unit powerhouse supplied via 6 km of tunnels and 8 km of canals from the Sevan plant discharge.

c. The Gyumush plant is supplied from Atarbekyan output via 12 km of tunnels and 6 km of canals connecting to a reservoir formed by a rockfill dam. The plant has the highest head (297 m), largest output (224 MW), and most storage (5.6 million cu. m.) on the hydro cascade system.

d. The Arzni plant has a concrete gravity dam and a 100-meter deep underground powerhouse with 3 units supplied via an 8-km long tunnel and canal system.

e. The Kanaker plant was the first plant constructed on the cascade system and comprises 13 km of tunnels and canals to convey water from the Arzni plant. It has a concrete dam, a small reservoir with limited storage capacity and 4 units installed in an above-ground powerhouse.

f. The Yerevan plant is the last plant in the cascade system and is located in the Razdan River valley within Yerevan city. It has a rockfill dam, 3 km of pressure tunnel, and an above-ground powerhouse with 2 units.

Armenia

The Vorotan Cascade Hydro Scheme

1. Three hydro plants have been installed in cascade on the Vorotan River in southeast Armenia. The plants capture the hydro power of the river, which flows from its head waters in the mountains east of Lake Sevan southeast through Armenia before crossing the border with Azerbaijan on its way to join the Araks River. The following table lists the characteristics of the three hydro plants:

Vorotan Hydro

Hydro Station	Installed Capacity MW	No. & MW of Units	Annual Energy GWh	Nominal Head m	Design Discharge cu. m/s	Reservoir Storage m. cu. m.	Year Units Commis-sioned
Spandaryan	76	2 x 38	157	394	30	276	1984
Shamb	170	2 x 85	330	314	75	96	1977
Tatev	156	3 x 52	670	576	33	14	1970
Total			1157				

2. The Vorotan hydro scheme utilizes 1300 meters of head over the path of the Vorotan River which flows through rugged mountainous country. The river has been largely diverted by a system of tunnels connecting the three plants. The upstream Spandaryan plant has an 87 meter high concrete dam which impounds 276 million cu. m., which serves as regulation for the three plants. A series of tunnels supply water from the Spandaryan plant downstream to Sham and, in turn, to Tatev. The river is almost totally diverted through tunnels linking the three high-head plants. The Tatev plant has the highest head at 576 meters, and it uses Pelton turbines, the first installed in the former Soviet Union and the only Pelton turbines at Armenia's hydro plants.

Armenia

Prospective Hydro Projects in Armenia

1. The total hydro power potential of Armenia is estimated at 6 billion kWh annually, or 3400 MW at 20% capacity factor for peaking plants. The developed hydro is almost 1000 MW, producing about 1.5 billion kWh annually (it was more when Lake Sevan was being drawn down, in the period 1940 to 1980). Only one-third of the hydro potential has been developed and quite likely considerable additional hydro may prove economic, because the alternatives to hydro are imported oil or gas-fueled thermal. The fuel prices in Armenia will soon be at international levels, while construction costs for hydro in C.I.S. countries are still lower than in the west, so hydro has some cost advantage relative to its position in the west.

2. The existing hydro projects in Armenia were designed and the construction was supervised by the Armenian Hydro Project Institute in Yerevan, under the general guidance of hydro engineering authorities in Moscow. The Hydro Institute does not have any capability in electrical and mechanical equipment design, which was handled from Moscow for the execution of the existing hydro plants.

3. The Hydro Institute has made a country-wide survey of Armenia's hydro resources. The Attachment prepared by the Institute shows a list of about 40 hydro sites the Institute believes are economic, totally 723 MW capacity and 2240 GWh annual energy output at 35% capacity factor. The sizes range from 138 MW for the Megri site on the Araks River to only 1 MW for many small mini hydro sites throughout the country.

4. The projects include many locations where existing storage reservoiRs for irrigation could incorporate hydro units for energy recovery during water releases. The project preparation status varies from resource survey only to completed designs with blueprints, as shown on the Attachment.

5. The Institute estimates the average construction cost is about Rb 16,000/kW in 1992 Rb (US$ 160/kW). If such low prices can be verified, some of the hydro will certainly be economic.

Technical Potential of Prospective Hydro Sites in Armenia

No.	Hydro Site	Head m	Av. Flow cu. m/s	Capacity MW	Av. Energy GWh	Cost in M 1992 Rb: Total Incl. Design	Cost in M 1992 Rb: Design Only	State of Preparation: Conceptual Design	State of Preparation: Tech/Econ Evaluation	State of Preparation: Workin Desig
1	Debed Cascade									
1.1	Loriberd	270	21	48	160	630	26	*	-	*
1.2	Shnoch	240	37	75	300	680	40	*	-	-
2	Argichi	358	10	22	42	290	10	*	*	*
3	Megri on River Araks	90	180	138	430	2370	50	*	-	-
4	Surmalins on River Araks	46	122	48	130	385	13	*	-	-
5	Small (Mini) Hydro									
	Run-of-River sites	-	-	305	935	5830	530	-	-	-
	Storage sites	-	-	52	104	900	80	-	-	-
	Irrigation canal sites	-	-	35	139	460	40	-	-	-
	Total Small Hydro	-	-	392	1178	7190	650	-	-	-
	Total Identified Hydro			723	2240	11545	789	-	-	-

(Average capacity factor is 35%; average capital cost is Rb 16,000/kW or US$ 160/kW.)

6	Small Hydro Plants for Quickest Construction in Near Future									
6.1	Site on Vorotar-Arpa tunnel using available head	45	15	4.4	17.3	70	1.2	*	-	-
6.2	Using head from water use of copper/ molybdenum plant	500	1.2	6.0	19.4	88	4	*	-	In progr
6.3	Using head on Arto-short irrigation channel	45	7.0	2.6	12.0	40	2.4	*	-	In progr
6.4	Using head on Talin irrigation channel, No. 1	45.3	7.3	2.3	8.5	55	2.0	*	-	-

	Hydro Site	Head m	Av. Flow cu. m/s	Capacity MW	Av. Energy GWh	Cost in M 1992 Rb: Total Incl. Design	Cost in M 1992 Rb: Design Only	State of Preparation: Conceptual Design	State of Preparation: Tech/Econ Evaluation	State of Preparation: Workin Desig
6.5	Using head on Talin irrigation channel, No. 2	22.2	7.2	1.36	4.0	23	1.0	*	-	-
6.6	Using head on right side at Azerian channel	165	4.0	5.6	27.7	67	3.3	*	-	-
6.7	Kapskaya site using Kaps storage	45	5.8	2.35	3.3	16	0.2	-	*	*
6.8	Ger-Gerskaya site on the Ger-Ger irrigation storage	62	2.4	1.2	2.6	21	0.7	-	*	*
6.9	Yogos site on the Yogos irrigation storage	53	5.5	2.4	4.4	28	2.0	*	-	-
6.10	Ajuricure site on the Ajuricure irrigation storage	39	23.0	7.6	18.7	94	3.0	*	-	In progr
6.11	Yegvard site on the Yegourd irrigation storage, No. 1	24	18.0	3.7	7.2	69	2.4	*	-	-
6.12	Yegvard site on the Yegourd irrigation storage, No. 2	25	7.0	1.5	2.3	31	2.0	*	-	-
6.13	Shanurou site on the Yegvard storage	13	2.0	2.2	2.3	42	2.5	*	-	-
6.14	Dzorozed hydro site No. 1	100	1.2	1.02	3.4	22	2.3	*	-	In progr
6.15	Dzorozed hydro site No. 2	70	2.0	1.19	4.2	26	2.1	*	-	In progr
6.16	Dzorozed hydro site No. 3 & 4	70	2.8	2 x 1.67	2 x 7.1	2 x 27	2 x 2.0	*	-	In progr
6.17	Dzorozed hydro site No. 5	70	4.5	2.67	16.0	43	3.1	*	-	In progr
6.18	Akstiv Nos. 1-4	70	3.0	4 x 1.785	4 x 5.3	4 x 27	4 x 2.0	*	-	-
6.19	Akstiv Nos. 5-6	70	7.6	2 x 4.52	2 x 14.3	2 x 57	2 x 4.0	*	-	-
6.20	Shanakhick hydro sites 1-3 on the River Dibed	100	1.8	3 x 1.53	3 x 6.24	3 x 24	3 x 20	*	-	-

	Hydro Site	Head m	Av. Flow cu. m/s	Capacity MW	Av. Energy GWh	Cost in M 1992 Rb: Total Incl. Design	Cost in M 1992 Rb: Design Only	State of Preparation: Conceptual Design	State of Preparation: Tech/Econ Evaluation	State of Preparation: Workin Desig
6.21	Gokhget hydro sites 1-5 on the River Azat, in the Vedi District	70	2.6	5 x 1.55	5 x 4.7	5 x 23	5 x 2.0	*	-	-
6.22	Gekhi hydro sites 1-3 on River Vokhchi	125	1.2	3 x 1.28	3 x 4.8	3 x 20	3 x 1.7	*	-	-
6.23	Kadjaran hydro sites 1-2 on the River Vokhchi	100	1.7	2 x 1.53	2 x 6.4	2 x 14	2 x 2.0	*	-	-
	Total for Small Hydros			**86.85**	**286.7**	**1286**	**79.3**			

Armenia

Installed Power Generating Capacity

Plant	Installed Capacity MW	Unit No. & Sizes	Max. Annual Hours	Av. Annual Energy GWh[1]	Year of Commis-sioning
Thermal					
Razdan Stm.	1100	2 x 50	4000	400	1966-67
		2 x 100	4000	800	1969
		4 x 200	5500	6,600	1971-74
Yerevan Stm.	550	5 x 50	4000	1,000	1963-65
		2 x 150	5500	1,750	1966-67
Kirovakan Stm.	96	2 x 12	4000	960	1964-65
		1 x 25	4000	1,000	1970
		1 x 47	4000	1,880	1976
Subtotal	**1,746**			**14,390**	
Sevan-Razdan Hydro					
Sevan	24	2 x 12	-	46	1949
Atarbekyan	66	2 x 33	-	129	1959
Gyumush	224	4 x 56	-	453	1953
Arzni	69	3 x 23	-	199	1956
Kanaker	100	4 x 12	-	225	1936
		2 x 26	-		1941
Yerevan	44	2 x 22	-	114	1961
Subtotal	**527**			**1166**	
Vorotan Hydro					
Spandaryan	76	2 x 38	-	157	1984
Shamb	170	2 x 85	-	330	1977
Tatev	156	3 x 52	-	670	1970
Subtotal	**402**			**1157**	
Dzora Hydro	24	3 x 8	-	50	1932
Nuclear	(816)[2]	2 x 204[3]	-	-	1976
(not operating)		2 x 204	-	-	1978
TOTAL	**2699**			**16,763**	

[1] Assuming normal gas and oil fuel supplies are available at thermal plants and average year flows prevail at hydro plants.
[2] Not included in total.
[3] Two turbines supplied by one reactor.

Armenia

Armenergo Divisions and Staffing

The following list shows the various divisions within Armenergo and the breakdown of the staff of about 10,000:

Divisions	Number of Staff
Administration & System Control	197
Razdan Thermal Power Station	1,087
Yerevan Thermal Power Station	646
Kirovakan Thermal Power Station	232
Sevan-Razdan Cascade Hydro Stations	240
Vorotan Cascade Hydro Stations	139
Nuclear Power Station (2000 when operating)	715
Central Transmission & Distribution Network	622
Southern TDN	511
Northern TDN	719
Western TDN	622
Eastern TDN	500
Zangerur TDN (Southeast)	385
Yerevan TDN (Feb. '92 transferred to Yerevan Municipal)	(500)
Communications Department	173
Commercial Department	256
Maintenance Department	667
Special Projects Department	263
Construction Department	89
Reinforced Concrete Plant	95
Transmission & Distribution Construction	758
Construction Coordination Department	65
Procurement Department	58
Coordination of Transmission & Distribution Construction	39
District Heating Section	194
Inspection Department	258
Security Division	487
Housing Services Staff	66
TOTAL	**10,083**

Annex P8

Armenia

Critical Materials, Parts, and Equipment Required In Energy Sector

Introduction

1. During the 1991/92 winter in Armenia the population suffered severely due to lack of heat, electricity, and water. This suffering was caused by a combination of lack of fuel, failed power distribution systems, frozen water systems, etc. Most industries, offices, and schools were shut down and the main thrust of government activities was the survival of the population; despite its efforts, however, there were some deaths of children and the aged. The close coupling of district heating, electric power, and water contributed to the difficulties. District heating requires electricity for pumps and controls, and water supply to maintain the volume of hot water for circulation to buildings. Therefore, effective operation of the energy sector also requires adequate support from other areas of the infrastructure.

2. During the May/June 1992 Bank energy sector mission the energy institutions were asked to compile their immediate requirements in terms of emergency materials, replacement parts and equipment needed to keep the energy services, particularly electric power and district heating, operative, at least for the 1992/93 winter. The attached lists of required goods resulted from that exercise. Most of the lists are in Russian or Armenian and will have to be translated. However, with the help of mission counterparts in the Ministry of Energy and the operating entities, the content of the lists has been reviewed in order to prepare the following overview.

Armenergo

3. The overriding need at Armenergo is to restore gas supply to the thermal plants, while also building the mazout storage (700,000 ton storage capacity throughout the country) as backup fuel supply. On June 3 there was no gas supply and only one day of mazout, so fuel supply is extremely critical.

4. The next critical requirement at Armenego is to keep the thermal and hydro plants operating by providing parts and materials. The details are as follows:

a. Yerevan Thermal The plant management compiled a very comprehensive list (25 pages) covering pumps, motors, pipes, pipe fittings, special oils, welding electrodes, replacement parts, supplies of plates, timber for cooling tower repairs, and various specialty items, etc., totalling Rb 73.6 million, reportedly in Jan. 1992 Rb or only US$ 0.74 million. On the list but not included in the above figures were 2 replacement 60 MW steam turbines, office air conditioners, and boiler emission test equipment (not critical to operation, for now).

b. Razdan Thermal The Razdan parts list is short for such a large (1100 MW) plant. There must be many additional items, but managers have been operating on such tight budgets probably only critical items are listed. A main item is 30 replacement radiator sections for the Heller dry cooling towers used on the 200 MW units. Other items are pump parts, parts for energy recovery

hydro turbines on cooling water systems, and specialty items. The Armenergo budget allotment for Razdan Thermal is US$ 1.49 million, which is low for such a large plant.

c. Kirovakan Thermal Armenergo did not provide a list of parts needed, but the June-December 1992 budget allocation for this plant is US$ 250,000.

d. No. 12 Thermal The budget allocation for No. 12 Thermal district heating plant is US$ 100,000.

e. Hydro Plants Armenergo's budget allocation for the Sevan and Vorotan hydro plants for the remainder of 1992 is US$ 200,000.

f. Transmission and Distribution The budget allocation for transmission and distribution is US$ 670,000.

Yerevan Municipal Transmission and Distribution

5. Rebuilding and strengthening the Yerevan City power distribution system is the largest single project to be done before the 1992/93 winter. Inadequate district heating due to fuel shortages resulted in consumers switching to electric heating as their only alternative. Old apartment wiring systems are designed for only 1 kW total load (newer are designed for 2.5 kW) and heavy overloading burnt out apartment wiring, low and high voltage distribution cables, and distribution transformers. Attachment 3 explains the work to be done, the required materials, and the costs. A major cost item is the need to run special feeders to district heating plants so electric power will be available during rotating load shedding to operate pumps circulating hot water. Last winter, loss of electricity resulted in loss of district heating by pump loss, and this aggravated the electric load, causing damage to the power distribution system.

6. The required distribution system work is summarized as follows:

Item	US$ Thousands
Repair of the 1991/92 winter damage	3,261
Strengthening of lines and substations	671
Equipment & vehicles for repair crews	82
Replenishing stores for 1992/93 winter	543
Special feeders for critical loads	6,874
Total	**11,431**

Small District Heating Boilers

7. Yerevan, Razdan, and Kirovakan cities have major district heating systems supplied from Armenergo's thermal plants, plus large district heating plants. There are 54 other cities and towns with district heating systems supplied from a total of 295 small boilers and 127 intermediate substations with heat exchanges to extend the range or distance of the heating systems. These district heating systems supply heat to 4087 buildings. The heating systems must be upgraded by repairing, restoring, or replacing the boilers and equipment at 192 boilers and 123 substations. The estimated cost is as follows:

	US$ Thousands
Mechanical equipment	816
Electrical equipment	798
Total	**1,614**

8. The mazout fuel required for an average winter is estimated to cost US$ 8.73 million for these small boiler systems.

Yerevan Municipal Heat, Water, Sewage & Building Systems

9. In addition to the power distribution systems, Yerevan Municipal operates district heating, water and sewage plants and systems, and also is the landlord for most of the city's apartment dwellers. Some of these activities go beyond the energy sector needs, but Attachment 5 presents the full needs, so they are summarized here for information purposes.

10. The Yerevan Municipal district heating needs include repairing large boilers, repairing small boilers, repairing boiler electrical equipment and controls, and rehabilitation of primary and secondary heating lines. The total cost is US$ 5.07 million.

11. Water supply is essential for the district heating systems because potable water use and water losses require a constant supply of treated water, safe for human consumption and for boiler use without scaling. The water treatment and supply system is therefore an important component for effective district heating. The water system needs encompass pipes, valves and fittings, pumps, cables, vehicles, operating materials, and insulation, and are estimated to cost US$ 3.97 million.

12. Yerevan Municipal also has a program to make immediate corrections and improvements at the water and sewage treatment plants if financing can be found. The work includes repairing sewage collector lines, rehabilitating the aeration plant, repairing water lines, maintaining pump stations, expanding the water supply system, and general improvements, estimated to cost a total of US$ 6.09 million.

13. As landlord, Yerevan Municipal has a large backlog of work to be done on apartment buildings and other structures, including adding insulation, repairing earthquake damage, upgrading electric systems, improving elevators, repairing doors and windows, and general improvements, estimated to cost a total of US$ 6.02.

Summary

14. The overall emergency parts, equipment, and materials can be summarized in 2 parts, energy and general infrastructure, as follows:

Item	US$ Millions
Thermal plant maintenance	
– Yerevan	0.74
– Kirovakan	0.25
– Hrazdan	1.49
– No. 12 boiler	0.10
Hydro plant maintenance	0.20
Armenergo transmission and distribution	0.67

Yerevan transmission and distribution	11.43
Small boiler district heating	1.61
Yerevan district heating	5.07
Yerevan water system (supply to heating systems)	3.97
Total requirements, power & district heating	**25.59**

Item	US$ Millions
Yerevan water & sewage systems	6.09
Yerevan building improvements	6.02
Total general infrastructure	**12.11**
GRAND TOTAL	**37.70**

15. It must be kept in mind that the above list of Armenian requirements is the bare minimum. Given the extremely limited resources, the low prices that have prevailed in CIS countries, and the current high rate of inflation, any estimates tend to be very low. For example, for power alone the maintenance requirements for a system this size typically are US$ 60 million annually. Any amount in the US$ 25 to 50 million range could probably be effectively spent 2 or 3 times over, the Armenian needs are so great.

11/09 92 10:40 ☎43 1 23 45 84 IAEA VIENNA-(E) 001/003

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1992-09-11 766982

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DATE: 1992-09-10

TOTAL NO. OF PAGES: 3

FAX NO.: 202 477 0558

Subject: Armenia - report on the Nuclear Plant

Here enclosed you will find a copy of the letter which will be sent to you by mail together with the last version of our final mission report to Armenia.

This letter contains the cost estimates which we could find to answer your questions on the subject.

As they are quite rough and uncertain, we judged it preferable not to include these figures in our report but to provide them separately.

We hope that this information will correspond to your needs and we look forward to your comments.

Warm regards,

F.Niehaus
Safety Assessment Section
Department of Nuclear Energy

INATOM

11/09 '92 10:41 ☎43 1 23 45 64 IAEA VIENNA-(E) 002/003

INTERNATIONAL ATOMIC ENERGY AGENCY
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1992-09-10

Dear Mr. Gilling,

In answer to your letter of August 5, 1992, please find enclosed the revision 1 of the IAEA final mission report to Armenia which takes your comments into account.

As concerns the cost estimates, they are very uncertain and only very rough estimates are available.

Preliminary studies, including seismic safety, can be estimated to cost between 2 and 3 million US dollars. Seismic safety, covering the study to determine if a fault exists close to the reactor site, would account for about half of this amount.

Concerning the work which would be required, should the decision to restart the plant be taken, our cost estimation of about 70 million US dollars for the 2 units is a minimum based on the following information.

Figures provided by the Czechoslovakian Safety Authorities related to backfitting Bohunice for short term operation until 1995 only, are about 65 million US dollars for the 2 units.

In Bulgaria the work performed during one year and a half before restarting units 1 and 2 will cost about 30 million US dollars for the 2 units and it covers activities which would be necessary in Armenia as well, such as: restoring units 1 and 2 to something close to their initial state, annealing of unit 2 reactor pressure vessel, implementing the safety upgradings required before start up, starting (6 months programme) the major safety studies, providing support from western experts (the Consortium) to the Bulgarian Safety Authorities. But additional studies and plant modifications will have to be performed during the following 2 outages to allow for operation of units 1 and 2.

Mr. Joseph Gilling
ESMAP Strategy and Programs Division
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USA

In the case of Armenia, the cost may be considerably higher, depending on the amount of equipment to be replaced after more than three years of outage and on the extent to which western experts and companies will be required.

All these figures refer to work which would be required before plant start up and during the following 2 or 3 outages (about 2-3 years), to allow plant operation for a limited period of about 5 years, however, not at a safety level as is international practice.

Operation beyond this time frame, if envisaged, would require a major plant reconstruction. The cost of such reconstruction has not yet been fully developed.

In Czechoslovakia, the utility operating Bohunice has indicated that they will consider a major reconstruction, to operate beyond 1995, if the cost for the 2 units does not exceed 400 million US dollars, or half of this amount, depending on less favourable financing arrangements. For Kozloduy 1-4, the BEQE study estimates a cost of 120 million US dollars to implement on the 4 units, only 4 items that they consider necessary for long term operation.

Finally, in this context, you might also consider the results of the report of the G-7 Working Group on nuclear safety in the CEC and CIS, presented for the Munich 1992 Summit.

We remain at your disposal for further cooperation.

Yours sincerely,

B. Gachot

B. Gachot
Safety Assessment Section
Division of Nuclear Safety

Attachment

WWER-SC-041
Distribution: Restricted
Original: English
Date: 4 August 1992

FINAL REPORT

THE WORLD BANK AND IAEA JOINT MISSION TO ARMENIA TO REVIEW THE ENERGY SECTOR

REPORT OF THE SAFETY REVIEW OF THE ARMENIA NUCLEAR POWER PLANT

Yerevan, Armenia
17-28 May, 1992

by

Bernard Gachot, IAEA
Antonio Godoy, IAEA

International Atomic Energy Agency

CONCLUSIONS

Armenia NPP is of a similar design to the other WWER 440/230 NPPs. Consequently, apart from the fact it has benefited from some safety improvements to take into account its location in a high seismicity area, Armenia NPP has the same generic safety problems as the other plants of this type.

In addition, Armenia NPP has specific problems which should be taken into account before any decision concerning recommissioning of the plant:

- The physical protection of the plant is not sufficient according to Western standards and this may raise concerns when considering the current local political situation.

- The plant is only 28 km from Yerevan which has a population of 1.3 million people, and this should be considered together with meteorological factors in a site evaluation.

- Armenian independence has deprived the country of direct support from the Russian designers and regulatory body. An independent safety authority is already needed to control the safety of the plant, even in shutdown conditions.

- The plant has been shutdown for 3 1/2 years now and this has had adverse effects on the plant buildings and equipment which are deteriorating continuously and also on the plant staff, a good part of the trained and experienced people having left the plant. As time passes, recommissioning will need more and more work and expenses to restore buildings and equipment to their original state and there will be increasing difficulties in restaffing the plant with well trained people.

- The design of the heat sink of the plant and of the associated reservoir and equipment is such that it will be necessary to make sure they can withstand the constraints defined in the seismic studies and a loss of offsite power.

- The plant is located in a high seismicity area and its original design, like in other WWER 440/230 NPPs, did not explicitly consider external events and, in particular, earthquakes. Although seismic reinforcement work to cope with a grade 8 MSK earthquake has been performed and is 70% completed, it has still to be confirmed that no fault exists under the site or in the close vicinity and what values of ground motion parameters the plant should be able to withstand.

Finally, in the decision process concerning Armenia NPP, three options should be considered:

(1) decommissioning the plant immediately, which would require investment, expertise and a specific project organization;

(2) undertaking preparatory work and feasibility studies on which to base a final

decision; or

(3) postponing the decision either to conduct preparatory activities or to decommission the plant.

For case 3, it has to be kept in mind that the reactor is still loaded with irradiated fuel and has to be maintained in safe shutdown conditions. Consequently, further degradation of the plant equipment and loss of the plant staff and its expertise should be discouraged. In addition, the safety level of the plant should be controlled continuously by an independent safety authority.

If option 2 is chosen, about 6 to 9 months of preparatory work would be needed to complete the knowledge of the site parameters and, particularly, to verify that there are no geological faults or atmospheric dispersion issues which, apart from the political situation, would rule out restarting the plant.

In parallel, a detailed assessment of the present state of the plant buildings, structures and equipment should be performed with the objective of defining the needs (and associated costs) to restore the plant to its original state and evaluate also the feasibility and cost of the seismic upgrading and other modifications required before starting, according to the following recommendations. In parallel also, a program for restoring the plant staff up to the needs (quantitatively and qualitatively) of an operating plant should be defined.

If a decision to restart the plant is finally taken by the Government of Armenia, this should be for a limited duration of about 5 years, considering that long term operation would require large modifications in order to bring the plant to a level of safety comparable with that of the currently operating Western plants. The technical feasibility and economic justification of such large improvements would then have to be established.

For the above short term operation, a program of actions based on the following recommendations would have to be set up. This program should cover all the actions necessary before startup and also short term safety upgradings to implement during the following two or three years like the ones which are under way at Bohunice and Kozloduy NPPs. Accomplishment of all the actions needed before startup will need a minimum of 18 months. This delay could be considerably extended, depending on the amount of equipment to replace and of the time needed for the spare parts to be provided by the original Soviet manufacturers or, if necessary, by Western suppliers.

It should be noted that longer annual outage periods should be anticipated in order to implement compensatory safety measures required even if the plant is scheduled to operate only for 5 years.

While Western expertise will be required in a number of areas, considerable input (the bulk of the work) should be supplied from Russian and Armenian experts.

The co-ordination of the program will probably require a joint Eastern/Western project management organization with design and plant startup experts. In the meantime,

3

the plant staff will have to improve their methods and organization and set up a team of well trained people able to operate and maintain the plant in a safe manner.

file = MIPOWER.W01

11/23/92 19:55 Table 5.7 Power Generation Planning - Capacity Balance

MEGAWATTS	Actual 1990	Est. 1992	1993	1994	1995	1996	1997	1998	1999	2000	2005	2010		
ELECTRICTY DEMAND INDEX	100	84	82	81	80	83	85	88	90	93	107	123		
NET PEAK LOAD (MW)	2146	1813	1788	1752	1727	1761	1795	1831	1867	1904	2160	2452		
Growth Rate		-15.5%	-1.4%	-2.0%	-1.5%	2.0%	2.0%	2.0%	2.0%	2.0%	3.0%	4.0%		
Annual Load Factor	60%	60.0%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%		
EXISTING INSTALLED CAPACITY (Less Retirements)														
HRAZDAN	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100	1100		
YEREVAN	550	550	550	550	550	300	300	300	300	0	0	0		
KIROVAKAN	96	96	96	96	72	72	72	72	72	25	25	25		
TOTAL THERMAL	1746	1746	1746	1746	1722	1472	1472	1472	1472	1125	1125	1125		
SEVAN-HRAZDAN CASCADE	527	527	527	527	527	527	527	527	527	527	527	527		
VOROTAN CASCADE	402	402	402	402	402	402	402	402	402	402	402	402		
SMALL HYDRO	24	24	24	24	24	24	24	24	24	24	24	24		
TOTAL HYDRO	953	953	953	953	953	953	953	953	953	953	953	953		
TOTAL EXISTING CAPACITY	2699	2699	2699	2699	2675	2425	2425	2425	2425	2078	2078	2078		
PLANT ADDITIONS (MW)													TOTAL ADDITIONS	
CONVENTIONAL THERMAL STEAM	0	0	0	300	0	0	0	0	0	0	0	0	300	
GAS TURBINES	0	0	0	0	0	200	0	100	0	0	0	100	400	
COMBINED CYCLE	0	0	0	0	0	0	0	0	0	300	300	300	900	
SMALL HYDRO	0	0	0	0	0	75	0	75	0	150	0	0	300	
														1900
PLANT RETIREMENTS (MW)													TOTAL RETIREMENTS	
HRAZDAN	0	0	0	0	0	0	0	0	0	0	0	0	0	
YEREVAN	0	0	0	0	0	250	0	0	0	300	0	0	550	
KIROVAKAN	0	0	0	0	24	0	0	0	0	47	0	0	71	
														621
NET THERMAL CAPACITY	1746	1746	1746	2046	2022	1972	1972	2072	2072	2025	2325	2725		
NET HYDRO CAPACITY	953	953	953	953	953	1028	1028	1103	1103	1253	1253	1253		
TOTAL INSTALLED CAPACITY	2699	2699	2699	2999	2975	3000	3000	3175	3175	3278	3578	3978		
FIRM CAPACITY ALLOWING FOR DERATINGS														
EXISTING THERMAL	1571	1571	1571	1571	1550	1325	1325	1325	1325	1013	1013	1013		
NEW THERMAL	0	0	0	300	300	500	500	600	600	900	1200	1600		
EXISTING HYDRO	400	400	400	400	400	400	400	400	400	400	400	400		
NEW HYDRO			0	0	0	25	25	50	50	100	100	100		
NET FIRM CAPACITY	1971	1971	1971	2271	2250	2250	2250	2375	2375	2413	2713	3113		
FIRM IMPORTS (MW)	100	0	0	0	0	0	0	0	0	0	0	0		
FIRM CAPACITY TO MEET NET PEAK LOA	2071	1971	1971	2271	2250	2250	2250	2375	2375	2413	2713	3113		
RESERVE CAPACITY MARGIN (FC-NPL)	-75	158	183	519	523	489	455	544	508	509	552	661		
RESERVE MARGIN %	-3%	9%	10%	30%	30%	28%	25%	30%	27%	27%	26%	27%		
RSRV RQD (25% MD OR 2 LRGST UNITS)	537	453	447	438	432	440	449	458	467	476	540	613		
RESERVE SURPLUS(DEFICIT)	-612	-295	-264	81	91	49	6	86	41	33	12	48		

Base Case - Capacity Balance

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19:55

Table 5.8 Power Generation Planning - Energy Balance

GIGAWATT HOURS	Actual 1990	Est. 1992	1993	1994	1995	1996	1997	1998	1999	2000	2005	2010
ELECRICITY DEMAND INDEX	100	84	82	81	80	83	85	88	90	93	107	123
SALES (GWH)	9021	7534	7429	7280	7252	7462	7678	7901	8130	8366	9651	11134
LOSSES IN NETWORK (%)	15.0%	15.0%	15.0%	15.0%	15.0%	14.4%	13.8%	13.2%	12.6%	12.0%	11.0%	10.0%
STATION USE (%)	7.0%	7.0%	7.0%	7.0%	6.0%	5.8%	5.6%	5.4%	5.2%	5.0%	4.5%	4.0%
GENERATION REQUIRED (GWH)	11282	9531	9398	9210	9076	9254	9436	9622	9812	10007	11355	12887
Annual Growth		-15.5%	-1.4%	-2.0%	-1.5%	2.0%	2.0%	2.0%	2.0%	2.0%	3.0%	4.0%
THERMAL PLANT AVAILABILITY	65%	65%	65%	65%	65%	66%	67%	68%	69%	70%	75%	75%
ANNUAL ENERGYCAPABILITY												
EXISTING HYDRO	1572	2856	2856	1500	1500	1500	1500	1500	1500	1500	1500	1500
NEW SMALL HYDRO				0	0	108	217	325	434	650	867	867
THERMAL	8948	8948	8948	10656	10533	10550	10710	11466	11634	11727	14536	17164
IMPORTS	920	500	500	0	0	0	0	0	0	0	0	0
TOTAL ENERGY CAPABILITY (GWH)	11440	12304	12304	12156	12033	12159	12427	13291	13568	13878	16903	19531
SURPLUS/DEFICIT (GWH)	158	2773	2906	2946	2957	2905	2991	3669	3756	3871	5548	6645
GENERATION REQUIRED	11299	9531	9398	9210	9076	9254	9436	9622	9812	10007	11355	12887
Of which,												
HYDRO	1572	2856	2856	1500	1500	1608	1717	1825	1934	2150	2367	2367
IMPORTS	920	500	500	0	0	0	0	0	0	0	0	0
THERMAL	8807	6175	6042	7710	7576	7645	7719	7797	7879	7856	8988	10520
CAPACITY UTILIZATION FACTORS %												
HYDRO	19%	34%	34%	18%	18%	18%	19%	19%	20%	20%	22%	22%
THERMAL	58%	40%	40%	43%	43%	44%	45%	43%	43%	44%	44%	44%
UTILIZATON OF GENERATING CAPABILITY												
HYDRO	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
THERMAL	98%	69%	68%	72%	72%	72%	72%	68%	68%	67%	62%	61%
PERCENTAGE GENERATION BY TYPE												
HYDRO	13.9%	30.0%	30.4%	16.3%	16.5%	17.4%	18.2%	19.0%	19.7%	21.5%	20.8%	18.4%
IMPORTS	8.1%	5.2%	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
THERMAL	77.9%	64.8%	64.3%	83.7%	83.5%	82.6%	81.8%	81.0%	80.3%	78.5%	79.2%	81.6%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Base Case - Energy Balance

ANNEX 3.3
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12/01/92 13:20

Power Generation Planning - Capacity Balance

MEGAWATTS	Actual 1990	Actual 1991	Est. 1992	1993	1994	1995	1996	1997	1998	1999	2000	2005	2010		
ELECTRICTY DEMAND INDEX	100	96	84	82	69	66	64	63	63	64	65	78	93		
NET PEAK LOAD (MW)	2146	2110	1813	1788	1499	1409	1359	1333	1325	1325	1326	1566	1844		
Growth Rate		-1.7%	-14.0%	-1.4%	-16.2%	-6.0%	-3.5%	-2.0%	-0.6%	-0.0%	0.1%	3.0%	4.0%		
Annual Load Factor	60%	60%	60.0%	60%	60%	60%	60%	60%	60%	60%	60%	60%	60%		
EXISTING INSTALLED CAPACITY (Less Retirements)															
MRAZDAN	1100	1100	1100	1100	1100	1100	1100	800	800	800	800	800	800		
YEREVAN	550	550	550	550	300	300	300	300	300	300	300	300	300		
KIROVAKAN	96	96	96	96	96	72	72	72	72	72	0	0	0		
TOTAL THERMAL	1746	1746	1746	1746	1496	1472	1472	1172	1172	1172	1100	1100	1100		
SEVAN-MRAZDAN CASCADE	527	527	527	527	527	527	527	527	527	527	527	527	527		
VORDTAN CASCADE	402	402	402	402	402	402	402	402	402	402	402	402	402		
SMALL HYDRO	24	24	24	24	24	24	24	24	24	24	24	24	24		
TOTAL HYDRO	953	953	953	953	953	953	953	953	953	953	953	953	953		
TOTAL EXISTING CAPACITY	2699	2699	2699	2699	2449	2425	2425	2125	2125	2125	2053	2053	2053		
PLANT ADDITIONS (MW)														TOTAL ADDITIONS	
CONVENTIONAL THERMAL STEAM	0	0	0	0	300	0	0	0	0	0	0	0	0	300	
GAS TURBINES	0	0	0	0	0	0	0	0	0	0	0	200	100	300	
COMBINED CYCLE	0	0	0	0	0	0	0	0	0	0	0	0	300	300	
SMALL HYDRO	0	0	0	0	0	0	75	0	75	0	150	0	0	300	
															1200
PLANT RETIREMENTS (MW)														TOTAL RETIREMENTS	
MRAZDAN	0	0	0	0	0	0	0	300	0	0	0	0	0	300	
YEREVAN	0	0	0	0	250	0	0	0	0	0	0	0	0	250	
KIROVAKAN	0	0	0	0	0	24	0	0	0	0	72	0	0	96	
															646
NET THERMAL CAPACITY	1746	1746	1746	1746	1796	1772	1772	1472	1472	1472	1400	1600	2000		
NET HYDRO CAPACITY	953	953	953	953	953	953	1028	1028	1103	1103	1253	1253	1253		
TOTAL INSTALLED CAPACITY	2699	2699	2699	2699	2749	2725	2800	2500	2575	2575	2653	2853	3253		
FIRM CAPACITY ALLOWING FOR DERATINGS															
EXISTING THERMAL	1571	1571	1571	1571	1346	1325	1325	1055	1055	1055	990	990	990		
NEW THERMAL	0	0	0	0	300	300	300	300	300	300	300	500	900		
EXISTING HYDRO	400	400	400	400	400	400	400	400	400	400	400	400	400		
NEW HYDRO				0	0	0	25	25	50	50	100	100	100		
NET FIRM CAPACITY	1971	1971	1971	1971	2046	2025	2050	1780	1805	1805	1790	1990	2390		
FIRM IMPORTS (MW)	100	100	0	0	0	0	0	0	0	0	0	0	0		
FIRM CAPACITY TO MEET NET PEAK LOA	2071	2071	1971	1971	2046	2025	2050	1780	1805	1805	1790	1990	2390		
RESERVE CAPACITY MARGIN (FC-NPL)	-75	-38	158	183	547	615	690	447	480	480	464	424	546		
RESERVE MARGIN %	-3%	-2%	9%	10%	37%	44%	51%	34%	36%	36%	35%	27%	30%		
RSRV RQD (25% MD OR 2 LRGST UNITS)	537	527	453	447	400	400	400	400	400	400	400	400	461		
RESERVE SURPLUS(DEFICIT)	-612	-566	-295	-264	147	215	290	47	80	80	64	24	86		

Low Demand Case - Capacity Balance

ANNEX 3.4
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13:20

...le 5.3 Power Generation Planning - Energy Balance

GIGAWATT HOURS	Actual 1990	Actual 1991	Est. 1992	1993	1994	1995	1996	1997	1998	1999	2000	2005	2010
ELECRICITY DEMAND INDEX	100	96	84	82	69	66	64	63	63	64	65	78	93
SALES (GWH)	9021	8635	7534	7429	6228	5919	5761	5699	5719	5769	5826	6997	8372
LOSSES IN NETWORK (%)	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	14.4%	13.8%	13.2%	12.6%	12.0%	11.0%	10.0%
STATION USE (%)	7.0%	7.0%	7.0%	7.0%	7.0%	6.0%	5.8%	5.6%	5.4%	5.2%	5.0%	4.5%	4.0%
GENERATION REQUIRED (GWH)	11282	11088	9531	9398	7878	7408	7145	7004	6964	6963	6969	8233	9689
Annual Growth		-1.7%	-14.0%	-1.4%	-16.2%	-6.0%	-3.5%	-2.0%	-0.6%	-0.0%	0.1%	3.0%	4.0%
THERMAL PLANT AVAILABILITY	65%	65%	65%	65%	65%	65%	66%	67%	68%	69%	70%	75%	75%
ANNUAL ENERGYCAPABILITY													
EXISTING HYDRO	1572	1572	2856	2856	1500	1500	1500	1500	1500	1500	1500	1500	1500
NEW SMALL HYDRO					0	0	108	217	325	434	650	867	867
THERMAL	8948	8948	8948	8948	9375	9252	9394	7952	8070	8189	7910	9789	12417
IMPORTS	920	920	500	500	0	0	0	0	0	0	0	0	0
TOTAL ENERGY CAPABILITY (GWH)	11440	11440	12304	12304	10875	10752	11002	9668	9895	10123	10061	12157	14785
SURPLUS/DEFICIT (GWH)	158	352	2773	2906	2996	3344	3858	2665	2931	3160	3092	3924	5095
GENERATION REQUIRED	11299	11088	9531	9398	7878	7408	7145	7004	6964	6963	6969	8233	9689
Of which,													
HYDRO	1572	1546	2856	2856	1500	1500	1608	1717	1825	1934	2150	2367	2367
IMPORTS	920	1572	500	500	0	0	0	0	0	0	0	0	0
THERMAL	8807	7970	6175	6042	6378	5908	5536	5287	5139	5029	4818	5865	7322
CAPACITY UTILIZATION FACTORS %													
HYDRO	19%	19%	34%	34%	18%	18%	18%	19%	19%	20%	20%	22%	22%
THERMAL	58%	52%	40%	40%	41%	38%	36%	41%	40%	39%	39%	42%	42%
UTILIZATON OF GENERATING CAPABILITY													
HYDRO	100%	98%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%
THERMAL	98%	89%	69%	68%	68%	64%	59%	66%	64%	61%	61%	60%	59%
PERCENTAGE GENERATION BY TYPE													
HYDRO	13.9%	13.9%	30.0%	30.4%	19.0%	20.2%	22.5%	24.5%	26.2%	27.8%	30.9%	28.8%	24.4%
IMPORTS	8.1%	14.2%	5.2%	5.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
THERMAL	77.9%	71.9%	64.8%	64.3%	81.0%	79.8%	77.5%	75.5%	73.8%	72.2%	69.1%	71.2%	75.6%
	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%

Low Demand Case - Energy Balance

ANNEX 3.4
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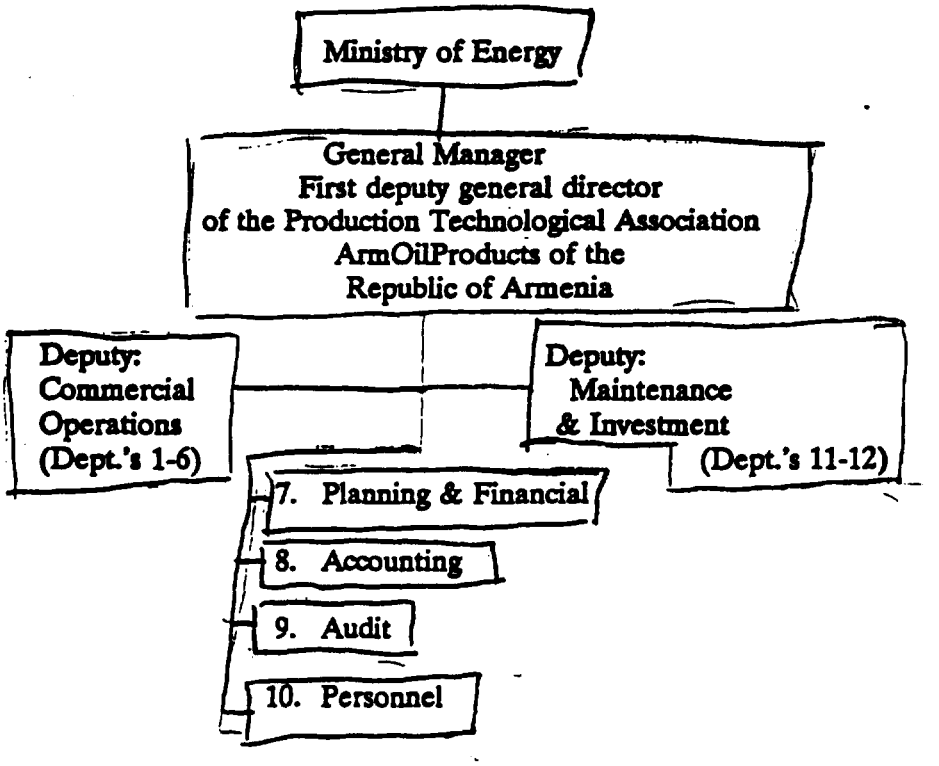
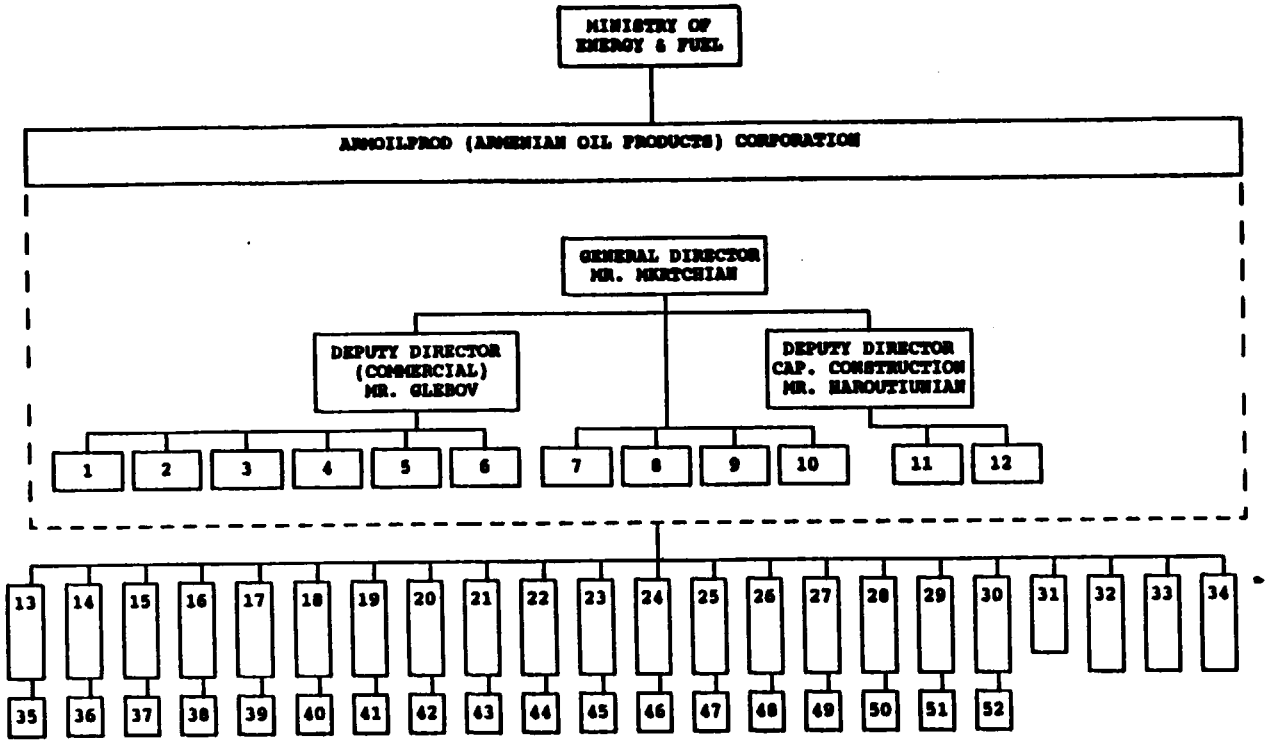
ANNEX 4.1

ARMOIL PRODUCTS ORGANIZATION




MINISTRY OF ENERGY & FUEL
ARMOILPROD (ARMENIAN OIL PRODUCTS) CORPORATION
GENERAL DIRECTOR MR. MKRTCHIAN
DEPUTY DIRECTOR (COMMERCIAL) MR. GLEBOV
DEPUTY DIRECTOR CAP. CONSTRUCTION MR. HAROUTIUNIAN
1 2 3 4 5 6 7 8 9 10 11 12
13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30 31 32 33 34
35 36 37 38 39 40 41 42 43 44 45 46 47 48 49 50 51 52

a. Shown above is the Central Administration of Armoil Products Corp. It consists of 12 operating departments; departments 1-6 report to the Deputy for Commercial Operations, departments 7-10 report to the General Manager, and departments 11 & 12 report to the Deputy for Maintenance & Investment.

b. The first 6 departments are listed below:

1. Document Control
2. Resources,Planning,& Oil Supply Transport
3. Lubricants & Used Oils
4. Consumer Inspection
5. Legal
6. Quality Control

Document Control handles the flow of paper information in the supply and distribution network. This where the inventory control system is maintained. In a largely non-computerized documentation system, there is a large flow of paper received and created on a daily basis for receipt of supplies, deliveries, inventory levels, and financial flows. The Armoil central administration directs each terminal in its inventory control, with each terminal reporting back to the central administration daily, and the central administration then directing the terminal for the next day's activities. Communications are difficult because of the poor telephone system, and the Armoil management is now installing a new teletype system. It would seem that some technical assistance in this area could be used, in computerizing reports and improving the communication network.

The resources, planning, and oil supply transport is the heart of the supply and distribution operation. It plans one month ahead, three months ahead and one year ahead, comparing planned to actual receipts and delivereies and adjusting the continuous forward plans commensurately. It is responsible for scheduling transportation, by rail into the terminals and by trucks out of the terminals. It is also responsible for working with the foreign suppliers, who are the agents for the Russian refineries which sell oil products to Armenia. These agents are the regional divisions of the Russian Oil Products Selling Company (Rus Neftzi Productzi) which today is responsible for all petroleum product sales within and outside of the Russian republic.

Lubricants and used oils are specialized activities managed outside of the bulk oil products distribution system.

The legal department handles contracts, disputes, and other regular functions.

Quality control manages laboratories both at the larger storage erminals and within the central administration. They have special equipment for sampling carloads of fuel and oil stored within the tanks.

c. The four departments reporting to the managing director are the same as is found in western oil distribution oranizations. The Planning & Financial department projects revenues and expenses, and estimates profits available for reinvestment in the business. The Accounting department keeps the financial records and also deals with the banks. Banking relationships are important in a high turnover oil distribution business, and involve dealing with banks who represent suppliers, customers, and lenders. The personnel department handles all employees of the central administration, as well the senior people in the terminal operations, including the terminal manager, the chief engineer, and the treasurer.

d. The last two departments of the central administration involve:

11. Maintenance & Operations
12. Capital Construction

Maintenance & Operations handles all questions relating to upkeep of facilities and equipment (tanks, pumps, pipes, hoses, guages, trucks, truck fill racks, fire extinguishers, etc.). The Capital Construction department plans and executes all new capital programs, including facilities expansion, new facilities, and service stations. In the past, they relied heavily on the expertise of the Volgograd Oil Storage Facility Construction and Design Institute,which acted as a technical consultant to oil storage organizations throughout the USSR. Armoil now plans to do more of this themselves and rely more on local experts.

e. Armoil operates 18 major storage facilities throughout the country, and other smaller facilities including 210 service stations. The service stations report to the managers of the storage terminals which supply them. (In the Organization Chart, the terminals are marked 13 to 31, and the smaller storage sites and service stations are marked 35 to 52. Terminal 30 in Yerevan is now under construction.)

f. In addition, there is a special enterprise of 24 service stations in Yerevan, reporting directly to the central administration. (Organization Chart #32)

g. There is a separate facility which purchases, stores and supplies all equipment needs throughout the Armoil storage and distribution network. This is managed by a separate organization which reports to the central administration. (Organization Chart #33)

h. There is, in addition, a separate group of employees who do construction, assembly and installation of equipment throughout the Armoil network. They work together with the equipment storage organization and report as well to the central administration. (Organization Chart #34)

i. The storage terminal managers report to the central administration by function. Financial and personnel issues go to those departments reporting to the Managing Director; commercial supply issues go to

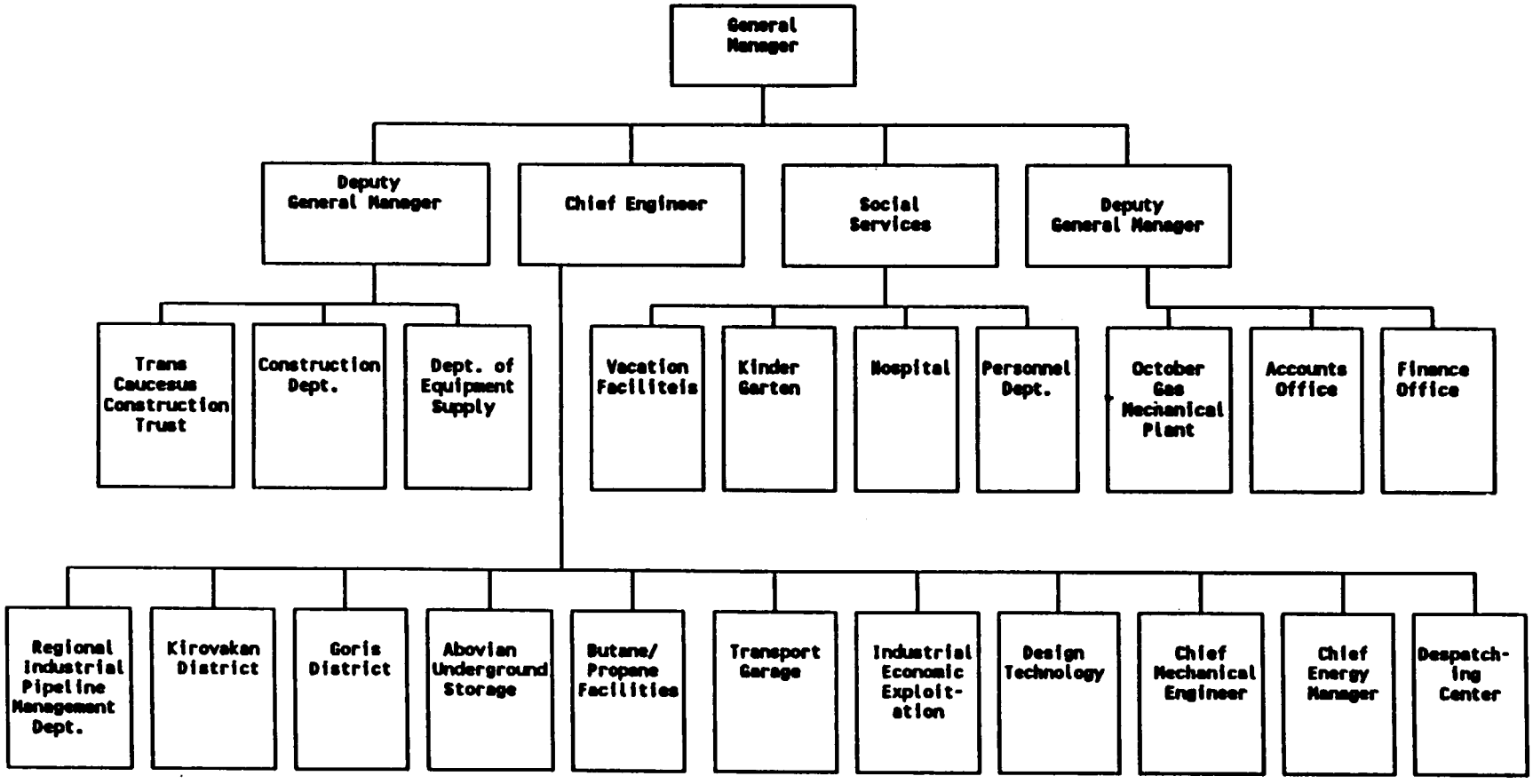
those departments reporting to the Deputy for Commercial Operations; and maintenance and construction issues go to those departments reporting to the Deputy for Maintenance and Construction. In this way, it would appear that an adequate span of management control can be maintained, in contrast to the more hierarchial system found in the west.

j. Armoil employs 1500 people.

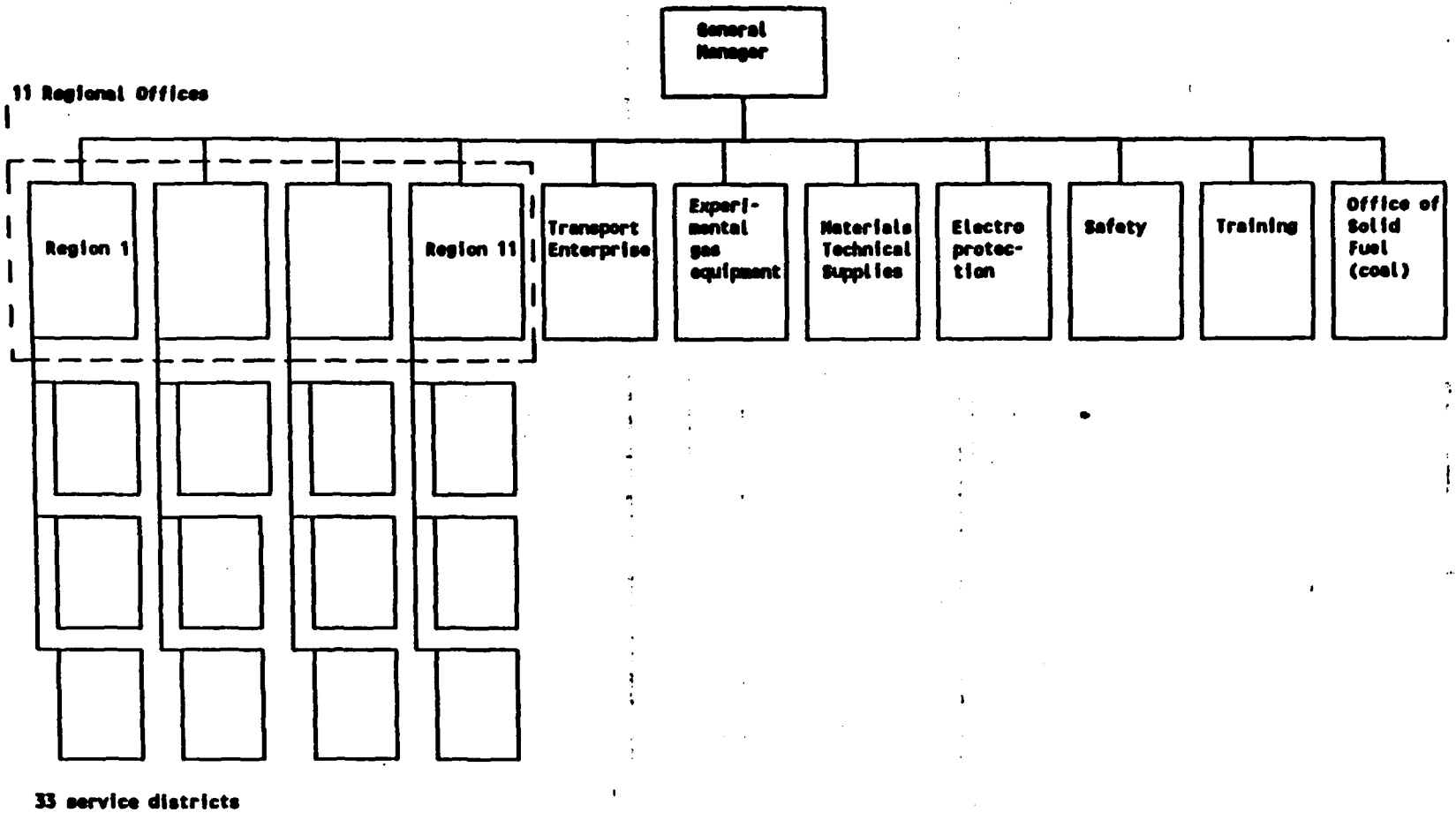
ANNEX 4.2

Armoil Products Balance Sheet 1985-91

	1985	1986	1987	1988	1989	1990	1991
CURRENT ASSETS							
Reserve for maintenance	2	6	14	19	21	26	204
Cash on hand	5	3	5	5	1	1	3
Cash in banks	1	88	126	0	981	254	0
Accounts receivable							
Commercial	2,994	3,201	4,537	7,853	8,841	7,858	24,622
Government	11,816	7,968	8,273	24,885	20,581	43,196	58,639
Supplier credits	114	101	115	227	493	793	1,673
Storage credits	104	230	1,298	2,095	68	66	9,120
Debts due from workers	46	41	39	47	38	33	26
Inventory at cost	4,275	6,825	6,890	14,184	7,970	8,480	12,925
Inventory losses	(144)	(92)	0	0	(74)	(2,037)	(3,570)
Total current assets	19,213	18,371	21,297	49,315	38,920	58,670	103,642
LONG TERM ASSETS							
Long term facilities	23,479	29,635	30,170	37,133	38,590	39,630	43,033
Facilities depreciation	(7,230)	(8,023)	(8,854)	(9,295)	(10,434)	(11,576)	(19,894)
Operating equipment	958	839	902	1,407	2,145	1,889	3,053
Equipment depreciation	(160)	(206)	(183)	(153)	(187)	(182)	(241)
Funds reserved for:							
Facilities repairs	257	526	648	0	0	0	0
Equipment replacement	0	0	0	609	0	519	1,186
Total long term assets	17,304	22,771	22,683	29,701	30,114	30,280	27,137
TOTAL ASSETS	36,517	41,142	43,980	79,016	69,034	88,950	130,779
Current Liabilities							
Short term debt to Banks	3,899	3,748	7,869	4,260	0	6,104	10,748
Short term debt to suppliers	5,295	6,220	5,128	15,067	13,678	12,346	36,689
Prepaid product sales	160	204	0	0	450	1,824	0
Special project needs	520	492	562	509	3,817	10,327	27,371
Salaries owed to workers	86	65	81	125	197	295	411
Loans owed to workers	46	41	39	50	38	33	24
Total current liabilities	10,006	10,770	13,679	20,011	18,180	30,929	75,243
LONG TERM LIABILITIES							
Long term debt to banks	8,450	5,842	5,873	23,703	5,246	29,621	21,256
Other long term debt	0	0	73	381	16,848	0	0
Supplier long term debt	528	282	1,076	2,439	855	730	6,962
OVERSTATEMENT OF:							
Net profit (loss)	(1,120)	(589)	(1,559)	(195)	(665)	(503)	(2,429)
Total long term liabilities	7,858	5,535	5,463	26,328	22,284	29,848	25,059
TOTAL LIABILITIES	17,864	16,305	19,142	46,339	40,464	60,777	101,302
Net worth							
Original government capital	13,993	19,211	18,992	25,287	24,843	26,117	26,309
Net retained earnings	236	1,138	785	(1,315)	(466)	(923)	3,168
Annual government capital	4,424	4,488	5,061	8,705	4,193	2,979	0
Total net worth	18,653	24,837	24,838	32,677	28,570	28,173	29,477
Liabilities + net worth	36,517	41,142	43,980	79,016	69,034	88,950	130,779



ARMGAZPROM ORGANIZATION



ARMGAS ORGANIZATION CHART

ARMENIA

Outline Terms of Reference for Technical Assistance and Pre-investment Studies

Introduction

1. Technical assistance (TA) and preinvestment studies are needed for the detailed analysis of issues and options in Armenia's energy sector in connection with policy formulation, sector reform, and project preparation. Specific technical assistance activities have been identified in the course of missions by World Bank, EBRD, European Commission (EC) and USAID. To provide maximum benefit through technical assistance to Armenia and avoid duplication or gaps in the support, the activities should be structured within an overall TA program for the energy sector and each of the subsectors

2. This document is a synthesis of the individual activities which have been identified and can provide a basis for coordination with the government and among donors.

3. Some studies will provide the information base needed for subsequent studies either at a subsector level or the broad energy sector level. The timing and sequencing of studies must be considered in TA coordination to avoid duplication of effort and to ensure that an adequate information base is available for each activity. No study can be entirely definitive, however, since the planning process is iterative.

4. Institutional reform could be difficult in the short term in view of the present energy shortages, the shortage of funds for normal operations, and the need for close control of available resources. While the long term objective of the government is to establish autonomous sector entities with private sector involvement, this objective may be difficult to implement in the short term. TA in sector reforms will thus need to be designed to take into account the short term constraints; however, the initial draft TORs for the activities below reflects the long term objective.

Draft Program of Technical Assistance and Planning Studies

5. TA and planning studies would be provided to assist government at the level of the ministries, notably Ministry of Energy and Fuel (MEF), to define and implement a strategy for sector development. In addition, studies at the subsector level such as physical planning for power generation, gas transmission and storage, are needed. Detailed TORs have been prepared for a number of activities while others are given in outline form with nominal budgets indicative of the level of effort.

6. The budgets shown cover the costs of international consultants (fees, travel, and subsistence) as well as local transportation, and equipment such as computers. Much of the detailed work is expected to be carried out by Armenian counterparts working with the consultants and for which no budget is required.

Program Financing

7. Sufficient funds appear to be available through EBRD, EC, and USAID to cover the activities indicated in Table 1 and described below. Project preparation funds could also be provided by World Bank. No donor agency has expressed a strong support for the gas sector which, like the power and heating sectors, is in need of rehabilitation preceeded by detailed studies. At present, there could be a duplication of effort in areas relating to energy conservation and hydrocarbon development and further coordination is needed.

A. Technical Assistance at Overall Energy Sector Level

1. Restructuring and Institutional Development US$ 75,000

Objective: To establish a sector for the energy sector that is consistent with the objectives of economic reform and democratic government which has been and is being established in Armenia. This study would set the stage for additional studies in each of the subsectors, namely, electric power/district heating, natural gas, and petroleum.

Scope of Work: Taking into account the constitution of the Republic of Armenia, the legal system, the long term objectives for economic reform, and the current institutional framework, the study would propose and analyze various institutional options with regard to sector structure, the assignment of responsibilities, the creation, dissolution, and/or merging of entities.

2. Regulatory Framework US$ 75,000

Objective: Develop the necessary legal mechanisms and bodies to ensure efficient operation of the energy sector where natural monopolies exist or where there is a risk that monopolistic practices would occur.

Scope of Work: Assess regulatory options. Prepare draft legislation and terms of reference for the entities required to administer the regulatory system.

3. Energy Data Management System US$ 150,000

Objective: Provide sector officials with sufficient, timely, consistent, and accurate information on energy supply and demand in terms of volumes, costs and analytical ratios as the basis for energy management and policy making.

Scope of Work: Assess the information needs at each level of management (senior government, sector planning, subsector management and operations).
Review existing data collection and information systems.
Propose system modifications, hardware, software and personnel requirements.
Design and implement the agreed system on hardware to be supplied as part of the activity.

International Consultants:	
Energy planner	
Data base management and systems specialist	
Total Fees, travel and subsistence:	US$ 100 K
Computing equipment and software:	50
Total Budget:	150

4. Demand Analysis and Forecasting — US$ 75, 000

Objective: Prepare short, medium and long term forecasts of primary energy requirements by type of fuel or energy carrier on the basis of demand projections for final energy and taking into account economic growth, structural changes in the economy and energy efficiency improvements.

Scope of work: For each end use sector, analyze historical demand and the factors influencing it. Work with subsector planners (power, heating, transportation, etc.) to derive forecasts of primary energy and fuel mix with allowance for supply contingencies.

5. Energy Macro Economic and Financial Issues — US$ 75,000

Objective: Assess the aggregate financial requirement of the energy sector for recurrent and capital cost local currency and foreign exchange.

Scope: Energy pricing will be dealt with in connection with financial planning for each subsector; however, a further review of overall energy pricing issues is needed to take into account social safety net and other objectives. The aggregate financing requirement for the energy sector should be assessed against overall macro resource availability.

Consultant: Economist/financial analyst

6. Energy Resource Exploration and Evaluation

Objective: Assess the viability of developing national energy resources.

Oil and Gas
Scope: Prepare promotional package to attract private sector exploration and development groups.

Funding: US Trade and Development Program with California Energy Commission.

Peat and coal:
Scope: Feasibility study of the development of coal and peat resources for power, heating, and household use.

Funding: USAID/US Geological Survey.

Wind: Private firms are interested in wind farm development. Economic cost/benefit analysis should be carried out as part of the power subsector studies.

Hydro: To be evaluated as part of the physical planning study for the electric power subsector.

7. Strategic Petroleum Reserve US$ 50,000

Objective: Increase the security of supply of fuels for transportation, power generation, and heating.

Scope: Assess the reserve required and cost of constructing, filling, and maintaining petroleum product storage facilities. Consideration is to be given to increasing the storage of natural gas as part of the natural gas studies.

8. Energy Conservation and Efficiency Improvement

Technical assistance is being provided with funding from the European Community (500,000 ECU) and USAID (in the order of $500,000). Responses to a Request for Proposals are now being evaluated by EC.

B. TECHNICAL ASSISTANCE AT THE SUBSECTORAL LEVEL

For each subsector, TA for physical and financial planning and institutional development is proposed. Draft TORs and budgets have been prepared in detail. EBRD has expressed interest in financing the activities for the electric power sector including assistance in fuels procurement and contracting.
USAID is currently supporting limited TA in the district heating subsector; however, a comprehensive study is needed to determine short run requirements for rehabilitation and a longer term strategy which could involve replacing district heating with more efficient localized heating systems.

Table 1 PROPOSED TECHNICAL ASSISTANCE PROGRAM

Study	Total Budget US$ thousands	Possible Financing
A. Overall Sector Activities		
1. Restructuring and Institutional Development	75	EBRD, EC
2. Regulatory Framework	75	EBRD, EC
3. Energy Data Management System	150	USAID?
4. Demand Analysis and Forecasting	75	USAID?
5. Energy, Macro Economic and Financial Issues	75	USAID?
6. Energy Resource Exploration and Evaluation - Oil and Gas - Peat and Coal	 ? ?	 US/TDP, EC USAID
7. Strategic Petroleum Reserve	50	USAID ?
8. Energy Conservation and Efficiency Improvement	?	European Community, USAID
B. Sub Sectoral Studies		
1. Power Sector Facilities Planning	550	EBRD
2. Power/Heating Sector Financial Planning and Institutional Development	270	EBRD
3. Gas Facilities Planning (incl Iran pipeline)	400	?
4. Gas Sector Financial Planning and Institutional Development	270	?
5. Heating Facilities Planning	300	USAID
6. Fuels contracting	90	EBRD
Total	2,380	

B.1. POWER SECTOR FACILITIES PLANNING STUDY

BACKGROUND

1. The Government of Armenia wishes to carry out a planning study concerning the physical and financial requirements for the rehabilitation and development of the power and combined district heating systems sectors. Additional studies for the preparation of a financing plan, institutional restructuring and the rehabilitation of the broader heating sector and will be carried out under separate TORs.

2. The existing situation in the energy sector is characterized by a back log of maintenance and repairs to generating plant, transmission and distribution facilities as the result of the lack of funds to carry out the required work. The energy blockade has placed greater emphasis on the attractiveness of national energy resources such as hydro, coal, peat, wind and solar energy.

3. In view of Armenia's dependence on imported fuels for the generation of about 85% of the 1990 level of electricity demand, the government is seriously considering the recommissioning of the nuclear plant. Two basic scenarios must therefore be considered, with and without one or both 400 MW nuclear units. Studies relating to the definition of requirements and costs of upgrading, recommissioning, or decommissioning the nuclear plant would be carried out under a separate TA program.

OBJECTIVES

4. The objective of the study is to carry out a planning study of the power sector facilities requirements for generation, transmission, and distribution facilities to meet demand up to 2010. The scope of work for this study does not include the district heating sector; however, account must be taken of the costs and benefits of continuing to supply heat from combined heat and power plants. Sector planning should be carried out to determine the least cost means of meeting final demand taking into account strategic needs for a degree (to be determined) of energy independence and increased supply reliability.

5. The study will provide a complete investment program showing financial requirements in foreign and local currencies for rehabilitation and expansion for generation, transmission and distribution as well as vehicles and equipment. A financing plan will be prepared separately.

6. Technology transfer to Armenian professional staff in all aspects of power system planning and methodologies will be a specific objective of the study. The consulting firm selected to lead the study will present seminars and short training courses and will carry out as much of the study as possible in Armenia.

SCOPE OF WORK

Assessment of Existing Facilities

7. The study will begin with an assessment of the condition of all existing facilities to a degree consistent with the resources provided in the budget. An estimate will be made of the condition of the plant, the requirements and cost of rehabilitation, and the expected duration of remaining plant life. The areas of focus are as follows:

(a) Hydro plants:

(b) Thermal plants and combined heating facilities:

(c) Transmission network for internal supply and for regional interconnection.

(d) Power distribution facilities.

8. Estimates of materials and costs of materials by type should be prepared for urgently needed repairs and provision of spare parts for operation. Requirements for rehabilitation and plant life extension should be estimated separately for evaluation as part of the long term planning options.

Load Forecasting

9. Given the uncertainties that confront Armenia, there is a need to follow a scenario approach in demand forecasting and to estimate, to the extent possible, the probability of occurrence of each scenario. High, low, and base case scenarios should be prepared based on the overall macro economic projections to be provided by the Ministry of Economics and Planning and the projections for economic restructuring.

10. Demand analysis for each consumer category (industry, household, agriculture, etc.) should be carried to determine, for instance, the frequency distribution of consumption per connection, intensity of demand related to industrial output, and other causal factors including price which influence demand.

Demand Management

11. A program of demand side management and energy conservation is being prepared under a separate study. The recommended plans should be assessed as to their impact on final demand in terms of load (kiloWatts) and energy (kiloWatt-hours).

Facilities Planning

12. **Hydro Generation.** For the existing hydro plants, the following characteristics should be assessed:

- hydrology
- storage (daily, seasonal, and annual)
- conjunctive water needs for irrigation, industrial, and municipal water supply
- hydro power dispatching (daily, weekly, seasonal) and firmness of power

13. Roughly 100 small hydro plants have been identified and studied to varying levels of detail. It is necessary to review the available documentation with regard to the status of design, power generation characteristics, technical and economic feasibility, and cost estimates.

14. **Renewable Energies.** Studies of wind power potential are currently underway and should be taken into account in this study. An assessment should also be made of the potential for solar (thermal and/or photovoltaic) power. Terms of reference for additional studies should be drawn up if it is apparent that wind and solar power can make a significant contribution power supply at an economic cost taking into account security of supply benefits.

15. **Thermal Generation.** Thermal plant types to be considered in power planning included conventional combined heat and power, multi-fuel fired (gas, mazut, and possibly coal and/or peat), and combined cycle gas fired combustion turbine plant. The report on the evaluation of the existing plants will be used to determine the feasibility and costs of plant life extension as well as the retirement schedule for which major rehabilitation is not warranted. Provision should be made for the supply of steam and heat for district heating.

16. The feasibility of converting the nuclear power plant to conventional steam plant assessed based on experience elsewhere and recommissioning/decommissioning studies on the Armenia plant previously prepared.

Power System Planning

17. A power system expansion model such as WASP should be used to determine the least cost sequence of power system and the provision of district heat. Sensitivity and risk analysis should be carried out to assess the consequences of uncertainties in demand, unit capital and fuel costs, possible constraints in fuel supplies and the costs of unserved power.

Transmission and Distribution

18. A transmission network load flow analysis should be carried out to assess the requirement for network and substation reinforcement down to the distribution substation level.

19. Requirements for reinforcement and expansion of the distribution network beyond the distribution substations to meet load growth should be assessed and combined with the requirements for rehabilitation and loss reduction. Total funding requirements should be identified in terms of material and erection costs per kilometer of distribution plant of each voltage and type. Requirements for transformers should be estimated in terms of total number of units by size or in terms of total number of kVA of capacity.

20. For both transmission and distribution networks, an assessment of the potential for loss reduction should be made. Terms of reference for loss reduction studies should be prepared as necessary

as a free standing project or as part of a rehabilitation project which could be identified without further study.

Investment Program

21. The consultants will prepare an investment program showing year by year disbursements in local and foreign exchange for each standalone project identified for generation, transmission, and distribution.

Study duration 6 months in country

Reporting

Working papers for each item identified in the scope of work will be prepared and discussed in the field.

Working Arrangements

All work will be carried out in Armenia with counterparts to be assigned by ARMENERGO and MEF.

BUDGET

	man.months
1. Evaluation of Existing Plant	
Hydro engineer	2
Thermal plant engineers - 2x3 mo.	6
Renewable energy planner	1
Transmission and Distribution engineer	3
District heating engineer	2
subtotal	14
2. Load forecasting, demand analysis	
Economist	2
3. Demand Management specialist	2
4. Supply Planning	
Hydro power	3
Power system planner/modeller	2
5. Investment Program, synthesis and report writing	2
Total manpower	25

Funding Requirements		US$ 000
Personnel	25 @ US$ 15,000/m.m	375
Travel and Subsistence		
trips	15 @ $3500	55
subsistence	600 days @ 100	60
Computer hardware and software		20
In country transportation		10
Interpretation and Translation		15
Contingencies		15
Total cost		550

B.3 GAS SECTOR FACILITIES PLANNING

OBJECTIVE

1. The government of Armenia wishes to evaluate the condition of existing gas sector transmission, storage, and distribution facilities and carry out a study of the requirements for system rehabilitation and development to meet current and future demand. Particular attention is to be given to strategic issues of increased storage and supply diversification through the construction of a pipeline to Iran.

SCOPE OF WORK

2. Various studies have already been carried out by ARMGAZPROM, ARMGAS, and international consultants concerning the proposed Iran gas, storage faciliities, and rehabilitation requirements. The scope of work will consist of a review of available documentation concerning the existing facilities and a limited physical inspection of plant and equipment in order to assess priorities in sufficient detail to prepare project budgets and annual capital investment and operating budgets.

3. The scope of work includes the following main items:

Gas Utilization and Demand Forecasting

(a) Evaluation of the current practices of gas utilization and metering and recommendations for improvements which could lead to savings in gas consumption.

(b) Preparation of demand forecasts based on macro economic projections (the same as for the power sector), estimates of end-use requirements by consumer category for cooking, heating, and as a boiler fuel and taking into account the implementation of energy conservation programs including the introduction of meters for household consumption (see below). The possibility of interfuel substitution especially for boiler fuels depending on contract terms for each fuel and non-availability of fuels is to be assessed in preparing the demand forecasts.

(c) The need for and sizing of gas storage facilities should be assessed taking into account the prospects for gas supply diversification and proposals made in other studies for the creation of a strategic petroleum reserve for mazut power generation and heating.

Evaluation of Existing Facilities

(a) Selective site inspections should be made of transmission and distribution pipelines to determine their condition, need for, and cost of rehabilitation or replacement, cathodic protection etc.

(b) Similar inspections are to be made for compressor, storage and pressure reduction facilities.

Gas Import Pipeline from Iran

(a) Review of existing plans for the sizing, routing and design of the proposed pipeline from Tabriz (Iran) to Goris (Armenia) (110 km) as Phase I and the extension of the pipeline from Goris to Yerevan (160

km) in Phase II. Preparation of cost estimates in foreign and local currencies for material supply and facilities construction.

(b) Alternative proposals as warranted together with project design and costings.

Distribution Network Development
(a) Based on the demand forecasts, determine the need for and design and cost of reinforcements and expansion required for the distribution network.

Metering Program
(a) Prepare a design and estimate the cost of and time required for installing consumer meters on all currently unmetered connections.

Storage Facilities

(a) Review plans for and costs of fully utilizing the existing storage and extending gas storage facilities to provide the required storage for both strategic and operational needs.

Overseas Training

(c) Three staff from the gas supply entities to travel for about three weeks to the home office of the gas company providing consulting services to work to attend seminars, visit facilities, and participate in report preparation.

BUDGET AND MANPOWER REQUIREMENT

Manpower		staff-weeks
Pipeline engineer (transmission and storage)		14
Pipeline engineer (distribution)		14
Gas utilization analyst		8
Energy economist/forecaster		8
Project manager		16
Total		60
Costs		**US$ 000**
Fees	60 @ US$4000/wk	240
Travel and subsistence	12 trips @ US$3500	42
	315 days @ US$150	47
Internal transportation (vehicle rental)		10
Interpretation and translation		15
Overseas training		25
Contingency/unallocated		21
Total		400

B.2 and B.4 INSTITUTIONAL DEVELOPMENT, FINANCIAL SYSTEMS AND PLANNING STUDIES

(two separate studies to be carried out for
the gas and power/heating subsectors)

OBJECTIVE

1. The government of Armenia wishes to restructure and reform operating entities in the energy sector including the power and heating company ARMENERGO, the Yerevan power and heating service, and the gas sector companies, ARMGAZPROM (high pressure transmission) and ARMGAZ (gas distribution). Within the gas sector, the government is further considering the merger of the two existing entities. The objective of the separate studies to be carried out for each entity to be retained is to strengthen the orientation of the energy sector companies along commercial lines based on internationally accepted principles of accounting and financial structure in order to promote operating efficiency and improve accountability, and provide timely and accurate information to managers, boards of directors, and the government in its role as owner and regulator.

2. The energy sector operating entities will be restructured in the longer term. In the near term, a brief organizational study is needed to recommend changes in structure and assignment of functional responsibilities in order to improve operating efficiency.

SCOPE OF WORK

3. For each entity the scope of work will be similar. The accounting and financial systems to be established must reflect the institutional structure and regulatory framework which is to be established as under the studies concerned with the restructuring of the energy sector. The scope of work includes, but is not limited to, the following aspects:

(a) The evaluation of existing accounting systems and recommendations for modifications as required for commercially oriented operations.

(b) Recommendations concerning the installation of computerized accounting system including broad estimates of costs of equipment, the design and implementation of a system of accounts, preparation of manuals, and staff training.

(c) The preparation of pro forma corporate financial statements for the most recent operating year based on internationally accepted principles. These statements should include the Balance Sheet, Income (Profit and Loss) Statement, and Source and Applications of Funds Statement.

(d) The analysis of operating and maintenance costs.

(e) Preparation of an investment program based on the cost estimates and disbursement profiles prepared under the system planning studies carried out separately.

(f) Preparation of a financing plan including international and domestic borrowing, financing from internal sources (revenues), and contributions (debt and equity) from government and/or others.

(g) Preparation of financial projections (Income statement, balance sheet, source and applications of funds, borrowing and debt service schedules, etc.) for the period up to 1997 and indicatively for a further five years based on assumptions concerning the sources of financing and the adjustment of tariffs as needed to meet average tariff requirement and financial objectives.

(h) A tariff analysis with respect to level and structure required to reflect the cost of service to each consumer category to meet the overall revenue requirements of each entity for the supply of gas and the cost of capital investments, operating, and maintenance costs, debt service, and a portion of the financing of new investments.

(i) An analysis of the impact of tariffs on the monthly bills of consumers of all categories and consumers' ability to pay.

(i) Recommendations concerning appropriate tariff adjustment mechanisms.

Institutional Development

For each subsector, planning for specific institutional restructuring is needed and is to follow on from the framework to be determined under the overall energy sector institutional development and regulatory studies. Subsector studies will include:

(a) A review of the existing subsector organization and institutions and the revised structure to be established within the overall energy sector framework.

(b) An analysis of functional requirements and recommendations concerning organization and reporting structure and staffing.

OUTPUTS

4. Working papers will be prepared in English and translated into Armenian (or Russian) concerning (1) accounting systems, (2) historical and projected financial statements, and (3) tariff requirements, and (4) recommendations institutional development.

BUDGET

		Staff Weeks
Consultants		
Accounting systems specialist		12
Financial Planner		12
Tariff specialist		10
Institutional specialist		6
Total manpower		40
Costs		US$ 000
Fees	40 @ US$ 4,000 staff-week	160
Travel and subsistence		
Trips	10 @ US$3500	35
Subsistence	240 @ US$ 150/day	35
Interpretation and translation		10
Local Transportation		10
Contingencies		20
Total		270

B.5 DISTRICT HEATING FACILITIES PLANNING STUDY

BACKGROUND

1. Most of the heating requirements in urban centers in Armenia is supplied from district heating systems which generally can burn natural gas and/or mazut. Heat is produced in combined heat and power plants in three cities (Yerevan, Hrazdan, and Kirovokan) and independent boiler houses serving a 20 km radius in the case of Yerevan. Heating systems in general are inefficient and deteriorating due to a lack of maintenance and repair. Heat in individual apartments is not controllable nor is it metered. Heat supply is charged at a flat rate per square meter of area.

OBJECTIVE

2. The objectives of the heating facilities planning study are to evaluate:

(a) the condition of the existing facilities, the needs for repair and rehabilitation.

(b) the opportunities for energy efficiency improvement in heat production, distribution, and consumption.

(c) the long term options range from (1) phasing out district heating and replacing with individual systems in each building or to (2) continuing with district heating and present extent of coverage. The optimum solution may lie between these extremes.

SCOPE OF WORK

3. The scope of work will include the following task:

(a) a physical assessment of
- boiler houses
- hot water and steam transmission and distribution networks
- building heating installations.

Each component should be assessed in terms of need for repair and rehabilitation, remaining life, and opportunities for efficiency improvements including metering and controls.

(b) an evaluation of alternative heating systems to determine the optimum strategy to supply heat at least cost taking into account the types and mix of fuels that can be used by each system.

(c) preparation of a rehabilitation and investment program with cost estimates in foreign and local currencies and showing annual disbursements. These estimates will be fed into the financial planning study to be carried out separately.

BUDGET

Consultants	Staff-weeks
Boiler engineer	12
Transmission and distribution engineer	12
Building heating engineer	12
Financial analyst/economist	10
Total	46

Costs	US$ 000
Fees 46 @ $4000	180
Travel 8 trips @ $3500	28
Subsistence	45
Local transportation	10
Interpretation/translation	10
Contingencies	27
Total cost	300

B.6 TECHNICAL ASSISTANCE IN FUEL SUPPLY CONTRACTING

OBJECTIVE

1. As fuel supply agreements between Armenia and traditional suppliers of natural gas and petroleum products, previously based on barter trade and state orders, are being replaced by monetized contracts which are likely to be denominated in hard currency, Armenia wishes to ensure that it is prepared to negotiate satisfactory contracts. To this end, technical assistance is to be provided to Armenian officials (MEF, ARMOIL, ARMENERGO, and ARMGAZPROM) to provide them with information concerning international practices in supply contracting for all types of fuels.

2. The government also wishes to consider alternative approaches for the acquisition of fuels. These alternatives range from assigning responsibility to a centralized state fuels procurement authority at one extreme to giving responsibility to individual operating entities for the negotiation of contracts for their own requirements. As the transaction costs of negotiations are substantial and bargaining power is greater when larger quantities are involved, some degree of centralization is likely to be advantageous. Complete centralization in a government body, however, would run counter to the objective of devolving responsibility away from government. In the case of petroleum products government wishes to privatize the supply of transportation fuels and currently most gasoline is supplied to individual consumers in this way. One objective of the study, therefore is to assess the various options for the procurement of fuels in terms of meeting overall objectives for sector reform while at the same time supporting the objective of ensuring a reliable supply of fuel at least cost.

3. Assistance with regard to features and forms of gas contracts is also requireed as an input to the preparation of the proposed Iran gas pipeline project, its design, and financing.

SCOPE OF WORK

4. The technical assistance to be provided by two individual procurement/contracting specialists will focus on the two main fuels -- petroleum products and natural gas. In each case, the specialists will familiarize themselves with the existing supply situation, quantity and seasonal characteristics of demand, fuel substitution possibilities, and other factors relevant to contract terms. A seminar will be given outlining procurement options and features of commonly used forms of contract and commercial practices.

5. In the near term, options for fuel procurement are severely constrained. Over the longer term these constraints will be lifted and options should be identified and assessed in terms of security of supply, logistics, likely payment terms, and remedies to both parties (Armenia and supplier) in the event of failure to meet the terms of the contract.

6. Advisory assistance in eventual contract negotiation would also be provided within the scope of work.

Petroleum Products

7. The present supply situation via Georgia gives little flexibility for contract negotiation. In the longer term with the easing of the trade and transport blockade, it may be advantageous for Armenia to investigate alternative sources of supply. The petroleum specialist should Armenian authorities in evaluating the impact of contract size, order interval, duration, fuel specification, and commercial terms for each fuel type but for mazut in particular.

Natural Gas

8. Existing contracts for gas supply and transiting should be reviewed and recommendations given as to possible revisions which could be proposed by either party and their impact on supply costs to Armenia.

9. In the case of the proposed Iran gas pipeline, it will be necessary for both Iran and Armenia to enter into a long term contract of, say, 10-15 years duration in order to ensure a stable trading relationship satisfactory to both parties. Factors to be considered include:

(a) The price of gas and its indexation to alternative fuels such as mazut which is the principal boiler fuel for heating and power generation.

(b) The seasonal flexibility of gas deliveries and the volume of storage available to smooth out the delivery schedule.

(c) Take or pay commitments as required by the supplier to recover the fixed cost of supply but which could commit Armenia to taking gas in excess of requirements.

DURATION

10. Assistance would be provided over a period of about 4-6 months including 1 or 2 trips.

OUTPUT

11. Each specialist would present a general seminar and provide documentation on contracting principles and practice. Further notes and memos should be provided as requested by Armenian authorities within the time available.

BUDGET

Consultants		Staff-weeks
Petroleum specialist		6
Gas specialist		8
Total		14
Costs		US$ 000
Fees	14 @ US$ 4500	63
Travel and subsistence		
	travel 4 @ US$3500	14
	subsistence 84 days @ US$ 150	13
Total		90

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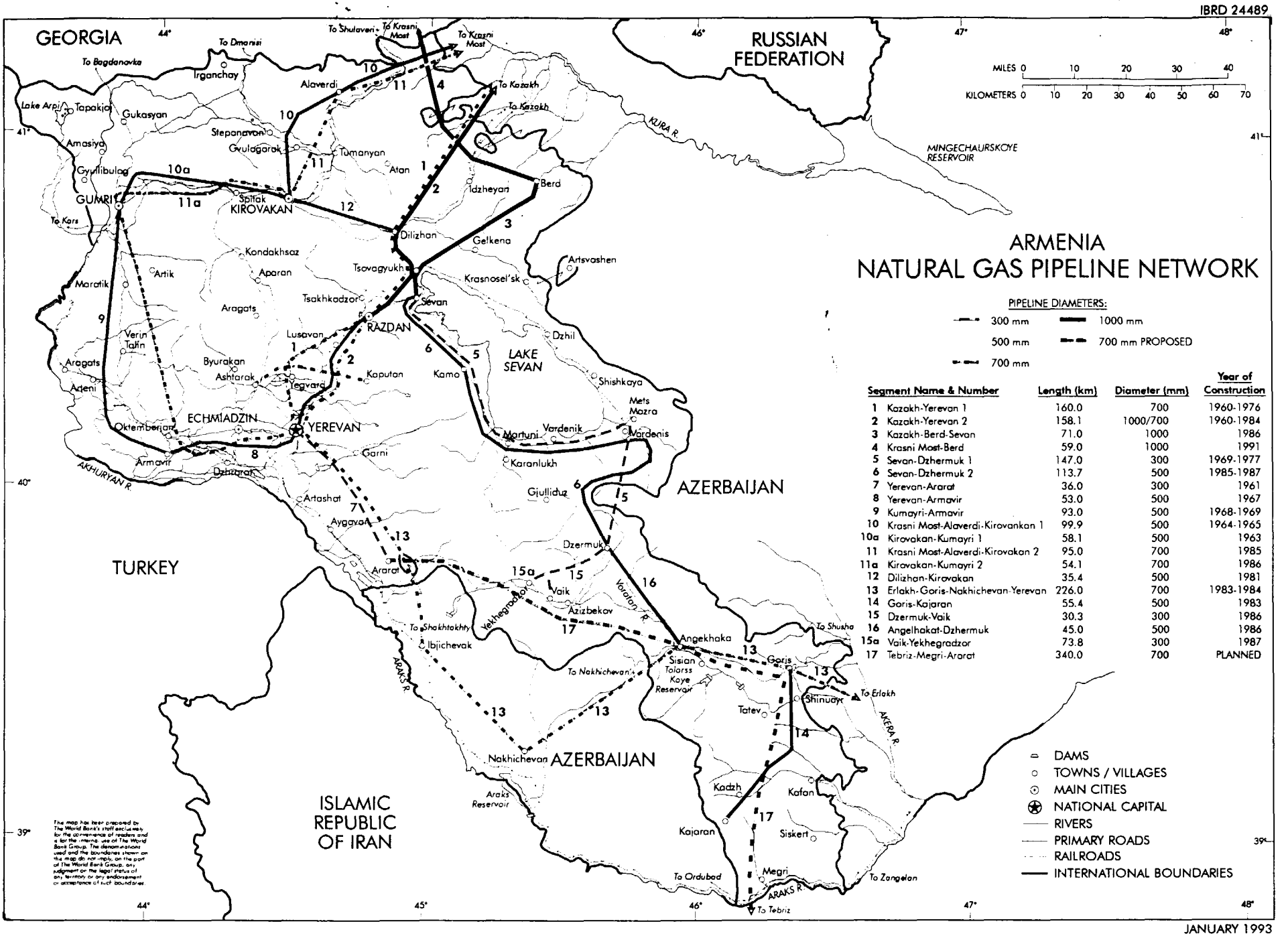

ARMENIA
NATURAL GAS PIPELINE NETWORK

PIPELINE DIAMETERS:

- 300 mm
- 500 mm
- 700 mm
- 1000 mm
- 700 mm PROPOSED

Segment Name & Number	Length (km)	Diameter (mm)	Year of Construction
1 Kazakh-Yerevan 1	160.0	700	1960-1976
2 Kazakh-Yerevan 2	158.1	1000/700	1960-1984
3 Kazakh-Berd-Sevan	71.0	1000	1986
4 Krasni Most-Berd	59.0	1000	1991
5 Sevan-Dzhermuk 1	147.0	300	1969-1977
6 Sevan-Dzhermuk 2	113.7	500	1985-1987
7 Yerevan-Ararat	36.0	300	1961
8 Yerevan-Armavir	53.0	500	1967
9 Kumayri-Armavir	93.0	500	1968-1969
10 Krasni Most-Alaverdi-Kirovankan 1	99.9	500	1964-1965
10a Kirovakan-Kumayri 1	58.1	500	1963
11 Krasni Most-Alaverdi-Kirovakan 2	95.0	700	1985
11a Kirovakan-Kumayri 2	54.1	700	1986
12 Dilizhan-Kirovakan	35.4	500	1981
13 Erlakh-Goris-Nakhichevan-Yerevan	226.0	700	1983-1984
14 Goris-Kajaran	55.4	500	1983
15 Dzermuk-Vaik	30.3	300	1986
16 Angelhakat-Dzhermuk	45.0	500	1986
15a Vaik-Yekhegradzor	73.8	300	1987
17 Tebriz-Megri-Ararat	340.0	700	PLANNED

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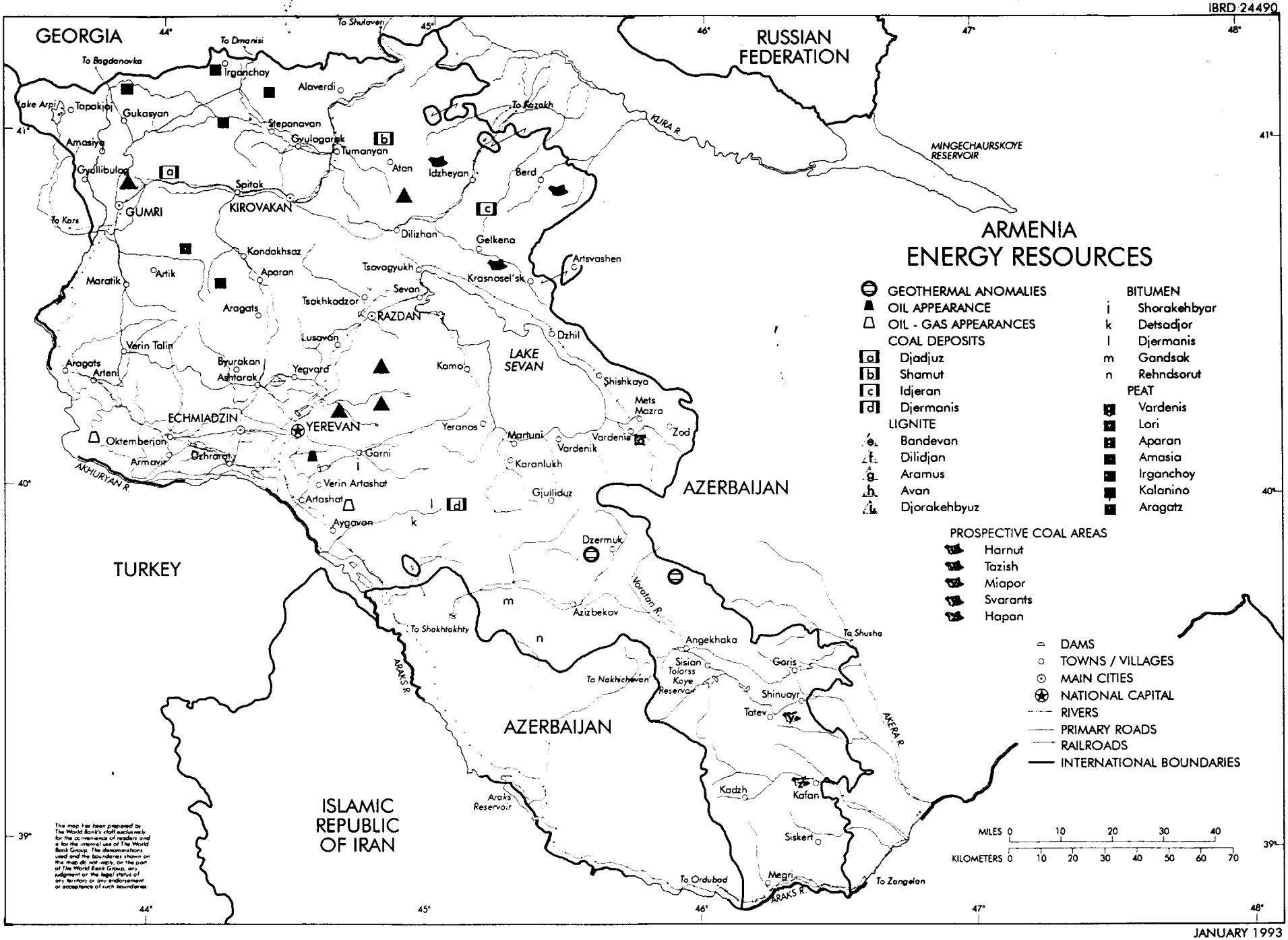

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