CHAPTER 1 EXECUTIVE SUMMARY

1. Introduction

The Ministry of Energy (MoE) of Republic of Armenia, in fall 1999 prepared a draft Least Cost Development Plan. After careful review of this plan by Government agencies and international organizations, the decision was made to expand this plan further and use international consultants' assistance in its preparation.

Hagler Bailly Services, Inc., USAID's lead consultant in the energy field in Armenia was assigned to provide consulting services to the Ministry of Energy in developing such a plan. This work was conducted in close cooperation between a team of Hagler Bailly consultants and experts from the Ministry of Energy of Armenia. As a result of this cooperation, the Least Cost Generation Plan has been developed and the process of power system planning used in this study was transferred to Armenian energy professionals.

2. Objectives

The principle objective of this study was to develop a least cost investment program for the rehabilitation and expansion of the Republic's of Armenia generation facilities for years 2001 through 2015. To fulfill this primary goal, a number of sub-tasks were completed, the most important of which were: development of an electricity demand forecast for the Armenian power system; determination of available fuel supply alternatives; analysis of Armenian power system reliability; and, evaluation of system expansion and energy generation sector capital requirements. As a result of this study, several projects were selected and proposed as potential candidates for future feasibility studies.

3. Methodology

The methodology applied to this study employed classical US and European least cost planning techniques tailored to an economy in transition. Data was obtained from a wide variety of sources, including, but not limited to the Ministry of Energy, Armenian power sector enterprises (power generation companies, Armenergo's dispatch and planning departments), and international organizations (the World Bank, EBRD, IFC, TACIS). As significant work was performed in the past by various reputable international consultants, such as Lahmeyer International, Burns and Roe Enterprises, Harza Engineering, Resource Management Associates and others, several tasks took into account their earlier findings.

From a methodological perspective, the study process consists of the following major components:

- **Electricity demand forecasting.** Three scenarios were considered – low, medium and high. An econometric model was created to determine long-term electricity demand growth in Armenia.

- **Power supply alternatives and screening analysis**. Several types of existing refurbishment and re-powering projects as well as new potential technologies available today were analyzed and assessed in terms of their economic effectiveness through a screening analysis process.

- **Scenario development.** Two matrices of study scenarios were developed. The first scenario set examined power supply options on a purely economic basis (i.e., least-cost). The second scenario set of cases included less cost-effective alternatives that would ensure Armenia's fuel supply independence.

- **Computer modeling and optimization.** Integrated Planning Model (IPM) by ICF Consulting, Inc. and XPRESS-MP Solver by Dash Associates were used in the modeling task to find optimal solutions in terms of technology types, installation timing, and total generation system costs for the long-term energy generation sector development program.

- **Results interpretation and recommendations.** An analysis of modeling results was summarized in the set of recommendations, describing the least-cost expansion plan for Armenia's energy generation sector.

Other tasks performed under this project included generation system reliability analysis, fuel supply options analysis, and analysis of DSM and Energy Efficiency programs and their impact on the load forecast.

4. Major Findings

The following sections describe all major findings related to the generation sector development plan. More specific details as well as more additional findings can be found in relevant chapters of the report.

4.1 Electricity Demand Forecast

An econometric approach was applied for projecting electricity demand in Armenia. The model created by Hagler Bailly's expert team produced GDP growth rates and forecasts of hourly energy consumption by different customer classes and peak loads. All model parameters were estimated statistically based on a time series analysis of the period from 1994 through 1998. The model incorporates a wide variety of variables that impact electricity demand, including macroeconomic (structure of economy, foreign debt, rate of accumulation/consumption), demographic (change in population) and technical factors (losses, electricity usage intensity by sector, impacts from restored gas supply, changes in load factor of hourly load curve).

The table below summarizes the main results for three forecasts.

	2000	2001	2002	2003	2004	2005	2010	2015	Average Annual Growth rate
Peak Load, MW									
High	1111	1147	1155	1179	1191	1209	1431	1751	3.1%
Medium	1109	1141	1145	1158	1159	1168	1308	1492	2.1%
Low	1102	1126	1120	1127	1123	1124	1229	1352	1.5%
Gross Generation, GWh									
High	5852	6008	6036	6156	6209	6247	7142	8604	2.6%
Medium	5840	5974	5982	6042	6042	6060	6674	7475	1.7%
Low	5825	5943	5896	5934	5902	5878	6323	6816	1.2%

4.2 Fuel Supply Options

Since Armenia is mostly dependent on imported fuel, a detailed analysis of fossil fuel supply options was conducted. For natural gas, these options included gas from Russia, Iran, and other neighboring countries. Local and Georgian coals were analyzed as fuel alternatives.

Two realistic natural gas prices can be foreseen for Armenia at present. One is the current price of $79.1 per tcm, which is considered rather high. At the same time the payment mechanism for that gas is not 100% in cash. Currently, there is substantial debt that existing power companies owe the gas supplier (through Armenergo). After thorough investigation conducted in Georgia, it became clear that in cases when payment arrangements for gas are arranged exclusively by currency (without any barter and/or mutual accounting), the price of natural gas at the Armenia/Georgia border is about $35-40 per 1000 cubic meters. Transportation within Armenian territory costs about $10 per tcm. In these instances, the price of natural gas at the Yerevan and/or Hrazdan sites is about $50 per tcm.

Actual full cash payment for gas purchases applies only to potential new gas-fired power plants, which may be considered to operate as Independent Power Producers (IPPs).

Various analyses and recommendations of gas supply from Iran and Azerbaijan can be found in Chapter 5 of the Report.

With impact to coal, further exploration should be conducted to gather additional information about the Ijevan deposit. This deposit is likely marginally economic, as are most deposits in Armenia, but it falls within the confines of the task that has been established for this program.

4.3 Generation System Reliability

The study adopted a target reserve margin at 35%. This reserve margin is equal to 0.996 generation system reliability level, or loss-of-load probability of 1.5 days/year. If the system reliability dropped below the target lend at any year, generation capacity was added. All modeling cases use this value as a benchmark.

4.4 Study Scenarios

The primary focus of this study is on least-cost economic development alternatives for the Armenian generation sector. However, certain attention should also be paid to national issues related to fuel security in the region, generation type diversification, and reduction of dependence on imported energy sources. Additionally, it should be noted that detailed analysis of energy security issues are outside of the scope of this study. These issues are evaluated in a separate study currently in process by the Government of Armenia under European Union funding. Therefore, two directions were taken in the modeling scenario preparation for this study: primary emphasis was given to the least-cost generation scenarios; however, secondary consideration was given to several non-economical alternative sensitivities that might provide greater long-term security to sector. For the secondary cases, no cost/benefit calculation was performed for the social and national effects of these options. Only total financial costs were calculated.

The table below presents the mix of generation scenarios that were analyzed under **the least-cost analysis**.

Case #	Demand Forecast			ANPP Retirement Year			Discount Rate		Fuel Forecast	
	Base	High	Low	2005	2010	2015	10%	15%	Base	High
1 Base	X			X			X		X	
2	X				X		X		X	
3	X					X	X		X	
4		X		X			X		X	
5		X			X		X		X	
6		X				X	X		X	
7			X	X			X		X	
8			X		X		X		X	
9			X			X	X		X	
10	X			X			X		X	
1a		X		X				X	X	
2a		X				X		X	X	
3a			X	X				X	X	
4a			X			X		X	X	
1b	X			X			X			X
2b	X					X	X			X

The **strategic matrix** is presented below.

Case	Demand Forecast		ANPP Retirement Date		Fuel Price Forecast		Discount Rate
	Base	High	2005	2015	Base	High	10%
1s	X		X		X		X
2s	X			X	X		X
3s	X			X		X	X
4s		X	X		X		X
5s		X		X	X		X
6s		X		X		X	X
7s	X		X			X	X
8s		X	X			X	X

In general, the major difference between least-cost (economic) and strategic matrixes is the choice of new expansion technologies derived in the screening analysis. While the least-cost matrix enjoys the benefits of less expensive gas-fired technologies, the strategic matrix uses new hydro, nuclear, and coal technologies as least dependent on imported gas.

4.5 Existing Generation Facilities Rehabilitation and Re-Powering

After careful review of existing generation facilities, the following projects are recommended for implementation during 2000-2005. It should be noted that these options proved to be least-cost and are available for near-term implementation. The following tables summarize the least-cost energy projects to be completed at existing facilities.

Thermal Power Projects

Project Name	Gross Capacity before Rehab., MW	Gross Capacity before Rehab., MW	Useful Life, years	Unit Cost, $/kW (Y2000)
Hrazdan TPP Block Unit 5 Completion and Re-Powering	0[*]	440	30	$284.2
Hrazdan TPP Block Units 1-3 Refurbishment for Steam Extraction	600 (3x200)	600 (3x200)	10	$3.4
Hrazdan TPP Block Section Cooling Towers Refurbishment	N/A[**]	N/A	30	Total $20 million
Yerevan TPP CHP Section Cooling Towers Refurbishment	N/A	N/A	5	Total $0.8 million

[*] The unit is currently not completed, hence the installed capacity is 0 MW

[**] Designated as "N/A" since it is not unit related, but rather applicable to the whole power plant

Hydro Power Plants

Project Name	Existing Generation, GWh/year	Generation after Rehab., GWh/year	Useful Life, years	Unit Cost, $/kW (Y2000)
Sevan-Hrazdan HPP Cascade				
Sevan	29.7	29.7	35	100.29
Hrazdan	89.1	89.1	35	31.25
Gumush	219.8	219.8	35	46.8
Kanaker	85.9	85.9	35	215.00
Yerevan-1	40.5	40.5	35	33.86
Vorotan HPP Cascade				
Tatev HPP	573.4	427.0	35	52.54
Shamb HPP	216.2	161.0	35	98.26
Spandaryan HPP	131.6	98.0	35	89.74

It should be noted that rehabilitation options at Sevan-Hrazdan HPP Cascade will not increase generation, because of water availability limitation, but are implemented to sustain at least the current level of generation.

The amount of energy generated at Vorotan HPP Cascade per year would actually decrease with or without rehabilitation due to the completion of Vorotan-Arpa tunnel, which will divert about 240-260 GWh of water per year in order to increase the level of Lake Sevan.

4.6 New Expansion Options

A screening evaluation of 11 newly proposed system expansion projects (technologies) was conducted. The following options were considered:

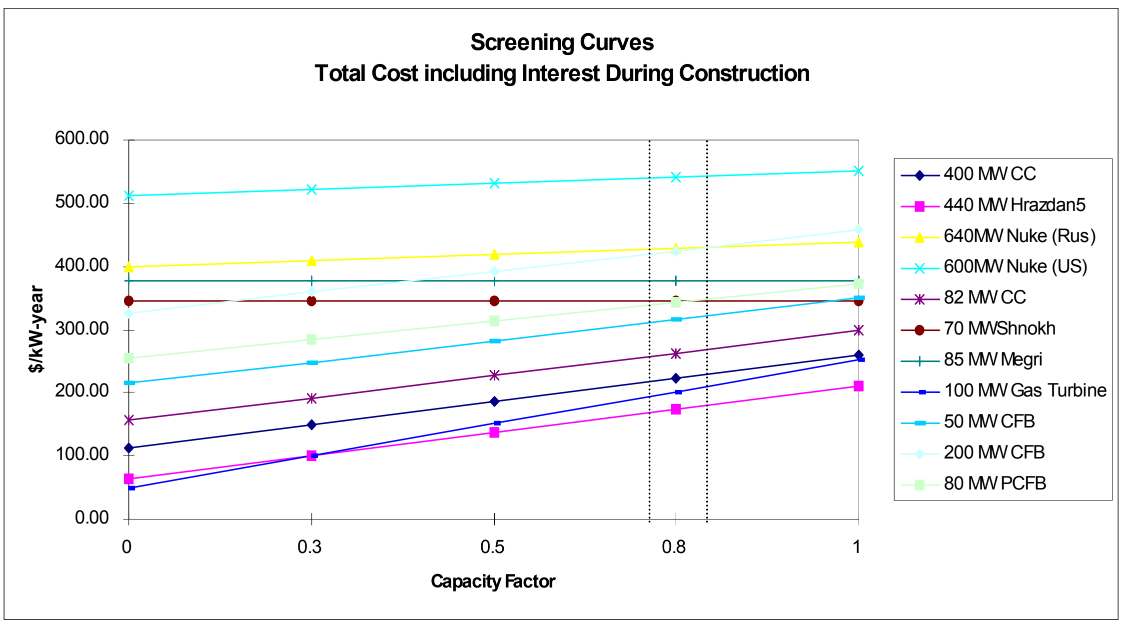
Technology	Gross Maximum Capacity, MW	Constructi on Time, years	Overnight Capital Cost, $/kW w/o IDC	Unit Life, years	O&M Cost: Fixed,$/kW/yr Var,$/MWh (w/o fuel)
Gas-Fired					
Combined Cycle I	400	2.5	$581	30	$14.0 $0.87
Combined Cycle II	82	2.5	$685	30	$34.4 $0.80
Gas Turbine	100	1.5	$414	30	$10.5 $0.20
Nuclear					
VVER-640 (Russian)	640	6	$1460 w/o decom.	50	$27.9
Western	600	6	$2000	40	$42.5
Coal and Shale					
Atmospheric Circulated Fluidized Bed (CFB) I	50	3	$1180	35	$12.0 $1.0
Atmospheric Circulated	200	3	$900	35	$37.60

Fluidized Bed II					$1.0
Pressurized Circulated Fluidized Bed I	80	3	$1300	35	$42.4 $1.0
Hydro Plants					
Shnokh HPP	70	5	$1730	40	$11.4
Megri HPP	85	5	$1882	40	$13.9
Loriberd HPP	56	4	$1732	40	$13.9

Based on screening analysis results, gas-fired alternatives (i.e., Hrazdan 5 Re-Powering, New 400 and 82 MW Combined Cycles, and the 100 MW Gas Turbine) have the lowest costs on a life-cycle basis. At a 75 percent capacity factor, the levelized cost ranges from $175 to $225/kW/year for these four options.

Coal-fired technologies (atmospheric and pressurized CFBs) produce levelized costs ranging between $320/kW-year and $425/kW-year at a 75 percent capacity factor. New hydro plants produce levelized costs of between $345/kW-year and $375/kW-year. Finally, new nuclear plants have the highest levelized life-cycle cost of $430/kW-year and $540/kW-year.

The complete results for all capacity factors are provided in the graph below.



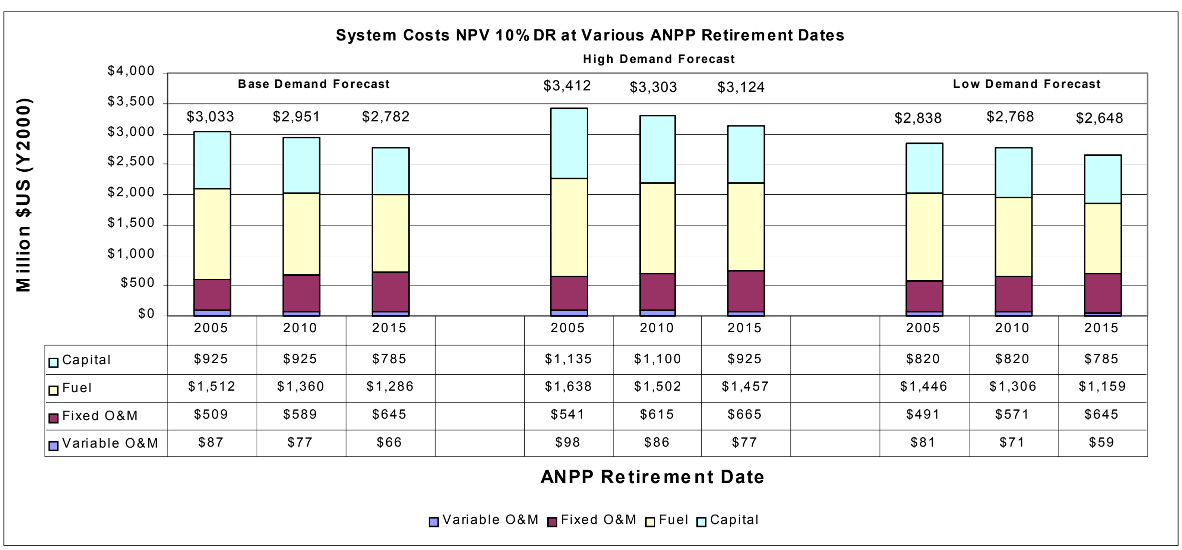
4.7 Demand-Side Management and Energy Efficiency

14 various DSM measures were screened, of which 6 measures passed the test. Short-term benefits are presented below.

Description of Measure	Market Penetration Achievable by 2004	Estimated Savings		Measure Costs (2000 $ Million)
	(%)	MW (Coincident Winter)	Annual Energy (GWh)	
Weatherization	33	8.4	37	5.5
Central Boilers	20	19.6	80	4.5
Large Electric Waste Heat Pump	5	0.6	6	0.9
Gas Heating, Gas Domestic Hot Water Heating and Cooking	10	4.2	43	5.4
Sodium Vapor Street Lighting	20	1.0	4	0.5
Compact Fluorescent Lighting	30	8.4	28	1.2
TOTAL	**-**	**42.2**	**203**	**18.9**

4.8 ANPP Retirement

One of the major tasks of this Report was to estimate the financial impact of an overall system cost ANPP shut-down timing. The following graph presents ANPP retirement dates for various demand forecast scenarios.



The retirement of ANPP in 2015 has the lowest total system cost impact primarily due to the fuel savings and deferral of new capital requirements. However, fixed O&M is higher for this case because of the more expensive maintenance of the existing ANPP.

5. Expansion Plan

The following decommissioning and new capacity addition plan is proposed for the base least-cost alternative (Case 1). The timing is based on the optimal solution found to minimize costs. It should be noted that the system reserve for this configuration slowly decreases from about 100% in year 2000 to about 45% in year 2020.

Year	2001	2002	2003	2004	2005	2011
N. Gas Other	-136x2 Yerevan 6 & 7	0	0	400 Hrazdan 5 CC	0	388 New CC
Nuclear	0	0	0	0	-380 ANPP Unit 2	0
Hydro	0	0	0	0	116 Vorotan Cascade Rehab.	0
Gas CHP	-56x2 Yerevan CHP 2 & 4	-46-92 Hrazdan CHP 1 and 3	82 MW CC CHP -2x56 MW Yerevan CHP 1 and 5 -46-92 MW Hrazdan CHP 2 and 4	0	0	0
Total	-384	-138	-170	400	-264	388

6. Capital Investment Requirements

The following capital requirements are estimated for the base least-cost (economic case). All figures are in million $US (Y2000).

	Nameplate Capacity	2001	2002	2003	2004	2005	2009	2010	2011	SUM	Comments
Yerevan TPP										0	
Yerevan CHP 1-1	65									0	Economic retirement in 2003
Yerevan CHP 1-2	65									0	Economic retirement in 2001
Yerevan CHP 1-4	65									0	Economic retirement in 2001
Yerevan CHP 1-5	65									0	Economic retirement in 2003
Yerevan 2-1 (6)	160									0	Economic retirement in 2001
Yerevan 2-2 (7)	160									0	Economic retirement in 2001
Common Facilities		0.4	0.4							0.8	Cooling towers rehabilitation
Yerevan CC	82	16.8	33.7	5.7						56.2	In-sevice in 2003 instead of existing CHP plant
										0	
Hrazdan TPP										0	
Hrazdan CHP 1-1	50									0	Retirement in 2002
Hrazdan CHP 1-2	50									0	Retirement in 2003
Hrazdan CHP 1-3	100									0	Retirement in 2003
Hrazdan CHP 1-4	100									0	Retirement in 2002
Hrazdan 2-1	200		0.7							0.7	Full maintenance, no retirement. DH extraction.
Hrazdan 2-2	200		0.7							0.7	Full maintenance, no retirement. DH extraction.
Hrazdan 2-3	200		0.7							0.7	Full maintenance, no retirement. DH extraction.
Hrazdan 2-4	210									0	Full maintenance, no retirement
Common Facilities		6.8		6.6	6.6					20	Cooling towers rehabilitation
Hrazdan 5	440		75	50						125	Completion as CC. In-service in 2004
CFB Unit	60									0	
Combined Cycle	400						69.7	139.4	23.2	232.3	New modern CC in-service in 2011
										0	
ANPP										0	
Unit 2	440				225					225	Retirement in 2005
New Unit	640									0	
										0	
Rehabilitated Hydro										0	
Sevan - Hrazdan Cascade	560		14.9	12.2	8.2	4.5				39.8	Full planned rehabilitation
Vorotan Cascade	405			19.1	12.6					31.7	Full planned rehabilitation
Dzorages	25									0	Private rehabilitation
Small Hydro	31									0	Private rehabilitation
										0	
New Hydro										0	
Megri	85									0	
Shnokh	70									0	
Loriberd	56									0	
										0	
TOTAL		**24**	**126**	**93.6**	**252**	**4.5**	**69.7**	**139**	**23.2**	**732.9**	

The investment breakdown by projects for the least-cost base scenario is provided below.

Type	Station	Cost Mil. USD (Y2000)
Hydro	Vorotan Cascade	31.7
	Sevan-Hrazdan Cascade	39.8
Thermal	Hrazdan TPP Rehab	20.0
	Yerevan TPP Rehab	0.8
	Hrazdan CHP Conversion	2.0
	Hrazdan Unit 5	125.0
	New 400 MW CC	232.3
	New 82 MW CC CHP	56.2
Nuclear	ANPP Decommissioning	225.0
TOTAL		**732.9**

7. Major Conclusions and Recommendations

7.1 Existing Units

Hydro Generation

Hydroelectric generation will continue to be one of the most important sources of electricity for Armenia for the foreseeable future. Geographic and weather features provide reliable conditions for hydro generation, and the extensive investment made during the Soviet Era in the country's hydro resources provides a good basis for rehabilitating existing plants. The major conclusions are:

- Sevan-Hrazdan HPP Cascade requires a capital investment of about $32 million for normal operation during 2000-2020. All rehabilitation work should be carried out by 2005. The rehabilitation effort will not increase cascade's installed capacity or planned energy generation level, since water limitation (due to Lake Sevan water level increase and irrigation needs) will remain.
- Vorotan Cascade requires a capital investment of about $40 million for rehabilitation by 2005. Although, the dependable available capacity will be increased by an estimated 116 MW at the cascade, energy generation will actually decrease. This decrease is not a result of rehabilitation, but is due to the expecation that the Vorotan-Arpa Water Tunnel will be completed by the end of 2004. The tunnel will divert significant amount of water (equivalent of about 240-260 GWh/yr.) to Lake Sevan from Vorotan Cascade.
- Existing small HPPs are subject to privatization (or already in private ownership) and all capital investment requirements are expected to be covered by potential buyers or current owners.

Thermal Generation

Thermal power will continue to play a major role in supplying Armenia's electric energy. Thermal power is primarily needed to provide base load energy during the fall and winter low water seasons. However, as the availability of new hydroelectric station sites that can be developed is exhausted, thermal power will increase its share of total generation. At that time, gas-fired combined cycle units will become the dominant technology for new plants.

Condensing Units

- Yerevan TPP Units 6 and 7 are fairly old, uneconomical, and expensive to maintain. Analysis performed shows that these units can be shut down to minimize overall system cost. Decommissioning can be performed as early as 2001. The exception is the case when new gas-fired capacity additions will not be able to enjoy the benefit of the IPP fuel arrangement.

In this case, the units should be preserved in the system until physical obsolescence, i.e., in 2010.

- Hrazdan TPP Block Units 1-4 should be maintained during 2000-2020. Although the units are not fully dispatched in economic scenarios due to relatively high cost, capacity factors for these units gradually increase, reaching 60-70% by the end of study. Units 1 (and possibly 2 and 3 depending on steam demand) can be refurbished to extract low-pressure steam for district heating. This project will allow Hrazdan TPP to close down the Combined Heat and Power (CHP) part of the plant. *A detailed feasibility study should be conducted for this project that should involve the original turbine manufacturer's advice before any work commences on the refurbishment of Units 1-3 and the decommissioning of the existing CHP part.* The current estimate for this project is about $2 million.
- In order to successfully operate Hrazdan TPP Block Units 1-4 for next 20 years, three (3) cooling towers should be rehabilitated. No other significant expenditures (in addition to regular and major overhaul maintenance) are proposed for the plant. Capital investment for these 3 cooling towers totals about $20 million and assumes gradual rehabilitation during 2001-2004.
- Non-completed Hrazdan Unit 5 should be treated as a new project and is discussed later in this Chapter.

CHP Units

- Current steam demand at Yerevan TPP cannot substantiate the maintenance of 4 operating CHP units. All of the steam demand can be satisfied with one unit in operation. The future increase in steam demand is questionable. Ministry of Industry (MoI) (through Ministry of Energy) has provided this steam demand forecast for 2004-2008, which shows that the increase in steam consumption almost quadruples from current level by 2008. However, no substantiation for such a steep increase was found, so that the forecast was modified to be in line with basic economic projections.
- Three cases were reviewed with regard to steam demand in Yerevan region: (a) High Steam Demand (corrected MoI forecast), (b) Current Steam Demand, and (c) No steam Demand (i.e., steam is generated by industrial enterprises and DH boilers). Cases (b) and (c) result in no new CHP capacity additions to the system. In case (b), the steam demand is satisfied with two (2) existing CHP units at Yerevan TPP. In case (a), there is merit in introducing a new 82 MW CC CHP. The capital requirements for this unit were assumed to be $56.2 million. Sensitivities show that the increase of capital up to $60-62 million will still make this project the least-cost steam generation alternative with high steam demand. The fuel price also impacts the decision on this unit: current natural gas price makes the unit installation unattractive. The decision reverses if the IPP fuel price and high steam demand are assumed.
- Since the steam situation is not clear, *a detailed study of any potential industrial customers should be conducted in Yerevan Region to determine the most probable steam demand level for next 10 years.* No active steps should be taken toward the contract and/or construction of this project before the proposed study is conducted.

- Hrazdan CHP plant is a subject for potential decommissioning. The decommissioning should be proposed only after the project to convert Block Units 1-3 to low-pressure steam is completed with positive results.

Nuclear Generation

The fate of the ANPP at Medzamor should be resolved in the near future. The analysis performed clearly shows the following:

- The Armenian energy system will enjoy significant total system savings with the deferral of the ANPP decommissioning. Total accumulated systems savings (in new capital deferral and fuel savings) is estimated to be about $82 million when ANPP is decommissioned in 2010 instead of 2005, and about $251 million when ANPP is decommissioned in 2015 instead of 2005.
- Nuclear safety issues are outside of scope of this study.
- Decommissioning cost for Unit 2 is assumed to be about $225 million (Y2000 $US) and is not expected to vary depending on decommissioning year. This figure is based on the typical decommissioning practice in the US and *should be updated upon the completion of a detailed cost estimate for ANPP decommissioning currently being performed by MoE under EU aegis.*

7.2 New Capacity Additions

Hydro Generation

In addition to the existing hydropower plants, 3 major projects have been proposed and a number of small hydro projects were studied as new generating plants. However, none of them were found to be economically attractive for implementation during the planning period in the economic evaluations. This was due to a few key factors. Most of the proposed plants have rather low yearly energy production capability and high capital investment needs. However, the issue of fuel security in the region may make hydro capacity more attractive in the future. Specific recommendations are as follows:

- Before any activities take place in regard to Megri HPP project, a water sharing agreement should be in force between Armenia, Iran, Turkey, and Azerbaijan. All of these countries may impact the availability of water with their irrigation, household, and electric needs.
- In order to accommodate the fuel security issues, Megri, Shnokh, and Loriberd plants were installed in system (in Strategic Base Case) the same year when a new 400 MW CC is installed in Base Economic Case. The capital investment requirement for all three plants is estimated to be about $378 million.

- Total system cost difference between economic and strategic base cases is about $363 million. In other words, this cost has to offset by external (i.e., political) factors in order to justify any hydro development.
- New hydro power projects have long lead times for design, engineering, construction, and commissioning. No new hydro generation options can be realistically operational before 2007.

Thermal Generation

- Hrazdan Unit 5 completion and re-powering to a combined cycle configuration is considered to be the least-cost option for thermal generation. Total capital investment requirement for this project is estimated to be $125 million. In all economic cases, Hrazdan 5 is assumed to be installed in 2004 based on an effort to minimize total system cost and energy requirements. *Since Hrazdan 5 is a non-completed gas-fired supercritical unit, a detailed feasibility study is required before any actual completion and/or conversion project is started to verify cost estimates and the economic attractiveness of this option.*
- A new standard 400 MW CC is the second least-cost alternative for the system. Total capital investment for this project is estimate at about $235 million. The per unit cost can be decreased based on the number of units required. The first addition of this unit in the Base Economic Case is in 2011.
- A new Circulated Fluidized Bed (CFB) unit is the only strategic generation alternative reviewed in this plan. The introduction of this unit is based on the assumption of local coal availability. Although this alternative is fairly expensive, it can be considered "least-cost" among all strategic alternatives. The only promising coal field in Armenia at this time is the Ijevan deposit. *Further exploration of this deposit is recommended before any activities on the new CFB unit are commenced.* The more expensive mix of Georgian and Armenian coals does not diminish the selection of this option.

Nuclear Generation

- Two nuclear technologies were considered for Armenia. US or European reactor technology was dismissed in the screening analysis based on the high life-cycle cost, while the future of new Russian VVER-640 reactor projects is uncertain, so that this reactor may not be available in the near to midium- term study period.
- Current capital investment estimates for new VVER-640 plant are nearly $1 billion. The option is included in this study, and total system costs with new NPP are calculated. The difference between economic and strategic cases with the nuclear option is in the range of $1-1.3 billion, which makes the substantiation of a new NPP for Armenia very difficult, even based on the need for the fuel security.