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STAFF APPRAISAL REPORT

NEPAL

ARUN III HYDROELECTRIC PROJECT

AUGUST 29, 1994

nergy and Infrastructure Division
ountry Department I
outh Asia Region

CURRENCY AND EQUIVALENTS

1 Nepalese Rupee (NRs)	=	100 Nepalese Paise
US$1.00 (June 1994)	=	NRs 49.48 (Official Rate)

WEIGHTS AND MEASURES

1 Kilovolt (kV)	=	1,000 volts (V)
1 Kilowatt (kW)	=	1,000 watts (W)
1 Megawatt (MW)	=	1,000 kilowatts (kW)
1 Kilowatt - hour (kWh)	=	1,000 watt - hours (Wh)
1 Megawatt - hour (MWh)	=	1,000 kilowatt - hours (kWh)
1 Gigawatt - hour (GWh)	=	1,000,000 kilowatt - hours (kWh)

ABBREVIATIONS AND ACRONYMS

ACRP	-	Land Acquisition, Compensation and Rehabilitation Plan
ADB	-	Asian Development Bank
AHP	-	Arun III Hydroelectric Project
ANL	-	Argonne National Laboratory
BITS	-	Swedish Agency for International Technical and Economic Cooperation
CIDA	-	Canadian International Development Agency
EA	-	Environmental Assessment
EAP	-	Environmental Action Plan
EDC	-	Electricity Development Center
EdF	-	Electricité de France International
EIRR	-	Economic Internal Rate of Return
FINNIDA	-	Finnish International Development Agency
GIS	-	Geographical Information System
GLOF	-	Glacier Lake Outburst Flood
GTZ	-	German Agency for Technical Cooperation
HMG	-	His Majesty's Government of Nepal
ICB	-	International Competitive Bidding
JICA	-	Japanese International Cooperation Agency
KfW	-	Kreditanstalt für Wiederaufbau
LCB	-	Local Competitive Bidding
LCGEP	-	Least Cost Generation Expansion Program
LRMC	-	Long Run Marginal Cost
MHPP	-	Marsyangdi Hydroelectric Power Project
MOI	-	Ministry of Industry
MOWR	-	Ministry of Water Resources
NEA	-	Nepal Electricity Authority
NIEMP	-	National Industrial Energy Management Plan
NPC	-	National Planning Commission
ODA	-	Overseas Development Association
OECF	-	Overseas Economic Cooperation Fund (Japan)
PAF	-	Project Affected Family
PA	-	Performance Agreement
POE	-	Panel of Experts
PSEP	-	Power Sector Efficiency Project
RAP	-	Regional Action Program
RAPCS	-	Regional Action Program Consultancy Support
SLA	-	Subsidiary Loan Agreement
SOE	-	Statement of Expenditures
SPAF	-	Severely Project Affected Family
T&D	-	Transmission and Distribution
TFC	-	Tariff Fixation Commission
TOE	-	Tonnes of Oil Equivalent
TS/DCS	-	Technical Services Department, Distribution and Customer Services Directorate (NEA)
UNDP	-	United Nations Development Programme

Fiscal Year

July 16 to July 15

All years refer to the Gregorian Calendar

NEPAL

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Credit and Project Summary

Borrower: Kingdom of Nepal (HMG)

Beneficiary: Nepal Electricity Authority (NEA)

Amount: SDR 99.5 million (US$140.7 million equivalent)

Terms: Standard, with 40 years' maturity

Onlending Terms: The Borrower would onlend to NEA US$136.1 million, plus US$34.3 million available under the existing Arun III Access Road Project (Cr. 2029-NEP), at a rate of 10.25% for a period of 30 years, including a grace period of nine years. The Borrower would bear the foreign exchange risk. The remaining US$4.6 million, covering the Regional Action Program, would be passed on as a grant to the Ministry of Water Resources (MOWR).

Project Description: The project is the first 201 MW stage of a 402 MW run-of-the-river hydroelectric power scheme, located on the Arun river. Major project components include a 122 km access road, a 68 m dam and power intake, desanding basins and appurtenant structures, an 11.4 km headrace tunnel, a surge tank leading to a power cavern to house three 67 MW turbo-generators, a downstream surge tank and tailrace tunnel, and outlet structures. Electro-mechanical equipment includes hydraulic steel structures, turbo-generators and construction power supply. Transmission equipment includes a 120 km, 220 kV double-circuit line to a 220 kV/132 kV substation at Duhabi. The project also provides for implementation of an Environmental Management Plan, comprised of a Land Acquisition, Compensation and Rehabilitation Plan, an Environmental Mitigation Plan to address the project's direct impacts and a Regional Action Program (RAP), the bulk of which was identified by the King Mahendra Trust for Nature Conservation, in the areas of conservation, income generation, institutional strengthening, extension and training, and energy and infrastructure development in the Arun Valley. In addition, the project provides for engineering consultancy services, technical assistance and training. Finally, the project includes a facility to promote private sector involvement in power development.

Benefits: The project benefits, only partly reflected in its 15.4% economic rate of return, would include meeting forecast electricity demand at least cost; enhancing resource mobilization and the operational autonomy and accountability of NEA; strengthening the capabilities of government institutions and NEA to prepare, design and supervise the construction of environmentally sustainable hydropower projects; and facilitating an appropriate regulatory framework for the power sector and an active role for the private sector. In addition, the project would provide benefits to the 450,000 inhabitants of the Arun Valley, enabling them to benefit from the project (primarily the access road) through implementation of the RAP.

Risks: Because of its size and complexity, the Arun III project entails significant risks relating to (a) crowding out of high-priority investments in other sectors, due to cost overruns, worse-than-expected management of the Government budget, or failure of NEA to meet its projected share of expenses; (b) unforeseen delays in project implementation; and (c) unsatisfactory implementation of the Environmental Management Plan, including the RAP, and of the Land Acquisition, Compensation and Rehabilitation Plan (ACRP). The crowding out issue would be addressed through the adoption of a macro-fiscal reform program, under which the Government will (i) increase revenues through fiscal measures; (ii) adopt a three-year rolling investment program starting in FY95, with a core investment program to protect investments in other high-priority sectors, particularly in the social sectors; and (iii) adopt institutional reforms in the Ministry of Finance and the National Planning Commission to promote better expenditure management. Appointment of a Panel of Experts to review project design and construction, adequate provision for supervision in close cooperation with the consulting engineer responsible for the detailed engineering studies, and the signature of the major civil works contract prior to project effectiveness would mitigate the risks of cost overruns and implementation delays. The risk of revenue shortfalls on the part of NEA would be reduced by implementing measures to enhance NEA's cost recovery, including reducing system losses and improving the handling of consumer accounts and collection performance. The Government's preparedness to adjust tariffs was indicated by the 38% tariff increase that took effect in March 1994. The risk of unsatisfactory implementation of the Environmental Management Plan or the ACRP would be addressed by close monitoring of NEA's and MOWR's performance in this regard through: (a) reconstituting the Panel of Experts and expanding it to include adequate environmental expertise, (b) regular on-site supervision, and (c) a detailed annual review during project implementation.

Estimated Cost [a]

	Local	Foreign	Total
	---------US$ Million---------		
A. Hydroelectric Power Plant - Physical Works	73.3	272.8	346.1
B. Hydroelectric Power Plant - Electro-mechanical Equipment	16.2	124.3	140.5
C. Transmission Line to Grid	9.1	47.1	56.2
D. Environmental Mitigation/ Area Development	10.3	5.9	16.2
E. Technical Assistance	2.9	50.4	53.3
F. Hydro Facility	0.0	5.0	5.0
Base Cost	111.9	505.5	617.4
Physical Contingencies	14.5	58.8	73.3
Price Contingencies	22.9	83.7	106.6
Total Project Cost	149.3	648.0	797.3
Interest During Construction	285.0	0.0	285.0
Total Financing Required	434.3	648.0	1082.3

[a] Total project cost net of taxes and duties (US$37.0 million) is US$760.1 million.

Financing Plan

	Local	Foreign	Total
	--------US$ Million----------		
IDA			
Credit 2029-NEP	-	34.3	34.3
Proposed Credit	-	140.7	140.7
Total IDA	-	175.0	175.0
ADB	-	127.6	127.6
KfW	-	124.4	124.4
To be determined[a]	-	163.3	163.3
OTHERS (France, Sweden[b], Finland)	-	46.3	46.3
Government	143.6	11.4	155.0
NEA[c]	290.7	-	290.7
Total	434.3	648.0	1082.3

[a] Japan is sending its own appraisal mission to make its assessment of the project.

[b] Sweden has stated that it is willing to allocate up to US$30 million to the project, of which about US$17 million has been committed so far. This may result in a reduction in project financing by HMG and for NEA.

[c] Includes US$285.0 million equivalent of interest during construction.

Estimated IDA Disbursements:

IDA FY	95	96	97	98	99	00	01	02	03	04	05
Annual	21.4	11.6	20.3	29.8	22.0	17.9	20.1	14.4	10.6	6.8	0.1
Cumulative	21.4	33.0	53.3	83.1	105.1	123.0	143.1	157.5	168.1	174.9	175.0

Economic Rate of Return: 15.4%

Poverty Category: Not Applicable

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STAFF APPRAISAL REPORT

This report is based on the findings of a joint IDA/ADB/KfW power mission to Nepal in September-October 1993. The IDA mission members were Messrs. D. O'Leary (Sr. Engineer/Systems Planner, Task Manager), S. Ahmed (Sr. Counsel), P. Paradine (Environmental Specialist), S. Mukherji (Financial Analyst), A. Alberti (Staffing Rationalization/Training, Consultant), A. Beach (Institutional Development, Consultant), W. Dobisch (Hydropower Engineer, Consultant), L. Maistre (Energy Economist, Consultant), C. Mulligan (Highway Engineer, Consultant) and T. Ragsdale (Resettlement Specialist, Consultant). Messrs. P. Mitra (Lead Economist), J. Besant-Jones (Principal Energy Economist) and R. Bacon (Energy Economist) carried out the project justification and economic evaluation of the project. A separate IDA mission consisting of Messrs. P. Mitra, P. Suriyaarachchi (Principal Economist) and A. Agbonyitor (Sr. Economist) appraised the project's macroeconomic aspects. Peer Reviewers were Messrs. P. N. Gupta (Principal Dam Engineer), A. Liebenthal (Principal Energy Economist) and A. Mejia (Principal Financial Analyst) who reviewed the engineering, economic and financial aspects of the project respectively. Secretarial support was provided by Ms. I. Christy and Mr. B. Mitchell. Ms. Marie Garcia-Zamor is the Chief, Energy and Infrastructure Division and Mrs. A. O. Hamilton is the Director of Country Department 1, South Asia Region.

ANNEXES

CHARTS

IBRD MAPS:

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STAFF APPRAISAL REPORT

I. ENERGY SECTOR AND POWER SUBSECTOR

A. Sectoral Importance

1.1 Nepal, with an estimated population of about 20.0 million and an annual per capita income of US$180, is one of the poorest countries in the world. The development of Nepal's abundant hydroelectric potential is a key component of the country's development strategy, particularly in view of the rapid depletion of its forests, Nepal's other main indigenous energy source. The efficient development of Nepal's hydroelectric potential can contribute not only to meeting its internal power needs but, through developing a surplus trade balance in commercial energy (fossil fuels and electricity), also to mobilizing resources to address Nepal's development needs. Local resource shortages, coupled with weak institutional capacity, have frustrated the sector's performance. Insufficient and unreliable power supply is a brake on economic growth; the pace of industrialization has been severely constrained by lack of power, and only 9% of the population has access to electricity. His Majesty's Government of Nepal (HMG) accords high priority to power development, allocating approximately 14% of development outlays to the sector during the period FY81-93. This is expected to increase to about 36% of projected development outlays during the peak implementation phase (FY96-00) of the proposed Arun III Hydroelectric Project[1/]. The share of the population with access to electricity is expected to double by the end of the project period.

B. Energy Resources and Supply

1.2 Nepal's main indigenous energy resources are fuelwood and hydropower. Agricultural residues are widely used for cooking and heating. Biogas potential is high because of the large livestock population. The solar energy potential also seems technically promising, and initial studies indicate that there may be some scope for utilizing wind energy. Except for lignite deposits which are extracted for use by brick kilns in the Kathmandu and Dang Valleys, all fossil fuels are imported; there are no known oil or coal deposits. In FY93, of the total energy supply of about 6.4 million tonnes of oil equivalent (toe), about 580 thousand toe (9%) was from commercial sources, of which about 523 thousand toe (90%) was imported; domestic electricity supply equivalent to about 70 thousand toe accounted for only 1% of the total energy supply (Annex 1.1).

1.3 Fuelwood accounts for approximately 68% of total energy supplies. It is the basic energy source for cooking and heating in rural areas, where the vast majority of the population lives. Forests cover some 38% of the total land area and are fairly evenly distributed throughout the country. Annual fuelwood consumption, currently about 4.3 million toe a year, exceeds the forests' sustainable annual yield. If present trends continue, deforestation would accelerate; this is leading to growing fuelwood shortages and hardship in rural areas. Government forest policy aims to reverse deforestation by taking action on both supply and demand, including energy conservation and interfuel substitution (paras. 1.9-1.10). Toward this end, the Government is carrying out a country-wide program to encourage sustainable utilization of forest resources by involving the local communities in the management and use of forest resources.

[1/] So called because it is the third potential site from the lower end of the Arun River identified in the Kosi Basin Master Plan Study (para. 3.17).

1.4 Other Renewable Energy Sources. An estimated 10% of Dung production by livestock is used directly as a fuel by rural households, accounting for about 8% of the total energy supplies. Dung converted into methane in biogas digesters could provide for the cooking and lighting needs of an estimated 40% of the population. However, the digesters developed so far generate an insignificant share of the total potential. Agricultural waste (straw, husks, etc.) is widely used and accounts for approximately 15% of total energy supplies. Solar energy applications have so far been limited primarily to demonstration/pilot projects (solar water heaters, solar driers, and photovoltaic and wind-power generating units). For example, in a pilot program financed by the Danish International Development Agency with IDA involvement, solar energy units are being installed in ten rural primary schools. The economic viability of solar energy applications, however, has still to be proven in Nepal.

1.5 Hydropower. In 1985, the Ministry of Water Resources (MOWR) estimated that Nepal's economically exploitable hydropower potential was around 25,000 MW, of which about 20,000 MW have been investigated. Only 241 MW of the potential have been developed (236 MW in the interconnected network and 5 MW at isolated centers), and a further 12 MW are under construction. Hydro plants in the national grid range from 5-92 MW of installed capacity. About 20 off-grid hydro plants ranging from 45-1,000 kW capacity are also operating in the country. Hydropower development faces serious technical impediments: lack of access, difficult geological conditions, extreme variation in river flows, a relatively weak hydrological data base, and heavy silt loads. Some potential projects (Chisapani, Pancheswar) are very large (3,000 MW or above) and would have to be developed as export projects to India requiring special institutional, financial and commercial arrangements.

1.6 The large number (about 30,000) of traditional water mills for grinding corn indicates that there is considerable scope for developing micro hydropower schemes[2/] through individual or community effort. If all these mills were replaced by dual-purpose mills (grinding corn and generating electricity), they could be used to operate small power generators with an average capacity of about 10 kW, giving a total potential of 300 MW. Recognizing that dual-purpose micro hydro units could help in meeting rural energy needs and also provide high returns for relatively modest investments, the Government offers tariff deregulation and credit through the Agricultural Development Bank to private entrepreneurs to develop schemes of up to 100 kW capacity. During recent years, 20 to 30 schemes a year were financed. In 1992, HMG raised to 1 MW the size of hydro generation projects which do not require licensing and are not regulated. These projects are tax exempt and eligible for concessional finance. Micro and mini schemes have a role in meeting rural needs, although larger scale investments are needed for the bulk of future demand. Actions by HMG to encourage private participation in the development of larger hydropower projects are discussed in para. 1.27.

[2/] Micro hydro schemes refer to schemes with installed capacity of up to 100 kW, mini hydro schemes between 101 kW and 10 MW, small hydro schemes between 10 MW and 50 MW, medium hydro schemes between 50 MW and 500 MW, and large hydro schemes above 500 MW.

C. Energy Consumption

1.7 Nepal's per capita consumption of commercial energy (29.0 kilograms of oil equivalent) is among the lowest recorded for any developing country. Commercial energy, which accounted for only 8% of total energy consumption (see para. 1.2), was distributed among petroleum (7%), coal (1%) and electricity (1%). End users of net energy consumption are households (91%), industry (3%), commercial (1%), transport (3%) and others including agriculture (1%). The bulk of commercial energy consumption in FY92 was in the residential (28%) and transport (39%) sectors (see Annex 1.1). During FY88-91, commercial energy consumption increased at the rate of 5% per annum compared with an annual real GDP growth rate of 4.7%. The resulting energy elasticity (1.09) compares with 1.1 for all developing countries. Steps are being taken to improve efficiency in commercial energy use in the industrial and transport sectors and in electricity generation, transmission and distribution. This is supported by various donor-assisted projects, including the IDA-financed Power Sector Efficiency Project (PSEP - Cr. 2347-NEP).

1.8 Energy Trade. All imported energy supplies are purchased from India (coal and electricity) or have to be routed through India (petroleum products). Until 1973 Nepal's petroleum product imports were all from India. Under the present agreement, the Nepal Oil Corporation can purchase products both on the international market at international prices and from the Indian Oil Company. (Nepal does not have a refinery.) Under a five-year agreement signed in June 1990 (which is expected to be extended), petroleum imports are delivered to India, which supplies Nepal's required mix of products from the most convenient Indian refineries under a product exchange agreement. The Nepal Oil Corporation maintains a minimum stock level of about 30 days' supply. Coal is imported from India by Nepal Coal Limited, which negotiates supply contracts with the Indian authorities including provision of rail wagons for transporting the coal to Nepal's border. Net electricity imports from India accounted for about 1% of net commercial energy supply in FY92. Altogether, in FY92, commercial energy imports absorbed about 24% of Nepal's foreign exchange earnings. A key objective of the Government's energy policy is to develop indigenous hydroelectric resources to minimize the impact of energy imports on Nepal's balance of payments (para. 1.21).

1.9 Interfuel Substitution and Energy Efficiency. In 1991, in conjunction with the preparation of the PSEP, the Government requested the joint United Nations Development Programme (UNDP)/World Bank Energy Sector Management Assistance Program to conduct an Interfuel Substitution and Energy Efficiency Study. The study[3/], which was completed in October 1992 with funding from the Finnish International Development Agency (FINNIDA), focussed on: (a) assessing the degree to which existing energy pricing policy supported or undermined economic and financial incentives for the rational use of energy by key energy-consuming sectors, (b) developing case studies for application as benchmarks for designing plant-specific actions under the proposed National Industrial Energy Management Plan (NIEMP) to improve energy efficiency and/or promote fuel substitution in the industrial sector, (c) evaluating the economics of applying energy efficiency and fuel substitution measures on a large scale to reduce the fuelwood intensity of brick production in kilns (including options to substitute coal for fuelwood) and to establish benchmarks for relevant follow-up action under the NIEMP to disseminate the appropriate technical packages, (d) justifying each of the core components of the proposed NIEMP, taking into account current and emerging HMG policies concerning energy and industrial development, pollution abatement and environmental improvement, and (e) recommending ways to apply effectively available financing from the PSEP to establish local capacity to

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[3/] Joint UNDP/WB ESMAP. NEPAL: Study on Energy Efficiency and Interfuel Substitution, Washington, D.C., February 1993.

implement energy efficiency improvements in the industrial sector, and also promote rational energy use practices in all sectors.

1.10 The NIEMP was launched in early FY94, under the Energy Management Services Unit of the Ministry of Industry (MOI). Under the chairmanship of MOI, a Steering Committee has been established with representatives of the Federation of Nepalese Chambers of Commerce and Industry, the Hotel Association of Nepal, the National Planning Commission (NPC) and NEA's Loss Reduction Unit. The first-year priority program is: (a) executing energy audits and pilot demonstrations of low-cost energy efficiency improvement measures for industrial boiler and steam systems, (b) executing electrical systems surveys and introduce a pilot "Electricity Load Management Scheme" for industrial and large commercial consumers of NEA, and (c) performing lighting energy audits at hotels in the Kathmandu area, and assist hotel owners to develop lighting system retrofit measures. To facilitate this effort, the Energy Management Services Unit is entering into a "twinning" arrangement with the Energy Conservation Center of Thailand, with support under the PSEP. NIEMP prospects are good because the project has been well-prepared and HMG is committed to its success.

D. Organization of the Energy Sector

1.11 Institutional responsibility for the energy sector is delegated to four main line ministries and their agencies. In addition, the Ministry of Finance is responsible for the financial aspects of the sector; the NPC reviews energy sector programs and projects, particularly in connection with the preparation of the national five-year development plans; and the Public Service Commission provides guidelines governing conditions of service (recruitment, promotion, discipline, etc.) in government departments and public enterprises involved in the sector.

1.12 The line ministries with specific energy responsibilities are: (a) the MOWR/NEA (electricity supply), (b) the Ministry of Forests and Soil Conservation (fuelwood), (c) the MOI (which has jurisdiction over Nepal Coal Limited and the Department of Mines and Geology, which is responsible for oil and gas exploration), and (d) the Ministry of Supply (which has jurisdiction over the Nepal Oil Corporation and the Timber Corporation of Nepal).

1.13 Within the power sector, the MOWR has general responsibility for all public and private activities related to electricity supply, including jurisdiction over the NEA, which plans, constructs and operates all public power facilities in Nepal. The Minister of MOWR is Chairman, and the Secretary of MOWR is a member, of the NEA Board. MOWR also controls the new Electricity Development Center (EDC), whose mandate is: (a) to promote private participation in the power sector, (b) to approve and license power generation projects larger than 1 MW undertaken by the private sector, (c) to work with the Tariff Fixation Commission (TFC) (para. 2.9) to set the selling price of electricity, and (d) to be responsible for promotion and development of binational and multipurpose projects, basinwide water resources plans, development of safety guidelines and codes of practice for project construction, quality control of generation, transmission and distribution facilities, and advising MOWR on the refinement of existing rules and regulations.

1.14 The Minister of MOWR is also the Chairman of the Water and Energy Commission, which includes representatives of all the relevant ministries. The Commission's responsibilities, carried out through its technical arm (the Water and Energy Commission Secretariat), include (a) investigation of national water and energy resources, (b) studies of national water and energy requirements, (c) conservation, (d) development of water and energy resources, and (e) preparation and coordination of short- and long-term plans for water and energy development, including the involvement of the public and private sectors. The Secretariat is supported by technical assistance provided by the Canadian

International Development Agency (CIDA) through the Secretariat/NEA Institutional Support Program.

E. Energy Pricing

1.15 About 93% of the energy in Nepal is not traded, and hence market clearing is not via the price mechanism. Pricing of commercial energy is administered by the Government. Pricing schedules for petroleum products are prepared by the Nepal Oil Corporation, and are approved by the Government. Electricity prices are prepared by NEA. In the past, the Government approved NEA's price adjustments; in future a TFC will perform this role (para. 1.24). The pricing of fuelwood sold by the Timber Corporation is based on proposals approved by the Government.

1.16 Since 1975, prices for all forms of energy have risen substantially in real terms, but much more so for fuelwood and electricity than for petroleum and coal (Annex 1.2). Until recently, HMG's policy for petroleum product pricing had been to adjust domestic prices to reflect the trend of international prices, with taxes on petroleum products as a major source of Government revenue. The current price structure for petroleum fuels sets prices for kerosene and diesel below their border prices and for gasoline and aviation fuel above border prices.

1.17 Coal prices reflect the border price of supply plus distribution and storage costs and are exempt from taxes and duties. Since 1975, fuelwood prices charged by the Timber Corporation (and its predecessor, the Fuelwood Corporation) have risen much more rapidly than electricity prices, but rather more slowly than kerosene prices. Despite these increases, the Timber Corporation's prices remain well below the free market level set by private suppliers, which account for only a small share of fuelwood consumption but which much more closely reflect the economic cost of supply.

1.18 Despite a 61% tariff increase in November 1991, and a 25% increase in March 1993, until recently, the average price of about NRs 2.78/kWh (Annex 1.3) on total NEA sales was well below the estimated long-run marginal cost (LRMC) of NRs 5.50/kWh. To help rectify this situation, HMG increased the average tariff by 38% as of March 15, 1994. This should increase the average tariff rate to NRs 3.88(US¢7.8)/kWh, or about 70% of LRMC. Under its financial plan NEA will increase tariffs further (para. 4.23).

F. The Government's Energy Sector Strategy

1.19 At the request of the Government, during 1987 the Asian Development Bank (ADB) and IDA conducted a diagnostic study of Nepal's power sector[4]; as a result, HMG, NEA, ADB and IDA agreed that further attention needed to be paid to improving institutional performance, energy pricing and resource mobilization, investment planning, and bulk electricity exports.

1.20 HMG has also prepared a Framework for Power Sector Development which evaluates and recommends options for sectoral policy; the institutional framework, including the roles of public, autonomous and private entities; safety and technical standards; the strategy and responsibility for development of hydropower exports; and the investment environment for the private sector.

1.21 Recognizing the key role of increasing energy supplies in Nepal's economic development, HMG has given high priority to energy sector investments, especially power, in its investment program. As set out in the Government's

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[4] Nepal: Power Subsector Review (January 15, 1988 - Report No. 6879a-NEP)

Eighth Plan, the principal objectives of energy policy are to: (a) develop a surplus trade balance in commercial energy (fossil fuels and electricity) and promote industrialization by developing indigenous hydropower resources, (b) meet the forecast demand for energy within Nepal at least cost to the economy, (c) reverse the deforestation trend, (d) increase the reliability and quality of electricity supply through upgrading the distribution system and reducing system losses, (e) adjust energy prices to promote efficient use while meeting the Government's social objectives, and (f) improve operational and financial performance and resource mobilization from energy sector entities.

1.22 HMG has made considerable progress in meeting these objectives through: (a) addressing interfuel substitution and energy efficiency issues (paras. 1.9-1.10), (b) collaborating with India in conducting preparatory studies for the Chisapani and Pancheswar hydro projects, (c) forest management (para. 1.3), (d) allocating responsibilities to the public and private sectors for the development of the energy sector, and (e) increasing electricity prices (para. 1.18).

G. Principles for Bank Group Lending to the Power Sector

1.23 Commitment to Sector Reform. The democratic Government, which was established following the June 1991 elections, has demonstrated commitment to power sector reform, moving from a state-centered bureaucratic approach toward commercialization of NEA and increasing the role of the private sector in power supply development. This was first evidenced by its adoption of the Power Sector Efficiency Project, the preparation of which had been initiated under the previous government. Since then, the Government has further demonstrated commitment by more than doubling power tariffs in real terms through three increases over a 30-month period, by encouraging efficiency in the production and end use of electricity, by passing legislation to establish the framework for increasing NEA's autonomy, accountability and commercialization and to facilitate private involvement in the power sector, and by embarking on a program of institutional reform and capacity development for NEA. The reorientation of the legal and regulatory framework in pursuit of power development goals included amending the NEA Act of 1984, enactment of the Water Resources Act, and enactment of the Electricity Act, which, inter alia, provides for establishment of a TFC. A Hydropower Development Policy Statement provides guidelines for private sector participation in power generation, transmission and distribution. It bears noting that major restructuring of the sector through breaking up the vertical integration of the generation, transmission, and distribution functions is unlikely to be beneficial because the loss of economies of integration are likely to outweigh any efficiency gains from competitive pressures in the operation of hydropower facilities.

1.24 Transparent Regulation. The Government has proposed a framework for power sector development, focusing on institutional roles and responsibilities, private sector development, the policy and regulatory framework, and NEA's ongoing commercialization program. HMG will put the framework into place in phases during the project period. Key actions have been agreed as part of the proposed project, and there will be in-depth consultations on progress during annual reviews of the project (para. 6.1(a)). As part of its efforts to increase transparency in decision-making in the power sector, HMG is in the process of setting up the TFC. The Commission will make tariff adjustments based on economic and financial criteria, including automatic adjustment to reflect changes in fuel costs, and ensure that tariffs are in accord with financial covenants agreed with IDA (para. 2.9).

1.25 Importation of Services. As part of its reform program, Nepal has opened up the power sector to entry by foreign investors; this has already begun bearing fruit with the development of private hydropower generation schemes by the private sector. Because of limitations in the availability of trained manpower, Nepal has relied on the importation of services, particularly consulting services. Specialized consultants provided by Canada, France and Germany have assisted in developing NEA's internal management systems, including operations and maintenance, and have mounted dedicated training programs for NEA technical staff. At the same time, international consultants have assisted in preparing, supervising and implementing hydro schemes. This practice is expected to continue, although the design and delivery of these services is expected to change to reflect the growing complexity of Nepal's power sector and the increasing Nepalese technical capacity.

1.26 NEA's Commercialization and Corporatization. The Government has laid the groundwork for NEA's commercialization and corporatization and increasing NEA's autonomy and accountability. It is also facilitating a fundamental change in NEA's corporate culture to foster the creation of a commercial environment. To date the Government and NEA have modified NEA's Board and replaced top management by more commercially oriented individuals as well as initiated a major staff retrenchment program (para. 2.10, 2.14). Continuation of this process will be guided by a Commercialization Plan (para. 2.13).

1.27 Private Sector Involvement. The Government is committed to facilitating private sector investment in the power sector to increase the resources available to meet its large investment needs and improve the sector's efficiency. An Electricity Act was promulgated in August 1993 to facilitate this process, and regulations to operationalize the Act have recently been prepared, with the assistance of a USAID-financed consultant. IFC is participating in the preparation of the 60 MW Khimti Khola private sector hydropower generation project with a target commissioning date of 1998. A consortium led by Statkraft, a Norwegian power utility, is mobilizing resources for the Khimti Khola project, including support from IFC (Report No. IFC/R94, June 8, 1994) and ADB's private sector window. Negotiations have been finalized with NEA to be the purchaser of power generated by Khimti Khola.

1.28 Load Management and Loss Reduction. NEA is committed to improved load management, including the use of tariffs to induce more efficient use of electric power in Nepal. The Power Sector Efficiency Project includes a program of load management measures such as equipment sizing, timing of plant operation, power factor correction and energy efficiency lighting, as well as the efficiency improvement of non-electrical loads such as industrial steam cycle systems. A central outreach facility to institutionalize these activities with the involvement of the private sector is also planned under the project.

1.29 NEA has been carrying out a program to identify and systematically reduce network losses. NEA staff are trained in repairing defective meters, rehabilitating service connections and deteriorated lines, and related tasks. Equipment has been introduced to monitor losses, meter testing facilities have been improved, and exempt consumers (such as temples and NEA's own consumption) have been brought within the billing system. Non-technical losses are being addressed by improved meter reading and billing procedures, as well as field inspections and correction of irregular connections. As a result of this program, network losses in the Kathmandu Valley, the main load center, have fallen by three percentage points per year from 32% in 1991 to 26% in 1993. Without such efforts, the share of losses would have increased with annual load growth, especially given the lack of system improvement over these years. NEA is continuing the program, including extending it to other load centers in the country (paras. 2.26-2.27).

H. IDA's Country and Sector Assistance Strategy

1.30 Country Assistance Strategy. The Government and IDA share a common view of Nepal's development priorities. The alleviation of widespread poverty is the overriding objective to be attained through the two-pronged strategy elaborated in the 1990 World Development Report. This approach is made up of broad-based, labor-intensive economic growth to provide income-generating opportunities for the poor, and investment in basic social services such as health care, family planning, nutrition and primary education, together with enhanced service delivery capabilities in the rural areas, to enable the poor to take better advantage of these opportunities. The key elements of the assistance strategy to attain these objectives include: (a) public resource management reforms -- revenue, expenditure, and administrative -- to improve the efficiency of investments and institutions; (b) improvement of the environment for efficient private sector activity through trade and industrial reforms, strengthening of the financial system, and gradual withdrawal of the public sector from selected economic activities through, inter alia, privatization of public enterprises; (c) implementation of effective population and human resource development programs, and (d) environmental sustainability of Nepal's growth and poverty reduction initiatives. The Board of Directors discussed and endorsed IDA's country assistance strategy for Nepal on April 12, 1994.

1.31 To achieve a noticeable improvement in the living standards of the poor, Nepal's annual growth rate will have to accelerate beyond the historical average of 3.5%, to 4-5%. The Government and IDA are identifying a set of promising interventions for accelerating agricultural growth over the medium term through the development of a new agricultural development program. For further developing light manufacturing oriented toward niche markets in India and third countries, as well as services, especially tourism, at the more upscale end of the market, a reliable and increased supply of power will be critical. Productive activities in Nepal are already seriously undercut by interruptions in power supply and blackouts, especially during the mid-October to mid-May dry season. If the proposed investments in the power sector are managed effectively, the increased supply of power, coupled with "lifeline" tariff rates for low-income groups, would relieve pressure on fuelwood and on forest resources which, in turn, should benefit other activities such as cropping and livestock.

1.32 Such growth and poverty reduction objectives will need to be supported by the development of Nepal's human capital. Nepal's competitive edge in its low-cost labor is offset by its low skill levels as compared to its neighbors, and its future growth will depend on its ability to reduce this human resource gap. This calls for systematic improvements in basic social services -- including education and skills training. Further investments in the social sectors are also needed to reduce the population growth rate and to improve the overall health of Nepal's labor force.

1.33 Sectoral Assistance Strategy. IDA's Power sector strategy for Nepal is in accord with the Association's overall approach to electricity sector development[5/] and is an integral component of its country assistance strategy. Consistent with HMG's own objectives, IDA's strategy is to assist Nepal to: (a) develop efficiently its hydroelectric potential, in a socio-environmentally responsible manner, (b) establish an institutional and regulatory framework which facilitates efficient sector development and private investment, (c) upgrade the corporate performance of NEA, (d) formulate an investment program to meet projected demand at least cost, and (e) establish mechanisms for setting tariffs that reflect the economic cost of supply. To date, IDA has supported this strategy by financing eleven energy projects including seven aimed at the

[5/] The Bank's Role in the Electric Power Sector: Policies for Effective Institutional, Regulatory and Financial Reform, June 30, 1992, R92-193.

development of hydroelectric schemes, three forestry projects, and a petroleum exploration promotion project which attracted one joint venture but has not led to any discoveries. The credits have totalled US$281 million equivalent, representing about 22% of IDA commitments to Nepal; lending for power projects, primarily through MOWR, amounted to US$206 million. The lessons learned from past support and the Power Sector Study (para. 1.19) have been important in developing today's coordinated donor strategy.

1.34 Past Experience and Lessons Learned. In the power sector, four credits supported project implementation[6], and three supported project preparation, including the feasibility study of the Karnali (Chisapani) Multipurpose Project (ultimate capacity in excess of 10,000 MW), site investigations of the 3,000-6,000 MW Pancheswar Project, and detailed engineering for the Arun III Hydroelectric Project (AHP). While progress on the preparatory studies has generally been satisfactory, experience with the two completed hydroelectric projects (Kulekhani and Marsyangdi) has been mixed. Physical implementation improved markedly from the first to the second project, but the institutional and financial performance of NEA was disappointing. The PSEP Project (Cr. 2347-NEP) approved in March 1992, was declared effective on January 15, 1993 (para. 1.36).

1.35 For the 60 MW Kulekhani Project (Cr. 600-NEP), the Project Performance Audit Report noted that the 21-month delay in project commissioning and the 80% cost overrun were caused by insufficient field investigations during preparation combined with overly optimistic scheduling of construction for a project of such scope (the largest in the counting at the time) in the Nepal Himalayas. The project suffered from the lack of a Panel of Experts (POE), and a detailed engineering cost estimate was not completed prior to the bidding process. Although the project did not take full cognizance of soil conservation and watershed management problems, the Government subsequently took corrective action with the help of donor agencies. In spite of the foregoing, the Audit Report considered the project to have been a successful endeavor that has provided Nepal with its only significant hydropower storage facility. For the 69 MW Marsyangdi Hydroelectric Power Project (Cr. 1478-NEP), implementation performance improved considerably, primarily due to application of lessons learned from the Kulekhani project. A POE was involved from the beginning, and bids were based on a detailed engineering study. The Marsyangdi project was commissioned in January 1991, within six months of its scheduled date and approximately US$90 million under budget. A major achievement consisted of sustaining project construction during the 1991 Trade and Transit impasse with India. As with the Kulekhani project, compliance with project covenants was mixed, primarily because HMG did not implement timely tariff increases. The major lessons learned from these projects include the need to address key issues early in the project cycle. The key project issues are the need to improve the level of confidence in cost estimation through increasing the levels of site investigation and incorporating bid prices in cost estimates, and to minimize start-up delays.

1.36 Implementation of Ongoing Projects. The PSEP provides for improvements in NEA's generation and transmission facilities and for institutional strengthening (particularly in management). In addition, the PSEP includes an industrial energy conservation component and the implementation of the Marsyangdi Catchment Management Pilot Plan prepared under Cr. 1478-NEP. Implementation of the project's physical components has been satisfactory; NEA's institutional performance, which started from a low base, has shown improvement, particularly in terms of financial management and reporting.

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[6] Kulekhani (Cr. 600-NEP) approved on December 23, 1975, for US$26.0 million, plus a supplemental Credit (Cr. 600-1-NEP) approved on May 10, 1979, for US$14.8 million; Marsyangdi (Cr. 1478-NEP; US$107.0 million) approved on May 22, 1984; Arun III Access Road (Cr. 2029-NEP approved on May 30, 1989; US$32.8 million); and Upgrading of Trisuli-Devighat approved on March 26, 1992 (PSEP, Cr. 2347-NEP; US$29.7 million).

1.37 Looking Ahead. The largest investment in IDA's present assistance program to Nepal is the proposed AHP. Because of its lumpiness, both the Government and the donors agree that project development and implementation requires a special risk management strategy. After investing more than seven years in developing this project -- controversial because of its size as compared to Nepal's modest economic resources and institutional capacity -- IDA's decision to proceed with the processing of a first stage 201 MW hydro project took explicit account of the risks involved. Because of the project's size (equal to about two years of Nepal's investment program) and ten-year implementation period, the areas of risk include (a) crowding out of high-priority investments in other sectors, due to cost over-runs, worse-than-expected management of the Government budget, or failure of NEA to meet the projected share of its expenses; (b) unforeseen delays in project implementation; and (c) unsatisfactory implementation of the Environmental Management Plan, including the Environmental Mitigation Plan, Regional Action Program and the Land Acquisition, Compensation and Rehabilitation Plan. These risks have been investigated and analyzed (paras. 5.28-5.32).

1.38 Rationale for IDA's Involvement. Besides assisting HMG's efforts to meet Nepal's demand for energy at least cost, the proposed project would, through IDA's involvement:

(a) improve NEA's ability to manage and meet the power demand in Nepal while reducing the cost of providing service;

(b) strengthen the capabilities of NEA and government institutions to prepare, design and supervise the construction of environmentally sustainable medium-sized hydropower projects;

(c) strengthen NEA's autonomy and accountability, and facilitate a program aimed at increasing NEA's commercialization;

(d) assist in progress toward institutionalization of an appropriate regulatory framework for Nepal's power sector; and

(e) promote the participation of the private sector in the planning and development of hydroelectric plants.

1.39 Cofinancing and Donor Coordination. Under Credits 600-NEP, 1478-NEP and 1902-NEP, there has been significant cofinancing involving IDA, CIDA, the European Community, the Kuwait Fund for Arab Economic Development, Kreditanstalt für Wiederaufbau (KfW) on behalf of the German Government, the Overseas Economic Cooperation Fund (OECF) of Japan, the Saudi Fund for Development, and UNDP in supporting the development of hydroelectric schemes; other donors, including ADB, FINNIDA, the Government of France and the Japanese International Cooperation Agency (JICA), have supported investments in transmission and distribution. ADB and IDA collaborated in the preparation of the Nepal Power Subsector Review (para. 1.19) that has guided both institutions' strategy for power development in Nepal. The strategy proposed in the review was endorsed by the donor community at a Donors' Meeting on the Nepal Power Sector chaired by IDA in Paris in May 1988, when preliminary commitments were made to support the Arun III Project; this was confirmed at a meeting chaired by IDA in Paris in February 1993, which paved the way for seven donors making commitments to the Arun III Project subject to appraisal.

I. Macroeconomic Considerations

1.40 The AHP is a large project relative to the size of Nepal's economy; its total expenditures, which will be spread over a 9-year period, are equivalent to about 25% of Nepal's FY94 GDP. This has raised concerns as to whether the project is affordable in the sense of being consistent with prudent macro-economic management and, more particularly, consistent with reasonable future growth in other priority types of expenditure such as primary education, primary health, family planning and rural infrastructure.

1.41 Macroeconomic Program. Nepal's macroeconomic program is described in the Policy Framework Paper (PFP) for FY94-96, which has been agreed with the Bank and the IMF. The public investment program embodied in the PFP includes the Government's preferred hydropower investments (i.e. both AHP and Kali Gandaki A) as well as human resource and rural infrastructure investments which Bank staff consider to be reasonable in light of Nepal's limited absorptive capacity in these sectors.[7] Hence appraisal of the affordability of AHP requires an assessment of the robustness of the PFP framework and consideration of how to manage the risk of a shortfall in resources for investments in other priority sectors of the economy.[8]

1.42 The key uncertainties which could affect Nepal's macroeconomic prospects over the next few years are: (a) slippages in policy implementation, especially in the areas of resource mobilization and expenditure prioritization; (b) inadequate and/or delayed private sector response to changes in the policy environment; and (c) exogenous shocks. On the policy side the performance of the Government to date has been encouraging. Measures to enhance revenue mobilization were initiated as part of the FY94 budget, raising overall revenues to an estimated 11.1% of GDP in FY94 from an average of 10.5% in FY92-FY93. A good beginning has also been made to rationalize the structure of import tariffs, simplify excise and sales taxes, expand the effective income tax base and strengthen tax administration. Measures to improve the pattern of public expenditures have also been taken. A preliminary core program was adopted as part of the FY94 budget and is being implemented satisfactorily. Budgetary allocations to priority activities, including the social sectors and rural infrastructure, were significantly increased in the FY94 budget, and spending on low priority items was curbed.

1.43 While policy performance under the PFP is thus off to a good start, it is critical that further progress in line with PFP understandings be achieved. With respect to the FY95 budget the Government has agreed, as a condition of credit effectiveness, to formulate a satisfactory public expenditure program (para. 6.4 (a)). The FY95 program is expected to include adequate resource allocations for the highest priority activities in the social sectors, rural infrastructure and power; cancellations of low priority projects; and limitations on new project starts. IDA has also made clear to the Government that its support for the other major near-term investment in the hydropower investment program (i.e. Kali Gandaki A) will depend on sustained progress in resource mobilization and expenditure prioritization as evidenced by actual performance in FY95 and budget provisions for FY96. While the details which would permit an assessment of compliance with these conditions are awaited, the broad aggregates of the recently presented FY95 budget are consistent with the macroeconomic framework of the PFP. Furthermore, the sectoral allocation of expenditures shows a strong continued shift towards the social sectors. HMG's ability to gain and sustain support for these policies has been enhanced by the argument that such policies are needed to underpin critical investments in both the social sectors and in hydropower. Should the international community withdraw its support for the hydropower investment program, the risk of policy slippage would no doubt increase.

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[7] This analysis is presented in *Nepal: Fiscal Restructuring and Public Resource Management in the Nineties*, Report No. 12281-NEP, March 17, 1994.

[8] The affordability analysis of the AHP is reported in Annex 1.4.

1.44 The second key factor affecting macro-economic prospects – namely; the strength of the private sector's response – is difficult to forecast. Experience in other low income countries shows that lags in private investment can be substantial. Much hinges on establishing the credibility of government policies. In Nepal's case, the shortage of reliable electric power is a major impediment to expansion in both service industries (e.g. tourism) and manufacturing. Hence a credible program to alleviate this shortage would be helpful to private sector confidence, and the absence of a credible program would inhibit the response which is needed if growth objectives are to be achieved. In judging the impact of AHP on availability of resources for social sector and rural infrastructure investment, it is important to remember that medium and long-term growth in GDP is probably the most important single factor influencing the capacity of HMG to support such critical expenditures.

1.45 Assessment and Management of Affordability Risk. Recognizing that the timing of private sector response cannot be assured and that exogenous shocks (e.g. floods) can always occur, the appraisal of AHP's affordability considered the scale of resource scarcity that could emerge as a consequence of the project's implementation and the scope available to HMG for corrective action. Details of this analysis are presented in Annex 1.4. Since foreign exchange reserves are projected to remain at a comfortable level, the key constraint is not foreign financing but the volume of rupee resources available to support priority human resource needs. In the base case – corresponding to the PFP assumptions – rupee availability is sufficient to support real growth at the rate of 8% per annum in public expenditure on the social sectors. However, if NEA's finances were to improve in line with Case B of the financial analysis presented in Section IV, and under the assumption that the additional resources thus made available to the Government are divided among sectors in accordance with their existing proportions in public expenditure, it would be possible to support growth in the social sectors at a rate of 9.5% in real terms in the base case.

1.46 The robustness of this conclusion is tested in two ways: first, by a sensitivity analysis with respect to changes in assumptions and second, by an integrated risk analysis which assigns probabilities to those assumptions to derive a probability distribution of growth in social sector programs. The sensitivity analysis considers a situation where growth in GDP averages 3% per cent per annum (as compared to 4.5% in the base case), the revenue-to-GDP ratio increases by 0.2% per annum (in line with historical experience but below what HMG achieved in FY94), regular expenditures grow somewhat more rapidly than envisaged in the PFP and no significant expenditure prioritization is achieved due to resistance by various affected groups. The impact of these assumptions – if no corrective action is taken – is to reduce the growth of social sector expenditures from 9.5% per annum to a little over 5.5% per annum. If, in addition, AHP were to experience a cost overrun of 20% (over and above the 14% per cent contingencies already built into the project financing plan), the growth rate would decline by another 1%.

1.47 The risk analysis shows that there is an 85% probability that even in quite adverse situations Nepal could sustain growth of at least 5% per annum in high priority social sector programs. Moreover, the cases in which spending growth is below 5% could be brought up to that level with a very small increment of rupee resources, equivalent to less than 0.2% of current average aid disbursements to Nepal. Hence the affordability risk of the AHP is considered to be manageable.

II. IMPLEMENTING AGENCY - THE NEPAL ELECTRICITY AUTHORITY

A. Introduction

2.1 In view of the imperative for rapid expansion of electric power in Nepal, HMG has set a course for reform and strengthening of its central power utility, the Nepal Electricity Authority (NEA), established in 1985. The objective of this institutional development program is to provide greater autonomy and a stronger commercial orientation to NEA operations, while still requiring accountability. This Section describes: the status of existing NEA facilities and infrastructure; the legislative and regulatory framework for power sector development, including autonomy of NEA; the status of internal NEA reforms geared to enhancing operational efficiency; NEA financial management and measures to secure accountability; and, finally, the program to reduce system losses.

B. Existing Facilities

2.2 NEA is Nepal's principal power supplier; electricity is also supplied by captive industrial generation plants (nominal capacity of 17.5 MW) and a number of privately owned hydroelectric plants.

2.3 Generation Capacity. Nepal's interconnected system has an installed generating capacity of 272 MW (Annex 2.1) of which 232 MW (85%) is hydroelectric plant and 40 MW (15%) is diesel plant; NEA's rated generating capacity is 261 MW. Since 1981, 180 MW of new hydroelectric plant has been installed, increasing the hydro proportion of generating plant from 67% to 81%. All hydroelectric plants are run-of-the-river plants except for the 92 MW Kulekhani I and II complex, which has seasonal storage. The 12 MW Jhimruk hydroelectric project (to be commissioned in 1995) is under construction by the Butwal Power Company (a non-governmental organization) with Norwegian assistance; this company also constructed the 5.1 MW Andhi Khola project, which was commissioned in 1991. With FINNIDA's assistance, NEA commissioned a 26 MW multifuel thermal plant in 1991. Outside the interconnected system, NEA operates a number of isolated hydroelectric plants with total installed capacity of 3.9 MW and small diesel plants with total installed capacity of 1.0 MW.

2.4 Transmission. Nepal's transmission system developed through the gradual interconnection of isolated networks built to serve regional centers. In the Central Region, a 66 kV network was developed to bring power into the Kathmandu valley from outlying hydroelectric plants: Kulekhani I (60 MW), Sunkosi (10 MW), Devighat (14 MW) and Trisuli (21 MW). A 66 kV double circuit line also links Kulekhani I with Hetauda and Siuchatar. To allow electricity to be transmitted to the Eastern, Western, Mid-Western and Far-Western Regions, a 132 kV transmission line is being superimposed on the 66 kV system from Anarmani in the Mechi Zone to Mahendranagar in the Mahakali Zone; in addition, the Kulekhani II and Marsyangdi hydroelectric plants are linked to the 132 kV system. A single line diagram of the existing transmission system is shown in Annex 2.2 together with a schedule of facilities. Interconnection with India takes place at Ramnagar at 132 kV and at fourteen other points along the border at the distribution voltage level (33 kV or 11 kV). The NEA system is not synchronized with the two border Indian State Electricity Boards (Bihar and Uttar Pradesh). Power exchange, currently limited to 50 MW equivalent, occurs in an ad hoc manner, depending upon the availability of supply. The PSEP provides for reinforcement/upgrading of the transmission system in the Kathmandu Valley, including provisions for spares, equipment and tools. An additional interconnection with the Bihar State Electricity Board (Biratnagar-Kataiya) is also being supported under the PSEP. In conjunction with the AHP, and with the assistance of the Swedish Agency for International Technical and Economic

Corporation (BITS), NEA is planning to string an extra 132 kV line from Biratnagar to Hetauda.

2.5 Distribution. The distribution system consists of 351 km of 33 kV lines, approximately 900 km of 11 kV (and 2.3 kV lines), and approximately 2,500 km of low voltage lines. JICA is supporting a program to rehabilitate and reinforce the distribution and transmission system in the Kathmandu Valley.

2.6 Maintenance and Rehabilitation. The generation rehabilitation component of the PSEP includes the upgrading of the civil works for the Trisuli and Devighat hydroelectric plants and the retrofitting of the Trisuli electromechanical equipment. When completed in 1996, the rehabilitation should increase NEA's effective supply capacity by 14 MW. The Overseas Development Association (ODA) (U.K.) is supporting the rehabilitation of the 14.4 MW Hetauda diesel complex. The Sunkosi, Gandak and Kulekhani hydroelectric plants and the Hetauda diesel plant need complete overhauls and repairs as soon as possible to avoid major breakdowns. Currently, NEA is undertaking overdue maintenance of the 92 MW Kulekhani I and II complex as well as the Hetauda diesel plant, and is discussing with IDA possible financing for overhauling the Sunkosi and Gandak projects from PSEP savings.

C. Autonomy

2.7 Legal Framework. NEA was created in August 1985 through the amalgamation of a number of public sector organizations, principally the Nepal Electricity Corporation, the Electricity Department, and the Small Hydro Development Board. The NEA Act of 1985 established NEA as a commercial entity with responsibilities for generation, transmission and distribution throughout Nepal. However, the Act interfered with NEA's capacity to realize commercial objectives, through limits on the Authority's autonomy, as well as in the lack of mechanisms for accountability. The Act was amended in 1992 to address these shortcomings, with the objective of establishing an institutional framework which would enable NEA to operate as a successful commercial entity. The current legal framework is satisfactory.

2.8 The new NEA Act anticipates that NEA's commercialization will include public participation in its ownership. It makes provision for the sale of NEA shares. When a minimum 10% of the total value of NEA's share capital is sold to the general public, an Annual General Meeting process is to commence, and the Board of Directors would be elected at this meeting. The timing of a public offering will be determined by NEA's commercial performance under the Commercialization Plan (para. 2.13).

2.9 The new Electricity Act provides, *inter alia*, for the establishment of a TFC to be responsible for setting tariffs and other charges. The Commission members would include representatives of the Government, the electric utility, and consumers. HMG has agreed to establish and maintain the TFC in a satisfactory manner (para. 6.1(d)). It has promulgated regulations for the Commission that specify the principles and procedures for tariff increases. During negotiations and as a condition of credit effectiveness, HMG agreed to revise the TFC's regulations to ensure that electricity tariffs and other charges are set in accordance with financial covenants agreed with IDA, including an automatic fuel adjustment clause in NEA's tariff schedule to reflect changes in the cost of fuel to the utility (para. 6.4(b)). Although the TFC comes into operation on August 15, 1994, its proposed institutional and operational aspects would benefit from review and staff training. For this purpose, HMG is obtaining consultant services under a KfW grant to carry out a study under agreed terms of reference. HMG will provide the completed study to IDA by January 31, 1995, and, by April 30, 1995, will carry out the agreed recommendations (para. 6.1(c)).

2.10 Governance of NEA. The day-to-day operations of NEA are the responsibility of its Managing Director, who reports to and is a member of the NEA Board. The recent amendments to the Act reduce the number of Government officials on the eight-member NEA Board from six to three. The Chairman of the Board is the Minister of Water Resources, and the Secretaries of the Ministries of Water Resources and Finance are Members. The remainder of the Board consists of three private sector representatives and one consumer representative nominated by HMG, together with NEA's Managing Director. Although these changes will not, of themselves, significantly enhance NEA's autonomy, they represent an important step. NEA's organization chart, reflecting recent improvements in its organizational structure, is shown in Annex 2.3.

2.11 Relationship Between HMG and NEA. The 1988 Power Sector Review identified a number of impediments to NEA's efficient operation. With IDA assistance (Cr. 1902-NEP), NEA followed up on the Review's recommendations by entering into a twinning arrangement with a mature utility, Electricité de France International (EdF), in October 1989. The agreement provided for expertise in all aspects of modern power utility practices, with special emphasis on assisting NEA to develop a corporate plan and improve operations management. Together, NEA, EdF and IDA developed a performance improvement plan which was incorporated into a Performance Agreement (PA) between the Government and NEA.

2.12 The PA signed by HMG and NEA in October 1992, covers, inter alia: (a) NEA objectives in supply to consumers, consumer relations, finance, accounting and auditing, technical operations and tariff policies, (b) the respective rights and obligations of NEA and HMG, including implementation of tariff policies, definition and financing of the investment program, settlement of arrears between HMG and NEA, and disconnection of supply, and (c) the agreed investment plan and its financing, performance indicators, and financial projections. The terms of the PA require an annual review. To strengthen NEA's autonomy and thereby facilitate the implementation of the Agreement, the NEA has promulgated by-laws for NEA's Board functions and procedures for collection of electricity revenues. NEA and HMG will update the Agreement by August 15, 1994. During negotiations, HMG and NEA agreed to review annually, by December 31, NEA's performance under the Agreement during the past year, and, after providing IDA with the recommendations resulting from the review, to carry them out promptly. Furthermore, NEA will present to IDA an updated version of the Agreement at least one month before the start of each fiscal year (para. 6.2(a)).

2.13 As part of the commercialization process, NEA has developed a preliminary three-year rolling Corporate Plan. The purpose of the corporate planning exercise is to assist NEA in focussing on corporate strategies and associated budgets, including the priority actions each Directorate will take to contribute to the corporate goals. NEA has agreed to submit to IDA its updated Corporate Plan 30 days prior to the start of each financial year, taking into account IDA's recommendations on a draft version, and to carry out the Plan in a manner satisfactory to the Association. Additionally, within nine months of the end of each fiscal year, starting in FY95, NEA would publish an Annual Report for the information of the general public, highlighting performance versus targets in its Corporate Plan (para. 6.3(a)). The next step in the process would be development of an NEA Commercialization Plan as anticipated under Cr. 1902-NEP. This plan will provide additional definition to the requirements of NEA in areas such as autonomy and accountability, strategic/business planning, human resource management, and customer service; in addition the Plan will consider financial restructuring to enable NEA to sell shares to the public (para. 2.8) as well as contracting out of services under competitive bidding to private operators by NEA. NEA has developed suitable terms of reference for a consultant to carry out a study to assist NEA in developing its Commercialization Plan; this assignment began in late March 1994. During negotiations it was agreed that, by December 31, 1994, NEA will provide IDA with a copy of the completed study, and, by March 31, 1995, NEA will provide IDA with a Commercialization Plan based on that study, together with a time-bound action plan for its implementation (para. 6.3(b)). NEA will thereafter implement the action plan.

D. Operational Efficiency

2.14 Staffing. NEA had 9,247 employees in February 1993. Approximately 52% of NEA's staff are permanent, 11% temporary, and 37% monthly and daily wage earners. NEA's Board has approved a total staffing of 8,268, a figure much higher than proposed by an EdF study three years ago. Although NEA is over-staffed, it is weak in key personnel in nearly every functional area. NEA has the lowest annual sales and generation per employee of any Asian country for which data are available: 60 MWh (net generation) and 81 MWh (gross generation) per employee, compared to 184 MWh and 263 MWh, respectively, for Bangladesh, the next lowest. NEA's management is conscious of the over-staffing problem and, in conjunction with an IDA-financed training program, commissioned an organizational structure and manpower rationalization study[2/] by the Nepal Administrative Staff College; NEA has begun to implement the study's recommendations. In the meantime, NEA retrenched 1,062 staff as of January 1994. In the context of the annual reviews of the project, NEA's progress in this area would be reviewed, and NEA will implement the agreed recommendations of such review.

2.15 The implementation of the performance improvement action plans developed by NEA and EdF has met with mixed results. NEA has made progress in streamlining its organization, including the creation of a separate Human Resources Department, which reports directly to the Managing Director and is responsible for corporate-wide manpower planning and training programs (para. 2.16) and setting up a separate Rural Electrification Directorate (para. 2.18). However, little progress was made on other key elements of the action plan, including (a) introduction of a compensation system based on actual performance, and (b) introduction of a staff career development process that allows for merit promotion and training. NEA subsequently undertook an analysis of how to put into practice the greater autonomy provided for in the NEA Act. On this basis, its Board adopted management recommendations concerning employee rules and regulations, job descriptions and working procedures; these are currently being implemented.

2.16 Training. With technical assistance provided by EdF under Cr. 1902-NEP, NEA has the essential elements in its Human Resources Department to manage training activities. The Department has two divisions, Training and Manpower, with Training activities carried out at three centers: Bhrikuti Mandap, Panauti Hydropower Station, and Balaju. Instructors for distribution, generation and maintenance, computers and general sciences, and administration and finance are at work in these centers. During FY93 about 720 NEA staff received training in a variety of seminars, courses, study tours, and special programs conducted by the Nepal Administrative Staff College, mainly for top and middle level managers. NEA's present plans provide for the training of about 550 staff, excluding possible programs to be agreed on with the Administrative Staff College. The lack of an NEA training complex has impeded the Human Resources Department from developing a sustainable training program. To address this issue, NEA is planning to acquire land and construct a training center, using local and foreign design and civil engineering consultants.

2.17 Power System Planning. The NEA Planning Directorate's System Planning Department, with the assistance of the Engineering Directorate's Project Preparation Department, is responsible for system planning in generation and transmission. Distribution planning is carried out in the Technical Services

[2/] Nepal Administrative Staff College. A Report on Study of Organization Structure and Manpower Rationalization of the Nepal Electricity Authority, Kathmandu, February 1994.

Department of the Distribution and Customer Services Directorate (TS/DCS). In 1993, Argonne National Laboratory (ANL) was retained to arrange a training course in the U.S. for NEA system planning staff in the Wien Automatic System Planning (WASP III) technology. NEA is now able to prepare its own generation expansion plans with minimal outside advice. It also has in-house capability in cost estimating for hydroelectric projects. Planning in transmission and distribution (T&D) is hampered by a multiplicity of planning criteria and standards from various consultants and the inexperience of NEA staff in developing a uniform approach. Also, NEA's work is constrained by a lack of basic system data. Recognizing this, NEA has completed a Ten-Year T&D Master Plan for the Nepal interconnected system with technical assistance provided under Cr. 1902-NEP. This activity has been complemented by technical assistance provided by ADB aimed at institutionalizing distribution planning at the regional/zonal levels as well as assisting TS/DCS in establishing drawing office facilities and a central registry for system plant and configuration data. This assistance provided NEA with the capability to develop transmission and distribution investment plans with less outside technical assistance.

2.18 Rural electrification is an important component of a strategy to meet rural energy needs at least cost and potentially an important element of a comprehensive rural development strategy because it delivers high quality, highly productive energy. At present, approximately 94% of Nepal's population lives in rural areas, of which an estimated 2% have access to electricity. To provide a framework for expanding and improving its rural electrification efforts, NEA prepared a Ten-Year Master Plan with assistance provided by the National Rural Electric Cooperative Association (USA) under Cr. 1902-NEP. A Rural Electrification Directorate was established in NEA in December 1992. Pursuant to the Performance Agreement (para. 2.12), NEA will be responsible for the construction and operation of such schemes which are viable in economic and financial terms. As agreed under the PSEP and reconfirmed during negotiations for the proposed project, HMG will compensate NEA for construction and operation of schemes which are found to be uneconomic or not financially viable, but are socially desirable (para. 6.1(d)). So far, HMG and NEA have identified eight proposed schemes for which NEA will be compensated by HMG.

E. Accountability

2.19 Financial Management. NEA's financial management, accounting and audit functions are in their initial stages of development and are being strengthened to bring them to satisfactory levels. Over the past years, donors, particularly ADB and IDA, have provided NEA with technical assistance to improve these functions so that an efficient and reliable commercial accounting system could be established. Progress has been slower than expected. This has been recognized by HMG and NEA, and under the PSEP a number of measures aimed at improving NEA's overall financial management and institutional development were initiated. These included *inter alia:* (a) appointment of a professionally qualified Finance Director and two professionally qualified accountants to assist him, (b) training of NEA's internal audit staff, (c) establishment of the Performance Agreement between HMG and NEA, and (d) introduction of a number of short-term remedial measures, such as a basic accountancy training program (funded by CIDA) for NEA's junior and mid-level accountants. However, because of turnover of key staff, these efforts were not sustained. The weaknesses in NEA's financial management have been compounded by the absence of an appropriate accounting system and a lack of suitably experienced finance staff. This situation is well recognized by both the Government and NEA, and encouraging reform measures have already been adopted in the key areas of financial management and control.

2.20 Accounting System. When NEA was created, it inherited an ineffective accounting system, not based on international accounting standards. The weaknesses of the system were manifested in the absence of complete records of assets and liabilities. This inadequate accounting system, combined with poor coordination between NEA's operating units, contributed to underpayment of debt servicing obligations, weak inventory control, and inefficient procurement practices.

2.21 To correct this situation, a number of changes have been initiated by NEA, including: (a) finalization of all Subsidiary Loan Agreements (SLA) between HMG and NEA, (b) reconciliation of NEA's debt and debt service records with HMG, (c) disbursement of funds by HMG to NEA's Finance Department for subsequent release to projects, replacing the previous practice of disbursing funds directly to project offices, and (d) streamlining of NEA's financial functions to make all accountants (including project accountants) functionally responsible to NEA's Finance Director. To strengthen NEA's financial functions and ensure that an appropriate uniform accounting system is adopted, NEA has engaged consultants to: (a) review the accounting system and practice, and (b) assist in implementing agreed recommendations on an appropriate accounting system, while providing on-the-job training to NEA's accounting staff. A revised accounting manual is being prepared in both Nepali and English, along with a time-bound implementation action plan. During negotiations, an action plan for implementation of the accounting system (Annex 2.4) was discussed and NEA agreed that the accounting system will be fully operational by September 30, 1995, in a manner satisfactory to the Association, and maintained thereafter (para. 6.3 (c)).

2.22 Audit. The auditors' reports for FY88-92 indicate deficiencies in NEA's financial management and control. To strengthen its Internal Audit Unit, NEA appointed consultants to carry out a training program. The initial results of the work were encouraging, but, because of inadequate management commitment, followed by staff transfers, the improvements were not sustained. However, NEA has now appointed local consultants to establish an effective internal audit system. Under the first phase, the consultants prepared an internal audit procedure manual which has been approved by NEA. For the second phase, the consultants have been appointed as NEA's internal auditors for FY94 under acceptable terms of reference. While conducting the audit work, they will provide on-the-job training to NEA's staff. The assignment is expected to be completed by the end of December 1994.

2.23 Under the NEA Act and HMG's Audit Act of 1991, the Office of the Auditor General is responsible for carrying out an annual audit of NEA's accounts. Over the past few years, the Auditor General has contracted out the work to local public accountants. As the statutory audit requirements are essentially those of compliance auditing, as distinct from commercial enterprise auditing, the donors who provide financing to NEA have required that NEA appoint auditors of international repute to conduct audits of its accounts based upon accepted international auditing standards. Accordingly, NEA appointed A.F. Ferguson & Company, India, for FY92-93 under terms of reference satisfactory to IDA.

2.24 Until 1993, NEA had not complied with the covenant requirement that annual audited accounts be submitted to IDA within nine months of the end of a fiscal year. Lately, the situation has improved, and the FY93 audited accounts were submitted within the covenanted period on March 31, 1994. To maintain this improvement, NEA has agreed to appoint independent auditors under terms of reference acceptable to IDA, three months prior to the beginning of each fiscal year. During negotiations it was agreed with NEA that, starting in FY94, annual unaudited financial statements, in a form and content acceptable to IDA, will be submitted as soon as available, but within six months of the year-end, and annual audited financial statements and report within nine months of the year-end (para. 6.3(d)). The auditor's report will include a statement on the adequacy of the accounting system and the internal controls, and on compliance with the agreed financial covenants. NEA will also furnish to IDA an interim audit report for the project accounts of the first six months of each fiscal year by March 15, and the annual audit report and audited accounts will include, as a separate schedule, audited project accounts. Finally, HMG has agreed that an audit report on all IDA reimbursements made through statement of expenditures (SOE) and special accounts will be submitted within six months of the end of the fiscal year, and will certify that the reimbursements are fully supported by the underlying data (para. 6.1(e)).

2.25 Materials Management. The present system of procurement and store management is mostly decentralized, ad hoc, and does not follow any consistent policy. These deficiencies have been noted in successive audit reports. To address the problem, NEA has, following appointment of CESCON, Calcutta, developed a materials management program, established a Materials Management Department and appointed a Director, Materials Management with requisite experience and qualifications and under Terms of Reference satisfactory to IDA. During negotiations, it was agreed that the program would be implemented by May 31, 1995, and maintained thereafter ((Annex 2.5) and (para. 6.3(e)).

F. System Losses

2.26 System losses have been a critical problem affecting NEA's operational and financial performance throughout its existence, with yearly losses averaging 24-30% of gross generation during FY86-92. Technical and non-technical losses have each contributed about half of the system losses. The technical losses are caused primarily by improperly planned and inadequately designed distribution systems, while improper billing, illegal connections and incorrect metering are the primary causes of non-technical losses. Since its inception, NEA has taken numerous steps, assisted by ADB and IDA, to reduce system losses. Under Cr. 1478-NEP, with the assistance of British Electricity International, NEA developed a five-year, two-phase system Loss Reduction Program to meet time-bound targets for the Kathmandu Valley, which accounts for more than half of NEA's billings. Technical losses are being reduced through a program of transformer additions, new feeders, reconductoring, phase balancing and reactive power compensation. Non-technical losses, such as pilferage, are being addressed through field inspections and vigilance coupled with meter resealing and rehabilitation of service connections. Metering errors are being addressed through testing and recalibration of three-phase and single phase meters, while billing errors are being handled by improved procedures for meter reading and billing. The Loss Reduction Program is being implemented by the Loss Reduction Division of the Directorate of Consumer Services, which was set up in 1990 to provide a focal point for all NEA commercial and loss reduction activities.

2.27 The first two years of the Loss Reduction Program implemented under Cr. 1478-NEP, provided for: (a) resealing of 100% of customer installations and rehabilitating 40% of the electrical services, (b) phase balancing of 60% of the electrical services, (c) trial installation of 55 km of Aerial Bundled Conductors (ABC), (d) equipping a meter test station in Kathmandu, and (e) upgrading statistical metering at generation, import and export points. Although initial progress was slow due to protracted delays in appointing consultants and procuring equipment, implementation progress is now satisfactory. The next phase of the Loss Reduction Program would continue work in the Kathmandu Valley and extend the successful elements to the rest of the country. Additional assistance is also being provided under the PSEP. Losses in the Kathmandu area (the main load center) have decreased from 32% in 1991 to 29% in 1992 and 26.5% in 1993. They are projected to drop to about 20% for the total system by FY00 due to the expansion of geographical scope and the increased emphasis on addressing non-technical losses.

G. Conclusion

2.28 While NEA is at an early stage of institutional development leading to a more business-like culture, concrete steps have already been taken. As indicated above, further actions, notably with respect to measures to enhance the autonomy and commercial orientation of NEA, and its accountability, have been agreed with IDA. These additional measures are important steps in the process of NEA's maturation.

III. THE PROJECT

A. Project Setting

3.1 Identification of the Arun III Project. Rich in hydro resources, Nepal has three major river basins, the Gandaki, Kosi and Karnali. The Southern basin also has hydro potential. During the past twenty years, reconnaissance investigations identified 107 potential project sites. Identified projects were screened for further study on the basis of energy, capacity, distance from load center, accessibility and rough cost/benefit analysis. This process yielded 18 projects for which engineering studies at or above the level of pre-feasibility have been completed. The studied projects range in size from 5 MW to 10,000 MW, with almost half of them under 100 MW. At an estimated average cost of US$1-1.3 million per pre-feasibility study and US$2.5 million per feasibility study, and with detailed engineering ranging up to approximately US$7 million for Kali Gandaki and US$15 million for Arun, the volume of engineering work carried out by Nepal represents considerable effort and investment of resources. By the mid-1980s, the investigations and studies had produced eight hydro projects for Least Cost Generation Expansion Plan (LCGEP) analysis, and, by the early 1990s, the LCGEP had 11 hydro projects as input. This provides a reasonable number of hydropower options for planning purposes.

3.2 In 1974 MOWR prepared a master plan of the Gandaki river basin with UNDP financing. Twenty-seven projects were identified within the basin. Projects selected for additional study included Kali Gandaki A (60-90 MW), Burhi Gandaki (600 MW), Kali Gandaki II (660 MW), and Sapta Gandaki (225 MW). In 1983 MOWR began to study the Kosi basin with support from JICA. Fifty-four projects were identified and, using the criteria mentioned above to prioritize them, 13 were selected for further study. Among those studied to at least the pre-feasibility stage were Arun III (402 MW), Lower Arun (308 MW), Upper Arun (335 MW), Bhote Kosi 2 (48 MW) and Khimti Kola (60 MW).

3.3 In the Karnali basin, IDA financed a detailed feasibility study of the 10,000 MW Chisapani-Karnali export project. A related IDA-supported study selected Upper Karnali (240 MW) from 18 identified projects as the most promising medium-sized project for pre-feasibility study. Five projects from the Southern river basin were identified, Kankai (60 MW), Bagmati (140 MW), Kulekhani I and II (92 MW), Naumure (245 MW) and Kulekhani III (22 MW). Bagmati was studied to the pre-feasibility stage with assistance from Germany. JICA and France financed detailed feasibility studies of Kankai. Kulekhani I and II have now been constructed. The pre-feasibility study of Naumure was conducted by NEA and the feasibility study of Kulekhani III was done by Nippon Koei of Japan. In the Mahakali River Basin, detailed investigations of Pancheswar Multipurpose Project were undertaken with IDA financing and pre-feasibility of Chameliya Gad (25 MW) was done by NEA.

3.4 By 1987, the above inventory yielded the following projects for a CIDA- and IDA-financed LCGEP analysis, i.e., they had met the criterion of having been studied to at least the pre-feasibility stage: Arun III, Bagmati, Kankai, Sapta Gandaki, West Seti, Burhi Gandaki, Kali Gandaki II and Kali Gandaki A. In

1990, Kulekhani III, Upper Arun and Upper Karnali were added to the inventory. By 1991 three additional projects were studied to pre-feasibility: Khimti Khola, Bhote Kosi 2 and Naumure. Khimti Khola has been committed. Naumure has not been included in any LCGEP analysis because of its negative present value. Preliminary technical studies have recently been completed for Chilime (17 MW) and Chameliya Gad (25 MW) and detailed engineering has been completed for Modi Khola (10 MW). Under the PSEP, NEA will prepare feasibility studies of two further hydroelectric projects in the 10 MW - 100 MW range as well as undertake detailed engineering studies of these or other projects already studied to the prefeasibility level.

3.5 The 1987 LCGEP analysis referred to above, carried out by Canadian International Water and Energy Consultants, took as its main inputs a load forecast through 2005 and estimates of the capital and recurrent costs of the projects. It considered the eight hydro projects as well as thermal options and concluded that the most economic generation sequence to meet forecast demand would be a combination of load management, thermal power, and the two-stage 402 MW Arun III project. A 1990 update of the LCGEP, undertaken with EdF support under Credit 1902-NEP, reconfirmed that Arun III was part of the least cost plan for the Nepal interconnected system. In 1992, in response to macroeconomic concerns, NEA redesigned the AHP as a two-stage investment. In 1993, ANL established that the configured scheme continued to form part of the least cost plan; this was reconfirmed in 1994. During the course of these studies, private and public sector hydropower projects (ranging in capacity from 10 MW to 600 MW), for which pre-feasibility studies were available, were analyzed. Projects for which pre-feasibility studies had not been completed were not considered because of the very preliminary and unreliable nature of information on their technical characteristics and thus their benefits and costs. (However, an indicative analysis was done of an alternative investment scenario, known as Plan B, which includes a number of medium-sized hydro projects not yet studied to the pre-feasibility stage (paras. 5.23-5.24)). No schemes of less than 10 MW capacity were included, because of their unsuitability for meeting grid power demands (para. 5.13). Since 1984 engineering studies have included assessments of socio-economic impacts. Over the past decade, these considerations have been handled with increasingly systematic attention. In evaluating alternative hydroelectric sites, information on the cost of implementing land acquisition and resettlement measures, as well as the cost of ameliorating their direct environmental impacts was considered to the extent available (Annex 5.4).

3.6 <u>The Project</u>. The AHP is located on the Arun river in Sankuwasabha District, about 170 km east of Kathmandu and 40 km from the Chinese (Autonomous Region of Tibet) border. The 26,747 km^2 catchment area, about 95% of which is located in the People's Republic of China, forms part of the Kosi River Basin and contains numerous glaciers and snow packed mountains that ensure the river's firm high level discharge throughout the year. The upstream catchment includes the Barun watershed that ranges from about 1,000 m to the peak of Mt. Makalu, at 8,463 m the fifth highest mountain in the world. The AHP is a run-of-the-river plant with an installed first stage capacity that will generate an average and firm supply of energy of 1,690 GWh and 1,513 GWh, respectively. The site geology has been investigated more thoroughly than for any previous scheme (para. 3.22). An unusual project feature is the long access road (122 km) which would enable Nepal to initiate a series of projects in the Arun river valley (with total estimated capacity of 1,044 MW capacity) and thereby to realize extensive benefits from the river basin. This approach would also confine impacts to one river system rather than scatter them among diverse sites.

3.7 In terms of the critical parameters of power production and geology, projects on the Arun River are the most attractive in Nepal. In fact, in terms of the linear distribution of power (a measure of the available power potential per kilometer length of river, expressed in MW/km), the Arun River, with 45 MW/km, is the highest in Nepal, followed by the Burhi Gandaki river (Gandaki Basin) with 33 MW/km. This is largely due to the hydrology of the glacier- and aquifer-fed Arun River which guarantees a high base flow throughout the year. Arun's firm energy generation of 85% of rated capacity, even in the dry season (December-March), represents an important addition to Nepal's hydroelectric generating capacity. The country currently has only limited water storage, and its existing run-of-the-river hydro plants depend on rivers whose flows diminish radically during the dry season. For example, Marsyangdi, which is rated at 69 MW, delivers only about 27 MW of firm capacity during the dry season. This means that the system has had to depend upon its one storage reservoir at Kulekhani and upon expensive thermal generation to compensate for its diminished hydro capacity during the dry season.

3.8 Access Road. Early in 1987, the Government requested IDA to be the lead donor in mobilizing resources for the AHP. Following a Donors' Meeting in Paris in 1988 which identified substantial support for the Arun III Project (para. 1.39), IDA's Board approved a US$40.0 million project in May 1989 for the construction of the Arun Access Road (Cr. 2029-NEP), in the expectation that the AHP would be presented for Board approval a few years later, after completion of its detailed design and when the access road was nearing completion. However, when the bids for the road proved to be higher than estimated, all bids were rejected as non-responsive, and no work has been undertaken on the proposed access road. Since the time advantage of building the access road separately has been lost, the road has now been integrated with the main hydroelectric civil works. To date, there have been no disbursements under Credit 2029-NEP. The funds available under that Credit would be used primarily for the advance payment to the principal civil works contractor (para. 3.51(a)). The necessary changes to the Access Road Project were agreed with HMG/NEA during the AHP negotiations in the form of an Agreement Amending the Development Credit Agreement for Cr. 2029-NEP and a new Project Agreement with NEA. These agreements have been submitted for Board approval together with the AHP project documentation. To expedite project implementation, Board approval is requested to permit disbursements (to pay advance amounts to the contractor) as soon as the amended Development Credit Agreement for the Access Road Project becomes effective. As a condition of effectiveness of such amended Development Credit Agreement, NEA will be required to sign the contract for the combined civil works lot (C1/C3), and HMG and NEA will have executed a Subsidiary Loan Agreement satisfactory to IDA for onlending the proceeds of the IDA credit for the Access Road Project (para. 6.5); effectiveness of the amending Agreement is a condition of effectiveness of the proposed Credit (para. 6.4(c)).

B. Project Objectives

3.9 The principal objectives of the project are to:

(a) increase the power capacity of the Nepal interconnected system at least cost;

(b) strengthen the capabilities of government institutions and NEA to prepare, design and supervise the construction of environmentally sustainable hydroelectric power projects.

(c) support the environmentally sustainable development of the Arun Valley and assure adequate compensation to, and rehabilitation of, the population adversely affected;

(d) enhance resource mobilization and the operational autonomy and accountability of NEA; and

(e) support the optimal development of Nepal's power sector including progress toward establishing an appropriate regulatory framework and an active role for the private sector.

C. Project Description

3.10 The proposed project is summarized below. Details of components (a) and (b) are provided in Annex 3.1 and of component (c) in Annexes 3.2 and 3.3; terms of reference for the Panel of Experts are in Annex 3.4 and for consultants' services in the project file (Annex 6.1). The geographic locations of the project's physical components are shown in the attached Maps 25523 and 25558 IBRD.

(a) Construction of the first stage of the Arun III Hydroelectric Power Plant including:

(i) preparatory works, including a 122 km access road, NEA camp facilities, construction electricity supply, and service buildings;

(ii) a 68 m high and 155 m long concrete gravity dam across the Arun river incorporating a three-gate overflow spillway;

(iii) a power intake with four openings and three integrated sluiceways;

(iv) two desanding basins approximately 17 m wide, 28 m high, and 110 m long each, and a flushing tunnel;

(v) a headrace tunnel about 500 m long and 7.5 m concrete finished diameter, common to the first and second stages, and a first stage headrace tunnel about 11.4 km long and 5.6 m concrete finished diameter;

(vi) a 95 m high and 15.9 m diameter surge tank;

(vii) a power cavern for three 67 MW generating units with a maximum gross head of 304 m, a transformer and switchgear cavern, and ancillary electrical and mechanical equipment; and

(viii) a tailrace system including a tunnel about 194 m long and 5.8 m concrete finished diameter and a surge tank 27 m high and 22 m in diameter.

(b) Construction of Power Evacuation Facilities for the Arun III Hydroelectric Power Plant including:

(i) a 120 km 220 kV double-circuit transmission line to Duhabi; and

(ii) a 220 kV/132 kV substation at Duhabi.

(c) Implementation of an Environmental Management Plan including:

(i) a Land Acquisition, Compensation and Rehabilitation Plan (ACRP) for the project-affected families; and

(ii) a Project Environmental Action Plan (EAP) that includes (a) an Environmental Mitigation Plan to deal with the direct impact of the construction activities, and (b) a Regional Action Program (RAP), including a rural electrification component, to address the project's induced impacts and promote sustainable development in the Arun Valley.

(d) Technical Assistance in the form of:

(i) consultant services to assist NEA in the implementation of components (a), (b), (c)(i) and c(ii)(a) of the project;

(ii) services of a consultant company/NGO to coordinate/implement component (c)(ii)(b) of the project;

(iii) a POE to make periodic reviews during project construction and oversee the implementation of the Environmental Management Plan; and

(iv) extension of NEA's ongoing training program.

(e) Private Sector Power Development

A Hydro Facility Fund will be set in place to strengthen the capacity of Nepal's private sector to undertake feasibility studies of micro/mini hydroelectric schemes, and to finance the implementation of viable schemes.

3.11 The proposed project includes only the first 201-MW stage, which accounts for about two thirds of the total cost of the two-stage AHP in real terms. The second stage of the AHP would include a duplication of the desanding basins, headrace tunnel, surge tank, pressure shaft and tailrace tunnel. It would also include the extension of the length of the powerhouse from 108.62 m to 168.24 m (to accommodate three additional turbo-generator sets) as well as an extension of the 220 kV transmission line from Duhabi to Kathmandu.

3.12 In addition, in parallel to the AHP, ADB will provide a grant (US$600,000) to provide technical assistance to upgrade NEA's Environmental Unit, particularly to strengthen its Environmental Impact Assessment procedures and guidelines and to introduce an improved Environmental Management System. The technical assistance will provide for (i) the services of an international expert, (ii) an in-country and external training program for the Environment Unit staff, and (iii) field survey and data management equipment. A more detailed description of this activity is available in the project files. NEA has recently appointed a Joint Director of the Unit as well as a forester. With the arrangements described above, the Unit would be in a position to fulfill its responsibilities.

3.13 Training. Under the proposed Project there will be two training components. The first focusses on strengthening NEA's technical, financial, administrative and managerial capabilities. Special emphasis will be put on the training of operations and maintenance personnel at existing generation plants. This component will be implemented under the responsibility of the Human Resources Department. The second component will be oriented toward helping NEA administer the supervision of the construction phase of Arun III, and ensure that the staff who will run the AHP plant (about 168) will be properly trained once it is commissioned. The project supervision contract (para. 3.25) includes provisions for this training for the AHP. Further details on the training and technical assistance components are included in Annex 3.5.

3.14 Hydro Facility: A facility will be created to promote involvement of the private sector in Nepal's power development. The allotted funds will be managed by the Nepal Industrial Development Corporation and will be used by the private sector to prepare technical studies/reports on potential hydro projects and to finance the implementation of viable schemes. Selection criteria, including technical, economic and institutional aspects of proposed projects, are set out in Annex 3.6. HMG has agreed to finalize arrangements for the hydro facility by December 31, 1994, and to submit quarterly reports on its operation (para. 6.1(f)).

D. Water Rights

3.15 The AHP would use the waters of the Arun River, an international inland waterway that originates in the Autonomous Region of Tibet, People's Republic of China, and flows through Nepal to India. With regard to the immediate downstream riparian, India, Nepal's right to use the water of the Arun River is covered by an agreement between the Government of India and HMG on the Kosi Project dated April 25, 1954, as amended on December 19, 1966, which does not require formal notification regarding the project component. The Government of China, the upstream riparian, raised no objections (January 4, 1988) in response to IDA's indication that it was considering supporting development of the AHP detailed engineering studies under Cr. 1902-NEP. Because of the lapse of time since the processing of Cr. 1902-NEP, China was notified on November 14, 1993, that IDA was considering supporting development of the AHP. In a letter dated January 14, 1994, the Government of China informed HMG that it had no objections to the construction of the AHP.

3.16 Concern has been expressed that a potential irrigation project might be undertaken in the Changsuo Basin in Tibet that would affect negatively the flow of the Arun River at the project site. However, the catchment area of the Changsuo Basin is about 230 km^2, less than 1% of the Arun Basin catchment, so any diversion is likely to be almost imperceptible at the project site. Even if the flow in the tributary were totally cut off the impact would not be significant. In the wet season, the Arun River flow would still be more than 400 m^3/second; in the dry season, the river is fed by aquifers throughout the basin as well as by glacier melt.

E. Project Engineering and Status of Preparation

3.17 The AHP was first identified as the most attractive of 54 alternative schemes under the JICA-financed Kosi Master Plan Study conducted from 1983 to 1985. Consequently, NEA with assistance from CIDA, carried out a pre-feasibility study of the project and issued a report in October 1985 which confirmed its technical and economic attractiveness. Under JICA financing, a feasibility study was conducted by a joint venture of Japanese consulting firms, including the Electric Power Development Corporation of Japan, whose report was issued in June 1987. This report recommended a project layout based on constructing the project in two stages (including two 11.4 km headrace tunnels) and established its technical and economic viability. The report included a recommendation that the access road, 115 km in length, should basically follow the river alignment. The feasibility study recommendations were subsequently reviewed and endorsed by the POE, which recommended additional field and desk investigations and studies of alternative designs. NEA executed pre-design and field investigations and prepared the terms of reference for detailed engineering studies.

3.18 Under KfW financing, NEA signed a contract with a consortium of consulting companies, Joint Venture (JV) Arun III (consisting of Lahmeyer International and Energy Engineering International, both of Germany, and the Electric Power Development Corporation of Japan), to conduct the detailed engineering studies for the hydroelectric power plant component. Under IDA financing, detailed engineering studies of the access road were conducted by Scott Wilson Kirkpatrick of the U.K., while Canadian International Water and Energy Consultants conducted the preliminary engineering studies of the power evacuation facilities. The detailed engineering studies of the access road identified a 192 km ridge route which also connected Khandbari, the headquarters of Sankuwasabha District, with the national road network (para. 3.19). The AHP detailed engineering studies, which commenced in January 1989, recommended that all civil works be completed initially with one headrace tunnel and that four 67 MW units be commissioned in the first stage with a further two 67 MW units to be commissioned in the second stage. In May 1992, in response to IDA's concerns about the affordability of such a large first stage, NEA produced a design concept and plan to develop the project in two 201 MW stages (each including a headrace tunnel and three 67 MW electro-mechanical units, with the access road included in the first stage) that was similar to the concept originally presented in the feasibility study. This is the concept of the proposed project, for which all the detailed engineering studies have been updated by JV Arun III in association with Scott Wilson Kirkpatrick.

3.19 The Arun Access Road (Valley Alignment). The proposed project includes a 122 km access road with a valley route alignment rather than the 192 km ridge route alignment that was to be financed in 1989 under Cr. 2029-NEP. The original alignment had the advantages of providing temporary employment through labor-based construction, because the ridge environment would not permit use of heavy construction equipment, and of linking a larger number of villages to the access road because more of them are located in the hills. For several reasons, however, it was decided to change to the valley alignment. This alignment would enable cost savings due to: (a) a saving of one year in the AHP commissioning, (b) shortening of the transmission line by about 20 km, (c) lessening the travel distance from the present roadhead to the dam site by 98 km, together with a large reduction in gradients and hairpin bends, and (d) easy availability of construction materials such as stones, sand and water. In addition, it would have a reduced impact on cultivated land (167 ha along the river alignment compared to 286 ha for the ridge route), less land take (394 ha compared to 510 ha for the ridge route), and fewer affected families (931 compared to 1,661 for the ridge route).

3.20 In addition to the Environmental Assessment (para. 3.36) a specific analysis was undertaken to compare the possible impacts of the two different proposed road alignments on forest degradation using geographical information system (GIS) technology[10/]. The primary data base used was derived from the CIDA-funded Land Resources Mapping Project depicting land use and land capability. The Mapping Project documents represent the only systematic assessment of Nepal's land resources and were derived from comprehensive air-photo interpretation, satellite image analysis, and ground survey work carried out between 1978 and 1984.

3.21 The GIS was used to identify forest "hot spots" showing forests of high ecological or habitat value which might be threatened as a result of the road construction within "impact corridors" of 2 km and 5 km of the alternative road alignments. Within a 2 km corridor, the valley alignment had a lower impact on forest resources (-9.3%) and agricultural land (-17.4%) than the ridge alignment; within a 5 km corridor (about a day's walk), the valley alignment had practically the same impact on forests and a marginally larger impact on agricultural resources (1.31%) than the ridge alignment. While 4.5 km of the valley alignment passes through the Conservation Area of the Makalu Barun National Park and Conservation Area, it does not pass through the Chichila forest, an area of high biodiversity value, which would be transversed by the ridge route. On balance, the valley alignment is preferable, taking both social and environment impacts into account.

3.22 Power Station. The power station has been the subject of intensive engineering and design studies and site investigations, executed in several phases. Most of the topographic surveys were carried out and completed in 1989, and other minor survey work was completed in 1992. Geological and geotechnical investigations include about 1,500 m of excavated adits, about 2,500 m of drilled cores, and about 14,500 m of geophysical and seismic surveys. The hydrological

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[10/] Glenn Morgan and Peter Nyborg. Using Geographical Information Systems to Support Watershed Management: Case Studies from Nepal and China. World Bank, Asia Information Technology Laboratory, Washington, D.C., 1993.

and sediment studies follow known engineering methods. Hydraulic model tests were made to examine and to improve the design as well as the operation of the dam, spillway, intake tunnels, desanding basins, and sluiceways. Special studies were conducted regarding transportation and access to the area, procurement strategy, camp facilities, construction power supply, telecommunications, and project risk assessment and insurance. The original engineering studies and design of the hydroelectric components of the two-stage development are based on the investigations and design for the completion of all civil works with one headrace tunnel.

3.23 The design of the two-stage development was endorsed by the seven-member panel of international experts established by NEA consisting of a design civil engineer, a hydrologist, an engineering geologist, a geotechnical engineer, a specialist in hydraulics and sedimentation, an expert in environmental management and resettlement, and a claims advisor to oversee project preparation. The panel reviewed the engineering designs, methods of construction, the environmental mitigation measures, the construction schedule, the bidding documents and the project cost estimates (including the power plant, the access road and transmission facilities) and expressed its satisfaction on the soundness of the project design.

3.24 Detailed engineering design and tender documents have been completed and issued for the combined civil works Lot C1/C3: Dam and Desanding Basins, Access Road, Headrace Tunnel and Camp Facilities. The engineering designs and tender documents for the other civil works lots, the electro-mechanical equipment, the hydraulic steel structures and miscellaneous works are completed. The design and construction of the transmission line and substation will be carried out on a turnkey basis. All the necessary surveys, field investigations and tests for the transmission works will be carried out during detailed design of those facilities.

3.25 NEA will retain JV Arun III, in association with Scott Wilson Kirkpatrick, under terms and conditions satisfactory to IDA, to complete the tender documents, provide procurement assistance, prepare construction drawings, carry out construction supervision and management of the hydroelectric power plant and the access road components, assist in implementing the ACRP and the dam safety program, and provide on-the-job and management training for NEA counterpart staff in construction supervision, operations management and maintenance and other on-the-job training. Negotiations were completed between NEA and the consultants and a Memorandum of Understanding was signed on December 21, 1993. The contract includes 5,850 staff months, of which 1,440 months (25%) are for expatriate and 4,410 months (75%) for Nepalese staff at the professional level, largely from the private sector.

F. Resettlement

3.26 The objective of the ACRP is to ensure that, after a reasonable transition period, the affected population will be able to regain or enhance their previous standard of living. The provisions for acquisition, compensation and rehabilitation set forth in HMG's Land Acquisition Guidelines of 2050 (the Guidelines of the year 1983 according to the Gregorian Calendar) will be applied to ensure fair and adequate compensation to the affected people. A comprehensive entitlement policy for all categories of affected people has been formulated for the achievement of this objective.

3.27 The ACRP establishes five categories of affected population for the purpose of compensation:

(a) "Project Affected Family" (PAF) means a family which is adversely affected by the project, including those whose land is acquired or whose assets, although not compulsorily acquired for the project, are nevertheless damaged by the construction activities;

(b) "Seriously Project Affected Family" (SPAF) means a project affected family: (i) whose main source of income is derived from or dependent upon a land holding (whether agricultural land, houseplot or business) which is under their direct cultivation or management, or (ii) whose main residence, place of business or main source of income-earning activity is a land holding, house or houseplot -- either as owner, tenant or physical possessor, and who, as a consequence of the acquisition for, or damage by, the project of such land holding, house or houseplot, is either: (a) left with no such holding, or (b) left with holdings of such land, house or houseplot which are not adequate to ensure them that, after a reasonable transition period, they will at least regain the standard of living enjoyed prior to the implementation of the project;

(c) "Tenants" includes both formal and informal tenants, the latter being without valid title or lease arrangements over land to be acquired. Such tenants may be classified as PAFs or SPAFs based on criteria in the respective definitions in the ACRP; the provisions pertaining to PAFs and SPAFs equally apply for both types of tenants;

(d) other families with temporary leasing arrangements; and

(e) other families affected by the transmission line right-of-way who may or may not be PAFs, SPAFs or tenants.

3.28 The ACRP and the Guidelines define the compensation categories for the categories of affected population as follows:

(a) PAFs. Compensation to PAFs is to include: (i) compensation in cash for assets acquired or damaged due to the project, and (ii) a rehabilitation grant to cover suffering and hardship (based on family size and other criteria to be determined by the Compensation Fixation and Rehabilitation Management Committee) (para 3.29);

(b) SPAFs. Compensation to the SPAFs is to include: (i) in case of land lost, compensation paid either in cash or substitute asset (land) of equal production potential to that lost; (ii) in case of other asset(s) (e.g. building), compensation paid in cash; (iii) a rehabilitation grant, and (iv) employment for at least one member of the SPAF in project-related activities, including training as needed;

(c) Formal and Informal Tenants are to receive 25% of the compensation for the land acquired, the remainder being paid to the registered landowner. In addition, a rehabilitation grant equivalent to 50% of the compensation for the land acquired will be paid to the tenants, formal or informal;

(d) Families Affected by Leasing Agreements will be compensated in relation to the type and productivity of the land being leased. Land used temporarily will be fully restored before being returned to its owner; and

(e) Families Located in the Transmission Right-of-Way, whose land is not acquired but is subject to way-leave and building height restrictions by the project. In these cases, compensation will be decided by the Compensation Committee, provided that such amounts shall not fall below 5% of the market value of the affected land.

3.29 Land compensation is to be paid at the current market value in the concerned area, to be determined by a Compensation Fixation and Rehabilitation Management Committee chaired by the Chief District Officer. The compensation is to take account of the type of land, the quality of the individual plots and their productivity, and the roads, shops and other facilities in the vicinity. The resettlement policy provides for "land-for-land" compensation for those SPAFs who opt for it. Grievances regarding compensation, implementation of the land-for-land provision, and other related compensation and rehabilitation issues can be referred directly to a committee chaired by the Secretary of the Ministry of Home Affairs, or a senior official of the Ministry designated by the Secretary, and consisting of at least two more members one of whom may be from an NGO. It will meet in the Project Area at least once every three months to:

(i) resolve any grievances regarding payment of compensation;

(ii) resolve grievances regarding provision of other resettlement entitlements such as training, employment, and/or rehabilitation grants; and

(iii) ensure fair implementation of the "land-for-land" policy for SPAFs who choose that option.

The committee will review appeals and communicate the results to PAFs, normally within 21 days of their receipt. In reviewing the appeal, the committee may seek the views of the Arun III Project Environmental Management Unit whose members include consultants, local officials, and NGO representatives as well as NEA staff.

3.30 The Guidelines were originally issued through the authority of the Ministry of Works and Transport, with the Department of Roads as the implementing agency. The Guidelines establish Acquisition and Rehabilitation Committees (now renamed Compensation Fixation and Rehabilitation Management Committees) for determining compensation rates, acquiring land, negotiating with PAFs and establishing rehabilitation measures. The procedures have changed to reflect that management of the ACRP is now the responsibility of NEA (under the MOWR) and NEA's Environmental Unit. NEA has contracted with JV Arun III to carry out the ACRP planning and implementation tasks. Responsibility for payment of compensation is with NEA. The ACRP implementation arrangements have been endorsed by HMG and NEA. During negotiations, agreement was reached with HMG and NEA that the ACRP will be implemented in a manner agreed with IDA (para. 6.2(b)). More detailed information on the ACRP is provided in Annex 3.3.

3.31 The ACRP will cover the three main components of the project -- the access road (valley route), the hydroelectric dam, and the transmission line -- and the associated construction camps. The 122 km access road will require acquisition of approximately 394 ha of land and affect approximately 931 households, including 115 SPAFs. JV Arun III estimates that approximately 74% of the land along the access road is privately held, giving an aggregate length for the ACRP of about 90 km. The dam reservoir would flood 50 ha; total land acquisition for the dam (including land for construction needs) would be about 117 ha. About 40 families would be affected by the work camps, of which 19 would be SPAFs. No families would be affected by the dam. The environmental assessment (EA) estimates that 602 ha of land will be required for the transmission line, affecting about 27 families, of which four would be SPAFs. Altogether, about 998 families would be affected by the three components of the Arun III Project, of which 138 would be SPAFs. Of the total land take, agricultural land affected will be 186 ha, which corresponds to about 0.14% of agricultural land in the Arun basin. The data are summarized in Table 3.1.

Table 3.1 - Estimated Total Project Land Take and Affected Families

Item	Project Component			Total
	Hydropower Site	Access Road	Transmission Lines	
1. Land take (ha)				
Permanent	47.8	375	7.6	430.4
Temporary	69.1	19	403.5	491.6
Partial	-	-	190.5	190.5
Total	116.9	394	601.6	1,112.5
Privately Held	76.7	293	312.2	681.9
Publicly Held	40.2	101	289.4	430.6
Total	116.9	394	601.6	1,112.5
2. Total PAFs	40	931[1/]	27	998
of which SPAFs	19	115	4	138

[1/] In addition seven informal tenants and 15 formal tenants were identified on the access road alignment of which one is a SPAF.

3.32 A detailed baseline survey of land-holders affected by the project works has been carried out. For the access road component, which encompasses the vast majority of project land-holders, 858 of the 931 PAFs have been interviewed and socio-economic details noted in a 17-page questionnaire (see Attachment 1 of Annex 3.3). Because the land to be acquired is of a dispersed character and generally in small parcels, resettlement sites as such, with the provision of civil infrastructure, are not a feature of the Arun project. Moreover, the interviews with the potential SPAFs indicate that they favor cash compensation and not land-for-land.

3.33 The cadastral data for the access road alignment has been digitized and is in a computer package. The detailed land survey information showing the location and areas of land to be taken for the project will be superimposed on the same data base. Each affected plot of land will be referenced with the PAF's name, address and essential data collected during the household survey. Monitoring of compensation payments made to each PAF and implementation of rehabilitation measures taken will also be included in the data base, so that at any one time information on the ACRP work can be recalled, reviewed and updated.

3.34 A bar chart (see Attachment 2 of Annex 3.3) indicates the timetable for compensation and rehabilitation payments for each of the three main project components. Of the total planned budget of NRs 85.4 million, 14% is for rehabilitation grants and 86% for compensation for land and properties. The resources allocated per person are consistent with the resources per person allocated under the Arun III Access Road Project (Cr. 2029-NEP) which was adjudged the third highest of the select portfolio of World Bank projects with resettlement components covered in the recent Bankwide review[11/].

[11/] See Resettlement and Development. The Bankwide Review of Projects Involving Involuntary Resettlement 1986-1993. The World Bank, Environment Department, April 8, 1994. Figure 5.1.

3.35 The risk in implementation of the ACRP will be largely mitigated by the comprehensiveness of the planning and monitoring arrangements. Supervision arrangements and monitoring indicators are detailed in Annex 3.7 and Annex 3.8, respectively. During negotiations, NEA agreed that the ACRP activities would be carried out sufficiently in advance of project activities that would affect the relevant families (para. 6.3(f)). Finally, in addition to the normal IDA supervision missions, there will be a full-time Project Monitor who will be responsible for reporting to the donors on all AHP-related activities, including progress of the ACRP and the Regional Action Plan (Annex 3.9).

G. Environmental Action Plan

3.36 Because the AHP is a run-of-the-river project without a large storage facility, its direct impact will be less than many hydro projects of similar capacity. In fact, a World Bank comparative review of the environmental impacts (expressed in kW per hectare) ranked as the second lowest of hydroelectric projects (Annex 3.2 Attachment 2). The main direct social impact will be the project-affected families along the access road, who are to be rehabilitated under the project. The induced impacts of the access road in this remote valley, already under environmental pressure from the population, will be considerable. The construction of the road provides an opportunity to foster a more sustainable pattern of development. Implementation of the prevention, mitigation and compensation measures recommended in the Environmental Assessment (EA) prepared for the project would minimize negative impacts and enhance the socio-environmental conditions in the valley. The EA work has been done in parallel with the design of the power generation system, the transmission line, and the access road. Also, from its inception in 1989, the POE for the AHP has included an environmental and resettlement specialist to ensure that project design takes appropriate account of these aspects. In addition, the King Mahendra Trust for Nature Conservation, a local NGO, has drawn on its professional skills and in-depth local knowledge to produce a Regional Action Program (RAP). The AHP Environmental Assessment and Management Executive Summary, which was distributed to the Executive Directors in May 1993 (Report No. SecM93-460), provides an overview of these environmental studies.

3.37 Extensive public consultation has taken place in Nepal during the environmental studies and following release of the Summary (para. 3.43 and Annex 3.10). Changes have been made in the project to accommodate the views of affected people including priority training and jobs with project contractors, and changes in the placement of the access road. The RAP, too, has been designed with the direct participation of those to be affected. Indigenous people have traditionally managed their forests on a community basis, and the RAP includes a program for forestry user groups. Further, the Government has responded to the disappointment expressed by communities on the changes in the access road alignment by making a commitment to build spur roads to link the communities of Kandbari and Chainpur with the access road. The EA Summary and other project information, including guidance on the rights of the people affected by land acquisition, has been distributed locally in Nepalese and English. The RAP is also intended to meet the policy requirements of OD 4.20 (indigenous peoples). The access road passes through land occupied by ten different ethnic groups. The indigenous peoples are Kirantis (represented by Rais and Limburs) who have a long tradition of service in the British and Indian armies). Others present are Bhotea, Kar Bhote and Gurungs, similar to the Kiranti in their Tibeto-Burman characteristics, and Brahmin-Chetri, occupational castes, and Newars, all of whom have migrated more recently to the valley and are organized along more hierarchical caste lines than the Kiranti. All ethnic groups are dependant to varying degrees on seasonal or long term migration out of the valley to India or the Nepalese Terai. However, the forest-user groups are a particular component of the RAP that will help to re-establish traditional ties to the land. Because vulnerability to change is not confined to indigenous peoples (the Kumar caste being a prominent example) the RAP concept has been developed with the active participation of all ethnic groups in the valley.

3.38 The access road, generation facilities, and transmission line have been located to avoid unnecessary direct environmental and socio-economic effects. A detailed listing of mitigation measures, provided in the EA Report, has been integrated into designs for the civil works contract. This will also be done for the transmission line (which is to be built at a later date). HMG and NEA have prepared a satisfactory Environmental Mitigation Plan, and HMG has granted necessary clearance of the project. During negotiations, HMG and NEA gave assurances that the plan would be implemented in a manner satisfactory to IDA (para. 6.2(c)). The location of temporary camps, borrow sites, quarry, and spoil disposal areas will be subject to advance approval and the location of environmentally sensitive areas is known in sufficient detail to guide construction. Tender documents for the civil works contract included comprehensive provisions for environmental and socio-economic considerations, and bids received reflect these requirements. In addition, in accord with the bidding documents, an Environmental Protection and Health and Safety Plan have been included in the contractor's program of work. Environmental and socio-economic staff will be required onsite to monitor the activities described above. The engineering services contract will include responsibility for detailed reports on adherence to socio-economic and environmental conditions. This will provide a basis for monitoring and supervising progress and allow management to authorize corrective measures as required. In addition, NEA's Environmental Unit is being expanded to handle the additional work arising from their involvement in the project. This will, inter alia, provide for qualified people to coordinate with the local population and NGOs. Resources have been budgeted and organizational structures established (para. 3.57). Suitable staff are being hired and trained before construction commences and ADB is providing a technical assistance grant for this purpose (para. 3.12).

3.39 Induced impacts predicted in the regional EA mainly derive from the effect of the new road access[12]. These include increased pressure on forest resources, reduced prices of certain crops within the Arun Valley, such as rice, due to lowered transportation costs (compared to the current cost of porters), and increased numbers of trekkers into the National Park. The RAP, consisting of sectoral activities in six major program areas, has been designed to minimize the negative impacts and maximize benefits. This program addressed both immediate requirements brought about by the construction process and the longer-term needs for sustainable development within the Arun basin. The six major program areas are: (a) conservation, (b) income generation, (c) institutional strengthening, (d) extension and training, (e) infrastructure and energy development, and (f) environmental monitoring (Annex 3.2).

3.40 Prior to initiation of road construction in any area, measures will be taken to prepare local communities to participate in community forestry activities and to provide opportunity for cultivation of food-crops for sale to road construction crews. In addition, environmental monitoring will be conducted, and communities will be provided with training and education. Many of these measures are already in place under ODA's Nepal-UK Community Forestry Project and Koshi Hills Seed and Vegetable Project. The Forestry Project is promoting the formation of forest user groups in the four districts of the Arun basin, including areas adjacent to the alignment of the Arun access road and several have already been established. A major objective of the latter project is to increase agricultural productivity, nutritional standards and cash income

[12] Even though the original Basinwide Environmental Impacts Study assumed that the access road would follow the ridge alignment, the alignment change does not affect the study's conceptual recommendations. Further, detailed RAP implementation studies, carried out by GTZ and ODA, are based on the valley alignment. For monitoring purposes, arrangements have been made to update the data base related to the new alignment.

of farmers in the Koshi Hills, including the four districts of the Arun basin. A particular emphasis of the project is support for the establishment of new seed and vegetable producer groups.

3.41 Longer-term sustainable development needs will be addressed in the RAP by the setting up of a new conservation area (Milke Danda); diversification of income-generation activities through programs in agricultural and livestock development and other economic activities; development of minor roads linking larger communities with the access road; and alternative energy programs, including rural electrification and micro hydropower schemes. Based on a recent appraisal, the German Government, through the German Agency for Technical Cooperation (GTZ), is expected to support implementation of selected elements of the RAP including ecotourism development, small business promotion, institutional strengthening, extension and training, and infrastructure and energy development. HMG is putting in place the necessary arrangements for implementing the RAP (para. 3.48), and donors are coordinating their efforts to ensure an overall development approach in the Arun Valley. In addition to IDA support, HMG will underwrite the RAP, which is an integral and long-term part of the Arun III Project, to cover any items not funded by bilateral donors. During negotiations, HMG gave assurances that the RAP will be implemented as agreed with IDA and that relevant pre-emptive RAP activities would be carried out in advance of road construction (para. 6.1(g)).

3.42 Given the crucial importance of the ACRP and Environmental Action Plan (EAP) to the welfare of the Arun Valley and its residents, HMG and NEA have reinforced implementation arrangements (paras. 3.29 and 3.48). In addition, special efforts will be made to address the risk of unsatisfactory implementation through close monitoring, by IDA and the other donors, of NEA's and MOWR's performance in this regard through: (a) involvement of a POE (para. 3.44); (b) regular supervision missions; (c) an on-site Project Monitor appointed by IDA; and (d) a detailed annual review during project implementation (paras. 3.58-3.59).

H. Participation and Consultation

3.43 Public participation has been an integral part of the preparation of the AHP. The Government has made unprecedented efforts, in collaboration with IDA and KfW, to ensure that all affected and interested parties have been consulted. Public participation occurred both within Nepal, particularly in the Arun Valley (para. 3.36), and externally. During the preparation of the RAP, there were extensive consultations between local governmental organizations and user groups (including women's groups) to ensure that the AHP would lead to the sustainable development of the whole valley. This is reflected in the video, "Sustainable Development in the Arun Basin." Subsequent to IDA's appraisal mission, there have been consultations with the inhabitants of the Valley in Hile, Tumlingtar, Khandbari, Pukhuwa (power house site), Amrang, and Phyaksinda (dam site). Many of these meetings have been recorded on tape and are available in the Arun Public Information Office in Kathmandu. On July 29, 1994, a delegation presented to the World Bank Resident Mission in Nepal a letter signed by over 3,000 local people in support of the AHP. The signatories represented diverse ethnic groups and castes resident in areas ranging from Hedanga, North of the dam site to Dharan in Sunsari Morang District in the foothills of the Siwaliks. The geographical coverage of public consultation and communication in the Arun Valley, in relation to the Arun III project, is shown in the IBRD Map #26235. In Kathmandu, numerous public meetings were held between Government representatives and local NGOs, and the project has been discussed in Parliament on numerous occasions. In the course of 23 public meetings, widespread support has been expressed for the project in the Valley itself because of the perceived benefits of the access road. The major issues raised were job and other income-earning opportunities, the change in the road alignment and environmental concerns. Outside Nepal, IDA and KfW have organized meetings with interested

NGOs. KfW has met with NGOs based in Germany, and IDA has met with NGOs in Switzerland, the U.K. and the U.S. Three meetings were scheduled with NGOs in Washington on June 10, 16 and 28, 1994 prior to the completion of negotiations between the Government and IDA on the AHP. The last meeting was attended by NGOs from Nepal, Germany, Japan, and the U.S. In addition to environmental concerns about the AHP, a number of the international NGOs expressed a strong preference for energy sector development relying on small hydro projects as an alternative to the AHP. These alternative options were examined and the results, which were shared with interested NGOs, are discussed. Public participation during project implementation will also be important. The long implementation period means that activities will inevitably need to be shaped in light of experience gained. During negotiations, the Government and NEA gave assurances that they would carry out public participation and consultation activities for all relevant project components throughout the implementation period, and to report annually to IDA on such activities starting in June 1995 (6.2(c)). A local NGO or consultant, under contract to MOWR, will provide assistance to the Government in implementing the RAP and coordinating with affected people. In addition, NEA's expanded Environmental Unit will coordinate with the local population and NGOs regarding adherence to socio-economic and environmental conditions outlined in the Environmental Mitigation Plan and incorporated in the engineering services contract.

I. Dam Safety Aspects

3.44 In accordance with the Bank's guidelines for the safety of Bank-financed dam projects, the project provides the following specific measures to ensure the safety of the proposed dam and the associated structures:

(a) Engineering: The joint venture JV Arun III, in association with Scott Wilson Kirkpatrick of the U.K., which has been involved in the project preparation from the initial stages of the project, including the feasibility study, prepared the layout of the project structures, the detailed designs, project cost estimates, environmental studies, preparation of technical specifications, the pre-qualification and tender documents for the civil works, studies of the economic viability and technical soundness of the project. The project documentation has been reviewed at various stages by the Bank's technical, economic and environmental experts.

(b) Independent Panel of Experts: An independent POE (para. 3.23) was associated with the project from the initial project feasibility stage. This included carrying out a comprehensive review of the detailed feasibility study, project layout of structures and the detailed designs of the project, and advising and ensuring the safety of the dam and the appurtenant structures, with specific consideration of the geologic, hydraulic, soil mechanics, sedimentation, seismic, structural and environmental aspects. The panel contributed some important modifications for safe designs and has endorsed the project as technically and environmentally sound and economically attractive. During negotiations agreement was reached with NEA that an independent POE will be reconstituted by end-December 1994 for review, assistance and guidance on the critical technical and safety aspects and dam safety monitoring during construction and supervision of the project (para. 6.3(g)) (Annex 3.4). The reconstituted Panel will be expanded to include environmental expertise to advise effectively on detailed RAP and resettlement issues. The Panel would meet semi-annually to guide and advise in a timely manner on the construction drawings and modified designs that take into account the additional field investigations and model studies, as well as to advise on and monitor the construction, safety aspects, and social and environmental aspects of the project structures. NEA will provide the donors with a schedule of the Panel meetings and submit a copy of minutes and Panel reports to the Bank. The Project Monitor would participate in the Panel meetings.

(c) Instrumentation: Extensive instrumentation is proposed to be installed at the project structures for safety monitoring and control of extreme events such as floods or glacier lake outburst floats (GLOFs). This will be further reviewed by the Panel and IDA staff for adequacy when instrumentation designs are finalized during construction. Additional instrumentation will be incorporated if considered necessary. The proposed instrumentation would provide data for studying the behavior of project structures and foundations after construction and enable development of protective measures to cope with emergency conditions (such as GLOFs). Special provisions have also been made for monitoring the abutment stability and controlling the accumulation of sediment in front of the dam at the power intake and in the reservoir itself during construction. The preparation of operation and maintenance manuals are part of the Engineer's services during the project design and supervision phases.

(d) Safety Inspections and Maintenance During Operation: NEA conducts inspections of dams and major hydraulic structures in the country that generally follow the practices of the US Bureau of Reclamation. These are carried out by NEA staff trained in dam safety monitoring, assisted by individual experts, and are acceptable to IDA. NEA will be responsible for maintaining, or causing to be maintained, all facilities relevant to the project, and for making, or causing to be made, all necessary repairs to those facilities (para. 6.3(h)).

(e) Emergency Action Plan: The scope of the project engineering services for design and supervision includes the formulation of an emergency action plan. NEA personnel will also participate during the period of installation, testing and commissioning of the plant. The immediate post-construction evaluation will be included in the Implementation Completion Report to be prepared by NEA with the assistance of the Engineer. The Engineer will also assist in developing and implementing a dam safety training program.

J. Project Cost Estimate

3.45 The cost estimate has been prepared using IDA's (March 1994) forecast for domestic and international inflation. It has been discussed and agreed among HMG/NEA and ADB, IDA and KfW during negotiations. The details are shown in Annex 3.11 and summarized in Table 3.2. The estimate is based on the results of the bid evaluation for the combined civil works Lot C1+C3 (comprising the access road, the camp facilities, the dam and desanding basins, and the headrace tunnel), detailed engineering for the other hydroelectric components (including the construction power supply), preliminary engineering of the transmission line and substation, a feasibility study of the Arun Basin RAP, detailed estimates for construction supervision, the POE, and the ACRP, technical assistance for training, and instituting the private sector Hydro Fund. Overall physical contingencies are about 12% of the total base costs; including dayworks, the overall physical contingencies are about 14%.

Table 3.2: Summary of Project Cost a/

Nepal: Arun III Hydroelectric Project
Components Project Cost Summary

	(N. Rupees Million)					(US$ Million)				
	Local	Foreign	Total	% Foreign Exchang	% Total Base Costs	Local	Foreign	Total	% Foreign Exchang	% Total Base Costs
A. Hydroelectric Power Plant - Physical Works										
Dam and Desanding Basins	925.75	3,532.38	4,458.12	79	15	18.71	71.39	90.10	79	15
Permanent Camps	355.16	459.17	814.33	56	3	7.18	9.28	16.46	56	3
Access Road	1,341.04	4,791.15	6,132.19	78	20	27.10	96.83	123.93	78	20
Headrace Tunnel and Surge Tank	609.79	2,453.22	3,063.01	80	10	12.32	49.58	61.90	80	10
Powerhouse and Appurtenant Structures	394.64	2,263.22	2,657.85	85	9	7.98	45.74	53.72	85	9
Subtotal Hydroelectric Power Plant - Physical Works	3,626.37	13,499.13	17,125.50	79	56	73.29	272.82	346.11	79	56
B. Hydroelectric Power Plant - Electromechanical Equipment										
Hydraulic Steel Structures D/S	124.93	1,129.63	1,254.56	90	4	2.52	22.83	25.35	90	4
Hydraulic Steel Structures PH/S	87.94	426.52	514.45	83	2	1.78	8.62	10.40	83	2
Electrical Equipment	224.49	1,975.24	2,199.74	90	7	4.54	39.92	44.46	90	7
Electrical Equipment	73.37	763.97	837.34	91	3	1.48	15.44	16.92	91	3
Mechanical Equipment	219.66	1,409.69	1,629.35	87	5	4.44	28.49	32.93	87	5
Construction Power Supply	71.67	447.30	518.97	86	2	1.45	9.04	10.49	86	2
Subtotal Hydroelectric Power Plant - Electromechanical Equipment	802.07	6,152.34	6,954.41	88	23	16.21	124.34	140.55	88	23
C. Transmission Line to Grid										
Arun-Duhabi Transmission Line	315.76	1,698.15	2,013.91	84	7	6.38	34.32	40.70	84	7
Duhabi Substation	136.53	631.36	767.89	82	3	2.76	12.76	15.52	82	3
Subtotal Transmission Line to Grid	452.29	2,329.52	2,781.81	84	9	9.14	47.08	56.22	84	9
D. Environmental Mitigation/Area Development										
Land Acquisition, Compensation & Rehabilitation	74.02	-	74.02	-	-	1.50	-	1.50	-	-
Regional Action Program	434.93	289.95	724.88	40	2	8.79	5.86	14.65	40	2
Subtotal Environmental Mitigation/Area Development	508.95	289.95	798.90	36	3	10.29	5.86	16.15	36	3
E. Technical Assistance										
Construction Supervision for HEP & Access Roads	-	1,990.90	1,990.90	100	7	-	40.24	40.24	100	7
Construction Supervision for Transmission Line/Substation	-	125.68	125.68	100	-	-	2.54	2.54	100	-
RAP Secretariat	-	98.96	98.96	100	-	-	2.00	2.00	100	-
Panel of Experts	-	98.91	98.91	100	-	-	2.00	2.00	100	-
NEA Project Management	144.48	-	144.48	-	-	2.92	-	2.92	-	-
NEA Training	-	178.12	178.12	100	1	-	3.60	3.60	100	1
Subtotal Technical Assistance	144.48	2,492.57	2,637.05	95	9	2.92	50.38	53.30	95	9
F. Miscellaneous										
Hydro Fund	-	247.40	247.40	100	1	-	5.00	5.00	100	1
Subtotal Miscellaneous	-	247.40	247.40	100	1	-	5.00	5.00	100	1
Total BASELINE COSTS	5,534.15	25,010.92	30,545.07	82	100	111.85	505.48	617.32	82	100
Physical Contingencies	718.65	2,910.00	3,628.65	80	12	14.52	58.81	73.34	80	12
Price Contingencies	2,340.12	9,461.18	11,801.30	80	39	22.93	83.66	106.59	78	17
Total PROJECT COSTS	8,592.92	37,382.10	45,975.02	81	151	149.30	647.95	797.25	81	129

a/ Taxes and duties are included in the project costs and amount to NRs 2,135.56 million, equivalent to US$ 36.99 million

K. Project Financing

3.46 The estimated financing requirements of the proposed project, including interest during construction, are US$1,082 million, including US$434 million in local costs and US$648 million in foreign costs. A proposed IDA credit of US$140.7 million, plus US$34.3 million from Cr. 2029-NEP, would finance 27% of the project's foreign costs, equivalent to 17% of the total cost. ADB would provide US$127.6 million and the German Government, through KfW, US$124.4 million equivalent. FINNIDA would finance about US$10 million, France would finance about US$19 million, and BITS (Sweden) about US$17 million. US$163 million would be financed by another cofinancier (to be determined). Disbursements are not expected to be required of these items for at least a year. The effectiveness of the cofinancing agreements with ADB and KfW and confirmation of all cofinancing needed for the project are conditions of credit effectiveness (para. 6.4(d) and (e)). NEA would finance US$290.5 million (27% of total financing). The Government would finance US$155 million, representing part of the local cost of the RAP and the AHP as well as the Hydro Facility. Except for the items for which financing has yet to be determined, the Government and NEA would bear the cost overrun risks. The proposed financing plan is shown in Table 3.3.

Table 3.3 Project Financing Plan
(US$ million equivalent)

Source	Local	Foreign	Total	% of Financing
IDA				
Credit 2029-NEP	-	34.3	34.3	3.2
Proposed Credit	-	140.7	140.7	13.0
Total IDA	-	175.0	175.0	16.2
ADB	-	127.6	127.6	11.8
KfW	-	124.4	124.4	11.5
To be determined[a]	-	163.3	163.3	15.1
OTHERS (France, Sweden[b], Finland)	-	46.3	46.3	4.3
Government	143.6	11.4	155.0	14.3
NEA[c]	290.7	-	290.7	26.8
Total	434.3	648.0	1082.3	100.0

[a] Japan is sending its own appraisal mission to make its assessment of the project.
[b] Sweden has stated that it is willing to allocate up to US$30 million to the project, of which about US$17 million has been committed so far. This may result in a reduction in project financing by HMG and for NEA.
[c] Includes US$285.0 million equivalent of interest during construction.

L. Project Implementation and Construction Schedule

3.47 Based on an IDA-financed study on appropriate project management arrangements and extensive discussions with the donors, HMG and NEA have undertaken an action plan to provide effective decision-making, minimize coordination problems, and reduce the risk of cost overruns. This includes (a) instituting an Arun III Coordinating Committee, chaired by the Minister of Water Resources, to facilitate close cooperation between relevant HMG agencies and NEA during implementation of the AHP; (b) delineating clear responsibilities in decision-making between NEA's Board, the NEA Managing Director, and the AHP Project Director; (c) appointment of a Project Director satisfactory to the donors, with the rank of Director-in-Chief, reporting directly to the Managing Director; (d) signature of a contract with the Engineer following the Federation International des Ingenieurs Counseils' conditions of contract, including assistance to NEA in implementing the Dam Safety Program (para. 3.43); and (e) award of the contract for the combined civil works lots C1/C3 that corresponds to approximately 85% of the project's civil works. Item (e) is a condition of credit effectiveness (para. 6.4(f)). Details on project implementation are set out in the paper entitled "Project Management and Organization" (Annex 3.12) which was agreed with the donors. The project implementation arrangements have been endorsed by NEA's Board and were agreed during negotiations (para. 6.3(i)). The construction supervision contract (SUP1) has been awarded.

3.48 The project implementation program (Chart 1), prepared by the consulting engineer, was agreed with the POE, IDA, ADB, KfW, and NEA. It reflects Nepal's experience in constructing hydroelectric projects, particularly the Marsyangdi Hydroelectric Power Project (Cr. 1478-NEP), with which Lahmeyer International of Frankfurt, the leading member of the JV Arun III, was also associated. The implementation program was originally based on full mobilization of the contractor for the combined Lot C1/C3 by the end of the 1994 monsoon season. That is no longer possible, with the result that commissioning of the first unit is now planned for April 2002. Keeping to this revised schedule requires that the contractor begin mobilization as early as possible during the 1995 dry season.

3.49 Regional Action Program. To coordinate, monitor and facilitate the implementation of the RAP, to be implemented by concerned line agencies, HMG has set up the Arun Basin Development Steering Committee under the National Planning Commission, assisted by:

(i) an Arun Basin Development Secretariat to be located in Kathmandu and an Arun Basin Implementation Office in the Arun Basin,

(ii) MOWR as the liaison ministry, and

(iii) local NGO/consultants under contract to MOWR to assist the Government in monitoring and facilitating the RAP implementation with experts located primarily at the Project site (Annex 3.15).

3.50 The primary implementation responsibility for the proposed action plans lies with concerned line agencies, elected local government bodies, NGOs and local organizations depending upon the scale and complexity of the specific activities. HMG has confirmed that the institutional arrangements for the RAP are in place.

M. Procurement

3.51 To enable effective implementation of the project, taking into account, inter alia, the physical features and topographic conditions of the hydroelectric power plant, access road and transmission system sites, as well as the participation of various sources of financing, the project components are divided into various major contract packages. For the hydroelectric power plant there will be three lots for the civil works including the access road, one lot for the mechanical equipment, two lots for the electrical equipment, two lots for the hydraulic steel structures and one for the construction power supply. The transmission system will have one turnkey contract for the line and a contract for the substation. The procurement schedule for the various lots will be in line with the overall Project Implementation Schedule (Chart No. 1). Table 3.4

defines the lots (and their acronyms) and summarizes the proposed procurement arrangements for the proposed project which, because of its size and complexity, has some exceptional features:

(a) Civil works have been split into two lots consisting of the combined Lot C1/C3 that includes the dam and desanding basins (Lot C1), the access road, camp facilities and the headrace tunnel and surge tank (Lot C3). External financing for the combined Lot C1/C3 will be from ADB, IDA, and Germany, through KfW (for the headrace tunnel (lot C3-3) only). Lot C2 (the powerhouse and appurtenant structures) will be bid in 1996 under international competitive bidding in accordance with another cofinancier's (to be determined) general untied procurement guidelines. Construction supervision for the hydroelectric and the access road components (Lot SUP1) will be the responsibility of the JV Arun III in association with Scott Wilson Kirkpatrick, and will be financed by Germany, through KfW and the other cofinancier (to be determined); IDA will finance supervision of for the ACRP component. For administrative purposes, two contracts will be signed with the consultants: the first will be for 75% of the total, to be jointly financed by KfW and IDA, and the second for the remainder, by another donor (to be determined).

(b) Electro-mechanical equipment has been split into six lots consisting of the hydraulic steel structures at the dam site (HSS1), the hydraulic steel structures at the powerhouse site (HSS2), electrical equipment including generators, instrumentation controls, protection and auxiliaries (E1), electrical equipment including bus-duct systems, transformers and high voltage switchgear (E2), mechanical equipment including three 67 MW Pelton turbines and ancillary equipment (M2), and construction power supply including a 7.2 MW diesel generator and ancillary equipment and a 33 kV transmission line. Lots HSS1, HSS2, E2 and M1 will be bid under ICB according to the other cofinancier's (to be determined) general untied guidelines. For Lot E1, KfW will invite bids from German suppliers and finance the foreign exchange component. FINNIDA will finance the foreign exchange component of the construction power supply (CPS) lot, for which bids will be invited from Finnish suppliers.

(c) The transmission equipment has been split into two lots consisting of the 120 km 220 kV double circuit transmission line from the power house to Duhabi (TR) and the 220 kV/132 kV substation at Duhabi (SSS). The Government of France (GOF) will finance the foreign exchange component of the fabrication and erection of the towers, with bids to be invited from French suppliers. Germany, through KfW, will finance the conductors, cables, and other accessories of the TR lot as well as their installation, with bids to be invited from German suppliers. BITS (Sweden) will finance the foreign exchange component of lot SSS. Both of these lots, to be bid in 1996, would be financed as turnkey contracts. France will finance the construction supervision contract relating to the transmission and substation components (SUP2).

(d) Environmental mitigation measures have been divided into two lots consisting of the ACRP, to be financed by NEA, and the RAP to be financed by IDA, HMG, and GTZ. IDA will finance the RAP components related to infrastructure and energy development (RAPP) and consultancy support (RAPCS), which is described in para. 3.49. This includes setting up a rural electrification scheme in the Arun Valley (including the erection and commissioning of lines and distribution works).

(e) In addition to the construction supervision detailed above, technical assistance has been split into four lots consisting of the Regional

Action Program Consultancy Support (RAPCS), the POE, and training and other technical assistance activities for NEA (TA). The RAPCS component will support the RAP Secretariat (RAPS) which will be set up to coordinate and monitor all the RAP activities as well as manage activities in conservation, income generation, extension and training. In all cases, 100% of the technical assistance lots will be financed by the indicated donors. Three lots (RAPCS, POE and TA) will be financed by IDA. In addition, NEA's project administration costs, to be financed by NEA, will be covered by the NEA Engineering and Management Lot.

(f) The Hydro Fund will be financed by HMG.

3.52 Contract Review. NEA has completed negotiations of a contract for the combined Lot C1/C3 with the lowest evaluated bidder (the Italian-French joint venture of Cogefar and Spie Batignolles), which was prequalified and selected in accord with IDA guidelines; contract award is subject to approval by ADB, IDA and KfW. There would be one contract (approximately US$2.50 million) to set up the rural electrification scheme in the Arun Valley which would be procured under Local Competitive Bidding (LCB). Items available off the shelf could be procured under international or local shopping up to US$75,000 per contract and US$1,000,000 in aggregate. In addition to the combined lot C1/C3 mentioned above, IDA's prior review of contracts would apply to: (a) all consultant services, studies and training above US$100,000 for consulting firms and US$50,000 for individuals; (b) all civil works above US$200,000 equivalent; and (c) materials and equipment above US$75,000 equivalent. This would cover more than 99% of the procurement to be financed under the proposed Credit. Other contracts would be subject to ex-post review by IDA.

Table 3.4 Summary of Procurement Arrangements

	Project Component	ICB	LCB	Other[a]	N.A[b]	Total	Comments[c]
		Procurement Method (US$ million)					
A.	**Works**						
C1/C3	Dam and Desanding Basins Camp Facilities Access Road Headrace Tunnel and Surge Tank	390.05 (162.93)[d]				390.05 (162.93)	Lot jointly financed by ADB and IDA; Germany will jointly finance Lot C3-3.
C2	Powerhouse and Appurtenant Structures	70.64 [e]				70.64	
RAPI	RAP Infrastructure Program		2.00 (0.20)			2.00 (0.20)	
B.	**Equipment**						
B1.	*Electromechanical Equipment*						
HSS1	Hydraulic Steel Structures (Dam Site)	30.68 [e]				30.68	
HSS2	Hydraulic Steel Structures (Powerhouse Site)	12.65 [e]				12.65	
E1	Electrical Equipment			54.83		54.83	Financed by Germany
E2	Electrical Equipment	20.85 [e]				20.85	
M1	Mechanical Equipment	39.95 [e]				39.95	
CPS	Construction Power Supply			11.97		11.97	Financed by FINNIDA
B2.	*Transmission Equipment*						
TR	Arun-Duhabi Transmission Line			53.96		53.96	Financed by France and Germany
SSS	Duhabi Substation			20.59		20.59	Financed by BITS (Sweden)
B3.	*Other Equipment*						
RAPP	RAP Energy Program		2.50 (2.00)			2.50 (2.00)	
	Vehicles, Equipment, Materials [f]			1.15 (1.0)		1.15 (1.0)	
C.	**Consultancies** - Project Implementation Support						
SUP1	Construction Supervision for HEP and Access Road			48.49 (0.95)		48.49 (0.95)	Cofinanced by IDA, KfW and another cofinancier (to be determined) in two sublots
SUP2	Construction Supervision for the Transmission System			3.13		3.13	Financed by France
RAPCS	RAP Consultancy Support			15.46 (1.42)		15.46 (1.42)	
POE	Panel of Experts			2.38 (2.38)		2.38 (2.38)	
D.	**Miscellaneous**						
TA	Training			4.12 (4.12)		4.12 (4.12)	
ACRP	Land Acquisition, Compensation and Rehabilitation				1.89	1.89	
NEA	NEA Engineering & Management				3.76	3.76	
HF	Hydro Fund				6.20	6.20	
	Total	564.82 (162.93)	4.50 (2.20)	216.08 (9.87)	11.85	797.25 (175.00)	

a/ Consulting services, tied procurement, local and international shopping for vehicles etc.

b/ Includes land acquisition, hydro fund administrative overheads and other items not subject to procurement

c/ For each lot, the financing plan is based on the donor(s) financing the foreign costs and HMG/NEA covering the local costs. The exceptions are the TA/consultancies lots, where the Donors cover 100% of the costs and the RAP lots where IDA covers 29% of the foreign exchange costs.

d/ Figures in parentheses are IDA financed portion

e/ General untied procurement guidelines of the cofinancier (to be determined)

f/ Vehicles, equipment materials to support the RAPCS implementation

N. Disbursement

3.53 Disbursements under the proposed Credit would be made as follows (net of taxes and duties): (a) 54% of foreign expenditures on the combined civil works Lot C1/C3; (b) 100% of total expenditures for (i) construction supervision of the ACRP relating to the power plant and the access road (other construction supervision by the same consultants would be financed by KfW and another cofinancier (to be determined), (ii) the consulting services under the RAP, (iii) the POE, and (iv) NEA training; (c) 100% of foreign expenditures, 100% of local expenditures (ex-factory cost) and 75% of other items procured locally for equipment, vehicles, and materials under the RAP; and (d) 90% of civil works under the RAP. Taking into account the contributions of other donors, external financing will cover about 85% of the total project cost net of taxes and duties.

3.54 To facilitate disbursements, a Special Account would be opened in the Nepal Rastra Bank or in an acceptable commercial bank on terms and conditions satisfactory to IDA. The account would be credited with at least three months of estimated expenditures (US$3.0 million) and replenishments requested every three months or as soon as the account is 40% depleted, whichever occurs first. IDA's Special Account would be used to cover all expenditures, both local and foreign, less than US$300,000 equivalent. All other expenses would be submitted to IDA directly for payment. Itemized SOEs would be used for civil works contracts less than US$200,000 equivalent, and for materials and equipment less than US$75,000 equivalent. Documentation supporting these SOEs would be maintained by NEA and MOWR and made available to IDA during supervision missions.

3.55 On the basis of the implementation schedule shown in Chart 1, a schedule of estimated quarterly disbursements has been prepared (Annex 3.14). This schedule is based on the assumption that the credit will become effective during the second semester of 1994 and that the first unit would be commissioned in April 2002; allowing time for payment of contractor retention money and unforeseen delays the credit Closing Date will be December 31, 2004.

3.56 Special arrangements would have to be made to simplify, to the extent possible, administration of a very large and complex project being financed by seven donors with differing internal regulations and procedures for project administration. It is essential to ensure that execution of the project by NEA is not hindered by poor donor coordination. In conjunction with the project launch workshop, the major cofinanciers, therefore, intend to establish agreed procedures for administration of their loans/credits, to regulate matters such as procurement, disbursement, monitoring of project implementation, reallocation of proceeds of loans/credits, changes in scope of implementation arrangements for the project, mutual consultation in relation to monitoring compliance with loan covenants, suspension or acceleration by any cofinancier of its loan/credit, and any other matters that may be needed to promote smooth implementation of the project. This will be reinforced by close coordination in project monitoring including the organization of joint supervision missions. These arrangements will be reflected in a Memorandum of Understanding among the cofinanciers, and would be signed following approval of the respective loans and credits by the donors.

O. Project Monitoring

3.57 In order to assess the impact of the AHP, including the RAP, on the economic condition of the inhabitants of the valley, data on consumption, income, employment, educational and health status, housing conditions, and other socio-economic indicators will be collected for a representative sample of households, in conjunction with the recently initiated Living Standards Measurement Survey (LSMS) Project. The project will collect the same information for the country as a whole using the survey, field work, and data management methodology developed by the Bank's LSMS Unit. The data collected in the valley will allow comparisons with other areas of the country, and provide baseline information; future rounds of the survey will provide comparable data to monitor the impact of the project over time.

3.58 In view of the project's complexity and multiple sectoral, environmental and project facets, as well as coordination among several donors and numerous NGOs, the procedures and resources applied to monitoring the AHP will be exceptional. During negotiations, agreement was reached with HMG and NEA on a monitoring, evaluation and reporting system acceptable to IDA and the other donors (para. 6.2(e)). This covers all aspects directly related to the AHP implementation, including the RAP. NEA would furnish to the donors brief monthly reports and comprehensive quarterly reports. It is expected that the POE will meet twice a year to review the status of implementation of the AHP and the RAP and advise on corrective actions needed, if any. In addition, HMG and NEA will also participate in annual reviews of the AHP and the RAP, during which progress toward project objectives and key targets will be reviewed in detail and experience gained incorporated in forward planning. During negotiations, agreement was reached with HMG and NEA that within six months of project completion, NEA would prepare and furnish to the donors an Implementation Completion Report on the AHP's and RAP's execution and, where appropriate, their initial operational costs and benefits, HMG's and NEA's performance, and the accomplishments of the Credit's objectives (para. 6.2(f)).

3.59 Annual supervision costs for IDA will be considerably more than the Bank-wide average. A long-term consultant, with expertise in the implementation of large civil works contracts and environmental management, will be retained to monitor project implementation (para. 3.35). Donor participation in the financing of the consultant is being sought. IDA supervision missions, to be organized jointly with the other donors whenever possible (para. 3.56), would visit Kathmandu and the project site every four months for the duration of the project (about 20-24 staff weeks per year). In-depth annual reviews with all relevant parties have been agreed which will focus on taking stock of experience gained, course connections needed and forward planning. A project supervision and monitoring plan is included in Annex 3.7 while environmental implementation indicators are set out in Annex 3.8.

P. Implementation Risks

3.60 Because of its size, complexity and wide implications, the Arun project entails significant implementation risks which HMG and the donors have endeavored to mitigate and manage through in-depth project preparation, careful design, appropriate implementation arrangements, and intensive monitoring and supervision. Delays in project implementation could occur during procurement and construction. To minimize procurement risks, the consultants assisting in bid evaluation and supervising implementation have already been appointed. Based on past experience in Nepal, construction delays could result from shortages of domestic financial resources and inadequate project management and supervision. The former risk would be reduced by implementing measures to enhance NEA's cost recovery, including reducing system losses, improving the handling of consumer accounts and collections performance, and otherwise increasing NEA's revenues. Further, HMG has demonstrated compliance with NEA's tariff covenant for FY95 (para. 4.21). Possible construction delays would be minimized by ensuring effective project management and supervision through NEA's internal organization for the project and hiring consultants to assist NEA during project implementation. Implementation risks concerning the RAP are addressed in para. 3.35.

3.61 The greatest risk of cost overruns for the project concerns the possibility of claims for its underground works (desanding basins, headrace tunnels and the powerhouse) which together account for about 28% of the first stage (201 MW) of the project costs. A number of steps have been taken to minimize the risk of cost overruns, claims, and delays including:

(a) geological and geophysical field investigations have been conducted to a more detailed level than for any other hydroelectric project ever considered or constructed in Nepal. These investigations are an important component of the approximately US$25.0 million spent on project preparation;

(b) evaluation of bids for the combined lot C1/C3 confirms that the major component of the civil works cost estimate is reasonable;

(c) the project implementation schedule is based on a detailed construction planning study and is considered realistic;

(d) the bidding documents reflect the results of a risk assessment and insurance study conducted by NEA that identified the least cost option for insurance coverage of identifiable risks; and

(e) bid documents are reviewed by an internationally-renowned claims advisor prior to their issuance.

3.62 Two steps are being taken to address the risk of unsatisfactory operation of the AHP: the consultant supervision contract (SUP1) provides for (a) appointment of a "shadow manager" for about two years and (b) training of NEA staff to operate the AHP (para. 2.16). The contractors, suppliers and consultants will insure against physical risks to equipment during transport, handling and erection and against third party risks. The individual works during execution will also be insured against most physical hazards. The insurance will cover design defects in the civil works as well as in the equipment.

IV. FINANCE

A. Introduction

4.1 During a period of rapid expansion, the soundness of NEA's financial management is critical to the realization of Nepal's power sector development program, including implementation and operation of the AHP. The principal objective of NEA's program to strengthen its financial management is to generate sufficient internal resources to cover cash operating expenses, finance a major share of the local cost of investments, meet outstanding debt obligations, and provide significant net positive transfers to HMG. Since its establishment in 1985, NEA has struggled to attain a sound financial position. A number of actions aimed at improving its financial management were initiated under the PSEP (Annex 4.1). These efforts have confronted numerous obstacles, including: inadequate tariffs, poor collections performance, and an ad hoc relationship with HMG which has resulted in the transfer of assets to NEA without proper financial planning. These are all indications of weak management and inadequate financial management systems. This chapter describes NEA's current financial position[11] and sets out the key elements of the ongoing and planned programs to strengthen its financial management as agreed with IDA in the context of the AHP and in cooperation with other donors. Indeed, commitment to AHP has been a major catalyst behind the consensus within HMG to accelerate NEA's institutional development and modernization program.

B. NEA's Past Performance and Present Position

4.2 Past Earnings Performance. The PSEP required NEA to generate funds from its internal sources sufficient to cover gradually increasing percentages of the local component of its investment requirements (inclusive of interest during construction) (FY92: 45%, FY93: 50%, FY94: 55%, FY95: 60%, FY96: 65%, FY97: 70% and 75% thereafter) . In addition, starting in FY96, NEA was to generate enough revenues to earn a rate of return on revalued assets of not less than 4.5% for FY96 and 6% thereafter. The audited FY92 accounts indicate compliance with the revenue covenant for FY92, and the preliminary FY93 accounts indicate compliance as well.

4.3 NEA's actual and forecast financial data are described in Annexes 4.2-4.7. The salient features of operating performance for FY88-93 are summarized as follows:

[11] The analysis of this chapter is based upon financial data up to FY92 audited accounts, pre-audited accounts of FY93, estimates for FY94 and projections thereafter. At the time of writing this report, the details available from NEA are not entirely consistent with the FY93 audited accounts. The necessary reconciliation is being completed.

	FY88 (-aud-)	FY89 (-aud-)	FY90 (-aud-)	FY91 (-aud-)	FY92 (-aud-)	FY93 (-preaud-)
Energy Generation (GWh)	561	558	479	872	902	851
Egy. Purchased - Nepal (GWh)[1]	-	-	232	-	25	30
Egy. Purchased - India (GWh)	63	114	61	35	55	87
Gross Systems Losses (%)	26.4	24.4	27.2	24.7	24.9	24.3
Egy. Sales - Nepal (GWh)	444	482	524	590	652	674
Egy. Sales - India (GWh)	16	18	27	81	84	59
Ave. Revenue Rate (NRs/kWh))	1.22	1.38	1.38	1.40	1.99	2.51
Increase in Av. Rev. Rate (%)	6.0	13.8	(0.3)	1.3	42.0	26.3
Operating Income (NRs Mil)	136	(317)	(467)	(374)	(104)	(47)
Interest Expenses (NRs Mil)	126	130	129	635	632	718
Net Income (NRs Mil) [2]	(6)	3	(115)	(425)	(50)	(122)
Asset Base (NRs Bil)	4.1	10.0	16.2	19.6	22.8	24.1
Operating Ratio (%)	78	145	159	138	107	103
Rate of Return [3]	3.0	(3.2)	(2.9)	(1.9)	(0.5)	(0.2)
Debt Service Coverage Ratio	1.6	1.4	1.6	3.3	6.3	1.2
Current Ratio	1.3	1.2	1.1	1.3	2.3	2.0
Debt/Equity Ratio	29/71	11/89	13/87	33/67	34/66	37/63

[1] The large purchase during FY90 was from the Marsyangdi Project prior to its transfer to NEA.
[2] Starting in FY89, Net Income is inclusive of transfer from revaluation surplus, the increase in depreciation because of asset revaluation.
[3] On revalued assets from FY89.

During this period, NEA's sales increased steadily. However, system losses, poor operational management, and the impact of the Trade and Transit impasse adversely affected NEA's earnings. The major reduction in NEA's operating income after FY88 was due to the introduction of annual asset revaluation and depreciation adjustment in NEA's accounting policy. Apart from a restructuring of tariffs in FY89, failure to increase tariffs appropriately until FY92, combined with NEA's continued operating inefficiencies, account for the continued poor state of NEA's finances. Under the PSEP, a major tariff increase of more than 60% was implemented in November 1991. With HMG's commitment to establish NEA on a sound commercial ground, along with other institutional development measures already adopted (para. 4.17), a gradual improvement in NEA's financial performance is already evident: the rate of return indicates a gradually improving trend; the debt service coverage ratio ranging between 1.2 and 1.6 has been adequate except for FY91 and FY92 when the ratio was affected by the Marsyangdi debt relief (para. 4.16); and the current ratio ranging between 1.1 and 1.3 has been quite comfortable. (Because of significant increases in accounts receivable and cash balances since FY92, the current ratio has been 2.0 or higher.) The debt/equity ratio of 37/63, after absorbing the heavy debt burden of the Marsyangdi Project, was satisfactory.

4.4 Sources and Applications of Funds. NEA's investment financing pattern for the period FY88-93 was as follows:

	NRs Billion	%
Funds Required		
Capital Investment	13.9	98
Interest During Construction	0.3	2
Total Funds Required	14.2	100
Sources of Funds		
Internal Cash Generation	3.4	
Add: Consumer Contribution	0.1	
Less: Debt Service	1.7	
Increase in Working Capital	0.4	
Internal Sources	1.5	10
HMG/N's Equity Contribution	1.7	12
Grant from Donors	0.6	5
Long Term Debts	10.4	73
Total Sources	14.2	100

These figures indicate that during FY88-93, NEA financed only about 10% of its investment program from its own resources. A major reason for this low level was the inadequate tariff levels that were insufficient for the sudden absorption of the Marsyangdi Project in FY91 (para. 4.16).

4.5 Capitalization. NEA's capitalization at the end of FY94, is estimated as follows:

		NRs Billion
Total Fixed Assets		31.2
Investments		0.2
Current Assets	1.2	
Less: Current Liability	0.3	0.9
		32.3
Financed by:		
Equity		19.0
Long Term Debt		13.3
		32.3

The estimated FY94 debt/equity ratio of 39/61 is quite sound and, given prudent financial management, would provide a comfortable margin for further borrowing.

4.6 Accounts Receivable. Under the PSEP, NEA is implementing an action plan to reduce consumer receivables by correcting and updating consumer ledgers including, *inter alia:* reconciliation of consumer ledgers with control accounts, aging analysis of consumer dues, writing-off of bad debts, establishment of a legal framework for disconnections, and punishment of theft. Overall progress must continue and will require increased management support. Accordingly, during negotiations, NEA agreed to accelerate the implementation of the action plan which is now scheduled to be completed by September 30, 1995 (para. 6.3(j) and Annex 4.8). In order that bills are issued on time and consumer accounting is done correctly, ADB financed a study under their Fifth Power Project on computerization of billings. The first phase is under implementation now, and during the second phase all consumer billings for the Kathmandu Valley are to be computerized; this is expected to be completed by July 1995. Thereafter, during the implementation of the third phase, billing of all consumers in the Terai region would be computerized; this is expected to be completed by December 1995.

During negotiations, NEA agreed to implement the above plan (Annex 4.9) for computerization of its consumer accounts (para. 6.3(k)).

4.7 NEA's accounts receivable have been subdivided into two broad consumer groups (a) domestic consumers, and (b) export consumers. The domestic consumers have again been subdivided into three categories: (i) HMG offices and departments, (ii) parastatals, and (iii) private consumers. The status of these are discussed in the following paragraphs.

4.8 *Domestic Consumers*. Under the PSEP, HMG is required to ensure that dues to NEA from its offices and departments do not exceed three months of average monthly sales. In addition, NEA is required to maintain its receivables from non-government domestic consumers at a level of not more than three months of average monthly sales. As of July 15, 1993, NEA's dues from non-government domestic consumers were at NRs 376 million, or equivalent to about 2.9 months of average monthly sales. The latest estimates, as of November 15, 1993, indicate these to be at NRs 391 million, which is about 2.7 months of average monthly sales. However, HMG's outstanding dues to NEA continued to remain above the agreed level of three months. A detailed breakdown of domestic accounts receivable is shown below:

Table 4.1: Details of Accounts Receivable by Domestic Categories

Category	Due as of July 15, 1993 (NRs Mil)	Accounts Receivable (months)	Due as of Nov. 15, 1993 (NRs Mil)	Accounts Receivable (Months)
(a) HMG's Offices and Departments	48.9	3.6	75.9	5.3[14/]
(b) Parastatals	13.2	0.8	30.5	1.7
(c) Private	362.7	3.2	360.8	2.8
Sub-total (b)+(c)	375.9	2.9	391.3	2.7
Total Domestic	424.8	3.0	467.3	2.9

4.9 In accord with the PA, as of July 15, 1990, NEA was to offset its receivables from HMG's offices and parastatals for unpaid electricity bills against its dues to HMG. However, for book-keeping reasons, NEA's accounts continue indicating higher receivable levels than would have resulted had NEA made those adjustments. The latest estimates (November 15, 1993) of NEA's receivables on account of its domestic consumers is shown in Table 4.1; against its outstanding amount of NRs 75.9 million, HMG cleared about NRs 48 million in May 1994.

4.10 *Export Consumers*. Power exchange with India started in the early 1970s. NEA is an importer from Uttar Pradesh State Electricity Board and exports small amounts to the Governments of Bihar and Uttar Pradesh; it carries out both import and export of power with the Bihar State Electricity Board. The fixation of power exchange tariffs is the responsibility of the binational Subcommission on Water Resources, co-chaired by Nepal's Secretary of Water Resources and his counterpart in the Government of India. Technical power exchange issues are under the purview of the Indo-Nepal Power Exchange Committee, co-chaired by the Director General, EDC, and the Member (Hydro) of the Central Electricity

[14/] Against the outstanding amount of NRs 75.9 million, a payment of about NRs 48 million was cleared by HMG in May 1994.

Authority of the Government of India. Although attempts have been made in the past, through meetings between senior HMG and NEA officials and their Indian counterparts the reconciliation of accounts between NEA and its export consumers has not been completed. To help ensure a satisfactory level of revenue collections from future bulk exports to India, this matter is expected to be brought under the purview of the Indo-Nepal Power Exchange Committee.

4.11 A breakdown of NEA's accounts receivable on account of its export consumers indicate that its receivables as of end FY93 were about NRs 281 million (about 45 months of average monthly sales); however, after netting out amounts due to and from the Bihar State Electricity Board, NEA's net accounts receivable as of the end of FY93 on account of export consumers is about NRs 75 million, or about 9.5 months of average monthly sales. At the end of the reporting period (November 15, 1993) these are estimated at NRs 79 million, or about seven months of average monthly sales (Table 4.2).

Table 4.2: <u>Accounts Receivable for Export Consumers</u>

Consumer	Due as of July 15, 1993 (NRs Mil.)	Accounts Receivable (Months)	Due as of Nov. 15, 1993 (NRs mil.)	Accounts Receivable (Months)
BSEB				
Receivable	251.1		293.3	
Less Payable	221.5		247.6	
Net Receivable	29.6	5.0	45.7	4.3
Govt.of Bihar/Govt. of Uttar Pradesh	30.3	59.0	33.0	49.0
Total	59.9	9.5	78.7	7.0

4.12 NEA's overall receivables as of November 15, 1993, (including both domestic and export consumers) are estimated at about three months of average monthly sales. In order to ensure that NEA's receivables are maintained within reasonable limits, during negotiations, NEA agreed that starting in FY94, its overall accounts receivable (including its export consumers) and its receivables from each of its domestic consumer categories will not exceed three months of average monthly sales (para. 6.3(l)).

4.13 <u>Pension Fund</u>. NEA's current liabilities for FY92 (audited) include a provision of about NRs 140 million for staff pensions and gratuities. During negotiations, NEA agreed that it will undertake an actuarial valuation of its liability for staff pensions by December 31, 1994, and by March 31, 1995, submit to IDA a financing plan to ensure that it has adequate coverage to meet pension liabilities; thereafter, at the end of every third year, NEA would carry out a similar exercise and provide IDA with a financing plan (para. 6.3(m)).

4.14 <u>Insurance</u>. NEA carried out a Risk and Insurance Management Development Study with the help of J. M. Gordon and Associates Consultants Ltd., Canada. The study concluded that insuring all exposure and risks would be extremely expensive for NEA, and insurance should only be purchased for catastrophic risks for large facilities while small losses would be more cost effectively self insured. Since FY93, NEA has been allocating funds annually to self-insure against small risks. In November 1993, NEA appointed insurance consultants to carry out a risk survey of its generating facilities. During negotiations NEA agreed to submit, by April 15, 1995, a report on steps taken to implement an Insurance Action Plan (Annex 4.10) so as to insure that all its generating facilities are appropriately insured by July 16, 1995; and its other assets by January 1, 1996 (para. 6.3(n)).

C. Tariffs

4.15 Prior to the amendment of the NEA Act in 1992, NEA was required to develop its electricity tariff recommendations for HMG's approval. After review by NEA's Board, its tariff proposals were submitted to HMG for consideration and approval. During the period from its incorporation in August 1985 until 1991, NEA was allowed only two tariff increases, the first of about 22%, effective September 17, 1985, and the second of about 18%, effective May 15, 1988. In April 1989, because of steep increases in fossil fuel prices (20% to 50%) and supply unreliability caused by the Trade and Transit impasse, HMG mandated a reduction in domestic electricity tariffs by 15% for the first 250 kWh consumed per month for all consumers with consumption of less than 500 kWh/month. With the satisfactory resolution of the Trade and Transit impasse, this subsidy was removed in August 1990, and HMG has agreed to compensate NEA for the revenue losses incurred during the subsidy period. Since FY92, three tariff increases have been implemented, the first one of more than 60%, effective November 17, 1991, a second of about 25%, effective March 13, 1993, and a third increase of about 38%, effective mid-March, 1994. Future tariff increases are discussed in para. 4.23.

4.16 Because the assumption by NEA of the debt on the Marsyangdi Hydroelectric Power Plant (MHPP) would have required a tariff increase of more than 100% in FY92, IDA agreed to a deferral of NEA's debt servicing to HMG on account of the MHPP debt for two years, i.e., for FY91 and FY92. Accordingly, it was agreed that starting in FY93 the MHPP debt would be repaid in 28 years instead of 30 years as originally scheduled under the SLA for MHPP. During FY93, NEA did not meet its debt servicing obligations to HMG on account of MHPP. Starting in FY94, NEA will service its MHPP debt (including repayment in 28 years of the unpaid interest accrued during FY91 and FY92) in accordance with the revised SLA.

D. Financial Strengthening

4.17 To improve its financial management, NEA has engaged consultants to (a) develop, and assist in the implementation of an appropriate accounting system (para. 2.21), (b) conduct its internal auditing functions (para. 2.22), and (c) introduce an appropriate materials management and inventory control system (para. 2.25). It has taken action to monitor and control its recoverable advances. During negotiations, NEA agreed to continue the process of identifying and disposing of its obsolete assets together with the inventory associated; starting in FY94, these would be reflected in its annual accounts (para. 6.3(o)). In order to preserve assets with their correct valuation, NEA also agreed that its fixed assets would be revalued each year in accordance with agreements reached under the PSEP (para. 6.3(p).

4.18 Close attention must be given by HMG to ensure that NEA can mobilize the required level of domestic resources instead of continuing the heavy demands that it has been imposing on the national budget in the past. NEA is by far the largest public enterprise in Nepal, and HMG's investment for the proposed project will also be the largest ever. It is therefore imperative that NEA fulfill its annual debt obligations to HMG strictly in accordance with agreed on-lending arrangements. During processing of the PSEP, most of the outstanding SLAs were finalized and NEA's overdue debts to HMG established and entered into its accounts. NEA's pre-audited FY93 accounts indicate significant accumulation of interest due to HMG, which increased from about NRs 21 million as of the end of FY92 to about NRs 224 million as of the end of FY93. However, during the same period, cash balances have been allowed to grow from about NRs 354 million to NRs 733 million. This is more than 40% of NEA's FY93 revenues from electricity sales and is excessive. HMG and NEA confirmed that necessary SLAs have been executed for all completed and ongoing projects and that by the end of FY94, NEA's debt servicing to HMG will be in accordance with the agreed on-lending arrangements. In view of past delays in concluding SLAs, HMG agreed during negotiations that they would conclude an SLA with NEA in connection with all future on-lending, whatever the source of funds to NEA (para. 6.1(h)). In order to permit effective monitoring of NEA's debt servicing, NEA has agreed to inform IDA about details of its debt servicing to HMG two months before the beginning of each fiscal year (para. 6.3(q)). Conclusion of an SLA for onlending the credit proceeds from HMG to NEA would be a <u>condition of credit effectiveness</u> for the proposed AHP project (para. 6.4(g)).

4.19 In accord with the joint HMG and IDA annual review of Nepal's macroeconomic framework for public expenditure planning and the resource envelope for the power sector (para. 1.44), NEA submitted to IDA a six-year rolling investment program on June 21, 1994 and financial projections, including steps to be taken to comply with revenue covenants. Such a rolling program will be updated annually. NEA would not undertake any investment not included in that program, as agreed with IDA, and would seek IDA's specific consent before undertaking any investment projects that would increase generation capacity by more than 10 MW capacity or transmission projects costing more than US$3 million. In granting such consent, IDA would need to be satisfied that the project is economically and technically justified and part of the LCGEP, that NEA has the financial and managerial capacity to undertake the project without delaying implementation of the AHP or the rest of its ongoing work program, that the project is consistent with HMG's public expenditure program and macroeconomic framework, and that NEA is carrying out AHP in a timely manner (para. 6.3(r)).

4.20 <u>Financial Covenants</u>. The cash generation covenant, currently in place under the PSEP, measures NEA's ability to finance its annual local currency investment from its internal sources. However, as insufficient data are available to estimate accurately annual local investment costs, this was found to be inadequate. An understanding was thus reached with NEA that cash generation as a share of a three-year moving average of total investments would become the driving force behind NEA's tariff determination; this would replace the current PSEP cash generation covenant. In addition, to ensure a more dependable measure for formulating long-term financial policy, it will be suitably augmented by a rate of return covenant. Accordingly, during negotiations, HMG and NEA agreed that NEA would take all measures necessary (including tariff increases) to produce revenues that would at least cover cash operating expenses, debt service requirements, additional non-cash working capital requirements and NEA's contribution to a three-year moving average of its total investment program (including interest during construction) of 12% (FY95), 14% (FY96), 15% (FY97), 16% (FY98), 17% (FY99), 20% (FY00), 21% (FY01), 22% (FY02), 25% (FY03) and 26% (FY04) and thereafter. Also starting in FY96, NEA would take all measures necessary (including tariff increases) to produce annual rates of return on revalued assets of not less than 4.5% during FY96 and 6% thereafter (para. 6.3(s) and (t)).

4.21 The June 1993 floods caused considerable damage to NEA's existing facilities. While most of the transmission and distribution facilities quickly underwent necessary repairs, the damages at Kulekhani Power Plant (Cr. 600-NEP) were considerable. After extensive repairs, the plant was recommissioned in December 1993, ahead of the original schedule. The damages caused serious shortages in energy generation and adversely affected NEA's revenues from electricity sales. Thus, it is unlikely that NEA will be in compliance with the PSEP's FY94 revenue covenant; accordingly IDA has agreed to waive this requirement for FY94, provided compliance with the FY95 revenue covenant can be ensured. The proposed revenue covenant, based on gradually increasing self-financing and the agreed assumptions underlying the financial projections, indicated a tariff increase requirement of about 38% in March 1994, for compliance with the FY95 revenue covenant. In February 1994, HMG announced the required 38% tariff increase, effective from mid-March 1994 (para. 1.18).

E. NEA's Future Financial Performance

4.22 The following estimates (FY94) and forecasts (FY95-04) of NEA's operating performance assume that the policies outlined in the previous sections, plus operational efficiency increases relating to loss reduction and accounts receivable, will be fully implemented. The assumptions for financial projections are included in Annex 4.2.

FY	94	95	96	97	98	99	00	01	02	03	04
Energy Generation (GWh)	920	1077	1161	1196	1349	1243	1631	1748	1928	2831	2964
Energy Purchased-Nepal (GWh)	27	24	105	105	176	526	526	526	526	526	526
Energy Purchased-India (GWh)	53	62	52	108	22	11	0	10	57	0	0
Gross System Losses (%)	23.5	22.5	22.0	21.5	21.0	20.5	20.0	19.6	19.2	18.8	18.4
Energy Sales-Nepal (GWh)	719	853	938	1031	1144	1269	1410	1559	1731	1924	2140
Energy Sales-India (GWh)	45	48	97	78	81	161	357	309	332	912	798
Ave. Revenue Rate (NRs/kWh)	3.17	3.88	4.88	6.09	6.32	7.12	7.12	7.82	7.82	7.82	8.58
Inc. in Av. Rev. Rate (%)	26.2	22.5	25.8	24.8	3.9	12.6	0.0	9.7	0.0	0.0	9.7
Operating Income (NRs Mil)	425	1089	2235	3447	3807	4378	5832	6979	7796	11662	13357
Interest Expenses (NRs Mil)	724	869	989	1263	1331	1509	1551	2786	2873	2826	6709
Net Income (NRs Mil) 1/	339	540	1165	1739	1937	2198	3055	3043	3518	5856	4645
Asset Base (NRs Bil)	26.5	28.9	32.7	36.0	37.8	39.6	51.1	62.9	63.3	94.5	125.7
Operating Ratio	83	79	69	64	65	69	65	62	63	58	53
Rate of Return	1.6	2.6	4.7	6.7	7.0	7.7	7.8	8.2	9.0	8.6	8.4
Debt Service Coverage Ratio	1.7	1.9	2.4	2.6	2.5	2.3	3.0	2.2	2.3	3.2	1.9
Current Ratio	4.7	2.3	1.8	1.7	1.6	1.7	1.6	1.8	1.7	1.5	2.1
Debt/Equity Ratio	39/61	44/56	50/50	54/46	54/46	54/46	55/45	55/45	54/46	54/46	53/47

1/ Net Income is inclusive of transfer from revaluation surplus, the increase in annual depreciation because of asset revaluation.

4.23 The increase of about 38% in the average tariff rate in March 1994 ensures compliance with the agreed covenant for FY95. Thus, no additional tariff increases will be required for FY95. Present forecasts indicate that, to meet requirements over the projected period, NEA's average tariffs will have to be further increased by about 26%, 25%, 4%, 13%, 0%, 10%, 0%, 0% and 10% at the beginning of FY 96, 97, 98, 99, 00, 01, 02, 03 and 04, respectively. Also, in view of the tariff sensitivity to fuel charges, during negotiations, NEA agreed to adjust promptly its tariffs to reflect changes in fuel costs (para. 6.3(u)).

4.24 NEA is on the threshold of major expansion; its assets are projected to increase from about NRs 36 billion at the end of FY93 to about NRs 169 billion by the end of FY04. In financing this expansion, long-term debt is expected to increase from about NRs 11 billion at the end of FY93 to about NRs 95 billion by the end of FY04. With heavy borrowing for NEA's proposed investment program, its debt/equity ratio is expected to decline from 37/63 in FY93 to 53/47 at the end of FY04; however, NEA would still have a comfortable margin for further borrowing at that time. For the period FY95-04, the debt service coverage of 1.9 to 3.2 times would be satisfactory. With the new financing pattern emerging with capital assets being increasingly financed by debt, the debt servicing position has to be closely monitored. During negotiations, NEA agreed not to incur any debt unless its actual net revenues for the fiscal year immediately preceding the date of such incurrence, or projected net revenues for any later twelve-month period, whichever net revenues are the greater, is at least 1.3 times the maximum debt service for any succeeding fiscal year on all debt incurrence by NEA (para. 6.3(v)).

4.25 NEA's current position during the review period ranges between 1.5 and 2.3, which is satisfactory. During negotiations, HMG agreed that it would provide NEA with any required additional working capital by way of equity contribution necessary to maintain a current ratio of not less than 1.5. (para. 6.1(i)).

4.26 Financing Plan. NEA's projected FY95-04 investment requirements and the expected financing sources are as follows:

	NRs Billion	%
Funds Required		
Capital Investment	121.4	82
Interest During Construction	26.8	18
Total	148.2	100
Sources of Funds		
Internal Cash Generation	64.8	
Add: Consumer Contribution	0.3	
Less: Debt Service	29.1	
Increase in Working Capital	3.3	
Internal Sources	32.7	22
HMG/N's Equity Contribution	15.6	11
Grants from Donors	11.9	8
Long Term Debt	88.0	59
Total	148.2	100

It is expected that external sources would finance the entire foreign exchange cost of the investment program, representing about 86% of investment costs net of custom duties and interest during construction. The local currency component of the investment program comprising custom duties (NRs 4.7 billion), interest during construction (NRs 26.8 billion) and local currency capital expenditure (NRs 16.7 billion), would be financed by NEA's internally generated funds (NRs 32.7 billion) and HMG (NRs 15.6 billion).

4.27 Given the assumed tariff increases and projected electricity sales, financial projections indicate that NEA would be a net contributor to HMG's budget. The table below summarizes the projected fiscal impact of NEA's operation for the period FY95-04 under two different scenarios. Case A, which is the base case, assumes tariff increases that would enable NEA to comply with agreed revenue covenants described in para. 4.20; they are about 26%, 25%, 4%, 13%, 0%, 10%, 0%, 0% and 10% for FY 96, 97, 98, 99, 00, 01, 02, 03 and 04, respectively, averaging about 9% p.a. in nominal terms and 4% p.a. in real terms. Case B assumes a nominal tariff increase of 26% in FY96 and no real increases thereafter. Sensitivity tests of adverse scenarios with respect to high system losses, a 20% cost overrun on the FY95-04 investment program and combinations of both have been carried out and results are given in Annex 4.11. Even in the most pessimistic scenario combining high system loss with a 20% investment cost overrun and no real tariff increase during FY97-04, NEA would remain as a net contributor throughout the forecast period, with a projected cumulative transfer of funds from NEA to HMG of about NRs 32 billion. This would enable HMG to assure that adequate resources are available for financing priority investments, particularly in the social sectors (para. 1.47).

Net Flow of Funds FY95-04	Case A	Case B
	(in NRs billion)	
NEA's Debt Service to HMG	29.1	29.1
Income Tax	16.7	11.5
Payment of CDST	4.7	4.7
Payment of Interest During Construction	23.7	17.5
Subtotal	74.2	62.8
Less: HMG's Debt Service to External Lenders	7.2	7.2
HMG's Equity Financing of Local Capital Expenditure	12.4	15.1
Net Flow of Funds from NEA to HMG	54.6	40.5

4.28 Rural Electrification. HMG requires NEA to charge uniform tariffs throughout the country even though NEA is obliged to provide service to unprofitable rural areas. The losses in these rural areas, which are a drain on NEA's financial resources, will become heavier as such activities expand. In accord with the PSEP, starting in FY93, HMG is required to reimburse NEA for the losses incurred in its non-profitable rural electrification operations. However, as NEA's present accounting system is not capable of identifying such losses, reimbursements have not been made so far. The revised accounting system, once implemented, would enable NEA to segregate these losses and seek compensation from HMG. During negotiations, HMG agreed that following implementation of NEA's revised accounting system, HMG will reimburse annually the losses incurred by NEA in providing services to the non-profitable rural areas (para. 2.18).

4.29 Evaluation Committees. In the past, plants and works executed by HMG (including Boards) and later transferred to NEA have been subject to appraisal by ad hoc evaluation committees formed by HMG which have determined the valuation of these transferred assets. These committees have often been convened long after the start of commercial operation of the plant concerned, and the valuation methodologies have not followed standard accounting practices. Such delays in asset valuation have further delayed finalization of SLAs, and consequently the resulting uncertain debt liability of NEA to HMG has put NEA's accounts in jeopardy. Since NEA has been established as the single enterprise responsible for planning, construction and operation of all public sector power facilities in Nepal, such committees will be unnecessary in the future. In accord with the PSEP, during negotiations, HMG agreed that unless the Association shall otherwise agree, (i) all future projects in the power sector financed by HMG will be included in NEA's Investment Program, and (ii) all power projects to be carried out by HMG's public sector will be implemented by NEA (para. 6.1(j)).

V. PROJECT JUSTIFICATION AND ECONOMIC ANALYSIS

5.1 The justification for this project has been reviewed in two steps. First, the standard tests of least cost analysis and economic evaluation have been applied. These show that the project is part of the least cost generation expansion plan under plausible assumptions about the future. The optimal commissioning date is delayed by a few years if load growth is lower than projected or costs are much higher than projected in the base case; otherwise the least cost solution is for Nepal to proceed with Arun as soon as possible. Proceeding with Arun III now is an attractive investment for Nepal in both economic and financial terms. The economic rate of return is just above 15% in the base case, and the risk of it falling below 10% is judged to be quite small (about 2%). Once on stream, the project is projected to generate the equivalent of more than US$100 million annually in revenues, which is about ten times the project's annual debt service costs to foreign creditors.

5.2 The second part of the justification considers the argument that has been put forward by project critics for overriding the results of these conventional approaches to project justification. The basic contention of the critics is that the rather small cost advantage in favor of Arun III is more than offset by the lower risks and greater capacity building benefits of an alternative strategy based on a series of smaller hydro investments. A comparison of the alternative strategies for meeting Nepal's power requirements shows that what is at stake is not a choice between Arun III and small, private-sector financed hydro investments. Government policy and the proposed project support both. The real choice is between Arun III and other medium and large-scale hydro investments. Nepal faces important risks whichever choice is made. Proceeding with an investment program that includes Arun III is probably less risky overall, and certainly more likely to have the risks well managed. Moreover, there is strong borrower commitment to this investment program, a factor which experience shows is crucial to effective implementation.

A. Standard Project Justification

5.3 Least Cost Analysis. The least cost analysis for selecting power generation projects is described in Annex 5.4. The analysis selects the generation expansion plan which minimizes the present value of the total system expansion cost. The candidate projects considered include thermal options as well as those hydro projects which have been examined to at least the pre-feasibility level. These projects range in size from the 10 MW Modi Khola project to the 660 MW Kali Gandaki A II project. The way in which projects were selected for pre-feasibility work has been described in Section III (above).

5.4 There are certain characteristics of Nepal's power situation which complicate the determination of the least cost expansion plan. The bulk of the current power supply is from run-of-the river hydro projects which supply much less power in the dry season (especially January to March) than in the wet season. During the dry season of a typical year hydro power must be supplemented by power supplied from diesel fired thermal plants and modest imports from India. During the wet season of a typical year there is a surplus of hydro energy. In principle, this pattern could be modified through development of hydro projects providing for substantial storage, but these projects tend to be very large, expensive and/or require first-of-a-kind construction which would be very risky for Nepal. Moreover, they can pose complex issues. In practice, therefore, Nepal faces a choice between surplus hydro energy in the wet season and large imports of fuel to run thermal plants in the dry season.

5.5 Under the assumptions described in detail in Annex 5.4 the least-cost solution for Nepal is to have surplus hydro energy in the wet season rather than import large quantities of fuel with major associated logistical problems and degree of dependence on potentially volatile imported fuel. One of the key attractions of the Arun III project in this connection is its ability to generate power during the dry season at a level which is not much less than during the wet season; that is, Arun III provides a high proportion of what is called firm power. This explains why traditional cost comparisons based on the cost per installed kilowatt -- which show Arun III to be relatively expensive -- are misleading. On the much more relevant measure of cost per kilowatt hour of firm power (i.e., power that can be supplied year round) Arun III is quite attractive.

5.6 The various assumptions underlying the least cost analysis are spelled out in Annex 5.4. The sensitivity of the recommended power investment program to changes in key assumptions is also explored. The key conclusion is that variation in these assumptions can result in a delay in the optimal commissioning date from 2003 (which begins in July 2002, i.e. only a few months after the scheduled April 2002 Arun III commissioning date) -- which is now the earliest feasible date -- to 2009, but that Arun III and Kali Gandaki A always remain among the first plants to be justified in the least cost expansion plan.

5.7 The greatest sensitivity is to the pace of growth in demand for power (i.e. the load forecast). The expansion projected in the base case is 12% per annum during FY94-FY2001 (as Nepal works its way out from under the load shedding which it now experiences) and 10.7% in FY2001-FY2015. While high in nominal terms, this growth rate is actually slightly below the growth sustained over the past few years. Moreover, the translation of demand growth into required generation capacity assumes a further drop in system losses and improvements in load management. Should progress in either of these areas prove to be less rapid than assumed, this would boost the required growth in new capacity to meet any given level of demand.

5.8 The consistency of the projected base case demand growth with the projected increase in incomes and power tariff levels has been investigated. The projections are internally consistent. In judging the impact of the projected increase in power tariffs it is important to keep in mind the cost which is currently being paid for alternative fuels -- kerosene-based lamps for unelectrified households and diesel generators for non-residential users (see Annex 5.7 for details).

5.9 While the base case load forecast is thus considered reasonable by IDA -- against the perception of the Government and some of the other co-financiers who regard it as being excessively conservative -- a low case forecast equivalent to 75% of the base case has also been examined. Under this assumption, the optimal commissioning date for Arun III would be deferred until 2009. The additional (discounted) cost incurred by Nepal is estimated at $38 million if it proceeds with Arun III and the low demand forecast materializes. This is a measure of the risk entailed in a decision to proceed now. It can be compared with the risk of delay in terms of potential unserved energy needs in the early years of the next decade and the uncertainty which attaches to Nepal's ability at some future date to mobilize the needed finance on comparably attractive terms and to receive comparably attractive bids from contractors.

5.10 Other key assumptions relate to the risk of cost overruns and the price assumed for the sale of surplus hydro power. Assumptions adverse to the Arun III project result in more limited delays in the optimal commissioning dates in these cases -- to 2005 or 2006. For each assumption, the base case is in the middle of a range of possible outcomes, but using assumptions more favorable to Arun III do not advance the commissioning date from 2003, since this is the earliest date that is technically feasible. What the more favorable assumptions do imply is a higher economic and/or financial return to the project.

B. Economic Rate of Return

5.11 Methodology and Assumptions. The economic internal rate of return (EIRR) to NEA's long-term development program for meeting growth in demand for electricity is evaluated from a comparison of the economic costs of this program with its economic benefits. Benefits are valued in terms of the incremental demand that is met under the program relative to the much lower level of demand that could be served if no new supply capacity were added to the power system. Likewise, the costs are the difference between power system costs for meeting the forecast demand with this program and the system costs without any new investments in supply capacity. The EIRR is the discount rate which sets the present value of the difference in the stream of net economic benefits (economic benefits less economic costs), between NEA's long-term development program and the scenario with no new supply capacity added to the system. Details of the analysis are presented in Annex 5.7.

5.12 The evaluated program is based on the proposed sequence of investments in new capacity for meeting the base case demand forecast up to the year 2015. The sequence includes the Kali Gandaki A and Arun III hydroelectric schemes as the first major generation components. It is taken up to the year 2015 to cover the full benefits of developing the hydropower potential of the Arun valley that the Arun III scheme facilitates, and hence it also includes the costs and benefits of developing the Upper Arun III and Lower Arun projects.

5.13 The costs associated with meeting the forecast demand comprise: (a) capital expenditures on generation, transmission and distribution facilities and service connections; (b) operations and maintenance costs; (c) fuel costs for thermal generators; (d) power purchases from privately owned power stations in Nepal; (e) power imports from India; and (f) costs associated with technical assistance and training. The earnings from exports to India of electricity generated as non-firm hydropower are deducted from the costs of power system expansion and operation to derive the net cost of meeting the forecast Nepalese demand for electricity. The same cost categories are calculated for the "without program" case. The difference between the costs of the "with program" case and the "without program" case represents the incremental costs of meeting the forecast growth in electricity demand.

5.14 The economic benefits associated with the power investment program are the values of the increments in NEA's sales made possible by carrying out the proposed long-term development program. The increments in sales are based on the difference in sales that could be served in the "with program" case and the "without program" case. This difference corresponds roughly to the increase in forecast sales from the year 2000 onward over the forecast sales in 1999, because the first major generation project of NEA's development program (Kali Gandaki A) enters into service in 2000 at the earliest. The increment is then reduced to reflect the extent to which NEA could increase its sales in 2000 onwards above the 1999 level from its supply capacity in the "without program" case.

5.15 The valuation of projected increments in sales varies among different groups of power users. Three groups of users are identified for this economic evaluation, and they correspond to the following user categories in NEA's tariff: residential, industrial, and "other" that comprises commercial, non-commercial, transport, irrigation, water supply, temples, street lighting, and temporary supply categories. Since increments in sales are the basis for the estimation of benefits, a distinction has to be made between users that are already connected to NEA's system by the end of 1999, and users that are first connected from 2000 onwards. In the case of existing users in the "without program" case, the incremental approach implies that they will continue to be supplied by NEA from its existing capacity at roughly their 1999 level of consumption. The benefits from NEA's power development program for this class of user is thus based on the incremental sales over the "without program" case. This increment is a function of the general increase in incomes from growth in the Nepalese economy. In general, new users would not be connected to NEA's system in the "without program" case because NEA would not have the capacity to serve them. The benefits from NEA's power development program for this class of user are thus based on their full consumption of electricity from NEA's system, once they are connected. The analysis also accounts for the lower consumption of new connections compared to that of mature users and its gradual build-up to the levels of consumption of the latter.

5.16 For the EIRR analysis, the adopted growth rate in household income over the evaluation period -- i.e., up to 2015 -- is 2.0% per year. This rate is derived from the projected long-term growth rate of GNP of 4.5% and projected population growth of 2.5%. Total consumption by new residential users is divided into two components for valuation purposes. The first component is the saving in resource costs arising from the substitution for existing methods of lighting, taken to be kerosene lamps, of electric lighting. The second component is the induced consumption of electricity above the substituted level caused by the large drop in the price of energy that comes with a switch from non-electrical forms of service, e.g., kerosene lighting, to electric forms. For residential consumers connected before 2000, the benefits are those arising from incremental sales over the "without program" case, which increase with the growth of household incomes.

5.17 The basis for valuing the benefits of post-1999 incremental sales to industrial and other users, i.e., all non-residential users, is the cost that these users would incur if they had to meet their electricity needs by investing in and operating diesel generators on their own premises, instead of being able to take supply from NEA. Hence, for this class of users, the benefit is taken to be avoided user cost. It is assumed that the consumption of electricity by non-residential users would not be sensitive to the price or own-incurred cost of electricity, since this cost forms a small proportion of the users' total costs of producing goods and services. Hence, there is no induced consumption caused by a switch from own-supply to NEA supply. It is assumed, however, that consumption rises with growth in national income.

5.18 Results. The EIRR for the base case is estimated at 15.4% based on the methodology and assumptions discussed in the above paragraphs. This rate exceeds the opportunity cost of capital of 10% that was used for project justification. The robustness of the EIRR is assessed in two ways: first, by a sensitivity analysis with respect to specific and discrete changes in assumptions, and second, by an integrated risk analysis in which discrete possibilities are weighted by probabilities to derive a probability distribution for the EIRR.

5.19 Sensitivity Analysis. The EIRR's sensitivity to cost overruns, revenue from exports, and exclusion of the Upper and Lower Arun III projects is assessed, for each of the three demand cases. (See Annex 5.7 for details.) The key results are:

- in the base case demand forecast, the EIRR is above 10% in all cases;
- in the low case demand forecast, the EIRR is above 10% in all cases except when Upper and Lower Arun III are excluded[15/]; and
- in the high demand case, the EIRR is over 15%, and as high as 17.5%.

The sensitivity analysis therefore shows the EIRR to be robust.

5.20 Risk Analysis. The purpose of the risk analysis is to attach probabilities to the different scenarios identified by the sensitivity analysis. This yields a risk-weighted EIRR as well as an assessment of the chances of the EIRR falling below the opportunity cost of capital. (see Annex 5.7 for details).

5.21 The major risks concerning the economic performance of the project are: demand risk, export sales risk, cost risk, and schedule risk. In the case of demand risk, the analysis attaches probabilities to base, low and high demand profiles based on country judgments. For export sales, probabilities are attached to the base case price and the case of zero price of exports of surplus hydro energy to India. Assessments of cost (no cost overrun, moderate cost overrun and high cost overrun), and of schedule risk (no schedule slip and positive schedule slip) are informed by experience with all Bank-financed completed hydropower projects initiated since 1965.[16/]

15/ The reason for testing the impact of excluding the Upper and Lower Arun Projects was to determine how attractive Arun III would be if, for whatever reason, further power development in the Arun Valley were not to proceed. Since the cost of the access road is included in the analysis, there is no reason a priori to exclude the net benefits of the two follow-on investments.

16/ There is of course some possibility of a cost underrun (viz. the experience with the Marsyangdi Project (para. 1.35). In such a case the project economic performance would be enhanced.

5.22 The risk-weighted EIRR is 13.5%, which is lower than the 15.4% reported earlier for the base case, but higher than the opportunity cost of capital. The chance of the EIRR being at or below 10% is very small at about 2%. Moreover, the risk-weighted EIRR is robust to changes in the basic probabilities, as is the result that the likelihood of falling below the opportunity cost of capital is very small. Therefore, the risk analysis shows the EIRR to be robust.

C. Assessment of Alternative Power Investment Strategies

5.23 Both least cost analysis and economic evaluation show that the Arun III project meets the Bank's normal standards. Nevertheless, because the project is large for Nepal, because the Bank's past experience with hydropower investments has shown a tendency for project costs to exceed estimates, and because of objections raised against the project by critics both inside and outside Nepal, the appraisal of AHP has gone beyond the standard appraisal and has given special consideration to alternative investment strategies. In particular, the possibility of meeting Nepal's power requirements through a series of smaller hydropower investments has been examined in some detail.

5.24 It is important to be clear what is meant by "smaller" hydropower investments. One concept emphasizes those projects which can be implemented by Nepalis on their own, without significant involvement of expatriate expertise. Nepalis have demonstrated such capacity with one project of 5 MW that is already completed and with one project of 12 MW which has just been commissioned. The Khimti Khola project is much larger (60 MW), but it will be receiving strong technical and financial support from a major Norwegian utility.

5.25 In 1992/93, with help from Germany, a master plan for mini-hydro projects in Nepal was prepared. A total of 33 such projects, ranging in size from 0.3 MW to 11.4 MW, were examined. Of the 33, some 13 were considered potentially suitable for integration into the national grid. These 13 projects are not seen by the Government of Nepal or the Bank as being competitive with Arun III. The total installed capacity of all 13 projects is less than 50 MW and the firm (i.e. year round) energy is less than 20 MW equivalent. Since under the most optimistic conceivable assumptions, it would be several years before all these projects could be completed, they could at most contribute a fraction of one year's growth in demand for power in the medium term.

5.26 The Government of Nepal has for some years been encouraging the development of micro-hydro projects. As part of the effort to support the growth of private power investment in larger projects, NEA has recently concluded a 20 year energy purchase contract with Himal Power Limited, the company that will implement the Khimti Khola project. HMG has guaranteed this contract and has made clear that similar power purchase arrangements would be provided to other private power projects. Moreover, as part of the Arun project itself, the Government has decided to establish a Hydro Fund to provide funding for feasibility work on mini and micro-hydro projects and to help meet their actual financing requirements. Thus, future development of hydropower projects up to 10 MW in rated capacity, or even somewhat larger, is not jeopardized by the Arun project. On the contrary, it is being encouraged both by the policy of HMG and by the creation of a new funding mechanism.

5.27 The only realistic alternative to the hydropower investment program proposed by the Government is a series of hydro investments in the range of 10 MW to 100 MW. While these are certainly small projects by international standards, most are similar in magnitude to the two previous major hydro investments made in Nepal; namely, Khulekhani (60 and 32 MW) and Marsyangdi (69 MW). Past pre-investment studies in Nepal's major river systems have identified a large number of such potential investments. As noted in Section I, pre-feasibility and feasibility work has been done on some 18 of the 107 sites identified. About half of the 18 are under 100 MW; these have already been taken into account in the least cost generation analysis. Hence, the effort to develop an alternative hydropower investment program has had to draw from among those projects, mostly in the 30 to 80 MW range, which had previously been screened out (on the basis of rather crude technical and economic criteria) as less attractive than those for which pre-feasibility work has been commissioned.

5.28 The alternative investment program thus identified has been labelled Plan B. Its specific characteristics are described in the SAR Annex 5.4. The costs of Plan B are estimated to be about 5% higher than the Government's proposed investment program under assumptions about the future considered most likely, and 5% less in the scenario where demand growth follows the low load forecast. Supporters of the Arun project argue that the cost comparisons used in this analysis understate the risks entailed in relying on reconnaissance level information for Plan B projects. Opponents of the project argue that is only because of inadequacies in past pre-investment work that more complete information is not available for the smaller projects. For purposes of appraisal, the key points are: (a) the differences in estimated cost of the alternative investment programs favor the Government's proposed program, but the cost advantage is relatively small and is sensitive to a number of assumptions; (b) the uncertainties on the technical side and with respect to estimated costs are significantly greater for Plan B; (c) all realistic hydropower programs for Nepal over the next few years will entail investments of a size and complexity requiring an input of expatriate expertise; and (d) all of the proposed alternative investment programs envisage continued and indeed intensified support for micro and mini-hydropower investments.

5.29 Since the cost differences among the alternative investment programs are relatively small, and the risks relatively large, it is appropriate to consider how the risks of the alternative strategies compare. The two main risks are those relating to affordability and environmental/social costs. In addition, there are the issues of domestic capacity-building and ownership.

5.30 The affordability analysis for the Government's proposed investment program has been summarized in Section I and is spelled out in SAR Annex 1.4. The conclusion reached is that the Government program can be implemented without crowding out desirable growth in spending for the social sectors. This conclusion applies even if there is some slippage in macro-economic management, the rate of GDP growth, the financial performance of NEA and a significant cost overrun for AHP. The alternative investment strategy (Plan B) is expected to have similar costs over a multi-year period: the costs over the remainder of the 1990s would be lower than under the Government's proposed program, but costs in the early part of the next decade would be substantially higher. Thus, both programs pose affordability risks, albeit with different time profiles.

5.31 The advantage of Plan B is that it can be more readily adapted to changing circumstances. If growth in power demand is less than projected or if rupee availability is reduced for any of a number of reasons, spending on hydropower investments can be slowed down. The disadvantage of Plan B is that it makes these adverse circumstances more likely. GNP growth requires a positive response from the private sector to the new policies the Government is putting in place. Shortage of power is inhibiting that response. A decision not to proceed with Arun and to rely instead on a series of smaller hydro projects is likely to be met with considerable skepticism by the private sector. Moreover, the likelihood of continued improvements in macro-economic management and progress in the financial strengthening of NEA would be reduced without the incentive/pressure associated with the challenge of the Arun III project. Overall, Plan B would gain flexibility at the cost of making a low growth, uneven performance scenario more likely. Since the rupees needed to support expanded spending in the social sectors depend above all on the rate of GNP growth and macro-performance (including future power tariff adjustments), this trade-off is not very attractive.

5.32 The environmental/social risks of the AHP have been extensively analyzed, mitigation plans have been developed and a high level of monitoring/assistance with implementation has been provided. Much less is known about the environmental and social risks that would be faced in Plan B. A larger number of sites would be involved and the total length of access roads would be greater. The Bank's Operational Directive (OD 4.00) states that "hydroelectric and other developments should preferably be concentrated on the same rivers if hydrological risks and other circumstances permit, in order to preserve elsewhere a representative sample of rivers in the natural state." The strategy proposed by the Government is in line with the Directive, particularly because the access road included in the Arun III project will also serve to support subsequent hydropower development in the same valley. Given sufficient time and resources, the environmental/social risks of the Plan B investments could of course be similarly investigated and mitigation plans devised. What could not realistically be duplicated, however, is the intensity of supervision and the capacity to respond to problems which has been built into the Arun III project.

5.33 Geographical diversification inherent in Plan B would protect Nepal against the risk of natural disaster. If diversification is measured in terms of the risk of an entire site being taken out of service (e.g. through an earthquake), then the Government's investment program would leave the system as exposed as it is currently, whereas Plan B would reduce this exposure. If diversification is measured in terms of the risk of a generator being lost to service (e.g. through a severe flood), the Government's investment program implies a reduction of risk compared to the present situation, with Plan B bringing an even greater reduction. Since the geology of the Arun III site is quite attractive, especially in comparison with the other options available in Nepal, the technical risks inherent in any single Plan B site would almost certainly be greater, thus somewhat offsetting the advantages of site diversification.

5.34 Comparison of the overall risks of the alternative strategies shows that both have problems requiring careful management. There is simply no low risk way to meet Nepal's power requirements over the next decade or so. Plan B offers some advantages in terms of flexibility and protection against extreme natural disasters. The Government's investment program is more likely to solve the underlying power problem in a timely manner and so is more consistent with the growth and development strategy set forth by the Government and supported by the Bank's country assistance strategy. The Government program is also more in line with the Bank's Operational Directive on the management of environmental risk and has better prospects for effective response if and when environmental problems arise during The course of implementation. On balance, therefore, consideration of risks does not justify overriding the modest cost advantage of the Government's proposed investment program. Indeed, if the affordability and environmental/social risks of the Government's program are well managed in practice, the Government's program should be more consistent with desired growth in social sector spending and with the Bank's environmental guidelines than is Plan B.

5.35 Critics of the Government's investment program have stressed the capacity-building advantages of an alternative strategy. As noted above, there is no conflict between either of the proposed strategies and expansion of micro and mini-hydro investments in Nepal. This is where much of the capacity-building will occur in practice. In addition, under the Government's proposed investment program, Nepali engineers and contracting firms will have opportunities to develop the skills needed for somewhat larger projects through participation in Khimti Khola (60 MW), Kali Gandaki (100 and 40 MW) and the Arun III project itself, where 75% of the man-months of consultant services will be supplied by Nepalis. The additional capacity-building advantage that could be obtained under Plan B by mandating a delay of several years in proceeding with Arun would appear to be modest. A more promising (and less protectionist) approach is to encourage smaller hydro investments through the Hydro Fund, and through NEA and HMG support for additional power purchase agreements.

5.36 Finally, there is the question of ownership as it relates to the prospects for successful implementation of the alternative investment strategies. The Government and NEA are strongly committed to the Arun III project. While there is a vocal domestic opposition to the project, the preponderance of opinion in the Arun Valley, in the domestic press, in professional fora, and in Parliament favors proceeding with it. The three large power tariff increases implemented by Nepal's first democratically elected government were justified as being needed to support the Arun investment and thereby to alleviate chronic power shortages. So too, at least in part, were the recent improvements in macro-economic management and NEA performance (e.g. staff retrenchment). Realistically, therefore, one can expect strong commitment to the implementation of Arun III and strong resistance to implementation of the alternative strategy.

5.37 Strong domestic commitment is, as the Wapenhans Report has shown, critical to successful implementation of Bank and IDA supported projects. Commitment alone does not justify proceeding with a project if it does not pass the standard appraisal tests or poses unacceptable risks. But the Arun III project does pass these tests and the affordability and environmental/social risks are judged to be manageable. This being the case, the strong domestic commitment to the project is a major advantage both for the project itself and for the Government's proposed investment strategy.

D. Risk Mitigation and Management Measures

5.38 To summarize, because of its size and complexity, the Arun III project entails significant risks relating to (a) crowding out of high-priority investments in other sectors, due to cost overruns, worse-than-expected management of the Government budget, or failure of NEA to meet the projected share of its expenses; (b) unforeseen delays in project implementation; and (c) unsatisfactory implementation of the EAP, including the RAP and the ACRP. Project preparation and design has included thorough risk assessment. Risk mitigation and management measures are being put in place as required. The implementation of the project is also subject to exceptionally close monitoring by NEA, HMG and donors.

5.39 With respect to the risk of crowding out other high priority investments, particularly in the social sectors, as noted in paras. 1.40-1.48, HMG has embarked on a macro-fiscal reform program under which the Government will (i) increase revenues through fiscal measures; (ii) adopt a three-year rolling investment program starting in FY95, with a core investment program to protect investments in other high-priority sectors, particularly in the social sectors; and (iii) adopt institutional reforms in the Ministry of Finance and the National Planning Commission to promote better expenditure management, and monitoring.

5.40 As for the risk that NEA may fail to meet the projected share of its expenses, it is clear that the projected financial performance depends essentially on the program to increase tariffs, the projected increase in sales and reduction in losses. Agreements in these critical areas should provide adequate cushion for NEA to meet current operational expenses and debt obligations and to shoulder a larger share of the local cost of future investments. This financial management program should also minimize future equity contributions by HMG to NEA, thereby helping free resources for other sectors (para. 4.29).

5.41 AHP implementation risks are being addressed through an unprecedented set of risk management and mitigation measures (paras. 3.59-3.60). Appointment of a Panel of Experts to review project design and construction, exceptionally thorough geological and geophysical field investigations, the advanced stage of procurement processing by negotiations, and proposed signature of the major works contract prior to credit effectiveness will combine to lower the risk of cost overruns.

5.42 The <u>risk of unsatisfactory implementation of the EAP, including the RAP</u>, is being addressed by provision of adequate financing, by technical assistance to help create necessary institutional capabilities, and by the comprehensiveness of the monitoring of NEA's and MOWR's performance in this regard through (a) reconstituting the POE and expanding it to include adequate environmental expertise, (b) by regular on-site supervision, and (c) a detailed biannual review during project implementation (para. 3.43). In addition, the risk that implementation of the ACRP will be delayed or fail to meet agreed standards is being addressed by (a) arrangements for close monitoring, (b) an agreement that ACRP activities would be carried out well in advance of project works that would affect the families concerned, and (c) arrangements for resolving grievances regarding payment of compensation or other entitlements that are transparent and timely (paras. 3.29 and 3.35).

VI. <u>AGREEMENTS REACHED AND RECOMMENDATION</u>

6.1 During negotiations, HMG agreed:

(a) that there will be annual reviews of project implementation, which will include a review of progress made during the past year in setting into place the framework for power sector development, together with an action plan for the current year (para. 1.24);

(b) on an annual joint review and updating of the macroeconomic framework for public expenditure planning and the resource envelope for the power sector (para. 1.45);

(c) that the TFC will be established and maintained satisfactorily and, will implement by April 1995, the agreed recommendations of a study on the Commission's institutional and operational aspects (para. 2.9);

(d) to reimburse NEA for losses on unprofitable rural electrification schemes (para. 2.18).

(e) on the timing of submitting audited accounts including the Special Account and SOEs (para. 2.24);

(f) to finalize arrangements for the operation of the hydro facility by December 31, 1994, and on the submission of quarterly reports on its operation (para. 3.14);

(g) that the RAP will be carried out as agreed with IDA and an appropriate institutional arrangement maintained including that relevant pre-emptive RAP activities would be carried out in advance of road construction (para. 3.41);

(h) to enter into SLAs for all future on-lending (para. 4.18);

(i) to maintain NEA's current ratio at 1.5 or more (para. 4.25); and

(j) that all public sector projects will be implemented by NEA (para. 4.29).

6.2 During negotiations, HMG and NEA agreed:

(a) that the Performance Agreement will be reviewed annually and agreed recommendations implemented (para. 2.12);

(b) on arrangements for implementing the ACRP (para. 3.30), including that ACRP activities would be carried out sufficiently in advance of project activities that would affect the relevant families (para. 3.35);

(c) on implementing the Environmental Mitigation Plan (para. 3.38);

(d) to carry out public participation and consultation activities and to report annually on such activities starting in June 1995 (para. 3.43);

(e) to establish a satisfactory monitoring, evaluation and reporting system (para. 3.58);

(f) that within six months of project completion, NEA would prepare and furnish to the Donors an Implementation Completion Report (para. 3.58); and

6.3 During negotiations, NEA agreed:

(a) on the carrying out of its Corporate Plan and on the timing of submitting its Plan and Annual Report to the Association (para. 2.13);

(b) to review with IDA its Commercialization Plan study and, based on the review, to submit and implement a Commercialization Plan satisfactory to IDA (para. 2.13);

(c) implement the Accounting Action Plan by September 30, 1995 (para. 2.21);

(d) that unaudited accounts will be submitted to IDA within six months and audited accounts within nine months of the end of each fiscal year (para. 2.24);

(e) implement the Materials Management Program by May 31, 1995 (para. 2.25);

(f) to carry out resettlement and rehabilitation activities in advance of construction (para. 3.35);

(g) on reconstituting and maintaining the POE and its function (para. 3.43);

(h) on operating and maintaining the project facilities (para. 3.43);

(i) on project implementation arrangements (paras. 3.47, 3.48);

(j) on an action plan to reduce consumer receivables (para. 4.6);

(k) on computerization of consumer accounts (para. 4.6);

(l) on limiting accounts receivable (para. 4.12);

(m) on valuation of pension liabilities (para. 4.13);

(n) on implementation of an insurance action plan (para. 4.14);

(o) on disposing of obsolete assets (para. 4.17);

(p) on revaluation of assets (para. 4.17);

(q) to inform IDA about debt servicing to HMG (para. 4.18);

(r) on obtaining IDA approval before undertaking new investments (para. 4.19);

(s) to contribute specified shares of its total investment program (para. 4.20);

(t) to earn a specified rate of return on revalued assets (para. 4.20);

(u) to adjust tariff to reflect fuel cost increases (para. 4.23); and

(v) on ensuring satisfactory debt service coverage (para. 4.24).

6.4 Prior to credit effectiveness:

(a) HMG will finalize a public expenditure program satisfactory to IDA (para. 1.45);

(b) HMG will revise the TFC's regulations to ensure that electricity tariffs and other charges are set in accordance with agreed financial covenants (para. 2.9);

(c) the Agreement Amending the DCA for the Access Road project will be effective (para. 3.8);

(d) the effectiveness conditions of the ADB and KfW cofinancing agreements will be fulfilled other than those related to the effectiveness of the DCA (para. 3.46);

(e) Confirmation of all cofinancing needed for the project (para. 3.46);

(f) the civil works contract will be awarded (para. 3.47); and

(g) HMG and NEA will execute an SLA satisfactory to IDA for onlending the proceeds of the IDA credit (para. 4.18).

6.5 Prior to effectiveness of the amended Development Credit Agreement for Cr. 2029-NEP, NEA will sign the contract for the combined civil works lot (C1/C3), and HMG and NEA will execute a Subsidiary Loan Agreement satisfactory to IDA for onlending the proceeds of IDA credit for the Access Road Project (para. 3.8).

6.6 With the above agreements reached, the proposed Project forms an appropriate basis for amendment of Credit 2029-NEP of SDR 24.4 million (US$34.3 million equivalent) for the Arun III Access Road Project and for an IDA credit of SDR 99.5 million (US$140.7 million equivalent) on standard IDA terms with a maturity of 40 years to His Majesty's Government of Nepal.

NEPAL
ARUN III HYDROELECTRIC PROJECT
ENERGY BALANCE 1992/93
000 toe

SUPPLY	FUEL WOOD	AGRI RESID.	DUNG	TOTAL N-COMM.	COAL	<--PETROLEUM PRODUCTS--> LPG	MOTOR SPIRIT	ATF	KERO-SENE	HIGH SPEED DIESEL	LIGHT DIESEL	FUEL OIL	NON-ENERGY	TOTAL PETRO. PROD.	ELECT.	TOTAL COMMER.	GRAND TOTAL ENERGY
PRIMARY																	
Primary Production	4312.20	943.94	516.42	5772.56	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.43	70.43	5842.99
Imports	0.00	0.00	0.00	0.00	65.12	8.90	32.12	29.78	163.17	193.69	1.78	20.98	1.77	452.19	6.94	524.25	524.25
Exports & Bunkers	0.00	0.00	0.00	0.00	0.00	0.00	0.08	0.48	5.63	2.83	0.00	0.00	0.00	9.02	5.01	14.03	14.03
From Stocks	0.00	0.00	0.00	0.00	0.00	0.00	6.32	1.22	6.34	14.86	0.00	0.10	0.00	28.84	0.00	28.84	28.84
Total Primary Supply	4312.20	943.94	516.42	5772.56	65.12	8.90	38.36	30.52	163.88	205.72	1.78	21.08	1.77	472.01	72.36	609.49	6382.05
TRANSFORMATION																	
Thermal Power Generation	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	-13.95	0.00	-13.95	3.99	-9.96	-9.96
Energy Sector Use and Loss					0.00		0.00	0.00						0.00	-19.39	-19.39	-19.39
Total Final Supply	4312.20	943.94	516.42	5772.56	65.12	8.90	38.36	30.52	163.88	205.72	1.78	7.13	1.77	458.06	56.96	580.14	6352.70
Residential	4201.64	937.16	516.42	5655.22	0.00	5.79	0.00	0.00	117.99	0.00	0.00	0.00	0.00	123.78	22.72	146.50	5801.72
Industrial	92.63	6.78	0.00	99.41	57.30	0.00	0.00	0.00	1.64	30.86	0.89	3.57	0.00	36.96	22.80	117.06	216.47
Commercial	17.93	0.00	0.00	17.93	7.16	3.11	0.00	0.00	44.25	0.00	0.89	3.57	0.00	51.82	9.51	68.49	86.42
Transport	0.00	0.00	0.00	0.00	0.65	0.00	38.36	30.52	0.00	133.72	0.00	0.00	0.00	202.60	0.13	203.38	203.38
Agriculture	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.14	0.00	0.00	0.00	41.14	0.98	42.12	42.12
Others	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.82	0.82	0.82
Non-Energy	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.77	1.77	0.00	1.77	1.77
Total Consumption	4312.20	943.94	516.42	5772.56	65.11	8.90	38.36	30.52	163.88	205.72	1.78	7.14	1.77	458.07	56.96	580.14	6352.70
% of Total Energy	67.88%	14.86%	8.13%	90.87%	1.02%	0.14%	0.60%	0.48%	2.58%	3.24%	0.03%	0.11%	0.03%	7.21%	0.90%	9.13%	100.00%

Source: Water and Energy Commission Secretariat

ANNEX 1.1

ANNEX 1.2

NEPAL
Arun III Hydroelectric Project
Fuel Prices, FY1975 - 1994 a/

FY	Gasoline		Diesel		Kerosene		Coal		Fuelwood b/c/		Electricity d/		Urban
	NRs/l	Index	NRs/l	Index	NRs/l	Index	NRs/t	Index	NRs/t	Index	NRs/l	Index	Index e/
1975	6.00	100	2.00	100	2.00	100	458.70	100	134.00	100	0.23	100	100
1980	9.30	155	5.65	283	5.15	258	458.70	100	270.00	201	0.44	191	
1981	9.30	155	5.65	283	5.15	258	-	-	370.00	276	0.52	226	148
1982	9.30	155	5.65	283	4.90	245	-	-	450.00	336	0.52	226	163
1983	9.30	155	5.65	283	4.90	245	-	-	450.00	336	0.55	239	187
1984	9.30	155	5.65	283	4.90	245	-	-	450.00	336	0.80	348	198
1985	10.90	182	7.50	375	5.90	295	643.70	140	550.00	410	0.84	365	206
1986	10.90	182	7.50	375	5.75	288	-	-	550.00	410	1.16	504	239
1987	12.90	215	7.50	375	5.75	288	-	-	550.00	410	1.18	513	271
1988	12.90	215	7.50	375	5.75	288	-	-	550.00	410	1.29	561	301
1989	12.90	215	7.50	375	5.75	288	-	-	950.00	709	1.39	604	325
1990	19.00	317	9.10	455	6.90	345	-	-	950.00	709	1.38	600	356
1991	20.00	333	10.00	500	8.50	425	-	-	950.00	709	1.45	629	391
1992	25.00	417	10.00	500	8.00	400	3556.00	775	950.00	709	1.98	861	473
1993	29.00	483	11.50	575	9.75	488	3566.00	775	2250.00	1679	2.50	1087	509
1994	29.00	483	11.50	575	9.75	488	-	-	-	-	3.17	1378	-

a/ To current Rupees

b/ Sale of fuelwood in the Kathmandu Valley by TCN and precursor, FCN

c/ Market price in Kathmandu Valley is 2,500 - 3,500 NRs/ton

d/ Average FY94 price per kWh increased from Rs 2.96 to Rs 3.88.

e/ Index, Economic Survey, FY93, Ministry of Finance

Sources:

(a) Commercial Energy and Pricing Study, Kathmandu, WECS

(b) Nepal: Issues and Options in the Energy Sector, Washington, D.C., UNDP/World Bank, Report No. 4474, August 1983

(c) Appraisal of the Seventh Power Project in Nepal. Asian Development Bank, Document #R176-89, Manila, November 1989

(d) Information supplied by the Nepal Oil Corporation and the Timber Corporation

(e) Economic Survey - FY92/93; HMG Ministry of Finance, 1993

(f) Nepal: The Equitable and Efficient Energy Pricing Study. ADB T.A. No. 1394NEP, deLucia & Associates, Inc., Cambridge, MA, Sept. 1993

WASHINGTON, D.C. MAY 16, 1994

ANNEX 1.3

NEPAL
ARUN III HYDROELECTRIC PROJECT
PAST AND PRESENT TARIFFS

	OLD TARIFF		TARIFF EFFECTIVE FROM 14-Mar-94	
CATEGORY A: DOMESTIC CONSUMERS				
A.1 Minimum Monthly Charges:				
Meter Capacity	Minimum Charge (NRs.)	Exempt (kWh)	Minimum Charge (NRs.)	Exempt (kWh)
Upto 5 ampere	30.00	20	50.00	20
6-30 ampere	90.00	40	130.00	40
31-60 ampere	210.00	80	290.00	80
Three phase supply	570.00	200	770.00	200
				Rs./unit
A.2 Energy Charge (in excess of exempt units)			(Upto 20 units)	2.50
Upto 250 units	Rs.3.00 per unit		21-250 units	4.00
Above 250 units	Rs. 4.50		251 and above	6.20
CATEGORY B: TEMPLES				
Minimum monthly charge	Rs. 39 (20 units exempt)			
Energy Charge	Rs. 1.95 per unit (units in excess of exempt units)			2.80
CATEGORY C: INDUSTRIAL				
Sub-category	Demand Fee (Rs./kW)	Energy Charge (Rs./Unit)	Minimum Charge (Rs./kVA)	
C.1 Low Voltage (400/230 volt)				
Cottage	10.00	2.20	16.00	3.30
Small Industry	40.00	3.90	32.00	4.00
C.2 Medium Voltage (11&33 volt)	90.00	2.30	72.00	3.80
C.3 High Voltage (above 66 kV)	80.00	1.90	64.00	2.80
CATEGORY D: COMMERCIAL				
D.1 Low Voltage	110.00	3.90	88.00	4.70
D.2 Medium Voltage	100.00	3.65	80.00	4.60
CATEGORY E: NON-COMMERCIAL				
E.1 Low Voltage	55.00	3.80	64.00	4.60
E.2 Medium Voltage	50.00	3.60	50.00	4.70
CATEGORY F: IRRIGATION				
F.1 Low Voltage				
Upto 10 kVA	10.00	1.15	8.00	2.00
Above 10 kVA	15.00	1.50	12.00	2.20
F.2 Medium Voltage	20.00	1.40	16.00	2.20
CATEGORY G: WATER SUPPLY				
G.1 Low Voltage	66.00	1.30	53.00	2.20
G.2 Medium Voltage	60.00	1.20	48.00	2.20
CATEGORY H: TRANSPORTATION				
H.1 Medium Voltage	60.00	1.50	64.00	2.20
CATEGORY I: STREET LIGHT				
I.1 Street Lights with Meter	-	2.30	-	2.80
I.2 Without Meter	28.00	-	100.00	-
CATEGORY J: TEMPORARY SUPPLY				
J.1 With Meter	-	6.00	-	7.50
J.2 Without Meter	2256.00	-	-	-
Temple	-	-	-	2.80

NEPAL

ARUN III HYDROELECTRIC PROJECT

Affordability Analysis

Background

1. Arun III (402 MW) hydropower project (AHP) is the main and largest physical investment being considered under the Government's Eighth Plan (EP) as an essential part of efforts to accelerate economic growth and development. Because of the size and site conditions of the project, AHP will be implemented in two phases. The first phase (201 MW) is to be completed by the year 2002; its financing claims will dominate the public investment program in the nineties. Under the revised resource envelope of the Policy Framework Paper adopted by Nepal in FY94 and extended to the end of the decade, which is adopted for the affordability analysis, power will absorb an average 30% (15% of local resources and 40% of foreign resources) during FY94-FY2000, more than double the level of the eighties; and AHP alone will account for about half of the power sector resource claims. Financing for power will be most needed during the peak implementation phase (FY96-FY99) when the sector will absorb an average of 36% and AHP close to 20% of projected development resources.

Foreign and Local Financing Issues

2. AHP would be affordable in terms of foreign financing. While its implementation will be accompanied by a fall in foreign reserves from the equivalent of over 8 months of imports presently to about 6.5 months by FY97 or an average of 5-6 months a year during the second half of the nineties, the initial strong reserves position and the availability of soft aid is expected to provide adequate coverage for the foreign costs of AHP.[1/] Thus, the affordability analysis focusses on local currency, which is emerging as a main constraint on development financing. The contribution of local currency (which comprises revenue surplus over regular expenditures, domestic borrowing and counterpart local currency generated from non-project aid) to development financing was 34% in FY90-FY92 compared to 50% in the eighties. This affects the financing of recurrent costs and the productivity of completed projects as well as local resource support to absorb new aid effectively. The tightness of the local funds situation is reflected in aid disbursements, which have declined from over 9% of GDP in FY89 to 7.7% currently. At the same time, priority social sector activities, which are being expanded as a critical element of Nepal's overall economic growth and development efforts use local currency resources intensively, about two and half times as much as infrastructure for one percent growth in each type of expenditures. Thus, given the large and lumpy nature of AHP, the analysis assesses the fiscal

1/ Based on reduced private capital inflows to under US$100 million a year by FY97; minimal spill-over effects of the expanded expenditures; average export volume growth of about 10 percent which is about half of recent average performance; increased responsiveness of imports to recent trade liberalization with import elasticity of 1.3 for non-aided imports, which is higher than 0.9 during the pre-liberalization period; and the ratio of aided imports to external financing rising from the historical level of about 60 percent to about 70-80 percent average during the peak implementation phase of Arun.

feasibility of AHP in terms of its potential to displace other important development projects, especially in the social sectors and rural infrastructure. The analysis indicates that in the base case AHP would be affordable in terms of local financing. Enough budgetary resources would be available to support growth in the social sectors at a rate of 8% in real terms, which is considered appropriate for Nepal's development goal and its ability to spend money in these sectors effectively. The base case assumes substantive reform measures to improve fiscal management, especially in the areas of revenue mobilization, expenditure prioritization, institutional reform and maintenance of the current level of electricity tariffs in real terms in order to cover AHP's local financing requirement of 0.14% of GDP. However, if NEA's finances were to improve in line with Case B of the financial analysis presented in Section IV, and under the assumption that the additional resources thus made available to the government are divided among sectors in accordance with their existing proportions in public expenditures, it would be possible to support growth in the social sectors at a rate of 9.5% in real terms is the base case.

3. The principal objectives of reform measures are to (i) pursue responsible fiscal policies that will provide a stable macro-fiscal environment for productive private sector investments, (ii) provide adequate recurrent cost financing to utilize existing assets efficiently and (iii) channel adequate resources to finance priority development activities. These measures required to support AHP and other important development activities adequately are consistent with the reform agenda of the PFP for FY94-FY96 already agreed with the Government and extended to the year 2000 for the purpose of the affordability analysis. First, revenue mobilization would be enhanced through measures directed at revamping tax administration, simplifying sales taxes, expanding the income tax net and introducing a VAT. These measures would raise average revenues by the equivalent of 0.5%-0.6% of GDP during FY94-FY96 and by 0.3% to the end of the decade. This revenue profile represents a significant effort compared to actual performance of 0.15%-0.2% of GDP achieved in the recent past; however, the government has already made a good start by initiating revenue reforms in the FY94 budget, with the revenue to GDP ratio rising by 0.5%-0.6% of GDP during the FY94 budget cycle. Second, development expenditures would be re-oriented to focus resources on the high rate of return activities and curb low priority projects. Regular expenditure growth would be restrained and would increase to 8.6% of GDP in the year 2000 from 8.0% in FY92-FY93. Reduction of staff in unsuitable positions, selective hiring in areas of staff shortages and limits on real wage increases will be expected to contain regular expenditure growth while allowing non-wage recurrent expenditure financing for completed investments. Third, domestic borrowing would be prudent in line with the PFP and restricted to an average 1.1% of GDP annually in gross terms. Fourth, the main institutions responsible for development management would be strengthened to improve the screening, implementation and evaluation of projects to raise their productivity. Under this scenario, GDP growth is assumed to be 4.2%-4.5%, which is consistent with performance under recent adjustment programs, but better than the long-term growth rate of 3.5%. No significant cost overruns beyond those provided in the contingencies for AHP are envisaged.

Tables 1a and 1b show the summary of the main assumptions and the macroeconomic outlook underlying the analysis during the period.

Reform Initiatives

4. The Government has already taken steps to begin improving fiscal and overall economic management with encouraging results. Performance on the PFP has been satisfactory and on schedule. A ceiling on power sector investments has been defined, based on an overall resource envelope consistent with the PFP as well as the spending targets in the priority sectors. The power sector resource envelope will be reviewed annually and power sector investments adjusted accordingly to make them consistent with the PFP and macroeconomic objectives. Revenue measures to enhance local resource mobilization were adopted in the FY94 budget. In this regard, specific steps were taken to revamp tax administration by instituting a revenue service and raising the quality of staff by adopting new personnel policies and training. The rate structure of customs duties, sales taxes and excises were simplified to limit tax evasion and promote compliance. The income tax base has been expanded by adding new payers to the income tax role and treating income from different sources similarly. The Government also adopted liberalization measures to promote private sector expansion and growth, which is critical for revenue performance. For example, import restrictions have been relaxed to facilitate access to imported inputs, and the exchange rate has been unified with full convertibility on the current account to encourage exports. Also, price controls on major products, including petroleum products, power and water have been relaxed to strengthen self-financing, expand services and limit the subsidy burden on the budget. The overall results of the tax measures are encouraging, as revenues increased to 11.1% of GDP in FY94, compared to 10.6% in the recent period FY92-FY93.

5. Actions have been taken to begin improving the quality of the development expenditure program and its management. The entire expenditure program, including the power sector, has been reviewed to make it consistent with development objectives. Initial prioritization measures were adopted in a core program in the FY94 budget, focussing resources on the priority activities in power, social sectors and rural infrastructure, which together accounted for 44% of the FY94 budget. Also, the fund release process has been reformed to ensure timely fund release for the core projects. Fund allocations for the social sectors and rural infrastructure were significantly increased in FY94, and low priority activities are being curbed. An important aspect of expenditure reform is to transfer appropriate activities to the private sector, reduce the role of the state in those activities and focus public resources on high priority projects and programs. For example, allocations for manufacturing industries were reduced by 50% as privatization is being emphasized, and subsidies for chemical fertilizers were reduced by 40%. Other measures include leasing of state farms to the private sector; phasing out state monopoly control in various activities, including import of chemical fertilizers and domestic aviation; and liberalizing private investment licensing requirements in power and other sectors. Institutional reforms have also been initiated by establishing the nuclei of project screening and expenditure reporting units to help improve the implementation

of programs. In the case of NEA, power tariffs were more than doubled over the last two and half years, and the management has been restructured to improve performance and strengthen its financial base for self-financing.

6. All these measures contributed to improvements in fiscal management and the overall macroeconomic situation. With market-determined exchange rates, improved revenue performance and tight expenditure programming, domestic borrowing has declined to under 2% of GDP from over 3% in the previous year. This has been accompanied by reduced inflation and a strengthened balance of payments. But much more remains to be done, and in that regard, there are effectiveness conditions to support further reforms. The Government has completed work required to prioritize its public expenditure program. A preliminary three-year rolling expenditure program has been prepared; and following discussions within line ministries, this work is expected to be finalized in the context of the FY95 budget. The multi-year rolling expenditure plan would provide a stronger link between the annual budgets and the five-year plans and make it easier to program activities, including recurrent financing requirements over a broader horizon. The Government plans to announce in the FY95 budget that a limit will be placed on new project starts. A number of projects are being terminated or cancelled as part of the expenditure prioritization, and it is understood that similar actions would be taken in FY96.

Risks

7. The extended PFP scenario is subject to a number of risks. The most important - for the purpose of affordability analysis - are slippages in macro-economic management, a slowdown in GNP growth and cost overruns in the implementation of the Arun III project itself. The approach used in the affordability analysis is to estimate the local currency shortfall which would arise under various adverse circumstances and then to consider what corrective measures are available. While some reduction in the growth rate of spending for the priority social sectors would be acceptable in these adverse circumstances, there should be a high probability that corrective measures would permit a growth rate of not less than 5% per annum.

8. While current macroeconomic performance, as described above, is in line with the PFP or base case scenario, there is a risk that once the large power sector investments (i.e. Arun III and Kali Gandaki) are firmly committed, slippages could occur. This possibility has been examined by considering a scenario in which the average increase in the revenue-to-GDP ratio if 0.2% per annum rather than the 0.4% per annum assumed in the extended PFP scenario. Regular expenditures have also been assumed to grow 0.3% per annum faster than in the PFP scenario while at the same time no significant expenditure prioritization occurs. The possibility of slower than projected GDP growth - at 3.0% rather than the 4.5% of the PFP - has also been taken into account. Indeed, macro-economic slippages and poorer than forecast GDP growth are assumed to be positively correlated.

9. All of these adverse assumptions reduce the availability of rupee resources. With respect to the demand for rupee resources the main risk is an

overrun in the costs of AHP. Significant contingencies for both price and physical risks are already included in the financing plan, and special measures have been incorporated into the project to monitor implementation and to manage overrun risks (cf. Section III N and P above). Nevertheless, past Bank experience with hydro projects suggests that significant cost overruns in excess of the contingencies provided can and do occur. Accordingly, the possibility of both a 20% and a 40% cost overrun has been considered.

10. The growth rates of the social sectors corresponding to a number of combinations of adverse events have been calculated using the macroeconomic model developed for the public expenditure review and reported in the Country Economic Memorandum "Nepal: Fiscal Restructuring and Public Resource Management in the Nineties" and taking into account the additional resources made available from NEA under Case B of the financial analysis presented in Section IV. Sensitivity analysis shows that if macroeconomic performance slips and GNP growth slows, the growth of social sector expenditures would slow to a little over 5.5%. If, additionally, AHP were to experience a cost overrun of 20% (over and above the 14% physical contingencies already built into the AHP financing plan), the growth rate would decline by another 1%. Turning to the risk analysis, if is assumed - for sake of illustration - that there is roughly a 50% probability of macroeconomic slippage, a 50% probability of significant cost overrun (roughly evenly divided between a 20% overrun and a 40% overrun), and a 60% probability of GNP growth at 4.5%, with a 30% probability of GNP growth at 3.0%, there is a 70% probability that growth in social sector spending would exceed 6 percent per annum and an 85% probability that it would exceed 5% per annum.

11. A percentage point increase in the growth rate for the social sectors would require additional local currency of about 0.08% of GNP. On this basis, it is calculated that the average additional local currency required annually to raise the growth rate of social sector spending to 6% is less than 0.03% of GNP. The corresponding figure required to attain a growth rate of social sector spending of 5% is less than 0.02% of GNP. It may be noted that the latter figure is equivalent to less than 0.2% of annual aid disbursements to Nepal. The risk of social sector expenditure growth being constrained below 5% is therefore judged to be very small and hence the affordability risk is deemed to be manageable.

Table 1.a: NEPAL: SUMMARY ECONOMIC AND BUDGETARY STATISTICS
(Rs Million) - Base Case Scenario

	FY90	FY91	FY92	FY93/a	FY94/b	FY95	FY96	FY97	FY98	FY99	FY2000	FY94-00
Nom GDP	91008	103949	126186	144959	166262	185906	205928	228106	251948	278281	307367	231971
Real GDP	91008	95158	97109	99897	106090	110864	115853	121067	126151	131450	136971	121207
GDP Growth (%)	8.0	4.6	2.1	2.9	6.2	4.5	4.5	4.5	4.2	4.2	4.2	4.6
GDP Deflator (%)	10.4	9.2	19.0	11.7	8.0	7.0	6.0	6.0	6.0	6.0	6.0	6.4
Revenue/c	9288	10731	13511	15148	18400	21565	25123	28513	32229	36566	41353	29107
Total Expenditure/c	19669	20277	26418	32406	32978	40261	50143	54745	60447	67873	74703	54450
Regular/d	6672	7570	9905	12001	12700	14550	16137	18933	21164	23654	26434	19082
Development/d	12997	12707	16513	20405	20278	25711	34006	35813	39284	44219	48269	35368
Deficit	-10381	-9546	-12907	-17258	-14578	-18696	-25020	-26232	-28218	-31307	-33349	-25343
Foreign Financing	7935	8423	8461	12364	12758	16546	22784	23723	25447	28246	29968	22782
Grants	1975	2701	1644	3311	3258	4090	4736	5246	5795	6261	6916	5186
Loans	5960	5722	6817	9053	9500	12456	18048	18477	19652	21984	23053	17595
Domestic Borrowing/e	2447	1123	4445	4894	1820	2150	2236	2509	2771	3061	3381	2561
					Percent of GDP							
Revenue/c	10.2	10.3	10.7	10.4	11.1	11.6	12.2	12.5	12.8	13.1	13.5	12.4
Total Expenditures/c	21.6	19.5	20.9	22.4	19.8	21.7	24.3	24.0	24.0	24.4	24.3	23.2
Regular/d	7.3	7.3	7.8	8.3	7.6	7.8	7.8	8.3	8.4	8.5	8.6	8.2
Development/d	14.3	12.2	13.1	14.1	12.2	13.8	16.5	15.7	15.6	15.9	15.7	15.1
Deficit	-11.4	-9.2	-10.2	-11.9	-8.8	-10.1	-12.1	-11.5	-11.2	-11.2	-10.9	-10.8
Foreign Financing	8.7	8.1	6.7	8.5	7.7	8.9	11.1	10.4	10.1	10.2	9.8	9.7
Grants	2.2	2.6	1.3	2.3	2.0	2.2	2.3	2.3	2.3	2.3	2.3	2.2
Loans	6.5	5.5	5.4	6.2	5.7	6.7	8.8	8.1	7.8	7.9	7.5	7.5
Domestic Borrowing/e	2.7	1.1	3.5	3.4	1.1	1.2	1.1	1.1	1.1	1.1	1.1	1.1
Memo Items (% of GDP)												
Revenue Surplus	2.9	3.0	2.9	2.2	3.4	3.8	4.4	4.2	4.4	4.6	4.9	4.2
Public Savings	-3.7	-3.6	-2.7	-4.3	-1.9	-0.9	0.4	-1.0	0.5	0.2	-1.3	-0.6
Local fund Gap	--	--	--	-0.0	0.1	-2.3	-2.4	-3.1	-2.4	-2.6	-2.9	-2.2

/a Preliminary Expenditures estimates
/b Revised mid-year budget
/c FY94 revenues include additional measures equivalent to Rs. 250 million based on mid-year budget review
/d In FY93, regular expenditures include a third of net freeze account and development expenditures includes two-thirds
/e Includes cash balances; these were substantial in FY92 (Rs. 2366 million) and FY93 (Rs. 2048 Million)

Table 1.b: NEPAL: MACROECONOMIC FRAMEWORK
Base Case Scenario

	FY90	FY91	FY92	FY93	FY94	FY95	FY96	FY97	FY98	FY99	FY2000
Macroeconomic Balances (Percent of GDP)											
GDP	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
Resource Balance	9.9	10.6	9.8	8.5	9.6	10.5	11.2	10.0	10.5	10.3	11.2
Resource Availability	109.9	110.6	109.8	108.5	109.6	110.5	111.2	110.0	110.5	110.3	111.2
Consumption	92.0	93.3	90.5	90.3	91.6	90.9	87.8	88.4	87.0	86.8	89.6
Private	80.6	81.7	80.5	79.7	82.1	81.4	77.9	78.4	76.6	76.1	78.6
Public	11.4	11.6	10.0	10.6	9.6	9.5	9.9	10.0	10.4	10.7	11.0
Gross Investment/b	17.9	17.3	19.3	18.2	18.0	19.6	23.4	21.5	23.5	23.4	21.6
Private/c	10.2	11.7	11.8	10.6	11.1	10.5	10.8	11.0	11.8	12.0	12.0
Public/b	7.7	5.6	7.5	7.6	6.9	9.1	12.6	10.5	11.7	11.4	9.6
O/W Arun	--	--	--	--	0.7	1.5	2.2	2.3	2.1	2.4	1.7
Domestic Savings	8.0	6.7	9.5	9.7	8.4	9.1	12.2	11.6	13.0	13.2	10.4
Public/b	-3.7	-3.6	-2.7	-4.3	-1.9	-0.9	0.4	-1.0	0.5	0.2	-1.3
Private/c	11.9	10.1	12.1	13.9	10.8	10.4	12.1	11.7	11.9	12.2	12.9
Exports/GDP	5.7	7.1	10.9	12.3	12.9	13.2	13.4	13.9	14.5	15.1	15.8
Imports/GDP	20.2	22.4	25.3	27.2	28.0	29.1	30.0	29.3	30.4	30.8	30.3
Curr Acc/GDP	-9.7	-10.8	-9.3	-8.9	-9.0	-10.1	-10.9	-10.8	-11.1	-11.1	-10.0
External Balance (US$ Million)											
Exports	181	235	306	365	439	500	556	620	691	771	859
Imports	642	737	712	806	949	1102	1243	1303	1450	1569	1653
Trade Balance	-461	-502	-406	-441	-510	-602	-687	-683	-759	-799	-794
Invisibles, Net	152	148	145	178	204	218	237	205	229	234	251
Curr Acc Balance	-309	-354	-261	-263	-306	-384	-450	-478	-530	-564	-543
Capital Account Balance	405	402	383	391	417	424	504	472	483	510	516
Grants	38	54	38	68	66	83	95	102	110	115	123
Loans, Net	207	200	163	121	165	219	323	279	283	306	303
Gross	232	227	194	155	194	254	363	360	371	403	409
Amortization	25	27	31	33	29	35	40	81	88	97	106
Miscellaneous Capital/a	160	148	182	202	186	122	85	90	90	90	90
Overall Balance	96	48	122	128	111	40	54	-7	-47	-54	-27
Reserves	411	454	568	706	817	858	911	905	858	804	777
Reserves (months of Imp)	6.4	6.1	7.0	8.4	8.3	7.5	7.0	6.7	5.7	4.9	4.5

/a Includes private capital inflows, errors and ommissions.
/b Adjusted to be consistent with fiscal accounts.
/c Includes errors.

ANNEX 2.1

NEPAL
ARUN III HYDROELECTRIC PROJECT
EXISTING GENERATING PLANTS ON THE INTERCONNECTED SYSTEM

Power Station	Generating Installed (MW)	Capacity Available Dry Season	Energy Capacity Design[1]	Generating (GWh) Available
A. Hydro				
Sunkoshi	10.1	10.0	71.5	50.0
Gandak	15.0	6.0	87.5[2]	38.0
Trishuli	21.0	18.0	269.3[3]	269.3
Devighat	14.1	14.0		
Kulekhani I	60.0[4]	60.0	230.0	230.0
Kulekhani II	32.0	28.0		
Marsyangdi	69.0	69.0	460.0	425.0
Misc. small hydro	6.1	4.0	20.0	20.0
TOTAL Hydro Interconnected System	227.3	209.0	1138.3	1032.3
B. Purchase				
Andhi Khola Hydro	5.1	3.0	44.4	27.0
India	24.0	22.0	96.4[5]	96.0
TOTAL Purchase	29.1	25.0	140.8	123.0
TOTAL Hydro and Purchase Interconnected System	256.4	234.0	1279.1	1155.3
C. Thermal				
Hetauda	13.0	11.5		
Mahendra Nagar	1.0	1.0		
Duhabi	26.0	24.0		
TOTAL Thermal Interconnected System	40.0	36.5		
TOTAL AVAILABLE CAPACITY	296.4	270.5		

Source: NEA

August 9, 1994

1/ Design capacity is based on average hydrology, and during a particular year, the generating capacity may be higher or lower than the design capacity.

2/ The Gandak plant has no spillway resulting that only a maximum of two of the three units may be operated safely to avoid the danger of flooding the powerhouse.

3/ Includes combined energy of the upgraded Trishuli and Devighat projects that are operated in tandem.

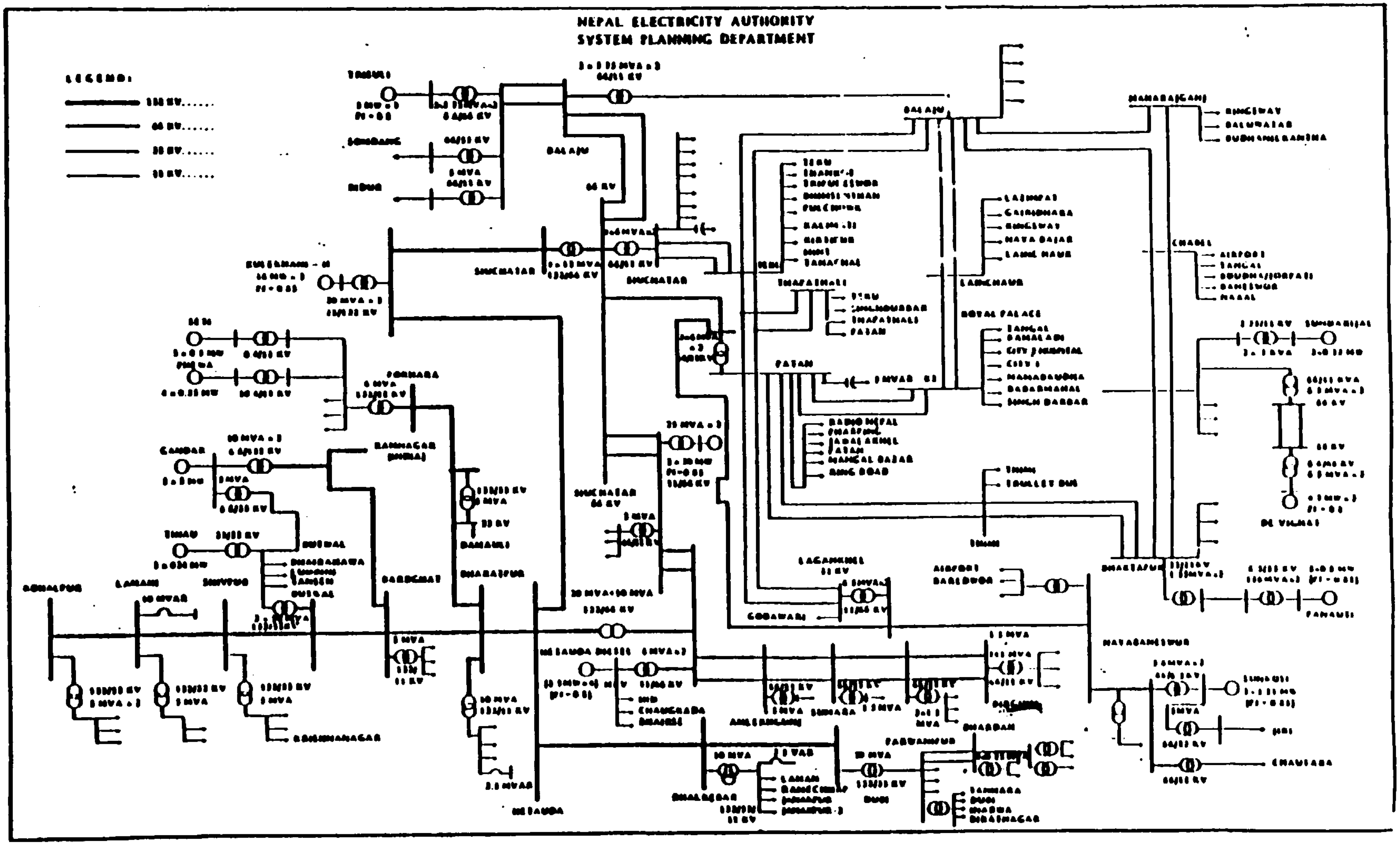
4/ Kulekhani I and II share a common hydraulic system and can only be operated in "tandem" as (60 MW + 32 MW = 92 MW)

5/ 50% load factor

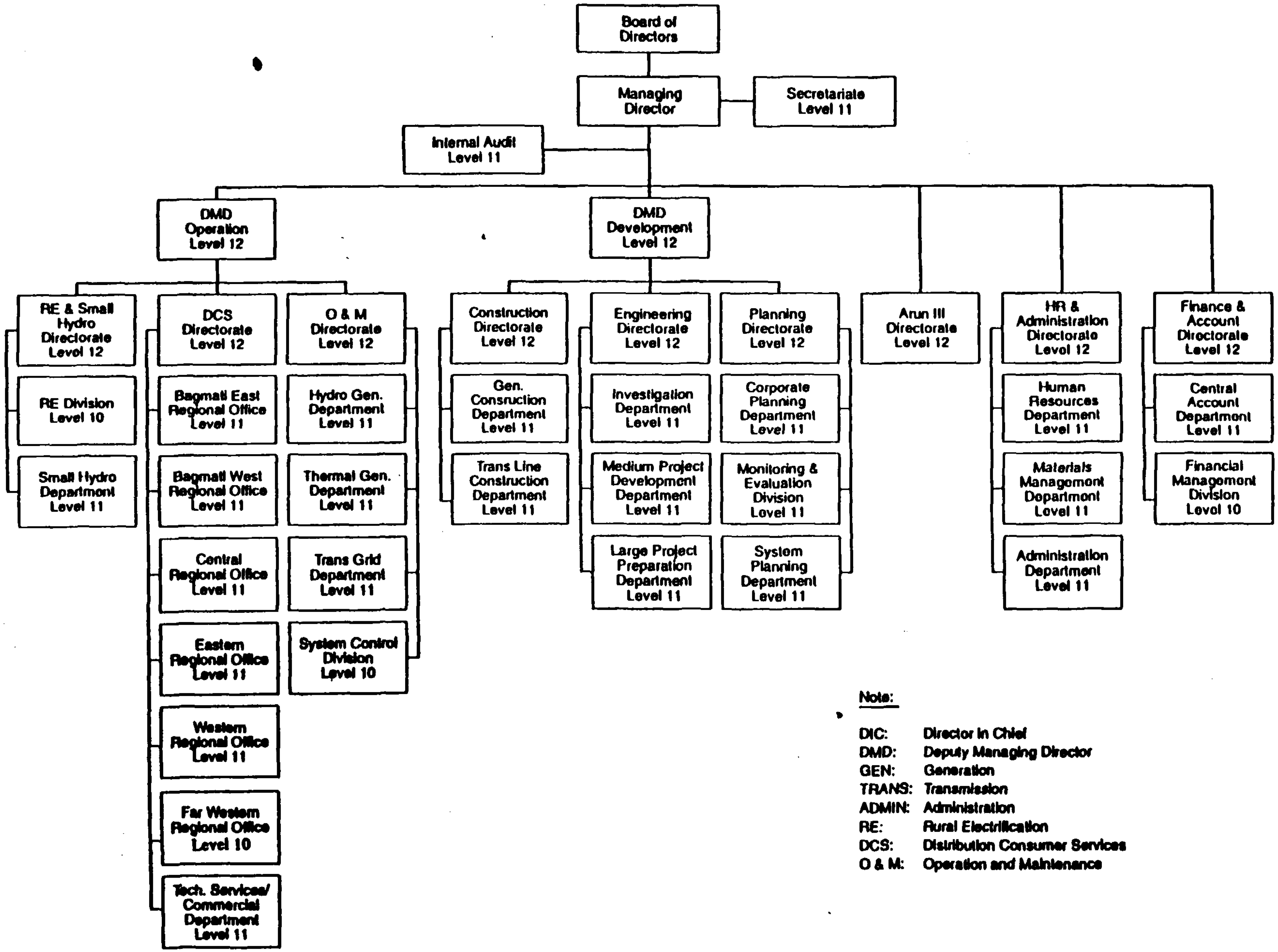
NEPAL

ARUN III HYDROELECTRIC PROJECT

NEA TRANSMISSION SYSTEM



NEPAL ELECTRICITY AUTHORITY
Approved Corporate Structure



Note:

DIC: Director in Chief
DMD: Deputy Managing Director
GEN: Generation
TRANS: Transmission
ADMIN: Administration
RE: Rural Electrification
DCS: Distribution Consumer Services
O & M: Operation and Maintenance

ANNEX 2.3

ANNEX 2.4

NEPAL ELECTRICITY AUTHORITY

ACTION PLAN FOR IMPLEMENTING THE REVISED ACCOUNTING SYSTEM

SL NO.	ACTIVITY	RESPONSIBILITY	TARGET DATE	REMARKS
1.	Review the existing accounting system and based on it, revise and update the existing accounting manuals (as discussed)	AFF	March 31 1994	Completed
2.	Review and design draft financial management system manuals	A FF	August 15, 1994	
3.	Submit financial accounting manuals	AFF	August 15, 1994	
4.	Translate the manuals into Nepalese	TRU/NEA		
	- Financial accounting system		September 15, 1994	
	- Financial management system (after approval by NEA of the manuals)		October 15, 1994	
5.	Assess requirement of accountants in different budget centers	AFF/NEA	August 15, 1994	
6.	Arrangement of accountants	NEA	September 30, 1994	
7.	Printing of new account books, ledgers and forms (for training and implementation at selected units)	NEA	October 31, 1994	
8.	Training to accounts staff			
	- Prepare training material (in English)	AFF	October 31, 1994	
	- Translate Training material (into Nepalese)	TRU	November 30, 1994	
	- Provide training to accounts staff (20 training courses)	AFF/TRU	December 1994 - April 1995	
9.	Implementation of accounting manuals (25 locations to be visited)	AFF/TRU	September 1995	
10.	Further implementation assistance beyond Sept. 1995 will be provided as and when required by NEA (Total involvement of 100 man days has been provided for)	AFF/TRU NEA		

Keys: AFF: A.F. Ferguson & Co., Management Consultancy Division, India
TRU: T.R. Upadhya & Co., Chartered Accountants (A local firm in Nepal)

Washington, D.C.
Date: June 21, 1994

NEPAL ELECTRICITY AUTHORITY
ACTION PLAN FOR IMPLEMENTATION OF MATERIALS MANAGEMENT PROGRAM

SL.NO	ACTIVITIES	1994									1995							
		APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG
1	SELECT AND APPOINT DIR. MATERIALS MGMT																	
2	SELECT OTHER MATERIAL MANAGEMENT PERSONNEL																	
3	INDUCTION OF NEW RECRUITS																	
4	DEPARTMENT STARTS FUNCTIONING																	
5	PREPARATION OF FORMS, INFORMATION																	
	FORMATS, SCHEDULES, ETC.																	
6	COMPILATION OF DATA FOR ABC ANALYSIS,																	
	SUPPLIERS DIRECTORY, ETC BY NEA																	
7	COMPILATION OF SUPPLIERS DIRECTORY																	
	AND ABC ANALYSIS																	
8	INVENTORY COMMITTEE STARTS FUNCTIONING																	
9	PREPARATION OF QUALITY STANDARDS, INSPECTION																	
	SCHEDULE, COMPILATION OF MANUALS, ETC.,																	
	BY QUALITY CONTROL CELL																	
10	DATA COLLECTION FOR CODIFICATION BY NEA																	
11	COMPLETION OF CODIFICATION																	
12	SETTING UP OF PURCHASE DEPT																	
13	SETTING UP OF STORES DEPT																	
14	INVENTORY CONTROL BY CARDEX, MANUAL LEDGER																	
15	INVENTORY CONTROL COMPUTERIZED STATEMENT																	
16	SYSTEM FULLY ESTABLISHED																	

Washington, D.C.
Date: 06/20/94

ANNEX 2.5

NEPAL

ARUN III HYDROELECTRIC PROJECT

DETAILED DESCRIPTION OF THE ARUN III HYDROELECTRIC PROJECT

1. Project Location. The power plant would be located on the Arun river in Sankhuwasabha District, about 170 km east of Kathmandu and 40 km south of the Chinese (Tibetan) border. The upstream catchment basin includes the Barun Khola watershed that ranges from 1,000 m to the peak of Mount Makalu, 8,250 m, the fifth highest mountain in the world. (See map). The Arun river has the highest linear distribution of power (45 MW/km) of any river in Nepal. There is potential for several hydroelectric projects along the river, with a combined capacity of 1,045 MW.

2. The proposed project consists of a hydroelectric component of 402 MW (to be constructed in two stages of 201 MW); an access road of approximately 122 km; and a transmission system (also to be constructed in two stages: the first stage is a 120 km double circuit single tower 220 kV line linking the hydroplant with the national grid at the 220 kV Duhabi substation; the second stage consists of a 220 kV double circuit link connecting Duhabi with Kathmandu). The proposed project will provide support for the first stage of the AHP.

3. The AHP would be a run-of-the river plant with an annual average and firm energy of 2,891 GWh and 1,558 GWh, respectively, and 1,660 GWh and 1,513 GWh for the first stage. The first stage would consist of a 68 m concrete gravity dam with a three-gate integrated overflow spillway, a power intake with four openings and three integrated sluiceways, two desanding caverns and a flushing tunnel, a headrace tunnel about 11.5 km long and 5.6 m finished diameter, a power cavern, for three generating units of 67 MW each, a transformer and switchgear cavern, and a tunnel tailrace system including the outlet structure. The associated transmission system includes a 120 km double circuit single tower 220 kV line linking the Arun power plant with the national grid at the 220 kV Duhabi substation.

4. The second stage would include two more the desanding basins and a headrace tunnel, an extension of the first stage power cavern to house three generating units of 67 MW each, and the complementary tunnel tailrace system. The transmission system would be extended about 312 km by a 220 kV line double circuit single tower between Duhabi and Kathmandu, with an accompanying extension at Duhabi and a switching station at Dhalkebar and substation at Kathmandu.

Hydroelectric Component

5. The staged development of Arun hydropower plant is summarized in Table 3.1.1.

ANNEX 3.1
Page 2 of 17

Table 3.1.1: Staged Development of Arun HEP (2x201 MW)

Project Component	Main Features	1st Stage of Construction	2nd Stage of Construction
Access Road Valley Route	122 km long	To be completed	
Concrete Gravity Dam	68 m high	To be completed	
Power Intake	4 intake openings; total intake capacity 160 m^3/s	To be completed, except intake tunnels Nos. 1 and 2	Intake tunnels Nos. 1 and 2
Underground Desanding Basins	4 basins and flushing system	Downstream basins Nos. 3 and 4 and entire flushing system	Upstream basins Nos. 1 and 2
Headrace System	2 headrace tunnels of 5.6 m finished diameter and 2 surge tanks	Mountainside headrace tunnel and surge tank	Valley side headrace tunnel and surge tank
High Pressure Waterways	2 steel lined penstocks of 4.3 m diameter	Penstock belonging to Units 1-3	Penstock belonging to Units 4-6
Power Cavern	Cavern for six generating units (Pelton turbines) of 67 MW capacity each	Units 1-3, service bay and unloading bay	Units 4-6
Tailrace System	2 tailrace tunnels and 2 downstream surge tanks; 1 common outlet structure	Tailrace tunnel and surge tank for Units 1-3; outlet structure	Tailrace tunnel and surge tank for Units 4-6
Buildings	A number of service buildings near the power cavern	To be completed	
NEA/Engineer's Camps	Powerhouse and dam site camp	To be completed	

Hydrology

6. The Arun river originates from glaciers in the Tibetan highland north of Xixabangma in the Himalayan range, due north of Kathmandu. The river then runs eastward in parallel with the Himalayan range. At the end of this easterly part of the course, the Arun river turns abruptly to the south and descends with an average gradient of 1/50 forming a deep V-shaped gorge, crosses the Himalayan and Mahabharat ranges in Nepal to join with the Sapta Kosi River at Tribeni. The total length of the river is 510 km. The drainage area at the dam site is 26,747 km^2 out of which 25,307 km^2 lie in Tibet. On the basis of the hydrological studies, the long term annual average discharge is calculated in 355 m^3/sec.

7. The probable maximum flood (PMF) has been adopted as the design flood discharge. Standard flood frequency analysis at the dam site gave the flood of 7,288 m^3/sec with a 10,000 years recurrence period, while the PMF is 8,100 m^3/sec at the dam site and 10,800 m^3/sec at powerhouse site. The PMF has been adopted for the design of the spillway. The occurrence of a glacier lake outburst flood (GLOF) may be expected in the Arun river which originates from glacier ranges. A study carried out concluded that a maximum GLOF of 4,000 m^3/sec magnitude could be expected at the dam site. The estimated maximum GLOF is of smaller magnitude than the PMF and can therefore safely be handled by the proposed dam and spillway.

Sedimentation

8. The Arun River carries substantial amounts of suspended sediment although these are comparatively smaller than those estimated for other rivers in Nepal. The suspended sediment concentration during the low flows is from 213 to 632 tons/day and for the period of maximum flows is from 0.3 to 0.5 million tons/day. The total average suspended load at the dam site is estimated as 25 million tons/annum where about 81% of the total is transported in the five months from June to October. For the representative diameter which ranges between 80 and 180 mm, the annual transport capacity at the dam site is estimated as 35.1 and 19.9 million tons/annum, respectively. The bedload transport capacity for the mentioned diameters are insignificant during the dry season from November to April. The tentative operation guidelines for sediment handling in the reservoir are based on the findings from the hydraulic model tests, numerical simulation and general knowledge of sediment handling, but should be modified and adjusted based on the prototype operation. The initial total reservoir volume is approximately 9.3 million cubic meter (MCM) and the initial effective volume is approximately 1.7 MCM. From system studies it was concluded that the minimum required effective volume would be 0.35 MCM. The sediment volume deposited in the reservoir is estimated to be approximately 1 to 2 MCM/year. Without flushing, after the fifth year of operation, the reservoir and effective volume would be reduced to about 1 and 0.8 MCM, respectively. Hence, reservoir flushing will be required after the fifth year of operation.

Geology

9. The Arun project area, comprised primarily of gneiss and mica schist, is located in the Himalayan group. The Himalayan group is intruded with the eastern wing of the Arun anticline fold with its axis running in the north-south direction. The right bank of the reservoir is formed by the eastern slope of the ridge, which is intersected at the dam site by the Arun river. For this reason, the rock mass is identical, consisting mainly of augend gneiss or micaceous augend gneiss with thin intercalations of mica schist. At the left bank of the reservoir area, the slope is generally steeper. In most areas the river touches outcrops of rock on the embankment. Only in some areas of the right bank, colluvium, talus and slope wash deposits reach the toe of the slope and the river embankment. Since the rock masses enclosing the reservoir area are not susceptible to dissolution, no karst problems are to be expected. Furthermore at the dam site no major fault zone has been found in the riverbed of the Arun or in the vicinity of the abutment. Hence, the reservoir tightness is considered satisfactory.

10. The rock mass on the right bank of the river near the dam site is principally composed of augend gneiss and micaceous augend gneiss, interbedded with mica schist layer of some 10 cm up to several meters of thickness. In most cases, these mica schist layers are intensely fractured and sheared. The right abutment of the dam is formed by the uppermost and first spur which is separated from the main ridge. All the drill holes and seismic survey lines show that the geological conditions are more favorable within the center of the spur. No major fault zone was detected in the riverbed. The maximum thickness of river deposit is expected to be about 12-13 m in the middle and left side of the riverbed. The upper bedrock layer of approximately 5 m thickness shows a higher degree of fracturing and weathering. Left bank rock mass of the dam site consists of massive augend gneiss, schistose micaceous augend gneiss and intercalations of mica schist and fine grained gneiss layers of various thickness.

11. The geology of the upper part of the headrace tunnel at the Adit 1 site consists of three rock types, namely: (a) dark grey mica schist with a varying quartz biotite content; (b) granite mica schist; and (c) quartzitic schist, and are of favorable nature. However, based on the surface geological data and the tests carried out at upper parts of headrace tunnel, basically augend gneiss, granite gneiss and mica schist, all of them having a wide range of appearances and rock mechanics parameters, can be expected to be encountered along the headrace tunnel alignment. A number of shear zones and/or major faults are also expected. Due to the height of the overburden, investigations directly along or in the vicinity of the headrace tunnel alignment had to be limited to a few sites.

12. The geology of the surge tank site consists mainly of granitic gneiss with intercalations of mica schist layers. The results based on test adit and drill hole investigations envisages that most of the surge tank will be constructed in augend gneiss of fair to good rock quality. Interbedded in the augend gneiss are sheared mica schist layers of poorer rock quality. At the lower part of the surge tank, sheared mica schist layers alternating with fine

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maintenance stoplogs, and a rack clearing machine with integrated hoist for handling of stoplogs. Each intake opening is designed for 40 m3/sec discharge and operates when the reservoir water level is within 842 and 838 m.a.s.l, high and low water levels, respectively. With respect to staged project implementation, the power intake structure will be constructed entirely during the first stage. The transition tunnels 1 and 2, will be constructed in the second stage.

18. An integral part of the power intake are the three sediment sluices which are equipped with stoplogs, three flushing channels and sluiceway control gates at the end of the channels. Coarse sediment accumulated in front of the power intake will be removed through the sediment sluices. Since the sluices will have only a locally limited effect, they are not suitable to control reservoir sedimentation. This has been verified by the hydraulic model test.

Desanding Basins

19. Each intake tunnel from the power intake will be connected to an underground desanding basin; 110 m long 17 m wide and 28 m high. All four of the desanding basins have been designed for removing about 90% of particles bigger than 0.2 mm diameter. To avoid unfavorable approach flow conditions (causing asymmetrical reverse flow patterns), a baffle block has been introduced at the upstream transition of the basin. A stilling basin equipped with a flushing gate and a flushing tunnel will be provided at the downstream end of each desanding cavern to remove the accumulated sediment from the basins. The length and the gradient of the flushing tunnel is 640 m and 2.6%, respectively. This horse-shoe shaped tunnel will have 7.5 m clear width at the base. To boost the flushing capacity of the flushing tunnel, a booster facility has been provided in the tunnel. Inspection tunnels will be provided. Clear water from each desanding basin will pass through the corresponding free flow connecting tunnel and inclined pressure tunnel to the head race tunnel. Only the desanding basins Nos. 3 and 4, each with its respective stilling basin, sediment flushing gate, connecting tunnel and pressure tunnel will be constructed in the first stage, whereas those for basins Nos. 1 and 2 will be constructed during the second stage of project implementation. The flushing tunnel and booster facilities will be fully constructed during the first stage.

Headrace Tunnel

20. The clear water from each desanding basin will be collected in a single headrace tunnel section of some 500 m length and 7.5 m concrete finished diameter. This tunnel will be bifurcated into two headrace tunnels of 5.6 m finished diameter. Each of these headrace tunnels is about 11 km long. The tunnel will be totally concrete lined for better hydraulic, safety and operational reasons. The minimum cover of 60 to 100 m will be under the Num Khola, Suki Khola and Raata Khola, whereas in other places the rock cover ranges from 200 m to 1,000 m. The mountain side headrace tunnel with bifurcation structure and some length of valley side headrace tunnel will be constructed in the first stage. If the headrace tunnel is excavated using the conventional blasting method (CBM), only three adits can be constructed to reach the tunnel

due to the predominantly high overburden above the tunnel alignment. These adits are at chainage 499 m, 7,927 m and 11,447 m, respectively. Whereas, if the tunnel boring machine (TBM) is used, excavation will be carried from downstream to upstream.

Surge Tank

21. There are two surge tanks, one on each headrace tunnel. The surge tanks will be of the throttle type, having a finished diameter of 15.9 m and a height of 95 m. Ventilation tunnels ending at the vault area of the both surge tanks will always guarantee atmospheric pressure condition at the free water surface. An emergency gate will be installed at the downstream side of each surge tank. Entrance to the gate chambers will be through an access tunnel, whose invert level will be approximately at the same level as the invert of the headrace tunnel below the throttle. Only the surge tank corresponding to the mountain side headrace tunnel and the access will be constructed in the first stage.

Pressure Shafts and Upstream Manifolds

22. Immediately downstream of each surge tank, a 40.5 m long tunnel followed by an inclined pressure shaft will be provided. Due to the oblique orientation of the power cavern's longitudinal axis relative to the headrace tunnel axis the inclination of the pressure shafts 1 and 2 is different (67.9° and 57.4°, respectively). However, both inclinations will enable self-mucking excavation methods. The finished diameter of each shaft is 4.3 m. At the downstream end of each pressure shaft, flow distribution to the three turbines connected to each shaft will be provided by a manifold system from 3.5 m to 2.5 m diameter. At the downstream end of the manifold, directly upstream of each unit, a 2.2 m diameter spherical valve will be installed to shut off the flow when necessary. Only the pressure shaft corresponding to mountain side surge tank (surge tank No. 1) will be constructed in the first stage. The pressure shaft-manifold system will be provided with steel lining. The thickness of the pressure shafts' steel lining will be variable along the shaft length in accordance with the relevant internal and external hydraulic pressures. Upper and lower erection chambers will, *inter alia*, allow for preparatory works on the steel lining and positioning of it in the pressure shafts and the manifolds respectively.

Access to the Headrace Tunnels

23. Access requirements during construction of the headrace tunnels will depend on the method of excavation to be selected by the contractor. In the case of CBM excavation, three adits will be necessary to guarantee the timely completion of the headrace tunnel. If TBM technology is used, adit No. 2 will not be needed. However, an intermediate ventilation shaft will then be required. Special consideration had to be given to the design of the adits in view of the staged construction of the two headrace tunnels. Since the mountainside headrace tunnel will be constructed first, the same three adits can also be used for construction of the second headrace tunnel. Adit No. 1 is located near the

damsite, the intermediate Adit No. 2 will enable access to the headrace tunnel approximately at two-thirds of the tunnel length and Adit No. 3 will be located close to the upstream surge tanks, and will later on also be used as access to the upstream erection chambers. For surge tank construction, short access tunnels are foreseen from Adit No. 3, perpendicular to this Adit. The upstream erection chamber will be arranged to enable the execution of preparatory works and positioning of the pressure shafts' steel lining, and provide sufficient working space for the civil contractor for excavation of the pressure shafts. The lower erection chambers close to the transitions pressure shaft-manifold can be used for installation of the manifold steel lining, and as work area for excavation of the pressure shafts from the bottom. Access to the lower erection chambers is provided via the auxiliary power cavern access tunnel.

Power and Transformer Caverns

24. The power cavern is a large underground structure, and its longitudinal axis orientation has been chosen to minimize the required rock support. The orientation of the longitudinal power cavern axis is N130°E, running oblique to the headrace tunnel axes (orientation N69°E). The dimensions of the power cavern are 168.24 m long, 22.00 m wide and 35.25 m high to house six generating units of 67 MW each including a vertical axis Pelton turbine, and the service and unloading bays. First stage construction comprises the service bay, units 1 to 3 and the unloading bay whereas the second stage construction comprises units 4 to 6. The axis of the turbine is lower than the high water levels in the Arun river during the monsoon season. Thus, a compressed air system has been introduced to lower the water level below the turbine axis. With this arrangement, the total average annual output is increased by increasing the effective head. The transformer and switchgear cavern is located downstream of the power cavern, and its longitudinal axis runs parallel to the main power cavern axis for geotechnical reasons and to keep the length of the connecting galleries as short as possible. The dimensions of cavern are 10 m high, 10 m wide and 213.95 m long, of which 163.95 m and 50 m is for the transformer hall and the switchgear hall, respectively.

Tailrace System

25. The tailrace system consists of a downstream manifold system, downstream surge tanks, tailrace tunnels and outlet structures. Each of the two downstream manifold system consists of three branches, connecting units 1 to 3 and units 4 to 6 with the corresponding downstream surge tank. Each manifold will have a finished diameter of 5 m and length between 67.5 m to 111.7 m. To compensate for flow variations, two downstream surge tanks of 34 m high and 22 m finished diameter are provided at the upstream end of the tailrace tunnel. Two concrete-lined tailrace tunnels with finished diameter of 5.8 m and lengths of 194.4 m and 132.9 m respectively will convey the water to the Arun river through an outlet structure. The outlets of both tailrace tunnels are combined in one structure. Special emphasis has been put on avoiding intrusion of sediment into the tailrace tunnels and enabling the removal of sediment that could possibly accumulate in front of the lower bulkhead outlet gates. Hence, upper bulkhead gates have been provided to allow a free overflow at the outlet structure to stir

up sediment deposits which then can be flushed away by opening the lower bulkhead gates. For protection of the tailrace system during construction, a sheetpile cofferdam will be constructed to cope with the estimated flood discharge of an average recurrence interval of 10 years. The outlet structure will be constructed entirely during the first stage of project implementation. The downstream manifolds, the downstream surge tank and the tailrace tunnel for units 4 to 6 will be implemented during the second stage.

NEA Camps

26. A permanent NEA camp, designed to serve both the dam and powerhouse sites, would be built at Amrang village. This camp is to be located in a flat area along the access road between the dam and the powerhouse sites, with 12 km and 17 km of distance to damsite and powerhouse site respectively. The camp will serve the following purposes:

- Provide housing, office and social facilities for the duration of project's construction period to the employer/engineer's supervisory staff.
- Serve NEA's operation and maintenance staff as permanent facilities during future project operation.

Access Road

27. Road Alignment. The 122-km long access road will form the northern section of a north-south corridor linking Itahari on the East-West Highway in the south, Dharan at the junction of the Terai Plain and the Himalayan foothills, Dhankuta, Hile and the hydropower facilities to the north. The river route alignment to the damsite starts from Hile and passes through Diyala, Mangma, Leguwa, Tumlingtar, Powerhouse and Adit No. 2.

28. Design Standards. The following geometric standards, have been applied for the design:

(a) Carriageway: 4.5m width carriageway with 0.5m shoulders widening to 5.5m width carriageway with 1.0m shoulders adjacent to settlements.

(b) Gradients: Average 7 percent over any one kilometer, with a maximum of 10 percent over not more than 300m length at a time (exceptionally, average gradients up to 9 percent have been unavoidable). Gradients at hairpin bends will be reduced to 4 percent or less wherever possible.

(c) Radius at Curves: Generally not less than 25m center line of the road, although exceptionally, radii down to 10m have been unavoidable.

29. Pavement, at the south and north of Tumlingtar, will consist of 150 mm and 125 mm thick graded crushed stone subbase respectively and 125 mm thick graded crushed stone base coarse, topped by a double surface dressing with stone chippings selected as the pavement structure.

30. Major Structures. Bridges, culverts and retaining walls are the major structures used in the road. The shape and material of the structures were chosen to facilitate construction at locations having limited and difficult access and also to maximize the use of available indigenous resources. The Standard Specification for Highway Bridges as adopted by the American State Highway and Transport Officials (AASHTO) has been used as the basis for structural design.

31. Culverts. Four forms of culverts have been specified for the project and are as follows:

- Reinforcement concrete pipe
- Corrugated metal pipe
- masonry slab
- masonry box

All forms are suitable for the smallest culvert sizes to a fill depth of 5 meters. Above 1.2m diameter, concrete pipes become difficult to handle manually and are therefore not specified. The limit diameter of 2m specified for corrugated metal pipes is the largest size commonly installed, and hence was considered appropriate as a maximum size for this project.

Masonry slab culverts less than 1.2 meters square are suitable for fill depths up to 50 meters. For sizes between 1.2 meters square and 2.0 meters square, fill depth is limited to 3 meters.

Masonry box culverts can be used over the full range of sizes and fill heights but it is anticipated that they will mainly be used for the larger sizes only. The total number of culverts on river route is estimated to be 1005.

32. Bridges. Thirteen sites requiring major bridgework have been identified along the preferred route alignment.

Bridge	Super Structures Type	Length (m)
Manamaya	Deck	190
Leguwa	Deck	120
Kenwa	Deck	128
Cliff	Through	60
Piluwa	Through	157
Sabhaya	Deck	130
Bettini	Deck	40
Chowbesi	Deck	34
Kaguwa	Deck	31
Arun (PH)	Through	120
Bagbasa	Deck	51
Arun (Adit)	Through	96
Suki	Deck	59
Total Length		1,216

Reinforced concrete construction has been chosen for the substructures to provide the required strength and ductility for the imposed loads and seismic conditions.

Single circular columns have been chosen for intermediate piers to minimize the possibility of debris impact and deposition.

Transmission System

33. The 220 kV transmission system will evacuate a large block of power from the power plant to the load centers, which are relatively far away, of the Nepal Interconnected System (NIS). The whole transmission system, which includes 432 km of transmission line and associated substations has been divided into three sectors. The proposed transmission route is shown in the Map IBRD 25523. Construction of the AHP-associated transmission system will occur in two stages.

Stage I

34. Arun-3 Powerhouse to Duhabi Substation. The first stage will consist of a 120 km long 220 kV/double circuit/single line transmission system from the Arun powerhouse to the Duhabi substation and a 220/132 kV substation at Duhabi. The Arun power plant would be integrated into the NIS at Duhabi. Thus the balance of power (Arun output less the load at Duhabi) would be transmitted to the Kathmandu area over the existing 132 kv system between Duhabi, Dhalkebar, Hetauda, Kulekhani and Siuchatar. This system presently consists of a double circuit tower line with one

circuit. The reinforcement of this system with the stringing of the second circuit will be done well before the commissioning of Arun first phase.

Stage II

35. Duhabi to Dhalkebar Switching Station. This sector consists of 179 km long 220 kV/double circuit/single line transmission system with switching station at Dhalkebar. The transmission line route is to follow the existing East-West Highway. The principle obstacles in this section of line will be the crossings of the Sapta Kosi and Kamala rivers. The finalization of the route will be done during the preparation of engineering design and bid documents.

36. Dhalkebar to Kathmandu Substation. This sector consists of a 133 km long/double circuit/single line transmission system with a 220/132 kV substation at Kathmandu. The route is to follow the existing road up to Sindhuli and then the proposed road from Sindhuli to Dhulikhel. The finalization of the route will be done during the preparation of engineering design and bid documents.

37. Additionally, a 100 km long single circuit 220 kV line is also proposed from Duhabi to Purnea in the Bihar state of India for the possible power export from the full stage development of 402 MW. The study has considered only the part of the transmission line within Nepal. Since the actual point of the border crossing has not yet been agreed, a route from Duhabi was considered on the same side of the road as the Duhabi substation, leading to the border in a southerly direction. With such route, the route length to the Nepal-India border is 20 km.

Summary of Arun III Hydro Power Plant

38. The main features of the power plant are summarized below:

Hydrology

Drainage area at dam site	26,747 km² (25,307 km² in China, Tibet)
Flow records used in design	1985-1992
Maximum recorded flow	2198.35 m³/s
Average annual estimated discharge	355 m³/s
Probable maximum flood (PMF) (10,000 years) at dam site	8,100 m³/s
Maximum estimated Glacier lake outburst flood (GLOF) at dam site	4,000 m³/s
Annual average suspended sediment load at dam site	25 million tons

Reservoir

Maximum water level	847.5 m.a.s.l.
High water level (HWL)	842.0 m.a.s.l.
Low water level	838.0 m.a.s.l.
Effective reservoir volume	1.7 million m³
Reservoir length	4 km
Reservoir area (HWL)	50 ha.

Diversion Works

Upstream cofferdam

Type	Rockfill with upstream slope sealing and extended sealing; downstream face protected against overtopping by an anchored reinforcement grid
Crest level	810.5 m.a.s.l.
Height	16 m

Downstream cofferdam

Type	Rockfill dam
Crest level	794.0 m.a.s.l.
Height	4 m

Diversion tunnel

Number and type	One horseshoe shaped tunnel,concrete lined
Length and diameter	466 m and 6.5 m concrete finished diameter

Concrete Gravity Dam

Type	Concrete gravity dam with integrated spillway
Crest elevation	849 m.a.s.l.
Crest length and width	155 m/15 m
Height	68 m

Spillway

Type	Gated spillway
Ogee crest elevation	822 m.a.s.l.
Number an type of gates	Three radial gates hydraulically operated
Dimensions of gates (w/h)	13.5 m/20.5 m
Discharge capacity	8,100 m^3/s

Power Intake

Type	Four openings with trashracks. Total capacity: 160 m^3/s.
Invert level of openings	834 m.a.s.l.
Stoplogs (w/h)	Four (4.0 m/7.0 m)
Gates	Four roller intake gates.
Intake tunnels	Four. Variable length. (4.0 m wide/5.0 m H
Nominal gate dimensions (w/h)	4.0 m/5.0 m
Sluiceways	Three integrated sediment sluiceways below intake openings. Each invert opening at level 824 m.a.s.l. Opening size (w/h) 5.8 m/3.6 m (steel lined invert)

Desanding Caverns

Number and type	Four underground desanding caverns; two in each stage
Cavern dimensions (w/h/l)	(17 m/28 m/110 m)
Flushing tunnel (l/diameter)	(640 m/7.5 m)
Estimated desanding efficiency at rated discharge of 40 m^3/s.	about 90% of particles of 0.2 mm size

Headrace Tunnel

Number and type	Two. One pressure tunnel in first stage Concrete lined
Length of tunnel: common section	502 m
mountain side	11,007 m (first stage)
valley side	11,012 m (second stage)
Distance between center lines of tunnels	50 m
Concrete finished diameter	
Common headrace section	7.5 m
Each tunnel	5.6 m

Upstream Surge Tank

Number and type	Two. One surge shaft in first stage. Orifice type
Diameter and height	15.9 m/ 95 m

Pressure Shafts and Manifolds

Number and type	Two inclined steel lined pressure shafts and manifolds are provided for: one for units 1,2, and 3 (second stage); and another for units 4,5, and 6 (first stage)
First stage	
Length (including manifold)	329 m/25 m /120 m
Diameter	4.3 m/3.5 m/2.5 m
Second stage	
Length (including manifold)	351 m/25 m /120 m
Diameter	4.3 m/3.5 m/2.5 m
Roller gate per shaft (w/h)	3.4 m/4.3 m
Spherical valves	One 2.2 m diameter valve for each unit at the end of the downstream end of each manifold.

Powerhouse Cavern

Final dimensions (w/h/l)	22 m/35.2 m/168.2 m (first stage: 109 m)
Number of generating units	Six. Three units in first stage

Turbines

Type	Pelton, vertical shaft, six nozzles
Center line of units	538.20 m.a.s.l.
Number/unit capacity	Six/67 MW each (three in first stage)
Maximum gross head	303.8 m
Maximum net head at full load	286.0 m
Rated head	285.98 m
Rated speed	231 rpm

Governors

Electric/hydraulic with air/oil pressure vessel, speed controlled

Generators

Number	Six (three in first stage)
Rated output	76 MVA
Rated voltage	13.8 kV
Rated frequency	50 Hz
Power factor	0.85

Transformer and Switchgear Cavern

Dimensions (w/h/l/)	10 m/10 m/214 m

Main Transformers

Type	oil immersed single phase
Number of units	10
Rated capacity	26 MVA each
Rated high voltage	220 kV
Rated low voltage	13.8 kV
Type of cooling	OFWF

High Voltage Switchgear

Type of circuit breaker	Gas insulated switchgear (GIS)
Number of 220 kV breakers	6
Rated current	1.25 A
Rated breaker current	25 kA
Rated voltage	220 kV
Configuration	Double bus bar

Tailrace System

Type and number of tunnels	Two concrete lined pressure tunnels One for each stage
Length of tunnels	194.4 m (first stage); 132.9 m (second stage)
Concrete finished diameter	5.8 m each tunnel
Surge tank number/diameter	Two/22.0 m each

Downstream manifolds

Number and type	Six free-flow tunnels, one for each unit.
Diameter/length	5.0 m/variable

Access Tunnel Portal and Transmission Line Terminal Structure (Main Data)

Overall dimensions(w/h/l)	9.0 m/11.0 m/31.1 m
Portal entrance elevation	553.2 m.a.s.l.

Access and Other Auxiliary Tunnels (Main Data)

Length of main access tunnel to powerhouse cavern	330 m
Length of auxiliary access tunnel to cavern	504 m

Average Annual Energy Output

Total average	2,891 GWh (1,715 GWh for first stage)
Firm energy	1,558 GWh (1,513 GWh for first stage)

Access Road	122 km long (Hile-Tumlingtar-Powerhouse-Adit No. 2-Dam site)

Transmission System

Lines (double circuit single tower line)

Arun-Duhabi	120 km (first stage)
Duhabi-Dhakelbar	179 km (second stage)
Dhakelbhar-Kathmandu	133 km (second stage)
Duhabi-Purnea	100 km (second stage)

Substations and Switching Stations

Duhabi substation	MVA, 220 kV/132 kV (first stage)
Dhalkebhar switching station	220 kV/130 kV (second stage)
Kathmandu substation	MVA, 220 kV/132 kV (second stage)

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ARUN III HYDROELECTRIC PROJECT

ENVIRONMENTAL MANAGEMENT PLAN

A. Introduction, Environmental Implications and Risks

1. The features and characteristics of the physical and socioeconomic environment of the Arun Valley, in combination with the nature, magnitude and pace of the proposed development program, create a unique and very complex set of environmental issues which must be considered in implementing the Arun Hydroelectric Project (AHP). Because AHP is to be a run-of-the-river project without a large storage facility and with most of its facilities underground, its direct physical impact will be less than many hydroelectric projects of similar capacity. However, the AHP project and proposed later projects will be a major intervention in this remote valley. The scale and pace of development that is intended create a potential for changes, both positive and negative, beyond that experienced in previous projects in Nepal. The potentially significant risks of the project can be summarized as:

- loss of forest habitat and concerns about natural hazards as a result of installation of the road and power plant and associated activities;

- effects on local people through loss of farm properties and displacement, social impacts of a concentrated work force and associated permanent and temporary migrants and possible inequitable distribution of economic benefits and costs;

- increased pressures on forests, and increased direct and indirect demand for forest products as a result of the project, leading to accelerated degradation of forests and threats to biodiversity;

- unmanaged tourism development resulting from improved access may be environmentally damaging and not bring benefits to local people;

- government and non-government institutions in the Arun basin may not have the ability or resources to meet increased demands.

However the prevention, mitigation and compensation measures associated with the project, have the potential - if properly implemented - to minimize negative impacts and enhance the deteriorating environmental and socio-economic conditions in the valley.

B. Project Description

2. The main components of the project are:

- 68 m high dam and 50 ha reservoir;
- 200 MW underground power-house and associated structures;

- 122 km. access road, along the Arun Valley, to dam and powerhouse;
- long distance 120 kV transmission lines to Duhabi;
- permanent offices and housing, between dam and powerhouse.

3. Temporary facilities include:

- quarries, borrow sites and spoil dumps;
- concrete batching and mixing plants;
- work and storage areas;
- construction camps, offices and housing;
- support facilities.

4. EA material for the various components has been prepared by the international engineering consultants responsible for design. Design of the power generation system and access road have been on-going for a number of years, with EA work being done in parallel and consolidated into a Report in early 1993. In addition, a regional EA was produced using UNDP funds, by a local NGO - the King Mahendra Trust for Nature Conservation. NEA's AHP Environmental Assessment and Management Executive Summary, issued in May 1993, provides an overview of these environmental studies. Extensive public consultation has occurred during the environmental study and following release of the summary.

C. Environmental Management in Nepal

5. The need for careful and responsible management of Nepal's unique environment is becomingly increasingly well recognized. However, it is also widely recognized that, in Nepal as in other developing countries, it is not practicable or desirable to consider management of the physical environment separately from promotion of the health and economic well being of people. Nepal is one of the poorest countries of the world, and the hill people of Nepal, such as those in the Arun Valley, are particularly affected by the problems of poverty. In these circumstances, it is generally recognized that the primary environmental issue is not whether development should occur. Rather, the need is to ensure that development which occurs is sustainable and environmentally sensitive, and that it brings real and lasting benefits to the people of Nepal, taking balanced account of national and local needs.

6. The Government and people of Nepal recognize that environmental management requires an integrated approach to management of the physical, biological, social, cultural and economic environment. His Majesty's Government of Nepal, with the assistance of IUCN, the World Conservation Union, has prepared and adopted a National Conservation Strategy. More recently work has been focused on a National Environmental Action Program. This was finished in mid 1993 and provides a strategy for future action on sustainable development.

7. Within the Arun valley, which is a food deficit area subject to unsustainable pressures on the resources, intervention of some sort will be necessary to prevent further degradation and increasing impoverishment. Several important activities aimed at improving conditions have been taken in conjunction with the AHP project, such as the Regional Action program, including a proposal for establishment of the Milke Danda Conservation Area, on the east side of the

Arun valley, and the establishment of the Makalu-Barun National Park and Conservation Area (MBNPCA), on the west side.

D. Regional EA and the Regional Action Program (RAP) for The Arun Basin

8. The goal of the RAP is to ensure that regional and local benefits of the AHP project and access road are maximized and negative impacts minimized. The study on which the Plan is based was not an environmental assessment in the normal sense, but was in effect a regional development study which focussed on ways in which management of the resources, economy and environment of the Arun Basin as a region might best respond to the processes of change brought by the hydroelectric development program. Consequently, it is in the regional EA that overall legal and administrative frameworks are considered and consultation with the local population conducted most extensively.

9. Induced impacts predicted in the regional EA mainly derive from the effect of the new road access. These include increased pressure on the forestry resources, reduced profitability of certain crops, such as rice, due to lowered transportation costs and increased numbers of trekkers into the National Park. An action program consisting of twenty one sectoral activities in six major program areas to minimize these effects and maximize benefits has been proposed. These programs are designed to address both immediate requirements brought about by the construction process and the longer term needs for sustainable development within the Arun basin. The six major program areas are: (i) conservation; (ii) income generation; (iii) institutional strengthening; (iv) extension and training; and (v) infrastructure and energy development; and (vi) environmental monitoring.

10. The preemptive program to be undertaken prior to initiation of road construction, included community forestry; involving local communities in servicing road construction requirements, training and education and environmental monitoring. It should be noted that most of the preemptive programs are already in place under two ODA projects namely the Nepal-UK Community Forestry Projects (NUKCFP) and the Koshi Hills Seed and Vegetable Project (KHSVP). The NUKCFP has the geographical coverage and program components in terms of formation of forest user groups in four districts of the Arun basin including areas adjacent to the alignment of the Arun access road. A major objective of the KHSVP is to increase agricultural productivity, nutritional standards and cash income of farmers in the Koshi Hills including the four districts of the Arun basin. A particular emphasis of the project is support for the establishment of new seeds and vegetable producer groups in the vicinity of the AHP.

11. Longer term sustainable development needs will be addressed by programs such as setting up a new conservation area (Milke Danda); diversification of income generation activities through programs in agricultural development and diversification, livestock development and economic development; development of spur roads linking larger communities with the access road and alternative energy programs including rural electrification in high impact areas and micro hydropower schemes. HMG/N is now putting in place the necessary arrangements for implementing the Action Program. Co-ordination is taking place with donors to ensure an overall development approach in the Arun Valley and

funding of RAP is an integral part of AHP. Further details of the RAP are included in Attachment 1.

E. Rural Electrification

12. The project design has made provision for electricity supply from the national grid for the major villages along the access road corridor as well as for electrification of isolated areas using micro-hydroelectric schemes. The details are as follows.

13. Grid Supply: Arrangements have been made at the powerhouse site to provide separate 33 kV bus bars which will be fed by two 8,000 kVA, 33.8/34.5 kV transformers (one each of these transformers will be installed in the first and second stages of the project). There is also provision for a number of station feeders for the camp site, dam site, surge tank and the emergency diesel building. In addition, there is the provision for separate feeders to Khandbari (the District Headquarters) and Num (the dam site) sub-stations for rural electrification (RE) schemes as well as one spare feeder to expand RE. All of these feeders are equipped with circuit breakers and isolaters. Power will be transmitted through a 33 kV transmission line. Step down transformers will be installed at each receiving end.

14. Since the 33 kV transmission line between the powerhouse and the dam site is originally used for construction power supply, it is included in CPS lot. All other electrical equipments required for the project, including the additional feeder for rural electrification, is included in electrical lot. In addition, it is envisaged that the distribution transformers used during construction would be re-used for rural electrification. Most of the villages in the vicinity of the road alignment up to Chainpur could be served from the powerhouse site. Distribution costs for the RE schemes are covered under the RAP.

15. Isolated Schemes: The RAP will also fund the preparation and implementation of micro-hydel schemes to meet the needs of isolated communities.

F. Project-Specific EA

16. The project-specific EA documentation clearly notes the direct environmental impact of the project. Mitigation plans for direct impacts have been developed with environmental protection clauses produced for the construction contract. Specific assignment of managerial responsibilities for on-site supervision have also been made.

17. The dam-site and access road are located in sub-tropical forests which contain endangered fauna and flora. Issues of biodiversity and wildlands have been examined in detail, with maps designating area of particular sensitivity and certain areas to be designated as off-limits during construction. Establishment of the MBNPCA, together with the proposed Milke-Danda Conservation area on the east side of the Arun, are important not only in terms of compensatory measures for AHP, but also for preservation of endangered species in Nepal generally.

18. Natural hazards have been well covered in the documentation, addressing important issues such as the effect of earthquakes, glacial lake outburst floods and slope stability. Not only the integrity of the dam but also the affect on the access road have been considered. The recommendation of the Panel of Experts (POE) established by the Bank have been followed, in designing the dam structure and in placement of the road in the valley.

19. Considerable attention has also been paid to the ethnic composition and socio-cultural aspects of those affected by the project. The majority of the indigenous people in the valley are Kiratis, practicing subsistence agriculture based on irrigated paddy and rain-fed maize. The area around the powerhouse and dam site, however, contains another people of Tibetan origin, who practice slash and burn agriculture. The lower Arun is dominated by Brahmin, Newar and occupational castes, some of which (i.e. around the airfield at Tumlingtar) are particularly vulnerable. The effects of work camps have also been addressed extensively, as there will be up to 3,500 workers at the dam and up to 5,000 people involved in road construction. The chosen routing will minimize loss of farmland and impacts on existing communities as most of the cultivation and homes are above the valley floor.

G. Makalu-Barun National Park and Conservation Area

20. The Makalu-Barun National Park and Conservation Area (MBNPCA) is being established in recognition that the Makalu-Barun area contains one of the last pristine ecosystems of the eastern Himalayas. The section of river on which the AHP project is to be sited forms the eastern boundary of the Conservation Area, which separates the river and the project site from the proposed national park boundary further to the west. The management plan proposes that major development projects, including hydroelectric schemes, will be prohibited within the National Park, but this prohibition will not apply to the Conservation Area. Socio-economic programs within the Conservation Area have been designed to take advantage of the new produce and labor markets that will result from the AHP and accompanying road construction.

21. Implementation of programs in the Conservation Area is being based upon a participatory model of land management and resource utilization. This model incorporates the experience, traditional management systems, and recommendations of local people into project policies, strategies, and actions. Additional income-generating opportunities will be developed, particularly for women, through production credit groups. Socio-economic improvements will thus be balanced with environmental protection and natural resource sustainability.

22. Both the National Park and the Conservation Area are being managed by HMG's Department of National Parks and Wildlife Conservation (DNPWC). The MBNPCA is supported through a collaborative agreement between the DNPWC and the Woodlands Mountain Institute, an international NGO, with funding from concerned international and private agencies, including GEF funding.

23. Proposed Milke - Danda Conservation Area. The highest biodiversity values in the Arun Basin are in the far east and northeast of Sankhuwasabha District along a series of contiguous mountain ranges: Milke Danda, Jaljale Himal and Lumbasumbha Himal. (The area also has significant watershed and

tourism values.) A 500 sq km conservation area is proposed for the area to manage and conserve the last patch of extensive, intact forest east of the Arun river.

H. Action Plan to Address Environmental Impacts

24. The access road, hydro plant and transmission line have been located so as to avoid unnecessary environmental and socio-economic effects. A detailed listing of mitigation measures, provided in the EA Report, has been integrated into designs for the road/hydro contract and will be done for the transmission line (which is to be built at a later date). Temporary camps, borrow sites, quarry and spoil disposal areas will be subject to approval beforehand and the location of environmentally sensitive areas is known in sufficient detail to guide construction.

25. Tender documents for the hydro site/access road included comprehensive provisions for environmental and socio-economic considerations, and bids received reflect these requirements. As referenced in the Executive Summary, an Environmental Protection Plan and a Health and Safety Plan has been presented with the contractors program of work. Environmental measures include provision for restrictions on location, (and provision for restoration) of borrow areas, and temporary work camps, as well as control of pollution from the latter. Also addressed are requirements for recruitment of local labor, establishment of fair-value shops leased to local operators, utilization of kerosene or fuelwood from legal sources, supply of free health service and safe water to workers as well as steps to control disorderly workers. **Similar provisions will be included in the transmission line contract.**

26. At this time roles and responsibilities to handle mitigation and monitoring at the implementation stage has been confirmed as follows:

(a) The main contractor is required, in the contract documents, to have a full time environmentalist, medical personnel and guards for road access gates.

(b) The engineering services contract call for a full-time professional environmentalist to direct the contractor, according to contract documents.

The Engineering services contract will include the responsibility for detailed reports on adherence to socio-economic and environmental conditions. This would provide a basis for supervision missions to confirm progress and allow management structures to authorize corrective measures as required.

27. Provisions for government control of illegal logging and unauthorized collection of fuelwood have been re-confirmed for the road and extended to the hydro and transmission line components. Budgeting and staffing allocations for these resources have been established by the Department of Forests of the Ministry of Forests and Soil Conservation. These needs will be integrated with suggestions for administration of community forestry programs under the Arun Regional Program, but qualified staff will be on-site at the time of contract

award. Measures to address poaching and harassment of wildlife are also being addressed as part of overall security needs in the area.

28. NEA's environmental unit is being expanded to handle the additional work that will exist as a result of their involvement in the project. To monitor activities as proposed will require both environmental and socio-economic staff on-site and reporting to senior management for the HQ group. This will also allow for qualified people to coordinate with the local population and NGO's. Resources have been budgeted and organizational structures established. Suitable staff are being hired and trained before construction commences and ADB is providing a technical assistant grant to strengthen the unit.

29. Regional Action Program Institutional Arrangements. To coordinate, monitor and facilitate the implementation of the RAP, to be implemented by concerned line agencies, HMG/N plans to set up the Arun Basin Development Steering Committee (ABDSC) under the National Planning Commission level assisted by

(i) an Arun Basin Development Secretariat and an Arun Basin Implementation Office (ABIO) in the Arun Basin.

(ii) MOWR as the liaison ministry, and

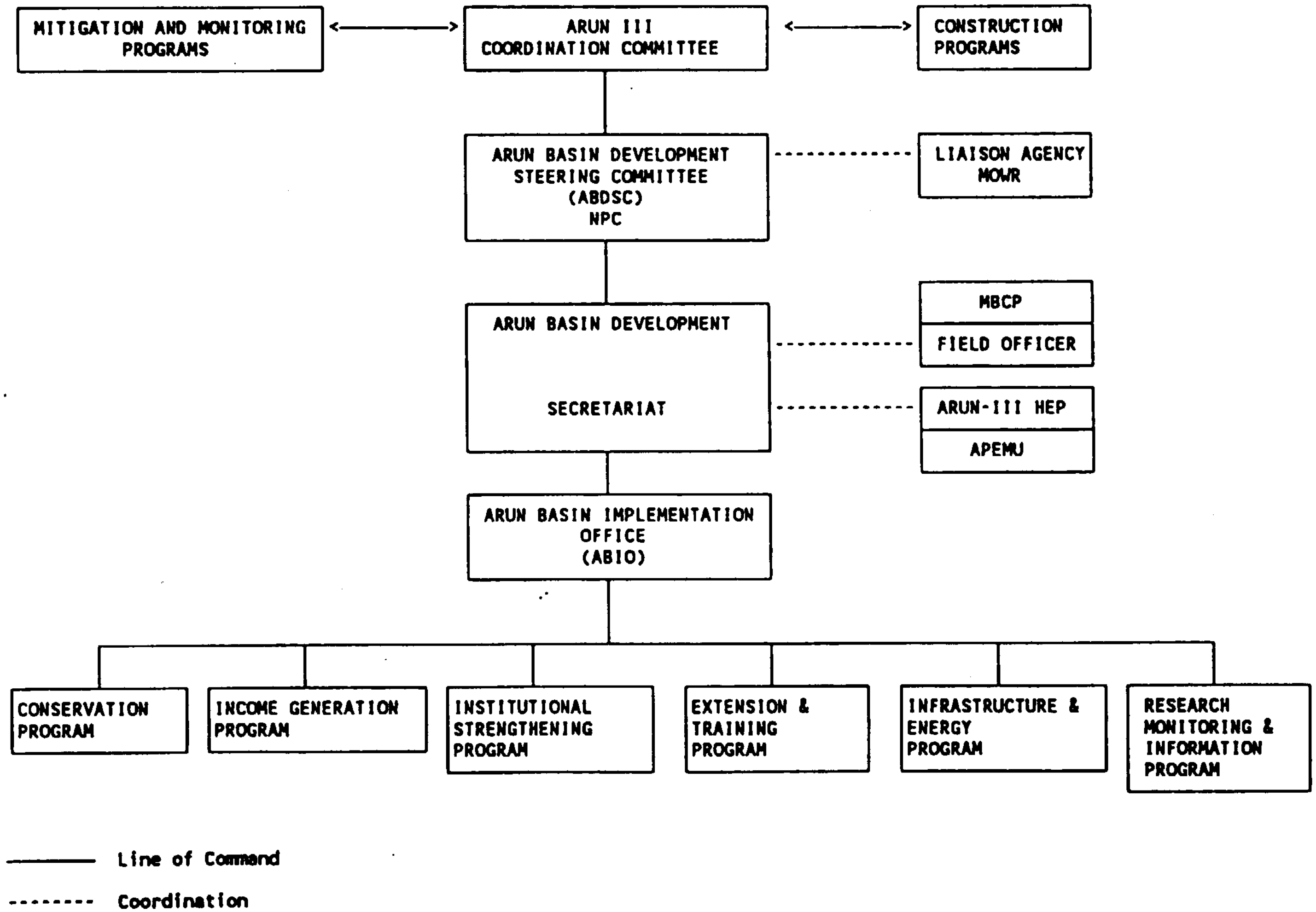
(iii) a local Non-Governmental Organization (NGO)/consultants under contract to MOWR with experts located primarily at the Project site.

To assure appropriate coordination with the AHP implementation, the ABDSC will keep the Arun III Coordinating Committee apprised of its activities.

30. The primary implementation responsibility for the proposed action plans lies with concerned line agencies, departments, government, parastatals government elected local government bodies, international Non-Governmental Organizations (INGOs), NGOs and local organizations depending upon the scale and complexity of the specific activities. An organization chart for the RAP is shown in Attachment 2.

FIGURE: 1

ORGANIZATIONAL STRUCTURE
ARUN BASIN DEVELOPMENT REGIONAL ACTION PLAN (ABD/RAP)



ANNEX 3.2
Attachment 1

Rank of Hydropower Generated per Hectare Inundated

Project (Country)	Final Rated Capacity (MW)	Normal Area of of reservoir (ha)	Kilowatts per hectare
Owen Falls (Uganda)	150	1	150,000
Arun (Nepal)	401	43	9,325
Kihansi (Tanzania)	153	30	5,100
Paulo Afonso I-IV (Brazil)	3,984	1,600	2,490
Pehuenche (Chile)	500	400	1,250
Guavio (Colombia)	1,600	1,440	1,067
Kapachira (Malawi)	125	200	625
Ertan (PRC)	3300	10,100	326
Rio Grande II (Colombia)	324	1,041	295
Longtan (PRC)	5,800	37,000	148
Itaipu (Brazil/Paraguay)	12,600	135,000	93
Aguamilpa (Mexico)	960	13,000	80
Sayanskaya (USSR)	6,400	80,000	80
Xiaolangdi (PRC)	1,800	27,200	66
Grand Coulee (USA)	2,025	32,400	63
Urra I (Colombia)	340	6,200	55
Jupia (Brazil)	1,400	33,300	42
Sao Simao (Brazil)	2,680	66,000	41
Tucurui (Brazil)	7,600	243,000	31
Ilha Solteira (Brazil)	3,200	120,000	27
Guri (Venezuela)	6,000	328,000	18
Paredao (Brazil)	40	2,300	17
Urra II (Colombia)	860	54,000	16
Cabora Bassa (Mozambique)	4,000	380,000	14
Three Gorges (PRC)	13,000	110,000	12
Churchill Falls (Canada)	5,225	665,000	8
Furnas (Brazil)	1,216	144,000	8
Aswan High Dam (Egypt)	2,100	400,000	5
Curua-Una (Brazil)	40	8,600	5
Samuel (Brazil)	217	57,900	4
Tres Marias (Brazil)	400	105,200	4
Kariba (Zimbabwe/Zambia)	1,500	510,000	3
Petit-Saut (French Guiana)	87	31,000	2.8
Sobradinho (Brazil)	1,050	412,400	2
Balbina (Brazil)	250	236,000	1
Babaquara (Brazil)	6,600	600,000	1
Akosombo (Ghana)	833	848,200	0.9
Kompienga (Burkina Faso)	14	20,000	0.7
Brokopondo (Suriname)	30	150,000	0.2
Garafiri (Guinea)	75	8,800	0.12

Note: This table is indicative only, since it does not reflect the value of the land inundated, which differs greatly in value. Some of the "land inundated" is river bed. The more reliable ratio derived from "kwh/ha" varies from year to year. The ranking would be improved, but little altered, if river bed or normal annual flood areas were subtracted. Islands in the reservoir also could be subtracted in certain cases. Some of these figures are for non-forest reservoirs and most are hydropower, rather than irrigation reservoirs. Area inundated is the key issue. Less seasonal tropical wet forest reservoirs do not need to be large. Optimizing the tradeoffs at the margin of reservoir capacity, is more influential than between having or not having a reservoir. An example of project selection to reduce oustees is PRC's Xiluodo near Leibo in Sichuan in the Jinsha river canyon, before it becomes called the Yangtze downstream of Yibin. This 12,000 MW project would be almost as powerful as the 13,000 MW Three Gorges, but with 20,000 oustees instead of over one million!

Source: R. Goodland. Environmental Sustainability in the Power Sector (In Process)

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ARUN III HYDROELECTRIC PROJECT

LAND ACQUISITION, COMPENSATION AND REHABILITATION PLAN (ACRP)
(Access Road, Hydroelectric Plant and Transmission Line)

ACRP Objectives and Guidelines

1. The objective of the ACRP is to implement the provisions for acquisition, compensation and rehabilitation set forth in HMG/N's Land Acquisition Guidelines of 2045 (the Guidelines). The Guidelines seek to ensure that after a reasonable transition period, the affected population will be able to regain if not enhance their previous standard of living. A comprehensive entitlement policy for all categories of affected people has been formulated for the achievement of this objective.

2. The Guidelines establish the following categories of affected population for the purpose of compensation:

(a) "Project Affected Family" and the acronym "PAF" means a family which is adversely affected by the Project, including those whose land is acquired or whose assets, although not compulsorily acquired for the Project, are nevertheless damaged by the construction activities thereunder;

(b) "Seriously Project Affected Families" and the acronym "SPAF" means a project affected family, as defined: (i) whose main source of income is derived from or dependent upon a land holding (whether agricultural land or houseplot or business) which is under their direct cultivation or management; (ii) whose main residence, place of business or main source of income earning activity is a house/houseplot -- either as owner, tenant or physical possessor, and who as a consequence of the acquisition for, or damage by, the Project of such land holding, house or houseplot is either: (a) left with no such holding; or (b) left with holdings of such land, houseplot or house which are not adequate to ensure them that, after reasonable transition period, they will at least regain the standard of living enjoyed prior to the implementation of the Project;

(c) Tenants, formal and informal without valid title or lease arrangements over land to be acquired. Such tenants may be classified as PAFs or SPAFs based on criteria used in their definitions in the Land Acquisition Guidelines, 2050; the provisions set forth in this ACRP in respect of PAFs and SPAFs will equally apply for such tenants;

(d) other families affected by temporary leasing arrangements; and

(e) other families affected by the transmission line Right of Way.

3. The Guidelines define the compensation categories for the categories of affected population as follows:

(a) Project Affected Families (PAFs). Compensation to PAFs is to include: (i) compensation in cash for assets acquired or damaged due to the Project; and (ii) a rehabilitation grant to cover suffering and hardship [based on family size and other criteria to be determined by the Compensation Fixation and Rehabilitation Management Committees (see para 3.29)];
(b) Seriously Project Affected Families (SPAFs). Compensation to the SPAFs is to include: (i) in case of land lost, compensation paid either in cash or substitute asset (land) of equal production potential to that lost; (ii) in case of other asset(s) (e.g. building), compensation paid in cash; (iii) a rehabilitation grant; and, (iv) employment for at least one member of the SPAF in project-related activities, including training as needed;
(c) Formal and Informal Tenants are to receive 25% of the compensation for the land acquired, the remainder being paid to the registered landowner. In addition, a rehabilitation grant equivalent to 50% of the compensation for the land acquired will be paid to the tenants, formal or informal;
(d) Families Affected by Leasing Agreements will be compensated in relation to the type and productivity of the land being leased. Land used temporarily will be fully restored before being returned to its owner; and
(e) Families Located in the Transmission Right of Way, whose land is not acquired but is subject to way-leave and building height restrictions by the project. In these cases, compensation will be decided by the Compensation Committee, provided that such amounts shall not fall below 5% of the market value of the affected land.

4. Land compensation is to be paid at the current market value in the concerned area, to be determined by a Compensation Fixation and Rehabilitation Management Committee (CFRMC) chaired by the Chief District Officer. The compensation is to take account of the type of land, the quality of the individual plots and their productivity and the vicinity of roads, shops and other facilities. Land required to be leased will need to be surveyed and values of crops produced and income losses from other economic activities assessed, since the rents payable will be equivalent to such annual crop and income loss. The resettlement policy provides for the "land for land" option for the SPAFs who opt for it.

Scope of ACRP

5. The AHP ACRP will cover the three main components of the project: the access road (valley route); the hydroelectric dam, the transmission line, and the associated construction camps. The 122 km access road will require acquisition of approximately 375 ha. of land and affect approximately 931 households of which 115 would be SPAFs. The Joint Venture Arun III (the project supervision consultants) estimates that approximately 74% of the land along the access road is privately held, giving an aggregate length for the ACRP at about 90 km. The dam reservoir would flood 50 ha. and total land acquisition for the dam (including land for construction needs) would be about 117 ha. About 40 families would be affected by the work camps of which 19

would be SPAFs. No families would be affected by the dam. About 27 families would be affected by the transmission line of which 4 would be SPAFs. The environmental assessment (EA) estimates that 602 ha. of land will be required for the transmission line. Altogether about 998 families would be affected by the three components of the Arun Project of which 138 would be SPAFs. Of the total landtake, agricultural land will be 186 ha. which corresponds to about 0.14% of agricultural land in the Arun basin. The data are summarized in Table 1.

6. The above data appear to be extremely low compared to comparable schemes. Table 2 shows a ranking of dam reservoir projects in terms of the people displaced from a reservoir to produce one GWh per year. It can be seen that the Arun scheme has a ratio less than half of the Berke scheme and less than 0.1% of the Nangbeto scheme in Togo, which was commissioned in 1989.

7. The transmission component includes an additional compensation category that obliges NEA to pay compensation for all the land and property lying in the RoW of the transmission line. Compensation will be fixed by the CFRMC in accord with Electricity Regulation 2050 B.S.

Land Values

8. Land values presented in this section are based on their potential for productive use (Khet, Beri or irrigated land) and their contiguousness to foot trails and bazaars.

9. Khet land is flat, either naturally or formed by terracing. Khet is capable of holding water and could therefore be used for cultivation of paddy. Khet is irrigated land. Beri land differs from khet in that it is often sloping.

Building Values

10. The value of buildings has a range of NRs 50 - NRs 620 per square foot, depending upon the type of house. Prices of individual houses will vary, depending on their construction (e.g. whether corrugated iron roofing or cement are used) and location.

Baseline Survey

11. The ACRP is based on a detailed baseline survey of land-holders affected by the project. For example, for the access road component which encompasses the vast majority of project land-holders, 858 of the 902 PAF's have been interviewed and socio-economic details noted in a 17 page questionnaire (see Attachment 1).

Table 1 - Estimated Total Project Land Take and Affected Families

Item	Project Component			Total
	Hydropower Site	Access Road	Transmission Lines	
1. Land take (ha)				
Permanent	47.8	375	7.6	430.4
Temporary	69.1	19	403.5	491.6
Partial	-	-	190.5	190.5
Total	116.9	394	601.6	1,112.5
Privately Held	76.7	293	312.2	681.9
Publicly Held	40.2	101	289.4	430.6
Total	116.9	394	601.6	1,112.5
2. Total PAFs	40	931 1/	27	998
of which SPAFs	19	115	4	138

1/ In addition seven informal tenants and 15 formal tenants were identified on the access road alignment of which one is a SPAF.

Table 2 - Ratio of the Number of People Displaced/Annual Power Production for a Number of Purely Hydroelectric Dams

	Date of Commissioning	Annual Power Production (GWh)	People Displaced from Dam Reservoir Area	Ratio People Displaced/ Annual Power Production (GWh^{-1})
Arun (Nepal)	2001	2891	114	0.036
Berke (Turkey)	1996	1669	144	0.087
Vouglans (France)	1968	230	150	0.65
Lokka and Porttipahta (2) (Finland)	1970	412	56	1.4
Sir (Turkey)	1991	725	3010 (3)	4.2
Adjarala (Togo/Benin) (4)	1996	270	7301	27
Nangbeto (Togo)	1989	150	12000	80

(1) Source: Arun III Hydroelectric Project, Environmental Assessment Executive Summary, 1993
(2) Source: CIGB, 1988
(3) Source: Yenicrioglu and Kaya, 1987, Table 1
(4) Source: Adjarala dam and HPP, Environmental Assessment, in progress, Coyne et Bellier
(5) Source: Direction du Project Nangbeto, 1988

Basis of Normal Compensation

12. The amount of "normal" compensation (i.e., excluding rehabilitation grant payable to all PAF/SPAFs and other rehabilitation measures, as described in the Guidelines) comprises sums for the market value of land lost, for the market value of trees on the land, for the market value of standing crops (if in place when the land is acquired) and for houses and buildings. The normal compensation will be equivalent to market values.

Basis of Rehabilitation Grant

13. The criteria used to determine rehabilitation (hardship) grants payable to PAFs and SPAFs are as follows:

(a) a cash amount equivalent to the annual income from crops on the land lost will be provided, as well as the income loss from other economic activities carried out on such land;

(b) where fruit trees fall on the acquired or damaged land, the replanting costs for each variety plus a cash amount equivalent to the market value of fruit produced by the trees over a four year period; and

(c) for the loss of a principal residence falling within the RoW, compensation (in addition to normal compensation of the value of the house) in the form of house rent for a four month period will be provided according to market rates.

Additional SPAF Rehabilitation Measures Under the Guidelines

14. The Guidelines state that SPAFs are entitled to employment and training. For SPAFs, they must be provided with employment for at least one member of their families.

Budget and Payment Schedule for the ACRP Works

15. A provisional year by year budget, including physical contingencies but excluding price contingencies, for the payment of compensation for the acquisition of land for the whole project (access road, hydropower sites and transmission lines) is shown in the Attachment. The total ACRP budget is estimated at NRs 81.42 million which will be funded by NEA. The budget is based on preliminary results of the ACRP work for the access road and with respect to land values are probably conservative; i.e., indications are that the final agreed compensation amounts will be less than those assumed. Approximately 500 staff months will be used by the supervision consultants to supervise/monitor the ACRP implementation (para 18).

16. The budget also includes direct field costs(for survey and interview teams); administrative costs for payments to PAFs; publication and printing; meeting allowances; special provisions for SPAFs including training; and rental accommodation for project administrations. Costs of supervision and monitoring are included in the supervisory consultants and NEA's engineering and management budget. The bar chart in Attachment 2 indicates the timetable for compensation and rehabilitation payments for each of the three main project components. Of the total planned budget of NRs 81,420,000, approximately 14% is for rehabilitation grants and trees and 86% for compensation.

Resettlement Planning, Implementation and Organization

17. The Guidelines were originally issued through the authority of the Ministry of Transportation, with the Department of Roads (DOR) as the implementing agency. The Guidelines establish Acquisition and Rehabilitation Committees (ARCs), now called the Compensation and Fixation Management Committees, for determining compensation rates, acquiring land, negotiating with PAFs and establishing rehabilitation measures. The Guidelines have been changed to ensure compliance with World Bank policies and to reflect that management of the AHP ACRP is now the responsibility of NEA (under the Ministry of Water Resources) and NEA's Environmental Unit. NEA has contracted with the consulting firm of the Joint Venture Arun III to carry out the ACRP planning and implementation tasks. Responsibility for payment of compensation is with NEA/HMG/N.

Proposed Implementation Process and Schedule

18. NEA has submitted a detailed action plan, satisfactory to IDA, for implementation of the ACRP, and a Due Process Manual. In implementing the ACRP, NEA shall ensure that except in case of extraordinary situations, the payment of compensation to affected families will be completed at least 35 days prior to the start of construction activities in the case of those families required to be relocated to other land parcels, and at least 15 days in the case of those families not required to relocate or who move within their existing land parcels. It has also appointed a resettlement advisor to its Arun Project Environmental Monitoring Unit (APEMU) which will be entrusted with day to day supervision of the ACRP. Staffing for the APEMU is laid down in the Environmental Monitoring Action Plan but additional staff will be needed. Though all necessary surveys of the families and properties affected by the project have been carried out, the time schedule of land acquisition, compensation, rehabilitation and resettlement related activities has not been finalized. This is because the implementation schedule of these activities is dependent on the construction schedule of the contractor, which has not been finalized until now. The detailed implementation schedule for various activities to be carried out under ACRP in the next two years will be prepared within three months from the date of the order to commence construction. The ACRP implementation schedule for successive years will be prepared annually, covering at least the following two years of the proposed construction schedule.

19. Grievance Redress Procedure. In the first instance, if a PAF is dissatisfied with a decision of the Compensation Fixation and Rehabilitation Management Committee (CFRMC) in regard to issues of compensation, resettlement/rehabilitation and in particular, the "land for land" option, he may contact NEA. His grievance, if then unresolved, would be referred to a Committee chaired by the Secretary of Home Affairs or a senior official (of the Ministry of Home Affairs) designated by the Secretary, and consisting of at least two more members. One such member may be a non-Government person. This committee will be operational prior to the initiation of implementation of the ACRP. This committee will meet in the Project Area at least once every three months to:

(i) resolve any grievances regarding payment of compensation;

(ii) resolve grievances regarding provision of other resettlement entitlements such as training, employment, and/or rehabilitation grants; and

(iii) ensure fair implementation of the "land for land" policy for SPAFs who choose that option.

The committee will review appeals and communicate the results to PAFs, normally within 21 days of its receipt. In reviewing the appeal, the committee may seek the views of APEMU, whose members include consultants, local officials, and NGO representatives as well as NEA staff.

20. Construction work on any front will start only after compensation and resettlement of the affected people on that section is completed.

Monitoring and Evaluation of ACRP

21. The basis for detailed monitoring program has been established with the use of a Geographic Information System (GIS) linked to a PAF/SPAF database. The cadastral data for the access road alignment has already been digitized. On the same database will be superimposed the detailed land survey information showing the location and areas of land to be taken for the project. Each affected plot of land will be referenced with the PAF's name, address and essential data collected during the household survey. Monitoring of compensation payments made to each PAF and implementation of rehabilitation measures taken will also be included in the database, so that at any one time information on the ACRP work can be recalled, reviewed and updated.

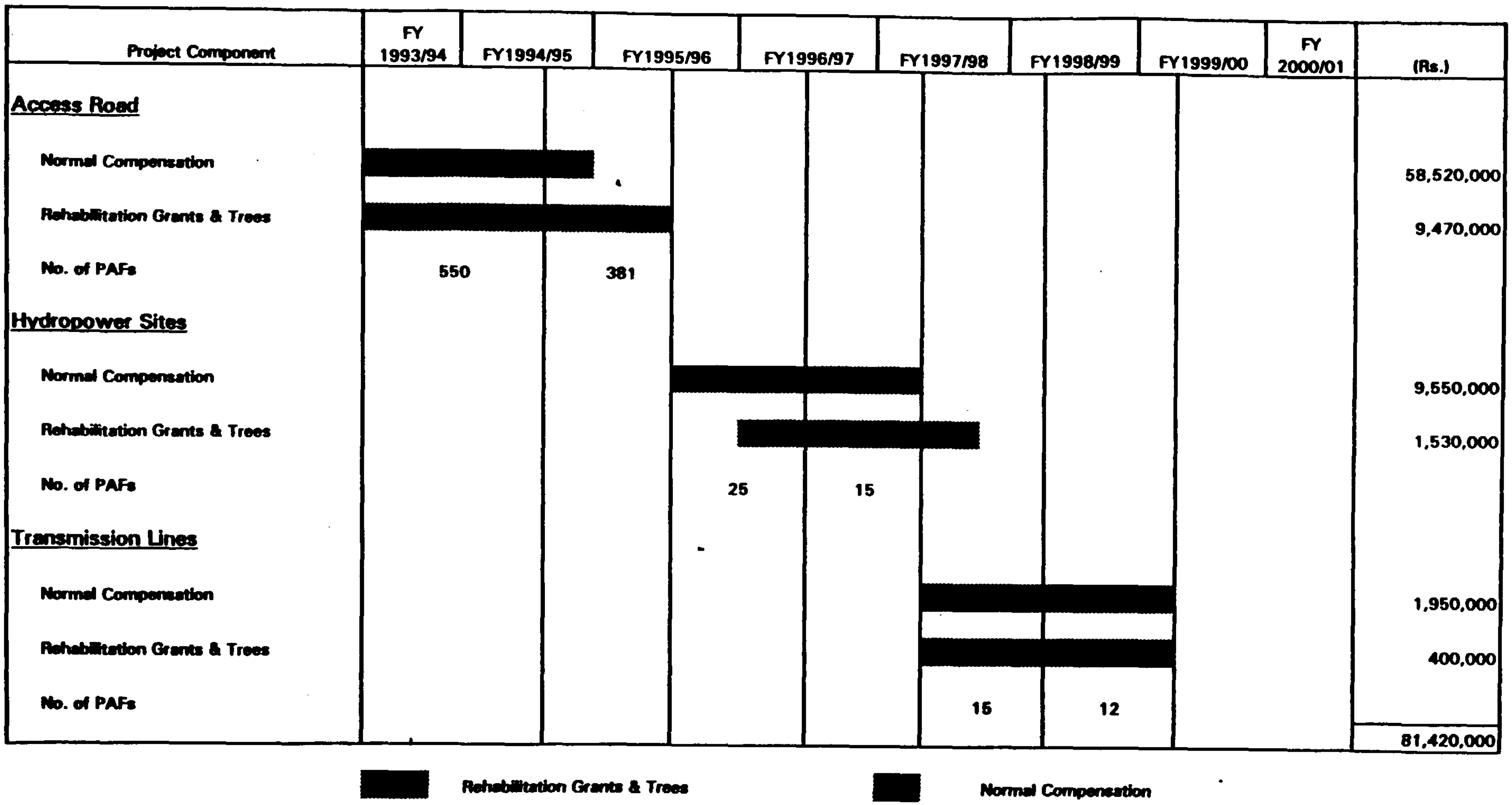
22. Supervision arrangements and monitoring indicators are detailed in Annexes 3.7 and 3.10, respectively. However, in addition to the normal supervision missions from Washington, there will be appointed a full time Project Monitor who will be responsible for reporting to the Donors on all AHP-related activities including progress of the ACRP and the Regional Action Program.

Risk

23. Because the land to be acquired is of a dispersed character and generally in small parcels, resettlement sites as such with the provision of civil infrastructure, are not a feature of the Arun project. Moreover, experience on the ridge road alignment indicates that the few SPAFs concerned are unlikely to choose the "land for land" option in favor of cash compensation.

24. The mitigation of risk in implementation of the ACRP will be largely effected by the comprehensiveness of the monitoring package.

Figure 3.1: TIMETABLE OF COMPENSATION PAYMENTS*



Includes physical contingencies of 10%.

Source: Nepal Electricity Authority and IDA estimates.

July 12, 1994

NEPAL

ARUN III HYDROELECTRIC PROJECT

Panel of Experts

Terms of Reference

General

1. An independent Panel of Experts (POE) will be retained for review, assistance and guidance on specific engineering design and construction issues as well as environmental aspects which may arise during the implementation of the project.

It will assist the Nepal Electricity Authority (NEA) and the Engineer to undertake periodic comprehensive review of the design needed for construction and of the execution of civil works for all major structures of the project including the access road, bridges, river diversion, dam, spillway, desanding basins, tunnels, surge shaft, power cavern and appurtenant structures, including installation and commissioning of generating units and transmission lines as well as review of environmental and rehabilitation works. The main purpose of the POE's engagement is to make recommendations to ensure that sound engineering, environmental and socio-economic practices are applied during implementation of the project with overall purpose of achieving cost effectiveness, adequacy, efficiency and safety of the project over its useful life.

Organization and Composition

2. The POE will consist of members with specialized experience in the following fields:

- Highway engineering including design of bridges
- Design of hydro electric power projects/hydraulic engineering
- Construction management of hydro electric power projects
- Engineering geology/seismology
- Geotechnical engineering
- Sedimentology/hydrology
- Gravity dams
- Electrical and mechanical engineering for hydropower projects including substation and transmission lines
- Claims handling/legal advice on contractual aspects
- Environmental and Land Acquisition and Rehabilitation Aspects

3. The POE may request the assistance, on a temporary basis, of specialists in other areas when in their opinion it is advisable to do so. Due to the diversity of topics, it may be necessary to have more than one specialist cover the project's environmental aspects.

4. NEA will appoint a Chairman from the members of the Panel to coordinate its activities and to chair its meetings to ensure the members

participation in the review and to provide a balance in its views, decisions and recommendations.

Meetings and Schedules

5. NEA, in consultation with the Engineer, will establish the frequency and timing of the Panel meeting to conform with the schedule of the work in progress. The period between meetings will not normally exceed six months during the construction of the works. NEA and the Engineer will provide all available information on the subject to be reviewed by the POE and will provide the necessary logistics, including transportation, offices and accommodations at site. At each meeting, the Engineer and the Panel will schedule dates for the next meeting and the tentative timing for the subsequent meetings to enable the Panel members to arrange their individual schedules. NEA in consultation with the Engineer may call for extraordinary meetings of the Panel in critical situations and may solicit the services of individual members between Panel meetings as considered necessary with copies of the member's input being sent to the other Panel members.

6. NEA in consultation with the Engineer will prepare and submit to the panel, 21 days before each Panel meeting, the tentative agenda and the background material for that meeting.

7. The Panel will prepare and submit to NEA and the Engineer, a written report including recommendations before the adjournment of each meeting. NEA will submit all POE reports, as well as its own and the engineers' comments on these reports (if any), to the Donors within three weeks of the closing of each meeting.

Scope of Work

8. The Panel should review and provide recommendations on the subjects mentioned below or any other which it perceives to be important to the investigations, design, construction, safety, operation and maintenance of the project.

(a) Highway Engineering and Bridges. The design of the access road, bridges and other major structures to be reviewed in regard to engineering soundness as well as to their behavior under the prevailing hydrological and sedimentological conditions.

(b) Design Aspects. The design criteria and assumption used or to be used for the project, the design of structures; the diversion works and the design of its various components; the spillways design and capacity; design of an early warning system for floods, including glacier lake outburst floods (GLOFS); the procedures for routine inspection of the dam and other structures and checking of safety thereof, including organization and staffing of units entrusted with these tasks.

(c) Sedimentology/Hydrology. Estimates of sediment load that will enter the reservoir, analysis of potential sedimentation of the reservoir and measures to ameliorate this. Assessment of the inflows to the reservoir and operation rules of the reservoir and desanding basins for attaining maximum safety and efficiency. Assess the impact of floods and sediments on bridges and other major structures of the access road.

(d) Hydraulic Engineering. The hydraulic design of the spillways and energy dissipation facilities, diversion works, and water conductors such as intake, power tunnel, surge chamber, manifolds and tail race, etc.

(e) Engineering Geology/Seismology. The quality and sufficiency of the geological investigations and interpretation thereof, including tests; determination of properties of material for construction, as well as the geology in the reservoir area, the access road, bridges and sites for the dam, tunnels, power cavern and underground work; the geological implications with regard to foundation design, stability of natural and excavated slopes and requirements of surface and underground excavations. The criteria and methodology for determination of the magnitude of ground acceleration of seismic impacts and adequacy of the design and execution in regard to earthquake resistance.

(f) Geotechnical Engineering. The design of surface and underground excavations, including selection of stable slopes; appropriate shape and orientation for underground excavations; and the design of temporary and permanent support systems and linings. The geotechnical implications on design of foundations and adequacy and sufficiency of the proposed cavern instrumentation and monitoring system, as well as the design of grouting works for the dam and underground structures.

(g) Gravity Dam. The adequacy of the field and laboratory investigations for the foundation and the materials for the construction of the dam; the analysis of the dam; the selection of the foundation levels; measures for drainage and treatment by grouting of foundation and abutments; and the instrumentation and proposed monitoring system.

(h) Construction management of Hydroelectric Projects. Construction planning, temporary facilities and access to the sites; the master implementation program and construction schedules; tender documents and conditions of contract; construction procedures in relation to the access road, dam, cofferdam, tunnels, and power cavern, etc., river diversion at closure; contractor's construction equipment and plant; safety arrangements, staffing and procedures for managing the implementation and construction of the project.

(i) Electrical and Mechanical Equipment for the Project incl. Transmission Lines. Specifications and manufacturers proposals for the turbines, generators and electrical and mechanical equipment in the power cavern, air pressure system for the tailrace tunnel, switchyard substations and other works, design of turbines, generators, switchgear and control equipment, etc. Erection specifications, procedures and schedule for equipment. Review of design of the Duhabi substation with emphasis to export power to India.

(j) Claims Handling, contract management, advice on legal and contractual aspects which are likely to lead to significant delays in completion of the project and/or to increases in cost for construction and consultant's services or O&M, or which may lead to claims by the contractors or suppliers. Assist NEA in resolving claims issues through participation in discussions with the contractors or in arbitration if necessary.

(k) Environmental and Rehabilitation Aspects: (i) Review of environmental protection and rehabilitation work to ensure compliance with the approved plans; (ii) provide a source of technical advice on studies necessary for final design measures (i.e., fisheries management, wildlife protection, transmission line routing, bio-diversity conservation areas and forestry protection management; (iii) review coordination and interface arrangements with RAP-Secretariat and field offices; (iv) monitor progress on implementation of agreed measures (including those identified under the Regional Action Program), in particular compatibility between timing of environmental/social measures and construction timetables; and (v) recommend improvements in measures and timing, as necessary.

Duration of POE's Assignment

9. The composition of the POE should be adopted in accordance with the actual requirements. It is not necessary to have the entire POE invited to each meeting. Once the excavation works are over, the participation of the geologist and geotechnical engineers may no longer be required. The mechanical and electrical engineers will mainly be needed during the erection period of equipment. It would, however, be advisable to have at least the Chairman of the POE participating in all meetings to ensure continuity.

10. The period of the assignment of the POE will last until the completion of the project.

NEPAL

ARUN III HYDROELECTRIC PROJECT

Training Component [1]

A. Training and Manpower Rationalization under HRD/NEA responsibility

		US$
a)	Training Center Complex	
i)	- Additional Equipment	1,000,000
ii)	T.A. Experts, 24 mm	360,000
iii)	Fellowships (Director + 9 Instructors) 10 x 2m = 20 m-m	200,000
		1,560,000
b)	Mobile Units for On-site Training	
i)	Equipment	600,000
ii)	T.A. Experts 6 m-m	90,000
		690,000
c)	Human Resources Department (Manpower Division) and Personnel Dept. (Follow-up of Manpower Rationalization)	
i)	T.A. Experts, 6 m-m	90,000
ii)	Fellowships, 8 m-m	80,000
		170,000
d)	Management Development Includes seminars focused on corporate strategy development, for top managers; senior & middle level management; workshops, and skill development programs for middle and supervisory management, plus trainers' training (four years program)	500,000
e)	T.A for financial management, including auditing, accounting systems and manuals	150,000
f)	Apprenticeship pilot plan (German dual system)	100,000
g)	T.A. for Operations & Maintenance of existing hydroelectric plants	230,000
	Total (A)	3,400,000

1/ Sub-components A) and B) will be financed by IDA and KfW respectively

		US$
B)	Training for the Arun Hydroelectric Plant (Under the responsibility of the project supervision consultant)	
	a) Training for Construction Supervision	400,000
	Includes T.A. and fellowships abroad, on-the-job training and lectures	
	b) Training for Operations Management and Maintenance	3,200,000
	Total (B)	3,600,000
	GRAND TOTAL	7,000,000

NEPAL

ARUN III HYDROELECTRIC PROJECT

Private Sector Hydro Facility, Selection Criteria and Administrative Reporting Requirements

Introduction

1. Under the Arun Hydroelectric Project, HMG has agreed to set up a hydro facility to promote involvement of the private sector in Nepal's power development. This annex sets out the objective of the facility, selection criteria, administrative and reporting requirements.

Objectives

2. The objectives of the hydro facility are to enable Nepal's private sector to (a) undertake feasibility studies of micro/mini hydro schemes and (b) assist in the implementation of viable schemes.

Project Selection Criteria

3. Project selection criteria refer to the conduct of feasibility studies and the implementation of viable schemes based on feasibility studies. In relation to the conduct of feasibility studies, each funding proposal should be supported by an analysis of the proposed project based on a reconnaissance study in terms of its technical, financial, economic, environmental and institutional viability[1]. Only projects that are shown to be economically and financially viable should be considered for financing.

4. In relation to the implementation of viable schemes each proposal should be supported by a feasibility study demonstrating that the project is viable in terms of its technical, financial, economic and institutional characteristics. If the project is designed to be connected to the national grid, then the applications should be accompanied by a power purchase agreement (PPA) with the buyer.

Administrative Requirements

5. HMG will arrange to transfer US$6 million equivalent from the Nepal Rastra Bank to the Nepal Industrial Development Corporation (NIDC) to set up the fund as of December 31, 1994. NIDC will set up a suitability staffed office to administer the fund and will enter into suitable arrangements with HMG to recover its administrative costs.

6. Onlent funds will be at commercial rates; any funds passed on as a grant will be explicitly justified and budgeted separately from onlent funds.

1/ For the purpose of project selection, the detailed methodology and procedures set out in the following NEA/GTZ report and manual will be used: "Small Hydropower Master Plan in Nepal: Main Report (2 Volumes)." Kathmandu, August 1993)

Reporting Requirements

7. The NIDC office will liaise with the Electricity Development Center (EDC) of the Ministry of Water Resources (MOWR) and the Nepal Electricity Authority (NEA) in relation to their experience in developing and/or entering into power purchase agreements (PPA) for private sector schemes. In particular, NIDC staff will coordinate with EDC and MOWR in relation to policy and/or other developments under the USAID- sponsored Private Electricity Project.

8. HMG will require NIDC to report quarterly on the progress of the Hydro Fund, with a copy to IDA. Discussions on the status of the Fund will be held with NIDC in conjunction with IDA supervision missions of the Arun III project. The first meeting between IDA and NIDC staff would take place in conjunction with the project launch workshop scheduled for December 1994, at which time the criteria for project selection/management will be further refined.

NEPAL

ARUN III HYDROELECTRIC PROJECT

Supervision Plan and Monitoring of Progress

1. As indicated in Chapter III of the text, detailed arrangements have been put in place in Nepal to assure that the AHP is adequately supervised and monitored. The keystone to this effort will be the contract supervision consultants assisted by the POE to advise on major design and construction problems. This effort will be complemented by the local NGO/consultants to facilitate appropriate coordination, monitoring and implementation of the RAP. Given the complexity of the project, a substantial program of field visits by IDA staff will be required to assure that the project is properly launched and stays on schedule. A supervision program is outlined below that takes into account the regular review of progress reports. This is estimated at an average of about 106 staff weeks per year for the life of the project of which approximately 80 weeks would be devoted to sectoral and project issues and 25 weeks to macroeconomic issues. IDA plans to hire a long-term expatriate consultant (initially for three years), with expertise in the implementation of large civil works contracts and environmental management and to be located in the Kathmandu Resident Mission, to monitor the project on behalf of the Donors. Field visits would account for approximately 20-26 staff weeks for supervising the project and sectoral issues. Another 16-20 weeks would be needed at the Nepal Resident Mission and at Bank Headquarters. In addition, IDA's supervision missions would be scheduled at least once a year to coincide with the POE missions. Where feasible all supervision missions will be conducted jointly with the other donors.

I. Sectoral/Project Missions

Approximate Date of Input (Mo/Yr)	Activity	Expected Skill Required	Staffweeks
12/94	Project Launch W/Shop	Task Manager (Hydropower Specialist), Environmental Expert, Resettlement Expert, Disbursement Specialist, Financial Analyst	10
2/95	Supervision Mission #2	Task Manager Highway Engineer Environmental Expert Financial Analyst	8
5/95	First Annual Review/ Supervision Mission #3	Task Manager Highway Engineer Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	14

9/95	Supervision Mission #4	Task Manager Resettlement Expert Financial Analyst	6
1/96	Supervision Mission #5	Task Manager Environmental Expert	4
5/96	Second Annual Review/Supervision Mission #6	Task Manager Highway Engineer Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	14
9/96	Supervision Mission #7	Task Manager Environmental Expert Financial Analyst	6
1/97	Supervision Mission #8	Task Manager Highway Engineer Resettlement Expert	6
5/97	Third Annual Review/ Supervision Mission #9	Task Manager Highway Engineer Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	14
9/97	Supervision Mission #10	Task Manager Resettlement Expert Financial Analyst	6
1/98	Supervision Mission #11	Task Manager Environmental Expert	4
5/98	Fourth Annual Review/Supervision Mission #12	Task Manager Highway Engineer Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	14
9/98	Supervision Mission #13	Task Manager Environmental Expert Financial Analyst	6
1/99	Supervision Mission #14	Task Manager Resettlement Expert Financial Analyst	6
5/99	Fifth Annual Review/ Supervision Mission #15	Task Manager Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	12
9/99	Supervision Mission #16	Task Manager Resettlement Expert Financial Analyst	6

1/00	Supervision Mission #17	Task Manager Environmental Expert	4
5/00	Sixth Annual Review/Supervision Mission #18	Task Manager Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	12
9/00	Supervision Mission #19	Task Manager Resettlement Expert Financial Analyst	6
1/01	Supervision Mission #20	Task Manager Environmental Expert	4
5/01	Seventh Annual Review/ Supervision Mission #21	Task Manager Environmental Expert Resettlement Expert Financial Analyst Energy Economist Training Expert	12
9/01	Supervision Mission #22	Task Manager Environmental Expert	4
1/02	Supervision Mission #23	Task Manager Environmental Expert	4
5/02	Eighth Annual Review/ Supervision Mission #24	Task Manager Environmental Expert Resettlement Expert Financial Analyst Training Expert	10
9/02	Supervision Mission #25	Task Manager Environmental Expert Resettlement Expert Financial Analyst Energy Economist	10
1/03	Supervision Mission #26	Task Manager Environmental Expert	4

II. Macroeconomic Missions

The macroeconomic situation will continue to be monitored very carefully through a combination of IDA (and IMF) missions, as well as quarterly reporting by the Bank's Resident Mission in Kathmandu. A second year PFP/ESAF program covering the period 1993/94 - 1995/96 is currently under preparation. This will provide the basis for a joint IDA/IMF review of the fiscal framework every year (around June/July); in addition, a mid-year review of the budget would be undertaken in January each year to ensure that the macro framework is being adhered to and appropriate corrective actions are taken, if needed. Once the PFP/ESAF arrangement (presently under consideration) is completed by 1995/96, it is expected that the IMF will continue to maintain a watching brief on the economy, while IDA will field regular macroeconomic missions (if possible, jointly with the Fund) around January and June/July each year. The government has also agreed that IDA missions will also review the resource envelope for the power sector annually (in June/July each year) in the context of IDA/IMF discussions on the annual fiscal framework. In addition, the Bank's Resident Mission in Kathmandu (staffed by a grade 25 level macro-economist) will provide quarterly updates of progress in macro-economic management around July, October, January and April each year. The presently planned supervision schedule is as follows:

Approximate Date	Frequency	Activity	Expected Skills	IDA Staff Weeks
January/February	Annually	Joint IDA/IMF PFP/ESAF mission	Macroeconomist (IDA) Task Manager (IMF), & possibly 3 other IMF economists	6
June/July	Annually	Joint IDA/IMF PFP/ESAF mission to agree on fiscal framework	Macroeconomist (IDA), Task Manager (IMF) & 3 other IMF economists	6
January April July October	Quarterly	Periodic reporting on macroeconomic situation	Resident macroeconomist in World Bank field office in Kathmandu	12

ARUN HYDRO PROJECT

ENVIRONMENTAL IMPLEMENTATION INDICATORS

PRE-CONSTRUCTION
TIME-BOUND IMPLEMENTATION

Indicators Yr-1

Activity	June	July	August	September	October	November	December	January	February	March	April	May
RAP revision underway			xxxxxxxxx	xxxxxxxxxxx	xxxxxxxxx	xxxxxxxxxxx	xxxxxxxxxxx	xxxx				
Project negotiations	xxxxxxx											
RAP Secretariat in place			xxxxxxxxx									
Field environment unit in place							xxxxxxxxxxx					
Compensation process initiated		xxxxxxx										
Env. and social expert mission	xxx			xxxxxxxxxxx			xxxxxxxxxxx					
Project effectiveness[1]						x						
Land compensation paid		xxxxxxx	xxxxxxxxx	xxxxxxxxxxx	xxxxxxxxx	xxxxxxxxxxx	xxxxxxxxxxx	xxxxxxxxx				
Contract mobilization						xxxxxxxxxxx	xxxxxxxxxxx	xxxxxxxxx				
Consultant, contractor, RAP, Bank Env. experts mobilized						xxxxxxxxxxx						
Contractors Env. Plan Agreed					xxxxxxxxx							
All RAP pre-emptive measures							xxxxxxxxxxx	xxxxxxxxx	xxxxxxxxxxx	xxxxxxx	xxxxxx	
Road construction begins									xxxxxxxxxxx	xxxxxxx	xxxxxx	

1/ Per Cr. 2029-NEP

ARUN III HYDROELECTRIC PROJECT

ENVIRONMENTAL IMPLEMENTATION INDICATORS

Annex	Activity Group	Achievement of Target*
1.	Construction direct impact mitigation	1-4
2.	Regional Action Program	1-4
3.	Resettlement	1-4
4.	Monitoring and Consultation	1-4
5.	Overall Rating (Form 590)	1-4

* In accord with the rating system used for supervising World Bank projects. This is based on planned expenditures within time-frame (estimated where necessary).

DIRECT IMPACT (CONSTRUCTION)

INDICATORS

		Mitigation Measures Achieved
A.	Access Road	1-4
B.	Campsites	1-4
C.	Hydropower	1-4
D.	Transmission Lines	1-4
E.	Overall	1-4

IMPACTS OF ARUN ACCESS ROAD
CONSTRUCTION

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
CONSTRUCTION				
NATURAL RESOURCES	Destabilization of sloped by cut and fill	Care in route alignment, design, construction sequence, drainage, slope stabilization measures	Engineer/ Contractor	1-4
	Damage to slopes, streams and fields from spoil disposal	Balance earthworks; locate and operate disposal sites with care; avoid sidecasting; use rivers for disposal if appropriate	Engineer/ Contractor	1-4
	Impacts on forests from land take and demands of workforce and incomers	Cut only those trees affected by Permanent Works; specify non-timber construction materials; ban use of wood for heating bitumen; control workforce and supply subsidized kerosene; strengthen forest protection and management	Engineer/ Contractor/RAP	1-4
	Severance of wildlife habitat, habitat destruction, disturbance, hunting	Route road around key ecological areas; ban Contractor use of key areas; control workforce; education	Engineer/ Contractor/RAP	1-4
	Increase in fishing; use of damaging methods	Supply subsidize food to workforce; control explosives; encourage sustainable fishing methods	Contractor/RAP	1-4
ECONOMY	Land take for road	Minimize road length and Right of Way width; compensate and rehabilitate	Engineer	1-4
	Employment on road construction, and resultant cash flow	Encourage local recruitment	Engineer/ Contractor	1-4
	Price inflation, and lowered availability of food to poor	Provide subsidized food for workforce; assist poor in obtaining employment and service opportunities	Contractor/RAP	1-4

IMPACTS OF TEMPORARY CAMPSITES

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
NATURAL RESOURCES	Erosion from storm drainage	Proper design of outfalls	Contractor	1-4
	Possible damage from earthquake	Proper design of structures, foundation	Contractor	
	Possible groundwater contamination from fuel spills and sewerage	Bunding around fuel storage	Contractor	
	Forest degradation and clearance to meet increased demand for forest products; risk of fire; clearance for cultivation by incomers or displaced persons	Avoid use of wood as fuel by labor force; supply subsidized kerosene; promote alternatives to wood for construction and heating/cooling; establish user groups; education	Contractor + RAP/NEA/NGO	
	Wildlife: loss of habitat; disturbance so reducing breeding success; direct hunting for new markets	Protect/manage forests; education; extend and enforce hunting regulations; flight path restrictions	Contractor RAP/NE/NGO, Civil Aviation	
	Increased fishing pressure for new market; use of destructive methods	Avoid providing any blasting materials to public. Encourage fishing by non-damaging methods	Contractor RAP/NEA/NGO	
DEMOGRAPHY/SETTLEMENT	Displacement of families	Minimize land requirement; for acquisition of land needed permanently use ACRP	Contractor/NEA	1-4
	Concentration of project workforce	Fully serviced camps near workplace	Contractor	
	Influx of hundreds of job seekers and entrepreneurs, uncontrolled settlements, urban growth	Regulation of settlement on public and private land; Training and strengthening of VDC	RAP/VDC/NGO	
ECONOMY	Loss of arable and grazing land, decrease of agricultural production and fodder resources	Minimize land requirement; Minimize acquisition of arable land; Acquisition of land only for permanent use; Rent land required temporarily according to recommendations; ACRP	Contractor/NEA	1-4
	Requirement of additional food, commodities, fuel, price inflation	Encourage production of crops & livestock; Provide goods, kerosene, electricity to workforce (fair price shops); Limited use of local fuelwood, prohibit unauthorized felling of trees; Forestry development programs	RAP/NGO/ Contractor	
	Increase of spatial and economic dissimilarities	Integrated rural development programs	RAP/NGO	
	Additional pressure on infrastructure	Improvement of public infrastructure	RAP/VDC	

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
	Increase of land values	Minimize land requirement. Rent land required temporarily. Minimize delays between property evaluation, compensation and acquisition	NEA/Contractor	
	Job opportunities for local people	Training of local people to fill appropriate positions	NEA/RAP	
HEALTH	Additional pressure on public health care system	Improvement of public health services; First aid facilities for project workforce, Information and extension programs	RAP/Contractor NGO/VDC	1-4
	Additional pressure on public water system	Water supply for project facilities to be constructed; Improvement of existing water system	Contractor/ HMG/JV	
	Additional waste and sewage	Project waste to be buried or burned, adequate sanitary system; Extension programs for latrines	Contractor/RAP/ NGO/JV	

IMPACTS OF HYDROPOWER COMPONENTS
CONSTRUCTION

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
AIR QUALITY	Increase of airborne dust from construction traffic and plant during dry season	Install dust collectors (filters), water sprays and emission control equipment; Dust control with water in dry season; black top heavy use areas; breathing protection	Contractor	1-4
TOPOGRAPHY SOILS, LANDUSE & REVEGETATION	Site and construction impacts on drainage systems, vegetation cover, run off, slopes; loss of cultivated land	Road construction methods to be controlled; Reduce to extent possible spoil dumps and associated roads; Combine adit and powerhouse camps; Slope protection measures; Reclaim and revegetate all temporary roads; Salvage soils for use in reclamation	Contractor	1-4
	Impacts of quarries and borrow pits on drainage systems, vegetation cover, slopes, and land; creation of steep highwall sections	Backfill borrow pits and quarries with spoil; Backfill to stable contours; Provide top soil; Excavate by having benches wide enough for later cultivation; Provide for controlled drainage; Reforest & revegetate disturbed slopes; Make temporary facilities subject to approval	Contractor	
	Spoil disposal areas: loss of cultivated land; creation of fill areas; construction of temporary access roads	Eliminate spoil dumps by using selected spoil for concrete, road maintenance, and backfill for quarry & borrow pits; Place remainder of spoil in river; Make temporary facilities subject to approval	Contractor	
	Contractor's Camps: temporary loss of cultivated lands; effects on drainage systems; loss of vegetation cover; loss of productive forest lands; construction of access roads; waste disposal	Pre-select sites. Alternative or additional sites proposed by Contractor to be subject to Engineer's approval; Combine adit and powerhouse construction camps; Implement erosion protection measures; minimize distance between camps & work areas; Salvage soils prior to grading; Replace soils & reclaim as cultivated land; Install drainage control systems for long term use; Revegetate all disturbed slopes; Make temporary facilities subject to approval; Reduce space requirements by specifying two story buildings	Contractor/NEA	

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
	Permanent NEA Camp: loss of cultivated land; displacement of local residents; changes in drainage systems; increase in erosion potential; creation of terraces; cutting of slopes	Salvage soils prior to grading; Minimize height of benches; Install drainage control systems; Revegetate slopes; Reduce area needs by eliminating free standing single family structures. Develop two story buildings where possible to reduce building sizes. Compensation payment and additional measures.	Contractor/NEA	
	Indirect impacts: Demand for fuelwood and other forest products	Program of forestry conservation and development; provide canteens for staff; make Contractor responsible for behavior of his workforce	Contractor/NEA/ RAP	
HYDROLOGY AND SEDIMENTS	Dam Construction & Operation: changes to hydrological regime; downstream dewatering; reservoir sedimentation and flushing	Hazard warning system for downstream areas when flushing reservoir	NEA	1-4
	Construction Activities: introduction of oil, greases from tunneling & other activities into water bodies	Collection of used lubricants for controlled disposal	Contractor	
BIRDS AND MAMMALS	Construction of Project Facilities: loss of habitat; disturbance of breeding sites	Minimize land take and forest clearance; controls on workforce; protect forests	NEA/Contractor/ RAP	1-4
DEMOGRAPHIC	Project Construction: concentration of hydropower workforce.	Site camps near workplaces & at a distance from indigenous settlements; ACRP; Rural Development & Training Program	NEA/RAP	1-4
	Indirect Impacts: influx of job seekers & entrepreneurs; uncontrolled settlement	Regulation of settlement on public and private land; strengthen local organizations	VDCs/NGOs/RAP	

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
SOCIO-ECONOMIC AND CULTURAL	Land take, loss of arable land	Intensity production of remaining land; Proclaim arable land after construction	NEA/RAP/ Contractor	1-4
	Loss of forest resources;	Control deforestation; Forestry conservation & development program	NEA/Contractor/ RAP	
	Displacement of approx. 144 families;	Minimize Project land requirements; Compensation & rehabilitation program;	NEA	
Project Construction	Interruption of normal farming activities;	Intensity production on remaining land; Provide skill training for employment on construction;	RAP NEA/RAP	
	Requirement for additional food for local people & workforce & immigrants;	Encourage production of crops & livestock products for sale to workforce and other outlets; Contractor to provide logistics for his workforce.	RAP/Contractor	
	Requirement for additional fuel supplies	Contractor to provide kerosene & electricity to workforce, limit use of local fuelwood; Prohibit unauthorized felling of tree and use of open fire; Forestry development program.	Contractor/ MOFSC/RAP	
	Disturbance of traditional social & cultural patterns by large scale immigration	Training and strengthening of Village Development Committees; programs for non-indigenous labor.	RAP	

TRANSMISSION LINE AND SUB-STATION IMPACTS-CONSTRUCTION PERIOD

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
PHYSICAL RESOURCES				
Water Quality	Sediment from earthworks	Careful working methods; revegetation.	Contractor	1-4
Slopes and Soils	Erosion from earthworks, especially access roads	Careful design and alignment controls on borrow areas and spoil disposal	NEA/Engineer/ Contractor	
ECOLOGICAL RESOURCES				
Forests	Vegetation clearance, fire risk	Route line away from forests; minimize ROW width fire precautions	NEA/Engineer/ Contractor	1-4
Wetlands	Vegetation clearance, disturbance, fire risk	Alternative line location, good working practices	NEA/Engineer/ Contractor	
Wildlife	Disturbance, habitat loss	Avoid wildlife areas and breeding seasons; control workforce	NEA/Engineer/ Contractor	
HUMAN USE VALUES				
Land Take	Permanent loss of arable land; decrease of agricultural production	Minimize land requirement Minimize acquisition of arable land	NEA/Engineer/ Contractor	1-4
	Temporary loss of arable land grazing land; decrease of agricultural production and fodder resources	Acquisition of land only for permanent use according to LAG 2045 and recommendations (comp. text)	NEA/Contractor	
	Loss of houses, displacement	Rent land required temporarily according to recommendations (comp. text)	NEA/Contractor	
	Damage to arable land, crops and facilities	Reinstatement, compensation	Contractor	
Employment	Concentration of project workforce	Camps near Workplace	Contractor, Engineer	1-4
	Influx of job seekers and entrepreneurs	Control of settlement on public and private land; Training, strengthing VDCs	VDC/RAP	
Health	Additional pressure on public heath care system	Improvement of public health services; Provide health facilities for workforce; Information and extension programs	RAP/Contractor	1-4
	Additional pressure on public water system	Water supply for project to be constructed; Improvement of existing water systems	Contractor/RAP	
	Additional waste sewage	Project waste to be buried or burned; Adequate sanitary system	Contractor/RAP	

TOPIC	IMPACT	MITIGATION	RESPONSIBILITY	ACHIEVEMENT OF TARGET
Trade/Infrastructure	Additional pressure on infrastructure	Improvement of public infrastructure	RAP	1-4
	Requirement of additional food, commodities, fuel; inflation	Provide goods, kerosene, electricity to workforce (fair price shops); Limit use of local fuelwood, prohibit unauthorized felling of trees	Contractor, Engineer	
QUALITY-OF-LIFE VALUES Socio-Cultural System	Unequal income opportunities in families and communities	Arun Valley: Income Generation Programs		1-4
		Planning rural electrification and roads	RAP/NEA	
	Negative attitudes towards government projects, implications for future development		HMG	

ATTACHMENT 2

RAP EVALUATION INDICATORS

	Current Year Activities	Achievement of Target
1.	Conservation	1-4
2.	Income generation	1-4
3.	Institution strengthening	1-4
4.	Extn. and training	1-4
5.	Infrastructure	1-4
6.	Monitoring	1-4

Table A3.1: SUMMARY TABLE OF RECOMMENDED ACTION PROGRAMMES AND PROJECTS, MANAGEMENT OF BASINWIDE ENVIRONMENTAL IMPACTS STUDY

Sector	Major Objectives	Recommended Action	Budget US$ 1000s	Implementation Schedule (Years) 1	2	3	4	5	6	7	8	9	10	Lead Participants
A. Conservation Programmme														
**Enhancing community participation in Forest management and conservation*	Sustainable use of forests; maintain biodiversity levels; minimize soil erosion; better use of highly degraded forest.	Establish and support user groups; support private planting, introduce community and leasehold forests; rural development action	690	■	■	■	■	■	■	>	>	>	>	DFO
***Involvement of local communities in servicing road construction requirements*	Meet labor camps' wood needs without severe forest damage; minimize potential social problems during road building.	Form local committees to liaise with and provide wood to road labor camps	20	■	■	■	>	>	>	>	>	>	>	DFO
Management of national forests and plantations	Provide for improved, exclusive HMG/N management of selected forests.	Link with institutional strengthening project for DFO to improve national forest management; establish forest management demonstration sites.	240	■	■	■	>	>	>	>	>	>	>	DFO
Milke Danda conservation area	Conserve last extensive forests in the east; protect threatened wildlife app; promote ecotourism; conserve watersheds.	Establish a ca 5 00 sq.km "Conservation Area"; nature conservation; pasture management; tourism development; rural development	1,325	■	■	■	■	■	>	>	>	>	>	Conservation NGO; DNPWC
Conservation of crop genetic diversity	Promote economic benefits from domestic and wild plants for local communities and the nation.	Establish short-term crop conservation plots; short-term preservation of material abroad; establish local conservation center.	805	x	x	x	x	x	x	x	■	■	■	National Agriculture Research Centre
Preservation of monuments, sacred sites and folk heritage	Preserve the Arun's cultural and folk heritage.	Restore/upgrade cultural sites; establish permanent folk heritage record; establish museum; heritage education program.	330	x	■	■	■	■	■	>	>	>	>	Dept. of Archaeology; Guthi Samsthan Nat. Museum

* Projects in *italics* are recommended for pre-emptive action prior to the road construction phase.

LEGEND

x Planning/preparation period
■ Core activity
\> Continuing routine operation

Sector	Major Objectives	Recommended Action	Budget US$ 1000s	Implementation Schedule (Years) 1	2	3	4	5	6	7	8	9	10	Lead Participants
B. Income Generation Programme														
Agricultural development and diversification	Improve possibilities for long-term economic sustainability in Sankhuwasabha District	Irrigation development; promotion of cardamon; vegetable production; seed production.	1,277						>	>	>	>	>	ADB/N; Agric.Inputs Corp; PAC; DAO
Livestock development	Minimize degradation of forests, pastures and other resources; improve household incomes.	Cow and buffalo milk production; meatproduction; piggery development; improved breeds.	847				>	>	>	>	>	>	>	DLO; PAC; KDHP
Ecotourism development	Develop a strategic framework for ecotourism development which is sensitive to environment and culture, and provides local benefits.	Establish District and Village Tourism Committees; provide infrastructure, training and other support.	350											Ministry of Tourism
Small business promotion	Promote economically and environmentally viable small business; provide assistance to women entrepreneurs.	Establish business promotion office, provide special loan programs, revolving funds, etc.; link with market outlets.	120			>	>	>						Ministry of Local Development
C. Institutional Strengthening Program														
**Strengthening government institutions*	Improve forest management; improve implementation of community-based development projects.	Institutional strengthening of DFO; support haka agencies with physical facilities and manpower.	470				>	>	>	>	>	>	>	ABIMB
Creation and strengthening of community institutions	Improve community-based resource management; initiate and strengthen local economic cooperatives.	From local user groups; form and train Community Development Committees; increase and strengthen cooperatives.	530	x	x				>	>	>	>	>	ABIMB

Sector	Major Objectives	Recommended Action	Budget US$ 1000s	Implementation Schedule (Years)										Lead Participants
				1	2	3	4	5	6	7	8	9	10	
D. Extension and Training Programme														
**Training and education*	Promote locally-based action for resource conservation, fund-raising; build a cadre of trained local people.	Establish Training and education Section; train local HMG/N resource agencies, local people, women; funding-raising.	655	x					>	>	>	>	>	ABEMU
Forestry extension	Create attitudinal changes among local people regarding forest conservation.	Support DFO in developing effective forest extension programs.	30			>	>	>	>	>	>	>	>	DFO
Arts action groups	Promote effective information dissemination on conservation, health, sanitation and other themes.	Support and provide training to district cultural service clubs.	30						>	>	>	>	>	UNICEF
E. Infrastructure and Energy Programme														
Direct access road related development project	Discourage tendency for communities to abandon their current locations and move to the roadside.	Provide for access road paving and link and spur roads to larger communities along the access road.	1,925	x	x							>	>	NEA
Settlement-related infrastructure development	Enable future development of necessary infrastructure within major settlements.	Identify funding to support settlement development plans to be prepared by Community Development Committees	1,500									>	>	ABIMB
Alternative energy proposals	Improve social, political and economic conditions by tapping local energy resources.	Develop rural electrification in high impact zone; develop micro hydropower schemes; study energy substitution.	2,500	x	x						>	>	>	Institution responsible for rural electrification

Sector	Major Objectives	Recommended Action	Budget US$ 1000s	Implementation Schedule (Years)										Lead Participants
				1	2	3	4	5	6	7	8	9	10	
F. Research, Monitoring and Information Programme														
Biodiversity research and database	Provide data to guide biodiversity management and monitoring programs.	Ethnobotanical research, vegetation and wildlife inventories and transects; wildlife depredation studies.	250											ABEMU
Preparation of trail network map	Encourage and support safe and timely travel in the basin.	Prepare a trail network map showing settlements, market centers, etc., action plan for upgrading/maintaining trails.	15				>	>	>	>	>	>	>	Trail & Sus. Bridge Div; Topograph. Survey Dept.
**Environmental monitoring*	Identify environmental trends and conditions for effective conservation and sustainable development of the Arun's resources.	Monitor and evaluagte the physical, social, cultural and economic environment of the Arun Basin.	750											ABEMU

Total Estimted Budget over 10 Years: US$14.6 million

ATTACHMENT 3

ACQUISITION, COMPENSATION AND REHABILITATION

PLAN INDICATORS

	Activity	Achievement of Target
1.	The disbursement of compensation and the implementation of related measures such as training and employment for SPAFS.	1-4
2.	The progress and condition of disadvantaged groups within the SPAF category.	1-4
3.	The level and nature of disputes and claims relating to compensation.	1-4
4.	For temporarily used land, APEMU will carry out annual fair-rent surveys to fix reasonable rents, and monitor payment of the agreed rentals return-to-owner process.	1-4
5.	Perception of the ACRP process by those affected and other members of the public.	1-4

See also detailed ARCP monitoring plan.

ATTACHMENT 4

MONITORING AND CONSULTATION EFFECTIVENESS

INDICATORS

	Activity	Achievement of Target
1.	Verification of contractors environmental protection and health and safety plan in accordance with contract specifications.	1-4
2.	Collection of information - physical - biological - social	1-4
3.	Checking of contractors work practices and prevention/correction of deficiencies.	1-4
4.	Identification of need for changes to mitigation measures and adoption of better measures.	1-4
5.	Consultation with affected communities and resolution of problems.	1-4

ATTACHMENT 4-A

VERIFICATION OF ENVIRONMENTAL PLAN/SPECIFICATIONS

	Activity	Achievement of Target
1.	Environmental Protection Plan Permanent Structures and Facilities Temporary Structures and Facilities Site Roads Maintenance of Other Services and Structures Spoil Dumps Pollution of Waterways Wildlife Prevention of Illegal Felling and Transport Timber Land Reinstatement Archeological Sites Control, Documentation and Monitoring Aerial Transport Measurement and Payment Fire Prevention and Firefighting Equipment Restricted Areas Waste Collection and Disposal Relations with Local communities and Administrations	1-4
2.	Health and Safety Plan Rates of Wages and Conditions of Labor Housing for Labor Accident Prevention Officer; Accidents Health and Safety Measures against Insect and Pest Nuisance Epidemics Burial/Cremation of the Dead Supply of Foodstuff and Fuel Supply of Water Sanitation Alcoholic Liquor or Drugs Arms and Ammunition Festivals and Religious Customs Disorderly Conduct Labor Negotiations Infringement Records to be kept	1-4

ATTACHMENT 4-B

MONITORING EFFECTIVENESS
COLLECTION OF INFORMATION
INDICATORS

	Type of Information To Be Collected	Achievement of Target
1.	PHYSICAL	1-4
	Location, design, operation and restoration of temporary facilities - e.g., camps, work areas;	
	Location design and impacts of pilot tracks;	
	Road-induced erosion and sedimentation, including monsoon drainage;	
	The implementation and success of slope stabilization measures, particularly bio-engineering;	
	The location, operation, stability and reclamation of spoil disposal areas;	
	Dust suppression;	
	Proper disposal for used oils, chemicals and other wastes;	
	Location and operation of quarries and borrow pits;	
	Location and design of access roads;	
	Location, design and operation of spoil disposal sites.	
2.	BIOLOGICAL	1-4
	Biological factors to be collected by APEMU include the condition of vegetation along the right-of-way and in the vicinity of power house, adit, CPS, intake sites, major camps;	
	Intensity of fishing, habitat and populations of any endangered species directly affected by the road.	
3.	SOCIAL	1-4
	Adherence to the requirements for recruitment of local labor, camp, health and safety conditions, operation of controlled-price shops and local price inflation	
	Project/Contractor relation with affected communities;	
	Contractor's camp location and design, local rental, land reclamation, reinstatement and return.	

ATTACHMENT 4-C

MONITORING EFFECTIVENESS
CHECKING OF CONTRACTORS
WORK PRACTICES

	Activity	Achievement of Target
1.	APEMU will mobilize the field inspectors to carry out necessary monitoring activities in different work fronts.	1-4
2.	The field inspectors will carry out compliance monitoring of construction activities daily with use of check list.	1-4
3.	If the construction work does not comply with the environmental guidelines as stipulated in the tender documents, the field inspectors will immediately discuss with contractor and give written instruction for corrective measures same day.	1-4
4.	If he fails to do so, the field inspectors are empowered to cease the work, giving written reason for this, and send report immediately to the APEMU head office with their recommendations.	1-4
5.	The APEMU will review and analyze the report on non-compliance. The remedial measures will be discussed with the Engineer and a written instruction will be given to field inspectors within 24 hours.	1-4
6.	The corrective measures will be instructed to the contractors in order to continue the construction works. If necessary, the Emgineer may seek the directives from the Project Director.	1-4
7.	The APMU will send reports to Project Director on weekly basis. All the data will be kept in the computer using GIS for easy retrieval and update of information.	1-4

LIST OF KEY ACTIVITIES

Subject	Activity/Plan Preference	Outputs	Responsible Agency	Implementation Milestones
Management of Direct Environmental Impacts	Environmental Assessment Report	(a) Road Alignment (b) Contract Specifications	NEA/Engineering Consultants	Completed
"	Environmental Mitigation Plan (EMP)	(a) Delineation of Responsibilities (b) Consultants Env. Specialist	NEA/Engineering Consultants	(a) Completed 1993 (b) Presently available
"	Environmental Protection and health and Safety Plan	Camp sites Pilot track Borrow/Spoil Forester Env. Monitor	Contractor Consultant NEA	Bid compliance completed 1993 detail plan 30 days after contract award
"	Environmental Monitoring Plan (MAP)	Monitoring of: (a) Physical Impacts (b) Biological Impacts (c) Socio-economic Impacts	Consultant, NEA	Plans completed, field unit to implement
"	Environmental Unit strengthen (work schedule and financial plan)	(a) New reporting structure, staff (b) Training program (c) Field Unit (APEMU)	NEA, ADB	(a) Staff hired (b) Funds Committed by ADB
Management of Induced Impacts	Management of basin-wide env. impacts study (MBEIS)	Regional action plan (RAP)	Bank, UNDP, KMTNC	Completed in 1991

"	Financial and Institutional arrangements for implementing RAP	(a) Management structure (b) Financing Plan	HMG/N Donors	Secretariat Chief appointed (02/01/94) Firm financing as condition of negotiations
"	RAP revision	Baseline data for RAP implementation	RAP Secretariat	TORs drafted Funds allocated Contractors being mobilized (02/94)
"	RAP Pre-emptive measures	(a) Implementation consultant (b) Forestry (c) Community Devel. (d) Gov. Institution	RAP Secretariat, donors	(a) Condition of effectiveness (b) 50% completed by ODA to date (c) GTz consultants mobilized (d) UNDP funds available
"	RAP Implementation Programs	(a) Biodiversity (b) Income Generation (c) Instit. Strengthen (d) External Training (e) Link Roads (f) Monitoring	RAP Secretariat	10 year timeframe for programs
Management of Resettlement	Arun Rehabilitation and Compensation Plan (ARCP)	(a) Due process manual (b) GIS monitoring system	Engineering consultant, NEA	(a) Completed (b) System established
Consultation	Public communications and consultation strategy	Public meeting information center NEA field presence, RAP field presence	NEA, HMG/N. ETAL	

Environmental Supervision	SAR Annex on Supervision Framework for evaluation of implementation	(a) Committee of Env. Experts (b) Long-term consultant (c) Regular supervision reports	Bank	Framework develop to date

NEPAL

ARUN III HYDROELECTRIC PROJECT

Terms of Reference for the Project Monitor

Background

1. Construction of the 402 MW Arun Hydroelectric Project (AHP) is scheduled to begin in early 1994 with commissioning of the scheme scheduled in April 2002. Because of the relatively long 115 km access road, the project will not only have direct impacts (such as land acquisition) but also induced effects through opening up the remote valley of approximately 350,000 inhabitants. Based on the project environmental assessment, a two-pronged mitigation plan has been developed:

(a) The Nepal Electricity Authority (NEA) will be responsible for managing the project to mitigate the project's direct environmental impacts, primarily the land acquisition, compensation and resettlement plan (ACRP) for the estimated 998 families of whom an estimated 138 are seriously affected, i.e. will lose more than half of their income through land acquisition; and

(b) the Ministry of Water Resources in collaboration with the National Planning Commission will be responsible for coordinating/-facilitating the regional action program (RAP), identified by the King Mahendra Trust for Nature Conservation (KMTNC) to address the project's induced effects. Key elements of the RAP include strengthening local forest management, conservation, agricultural development and income generation.

2. The Donors supporting the AHP wish to appoint a Project Monitor, to be resident in Kathmandu, to assure that the project is appropriately supervised and monitored and that quick corrective action is taken, particularly in relation to addressing the AHP's environmental issues.

Objectives

3. The objectives of the assignment are:

(a) Monitor implementation of all activities relating to the AHP implementation including the RAP as well as other ongoing activities in the Arun Valley including the Makalu-Barun National Park and Conservation Area (MBNPCA); and

(b) report to HMG and the project donors on a regular basis advising on corrective actions where appropriate;

Scope of Work

4. The scope of the assignment includes *inter alia*:

(a) Reviewing all progress reports in relation to the implementation of the AHP, the RAP, the MBNPCA and other relevant activities;

(b) designing/implementing a "real time" monitoring system which could include the use of camcorders and telecommunication technology as appropriate; and

(c) organizing regular AHP implementation reviews in coordination with other ongoing activities in the Arun Valley.

Reporting

5. The project monitor will prepare regular supervision and monitoring reports of the AHP and related activities for HMG and the Donors.

6. The assignment is expected to last three years initially; subject to approval it could then be renewed on a year by year basis as appropriate.

Qualifications

7. It is expected that the individual selected for this position would have at least the equivalent of a masters degree in agricultural or natural sciences or in an appropriate engineering or environmental discipline. The person should have at least twenty years experience (of which at least ten should be in developing countries - preferably South Asia) in project management/implementation in more than one of the following areas: civil engineering projects (roads, hydroelectric), forestry, agricultural development, setting up of national parks.

NEPAL

ARUN III HYDROELECTRIC PROJECT

Public Consultation and Participation

Introduction

1. Public consultation/communication has been an integral part of the preparation of the Arun project for which unprecedented effort has been made by HMG in collaboration with IDA and KfW. A two pronged approach was followed. The first part relates to the consultation/communication process within Nepal, and particularly in the Arun Valley, while the second part relates to consultation/communication outside of Nepal.

Consultation/Communication within Nepal

2. The consultation strategy within Nepal was mainly concentrated within the Arun Valley but also included national fora:

(i) during the preparation of the Basinwide Environmental Impact Assessment Study, in conjunction with the ridge alignment, conducted by the King Mahandra Trust for Nature Conservation there was extensive consultation with local government organizations and user groups to ensure that the construction of the project would lead to the sustainable development of the whole valley. This consultation is recorded in the video "Sustainable Development in the Arun Basin". In addition to the major communities listed below, many outlying areas were surveyed;

(ii) subsequent to the appraisal mission there have been consultations with the inhabitants of the Arun valley in the following locations: Hile, Tumlingtar, Khandbari, Pukhuwa (P/H site), Amrang and Phyaksinda (dam site). Many of these consultations have been captured on tape (sound and video); recorded discussions center on project benefits and land compensation;

(iii) an Information Center, containing approximately 300 items (reports, videos, tape recordings), has been opened by the Project Office in Kathmandu. Nepali language summaries have been made available to residents of the Arun valley and other interested people;

(iv) numerous public meetings have been organized in Kathmandu to discuss the project with the participation of Government representatives and local NGOs. In addition, there was a presentation on the project on Nepali television;

(v) the project has been discussed in Parliament on numerous occasions through questions to the Minister of Water Resources by various Members of Parliament. There was an almost day long debate on the project on March 31, 1994 where the Minister of Water Resources provided responses to 31 questions on the project. In addition, the project has been discussed in conjunction with the presentation of the Annual Budget.

3. In addition, the World Bank Resident Mission in Kathmandu has organized various briefings for the press and other donors on the project. In late January 1994, the World Bank Vice President for Environment and Sustainable Development visited Nepal; he met briefly with inhabitants of the Arun valley in addition to meeting with various NGOs in Kathmandu.

4. The World Bank Kathmandu Mission received a letter dated July 29, 1994 supporting the project with more than 3,000 signatures. The signatories included representatives of different ethnic groups and castes living in the project area ranging from Hedanga to the north of the dam site to Dharan, the headquarters of the adjoining Sunsari Morang District.

5. In general, the consultations in the 23 public meetings have shown that there is widespread support for the project in the Arun Valley itself because of the perceived benefits of the access road. The major issues raised were the change in the road alignment and job opportunities. HMG has responded by making a commitment to build spur roads to link the communities of Khandbari and Chainpur and to hire at least one member from each SPAF to work on the Arun project. The IBRD Map #26235 shows the locations of public consultation/communication in the Arun valley.

6. Outside of the Arun Valley, there is widespread bipartisan support for the project in Parliament. This was reflected in the debate of March 31, 1994 as well as in the letter dated April 4, 1994, written to the President of the World Bank by Members of Parliament, including Opposition members, and representatives of various local bodies where the project is located.

Consultation/Communication Outside Nepal

7. IDA and KfW have taken the lead in organizing consultations with NGOs outside of Nepal. KfW has organized consultations with NGOs based in Germany. Discussions have been held by Bank staff with NGOs in Switzerland and the U.K. with particular knowledge of Nepal and/or hydropower (ITDG of the U.K.). In addition, two consultations were held with NGOs in Washington on June 10, 1994 and June 28, 1994, prior to the completion of negotiations between HMG and IDA on the project. During the June 28, 1994 meeting, representatives of NGOs based in Kathmandu participated in addition to representatives of NGOs based in Germany, Japan and the U.S.

8. Views of NGOs. With regard to environmental NGOs, most of the inputs have been from international groups based in national capitals. The issues here have been the intrusion of a road into an area of biological diversity, doubts as to delivery of the proposed mitigation/compensation measures and a desire for more studies. Within Nepal, the Alliance for Energy took a similar position to the international groups while the King Mahendra Trust for Nature Conservation conducted studies, proposed a Regional Action Plan and is involved in the follow-up.

9. In addition to environmental concerns about the AHP, the international groups, the Alliance for Energy and one or two other domestic NGOs, expressed a strong preference for an energy sector development strategy which would develop smaller hydro sites in Nepal. Other domestic NGOs have written to express strong support for the Arun project. Alternative investment strategies were examined in the Argonne Report, which was distributed to interested NGOs in early June. Follow-up discussions with groups having particular expertise (such as ITDG) have indicated that the principal concern is perceived government neglect of smaller hydro investments rather than opposition to the Arun project per se, which is seen as being needed in due course but not on the schedule proposed by government.

Nepal: Arun III Hydroelectric Project
Components Project Cost Summary

	(N. Rupees Million)					(US$ Million)				
	Local	Foreign	Total	% Foreign Exchang	% Total Base Costs	Local	Foreign	Total	% Foreign Exchang	% Total Base Costs
A. Hydroelectric Power Plant - Physical Works										
Dam and Desanding Basins	925.75	3,532.38	4,458.12	79	15	18.71	71.39	90.10	79	15
Permanent Camps	355.16	459.17	814.33	56	3	7.18	9.28	16.46	56	3
Access Road	1,341.04	4,791.15	6,132.19	78	20	27.10	96.83	123.93	78	20
Headrace Tunnel and Surge Tank	609.79	2,453.22	3,063.01	80	10	12.32	49.58	61.90	80	10
Powerhouse and Appurtenant Structures	394.64	2,263.22	2,657.85	85	9	7.98	45.74	53.72	85	9
Subtotal Hydroelectric Power Plant - Physical Works	3,626.37	13,499.13	17,125.50	79	56	73.29	272.82	346.11	79	56
B. Hydroelectric Power Plant - Electromechanical Equipment										
Hydraulic Steel Structures D/S	124.93	1,129.63	1,254.56	90	4	.2.52	22.83	25.35	90	4
Hydraulic Steel Structures PH/S	87.94	426.52	514.45	83	2	1.78	8.62	10.40	83	2
Electrical Equipment	224.49	1,975.24	2,199.74	90	7	4.54	39.92	44.46	90	7
Electrical Equipment	73.37	763.97	837.34	91	3	1.48	15.44	16.92	91	3
Mechanical Equipment	219.66	1,409.69	1,629.35	87	5	4.44	28.49	32.93	87	5
Construction Power Supply	71.67	447.30	518.97	86	2	1.45	9.04	10.49	86	2
Subtotal Hydroelectric Power Plant - Electromechanical Equipment	802.07	6,152.34	6,954.41	88	23	16.21	124.34	140.55	88	23
C. Transmission Line to Grid										
Arun-Duhabi Transmission Line	315.76	1,698.15	2,013.91	84	7	6.38	34.32	40.70	84	7
Duhabi Substation	136.53	631.36	767.89	82	3	2.76	12.76	15.52	82	3
Subtotal Transmission Line to Grid	452.29	2,329.52	2,781.81	84	9	9.14	47.08	56.22	84	9
D. Environmental Mitigation/Area Development										
Land Acquisition, Compensation & Rehabilitation	74.02	-	74.02	-	-	1.50	-	1.50	-	-
Regional Action Program	434.93	289.95	724.88	40	2	8.79	5.86	14.65	40	2
Subtotal Environmental Mitigation/Area Development	508.95	289.95	798.90	36	3	10.29	5.86	16.15	36	3
E. Technical Assistance										
Construction Supervision for HEP & Access Roads	-	1,990.90	1,990.90	100	7	-	40.24	40.24	100	7
Construction Supervision for Transmission Line/Substation	-	125.68	125.68	100	-	-	2.54	2.54	100	-
RAP Secretarial	-	98.96	98.96	100	-	-	2.00	2.00	100	-
Panel of Experts	-	98.91	98.91	100	-	-	2.00	2.00	100	-
NEA Project Management	144.48	-	144.48	-	-	2.92	-	2.92	-	-
NEA Training	-	178.12	178.12	100	1	-	3.60	3.60	100	1
Subtotal Technical Assistance	144.48	2,492.57	2,637.05	95	9	2.92	50.38	53.30	95	9
F. Micellaneous										
Hydro Fund	-	247.40	247.40	100	1	-	5.00	5.00	100	1
Subtotal Micellaneous	-	247.40	247.40	100	1	-	5.00	5.00	100	1
Total BASELINE COSTS	5,534.15	25,010.92	30,545.07	82	100	111.85	505.48	617.32	82	100
Physical Contingencies	718.65	2,910.00	3,628.65	80	12	14.52	58.81	73.34	80	12
Price Contingencies	2,340.12	9,461.18	11,801.30	80	39	22.93	83.66	106.59	78	17
Total PROJECT COSTS	8,592.92	37,382.10	45,975.02	81	151	149.30	647.95	797.25	81	129

a/ Taxes and duties are included in the project costs and amount to NRs 2,135.56 million, equivalent to US$36.99 million

Nepal: Arun III Hydroelectric Project
Project Components by Year – Totals Including Contingencies
(US$ Million)

	Totals Including Contingencies											
	93/94	94/95	95/96	96/97	97/98	98/99	99/00	00/01	01/02	02/03	03/04	Total
A. Hydroelectric Power Plant - Physical Works												
Dam and Desanding Basins	-	-	-	16.10	3.89	20.90	26.35	28.06	10.52	17.15	-	122.95
Permanent Camps	-	-	-	8.78	6.86	2.59	0.68	0.68	0.70	0.31	-	20.60
Access Road	-	28.94	45.59	45.13	42.01	-	-	-	-	-	-	161.67
Headrace Tunnel and Surge Tank	-	-	-	-	13.10	14.37	18.07	19.40	7.35	12.54	-	84.83
Powerhouse and Appurtenant Structures	-	-	-	9.97	14.31	11.17	10.02	17.54	4.50	3.17	-	70.67
Subtotal Hydroelectric Power Plant - Physical Works	-	28.94	45.59	79.98	80.16	49.02	55.11	65.68	23.08	33.16	-	460.72
B. Hydroelectric Power Plant - Electromechanical Equipment												
Hydraulic Steel Structures D/S	-	-	-	8.59	-	7.28	9.70	1.68	3.44	-	-	30.68
Hydraulic Steel Structures PH/S	-	-	-	3.44	-	2.75	3.97	0.96	1.52	-	-	12.65
Electrical Equipment	-	-	-	10.20	-	7.63	15.81	11.42	3.86	5.91	-	54.83
Electrical Equipment	-	-	-	3.89	-	2.96	6.09	4.33	1.34	2.24	-	20.85
Mechanical Equipment	-	-	-	11.02	-	9.07	12.59	2.61	4.65	-	-	39.95
Construction Power Supply	-	-	5.29	4.82	1.86	-	-	-	-	-	-	11.97
Subtotal Hydroelectric Power Plant - Electromechanical Equipment	-	-	5.29	41.96	1.86	29.69	48.17	21.00	14.82	8.15	-	170.93
C. Transmission Line to Grid												
Arun-Duhabi Transmission Line	-	-	-	0.05	0.97	3.89	11.77	21.97	14.30	1.01	-	53.96
Duhabi Substation	-	-	-	0.05	0.30	1.45	5.24	7.86	4.74	0.94	-	20.59
Subtotal Transmission Line to Grid	-	-	-	0.10	1.27	5.34	17.01	29.83	19.04	1.95	-	74.54
D. Environmental Mitigation/Area Development												
Land Acquisition, Compensation & Rehabilitation	-	-	0.47	0.74	0.33	0.14	0.12	0.06	0.04	-	-	1.89
Regional Action Program	-	0.33	1.70	2.45	2.15	2.21	2.26	2.32	2.38	2.03	0.83	18.68
Subtotal Environmental Mitigation/Area Development	-	0.33	2.17	3.19	2.49	2.34	2.38	2.38	2.41	2.03	0.83	20.56
E. Technical Assistance												
Construction Supervision for HEP & Access Roads	-	2.12	4.09	8.98	4.89	5.74	8.80	5.82	3.28	3.72	1.06	48.49
Construction Supervision for Transmission Line/Substation	-	-	-	0.03	0.15	0.61	1.34	0.92	0.06	-	-	3.13
RAP Secretariat	-	0.22	0.22	0.23	0.35	0.24	0.25	0.25	0.26	0.27	0.14	2.42
Panel of Experts	-	-	0.37	0.38	0.39	0.40	0.41	0.42	-	-	-	2.38
NEA Project Management	-	0.17	0.28	0.40	0.51	0.46	0.47	0.54	0.60	0.32	-	3.76
NEA Training	-	0.61	2.46	0.72	0.33	-	-	-	-	-	-	4.12
Subtotal Technical Assistance	-	3.12	7.42	10.75	6.63	7.45	11.27	7.95	4.21	4.31	1.20	64.30
F. Miscellaneous												
Hydro Fund	-	0.29	0.59	0.90	1.23	1.58	1.29	0.33	-	-	-	6.20
Total PROJECT COSTS	-	32.68	61.06	136.87	93.63	95.42	135.23	127.18	63.56	49.59	2.03	797.25

NEPAL: ARUN-III HYDROELECTRIC PROJECT

First Stage Foreign Cost Financing Plan (201 MW)

(Million US$)

Lots	Escalated Total Cost	ADB	IDA	Germany	To be determined 5/	Finland	France	Sweden	HMG/NEA
1 . Lot C1 - Dam and Desanding Basin									
2 . Lot C3 - Access Road, Headrace Tunnel and Camp Facilities 1/	390.05	127.62	162.93	10.46					89.04
3 . Lot C2-Powerhouse and Appurtenant Structures	70.67				59.92				10.75
4 . Lot HSS1-Hydraulic Steel Structures (DAM)	30.68				27.54				3.14
Lot HSS2-Hydraulic Steel Structures (P/H)	12.65				10.40				2.25
5 . Lot M1-Mechanical Equipment	39.95				34.37				5.58
6 . Lot E1-Electrical Equipment	54.83			49.08					5.75
7 . Lot E2-Electrical Equipment	20.85				18.98				1.87
8 . Lot CPS-Construction Power Supply	11.97					10.27			1.70
9 . Lot TL-Arun-Duhabi Transmission Line	53.96			29.45			16.00		8.51
10 . Lot SSS-Substation at Duhabi	20.58							16.89	3.69
11 . Lot ACRP Acquisition, Compensation and Resettlement	1.89								1.89
12 . Lot RAP-Regional Action Plan	18.67		2.20 3/						16.47
13 . Lot SUP1-Construction Supervision (lots 1-8)	48.49		0.95	35.42	12.12 5/				0.00
14 . Lot Sup2-ConstructionSupervision (lots9,10)	3.13						3.13		0.00
15 . Lot RAPS - RAP Secretariat	2.42		2.42						0.00
16 . Lot HF - Hydrofacility	6.20								6.20
17 . Lot POE-Panel of Experts	2.38		2.38						0.00
18 . Lot NEA-Project Management	3.76								3.76
19 . Lot TR Training	4.12		4.12						0.00
TOTAL	797.25	127.62 2/	175.00	124.41 4/	163.33	10.27	19.13	16.89	160.60

Notes: Taxes and duties (US$36.28 million) are included. Cost estimate is based on the lowest evaluated bid for the combined Lot C1/C3; for other lots estimates are based on July 1993 prices.
The cost estimate is subject to change after negotiations are concluded between NEA and the C1/C3 contractor.

1/ It is assumed that the combined Lot C1/C3 will be jointly financed by ADB, IDA and Germany following IDA procurement guidelines. Contract award will be subject to approval by NEA, ADB, IDA and Germany.

2/ ADB's total allocation is US$135 million including US$7.4 million to cover its loan service charge.

3/ Excludes German contributions to the RAP financing. Germany through GtZ has agreed to finance a pilot DM5.0 million program.
In fact with the support of GtZ, IDA and ODA, nearly all aspects of the RAP are covered by Donor assistance.

4/ Germany's committed amount is DM 235.00 million, which converted to US$ using today's exchange rate (US$1.00=DM1.65) is equivalent to US$124.41 million excluding the amount expended for detailed engineering and tender document preparation (DM23.5 million).

5/ Japan is sending its own appraisal mission to make an assessment of the project, including the indicated lots.

8/30/94

NEPAL ELECTRICITY AUTHORITY
(A HMG/N UNDERTAKING)

ARUN III HYDROELECTRIC PROJECT

PROJECT MANAGEMENT
AND
ORGANIZATION

KATHMANDU, NEPAL
OCTOBER,1993

1 PROJECT MANAGEMENT & ORGANIZATION

During the course of the Second Donors Preparatory Meeting held in July 1990 in Kathmandu the terms of reference for the Project Implementation Study and report were outlined as follows.

a. Review and recommend appropriate arrangements for the implementation of the Arun-3 Project.
b. Recommend how the project organization should be inserted into NEA.
c. A critical aspect of the review should focus on decision making (including procedures and organizational structures) taking into account the experience with the Kulekhani-I and Marsyangdi Project.

The study was started from Oct. 21, 1990 with the appointment of a Project Management Advisor. The hiring of the Project Management Advisor was agreed by IDA and NEA during the World Bank Project Preparation Mission of March 1990 to develop a Project Management system to link all project outputs and inputs (from HMG/N, Donors, consultants contractors, etc) and a regular project report system. The study was completed. The study recommended appropriate arrangement at the different phases of the implementation of Arun-III Project. The report consists of the proposal to place the management in the existing system of NEA for effective, efficient and timely execution of the project.

Based on the above study and subject to the provision of Arun-3 project contracts, following Project Management and Project Organization are proposed:

1.1 Project Management

The Project Management System proposed for the Arun-3 Project is of the owner - engineer - contractors type. NEA, the owner, as the executing agency is responsible for the management of the project. Under this system the contract will be between NEA and the contractor, in which an engineer acts as an agent of the owner (NEA). The engineer should be provided under a consulting engineering services contract.

Each contractor is construction manager for the work to be done under its contract and shall be instructed, supervised and certified by the engineer.

The coordination of the various contracts is directed by the engineer acting for the owner by instruction to the various contractors under the terms of their individual contracts.

The Role of NEA, NEA Board, Subcommittee, Managing Director, Project Director, Engineer and the contractor are as follows:

1.1.1 Role of NEA

The Role of NEA in project management during the construction phase will be as follows:

* NEA will employ consultants and contractors for the technical and contractual functions involved in getting the project completed on time and within budget and to the required technical standard. NEA will be responsible for ensuring that the terms of these agreements and contracts are met by the contracting parties (consultants and contractors).

* NEA will be responsible for fulfilling its contractual obligations as set out in its agreements or contracts with the consultants and the contractors. These include:

  (a) timely payments in accordance with its contracts
  (b) timely approvals where required
  (c) timely provision of services in relation to legal or government requirements.
  (d) timely provision of services in relation to requirements of the donors where these have been written into the contracts (i.e. environmental provisions).

* NEA will be responsible for fulfilling its agreements with the donors with respect to the project, this will include;

  (a) meeting the contractual obligations as mentioned above.
  (b) undertaking its role in the management of project impacts.
  (c) following the donors procedures for withdrawal of proceeds of loans or credits.
  (d) raising any loans to meet the proportions of the project cost required to be funded by HMG/N.
  (e) maintaining audited and auditor approved accounts of project expenditure.
  (f) reporting technical and financial progress and status to the donors and Environmental Monitoring.
  (g) Provide information to public in regular basis of the project.
  (h) Seeking donors concurrence for extension of time beyond six months for project completion.

* In view of the size of the project relative to the economy of Nepal, NEA will keep HMG/N regularly informed on the technical and financial status of Arun-3.

* A management system for NEA to meet its role in the Arun-3 Project is proposed in Section 1.2 of this report.

1.1.2 Role of NEA Board

The relation between NEA Board and Arun-3 Project will be;

(a) receipt of the Project Progress Report.
(b) consideration and comment on progress.
(c) decisions on major financial questions including:

* project funding.
* project implementation.
* contract award.
* contract or project termination.

(d) resolution of difficulties at Government or ministry level and of major contractual disputes.

1.1.3 Role of Arun-3 Subcommittee

For timely decision making a Arun-III HEP Sub Committee comprising of one member of the Board, one representative from Ministry of Water Resources, Managing Director, Director in Chief Construction, Director in Chief Engineering and Director in Chief Arun-3 has been formed to advise NEA Board on issues related to the project. This subcommittee will be chaired by Managing Director while Project Director will function as Member Secretary.

The responsibility of Arun-3 sub-committee shall be as follows:

* To regularly review and closely monitor the progress of the project.

* To help make decisions on major project related issues such as:

  - Project funding
  - Project implementation

* Assist in resolving problems addressed to the NEA Board by the project.

* To assist NEA Board in scrutinizing various files submitted to the Board by the project.

* Arun Sub-committee will be responsible for fulfilling NEA Agreements with the donors including;

  - Monitoring and ensuring the timely auditing of the project expenditure.

  - Reporting on technical and financial progress and status of the project to NEA Board.

- Monitoring the technical and financial aspects of the project in regular basis.

1.1.4 Role of the Managing Director.

The Managing director of NEA shall responsible for implementation of the Arun-3 Project by delegating to the Project Manager responsibility for management of the project but he shall remain responsible to the Board for all activities of NEA.

The Managing Director shall monitor the Project Manager's performance by requiring the Project Manager to;

(a) keep him informed on major matters.

(b) submit monthly reports on progress, expenditure and budget and schedule forecasts.

(c) submit monthly detailed accounts of expenditure on the administration account which should be audited annually by the NEA internal and external auditor.

1.1.5 Role of Project Director

Recently the NEA Board has upgraded Project Director to level of Director in Chief. The Project Director level 12 shall have full responsibility for the implementation of the project on behalf of the Managing Director (MD). Following are the responsibilities of the Project Director:

* to conduct all the activities required to complete the project within time and budget with required quality.

* to manage all the administrative and financial aspects of the project in order to carry out the implementation of the project smoothly and efficiently.

* to inform the MD on progress, expenditure, budget and schedule forecasts of the project.

* to make final decisions on control and technical functions of the project.

* to bear the responsibilities of the member secretary of the Arun-III HEP Sub Committee.

* to give final approval of the contractors' and engineers bills and preparation and submission of withdrawal application to donors. This responsibility can be decentralized to the Department Directors of various Departments and Divisions as per requirement.

* consultation with Project Consultant on Technical matters.

(a) Instructing the Work

Issuing drawings, specifications, schedules and including redesign or amendments where required by changed site conditions or to benefit construction, and

(b) Quality Control

Inspection, testing, supervision, document control and certification.

The engineer's management, administrative activities are;

(c) Contract Management

Measurement, records, monitoring of progress, administration of contractors claims.

(d) Project Management

Coordination of contracts, management of variations, overall monitoring and initiating responses to adverse circumstances or opportunities relating to timely and minimum cost completion.

1.1.7 Role of Contractor

The Role of Contractor in project management during the construction phase is as follows:

* The contractor's role in project management is to complete the construction of the work instructed to the quality specified and within the times for completion in accordance with its contract under their own management system.

* Each contractor is to manage construction to achieve the contractual requirements.

* Control of construction cost and time is effected initially through competitive bidding. The bid documents specify the quality and scope of works and the times to completion of sections of the work and the completed works. Any change on it during the construction shall be handled as per conditions set on contract between contractor and NEA.

1.2 Project Organization

Based on the management concept, roles and requirements described in the previous section following concepts have been adopted to set the project organization.

* The relationship of the project with HMG/N, donors and engineer are shown in Fig. No. 1.1. NEA as an

1.1.6 Role of Engineer

The Role of Engineer in project management during the construction phase will be as follows:

* The Engineer acts as the sole agent of the NEA in the implementation of Arun-3 in;

  (a) issuing instructions.
  (b) supervising, inspecting and accepting the quality of the work.
  (c) monitoring progress and reporting as required.
  (d) measuring and certifying payment and completion.
  (e) agreeing and settling additional payments and time extensions due under the terms of the contract.
  (f) Supervise contractor's compliance with contractual provisions related to Environmental protection

* The Engineer shall seek approval of the NEA before issuing approvals, decisions, instructions or orders which involve the following matters:

  (a) extension of time for completion.

  (b) variation orders causing additional cost to the Employer exceeding the amount of US $ 100,000.00. The sum total of all variations which do not require the approval of the Employer shall be limited to US $ 1,000,000.00 after which the Engineer shall require a renewal of his authority with respect to further variation.

  (c) establishment of new rates and prices, in case applicable rates and prices are not found in the Bill of Quantities.

It the decision on the (c) is not made by the Employer within 28 days of the submission of the recommendation by the Engineer, then the Engineer is allowed to decide on behalf of the Employer.

* The Engineer should take full responsibility for the design and supervision of technical aspects of the project.

* The need to coordinate several separate contracts requires additional management effort. Since the owners contact with contractors is through the engineer, the engineer should undertake this additional role.

* The Engineer's activities as the NEA's agent may thus be identified under four heads; two largely technical and two managerial and administrative. The technical activities are;

implementation agency is fully responsible for the implementation of the project and is to act according to the policies set by the HMG/N. NEA shall keep close coordination with various donors under an agreement between HMG/N and Donors.

* The high level steering committee shall be responsible for monitoring and ensuring quick decisions required for the timely completion of the project.

* The project would be managed by the appointed NEA Project Manager with the rank of Director in-chief.

* A consultant would be appointed to act as engineer for the supervision of the construction contracts.

* Contractor would be engaged for construction of the project.

* The NEA Project Director would have the dedicated staff and facilities necessary to carry out his responsibilities.

* Substantial number of local professionals from NEA as well as from local market will be involved with the consultant to work with him as member of integrated team. The selection and hiring of them will be the promulgative of the consultant.

* The NEA line organization would provide the necessary corporate support in staffing and funding.

Out of various options available to set the position of the project in the NEA organization, the option which follows the concept of Arun-3 Project Manager reporting in line to Managing Director NEA, has been proposed. The proposed position of the project within NEA is shown in Figure No. 1.2

The NEA Finance Directorate which shall have link to Administration and Finance Department of the Project, shall be responsible for ensuring that local funds are raised or made available for the project and for ensuring that moneys are provided for the Project Office.

The Project Office shall supply the necessary budget for its administrative expenses to the Finance Directorate in accordance with requirements.

After completion of the project, operational and maintenance aspects of the project shall be looked after by the Operation and Maintenance Directorate (OMD), OMD's will be linked to the project during the project construction period. During the course of the installation of electromechanical and hydraulic steel structures, the OMD shall assigned required staff to the project during erection and installation and such staff shall be responsible for operation and maintenance thereafter.

1.2.1 Concept of the Project Organization

In conformity with the basic concept of the project organization and the execution of the objective like transfer of technology, proposed project organization has been broadly classified into two groups.

a. Independent NEA monitoring body
b. Integrated team in association with the consultant for supervision and get things done.

a. Independent Monitoring Body:

Divisions and departments under this concept are directly responsible to the Project Director for the monitoring the project, activities of Contractors and Engineers. Planning & Monitoring Department, Environmental Monitoring Unit, Kathmandu and Biratnagar Liaison Offices. Secretariat, Internat Audits, Administration Department, Finance Department will come under Deputy Project Director while four construction departments will be headed by Directors of the respective departments.

b. Integrated Team in association with the consultant:

To fulfil the objective of transfer of technology, upgrade the technical quality of the NEA technical staff and economise the construction supervision cost, NEA/local technical staff will be integrated with the consultant for the construction supervision. Technical staff employed by the consultant shall be responsible to the consultant. All such staff of the consultant are marked asterix (*) in the organization chart.

1.2.2 Duration of Various Offices

All departments and divisions required for monitoring by NEA will function throughout the project duration i.e. from 1994 to 2001. Four construction departments will function in accordance with the construction schedule. Access Road Construction Department will function from 1994 to 1997.As the construction of the headworks and power cavern will start from the year 1996 the related sections under the HEP Construction Department to execute these functions will be established in 1996 and will work till 2001. Rest of the divisions and sections under the HEP construction Department and all divisions and sections under the Transmission System Department will function from 1997 to 2001. Accordingly, Electromechanical Department will function from 1998 to 2001.

Detail time of existence of Departments, Divisions and Sections are shown in Figure no. 1.3 Organization Chart and are indicated by separate box type.

1.2.3 Proposed Financial Authority for the Project

The present financial authority results in considerable and unnecessary administrative effort and risk of delay through the time needed to obtain quotations and advertise for tenders for minor items.

To avoid this the limits will be raised to facilitate the purchase of office equipment, furniture, vehicles, the renting of office accommodation prior to the establishment of site facilities and other similar preparatory and administrative activities.

Hence, expenditure on such items shall be budgeted for and authority granted to the Project Director. Purchase shall be always within budget and from suppliers approved by the Project Director.

* Sufficient authority will be given to the Project Director for direct purchase and purchase from quotation. The amount that limits the direct purchase and purchase from quotation will be raised from existing limit and these amounts should be revised from time to time in accordance with price escalation.

* For purchase by tender the Project Director shall have the same status as that of the level immediately below Managing Director level.

The final decisions on the amount of additional costs and time extensions should be made in accordance with the conditions set in the Contract Document.

1.2.4 Responsibility of the Personnel and Departments

The Project Director will be assisted by the Planning and Monitoring Department headed by Deputy Project Director, four Department Directors (Site Offices), Kathmandu Liaison Office, Biratnagar Liaison Office, Administration Division, Finance Division, Secretariat, Internal Audit, Environmental Monitoring Unit, Project Consultant and Panel of Experts including claim advisor.

Following are the main responsibilities of the Personnel and Departments:

<u>Planning and Monitoring Department(Deputy Project Director)</u>

This department headed by the Deputy Project Director, level 11, shall be responsible to the Project Director for the monitoring, contractual administration, planning, claim and project control functions. Apart from this, in absence of Project Director he shall take all the responsibility of Project Director. Following are the responsibilities of this Department and will be executed through the various divisions.

* Inventory Control Division. Duties of this division is to monitor the project procurement, inventory control and preparation of project inventory.

* Cost and Schedule Control Division. Duties of this division include formulation and updating of project schedule, recording of progress, estimate completion dates, advice on critical activities, update the cost estimation, forecast cash flow, monitor the progress of the project, process loan disbursement and monitor the situation of loan disbursement.

* Contract Administration Division. Duties of this division include formulation of contract documents, carry out prequalification, bidding and negotiation of contracts, and monitor the execution of the terms and conditions of agreed contract.

* Legal and Claim Division. This division is responsible for processing the settlement of any claim.

* Quality Control and Technical Division. Duties of this division are to monitor technical aspects such as quality control and implementation of job according to the approved design.

* Resettlement Division. This division is responsible for the execution of permanent and temporary land acquisition and necessary compensation and resettlement of the affected families.

Liaison Offices

The Liaison Offices stationed at Kathmandu and Biratnagar headed by Deputy Directors shall be responsible to the Project Director and shall keep coordination with all the related agencies and organizations stationed away from the site. These Offices will be responsible for the following activities:

* liaison with other Directorates of NEA.

* liaison with concern Ministries of HMG/N to expedite approvals and processes required for AHP.

* liaison with NEA Board and Sub Committee members .

* preparation of documents for the Board Meeting and secretarial duties required in Kathmandu.

* liaison with customs and immigration officials to expedite the import of equipment and materials and facilitate the immigration processing to the project personnel.

* liaison with Eastern Region Administration Office.

Finance Division

This division shall be headed by the chief Accountant level 10, who shall be responsible to the Project Director for overall Project finance. This division shall also be responsible for ensuring that all NEA financial reporting and procedural requirements including processing of bills for payment are satisfied in a timely manner.

Administration Division

This division headed by the Chief Administration Officer level 10 shall be responsible to the Project Director for the overall project administration. This department will be responsible for the following activities:

* day to day administration of project, record keeping, correspondence and office management.

Internal Audit Division

This division headed by the Chief Auditor level 10 shall be reporting to Project Director and be responsible to the Managing Director for the auditing of the project expenditure.

Environmental Monitoring Unit

This unit headed by Joint Director level 10 (Environmentalist) shall be responsible to the PD for monitoring the implementation of environmental impact mitigation measures undertaken by Contractors during the construction phase of the Arun-III Hydroelectric Project as a whole, and to ensure compliance with contractual conditions with respect to environmental mitigation measures.

Following are the responsibilities of this unit;

* to coordinate and monitor the implementation of the project's Environmental Mitigation Plan including taking all necessary measures to ensure compliance with the plan.

* to advise or assist the Arun-III project supervising engineer on the administration and implementation of environmental components of the project contract documents.

* to undertake or assist monitoring of conditions and trends in the physical, social, economic and cultural environment in the project area during the implementation of the Arun III HEP.

* to undertake and monitor the implementation of the Acquisition, Compensation and Rehabilitation Plan (ACRP).

* liaison with the Makalu-Barun National Park and Conservation Area Project.

* liaison with the Arun Basin Regional Action Programme (ABRAP).

* with ABRAP, to establish and maintain a GIS system for the project area as a basis for resource management.

* to undertake or assist the post auditing of environmental management, to update and review the finding as well as recommendations of the various environmental studies.

Department Directors. Site Offices

The Directors (level 11) of Road Construction Department, HEP Construction Department, Transmission Line Construction Department and Electro-Mechanical Department shall be responsible to the PD for monitoring various construction, installation activities including the following:

* monitor construction activities and schedules

* certify the Engineer's monthly statement

* monitor contract cost

* on the recommendation of the consultant approve the bills of contractors

* inform the PD on progress, expenditure, quality of construction

* keep available day to day progress data from the divisions and send to Monitoring Division.

1.3 Arun-III Coordinating Committee

Having recognized the need for close and effective coordination among various government and other agencies to process the project of such magnitude and complexity HMG/N has formed a high level Arun-III Coordinating Committee (ACC) comprising:

* Minister for Water Resources (Chairman)
* Member, National Planning Commission, Energy & Infrastructure (Member)
* Secretary, Ministry of Finance (Member)
* Secretary, Ministry of Water Resources (Member)
* Executive Secretary, Water and Energy Commission Secretariat (Member)
* Managing Director, NEA (Member)
* Project Director, Arun-III HEP (Member)
* Project Coordinator Arun-III Member (Secretary)

The main objective of the ACC is to assist in the efficient processing of all aspects of the Project through coordination of all the works of HMG/N for expediting the implementation of the Project.

To achieve the objectives stated above the committee shall execute, but not limited to, the following activities:

* To take necessary decisions regarding all preparatory activities to be undertaken by HMG/N for quick and effective implementation of Arun-3 Hydroelectric Project and implement or cause to implement the same in timely manner by establishing close coordination among the concerned agencies.

* To arrange financing of foreign and local components of the project cost from donors and HMG/N respectively by maintaining close co-ordination with these agencies.

* To monitor and review regularly progress of the work required to be done by HMG/N and the progress undertaken in connection with the NEA's longterm financial management reform and keep donors informed on this.

* To take timely action to solve the problems which may be encountered in undertaking actions in pursuant to item (c) and to make necessary policy decisions regarding execution of the Arun-3 Hydroelectric Project and implement or cause to implement the decision through HMG/N concerned agencies.

* To undertake monitoring and other activities related to the project on behalf of HMG/N even after the necessary agreements has been concluded with the donors an project has entered the implementation phase.

Ministry of Water Resources shall act as Arun-3 Co-ordination Committee Secretariat.

PROJECT RELATIONSHIP

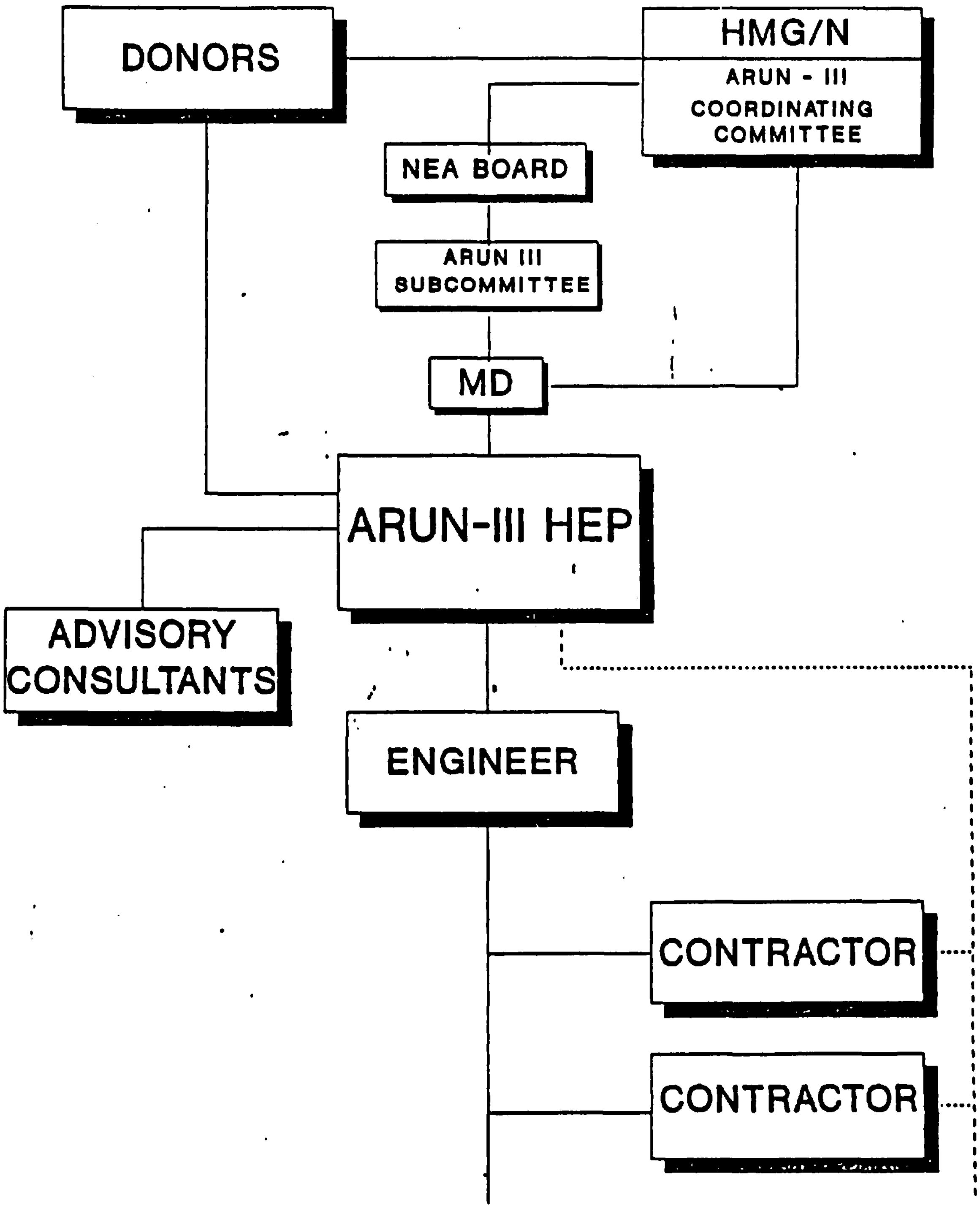
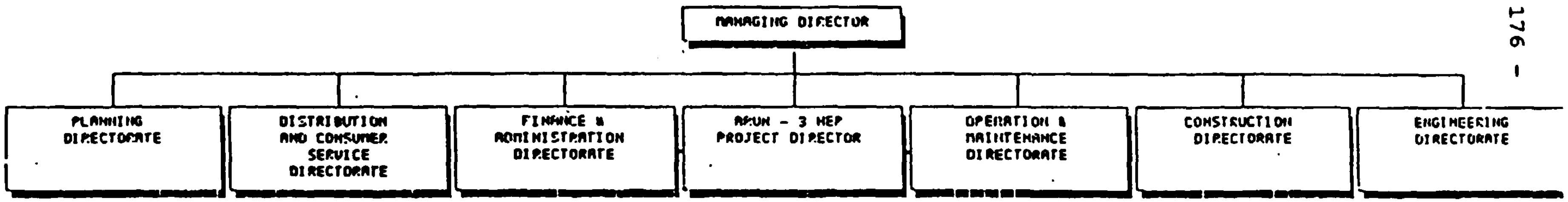


FIGURE NO. 1.1

POSITION OF PROJECT IN NEA

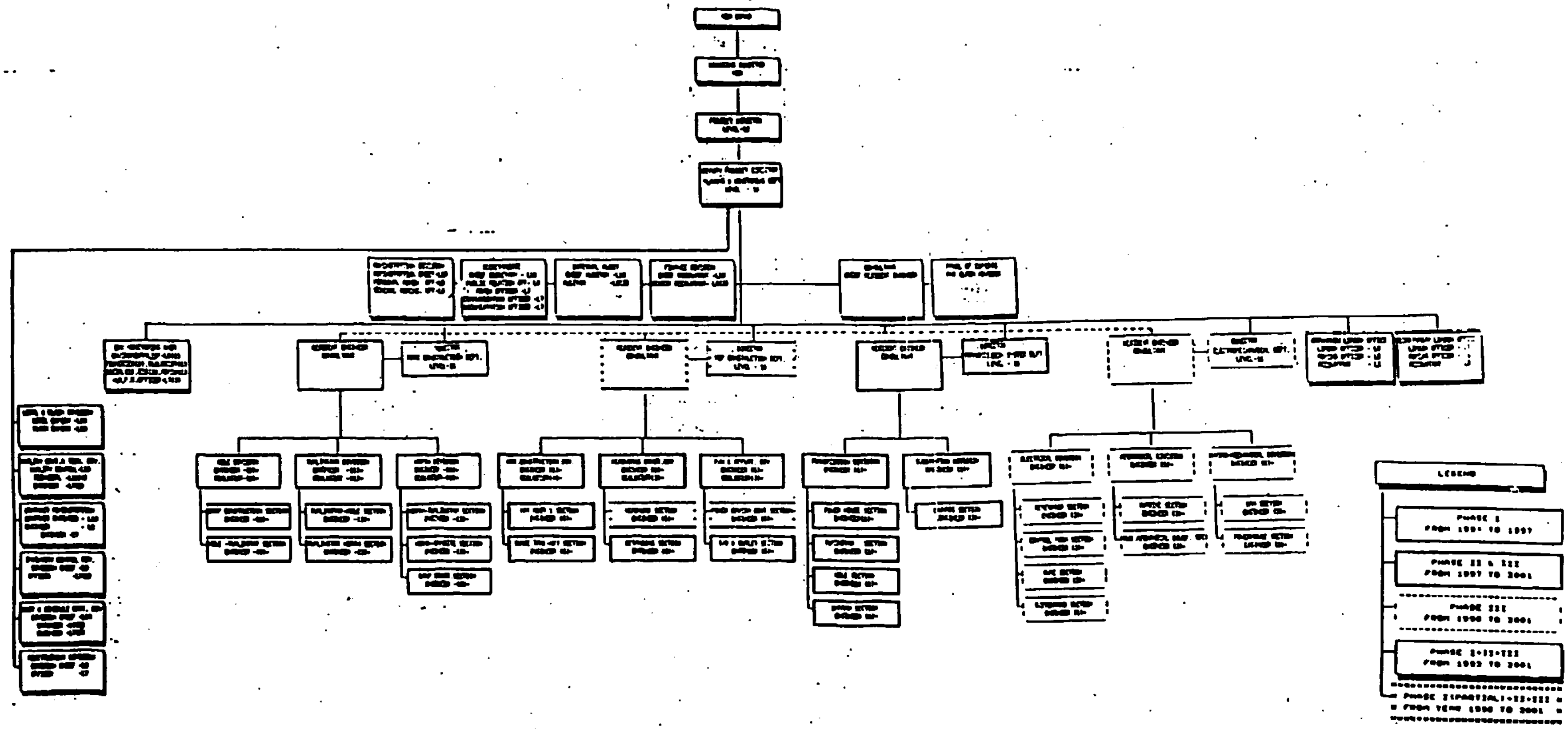
Arun -3 Hydroelectric Project



ARUN III HYDROELECTRIC PROJECT

ORGANIZATION FOR IMPLEMENTATION

(PROPOSED)



NEPAL

ARUN III HYDROELECTRIC PROJECT

Regional Action Program (RAP) Consultancy

Terms of Reference

Background

1. Measures to minimize the indirect impacts of the access road and hydropower project, and to capitalize on the economic opportunities provided by improved access such as tourism, have been identified by the Management of Basinwide Environmental Impacts Study carried out by the King Mahendra Trust for Nature Conservation for HMG. Together, these measures constitute the Regional Action Program (RAP). This major program will compliment the Arun III Project's Environmental Mitigation Plan, and will continue well after the Project has ben commissioned.

2. The proposed macro-management model for Arun Basin Environmental Management is based on a Steering Committee chaired by NPC, and an independent Secretariat (Figure 1). The Secretariat will be composed of seconded HMG staff and an appointed Director.

RAP Program Areas

3. The Basinwide Impact Study's report lists 21 recommended sectoral programs in six major program areas (see below). These programs are designed to address both the immediate requirements brought about by the construction process, and the longer-term needs for sustainable development within the valley.

4. The six major programs areas are:

- Conservation
- Income Generation
- Institutional Strengthening
- Extension and Training
- Infrastructure and Energy
- Research, Monitoring and Information

5. In terms of scheduling, five sectoral programs were regarded as priorities for pre-emptive implementation ahead of road construction. These relate to:

(a) Strengthening local forest management;
(b) helping local communities service construction related demands, particularly for wood;
(c) strengthening government institutions to cope with impacts;
(d) training and education for local human resource development;
(e) environmental monitoring.

6. These activities comprise a "Core Program" to be implemented by HMG as a priority, initially through existing organizations, particularly the Ministry of Forests and Soil Conservation. Local consultants and NGOs will be contracted to expedite the work.

Costs

7. The total cost of the RAP programs has been estimated at US$14.6 million, excluding physical and price contingencies over ten years. Within this, the cost of the Core Program for priority implementation is estimated at US$2.6 million, excluding contingencies. The RAP financing plan is set out in Annex 3.11. This takes into account the community forestry project and the Kosi Hills Seed and Vegetable project already being implemented with ODA-assistance and the proposed GtZ RAP project.

Scope of Work

8. There would be an implementation unit attached to the Secretariat. This would consist of both short- and long-term consultants and local experts.

9. The team would have a core team and other experts. The core team would consist of long-term experts in the fields of agriculture, forestry, environmental management, civil engineering, information management and sociology/anthropology. Other short-term experts would be hired as necessary.

10. The team would also have a management expert who would also work as the Team Leader.

11. The core team and Team Leader would be hired for a period of at least five years with a provision for extension.

12. A consulting firm specialized in regional and multi-sectoral projects will be hired for this purpose. (A consortium of these agencies could also be hired.) A foreign agency interested in affecting the consultancy service would be required to collaborate with local firms of agencies.

13. The TA team would be primarily responsible for providing support to the Secretariat in the following areas:

- Preparation and implementation of the annual program.
- Establishment of the monitoring and management information systems.
- Supervision and monitoring of project activities.
- Formation of internal working procedures, including financial working rules.
- Preparation and implementation of a human resources development plan.
- Preparation and publication of project related documents and audio visual material.
- Arrangements for project related specialized studies.
- Documentation of project related studies and documents.
- Arrangements for a review room and display of facts, figures and charts/graphs.

Work Program

14. The first task of the proposed consultancy (with an anticipated completion date of January 1995) is to develop a plan for monitoring the RAP which should take into account the baseline data developed under the ongoing King Mahendra Trust for Nature Conservation study.

Annex 3.14

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ARUN HYDROELECTRIC PROJECT

Disbursement Profile[1/]

Fiscal Year		Cumulative Disbursement (Project) US$ Million	Cumulative Disbursements (Project) %
1994/95	December 31, 1994	17.50[2/]	
	June 30, 1995	21.38	12.2
1995/96	December 31, 1995	25.26	
	June 30, 1996	32.97	18.8
1996/97	December 31, 1996	41.18	
	June 30, 1997	53.26	30.5
1997/98	December 31, 1997	69.34	
	June 30, 1998	83.12	47.5
1998/99	December 31, 1998	96.90	
	June 30, 1999	105.10	60.1
1999/00	December 31, 1999	113.30	
	June 30, 2000	123.02	70.3
2000/01	December 31, 2000	132.74	
	June 30, 2001	143.11	81.8
2001/02	December 31, 2001	153.48	
	June 30, 2002	157.52	90.0
2002/03	December 31, 2002	161.60	
	June 30, 2003	168.13	96.1
2003/04	December 31, 2003	174.68	
	June 30, 2004	174.85	99.9
2004/05	December 31, 2004	175.00	
	June 30, 2005	175.00	100.0

July 9, 1994

1/ Includes disbursements from Cr. 2029-NEP

2/ Includes mobilization advance for the contractor for the combined Lot C1/C3

Annex 4.1

NEPAL

ARUN III HYDROELECTRIC PROJECT

Status of Financial Management Actions Initiated During the PSEP

Actions	*Current Status and Proposed Actions*
A. *Institutional*	
1. To appoint qualified finance managers.	*A Finance Director and two deputies were appointed, all three are qualified accountants.*
2. To make all accountants functionally responsible to the Finance Director.	*About 50% of all accountants have so far been brought under the direct functional responsibility of the Finance Director. This is expected to improve in due course and needs follow-up.*
3. To channelize all budgetary inflow from HMG through NEA's finance department.	*Done*
4. To require HMG and NEA enter into a Performance Contract that would be updated annually.	*The Performance Agreement (PA) was executed in August 1992. A review of the PA is scheduled soon and an updated version will be provided to IDA by August 15, 1994.*
5. To implement "An Action Plan For Reducing Consumer Receivables"	*Action Plan started, but implementation is unsatisfactory. This is being addressed under processing of the AHP.*
6. To establish a Rural Electrification-Directorate.	*Done.*
7. To train NEA's internal audit staff.	*A one year training done; further actions to be taken under AHP.*
8. To ensure continued appointment of external auditors satisfactory to IDA	*Except for FY91 (when the AG appointed his office as NEA's auditor), NEA's auditors since FY88 have been acceptable to IDA.*
B. *Finance/Accounts*	
1. To reconcile NEA's outstanding debt to HMG	*Done*
2. To ensure completion of all SLAs	*Done. The SLA for Marsyangdi Hydroelectric Power Project has been revised.*
3. To revalue assets annually in a manner satisfactory to IDA.	*Done.*
4. To maintain accounts so that NEA's losses on account of providing services to non-viable RE projects can be identified and compensated by HMG.	*The necessary accounting system for identifying such losses will be developed as a part of the ongoing consultancy work on Improvement of NEA's accounting system.*
5. To insure NEA's assets.	*A study (funded through 1478-NEP) was completed and NEA started allocating NRs. 20 million each year for small or non-frequent losses. In accordance with NEA's insurance plan that was discussed during negotiations of the AHP, all generating facilities are now expected to be insured by January 1, 1996.*

NEPAL

ARUN III HYDROELECTRIC PROJECT

NOTES AND ASSUMPTIONS FOR FINANCIAL PROJECTIONS

A. General

1. **Escalation and Exchange Rates**. The financial projections are based on the following escalation rates for foreign and local currency, and for converting US$ 1.00 with Nepalese Rupees.

Fiscal Year	Local Infl. Rate	Foreign Infl. Rate	Exchange Rate
[1]1993	11.7	1.9	49.48
1994	8.0	2.5	49.48
1995	7.0	2.5	51.65
1996	6.0	2.5	53.42
1997	5.0	2.5	54.72
1998	5.0	2.5	56.05
1999	5.0	2.5	57.42
2000	5.0	2.5	58.82
2001	5.0	2.5	60.26
2002	5.0	2.5	61.73
2003	5.0	2.5	63.23
2004	5.0	2.5	64.77

B. Income Statement

2. **Energy Generation**. The forecast of hydro, thermal and private generation required to meet the load demand over the 11 year period FY94-04 was determined by the power system simulation program (WASP).

3. **Energy Purchased**

(a) **From India**. The total energy purchased from India is based on agreements between HMG and BSEB/GOB/UPSEB and is based on the demand in those areas of Nepal connected to India. These are limited to 65 GWh up to FY96 due to limitations of the available physical facilities. Thereafter, upon completion of Duhabi-Kataiya and other interconnectors, Nepal could import up to 50 MW of power.

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1 The local and foreign inflation rates for FY93 are actual.

(b) **From Nepal**. (Other hydroelectric plants): Purchases from Andhikhola are assumed at 24 GWh per annum. Starting FY98, NEA is expected to buy power from other private sector generating plants; the total GWh purchase will depend upon NEA's demand forecast, and the contractual agreement between HMG/NEA and the private sector power producers.

4. **NEA's Self Consumption (GWh)**. Forecasts assume that NEA's electricity consumption will amount to about 1% of total hydroelectric units generated plus 5% of total thermal units generated.

5. **System Losses**. Under NEA's System Loss Reduction Program, system losses within Nepal, including NEA's own consumption are projected to decrease from 25% of gross generation in FY1993 to 18.4% by FY04; system loss for the 50 MW export is assumed at 5%.

6. **Energy Sales**. Sales within Nepal are based on the agreed load forecast. Sales to India are according to existing arrangements to supply areas of India connected to the Nepal grid but based on availability of power.

7. **Average Revenue Rate (NRs./kWh)**. Forecast average revenue rate (NRs./kWh) is calculated on the basis that NEA will be permitted to set tariffs at such levels so as to satisfactorily comply with both: (a) a self-financing ratio covenant, and (b) a rate of return covenant.

(a) Under the self-financing covenant, forecast average revenue is calculated on the basis that NEA set tariffs at levels which will provide funds to cover: (i) cash operating expenses; (ii) debt service; (iii) additional working capital other than cash; and (iv) self-finance a percentage of total capital investment including IDC averaged over the past, the current and the next year. This percentage is set out as follows:

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
12.0	14.0	15.0	16.0	17.0	20.0	21.0	22.0	25.0	26.0

(b) Under the rate of return covenant starting in FY96, NEA is to earn rates of return on average net revalued fixed assets of not less than 4.5% for FY96 and 6% thereafter.

8. **Revenue from Electricity Sales**

(i) Nepal: Forecasts of revenue for the period FY95-04 are based on the sales forecast and the average revenue rate derived from calculations based on the previous paragraph.

(ii) India: As agreed between HMG and GOI (meeting of February 24, 1994), starting January 1993, the average selling price of electricity between Nepal and India was fixed at IRs. 1.250/kWh (NRs. 2.000/kWh @ IRs. 1.00 = NRs. 1.60). The agreement further stipulates an escalation rate of 8.5% per annum (CY). Based on this the FY94 sale price to India is estimated to be NRs. 2.262/kWh. However, in absence of any firm contractual agreement on sale of surplus energy to India, starting FY96, it is assumed that 50% of the surplus energy available is sold to India at the prevailing rate. This is equivalent to the assumption used in the economic analysis that all surplus energy is exported at 50% of the prevailing rate.

9. **Other Operating Revenue**. This revenue includes miscellaneous services to consumers such as transfer/replacement of meters, application fees and fees for re-connection of services and are assumed to increase at 10 per cent per annum.

OPERATING EXPENSES

10. **Fuel Expenses**. These have been projected on the basis of required thermal generation, heat rates and existing fuel prices (adjusted for inflation in future years plus a one-time increase of 5% in FY98 for infrastructure expenditures of NOC).

11. **Energy Purchases**

(a) **From India:** The purchase price is same as the sale price mentioned above.

(b) **From Nepal:** (Other Hydroelectric plants): NEA's purchase price from Andhikhola is based upon the agreement concluded; and from Jhimruk it is assumed at NRs. 1.75/RWh in FY93 prices. For the purchase price from other proposed private sector power generating plants, the overall purchase price assumed is NRs. 2.83/RWh in FY93 prices (e.g., US$5.72 cents/RWh inclusive of royalty at 10%).

12. **Salaries, Wages and Allowances**. Salaries, wages and allowances are projected to increase at 10% per annum.

13. **Operation and Administration**. These expenses comprise of maintenance and general administration and overhead expenses other than salaries, wages and allowances. Annual increases are estimated at 15% per annum.

14. **Depreciation**. Depreciation expense is forecast as 3.0 per cent of average revalued gross fixed assets in service. Assets in service were valued in FY89 and since then have been revalued annually using the foreign and local inflation rates and assuming that asset costs are comprised of 80 per cent foreign and 20 per cent local cost.

15. **Provisions**. This provision is general and is projected to increase at 10 per cent per annum.

16. <u>**Interest Expense**</u>. Interest expense consists of projected interest cost of all short and long term debts.

17. <u>**Income Tax**</u>. Income tax is calculated at 35% of net income less interest expenses and depreciation on historical asset value. Losses incurred in any year are allowed to roll for three years.

18. <u>**Insurance Fund**</u>. An amount of NRs. 20 million is assumed to be allocated to this fund each year.

19. <u>**Contingency Reserve**</u>. These are meant to create a reserve fund and are assumed to remain at 10% of net profit after tax.

C. <u>Balance Sheet</u>

20. <u>**Fixed Assets**</u>. NEA has been revaluing its assets since FY89. Forecast revaluation rates are based on the methodology agreed with IDA during the Power Sector Efficiency Project (PSEP).

<u>**Current Assets**</u>

21. <u>**Cash**</u>. Cash balances have been projected to remain at two months of cash operating expenses.

22. <u>**Inventories**</u>. Inventories consisting of stores, maintenance supplies and fuel have been estimated to remain at 1.0 per cent of average gross revalued fixed assets.

23. <u>**Accounts Receivables**</u>. Starting FY94 accounts receivable are projected to remain at the equivalent of three months of yearly sales.

24. <u>**Recoverable Advances**</u>. These advances consist of advances for letters of credit, official staff travel and expense, suppliers of stores and equipment and services contracted. These amounts are projected to increase at 10.0 per cent per annum.

25. <u>**Short-term Investments**</u>. Cash surpluses are assumed to be invested in short term deposits.

<u>**Current Liabilities**</u>

26. <u>**Accounts Payable**</u>. Accounts payable are forecast at three months of cash operating expenses excluding energy purchases.

27. <u>**Miscellaneous Deposits**</u>. These deposits include consumer deposits and suppliers' and contractors' deposits which are projected to remain at 2.0 per cent of yearly revenue sales in Nepal.

28. **Purchase of Energy**. These are assumed to remain at three months of yearly purchase up to FY96 and two months thereafter.

D. Sources and Application of Funds

29. **Consumers Contributions**. Consumer contributions are projected to increase at 5% per cent per annum.

30. **Long Term Debt and HMG's equity contribution**. Long term debt is incurred to finance the foreign cost of NEA's investment program. It is projected that 80 per cent of the foreign currency cost of NEA's investment program will be financed by long term loans (from HMG) while the remaining 20 per cent will be provided as equity. Any HMG contributions to the local cost of the investment program also are assumed to be provided as equity.

31. **Debt Service**. Loan terms for other than rural electrification, are projected to include an interest rate of 10.25 per cent per annum with equal annual debt service payments. All loans are assumed to be paid in 25 years including five years grace, but for the proposed AHP this will be extended to 30 years including a grace period of nine years. Rural electrification projects will carry an interest rate of 1.0 per cent to be repaid in 25 years including a grace period of five years. Any foreign exchange risk that may arise during repayment shall be born by HMG

32. Interest charges during the construction period shall be capitalised and added to the asset value upon completion. However, each year these will have to be financed by NEA (shared with HMG as the case may be) and not added to the loan balances.

NEPAL
NEPAL ELECTRICITY AUTHORITY
INVESTMENT PROGRAM
BASE COST ('000 US DOLLARS) IN FY93 PRICES

GENERATION - FOREIGN COMPONENT

PROJECTS	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	FY95-04 TOTAL (US $ MIL.)
Trishuli upgrading	7170	0	0	0	0	0	0	0	0	0	7.17
Kaligandaki 'A-1' - 100MW (FY2000)	10	58400	65463	66010	43385	6888	0	0	0	0	240.16
Kaligandaki 'A-2' - 40MW (FY2002)	0	0	0	0	0	0	20254	0	0	0	20.25
Arun - 3 (Phase I) (FY2003)	24710	52220	104610	60660	74040	109900	68750	27080	27610	820	550.40
Arun - 3 (Phase II) (FY2007)	0	0	0	0	0	0	50250	59750	49930	49890	209.82
M.F.D. # 1&2 (2X20 MW) (FY1998)	0	12240	16320	12240	0	0	0	0	0	0	40.80
Upper Arun (FY2009)	0	0	0	0	0	0	0	50100	51300	80000	181.40
Other hydro	200	0	0	0	0	0	0	0	0	0	0.20
SUB-TOTAL (FOREIGN) :	32090	122860	186393	138910	117425	116788	139254	136930	128840	130710	1250.20

GENERATION - LOCAL COMPONENT

PROJECTS	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	FY95-04 TOTAL (US $ MIL.)
Trishuli upgrading	1200	0	0	0	0	0	0	0	0	0	1.20
Kaligandaki 'A-1' - 100MW (FY2000)	839	18722	15980	16137	10141	1151	0	0	0	0	62.97
Kaligandaki 'A-2' - 40MW (FY2002)	0	0	0	0	0	0	1083	0	0	0	1.08
Arun - 3 (Phase I) (FY2003)	6250	11850	20830	18120	12900	19000	15280	7190	5570	0	116.99
Arun - 3 (Phase II) (FY2007)	0	0	0	0	0	0	6083	6663	6518	7566	26.83
M.F.D. # 1&2 (2X20 MW) (FY1998)	0	2880	3840	2880	0	0	0	0	0	0	9.60
Upper Arun (FY2009)	0	0	0	0	0	0	0	10905	11553	14332	36.79
Other hydro	100	0	0	0	0	0	0	0	0	0	0.10
SUB-TOTAL (LOCAL) :	8389	33452	40650	37137	23041	20151	22445	24758	23641	21898	255.56

Note: The Arun-3 Ph.II includes cost of the Transmission Line between Duhabi-Indian border.

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NEPAL
NEPAL ELECTRICITY AUTHORITY
INVESTMENT PROGRAM
BASE COST ('000 US DOLLARS) IN FY93 PRICES

PROJECTS	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	FY95-04 TOTAL (US $ MIL.)
TRANSMISSION (FOREIGN)											
PSEP T/L Comp. w/in Kathmandu	3337	1252	0	0	0	0	0	0	0	0	4.59
PSEP T/L Comp. Outside Kathmandu	579	241	0	0	0	0	0	0	0	0	0.82
PSEP T/L Comp.Duhabi-Kataiya T/L	240	110	0	0	0	0	0	0	0	0	0.35
Project 1996 (1994-1996)	4751	6356	0	0	0	0	0	0	0	0	11.11
Project 1997 (1995-1997)	5540	7386	5540	0	0	0	0	0	0	0	18.47
Project 1999 (1997-1999)	0	0	3745	4993	3745	0	0	0	0	0	12.48
Project 2000 (1998-2000)	0	0	0	2147	2862	2147	0	0	0	0	7.16
Project 2002 (2000-2002)	0	0	0	0	0	909	1212	909	0	0	3.03
Project 2003 (2001-2003)	0	0	0	0	0	0	3777	5036	3777	0	12.59
Project 2004 (2002-2004)	0	0	0	0	0	0	0	1246	1661	1246	4.15
Project 2005 (1998-2005)	0	0	0	667	667	667	667	667	2387	2961	8.68
Project 2006 (2004-2006)	0	0	0	0	0	0	0	0	0	1264	1.26
SUB-TOTAL (FOREIGN)	14446	15345	9284	7806	7274	3723	5656	7858	7826	5471	84.69
TRANSMISSION (LOCAL)											
PSEP T/L Comp. w/in Kathmandu	408	0	0	0	0	0	0	0	0	0	0.41
PSEP T/L Comp. Outside Kathmandu	79	0	0	0	0	0	0	0	0	0	0.08
PSEP T/L Comp.Duhabi-Kataiya T/L	160	30	0	0	0	0	0	0	0	0	0.19
Project 1996 (1994-1996)	1114	1491	0	0	0	0	0	0	0	0	2.60
Project 1997 (1995-1997)	999	1332	999	0	0	0	0	0	0	0	3.33
Project 1999 (1997-1999)	0	0	900	1200	900	0	0	0	0	0	3.00
Project 2000 (1998-2000)	0	0	0	343	458	343	0	0	0	0	1.14
Project 2002 (2000-2002)	0	0	0	0	0	213	284	213	0	0	0.71
Project 2003 (2001-2003)	0	0	0	0	0	0	885	1180	885	0	2.95
Project 2004 (2002-2004)	0	0	0	0	0	0	0	292	389	292	0.97
Project 2005 (1998-2005)	0	0	0	156	156	156	156	156	564	700	2.04
Project 2006 (2004-2006)	0	0	0	0	0	0	0	0	0	296	0.30
SUB-TOTAL (LOCAL)	2760	2853	1899	1700	1514	713	1325	1841	1838	1288	17.73

21-Jun-94

NEPAL
NEPAL ELECTRICITY AUTHORITY
INVESTMENT PROGRAM
BASE COST ('000 US DOLLARS) IN FY93 PRICES

PROJECTS	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	FY95-04 TOTAL (US $ MIL.)
DISTRIBUTION (FOREIGN)											
Seventh Power Project	10848	10066	0	0	0	0	0	0	0	0	20.91
Attariya - Dadeldhura	1000	0	0	0	0	0	0	0	0	0	1.00
Seventh Power Project (RE)	15068	13429	0	0	0	0	0	0	0	0	28.50
Dumre-Beshishahar (RE)	705	153	0	0	0	0	0	0	0	0	0.86
Distribution Phase I	0	0	1377	1377	918	0	0	0	0	0	3.67
Distribution Phase II	0	0	0	531	956	1593	1062	0	0	0	4.14
Distribution Phase III	0	0	0	0	0	1530	4590	4590	3060	0	13.77
Distribution Phase IV	0	0	0	0	0	0	0	6048	9072	9072	24.19
Distribution Phase V	0	0	0	0	0	0	0	0	0	7452	7.45
SUB-TOTAL (FOREIGN)	27620	23648	1377	1908	1874	3123	5652	10638	12132	16524	104.50
DISTRIBUTION (LOCAL)											
Seventh Power Project	1499	2474	0	0	0	0	0	0	0	0	3.97
Attariya - Dadeldhura	1270	0	0	0	0	0	0	0	0	0	1.27
Seventh Power Project (RE)	2083	4222	0	0	0	0	0	0	0	0	6.30
Dumre-Beshishahar (RE)	617	134	0	0	0	0	0	0	0	0	0.75
Distribution Phase I	0	0	689	689	459	0	0	0	0	0	1.84
Distribution Phase II	0	0	0	212	319	796	531	0	0	0	1.86
Distribution Phase III	0	0	0	0	0	153	1148	1148	765	0	3.21
Distribution Phase IV	0	0	0	0	0	0	0	1008	1512	1512	4.03
Distribution Phase V	0	0	0	0	0	0	0	0	0	1242	1.24
SUB-TOTAL (LOCAL)	5468	6830	689	901	778	949	1679	2156	2277	2754	24.48
MISCELLANEOUS PROJECTS (FOREIGN)											
Miscellaneous (Total PSEP)	1860	192	0	0	0	0	0	0	0	0	2.05
Miscellaneous (Trng/Proj. Mgt.)	300	0	0	0	0	0	0	0	0	0	0.30
SUB-TOTAL (FOREIGN)	2160	192	0	0	0	0	0	0	0	0	2.35
MISCELLANEOUS PROJECTS (LOCAL)											
Miscellaneous (Total PSEP)	436	380	0	0	0	0	0	0	0	0	0.82
Miscellaneous (Trng/Proj. Mgt.)	392	0	0	0	0	0	0	0	0	0	0.39
SUB-TOTAL (LOCAL)	828	380	0	0	0	0	0	0	0	0	1.21

21-Jun-94

NEPAL ELECTRICITY AUTHORITY
ACTUAL AND FORECAST INCOME STATEMENTS
(Rs million)

Fiscal year ending 15 July	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	[------ audited ------]					[preaud]	[est]	[------ forecast ------]									
Energy generated (GWh)																	
- hydro	559	549	478	872	870	804	865	961	1079	1104	1129	1067	1552	1612	1754	2831	2964
- thermal	3	10	1	1	32	47	55	116	82	92	220	176	78	136	174	0	0
Total Energy Generated (GWh)	561	558	479	872	902	851	920	1077	1161	1196	1349	1243	1631	1748	1928	2831	2964
Energy purchased from India (GWh)	63	114	61	35	55	87	53	62	52	108	22	11	0	10	57	0	0
Energy purchased from Nepal (GWh)	0	0	232	0	25	30	27	24	105	105	176	526	526	526	526	526	526
Total Energy Available (GWh)	624	672	772	908	981	969	999	1163	1317	1409	1547	1781	2157	2283	2511	3357	3490
NEA consumption (GWh)	7	9	11	13	14	14	15	15	15	16	22	19	19	23	26	28	30
System Losses (GWh)	157	164	210	224	245	235	235	262	282	300	322	351	390	415	449	521	552
System Losses as a % of Av.Energy	26.4%	24.4%	27.2%	24.7%	24.9%	24.3%	23.5%	22.5%	22.0%	21.5%	21.0%	20.5%	20.0%	19.6%	19.2%	18.8%	18.4%
Energy Sold (GWh) - Nepal	444	482	524	590	652	674	719	853	938	1031	1144	1269	1410	1559	1731	1924	2140
- India	16	18	27	81	84	59	45	48	97	78	81	161	357	309	332	912	798
Total Energy sold	460	500	551	671	736	734	764	901	1035	1110	1225	1430	1767	1868	2062	2836	2938
Av. revenue rate in Nepal (Rs/kWh)	1.22	1.38	1.38	1.40	1.99	2.51	3.17	3.88	4.88	6.09	6.32	7.12	7.12	7.82	7.82	7.82	8.58
Increase in Av. Rev. Rate (%)	6.0%	13.8%	-0.3%	1.3%	42.0%	26.3%	26.2%	22.5%	25.8%	24.8%	3.9%	12.6%	0.0%	9.7%	0.0%	0.0%	9.7%
Av.rev.rate on date of effectiveness					2.24	2.81	3.88	3.88									
Percentage increase:-					60.2%	25.4%	38.0%	0.0%									
Date of effectiveness:-					Nov 15	Mar 15	Mar 15	Jul 15									
OPERATING REVENUE																	
Electricity sales																	
- Nepal	539	667	723	826	1295	1692	2276	3309	4577	6279	7235	9038	10046	12185	13527	15037	18354
- India	12	23	37	135	146	81	98	118	258	226	254	548	1318	1238	1441	4301	4082
Total Electricity Sales	552	690	760	961	1440	1773	2375	3427	4835	6505	7489	9586	11364	13424	14967	19338	22436
Other operating revenue	16	22	25	32	74	81	89	98	108	119	131	144	158	174	191	210	232
TOTAL OPERATING REVENUE	568	712	785	993	1514	1854	2464	3525	4943	6624	7619	9730	11522	13598	15159	19548	22667
OPERATING EXPENSES																	
Fuel	5	27	5	4	85	92	116	301	197	236	612	514	239	437	587	0	1
Energy purchases	64	139	172	50	111	211	149	186	346	532	572	1973	2033	2174	2491	2357	2476
Salaries, wages & allowances	140	171	194	279	294	332	365	402	442	486	535	588	647	712	783	861	947
Operation & administration	62	86	92	97	120	189	217	250	287	331	380	437	503	578	665	765	879
Depreciation	135	579	684	880	954	1022	1135	1255	1423	1580	1699	1823	2249	2698	2815	3879	4979
Provisions(Grat, Bonus & Bad Debts)	27	26	49	0	9	10	11	12	13	14	15	17	19	21	23	25	27
Reduction of Def. Charges (Other)	0	0	57	57	45	45	45	31	0	0	0	0	0	0	0	0	0
Bad Debt Expenses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL OPERATING EXPENSES	432	1029	1252	1367	1618	1901	2038	2436	2708	3178	3812	5352	5690	6619	7363	7886	9310
OPERATING INCOME	136	-317	-467	-374	-104	-47	425	1089	2235	3447	3807	4378	5832	6979	7796	11662	13357
Interest expenses	126	130	129	635	632	718	724	869	989	1263	1331	1509	1551	2786	2873	2826	6709
Income after Interest before Tax	10	-447	-596	-1009	-736	-765	-299	220	1246	2183	2476	2869	4281	4193	4923	8836	6648
Prior Yrs' Adjustment	-2	33	-41	15	76	0	0	0	0	0	0	0	0	0	0	0	0
Trans. from revaluation surplus	0	424	522	569	610	664	698	738	779	823	870	921	976	1043	1124	1209	1325
Income tax	14	7	0	0	0	0	0	335	709	1052	1171	1327	1840	1833	2117	3516	2791
Insurance Fund	0	0	0	0	0	20	20	20	20	20	20	20	20	20	20	20	20
Contingency Reserve	0	0	0	0	0	0	40	62	132	195	217	246	342	340	393	653	518
NET INCOME	-6	3	-115	-425	-50	-122	339	540	1165	1739	1937	2198	3055	3043	3518	5856	4645
Av. Net Fixed Assets in service	4134	10032	16239	19576	22776	24112	26484	28899	32715	35996	37819	39616	51164	62931	63263	94485	125674
RATIOS :- Operating Ratio (%)	78	145	159	138	107	103	83	79	69	64	65	69	65	62	63	58	53
Rate of return (%)	3.0	-3.2	-2.9	-1.9	-0.5	-0.2	1.6	2.6	4.7	6.7	7.0	7.7	7.8	8.2	9.0	8.6	8.4

Note: Systems losses (%) as indicated above is within Nepal grid system and excludes transmission losses (at 5%) for the export system.

NEPAL ELECTRICITY AUTHORITY
ACTUAL AND FORECAST SOURCES & APPLICATIONS OF FUNDS
(Rs millions)

Fiscal year ending 15 July	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	[---------------		audited		---------------]	[preaud]	[est]	[------------------				forecast					------------------]
SOURCES OF FUNDS																	
Internal Cash Generation																	
Op.inc.after Tax & Prior Yrs'adj.	120	-187	-508	-358	-28	-47	425	754	1526	2394	2636	3051	3992	5146	5679	8146	10567
Depreciation	135	560	683	881	952	1022	1135	1255	1423	1580	1699	1823	2249	2698	2815	3879	4979
Reduction of Def. Charges (Other)	0	0	57	57	49	45	45	31	0	0	0	0	0	0	0	0	0
Total internal cash generation	255	373	232	580	973	1020	1606	2040	2949	3974	4335	4874	6241	7844	8494	12025	15546
Consumer Contributions	20	10	12	11	21	22	23	24	25	26	28	29	30	32	34	35	37
Long term loans (Foreign)	193	404	547	5929	781	1550	2020	4024	8351	10785	8310	7729	8452	9852	10002	10082	10396
Equity Contr.-Donor (Foreign Comp.)	607	0	0	0	0	36	88	117	971	1117	1116	700	192	1201	1979	1962	2582
-HMG (Local Comp.)	352	-113	644	770	40	0	399	398	1858	2084	2749	2616	1532	1998	2287	47	0
Spl. Loan - Marsyangdi unpaid interest	0	0	0	501	499	0	0	0	0	0	0	0	0	0	0	0	0
Revaluation Surplus	0	-4521	522	569	610	664	698	738	779	823	870	921	976	1043	1124	1209	1325
TOTAL SOURCES OF FUNDS	1426	-3846	1956	8360	2923	3291	4833	7341	14932	18810	17407	16869	17424	21971	23920	25361	29886
APPLICATIONS OF FUNDS																	
Capital investment:																	
Proposed Project								1698	3722	7644	5058	5835	9084	6229	2671	2710	70
Other Capital Expenditure (Foreign)	721	309	624	6567	560	1586	2108	2801	6317	5584	5579	3498	960	6006	9894	9809	12908
Other Capital Expenditure (Local)	561	215	377	342	404	234	318	640	1919	1426	1445	872	207	787	1752	1892	2323
Interest During Construction	0	0	0	73	70	166	283	365	789	1445	2336	2956	3701	3374	4246	5257	2350
Total capital investment	1281	523	1000	6982	1034	1986	2710	5504	12748	16098	14417	13162	13953	16396	18562	19668	17651
Asset Revaluation	0	-4521	522	569	610	664	698	738	779	823	870	921	976	1043	1124	1209	1325
Investment in Govt. Bonds	2	0	4	0	22	64	0	0	0	0	0	0	0	0	0	0	240
Inc.in def.charges (Marsy.unpaid int.)	0	0	0	501	499	0	0	0	0	0	0	0	0	0	0	0	0
Long term Inv. (Insur.,Cont. Reserve)	0	0	0	0	0	20	60	82	152	215	237	266	362	360	413	673	538
Debt Service:																	
Interest	126	130	129	134	134	718	724	869	989	1263	1331	1509	1551	2786	2873	2826	6709
Principal repayments	30	56	14	41	21	144	199	225	243	286	427	620	497	765	836	908	1612
Total debt service	156	186	143	174	155	862	923	1095	1231	1549	1758	2129	2049	3550	3709	3734	8321
Inc.in Def.charges	0	0	283	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Changes in working capital:																	
Cash increase	-23	19	67	32	179	-145	-66	37	34	51	87	236	-15	80	105	-90	54
Other than Cash increase	10	-54	-63	101	423	-159	508	-114	-12	73	37	154	99	541	7	167	1756
Net change	-13	-35	4	134	603	-305	443	-77	22	124	124	390	85	621	111	77	1810
TOTAL APPLICATIONS OF FUNDS	1426	-3846	1956	8360	2923	3291	4833	7341	14932	18810	17407	16869	17424	21971	23920	25361	29886
Times Debt Service Coverage	1.6	1.4	1.6	3.3	6.3	1.2	1.7	1.9	2.4	2.6	2.5	2.3	3.0	2.2	2.3	3.2	1.9

Note: The investments incurred for Arun prior to FY94 are included in other investments

NEPAL ELECTRICITY AUTHORITY
ACTUAL AND FORECAST BALANCE SHEETS
(Rs millions)

As of July 15	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	[------	------	audited	------	------]	[preaud]	[est]	[------	------	------	------	forecast	------	------	------	------	------]
ASSETS																	
Fixed assets:																	
Gross fixed assets	4973	20950	23338	30139	32479	35639	40042	43654	51205	54130	59129	62375	87564	92285	95358	163257	168685
Less: depreciation	602	5258	6553	7772	9294	10598	12115	13783	15646	17696	19926	22346	25265	28721	32397	37249	43345
Net fixed assets	4372	15692	16785	22367	23185	25040	27927	29871	35558	36434	39203	40029	62299	63564	62961	126009	125340
Work in progress	723	779	1498	2890	3816	3630	3218	6473	13066	27776	38818	50508	41142	55444	73702	28332	45453
Total Net Fixed Assets	5095	16471	18284	25257	27001	28670	31146	36344	48625	64210	78021	90537	103441	119008	136663	154340	170793
Deferred Charges not written off	0	0	226	170	121	76	31	0	0	0	0	0	0	0	0	0	0
Current assets:																	
Cash	57	76	142	175	354	209	143	180	214	265	352	588	573	653	758	668	722
Inventories	141	198	217	251	270	307	378	418	474	527	566	608	750	899	938	1293	1660
Accounts receivable	240	286	357	556	718	443	594	857	1209	1626	1872	2397	2841	3356	3742	4834	5609
Advances recoverable	64	74	154	122	114	106	117	129	142	156	171	189	207	228	251	276	304
Total current assets	501	634	871	1104	1456	1065	1232	1583	2039	2574	2962	3781	4371	5137	5689	7071	8294
Investments in Govt. Bonds	4	4	8	8	30	94	94	94	94	94	94	94	94	94	94	94	334
Long term Inv. (Insur., Cont. Reserves)	0	0	0	0	0	20	80	162	314	529	767	1033	1395	1755	2168	2841	3379
TOTAL ASSETS	5600	17108	19389	26538	28609	29924	32582	38184	51071	67407	81844	95444	109301	125994	144614	164347	182800
EQUITY & LIABILITIES																	
EQUITY:																	
HMG's Cap.Contr. & Foreign Grants	3615	3503	4146	4917	4957	4992	5479	5995	8823	12024	15889	19205	20928	24128	28393	30402	32984
Cap. Reserves (Cons.Contr.& Cap. Gains)	35	45	57	68	88	110	133	157	182	208	236	265	295	327	361	396	433
Insurance Fund and Cont. Reserves	0	0	0	0	0	20	80	162	314	529	767	1033	1395	1755	2168	2841	3379
Retained earnings	36	40	-76	-500	-551	-672	-333	207	1371	3110	5048	7245	10300	13344	16861	22718	27362
Revaluation Surplus	0	11091	12065	12369	13422	13463	13666	13878	14055	14299	14522	14776	15001	15827	16609	17289	19744
TOTAL EQUITY	3687	14679	16193	16853	17916	17913	19025	20398	24745	30170	36460	42524	47920	55381	64393	73647	83903
LIABILITIES:																	
Long term debt	1542	1890	2423	8311	9071	10512	12369	16204	24347	34882	42801	49945	57936	67059	76262	85471	94291
Spl. Loan - Marsyangdi unpaid interest	0	0	0	501	1000	964	928	893	857	821	786	750	714	679	643	607	571
Current liabilities:																	
Accounts payable	237	354	489	557	331	449	177	241	235	267	385	389	352	437	514	413	464
Miscellaneous deposits	21	24	35	46	68	34	46	66	92	126	145	181	201	244	271	301	367
Royalty and surchage	0	0	0	72	53	0	0	0	0	0	0	0	0	0	0	0	0
Purchase of energy	78	126	220	190	161	53	37	46	87	89	95	329	339	362	415	393	413
Accrued income tax liability	36	35	28	7	10	0	0	335	709	1052	1171	1327	1840	1833	2117	3516	2791
Total current liabilities	372	540	773	872	623	535	260	689	1122	1533	1797	2225	2732	2876	3317	4622	4034
TOTAL LIABILITIES	1914	2430	3196	9685	10693	12012	13558	17785	26326	37237	45383	52921	61382	70613	80221	90700	98897
TOTAL EQUITY AND LIABILITIES	5600	17108	19389	26538	28609	29924	32582	38184	51071	67407	81844	95444	109301	125994	144614	164347	182800

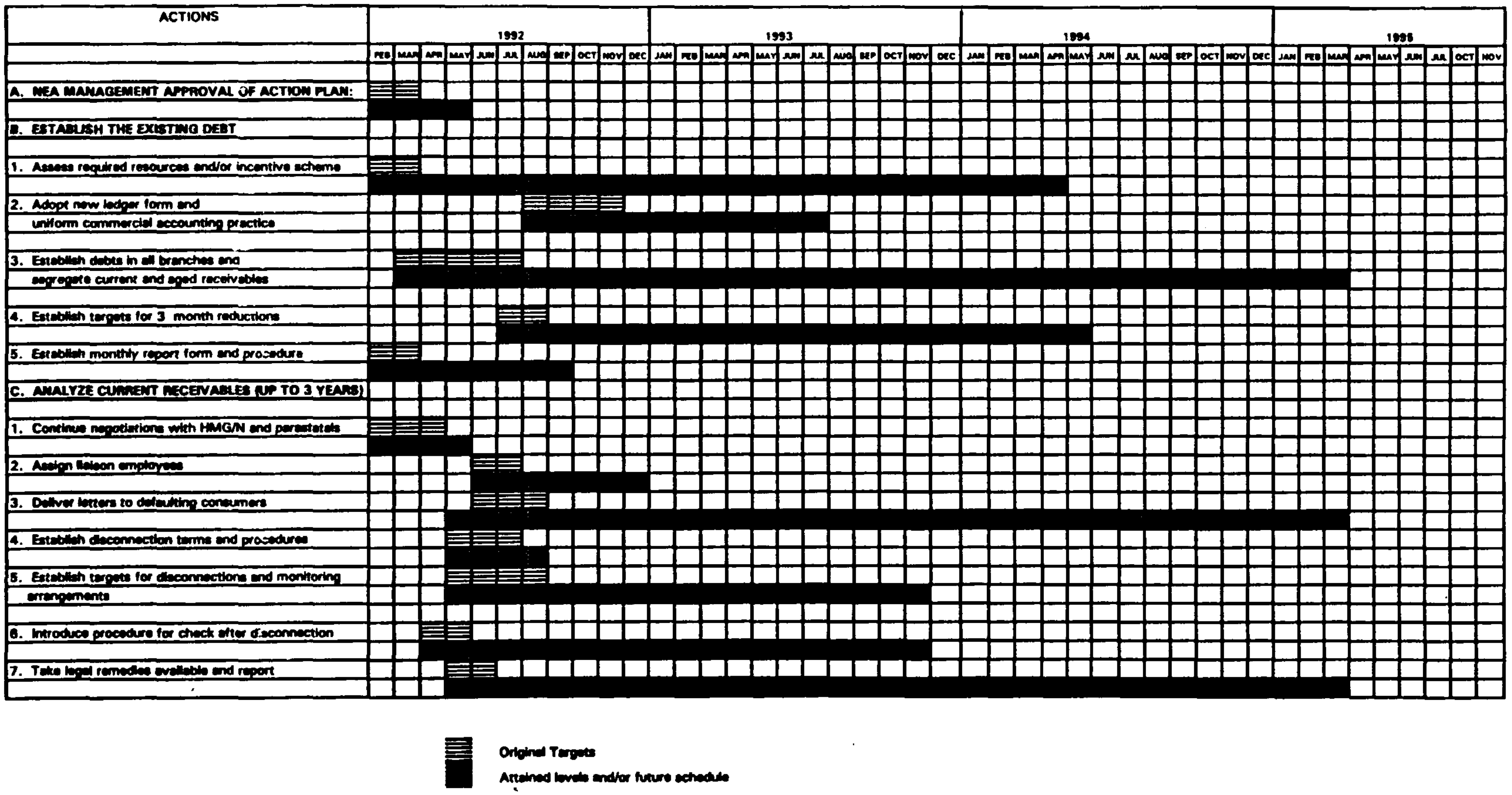
ANNEX 4.7

NEPAL ELECTRICITY AUTHORITY
KEY FINANCIAL INDICATORS

	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
	[---------- audited				----------]	[preaud]	[est]	[---------- forecast									----------]
Rate of Return(on rev.assets from FY 90)	3.0	-3.2	-2.9	-1.9	-0.5	-0.2	1.6	2.6	4.7	6.7	7.0	7.7	7.8	8.2	9.0	8.6	8.4
Contr. to Constr. - Annual-Local (%)	19.7	61.8	54.6	71.7	71.1	79.6	22.8	73.4	46.8	51.6	46.7	49.7	70.9	64.1	66.8	98.2	106.3
Contr. to Constr. - 3 Yr. Avg. (%)	10.6	14.2	7.3	9.9	10.1	16.7	4.0	14.3	14.0	15.0	16.0	17.0	25.9	21.0	24.2	40.2	26.0
Operating ratio (%)	78.5	145.5	159.4	137.7	106.9	102.6	82.7	78.6	69.1	63.9	65.4	68.6	65.3	62.2	62.5	58.3	53.4
Debt as a % of Debt + Equity	29	11	13	33	34	37	39	44	50	54	54	54	55	55	54	54	53
Debt Service Coverage Ratio	1.6	1.4	1.6	3.3	6.3	1.2	1.7	1.9	2.4	2.6	2.5	2.3	3.0	2.2	2.3	3.2	1.9
Current ratio	1.3	1.2	1.1	1.3	2.3	2.0	4.7	2.3	1.8	1.7	1.6	1.7	1.6	1.8	1.7	1.5	2.1
Accounts Payables (# of months)	3.5	6.5	4.2	2.8	2.0	3.0	3.0	3.2	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0
Accounts Receivable (# of months)	5.2	5.0	5.6	6.9	6.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0	3.0

NEPAL ELECTRICITY AUTHORITY

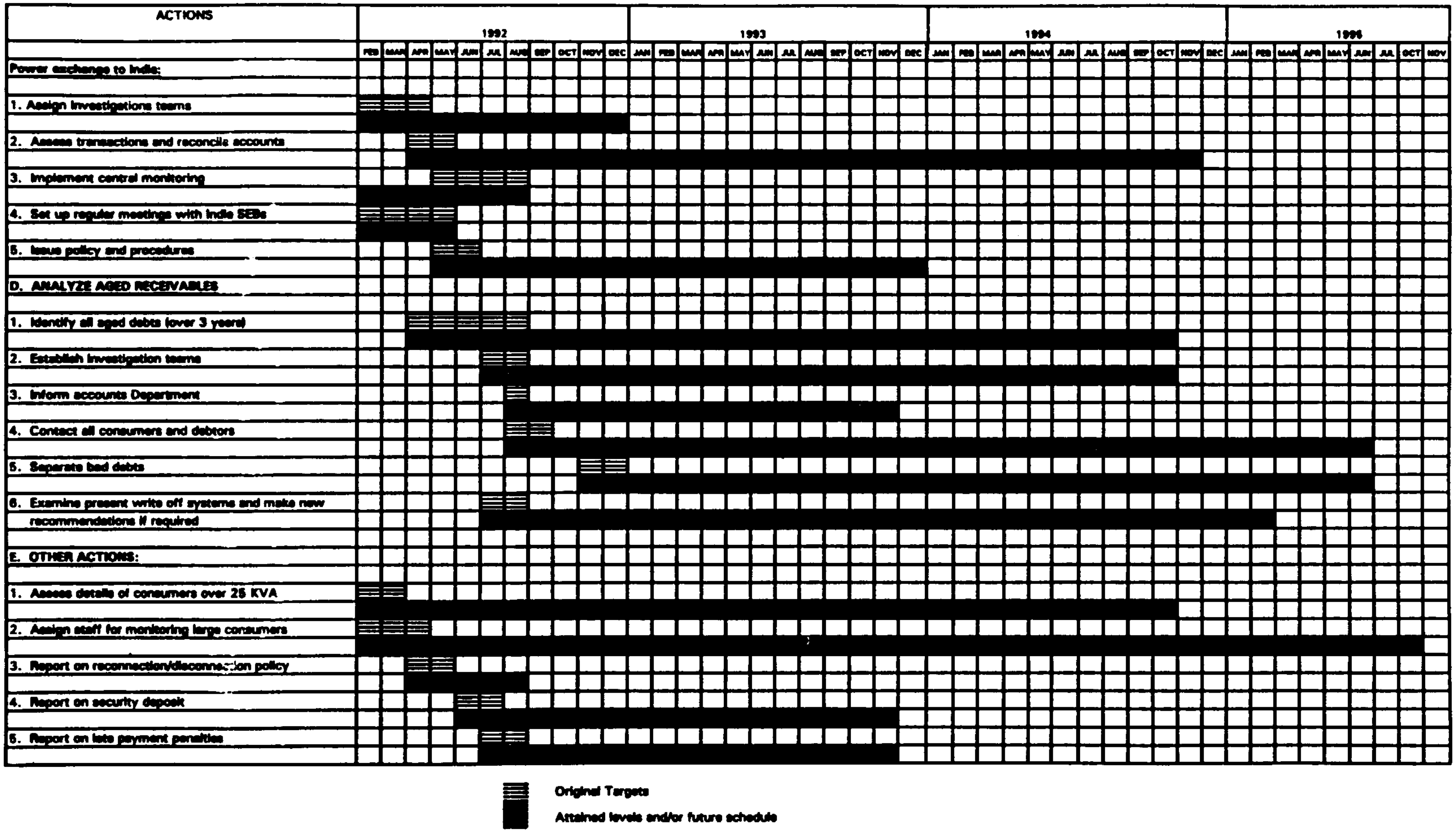
ACTION PLAN TIMETABLE FOR THE REDUCTION OF CONSUMER RECEIVABLE



7/13/94

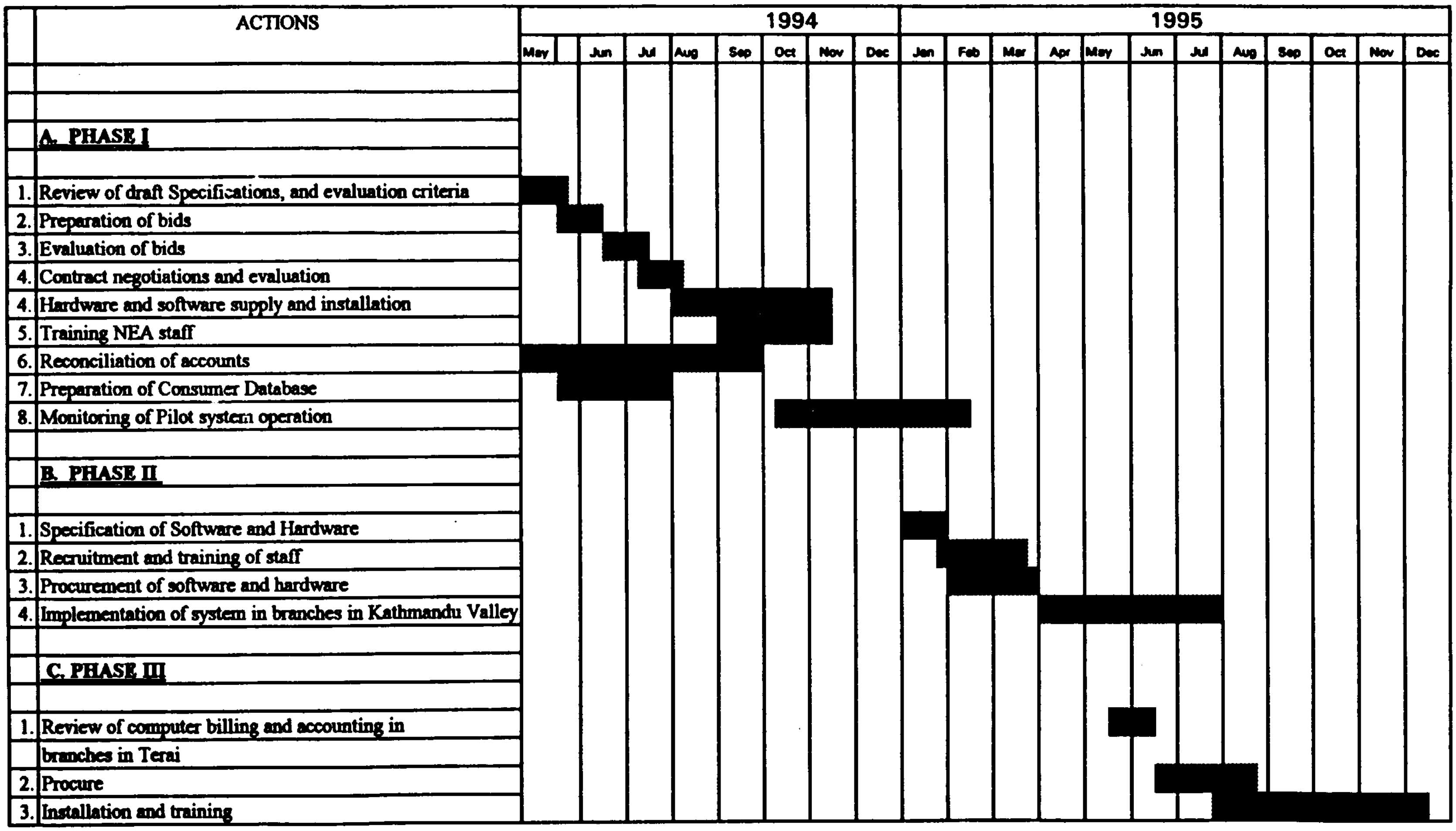
NEPAL ELECTRICITY AUTHORITY

ACTION PLAN TIMETABLE FOR THE REDUCTION OF CONSUMER RECEIVABLE



7/13/94

NEPAL ELECTRICITY AUTHORITY
ACTION PLAN FOR COMPUTERIZATION OF CONSUMER BILLING SYSTEM



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ANNEX 4.9

Annex 4.10

NEPAL ELECTRICITY AUTHORITY

ACTION PLAN FOR IMPLEMENTING INSURANCE PROGRAM

SL NO.	ACTIVITY	RESPONSIBILITY	TARGET DATE	REMARKS
1.	Appointment of in-house consultant	NEA	July 15, 1994	
2.	Valuation of assets and assessment of cost of insurance (generating facilities)	NEA/Consultant	December 31, 1994	
3.	Valuation of other assets and assessment of cost of insurance	NEA/Consultant	July 15, 1995	
4.	Policy decision for insuring generating facilities	NEA	January 31, 1995	
5.	Policy decision for insuring other assets	NEA	August 15,,1995	
6.	Receipt and decision on quotations from insurance brokers for generating facilities	NEA	June 30, 1995	
7.	Receipt and decision on quotations from insurance brokers for other assets	NEA	December 15, 1995	
8.	All generating facilities insured	NEA	July 16, 1995	
9.	All other assets insured	NEA	January 1, 1996	

Washington, D.C.
Date: June 21, 1994

ANNEX 4.11

NEPAL
Nepal Electricity Authority
Flow of Funds to HMG During the Period FY95-04
Results of Sensitivity Analyses

Scenarios

1. Case A: Base Case.

2. Case B: Average tariff is assumed to increase by 26% in FY96 and remains constant in real terms from FY97 onwards.

3. Case C: Tariff increases as per Case A, but starting in FY95, system losses assumed to remain constant at 23.5%.

4. Case D: Tariff increases as per Case A, but starting in FY95, all investment costs assumed to increase by 20%.

5. Case E: Tariff increases as per Case A, but starting in FY95, system losses assumed to remain constant at 23.5% and all investment costs increase by 20%.

6. Case F: Tariff increases as per Case B, but starting in FY95, system losses assumed to remain constant at 23.5%.

7. Case G: Tariff increases as per Case B, but starting in FY95, all investment costs assumed to increased by 20%.

8. Case H: Tariff increases as per Case B, but starting in FY95, system losses assumed to remain constant at 23.5% and all investment costs increased by 20%.

Net Flow of Funds to HMG for the Period FY95-04
(Amounts in NRs million)

Fiscal Year	95	96	97	98	99	00	01	02	03	04	Total FY95-04
Case A	993	714	1878	2330	3465	5698	6520	7564	12213	13222	54597
Case B	993	722	835	1315	1632	4160	4125	5548	10572	10618	4052[illegible]
Case C	946	622	1711	2095	3115	5252	5918	6839	11337	12291	50125
Case D	838	276	1427	1889	3178	5416	6122	7227	11763	12804	50940
Case E	790	183	1260	1654	2828	4970	5520	6502	10887	11641	46235
Case F	946	629	696	1115	1355	3787	3647	4937	9797	9642	36552
Case G	838	284	384	874	1344	3879	3727	5212	10121	9967	36631
Case H	790	191	245	674	1068	3505	3249	4601	9347	8992	32661

N E P A L

ARUN III HYDROELECTRIC PROJECT

Historical Growth in Peak Demand, Energy Generation and Sales, 1976 - 1993

FISCAL YEARS		1976	1984	1985	1986	1987	1988	1989	1990 1/	1991	1992	1993	YEARLY GROWTH RATES 76/84	84/93	76/93
NUMBER OF CONSUMERS															
Residential	'000	76.7	139.4	162.0	175.9	208.9	230.2	251.8	274.9	304.5	337.7	369.9	7.8%	11.5%	9.7%
Total	'000	78.3	143.8	166.8	183.6	217.7	241.5	264.8	290.0	321.8	356.0	389.5	7.9%	11.7%	9.9%
SALES 2/															
Residential	GWh	61.8	129.6	154.9	140.6	162.3	185.7	193.3	230.5	261.4	275.2	264.8	9.7%	8.3%	8.9%
Industry	GWh	32.1	88.7	100.1	110.4	148.5	161.6	175.3	178.4	206.9	246.4	278.8	13.5%	13.6%	13.6%
Com. & N-Com.	GWh	9.2	19.5	21.2	50.8	49.4	77.8	78.8	80.8	82.9	91.9	95.9	9.9%	19.4%	14.8%
Irr, Transp.& Wat.Sup	GWh				13.0	16.9	17.1	25.3	25.1	29.5	29.2	25.5		10.1%	
Others	GWh	4.2	8.7	11.6	5.2	5.1	6.9	5.9	8.8	8.1	9.2	9.5	9.6%	0.9%	4.9%
Sales to Nepal	GWh	107.3	246.5	287.8	320.0	382.1	449.1	478.5	523.5	588.8	651.9	674.4	11.0%	11.8%	11.4%
Exports to India	GWh	5.9	10.3	10.6	21.5	20.5	16.1	17.6	23.3	80.6	85.4	44.1	7.1%	17.5%	12.5%
Total Sales	GWh	113.2	256.8	298.4	341.4	402.6	465.1	496.1	546.8	669.4	737.3	718.6	10.8%	12.1%	11.5%
NEA Consumption	GWh		4.6	3.1	7.0	10.9	7.4	8.7	10.6	12.0	13.6	13.3		12.5%	
System Losses	GWh	39.8	107.3	102.4	139.7	153.2	151.4	167.5	209.8	226.0	230.2	226.3	13.2%	8.7%	10.8%
Loss ratio	%	26.0%	30.3%	26.1%	30.1%	29.0%	25.4%	26.2%	28.7%	26.3%	24.8%	25.0%			
SUPPLY															
Hydro	GWh	128.8	312.9	333.6	427.0	533.0	557.6	545.4	707.0	865.4	865.8	780.9	11.7%	10.7%	11.2%
Small Hydro	GWh									4.8	4.2	18.9			
Thermal	GWh	2.0	2.7	3.7	3.0	1.1	1.1	11.2	1.0	0.8	31.5	46.9	3.9%	37.5%	20.5%
Generation	GWh	130.8	315.6	337.3	430.0	534.1	558.7	556.5	707.9	871.0	901.5	846.8	11.6%	11.6%	11.6%
Purchases	GWh									1.58	24.65	30.4			
Imports from India	GWh	22.2	53.1	66.6	58.2	32.6	65.2	115.8	60.2	33.7	54.9	81.1	11.5%	4.8%	7.9%
Total Supply	GWh	153.0	368.7	403.9	488.1	566.7	623.9	672.4	768.1	906.3	981.1	958.2	11.6%	13.0%	11.4%
PEAK DEMAND															
System Peak	MW	31.9	76.0	79.7	110.0	126.0	141.0	150.0	176.0	204.0	222.3	183.7	11.5%	10.3%	10.8%
Internal Peak	MW	31.4	75.0	78.5	109.0	124.7	139.0	147.5	166.6	192.0	205.9	173.9	11.5%	9.8%	10.6%
Export Peak	MW	0.5	1.0	1.2	1.0	1.3	2.0	2.5	9.4	12.0	16.4	9.8	9.1%	28.9%	19.1%
System Load Factor	%	54.8%	55.4%	57.9%	50.7%	51.3%	50.5%	51.2%	49.8%	50.7%	50.4%	59.5%			
CONSUMPTION PATTERN															
Residential	%	58%	53%	54%	44%	42%	41%	40%	44%	44%	42%	39%			
Industry	%	30%	36%	35%	34%	39%	36%	37%	34%	35%	38%	41%			
Com. & N-Com.	%	9%	8%	7%	16%	13%	17%	16%	15%	14%	14%	14%			
Irr, Transp.& Wat.Sup	%				4%	4%	4%	5%	5%	5%	4%	4%			
Others	%	4%	4%	4%	2%	1%	2%	1%	2%	1%	1%	1%			
Sales to Nepal	%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%			
Exports to India	%	6%	4%	4%	7%	5%	4%	4%	4%	14%	13%	7%			
Total Sales	%	106%	104%	104%	107%	105%	104%	104%	104%	114%	113%	107%			
NEA Consumption	%		2%	1%	2%	3%	2%	2%	2%	2%	2%	2%			
Losses	%	37%	44%	36%	44%	40%	34%	35%	40%	38%	35%	34%			
Generation	%	122%	128%	117%	134%	140%	124%	116%	135%	148%	138%	126%			
Imports from India		21%	22%	23%	18%	9%	15%	24%	11%	6%	8%	12%			
Total Supply		143%	150%	140%	153%	148%	139%	141%	147%	154%	150%	142%			

1/ Pattern and growth of energy was affected by the Trade and Transit dispute between Nepal and India that began in March 1989.

2/ NEA's tariff classification changed in April 1983; since then the commercial sector consists of: i) starred hotels; ii) schools, hospitals, offices, shops, etc . . ., that previously were under residential category; while irrigation, water supply and transportation, previously under the commercial category, are now reported separately.

Sources: NEA historical data, Managing Director's letter dated 02-09-93 and Statement of unit sold, finance department, NEA; and IDA mission estimates.

19-Oct-93

N E P A L

ARUN III HYDROELECTRIC PROJECT

NUMBER OF CONSUMERS CATEGORYWISE

WHOLE SYSTEM	85/86	86/87	87/88	88/89	89/90	90/91	91/92	92/93
Residential	175,860	208,870	230,178	251,758	274,921	304,941	337,670	369,931
Industry	4,575	5,464	6,181	6,769	7,482	8,324	9,043	9,935
Commercial	527	315	641	1,678	1,749	1,828	1,558	1,654
Non-Commercial	1,881	1,768	2,403	3,477	4,506	5,742	5,990	6,369
Transport	8	8	8	9	9	9	8	8
Irrigation	278	283	311	343	382	421	455	592
Water Supply	0	68	77	105	112	120	122	137
Temples	0	0	59	152	205	249	339	397
Street Lighting	318	675	1,474	385	517	532	541	307
Temporary Supply	113	275	145	104	123	135	169	192
Bulk Supply 1/	3	4	2	2	2	2	2	4
	-------	-------	-------	-------	-------	-------	-------	-------
TOTAL	183,563	217,730	241,479	264,782	290,008	322,303	355,897	389,526
	10.0%	18.6%	10.9%	9.7%	9.5%	11.1%	10.4%	9.4%
Residential	175,860	208,870	230,178	251,758	274,921	304,941	337,670	369,931
Non-Residential	7,703	8,860	11,301	13,024	15,087	17,362	18,227	19,595
ISOLATED								6,957
Residential								6,056
Industry								53
Commercial								63
Non-Commercial								743
Transport								
Irrigation								
Water Supply								
Temples								6
Street Lighting								1
Temporary Supply								35

1/ Import/Export gates.

19-Oct-93

NEPAL

ARUN HYDROELECTRIC PROJECT

DETAILED LOAD FORECAST

FISCAL YEARS		1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	84/93	94/01
SALES																					
Residential	GWh	130	155	141	162	186	193	230	261	275	265	283	334	358	383	411	444	477	512	8.3%	8.8%
Industry	GWh	89	100	110	148	162	175	178	207	246	279	281	350	394	445	505	573	650	735	13.6%	14.7%
Com. & N-Com.	GWh	19	21	51	49	78	79	81	83	92	96	104	128	144	162	183	206	233	262	19.4%	14.1%
Ir.,Tr.& Wat.Sup	GWh			13	17	17	25	25	29	29	26	29	33	34	36	37	39	41	43		5.8%
Others	GWh	9	12	5	5	7	6	9	8	9	9	8	9	9	9	9	9	9	9	0.9%	1.7%
Nepal Sales	GWh	247	288	320	382	449	479	524	589	652	674	705	854	939	1035	1145	1272	1411	1561	11.8%	12.0%
Exports	GWh	10	11	21	20	16	18	23	81	84	44	44	48	53	58	64	70	77	85	17.5%	9.9%
Total Sales	GWh	257	298	341	403	465	496	547	669	736	719	749	902	992	1093	1209	1342	1488	1646	12.1%	11.9%
NEA Consumption	GWh	5	3	7	11	7	9	11	12	14	13	16	17	18	19	19	20	21	23		
Losses	GWh	107	102	140	153	151	168	209	222	228	226	228	243	260	278	299	322	347	374		
Loss ratio	%	30.3%	26.1%	30.1%	29.0%	25.4%	26.2%	28.7%	26.2%	25.0%	25.2%	24.7%	22.5%	22.0%	21.5%	21.0%	20.5%	20.0%	19.6%		
Export Losses	GWh							1	4	4	2	2	2	3	3	3	4	4	4		
Exp.Loss Ratio	%							5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%		
Required Supply	GWh	369	404	488	567	624	672	767	907	981	958	995	1164	1272	1392	1530	1688	1860	2047	11.2%	10.9%
System Lf	%	55.4%	57.9%	50.7%	51.3%	50.5%	51.2%	49.8%	50.8%	51.9%	51.1%	50.8%	51.6%	51.7%	52.4%	53.3%	54.4%	55.5%	56.6%		1.6%
System Peak	MW	76	80	110	126	141	150	176	204	216	214	224	258	281	303	328	354	383	413	12.2%	9.1%
Consumers	'000	144	167	184	218	241	265	290	322	356	390	430	478	533	584	640	701	768	841	11.7%	10.1%
kWh/cons.	kWh	1714	1725	1743	1755	1860	1807	1805	1826	1832	1731	1639	1787	1763	1773	1789	1815	1838	1856	0.1%	1.8%
SALES STRUCTURE																					
Residential		53%	54%	44%	42%	41%	40%	44%	44%	42%	39%	40%	39%	38%	37%	36%	35%	34%	33%		
Industry		36%	35%	34%	39%	36%	37%	34%	35%	38%	41%	40%	41%	42%	43%	44%	45%	46%	47%		
Com. & N-Com.		8%	7%	16%	13%	17%	16%	15%	14%	14%	14%	15%	15%	15%	16%	16%	16%	17%	17%		
Ir.,Tr.& Wat.Sup				4%	4%	4%	5%	5%	5%	4%	4%	4%	4%	4%	3%	3%	3%	3%	3%		
Others		4%	4%	2%	1%	2%	1%	2%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%	1%		
Nepal Sales		100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%	100%		
Exports		4%	4%	7%	5%	4%	4%	4%	14%	13%	7%	6%	6%	6%	6%	6%	6%	5%	5%		
Total Sales		104%	104%	107%	105%	104%	104%	104%	114%	113%	107%	106%	106%	106%	106%	106%	106%	105%	105%		
NEA Consumption		2%	1%	2%	3%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%		
Losses		44%	36%	44%	40%	34%	35%	40%	38%	35%	34%	32%	28%	28%	27%	26%	25%	25%	24%		
Export Losses								0%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%		
Required Supply		150%	140%	153%	148%	139%	141%	147%	154%	150%	142%	141%	136%	135%	135%	134%	133%	132%	131%		

NEPAL

ARUN III HYDROELECTRIC PROJECT

Least Cost Analysis

A. Introduction

1. A very commonly used analytical technique for determining the optimal pattern of power system expansion to meet forecast demand is least cost analysis. The main inputs for least cost analysis are an electricity demand forecast and estimates of the investment and recurrent costs of various investment projects which could meet the forecast demand for power. All costs are estimated in a comparable manner and expressed in economic terms, and the estimated cost streams are discounted to enable quantitative comparison of alternative investment programs. The optimum is evaluated in terms of minimum present value of total costs. Sensitivity analysis can be used to determine the impacts of the changes of selected variables (such as the rate of load growth, implementation period, costs of alternative projects and the discount rate used for project justification).

2. In conjunction with the appraisal of the Arun Hydroelectric project, an updating of the least cost generation expansion plan (LCGEP) was conducted by Argonne National Laboratory using the Wien Automatic System Planning (WASP III) technology. The assumptions used were provided by IDA, taking into account information provided by ADB and KfW and discussions between HMG/NEA staff and the ADB, IDA and KfW appraisal teams.

B. Load Forecast

3. The load forecast shows Nepal's total sales increasing at an average rate of 12 percent a year during FY94-FY2001 and 10.7 percent a year during FY2001-2015, or an average 11.1 percent a year during FY94-2015. Committed exports to India were assumed to be 40 GWh in FY93 growing at 10 percent a year thereafter. When more hydroelectric energy is available in Nepal than Nepal can use or store, it is assumed that this surplus hydroelectric energy, that otherwise would be spilled, will be exported to India at a price of US¢2.2/kWh. This is approximately 50 percent of the current export price. The projected decrease in the annual sales growth compared to historical trends reflects the projected major extension of service to new consumers, principally in the residential sub-sector (where consumers have a low initial demand for electricity) and the implementation of strong load and demand management measures.

4. The load forecast also assumes that gross system losses will be reduced progressively from 25 percent in FY92 to 15 percent in FY2011 and subsequently remain at that level. Thus, due to the reduction in losses, total generation is projected to increase at an average rate of 9.6 percent per year during FY94-2001 and 10.7 percent per year during FY2001-2015, or an average of 10.3 percent per year during FY94-2015. The overall load factor is expected to increase from below 50.4 percent in FY92 to about 57.1 percent in FY2002 and subsequently increase slowly until it reaches about 58.1 percent by FY2011. This is because of the complementary effects of projected increases in industrial sales (which improve the load factor) coupled with the implementation of vigorous load management programs. Peak demand is projected to increase from 242 MW in FY92 to 413 MW in FY2001 and 1642 MW in FY2015 at

an average growth rate over the period FY94-2015 of 9.5 percent a year. Annex 5.3 sets out the details of the load forecast through 2001.

C. Characterization of the Existing System

5. The existing and planned generating system, including hydroelectric and thermal generating units as well as purchases from India, are characterized for the WASP III Model as follows.

6. For the hydroelectric system, the stochastic nature of the hydrology is treated by identifying five hydro conditions (representing variation of water availability on an annual basis) according to assumed probabilities of occurrence: (a) very wet (5%), (b) wet (20%), (c) normal (50%), (d) dry (20%), and (e) very dry (5%). The capacity and energy available from each hydroelectric project is specified in each hydro condition. The WASP simulations (performed for 12 periods per year) are repeated with each of the five hydro conditions, and the results are weighted by the probability of occurrence of each hydro condition. Thus, system costs and reliability are expected values that do not refer to any hydroelectric year or type of year; the WASP results are therefore generally quite different from those obtained using an average hydroelectric year. This is especially true for system reliability because dry or very dry years often result in severe reliability problems while normal years have little or no problem.

7. The existing generating plants for the Nepal grid, including hydroelectric schemes, are listed in Annex 2.1. The operating hydroelectric schemes owned by NEA vary in capacity from 10.5 MW (Sunkosi) to 92 MW (the Kulekhani complex) in addition to 7.0 MW in miscellaneous small hydro schemes. In addition, the 5.1 MW Andi Khola scheme is owned and operated by the Butwal Power Company. IDA has supported the construction of the 60 MW Kulekhani I scheme, which was commissioned in 1982, and the 69 MW Marsyangdi scheme, which was commissioned in 1989.

8. The upgraded Trisuli-Devighat hydroelectric complex (with an additional 11 MW capacity, 82 GWh) is expected to be online at the beginning of FY96 as is the Jhimruk hydroelectric project (11 MW, 81 GWh). With these projects in place, the average electrical hydro generation available will range from 1322 GWh (very wet) to 1186 GWh (very dry) in FY97.

9. Two private sector hydro projects, Modi Khola (10 MW, 71 GWh) and Khimti Khola (60 MW, 350 GWh) are assumed to be added in 1998 and 1999, respectively.

10. The existing thermal plants include a total of 10 MW of small diesels (7 MW for Hetauda and 3 MW for others) and a 26 MW multifuel plant. The Hetauda and small diesels are assumed to be upgraded by 6 MW in FY95 and to be retired in FY2002 and the multifuel diesel plant to be retired in FY 2012.

11. With regard to power imports, 20 MW is assumed to be currently available, with an additional 30 MW available in FY96 after the commissioning of the Duhabi (Nepal)-Kataiya (Bihar) 132 kV transmission line. The component within Nepal is being financed under Cr. 2347-NEP. These assumptions are in accord with understandings reached between the Prime Ministers of India and Nepal in Delhi in December 1991. Imports according to the Tanakpur agreement

contribute 5 MW and 20 GWh beginning in FY98; these are treated as part of the hydrosystem.

D. Candidate Generating Units for System Expansion

12. Hydroelectric Candidates. Several promising hydroelectric projects were characterized for analysis of the NEA generating system over the period FY1994-2020. To assure a minimum level of reliability in their characterization and cost and output estimates, only hydroelectric schemes that have been studied at least to the prefeasibility level were considered[1]. The process by which the set of hydroelectric projects considered in the least cost analysis came to be identified has been described in Chapter 3. Two sequences of hydro projects were used for the analysis. One sequence was used for the Arun projects as listed in Table 1 because the selection and the optimal commissioning dates for these projects was one of the key issues to be examined. The other sequence included Kali Gandaki 'A' and the remaining hydro plants in the order listed in the table. No mini-hydro schemes (of less than 10 MW capacity) were included because of their unsuitability for meeting grid power demands (para. 48). Of the three schemes of less than 100 MW capacity, only one, the 48 MW Bhote Kosi 2 project, is uncommitted. The projects considered in the analysis and summary characteristics are listed in Table 1.[2] Overnight capital cost is the cost that would occur if the generating unit could be constructed and paid for overnight (no interest during construction included). Cost data for these projects were based on the 1990 LCGEP updated to mid-1993 US dollars. Exceptions are Arun and Lower Arun (based on the latest cost information), Upper Arun (cost based on information from the Upper Arun feasibility study), and Kali Gandaki 'A' projects (based on the revised cost estimate of the consultants provided by ADB). Where available, project costs include the costs of ameliorating their direct environmental impacts as well as the costs of land acquisition, compensation and rehabilitation. This information is complete for the projects studied at detailed engineering and above (the Arun and Kali Gandaki 'A' Projects); for projects, studied at the feasibility level (Upper Arun, West Seti 'B'), considerable information is available. For others, the information is more preliminary.

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[1] A notable exception to this criterion is, however, reported in Section H which presents a somewhat indicative analysis of an alternative strategy for meeting Nepal's forecast power demand.

[2] Subsequent to the analysis completed in May 1994, two additional projects - (Chilime 17 MW; Chameliya Gad 25 MW) - were identified by NEA as having proceeded beyond the reconnaisance stage. Updating runs were performed by the Argonne Laboratory. The new projects have the least cost sequence through FY2004 (i.e. completion of Arun) unaffected in the base case. As with the other sequences tested, these results are sensitive to the assumptions made. A slightly lower cost for the new project would bring them into the least cost sequence before Arun and the second stage of Kali Gandaki A, but the difference in present value as compared to the government's proposed program is de minimis.

Table 1: Key Characteristics for Candidate Hydroelectric Projects

	Size (MW)	Earliest Commissioning Date (FY)	Energy In An Average Year (Gwh)	Energy Storage Capability (GWh)	Overnight Capital Cost ($/kW)	Construction Period (from Award of contract) (years)
Arun-III,Phase 1	201	2002	1690	1.2	3120	7.0
Arun-III,Phase 2	201	2005	1200	1.2	1560	3.0
Upper Arun	335	2007	2774	0.7	1680	6.0
Lower Arun	307	2008	2276	1.7	1697	4.0
Kali Gandaki 'A'1[1]	100	2000	687	0.8	2921	4.0
Kali Gandaki 'A'2	40	2001	156	0.8	700	1.0
Bhote Kosi 2	48	2002	359	1.0	2516	4.0
Upper Karnali	240	2006	1878	1.1	2168	7.5
West Seti 'B'	360	2006	2233	888.0	2615	7.5
Burhi Gandaki	600	2007	2396	1067.0	1857	8.5
Kali Gandaki 2	660	2008	3179	1081.0	1878	7.0
Sapta Gandaki	225	2009	1848	0.9	3762	5.0

13. <u>Thermal Candidates</u>. Thermal candidates included medium speed diesel (20 MW), low speed diesel (30 MW) and multifuels (20 MW). For the medium term (after 2005), gas turbines (25 MW and 50 MW) were considered, and for the long term (after 2015), a combined cycle plant (120 MW). Technical characteristics (Table 2) and capital costs (Table 3) were based on recent NEA analysis and prior LCGEP studies. Capital costs of thermal candidates with short lifetimes relative to the study period (27 years) are adjusted upward in WASP III to simulate replacement at the end of their useful life with the same technology (i.e., a multifuel diesel starting operating in 1998 is assumed to be replaced by an identical diesel in 2018).

14. Studies of expansion plans with only thermal capacity additions (no hydroelectric) were not considered. NEA staff emphasize their concern over reliability of supply and lack of experience with thermal generators. Therefore, other thermal options such as coal and oil-fired steam candidates (whose unit sizes are typically 200 MW or more and therefore too large for the Nepalese grid), were not included in the study.

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[1] The two-phase project, with at least one year between implementation dates, was used for this study. The cost estimate was based on the civil works for a 140 MW development. The cost of Phase 1, inclusive of contingencies, was assumed to be US$292.1 million. The second phase was assumed to cost US$28 million or $700/kW.

Table 2: Technical Characteristics of Thermal Candidates

Type	Size (MW)	Heat Rate (kcal/kWh)	Forced Outage Rate (%)	Days/yr of Scheduled Maintenance	Fixed O&M Cost ($/kW-month)	Variable O&M Cost ($/MWh)	Lifetime (years)
Gas Turbine	25	3075	20	37	2.6	2.5	15
Gas Turbine	50	3075	20	37	2.5	2.5	15
Medium Speed Diesel	20	2170	15	40	4.8	2.5	20
Low Speed Diesel	30	1965	8	40	6.0	2.5	25
Multifuel Diesel	26	2120	15	40	5.0	2.5	20
Combined Cycle	120	1900	22	40	3.3	2.5	15

* Annual fixed operation and maintenance costs were assumed to be 5% of the capital cost

Table 3: Capital Costs for Thermal Candidates (mid-1993 $)

Type	Overnight Capital Cost ($/kWe)	Construction Period (years)
Gas Turbine (25 MW)	625	1.5
Gas Turbine (50 MW)	600	1.5
Medium Speed Diesel	1150	2.5
Low Speed Diesel	1450	3.0
Multifuel Diesel	1200	2.5
Combined Cycle	800	3.0

E. Economic Assumptions and Constraints

15. A real discount rate of 10 percent, which is the opportunity cost of capital, was used. The higher the discount rate, the lower is the competitiveness of capital intensive projects, such as Nepal's hydroelectric projects, because the latter are justified on account of the savings in fuel and operating costs that they make possible in later years. The higher the discount rate, the less are those future savings worth in present value terms.

16. The fuel prices used were based on delivered fuel prices (including local costs to account for transportation, handling and storage as well as currency fluctuations) and are presented in Annex 1.2. A 5 percent surcharge was applied to account for additional infrastructure costs incurred to supply large amounts of fuel to NEA.

17. System reliability was measured through the following indexes. First, a minimum reserve margin[4] of 5 percent was used in the critical period of February-March, when river flows are at their lowest under the "dry" hydrological condition (i.e., with a 25 percent probability of lower outputs of hydro energy -- see para. 6). This criterion is considered modest in comparison to reserve margins of 15% - 20% used by mature utilities for

[4] Percent by which installed capacity exceeds period peak loads.

critical periods. Second, a maximum loss of load probability (LOLP)[5] of 0.63 percent (55 hours per year) was imposed. This limit is equivalent to a maximum LOLP of about 2.5 percent in the critical three months of the dry season when most loss of load is likely to occur. It was found from systems studies that this combination of criteria gave similar requirements for new capacity as a criterion that required the system to meet the "very low" hydrological condition. These constraints are, however, not introduced until 1998 to allow NEA to recover from the present shortfall position. Third, the cost of unserved energy[6] implied by alternative self-owned diesel generators was calculated. The results ranged from US$0.345/kWh in 1993 US dollars to US$0.61/kWh. NEA had conducted studies that showed a value of US$0.28/kWh. The lowest, NEA-recommended value was used for these studies. The cost of unserved energy is an element of the total costs which WASP-III seeks to minimize.

18. Energy imports from India and bulk sales to India were assumed to be transacted at US¢4.4/kWh (1993 prices). Surplus hydroelectric energy was assumed to be exportable at US¢ 2.2/kWh (1993 prices).

19. A preliminary analysis was conducted of the impact of offering firm sales of energy to India. This is because firm sales were presumed to have the advantage that a higher price could be obtained than would be the case from offering short-term surplus energy. Several cases involving a 50 MW firm export beginning in 2002 were examined. The addition of the 50 MW firm export required thermal generation in dry periods of the year in some years. A comparison of preliminary least-cost expansion plans with and without the firm sales showed that, at a value for firm sales that is twice the assumed value for surplus hydro energy, the benefits of the firm sales are slightly less than the benefits of just selling all surplus hydro energy at US¢2.2/kWh. The result of the preliminary analysis was therefore to assume no firm export requirement. (The option of offering firm sales beginning in later years was not examined.)

20. All costs were valued at border prices. Local costs were converted to border prices by using a Standard Conversion Factor (SCF) of 0.9.

F. Justification for the Base Case Sequence

21. Base Case: The present value of the total system expansion cost includes all investment costs for new generating capacity, operation and maintenance costs, fuel costs, unserved energy costs, and salvage value of new generating capacity at the end of the study period (1994-2020). It does not include investment costs for existing plants or for firmly committed capacity additions. The present value is expressed in 1993 US dollars, discounted to January 1, 1994. In identifying the LCGEP, up to three thousand combinations of projects (both hydro and thermal) and their commissioning dates were examined. With the exception of committed additions such as Modi Khola (10

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[5] The proportion of time when the available generation is expected to be unable to meet the system load.

[6] The expected (probabilistically determined) amount of energy not supplied per year owing to generating capacity deficiencies and/or shortages in basic energy supplies.

MW) and Khimti Khola (60 MW), all the sequences examined consisted of projects of ultimate installed capacity of at least 100 MW, except for those that contained the 48 MW Bhote Kosi 2 project. The least cost solution integrates the hydro and thermal candidate projects into the generating system in the most efficient way.

22. The results of the LCGEP analysis are summarized in Table 4. The long gestation period of hydroelectric projects and ongoing commitments imply that additions to Nepal's generating system are committed through 1999. The earliest non-committed hydroelectric schemes cannot be taken up prior to 2000.

Least-Cost Generation Expansion Schedule for Base Load Forecast

Year	Peak Load [MW]	Capacity Additions (committed additions shown in parentheses)	Total Uncommitted Additions [MW]	Total System Capacity [MW]	LOLP* [%]
1994	242		0	242	5.215
1995	258	(Diesel upgrade; Kulekhani normal operation)	0	281	2.313
1996	281	(Jhimruk, Trisuli-Devighat repairs and upgrade, additional imports from India)	0	323	0.270
1997	303		0	323	1.259
1998	328	(Modi Khola, Tanakpur), 2 x 20 MW Multifuels	40	378	0.337
1999	354	(Khimti Khola 1)	40	438	0.268
2000	383	100 MW Kali Gandaki A, Phase 1	140	538	0.000
2001	413		140	538	0.010
2002	452	(Diesels retired), 40 MW Kali Gandaki A, Phase 2	180	562	0.060
2003	498	201 MW Arun-III, Phase 1	381	763	0.000
2004	549		381	763	0.000
2005	610		381	763	0.000
2006	676		381	763	0.179
2007	748	201 MW Arun-III, Phase 2	582	964	0.056
2008	824	50 MW Gas Turbine	632	1014	0.230
2009	909	335 MW Upper Arun	967	1349	0.000
2010	1002		967	1349	0.000
2011	1104		967	1349	0.028
2012	1215	(26 MW Multifuel retired), 307 MW Lower Arun	1274	1630	0.000
2013	1340		1274	1630	0.132
2014	1483	48 MW Bhote Kosi 2, 20 MW Multifuel, 50 MW Gas Turbine	1392	1748	0.376
2015	1642	240 MW Upper Karnali	1632	1988	0.067
2016	1815	2 x 50 MW Gas Turbines	1732	2088	0.305
2017	2009	4 x 50 MW Gas Turbines	1932	2288	0.445
2018	2232	3 x 50 MW Gas Turbines, 4 x 20 MW Multifuels	2162	2518	0.623
2019	2479	360 MW West Seti B	2522	2878	0.158
2020	2749	2 x 20 MW Multifuels 50 MW Gas Turbine, 120 MW Combined Cycle	2732	3088	0.561

* LOLP is loss-of-load probability. A maximum limit of 55 hours/year (0.63%) was set for 1998 and later.

Note: Total discounted cost = US$927.1 million.

As may be seen from the table, as part of the least cost generation expansion sequence, the WASP program selected the non-committed hydroelectric schemes for commissioning after 1999 in an orderly fashion, paying particular attention to project sequencing and their commissioning dates. The hydropower plants brought in as part of the least cost generation expansion plan are: the 140 MW Kali Gandaki 'A" project--in two stages of 100 MW (in 2000) and 40 MW (in 2002), the 402 MW Arun project--in two stages of 201 MW each (in 2003 and 2007), followed by the 335 MW Upper Arun project (in 2009), the 307 MW Lower Arun project (in 2012), the 48 MW Bhote Kosi 2 project (in 2014), the 240 MW Upper Karnali project (in 2015) and the 360 MW West Seti 'B' project (in 2019) Besides the firmly committed (fixed) capacity additions, a total of 2,732 MW of new generating capacity is needed for the least-cost expansion plan. The new capacity additions through the year 2010 totalled 967 MW, including 877 MW of hydro (91%), provided by the Kali Gandaki 'A' and Arun III projects, together with Upper Arun, 50 MW of gas turbines (5%) and 40 MW of multifuel units (4%). The 30 MW additional purchase from India (for a total of 50 MW) was assumed available in 1996 and was considered a fixed addition to the system. Also, hydropower plants Jhimruk (12 MW), Modi Khola (10 MW) and Khimti Khola (60 MW) were considered as fixed additions and added to the generating system in 1996, 1998 and 1999, respectively. Table 4 shows a need for new thermal capacity of only 40 MW of multifuels before Phase 2 of the Arun 3 hydroelectric project is added in 2007. The total discounted cost of the LCGEP through the year 2020 is US $927.1 million.

23. <u>The Arun Hydroelectric Project, Phase 1</u> is considered attractive because, of all the new schemes under consideration, it provides the most firm energy relative to its capacity throughout the year. This is particularly valuable during the dry season (mid-December to mid-March), when the Nepal grid is vulnerable to high dependency on electricity imports or fuel imports to operate its diesel plants. In terms of fitting into the Nepal grid and contributing to its reliability, the Arun project, Phase 1, compares favorably with previous schemes. A measure of system reliability is the ratio of the largest unit to the grid peak demand. The larger the ratio, the more the system is put at risk when one of the units is out of commission. As may be seen in Table 5, this ratio has declined from 41.1 percent for the Kulekhani I project on its commissioning date to 15.3 percent for the Marsyangdi project. This is expected to decline further to 13.5 percent on the commissioning of the Arun project.

Table 5: <u>Characteristics of Nepal Grid Hydroelectric Schemes</u>

Project (1)	Commissioning Date (FY) (2)	Capacity (MW) (3)	Generating Unit Size (MW) (4)	Grid Peak Demand (MW) (5)	(4)/(5) %
Kulekhani I	1982	60	30	73	41.1
Marsyangdi	1989	69	23	150	15.3
Arun, Phase 1	2003	201	67	498	13.5

24. Table 6 shows generation by fuel type in the LCGEP on a year-by-year basis. The importance of purchases from India is shown by the amount of 107.7 Gwh which is required in 1997 (this is an annual capacity factor[1] of approximately 25 percent for the 50 MW purchase). In the dry season of 1997, the 50 MW purchases is needed virtually full time. With the commissioning of Kali Gandaki A, Phase 1 in 2000, Kali Gandaki A, Phase 2 in 2002, and Arun 3, Phase 1 in 2003, the required generation from these purchases drops off considerably. However, since the monthly water inflows of Nepal's rivers are extremely unevenly distributed during the year with clear dry and wet seasons, the availability of the 50 MW from India remains important for system reliability in most years, especially in the dry season.

25. The 40 MW of new multifuels (2x20 MW in 1998), together with the existing 26 MW multifuels, generate a maximum of 220 GWh in 1998 (average annual capacity factor of 38 percent). The multifuels provide significant generation to the system in the dry season until the Arun project is added. The generation needed from multifuels after that generally increases to a maximum just before the next major hydro addition is made to the system.

26. Surplus Hydro Energy. Table 6 shows that, for most years of the LCGEP, the NEA generating system has a significant amount of surplus hydro energy. This is the result of the very high water inflows during the wet season. The table shows that surplus hydro energy (expected value, considering all five hydroconditions and the estimated probabilities of occurrence), which is only 36 GWh in 1998, increases following the addition of both phases of the Kali Gandaki project and Arun 3, Phase 1 in 2003, to 1,722 GWh (expected value, with a range from 1,483 GWh for a very dry year to 1,970 GWh for a very wet year). The difference of nearly 500 GWh in surplus hydro between the very wet and very dry year is worth nearly US$11 million to the generating system. Following the addition of Phase 2 of the Arun 3 project in 2007, surplus hydro energy increases to 1,749 GWh (value of approximately US$38 million) and to 4,247 GWh in 2012 with the commissioning of the 302 MW Lower Arun project. However, in the dry season for a normal hydro year, the generating system is short of hydro energy. During the period January to March, thermal plants must be run and purchases from India are needed. In the dry season of a dry or very dry year, the gap between system energy demand and hydro energy available is even greater. In particular for the driest month of the year (February/March) except for four years, there is no appreciable surplus hydro energy for this hydro condition, which is the planning norm for the Nepal interconnected system (see Attachment to this Annex). Thus, in the same year (e.g. 2008), the Nepal system could generate significant amounts of surplus hydro in the wet season while requiring substantial thermal generation as well as significant imports from India in the dry season. This situation would be alleviated if additional hydro storage capacity were added to NEA's system. However, the only storage projects that have been characterized are very large, expensive, and/or require first-of-a-kind construction, which is very risky for Nepal; moreover,

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[1] The capacity factor for a given period of time is the ratio of energy produced by a generating unit to the energy that could have been provided by operating that generating unit continuously at maximum rated capacity during the whole of that period (expressed as a percentage).

Generation (GWh/fiscal year) for Least-Cost Generation Expansion Plan — Base Load Forecast

1. Generation (except as noted)	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
2. Hydro	895.7	984.6	1136.9	1188.0	1287.1	1496.7	1780.8	1899.2	2026.5	2495.9	2760.9	3058.9	3332.4	3668.8	3973.4	4588.0	5069.4	5561.6	6200.9
3. Thermal (multi-fuel)	92.8	101.2	81.6	90.6	219.8	176.0	78.3	135.8	174.0	0.0	0.2	3.6	54.3	61.8	104.5	0.4	5.1	38.3	4.0
4. Thermal (diesel)	18.2	14.8	0.3	1.4	0.3	0.2	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. Thermal (gas turb.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	19.1	0.0	0.0	1.2	0.2
6. Purchase from India	58.0	62.3	51.6	107.7	21.7	11.29	0.1	9.7	57.1	0.0	0.0	0.1	1.4	18.0	46.1	0.0	0.6	8.9	1.4
7. Unserved	10.5	1.3	0.1	0.9	0.2	0.1	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.4	1.3	0.0	0.0	0.1	0.0
8. Total	1075.1	1164.3	1270.6	1388.6	1529.1	1684.4	1859.3	2044.8	2257.8	2496.3	2761.5	3063.0	3388.5	3749.4	4144.8	4588.4	5075.3	5611.3	6207.5
9. Surplus hydro	39.8	32.9	94.0	42.9	36.3	193.0	595.3	477.0	506.5	1722.4	1457.4	1159.5	885.9	1749.3	1444.7	3587.6	3106.1	2613.9	4246.5
10. Peak load (MW)	242	258	281	303	328	354	383	413	452	498	549	610	676	748	824	909	1002	1104	1215
11. Load factor (%)	50.7	51.5	51.6	52.3	53.2	54.3	55.4	56.5	57.0	57.2	57.4	57.3	57.2	57.2	57.4	57.6	57.8	58.0	58.3

Notes:
(1) All surplus hydro energy is assumed to be valued at 22.2 $/MWh.
(2) Gas turbines (50 MW) are not allowed before 2006. Only 20 MW multifuels (and less competitive diesels) are considered before 2006.
(3) Capacity additions and subtractions through the year 2012 are:

1995	Diesel upgrade (6 MW)
1996	12 MW Jhimruk; 30 MW additional imports from India
1998	10 MW Modi Khola; 5 MW import from Tanakpur; 2 x 20 MW multifuels
1999	60 MW Khimti Khola
2000	100 MW Kali Gandaki A, Phase 1
2002	40 MW Kali Gandaki A, Phase 2; 16 MW diesel retired
2003	201 MW Arun-III, Phase 1
2007	201 MW Arun-III, Phase 2
2008	50 MW Gas Turbine
2009	335 MW Upper Arun
2012	307 MW Lower Arun; 26 MW multifuel retired

(4) All generation figures are probability-weighted expected values. Each number is the sum of the probability-weighted 60 system simulations per year (12 periods, 5 hydroconditions).

(5) "Hydro generation" listed above (Row 2) is generation that supplies Nepal demand and does not include additional available hydro generation (surplus hydro in Row 9).

(6) Small differences between total demand (Row 8) and the sum of generation figures is due to rounding and, in some cases, slight simulation inaccuracies.

because of their impacts on the river flow regimes, all of which flow into India, many of these projects would require the concurrence of the Government of India. Thus, the primary domestic hydro projects under consideration typically result in contributions to needed energy in the dry season and large amounts of surplus hydro energy in the wet season. Nepal therefore currently faces a choice between surplus hydro energy in the wet season or large imports of fuel to run new thermal plants in the dry season. Under the assumptions set out in Section E, the least-cost solution is to have surplus hydro energy in the wet season rather than import large quantities of fuel with major associated logistical problems. Trade-offs between surplus hydro energy and dependence on thermal generation and fuel imports are discussed further in paras. 31 and 32.

G. Sensitivity Analysis

27. Sensitivity analysis was carried out to test the robustness of the LCGEP to changes in four input parameters: the load forecast, schedule slippages for the hydroelectric projects, cost overruns for the hydroelectric schemes and valuation of surplus hydro energy exported to India. In addition, the impact of combining the two phases of Kali Gandaki 'A' into a single plant was examined. The potential for the Arun project to be accepted ahead of the Kali Gandaki 'A' project in the LCGEP was also investigated. Sensitivity to the discount rate used for project justification was tested as well. A summary of the results is presented in Table 10.

28. The solution was tested for load forecasts of 75 percent ("low") and 125 percent ("high") of the growth rate in the base case load forecast.

29. Low Load Forecast Case. The results of the LCGEP analysis for this case are summarized in Table 7. The program shows considerable delay in the implementation of most hydro projects compared to the base load forecast. The hydropower plants brought in as part of the least cost generation expansion plan are: the 140 MW Kali Gandaki 'A' project in two phases in 2002 and 2005, (postponed from 2000 and 2002, respectively, in the base case), the Bhote Kosi 2 project in 2006 (advanced from 2014 in the base case), the Arun Phase 1 project in 2009 (postponed from 2003 in the base case), the Arun Phase 2 project in 2012 (postponed from 2007 in the base case), followed by the Upper Arun project in 2014 (postponed from 2012 in the base case) and the Lower Arun project in 2018 (postponed from 2012 in the base case). Besides the firmly committed (fixed) capacity additions, a total of 1,462 MW of uncommitted capacity is added by 2020 in this case, compared to 2,732 MW for the base load forecast. The multifuels play a much bigger generation role in the low load case than in the base load LCGEP. Three multifuels are needed for the low load LCGEP through the year 2005, while only two were needed for the base load LCGEP, and a fourth is added in 2008. The new capacity additions through the year 2010 total 519 MW, including 389 MW of hydro (75%), 80 MW of multifuel units (15%) and 50 MW of gas turbines (10%). The corresponding proportions for the base load forecast in 2010 were seen to be 91%, 4%, and 5%, respectively. The total discounted cost of this program through the year 2020 is US$590.5 million. Imposing Kali Gandaki 'A' Phase 1 in 2000 and Phase 1 of

Least-Cost Generation Expansion Schedule for Low Load Forecast

Year	Capacity Additions (committed additions shown in parentheses)	Total Uncommitted Additions [MW]	Total System Capacity [MW]	LOLP* [%]
1994		0	242	5.215
1995	(Diesel upgrade; Kulekhani normal operation)	0	281	1.773
1996	(Jhimruk, Trisuli-Devighat repairs and upgrade, additional imports from India)	0	323	0.112
1997		0	323	0.446
1998	(Modi Khola, Tanakpur), 20 MW Multifuel	20	358	0.185
1999	(Khimti Khola 1)	20	418	0.089
2000	20 MW Multifuel	40	438	0.136
2001	20 MW Multifuel	60	458	0.195
2002	(Diesels retired), 100 MW Kali Gandaki A, Phase 1	160	542	0.001
2003		160	542	0.014
2004		160	542	0.174
2005	40 MW Kali Gandaki A, Phase 2	200	582	0.275
2006	48 MW Bhote Kosi 2	248	630	0.320
2007	50 MW Gas Turbine	298	680	0.181
2008	20 MW Multifuel	318	700	0.583
2009	201 MW Arun-III, Phase 1	519	901	0.000
2010		519	901	0.003
2011		519	901	0.070
2012	(26 MW Multifuel retired), 201 MW Arun-III, Phase 2	720	1076	0.000
2013		720	1076	0.443
2014	335 MW Upper Arun	1055	1411	0.000
2015		1055	1411	0.000
2016		1055	1411	0.000
2017		1055	1411	0.132
2018	307 MW Lower Arun	1362	1718	0.000
2019		1362	1718	0.146
2020	2 x 50 MW Gas Turbines	1462	1818	0.213

* LOLP is loss-of-load probability. A maximum limit of 55 hours/year (0.63%) was set for 1998 and later.

Note: Total discounted cost = US$590.5 million.

the Arun project in 2003 -- the proposed timing of these projects in the base case -- in the face of a low demand forecast, but with the rest of the program optimized for this demand forecast, leads to the introduction of Arun Phase 2 in 2009, Upper Arun in 2012, Lower Arun in 2017 and Kali Gandaki 'A' Phase 2 in 2019. The total discounted cost of the program is US$628.5 million, which is $38 million or 6.4 percent higher than that of the fully optimized low case. This is a measure of the cost of inflexibility in the low load forecast case of the proposed base case timing of Kali Gandaki 'A' Phase 1 and Arun Phase 1.

30. High Load Forecast Case: The results of the LCGEP for this case are summarized in Table 8. The two phases of the Kali Gandaki 'A' project and Phase 1 of the Arun project are taken up in the same years as in the base case. The remaining hydropower plants are, however, advanced, with the sequence being: Phase 2 of the Arun project (in 2005, compared to 2007 in the base case), the Upper Arun project (in 2007, compared to 2009 in the base case), the Lower Arun project (in 2010, compared to 2012 in the base case), followed by the Bhote Kosi 2 project (2011, compared to 2014 in the base case), the Upper Karnali project (2012, compared to 2015 in the base case), the West Seti 'B' project (2014, compared to 2019 in the base case) and, finally, the Burhi Gandaki project (2016), the Kali Gandaki 2 project (2018) and the Sapta Gandaki project (2019). A total of 5,017 MW of uncommitted capacity is added by 2020 in this case, compared to 2,732 MW for the base load forecast. Five multifuels are needed before Phase 1 of the Arun project in the high load forecast case, while only two are needed in the base case. The new capacity additions through the year 2010 total 1,284 MW in the high case compared to 967 MW in the base case, a difference approximately equivalent to building the Lower Arun project earlier by two years. This total of 1,284 MW comprises 1,184 MW of hydro (92%) and 100 MW of multifuel units (8%). The total discounted cost of the program through the year 2020 is US$1473 million.

31. Zero Value for Surplus Hydro Energy: The LCGEP was seen to produce a significant amount of surplus hydro energy. The sensitivity of the least cost program was examined under the assumption of a zero value for surplus hydro energy, corresponding to a situation where exports of such energy to India are not possible, compared to a price of US¢2.2/kWh in the base case. The lowest cost expansion plan had a total present value of US $1043 million, which is 11.3 percent higher than in the base case. The commissioning dates of the hydropower plants are in general delayed, with Kali Gandaki 'A' Phase 1 being introduced in 2002 and Arun 3 Phase 1 in 2008, but with Bhote Kosi 2 being taken up in 2005. In order to meet demand, however, this case requires 310 MW of thermal capacity (8 x 20 MW multifuels and 3 x 50 MW gas turbines) to be installed by the year 2007, compared to 40 MW over the same period in the base case. The foreign fuel cost of this scenario is over US $30 million in 2007 and US $ 523 million over the planning period and would involve logistical problems associated with the import of large quantities of fuel.

32. In order to limit thermal capacity additions, it was decided to run a case which allowed no gas turbines and no more than one 20 MW multifuel to be added per year over the period 2006--2010. This resulted in 140 MW thermal capacity being added through the year 2010. The total discounted cost of this scenario is US $1063.3 million, which is 1.9 percent higher than in the preceding case. However, the total foreign fuel bill is about $100 million

Least-Cost Generation Expansion Schedule for High Load Forecast

Year	Capacity Additions (committed additions shown in parentheses)	Total Uncommitted Additions [MW]	Total System Capacity [MW]	LOLP* [%]
1994		0	242	5.215
1995	(Diesel upgrade; Kulekhani normal operation)	0	281	2.945
1996	(Jhimruk, Trisuli-Devighat repairs and upgrade, additional imports from India)	0	323	0.574
1997		0	323	2.794
1998	(Modi Khola, Tanakpur), 3 x 20 MW Multifuels	60	398	0.620
1999	(Khimti Khola 1), 20 MW multifuel	80	478	0.279
2000	100 MW Kali Gandaki A, Phase 1	180	578	0.005
2001		180	578	0.092
2002	(Diesels retired), 20 MW multifuel, 40 MW Kali Gandaki A, Phase 2	240	622	0.193
2003	201 MW Arun-III, Phase 1	441	823	0.000
2004		441	823	0.001
2005	201 MW Arun-III, Phase 2	642	1024	0.000
2006		642	1024	0.577
2007	335 MW Upper Arun	977	1359	0.000
2008		977	1359	0.000
2009		977	1359	0.603
2010	307 MW Lower Arun	1284	1666	0.162
2011	48 MW Bhote Kosi 2, 3 x 50 MW Gas Turbines	1482	1864	0.188
2012	(26 MW Multifuel retired), 240 MW Upper Karnali	1722	2078	0.152
2013	20 MW Multifuel, 4 x 50 MW Gas Turbines	1942	2298	0.336
2014	360 MW West Seti B	2302	2658	0.077
2015	2 x 50 MW Gas Turbines, 120 MW Combined Cycle	2522	2878	0.529
2016	600 MW Burhi Gandaki	3122	3478	0.020
2017	2 x 50 MW Gas Turbines, 2 x 20 MW Multifuels	3262	3618	0.582
2018	660 MW Kali Gandaki 2	3922	4278	0.102
2019	225 MW Sapta Gandaki, 6 x 20 MW Multifuels	4267	4623	0.526
2020	3 x 20 MW Multifuels, 9 x 50 MW Gas Turbines, 2 x 120 MW Combined Cycles	5017	5373	0.610

* LOLP is loss-of-load probability. A maximum limit of 55 hours/year (0.63%) was set for 1998 and later.

Note: Total discounted cost = US$1,473.0 million.

lower through 2020, and is particularly lower through 2010. The hydro projects, although delayed in relation to the base case, are taken up earlier than in the preceding case. The sequence is: the two phases of Kali Gandaki 'A' in 2002 and 2004, the two phases of Arun 3 in 2005 and 2008, followed by Upper Arun in 2010 and Lower Arun in 2015.

33. Schedule Slippages and Cost Overruns: The base case load forecast is assumed in the sensitivity experiments for schedule slippages and cost overruns. The specification of schedule slippages and cost overruns is presented in Table 9. In relation to schedule slippage, the analysis assumed that the earliest in-service date for project commissioning would be delayed by two to three years depending on the status of readiness of the projects for implementation and/or the slack in their schedules. In relation to cost overruns, the analysis assumed that the overruns were dependent on the level of preparation of the project. For projects prepared to the detailed engineering level or better, a cost overrun of 20 percent was assumed; projects prepared to the feasibility or prefeasibility levels were subject to overruns of 25 percent and 30 percent, respectively. The conclusions of the analysis are as follows.

34. For the schedule slippage scenario, but with the base case load forecast and no cost overruns, the two phases of the Kali Gandaki 'A' project are taken up in 2002 and 2003, i.e., as soon as they are available, while the two phases of the Arun project are taken up in 2005 and 2008 respectively, i.e., one year later than their earliest availability. The Upper Arun project is introduced in 2010, i.e., one year later than its earliest availability, while the Lower Arun project is introduced in 2013, i.e., two years later than its earliest availability. The total discounted cost for this scenario is US $938.8 million, which is 1.3 percent higher than in the base case.

Table 9: Specification of Schedule Slippages and Cost Overruns

Project	Status of Preparation[a]	Earliest Commissioning Date	New Commissioning Date	% Increase in Overnight Costs
Arun Phase 1	MCWCN	2002	2004	20
Arun Phase 2	DE	2005	2007	20
Upper Arun	F	2007	2009	25
Lower Arun	PF	2008	2011	30
Kali Gandaki "A" 1	DE	2000	2002	20
Kali Gandaki "A" 2	DE	2001	2003	20
Bhote Kosi 2	PF	2002	2004	30
Upper Karnali	PF	2006	2009	30
West Seti "B"	F	2006	2009	25
Burhi Gandaki	PF	2007	2009	30
Kali Gandaki 2	PF	2008	2010	30
Sapta Gandaki	F	2009	2011	25

35. For the cost overrun scenario, but with the base case load forecast and no schedule slippages, the two phases of the Kali Gandaki 'A' project are taken up in 2002 and 2004, while the Arun Valley projects are taken up as follows: Arun Phase 1 (in 2005), Arun Phase 2 (in 2008), Upper Arun (in 2010) and Lower Arun (in 2014). Since the relative costs of hydrogeneration are increased in relation to thermal generation, appreciably more thermal generation would be least cost in this case. The breakdown of new capacity additions through the year 2010 are hydro (71%), gas turbines/combined cycle (12%), and multifuel (17%), compared to 91%, 5% and 4% respectively in the base case without cost overruns. The total discounted cost for this scenario is US $1071.0 million, which is 15.5 percent higher than in the base case without cost overruns. The scenario was also run under the low and high load forecast demand cases. With a fully optimized generation planting sequence under the low load forecast, the two phases of the Kali Gandaki 'A' project are taken up in 2002 and 2005, while the Arun valley projects are commissioned as follows: Arun Phase 1 (in 2010), Arun Phase 2 (in 2013), Upper Arun (in 2015) and Lower Arun (in 2019). The total discounted cost for this scenario is US $666.4 million, which is 12.9 percent higher than in the low case without cost overruns. However, if the cost overrun scenario is run under the

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[a] MCWCN: Major Civil Works Contract Negotiated; DE: Detailed Engineering; F: Feasibility; PF: Prefeasibility.

low load forecast, but with Kali Gandaki 'A' Phase 1 is imposed in 2000 and Arun Phase 1 in 2003 and the rest of the generation planting sequence optimized for this load forecast, the total discounted cost is US $752.8 million. This is 19.8 percent higher than the figure of US $628.5 million for the low case without cost overruns with Kali Gandaki 'A' Phase 1 imposed in 2000 and Arun Phase 1 imposed in 2003. The reason this is significantly higher than is the case under a fully optimized scenario is as follows. It is in general optimal, when faced with a relative increase in hydro compared to thermal costs, to delay the introduction of hydro plants. Imposing commissioning dates for Kali Gandaki 'A' Phase 1 and Arun Phase 1 a priori is therefore particularly suboptimal in the cost overrun scenario and results in a substantially higher cost of regret as compared to the case without cost overruns. With a fully optimized sequence under the high load forecast, the two phases of the Kali Gandaki 'A' project are taken up in 2001 and 2002, while the Arun valley projects are introduced as follows: Arun Phase 1 (in 2004), Arun Phase 2 (in 2006), Upper Arun (in 2008) and Lower Arun (in 2011). The total discounted cost for this scenario is US $1719.1 million, which is 16.7 percent higher than in the high case without cost overruns.

36. Combining the Two Phases of Kali Gandaki 'A': Detailed engineering of the Kali Gandaki 'A' project is virtually complete. The LCGEP presented here considered Kali Gandaki 'A' as a two phase project, with the second phase having an implementation date at least one year later than the first phase. However, combining them into a single phase offers a saving in cost estimated at around $7 million. With this saving in cost, it is least cost to introduce Kali Gandaki 'A' as a single stage 140 MW plant in 2000. The total discounted cost of the program under the base load forecast is US $925.1 million, which is 0.21 percent lower than in the base case. If these cost estimates are confirmed during further reviews, the LCGEP would be modified by the introduction of Kali Gandaki 'A' as a single stage plant in 2000.

37. Commissioning Dates for the Arun and Kali Gandaki 'A' projects: A number of runs were performed to analyze the potential for Phase 1 of the Arun project to be accepted ahead of Kali Gandaki 'A' in the LCGEP. Two are reported here.

38. Phase 1 of the Arun project could be available in 2002, rather than in 2003, for an additional US$10 million in overnight capital cost. If Arun Phase 1 is imposed in 2002, with the associated increased overnight capital cost, and the rest of the program is optimized for the base case demand forecast, both phases of Kali Gandaki 'A' are postponed beyond the Arun series of projects and enter the LCGEP together in 2013. This shows that the economics of Kali Gandaki 'A' depends on the commissioning date for Arun Phase 1. The total discounted cost of this case is US$932.3 million, which is 0.6 percent higher than in the base case. In a second experiment, if the capital cost of Kali Gandaki 'A' Phase 1 is increased by 8.5 percent, then the LCGEP for the base case demand forecast finds it optimal to take up Arun Phase 1 in 2002, with its associated increased US$10 million capital cost, and both phases of Kali Gandaki 'A' enter the expansion plan together in 2014 after the entire Arun series of projects. This experiment determines the cost threshold below which Kali Gandaki 'A' is the first project in the LCGEP. The total discounted cost of this case is US$934.4 million, which is 0.80 percent higher than in the base case.

39. Delaying the Commissioning of Arun: In view of the macroeconomic affordability and institutional NEA concerns arising out of the lumpy nature of the Arun investment, the WASP program was also run with the constraint that Arun not be brought in before 2010. In that event, the chosen sequence in the base demand forecast case is Kali Gandaki 'A' (in 2000 and 2002), the 48 MW Bhote Kosi 2 project (in 2003), the 240 MW Upper Karnali project (in 2006), followed by Arun Phase 1 (in 2010), Arun Phase 2 (in 2012), Upper Arun (in 2013) and Lower Arun (in 2015). The total discounted cost of this program is US $938.2 million, which is only 1.2 percent higher than the corresponding figure in the base case. However, the gap caused by the delayed commissioning of Arun requires that the system take up the 48 MW Bhote Kosi 2 project in 2003 and the 240 MW Upper Karnali project in 2006. Both these projects have, however, been studied only to the prefeasibility stage. These schemes are therefore subject to considerable technical and cost modifications as they undergo further study and investigation prior to implementation. In the low demand forecast scenario, the delayed commissioning of Arun constraint is met by introducing Arun III, Phase 1 in 2013, and the total discounted cost of postponing Arun to 2010 or later is US $592.9 million, which is only 0.4 percent higher than when such a constraint is not imposed. This is because the unconstrained low demand forecast case only takes up Phase 1 of the Arun project in 2009, as previously mentioned. In the high demand forecast scenario, Arun was permitted to be commissioned, not necessarily in 2010 or later, but as soon as it was required to meet demand, once the Kali Gandaki 'A' and Bhote Kosi 2 projects were commissioned. It was taken up in 2004 (instead of in 2003 in the base demand forecast case), with both phases of Kali Gandaki "A" being introduced in 2000 and 2002 and with Bhote Kosi 2 being introduced in 2003; the total discounted cost in this scenario is US $1482.3 million, which is 0.6 percent higher than when such a constraint is not imposed.

The analysis of the delayed commissioning of Arun to 2010 shows that, while the total discounted cost of the two scenarios are close enough to make them equally attractive, the perceived macroeconomic and institutional risks associated with proceeding with Arun at the present time would need to be balanced against the risks of technical and cost modifications associated with processing projects studied up to the pre-feasibility stage through feasibility and detailed engineering to the bids stage and the risks that timely financing might not be available for those projects.

40. Sensitivity to the Discount Rate: The analysis was also run under the base case load forecast to determine the discount rate at which the total discounted cost of the optimized least cost scenario equals that of the "delayed commissioning of Arun to 2010" scenario. The two scenarios break even at a discount rate of 12 percent with a total discounted cost of US$806.0 million. This arises because the higher the discount rate, the less favorable the situation for large hydro projects that are expensive to build but reduce thermal generation and, in the case of surplus hydro, increase exports. The analysis shows that a 12 percent discount rate -- higher than the opportunity cost of capital of 10 percent used in the base case -- has the effect of postponing Phase 1 of the Arun project to 2010 in the least cost solution. The LCGEP introduces 629 MW of uncommitted hydro capacity through 2010, compared to 877 MW with a 10 percent discount rate. The sensitivity of the solution was also examined for a discount rate of 8 percent. In this case, it is still optimal to take up Kali Gandaki 'A' Phase 1 in 2000 and Arun

Phase 1 in 2003 and to introduce 877 MW of uncommitted hydro capacity through 2010. The total discounted cost of the program is US $1040 million. At this discount rate, the total discounted cost of the "delay-Arun-to-no-earlier-than-2010" scenario is US $1080 million, which is 3.8 percent higher than in the case where the constraint is not introduced.

Table 10: Least Cost Generation Expansion Plan: Base Case and Sensitivity Analysis

Scenario (1)	Commissioning Date of Arun Stage 1 in the Optimum Solution (2)	Commissioning Date of Kali Gandaki 'A' Phase 1 in the Optimum Solution (3)	Total Discounted Cost of the Optimum Solution (US$ million) (4)	Total Discounted Cost when Arun is postponed until 2010 or later (US$M) (5)	(5)/(4) %	Comments
Base Load Forecast	2003	2000	927.1	938.2	101.20	
Low Load Forecast	2009	2002	590.5	592.9	100.4	
Low Load Forecast (KGA1 2000, AHP1 2003[1])	2003	2000	628.5	-	-	
High Load Forecast	2003	2000	1473.0	1482.3	100.6	In column 5 of this case Arun was permitted to be commissioned, not necessarily in 2010 or later, but once the Kali Gandaki 'A' and the Bhote Kosi 2 projects were commissioned.
Zero value for surplus hydro	2008	2002	1043.0	-	-	Base case load forecast used
Zero value for surplus hydro (with thermal additions restricted to 140 MW through 2010)	2005	2002	1063.3	-	-	Base case load forecast used
Schedule Slippage	2005	2002	938.8	983.1	104.7	Base case load forecast used
Cost Overrun	2005	2002	1,071.0	1,086.0	101.4	Base case load forecast used
Cost Overrun	2010	2002	666.4	-	-	Low load forecast used
Cost Overrun	2003	2000	752.8	-	-	Low load forecast (KGA1 2000, AHP1 2003)
Cost Overrun	2004	2001	1719.1	-	-	High load forecast used
8% Discount Rate	2003	2000	1040.0	1080.0	103.9	Base case load forecast used
12% Discount Rate	2010	2000	806.0	806.0	100.0	Base case load forecast used
KGA1 & KGA2 combined as a single plant[2]	2003	2000	925.1	-	-	Base case load forecast used
AHP1 imposed in 2002 with a capital cost increase of US$10 million	2002	2013	932.3	-	-	Base case load forecast used
KGA capital cost increased 8.5%; AHP1 allowed to be commissioned in 2002 with capital cost increased by $10 million	2002	2014	934.4	-	-	Base case load forecast used

[1] With Kali Gandaki 'A' Phase 1 imposed in 2000 and Arun Phase 1 imposed in 2003 and the remaining program optimized under the low load forecast.
[2] The two phases of Kali Gandaki 'A' are combined as a single plant with a reduction in capital cost to US$313.1 million, or around $7 million less than the two-stage plant.

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H. Plan B

41. Concerns regarding the various risks -- macroeconomic, institutional and the growth of the load forecast -- associated with the Arun project led to consideration of an alternative generation expansion plan, which is known as Plan B. This plan defers Arun 3 till 2010 and consists primarily of medium-sized hydropower projects in the 30-80 MW range, of which a number, having been studied only up to the reconnaissance stage, had been screened out in the earlier analysis. The analysis of Plan B is necessarily somewhat indicative in nature since these projects, 11 of which would precede Arun and which are listed in Table 11 in the order in which they were assumed available, are at varying stages of preparedness, ranging from reconnaissance (Khimti Khola 2, Bhote Kosi 1, Tama Kosi 3, Tama Kosi 2, Indravati 3, Indravati 2) through detailed engineering (Kali Gandaki A-1 and A-2). A number of the candidate projects considered in the plan do not therefore presently meet the standards of reliability in their characterization and cost and output estimates that were imposed on the candidate generating units previously discussed in Section D. Although the cost estimates for every project unique to Plan B were verified to ensure that the costs of the access road and transmission lines to connect the project with the national grid were included, limitations in the methodologies for preparing the cost estimates precluded a comparison of whether the unit prices underlying those estimates were consistent with those used for the projects listed in Table 1. In addition, it was not possible to verify whether appropriate environmental mitigation costs were included. It is therefore possible that the cost estimates used were still under-estimates of the true cost of implementing these projects. However, in order to examine the outlines of a strategy of developing Nepal's power system with medium-sized hydropower plants prior to the commissioning of Arun, while retaining comparability with the earlier results, these candidate projects were characterized for the WASP III model as follows. In line with the assumptions in para. 33, the cost estimates for projects prepared to the detailed engineering level were adjusted upwards by 20 percent; those for projects prepared to the feasibility or prefeasibility levels were adjusted upwards by 25 percent and 30 percent, respectively; and those for projects at the reconnaissance level were adjusted upwards by 40 percent. The only exception is Bhote Kosi 2, which was originally only a Plan B project and had its cost estimated accordingly. The summary characteristics of the projects, so adjusted, are reported in Table 11. These medium-sized plants do not, however, enter the LCGEP unless WASP-III is constrained not to introduce the Arun project before 2010. This constraint is therefore imposed, together with the following restrictions on thermal additions: (a) no gas turbines (50 MW) allowed before 2006, a constraint which was also imposed on the runs so far discussed (see para 13); and, additionally, (b) a maximum of 6 multifuels through 2009 and no gas turbines in 2008 and 2009.

42. The hydropower plants brought in as part of the LCGEP in this scenario, as shown in Table 11 and in more detail in Table 12, are: the 22 MW Khimti Khola 2 project (in 2000), the 140 MW Kali Gandaki 'A' project in two stages (100 MW in 2002 and 40 MW in 2004), the 48 MW Bhote Kosi 2 project (in 2004), the 64 MW Bhote Kosi 1 project (in 2005), the 48 MW Tama Kosi 3 project (in 2008), the 68 MW Tama Kosi 2 project (in 2008), the 64 MW Indravati 3 project (in 2009), the 33 MW Indravati 2 project (in 2009), Arun 3 in two phases (in 2011 and 2013, respectively), Upper Arun (in 2014), Lower Arun (in 2016), Upper Karnali (in 2017) and West Seti 'B' (in 2018). The total discounted cost of Plan B is US $1127.4 million, which is $56.3 million or 5 percent higher than the US$ 1071.0 million applying to the comparable "cost overrun" scenario for the base case shown in Table 10. The cost overrun

scenarios shown in Table 10 are referred to in what follows as the comparable Plan A, with the base, low and high load forecasts specified as appropriate. Thus, a measure of the cost of adopting Plan B as opposed to the comparable Plan A if demand follows the base load forecast is $56.3 million.

Table 11: Hydroelectric Projects in Plan B

	Size (MW)	Energy in an Average Year (GWh)	Overnight Capital Cost ($/KW)	Earliest Introduction Date
Khimti Khola 2	22	154	3223	1999
Kali Gandaki "A"1	100	687	3505	2000
Kali Gandaki "A"2	40	156	841	2001
Bhote Kosi 2	48	359	2516	2001
Bhote Kose 1	64	444	3053	2002
Tama Kosi 3	48	350	4488	2002
Tama Kosi 2	68	495	3721	2002
Indravati 3	25	172	3820	2003
Indravati 2	33	234	4518	2003
Arun III, Phase 1	201	1690	3744	2010
Arun III, Phase 2	201	1200	1872	2010
Upper Arun	335	2774	2100	2010
Lower Arun	307	2276	2206	2010
Upper Karnali	240	1873	2818	2010
West Seti "B"	360	2233	3269	2010
Burhi Gandaki	600	2396	2414	2010
Kali Gandaki 2	660	3179	2441	2010
Sapta Gandaki	225	1848	4702	2010

Data Sources:

(a) Nepal: *Kosi Master Plan (Draft Final Report).* Japanese International Cooperation Agency, Feb. 1985.

(b) Nepal: *Kali Gandaki "A" Detailed Feasibility Study (Final Report),* Norpower S.A., April 1992.

(c) Nepal: *Bhote Kosi (2) Hydroelectric Project -- Prefeasibility Study,* Kathmandu, Nepal Electricity Authority, July 1987.

(d) Nepal: *Reassessment of the Kosi Basin Master Plan Study,* Kathmandu, Nepal Electricity Authority, 1989.

43. Table 13 shows generation by fuel type in Plan B on a year-by-year basis. A total of 2,702 MW of uncommitted capacity is added by 2020 in this case, compared to 2,842 MW for the comparable Plan A. Plan B also has a more prominent role for thermal generation. The breakdown of new capacity additions through 2010, which total 768 MW is: hydro (58%), multifuels (16%) and gas turbines/combined cycle (26%). The corresponding proportions for the comparable Plan A under the base load forecast, where uncommitted capacity additions through 2010 are 830 MW, were seen to be: hydro (71%), multifuels (17%) and gas turbines/combined cycle (12%).

44. Tables 14 and 15 report the results of running Plan B for the different load forecasts, while Table 16 presents the total discounted costs for the different scenarios. Under the low load forecast, the total discounted cost of Plan B is US $703.5 million, which is 6 percent higher than the comparable Plan A under the low load forecast case. However, if the comparable Plan A scenario is defined as the one where Kali Gandaki 'A' Phase 1 is imposed in 2000 and Arun Phase 1 is imposed in 2003 -- the optimal commissioning dates under the base case without cost overruns -- and the rest of the sequence is optimized under the low load forecast, the total discounted cost of Plan B is 6 percent lower--$703.5 million compared to $752.8 million. This arises because the cost of early commissioning dates imposed *a priori* is, as previously noted, particularly high in the presence of cost overruns on hydro projects. The hydropower plants brought in as part of the LCGEP in Plan B in the low case are: Khimti Khola 2 (in 2000), the two phases of Kali Gandaki 'A' (in 2003 and 2006), Bhote Kosi 2 (in 2009), Bhote Kosi 1 (in 2010), Tama Kosi 3 (in 2011), Tama Kosi 2, Indravati 3 and Indravati 2 (in 2012), Arun 3 Phase 1 (in 2013), Arun 3 Phase 2 (in 2016) and Upper Arun (in 2017). Although all the project commissioning dates are moved back, the requirement that all projects that are unique to Plan B be taken before Arun 3 Phase 1 and that the latter not be brought in before 2010 ensures that the sequence in which projects are introduced is the same as that in Plan B under the base load forecast. However, the Upper Karnali and West Seti 'B' projects are not introduced in the period up to 2020.

Least-Cost Generation Expansion Schedule for Plan B

Year	Capacity Additions (committed additions shown in parentheses)	Total Uncommitted Additions [MW]	Total System Capacity [MW]	LOLP* [%]
1994		0	242	5.215
1995	(Diesel upgrade; Kulekhani normal operation)	0	281	2.313
1996	(Jhimruk, Trisuli-Devighat repairs and upgrade, additional imports from India)	0	323	0.270
1997		0	323	1.259
1998	(Modi Khola, Tanakpur), 2 x 20 MW Multifuels	40	378	0.337
1999	(Khimti Khola 1)	40	438	0.268
2000	22 MW Khimti Khola 2, 20 MW Multifuel	82	480	0.153
2001	20 MW Multifuel	102	500	0.374
2002	(Diesels retired), 100 MW Kali Gandaki A, Phase 1	202	584	0.011
2003		202	584	0.300
2004	40 MW Kali Gandaki A, Phase 2, 48 MW Bhote Kosi 2	290	672	0.051
2005	64 MW Bhote Kosi 1	354	736	0.269
2006	50 MW Gas Turbine	404	786	0.408
2007	20 MW Multifuel, 50 MW Gas Turbine	474	856	0.600
2008	48 MW Tama Kosi 3, 68 MW Tama Kosi 2	590	972	0.144
2009	20 MW Multifuel, 25 MW Indravati 3, 33 MW Indravati 2	668	1050	0.332
2010	2 x 50 MW Gas Turbines	768	1150	0.365
2011	201 MW Arun-III, Phase 1	969	1351	0.016
2012	(26 MW Multifuel retired), 20 MW Multifuel	989	1345	0.485
2013	201 MW Arun-III, Phase 2	1190	1546	0.475
2014	335 MW Upper Arun	1525	1881	0.003
2015		1525	1881	0.132
2016	307 MW Lower Arun	1832	2188	0.094
2017	240 MW Upper Karnali	2072	2428	0.057
2018	2 x 50 MW Gas Turbines	2172	2528	0.462
2019	360 MW West Seti B	2532	2888	0.043
2020	50 MW Gas Turbine, 120 MW Combined Cycle	2702	3058	0.405

* LOLP is loss-of-load probability. A maximum limit of 55 hours/year (0.63%) was set for 1998 and later.

Note: Total discounted cost = US$1,127.4 million.

Generation (GWh/fiscal year) for Plan B - Base Load Forecast

1. Generation (except as noted)	1994	1995	1996	1997	1998	1999	2000	2001	2002
2. Hydro	895.7	984.6	1136.9	1188.0	1287.1	1496.7	1638.7	1724.9	2065.6
3. Thermal (multi-fuel)	92.8	101.2	81.6	90.6	219.8	176.0	215.1	308.5	191.8
4. Thermal (diesel)	18.2	14.8	0.3	1.4	0.3	0.2	0.1	0.3	0.0
5. Thermal (gas turb.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
6. Purchase from India	58.0	62.3	51.6	107.7	21.7	11.3	5.3	10.9	0.3
7. Unserved	10.5	1.3	0.1	0.9	0.2	0.1	0.1	0.2	0.0
8. Total	1075.1	1164.3	1270.6	1388.6	1529.1	1684.4	1859.3	2044.8	2257.8
9. Surplus hydro	39.8	32.9	94.0	42.9	36.3	193.0	204.4	118.3	464.0
10. Peak load (MW)	242	258	281	303	328	354	383	413	452
11. Load factor (%)	50.7	51.5	51.6	52.3	53.2	54.3	55.4	56.5	57.0

1. Generation (except as noted)	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
2. Hydro	2194.3	2469.6	2772.2	2948.3	3113.7	3641.0	4003.5	4224.1	5276.3	5584.4
3. Thermal (multi-fuel)	276.7	258.8	248.0	309.3	422.5	354.2	417.6	497.1	295.0	422.0
4. Thermal (diesel)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
5. Thermal (gas turb.)	0.0	0.0	0.0	30.4	83.7	52.2	67.7	206.8	7.7	90.8
6. Purchase from India	25.2	32.8	41.4	99.4	129.1	97.2	98.4	147.0	31.8	109.3
7. Unserved	0.1	0.1	1.2	1.1	0.5	0.2	1.1	0.3	0.1	0.4
8. Total	2496.3	2761.5	3063.0	3388.5	3749.4	4144.8	4588.4	5075.3	5611.3	6207.5
9. Surplus hydro	335.3	574.8	715.6	539.6	374.2	689.7	731.9	511.4	1144.5	836.5
10. Peak load (MW)	498	549	610	676	748	824	909	1002	1104	1215
11. Load factor (%)	57.2	57.4	57.3	57.2	57.2	57.4	57.6	57.8	58.0	58.3

Notes:
(1) All surplus hydro energy is assumed to be valued at 22.2 $/MWh.
(2) Gas turbines (50 MW) are not allowed before 2006. Only 20 MW *multifuels* (and less competitive diesels) are considered before 2006. Thermal additions are limited to 220 MW through the year 2009.
(3) Capacity additions and subtractions through the year 2012 are:

1995	Diesel upgrade (6 MW)
1996	12 MW Jhimruk; 30 MW additional imports from India
1998	10 MW Modi Khola; 5 MW import from Tanakpur; 2 x 20 MW multifuels
1999	60 MW Khimti Khola 1
2000	22 MW Khimti Khola 2; 20 MW Multifuel
2001	20 MW Multifuel
2002	100 MW Kali Gandaki A, Stage 1; 16 MW diesel retired
2004	40 MW Kali Gandaki A, Stage 2; 48 MW Bhote Kosi 2
2005	64 MW Bhote Kosi 1
2006	50 MW Gas Turbine
2007	50 MW Gas Turbine; 20 MW Multifuel
2008	48 MW Tama Kosi 3; 68 MW Tama Kosi 2
2009	25 MW Indravati 3; 33 MW Indravati 2; 20 MW Multifuel
2010	2 x 50 MW Gas Turbines
2011	201 MW Arun 3, Stage 1
2012	20 MW Multifuel; 26 MW multifuel retired

(4) All generation figures are probability-weighted expected values. Each number is the sum of the probability-weighted 60 system simulations per year (12 periods, 5 hydroconditions).
(5) "Hydro generation" listed above (Row 2) is generation that supplies Nepal demand and does not include additional available hydro generation (surplus hydro in Row 9).
(6) Small differences between total demand (Row 8) and the sum of generation figures is due to rounding and, in some cases, slight simulation inaccuracies.

Expansion Schedule for Plan B — Low Load Forecast

Year	Capacity Additions (committed additions shown in parentheses)	Total Uncommitted Additions [MW]	Total System Capacity [MW]	LOLP* [%]
1994		0	242	5.215
1995	(Diesel upgrade; Kulekhani normal operation)	0	281	1.773
1996	(Jhimruk, Trisuli-Devighat repairs and upgrade, additional imports from India)	0	323	0.112
1997		0	323	0.446
1998	(Modi Khola, Tanakpur)	0	338	0.571
1999	(Khimti Khola 1)	0	398	0.291
2000	22 MW Khimti Khola 2	22	420	0.256
2001	20 MW Multifuel	42	440	0.349
2002	(Diesels retired), 2 x 20 MW Multifuels	82	464	0.474
2003	100 MW Kali Gandaki A, Phase 1	182	564	0.003
2004	20 MW Multifuel	202	584	0.009
2005		202	584	0.166
2006	40 MW Kali Gandaki A, Phase 2	242	624	0.214
2007	2 x 50 MW Gas Turbines	342	724	0.071
2008		342	724	0.420
2009	48 MW Bhote Kosi 2	390	772	0.398
2010	64 MW Bhote Kosi 1	454	836	0.245
2011	48 MW Tama Kosi 3	502	884	0.473
2012	(26 MW Multifuel retired), 68 MW Tama Kosi 2, 25 MW Indravati 3, 33 MW Indravati 2	628	984	0.419
2013	201 MW Arun-III, Phase 1	829	1185	0.000
2014		829	1185	0.001
2015		829	1185	0.084
2016	201 MW Arun-III, Phase 2	1030	1386	0.473
2017	335 MW Upper Arun	1365	1721	0.000
2018		1365	1721	0.000
2019		1365	1721	0.096
2020	20 MW Multifuel	1385	1741	0.595

* LOLP is loss-of-load probability. A maximum limit of 55 hours/year (0.63%) was set for 1998 and later.

Note: Total discounted cost = US$703.5 million.

Expansion Schedule for Plan B — High Load Forecast

Year	Capacity Additions (committed additions shown in parentheses)	Total Uncommitted Additions [MW]	Total System Capacity [MW]	LOLP* [%]
1994		0	242	5.215
1995	(Diesel upgrade; Kulekhani normal operation)	0	281	2.945
1996	(Jhimruk, Trisuli-Devighat repairs and upgrade, additional imports from India)	0	323	0.574
1997		0	323	2.794
1998	(Modi Khola, Tanakpur), 3 x 20 MW Multifuels	60	398	0.620
1999	(Khimti Khola 1); 22 MW Khimti Khola 2	82	480	0.186
2000	2 x 20 Multifuels	122	520	0.313
2001	100 MW Kali Gandaki A, Phase 1	222	620	0.006
2002	(Diesels retired), 40 MW Kali Gandaki A, Phase 2	262	644	0.047
2003	48 MW Bhote Kosi 2	310	692	0.220
2004	64 MW Bhote Kosi 1, 20 MW Multifuel	394	776	0.368
2005	48 MW Tama Kosi 3, 68 MW Tama Kosi 2	510	892	0.401
2006	25 MW Indravati 3, 33 MW Indravati 2, 2 x 20 MW Multifuels	608	990	0.551
2007	20 MW Multifuel, 2 x 50 MW Gas Turbines	728	1110	0.328
2008	201 MW Arun-III, Phase 1	929	1311	0.023
2009	50 MW Gas Turbine	979	1361	0.580
2010	201 MW Arun-III, Phase 2, 20 MW Multifuel	1200	1582	0.463
2011	335 MW Upper Arun	1535	1917	0.000
2012	(26 MW Multifuel retired), 50 MW Gas Turbine	1585	1941	0.574
2013	307 MW Lower Arun, 50 MW Gas Turbine	1942	2298	0.338
2014	240 MW Upper Karnali, 20 MW Multifuel	2202	2558	0.402
2015	4 x 50 MW Gas Turbines, 20 MW Multifuel, 120 MW Combined Cycle	2542	2898	0.562
2016	360 MW West Seti B	2902	3258	0.426
2017	600 MW Burhi Gandaki	3502	3858	0.044
2018	2 x 20 MW Multifuels, 2 x 50 MW Gas Turbines, 120 MW Combined Cycle	3762	4118	0.621
2019	660 MW Kali Gandaki 2	4422	4778	0.229
2020	225 MW Sapta Gandaki, 8 x 20 MW Multifuels, 2 x 50 MW Gas Turbines	4907	5263	0.624

* LOLP is loss-of-load probability. A maximum limit of 55 hours/year (0.63%) was set for 1998 and later.

Note: Total discounted cost = US$1,786.5 million.

45. Under the high load forecast, the total discounted cost of Plan B is US $1786.5 million, which is 4 percent higher than the figure of US $1719.1 million for the comparable Plan A under the high load forecast. The hydropower plants brought in as part of the LCGEP in Plan B in the high case are: Khimti Khola 2 (in 1999), the two phases of Kali Gandaki 'A' (in 2001 and 2002), Bhote Kosi 2 (in 2003), Bhote Kosi 1 (in 2004), Tama Kosi 3 and Tama Kosi 2 (in 2005), Indravati 3 and Indravati 2 (in 2006), Arun 3 Phase 1 (in 2008), Arun 3 Phase 2 (in 2010), Upper Arun (in 2011), Lower Arun (in 2013), Upper Karnali (in 2014), West Seti 'B' (in 2016), Burhi Gandaki (in 2017) and Kali Gandaki 2 (in 2019). Although all project commissioning dates are advanced, the sequence in which projects are introduced is the same as in Plan B under the base load forecast upto the introduction of the West Seti 'B' project. However, the LCGEP for Plan B in the high case requires that the Burhi Gandaki and Kali Gandaki 'A' projects be introduced as well.

Table 16 - Total discounted costs for Comparable Plan A and Plan B
(US$ million)

	Comparable Plan A (increased overnight costs for all hydroprojects)	Plan B
Base Load Forecast	1071.1	1127.4
Low Load Forecast	666.4	703.5
Low Load Forecast (KGAI in 2000, AHP in 2003 imposed)	752.8	N/A
High Load Forecast	1719.1	1786.5

N/A - not applicable

46. The purpose of analyzing a sequence such as Plan B is to suggest the possibility of meeting Nepal's forecast power demand through an alternative strategy which relies on a series of hydropower projects in the 30--80 MW range before moving on to Arun III and subsequent projects in the Arun valley. However, since projects unique to Plan B had not been chosen for development to the pre-feasibility level based on criteria such as energy, capacity, distance from the load center and accessibility, the information available about them could not be readily compared with that available for projects such as Kali Gandaki 'A' and Arun Phase 1 which have been studied to the detailed engineering stage. The difficulty of noncomparability between the two plans was sought to be addressed by assigning contingencies based on the state of preparedness to available cost estimates. The analysis showed that the total discounted cost of Plan B is $56.3 million higher than that of the comparable Plan A under base case assumptions. Plan B is, however, less expensive by $49.3 million than a comparable Plan A if demand follows the low load forecast and if Kali Gandaki 'A' Phase 1 and Arun Phase 1 are nevertheless commissioned in 2000 and 2003 respectively, which are their optimal commissioning dates under the base load forecast when there are no cost overruns. The least cost analysis therefore shows that the cost advantage of Plan A under base case assumptions is close to the cost advantage of Plan B if Kali Gandaki 'A' Phase 1 and Arun Phase 1 are introduced in the years which are optimal under the base case without cost overruns, but demand turns out to follow the low load forecast.

47. The choice between the two plans therefore turns on whether the simple cost advantage of Plan A over Plan B in the base case is reinforced or overridden by considerations other than those captured in the least cost analysis. Plan A has a number of important advantages which are not formally captured by least cost analysis, economic analysis and affordability analysis. First, there is the risk that further investigations might reveal that some of the projects which are unique to Plan B are technically infeasible. Second, experience in Nepal suggests that the time taken to arrange financing for projects which prove to be technically feasible is, on average, about 3 years. A postponement of power investments caused by difficulties in putting together a financing plan would lead to additional costs in the form of more expensive thermal alternatives and in unserved energy. Third, the need to manage the construction of a larger number of projects in parallel and to bring several of them on stream at the same time, as Plan B requires, would carry significantly higher implementation risks than in the case of Plan A. Those risks could be managed with substantial expatriate technical skills, a strategy which, however, would not further the objective of developing institutional capacity in Nepal. In contrast, a high-level oversight mechanism is ready to be put in place to implement the Arun project. Fourth, Plan A carries lower environmental risks, both because fewer sites need to be developed, and because the plans for mitigating environmental impact and maximizing the benefits to the local people are relatively well developed in the case of the early projects in the power investment program. Fifth, although Plan A continues to be economically viable in the base case even without the development of the Upper and Lower Arun projects, as demonstrated by the economic analysis presented in Annex 5.7, the completion of Arun 3 would put Nepal in an attractive position for subsequent power development in the Arun valley, should arrangements be worked out for major exports to the North Indian market. Finally, Government commitment to Plan A is notably strong, an ingredient which World Bank experience shows to be critical in successful project implementation.

48. Mini Hydros as an Alternative Plan. It has been suggested that there are available in Nepal a large number of small and mini hydro projects ready for implementation, which could be considered as an alternative to the Arun project; this, however, is not well supported by the facts. With support from German TA, a mini-hydro master plan for Nepal was developed in 1992/93.[9] In the course of the study, 33 hydropower plants with installed (rather than firm) power capacities ranging from 300 kW to 11,400 kW were identified; of those, 13 might be suitable for integration into the national power grid. Studies of only two of the identified sites - Langtang Khola (5 MW) and Rawa Khola (2.3 MW) - have reached feasibility level. Most of the others have not been studied beyond the early reconnaissance stage. The total capacity of the 33 plants amounts to 66.3 MW. Even if the technical capacity existed to implement them all, in parallel and immediately, they could not contribute significantly to covering the electricity demand of Nepal. In addition, economies of scale do bear on the alternatives of mini-hydro schemes. Existing mini-hydro schemes have costs between US$2,854/kW and US$12,032/kW to construct. Hence, mini-hydros do not constitute an alternative to the proposed Kali Gandaki "A" and Arun Phase 1 projects. They should be viewed instead as options for isolated small load centres that are located far from the NEA grid.

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[9] NEA/GTZ. *Small Hydropower Master Plan in Nepal* (2 volumes). Kathmandu, August 1993.

ANNEX 5.4
Attachment 1

ENERGY BALANCE FOR FEBRUARY - BASE CASE LOAD FORECAST
(Dry Hydro Condition)

Year	Hydro (GWh)	Imports (GWh)	Thermal (GWh)	Spilled Hydro (Gwh)	Unserved Energy (GWh)
1994	57.4	13.1	21.1	0.0	3.1
1995	68.3	13.1	20.8	0.0	0.5
1996	79.0	17.5	15.3	0.0	0.1
1997	79.0	27.3	15.7	0.0	0.4
1998	84.9	9.6	40.1	0.0	0.1
1999	99.4	8.8	40.1	0.0	0.1
2000	128.3	0.0	35.5	0.0	0.0
2001	128.3	11.8	40.0	0.0	0.0
2002	129.4	29.5	40.0	0.0	0.0
2003	219.8	0.0	0.0	41.6	0.0
2004	243.1	0.0	0.1	18.3	0.0
2005	261.4	0.0	8.3	0.0	0.0
2006	261.4	0.4	36.7	0.0	0.0
2007	261.4	28.6	40.1	0.0	0.0
2008	261.4	33.1	67.4	0.0	3.2
2009	403.9	0.0	0.0	29.1	0.0
2010	432.4	0.0	14.4	0.7	0.0
2011	433.3	22.4	38.3	0.0	0.0
2012	532.3	0.0	14.2	3.8	0.0
2013	535.9	27.9	41.0	0.1	0.0
2014	551.4	30.7	85.1	0.0	4.4
2015	661.8	29.2	55.3	0.0	0.0
2016	661.5	32.5	135.0	0.0	0.0
2017	661.5	33.0	226.1	0.0	0.3
2018	661.5	32.9	328.1	0.0	0.7
2019	841.2	32.8	262.7	0.0	0.0
2020	841.2	32.9	388.0	0.0	0.5

ANNEX 5.5

NEPAL
ENERGY BALANCE (GWh) FOR THE DRY MONTH (FALGUN)
Dry Hydro Condition (#4)

Fiscal Year	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
A. EXISTING STATIONS POTENTIAL														
HYDRO														
NEA Hydro	55.4	66.3	71.2	71.2	72.9	72.8	72.8	72.8	72.8	72.8	72.8	72.8	72.8	72.8
Private	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
THERMAL														
Diesels	5.1	5.1	5.1	5.1	5.1	5.1	5.1	5.1	.0					
Multifuel 1992	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0	19.0
B. ONGOING/PLANNED														
NEA HYDRO														
KGA-1 100 MW 2000							28.9	28.9	28.9	28.9	28.9	28.9	28.9	28.9
KGA-2 40 MW 2002									1.1	1.1	1.1	1.1	1.1	1.1
ARUN 3-1 201 MW 2003										132.0	132.0	132.0	132.0	132.0
ARUN 3-2 201 MW 2007														.0
PRIVATE HYDRO														
Jhimruk 1995			5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
Modi Khola 1998					4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2	4.2
Khimti Khola 1999						14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6	14.6
THERMAL														
Diesel/Rehab. 1995		3.1	3.1	3.1	3.1	3.1	3.1	3.1	.0					
MF20 MW # 1&2 1998				-	29.2	29.2	29.2	29.2	29.2	29.2	29.2	29.2	29.2	29.2
C. AVALABLE (GWh)														
HYDRO:NEA	55.4	66.3	71.2	71.2	72.9	72.8	101.7	101.7	102.8	234.8	234.8	234.8	234.8	234.8
PRIVATE	2.0	2.0	7.8	7.8	12.0	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6	26.6
THERMAL	24.1	27.2	27.2	27.2	56.4	56.4	56.4	56.4	48.2	48.2	48.2	48.2	48.2	48.2
TOTAL AVAILABLE	81.5	95.5	106.2	106.2	141.3	155.8	184.7	184.7	177.6	309.6	309.6	309.6	309.6	309.6
D. REQUIRED (GWh)	94.7	102.7	111.9	122.4	134.7	148.4	163.8	180.1	198.9	219.8	243.2	269.7	298.5	330.1
E. BALANCE FORECAST (GWh)														
HYDRO: NEA	55.4	66.3	71.2	71.2	72.9	72.8	101.7	101.7	102.8	234.8	234.8	234.8	234.8	234.8
PRIVATE	2.0	2.0	7.8	7.8	12.0	26.6	26.6	26.6	26.8	26.6	26.6	26.6	26.6	26.6
THERMAL	21.1	20.8	15.3	15.7	40.1	40.1	35.5	40.0	40.0	.0	.1	8.3	36.7	40.1
IMPORTS	13.1	13.1	17.5	27.3	9.6	8.8	.0	11.8	29.5	.0	.0	.0	.4	28.6
SURPLUS HYDRO	.0	.0	.0	.0	.0	.0	.0	.0	.0	41.6	18.3	.0	.0	.0
F. UNSERVED ENERGY	3.1	.5	.1	.4	.1	.1	.0	.0	.0	.0	.0	.0	.0	.0

Source: Argonne National Laboratory

ANNEX 5.6

NEPAL

CAPACITY BALANCE (MW)

Fiscal Year	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
A. EXISTING STATIONS POTENTIAL														
HYDRO														
NEA Hydro	181.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0	214.0
Private	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
THERMAL														
Diesels	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	.0					
Multifuel 1992	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0	26.0
B. ONGOING/PLANNED														
NEA HYDRO														
T/D Upgrading 1996 1/	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0	11.0
KGA-1 100 MW 2000							100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0
KGA-2 40 MW 2002									40.0	40.0	40.0	40.0	40.0	40.0
ARUN 3-1 201 MW 2003										201.0	201.0	201.0	201.0	201.0
ARUN 3-2 201 MW 2007														201.0
PRIVATE HYDRO														
Jhimruk 1995			12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0	12.0
Modi Khola 1998					10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
Khimti Khola 1999						60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0	60.0
THERMAL														
Diesel/Rehab. 1995		6.0	6.0	6.0	6.0	6.0	6.0	6.0	.0					
MF20 MW # 1&2 1998					40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
C. NET POTENTIAL AVAILABLE (MW)														
HYDRO:NEA	181.0	214.0	214.0	214.0	214.0	214.0	314.0	314.0	354.0	555.0	555.0	555.0	555.0	756.0
PRIVATE	5.0	5.0	17.0	17.0	27.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0	87.0
THERMAL	36.0	42.0	42.0	42.0	82.0	82.0	82.0	82.0	66.0	66.0	66.0	66.0	66.0	66.0
IMPORTS 2/	20.0	20.0	50.0	50.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0	55.0
TOTAL	242.0	281.0	323.0	323.0	378.0	438.0	538.0	538.0	562.0	763.0	763.0	763.0	763.0	964.0
D. ANNUAL PEAK LOAD	242.0	258.0	281.0	303.0	328.0	354.0	383.0	413.0	452.0	498.0	549.0	610.0	676.0	748.0
E. GROSS RESERVE MARGIN (%) 3/	.0	8.9	14.9	6.6	15.2	23.7	40.5	30.3	24.3	53.2	39.0	25.1	12.9	28.9

Source: Argonne National Laboratory

1/ T/D upgrading does not contribute new capacity

2/ Import facilities include Tanakpur project: 5 MW, 20 GWh from FY1998

3/ During the Dry season, the gross reserve margin is considerably lower

NEPAL

ARUN III HYDROELECTRIC PROJECT

Economic Return to NEA's Power Development Program

Introduction

1. The economic internal rate of return (EIRR) to NEA's long-term development program for meeting growth in demand for electricity is evaluated from a comparison of the economic costs of this program with its economic benefits. The EIRR is the discount rate that produces a zero net present value for the difference between costs and benefits.

2. Benefits are valued in terms of the incremental demand that is met under this program relative to the much lower level of demand that could be served if no new supply capacity were added to the power system. Likewise, the costs are the difference between power system costs for meeting the forecast demand with this program and the system costs without any new investments in supply capacity entering service from the year 2000 onwards. Investments that enter service before 2000 are the same for both cases. This comparison of a with program case and a without program case differs radically in concept from the approach to justifying the proposed projects as part of a long term development program. In the latter case, the comparison is made between various development programs for meeting a common level of demand, i.e., between different costs for achieving a common benefit.

3. The evaluated program is based on the proposed sequence of investments in new capacity for meeting the base case demand forecast up to the year 2013 (the least cost generation expansion plan given in Table 5 of Annex 5.4). The sequence includes the Kali Gandaki 'A' and Arun III hydroelectric schemes as the first major generation components from 2000 onwards. It is taken up to the year 2013 to include the costs and benefits of developing the Upper Arun and Lower Arun projects, thereby covering the full benefits of developing the hydropower potential of the upper Arun valley that the Arun III scheme facilitates.

4. All costs and benefits are valued at 1993 border prices. Local costs are converted to border prices by using a Standard Conversion Factor (SCF) of 0.9. Since the major investments in the power development program have economic lives that stretch well beyond 2013, the last year for the projection of costs and benefits, a run-out period of 25 years is added to the cost and benefit streams for computing the EIRR in which costs and benefits are maintained at the levels for 2013. The economic evaluation is based on the same demand forecast and cost estimates for power system operation and development that are used in the analysis for project justification, as well as the projected energy outputs and purchases for the Case 1 long term development program in that analysis. The costs of petroleum products, which feature in the valuation of both costs (light fuel oil and distillate for NEA's generators) and benefits (in the without program, case kerosene for residential lighting and light diesel oil for users' generators), are assumed

to increase by 40 percent in real terms by 2005 from current levels. It is assumed that these prices remain constant thereafter.

Economic Costs

5. The costs associated with meeting the forecast demand under NEA's long-term development program comprise: (a) capital expenditures on generation, transmission and distribution facilities and service connections; (b) operations and maintenance costs, estimated as a percentage of cumulative investments in generation (1% of the capital cost/year for hydropower stations, 5%/year for thermal generators), transmission (2%) and distribution (3%); (c) fuel costs for thermal generators (multifuel diesels and gas turbines); (d) power purchases from privately owned power stations in Nepal, notably the planned Khimti Kola (60MW) scheme; (e) power imports from India; and (e) costs associated with technical assistance and training. The earnings from exports to India of electricity generated as non-firm hydropower - valued at US$22/MWh - are deducted from the costs of power system expansion and operation to derive the net cost of meeting the forecast Nepalese demand for electricity.

6. The same cost categories are calculated for the without program case. The difference between the costs of the with program case and the without program case represents incremental costs for meeting the forecast growth in electricity demand, and are the costs used in analyzing the rate of return to NEA's power development program. Technical losses in NEA's system - projected to be around 19 percent of energy supplied to the system after 2000 - are implicitly accounted for under this approach.

Economic Benefits

7. The economic benefits associated with the power investment program are the values of the increments in NEA's sales made possible by carrying out the proposed long term development program.

8. The increments in sales are based on the difference in sales that could be served in the with program case and the without program case. A first approximation of this difference is obtained from the increase in forecast sales from the year 2000 onwards over the forecast sales in 1999, because the first major generation project of NEA's development program (Kali Gandaki "A") enters into service in 2000 at the earliest. NEA could meet, however, a slightly higher level of demand than the 1999 level from its own capacity in 1999 and power imports (under current terms). The benefits from the sales increments are thus reduced by an amount that reflects the extent to which NEA could increase its sales in 2000 onwards above the 1999 level from its supply capacity in the without program case. The corresponding additional costs are also included in the without program case.

9. The valuation of projected increments in sales varies among different groups of power users. Three groups of users are identified for this economic evaluation, and they correspond to the following user categories in NEA's tariff: residential, industrial, and "other" that comprises

commercial, non-commercial, transport, irrigation, water supply, temples, street lighting, and temporary supply categories.

10. Currently, about 40 percent of NEA's sales are made to the residential category, 40 percent to the industrial category, and 20 percent to other categories. According to the base case demand forecast, NEA's total sales to Nepalese consumers would grow at 14.0 percent from 1994 to 2001. Thereafter, sales are assumed to increase in line with the long term growth in demand that is used in the analysis for project justification, with an allowance for a small drop in system losses. On this basis, NEA's total sales would increase at 10.7 percent/year from 2001 to 2013

11. The projection of total sales is disaggregated between the three consumer categories. The detailed load forecast for the period 1994 to 2001 projects residential sales to increase at 8.8 percent/year, industrial sales at 14.7 percent/year, and other categories at an average rate of 12.1 percent. For the period 2001 to 2013, it is assumed for the EIRR analysis that residential sales would continue to grow at 8.8 percent/year, but that growth in industrial sales would drop to 11.0 percent (since 14.7 percent growth is too high to be compatible with growth of 10.7 percent in total sales over a long period). Sales in the other categories would then grow at a residual rate of 12.5 percent. These growth rates would change the composition of sales by 2013 to 26 percent residential, 49 percent industrial, and 25 percent other categories.

12. Because increments in sales are the basis for estimation of benefits, units sold of electricity have to be classified by their position on users' demand curves (the first units of served demand are the most valuable to users). A distinction has to be made, therefore, between users that are already connected to NEA's system by the end of 1999, and users that are first connected from 2000 onwards. In the case of existing users in the without program case, the incremental approach implies that they will continue to be supplied by NEA from its existing capacity at roughly their 1999 level of consumption. The benefits from NEA's power development program for this class of user is thus based on the incremental sales over the without program case. This increment is taken to be a function of the general increase in incomes from growth in the Nepalese economy. The way that this benefit is related to income-led growth in electricity use is shown in Figure A.

13. In general, new users would not be connected to NEA's system in the without program case because NEA would not have the capacity to serve them. A small number could in fact be served from NEA's ability to increase sales a little above the 1999 level, and this feature is implicitly accounted for in the adjustment to incremental benefits noted in para. 8 above. The benefits from NEA's power development program for this class of user are thus based on their full consumption of electricity from NEA's system, once they are connected. The analysis also allows for the lower consumption of new connections compared to mature users. Based on consultant's fieldwork, the analysis uses an eleven-year build-up of consumption by new users to the consumption level of mature users. The effect of this buildup on a user's demand is shown in Figure B.

14. The projected sales for each consumer category are therefore disaggregated between existing users and new users. This is done by constructing a spreadsheet model of projected sales as a function of the overall sales growth rate, the rate of new connections, the projected tariff levels needed to meet NEA's financial objectives (see Annex 4.3), price elasticity of category demand, the projected growth in incomes, income elasticity of projected demand, and the build-up rate of consumption from new connections. The overall sales growth rate is the only factor for which information is available from the demand forecast. Assumptions have to be made about the other factors to break down the sales projection for analysis. Combinations of values for the other factors were chosen to calibrate the total of the disaggregated sales against the projected overall path of projected sales. Sales levels modelled in this way came very close to the projected levels. The estimates of benefits from the modelled sales were adjusted to fit the projected sales.

Benefits to Residential Users

15. For the EIRR analysis, the adopted growth rate in household income over the evaluation period - i.e., up to 2013 - is 2.0 percent/year. This rate is derived from the projected growth rate of 4.5 percent for the economy (according to the Bank's 1994 economic report "Fiscal Restructuring and Public Resource Management in the Nineties - Nepal") and projected population growth of 2.5 percent. At 2.0 percent/year, real household incomes would be 46 percent greater in 2013 than in 1994; this assumes no change in average household size.

16. The modelling of residential sales between existing and new users under a total growth of 8.8 percent/year is based on the following values for the demand parameters: 40 to 45 thousand new connections annually (which should be feasible for a strengthened NEA, and compares to an average annual rate of about 30 thousand for 1990-1993), electricity prices approximately doubling in real terms from 1994 to 2000 and remaining constant thereafter, price elasticity of -0.30, income elasticity of 1.5, and an average consumption rate of 863 kWh/year for a mature user in 1994. Under these assumptions, this consumption rate would rise to 1383 kWh/year in 2013. Also under these assumptions, the proportion of the total population that uses electricity would rise from about 12 percent in 1994 to 23 percent in 2013.

17. There is a substantial difference between the economic value of electricity sales from 2000 onwards to existing residential users and to new users. For a mature user connected before 2000, the incremental benefit would be worth only about 190 NR in 2000, increasing to about 3727 NR in 2013 in line with the assumption about rising incremental consumption over the 1999 level from growth in household income. For a new user connected in 2000, however, the economic benefit of electricity use would rise from about 5960 NR in the first year of use (2000) to about 19285 NR when this user achieves the level of mature users (2010) and to about 21083 NR in 2013 under the assumption of increasing household income.

18. Total consumption by new residential users is divided into two components for valuation purposes. The first component is the substitution of

existing methods of lighting by electric lighting, and it represents a saving in resource costs. The substitute form is taken to be kerosene lamps, and it is estimated from field observations that unelectrified households presently use on average the equivalent of 35 kWh/year of this form at an average cost of 42.4 NR/kWh. Under the modelling assumptions for residential demand, these values change by 1999 to 50 NR/kWh and 39 kWh/year. This estimate provides a lower case point at the margin of substituted use on a user's demand curve for electricity in that year.

19. An upper case point at the margin of total consumption is the consumption rate for a mature connection at NEA's tariff. In 1999, this point is defined by 5.6 NR/kWh (the projected tariff level in 1993 prices) and 796 kWh/year consumption (which is less than the corresponding rate in 1994 because the negative effect of price increases outweighs the positive effect of income growth between 1994 and 1999). A user would be induced to consume the additional quantity of electricity above the substituted level by the large drop in the price of energy that comes with a switch from non-electrical forms of service, e.g., kerosene lighting, to electric forms. The difference between substituted use and induced use is shown in Figure C.

20. The benefit of induced consumption is a function of the area under the user's demand curve for electricity, and thus requires knowledge of the shape of this curve. Since the shape of the true demand curve is not observable, this benefit is valued on the assumption of a semi-log demand curve of the form:

$$Q = A + B \ln P$$

that passes through the two points described above, where A is a positive constant and B is a negative constant. For a mature user in 2000, A would be equal to 1445 and B to -357. The values of these constants change over time (increase in absolute terms) as the level of mature consumption rises with income growth. These values change similarly for new users as their consumption approaches the mature level.

21. The semi-log form is chosen in preference to a straight line demand curve since the latter could lead to an overestimation of the consumers surplus from the use of electricity. Even an estimate of consumers surplus on the basis of a semi-log demand curve overstates the true gain to users from electricity use, because of the income effect created by the large drop in the price of energy. The estimates are thus adjusted to reflect the compensating variation for the consumer, i.e., the area under the compensated demand curve for this income effect that corresponds to the uncompensated semi-log demand curve presented above. On the assumption of a linear relationship between the level of electricity consumption and household income, a 1994 per capita income of $170, and an average of 6 people per household, this adjustment factor varies between 0.74 for a mature user and 0.87 for a new user. The economic value of benefits from induced electricity consumption also incorporates a factor of 0.9 in order to minimize the risk of overstating the aggregate economic value of users' gains.

Benefits to Industrial and Other Users

22. The basis for valuing the benefits of post-1999 incremental sales to industrial and other users, i.e., non-residential users, is the cost that these users would incur if they had to meet their electricity needs by investing in and operating diesel generators on their own premises, instead of being able to take supply from NEA. In other words, an avoided user cost is the basis for this class of users, and this benefit is essentially a resource saving.

23. It is assumed that the consumption of electricity by non-residential users would not be sensitive to the price or own-incurred cost of electricity, since this cost forms a small proportion of the users total costs of producing goods and services (generally less than 5 percent). Hence there is assumed to be no induced consumption caused by a switch from own-supply to NEA supply. It is assumed, however, that consumption rises with growth in national income.

24. In other respects, the evaluation methodology is similar to that adopted for residential users. New users are treated differently from existing users, and the demand for each consumer category is decomposed into demands for these groups. An eleven-year build-up period is assumed for new users. With the assumption of zero price elasticity, calibration of the demand model indicates that income elasticity for industrial users would be 1.5 up to 2005 and 1.3 thereafter, and for users in the other category would be 1.3. In combination with the projected economic growth of 4.5 percent/year, this assumption leads to a substantial increase in consumption. Consumption by a mature non-residential user in 2013 would be about three and one-third times as high as in 1994 on account of the income effect in this case.

25. For both user categories, avoided costs are estimated on the assumption that a mix of three sizes of diesel generators would be used for user-owned supply in the without NEA program case. For industrial users, the assumed capacities are 1 MVA, 50 kVA, and 10 kVA. Assuming that these units would be used for 2000 hours, 1500 hours, and 1000 hours per year respectively, the numbers of user-owned units that would be in place is estimated for supplying the projected sales by NEA to industrial users in 1994. The numbers of new units for later years are estimated from growth in connections in the demand model and an assumption of 7 years of average working life for this group. Likewise, for the category of other users, the assumed mix of user-owned diesel generators is based on capacities of 50 kVA, 10 kVA, and 3 kVA.

Economic Rate of Return for the Base Case

26. The Economic Internal Rate of Return (EIRR) for the base case is estimated at 15.4 percent based on the methodology and assumptions discussed in the above paragraphs. The streams of total costs and benefits are summarized in Table A. This rate exceeds the 10 percent opportunity cost of capital that is used for project justification.

Sensitivity Analysis

27. This section presents the results of analysis into how much the EIRR for the proposed development program would fall under unfavorable change in planning assumptions about the following evaluation variables: (a) the capital costs of hydropower projects are higher than estimated, for which an overrun of 20 percent is considered; (b) Nepal does not gain any revenues by exporting its surplus non-firm hydroelectric energy; and (c) a shorter evaluation period for computing the EIRR that ends before the commissioning of the two following hydro projects to Arun-3 in the upper Arun valley, namely the Upper Arun and Lower Arun projects. The analysis also covers cases that are combinations of these events. All these cases are analyzed on the assumption that growth in the long-term demand for electricity in Nepal will follow the base case forecast of 10.7 percent per year after 2001 (12.0 percent between 1994 and 2001).

28. The results of this sensitivity analysis are given below. They show that the estimated EIRR is robust to the changes in hydroproject capital costs and export revenues. They also show that the assumption about further development of hydropower in the upper Arun valley is important (accounting for about 2.5 percentage points). The EIRR remains above the 10 percent rate for opportunity cost of capital in all these cases. The results do not give any indication of the probability of occurrence, and in fact the likelihoods of some of the cases, particularly the combinations, could be small. This aspect is examined by the risk analysis reported on later in this Annex.

Base case demand forecast:	EIRR
• Base Case	15.4%
• 20% higher capital cost for all hydropower projects	14.0%
• Zero revenue from exports of non-firm energy	14.3%
• Excluding Upper and Lower Arun projects	13.2%
• 20% higher capital cost for all hydro projects; zero revenue from exports of non-firm energy	13.0%
• Excluding Upper and Lower Arun projects; 20% higher capital cost	11.9%
• Excluding Upper and Lower Arun projects; 20% higher capital cost; zero revenue from exports of non-firm energy	10.9%

29. Sensitivity analysis of the EIRR is also carried out for a similar set of cases at a low demand forecast in which average long term growth in sales is 8.0 percent per year, equal to 75 percent of the growth rate in the base case. The relevant power development program for this case starts with Kali Gandaki Phase 1 in 2000 and Arun III Phase 1 in 2003. The rest of the

program is optimized for this demand forecast, up to the commissioning of Lower Arun in 2017. This provides sufficient capacity to meet growth in demand to 2018, and the run-out period thus starts in 2019. The EIRR is thus a measure of the economic return to the decision to proceed with these two projects as proposed but in the eventuality that demand follows the low forecast case. The expansion program in this case differs from the fully optimized expansion program in the low demand forecast case that is described in Annex 5.4. The benefits for this case were evaluated on the assumption of a 3 percent long-term growth in GDP and a somewhat lower rate of new connections than in the base demand forecast (82 percent of the base case rate for industrial users and 92 percent for users in other categories between 1994 and 2015, but the same rate for residential users). All other assumptions remain unchanged. The results are presented below.

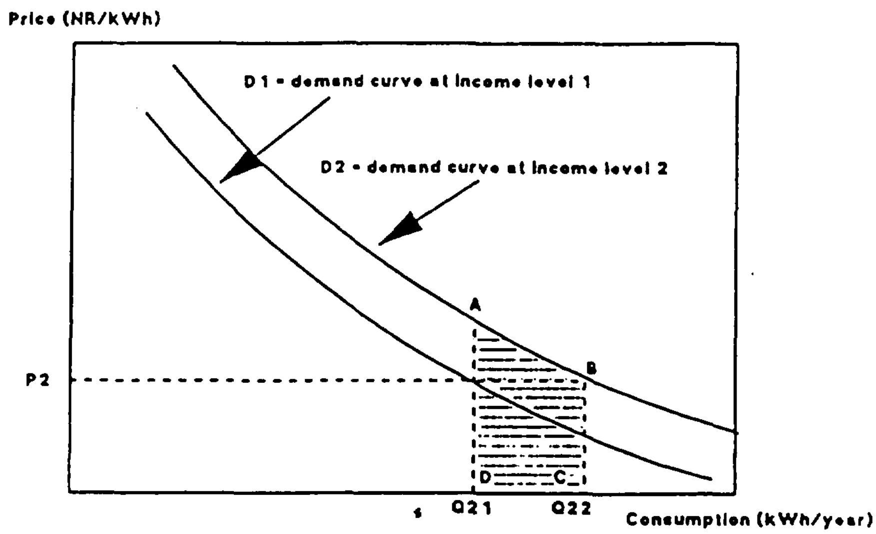
Low case demand forecast:	EIRR
• Base Case	12.8%
• 20% higher capital cost for all hydropower projects	11.8%
• Zero revenue from exports of non-firm energy	11.8%
• Excluding Upper and Lower Arun projects	9.9%
• 20% higher capital cost for all hydro projects; zero revenue from exports of non-firm energy	10.8%
• Excluding Upper and Lower Arun projects; 20% higher capital cost	8.9%
• Excluding Upper and Lower Arun projects; 20% higher capital cost; zero revenue from exports of non-firm energy	7.7%

The EIRR drops by 2.6 percentage points to 12.8 percent at the low demand forecast. It is not very robust to the case that excludes the Upper Arun and Lower Arun projects, falling to just below 10 percent. The drop below this level becomes serious in the combination cases, reaching 7.7 percent when all three unfavorable cases are combined. However, as previously mentioned, the likelihoods of the combination cases could be small. This possibility is looked at in the risk analysis reported below.

30. The EIRR is also calculated for a high demand forecast in which average long term growth in sales over the period 2001 to 2013 is 13.4 percent per year. The generation expansion plan is optimized to yield the least cost plan for this high demand forecast. The benefits for this case are evaluated on the assumption of a 5.75 percent long-term growth in GDP and a somewhat higher rate of new connections than in the base demand forecast (127 percent of the base case rate for industrial users and 158 percent for users in other categories between 1994 and 2015, but the same rate for residential users.) The results are as follows:

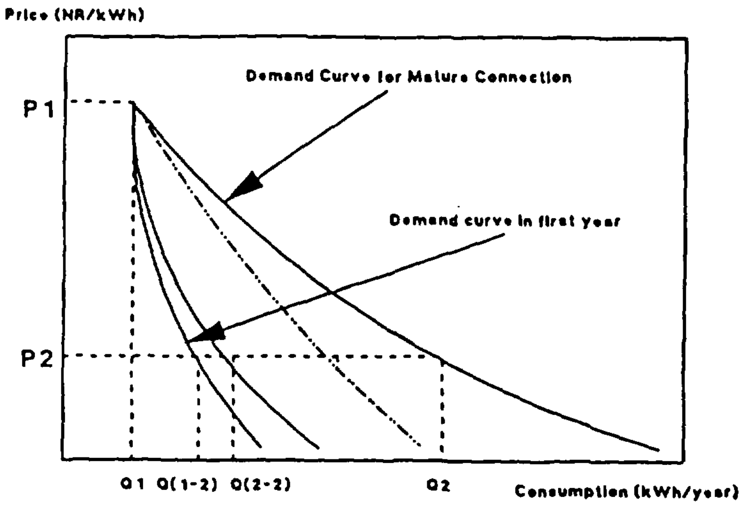
<u>High case demand forecast</u>:	<u>EIRR</u>
• Base case	17.5%
• 20% higher capital cost for all hydropower projects	15.8%

Figure A: Benefit of Incremental Consumption by a Mature User arising from Income Growth



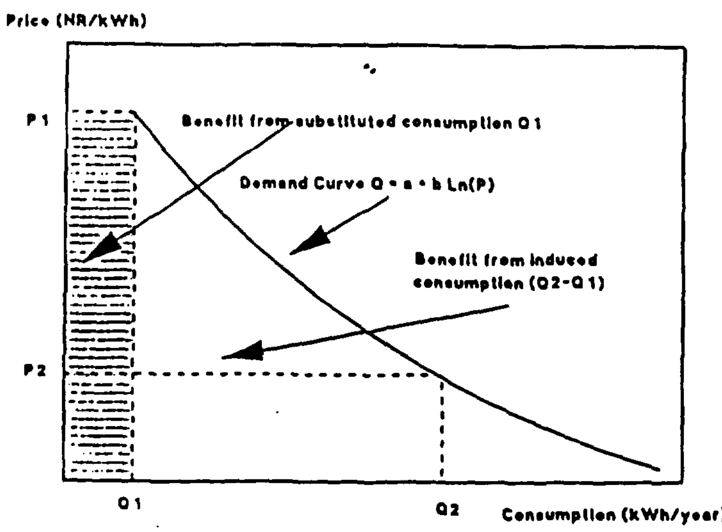
ABCD is the benefit of induced consumption from the effect of income growth made possible by a power expansion program

Figure B: Build up in Consumption from a New Connection
(excluding the effect of income growth)



Q(1-2) = consumption in first year of a new connection,
Q(2-2) = consumption in second year of a new connection, etc
Q2 = consumption from a mature connection

Figure C: Benefit of Electricity Consumption from a New Connection



P1 is cost of substituted service e.g., kerosene lighting
Q1 is equivalent consumption of substituted service before electrification
P2 is the electricity tariff
Q2 is the consumption of electricity

Table A

Economic Rate of Return to NEA's Investment Program

Base Case Demand Forecast: No Schedule Delay
No Overrun Hydro Project Capital Costs

Fiscal Year	Value of Incremental Consumption (a)	Value of Incremental Net Exports (b)	Incremental Costs incurred by NEA (c)	Stream of Net Benefits (a+b-c)
	(US$ '000)			
1994	0	0	9,870	(9,870)
1995	0	0	56,248	(56,248)
1996	0	0	177,764	(177,764)
1997	0	0	227,782	(227,782)
1998	0	0	185,042	(185,042)
1999	0	0	143,421	(143,420)
2000	0	13,376	148,513	(135,137)
2001	0	15,028	123,757	(108,729)
2002	0	16,523	63,245	(46,722)
2003	17,689	47,558	172,580	(107,334)
2004	59,507	45,959	216,952	(111,486)
2005	118,042	41,944	299,090	(139,104)
2006	185,802	36,308	202,891	19,218
2007	283,095	54,877	137,884	200,089
2008	363,983	46,900	62,717	348,167
2009	450,184	96,506	134,790	411,900
2010	543,712	85,790	238,723	390,779
2011	642,973	74,498	241,801	475,670
2012	751,706	111,072	52,321	810,457
2013	861,563	96,595	32,877	925,281
2014	861,563	96,595	32,877	925,281
2015	861,563	96,595	32,877	925,281
2016	861,563	96,595	32,877	925,281
2017	861,563	96,595	32,877	925,281
2018	861,563	96,595	32,877	925,281
2019	861,563	96,595	32,877	925,281
2020	861,563	96,595	32,877	925,281
2021	861,563	96,595	32,877	925,281
2022	861,563	96,595	32,877	925,281
2023	861,563	96,595	32,877	925,281
2024	861,563	96,595	32,877	925,281
2025	861,563	96,595	32,877	925,281
2026	861,563	96,595	32,877	925,281
2027	861,563	96,595	32,877	925,281
2028	861,563	96,595	32,877	925,281
2029	861,563	96,595	32,877	925,281
2030	861,563	96,595	32,877	925,281
2031	861,563	96,595	32,877	925,281
2032	861,563	96,595	32,877	925,281
2033	861,563	96,595	32,877	925,281
2034	861,563	96,595	32,877	925,281
2035	861,563	96,595	32,877	925,281
2036	861,563	96,595	32,877	925,281
2037	861,563	96,595	32,877	925,281

Economic Internal Rate of Return, (EIRR) = 15.44%

Risk Analysis

31. The Arun Hydro project is subject to a number of risks which are largely outside the control of project design. The major risks concerning the economic performance of the project are : (a) demand risk; (b) cost risk; (c) schedule risk; and (d) export sales risk. The economic analysis of the project made a best estimate for each of these factors and calculated the associated economic internal rate of return (EIRR). Sensitivity analysis was carried out with respect to (a), (b) and (d) and alternative values of the EIRR were derived as described above.

32. The purpose of the risk analysis is to attach probabilities to the different scenarios so that a weighted average EIRR can be obtained. This produces an output that is easier to interpret, since it does not treat all outcomes as simple alternatives, as is the case for sensitivity analysis, but indicates which outcomes are more or less likely. This approach also allows a probability distribution of EIRRs to be constructed. Such a distribution indicates what the assessed chances are of an EIRR falling below a cut-off level.

Demand profiles

33. Three demand profiles are considered. The base demand case (BD) has GNP growing at 4.5 percent per annum. The corresponding figures for the low demand case (LD) and high demand case (HD) are 3.0 percent and 5.75 percent, respectively. The treatment of these alternatives is different from the other risks considered below. Although, as of today, the future growth rate of demand is unknown and must be estimated, the actual value will be constantly monitored and deviations from the assumed rate will become apparent. This would allow reoptimization of the generation expansion plan to take place if necessary, with consequent delays or advancement of the more distant dates. In effect it is assumed that changes in the trend growth rate will not lead to the implementation of a sub-optimal generation expansion strategy. The EIRRs calculated for the three demand scenarios then assume that there will be sufficient time to recognize demand shifts and to react to them by utilizing an optimal planting schedule. This approach, however, is modified for the cases of the Kali Gandaki 'A', Phase 1 project and the Arun 3, Phase 1 project. The former is planned to come on stream in 2000 and the latter in 2003, even if the demand experienced were to alter so that optimal dates would be later than these. In fact, for the base and high demand scenarios these dates are ones that would be chosen in a fully optimized scenario with full knowledge of the demand path, but for the low demand scenario it would in fact be optimal to delay Kali Gandaki 'A' Phase 1 to 2002 and Arun Phase 1 to 2009. It is assumed that decisions must be taken very soon on the implementation of these projects and that by the time it becomes clear that trend growth really was running at the lower rate, it would be too late to reschedule these two projects. Hence, Kali Gandaki 'A' Phase 1 and Arun Phase 1 are imposed in 2000 and 2003, respectively, under all three demand scenarios. The rest of the generation sequence is optimized, i.e., all other projects are assumed able to be rescheduled in the light of the actual demand path.

34. Growth has averaged 3.5 percent per annum in Nepal during the last two decades. Since the Government has launched a reform program, the twin pillars of which are improved macroeconomic and fiscal management, and accelerated private sector development, it is assumed that there is a better than even

chance, taken to be 60 percent, that the growth rate of GNP will be in the range of 3.5 percent to 5.25 percent per annum. A probability of 30 percent is attached to a growth rate in the range between 2.5 percent and 3.5 percent per annum, if the reform program unravels in a way that leads to a significant deterioration in the quality of economic management. A probability of 10 percent is assigned to a growth rate of 5.25 percent to 6 percent per annum. Although it is reasonable to interpret these probabilities as attaching to ranges of growth rates, the risk analysis assigns those probabilities to point estimates of demand. Thus, it is assumed that there is a 60 percent chance that the base demand (BD) corresponding to 4.5 percent growth will occur, that there is a 30 percent chance that the low demand (LD) corresponding to 3.0 percent growth will occur, and that there is a 10 percent chance that the high demand (HD) corresponding to a 5.75 percent growth will occur.

35. It is also assumed that the probabilities attached to the states of demand are independent of the probabilities attached to the other risk variables. Statistical analysis currently being carried out on all World Bank financed completed hydro projects initiated since 1965 shows no correlation between the rate of growth of demand and cost overruns or schedule overruns (both squared correlations being less than 1 percent).

Cost Profiles

36. The risk analysis considers three scenarios with respect to cost overruns. Both the magnitude of the overruns and the assigned probabilities are based on the analysis of Bank experience with hydro projects elsewhere. An analysis of the 56 completed cases (excluding three exceptional cases affected by civil war) of hydro projects showed a mean percentage overrun for costs of 30 percent of the original estimated cost. Of these cases, 27, or 48 percent of the total, came in with a cost overrun of less than 20 percent, with a few projects actually exhibiting a cost underrun; 12 projects, or 21 percent of the total, fell between the 20 and 40 percent overrun range, and the remaining 17 (31 percent) had more than a 40 percent cost overrun. However, the detailed preparatory work for the Arun project and the tightening of Bank standards in more recent years suggest that it is reasonable to expect some improvements compared to past experience. It is therefore assumed in the risk analysis that there is a probability of 50 percent for no cost overrun (BC), a probability of 25 percent for a 20 percent cost overrun (MC) and 25 percent probability of a 40 percent cost (HC) overrun. This yields an average expected cost overrun of 15 percent. Using the same evidence from Bank experience, it is also assumed that cost overruns and demand variations are uncorrelated, and, furthermore, that cost overruns and schedule overruns are uncorrelated. This last assumption is also supported by the analysis of Bank financed hydro projects, where the squared correlation between cost overrun and schedule slip is less than 1 percent. Finally, it is assumed that the correlation of cost overruns among projects is zero,and likewise with schedule overruns.

37. With these three cost profiles, the economic benefits and EIRR were calculated for each of the three demand schedules by varying the cost data, but without attempting to reoptimize the generation expansion plan. This implies, realistically, that cost overruns are observable only at such a late stage in project completion that it would be impossible to change the overall plan. Cost overruns are thus a genuine risk which must be allowed for in an overall EIRR analysis.

Schedule Profiles

38. The risk analysis of schedule delay is also strongly influenced by Bank experience with hydro projects. For the 56 projects, the mean schedule delay was 29 percent of the original estimated schedule - that is about 18 months late for a project predicted to take 5 years to complete. Some 23 projects, or 41 percent of the total, came in less than 20 percent late and the rest were more than 20 percent late. Again, the substantial preparatory work done on the Arun project suggests that an improvement can be expected relative to past performance. The following slip factors (which are in multiples of a year) have been attached to different plants, depending on the expected disbursement profiles:

Kali Gandaki 'A' Phase 1	2 year slip	(40%)
Kali Gandaki 'A' Phase 2	1 year slip	(50%)
Arun 3, Phase 1	2 year slip	(22%)
Arun 3, Phase 2	1 year slip	(25%)
Gas Turbines	1 year slip	(50%)
Upper Arun	1 year slip	(16%)
Lower Arun	1 year slip	(25%)

These slip factors produce an overall profile of average schedule slip (weighted by capacity) of around 26 percent. A 40 percent chance is attached to scenarios where the schedule (BS) is adhered to, and a 60 percent probability is attached to schedules where the set of slip factors occurs (HS). It is assumed, as justified above, that the probability of schedule slip is independent of the probability of cost overrun and of demand variations.

39. The three demand scenarios are optimized as explained above and then the schedule slips are imposed. This generates new values for fuel used and for exports, as well as for disbursement over a longer period, but no reoptimization of the sequence of capacity additions to take these factors into account is permitted. The EIRRs are then calculated for the schedule slips under the different demand and cost assumptions. This approach treats schedule slip as a risk which, if it occurs, cannot be anticipated by advancing the construction start dates.

Export Price Profiles

40. The project is optimized on the assumption that exports of surplus hydro to India will be sold at 2.22¢/kWh. Since this is not certain, it is important to allow for the risk that there will be a different outcome. The analysis assumes as the alternative that there will be no exports to India, i.e., a price of zero cents, and recalculates the EIRR for all cases. Again the system is not re-optimized for this outcome, to express the fact that it would not be possible to alter the generation expansion plan at the last minute if the sales of exports did not materialize. The EIRRs are calculated for the various demand, cost and schedule assumptions while varying the export price. The probability of exports at the base price (BE) is set at 75 percent, with a 25 percent chance of zero exports (ZE). These probabilities are assumed independent of those of demand cost and schedule factors, since there is no strong reason to assume such factors to be correlated with the export price.

Risk Analysis: Results

41. The four factors, two (demand and cost profiles) with three alternative states, and two (schedule and export price profiles) with two states give 36 possible outcomes, for each of which the probability is the product of the probability of the individual factors. Thus, for each outcome, the expected value of the EIRR (probability times its own EIRR) is calculated and then this is summed over all outcomes to give the expected (weighted average) EIRR. The outcomes are next ranked by value, from the lowest return to the highest, and the probabilities attached to these successive outcomes are cumulated. Table 1 shows the results for the set of assumed probabilities as reported above.

42. The first result is that the cumulated expected value of the EIRR is 13.53 percent - this should be compared with the case in row 2 (BC, BS, BE, BD) which has an EIRR of 15.44 percent. The latter is the central case used for the economic analysis, so that the risk-weighted return is lower than in the central case but is still substantially above 10 percent, which is the opportunity cost of capital.

43. A crucial result is that only two combinations of factors show returns at or below 10 percent (rows 1 and 2 in the second block of Table 1). Both cases have three unfavorable factors (high costs, zero exports and low demand) while one case also has schedule slip. The chance of being at or below 10 percent is thus very small at about 2 percent.

44. The histogram of the EIRRs (Figure D) shows a bimodal distribution. The higher mode, in the range 15-16 percent, corresponds to the single most likely case (22 percent chance) -- base cost, base exports and base demand (whether or not the schedule slips affects the EIRR very little). The lower mode, around 12 to 13 percent, occurs where several combinations of negative and positive influences are felt, no one of which is seen as particularly likely. Because there are several combinations of positive and negative factors, a modal value emerges. The higher mode corresponds to the case taken as the base case in the main analysis.

45. Some sensitivity of the risk analysis is carried out by varying the basic probabilities (see Table 2). If the export price of 2.22¢/KWh is treated as certain (BE=1.0, ZE=0.0) then the weighted average (expected) EIRR rises to 13.75 percent, from 13.53 percent. The elimination of any probability of zero export revenue also means that there is a zero probability of the EIRR falling below 10 percent. The base case is also perturbed by assuming different demand probabilities - 40 percent chance of low demand, 50 percent chance of base demand and 10 percent chance of high demand. In this case the weighted average EIRR falls to 13.44 percent showing that, unless very large changes are made in the demand forecasts, the results are robust to the distribution of probabilities. The cost profile is also varied by assuming a probability of 40 percent for no cost overrun, a probability of 30 percent for a 30 percent cost overrun and a probability of 30 percent for a 60 percent cost overrun. This variation yields an average expected cost overrun of 27 percent, which is close to the actual experience of an average of 30 percent. In effect, it therefore assigns no value to the detailed preparatory work done for the Arun project. Even in this case, the weighted average EIRR is 12.92 percent, so that the project is robust to this extreme set of assumptions, and there is only a 6.3 percent chance of falling below the

opportunity cost of capital. Finally, assigning 100 percent probability to the schedule delay case (HS), so that the expected delay (at 26 percent) is equal to Bank experience over all hydro projects, results in an average return of 13.5 per cent, with still a 2 percent chance of falling below a 10 percent return.

46. An analysis of the complete set of EIRRs shows that although the range is fairly broad, from 9.44 percent to 17.45 percent, the average value will not change much unless very extreme probabilities are chosen. Furthermore, the chances of the return falling below 10 percent will be very small in nearly all circumstances.

47. Table 1 also shows how each factor affects the outcome, while other factors are held constant. Comparing rows 2, 5 and 8 shows that the cost overrun of 20 percent reduces the EIRR by about 1.5 percentage points, while a further increase in cost overrun reduces the EIRR by just over another 1 percentage point. Comparing rows 1, 2 and 3 shows that the demand variations analyzed are more important than the cost variations - a change in the growth rate from 4.5 percent to 3.0 percent per annum reduces the EIRR from 15.44 percent to 12.88 percent, while an increase to 5.75 percent would increase the EIRR to 17.45 percent. Comparing rows 2 and 20 allows the impact of the export price to be isolated - the loss of the 2.22 cents/kWh export revenue lowers the EIRR from 15.44 percent to 14.31 percent, showing that this is not a dominating factor in the overall return of the scheme. Finally the schedule slip can be compared by looking at rows 2 and 11, where the EIRR in the latter case is 15.23 percent. The fact that the effect of schedule slip on the EIRR is so small can be explained by remembering that, although a slipped schedule requires other more expensive forms of fuel to be purchased in the earlier years in order to meet projected demand, the disbursement profile is stretched out, thus ensuring that some capital costs are discounted more heavily from today's standpoint.

Table 1

Probability Distribution of EIRRs for Arun Hydro Project

	Cost			Schedule		Exports cents/kWh		Demand		
	BASE	+ 20%	+ 40%	BASE	SLIP	2.22	0	LOW	BASE	HIGH
	BC	MC	HC	BS	HS	BE	ZE	LD	BD	HD
Probabilities	0.50	0.25	0.25	0.40	0.60	0.75	0.25	0.30	0.60	0.10

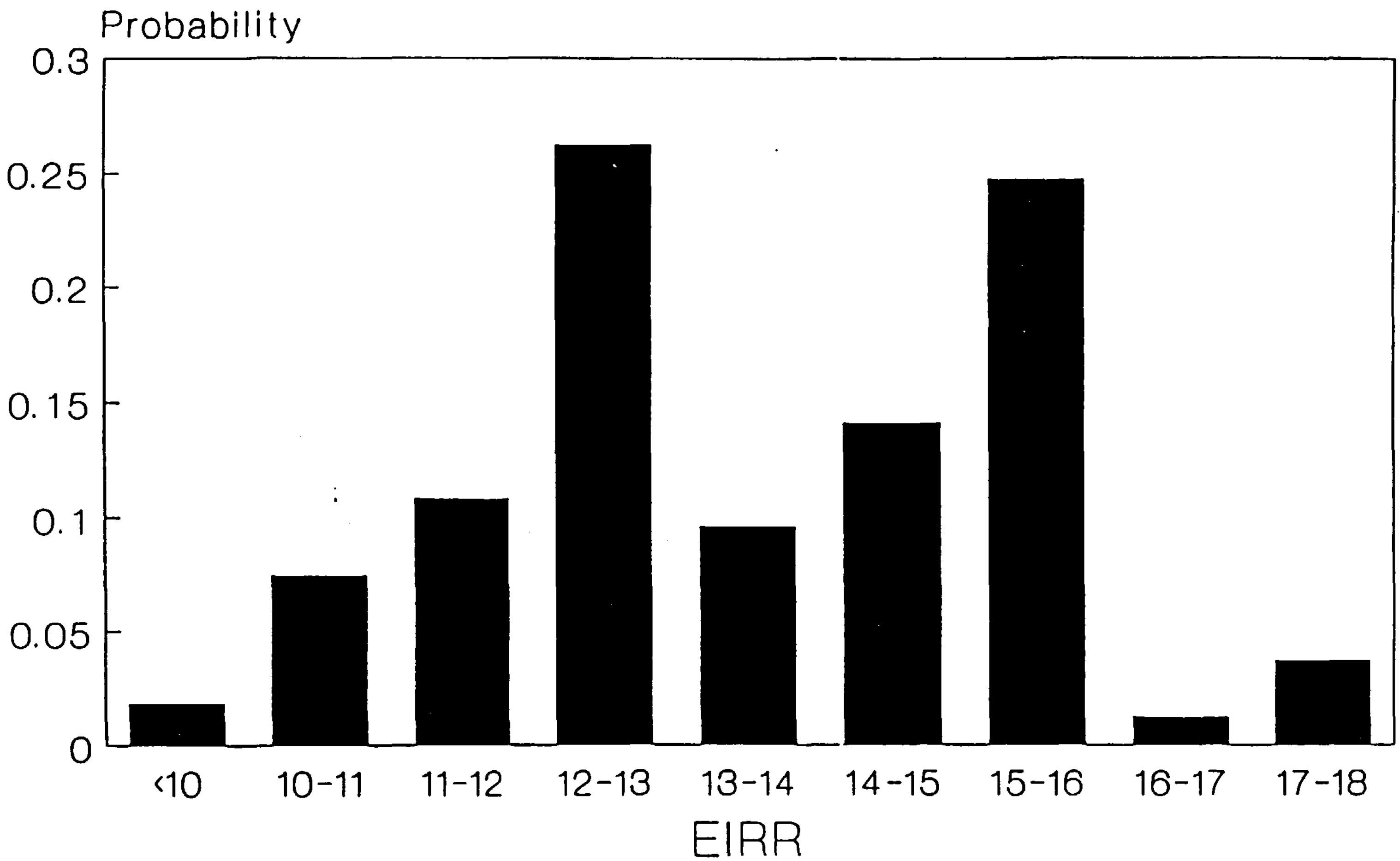
	Case		Prob. (P)	EIRR Value (V)	Expected Value PxV	Cumulated E.V.	Sorted by Value: Case		Cumulated Probabilities	EIRR Value
1	BC BS BE LD	=	0.0450	12.84	0.58	0.58	HC HS ZE LD	=	0.0113	9.74
2	BC BS BE BD	=	0.0900	15.44	1.39	1.97	HC BS ZE LD	=	0.0188	9.94
3	BC BS BE HD	=	0.0150	17.45	0.26	2.23	HC HS BE LD	=	0.0525	10.50
4	MC BS BE LD	=	0.0225	11.76	0.26	2.49	MC HS ZE LD	=	0.0638	10.52
5	MC BS BE BD	=	0.0450	14.04	0.63	3.13	MC BS ZE LD	=	0.0713	10.77
6	MC BS BE HD	=	0.0075	15.82	0.12	3.24	HC BS BE LD	=	0.0938	10.85
7	HC BS BE LD	=	0.0225	10.85	0.24	3.49	MC HS BE LD	=	0.1275	11.31
8	HC BS BE BD	=	0.0450	12.88	0.58	4.07	BC HS ZE LD	=	0.1500	11.44
9	HC BS BE HD	=	0.0075	14.47	0.11	4.18	BC BS ZE LD	=	0.1650	11.76
10	BC HS BE LD	=	0.0675	12.27	0.83	5.00	MC BS BE LD	=	0.1875	11.76
11	BC HS BE BD	=	0.1350	15.23	2.06	7.06	HC BS ZE BD	=	0.2025	11.89
12	BC HS BE HD	=	0.0225	17.09	0.38	7.45	HC HS ZE BD	=	0.2250	12.03
13	MC HS BE LD	=	0.0337	11.31	0.38	7.83	BC HS BE LD	=	0.2925	12.27
14	MC HS BE BD	=	0.0675	13.88	0.94	8.76	HC HS BE BD	=	0.3600	12.75
15	MC HS BE HD	=	0.0113	15.48	0.17	8.94	BC BS BE LD	=	0.4050	12.84
16	HC HS BE LD	=	0.0337	10.50	0.35	9.29	HC BS BE BD	=	0.4500	12.88
17	HC HS BE BD	=	0.0675	12.75	0.86	10.15	MC BS ZE BD	=	0.4650	12.99
18	HC HS BE HD	=	0.0113	14.14	0.16	10.31	MC HS ZE BD	=	0.4875	13.13
19	BC BS ZE LD	=	0.0150	11.76	0.18	10.49	HC BS ZE HD	=	0.4900	13.62
20	BC BS ZE BD	=	0.0300	14.31	0.43	10.92	HC HS ZE HD	=	0.4937	13.73
21	BC BS ZE HD	=	0.0050	16.50	0.08	11.00	MC HS BE BD	=	0.5612	13.88
22	MC BS ZE LD	=	0.0075	10.77	0.08	11.08	MC BS BE BD	=	0.6063	14.04
23	MC BS ZE BD	=	0.0150	12.99	0.19	11.28	HC HS BE HD	=	0.6175	14.14
24	MC BS ZE HD	=	0.0025	14.92	0.04	11.31	BC BS ZE BD	=	0.6475	14.31
25	HC BS ZE LD	=	0.0075	9.94	0.07	11.39	BC HS ZE BD	=	0.6925	14.45
26	HC BS ZE BD	=	0.0150	11.89	0.18	11.57	HC BS BE HD	=	0.7000	14.47
27	HC BS ZE HD	=	0.0025	13.62	0.03	11.60	MC BS ZE HD	=	0.7025	14.92
28	BC HS ZE LD	=	0.0225	11.44	0.26	11.86	MC HS ZE HD	=	0.7062	15.04
29	BC HS ZE BD	=	0.0450	14.45	0.65	12.51	BC HS BE BD	=	0.8412	15.23
30	BC HS ZE HD	=	0.0075	16.63	0.12	12.63	BC BS BE BD	=	0.9312	15.44
31	MC HS ZE LD	=	0.0113	10.52	0.12	12.75	MC HS BE HD	=	0.9425	15.48
32	MC HS ZE BD	=	0.0225	13.13	0.30	13.05	MC BS BE HD	=	0.9500	15.82
33	MC HS ZE HD	=	0.0038	15.04	0.06	13.10	BC BS ZE HD	=	0.9550	16.50
34	HC HS ZE LD	=	0.0113	9.74	0.11	13.21	BC HS ZE HD	=	0.9625	16.63
35	HC HS ZE BD	=	0.0225	12.03	0.27	13.48	BC HS BE HD	=	0.9850	17.09
36	HC HS ZE HD	=	0.0038	13.73	0.05	13.53	BC BS BE HD	=	1.0000	17.45

Table 2: Sensitivity Analysis

	Weighted Average EIRR	Probability of EIRR <10%
Basic Risk Analysis (for parameters see Table 1)	13.53%[1]	1.9%
Without Export Price Risk (Prob: BE=1,ZE=0)	13.75%	0
With Greater Demand Risk (Prob: LD=0.4, BD=0.5, HD=0.1)	13.44%	2.5%
With Greater Cost Overrun Risk (Prob: +30%=0.3,+60%=0.3)	12.92%	6.3%
With Greater Schedule Risk (Prob: HS=1.0)	13.45%	1.9%

[1]Note: EIRR in Central Case without risk = 15.44%.

Probability Distribution of EIRR



ANNEX 5.7
Attachment

NEPAL

ARUN III HYDROELECTRIC PROJECT

Data and Documents in the Project File

1. Nepal Electricity Authority joint venture Arun III Hydroelectric Project. Detailed engineering services. Project Formulation Report I: Volumes 1 and 2. May 1989.

2. HMG/N - Water and Energy Commission Secretariat. "Background Paper for Energy Issues and Options and Eighth Five Year Plan." Report No. 4/3/040989 1,1 Seq. 328. September 1989.

3. Nepal Electricity Authority Joint Venture Arun III Hydroelectric project. Construction Planning Study - Final Report, November 1990.

4. HMG/N- Ministry of Forests and Environment. Environmental Management and Sustainable Development in the Arun Basin (13 Volumes). Prepared by the King Mahendra Trust for Nature Conservation. October 1991.

5. IVO International, Vartaa, Finland. Power Exchange Between Nepal and India. Final Report. December 1991.

6. Argonne National Laboratory, Argonne, Illinois. Nepal: Analysis of the Electrical Generating System and the Upper Arun Hydroelectric Project. July 1992.

7. Nepal Electricity Authority/Joint Venture Arun III. Arun Access Road - Valley Alignment - Preliminary Design Report. Volume 1/2 - Main Report. September 1992.

7. Nepal Electricity Authority/Joint Venture Arun III. Engineering Design Report. November 1992.

9. Nepal Electricity Authority/Joint Venture Arun III. Access Road - Valley Alignment: Acquisition, Compensation and Rehabilitation Plan (ACRP). Inception Report. December 1992.

10. Nepal Electricity Authority. Report on Implementation of the Arun III HEP. January 1993.

11. Nepal Electricity Authority. Reform of the Nepal Electricity Authority. February 1993.

12. Nepal Electricity Authority. Arun III Hydroelectric Project Environmental Mitigation Plan. February 1993.

13. Nepal Electricity Authority. Arun III Hydroelectric Project. Environmental Assessment and Management. Executive Summary. April 1993.

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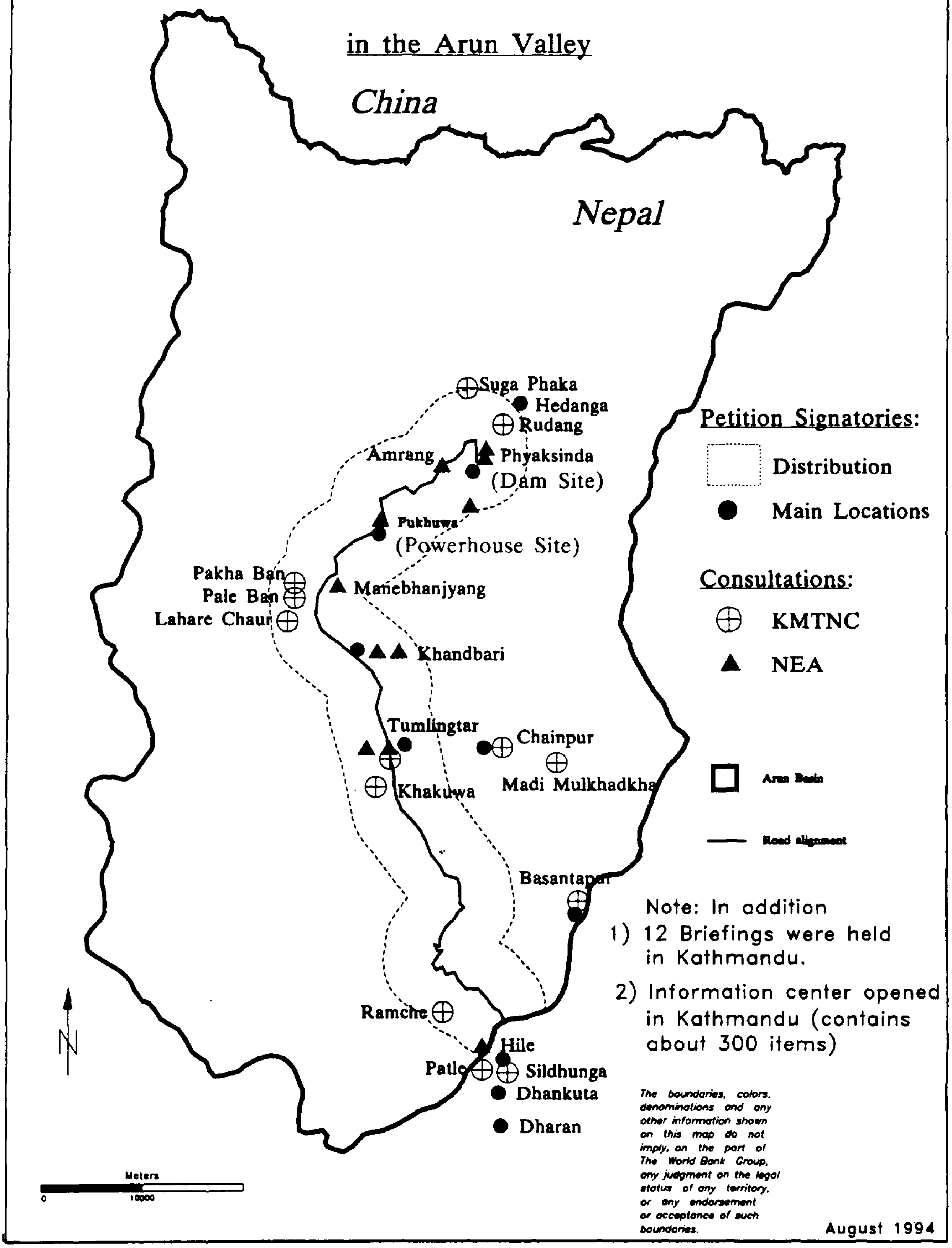
NEPAL: Arun III Hydroelectric Project

Public Consultations and Communications

in the Arun Valley



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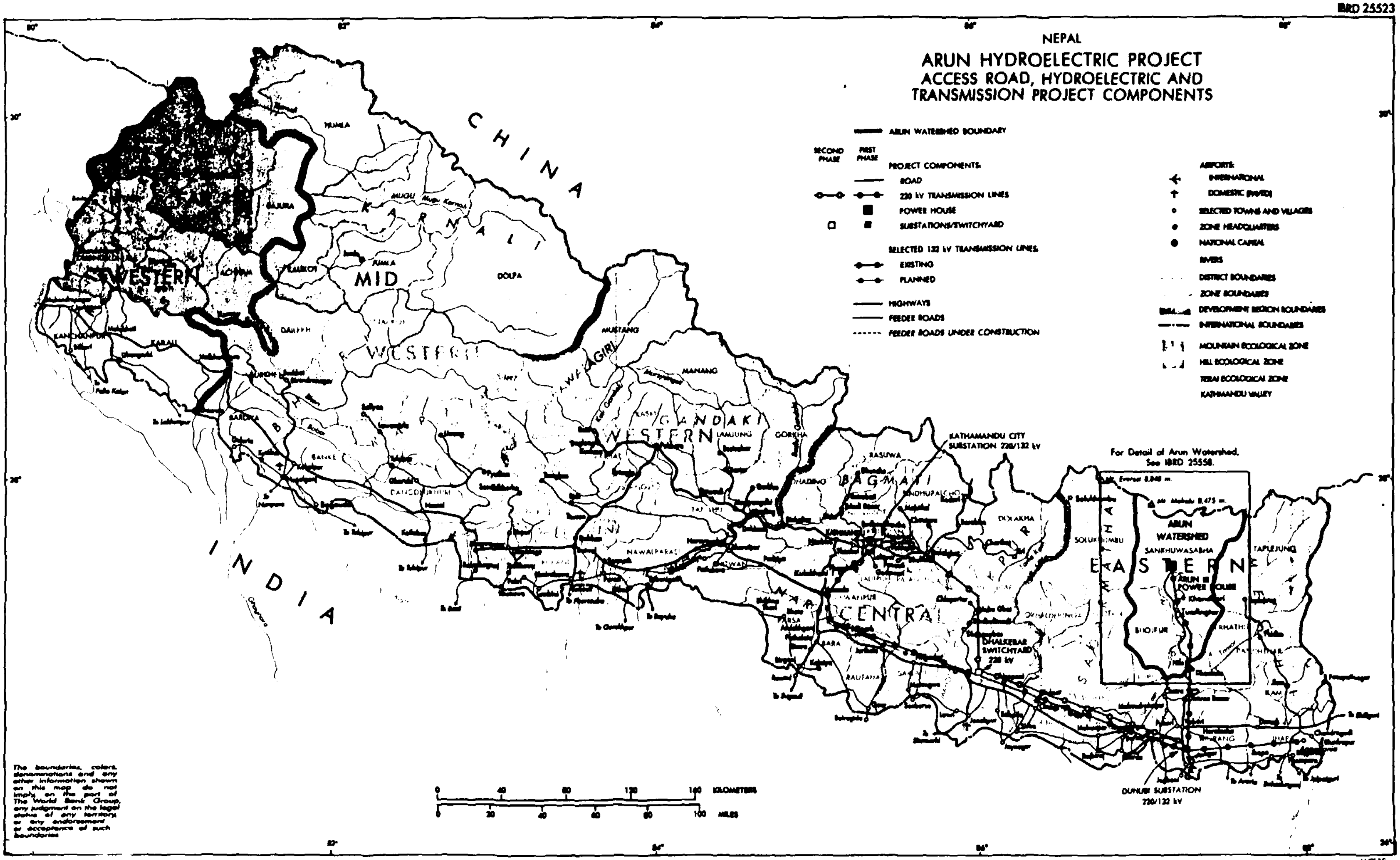
NEPAL
ARUN HYDROELECTRIC PROJECT
ACCESS ROAD, HYDROELECTRIC AND
TRANSMISSION PROJECT COMPONENTS
ARUN WATERSHED BOUNDARY
SECOND PHASE
FIRST PHASE
PROJECT COMPONENTS:
ROAD
220 kV TRANSMISSION LINES
POWER HOUSE
SUBSTATIONS/SWITCHYARD
SELECTED 132 kV TRANSMISSION LINES:
EXISTING
PLANNED
HIGHWAYS
FEEDER ROADS
FEEDER ROADS UNDER CONSTRUCTION
AIRPORTS:
INTERNATIONAL
DOMESTIC (PAVED)
SELECTED TOWNS AND VILLAGES
ZONE HEADQUARTERS
NATIONAL CAPITAL
RIVERS
DISTRICT BOUNDARIES
ZONE BOUNDARIES
DEVELOPMENT REGION BOUNDARIES
INTERNATIONAL BOUNDARIES
MOUNTAIN ECOLOGICAL ZONE
HILL ECOLOGICAL ZONE
TERAI ECOLOGICAL ZONE
KATHMANDU VALLEY
CHINA
INDIA
KARNALI
MID
WESTERN
FAR WESTERN
DHAWALAGIRI
GANDAKI
BAGMATI
CENTRAL
EASTERN
KATHMANDU CITY SUBSTATION 220/132 kV
For Detail of Arun Watershed, See IBRD 25558.
ARUN WATERSHED
SANKHUWASABHA
ARUN III POWER HOUSE
DHALKEBAR SWITCHYARD 220 kV
DUHABI SUBSTATION 220/132 kV
HUMLA
MUGU
JUMLA
DOLPA
MUSTANG
MANANG
GORKHA
RASUWA
DHADING
SINDHUPALCHOK
DOLAKHA
SOLUKHUMBU
TAPLEJUNG
BHOJPUR
NAWALPARASI
MAKWANPUR
PARSA
BARA
RAUTAHAT
ILAM
JHAPA
MORANG
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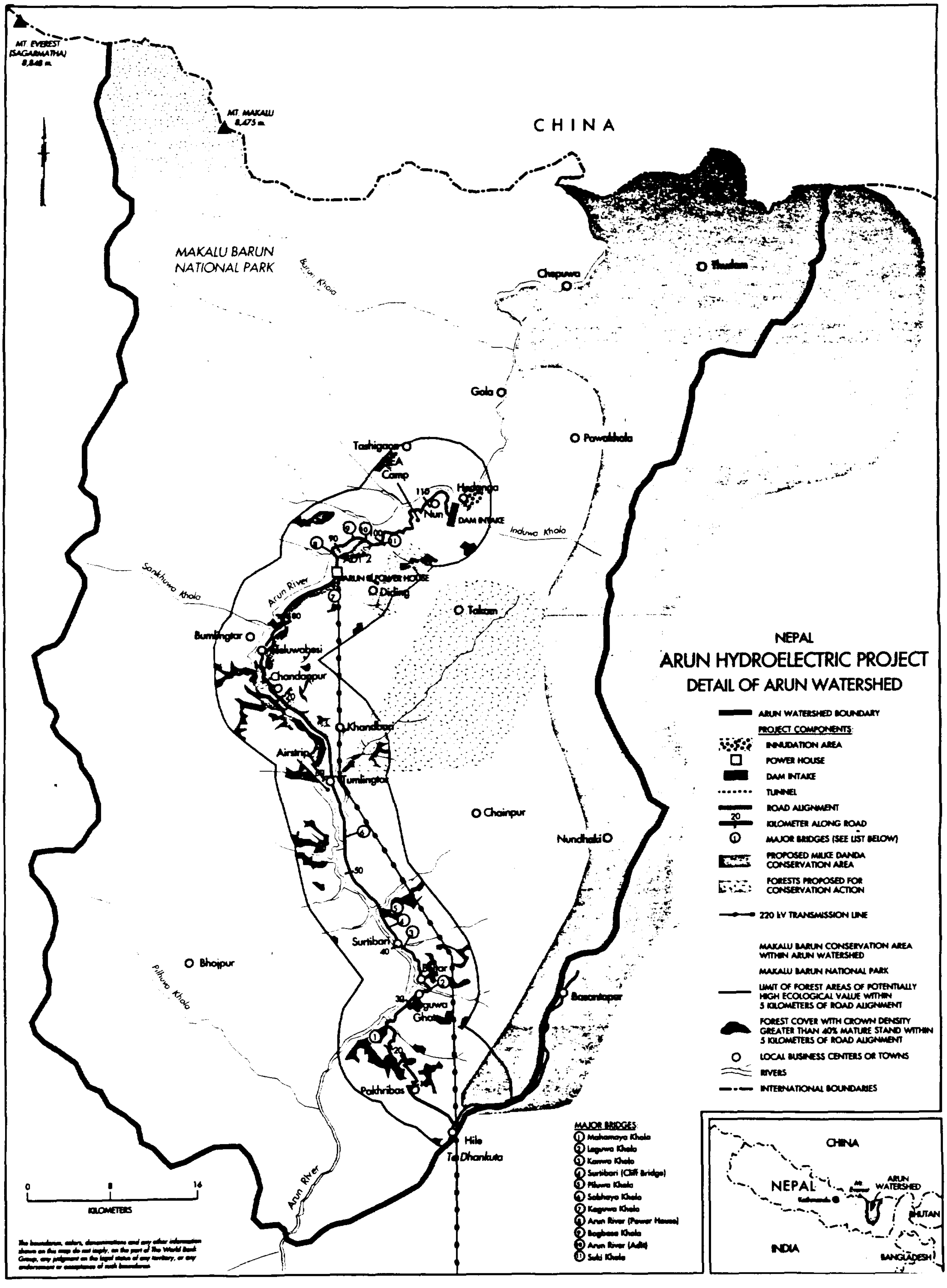

MAY 1994

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